Enclosure 3
PG&E Letter DCL-26-035

List of Information Redacted from Updated Final Safety Analysis Report, Revision 29 in Accordance with RIS 2015-17

List of Information Redacted from Updated Final Safety Analysis Report, Revision 29 in Accordance with RIS 2015-17

Information Withheld	Description
Figures 6.2-53, 6.2-54, 6.2-55, and 6.2-56	Containment subcompartment analyses drawings.
Figures 12.1-1, 12.1-2, 12.1-3, 12.1-4, 12.1-5, 12.1-6, 12.1-7, 12.1-8, 12.1-9, 12.1-10, 12.1-11, 12.1-12	Radiation zone maps that contain general arrangement features.

Enclosure 4
PG&E Letter DCL-26-035

Diablo Canyon Power Plant Updated Final Safety Analysis Report, Revision 29 (redacted), dated May 2026

Pacific Gas and Electric Company®

Diablo Canyon Power Plant Units 1 and 2

Final Safety Analysis Report Update

Revision 29 May 2026

Docket No. 50-275

Docket No. 50-323

DIABLO CANYON POWER PLANT
UNITS 1 AND 2

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Chapter 1

INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

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NOTE:

[a] This figure corresponds to a controlled engineering drawing that is incorporated by reference into the FSAR Update. See Table 1.6-1 for the correlation between the FSAR Update figure number and the corresponding controlled engineering drawing number.

CHAPTER 1

INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

1.1 INTRODUCTION

The Updated Final Safety Analysis Report (UFSAR) for the Diablo Canyon Power Plant (DCPP) is submitted in accordance with the requirements of 10 CFR 50.71(e) and contains all the changes necessary to reflect information and analyses submitted to the U.S. Nuclear Regulatory Commission (NRC) by Pacific Gas and Electric Company (PG&E) or prepared by PG&E pursuant to NRC requirements since the submittal of the original FSAR.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

The original FSAR was submitted in support of applications for permits to operate two substantially identical nuclear power units (Unit 1 and Unit 2) at the DCPP site. The DCPP site is located on the central California coast in San Luis Obispo County, approximately 12 miles west southwest of the city of San Luis Obispo.

The Construction Permit for Unit 1 (CPPR-39) was issued April 23, 1968, in response to PG&E's application dated January 16, 1967 (USAEC, Docket No. 50-275). The Construction Permit for Unit 2 (CPPR-69) was issued on December 9, 1970; the application was made on June 28, 1968 (USAEC, Docket No. 50-323).

Westinghouse Electric Corporation and PG&E jointly participated in the design and construction of each unit. The plant is operated by PG&E. Each unit employs a pressurized water reactor (PWR) nuclear steam supply system (NSSS) furnished by Westinghouse Electric Corporation and similar in design concept to several projects licensed by the NRC.

Certain components of the auxiliary systems are shared by the two units, but in no case does such sharing compromise or impair the safe and continued operation of either unit. Those systems and components that are shared are identified and the effects of the sharing are discussed in the chapters in which they are described (refer to Section 1.2.2.10).

The NSSS for each unit is contained within a steel-lined reinforced concrete structure that is capable of withstanding the pressure that might be developed as a result of the most severe postulated loss-of-coolant accident (LOCA).

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The containment structure was designed by PG&E to meet the requirements specified by Westinghouse Electric Corporation.

While the reactors, structures, and all auxiliary equipment are substantially identical for the two units, there is a difference in the reactor internal flow path that results in a lower coolant flow rate for Unit 1.

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Consequently, the original license application reactor ratings were 3,338 MWt for Unit 1 and 3,411 MWt for Unit 2. The corresponding net electrical outputs were approximately 1,084 MWe and 1,106 MWe, respectively.

During the design phase, the expected ultimate output of the Unit 1 reactor was 3,488 MWt; the expected ultimate output of the Unit 2 reactor was 3,568 MWt. The corresponding NSSS outputs were 3,500 MWt and 3,580 MWt. (The difference of 12 MWt is due to the net contribution of heat to the reactor coolant system (RCS) from nonreactor sources, primarily pump heat.) The corresponding estimated ultimate net electrical outputs were 1,131 MWe for Unit 1 and 1,156 MWe for Unit 2.

The NRC issued a low power-operating license for Unit 1 on September 22, 1981. PG&E voluntarily postponed fuel loading due to the discovery of design errors in the annulus region of the containment structure. Subsequently, the NRC suspended portions of the license on November 19, 1981, pending completion of an Independent Design Verification Program.

After completion of redesign and construction activities in November 1983, the NRC reinstated the fuel load portion of the Unit 1 low power-operating license. On April 19, 1984, the NRC fully reinstated the low power-operating license, which included low power testing. The Unit 1 full power-operating license was issued on November 2, 1984. Commercial operation for Unit 1 began on May 7, 1985, with a license expiration date of April 23, 2008.

The NRC issued a low power-operating license for Unit 2 on April 26, 1985. Unit 2 fuel loading was completed on May 15, 1985. A full power-operating license for Unit 2 was issued on August 26, 1985. Unit 2 commercial operation began on March 13, 1986, with a license expiration date of December 9, 2010.

In March 1996, the NRC approved license amendments extending the operating license for Unit 1 until September 22, 2021, and for Unit 2 until April 26, 2025.

In July 2006, the NRC approved license amendments extending the operating license for Unit 1 until November 2, 2024, and for Unit 2 until August 26, 2025.

In October 2000, the NRC approved a license amendment (LA) 143 to increase the Unit 1 rated reactor thermal power from the original value of 3,338 MWt to 3,411 MWt to increase production and be consistent with Unit 2. LA 143 also documented the evaluation performed to revise the net contribution of heat to the RCS from nonreactor

sources (primarily pump heat) to a nominal value of 14 MWt and established a NSSS power outlet of 3,425 MWt for both Unit 1 and Unit 2.

1.2 GENERAL PLANT DESCRIPTION

1.2.1 PRINCIPAL SITE CHARACTERISTICS

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

1.2.1.1 Location

The DCPP site consists of approximately 750 acres located in San Luis Obispo County, California, adjacent to the Pacific Ocean and roughly equidistant from San Francisco and Los Angeles. The site location, the site boundary, and the location of principal structures are shown in Figure 1.2-1. The minimum distance from either reactor to the nearest site boundary on land is one-half mile, the minimum exclusion distance. The low population zone (LPZ), as defined in 10 CFR 100.3, is the area immediately surrounding the exclusion area. For DCPP, the LPZ is an area encompassed by a radius of 6 miles. This zone contains residents for whom there is reasonable probability that appropriate protective measures, as described in the DCPP Emergency Plan (Reference 1) can be taken in the event of a serious accident. The population center distance, as defined by 10 CFR 100.3, is approximately 10 miles, the distance to the nearest boundary of the city of San Luis Obispo.

1.2.1.2 Topography

The plant site occupies a coastal terrace that ranges in elevation from 60 to 150 feet above sea level and is approximately 1000 feet wide. Plant grade is at elevation 85 feet. The seaward edge of the terrace is a near-vertical cliff. Back from the terrace and extending for several miles inland are the rugged Irish Hills, an area of steep, brush-covered hillsides and deep canyons that are part of the San Luis Mountains and attain an elevation of 1500 feet within about a mile of the site. Access to the site is by a private road from Avila Beach, a distance of nearly 8 miles.

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1.2.1.3 Meteorology

The climate of the site area is typical of that along the central California coast. In the dry season, mainly May through September, the Pacific Anticyclone stays off the California coast and prevents Pacific storms from moving eastward across the state. In the winter or wet season, November through March, the Pacific Anticyclone moves southward, weakening in intensity, and allows Pacific storms to enter the state. More than 80 percent of the average annual rainfall of 16 inches occurs during this 5-month period. April and October are considered transitional months. The average annual temperature of the site area is about 55°F, which reflects the strong maritime influence.

Most stations along the coast show a 5 to 10°F mean temperature difference between the coldest winter month and the warmest summer month. Extreme temperatures may

range from 104°F in the summer to as low as 24°F in the winter. However, the recurrence interval of days having these extremes is in the order of 5 to 10 years. Maximum summer temperatures of 85°F and minimum winter temperatures of 35°F are exceeded only 1 percent of the time at both Morro Bay and Pismo Beach. Additional site temperature data are presented in Section 2.3. The onsite meteorological measurements program was initiated in July 1967. Data collected are presented in Section 2.3 and are used to establish atmospheric diffusion characteristics of the site. Severe weather conditions, such as tornadoes and hurricanes, have not been recorded in this area. Thunderstorms are also a rare phenomenon with the average occurrence of lightning being less than 3 days per year.

1.2.1.4 Hydrology

Hydrological considerations at the plant site are limited to possible effects of plant operations on domestic water supplies and to the possibility of flooding. A survey of domestic water supplies in the environs shows that operation of the plant will not jeopardize any existing or planned facility. The topography of the site and the limited rainfall preclude any possibility of flooding.

1.2.1.5 Geology

A comprehensive geological investigation has demonstrated that the site is geologically suitable for a nuclear power plant. Foundations are on firm bedrock fully capable of carrying the loads. Movement along the few small breaks in the vicinity of the plant has not occurred for at least 100,000 years and may well have taken place millions of years ago. The site was investigated in detail for faulting and other possibly detrimental geologic conditions. Results of faulting investigations are discussed in Section 2.5.4.7 and are based on site geology data presented in Section 2.5.2.2. Landslides do not threaten the plant.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

1.2.1.6 Seismology

Seismological investigations were undertaken to determine the potential for earthquakes in the site area, to form a basis of the establishment of seismic design criteria, and to evaluate the adequacy of seismic design margins for the plant (refer to Section 2.5). Records indicate that seismic activity within 20 miles of Diablo Canyon has been very low compared to other parts of California. Until PG&E's seismological investigation of the Hosgri fault zone located approximately 3 miles offshore, the seismically significant fault system nearest the site was considered to be the Nacimiento Fault located about 20 miles away as discussed in Section 2.5.3.9. The largest earthquake known to have been associated with this fault system occurred at an epicentral distance to the site of about 44 miles. It is listed with a Richter magnitude 6. At its closest point, the San Andreas Fault passes some 48 miles from the site.

PG&E's reevaluation of the plant's capability to withstand a Richter magnitude 7.5 "Hosgri" Earthquake is discussed in Section 3.7.

1.2.1.7 Oceanography

Condenser cooling water for the plant is pumped from the Pacific Ocean and returned to the ocean at Diablo Cove through an outfall at the water's edge. Controlled releases of low-level liquid radioactive wastes are discussed in Section 11.2. The Pacific Ocean in the area of the site is turbulent and has a great capacity for dilution of wastes and diffusion of heated cooling water. Investigations of the occurrence and maximum size of tsunamis (seismic sea waves) coincident with high tide and with short period storm waves are discussed in Section 2.4.7. These studies showed that extreme water elevation within the intake basin without a breakwater would be 44.32 feet above mean lower low water. The intake structure houses the safety-related auxiliary cooling water systems, which are protected against tsunami and wave splash with watertight compartments. This is discussed in Section 2.4.6.7.

1.2.2 FACILITY DESCRIPTION

The plant incorporates two substantially identical PWR nuclear power units, each consisting of an NSSS, turbine-generator, auxiliary equipment, controls, and instrumentation. The general arrangement of the plant and the site is shown in Figure 1.2-1. Principal structures, shown in Figure 1.2-2, include the containment structures, turbine building, and auxiliary building (which includes the control room, the fuel handling areas, and the ventilation areas). Arrangement plans and sections are shown in Figures 1.2-3 through 1.2-32. The descriptions that follow apply to both units unless otherwise specified.

1.2.2.1 Design Criteria

The principal design criteria for the DCPP nuclear units are those fundamental architectural and engineering design objectives established for the plant. The bases for development and selection of the design criteria used in this plant are: (a) those that provide protection to public health and safety, (b) those that provide for reliable and economic plant performance, and (c) those that provide an attractive external appearance to the plant.

The essential systems and components of the plant are designed to enable the facility to withstand, without loss of capability to protect the public, the forces resulting from normal operation plus those that might be imposed by natural phenomena. The designs are based on the most severe of the natural phenomena recorded for the vicinity of the site, with margin to account for uncertainties in the historical data.

The DCPP units are designed to comply with the "General Design Criteria for Nuclear Power Plant Construction Permits," published in July 1967. A discussion of conformance to these criteria is contained in Section 3.1. In addition, a summary

discussion of the designs and procedures that are intended to meet the NRC General Design Criteria published as Appendix A to 10 CFR Part 50 in 1971 is provided in Chapter 3, Section 3.1, Appendix 3.1A.

1.2.2.2 Nuclear Steam Supply System

The NSSS consists of a PWR and associated auxiliary fluid systems. The RCS consists of four parallel reactor coolant loops, each containing a steam generator and a reactor coolant pump (RCP). A pressurizer is connected to the hot leg of one reactor coolant loop.

The reactor core is composed of an array of 193 fuel assemblies, each containing 264 fuel rods. These rods are composed of uranium dioxide pellets enclosed in zirconium alloy tubes with welded end plugs. All fuel rods are pressurized with helium during fabrication to reduce stress and increase fatigue life. Reactor control and shutdown functions are performed by the rod cluster control assemblies (RCCAs). The RCCAs are stainless steel tubes containing a silver-indium-cadmium absorber and are positioned by drive mechanisms of the magnetic latch type. A soluble poison (boron) is introduced into the reactor coolant to compensate for long-term reactivity changes. The moderator temperature coefficient can be slightly positive at the beginning of cycle when boron concentration is high. However, for most operating conditions, the moderator coefficient is non-positive, but the power coefficient is negative at all times.

The reactor vessel and reactor internals contain and support the fuel and RCCAs. The vessel is cylindrical with hemispherical heads and is clad with stainless steel.

The pressurizer is a vertical cylindrical pressure vessel with hemispherical heads and is equipped with electrical heaters and spray nozzles for system pressure control.

The steam generators are vertical U-tube type heat exchangers with Inconel tubes. Reactor coolant flows inside the tubes; steam is generated in the shell and flows through the main steam lines to the turbine. When operating at 100 percent power, integral moisture separating equipment reduces moisture content of the steam at the exit of the steam generators to ≤0.05 percent. Under transient conditions at ≤100 percent power, the moisture content at the exit of the steam generators is <0.25 percent. The RCPs are vertical, single-stage, centrifugal units equipped with controlled leakage shaft seals.

Auxiliary systems are provided to charge the RCS and add makeup water, to purify reactor coolant water, to provide chemicals for corrosion inhibition and reactor control, to cool system components, to remove residual heat when the reactor is shut down, to cool the spent fuel storage pool, to sample reactor coolant water, to provide for emergency safety injection, and to vent and drain the RCS. Refer to Chapters 4 and 5 for additional discussion of the reactor and RCS, respectively.

1.2.2.3 Engineered Safety Features

The engineered safety features (ESFs) provided for the DCPP have sufficient capacity and redundancy to protect the health and safety of the public by keeping exposure below the limits set forth in 10 CFR 50.67 for any of the postulated malfunctions or accidents, including the most severe LOCA (refer to Chapter 15 for additional discussion).
The ESFs provided in the DCPP are:

(1) A containment system that consists primarily of a steel-lined, reinforced concrete containment structure designed to prevent significant release to the environs of radioactive materials that could result from accidents inside the containment (refer to Sections 6.2.1 and 6.2.4).

(2) An emergency core cooling system (ECCS) that provides water to cool the core in the event of an accidental loss of primary reactor coolant water. The ECCS also supplies dissolved boron into the cooling water to provide shutdown margin (refer to Section 6.3).

(3) A containment spray system (CSS) to help limit the peak temperature and pressure in the containment in the event of a LOCA or main steam line break (MSLB) (refer to Section 6.2.2). The CSS, in conjunction with the spray additive system (SAS), also helps to limit the offsite radiation levels following the postulated LOCA by removing airborne fission products from the containment atmosphere during the injection and recirculation phase (refer to Section 6.2.2 and 6.2.3).

(4) A containment fan cooler system (CFCS) that functions in conjunction with the CSS to limit the temperature and pressure in the containment structure in the event of a LOCA or MSLB (refer to Section 6.2.2). The CFCS also provides mixing of the sprayed and unsprayed regions of the containment atmosphere to improve airborne fission product removal (refer to Section 6.2.3). The CFCS function of mixing the containment atmosphere for hydrogen control is discussed below.

(5) A SAS that functions by adding sodium hydroxide, an effective iodine scrubbing solution, to the CSS water, to reduce the content of iodine and other fission products in the containment atmosphere and prevent the re-evolution of the iodine in the recirculated core cooling solution following a LOCA (refer to Section 6.2.3).

(6) The long term buildup of gaseous hydrogen in the containment following a LOCA is primarily controlled by ensuring a mixed containment atmosphere and providing equipment for monitoring hydrogen concentrations. The CFCS and the CSS are the primary means credited for containment atmosphere mixing (refer to Section 6.2.5).

(7) A fuel handling building ventilation system provides a significant reduction in the amounts of volatile radioactive materials that could be released to the atmosphere in the event of a major fuel handling accident in the Fuel Handling Building (refer to Section 9.4.4). Note that the dose consequence analysis in Section 15.5 does not credit the filtration capability of the FHBVS.

(8) An auxiliary building ventilation system (ABVS) that provides the capability for significant reduction in the amounts of volatile radioactive materials that could be released to the atmosphere in the event of leakage from the residual heat removal system recirculation loop following a LOCA (refer to Section 9.4.2).

(9) A control room ventilation system (CRVS) permits continuous occupancy of the control room and technical support center (TSC) under design basis accidents by providing the capability to control infiltration of volatile radioactive material (refer to Sections 6.4.1 and 9.4.1).

(10) An auxiliary feedwater (AFW) system supplies water to the secondary side of the steam generators for reactor decay heat removal, when the main feedwater system is unavailable (refer to Section 6.5).

1.2.2.4 Instrumentation and Control

The primary purpose of the instrumentation and control system is to provide automatic protection against unsafe and improper reactor operation during steady state and transient power operation (ANS Conditions I, II, and III) and to provide initiating signals to mitigate the consequences of faulted conditions (ANS Condition IV). These plant conditions are discussed in Chapter 15, Accident Analysis.

The operation of the plant is monitored and controlled by operators in the control room, which is located in the auxiliary building.

Refer to Chapter 7 for additional discussion of the various instrumentation systems.

1.2.2.5 Electrical Systems

The electrical systems generate and transmit power to PG&E's high-voltage system, distribute power to the auxiliary loads, and provide control, protection, instrumentation, and annunciator power supplies for the units. Power is generated at 25-kV. Auxiliary loads are served at 12-kV, 4.16-kV, 480-V, 120-Vac, 125-Vdc, and 250-Vdc.

Offsite ac power (the preferred power supply) for the units' auxiliaries is available from two 230-kV transmission circuits and three 500-kV transmission circuits.

Onsite ac auxiliary power is supplied by each unit's main generator (normal onsite power source) and is also available for Class 1E loads from six diesel engine-driven generators (standby power supply). Three diesel generators are dedicated to each unit.

Onsite dc power is provided by three Class 1E and two non-Class 1E 125-Vdc batteries in each unit. The two non-Class 1E batteries are connected in series to provide 250-Vdc power in each unit.

Refer to Chapter 8 for additional discussion of the various electric power systems.

1.2.2.6 Power Conversion System

The turbines are each tandem-compound, four-element, 1800 rpm units, having one high-pressure and three identical double flow low-pressure elements. Combination moisture separator-reheaters are employed between the high- and low-pressure elements to dry and superheat the steam. The auxiliaries include deaerating surface condensers, steam jet air ejectors, motor-driven condensate pumps, motor-driven condensate booster pumps, turbine-driven main feedwater pumps, six stages of feedwater heating, and a full flow condensate demineralizer system.

The steam and power conversion system is designed to receive the heat generated by the RCS during normal power operation, as well as following an emergency shutdown of the turbine-generator from full load. Heat rejection under the latter condition is accomplished by steam bypass to the condenser and pressure relief to the atmosphere.

Refer to Chapter 10 for additional discussion of the steam and power conversion system.

1.2.2.7 Fuel Handling and Storage

The reactor is refueled using equipment designed to handle spent fuel under water from the time it leaves the reactor vessel until it is placed in a cask either for transport to the Diablo Canyon Independent Spent Fuel Storage Installation or for shipment from the site. Underwater transfer of spent fuel provides an optically transparent radiation shield, as well as a reliable source of coolant for removal of decay heat. Spent fuel is stored onsite in the spent fuel pools, which are fitted with special spent fuel storage racks to ensure that criticality cannot be approached. The fuel handling system (FHS) also provides capability for receiving, handling, and storing new fuel assemblies. Refer to Section 9.1.4 for additional discussion.

1.2.2.8 Auxiliary Systems

Auxiliary systems are supporting systems included in the facility, some of which are required to perform certain functions during emergency or accident conditions such as supporting the ESFs. Included are the cooling water systems (refer to Section 9.2), the heating and ventilating systems (refer to Section 9.4), the fire protection system (refer to Section 9.5.1), the process auxiliaries (refer to Sections 9.3.2, 9.3.3, and 9.3.7), the compressed air system (refer to Sections 9.3.1 and 9.3.6), the diesel generator fuel oil system (refer to Section 9.5.4), the communication systems (refer to Section 9.5.2), and the lighting systems (refer to Section 9.5.3).

1.2.2.9 Radioactive Wastes

The radioactive waste treatment systems provide all equipment necessary to collect, process, monitor, and discharge radioactive liquid, gaseous, and solid wastes that are produced during reactor operation. Refer to Sections 11.2, 11.3, and 11.5 for additional discussion. A major portion of the waste treatment equipment is common for Unit 1 and Unit 2. This equipment is located in the shared auxiliary building (refer to Section 1.2.2.10.5).

1.2.2.10 Shared Facilities and Equipment

Separate systems and equipment are provided for each unit, with few exceptions. A brief summary of shared facilities and equipment between both units follows. Interconnections between systems for Unit 1 and Unit 2 are shown in the system diagrams. The system diagrams are contained in the UFSAR chapters referenced in the following paragraphs.

1.2.2.10.1 Site Facilities

The two units share a common auxiliary building (refer to Section 3.8.2.3). The turbine building is common to both units (refer to Section 3.8.3). The machine shop, access control area, warehouse area, telecommunications systems (refer to Figure 9.5-1), and administrative offices are common.

The two units also share a common raw water storage reservoir (refer to Section 6.5.3.3), fire pumps (refer to Section 9.5.1), fire water storage tank (refer to Section 9.5.1), diesel fuel oil storage tanks and transfer pumps (refer to Section 9.5.4.3.3), auxiliary boiler (refer to Section 9.3.7.1.3.3), makeup water system (refer to Section 9.2.3.3.3), plant air system (refer to Sections 9.3.1.3.3 and 9.3.6.3.3), and lubricating oil storage system.

Refer to Section 9.1.4.3.2 for a discussion of sharing of the FHS. Refer to Section 9.3.3.3.2 for a discussion of sharing of the equipment and floor drainage system.

1.2.2.10.2 Electrical Systems

The 230-kV line from the 230-kV switchyard serves the standby startup transformers for both Unit 1 and Unit 2. These are normally arranged on the low voltage sides to serve a single unit; however, the 12-kV buses for Unit 1 and Unit 2 are connected by an open circuit breaker (refer to Sections 8.2.3.1 and 8.3.1.1.2.3.2, respectively).

The plant has six diesel generator sets for emergency power. Refer to Section 8.3.1.1.6.3.3 for a discussion of sharing of diesel generator support systems.

Refer to Section 8.3.1.1.4.3.3 for a discussion of sharing of the 480-V system. Refer to Section 8.3.1.1.5.3.3 for a discussion of sharing of the 120-Vac system. Refer to Section 8.3.2.3.3 for a discussion of sharing of the 125-Vdc system.

1.2.2.10.3 Control Room

The plant is provided with a central control room located in the auxiliary building which is common to Unit 1 and Unit 2. Physical separation of control panels prevents interaction of the Unit 1 and Unit 2 control systems. Refer to Section 6.4.1.3.3 for a discussion of the common CRVS and common control room pressurization system, and Section 9.4.1.3.3 for a discussion of the common control room heating, ventilation and air-conditioning (HVAC) system.

Refer to Section 5.1.8.3 for a discussion of sharing of the RCP vibration monitoring system.

1.2.2.10.4 Chemical and Volume Control System

Several components of the chemical and volume control system are shared, as detailed in Chapter 9 (refer to Section 9.3.4.3.3).

1.2.2.10.5 Radioactive Waste Treatment Systems

The major portion of the waste treatment equipment is shared by Unit 1 and Unit 2. This equipment is located in the shared auxiliary building and is described in Chapter 11 (refer to Sections 11.2.3.3, 11.3.3.3, and 11.5.3.2).

1.2.2.10.6 Emergency Facilities and Equipment

The emergency facilities and equipment, both onsite and offsite, are discussed in the Emergency Plan which applies to both Unit 1 and Unit 2. For a discussion of the TSC habitability and HVAC systems (refer to Sections 6.4.2.3.1, 9.4.1.3.3, and 9.4.11.3.1).

1.2.2.10.7 Other Systems

Refer to Sections 9.2.6.3.3 and 6.5.3.3 for a discussion of the sharing of the condensate storage tanks.

Refer to Section 9.2.2.3.3 for a discussion of the sharing of the component cooling water system.

Refer to Section 9.2.7.3.3 for a discussion of the sharing of the auxiliary saltwater system.

Refer to Section 9.2.1.3.1 for a discussion of the sharing of the service cooling water system.

Refer to Section 9.2.5.3.2 for a discussion of the sharing of the ultimate heat sink system.

Refer to Section 9.4.23.3 for a discussion of the sharing of the ABVS.

Refer to Section 6.5.3.3 for a discussion of the sharing of the AFW system.

Refer to Section 10.3.3.3 for a discussion of the sharing of the main steam system.

1.2.3 REFERENCES

1. Emergency Plan, Diablo Canyon Power Plant - Units 1 and 2, Pacific Gas and Electric Company.

1.2.4 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

1.3 COMPARISON TABLES

1.3.1 COMPARISON WITH SIMILAR FACILITY DESIGNS

Table 1.3-1 presents a comparison of the principal similarities and differences of the design of the DCPP units with those of Unit 1 at Trojan Nuclear Power Plant and Unit 1 and Unit 2 at Zion Station. This comparison is historical in nature and is valid only through March 1984.

1.3.2 COMPARISON OF FINAL AND PRELIMINARY DESIGNS

Table 1.3-2 identifies the major design changes made since the submittal of the DCPP Unit 2 Preliminary Safety Analysis Report. The comparison was considered to be valid through July 1974.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

1.4 IDENTIFICATION OF AGENTS AND CONTRACTORS

PG&E is the architect engineer, constructor, operator, and owner of DCPP and, as such, assumes full responsibility and authority for the design, construction, startup, and operation of Diablo Canyon Unit 1 and Unit 2. This section identifies the principal consultants, the nuclear steam system supplier, the suppliers of other equipment affecting nuclear safety, and the principal contractors engaged in the construction of the units. PG&E has performed all work for the planning, design, estimating, procurement, construction, installation, inspection, testing, and associated services necessary to provide complete plans and specifications and related services necessary to furnish a complete, operable, and acceptable plant, except for those items and functions that were furnished by those mentioned below.

1.4.1 CONSULTANTS

The consultants whose contracts exceed one hundred thousand dollars are listed in Table 1.4-1. The list is historical in nature and is valid only through March 1986. They performed investigations and submitted reports and recommendations to PG&E on the subjects indicated in the table. Application of the material submitted is the responsibility of PG&E.

1.4.2 NUCLEAR STEAM SUPPLY SYSTEM SUPPLIER

The NSSS was designed and furnished by the Westinghouse Electric Corporation. Westinghouse performed the detailed engineering design for all Westinghouse-supplied components and systems of the NSSS and procured, expedited, inspected, and delivered to PG&E all such equipment and components. Westinghouse provided design criteria, outline and/or assembly drawings, systems flow diagrams, and other data, as required, for PG&E to install, erect, operate, and maintain Westinghouse-supplied equipment and components. For all Westinghouse-supplied nuclear auxiliary systems, Westinghouse performed systems engineering, prepared reference designs and systems descriptions, and provided overall operating and engineering instructions.

Westinghouse further provided pertinent design criteria and data on the NSSS to enable PG&E to design the balance of plant. Westinghouse provided functional test procedures and technical assistance during construction, installation, inspections, and testing of its equipment and systems. A description of Westinghouse-provided technical assistance is given in Chapter 14, Initial Tests and Operations.

Westinghouse also performed the post-accident transient analysis of the plant containment system. This analysis consisted of determining the mass and energy releases (including metal-water reaction) as a function of time for the design basis LOCA and MSLB. From the foregoing data, PG&E has determined the design pressure and temperature, containment volume cooling requirements, etc. In general, Westinghouse has performed such transient analyses on the plant as are required for

the Westinghouse-furnished NSSS and turbine-generator unit. Transient analyses involving non-Westinghouse-supplied systems and components are PG&E's responsibility.

Westinghouse also supplied material that is informational in nature, some of which appears in response to questions asked of Westinghouse during review meetings. Other information and recommendations have been offered by Westinghouse from their background experience. This type of material is not contractually binding for either company, nor was it intended to be a commitment of final design or operation. This material includes:

(1) The conceptual design of the dry reactor containment system. The specific designs of the reactor containment structure and associated ESFs are developed by PG&E.

(2) The details of a recommended waste disposal system that consists of equipment to collect, process, and dispose of radioactive liquid, gaseous, and solid wastes produced as a result of reactor operation

(3) Five recommended ESFs that consist of: steel-lined concrete reactor containment vessel, the safety injection system, the containment fan coolers, the containment spray equipment, and the air recirculation filters. Emergency power systems to operate the ESF systems are also as recommended by Westinghouse.

(4) The details of the recommended fuel handling facilities including structures, equipment, transfer, and operation

(5) The details of the recommended sampling system and analytical facilities

(6) The details of the recommended radiation shielding

(7) The outline of a recommended health physics program and recommended supplies

(8) The general criteria and preliminary design data for certain balance of plant.

Westinghouse, as a supplier to PG&E, is required to conform to the PG&E Quality Assurance Program as described in Chapter 17, Quality Assurance.

1.4.3 OTHER EQUIPMENT SUPPLIERS

Suppliers of important equipment or materials furnished to PG&E are listed in Table 1.4-2. In each case, the equipment was fabricated, or the material supplied qualified, to written specifications and, if PG&E Design Class I, under the Quality

Assurance Program in effect at the time of purchase. This list of suppliers is historical in nature and is valid only through March 1986.

1.4.4 CONSTRUCTION AND INSTALLATION CONTRACTORS

The principal construction and installation contractors whose contracts exceed one hundred thousand dollars are listed in Table 1.4-3. The list of contractors is historical in nature and is valid only through March 1986. The contracts are agreements between PG&E as owner-constructor and the contractors as independent contractors, with specific provisions for inspection, testing, and quality assurance.

Each contract specification identifies any PG&E Design Class I equipment involved and requires the implementation of the supplier's Quality Assurance Program (refer to Chapter 17, Quality Assurance). In addition, PG&E maintains a staff of inspectors to assure the quality of non-Class I equipment installation.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

1.5 REQUIREMENTS FOR FURTHER TECHNICAL INFORMATION

The design of DCPP is based on proven concepts, systems, and equipment in order to minimize the potential for cost and schedule overruns and to enhance the reliability of operation. As a consequence, there have been few requirements for research and development programs to confirm the adequacy of the design. Those programs identified for DCPP have been satisfactorily completed, as well as any other programs that have been identified as valuable to define margins of conservatism or possible design improvements. Table 1.5-1 is a list of those programs that have been addressed in earlier revisions of the original FSAR. This table provides a listing of the technical reports that include a discussion of the programs and their results. The listing is historical in nature and is valid only through November 1975.

1.6 MATERIAL INCORPORATED BY REFERENCE

1.6.1 WESTINGHOUSE TECHNICAL REPORTS

	Title	Section Reference	Date Submitted To AEC/NRC
1.	C. J. Kubit, Safety-Related Research and Development for Westinghouse Pressurized Water Reactors, Program Summaries-Fall, 1971-Spring, 1972, WCAP-7856, April 1972.	1.5	5/9/72
2.	F. T. Eggleston, Safety-Related Research and Development for Westinghouse PWRs, Program Summaries. Winter 77 - Summer 78, WCAP-8768, Revision 2, October 1978.	1.5, 4.2	10/78
3.	R. M. Hunt, Safety-Related Research and Development for Westinghouse PWRs, Program Summaries. Fall 1970, WCAP-7614-L, November 1970.	1.5	11/70
4.	R. M. Hunt, Safety-Related Research and Development for Westinghouse PWRs, Program Summaries. Spring 1970, WCAP-7498-L, May 1970.	1.5	5/70
5.	M. D. Davis, Safety-Related Research and Development for Westinghouse PWRs, Program Summaries. Fall 1974, WCAP-8485, March 1975.	1.5	3/75
6.	C. J. Kubit, Safety-Related Research and Development for Westinghouse PWRs, Program Summaries. Spring 1974, WCAP-8385, July 1974.	1.5	7/74
7.	Deleted		
8.	J. M. Hellman, Fuel Densification Experimental Results and Model for Reactor Operation, WCAP-8218-P-A, March 1975 (Proprietary) and WCAP-8219-A, March 1975 (Non-Proprietary).	1.5	3/75
9.	L. Geninski, et al, Safety Analysis of the 17 x 17 Fuel Assembly for Combined Seismic and Loss-of-Coolant Accident, WCAP-8288, December 1973.	1.5	12/73

	Title	Section Reference	Date Submitted To AEC/NRC
10.	E. E. DeMario and S. Nakazato, Hydraulic Flow Test of the 17 x 17 Fuel Assembly, WCAP-8279, February 1974.	1.5	2/74
11.	F. W. Cooper, Jr., 17 x 17 Drive Line Components Test - Phase IB, II, III - Drop and Deflection, WCAP-8446, December 1974.	1.5	12/74
12.	K. W. Hill, et al, Effect of 17 x 17 Fuel Assembly Geometry on DNB, WCAP-8296-P-A, February 1975 (Proprietary) and WCAP-8297-A, February 1975.	1.5	2/75
13.	F.E. Motley, et al, The Effect of 17 x 17 Fuel Assembly Geometry on Interchannel Thermal Mixing, WCAP-8298-P-A (Proprietary) and WCAP-8299-A, January 1975.	1.5	1/75
14.	A. J. Burnett and S. D. Kopelic, Westinghouse ECCS Evaluation Model October 1975 Version, WCAP-8622 (Proprietary) and WCAP-8623 (Non-Proprietary), November 1975.	1.5	11/75
15.	Irradiation of 17 x 17 Demonstration Assemblies in Surry Units No.1 and 2, Cycle 2, WCAP-8262, July 1974.	1.5	7/74
16.	G.J. Bohm, Indian Point Unit 2 Internals Mechanical Analysis for Blowdown Exitation, WCAP-7822, December 1971.	3.9	12/20/71
17.	P. M. Wood, et al, Use of Burnable-Poison Rods in Westinghouse Pressurized Water Reactors, WCAP-7113, October 1967.	3.9	11/6/67
18.	R. F. Barry, et al, Power Distribution Monitoring in the R. E. Ginna PWR, WCAP-7756, September 1971.	3.9	10/5/71
19.	L. T. Gesinski, Fuel Assembly Safety Analysis for Combined Seismic and Loss-of-Coolant Accident, WCAP-7950, July 1972.	3.9	7/14/72
20.	Deleted		

Title	Section Reference	Date Submitted To AEC/NRC
21. Deleted		
22. S. Kraus, Neutron Shielding Pads, WCAP-7870 including Appendix B, February 1972.	4.2	2/17/72
23. Deleted in Revision 23.		
24. A. F. McFarlane, Power Peaking Factors, WCAP-7912-P-A, January 1975 (Westinghouse Proprietary) and WCAP-7912-A, January 1975.	4.3, 4.4	3/8/72
25. J. A. Christensen, et al, Melting Point of Irradiated Uranium Dioxide, WCAP-6065, February 1965.	4.2, 4.4	2/65
26. G. Hetsroni, Hydraulic Tests of the San Onofre Reactor Model, WCAP-3269-8, June 1964.	4.4	6/64
27. G. Hetsroni, Studies of the Connecticut-Yankee Hydraulic Model, WCAP-2761, June 1965, (NYO-3250-2).	4.4	6/65
28. J. S. Shefcheck, Application of the THINC Program to PWR Design, WCAP-7359-L, August 1969 (Westinghouse Proprietary) and WCAP-7838, January 1972.	4.4, 15.1, 15.2, 15.4	1/17/72
29. F. D. Carter, Inlet Orificing of Open PWR Cores, WCAP-9004, (Westinghouse Proprietary), January 1969, and WCAP-7836, January 1972.	4.4	3/19/69 1/17/72
30. J. A. Nay, Process Instrumentation for Westinghouse Nuclear Steam Supply System, WCAP-7671, April 1971.	5.2, 7.1, 7.2, 7.3	5/10/71
31. W. O. Shabbits, Dynamic Fracture Toughness Properties of Heavy Section-A-533 Grade B Class I Steel Plate, WCAP-7623, September 1972.	5.2	9/15/72
32. W. S. Hazelton, et al, Basis for Heatup and Cooldown Limit Curves, WCAP-7924, July 1972.	5.2	8/14/72
33. Deleted		
34. J. Locante and E. G. Igne, Environmental Testing of	6.3	9/14/71

	Title	Section Reference	Date Submitted To AEC/NRC
	Engineered Safety Features Related Equipment (NSSS-Standard Scope), WCAP-7744, Volume 1, August 1971.		
35.	J. B. Lipchak and R. A. Stokes, Nuclear Instrumentation System, WCAP-7669, April 1971.	7.1, 7.2, 7.7	5/6/71
36.	D. N. Katz, Solid State Logic Protection System Description, WCAP-7672, June 1971.	7.1, 7.2, 7.3	5/27/71
37.	J. T. Haller, Engineered Safeguard Final Device or Activator Testing, WCAP-7705, February 1973.	7.1	2/27/73
38.	Deleted		
39.	R. Bartholomew and J. Lipchak, Test Report, Nuclear Instrumentation System Isolation Amplifier, WCAP-7819, Revision 1, January 1972.	7.2	1/17/72
40.	W. C. Gangloff, An Evaluation of Anticipated Operational Transients in Westinghouse Pressurized Water Reactors, WCAP-7486, May 1971.	7.2, 15.2	5/21/71
41.	T. W. T. Burnett, Reactor Protection System Diversity in Westinghouse Pressurized Water Reactors, WCAP-7306, April 1969.	7.2, 15.4	4/9/69
42.	A. E. Blanchard, Rod Position Monitoring, WCAP-7571, March 1971.	7.7	4/5/71
43.	J. J. Loving, In-Core Instrumentation (Flux Mapping System and Thermocouples), WCAP-7607, July 1971.	7.7	7/27/71
44.	H.G. Hargrove, FACTRAN, A Fortran IV Code for Thermal Transients in a UO_2 Fuel Rod, WCAP-7908-A, December 1989.	15.1,15.2, 15.3,15.4	11/29/83
45.	Deleted in Revision 22		
46.	Deleted in Revision 22		

	Title	Section Reference	Date Submitted To AEC/NRC
47.	T. W. T. Burnett, et al, LOFTRAN Code Description, WCAP-7907-P-A (Proprietary), April 1984 and WCAP-7907-A (Non-Proprietary), April 1984.	15.1,15.2, 15.3,15.4	10/11/72
48.	R. F. Barry, LEOPARD - A Spectrum Dependent Non-Spatial Depletion Code for the IBM-7094, WCAP-3269-26, September 1963.	4.3	9/63
49.	S. Altomare and R. F. Barry, The TURTLE 24.0 Diffusion Depletion Code, WCAP-7213-P-A, February 1975 (Westinghouse Proprietary) and WCAP-7758-A, February 1975.	4.3	6/68, 9/71
50.	D. H. Risher, Jr. and R. F. Barry, TWINKLE - A Multi-Dimensional Neutron Kinetics Computer Code, WCAP-7979-P-A (Proprietary) and WCAP-8028-A (Non-Proprietary), January 1975.	15.1,15.2, 15.4	1/4/73
51.	Deleted in Revision 22		
52.	Deleted		
53.	M. Ko, Setpoint Study for PG&E Diablo Canyon Units 1 and 2, WCAP-8320, June 1974.	15.1	6/74
54.	F. W. Cooper, Jr., 17x17 Drive Line Components Tests Phase IB-II-III D-Loop Drop and Deflection, WCAP-8446 (Proprietary) and WCAP-8449 (Non-proprietary), (December 1974).	15.1	12/74
55.	J. V. Miller (Ed.), Improved Analytical Methods Used in Westinghouse Fuel Rod Design Calculations, WCAP-8720, October 1976.	4.2	10/76
56.	F. E. Motley and F. F. Cadek, DNB Test Results for New Mixing Vane Grids (R), WCAP-7695-P-A (Proprietary) and WCAP-7958-A (Non-Proprietary), January 1975.	4.4	1/75

	Title	Section Reference	Date Submitted To AEC/NRC
57.	Cooper, et al., Overpressure Protection for Westinghouse Pressurized Water Reactors, WCAP-7769, Revision 1, June 1972.	5.2, 15.2	10/8/71
58.	D.S. Huegel, et al, RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, WCAP-14882-P-A (Proprietary), April 1999 and WCAP-15234-A (Non-Proprietary), May 1999.	6.2D, 15.1, 15.2, 15.4	6/6/97
60.	T. Q. Nguyen, et al, Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores, WCAP-11596-P-A (Proprietary),June 1988.	4.3, 15.1	11/87
61.	Y. S. Liu, et al, ANC: A Westinghouse Advanced Nodal Computer Code, WCAP-10965-P-A (Proprietary), September 1986 and WCAP-10966-A (Non-Proprietary), September 1986.	4.3, 15.1, 15.3	5/86
65.	J. C. Schmertz, et al, Technical Justification for Eliminating Large Primary Loop Rupture as the Structural Design Basis for the Diablo Canyon Units 1 and 2 Nuclear Power Plants, WCAP-13039 (Proprietary) and WCAP-13038 (Non-proprietary), November 1991.	3.6	3/92
66.	J.R. Kobelak, et al, Realistic LOCA Evaluation Methodology Applied to the Full Spectrum of Break Sizes (FULL SPECTRUM LOCA Methodology), WCAP-16996-P-A, Revision 1, November 2016.	15.1, 15.4	11/23/2010

1.6.2 MISCELLANEOUS TECHNICAL REPORTS

	Title	Section Reference
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2.	C. R. Dickson, et al, "Aerodynamic Effects of the EBR-II Containment Vessel Complex on Effluent Concentration," Proc. of the AEC Meteor. Inf. Meeting at Chalk River, Ontario, September 11-14, 1967, pp. 87-104.	2.3(1)
3.	J. G. Edinger, "The Influence of Terrain and Thermal Stratification of Flow Across the California Coastline," AFCRL-TR-60-438, Final Report, Contract No. AF(604)-5212, University of California, Los Angeles, 1960	2.3(1)
4.	P. A. Leighton, "Geographic Aspects of Air Pollution," Geographic Review, LVI, No. 2, 1966, pp. 153-174.	2.3(1)
5.	J. C. Ulberg, "Meteorological Data for Predicting Inhalation Hazards from Space Unit Launch Operations at Point Arguello," USNRDL-TR-1112, U.S. Naval Radiological Defense Laboratory, San Francisco, Ca., 1966, pp. 83.	2.3(1)
6.	H. E. Cramer, et al, "Meteorological Prediction Techniques and Data System," Final Report Contract No. DA-42-007-CML-552, U.S. Army, Dugway Proving Ground, Dugway, Utah, 1964.	2.3(1)
7.	F. Pasquill, Atmospheric Diffusion, D. Van Nostrand Company, Ltd., London, 1962, pp. 190.	2.3
8.	R. A. Dean, "Thermal Contact Conductance Between $U0_2$ and Zircaloy-2," CVNA-127, May, 1962.	4.4
9.	A. M. Ross and R. L. Stoute, "Heat Transfer Coefficient Between $U0_2$ and Zircaloy-2," NRCL-1552, June, 1962.	4.4
10.	L. S. Tong, "Prediction of Departure from Nucleate Boiling for an Auxiliary Non-Uniform Heat Flux Distribution," Journal of Nuclear Energy, Vol. 21, 1967, pp. 241-248.	4.4

	Title	Section Reference
11.	J. Weisman, et al, "Experimental Determination of the Departure from Nucleate Boiling in Large Rod Bundles at High Pressure," Chem, Eng., Prog. Sump. Ser., 64, No. 82, 1968, pp. 114-125.	4.4
12.	L. S. Tong, et al, "Critical Heat Flux (DNB) in Square and Triangular Array Rod Bundles," JSME, Semi-International Symposium, Paper No. 256, Tokyo, Japan 1967	4.4
13.	L. A. Stephan, The Effects of Cladding Material and Heat Treatment on the Response of Waterlogged $U0_2$ Fuel Rods to Power Bursts, IN-ITR-111, January, 1970.	4.4
14.	Deleted	
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16.	M. A. Styrikovich, et al, Atomnoya Energya, Vol. 17, No. 1, July 1964, pp. 45-49, (Translation in UD 621.039.562.5)	6.2
17.	W. F. Pasedag and J. L. Gallagher, "Drop Size Distribution and Spray Effectiveness," Nuclear Technology, 10, 1971, p. 412.	6.2
18.	L. F. Parsly, Design Considerations of Reactor Containment Spray Systems, ORNL-TM-2412, Part VII, 1970.	6.2
19.	W. D. Fletcher, et al, "Post-LOCA Hydrogen Generation in PWR Containments," Journal of American Nuclear Society, June 1970.	6.2
20.	W. D. Fletcher, et al, "Post-LOCA Hydrogen Generation in PWR Containments," Nuclear Technology 10, 1971, pp. 420-427.	6.2
21.	H. E. Zittel, Radiation and Thermal Stability of Spray Solutions, ORNL-NSRD Program Bi-Monthly Report for May-June, 1969. ORNL-TM-2663, September 1969.	6.2
22.	W. B. Cottrell, ORNL Nuclear Safety Research and Development Program Bi-Monthly Report for July-August 1968, ORNL-TM-2368, November 1968.	6.2

	Title	Section Reference
23.	W. B. Cottrell, ORNL Nuclear Safety Research and Development Program Bi-Monthly Report for September-October 1968, ORNL-TM-2425, p. 53, January 1969.	6.2
24.	H. E. Zittel and T. H. Row, "Radiation and Thermal Stability of Spray Solutions," Nuclear Technology, 10, 1971, pp. 436-443.	6.2
25.	A. O. Allen, The Radiation Chemistry of Water and Aqueous Solutions, Princeton, N.J., Van Nostrand, 1961.	6.2
26.	Deleted	
27.	Deleted	
28.	E. A. J. Eggleton, A Theoretical Examination of Iodine-Water Partition Coefficients, AERE(R)-4887, 1967.	6.2
29.	M. E. Meek and B. F. Rider, Summary of Fission Product Yields for U-235, U-238, Pu-239, and Pu-241 at Thermal, Fission Spectrum and 14 Mey Neutron Energies, APED-5398, March 1, 1968.	11.1
30.	J. J. DiNunno, et al, Calculation of Distance Factors for Power and Test Reactor Sites, TID-14844, March 23, 1962.	6.2, 11.1
31.	J. O. Blomeke and M. F. Todd, Uranium-235 Fission - Product Production as a Function of Thermal Neutron Flux, Irradiation Time, and Decay Time, ORNL-2127, August 19, 1957.	11.1
32.	F. J. Perkins and R. W. King, "Energy Release from the Decay of Fission Products," Nuclear Science and Engineering,1958.	11.1
33.	D. F. Toner and J. S. Scott, Fission Product Release from UO_2 Nuclear Safety, Volume 3, No. 2, December 1961.	11.1
34.	J. Belle, "Uranium Dioxide: Properties and Nuclear Applications," Naval Reactor, DRD of NRC, 1961.	11.1

	Title	Section Reference
35.	S. G. Gillespie and W. K. Brunot, "EMERALD NORMAL - A Program for the Calculation of Activity Releases and Doses from Normal Operation of a Pressurized Water Plant," Program Description and User's Manual, Pacific Gas and Electric Company, January 1973. (Provided to AEC in 1973.)	11.1, 11.2, 11.3, 12.1, 15.5
36.	Deleted in Revision 1.	
37.	A. B. Sisson, et al, "Evaluation for Removal of Radio-nuclides from PWR Steam Generator Blowdowns," International Water Conference, November 2, 1971.	11.2
38.	Deleted	
39.	Deleted	
40.	Deleted	
41.	W. K. Brunot, EMERALD - A Program for the Calculation of Activity Releases and Potential Doses From a Pressurized Water Reactor Plant, Pacific Gas and Electric Company, October 1971. (Provided to AEC in 1971.)	6.2
42.	L. S. Tong, "Prediction of Departure from Nucleate Boiling for an Axially Non-Uniform Heat Flux Distribution," J. Nuclear Energy, 21, 1967, pp. 241-248.	4.4
43.	F. W. Dittus and L. M. K. Boelter, University of California (Berkeley), Public Eng., 1930, 2,433.	4.4, 15.4
44.	W. H. Jens and P. A. Lottes, Analysis of Heat Transfer, Burnout, Pressure Drop, and Density Data for High Pressure Water, USAEC Report ANL-4627, 1951.	15.4
45.	T. G. Taxelius, ed. Annual Report - Spert Project, October 1968 September 1969. Idaho Nuclear Corporation, IN-1370, June 1970.	15.4
46.	R. C. Liimatainen and F. J. Testa, Studies in TREAT of Zircaloy-2-Clad, UO_2 Core Simulated Fuel Elements, ANL-7225, January-June 1966, November, 1966, p. 177.	15.4

Title	Section Reference
47. Regulatory Guide 1.109, Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I, Revision 1, October 1977.	11.2, 11.3, 11.6

Note 1. These technical reports were originally referenced in FSAR Amendment 85, Appendices 2.3A and 2.3B (refer to Section 2.3.3.1).

1.6.3 DRAWINGS INCORPORATED BY REFERENCE

Controlled engineering drawings were removed from the UFSAR at Revision 15. The drawings are considered incorporated by reference. Table 1.6-1 identifies the controlled engineering drawings that are incorporated by reference and also provides a cross-reference of the controlled engineering drawings to the respective UFSAR figure number. The contents of the drawings are controlled by DCPP procedures.

1.6.4 DIABLO CANYON QUALITY ASSURANCE PROGRAM DESCRIPTION

The Diablo Canyon Quality Assurance Program Description is incorporated by reference in the DCPP UFSAR. The Quality Assurance Program Description is included in a separate document controlled in accordance with 10 CFR 50.54(a) and submitted to the NRC in accordance with the requirements in 10 CFR 50.71(e).

TABLE 1.3-1

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

DESIGN COMPARISON OF DIABLO CANYON POWER PLANT UNITS 1 & 2, ZION STATION, AND TROJAN NUCLEAR PLANT
(Historical-valid through March 1984)

Chapter Number	*System/Component*	*Section Reference*	*Discussion*
1	*Introduction*	*1.1*	*All are 4-loop plants* *Reactor power ratings (Core thermal output):* *Diablo Canyon Unit 1: 3338 MWt* *Diablo Canyon Unit 2 & Trojan: 3411 MWt* *Zion: 3250 MWt*
3	*Containment*	*3.8.2*	*All containments are steel-lined concrete structures. Diablo Canyon uses conventional reinforcing; Trojan and Zion are posttensioned. Comparative dimensions and designed pressures are:*

	I.D., ft	*Net Vol, cu ft*	*Design Press, psig*
Diablo Canyon	*140*	*2,630,000*	*47*
Trojan	*124*	*2,000,000*	*60*
Zion	*140*	*2,860,000*	*47*

4	*Reactor*	*4.2.1*	*Generally similar to Zion and Trojan, but differences exist in design based on nuclear and thermal-hydraulic design parameters.*
	Reactor Vessel	*4.2.2*	*Diablo Canyon Unit 1: Design of thermal shields and upper and lower Internals support structures, etc., is similar to Zion.* *Diablo Canyon Unit 2: Design of neutron pads and upper and lower support structures, etc., is similar to Trojan.*
	Reactivity Control	*4.2.3*	*Similar to Zion and Trojan.*

TABLE 1.3-1

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Chapter Number	*System/Component*	*Section Reference*	*Discussion*
4 (Cont'd)	*Nuclear Design*	*4.3*	*Similar to Zion and Trojan except differences exist in fuel burnup rates, fuel enrichments, k_{eff}, and core kinetics characteristics.*
	Thermal-hydraulic Design	*4.4*	*Similar to Zion and Trojan except for rating differences.*
5	*Reactor Coolant System*	*5.1, 5.2, 5.3, 5.4, 5.5*	*All three plants are similar in design except Diablo Canyon will use codes that specifically apply. Zion has loop stop valves.*
	Reactor Vessel	*5.4*	*Diablo Canyon Units 1 and 2 each have 50-year design life while Trojan and Zion are designed for 40 years.* *Diablo Canyon Unit 2, Trojan, and Zion have four of the inner CRDM housings moved into the outer rows as compared to Diablo Canyon Unit 1. All have the same number of CRDM housings.* *Diablo Canyon Unit 1 uses ASME Code, Section III, 1965 Edition and addenda through winter 1966. Zion uses ASME Code, Section III, 1965 Edition and addenda through summer 1966. Diablo Canyon Unit 2 and Trojan use ASME Code, Section III, 1968 Edition.* *Diablo Canyon Unit 1 and Zion have blowout collars on bottom tubes only. Diablo Canyon Unit 2 does not have blowout collars. Trojan has blowout collars on control rod drive mechanisms and bottom tubes.*
	Reactor Coolant Pumps	*5.5.1*	*Diablo Canyon Units 1 and 2 and Trojan have spacer couplings. Zion does not.*

TABLE 1.3-1

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Chapter Number	*System/Component*	*Section Reference*	*Discussion*
5 (Cont'd)	*Steam Generators*	*5.5.2*	*Diablo Canyon and Zion have 1,100 psia secondary side design pressure. Trojan uses 1,200 psia.*
	Reactor Coolant Piping	*5.5.3*	*Diablo Canyon Units 1 and 2 and Zion use seamless forged pipe sections and 90° elbows which are cast sections joined by electroslag welds. Trojan uses centrifugally cast pipe sections. Zion's design is modified to accommodate the loop stop valves. Diablo Canyon and Zion are designed to B31.1. Trojan is designed to B31.7.*
	Residual Heat Removal System	*5.5.6*	*All are similar in design.*
	Pressurizer	*5.5.10*	*Head material is cast for Diablo Canyon Unit 1 and Zion while it is fabricated plate for Diablo Canyon Unit 2 and Trojan. The shell material is fabricated plate for all four units.*
6	*Containment Spray System*	*6.2.3*	*All are similar in design.*
	Emergency Core Cooling System	*6.3*	*All are similar in design.*
7	*Reactor Trip System*	*7.2*	*Diablo Canyon Units 1 and 2 and Trojan have solid-state logic protection systems while Zion has relay protection. The logic on trips associated with the reactor coolant pump power supplies is similar at Diablo Canyon Units 1 and 2 and Trojan. Zion is different because it has four separate buses, one for each pump, while Diablo Canyon and Trojan have two reactor coolant pumps per bus.*
	Engineered Safety Features Actuation System	*7.3*	*All four units have extended engineered safety features testability. Diablo Canyon Units 1 and 2 and Trojan have 2/3 high*

TABLE 1.3-1

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Chapter Number	*System/Component*	*Section Reference*	*Discussion*
			containment pressure logic for safety injection initiation, while Zion uses 2/4 high containment pressure.
7 (Cont'd)	*Systems Required for Safe Shutdown*	*7.4*	*System functions are similar on all four units.*
	Safety-related Display Instrumentation	*7.5*	*Parametric display is similar for all four units. The physical configuration may differ.*
	Other Safety Systems	*7.6*	*All four units have residual heat removal isolation valve interlocking and automatic closure devices.*
	Control Systems	*7.7*	*Diablo Canyon Units 1 and 2 and Trojan have digital rod position indication systems, while Zion has analog rod position indication.*
8	*Electric Power*	*Fig. 8.1-1*	*Diablo Canyon and Trojan auxiliary systems supply loads at 12 and 4.16 kV. Zion does not have 12-kV loads.*
	Standby Power	*8.3.2*	*Trojan has two 4.16-kV ESF buses with one standby diesel generator unit (two engines in line per unit) on each bus. Diablo Canyon and Zion have five standby diesel generators, two for each unit and one that can be transferred to either unit.*
9	*Chemical and Volume*	*9.3.4*	*Similar, except Diablo Units 1 and 2 and Zion have 12 percent boric acid concentration systems, while Trojan has a 4 percent system.*
10	*Steam and Power Conversion System*	*10.2*	*Turbines are similar with three double-flow low pressure elements and six stages of feedwater heating.*
11	*Radioactive Waste Management*	*Entire chapter*	*Systems and treatment provided are similar.*

TABLE 1.3-2

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

MAJOR DESIGN CHANGES SINCE THE PSAR
(Historical-valid through July 1974)

Item	*Changes in Design*	*Original FSAR Section References*
1.	*Reactor vessel internals changes (Unit 2) - Thermal shield replaced by neutron pads, and lower core support plate and upper internals support system redesigned.*	*4.2.2*
2.	*Tetra boron carbide control rod poison material changed to silver-indium-cadmium.*	*4.2.3*
3.	*Pellet density, fuel rod pressure, and burnable poison loading pattern have changed to reflect more detailed design calculations and latest operating experience.*	*4.3*
4.	*Reactor vessel top and bottom head penetration and control rod drive mechanisms have been redesigned and removable insulation has been provided on the closure head to enable inservice inspection.*	*4.3, 5.4, 5.4.2, 5.4.4*
5.	*Safety injection now provides cold leg injection with cold leg or hot leg recirculation.*	*6.3*
6.	*Rod withdrawal step from rod drop signal and automatic turbine load cutback initiated by rod drop have been replaced by the power range neutron flux rate trips.*	*7.2*
7.	*Relay logic for reactor protection and engineered safety features actuation system has been changed to solid-state logic.*	*7.2, 7.3*
8.	*On-line testing has been provided for engineered safety features actuation system.*	*7.3*
9.	*Analog rod position indication has been replaced by digital rod position indication.*	*7.7.1*
10.	*Deleted in Revision 15*	
11.	*Design criteria changes in the event of inleakage of contaminated water into component cooling water (CCW) system. This tends to minimize possible release of reactor coolant outside containment via the CCW system.*	*9.2.2*

TABLE 1.3-2

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Item	*Changes in Design*	*Original FSAR Section References*
12.	*The compressed air system is revised to eliminate the emergency air system. This satisfies safety criteria while reducing potential leakage paths from containment.*	*9.3.1*
13.	*The stainless steel liner in the spent fuel pool and transfer canal is changed from Design Class I to Design Class II. The liners prevent minor leakage, and the pool and canal structures remain Design Class I and are relied upon to prevent major failure.*	*9.1.2*
14.	*The primary water storage tank is reclassified from Design Class I to Design Class II. This is no longer the primary source of makeup water to the CCW System. A backup source to a makeup supply to a Design Class I system itself need not be classified Design Class I.*	*9.2.4*
15.	*The detectors for the fire detection alarm system are relocated to give more specific identification of the location of the source. Instrument ac power is provided.*	*9.5.1*
16.	*In the containment structure, vertical joints are provided with a shear key, as required by ACI 301-66.*	*3.8.2*
17.	*The Chief Mechanical Engineer is no longer the designated Project Engineer. This change was made April 26, 1971.*	*17.0*
18.	*Those parts of the fire protection system that protect Design Class II and III equipment and structures are not required to be Design Class I.*	*9.5.1*
19.	*Inspection procedures for cable were modified to require tests on sample reels from each production run, rather than on each reel.*	*8.5.2*
20.	*The fuel assembly array is revised from 15 x 15 to 17 x 17. The change was initiated to maintain sufficient flexibility to fulfill the requirements of, or any changes to, 10 CFR 50.46: "Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors."*	*4 and 15*
21.	*The steam generator blowdown treatment system is added to provide for treatment in the event that there is primary-to-secondary leakage.*	*11.2.2*

TABLE 1.3-2

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Item	*Changes in Design*	*Original FSAR Section References*
22.	*An alarm system is added to indicate the rupture of a auxiliary seawater cooling header. The function of the alarm is to alert the operator in the event that the header breaks, so that the operator can route the cooling water to the redundant supply header and restore the cooling function to the CCW system.*	*9.2*
23.	*The turbine building is protected from floods due to pipe breaks by the addition of an 18-inch overflow drain from the sump system to the circulating water discharge canal.*	*9.2*
24	*Protection against flooding of the turbine building is provided by design changes to decrease the probability of rupturing the expansion joints at the water box. Also, the consequences of a rupture are minimized by the addition of expansion joint sleeves.*	*10.4*
25.	*A system is added and designed to detect and alarm in the event that there are loose parts in the reactor coolant system.*	*3.9*
26.	*A Design Class I supply of demineralized water is provided for makeup to the spent fuel pool.*	*9.1*
27.	*The ventilation system for the fuel handling area is modified and reclassified to Design Class I.*	*9.4*
28.	*A Design Class I containment hydrogen purge system is provided for reducing the containment atmosphere hydrogen concentration in the event of a LOCA. The system has redundant sets of supply and exhaust fans and filters. Each fan is on a separate vital bus.*	*6.2*
29.	*The heating, ventilating, and air conditioning system for the control room is modified and is reclassified as Design Class I. The system has four modes of operation designed to make the control room habitable: (a) during normal operation,(b) during long-term occupancy, (c) in the event that there is excessive airborne activity external to the control room, and (d) in the event that there is a fire in the control room.*	*9.4*

TABLE 1.3-2

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Item	*Changes in Design*	*Original FSAR Section References*
30.	*Design changes add the capability of maintaining reactor coolant system temperature during hot shutdown operations; when the reactor is subcritical, the steam dumps to the main condenser. This is accomplished by a controller in the steam line, operating in the pressure control mode, which is set to maintain the steam generator steam pressure.*	*5.1*
31.	*Meteorological monitoring equipment will provide data to be recorded in the control room during plant operation.*	*16.4*

TABLE 1.4-1

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PRINCIPAL CONSULTANTS AND CONTRACT DESCRIPTION
(Historical-valid through March 1986)

Principal Consultant	*Contract (Over $100,000)*
Anco Engineers, Inc.	*Raceway system qualification; seismic testing of mechanical equipment*
Arremany & Associates	*Nondestructive examination services*
Associated Technical Training Services	*Operator training*
Babcock & Wilcox, Inc.	*Engineering support*
Bechtel Power Corporation	*Project management, engineering, construction procurement, startup, project cost and scheduling, quality assurance*
J. R. Benjamin and Associates, Inc.	*Seismic verification of auxiliary and turbine buildings; frequency of vessel impact on intake structure*
William K. Brunot	*Reliability and risk analysis*
Burns & Roe, Inc.	*Engineering quality control services*
California Department of Fish and Game	*Marine biology studies*
California Polytechnic State University	*Marine biology studies*
Chemrad Corporation	*Radiological and health physics support*
Cygna Energy Services, Inc.	*Piping support and HVAC equipment qualification*
Earth Sciences Associates	*Geological investigations*
Ecological Analysts, Inc.	*Marine biology studies*

TABLE 1.4-1

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Principal Consultant	*Contract (Over $100,000)*
EDS Nuclear, Inc.	*Control room (HVAC) design, technical support center pressurization system design, piping anchors design review, radiation shielding design review, emergency core cooling system nozzle fatigue analysis*
Energy Training Corporation	*Operator training*
Geri Engineering, Inc.	*Reactor vessel inservice inspection tool modification*
Harding - Lawson Associates	*Soil investigations, geophysical surveys*
Hydro - Research Science	*Discharge structure model study*
Innova Corporation	*Pipe support design review and redesign engineering*
James Engineering Company	*Engineering support*
Kaiser Engineers, Inc.	*Program management and engineering services, independent assessment of alternative cooling water systems*
Lambert & Company	*Nondestructive examination services*
Nuclear Services Corporation	*Pipe break analysis*
Nucon, Inc.	*Engineering support for fuel load and startup*
NUS Corporation	*Engineering studies of spent fuel pool storage expansion*
Nutech Engineers, Inc.	*Seismic and environmental qualification engineering support*
Offshore Technology Corporation	*Intake structure hydraulic model studies*
Omar J. Lillevang	*Breakwater design, breakwater damage study*

TABLE 1.4-1

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Principal Consultant	*Contract (Over $100,000)*
Pickard, Lowe, & Garrick, Inc.	*Probabilistic risk assessment*
Project Assistance Corporation	*Quality assurance program support*
Radiation Research Associates, Inc.	*Shielding design review*
Regents of the University of California	*Thermal physical modeling studies*
R. F. Reedy and Associates	*Quality assurance verification*
Robert L. Cloud Associates, Inc.	*Hosgri seismic reverification program*
Stone & Webster Engineering Corporation	*Independent design verification program - Phase II*
TERA Corporation	*Source modeling studies, general engineering, thermal discharge assessment, assessment of alternative cooling water systems*
Terra Technology Corporation	*Seismic recording system maintenance and records processing*
Teledyne Engineering Services	*Independent design verification program*
URS/John A. Blume and Associates	*Seismic structural criteria, electrical seismic testing criteria, seismic research program, seismic review and reverification, independent internal review, Hosgri seismic evaluation*
Waltek Services	*Technical support services*
Westinghouse Electric Corporation	*Long-term seismic research program, environmental qualification, piping redesign and qualification, seismic reverification technical support*
Woodward - Clyde and Associates	*Seismic surveys*
Wyle Laboratories	*Seismic test and engineering support*

TABLE 1.4-2

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

SUPPLIERS OF IMPORTANT EQUIPMENT AND MATERIALS
OTHER THAN NUCLEAR STEAM SUPPLY SYSTEM
(Historical-valid through March 1986)

Supplier	*Equipment/Materials*
Alco Engines Division, White Industrial Power, Inc.	*Diesel generator units*
American Bridge Co., Division of U.S. Steel Corp.	*Furnish structural steel*
AMF Cuno Division	*Radioactive waste filters*
Armco Steel Corp.	*Containment wall penetration flued heads*
Babcock & Wilcox	*Safety parameter display system*
Berkeley Steel Construction Co.	*Radioactive waste tanks*
Bingham-Willamette Pump Co.	*Component cooling water pumps, auxiliary saltwater pumps*
Byron Jackson Pump, Division of Borg-Warner Corp.	*Auxiliary feedwater pumps*
Capital Westward Inc.	*Radioactive waste tanks*
Chem-Nuclear Services Inc.	*Radioactive resin removal and transfer system*
Chemetron Corp.	*Carbon dioxide*
Combustion Engineering	*Subcooled margin monitor*
Contromatics Corp.	*Radioactive waste valves*
De Laval Turbine Inc.	*Diesel fuel transfer pumps*
Dresser Industries Inc.	*Steam generator safety valves*
Fairbanks-Morse Co.	*Fire pumps*

TABLE 1.4-2

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Supplier	*Equipment/Materials*
Fenwall Inc.	*Halon 1301 system*
Fisher Controls Co.	*Class I pressure/level controllers, and control valves*
Fulton Shipyard	*Fuel handling area crane*
General Electric Co.	*Electrical penetrations of containment structure, 12 and 4.16-kV switchgear*
Grinnell Co.	*Radioactive waste valves*
Harnischfeger P&H	*Turbine building bridge cranes*
Ingersoll-Rand Co.	*Radioactive waste pumps, reactor coolant drain tank pump, makeup water system pumps*
J. E. Lonergan Co.	*Class I safety relief valves*
Mine Safety Appliances Co.	*Radwaste gas analyzers*
Murphy Pacific Corp.	*Furnish structural steel*
M. W. Kellogg Co. (Pullman Power Products)	*Main systems piping*
National Controls, Inc.	*Condensed waste drumming system*
Paul Monroe Hydraulics	*Dome service crane snubbers*
Pyrotronics, Inc.	*Fire detection and alarm system*
Quick Manufacturing Co.	*Dome service crane*
Schutte and Koerting Co.	*Main steam isolation and check valves*
Scott Company of California	*Ventilation and air filters, fire water and stand pipe system*

TABLE 1.4-2

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Supplier	*Equipment/Materials*
Velan Valve Corp.	*Radioactive waste valves*
Viking Automatic Sprinkler Co., Chemtron Corp. (Subcontractor)	*Water spray and CO_2 fire protection systems*
Westinghouse Electric Corp.	*Radioactive waste evaporators*
Yuba Manufacturing Co.	*Component cooling water heat exchanger, polar crane*

TABLE 1.4-3

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

CONSTRUCTION AND INSTALLATION CONTRACTORS
(Historical-valid through March 1986)

Contractor	*Units 1 and 2 In-progress Contracts Over $100,000*
Bechtel Construction Inc.	*Plant maintenance*
Plant Asbestos - Thorpe Insulation	*Furnish and install insulation*
Promatec	*Furnish and install insulation*
Pullman Power Products	*Erect plant and steam piping*
Westinghouse Electric Corporation	*Erect turbine-generator*
Contractor	*Units 1 and 2 Completed Contracts Over $100,000*
A. J. Diani Construction	*Paving of access roads*
American Bridge	*Complete structural steel*
Ames Associates	*Repair breakwater*
Arrowhead Industrial Water	*Furnish demineralizer*
Bigge Crane & Rigging Co.	*Heavy equipment handling*
Bigge Drayage Co.	*Material receiving/storage (Pismo Beach laydown and storage yard)*
Bostrom-Bergen	*Structural steel*
Bovee & Crail Construction	*Erect intake equipment & pipe*
Chemtrol Corporation	*Furnish and install penetration seals*
Continental Heller Corp.	*Construct security building*
E.H. Haskell Company	*Parking lot*

TABLE 1.4-3

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Contractor	*Units 1 and 2 Completed Contracts Over $100,000*
Endurance Metal Product Co.	*Erect miscellaneous steel*
Granite Constr. Co. and Gordon H. Ball, Inc.	*Construct breakwaters*
Guy F. Atkinson Company	*Construction of seismic modifications, construct buildings*
Healy - Tibbits	*Repair breakwater*
H&H Construction, Inc.	*Grading and paving (Pismo Beach laydown and storage yard)*
H. H. Robertson Co.	*Install siding and roofing*
H.P. Foley Company	*Install wiring, electrical equipment, and instrumentation. Construct seismic modifications of buildings.*
Morgan Equipment Co.	*Batch plant*
Murphy Pacific Corp.	*Furnish and install structural steel erect turbine building cranes*
Pinkerton's Inc.	*Security guard service*
Pittsburg-Des Moines Steel Co.	*Fabricate auxiliary building tanks, construct storage tanks*
Pullman Power Products	*Construct pipe rupture restraints*
Relocate Structures, Inc.	*Construct administration building*
Robert McMullan & Son, Inc.	*Finish painting*
Sanchez & Son, Inc.	*Grading and paving (Pismo Beach laydown and storage yard)*
San Luis Garbage	*Disposal of waste water*

TABLE 1.4-3

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Contractor	*Units 1 and 2 Completed Contracts Over $100,000*
Scott Company of California	*Furnish and install air conditioning and ventilation*
System Steel Builders	*Construction offices, warehouse buildings (Pismo Beach laydown and storage yard)*
Tech-Sil, Inc.	*Furnish and install penetration seals*
Valley Trucking of Santa Maria, Inc.	*Disposal of waste water*
Viking Automatic Sprinkler Co.	*Furnish and install fire protection*
Walter Bros. Construction Co. and Milburn & Sansome Co.	*Plant roads and site preparation, construct Harford Drive-County Road construct access road*
Wismer & Becker Contracting Engineers	*Install electrical equipment switchyard, install mechanical equipment/erect NSSS*

TABLE 1.5-1

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

RESEARCH AND DEVELOPMENT PROGRAMS
(Historical-valid through November 1975)

PROGRAM	*TECHNICAL REPORTS*
Fuel development for operations at high power densities *Full-length emergency core cooling heat transfer tests (FLECHT)* *Reactor vessel thermal shock* *Verification test (17 x 17)* *Delayed departure from nucleate boiling (DDNB)*	*F. T. Eggleston, Safety-Related Research and Development for Westinghouse PWRs, Program Summaries. Winter 77 - Summer 78, WCAP-8768, Rev. 2, October 1978.*
Core stability evaluation *Blowdown forces program*	*C. J. Kubit, Safety-Related Research and Blowdown Development for Westinghouse PWRs, Program Summaries. Fall 1972, WCAP-8004, January 1973.*
Containment spray *Fuel rod burst* *Loss-of-coolant analysis* *ESADA DNB*	*R. M. Hunt, Safety-Related Research and Development for Westinghouse PWRs, Program Summaries. Fall 1970, WCAP-7614-L, November 1970.*
Burnable poison *Flashing heat transfer*	*R. M. Hunt, Safety-Related Research and Development for Westinghouse PWRs, Program Summaries. Spring 1970, WCAP-7498-L, May 1970.*
Fuel development for operation at high power densities	*M. D. Davis, Safety-Related Research and Development for Westinghouse PWRs, Program Summaries. Fall 1974, WCAP-8485, March 1975.*

TABLE 1.5-1

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PROGRAM	*TECHNICAL REPORTS*
Incore detector *Gross failed fuel detector*	*C. J. Kubit, Safety-Related Research and Development for Westinghouse PWRs, Program Summaries. Spring 1974, WCAP-8385, July 1974.*
Environmental testing of engineered safety features related equipment	*C. J. Kubit, Safety-Related Research and Development for Westinghouse PWRs, Program Summaries. Spring 1972, WCAP-7856, May 1972.*
In-pile fuel densification	*J. M. Hellman, Fuel Densification Experimental Results and Model for Reactor Operation, WCAP-8218-P-A March 1975 (Proprietary) and WCAP-8219-A, March, 1975 (Non-proprietary).*
Verification test (17 x 17)	*L. Geninski, et al, Safety Analysis of the 17 x 17 Fuel Assembly for Combined Seismic and Loss-of-Coolant Accident, WCAP-8288, December 1973.*
Verification test (17 x 17)	*E. E. DeMario and S. Makazato, Hydraulic Flow Test of the 17 x 17 Fuel Assembly, WCAP-8279, February 1974.*
Verification test (17 x 17)	*F. W. Cooper, Jr., 17 x 17 Drive Line Components Test - Phase IB, II, II, - Drop and Deflections, WCAP-8446, December 1974.*

TABLE 1.5-1

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PROGRAM	*TECHNICAL REPORTS*
Departure from nucleate boiling (DNB)	*K. W. Hill, et al, Effect of 17 x 17 Fuel Assembler Geometry on DNB, WCAP-8396-P-A, February 1975 (Proprietary) and WCAP-8297-A, February 1975.*
Incore flow mixing	*F. E. Motley, et al, The Effect of 17 x 17 Fuel Assembly Geometry on Interchannel Thermal Mixing, (WCAP-8298-P-A) (Proprietary) and WCAP-8299-, January 1975.*
LOCA heat transfer tests	*A. J. Burnett and S. D. Kopelic, Westinghouse ECCS Evaluation Model October 1975 Version, WCAP-8622 (Proprietary) and WCAP-8623 (Non-Proprietary), November 1975.*
17 x 17 fuel surveillance program	*Irradiation of 17 x 17 Demonstration Assemblies in Surry Units No. 1 and 2, Cycle 2, WCAP-8262, July 1974.*

TABLE 1.6-1

CONTROLLED ENGINEERING DRAWINGS/FSAR UPDATE FIGURES CROSS REFERENCE

Figure	Sheet	Drawing	Description
1.2-3		500001-1	Area Location Plan
1.2-4		57727-1	Auxiliary, Containment, and Fuel Handling Buildings (Units 1 & 2), Plan at Elevation 140 ft
1.2-5		57726-1	Auxiliary, Containment, and Fuel Handling Buildings (Units 1 & 2), Plan at Elevation 115 ft
1.2-6		57725-1	Auxiliary, Containment, and Fuel Handling Buildings (Units 1 & 2), Plan at Elevations 91 and 100 ft
1.2-7		57724-1	Auxiliary and Containment Buildings (Units 1 & 2), Plan at Elevation 85 ft
1.2-8		57723-1	Auxiliary and Containment Buildings (Units 1 & 2), Plan at Elevation 73 ft
1.2-9		57722-1	Auxiliary and Containment Buildings (Unit 1 & 2), Plan at Elevations 60 and 64 ft
1.2-10		500977-1	Containment Building (Unit 2), Plan at Elevations 115 and 140 ft
1.2-11		500971-1	Containment & Fuel Handling Buildings (Unit 2), Plan at Elevations 85, 91, and 100 ft
1.2-12		500968-1	Containment Building (Unit 2), Plan at Elevations 60, 64, and 73 ft
1.2-13		57721-1	Turbine Building (Unit 1), Plan at Elevation 140 ft
1.2-14		57720-1	Turbine Building (Unit 1), Plan at Elevation 119 ft
1.2-15		57719-1	Turbine Building (Unit 1), Plan at Elevation 104 ft
1.2-16		57718-1	Turbine Building (Unit 1), Plan at Elevation 85 ft
1.2-17		500967-1	Turbine Building (Unit 2), Plan at Elevation 140 ft
1.2-18		500966-1	Turbine Building (Unit 2), Plan at Elevation 119 ft
1.2-19		500965-1	Turbine Building (Unit 2), Plan at Elevation 104 ft
1.2-20		500964-1	Turbine Building (Unit 2), Plan at Elevation 85 ft
1.2-21		57728-1	Auxiliary Building (Units 1 & 2), Section A-A
1.2-22		57729-1	Auxiliary and Containment Buildings (Unit 1 & 2), Section B-B
1.2-23		57730-1	Auxiliary and Fuel Handling Buildings (Unit 1 & 2), Section C-C

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Figure	Sheet	Drawing	Description
1.2-24		57731-1	Containment, Turbine, and Fuel Handling Buildings (Unit 1) Section D-D
1.2-25		57732-1	Auxiliary, Turbine, and Fuel Handling Buildings (Unit 1), Section E-E
1.2-26		57733-1	Auxiliary, Fuel Handling, and Turbine Buildings (Units 1 & 2), Section F-F
1.2-27		57734-1	Turbine Building (Unit 1), Section G-G
1.2-28		500969-1	Containment Building (Unit 2), Section A-A
1.2-29		500972-1	Vent & Fuel Handling Buildings (Unit 2), Section B-B
1.2-30		500973-1	Turbine, Containment, & Fuel Handling Buildings (Unit 2), Section C-C
1.2-31		500974-1	Turbine Building (Unit 2), Sections D-D and E-E
1.2-32		500976-1	Turbine Building (Unit 2), Section F-F
2.4-7		468999-1	Typical Sections for Tribar Armor Construction
2.4-8		469001-1	Restored Cross-sections and Embedment Plan
3.2-1	1 of 4	102001-3	Piping Schematic Legend
3.2-1	1A of 4	102023-2	Piping Schematic Legend
3.2-1	2 of 4	108001-3	Piping Schematic Legend
3.2-1	2A of 4	108023-2	Piping Schematic Legend
3.2-2	1 of 23	102002-4	Piping Schematic - Condensate System (23 Sheets)
3.2-2	2 of 23	108002-4	
3.2-2	3 of 23	102002-5	
3.2-2	3A of 23	102002-5A	
3.2-2	4 of 23	108002-5	
3.2-2	5 of 23	102002-6	
3.2-2	5A of 23	102002-6A	
3.2-2	6 of 23	108002-6	
3.2-2	7 of 23	102002-7	
3.2-2	8 of 23	108002-7	
3.2-2	9 of 23	102002-8	
3.2-2	9A of 23	102002-8A	
3.2-2	10 of 23	108002-8	
3.2-2	10A of 23	108002-8A	
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Figure	Sheet	Drawing	Description
3.2-2	11B of 23	102002-9B	
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3.2-2	12A of 23	108002-9A	
3.2-2	13 of 23	102002-10	
3.2-2	14 of 23	108002-10	
3.2-2	15 of 23	102002-11	
3.2-2	16 of 23	108002-11	
3.2-3	1 of 11	102003-3	Piping Schematic - Feedwater System (11 Sheets)
3.2-3	1A of 11	102003-3A	
3.2-3	2 of 11	108003-3	
3.2-3	3 of 11	102003-4	
3.2-3	4 of 11	108003-4	
3.2-3	5 of 11	102003-4A	
3.2-3	6 of 11	108003-4A	
3.2-3	7 of 11	102003-5	
3.2-3	8 of 11	108003-5	
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3.2-3	10 of 11	108003-6	
3.2-4	1 of 16	102004-3	Piping Schematic - Turbine Steam Supply System (16 Sheets)
3.2-4	2 of 16	108004-3	
3.2-4	3 of 16	102004-4	
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3.2-4	5 of 16	102004-5	
3.2-4	6 of 16	108004-5	
3.2-4	7 of 16	102004-6	
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3.2-4	9 of 16	102004-7	
3.2-4	10 of 16	108004-7	
3.2-4	11 of 16	102004-8	
3.2-4	12 of 16	108004-8	
3.2-4	13 of 16	102004-9	
3.2-4	14 of 16	102004-10	
3.2-4	15 of 16	108004-9	
3.2-4	16 of 16	108004-10	

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Figure	Sheet	Drawing	Description
3.2-5	1 of 12	102005-2	Piping Schematic - Extraction Steam and Heater Drip System (12 Sheets)
3.2-5	2 of 12	108005-2	
3.2-5	3 of 12	102005-3	
3.2-5	4 of 12	108005-3	
3.2-5	5 of 12	102005-4	
3.2-5	6 of 12	108005-4	
3.2-5	7 of 12	102005-5	
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3.2-5	9 of 12	102005-6	
3.2-5	10 of 12	108005-6	
3.2-5	11 of 12	102005-7	
3.2-5	12 of 12	108005-7	
3.2-6	1 of 10	102006-3	Piping Schematic - Auxiliary Steam System (10 Sheets)
3.2-6	1A of 10	102006-3A	
3.2-6	2A of 10	102006-3B	
3.2-6	2 of 10	108006-3	
3.2-6	3 of 10	102006-4	
3.2-6	4 of 10	108006-4	
3.2-6	5 of 10	102006-4A	
3.2-6	6 of 10	108006-4A	
3.2-6	7 of 10	102006-5	
3.2-6	8 of 10	108006-5	
3.2-7	1 of 9	102007-3	Piping Schematic - Reactor Coolant System (9 Sheets)
3.2-7	2 of 9	108007-3	
3.2-7	3 of 9	102007-4	
3.2-7	4 of 9	108007-4	
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3.2-7	6 of 9	108007-5	
3.2-7	7 of 9	102007-5A	
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3.2-8	1 of 34	102008-3	Piping Schematic - Chemical and Volume Control System (34 Sheets)

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Figure	Sheet	Drawing	Description
3.2-8	1A of 34	102008-3A	
3.2-8	1B of 34	102008-3B	
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3.2-8	2 of 34	108008-3	
3.2-8	3 of 34	102008-4A	
3.2-8	4 of 34	108008-4A	
3.2-8	5 of 34	102008-4	
3.2-8	6 of 34	108008-4	
3.2-8	7 of 34	102008-4B	
3.2-8	7A of 34	102008-4C	
3.2-8	7B of 34	102008-4D	
3.2-8	7C of 34	102008-4E	
3.2-8	8 of 34	108008-4B	
3.2-8	8A of 34	108008-4C	
3.2-8	9 of 34	102008-5	
3.2-8	10 of 34	108008-5	
3.2-8	11 of 34	102008-5A	
3.2-8	12 of 34	108008-5A	
3.2-8	13 of 34	102008-5B	
3.2-8	14 of 34	108008-5B	
3.2-8	15 of 34	102008-5C	
3.2-8	16 of 34	108008-5C	
3.2-8	16A of 34	102008-5D	
3.2-8	17 of 34	102008-6	
3.2-8	17A of 34	102008-6A	
3.2-8	18 of 34	108008-6	
3.2-8	19 of 34	102008-7	
3.2-8	20 of 34	108008-7	
3.2-8	21 of 34	102008-8	
3.2-8	21A of 34	102008-8A	
3.2-8	22 of 34	108008-8	
3.2-8	23 of 34	102008-9	
3.2-8	24 of 34	108008-9	
3.2-9	1 of 12	102009-3	Piping Schematic - Safety Injection System (12 Sheets)
3.2-9	2 of 12	108009-3	

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Figure	Sheet	Drawing	Description
3.2-9	3 of 12	102009-4	
3.2-9	4 of 12	108009-4	
3.2-9	5 of 12	102009-5	
3.2-9	5A of 12	102009-5A	
3.2-9	6 of 12	108009-5	
3.2-9	6A of 12	108009-5A	
3.2-9	7 of 12	102009-6	
3.2-9	8 of 12	108009-6	
3.2-9	9 of 12	102009-7	
3.2-9	10 of 12	108009-7	
3.2-10	1 of 6	102010-3	Piping Schematic - Residual Heat Removal System (6 Sheets)
3.2-10	2 of 6	108010-3	
3.2-10	3 of 6	102010-4	
3.2-10	4 of 6	108010-4	
3.2-10	5 of 6	102010-5	
3.2-10	6 of 6	108010-5	
3.2-11	1 of 11	102011-2	Piping Schematic - Nuclear Steam Supply Sampling System (11 Sheets)
3.2-11	1A of 11	102011-2A	
3.2-11	2 of 11	108011-2	
3.2-11	3 of 11	102011-3	
3.2-11	4 of 11	108011-3	
3.2-11	5 of 11	102011-4	
3.2-11	6 of 11	108011-4	
3.2-11	7 of 11	102011-5	
3.2-11	8 of 11	108011-5	
3.2-11	9 of 11	102011-6	
3.2-11	10 of 11	108011-6	
3.2-12	1 of 2	102012-3	Piping Schematic - Containment Spray System (2 Sheets)
3.2-12	2 of 2	108012-3	
3.2-13	1 of 3	102013-2	Piping Schematic - Spent Fuel Pool Cooling System (3 Sheets)
3.2-13	1A of 3	102013-2A	
3.2-13	2 of 3	108013-2	

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Figure	Sheet	Drawing	Description
3.2-14	1 of 17	102014-5	Piping Schematic - Component Cooling Water System (17 Sheets)
3.2-14	2 of 17	108014-5	
3.2-14	3 of 17	102014-5A	
3.2-14	3A of 17	102014-5B	
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3.2-14	5 of 17	102014-6	
3.2-14	6 of 17	108014-6	
3.2-14	7 of 17	102014-6A	
3.2-14	8 of 17	108014-6A	
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3.2-14	10 of 17	108014-7	
3.2-14	11 of 17	102014-8	
3.2-14	12 of 17	108014-8	
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3.2-14	14 of 17	108014-9	
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3.2-15	1 of 14	102015-3	Piping Schematic - Service Cooling Water System (14 Sheets)
3.2-15	1A of 14	102015-3A	
3.2-15	2 of 14	108015-3	
3.2-15	2A of 14	108015-3A	
3.2-15	2B of 14	108015-3B	
3.2-15	3 of 14	102015-4	
3.2-15	3A of 14	102015-4A	
3.2-15	4 of 14	108015-4	
3.2-15	5 of 14	102015-5	
3.2-15	6 of 14	108015-5	
3.2-15	7 of 14	102015-6	
3.2-15	8 of 14	108015-6	
3.2-15	9 of 14	102015-7	
3.2-15	10 of 14	108015-7	
3.2-16	1 of 21	102016-1	Piping Schematic - Makeup Water System (21 Sheets)
3.2-16	1A of 21	108016-1	

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Figure	Sheet	Drawing	Description
3.2-16	2 of 21	108016-3	
3.2-16	3 of 21	102016-4	
3.2-16	4 of 21	108016-5	
3.2-16	5 of 21	102016-6	
3.2-16	6 of 21	102016-7	
3.2-16	7 of 21	102016-8	
3.2-16	8 of 21	102016-9	
3.2-16	9 of 21	102016-9A	
3.2-16	10 of 21	102016-10	
3.2-16	11 of 21	102016-11	
3.2-16	12 of 21	102016-13	
3.2-16	13 of 21	102016-14	
3.2-16	14 of 21	102016-16	
3.2-16	15 of 21	108016-17	
3.2-16	16 of 21	102016-18	
3.2-16	17 of 21	108016-19	
3.2-16	18 of 21	102016-20	
3.2-16	19 of 21	102016-21	
3.2-16	19A of 21	102016-21A	
3.2-17	1 of 18	102017-3	Piping Schematic - Saltwater Systems (18 Sheets)
3.2-17	1A of 18	102017-3A	
3.2-17	1B of 18	102017-3B	
3.2-17	2 of 18	108017-3	
3.2-17	2A of 18	108017-3A	
3.2-17	2B of 18	108017-3B	
3.2-17	3 of 18	102017-4	
3.2-17	4 of 18	108017-4	
3.2-17	5 of 18	102017-5	
3.2-17	5A of 18	102017-5A	
3.2-17	6 of 18	108017-5	
3.2-17	7 of 18	102017-6	
3.2-17	7A of 18	102017-6A	
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3.2-17	8 of 18	108017-6	
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Figure	Sheet	Drawing	Description
3.2-17	8B of 18	108017-6B	
3.2-17	8C of 18	108017-6C	
3.2-18	1 of 27	102018	Piping Schematic - Fire Protection Systems (27 Sheets)
3.2-18	1A of 27	102018-2A	
3.2-18	1B of 27	102018-2B	
3.2-18	2 of 27	108018-2	
3.2-18	3 of 27	102018-3	
3.2-18	4 of 27	108018-3	
3.2-18	4A of 27	108018-3A	
3.2-18	5 of 27	102018-4	
3.2-18	6 of 27	108018-4	
3.2-18	7 of 27	102018-4A	
3.2-18	8 of 27	108018-4A	
3.2-18	9 of 27	102018-5	
3.2-18	9A of 27	102018-5A	
3.2-18	10 of 27	108018-5	
3.2-18	10A of 27	108018-5A	
3.2-18	11 of 27	102018-6	
3.2-18	11A of 27	102018-6A	
3.2-18	12 of 27	108018-6	
3.2-18	12A of 27	108018-6A	
3.2-18	13 of 27	102018-7	
3.2-18	14 of 27	108018-7	
3.2-18	15 of 27	102018-8	
3.2-18	16 of 27	108018-8	
3.2-18	17 of 27	102018-9	
3.2-18	18 of 27	108018-9	
3.2-18	19 of 27	102018-19	
3.2-18	20 of 27	102018-20	
3.2-19	1 of 26	102019-3	Piping Schematic - Liquid Radwaste System (26 Sheets)
3.2-19	2 of 26	108019-3	
3.2-19	3 of 26	102019-3A	
3.2-19	3A of 26	102019-3B	
3.2-19	4 of 26	108019-3A	

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Figure	Sheet	Drawing	Description
3.2-19	4A of 26	108019-3B	
3.2-19	5 of 26	102019-4	
3.2-19	6 of 26	108019-4	
3.2-19	7 of 26	102019-5	
3.2-19	7A of 26	102019-5A	
3.2-19	7B of 26	102019-5B	
3.2-19	7C of 26	102019-5C	
3.2-19	8 of 26	108019-5	
3.2-19	8A of 26	108019-5A	
3.2-19	8B of 26	108019-5B	
3.2-19	9 of 26	102019-6	
3.2-19	10 of 26	108019-6	
3.2-19	11 of 26	102019-6A	
3.2-19	11A of 26	102019-6B	
3.2-19	12 of 26	108019-6A	
3.2-19	12A of 26	108019-6B	
3.2-19	13 of 26	102019-7	
3.2-19	14 of 26	108019-7	
3.2-19	15 of 26	102019-8	
3.2-19	15A of 26	102019-8A	
3.2-19	16 of 26	108019-8	
3.2-20	1 of 26	102020-3	Piping Schematic - Lube Oil Distribution and Purification System (26 Sheets)
3.2-20	1A of 26	102020-3A	
3.2-20	1B of 26	102020-3B	
3.2-20	2 of 26	108020-3	
3.2-20	2A of 26	108020-3A	
3.2-20	2B of 26	108020-3B	
3.2-20	3 of 26	102020-4	
3.2-20	4 of 26	108020-4	
3.2-20	5 of 26	102020-5	
3.2-20	6 of 26	108020-5	
3.2-20	7 of 26	102020-6	
3.2-20	7A of 26	102020-6A	
3.2-20	7B of 26	102020-6B	
3.2-20	8 of 26	108020-6	

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Figure	Sheet	Drawing	Description
3.2-20	8A of 26	108020-6A	
3.2-20	8B of 26	108020-6B	
3.2-20	9 of 26	102020-7	
3.2-20	10 of 26	108020-7	
3.2-20	11 of 26	102020-8	
3.2-20	12 of 26	108020-8	
3.2-20	13 of 26	102020-9	
3.2-20	14 of 26	108020-9	
3.2-20	15 of 26	102020-10	
3.2-20	16 of 26	108020-10	
3.2-20	17 of 26	102020-11	
3.2-20	18 of 26	108020-11	
3.2-21	1 of 35	102021-2	Piping Schematic - Diesel Engine-Generator Systems (35 Sheets)
3.2-21	2 of 35	108021-2	
3.2-21	3 of 35	102021-3	
3.2-21	3A of 35	102021-3A	
3.2-21	4 of 35	108021-3	
3.2-21	4A of 35	108021-3A	
3.2-21	4B of 35	108021-3B	
3.2-21	5 of 35	102021-4	
3.2-21	5A of 35	102021-4A	
3.2-21	6 of 35	108021-4	
3.2-21	6A of 35	108021-4A	
3.2-21	6B of 35	108021-4B	
3.2-21	7 of 35	102021-5	
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3.2-21	8A of 35	108021-5A	
3.2-21	8B of 35	108021-5B	
3.2-21	9 of 35	102021-6	
3.2-21	9A of 35	102021-6A	
3.2-21	10 of 35	108021-6	
3.2-21	10A of 35	108021-6A	
3.2-21	10B of 35	108021-6B	
3.2-21	11 of 35	102021-7	
3.2-21	11A of 35	102021-7A	

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Figure	Sheet	Drawing	Description
3.2-21	11B of 35	102021-7B	
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3.2-21	12A of 35	108021-7A	
3.2-21	12B of 35	108021-7B	
3.2-21	13 of 35	102021-8	
3.2-21	14 of 35	108021-8	
3.2-21	14A of 35	108021-8A	
3.2-21	14B of 35	108021-8B	
3.2-21	15 of 35	102021-9	
3.2-21	16 of 35	108021-9	
3.2-21	16A of 35	108021-9A	
3.2-21	16B of 35	108021-9B	
3.2-22	1 of 16	102022-2	Piping Schematic - Turbine and Generator-Associated Systems (16 Sheets)
3.2-22	2 of 16	108022-2	
3.2-22	3 of 16	102022-3	
3.2-22	4 of 16	108022-3	
3.2-22	5 of 16	102022-4	
3.2-22	6 of 16	108022-4	
3.2-22	7 of 16	102022-5	
3.2-22	7A of 16	102022-5A	
3.2-22	8 of 16	108022-5	
3.2-22	8A of 16	108022-5A	
3.2-22	9 of 16	102022-6	
3.2-22	9A of 16	102022-6A	
3.2-22	10 of 16	108022-6	
3.2-22	10A of 16	108022-6A	
3.2-22	11 of 16	102022-7	
3.2-22	12 of 16	108022-7	
3.2-23	1 of 53	102023-3	Piping Schematic - Ventilation and Air Conditioning Systems (53 Sheets)
3.2-23	2 of 53	108023-3	
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3.2-23	8 of 53	108023-6	
3.2-23	8A of 53	108023-6A	
3.2-23	9 of 53	102023-7	
3.2-23	10 of 53	108023-7	
3.2-23	11 of 53	102023-8	
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3.2-23	13A of 53	102023-9A	
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3.2-23	15 of 53	102023-10	
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3.2-23	18 of 53	108023-11	
3.2-23	19 of 53	102023-12	
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3.2-23	24A of 53	108023-15	
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3.2-23	25A of 53	108023-16	
3.2-23	26A of 53	102023-17A	
3.2-23	26B of 53	102023-17B	
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3.2-23	26D of 53	108023-17	
3.2-23	27 of 53	102023-15	
3.2-23	28 of 53	102023-19	
3.2-23	29 of 53	102023-18	
3.2-23	29A of 53	102023-18A	

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Figure	Sheet	Drawing	Description
3.2-23	29B of 53	102023-18B	
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3.2-23	29D of 53	102023-18D	
3.2-23	29E of 53	102023-18E	
3.2-23	29F of 53	102023-18F	
3.2-23	30 of 53	108023-18	
3.2-23	30A of 53	108023-18A	
3.2-23	30B of 53	108023-18B	
3.2-23	30C of 53	108023-18C	
3.2-23	30D of 53	108023-19	
3.2-23	31 of 53	102023-20	
3.2-23	32 of 53	108023-20	
3.2-24	1 of 2	102024-3	Piping Schematic - Gaseous Radwaste System (2 Sheets)
3.2-24	2 of 2	108024-3	
3.2-25	1 of 13	102025-3	Piping Schematic - Compressed Air System (13 Sheets)
3.2-25	1A of 13	102025-3A	
3.2-25	1B of 13	102025-3B	
3.2-25	2 of 13	108025-3	
3.2-25	3 of 13	102025-4	
3.2-25	3A of 13	102025-4A	
3.2-25	4 of 13	108025-4	
3.2-25	5 of 13	102025-5	
3.2-25	6 of 13	108025-5	
3.2-25	7 of 13	102025-6	
3.2-25	8 of 13	108025-6	
3.2-25	8A of 13	102025-8	
3.2-25	9 of 13	108025-8	
3.2-26	1 of 5	102026-3	Piping Schematic - Nitrogen and Hydrogen System (5 Sheets)
3.2-26	1A of 5	102026-3A	
3.2-26	2 of 5	108026-3	
3.2-26	3 of 5	102026-4	
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3.2-27	1 of 2	102027-3	Piping Schematic - Oily Water Separator and Turbine Building Sump System (2 Sheets)
3.2-27	2 of 2	108027-3	
3.5-6		505481-1	Auxiliary Feedwater Pump Turbine Missile Shield
3.6-2	1 of 2	438288-1	Containment Structure Pipe Rupture Restraints (2 sheets)
3.6-2	2 of 2	443359-1	
3.6-5		515939-1	HELB Compartment Pressurization Study El. 85 ft Turbine Building
3.6-6		515940-1	HELB Compartment Pressurization Study El. 104 ft Turbine Building
3.6-7		515941-1	HELB Compartment Pressurization Study El. 119 ft Turbine Building
3.6-8		515942-1	HELB Compartment Pressurization Study El. 140 ft Turbine Building
3.6-9		515943-1	HELB Compartment Pressurization Study El. 60 ft Auxiliary and Containment Building
3.6-10		515944-1	HELB Compartment Pressurization Study El. 73 ft Auxiliary and Containment Building
3.6-11		515945-1	HELB Compartment Pressurization Study El. 85 ft Auxiliary and Containment Building
3.6-12		515946-1	HELB Compartment Pressurization Study El. 91 and 100 ft Auxiliary, Containment and Fuel Handling Bldg
3.6-13		515947-1	HELB Compartment Pressurization Study El. 115 ft Auxiliary, Containment and Fuel Handling Bldg
3.6-14		515948-1	HELB Compartment Pressurization Study El. 140 ft Auxiliary, Containment and Fuel Handling Bldg
3.6-15		515949-1	HELB Compartment Pressurization Study Section A-A Auxiliary Bldg
3.8-16	1 of 2	443252-1	Interior Concrete Outline – Plan at El. 119 ft and 140 ft, Containment Structure Areas G and F (2 sheets)
3.8-16	2 of 2	438233-1	
3.8-17	1 of 2	443254-1	Interior Concrete Outline Main Sections Containment Structure (2 sheets)
3.8-17	2 of 2	438234-1	

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Figure	Sheet	Drawing	Description
3.8-18	1 of 2	443276-1	Interior Concrete Reinforcing Typical Details and Drawing List Containment Structure (2 sheets)
3.8-18	2 of 2	438231-1	
3.8-19	1 of 4	443277-1	Interior Concrete Reinforcing Sections and Details Containment Structure (4 sheets)
3.8-19	2 of 4	438239-1	
3.8-19	3 of 4	438240-1	
3.8-19	4 of 4	438242-1	
3.8-20	1 of 2	443370-1	Concrete Outline and Reinforcing Annulus Platform at El. 140 ft, Containment Structure Areas F and G (2 sheets)
3.8-20	2 of 2	447254-1	
3.8-23		438267-1	Containment Structure, Polar Crane
3.8-45		438431-1	Auxiliary Building, Concrete Outline - Plan at El. 100 ft Areas H and K
3.8-46	1 of 2	438432-1	Auxiliary Building, Concrete Outline - Plan at El. 115 ft Areas J, GE, and GW (2 sheets)
3.8-46	2 of 2	439533-1	
3.8-47	1 of 3	438449-1	Auxiliary Building, Concrete Outline - Plans at El. 85, 100, 115, and 140 ft - Area L (3 sheets)
3.8-47	2 of 3	443204-1	
3.8-47	3 of 3	443205-1	
3.8-48		438445-1	Auxiliary Building, Concrete Outline - Section Areas J and K
3.8-49		438441-1	Auxiliary Building, Concrete Outline - Section Areas H and K
3.8-50	1 of 2	438457-1	Auxiliary Building, Concrete Reinforcing - Plan at El. 115 ft - Areas J, GE, and GW (2 sheets)
3.8-50	2 of 2	443227-1	
3.8-51		438458-1	Auxiliary Building, Concrete Reinforcing - Plan at El. 115 ft - Areas H and K
3.8-52		443216-1	Auxiliary Building, Concrete Reinforcing - Plans at El. 115 and 140 ft - Area L
3.8-53		443460-1	Auxiliary Building, Concrete Reinforcing - Miscellaneous Sections - Area K
3.8-54		438471-1	Auxiliary Building, Concrete Reinforcing – Section Areas H, K, and GE
3.8-55		438465-1	Auxiliary Building, Control Room - Sections

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3.8-56		438474-1	Auxiliary Building, Spent Fuel Pool - Concrete Reinforcing
3.8-57		439506-1	Auxiliary Building, Crane Support Structure - Elevations and Details
3.8-58		439507-1	Auxiliary Building, Crane Support Structure - Section and Details
3.8-59		439509-1	Auxiliary Building, Refueling Areas Overhead Crane
3.8-65	1 of 2	438034-1	Design Class I Tanks Concrete Foundations (2 Sheets)
3.8-65	2 of 2	463987-1	
3.8-72	1 of 2	59459-1	Concrete Outline Plan – Top Deck Area 1 Intake Structure
3.8-72	2 of 2	59460-1	Concrete Outline Plan – Top Deck Area 2 Intake Structure
3.8-73	1 of 2	59461-1	Concrete Outline Plan – Pump Deck Area 1 Intake Structure
3.8-73	2 of 2	59462-1	Concrete Outline Plan – Pump Deck Area 2 Intake Structure
3.8-74	1 of 2	59463-1	Concrete Outline Plan – Invert Area 1 Intake Structure
3.8-74	2 of 2	59464-1	Concrete Outline Plan – Invert Area 2 Intake Structure
3.8-83		515213-1	Safety Related Masonry Walls, Turbine Bldg - Unit 1
3.8-84		515214-1	Safety Related Masonry Walls, Turbine Bldg - Unit 2
3.8-85		515215-1	Safety Related Masonry Walls, Auxiliary Bldg
4.2-1	1 of 2	6006510-7	Core Cross Section Outline – Unit 1
4.2-1	2 of 2	6006510-14	Core Cross Section Outline – Unit 2
4.2-2	1 of 2	6006510-155	17x17 Fuel Assembly Outline – Unit 1
4.2-2	2 of 2	6006510-132	17x17 Fuel Assembly Outline – Unit 2
4.2-3	1 of 2	6006510-156	Fuel Rod Assembly Outline – Unit 1
4.2-3	2 of 2	6006510-133	Fuel Rod Assembly Outline – Unit 2
4.2-16	1 of 5	6006510-61	RCCA Outline (Framatome)
4.2-16	2 of 5	6006510-134 Page 1	RCCA Outline (Westinghouse)
4.2-16	3 of 5	6006510-134 Page 2	RCCA Outline (Westinghouse)

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Figure	Sheet	Drawing	Description
4.2-16	4 of 5	6006510-190	RCCA Outline - Control Rod Spider Pack (Westinghouse NG-RCCA)
4.2-16	5 of 5	6006510-191	RCCA Outline - Control Rod Assembly (Westinghouse NG-RCCA)
4.2-17	1 of 2	6006510-65	Absorber Rod (Framatome)
4.2-17	2 of 2	6006510-135 Page 1	Absorber Rod (Westinghouse)
4.2-18A		6006510-21	Wet Annular Burnable Absorber Rod
4.2-21		6006510-22	Secondary Source Assembly
4.2-22		6006510-23	Thimble Plug Assembly
4.2-24	1 of 2	6023226-24	Control Rod Drive Mechanism – Unit 1
4.2-24	2 of 2	6023226-27	Control Rod Drive Mechanism – Unit 2
5.5-13		500825-1	U1: Function Diagram, Reactor-Turbine Generator Protection
5.5-17		500800-1	U2: Function Diagram, Reactor-Turbine Generator Protection
6.3-6		6023231-1	DCPP1 Strainer Installation
6.3-7		6023231-20	DCPP2 Strainer Installation
6.5-1		107031-4	Auxiliary Feedwater System
6.5-2		107031-1A	Long Term Cooling Water System
7.2-1	1 of 36	495841-1	Instrumentation and Control System Logic Diagrams (36 Sheets)
7.2-1	2 of 36	495871-1	
7.2-1	3 of 36	495842-1	
7.2-1	4 of 36	495872-1	
7.2-1	5 of 36	495843-1	
7.2-1	6 of 36	495873-1	
7.2-1	7 of 36	495844-1	
7.2-1	8 of 36	495874-1	
7.2-1	9 of 36	495845-1	
7.2-1	10 of 36	495875-1	
7.2-1	11 of 36	495846-1	
7.2-1	12 of 36	495876-1	
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7.2-1	14 of 36	495877-1	
7.2-1	15 of 36	495848-1	

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7.2-1	18 of 36	495879-1	
7.2-1	19 of 36	495850-1	
7.2-1	20 of 36	495880-1	
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7.2-1	24 of 36	495882-1	
7.2-1	25 of 36	495853-1	
7.2-1	26 of 36	495883-1	
7.2-1	27 of 36	495854-1	
7.2-1	28 of 36	495884-1	
7.2-1	29 of 36	495855-1	
7.2-1	30 of 36	495885-1	
7.2-1	31 of 36	495856-1	
7.2-1	32 of 36	495886-1	
7.2-1	33 of 36	495857-1	
7.2-1	34 of 36	495887-1	
7.2-1	35 of 36	495858-1	
7.2-1	36 of 36	495888-1	
7.3-1		19425-1	Logic Diagram Symbols
7.3-2	1 of 2	338070-1	Logic Diagram - Reactor Coolant Pump (2 sheets)
7.3-2	2 of 2	102787-1	
7.3-3	1 of 2	19404-1	Logic Diagram – Centrifugal Charging Pump (CCP3) (2 sheets)
7.3-3	2 of 2	102788-1	
7.3-4	1 of 2	19405-1	Logic Diagram - Centrifugal Charging Pumps (CCP1 and CCP2) (2 sheets)
7.3-4	2 of 2	102789-1	
7.3-5	1 of 2	19406-1	Logic Diagram - Auxiliary Saltwater Pumps (2 sheets)
7.3-5	2 of 2	102790-1	
7.3-6	1 of 2	19407-1	Logic Diagram - Containment Fan Coolers (2 sheets)

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7.3-6	2 of 2	102791-1	
7.3-7	1 of 2	19408-1	Logic Diagram - Component Cooling Water Pumps (2 sheets)
7.3-7	2 of 2	102792-1	
7.3-8	1 of 2	19409-1	Logic Diagram - Auxiliary Feedwater Pumps (2 sheets)
7.3-8	2 of 2	102800-1	
7.3-9		19410-1	Logic Diagram - Residual Heat Removal Pumps (2 sheets)
7.3-9	2 of 2	102793-1	
7.3-10	1 of 2	19411-1	Logic Diagram - Safety Injection Pumps (2 sheets)
7.3-10	2 of 2	102794-1	
7.3-11	1 of 2	19412-1	Logic Diagram - Containment Spray Pumps (2 sheets)
7.3-11	2 of 2	102795-1	
7.3-12	1 of 2	19413-1	Logic Diagram - Primary Makeup Water Pumps (2 sheets)
7.3-12	2 of 2	102796-1	
7.3-13	1 of 2	19414-1	Logic Diagram - Boric Acid Transfer Pumps (2 sheets)
7.3-13	2 of 2	102797-1	
7.3-14	1 of 2	437507-1	Schematic Diagram - Auxiliary Feedwater Motor-Operated Valves (2 sheets)
7.3-14	2 of 2	441301-1	
7.3-15	1 of 2	437551-1	Schematic Diagram - Turbine Control (2 sheets)
7.3-15	2 of 2	441253-1	
7.3-16	1 of 2	437567-1	Schematic Diagram - Feedwater Pump Turbine Control (2 sheets)
7.3-16	2 of 2	441270-1	
7.3-17	1 of 2	437583-1	Schematic Diagram - Motor-Driven Auxiliary Feedwater Pumps (2 sheets)
7.3-17	2 of 2	441302-1	
7.3-18	1 of 4	437584-1	Schematic Diagram - Auxiliary Feedwater Pumps Turbine Control (4 Sheets)
7.3-18	2 of 4	455060-1	

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7.3-18	3 of 4	441303-1	
7.3-18	4 of 4	455097-1	
7.3-19	1 of 2	437585-1	Schematic Diagram - Feedwater Motor-Operated Isolation Valves (2 sheets)
7.3-19	2 of 2	441304-1	
7.3-20	1 of 2	477846-1	Schematic Diagram - Reactor Coolant Pump (2 sheets)
7.3-20	2 of 2	441305-1	
7.3-21	1 of 4	437587-1	Schematic Diagram - Reactor Coolant Motor-Operated Valves and Reactor Coolant System Solenoid Valves (4 Sheets)
7.3-21	2 of 4	437609-1	
7.3-21	3 of 4	441306-1	
7.3-21	4 of 4	441328-1	
7.3-22	1 of 2	437588-1	Schematic Diagram - Safety Injection System Solenoid Valves (2 sheets)
7.3-22	2 of 2	441316-1	
7.3-23	1 of 2	437589-1	Schematic Diagram - Safety Injection Pumps (2 sheets)
7.3-23	2 of 2	441315-1	
7.3-24	1 of 2	437590-1	Schematic Diagram - Containment Spray Pumps (2 sheets)
7.3-24	2 of 2	441307-1	
7.3-25	1 of 2	437591-1	Schematic Diagram - Residual Heat Removal Pumps (2 sheets)
7.3-25	2 of 2	441309-1	
7.3-26	1 of 2	437592-1	Schematic Diagram - Residual Heat Removal Flow Control Valves (2 sheets)
7.3-26	2 of 2	441310-1	
7.3-27	1 of 2	437593-1	Schematic Diagram - Component Cooling Water Pumps (2 sheets)
7.3-27	2 of 2	441311-1	
7.3-28	1 of 2	437594-1	Schematic Diagram - Auxiliary Saltwater Pumps (2 sheets)
7.3-28	2 of 2	441287-1	
7.3-29	1 of 2	437595-1	Schematic Diagram - Charging Pumps (2 sheets)
7.3-29	2 of 2	441312-1	

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7.3-30	1 of 8	437596-1	Schematic Diagram - Chemical and Volume Control System (8 Sheets)
7.3-30	2 of 8	437597-1	
7.3-30	3 of 8	437598-1	
7.3-30	4 of 8	437599-1	
7.3-30	5 of 8	441320-1	
7.3-30	6 of 8	441321-1	
7.3-30	7 of 8	441322-1	
7.3-30	8 of 8	477316-1	
7.3-31	1 of 4	437600-1	Schematic Diagram - Containment Fan Coolers (4 sheets)
7.3-31	2 of 4	437600-2	
7.3-31	3 of 4	441313-1	
7.3-31	4 of 4	441313-2	
7.3-32	1 of 2	437604-1	Schematic Diagram - Containment Spray System Motor-Operated Valves (2 sheets)
7.3-32	2 of 2	441308-1	
7.3-33	1 of 6 (U1)	437605-1	Schematic Diagram - Safety Injection System Motor-Operated Valves (6 Sheets)
7.3-33	2 of 6 (U1)	437606-1	
7.3-33	3 of 6(U1)	437606-2	
7.3-33	4 of 6 (U2)	441317-1	
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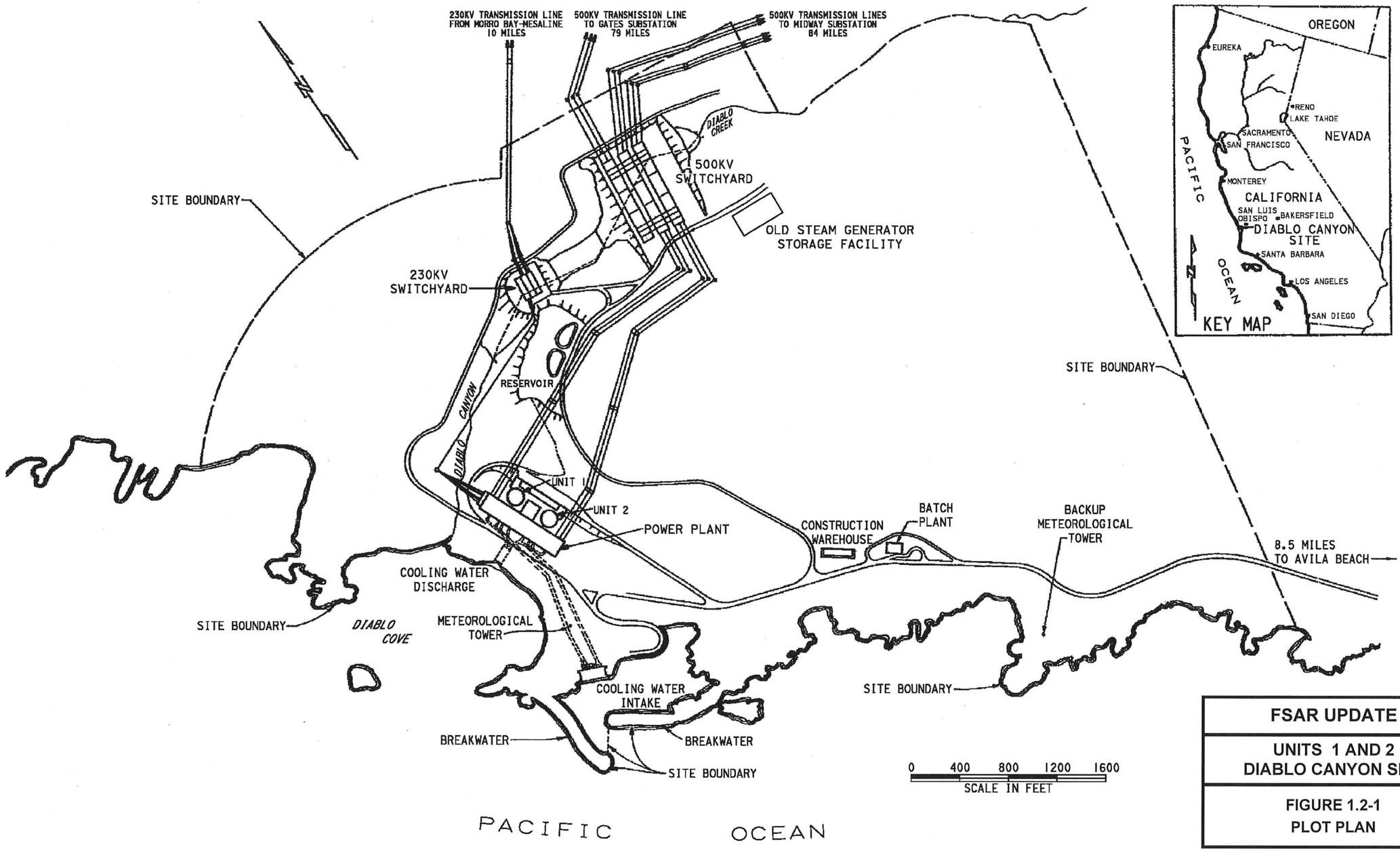
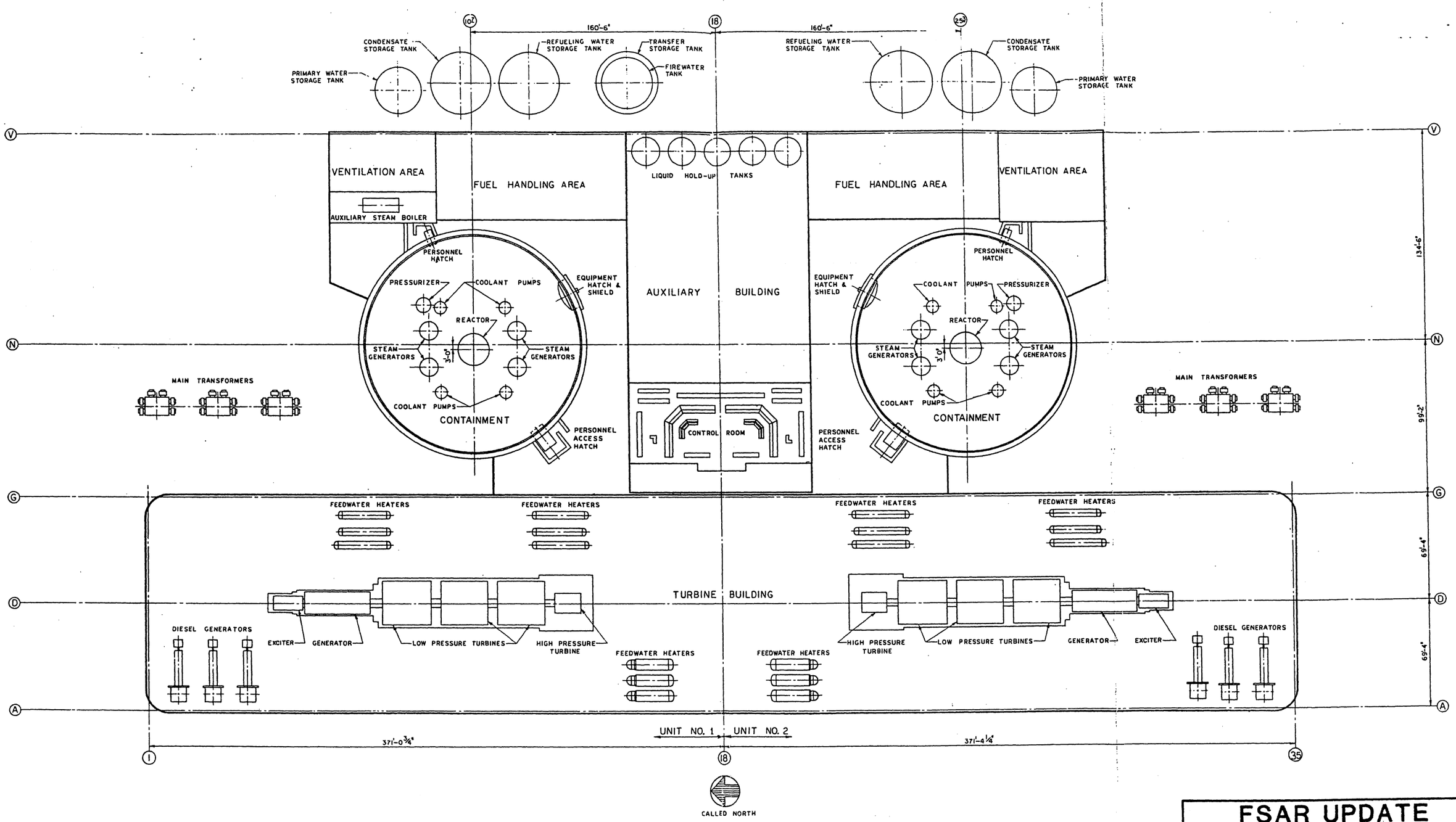


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 1.2-1 PLOT PLAN

Revision 18 October 2008



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

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Chapter 2

SITE CHARACTERISTICS

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NOTE:

(a) This figure corresponds to a controlled engineering drawing that is incorporated by reference into the FSAR Update. See Table 1.6-1 for the correlation between the FSAR Update figure number and the corresponding controlled engineering drawing number.

Chapter 2

SITE CHARACTERISTICS

This chapter describes the Diablo Canyon Power Plant (DCPP) site and vicinity as they existed when the facility was licensed. In the past some changes to site characteristics have been incorporated into this chapter and parts of this chapter reflect this more recent information. Details of the current site area may not be completely consistent with the historic descriptions. Accurate and current site characteristics germane to the licensing bases are contained in the Emergency Plan, Annual Radiological Environmental Operating Report, and the Annual Radioactive Effluent Release Report.

HISTORICAL INFORMATION BELOW IS SHOWN IN ITALICS

This chapter provides information on the geological, seismological, hydrological, and meteorological characteristics of the DCPP site and vicinity. Population distribution, land use, and site activities and controls are also discussed. This information, used in conjunction with the detailed technical discussions provided in other chapters, shows the adequacy of the site for the safe operation of nuclear power units.

2.1 GEOGRAPHY AND DEMOGRAPHY

2.1.1 DESIGN BASES

2.1.1.1 10 CFR Part 100 – Reactor Site Criteria

DCPP is committed to following the guidance set by the standard definition of exclusion area, low population zone (LPZ) and population center distance.

2.1.2 SAFETY EVALUATION

2.1.2.1 10 CFR Part 100 – Reactor Site Criteria

The DCPP commitment to exclusion area, LPZ and population center distance is described in the following sections.

HISTORICAL INFORMATION BELOW IS SHOWN IN ITALICS

2.1.2.1.1 Site Location

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

and 3,898,400 meters N. Figure 2.1-1 locates the site on a map of western San Luis Obispo County.

2.1.2.1.2 Site Description

The site boundary and the location of principal structures are shown in Figure 2.1-2. A portion of the site is bounded by the Pacific Ocean.

The DCPP site consists of approximately 750 acres of land located near the mouth of Diablo Creek. 165 acres of the DCPP site are located north of Diablo Creek; this acreage is owned by Pacific Gas and Electric Company (PG&E). The remaining 585 acres are located adjacent to and south of Diablo Creek. It was purchased in 1995 by Eureka Energy Company (Eureka), a wholly owned subsidiary of PG&E.

All coastal properties located north of Diablo Creek, extending north to the southerly boundary of Montana de Oro State Park and reaching inland approximately 1.5 mile has been owned by PG&E since 1988. Coastal properties located south of Diablo Creek and also reaching inland approximately 1.5 mile has been owned by Eureka since 1995. Prior to 1995, PG&E leased the property from the owner, Luigi Marre Land and Cattle Company. In 1988, PG&E purchased approximately 4500 acres located north of the DCPP site. This section of land consists of approximately 5 miles of coastline and reaches inland approximately 1.5 mile. Except for the DCPP site, the approximately 4500 acres are encumbered by a grazing lease that expires in the year 2000.

There are no plans for development of the property, most of which is within the area subject to the California Coastal Act of 1976. Any development plans would be subject to approval by a discretionary land use permitting process. In 1988 the San Luis Obispo County Planning Department was given authority by the California Coastal Commission to interpret the Act and incorporate it into the County of San Luis Obispo's General Plan, which included the right to issue coastal land use permits. Because it is a discretionary permitting process, the County of San Luis Obispo has the authority to require development projects to be approved by the California Coastal Commission rather than obtaining final approval by the County of San Luis Obispo, Board of Supervisors.

In addition, portions of the coastal property have been listed in the National Register of Historic Places pursuant to the "National Historic Preservation Act of 1966" as a place of historic significance due to the presence of numerous Native American remains and scientific data potential.

2.1.2.1.3 Exclusion Area Control

PG&E has complete authority to determine all activities within the site boundary and this authority extends to the mean high water line along the ocean. On land, the site boundary, the boundary of the exclusion area (as defined in 10 CFR 100), and the boundary of the unrestricted area (as defined in 10 CFR 20) are shown in Figure 2.1-2.

Minimum distances from potential release points for radioactive materials to the unrestricted area boundary and to the mean high water line are also shown in Figure 2.1-2.

The definition of unrestricted area has been expanded over that in 10 CFR 20.1003. The unrestricted area boundary may coincide with the exclusion (fenced) area boundary, as defined in 10 CFR 100.3, but the unrestricted area does not include areas over water bodies. The concept of unrestricted areas, established at or beyond the site boundary, is utilized in the Technical Specifications limiting conditions for operation to keep levels of radioactive materials in liquid and gaseous effluents as low as is reasonably achievable (ALARA), pursuant to 10 CFR 50.36a.

On land, there are no activities unrelated to plant operation within the exclusion area; it is not traversed by public highway or railroad. Normal access to the site is from the south by private road (PG&E road easement) that is fenced and posted by PG&E.

PG&E has the right, within the DCPP site, to use excavated materials during the construction of the plant (considering that PG&E obtains all permitting required by regulatory agencies prior to excavation). It is unclear legally if the owner retains all mineral rights. Whatever mineral rights an owner may retain, the owner cannot exercise any such rights in a manner that would interfere with PG&E's rights. Any proposed mining operation (including but not limited to excavation, drilling, and blasting) that would be conducted close enough to the plant to threaten the structural integrity of its foundations will be carefully reviewed and PG&E will take whatever steps it deems necessary to ensure that: (a) the health and safety of the public is not jeopardized, and (b) the operation of the plant is not disrupted. Any entry by the lessee onto the land is subject to PG&E's safety rules and regulations, as is the right to restrict the use of buildings and other structures, and to exclude persons therefrom to the extent necessary to comply with nuclear reactor site criteria.

The mineral rights within the 165 acre PG&E portion of the DCPP site are owned by PG&E, but there is no information suggesting that the land contains any commercially valuable minerals other than for use as borrow materials.

The offshore area (below the mean high water line) is not under PG&E's control. Due to the natural rough and precipitous conditions of the offshore area at Diablo Cove and near its southerly boundary, as shown in the aerial photograph, Figure 2.1-3, the area could only be occupied with great difficulty. (Some of these rocks have since been incorporated into the breakwater.) There is no history of public access to these rocks.

For the offshore area, the modeled distances to the EAB over the ocean are based in an extension of the arc (shown in UFSAR Figure 2.1-2 in the northern direction) over the water until it touches the shore line. From this point, the EAB follows the shoreline until it intersects with the farm type fence that defines the EAB on land in the southern section. The approach in defining the EAB over the water is conservative since it remains well within the 2000-yard radius offshore security zone maintained by the U.S.

coast guard in the south-southeast clockwise through the west-northwest direction sectors.

HISTORICAL INFORMATION BELOW IS SHOWN IN ITALICS

The Captain of the Port of Los Angeles-Long Beach, under the authority of 33 U.S.C. Section 1226 and Section 1231, has established a Security Zone in the Pacific Ocean, from surface to bottom, within a 2,000-yard radius of DCPP centered at position 35 12' 23"N, 120 51' 23" W (Datum 83). No person or vessel may enter or remain in this Security Zone without the permission of the Captain of the Port Los Angeles-Long Beach. This Security Zone will be enforced by representatives of the Captain of the Port of Los Angeles-Long Beach, San Luis Obispo County Sheriff, and DCPP Security.

2.1.2.1.4 Population and Population Distribution

PG&E has reviewed the original population totals and projections within the 50-mile radius of the plant. The following population data are based on the 2000 census and on projections based on estimates prepared by the State of California Department of Finance. The portion of California that lies within 50 miles of the site is relatively sparsely populated, having approximately 424, 013 residents in 2000. A circle with a 50-mile radius includes most of San Luis Obispo County, about one-third of Santa Barbara County, and a minor, sparsely-populated portion of Monterey County. About 55 percent of the area within the 50-mile circle is on land, the balance being on the Pacific Ocean.

The 2000 census population of this region is very close to that projected in the original Final Safety Analysis Report (FSAR), and subsequent projections by the Department of Finance are similarly close to earlier projections. Table 2.1-1 shows population trends of the State of California and of San Luis Obispo and Santa Barbara Counties. Table 2.1-2 shows the growth since 1960 of the principal cities within 50 miles of the site. Table 2.1-3 lists all communities within 50 miles having a population of 1000 or more, gives distance and direction from the site, and gives the 2000 population.

2.1.2.1.4.1 Population Within 10 Miles

In 1980, approximately 16,760 persons resided within 10 miles of the site. The 1990 census counted approximately 22,200 residents within the same 10 miles. The 2000 census counted approximately 23,661 residents within the same 10 miles. As in 1980, the nearest residence is about 1-1/2 miles north-northwest of the site and two persons occupy this dwelling. There are 9 permanently inhabited dwellings, for about 17 residents, within 5 miles of the plant. The population within the 6-mile radius, used in the emergency plan, is estimated to be 100.

Figure 2.1-4 shows the 2000 population distribution within a 10-mile radius wherein the area is divided into 22-1/2° sectors, with part circles of radii of 1, 2, 3, 4, 5, and 10 miles. Figures 2.1-5 and 2.1-6 show projected population distributions for 2010 and 2025,

respectively, and are based primarily on population projections published by the California Department of Finance. The distributions are based on the assumption that the land usage will not change in character during the next 25 years, and that population growth within 10 miles will be proportional to growth in San Luis Obispo County as a whole.

2.1.2.1.4.2 Population Between 10 and 50 Miles

Figure 2.1-7 shows the 2000 population distribution between 10 and 50 miles, within the sectors of 22-1/2°, as before, but with part circles of radii of 10, 20, 30, 40, and 50 miles. Figures 2.1-8 and 2.1-9 show projected distributions for 2010 and 2025, respectively, and are based primarily on population projections published by the California Department of Finance and interviews with area government officials. In 2000, some 82 percent of those persons within 50 miles of the site resided in the population centers listed in Table 2.1-3.

2.1.2.1.4.3 Low Population Zone

As previously mentioned, the population within the 6-mile radius used in the emergency plan is estimated to be 100. This number is derived from a survey of residences in this area, and approximates the LPZ as defined in 10 CFR 100. Coincidentally, 6 miles is the distance to the nearest residential community development at Los Osos, north of the site. It is assumed that the population within this mountainous and largely inaccessible zone will stay constant for the foreseeable future. Figure 2.1-15 shows the LPZ.

2.1.2.1.4.4 Transient Population

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

During August, the month of heaviest influx, the maximum overnight transient population in motels and state parks in this area is approximately 100,000 persons. However, there are no significant seasonal or diurnal shifts in population or population distribution within the LPZ. Table 2.1-4 lists transient population for recreation areas within 50 miles of the site for the periods of record listed.

Within the LPZ, the maximum recorded number of persons at any single time is estimated to be 5000. This figure is provided by the State Department of Parks and Recreation and corresponds to the maximum daytime use of Montana de Oro State Park. Overnight use is considerably less, an estimated maximum of 400. Evacuation of these numbers of persons from the park in the event of a radiation release could be accomplished as provided for in the emergency plan, with a reasonable probability that no injury would result. For all accident analyses considered in Chapter 15, there is a wide margin of safety between exposures at the outer boundary of the LPZ for a 30-day

period following a postulated accident and the allowable doses considered acceptable in 10 CFR 100 for the same location.

2.1.2.1.4.5 Population Center Distance

The population center distance as defined in 10 CFR 100 is approximately 10 miles, the distance to the nearest boundary of San Luis Obispo, situated beyond the San Luis Range, east-northeast of the site, with a 2000 population of 44,174.

2.1.2.1.4.6 Public Facilities and Institutions

Several elementary schools are located within 10 miles of the site, near Los Osos and Avila Beach. These serve the local community and do not draw from outlying areas. California Polytechnic State University is 12 miles north-northeast of the DCPP site and has an enrollment of approximately 16,000. Cuesta College is located 10 miles northeast of the DCPP site and has an enrollment of approximately 7,000.

Montana de Oro State Park is located north of the site. Its area of principal use is along the beach, between 4 and 5 miles north-northwest of the site. The total number of visitor days during a 12-month period over the last five years averages approximately 680,000.

2.1.2.1.5 Boundaries for Establishing Effluent Release Limits

On land, the boundary line of the unrestricted area (as defined in 10 CFR 20) coincides with the site boundary as shown in Figure 2.1-2. The relationship of the exclusion area to the unrestricted area and the site area is also shown in Figure 2.1-2. Control of access to the land area within this boundary is as described for the exclusion area control. As therein described, no special provisions have been made for control of access, during normal operation, to the offshore area below the mean high water line. Occupancy of this area by any member of the public is expected to result in exposures, during normal operation, within the limits established by 10 CFR 20 and will be maintained ALARA.

2.1.2.1.6 Uses of Adjacent Lands and Waters

The San Luis Range, attaining a height of 1800 feet, dominates the region between the site and US Route 101. This upland country is used to a limited extent for grazing beef cattle and, to a very minor extent, dairy cattle. The terrain east of US Route 101, lying in the mostly inaccessible Santa Lucia Mountains, is sparsely populated with little development. A large portion of this area is included within the Los Padres National Forest.

2.1.2.1.6.1 Agriculture

San Luis Obispo County has relatively little level land, except for a few small coastal valleys such as the Santa Maria and San Luis Valleys, and some land along the county's northern border in the Salinas Valley and Carrizo Plain areas. Farming is a significant land use in the county. Principal crops include wine grapes, vegetables, cattle, nurseries, fruits, nuts, and grain. There are several vineyards and wineries located in the county. The county's leading agricultural product is wine grapes, valued at $123,500,000 in 2003. The total farm acreage in the county is approximately 1,300,000. The county contains a total of 2,128,640 acres.

2.1.2.1.6.2 Dairying

The nearest dairying activity is 12 miles northeast of the site at California State Polytechnic College and produces 1000 gallons of milk per day. Some replacement heifers and dry cows are sometimes pastured on property adjacent to site.

2.1.2.1.6.3 Fisheries

The DCPP site is located between two fishing harbors that support commercial and sport fishing activities. Port San Luis Harbor is located in Avila Beach, approximately 7 miles downcoast of the DCPP site. Morro Bay Harbor is located in Morro Bay, approximately 14 miles upcoast of the site. In 2003 the combined landings for the sport catch (known as commercial passenger fishing vessel fleet) totaled approximately 110,510 rockfish and 10,683 fish of other species, for a total of 8 fishing vessels. Sport catch are calculated by the number of fish caught.

Commercial landings are calculated by poundage of landings by port. In 2003 at Port San Luis and at Morro Bay Harbor, the landings were estimated to be as follows: 450,423 pounds of rockfish, 1,433,650 pounds of squid; 534,000 pounds of crab; 282,696 pounds of shrimp; and 1,592 pounds of urchins were landed.

There has been a dramatic decrease since 1970 in the abalone fishery, with approximately 621,000 pounds taken in 1966 and 200,000 pounds taken in 1970. Some data suggest that the southern movement of the Southern California sea otter may have had an impact on the red abalone population.

2.1.2.1.6.4 Surface and Groundwater

As discussed in Section 2.4, there are two public water supply groundwater basins within 10 miles of the site. Avila Beach County Water and Sewer District and San Miguelito Mutual Water and Sewer Company provide water to the Avila Beach and Avila Valley area.

2.1.2.1.6.5 Land Usage Within 5 Miles

An annual land use census is required by Regulatory Guide 4.8 (Reference 6). A census is required to be conducted at least once per year during the growing season (between February 15 and December 1 for the Diablo Canyon environs). The census is to identify the nearest milk animal and nearest garden greater than 50 square meters (500 square feet) producing broadleaf vegetation in each of 16 22-1/2° sectors within a distance of 8 kilometers (5 miles) of the plant. In addition, Regulatory Guide 4.8 requires the identification of the location of the nearest residence in each of the 16 sectors within a distance of 5 miles.

Land owners were identified from San Luis Obispo County records, and direct contact was made with them or their tenants. The only agricultural activities indicated by County personnel were cattle grazing in much of the area surrounding the site, and a farm in the east-southeast sector (along the site access road) producing legumes and cereal grass (grains).

Personal and telephone contacts with the land owners or tenants also identified a household garden greater than 500 square feet in the east sector in addition to the above mentioned farming. No milk animals were identified on these properties or within the first 5 miles in any sector.

The 1985 land use census results indicate the land use in the vicinity of the plant site has not changed significantly from that identified in Amendment 44 (July 1976) of the FSAR. A summary of the land use census is presented in Table 2.1-5 and Figure 2.1-14. Table 2.1-5 lists the distances measured in miles from the Unit 1 reactor centerline to the nearest animal, residence, and vegetable garden. The locations of gardens or farms greater than 500 square feet are shown in Figure 2.1-14. There is a farm in the southeast sector along the site access road on the coastal plateau; it starts approximately 2 miles from the plant and extends to 4.5 miles from the plant. Figure 2.1-14 also shows the nearest residence is 1.55 miles north-northwest of the plant. Nine permanent residences were identified within 5 miles of the plant.

2.1.3 REFERENCES

1. Regulatory Guide 4.8, Environmental Technical Specifications for Nuclear Power Plants, USNRC, December 1975.

2.2 NEARBY INDUSTRIAL, TRANSPORTATION, AND MILITARY FACILITIES

This section establishes that DCPP is designed to safely withstand the effects of potential accidents at, or as a result of the presence of, other industrial, transportation, mining, and military installations or operations near the site which may have a potentially significant effect on the safe operation of the plant.

2.2.1 DESIGN BASES

2.2.1.1 Nearby Industrial, Transportation, and Military Facilities Safety Function Requirement

(1) Protection of the Intake Structure

The DCPP intake structure is appropriately protected from marine vessel collisions that may pose a significant hazard to the PG&E Design Class I auxiliary saltwater (ASW) system.

2.2.1.2 10 CFR Part 100 - Reactor Site Criteria

PG&E considered the characteristics peculiar to the site, the site location and the use characteristics of the site environs when evaluating the DCPP site.

2.2.1.3 Regulatory Guide 1.78, June 1974 - Assumptions For Evaluating The Habitability Of A Nuclear Power Plant Control Room During A Postulated Hazardous Chemical Release

The DCPP control room is appropriately protected from hazardous chemicals that may be discharged as a result of events and conditions outside the control of the plant.

2.2.2 LOCATIONS AND ROUTES

There are no industrial, transportation, mining, or military facilities within 5 miles of the DCPP site. The DCPP site is adjacent to the Pacific Ocean; however, no people or vessels are permitted to come within 2000 yards of the plant (refer to Section 2.1).

Coastal shipping lanes are approximately 20 miles offshore. Prior to 1998, there were local tankers coming into and out of Estero Bay, which is north of the DCPP site. There is no further tanker traffic in either Port San Luis or Estero Bay. The local tanker terminal at Estero Bay closed in 1994, and Avila Pier ceased operation in 1998. Petroleum products and crude oil are no longer stored at Avila Beach, since the storage tanks there were removed in 1999. However, some petroleum products and crude oil continue to be stored at Estero Bay approximately 10 miles from the DCPP site.

Port San Luis Harbor and the Point San Luis Lighthouse are located approximately 6.5 miles south-southeast of the DCPP site. The Coast Guard operates and maintains a

modern light station and navigating equipment adjacent to the lighthouse. Located approximately 6.5 miles east-southeast of the DCPP site is the Cal Poly pier that is owned by California Polytechnic State University and is used for research.

US Highway 101 is the main arterial road serving the coastal region in this portion of California. It passes about 9 miles east of the site, separated from it by the Irish Hills. US Highway 1 passes 10 miles to the north and carries moderate traffic between San Luis Obispo and the coast. The nearest public access is by county roads in Clark Valley (5 miles north) and See Canyon (5 miles east). Access to the site is by Avila Beach Drive (county road) to the entrance of PG&Es private access road (easement).

The Union Pacific Transportation Company provides rail service to the county by a route that roughly parallels US Highway 101. There is no spur track into the site.

The San Luis Obispo County Airport is 12 miles east of the site. There is a smaller airport near Oceano, 15 miles east-southeast of the DCPP site, which accommodates private planes only. The Camp San Luis Obispo airfield, 8 miles northeast of the DCPP site, is not operational.

Aircraft operating out of the San Luis Obispo County Airport are limited to general aviation, freight, and commuter flights weighing generally less than 100,000 pounds.

The approach route for visual landings passes 8 miles from the site, on the far side of the San Luis Range. The approach route for a portion of the traffic passes within approximately 4 miles of the DCPP site at an elevation of 3,000 feet, but is used infrequently.

The largest military and industrial complex is Vandenberg Air Force Base, located about 35 miles south-southeast of the site in Santa Barbara County. Vandenberg Air Force Base employs several thousand military and civilian personnel in the area of Lompoc-Santa Maria.

The closest US Army installation is the Hunter-Liggett Military Reservation located in Monterey County approximately 45 miles north of the site. The California National Guard maintains Camp Roberts, located on the border of Monterey County and San Luis Obispo County, southeast of the Hunter-Liggett Military Reservation and approximately 30 miles north of the DCPP site, and Camp San Luis Obispo, in San Luis Obispo County, located about 14 miles northeast of the DCPP site. In addition, as previously described, a US Coast Guard light station is located in Avila Beach on property commonly known as the Point San Luis Lighthouse property.

2.2.2.1 DESCRIPTIONS

No products are manufactured, stored or transported within 5 miles of DCPP site. Industry in the vicinity of DCPP site is mainly light and of a local nature serving the needs of agriculture in the area. Food processing and refining of crude oil are the area's major industries, although the numbers employed are not large.

2.2.3 SAFETY EVALUATION

2.2.3.1 Nearby Industrial, Transportation, and Military Facilities Safety Function Requirement

(1) Protection of the Intake Structure

Collisions of marine vessels with the intake structure are not a significant hazard to the safe operation of DCPP. The intake structure is protected by massive breakwaters as described in Sections 2.4 and 3.4. Jack R. Benjamin & Associates, Inc., (JBA) (Reference 1), consultants to PG&E, assessed the likelihood of marine vessel collisions with the intake structure thereby endangering operation of the PG&E Design Class I ASW system pumps.

JBA investigated maritime traffic in the vicinity of Diablo Canyon looking for events that could lead to a marine vessel collision with the intake structure. The study considered 13 categories of large vessels, those greater than 100 feet in length and of more than 250 long tons displacement, and a single category including all smaller vessels. Quantitative data were developed for the larger vessel collisions and probability analyses made for both storm dependent and storm independent cases. Development of quantitative data for the smaller vessel collision proved to be not feasible due to the lack of sufficient records of small vessel traffic and accidental groundings. As an alternative approach for smaller vessels, a deterministic structural analysis was made to assess the potential damage to the intake structure for an extreme case collision scenario involving the largest of the smaller vessel category.

The investigations were based on the following conservative assumptions that resulted in computed frequencies of collisions substantially greater than likely to occur:

(1) The entire length of the breakwater is degraded to the mean lower low water (MLLW) level

(2) Any vessel crossing the breakwater boundary always impacts the intake structure

(3) All barges (either large or small vessels) are empty and have only a 3 to 4-foot draft

The storm-independent case probabilistic analysis for large vessels yielded a best estimate frequency of 6.7×10^{-6} collisions per year. The storm-dependent probabilistic analysis, the best estimate annual frequency of collision increased only moderately to 1.9×10^{-5}. The storm independent case, which realistically assumes vessels arriving randomly and encountering storm conditions only a fraction of the time, was used as the basis for evaluating the frequency of impact.

The results of the deterministic analysis indicated that collisions with the intake structure by small vessels of 250 tons or less would be inconsequential to the PG&E Design Class I function of the ASW pumps.

The study demonstrated that larger marine vessels are not likely to collide with the intake structure and that collisions by smaller vessels would not cause sufficient damage to the intake structure to impair the operation of the ASW system. It is, therefore, concluded that collisions of marine vessels with the intake structure are not a significant hazard to the safe operation of the power plant even if the entire breakwater were to be degraded to the MLLW level. The breakwater in the fully repaired normal condition provides a substantial physical barrier to vessels approaching the intake structure, further reducing the potential hazard from collisions.

2.2.3.2 10 CFR Part 100 - Reactor Site Criteria

PG&E has identified and evaluated the characteristics peculiar to the site, including the site location and the use characteristics of the site environment.

DCPP is located in a remote, sparsely populated, undeveloped site that is an essentially agricultural area. None of the activities described in Sections 2.2.2 and 2.2.2.1 could constitute a hazard to the plant.

Due to very limited industry within San Luis Obispo County, any products or materials manufactured, stored, or transported beyond 5 miles are not likely to be a significant hazard to the plant.

No explosive or combustible materials are stored within 5 miles of the site and no natural gas or other pipelines pass within 5 miles of the DCPP site. The risk of fire is minimal, since adjacent hills are sparsely covered with low lying brush and grasses.

Missiles fired from Vandenberg Air Force base to the Western Pacific Missile Range are not directed north or west. Missile launch sites are some 36 miles due south of DCPP. Polar orbit launches are in a southerly direction.

Local shipping tankers come within 5 to 10 miles of the DCPP site. Coastal shipping lanes are approximately 20 miles offshore. Because shipping does not approach closer than 5 miles of the DCPP site and a limited number of tankers pass through, shipping does not pose a hazard to the DCPP site.

Aircraft operating in the area are small in size and few in number. Take-off and landing patterns do not come near the DCPP site and the probability of aircraft impacting or damaging the plant is very low.

On the DCPP site, as well as surrounding properties, there are no natural-draft cooling towers or other tall structures with a potential for damage to PG&E Design Class I equipment or structures in the event of collapse of such tall structures.

2.2.3.3 Regulatory Guide 1.78, June 1974 - Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release

DCPP has evaluated control room habitability in accordance with the Regulatory Guide 1.78, June 1974 screening criteria for stationary sources (refer to Section 6.4.1.3.13).

The nearby industrial, transportation, and military facilities are all located at distances greater than 5 miles from the site. Chemicals stored or situated or frequently shipped by rail, water, or road routes at distances greater than 5 miles from the plant need not be considered because, if a release occurs at such a distance, atmospheric dispersion will dilute and disperse the incoming plume to such a degree that either toxic limits will never be reached or there would be sufficient time for the control room operators to take appropriate action. In addition, the probability of a plume remaining within a given sector for a long period of time is quite small.

2.2.4 REFERENCES

1. Charles A. Kircher, et al, Frequency of Vessel Impact With the Diablo Canyon Intake Structure, Jack R. Benjamin & Associates, Inc., Mountain View, CA, 1982.

2.3 METEOROLOGY

Historical summaries of normal and extreme values of meteorological parameters such as wind speed, wind direction, ambient air temperature, and precipitation are presented in this section. The historical data contained in this section were used for initial plant licensing and are not required to be updated. Wind speed and wind direction for tornado and dose analysis are discussed in Sections 3.3.2 and 2.3.5, respectively. The ambient air temperature for heating, ventilating, and air conditioning (HVAC) analysis is discussed in Section 9.4. Precipitation data for probable maximum flood (PMF) are discussed in Section 2.4.3.

The onsite meteorological monitoring program and the design basis radiological analysis dispersion factors are discussed in this section. The program provides meteorological information for use in (1) estimating potential radiation doses to the public resulting from actual, routine or accidental releases of radioactive materials to the atmosphere and (2) coping with radiological emergencies. Note that the dispersion factors calculated by the onsite meteorological computer described in Section 2.3.4.7 are produced and used for purposes of immediate radionuclide transport and dispersion assessment, and are therefore separate from those used for design bases radiological analyses.

The design basis radiological analysis dispersion factors are described in Section 2.3.5.2 and are applicable to all dose consequence analyses documented in Section 15.5, and the tank rupture events are discussed in Sections 11.2.3.12 and 11.3.3.9.

2.3.1 DESIGN BASES

2.3.1.1 General Design Criterion 11, 1967 – Control Room

Meteorological monitoring is provided to support actions to maintain and control the safe operational status of the plant from the control room.

2.3.1.2 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor meteorological conditions.

2.3.1.3 Meteorology Safety Function Requirements

(1) Calculation of Atmospheric Dispersion

The calculated relative concentration values are provided for use in (1) estimating potential radiation doses to the public resulting from actual, routine or accidental releases of radioactive materials to the atmosphere and (2) coping with radiological emergencies.

2.3.1.4 Safety Guide 23, February 1972 – Onsite Meteorological Programs

An onsite meteorological monitoring program that is capable of providing meteorological data needed to estimate potential radiation doses to the public as a result of routine or accidental release of radioactive material to the atmosphere and to asses other environmental effects is provided.

2.3.1.5 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Control room display instrumentation for use in determining the magnitude of the release of radioactive materials and in continuously assessing such releases during and following an accident is provided.

2.3.1.6 Regulatory Guide 1.111, March 1976 – Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors

Annual average relative concentration values are used during the postulated accident to estimate the long-term atmospheric transport and dispersion of gaseous effluents in routine releases.

2.3.1.7 Regulatory Guide 1.111, Revision 1, July 1977 – Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors

In accordance with the guidance of Regulatory Guide 1.145, Revision 1 annual average relative concentration values are developed for each sector at the outer low population zone (LPZ) boundary distance for that sector, using the method described in Regulatory Position C.1.c of Regulatory Guide 1.111, Revision 1. This information is used as input to develop the design basis radiological analysis χ/Q values at the LPZ using Regulatory Guide 1.145, Revision 1 methodology.

2.3.1.8 Regulatory Guide 1.145, Revision 1, February 1983 – Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants

The method outlined in Regulatory Guide 1.145, Revision , (with the exception of methodology associated with elevated or stack releases, i.e., Regulatory Positions C.1.3.2, C.2.1.2, and C.2.2.2), is used for calculating short-term atmospheric dispersion factors for off-site locations such as the exclusion area boundary or the low population zone for design basis radiological analysis dispersion factors.

2.3.1.9 Regulatory Guide 1.194, June 2003 – Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessments at Nuclear Power Plants

The method outlined in Regulatory Positions C.1 through C.3 and the adjustment factor for vertically orientated energetic releases from steam relief valves and atmospheric dump valves allowed by Regulatory Position C.6 of Regulatory Guide 1.194, June 3003 is used to determine short-term on-site atmospheric dispersion factors in support of design basis radiological habitability assessments.

2.3.1.10 NUREG-0737 (Items III.A.2 and III.A.2.2), November 1980 – Clarification of TMI Action Plan Requirements

Item III.A.2 - Improving Licensee Emergency Preparedness–Long-Term:

Reasonable assurance is provided that adequate protective measures can and will be taken in the event of a radiological emergency. The requirements of NUREG-0654, Revision 1, which provides meteorological criteria to ensure that the methods, systems and equipment for monitoring and assessing the consequences of radiological emergencies are in use, is implemented.

Item III.A.2.2 - Meteorological Data: NUREG-0737, Supplement 1, January 1983 provides the requirements for III.A.2.2 as follows:

Reliable indication of the meteorological variables specified in Regulatory Guide 1.97, Revision 3, for site meteorology is provided.

2.3.1.11 IE Information Notice 84-91, December 1984 – Quality Control Problems of Meteorological Measurements Programs

Meteorological data that are climatically representative, of high quality, and reliable in providing credible dose calculations and recommendations for protective actions in an emergency situation, and for doses calculated to assess the impact of routine releases of radioactive material to the atmosphere are available.

2.3.2 REGIONAL CLIMATOLOGY

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

2.3.2.1 Data Sources

The information used in determining the regional meteorological characteristics of DCPP site consists of climatological summaries, technical studies, and reports by Dye (Reference 2), Edinger (Reference 3), Elford (Reference 4), Holzworth (Reference 6), Martin (Reference 8), Thom References 13 and 14), and a Weather Bureau Technical Paper (Reference 16), all pertinent to the region.

2.3.2.2 General Climate

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

The mean height of the inversion base is approximately 1100 feet. During the wet season, extending from November through March, the Pacific high-pressure area moves southward and weakens in intensity, allowing storms to move into and across the state. More than 80 percent of the annual rainfall occurs during this 5-month period. Middle and high clouds occur mainly with winter storm activity, and strong winds may be associated with the arrival and passage of storm systems. April and October are considered transitional months separating the two seasons.

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

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

2.3.2.3 *Severe Weather*

The annual mean number of days with severe weather conditions, such as tornadoes and ice storms at west coast sites, is zero. Thunderstorms and hail are also rare phenomena, the average occurrence being less than three days per year, as reported by Dye (Reference 2) and Thom (Reference 13). The maximum recorded precipitation in the San Luis Obispo region is 2.35 inches in 1 hour at the DCPP site, and 5.98 inches in 24 hours at San Luis Obispo. The 24 hour maximum and the 1 hour maximum occurred on March 4, 1978. The 24 hour maximum recorded precipitation resulted from

a semistationary low-pressure system located southwest of the central California coast that produced a series of frontal waves. These surges of warm, moist air moved into and across the central portion of the state and produced heavy precipitation. The 1 hour maximum was associated with the passage of a strong cold front.

The maximum recorded annual precipitation at San Luis Obispo was 54.53 inches during 1969. The average annual precipitation at San Luis Obispo is 21.53 inches. There are no fastest mile wind speed records in the general area of Diablo Canyon; surface peak gusts at 46 mph have been reported at Santa Maria, California, and peak gusts of 56 mph have been recorded at the 250 foot level on the tower at DCPP site. The frequency of occurrence of peak gusts of this magnitude is approximately once every 10 years. The 100 year recurrence interval wind speed for the site area is 80 mph, Thom (Reference 14). The number of days having a high air pollution potential averages ten per year, Holzworth (Reference 6).

One of the most severe tropical storms on record along the Southern California coast occurred September 24-25, 1939. It moved northward off the Southern California coast and came inland on the 25th in the Los Angeles area, but dissipated rapidly. This storm was attended by extremely heavy rains and winds of gale force in the Los Angeles area and southward. Precipitation amounts recorded during the storm are shown below; these data show that this storm had little or no effect on the DCPP site:

	Precipitation in Inches			
Location	*September 24*	*September 25*	*September 26*	*Total*
Los Angeles	*1.62*	*3.96*	*0.04*	*5.62*
Oxnard	*0.00*	*1.67*	*0.02*	*1.69*
Ventura	*0.00*	*0.80*	*0.00*	*0.80*
Santa Barbara	*0.09*	*0.16*	*0.01*	*0.26*
Santa Maria	*1.13*	*0.29*	*0.00*	*1.42*
San Luis Obispo	*0.04*	*0.48*	*0.07*	*0.59*

By definition, gale force winds range from 30 to 60 mph, so the intensity of this storm was about equal to the expected wind speed having a recurrence interval of 10 years at the site. The maximum daily precipitation of 4 inches recorded in this storm was well under the expected maximum probable precipitation estimated for DCPP site.

2.3.3 LOCAL METEOROLOGY

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

2.3.3.1 Data from Offsite Sources

Meteorological data from National Weather Service Stations are indicated below and data from other sources near the DCPP site had been gathered and reported previously in prior FSAR Updates as Appendix 2.3J. Since this appendix, as well as other

appendices to this chapter (including Appendices 2.3A-K, 2.4A-C, and 2.5A-F) is merely of historical value at this time, they have been removed from this revision of the FSAR Update and are included only by reference collectively as Reference 27. However, all of these appendices are maintained available for review at PG&E offices. In addition, these appendices have also been docketed at the U.S. Nuclear Regulatory Commission (NRC) as a part of Revision 0 through Revision 10 of the FSAR Update. Further, since the nearest National Weather Service Station is located approximately 30 airline miles southeast of the DCPP site, and since other offsite sources are separated from the site by rugged terrain, data from other sources are not considered indicative of site conditions. The only representative local data source is the onsite meteorological measurement program, data from which are summarized in Section 2.3.3.2, below, and presented in detail in Appendix 2.3J of Reference 27.

Precipitation and ambient air temperature data at National Weather Service stations surrounding DCPP are shown in Tables 2.3-6 and 2.3-7. Annual and monthly wind data summaries for Santa Maria, California, are shown in Tables 2.3-8 through 2.3-20.

The results of the analysis of the meteorological observations made at the DCPP site are summarized in the following sections and presented in further detail in References 1, 9, 10, and 11, and in Appendix 2.3J of Reference 27.

2.3.3.2 Onsite Normal and Extreme Values of Meteorological Parameters

Summaries of normal and extreme values of meteorological parameters are presented in this section for six stations located on DCPP property. Detailed data are included in the locations described in this section. Additional data from continued long-term operation of one site station (Station E) are presented in Appendix 2.3J of Reference 27.

2.3.3.2.1 Wind Speed and Wind Direction

The wind speed units in References 1, 9, and 10, and in Appendix 2.3J of Reference 27 are in miles per hour and were estimated to the nearest mile per hour. The wind speed values in the tables contained in Reference 9 and Appendix 2.3J of Reference 27 refer to the values included in each category. For example, the category of 4-7 includes all wind speed values for 4, 5, 6, and 7 mph. The wind speed values in the tables contained in References 1 and 10 are the midpoint values of the class intervals.

The seasonal and annual frequency distributions of wind speed and wind direction are shown graphically in Figures 1 through 4, Reference 9. The percentage occurrence (expressed as the percent of the total number of observations in the period) for each of the 16 wind direction sectors is represented by the length of the bars on the wind rose, and the average wind speed for each wind direction sector is plotted at the end of each bar.

The annual frequency distribution of wind speed and wind direction at the six DCPP stations is shown in Figure 1, Reference 9. The patterns at Stations E, A, and B are grossly similar with about 50 percent of the observations comprising northwesterly winds with average speeds of 10 to 15 mph. The percentage of indicated hourly mean wind speeds that are 2 mph or less varies from 21 percent at Station E to 14 percent at Station A. This variation may be attributed, in part, to the higher starting threshold of the sensors at Station E.

As shown in Tables S.2-1 and S.2-2 of Reference 11, there is a 4 percent difference in the percentage of indicated hourly mean wind speeds that are 2 mph or less for the two concurrent sets of measurements at the 25 foot level of Station E for the period April 1970 through March 1972. The measurements presented in Table S.2-1 were obtained from a lightweight cup and vane wind system, while the observations shown in Table S.2-2 are concurrent measurements obtained from a Bendix-Friez aerovane wind system. The wind flows at Stations C and D, both located in Diablo Canyon, reflect the channeling of the wind by the canyon walls; the predominant directions are up-canyon and down-canyon. The wind distribution at Station F tends to be somewhat circular, because of topographical factors, with the highest mean wind speeds identified with easterly flow.

The highest recorded peak gust at Station E is 84 mph, and the maximum recorded hourly mean wind speed is 54 mph, both recorded at the 76-m level of the primary tower.

Figure 2 of Reference 9 shows that during the dry season northwesterly flow is predominant; Figure 3 of Reference 9 shows there is an increase in southeasterly flow during the wet season compared to the annual distribution. Wind frequency distributions for the transitional months, April and October, show all six stations similar to the annual patterns. Because of the small variability from month to month within a particular season, monthly wind distributions have not been prepared.

The strong diurnal variability of the wind patterns at DCPP site is revealed in Figure 5 and in Figures I-1 through I-7 of Reference 9. The following time periods are shown in the figures for the six stations: Day, 1200-1700 PDT; Night, 2300-0500 PDT; Morning 0600-1100 PDT; and Evening, 1800-2200 PDT. During the day, the winds are northwesterly at Stations E, A, and B. The daytime flow at Stations C and D in Diablo Canyon is directed up-canyon. The most frequent daytime wind direction at Station F is from the northwest. During the night and morning periods, northerly and easterly drainage winds are typically present at all stations. The average nighttime wind speeds at Stations E, A, and B are approximately one-half as great as the average daytime speeds. At the other three stations, no large differences in mean wind speed between the daytime and nighttime regimes are apparent.

2.3.3.2.2 Ambient Air Temperature

Average ambient air temperatures for each month of the year, calculated from the hourly temperature measurements at Stations E, B, and F up to the year 1980, are plotted in Figures I-15 through I-17 of Reference 9. The average annual temperature at the plant site is about 55°F. Generally, the warmest mean monthly temperature occurs in October, and the coldest mean monthly temperature occurs in December. The highest and lowest hourly temperatures recorded at the Diablo Canyon site through the year 2000 were 97°F in October 1987 and 33°F in December 1990, respectively.

2.3.3.2.3 Atmospheric Water Vapor and Fog

Measurements of atmospheric water vapor and fog observations are not present throughout the entire meteorological data collection program. However, measurements of these parameters are not essential at DCPP site since regional data are adequate for design purposes and cooling towers are not being used.

2.3.3.2.4 Precipitation

Rainfall measurements made at the DCPP shown herein for two report periods. The first period was from July 1, 1967 through October 31, 1969 and is discussed in Section 7.7 and summarized in Table 7 of Appendix 2.3A in Reference 27. The second period was from May 1973 through April 1981 and is discussed in Section 2.3J.4.2 and summarized in Table 2.3J-3 of Appendix 2.3J of Reference 27. Precipitation occurs typically during the period of late October through the first part of May and most frequently in the presence of southeasterly wind flow in advance of a frontal system. The average annual precipitation in the area is about 16 inches. The highest monthly total during the period of record (1967-1981) was 11.26 inches as shown in Section 7.7 of Appendix 2.3A of Reference 27. The greatest amount of precipitation received in a 24 hour period was 3.28 inches as shown in Section 2.3J.4.2 and Table 2.3J-3 of Appendix 2.3J of Reference 27. These maximums were recorded in January 1969 and March 1978, respectively. The maximum hourly amount recorded at DCPP site during the periods of record is 2.35 inches as shown in Section 2.3J.4.2 of Appendix 2.3J of Reference 27. The 1978-1979 winter season with 35.22 inches of rainfall was one of the heaviest precipitation seasons of record.

2.3.3.2.5 Wind Direction Persistence

The steadiness of the wind flow at DCPP site has been studied by tabulating the number of consecutive hours the hourly mean wind direction remained within a given 22.5° angular sector. The results, expressed in terms of percentage of all hourly observations, are plotted in Figures I-8 through I-14 of Reference 9, and presented also in Table 2.3J-17 of Appendix 2.3J of Reference 27, for periods ranging from 1 through 24 hours. The mean wind direction at all stations in the analysis of Reference 9 remained within the same 22.5° sector for two consecutive hours or longer in 31 to 42 percent of the observations. The persistence of the wind direction decreases rapidly

for a longer time period with only 3 to 4 percent of the observations showing a persistence of 8 hours or longer.

The longest run of persistent wind direction in the total set of measurements occurred at Station B where a northwest wind direction lasted for 51 consecutive hours. The longest period of calm (hourly mean wind speed less than 1 mph) observed at Station E, near the plant location, was 10 hours. As shown in Table 2.3-1, the percentage of the total hourly mean wind speed observations that are less than 1 mph at Station E is 5.9 and 4.9 percent at the 25 foot and 250 foot levels, respectively. The percentage of time that the mean hourly wind speed would be less than 1 mph for 8 consecutive hours or longer is less than 0.5.

As indicated by the persistence analysis, despite the prevalence of the marine inversion and the northwesterly wind flow gradient along the California coast, the long-term accumulation of plant emissions in any particular geographical area downwind is virtually impossible. Pollutants injected into the marine inversion layer of the coastal wind regime are transported and dispersed by a complex array of land-sea breeze regimes that exist all along the coast wherever canyons or valleys indent the coastal range. These conclusions are strongly supported by Edinger's (Reference 3) comprehensive analysis of the influence of terrain and thermal stratification on wind circulations along the California coast, as well as the onsite diffusion studies by Cramer and Record (Reference 1).

2.3.3.2.6 Atmospheric Stability Conditions Defined by Turbulence Measurements

The Pasquill (Reference 17) stability categories (refer to Table 2.3-141) are frequently used as a convenient practical index for gauging the dispersal capacity of the atmosphere. For example, unstable and near-neutral stability conditions (Pasquill Categories A, B, C, D) are favorable for the dilution of pollutants; on the other hand, poor dilution occurs under stable conditions (Pasquill Categories E, F, G). Following a procedure outlined by Slade (Reference 12) the turbulence measurements obtained from the bidirectional vanes at Station E have been used to classify the wind observations at DCPP site according to the Pasquill stability categories. Table 4 of Reference 9, shows the relationship between the range in azimuth and vertical wind angle and the Pasquill stability categories. Scaling factors used to convert the angle ranges to standard deviations were determined from the data presented in Table 2 of Reference 9.
The annual wind distributions for the 250 foot level at Station E, given by the measurements made during the period from July 1967 through October 1969, are classified according to the range values of azimuth and vertical wind angles associated with the various Pasquill categories, Tables I-2 through I-6 and Tables I-14 through I-18 of Reference 9. The corresponding annual wind distributions for the 25 foot level are similarly classified, using the 250 foot turbulence measurements, in Tables I-8 through I-12, and I-20 through I-24 of Reference 9. As mentioned above, turbulence measurements were available only at the 250-foot level for this period.

As shown in Table 5 of Reference 9, when the range in azimuth wind angle is used to determine the number of wind observations at Station E in the various Pasquill stability categories, 57 percent of the total observations are in the stable E, F, and G categories. The unstable categories A, B, and C contain 25 percent of the total observations. When the range in vertical wind angle is used to classify the Station E wind data, less than 20 percent of the total observations are in the E, F, and G stable categories. The unstable categories A, B, and C account for about 65 percent of the total observations. These apparent inconsistencies are explained in part by terrain restrictions on the azimuth wind variations at the site.

The results also indicate the routine presence of relatively large vertical turbulence intensities that are caused by the rough terrain at the site. Therefore, it is concluded that the range in vertical wind-angle is a better index of turbulent mixing at DCPP site than the range in azimuth angle. This conclusion is strongly supported by Luna and Church's (Reference 7) comprehensive analysis of the use of measured vertical turbulence values to define stability conditions at sites with rough terrain.

Toward the end of the 2 year meteorological measurement program, July 1967 through October 1969, a question arose as to the applicability of the azimuth and vertical wind fluctuations measured at the 250-foot level in determining the site dispersion characteristics for low-level releases resulting from an accident. Therefore, 1 year (October 1969 through September 1970) of concurrent azimuth and vertical wind-angle measurements were obtained at the 25- and 250-foot levels. A detailed analysis of these data is contained in Reference 10 where Tables S.1-1 through S.1-6, pages 7 through 12, and Tables S.1-13 through S.1-18, pages 19 through 24, contains the annual wind distributions classified according to the azimuth wind-angle for the 25- and 250-foot levels, respectively. The annual distributions classified according to vertical wind angle for the two levels are shown in Tables S.1-7 through S.1-12, pages 13 through 18, and Tables S.1-19 through S.1-24, pages 25 through 30.

When the range in azimuth wind-angle is used to classify these concurrent measurements, the 250 foot azimuth range yields the same percentages as the data collected during the period July 1967 through October 1969 (57 percent for the E, F, and G stable categories, and 25 percent for the unstable categories A, B, and C). However, when the azimuth range measured at the 25 foot level is used to classify the total number of observations at the 25-foot level in the various Pasquill stability categories, 48 percent of the total observations are in the E, F, and G stable categories; the unstable categories A, B, and C contain 29 percent of the total observations.

When the range in vertical wind-angle is used to classify the 1 year of concurrent measurement, again at the 250 foot level, there is very little change from the data collected during the period of July 1967 through October 1969: 17 percent of the total observations are in the E, F, and G stable categories and 68 percent are in the unstable categories A, B, and C. At the 25-foot level, only 7 percent of the total observations are in the E, F, and G stable categories. The percentage of total observations in the unstable categories A, B, and C is 80 percent, compared to 66 percent calculated from

the wind-angle measurements from the 250 foot level during the period of July 1967 through October 1969.

Because of the poor dilution normally associated with the Pasquill F and G stable categories, the annual percentage occurrences of the F and G categories, in combination with onshore winds of 2 mph or less were also determined and are shown in Tables S.1-1 and S.1-7 of Reference 10. Onshore wind directions include winds for southeast through west-northwest, measured clockwise. The results from the 25-foot level indicate that the Pasquill F and G and onshore wind combination defined above occurs slightly less than 4 percent of the time when the azimuth angle-range data are used as indices, and slightly more than 3 percent of the time when the vertical range-angle data are used as indices. These percentages, which were calculated from the wind-angle measurements from the 250-foot level, are approximately one percentage point less than those for the 25 foot level shown in Table 5 of Reference 9.

The seasonal distributions given in Figure 6 of Reference 9 show the highest percentage of stable conditions during the dry season for both the azimuth and vertical wind-angle classifications. Additional analyses and discussion are presented in Appendix 2.3K of Reference 27.

2.3.3.2.7 Atmospheric Stability Conditions Defined by Vertical Temperature Gradient Measurements

The gross relationship between the hourly wind observations at Station E and the thermal stratification can be shown by classifying the wind data into three stability categories defined by the vertical temperature difference measured between the 250- and 25-foot levels on the tower.

The following ranges of the vertical temperature difference between these two levels can be used to define the categories:

Stable	$(T_{250} - T_{25}) = +25.0$ *to* $+1.6°F$
Near Neutral	$(T_{250} - T_{25}) = +1.5$ *to* $-1.5°F$
Unstable	$(T_{250} - T_{25}) = -1.6$ *to* $-25.0°F$

A discussion of the effect of measurement interval on stability estimates of temperature gradients is provided in Appendix 2.3G of Reference 27.

Joint frequency distributions of hourly wind speed and wind direction measurements at the 250-foot level for the three stability categories are contained in Reference 9, Tables I-26 through I-28. Similar frequency distributions of the hourly wind observations at the 25-foot level are shown in Tables I-30 through I-32.

Over 70 percent of all the wind observations are grouped in the near-neutral category at both levels. This large percentage is probably explained by the small vertical temperature gradients in the surface layer of the maritime air that reaches the tower

during onshore winds; the proximity of the tower to the shoreline, and the intense turbulent mixing induced by the rough terrain at DCPP site. Approximately 5 percent of the total hourly observations at each level are identified with stable thermal stratification and mean wind speeds of 2 mph or less. The percentage of total hourly observations and onshore winds (southeast through west-northwest measured clockwise), with mean wind speeds of 2 mph or less, is 3.2 for the 250-foot level and 1.4 for the 25-foot level. The corresponding percentages for the Pasquill F and G stability categories, as shown in Table 2 of Reference 10, page 4, are 6 at the 250-foot level and 3.2 at the 25-foot level when the range data for the vertical wind angle are used to define the Pasquill categories.

Wind data (speed and direction) classified into seven stability categories (Pasquill A through G) are shown in Tables 2.3-21 through 2.3-27. The wind data were measured at the 250-foot level and the vertical temperature difference measurements are 250-foot level minus 25-foot level. The wind speed values are in miles per hour and the values in the tables refer to the midpoint of each class interval. The rows are labeled with the wind direction at the midpoint of 22.5° intervals:

Midpoint, mph	*Class Interval, mph*
Calm	*Less than 1*
2.0	*1-3*
5.1	*4-7*
9.6	*8-12*
15.1	*13-18*
21.1	*19-24*
39.6	*> 24*

Wind data (speed and direction) classified into seven stability categories (Pasquill A through G) for the period May 1973 through April 1974 are shown in Tables 2.3-42 through 2.3-48. The wind data were measured at the 25-foot level and the vertical temperature difference measurements are 250-foot level minus 25-foot level. The wind speed values are in miles per hour and the values in the tables refer to the midpoint of each class interval. The rows are labeled with the wind direction at the midpoint of 22.5° intervals:

Midpoint, mph	*Class Interval, mph*
Calm	*Less than 1*
1.8	*0.6 to 3.1*
5.1	*3.1 to 7.1*
9.6	*7.1 to 12.1*
15.1	*12.1 to 18.1*
21.1	*18.1 to 24.1*
39.6	*> 24*

Wind data (speed and direction) classified into seven stability categories (Pasquill A through G) for the period May 1973 through April 1975 are shown in Tables 2.3-49

through 2.3-55 on an annual basis, and in Tables 2.3-56 through 2.3-139, on a monthly basis. The wind data were measured at the 10-meter level, and the vertical temperature gradient measurements were made at 76 meters minus 10 meters.

The wind speed values are in miles per hour and the values in the tables refer to the midpoint of each class interval. The rows are labeled with the wind direction at the midpoint of 22.5° intervals:

Midpoint, mph	Class Interval, mph
1.5	1.0-3
5.1	3.1-7
9.6	7.1-12
15.1	12.1-18
21.1	18.1-24
29.6	24.1-35
40.1	35.1-45
50.1	>45

These 2 years of data, May 1973 through April 1975, are considered representative of long-term conditions at DCPP site, and are in agreement with other data taken at the site, such as that in Reference 9, Table I-7, page 2.3A-87, July 1967 through December 1969 and the data in Appendix 2.3J of Reference 27. The prevailing wind direction is from the northwest and the mean annual wind speed is about 10 mph. Between 70 to 90 percent of the observations are contained in the stability classes D and E, Tables 2.3-42 through 2.3-48, and Tables 2.3-49 through 2.3-55.

During the August 1969 review by the Environmental Science Services Administration (ESSA) for Diablo Canyon Nuclear Unit 2, it was requested that the wind data be processed so that the distribution of wind speeds of 3 mph and less could be examined. Since the wind sensor had a nominal starting speed of 2.2 mph, the following procedures were followed in processing the wind data:

(1) Calm refers to hourly wind speed traces indicating zero wind speed and hourly direction traces that were either squarewave or straight line

(2) The values shown for the 1 and 2 mph categories were determined by equal area averaging

(3) For wind speed entries in the 1 and 2 mph categories that show a calm wind direction, refer to hourly records for which a mean wind direction could not be defined

Additional analyses and discussion are presented in Appendix 2.3J of Reference 27.

2.3.3.2.8 Atmospheric Stability Conditions Defined by Onsite Diffusion Studies

Twenty-seven onsite field tests involving releases of smoke and fluorescent particles were made during various meteorological regimes. The data from these tests were used for verifying the diffusion model computations by comparing predicted ground level concentrations to observed concentrations. The data also served as a guide in the selection of parameters used in the long-term diffusion model. The analysis of the field measurements was performed by the GCA Corporation and is described in Reference 1. Additional analyses and discussion are contained in Appendix 2.3K of Reference 27.

Analysis of the meteorological and diffusion data obtained during the onsite field tests at Diablo Canyon leads to the following conclusions:

(1) For daytime elevated (250 foot) releases into northwesterly flow, only four measured concentrations exceeded the values predicted by the Pasquill-Gifford curve for Category D; these four values exceed the predicted values for Category D by a factor of 2 or less.

(2) For releases into southeasterly flow (generally prefrontal conditions), the Pasquill-Gifford curve for Category B serves as the upper bound for the concentrations measured during the 250-foot releases.

(3) During light and variable winds, the fluorescent particle tracer was found along the coast both north and south of the release point; all measured concentrations for both 250 and 25-foot releases were below the Pasquill-Gifford curve for Category B.

2.3.3.3 Potential Influence of the Plant and Its Facilities on Local Meteorology

Modification of local meteorological parameters is not expected by the presence and operation of DCPP.

2.3.3.4 Topographical Description

The topographical features within a 10-mile radius of the plant site are shown in Figure 2.3-1. The vertical cross-sections for the eight 22.5° onshore wind direction sectors (southeast through west-northwest) radiating from the plant are shown in Figure 2.3-2. Modification of the local topography by the plant is considered negligible.

Topographical influences on both short-term and long-term diffusion estimates are quite pronounced in that the ridge lines east of the plant location extend at least to the average height of the marine inversion base.

The implications of this barrier are:

(1) Any material released that is diverted along the coastline will be diluted and dispersed by the natural valleys and canyons, which indent the coastline.

(2) Any material released that is transported over the ridgeline will be distributed through a deep layer because of the enhanced vertical mixing due to topographic features.

2.3.4 ONSITE METEOROLOGICAL MEASUREMENT PROGRAM

The preoperational meteorological data collection program is described in detail in the references. This meteorological program was designed and has been updated continually to meet the requirements of Safety Guide 23, February 1972 (Reference 21).

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Onsite Meteorological Measurement Program

Data were collected from a comprehensive station network, shown as points A through F in Figure 2.3-3, over a 28-month period from July 1967 through October 1969. Because of a considerable amount of missing data during the first few months of the operation of the meteorological data network, the data collection period was extended four additional months beyond July 1, 1969, to eliminate any bias in the annual distributions caused by incomplete data. The above meteorological measurements were also supplemented by a 12-month program of concurrent turbulence measurements at heights of 250 and 25 feet from October 1969 through September 1970, and by a 24-month program of concurrent wind measurements at the 25 foot level of Station E using a Bendix-Friez aerovane wind system and a lightweight cup and vane system from April 1970 through March 1972. A complete description of the onsite meteorological measurement program is given in Reference 9.

Figure 2.3-1 shows the plant location and site boundary. Locations of Stations A through F of the meteorological measurement network are as shown in Figure 2.3-3. Stations A and B are approximately 3000 feet southeast of the plant location at elevations of 125 and 600 feet Mean Sea Level (MSL), respectively. Station C at elevation of 75 feet MSL and Station D at 350 feet MSL are in Diablo Canyon. Stations E and F are at elevations 85 and 920 feet MSL, respectively. The meteorological instruments at each of the six stations consisted of a Climet Model CI-26 cup and vane assembly mounted at a height of 35 feet above the surface. In addition, air temperature measurements were made at Station B at a height of 5 feet above the surface using a Foxboro Capillary System.

At Station E, currently the primary tower site, meteorological sensors were mounted at heights of 250 and 25 feet on a 260-foot tower. The sensors at the 250-foot level comprised a Bendix-Friez Model 120 Aerovane, a Meteorology Research Incorporated bidirectional vane, and a platinum resistance thermometer for measuring the vertical

temperature gradient. The sensor installation at the 25-foot level comprised a Bendix-Friez Model 120 Aerovane and a platinum resistance thermometer for measuring ambient air temperature. A second Meteorology Research Incorporated bidirectional vane was installed at the 25-foot level at Station E in October 1969, and a Climet Model CI-26 cup and vane system was installed at the 25-foot level of Station E in April 1970 to obtain supplementary data. A tipping-bucket rain gauge was located near Station E at the surface.

At Station F, approximately 3000 feet directly east of the plant location at an elevation of 920 feet MSL, a Bendix-Friez Model 120 Aerovane and a Meteorology Research Incorporated bidirectional vane were mounted at the top of a 100-foot tower. Ambient air temperature measurements were made at the 5-foot level by means of a Foxboro Capillary Sensor. Accuracy specifications of the instrumentation used prior to the spring of 1973 are:

(1) The Bendix-Friez Model 120 Aerovane has a stated accuracy of ±2° over the complete direction range, an average wind speed error of ±0.5 mph for speeds under 10 mph, and ±1 mph for speeds between 10 and 200 mph

(2) A Climet Model CI-26 wind speed sensor has a stated accuracy of 2 percent or 0.25 mph (whichever is greater) and a wind direction accuracy of ±5°

(3) Meteorology Research Inc. bivanes have stated accuracies of ±3.6° for horizontal and ±2° for vertical direction

(4) The platinum resistance temperature gradient measurement system has an accuracy of ±0.2°F

Additional descriptions of the instruments are contained in Reference 9. The temperature gradient system and the Bendix-Friez wind systems were calibrated annually or more often when required. The lightweight cup and vane wind systems and the bidirectional wind systems were calibrated every 90 days, or sooner when required. Inspection was performed on a daily basis, and maintenance as necessary.

All of the meteorological sensor outputs from the network described above were recorded on continuous strip chart recorders at the site. Measurements of wind speed, azimuth wind direction, ambient air temperature, and vertical temperature gradient were reduced as hourly averages; rain gauge measurements were reduced to hourly totals; bidirectional vane measurements of the fluctuations in azimuth and vertical wind angles at Stations E and F were abstracted from the chart records in the form of 10 minute range values for the last 10 minutes of each hour. These range values were converted to 10 minute standard deviations of azimuth and vertical wind angle by the use of simple scaling factors and classified according to stability category following a procedure outlined by Slade (Reference 12).

Subsequent to November 1969, Station E became the primary meteorological measurement site at Diablo Canyon, and measurements were discontinued at Stations B, C, D, and F. Measurements at Station A were continued through August 1974.

During the spring of 1973 the instrumentation was changed. The Climet and Bendix-Friez systems were replaced with Teledyne Geotech Series 50 cup and vane sensors to improve reliability and response characteristics. The resistance thermometer system was changed to 4-wire Rosemont bridges and Teledyne Geotech aspirated shields and a sensor was added at the 150-foot level. The precipitation measurement system was changed to a weighing bucket gauge with a potentiometer. Signals from all of the above devices are processed by Teledyne Geotech Series 40 processors that provide output voltages and currents of 0-5 Vdc and 0-1 milliampere, respectively, to the digital and strip chart recorders. A Cambridge systems/EG&G chilled mirror dew point system was added at this time to provide dew point and backup ambient temperature at the 25 foot level. H. E. Cramer Corporation installed signal conditioning equipment of their own design that produced analog signals from the above equipment and the existing bivane equipment that were equivalent to 5 minute values of:

(1) Means of all parameters, except precipitation

(2) Variance of horizontal and vertical wind directions

(3) Peak wind speeds

The signal conditioning provided by H. E. Cramer also converted the Teledyne Geotech 0-360° wind direction output to a 0-540° wind direction signal to accomplish Items 1 and 2 above. H. E. Cramer also provided a digitizing and recording system that utilized Nonlinear Systems' equipment for digitizing and a Bright Industries 7-track magnetic tape recorder for storage of the 5 minute data.

In 1973, a minicomputer and printer were added to the digital system in the control room. Digital data were taken at the tape recorder input and transmitted to the control room computer. The computer system was designed to calculate and display downwind concentrations based on real-time data.

The weighing bucket precipitation gauge was replaced with a tipping bucket gauge in December 1976.

In December 1978, Station E was again upgraded. The equipment was moved to a new equipment shelter at the site and completely rewired. Although the sensors were retained, considerable changes were made to the processors and recording system. A new microprocessor temperature processor was installed to replace the Rosemont Bridge system and improve the accuracy of the temperature difference measurements. The entire H.E. Cramer signal conditioning, digitizing, and recording system was replaced by a Teledyne Geotech Automet V microprocessor-based digital data system. The Automet V also replaced the minicomputer and only the printer remained in the

control room. The multipoint Servo recorder was modified to record 25 foot temperature and temperature differences: 150 foot by 25 foot and 250 foot by 25 foot. The Bright Industries 7-track magnetic tape recorder was replaced with a Kennedy Model 9000, 9-track, 1600 bits per inch, phase encoded, buffered tape system.

In June 1980, the system was again upgraded by incorporation of improved wind direction processors using a linear output voltage with no step changes and phase-locked loops to increase immunity to sensor signal distortion. The new processors output a signal that changes linearly from 0 to 5 volts at 180° and back to 0 volts at 360°. A digital signal is used to identify which 180° is being processed. This eliminates errors in the 360° transition as 0° and 360° are both 0 volts rather than 5 volts for 360° in the old system. Digital processing was also changed at this time to use unit vectors for standard deviation and mean direction calculations to eliminate potential ambiguities inherent in the older system. An additional communications link was installed at this time to transmit meteorological data to the technical support center (TSC) computer.

In May of 1981, the Automet system was revised to allow polling from the DCPP Emergency Assessment and Response System (EARS) computer, and a math processor was incorporated to speed up the processing of wind direction vectors.

In October of 1981, a new 60 meter tower was installed as a backup meteorological system. The backup tower has two levels of wind direction, wind speed, and temperature instrumentation. It is located approximately 1.2 km southeast of the primary tower. The instruments are at the 10 meter and 60 meter levels. Wind speed and wind direction processing is identical to the primary system. The temperature processing incorporates new analog processors from Teledyne Geotech with the same type of aspirated platinum resistance thermometers. The backup system is powered by batteries and is capable of 7 days of operation without external power.

The Automet microcomputer for the backup system is located in the TSC and receives data digitally from a remote terminal at the tower location over a 4-wire communications link. The backup system printer and a 9-track magnetic tape recorder are also located in the TSC. A switching system has been incorporated into the primary meteorological printer in the control room and allows the backup system printout to be substituted for the primary system printout. This switching system reconfigures the backup system automatically when the switch is actuated so that 5-minute updates of the current 15-minute logs derived from backup data are printed on the control room printer. The primary system data are output on the printer in the TSC when the backup system is selected in the control room.

In the spring of 1982, a visibility measurement system was installed at the base of the primary tower. The system relates local visual range to forward light scattering by the air along a 4 foot horizontal path. This system was removed in February 1985 after a sufficient record of information had been collected.

Onsite Meteorological Measurement Program (Current)

The current onsite meteorological monitoring system consists of two independent subsystems that measure meteorological conditions and process the information into useable data. The measurement subsystems consist of a primary meteorological tower and a backup meteorological tower.

The primary meteorological tower location is shown in Figure 2.3-3 as Station E. There are instruments located at the 10 m, 46 m, and 76 m elevations. The 10 m and 76 m elevations have wind speed, wind direction, and temperature sensors. The 46 m elevation has a temperature sensor. The 10 m level also has a dewpoint sensor. There is a precipitation measurement system at the base of the tower.

The backup meteorological tower is located approximately 1.2 km southeast of the primary tower and is listed as Station A in Figure 2.3-3. There are wind speed, wind direction, and temperature sensors at the 10 m and 60 m elevations.

The processors for the above instruments reside in the meteorological facilities located near the towers. The temperature in these facilities is maintained to support processor operation. These processors provide input to multi-point recorders and the meteorological digital data acquisition system.
A primary meteorological remote input/output (IO) data processor is located in the primary meteorological facility. A backup meteorological remote IO data processor is located in the backup meteorological facility. These two local meteorological remote IO data processors communicate data to redundant meteorological computers located in the Technical Support Center (TSC). The redundant TSC meteorological computers provide data to the Unit 1 and 2 network communication to the Plant Data Network, the Emergency Assessment and Response System (EARS), and the Plant Process Computers (PPC). Thus meteorological data are available in the control room and emergency response facilities in accordance with NUREG-0654, Revision 1, (Reference 23).

A detailed discussion of each of the above instruments is provided in the following sections.

2.3.4.1 Wind Measurement System

The wind direction processor supplies voltage and current signals corresponding to 0-360 degrees. The meteorological data acquisition system provides a corresponding digital output signal of 0-360 degrees. The meteorological multi-point recorders provide hemispherical indication of 0 to 180 degree corresponding to 0-360 degrees. Recorder indication is provided to identify which 180-degree sector the signal represents.

The wind speed signal is processed to develop a current signal to the data acquisition system and the multi-point recorder.

2.3.4.2 Temperature Measurement System

The primary tower temperature measurement system employs a microprocessor system in conjunction with platinum resistance temperature detectors (RTDs) to measure temperature at three levels on the meteorological tower.

Analog outputs of the temperature processor are recorded on a multi-point recorder and depict:

(1) 10 m temperature in degrees Fahrenheit from 0 to 120
(2) 46 m temperature in degrees Fahrenheit from 0 to 120
(3) 76 m temperature in degrees Fahrenheit from 0 to 120

The data acquisition system and primary tower recorder uses the data to provide a temperature difference between 76 m to 10 m from -15 to 21°F. The data acquisition system and primary tower recorder also provides a temperature difference between 46 m to 10 m from -15 to 21°F.

Temperature probes are housed in aspirated radiation shields. Radiation errors are limited to less than 0.2°F at a radiation intensity of 1.56 gram-calories/cm/min. This radiation level represents approximately twice the highest summer radiation level for the DCPP site. Aspirators are individually monitored by motor frequency sensors and temperatures are invalidated if the motor frequency is out of a specified range.

The backup tower 10-m and 60 m temperature processor supplies an intermediate output that is used for the data acquisition system and backup tower recorder to provide a temperature difference between 60 m to 10 m from -15 to 21°F. Both processors supply a current signal to a multipoint recorder at the tower location and to the data acquisition system.

Measurement ranges are 0 to 120°F for the 10 m and 60 m temperature.

2.3.4.3 Dew Point Measurement System

A chilled mirror dew point measuring system is used to monitor the dew point at the primary tower 10-m level. The output voltage signal represents a range of 0 to 100°F. The sensor head is equipped with an aspirator to present a representative atmospheric sample to the mirror.

The voltage signal is further processed to generate a current output to the data acquisition system and to the multi-point recorder.

2.3.4.4 Precipitation Measurement System

Precipitation is measured by a tipping bucket rain gauge that delivers a pulse for each 0.01-inch increment of rainfall. This pulse is digitally accumulated by a processor

module. The digital accumulator resets to zero after the 250th pulse and begins a new cycle. The digital accumulator output is processed by a digital-to-analog converter that provides a current signal to the data acquisition system and the signal to the multi-point recorder.

2.3.4.5 Supplemental Measurement System

A supplemental meteorological measurement system is present in the vicinity of the DCPP site. This supplemental measurement system consists of three Doppler Sonic Detection and Ranging (SODAR) and seven tower sites located as indicated in Figure 2.3-4.

The Doppler sounders provide remote sensing of wind speed, wind direction, standard deviation of wind direction variability (sigma theta), vertical velocity, and standard deviation of vertical velocity (sigma w), as well as information on echo characteristics useful in deducing the presence of inversion layers. At each Doppler location, the above parameters are provided as 15-minute average values for each of twenty 30-m thick vertical layers above the instrument site. Layer midpoints extend from 40 m to 610 m above ground level, providing data to heights just exceeding the maximum height of the local terrain. A thorough evaluation of the Doppler technique has been made by the National Oceanic and Atmospheric Administration (NOAA) (Reference 25). The NOAA evaluation of the Doppler produced correlation coefficients on the order of 0.93 and higher for both wind speed and direction in comparison with measurements by sonic anemometers.

The offsite towers provide measurements of wind speed, wind direction, sigma theta, and temperatures as 15 minute averages. All of the supplemental tower measurements are taken at or near the 10-m level using instrumentation designed to meet or exceed ANSI/ANS 2.5-1984 (Reference 24) for meteorological measurements at nuclear plant sites. Tower data are telemetered to the TSC, Alternate Technical Support Center/Operational Support Center (Alternate TSC/OSC), Emergency Operations Facility (EOF), and General Office headquarters on a continuous basis. The data are archived as a permanent record. SODAR data are available on-demand via a dial-up modem interface in the EOF or remotely via computer.

Onsite meteorological data and supplemental wind speed and direction data are processed by the EARS software. The data are provided to the Meteorological Information and Dose Assessment System (MIDAS) software to make estimates and predictions of atmospheric effluent transport and diffusion during and immediately following an accidental airborne radioactivity release from the plant. The software can produce initial transport and diffusion estimates for the plume exposure emergency planning zone within 15 minutes following the classification of an incident. The MIDAS model is designed to use actual 15-minute average meteorological data from onsite and offsite meteorological measurement systems. The output from the model includes the dimensions, position, locations, and arrival time of the plume.

If one or more of the supplemental tower data are unavailable, EARS and MIDAS will fail over to the supplemental tower most representative of the region that is missing data. If transmission of all supplemental data fails, EARS and MIDAS will continue to be functional with onsite meteorological data as the only source.

2.3.4.6 Meteorological Data

The following data is obtained by the primary and backup meteorological facilities. The meteorological sensors and signal processors transmit signals to the meteorological computers to derive 15-minute averages and maximums. Quality values are assigned to each of the 15-minute values. On the quarter hour, 15-minute data sets are transmitted to the meteorological data network.

The primary tower transmits the following data:

(1) 10-m and 76-m wind speeds

(2) 10-m and 76-m wind direction

(3) 10-m temperature

(4) 76 m temperature

(5) 46 m temperature

(6) precipitation

(7) dewpoint

(8) 10-m, 46-m, and 76-m aspirator frequency

(9) Battery condition monitor

The backup tower transmits the following data:

(1) 10-m and 60-m wind speeds

(2) 10-m and 60-m wind direction

(3) 10-m temperature

(4) 60 m temperature

(5) 10 m and 60 m aspirator frequency

(6) Battery condition monitor

The meteorological data acquisition system scans their inputs at least once every 2 seconds (or greater than or equal to 450 samples per 15 minutes). The following tests are performed to determine the validity of the meteorological sensor data:

(1) If the wind direction standard deviation (calculated using the Yamartino method) is less than 1, the wind data are considered invalid. (Appendix 2.3F of Reference 27 presents the historical Wind Direction Deviation Computation at Diablo Canyon and its reference has been retained to provide a continuity of understanding.

(2) If the 15-minute average wind speed is greater than 0.75 mph and the difference between the peak wind speed and the average wind speed is less than 0.3, then the wind speed data are considered invalid.

(3) If the wind speed is greater than 100 mph or less than 0 mph, then sample is invalid. If more than 5 minute number of samples are invalid (i.e., less than 10 minutes worth of good data), then the 15-minute wind speed data are invalid.

(4) If more than 5 minute number of delta temperature samples are greater than 21 or less than -15, then the 15-minute temperature difference data are invalid.

(5) If more than 5 minute number of dew point samples are greater than the 10-m temperature by 2 degrees, then the 15-minute dew point data are invalid.

(6) If more than 5 minute number of aspirator samples are out of a specified range, then both the 15-minute aspirator value and the associated temperature value are invalid.

2.3.4.7 Meteorological Data Acquisition System

The primary meteorological remote input/output (IO) data processor is located in the primary meteorological facility. The backup meteorological remote IO data processor is located in the backup meteorological facility. These two local meteorological remote IO data processors communicate data to redundant meteorological computers located in the Technical Support Center (TSC). The redundant TSC meteorological computers provide data to the Plant Data Network, the Emergency Assessment and Response System (EARS), and the Plant Process Computers (PPC).

Each TSC computer processes and transmits 15 minute mean meteorological data to the plant network. Each computer calculates χ/Q, sigma Y, and sigma Z for 10 distances for both the primary and backup data sets.

Along with the 15-minute data set, each computer receives error flags, which are assigned to the appropriate data values, and these error flags are also sent to the PPCs and the EARS system. In this manner, the correct data quality is propagated through the entire system (meteorological computer, PPC, and EARS).

The equation used to compute centerline χ/Q values is based on lateral fluctuations of wind direction (σ_A) for horizontal spread, and vertical temperature gradient (ΔT) for vertical spread of the plume for all daytime cases when the 10-meter speeds are not less than 1.5 m/sec. Nighttime cases in the same wind speed class are treated in accordance with the method of Mitchell and Timbre (Reference 19) as outlined in Table 2.3-144. For speeds less than 1.5 m/sec at the 10-meter level, both lateral and vertical spread of the plume are determined by the vertical temperature gradient. Estimates of both lateral and vertical plume dimensions are determined from the procedures described by Sagendorf (Reference 15).

Equations used to determine χ/Q are:

$$\frac{\chi}{Q} = \frac{1}{\bar{u}(\pi \sigma_y \sigma_z + CA)} \tag{2.3-1}$$

$$\frac{\chi}{Q} = \frac{1}{\bar{u}(3\pi \sigma_y \sigma_z)} \tag{2.3-2}$$

$$\frac{\chi}{Q} = \frac{1}{\pi \bar{u} \sum_y \sigma_z} \tag{2.3-3}$$

where:

$\frac{\chi}{Q}$ is the relative concentration (sec/m^3)

π is 3.14159

$\bar{u}$ is the wind speed at the 10-meter level (m/sec)

$\sigma_y \sigma_z$ are the lateral and vertical cloud dimensions, respectively, as a function of downwind distance. The vertical cloud dimension has an upper limiting value of 1000 m or the product (T_m) (H_m), whichever is less. T_m is a multiplier that is used as a simple substitute for the multiple reflection term and is approximately 0.8 (References 5 and 12)

H_m is the monthly average mixing layer depth for the four time periods of the day which were derived from Holzworth (Reference 6); data are given in Table 2.3-3.

A is the minimum cross-sectional area of the reactor building (1600 m^2). This default value of 1600 m^2 used for the cross-sectional area is conservative. The calculated cross-sectional area for the reactor building as used in support of establishing dose consequences in licensing basis analyses is 2744.5 m^2.

C is constant (0.5)

$\sum_y$ = $M\sigma_y$ - at distances less than or equal to 800 m;

at distances greater than 800 m -

$$\sum_y = (M-1)(\sigma_y)_{800m} + \sigma_y$$

M is a correction factor for meandering and assumes the following values for speeds less than 2 m/sec:

Stability	$\bar{u} \leq 2$ m/sec M	2 m/sec $< \bar{u} <$ 6 m/sec M
A,B,C	1	1
D	2	$(\bar{u}/6)^{-0.631}$
E	3	$(\bar{u}/6)^{-1.00}$
F	4	$(\bar{u}/6)^{-1.262}$
G	6	$(\bar{u}/6)^{-1.631}$

If both values at all levels are invalid, temperature differences (ΔT) are used to determine both lateral and vertical stability categories regardless of wind speed. When this occurs, the dispersion equation used contains the plume meandering correction term. The applicable correction term M for the specific stability and wind speed is that derived from Figure 3 of Regulatory Guide 1.145, Revision 1 (Reference 22), page 1.145-9.

During neutral (D) or stable (E, F, G) stability conditions when 10-m wind speed is less than 6 m/sec, horizontal plume meander is considered. This process consists of comparing the values from Equations 1 and 2, and selecting the higher value. This value is then compared with the value from Equation 3 and the lower value of these selected for χ/Q value. During all other meteorological conditions, plume meander is not considered. The appropriate χ/Q value in these cases is the higher value calculated from Equations 1 and 2.

The dispersion model described above is a generic model and was not developed specifically for the DCPP site. Certain factors specific to the DCPP site bear upon the use and interpretation of the modeling output. Analysis and treatment of such site-specific factors are presented in Appendix 2.3H of Reference 27.

2.3.4.8 Power Supply For Meteorological Equipment

Power for the main meteorological instrumentation building is supplied from Unit 1 480-V non-Class 1E bus. This source is supplied through a transfer switch and will automatically switch to Unit 2 480-V non-Class 1E bus if a failure occurs on the Unit 1 bus. The microprocessor and the meteorological sensors are backed up by an 8-hour battery source to prevent any problems during switching and maintain a continuous database.

The backup meteorological instrumentation is supplied with ac power from the underground Unit 2 12-kV startup bus. In case of an ac power failure, batteries supply emergency power for up to 1 week.

χ/Q values are based on lateral fluctuations of wind direction (σ_A) for both horizontal and vertical spread of the plume. Nighttime stability categories are adjusted, however, in accordance with the method of Mitchell and Timbre (Reference 19) as outlined in Table 2.3-144.

Should both automated tower systems become inoperative, a portable battery-powered meteorological system is available for deployment and use in providing χ/Q values for input to dose-calculation algorithms as described in the Emergency Plan and outlined in Appendix 2.3I of Reference 27. Translation of χ/Q values to centerline and plume-spread estimates may be accomplished in accordance with procedures in the same Appendix 2.3I of Reference 27. (Appendix 2.3I of Reference 27 is historical in nature; however, reference to it has been retained to provide a continuity of understanding. Current procedures meet the requirements of Regulatory Guide 1.145, Revision 1 [Reference 22]).

2.3.5 SHORT-TERM (ACCIDENT) DIFFUSION ESTIMATES

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

2.3.5.1 Historical Diffusion Estimates

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

2.3.5.1.1 Objective

Estimates of dilution factors that apply at distances of 0.8 to 80 kilometers downwind from DCPP are shown in Table 2.3-41 for each wind direction sector. These dilution factors represent the distribution of χ/Q value within each wind direction sector at the various downwind distances.

2.3.5.1.2 Calculations

The cumulative probability distribution of the dilution factor at the distances noted above were computed using one of the diffusion models shown below for centerline dispersion estimates from a ground level release. These are defined as:

$$\frac{\chi}{Q} = \frac{1}{\bar{u}\left(\pi \sigma_y \sigma_z + CA\right)} \qquad (2.3\text{-}4)$$

$$\frac{\chi}{Q} = \frac{1}{3\pi \bar{u} \sigma_y \sigma_z} \qquad (2.3\text{-}5)$$

$$\frac{\chi}{Q} = \frac{1}{\pi \bar{u} \sum \sigma_y \sigma_z} \qquad (2.3\text{-}6)$$

where:

χ	=	*ground level centerline concentration, curies/cubic meter*
Q	=	*source emission rate, curies/second*
σ_y	=	*standard deviation of the lateral concentration distribution, meters*
σ_z	=	*standard deviation of the vertical concentration distribution, meters*
$\bar{u}$	=	*mean wind speed, meters/second*
C	=	*building wake shape factor, 0.5*
A	=	*minimum cross-sectional area of the reactor building, 1600 m^2*
Σ_y	=	*f(σy) = meander correction factor*

A complete description of the models and their selection for use is included in Reference 18.

The year-to-year variation in the frequency of occurrence of conditions producing high χ/Q values is small, so that data from one complete year are representative of the site. In fact, the addition of the second year's data from October 1970 through March 1971 and April 1972 through September 1972, resulted in a change in percentage frequency for the combined F and G categories of only 0.1 percent. Frequency distributions for joint probabilities using the 2-year length of record are given in Tables 2.3-29 through 2.3-40. The wind speed values are in miles per hour and the values in the tables refer to the midpoint of each of the following class intervals: 0-3, 4-7, 8-12, 13-18, 19-24, and

greater than 24. The rows are labeled with the wind direction at the midpoint of each 22.5° interval. The 1-year gap (April 1971 through March 1972) in the period of record, October 1970 through September 1972, resulted from an unauthorized bivane modification.

Frequency distributions of wind speed and wind direction classified into seven stability classes as defined by the vertical temperature gradient are shown in Tables 2.3-21 through 2.3-28. The column headings are labeled in terms of mean hourly wind speed in miles per hour. The six wind speed categories are as follows: 1-3, 4-7, 8-12, 13-18, 19-24, and 25-55. The rows are labeled with the wind direction at the midpoints of 22.5° intervals. Table 2.3-28 shows the number of observations in each of the seven stability classes (Pasquill A through G) for the period of record July 1, 1967, through October 31, 1969, when the mean hourly wind speed is less than 1 mph. The wind data were measured at the 76 meter level, and the vertical temperature difference measurements are the 76 meter level minus the 10 meter level.

The radius of the LPZ at DCPP has been established to be 6 miles. Cumulative frequency distributions of atmospheric dilution factors at each 22.5° intersection with a 10,000-meter radius (slightly greater than 6 miles) for the period May 1973 through April 1975 are presented in Table 2.3-41, Sheets 7, 8, 9, and 10. Each data set used to compile the frequency distribution is comprised of averages taken over 1 hour, 8 hours, 16 hours, 3 days, or 26 days, using overlapping means updated at 1-hour increments as specified by the NRC.

Because of overlapping means, a 1 hour χ/Q is included in several observation periods: for example, an hourly χ/Q is included in 624 estimates of the 26-day averages. As a result, a single hourly measurement may influence the value of over 5 percent of the observations. Since overlapping means are used in the distributions, the data are not independent and no assumption of normality can be made. These data show χ/Q estimates from the 25th through the 100th percentile levels for each of the averaging periods.

2.3.5.2 Design Basis Radiological Analysis Dispersion Factors

2.3.5.2.1 Exclusion Area Boundary and Low Population Zone Atmospheric Dispersion Factors

Atmospheric dispersion factors (i.e., χ/Qs) are calculated at the EAB and LPZ for post-accident environmental releases originating from Unit 1 and Unit 2. These χ/Qs are applicable to all dose consequence analyses documented in Section 15.5 and the tank rupture events discussed in Sections 11.2.3.12 and 11.3.3.9.

The applicable methodology is identified in Regulatory Guide 1.145, Revision 1 (Reference 22). The methodology is implemented by executing the CB&I computer program "Atmospheric Dispersion Factors" EN-113 (Refer to Section 15.5.8.10 for a description of computer program EN-113) using a continuous temporally representative 5-year period of hourly meteorological data from the onsite meteorological tower (i.e., January 1, 2007 through December 31, 2011). EN-113 calculated χ/Q values for the various averaging periods using hourly meteorological data related to wind speed, wind direction, and stability class.

Equations used to determine the χ/Q's are as follows:

$$\chi/Q_1 = \{(u)[(\pi)(\sigma_y)(\sigma_z) + (A/2)]\}^{-1} \quad (2.3.7)$$

$$\chi/Q_2 = [(u)(3\pi)(\sigma_y)(\sigma_z)]^{-1} \quad (2.3\text{-}8)$$

$$\chi/Q_3 = [(u)(\pi)(\Sigma_y(\sigma_z)]^{-1} \quad (2.3\text{-}9)$$

Where:

χ/Q	=	relative concentration (sec/m^3);
σ_y, σ_z	=	horizontal and vertical dispersion coefficients, respectively, based on stability class and horizontal downwind distance (m);
u	=	wind speed at the 10-meter elevation (m/sec);
A	=	cross-sectional building area (m^2);
Σ_y	=	(M)(σ_y) for distances of 800 meters or less; and
Σ_y	=	[(M-1)(σ_{y800m}) + σ_y] for distances greater than 800 meters with M representing the meander factor in Reference 22, Figure 3.

Per Regulatory Guide 1.145, Revision 1, χ/Q_1 and χ/Q_2 values are calculated by EN-113 and the higher value selected. This value is then compared to the χ/Q_3 value calculated by EN-113, and the smaller value is then selected as the appropriate value.

The EAB distances for the sixteen 22.5°-azimuth downwind sectors are derived from Figure 2.1-2, taking into consideration a 45-degree azimuth sector centered on each 22.5°-azimuth sector as described in Regulatory Guide 1.145, Revision 1, Regulatory Position C.1.2. The EAB χ/Q values for the radiological releases from each unit are

conservatively based on the EAB distances from the outer edge of each containment building.

As shown in UFSAR Figure 2.1-2, on land, the DCPP EAB is marked by a farm type fence. As demonstrated by Table 2.3-145A, the location of the “as modeled” continuous EAB over the ocean is based on an extension of the arc (shown in UFSAR Figure 2.1-2 in the northern direction) over the water until it once again touches the shore line, at which point it follows the shoreline till it intersects with the farm type fence that defines the EAB on land in the southern direction.

The above approach in defining the EAB over the water is conservative since it remains well within the 2000-yard radius offshore security zone maintained by the U.S. coast guard in the south-southeast clockwise through the west-northwest direction sectors. An LPZ distance of 6 miles (9,654 meters) is used in the analysis. The use of one LPZ distance in all downwind directions from the center of the site for all release points is reasonable given the magnitude of this distance relative to the separation of the release point locations from one another.

The containment building cross-sectional area along with the containment building height is used for the annual average □/Q calculations (used as input to develop the accident χ/Q values at the LPZ using Regulatory Guide 1.145 methodology). The applicable methodology for the annual average □/Q calculations is identified in Regulatory Guide 1.111, Revision 1, Regulatory Position C.1.c (Reference 28). These annual average χ/Q values are used to calculate the intermediate averaging time χ/Q values for the periods of 2-8 hours, 8-24 hours, 1-4 days, and 4-30 days by logarithmic interpolation.

The enhancement of vertical turbulence (sector averaging eliminates the horizontal component) is only a function of building height, which has been credited for the containment (i.e., 66.5 meters is based on the height of the containment structure above grade (i.e., 218 feet).

The building wake effect cross sectional area of 2744.5 m^2 is based on the geometry of the containment building. The containment building area that has an effect on the dispersion of the releases is its entire cross-sectional area. The containment has a radius of 73 ft and is shaped like a cylinder from the base at El 85 ft to an elevation of 230 ft. It is essentially a hemisphere shape from El 230 ft to 303 ft. The cross-sectional area is calculated as the sum of the cylinder and hemisphere.

The following conservative assumptions are made for these calculations:

- Releases are treated as point sources;
- Releases are treated as ground-level as there are no release conditions that are sufficiently high to escape the aerodynamic effects of the plant buildings;

- The distances from the Unit 1 and Unit 2 releases are determined from the closest edge of the containment buildings to the EAB;
- The plume centerline from each release is transported directly over the receptor;
- The terrain adjustment factor (TAF) used in the calculation of the annual average χ/Q values for the EAB and LPZ models are 4.0 and 1.25, respectively, and are based on the default open TAF values presented as a function of distance in Figure 4.2 of NUREG/CR 2858;
- Radioactive decay or plume depletion due to deposition is not considered.

Table 2.3-145A provides the sixteen sector-specific 0.5% 0-2 hour χ/Q values from the Unit 1 EAB, Unit 2 EAB, and LPZ model runs, the sixteen sector-dependent annual average χ/Q values from the U1/U2 (LPZ) model run, and the sector-specific distances to the EAB relative to both units.

Table 2.3-145B provides the 5-percent overall site 0-2 hour χ/Q values for the U1 (EAB) and the U2 (EAB), and the intermediate, short-term χ/Q values (i.e., 2-8 hours, 8-24 hours, 1-4 days, and 4-30 days) from the U1/U2 (LPZ).

The highest EAB and LPZ χ/Q values from among all 22.5°-downwind sectors for each release/receptor combination and accident period are summarized in Table 2.3-145. EAB χ/Q values are presented for releases from Unit 1 and Unit 2, while the LPZ χ/Q values are applicable to both units.

2.3.5.2.2 On-Site Atmospheric Dispersion Factors

The control room and technical support center χ/Q values for radiological releases from Unit 1 and Unit 2 are calculated using the NRC "**A**tmospheric **R**elative **CON**centrations in Building Wakes" (ARCON96) methodology as documented in NUREG/CR-6331, Revision 1 (Reference 29). Input data consists of: hourly on-site meteorological data; release characteristics (e.g., release height, building area affecting the release); and various receptor parameters (e.g., distance and direction from the control room air intake and intake height). Refer to Section 15.5.8.11 for a description of computer program ARCON96.

A continuous temporally representative 5-year period of hourly on-site meteorological data from the DCPP onsite meteorological tower (i.e., January 1, 2007 through December 31, 2011) is used for the ARCON96 analysis. Each hour of data, at a minimum, has a validated wind speed and direction at the 10-meter level and a temperature difference between the 76- and 10-meter levels. This period of data is temporally representative and meets the requirements of Safety Guide 23, February 1972 (Reference 21).

The ARCON96 modeling follows the ground level release guidance of Regulatory Position C.3 of Regulatory Guide 1.194, June 2003 (Reference 30) relative to determination of: (1) release height (i.e., ground-level vs. elevated); (2) release type

(i.e., diffuse vs. point); and (3) configuration of release points and receptors (i.e., building cross-sectional area, release heights, line-of-sight distance between release and receptor locations, initial diffusion coefficients etc.).

The cross-sectional areas of the Containment Buildings, Refueling Water Storage Tanks, and Fuel Handling Buildings for DCPP Units 1 and 2 as input to the ARCON96 dispersion modeling analysis are based on the geometry of the site buildings as discussed below:

Containment Building (CB): The CB area that has an effect on the dispersion of the releases is its entire cross-sectional area. The containment has a radius of 73 ft and is shaped like a cylinder from the base at El 85 ft to an elevation of 230 ft. It is a hemisphere shape from El 230 ft to 303 ft. The cross-sectional area is the sum of the cylinder and hemisphere. As discussed earlier in UFSAR section 2.3.5.2.1, the total containment cross-sectional area is estimated to be = 2744.5 m^2.

Fuel Handling Building (FHB): The highest elevation of the FHB is 190 ft. The elevation of the containment penetration area leakage releases is 140 ft. The FHB elevation relative to these release points is 190 ft – 140 ft = 50 ft. The diagonal length of the FHB is measured to be approximately 114 ft. This width is conservative in that the FHB is contained within a larger structure that could have been considered in this calculation. Therefore, the conservative cross-sectional area is given by:

(50 ft) x (114.2 ft) = 5,710 ft^2 / (10.76365 ft^2 / m^2) = 530.4 m^2.

Refueling Water Storage Tank (RWST): The RWST roof elevation is 173 ft and the grade elevation at the RWST is 115 ft. The RWST height relative to local grade is 173 ft – 115 ft = 58 ft. The diameter of the RWST is approximately 40 ft. Therefore, the cross-sectional area of the RWST is given by:

(58 ft) x (40 ft) = 2,320 ft^2 / (10.76365 ft^2 / m^2) = 215.5 m^2.

Releases are assumed to be ground-level as none of the release points meet the definition of an elevated release as guided by Regulatory Position C.3.2.2 of Regulatory Guide 1.194, June 2003 (i.e., do not meet the requirement to be at a minimum 2.5 times the height of plant buildings).

Only the containment building edge releases are treated as diffuse sources as the releases occur from the entire surface of the building. In these cases, initial values of the diffusion coefficients (sigma y, sigma z) are determined in accordance with the requirements in Regulatory Guide 1.194, June 2003 Regulatory Position C.3.2.4. Release and receptor locations are applied in accordance with Regulatory Guide 1.194, June 2003 Regulatory Position C.3.4 requirements for building geometry and line-of-site distances.

The following recommended default values from Regulatory Guide 1.194, June 2003, Table A-2, are judged to be applicable to DCPP:

Wind direction range = 90 degrees azimuth;
Wind speed assigned to calm = 0.5 m/sec;
Surface roughness length = 0.20 m; and
Sector averaging constant = 4.3 (dimensionless)

The following assumptions are made for χ/Q calculations:

- The plume centerline from each release is transported directly over the control room or technical support center air intake/receptor (conservative);
- The distances from the Unit 1 and Unit 2 containment building surfaces to the receptors are determined from the closest edge of the containment buildings and the release/receptor elevation differences are set to zero (conservative);
- The applicable structure relative to quantifying building wake effects on the dispersion of the releases is based on release/receptor orientation relative to the plant structures;
- The releases from the Unit 1 and Unit 2 containment building surfaces are treated as diffuse sources;
- All releases are treated as ground level as there are no release conditions that merit categorization as an elevated release (i.e., 2.5 times containment building height) at this site (conservative); and
- The χ/Q value from the accident release point to the center of the control room boundary at roof level is utilized for control room in-leakage since the above χ/Q can be considered an average value for in-leakage locations around the control room envelope. The χ/Q from the accident release point to the center of the control room boundary at roof level is also utilized for control room egress-ingress. The outer doors to the control room are located at approximately the middle of a) the east side (i.e., auxiliary building side) wall of the control room and b) the west side (i.e., turbine building side) wall of the control room. Similarly, the χ/Q from the accident release point to the center of the TSC at its roof level is utilized for TSC in-leakage since the above χ/Q can be considered an average value for in-leakage locations around the TSC building envelope.

Summarized below are some of the other salient aspects of the control room and technical support center χ/Q analyses, as applicable.

<u>Control Room Receptors within 10-meters of Release</u>

Regulatory Guide 1.194, June 2003, Regulatory Position C.3.4 recommends that ARCON96 methodology not be used for analysis at distances less than about 10 meters. However, as an exception to Regulatory Guide 1.194, June 2003, Regulatory Position C.3.4 the ARCON96 methodology has been applied for two cases when the distance from the release to the receptor is less than 10 meters. The distances in question (i.e., 9.4 meters for Unit 1 containment building to Unit

1 control room normal intake and 7.8 meters for Unit 2 containment building to Unit 2 control room normal intake) is considered acceptable since the dominating factors in the calculation are building cross-sectional area and plume meander, not the normal atmospheric dispersion coefficients.

Control Room Receptors at 1.5-meters from Release

Since the Unit 1 and Unit 2 MSSVs, 10% ADVs, and MSLB release points are located within 1.5 meters line-of-sight distance from the affected unit's control room normal intake, this near-field distance is considered outside of the ARCON96 application domain. Although ARCON96 is capable of estimating near-field dispersion, the 1.5-meter line-of-sight distance from the releases to the receptors is much less than the 10-meter distance recommended as the minimum applicable distance in Regulatory Position C.3.4 of Regulatory Guide 1.194, June 2003. Thus no χ/Qs are developed for the above release point / receptor combinations.

Energetic Releases

The 95th-percentile high wind speed values for the 10-m and 76-m levels are 11.0 and 12.1 m/sec, respectively. The vertical exit velocity of the releases from the MSSVs and 10% ADVs, to wind speed ratios are 94.9 m/sec to 11.0 m/sec (i.e., 8.6) and 94.9 m/sec to 12.1 m/sec (i.e., 7.5) for the 10-m and 76-m tower levels over the 5-year meteorological data base. The large vertical velocities of the MSSV and 10% ADVs releases, ranging from 94.9 to 98.9 m/sec, preclude any down-washing of the releases by the aerodynamic effects of the containment buildings such that the control room normal intake of the same unit as the release (e.g., Unit 1 MSSV/10% ADVs releases to Unit 1 CR normal intake) is not contaminated. Moreover, since the horizontal distance is only 1.5 meters, this short distance precludes the releases from reaching the control room normal intakes of the same unit given the height of the MSSV and 10% ADVs releases (i.e., 27.1 and 26.5 meters, respectively) relative to the height of the normal intakes (i.e., 22 meters). Plume rise calculations indicate that the MSSV and ADV release heights will be enhanced by 2 meters at the 95th percentile wind speed of 11.0 m/sec and 12.1 m/sec for the 10-m and 76-m tower levels, respectively, due to the large vertical velocities of the releases. Thus, for purposes of estimating dose consequences, it is appropriate to use the χ/Q associated with the normal control room intake of the opposite unit for releases from the MSSVs/10% ADVs as the worst case control room intake location.

Vertically-Oriented Energetic Releases

Regulatory Position C.6 of Regulatory Guide 1.194, June 2003 establishes the use of a deterministic reduction factor of 5 applied to ARCON96 χ/Q values for energetic releases from steam relief valves or atmospheric dump valves. These valves must be uncapped and vertically-oriented and the time-dependent vertical

velocity must exceed the 95th-percentile wind speed at the release point height by at least a factor of 5. Since the DCPP MSSVs and 10% ADVs are vertically oriented / uncapped and will have a vertical velocity of at least 94.9 m/sec for the first 10.73 hours of the accident, the reduction factor of 5 is clearly applicable to the DCPP MSSV and 10% ADVs releases. Note that since χ/Q values are averaged over the identified period (i.e., 0-2 hours, 2-8 hours, 8-24 hours, etc.), and the vertical velocity has been estimated to occur for 10.73 hours, application of the factor of 5 reduction is not appropriate for χ/Q values applicable to averaging periods beyond the 2-8 hours averaging period. For assessment of an environmental release between 8 to 10.73 hours, continued use of the 2-8 hour χ/Q, with the factor of 5 reduction, is acceptable and conservative.

Dual Intakes

The Unit 1 and Unit 2 control room pressurization air intakes which also serve the technical support center, may be considered dual intakes for the purpose of providing a low contamination intake regardless of wind direction for any of the release points since the two control room pressurization air intakes are never within the same wind direction window; defined as a wedge centered on the line of sight between the release and the receptor with the vertex located at the release point. The size of the wedge for each release-receptor combination is 90 degrees azimuth with the use of ARCON96, as described in Regulatory Position C.3.3.2 of Regulatory Guide 1.194, June 2003.

Redundant Radiation Monitors

Per Regulatory Guide 1.194, June 2003, Regulatory Position C.3.3.2.3, based on the dual intake design of the control room pressurization intakes, and the availability of redundant PG&E Design Class I radiation monitors at each pressurization intake (which provide the capability of initial selection of the cleaner intake and support the expectation that the operator will manually make the proper intake selection throughout the event), allows the χ/Q values applicable to the more favorable control room pressurization intake to be reduced by a factor of 4 and utilized to estimate the dose consequences.

PG&E Design Class II Lines Connecting to PG&E Design Class I Plant Vent

The 16 inch PG&E Design Class II gland seal steam exhauster line and the 2-inch PG&E Design Class II gas decay tank vent line connect to the PG&E Design Class I plant vent. In addition, the plant vent expansion joint may experience a tear during a seismic event; however the plant vent will remain intact and functional.

a) The gland seal steam 16 inch exhauster line connects to the plant vent at El 144’-6” (Centerline) on the North-East side / South–East side of the Unit 1 and Unit 2 containments, respectively. The 2-inch gas decay tank vent line

connects to the plant vent at EL 137'-6" on the North-East side / South-East side of the Unit 1 and Unit 2 containments, respectively. It has been determined that should a failure occur due to a seismic event, it would occur at the interface of this line and the pant vent.

b) The plant vent expansion joint is located at El 155.83' North-East side / South–East side of the Unit 1 and Unit 2 containments, respectively. As discussed earlier, the plant vent expansion joint may experience a tear during a seismic event.

An assessment of the potential release locations identified above indicates that the χ/Q values developed for the plant vent are either conservative or representative of these potential release points.

Release points and receptor locations are provided in Figure 2.3-5, while Table 2.3-146 provides the release point / receptor combinations that were evaluated. Tables 2.3-147 and 2.3-148 provide the control room χ/Q values for the individual release point-receptor combinations for Unit 1 and Unit 2, respectively.

The χ/Q values selected for use in the dose consequence analyses are intended to support bounding analyses for an accident that occurs at either unit. They take into consideration the various release points-receptors applicable to each accident in order to identify the bounding χ/Q values and reflect the allowable adjustments and reductions in the values as discussed earlier and further summarized in the notes of Tables 2.3-147 and 2.3-148.

Table 2.3-149 presents the χ/Q values for the individual post-accident release point TSC receptor combinations for Unit 1 and Unit 2 applicable to the TSC normal intake and the center of the TSC boundary at roof level (considered an average value for potential TSC unfiltered in-leakage locations around the envelope). In the interest of model simplification, the Unit 1 & 2 Main Steam Line (MSL) Break locations were also used to represent the Unit 1 and Unit 2 Main Steam Safety Valves (MSSVs) and 10 percent Atmospheric Dump Valves (ADVs). This approach is acceptable since these release points are essentially co-located, but the MSL Break location releases have the lowest elevation and is therefore the closest to the TSC. The Unit 1 and Unit 2 control room pressurization air intakes also serve the TSC during the emergency mode. Thus, the χ/Qs presented in Tables 2.3-147 and 2.3-148 for the control room pressurization intakes inclusive of the credit for dual intake design and ability to select the more favorable intake are also applicable to the TSC.

2.3.6 LONG-TERM (ROUTINE) DIFFUSION ESTIMATES

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

2.3.6.1 Objective

Annual relative concentrations (χ/Q) were estimated for distances out to 80 kilometers from onsite meteorological data for the period May 1973 through April 1975. These relative concentrations are presented in Table 2.3-2; they were estimated using the models described in Reference 18. The same program also produces cumulative frequency distributions for selected averaging periods using overlapping means having hourly updates. For critical offsite locations, measured lateral standard deviations of wind direction, σ_A, and bulk Richardson number, R_i, were used as the stability parameters in the computations. The meteorological input data were measured at the 10 meter level of the meteorological tower at DCPP site. Annual averaged relative concentrations calculated by the above methods are presented in Table 2.3-4.

2.3.6.2 Calculations

The meteorological instrumentation that was used to obtain the input data for the previously discussed relative concentration calculations at DCPP site is described in Section 2.3.4. Procedures for obtaining annual averaged relative concentrations are described in detail in Reference 15.

2.3.6.3 Meteorological Parameters

The following assumptions were used in developing the meteorological input parameters required in the dispersion model:

(1) There is no wind direction change with height

(2) Wind speed changes with height can be estimated by a power law function where the exponent, P, varies with stability class and is assigned the following values:

Pasquill Stability Class	*Exponent (P)*
A & B	*0.10*
C	*0.15*
D	*0.20*
E	*0.25*
F & G	*0.30*

If more than five hourly observations are missing in any 24-hour period, the estimated 24-hour concentration value is not included in the analyses.

Meteorological data collected at DCPP site are representative of atmospheric conditions along a Pacific coastal area having a complex terrain near the shoreline. Use of these

data in estimating downwind relative concentrations results in realistic estimates as shown in the report by Cramer and Record (Reference 1). This field program included ground level concentration measurements out to a distance of about 20 kilometers. All concentration measurements were approximated by near-neutral through unstable stability classifications, even though both vertical and lateral turbulence measurements, σ_E and σ_A in Table 3.1 of Reference 1, indicated several stable regimes.

Even during the nighttime periods when extreme stability may be expected, the relative concentrations in the area were characteristic of unstable lapse rates. Actual average temperature differences over the height of the tower for these trials, given in Table 2.3-142, show a high percentage of test periods with stable lapse rates. Five nighttime trials having light and variable winds were included; three were near ground level (8 meters) and two were elevated (76 meters) releases. Temperature gradient measurements indicated three of these trials having near-neutral and two with stable lapse rates, yet the measured ground level concentrations were at least two orders of magnitude less than the predicted peak concentrations for those stabilities. In fact, the diffusion rates, as shown in Figure 3-3 of Reference 1, based on measured ground level concentrations, were typical of those expected for extreme instability.

Results of this series of diffusion trials conducted at DCPP site have yielded considerable insight into the dispersal capabilities of a coastal site. They indicate that use of direct turbulence measurements and the split sigma approach to independently predict lateral and vertical cloud growth yield realistic estimates of site dilution factors without including any corrections or recirculation.

2.3.7 CONCLUSIONS

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

The principal conclusions reached as the result of the analysis of the data obtained during the onsite meteorological measurement program at DCPP site are listed below:

(1) Northwesterly wind directions with wind speeds averaging 10 to 15 mph can be expected to occur approximately 50 percent of the time.

(2) Wind directions within a 22.5° sector that persist for periods of 8 hours or longer will occur 3 to 4 percent of the time.

(3) Less than 4 percent of the total observations at the 25 foot level at Station E refer to the joint occurrence of mean wind speeds of 2 mph or less, onshore wind directions (southeast through west-northwest measured clockwise), and moderately stable and/or extremely stable thermal stratifications.

(4) Despite the prevalence of the marine inversion and the northwesterly wind flow gradient along the California coast in the dry season, the long-term

accumulation of plant emissions, released routinely or accidentally, in any particular geographical area downwind from the plant is virtually impossible. Pollutants injected into the marine inversion layer of the coastal wind regime are transported and dispersed by a complex array of land-sea breeze regimes that exist all along the coast wherever canyons or valleys indent the coastal range. Because of the complexities of the wind circulation in these regimes and their fundamental diurnal nature, the net result is a very effective and wide daily dispersal of any pollutants that are present in the marine coastal air.

2.3.8 SAFETY EVALUATION

2.3.8.1 General Design Criterion 11, 1967 – Control Room

Wind speed, wind direction, and differential air temperature measurements from the primary and backup meteorological towers are provided to control room personnel to respond to abnormal meteorological conditions in order to maintain safe operational status of the plant. The data are retrieved continually and provided to the PPC. High ambient air temperature is annunciated on the main control board.

2.3.8.2 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Meteorological monitoring instrumentation is provided for DCPP Unit 1 and Unit 2 to provide meteorological conditions as discussed in Section 2.3.4.

2.3.8.3 Meteorology Safety Function Requirements

(1) Calculation of Atmospheric Dispersion

Calculation of atmospheric dispersion as discussed in Section 2.3.4.7 is based on methodology in Sagendorf (Reference 15) and Regulatory Guide 1.145, Revision 1.

2.3.8.4 Safety Guide 23, February 1972 – Onsite Meteorological Programs

As discussed in Section 2.3.4, the meteorological data collection program was designed and has been updated continually to meet the requirements of Safety Guide 23, February 1972.

2.3.8.5 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Wind speed, wind direction, and estimation of atmospheric stability indication in the control room provide information for use in determining the magnitude of the release of radioactive materials and in continuously assessing such releases during and following an accident (refer to Table 7.5-6 for a summary of compliance to Regulatory Guide 1.97, Revision 3).

2.3.8.6 Regulatory Guide 1.111, March 1976 – Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors

The pre-operational values of dilution factor and deposition factor used in the calculation of annual average offsite radiation dose are discussed in Section 11.3.2.4. The values of deposition rate were derived from Figure 7 of Regulatory Guide 1.111, March 1976, for a ground-level release.

2.3.8.7 Regulatory Guide 1.111, Revision 1, July 1977 – Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors

The annual average relative concentration values are developed for each sector, at the outer LPZ boundary distance for that sector, using the method described in Regulatory Position C.1.c of Regulatory Guide 1.111, Revision 1. These values are used to calculate the intermediate averaging time χ/Q values at the LPZ for the periods of 2-8 hours, 8-24 hours, 1-4 days, and 4-30 days following the postulated accident. This information is used as input to develop the accident χ/Q values at the LPZ using Regulatory Guide 1.145, Revision 1 methodology. Refer to Section 2.3.5.2.

2.3.8.8 Regulatory Guide 1.145, Revision 1, February 1983 – Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants

The short-term atmospheric dispersion factors applicable to the exclusion area boundary and the low population zone for post-accident accident releases from Unit 1 and Unit 2 are calculated using methodology applicable to “ground level” releases provided in Regulatory Guide 1.145, Revision 1. Refer to Section 2.3.5.2.

2.3.8.9 Regulatory Guide 1.194, June 2003 – Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessments at Nuclear Power Plants

The control room and technical support center atmospheric dispersion factors for radiological releases from Unit 1 and Unit 2 are calculated using methodology outlined

in Regulatory Positions C.1 through C.3, and the adjustment factor for vertically orientated energetic releases from steam relief valves and atmospheric dump valves allowed by Regulatory Position C.6, and NRC ARCON96 methodology as documented in NUREG/CR-6331, Revision 1. Refer to Section 2.3.5.2.

2.3.8.10 NUREG-0737 (Items III.A.2 and III.A.2.2), November 1980 – Clarification of TMI Action Plan Requirements

Item III.A.2 - Improving Licensee Emergency Preparedness–Long-Term:

As discussed in Section 2.3.4, the primary and backup meteorological data are available in the control room and emergency response facilities in accordance with NUREG-0654, Revision 1.

As discussed in Section 2.3.4, the measurement subsystems consist of a primary meteorological tower and a backup meteorological tower. The meteorological data acquisition system communicates through the Plant Data Network (PDN), to the Emergency Assessment and Response System (EARS) and the Plant Process Computer (PPC) and thus all meteorological data is available in the emergency response facility and the control room.

Item III.A.2.2 - Meteorological Data: NUREG-0737, Supplement 1, January 1983:

Table 7.5-6 and Section 2.3.8.5 summarize DCPP conformance with Regulatory Guide 1.97, Revision 3. Wind direction, wind speed, and estimation of atmospheric stability are categorized as Type E variables, based on Regulatory Guide 1.97, Revision 3. The PPC is used as the indicating device to display meteorological instrument signals. In addition, Type E, Category 3, recorders are located in the meteorological towers.

2.3.8.11 IE Information Notice 84-91, December 1984 – Quality Control Problems of Meteorological Measurements Programs

In addition to the primary meteorological towers, a supplemental meteorological measurement system is provided in the vicinity of the plant site in order to meet IE Information Notice 84-91. As discussed in Section 2.3.4.5, this supplemental measurement system consists of three Doppler SODAR and seven tower sites located as indicated in Figure 2.3-4. The primary and secondary meteorological towers in conjunction with the supplemental system adequately predict the meteorological conditions at the site boundary (800 meters) and beyond.

2.3.9 REFERENCES

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2.4 HYDROLOGIC ENGINEERING

2.4.1 DESIGN BASES

2.4.1.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I structures, systems and components (SSCs) are designed to withstand the effects of, or are protected against, natural phenomena such as flooding.

2.4.1.2 Regulatory Guide 1.59, Revision 2, August 1977 – Design Basis Floods for Nuclear Power Plants

The PG&E Design Class I SSCs are designed to withstand and retain the capability to achieve and maintain cold shutdown during the worst probable site-related flood.

2.4.1.3 Regulatory Guide 1.102, Revision 1, September 1976 – Flood Protection for Nuclear Power Plants

The PG&E Design Class I SSCs are appropriately protected from damage caused by flooding through the use of exterior and incorporated barriers.

2.4.1.4 Regulatory Guide 1.125, Revision 1, October 1978 – Physical Models for Design and Operation of Hydraulic Structures and Systems for Nuclear Power Plants

Hydraulic modeling of the site intake breakwaters, systems, and structures is appropriately designed, tested, and documented to accurately describe the behavior of these plant facilities.

2.4.2 HYDROLOGIC DESCRIPTION

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

2.4.2.1 Site and Facilities

The general topography with outline of the drainage basin at DCPP site is shown in Sheet 1 of 2 of Figure 2.4-1, reproduced from the United States Geological Survey (USGS) Port San Luis and Pismo Beach 7.5 minute topographic quadrangles (contour interval 40 feet, original scale 1:24,000). Figure 2.4-2 shows the Diablo Creek drainage basin to a larger scale. The area encompasses some 5 square miles and is bounded by ridges reaching a maximum elevation of 1819 feet at Saddle Peak. The figure also shows changes to the natural drainage features.

2.4.2.2 Hydrosphere

The hydrologic characteristics of the site are influenced by the Pacific Ocean on the west and by local storm runoff collected from the 5 square mile egg-shaped area drained by Diablo Creek. The maximum and minimum flows in Diablo Creek are highly variable. Average flows tend to be nearer the minimum flow value of 0.44 cfs. Maximum flows reflect short-term conditions associated with storm events. Usually within 1 or 2 days following a storm, flows return to normal. Flows during the wet season (October-April) vary daily and monthly. Dry season flows are sustained by groundwater seepage and are more consistent from day to day, tapering off over time. There is no other creek or river within the site area.

Water for the city of San Luis Obispo is obtained principally from Salinas Reservoir, about 23 miles east-northeast of the site. Whale Rock Reservoir on Old Creek, 17 miles north of the site, and Chorro Reservoir, about 13 miles northeast of the site, are also used. A few small uncovered reservoirs are used in connection with the San Luis Obispo water system and are located about 18 miles northeast of the site. A reservoir in Lopez Canyon is 20 miles east of the site. Smaller towns in the region of San Luis Obispo depend on wells for domestic water.

There are two public water supply groundwater basins within 10 miles of the DCPP site. Avila Beach County Water District serves Avila Beach (including Unocal) with water and sewer needs, and the San Miguelito Mutual Water District and Sewer District serves most of the Avila Valley area. An ocean water desalinization plant has been built and in operation at the site since 1985 (Reference 1).

The property owners to the north and south of the DCPP site capture surface water from small intermittent streams and springs for minimal domestic use. Property owned by PG&E captures water from Crowbar Canyon, 1 mile north of the DCPP site. PG&E's lessee captures water 2 to 4 miles south of the DCPP site from streams and springs between Pecho Canyon and Rattlesnake Canyon.

2.4.3 FLOODS

2.4.3.1 Flood History

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Since 1968, PG&E has kept a record of flows through a V-notched weir located on Diablo Creek, as shown in Figure 2.4-2.

Two major storms occurred in the area between the time the weir was established and June 1973. One occurred on January 18-25, 1969, and the other on January 16-19, 1973. On each occasion, streamflow washed out the weir so no definitive readings were obtained. Flood hydrograph reconstitution indicated that the

1969 flood could have peaked with a flow of approximately 430 cfs and the 1973 flood could have peaked with a flow of approximately 400 cfs.

A USGS gauging station (Los Berros Creek, No. 11-1416), located 21 miles southeast of the site near Nipomo, has a 15 square mile drainage basin, approximately three times the size of the Diablo Creek basin. The gauge at this station recorded a peak flow of 599 cfs on January 25, 1969. The flow at the same station on January 18, 1973, was about 324 cfs. Regional floods of January and February 1969 are reported by U.S. government publications in References 2, 3, and 4.

Ocean wave history is discussed in Reference 5.

2.4.3.2 Flood Design Considerations

2.4.3.2.1 Site Flooding

Topography and plant site arrangement limit flood design considerations to local floods from Diablo Creek and sea wave action from the Pacific Ocean. As discussed in Section 2.4.4, the canyon confining Diablo Creek remains intact and will pass any conceivable flood without hazard to PG&E Design Class I equipment. Channel blockage from landslides downstream of the plant, sufficient to flood the plant yard, is not possible because of the topographic arrangement of the site.

2.4.3.2.2 Flood Waves

Flooding conditions, for purposes of the following discussion, include the combined effects of a tsunami, wind-generated storm waves, storm surge ("piling up" of water near the shore due to a storm), and tides. The combination of these effects results in a rise and fall of the ocean surface level relative to a defined datum level. The reference datum is the MLLW level. At DCPP, MLLW is 2.6 feet below the MSL, which is used as a reference datum for plant elevation. Values of water level rise and fall are expressed relative to MLLW. References to plant elevation are expressed relative to MSL.

When considering tsunami effects alone, the rise in water level is termed tsunami runup, and the fall of the water level is termed tsunami drawdown. Effects of both locally-generated (near-shore) tsunami and distantly-generated tsunami are considered. Tsunami runup and drawdown values given for locally-generated tsunami include the effects of subsidence at the plant site that is considered to occur as a result of near-shore earthquakes.

The wave terms are defined as follows:

Still Water Level (SWL)	The water level that includes the effects of tsunami, tide, and storm surge

Combined Wave Runup	The peak water level associated with storm wave action on top of SWL, but not including splash or spray effects associated with wave impacts
Splash Runup	The water level that includes wave runup effects plus splash effects, but not including spray effects
Combined Wave Drawdown	The lowest water level associated with tsunami coincident with low tide and short period storm waves

The rise in water level may result in submersion, associated hydraulic loading and ground erosion effects, and may result in flooding effects, on structures and system components located in the zone of influence.

The following effects are considered in determining the design water levels for DCPP:

Storm Waves: waves induced by the wind and pressure effects of a storm

Storm Surge: the “piling up” of water at the shore due to (a) a long duration storm wind acting on the water surface, (b) local reduction in atmospheric pressure, and (c) wave effects near the shoreline

Tide: the rise and fall of the surface of the ocean caused by the gravitational attraction of the sun and moon on the earth. Tidal range is typically based on the maximum annual higher high tide and the minimum annual lower low tide.

Tsunami: a long-period wave generated by a seismic event

In addition to water level changes resulting from the effects described above, the following effects are also considered:

Breakwater Damage: only partial credit is taken for protection provided by the breakwaters, considering that they could potentially be damaged by near-shore seismic activity or by storm waves

Resonance/Ponding Effects: local amplification of wave activity as a result of resonance effects in the intake basin, or increase in water level in the intake basin as a result of wave overtopping of the breakwaters, or wave ingress through the breakwater opening

Combined runup and drawdown effects on PG&E Design Class I structures and systems are as follows:

- Combined splash runup effects for applicable PG&E Design Class I facilities and their supporting structures are discussed in Section 2.4.7.6

- PG&E Design Class I systems include consideration of the effects of the combined drawdown and are discussed in Section 2.4.7.1.5

- Tsunami loads on the intake structure, including the effects of the combined wave runup are discussed in Section 2.4.7.6

2.4.3.2.3 Structural Evaluation

As discussed in Section 2.4.7.6, testing and analyses demonstrate that equipment and structures important to safety will remain operable in the event of a probable maximum tsunami, storm, and tide occurrence (Reference 21).

2.4.4 PROBABLE MAXIMUM FLOOD ON STREAMS AND RIVERS

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

The only stream on the site subject to a PMF study is Diablo Creek. The creek collects runoff from a drainage area of 5.19 square miles up from the ocean side.

The PMF was obtained by deriving an estimated probable maximum precipitation (PMP) with a duration of 24 hours over the subject drainage area. The most severe antecedent condition of ground wetness favorable to high flood runoff was assumed. In view of the low elevation of the site, snowmelt was not considered in the study.

It was assumed that during a PMF all culverts are plugged, and water is impounded to the crest of the lowest depression of the switchyard's fill. The artificial reservoir formed in this assumption is so small that the PMF could not affect the plant.

For a drainage area of 5.19 square miles, the PMF was found to have a peak discharge of 6878 cfs (1325 cfs/sq mi) or a total volume of about 4306 acre-feet for the 24-hour storm.

2.4.4.1 Probable Maximum Precipitation

Due to the small drainage area of the site, a PMP with 24 hours duration of rain was selected. Determination of the PMP is based entirely on the methods and procedures outlined in Reference 6. The unrestricted cumulative convergence PMP determined by the above method is found to be 16.6 inches during the month of October. PMP values for other durations as interpolated by the method suggested in Reference 6 are shown in Table 2.4-1.

2.4.4.2 Precipitation Losses

Losses are a complex function of rain intensity and accumulated loss (as an index of ground wetness). Five loss rate variables in this study represent average loss, initial loss, rate of decrease of loss with wetness, relation of loss to rain intensity, and rate of recovery of loss rate between storm periods. The unit hydrograph and loss rate parameters are determined in a sequential successive approximation manner as described in Reference 7. Optimization of the basin parameters was performed with the aid of computer program No. 23-J-L211, "Unit Hydrograph and Loss Rate Optimization," developed by the U.S. Army Corps of Engineers, and modified by PG&E (Reference 8).

To obtain precipitation losses, the storm at DCPP site on January 24-25, 1969, was optimized with the runoff record at the USGS gauging station at Los Berros Creek for the same period. Actual rainfall-runoff optimization on Diablo Creek could have been done if the weir had not washed out during the major storms of 1969 and 1973. Nevertheless, geographic and geologic conditions of Los Berros Creek are similar to those of Diablo Creek; Los Berros is the nearest USGS gauging station in the vicinity of DCPP site. The records are good and unregulated. It is in the same hydrographic drainage area as the plant site and both drainage areas have relatively similar elevations. Geologic map comparison shows similarity of ground conditions. Isohyetal maps of major storms show similar magnitude of rainfall in both areas.

In the rainfall-runoff optimization fit using rainfall at DCPP site, the Los Berros recorded runoff responded well to the rainfall distribution at Diablo Canyon. Other rainfall stations around the gauging station were tried but no better fit could be derived than the above. On the foregoing consideration, the optimized loss rates are judged to be representative of the Diablo Canyon drainage basin.

The antecedent condition for the storm of January 24-25, 1969, was very favorable to heavy runoff. Heavy rains during the period of January 18-22, 1969, brought widespread but generally moderate flooding in the area. According to flood reports from USGS, this rain saturated the soil over much of the area. The time distribution of precipitation during the January 24-25 storm was conducive to rapid and intense runoff, because the heaviest rain occurred near the end of the storm when streams were already carrying large flood flows.

Choice of the January 24-25, 1969, storm gave, therefore, conservative results of loss rates. Precipitation data indicate that January 1969 was the wettest January in many years in the area.

As stated in Section 2.4.2.2, Hydrosphere, the average discharge at Diablo Creek is 0.5 cfs in its 16 years of record. However, base flow considerations were taken from the hydrograph of flood flow at Los Berros. The result of the optimization study is shown in Figure 2.4-4.

2.4.4.3 Runoff Model

Based on the discussion in the preceding section, the hydrologic response characteristics of Diablo Creek were considered as those that were optimized. The time of concentration of the Diablo Creek basin was calculated using the formula of the Bureau of Reclamation, Design of Small Dams, where:

$$T_c = \frac{\left(11.9L^3\right)^{0.385}}{H} \qquad (2.4\text{-}1)$$

where:

T_c = *time of concentration in hours*

L = *length of longest water course in miles*

H = *elevation difference in feet*

Due to the small size of the basins, Variables 2 and 3 in the rainfall-runoff study were taken as the optimized values. The definitions of the variables or parameters in the optimized model are shown in Sheet 3 of Figure 2.4-5. The first three variables represent unit hydrograph parameters.

The mechanics of the mathematical model used in this study are described in the program documentation of the "Unit Hydrograph and Loss Rate Optimization" computer program of the U.S. Army Corps of Engineers.

Based on the mechanics of this program, PG&E developed the computer program listed as Reference 8. The parameters obtained and defined in the optimization, or other values considered, are held constant and considered representative of the basin. No optimization is performed. This model is capable of modeling any basin rainfall amount and time distribution up to and including the PMP. Loss rates are also calculated in a nonlinear function represented by the equation:

$$L = K\,P^E \qquad (2.4\text{-}2)$$

where:

L = loss for each period
K = a function of four variables (average value and initial loss increment, which differ from flood to flood, and recovery rate and exponential recession rate, which are uniform for all floods)
P = rain for each period
E = loss rate variable equal to Variable 7 in the program

2.4.4.4 Probable Maximum Flood Flow

The PMP estimate obtained in Section 2.4.4.1 was distributed according to Reference 6. The loss rate parameters obtained in Section 2.4.4.2 were reduced by 50 percent to represent a much more severe antecedent condition and loss rate recession. The exponent of the loss rate equation (Variable 7) was not changed, but it was considered as an optimized regional value. Using the foregoing values as input, the synthetic PMF hydrograph for Diablo Creek up to the ocean side was derived with the aid of the PG&E computer program, Reference 8. The unit hydrograph constants were those that were derived in the runoff model. The hydrograph of inflow for the PMF is presented as a computer printout in Figure 2.4-5, Sheet 2. The peak flow for the PMF was found to be 6878 cfs (1325 cfs/sq mi) with a runoff factor of 0.92.

The switchyard embankment creates a dam upstream of the plant with a potential reservoir storage capacity of 1100 acre-feet. The possibility exists that this small reservoir is full prior to a PMF as a result of culvert plugging. Therefore, storage attenuation of inflow PMF was not considered.

Section 2.4.11 discusses the capability of roof and yard drainage to handle runoff from local PMP without risk of flooding PG&E Design Class I buildings.

2.4.4.5 Water Level Determinations

Figure 2.4-3 shows that the hydraulic capacity of the canyon is in excess of 10,000 cfs. There is more than 11 feet of freeboard if the road crossing is washed out and more than 7 feet of freeboard if the road crossing remains intact; thus, there is no risk of flood to PG&E Design Class I equipment.

2.4.4.6 Coincident Wind Wave Activity

Wave runup, discussed in Section 2.4.6, coincident with PMF will have little effect on computed water surfaces. The roadway acting as a weir at an elevation of 65 feet above MLLW (refer to Figure 2.4-3) provides higher backwaters than the combined waves discussed in Sections 2.4.6 and 2.4.7.

2.4.5 POTENTIAL DAM FAILURES (SEISMICALLY INDUCED)

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

There are no dams in the watershed and failure of dams outside the watershed could not generate sea waves higher than those discussed in Sections 2.4.6 and 2.4.7. The potential storage of water upstream of the switchyard fill described in Section 2.4.4.4 poses no flood threat since the switchyard fill is more than five times as wide as it is deep and the maximum storage of 1100 acre-feet has a face depth of 120 feet.

2.4.6 PROBABLE MAXIMUM SURGE AND SEICHE FLOODING

2.4.6.1 Probable Maximum Winds and Associated Meteorological Parameters

Hurricanes or line squalls of sufficient magnitude to generate surge flooding (storm-generated, long-period sea waves) have not been recorded on the Pacific coastline. This lack of observed events in 200 years of record lends reasonable assurance that such an event will not occur during the lifetime of the power plant. However, the effects of wind-generated storm waves, storm surge, and tides are conservatively considered in the evaluation of water level and its effects on PG&E Design Class I equipment and structures.

2.4.6.2 Surge and Seiche History

As discussed above, there is no record of surge flooding associated with hurricanes or line squalls. The history of short-period wave trains generated from remote storms in this region is limited. As described below, to compensate for the lack of historical knowledge, conservative flood levels have been developed on the basis of hindcasts and three-dimensional model testing.

2.4.6.3 Surge and Seiche Sources

Since there is no record of hurricanes, cyclonic type wind storms, squall lines, etc., on the Pacific Coast, these phenomena are not a design consideration. However, design for any credible flooding, including tsunami in combination with wave and tide action as discussed in Section 2.4.7, is conservatively considered.

2.4.6.4 Wave Action

Wave action behavior at DCPP was originally developed on the basis of hindcasts based on a statistical evaluation of historical data in combination with previous scale model testing. PG&E conducted an extensive review of the historical data that led to the estimation of the return periods of the critical storms; e.g., the 1905 storm and the 1981 storm. A major Pacific storm in January 1981 resulted in extensive damage to the west breakwater protecting the intake basin, and led to a review of all the design waves and water levels.

As a result of the damage, PG&E undertook a test program to determine critical wave behavior at the intake basin, including wave height, wave direction, wave runup, resulting forces, and the effects of wave splash on the intake structure and the ASW system. A three-dimensional physical model of the basin and its surroundings was constructed, representing in a 1:45 scale the sea floor, the intake structure, and the breakwaters in storm-induced damage conditions.

The tests included the effects of: (a) wind-generated storm waves, including storm surge and tides, and (b) the effects of tsunami plus storm waves. The effects of the waves, including the wave heights, are discussed in detail in Section 2.4.7.

Because data related to wind-generated storm waves were very limited, PG&E developed and implemented a test program to generate the required data (Reference 16). The test program developed site-specific design basis flood events (References 16 and 20).

Although the maximum SWL of 17 feet, for probable maximum tsunami, high tide, and storm surge, was conservatively used in the scale model tests (References 16 and 20), the SWL of 15.5 feet, as approved by the NRC, may be used (Reference 28).

Waves for the scale model tests were mechanically generated. Wave heights, outside the breakwater, of up to 45 feet, with periods of 12, 16, and 20 seconds were generated. The results for the model testing indicated that the response waves within the intake basin reached a maximum height that did not increase further in response to increases in the offshore wave height. This phenomenon is due to the effects of the natural terrain and the presence of the degraded breakwater. Therefore, the maximum credible wave event is based on the maximum response of the wave height within the basin, in combination with the SWL in the basin, and is used for assessing the maximum inundating effects and wave forces at the intake structure.

A wave data buoy was installed immediately off DCPP in May 1983 to directly obtain data on wave action. The data are recorded on site and telemetered to the Scripps Institute at La Jolla, California, where they are assimilated with data from other Pacific Coast buoys interconnected with the Scripps "Coastal Data Information Program."

2.4.6.5 Resonance/Ponding

As discussed in Section 2.4.6.4, PG&E developed and implemented a test program to simulate the effects of storm waves and tsunamis on the intake basin. The scale model included the detailed relief of the surrounding submerged terrain, the breakwaters, and the intake structure. The action of the waves on the scale model automatically incorporates the resonance and ponding effects of the intake basin.

2.4.6.6 Runup and Drawdown

Estimates of storm and tsunami wave runup and drawdown, and their effects on the plant, are presented in Section 2.4.7.

2.4.6.7 Protective Structures

The only PG&E Design Class I system that has components within the projected sea wave zone is the ASW system. The ASW pump motors are housed in watertight compartments within the intake structure. These compartments are designed for a combination tsunami-storm wave activity to elevation +48 feet MLLW (+45.4 feet MSL). The massive concrete intake structure ensures that the pumps remain in place and operate during extreme wave events. The intake structure is arranged to provide redundant paths for seawater to the pumps, ensuring a dependable supply of seawater.

In addition to the ASW pumps, the buried ASW piping outside of the intake structure, which is not attached to the circulating water tunnels, is vulnerable to the effects of tsunami and storm waves. An evaluation was conducted by Bechtel Corporation for PG&E to determine what protective measures were required to protect this buried ASW piping. This evaluation is described in Reference 40. Based on this evaluation, erosion protection, consisting of gabion mattresses, reinforced concrete pavement above this buried piping, and an armored embankment southeast of the intake structure, were designed and installed to resist the effects of tsunami and storm waves.

The model test program (References 16 and 20) and resultant evaluations led to various structural modifications, including the extension of the ASW air vent structures with steel tubular snorkels having openings between elevations 48 and 52 feet MLLW. The snorkels were installed during 1982 and 1983 plant modifications. Analysis of the installed extensions by P. J. Ryan (Reference 18) further demonstrated that ingestion of sufficient water by the snorkels is extremely unlikely to jeopardize the operation of the ASW pumps. Section 2.4.7.6 provides additional details.

2.4.7 PROBABLE MAXIMUM TSUNAMI FLOODING

The tsunami evaluation and design have evolved as a result of a number of studies and analyses during the original plant design period, the operating license review period, and following the breakwater damage in 1981. The licensing basis for tsunami evaluation is presented in Sections 2.4.7.1 to 2.4.7.6. The background and evolution of the tsunami design and evaluation are provided in Section 2.4.7.7.

2.4.7.1 Probable Maximum Tsunami

Tsunamis are classified according to the distance from the shore to the location of the event (generator) that causes the wave. The design tsunami for DCPP represents the envelope of the following two classes of tsunamis:

> Distantly-generated tsunami: a tsunami whose generator is located more than several times the principal source dimension (e.g., length of postulated fault rupture) from the plant, Marine Advisors, Inc., 1966 (Reference 24)

Locally-generated (near-shore) tsunami: a tsunami whose generator is closer than the distance defined for distantly-generated tsunami

The tsunami runup and drawdown at the intake structure are dependent on the source of the tsunami, the distance to the tsunami generator, and the near-shore undersea terrain, including the topography of the intake basin and the configuration of the breakwater.

Wave heights for the two classes of tsunamis considered in the design of DCPP are described in the following sections.

2.4.7.1.1 Distantly-Generated Tsunamis

The predominant sources of distantly-generated tsunamis are limited to areas of earthquake and volcanic activity on the circum-Pacific belt. Distant sources relative to DCPP include the Aleutian area, the Kuril-Kamchatka region, and the South American coast.

The lack of historical data for the site during the construction permit review raised a question on the degree of confidence for a “virtually no risk of being exceeded” assurance. In 1967, the U.S. Atomic Energy Commission (AEC) staff and its consultants, the United States Coast and Geodetic Survey (USCGS), agreed that the probable maximum tsunami at the site, which had virtually no risk of being exceeded, would be less than the 17- to 20- foot waves experienced at Crescent City, California, as a result of the 1964 Anchorage, Alaska, earthquake (Reference 35). To expedite the permit schedule, PG&E decided to use 20 feet as the maximum distantly-generated tsunami wave height.

2.4.7.1.2 Near-Shore Tsunami

A number of investigations and analyses to determine the tsunami-generation potential of near-shore earthquake faults were performed during the period from 1966 to 1975. The design basis tsunami wave heights are based on the analysis performed in 1975 by Hwang, Yuen, and Brandsma (Reference 28). The following earthquake sources and characteristics were considered in the analysis:

- Santa Lucia Bank fault, located approximately 29 miles from the site, considering a resultant displacement of 9.8 feet and a vertical displacement (6.6 feet) equal to 2/3 of the resultant displacement

- Santa Maria Basin fault (later identified as the Hosgri fault), located approximately 3.5 miles from the site, considering a resultant displacement of 11 feet and a vertical displacement (7.3 feet) equal to 2/3 of the resultant displacement

The analysis considered the cases of the breakwaters (a) present as originally constructed, (b) completely absent, and (c) in damaged conditions, in which the sides of the breakwaters slump to a 1-on-4, 1-on-5, or 1-on-6 vertical-to-horizontal slope.

The Santa Maria Basin fault source controls, producing a maximum runup of 9.2 feet and a maximum drawdown of 0.0 feet (Reference 28).

The design basis maximum combined wave runup is the greater of that determined for near-shore or distantly-generated tsunamis, and results from near-shore tsunamis. The bases of these runup values are given in the following two subsections.

- For distantly-generated tsunamis, the combined runup is 30 feet
- For near-shore tsunamis, the combined wave runup is 34.6 feet, as determined by hydraulic model testing (References 21 and 37)

2.4.7.1.3 Combined Wave Runup for Distantly-Generated Tsunamis

The combined wave runup for distantly-generated tsunamis is the same as the value adopted during the construction permit review. The value adopted at that time was 30 feet, as imposed by the NRC (Reference 35).

2.4.7.1.4 Combined Wave Runup for Near-Shore Tsunamis

The combined wave runup for near-shore tsunamis, 34.6 feet, is based on observations during scale model testing (Reference 21), which was performed subsequent to the 1981 breakwater damage. This runup value represents the maximum runup observed at the location of the ventilation shafts in the test model, excluding wave spray. Wave splash and spray, which can extend to higher elevations, are discussed in Section 2.4.7.6.

A degraded breakwater model was used, representing the crest of both breakwaters reduced to MLLW, the seaward slopes below that level remaining as originally constructed, and the intake basin sides widened by as much as the material above MLLW could achieve while coming to rest at a slope of 1 vertical to 1.5 horizontal. The model represents the worst-case breakwater damage that could result from the cumulative effects of severe storms, a tsunami, and Hosgri effects (References 23 and 33).

Tsunami, storm surge, and tide effects have relatively long periods and were combined to represent a static change in the elevation of the still water surface. The dynamic effects of storm waves, which have shorter periods, were then superimposed.

2.4.7.1.5 Combined Wave Drawdown Minimum Water Level

The maximum combined wave drawdown is the greater of that determined for near-shore or distantly-generated tsunamis, and results from distantly-generated tsunamis. This value constitutes the design combined drawdown value, which is 9.0 feet.

- Combined wave drawdown for distantly-generated tsunamis: The combined wave drawdown value of 9 feet, derived by a study performed during the construction permit review, is based on the combination of tsunami, storm wave, storm surge, and tide (Reference 24).

- Combined wave drawdown for near-shore tsunamis: The maximum combined wave drawdown determined by analysis for the case with the breakwaters intact, as originally constructed, is 4.07 feet (Reference 28). The maximum combined drawdown for the case with the breakwater degraded to MLLW has not been evaluated. However, analysis for the case of no breakwater present shows that the drawdown effect is 4.40 feet (Reference 28). Therefore, the drawdown for near-shore tsunamis will be less than for distantly-generated tsunamis. There is a significant margin between the 4.07 feet of drawdown and the available pump submergence depth.

2.4.7.2 Historical Tsunami Record

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

There is no historical record of tsunamis for DCPP site due to the remote location with respect to populated areas. The historical review of the region shows tsunamis that have been recorded in the region are of the same order of magnitude as the normal tide range and that local configurations play a large part in the ultimate effects of the tsunami.

At the California coast, reactions to tsunamis from distant sources have been generally moderate, with the exception of certain sensitive areas that have historically shown an abnormally high response as compared to the coast in general. Avila Beach is the closest sensitive area to DCPP.

A review of historical tsunami records and studies of the underwater topography has determined that wave heights recorded at Avila Beach are the result of local conditions that do not affect DCPP (Reference 24). The review demonstrated that DCPP need consider only a distantly-generated tsunami height of 5.0 to 6.0 feet, corresponding to the normal tidal range. Thus, a 6-foot change in the water level above or below MLLW could result (Reference 24). Hence, the 20-foot tsunami runup from a distantly-generated tsunami suggested by the USCGS (Reference 32) is extremely conservative.

2.4.7.3 Source of Tsunami Wave Height

2.4.7.3.1 Distantly-Generated Tsunamis

As discussed in Section 2.4.7.1.1, the predominant sources of distantly-generated tsunamis are limited to areas of earthquake and volcanic activity on the circum-Pacific belt. Distant sources relative to DCPP include the Aleutian area, the Kuril-Kamchatka region, and the South American coast.

2.4.7.3.2 Near-Shore Tsunamis

A number of investigations and analyses to determine the tsunami-generation potential of near-shore earthquake faults was performed during the period from 1966 to 1975. The following earthquake sources and characteristics were considered in the analyses:

- Santa Lucia Bank fault, located approximately 29 miles from the site, considering a resultant displacement of 9.8 feet and a vertical displacement (6.6 feet) equal to 2/3 of the resultant displacement

- Santa Maria Basin fault (later identified as the Hosgri fault), located approximately 3.5 miles from the site, considering a resultant displacement of 11 feet and a vertical displacement (7.3 feet) equal to 2/3 of the resultant displacement

The design basis tsunami wave heights are based on the analysis performed in 1975 by Hwang, Yuen, and Brandsma of Tetra Tech, Inc. (Reference 28).

2.4.7.4 Tsunami Height Offshore

Estimates of tsunami heights from distant generators offshore are postulated to have dissipated to wave trains with heights on the order of astronomical tidal range of 6 feet. Locally-generated tsunami runup heights from seismic activity or from submarine landslides are estimated to be a maximum of 9.2 feet (Reference 28).

2.4.7.5 Hydrography and Harbor or Breakwater Influences on Tsunami

Since the approach to the intake structure is across very irregular submerged terrain, PG&E decided after the January 1981 storm, which significantly damaged the breakwater, that the wave behavior under both extreme tide and tsunami condition would most reliably be evaluated through the use of a three-dimensional physical scale model. The effects of the intake basin, natural sea floor, and the breakwaters (in the damaged state) were considered in the testing and evaluation. Resonance and ponding effects are automatically incorporated by the model testing.

The 80- by 120-foot, 1:45 scale model was designed and constructed on the basis of detailed surveys and soundings. Wave-making machines were positioned at various

parts of the basin to drive waves of defined heights, periods, and directions toward the intake basin. Appropriate instrumentation was included to measure and record wave characteristics, and to measure and record critical forces and loads on the intake structure (References 16 and 20).

2.4.7.6 Effects on PG&E Design Class I Facilities

The only PG&E Design Class I system that has components within the projected sea wave zone is the ASW system. The intake structure, within which this equipment is housed, has a main deck elevation of +20 feet above MLLW; it will withstand a tsunami coincident with high tide and depth-limited maximum storm waves that can occur within the intake basin. The PG&E Design Class I equipment is installed in watertight compartments to protect it from adverse sea wave events to elevation +48 feet above MLLW.

In addition to the ASW pumps, the buried ASW piping outside of the intake structure, which is not attached to the circulating water tunnels, is vulnerable to the effects of tsunami and storm waves. An evaluation was conducted by Bechtel Corporation for PG&E to determine what protective measures were required to protect this buried ASW piping. This evaluation is described in Reference 40. Based on this evaluation, erosion protection, consisting of gabion mattresses, reinforced concrete pavement above this buried piping, and an armored embankment southeast of the intake structure, were designed and installed to resist the effects of tsunami and storm waves.

The ability of the breakwater to resist damage to the intake structure caused by collisions of marine vessels was demonstrated by Kircher et al. (Reference 41) as described in Section 2.2.3.1. The structural integrity of the intake structure to resist extreme wave attack (design flood event) in the unlikely event of degradation of the breakwater was reviewed by model tests conducted by O. J. Lillevang (Reference 16) and Dr. Fredric Raichlen (Reference 20). Data from the model study were used by E. N. Matsuda (Reference 21) to structurally analyze the ability of the intake structure to resist the most extreme wave forces. Matsuda determined that, with minor modifications, the intake structure would not be structurally damaged by the most extreme wave forces that might occur even in the unlikely event the entire breakwater were to be degraded to zero feet MLLW. The modifications were completed in 1983.

In addition to the structural evaluations discussed above, the potential effects of splash and spray of the sea waves on PG&E Design Class I equipment were evaluated. Splashing of water up to and above the top of the ventilation shaft (52 feet MLLW) for the ASW pump rooms was observed during the performance of the scale model testing (Reference 16). The testing demonstrated that the ventilation shaft extensions remained free of the upward splashed water as they are set back from the seaward edge of the concrete vent huts at a considerable distance from the seaward edge of the intake structure, and the openings face away from the sea.

Although the air intake would not be inundated by splashing of water, it could be subject to windborne spray. This spray could potentially wet the vent openings and enter the ASW pump rooms. As described in the following subsections, testing and analysis showed that it is not credible that the water level in a pump room would exceed the maximum design flood level for the room.

Additional tests, using the 1:45 scale model of the intake structure and intake basin, were performed by Offshore Technology Corporation to determine the potential for ingestion of water by the ASW pump room ventilation shafts (Reference 30). Wave splash behavior in the vicinity of the ventilation shafts was recorded using high-speed motion pictures, still photography, and visual observation. Subsequent to the testing, analyses were conducted to evaluate the effect of the splashing on the ASW pumps (Reference 18). The conclusion of this analysis was that the combination of degraded breakwater, tsunami, high tide, severe storm, and extreme winds in the offshore direction necessary to result in a critical volume of water being ingested is not credible (Reference 18).

The ASW pumps are protected against flooding for the maximum wave height under tsunami and storm wave conditions even if the entire length of the breakwater were degraded to MLLW. Since there is no assurance that the breakwater would not degrade below MLLW, even though Wiegel (Reference 33) indicates that this is very unlikely, the DCPP Equipment Control Guidelines (Reference 29) include requirements to monitor the condition of the breakwater, to implement corrective action when limited damage is sustained, and to identify the limiting condition for operation relative to the configuration of the breakwaters.

2.4.7.7 Background and Evolution of the Tsunami Design Basis

The background and evolution of the tsunami design basis have been documented in detail in NRC Supplemental Safety Evaluation Reports (SSERs) 1, 5, 7, 13, and 17.

2.4.8 ICE FLOODING

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

As described in Section 2.3, the mild climate and general lack of freezing temperatures in this region make regional ice formation highly unlikely, and it was, therefore, not considered.

2.4.9 COOLING WATER CANALS AND RESERVOIRS

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

The Pacific Ocean is the source of cooling water for the plant. This cooling water system contains no canals or reservoirs.

2.4.10 CHANNEL DIVERSIONS

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Upstream diversions associated with rivers, where low flow has an impact on dependable cooling water sources, is not a factor for this site.

2.4.11 FLOODING PROTECTION REQUIREMENTS

The site arrangement, with the plant situated on a coastal terrace 85 feet above MSL, virtually eliminates all risks from flooding.

Roofs of PG&E Design Class I buildings have a drainage system designed in accordance with the Uniform Plumbing Code for an adjusted regional PMP of 4 inches/hour. In addition, overflow scuppers are provided in parapet walls at roof level to prevent ponding of accumulated rainwater in excess of drain capacity. Yard areas around PG&E Design Class I buildings are graded to provide positive slope away from buildings. Storm runoff is overland and unobstructed. It is, therefore, not possible for ponding from local PMP to flood PG&E Design Class I buildings.

2.4.12 LOW WATER CONSIDERATIONS

2.4.12.1 Low Flow in Rivers and Streams

There are no rivers or streams involved in plant operations; therefore, low flow conditions were not evaluated.

2.4.12.2 Low Water Resulting from Surges, Seiches, or Tsunamis

Low water, as a result of tsunami drawdown occurring coincident with low tide and short-period storm waves, is projected by Marine Advisers (Reference 24) to result in a possible low water elevation of 9 feet below MLLW.

2.4.12.3 Historical Low Water

As discussed in Section 2.4.7.2, there is no historical record for the site. Regional ocean low water history is reported in Reference 24.

2.4.12.4 Future Control

Flowrate factors generally associated with plants situated on rivers are not applicable to DCPP.

2.4.12.5 Plant Requirements

The only PG&E Design Class I system impacted by tsunami drawdown is the ASW. To ensure adequate water supply to the ASW system in the event a tsunami downsurge occurs, the arrangement of the intake structure provides free access to the ocean. In the event of a low water elevation of 9 feet below MLLW, each ASW pump will provide approximately 85 percent of the design flow due to increased static head losses (while operating in the one-pump one-heat exchanger alignment) (refer to Section 9.2.7.3.1). This is a temporary condition and would not result in a significant increase in component cooling water (CCW) temperature.

2.4.12.6 Heat Sink Dependability Requirements

The ASW pumps are designed to operate with the water level down to 17.4 feet below MLLW, substantially below the minimum water level of 9 feet below MLLW that might occur during a tsunami. Therefore, operation of the ASW system would not be interrupted by low water levels.

Cavitation (with the potential to significantly reduce system flow) is predicted to occur when operating with one ASW pump supplying two CCW heat exchangers during a tsunami drawdown. In the event a tsunami is indicated (by a tsunami warning or a severe earthquake) with two CCW heat exchangers in service, a loss of suction would be indicated by low ASW pump discharge pressure and/or low CCW heat exchanger differential pressure (D/P), low ASW bay level, or fluctuating pump motor current. Operator action would be required to remove one of the CCW heat exchangers from service to reduce system flow and decrease pump suction head requirements.

2.4.13 ENVIRONMENTAL ACCEPTANCE OF EFFLUENTS

Deep Well 0-2 is the source for groundwater for use at the DCPP site only, and there is no public use of this groundwater (as discussed in Section 2.4.14). No other significant groundwater source exists in this area. No detailed analysis of acceptance of effluents by surface or groundwater is relevant. The releases to the environment via the discharge canal are described in Sections 11.2.2.5.2 and 11.2.3.13.2.2.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Estimated releases of activity from the liquid radwaste system are discussed in Section 11.2.2.5, and dilution factors for dilution of liquid wastes are discussed in Section 11.2.2.6. The release points for liquid waste are shown in Figure 11.2-9. *A flow diagram for the design basis case for liquid radwaste processing is shown in Figure 11.2-2. The numbered waste input streams have their annual flow and isotopic spectra listed in Tables 11.2-3 and 11.2-5. The numbered process streams are listed in Tables 11.2-8 and 11.2-9, with flows and isotopic concentrations.*

The possibility of accidental releases and the consequent dispersion of such releases are discussed in Chapter 15. Because of the location of the plant on the ocean and the separation of intake and discharge structures, insignificant recirculation occurs.

2.4.14 GROUNDWATER

2.4.14.1 Description and Onsite Use

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Groundwater at the site is limited to Deep Well 0-2. No other significant groundwater has been encountered. Three small springs were encountered during excavation for plant construction; two of these were wet spots and the third had a flow of less than thirty gallons per minute. The water was analyzed and found to be very hard (1050 mg/l $CaCO_3$ and high in dissolved residue [2148 mg/l]). Groundwater and domestic water supplies are not affected by the operation of the plant. (Draft Environmental Statement of the Directorate of Licensing, United States Atomic Energy Commission, December 1972.) There is no public use of onsite groundwater.

2.4.14.2 Monitoring and Safeguard Requirements

Process and effluent streams are monitored wherever a potential release of radioactivity exists during all modes of plant operation.

Differential temperature across the condenser is monitored as a condition of the national pollution discharge elimination system (NPDES) permit.

2.4.15 TECHNICAL SPECIFICATIONS AND EMERGENCY OPERATION REQUIREMENTS

Technical Specifications that describe the safe operation or shutdown requirements for the plant are contained in Appendix A to the operating license.

2.4.16 SAFETY EVALUATION

2.4.16.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I SSCs essential to the prevention of accidents or to mitigate their consequences are designed to withstand or are protected from the effects of flooding. Refer to Sections 2.4.3.2.1, 2.4.3.2.2, 2.4.6.7, 2.4.11, 2.4.12.1, 2.4.12.4, 2.4.13, 2.4.14.1, and 2.4.14.2.

2.4.16.2 Regulatory Guide 1.59, Revision 2, August 1977 – Design Basis Floods for Nuclear Power Plants

The PG&E Design Class I SSCs are designed to withstand and continue to perform their function during the worst site-related flood probable to occur. Refer to Sections 2.4.3.2.2, 2.4.3.2.3, 2.4.6.7, 2.4.7, 2.4.7.1, 2.4.7.1.1, 2.4.7.1.2, 2.4.7.1.3, 2.4.7.1.4, 2.4.7.1.5, 2.4.7.3.1, 2.4.7.3.2, 2.4.7.4, 2.4.7.6, 2.4.12.2, 2.4.12.3, 2.4.12.5, and 2.4.12.6.

2.4.16.3 Regulatory Guide 1.102, Revision 1, September 1976 – Flood Protection for Nuclear Power Plants

The PG&E Design Class I SSCs are appropriately protected from damage caused by flooding. Refer to Sections 2.4.3.2.3, 2.4.6.7, 2.4.7.6, and 2.4.12.6.

2.4.16.4 Regulatory Guide 1.125, Revision 1, October 1978 – Physical Models for Design and Operation of Hydraulic Structures and Systems for Nuclear Power Plants

Hydraulic modeling of the site intake breakwaters, systems, and structures is appropriately designed, verified, tested, and documented to accurately describe the behavior of these plant facilities. Refer to Sections 2.4.3.2.3, 2.4.6.7, 2.4.7.1.4, 2.4.7.5, and 2.4.7.6.

2.4.17 REFERENCES

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2. A. O. Waananen, Open File Report, Water Resources Division, Geological Survey, U.S. Department of the Interior, 1977.

3. Report on January - February 1969 Floods, Central Coastal Streams (2 Vol.), San Francisco District, Corps of Engineers, Department of the Army, 1969.

4. Floods of January and February 1969 in Southern California, Los Angeles District, Corps of Engineers, Department of the Army, 1969.

5. PG&E, Ocean Wave History, Appendix E, of the Preliminary Safety Analysis Report (PSAR) for Nuclear Unit No. 2, San Francisco, California, 1967.

6. United States Weather Bureau (USWB), Hydrometeorological Report (HMR) No. 36, Interim Report - Probable Maximum Precipitation in California, and modification thereto suggested in Revisions of October 1969 to

Hydrometeorological Report No. 36, Interim Report - Probable Maximum Precipitation in California, 1969.

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9. Deleted

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16. O. J. Lillevang, et al., The Height Limiting Effect of Sea Floor Terrain Features and of Hypothetically Extensively Reduced Breakwaters on Wave Action at Diablo Canyon Sea Water Intake, California, 1982.

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20. F. Raichlen, The Investigation of Wave-Structure Interactions for the Cooling Water Intake Structure of the Diablo Canyon Nuclear Power Plant, California, 1982.

21. E. N. Matsuda, Wave Effects on the Intake Structure, DCPP, California, 1983.

22. O. J. Lillevang, Letter/Report dated May 20, 1982, to R. V. Bettinger.

23. H. Bolton Seed, Letter/Report dated September 22, 1981, to R. V. Bettinger.

24. An Evaluation of Tsunami Potential at the Diablo Canyon Site, Marine Advisers, Inc., Report A-253, 1966. (Appendix E of the PSAR).

25. O. J. Lillevang, A Basin Intake for Cooling Water at Diablo Canyon Power Plant, 1969. (Appendix 2.4A to Diablo Canyon Power Plant Final Safety Analysis Report as amended through August 1980) (refer to Reference 27 of Section 2.3).

26. Deleted

27. Li-San Hwang, et al., Earthquake Generated Water Waves at the Diablo Canyon Power Plant, 1974. (Appendix D of Appendix 2.4C to Diablo Canyon Power Plant Final Safety Analysis Report as amended through August 1980) (refer to Reference 27 of Section 2.3).

28. Li-San Hwang, et al., Earthquake Generated Water Waves at the Diablo Canyon Power Plant, (Part Two), 1975. (Appendix E of Appendix 2.4C to Diablo Canyon Power Plant Final Safety Analysis Report as amended through August 1980) (refer to Reference 27 of Section 2.3).

29. DCPP Equipment Control Guideline 17.3, "Flood Protection," Pacific Gas and Electric Company.

30. J. I. Collins and W. G. Groskopf, Hydraulic Model Study of Diablo Canyon Intake Structure, Test Results - Ingestion Studies, OTC Corporation, 1983.

31. Deleted in Revision 22.

32. U. S. Coast and Geodetic Survey, Report on the Seismicity of the Nuclear Plant at the Diablo Canyon Site, September 1967.

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34. Hydraulic Model Study of Diablo Canyon Intake Structure Test Results, December 1982, OTC-82-42.

35. Department of Engineering Memorandum, "Meeting with AEC Staff and Consultants, November 21, 1967," Pacific Gas and Electric Company, December 4, 1967.

36. F. Raichlen, "Wave Induced Effects in a Cooling Water Basin," Chapter 196, Proceedings of International Coastal Engineering Conference, 1986.

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40. Diablo Canyon Power Plant - Auxiliary Saltwater Cooling System Erosion Protection for New Bypass Piping, Bechtel Corporation, October 1996.

41. C. A. Kircher, et al., Frequency of Vessel Impact with the Diablo Canyon Intake Structures, December 10, 1982.

42. Regulatory Guide 1.59, Revision 2, Design Basis Floods for Nuclear Power Plants, USNRC, August 1977.

43. Regulatory Guide 1.125, Revision 1, Physical Models for Design and Operation of Hydraulic Structures and Systems for Nuclear Power Plants, USNRC, October 1978.

2.4.18 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

2.5 GEOLOGY AND SEISMOLOGY

This section presents the findings of the regional and site-specific geologic and seismologic investigations of the DCPP site. Information presented is in compliance with the criteria of 10 CFR Part 100 Appendix A, as described below, and meets the format and content recommendations of Regulatory Guide 1.70, Revision 1 (Reference 39). Because the development of the seismic inputs for DCPP predates the issuance of 10 CFR Part 100 Appendix A, "Seismic and Geologic Siting Criteria for Nuclear Power Plants," the DCPP earthquakes are plant specific.

To capture the historical progress of the geotechnical and seismological investigations associated with the DCPP site, information pertaining to the following three time periods is described herein:

(1) Original Design Phase: investigations performed in support of the Preliminary Safety Analysis Report, prior to the issuance of the Unit 1 construction permit (1967), through the early stages of the construction of Unit 1 (1971). The Design Earthquake (DE) and Double Design Earthquake (DDE) ground motions are associated with this phase. These earthquakes are similar to the regulatory ground motion level that the NRC subsequently developed in 10 CFR Part 100 Appendix A as the "Operating Basis Earthquake (OBE)" ground motion and the "Safe Shutdown Earthquake (SSE)" ground motion, respectively.

(2) Hosgri Evaluation Phase: investigations performed in response to the identification of the offshore Hosgri fault zone (1971) through the issuance of the Unit 1 operating license (1984). The 1977 Hosgri Earthquake (HE) ground motions are associated with this phase. The Hosgri Evaluation Phase does not affect or change the investigations and conclusions of the Original Design Phase.

(3) Long Term Seismic Program (LTSP) Evaluation Phase: investigations performed in response to the License Condition 2.C.(7) of the Unit 1 operating license (1984) through the removal of the License Condition (1991), including current on-going investigations described in Section 2.5.7. The 1991 LTSP ground motion is associated with this phase. The LTSP Evaluation Phase does not affect or change the investigations and conclusions of either the Original Design Phase or the Hosgri Evaluation Phase.

Overview

Locations of earthquake epicenters within 200 miles of the plant site, and faults and earthquake epicenters within 75 miles of the plant site for either magnitudes or intensities, respectively, are shown in Figures 2.5-2, 2.5-3, and 2.5-4 (through 1972). A geologic and tectonic map of the region surrounding the site is shown in Figure 2.5-5,

and detailed information about site geology is presented in Figures 2.5-8 through 2.5-16. Geology and seismology are discussed in detail in Sections 2.5.2 through 2.5.5. Additional information on site geology is contained in References 1 and 2.

Detailed supporting data pertaining to this section are presented in Appendices 2.5A, 2.5B, 2.5C, and 2.5D of Reference 27 in Section 2.3. Geologic and seismic information from investigations that responded to NRC licensing review questions are presented Appendices 2.5E and 2.5F of the same reference. A brief synopsis of the information presented in Reference 27 of Section 2.3 is given below.

The DCPP site is located in San Luis Obispo County approximately 190 miles south of San Francisco and 150 miles northwest of Los Angeles, California. It is adjacent to the Pacific Ocean, 12 miles west-southwest of the city of San Luis Obispo, the county seat. The plant site location and topography are shown in Figure 2.5-1.

The site is located near the mouth of Diablo Creek which flows out of the San Luis Range, the dominant feature to the northeast. The Pacific Ocean is southwest of the site. Facilities for the power plant are located on a marine terrace that is situated between the mountain range and the ocean.

The terrace is bedrock overlain by surficial deposits of marine and nonmarine origin. PG&E Design Class I structures at the site are situated on bedrock that is predominantly stratified marine sedimentary rocks and volcanics, all of Miocene age. A more extensive discussion of the regional geology is presented in Section 2.5.2.1 and site geology in Section 2.5.2.2.

Several investigations were performed at the site and in the vicinity of the site to determine: potential vibratory ground motion characteristics, existence of surface faulting, and stability of subsurface materials and cut slopes adjacent to structures analyzed to the same seismic requirements as PG&E Design Class I structures. Details of these investigations are presented in Sections 2.5.2 through 2.5.5. Consultants retained to perform these studies included: Earth Science Associates (geology and seismicity), John A. Blume and Associates (seismic design and foundation materials dynamic response), Harding-Lawson and Associates (stability of cut slope), Woodward-Clyde-Sherard and Associates (soil testing), and Geo-Recon, Incorporated (rock seismic velocity determinations). The findings of these consultants are summarized in this section and the detailed reports are included in Appendices 2.5A, 2.5B, 2.5C, 2.5D, 2.5E, and 2.5F of Reference 27 in Section 2.3.

Geologic investigation of the Diablo Canyon coastal area, including detailed mapping of all natural exposures and exploratory trenches, yielded the following basic conclusions:

(1) The area is underlain by sedimentary and volcanic bedrock units of Miocene age. Within this area, the power plant site is underlain almost wholly by sedimentary strata of the Monterey Formation, which dip northward at moderate to very steep angles. More specifically, the reactor

site is underlain by thick-bedded to almost massive Monterey sandstone that is well indurated and firm. Where exposed on the nearby hillslope, this rock is markedly resistant to erosion.

(2) The bedrock beneath the main terrace area, within which the power plant site has been located, is covered by 3 to 35 feet of surficial deposits. These include marine sediments of Pleistocene age and nonmarine sediments of Pleistocene and Holocene age. In general, they are thickest in the vicinity of the reactor site.

(3) The interface between the unconsolidated terrace deposits and the underlying bedrock comprises flat to moderately irregular surfaces of Pleistocene marine planation and intervening steeper slopes that also represent erosion in Pleistocene time.

(4) The bedrock beneath the power plant site occupies the southerly flank of a major syncline that trends west to northwest. No evidence of a major fault has been recognized within or near the coastal area, and bedrock relationships in the exploratory trenches positively indicate that no such fault is present within the area of the power plant site.

(5) Minor surfaces of disturbance, some of which plainly are faults, are present within the bedrock that underlies the power plant site. None of these breaks offsets the interface between bedrock and the cover of terrace deposits, and none of them extends upward into the surficial cover. Thus, the latest movements along these small faults must have antedated erosion of the bedrock section in Pleistocene time.

(6) No landslide masses or other gross expressions of ground instability are present within the power plant site or on the main hillslope east of the site. Some landslides have been identified in adjacent ground, but these are minor features confined to the naturally oversteepened walls of Diablo Canyon.

(7) No water of subsurface origin was encountered in the exploratory trenches, and the level of permanent groundwater beneath the main terrace area probably is little different from that of the adjacent lower reaches of the deeply incised Diablo Creek.

2.5.1. DESIGN BASES

2.5.1.1 General Design Criterion 2, 1967 - Performance Standards

The PG&E Design Class I SSCs are designed to withstand the effects of, or are protected against, natural phenomena such as earthquakes.

2.5.1.2 License Condition 2.C(7) of DCPP Facility Operating License DPR-80 Revision 44 (Long Term Seismic Program), Elements (1), (2) and (3)

DCPP developed and implemented a program to re-evaluate the seismic design bases used for the DCPP.

The program included the following three Elements that were completed and accepted by the NRC (References 40, 41, and 43):

(1) The identification, examination, and evaluation of all relevant geologic and seismic data, information, and interpretations that have become available since the 1979 ASLB hearing in order to update the geology, seismology and tectonics in the region of the Diablo Canyon Nuclear Power Plant. If needed to define the earthquake potential of the region as it affects the Diablo Canyon Plant, PG&E has also re-evaluated the earlier information and acquired additional data.

(2) DCPP has re-evaluated the magnitude of the earthquakes used to determine the seismic basis of the Diablo Canyon Nuclear Plant using the information from Element 1.

(3) DCPP has re-evaluated the ground motion at the site based on the results obtained from Element 2 with full consideration of site and other relevant effects.

As a condition of the NRC's closeout of License Condition 2.C.(7), PG&E committed to several ongoing activities in support of the LTSP, as discussed in a public meeting between PG&E and the NRC on March 15, 1991 (Reference 53), described as the "Framework for the Future," in a letter to the NRC, dated April17, 1991 (Reference 50), and affirmed by the NRC in SSER 34 (Reference 43). These ongoing activities are discussed in Section 2.5.7.

2.5.1.3 10 CFR Part 100, March 1966- Reactor Site Criteria

During the determination of the location of the DCPP, consideration was given to the physical characteristics of the site, including seismology and geology.

2.5.2 BASIC GEOLOGIC AND SEISMIC INFORMATION

This section presents the basic geologic and seismic information for DCPP site and surrounding region. Information contained herein has been obtained from literature studies, field investigations, and laboratory testing and is to be used as a basis for evaluations required to provide a safe design for the facility. The basic data contained in this section and in Reference 27 of Section 2.3 are referenced in several other sections of this FSAR Update. Additional information, developed during the Hosgri and LTSP evaluations, is described in Sections 2.5.3.9.3 and 2.5.3.9.4, respectively.

2.5.2.1 Regional Geology

2.5.2.1.1 Regional Physiography

Diablo Canyon is in the southern Coast Range which is a part of the California Coast Ranges section of the Pacific Border physiographic province (refer to Figure 2.5-1). The region surrounding the power plant site consists of mountains, foothills, marine terraces, and valleys. The dominant features are the San Luis Range adjacent to the site to the northeast, the Santa Lucia Range farther inland, the lowlands of the Los Osos and San Luis Obispo Valleys separating the San Luis and Santa Lucia Ranges, and the marine terrace along the coastal margin of the San Luis Range.

Landforms of the San Luis Range and the adjacent marine terrace produce the physiography at the site and in the region surrounding the site. The westerly end of the San Luis Range is a mass of rugged high ground that extends from San Luis Obispo Creek and San Luis Obispo Bay on the east and is bounded by the Pacific Ocean on the south and west. Except for its narrow fringe of coastal terraces, the range is featured by west-northwesterly-trending ridge and canyon topography. Ridge crest altitudes range from about 800 to 1800 feet. Nearly all of the slopes are steep, and they are modified locally by extensive slump and earthflow landslides.

Most of the canyons have narrow-bottomed, V-shaped cross-sections. Alluvial fans and talus aprons are prominent features along the bases of many slopes and at localities where ravines debouch onto relatively gentle terrace surfaces. The coastal terrace belt extends between a steep mountain-front backscarp and a near-vertical sea cliff 40 to 200 feet in height. Both the bedrock benches of the terraces and the present offshore wave-cut bench are irregular in detail, with numerous basins and rock projections.

The main terrace along the coastal margin of the San Luis Range is a gently to moderately sloping strip of land as much as 2000 feet in maximum width. The more landward parts of its surface are defined by broad aprons of alluvial deposits. This cover thins progressively in a seaward direction and is absent altogether in a few places along the present sea cliff. The main terrace represents a series of at least three wave-cut rock benches that have approximate shoreline-angle elevations of 70, 100, and 120 feet.

Owing to both the prevailing seaward slopes of the rock surfaces and the variable thickness of overlying marine and nonmarine cover, the present surface of the main terrace ranges from 70 to more than 200 feet in elevation. Remnants of higher terraces exist at scattered locations along upper slopes and ridge crests. The most extensive among these is a series of terrace surfaces at altitudes of 300+, 400+, and 700+ feet at the west end of the ridge between Coon and Islay Creeks, north of Point Buchon. A surface described by Headlee (Reference 19) as a marine terrace at an altitude of about 700 feet forms the top of San Luis Hill. Remnants of a lower terrace at an altitude of 30

to 45 feet are preserved at the mouth of Diablo Canyon and at several places farther north.

Owing to contrasting resistance to erosion among the various bedrock units of the San Luis Range, the detailed topography of the wave-cut benches commonly is very irregular. As extreme examples, both modern and fossil sea stacks rise as much as 100 feet above the general levels of adjacent marine-eroded surfaces at several localities.

2.5.2.1.2 Regional Geologic and Tectonic Setting

2.5.2.1.2.1 Geologic Setting

The San Luis Range is underlain by a synclinal section of Tertiary sedimentary and volcanic rocks, which have been downfolded into a basement of Mesozoic rocks now exposed along its southwest and northeast sides. Two zones of faulting have been recognized within the range. The Edna fault zone trends along its northeast side, and the Miguelito fault zone extends into the range from the vicinity of Avila Bay. Minor faults and bedding-plane shears can be seen in the parts of the section that are well exposed along the sea cliff fringing the coastal terrace benches. None of these faults shows evidence of geologically recent activity, and the most recent movements along those in the rocks underlying the youngest coastal terraces can be positively dated as older than 80,000 to 120,000 years. Geologic and tectonic maps of the region surrounding the site are shown in Figures 2.5-5 (2 sheets), 2.5-6, 2.5-8, and 2.5-9.

2.5.2.1.2.2 Tectonic Features of the Central Coastal Region

DCPP site lies within the southern Coast Ranges structural province, and approximately upon the centerline axis of the northwest-trending block of crust that is bounded by the San Andreas fault on the northeast and the continental margin on the southwest. This crustal block is characterized by northwest-trending structural and geomorphic features, in contrast to the west-trending features of the Transverse Ranges to the south. A major geologic boundary within the block is associated with the Sur-Nacimiento and Rinconada faults, which separate terrains of contrasting basement rock types. The ground southwest of the Sur-Nacimiento zone and the southerly half of the Rinconada fault, referred to as the Coastal Block, is underlain by Franciscan basement rocks of dominantly oceanic types, whereas that to the northeast, referred to as the Salinia Block, is underlain by granitic and metamorphic basement rocks of continental types. Page (Reference 10) outlined the geology of the Coast Ranges, describing it generally in terms of "core complexes" of basement rocks and surrounding sections of younger sedimentary rocks. The principal Franciscan core complex of the southern Coast Range crops out on the coastal side of the Santa Lucia Range from the vicinity of San Luis Obispo to Point Sur, a distance of 120 miles. Its complex features reflect numerous episodes of deformation that evidently included folding, faulting, and the tectonic emplacement of extensive bodies of ultrabasic rocks. Other core complexes consisting of granitic and metamorphic basement rocks are exposed in the southern

Coast Ranges in the ground between the Sur-Nacimiento and Rinconada and in the San Andreas fault zones. The locations of these areas of basement rock exposure are shown in Figure 2.5-6 and in Figure 1 of Appendix 2.5D of Reference 27 in Section 2.3.

Younger structural features include thick folded basins of Tertiary strata and the large faults that form structural boundaries between and within the core complexes and basins.

The structure of the southern Coast Ranges has evolved during a lengthy history of deformation extending from the time when the ancestral Sur-Nacimiento zone was a site for subduction (a Benioff zone) along the then-existing continental margin, through subsequent parts of Cenozoic time when the San Andreas fault system was the principal expression of the regional stress-strain system. The latest episodes of major deformation involved folding and faulting of Pliocene and older sediments during mid-Pliocene time, and renewed movements along preexisting faults during early or mid-Pliocene time. Present tectonic activity within the region is dominated by interaction between the Pacific and American crustal plates on opposite sides of the San Andreas fault and by continuing vertical uplift of the Coast Ranges. In the regional setting of DCPP site, the major structural features addressed during the original design phase are the San Andreas, Rinconada-San Marcos-Jolon, Sur-Nacimiento, and Santa Lucia Bank faults. Additional faults were identified during the Hosgri evaluation and LTSP evaluation phases, discussed in Sections 2.5.3.9.3 and 2.5.3.9.4, respectively. The San Simeon fault may also be included with this group. These original design phase faults are described as follows:

1. San Andreas Fault

The San Andreas fault is recognized as a major transform fault of regional dimensions that forms an active boundary between the Pacific and North American crustal plates. Cumulative slip along the San Andreas fault may have amounted to several hundred miles, and a substantial fraction of the total slip has occurred during late Cenozoic time. The fault has spectacular topographic expression, generally lying within a rift valley or along an escarpment mountain front, and having associated sag ponds, low scarps, right-laterally deflected streams, and related manifestations of recent activity.

The most recent episode of large-scale movement along the reach of the San Andreas fault that is closest to the San Luis Range occurred during the great Fort Tejon earthquake of 1857. Geologic evidence pertinent to the behavior of the fault during this and earlier seismic events was studied in great detail by Wallace (Reference 15 and 32) who reported in terms of infrequent great earthquakes accompanied by ground rupture of 10 to 30 feet, with intervening periods of near total quiescence. Allen (Reference 16) suggested that such behavior has been typical for this reach of the San Andreas fault and has been fundamentally different from the behavior of the fault along the reach farther northwest, where creep and numerous small earthquakes have occurred. He further suggested that release of accumulating strain energy might have been facilitated by the presence of large amounts of serpentine in the fault zone to the northwest, and

retarded by the locking effect of the broad bend of the fault zone where it crosses the Transverse Ranges to the southeast.

Movement is currently taking place along large segments of the San Andreas fault. The active reach of the fault between Parkfield and San Francisco is currently undergoing relative movement of at least 3 to 4 cm/yr, as determined geodetically and analyzed by Savage and Burford (Reference 33). When the movement that occurs during the episodes of fault displacement in the western part of the Basin and Ranges Province is added to the minimum of 3 to 4 cm/yr of continuously and intermittently released strain, the total probably amounts to at least 5 to 6 cm/yr. This may account for essentially all of the relative motion between the Pacific and North American plates at present. In the Transverse Ranges to the south, this strain is distributed between lateral slip along the San Andreas system and east-west striking lateral slip faulting, thrust faulting, and folding. North of the latitude of Monterey Bay and south of the Transverse Ranges, transcurrent movement is again concentrated along the San Andreas system, but in those regions, it is distributed among several major strands of the system.

2. Sur-Nacimiento Fault Zone

The Sur-Nacimiento fault zone has been regarded as the system of faults that extends from the vicinity of Point Sur, near the northwest end of the Santa Lucia Range, to the Big Pine fault in the western Transverse Ranges, and that separates the granitic-metamorphic basement of the Salinian Block from the Franciscan basement of the Coastal Block. The most prominent faults that are included within this zone are, from northwest to southeast, the Sur, Nacimiento, Rinconada, and (south) Nacimiento faults. The Sur fault, which extends as far northward as Point Sur on land, continues to the northwest in the offshore continental margin. At its southerly end, the zone terminates where the (south) Nacimiento fault is cut off by the Big Pine fault. The overall length of the Sur-Nacimiento fault zone between Point Sur and the Transverse Ranges is about 180 miles. The 60 mile long Nacimiento fault, between points of juncture with the Sur and Rinconada faults, forms the longest segment within this zone. Page (Reference 11) stated that:

> "It is unlikely that the Nacimiento fault proper has displaced the ground surface in Late Quaternary time, as there are no indicative offsets of streams, ridges, terrace deposits, or other topographic features. The Great Valley-type rocks on the northeast side must have been down-dropped against the older Franciscan rocks on the southwest, yet they commonly stand higher in the topography. This implies relative quiescence of the Late Quaternary time, allowing differential erosion to take place. In a few localities, the northeast side is the low side, and this inconsistency favors the same conclusion. In addition to the foregoing circumstances, the fault is offset by minor cross-faults in a manner suggesting that little, if any, Late Quaternary near-surface movement had occurred along the main fracture."

Hart (Reference 14), on the other hand, stated that: ". . . youthful topographic features (offset streams, sag ponds, possible fault scarplets, and apparently oversteepened slopes) suggest movement along both (Sur-Nacimiento and Rinconada) fault zones." The map compiled by Jennings (Reference 23), however, shows only the Rinconada with a symbol indicating "Quaternary fault displacement."

The results of photogeologic study of the region traversed by the Sur-Nacimiento fault zone tend to support Page's view. A pronounced zone of fault-controlled topographic lineaments can be traced from the northwest end of the Nacimiento fault southeastward to the Rinconada (south Nacimiento), East Huasna, and West Huasna faults. Only along the Rinconada, however, are there topographic features that seem to have originated through fault disturbances of the ground surface rather than through differential erosion along zones of shearing and juxtaposition of differing rocks. Richter (Reference 13) noted that some historic seismicity, particularly the 1952 Bryson earthquake, appears to have originated along the Nacimiento fault. This view is supported by recent work of S. W. Smith (Reference 30) that indicates that the Bryson shock and the epicenters of several smaller, more recent earthquakes were located along or near the trace of the Nacimiento.

3. Rinconada (Nacimiento)-San Marcos-Jolon-San Antonio Fault System

A system of major faults extends northwestward, parallel to the San Andreas fault, from a point of junction with the Big Pine fault in the western Transverse Ranges. This system includes several faults that have been mapped as separate features and assigned individual names. Dibblee (Reference 27) however, has suggested that these faults are part of a single system, provisionally termed the Rinconada fault zone after one of its more prominent members. He also proposed abandoning the name Nacimiento for the large fault that constitutes the most southerly part of this system, as it is not continuous with the Nacimiento fault to the north, near the Nacimiento River. The newly defined Rinconada fault system comprises the old (south) Nacimiento, Rinconada, and San Marcos faults. Dibblee proposed that the system also include the Espinosa and Reliz faults, to the north, but detailed work by Durham (Reference 28) does not seem to support this interpretation. Instead, the system may extend into Lockwood Valley and die out there along the Jolon and San Antonio faults. All the faults of the Rinconada system have undergone significant movement during middle and late Cenozoic time, though the entire system did not behave as a unit. Dibblee pointed out that: "Relative vertical displacements are controversial, inconsistent, reversed from one segment to another; the major movement may be strike slip, as on the San Andreas fault."

Regarding the structural relationship of the Rinconada fault to nearby faults, Dibblee wrote as follows:

> "Thrust or reverse faults of Quaternary age are associated with the Rinconada fault along much of its course on one or both sides, within 9 miles, especially in areas of intense folding. In the northern part several, including the San Antonio fault, are

present along both margins of the range of hills between the Salinas and Lockwood Valleys . . . . along which this range was elevated in part. Near the southern part are the major southwest-dipping South Cuyama and Ozena faults along which the Sierra Madre Range was elevated against Cuyama Valley, with vertical displacements possibly up to 8000 feet. All these thrust or reverse faults dip inward toward the Rinconada fault and presumably either splay from it at depth, or are branches of it. These faults, combined with the intense folding between them, indicated that severe compression accompanied possible transcurrent movement along the Rinconada fault."

"The La Panza fault along which the La Panza Range was elevated .... in Quaternary time, is a reverse fault that dips northeast under the range, and is not directly related to the Rinconada fault.

"The Big Pine fault against which the Rinconada fault abuts . . . is a high angle left-lateral transcurrent fault active in Quaternary time (Reference 35). The Pine Mountain fault south of it . . . . is a northeast-dipping reverse fault along which the Pine Mountain Range was elevated in Quaternary time. This fault may have been reactivated along an earlier fault that may have been continuous with the Rinconada fault, but displaced about 8 miles from it by left slip on the Big Pine fault (Reference 12) in Quaternary time."

"The Rinconada and Reliz faults were active after deposition of the Monterey Shale and Pancho Rico Formation, which are severely deformed adjacent and near the faults. The faults were again active after deposition of the Paso Robles Formation but to a lesser degree. These faults do not affect the alluvium or terrace deposits. There are no offset stream channels along these faults. However, in two areas several canyons and streams are deviated, possibly by right-lateral movement on the (Espinosa and San Marcos segments of the) Rinconada fault. There are no indications that these faults are presently active."

4. San Simeon Fault

The fault here referred to as the San Simeon fault trends along the base of the peninsula that lies north of the settlement of San Simeon. This fault is on land for a distance of 12 miles between its only outcrop, north of Ragged Point, and Point San Simeon. It may extend as much as 16 miles farther to the southeast, to the vicinity of Point Estero. This possibility is suggested by the straight reach of coastline between Cambria and Point Estero, which is directly aligned with the onshore trend of the fault; its linear form may well have been controlled by a zone of structural weakness associated with the inferred southerly part of the fault. South of Port Estero, however, there is no evidence of faulting observable in the seismic reflection profiles across Estero Bay, and the trend defined by the Los Osos Valley-Estero Bay series of lower Miocene or Oligocene intrusives extends across the San Simeon trend without deviation.

North of Point Piedras Blancas, Silver (Reference 26) reports a fault with about 5 kilometers of vertical separation between the 4-kilometer-thick Tertiary section in the offshore basin and the nearby 1-kilometer-high exposure of Franciscan basement rocks in the coastline mountain front. The existence of a fault in this region is also indicated by the 30- milligal gravity anomaly between the offshore basin and the onshore ranges (Plate II of Appendix 2.5D of Reference 27 in Section 2.3). This postulated fault may well be a northward extension of the San Simeon fault. If this is the case, the San Simeon fault may have a total length of as much as 60 miles.

Between Point San Simeon and Ragged Point, the San Simeon fault lies along the base of a broad peninsula, the surface of which is characterized by elevated marine terraces and younger, steep-walled ravines and canyons. The low, terraced topography of the peninsula contrasts sharply with that of the steep mountain front that rises immediately behind it. Clearly, the ground west of the main fault represents a part of the sea floor that has been locally arched up.

This has resulted in exposure of the fault, which elsewhere is concealed underwater off the shoreline.

The ground between the San Simeon fault and the southwest coastline of the Piedras Blancas peninsula is underlain by faulted blocks and slivers of Franciscan rocks, serpentinites, Tertiary sedimentary breccia and volcanic rocks, and Miocene shale. The faulted contacts between these rock masses trend somewhat more westerly than the trend of the San Simeon fault. One north-dipping reverse fault, which separates serpentinite from graywacke, has broken marine terrace deposits in at least two places, one of them in the basal part of the lowest and youngest terrace. Movement along this branch fault has therefore occurred less than 130,000 years before the present, although the uppermost, youngest Pleistocene deposits are apparently not broken. Prominent topographic lineations defined by northwest-aligned ravines that incise the upper terrace surface, on the other hand, apparently have originated through headward gully erosion along faults and faulted contacts, rather than through the effects of surface faulting.

The characteristics of the San Simeon fault can be summarized as follows: The fault may be related to a fault along the coast to the north that displays some 5 kilometers of vertical displacement. Near San Simeon, it exhibits probable Pleistocene right-lateral strike-slip movement of as much as 1500 feet near San Simeon, although it apparently does not break dune sand deposits of late Pleistocene or early Holocene age. A branch reverse fault, however, breaks upper Pleistocene marine terrace deposits. The San Simeon fault may extend as far south as Point Estero, but it dies out before crossing the northern part of Estero Bay.

5. Santa Lucia Bank Fault

South of the latitude of Point Piedras Blancas, the western boundary of the main offshore Santa Maria Basin is defined by the east-facing scarp along the east side of the

Santa Lucia Bank. This scarp is associated with the Santa Lucia Bank fault, the structure that separates the subsided block under the basin from the structural high of the bank. The escarpment that rises above the west side of the fault trace has a maximum height of about 450 feet, as shown on U.S. Coast and Geodetic Survey (USC&GS) Bathymetric Map 1306N-20.

The Santa Lucia Bank fault can be traced on the sea floor for a distance of about 65 miles. Extensions that are overlapped by upper Tertiary strata continue to the south for at least another 10 miles, as well as to the north. The northern extension may be related to another, largely buried fault that crosses and may intersect the trend of the Santa Lucia Bank fault. This second fault extends to the surface only at points north of the latitude of Point Piedras Blancas.

West of the Santa Lucia Bank fault, between N latitudes 34°30' and 30°, several subparallel faults are characterized by apparent surface scarps. The longest of these faults trends along the upper continental slope for a distance of as much as 45 miles, and generally exhibits a west-facing scarp. Other faults are present in a zone about 30 miles long lying between the 45 mile fault and the Santa Lucia Bank fault. These faults range from 5 to 15 or more miles in length, and have both east-and west-facing scarps.

This zone of faulting corresponds closely in space with the cluster of earthquake epicenters around N latitude 34°45' and 121°30'W longitude, and it probably represents the source structure for those shocks (refer to Figure 2.5-3).

2.5.2.1.2.3 Tectonic Features in the Vicinity of the DCPP Site

Geologic relationships between the major fold and fault structures in the vicinity of Diablo Canyon are shown in Figures 2.5-5, 2.5-6, and 2.5-7, and are described and illustrated in Appendix 2.5D of Reference 27 of Section 2.3. The San Luis Ranges-Estero Bay area is characterized structurally by west-northwest-trending folds and faults. These include the San Luis-Pismo syncline and the bordering Los Osos Valley and Point San Luis antiformal highs, and the West Huasna, Edna, and San Miguelito faults. A few miles offshore, the structural features associated with this trend merge into a north-northwest-trending zone of folds and faults that is referred to herein as the offshore Santa Maria Basin East Boundary zone of folding and faulting. The general pattern of structural highs and lows of the onshore area is warped and stepped downward to the west across this boundary zone, to be replaced by more northerly-trending folds in the lower part of the offshore basin section. The overall relationship between the onshore Coast Ranges and the offshore continental margin is one of differential uplift and subsidence. The East Boundary zone represents the structural expression of the zone of inflection between these regions of contrasting vertical movement.

In terms of regional relationships, structural style, and history of movement, the faults in the San Luis Ranges-Estero Bay vicinity, identified during the original design phase, may be characterized as follows:

1. West Huasna Fault

This fault zone separates the large downwarp of the Huasna syncline on the northeast from Franciscan assemblage rocks of the Los Osos Valley antiform and the Tertiary section of the southerly part of the San Luis-Pismo syncline on the southwest. The West Huasna fault is thought to join with the Suey fault to the south. Differences in thicknesses and facies relationships between units of apparently equivalent age on opposite sides of the fault are interpreted as indicating lateral movement along the fault; however, the available evidence regarding the amount and even the relative sense of displacement is not consistent. The West Huasna shows no evidence of late Quaternary activity.

2. Edna Fault Zone

The Edna fault zone lies along a west-northwesterly trend that extends obliquely from the West Huasna fault at its southeast end to the hills of the San Luis Range south of Morro Bay. Several isolated breaks that lie on a line with the trend are present in the Tertiary strata beneath the south part of Estero Bay, east of the Santa Maria Basin East Boundary fault zone across the mouth of the bay.

The Edna fault is typically a zone of two or more anastomosing branches that range in width from 1/2 mile to as much as 1-1/2 miles. Although individual strands are variously oriented and exhibit various senses of amounts of movement, the zone as a whole clearly expresses high-angle dip-slip displacement (down to the southwest). The irregular traces of major strands suggest that little, if any, strike-slip movement has occurred. Preliminary geologic sections shown by Hall and Surdam (Reference 21) and Hall (Reference 20) imply that the total amount of vertical separation ranges from 1500 to a few thousand feet along the central part of the fault zone. The amount of displacement across the main fault trend evidently decreases to the northwest, where the zone is mostly overlapped by upper Tertiary strata.

It may be, however, that most of the movement in the Baywood Park vicinity has been transferred to the north-trending branch of the Edna, which juxtaposes Pliocene and Franciscan rocks where last exposed. In the northwesterly part of the San Luis Range, the Edna fault forms much of the boundary between the Tertiary and basement rock sections. Most of the measurable displacements along this zone of rupture occurred during or after folding of the Pliocene Pismo Formation but prior to deposition of the lower Pleistocene Paso Robles Formation. Some additional movement has occurred during or since early Pleistocene time, however, because Monterey strata have been faulted against Paso Robles deposits along at least one strand of the Edna near the head of Arroyo Grande valley. This involved steep reverse fault movement, with the

southwest side raised, in contrast to the earlier normal displacement down to the southwest.

Search has failed to reveal dislocation of deposits younger than the Paso Robles Formation, disturbance of late Quaternary landforms, or other evidence of Holocene or late Pleistocene activity.

3. San Miguelito Fault Zone

Northwesterly-trending faults have been mapped in the area between Pismo Beach and Arroyo Grande, and from Avila Beach to the vicinity of the west fork of Vineyard Canyon, north of San Luis Hill. Because these faults lie on the same trend, appear to reflect similar senses of movement, and are "separated" only by an area of no exposure along the shoreline between Pismo Beach and Avila Beach, they may well be part of a more or less continuous zone about 10 miles long. As on the Edna fault, movements along the San Miguelito fault appear to have been predominantly dip-slip, but with displacement down on the northeast. Hall's preliminary cross-section indicates total vertical separation of about 1400 feet. The fault is mapped as being overlain by unbroken deposits of the Paso Robles Formation near Arroyo Grande.

Field checking of the ground along the projected trend of the San Miguelito fault zone northwest of Vineyard Canyon in the San Luis Range has substantiated Hall's note that the fault cannot be traced west of that area.

Detailed mapping of the nearly continuous sea cliff exposures extending across this trend northeast of Point Buchon has shown there is no faulting along the San Miguelito trend at the northwesterly end of the range. Like the Edna fault zone, the San Miguelito fault zone evidently represents a zone of high-angle dip-slip rupturing along the flank of the San Luis-Pismo syncline.

4. East Boundary Zone of the Offshore Santa Maria Basin

The boundary between the offshore Santa Maria Basin and the onshore features of the southern Coast Ranges is a 4 to 5 wide zone of generally north-northwest-trending folds, faults, and onlap unconformities referred to as the "Hosgri fault zone" by Wagner (Reference 31). The geology of this boundary zone has been investigated in detail by means of extensive seismic reflection profiling, high resolution surface profiling, and side scan sonar surveying.

More general information about structural relationships along the boundary zone has been obtained from the pattern of Bouguer Gravity anomaly values that exist in its vicinity. These data show the East Boundary zone to consist of a series of generally parallel north-northwest-trending faults and folds, developed chiefly in upper Pliocene strata that flank upwarped lower Pliocene and older rocks. The zone extends from south of the latitude of Point Sal to north of Point Piedras Blancas. Within the zone, individual fault breaks range in length from less than 1000 feet up to a maximum of

about 30 miles. The overall length of the zone is approximately 90 miles, with about 60 miles of relatively continuous faulting.

The apparent vertical component of movement is down to the west across some faults and down to the east across others. Along the central reach of the zone, opposite the San Luis Range, a block of ground has been dropped between the two main strands of the fault to form a graben structure. Within the graben, and at other points along the East Boundary zone, bedding in the rock has been folded down toward the upthrown side of the west side down fault. This feature evidently is an expression of "reverse drag" phenomena.

The axes of folds in the ground on either side of the principal fault breaks can be traced for distances of as much as 22 miles. The fold axes typically are nearly horizontal; maximum axial plunges seem to be 5° or less. The structure and onlap relationships of the upper Pliocene, as reflected in the configuration of the unconformity at its base, are such that it consistently rises from the offshore basin and across the boundary zone via a series of upwarps, asymmetric folds, and faults. This configuration seems to correspond generally to a zone of warping and partial disruption along the boundary between relatively uplifting and subsiding regions.

2.5.2.1.3 Geologic History

The geologic history reflected by the rocks, structural features, and landforms of the San Luis Range is typical of that of the southern Coast Ranges of California in its length and complexity. Six general episodes for which there is direct evidence can be tabulated as follows:

Age	Episode	Evidence
Late Mesozoic	Development of Franciscan and Upper Cretaceous rock assemblages	Franciscan and other Mesozoic rocks
Late Mesozoic - Early Tertiary	Early Coast Ranges deformation	Structural features pre-served in the Mesozoic rocks
Mid-Tertiary	Uplift and erosion	Erosion surface at the base of the Tertiary section
Mid- and late-Tertiary	Accumulation of Miocene and Pliocene sedimentary and volcanic rocks	Vaqueros, Rincon, Obispo, Point Sal, Monterey, and Pismo Formation and associated volcanic intrusive, and brecciated rocks
Pliocene	Folding and faulting associated with the Pliocene Coast Ranges deformation	Folding and faulting of the Tertiary and basement rocks

Pleistocene	Uplift and erosion, development of successive tiers of wave-cut-benches alluvial fan, talus, and landslide deposition.	Pleistocene and Holocene deposits, present land-forms.

The earliest recognizable geologic history of the southern Coast Ranges began in Mesozoic time, during the Jurassic period when eugeosynclinal deposits (graywacke sandstone, shale, chert, and basalt) accumulated in an offshore trench developed in oceanic crust.

Sometime after the initiation of Franciscan sedimentation, deposition of a sequence of miogeosynclinal or shelf sandstones and shales, known as the Great Valley Sequence, began on the continental crust, at some distance to the east of the Franciscan trench. Deposition of both sequences continued into Cretaceous time, even while the crustal basement section on which the Great Valley strata were being deposited was undergoing plutonism involving emplacement of granitic rocks. Subsequently, the Franciscan assemblage, the Great Valley Sequence, and the granite-intruded basement rocks were tectonically juxtaposed. The resulting terrane consisted generally of granitic basement thrust over intensely deformed Franciscan, with Great Valley Sequence strata overlying the basement, but thrust over and faulted into the Franciscan.

The processes that were involved in the tectonic juxtaposition evidently were active during the Mesozoic, and continued into the early Tertiary. Page (Reference 25) has shown that they were completed by no later than Oligocene time, so that the dual core complex basement of the southern Coast Ranges was formed by then.

The Miocene and later geologic history of the southern Coast Ranges region began with deposition of the Vaqueros and Rincon Formations on a surface eroded on the Franciscan and Great Valley core complex rocks.

Following deposition and some deformation and erosion of these formations, the stratigraphic unit that includes the Point Sal and Obispo Formations as approximately contemporaneous facies was laid down. The Obispo consists of a section of tuffaceous sandstone and mudstone, with lesser amounts of shale, and lensing layers of vitric and lithic-crystal tuff. Locally, the unit is featured by masses of clastic-textured tuffaceous rock that exhibit cross-cutting intrusive relations with the bedded parts of the formation. The Obispo and Point Sal were folded and locally eroded prior to initiation of the main episode of upper Miocene and Pliocene marine sedimentation.

During late middle Miocene to late Miocene time, deposition of the thick sections of silica-rich shale of the Monterey Formation began. Deposition of this formation and equivalent strata took place throughout much of the coastal region of California, but apparently was centered in a series of offshore basins that all developed at about the same time, some 10 to 12 million years ago. Local volcanism toward the latter part of this time is shown by the presence of diabase dikes and sills in the Monterey. Near the end of the Miocene, the Monterey strata were subjected to compressional deformation resulting in folding, in part with great complexity, and in faulting. Near the old

continental margin, represented by the Sur-Nacimiento fault zone, the deformation was most intense, and was accompanied by uplift. This apparently resulted in the first development of many of the large folds of the southern Coast Ranges including the Huasna and San Luis-Pismo synclines, and in the partial erosion of the folded Monterey section in areas of uplift. The pattern of regional uplift of the Coast Ranges and subsidence of the offshore basins, with local upwarping and faulting in a zone of inflection along the boundary between the two regions, apparently became well established during the episode of late Miocene and Mio-Pliocene diastrophism.

Sedimentation resumed in Pliocene time throughout much of the region of the Miocene basins, and several thousand feet of siltstone and sandstone was deposited. This was the last significant episode of marine sedimentation in the region of the present Coast Ranges. Pliocene deposits in the region of uplift were then folded, and there was renewed movement along most of the preexisting larger faults.

Differential movements between the Coast Ranges uplift and the offshore basins were again concentrated along the boundary zone of inflection, resulting in upwarping and faulting of the basement, Miocene, and Pliocene sections. Relative displacement across parts of this zone evidently was dominantly vertical, because the faulting in the Pliocene has definitely extensional character, and Miocene structures can be traced across the zone without apparent lateral offset. The basement and Tertiary sections step down seaward, away from the uplift, along a system of normal faults having hundreds to nearly a thousand feet of dip-slip offset. A second, more seaward system of normal faults is antithetic to the master set and exhibits only tens to a few hundreds of feet of displacement. Strata between these faults locally exhibit reverse drag downfolding toward the edge of the Pliocene basin, whereas the section is essentially undeformed farther offshore. This style of deformation indicates a passive response, through gravity tectonics, to the onshore uplift.

The Plio-Pleistocene uplift was accompanied by rapid erosion, with consequent nearby deposition of clastic sediments such as the Paso Robles Formation in valleys throughout the southern Coast Ranges. The high-angle reverse and normal faulting observed by Compton (Reference 38) in the northern Santa Lucia Range also occurred farther south, probably more or less contemporaneously with accumulation of the continental deposits. Much of the Quaternary faulting other than that related to the San Andreas right lateral stress-strain system may well have occurred at this time.

Tectonic activity during the Quaternary has involved continued general uplift of the southern Coast Ranges, with superimposed local downwarping and continued movement along faults of the San Andreas system. The uplift is shown by the general high elevation and steep youthful topography that characterizes the Coast Ranges and by the widespread uplifted marine and stream terraces. Local downwarping can be seen in valleys, such as the Santa Maria Valley, where thick sections of Plio-Pleistocene and younger deposits have accumulated. Evidence of significant late Quaternary fault movement is seen in the topography along the Rinconada-San Marcos, Espinosa, San Simeon, and Santa Lucia Bank faults, as well

as along the San Andreas itself. Only along the San Andreas, however, is there evidence of Holocene or contemporary movement.

The latest stage in the evolution of the San Luis Range has extended from mid-Pleistocene time to the present, and has involved more or less continuous interaction between apparent uplift of the range and alternating periods of erosion or deposition, especially along the coast, during times of relatively rising, falling, or unchanging sea level. The development of wave-cut benches and the accumulation of marine deposits on these benches have provided a reliable guide to the minimum age of latest displacements along breaks in the underlying bedrock. Detailed exploration of the interfaces between wave-cut benches and overlying marine deposits at the site of DCPP has shown that no breaks extend across these interfaces. This demonstrates that the youngest faulting or other bedrock breakage in that area antedated the time of terrace cutting, which is on the order of 80,000 to 120,000 years before the present.

The bedrock section and the surficial deposits that formerly capped this bedrock on which the power plant facilities are located have been studied in detail to determine whether they express any evidence of deformation or dislocation ascribable to earthquake effects.

The surficial geologic materials at the site consisted of a thin, discontinuous basal section of rubbly marine sand and silty sand, and an overlying section of nonmarine rocky sand and sandy clay alluvial and colluvial deposits. These deposits were extensively exposed by exploratory trenches, and were examined and mapped in detail. No evidence of earthquake-induced effects such as lurching, slumping, fissuring, and liquefaction was detected during this investigation.

The initial movement of some of the landslide masses now present in Diablo Canyon upstream from the switchyard area may have been triggered by earthquake shaking. It is also possible that some local talus deposits may represent earthquake-triggered rock falls from the sea cliff or other steep slopes in the vicinity.

Deformation of the rock substrata in the site area may well have been accompanied by earthquake activity at the time of its occurrence in the geologic past. There is no evidence, however, of post-terrace earthquake effects in the bedrock where the power plant is being constructed.

2.5.2.1.4 Stratigraphy of the San Luis Range and Vicinity

The geologic section exposed in the San Luis Range comprises sedimentary, igneous, and tectonically emplaced ultrabasic rocks of Mesozoic age, sedimentary, pyroclastic, and hypabyssal intrusive rocks of Tertiary age, and a variety of surficial deposits of Quaternary age. The lithology, age, and distribution of these rocks were studied by Headlee and more recently have been mapped in detail by Hall. The geology of the San Luis Range is shown in Figure 2.5-6 with a geologic cross-section constructed

using exploratory oil wells shown in Figure 2.5-7. The geologic events that resulted in the stratigraphic units described in this section are discussed in Section 2.5.2.1.3.

2.5.2.1.4.1 Basement Rocks

An assemblage of rocks typical of the Coast Ranges basement terrane west of the Nacimiento fault zone is exposed along the south and northeast sides of the San Luis Range. As described by Headlee, this assemblage includes quartzose and greywacke sandstone, shale, radiolarian chert, intrusive serpentine and diabase, and pillow basalt. Some of these rocks have been dated as Upper Cretaceous from contained microfossils, including pollen and spores, and Headlee suggested that they may represent dislocated parts of the Great Valley Sequence. There is contrasting evidence, however, that at least the pillow basalt and associated cherty rocks may be more typically Franciscan. Certainly, such rocks are characteristic of the Franciscan terrane. Further, a potassium-argon age of 156 million years, equivalent to Upper Jurassic, has been determined for a core of similar rocks obtained from the bottom of the Montodoro Well No. 1 near Point Buchon.

2.5.2.1.4.2 Tertiary Rocks

Five formational units are represented in the Tertiary section of the San Luis Range. The lower part of this section comprises rocks of the Vaqueros, Rincon, and Obispo Formations, which range in age from lower Miocene through middle Miocene. These strata crop out in the vicinity of Hazard Canyon, at the northwest end of the range, and in a broad band along the south coastal margin of the range. In both areas the Vaqueros rests directly on Mesozoic basement rocks. The core of the western San Luis Range is underlain by the Upper Miocene Monterey Formation, which constitutes the bulk of the Tertiary section. The Upper Miocene to Lower Pliocene Pismo Formation crops out in a discontinuous band along the southwest flank and across the west end of the range, resting with some discordance on the Monterey section and elsewhere directly on older Tertiary or basement rocks.

The coastal area in the vicinity of Diablo Canyon is underlain by strata that have been variously correlated with the Obispo, Point Sal, and Monterey Formations. Headlee, for example, has shown the Point Sal as overlying the Obispo, whereas Hall has considered these two units as different facies of a single time-stratigraphic unit. Whatever the exact stratigraphic relationships of these rocks might prove to be, it is clear that they lie above the main body of tuffaceous sedimentary rocks of the Obispo Formation and below the main part of the Monterey Formation. The existence of intrusive bodies of both tuff breccia and diabase in this part of the section indicates either that local volcanic activity continued beyond the time of deposition of the Obispo Formation, or that the section represents a predominantly sedimentary facies of the upper part of the Obispo Formation. In either case, the strata underlying the power plant site range downward through the Obispo Formation and presumably include a few hundred feet of the Rincon and Vaqueros Formations resting upon a basement of Mesozoic rocks.

A generalized description of the major units in the Tertiary section follows, and a more detailed description of the rocks exposed at the power plant site is included in a later section.

The Vaqueros Formation has been described by Headlee as consisting of 100 to 400 feet of resistant, massive, coarse-grained, calcareously cemented bioclastic sandstone. The overlying Rincon Formation consists of 200 to 300 feet of dark gray to chocolate brown calcareous shale and mudstone.

The Obispo Formation (or Obispo Tuff) is 800 to 2000 feet thick and comprises alternating massive to thick-bedded, medium to fine grained vitric-lithic tuffs, finely laminated black and brown marine siltstone and shale, and medium grained light tan marine sandstone. Headlee assigned to the Point Sal Formation a section described as consisting chiefly of medium to fine grained silty sandstone, with several thin silty and fossiliferous limestone lenses; it is gradational upward into siliceous shale characteristic of the Monterey Formation. The Monterey Formation itself is composed predominantly of porcelaneous and finely laminated siliceous and cherty shales.

The Pismo Formation consists of massive, medium to fine grained arkosic sandstone, with subordinate amounts of siltstone, sandy shale, mudstone, hard siliceous shale, and chert.

2.5.2.1.4.3 Quaternary Deposits

Deposits of Pleistocene and Holocene age are widespread on the coastal terrace benches along the southwest margin of the San Luis Range, and they exist farther onshore as local alluvial and stream-terrace deposits, landslide debris, and various colluvial accumulations. The coastal terrace deposits include discontinuous thin basal sections of marine silt, sand, gravel, and rubble, some of which are highly fossiliferous, and generally much thicker overlying sections of talus, alluvial-fan debris, and other deposits of landward origin. All of the marine deposits and most of the overlying nonmarine accumulations are of Pleistocene age, but some of the uppermost talus and alluvial deposits are Holocene. Most of the alluvial and colluvial materials consist of silty clayey sand with irregularly distributed fragments and blocks of locally exposed rock types. The landslide deposits include chaotic mixtures of rock fragments and fine-grained matrix debris, as well as some large masses of nearly intact to thoroughly disrupted bedrock.

A more detailed description of surficial deposits that are present in the vicinity of the power plant site is included in a later section.

2.5.2.1.5 Structure of the San Luis Range and Vicinity

2.5.2.1.5.1 General Features

The geologic structure of the San Luis Range-Estero Bay and adjacent offshore area is characterized by a complex set of folds and faults (refer to Figures 2.5-5 through 2.5-7). Tectonic events that produced these folds and faults are discussed in Section 2.5.2.1.3, Geologic History. The San Luis Range-Estero Bay and adjacent offshore area lies within the zone of transition from the west-trending Transverse Range structural province to the northwest-trending Coast Ranges province. Major structural features are the long narrow downfold of the San Luis-Pismo syncline and the bordering antiformal structural highs of Los Osos Valley on the northeast, and of Point San Luis and the adjacent offshore area on the southwest. This set of folds trends obliquely into a north-northwest aligned zone of basement upwarping, folding, and high-angle normal faulting that lies a few miles off the coast. The main onshore folds can be recognized, by seismic reflection and gravity techniques, in the structure of the buried, downfaulted Miocene section that lies across (west of) this zone.

Lesser, but yet important structural features in this area include smaller zones of faulting and trends of volcanic intrusives. The Edna and San Miguelito fault zones disrupt parts of the northeast and southwest flanks of the San Luis-Pismo syncline. A southward extension of the San Simeon fault, the existence of which is inferred on the basis of the linearity of the coastline between Cambria and Point Estero, and of the gravity gradient in that area, may extend into, and die out within, the northern part of Estero Bay. An aligned series of plugs and lensoid masses of Tertiary volcanic rocks that intrude the Franciscan Formation along the axis of the Los Osos Valley antiform extends from the outer part of Estero Bay southeastward for 22 miles (refer to Figure 2.5-6).

These features define the major elements of geologic structure in the San Luis Range-Estero Bay area. Other structural elements include the complex fold and fault structures within the Franciscan core complex rocks and the numerous smaller folds within the Tertiary section.

2.5.2.1.5.2 San Luis-Pismo Syncline

The main synclinal fold of the San Luis Range, referred to here as the San Luis-Pismo syncline, trends about N60°W and forms a structural trend more than 15 miles in length. The fold system comprises several parallel anticlines and synclines across its maximum onshore width of about 5 miles. Individual folds of the system typically range in length from hundreds of feet to as much as 10,000 feet. The folds range from zero to more than 30° in plunge, and have flank dips as steep as 90°. Various kinds of smaller folds exist locally, especially flexures and drag folds associated with tuff intrusions and with zones of shear deformation.

Near Estero Bay, the major fold extends to a depth of more than 6000 feet. Farther south, in the central part of the San Luis Range, it is more than 11,000 feet deep. Parts

of the northeast flank of the fold are disrupted by faults associated with the Edna fault zone. Local breaks along the central part of the southwest flank have been referred to as the San Miguelito fault zone.

2.5.2.1.5.3 Los Osos Valley Antiform

The body of Franciscan and Great Valley Sequence rocks that crops out between the San Luis-Pismo and Huasna synclines is here referred to as the Los Osos Valley antiform. This composite structure extends southward from the Santa Lucia Range, across the central and northern part of Estero Bay, and thence southeastward to the point where it is faulted out at the juncture of the Edna and the West Huasna fault zones.

Notable structural features within this core complex include northwest- and west-northwest- trending-faults that separate Franciscan melange, graywacke, metavolcanic, and serpentinite units. The serpentinites have been intruded or dragged within faults, apparently over a wide range of scales. One of the more persistent zones of serpentinite bodies occurs along a trend which extends west-northwestward from the West Huasna fault. It has been suggested that movement from this fault may have taken place within this serpentine belt. The range of hills that lies between the coast and Highway 1 between Estero Bay and Cambria is underlain by sandstone and minor shale of the Great Valley Sequence, referred to as the Cambria slab, which has been underthrust by Franciscan rocks. The thrust contact extends southeastward under Estero Bay near Cayucos. This contact is probably related to the fault contact between Great Valley and Franciscan rocks located just north of San Luis Obispo, which Page has shown to be overlain by unbroken lower Miocene strata.

A prominent feature of the Los Osos Valley antiform is the line of plugs and lensoid masses of intrusive Tertiary volcanic rocks. These distinctive bodies are present at isolated points along the approximate axis of the antiform over a distance of 22 miles, extending from the center of outer Estero Bay to the upper part of Los Osos Valley (refer to Figure 2.5-6). The consistent trend of the intrusives provides a useful reference for assessing the possibility of northwest-trending lateral slip faulting within Estero Bay. It shows that such faulting has not extended across the trend from either the inferred San Simeon fault offshore south extension, or from faults in the ground east of the San Simeon trend.

2.5.2.1.5.4 Edna and San Miguelito Fault Zones

These fault zones are described in Section 2.5.2.1.2.3.

2.5.2.1.5.5 Adjacent Offshore Area and East Boundary of the Offshore Santa Maria Basin

The stratigraphy and west-northwest-trending structure that characterize the onshore region from Point Sal to north of Point Estero have been shown by extensive marine

geophysical surveying to extend into the adjacent offshore area as far as the north-northwest trending structural zone that forms a boundary with the main offshore Santa Maria Basin. Owing to the irregular outline of the coast, the width of the offshore shelf east of this boundary zone ranges from 2-1/2 to as much as 12 miles. The shelf area is narrowest opposite the reach of coast between Point San Luis and Point Buchon, and widest in Estero Bay and south of San Luis Bay.

The major geologic features that underlie the near-shore shelf include, from south to north, the Casmalia Hills anticline, the broad Santa Maria Valley downwarp, the anticlinal structural high off Point San Luis, the San Luis-Pismo syncline, and the Los Osos Valley antiform.

The form of these features is defined by the outcrop pattern and structure of the older Pliocene, Miocene, and basement core complex rocks. The younger Pliocene strata that constitute the upper 1000 to 2000 feet of section in the adjacent offshore Santa Maria Basin are partly buttressed and partly faulted against the rocks that underlie the near-shore shelf, and they unconformably overlap the boundary zone and parts of the shelf in several areas.

The boundaries between the San Luis-Pismo syncline and the adjacent Los Osos Valley and Point San Luis antiforms can be seen in the offshore area to be expressed chiefly as zones of inflection between synclinal and anticlinal folds, rather than as zones of fault rupture such as occurs farther south along the Edna and San Miguelito faults. Isolated west-northwest- trending faults of no more than a few hundred feet displacement are located along the northeast flank of the syncline in Estero Bay. These faults evidently are the northwesternmost expressions of breakage along the Edna fault trend.

The main San Luis-Pismo synclinal structure opens to the northwest, attaining a maximum width of 8 or 9 miles in the southerly part of Estero Bay. The Point San Luis high, on the other hand, is a domal structure, the exposed basement rock core of which is about 10 miles long and 5 miles wide.

The general characteristics of the Santa Maria Basin East Boundary zone have been described in Section 2.5.2.1.2.3. As was noted there, the zone is essentially an expression of the boundary between the synclinorial downwarp of the offshore basin and the regional uplift of the southern Coast Ranges. In the vicinity of the San Luis Range, the zone is characterized by pronounced upwarping and normal faulting of the basement and overlying Tertiary rock sections. Both modes of deformation have contributed to the structural relief of about 500 feet in the Pliocene section, and of 1500 feet or more in the basement rocks, across this boundary. Successively younger strata are banked unconformably against the slopes that have formed from time to time in response to the relative uplifting of the ground east of the boundary zone.

A series of near-surface structural troughs forms prominent features within the segment of the boundary zone structure that extends between the approximate latitudes of

Arroyo Grande and Estero Bay. This trough structure apparently has formed through the extension and subsidence of a block of ground in the zone where the downwarp of the offshore basin has pulled away from the Santa Lucia uplift. Continued subsidence of this block has resulted in deformation and partial disruption of the buttress unconformity between the offshore Pliocene section and the near-shore Miocene and older rocks. This deformation is expressed by normal faulting and reverse drag type downfolding of the Pliocene strata adjacent to the contact, along the east side of the trough.

On the opposite, seaward side of the trough, a series of antithetic down-to-the-east normal faults of small displacement has formed in the Pliocene strata west of the contact zone. These faults exhibit only a few tens of feet displacement, and they seem to exhibit constant or even decreasing displacement downward.

The structural evolution of the offshore area near Estero Bay and the San Luis Range involved episodes of compressional deformation that affected the upper Tertiary section similarly on opposite sides of the boundary zone. The section on either side exhibits about the same intensity and style of folding. Major folds, such as the San Luis-Pismo syncline and the Piedras Blancas anticline, can be traced into the ground across the boundary zone.

The internal structure of the zone, including the presence of several on-lap unconformities in the adjacent Pliocene section, shows that, at least during Pliocene and early Pleistocene time, the boundary zone has been the inflection line between the Coast Ranges uplift and the offshore Santa Maria Basin downwarp.

Evidence that uplift has continued through late Pleistocene time, at least in the vicinity of the San Luis Range, is given by the presence of successive tiers of marine terraces along the seaward flank of the range. The wave-cut benches and back scarps of these terraces now exist at elevations ranging from about -300 feet (below sea level) to more than 300 feet above sea level.

The ground within which the East Boundary zone lies has been beveled by the post-Wisconsin marine transgression, and so the zone generally is not expressed topographically. Small topographic features, such as a seaward topographic step-up of the sea floor surface across the east-down fault at the BBN (Reference 37) (offshore) survey line 27 crossing, in Estero Bay, and several possible fault-line notch back scarps, however, may represent minor topographic expressions of deformation within the zone.

2.5.2.1.6 Structural Stability

The potential for surface or subsurface subsidence, uplift, or collapse at the site or in the region surrounding the site, is discussed in Section 2.5.5, Stability of Subsurface Materials.

2.5.2.1.7 Regional Groundwater

Groundwater in the region surrounding the site is used as a backup source due to its poor quality and the lack of a significant groundwater reservoir. Section 2.4.13 states that most of the groundwater at the site or in the area around the site is either in the alluvial deposits of Diablo Creek or seeps from springs encountered in excavations at the site.

2.5.2.2 Site Geology

2.5.2.2.1 Site Physiography

The site consists of approximately 750 acres near the mouth of Diablo Creek and is located on a sloping coastal terrace, ranging from 60 to 150 feet above sea level. The terrace terminates at the Pacific Ocean on the southwest and extends toward the San Luis Mountains on the northeast. The terrace consists of bedrock overlain by surficial deposits of marine and nonmarine origin.

The remainder of this section presents a detailed description of site geology.

2.5.2.2.2 General Features

The area of the DCPP site is a coastal tract in San Luis Obispo County approximately 6.5 miles northwest of Point San Luis. It lies immediately southeast of the mouth of Diablo Canyon, a major westward-draining feature of the San Luis Range, and about a mile southeast of Lion Rock, a prominent offshore element of the highly irregular coastline.

The ground being developed as a power plant site occupies an extensive topographic terrace about 1000 feet in average width. In its pregrading, natural state, the gently undulating surface of this terrace sloped gradually southwestward to an abrupt termination along a cliff fronting the ocean; in a landward, or northeasterly, direction, it rose with progressively increasing slope to merge with the much steeper front of a foothill ridge of the San Luis Range. The surface ranged in altitude from 65 to 80 feet along the coastline to a maximum of nearly 300 feet along the base of the hillslope to the northeast, but nowhere was its local relief greater than 10 feet. Its only major interruption was the steep-walled canyon of lower Diablo Creek, a gash about 75 feet in average depth.

The entire subject area is underlain by a complex sequence of stratified marine sedimentary rocks and tuffaceous volcanic rocks, all of Tertiary (Miocene) age. Diabasic intrusive rocks are locally exposed high on the walls of Diablo Canyon at the edge of the area. Both the sedimentary and volcanic rocks have been folded and otherwise disturbed over a considerable range of scales.

Surficial deposits of Quaternary age are widespread. In a few places, they are as thick as 50 feet, but their average thickness probably is on the order of 20 feet over the terrace areas and 10 feet or less over the entire mapped ground. The most extensive deposits underlie the main topographic terrace.

Like many other parts of the California coast, the Diablo Canyon area is characterized by several wave-cut benches of Pleistocene age. These surfaces of irregular but generally low relief were developed across bedrock by marine erosion, and they are ancient analogues of the benches now being cut approximately at sea level along the present coast. They were formed during periods when the sea level was higher, relative to the adjacent land, than it is now. Each is thinly and discontinuously mantled with marine sand, gravel, and rubble similar to the beach and offshore deposits that are accumulating along the present coastline. Along its landward margin each bears thicker and more localized coarse deposits similar to the modern talus along the base of the present sea cliff.

Both the ancient wave-cut benches and their overlying marine and shoreline deposits have been buried beneath silty to gravelly detritus derived from landward sources after the benches were, in effect, abandoned by the ocean. This nonmarine cover is essentially an apron of coalescing fan deposits and other alluvial debris that is thickest adjacent to the mouths of major canyons.

Where they have been deeply trenched by subsequent erosion, as along Diablo Canyon in the map areas, these deposits can be seen to have buried some of the benches so deeply that their individual identities are not reflected by the present (pregrading) rather smooth terrace topography. Thus, the surface of the main terrace is defined mainly by nonmarine deposits that conceal both the older benches of marine erosion and some of the abruptly rising ground that separates them (refer to Figures 2.5-8 and 2.5-10).

The observed and inferred relationships among the terrace surfaces and the wave-cut benches buried beneath them can be summarized as follows:

Wave-cut Bench		Terrace Surface	
Altitude, feet	Location	Altitude, feet	Location
170-175	Small remnants on sides of Diablo Canyon	Mainly 170-190	Sides of Diablo Canyon and upper parts of main terrace; in places separated from lower parts of terrace by scarps
145-155	Very small remnants on sides of Diablo Canyon	Mainly 150-170	
120-130 90-100 65-80	Subparallel benches elongate in a northwest-southeast direction but with considerable aggregate width; wholly	Mainly 70-160	Most of main terrace, a wide-spread surface on a composite section of nonmarine deposits; no well-defined scarps

	beneath main terrace surface	50-100	Small remnants above modern sea cliff
30-45	Small remnants above modern sea cliff		No depositional terrace
Approx. 0	Small to moderately large areas along present coastline.		

Within the subject area the wave-cut benches increase progressively in age with increasing elevation above present sea level; hence, their order in the above list is one of decreasing age. By far, the most extensive of these benches slopes gently seaward from a shoreline angle that lies at an elevation of 100 feet above present sea level.

The geology of the power plant site is shown in the site geologic maps, Figures 2.5-8 and 2.5-9, and geologic section, Figure 2.5-10.

2.5.2.2.3 Stratigraphy

2.5.2.2.3.1 Obispo Tuff

The Obispo Tuff, which has been classified either as a separate formation or as a member of the Miocene Monterey Formation, is the oldest bedrock unit exposed in the site area. Its constituent rocks generally are well exposed, appear extensively in the coastward parts of the area, and form nearly all of the offshore prominences and shoals. They are dense to highly porous, and thinly layered to almost massive. Their color ranges from white to buff in fresh exposures, and from yellowish to reddish brown on weathered surfaces, many of which are variegated in shades of brown. Outcrop surfaces have a characteristic "punky" to crusty appearance, but the rocks in general are tough, cohesive, and relatively resistant to erosion.

Several pyroclastic rock types constitute the Obispo Tuff ("To" on map, Figure 2.5-8) in and near the subject area. By far, the most widespread is fine-grained vitric tuff with rare to moderately abundant tabular crystals of sodic plagioclase. The constituent glass commonly appears as fresh shards, but in many places it has been partly or completely devitrified. Crystal tuffs are locally prominent, and some of these are so crowded with 1/8 to 3/8 inch crystals of plagioclase that they superficially resemble granitoid plutonic rocks. Other observed rock types include pumiceous tuffs, pumice-pellet tuff breccias, perlitic vitreous tuffs, tuffaceous siltstones and mudstones, and fine-grained tuff breccias with fragments of glass and various Monterey rocks. No massive flow rocks were recognized anywhere in the exposed volcanic section.

In terms of bulk composition, the pyroclastic rocks appear to be chiefly soda rhyolites and soda quartz latites. Their plagioclase, which ranges from calcic albite to sodic oligoclase, commonly is accompanied by lesser amounts of quartz as small rounded

crystals and irregular crystal fragments. Biotite, zircon, and apatite also are present in many of the specimens that were examined under the microscope. Most of the tuffaceous rocks, and especially the more vitreous ones, have been locally to pervasively altered. Products of silicification, zeolitization, and pyritization are readily recognizable in many exposures, where the rocks generally are traversed by numerous thin, irregular veinlets and layers of cherty to opaline material. Veinlets and thin, pod-like concentrations of gypsum also are widespread. Where pyrite is present, the rocks weather yellowish to brownish and are marked by gossan-like crusts.

The various contrasting rock types are simply interlayered in only a few places; much more typical are abutting, intertonguing, and irregularly interpenetrating relationships over a wide range of scales. Septa and inclusions of Monterey rocks are abundant, and a few of them are large enough to be shown separately on the accompanying geologic map (refer to Figure 2.5-8). Highly irregular inclusions, a few inches to several feet in maximum dimension, are so densely packed together in some places that they form breccias with volcanic matrices.

The Obispo Tuff is underlain by mudstones of early Miocene (pre-Monterey) age, on which it rests with a highly irregular contact that appears to be in part intrusive. This contact lies offshore in the vicinity of the power plant site, but it is exposed along the seacoast to the southeast.

In a gross way, the Obispo underlies the basal part of the Monterey formation, but many of its contacts with these sedimentary strata are plainly intrusive. Moreover, individual sills and dikes of slightly to thoroughly altered tuffaceous rocks appear here and there in the Monterey section, not uncommonly at stratigraphic levels well above its base (refer to Figures 2.5-8 and 2.5-13). The observed physical relationships, together with the local occurrence of diatoms and foraminifera within the principal masses of volcanic rocks, indicate that much of the Obispo Tuff in this area probably was emplaced at shallow depths beneath the Miocene sea floor during accumulation of the Monterey strata. The tuff unit does not appear to represent a single, well-defined eruptive event, nor is it likely to have been derived from a single source conduit.

2.5.2.2.3.2 Monterey Formation

Stratified marine rocks variously correlated with the Monterey Formation, Point Sal Formation, and Obispo Tuff underlie most of the subject area, including all of that portion intended for power plant location. They are almost continuously exposed along the crescentic sea cliff that borders Diablo Cove, and elsewhere they appear in much more localized outcrops. For convenience, they are here assigned to the Monterey Formation ("Tm" on map, Figure 2.5-8) in order to delineate them from the adjacent more tuffaceous rocks so typical of the Obispo Tuff.

The observed rock types, listed in general order of decreasing abundance, are silty and tuffaceous sandstone, siliceous shale, shaly siltstone and mudstone, diatomaceous shale, sandy to highly tuffaceous shale, calcareous shale and impure limestone,

bituminous shale, fine- to coarse-grained sandstone, impure vitric tuff, silicified limestone and shale, and tuff-pellet sandstone. Dark colored and relatively fine-grained strata are most abundant in the lowest part of the section, as exposed along the east side of Diablo Cove, whereas lighter colored sandstones and siliceous shales are dominant at stratigraphically higher levels farther north. In detail, however, the different rock types are interbedded in various combinations, and intervals of uniform lithology rarely are thicker than 30 feet. Indeed, the closely-spaced alternations of contrasting strata yield a prominent rib-like pattern of outcrop along much of the sea cliff and shoreline bench forming the margin of Diablo Cove.

The sandstones are mainly fine- to medium-grained, and most are distinctly tuffaceous. Shards of volcanic glass generally are recognizable under the microscope, and the very fine-grained siliceous matrix may well have been derived largely through alteration of original glassy material. Some of the sandstone contains small but megascopically visible fragments of pumice, perlitic glass, and tuff, and a few beds grade along strike into submarine tuff breccia. The sandstones are thinly to very thickly layered; individual beds 6 inches to 4 feet thick are fairly common, and a few appear to be as thick as 15 feet. Some of them are hard and very resistant to erosion, and they typically form subdued but nearly continuous elongated projections on major hillslopes (refer to Figure 2.5-8).

The siliceous shales are buff to light gray platy rocks that are moderately hard to extremely hard according to their silica content, but they tend to break readily along bedding and fracture surfaces. The bituminous rocks and the siltstones and mudstones are darker colored, softer, and grossly more compact. Some of them are very thinly bedded or laminated, others appear almost massive or form matrices for irregularly ellipsoidal masses of somewhat sandier material. The diatomaceous, tuffaceous, and sandy rocks are lighter colored. The more tuffaceous types are softer, and the diatomaceous ones are soft to the degree of punkiness; both kinds of rocks are easily eroded, but are markedly cohesive and tend to retain their gross positions on even the steepest of slopes.

The siliceous shale and most of the hardest, highly silicified rocks weather to very light gray, and the dark colored, fine-grained rocks tend to bleach when weathered. The other types, including the sandstones, weather to various shades of buff and light brown. Stains of iron oxides are widespread on exposures of nearly all the Monterey rocks, and are especially well developed on some of the finest-grained shales that contain disseminated pyrite. All but the hardest and most thick-bedded rocks are considerably broken to depths of as much as 6 feet in the zone of weathering on slopes other than the present sea cliff, and the broken fragments have been separated and displaced by surface creep to somewhat lesser depths.

2.5.2.2.3.3 Diabasic Intrusive Rocks

Small, irregular bodies of diabasic rocks are poorly exposed high on the walls of Diablo Canyon at and beyond the northeasterly edge of the map area. Contact relationships

are readily determined at only a few places where these rocks evidently are intrusive into the Monterey Formation. They are considerably weathered, but an ophitic texture is recognizable. They consist chiefly of calcic plagioclase and augite, with some olivine, opaque minerals, and zeolitic alteration products.

2.5.2.2.3.4 Masses of Brecciated Rocks

Highly irregular masses of coarsely brecciated rocks, a few feet to many tens of feet in maximum dimension, are present in some of the relatively siliceous parts of the Monterey section that adjoin the principal bodies of Obispo Tuff. The fracturing and dislocation is not genetically related to any recognizable faults, but instead seems to have been associated with emplacement of the volcanic rocks; it evidently was accompanied by, or soon followed by, extensive silicification. Many adjacent fragments in the breccias are closely juxtaposed and have matching opposed surfaces, so that they plainly represent no more than coarse crackling of the brittle rocks. Other fragments, though angular or subangular, are not readily matched with adjacent fragments and hence may represent significant translation within the entire rock masses.

The ratio of matrix materials to coarse fragments is very low in most of the breccias and nowhere was it observed to exceed about 1:3. The matrices generally comprise smaller angular fragments of the same Monterey rocks that are elsewhere dominant in the breccias, and they characteristically are set in a siliceous cement. Tuffaceous matrices, with or without Monterey fragments, also are widespread and commonly show the effects of pervasive silicification. All the exposed breccias are firmly cemented, and they rank among the hardest and most resistant units in the entire bedrock section.

A few 3 to 18 inch beds of sandstone have been pulled apart to form separate tabular masses along specific stratigraphic horizons in higher parts of the Monterey sequence. Such individual tablets, which are boudins rather than ordinary breccia fragments, are especially well exposed in the sea cliff at the northern corner of Diablo Cove. They are flanked by much finer-grained strata that converge around their ends and continue essentially unbroken beyond them. This boudinage or separation and stringing out of sandstone beds that lie within intervals of much softer and more shaly rocks has resulted from compression during folding of the Monterey section. Its distribution is stratigraphically controlled and is not systematically related to recognizable faults in the area.

2.5.2.2.3.5 Surficial Deposits

1. Coastal Terrace Deposits

The coastal wave-cut benches of Pleistocene age, as described in a foregoing section, are almost continuously blanketed by terrace deposits (Qter in Figure 2.5-8) of several contrasting types and modes of origin. The oldest of these deposits are relatively thin and patchy in their occurrence, and were laid down along and adjacent to ancient

beaches during Pleistocene time. They are covered by considerably thicker and more extensive nonmarine accumulations of detrital materials derived from various landward sources.

The marine deposits consist of silt, sand, gravel, and cobbly to bouldery rubble. They are approximately 2 feet in average thickness over the entire terrace area and reach a maximum observed thickness of about 8 feet. They rest directly upon bedrock, some of which is marked by numerous holes attributable to the action of boring marine mollusks, and they commonly contain large rounded cobbles and boulders of Monterey and Obispo rocks that have been similarly bored. Lenses and pockets of highly fossiliferous sand and gravel are present locally.

The marine sediments are poorly to very well sorted and loose to moderately well consolidated. All of them have been naturally compacted; the degree of compaction varies according to the material, but it is consistently greater than that observed in any of the associated surficial deposits of other types. Near the inner margins of individual wave-cut benches the marine deposits merge landward into coarser and less well-sorted debris that evidently accumulated along the bases of ancient sea cliffs or other shoreline slopes. This debris is locally as much as 12 feet thick; it forms broad but very short aprons, now buried beneath younger deposits, that are ancient analogues of the talus accumulations along the inner margin of the present beach in Diablo Cove. One of these occurrences, identified as "fossil Qtb" in the geologic map of Figure 2.5-8, is well exposed high on the northerly wall of Diablo Canyon.

A younger, thicker, and much more continuous nonmarine cover is present over most of the coastal terrace area. It consistently overlies the marine deposits noted above, and, where these are absent, it rests directly upon bedrock. It is composed in part of alluvial detritus contributed during Pleistocene time from Diablo Canyon and several smaller drainage courses, and it thickens markedly as traced sourceward toward these canyons. The detritus represents a series of alluvial fans, some of which appear to have partly coalesced with adjacent ones. It is chiefly fine- to moderately-coarse-grained gravel and rubble characterized by tabular fragments of Monterey rocks in a rather abundant silty to clayey matrix. Most of it is thinly and regularly stratified, but the distinctness of this layering varies greatly from place to place.

Slump, creep, and slope-wash deposits, derived from adjacent hillsides by relatively slow downhill movement over long periods of time, also form major parts of the nonmarine terrace cover. All are loose and uncompacted. They comprise fragments of Monterey rocks in dark colored clayey matrices, and their internal structure is essentially chaotic. In some places they are crudely interlayered with the alluvial fan deposits, and elsewhere they overlie these bedded sediments. On parts of the main terrace area not reached by any of the alluvial fans, a cover of slump, creep, and slope-wash deposits, a few inches to nearly 10 feet thick, rests directly upon either marine terrace deposits or bedrock.

Thus, the entire section of terrace deposits that caps the coastal benches of Pleistocene marine erosion is heterogeneous and internally complex; it includes contributions of detritus from contrasting sources, from different directions at different times, and via several basically different modes of transport and deposition.

2. Stream-terrace Deposits

Several narrow, irregular benches along the walls of Diablo Canyon are veneered by a few inches to 6 feet of silty gravels that are somewhat coarser but otherwise similar to the alluvial fan deposits described above. These stream-terrace deposits (Qst) originally occupied the bottom of the canyon at a time when the lower course of Diablo Creek had been cut downward through the alluvial fan sediments of the main terrace and well into the underlying bedrock. Subsequent deepening of the canyon left remnants of the deposits as cappings on scattered small terraces.

3. Landslide Deposits

The walls of Diablo Canyon also are marked by tongue- and bench-like accumulations of loose, rubbly landslide debris (Qls), consisting mainly of highly broken and jumbled masses of Monterey rocks with abundant silty and soily matrix materials. These landslide bodies represent localized failure on naturally oversteepened slopes, generally confined to fractured bedrock in and immediately beneath the zone of weathering. Individual bodies within the mapped area are small, with probable maximum thicknesses no greater than 20 feet. All of them lie outside the area intended for power plant construction.

Landslide deposits along the sea cliff have been recognized at only one locality, on the north side of Diablo Cove about 400 feet northwest of the mouth of Diablo Canyon. Here slippage has occurred along bedding and fracture surfaces in siliceous Monterey rocks, and it has been confined essentially to the axial region of a well-defined syncline (refer to Figure 2.5-8). Several episodes of sliding are attested by thin, elongate masses of highly broken ground separated from one another by well-defined zones of dislocation. Some of these masses are still capped by terrace deposits. The entire composite accumulation of debris is not more than 35 feet in maximum thickness, and ground failure at this locality does not appear to have resulted in major recession of the cliff. Elsewhere within the mapped area, landsliding along the sea cliff evidently has not been a significant process.

Large landslides, some of them involving substantial thickness of bedrock, are present on both sides of Diablo Canyon not far northeast of the power plant area. These occurrences need not be considered in connection with the plant site, but they have been regarded as significant factors in establishing a satisfactory grading design for the switchyard and other up-canyon installations. They are not dealt with in this section.

4. Slump, Creep, and Slope-wash Deposits

As noted earlier, slump, creep, and slope-wash deposits (Qsw) form parts of the nonmarine sedimentary blanket on the main terrace. These materials are shown separately on the geologic map only in those limited areas where they have been considerably concentrated along well-defined swales and are readily distinguished from other surficial deposits. Their actual distribution is much wider, and they undoubtedly are present over a large fraction of the areas designated as Qter; their average thickness in such areas, however, is probably less than 5 feet.

Angular fragments of Monterey rocks are sparsely to very abundantly scattered through the slump, creep, and slope-wash deposits, whose most characteristic feature is a fine-grained matrix that is dark colored, moderately rich in clay minerals, and extremely soft when wet. Internal layering is rarely observable and nowhere is sharply expressed. The debris seems to have been rather thoroughly intermixed during its slow migration down hillslopes in response to gravity. That it was derived mainly from broken materials in the zone of weathering is shown by several exposures in which it grades downward through soily debris into highly disturbed and partly weathered bedrock, and thence into progressively fresher and less broken bedrock.

5. Talus and Beach Deposits

Much of the present coastline in the subject area is marked by bare rock, but Diablo Cove and a few other large indentations are fringed by narrow, discontinuous beaches and irregular concentrations of sea cliff talus. These deposits (Qtb) are very coarse grained. Their total volume is small, and they are of interest mainly as modern analogues of much older deposits at higher levels beneath the main terrace surface.

The beach deposits consist chiefly of well-rounded cobbles. They form thin veneers over bedrock, and in Diablo Cove they grade seaward into patches of coarse pebbly sand. The floors of both Diablo Cove and South Cove probably are irregular in detail and are featured by rather hard, fresh bedrock that is discontinuously overlain by irregular thin bodies of sand and gravel. The distribution and abundance of kelp suggest that bedrock crops out over large parts of these cove areas where the sea bottom cannot be observed from onshore points.

6. Stream-laid Alluvium

Stream-laid alluvium (Qal) occurs as a strip along the present narrow floor of Diablo Canyon, where it is only a few feet in average thickness. It is composed of irregularly intertongued silt, sand, gravel, and rubble. It is crudely to sharply stratified, poorly to well sorted, and, in general, somewhat compacted. Most of it is at least moderately porous.

7. Other Deposits

Earlier inhabitation of the area by Indians is indicated by several midden deposits that are rich in charcoal and fragments of shells and bones. The most extensive of these occurrences marks the site of a long-abandoned village along the edge of the main terrace immediately northwest of Diablo Canyon. Others have been noted on the main terrace just east of the mouth of Diablo Canyon, on the shoreward end of South Point, and at several places in and near the plant site.

2.5.2.2.4 Structure

2.5.2.2.4.1 Tectonic Structures Underlying the Region Surrounding the Site

The dominant tectonic structure in the region of the power plant site is the San Luis-Pismo downwarp system of west-northwest-trending folds. This structure is bounded on the northeast by the antiformal basement rock structure of the Los Osos and San Luis Valley trend. The west-northwest-trending Edna fault zone lies along the northeast flank of the range, and the parallel Miguelito fault extends into the southeasterly end of the range. A north-northwest- trending structural discontinuity that may be a fault has been inferred or interpolated from widely spaced traverses in the offshore, extending within about 5 miles of the site at its point of closest approach. To the west of this discontinuity, the structure is dominated by north to north-northwest-trending folds in Tertiary rocks. These features are illustrated in Figure 2.5-3 and described in this section.

Tectonic structures underlying the site and region surrounding the site are identified in the above and following sections, and they are shown in Figures 2.5-3, 2.5-5, 2.5-8, 2.5-10, 2.5-15, and 2.5-16. They are listed as follows:

2.5.2.2.4.2 Tectonic Structures Underlying the Site

The rocks underlying the DCPP site have been subjected to intrusive volcanic activity and to later compressional deformation that has given rise to folding, jointing and fracturing, minor faulting, and local brecciation. The site is situated in a section of moderately to steeply north-dipping strata, about 300 feet south of an east-west-trending synclinal fold axis (refer to Figures 2.5-8 and 2.5-10). The rocks are jointed throughout, and they contain local zones of closely spaced high-angle fractures (refer to Figure 2.5-16).

A minor fault zone extends into the site from the west, but dies out in the vicinity of the Unit 1 turbine building. Two other minor faults were mapped for distances of 35 to more than 200 feet in the bedrock section exposed in the excavation for the Unit 1 containment structure. In addition to these features, cross-cutting bodies of tuff and tuff brecia, and cemented "crackle breccia" could be considered as tectonic structures.

Exact ages of the various tectonic structures at the site are not known. It has been clearly demonstrated, however, that all of them are truncated by, and therefore antedate, the principal marine erosion surface that underlies the coastal terrace bench. This terrace can be correlated with coastal terraces to the north and south that have been dated as 80,000 to 120,000 years old. The tectonic structures probably are related to the Pliocene-lower Pleistocene episode of Coast Ranges deformation, which occurred more than 1 million years ago.

The bedrock units within the entire subject area form part of the southerly flank of a very large syncline that is a major feature of the San Luis Range. The northerly-dipping sequence of strata is marked by several smaller folds with subparallel trends and flank-to-flank dimensions measured in hundreds of feet. One of these, a syncline with gentle to moderate westerly plunge, is the largest flexure recognized in the vicinity of the power plant site. Its axis lies a short distance north of the site and about 450 feet northeast of the mouth of Diablo Canyon (refer to Figures 2.5-8 and 2.5-10). East of the canyon this fold appears to be rather open and simple in form, but farther west it probably is complicated by several large wrinkles and may well lose its identity as a single feature. Some of this complexity is clearly revealed along the northerly margin of Diablo Cove, where the beds exposed in the sea cliff have been closely folded along east to northeast trends. Here a tight syncline (shown in Figure 2.5-8) and several smaller folds can be recognized, and steep to near-vertical dips are dominant in several parts of the section.

The southerly flank of the main syncline within the map area steepens markedly as traced southward away from the fold axis. Most of this steepening is concentrated within an across-strike distance of about 300 feet as revealed by the strata exposed in the sea cliff southeastward from the mouth of Diablo Canyon; farther southward the beds of sandstone and finer-grained rocks dip rather uniformly at angles of 70° or more. A slight overturning through the vertical characterizes the several hundred feet of section exposed immediately north of the Obispo Tuff that underlies South Point and the north shore of South Cove (refer to Figure 2.5-8). Thus the main syncline, though simple in gross form, is distinctly asymmetric. The steepness of its southerly flank may well have resulted from buttressing, during the folding, by the relatively massive and competent unit of tuffaceous rocks that adjoins the Monterey strata at this general level of exposure.

Smaller folds, corrugations, and highly irregular convolutions are widespread among the Monterey rocks, especially the finest-grained and most shaley types. Some of these flexures trend east to southeast and appear to be drag features systematically related to the larger-scale folding in the area. Most, however, reflect no consistent form or trend, range in scale from inches to only a few feet, and evidently are confined to relatively soft rocks that are flanked by intervals of harder and more massive strata. They constitute crudely tabular zones of contortion within which individual rock layers can be traced for short distances but rarely are continuous throughout the deformed ground.

Some of this contortion appears to have derived from slumping and sliding of unconsolidated sediments on the Miocene sea floor during accumulation of the Monterey section. Most of it, in contrast, plainly occurred at much later times, presumably after conversion of the sediments to sedimentary rocks, and it can be most readily attributed to highly localized deformation during the ancient folding of a section that comprises rocks with contrasting degrees of structural competence.

2.5.2.2.4.3 Faults

Numerous faults with total displacements ranging from a few inches to several feet cut the exposed Monterey rocks. Most of these occur within, or along the margins of, the zones of contortion noted above. They are sharp, tight breaks with highly diverse attitudes, and they typically are marked by 1/16-inch or less of gouge or microbreccia. Nearly all of them are curving or otherwise somewhat irregular surfaces, and many can be seen to terminate abruptly or to die out gradually within masses of tightly folded rocks. These small faults appear to have been developed as end products of localized intense deformation caused by folding of the bedrock section. Their unsystematic attitudes, small displacements, and limited effects upon the host rocks identify them as second-order features, i.e., as results rather than causes of the localized folding and convolution with which they are associated.

Three distinctly larger and more continuous faults also were recognized within the mapped area. They are well exposed on the sea cliff that fringes Diablo Cove (refer to Figure 2.5-8), and each lies within a zone of moderately to severely contorted fine-grained Monterey strata. Each is actually a zone, 6 inches to several feet wide, within which two or more subparallel tight breaks are marked by slickensides, 1/4-inch or less of gouge, and local stringers of gypsum. None of these breaks appears to be systematically related to individual folds within the adjoining rocks. None of them extends upward into the overlying blanket of Quaternary terrace deposits.

One of these faults, exposed on the north side of the cove, trends north-northwest essentially parallel to the flanking Monterey beds, but it dips more steeply than these beds. Another, exposed on the east side of the cove, trends east-southeast and is essentially vertical; thus, it is essentially parallel to the structure of the host Monterey section. Neither of these faults projects toward the ground intended for power plant construction. The third fault, which appears on the sea cliff at the mouth of Diablo Canyon, trends northeast and projects toward the ground in the northernmost part of the power plant site. It dips northward somewhat more steeply than the adjacent strata.

Total displacement is not known for any of these three faults on the basis of natural exposures, but it could amount to as much as tens of feet. That these breaks are not major features, however, is strongly suggested by their sharpness, by the thinness of gouge along individual surfaces of slippage, and by the essential lack of correlation between the highly irregular geometry of deformation in the enclosing strata and any directions of movement along the slip surfaces.

The possibility that these surfaces are late-stage expressions of much larger-scale faulting at this general locality was tested by careful examination of the deformed rocks that they transect. On megascopic scales, the rocks appear to have been deformed much more by flexing than by rupture and slippage, as evidenced by local continuity of numerous thin beds that denies the existence of pervasive faulting within much of the ground in question. That the finer-grained rocks are not themselves fault gouged was confirmed by examination of 34 samples under the microscope.

Sedimentary layering, recognized in 27 of these samples, was observed to be grossly continuous even though dislocated here and there by tiny fractures. Moreover, nearly all the samples were found to contain shards of volcanic glass and/or the tests of foraminifera; some of these delicate components showed effects of microfracturing and a few had been offset a millimeter or less along tiny shear surfaces, but none appeared to have been smeared out or partially obliterated by intense shearing or grinding. Thus, the three larger faults in the area evidently were superimposed upon ground that already had been deformed primarily by small-scale and locally very intense folding rather than by pervasive grinding and milling.

It is not known whether these faults were late-stage results of major folding in the region or were products of independent tectonic activity. In either case, they are relatively ancient features, as they are capped without break by the Quaternary terrace deposits exposed along the upper part of the sea cliff. They probably are not large-scale elements of regional structure, as examination of the nearest areas of exposed bedrock along their respective landward projections revealed no evidence of substantial offsets among recognizable stratigraphic units.

Seaward projection of one or more of these faults might be taken to explain a possible large offset of the Obispo Tuff units exposed on North Point and South Point. The notion of such an offset, however, would rest upon the assumption that these two units are displaced parts of an originally continuous body, for which there is no real evidence. Indeed, the two tuff units are bounded on their northerly sides by lithologically different parts of the Monterey Formation; hence, they were clearly originally emplaced at different stratigraphic levels and are not directly correlative.

2.5.2.2.5 Geological Relationships at the Unit 1 and Unit 2 Power Plant Site

2.5.2.2.5.1 Geologic Investigations at the Site

The geologic relationships at DCPP site have been studied in terms of both local and regional stratigraphy and structure, with an emphasis on relationships that could aid in dating the youngest tectonic activity in the area. Geologic conditions that could affect the design, construction, and performance of various components of the plant installation also were identified and evaluated. The investigations were carried out in three main phases, which spanned the time between initial site selection and completion of foundation construction.

2.5.2.2.5.2 Feasibility Investigation Phase

Work directed toward determining the pertinent general geologic conditions at the plant site comprised detailed mapping of available exposures, limited hand trenching in areas with critical relationships, and petrographic study of the principal rock types. The results of this feasibility program were presented in a report that also included recommendations for determining suitability of the site in terms of geologic conditions. Information from this early phase of studies is included in the preceding four sections and illustrated in Figures 2.5-8, 2.5-9, and 2.5-10.

2.5.2.2.5.3 Suitability Investigation Phase

The record phase of investigations was directed toward testing and confirming the favorable judgments concerning site feasibility. Inasmuch as the principal remaining uncertainties involved structural features in the local bedrock, additional effort was made to expose and map these features and their relationships. This was accomplished through excavation of large trenches on a grid pattern that extended throughout the plant area, followed by photographing the trench walls and logging the exposed geologic features. Large-scale photographs were used as a mapping base, and the recorded data were then transferred to controlled vertical sections at a scale of 1 inch = 20 feet. The results of this work were reported in three supplements to the original geologic report (Reference 1). Supplementary Reports I and III presented data and interpretation based on trench exposures in the areas of the Unit 1 and Unit 2 installations, respectively. Supplementary Report II described the relationships of small bedrock faults exposed in the exploratory trenches and in the nearby sea cliff. During these suitability investigations, special attention was given to the contact between bedrock and overlying terrace deposits in the plant site area. It was determined that none of the discontinuities present in the bedrock section displaces either the erosional surface developed across the bedrock or the terrace deposits that rest upon this surface. The pertinent data are presented farther on in this section and illustrated in Figures 2.5-11, 2.5-12, 2.5-13, and 2.5-14.

2.5.2.2.5.4 Construction Geology Investigation Phase

Geologic work done during the course of construction at the plant site spanned an interval of 5 years, which encompassed the period of large-scale excavation. It included detailed mapping of all significant excavations, as well as special studies in some areas of rock bolting and other work involving rock reinforcement and temporary instrumentation. The mapping covered essentially all parts of the area to be occupied by structures for Unit 1 and Unit 2, including the excavations for the circulating water intake and outlet, the turbine-generator building, the auxiliary building, and the containment structures. The results of this mapping are described farther on and illustrated in Figures 2.5-15 and 2.5-16.

2.5.2.2.5.5 Exploratory Trenching Program, Unit 1 Site

Four exploratory trenches were cut beneath the main terrace surface at the power plant site, as shown in Figures 2.5-8, 2.5-11, 2.5-12, and 2.5-13. Trench AF (Trench A), about 1080 feet long, extended in a north-northwesterly direction and thus was roughly parallel to the nearby margin of Diablo Cove. Trench BE (Trench B), 380 feet long, was parallel to Trench A and lay about 150 feet east of the northerly one-third of the longer trench. Trenches C and D, 450 and 490 feet long, respectively were nearly parallel to each other, 130 to 150 feet apart, and lay essentially normal to Trenches A and B. The two pairs of trenches crossed each other to form a "#" pattern that would have been symmetrical were it not for the long southerly extension of Trench A. They covered the area intended for Unit 1 power plant construction, and the intersection of Trenches B and C coincided in position with the center of the Unit 1 nuclear reactor structure.

All four trenches, throughout their aggregate length of approximately 2400 feet, revealed a section of surficial deposits and underlying bedrock that corresponds to the two-ply sequence of surficial deposits and Monterey strata exposed along the sea cliff in nearby Diablo Cove. The trenches ranged in depth from 10 feet to nearly 40 feet, and all had sloping sides that gave way downward to essentially vertical walls in the bedrock encountered 3 to 8 feet above their floors.

To facilitate detailed geologic mapping, the easterly walls of Trenches A and B and the southerly walls of Trenches C and D were trimmed to near-vertical slopes extending upward from the trench floors to levels well above the top of bedrock. These walls subsequently were scaled back by means of hand tools in order to provide fresh, clean exposures prior to mapping of the contact between bedrock and overlying unconsolidated materials.

1. Bedrock

The bedrock that was continuously exposed in the lowest parts of all the exploratory trenches lies within a portion of the Montery Formation characterized by a preponderance of sandstone. It corresponds to the part of the section that crops out in lower Diablo Canyon and along the sea cliff souteastward from the canyon mouth. The sandstone ranges from light gray through buff to light reddish brown, from silty to markedly tuffaceous, and from thin-bedded and platy to massive. The distribution and thickness of beds can be readily appraised from sections along Trenches A and B (refer to Figure 2.5-12) that show nearly all individual bedding surfaces that could be recognized on the ground.

The sandstone ranges from very hard to moderately soft, and some of it feels slightly punky when struck with a pick. All of it is, however, firm and very compact. In general, the most platy parts of the sequence are also the hardest, but the soundest rock in the area is almost massive sandstone of the kind that underlies the site of the intended reactor structure. This rock is well exposed on the nearby hillslope adjoining the main

terrace area, where it has been markedly resistant to erosion and stands out as distinct low ridges.

Tuff, consisting chiefly of altered volcanic glass, forms irregular sills and dikes in several parts of the bedrock section. This material, generally light gray to buff, is compact but distinctly softer than the enclosing sandstone. Individual bodies are 1/2 inch to 4 feet thick. They are locally abundant in Trench C west of Trench A, and in Trench A southward beyond the end of the section in Figure 2.5-12. They are very rare or absent in Trenches B and D, and in the easterly parts of Trench C and the northerly parts of Trench A. These volcanic rocks probably are related to the Obispo Tuff as described earlier, but all known masses of typical Obispo rocks in this area lie at considerable distances west and south of the ground occupied by the trenches.

2. Bedrock Structure

The stratification of the Monterey rocks dips northward wherever it was observable in the trenches, in general, at angles of 35 to 55°. Thus, the bedrock beneath the power plant site evidently lies on the southerly flank of the major syncline noted and described earlier. Zones of convolution and other expressions of locally intense folding were not recognized, and probably are much less common in this general part of the section than in other, previously described parts that include intervals of softer and more shaley rocks.

Much of the sandstone is traversed by fractures. Planar, curving, and irregular surfaces are well represented, and, in places, they are abundant and closely spaced. All prominent fractures and many of the minor and discontinuous ones are shown in the sections of Figure 2.5-12. Also shown in these sections are all recognized slip joints, shear surfaces, and faults, i.e., all surfaces along which the bedrock has been displaced. Such features are most abundant in Trenches A and C near their intersection, in Trench D west of the intersection with Trench A, and near the northerly end of Trench B.

Most of the surfaces of movement are hairline features with or without thin films of clay and/or gypsum. Displacements range from a small fraction of an inch to several inches. The other surfaces are more prominent, with well-defined zones of gouge and fine-grained breccia ordinarily 1/8 inch or less in thickness. Such zones were observed to reach a maximum thickness of nearly 1/2 inch along two small faults, but only as local lenses or pockets. Exposures were not sufficiently extensive in three dimensions for definitely determining the magnitude of slip along the more prominent faults, but all of these breaks appeared to be minor features. Indeed, no expressions of major faulting were recognized in any of the trenches despite careful search, and the continuous bedrock exposures precluded the possibility that such features could have been readily overlooked.

A northeast-trending fault that appears on the sea cliff at the mouth of Diablo Canyon projects toward the ground in the northernmost part of the power plant site, as noted in

a foregoing section. No zone of breaks as prominent as this one was identified in the trench exposures, and any distinct northeastward continuation of the fault would necessarily lie north of the trenched ground. Alternatively, this fault might well separate northeastward into several smaller faults; some or all of these could correspond to some or all of the breaks mapped in the northerly parts of Trenches A and B.

3. Terrace Deposits

Marine terrace deposits of Pleistocene age form a cover, generally 2 to 5 feet thick, over the bedrock that lies beneath the power plant site. This cover was observed to be continuous in Trench C and the northerly part of Trench A, and to be nearly continuous in the other two trenches. Its lithology is highly variable, and includes bouldery rubble, loose beach sand, pebbly silt, silty to clayey sand with abundant shell fragments, and soft clay derived from underlying tuffaceous rocks. Nearly all of these deposits are at least sparsely fossiliferous, and, in a few places, they consist mainly of shells and shell fragments. Vertebrate fossils, chiefly vertebral and rib materials representing large marine mammals, are present locally; recognized occurrences are designated by the symbol X in the sections of Figure 2.5-12.

At the easterly ends of Trenches C and D, the marine deposits intergrade and intertongue in a landward direction with thicker and coarser accumulations of poorly sorted debris. This material evidently is talus that was formed along the base of an ancient sea cliff or other shoreline slope. In some places, the marine deposits are overlain by nonmarine terrace sediments with a sharp break, but elsewhere the contact between these two kinds of deposits is a dark colored zone, a few inches to as much as 2 feet thick, that appears to represent a soil developed on the marine section. Fragments of these soily materials appear here and there in the basal parts of the nonmarine section.

The nonmarine sediments that were exposed in Trenches B, C, and D and in the northerly part of Trench A are mainly alluvial deposits derived in ancient times from Diablo Canyon. They consist of numerous tabular fragments of Monterey rocks in a relatively dark colored silty to clayey matrix, and, in general, they are distinctly bedded and moderately to highly compact. As indicated in the sections of Figure 2.5-12, they thicken progressively in a north-northeastward direction, i.e., toward their principal source, the ancient mouth of Diablo Canyon.

Slump, creep, and slope-wash deposits, which constitute the youngest major element of the terrace section, overlie the alluvial fan gravels and locally are interlayered with them. Where the gravels are absent, as in the southerly part of Trench A, this younger cover rests directly upon bedrock. It is loose and uncompacted, internally chaotic, and is composed of fragments of Monterey rocks in an abundant dark colored clayey matrix.

All the terrace deposits are soft and unconsolidated, and hence are much less resistant to erosion than is the underlying bedrock. Those appearing along the walls of exploratory trenches were exposed to heavy rainfall during two storms, and showed

some tendency to wash and locally to rill. Little slumping and no gross failure were noted in the trenches, however, and it was not anticipated that these materials would cause special problems during construction of a power plant.

4. Interface Between Bedrock and Surficial Deposits

As once exposed continuously in the exploratory trenches, the contact between bedrock and overlying terrace deposits represents a broad wave-cut platform of Pleistocene age. This buried surface of ancient marine erosion ranges in altitude between extremes of 82 and 100 feet, and more than three-fourths of it lies within the more limited range of 90 to 100 feet. It terminates eastward against a moderately steep shoreline slope, the lowest parts of which were encountered at the extreme easterly ends of Trenches C and D, and beyond this slope is an older buried bench at an altitude of 120 to 130 feet.

Available exposures indicate that the configuration of the erosional platform is markedly similar, over a wide range of scales, to that of the platform now being cut approximately at sea level along the present coast. Grossly viewed, it slopes very gently in a seaward (westerly) direction and is marked by broad, shallow channels and by upward projections that must have appeared as low spines and reefs when the bench was being formed (refer to Figures 2.5-12 and 2.5-13). The most prominent reef, formerly exposed in Trenches B and D at and near their intersection, is a wide, westerly-trending projection that rises 5 to 15 feet above neighboring parts of the bench surface. It is composed of massive sandstone that was relatively resistant to the ancient wave erosion.

As shown in the sections and sketches of Figure 2.5-12, the surface of the platform is nearly planar in some places but elsewhere is highly irregular in detail. The small-scale irregularities, generally 3 feet or less in vertical extent, including knob, spine, and rib like projections and various wave-scoured pits, crevices, notches, and channels. The upward projections clearly correspond to relatively hard, resistant beds or parts of beds in the sandstone section. The depressions consistently mark the positions of relatively soft silty or shaley sandstone, of very soft tuffaceous rocks, or of extensively jointed rocks. The surface traces of most faults and some of the most prominent joints are in sharp depressions, some of them with overhanging walls. All these irregularities of detail have modern analogues that can be recognized on the bedrock bench now being cut along the margins of Diablo Cove.

The interface between bedrock and overlying surficial deposits is of particular interest in the trenched area because it provides information concerning the age of youngest fault movements within the bedrock section. This interface is nowhere offset by faults revealed in the trenches, but instead has been developed irregularly across these faults after their latest movements. The consistency of this general relationship was established by highly detailed tracing and inspection of the contact as freshly exhumed by scaling of the trench walls. Gaps in exposure of the interface necessarily were developed at the four intersections of trenches; at these localities, the bedrock was carefully laid bare so that all joints and faults could be recognized and traced along the

trench floors to points where their relationships with the exposed interface could be determined.

Corroborative evidence concerning the age of the most recent fault displacements stems from the marine deposits that overlie the bedrock bench and form the basal part of the terrace section. That these deposits rest without break across the traces of faults in the underlying bedrock was shown by the continuity of individual sedimentary beds and lenses that could be clearly recognized and traced.

Further, some of the faults are directly capped by individual boulders, cobbles, pebbles, shells, and fossil bones, none of which have been affected by fault movements. Thus, the most recent fault displacements in the plant site area occurred prior to marine planation of the bedrock and deposition of the overlying terrace sediments. As pointed out earlier, the age of the most recent faulting in this area is therefore at least 80,000 years and more probably at least 120,000 years. It might be millions of years.

2.5.2.2.5.6 Exploratory Trenching Program, Unit 2 Site

Eight additional trenches were cut beneath the main terrace surface south of Diablo Canyon (refer to Figure 2.5-13) in order to extend the scope of subsurface exploration to include all ground in the Unit 2 plant site. As in the area of the Unit 1 plant site, the trenches formed two groups; those in each group were parallel with one another and were oriented nearly normal to those of the other group. The excavations pertinent to the Unit 2 plant site can be briefly identified as follows:

1. North-northwest Alignment

    a. Trench EJ, 240 feet long, was a southerly extension of older Trench BE (originally designated as Trench B).

    b. Trench WU, 1300 feet long, extended southward from Trench DG (originally designated as Trench D), and its northerly part lay about 65 feet east of Trench EJ. The northernmost 485 feet of this trench was mapped in connection with the Unit 2 trenching program.

    c. Trench MV, 700 feet long, lay about 190 feet east of Trench WU. The northernmost 250 feet of this trench was mapped in connection with the Unit 2 trenching program.

    d. Trench AF (originally designated as Trench A) was mapped earlier in connection with the detailed study of the Unit 1 plant site. A section for this trench, which lay about 140 feet west of Trench EJ, was included with others in the report on the Unit 1 trenching program.

2. East-northeast Alignment

    a. Trench KL, about 750 feet long, lay 180 feet south of Trench DG (originally designated as Trench D) and crossed Trenches AF, EJ, and WU.

    b. Trench NO, about 730 feet long, lay 250 feet south of Trench KL and crossed Trenches AF, WU, and MV.

These trenches, or parts thereof, covered the area intended for the Unit 2 power plant construction, and the intersection of Trenches WU and KL coincided in position with the center of the Unit 2 nuclear reactor structure.

All five additional trenches, throughout their aggregate length of nearly half a mile, revealed a section of surficial deposits and underlying Monterey bedrock that corresponded to the two-ply sequence of surficial deposits and Monterey strata exposed in the older trenches and along the sea cliff in nearby Diablo Cove. The trenches ranged in depth from 10 feet (or less along their approach ramps) to nearly 35 feet, and all had sloping sides that gave way downward to essentially vertical walls in the bedrock encountered 3 to 22 feet above their floors. To facilitate detailed geologic mapping, the easterly walls of Trenches EJ, WU, and MV and the southerly walls of Trenches KL and NO were trimmed to near-vertical slopes extending upward from the trench floors to levels well above the top of bedrock. These walls subsequently were scaled back by means of hand tools in order to provide fresh, clean exposures prior to mapping of the contact between bedrock and overlying unconsolidated materials.

The geologic sections shown in Figures 2.5-12 and 2.5-13 correspond in position to the vertical portions of the mapped trench walls. Relationships exposed at higher levels on sloping portions of the trench walls have been projected to the vertical planes of the sections. Centerlines of intersecting trenches are shown for convenience, but the planes of the geologic sections do not contain the centerlines of the respective trenches.

3. Bedrock

The bedrock that was continuously exposed in the lowest parts of all the exploratory trenches lies within a part of the Monterey Formation characterized by a preponderance of sandstone. It corresponds to the portion of the section that crops out along the sea cliff southward from the mouth of Diablo Canyon. The sandstone is light to medium gray where fresh, and light gray to buff and reddish brown where weathered. It ranges from silty to markedly tuffaceous, with tuffaceous units tending to dominate southward and southwestward from the central parts of the trenched area (refer to geologic section in Figure 2.5-13). Much of the sandstone is thin-bedded and platy, but the most siliceous parts of the section are characterized by a strata a foot or more in thickness. Individual beds commonly are well defined by adjacent thin layers of more silty material.

Bedding is less distinct in the more tuffaceous parts of the section, some of which seem to be almost massive. These rocks typically are broken by numerous tight fractures disposed at high angles to one another so that, where weathered, their appearance is coarsely blocky rather than layered.

As broadly indicated in the geologic sections, the sandstone ranges from very hard to moderately soft, and some of it feels slightly punky when struck with a pick. All of it, however, is firm and very compact. In general, the most platy parts of the sequence are relatively hard, but the hardest and soundest rock in the area is thick-bedded to almost massive sandstone of the kind at and immediately north of the site for the intended reactor structure. This resistant rock is well exposed as distinct low ridges on the nearby hillslope adjoining the main terrace area.

Tuff, consisting chiefly of altered volcanic glass, is abundant within the bedrock section. Also widely scattered, but much less abundant, is tuff breccia, consisting typically of small fragments of older tuff, pumice, or Monterey rocks in a matrix of fresh to altered volcanic glass. These materials, which form sills, dikes, and highly irregular intrusive masses, are generally light gray to buff, gritty, and compact but distinctly softer than much of the enclosing sandstone. Individual bodies range from stringers less than a quarter of an inch thick to bulbous or mushroom-shaped masses with maximum exposed dimensions measured in tens of feet. As shown on the geologic sections, they are abundant in all the trenches.

These volcanic rocks probably are related to the Obispo Tuff, large masses of which are well exposed west and south of the trenched ground. The bodies exposed in the trenches doubtless represent a rather lengthy period of Miocene volcanism, during which the Monterey strata were repeatedly invaded by both tuff and tuff breccia. Indeed, several of the mapped tuff units were themselves intruded by dikes of younger tuff, as shown, for example, in Sections KL and NO.

4. Bedrock Structure

The stratification of the Monterey rocks dips northward wherever it was observable in the trenches, in general, at angles of 45 to 85°. The steepness of dip increases progressively from north to south in the trenched ground, a relationship also noted along the sea cliff southward from the mouth of Diablo Canyon. Thus, the bedrock beneath the power plant site evidently lies on the southerly flank of the major syncline that was described previously. Zones of convolution and other expressions of locally intense folding were not recognized, and they probably are much less common in this general part of the section than in other (previously described) parts that include intervals of softer and more shaley rocks.

Much of the sandstone is traversed by fractures. Planar, curving, and irregular surfaces are well represented, and in places they are abundant and closely spaced. All prominent fractures and nearly all of the minor and discontinuous ones are shown on the geologic sections (refer to Figure 2.5-13). Also shown in these sections are all

recognized shear surfaces, faults, and other discontinuities along which the bedrock has been displaced. Such features are nowhere abundant in the trench exposures.

Most of the surfaces of movement are hairline breaks with or without thin films of clay, calcite, and/or gypsum. Displacements range from a small fraction of an inch to several inches. A few other surfaces are more prominent, with well-defined zones of fine-grained breccia and/or infilling mineral material ordinarily 1/8 inch or less in thickness. Such zones were observed to reach maximum thicknesses of 3/8 to 1/2 inch along three small faults, but only as local lenses or pockets.

Exposures are not sufficiently extensive in three dimensions for definitely determining the magnitude of slip along all the faults, but for most of them it is plainly a few inches or less. None of them appears to be more than a minor break in a bedrock section that has been folded on a large scale. Indeed, no expressions of major faulting were recognized in any of the trenches despite careful search, and the continuous bedrock exposures preclude the possibility that such features could be readily overlooked.

Most surfaces of past movement probably were active during times when the Monterey rocks were being deformed by folding, when rupture and some differential movements would be expected in a section comprising such markedly differing rock types. Some of the fault displacements may well have been older, as attested in two places by relationships involving small faults, the Monterey rocks, and tuff.

In Trench WU south of Trench KL, for example, sandstone beds were seen to have been offset about a foot along a small fault. A thin sill of tuff occupies the same stratigraphic horizon on opposite sides of this fault, but the sill has not been displaced by the fault. Instead, the tuff occupies a short segment of the fault to effect the slight jog between its positions in the strata on either side. Intrusion of the tuff plainly postdated all movements along this fault.

5. Terrace Deposits

Marine terrace deposits of Pleistocene age form covers, generally 2 to 5 feet thick, but locally as much as 12 feet thick, over the bedrock that lies beneath the Unit 2 plant site. These covers were observed to be continuous in some parts of all the trenches, and thin and discontinuous in a few other parts. Elsewhere, the marine sediments were absent altogether, as in the lower and more southerly parts of Trenches EJ and WU and in the lower and more westerly parts of Trenches KL and NO.

The range in lithology of these deposits is considerable, and includes bouldery rubble, gravel composed of well-rounded fragments of shells and/or Monterey rocks, beach sand, loose accumulations of shells, pebbly silt, silty to clayey sand with abundant shell fragments, and soft clay derived from underlying tuffaceous rocks. Nearly all of the deposits are at least sparsely fossiliferous, and many of them contain little other than shell material. Vertebrate fossils, chiefly vertebral and rib materials representing large marine mammals, are present locally.

The trenches in and near the site of the reactor structure exposed a buried narrow ridge of hard bedrock that once projected westward as a bold promontory along an ancient sea coast, probably at a time when sea level corresponded approximately to the present 100 foot contour (refer to Figure 2.5-11). Along the flanks of this promontory and the face of an adjoining buried sea cliff that extends southeastward through the area in which Trenches MV and NO intersected, the marine deposits intergrade and intertongue with thicker and coarser accumulations of poorly sorted debris. This rubbly material evidently is talus that was formed and deposited along the margins of the ancient shoreline cliff.

Similar gradations of older marine deposits into older talus deposits were observable at higher levels in the easternmost parts of Trenches KL and NO, where the rubbly materials doubtless lie against a more ancient sea cliff that was formed when sea level corresponded to the present 140 foot contour. The cliff itself was not exposed, however, as it lies slightly beyond the limits of trenching.

In many places, the marine covers are overlain by younger nonmarine terrace sediments with a sharp break, but elsewhere the contact between these two kinds of deposits is a zone of dark colored material, a few inches to as much as 6 feet thick, that represents weathering and development of soils on the marine sections. Fragments of these soily materials are present here and there in the basal parts of the nonmarine section. Over large areas, the porous marine deposits have been discolored through infiltration by fine-grained materials derived from the overlying ancient soils.

The nonmarine accumulations, which form the predominant fraction of the entire terrace cover, consist mainly of slump, creep, and slope-wash debris that is characteristically loose, uncompacted, and internally chaotic. These relatively dark colored deposits are fine grained and clayey, but they contain sparse to very abundant fragments of Monterey rocks generally ranging from less than an inch to about 2 feet in maximum dimension. Toward Diablo Canyon they overlie and, in places, intertongue with silty to clayey gravels that are ancient contributions from Diablo Creek when it flowed at levels much higher than its present one. These "dirty" alluvial deposits appeared only in the most northerly parts of the more recently trenched terrace area, and they are not distinguished from other parts of the nonmarine cover on the geologic sections (refer to Figure 2.5-13).

All the terrace deposits are soft and unconsolidated, and hence are much less resistant to erosion than is the underlying bedrock. Those appearing along the walls of the exploratory trenches showed some tendency to wash and locally to rill when exposed to heavy rainfall, but little slumping and no gross failure were noted in the trenches.

6. Interface Between Bedrock and Surficial Deposits

As exposed continuously in the exploratory trenches, the contact between bedrock and overlying terrace deposits represents two wave-cut platforms and intervening slopes, all of Pleistocene age. The broadest surface of ancient marine erosion ranges in altitude

from 80 to 105 feet, and its shoreward margin, at the base of an ancient sea cliff, lies uniformly within 5 feet of the 100 foot contour. A higher, older, and less extensive marine platform ranges in altitude from 130 to 145 feet, and most of it lies within the ranges of 135 to 140 feet. As noted previously, these are two of several wave-cut benches in this coastal area, each of which terminates eastward against a cliff or steep shoreline slope and westward at the upper rim of a similar but younger slope.

Available exposures indicate that the configurations of the erosional platforms are markedly similar, over a wide range of scales, to that of the platform now being cut approximately at sea level along the present coast. Grossly viewed, they slope very gently in a seaward (westerly) direction and are marked by broad, shallow channels and by upward projections that must have appeared as low spines and reefs when the benches were being formed. The most prominent reefs, which rise from a few inches to about 5 feet above neighboring parts of the bench surfaces, are composed of hard, thick-bedded sandstone that was relatively resistant to ancient wave erosion.
As shown in the geologic sections (refer to Figure 2.5-13), the surfaces of the platforms are nearly planar in some places but elsewhere are highly irregular in detail. The small scale irregularities, generally 3 feet or less in vertical extent, include knob-, spine-, and rib-like projections and various wave-scoured pits, notches, crevices, and channels. Most of the upward projections closely correspond to relatively hard, resistant beds or parts of beds in the sandstone section. The depressions consistently mark the positions of relatively soft silty or shaley sandstone, of very soft tuffaceous rocks, or of extensively jointed rocks. The surface traces of most faults and some of the most prominent joints are in sharp depressions, some of them with overhanging walls. All these irregularities of detail have modern analogues that can be recognized on the bedrock bench now being cut along the margins of Diablo Cove.

The interface between bedrock and overlying surficial deposits provides information concerning the age of youngest fault movements within the bedrock section. This interface is nowhere offset by faults that were exposed in the trenches, but instead has been developed irregularly across the faults after their latest movements. The consistency of this general relationship was established by highly detailed tracing and inspection of the contact as freshly exhumed by scaling of the trench walls. Gaps in exposure of the interface necessarily were developed at the intersections of trenches as in the exploration at the Unit 1 site. At such localities, the bedrock was carefully laid bare so that all joints and faults could be recognized and traced along the trench floors to points where their relationships with the exposed interface could be determined.

Corroborative evidence concerning the age of the most recent fault displacements stems from the marine deposits that overlie the bedrock bench and form a basal part of the terrace section. That these deposits rest without break across the traces of faults in the underlying bedrock was shown by the continuity of individual sedimentary beds and lenses that could be clearly recognized and traced. As in other parts of the site area, some of the faults are directly capped by individual boulders, cobbles, pebbles, shells, and fossil bones, none of which have been affected by fault movements. Thus, the

most recent fault displacements in the plant site area occurred before marine planation of the bedrock and deposition of the overlying terrace sediments.

The age of the most recent faulting in this area is therefore at least 80,000 years. More probably, it is at least 120,000 years, the age most generally assigned to these terrace deposits along other parts of the California coastline. Evidence from the higher bench in the plant site area indicates a much older age, as the unfaulted marine deposits there are considerably older than those that occupy the lower bench corresponding to the 100 foot terrace. Moreover, it can be noted that ages thus determined for most recent fault displacements are minimal rather than absolute, as the latest faulting actually could have occurred millions of years ago.

During the Unit 2 exploratory trenching program, special attention was directed to those exposed parts of the wave-cut benches where no marine deposits are present, and hence where there are no overlying reference materials nearly as old as the benches themselves. At such places, the bedrock beneath each bench has been weathered to depths ranging from less than 1 inch to at least 10 feet, a feature that evidently corresponds to a lengthy period of surface exposure from the time when the bench was abandoned by the sea to the time when it was covered beneath encroaching nonmarine deposits derived from hillslopes to the east.

Stratification and other structural features are clearly recognizable in the weathered bedrock, and they obviously have exercised some degree of control over localization of the weathering. Moreover, in places where upward projections of bedrock have been gradually bent or rotationally draped in response to weathering and creep, their contained fractures and surfaces of movement have been correspondingly bent. Nowhere in such a section that has been disturbed by weathering have the materials been cut by younger fractures that would represent straight upward projections of breaks in the underlying fresh rocks. Nor have such fractures been observed in any of the overlying nonmarine terrace cover.

Thus, the minimum age of any fault movement in the plant site area is based on compatible evidence from undisplaced reference features of four kinds: (a) Pleistocene wave-cut benches developed on bedrock, (b) immediately overlying marine deposits that are very slightly younger, (c) zones of weathering that represent a considerable span of subsequent time, and (d) younger terrace deposits of nonmarine origin.

2.5.2.2.5.7 Bedrock Geology of the Plant Foundation Excavations

Bedrock was continuously exposed in the foundation excavations for major structural components of Unit 1 and Unit 2. Outlines and invert elevations of these large openings, which ranged in depth from about 5 to nearly 90 feet below the original ground surface, are shown in Figures 2.5-15 and 2.5-16. The complex pattern of straight and curved walls with various positions and orientations provided an excellent three-dimensional representation of bedrock structure. These walls were photographed at large scales as construction progressed, and the photographs were used directly as a

geologic mapping base. The largest excavations also were mapped in detail on a surveyed planimetric base.

Geologic mapping of the plant excavations confirmed the conclusions based on earlier investigations at the site. The exposed section of Monterey strata was found to correspond in lithology and structure to what had been predicted from exposures at the mouth of Diablo Canyon, along the sea cliffs in nearby Diablo Cove, and in the test trenches. Thus, the plant foundation is underlain by a moderately to steeply north-dipping sequence of thin to thick bedded sandy mudstone and fine-grained sandstone. The rocks at these levels are generally fresh and competent, as they lie below the zone of intense near-surface weathering.

Several thin interbeds of claystone were exposed in the southwestern part of the plant site in the excavations for the Unit 2 turbine-generator building, intake conduits, and outlet structure. These beds, which generally are less than 6 inches thick, are distinctly softer than the flanking sandstone. Some of them show evidence of internal shearing.

Layers of tuffaceous sandstone and sills, dikes, and irregular masses of tuff and tuff breccia are present in most parts of the foundation area. They tend to increase in abundance and thickness toward the south, where they are relatively near the large masses of Obispo Tuff exposed along the coast south of the plant site.

Some of the tuff bodies are conformable with the enclosing sandstone, but others are markedly discordant. Most are clearly intrusive. Individual masses, as exposed in the excavations, range in thickness from less than 1 inch to about 40 feet. The tuff breccia, which is less abundant than the tuff, consists typically of small fragments of older tuff, pumice, or Monterey rocks in a matrix of fresh to highly altered volcanic glass. At the levels of exposure in the excavations, both the tuff and tuff breccia are somewhat softer than the enclosing sandstone.

The stratification of the Monterey rocks dips generally northward throughout the plant foundation area. Steepness of dips increases progressively and, in places, sharply from north to south, ranging from 10 to 15° on the north side of Unit 1 to 75 to 80° in the area of Unit 2. A local reversal in direction of dip reflects a small open fold or warp in the Unit 1 area. The axis of this fold is parallel to the overall strike of the bedding, and strata on the north limb dip southward at angles of 10 to 15°. The more general steepening of dips from north to south may reflect buttressing by the large masses of Obispo Tuff south of the plant site.

The bedrock of the plant area is traversed throughout by fractures, including various planar, broadly curving, and irregular breaks. A dominant set of steeply dipping to vertical joints trends northerly, nearly normal to the strike of bedding. Other joints are diversely oriented with strikes in various directions and dips ranging from 10° to vertical. Many fractures curve abruptly, terminate against other breaks, or die out within single beds or groups of beds.

Most of the joints are widely spaced, ranging from about 1 to 10 feet apart, but within several northerly trending zones, ranging in width from 10 to 20 feet, closely spaced near vertical fractures give the rocks a blocky or platy appearance. The fracture and joint surfaces are predominantly clean and tight, although some irregular ones are thinly coated with clay or gypsum. Others could be traced into thin zones of breccia with calcite cement.

Several small faults were mapped in the foundation excavations for Unit 1 and the outlet structure. A detailed discussion of these breaks and their relationship to faults that were mapped earlier along the sea cliff and in the exploratory trenches is included in the following section.

2.5.2.2.5.8 Relationships of Faults and Shear Surfaces

Several subparallel breaks are recognizable on the sea cliff immediately south of Diablo Canyon, where they transect moderately thick-bedded sandstone of the kind exposed in the exploratory trenches to the east. These breaks are nearly concordant with the bedrock stratification but, in general, they dip more steeply (refer to detailed structure section, Figure 2.5-14) and trend more northerly than the stratification. Their trend differs significantly from much of their mapped trace, as the trace of each inclined surface is markedly affected by the local steep topography. The indicated trend, which projects eastward toward ground north of the Unit 1 reactor site, has been summed from numerous individual measurements of strike on the sea cliff exposures, and it also corresponds to the trace of the main break as observed in nearly horizontal outcrop within the tidal zone west of the cliff.

The structure section shows all recognizable surfaces of faulting and shearing in the sea cliff that are continuous for distances of 10 feet or more. Taken together, they represent a zone of dislocation along which rocks on the north have moved upward with respect to those on the south as indicated by the attitude and roughness sense of slickensides. The total amount of movement cannot be determined by any direct means, but it probably is not more than a few tens of feet and could well be less than 10 feet. This is suggested by the following observed features:

(1) All individual breaks are sharp and narrow, and the strata between them are essentially undeformed except for their gross inclination.

(2) Some breaks plainly die out as traced upward along the cliff surface, and others merge with adjoining breaks. At least one well-defined break butts downward against a cross-break, which in turn butts upward against a break that branches and dies out approximately 20 feet away (refer to structure section, Figure 2.5-14, for details).

(3) Nearly all the breaks curve moderately to abruptly in the general direction of movement along them.

(4) Most of the breaks are little more than knife-edge features along which rock is in direct contact with rock, and others are marked by thin films of gouge. Maximum thickness of gouge anywhere observed is about 1/2 inch, and such exceptional occurrences are confined to short curving segments of the main break at the southerly margin of the zone.

(5) No fault breccia is present; instead, the zone represents transection of otherwise undeformed rocks by sharply-defined breaks. No bedrock unit is cut off and juxtaposed against a unit of different lithology along any of the breaks.

(6) Local prominence of the exposed breaks, and especially the main one, is due to slickensides, surface coatings of gypsum, and iron-oxide stains rather than to any features reflecting large-scale movements.

This zone of faulting cannot be regarded as a major tectonic element, nor is it the kind of feature normally associated with the generation of earthquakes. It appears instead to reflect second-order rupturing related to a marked change in dip of strata to the south, and its general sense of movement is what one would expect if the breaks were developed during folding of the Monterey section against what amounts to a broad buttress of Obispo Tuff farther south (refer to geologic map, Figure 2.5-8). That the fault and shear movements were ancient is positively indicated by upward truncation of the zone at the bench of marine erosion along the base of the overlying terrace deposits.

As indicated earlier, bedrock was continuously exposed along several exploratory trenches. This bedrock is traversed by numerous fractures, most of which represent no more than rupture and very small amounts of simple separation. The others additionally represent displacement of the bedrock, and the map in Figure 2.5-14 shows every exposed break in the initial set of trenches along which any amount of displacement could be recognized or inferred.

That the surfaces of movement constitute no more than minor elements of the bedrock structure was verified by detailed mapping of the large excavations for the plant structures. Detailed examination of the excavation walls indicated that the faults exposed in the sea cliff south of Diablo Canyon continue through the rock under the Unit 1 turbine-generator building, where they are expressed as three subparallel breaks with easterly trend and moderately steep northerly dips (refer to Figure 2.5-15). Stratigraphic separation along these breaks ranges from a few inches to nearly 5 feet, and, in general, decreases eastward on each of them. They evidently die out in the ground immediately west of the containment excavation, and their eastward projections are represented by several joints along which no offsets have occurred. Such joints, with eastward trend and northward dip, also are abundant in some of the ground adjacent to the faults on the south (refer to Figure 2.5-15).

The easterly reach of the Diablo Canyon sea cliff faults apparently corresponds to the two most northerly of the north-dipping faults mapped in Trench A (refer to Figure 2.5-

14). Dying out of these breaks, as established from subsequent large excavations in the ground east of where Trench A was located, explains and verifies the absence of faults in the exposed rocks of Trenches B and C. Other minor faults and shear surfaces mapped in the trench exposures could not be identified in the more extensive exposures of fresher rocks in the Unit 1 containment and turbine-generator building excavations. The few other minor faults that were mapped in these large excavations evidently are not sufficiently continuous to have been present in the exploratory trenches.

2.5.2.2.6 Site Engineering Properties

2.5.2.2.6.1 Field and Laboratory Investigations

In order to determine anticipated ground accelerations at the site, it was necessary to conduct field surveys and laboratory testing to evaluate the engineering properties of the materials underlying the site.

Bore holes were drilled into the rock upon which PG&E Design Class I structures are founded. The borings were located at or near the intersection of the then existing Unit 1 exploration trenches. Refer to Figures 2.5-11 through 2.5-13 for exploratory trenching programs and boring locations. These holes were cored continuously and representative samples were taken from the cores and submitted for laboratory testing.

The field work also included a reconnaissance to evaluate physical condition of the rocks that were exposed in trenches, and samples were collected from the ground surface in the trenches for laboratory testing. These investigations included seismic refraction measurements across the ground surface and uphole seismic measurements in the various drill holes to determine shear and compressional velocities of vertically propagated waves.

Laboratory testing, performed by Woodward-Clyde-Sherard & Associates, included unconfined compression tests, dynamic elastic moduli tests under controlled stress conditions, density and water content determinations, and Poisson's ratio tests. Tests were also carried out by Geo-Recon, Incorporated, to determine seismic velocities on selected rock samples in the laboratory. The results of seismic measurements in the field were used to construct a three-dimensional model of the subsurface materials beneath the plant site showing variations of shear wave velocity and compressional wave velocity both laterally and vertically. The seismic velocity data and elastic moduli determined from laboratory testing were correlated to determine representative values of elastic moduli necessary for use in dynamic analyses of structures.

Details of field investigations and results of laboratory testing and correlation of data are contained in Appendices 2.5A and 2.5B of Reference 27 in Section 2.3.

2.5.2.2.6.2 Summary and Correlation of Data

The foundation material at the site can be categorized as a stratified sequence of fine to very fine grained sandstone deeply weathered to an average elevation of 75 to 80 feet, MSL. The rock is closely fractured, with tightly closed or healed fractures generally present below elevation 75 feet. Compressional and shear wave velocity interfaces generally are at an average elevation of 75 feet, correlating with fracture conditions.

Time-distance plots and seismic velocity profiles presenting results of each seismic refraction line and time depth plots with results for each uphole seismic survey are included in Appendices 2.5A and 2.5B of Reference 27 in Section 2.3. Compressional wave velocities range from 2350 to 5700 feet per second and shear wave velocities from 1400 to 3600 feet per second as determined by the refraction survey. These same parameters range from 2450 to 9800 and 1060 to 6050 feet per second as determined by the uphole survey. For the Hosgri Evaluation an average shear wave velocity of 3600 feet per second is used at the foundation grade. An isometric diagram summarizing results of the refraction survey for Unit 1 is also included in Appendix 2.5A of Reference 27 in Section 2.3.

Table 1 of Appendix 2.5A of Reference 27 of Section 2.3 shows calculations of Poisson's ratio and Young's Modulus based on representative compressional and shear wave velocities from the field geophysical investigations and laboratory measurements of compressional wave velocities. Table 2 of Appendix 2.5A of the same reference presents laboratory test results including density, unconfined compressive strength, Poisson's ratio and calculated values for compressional and shear wave velocities, shear modulus, and constrained modulus. Secant modulus values in Table 2 were determined from cyclic stress-controlled laboratory tests.

Compressional wave velocity measurements were made in the laboratory of four selected core samples and three hand specimens from exposures in the trench excavations. Measured values ranged from 5700 to 9500 feet per second. A complete tabulation of these results can be found in Appendix 2.5A of Reference 27 of Section 2.3.

2.5.2.2.6.3 Dynamic Elastic Moduli and Poisson's Ratio

Laboratory test results are considered to be indicative of intact specimens of foundation materials. Field test results are considered to be indicative of the gross assemblage of foundation materials, including fractures and other defects. Load stress conditions are obtained by evaluating cyclic load tests. In-place load stress conditions and confinement of the material at depth are also influential in determining elastic behavior. Because of these considerations, originally recommended representative values for Young's Modulus of Elasticity and Poisson's ratio for the site were:

Depth Below Bottom of Trench	E	δ
0 to approximately 15 feet	44×10^6 lb/ft^2	0.20
Below 15 feet	148×10^6 lb/ft^2	0.18

A single value was selected for Young's Modulus below 15 feet because the initial analyses of the seismic response of the structures utilized a single value that was considered representative of the foundation earth materials as a whole.

More detailed seismic analyses were performed subsequent to the initial analyses. These analyses, discussed in Section 3.7.2, incorporated the finite element method and made it possible to model the rock beneath the plant site in a more refined manner by accounting for changes in properties with increasing depth. To determine the refined properties of the founding materials for these analyses, the test data were reviewed and consideration was given to: (a) strain range of the materials at the site, (b) overburden pressure and confinement, (c) load imposed by the structure, (d) observation of fracture condition and geometry of the founding rock in the open excavation, (e) decreases in Poisson's ratio with depth, and (f) significant advances in state-of-the-art techniques of testing and analysis in rock mechanics that had been made and which resulted in considerably more being known about the behavior of rock under seismic strains in 1970 than in 1968 or 1969.

For the purposes of developing the mathematical models that represented the rock mass, the foundation was divided into horizontal layers based on: (a) the estimated depth of disturbance of the foundation rock below the base of the excavation,
(b) changes in rock type and physical condition as determined from bore hole logs,
(c) velocity interfaces as determined by refraction geophysical surveys, and
(d) estimated depth limit of fractures across which movement cannot take place because of confinement and combined overburden and structural load. Based on these considerations, the founding material properties as shown in Figure 2.5-19 were selected as being representative of the physical conditions in the founding rock.

2.5.2.2.6.4 Engineered Backfill

Backfill operations were carefully controlled to ensure stability and safety. All engineered backfill was placed in lifts not exceeding 8 inches in loose depth. Yard areas and roads were compacted to 95 percent relative compaction as determined by the method specified in ASTM D1557. Rock larger than 8 inches in its largest dimension that would not break down under the compactors was not permitted. Figures 2.5-17 and 2.5-18 show the plan and profile view of excavation and backfill for major plant structures.

2.5.2.2.6.5 Foundation Bearing Pressures

PG&E Design Class I structures were analyzed to determine the foundation pressures resulting from the combination of dead load, live load, and the DDE. The maximum

pressure was found to be 158 ksf and occurs under the containment structure foundation slab. This analysis assumed that the lateral seismic shear force will be transferred to the rock at the base of the slab which is embedded 11 feet into rock. This computed bearing pressure is considered conservative in that no passive lateral pressure was assumed to act on the sides of the slab. Based on the results of the laboratory tests of unconfined compressive strength of representative samples of rock at the site, which ranged from 800 to 1300 ksf, the calculated foundation pressure is well below the ultimate in situ rock bearing capacity.

Adverse hydrologic effects on the foundations of PG&E Design Class I structures (there are no PG&E Design Class I embankments) can be safely neglected at this site, since PG&E Design Class I structures are founded on a substantial layer of bedrock, and the groundwater level lies well below grade, at a level corresponding to that of Diablo Creek. Additionally, the computed factors of safety (minimum of 5 under DDE) of foundation pressures versus unconfined compressive strength of rock are sufficiently high to ensure foundation integrity in the unlikely event groundwater levels temporarily rose to foundation grade.

Soil properties such as grain size, Atterberg limits, and water content need not be considered since PG&E Design Class I structures and PG&E Design Class II structures housing PG&E Design Class I equipment are founded on rock.

2.5.3 VIBRATORY GROUND MOTION

2.5.3.1 Geologic Conditions of the Site and Vicinity

DCPP is situated at the coastline on the southwest flank of the San Luis Range, in the southern Coast Ranges of California. The San Luis Range branches from the main coastal mountain chain, the Santa Lucia Range, in the area north of the Santa Maria Valley and southeast of the plant site, and thence follows an alignment that curves toward the west. Owing to this divergence in structural grain, the range juts out from the regional coastline as a broad peninsula and is separated from the Santa Lucia Range by an elongated lowland that extends southeasterly from Morro Bay and includes Los Osos and San Luis Obispo Valleys. It is characterized by rugged west-northwesterly trending ridges and canyons, and by a narrow fringe of coastal terraces along its southwesterly flank.

Diablo Canyon follows a generally west-southwesterly course from the central part of the range to the north-central part of the terraced coastal strip. Detailed discussions of the lithology, stratigraphy, structure, and geologic history of the plant site and surrounding region are presented in Section 2.5.2.

2.5.3.2 Underlying Tectonic Structures

Evidence pertaining to tectonic and seismic conditions in the region of the DCPP site, developed during the original design phase, is summarized later in the section, and is

illustrated in Figures 2.5-2, 2.5-3, 2.5-4, and 2.5-5. Table 2.5-1 includes a summary listing of the nature and effects of all significant historic earthquakes within 75 miles of the site that have been reported through the end of 1972. Table 2.5-2 shows locations of 19 selected earthquakes that have been investigated by S. W. Smith. Table 2.5-3 lists the principal faults in the region that were identified during the original design phase and indicates major elements of their histories of displacement, in geological time units.

Prior to the start of construction of DCPP, Benioff and Smith (Reference 5) assessed the maximum earthquakes to be expected at the site, and John A. Blume and Associates (References 6 and 7) derived the site vibratory motions that could result from these maximum earthquakes, which form the basis of the DE. An extensive discussion of the geology of the southern Coast Ranges, the western Transverse Ranges, and the adjoining offshore region is presented in Appendix 2.5D of Reference 27 of Section 2.3. Tectonic features of the central coastal region are discussed in Section 2.5.2.1.2, Regional Geologic and Tectonic Setting.

Additional information about the tectonic and seismic conditions was gathered during the Hosgri evaluation and LTSP evaluation phases, as discussed in Sections 2.5.3.9.3 and 2.5.3.9.4, respectively.

2.5.3.3 Behavior During Prior Earthquakes

Physical evidence that indicates the behavior of subsurface materials, strata, and structure during prior earthquakes is presented in Section 2.5.2.2.5. The section presents the findings of the exploratory trenching programs conducted at the site.

2.5.3.4 Engineering Properties of Materials Underlying the Site

A description of the static and dynamic engineering properties of the materials underlying the site is presented in Section 2.5.2.2.6, Site Engineering Properties.

2.5.3.5 Earthquake History

The seismicity of the southern Coast Ranges region is known from scattered records extending back to the beginning of the 19th century, and from instrumental records dating from about 1900. Detailed records of earthquake locations and magnitudes became available following installation of the California Institute of Technology and University of California (Berkeley) seismograph arrays in 1932.

A plot of the epicenters for all large historical earthquakes and for all instrumentally recorded earthquakes of Magnitude 4 or larger that have occurred within 200 miles of DCPP site, through the end of 1972, is given in Figure 2.5-2. Plots of all historically and instrumentally recorded epicenters and all mapped faults within about 75 miles of the site, known through the end of 1972, are shown in Figures 2.5-3 and 2.5-4.

A tabulated list of seismic events through the end of 1972, representing the computer printout from the Berkeley Seismograph Station records, supplemented with records of individual shocks of greater than Magnitude 4 that appear only in the Caltech records, is included as Table 2.5-1. Table 2.5-2 gives a summary of revised epicenters of a representative sample of earthquakes off the coast of California near San Luis Obispo, as determined by S. W. Smith.

2.5.3.6 Correlation of Epicenters With Geologic Structures

Studies of particular aspects of the seismicity of the southern Coast Ranges region have been made by Benioff and Smith, Richter, and Allen. From results of these studies, together with data pertaining to the broader aspects of the geology and seismicity of central and eastern California, it can be concluded that, although the southern Coast Ranges region may be subjected to vibratory ground motion from earthquakes originating along faults as distant as 200 miles or more, the region itself is traversed by faults capable of producing large earthquakes, and that the strongest shaking possible for sites within the region probably would be caused by earthquakes no more than a few tens of miles away. Therefore, only the seismicity of the southern Coast Ranges, the adjacent offshore area, and the western Transverse Ranges is reviewed in detail.

Figure 2.5-3 shows three principal concentrations of earthquake epicenters, three smaller or more diffuse areas of activity, and a scattering of other epicenters, for earthquakes recorded through 1972. The most active areas, in terms of numbers of shocks, are the reach of the San Andreas fault north of about 35°7' latitude, the offshore area near Santa Barbara, and the offshore Santa Lucia Bank area. Notable concentrations of epicenters also are located as occurring in Salinas Valley, at Point San Simeon, and near Point Conception. The scattered epicenters are most numerous in the general vicinities of the most active areas, but they also occur at isolated points throughout the region.

The reliability of the position of instrumentally located epicenters of small shocks in the central California region has been relatively poor in the past, owing to its position between the areas covered by the Berkeley and Caltech seismograph networks. A recent study by Smith, however, resulted in relocation of nineteen epicenters in the coastal and offshore region between the latitudes of Point Arguello and Point Sur. Studies by Gawthrop (Reference 29) and reported in Wagner have led to results that seem to accord generally with those achieved by Smith.

The epicenters relocated by Smith and those recorded by Gawthrop are plotted in Figure 2.5-3. This plot shows that most of the epicenters recorded in the offshore region seem to be spatially associated with faults in the Santa Lucia Bank region, the East Boundary zone, and the San Simeon fault. Other epicenters, including ones for the 1952 Bryson shock, and several smaller shocks originally located in the offshore area, were determined to be centered on or near the Sur-Nacimiento fault north of the latitude of San Simeon.

2.5.3.7 Identification of Active Faults

Faults that have evidence of recent activity and have portions passing within 200 miles of the site, as known through the end of 1972, are identified in Section 2.5.2.1.2.

2.5.3.8 Description of Active Faults

Active faults that have any part passing within 200 miles of the site, as known through the end of 1972, are described in Section 2.5.2.1.2. Additional active faults were identified during the Hosgri and LTSP evaluation phases, as described in Sections 2.5.3.9.3 and 2.5.3.9.4, respectively.

2.5.3.9 Design and Licensing Basis Earthquakes

The seismic design and evaluation of DCPP is based on the earthquakes described in the following four subsections. Refer to Section 3.7 for the design criteria associated with the application of these earthquakes to the SSCs. The DE, DDE, and HE are design bases earthquakes and the LTSP is a licensing bases earthquake.

2.5.3.9.1 Design Earthquake

During the original design phase, Benioff and Smith, in reviewing the seismicity of the region around DCPP site, determined the maximum earthquakes that could reasonably be expected to affect the site. Their conclusions regarding the maximum size earthquakes that can be expected to occur during the life of the reactor are listed below:

(1) Earthquake A: A great earthquake may occur on the San Andreas fault at a distance from the site of more than 48 miles. It would be likely to produce surface rupture along the San Andreas fault over a distance of 200 miles with a horizontal slip of about 20 feet and a vertical slip of 3 feet. The duration of strong shaking from such an event would be about 40 seconds, and the equivalent magnitude would be 8.5.

(2) Earthquake B: A large earthquake on the Nacimiento (Rinconada) fault at a distance from the site of more than 20 miles would be likely to produce a 60 mile surface rupture along the Nacimiento fault, a slip of 6 feet in the horizontal direction, and have a duration of 10 seconds. The equivalent magnitude would be 7.25.

(3) Earthquake C: Possible large earthquakes occurring on offshore fault systems that may need to be considered for the generation of seismic sea waves are listed below:

Location	Length of Fault Break	Slip, feet	Magnitude	Distance to Site
Santa Ynez Extension	80 miles	10 horizontal	7.5	50 miles
Cape Mendocino, NW Extension of San Andreas fault	100 miles	10 horizontal	7.5	420 miles
Gorda Escarpment	40 miles	5 vertical or horizontal	7	420 miles

(4) Earthquake D: Should a great earthquake occur on the San Andreas fault, as described in "A" above, large aftershocks may occur out to distances of about 50 miles from the San Andreas fault, but those aftershocks which are not located on existing faults would not be expected to produce new surface faulting, and would be restricted to depths of about 6 miles or more and magnitudes of about 6.75 or less. The distance from the site to such aftershocks would thus be more than 6 miles.

The available information suggests that the faults in this region can be associated with contrasting general levels of seismic potential. These are as follows:

(1) Level I: Potential for great earthquakes involving surface faulting over distances on the order of 100 miles: seismic activity at this level should occur only on the reach of the San Andreas fault that extends between the locales of Cajon Pass and Parkfield. This was the source of the 1857 Fort Tejon earthquake, estimated to have been of Magnitude 8.

(2) Level II: Potential for large earthquakes involving faulting over distances on the order of tens of miles: seismic activity at this level can occur along offshore faults in the Santa Lucia Bank region (the likely source of the Magnitude 7.3 earthquake of 1927), and possibly along the Big Pine and Santa Ynez faults in the Transverse Ranges.

Although the Rinconada-San Marcos-Jolon, Espinosa, Sur-Nacimiento, and San Simeon faults do not exhibit historical or even Holocene activity indicating this level of seismic potential, the fault dimensions, together with evidence of late Pleistocene movements along these faults, suggest that they may be regarded as capable of generating similarly large earthquakes.

(3) Level III: Potential for earthquakes resulting chiefly from movement at depth with no surface faulting, but at least with some possibility of surface faulting of as much as a few miles strike length and a few feet of slip:

Seismic activity at this level probably could occur on almost any major fault in the southern Coast Ranges and adjacent regions.

From the observed geologic record of limited fault activity extending into Quaternary time, and from the historical record of apparently associated seismicity, it can be inferred that both the greater frequency of earthquake activity and larger shocks from earthquake source structures having this level of seismic potential probably will be associated with one of the relatively extensive faults. Faults in the vicinity of the San Luis Range that may be considered to have such seismic potential include the West Huasna, Edna, and offshore Santa Maria Basin East Boundary zone.

(4) Level IV: Potential for earthquakes and aftershocks resulting from crustal movements that cannot be associated with any near-surface fault structures: such earthquakes apparently can occur almost anywhere in the region.

This information forms the basis of the DE, described in Section 2.5.3.10.1.

2.5.3.9.2 Double Design Earthquake

During the original design phase, in order to assure adequate reserve seismic resisting capability of safety related SSCs, an earthquake producing two-times the acceleration values of the DE was also considered (Reference 51).

2.5.3.9.3 Hosgri Earthquake

In 1976, subsequent to the issuance of the construction permit of Unit 1, PG&E was requested by the NRC to evaluate the plant's capability to withstand a Richter Magnitude 7.5 earthquake centered along an offshore zone of geologic faulting, approximately 3 miles offshore, generally referred to as the "Hosgri fault." Details of the investigations associated with this fault are provided in Appendices 2.5D, 2.5E, and 2.5F of Reference 27 in Section 2.3. An overview is provided in Section 2.5.3.10.3. Note that the Shoreline Fault Zone (refer to Section 2.5.7.1) is considered to be a lesser included case under the Hosgri evaluation (Reference 55).

A further assessment of the seismic potential of faults mapped in the region of DCPP site was made following the extensive additional studies of on and offshore geology and is reported in Appendix 2.5D of Reference 27 of Section 2.3. This was done in terms of observed Holocene activity, to achieve assessment of what seismic activity is reasonably probable, in terms of observed late Pleistocene activity, fault dimensions, and style of deformation.

2.5.3.9.4 1991 Long Term Seismic Program Earthquake

PG&E performed a reevaluation of the seismic design bases of DCPP in response to License Condition 2.C.(7) of the Unit 1 Operating License. Details of this reevaluation, referred to as the LTSP, are provided in Section 2.5.7.

PG&E's evaluations included the development of significant additional data applicable to the geology, seismology, and tectonics of the DCPP region, including characterization of the Hosgri, Los Osos, San Luis Bay, Olson, San Simeon, and Wilmar Avenue faults. These faults were evaluated as potential seismic sources (Reference 40, Chapter 3). However, PG&E determined that the potential seismic sources of significance to the ground motions at the site are: the Hosgri and Los Osos fault zones, and the San Luis Bay fault, based on the probabilistic seismic hazard analysis; and the Hosgri fault zone, based on the deterministic analysis. Details are provided in Reference 40, Chapters 2 and 3, and summarized in SSER 34, Section 2.5.1, "Geology" and Section 2.5.2, "Seismology".

The NRC's review of PG&E's evaluations is documented in References 42 and 43.

2.5.3.10 Ground Accelerations and Response Spectra

The seismic design and evaluation of DCPP is based on the earthquakes described in the following four subsections. Refer to Section 3.7 for the design criteria associated with the application of the DE, DDE, and HE to the SSCs. Refer to Section 2.5.7 for a discussion of the seismic probabilistic risk assessment associated with the LTSP.

2.5.3.10.1 Design Earthquake

During the original design phase, the maximum ground acceleration that would occur at the DCPP site was estimated for each of the postulated earthquakes listed in Section 2.5.3.9, using the methods set forth in References 12 and 24. The plant site acceleration was primarily dependent on the following parameters: Gutenberg-Richter magnitude and released energy, distance from the earthquake focus to the plant site, shear and compressional velocities of the rock media, and density of the rock. Rock properties are discussed under Section 2.5.2.2.6, Site Engineering Properties.

The maximum rock accelerations that would occur at the DCPP site were estimated as:

Earthquake A . . . . 0.10 g	Earthquake C . . . . 0.05 g
Earthquake B . . . . 0.12 g	Earthquake D . . . . 0.20 g

In addition to the maximum acceleration, the frequency distribution of earthquake motions is important for comparison of the effects on plant structures and equipment. In general, the parameters affecting the frequency distribution are distance, properties of the transmitting media, length of faulting, focus depth, and total energy release. Earthquakes that might reach the site after traveling over great distances would tend to have their high frequency waves filtered out. Earthquakes that might be centered close

to the site would tend to produce wave forms at the site having minor low frequency characteristics.

In order to evaluate the frequency distribution of earthquakes, the concept of the response spectrum is used.

For nearby earthquakes, the resulting response spectra accelerations would peak sharply at short periods and would decay rapidly at longer periods. Earthquake D would produce such response spectra. The March 1957 San Francisco earthquake as recorded in Golden Gate Park (S80°E component) was the same type. It produced a maximum recorded ground acceleration of 0.13 g (on rock) at a distance of about 8 miles from the epicenter. Since Earthquake D has an assigned hypocentral distance of 12 miles, it would be expected to produce response spectra similar in shape to those of the 1957 event.

Large earthquakes centered at some distance from the plant site would tend to produce response spectra accelerations that peak at longer periods than those for nearby smaller shocks. Such spectra maintain a higher spectral acceleration throughout the period range beyond the peak period. Earthquakes A and C are events that would tend to produce this type of spectra. The intensity of shaking as indicated by the maximum predicted ground acceleration shows that Earthquake C would always have lower spectral accelerations than Earthquake A.

Since the two shocks would have approximately the same shape spectra, Earthquake C would always have lower spectral accelerations than Earthquake A, and it is therefore eliminated from further consideration. The north-south component of the 1940 El Centro earthquake produced response spectra that emphasized the long period characteristics described above. Earthquake A, because of its distance from the plant site, would be expected to produce response spectra similar in shape to those produced by the El Centro event. Smoothed response spectra for Earthquake A were constructed by normalizing the El Centro spectra to 0.10 g. These spectra, however, show smaller accelerations than the corresponding spectra for Earthquake B (discussed in the next paragraph) for all building periods, and thus Earthquake A is also eliminated from further consideration.

Earthquake B would tend to produce response spectra that emphasize the intermediate period range inasmuch as the epicenter is not close enough to the plant site to produce large high frequency (short-period) effects, and it is too close to the site and too small in magnitude to produce large low frequency (long-period) effects. The N69°W component to the 1952 Taft earthquake produced response spectra having such characteristics. That shock was therefore used as a guide in establishing the shape of the response spectra that would be expected for Earthquake B.

Following several meetings with the AEC staff and their consultants, the following two modifications were made in order to make the criteria more conservative:

(1) The Earthquake D time-history was modified in order to obtain better continuity of frequency distribution between Earthquakes D and B.

(2) The accelerations of Earthquake B were increased by 25 percent in order to provide the required margin of safety to compensate for possible uncertainties in the basic earthquake data.

Accordingly, Earthquake D-modified was derived by modifying the S80°E component of the 1957 Golden Gate Park, San Francisco earthquake, and then normalizing to a maximum ground acceleration of 0.20 g. Smoothed response spectra for this earthquake are shown in Figure 2.5-21. Likewise, Earthquake B was derived by normalizing the N69°W component of the 1952 Taft earthquake to a maximum ground acceleration of 0.15 g. Smoothed response spectra for Earthquake B are shown in Figure 2.5-20. The maximum vibratory motion at the plant site would be produced by either Earthquake D-modified or Earthquake B, depending on the natural period of the vibrating body.

2.5.3.10.2 Double Design Earthquake

The maximum ground acceleration and response spectra for the DDE are twice those associated with the DE, as described in Section 2.5.3.10.1 (Reference 51).

2.5.3.10.3 Hosgri Earthquake

As mentioned earlier, based on a review of the studies presented in Appendices 2.5D and 2.5E (refer to Reference 27 in Section 2.3) by the NRC and the USGS (acting as the NRC's geological consultant), the NRC issued SSER 4 in May 1976. This supplement included the USGS conclusion that a magnitude 7.5 earthquake could occur on the Hosgri fault at a point nearest to the Diablo Canyon site. The USGS further concluded that such an earthquake should be described in terms of near fault horizontal ground motion using techniques and conditions presented in Geological Survey Circular 672. The USGS also recommended that an effective, rather than instrumental, acceleration be derived for seismic analysis.

The NRC adopted the USGS recommendation of the seismic potential of the Hosgri fault. In addition, based on the recommendation of Dr. N. M. Newmark, the NRC prescribed that an effective horizontal ground acceleration of 0.75g be used for the development of response spectra to be employed in a seismic evaluation of the plant. The NRC outlined procedures considered appropriate for the evaluation including an adjustment of the response spectra to account for the filtering effect of the large building foundations. An appropriate allowance for torsion and tilting was to be included in the analysis. A guideline for the consideration of inelastic behavior, with an associated ductility ratio, was also established.

The NRC issued SSER 5 in September 1976. This supplement included independently-derived response spectra and the rationale for their development. Parameters to be

used in the foundation filtering calculation were delineated for each major structure. The supplement prescribed that either the spectra developed by Blume or Newmark would be acceptable for use in the evaluation with the following conditions:

(1) In the case of the Newmark spectra no reduction for nonlinear effects would be taken except in certain specific areas on an individual case basis.

(2) In the case of the Blume spectra a reduction for nonlinear behavior using a ductility ratio of up to 1.3 may be employed.

(3) The Blume spectra would be adjusted so as not to fall below the Newmark spectra at any frequency.

The development of the Blume ground response spectra, including the effect of foundation filtering, is briefly discussed below. The rationale and derivation of the Newmark ground response spectra is discussed in Appendix C to Supplement No. 5 of the SER.

The time-histories of strong motion for selected earthquakes recorded on rock close to the epicenters were normalized to a 0.75g peak acceleration. Such records provide the best available models for the Diablo Canyon conditions relative to the Hosgri fault zone. The eight earthquake records used are listed in the table below.

Earthquake	M	Depth, km	Recorded at	Epicentral Distance, km	Component	Peak Acceleration g
Helena 1935	6	5	Helena	3 to 8	EW	0.16
Helena 1935	6	5	Helena	3 to 8	NS	0.13
Daly City 1957	5.3	9	Golden Gate Park	8	N80W	0.13
Daly City 1957	5.3	9	Golden Gate Park	8	N10E	0.11
Parkfield 1966	5.6	7	Temblor 2	7	S25W	0.33
Parkfield 1966	5.6	7	Temblor 2	7	N65W	0.28
San Fernando 1971	6.6	13	Pacoima Dam	3	S14W	1.17
San Fernando 1971	6.6	13	Pacoima	3	N76W	1.08

The magnitudes are the greatest recorded thus far (September 1985) close in on rock stations and range from 5.3 to 6.6. Adjustments were made subsequently in the period range of the response spectrum above 0.40 sec for the greater long period energy expected in a 7.5M shock as compared to the model magnitudes.

The procedure followed was to develop 7 percent damped response spectra for each of the eight records normalized to 0.75g and then to treat the results statistically according to period bands to obtain the mean, the median, and the standard deviations of spectral response. At this stage, no adjustments for the size of the foundation or for ductility

were made. The 7 percent damped response spectra were used as the basis for calculating spectra at other damping values.

Figures 2.5-29 and 2.5-30 show free-field horizontal ground response spectra as determined by Blume and Newmark, respectively, at damping levels from two to seven percent.

Figures 2.5-31 and 2.5-32 show vertical ground response spectra as determined by Blume and Newmark, respectively, for two to seven percent damping. The ordinates of vertical spectra are taken as two-thirds of the corresponding ordinates of the horizontal spectra. These response spectra, finalized in 1977, are described as the ”1977 Hosgri response spectra.” Note that the Shoreline Fault Zone (refer to Section 2.5.7.1) is considered to be a lesser included case under the Hosgri evaluation (Reference 55).

2.5.3.10.4 1991 Long Term Seismic Program Earthquake

As discussed in Section 2.5.3.9.4, the LTSP, in response to License Condition 2.C.(7) determined that the governing earthquake source for the deterministic seismic margins evaluation of DCPP (84th percentile ground motion response spectrum) is the Hosgri fault. Ground motions, and the corresponding free-field response spectra for a Richter Magnitude 7.2 earthquake centered along the Hosgri fault, approximately 4.5 km from DCPP, were developed by PG&E, as documented in Reference 40. This event is referred to as the “LTSP Earthquake.” As part of their review of Reference 40, the NRC concluded that spectra developed by PG&E could underestimate the ground motion (Reference 42). As a result, the final spectra, applicable to the LTSP evaluation of DCPP, is an envelope of that developed by PG&E and that developed by the NRC. Figures 2.5-33 and 2.5-34 show the 84th percentile ground motion response spectrum at 5% damping for the horizontal and vertical directions, respectively, described as the "1991 LTSP response spectra". These spectra define the current licensing basis for the LTSP.

Figure 2.5-35 shows a comparison of the horizontal 1991 LTSP response spectrum with the 1977 Newmark Hosgri spectrum (based on Reference 40, Figure 7-2). This comparison indicates that the 1977 Hosgri spectrum is greater than the 1991 LTSP spectrum at all frequencies less than about 15 Hz, but the 1991 LTSP spectrum exceeds the 1977 Hosgri spectrum by approximately 10 percent for frequencies above 15 Hz. This exceedance was accepted by the NRC in SSER 34 (Reference 42), Section 3.8.1.1 (Ground-Motion Input for Deterministic Evaluations):

> "On the basis of PG&E's margins evaluation discussed in Section 3.8.1.7 of this SSER, the staff concludes that these high-frequency spectral exceedances are not significant."

In addition, the NRC states in SSER 34 (Reference 42), Section 1.4 (Summary of Staff Conclusions):

> "The staff notes that the seismic qualification basis for Diablo Canyon will continue to be the original design basis plus the Hosgri evaluation basis, along with the associated analytical methods, initial conditions, etc. The LTSP has served as a useful check of the adequacy of the seismic margins and has generally confirmed that the margins are acceptable."

Therefore, the 1991 LTSP ground motion response spectra does not replace or modify, the DE, DDE, or 1977 Hosgri response spectra described above.

2.5.4 SURFACE FAULTING

2.5.4.1 Geologic Conditions of the Site

The geologic history and lithologic, stratigraphic, and structural conditions of the site and the surrounding area are described in Section 2.5.2 and are illustrated in the various figures included in Section 2.5.

2.5.4.2 Evidence for Fault Offset

Substantive geologic evidence, described under Section 2.5.2.2, Site Geology, indicates that the ground at and near the site has not been displaced by faulting for at least 80,000 to 120,000 years. It can be inferred, on the basis of regional geologic history, that minor faults in the site bedrock date from the mid-Pliocene or, at the latest, from mid-Pleistocene episodes of tectonic activity.

2.5.4.3 Identification of Active Faults

Three zones that include faults greater than 1000 feet in length were mapped within about 5 miles of the site. Two of these, the Edna and San Miguelito fault zones, were mapped on land in the San Luis Range. The third, consisting of several breaks associated with the offshore Santa Maria Basin East Boundary zone of folding and faulting, is described in Sections 2.5.2.1.2.3 and 2.5.2.1.5.5 under Regional Geologic and Tectonic Setting. The mapped trace of each of these structures is shown in Figures 2.5-3 and 2.5-4. Additional active faults that were identified through the studies associated with the Hosgri Evaluation and LTSP are discussed in Sections 2.5.3.9.3 and 2.5.3.9.4, respectively.

2.5.4.4 Earthquakes Associated With Active Faults

The earthquakes discussions are limited to those identified during the original design phase and do not include any earthquakes recorded since 1971.

The Edna fault or fault zone has been active at some time since the deposition of the Plio-Pleistocene Paso Robles Formation, which it displaces. It has no morphologic expression suggestive of late Pleistocene activity, nor is it known to displace late Pleistocene or younger deposits. Four epicenters of small (3.9 to 3M) shocks and

42 other epicenters for shocks of "small" or "unknown" intensity have been reported as occurring in the approximate vicinity of the Edna fault (refer to Figures 2.5-3 and 2.5-4). Owing to the small size of the earthquakes that they represent, however, all of these epicenters are only approximately located. Further, they fall in the energy range of shocks that can be generated by fairly large construction blasts. At present, no conclusive evidence is available to determine whether the Edna fault could be classified as seismically active, or as geologically active in the sense of having undergone multiple movements within the last 500,000 years.

The San Miguelito fault has been mapped as not displacing the Plio-Pleistocene Paso Robles Formation. No instrumental epicenter has been reliably recorded from its vicinity, but the Berkeley Seismological Laboratory indicates Avila Bay as the presumed epicentral location for a moderately damaging (Intensity VII at Avila) earthquake that occurred on December 1, 1916. It seems likely, however, that this shock occurred along the offshore East Boundary zone rather than on the San Miguelito fault zone.

The East Boundary zone has an overall length of about 70 miles. Individual breaks within the zone are as much as 30 miles long, though the varying amount of displacement that occurs along specific breaks indicates that movement along them is not uniform, and it suggests that breakage may have occurred on separate, limited segments of the faults. The reach of the zone that is opposite DCPP site contains four fault breaks. These breaks range from 1 to 15 miles in length, and they have minimum distances of 2.1 to 4.5 miles from the site. The East Boundary zone is considered to be seismically active, since at least five instrumentally well located epicenters and as many as ten less reliably located other epicenters are centered along or near the zone. One of the breaks (located 3-1/2 miles offshore from the site) exhibits topographic expression that may represent a tectonic offset of the sea floor surface at a point along its trace 6 miles north of the site. Other faults in the East Boundary zone have associated erosion features, a few of which could possibly be partly of faultline origin.

The earthquake of December 1, 1916, though listed as having an epicentral location at Avila Bay, is considered more probably to have originated along either the East Boundary zone or, possibly, the Santa Lucia Bank fault. Effects of this shock at Avila included landsliding in Dairy Canyon, 2 miles north of town, and "...disturbance of waters in the Bay of San Luis Obispo." "...plaster in several cottages...was jarred loose...while some of the smokestacks on the (Union Oil Company) refinery were toppled over." It is apparently on this basis that the Berkeley listing of earthquakes assigns this shock a "large" intensity and places its approximate epicentral location at Port San Luis.

A small (Magnitude 2.9) shock that apparently originated near the East Boundary zone a short distance south of DCPP site was lightly felt at the site on September 24, 1974. This shock, like most of those recorded along the East Boundary zone, was not damaging.

The minor fault zone that was mapped in the sea cliff at the mouth of Diablo Creek and in the excavation for the Unit 1 turbine building has an onshore length of about 550 feet, and it probably continues for some distance offshore. It has been definitely determined to be not active.

2.5.4.5 Correlation of Epicenters With Active Faults

Earthquake epicenters located within 50 miles of DCPP site, for earthquakes recorded through 1972, have been approximately located in the vicinity of each of the faults. The reported earthquakes are listed in Table 2.5-1 and as follows, and their indicated epicentral locations are shown in Figures 2.5-3 and 2.5-4:

Earthquake Epicenters Reported as Being Located Approximately in the Vicinities of San Luis Obispo, Avila, and Arroyo Grande

Date	Geographic N Latitude	Coordinates W Longitude	Magni-tude	Inten-sity	Notes and Greenwich Mean Time (GMT)
7.10.1889	35.17°	120.58°			Arroyo Grande. Shocks for several days.
12.1.1916	35.17°	120.75°		VII	VII at Avila. Considerable glass broken and goods in stores thrown from shelves at San Luis Obispo. Water in bay disturbed, plaster in cottages jarred loose, smoke stacks of Union Oil refinery toppled over at Avila. Severe at Port San Luis. III at Santa Maria: 22:53:00
4.26.1950	35.20°	120.60°	3.5	V	V at Santa Maria. Also felt at Orcutt: 7:23:29
1.26.1971	35.20°	120.70°	3		Near San Luis Obispo: 21:53:53
1830 to 7.21.1931	35.25°	120.67°			42 epicenters

Earthquake Epicenters Reported as Being Located Approximately in the Vicinity of the Offshore Santa Maria Basin East Boundary Zone

Date	Geographic Coordinates N Latitude	W Longitude	Magni-tude	Inten-sity	Notes and Greenwich Mean Time (GMT)
5.27.1935(30-1)	35.62°	121.64°	3	III	Felt at Templeton: 16:08:00
9.7.1939(30-6)	35.46°	121.50°	3		Off San Luis Obispo County; felt at Cambria: 2:50:30
1.27.1945	34.75°	120.67°	3.9		17:50:31
12.31.1948(30-10)	35.60°	121.23°	4.6		Felt along coast from Lompoc to Moss Landing. VI at San Simeon. V at Cayucos, Creston, Moss Landing, Piedras Blancas Light Station: 14:35:46
11.17.1949	34.80°	120.70°	2.8		IV at Santa Maria. Near Priest: 5:06:60
2.5.1955(30-23)	35.86°	121.15°	3.3		West of San Simeon: 7:10:19
6.21.1957(30-25A)	35.23°	120.95°	3.7		Off Coast. Felt in San Luis Obispo, Morro Bay: 20:46:42
8.18.1958	35.60°	121.30	3.4		Near San Simeon: 5:30:42
10.25.1967	35.73°	121.45°	2.6		Near San Simeon: 23:05:39.5

(Figures in parentheses refer to events relocated by S. W. Smith, refer to Table 2.5-2).

2.5.4.6 Description of Active Faults

Data pertaining to faults with lengths greater than 1000 feet and reaches within 50 miles of the site, as identified during the original design phase, are included in Section 2.5.2.1.5, Structure of the San Luis Range and Vicinity, and in Figures 2.5-3 and 2.5-4. These data indicate the fault lengths, relationship of the faults to regional tectonic structures, known history of displacements, outer limits, and whether the faults can be considered as active.

2.5.4.7 Results of Faulting Investigation

The site for Unit 1 and Unit 2 of DCPP was investigated in detail for faulting and other possibly detrimental geologic conditions. From studies made prior to design of the plant, it was determined that there was need to take into account the possibility of surface faulting in such design. The data on which this determination was based are presented in Section 2.5.2.2, Site Geology.

2.5.5 STABILITY OF SUBSURFACE MATERIALS

The possibility of past or potential surface or subsurface ground subsidence, uplift, or collapse in the vicinity of DCPP was considered during the course of the geologic investigations for Unit 1 and Unit 2.

2.5.5.1 Geologic Features

The site is underlain by folded bedrock strata consisting predominantly of sandy mudstone and fine-grained sandstone. The existence of an unbroken and otherwise undeformed section of upper Pleistocene terrace deposits overlying a wave-cut bedrock bench at the site provides positive evidence that all folding and faulting in the bedrock antedated formation of the terrace. Local depressions and other irregularities on the bedrock surface plainly reflect erosion in an ancient surf zone.

The rocks that constitute the bedrock section are not subject to significant solution effects (i.e., development of cavities or channels that could affect the engineering or fluid conducting character of the rock) because the bedrock section does not contain thick or continuous bodies of soluble rock types such as limestone or gypsum. Voids encountered during excavation at the site were limited to thin zones of vuggy breccia and isolated vugs in some beds of calcareous mudstone. Areas where such minor vuggy conditions were present were noted at a few locations in the excavation for the Unit 2 containment and fuel handling structures (at plant grid coordinates N59, N597, E10, E005 and N59, N700, E10, E120).

The maximum size of any individual opening was 3 inches or less, and most were less than 1 inch in maximum dimension. Because of the limited extent and isolated nature of these small voids, they were not considered significant in foundation engineering or slope stability analyses.

It has been determined by field examination that no sea caves exist in the immediate vicinity of the site. The only cave like natural features in the area are shallow pits and hollows in some of the sea cliff outcrops of resistant tuff. These features generally have dimensions of a few inches to about 10 feet. They are superficial, and have originated through differential weathering of variably cemented rock.

Several exploratory wells have been drilled for petroleum within the San Luis Range, but no production was achieved and the wells were abandoned. The area is not now active in terms of either production or exploration. The location of the abandoned wells is shown in Figure 2.5-6, and the geologic relationships in the Range are illustrated in Section A-A' of Figure 2.5-6 and in Figure 2.5-7, Section D-D'. The nearest oil-producing area is the Arroyo Grande field, about 15 miles to the southeast.

The potential for future problems of ground instability at the site, because of nearby petroleum production, can be assessed in terms of the geologic potential for the occurrence of oil within, or offshore from, the San Luis Range. In addition, assessment can be made in terms of the geologic relationships in the site as contrasted with geologic conditions in places where oil field exploitation has resulted in deformation of the ground surface.

As shown in Figures 2.5-6 and 2.5-7, the San Luis Range has the structural form of a broad synclinal fold, which in turn is made up of several tightly compressed anticlines and synclines of lesser order. The configuration is not conducive to entrapment of hydrocarbon fluids, as such fluids tend to migrate upward through bedding and fracture-controlled zones of higher primary and secondary permeability until they reach a local trap or escape into the near surface or surface environment.

Within the San Luis Range, the only recognizable structural traps are in local zones where plunge reversals exist along the crests of the second-order anticlines. Such structures evidently were the actual or hoped-for targets for most of the exploratory wells that have been drilled in the San Luis Range, but none of these wells has produced enough oil or gas to record; thus, the traps have not been effective, or perhaps the strata are essentially lacking in hydrocarbon fluids. Other conditions that indicate poor petroleum prospects for the Range include the general absence of good reservoir rocks within the section and the relatively shallow basement of non petroliferous Franciscan rocks.

In the offshore, adjacent to the southerly flank of the San Luis Range, subsurface conditions are not well known, but are probably generally similar. Scattered data suggest that a structural high, perhaps defined by a west-northwest plunging anticline, may exist a few miles offshore from DCPP site. Such a feature could conceivably serve as a structural trap, if local closure were present along its axis; however, it seems unlikely that it would contain significant amounts of petroleum.

Available data pertaining to exploratory oil wells drilled in the region of the site are given here:

Exploratory Oil Wells in the Vicinity of DCPP Site

Data from exploratory wells drilled outside of oil and gas fields in California to December 31, 1963: Division of Oil and Gas, San Francisco.

Mount Diablo B. & M. T R Sec	Operator	Well No.	Elev, ft	Date Started	Total Depth, ft	Stratigraphy (depth in ft) Age at Bottom of Hole
31S 10E 3	Tidewater Oil Co.	"Montadoro" 1	365	April 1954	6,146	Monterey 0-3800; Obispo Tuff 3800: Franciscan; U. Jurassic
30S 10E 24	Gretna Corp.	"Maino-Gonzales" 1	275	March 1937	1,575	Franciscan; Jurassic
24	Wm. H. Provost	"Spooner" 1	325	July 1952	1,749	Jurassic
24	Shell Oil Co.	"Buchon"	-	-	-	-
34	A. O. Lewis	"Pecho" 1	177	May 1937	2,745	Monterey 0-2612; U. Miocene
30S 11E 9	Van Stone and Dallaston	"Souza" 1	42	Oct 1951	1,233	Franciscan; Jurassic
31S 11E 15	Tidewater Oil Co.	"Honolulu-Tidewater-U.S.L.-Heller "Lease" 1	1,614	Jan 1958	10,788	Monterey 0-4363; Pt. Sal 4363; Obispo Tuff 4722; Rincon Shale 5370; 2nd Tuff 5546; 2nd Rincon Shale 6354; 3rd Tuff 10,174; L. Miocene

For the purpose of assessing the potential for the occurrence of adverse oil field related ground deformation effects at DCPP site, in the unlikely event that petroleum should be discovered and produced at a nearby location, it is useful to review the nature and causes of such ground deformation, and the types of geologic conditions at places where it has been observed.

The general subject of surface deformation associated with oil and gas field operations has been reviewed by Yerkes and Castle (Reference 22), among others. Such deformation includes differential subsidence, development of horizontally compressive strain effects within the central parts of subsidence bowls and horizontally extensive strain effects around their margins, and development or activation of cracks and faults. Pull-apart cracks and normal faults may develop in the marginal zone of extensive strain, while reverse and thrust faults sometimes occur in the central, compressive part of subsidence bowls. These effects all can develop when extraction of petroleum, water, and sand, plus lowering of fluid pressures, result in compression within and adjacent to producing zones, and attendant subsidence of the overlying ground. Other effects, including rebound of the ground surface, fault activation, and earthquake generation, have resulted from injection of fluid into the ground for purposes of secondary recovery, subsidence control, and disposal of fluid waste.

In virtually all instances of ground-surface deformation associated with petroleum production, the producing field has been centered on an anticlinal structure, in general relatively broad and internally faulted. The strata in the producing and overlying parts of the section typically are poorly consolidated sandstone, siltstone, claystone, and shale of low structural competence. The field generally is one with relatively large production, with significant decline of fluid pressure in the producing zones.

The conditions just cited can be contrasted with those obtained in the vicinity of DCPP site, where the rocks lie along the flank of a major syncline. They consist of tight sandstone, tuffaceous sandstone, mudstone, and shale, together with large resistant masses of tuff and diabase. Bedding dips range from near horizontal to vertical and steeply overturned, as shown in Section D-D' of Figure 2.5-7 and Section A-B of Figure 2.5-10. This structural setting is unlike any reported from areas where oil-field-associated surface deformation has occurred.

The foregoing discussion leads to the following conclusions: (a) future development of a producing oil field in the vicinity of DCPP site is highly unlikely because of unfavorable geologic conditions, and (b) geologic conditions in the site vicinity are not conducive to the occurrence of surface deformation, even if nearby petroleum production could be achieved.

As was noted in Section 2.4, the rocks underlying the site do not constitute a significant groundwater reservoir, so that future development of deep rock water wells in the vicinity is not a reasonable possibility. The considerations pertaining to surface deformation resulting from water extraction are about the same as for petroleum extraction, so there is no likelihood that DCPP site could experience artificially induced and potentially damaging subsidence, uplift, collapse, or changes in subsurface effective stress related to pore pressure phenomena.

There are no mineral deposits of economic significance in the ground underlying the site.

Although some regional warping and uplift may well be taking place in the southern Coast Ranges, such deformation cannot be sufficiently rapid and local to impose significant effects on coastal installations. Apparent elevation of the San Luis Range has increased about 100 feet relative to sea level since the cutting of the main terrace bench at least 80,000 years ago.

Expressions of deformation preserved in the bedrock at the site include minor faults, folds, and zones of blocky fracturing in sandstone and intra-bed shearing in claystone. Zones of cemented breccia also are present, as is widespread evidence of disturbance adjacent to intrusive bodies of tuff. Local weakening of the rocks in some of these zones led to some problems during construction, but these were handled by conventional techniques such as overexcavation and rock bolting. No observed features of deformation are large or continuous enough to impose significant effects on the overall performance of the site foundation.

The foundation excavations for Unit 1 and Unit 2 were extended below the zone of intense near surface weathering so that the exposed bedrock was found to be relatively fresh and firm. The principal zones of structural weakness are associated with small bodies of altered tuff and with internally sheared beds of claystone. The claystone intra-bed shear was expressed by the development of numerous slickensided shear surfaces within parts of the beds, especially in places where the claystone had locally been squeezed into pod like masses. The shearing and local squeezing clearly are expressions of the preferential occurrence of differential adjustments in the relatively weaker claystone beds during folding of the section.

The claystone beds are localized in a part of the rock section that underlies the discharge structure and extends across the southerly part of the Unit 2 turbine-generator building, thence continuing easterly, along a strike through the ground south of the Unit 2 containment. The bedding dips 48 to 75° north within this zone. Individual claystone beds range from 1/2 inch to about 6 inches in thickness, and they occur as interbeds in the sandstone-mudstone rock section.

The relationship of the claystone layers to the foundation excavation is such that they crop out in several narrow bands across the floor and walls (refer to Figures 2.5-15 and 2.5-16). Thus, the claystone bed remains confined within the rock section, except in a narrow strip at the face of the excavation. Because of the small amount of claystone mass and the geometric relationship of the steeply dipping claystone interbeds to the foundation structures, it was determined that the finished structure would not be affected by any tendency of the claystone to undergo further changes in volume.

The only area in which claystone swelling was monitored was along the north wall of the lower part of the large slot cut for the cooling water discharge structure. There are several thin (6 inches or less) claystone interbeds in the sandstone-mudstone section. Because the orientation of the bedding and the plane of the cut face differ by only about 30°, and the bedding dips steeply into the face, opening of the cut served both to remove lateral support from the rock behind the face, and also to expose the clay beds

to rainfall and runoff. This apparently resulted in both load relief and hydration swelling of the newly exposed claystone, which in turn caused some outward movement of the cut face. The movement then continued as gravity creep of the locally destabilized mass of rock between the claystone beds and the free face. The movement was finally controlled by installation of drilled-in lateral tie-backs, prior to placement of the reinforced concrete wall of the discharge structure.

No evidence of unrelieved residual stresses in the bedrock was noted during the excavation or subsequent construction of the plant foundation. Isolated occurrences of temporary slope instability clearly were related to locally weathered and fractured rock, hydration swelling of claystone interbeds, and local saturation by surface runoff. The Unit 1 and Unit 2 power plant facilities are founded on physically and chemically stable bedrock.

2.5.5.2 Properties of Underlying Materials

Static and dynamic engineering properties of materials in the subsurface at the site are presented in Section 2.5.2.2.6, Site Engineering Properties.

2.5.5.3 Plot Plan

Plan views of the site indicating exploratory boring and trenching locations are presented in Figures 2.5-8 and 2.5-11 through 2.5-15. Profiles illustrating the subsurface conditions relative to the PG&E Design Class I structures are furnished in Figures 2.5-12 through 2.5-16. Discussions of engineering properties of materials and groundwater conditions are included in Section 2.5.2.2.6, Site Engineering Properties.

2.5.5.4 Soil and Rock Characteristics

Information on compressional and shear wave velocity surveys performed at the site are included in Appendices 2.5A and 2.5B of Reference 27 of Section 2.3. Values of soil modulus of elasticity and Poisson's ratio calculated from seismic measurements are presented in Table 1 of Appendix 2.5A of Reference 27 of Section 2.3, and in Figure 2.5-19. Boring and trench logs are presented in Figures 2.5-23 through 2.5-28.

2.5.5.5 Excavations and Backfill

Plan and profile drawings of excavations and backfill at the site are presented in Figures 2.5-17 and 2.5-18. The engineered backfill placement operations are discussed in Section 2.5.2.2.6.4, Engineered Backfill.

2.5.5.6 Groundwater Conditions

Groundwater conditions at the site are discussed in Section 2.4.13. The effect on foundations of PG&E Design Class I structures is discussed in Section 2.5.2.2.6, Site Engineering Properties.

2.5.5.7 Response of Soil and Rock to Dynamic Loading

Details of dynamic testing on site materials are contained in Appendices 2.5A and 2.5B of Reference 27 in Section 2.3.

2.5.5.8 Liquefaction Potential

As stated in Section 2.5.2.2.6.5, adverse hydrologic effects on foundations of PG&E Design Class I structures can be neglected due to the structures being founded on bedrock and the groundwater level lying well below final grade.

There is a small local zone of medium dense sand located northeast of the intake structure and beneath a portion of buried ASW piping that is not attached to the circulating water tunnels. This zone is susceptible to liquefaction during design basis seismic events (References 45 and 46). The associated liquefaction-induced settlements from seismic events are considered in the design of the buried ASW piping. (References 48 and 49)

2.5.5.9 Earthquake Design Basis

The earthquake design bases for the DCPP site are discussed in Section 2.5.3.9, a discussion of the design response spectra is provided in Section 2.5.3.10, and the application of the earthquake ground motions to the seismic analysis of SSCs is provided in Section 3.7. Response acceleration curves for the site resulting from Earthquake B and Earthquake D-modified are shown in Figures 2.5-20 and 2.5-21, respectively. Response spectrum curves for the HE are shown in Figures 2.5-29 through 2.5-32.

2.5.5.10 Static Analysis

A discussion of the analyses performed on materials at the site is presented in Section 2.5.2.2.6, Site Engineering Properties.

2.5.5.11 Criteria and Design Methods

The criteria and methods used in evaluating subsurface material stability are presented in Section 2.5.2.2.6, Site Engineering Properties.

2.5.5.12 Techniques to Improve Subsurface Conditions

Due to the bearing of in situ rock being well in excess of the foundation pressure, no treatment of the in situ rock is necessary. Compaction specifications for backfill are presented in Section 2.5.2.2.6.4, Engineered Backfill.

2.5.6 SLOPE STABILITY

2.5.6.1 Slope Characteristics

The only slope whose failure during a DDE could adversely affect the nuclear power plant is the slope east of the building complex (refer to Figures 2.5-17, 2.5-18, and 2.5-22). To evaluate the stability of this slope, the soil and rock conditions were investigated by exploratory borings, test pits, and a thorough geological reconnaissance by the soil consultant, Harding-Lawson Associates, and was in addition to the overall geologic investigation performed by other consultants.

The slope configuration and representative locations of the subsurface conditions determined from the exploration are shown on Plates 2, 3, and 4 of Appendix 2.5C of Reference 27 of Section 2.3. Reference 44 provides further information compiled in 1997 in response to NRC questions on landslide potential.

Bedrock is exposed along the lower portions of the cut slope up to about the lower bench at elevation 115 feet. It consists of tuffaceous siltstone and fine-grained sandstone of the Monterey Formation. Terrace gravel overlies bedrock and extends to an approximate elevation of 145 feet. Stiff clays and silty soils with gravel and rock fragments constitute the upper material on the site. The upper few feet of fine-grained soils are dark brown and expansive.

No free groundwater was observed in any of the borings which were drilled in April 1971, nor was any evidence of groundwater observed in this slope during the previous years of investigation and construction of the project.

In response to an NRC request in early 1997, PG&E conducted further investigations of slope stability at the site (Reference 44). The results of the investigations showed that earthquake loading, as a result of an earthquake on the Hosgri fault zone, following periods of prolonged precipitation will not produce any significant slope failure that can impact PG&E Design Class I structures and equipment. In addition, potential slope failures under such conditions will not adversely impact other important facilities, including the raw water reservoirs, the 230-kV and 500-kV switchyards, and the intake and discharge structures. Potential landslides may temporarily block the access road at several locations. However, there is considerable room adjacent to and north of the road to reroute emergency traffic.The investigation of the cut slope included geologic mapping of the soil and rock conditions exposed on the surface of slope and existing benches. Subsurface conditions were investigated by drilling test borings and by excavating test pits in the natural slope above the plant site (refer to Figure 2.5-22). The test borings were drilled with a truck mounted, 24 inch flight auger drill rig, and the test pits were excavated with a track-mounted backhoe. Boring and Log of Test Pits 1, 2, and 3 were logged by the soil consultant; borings 2 and 3 were logged by PG&E engineering personnel. The logs of all borings were verified by the soil consultant, who examined all samples obtained from each boring. Undisturbed samples were obtained from boring 2 and each of the test pits. Because of the stiffness of the soil, hardness of

the rock, and type of drilling equipment used, the undisturbed samples were obtained by pushing an 18-inch steel tube that measured 2.5 inches in outside diameter. A Sprague & Henwood split-barrel sampler containing brass liners was used to obtain undisturbed soil samples from the test pits. The brass liners measured 2.5 inches in outside diameter and 6 inches in height. Logs of the borings and pits are shown in Figures 2.5-23 through 2.5-27. The soils were classified in accordance with the Unified Soil Classification System presented in Figure 2.5-28.

2.5.6.2 Design Criteria and Analyses

Undisturbed samples of the materials encountered in pits and borings were examined by the soil consultant in the laboratory and were subsequently tested to determine the shear strength, moisture content, and dry density. Strain controlled, unconsolidated, undrained triaxial tests at field moisture were performed on the clay to evaluate the shear strength of the materials penetrated. (The samples were maintained at field moisture since adverse moisture or seepage conditions were not encountered during this investigation nor previous investigations.) The confining stress was varied in relation to depth at which the undisturbed sample was taken. The test results are presented on the boring logs and are explained by the Key to Test Data, Figure 2.5-28.

The results of strength tests were correlated with the results developed during earlier investigations of DCPP site. Mohr circles of stresses at failure (6 to 7 percent strain) were drawn for each strength test result, and failure lines were developed through points representing one-half the deviator stresses. An average C-θ strength equal to a cohesion (C) value of 1000 psf and an angle of internal friction (θ) of 29° was selected for the slope stability analysis. The analysis was checked by maintaining the angle of internal friction (θ) constant at 19° and varying the cohesion (C) from 950 psf (weakest layer) to 3400 psf (deepest and strongest layer).

Because of the presence of large gravel sizes, it was not possible to accurately determine the strength of the sand and gravel lense. However, based on tests on sand samples from other parts of the site, an angle of internal friction of 35° was selected as being the minimum available. An assumed rock strength of 5000 psf was used. This value is consistent with strength tests performed on remold rock samples from other areas of the site.

The stability of the slope was analyzed for the forces of gravity using a static method that is, the conventional method of slices. This analysis was checked using Bishop's modified method. The static method of analysis was chosen because, for the soil conditions at the site, it was judged to be more conservative than a dynamic analysis.

Because the overall strength of the rock would preclude a stability failure except along a plane of weakness which was not encountered in the borings or during the many geologic mappings of the slope, only the stability of the soil over the rock was analyzed. The strength parameters were varied as previously discussed to determine the minimum factor of safety under the most critical strength condition. For the static

analysis excluding horizontal forces, the factor of safety was computed to be 3. When the additional unbalanced horizontal force of 0.4 times the weight of the soil within the critical surface combined with a vertical force of 0.26 times the weight was included, the minimum computed factor of safety was 1.1.

On the basis of the investigation and analysis, it was concluded that the slope adjacent to DCPP site would not experience instability of sufficient magnitude to damage adjacent safety-related structures.

The above conclusion is substantiated by additional field exploration, laboratory tests, and dynamic analyses using finite element techniques. Refer to Appendix 2.5C of Reference 27 in Section 2.3, Harding-Lawson Associates' report on this work.

2.5.6.3 Slope Stability for Buried Auxiliary Saltwater System Piping

A portion of the buried ASW piping for Unit 1 ascends an approximate 2:1 (horizontal/vertical) slope to the parking area near the meteorology tower (Plates 1 and 2 of Reference 47). To ensure the stability of this slope in which the ASW piping is buried, a geotechnical evaluation, considering various design basis seismic events, was performed by Harding Lawson Associates. This evaluation is described in Reference 47. Based on this evaluation, it was concluded that this slope will be stable during seismic events and that additional loads resulting from permanent deformation of the slope will not impact the buried ASW piping.

2.5.7 LONG TERM SEISMIC PROGRAM

On November 2, 1984, the NRC issued the Diablo Canyon Unit 1 Facility Operating License DPR-80. In DPR-80, License Condition 2.C(7), the NRC stated, in part:

> "PG&E shall develop and implement a program to reevaluate the seismic design bases used for the Diablo Canyon Power Plant."

PG&E’s reevaluation effort in response to the license condition was titled the "Long Term Seismic Program". PG&E prepared and submitted to the NRC the "Final Report of the Diablo Canyon Long Term Seismic Program" in July 1988 (Reference 40). Between 1988 and 1991, the NRC performed an extensive review of the Final Report, and PG&E prepared and submitted written responses to formal NRC questions. In February 1991, PG&E issued the "Addendum to the 1988 Final Report of the Diablo Canyon Long Term Seismic Program" (Reference 41). In June 1991, the NRC issued Supplement Number 34 to the Diablo Canyon Safety Evaluation Report (Reference 42) in which the NRC concluded that PG&E had satisfied License Condition 2.C(7) of Facility Operating License DPR-80. In the SSER the NRC requested certain confirmatory analyses from PG&E, and PG&E subsequently submitted the requested analyses. The NRC’s final acceptance of the LTSP is documented in a letter to PG&E dated April 17, 1992 (Reference 43).

The LTSP contains extensive data bases and analyses that update the basic geologic and seismic information in this section of the UFSAR. However, the LTSP material does not address or alter the current design licensing basis for the plant. In SSER 34 (Reference 42), the NRC stated, "The Staff notes that the seismic qualification basis for Diablo Canyon will continue to be the original design basis plus the Hosgri Evaluation basis, along with associated analytical methods, initial conditions, etc."

As a condition of the NRC's close out of License Condition 2.C(7), PG&E committed to several ongoing activities in support of the LTSP, as discussed in a public meeting between PG&E and the NRC on March 15, 1991 (Reference 53), described as the "Framework for the Future," in a letter to the NRC, dated April 17, 1991 (Reference 50), and affirmed by the NRC in SSER 34 (Reference 43). These ongoing activities include the following that are related to geology and seismology (Reference 42, Section 2.5.2.4):

(1) To continue to maintain a strong geosciences and engineering staff to keep abreast of new geological, seismic, and seismic engineering information and evaluate it with respect to its significance to Diablo Canyon.

(2) To continue to operate the strong-motion accelerometer array and the coastal seismic network.

A complete listing of bibliographic references to the LTSP reports and other documents may be found in References 40, 41 and 42.

2.5.7.1 Shoreline Fault Zone

In November 2008, as a result of the ongoing activities described in Section 2.5.7, the USGS, working in collaboration with the PG&E Geosciences Department, identified an alignment of microseismicity subparallel to the coastline adjacent to DCPP indicating the possible presence of a previously unidentified fault located approximately 1 km offshore of DCPP. The offshore region associated with this fault was subsequently named the Shoreline fault zone.

PG&E developed estimates of the 84th percentile deterministic ground motion response spectrum for earthquakes associated with the Shoreline fault zone. The results of the study of the Shoreline fault zone are documented in Reference 52. A map showing the location of the Shoreline Fault Zone is provided in Figure 2.5-36. This report includes a comparison of the updated 84th percentile deterministic response spectra with the 1991 LTSP and 1977 HE response spectra. This comparison indicates that the updated deterministic response spectra are enveloped by both the 1977 HE spectrum and the 1991 LTSP earthquake spectrum.

The NRC developed an independent assessment of the seismic source characteristics of the Shoreline fault and performed an independent deterministic seismic hazard

assessment (References 54 and 55). The NRC concluded that their conservative estimates for the potential ground motions from the Shoreline fault are at or below the ground motions for which the DCPP has been evaluated previously and demonstrated to have a reasonable assurance of safety (i.e., the 1977 HE and 1991 LTSP earthquake ground motion response spectra). The NRC stated that the "Shoreline scenario should be considered as a lesser included case under the Hosgri evaluation."

2.5.7.2 Evaluation of Updated Estimates of Ground Motion

As an outcome of the Shoreline fault zone evaluation described in Section 2.5.7.1, the process to be used for the evaluation of new/updated geological/seismological information has been developed (References 55 and 56). The new/updated geological/seismological information, resulting from the activities described in Section 2.5.7, will be evaluated using a process that is consistent with the evaluation process defined by the NRC in Reference 57, as described in Reference 58 and endorsed by the NRC in Reference 59.

2.5.7.2.1 Updated Seismic Hazard Evaluation and Probabilistic Risk Assessment

In response to the NRC's request for information pursuant to 10 CFR 50.54(f) Regarding Recommendation Nos. 2.1, 2.3, and 9.3 of the Near-Term Task Force (NTTF) Review of Insights from the Fukushima Dai-Ichi Accident (Reference 57), PG&E prepared updates to the DCPP seismic hazards evaluation and seismic probabilistic risk assessment (SPRA) associated with the 1991 LTSP, in accordance with Reference 58.

2.5.7.2.1.1 Updated Probabilistic Seismic Hazard Evaluation

An update to the seismic hazard evaluation associated with the 1991 LTSP was performed in accordance with Reference 58. This evaluation included the following elements:

(1) Seismic Source Characterization

(2) Ground Motion Characterization

(3) Site Seismic Response Analysis

(4) Probabilistic Seismic Hazard Analysis

(5) Control Point Ground Motion Response Spectrum Development

The seismic hazard evaluation considered regional faults in the seismic source characterization, including the following faults/fault zones (see Figure 2.5-36 for locations and Reference 60 for bases):

(1) Hosgri Fault Zone, which corresponds to the fault zone considered in the Hosgri Evaluation Phase of DCPP, as discussed in Section 2.5.3.9.3

(2) Shoreline Fault Zone, which corresponds to the fault zone discussed in Section 2.5.7.1

(3) Los Osos Fault Zone, which corresponds to one of the fault zones identified in the 1991 LTSP, as discussed in Section 2.5.3.9.4

(4) San Luis Bay Fault within the Southwestern Boundary Zone, which corresponds to one of the faults identified in the 1991 LTSP, as discussed in Section 2.5.3.9.4

The results of the updated probabilistic seismic hazards evaluation were submitted to the NRC in the DCPP Seismic Hazards and Screening Report (Reference 60), including the associated PG&E responses to requests for additional information (References 61, 62, 63, and 64). The NRC Staff Assessment of the updated probabilistic seismic hazards evaluation (Reference 65) concluded that the reevaluated seismic hazard for DCPP is suitable for use in the other seismic assessments with Reference 57, which includes the seismic probabilistic risk assessment described in Section 2.5.7.2.1.2.

2.5.7.2.1.2 Updated Seismic Probabilistic Risk Assessment

An update to the seismic probabilistic risk assessment (SPRA) associated with the 1991 LTSP was performed in accordance with Reference 58. This evaluation included the following elements:

(1) Refinements to the structural modelling

(2) Refinements to the soil characterization for use in the soil-structural-interaction (SSI) analyses

(3) Development of structure-specific foundation input response spectra (FIRS)

(4) Probabilistic SSI analyses of the major structures

(5) Refinements to the SPRA logic model, including updates to the seismic equipment list (SEL)

(6) Refinements to the fragility parameters for the structures, systems, and components included in the SEL

(7) Updated quantification of the seismic core damage frequency (SCDF)

(8) Quantification of the seismic large early release frequency (SLERF)

The results of the updated SPRA were submitted to the NRC in the DCPP Seismic Probabilistic Risk Assessment Report (Reference 66). The NRC Staff Assessment of the updated SPRA is documented in Reference 67. The Staff Assessment concluded that the updated SPRA for DCPP meets the intent of the guidance given in Reference 58 and represents an appropriate response to Enclosure 1, Item (8) of Reference 57. Additionally, the staff's review concluded that the SPRA is of sufficient technical adequacy to support NTTF Phase 2 regulatory decision-making in accordance with the intent of Reference 57. Based on the results and risk insights of the updated SPRA, the NRC staff also concluded that no further response or regulatory actions associated with Reference 57 are required. DCPP has been assigned to Group 1, as defined in Reference 67, which applies to plants for which the mean SCDF and SLERF clearly demonstrate that that a plant-specific back-fit would not be warranted.

2.5.8 SAFETY EVALUATION

2.5.8.1 General Design Criterion 2, 1967 - Performance Standards

The determination of the appropriate earthquake parameters for design of plant SSCs is addressed throughout Section 2.5, and the maximum earthquakes for the plant site are presented in Sections 2.5.3.9.1 through 2.5.3.9.3. The associated design basis site free field accelerations and response spectra are presented in Sections 2.5.3.10.1 through 2.5.3.10.3. The seismic design of these SSCs is addressed in Section 3.7.

2.5.8.2 License Condition 2.C(7) of DCPP Facility Operating License DPR-80 Revision 44 (Long Term Seismic Program), Elements (1), (2) and (3)

PG&E's reevaluation effort in response to the license condition was titled the "Long Term Seismic Program". PG&E prepared and submitted to the NRC the "Final Report of the Diablo Canyon Long Term Seismic Program" in July 1988. Between 1988 and 1991, the NRC performed an extensive review of the Final Report, and PG&E prepared and submitted written responses to formal NRC questions. In February 1991, PG&E issued the "Addendum to the 1988 Final Report of the Diablo Canyon Long Term Seismic Program". In June 1991, the NRC issued Supplement Number 34 to the Diablo Canyon Safety Evaluation Report in which the NRC concluded that PG&E had satisfied License Condition 2.C(7) of Facility Operating License DPR-80. In the SSER the NRC requested certain confirmatory analyses from PG&E, and PG&E subsequently submitted the requested analyses. The NRC's final acceptance of the LTSP is documented in a letter to PG&E dated April 17, 1992.

The commitments made as a part of the Diablo Canyon LTSP are detailed in Sections 2.5.3.9.4 and 2.5.7.

2.5.8.3 10 CFR Part 100, March 1966 - Reactor Site Criteria

As described in Sections 2.5.2 through 2.5.6 above, the physical characteristics of the site, including seismology and geology have been considered.

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TABLE 2.1-1

HISTORICAL INFORMATION BELOW IS SHOWN IN ITALICS

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

Year	*State of California*	*San Luis Obispo County*	*Santa Barbara County*	*Notes*
1940	*6,907,387*	*33,246*	*70,555*	*(a)*
1950	*10,586,233*	*51,417*	*98,220*	*(a)*
1960	*15,717,204*	*81,044*	*168,962*	*(a)*
1970	*19,953,134*	*105,690*	*264,324*	*(a)*
1980	*23,668,562*	*155,345*	*298,660*	*(a)*
1990	*29,760,021*	*217,162*	*369,608*	*(a)*
2000	*33,871,648*	*246,681*	*399,347*	*(a)*
2010	*40,262,400*	*323,100*	*467,700*	*(b)*
2025	*48,626,052*	*426,812*	*603,966*	*(c)*

Notes: *(a) U.S. Bureau of the Census*
(b) State of California Department of Finance (June 2001)
(c) State of California Department of Finance Data Files (March 16, 2000)

TABLE 2.1-2

HISTORICAL INFORMATION BELOW IS SHOWN IN ITALICS

GROWTH OF PRINCIPAL COMMUNITIES WITHIN 50 MILES OF DCPP SITE

Community	*Population (1960 Census)*	*Population (1970 Census)*	*Population (1980 Census)*	*Population (1990 Census)*	*Population (2000 Census)*
Arroyo Grande	*3,291*	*7,454*	*10,350*	*14,378*	*15,851*
Atascadero	*5,983*	*10,290*	*15,930*	*23,138*	*26,411*
Grover City	*5,210*	*5,939*	*8,827*	*11,656*	*13,067*
Guadalupe	*2,614*	*3,145*	*3,629*	*5,479*	*5,659*
Lompoc	*14,415*	*25,284*	*26,267*	*37,649*	*41,103*
Morro Bay	*3,692*	*7,109*	*9,064*	*9,664*	*10,350*
Paso Robles	*6,617*	*7,168*	*9,163*	*18,583*	*24,297*
Pismo Beach	*1,762*	*4,043*	*5,364*	*7,669*	*8,551*
San Luis Obispo	*20,437*	*28,036*	*34,253*	*41,958*	*44,174*
Santa Maria	*20,027*	*32,749*	*39,685*	*61,284*	*77,423*

TABLE 2.1-3

HISTORICAL INFORMATION BELOW IS SHOWN IN ITALICS

POPULATION CENTERS OF 1,000 OR MORE
WITHIN 50 MILES OF DCPP SITE

Community	*County*	*Distance and Direction From the Site*	*Population (1970 Census)*	*Population (1980 Census)*	*Population (1990 Census)*	*Population (2000 Census)*
Baywood-Los Osos	*San Luis Obispo*	*8 miles N*	*3,487*	*10,933*	*15,290*	*14,351*
Morro Bay	*San Luis Obispo*	*10 miles N*	*7,109*	*9,064*	*12,949*	*10,350*
San Luis Obispo	*San Luis Obispo*	*12 miles ENE*	*28,036*	*34,253*	*51,173*	*44,174*
Pismo Beach	*San Luis Obispo*	*13 miles ESE*	*4,043*	*5,364*	*7,699*	*8,551*
Grover City	*San Luis Obispo*	*14 miles ESE*	*5,939*	*8,827*	*11,656*	*13,067*
Oceano	*San Luis Obispo*	*15 miles ESE*	*2,564*	*4,478*	*6,169*	*7,260*
Arroyo Grande	*San Luis Obispo*	*17 miles ESE*	*7,454*	*10,350*	*14,378*	*15,851*
Cayucos	*San Luis Obispo*	*17 miles N*	*1,772*	*2,301*	*2,960*	*2,943*
Atascadero	*San Luis Obispo*	*21 miles NNE*	*10,290*	*15,930*	*23,138*	*26,411*
Guadalupe	*Santa Barbara*	*23 miles SE*	*3,145*	*3,629*	*5,479*	*5,659*
Nipomo	*San Luis Obispo*	*24 miles ESE*	*3,642*	*5,247*	*7,109*	*12,626*
Cambria	*San Luis Obispo*	*28 miles NNW*	*1,716*	*3,061*	*5,382*	*6,232*
Santa Maria	*Santa Barbara*	*29 miles SE*	*39,878*	*39,685*	*61,284*	*77,423*
Paso Robles	*San Luis Obispo*	*30 miles NNE*	*7,168*	*9,163*	*18,583*	*24,297*
Orcutt	*Santa Barbara*	*33 miles SE*	*8,500*	*1,469*	*----*	*28,830*
Vandenberg	*Santa Barbara*	*35 miles SSE*	*13,193*	*13,975*	*----*	*11,953*
Lompoc	*Santa Barbara*	*45 miles SSE*	*25,284*	*26,267*	*37,649*	*41,103*
		Total	*180,793*	*203,996*	*280,898*	*351,081*

TABLE 2.1-4
HISTORICAL INFORMATION BELOW IS SHOWN IN ITALICS
TRANSIENT POPULATION AT RECREATION AREAS
WITHIN 50 MILES OF DCPP SITE

Names	*Visitor - Days*
State Parks (a)	
Cayucos State Beach	*698,000*
Hearst San Simeon State Historical Monument	*795,000*
Montana de Oro State Park	*683,000*
Morro Bay State Park	*1,129,000*
Morro Strand State Beach	*129,000*
Pismo State Beach	*1,297,000*
San Simeon State Beach	*696,000*
W. R. Hearst Memorial State Beach	*213,000*
County and Local Parks (b)	
Atascadero Lake	*300,000*
Avila Beach	*800,000*
Cambria	*15,000*
Cayucos Beach	*918,000*
Cuesta	*67,000*
Lake Nacimiento	*345,000*
Lopez Recreation Area	*379,000*
Los Alamos Park	*45,000*
Miquelito Park	*36,000*
Nipomo	*168,000*
Ocean Park	*105,000*
Oceano	*95,000*
Rancho Guadalupe Dunes Park	*48,000*
San Antonio Reservoir	*361,000*
San Miguel	*54,000*
Santa Margarita Lake	*169,000*
Shamel	*130,000*
Templeton	*99,000*
Waller	*450,000*

Name	*Visitor - Days*
Los Padres National Forest [c]	
Agua Escondido	*700*
American Canyon	*800*
Balm of Gilead	*200*
Brookshire Springs	*1,600*
Buckeye	*200*
Cerro Alto	*15,600*
French	*200*
Frus	*700*
Hi Mountain	*4,800*
Horseshoe Springs	*1,400*
Indians	*600*
Kerry Canyon	*300*
La Panza	*4,400*
Lazy Camp	*500*
Miranda Pine	*2,300*
Navajo	*2,800*
Pine Flat	*300*
Pine Springs	*400*
Plowshare Springs	*300*
Queen Bee	*2,200*
Stony Creek	*1,100*
Sulphur Pot	*1,000*
Upper Lopez	*600*
Wagon Flat	*2,200*

(a) California Department of Parks and Recreation (July 1998 through June 1999).
(b) County Park Departments.
Monterey County (July 1, 1998 through June 30, 1999).
San Luis Obispo and Santa Barbara Counties (July 1998 through June 1999).
(c) Los Padres National Forest (July 1, 1971 through June 30, 1972. Current data is no longer compiled.).

TABLE 2.1-5

HISTORICAL INFORMATION BELOW IS SHOWN IN ITALICS

1985 LAND USE CENSUS
DISTANCES IN MILES FROM THE UNIT 1 CENTERLINE
TO THE NEAREST MILK ANIMAL, RESIDENCE, VEGETABLE GARDEN

22-1/2 Degree[a] Radial Sector	*Nearest Milk Animal*	*Nearest Residence km (mi)*	*Residence Azimuth degree*	*Nearest Vegetable Garden*
NW	*None*	*5.95 (3.7)*	*326*	*None*
NNW	*None*	*2.50 (1.55)*	*333*	*None*
N	*None*	*7.15 (4.44)*	*008*	*None*
NNE	*None*	*5.30 (3.3)*	*018.5*	*None*
NE	*None*	*8.15 (5.06)*	*037*	*None*
ENE	*None*	*7.15 (4.44)*	*062.5*	*None*
E	*None*	*7.25 (4.5)*	*096.5*	*None*
ESE	*None*	*None*	*--*	*2*
SE	*None*	*None*	*--*	*None*

(a) *Sectors not shown contain no land beyond the site boundary, other than islets not used for the purposes indicated in this table.*

TABLE 2.3-1
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
PERSISTENCE OF CALM AT DIABLO CANYON EXPRESSED AS PERCENTAGE OF TOTAL HOURLY OBSERVATIONS FOR WHICH THE MEAN HOURLY WIND SPEED WAS LESS THAN 1 MILE PER HOUR FOR MORE THAN 1 TO 10 HOURS

	Station E	
Consecutive Hours	*25-foot level*	*250-foot level*
1	*5.9*	*4.9*
2	*3.8*	*3.1*
3	*2.5*	*2.0*
4	*1.8*	*1.2*
5	*1.0*	*0.7*
6	*0.7*	*0.4*
7	*0.5*	*0.3*
8	*0.3*	*0.2*
9	*0.2*	*0.2*
10	*0.1*	*0.1*

TABLE 2.3-2
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
NORMALIZED ANNUAL GROUND LEVEL CONCENTRATIONS DOWNWIND FROM DCPP SITE GROUND RELEASE

Ground Level Release 10-meter wind data and Temperature Gradient (76-10 meters). For calculations with wind speeds below 1.5 meters per second stability is based on Temperature Gradient only and either building wake or wind meander is considered - with wind speed above 1.5 meters per second stability is based on measured Sigma A and Temperature Gradient with building wake only considered. Data Period May 1973 through April 1975.

Midpoint of Directions from Plant for each 22.5 degree Sector

Dilution Factors $\chi/Q \times 10^{-8}$ sec m^{-3}

Downwind Distance (km)	NW	NNW	N	NNE	NE	ENE	E	ESE	SE
0.8	387.15	220.81	95.726	57.503	61.687	49.292	89.447	355.48	978.67
5.0	24.738	12.860	5.6009	3.2347	3.8566	2.9593	5.0400	21.388	68.029
10.0	9.2115	4.6658	2.0693	1.1535	1.4426	1.0949	1.8138	7.6144	25.269
15.0	5.3897	2.6719	1.2018	0.65477	0.84233	0.63167	1.0391	4.3081	14.651
30.0	2.3889	1.1375	0.52497	0.27935	0.36768	0.27011	0.45145	1.8261	6.3086
40.0	1.7484	0.82010	0.38341	0.20223	0.26689	0.19464	0.33046	1.3223	4.5669
50.0	1.3803	0.64135	0.30252	0.15868	0.20947	0.15208	0.26155	1.0377	3.5778
80.0	0.84914	0.38822	0.18632	0.09654	0.12747	0.09173	0.16222	0.63113	2.1699

TABLE 2.3-3
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
MONTHLY MIXING HEIGHTS[a] AT DCPP SITE

Month	*Morning*	*Hours of Day[b]*	*Afternoon*	*Hours of Day[b]*	*Evening*	*Hours of Day[b]*	*Night*	*Hours of Day[b]*
January	*500*	*9-11*	*600*	*12-16*	*700*	*17-19*	*500*	*20-8*
February	*600*	*9-11*	*600*	*12-17*	*800*	*18-20*	*600*	*21-8*
March	*700*	*8-10*	*800*	*11-17*	*1,000*	*18-20*	*800*	*21-7*
April	*600*	*7-10*	*700*	*11-18*	*800*	*19-21*	*700*	*22-6*
May	*500*	*7-11*	*600*	*12-20*	*700*	*21-23*	*600*	*24-6*
June	*500*	*7-10*	*500*	*11-20*	*600*	*21-23*	*500*	*24-6*
July	*500*	*7-9*	*500*	*10-20*	*700*	*21-23*	*500*	*24-6*
August	*500*	*7-9*	*600*	*10-20*	*700*	*21-23*	*600*	*24-6*
September	*500*	*8-10*	*600*	*11-19*	*800*	*20-22*	*600*	*23-7*
October	*500*	*8-10*	*600*	*11-19*	*800*	*20-22*	*500*	*23-7*
November	*500*	*8-10*	*600*	*11-17*	*700*	*18-20*	*500*	*21-7*
December	*500*	*9-11*	*600*	*12-17*	*700*	*18-20*	*500*	*21-8*

(a) Mixing heights (in meters) derived from seasonal estimates given by Holzworth[6]

(b) Definition of morning, afternoon, evening, and nighttime hours. Hours are inclusive in local time.

TABLE 2.3-4
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
ESTIMATES OF RELATIVE CONCENTRATIONS (χ/Q sec m^{-3}) AT SPECIFIED LOCATIONS DOWNWIND OF DCPP SITE[a, b]

Direction From Site	*Distance, mi*	*χ/Q (σ_r - ΔT)*
NW	*0.5*	*3.87×10^{-6}*
326	*3.6*	*1.71×10^{-7}*
NW	*5.0*	*1.25×10^{-7}*
NNW	*0.5*	*2.21×10^{-6}*
330	*1.75*	*4.28×10^{-7}*
NNW	*5.0*	*6.37×10^{-8}*
N	*0.5*	*9.57×10^{-7}*
N	*5.0*	*2.81×10^{-8}*
NNE	*0.5*	*5.75×10^{-7}*
NNE	*3.3*	*2.93×10^{-8}*
NNE	*5.0*	*1.58×10^{-8}*
NE	*0.5*	*6.17×10^{-7}*
035	*4.9*	*1.64×10^{-8}*
NE	*5.0*	*1.95×10^{-8}*
ENE	*0.7*	*2.83×10^{-7}*
ENE	*4.7*	*1.62×10^{-8}*
ENE	*5.0*	*1.49×10^{-8}*
E	*1.0*	*2.86×10^{-7}*
E	*3.8*	*3.70×10^{-8}*
E	*5.0*	*2.48×10^{-8}*
ESE	*1.0*	*1.21×10^{-6}*
ESE	*5.0*	*1.05×10^{-7}*
SE	*1.1*	*3.10×10^{-6}*
124	*2.0*	*9.42×10^{-7}*
SE	*5.0*	*3.43×10^{-7}*

(a) Based on the models described in Reference 21 and used for Table 2.3-2 (January 1978, Amendment 57) of the DCPP FSAR.

(b) Estimates Involve Wind Data From the 10 Meter Level and Temperature Gradient From the 76m - 10m Levels.

TABLE 2.3-6
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE PRECIPITATION DATA

Mean Monthly and Annual Precipitation for Indicated Period of Record
Precipitation in Inches -- Record in Years

													Annual			Mean No. Days [(a)] Precipitation Greater Than 0.09 and 0.49	
STATIONS	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	MEAN	MAX	MIN		
Morro Bay	2.94	2.72	1.86	1.46	0.22	0.05	0.06	0.01	0.21	0.72	2.65	2.50	15.40	24.12	6.60	31	(10)
Years	14	14	14	14	14	14	13	13	13	12	13	13					
Pismo Beach	3.79	3.05	2.10	1.92	0.34	0.04	0.06	0.01	0.20	0.46	1.82	2.65	16.44	27.45	6.75	28	(11)
Years	11	11	11	11	11	11	12	12	12	12	12	12					
San Luis Obispo	4.72	4.12	3.34	1.60	0.51	0.11	0.01	0.02	0.20	0.82	1.72	3.94	21.11	48.76	6.93	30	(14)
Years	91	91	91	91	91	91	92	92	92	92	92	92					
Santa Maria	2.81	2.50	2.60	1.05	0.39	0.08	0.02	0.02	0.20	0.73	1.18	2.32	13.90	28.46	4.40	25	(7)
Years	69	69	69	68	68	68	68	69	69	69	69	69					
Santa Margarita	6.04	5.81	5.27	3.25	0.73	0.05	0.06	0.01	0.22	1.03	3.11	6.47	32.05	49.55	7.67	34	(21)
Years	20	20	20	20	21	21	21	21	20	21	21	21					
Camp San Luis	3.91	3.48	3.29	1.95	0.45	0.05	0.03	0.01	0.13	0.59	2.02	3.62	19.53	29.89	10.29	32	(13)
Years	18	18	18	18	18	18	17	18	18	18	18	19					

(a) Values shown in parentheses are mean number of days with precipitation amounts greater than 0.49.

TABLE 2.3-7
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE TEMPERATURE DATA

Coastal Stations Morro Bay and Pismo Beach. Values Shown in Parentheses are Pismo Beach. Period of Record: Morro Bay 14 years; Pismo Beach 12 years
Temperature in °F

Months	Mean Temperature		Mean Maximum		Mean Minimum		Extreme Maximum		Extreme Minimum		Mean No. of Days Above 90°F		Mean No. of Days Below 32°F	
January	52.6	(51.7)	62.0	(61.3)	43.2	(42.0)	82	(80)	30	(24)	0	(0)	1	(2)
February	53.8	(53.7)	63.0	(64.0)	44.6	(43.4)	82	(82)	30	(29)	0	(0)	0	(1)
March	53.1	(54.8)	62.5	(65.5)	43.6	(44.0)	85	(88)	32	(30)	0	(0)	0	(1)
April	54.1	(56.1)	63.5	(66.1)	44.7	(46.1)	93	(90)	33	(32)	0	(0)	0	(0)
May	55.1	(57.3)	62.9	(67.5)	47.3	(47.1)	98	(89)	33	(36)	0	(1)	0	(0)
June	57.5	(59.8)	64.4	(69.8)	50.5	(49.7)	98	(96)	40	(40)	0	(0)	0	(0)
July	58.2	(60.5)	65.1	(68.7)	51.3	(52.3)	89	(104)	34	(38)	0	(0)	0	(0)
August	55.5	(60.6)	66.7	(68.5)	52.7	(52.7)	94	(102)	45	(43)	0	(0)	0	(0)
September	60.7	(62.1)	68.8	(71.8)	52.5	(52.3)	101	(99)	43	(41)	1	(1)	0	(0)
October	60.8	(60.6)	70.5	(71.3)	51.0	(49.8)	99	(95)	38	(32)	1	(1)	0	(0)
November	57.0	(58.3)	66.0	(69.4)	47.8	(47.1)	92	(91)	32	(29)	0	(0)	0	(0)
December	52.4	(54.6)	61.6	(65.3)	43.2	(43.9)	79	(92)	29	(28)	0	(0)	1	(1)
Annual	55.9	(57.5)	64.8	(67.4)	47.7	(47.5)	101	(104)	29	(24)	2	(3)	2	(5)

Inland Stations San Luis Obispo and Santa Maria. Values Shown in Parenthesis are Santa Maria. Period of Record: San Luis Obispo 66 years; Santa Maria 17 years.

Months	Mean Temperature		Mean Maximum		Mean Minimum		Extreme Maximum		Extreme Minimum		Mean No. of Days Above 90°F		Mean No. of Days Below 32°F	
January	51.8	(50.2)	62.1	(62.3)	41.5	(38.2)	84	(82)	20	(21)	0	(0)	1	(4)
February	53.6	(51.6)	63.5	(63.3)	43.5	(39.9)	89	(87)	25	(24)	0	(0)	1	(4)
March	54.9	(53.0)	65.2	(64.3)	44.8	(41.6)	93	(88)	28	(29)	0	(0)	0	(1)
April	56.7	(55.3)	67.6	(66.3)	46.0	(44.3)	97	(97)	30	(31)	0	(0)	0	(0)
May	58.6	(57.2)	69.3	(67.7)	47.8	(46.8)	100	(93)	34	(34)	0	(0)	0	(0)
June	62.0	(59.8)	73.6	(70.2)	50.2	(49.4)	110	(95)	37	(36)	1	(0)	0	(0)
July	64.6	(62.0)	76.9	(71.6)	52.0	(52.4)	106	(104)	42	(43)	2	(0)	0	(0)
August	64.7	(61.9)	77.0	(71.5)	52.4	(52.2)	107	(93)	40	(43)	1	(0)	0	(0)
September	64.9	(62.7)	77.8	(74.1)	52.0	(51.3)	110	(102)	38	(36)	4	(1)	0	(0)
October	62.5	(60.0)	75.3	(72.6)	49.8	(47.4)	103	(103)	35	(30)	2	(1)	0	(0)
November	58.3	(55.8)	70.7	(69.7)	45.9	(42.0)	96	(93)	24	(25)	0	(0)	0	(1)
December	53.5	(52.2)	64.4	(64.8)	42.8	(39.6)	92	(90)	24	(26)	0	(0)	0	(3)
Annual	58.8	(56.8)	70.3	(68.2)	47.4	(45.4)	110	(104)	20	(21)	10	(2)	2	(13)

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TABLE 2.3-8

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PERCENTAGE FREQUENCY OF OCCURRENCE
DIRECTIONS BY SPEED GROUPS

23273	*Santa Maria, California WBAS*	*All*	
Station	*Station Name*	*Month*	*Class*

Jan 1948 - Jun 1958
Years

Speed Dir.	*1-3 Knots*	*4-10 Knots*	*11-21 Knots*	*22-27 Knots*	*28-40 Knots*	*41 Knots and Over*	*Total 4 Knots and Over*	*Total No. of Observations*		*Sum of Speed*	*Mean Wind Speed, Knots*
								%	*Obs*		
N	*0.5*	*1.1*	*0.7*				*1.8*	*2.2*	*2095*	*17809*	*8.5*
NNE	*0.3*	*1.0*	*0.9*	*0.1*			*2.0*	*2.3*	*2160*	*21637*	*10.0*
NE	*0.8*	*1.2*	*0.5*	*0.1*			*1.8*	*2.6*	*2412*	*18236*	*7.6*
ENE	*0.5*	*1.2*	*0.1*				*1.3*	*1.8*	*1637*	*8937*	*5.5*
E	*1.2*	*5.2*	*0.2*				*5.5*	*6.7*	*6230*	*37649*	*6.0*
ESE	*0.8*	*2.9*	*0.3*				*3.3*	*4.1*	*3814*	*24253*	*6.4*
SE	*0.8*	*2.9*	*0.8*	*0.1*			*3.8*	*4.6*	*4295*	*33136*	*7.7*
SSE	*0.4*	*0.9*	*0.5*				*1.4*	*1.8*	*1644*	*13935*	*8.5*
S	*0.5*	*0.8*	*0.2*				*1.0*	*1.6*	*1455*	*9343*	*6.4*
SSW	*0.4*	*0.7*	*0.2*				*0.9*	*1.3*	*1205*	*7848*	*6.5*
SW	*0.9*	*2.0*	*0.3*				*2.4*	*3.3*	*3119*	*18690*	*6.0*
WSW	*0.9*	*3.3*	*0.9*				*4.2*	*5.1*	*4737*	*34900*	*7.4*
W	*1.6*	*9.4*	*4.4*	*0.1*			*13.8*	*15.5*	*14446*	*127257*	*8.8*
WNW	*1.2*	*9.8*	*5.4*	*0.1*			*15.3*	*16.5*	*15458*	*142383*	*9.2*
NW	*0.9*	*4.5*	*1.2*				*5.8*	*6.7*	*6221*	*46750*	*7.5*
NNW	*0.3*	*1.0*	*0.2*				*1.1*	*1.5*	*1375*	*9091*	*6.6*
CALM								*21.8*	*20397*		
TOTALS	*12.0*	*47.9*	*16.8*	*0.6*	*0.1*		*65.3*	*100.0*	*92700*	*571854*	*6.1*

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TABLE 2.3-9

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PERCENTAGE FREQUENCY OF OCCURRENCE
DIRECTIONS BY SPEED GROUPS

23273 — Station
Santa Maria, California WBAS — Station Name
Jan — Month
Class

48 49 50 51 52 53 54 55 56 57 58
Years

Speed Dir.	1-3 Knots	4-10 Knots	11-21 Knots	22-27 Knots	28-40 Knots	41 Knots and Over	Total 4 Knots and Over	Total No. of Observations %	Total No. of Observations Obs.	Sum of Speed	Mean Wind Speed, Knots
N	0.4	1.9	1.4	0.1			3.3	3.7	300	2892	9.6
NNE	0.3	2.2	1.6	0.2			4.0	4.3	350	3671	10.5
NE	0.9	2.3	1.2	0.2			3.8	4.7	383	3408	8.9
ENE	0.7	2.3	0.1				2.4	3.1	254	1476	5.8
E	1.7	10.5	0.5				11.0	12.7	1042	6790	6.5
ESE	1.4	5.6	0.9				6.5	7.9	644	4443	6.9
SE	1.0	6.1	1.8	0.1			8.1	9.1	743	6108	8.2
SSE	0.4	1.3	1.0	0.1			2.4	2.8	229	2209	9.6
S	0.4	1.0	0.4				1.4	1.8	148	1070	7.2
SSW	0.3	0.7	0.4				1.1	1.4	115	964	8.4
SW	0.7	1.4	0.3				1.8	2.5	201	1308	6.5
WSW	0.5	1.6	0.4				1.9	2.4	196	1327	6.8
W	1.1	6.0	1.6				7.6	8.7	712	5493	7.7
WNW	0.7	6.7	1.8				8.5	9.3	757	6090	8.0
NW	0.6	4.0	0.7				4.7	5.4	439	3165	7.2
NNW	0.2	1.5	0.3				1.8	2.0	164	1207	7.4
CALM								18.3	1501		
TOTALS	11.4	54.9	14.5	0.8			70.2	100.0	8178	51621	6.3

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TABLE 2.3-10

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PERCENTAGE FREQUENCY OF OCCURRENCE
DIRECTIONS BY SPEED GROUPS

23273	*Santa Maria, California WBAS*	*Feb*	
Station	*Station Name*	*Month*	*Class*

48 49 50 51 52 53 54 55 56 57 58

Years

Speed Dir.	*1-3 Knots*	*4-10 Knots*	*11-21 Knots*	*22-27 Knots*	*28-40 Knots*	*41 Knots and Over*	*Total 4 Knots and Over*	*Total No. of Observations*		*Sum of Speed*	*Mean Wind Speed, Knots*
								%	*Obs.*		
N	*0.6*	*2.1*	*1.6*	*0.1*			*3.8*	*4.4*	*325*	*3152*	*9.7*
NNE	*0.4*	*1.4*	*1.5*	*0.2*			*3.1*	*3.5*	*259*	*2822*	*10.9*
NE	*0.9*	*2.2*	*1.0*				*3.3*	*4.2*	*312*	*2458*	*7.9*
ENE	*0.7*	*2.4*					*2.5*	*3.2*	*240*	*1419*	*5.9*
E	*1.3*	*9.6*	*0.5*				*10.2*	*11.5*	*857*	*5626*	*6.6*
ESE	*1.2*	*4.6*	*0.4*	*0.1*			*5.1*	*6.3*	*472*	*3078*	*6.5*
SE	*1.0*	*4.5*	*1.5*	*0.1*			*6.0*	*7.0*	*524*	*4300*	*8.2*
SSE	*0.3*	*1.1*	*1.0*	*0.1*			*2.1*	*2.5*	*183*	*1758*	*9.6*
S	*0.5*	*1.0*	*0.5*				*1.6*	*2.0*	*152*	*1140*	*7.5*
SSW	*0.3*	*0.9*	*0.4*				*1.2*	*1.5*	*112*	*0841*	*7.5*
SW	*0.5*	*1.7*	*0.4*				*2.2*	*2.7*	*201*	*1393*	*6.9*
WSW	*0.4*	*2.5*	*0.6*				*3.1*	*3.5*	*260*	*1951*	*7.5*
W	*0.7*	*6.9*	*2.9*	*0.1*			*9.8*	*10.5*	*787*	*6984*	*8.9*
WNW	*0.7*	*9.8*					*10.5*	*11.3*	*841*	*7341*	*8.7*
NW	*0.8*	*4.5*	*1.0*				*5.5*	*6.3*	*470*	*3511*	*7.5*
NWW	*0.3*	*5.5*	*6.3*				*2.0*	*2.3*	*170*	*1332*	*7.8*
CALM								*17.4*	*1297*		
TOTALS	*10.6*	*54.4*	*17.2*	*0.5*			*72.0*	*100.0*	*7462*	*49106*	*6.6*

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TABLE 2.3-11

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PERCENTAGE FREQUENCY OF OCCURRENCE
DIRECTIONS BY SPEED GROUPS

23273	*Santa Maria, California WBAS*	*Mar*	
Station	*Station Name*	*Month*	*Class*

48 49 50 51 52 53 54 55 56 57 58

Years

Speed Dir.	*1-3 Knots*	*4-10 Knots*	*11-21 Knots*	*22-27 Knots*	*28-40 Knots*	*41 Knots and Over*	*Total 4 Knots and Over*	*Total No. of Observations %*	*Total No. of Observations Obs.*	*Sum of Speed*	*Mean Wind Speed, Knots*
N	*0.5*	*1.5*	*0.9*				*2.4*	*2.9*	*239*	*2069*	*8.7*
NNE	*0.4*	*1.4*	*1.6*	*0.1*			*3.0*	*3.4*	*281*	*2894*	*10.3*
NE	*0.8*	*1.4*	*0.7*	*0.1*			*2.2*	*3.0*	*249*	*2015*	*8.1*
ENE	*0.5*	*1.4*	*0.0*				*1.4*	*1.9*	*153*	*807*	*5.3*
E	*1.0*	*6.2*	*0.2*				*6.4*	*7.4*	*605*	*3667*	*6.1*
ESE	*0.8*	*4.2*	*0.5*				*4.7*	*5.5*	*448*	*3059*	*6.8*
SE	*0.9*	*3.8*	*1.5*	*0.2*	*0.1*		*5.5*	*6.4*	*524*	*4696*	*9.0*
SSE	*0.6*	*1.2*	*0.9*	*0.1*	*0.1*		*2.4*	*3.0*	*242*	*2502*	*10.3*
S	*0.4*	*0.8*	*0.4*				*1.3*	*1.7*	*140*	*1188*	*8.5*
SSW	*0.4*	*0.8*	*0.3*	*0.1*			*1.2*	*1.6*	*129*	*1029*	*8.0*
SW	*0.8*	*1.9*	*0.6*				*2.5*	*3.3*	*266*	*1898*	*7.1*
WSW	*0.4*	*2.9*	*1.0*				*4.0*	*4.4*	*359*	*2917*	*8.1*
W	*1.1*	*6.1*	*4.8*	*0.2*			*11.2*	*12.2*	*999*	*10067*	*10.1*
WNW	*0.9*	*8.6*	*7.4*	*0.1*			*16.1*	*17.0*	*1391*	*14436*	*10.3*
NW	*0.8*	*5.3*	*1.8*				*7.1*	*7.9*	*645*	*5282*	*8.2*
NNW	*0.3*	*1.3*	*0.3*				*1.6*	*1.8*	*148*	*1078*	*7.3*
CALM								*16.7*	*1365*		
TOTALS	*10.4*	*48.7*	*22.9*	*1.0*	*0.3*		*73.0*	*100.0*	*8183*	*59504*	*7.3*

Air Weather Service - Directorate of Climatology
Data Control Division

Surface Winds

TABLE 2.3-12

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PERCENTAGE FREQUENCY OF OCCURRENCE
DIRECTIONS BY SPEED GROUPS

23273	*Santa Maria, California WBAS*	*Apr*	
Station	*Station Name*	*Month*	*Class*

48 49 50 51 52 53 54 55 56 57 58

Years

Speed Dir.	*1-3 Knots*	*4-10 Knots*	*11-21 Knots*	*22-27 Knots*	*28-40 Knots*	*41 Knots and Over*	*Total 4 Knots and Over*	*Total No. of Observations %*	*Total No. of Observations Obs.*	*Sum of Speed*	*Mean Wind Speed, Knots*
N	*0.4*	*0.9*	*0.4*				*1.4*	*1.7*	*138*	*1061*	*7.7*
NNE	*0.2*	*0.7*	*0.7*				*1.5*	*1.7*	*133*	*1322*	*9.9*
NE	*0.9*	*0.9*	*0.2*				*1.1*	*2.0*	*156*	*822*	*5.3*
ENE	*0.4*	*0.4*	*0.0*				*0.4*	*0.9*	*68*	*282*	*4.1*
E	*1.1*	*3.3*	*0.1*				*3.4*	*4.5*	*356*	*1814*	*5.1*
ESE	*0.6*	*2.5*	*0.2*				*2.7*	*3.4*	*266*	*1564*	*5.9*
SE	*0.8*	*3.2*	*1.1*	*0.1*			*4.4*	*5.2*	*409*	*3269*	*8.0*
SSE	*0.5*	*1.2*	*0.6*				*1.9*	*2.4*	*188*	*1543*	*8.2*
S	*0.5*	*1.1*	*0.4*				*1.5*	*1.9*	*154*	*1118*	*7.3*
SSW	*0.5*	*0.8*	*0.3*				*1.1*	*1.6*	*123*	*870*	*7.1*
SW	*0.8*	*2.8*	*0.9*				*3.7*	*4.4*	*352*	*2651*	*7.5*
WSW	*0.7*	*3.2*	*1.3*				*4.5*	*5.1*	*408*	*3280*	*8.0*
W	*1.7*	*9.0*	*5.5*	*0.2*			*14.7*	*16.3*	*1294*	*12182*	*9.4*
WNW	*1.3*	*10.5*	*7.9*	*0.2*			*18.7*	*20.0*	*1583*	*15873*	*10.0*
NW	*1.0*	*5.1*	*1.3*				*6.4*	*7.4*	*587*	*4502*	*7.7*
NNW	*0.3*	*1.1*	*0.1*				*1.2*	*1.5*	*117*	*731*	*6.2*
CALM								*20.0*	*1588*		
TOTALS	*11.4*	*46.6*	*21.0*	*0.7*			*68.6*	*100.0*	*7920*	*52884*	*6.7*

Air Weather Service - Directorate of Climatology
Data Control Division

Surface Winds

TABLE 2.3-13

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PERCENTAGE FREQUENCY OF OCCURRENCE
DIRECTIONS BY SPEED GROUPS

23273	*Santa Maria, California WBAS*	*May*	
Station	*Station Name*	*Month*	*Class*

48 49 50 51 52 53 54 55 56 57 58

Years

Speed Dir.	*1-3 Knots*	*4-10 Knots*	*11-21 Knots*	*22-27 Knots*	*28-40 Knots*	*41 Knots and Over*	*Total 4 Knots and Over*	*Total No. of Observations*		*Sum of Speed*	*Mean Wind Speed, Knots*
								%	*Obs.*		
N	*0.4*	*0.5*	*0.3*				*0.8*	*1.2*	*102*	*763*	*7.5*
NNE	*0.2*	*0.5*	*0.2*				*0.7*	*0.9*	*75*	*509*	*6.8*
NE	*0.5*	*0.7*	*0.2*				*0.9*	*1.3*	*107*	*682*	*6.4*
ENE	*0.4*	*0.6*					*0.7*	*1.1*	*87*	*421*	*4.8*
E	*0.7*	*2.2*					*2.2*	*3.0*	*244*	*1298*	*5.3*
ESE	*0.7*	*1.4*	*0.1*				*1.4*	*2.1*	*173*	*898*	*5.2*
SE	*0.7*	*1.6*	*0.1*				*1.7*	*2.5*	*201*	*1128*	*5.6*
SSE	*0.3*	*0.6*	*0.1*				*0.7*	*1.0*	*83*	*508*	*6.1*
S	*0.7*	*0.9*	*0.2*				*1.1*	*1.8*	*146*	*850*	*5.8*
SSW	*0.5*	*1.1*	*0.2*				*1.2*	*1.7*	*139*	*820*	*5.9*
SW	*1.0*	*2.8*	*0.4*				*3.3*	*4.3*	*352*	*2071*	*5.9*
WSW	*1.1*	*4.4*	*2.0*				*6.5*	*7.5*	*615*	*5056*	*8.2*
W	*1.6*	*10.7*	*7.7*	*0.3*			*18.7*	*20.3*	*1664*	*16546*	*9.9*
WNW	*1.3*	*11.7*	*7.9*	*0.2*			*19.9*	*21.1*	*1730*	*16949*	*9.8*
NW	*1.0*	*4.3*	*1.8*				*6.1*	*7.1*	*581*	*4684*	*8.1*
NNW	*0.4*	*0.7*	*0.1*				*0.8*	*1.2*	*95*	*511*	*5.4*
CALM								*21.9*	*1789*		
TOTALS	*11.5*	*44.6*	*21.5*	*0.6*			*66.7*	*100.0*	*8183*	*53694*	*6.6*

Air Weather Service - Directorate of Climatology
Data Control Division

Surface Winds

TABLE 2.3-14

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PERCENTAGE FREQUENCY OF OCCURRENCE
DIRECTIONS BY SPEED GROUPS

23273	*Santa Maria, California WBAS*	*June*	
Station	*Station Name*	*Month*	*Class*

48 49 50 51 52 53 54 55 56 57 58

Years

Speed Dir.	*1-3 Knots*	*4-10 Knots*	*11-21 Knots*	*22-27 Knots*	*28-40 Knots*	*41 Knots and Over*	*Total 4 Knots and Over*	*Total No. of Observations*		*Sum of Speed*	*Mean Wind Speed, Knots*
								%	*Obs.*		
N	*0.4*	*0.5*	*0.1*				*0.5*	*0.9*	*73*	*361*	*4.9*
NNE	*0.2*	*0.2*	*0.2*				*0.4*	*0.6*	*49*	*378*	*7.7*
NE	*0.5*	*0.4*	*0.1*				*0.5*	*1.0*	*83*	*455*	*5.5*
ENE	*0.3*	*0.2*					*0.2*	*0.5*	*43*	*160*	*3.7*
E	*1.0*	*1.3*					*1.4*	*2.3*	*185*	*780*	*4.2*
ESE	*0.4*	*0.6*					*0.6*	*1.0*	*78*	*326*	*4.2*
SE	*0.6*	*1.1*					*1.1*	*1.7*	*133*	*610*	*4.6*
SSE	*0.3*	*0.4*					*0.4*	*0.6*	*51*	*241*	*4.7*
S	*0.5*	*0.6*					*0.7*	*1.1*	*89*	*414*	*4.7*
SSW	*0.4*	*0.7*	*0.1*				*0.9*	*1.2*	*97*	*596*	*6.1*
SW	*1.4*	*2.7*	*0.4*				*3.1*	*4.5*	*357*	*2029*	*5.7*
WSW	*0.9*	*3.9*	*1.8*				*5.8*	*6.7*	*528*	*4395*	*8.3*
W	*2.1*	*12.3*	*8.0*	*0.1*			*20.4*	*22.5*	*1782*	*16856*	*9.5*
WNW	*1.7*	*13.5*	*10.0*	*0.2*			*23.6*	*25.3*	*2004*	*19743*	*9.9*
NW	*0.9*	*4.9*	*1.8*				*6.7*	*7.6*	*605*	*4861*	*8.0*
NNW	*0.3*	*0.3*	*0.1*				*0.4*	*0.7*	*52*	*290*	*5.6*
CALM								*21.6*	*1710*		
TOTALS	*11.8*	*43.9*	*22.6*	*0.3*			*66.6*	*100.0*	*7919*	*52495*	*6.6*

Air Weather Service - Directorate of Climatology
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Surface Winds

TABLE 2.3-15

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PERCENTAGE FREQUENCY OF OCCURRENCE
DIRECTIONS BY SPEED GROUPS

23273	*Santa Maria, California WBAS*	*July*	
Station	*Station Name*	*Month*	*Class*

48 49 50 51 52 53 54 55 56 57 58

Years

Speed Dir.	*1-3 Knots*	*4-10 Knots*	*11-21 Knots*	*22-27 Knots*	*28-40 Knots*	*41 Knots and Over*	*Total 4 Knots and Over*	*Total No. of Observations*		*Sum of Speed*	*Mean Wind Speed, Knots*
								%	*Obs.*		
N	*0.5*	*0.6*					*0.6*	*1.1*	*89*	*352*	*4.0*
NNE	*0.3*	*0.4*					*0.4*	*0.7*	*58*	*246*	*4.2*
NE	*0.4*	*0.5*					*0.5*	*0.9*	*74*	*277*	*3.7*
ENE	*0.3*	*0.2*					*0.2*	*0.5*	*40*	*146*	*3.7*
E	*0.4*	*0.7*					*0.7*	*1.2*	*96*	*403*	*4.2*
ESE	*0.3*	*0.3*					*0.3*	*0.6*	*52*	*196*	*3.8*
SE	*0.3*	*0.7*					*0.7*	*1.0*	*84*	*370*	*4.4*
SSE	*0.1*	*0.3*					*0.3*	*0.5*	*38*	*175*	*4.6*
S	*0.5*	*0.5*					*0.5*	*1.0*	*83*	*314*	*3.8*
SSW	*0.5*	*0.5*					*0.5*	*1.0*	*82*	*334*	*4.1*
SW	*1.3*	*2.1*	*0.1*				*2.2*	*3.5*	*285*	*1410*	*4.9*
WSW	*1.6*	*4.3*	*0.6*				*4.9*	*6.5*	*533*	*3422*	*6.4*
W	*2.7*	*14.5*	*5.6*				*20.1*	*22.8*	*1863*	*15557*	*8.4*
WNW	*2.2*	*14.4*	*6.7*				*21.1*	*23.3*	*1906*	*16377*	*8.6*
NW	*1.2*	*5.2*	*1.5*				*6.7*	*7.9*	*646*	*4697*	*7.3*
NNW	*0.4*	*0.5*					*0.5*	*0.9*	*76*	*313*	*4.1*
CALM								*26.6*	*2177*		
TOTALS	*12.9*	*45.8*	*14.6*				*60.4*	*100.0*	*8182*	*44589*	*5.4*

Air Weather Service - Directorate of Climatology
Data Control Division

Surface Winds

TABLE 2.3-16

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PERCENTAGE FREQUENCY OF OCCURRENCE
DIRECTIONS BY SPEED GROUPS

23273	*Santa Maria, California WBAS*	*Aug*	
Station	*Station Name*	*Month*	*Class*

48 49 50 51 52 53 54 55 56 57

Years

Speed Dir.	*1-3 Knots*	*4-10 Knots*	*11-21 Knots*	*22-27 Knots*	*28-40 Knots*	*41 Knots and Over*	*Total 4 Knots and Over*	*Total No. of Observations %*	*Total No. of Observations Obs.*	*Sum of Speed*	*Mean Wind Speed, Knots*
N	*0.5*	*0.6*					*0.6*	*1.1*	*79*	*311*	*3.9*
NNE	*0.2*	*0.2*					*0.2*	*0.5*	*36*	*140*	*3.9*
NE	*0.5*	*0.4*					*0.4*	*0.9*	*64*	*228*	*3.6*
ENE	*0.3*	*0.5*					*0.5*	*0.7*	*55*	*235*	*4.3*
E	*0.4*	*0.7*					*0.7*	*1.1*	*83*	*354*	*4.3*
ESE	*0.3*	*0.6*					*0.6*	*0.9*	*69*	*287*	*4.2*
SE	*0.5*	*1.2*					*1.2*	*1.7*	*128*	*578*	*4.5*
SSE	*0.4*	*0.5*					*0.5*	*0.9*	*68*	*286*	*4.2*
S	*0.7*	*0.6*					*0.6*	*1.2*	*91*	*348*	*3.8*
SSW	*0.4*	*0.5*					*0.5*	*0.9*	*67*	*274*	*4.1*
SW	*1.5*	*3.2*	*0.1*				*3.3*	*4.8*	*356*	*1755*	*4.9*
WSW	*1.5*	*5.2*	*1.1*				*6.3*	*7.8*	*579*	*4012*	*6.9*
W	*2.1*	*14.9*	*5.5*				*20.4*	*22.5*	*1676*	*14120*	*8.4*
WNW	*1.1*	*12.5*	*4.8*				*17.3*	*18.4*	*1369*	*11893*	*8.7*
NW	*1.1*	*4.7*	*1.2*				*5.9*	*7.0*	*522*	*3765*	*7.2*
NNW	*0.4*	*0.4*					*0.4*	*0.8*	*60*	*251*	*4.2*
CALM								*28.7*	*2132*		
TOTALS	*11.8*	*46.7*	*12.8*				*59.5*	*100.0*	*7434*	*38837*	*5.2*

Air Weather Service - Directorate of Climatology
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Surface Winds

TABLE 2.3-17

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PERCENTAGE FREQUENCY OF OCCURRENCE

DIRECTIONS BY SPEED GROUPS

23273 — *Santa Maria, California WBAS* — *Sept*

Station — *Station Name* — *Month* — *Class*

48 49 50 51 52 53 54 55 56 57

Years

Speed Dir.	1-3 Knots	4-10 Knots	11-21 Knots	22-27 Knots	28-40 Knots	41 Knots and Over	Total 4 Knots and Over	Total No. of Observations %	Total No. of Observations Obs.	Sum of Speed	Mean Wind Speed, Knots
N	0.6	0.5	0.1				0.7	1.2	89	474	5.3
NNE	0.5	0.5	0.1				0.7	1.2	85	461	5.4
NE	0.7	0.8	0.1				0.9	1.6	118	574	4.9
ENE	0.3	0.7					0.8	1.1	77	379	4.9
E	0.9	2.3					2.4	3.3	239	1191	5.0
ESE	0.7	1.4					1.4	2.1	154	716	4.6
SE	1.0	1.6					1.7	2.6	189	874	4.6
SSE	0.3	0.6					0.6	1.0	69	320	4.6
S	0.6	0.8					0.8	1.4	101	436	4.3
SSW	0.5	0.5					0.5	1.0	71	309	4.4
SW	1.2	2.1	0.1				2.2	3.4	244	1240	5.1
WSW	1.3	4.4	0.9				5.3	6.6	473	3287	6.9
W	2.1	12.7	4.6	0.1			17.3	19.4	1394	11723	8.4
WNW	1.3	10.3	5.0	0.1			15.4	16.7	1202	10714	8.9
NW	1.1	4.3	0.9				5.2	6.3	452	3068	6.8
NNW	0.5	0.5					0.5	1.0	74	342	4.6
CALM								30.1	2166		
TOTALS	13.6	44.0	12.1	0.2			56.3	100.0	7197	36108	5.0

Air Weather Service - Directorate of Climatology
Data Control Division

Surface Winds

TABLE 2.3-18

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PERCENTAGE FREQUENCY OF OCCURRENCE
DIRECTIONS BY SPEED GROUPS

23273 — Station
Santa Maria, California WBAS — Station Name
Oct — Month
Class

48 49 50 51 52 53 54 55 56 57
Years

Speed Dir.	1-3 Knots	4-10 Knots	11-21 Knots	22-27 Knots	28-40 Knots	41 Knots and Over	Total 4 Knots and Over	Total No. of Observations %	Total No. of Observations Obs.	Sum of Speed	Mean Wind Speed, Knots
N	0.4	0.7	0.5				1.2	1.6	119	1046	8.8
NNE	0.4	0.9	0.6	0.1			1.7	2.1	157	1466	9.3
NE	1.1	1.4	0.7	0.1			2.2	3.3	247	1775	7.2
ENE	0.5	1.3					1.3	1.8	132	736	5.6
E	1.7	6.0	0.2				6.3	8.0	592	3348	5.7
ESE	1.2	3.4	0.1				3.5	4.7	347	1921	5.5
SE	0.9	3.3	0.3				3.6	4.5	335	2030	6.1
SSE	0.4	0.8	0.2				1.0	1.4	102	679	6.7
S	0.5	0.7	0.3				1.0	1.5	112	726	6.5
SSW	0.5	0.5	0.2				0.7	1.1	84	496	5.9
SW	1.1	1.8	0.2				1.9	3.0	223	1173	5.3
WSW	1.0	3.2	0.7				3.9	4.9	363	2503	6.9
W	2.1	9.1	3.7				12.8	15.0	1112	9125	8.2
WNW	1.3	8.6	4.8	0.2			13.6	14.9	1109	10269	9.3
NW	0.9	4.2	1.0				5.2	6.1	454	3204	7.1
NNW	0.3	0.6	0.1				0.7	1.1	79	470	5.9
CALM								25.0	1856		
TOTALS	14.3	46.5	13.7	0.5	0.0		60.7	100.0	7423	40967	5.5

Air Weather Service - Directorate of Climatology
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Surface Winds

TABLE 2.3-19

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PERCENTAGE FREQUENCY OF OCCURRENCE

DIRECTIONS BY SPEED GROUPS

23273 — *Station*
Santa Maria, California WBAS — *Station Name*
Nov — *Month*
Class

48 49 50 51 52 53 54 55 56 57

Years

Speed Dir.	1-3 Knots	4-10 Knots	11-21 Knots	22-27 Knots	28-40 Knots	41 Knots and Over	Total 4 Knots and Over	Total No. of Observations %	Total No. of Observations Obs.	Sum of Speed	Mean Wind Speed, Knots
N	0.5	1.4	1.2	0.1			2.6	3.1	224	2109	9.4
NNE	0.5	1.7	1.7	0.3			3.7	4.2	302	3374	11.2
NE	0.8	1.8	0.8	0.4	0.2		3.2	4.0	288	2840	9.9
ENE	0.7	2.1					2.1	2.8	204	1125	5.5
E	2.1	10.2	0.6				10.8	13.0	933	6008	6.4
ESE	1.1	5.3	0.8				6.1	7.2	516	3491	6.8
SE	1.0	3.9	0.9	0.2			5.0	6.0	433	3400	7.9
SSE	0.5	1.0	0.5				1.5	2.1	148	1190	8.0
S	0.5	0.9	0.3				1.2	1.7	120	795	6.6
SSW	0.4	0.5	0.3				0.9	1.3	96	733	.6
SW	0.6	1.0	0.3				1.3	2.0	141	947	.7
WSW	0.6	2.1	0.3				2.4	3.0	219	1418	6.5
W	1.4	6.6	1.4				8.1	9.4	678	5104	7.5
WNW	1.1	7.6	3.3				10.9	12.1	868	7440	8.6
NW	0.7	3.9	0.7				4.6	5.3	379	2732	7.2
NNW	0.3	1.4	0.4				1.8	2.1	148	1127	7.6
CALM								20.7	1490		
TOTALS	13.0	51.4	13.7	0.9	0.2		66.3	100.0	7187	43833	6.1

Air Weather Service - Directorate of Climatology
Data Control Division

Surface Winds

TABLE 2.3-20

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PERCENTAGE FREQUENCY OF OCCURRENCE
DIRECTIONS BY SPEED GROUPS

23273 — Station
Santa Maria, California WBAS — Station Name
Dec — Month
Class

48 49 50 51 52 53 54 55 56 57
Years

Speed Dir.	1-3 Knots	4-10 Knots	11-21 Knots	22-27 Knots	28-40 Knots	41 Knots and Over	Total 4 Knots and Over	Total No. of Observations %	Total No. of Observations Obs.	Sum of Speed	Mean Wind Speed, Knots
N	0.5	2.0	1.6	0.1			3.8	4.3	318	3219	10.1
NNE	0.4	1.9	2.4	0.3	0.1		4.6	5.0	375	4354	11.6
NE	1.1	2.1	1.1	0.2			3.3	4.5	331	2702	8.2
ENE	1.0	2.6	0.2				2.8	3.8	284	1751	6.2
E	2.4	10.5	0.6				11.1	13.4	998	6370	6.4
ESE	1.3	5.6	1.1				6.7	8.0	595	4274	7.2
SE	0.9	4.5	2.1	0.3	0.1		7.1	8.0	592	5773	9.8
SSE	0.5	1.4	1.1	0.2	0.1		2.8	3.3	243	2524	10.4
S	0.5	0.8	0.3				1.1	1.6	119	944	7.9
SSW	0.4	0.6	0.2				0.8	1.2	90	582	6.5
SW	0.6	1.0	0.2				1.3	1.9	141	815	5.8
WSW	0.7	1.7	0.4				2.1	2.7	204	1332	6.5
W	1.1	4.4	1.0				5.4	6.5	485	3500	7.2
WNW	1.0	6.8	1.6				8.4	9.4	698	5358	7.7
NW	0.7	4.4	0.8				5.2	5.9	441	3279	7.4
NNW	0.4	1.8	0.4				2.2	2.6	192	1439	7.5
CALM								17.8	1326		
TOTALS	13.5	52.2	15.0	1.2	0.3		68.7	100.0	7432	48216	6.5

TABLE 2.3-21
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
EXTREMELY UNSTABLE (ΔT less than -1.9°C/100M)
DIABLO CANYON PERIOD OF RECORD JULY 1967-OCTOBER 1969

FREQUENCY TABLE

			Wind Speed, mph						
Direction	*Calm*	*2.0*	*5.1*	*9.6*	*15.1*	*21.1*	*39.6*	*Row Sums*	*Row Avg*
CALM	*3*	*0*	*0*	*0*	*0*	*0*	*0*	*3*	*0.0*
22.50	*0*	*1*	*7*	*6*	*0*	*0*	*0*	*14*	*7.4*
45.00	*0*	*0*	*1*	*3*	*1*	*0*	*0*	*5*	*9.6*
67.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
90.00	*0*	*1*	*2*	*0*	*0*	*0*	*0*	*3*	*3.7*
112.50	*0*	*0*	*1*	*3*	*11*	*12*	*9*	*36*	*19.9*
135.00	*0*	*2*	*3*	*12*	*24*	*12*	*14*	*67*	*17.6*
157.50	*0*	*2*	*5*	*7*	*6*	*10*	*4*	*34*	*15.7*
180.00	*0*	*3*	*5*	*5*	*4*	*7*	*3*	*27*	*13.2*
202.50	*0*	*0*	*2*	*4*	*1*	*0*	*0*	*7*	*9.3*
225.00	*0*	*1*	*1*	*3*	*3*	*0*	*0*	*8*	*10.4*
247.50	*0*	*13*	*1*	*1*	*3*	*0*	*0*	*18*	*4.8*
270.00	*0*	*15*	*7*	*1*	*3*	*0*	*0*	*26*	*4.7*
292.50	*0*	*3*	*12*	*6*	*12*	*2*	*0*	*35*	*10.2*
315.00	*0*	*2*	*4*	*24*	*39*	*24*	*7*	*100*	*16.0*
337.50	*0*	*0*	*1*	*6*	*6*	*5*	*3*	*21*	*16.3*
360.00	*0*	*0*	*1*	*1*	*2*	*0*	*0*	*4*	*11.0*
Column Sums	*3*	*43*	*53*	*82*	*15*	*72*	*40*	*408*	*13.9*

TABLE 2.3-22
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
MODERATELY UNSTABLE (ΔT -1.9 to -1.7°C/100M)
DIABLO CANYON PERIOD OF RECORD JULY 1967-OCTOBER 1969

FREQUENCY TABLE

			Wind Speed, mph					*Row*	*Row*
Direction	*Calm*	*2.0*	*5.1*	*9.6*	*15.1*	*21.1*	*39.6*	*Sums*	*Avg*
CALM	*5*	*0*	*0*	*0*	*0*	*0*	*0*	*5*	*0.0*
22.50	*0*	*0*	*1*	*1*	*0*	*0*	*0*	*2*	*8.0*
45.00	*0*	*0*	*0*	*2*	*0*	*0*	*0*	*2*	*10.0*
67.50	*0*	*0*	*0*	*1*	*0*	*0*	*0*	*1*	*12.0*
90.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
112.50	*0*	*0*	*0*	*1*	*4*	*1*	*0*	*6*	*15.5*
135.00	*0*	*1*	*1*	*3*	*2*	*0*	*1*	*8*	*13.0*
157.50	*0*	*0*	*3*	*4*	*0*	*0*	*8*	*15*	*21.3*
180.00	*0*	*2*	*0*	*2*	*1*	*1*	*2*	*8*	*14.2*
202.50	*0*	*1*	*1*	*0*	*0*	*0*	*0*	*2*	*4.5*
225.00	*0*	*7*	*0*	*2*	*1*	*0*	*0*	*10*	*4.5*
247.50	*0*	*2*	*0*	*0*	*0*	*0*	*0*	*2*	*2.5*
270.00	*0*	*3*	*5*	*0*	*0*	*0*	*0*	*8*	*3.7*
292.50	*0*	*0*	*2*	*5*	*6*	*0*	*0*	*13*	*11.8*
315.00	*0*	*2*	*3*	*5*	*12*	*4*	*1*	*27*	*13.9*
337.50	*0*	*0*	*2*	*0*	*2*	*1*	*0*	*5*	*12.8*
360.00	*0*	*0*	*1*	*1*	*0*	*0*	*0*	*2*	*9.0*
Column Sums	*5*	*18*	*19*	*27*	*28*	*7*	*12*	*116*	*11.9*

TABLE 2.3-23
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
SLIGHTLY UNSTABLE (ΔT -1.7 to -1.5°C/100M)
DIABLO CANYON PERIOD OF RECORD JULY 1967-OCTOBER 1969

FREQUENCY TABLE

			Wind Speed, mph					*Row*	*Row*
Direction	*Calm*	*2.0*	*5.1*	*9.6*	*15.1*	*21.1*	*39.6*	*Sums*	*Avg*
CALM	*6*	*0*	*0*	*0*	*0*	*0*	*0*	*6*	*0.0*
22.50	*0*	*0*	*0*	*1*	*1*	*0*	*0*	*2*	*13.0*
45.00	*0*	*1*	*0*	*1*	*0*	*0*	*0*	*2*	*6.5*
67.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
90.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
112.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
135.00	*0*	*1*	*2*	*1*	*5*	*5*	*1*	*15*	*15.5*
157.50	*0*	*2*	*10*	*2*	*1*	*1*	*4*	*20*	*13.1*
180.00	*0*	*1*	*0*	*0*	*1*	*0*	*1*	*3*	*18.0*
202.50	*0*	*0*	*1*	*1*	*0*	*0*	*0*	*2*	*6.5*
225.00	*0*	*3*	*0*	*0*	*0*	*0*	*0*	*3*	*1.7*
247.50	*0*	*2*	*1*	*0*	*0*	*0*	*0*	*3*	*3.0*
270.00	*0*	*2*	*5*	*0*	*1*	*2*	*0*	*10*	*8.9*
292.50	*0*	*1*	*2*	*11*	*0*	*1*	*2*	*17*	*11.4*
315.00	*0*	*0*	*1*	*5*	*8*	*9*	*2*	*25*	*17.4*
337.50	*0*	*0*	*0*	*2*	*0*	*0*	*0*	*2*	*12.0*
360.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
Column Sums	*6*	*13*	*22*	*24*	*17*	*18*	*10*	*110*	*12.3*

TABLE 2.3-24
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
NEUTRAL (ΔT -1.5 to -0.5°C/100M)
DIABLO CANYON PERIOD OF RECORD JULY 1967-OCTOBER 1969

FREQUENCY TABLE

			Wind Speed, mph					*Row*	*Row*
Direction	*Calm*	*2.0*	*5.1*	*9.6*	*15.1*	*21.1*	*39.6*	*Sums*	*Avg*
CALM	*290*	*2*	*0*	*0*	*0*	*0*	*0*	*292*	*0.0*
22.50	*0*	*24*	*36*	*40*	*17*	*4*	*0*	*121*	*8.1*
45.00	*0*	*20*	*35*	*39*	*17*	*1*	*0*	*112*	*8.0*
67.50	*0*	*23*	*20*	*33*	*6*	*0*	*0*	*82*	*6.8*
90.00	*0*	*25*	*18*	*6*	*3*	*0*	*0*	*52*	*4.6*
112.50	*0*	*32*	*51*	*60*	*53*	*9*	*1*	*206*	*9.4*
135.00	*0*	*171*	*284*	*203*	*157*	*54*	*17*	*886*	*8.9*
157.50	*0*	*182*	*155*	*61*	*29*	*23*	*13*	*463*	*6.5*
180.00	*0*	*126*	*46*	*21*	*22*	*17*	*9*	*241*	*6.9*
202.50	*0*	*79*	*16*	*11*	*6*	*6*	*0*	*120*	*4.9*
225.00	*0*	*87*	*12*	*5*	*8*	*2*	*0*	*114*	*3.5*
247.50	*0*	*95*	*20*	*1*	*2*	*3*	*0*	*121*	*3.0*
270.00	*0*	*126*	*96*	*17*	*1*	*4*	*0*	*244*	*4.1*
292.50	*0*	*110*	*223*	*187*	*104*	*28*	*4*	*656*	*8.5*
315.00	*0*	*67*	*242*	*530*	*652*	*308*	*143*	*1942*	*14.2*
337.50	*0*	*42*	*97*	*210*	*160*	*98*	*80*	*687*	*13.9*
360.00	*0*	*41*	*5*	*63*	*53*	*6*	*0*	*218*	*8.7*
Column Sums	*290*	*1252*	*1406*	*1487*	*1290*	*563*	*269*	*6557*	*9.8*

TABLE 2.3-25
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
SLIGHTLY STABLE (ΔT -0.5 to 1.5°C/100M)
DIABLO CANYON PERIOD OF RECORD JULY 1967-OCTOBER 1969

FREQUENCY TABLE

			Wind Speed, mph					*Row*	*Row*
Direction	*Calm*	*2.0*	*5.1*	*9.6*	*15.1*	*21.1*	*39.6*	*Sums*	*Avg*
CALM	*405*	*12*	*0*	*0*	*0*	*0*	*0*	*417*	*0.0*
22.50	*0*	*66*	*92*	*96*	*58*	*14*	*2*	*328*	*8.7*
45.00	*0*	*53*	*94*	*66*	*29*	*1*	*0*	*243*	*6.9*
67.50	*0*	*42*	*58*	*35*	*21*	*2*	*0*	*158*	*6.7*
90.00	*0*	*84*	*40*	*13*	*4*	*0*	*0*	*141*	*3.8*
112.50	*0*	*128*	*57*	*25*	*9*	*5*	*0*	*224*	*4.5*
135.00	*0*	*296*	*279*	*164*	*47*	*11*	*5*	*802*	*5.9*
157.50	*0*	*330*	*129*	*16*	*1*	*0*	*4*	*480*	*3.0*
180.00	*0*	*188*	*16*	*2*	*1*	*3*	*1*	*211*	*2.2*
202.50	*0*	*94*	*13*	*2*	*0*	*0*	*0*	*109*	*1.9*
225.00	*0*	*91*	*12*	*4*	*3*	*0*	*0*	*110*	*2.7*
247.50	*0*	*83*	*16*	*1*	*0*	*0*	*0*	*100*	*2.2*
270.00	*0*	*158*	*33*	*5*	*3*	*0*	*0*	*199*	*2.6*
292.50	*0*	*166*	*154*	*132*	*99*	*44*	*12*	*607*	*8.5*
315.00	*0*	*161*	*344*	*454*	*497*	*479*	*304*	*2239*	*14.9*
337.50	*0*	*97*	*136*	*159*	*97*	*62*	*35*	*586*	*10.7*
360.00	*0*	*99*	*123*	*130*	*78*	*20*	*4*	*454*	*8.5*
Column Sums	*405*	*2148*	*1596*	*1304*	*947*	*641*	*367*	*7408*	*8.6*

TABLE 2.3-26
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
MODERATELY STABLE (ΔT 1.5 to 4.0°C/100M)
DIABLO CANYON PERIOD OF RECORD JULY 1967-OCTOBER 1969

FREQUENCY TABLE

			Wind Speed, mph						
Direction	*Calm*	*2.0*	*5.1*	*9.6*	*15.1*	*21.1*	*39.6*	*Row Sums*	*Row Avg*
CALM	*117*	*1*	*0*	*0*	*0*	*0*	*0*	*118*	*0.0*
22.50	*0*	*9*	*9*	*5*	*6*	*2*	*0*	*31*	*8.0*
45.00	*0*	*12*	*10*	*3*	*3*	*0*	*0*	*28*	*5.1*
67.50	*0*	*12*	*6*	*4*	*1*	*1*	*0*	*24*	*5.6*
90.00	*0*	*20*	*12*	*2*	*0*	*0*	*0*	*34*	*3.0*
112.50	*0*	*33*	*16*	*5*	*0*	*0*	*0*	*54*	*3.4*
135.00	*0*	*54*	*52*	*25*	*2*	*0*	*0*	*133*	*4.6*
157.50	*0*	*68*	*17*	*1*	*0*	*0*	*0*	*86*	*2.3*
180.00	*0*	*35*	*6*	*0*	*0*	*0*	*0*	*41*	*1.8*
202.50	*0*	*20*	*0*	*1*	*0*	*0*	*0*	*21*	*1.8*
225.00	*0*	*18*	*3*	*0*	*0*	*0*	*0*	*21*	*2.0*
247.50	*0*	*30*	*2*	*0*	*0*	*0*	*0*	*32*	*1.7*
270.00	*0*	*34*	*4*	*1*	*0*	*0*	*0*	*39*	*2.5*
292.50	*0*	*38*	*28*	*28*	*8*	*4*	*3*	*109*	*7.2*
315.00	*0*	*43*	*65*	*114*	*167*	*179*	*170*	*738*	*17.3*
337.50	*0*	*20*	*39*	*25*	*15*	*13*	*0*	*112*	*8.7*
360.00	*0*	*20*	*14*	*11*	*7*	*3*	*0*	*55*	*6.9*
Column Sums	*117*	*467*	*283*	*225*	*209*	*202*	*173*	*1676*	*10.1*

TABLE 2.3-27
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
EXTREMELY STABLE (ΔT greater than 4.0°C/100M)
DIABLO CANYON PERIOD OF RECORD JULY 1967-OCTOBER 1969

FREQUENCY TABLE

			Wind Speed, mph						
Direction	*Calm*	*2.0*	*5.1*	*9.6*	*15.1*	*21.1*	*39.6*	*Row Sums*	*Row Avg*
CALM	*46*	*0*	*0*	*0*	*0*	*0*	*0*	*46*	*0.0*
22.50	*0*	*9*	*8*	*6*	*0*	*0*	*0*	*23*	*5.2*
45.00	*0*	*8*	*13*	*3*	*0*	*0*	*0*	*24*	*4.6*
67.50	*0*	*11*	*7*	*1*	*0*	*0*	*0*	*19*	*3.5*
90.00	*0*	*13*	*10*	*1*	*0*	*0*	*0*	*24*	*3.7*
112.50	*0*	*14*	*6*	*1*	*0*	*0*	*0*	*21*	*3.3*
135.00	*0*	*36*	*11*	*2*	*0*	*0*	*0*	*49*	*2.9*
157.50	*0*	*23*	*7*	*1*	*0*	*0*	*0*	*31*	*2.8*
180.00	*0*	*29*	*2*	*0*	*0*	*0*	*0*	*31*	*1.5*
202.50	*0*	*13*	*1*	*0*	*0*	*0*	*0*	*14*	*1.7*
225.00	*0*	*12*	*1*	*0*	*0*	*0*	*0*	*13*	*1.6*
247.50	*0*	*13*	*1*	*0*	*0*	*0*	*0*	*14*	*2.2*
270.00	*0*	*22*	*6*	*2*	*0*	*0*	*0*	*30*	*3.0*
292.50	*0*	*12*	*19*	*14*	*4*	*3*	*0*	*52*	*7.4*
315.00	*0*	*19*	*32*	*73*	*87*	*94*	*95*	*400*	*17.7*
337.50	*0*	*16*	*16*	*12*	*9*	*6*	*0*	*59*	*8.5*
360.00	*0*	*9*	*12*	*5*	*2*	*0*	*0*	*28*	*5.7*
Column Sums	*46*	*259*	*152*	*121*	*102*	*103*	*95*	*878*	*10.3*

TABLE 2.3-28
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DISTRIBUTION OF WIND SPEED OBSERVATIONS BY STABILITY CLASS

Stability Class	*T, °C/100M*		*Number of Observations*
Extremely unstable	*Less than*	*-1.9*	*3*
Moderately unstable	*-1.9 to*	*-1.7*	*5*
Slightly unstable	*-1.7 to*	*-1.5*	*6*
Neutral	*-1.5 to*	*-0.5*	*290*
Slightly stable	*-0.5 to*	*1.5*	*405*
Moderately stable	*1.5 to*	*4.0*	*117*
Extremely stable	*Greater than*	*4.0*	*46*

(a) Observations for which the mean hourly wind speed was less than one mile per hour when stability is defined by vertical temperature gradient between the 25-foot levels at Station E period of record July 1, 1967 through October 31, 1969.

(b) Total hourly observations for period of record: 17,153.

TABLE 2.3-29
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - STATION E 25-FOOT LEVEL
OCTOBER 1969 THROUGH MARCH 1971 AND
APRIL 1972 THROUGH SEPTEMBER 1972
VERTICAL ANGLE STABILITY CLASS A

Direction, deg.	*Wind Speed, mph* 1.5	5.5	10.0	15.5	21.5	37.5	*Row Sum*	*Row Avg.*
Calm	*2*	*0*	*0*	*0*	*0*	*0*	*2*	*0.0*
22.5	*106*	*185*	*63*	*14*	*1*	*0*	*369*	*5.6*
45.0	*127*	*152*	*71*	*12*	*1*	*0*	*363*	*5.3*
67.5	*77*	*69*	*44*	*9*	*0*	*0*	*199*	*5.3*
90.0	*101*	*47*	*16*	*7*	*2*	*0*	*173*	*4.1*
112.5	*97*	*25*	*17*	*11*	*4*	*0*	*144*	*3.9*
135.0	*178*	*111*	*27*	*10*	*3*	*0*	*329*	*4.2*
157.5	*185*	*168*	*22*	*1*	*0*	*0*	*376*	*3.9*
180.0	*209*	*64*	*5*	*1*	*0*	*0*	*279*	*3.0*
202.5	*117*	*19*	*1*	*0*	*0*	*0*	*137*	*2.2*
225.0	*83*	*10*	*1*	*1*	*0*	*0*	*95*	*2.0*
247.5	*90*	*15*	*2*	*1*	*0*	*0*	*108*	*2.2*
270.0	*126*	*23*	*9*	*1*	*0*	*0*	*159*	*2.7*
292.5	*164*	*98*	*60*	*18*	*5*	*3*	*348*	*5.6*
315.0	*108*	*166*	*126*	*64*	*13*	*1*	*478*	*7.7*
337.5	*79*	*126*	*119*	*66*	*15*	*3*	*408*	*8.2*
360.0	*91*	*215*	*146*	*32*	*4*	*0*	*488*	*6.8*
Column Sums	*1,940*	*1,493*	*729*	*238*	*48*	*7*	*4,455*	*5.7*

TABLE 2.3-30
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - STATION E 25-FOOT LEVEL
OCTOBER 1969 THROUGH MARCH 1971 AND
APRIL 1972 THROUGH SEPTEMBER 1972
VERTICAL ANGLE STABILITY CLASS B

Direction, deg.	*Wind Speed, mph* 1.5	5.5	10.0	15.5	21.5	37.5	*Row Sum*	*Row Avg.*
Calm	*2*	*0*	*0*	*0*	*0*	*0*	*2*	*0.0*
22.5	*32*	*43*	*27*	*12*	*4*	*1*	*119*	*7.1*
45.0	*44*	*55*	*28*	*3*	*0*	*0*	*130*	*5.5*
67.5	*33*	*20*	*18*	*9*	*0*	*0*	*80*	*5.9*
90.0	*46*	*18*	*8*	*2*	*1*	*1*	*76*	*4.4*
112.5	*52*	*19*	*32*	*27*	*6*	*0*	*136*	*7.8*
135.0	*107*	*152*	*104*	*57*	*11*	*1*	*432*	*7.4*
157.5	*94*	*127*	*52*	*10*	*2*	*3*	*288*	*5.6*
180.0	*59*	*47*	*6*	*0*	*0*	*0*	*112*	*3.6*
202.5	*24*	*7*	*0*	*0*	*0*	*0*	*31*	*2.4*
225.0	*19*	*8*	*1*	*0*	*0*	*0*	*28*	*2.5*
247.5	*23*	*6*	*1*	*0*	*0*	*0*	*30*	*2.4*
270.0	*48*	*7*	*2*	*0*	*0*	*0*	*57*	*2.5*
292.5	*74*	*90*	*47*	*33*	*16*	*3*	*263*	*7.6*
315.0	*52*	*143*	*156*	*110*	*65*	*19*	*545*	*11.1*
337.5	*43*	*81*	*102*	*98*	*58*	*8*	*390*	*11.5*
360.0	*32*	*92*	*64*	*21*	*7*	*0*	*216*	*7.6*
Column Sums	*784*	*915*	*648*	*382*	*170*	*36*	*2,935*	*7.9*

TABLE 2.3-31
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - STATION E 25-FOOT LEVEL
OCTOBER 1969 THROUGH MARCH 1971 AND
APRIL 1972 THROUGH SEPTEMBER 1972
VERTICAL ANGLE STABILITY CLASS C

Direction, deg.	*Wind Speed, mph* 1.5	5.5	10.0	15.5	21.5	37.5	*Row Sum*	*Row Avg.*
Calm	*2*	*0*	*0*	*0*	*0*	*0*	*2*	*0.0*
22.5	*7*	*12*	*8*	*2*	*1*	*0*	*30*	*7.1*
45.0	*24*	*24*	*6*	*4*	*0*	*0*	*58*	*5.3*
67.5	*19*	*17*	*10*	*5*	*0*	*0*	*51*	*5.6*
90.0	*18*	*6*	*3*	*6*	*0*	*1*	*34*	*6.2*
112.5	*34*	*4*	*19*	*16*	*6*	*3*	*82*	*8.8*
135.0	*76*	*102*	*134*	*63*	*29*	*9*	*413*	*9.3*
157.5	*55*	*96*	*56*	*20*	*6*	*0*	*233*	*6.7*
180.0	*21*	*18*	*2*	*3*	*1*	*1*	*46*	*5.4*
202.5	*10*	*4*	*4*	*0*	*0*	*0*	*17*	*3.5*
225.0	*8*	*6*	*0*	*0*	*0*	*0*	*14*	*3.5*
247.5	*15*	*4*	*0*	*0*	*0*	*0*	*19*	*2.5*
270.0	*32*	*23*	*4*	*0*	*1*	*1*	*61*	*4.3*
292.5	*29*	*94*	*76*	*73*	*43*	*2*	*317*	*10.8*
315.0	*49*	*222*	*388*	*445*	*390*	*148*	*1,642*	*15.0*
337.5	*35*	*65*	*114*	*123*	*93*	*28*	*458*	*13.6*
360.0	*14*	*27*	*12*	*7*	*3*	*0*	*63*	*7.3*
Column Sums	*448*	*724*	*836*	*767*	*573*	*192*	*3,540*	*12.0*

TABLE 2.3-32
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - STATION E 25-FOOT LEVEL
OCTOBER 1969 THROUGH MARCH 1971 AND
APRIL 1972 THROUGH SEPTEMBER 1972
VERTICAL ANGLE STABILITY CLASS D

Direction, deg.	*Wind Speed, mph* 1.5	5.5	10.0	15.5	21.5	37.5	*Row Sum*	*Row Avg.*
Calm	*2*	*0*	*0*	*0*	*0*	*0*	*2*	*0.0*
22.5	*1*	*5*	*0*	*0*	*0*	*0*	*6*	*4.5*
45.0	*16*	*4*	*1*	*0*	*0*	*0*	*21*	*3.1*
67.5	*9*	*5*	*4*	*5*	*1*	*0*	*24*	*9.7*
90.0	*15*	*4*	*3*	*0*	*1*	*0*	*23*	*5.4*
112.5	*31*	*5*	*2*	*2*	*0*	*0*	*40*	*4.5*
135.0	*63*	*40*	*15*	*8*	*4*	*5*	*135*	*5.9*
157.5	*30*	*17*	*12*	*5*	*2*	*0*	*66*	*5.7*
180.0	*8*	*4*	*1*	*2*	*1*	*0*	*16*	*6.1*
202.5	*7*	*1*	*0*	*0*	*0*	*0*	*8*	*1.6*
225.0	*4*	*4*	*0*	*1*	*0*	*0*	*9*	*5.2*
247.5	*6*	*5*	*1*	*0*	*0*	*0*	*12*	*3.7*
270.0	*22*	*6*	*4*	*2*	*3*	*0*	*37*	*5.5*
292.5	*14*	*43*	*55*	*55*	*40*	*12*	*219*	*12.7*
315.0	*31*	*181*	*369*	*556*	*463*	*271*	*1,871*	*16.5*
337.5	*16*	*33*	*69*	*85*	*63*	*50*	*316*	*15.6*
360.0	*3*	*11*	*9*	*0*	*0*	*0*	*23*	*6.5*
Column Sums	*278*	*368*	*545*	*721*	*578*	*338*	*2,828*	*14.5*

TABLE 2.3-33
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - STATION E 25-FOOT LEVEL
OCTOBER 1969 THROUGH MARCH 1971 AND
APRIL 1972 THROUGH SEPTEMBER 1972
VERTICAL ANGLE STABILITY CLASS E

Direction, deg.	*Wind Speed, mph*						*Row Sum*	*Row Avg.*
	1.5	*5.5*	*10.0*	*15.5*	*21.5*	*37.5*		
Calm	*1*	*0*	*0*	*0*	*0*	*0*	*1*	*0.0*
22.5	*0*	*1*	*0*	*0*	*0*	*0*	*1*	*4.0*
45.0	*2*	*1*	*1*	*0*	*0*	*0*	*4*	*3.8*
67.5	*0*	*2*	*3*	*0*	*0*	*0*	*5*	*7.6*
90.0	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
112.5	*10*	*1*	*0*	*0*	*0*	*0*	*11*	*1.9*
135.0	*15*	*3*	*0*	*0*	*0*	*0*	*18*	*2.3*
157.5	*7*	*2*	*1*	*0*	*2*	*0*	*12*	*2.8*
180.0	*4*	*1*	*0*	*0*	*0*	*0*	*5*	*2.4*
202.5	*2*	*0*	*0*	*1*	*0*	*0*	*3*	*5.3*
225.0	*2*	*2*	*0*	*0*	*0*	*0*	*4*	*3.3*
247.5	*2*	*3*	*1*	*0*	*0*	*0*	*6*	*4.6*
270.0	*1*	*0*	*1*	*1*	*0*	*0*	*3*	*8.3*
292.5	*2*	*8*	*8*	*4*	*11*	*8*	*41*	*15.8*
315.0	*8*	*30*	*42*	*105*	*111*	*47*	*343*	*17.3*
337.5	*3*	*3*	*5*	*4*	*2*	*3*	*20*	*13.2*
360.0	*0*	*0*	*1*	*0*	*0*	*0*	*1*	*8.0*
Column Sums	*59*	*57*	*63*	*115*	*126*	*58*	*478*	*14.8*

TABLE 2.3-34
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - STATION E 25-FOOT LEVEL
OCTOBER 1969 THROUGH MARCH 1971 AND
APRIL 1972 THROUGH SEPTEMBER 1972
VERTICAL ANGLE STABILITY CLASS F AND G

Direction, deg.	*Wind Speed, mph* 1.5	5.5	10.0	15.5	21.5	37.5	*Row Avg.*	*Row Sum*
Calm	*516*	*0*	*0*	*0*	*0*	*0*	*516*	*0.0*
22.5	*5*	*0*	*0*	*0*	*0*	*0*	*5*	*1.2*
45.0	*5*	*1*	*0*	*0*	*0*	*0*	*6*	*2.5*
67.5	*11*	*0*	*0*	*0*	*0*	*0*	*11*	*1.7*
90.0	*8*	*1*	*0*	*0*	*0*	*0*	*9*	*1.4*
112.5	*15*	*0*	*0*	*0*	*0*	*0*	*15*	*1.6*
135.0	*55*	*3*	*0*	*0*	*0*	*0*	*58*	*1.7*
157.5	*32*	*2*	*1*	*0*	*0*	*0*	*35*	*1.9*
180.0	*19*	*0*	*1*	*0*	*0*	*0*	*20*	*1.9*
202.5	*11*	*0*	*0*	*0*	*0*	*0*	*11*	*1.4*
225.0	*8*	*0*	*0*	*0*	*0*	*0*	*8*	*1.3*
247.5	*11*	*0*	*0*	*0*	*0*	*0*	*11*	*1.0*
270.0	*17*	*0*	*0*	*0*	*0*	*0*	*17*	*1.3*
292.5	*9*	*5*	*5*	*0*	*2*	*0*	*22*	*6.5*
315.0	*21*	*18*	*25*	*32*	*27*	*15*	*138*	*13.4*
337.5	*15*	*3*	*4*	*4*	*2*	*0*	*28*	*4.8*
360.0	*11*	*4*	*0*	*0*	*0*	*0*	*15*	*2.7*
Column Sums	*769*	*37*	*36*	*36*	*31*	*15*	*925*	*2.7*

TABLE 2.3-35
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - STATION E 25-FOOT LEVEL
OCTOBER 1969 THROUGH MARCH 1971 AND
APRIL 1972 THROUGH SEPTEMBER 1972
AZIMUTH ANGLE STABILITY CLASS A

Direction, deg.	*Wind Speed, mph* 1.5	5.5	10.0	15.5	21.5	37.5	*Row Sum*	*Row Avg.*
Calm	*1*	*0*		*0*	*0*	*0*	*1*	*0.0*
22.5	*44*	*87*	*26*	*4*	*0*	*0*	*161*	*5.4*
45.0	*42*	*88*	*46*	*8*	*0*	*0*	*184*	*6.0*
67.5	*35*	*43*	*40*	*4*	*0*	*0*	*122*	*6.0*
90.0	*63*	*34*	*12*	*1*	*0*	*0*	*110*	*3.7*
112.5	*61*	*11*	*4*	*0*	*0*	*0*	*76*	*2.8*
135.0	*84*	*32*	*4*	*2*	*0*	*0*	*122*	*3.1*
157.5	*54*	*26*	*4*	*0*	*0*	*0*	*84*	*3.2*
180.0	*55*	*17*	*2*	*0*	*0*	*0*	*74*	*2.7*
202.5	*39*	*6*	*1*	*0*	*0*	*0*	*46*	*2.6*
225.0	*25*	*3*	*2*	*1*	*0*	*0*	*31*	*3.1*
247.5	*41*	*5*	*1*	*0*	*0*	*0*	*47*	*2.0*
270.0	*46*	*12*	*6*	*0*	*0*	*0*	*64*	*3.2*
292.5	*32*	*29*	*16*	*6*	*1*	*0*	*84*	*5.7*
315.0	*28*	*55*	*53*	*23*	*6*	*2*	*167*	*8.6*
337.5	*32*	*71*	*53*	*13*	*3*	*1*	*173*	*7.1*
360.0	*41*	*96*	*40*	*11*	*1*	*0*	*189*	*6.4*
Column Sums	*723*	*615*	*310*	*73*	*11*	*3*	*1,735*	*5.2*

TABLE 2.3-36
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - STATION E 25-FOOT LEVEL
OCTOBER 1969 THROUGH MARCH 1971 AND
APRIL 1972 THROUGH SEPTEMBER 1972
AZIMUTH ANGLE STABILITY CLASS B

Direction, deg.	*Wind Speed, mph* 1.5	5.5	10.0	15.5	21.5	37.5	*Row Sum*	*Row Avg.*
Calm	2	0	0	0	0	0	2	0.0
22.5	31	43	18	7	0	0	99	5.9
45.0	30	38	22	2	0	0	92	5.4
67.5	24	19	13	3	0	0	59	5.1
90.0	26	12	3	5	1	0	47	5.6
112.5	22	10	4	0	1	0	37	4.7
135.0	40	14	4	1	0	0	59	3.2
157.5	25	19	1	0	0	0	45	3.7
180.0	20	5	0	0	0	0	25	2.4
202.5	20	3	0	0	0	0	23	2.5
225.0	17	2	0	0	0	0	19	2.4
247.5	21	4	2	0	0	0	27	2.8
270.0	25	9	4	0	0	0	38	3.6
292.5	22	22	9	1	0	1	55	5.7
315.0	13	23	27	20	12	3	98	10.8
337.5	19	24	31	20	4	1	99	9.1
360.0	20	64	61	16	3	0	164	8.0
Column Sums	377	311	199	75	21	5	988	6.2

TABLE 2.3-37
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - STATION E 25-FOOT LEVEL
OCTOBER 1969 THROUGH MARCH 1971 AND
APRIL 1972 THROUGH SEPTEMBER 1972
AZIMUTH ANGLE STABILITY CLASS C

Direction, deg.	*Wind Speed, mph* 1.5	5.5	10.0	15.5	21.5	37.5	*Row Sum*	*Row Avg.*
Calm	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
22.5	*34*	*58*	*35*	*8*	*3*	*0*	*138*	*6.5*
45.0	*44*	*53*	*27*	*5*	*1*	*0*	*130*	*5.6*
67.5	*24*	*24*	*11*	*6*	*1*	*0*	*66*	*5.6*
90.0	*21*	*12*	*7*	*3*	*2*	*0*	*45*	*5.4*
112.5	*43*	*12*	*6*	*5*	*1*	*0*	*67*	*4.2*
135.0	*79*	*43*	*19*	*8*	*1*	*0*	*150*	*4.8*
157.5	*54*	*43*	*11*	*2*	*0*	*0*	*110*	*4.3*
180.0	*39*	*9*	*1*	*0*	*0*	*0*	*49*	*2.6*
202.5	*28*	*5*	*0*	*0*	*0*	*0*	*33*	*1.9*
225.0	*19*	*6*	*1*	*0*	*0*	*0*	*26*	*2.7*
247.5	*29*	*3*	*1*	*0*	*0*	*0*	*33*	*2.3*
270.0	*34*	*6*	*2*	*1*	*0*	*0*	*44*	*2.9*
292.5	*49*	*36*	*23*	*11*	*5*	*0*	*124*	*6.4*
315.0	*36*	*55*	*78*	*56*	*36*	*3*	*270*	*11.2*
337.5	*26*	*50*	*65*	*59*	*24*	*7*	*229*	*11.1*
360.0	*30*	*78*	*75*	*18*	*2*	*4*	*203*	*8.9*
Column Sums	*589*	*93*	*363*	*182*	*76*	*14*	*1,717*	*7.2*

TABLE 2.3-38
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - STATION E 25-FOOT LEVEL
OCTOBER 1969 THROUGH MARCH 1971 AND
APRIL 1972 THROUGH SEPTEMBER 1972
AZIMUTH ANGLE STABILITY CLASS D

Direction, deg.	*Wind Speed, mph* 1.5	5.5	10.0	15.5	21.5	37.5	*Row Sum*	*Row Avg.*
Calm	*1*	*0*	*0*	*0*	*0*	*0*	*1*	*0.0*
22.5	*34*	*44*	*17*	*9*	*3*	*1*	*108*	*6.4*
45.0	*55*	*54*	*22*	*5*	*0*	*0*	*136*	*5.1*
67.5	*34*	*16*	*16*	*10*	*0*	*0*	*76*	*6.0*
90.0	*46*	*23*	*9*	*6*	*1*	*1*	*86*	*5.6*
112.5	*56*	*17*	*35*	*24*	*7*	*1*	*140*	*7.9*
135.0	*126*	*178*	*122*	*65*	*15*	*6*	*512*	*7.5*
157.5	*106*	*148*	*45*	*9*	*3*	*1*	*312*	*5.2*
180.0	*70*	*36*	*6*	*2*	*1*	*0*	*115*	*3.7*
202.5	*27*	*7*	*0*	*0*	*0*	*0*	*34*	*2.3*
225.0	*30*	*8*	*2*	*0*	*0*	*0*	*40*	*2.6*
247.5	*23*	*8*	*0*	*0*	*0*	*0*	*31*	*2.3*
270.0	*53*	*9*	*4*	*0*	*1*	*1*	*68*	*3.4*
292.5	*73*	*81*	*62*	*43*	*32*	*10*	*301*	*9.2*
315.0	*69*	*171*	*222*	*209*	*138*	*47*	*856*	*12.6*
337.5	*35*	*83*	*116*	*139*	*109*	*25*	*507*	*13.4*
360.0	*39*	*62*	*53*	*15*	*8*	*0*	*177*	*7.4*
Column Sums	*877*	*945*	*731*	*536*	*318*	*93*	*3,500*	*9.0*

TABLE 2.3-39
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - STATION E 25-FOOT LEVEL
OCTOBER 1969 THROUGH MARCH 1971 AND
APRIL 1972 THROUGH SEPTEMBER 1972
AZIMUTH ANGLE STABILITY CLASS E

Direction, deg.	*Wind Speed, mph* 1.5	5.5	10.0	15.5	21.5	37.5	*Row Sum*	*Row Avg.*
Calm	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
22.5	*11*	*13*	*4*	*1*	*0*	*0*	*29*	*5.2*
45.0	*44*	*32*	*4*	*2*	*0*	*0*	*82*	*4.0*
67.5	*28*	*19*	*17*	*7*	*0*	*0*	*71*	*5.8*
90.0	*30*	*8*	*2*	*0*	*0*	*1*	*41*	*3.9*
112.5	*47*	*10*	*11*	*8*	*2*	*1*	*79*	*5.6*
135.0	*120*	*116*	*96*	*56*	*25*	*7*	*420*	*8.0*
157.5	*105*	*136*	*69*	*18*	*6*	*2*	*336*	*6.1*
180.0	*64*	*41*	*4*	*3*	*1*	*1*	*114*	*4.0*
202.5	*20*	*5*	*2*	*1*	*0*	*0*	*28*	*3.3*
225.0	*24*	*10*	*1*	*0*	*0*	*0*	*35*	*3.0*
247.5	*22*	*8*	*2*	*0*	*0*	*0*	*32*	*2.9*
270.0	*47*	*23*	*5*	*2*	*2*	*0*	*79*	*4.2*
292.5	*72*	*129*	*106*	*90*	*54*	*9*	*460*	*10.2*
315.0	*83*	*319*	*549*	*696*	*608*	*292*	*2,547*	*15.5*
337.5	*46*	*63*	*126*	*120*	*101*	*61*	*517*	*14.3*
360.0	*20*	*29*	*13*	*5*	*0*	*0*	*67*	*6.0*
Column Sums	*783*	*961*	*1,011*	*1,009*	*799*	*374*	*4,937*	*12.1*

TABLE 2.3-40
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - STATION E 25-FOOT LEVEL
OCTOBER 1969 THROUGH MARCH 1971 AND
APRIL 1972 THROUGH SEPTEMBER 1972
AZIMUTH ANGLE STABILITY CLASS F AND G

Direction, deg.	*Wind Speed, mph* 1.5	5.5	10.0	15.5	21.5	37.5	*Row Sum*	*Row Avg.*
Calm	*564*	*0*	*0*	*0*	*0*	*0*	*564*	*0.0*
22.5	*7*	*2*	*0*	*0*	*0*	*0*	*9*	*2.3*
45.0	*17*	*4*	*0*	*0*	*0*	*0*	*21*	*2.5*
67.5	*17*	*2*	*2*	*1*	*0*	*0*	*22*	*3.6*
90.0	*15*	*3*	*1*	*0*	*0*	*0*	*19*	*2.5*
112.5	*27*	*1*	*0*	*1*	*0*	*0*	*29*	*2.0*
135.0	*75*	*19*	*6*	*2*	*2*	*1*	*105*	*3.4*
157.5	*65*	*31*	*5*	*3*	*2*	*0*	*106*	*3.8*
180.0	*52*	*7*	*2*	*1*	*0*	*0*	*62*	*2.5*
202.5	*29*	*4*	*1*	*0*	*0*	*0*	*34*	*2.0*
225.0	*16*	*1*	*0*	*1*	*0*	*0*	*18*	*2.2*
247.5	*17*	*4*	*1*	*0*	*0*	*0*	*22*	*2.3*
270.0	*55*	*9*	*1*	*0*	*0*	*0*	*65*	*2.2*
292.5	*50*	*55*	*53*	*36*	*23*	*7*	*224*	*9.4*
315.0	*56*	*151*	*222*	*314*	*286*	*172*	*1,201*	*15.8*
337.5	*32*	*15*	*21*	*37*	*9*	*5*	*118*	*10.4*
360.0	*9*	*7*	*2*	*0*	*0*	*0*	*18*	*3.7*
Column Sums	*1,103*	*315*	*317*	*396*	*322*	*185*	*2,637*	*9.4*

TABLE 2.3-41

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

CUMULATIVE PERCENTAGE DISTRIBUTIONS OF χ/Q ESTIMATES BASED ON DISTANCE AND WIND SECTOR CENTERLINE FOR GROUND LEVEL RELEASES

10-meter wind data and stability categories based on measured Sigma A and Temperature Gradient (76M - 10M) values. For calculations with wind speed below 1.5 meters per second stability is based on Temperature Gradient only and building wake or a meander factor is considered - with wind speeds above 1.5 meters per second stability is based on measured Sigma A and Temperature Gradient with building wake only considered. X is downwind distance in meters, Y is sector centerline from north in degrees, and Z is terrain height defined as zero for Ground Level Releases. Data Period May 1973 through April 1975. In the following Tables Y=0.0 is equivalent to Y=360°=North.

CUMULATIVE FREQUENCY DISTRIBUTION AT X=800.0 Y=315.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.60140297E-06	0.17928305E-05
50	0.0	0.0	0.34090243E-06	0.11967086E-05	0.22880003E-05	0.36180809E-05
75	0.0	0.35322555E-05	0.47339599E-05	0.52474825E-05	0.51153211E-05	0.56741301E-05
90	0.46975747E-05	0.13407243E-04	0.12096141E-04	0.11476736E-04	0.96943622E-05	0.75202488E-05
95	0.26914247E-04	0.21392218E-04	0.18613035E-04	0.16908802E-04	0.13674124E-04	0.82745992E-05
99	0.79830948E-04	0.41694584E-04	0.31726566E-04	0.28974857E-04	0.22724547E-04	0.93198487E-05
99.5	0.10060299E-03	0.48705522E-04	0.38378115E-04	0.35206263E-04	0.25349524E-04	0.97140346E-05
99.9	0.17863358E-03	0.69454283E-04	0.52891977E-04	0.55085635E-04	0.29252842E-04	0.98666351E-05
100	0.42693969E-03	0.16204809E-03	0.91344118E-04	0.63421554E-04	0.31318254E-04	0.10198001E-04

CUMULATIVE FREQUENCY DISTRIBUTION AT X=800.0 Y=337.5 Z=0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.27897920E-06	0.14245843E-05
50	0.0	0.0	0.39965435E-07	0.47623541E-06	0.11941902E-05	0.21688302E-05
75	0.0	0.11479096E-05	0.25813661E-05	0.28035602E-05	0.31818436E-05	0.30996152E-05
90	0.16196464E-06	0.73396404E-05	0.71391196E-05	0.69225625E-05	0.60822440E-05	0.39170363E-05
95	0.10839826E-04	0.13190673E-04	0.11428615E-04	0.10343385E-04	0.76751812E-05	0.42903375E-05
99	0.57332712E-04	0.28498354E-04	0.21073996E-04	0.16707505E-04	0.10494983E-04	0.51341722E-05
99.5	0.77042845E-04	0.34250028E-04	0.23407832E-04	0.18469131E-04	0.11948351E-04	0.52089890E-05
99.9	0.11422510E-03	0.46669331E-04	0.30434865E-04	0.26693204E-04	0.17508937E-04	0.54098209E-05
100	0.45017432E-03	0.59372076E-04	0.29615683E-04	0.30263240E-04	0.18352424E-04	0.55004302E-05

CUMULATIVE FREQUENCY DISTRIBUTION AT X=800.0 Y=0.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.20178135E-07	0.61033268E-06
50	0.0	0.0	0.0	0.84964356E-08	0.52331109E-06	0.96415260E-06
75	0.0	0.25302236E-08	0.70840883E-06	0.11574984E-05	0.13509989E-05	0.12979572E-05
90	0.0	0.30571773E-05	0.34360637E-05	0.30373176E-05	0.24284118E-05	0.16593158E-05
95	0.11744612E-06	0.66978700E-05	0.51172337E-05	0.42316142E-05	0.33221295E-05	0.19114732E-05
99	0.33281089E-04	0.14604380E-04	0.10118109E-04	0.86893342E-05	0.67918800E-05	0.23723878E-05
99.5	0.49149618E-04	0.18833016E-04	0.13381233E-04	0.12046017E-04	0.82666420E-05	0.24336141E-05
99.9	0.88619912E-04	0.34606783E-04	0.24519803E-04	0.19771018E-04	0.94038032E-05	0.25613817E-05
100	0.31923875E-03	0.49039605E-04	0.29722723E-04	0.24404493E-04	0.10373947E-04	0.25717727E-05

CUMULATIVE FREQUENCY DISTRIBUTION AT X=800.0 Y=22.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.31590432E-08	0.33214155E-06
50	0.0	0.0	0.0	0.0	0.31713915E-06	0.54789928E-06
75	0.0	0.0	0.12785688E-06	0.61485019E-06	0.78384534E-06	0.75719402E-06
90	0.0	0.14533725E-05	0.21641408E-05	0.18840965E-05	0.15855258E-05	0.10827689E-05
95	0.0	0.41104977E-05	0.33112265E-05	0.28097411E-05	0.22921749E-05	9.12460659E-05
99	0.20790569E-04	0.10313162E-04	0.76756214E-05	0.57558864E-05	0.31460195E-05	0.15083806E-05
99.5	0.36712212E-04	0.13969571E-04	0.84455642E-05	0.69937705E-05	0.38429389E-05	0.15696178E-05
99.9	0.64066669E-04	0.20981301E-04	0.12264602E-04	0.12232087E-04	0.47792591E-05	0.16129306E-05
100	0.29356778E-03	0.36696263E-04	0.18348132E-04	0.14337682E-04	0.54107604E-05	0.16385302E-05

CUMULATIVE FREQUENCY DISTRIBUTION AT X=800.0 Y=45.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.55598703E-09	0.35731915E-06
50	0.0	0.0	0.0	0.0	0.20440370E-06	0.49795892E-06
75	0.0	0.0	0.86261821E-07	0.39869042E-06	0.85617688E-06	0.81063536E-06
90	0.0	0.11350148E-05	0.24830606E-05	0.22180611E-05	0.16361364E-05	0.12692826E-05
95	0.0	0.49661339E-05	0.38527442E-05	0.31920190E-05	0.23277044E-05	0.14467960E-05
99	0.19482410E-04	0.11177684E-04	0.85418196E-05	0.70383176E-05	0.53034983E-05	0.17087514E-05
99.5	0.42459200E-04	0.15879719E-04	0.10553575E-04	0.93715735E-05	0.57840080E-05	0.20348043E-05
99.9	0.77170160E-04	0.28114708E-04	0.16107486E-04	0.15625614E-04	0.76384376E-05	0.21556871E-05
100	0.37501496E-03	0.46876870E-04	0.23438435E-04	0.15689511E-04	0.81559456E-05	0.21701553E-05

CUMULATIVE FREQUENCY DISTRIBUTION AT X=800.0 Y=67.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.19910218E-08	0.24889209E-06
50	0.0	0.0	0.0	0.0	0.14546737E-06	0.42911802E-06
75	0.0	0.0	0.10832360E-06	0.32727348E-06	0.79993595E-06	0.62177327E-06
90	0.0	0.88918227E-06	0.17428902E-05	0.17519760E-05	0.13282652E-05	0.91909624E-06
95	0.0	0.34773839E-05	0.31748004E-05	0.28340100E-05	0.18950996E-05	0.11182974E-05
99	0.16080114E-04	0.89836503E-05	0.65093709E-05	0.54437296E-05	0.31568488E-05	0.19424133E-05
99.5	0.32439624E-04	0.12748404E-04	0.83791401E-05	0.62988538E-05	0.35999619E-05	0.19563859E-05
99.9	0.63343803E-04	0.18939914E-04	0.11131005E-04	0.77977775E-05	0.47309759E-05	0.19899007E-05
100	0.16785040E-03	0.30303869E-04	0.11655334E-04	0.92206838E-05	0.59454760E-05	0.20108682E-05

CUMULATIVE FREQUENCY DISTRIBUTION AT X=800.0 Y=90.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.98381292E-07	0.42774644E-06
50	0.0	0.0	0.67347941E-08	0.10075223E-06	0.47905326E-06	0.81535012E-06
75	0.0	0.11733863E-06	0.85482128E-06	0.11202137E-05	0.12998180E-05	0.12833762E-05
90	0.0	0.30206447E-05	0.28861887E-05	0.27604883E-05	0.22959002E-05	0.16845443E-05
95	0.47983724E-06	0.56365625E-05	0.45940978E-05	0.41290305E-05	0.30253241E-05	0.18356177E-05
99	0.30167124E-04	0.12510503E-04	0.89678560E-05	0.74601758E-05	0.54740649E-05	0.24251367E-05
99.5	0.43825232E-04	0.15991667E-04	0.11190264E-04	0.10325079E-04	0.61040009E-05	0.25050431E-05
99.9	0.80253856E-04	0.25524816E-04	0.16437087E-04	0.13011633E-04	0.64430151E-05	0.26079852E-05
100	0.26299339E-03	0.32874173E-04	0.25596077E-04	0.17605096E-04	0.77006334E-05	0.26970001E-05

CUMULATIVE FREQUENCY DISTRIBUTION AT X=800.0 Y=112.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.21881338E-07	0.17739683E-06	0.80441509E-06	0.15274791E-05
50	0.0	0.15332762E-06	0.99273075E-06	0.15290261E-05	0.21965543E-05	0.28209042E-05
75	0.36544221E-08	0.36351485E-05	0.45084162E-05	0.49050886E-05	0.52850155E-05	0.55923738E-05
90	0.58355099E-05	0.11542677E-04	0.10774902E-04	0.99791041E-05	0.84557751E-05	0.71882914E-05
95	0.24372421E-04	0.19057174E-04	0.15440848E-04	0.13660998E-04	0.11346160E-04	0.84373014E-05
99	0.73329080E-04	0.35874895E-04	0.26128837E-04	0.22772845E-04	0.17065628E-04	0.94562383E-05
99.5	0.92018949E-04	0.41281746E-04	0.31428004E-04	0.29057730E-04	0.19443658E-04	0.98133150E-05
99.9	0.13031083E-03	0.60571503E-04	0.44662738E-04	0.35700417E-04	0.23957633E-04	0.10166443E-04
100	0.25177584E-03	0.87236898E-04	0.52296658E-04	0.39889244E-04	0.25460802E-04	0.10185076E-04

CUMULATIVE FREQUENCY DISTRIBUTION AT X=800.0 Y=135.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.15051785E-06	0.19566469E-05	0.29644816E-05	0.44178805E-05	0.58212872E-05
50	0.81038642E-08	0.53202129E-05	0.68629924E-05	0.74960581E-05	0.86957034E-05	0.92801483E-05
75	0.10795834E-04	0.14239811E-04	0.13835153E-04	0.13944897E-04	0.13847120E-04	0.13906842E-04
90	0.31399934E-04	0.25514790E-04	0.22496853E-04	0.20765699E-04	0.18985549E-04	0.15998783E-04
95	0.47333873E-04	0.34454075E-04	0.29741001E-04	0.27354195E-04	0.21924367E-04	0.17443468E-04
99	0.98935401E-04	0.62552077E-04	0.51852519E-04	0.41265914E-04	0.32405180E-04	0.20288542E-04
99.5	0.13996252E-03	0.73905539E-04	0.57608209E-04	0.50959148E-04	0.36743804E-04	0.21132306E-04
99.9	0.21938581E-03	0.92197675E-04	0.76897748E-04	0.72839248E-04	0.58351958E-04	0.22017281E-04
100	0.43604663E-03	0.12359285E-03	0.10618559E-03	0.90063026E-04	0.63509433E-04	0.23351851E-04

CUMULATIVE FREQUENCY DISTRIBUTION AT X=5000.0 Y=315.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.36168682E-07	0.10453664E-06
50	0.0	0.0	0.85387946E-08	0.58115610E-07	0.13548572E-06	0.22112152E-06
75	0.0	0.17811465E-06	0.27010481E-06	0.30452969E-06	0.31845224E-06	0.36362576E-06
90	0.13189924E-06	0.80447398E-06	0.75813131E-06	0.73916146E-06	0.64316288E-06	0.50780699E-06
95	0.14717771E-05	0.13776043E-05	0.12477758E-05	0.11084267E-05	0.88879460E-06	0.56026227E-06
99	0.54080638E-05	0.29498933E-05	0.22118938E-05	0.19417621E-05	0.16314389E-05	0.61426806E-06
99.5	0.72580106E-05	0.35909725E-05	0.27032129E-05	0.25552408E-05	0.19728277E-05	0.63870863E-06
99.9	0.15196728E-04	0.59458198E-05	0.44717808E-05	0.66192533E-05	0.26420630E-05	0.64619587E-06
100	0.84131505E-04	0.20947293E-04	0.10490432E-04	0.71668255E-05	0.29852199E-05	0.66191802E-06

CUMULATIVE FREQUENCY DISTRIBUTION AT X=5000.0 Y=337.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.13080108E-07	0.80222492E-07
50	0.0	0.0	0.34313286E-09	0.19187748E-07	0.69095165E-07	0.12573850E-06
75	0.0	0.35439491E-07	0.13064300E-06	0.15438911E-06	0.18920201E-06	0.17924884E-06
90	0.10963741E-08	0.41085059E-06	0.41715919E-06	0.41353013E-06	0.36168058E-06	0.22895489E-06
95	0.43192472E-06	0.78051630E-06	0.69862722E-06	0.63962761E-06	0.45303062E-06	0.26817463E-06
99	0.36181909E-05	0.18028550E-05	0.12881756E-05	0.10581916E-05	0.65855136E-06	0.29816505E-06
99.5	0.51098368E-05	0.22534186E-05	0.15325004E-05	0.11887769E-05	0.76233380E-06	0.30169258E-06
99.9	0.90557323E-05	0.33098568E-05	0.18670871E-05	0.14873640E-05	0.91363347E-06	0.31337936E-06
100	0.21146378E-04	0.37607297E-05	0.22657759E-05	0.17264520E-05	0.96313761E-06	0.31662830E-06

CUMULATIVE FREQUENCY DISTRIBUTION AT X=5000.0 Y=0.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.14577914E-09	0.35206888E-07
50	0.0	0.0	0.0	0.45826593E-10	0.29770831E-07	0.52756821E-07
75	0.0	0.58812052E-11	0.27133446E-07	0.58794626E-07	0.75742776E-07	0.73219780E-07
50	0.0	0.15007060E-06	0.19557928E-06	0.17316466E-06	0.12850018E-06	0.11007444E-06
95	0.59110117E-09	0.38010899E-06	0.29189255E-06	0.24359178E-06	0.19158728E-06	0.12307993E-06
99	0.17581433E-05	0.83792327E-06	0.62629374E-06	0.58788004E-06	0.49176458E-06	0.14301321E-06
99.5	0.29224684E-05	0.11764350E-05	0.91553710E-06	0.82102144E-06	0.56503490E-06	0.14409750E-06
99.9	0.56128920E-05	0.24570221E-05	0.21853366E-05	0.17620714E-05	0.10170143E-05	0.14915304E-06
100	0.42233936E-04	0.52862160E-05	0.26431080E-05	0.28504437E-05	0.10222102E-05	0.15006066E-06

CUMULATIVE FREQUENCY DISTRIBUTION AT X=5000.0 Y=22.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.20389176E-10	0.19992385E-07
50	0.0	0.0	0.0	0.0	0.13813594E-07	0.28445811E-07
75	0.0	0.0	0.23833167E-08	0.24813552E-07	0.42410218E-07	0.40333958E-07
90	0.0	0.54455477E-07	0.11946088E-06	0.10623080E-06	0.94955624E-07	0.62961988E-07
95	0.0	0.22869460E-06	0.19328428E-06	0.16950753E-06	0.13235518E-06	0.75315427E-07
99	0.11487864E-05	0.60345269E-06	0.46176353E-06	0.36859063E-06	0.18517102E-06	0.90167873E-07
99.5	0.21258884E-05	0.90078481E-06	0.56635531E-06	0.42334409E-06	0.24530493E-06	0.90845560E-07
99.9	0.40991818E-05	0.12700320E-05	0.76666845E-06	0.98082091E-06	0.37735197E-06	0.92208381E-07
100	0.23539702E-04	0.29424627E-05	0.14712314E-05	0.11320553E-05	0.37735197E-06	0.93904873E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=5000.0 Y=45.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.14582606E-11	0.20480179E-07
50	0.0	0.0	0.0	0.0	0.10482022E-07	0.29226378E-07
75	0.0	0.0	0.10083996E-08	0.14940628E-07	0.50052737E-07	0.50985456E-07
90	0.0	0.43275435E-07	0.13510913E-06	0.12896214E-06	0.10230991E-06	0.85150248E-07
95	0.0	0.27654005E-06	0.24085580E-06	0.20941150E-06	0.14324081E-06	0.93926701E-07
99	0.10752683E-05	0.72607270E-06	0.58212339E-06	0.46406512E-06	0.39380984E-06	0.12303661E-06
99.5	0.25677864E-05	0.10686435E-05	0.78176242E-06	0.65926480E-06	0.44854397E-06	0.15118201E-06
99.9	0.53723543E-05	0.19507843E-05	0.17475313E-05	0.12004366E-05	0.52173317E-06	0.15981925E-06
100	0.28810478E-04	0.36013098E-05	0.18006549E-05	0.12010714E-05	0.56730175E-06	0.16089183E-06

CUMULATIVE FREQUENCY DISTRIBUTION AT X=5000.0 Y=67.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.71000514E-11	0.14641117E-07
50	0.0	0.0	0.0	0.0	0.70953732E-08	0.25460412E-07
75	0.0	0.0	0.14370967E-08	0.15539950E-07	0.47672188E-07	0.39219451E-07
90	0.0	0.31356308E-07	0.95708401E-07	0.10693691E-06	0.83028453E-07	0.52725785E-07
95	0.0	0.19428228E-06	0.20763008E-06	0.16664444E-06	0.12739076E-06	0.63567370E-07
99	0.87763675E-06	0.55491716E-06	0.43887115E-06	0.35722360E-06	0.18691651E-06	0.12359015E-06
99.5	0.20100751E-05	0.87702165E-06	0.58959779E-06	0.42241618E-06	0.20926058E-06	0.12442842E-06
99.9	0.40991790E-05	0.14034076E-05	0.70586043E-06	0.50623231E-06	0.30232917E-06	0.12563163E-06
100	0.12149576E-04	0.24299152E-05	0.93458272E-06	0.58561466E-06	0.37802903E-06	0.12742345E-06

CUMULATIVE FREQUENCY DISTRIBUTION AT X=5000.0 Y=90.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.40193058E-08	0.23817272E-07
50	0.0	0.0	0.25931188E-10	0.20316566E-08	0.25079416E-07	0.43462933E-07
75	0.0	0.12126509E-08	0.35333194E-07	0.55407174E-07	0.67701819E-07	0.66386406E-07
90	0.0	0.14632678E-06	0.15654877E-06	0.15234110E-06	0.12525743E-06	0.98119585E-07
95	0.42502215E-08	0.31009449E-06	0.26077959E-06	0.23628263E-06	0.18326324E-06	0.11449896E-06
99	0.16467056E-05	0.79867789E-06	0.58171133E-06	0.52813391E-06	0.34962306E-06	0.17958166E-06
99.5	0.26262996E-05	0.10492295E-05	0.89531187E-06	0.76633961E-06	0.43603438E-06	0.18571274E-06
99.9	0.58168962E-05	0.21671476E-05	0.17486946E-05	0.11915372E-05	0.50521476E-06	0.19400682E-06
100	0.28155948E-04	0.35194935E-05	0.19037416E-05	0.12691607E-05	0.66004691E-06	0.20071275E-06

CUMULATIVE FREQUENCY DISTRIBUTION AT X=5000.0 Y=112.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.21045696E-09	0.42891095E-08	0.41060400E-07	0.84093926E-07
50	0.0	0.19965642E-08	0.40799645E-07	0.77697678E-07	0.12948186E-06	0.16824447E-06
75	0.95705752E-11	0.18900982E-06	0.26854855E-06	0.29308774E-06	0.31357575E-06	0.32824516E-06
90	0.18181407E-06	0.71684804E-06	0.64501506E-06	0.61001066E-06	0.51318074E-06	0.45536137E-06
95	0.13917124E-05	0.11540496E-05	0.95202239E-06	0.85374086E-06	0.71276997E-06	0.51387065E-06
99	0.49232312E-05	0.22464483E-05	0.19052277E-05	0.15245078E-05	0.10616695E-05	0.57821558E-06
99.5	0.62745294E-05	0.29965740E-05	0.22118547E-05	0.19582285E-05	0.12047130E-05	0.59775459E-06
99.9	0.10065412E-04	0.42593965E-05	0.29897665E-05	0.24965957E-05	0.15395262E-05	0.60724216E-06
100	0.18854073E-04	0.69515136E-05	0.40005962E-05	0.26940934E-05	0.16514177E-05	0.60842700E-06

CUMULATIVE FREQUENCY DISTRIBUTION AT X=5000.0 Y=135.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.23127003E-08	0.10091179E-06	0.16987104E-06	0.27334886E-06	0.38332479E-06
50	0.21753807E-10	0.29918658E-06	0.41405730E-06	0.45959354E-06	0.55291048E-06	0.61919405E-06
75	0.54507149E-06	0.90911567E-06	0.91407458E-06	0.91384572E-06	0.93934290E-06	0.97202701E-06
90	0.20855923E-05	0.17987522E-05	0.15966352E-05	0.15276491E-05	0.14050647E-05	0.11763577E-05
95	0.23725582E-05	0.26130037E-05	0.23192615E-05	0.21618853E-05	0.16822378E-05	0.12873825E-05
99	0.82008863E-05	0.53806925E-05	0.41197482E-05	0.35819121E-05	0.27855021E-05	0.15215419E-05
99.5	0.12291127E-04	0.63633797E-05	0.50722783E-05	0.40628656E-05	0.34123441E-05	0.16112281E-05
99.9	0.21577056E-04	0.95259120E-05	0.79465844E-05	0.73275551E-05	0.51353773E-05	0.17033917E-05
100	0.48696151E-04	0.12974342E-04	0.11042428E-04	0.87179824E-05	0.56531680E-05	0.17843304E-05

CUMULATIVE FREQUENCY DISTRIBUTION AT X=10000.0 Y=315.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.11898855E-07	0.39420250E-07
50	0.0	0.0	0.16825294E-08	0.17398602E-07	0.48724825E-07	0.81325879E-07
75	0.0	0.57269261E-07	0.95579821E-07	0.10819360E-06	0.11580113E-06	0.13432509E-06
90	0.26942164E-07	0.29764158E-06	0.28247553E-06	0.26897686E-06	0.24290699E-06	0.19045433E-06
95	0.50944533E-06	0.51394477E-06	0.46507063E-06	0.40625190E-06	0.33735540E-06	0.21974654E-06
99	0.20018133E-05	0.11472730E-05	0.87053417E-06	0.76213655E-06	0.63080751E-06	0.24315244E-06
99.5	0.28199247E-05	0.14036650E-05	0.10350741E-05	0.95666292E-06	0.74433427E-06	0.24778973E-06
99.9	0.60016846E-05	0.23125722E-05	0.17085695E-05	0.31087411E-05	0.12042174E-05	0.25372725E-06
100	0.44052867E-04	0.98463388E-05	0.49264872E-05	0.33393026E-05	0.13460522E-05	0.25695738E-06

CUMULATIVE FREQUENCY DISTRIBUTION AT X=10000.0 Y=337.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.38649119E-08	0.29699688E-07
50	0.0	0.0	0.30288896E-10	0.48866617E-08	0.23919647E-07	0.44517531E-07
75	0.0	0.79878504E-08	0.48146685E-07	0.55628789E-07	0.67815961E-07	0.64992946E-07
90	0.87539087E-10	0.14584339E-06	0.15432619E-06	0.15032344E-06	0.13241515E-06	0.83584041E-07
95	0.12040977E-06	0.28320778E-06	0.25935333E-06	0.23495539E-06	0.16971364E-06	0.97883003E-07
99	0.13245890E-05	0.67357894E-06	0.48515130E-06	0.40291360E-06	0.24880012E-06	0.10802484E-06
99.5	0.19078780E-05	0.87823923E-06	0.57994760E-06	0.44074397E-06	0.27561646E-06	0.11238512E-06
99.9	0.35605253E-05	0.13149829E-05	0.72390708E-06	0.52097437E-06	0.30930397E-06	0.11448327E-06
100	0.81129356E-05	0.14976467E-05	0.78242454E-06	0.62768413E-06	0.32477283E-06	0.11568238E-06

CUMULATIVE FREQUENCY DISTRIBUTION AT X=10000.0 Y=0.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.16834784E-10	0.12309329E-07
50	0.0	0.0	0.0	0.31556008E-11	0.10926414E-07	0.19151265E-07
75	0.0	0.27285314E-12	0.70115966E-08	0.20003114E-07	0.27724038E-07	0.26369385E-07
90	0.0	0.49454080E-07	0.68042254E-07	0.63437994E-07	0.45896854E-07	0.41167368E-07
95	0.48697504E-10	0.13497800E-06	0.10816240E-06	0.87966214E-07	0.67900999E-07	0.47427534E-07
99	0.66222321E-06	0.31061472E-06	0.23853221E-06	0.20138287E-06	0.19189895E-06	0.63146729E-07
99.5	0.10830563E-05	0.42724957E-06	0.35048373E-06	0.30563172E-06	0.21208240E-06	0.63680375E-07
99.9	0.21694095E-05	0.14475672E-05	0.93568065E-06	0.86835882E-06	0.46961736E-06	0.64146434E-07
100	0.20840351E-04	0.26050766E-05	0.13025383E-05	0.13460503E-05	0.47182988E-06	0.64146434E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=10000.0 Y=22.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.14361038E-11	0.71856725E-08
50	0.0	0.0	0.0	0.0	0.40441996E-11	0.96102717E-08
75	0.0	0.0	0.40697401E-09	0.68615691E-08	0.14953013E-07	0.14444218E-07
90	0.0	0.14685845E-07	0.40945434E-07	0.39981616E-07	0.25217113E-07	0.23196083E-07
95	0.0	0.81890562E-07	0.67836766E-07	0.60708089E-07	0.48405600E-07	0.28668552E-07
99	0.38537263E-06	0.21330425E-06	0.17496620E-06	0.13972345E-06	0.71506918E-07	0.32824058E-07
99.5	0.75938635E-06	0.32788751E-06	0.22722116E-06	0.16397127E-06	0.89498371E-07	0.33046216E-07
99.9	0.15570795E-05	0.49191385E-06	0.29049704E-06	0.40790667E-06	0.15543850E-06	0.33252277E-07
100	0.97897600E-05	0.12237197E-05	0.61186000E-06	0.46631561E-06	0.15543850E-06	0.33908496E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=10000.0 Y=45.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.15478715E-12	0.75894029E-08
50	0.0	0.0	0.0	0.0	0.30787499E-08	0.10594668E-07
75	0.0	0.0	0.17251980E-09	0.45243382E-08	0.18642215E-07	0.18259620E-07
90	0.0	0.10589190E-07	0.49752124E-07	0.47352728E-07	0.39567627E-07	0.32490437E-07
95	0.0	0.10258418E-06	0.87888225E-07	0.79934239E-07	0.54511247E-07	0.35676820E-07
99	0.41110115E-06	0.28796683E-06	0.22915549E-06	0.18589975E-06	0.16457756E-06	0.48509975E-07
99.5	0.93040444E-06	0.42667341E-06	0.29673453E-06	0.25408576E-06	0.17955091E-06	0.59185670E-07
99.9	0.20388570E-05	0.75091657E-06	0.73016986E-06	0.49865224E-06	0.19861722E-06	0.62496042E-07
100	0.11967654E-04	0.14967463E-05	0.74837357E-06	0.49891571E-06	0.21501700E-06	0.62915490E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=10000.0 Y=67.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.48820513E-12	0.53997553E-08
50	0.0	0.0	0.0	0.0	0.21488484E-08	0.90656442E-08
75	0.0	0.0	0.19064900E-09	0.42332360E-08	0.16774479E-07	0.14740483E-07
90	0.0	0.88868433E-08	0.35620776E-07	0.38310301E-07	0.30575201E-07	0.19366762E-07
95	0.0	0.71241516E-07	0.74582317E-07	0.61896685E-07	0.48626674E-07	0.24230758E-07
99	0.29504389E-06	0.22101483E-06	0.16693326E-06	0.13171086E-06	0.73985177E-07	0.47917510E-07
99.5	0.72123976E-06	0.32533364E-06	0.22253283E-06	0.17043118E-06	0.80711118E-07	0.48377270E-07
99.9	0.17442262E-05	0.54720454E-06	0.29351366E-06	0.19567574E-06	0.10984843E-06	0.48791776E-07
100	0.50527960E-05	0.10105587E-05	0.38867660E-06	0.24060932E-06	0.13656671E-06	0.49360189E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=10000.0 Y=90.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.91895269E-09	0.89162064E-08
50	0.0	0.0	0.15489381E-11	0.33227221E-09	0.85072607E-08	0.14988771E-07
75	0.0	0.14541743E-09	0.10274171E-07	0.19407693E-07	0.24531005E-07	0.23121000E-07
90	0.0	0.49379487E-07	0.55943179E-07	0.53257811E-07	0.46220329E-07	0.35295201E-07
95	0.44333115E-09	0.11061496E-06	0.93854453E-07	0.86122611E-07	0.65709855E-07	0.42358931E-07
99	0.60299112E-06	0.31099250E-06	0.22322087E-06	0.20123827E-06	0.13368032E-06	0.69289285E-07
99.5	0.95648102E-06	0.41436692E-06	0.34033985E-06	0.30379016E-06	0.17566379E-06	0.71729801E-07
99.9	0.23944494E-05	0.80091729E-06	0.71727061E-06	0.51419346E-06	0.21365605E-06	0.74848742E-07
100	0.12227629E-04	0.15284531E-05	0.77249723E-06	0.51499813E-06	0.28325258E-06	0.77379980E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=10000.0 Y=112.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.20839219E-10	0.84166718E-09	0.14151624E-07	0.29900782E-07
50	0.0	0.27501934E-09	0.11402463E-07	0.25803622E-07	0.47297128E-07	0.60711443E-07
75	0.16949690E-12	0.60673813E-07	0.94820109E-07	0.10325118E-06	0.10866609E-06	0.11630510E-06
90	0.40460890E-07	0.26155215E-06	0.23049108E-06	0.21451825E-06	0.18499907E-06	0.16472660E-06
95	0.45990720E-06	0.41155283E-06	0.34330810E-06	0.30469738E-06	0.25186006E-06	0.18124632E-06
99	0.18238316E-05	0.83206919E-06	0.70830458E-06	0.56533167E-06	0.40792537E-06	0.19859812E-06
99.5	0.23300199E-05	0.10834447E-05	0.81554646E-06	0.70112458E-06	0.43298786E-06	0.20610111E-06
99.9	0.29353081E-05	0.15642336E-05	0.10322783E-05	0.92796711E-06	0.53611660E-06	0.20792345E-06
100	0.73103029E-05	0.27324531E-05	0.15486767E-05	0.10390831E-05	0.58725243E-06	0.20836592E-06

CUMULATIVE FREQUENCY DISTRIBUTION AT X=10000.0 Y=135.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.30513836E-09	0.33975152E-07	0.60142440E-07	0.97421378E-07	0.14158559E-06
50	0.81213882E-12	0.10084892E-06	0.14449859E-06	0.15982766E-06	0.19696233E-06	0.22543361E-06
75	0.16013809E-06	0.32541402E-06	0.32830889E-06	0.32482870E-06	0.34691823E-06	0.35846648E-06
90	0.76552914E-06	0.66848929E-06	0.60408695E-06	0.57567422E-06	0.53463327E-06	0.45199931E-06
95	0.12743885E-05	0.99710542E-06	0.89382365E-06	0.83963278E-06	0.65709690E-06	0.48823017E-06
99	0.32882863E-05	0.21611031E-05	0.16481881E-05	0.14180096E-05	0.11066504E-05	0.58373649E-06
99.5	0.49012660E-05	0.25623904E-05	0.20536236E-05	0.16799531E-05	0.13855224E-05	0.61466212E-06
99.9	0.90633584E-05	0.39299375E-05	0.32929020E-05	0.30402252E-05	0.20607076E-05	0.64537051E-06
100	0.21114320E-04	0.53340282E-05	0.45244979E-05	0.35760759E-05	0.22838203E-05	0.69248154E-06

CUMULATIVE FREQUENCY DISTRIBUTION AT X=15000.0 Y=315.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.65581034E-08	0.22620974E-07
50	0.0	0.0	0.55711591E-09	0.87253866E-08	0.28744893E-07	0.47982880E-07
75	0.0	0.28775133E-07	0.54719095E-07	0.61016749E-07	0.68279519E-07	0.77431821E-07
90	0.98195940E-08	0.16965191E-06	0.16625148E-06	0.15875236E-06	0.14214334E-06	0.11057045E-06
95	0.28281733E-06	0.30325634E-06	0.27776838E-06	0.24559421E-06	0.19655960E-06	0.12945674E-06
99	0.11925194E-05	0.69576959E-06	0.51861451E-06	0.47041817E-06	0.37303488E-06	0.15222821E-06
99.5	0.17336597E-05	0.83605255E-06	0.63974949E-06	0.57241328E-06	0.43054570E-06	0.15427327E-06
99.9	0.41135654E-05	0.13727631E-05	0.10024742E-05	0.20443877E-05	0.78021060E-06	0.15839174E-06
100	0.30345429E-04	0.64752967E-05	0.32388989E-05	0.21875321E-05	0.86791459E-06	0.16016929E-06

CUMULATIVE FREQUENCY DISTRIBUTION AT X=15000.0 Y=337.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
250.0	0.0	0.0	0.0	0.0	.19011699E-08	0.16883281E-07
50	0.0	0.0	0.66232393E-11	0.20247073E-08	0.13712853E-07	0.25553373E-07
75	0.0	0.31021297E-08	0.26537951E-07	0.30617500E-07	0.38804675E-07	0.37484096E-07
90	0.17074051E-10	0.84400710E-07	0.87690921E-07	0.88357922E-07	0.76232027E-07	0.48131973E-07
95	0.55542273E-07	0.16197566E-06	0.15089341E-06	0.13481110E-06	0.10000292E-06	0.55359607E-07
99	0.77743528E-06	0.38396513E-06	0.27873079E-06	0.23427765E-06	0.14466826E-06	0.65524091E-07
99.5	0.11094689E-05	0.51570566E-06	0.34316957E-06	0.26858902E-06	0.16511478E-06	0.69627163E-07
99.9	0.21586957E-05	0.78843152E-06	0.43353373E-06	0.30150534E-06	0.17615287E-06	0.71047509E-07
100	0.50085073E-05	0.90445928E-06	0.45224823E-06	0.37201784E-06	0.18749381E-06	0.71783518E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=15000.0 Y=0.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.42491158E-11	0.68898416E-08
50	0.0	0.0	0.0	0.50700438E-12	0.60802101E-08	0.10994714E-07
75	0.0	0.0	0.29931513E-08	0.10471879E-07	0.15913940E-07	0.15212056E-07
90	0.0	0.25995199E-07	0.39465355E-07	0.37539614E-07	0.26602049E-07	0.23917156E-07
95	0.84520620E-11	0.78655887E-07	0.64125516E-07	0.50901349E-07	0.38762082E-07	0.27592829E-07
99	0.39688416E-06	0.18071910E-06	0.13130398E-06	0.12209216E-06	0.10809686E-06	0.39930477E-07
99.5	0.63648679E-06	0.24657982E-06	0.21058162E-06	0.17981279E-06	0.13211240E-06	0.40202647E-07
99.9	0.13129211E-05	0.89727888E-06	0.59065110E-06	0.57528712E-06	0.30167593E-06	0.40480511E-07
100	0.13806886E-04	0.17258608E-05	0.86293073E-06	0.87396558E-06	0.30306848E-06	0.40480511E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=15000.0 Y=22.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.33338339E-12	0.39631480E-08
50	0.0	0.0	0.0	0.0	0.18983932E-08	0.53384994E-08
75	0.0	0.0	0.13741124E-09	0.32824041E-08	0.85651628E-08	0.81658236E-08
90	0.0	0.67215353E-08	0.22862757E-07	0.21644198E-07	0.19387659E-07	0.13477994E-07
95	0.0	0.47744486E-07	0.40322814E-07	0.35388123E-07	0.26921331E-07	0.16593361E-07
99	0.20850109E-06	0.12234443E-06	0.10114360E-06	0.81633004E-07	0.41390166E-07	0.19006450E-07
99.5	0.43771365E-06	0.19947140E-06	0.13024169E-06	0.96822475E-07	0.51571217E-07	0.19195689E-07
99.9	0.91841656E-06	0.30954106E-06	0.16814755E-06	0.25093811E-06	0.95084317E-07	0.19331665E-07
100	0.60225157E-05	0.75281446E-06	0.37640723E-06	0.28525307E-06	0.95084317E-07	0.19398097E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=15000.0 Y=45.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.16775125E-13	0.43620254E-08
50	0.0	0.0	0.0	0.0	0.15074273E-08	0.62900263E-08
75	0.0	0.0	0.50292701E-10	0.18487309E-08	0.10394373E-07	0.10547602E-07
90	0.0	0.46893938E-08	0.29167751E-07	0.26986175E-07	0.22845800E-07	0.19048986E-07
95	0.0	0.59042485E-07	0.54270807E-07	0.46654009E-07	0.32093070E-07	0.21249946E-07
99	0.23026769E-06	0.16328897E-06	0.13279731E-06	0.13307749E-06	0.98863723E-07	0.29389479E-07
99.5	0.55310579E-06	0.24180156E-06	0.19961624E-06	0.15243188E-06	0.10709704E-06	0.35758887E-07
99.9	0.11425655E-05	0.44322462E-06	0.43867260E-06	0.31491277E-06	0.12175013E-06	0.37773642E-07
100	0.75579073E-05	0.94493657E-06	0.47246829E-06	0.31497882E-06	0.13047810E-06	0.38027157E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=15000.0 Y=67.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.84983778E-13	0.28847238E-08
50	0.0	0.0	0.0	0.0	0.10945815E-08	0.51356537E-08
75	0.0	0.0	0.51957716E-10	0.18548296E-08	0.95388017E-08	0.86745793E-08
90	0.0	0.39902375E-08	0.20557884E-07	0.22688319E-07	0.18057346E-07	0.11139001E-07
95	0.0	0.41215444E-07	0.40739160E-07	0.35761879E-07	0.28582093E-07	0.14339826E-07
99	0.15917016E-06	0.13336694E-06	0.99734848E-07	0.77640095E-07	0.45095966E-07	0.28247744E-07
99.5	0.42300820E-06	0.19946970E-06	0.12478461E-06	0.10174961E-06	0.48676057E-07	0.28512972E-07
99.9	0.10532685E-05	0.31382297E-06	0.18011775E-06	0.12007848E-06	0.62027539E-07	0.28752943E-07
100	0.31094064E-05	0.62168124E-06	0.23910815E-06	0.14801935E-06	0.76844231E-07	0.29126156E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=15000.0 Y=90.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.35814640E-09	0.50313389E-08
50	0.0	0.0	0.26058447E-12	0.10601167E-09	0.45774478E-08	0.82628588E-08
75	0.0	0.35607323E-10	0.48928221E-08	0.10372965E-07	0.13553148E-07	0.13117738E-07
90	0.0	0.27021031E-07	0.31015087E-07	0.31375979E-07	0.26601228E-07	0.20073045E-07
95	0.98749744E-10	0.61981723E-07	0.54284722E-07	0.49494322E-07	0.39624183E-07	0.24721672E-07
99	0.34081376E-06	0.17759987E-06	0.13384806E-06	0.12186308E-06	0.83738769E-07	0.40617124E-07
99.5	0.56139402E-06	0.26591306E-06	0.19706977E-06	0.18206487E-06	0.10600883E-06	0.42088498E-07
99.9	0.13590184E-05	0.48480365E-06	0.43750231E-06	0.31885628E-06	0.13196990E-06	0.43901814E-07
100	0.76525512E-05	0.95656833E-06	0.48143238E-06	0.32095488E-06	0.17561098E-06	0.45360050E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=15000.0 Y=112.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.43523128E-11	0.30470293E-09	0.75992297E-08	0.16716541E-07
50	0.0	0.77833850E-10	0.54824341E-08	0.13232260E-07	0.27178555E-07	0.34113487E-07
75	0.0	0.32367581E-07	0.53171512E-07	0.58579150E-07	0.60095658E-07	0.64531093E-07
90	0.15921973E-07	0.14831653E-06	0.12985015E-06	0.12489033E-06	0.10569761E-06	0.94182724E-07
95	0.24518067E-06	0.23630218E-06	0.19737212E-06	0.16936474E-06	0.14695985E-06	0.10216166E-06
99	0.10542435E-05	0.48661377E-06	0.40624525E-06	0.32735522E-06	0.23301607E-06	0.11407087E-06
99.5	0.13866784E-05	0.62256959E-06	0.47548781E-06	0.39148244E-06	0.25524099E-06	0.11504034E-06
99.9	0.23214416E-05	0.91088100E-06	0.58397745E-06	0.54756902E-06	0.30177517E-06	0.11607568E-06
100	0.44572580E-05	0.16203585E-05	0.91777423E-06	0.61470507E-06	0.32979307E-06	0.11660666E-06

CUMULATIVE FREQUENCY DISTRIBUTION AT X=15000.0 Y=135.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.87701235E-10	0.17875784E-07	0.32972068E-07	0.54499544E-07	0.83042266E-07
50	0.0	0.54354430E-07	0.80337145E-07	0.89459093E-07	0.11152611E-06	0.13161014E-06
75	0.76664151E-07	0.18519063E-06	0.18656362E-06	0.18567346E-06	0.19885351E-06	0.20508207E-06
90	0.43765573E-06	0.38521569E-06	0.35380822E-06	0.33945889E-06	0.31262346E-06	0.26365655E-06
95	0.74108164E-06	0.58376895E-06	0.53680361E-06	0.49867924E-06	0.38944358E-06	0.28592308E-06
99	0.20399293E-05	0.12813935E-05	0.98928103E-06	0.86699043E-06	0.64731728E-06	0.34321846E-06
99.5	0.28955837E-05	0.15893529E-05	0.12666242E-05	0.10356380E-05	0.83330207E-06	0.35980611E-06
99.9	0.57216357E-05	0.24207111E-05	0.20257066E-05	0.18715227E-05	0.12421297E-05	0.37859621E-06
100	0.13350488E-04	0.32579665E-05	0.27657179E-05	0.21882661E-05	0.13833542E-05	0.40881116E-06

CUMULATIVE FREQUENCY DISTRIBUTION AT X=30000.0 Y=315.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.9	0.0	0.25466331E-08	0.95368655E-08
50	0.0	0.0	0.78097778E-10	0.29290086E-08	0.12006758E-07	0.21992719E-07
75	0.0	0.96733572E-08	0.23271738E-07	0.26817059E-07	0.29294508E-07	0.33200383E-07
90	0.15804347E-08	0.75784897E-07	0.72687101E-07	0.69492899E-07	0.62654692E-07	0.50567294E-07
95	0.11228110E-06	0.13580825E-06	0.12496923E-06	0.11077958E-06	0.87188369E-07	0.57074697E-07
99	0.54333287E-06	0.31370473E-06	0.23337026E-06	0.20854372E-06	0.16181275E-06	0.73323690E-07
99.5	0.78534606E-06	0.38627832E-06	0.29357693E-06	0.25960179E-06	0.18710909E-06	0.74192769E-07
99.9	0.18420833E-05	0.59907313E-06	0.44757218E-06	0.10596832E-05	0.39342717E-06	0.77013965E-07
100	0.16618098E-04	0.33369779E-05	0.16687000E-05	0.11220336E-05	0.43589006E-06	0.77496850E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=30000.0 Y=337.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.57549632E-09	0.73884365E-08
50	0.0	0.0	0.36937684E-12	0.42537796E-09	0.53889941E-08	0.10797148E-07
75	0.0	0.60633898E-09	0.98081117E-08	0.13246350E-07	0.16726691E-07	0.15961593E-07
90	0.53020040E-12	0.36850878E-07	0.36645520E-07	0.38873999E-07	0.32473420E-07	0.19701353E-07
95	0.14082605E-07	0.69344082E-07	0.68281850E-07	0.57674050E-07	0.43507271E-07	0.22800123E-07
99	0.35425074E-06	0.16567549E-06	0.12153515E-06	0.10311425E-06	0.63890070E-07	0.31202003E-07
99.5	0.49062709E-06	0.21010817E-06	0.15162880E-06	0.11906582E-06	0.68105351E-07	0.32523928E-07
99.9	0.93845620E-06	0.35708922E-06	0.20588476E-06	0.15175669E-06	0.90669801E-07	0.33244039E-07
100	0.23853527E-05	0.45305342E-06	0.22763510E-06	0.16396825E-06	0.99481440E-07	0.33542680E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=30000.0 Y=0.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.29609935E-12	0.28636971E-08
50	0.0	0.0	0.0	0.11113838E-13	0.22228508E-08	0.47122803E-08
75	0.0	0.0	0.73223183E-09	0.38157530E-08	0.69859922E-08	0.66229759E-07
90	0.0	0.97641788E-08	0.17463666E-07	0.17415971E-07	0.11571441E-07	0.10530172E-07
95	0.15624204E-12	0.34692391E-07	0.29171744E-07	0.23136387E-07	0.16517987E-07	0.12725344E-07
99	0.16071755E-06	0.76794834E-07	0.58218461E-07	0.51091696E-07	0.47019551E-07	0.18705244E-07
99.5	0.29896370E-06	0.10925226E-06	0.93230540E-07	0.79488757E-07	0.63624952E-07	0.18805757E-07
99.9	0.58652580E-06	0.42542558E-06	0.28551841E-06	0.28332755E-06	0.14418623E-06	0.18922940E-07
100	0.67998617E-05	0.84998271E-06	0.42499136E-06	0.42281243E-06	0.14469254E-06	0.18922940E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=30000.0 Y=22.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.10799511E-13	0.15164612E-08
50	0.0	0.0	0.0	0.0	0.61131900E-09	0.21830511E-08
75	0.0	0.0	0.16979002E-10	0.87244656E-09	0.35564787E-08	0.36691099E-08
90	0.0	0.17925390E-08	0.95135775E-08	0.92867367E-08	0.84610576E-08	0.63178405E-08
95	0.0	0.19747674E-07	0.18311582E-07	0.16318879E-07	0.12306064E-07	0.74280209E-08
99	0.73414014E-07	0.58875209E-07	0.44931362E-07	0.37825529E-07	0.19342966E-07	0.87324601E-08
99.5	0.19305151E-06	0.85239321E-07	0.57500131E-07	0.45481329E-07	0.23543205E-07	0.88065910E-08
99.9	0.40763098E-06	0.14512125E-07	0.78058292E-07	0.11679180E-06	0.43894588E-07	0.88819903E-08
100	0.28030036E-05	0.35037544E-06	0.17518772E-06	0.13168375E-06	0.43894588E-07	0.89204555E-08

CUMULATIVE FREQUENCY DISTRIBUTION AT X=30000.0 Y=45.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.0	0.18662873E-08
50	0.0	0.0	0.0	0.0	0.50042726E-09	0.26730709E-08
75	0.0	0.0	0.39705583E-11	0.52659033E-09	0.46017661E-08	0.47644235E-08
90	0.0	0.10701231E-08	0.11990824E-07	0.11826288E-07	0.10011917E-07	0.81641041E-08
95	0.0	0.24349113E-07	0.24542345E-07	0.20046127E-07	0.13839816E-07	0.92468966E-08
99	0.92524488E-07	0.69798716E-07	0.60351681E-07	0.59177616E-07	0.43500155E-07	0.13539605E-07
99.5	0.23834008E-06	0.11319975E-06	0.89329035E-07	0.70118176E-07	0.51050378E-07	0.16306434E-07
99.9	0.53826830E-06	0.28328691E-06	0.19303008E-06	0.15226681E-06	0.54461015E-07	0.17222273E-07
100	0.36544034E-05	0.45681497E-06	0.22840749E-06	0.15227164E-06	0.61999003E-07	0.17337861E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=30000.0 Y=67.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.22644992E-14	0.11720056E-08
50	0.0	0.0	0.0	0.0	0.31417380E-09	0.22692874E-08
75	0.0	0.0	0.52800845E-11	0.48673421E-09	0.40366999E-08	0.38441001E-08
90	0.0	0.88995789E-09	0.85814769E-08	0.10402204E-07	0.83399527E-08	0.47788618E-08
95	0.0	0.17683718E-07	0.17903890E-07	0.14717511E-07	0.11889053E-07	0.60918310E-08
99	0.54966797E-07	0.61008564E-07	0.43119574E-07	0.35202913E-07	0.19701574E-07	0.12019374E-07
99.5	0.18337704E-06	0.85349200E-07	0.53488929E-07	0.43651355E-07	0.22257193E-07	0.12152224E-07
99.9	0.49097372E-06	0.14134537E-06	0.80181849E-07	0.53454563E-07	0.25143208E-07	0.12246886E-07
100	0.14467178E-05	0.28934352E-06	0.11128594E-06	0.68891268E-07	0.31165513E-07	0.12445035E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=30000.0 Y=90.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.65864397E-10	0.20825124E-08
50	0.0	0.0	0.92840334E-14	0.11592745E-10	0.16247081E-08	0.35264047E-08
75	0.0	0.25062209E-11	0.12690611E-08	0.36838277E-08	0.57753837E-08	0.57722005E-08
90	0.0	0.98424167E-08	0.14377200E-07	0.13429144E-07	0.12304604E-07	0.88840082E-08
95	0.59097033E-11	0.28230950E-07	0.25187923E-07	0.21970269E-07	0.19115102E-07	0.10852848E-07
99	0.13526767E-06	0.80749828E-07	0.62610525E-07	0.57959785E-07	0.40544993E-07	0.17481465E-07
99.5	0.25345207E-06	0.11674047E-06	0.94287941E-07	0.81522671E-07	0.47361077E-07	0.17962108E-07
99.9	0.62218726E-06	0.22123038E-06	0.19813035E-06	0.14556815E-06	0.59094461E-07	0.18709208E-07
100	0.34936356E-05	0.43670445E-06	0.21909176E-06	0.14606115E-06	0.78980747E-07	0.19330866E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=30000.0 Y=112.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.23345361E-12	0.47088083E-10	0.28057887E-08	0.67437043E-08
50	0.0	0.62331269E-11	0.15318589E-08	0.47521667E-08	0.10813505E-07	0.14239223E-07
75	0.0	0.11210062E-07	0.22545485E-07	0.23727203E-07	0.25251463E-07	0.28560905E-07
90	0.30338845E-08	0.61439380E-07	0.58503737E-07	0.54185911E-07	0.46454740E-07	0.40374253E-07
95	0.90963283E-07	0.10561797E-06	0.86726743E-07	0.76200081E-07	0.62735467E-07	0.44272010E-07
99	0.47112485E-06	0.22302675E-06	0.16909689E-06	0.14090898E-06	0.99676811E-07	0.50122829E-07
99.5	0.65351367E-06	0.27533167E-06	0.20922118E-06	0.17070170E-06	0.11543676E-06	0.51748586E-07
99.9	0.10784406E-05	0.41844237E-06	0.29186162E-06	0.24557761E-06	0.13325729E-06	0.52903065E-07
100	0.20587149E-05	0.70244937E-06	0.40353405E-06	0.26973731E-06	0.14793858E-06	0.53056681E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=30000.0 Y=135.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.69041387E-11	0.64947194E-08	0.12591528E-07	0.23224793E-07	0.36272571E-07
50	0.0	0.20490724E-07	0.33088554E-07	0.36662065E-07	0.46559546E-07	0.58065218E-07
75	0.22570859E-07	0.77671871E-07	0.77909647E-07	0.78995015E-07	0.85990962E-07	0.85851411E-07
90	0.18494472E-06	0.16740989E-06	0.15365777E-06	0.14811320E-06	0.13546395E-06	0.11276023E-06
95	0.33302257E-06	0.26129362E-06	0.23807456E-06	0.22218791E-06	0.16813664E-06	0.12399533E-06
99	0.94607157E-06	0.56286763E-06	0.45282661E-06	0.38698556E-06	0.27706278E-06	0.14644928E-06
99.5	0.13263107E-05	0.73711476E-06	0.56172013E-06	0.48058166E-06	0.37332501E-06	0.15398774E-06
99.9	0.27695505E-05	0.11265029E-05	0.93776180E-06	0.85681131E-06	0.55677998E-06	0.16290767E-06
100	0.65669201E-05	0.14959496E-05	0.12713581E-05	0.10003M147E-05	0.62457548E-06	0.17522251E-06

CUMULATIVE FREQUENCY DISTRIBUTION AT X=40000.0 Y=315.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.16415163E-08	0.70380430E-08
50	0.0	0.0	0.29444877E-10	0.19349189E-08	0.84524601E-08	0.16231006E-07
75	0.0	0.60881220E-08	0.16645327E-07	0.19264924E-07	0.20944906E-07	0.24019435E-07
90	0.71701356E-09	0.53886090E-07	0.53000878E-07	0.51506767E-07	0.45976762E-07	0.37226414E-07
95	0.75505227E-07	0.99917543E-07	0.91774098E-07	0.81905512E-07	0.63249729E-07	0.41935728E-07
99	0.41088538E-06	0.22936251E-06	0.17727916E-06	0.15149800E-06	0.11761983E-06	0.55074278E-07
99.5	0.58249861E-06	0.28886063E-06	0.21878833E-06	0.18809868E-06	0.13698002E-06	0.55732723E-07
99.9	0.13457156E-05	0.43757666E-06	0.32631584E-06	0.82002043E-06	0.30040792E-06	0.58093370E-07
100	0.12992401E-04	0.25675909E-05	0.12838909E-05	0.86207729E-06	0.33248313E-06	0.58379729E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=40000.0 Y=337.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.35253844E-09	0.53102625E-08
50	0.0	0.0	0.67349663E-13	0.23781399E-09	0.38566021E-08	0.76761992E-08
75	0.0	0.29737235E-09	0.68120087E-08	0.97082982E-08	0.12000356E-07	0.11549659E-07
90	0.0	0.26685257E-07	0.26478013E-07	0.29063639E-07	0.24013083E-07	0.13988611E-07
95	0.76828286E-08	0.51009202E-07	0.48923273E-07	0.42713317E-07	0.31614430E-07	0.15853630E-07
99	0.25945445E-06	0.12263331E-06	0.88253955E-07	0.72231558E-07	0.46019963E-07	0.23189518E-07
99.5	0.36299582E-06	0.15003980E-06	0.10998303E-06	0.91423658E-07	0.50830963E-07	0.24025013E-07
99.9	0.69772511E-06	0.27427109E-06	0.15174987E-06	0.11625650E-06	0.69469593E-07	0.24556485E-07
100	0.17996481E-05	0.34739230E-06	0.17438481E-06	0.12516523E-06	0.76494473E-07	0.24756925E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=40000.0 Y=0.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.69631855E-13	0.20553141E-08
50	0.0	0.0	0.0	0.0	0.14375043E-08	0.34248908E-08
75	0.0	0.0	0.38991144E-09	0.25732849E-08	0.51838285E-08	0.49844573E-08
90	0.0	0.63576451E-08	0.12781506E-07	0.12009970E-07	0.85428482E-08	0.77559221E-08
95	0.0	0.24914229E-07	0.21519909E-07	0.17115667E-07	0.11925533E-07	0.95558512E-08
99	0.11585513E-06	0.58398037E-07	0.43353321E-07	0.38138676E-07	0.35706218E-07	0.13780717E-07
99.5	0.22897450E-06	0.80479367E-07	0.68184363E-07	0.57399269E-07	0.48447543E-07	0.13859413E-07
99.9	0.43573579E-06	0.31790933E-06	0.21758177E-06	0.21185264E-06	0.10697067E-06	0.13931686E-07
100	0.50844637E-05	0.63555797E-06	0.31777898E-06	0.31517305E-06	0.10728007E-06	0.13931686E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=40000.0 Y=22.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.22825323E-14	0.10253214E-08
50	0.0	0.0	0.0	0.0	0.37899350E-09	0.15423209E-08
75	0.0	0.0	0.60948772E-11	0.50212967E-09	0.25850413E-08	0.26817426E-08
90	0.0	0.94948893E-09	0.64822387E-08	0.66115007E-08	0.59713088E-08	0.46137707E-08
95	0.0	0.13425790E-07	0.13770709E-07	0.11709076E-07	0.89902592E-08	0.53256137E-08
99	0.47268532E-07	0.42771248E-07	0.31585852E-07	0.26871376E-07	0.14729572E-07	0.65359025E-08
99.5	0.14044599E-06	0.62980973E-07	0.42434817E-07	0.32666609E-07	0.18163774E-07	0.65801409E-08
99.9	0.32420206E-06	0.10505386E-06	0.62342622E-07	0.86487489E-07	0.32380285E-07	0.66406116E-08
100	0.20757006E-05	0.25946258E-06	0.12973129E-06	0.97140855E-07	0.32380285E-07	0.66714563E-08

CUMULATIVE FREQUENCY DISTRIBUTION AT X=40000.0 Y=45.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.0	0.13420420E-08
50	0.0	0.0	0.0	0.0	0.30277159E-09	0.19575030E-08
75	0.0	0.0	0.98163491E-12	0.26609581E-09	0.33844989E-08	0.35684173E-08
90	0.0	0.54799099E-09	0.85229992E-08	0.87782972E-08	0.71423401E-08	0.58347283E-08
95	0.0	0.17286126E-07	0.17707460E-07	0.14583417E-07	0.11001159E-07	0.67578902E-08
99	0.60002037E-07	0.51943729E-07	0.43389754E-07	0.41945697E-07	0.31346310E-07	0.10047788E-07
99.5	0.16618321E-06	0.83851432E-07	0.64742324E-07	0.49712447E-07	0.37315683E-07	0.12012599E-07
99.9	0.38219673E-06	0.23010818E-06	0.13909863E-06	0.11604084E-06	0.39791168E-07	0.12678129E-07
100	0.27849810E-05	0.34812706E-06	0.17406353E-06	0.11604232E-06	0.46856055E-07	0.12763220E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=40000.0 Y=67.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.0	0.86270013E-09
50	0.0	0.0	0.0	0.0	0.18723927E-09	0.16437189E-08
75	0.0	0.0	0.19616964E-11	0.29583536E-09	0.29029823E-08	0.27648739E-08
90	0.0	0.45677395E-09	0.62707031E-08	0.75733055E-08	0.63489232E-08	0.35549321E-08
95	0.0	0.12763330E-07	0.13008794E-07	0.11139939E-07	0.89749221E-08	0.43838959E-08
99	0.33933272E-07	0.47509751E-07	0.33027465E-07	0.24448063E-07	0.15027211E-07	0.84558280E-08
99.5	0.13824439E-06	0.66054895E-07	0.40431871E-07	0.30825113E-07	0.16482073E-07	0.85466070E-08
99.9	0.38007801E-06	0.10414516E-06	0.57283035E-07	0.38188688E-07	0.17925203E-07	0.86144318E-08
100	0.10713347E-05	0.21426695E-06	0.82410338E-07	0.51015938E-07	0.21639782E-07	0.87671630E-08

CUMULATIVE FREQUENCY DISTRIBUTION AT X=40000.0 Y=90.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.	0	0.36115860E-10	0.15164872E-08
50	0.0	0.0	0.0	0.41449916E-11	0.10705856E-08	0.26077296E-08
75	0.0	0.82237873E-12	0.68779538E-09	0.23202409E-08	0.42293387E-08	0.43136446E-08
90	0.0	0.65096906E-08	0.10405316E-07	0.10173373E-07	0.89387164E-08	0.67975172E-08
95	0.15404657E-11	0.20744508E-07	0.19049246E-07	0.16678687E-07	0.13891455E-07	0.80735063E-08
99	0.93648168E-07	0.59597937E-07	0.5060003M3E-07	0.41623515E-07	0.30180381E-07	0.12550590E-07
99.5	0.18856923E-06	0.83812040E-07	0.69579073E-07	0.59586302E-07	0.34338292E-07	0.12818862E-07
99.9	0.44919136E-06	0.16302067E-06	0.14433573E-06	0.10652877E-06	0.42909726E-07	0.13341559E-07
100	0.25566906E-05	0.31958632E-06	0.16018430E-06	0.10678951E-06	0.57358410E-07	0.13782877E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=40000.0 Y=112.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.44786206E-13	0.20067781E-10	0.18704158E-08	0.47645052E-08
50	0.0	0.20901163E-11	0.88423890E-09	0.31391185E-08	0.74166522E-08	0.10151794E-07
75	0.0	0.72699855E-08	0.16055758E-07	0.16961692E-07	0.18201654E-07	0.21012170E-07
90	0.13907424E-08	0.44147285E-07	0.42939924E-07	0.39192841E-07	0.34247254E-07	0.29138306E-07
95	0.62572951E-07	0.77944890E-07	0.62158051E-07	0.56820568E-07	0.46285223E-07	0.32769321E-07
99	0.35544366E-06	0.16516822E-06	0.12869509E-06	0.10627093E-06	0.72404021E-07	0.37315800E-07
99.5	0.48561060E-06	0.20236121E-06	0.15044947E-06	0.12279213E-06	0.86895113E-07	0.39183174E-07
99.9	0.79982300E-06	0.30243359E-06	0.23379363E-06	0.18339102E-06	0.10336390E-06	0.40233235E-07
100	0.15243104E-05	0.50295489E-06	0.29130939E-06	0.19718789E-06	0.11713684E-06	0.40354642E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=40000.0 Y=135.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.17996013E-11	0.42544315E-08	0.87951726E-08	0.16500621E-07	0.26431923E-07
50	0.0	0.13923973E-07	0.23451772E-07	0.26243036E-07	0.33586602E-07	0.42776964E-07
75	0.12926265E-07	0.55918868E-07	0.56889608E-07	0.57493668E-07	0.62766333E-07	0.61176479E-07
90	0.13196137E-06	0.12335147E-06	0.11182908E-06	0.11028703E-06	0.97954683E-07	0.81658641E-07
95	0.24321042E-06	0.19214144E-06	0.17277318E-06	0.16163261E-06	0.12189474E-06	0.89847731E-07
99	0.69058160E-06	0.40855002E-06	0.32181708E-06	0.27994167E-06	0.20150475E-06	0.10477578E-06
99.5	0.10288722E-05	0.54148290E-06	0.39110370E-06	0.34589146E-06	0.27409010E-06	0.11023269E-06
99.9	0.19892714E-05	0.83666066E-06	0.69441830E-06	0.63590898E-06	0.40677452E-06	0.11642396E-06
100	0.49683067E-05	0.11077846E-05	0.94137056E-06	0.74459365E-06	0.45793308E-06	0.12506968E-06

CUMULATIVE FREQUENCY DISTRIBUTION AT X=50000.0 Y=315.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.11853969E-08	0.55911684E-08
50	0.0	0.0	0.15915338E-10	0.13169581E-08	0.67191372E-08	0.13015494E-07
75	0.0	0.43038213E-08	0.12962797E-07	0.15104355E-07	0.16195525E-07	0.18793767E-07
90	0.36273518E-09	0.42316998E-07	0.42017792E-07	0.40966444E-07	0.36742584E-07	0.29288746E-07
95	0.54992793E-07	0.78129574E-07	0.72207968E-07	0.64581457E-07	0.49703644E-07	0.32882163E-07
99	0.33280520E-06	0.18264325E-06	0.14367447E-06	0.12006387E-06	0.90980166E-07	0.44202082E-07
99.5	0.48250172E-06	0.23287839E-06	0.17397065E-06	0.15041292E-06	0.10630970E-06	0.44734783E-07
99.9	0.10621479E-05	0.34794130E-06	0.25547547E-06	0.67242036E-06	0.24399679E-06	0.46763812E-07
100	0.10739011E-04	0.20961907E-05	0.10481454E-05	0.70316611E-06	0.26973709E-06	0.46990777E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=50000.0 Y=337.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.23571856E-09	0.41648924E-08
50	0.0	0.0	0.19380348E-13	0.14101728E-09	0.30366298E-08	0.60264966E-08
75	0.0	0.17223564E-09	0.51954352E-08	0.76911952E-08	0.91056904E-08	0.90638999E-08
90	0.0	0.21044961E-07	0.20916513E-07	0.22435927E-07	0.18708000E-07	0.11039180E-07
95	0.45941526E-08	0.40792976E-07	0.38187956E-07	0.33429160E-07	0.24837654E-07	0.12232128E-07
99	0.20600692E-06	0.97148813E-07	0.70691158E-07	0.58054486E-07	0.36737926E-07	0.18491644E-07
99.5	0.28410670E-06	0.11614532E-06	0.87081730E-07	0.74278603E-07	0.39955427E-07	0.19061513E-07
99.9	0.55124275E-06	0.22283587E-06	0.11997895E-06	0.94546067E-07	0.56433741E-07	0.19482982E-07
100	0.14447642E-05	0.28267436E-06	0.14182086E-06	0.10229849E-06	0.62306071E-07	0.19628473E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=50000.0 Y=0.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.25092474E-13	0.16122919E-08
50	0.0	0.0	0.0	0.0	0.99717168E-09	0.26935338E-08
75	0.0	0.0	0.22834719E-09	0.18305966E-08	0.41064112E-08	0.39980179E-08
90	0.0	0.46071484E-08	0.10087042E-07	0.96617967E-08	0.68796489E-08	0.61201533E-08
95	0.0	0.20100636E-07	0.16803586E-07	0.14196448E-07	0.98225712E-08	0.76537745E-08
99	0.87091394E-07	0.45476163E-07	0.36103128E-07	0.31477288E-07	0.28805363E-07	0.10817931E-07
99.5	0.17823288E-06	0.65993390E-07	0.54441589E-07	0.45532108E-07	0.39213191E-07	0.10876999E-07
99.9	0.36152659E-06	0.25359185E-06	0.17618959E-06	0.16722169E-06	0.84218016E-07	0.10931323E-07
100	0.40133209E-05	0.50166511E-06	0.25083256E-06	0.24891347E-06	0.84423675E-07	0.10931323E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=50000.0 Y=22.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.0	0.78266593E-09
50	0.0	0.0	0.0	0.0	0.27549363E-09	0.12099282E-08
75	0.0	0.0	0.29529669E-11	0.33172798E-09	0.19754711E-08	0.20782787E-08
90	0.0	0.62962968E-09	0.48998245E-08	0.52175260E-08	0.45992010E-08	0.36191163E-08
95	0.0	0.10249266E-07	0.10755432E-07	0.94190682E-08	0.71207644E-08	0.41645407E-08
99	0.36101284E-07	0.35021920E-07	0.26912769E-07	0.21362300E-07	0.12348206E-07	0.52444129E-08
99.5	0.11135671E-06	0.50203244E-07	0.33474695E-07	0.25565598E-07	0.15020778E-07	0.52745222E-08
99.9	0.26841957E-06	0.82788972E-07	0.52334890E-07	0.68378199E-07	0.25531119E-07	0.53263918E-08
100	0.16410777E-05	0.20513471E-06	0.10256736E-06	0.76593324E-07	0.25531119E-07	0.53520317E-08

CUMULATIVE FREQUENCY DISTRIBUTION AT X=50000.0 Y=45.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.0	0.10340857E-08
50	0.0	0.0	0.0	0.0	0.18030499E-09	0.15494794E-08
75	0.0	0.0	0.42945606E-12	0.15061261E-09	0.25657800E-08	0.29090854E-08
90	0.0	0.33783154E-09	0.64839725E-08	0.69931403E-08	0.54554761E-08	0.45059920E-08
95	0.0	0.13322733E-07	0.13732663E-07	0.11582031E-07	0.86609830E-08	0.52724012E-08
99	0.43783377E-07	0.41510184E-07	0.33729030E-07	0.32147092E-07	0.24144676E-07	0.79870048E-08
99.5	0.13243022E-06	0.66692735E-07	0.49707701E-07	0.38130608E-07	0.28835643E-07	0.94942649E-08
99.9	0.30703234E-06	0.19617551E-06	0.10707288E-06	0.93966776E-07	0.31763602E-07	0.10014510E-07
100	0.22552031E-05	0.28190198E-06	0.14095099E-06	0.93967287E-07	0.37749661E-07	0.10081720E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=50000.0 Y=67.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.0	0.66957306E-09
50	0.0	0.0	0.0	0.0	0.13316517E-09	0.12845931E-08
75	0.0	0.0	0.85038216E-12	0.16582083E-09	0.22065068E-08	0.21248860E-08
90	0.0	0.25389424E-09	0.50534226E-08	0.57119536E-08	0.50176823E-08	0.28658880E-08
95	0.0	0.10465790E-07	0.10157930E-07	0.91188816E-08	0.68588584E-08	0.34008540E-08
99	0.24164102E-07	0.35183987E-07	0.27026164E-07	0.18310264E-07	0.11509790E-07	0.64450134E-08
99.5	0.11171124E-06	0.54052329E-07	0.32624158E-07	0.23696042E-07	0.13030974E-07	0.65142629E-08
99.9	0.28228010E-06	0.82283577E-07	0.44146546E-07	0.29431028E-07	0.14633770E-07	0.65637700E-08
100	0.84701344E-06	0.16940265E-06	0.65154836E-07	0.40333973E-07	0.16320641E-07	0.66900334E-08

CUMULATIVE FREQUENCY DISTRIBUTION AT X=50000.0 Y=90.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.20694460E-10	0.11800114E-08
50	0.0	0.0	0.0	0.19688175E-11	0.81600304E-09	0.20301589E-08
75	0.0	0.31775851E-12	0.43454973E-09	0.16164319E-08	0.33696921E-08	0.34307661E-08
90	0.0	0.45849120E-08	0.82456673E-08	0.81490867E-08	0.73634006E-08	0.54987304E-08
95	0.51647667E-12	0.16686656E-07	0.15317362E-07	0.13467044E-07	0.11251270E-07	0.63576735E-08
99	0.73126216E-07	0.48637965E-07	0.42723254E-07	0.32386758E-07	0.24012792E-07	0.97243422E-08
99.5	0.14855880E-06	0.67772135E-07	0.55989315E-07	0.47435265E-07	0.26773638E-07	0.98806865E-08
99.9	0.36986239E-06	0.14183593E-06	0.11295282E-06	0.83600185E-07	0.33485254E-07	0.10276274E-07
100	0.20064053E-05	0.25080067E-06	0.12563481E-06	0.83756504E-07	0.44745281E-07	0.10615800E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=50000.0 Y=112.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.12215150E-13	0.94269731E-11	0.13790900E-08	0.36257559E-08
50	0.0	0.84960749E-12	0.57637051E-09	0.22458901E-08	0.57519642E-08	0.77996631E-08
75	0.0	0.50542823E-08	0.12315439E-07	0.13372876E-07	0.14208720E-07	0.16725675E-07
90	0.75359941E-09	0.34573283E-07	0.33278660E-07	0.30816604E-07	0.27703496E-07	0.22581052E-07
95	0.44954490E-07	0.63112225E-07	0.49922416E-07	0.45039464E-07	0.36442820E-07	0.25874247E-07
99	0.29372399E-06	0.13212582E-06	0.10093214E-06	0.83105817E-07	0.58743339E-07	0.29899567E-07
99.5	0.39168447E-06	0.16215336E-06	0.11737382E-06	0.97298368E-07	0.68320730E-07	0.31828201E-07
99.9	0.64866003E-06	0.23529321E-06	0.19623712E-06	0.14293482E-06	0.86031491E-07	0.32638635E-07
100	0.12040582E-05	0.39247425E-06	0.22610521E-06	0.16602985E-06	0.97728844E-07	0.32739788E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=50000.0 Y=135.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.61075624E-12	0.31693310E-08	0.66972738E-08	0.12690837E-07	0.20674896E-07
50	0.0	0.10099292E-07	0.18149407E-07	0.20214408E-07	0.26503898E-07	0.34343568E-07
75	0.83025924E-08	0.44163883E-07	0.44727006E-07	0.45825875E-07	0.49546831E-07	0.47610992E-07
90	0.10267865E-06	0.97962243E-07	0.87843659E-07	0.87005276E-07	0.77128107E-07	0.63993582E-07
95	0.19357014E-06	0.15113994E-06	0.13635895E-06	0.12813746E-06	0.95651558E-07	0.70772842E-07
99	0.54038247E-06	0.32589605E-06	0.24782901E-06	0.22050733E-06	0.16026121E-06	0.81001417E-07
99.5	0.80859462E-06	0.42909994E-06	0.30845001E-06	0.27604972E-06	0.21563494E-06	0.85226077E-07
99.9	0.16250297E-05	0.66202301E-06	0.54818537E-06	0.50672486E-06	0.31821128E-06	0.89998935E-07
100	0.40223113E-05	0.87409626E-06	0.74308213E-06	0.58785832E-06	0.35921062E-06	0.96486076E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=80000.0 Y=315.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.65276673E-09	0.35078707E-08
50	0.0	0.0	0.33894190E-11	0.60718031E-09	0.38736765E-08	0.80197466E-08
75	0.0	0.19328388E-08	0.77655038E-08	0.92039798E-08	0.10344905E-07	0.11389400E-07
90	0.76484916E-10	0.25294739E-07	0.25548477E-07	0.25730539E-07	0.22523533E-07	0.17330667E-07
95	0.29226076E-07	0.48009852E-07	0.43391363E-07	0.39309654E-07	0.30696153E-07	0.21243380E-07
99	0.20973710E-06	0.11531552E-06	0.87721560E-07	0.75226922E-07	0.55266543E-07	0.27757252E-07
99.5	0.30590235E-06	0.14711543E-06	0.10695692E-06	0.91145296E-07	0.67181190E-07	0.28096817E-07
99.9	0.63627107E-06	0.21613107E-06	0.15217483E-06	0.43817931E-06	0.15639898E-06	0.29515526E-07
100	0.70768247E-05	0.13542603E-05	0.67714234E-06	0.45366562E-06	0.17241052E-06	0.29666275E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=80000.0 Y=337.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.84785207E-10	0.24457543E-08
50	0.0	0.0	0.0	0.45899451E-10	0.17995252E-08	0.35901322E-08
75	0.0	0.51442711E-10	0.28513145E-08	0.44887614E-08	0.54845017E-08	0.56187446E-08
90	0.0	0.12769597E-07	0.12972219E-07	0.13275660E-07	0.10979658E-07	0.66874719E-08
95	0.14491313E-08	0.25121921E-07	0.22533687E-07	0.20588466E-07	0.15167060E-07	0.73721367E-08
99	0.12983469E-06	0.61765377E-07	0.44980368E-07	0.35164355E-07	0.23213261E-07	0.11513386E-07
99.5	0.18876881E-06	0.73988758E-07	0.51687838E-07	0.46414165E-07	0.24687512E-07	0.11739687E-07
99.9	0.32741599E-06	0.13922465E-06	0.73254171E-07	0.61163576E-07	0.36286373E-07	0.12001777E-07
100	0.90657738E-06	0.18304536E-06	0.91745505E-07	0.66791301E-07	0.40278195E-07	0.12073233E-07

CUMULATIVE FREQUENCY DISTRIBUTION AT X=80000.0 Y=0.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.25106469E-14	0.99453712E-09
50	0.0	0.0	0.0	0.0	0.55796257E-09	0.16581954E-08
75	0.0	0.0	0.80589202E-10	0.95763264E-09	0.24900506E-08	0.25746785E-08
90	0.0	0.22760132E-08	0.61041199E-08	0.57902909E-08	0.43640469E-08	0.38284007E-08
95	0.0	0.12208240E-07	0.10959212E-07	0.91982102E-08	0.62144672E-08	0.48259530E-08
99	0.48402377E-07	0.30818953E-07	0.21944107E-07	0.20212426E-07	0.19731385E-07	0.65269639E-08
99.5	0.11177519E-06	0.42664013E-07	0.32363843E-07	0.32549750E-07	0.25111248E-07	0.65584551E-08
99.9	0.24386242E-06	0.15219257E-06	0.11290774E-06	0.10185670E-06	0.50956118E-07	0.65897545E-08
100	0.24445608E-05	0.30557010E-06	0.15278505E-06	0.15143064E-06	0.51036523E-07	0.65897545E-08

CUMULATIVE FREQUENCY DISTRIBUTION AT X=80000.0 Y=22.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.0	0.46133164E-09
50	0.0	0.0	0.0	0.0	0.12066736E-09	0.72181616E-09
75	0.0	0.0	0.52365095E-12	0.12807970E-09	0.12061769E-08	0.12459991E-08
90	0.0	0.22165453E-09	0.29164720E-08	0.31495748E-08	0.29592928E-08	0.22402589E-08
95	0.0	0.59576664E-08	0.67835089E-08	0.59894063E-08	0.43192188E-08	0.26721245E-08
99	0.17530951E-07	0.22263201E-07	0.17530020E-07	0.13612464E-07	0.84006615E-08	0.33540584E-08
99.5	0.65391646E-07	0.31685744E-07	0.21958471E-07	0.17399760E-07	0.99603028E-08	0.33648779E-08
99.9	0.16862316E-06	0.52199283E-07	0.35745270E-07	0.41626812E-07	0.15459236E-07	0.34284178E-08
100	0.99904355E-06	0.12488044E-06	0.62440222E-07	0.46377711E-07	0.15459236E-07	0.34394771E-08

CUMULATIVE FREQUENCY DISTRIBUTION AT X=80000.0 Y=45.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.0	0.62765548E-09
50	0.0	0.0	0.0	0.0	0.86242069E-10	0.94237307E-09
75	0.0	0.0	0.60965772E-13	0.47255977E-10	0.15263830E-08	0.18479362E-08
90	0.0	0.10838444E-09	0.36246495E-08	0.43227182E-08	0.32060408E-08	0.26872247E-08
95	0.0	0.74232460E-08	0.83683602E-08	0.71442834E-08	0.56041856E-08	0.31772152E-08
99	0.23824935E-07	0.25591824E-07	0.20618280E-07	0.19569001E-07	0.15346156E-07	0.49528595E-08
99.5	0.82678980E-07	0.39745835E-07	0.29984275E-07	0.22488898E-07	0.16998818E-07	0.58194978E-08
99.9	0.19101225E-06	0.12275189E-06	0.69057705E-07	0.60217360E-07	0.20355181E-07	0.61314793E-08
100	0.14452171E-05	0.18065225E-06	0.90326125E-07	0.60217417E-07	0.24044109E-07	0.61726304E-08

CUMULATIVE FREQUENCY DISTRIBUTION AT X=80000.0 Y=67.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.0	0.40123016E-09
50	0.0	0.0	0.0	0.0	0.57695071E-10	0.76099349E-09
75	0.0	0.0	0.11640369E-12	0.46190177E-10	0.12886678E-08	0.12265651E-08
90	0.0	0.74503903E-10	0.28157352E-08	0.34115928E-08	0.29993801E-08	0.18697315E-08
95	0.0	0.57772347E-08	0.62005761E-08	0.55078466E-08	0.41141384E-08	0.20978645E-08
99	0.11210879E-07	0.23970365E-07	0.16480179E-07	0.12894198E-07	0.64184746E-08	0.36281811E-08
99.5	0.69407463E-07	0.31309682E-07	0.20505123E-07	0.14411793E-07	0.79329112E-08	0.36715551E-08
99.9	0.19176292E-06	0.50278885E-07	0.25450035E-07	0.17403586E-07	0.90481507E-08	0.37003107E-08
100	0.51563939E-06	0.10312783E-06	0.39664567E-07	0.24554254E-07	0.95206083E-08	0.37798848E-08

CUMULATIVE FREQUENCY DISTRIBUTION AT X=80000.0 Y=90.0 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours(16978)	24 Hours(16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.0	0.59401772E-11	0.70902839E-09
50	0.0	0.0	0.0	0.26056636E-12	0.40447090E-09	0.12827850E-08
75	0.0	0.31595447E-13	0.16143946E-09	0.78973983E-09	0.20683550E-08	0.21955537E-08
90	0.0	0.21497186E-08	0.51419100E-08	0.51890368E-08	0.45642992E-08	0.33887582E-08
95	0.16535089E-13	0.10429602E-07	0.94783310E-08	0.87783860E-08	0.73252231E-08	0.39429153E-08
99	0.45823214E-07	0.33394400E-07	0.24858196E-07	0.21363114E-07	0.14849093E-07	0.56996932E-08
99.5	0.93907090E-07	0.46579807E-07	0.37967766E-07	0.33527250E-07	0.15856369E-07	0.57991549E-08
99.9	0.24400498E-06	0.10003M176E-06	0.67518158E-07	0.50156849E-07	0.19876644E-07	0.59569629E-08
100	0.12037644E-05	0.15047056E-06	0.75310766E-07	0.50207177E-07	0.26520990E-07	0.61537762E-08

CUMULATIVE FREQUENCY DISTRIBUTION AT X=80000.0 Y=112.5 Z=0.0

Percentage of Total Hours	Hourly (17127)	8 Hours (17140)	16 Hours (16978)	24 Hours (16827)	3 Days (17161)	26 Days (16606)
25	0.0	0.0	0.0	0.17013136E-11	0.72735729E-09	0.21114108E-08
50	0.0	0.90145935E-13	0.24937985E-09	0.10941141E-08	0.33791445E-08	0.45784425E-08
75	0.0	0.23630458E-08	0.70595156E-08	0.79780342E-08	0.87566576E-08	0.10210552E-07
90	0.18571251E-09	0.20381883E-07	0.20710111E-07	0.18896735E-07	0.17511347E-07	0.13531970E-07
95	0.21296035E-07	0.38957580E-07	0.31680546E-07	0.28699560E-07	0.22742029E-07	0.16043234E-07
99	0.18808896E-06	0.83608597E-07	0.64716914E-07	0.50944852E-07	0.37962000E-07	0.18823801E-07
99.5	0.25296754E-06	0.10035802E-06	0.73881438E-07	0.61447224E-07	0.41299103E-07	0.20404279E-07
99.9	0.39284362E-06	0.15931448E-06	0.12458219E-06	0.88562729E-07	0.57374056E-07	0.20854820E-07
100	0.72630843E-06	0.26562009E-06	0.13284415E-06	0.11288694E-06	0.65481743E-07	0.20917575E-07

TABLE 2.3-41

CUMULATIVE FREQUENCY DISTRIBUTION AT X=80000.0 Y=135.0 Z=0.0

Percentage of Total Hours	*Hourly (17127)*	*8 Hours (17140)*	*16 Hours (16978)*	*Hours (16827)*	*3 Days (17161)*	*26 Days (16606)*
25	*0.0*	*0.53608065E-13*	*0.15507566E-08*	*0.37072401E-08*	*0.72642301E-08*	*0.12430696E-07*
50	*0.0*	*0.54108469E-08*	*0.10682420E-07*	*0.12110306E-07*	*0.16393336E-07*	*0.21119209E-07*
75	*0.31305785E-08*	*0.26878141E-07*	*0.27722947E-07*	*0.28005950E-07*	*0.30296825E-07*	*0.29032226E-07*
90	*0.61701087E-07*	*0.60302057E-07*	*0.54364037E-07*	*0.52630334E-07*	*0.46747747E-07*	*0.38486551E-07*
95	*0.11980205E-06*	*0.91934908E-07*	*0.84140481E-07*	*0.78212679E-07*	*0.58057847E-07*	*0.43278874E-07*
99	*0.33317684E-06*	*0.19935442E-06*	*0.14976899E-06*	*0.13110741E-06*	*0.99965803E-07*	*0.47624940E-07*
99.5	*0.48037498E-06*	*0.25995200E-06*	*0.18830934E-06*	*0.17129037E-06*	*0.13088629E-06*	*0.50088705E-07*
99.9	*0.10322974E-05*	*0.40344401E-06*	*0.33194232E-06*	*0.30887401E-06*	*0.18952687E-06*	*0.52885735E-07*
100	*0.25595009E-05*	*0.53274880E-06*	*0.45236368E-06*	*0.35789134E-06*	*0.21528973E-06*	*0.56458632E-07*

TABLE 2.3-42
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - STABILITY BASED ON VERTICAL TEMPERATURE GRADIENT MAY 1973-APRIL 1974 EXTREMELY UNSTABLE (ΔT < -1.9°C/100M)

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.8	5.1	9.6	15.1	21.1	39.6	*Row Sums*	*Row Avg.*
CALM	1	0	0	0	0	0	1	11.3
22.50	6	6	5	0	0	0	17	5.1
45.00	4	6	1	1	0	0	12	4.8
67.50	8	18	0	1	1	0	28	4.9
90.00	8	10	4	2	0	0	24	5.6
112.50	3	11	2	4	5	1	26	10.3
135.00	7	10	3	7	1	0	28	8.2
157.50	4	5	0	1	0	0	10	4.9
180.00	4	6	0	0	0	0	10	3.5
202.50	1	7	3	1	0	0	12	6.4
225.00	3	4	5	12	1	0	25	11.3
247.50	1	2	0	1	2	0	6	11.4
270.00	6	3	1	0	0	0	10	3.9
292.50	9	14	11	2	6	1	43	8.6
315.00	17	22	21	38	2	18	138	13.9
337.50	8	17	13	20	1	7	76	12.5
360.00	7	10	15	2	0	0	34	7.1
Column Sums	96	51	85	92	49	27	500	9.9

TABLE 2.3-43
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - STABILITY BASED ON VERTICAL TEMPERATURE GRADIENT MAY 1973-APRIL 1974 MODERATELY UNSTABLE (ΔT -1.9° to -1.7°C/100M)

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.8	5.1	9.6	15.1	21.1	39.6	*Row Sums*	*Row Avg.*
CALM	0	0	0	0	0	0	0	0.0
22.50	1	0	1	0	0	0	2	5.3
45.00	0	0	0	0	0	0	0	0.0
67.50	4	1	1	0	0	0	6	3.9
90.00	1	1	5	1	0	0	8	8.6
112.50	1	0	3	1	0	0	5	8.8
135.00	2	3	3	5	0	0	13	9.9
157.50	4	5	1	0	0	0	10	4.5
180.00	1	1	0	0	0	0	2	3.6
202.50	1	1	0	0	0	0	2	3.9
225.00	1	1	0	0	0	0	2	3.3
247.50	1	0	1	0	0	0	2	5.3
270.00	0	2	1	0	0	0	3	5.9
292.50	2	2	2	3	0	0	9	8.6
315.00	4	8	6	6	4	0	28	10.1
337.50	1	0	3	5	2	3	14	16.8
360.00	1	3	6	1	0	0	11	8.7
Column Sums	25	28	33	22	6	3	117	9.1

TABLE 2.3-44
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - STABILITY BASED ON VERTICAL TEMPERATURE GRADIENT MAY 1973-APRIL 1974 SLIGHTLY UNSTABLE
(ΔT -1.7 to -1.5°C/100M)

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph*						*Row Sums*	*Row Avg.*
	1.8	*5.1*	*9.6*	*15.1*	*21.1*	*39.6*		
CALM	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
22.50	*2*	*1*	*2*	*0*	*0*	*0*	*5*	*6.0*
45.00	*2*	*1*	*3*	*0*	*0*	*0*	*6*	*6.1*
67.50	*1*	*2*	*1*	*0*	*0*	*0*	*4*	*4.4*
90.00	*1*	*0*	*1*	*0*	*0*	*0*	*2*	*4.8*
112.50	*1*	*2*	*0*	*0*	*1*	*1*	*5*	*12.6*
135.00	*1*	*8*	*6*	*11*	*0*	*0*	*26*	*10.1*
157.50	*2*	*8*	*2*	*0*	*1*	*0*	*13*	*6.7*
180.00	*1*	*5*	*0*	*0*	*2*	*0*	*8*	*7.7*
202.50	*1*	*3*	*0*	*0*	*0*	*0*	*4*	*3.4*
225.00	*0*	*2*	*0*	*0*	*0*	*0*	*2*	*4.1*
247.50	*2*	*0*	*0*	*0*	*0*	*0*	*2*	*2.3*
270.00	*1*	*2*	*0*	*0*	*0*	*0*	*3*	*4.2*
292.50	*4*	*12*	*7*	*1*	*0*	*0*	*24*	*6.1*
315.00	*1*	*4*	*4*	*2*	*1*	*0*	*12*	*10.0*
337.50	*1*	*3*	*8*	*13*	*4*	*4*	*33*	*15.4*
360.00	*0*	*2*	*2*	*1*	*0*	*0*	*5*	*8.5*
Column Sums	*21*	*55*	*36*	*28*	*9*	*5*	*154*	*9.2*

TABLE 2.3-45
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - STABILITY BASED ON VERTICAL TEMPERATURE GRADIENT MAY 1973-APRIL 1974 NEUTRAL
(ΔT -1.5 to -0.5°C/100M)

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.8	5.1	9.6	15.1	21.1	39.6	*Row Sums*	*Row Avg.*
CALM	2	0	0	0	0	0	2	1.4
22.50	8	31	24	4	0	1	68	6.9
45.00	12	22	19	10	0	0	63	7.1
67.50	15	12	14	3	0	1	45	6.4
90.00	12	22	8	5	1	0	48	6.3
112.50	8	37	32	33	12	3	125	10.8
135.00	22	83	73	39	16	7	240	9.3
157.50	27	107	20	12	10	11	187	8.2
180.00	20	54	5	1	0	0	80	4.2
202.50	15	23	3	2	1	0	44	4.9
225.00	23	12	4	7	2	0	48	6.0
247.50	13	15	3	0	1	0	32	4.3
270.00	22	32	4	1	0	0	59	4.1
292.50	28	124	71	27	4	1	255	7.2
315.00	18	106	222	230	209	145	930	15.7
337.50	9	44	69	65	61	35	283	14.9
360.00	17	50	42	19	2	0	130	7.6
Column Sums	271	774	613	458	319	204	2639	11.2

TABLE 2.3-46
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - STABILITY BASED ON VERTICAL TEMPERATURE GRADIENT MAY 1973-APRIL 1974 SLIGHTLY STABLE
(ΔT -0.5 to 1.5°C/100M)

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph*						*Row Sums*	*Row Avg.*
	1.8	*5.1*	*9.6*	*15.1*	*21.1*	*39.6*		
CALM	*8*	*0*	*0*	*0*	*0*	*0*	*8*	*4.9*
22.50	*39*	*125*	*44*	*7*	*0*	*0*	*215*	*5.4*
45.00	*52*	*92*	*48*	*16*	*3*	*0*	*211*	*6.0*
67.50	*48*	*39*	*25*	*20*	*4*	*0*	*136*	*6.6*
90.00	*56*	*64*	*25*	*6*	*2*	*0*	*153*	*5.1*
112.50	*41*	*95*	*49*	*29*	*19*	*1*	*234*	*8.0*
135.00	*34*	*167*	*109*	*37*	*5*	*2*	*354*	*7.5*
157.50	*27*	*99*	*23*	*8*	*3*	*1*	*161*	*6.1*
180.00	*25*	*26*	*5*	*0*	*0*	*0*	*56*	*4.0*
202.50	*15*	*10*	*4*	*0*	*0*	*0*	*29*	*4.1*
225.00	*21*	*16*	*3*	*3*	*3*	*1*	*47*	*6.1*
247.50	*19*	*16*	*1*	*2*	*1*	*0*	*39*	*4.5*
270.00	*19*	*16*	*6*	*1*	*0*	*0*	*42*	*4.6*
292.50	*28*	*116*	*53*	*39*	*13*	*5*	*254*	*8.2*
315.00	*48*	*203*	*202*	*298*	*275*	*185*	*1211*	*15.3*
337.50	*29*	*120*	*128*	*113*	*30*	*10*	*430*	*10.5*
360.00	*33*	*128*	*101*	*32*	*2*	*0*	*296*	*7.3*
Column Sums	*537*	*1336*	*827*	*611*	*360*	*205*	*3876*	*9.8*

TABLE 2.3-47
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - STABILITY BASED ON VERTICAL TEMPERATURE GRADIENT MAY 1973-APRIL 1974 MODERATELY STABLE (ΔT +1.5 to +4.0°C/100M)

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.8	5.1	9.6	15.1	21.1	39.6	*Row Sums*	*Row Avg.*
CALM	0	0	0	0	0	0	0	0.0
22.50	11	15	2	0	0	0	28	4.2
45.00	14	13	7	2	2	0	38	5.9
67.50	14	7	2	0	0	0	23	3.4
90.00	24	13	1	0	0	0	38	3.3
112.50	18	26	1	0	0	0	45	3.6
135.00	15	33	22	1	0	0	71	5.8
157.50	9	20	4	0	0	0	33	5.1
180.00	9	9	0	0	0	0	18	3.8
202.50	4	2	0	0	0	0	6	2.9
225.00	3	2	0	1	0	0	6	5.2
247.50	4	3	1	0	0	0	8	4.2
270.00	2	0	3	0	0	0	5	6.8
292.50	7	20	12	14	15	9	77	13.2
315.00	13	38	72	78	81	68	350	16.6
337.50	8	23	15	12	3	0	61	8.7
360.00	4	14	4	0	0	0	22	5.4
Column Sums	159	238	146	108	101	77	829	10.8

TABLE 2.3-48
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - STABILITY BASED ON VERTICAL TEMPERATURE GRADIENT MAY 1973-APRIL 1974 EXTREMELY STABLE (ΔT GREATER THAN 4.0°C/100M)

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph*						*Row Sums*	*Row Avg.*
	1.8	*5.1*	*9.6*	*15.1*	*21.1*	*39.6*		
CALM	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
22.50	*4*	*1*	*0*	*0*	*0*	*0*	*5*	*3.3*
45.00	*2*	*2*	*1*	*0*	*0*	*0*	*5*	*4.8*
67.50	*1*	*0*	*0*	*0*	*0*	*0*	*1*	*2.9*
90.00	*3*	*3*	*0*	*0*	*0*	*0*	*6*	*3.3*
112.50	*3*	*8*	*0*	*0*	*0*	*0*	*11*	*3.7*
135.00	*7*	*18*	*4*	*1*	*0*	*0*	*30*	*4.9*
157.50	*7*	*7*	*0*	*0*	*0*	*0*	*14*	*3.5*
180.00	*2*	*1*	*0*	*0*	*0*	*1*	*4*	*8.6*
202.50	*5*	*0*	*0*	*1*	*0*	*0*	*6*	*3.5*
225.00	*3*	*0*	*0*	*0*	*0*	*0*	*3*	*2.0*
247.50	*1*	*2*	*0*	*0*	*0*	*0*	*3*	*3.7*
270.00	*0*	*3*	*0*	*1*	*0*	*0*	*4*	*6.7*
292.50	*0*	*10*	*6*	*5*	*4*	*6*	*31*	*13.3*
315.00	*6*	*45*	*40*	*30*	*27*	*28*	*176*	*14.0*
337.50	*3*	*7*	*2*	*1*	*2*	*0*	*15*	*8.0*
360.00	*2*	*0*	*1*	*0*	*0*	*0*	*3*	*4.6*
Column Sums	*49*	*107*	*54*	*39*	*33*	*35*	*317*	*10.7*

TABLE 2.3-49
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS A ANNUAL

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph*								*Row Sums*	*Row Avg.*
	1.5	*5.1*	*9.6*	*15.1*	*21.1*	*29.6*	*40.1*	*50.1*		
22.50	*0*	*4*	*5*	*2*	*0*	*0*	*0*	*0*	*11*	*8.9*
45.00	*0*	*1*	*1*	*3*	*0*	*0*	*0*	*0*	*5*	*11.7*
67.50	*0*	*3*	*1*	*1*	*0*	*0*	*0*	*0*	*5*	*7.4*
90.00	*0*	*1*	*7*	*1*	*0*	*0*	*0*	*0*	*9*	*10.5*
112.50	*0*	*3*	*2*	*5*	*5*	*2*	*0*	*0*	*17*	*15.4*
135.00	*1*	*9*	*6*	*9*	*4*	*1*	*0*	*0*	*30*	*12.3*
157.50	*1*	*10*	*1*	*2*	*0*	*0*	*0*	*0*	*14*	*7.2*
180.00	*1*	*6*	*1*	*1*	*0*	*1*	*0*	*0*	*10*	*7.7*
202.50	*0*	*2*	*0*	*1*	*0*	*1*	*0*	*0*	*4*	*12.6*
225.00	*1*	*3*	*2*	*1*	*0*	*0*	*0*	*0*	*7*	*6.6*
247.50	*0*	*3*	*0*	*1*	*0*	*0*	*0*	*0*	*4*	*7.8*
270.00	*1*	*2*	*1*	*1*	*0*	*0*	*0*	*0*	*5*	*7.0*
292.50	*1*	*15*	*2*	*1*	*3*	*2*	*0*	*0*	*24*	*9.3*
315.00	*2*	*11*	*14*	*20*	*11*	*24*	*0*	*0*	*82*	*17.6*
337.50	*2*	*5*	*10*	*12*	*13*	*7*	*0*	*0*	*49*	*15.5*
360.00	*1*	*6*	*9*	*3*	*4*	*0*	*0*	*0*	*23*	*10.6*
Column Sums	*11*	*84*	*62*	*64*	*40*	*8*	*0*	*0*	*299*	*13.2*

Hours of Calm = 0
Sums of this table: row totals = 299 and column totals = 299

TABLE 2.3-50
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS B ANNUAL

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph*								*Row Sums*	*Row Avg.*
	1.5	*5.1*	*9.6*	*15.1*	*21.1*	*29.6*	*40.1*	*50.1*		
22.50	*1*	*1*	*2*	*1*	*0*	*0*	*0*	*0*	*5*	*7.7*
45.00	*0*	*1*	*0*	*0*	*1*	*0*	*0*	*0*	*2*	*13.0*
67.50	*1*	*0*	*2*	*0*	*0*	*0*	*0*	*0*	*3*	*8.5*
90.00	*0*	*2*	*5*	*1*	*0*	*0*	*0*	*0*	*8*	*8.7*
112.50	*0*	*0*	*6*	*1*	*0*	*0*	*0*	*0*	*7*	*10.7*
135.00	*2*	*4*	*8*	*6*	*0*	*1*	*0*	*0*	*21*	*10.7*
157.50	*4*	*9*	*6*	*0*	*0*	*2*	*0*	*0*	*21*	*7.8*
180.00	*2*	*1*	*3*	*2*	*0*	*0*	*0*	*0*	*8*	*8.5*
202.50	*1*	*4*	*0*	*0*	*0*	*0*	*0*	*0*	*5*	*3.8*
225.00	*1*	*2*	*2*	*0*	*0*	*0*	*0*	*0*	*5*	*6.2*
247.50	*2*	*3*	*1*	*0*	*0*	*0*	*0*	*0*	*6*	*4.4*
270.00	*1*	*4*	*1*	*0*	*1*	*0*	*0*	*0*	*7*	*6.8*
292.50	*3*	*11*	*6*	*2*	*0*	*0*	*0*	*0*	*22*	*6.7*
315.00	*4*	*10*	*12*	*13*	*9*	*9*	*0*	*0*	*57*	*14.4*
337.50	*1*	*0*	*3*	*7*	*6*	*4*	*0*	*0*	*21*	*18.1*
360.00	*0*	*3*	*8*	*1*	*1*	*0*	*0*	*0*	*13*	*10.1*
Column Sums	*23*	*55*	*65*	*34*	*18*	*16*	*0*	*0*	*211*	*10.9*

Hours of Calm = 3
Sums of this table: row totals = 211 and column totals = 211

TABLE 2.3-51
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS C ANNUAL

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	1	1	2	1	0	0	0	0	5	8.5
45.00	1	1	3	0	0	0	0	0	5	6.7
67.50	1	0	1	0	0	0	0	0	2	4.9
90.00	1	1	1	0	0	0	0	0	3	5.1
112.50	1	2	0	1	3	1	0	0	8	14.4
135.00	1	8	0	12	0	0	0	0	31	10.2
157.50	3	15	7	2	5	0	0	0	32	8.6
180.00	2	10	1	0	2	1	0	0	16	7.8
202.50	1	3	0	0	0	0	0	0	4	3.4
225.00	2	4	0	0	0	0	0	0	6	3.7
247.50	4	2	0	0	0	0	0	0	6	3.1
270.00	1	5	1	0	0	0	0	0	7	5.3
292.50	4	14	11	3	0	0	0	0	32	7.0
315.00	1	9	15	29	27	17	2	0	100	17.9
337.50	1	1	8	29	9	6	0	0	54	17.0
360.00	0	3	3	2	0	0	0	0	8	9.0
Column Sums	25	79	63	79	46	25	2	0	319	12.6

Hours of Calm = 0
Sums of this table: row totals = 319 and column totals = 319

TABLE 2.3-52
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS D ANNUAL

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	18	79	62	14	0	1	0	0	174	7.1
45.00	22	62	41	14	1	0	0	0	140	6.8
67.50	18	32	22	6	0	0	0	0	78	6.0
90.00	23	48	13	8	1	0	0	0	93	5.8
112.50	23	130	97	61	27	9	0	0	347	9.7
135.00	37	237	167	88	41	40	0	0	610	10.0
157.50	46	215	56	26	15	21	3	0	382	8.1
180.00	32	105	16	6	0	0	0	0	159	4.7
202.50	40	48	8	2	1	0	0	0	99	4.4
225.00	50	29	4	5	1	0	0	0	89	4.2
247.50	25	34	6	1	0	0	0	0	66	4.2
270.00	57	78	15	3	1	0	0	0	154	4.4
292.50	62	290	200	81	13	5	0	0	651	7.8
315.00	41	247	532	652	501	319	6	0	2298	15.6
337.50	22	143	230	202	156	77	3	0	833	13.9
360.00	31	113	101	36	3	0	0	0	284	7.6
Column Sums	547	1890	1570	1205	761	472	12	0	6457	11.3

Hours of Calm = 5
Sums of this table: row totals = 6457 and column totals = 6457

TABLE 2.3-53
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS E ANNUAL

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	77	270	82	16	1	0	0	0	446	5.5
45.00	123	207	76	20	3	0	0	0	429	5.3
67.50	127	114	53	37	4	1	0	0	336	5.8
90.00	127	130	28	8	2	0	0	0	295	4.4
112.50	107	188	74	41	27	5	0	0	442	7.1
135.00	66	281	150	46	5	10		0	559	7.3
157.50	46	139	31	10	3	2	0	0	231	5.8
180.00	41	39	5	1	0	0	0	0	86	3.8
202.50	26	22	6	1	0	0	0	0	55	4.1
225.00	37	27	9	12	3	1	0	0	89	6.4
247.50	25	24	3	3	3	0	0	0	58	5.2
270.00	44	28	13	3	1	0	0	0	89	4.8
292.50	70	216	121	81	42	18	0	0	548	9.0
315.00	85	358	441	611	502	353	14	0	2364	15.4
337.50	68	253	210	169	52	11	1	0	764	9.6
360.00	78	266	171	44	3	1	0	0	563	6.8
Column Sums	1147	2562	1473	1103	651	402	16	0	7354	9.6

Hours of Calm = 12
Sums of this table: row totals = 7354 and column totals = 7354

TABLE 2.3-54
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS F ANNUAL

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph*								*Row Sum*	*Row Avg.*
	1.5	*5.1*	*9.6*	*15.1*	*21.1*	*29.6*	*40.1*	*50.1*		
22.50	*22*	*32*	*9*	*0*	*0*	*0*	*0*	*0*	*63*	*4.6*
45.00	*23*	*24*	*14*	*2*	*2*	*0*	*0*	*0*	*65*	*5.5*
67.50	*28*	*20*	*3*	*0*	*1*	*0*	*0*	*0*	*52*	*3.9*
90.00	*46*	*24*	*1*	*1*	*0*	*0*	*0*	*0*	*72*	*3.4*
112.50	*41*	*58*	*6*	*0*	*0*	*0*	*0*	*0*	*105*	*4.0*
135.00	*26*	*66*	*32*	*1*	*0*	*0*	*2*	*0*	*127*	*6.0*
157.50	*19*	*32*	*4*	*0*	*0*	*0*	*0*	*0*	*55*	*4.5*
180.00	*11*	*14*	*0*	*0*	*0*	*0*	*0*	*0*	*25*	*3.8*
202.50	*11*	*3*	*0*	*0*	*0*	*0*	*0*	*0*	*14*	*2.6*
225.00	*7*	*9*	*1*	*6*	*3*	*0*	*0*	*0*	*26*	*8.1*
247.50	*5*	*9*	*3*	*1*	*1*	*0*	*0*	*0*	*19*	*5.8*
270.00	*9*	*3*	*4*	*0*	*0*	*0*	*0*	*0*	*16*	*4.6*
292.50	*14*	*35*	*29*	*21*	*22*	*18*	*0*	*0*	*139*	*12.6*
315.00	*30*	*83*	*121*	*147*	*158*	*176*	*16*	*0*	*731*	*17.7*
337.50	*16*	*47*	*30*	*27*	*10*	*0*	*0*	*0*	*130*	*9.1*
360.00	*11*	*29*	*11*	*0*	*1*	*0*	*0*	*0*	*52*	*5.6*
Column Sums	*319*	*488*	*268*	*206*	*198*	*194*	*18*	*0*	*1691*	*11.4*

Hours of Calm = 0
Sums of this table: row totals = 1691 and column totals = 1691

TABLE 2.3-55
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS G ANNUAL

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph*								*Row Sums*	*Row Avg.*
	1.5	*5.1*	*9.6*	*15.1*	*21.1*	*29.6*	*40.1*	*50.1*		
22.50	*4*	*2*	*0*	*0*	*0*	*0*	*0*	*0*	*6*	*3.4*
45.00	*6*	*5*	*1*	*1*	*0*	*0*	*0*	*0*	*13*	*4.7*
67.50	*3*	*3*	*0*	*0*	*0*	*0*	*0*	*0*	*6*	*3.0*
90.00	*7*	*6*	*0*	*0*	*0*	*0*	*0*	*0*	*13*	*3.3*
112.50	*14*	*21*	*3*	*1*	*0*	*0*	*0*	*0*	*39*	*4.4*
135.00	*22*	*39*	*8*	*1*	*0*	*0*	*0*	*0*	*70*	*4.6*
157.50	*12*	*13*	*0*	*0*	*0*	*0*	*0*	*0*	*25*	*3.4*
180.00	*5*	*3*	*0*	*1*	*0*	*1*	*0*	*0*	*10*	*6.6*
202.50	*5*	*0*	*0*	*1*	*0*	*0*	*0*	*0*	*6*	*3.5*
225.00	*8*	*3*	*1*	*2*	*0*	*0*	*0*	*0*	*14*	*5.3*
247.50	*4*	*9*	*0*	*0*	*0*	*0*	*0*	*0*	*13*	*4.2*
270.00	*5*	*4*	*0*	*1*	*0*	*0*	*0*	*0*	*10*	*4.8*
292.50	*3*	*15*	*21*	*10*	*5*	*8*	*0*	*0*	*62*	*12.0*
315.00	*19*	*75*	*62*	*61*	*52*	*69*	*10*	*0*	*348*	*15.5*
337.50	*3*	*17*	*8*	*5*	*2*	*2*	*0*	*0*	*37*	*9.3*
360.00	*7*	*2*	*2*	*0*	*0*	*0*	*0*	*0*	*11*	*4.2*
Column Sums	*127*	*217*	*106*	*84*	*59*	*80*	*10*	*0*	*683*	*11.0*

Hours of Calm = 0
Sums of this table: row totals = 683 and column totals = 683

TABLE 2.3-56
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS A JAN.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	2	1	2	0	0	0	0	5	10.7
45.00	0	0	0	3	0	0	0	0	3	14.7
67.50	0	0	1	0	0	0	0	0	1	9.0
90.00	0	0	1	0	0	0	0	0	1	11.0
112.50	0	0	0	0	0	0	0	0	0	0.0
135.00	0	1	2	2	0	1	0	0	6	14.3
157.50	0	1	0	0	0	0	0	0	1	5.0
180.00	0	0	0	0	0	1	0	0	1	25.0
202.50	0	0	0	0	0	1	0	0	1	28.0
225.00	0	0	2	0	0	0	0	0	2	9.5
247.50	0	0	0	1	0	0	0	0	1	17.1
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	0	0	2	0	0	0	0	0	2	8.0
315.00	0	1	6	2	1	2	0	0	12	15.3
337.50	0	0	1	0	0	0	0	0	1	9.0
360.00	0	0	0	1	4	0	0	0	5	20.0
Column Sums	0	5	16	11	5	5	0	0	42	14.4

Hours of Calm = 0
Sums of this table: row totals = 42 and column totals = 42

TABLE 2.3-57
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS B JAN.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	1	1	0	0	0	0	2	12.0
45.00	0	1	0	0	1	0	0	0	2	13.0
67.50	0	0	1	0	0	0	0	0	1	11.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	0	0	0	0	0	0	0	0	0.0
135.00	0	0	1	0	0	1	0	0	2	20.7
157.50	0	0	0	0	0	0	0	0	0	0.0
180.00	0	0	1	0	0	0	0	0	1	8.0
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	0	0	2	0	0	0	0	0	2	10.5
247.50	1	0	0	0	0	0	0	0	1	3.0
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	0	0	0	0	0	0	0	0	0	0.0
315.00	0	0	0	5	1	2	0	0	8	18.5
337.50	0	0	0	2	0	0	0	0	2	13.0
360.00	0	0	2	0	1	0	0	0	3	12.7
Column Sums	1	1	8	8	3	3	0	0	24	14.4

Hours of Calm = 0
Sums of this table: row totals = 24 and column totals = 24

TABLE 2.3-58
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS C JAN.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	*0*	*0*	*0*	*1*	*0*	*0*	*0*	*0*	*1*	*14.2*
45.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
67.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
90.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
112.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
135.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
157.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
180.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
202.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
225.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
247.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
270.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
292.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
315.00	*0*	*0*	*2*	*0*	*1*	*0*	*0*	*0*	*3*	*14.2*
337.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
360.00	*0*	*0*	*0*	*1*	*0*	*0*	*0*	*0*	*1*	*16.2*
Column Sums	*0*	*0*	*2*	*2*	*1*	*0*	*0*	*0*	*5*	*14.6*

Hours of Calm = 0
Sums of this table: row totals = 5 and column totals = 5

TABLE 2.3-59
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS D JAN.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	3	7	11	6	0	0	0	0	27	9.0
45.00	0	12	5	5	0	0	0	0	22	8.0
67.50	4	4	1	2	0	0	0	0	11	6.3
90.00	1	5	1	5	1	0	0	0	13	10.2
112.50	3	6	15	19	3	0	0	0	46	11.3
135.00	1	12	14	17	7	14	0	0	65	15.7
157.50	1	11	6	7	1	8	3	0	37	16.1
180.00	0	5	0	0	0	0	0	0	5	4.2
202.50	1	10		0	0	0	0	0	11	4.4
225.00	4	1	0	0	0	0	0	0	5	3.1
247.50	1	1	3	0	0	0	0	0	5	7.3
270.00	1	6	1	1	0	0	0	0	9	5.8
292.50	1	5	10	3	0	1	0	0	20	10.0
315.00	0	1	19	46	29	9	0	0	104	16.7
337.50	1	3	12	9	9	13	3	0	50	18.7
360.00	1	4	7	3	1	0	0	0	16	9.9
Column Sums	23	93	105	123	51	45	6	0	446	13.4

Hours of Calm = 0
Sums of this table: row totals = 446 and column totals = 446

TABLE 2.3-60
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS E JAN.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	10	45	11	1	0	0	0	0	67	5.5
45.00	14	23	10	2	0	0	0	0	49	5.3
67.50	11	18	13	5	2	0	0	0	49	7.1
90.00	9	19	7	2	1	0	0	0	38	5.9
112.50	12	24	18	10	5	0	0	0	69	8.1
135.00	3	36	38	11	2	1	1	0	92	9.0
157.50	5	7	4	6	0	1	0	0	23	9.5
180.00	4	1	3	1	0	0	0	0	9	6.5
202.50	2	1	2	0	0	0	0	0	5	5.4
225.00	4	1	1	0	0	0	0	0	6	3.3
247.50	1	2	1	1	0	0	0	0	5	6.7
270.00	4	1	3	1	0	0	0	0	9	6.6
292.50	2	4	3	2	5	0	0	0	16	11.8
315.00	3	17	18	46	21	2	0	0	107	13.5
337.50	5	13	29	13	1	0	0	0	61	9.2
360.00	4	38	24	2	0	0	0	0	68	6.5
Column Sums	93	250	185	103	37	4	1	0	673	8.4

Hours of Calm = 0
Sums of this table: row totals = 673 and column totals = 673

TABLE 2.3-61
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS F JAN.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	*5*	*11*	*5*	*0*	*0*	*0*	*0*	*0*	*21*	*5.2*
45.00	*5*	*3*	*4*	*0*	*1*	*0*	*0*	*0*	*13*	*5.7*
67.50	*4*	*2*	*1*	*0*	*0*	*0*	*0*	*0*	*7*	*4.3*
90.00	*8*	*6*	*0*	*0*	*0*	*0*	*0*	*0*	*14*	*3.6*
112.50	*7*	*17*	*1*	*0*	*0*	*0*	*0*	*0*	*25*	*4.6*
135.00	*3*	*11*	*7*	*0*	*0*	*0*	*0*	*0*	*21*	*6.1*
157.50	*5*	*6*	*0*	*0*	*0*	*0*	*0*	*0*	*11*	*3.6*
180.00	*0*	*3*	*0*	*0*	*0*	*0*	*0*	*0*	*3*	*4.2*
202.50	*3*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*3*	*2.3*
225.00	*2*	*4*	*0*	*0*	*0*	*0*	*0*	*0*	*6*	*4.1*
247.50	*1*	*3*	*2*	*0*	*0*	*0*	*0*	*0*	*6*	*4.7*
270.00	*3*	*2*	*0*	*0*	*0*	*0*	*0*	*0*	*5*	*3.4*
292.50	*1*	*6*	*5*	*0*	*0*	*0*	*0*	*0*	*12*	*6.0*
315.00	*3*	*14*	*8*	*8*	*2*	*0*	*0*	*0*	*35*	*9.3*
337.50	*6*	*6*	*2*	*0*	*0*	*0*	*0*	*0*	*14*	*4.5*
360.00	*1*	*5*	*0*	*0*	*0*	*0*	*0*	*0*	*6*	*4.1*
Column Sums	*57*	*99*	*35*	*8*	*3*	*0*	*0*	*0*	*202*	*5.5*

Hours of Calm = 0
Sums of this table: row totals = 202 and column totals = 202

TABLE 2.3-62
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS G JAN.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	2	0	0	0	0	0	0	0	2	2.5
67.50	0	1	0	0	0	0	0	0	1	4.0
90.00	0	1	0	0	0	0	0	0	1	4.0
112.50	3	4	0	0	0	0	0	0	7	3.7
135.00	6	6	3	0	0	0	0	0	15	4.8
157.50	2	2	0	0	0	0	0	0	4	3.3
180.00	2	1	0	1	0	0	0	0	4	6.4
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	1	2	0	0	0	0	0	0	3	3.9
247.50	2	6	0	0	0	0	0	0	8	4.5
270.00	1	1	0	0	0	0	0	0	2	5.0
292.50	1	0	5	1	0	0	0	0	7	9.8
315.00	5	9	4	3	1	0	0	0	22	7.8
337.50	0	1	0	0	0	0	0	0	1	5.0
360.00	2	0	1	0	0	0	0	0	3	5.0
Column Sums	27	34	13	5	1	0	0	0	80	5.9

Hours of Calm = 0
Sums of this table: row totals = 80 and column totals = 80

TABLE 2.3-63
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS A FEB.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
45.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
67.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
90.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
112.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
135.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
157.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
180.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
202.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
225.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
247.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
270.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
292.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
315.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
337.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
360.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
Column Sums	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*

Hours of Calm = 0
Sums of this table: row totals = 0 and column totals = 0

TABLE 2.3-64
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS B FEB.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
45.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
67.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
90.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
112.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
135.00	*0*	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*1*	*11.5*
157.50	*0*	*0*	*1*	*0*	*0*	*1*	*0*	*0*	*2*	*19.7*
180.00	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*2.7*
202.50	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*3.7*
225.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
247.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
270.00	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*2.7*
292.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
315.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
337.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
360.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
Column Sums	*2*	*1*	*2*	*0*	*0*	*1*	*0*	*0*	*6*	*10.0*

Hours of Calm = 0
Sums of this table: row totals = 6 and column totals = 6

TABLE 2.3-65
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS C FEB.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
45.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
67.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
90.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
112.50	*0*	*0*	*0*	*0*	*1*	*0*	*0*	*0*	*1*	*21.2*
135.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
157.50	*0*	*2*	*0*	*0*	*0*	*0*	*0*	*0*	*2*	*5.6*
180.00	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*4.0*
202.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
225.00	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*3.6*
247.50	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*2.6*
270.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
292.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
315.00	*0*	*0*	*0*	*0*	*1*	*0*	*0*	*0*	*1*	*23.8*
337.50	*0*	*0*	*0*	*1*	*0*	*0*	*0*	*0*	*1*	*17.2*
360.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
Column Sums	*1*	*4*	*0*	*1*	*2*	*0*	*0*	*0*	*8*	*10.4*

Hours of Calm = 0
Sums of this table: row totals = 8 and column totals = 8

TABLE 2.3-66
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS D FEB.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph*								*Row Sums*	*Row Avg.*
	1.5	*5.1*	*9.6*	*15.1*	*21.1*	*29.6*	*40.1*	*50.1*		
22.50	*2*	*7*	*12*	*2*	*0*	*0*	*0*	*0*	*23*	*7.6*
45.00	*0*	*3*	*8*	*4*	*0*	*0*	*0*	*0*	*15*	*9.9*
67.50	*0*	*1*	*3*	*1*	*0*	*0*	*0*	*0*	*5*	*9.5*
90.00	*2*	*4*	*0*	*1*	*0*	*0*	*0*	*0*	*7*	*5.6*
112.50	*0*	*11*	*3*	*4*	*6*	*0*	*0*	*0*	*24*	*10.9*
135.00	*0*	*14*	*25*	*16*	*7*	*9*	*0*	*0*	*71*	*12.8*
157.50	*2*	*27*	*18*	*5*	*2*	*8*	*0*	*0*	*62*	*10.6*
180.00	*4*	*11*	*9*	*3*	*0*	*0*	*0*	*0*	*27*	*6.8*
202.50	*1*	*4*	*2*	*0*	*0*	*0*	*0*	*0*	*7*	*5.4*
225.00	*4*	*5*	*0*	*1*	*0*	*0*	*0*	*0*	*10*	*4.4*
247.50	*1*	*3*	*0*	*0*	*0*	*0*	*0*	*0*	*4*	*3.8*
270.00	*1*	*2*	*3*	*1*	*0*	*0*	*0*	*0*	*7*	*7.5*
292.50	*5*	*11*	*1*	*0*	*0*	*0*	*0*	*0*	*17*	*4.1*
315.00	*0*	*13*	*12*	*32*	*22*	*8*	*0*	*0*	*87*	*15.1*
337.50	*0*	*4*	*24*	*34*	*19*	*33*	*0*	*0*	*114*	*18.6*
360.00	*4*	*12*	*13*	*8*	*0*	*0*	*0*	*0*	*37*	*8.4*
Column Sums	*26*	*132*	*133*	*112*	*56*	*58*	*0*	*0*	*517*	*12.3*

Hours of Calm = 0
Sums of this table: row totals = 517 and column totals = 517

TABLE 2.3-67
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS E FEB.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	8	42	16	1	0	0	0	0	67	5.4
45.00	21	29	19	4	1	0	0	0	74	5.8
67.50	19	19	7	7	0	0	0	0	52	5.5
90.00	27	24	4	0	0	0	0	0	55	3.7
112.50	20	24	4	1	4	0	0	0	53	5.4
135.00	6	10	2	7	1	0	0	0	26	7.9
157.50	0	10	4	1	1	0	0	0	16	7.4
180.00	1	0	0	0	0	0	0	0	1	1.7
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	1	1	1	1	0	0	0	0	4	8.1
247.50	1	2	0	0	0	0	0	0	3	3.2
270.00	1	2	0	0	1	0	0	0	4	7.3
292.50	3	2	3	1	3	0	0	0	12	10.0
315.00	3	13	22	30	35	4	0	0	107	14.6
337.50	4	17	23	26	10	1	0	0	81	11.4
360.00	8	26	44	8	0	0	0	0	86	8.2
Column Sums	123	221	149	87	56	5	0	0	641	8.2

Hours of Calm = 0
Sums of this table: row totals = 641 and column totals = 641

TABLE 2.3-68
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS F FEB.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	*0*	*5*	*1*	*0*	*0*	*0*	*0*	*0*	*6*	*4.5*
45.00	*1*	*4*	*1*	*2*	*1*	*0*	*0*	*0*	*9*	*8.9*
67.50	*2*	*3*	*0*	*0*	*0*	*0*	*0*	*0*	*5*	*3.5*
90.00	*7*	*4*	*0*	*0*	*0*	*0*	*0*	*0*	*11*	*2.8*
112.50	*5*	*1*	*1*	*0*	*0*	*0*	*0*	*0*	*7*	*3.2*
135.00	*4*	*3*	*0*	*0*	*0*	*0*	*0*	*0*	*7*	*3.4*
157.50	*0*	*2*	*0*	*0*	*0*	*0*	*0*	*0*	*2*	*5.8*
180.00	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*2.2*
202.50	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*2.9*
225.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
247.50	*2*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*3*	*3.1*
270.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
292.50	*1*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*2*	*3.0*
315.00	*1*	*3*	*7*	*9*	*9*	*1*	*0*	*0*	*30*	*14.7*
337.50	*0*	*8*	*3*	*1*	*0*	*0*	*0*	*0*	*12*	*6.9*
360.00	*0*	*2*	*0*	*0*	*0*	*0*	*0*	*0*	*2*	*4.8*
Column Sums	*25*	*37*	*13*	*12*	*10*	*1*	*0*	*0*	*98*	*7.8*

Hours of Calm = 0
Sums of this table: row totals = 98 and column totals = 98

TABLE 2.3-69
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS G FEB.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	1	1	0	0	0	0	0	0	2	3.0
135.00	0	2	0	0	0	0	0	0	2	4.0
157.50	1	0	0	0	0	0	0	0	1	2.8
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	0	0	0	0	0	0	0		0	0.0
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	0	0	0	0	0	0	0	0	0	0.0
315.00	0	3	4	0	3	0	0	0	10	11.8
337.50	0	6	2	0	0	0	0	0	8	6.2
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	2	12	6	0	3	0	0	0	23	8.1

Hours of Calm = 0
Sums of this table: row totals = 23 and column totals = 23

TABLE 2.3-70
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS A MARCH

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	1	0	0	0	0	0	0	1	6.1
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	1	0	0	0	0	0	0	1	6.5
135.00	0	1	0	0	3	0	0	0	4	17.8
157.50	0	1	1	1	0	0	0	0	3	10.7
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	0	0	0	0	0	0	0	0	0	0.0
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	1	0	0	0	0	0	0	1	3.8
292.50	0	1	0	0	0	0	0	0	1	7.0
315.00	0	0	0	0	0	0	0	0	0	0.0
337.50	0	0	0	0	0	0	0	0	0	0.0
360.00	0	1	0	0	0	0	0	0	1	3.5
Column Sums	0	7	1	1	3	0	0	0	12	10.9

Hours of Calm = 0
Sums of this table: row totals = 12 and column totals = 12

TABLE 2.3-71
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS B MARCH

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*3.9*
45.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
67.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
90.00	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*3.2*
112.50	*0*	*0*	*2*	*0*	*0*	*0*	*0*	*0*	*2*	*10.8*
135.00	*0*	*0*	*0*	*1*	*0*	*0*	*0*	*0*	*1*	*12.2*
157.50	*0*	*1*	*1*	*0*	*0*	*1*	*0*	*0*	*3*	*12.8*
180.00	*0*	*0*	*1*	*2*	*0*	*0*	*0*	*0*	*3*	*14.4*
202.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
225.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
247.50	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*4.8*
270.00	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*3.1*
292.50	*0*	*1*	*1*	*0*	*0*	*0*	*0*	*0*	*2*	*7.7*
315.00	*0*	*0*	*2*	*2*	*3*	*4*	*0*	*0*	*11*	*21.4*
337.50	*0*	*0*	*0*	*0*	*4*	*1*	*0*	*0*	*5*	*23.6*
360.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
Column Sums	*0*	*6*	*7*	*5*	*7*	*6*	*0*	*0*	*31*	*16.1*

Hours of Calm = 0
Sums of this table: row totals = 31 and column totals = 31

TABLE 2.3-72
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS C MARCH

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
45.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
67.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
90.00	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*2.8*
112.50	*0*	*0*	*0*	*1*	*1*		*0*	*0*	*2*	*15.5*
135.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
157.50	*1*	*3*	*3*	*1*	*4*	*0*	*0*	*0*	*12*	*11.8*
180.00	*1*	*3*	*1*	*0*	*0*	*1*	*0*	*0*	*6*	*8.6*
202.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
225.00	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*4.6*
247.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
270.00	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*5.5*
292.50	*0*	*0*	*2*	*1*	*0*	*0*	*0*	*0*	*3*	*11.3*
315.00	*0*	*5*	*2*	*15*	*17*	*13*	*2*	*0*	*54*	*20.2*
337.50	*0*	*0*	*0*	*14*	*4*	*2*	*0*	*0*	*20*	*18.2*
360.00	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*5.9*
Column Sums	*3*	*14*	*8*	*32*	*26*	*16*	*2*	*0*	*101*	*17.2*

Hours of Calm = 0
Sums of this table: row totals = 101 and column totals = 101

TABLE 2.3-73
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS D MARCH

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph*								*Row Sums*	*Row Avg.*
	1.5	*5.1*	*9.6*	*15.1*	*21.1*	*29.6*	*40.1*	*50.1*		
22.50	*1*	*7*	*3*	*0*	*0*	*0*	*0*	*0*	*11*	*5.7*
45.00	*3*	*9*	*9*	*0*	*0*	*0*	*0*	*0*	*21*	*6.4*
67.50	*1*	*2*	*0*	*1*	*0*	*0*	*0*	*0*	*4*	*7.3*
90.00	*2*	*3*	*3*	*0*	*0*	*0*	*0*	*0*	*8*	*5.9*
112.50	*1*	*6*	*11*	*9*	*9*	*1*	*0*	*0*	*37*	*13.2*
135.00	*1*	*13*	*30*	*24*	*20*	*11*	*0*	*0*	*99*	*14.6*
157.50	*1*	*20*	*7*	*5*	*9*	*1*	*0*	*0*	*43*	*10.5*
180.00	*1*	*10*	*2*	*1*	*0*	*0*	*0*	*0*	*14*	*5.6*
202.50	*4*	*4*	*1*	*1*	*0*	*0*	*0*	*0*	*10*	*5.1*
225.00	*5*	*4*	*0*	*0*	*0*	*0*	*0*	*0*	*9*	*2.9*
247.50	*4*	*1*	*2*	*1*	*0*	*0*	*0*	*0*	*8*	*6.4*
270.00	*1*	*4*	*2*	*1*	*0*	*0*	*0*	*0*	*8*	*6.5*
292.50	*4*	*24*	*13*	*4*	*3*	*1*	*0*	*0*	*49*	*8.0*
315.00	*5*	*25*	*42*	*78*	*97*	*28*	*0*	*0*	*275*	*16.3*
337.50	*4*	*15*	*50*	*48*	*53*	*7*	*0*	*0*	*177*	*14.7*
360.00	*1*	*23*	*8*	*1*	*0*	*0*	*0*	*0*	*33*	*6.7*
Column Sums	*39*	*170*	*183*	*174*	*191*	*9*	*0*	*0*	*806*	*13.2*

Hours of Calm = 0
Sums of this table: row totals = 806 and column totals = 806

TABLE 2.3-74
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS E MARCH

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph*								*Row Sums*	*Row Avg.*
	1.5	*5.1*	*9.6*	*15.1*	*21.1*	*29.6*	*40.1*	*50.1*		
22.50	*3*	*26*	*7*	*2*	*0*	*0*	*0*	*0*	*38*	*5.4*
45.00	*9*	*24*	*10*	*3*	*0*	*0*	*0*	*0*	*46*	*5.7*
67.50	*5*	*6*	*4*	*3*	*0*	*0*	*0*	*0*	*18*	*6.6*
90.00	*4*	*10*	*3*	*2*	*0*	*0*	*0*	*0*	*19*	*6.3*
112.50	*5*	*16*	*6*	*12*	*7*	*0*	*0*	*0*	*46*	*10.0*
135.00	*6*	*35*	*22*	*9*	*2*	*4*	*0*	*0*	*78*	*9.1*
157.50	*4*	*18*	*5*	*1*	*2*	*0*	*0*	*0*	*30*	*6.7*
180.00	*2*	*2*	*0*	*0*	*0*	*0*	*0*	*0*	*4*	*3.1*
202.50	*4*	*1*	*1*	*0*	*0*	*0*	*0*	*0*	*6*	*4.2*
225.00	*3*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*4*	*2.9*
247.50	*1*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*2*	*3.7*
270.00	*2*	*1*	*2*	*0*	*0*	*0*	*0*	*0*	*5*	*5.2*
292.50	*1*	*10*	*8*	*2*	*0*	*0*	*0*	*0*	*21*	*6.7*
315.00	*3*	*19*	*14*	*22*	*19*	*4*	*0*	*0*	*81*	*13.4*
337.50	*1*	*10*	*20*	*17*	*6*	*1*	*0*	*0*	*55*	*11.8*
360.00	*0*	*20*	*13*	*7*	*0*	*0*	*0*	*0*	*40*	*8.1*
Column Sums	*53*	*200*	*115*	*80*	*36*	*9*	*0*	*0*	*493*	*8.8*

Hours of Calm = 0
Sums of this table: row totals = 493 and column totals = 493

TABLE 2.3-75
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS F MARCH

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph*								*Row Sums*	*Row Avg.*
	1.5	*5.1*	*9.6*	*15.1*	*21.1*	*29.6*	*40.1*	*50.1*		
22.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
45.00	*0*	*1*	*2*	*0*	*0*	*0*	*0*	*0*	*3*	*9.7*
67.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
90.00	*1*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*2*	*3.0*
112.50	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*3.3*
135.00	*0*	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*1*	*8.0*
157.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
180.00	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*2.4*
202.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
225.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
247.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
270.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
292.50	*0*	*3*	*0*	*2*	*3*	*0*	*0*	*0*	*8*	*13.2*
315.00	*1*	*3*	*2*	*2*	*7*	*0*	*0*	*0*	*15*	*14.4*
337.50	*0*	*2*	*0*	*0*	*0*	*0*	*0*	*0*	*2*	*6.1*
360.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
Column Sums	*3*	*11*	*5*	*4*	*10*	*0*	*0*	*0*	*33*	*11.6*

Hours of Calm = 0
Sums of this table: row totals = 33 and column totals = 33

TABLE 2.3-76
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS G MARCH

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph*								*Row Sums*	*Row Avg.*
	1.5	*5.1*	*9.6*	*15.1*	*21.1*	*29.6*	*40.1*	*50.1*		
22.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
45.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
67.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
90.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
112.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
135.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
157.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
180.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
202.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
225.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
247.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
270.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
292.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
315.00	*0*	*0*	*3*	*1*	*1*	*0*	*0*	*0*	*5*	*12.6*
337.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
360.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
Column Sums	*0*	*0*	*3*	*1*	*1*	*0*	*0*	*0*	*5*	*12.6*

Hours of Calm = 0
Sums of this table: row totals = 5 and column totals = 5

TABLE 2.3-77
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS A APRIL

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph*								*Row Sums*	*Row Avg.*
	1.5	*5.1*	*9.6*	*15.1*	*21.1*	*29.6*	*40.1*	*50.1*		
22.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
45.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
67.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
90.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
112.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
135.00	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*6.0*
157.50	*0*	*5*	*0*	*0*	*0*	*0*	*0*	*0*	*5*	*5.5*
180.00	*0*	*4*	*1*	*0*	*0*	*0*	*0*	*0*	*5*	*5.6*
202.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
225.00	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*5.1*
247.50	*0*	*2*	*0*	*0*	*0*	*0*	*0*	*0*	*2*	*5.0*
270.00	*1*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*2*	*3.1*
292.50	*0*	*2*	*0*	*1*	*0*	*0*	*0*	*0*	*3*	*7.7*
315.00	*0*	*1*	*2*		*0*	*0*	*0*	*0*	*3*	*9.0*
337.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
360.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
Column Sums	*1*	*17*	*3*	*1*	*0*	*0*	*0*	*0*	*22*	*6.0*

Hours of Calm = 0
Sums of this table: row totals = 22 and column totals = 22

TABLE 2.3-78
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS B APRIL

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
45.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
67.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
90.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
112.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
135.00	*0*	*3*	*1*	*0*	*0*	*0*	*0*	*0*	*4*	*5.8*
157.50	*0*	*3*	*4*	*0*	*0*	*0*	*0*	*0*	*7*	*7.1*
180.00	*0*	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*1*	*7.1*
202.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
225.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
247.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
270.00	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*4.0*
292.50	*1*	*4*	*2*	*0*	*0*	*0*	*0*	*0*	*7*	*5.8*
315.00	*1*	*4*	*6*	*2*	*2*	*2*	*0*	*0*	*17*	*12.5*
337.50	*0*	*0*	*0*	*0*	*1*	*1*	*0*	*0*	*2*	*24.5*
360.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
Column Sums	*2*	*15*	*14*	*2*	*3*	*3*	*0*	*0*	*39*	*9.9*

Hours of Calm = 0
Sums of this table: row totals = 39 and column totals = 39

TABLE 2.3-79
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS C APRIL

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
45.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
67.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
90.00	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*5.0*
112.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
135.00	*0*	*1*	*2*	*0*	*0*	*0*	*0*	*0*	*3*	*8.6*
157.50	*0*	*1*	*1*	*1*	*0*	*0*	*0*	*0*	*3*	*7.9*
180.00	*0*	*2*	*0*	*0*	*0*	*0*	*0*	*0*	*2*	*5.6*
202.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
225.00	*2*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*2*	*2.9*
247.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
270.00	*0*	*1*	*1*	*0*	*0*	*0*	*0*	*0*	*2*	*7.9*
292.50	*1*	*2*	*2*	*0*	*0*	*0*	*0*	*0*	*5*	*7.4*
315.00	*0*	*0*	*7*	*12*	*6*	*4*	*0*	*0*	*29*	*17.0*
337.50	*0*	*0*	*0*	*0*	*1*	*0*	*0*	*0*	*1*	*19.2*
360.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
Column Sums	*3*	*8*	*13*	*13*	*7*	*4*	*0*	*0*	*48*	*13.3*

Hours of Calm = 0
Sums of this table: row totals = 48 and column totals = 48

TABLE 2.3-80
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS D APRIL

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	14	4	1	0	0	0	0	19	6.2
45.00	1	4	2	0	0	0	0	0	7	5.3
67.50	4	0	3	0	0	0	0	0	7	4.9
90.00	1	2	0	0	0	0	0	0	3	3.7
112.50	1	10	23	0	0	0	0	0	34	8.5
135.00	2	17	7	1	0	0	0	0	27	6.5
157.50	4	9	5	3	0	0	0	0	21	6.6
180.00	1	4	1	2	0	0	0	0	8	7.3
202.50	2	3	0	0	0	0	0	0	5	3.4
225.00	1	2	1	0	0	0	0	0	4	5.5
247.50	1	2	0	0	0	0	0	0	3	4.2
270.00	3	1	2	0	1	0	0	0	7	7.2
292.50	4	13	12	6	0	0	0	0	35	7.8
315.00	1	17	61	71	66	69	0	0	285	17.5
337.50	3	24	63	39	25	9	0	0	163	12.9
360.00	4	13	21	1	0	0	0	0	39	7.2
Column Sums	33	135	205	124	92	78	0	0	667	12.9

Hours of Calm = 0
Sums of this table: row totals = 667 and column totals = 667

TABLE 2.3-81
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS E APRIL

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	7	21	10	0	0	0	0	0	38	5.5
45.00	13	14	3	4	0	0	0	0	34	5.3
67.50	7	4	2	1	0	0	0	0	14	5.0
90.00	7	6	1	0	0	0	0	0	14	3.8
112.50	7	13	4	3	0	0	0	0	27	5.7
135.00	6	5	6	1	0	0	0	0	18	6.1
157.50	1	3	1	0	0	0	0	0	5	4.4
180.00	3	0	0	0	0	0	0	0	3	3.0
202.50	1	1	0	0	0	0	0	0	2	3.5
225.00	0	1	0	0	0	0	0	0	1	4.8
247.50	0	1	0	1	0	0	0	0	2	9.5
270.00	2	0	0	1	0	0	0	0	3	7.3
292.50	0	1	7	9	1	0	0	0	18	12.9
315.00	3	7	19	38	48	42	0	0	157	18.7
337.50	2	12	15	23	11	6	0	0	69	13.6
360.00	14	20	28	5	0	0	0	0	67	6.8
Column Sums	73	109	96	86	60	48	0	0	472	11.5

Hours of Calm = 1
Sums of this table: row totals = 472 and column totals = 472

TABLE 2.3-82
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS F APRIL

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	2	2	0	0	0	0	0	0	4	4.6
45.00	3	3	3	0	0	0	0	0	9	5.2
67.50	6	4	0	0	0	0	0	0	10	3.2
90.00	5	5	0	0	0	0	0	0	10	3.7
112.50	3	0	0	0	0	0	0	0	3	2.7
135.00	3	1	1	0	0	0	0	0	5	5.0
157.50	2	1	0	0	0	0	0	0	3	3.4
180.00	3	1	0	0	0	0	0	0	4	3.4
202.50	1	1	0	0	0	0	0	0	2	3.0
225.00	1	0	0	0	0	0	0	0	1	2.9
247.50	0	1	0	0	0	0	0	0	1	5.2
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	0	1	2	2	2	0	0	0	7	12.7
315.00	3	3	12	9	22	15	0	0	64	18.2
337.50	1	3	3	1	0	0	0	0	8	7.4
360.00	0	3	1	0	0	0	0	0	4	6.3
Column Sums	33	29	22	12	24	15	0	0	135	11.4

Hours of Calm = 0
Sums of this table: row totals = 135 and column totals = 135

TABLE 2.3-83
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS G APRIL

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	2	0	0	0	0	0	0	0	2	2.4
45.00	0	0	1	0	0	0	0	0	1	8.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	2	2	0	0	0	0	0	0	4	3.5
112.50	0	1	0	0	0	0	0	0	1	3.6
135.00	0	1	0	0	0	0	0	0	1	4.0
157.50	0	0	0	0	0	0	0	0	0	0.0
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	1	0	0	0	0	0	0	0	1	1.6
225.00	0	0	0	0	0	0	0	0	0	0.0
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	0	3	1	0	0	0	0	0	4	5.9
315.00	0	8	8	3	10	2	0	0	31	13.6
337.50	0	1	2	0	0	0	0	0	3	9.0
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	5	16	12	3	10	2	0	0	48	10.6

Hours of Calm = 0
Sums of this table: row totals = 48 and column totals = 48

TABLE 2.3-84
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS A MAY

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
45.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
67.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
90.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
112.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
135.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
157.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
180.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
202.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
225.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
247.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
270.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
292.50	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*3.0*
315.00	*1*	*4*	*0*	*0*	*0*	*0*	*0*	*0*	*5*	*4.8*
337.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
360.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
Column Sums	*2*	*4*	*0*	*0*	*0*	*0*	*0*	*0*	*6*	*4.5*

Hours of Calm = 0
Sums of this table: row totals = 6 and column totals = 6

TABLE 2.3-85
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS B MAY

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	0	0	0	0	0	0	0	0	0.0
135.00	0	0	0	0	0	0	0	0	0	0.0
157.50	0	1	0	0	0	0	0	0	1	4.0
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	0	1	0	0	0	0	0	0	1	3.8
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	2	0	0	0	0	0	0	2	4.1
292.50	0	0	0	0	0	0	0	0	0	0.0
315.00	0	0	0	0	0	0	0	0	0	0.0
337.50	0	0	0	0	0	0	0	0	0	0.0
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	0	4	0	0	0	0	0	0	4	4.0

Hours of Calm = 0
Sums of this table: row totals = 4 and column totals = 4

TABLE 2.3-86
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS C MAY

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	0	0	0	0	0	0	0	0	0.0
135.00	0	0	0	0	0	0	0	0	0	0.0
157.50	0	1	0	0	0	0	0	0	1	6.5
180.00	0	1	0	0	0	0	0	0	1	4.4
202.50	0	1	0	0	0	0	0	0	1	3.1
225.00	0	1	0	0	0	0	0	0	1	3.8
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	1	0	0	0	0	0	0	1	5.4
292.50	0	2	1	0	0	0	0	0	3	5.6
315.00	0	0	0	0	0	0	0	0	0	0.0
337.50	0	0	0	0	0	0	0	0	0	0.0
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	0	7	1	0	0	0	0	0	8	5.0

Hours of Calm = 0
Sums of this table: row totals = 8 and column totals = 8

TABLE 2.3-87
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS D MAY

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	3	2	0	0	0	0	0	5	6.1
45.00	3	1	0	0	0	0	0	0	4	2.6
67.50	0	7	0	0	0	0	0	0	7	3.6
90.00	3	3	1	0	0	0	0	0	7	4.4
112.50	2	15	2	0	0	0	0	0	19	5.3
135.00	8	25	5	0	0	0	0	0	38	4.8
157.50	9	12	1	0	0	0	0	0	22	3.8
180.00	3	13	0	0	0	0	0	0	16	3.7
202.50	4	3	0	0	0	0	0	0	7	3.0
225.00	6	1	0	0	0	0	0	0	7	2.7
247.50	4	5	0	0	0	0	0	0	9	3.4
270.00	9	12	1	0	0	0	0	0	22	3.5
292.50	8	32	25	6	0	0	0	0	71	6.9
315.00	2	23	72	94	79	80	2	0	352	17.7
337.50	1	15	22	8	18	11	0	0	75	15.0
360.00	2	5	2	0	0	0	0	0	9	4.7
Column Sums	64	175	133	108	97	91	2	0	670	12.8

Hours of Calm = 0
Sums of this table: row totals = 670 and column totals = 670

TABLE 2.3-88
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS E MAY

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	4	11	5	0	0	0	0	0	20	5.2
45.00	5	3	1	0	0	0	0	0	9	4.1
67.50	4	2	1	0	0	0	0	0	7	4.1
90.00	2	3	1	0	0	0	0	0	6	5.0
112.50	1	12	5	1	0	0	0	0	19	6.3
135.00	6	22	1	1	0	0	0	0	30	4.6
157.50	3	7	2	0	0	0	0	0	12	4.8
180.00	5	2	0	0	0	0	0	0	7	2.9
202.50	3	4	0	0	0	0	0	0	7	4.2
225.00	5	3	0	0	0	0	0	0	8	2.9
247.50	6	2	0	0	0	0	0	0	8	2.8
270.00	6	3	1	0	0	0	0	0	10	3.9
292.50	7	32	2	10	6	1	0	0	58	8.3
315.00	13	42	47	45	47	56	0	0	250	15.7
337.50	5	27	23	15	9	1	0	0	80	9.8
360.00	6	28	8	1	0	0	0	0	43	5.6
Column Sums	81	203	97	73	62	58	0	0	574	10.6

Hours of Calm = 0
Sums of this table: row totals = 574 and column totals = 574

TABLE 2.3-89
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS F MAY

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	1	1	0	0	0	0	0	0	2	3.9
45.00	0	0	1	0	0	0	0	0	1	7.1
67.50	0	1	0	0	0	0	0	0	1	3.9
90.00	1	1	0	0	0	0	0	0	2	3.1
112.50	0	1	0	0	0	0	0	0	1	6.3
135.00	0	4	3	0	0	0	0	0	7	6.6
157.50	0	0	1	0	0	0	0	0	1	7.5
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	0	1	0	1	0	0	0	0	2	9.3
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	2	0	0	0	0	0	2	10.3
292.50	1	3	1	5	4	2	0	0	16	15.2
315.00	2	6	10	15	14	37	0	0	84	20.6
337.50	0	1	1	4	1	0	0	0	7	13.7
360.00	1	1	0	0	0	0	0	0	2	3.1
Column Sums	6	20	19	25	19	39	0	0	128	17.2

Hours of Calm = 0
Sums of this table: row totals = 128 and column totals = 128

TABLE 2.3-90
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS G MAY

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	1	0	0	0	0	0	0	0	1	2.6
45.00	0	1	0	0	0	0	0	0	1	4.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	1	0	0	0	0	0	0	0	1	2.6
112.50	1	3	3	1	0	0	0	0	8	7.3
135.00	2	3	2	0	0	0	0	0	7	5.3
157.50	1	0	0	0	0	0	0	0	1	2.5
180.00	0	0	0	0	0	1	0	0	1	24.4
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	1	0	0	0	0	0	0	0	1	3.0
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	1	0	0	0	0	0	0	0	1	2.7
292.50	0	2	2	1	0	1	0	0	6	10.5
315.00	3	9	15	8	7	19	0	0	61	16.5
337.50	0	2	1	1	0	2	0	0	6	14.7
360.00	0	1	0	0	0	0	0	0	1	5.8
Column Sums	11	21	23	11	7	23	0	0	96	13.5

Hours of Calm = 0
Sums of this table: row totals = 96 and column totals = 96

TABLE 2.3-91
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS A JUNE

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	1	0	0	0	0	0	0	1	4.0
90.00	0	1	1	0	0	0	0	0	2	9.0
112.50	0	0	0	0	0	0	0	0	0	0.0
135.00	0	3	1	0	0	0	0	0	4	6.2
157.50	0	0	0	0	0	0	0	0	0	0.0
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	0	1	0	0	0	0	0	0	1	5.0
225.00	0	0	0	0	0	0	0	0	0	0.0
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	0	2	0	0	0	0	0	0	2	4.0
315.00	0	1	1	0	0	0	0	0	2	8.0
337.50	1	1	0	0	2	0	0	0	4	12.5
360.00	0	1	0	0	0	0	0	0	1	5.0
Column Sums	1	11	3	0	2	0	0	0	17	7.7

Hours of Calm = 0
Sums of this table: row totals = 17 and column totals = 17

TABLE 2.3-92
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS B JUNE

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
45.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
67.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
90.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
112.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
135.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
157.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
180.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
202.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
225.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
247.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
270.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
292.50	*0*	*2*	*0*	*0*	*0*	*0*	*0*	*0*	*2*	*4.2*
315.00	*0*	*1*	*1*	*0*	*0*	*0*	*0*	*0*	*2*	*9.0*
337.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
360.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
Column Sums	*0*	*3*	*1*	*0*	*0*	*0*	*0*	*0*	*4*	*6.6*

Hours of Calm = 0
Sums of this table: row totals = 4 and column totals = 4

TABLE 2.3-93
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS C JUNE

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	0	0	0	0	0	0	0	0	0.0
135.00	0	0	0	0	0	0	0	0	0	0.0
157.50	0	0	0	0	0	0	0	0	0	0.0
180.00	0	2	0	0	0	0	0	0	2	4.2
202.50	0	1	0	0	0	0	0	0	1	3.7
225.00	0	0	0	0	0	0	0	0	0	0.0
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	0	0	0	0	0	0	0	0	0	0.0
315.00	0	0	0	0	0	0	0	0	0	0.0
337.50	0	0	0	0	0	0	0	0	0	0.0
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	0	3	0	0	0	0	0	0	3	4.1

Hours of Calm = 0
Sums of this table: row totals = 3 and column totals = 3

TABLE 2.3-94
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS D JUNE

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	2	0	0	0	0	0	0	2	3.6
45.00	0	3	0	0	0	0	0	0	3	4.5
67.50	2	1	0	0	0	0	0	0	3	2.8
90.00	1	3	1	1	0	0	0	0	6	7.1
112.50	0	7	11	2	0	0	0	0	20	8.5
135.00	4	19	10	3	0	0	0	0	36	6.3
157.50	6	17	3	0	0	0	0	0	26	4.6
180.00	3	6	0	0	0	0	0	0	9	3.5
202.50	2	1	0	0	0	0	0	0	3	3.2
225.00	4	3	0	0	0	0	0	0	7	3.1
247.50	3	2	0	0	0	0	0	0	5	3.2
270.00	8	8	0	0	0	0	0	0	16	3.4
292.50	3	18	19	0	0	0	0	0	40	6.9
315.00	8	29	62	73	47	37	0	0	256	15.3
337.50	2	10	8	13	11	3	0	0	47	13.5
360.00	1	7	1	0	0	0	0	0	9	5.0
Column Sum	47	136	115	92	58	40	0	0	488	11.5

Hours of Calm = 0
Sums of this table: row totals = 488 and column totals = 488

TABLE 2.3-95
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS E JUNE

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	4	5	4	0	0	0	0	0	13	5.2
45.00	4	1	0	0	0	0	0	0	5	2.6
67.50	3	0	0	0	0	0	0	0	3	2.3
90.00	4	2	0	0	0	0	0	0	6	2.8
112.50	4	12	10	3	0	0	0	0	29	6.7
135.00	4	16	8	1	0	0	0	0	29	5.9
157.50	4	13	3	0	0	0	0	0	20	5.0
180.00	4	4	0	0	0	0	0	0	8	3.4
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	1	2	0	0	0	0	0	0	3	3.7
247.50	3	0	0	0	0	0	0	0	3	2.4
270.00	4	0	0	0	0	0	0	0	4	2.4
292.50	7	22	11	4	2	1	0	0	47	7.7
315.00	7	29	46	87	60	66	7	0	302	17.8
337.50	10	19	10	6	2	0	0	0	47	7.4
360.00	4	21	1	1	0	1	0	0	28	5.6
Column Sums	67	46	93	107	64	68	7	0	547	12.6

Hours of Calm = 0
Sums of this table: row totals = 547 and column totals = 547

TABLE 2.3-96
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS F JUNE

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	1	0	0	0	0	0	0	0	1	3.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	1		0	0	0	0	0	1	4.3
112.50	0	3	2	0	0	0	0	0	5	6.7
135.00	1	3	3	0	0	0	0	0	7	6.2
157.50	0	0	1	0	0	0	0	0	1	10.1
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	0	0	0	0	0	0	0	0	0	0.0
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	1	0	0	0	0	0	0	1	3.7
292.50	0	0	2	2	1	0	0	0	5	14.2
315.00	1	8	3	21	23	24	6	0	86	21.2
337.50	2	2	3	5	6	0	0	0	18	13.1
360.00	1	0	2	0	0	0	0	0	3	7.0
Column Sums	6	18	16	28	30	24	6	0	128	17.6

Hours of Calm = 0
Sums of this table: row totals = 128 and column totals = 128

TABLE 2.3-97
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS G JUNE

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	1	0	0	0	0	0	0	1	4.7
112.50	1	2	0	0	0	0	0	0	3	3.1
135.00	2	3	0	0	0	0	0	0	5	4.1
157.50	3	2	0	0	0	0	0	0	5	3.7
180.00	1	0	0	0	0	0	0	0	1	1.8
202.50	3	0	0	0	0	0	0	0	3	1.6
225.00	1	0	0	0	0	0	0	0	1	1.1
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	0	1	3	4	0	1	0	0	9	14.2
315.00	1	15	11	18	13	30	7	0	95	19.7
337.50	2	1	2	1	1	0	0	0	7	9.3
360.00	1	0	0	0	0	0	0	0	1	2.4
Column Sums	15	25	16	23	14	31	7	0	131	16.2

Hours of Calm = 0
Sums of this table: row totals = 131 and column totals = 131

TABLE 2.3-98
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS A JULY

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	0	0	0	0	0	0	0	0	0.0
135.00	0	2	0	0	0	0	0	0	2	5.1
157.50	0	0	0	0	0	0	0	0	0	0.0
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	0	0	0	0	0	0	0	0	0	0.0
247.50	0	1	0	0	0	0	0	0	1	4.0
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	0	2	0	0	3	0	0	0	5	14.9
315.00	0	0	3	10	7	11	0	0	31	20.8
337.50	0	0	0	0	0	0	0	0	0	0.0
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	0	5	3	10	10	11	0	0	39	18.8

Hours of Calm = 0
Sums of this table: row totals = 39 and column totals = 39

TABLE 2.3-99
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS B JULY

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	0	1	0	0	0	0	0	1	12.0
135.00	1	0	2	0	0	0	0	0	3	6.8
157.50	0	0	0	0	0	0	0	0	0	0.0
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	0	1	0	0	0	0	0	0	1	4.0
225.00	1	0	0	0	0	0	0	0	1	2.9
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	0	0	0	0		0	0	0.0
292.50	0	3	1	0	0	0	0	0	4	6.5
315.00	0	0	0	0	0	0	0	0	0	0.0
337.50	0	0	0	0	0	0	0	0	0	0.0
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	2	4	4	0	0	0	0	0	10	6.5

Hours of Calm = 0
Sums of this table: row totals = 10 and column totals = 10

TABLE 2.3-100
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS C JULY

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	1	0	0	0	0	0	0	0	1	2.5
135.00	0	0	1	0	0	0	0	0	1	7.1
157.50	0	1	0	0	0	0	0	0	1	4.6
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	0	0	0	0	0	0	0	0	0	0.0
247.50	1	0	0	0	0	0	0	0	1	2.6
270.00	1	1	0	0	0	0	0	0	2	3.6
292.50	1	3	1	0	0	0	0	0	5	5.2
315.00	0	1	0	0	1	0	0	0	2	10.7
337.50	0	0	0	0	0	0	0	0	0	0.0
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	4	6	2	0	1	0	0	0	13	5.5

Hours of Calm = 0
Sums of this table: row totals = 13 and column totals = 13

TABLE 2.3-101
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS D JULY

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	3	6	0	0	0	0	0	0	9	3.4
45.00	4	0	0	0	0	0	0	0	4	2.4
67.50	1	1	0	0	0	0	0	0	2	3.9
90.00	1	3	0	0	0	0	0	0	4	4.3
112.50	2	22	8	5	0	0	0	0	37	7.1
135.00	6	21	17	2	0	0	0	0	46	6.6
157.50	7	29	4	0	0	0	0	0	40	5.0
180.00	7	10	0	0	0	0	0	0	17	3.3
202.50	3	2	0	0	0	0	0	0	5	2.5
225.00	9	5	1	0	0	0	0	0	15	3.5
247.50	3	5	0	0	0	0	0	0	8	3.2
270.00	6	8	0	0	0	0	0	0	14	3.4
292.50	9	46	23	14	0	0	0	0	92	7.5
315.00	7	55	84	49	56	39	3	0	293	14.4
337.50	4	18	8	3	0	0	0	0	33	6.8
360.00	7	8	0	0	0	0	0	0	15	3.5
Column Sums	79	239	145	73	56	39	3	0	634	9.8

Hours of Calm = 0
Sums of this table: row totals = 634 and column totals = 634

TABLE 2.3-102
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS E JULY

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	1	2	0	0	0	0	0	0	3	3.8
45.00	1	1	0	0	0	0	0	0	2	3.2
67.50	1	0	0	0	0	0	0	0	1	2.1
90.00	5	2	0	0	0	0	0	0	7	2.7
112.50	3	7	3	0	0	0	0	0	13	5.8
135.00	6	15	9	2	0	0	0	0	32	5.9
157.50	4	15	2	0	0	0	0	0	21	4.7
180.00	6	6	0	0	0	0	0	0	12	3.3
202.50	3	2	1	0	0	0	0	0	6	3.9
225.00	3	2	0	0	0	0	0	0	5	2.7
247.50	2	4	0	0	0	0	0	0	6	3.3
270.00	7	4	2	0	0	0	0	0	13	3.6
292.50	15	24	25	15	2	2	0	0	83	8.2
315.00	15	59	83	86	80	74	5	0	402	15.9
337.50	7	20	11	7	0	0	0	0	45	7.3
360.00	5	6	3	0	0	0	0	0	14	4.9
Column Sums	84	169	139	110	82	76	5	0	665	12.1

Hours of Calm = 0
Sums of this table: row totals = 665 and column totals = 665

TABLE 2.3-103
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS F JULY

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	0	1	0	0	0	0	0	1	9.3
135.00	1	5	2	0	0	0	0	0	8	5.7
157.50	0	1	0	0	0	0	0	0	1	6.8
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	1	0	0	0	0	0	0	0	1	2.7
225.00	0	0	0	0	0	0	0	0	0	0.0
247.50	1	0	0	0	0	0	0	0	1	1.9
270.00	1	0	0	0	0	0	0	0	1	2.5
292.50	1	3	4	1	0	4	0	0	13	14.0
315.00	2	6	3	12	8	31	4	0	66	22.0
337.50	0	0	0	1	0	0	0	0	1	17.0
360.00	0	0	0	0	1	0	0	0	1	19.0
Column Sums	7	15	10	14	9	35	4	0	94	18.5

Hours of Calm = 0
Sums of this table: row totals = 94 and column totals = 94

TABLE 2.3-104
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS G JULY

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	1	0	0	0	0	0	0	1	3.1
112.50	0	0	0	0	0	0	0	0	0	0.0
135.00	0	2	1	0	0	0	0	0	3	6.5
157.50	0	2	0	0	0	0	0	0	2	4.6
180.00	0	1	0	0	0	0	0	0	1	6.4
202.50	0	0	0	1	0	0	0	0	1	12.2
225.00	0	0	0	0	0	0	0	0	0	0.0
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	0	0	0	0	0	0	0	0	0	0.0
315.00	0	1	1	0	2	3	1	0	8	23.0
337.50	0	0	0	0	0	0	0	0	0	0.0
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	0	7	2	1	2	3	1	0	16	14.7

Hours of Calm = 0
Sums of this table: row totals = 16 and column totals = 16

TABLE 2.3-105
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS A AUG.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	0	0	0	0	0	0	0	0	0.0
135.00	0	0	0	0	0	0	0	0	0	0.0
157.50	0	1	0	0	0	0	0	0	1	5.8
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	0	1	0	0	0	0	0	0	1	4.2
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	0	5	0	0	0	0	0	0	5	4.4
315.00	1	2	0	0	0	1	0	0	4	9.7
337.50	0	0	0	0	0	0	0	0	0	0.0
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	1	9	0	0	0	1	0	0	11	6.4

Hours of Calm = 0
Sums of this table: row totals = 11 and column totals = 11

TABLE 2.3-106
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS B AUG.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	0	0	0	0	0	0	0	0	0.0
135.00	0	0	0	0	0	0	0	0	0	0.0
157.50	0	0	0	0	0	0	0	0	0	0.0
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	0	1	0	0	0	0	0	0	1	3.7
225.00	0	1	0	0	0	0	0	0	1	3.5
247.50	0	2	0	0	0	0	0	0	2	4.0
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	1	0	0	0	0	0	0	0	1	2.5
315.00	0	1	0	0	0	0	0	0	1	5.4
337.50	0	0	0	0	0	0	0	0	0	0.0
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	1	5	0	0	0	0	0	0	6	3.8

Hours of Calm = 0
Sums of this table: row totals = 6 and column totals = 6

TABLE 2.3-107
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS C AUG.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	0	0	0	0	0	0	0	0	0.0
135.00	0	0	1	0	0	0	0	0	1	7.9
157.50	0	0	1	0	0	0	0	0	1	7.7
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	0	0	0	0	0	0	0	0	0	0.0
247.50	0	2	0	0	0	0	0	0	2	4.4
270.00	0	1	0	0	0	0	0	0	1	3.2
292.50	0	1	2	1	0	0	0	0	4	9.6
315.00	0	0	0	0	0	0	0	0	0	0.0
337.50	0	0	0	0	0	0	0	0	0	0.0
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	0	4	4	1	0	0	0	0	9	7.3

Hours of Calm = 0
Sums of this table: row totals = 9 and column totals = 9

TABLE 2.3-108
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS D AUG.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	3	4	0	0	0	0	0	0	7	3.1
45.00	2	3	0	0	0	0	0	0	5	3.2
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	1	1	0	0	0	0	0	0	2	3.3
112.50	3	3	0	0	0	0	0	0	6	3.2
135.00	0	13	5	2	0	0	0	0	20	6.9
157.50	7	21	1	0	0	0	0	0	29	4.3
180.00	5	15	0	0	0	0	0	0	20	3.7
202.50	11	5	0	0	0	0	0	0	16	3.1
225.00	5	4	0	0	0	0	0	0	9	3.0
247.50	5	5	0	0	0	0	0	0	10	2.9
270.00	13	15	3	0	0	0	0	0	31	4.2
292.50	17	75	43	25	5	1	0	0	166	7.8
315.00	9	33	79	67	36	14	0	0	238	12.9
337.50	2	17	3	0	0	0	0	0	22	6.0
360.00	4	11	0	0	0	0	0	0	15	3.5
Column Sums	87	225	134	94	41	15	0	0	596	8.7

Hours of Calm = 2
Sums of this table: row totals = 596 and column totals = 596

TABLE 2.3-109
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS E AUG.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	8	7	0	0	0	0	0	0	15	3.2
45.00	8	4	0	0	0	0	0	0	12	3.3
67.50	3	0	1	0	0	0	0	0	4	3.5
90.00	5	1	0	0	0	0	0	0	6	2.5
112.50	7	2	3	0	0	0	0	0	12	4.2
135.00	5	11	6	1	0	0	0	0	23	5.9
157.50	7	18	2	0	0	0	0	0	27	4.4
180.00	5	4	0	0	0	0	0	0	9	3.4
202.50	2	2	0	0	0	0	0	0	4	3.0
225.00	4	4	1	0	0	0	0	0	9	4.3
247.50	5	3	0	0	0	0	0	0	8	3.3
270.00	6	4	2	0	0	0	0	0	12	4.5
292.50	11	52	19	10	7	8	0	0	107	9.3
315.00	18	68	75	107	70	61	2	0	401	15.0
337.50	10	31	7	0	0	0	0	0	48	5.3
360.00	14	17	0	0	0	0	0	0	31	4.1
Column Sums	118	228	116	118	77	69	2	0	728	11.0

Hours of Calm = 3
Sums of this table: row totals = 728 and column totals = 728

TABLE 2.3-110
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS F AUG.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	1	0	0	0	0	0	1	7.6
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	0	0	0	0	0	0	0	0	0.0
135.00	0	0	0	0	0	0	0	0	0	0.0
157.50	1	4	0	0	0	0	0	0	5	4.3
180.00	1	3	0	0	0	0	0	0	4	4.4
202.50	0	1	0	0	0	0	0	0	1	3.4
225.00	0	0	0	0	0	0	0	0	0	0.0
247.50	0	0	1	0	0	0	0	0	1	9.0
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	1	2	2	3	6	9	0	0	23	20.3
315.00	2	1	5	5	14	22	6	0	55	24.3
337.50	2	0	0	1	0	0	0	0	3	6.8
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	7	11	9	9	20	31	6	0	93	20.3

Hours of Calm = 0
Sums of this table: row totals = 93 and column totals = 93

TABLE 2.3-111
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS G AUG.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	0	0	0	0	0	0	0	0	0.0
135.00	0	0	0	0	0	0	0	0	0	0.0
157.50	0	0	0	0	0	0	0	0	0	0.0
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	0	0	0	0	0	0	0	0	0	0.0
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	3	0	1	0	0	0	0	4	6.7
292.50	0	1	0	0	2	3	0	0	6	20.1
315.00	0	0	0	1	2	0	1	0	4	24.0
337.50	0	0	0	0	0	0	0	0	0	0.0
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	0	4	0	2	4	3	1	0	14	17.4

Hours of Calm = 0
Sums of this table: row totals = 14 and column totals = 14

TABLE 2.3-112
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS A SEPT.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	0	0	0	0	0	0	0	0	0.0
135.00	0	0	0	0	0	0	0	0	0	0.0
157.50	0	0	0	0	0	0	0	0	0	0.0
180.00	0	1	0	0	0	0	0	0	1	4.4
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	1	0	0	0	0	0	0	0	1	2.4
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	0	2	0	0	0	0	0	0	2	6.5
315.00	0	0	0	0	0	3	0	0	3	28.7
337.50	0	0	0	0	0	0	0	0	0	0.0
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	1	3	0	0	0	3	0	0	7	15.1

Hours of Calm = 0
Sums of this table: row totals = 7 and column totals = 7

TABLE 2.3-113
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS B SEPT.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	0	0	0	0	0	0	0	0	0.0
135.00	0	0	0	0	0	0	0	0	0	0.0
157.50	0	0	0	0	0	0	0	0	0	0.0
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	0	0	0	0	0	0	0	0	0	0.0
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	0	1	0	0	0	0	0	0	1	3.8
315.00	1	0	0	0	0	0	0	0	1	2.9
337.50	0	0	0	0	0	0	0	0	0	0.0
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	1	1	0	0	0	0	0	0	2	3.3

Hours of Calm = 0
Sums of this table: row totals = 2 and column totals = 2

TABLE 2.3-114
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS C SEPT.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	0	0	0	0	0	0	0	0	0.0
135.00	0	0	0	0	0	0	0	0	0	0.0
157.50	0	1	0	0	0	0	0	0	1	7.0
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	0	0	0	0	0	0	0	0	0	0.0
247.50	2	0	0	0	0	0	0	0	2	2.2
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	1	2	2	0	0	0	0	0	5	6.1
315.00	0	0	1	0	0	0	0	0	1	11.2
337.50	0	0	0	1	0	0	0	0	1	16.0
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	3	3	3	1	0	0	0	0	10	6.9

Hours of Calm = 0
Sums of this table: row totals = 10 and column totals = 10

TABLE 2.3-115
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS D SEPT.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	4	2	0	0	0	0	0	0	6	3.5
45.00	1	2	0	0	0	0	0	0	3	3.2
67.50	0	2	0	0	0	0	0	0	2	3.5
90.00	1	2	0	0	0	0	0	0	3	3.6
112.50	5	21	4	1	0	0	0	0	31	5.2
135.00	9	54	9	1	0	0	0	0	73	5.4
157.50	3	15	4	0	0	0	0	0	22	5.0
180.00	3	14	0	0	0	0	0	0	17	3.5
202.50	7	3	0	0	0	0	0	0	10	2.8
225.00	6	1	0	0	0	0	0	0	7	2.9
247.50	1	5	1	0	0	0	0	0	7	4.8
270.00	3	7	1	0	0	0	0	0	11	4.1
292.50	3	30	23	13	3	0	0	0	72	8.9
315.00	4	24	42	40	24	6	0	0	140	12.6
337.50	1	15	5	2	0	0	0	0	23	6.3
360.00	4	4	0	0	0	0	0	0	8	3.5
Column Sums	55	201	89	57	27	6	0	0	435	8.0

Hours of Calm = 0
Sums of this table: row totals = 435 and column totals = 435

TABLE 2.3-116
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS E SEPT.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	7	13	1	0	0	0	0	0	21	3.9
45.00	6	9	1	0	0	0	0	0	16	4.0
67.50	5	6	1	1	0	0	0	0	13	5.0
90.00	8	3	0	0	0	0	0	0	11	2.9
112.50	7	15	1	0	0	0	0	0	23	4.2
135.00	8	20	10	0	0	0	0	0	38	5.2
157.50	4	11	5	0	0	0	0	0	20	5.5
180.00	1	3	0	0	0	0	0	0	4	3.7
202.50	3	4	0	1	0	0	0	0	8	4.3
225.00	9	1	0	0	0	0	0	0	10	2.6
247.50	2	3	0	1	1	0	0	0	7	8.0
270.00	6	2	0	1	0	0	0	0	9	4.5
292.50	4	27	17	10	2	1	0	0	61	8.6
315.00	4	36	46	52	56	27	0	0	221	15.0
337.50	3	25	10	7	1	1	0	0	47	7.8
360.00	2	12	1	0	0	0	0	0	15	4.4
Column Sums	79	190	93	73	60	29	0	0	524	9.7

Hours of Calm = 2
Sums of this table: row totals = 524 and column totals = 524

TABLE 2.3-117
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS F SEPT.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	4	2	0	0	0	0	0	0	6	3.3
45.00	3	3	0	0	0	0	0	0	6	3.5
67.50	2	0	0	0	0	0	0	0	2	1.5
90.00	4	1	0	0	0	0	0	0	5	2.6
112.50	2	5	0	0	0	0	0	0	7	4.1
135.00	2	3	1	0	0	0	0	0	6	5.3
157.50	1	9	0	0	0	0	0	0	10	5.3
180.00	1	5	0	0	0	0	0	0	6	4.3
202.50	2	0	0	0	0	0	0	0	2	1.7
225.00	2	1	0	0	0	0	0	0	3	3.3
247.50	1	2	0	0	0	0	0	0	3	4.0
270.00	1	0	1	0	0	0	0	0	2	5.2
292.50	2	7	1	1	3	0	0	0	14	9.7
315.00	2	14	40	1	28	38	0	0	153	17.2
337.50	1	5	6	1	1	0	0	0	14	9.2
360.00	3	5	0	0	0	0	0	0	8	4.2
Column Sums	33	62	49	33	32	8	0	0	247	12.8

Hours of Calm = 0
Sums of this table: row totals = 247 and column totals = 247

TABLE 2.3-118
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS G SEPT.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	1	1	0	0	0	0	0	0	2	4.4
45.00	2	1	0	0	0	0	0	0	3	4.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	2	1	0	0	0	0	0	0	3	2.9
135.00	1	6	0	0	0	0	0	0	7	4.0
157.50	0	1	0	0	0	0	0	0	1	3.1
180.00	1	0	0	0	0	0	0	0	1	1.8
202.50	1	0	0	0	0	0	0	0	1	2.5
225.00	1	0	0	0	0	0	0	0	1	1.8
247.50	1	1	0	0	0	0	0	0	2	4.0
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	0	1	2	1	1	3	0	0	8	17.8
315.00	1	4	7	9	4	10	1	0	36	17.8
337.50	1	0	0	0	1	0	0	0	2	11.0
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	12	16	9	10	6	13	1	0	67	13.1

Hours of Calm = 0
Sums of this table: row totals = 67 and column totals = 67

TABLE 2.3-119
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS A OCT.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	0	0	0	0	0	0	0	0	0.0
135.00	0	0	0	0	0	0	0	0	0	0.0
157.50	0	0	0	0	0	0	0	0	0	0.0
180.00	1	0	0	0	0	0	0	0	1	2.8
202.50	0	1	0	0	0	0	0	0	1	4.9
225.00	0	0	0	0	0	0	0	0	0	0.0
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	0	0	0	0	0	0	0	0	0	0.0
315.00	0	0	0	0	0	0	0	0	0	0.0
337.50	0	0	0	0	0	0	0	0	0	0.0
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	1	1	0	0	0	0	0	0	2	3.8

Hours of Calm = 0
Sums of this table: row totals = 2 and column totals = 2

TABLE 2.3-120
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS B OCT.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	5	1	0	0	0	0	6	10.2
90.00	0	0	1	0	0	0	0	0	1	8.2
112.50	1	0	0	0	0	0	0	0	1	3.0
135.00	2	0	0	0	0	0	0	0	2	3.0
157.50	0	0	0	0	0	0	0	0	0	0.0
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	0	0	0	0	0	0	0	0	0	0.0
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	1	0	0	0	0	0	1	9.3
292.50	0	0	1	2	0	0	0	0	3	13.8
315.00	0	2	2	1	0	0	0	0	5	8.6
337.50	0	0	0	0	0	0	0	0	0	0.0
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	3	2	10	4	0	0	0	0	19	9.1

Hours of Calm = 0
Sums of this table: row totals = 19 and column totals = 19

TABLE 2.3-121
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS C OCT.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	0	0	0	0	0	0	0	0	0.0
135.00	0	1	0	1	0	0	0	0	2	8.7
157.50	0	1	0	0	0	0	0	0	1	3.2
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	0	0	0	0	0	0	0	0	0	0.0
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	0	1	0	1	0	0	0	0	2	8.2
315.00	0	0	0	0	0	0	0	0	0	0.0
337.50	1	0	0	0	0	0	0	0	1	2.0
360.00	0	0	0	0	0	0	0	0	0	0.0
Column Sums	1	3	0	2	0	0	0	0	6	6.5

Hours of Calm = 0
Sums of this table: row totals = 6 and column totals = 6

TABLE 2.3-122
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS D OCT.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	3	0	0	0	0	0	0	3	4.4
45.00	2	6	1	0	0	0	0	0	9	4.5
67.50	0	3	0	0	0	0	0	0	3	3.5
90.00	4	4	4	0	0	0	0	0	12	5.7
112.50	5	17	12	2	0	0	0	0	36	6.7
135.00	4	25	21	5	0	0	0	0	55	7.1
157.50	2	18	1	0	0	0	0	0	21	4.7
180.00	3	7	0	0	0	0	0	0	10	3.4
202.50	2	6	1	0	0	0	0	0	9	4.8
225.00	4	2	0	2	0	0	0	0	8	5.0
247.50	0	1	0	0	0	0	0	0	1	3.3
270.00	8	10	0	0	0	0	0	0	18	3.5
292.50	5	25	23	6	0	1	0	0	60	7.9
315.00	3	22	29	31	4	18	1	0	108	13.8
337.50	1	11	9	2	0	0	0	0	23	7.7
360.00	0	3	1	0	0	0	0	0	4	5.4
Column Sums	43	163	102	48	4	19	1	0	380	8.4

Hours of Calm = 2
Sums of this table: row totals = 380 and column totals = 380

TABLE 2.3-123
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS E OCT.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	7	28	2	2	0	0	0	0	39	5.0
45.00	10	17	1	4	2	0	0	0	34	6.2
67.50	27	23	0	2	0	1	0	0	53	4.1
90.00	20	22	4	1	0	0	0	0	47	4.1
112.50	17	15	11	3	2	0	0	0	48	6.7
135.00	7	53	22	8	0	0	0	0	90	6.6
157.50	5	9	0	0	0	0	0	0	14	3.7
180.00	5	6	0	0	0	0	0	0	11	3.3
202.50	4	4	2	0	0	0	0	0	10	4.7
225.00	3	2	5	10	1	0	0	0	21	11.8
247.50	3	1	1	0	2	0	0	0	7	9.2
270.00	4	2	0	0	0	0	0	0	6	3.1
292.50	12	20	20	8	6	3	0	0	69	9.4
315.00	11	23	21	37	19	9	0	0	120	12.9
337.50	14	24	13	4	2	0	0	0	57	6.7
360.00	5	16	6	2	0	0	0	0	29	6.1
Column Sums	154	265	108	81	34	13	0	0	655	7.6

Hours of Calm = 3
Sums of this table: row totals = 655 and column totals = 655

TABLE 2.3-124
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS F OCT.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	4	4	2	0	0	0	0	0	10	4.9
45.00	3	1	1	0	0	0	0	0	5	4.4
67.50	5	5	0	0	1	0	0	0	11	5.1
90.00	4	1	0	1	0	0	0	0	6	5.2
112.50	5	12	1	0	0	0	0	0	18	4.3
135.00	3	10	5	1	0	0	0	0	19	6.2
157.50	3	1	0	0	0	0	0	0	4	2.4
180.00	2	0	0	0	0	0	0	0	2	2.1
202.50	0	1	0	0	0	0	0	0	1	4.0
225.00	0	2	1	5	3	0	0	0	11	13.5
247.50	0	1	0	1	1	0	0	0	3	12.4
270.00	3	0	1	0	0	0	0	0	4	4.1
292.50	3	5	0	4	2	3	0	0	27	11.2
315.00	10	11	14	15	15	7	0	0	72	12.8
337.50	3	10	7	7	0	0	0	0	27	8.7
360.00	3	4	4	0	0	0	0	0	11	6.3
Column Sums	51	68	46	34	22	10	0	0	231	9.1

Hours of Calm = 0
Sums of this table: row totals = 231 and column totals = 231

TABLE 2.3-125
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS G OCT.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	1	0	0	0	0	0	0	1	4.2
45.00	1	2	0	1	0	0	0	0	4	6.5
67.50	2	1	0	0	0	0	0	0	3	2.7
90.00	3	0	0	0	0	0	0	0	3	2.8
112.50	2	6	0	0	0	0	0	0	8	4.4
135.00	8	6	0	0	0	0	0	0	14	3.5
157.50	3	5	0	0	0	0	0	0	8	3.3
180.00	0	1	0	0	0	0	0	0	1	4.0
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	0	1	0	2	0	0	0	0	3	13.1
247.50	1	1	0	0	0	0	0	0	2	2.5
270.00	2	0	0	0	0	0	0	0	2	2.9
292.50	2	3	6	2	2	0	0	0	15	9.7
315.00	8	11	5	14	7	5	0	0	50	12.2
337.50	0	2	0	2	0	0	0	0	4	10.4
360.00	3	1	0	0	0	0	0	0	4	2.7
Column Sums	35	41	11	21	9	5	0	0	122	8.3

Hours of Calm = 0
Sums of this table: row totals = 122 and column totals = 122

TABLE 2.3-126
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS A NOV.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	1	2	0	0	0	0	0	3	6.9
45.00	0	0	1	0	0	0	0	0	1	7.9
67.50	0	2	0	1	0	0	0	0	3	8.0
90.00	0	0	4	1	0	0	0	0	5	11.2
112.50	0	2	2	4	5	1	0	0	14	15.4
135.00	1	1	1	7	1	0	0	0	11	13.5
157.50	0	2	0	1	0	0	0	0	3	9.3
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	0	1	0	0	0	0	0	0	1	3.6
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	1	0	0	0	0	0	1	10.1
292.50	0	0	0	0	0	0	0	0	0	0.0
315.00	0	2	2	8	3	5	0	0	20	18.4
337.50	1	2	9	11	11	7	0	0	41	16.4
360.00	1	4	7	2	0	0	0	0	14	8.5
Column Sums	3	17	29	35	20	13	0	0	117	14.3

Hours of Calm = 0
Sums of this table: row totals = 117 and column totals = 117

TABLE 2.3-127
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS B NOV.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	1	0	0	0	0	0	0	0	1	2.1
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	1	0	1	0	0	0	0	0	2	7.2
90.00	0	1	0	0	0	0	0	0	1	5.2
112.50	0	0	2	1	0	0	0	0	3	11.1
135.00	0	1	3	5	0	0	0	0	9	12.6
157.50	2	3	0	0	0	0	0	0	5	4.2
180.00	1	1	0	0	0	0	0	0	2	3.6
202.50	1	1	0	0	0	0	0	0	2	3.9
225.00	0	0	0	0	0	0	0	0	0	0.0
247.50	1	0	1	0	0	0	0	0	2	5.3
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	1	0	0	0	0	0	0	0	1	2.9
315.00	2	2	1	3	3	0	0	0	11	12.0
337.50	1	0	2	3	1	2	0	0	9	15.9
360.00	0	3	5	1	0	0	0	0	9	9.2
Column Sums	11	12	15	13	4	2	0	0	57	10.1

Hours of Calm = 0
Sums of this table: row totals = 57 and column totals = 57

TABLE 2.3-128
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS C NOV.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	1	1	2	0	0	0	0	0	4	7.0
45.00	1	1	3	0	0	0	0	0	5	6.7
67.50	1	0	1	0	0	0	0	0	2	4.9
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	2	0	0	1	1	0	0	4	15.2
135.00	1	6	5	10	0	0	0	0	22	10.6
157.50	2	5	2	0	1	0	0	0	10	7.1
180.00	1	1	0	0	1	0	0	0	3	8.4
202.50	1	1	0	0	0	0	0	0	2	3.4
225.00	0	1	0	0	0	0	0	0	1	4.4
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	1	3	0	0	0	0	0	0	4	3.5
315.00	0	3	3	2	1	0	0	0	9	11.6
337.50	0	1	4	10	4	4	0	0	23	17.8
360.00	0	0	1	1	0	0	0	0	2	12.2
Column Sums	9	25	21	23	8	5	0	0	91	11.3

Hours of Calm = 0
Sums of this table: row totals = 91 and column totals = 91

TABLE 2.3-129
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS D NOV.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	2	14	9	1	0	1	0	0	27	7.4
45.00	6	12	4	0	1	0	0	0	23	5.7
67.50	6	4	9	0	0	0	0	0	19	5.8
90.00	5	8	3	0	0	0	0	0	16	4.5
112.50	0	5	1	5	4	3	0	0	18	15.3
135.00	2	17	16	9	1	2	0	0	47	9.6
157.50	4	20	2	1	2	1	0	0	30	7.4
180.00	1	2	2	0	0	0	0	0	5	5.5
202.50	2	3	4	1	1	0	0	0	11	8.5
225.00	2	0	2	2	1	0	0	0	7	11.2
247.50	0	2	0	0	0	0	0	0	2	4.5
270.00	2	1	2	0	0	0	0	0	5	5.7
292.50	2	6	6	2	2	0	0	0	18	10.0
315.00	0	3	24	38	24	3	0	0	92	15.3
337.50	1	5	13	22	10	0	0	0	51	13.5
360.00	2	5	26	12	2	0	0	0	47	10.5
Column Sums	37	107	123	93	48	10	0	0	418	10.7

Hours of Calm = 0
Sums of this table: row totals = 418 and column totals = 418

TABLE 2.3-130
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS E NOV.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	12	20	9	1	0	0	0	0	42	5.4
45.00	22	33	10	1	0	0	0	0	66	4.6
67.50	20	14	5	7	0	0	0	0	46	5.7
90.00	17	13	2	1	0	0	0	0	33	4.1
112.50	9	18	0	2	1	1	0	0	31	6.1
135.00	5	28	5	3	0	0	0	0	41	6.1
157.50	3	14	1	2	0	0	0	0	20	5.4
180.00	1	2	0	0	0	0	0	0	3	3.6
202.50	2	0	0	0	0	0	0	0	2	2.5
225.00	1	4	1	1	1	1	0	0	9	10.4
247.50	1	2	1	0	0	0	0	0	4	5.0
270.00	1	3	2	0	0	0	0	0	6	6.6
292.50	5	12	3	3	5	0	0	0	28	9.2
315.00	1	21	24	28	16	7	0	0	97	13.3
337.50	3	19	13	18	7	1	0	0	61	11.0
360.00	7	23	14	6	3	0	0	0	53	7.6
Column Sums	110	226	90	73	33	10	0	0	542	7.9

Hours of Calm = 0
Sums of this table: row totals = 542 and column totals = 542

TABLE 2.3-131
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS F NOV.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	3	5	0	0	0	0	0	0	8	3.7
45.00	4	8	1	0	0	0	0	0	13	4.2
67.50	5	4	1	0	0	0	0	0	0	4.1
90.00	9	2	0	0	0	0	0	0	11	2.9
112.50	8	7	0	0	0	0	0	0	15	3.2
135.00	3	9	5	0	0	0	0	0	17	5.3
157.50	4	0	1	0	0	0	0	0	5	4.0
180.00	0	2	0	0	0	0	0	0	2	4.8
202.50	1	0	0	0	0	0	0	0	1	2.7
225.00	2	1	0	0	0	0	0	0	3	2.5
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	2	2	2	0	0	0	0	0	6	5.1
315.00	2	9	9	8	6	1	0	0	35	11.6
337.50	1	3	1	1	2	0	0	0	8	10.4
360.00	1	4	1	0	0	0	0	0	6	4.5
Column Sums	45	56	21	9	8	1	0	0	140	6.3

Hours of Calm = 0
Sums of this table: row totals = 140 and column totals = 140

TABLE 2.3-132
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS G NOV.

Mean Wind Direction	*Mean Wind Speed, mph*								*Row Sums*	*Row Avg.*
	1.5	*5.1*	*9.6*	*15.1*	*21.1*	*29.6*	*40.1*	*50.1*		
22.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
45.00	*1*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*2*	*2.8*
67.50	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*3.3*
90.00	*1*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*2*	*3.0*
112.50	*4*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*5*	*2.7*
135.00	*2*	*7*	*1*	*1*	*0*	*0*	*0*	*0*	*11*	*5.3*
157.50	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*4.1*
180.00	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*2.2*
202.50	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
225.00	*3*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*3*	*2.3*
247.50	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*4.7*
270.00	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*2.2*
292.50	*0*	*2*	*2*	*1*	*0*	*0*	*0*	*0*	*5*	*9.0*
315.00	*1*	*7*	*2*	*3*	*1*	*0*	*0*	*0*	*14*	*9.0*
337.50	*0*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*5.9*
360.00	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*
Column Sums	*14*	*23*	*5*	*5*	*1*	*0*	*0*	*0*	*48*	*5.9*

Hours of Calm = 0
Sums of this table: row totals = 48 and column totals = 48

TABLE 2.3-133
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS A DEC.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	2	0	0	0	0	0	2	8.7
45.00	0	1	0	0	0	0	0	0	1	6.8
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	1	0	0	0	0	0	1	9.5
112.50	0	0	0	1	0	1	0	0	2	20.3
135.00	0	0	2	0	0	0	0	0	2	10.7
157.50	1	0	0	0	0	0	0	0	1	3.0
180.00	0	1	0	1	0	0	0	0	2	8.2
202.50	0	0	0	1	0	0	0	0	1	12.7
225.00	0	0	0	1	0	0	0	0	1	12.1
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	0	1	0	0	0	0	1	15.1
292.50	0	1	0	0	0	2	0	0	3	18.6
315.00	0	0	0	0	0	2	0	0	2	29.4
337.50	0	2	0	1	0	0	0	0	3	9.0
360.00	0	0	2	0	0	0	0	0	2	8.3
Column Sums	1	5	7	6	0	5	0	0	24	13.1

Hours of Calm = 0
Sums of this table: row totals = 24 and column totals = 24

TABLE 2.3-134
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS B DEC.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	1	0	0	0	0	0	1	8.6
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	0	0	0	0	0	0	0	0	0.0
135.00	0	1	0	0	0	0	0	0	1	5.0
157.50	0	0	0	0	0	0	0	0	0	0.0
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	0	0	0	0	0	0	0	0	0	0.0
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	0	0	1	0	0	0	1	20.3
292.50	0	0	1	0	0	0	0	0	1	7.5
315.00	0	0	0	0	0	1	0	0	1	25.3
337.50	0	0	1	2	0	0	0	0	3	14.4
360.00	0	0	1	0	0	0	0	0	1	10.9
Column Sums	0	1	4	2	1	1	0	0	9	13.4

Hours of Calm = 0
Sums of this table: row totals = 9 and column totals = 9

TABLE 2.3-135

DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS C DEC.
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	0	0	0	0	0	0	0	0	0	0.0
90.00	0	0	1	0	0	0	0	0	1	7.5
112.50	0	0	0	0	0	0	0	0	0	0.0
135.00	0	0	1	1	0	0	0	0	2	11.5
157.50	0	0	0	0	0	0	0	0	0	0.0
180.00	0	0	0	0	1	0	0	0	1	19.3
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	0	0	0	0	0	0	0	0	0	0.0
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	0	0	1	0	0	0	0	0	1	10.8
315.00	1	0	0	0	0	0	0	0	1	2.0
337.50	0	0	4	3	0	0	0	0	7	12.6
360.00	0	2	2	0	0	0	0	0	4	6.4
Column Sums	1	2	9	4	1	0	0	0	17	10.4

Hours of Calm = 0
Sums of this table: row totals = 17 and column totals = 17

TABLE 2.3-136
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS D DEC.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	10	21	4	0	0	0	0	35	8.8
45.00	0	7	12	5	0	0	0	0	24	9.3
67.50	0	7	6	2	0	0	0	0	15	8.0
90.00	1	10	0	1	0	0	0	0	12	5.5
112.50	1	7	7	14	5	5	0	0	39	14.6
135.00	0	7	8	8	6	4	0	0	33	14.0
157.50	0	16	4	5	1	3	0	0	29	10.4
180.00	1	8	2	0	0	0	0	0	11	5.1
202.50	1	4	0	0	0	0	0	0	5	4.4
225.00	0	1	0	0	0	0	0	0	1	5.0
247.50	2	2	0	0	0	0	0	0	4	3.5
270.00	2	4	0	0	0	0	0	0	6	4.7
292.50	1	5	2	2	0	1	0	0	11	9.2
315.00	2	2	6	33	17	8	0	0	68	16.9
337.50	2	6	13	22	11	1	0	0	55	13.2
360.00	1	18	22	11	0	0	0	0	2	8.7
Column Sums	14	114	103	107	40	22	0	0	400	11.5

Hours of Calm = 0
Sums of this table: row totals = 400 and column totals = 400

TABLE 2.3-137
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS E DEC.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	6	50	17	9	1	0	0	0	83	6.7
45.00	10	49	21	2	0	0	0	0	82	5.8
67.50	22	22	19	11	2	0	0	0	76	6.8
90.00	19	25	6	2	1	0	0	0	53	4.8
112.50	15	30	9	6	8	4	0	0	72	8.7
135.00	4	30	21	2	0	5	0	0	62	8.6
157.50	6		2	0	0	1	0	0	23	5.9
180.00	4	9	2	0	0	0	0	0	15	4.4
202.50	2	3	0	0	0	0	0	0	75	3.3
225.00	3	5	0	0	1	0	0	0	9	5.5
247.50	0	3	0	0	0	0	0	0	3	4.9
270.00	1	6	1	0	0	0	0	0	8	4.8
292.50	3	10	3	7	3	2	0	0	28	11.0
315.00	4	24	26	33	31	1	0	0	119	13.1
337.50	4	36	36	33	3	0	1	0	113	10.0
360.00	9	39	29	12	0	0	0	0	89	7.3
Column Sums	112	355	192	117	50	13	1	0	840	8.3

Hours of Calm = 0
Sums of this table: row totals = 840 and column totals = 840

TABLE 2.3-138
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS F DEC.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	2	2	1	0	0	0	0	0	5	5.3
45.00	4	1	1	0	0	0	0	0	6	3.8
67.50	4	1	0	0	0	0	0	0	5	2.8
90.00	7	2	1	0	0	0	0	0	10	3.6
112.50	11	11	0	0	0	0	0	0	22	3.1
135.00	6	17	4	0	0	0	2	0	29	6.9
157.50	3	8	1	0	0	0	0	0	12	4.6
180.00	2	0	0	0	0	0	0	0	2	2.8
202.50	2	0	0	0	0	0	0	0	2	2.4
225.00	0	0	0	0	0	0	0	0	0	0.0
247.50	0	1	0	0	0	0	0	0	1	6.3
270.00	1	0	0	0	0	0	0	0	1	3.0
292.50	2	2	0	1	1	0	0	0	6	8.2
315.00	1	5	8	12	10	0	0	0	36	13.8
337.50	0	7	4	5	0	0	0	0	16	9.6
360.00	1	5	3	0	0	0	0	0	9	6.4
Column Sums	46	62	23	18	11	0	2	0	162	7.4

Hours of Calm = 0
Sums of this table: row totals = 162 and column totals = 162

TABLE 2.3-139
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE - MAY 1973 - APRIL 1975 WIND DATA 10M,
TEMP GRAD 76-10M STABILITY CLASS G DEC.

FREQUENCY TABLE

Mean Wind Direction	*Mean Wind Speed, mph* 1.5	5.1	9.6	15.1	21.1	29.6	40.1	50.1	*Row Sums*	*Row Avg.*
22.50	0	0	0	0	0	0	0	0	0	0.0
45.00	0	0	0	0	0	0	0	0	0	0.0
67.50	1	0	0	0	0	0	0	0	1	2.9
90.00	0	0	0	0	0	0	0	0	0	0.0
112.50	0	2	0	0	0	0	0	0	2	5.3
135.00	1	3	1	0	0	0	0	0	5	5.0
157.50	2	0	0	0	0	0	0	0	2	2.6
180.00	0	0	0	0	0	0	0	0	0	0.0
202.50	0	0	0	0	0	0	0	0	0	0.0
225.00	1	0	1	0	0	0	0	0	2	5.4
247.50	0	0	0	0	0	0	0	0	0	0.0
270.00	0	0	0	0	0	0	0	0	0	0.0
292.50	0	2	0	0	0	0	0	0	2	3.3
315.00	0	8	2	1	1	0	0	0	12	8.0
337.50	0	3	1	1	0	0	0	0	5	8.1
360.00	1	0	1	0	0	0	0	0	2	5.7
Column Sums	6	18	6	2	1	0	0	0	33	6.3

Hours of Calm = 0
Sums of this table: row totals = 33 and column totals = 33

TABLE 2.3-141
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
RANGES OF STABILITY CLASSIFICATION PARAMETERS
FOR EACH STABILITY CATEGORY AT DCPP SITE

Pasquil Stability Class[(a)]	σ_θ *Range, (deg)*	ΔT *Range, (°C/100m)*	R_i *Range* $g = \frac{\theta_{76m} - \theta_{10m}}{\theta \quad U^2}$
A	$\sigma_\theta \geq 22.5$	< -1.9	< -0.02
B	$22.5 > \sigma_\theta \geq 17.5$	-1.9 to -1.7	-0.02 to- .01
C	$17.5 > \sigma_\theta \geq 12.5$	-1.7 to -1.5	-0.01 to -.001
D	$12.5 > \sigma_\theta \geq 7.5$	-1.5 to -0.5	-0.001 to +0.005
E	$7.5 > \sigma_\theta \geq 3.8$	-0.5 to +1.5	+0.005 to +0.02
F	$3.8 > \sigma_\theta \geq 2.1$	+1.5 to +4.0	+0.02 to +0.07
G	$2.1 > \sigma_\theta$	≥ +4.0	≥ +0.07

(a) See Reference 17, Section 2.3.9.

TABLE 2.3-142
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
SUMMARY OF METEOROLOGICAL DATA
FOR DIFFUSION EXPERIMENTS AT DCPP SITE

Trial No.	*Date*	*Release Time (Local Time)*	*h (ft)*	*Wind Dir. (deg)*	*m (mph)*	*^{H} m (ft)*	*Δ T 250 30 (°F)*
			Trials with Northwesterly Flow				
1	*11-20-68*	*1552-1652*	*250*	*304*	*11*	*1000*	*11.7*
2	*11-21-68*	*1411-1510*	*250*	*313*	*15*	*800*	*3.1*
3	*11-22-68*	*1540-1632*	*250*	*303*	*20*	*400*	*5.9*
4	*11-24-68*	*1036-1135*	*250*	*310*	*19*	*2500*	*-2.0*
9	*03-04-69*	*1110-1210*	*250*	*294*	*16*	*800*	*-3.0*
10	*03-06-69*	*1220-1320*	*250*	*311*	*26*	*2400*	*-3.0*
11	*03-07-69*	*1100-1200*	*250*	*297*	*16*	*4600*	*-4.2*
12	*03-08-69*	*1418-1518*	*250*	*306*	*14*	*1400*	*-2.0*
15	*05-20-69*	*1100-1200*	*250*	*305*	*15*	*1000*	*-0.2*
16	*05-20-69*	*1445-1545*	*250*	*306*	*18*	*600*	*-0.6*
17	*05-21-69*	*1240-1340*	*250*	*308*	*24*	*800*	*+1.5*
18	*05-22-69*	*1230-1330*	*250*	*310*	*20*	*1000*	*+0.3*
20	*07-15-69*	*1412-1512*	*250*	*305*	*27*	*600*	*+4.5*
22	*07-16-69*	*1500-1600*	*250*	*304*	*16*	*500*	*+1.0*
24	*07-24-69*	*1238-1338*	*250*	*305*	*24*	*600*	*+1.7*
25	*07-25-69*	*1054-1155*	*250*	*306*	*20*	*1500*	*+0.1*
			Trials with Southeasterly Flow				
6	*01-12-69*	*0940-1040*	*250*	*133*	*15*	*2500*	*-1.3*
8	*02-22-69*	*1300-1400*	*250*	*168*	*9*	*2500*	*-2.7*
13	*04-02-69*	*0930-1030*	*250*	*146*	*10*	*1500*	*-0.4*
14	*04-02-69*	*1300-1400*	*250*	*148*	*9*	*2500*	*-2.2*
23	*07-17-69*	*0205-0305*	*250*	*131*	*8*	*500*	*+1.9*
30	*10-15-69*	*0742-0842*	*25*	*143*	*6*	*2500*	*+0.4*
			Trials with Light and Variable Winds[a]				
19	*07-15-69*	*0201-0301*	*250*				*-0.8*
21	*07-16-69*	*0433-0500*	*250*				*0.9*
26	*09-29-69*	*0037-0137*	*25*				*-1.1*
27	*09-30-69*	*0220-0322*	*25*				*+0.4*
28	*10-01-69*	*0250-0350*	*25*				*+0.3*

[a] *Wind speed of 2 mph was assumed.*

TABLE 2.3-144
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
DCPP SITE NIGHTTIME P-G STABILITY CATEGORIES BASED ON σ_θ

If the σ_θ Stability Class is:	*And if the 10m Wind Speed, u is:* m/s	mi/hr	*The Stability Class for the σ_z is:*
A	*u<2.9*	*u<6.4*	*F*
	2.9 ≤ u<3.6	*6.4 ≤ u<7.9*	*E*
	3.6 ≤ u	*7.9 ≤ u*	*D*
B	*u<2.4*	*u<5.3*	*F*
	2.4 ≤ u<3.0	*5.3 ≤ u<6.6*	*E*
	3.0<u	*6.6 ≤ u*	*D*
C	*u<2.4*	*u<5.3*	*E*
	2.4<u	*5.3<u*	*D*
D, E, F, or G	*wind speed not considered*		

TABLE 2.3-145
EXCLUSION AREA BOUNDARY AND LOW POPULATION ZONE
ATMOSPHERIC DISPERSION FACTORS

	χ/Q (sec/m^3)				
Receptor	0 - 2 hours	2 - 8 hours	8 - 24 hours	1 - 4 days	4 - 30 days
Unit 1 EAB	2.50E-04	-	-	-	-
Unit 2 EAB	2.17E-04	-	-	-	-
Unit 1/2 LPZ	2.00E-05	8.94E-06	6.14E-06	2.72E-06	8.48E-07

Notes:

1. An EAB χ/Q value of 2.5E-04 sec/m^3 is used for radiological dose calculations from all release points.

2. The 0.5% sector dependent □/Q values are presented in Table 2.3-145A, with the maximum value applicable to all sectors being presented above in Table 2.3-145 and used to establish dose consequences. The worst case downwind sector for the 0-2 hour period for all receptors is northwest. For Unit 1/2 LPZ the worst case sector for periods 2-8 hours and longer is southeast.

TABLE 2.3-145A
UNITS 1 & 2 - EAB/LPZ SECTOR DEPENDENT DISTANCES & ATMOSPHERIC DISPERSION FACTORS

Downwind Sector	Unit 1 EAB		Unit 2 EAB		Unit 1/2 LPZ*	
	0-2hr χ/Q (sec/m^3)	Distance (m)	0-2 hr χ/Q (sec/m^3)	Distance (m)	0-2 hr χ/Q (sec/m^3)	Annual Average χ/Q (sec/m^3)
S	7.77E-05	830	9.46E-05	730	4.73E-06	3.85E-08
SSW	8.39E-05	830	1.02E-04	730	4.99E-06	3.92E-08
SW	1.12E-04	780	1.22E-04	740	6.20E-06	4.69E-08
WSW	1.04E-04	780	1.04E-04	780	5.80E-06	3.66E-08
W	1.47E-04	750	1.38E-04	780	8.17E-06	4.43E-08
WNW	2.02E-04	750	1.89E-04	780	1.38E-05	7.81E-08
NW	2.50E-04	750	2.17E-04	830	2.00E-05	1.31E-07
NNW	2.17E-04	750	1.88E-04	830	1.49E-05	8.83E-08
N	1.46E-04	730	1.19E-04	830	7.19E-06	4.70E-08
NNE	1.16E-04	730	9.53E-05	830	4.76E-06	3.03E-08
NE	9.99E-05	740	8.51E-05	820	4.28E-06	2.60E-08
ENE	9.25E-05	740	7.88E-05	820	3.89E-06	2.50E-08
E	8.75E-05	890	9.00E-05	870	4.99E-06	3.35E-08
ESE	1.52E-04	890	1.56E-04	870	1.33E-05	1.02E-07
SE	1.92E-04	920	2.09E-04	850	1.89E-05	2.03E-07
SSE	1.12E-04	830	1.29E-04	730	6.75E-06	6.44E-08

* LPZ distance (all sectors) = 9650 m (6 miles)

TABLE 2.3-145B
EAB/ LPZ 5-PERCENT OVERALL SITE ATMOSPHERIC DISPERSION FACTORS

	χ/Q (sec/m^3)				
	0 - 2 hrs	2 - 8 hrs	8 - 24 hrs	1 - 4 days	4 - 30 days
Unit 1 EAB	1.89E-04	-	-	-	-
Unit 2 EAB	1.88E-04	-	-	-	-
Unit 1/Unit 2 LPZ	1.46E-05	7.20E-06	5.06E-06	2.35E-06	7.81E-07

TABLE 2.3-146
ON-SITE ATMOSPHERIC DISPERSION FACTOR EVALUATION
POST-ACCIDENT RELEASE POINT / RECEPTOR COMBINATIONS

Release Points	On-Site Receptors
1. Unit 1 Containment Building Edge	1. Unit 1 Control Room Normal Intake
2. Unit 2 Containment Building Edge	2. Unit 2 Control Room Normal Intake
3. Unit 1 Plant Vent	3. Unit 1 Control Room Emergency Intake
4. Unit 2 Plant Vent	4. Unit 2 Control Room Emergency Intake
5. Unit 1 Refueling Water Storage Tank (RWST) Vent[1]	5. Control Room Center (i.e., In-leakage)
6. Unit 2 RWST Vent[1]	6. TSC Normal Intake[2]
7. Unit 1 Containment Penetration (GE Area)	7. TSC Center[2](i.e., In-leakage)
8. Unit 2 Containment Penetration (GE Area)	
9. Unit 1 Containment Penetration (GW/FW Area)	
10. Unit 2 Containment Penetration (GW/FW Area)	
11. Unit 1 Fuel Handling Building	
12. Unit 2 Fuel Handling Building	
13. Unit 1 Equipment Hatch	
14. Unit 2 Equipment Hatch	
15. Unit 1 Main Steam Safety Valves (MSSVs)	
16. Unit 2 MSSVs	
17. Unit 1 10% Atmospheric Dump Valves	
18. Unit 1 10% Atmospheric Dump Valves	
19. Unit 1 Main Steam Line Break Location	
20. Unit 2 Main Steam Line Break Location	

Notes:

a. χ/Q values for RWST releases to the control room normal intakes are not needed for the dose calculations since the normal intakes are isolated prior to releases occurring from the RWST vent.

b. The Unit 1 & 2 MSL break locations are also used to represent the Unit 1 and Unit 2 MSSVs and 10% ADVs. This approach is acceptable since these release points are essentially co-located, but the MSLB location releases have the lowest elevation and is therefore the closest to the TSC.

TABLE 2.3-146A
ON-SITE ATMOSPHERIC DISPERSION FACTOR EVALUATION
POST-ACCIDENT RELEASE POINT & RECEPTOR LOCATION

ID[1] (See Figure 2.3-5)	Release/Receptor	Description
Note 2	Release Point	Unit 1 Containment Building (CB) edge
Note 2	Release Point	Unit 2 Containment Building (CB) edge
1	Release Point	U1 Plant Vent
2	Release Point	U2 Plant Vent
3	Receptor	U1 Control Room Normal Intake
4	Receptor	U2 Control Room Normal Intake
5	Receptor	U1 Control Room Emergency Intake
6	Receptor	U2 Control Room Emergency Intake
7	Release Point	U1 RWST Vent
8	Release Point	U2 RWST Vent
9	Receptor	Control Room Center (location assigned for unfiltered)
10	Release Point	Unit 1 Containment Penetration Area, GE
11	Release Point	Unit 2 Containment Penetration Area, GE
12	Release Point	Unit 1 Containment Penetration Area, FW/GW
13	Release Point	Unit 2 Containment Penetration Area, FW/GW
14	Release Point	U1 Fuel Handling Building
15	Release Point	U2 Fuel Handling Building
16	Release Point	U1 Equipment Hatch
17	Release Point	U2 Equipment Hatch
18	Release Point	U1 MSSV
19	Release Point	U2 MSSV
20	Release Point	U1 10% ADVs
21	Release Point	U2 10% ADVs
22	Release Point	U1 MSL Break location
23	Release Point	U2 MSL Break location
24	Receptor	TSC Normal Intake
25	Receptor	TSC Center (location assigned for unfiltered inleakage)

Note 1: Refer to Figure 2.3-5 for location of the above release points / receptors on the site layout and arrangement drawing.

Note 2: Though not depicted in Figure 2.3-5, atmospheric dispersion factors were also calculated from the closest edge of the containment building to the various receptors; this release point was treated as a diffuse source.

TABLE 2.3-147
DCPP UNIT 1 RADIOACTIVITY RELEASE POINTS CONTROL ROOMS (UNIT 1 AND UNIT 2)
ATMOSPHERIC DISPERSION FACTORS (SEC/M^3)

Release Point and Receptor	0-2 Hour	2-8 Hour	8-24 Hour	1-4 Day	4-30 Day
Unit 1 Containment Building Edge to Unit 1 Control Room (CR) Normal Intake	1.44E-03	7.03E-04	3.00E-04	3.06E-04	3.04E-04
Unit 1 Containment Building Edge to Unit 2 CR Normal Intake	6.41E-04	3.51E-04	1.49E-04	1.49E-04	1.36E-04
Unit 1 Containment Building Edge to Unit 1 CR Emergency Intake[4]	4.09E-04	2.31E-04	9.54E-05	8.61E-05	7.04E-05
Unit 1 Containment Building Edge to Unit 2 CR Emergency Intake[4]	1.57E-04	7.82E-05	2.57E-05	2.71E-05	2.32E-05
Unit 1 Containment Building Edge to CR Center	9.21E-04	4.38E-04	1.77E-04	1.80E-04	1.67E-04
Unit 1 Plant Vent to Unit 1 CR Normal Intake	1.67E-03	1.22E-03	4.93E-04	4.89E-04	4.36E-04
Unit 1 Plant Vent to Unit 2 CR Normal Intake	9.08E-04	6.53E-04	2.69E-04	2.62E-04	2.38E-04
Unit 1 Plant Vent to Unit 1 CR Emergency Intake[4]	5.56E-04	3.33E-04	1.29E-04	1.11E-04	8.34E-05
Unit 1 Plant Vent to Unit 2 CR Emergency Intake[4]	2.22E-04	1.47E-04	5.44E-05	5.52E-05	4.45E-05
Unit 1 Plant Vent to CR Center	1.25E-03	9.08E-04	3.61E-04	3.65E-04	3.17E-04
Unit 1 Containment Penetration (GE Area) to Unit 1 CR Normal Intake	6.59E-03	2.81E-03	1.16E-03	1.07E-03	8.31E-04
Unit 1 Containment Penetration (GE Area) to Unit 2 CR Normal Intake	2.07E-03	1.13E-03	3.73E-04	3.78E-04	3.05E-04
Unit 1 Containment Penetration (GE Area) to Unit 1 CR Emergency Intake[4]	3.67E-04	2.31E-04	9.02E-05	8.38E-05	6.42E-05
Unit 1 Containment Penetration (GE Area) to Unit 2 CR Emergency Intake[4]	2.39E-04	1.20E-04	4.27E-05	4.22E-05	3.39E-05
Unit 1 Containment Penetration (GE Area) to CR Center	3.01E-03	1.33E-03	5.43E-04	4.93E-04	4.01E-04
Unit 1 Containment Penetration (GW/FW Area) to Unit 1 CR Normal Intake	4.86E-03	3.43E-03	1.35E-03	1.37E-03	1.25E-03
Unit 1 Containment Penetration (GW/FW Area) to Unit 2 CR Normal Intake	1.35E-03	9.79E-04	3.86E-04	3.84E-04	3.46E-04
Unit 1 Containment Penetration (GW/FW Area) to Unit 1 CR Emergency Intake[4]	8.05E-04	5.32E-04	2.12E-04	1.86E-04	1.40E-04
Unit 1 Containment Penetration (GW/FW Area) to Unit 2 CR Emergency Intake[4]	2.40E-04	1.53E-04	4.83E-05	5.20E-05	4.41E-05
Unit 1 Containment Penetration (GW/FW Area) to CR Center	2.55E-03	1.80E-03	7.17E-04	7.13E-04	6.50E-04
Unit 1 RWST Vent to Unit 1 CR Emergency Intake[4,5]	3.24E-04	1.83E-04	6.94E-05	6.82E-05	5.57E-05
Unit 1 RWST Vent to Unit 2 CR Emergency Intake[4,5]	1.88E-04	9.18E-05	3.40E-05	3.28E-05	2.69E-05
Unit 1 RWST Vent to CR Center[5]	1.01E-03	4.26E-04	1.85E-04	1.62E-04	1.31E-04

TABLE 2.3-147 (Continued)
DCPP UNIT 1 RADIOACTIVITY RELEASE POINTS CONTROL ROOMS (UNIT 1 AND UNIT 2)
ATMOSPHERIC DISPERSION FACTORS (SEC/M^3)

Release Point and Receptor	0-2 Hour	2-8 Hour	8-24 Hour	1-4 Day	4-30 Day
Unit 1 MSSVs to Unit 1 CR Normal Intake [1, 2]	N/A	N/A	N/A	N/A	N/A 8.95E-
Unit 1 MSSVs to Unit 2 CR Normal Intake [3]	4.05E-03	2.65E-03	1.02E-03	1.02E-03	04
Unit 1 MSSVs to Unit 1 CR Emergency Intake [3, 4]	4.52E-04	2.86E-04	1.14E-04	1.01E-04	7.82E-05
Unit 1 MSSVs to Unit 2 CR Emergency Intake[3, 4]	2.75E-04	1.49E-04	4.79E-05	5.02E-05	4.14E-05
Unit 1 MSSVs to CR Center[3]	1.23E-02	7.28E-03	2.21E-03	2.43E-03	2.06E-03
Unit 1 10% ADVs to Unit 1 CR Normal Intake[1, 2]	N/A	N/A	N/A	N/A	N/A
Unit 1 10% ADVs to Unit 2 CR Normal Intake[3]	4.06E-03	2.66E-03	1.03E-03	1.02E-03	9.03E-04
Unit 1 10% ADVs to Unit 1 CR Emergency Intake[3, 4]	4.52E-04	2.86E-04	1.14E-04	1.01E-04	7.82E-05
Unit 1 10% ADVs to Unit 2 CR Emergency Intake[3, 4]	2.75E-04	1.50E-04	4.82E-05	5.03E-05	4.15E-05
Unit 1 10% ADVs to CR Center[3]	1.23E-02	7.34E-03	2.22E-03	2.45E-03	2.08E-03
Unit 1 MSL Break Location to Unit 1 CR Normal Intake[1]	N/A	N/A	N/A	N/A	N/A
Unit 1 MSL Break Location to Unit 2 CR Normal Intake	4.07E-03	2.86E-03	1.11E-03	1.10E-03	9.70E-04
Unit 1 MSL Break Location to Unit 1 CR Emergency Intake[4]	4.30E-04	2.89E-04	1.14E-04	1.00E-04	7.63E-05
Unit 1 MSL Break Location to Unit 2 CR Emergency Intake[4]	2.74E-04	1.54E-04	4.98E-05	5.12E-05	4.20E-05
Unit 1 MSL Break Location to CR Center	1.14E-02	7.05E-03	2.19E-03	2.37E-03	1.98E-03
Unit 1 FHB to Unit 1 CR Normal Intake	6.68E-03	-	-	-	-
Unit 1 FHB to Unit 2 CR Normal Intake	2.69E-03	-	-	-	-
Unit 1 FHB to Unit 1 CR Emergency Intake[4]	3.28E-04	-	-	-	-
Unit 1 FHB to Unit 2 CR Emergency Intake[4]	2.39E-04	-	-	-	-
Unit 1 FHB to CR Center	3.54E-03	-	-	-	-
Unit 1 Equipment Hatch to Unit 1 CR Normal Intake	2.43E-02	-	-	-	-
Unit 1 Equipment Hatch to Unit 2 CR Normal Intake	2.67E-03	-	-	-	-
Unit 1 Equipment Hatch to Unit 1 CR Emergency Intake[4]	4.32E-04	-	-	-	-
Unit 1 Equipment Hatch to Unit 2 CR Emergency Intake[4]	2.45E-04	-	-	-	-
Unit 1 Equipment Hatch to CR Center	5.06E-03	-	-	-	-

Notes (Refer to Section 2.3.5.2 for additional detail):

1. ARCON96 based χ/Qs are not applicable for these cases given that the horizontal distance from the source to the receptor is 1.5 meters (which is much less than the 10 meters required by ARCON96 methodology).

2. Due to the proximity of the release from the MSSVs/10% (ADVs, to the normal operation control room intake of the affected unit, and due to the high vertical velocity of the steam discharge from the MSSVs/10% ADVs, the resultant plume from the MSSVs/10% ADVs will not contaminate the control room normal intake of the affected unit.

3. For releases from the MSSVs and 10% ADVs (they are uncapped / vertically oriented, have a high vertical velocity discharge for the first 10.73 hours of the accident), a χ/Q reduction factor of 5 is applicable to the values listed above until t=10.73 hrs. Since χ/Q values are averaged over the identified period (i.e., 0-2 hours, 2-8 hours, 8-24 hours, etc.), and the vertical velocity has been estimated only up to 10.73 hours, application of the factor of 5 reduction is not appropriate for χ/Q values applicable to averaging periods beyond the 2-8 hours averaging period. For assessment of an environmental release between T= 8 to 10.73 hours, continued use of the 2-8 hour χ/Q with the factor of 5 reduction is acceptable and slightly conservative.

4. The more favorable χ/Q value presented above for the control room pressurization Intakes is further reduced by a factor of 4 to address the “dual intake” credit and the capability of initial selection of the cleaner intake and expectation that the operator will manually make the proper intake selection throughout the event.

5. χ/Q values for RWST releases to the control room normal intakes are not needed for the dose calculations since the normal intakes are isolated prior to releases occurring from the RWST vent.

TABLE 2.3-148
DCPP UNIT 2 RADIOACTIVITY RELEASE POINTS CONTROL ROOMS (UNIT 1 AND UNIT 2) ATMOSPHERIC DISPERSION FACTORS (SEC/M^3)

Release Point and Receptor	0-2 Hour	2-8 Hour	8-24 Hour	1-4 Day	4-30 Day
Unit 2 Containment Edge to Unit 2 CR Normal Intake	1.99E-03	9.59E-04	4.60E-04	4.04E-04	3.20E-04
Unit 2 Containment Edge to Unit 1 CR Normal Intake	6.89E-04	3.85E-04	1.66E-04	1.41E-04	1.08E-04
Unit 2 Containment Edge to Unit 1 CR Emergency Intake[4]	1.66E-04	1.05E-04	4.19E-05	3.73E-05	2.93E-05
Unit 2 Containment Edge to Unit 2 CR Emergency Intake[4]	3.78E-04	1.47E-04	5.99E-05	5.87E-05	4.90E-05
Unit 2 Containment Edge to CR Center	1.09E-03	5.49E-04	2.47E-04	2.12E-04	1.70E-04
Unit 2 Plant Vent to Unit 1 CR Normal Intake	1.49E-03	9.29E-04	3.80E-04	3.16E-04	2.21E-04
Unit 2 Plant Vent to Unit 1 CR Normal Intake	7.79E-04	4.80E-04	1.98E-04	1.65E-04	1.15E-04
Unit 2 Plant Vent to Unit 1 CR Emergency Intake[4]	2.02E-04	1.27E-04	5.11E-05	4.20E-05	3.15E-05
Unit 2 Plant Vent to Unit 2 CR Emergency Intake[4]	5.61E-04	2.91 E-04	1.16E-04	1.02E-04	8.03E-05
Unit 2 Plant Vent to CR Center	1.11E-03	6.96E-04	2.82E-04	2.35E-04	1.66E-04
Unit 2 Containment Penetration (GE Area) to Unit 2 CR Normal Intake	6.60E-03	3.01E-03	1.17E-03	1.20E-03	1.01E-03
Unit 2 Containment Penetration (GE Area) to Unit 1 CR Normal Intake	2.08E-03	1.38E-03	5.62E-04	4.76E-04	3.59E-04
Unit 2 Containment Penetration (GE Area) to Unit 1 CR Emergency Intake[4]	2.26E-04	1.57E-04	6.15E-05	5.47E-05	4.08E-05
Unit 2 Containment Penetration (GE Area) to Unit 2 CR Emergency Intake[4]	3.74E-04	1.67E-04	6.72E-05	6.14E-05	5.08E-05
Unit 2 Containment Penetration (GE Area) to CR Center	3.09E-03	1.83E-03	7.22E-04	6.74E-04	5.35E-04
Unit 2 Containment Penetration (GW/FW Area) to Unit 2 CR Normal Intake	3.45E-03	1.14E-03	4.70E-04	4.42E-04	2.93E-04
Unit 2 Containment Penetration (GW/FW Area) to Unit 1 CR Normal Intake	1.20E-03	6.21E-04	2.49E-04	2.09E-04	1.41E-04
Unit 2 Containment Penetration (GW/FW Area) to Unit 1 CR Emergency Intake[4]	2.26E-04	1.59E-04	6.50E-05	5.36E-05	3.96E-05
Unit 2 Containment Penetration (GW/FW Area) to Unit 2 CR Emergency Intake[4]	8.08E-04	4.07E-04	1.43E-04	1.42E-04	1.14E-04
Unit 2 Containment Penetration (GW/FW Area) to CR Center	2.19E-03	1.16E-03	4.56E-04	3.83E-04	2.58E-04
Unit 2 RWST Vent to Unit 1 CR Emergency Intake[4,5]	1.90E-04	1.29E-04	5.00E-05	4.57E-05	3.49E-05
Unit 2 RWST Vent to Unit 2 CR Emergency Intake[4,5]	3.17E-04	1.40E-04	5.64E-05	5.12E-05	4.16E-05
Unit 2 RWST Vent to CR Center[5]	1.05E-03	5.55E-04	2.12E-04	2.12E-04	1.72E-04

TABLE 2.3-148 (Continued)
DCPP UNIT 2 RADIOACTIVITY RELEASE POINTS CONTROL ROOMS (UNIT 1 AND UNIT 2)
ATMOSPHERIC DISPERSION FACTORS (SEC/M^3)

Release Point and Receptor	0-2 Hour	2-8 Hour	8-24 Hour	1-4 Day	4-30 Day
Unit 2 MSSVs to Unit 1 CR Normal Intake[3]	3.80E-03	2.36E-03	9.80E-04	8.00E-04	5.99E-04
Unit 2 MSSVs to Unit 2 CR Normal Intake[1,2]	N/A	N/A	N/A	N/A	N/A
Unit 2 MSSVs to Unit 1 CR Emergency Intake[3,4]	2.79E-04	1.87E-04	7.33E-05	6.50E-05	4.89E-05
Unit 2 MSSVs to Unit 2 CR Emergency Intake[3,4]	4.39E-04	2.14E-04	7.68E-05	7.54E-05	6.09E-05
Unit 2 MSSVs to CR Center[3]	1.19E-02	7.90E-03	3.22E-03	2.68E-03	2.05E-03
Unit 2 10% ADVs to Unit 1 CR Normal Intake[3]	3.82E-03	2.36E-03	9.86E-04	8.01E-04	6.01E-04
Unit 2 10% ADVs to Unit 2 CR Normal Intake[1,2]	N/A	N/A	N/A	N/A	N/A
Unit 2 10% ADVs to Unit 1 CR Emergency Intake[3,4]	2.77E-04	1.88E-04	7.35E-05	6.49E-05	4.89E-05
Unit 2 10% ADVs to Unit 2 CR Emergency Intake[3,4]	4.39E-04	2.14E-04	7.68E-05	7.54E-05	6.09E-05
Unit 2 10% ADVs to CR Center[3]	1.19E-02	7.94E-03	3.23E-03	2.70E-03	2.05E-03
Unit 2 MSL Break Location to Unit 1 CR Normal Intake	3.75E-03	2.37E-03	1.00E-03	7.93E-04	5.81E-04
Unit 2 MSL Break Location to Unit 2 CR Normal Intake[1]	N/A	N/A	N/A	N/A	N/A
Unit 2 MSL Break Location to Unit 1 CR Emergency Intake[4]	2.72E-04	1.88E-04	7.40E-05	6.42E-05	4.80E-05
Unit 2 MSL Break Location to Unit 2 CR Emergency Intake[4]	4.29E-04	2.19E-04	7.73E-05	7.57E-05	6.11E-05
Unit 2 MSL Break Location to CR Center	1.08E-02	7.22E-03	3.00E-03	2.44E-03	1.83E-03
Unit 2 FHB to Unit 1 CR Normal Intake	2.68E-03	-	-	-	-
Unit 2 FHB to Unit 2 CR Normal Intake	6.68E-03	-	-	-	-
Unit 2 FHB to Unit 1 CR Emergency Intake[4]	2.45E-04	-	-	-	-
Unit 2 FHB to Unit 2 CR Emergency Intake[4]	3.23E-04	-	-	-	-
Unit 2 FHB to CR Center	3.61E-03	-	-	-	-
Unit 2 Equipment Hatch to Unit 1 CR Normal Intake	2.47E-03	-	-	-	-
Unit 2 Equipment Hatch to Unit 2 CR Normal Intake	2.48E-02	-	-	-	-
Unit 2 Equipment Hatch to Unit 1 CR Emergency Intake[4]	2.46E-04	-	-	-	-
Unit 2 Equipment Hatch to Unit 2 CR Emergency Intake[4]	4.26E-04	-	-	-	-
Unit 2 Equipment Hatch to CR Center	5.09E-03	-	-	-	-

Notes (Refer to Section 2.3.5.2 for additional detail):

1 ARCON96 based χ/Qs are not applicable for these cases given that the horizontal distance from the source to the receptor is 1.5 meters (which is much less than the 10 meters required by ARCON96 methodology).

2 Due to the proximity of the release from the MSSVs/10% ADVs, to the normal operation control room intake of the affected unit, and due to the high vertical velocity of the steam discharge from the MSSVs/10% ADVs, the resultant plume from the MSSVs/10% ADVs will not contaminate the control room normal intake of the affected unit.

3 For releases from the MSSVs and 10% ADVs (they are uncapped / vertically oriented, have a high vertical velocity discharge for the first 10.73 hours of the accident), a χ/Q reduction factor of 5 is applicable to the values listed above until t=10.73 hours. Since χ/Q values are averaged over the identified period (i.e., 0-2 hours, 2-8 hours, 8-24 hours, etc.), and the vertical velocity has been estimated only up to 10.73 hours, application of the factor of 5 reduction is not appropriate for χ/Q values applicable to averaging periods beyond the 2-8 hours averaging period. For assessment of an environmental release between T= 8 to 10.73 hours, continued use of the 2-8 hour χ/Q with the factor of 5 reduction is acceptable and slightly conservative.

4. The more favorable χ/Q value presented above for the control room pressurization Intakes is further reduced by a factor of 4 to address the “dual intake” credit and the capability of initial selection of the cleaner intake and expectation that the operator will manually make the proper intake selection throughout the event.

5. χ/Q values for RWST releases to the control room normal intakes are not needed for the dose calculations since the normal intakes are isolated prior to releases occurring from the RWST vent.

TABLE 2.3-149
UNITS 1 AND 2 TECHNICAL SUPPORT CENTER INTAKE AND CENTER ATMOSPHERIC DISPERSION FACTORS (SEC/M^3)

Release Point and Receptor	0-2 Hour	2-8 Hour	8-24 Hour	1-4 Day	4-30 Day
UNIT 1					
Unit 1 Containment Building Edge to TSC Normal Intake	2.45E-04	1.16E-04	4.08E-05	4.17E-05	3.48E-05
Unit 1 Containment Building Edge to TSC Center	2.74E-04	1.31E-04	4.80E-05	4.70E-05	4.00E-05
Unit 1 Plant Vent to TSC Normal Intake	3.04E-04	1.76E-04	6.82E-05	6.21E-05	5.20E-05
Unit 1 Plant Vent to TSC Center	3.41E-04	1.94E-04	7.63E-05	6.61E-05	5.62E-05
Unit 1 RWST Vent to TSC Normal Intake	2.48E-04	1.15E-04	4.52E-05	4.11E-05	3.40E-05
Unit 1 RWST Vent to TSC Center	2.76E-04	1.23E-04	5.00E-05	4.53E-05	3.65E-05
Unit 1 Containment Penetration (GE Area) to TSC Normal Intake	3.51E-04	1.61E-04	6.43E-05	5.89E-05	4.83E-05
Unit 1 Containment Penetration (GE Area) to TSC Center	4.05E-04	1.80E-04	7.26E-05	6.60E-05	5.37E-05
Unit 1 Containment Penetration (GW/FW Area) to TSC Normal Intake	4.44E-04	2.48E-04	8.04E-05	8.31E-05	6.68E-05
Unit 1 Containment Penetration (GW/FW Area) to TSC Center	5.61E-04	2.93E-04	1.00E-04	9.86E-05	8.16E-05
Unit 1 MSL Break Location to TSC Normal Intake[1,2]	5.05E-04	2.34E-04	8.95E-05	8.50E-05	6.94E-05
Unit 1 MSL Break Location to TSC Center[1,2]	6.03E-04	2.70E-04	1.07E-04	1.00E-04	8.16E-05
Unit 1 FHB to TSC Normal Intake	3.77E-04	1.68E-04	6.74E-05	6.09E-05	5.06E-05
Unit 1 FHB to TSC Center	4.21E-04	1.87E-04	7.84E-05	6.91E-05	5.57E-05
Unit 1 EH to TSC Normal Intake	4.19E-04	1.93E-04	7.41E-05	7.03E-05	5.76E-05
Unit 1 EH to TSC Center	4.93E-04	2.16E-04	8.73E-05	8.03E-05	6.55E-05
UNIT 2					
Unit 2 Containment Building Edge to TSC Normal Intake	5.31E-04	1.97E-04	8.36E-05	8.25E-05	6.72E-05
Unit 2 Containment Building Edge to TSC Center	5.39E-04	2.01E-04	8.73E-05	8.78E-05	6.84E-05
Unit 2 Plant Vent to TSC Normal Intake	5.47E-04	2.27E-04	1.03E-04	8.46E-05	6.68E-05
Unit 2 Plant Vent to TSC Center	5.41E-04	2.09E-04	9.67E-05	7.95E-05	6.43E-05
Unit 2 RWST Vent to TSC Normal Intake	3.52E-04	1.46E-04	6.12E-05	5.66E-05	4.63E-05
Unit 2 RWST Vent to TSC Center	3.61E-04	1.48E-04	6.30E-05	5.80E-05	4.69E-05
Unit 2 Containment Penetration (GE Area) to TSC Normal Intake	5.22E-04	2.21E-04	9.14E-05	8.61E-05	6.71E-05
Unit 2 Containment Penetration (GE Area) to TSC Center	5.49E-04	2.24E-04	9.60E-05	8.85E-05	7.05E-05
Unit 2 Containment Penetration (GW/FW Area) to TSC Normal Intake	1.71E-03	7.07E-04	2.98E-04	2.76E-04	2.21E-04
Unit 2 Containment Penetration (GW/FW Area) to TSC Center	1.76E-03	7.16E-04	3.01E-04	2.84E-04	2.28E-04

TABLE 2.3-149 (Continued)
UNITS 1 AND 2 TECHNICAL SUPPORT CENTER INTAKE AND CENTER ATMOSPHERIC DISPERSION FACTORS (SEC/M^3)

Release Point and Receptor	0-2 Hour	2-8 Hour	8-24 Hour	1-4 Day	4-30 Day
Unit 2 MSL Break Location to TSC Normal Intake[1,2]	9.00E-04	4.17E-04	1.83E-04	1.52E-04	1.22E-04
Unit 2 MSL Break Location to TSC Center[1,2]	1.01E-03	4.62E-04	1.93E-04	1.71E-04	1.38E-04
Unit 2 FHB to TSC Normal Intake	4.88E-04	2.10E-04	8.65E-05	8.05E-05	6.24E-05
Unit 2 FHB to TSC Center	5.26E-04	2.19E-04	9.19E-05	8.55E-05	6.83E-05
Unit 2 EH to TSC Normal Intake	6.97E-04	2.92E-04	1.23E-04	1.14E-04	8.75E-05
Unit 2 EH to TSC Center	7.44E-04	3.03E-04	1.28E-04	1.19E-04	9.42E-05

Notes:

1. The MSL Break location release χ/Q values are used to conservatively represent releases from either the MSSVs, the 10% ADVs or the MSL Break location since these release points are essentially co-located, but the MSL Break location releases have the lowest elevation and is therefore the closest to the TSC.

2. When these χ/Q values are used for the MSSVs and 10% ADVs (which are uncapped / vertically oriented and have a high vertical velocity discharge for the first 10.73 hours of the accident), a χ/Q reduction factor of 5 is applicable to the values listed above until t=10.73 hrs. Since χ/Q values are averaged over the identified period (i.e., 0-2 hrs, 2-8 hrs, 8-24 hrs, etc), and the vertical velocity has been estimated only up to 10.73 hrs, application of the factor of 5 reduction is not appropriate for χ/Q values applicable to averaging periods beyond the 2-8 hrs averaging period. For assessment of an environmental release between T= 8 to 10.73 hrs, continued use of the 2-8 hr χ/Q (with the factor of 5 reduction) is acceptable and conservative.

TABLE 2.4-1

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PROBABLE MAXIMUM PRECIPITATION (PMP) AS A FUNCTION OF DURATION AT DCPP SITE AS DETERMINED FROM USWB HMR NO. 36

Duration, hours	*PMP, inches*
1	*4.3*
3	*7.1*
6	*9.1*
12	*12.0*
18	*14.8*
24	*16.6*

TABLE 2.5-1

LISTING OF EARTHQAKES WITHIN 75 MILES OF THE DIABLO CANYON POWER PLANT SITE
SELECTED EARTHQUAKES

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
-?/-?/1800	-?--?--?	34.50	119.67	D			F	SANTA BARBARA.
03/25/1806	08--?--?	34.50	119.67	D			F	VIII AT SANTA BARBARA.
12/21/1812	18--?--?	34.50	120.00	D			F	VIII AT SAN FERNANDO.
12/21/1812	19--?--?	34.50	120.00	D			F	IX AT SAN FERNANDO.
01/18/1815	-?--?--?	34.50	119.67	D			F	SANTA BARBARA; 5 SHOCKS.
01/30/1815	-?--?--?	34.50	119.67	D			F	SANTA BARBARA.
07/08/1815	-?--?--?	34.50	119.67	D			F	SANTA BARBARA; 6 SHOCKS ON THE EIGHTH AND NINTH.
-?/-?/1830	-?--?--?	35.25	120.67	D			F	VIII AT SAN LUIS OBISPO.
07/03/1841	-?--?--?	36.30	122.30		6.3			(CALTECH FILE)
06/13/1851	-?--?--?	35.25	120.67	D			F	V AT SAN LUIS OBISPO.
10/26/1852	-?--?--?	35.67	121.17	D			F	X AT SAN SIMEON; 11 SHOCKS.
12/17/1852	-?--?--?	35.25	120.67	D			F	IX AT SAN LUIS OBISPO; 2 SHOCKS.
01/10/1853	-?--?--?	35.25	120.67	D			F	DANA RANCHO.
01/29/1853	-?--?--?	34.50	119.67	D			F	SANTA BARBARA.
02/01/1853	21--?--?	35.67	121.17	D			F	VIII AT SAN SIMEON.
02/14/1853	-?--?--?	35.25	120.67	D			F	SAN LUIS OBISPO.
03/01/1853	-?--?--?	34.50	119.67	D			F	V AT SAN LUIS OBISPO.
04/20/1854	-?--?--?	34.50	119.67	D			F	SANTA BARBARA.
04/29/1854	-?--?--?	34.50	119.67	D			F	III AT SANTA BARBARA.
05/03/1854	13-10--?	34.50	119.67	D			F	SANTA BARBARA; 3 SEVERE SHOCKS.
05/13/1854	-?--?--?	34.50	119.67	D			F	SANTA BARBARA.
05/29/1854	-?--?--?	34.50	119.67	D			F	SANTA BARBARA.
05/31/1854	12-50--?	34.50	119.67	D			F	VI AT SANTA BARBARA; 3 SHOCKS.
01/14/1855	02-30--?	35.75	120.67	D			F	SAN BENITO AND SAN MIGUEL.
06/25/1855	22--?--?	34.50	119.67	D			F	V AT SANTA BARBARA.
01/08/1857	14--?--?	34.50	119.67	D			F	SANTA BARBARA.
01/08/1857	17--?--?	34.50	119.67	D			F	SANTA BARBARA.
01/08/1857	18--?--?	34.50	119.67	D			F	SANTA BARBARA.
01/09/1857	07-20--?	34.50	119.67	D			F	IX AT SANTA BARBARA.
01/21/1857	-?--?--?	36.50	121.08	D			F	III AT A POINT NORTHWEST OF SAN BENITO.
03/14/1857	23--?--?	34.50	119.67	D			F	V AT MONTECITO AND SANTA BARBARA.
09/02/1858	-?--?--?	34.50	119.67	D			F	V AT SANTA BARBARA.
04/03/1860	04--?--?	36.50	121.08	D			F	VI AT SAN JOSE.
04/17/1860	-?--?--?	34.50	119.67	D			F	SANTA BARBARA.
-?/-?/1862	-?--?--?	34.42	119.63	D			F	VIII AT GOLETA.
09/13/1869	-?--?--?	35.25	120.67	D			F	V AT SAN LUIS OBISPO.
09/14/1869	-?--?--?	35.25	120.67	D			F	SAN LUIS OBISPO.
12/15/1869	-?--?--?	35.25	120.67				F	V AT SAN LUIS OBISPO.
02/06/1872	-?--?--?	34.50	119.67	D			F	SANTA BARBARA; FIRST SINCE APRIL 1860.
11/07/1875	-?--?--?	36.50	121.08	D			F	V IN SAN BENITO COUNTY.
12/21/1875	-?--?--?	34.50	119.67	D			F	SANTA BARBARA.
05/10/1876	-?--?--?	34.50	119.67	D			F	SANTA BARBARA.
05/30/1877	-?--?--?	35.67	120.67	D			F	V AT PASO ROBLES.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
06/24/1877	07-30--?	34.50	119.67	D			F	SANTA BARBARA.
01/08/1878	-?--?--?	34.50	119.67	D			F	SANTA BARBARA.
11/13/1880	06-30--?	34.50	119.67	D			F	SANTA BARBARA.
02/02/1881	-?--?--?	36.37	121.67	D			F	III AT SALINAS.
08/31/1881	03--?--?	34.50	119.67	D			F	III AT SANTA BARBARA.
09/13/1883	22-30--?	34.50	119.67	D			F	IV AT SANTA BARBARA.
08/03/1884	-?--?--?	34.50	119.67	D			F	III AT SANTA BARBARA; NIGHT.
08/04/1884	09--?--?	34.50	119.67	D			F	III AT SANTA BARBARA; 3 SHOCKS.
03/31/1885	-?--?--?	36.30	121.00		7.0			(CALTECH FILE)
04/07/1885	10--?--?	34.50	119.67	D			F	SANTA BARBARA AND SAN BUENAVENTURA.
04/09/1885	-?--?--?	35.58	121.08	D			F	CAMBRIA.
04/12/1885	04-05--?	36.25	120.80	D			F	IX IN CENTRAL CALIFORNIA; FELT OVER AN AREA OF 125,000 SQ. MI.- EPICENTER PROBABLY EAST OF KING CITY.
04/12/1885	11--?--?	36.33	119.67	D			F	HANFORD.
07/09/1885	09-15--?	34.50	119.67	D			F	V AT SANTA BARBARA.
07/09/1885	16-15--?	34.50	119.67	D			F	V AT SANTA BARBARA; 5 EARTHQUAKES.
10/03/1888	20-52--?	35.75	120.67	D			F	III AT SAN MIGUEL.
10/03/1888	21-02--?	35.75	120.67	D			F	VI AT SAN MIGUEL.
10/04/1888	-?--?--?	35.67	120.67	D			F	PASO ROBLES.
05/01/1889	19-55--?	34.67	120.42	D			F	SUSANVILLE.
05/26/1889	15-13--?	36.50	121.42	D			F	GONZALES, SAN FRANCISCO, AND SANTA CRUZ; RECORDED AT MT. HAMILTON.
07/10/1889	-?--?--?	35.17	120.58	D			F	ARROYO GRANDE; SHOCKS FOR SEVERAL DAYS.
09/30/1889	20-17--?	36.50	119.58	D			F	KINGSBURG.
01/-?/1890	23-30--?	34.50	119.67	D			F	SANTA BARBARA.
11/13/1892	-?--?--?	36.30	122.00		6.0			(CALTECH FILE)
05/19/1893	-?-35--?	34.17	119.50	D			F	VII FELT FROM SAN DIEGO TO LOMPOC, INLAND TO SAN BERNADINO. MOST SEVERE SE OF VENTURA. POSSIBLY OF SUBMARINE ORIGIN OFF THE COAST OF VENTURA COUNTY
06/01/1893	12--?--?	34.50	119.67	D			F	VII AT NORDHOFF (OJAI), SANTA BARBARA, AND VENTURA.
06/01/1893	12--?--?	34.50	119.67	D			F	NORDHOFF, SANTA BARBARA, AND VENTURA.
06/01/1893	12-10--?	34.50	119.67	D			F	NORDHOFF, SANTA BARBARA, AND VENTURA.
12/06/1893	04-56--?	35.67	121.33	D			F	PIEDRAS BLANCAS LIGHTHOUSE.
07/27/1895	-?-10--?	34.50	119.67	D			F	SANTA BARBARA.
12/24/1895	05-30--?	34.50	119.67	D			F	SANTA BARBARA.
06/24/1897	14-10--?	34.50	119.67	D			F	SANTA BARBARA.
07/18/1897	-?--?--?	34.50	119.67	D			F	CASTLE PINCKNEY.
07/20/1897	07-45--?	34.50	119.67	D			F	SANTA BARBARA.
05/30/1898	03-03--?	34.50	119.67	D			F	SANTA BARBARA.
06/04/1898	06-20--?	34.67	120.08	D			F	LOS OLIVOS; FELT THROUGHOUT THE SANTA YNEZ VALLEY; AT SANTA BARBARA THE HEAVIEST FOR SOME YEARS.
02/08/1899	04-55--?	36.33	121.92	D			F	POINT SUR LIGHT STATION.
06/05/1899	-?--?--?	35.83	120.83	D			F	BRADLEY.
06/25/1899	-?--?--?	35.75	120.67	D			F	SAN MIGUEL.
06/09/1900	-?--?--?	36.00	120.92	D			F	SAN ARDO.
10/18/1900	-?--?--?	35.25	120.67	D			F	SAN LUIS OBISPO.
03/03/1901	-?--?--?	35.25	120.67	D			F	SAN LUIS OBISPO.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
03/03/1901	07-45--?	36.08	120.58	D			F	IX AT STONE CANYON - SURFACE CRACKS IN THE GROUND; ALSO FELT AT ADELAIDA, ESTRELLA, PARKFIELD, PASO ROBLES, PORTERVILLE, SAN JOSE, SAN LUIS OBISPO, AND SAN MIGUEL.
03/05/1901	-?--?--?	35.67	120.67	D			F	PASO ROBLES.
03/06/1901	-?--?--?	36.00	120.92	D			F	SAN ARDO AND SAN LUIS OBISPO.
06/03/1901	-?--?--?	35.25	120.67	D			F	SAN LUIS OBISPO.
07/30/1901	19--?--?	35.25	120.67	D			F	SAN LUIS OBISPO.
08/14/1901	11-11--?	35.42	120.92	D			F	CAYUCOS, HOLLISTER, SALINAS, SAN LUIS OBISPO, AND SANTA CRUZ.
02/07/1902	-?--?–?	34.50	119.67	D			F	SANTA BARBARA.
02/09/1902	15--?--?	34.50	119.67	D			F	PINE CREST, SAN LUIS OBISPO, SANTA BARBARA, AND VENTURA.
04/06/1902	-?--?--?	35.25	120.67	D			F	SAN LUIS OBISPO.
07/21/1902	-?--?--?	34.75	120.00	D			F	PINE CREST.
07/28/1902	06-57--?	34.75	120.25	D			F	IX AT LOMPOC AND LOS ALAMOS; CONFINED TO THE NORTHERN PART OF SANTA BARBARA COUNTY.
07/28/1902	13--8--?	35.25	120.67	D			F	SAN LUIS OBISPO; AFTERSHOCK OF 06-57-?.
07/31/1902	09-20--?	34.75	120.25	D			F	IX AT LOS ALAMOS AND SURROUNDING COUNTRY; FISSURES, CRACKS IN THE GROUND, AND LANDSLIDES.
08/01/1902	-?--?--?	34.75	120.25	D			F	LOS ALAMOS. SEVERAL SHOCKS.
08/01/1902	03-30--?	34.75	120.25	D			F	VIII AT LOS ALAMOS.
08/02/1902	-?--?–?	34.75	120.25	D			F	LOS ALAMOS.
08/03/1902	-?--?–?	34.75	120.25	D			F	LOS ALAMOS.
08/04/1902	10 -5--?	34.75	120.25	D			F	LOS ALAMOS.
08/04/1902	11-18--?	34.75	120.25	D			F	LOS ALAMOS.
08/04/1902	12-15--?	34.75	120.25	D			F	LOS ALAMOS.
08/04/1902	21-29--?	34.75	120.25	D			F	LOS ALAMOS.
08/04/1902	23-40--?	34.75	120.25	D			F	LOS ALAMOS.
08/05/1902	-?-55--?	34.75	120.25	D			F	LOS ALAMOS.
08/10/1902	-?--?--?	34.75	120.25	D			F	LOS ALAMOS; DISTINCT EARTHQUAKE DETONATION AND TREMOR.
08/10/1902	10-40--?	34.75	120.25	D			F	LOS ALAMOS; HEAVY DETONATION FOLLOWED BY TREMBLING.
08/10/1902	22-40--?	34.50	119.67	D			F	SANTA BARBARA.
08/14/1902	10-15--?	34.75	120.25	D			F	LOS ALAMOS.
08/14/1902	11-05--?	34.75	120.25	D			F	LOS ALAMOS.
08/14/1902	11-20--?	34.75	120.25	D			F	LOS ALAMOS; SHOOK GROUND VIOLENTLY.
08/14/1902	21-50--?	34.75	120.25	D			F	LOS ALAMOS.
08/14/1902	23-50--?	34.75	120.25	D			F	LOS ALAMOS.
08/28/1902	-?--?–?	35.25	120.67	D			F	SAN LUIS OBISPO.
08/31/1902	-?--?–?	35.25	120.67	D			F	SAN LUIS OBISPO.
09/11/1902	05-30--?	34.25	120.25	D			F	V AT LOS ALAMOS.
10/21/1902	21-45--?	34.75	120.25	D			F	LOMPOC AND LOS ALAMOS.
10/21/1902	22-15--?	34.75	120.25	D			F	LOMPOC AND LOS ALAMOS.
10/22/1902	10--?--?	34.75	120.25	D			F	LOS ALAMOS.
12/12/1902	-?--?–?	34.75	120.25	D			F	VIII AT LOS ALAMOS -3 SHOCKS IN 5 MINUTES; FELT THROUGHOUT THE NORTHERN PART OF SANTA BARBARA COUNTY, ESPECIALLY AT LOMPOC, LOS ALAMOS, SAN LUIS OBISPO, SANTA BARBARA, AND SANTA MARIA.
01/11/1903	-?--?–?	35.25	120.67	D			F	SAN LUIS OBISPO.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
03/07/1903	-?--?--?	36.50	121.42	D			F	GONZALES.
03/24/1903	-?--?--?	36.50	121.42	D			F	GONZALES AND SANTA MARGARITA.
04/24/1903	-?--?--?	35.42	120.58	D			F	SANTA MARGARITA.
07/29/1903	07-13--?	35.67	121.33	D			F	V AT POINT PIEDRAS BLANCAS LIGHTHOUSE.
07/29/1903	10-30--?	35.67	121.33	D			F	POINT PIEDRAS BLANCAS LIGHTHOUSE.
08/24/1903	-?--?--?	34.67	120.08	D			F	LOS OLIVOS.
01/22/1904	-?--?--?	34.75	120.25	D			F	LOS ALAMOS.
01/23/1904	-?--?--?	34.75	120.25	D			F	LOS ALAMOS.
09/10/1904	-?--?--?	35.25	120.67	D			F	SAN LUIS OBISPO.
05/26/1905	05-49--?	35.25	120.67	D			F	LOS GATOS, SALINAS, SAN FRANCISCO, SAN LUIS OBISPO, SANTA CRUZ AND SOLEDAD.
07/06/1906	-?--?--?	35.25	120.67	D			F	SAN LUIS OBISPO.
07/22/1906	-?--?–?	35.25	120.67	D			F	SAN LUIS OBISPO.
08/01/1906	-?--?–?	35.25	120.67	D			F	SAN LUIS OBISPO.
12/07/1906	06-40--?	35.67	121.33	D			F	VII AT SAN LUIS OBISPO AND SANTA MARIA; DURATION 30 SECONDS, FOLLOWED BY SECOND SHOCK HALF AN HOUR LATER.
+12/08/1906	06-55--?	35.75	120.67	D			F	SAN MIGUEL.
06/19/1907	12--?--?	36.17	120.67	D			F	PRIEST VALLEY.
07/02/1907	18-10--?	35.25	120.67	D			F	SAN LUIS OBISPO.
07/21/1907	-?--?–?	35.25	120.67	D			F	SAN LUIS OBISPO.
07/29/1907	05-10--?	34.75	120.00	D			F	PINE CREST.
08/-?/1907	-?--?--?	34.75	120.00	D			F	PINE CREST AND SANTA BARBARA.
12/27/1907	09-15--?	34.50	119.67	D			F	SANTA BARBARA; ALSO FELT AT VENTURA; REPORTED FROM OJAI AND PINE CREST.
04/27/1908	10-50--?	36.00	121.17	D			F	JOLON, PASO ROBLES, PRIEST VALLEY, SAN LUIS OBISPO, SANTA MARGARETA, AND SAN MIGUEL.
05/19/1908	-?--?--?	35.25	120.67	D			F	SAN LUIS OBISPO.
09/16/1908	-?--?--?	36.17	120.67	D			F	PRIEST VALLEY.
11/-?/1908	19-30--?	36.17	120.67	D			F	PRIEST VALLEY.
01/23/1909	14-58--?	34.50	119.67	D			F	PINE CREST AND SANTA BARBARA.
04/10/1909	-?--?–?	34.50	119.67	D			F	MONO RANCH AND SANTA PAULA CANYON.
06/17/1909	08-20--?	36.42	121.33	D			F	SOLEDAD.
07/03/1909	07--?--?	34.50	119.67	D			F	MONTECITO AND SANTA BARBARA.
07/05/1909	06-10--?	34.50	119.67	D			F	III AT SANTA BARBARA.
07/16/1909	10-28--?	34.50	119.67	D			F	IV AT LOS ANGELES AND SANTA BARBARA.
07/31/1909	19-37--?	34.50	119.67	D			F	IV AT OJAI AND SANTA BARBARA.
08/18/1909	-?--?--?	35.25	120.67	D			F	SAN LUIS OBISPO.
11/24/1909	15--?--?	36.00	121.17	D			F	JOLON.
03/08/1910	09-30--?	36.17	120.67	D			F	PRIEST VALLEY.
04/30/1910	18-25--?	36.17	120.67	D			F	PRIEST VALLEY; 3 SHOCKS, THE SECOND ONE QUITE VIOLENT.
11/-?/1910	-?--?--?	34.50	119.67	D			F	SANTA BARBARA; 2 SLIGHT QUAKES DURING NOVEMBER.
02/02/1911	-?--?--?	34.75	120.25	D			F	LOS ALAMOS.
03/22/1911	10-55--?	35.75	120.67	D			F	SAN MIGUEL; QUITE SEVERE.
06/02/1911	-?--?--?	36.17	120.67	D			F	PRIEST VALLEY.
06/18/1912	22-27--?	36.00	121.17	D			F	JOLON. (RECORDED AT BERKELEY.)
10/20/1913	11-25--?	35.25	120.67	D			F	BETTERAVIA, PASO ROBLES, SAN LUIS OBISPO,AND SANTA MARIA.
11/27/1913	19--?--?	34.50	119.67	D			F	MONO RANCH.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
12/26/1913	12--?--?	36.17	121.00	D			F	SAN LUCAS.
11/24/1914	04-25--?	35.25	120.67	D			F	II AT SAN LUIS OBISPO; ABRUPT TREMBLING, LASTING 20 SECONDS.
01/12/1915	-?--?--?	34.92	120.50	D			F	BETTERAVIA.
01/12/1915	04-31--?	34.75	120.25	B			F	VIII AT LOS ALAMOS - EPICENTER 2 OR 3 MI. EAST OF LOS ALAMOS; FELT FROM SAN JOSE TO LOS ANGELES; SHAKEN AREA IN EXCESS OF 50,000 SQ. MI. - PRACTICALLY EVERY CHIMNEY DAMAGED AT LOS ALAMOS, VII AT LOMPOC, VI-VII AT SANTA MARIA, V AT SAN LUIS OBISPO AND SANTA BARBARA, IV AT PASO ROBLES, AND II AT LOS ANGELES, WEATHER BUREAU REPORTED V-VI AT SANTA BARBARA, V AT OZENA AND SAN LUIS OBISPO, IV AT PASO ROBLES, III AT OJAI, AND II IN PRIEST VALLEY; ALSO II AT BAKERSFIELD.
01/14/1915	-?--?--?	34.92	120.50	D			F	BETTERAVIA.
01/15/1915	-?--?--?	34.75	120.25	D			F	LOS ALAMOS.
01/20/1915	-?--?--?	34.75	120.25	D			F	LOS ALAMOS.
01/26/1915	-?--?--?	34.75	120.25	D			F	LOS ALAMOS.
01/27/1915	-?--?--?	34.75	120.25	D			F	LOS ALAMOS.
04/21/1915	09-58--?	35.25	120.67	D			F	IV AT SAN LUIS OBISPO; ALSO FELT 3 MI. NW OF PRIEST VALLEY.
08/23/1915	23-15--?	34.75	119.75	D			F	HILL CAMP.
08/31/1915	21--?--?	34.75	119.75	D			F	HILL CAMP.
09/08/1915	12-45--?	35.67	120.67	D			F	V IN REGION EAST OF PASO ROBLES; ANTELOPE - 2 SHOCKS, FIRST THE HEAVIER, OIL CAME UP WITH WATER IN WELL AFTER SHOCK. AT SHANDON A SEATED MAN WAS SHAKEN SO HARD HE THOUGHT A PERSON WAS SHAKING HIM. AT CRESTON THE SHOCK WAS SHORT AND SHARP. A SLIGHT LANDSLIDE AT PORT SAN LUIS. WEATHER BUREAU REPORTS -PASO ROBLES V AND SAN LUIS OBISPO III-IV.
09/14/1915	-?--?–?	34.75	119.75	D			F	HILL CAMP; 3 HARD SHOCKS - EARTH TREMBLED FOR 15 MINUTES AFTERWARDS.
02/27/1916	13-26--?	34.75	120.25	D			F	LOS ALAMOS.
03/01/1916	19-15--?	34.75	120.25	D			F	LOS ALAMOS.
05/06/1916	03-45--?	34.75	120.25	D			F	III AT LOS ALAMOS. FELT BY MANY AT EL ROBLAR RANCH, 2 MI. SE OF LOS ALAMOS.
08/06/1916	-?--?--?	36.00	121.00		7.0			(CALTECH FILE)
10/24/1916	13-03--?	35.25	120.67	D			F	II AT SAN LUIS OBISPO; PROBABLY NEXT SHOCK, WITH TIME ERROR.
10/24/1916	13-30--?	36.00	121.17	D			F	V AT JOLON; III AT A POINT 3.5 MI. NW OF PRIEST VALLEY.
12/01/1916	22-53--?	35.17	120.75	D			F	VII AT AVILA - CONSIDERABLE GLASS BROKEN AND GOODS IN STORES THROWN FROM SHELVES. FELT AT SAN LUIS OBISPO; WATER IN BAY DISTURBED, PLASTER IN COTTAGES JARRED LOOSE, SMOKESTACKS OF UNION OIL CO. REFINERY TOPPLED OVER. SEVERE AT PORT SAN LUIS; III AT SANTA MARIA.
02/01/1917	05-18--?	34.92	120.42	D			F	III AT SANTA MARIA.
04/05/1917	19--?--?	34.67	120.33	D			F	IV AT SANTA RITA; ALSO FELT AT LOMPOC.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
04/13/1917	03-59--?	34.25	119.67	D			F	VI AT SANTA BARBARA CHANNEL REGION; FELT OVER AN AREA OF COAST SOUTH AND EAST OF SANTA BARBARA AS FAR AS VENTURA, AND ON SANTA CRUZ ISLAND.
04/21/1917	06-59--?	34.25	119.67	D			F	V AT SANTA BARBARA CHANNEL; PERCEPTIBLE OVER AN AREA OF PERHAPS 4000 SQ. MI.
07/07/1917	20-57--?	35.25	120.50	D			F	LOPEZ CANYON; ALSO AT SAN LUIS OBISPO.
07/07/1917	21-02--?	35.25	120.50	D			F	LOPEZ CANYON.
07/07/1917	21-15--?	35.25	120.50	D			F	LOPEZ CANYON.
07/08/1917	03-20--?	34.92	120.42	D			F	II AT SANTA MARIA.
07/08/1917	11-29--?	35.25	120.50	D			F	IV IN LOPEZ CANYON.
07/09/1917	22-22--?	35.25	120.50	D			F	VII IN LOPEZ CANYON; IV AT SAN LUIS OBISPO.
07/09/1917	22-38--?	35.25	120.50	D			F	LOPEZ CANYON.
07/10/1917	-?-43--?	35.25	120.50	D			F	LOPEZ CANYON.
07/10/1917	-?-45--?	35.25	120.50	D			F	LOPEZ CANYON.
07/26/1917	08-31--?	34.92	120.42	D			F	V AT SANTA MARIA - FURNITURE MOVED. IV AT LOS OLIVOS - AWAKENED SLEEPERS AT SAN LUIS OBISPO
12/05/1918	02-38--?	35.67	120.67	D			F	IV AT PASO ROBLES; II AT SAN LUIS OBISPO.
12/05/1918	04-30--?	35.25	120.67	D			F	SAN LUIS OBISPO.
03/01/1919	04-19--?	36.17	120.67	D			F	IV IN PRIEST VALLEY.
03/15/1919	07-53--?	35.25	120.67	D			F	SAN LUIS OBISPO.
07/31/1919	21-31--?	36.33	120.67	D			F	V IN SAN BENITO COUNTY; FELT AT IDRIA - ORIGIN SOME DISTANCE FROM IDRIA
08/26/1919	12-12--?	34.50	119.67	D			F	V IN SANTA BARBARA COUNTY - FELT AT OJAI, SAN LUIS OBISPO (3 SHOCKS), SANTA BARBARA.
08/26/1919	14.57--?	34.50	119.67	D			F	V IN SANTA BARBARA COUNTY - THIS SHOCK STRONGER AT SANTA BARBARA THAN PREVIOUS SHOCK. BUILDINGS AND WHARVES SWAYED; FELT AT OJAI.
12/18/1919	07-15--?	35.67	120.67	D			F	PASO ROBLES.
01/30/1920	23-30--?	34.50	119.67	D			F	III AT SANTA BARBARA.
01/30/1920	23-33--?	34.50	119.67	D			F	II AT SANTA BARBARA.
01/30/1920	23-35--?	34.50	119.67	D			F	II AT SANTA BARBARA.
01/30/1920	23-38--?	34.50	119.67	D			F	II AT SANTA BARBARA.
01/31/1920	01--?--?	34.50	119.67	D			F	III AT SANTA BARBARA.
01/31/1920	01-03--?	34.50	119.67	D			F	III AT SANTA BARBARA.
01/31/1920	01-07--?	34.50	119.67	D			F	III AT SANTA BARBARA.
03/20/1920	07-04--?	35.25	120.67	D			F	II AT SAN LUIS OBISPO.
05/07/1920	01-59--?	35.25	120.67	D			F	IV AT SAN LUIS OBISPO.
06/28/1920	09-01--?	35.25	120.67	D			F	V AT SAN LUIS OBISPO.
12/01/1920	01-30--?	35.17	119.50	D			F	VI AT TAFT - MANY PEOPLE MADE "SEASICK", DISHES SHAKEN FROM SHELVES, IV AT MARICOPA.
12/05/1920	11-58--?	34.50	119.67	D			F	V IN SANTA BARBARA COUNTY MOUNTAINS, V AT LOMPOC, LOS ALAMOS, MARICOPA, OJAI, AND SANTA BARBARA.
12/06/1920	-?--?--?	35.25	120.67	D			F	SAN LUIS OBISPO.
03/10/1922	11-21-20	35.75	120.25	C	6.5	43	F	IX IN CHOLAME VALLEY REGION OF SAN ANDREAS FAULT. FELT OVER AN AREA OF 100,000 SQ. MI. - CRACKS IN THE GROUND AND NEW SPRINGS. VII-VIII AT PARKFIELD AND SHANDON. VI-VII AT SAN LUIS OBISPO AND SIMMLER, AND V AT LOS ANGELES.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
03/16/1922	23-10--?	35.75	120.33	D			F	VI IN CHOLAME VALLEY - RATHER STRONG AFTERSHOCKS, V AT PASO ROBLES AND SAN LUIS OBISPO, AND IV AT ANTELOPE VALLEY; ALSO IV AT SHANDON.
03/19/1922	11--?--?	35.67	120.67	D			F	III AT PASO ROBLES.
03/23/1922	10--?--?	35.67	120.67	D			F	III AT PASO ROBLES.
03/25/1922	12--?--?	35.67	120.67	D			F	III AT PASO ROBLES.
05/31/1922	01-25--?	35.67	120.67	D			F	III AT PASO ROBLES; 2 SHOCKS.
07/05/1922	19--?--?	34.75	120.25	D			F	LOS ALAMOS.
07/09/1922	12--?--?	34.75	120.25	D			F	LOS ALAMOS.
07/11/1922	03--?--?	34.75	120.25	D			F	LOS ALAMOS.
07/11/1922	15-30--?	34.75	120.25	D			F	LOS ALAMOS.
08/18/1922	05-12--?	35.75	120.33	D			F	VII IN CHOLAME VALLEY; V AT PASO ROBLES AND SAN LUIS OBISPO.
08/20/1922	21-14--?	35.50	120.67	D			F	III AT ATASCADERO.
09/04/1922	10-15--?	35.67	120.67	D			F	IV AT PASO ROBLES.
09/05/1922	09-05--?	35.25	120.67	D			F	V AT SAN LUIS OBISPO; 2 SHOCKS.
12/29/1922	11--?--?	35.67	120.67	D			F	III AT PASO ROBLES.
12/29/1922	12--?--?	35.67	120.67	D			F	III AT PASO ROBLES.
03/12/1923	06--?--?	34.75	120.25	D			F	LOS ALAMOS.
05/04/1923	22-45--?	35.25	120.67	D			F	V AT SAN LUIS OBISPO; 2 SHOCKS, SECOND EQUALED INTENSITY II.
05/08/1923	05-02--?	35.75	120.33	D			F	II AT CHOLAME.
06/16/1923	20-40--?	35.67	120.67	D			F	IV AT PASO ROBLES - DURATION 15-20 SECONDS.
06/25/1923	13-21--?	35.25	120.67	D			F	II AT SAN LUIS OBISPO.
12/19/1923	07-35--?	34.92	120.42	D			F	II AT SANTA MARIA - DURATION 20 SECONDS.
07/02/1924	58-02--?	34.50	119.67	D			F	SANTA BARBARA.
12/30/1924	12-17--?	34.50	119.67	D			F	SANTA BARBARA.
12/30/1924	14-15--?	34.50	119.67	D			F	SANTA BARBARA.
06/29/1925	14-42-16	34.30	119.80	B	6.3	1	F	IX AT SANTA BARBARA; FELT OVER AN AREA OF 100,000 SQ. MI. - RECORDED WORLD-WIDE. RUPTURE AT DEPTH ON THE MESA AND RECORDED WORLD-WIDE. RUPTURE AT DEPTH ON THE MESA AND SANTA YNEZ FAULTS (BAILEY WILLIS); A FEW DEATHS, SEVERAL MILLION DOLLARS DAMAGE; IX AT GOLETA, NAPLES, AND SANTA BARBARA; VIII AT GAVIOTA, MIRAMAR, AND SANTA YNEZ, LOS ALAMOS, LOS OLIVOS; VII AT ARROYO GRANDE, NIPOMO, ORCOTT, ALAMOS, LOS OLIVOS; VII AT ARROYO GRANDE, NIPOMO, ORCOTT, ALAMOS, LOS OLIVOS; VII AT ARROYO GRANDE, NIPOMO, ORCOTT, PISMO BEACH, SANTA MARIA, AND VENTURA, AND VI AT AVILA, LOMPOC, AND PORT SAN LUIS.
06/29/1925	15-20--?	35.25	120.67	D			F	III AT SAN LUIS OBISPO.
06/29/1925	16-35--?	34.50	119.67	D			F	SANTA BARBARA; II AT OXNARD.
06/29/1925	18-54--?	34.50	119.67	D			F	IV AT SANTA BARBARA; II AT OXNARD - STRONGEST AFTERSHOCK OF THE DAY.
06/30/1925	01-37--?	34.50	119.67	D			F	SANTA BARBARA.
06/30/1925	02-47--?	34.50	119.67	D			F	SANTA BARBARA.
06/30/1925	09-19--?	34.50	119.67	D			F	SANTA BARBARA - VIOLENT; FELT AT OJAI AND OXNARD.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
07/03/1925	16-38--?	34.50	119.67	D			F	VII AT SANTA BARBARA; III AT PASADENA AND OJAI - STIFF TREMOR AT VENTURA.
07/03/1925	18-21--?	34.50	119.67	D			F	VII AT SANTA BARBARA - STRONGEST AFTERSHOCK; FELT AT LOS ANGELES, OJAI, AND PASADENA.
07/03/1925	18-46--?	34.50	119.67	D			F	SANTA BARBARA.
07/04/1925	19-18--?	34.50	119.67	D			F	SANTA BARBARA - ANOTHER SHOCK FELT LATER IN DAY.
07/05/1925	12--?--?	34.50	119.67	D			F	SANTA BARBARA; 11 SHOCKS IN THE NEXT 19 HOURS.
07/06/1925	21-45--?	34.50	119.67	D			F	SANTA BARBARA - SEVERAL FAIRLY SEVERE SHOCKS.
07/09/1925	-?--?--?	34.50	119.67	D			F	SANTA BARBARA.
07/20/1925	09-50--?	34.50	119.67	D			F	SANTA BARBARA.
07/29/1925	14--?--?	34.50	119.67	D			F	V AT WASIOJA - CEMENT WALK CRACKED.
07/30/1925	09-50--?	34.50	119.67	D			F	SANTA BARBARA.
07/30/1925	12--?--?	34.50	119.67	D			F	SANTA BARBARA.
08/13/1925	11--?--?	34.50	119.67	D			F	SANTA BARBARA - 5 LIGHT SHOCKS DURING NIGHT; THE STRONGEST TOOK PLACE JUST BEFORE 11--?--?.
10/04/1925	-?-50--?	34.50	119.67	D			F	SANTA BARBARA.
10/08/1925	21-30--?	34.50	119.67	D			F	SANTA BARBARA.
10/30/1925	09-45--?	34.50	119.67	D			F	SANTA BARBARA.
10/30/1925	13-30--?	34.50	119.67	D			F	SANTA BARBARA AND VENTURA.
02/18/1926	18-18--?	34.17	119.50	D			F	VII ORIGIN AT SEA, SW OF VENTURA; FELT ALONG COAST FROM SAN LUIS OBISPO ON NW TO SOUTH OF SANTA ANA, A DISTANCE OF 200 MI. AT SANTA BARBARA WINDOWS OF A SCHOOL WERE BROKEN, WATER PIPE IN ROUNDHOUSE WAS BROKEN. THERE WAS DAMAGE TO TELEPHONE EQUIPMENT AT SIMI. ALSO FELT AT LOS ANGELES, PASADENA, SANTA MONICA, SANTA SUSANA, AND VENTURA.
04/29/1926	12-18--?	34.67	120.17	D			F	IV AT BUELLTON.
06/18/1926	-?--?--?	34.50	119.67	D			F	SANTA BARBARA.
06/24/1926	15-30--?	34.50	119.67	D			F	V AT SANTA BARBARA.
06/29/1926	23-21--?	34.50	119.67	D			F	VII-VIII AT SANTA BARBARA - ONE PERSON KILLED BY FALLING CHIMNEY. VI AT BUELLTON AND VENTURA; ALSO FELT AT CAMARILLO, LOS ANGELES, OJAI, OXNARD, PORT HUENEME, AND SANTA PAULA - POSSIBLY SUBMARINE ORIGIN; FELT OVER AN AREA OF 30,000 SQ. MI.
07/03/1926	23--?--?	34.50	119.67	D			F	II AT SANTA BARBARA.
07/06/1926	17-45--?	34.50	119.67	D			F	V AT SANTA BARBARA.
07/25/1926	-?--?--?	36.30	120.30					(CALTECH FILE)
08/06/1926	17-42--?	34.50	119.67	D			F	IV IN SANTA BARBARA REGION; 2 SHOCKS AT OJAI - LASTED 30 SECONDS AT VENTURA WITH SHARP SHOCK AT SANTA BARBARA.
08/09/1926	04-12--?	34.50	119.67	D			F	V AT SANTA BARBARA; 2 SHOCKS AT VENTURA.
10/22/1926	10-10--?	35.67	120.67	D			F	III AT PASO ROBLES.
10/22/1926	-?--?--?	36.45	122.00					(CALTECH FILE)
12/09/1926	-?-03--?	35.67	120.67	D			F	IV AT PASO ROBLES - PROBABLY MISTIMED REPORT OF SHOCK AT -? 41-?.
12/09/1926	-?-41--?	35.25	120.67	D			F	NE OF SAN LUIS OBISPO; AT SAN LUIS OBISPO DURATION 20 SECONDS; FELT AT COALINGA WITH ORIGIN ABOUT 120 MI. FROM MT HAMILTON.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
12/27/1926	09-19--?	36.17	120.33	D			F	VI NEAR COALINGA; FELT OVER AN AREA OF 25,000 SQ. MI. FELT AT FIREBAUGH, FRESNO, LOS BANOS, MENDOTA, OAKDALE, OILFIELDS, PORTERVILLE, AND SAN LUIS OBISPO.
11/04/1927	11--?--?	34.58	120.67	D			F	LOMPOC, POINT ARGUELLO, AND SAN LUIS OBISPO.
11/04/1927	11-30--?	34.58	120.67	D			F	LOMPOC.
11/04/1927	13-50-53	34.54	121.40	A	7.3	3	F	X AT SEA, WEST OF POINT ARGUELLO. AREA SHAKEN WITH INTENSITY VI OR GREATER WAS 40,000 SQ. MI. A SMALL SEA WAVE WAS PRODUCED, RECORDED ON TIDE GAUGES AT SAN DIEGO AND SAN FRANCISCO, AND OBSERVED AS 6 FEET HIGH AT SURF; IX AT HONDA, ROBERDS RANCH, SURF, AND WHITE HILLS, VIII AT ARLIGHT, ARROYO GRANDE, BERROS, BETTERAVIA, CAMBRIA, CASMALIA, CAYUCOS, GUADOCEANO, PISMO BEACH, POINT CONCEPTION, SAN JULIAN RANCH, SAN LUIS OBISPO, AND SANTA MARIA, VI-VII AT GUADOCEANO, PISMO BEACH, POINT CONCEPTION, SAN JULIAN RANCH, SAN LUIS OBISPO, AND SANTA MARIA, VI-VII AT ALUPE, HALCYON, HARRISTON, HUASNO, LOMPOC, LOS ALAMOS, LOS OLIVOS, MORRO BAY, NIPOMO, ADELAIDA, ATASCADERO, BAKERSFIELD, BICKNELL, BUTTONWILLOW,CARPINTERIA CHOLAME, CRESTON, EDNA GAVIOTA, GOLETA, HARMONY, KING CITY, LAS CRUCES, NAPLES, OXNARD, PASO ROBLES, REWARD, SANTA BARBARA, SANTA MARGARITA, SANTA YNEZ, SOLVANG, TAFT, TEMPLETON, VENTURA, AND WASIOJA, AND IV-V AT ANNETTE, BIG SUR, CASTROVILLE, COALINGA, FELLOWS, GONZALES, GORMAN, HOLLISTER, LOCKWOOD, LUCIA, MCKITTRICK, MONTEREY, PARKFIELD, PATTIWAY, PORT SAN LUIS, POZO, PRIEST, SALINAS, SANGER, SAN LUCAS, SAN SIMEON, SANTA PAULA, SCHEIDECK, SESPE, SIMMLER, SOLEDAD, AND TEHACHAPI. DATA FROM BSSA V. 17, P. 258 AND V. 20, P. 53.
11/04/1927	14-12--?	34.58	120.67	D			F	SANTA MARIA - AFTERSHOCK.
11/04/1927	14-14--?	34.58	120.67	D			F	SANTA MARIA - AFTERSHOCK.
11/04/1927	15--?--?	34.58	120.67	D			F	SAN LUIS OBISPO - AFTERSHOCK.
11/04/1927	15-42--?	34.58	120.67	D			F	SANTA MARIA - AFTERSHOCK.
1/05/1927	08-17--?	34.58	120.67	D			F	POINT ARGUELLO - AFTERSHOCK; MILD AT SURF.
11/05/1927	09--?--?	34.58	120.67	D			F	POINT ARGUELLO - AFTERSHOCK; REPORTED FROM PASO ROBLES TO HADLEY TOWER.
11/05/1927	11-37--?	34.58	120.67	D			F	POINT ARGUELLO - AFTERSHOCK; REPORTED FROM SURF TO HADLEY TOWER, AND SOUTH OF SAN LUIS OBISPO.
11/06/1927	-?-06--?	34.67	120.17	D			F	IV AT BUELLTON.
11/06/1927	02-25--?	34.67	120.17	D			F	POINT ARGUELLO - AFTERSHOCK; STRONGEST IMMEDIATE AFTERSHOCK AT LOMPOC.
11/06/1927	03-10--?	34.67	120.17	D			F	IV AT BUELLTON.
11/06/1927	22-10--?	34.67	120.17	D			F	OFF POINT CONCEPTION.
11/06/1927	22-50--?	34.67	120.17	D			F	IV AT BUELLTON.
11/06/1927	23-10--?	34.67	120.17	D			F	OFF POINT CONCEPTION.
11/08/1927	10-10--?	34.67	120.17	D			F	IV AT BUELLTON - SHARP BUMPING AT 10-02--?, AROUSED NEARLY ALL. AT LOMPOC MANY AWAKENED BY SHOCK AT 10-15--?.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
11/19/1927	03-32--?	34.92	120.42	D			F	VII AT SANTA MARIA - CENTERED TO NW OF ORIGIN OF NOVEMBER 4 QUAKE -WEAKER, YET NEARLY AS STRONG AT SANTA MARIA,AND VI AT BETTERAVIA AND BICKNELL; REPORTED FROM SAN MIGUEL AND PARKFIELD ON THE NORTH TO SANTA BARBARA CHANNEL ON THE SOUTH.
12/05/1927	11-45--?	34.58	120.67	D			F	IV AT POINT ARGUELLO, AND IV AT BUELLTON WITH 2 SHOCKS 15 SECONDS APART; FELT AT GUADALUPE, SANTA MARGARITA, SANTA MARIA AND SURF.
12/31/1927	10-10--?	34.58	120.67	D			F	V AT POINT ARGUELLO.
03/15/1928	12-03--?	34.92	120.42	D			F	SANTA MARIA.
03/15/1928	12-20--?	34.50	119.67	D			F	SANTA BARBARA.
03/16/1928	14-30--?	34.92	120.42	D			F	SANTA MARIA.
03/29/1928	06-25--?	34.92	120.42	D			F	VII AT SANTA MARIA.
06/09/1928	08-22--?	35.17	119.50	D			F	TAFT.
06/09/1928	08-31--?	35.17	119.50	D			F	TAFT.
06/09/1928	12-25--?	35.17	119.50	D			F	TAFT.
09/03/1928	04-01-54	34.50	122.50	D	5.0	1		OFF POINT ARGUELLO - LICK OBSERVATORY S-P= 39 SECONDS.
11/02/1928	05--?--?	34.67	120.42	D			F	LOMPOC.
05/28/1929	07-10--?	36.17	120.33	D			F	COALINGA.
07/03/1929	09-24--?	34.50	119.67	D			F	SANTA BARBARA.
07/12/1929	13-10--?	36.17	120.33	D			F	COALINGA.
08/28/1929	18-10--?	34.50	119.67	D			F	SANTA BARBARA.
09/09/1929	05-15--?	34.50	119.67	D			F	GAVIOTA, NAPLES, AND SANTA BARBARA.
09/16/1929	03-16--?	35.42	120.92	D			F	CAYUCOS.
09/16/1929	06-15--?	35.42	120.92	D			F	CAYUCOS.
10/05/1929	20-03--?	36.17	120.33	D			F	COALINGA AND LIGHTHIPE.
10/06/1929	21-14--?	36.17	120.33	D			F	COALINGA.
10/07/1929	08--?--?	36.17	120.33	D			F	COALINGA.
10/07/1929	11-30--?	34.83	120.42	D			F	ORCUTT.
10/11/1929	17-55--?	36.17	120.33	D			F	COALINGA.
10/15/1929	22-02--?	36.17	120.67	D			F	COALINGA, KETTLEMEN HILLS, OILFIELDS, AND PRIEST VALLEY,.
11/07/1929	06-30--?	36.33	119.67	D			F	HANFORD.
11/09/1929	02-30--?	36.17	120.33	D			F	BITTER WATER, COALINGA, AND MCKITTRICK.
11/20/1929	22-50--?	36.42	121.00	D			F	BITTER WATER.
11/24/1929	09-54--?	36.42	121.00	D			F	LONOAK, BITTER WATER, AND LEWIS CREEK.
11/26/1929	08-05--?	36.42	121.00	D			F	V AT BITTER WATER AND SAN ARDO; FELT FROM HOLLISTER TO SANTA MARGARITA.
11/26/1929	09--?--?	36.42	120.83	D			F	HERNANDEZ.
11/26/1929	18-06--?	36.42	121.00	D			F	BITTER WATER.
12/05/1929	07-40--?	36.33	119.67	D			F	HANFORD.
03/11/1930	23-59--?	36.42	121.25	D			F	PINNACLES.
06/21/1930	05-15--?	34.83	120.50	D			F	CASMALIA.
08/05/1930	11-25--?	34.42	119.50	D			F	NEAR SANTA BARBARA - FELT OVER AN AREA OF 9000 SQ. MI. V-VI AT CARPINTERIA, GOLETA, OJAI, OXNARD, AND SANTA BARBARA,.
08/08/1930	16.46--?	34.42	119.67	D			F	SANTA BARBARA AND GOLETA.
08/18/1930	13-09--?	34.33	120.58	D			F	OFF POINT CONCEPTION; V OVER A LAND AREA OF 500 SQ. MI. NEAR POINT CONCEPTION.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
08/28/1930	05-15--?	36.42	121.33	D			F	SOLEDAD.
09/02/1930	13-35--?	35.00	121.00	D			F	OFF COAST - FELT AT HALCYON AND SAN LUIS OBISPO.
09/09/1930	05-27--?	34.42	119.50	D			F	SANTA BARBARA.
10/02/1930	14-18--?	34.58	120.67	D			F	OFF POINT ARGUELLO - FELT AT HALCYON.
10/28/1930	13-57--?	35.42	120.92	D			F	OFF COAST NEAR CAYUCOS - FELT AT NIPOMO.
12/08/1930	01-23--?	34.50	119.67	D			F	GOLETA AND SANTA BARBARA.
12/08/1930	01-29--?	34.50	119.67	D			F	GOLETA AND SANTA BARBARA.
02/21/1931	08-10--?	35.67	121.33	D			F	NW OF SAN LUIS OBISPO - FELT AT BRYSON AND PIEDRAS BLANCAS.
02/23/1931	10-01--?	35.83	120.50	D			F	OVER AN AREA OF 5000 SQ. MI.; V AT CAYUCOS, PARKFIELD, AND TEMPLETON.
02/23/1931	10-33--?	35.83	120.50	D			F	SAME AS ABOVE.
04/05/1931	03--?--?	36.17	121.00	D			F	SE OF KING CITY.
07/15/1931	18-40--?	35.00	120.58	D			F	GUADALUPE, NIPOMO, AND SANTA MARGARITA.
07/21/1931	03-25--?	35.25	120.67	D			F	SAN LUIS OBISPO.
07/21/1931	12-08--?	35.25	120.67	D			F	IV AT HALCYON, LOS ALAMOS, NIPOMO, OCEANO, AND TEMPLETON:ALSO FELT AT CAMBRIA, GAVIOTA, PIEDRAS BLANCAS, PORT SAN LUIS, SAN LUIS OBISPO, SANTA MARGARITA, AND SANTA MARIA
09/03/1931	13-50--?	34.50	119.67	D			F	SANTA BARBARA.
09/10/1931	14-35--?	35.50	120.67	D			F	ATASCADERO.
09/30/1931	14-35--?	35.50	120.67	D			F	ATASCADERO.
10/13/1931	12-25--?	36.33	121.67	D			F	JAMESBURG.
10/18/1931	19-58--?	36.33	121.67	D			F	IV AT HOLLISTER, JAMESBURG, AND SPRECKLES; ALSO FELT AT APTOS, CARMEL, CHUALAR, MOSS LANDING, MONTEREY, PARAISO, SALINAS, AND SANTA CRUZ.
12/04/1931	-?-53--?	36.50	121.67	D			F	10 MI. S OF SPRECKELS. FELT AT HOLLISTER, METZ, PIGEON POINT, SPRECKELS, AND SANTA CRUZ.
02/04/1932	16-02-58	34.55	119.73	C	3.0	1	F	SANTA BARBARA AND VENTURA.
02/05/1932	04-14-45	35.83	121.47	C	3.5	1	F	COAST OF MONTEREY COUNTY; FELT AT PIEDRAS BLANCAS LIGHT AND SALMON CREEK.
02/05/1932	06-46-54	35.83	121.47	C	3.5	1	F	COAST OF MONTEREY COUNTY; FELT AT PIEDRAS BLANCAS LIGHT AND SALMON CREEK.
02/05/1932	07-10--?	35.83	121.47	C			F	AFTERSHOCK OF PRECEDING.
02/26/1932	16-58--?	36.00	121.00		5.0		F	IV AT APTOS, ASILOMAR, CARMEL, DEL MONTE, GONZALES, METZ, MONTEREY, PACIFIC GROVE, AND PEBBLE BEACH.
03/13/1932	23-09-24	34.44	120.17	B	3.5	1	F	OFF POINT CONCEPTION; FELT AT BUELLTON.
04/21/1932	03-36-20	35.50	120.67	D	3.0		F	ATASCADERO.
05/06/1932	03-37-08	36.00	120.50	C	3.0	1	F	PARKFIELD.
06/27/1932	05-17-25	36.00	122.00	D	4.0			COAST OF MONTEREY COUNTY.
10/24/1932	04-45--?	35.75	120.75	D			F	PASO ROBLES.
01/30/1933	17--?--?	34.67	120.42	D			F	LOMPOC.
02/26/1933	09-34-32	36.40	121.30	D			F	III AT HOLLISTER, SALINAS, AND SPRECKLES.
04/12/1933	10-03--?	36.33	121.75	D			F	IV AT PORTERVILLE AND VISALIA.
06/26/1933	06-26--?	34.42	120.50	D			F	V AT BUELLTON AND POINT CONCEPTION.
06/26/1933	06-29--?	34.42	120.50	D			F	V AT BUELLTON AND POINT CONCEPTION.
01/09/1934	12-48--?	35.13	120.08	C	3.0			

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
01/12/1934	12-50--?	34.45	120.15	D			F	IV AT LOS ALAMOS.
02/01/1934	16-09--?	34.55	119.53	B	3.5		F	II AT SANTA BARBARA.
02/11/1934	15-16--?	34.55	119.53	C	2.0			
03/20/1934	11-48--?	36.00	120.00	D	3.0			
05/06/1934	20-14--?	35.83	120.75	B	3.5			
05/10/1934	11-28--?	34.50	119.58	C	3.0			
05/19/1934	06-37--?	34.58	120.75	D	3.0			
05/24/1934	06-52--?	34.42	119.75	C	2.5			
05/24/1934	09-04--?	34.42	119.75	C	2.5			
05/24/1934	11-18--?	34.42	119.75	C	2.0			
06/05/1934	09-51--?	35.80	120.33	D			F	COALINGA AND KETTLEMAN HILLS; ALSO FELT AT MONTEREY AND SANTA CRUZ.
06/05/1934	11-30--?	35.80	120.33	D			F	SAN MIGUEL AND SHANDON.
06/05/1934	11-47--?	35.80	120.33	B	3.0			
06/05/1934	13-46--?	35.80	120.33	C	3.0			
06/05/1934	21-30--?	35.80	120.33	D			F	SAN MIGUEL.
06/05/1934	21-48--?	35.80	120.33	B	5.0		F	V AT ADELAIDA, PARKFIELD, AND PRIEST, IV AT ATASCADERO, AVENAL, BIG SUR, BRYSON, CARMEL, HANFORD, KING CITY, LEMOORE, LONOAK, PARAISO, SAN MIGUEL, SANTA CRUZ, SHANDON, AND TEMPLETON, III AT APTOS, BOULDER CREEK, CAMBRIA, CHUALAR, COALINGA, GONZALES, HOLLISTER, MONTEREY, MORRO BAY, PASO ROBLES, SALINAS, SAN FRANCISCO, SAN JOAQUIN VALLEY, SAN LUIS OBISPO, SOLEDAD, SPRECKLES, ETC.; NOT FELT AT ANTIOCH, ETC., BAKERSFIELD, FRESNO, GILROY, LIVERMORE, LOS GATOS, MARICOPA, MERCED, MODESTO, MORGAN HILL, REDWOOD CITY, SAN JOSE, SANTA MARIA, TULARE, OR WATSONVILLE.
06/05/1934	22-52--?	35.80	120.33	C	4.0		F	VI AT ADELAIDA; IV AT ATASCADERO.
06/05/1934	23-30--?	35.80	120.33	D			F	V AT LEMOORE; ALSO FELT AT CASTROVILLE.
06/06/1934	-?-55--?	35.80	120.33	C	3.0			
06/06/1934	16-40--?	35.80	120.33	C	3.5			
06/06/1934	22-40--?	35.80	120.33	C	3.5		F	ADELAIDA, GRAEAGLE, AND PAYNES CREEK.
06/07/1934	22-30--?	35.80	120.33	D			F	STONE CANYON.
06/08/1934	04-15--?	35.80	120.33	D			F	IV AT GONZALES AND MCKITTRICK.
06/08/1934	04-30--?	35.80	120.33	B	5.0		F	VI TO VII AT CHOLOME RANCH, PARKFIELD, AND STONE CANYON DURATION 30 SECONDS, DAMAGE SLIGHT, V AT ATASCADERO, AT ANTELOPE, BIG SUR, CAMBRIA, CASTROVILLE, DELANO, MONTEREY, PASO ROBLES, SAN LUIS OBISPO, SANTA BARBARASANTA MARGARITA, SANTA MARIA, SOLEDAD, TAFT, VENTURA, VISALIA, ETC., AND III OR LESS AT ARVIN, BAKERSFIELD, FRESNO, KERNVILLE, LOMPOC, LOS ANGELES, MENDOTA, PORTERVILLE, SALINAS, SAN BENITO, SANTA ANA, SANTA BARBARA, TULARE, WATSONVILLE, ETC.; NOT FELT AT BIG BASIN, CAJON, COYOTE, GILROY, HUNTINGTON BEACH, INDEPENDENCE, INYOKERN, LANCASTER, MERCED, POMONA, OR SAN JOSE.
06/08/1934	04-37--?	35.60	121.30	D			F	IV AT PIEDRAS BLANCAS, SAN LUIS OBISPO, AND SANTA CRUZ; ALSO FELT AT BRYSON AND LOS ALAMOS.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
06/08/1934	04-45--?	35.80	120.33	D			F	ATASCADERO, COALINGA, LOCKWOOD, PASO ROBLES, PORT SAN LUIS, PRIEST, SAN MIGUEL, AND WESTHAVEN.
06/08/1934	04-47--?	35.80	120.33	B	6.0		F	WITHIN A RADIUS OF 250 KM FROM THE EPICENTER NEAR THE SOUTHEASTERN ANGLE OF MONTEREY COUNTY; VII TO VIII AT PARKFIELD, VI AT COALINGA, KETTLEMAN CITY, LEMOORE, AND STONE CANYON, V AT ATASCADERO, DUDLEY, HOLLISTER, KING CITY, OILFIELDS, SAN MIGUEL, SEASIDE, SHALE PUMP STATION, AND SHANDON, IV AT ANTELOPE, AVILA, CANOGA PARK, HANFORD, LOS ALAMOS, MARICOPA, MORRO BAY, NIPOMO, PASO ROBLES, PRIEST, SAN LUIS OBISPO, SANTA CRUZ, SANTA MARIA, SOLEDAD, VISALIA ETC., AND III OR LESS AT APTOS, FRESNO, KERNVILLE, LONE PINE, LOS BANOS, MENDOTA, MONTEREY, OAKLAND HARBOR, SALINAS, SAN BENITO, SANTA ANA, TEHACHAPI, TULARE, ETC.
06/08/1934	05--?--?	35.60	121.30	D			F	PIEDRAS BLANCAS LIGHT; ALSO BRYSON, KERNVILLE, LA PANZA, LEMOORE, PARKFIELD, SANDBERG, AND SAN FERNANDO.
06/08/1934	05-20--?	35.80	120.33	D			F	III AT ATASCADERO.
06/08/1934	05-23--?	35.80	120.33	C	3.5		F	ATASCADERO AND SAN MIGUEL.
06/08/1934	05-36--?	35.80	120.33	C	3.0			
06/08/1934	05-42--?	35.80	120.33	B	4.5		F	ATASCADERO, BIG SUR, COALINGA, KING CITY, PASO ROBLES, AND WESTHAVEN.
06/08/1934	05-50--?	35.80	120.33	D			F	IV AT ATASCADERO; ALSO FELT AT COALINGA AND SAN LUIS OBISPO.
06/08/1934	09-30--?	35.80	120.33	B	4.0		F	ATASCADERO AND PARKFIELD.
06/08/1934	15-30--?	35.80	120.33	C	3.5			
06/08/1934	16-30--?	35.80	120.33	D			F	PARKFIELD.
06/08/1934	23-23--?	35.80	120.33	B	4.0		F	NEAR PARKFIELD.
06/10/1934	06-47--?	35.80	120.33	C	3.0			
06/10/1934	08-03--?	35.80	120.33	B	4.5		F	NEAR PARKFIELD; IV AT SAN MIGUEL.
06/10/1934	20-02--?	35.80	120.33	D			F	IV AT SAN MIGUEL; ALSO PARKFIELD AND WOODY.
06/11/1934	03-25--?	35.80	120.33	C	3.0			
06/12/1934	10-47--?	35.80	120.33	C	3.5			
06/14/1934	14-55--?	35.80	120.33	C	4.0		F	IV AT ATASCADERO; ALSO FELT AT SAN MIGUEL AND TEMPLETON.
06/14/1934	15-54--?	35.80	120.33	C	4.0		F	III AT ATASCADERO AND SAN MIGUEL.
06/14/1934	19-26--?	35.80	120.33	C	4.5		F	ATASCADERO AND TEMPLETON.
06/14/1934	22-02--?	35.80	120.33	C	3.5		F	ATASCADERO.
06/15/1934	04-48--?	35.80	120.33	C	3.0			
06/16/1934	23-03--?	36.50	121.00	D	4.0		F	IV AT HOLLISTER AND MONTEREY, AND III AT GONZALES, PARKFIELD, AND SALINAS.
07/02/1934	18-44--?	35.80	120.33	B	3.0			
08/04/1934	-?-18--?	35.80	120.33	B	3.0			
08/21/1934	03-37--?	36.08	120.58	D			F	IV IN STONE CANYON.
08/25/1934	18-52--?	34.42	119.75	C	2.5			
08/26/1934	03-02--?	35.57	119.85	B	3.0			
09/06/1934	23-24--?	36.00	120.55	C	3.0			
09/16/1934	14-38--?	35.83	120.33	C	3.5			
10/07/1934	-?-18--?	34.55	120.78	C	3.5			

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
10/08/1934	04-57--?	34.50	119.58	C	2.0			
10/10/1934	10-52--?	34.55	120.78	C	3.0			
10/19/1934	15-39--?	35.80	120.33	C	3.0			
11/04/1934	22-17--?	34.53	119.67	B	3.0			
11/21/1934	01-02--?	34.58	119.62	B	2.5			
12/01/1934	13-05--?	36.00	121.50	D			F	15 MI. S OF PARAISO; V AT PIEDRAS BLANCAS LIGHT AND IV AT PARAISO.
12/02/1934	16-07--?	35.97	120.58	C	4.0		F	SAN MIGUEL.
12/03/1934	01-54--?	35.95	121.50	C	4.5		F	IV AT BRYSON, KING CITY, AND PARAISO; ALSO FELT AT PARKFIELD, PASO ROBLES, SAN LUCAS, AND SAN MIGUEL.
12/17/1934	11-10--?	34.58	120.33	B	4.5		F	VI AT LOS ALAMOS.
12/17/1934	13-51--?	34.58	120.33	C	2.5		F	LOS ALAMOS.
12/17/1934	15-16--?	34.55	119.67	C	2.5			
12/17/1934	15-35--?	34.58	120.33	C	2.5			
12/18/1934	03-09--?	34.58	120.33	C	4.0		F	LOS ALAMOS.
12/18/1934	04-34--?	34.58	120.33	C	3.0		F	LOS ALAMOS.
12/18/1934	05-28--?	34.58	120.33	C	3.0		F	LOS ALAMOS.
12/19/1934	20-39--?	34.28	119.50	B	2.5			
12/20/1934	12-37--?	34.58	120.33	C	2.5		F	LOS ALAMOS.
12/20/1934	12-39--?	34.58	120.33	C	3.0			
12/20/1934	22-21--?	34.58	120.33	C	3.0			
12/23/1934	16-08--?	34.58	120.33	C	2.5			
12/24/1934	10-22--?	34.58	120.33	B	3.0		F	LOS ALAMOS.
12/24/1934	16-26--?	35.93	120.48	B	5.0		F	IV AT LOS ALAMOS AND SHANDON; ALSO FELT AT KING CITY TEMPLETON.
12/25/1934	04-03--?	34.58	120.33	C	3.0			
01/06/1935	04-04--?	35.98	120.48	C	4.0		F	IV AT PARKFIELD; ALSO FELT AT SHANDON.
01/06/1935	04-25--?	35.90	120.45	D			F	IV AT PARKFIELD.
01/06/1935	04-40--?	35.98	120.48	C	4.0		F	IV AT PARKFIELD AND III AT SHANDON.
01/07/1935	-?-11--?	35.75	119.67	D	3.0			
01/23/1935	03-16--?	34.58	120.33	C	3.5		F	IV AT LOS ALAMOS.
01/27/1935	09-49--?	34.50	119.62	B	2.5			
02/18/1935	04-02--?	35.93	120.48	C	3.5			
02/19/1935	14-17--?	35.93	120.48	D	3.0			
02/28/1935	19-06--?	35.80	120.33	C	3.0			
03/03/1935	11-26--?	36.42	121.75	C	3.0			
03/06/1935	23-14--?	34.43	119.87	C	3.5		F	III AT SANTA BARBARA.
03/19/1935	03-59--?	34.55	120.78	B	4.0			OFF POINT ARGUELLO.
04/05/1935	10-13--?	35.93	120.48	C	3.5			
05/05/1935	12-58--?	34.58	119.68	C	2.5			
05/18/1935	04-36--?	34.58	120.33	B	3.5		F	IV AT LOS ALAMOS.
05/19/1935	03-44--?	34.58	120.33	C	3.0			
05/20/1935	23-44--?	34.58	120.33	C	3.0			
05/27/1935	16-08--?	35.37	120.97	C	3.0		F	III AT TEMPLETON.
06/10/1935	02-02--?	35.33	119.83	C	3.5			
06/18/1935	08-52--?	34.60	119.60	C	2.0			
06/23/1935	23-53--?	34.55	119.68	C	3.0			

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
06/30/1935	23-28--?	36.00	121.00	D	4.0		F	SE OF SALINAS; III AT HOLLISTER.
07/25/1935	04-16--?	35.80	120.33	C	3.0		F	V AT PARKFIELD.
07/28/1935	06--?--?	35.70	121.12	B	4.0		F	SAN SIMEON.
08/06/1935	19-05--?	34.62	119.62	C	3.0		F	SANTA BARBARA.
08/07/1935	22-30--?	34.55	120.78	C	3.5			
08/09/1935	17-14--?	36.17	120.98	C	3.5		F	PRIEST VALLEY.
08/31/1935	09-28--?	34.50	119.70	C	2.5			
10/18/1935	09-24--?	35.80	120.70	D	3.5		F	IV AT PARKFIELD - AFTERSHOCK.
10/22/1935	18-37--?	35.93	120.48	C	4.0		F	PARKFIELD.
10/25/1935	19-43--?	36.40	121.55	D			F	13 MI. W OF SOLEDAD; IV AT SAN BENITO.
10/26/1935	10-46--?	35.85	121.40	D			F	AFTERSHOCK.
12/22/1935	06-54--?	34.55	120.78	C	3.0			
02/03/1936	09-12--?	34.75	119.75	C	2.5			
02/21/1936	23-06--?	34.42	119.67	C	3.0			
02/22/1936	-?-18--?	34.42	119.67	C	3.0			
02/22/1936	-?-21--?	34.42	119.67	C	2.5			
02/22/1936	-?-23--?	34.42	119.67	C	3.0			
02/22/1936	04-55--?	34.42	119.67	C	3.0			
03/06/1936	03-45--?	35.90	120.40	D	3.0			
03/17/1936	01-55--?	36.50	120.92	C	4.0		F	IV AT CHUALAR, HOLLISTER, AND TRES PINOS.
03/18/1936	09-07--?	35.93	120.48	C	2.5			
03/27/1936	-?-58--?	34.55	120.78	C	3.0			
03/29/1936	09-26--?	34.50	119.62	C	2.5			
05/20/1936	17-22--?	35.93	120.48	C	3.0			
05/23/1936	04-41--?	36.17	120.92	C	4.0		F	IV AT KING CITY.
05/27/1936	19-55--?	36.50	121.17	C	4.5			SAN BENITO COUNTY.
06/24/1936	12-23--?	35.12	120.08	C	3.0		F	SAN LUIS OBISPO CO.; IV AT LOS ALAMOS.
07/13/1936	18-09--?	34.50	119.60	D	2.5			
07/22/1936	04-03--?	34.50	119.80	C	2.5			
07/30/1936	09-36--?	34.57	119.63	C	3.0			
09/07/1936	16-47--?	34.37	120.38	C	3.0			
09/09/1936	04-54--?	34.37	120.38	C	4.0		F	LOS ALAMOS.
09/10/1936	21-21--?	34.40	120.40	D	3.0			
09/12/1936	13-56--?	34.75	120.33	C	3.5			
09/15/1936	-?-09--?	34.50	120.50	D	2.5			
10/16/1936	15-30--?	34.83	120.58	C	4.0			NEAR CASMALIA.
10/16/1936	15-36--?	34.83	120.58	C	3.0			
10/17/1936	01-17--?	34.83	120.58	C	3.0			
10/19/1936	14-01--?	34.83	120.58	C	3.0			
11/01/1936	15-10--?	34.55	120.78	B	4.0			OFF POINT ARGUELLO.
11/02/1936	01-29--?	34.55	120.78	C	3.0			
11/05/1936	14-30--?	35.85	121.40	D			F	HOLLISTER.
11/08/1936	16-51--?	34.55	120.78	C	3.0			
11/08/1936	22-43--?	34.55	120.78	C	3.0			
11/18/1936	17-15--?	35.35	120.60	D			F	POZO, SAN LUIS OBISPO, AND SANTA MARGARITA.
11/18/1936	18-02--?	34.70	120.25	C	4.5		F	IV AT ARROYO GRANDE, ATASCADERO, BETTERAVIA, LOS ALAMOS OCEANO, POZO, SAN LUIS OBISPO, AND SANTA MARGARITA.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
11/22/1936	02-16--?	34.58	120.78	C	3.5			
11/25/1936	21-51--?	34.58	120.78	C	3.0			
12/23/1936	17-16--?	35.93	120.48	B	3.5			
12/26/1936	01-12--?	34.55	119.68	C	2.5			
01/12/1937	15-44--?	34.50	120.80	D	3.0			
01/28/1937	17-36--?	34.43	119.87	C	2.5			
02/16/1937	17-40--?	34.55	120.78	C	4.0			OFF POINT ARGUELLO.
02/17/1937	03-33--?	36.50	121.58	C	4.5		F	9 MI. SE OF PAICINE; FELT AT ANTELOPE, HOLLISTER, AND PANOCHE.
02/20/1937	09-58--?	35.93	120.48	C	4.0		F	PARKFIELD AND PASO ROBLES.
02/22/1937	18-10--?	36.17	121.53	C	4.0		F	KING CITY.
02/24/1937	13-37--?	34.50	119.70	C	2.0			
02/25/1937	03-20--?	34.50	119.70	C	2.0			
03/26/1937	21-35--?	34.60	119.70	C	3.5			
03/31/1937	17-43--?	34.50	119.70	C	3.0			
04/17/1937	08-30--?	34.60	119.70	C	2.5			
04/30/1937	08-16--?	34.50	119.70	D	2.5			
05/31/1937	15-33--?	36.50	120.70	C	3.0			
06/02/1937	09-32--?	34.40	119.70	C	2.5			
07/31/1937	14-18--?	34.22	119.55	C	3.0			
07/31/1937	15-14--?	34.22	119.55	C	2.5			
08/15/1937	19-01--?	36.50	120.70	D	3.0			
08/22/1937	01-56--?	35.00	121.00	D	3.5			
09/16/1937	02-48--?	35.93	120.48	B	3.5		F	NEAR PARKFIELD; FELT AT BRADLEY.
09/18/1937	13-29--?	36.50	121.50	D	4.0		F	9 MI. SE OF PAICINES; FELT AT CHUALAR, SALINAS, AND SPRECKLES.
09/22/1937	02-41--?	34.50	119.70	C	3.0			
09/29/1937	22-39--?	34.50	119.70	C	3.0			
10/13/1937	08-32--?	34.40	119.70	C	2.5			
11/01/1937	21-40--?	36.50	121.40	D			F	6 MI. N OF GONZALES.
11/03/1937	10--?--?	36.15	121.00	D			F	V AT SAN LUCAS; FELT ALSO AT KING CITY AND SAN ARDO.
11/22/1937	04-12--?	34.55	120.78	C	4.5		F	OFF POINT ARGUELLO; V AT BUELLTON, GOLETA, PISMO BEACH, POINT D SANTA MARIA, AND IV AT ARLIGHT, BETTERAVIA, BICKNELL, E, GAVIOTA, GUADALUPE, LOMPOC, LOS ALAMOS, LOS OLIVOS, SANTA URF.
11/22/1937	04-51--?	34.55	120.78	C	3.5			
11/28/1937	09-55--?	34.55	120.78	C	3.5			
12/03/1937	15-28--?	34.55	120.78	C	4.0		F	OFF POINT ARGUELLO; FELT AT GAVIOTA AND POINT CONCEPTION.
12/03/1937	21-13--?	34.55	120.78	C	3.5			
12/05/1937	01-36--?	36.00	121.00	D	3.5		F	19 MI. S OF LOS BANOS; V AT LOS BANOS.
12/05/1937	01-37--?	36.00	121.00	D	4.0			SAN BENITO COUNTY.
12/05/1937	02-05--?	36.00	121.00	D	3.0		F	19 MI. S OF LOS BANOS.
12/24/1937	11-57--?	34.50	120.80	D	4.0		F	OFF POINT ARGUELLO. FELT AT CASMALIA, LOS ALAMOS, POINT CONCEPTION.
12/25/1937	13-01--?	36.00	120.00	D	3.0			
01/01/1938	01-59--?	34.55	120.78	C	3.5			

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
01/18/1938	04-35--?	34.55	120.78	B	3.5			
01/24/1938	04-38--?	34.55	120.78	C	3.5			
01/25/1938	12-24--?	34.55	120.78	C	3.5			
02/01/1938	18-14--?	34.55	120.78	C	3.5			
02/20/1938	14--?--?	34.55	120.78	C	3.5			
02/21/1938	10-59--?	35.93	120.78	C	3.0			
03/04/1938	15-14--?	34.30	119.57	C	2.5			
03/04/1938	18-25--?	34.30	119.57	C	2.5			
04/12/1938	01-50--?	34.55	120.78	C	3.5			
05/10/1938	10-32--?	36.20	121.30	D	4.5		F	BIG SUR, HOLLISTER, KING CITY, PINNACLES, SALINAS, SOLEDAD, SOQUEL, AND TRES PINOS-6 SHOCKS FELT AT PINNACLES.
05/10/1938	10-41--?	36.20	121.30	D	4.0		F	SAN BENITO.
05/13/1938	19-34--?	36.20	121.30	D	4.0			MONTEREY COUNTY.
05/27/1938	22-03--?	36.20	120.00	D	3.5			
06/01/1938	05-17--?	34.55	119.68	D			F	SANTA BARBARA.
06/01/1938	06-17--?	34.55	119.68	D	3.0			
06/06/1938	02-55--?	34.50	119.67	C	3.0			
09/16/1938	06-11--?	36.40	121.20	D	4.0		F	PINNACLES.
09/27/1938	10-21--?	34.50	119.70	C	2.5			
09/27/1938	12-23--?	36.30	120.90	C	5.0		F	OVER AN AREA OF 9000 SQ. MI. OF WEST-CENTRAL CALIFORNIA, ALONG THE COAST AS FAR NORTH AS PESCADERO AND SOUTH TO SAN LUIS OBISPO. INLAND IT WAS FELT AT COALINGA, MENDOTA, AND STEVENSON, WITH A V AT BIG SUR, BRYSON, CHUALAR, GONZALES, GREENFIELD, HARMONY, HOLLISTER, JOLON, LOCKWOOD, PAICINES, PARAISO, PINNACLES, SAN ARDO, SAN BENITO, SAN LUCAS, SOLEDAD, AND SPRECKLES, AND IV AT BEN LOMOND, CAMBRIA, CARMEL, CASTROVILLE, DOS PALOS, GILROY, KING CITY, LOS BANOS, MENDOTA, MONTEREY, PASO ROBLES, PRIEST, SALINAS, SAN LUIS OBISPO, TRES PINOS, WATSONVILLE, ETC.
09/27/1938	16-20--?	36.45	121.25	D			F	PAICINES AND PINNACLES.
09/29/1938	12-12--?	34.55	120.78	C	4.0			OFF POINT ARGUELLO.
10/02/1938	18-45--?	34.33	119.58	C	4.0		F	SANTA BARBARA AND SUMMERLAND.
10/24/1938	13-40--?	36.45	121.25	D			F	HOLLISTER AND PINNACLES.
10/28/1938	10-07--?	35.80	120.33	C	3.5			
11/01/1938	22-46--?	35.12	120.08	C	3.0			
11/16/1938	13-39--?	35.80	120.33	C	3.0			
11/22/1938	15-30--?	35.93	120.48	B	4.5		F	NEAR PARKFIELD; FELT AT ATASCADERO, CAMBRIA, CRESTON, MORRO BAY, PARKFIELD, PASO ROBLES, SAN MIGUEL, AND SHANDON.
01/01/1939	-?-53--?	34.58	120.33	C	3.0			
01/21/1939	07-08--?	36.45	121.25	D			F	PINNACLES.
01/22/1939	15-52--?	34.40	119.70	C	2.5			
02/05/1939	03-30--?	35.65	120.65	D			F	PASO ROBLES.
02/09/1939	06-44--?	35.93	120.48	C	3.0		F	NEAR PARKFIELD.
02/12/1939	03-12--?	34.42	119.83	B	3.0		F	GOLETA AND SANTA BARBARA .
03/24/1939	02-49--?	34.55	120.78	C	3.5			

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
03/25/1939	03-45--?	36.45	121.25	D			F	PINNACLES.
03/30/1939	10-11--?	34.50	119.80	C	2.5			
05/02/1939	18-49--?	35.93	120.48	C	4.0		F	IV AT PARKFIELD.
05/03/1939	07-55--?	34.55	120.78	C	3.0			
05/03/1939	12-39--?	35.65	120.65	D			F	PASO ROBLES.
05/18/1939	23--?--?	35.80	120.33	C	3.0			
06/15/1939	21-12--?	34.50	119.70	C	2.5			
06/17/1939	04-30--?	34.75	120.25	D			F	LOS ALAMOS. REPORTS OF SEVERAL SHOCKS.
06/24/1939	12-55--?	35.85	120.85	D			F	BRADLEY.
06/24/1939	13-02--?	36.40	121.00	C	5.5		F	OVER AN AREA OF 10,000 SQ. MI. IN WEST-CENTRAL CALIFORNIA, ALONG THE COAST AS FAR NORTH AS HALF MOON BAY AND SOUTH TO ESTERO BAY. INLAND IT WAS FELT AT COALINGA, TRANQUILITY, AND VOLTA, WITH A VII AT HOLLISTER, VI AT KING CITY AND PAICINES, V AT CAYUCOS, SOLEDAD, AND SPRECKLES, AND IV AT PAICINES, V AT CAYUCOS, SOLEDAD, AND SPRECKLES, AND IV AT CAMBRIA, CARMEL, CASTROVILLE, CHUALAR, GILROY, GONZALES, LOCKWOOD, MILPITAS, MONTEREY, NIPOMO, PASO ROBLES, PINNACLES, SALINAS, SAN ARDO, SAN BENITO, SAN JUAN, SAN MIGUEL, SAN SIMEON, SANTA CRUZ, TRES PINOS, AND WATSONVILLE.
07/04/1939	10-49--?	36.40	121.00	C	4.0		F	HOLLISTER, PAICINES, AND SALINAS.
07/10/1939	18-33--?	36.40	121.25	D			F	PINNACLES.
07/24/1939	09-30--?	36.25	121.80	D			F	BIG SUR.
07/24/1939	13--?--?	36.00	121.15	D			F	JOLON.
09/06/1939	01-53-43	34.58	120.42	C	3.0			
09/07/1939	02-50-30	35.42	121.08	C	3.0		F	OFF SAN LUIS OBISPO CO.; FELT AT CAMBRIA.
09/08/1939	01-57--?	34.75	120.25	D			F	LOS ALAMOS.
09/08/1939	05--?--?	34.75	120.25	D			F	LOS ALAMOS.
09/12/1939	-?--?-47	34.25	119.75	C	3.0			
09/24/1939	11-57-40	36.40	121.00	D	3.5			
10/06/1939	04-39--?	35.80	121.50	D	3.5			
10/17/1939	19-21-41	34.55	120.78	C	3.5			
10/17/1939	20-42-43	34.55	120.78	C	4.0			OFF POINT ARGUELLO.
11/02/1939	14-02--?	34.40	120.50	D			F	POINT CONCEPTION LIGHT STATION.
11/04/1939	14-11-33	36.20	120.90	D	3.0		F	SALINAS AND SAN LUCAS.
12/14/1939	03-45-18	36.10	120.00	D	3.0			
12/25/1939	15-36-23	34.28	119.83	C	3.5			
12/28/1939	12-15-38	35.80	120.33	B	5.0		F	OVER AN AREA OF 15,000 SQ. MI. IN WEST-CENTRAL CALIFORNIA, ON THE COAST FROM SANTA CRUZ SOUTH TO POINT ARGUELLO, AND INLAND TO LOST HILLS AND FRESNO. V AT COALINGA, FRESNO, GREENFIELD, PRIEST, SAN ARDO, AND SAN LUCAS, AND IV AT APTOS, ATASCADERO, BIG SUR, CAMBRIA, CARMEL, CASTROVILLE, CAYUCOS, CHUALAR, GONZALES, HOLLISTER, KING CITY, MENDOTA, MONTEREY, MORRO BAY, PARKFIELD, PASO ROBLES, PINNACLES, SALINAS, SAN JUAN BAUTISTA, SAN LUIS OBISPO, SANTA CRUZ, SOLEDAD, TAFT, ETC.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
12/29/1939	04--?--?	36.40	121.25	D			F	PINNACLES.
12/30/1939	15-24-37	35.80	120.33	D	3.5		F	NEAR PARKFIELD. FELT AT SAN LUCAS.
02/27/1940	11-40-25	34.25	119.50	B	3.0			
05/21/1940	10-05-34	35.28	120.48	B	4.0		F	ATASCADERO, CAMBRIA, CAYUCOS, MORRO BAY, PASO ROBLES, PISMO BEACH, AND SAN LUIS OBISPO.
06/16/1940	09-25-04	34.55	120.78	C	4.0		F	OFF POINT ARGUELLO; FELT AT GUADALUPE AND LOS ALAMOS.
06/26/1940	08-56--?	36.08	120.32	C	3.5			
06/28/1940	04-06-42	34.55	120.78	C	3.0			
08/13/1940	22-07-29	36.23	120.32	B	4.0			(DEPT. OF WATER RESOURCES DATA.)
08/31/1940	08-52-46	34.55	120.78	B	3.5			
09/07/1940	10-36-30	36.50	121.50	D	3.5			
09/07/1940	10-38-36	36.50	121.50	D	3.5			
09/07/1940	13-02-06	36.50	121.50	D	4.5		F	CARMEL AND SALINAS.
10/20/1940	22-18-45	34.55	120.78	C	3.0			
11/10/1940	10-25-10	34.35	119.77	C	4.0		F	SANTA BARBARA CHANNEL; FELT AT GOLETA, PARADISE CAMP, AND SANTA BARBARA.
11/17/1940	21-23-43	35.00	119.50	C	3.0			
01/29/1941	08-54-01	34.48	119.53	B	3.0			
02/04/1941	03-19-12	34.55	119.68	C	3.0			
02/04/1941	03-42-09	34.55	119.68	C	3.0			
02/08/1941	15-58-50	34.55	119.68	C	3.5		F	SANTA BARBARA.
02/09/1941	23-49-18	34.50	119.70	C	2.0			
02/11/1941	06-43-30	34.27	119.57	B	3.5		F	SANTA BARBARA.
02/12/1941	20-10-24	34.40	119.70	C	3.0			
02/14/1941	22-19-06	34.40	119.70	C	2.5			
05/07/1941	16-17-34	34.55	120.78	C	3.5			
05/15/1941	03-29--?	36.15	120.35	D			F	COALINGA.
05/15/1941	06--?--?	36.15	120.35	D			F	COALINGA.
07/01/1941	07-50-57	34.33	119.58	A	6.0		F	SANTA BARBARA; FELT OVER AN AREA OF 20,000 SQ. MI. VIII AT CARPINTERIA AND SANTA BARBARA, VII AT GOLETA AND VENTURA, VI AT FILLMORE, KEYSTONE, LOS ALAMOS, OJAI, OXNARD, PORT HUENEME, SANTA PAULA, SUMMERLAND, AND WHEELER SPRINGS, AND V AT ACTON, ALTADENA, ARLIGHT, ARTESIA, ARVIN, BETTERAVIA, BUELLTON, BURBANK, CAMARILLO, CANOGA PARK, CASMALIA, CAYUCOS, CHATSWORTH, COMPTON, EL SEGUNDO, GAVIOTA, GLENDALE, HERMOSA BEACH, INGLEWOOD, LA CRESCENTA, LAGUNA BEACH, LANCASTER, LOMITA, LOMPOC, LONG BEACH, LOS ANGELES, LOS OLIVOS, MAYWOOD, MCKITTRICK, MONTALVO, MOORPARK, NEWBURY PARK, NEWPORT, NIPOMO, NORTH HOLLYWOOD, OCEANO, ORCUTT, PASADENA, PATTIWAY, IRU, POINT CONCEPTION, SANDBERG, SAN NICHOLAS ISLAND, SAN PEDRO, SANTA ANA, SANTA MARIA, SANTA MONICA, SANTA YNEZ, SIERRA MADRE, SIMI, STANTON, SUNLAND, SURF, TEHACHAPI, UPPER SESPE MOUNTAINS, VALYERMO, WHEELER RIDGE, AND WHITTIER.
07/01/1941	07-57--?	34.33	119.58	B	3.0			
07/01/1941	07-58--?	34.33	119.58	B	3.5			

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
07/01/1941	08-05--?	34.33	119.58	B	3.0			
07/01/1941	08-07--?	34.33	119.58	B	3.0			
07/01/1941	08-10--?	34.33	119.58	B	3.0			
07/01/1941	08-13--?	34.33	119.58	B	3.0			
07/01/1941	08-15--?	34.33	119.58	B	3.0			
07/01/1941	08-19--?	34.33	119.58	B	4.0		F	AFTERSHOCK OF 07-50-57 (THIS DATE).
07/01/1941	08-21--?	34.33	119.58	B	4.0		F	AFTERSHOCK OF 07-50-57.
07/01/1941	08-25--?	34.33	119.58	B	3.5			
07/01/1941	08-30--?	34.33	119.58	B	4.0		F	AFTERSHOCK OF 07-50-57.
MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
07/01/1941	08-48--?	34.33	119.58	B	4.0		F	AFTERSHOCK OF 07-50-57.
07/01/1941	08-58--?	34.33	119.58	B	4.0		F	AFTERSHOCK OF 07-50-57.
07/01/1941	09-05--?	34.33	119.58	B	4.0		F	AFTERSHOCK OF 07-50-57.
07/01/1941	09-45--?	34.33	119.58	B	4.0		F	AFTERSHOCK OF 07-50-57.
07/01/1941	10-25--?	34.33	119.58	B	4.0		F	AFTERSHOCK OF 07-50-57.
07/01/1941	12-37--?	34.33	119.58	B	3.0			
07/01/1941	14-22--?	34.33	119.58	B	3.0			
07/01/1941	18-13--?	34.33	119.58	B	3.0			
07/01/1941	18-20--?	34.33	119.58	B	4.0		F	AFTERSHOCK OF 07-50-57.
07/01/1941	19-48--?	34.33	119.58	B	3.0			
07/01/1941	20-15--?	34.33	119.58	B	3.5			
07/01/1941	22-51--?	34.33	119.58	B	3.5			
07/01/1941	23-54--?	34.33	119.58	B	4.5		F	AFTERSHOCK OF 07-50-57; FELT AT FILLMORE, GAVIOTA, LOS ALAMOS, AND SANTA BARBARA.
07/02/1941	-?-17--?	34.33	119.58	B	3.0			
07/02/1941	04-33--?	34.33	119.58	B	3.5			
07/02/1941	08-45--?	34.33	119.58	B	3.5			
07/02/1941	11-41--?	34.33	119.58	B	3.0			
07/02/1941	22-19--?	34.33	119.58	B	4.0		F	AFTERSHOCK OF 07-50-57.
07/03/1941	-?-25--?	34.33	119.58	B	3.5			
07/03/1941	19-26--?	34.33	119.58	B	4.0		F	AFTERSHOCK OF 07-50-57.
07/07/1941	01-06--?	34.33	119.58	B	3.0			
07/07/1941	06-25--?	34.33	119.58	B	3.5			
07/08/1941	19-37--?	34.33	119.58	B	3.0			
07/12/1941	16-18--?	34.33	119.58	B	4.5		F	AFTERSHOCK OF 07-50-57; FELT AT FILLMORE, GLENDALE, MONTROSE, SATICOY, SAUGUS, AND WHEELER SPRINGS.
07/12/1941	16-41--?	34.33	119.58	B	3.0			
07/12/1941	21-07--?	34.33	119.58	B	3.0			
07/12/1941	21-12--?	34.33	119.58	B	3.0			
07/13/1941	06-11--?	34.33	119.58	B	3.5			
07/16/1941	23-10--?	34.33	119.58	B	3.0			
07/17/1941	18-31--?	34.33	119.58	B	3.0			
07/27/1941	12-44--?	34.33	119.58	B	3.0			
07/31/1941	13-23--?	34.33	119.58	B	3.0			
08/02/1941	12-31-19	34.33	119.58	C	3.0			
08/09/1941	05-05-24	34.33	119.58	C	3.5			

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
08/12/1941	22-35-24	34.33	119.58	C	3.5			
08/19/1941	10-20-25	34.33	119.58	C	3.0			
08/25/1941	06-58-22	34.33	119.58	C	3.0			
08/27/1941	17-11-02	34.33	119.58	C	3.0			
08/29/1941	08-43-24	34.60	120.30	C	3.0			
09/08/1941	03-12-45	34.33	119.58	B	4.5		F	AFTERSHOCK OF 07/01/41, 07-50-57. V AT GOLETA AND SANTA BARBARA; FELT STRONGLY AT LOS ALAMOS AND SUMMERLAND.
09/08/1941	03-14-23	34.33	119.58	B	4.0		F	TWIN SHOCK OF 03-12-45; SAME "FELT" REPORT.
09/08/1941	04-45-16	34.33	119.58	B	3.5		F	SANTA BARBARA.
09/09/1941	03-23-17	34.33	119.58	B	3.5		F	SANTA BARBARA.
09/09/1941	13-44-46	34.33	119.58	B	3.0			
09/14/1941	01-45-18	34.33	119.58	B	4.0		F	AFTERSHOCK OF 07/01/41, 07-50-57.
09/14/1941	02-20-42	34.33	119.58	B	3.0			
09/15/1941	01-37-02	34.33	119.58	B	4.0		F	GOLETA, SANTA BARBARA, AND SUMMERLAND.
09/15/1941	01-55-18	34.33	119.58	B	3.0			
09/15/1941	02-49-06	34.33	119.58	B	3.5			
09/16/1941	07-27--?	34.33	119.58	B	3.5			
09/25/1941	05-12-56	34.33	119.58	B	4.0		F	GOLETA AND SANTA BARBARA.
10/07/1941	12-05-42	34.33	119.58		3.0			
10/19/1941	23-22-19	34.33	119.58	B	3.0			
11/05/1941	16-36--?	35.00	121.00	D	3.5		F	OFF POINT CONCEPTION; FELT AT SAN SIMEON.
11/17/1941	17-30-27	34.33	119.58	C	3.0			
11/18/1941	18-08-10	34.33	119.58	C	4.0		F	CARPINTERIA AND SANTA BARBARA.
11/21/1941	16-56-03	34.33	119.58	C	4.0		F	GOLETA AND SANTA BARBARA.
11/25/1941	20-01-48	34.33	119.58	C	3.0			
11/28/1941	06-33--?	35.00	120.00	D	3.5			
12/08/1941	-?-29-42	36.00	121.00	D	3.5			
12/22/1941	-?-54-09	35.93	120.48	C	4.0		F	NEAR PARKFIELD-NOT RECORDED ON BERKELEY NETWORK.
01/06/1942	09-20--?	36.15	120.65	D			F	PRIEST VALLEY-RECORDED AT TINEMAHA.
01/06/1942	09-23--?	36.15	120.65	D			F	PRIEST VALLEY-RECORDED AT TINEMAHA.
01/08/1942	18-21-05	34.13	119.58	C	2.5			
01/18/1942	11-35--?	36.40	121.25	D			F	PINNACLES.
01/18/1942	16-50--?	36.40	121.25	D			F	PINNACLES.
02/19/1942	18-33--?	36.40	121.25	D			F	PINNACLES.
03/09/1942	05-57-42	34.30	119.60		3.0			
03/25/1942	-?--?--?	36.40	121.25	D			F	PINNACLES; LIGHT SHOCK.
04/19/1942	04-02-47	34.30	119.60	D	3.0			
04/22/1942	05-32-52	35.30	119.50	D	3.0			
05/08/1942	17-19-13	34.33	119.58	C	3.0			
06/06/1942	06-42-11	34.35	119.85	C	3.0		F	GOLETA.
06/29/1942	21-07-30	35.60	120.80	D	4.0		F	IV AT CAMBRIA AND SAN LUIS OBISPO.
07/19/1942	10-42-07	36.40	121.10	D	1.6			SW OF LLANADA.
09/15/1942	10-36-33	36.13	122.18	B	3.0			SW OF KING CITY.
10/04/1942	10--?--?	34.60	120.00	D			F	IV AT SANTA YNEZ PEAK.
10/11/1942	23-48-23	36.48	121.40	C	1.9			FORESHOCK OF QUAKE ON OCTOBER 15 AT 13-53-56.
10/15/1942	13-53-56	36.48	121.40	B	4.3		F	IV AT BIG SUR, GONZALES, GREENFIELD, HOLLISTER, SALINAS, AND SOLEDAD.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
10/18/1942	08--?--?	36.00	121.00	D			F	CAMBRIA.
10/18/1942	12-01-42	36.00	121.00	D			F	V AT CAMBRIA.
10/19/1942	10-23--?	34.50	119.65	D			F	V AT SANTA BARBARA.
10/20/1942	10-25--?	36.00	121.00	D			F	V AT CAMBRIA.
10/26/1942	01-09-01	36.40	121.60	D	1.8			DEPTH ABOUT 12 KM.
12/02/1942	11-46--?	34.33	119.58	C	3.5		F	V AT SANTA BARBARA.
12/06/1942	16-57-49	35.93	120.48	C	3.5			
01/24/1943	06-55-57	34.33	119.58	C	3.0			
03/16/1943	09-27-47	34.28	119.60	C	3.0			
04/01/1943	13-39-66	34.68	121.75	B	3.1			OFF COAST, WEST OF POINT ARGUELLO.
06/29/1943	02-50-53	36.50	121.10	D	3.1			SW OF LLANADA.
07/05/1943	16-30-29	36.38	121.83	C	3.9			SOUTH OF SALINAS.
07/15/1943	-?-44-42	36.00	120.15	D			F	NEAR AVENAL.
08/07/1943	16-59-47	34.28	119.57	C	3.5			
08/12/1943	15-56-33	34.75	121.15	C	3.5			
08/27/1943	08-16-53	34.43	119.87	C	3.5		F	IV AT SANTA BARBARA.
09/13/1943	12-40--?	35.65	120.65	D			F	PASO ROBLES, POSSIBLY GUN FIRE.
09/18/1943	17-07-16	34.37	119.58	C	3.0			
10/22/1943	12--?--?	36.00	120.90	D			F	SAN ARDO; 2 SHOCKS.
10/26/1943	22-10--?	34.75	120.25	D			F	LOS ALAMOS.
10/31/1943	17-54-06	35.80	120.40	D	3.5			
10/31/1943	20--?--?	36.40	121.00	D			F	LONOAK.
11/08/1943	11-33-46	36.00	119.92	C	3.0		F	KETTLEMAN HILLS; FELT AT AVENAL.
11/30/1943	21-57-18	36.30	120.50	D	4.0			NEAR COALINGA.
12/01/1943	04-51--?	36.50	121.10	D			F	SAN BENITO.
01/04/1944	18-06-40	34.10	120.40	D	3.3			
02/18/1944	16-29-37	34.10	119.52	C	2.1			
02/21/1944	13--?-11	36.17	120.93	C	3.8			WEST OF PRIEST.
03/06/1944	21-32-16	36.40	121.25	C	3.4			NE OF PARAISO.
04/03/1944	02-33--?	34.50	121.40	D	4.0			OFF POINT ARGUELLO.
04/12/1944	15-33-10	34.27	119.52	C	4.0		F	OFF CARPINTERIA; FELT EAST OF SANTA BARBARA.
06/13/1944	08-27-32	34.67	120.50	C	4.6		F	NEAR LOMPOC; VI AT LOS ALAMOS AND IV AT SANTA MARIA.
06/13/1944	08-46-43	34.67	120.50	C	4.0		F	AFTERSHOCK OF 08-27-32.
06/13/1944	11-07-24	34.67	120.50	C	4.4		F	AFTERSHOCK OF 08-27-32.
07/11/1944	22-33--?	36.50	121.10	D			F	SAN BENITO.
07/15/1944	19-22-37	34.37	119.62	C	3.1			
09/04/1944	02-47-46	35.00	120.00	D	3.4		F	LOS ALAMOS.
09/04/1944	05--?--?	35.00	120.00	D			F	LOS ALAMOS.
09/15/1944	14-12-42	34.70	120.20	D	2.6		F	KETTLEMAN HILLS REGION; FELT AT PARKFIELD.
09/18/1944	01-30--?	35.00	120.00	D	3.5			
11/04/1944	08-12-01	36.33	120.08	C	3.4			
11/08/1944	16-12-36	34.33	119.72	C	3.1			
11/28/1944	10-36--?	35.80	120.00	D	3.3			
11/30/1944	18-53-15	34.72	120.42	C	4.1		F	NEAR LOS ALAMOS; FELT AT LOS ALAMOS AND LOS OLIVOS.
12/02/1944	15-09-12	35.80	120.00	D	3.2			
01/27/1945	17-50-31	34.75	120.67	C	3.9			
02/25/1945	20-18-38	36.00	120.48	C	3.6			

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
04/15/1945	22-59-57	34.13	119.83	C	3.1			
06/11/1945	03-54-52	34.50	120.80	D	3.2			
07/11/1945	16-13--?	35.67	121.25	D	4.0		F	NEAR SAN SIMEON; IV AT CAMBRIA.
07/28/1945	02-33-48	34.70	120.10	D	4.2		F	EAST OF SANTA MARIA; IV AT LOS ALAMOS.
09/04/1945	12-38-31	34.32	119.63	C	3.2			
09/07/1945	11-34-20	35.83	120.75	C	4.2		F	NEAR BRADLEY; IV AT CAMBRIA, PARKFIELD, PASO ROBLES, AND SAN MIGUEL.
11/04/1945	-?-46-34	36.38	121.28	C	3.3			NEAR SOLEDAD.
02/09/1946	02-55-28	34.33	119.92	C	2.5			
02/10/1946	11-01-19	36.50	121.00	D	4.2		F	OVER AN AREA OF 2000 SQ. MI. IN WEST CENTRAL CALIFORNIA. V AT SAN BENITO, AND IV AT BIG SUR, CHUALAR, GREENFIELD, HOLLISTER, LONOAK, SAN LUCAS, SAN MIGUEL, SANTA CRUZ, AND SOLEDAD.
02/15/1946	12-07-00	35.90	121.45	D			F	PARKFIELD; LIGHT SHOCK.
04/19/1946	12-50--?	34.00	120.40	D			F	SANTA MARIA.
07/08/1946	19-59-44	34.83	120.53	C	3.2			
08/06/1946	04-55-07	34.95	120.18	C	2.8		F	E OF SANTA MARIA; FELT AT LOS ALAMOS.
09/02/1946	10-09-47	34.18	119.62	C	3.0			
09/09/1946	11-20--?	34.90	120.40	D			F	SANTA MARIA.
09/19/1946	06-35-44	35.83	119.67	C	3.2			
10/24/1946	18-26-50	34.37	119.62	C	2.7			
11/22/1946	09-47-59	34.83	120.68	D	3.0			
11/27/1946	14-44-51	35.50	120.92	C	4.3		F	NEAR CAYUCOS; V AT MORRO BAY AND SANTA MARGARITA; ALSO FELT ATASCADERO, LOS ALAMOS, PISMO BEACH, AND SAN LUIS OBISPO.
12/13/1946	-?-40-01	34.17	119.53	C	3.5			
01/06/1947	21-05-47	35.85	120.47	C	3.6			
01/13/1947	19-38-31	34.32	119.65	C	2.2			
01/14/1947	20-49-27	34.23	119.65	C	2.7			
01/18/1947	12--?-42	34.20	121.50	D	3.3			
01/19/1947	19-32--?	35.60	120.30	D	3.1		F	PASO ROBLES.
02/05/1947	06-14--?	38.23	120.65	B	5.0		F	VI AT LONOAK, V AT COALINGA, IDRIA, AND KING CITY, AND IV AT BIG SUR, HURON, PARKFIELD, SAN ARDO, AND WESTHAVEN.NEAR COALINGA - AFTERSHOCK OF 2/5/47 OF 06-14--?.
02/25/1947	11-45-18	36.20	120.50	D	4.2			
03/23/1947	16-04-51	35.15	121.30	D	3.7			
03/27/1947	09-16-46	35.00	121.00	D	4.2		F	OFF COAST; V AT LOMPOC.
04/29/1947	07-44--?	34.33	119.55	C	3.2			
06/25/1947	18-39-53	34.25	119.50	C	3.1		F	NEAR CARPINTERIA.
06/25/1947	13-41-21	34.25	119.50	C	3.6		F	NEAR CARPINTERIA.
06/25/1947	18-48-26	34.25	119.50	C	2.5			
06/25/1947	20-55-16	34.25	119.50	C	3.2		F	NEAR CARPINTERIA.
06/25/1947	20-55-54	34.25	119.50	C	3.8			
07/13/1947	05-35--?	36.08	121.10	D	3.4			SOUTH OF KING CITY.
07/14/1947	05-40-06	35.92	119.92	C	4.0		F	KETTLEMAN HILLS; IV AT KETTLEMAN CITY.
10/6/1947	18-39--?	36.50	121.23	A	3.2			EAST OF GONZALES.
12/14/1947	05-42--?	36.45	121.08	B	3.4			SW OF LLANADA.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
12/16/1947	09-21-03	36.25	120.77	C	3.6		F	IV AT SAN LUCAS.
12/18/1947	19-30-06	36.12	120.90	D			F	IV AT PARKFIELD.
12/25/1947	06-05--?	35.60	121.10	D			F	CAMBRIA.
12/25/1947	06-20--?	35.60	121.10	D			F	CAMBRIA.
01/11/1948	05-37-28	36.43	121.48	B	4.3		F	IV AT HOLLISTER.
02/01/1948	17--?-54	34.42	119.92	C	3.0			
02/15/1948	08-04-06	35.88	120.37	A	3.4			EAST OF PARKFIELD.
03/07/1948	07-46-22	36.10	120.40	D	3.0			NEAR COALINGA.
03/10/1948	23-24-34	34.43	119.73	C	2.6			
03/18/1948	09-35-05	34.40	119.60	C	2.8			
03/29/1948	02-40--?	35.85	121.40	D			F	IV AT HOLLISTER.
04/23/1948	15-23-43	34.10	120.93	C	3.7			
05/05/1948	06-47-06	34.45	119.72	B	2.7			
05/07/1948	12--?-32	36.20	121.90	D	3.0			WEST OF PRIEST.
05/09/1948	11-10--?	34.75	120.25	D			F	V AT LOS ALAMOS.
07/14/1948	11-05-37	34.67	120.92	C	3.2			
07/17/1948	05-26-31	34.55	120.05	C	3.4			
07/28/1948	01-30-57	36.05	120.53	C	3.1			SE OF PRIEST.
07/29/1948	13-16-23	35.12	120.47	C	3.4			
08/04/1948	10-22-57	35.92	120.33	C	3.6			
09/03/1948	23-42-26	34.33	119.53	C	3.9		F	SANTA BARBARA.
09/17/1948	15-41-01	34.40	119.62	C	3.1			
10/27/1948	03-05--?	34.75	120.25	D			F	IV AT LOS ALAMOS.
10/29/1948	03-04-59	34.10	120.40	D	3.4		F	V AT ARLIGHT AND POINT ARGUELLO LIGHT STATION.
11/02/1948	19-06-45	34.37	119.58	C	2.9			
12/04/1948	06-44-20	34.43	119.72	C	2.8			
12/04/1948	23-32-51	34.42	119.50	C	2.7			
12/20/1948	04-42-46	35.80	121.50	C	4.5		F	OFF COAST, NEAR PIEDRAS BLANCAS POINT; III AT SAN SIMEON.
12/31/1948	14-35-46	35.67	121.40	B	4.6		F	ALONG THE COAST FROM LOMPOC TO MOSS LANDING; VI AT SAN SIMEON AND V AT CAYUCOS, CRESTON, MOSS LANDING, AND PIEDRAS BLANCAS LIGHT STATION.
01/25/1949	04-29--?	34.90	120.40	D			F	V AT ORCUTT AND SANTA MARIA.
03/27/1949	06-31-16	34.25	119.62	C	2.6			
04/06/1949	14-07--?	35.00	120.00		2.6			
04/08/1949	13-17-07	34.60	120.35	C	3.2		F	IV AT LOS ALAMOS.
04/14/1949	01-46-12	34.28	119.52	C	2.6			
04/23/1949	09-18-09	36.38	121.37	C	3.7			NORTH OF PARAISO.
05/06/1949	04-23-46	34.50	121.00	C	3.4			
05/10/1949	06-20--?	35.90	120.40	D			F	SANTA MARIA - SLIGHT.
05/10/1949	11--?--?	35.90	120.40	D			F	SANTA MARIA - SLIGHT.
05/16/1949	03-01-03	34.72	120.02	C	3.2			
05/17/1949	23-57-55	35.63	121.15	D	4.1		F	IV AT SAN SIMEON.
06/27/1949	10-35-31	35.80	121.10	D	4.5		F	V AT SAN ARDO AND SAN MIGUEL; ALSO FELT AT PASO ROBLES, SAN LUIS OBISPO, AND SANTA MARGARITA.
07/21/1949	16-50--?	36.15	120.35	D			F	IV AT COALINGA.
07/21/1949	17-01--?	36.15	120.35	D			F	IV AT COALINGA.
07/24/1949	03-04-05	36.00	120.00	D	2.3			SE. KINGS C0. AFTER SHOCK AT 06-26--?, MAG. 2.0.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
07/27/1949	18-21-35	34.53	120.37	C	3.6			
08/01/1949	-?-07-24	36.90	121.20	D	3.0			SOUTH OF KING CITY.
08/07/1949	01-38-43	36.50	121.50	D	2.3			NO. MONTEREY CO.
08/10/1949	09-17-39	36.50	121.00	C	2.6			CENTRAL SAN BENITO CO.
08/22/1949	03--?--?	36.00	120.00	D			F	KETTLEMAN HILLS. FIFTH SHOCK IN 2 WEEKS.
08/26/1949	16-52-32	34.50	120.50	D	4.2		F	NEAR POINT CONCEPTION. VI AT ARLIGHT AND SURF. IV AT GUADALUPE, LOMPOC, AND LOS ALAMOS.
08/27/1949	14-15--?	34.50	120.50	D			F	ARLIGHT. SLIGHT SHOCK.
08/27/1949	14-51-46	34.50	120.50	D	4.9		F	NEAR POINT CONCEPTION. VI AT ARLIGHT, LOMPOC, AND SUDDEN. V AT COSMALIA, LOS ALAMOS, NIPOMO, SANTA BARBARA, AND SURF.
08/29/1949	12-07-20	36.00	120.10	D	3.0		F	IV IN AVENAL AND KETTLEMAN CITY.
10/28/1949	08-07-02	36.80	120.90	C	2.6			NW OF PRIEST.
11/17/1949	05-06-06	34.80	120.70	D	2.8		F	IV AT SANTA MARIA.
12/28/1949	09-17-12	36.20	120.70	D	2.6			NEAR PRIEST.
02/19/1950	08-29-44	34.50	120.70	D	3.5			
03/09/1950	23-43-19	36.35	121.22	C	3.2		F	NORTH OF KING CITY; V AT ROBLES DEL RIO.
03/22/1950	01-31-57	35.97	120.63	C	3.7			
03/29/1950	12-43-20	35.97	120.88	D	3.5			
04/15/1950	11-56-32	35.75	119.62	C	4.6		F	NE OF LOST HILLS; V AT ASH MOUNTAIN, (SEQUOIA NATIONAL PARK), KERNVILLE, AND SHAFTER, AND IV AT BUTTONWILLOW, JAWBONE AQUEDUCT STATION, LOST HILLS, THREE RIVERS, AND VISALIA.
04/21/1950	13-17-29	34.38	119.58	B	3.0		F	IV AT SANTA BARBARA.
04/26/1950	07-23-29	35.20	120.60	C	3.5		F	V AT SANTA MARIA; ALSO FELT AT ORCUTT.
04/26/1950	07-38--?	35.20	120.60	D			F	SANTA MARIA.
05/21/1950	18-59-03	34.57	119.63	C	2.6			
05/21/1950	19-26-48	35.88	119.73	C	3.4			
05/24/1950	01-46-57	36.43	120.77	C	2.9			SE OF LLANADA.
07/13/1950	15-01-47	34.33	119.50	C	2.8		F	OFF CARPINTERIA; V AT MONTECITO; ALSO FELT AT SANTA BARBARA AND NEARBY AREAS.
08/01/1950	21-08-43	36.20	122.23	B	2.0			OFF COAST, WEST OF BIG SUR.
08/02/1950	06-50-48	34.67	120.63	C	3.3			
08/23/1950	09-10--?	34.40	119.50	D			F	IV AT RINCON POINT; FELT AT CARPINTERIA.
09/24/1950	04-45--?	34.50	120.50	D			F	III AT ARLIGHT.
09/24/1950	12-23--?	34.22	119.58	C	3.3			
09/24/1950	21-51-44	36.20	120.50	D	2.9			EAST OF PRIEST.
10/20/1950	08-23-25	36.33	121.07	C	2.7			SOUTH OF KING CITY.
11/21/1950	04-30--?	30.90	120.40	D			F	SANTA MARIA.
03/02/1951	02-13-44	36.10	120.60	D	3.1			SE OF PRIEST
03/04/1951	13-32--?	34.90	120.40	D			F	IV AT SANTA MARIA; 2 SHOCKS.
03/05/1951	09-50--?	34.90	120.40	D			F	IV AT SANTA MARIA.
03/10/1951	05-35--?	34.50	120.50	D			F	IV AT ARLIGHT.
03/15/1951	13-50-43	35.02	120.48	C	3.8		F	IV AT LOS ALAMOS.
03/26/1951	06-07-34	34.62	119.50	C	3.5		F	IV AT OJAI AND SUMMERLAND; FELT AT VENTURA.
05/04/1951	03-28-36	36.20	120.20	D	3.1			FORESHOCK OF QUAKE AT 20-08-10.
05/04/1951	20-08-10	36.20	120.20	D	3.2			EAST OF COALINGA.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
05/06/1951	03-18-03	36.40	120.40	D	2.8			NORTH OF COALINGA.
05/25/1951	05-11-18	36.30	120.30	D	3.1			NORTH OF COALINGA.
05/29/1951	05-08-24	35.08	119.65	C	3.2		F	ELKHORN HILLS; IV IN CUYAMA VALLEY.
05/31/1951	06-28-42	36.30	120.20	D	2.7			NE OF COALINGA.
06/16/1951	19-01-17	34.40	120.08	C	3.3			
06/19/1951	06-13-47	35.97	120.42	C	3.6			SOUTH OF COALINGA.
07/01/1951	-?-13-19	36.20	120.95	B	3.2			EAST OF KING CITY.
07/07/1951	05-53-33	34.75	120.75	C	3.5			
08/02/1951	05-09-25	36.35	121.27	B	3.9		F	NEAR GREENFIELD; IV AT BIG SUR, AT 7 MI. S OF HOLLISTER, AND ROBLES DEL RIO.
08/08/1951	19-42--?	34.80	120.40	D			F	IV AT ORCUTT.
08/09/1951	09-20-48	36.15	121.75	C	2.2			NEAR BIG SUR.
08/25/1951	01-04-10	36.47	121.15	B	3.1			SW OF LLANADA.
08/28/1951	22-12-27	34.60	121.00	D	3.5		F	OFF POINT ARGUELLO; III AT LOS ALAMOS.
09/18/1951	02-30--?	36.25	121.80	D			F	IV AT BIG SUR.
09/19/1951	22-50--?	36.25	121.80	D			F	IV AT BIG SUR.
10/03/1951	13-44-33	35.92	120.52	C	3.8			
10/26/1951	16-25-40	34.42	119.73	C	3.0			
11/17/1951	03-19-48	34.70	120.50	D	2.5		F	NEAR LOMPOC; III AT LOS ALAMOS.
11/25/1951	23-15-39	35.33	119.50	B	3.8			
12/20/1951	04-13-06	36.00	120.05	C	3.7			
01/24/1952	-?-32-38	34.18	119.88	C	2.7			
01/30/1952	11-05-33	36.30	121.13	C	2.7			NEAR KING CITY.
01/31/1952	20-09-02	34.18	119.53	C	2.6			
01/31/1952	21-33-12	36.40	121.40	C	3.6			SOUTHEAST CF SOLEDAD.
02/09/1952	22-26-39	34.07	120.75	C	3.6			
03/25/1952	09-18-50	34.18	120.95	C	3.6			
04/02/1952	05-21-10	36.45	121.25	B	3.1			NEAR SOLEDAD.
05/07/1952	05-45--?	34.40	119.60	D			F	IV AT MONTECITO AND SUMMERLAND.
06/18/1952	04--?--?	34.60	120.65	D			F	IV AT POINT ARGUELLO LIFEBOAT STATION.
07/01/1952	15-29-24	34.30	119.80	D	3.1			
07/15/1952	06-07-55	36.42	121.00	C	2.5			ABOUT 15 MI. NE OF KING CITY.
07/27/1952	18-15-14	34.18	119.70	C	3.1			
07/27/1952	20-20-35	34.22	119.67	C	3.2			
07/27/1952	20-30-05	34.20	119.67	B	3.5			
08/07/1952	19-l6-12	34.33	120.68	C	3.6		F	OFF POINT CONCEPTION; IV AT LOS ALAMOS.
08/11/1952	21-42-29	34.17	119.67	C	3.1			
08/23/1952	20-10--?	34.85	119.50	D			F	IV AT VENTUCOPA - SECOND SHOCK AT 21-20--?.
08/30/1952	14-58-11	34.35	119.62	B	3.3			
09/01/1952	12-03--?	34.30	119.60	D	3.0			
09/12/1952	21--?-15	34.25	119.70	C	3.0			
09/14/1952	11-46-06	35.90	120.30	D	3.3			
10/09/1952	14-46-02	34.20	122.20	D	4.6			(DEPT. OF WATER RESOURCES DATA)

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
11/22/1952	07-46-37	35.73	121.20	B	6.0		F	6 MI. NORTH OF SAN SIMEON, NEAR BRYSON; FELT OVER AN AREA OF 20,000 SQ. MI. VII AT BRADLEY AND BRYSON, VI AT ARROYO GRANDE, ATASCADERO, CAMBRIA, CAMP COOKE, CARMEL VALLEY, CAYUCOS, CHUALAR, CRESTON, GORDA STATION, GUADALUPE, HARMONY, HEARST RANCH, KING CITY, LOCKWOOD, LONOAK, MORRO BAY, OCEANO, PARKFIELD, PASO ROBLES, PISMO BEACH, SALINAS, SAN ARDO, SAN LUIS OBISPO, SAN SIMEON, SANTA MARGARITA, AND TEMPLETON, AND V AT AVENAL, BEN LOMOND, BIG SUR, BUELLTON, BUTTONWILLOW, CARUTHERS, CASMALIA, CHOLAME, COALINGA, CORCORAN, DOS PALOS, HOLLISTER, HUASNA, KETTLEMAN CITY, LOMPOC, LOST HILLS, LUCIA, MARICOPA, MONTEREY, MOSS LANDING, NIPOMO, ORCUTT, PAICINES, RIVERDALE, SAN MIGUEL, SANTA CRUZ, SANTA MARIA, SHAFTER, STRATFORD, SUDDEN, AND SURF.
11/22/1952	08-02-40	35.73	121.20	B	3.2			SAN SIMEON AFTERSHOCK.
11/22/1952	08-29-47	35.73	121.20	B	3.1			SAN SIMEON AFTERSHOCK.
11/22/1952	08-53-04	35.73	121.20	B	3.4		F	SAN SIMEON AFTERSHOCK; IV AT ARVIN, CALIENTE, JOLON, LOST HILLS, MALIBU, MARICOPA, MCFARLAND, MIRACLE HOT SPRINGS, MORGAN HILL, NIPOMO, PISMO BEACH, AND SHAFTER.
11/22/1952	11-08-44	35.73	121.20	B	3.1			SAN SIMEON AFTERSHOCK.
11/22/1952	11-45-31	35.73	121.20	B	3.1			SAN SIMEON AFTERSHOCK.
11/22/1952	12-34-44	35.73	121.20	B	3.0			SAN SIMEON AFTERSHOCK.
11/22/1952	13-37-31	35.73	121.20	B	4.0		F	SAN SIMEON AFTERSHOCK; V AT CALIENTE, MIRACLE HOT SPRINGS, AND WHEELER SPRINGS.
11/22/1952	19-25-21	35.73	121.20	B	3.9			SAN SIMEON AFTERSHOCK.
11/22/1952	19-36-27	35.70	121.20	D	3.1			SAN SIMEON AFTERSHOCK.
11/22/1952	23-39-20	35.70	121.20	D	3.1			SAN SIMEON AFTERSHOCK.
11/23/1952	09-22-35	36.00	120.90	D	3.2			20 MI. SE OF KING CITY.
11/23/1952	18-40-19	35.67	121.17	C	4.2			SAN SIMEON AFTERSHOCK.
11/25/1952	19-17-54	36.20	120.00	D	3.2			
11/25/1952	20-14-45	35.73	121.20	C	3.6			SAN SIMEON AFTERSHOCK.
11/25/1952	21-59-17	35.73	121.20	C	4.4			SAN SIMEON AFTERSHOCK.
11/26/1952	13-32-09	35.73	121.20	C	3.5			SAN SIMEON AFTERSHOCK.
11/27/1952	17-37-05	35.70	121.20	D	3.3			SAN SIMEON AFTERSHOCK.
11/28/1952	10-22-33	35.90	121.20	D	3.0			SAN SIMEON AFTERSHOCK.
11/29/1952	16--?--?	36.00	121.15	D			F	IV AT JOLON - TIME MAY BE 04--?--? ON 11/30/1952.
11/29/1952	23-15-58	35.70	121.20	D	3.5			SAN SIMEON AFTERSHOCK.
12/05/1952	01-05-57	36.50	120.70	D	3.0			14 MI. SE OF LLANADA.
12/06/1952	23-50--?	35.66	120.65	D			F	IV AT PASO ROBLES; FELT AT ADELAIDA.
12/12/1952	-?-27-07	36.40	120.97	B	3.0		F	17 MI. NE OF KING CITY; III AT LONOAK.
12/25/1952	16-44-10	34.40	121.40	D	3.6			
01/12/1953	13-05-18	35.80	121.10	D	3.2			14 MI. NE OF SAN SIMEON.
01/24/1953	-?--?--?	35.90	121.00	D			F	TEN SHOCKS REPORTED FELT FROM 1/24 TO 1/31 AT BRYSON (E. WEFERLING RANCH).
01/29/1953	20-31-19	35.80	121.10	D	3.1			14 MI. NE OF SAN SIMEON.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
02/03/1953	14-50-18	35.47	120.75	C	4.1		F	12 MI. NNW OF SAN LUIS OBISPO; V AT ATASCADERO, BRYSON, CRESTON, MORRO BAY, SANTA MARGARITA, AND IV AT CAYUCOS, PASO ROBLES, SAN LUIS OBISPO, AND TEMPLETON.
02/05/1953	02-54-12	35.90	121.00	D	2.8		F	IV AT BRYSON (E. WEFERLING RANCH).
02/15/1953	15-30--?	35.90	121.00	D			F	BRYSON (E. WEFERLING RANCH).
02/17/1953	08-06--?	35.90	121.00	D			F	III AT BRYSON (PLEYTO SCHOOL) - SEVERAL MILD SHOCKS REPORTED FELT DAILY SINCE SHOCK OF 11/21/52, 23-46-38 (NOT LISTED).
02/18/1953	14-10--?	35.90	121.00	D			F	BRYSON (E. WEFERLING RANCH) - MILD.
03/01/1953	18-53--?	35.90	121.00	D			F	V AT BRYSON.
03/04/1953	03-40--?	35.90	121.00	D			F	BRYSON (PLEYTO SCHOOL) - LIGHT.
03/15/1953	21--?-32	34.87	121.53	C	3.7			
03/18/1953	05-03--?	35.90	121.00	D			F	III AT BRYSON (PLEYTO SCHOOL).
03/29/1953	17-19-48	35.90	120.20	D	3.7			
04/08/1953	-?-59-20	34.80	120.60	D	3.6		F	NEAR CASMALIA; IV AT LOS ALAMOS.
04/15/1953	-?-29-10	35.83	121.07	C	3.1		F	14 MI. NNE OF SAN SIMEON; IV AT BRYSON.
04/15/1953	05-30--?	35.90	121.00	D			F	BRYSON - LIGHT.
04/29/1953	05-26-53	36.00	121.15	C	3.5		F	14 MI. S OF KING CITY - USCGS GIVES TIME AS 05-26-52, LOCATION AS N35.8 121.2W, REPORT AS NEAR BRYSON; V AT PLEYTO SCHOOL. 22 MI. NE OF KING CITY.
05/01/1953	22-16-51	36.40	120.80	D	3.0			
05/08/1953	08-15--?	34.65	120.45	D			F	III AT LOMPOC.
05/14/1953	03-36--?	36.00	120.00	D	3.3			
05/14/1953	09-36-09	35.75	121.08	B	3.7		F	9 MI. NE OF SAN SIMEON - USCGS GIVES N35.52 121.28W, OFF CAMBRIA; V AT BRYSON.
05/15/1983	07-15--?	35.90	121.00	D			F	IV AT BRYSON (PLEYTO SCHOOL).
05/28/1953	03-51-13	35.88	120.50	B	4.3		F	20 MI. SW OF COALINGA; IV AT PASO ROBLES AND III AT SAN MIGUEL.
05/28/1953	07-58-33	35.88	120.50	C	3.5		F	AFTERSHOCK OF 03-51-13; FELT AT SAN MIGUEL.
05/29/1953	10-20-16	35.90	121.20	D	2.9			20 MI. SOUTH OF KING CITY.
05/31/1953	23-51-17	36.10	120.40	D	3.2			NEAR COALINGA.
06/04/1953	11-40--?	35.50	120.50	D			F	V AT CRESTON - PROBABLY A BLAST.
06/06/1953	20-26-33	36.00	120.30	D	2.9			10 MI. SOUTH OF COALINGA.
06/19/1953	11-24-50	36.30	120.70	D	2.8			20 MI. EAST OF KING CITY.
06/22/1953	15-22-35	35.93	120.38	C	4.3		F	15 MI. WSW OF COALINGA; FELT AT COALINGA AND PASO ROBLES.
07/01/1953	22-17-20	34.60	121.35	D	3.2		F	OFF POINT ARGUELLO; IV AT POINT ARGUELLO LIGHT STATION.
08/14/1953	01-40-06	36.30	120.30	D	2.9			8 MI. NORTH OF COALINGA.
08/14/1953	09-22-50	36.50	121.20	D	2.3			20 MI. NORTH OF KING CITY.
09/02/1953	09-41-20	35.90	120.80	D	3.0			30 MI. SE OF KING CITY.
09/03/1953	11--?--?	35.50	120.50	D			F	CRESTON.
09/04/1953	03-54-25	35.90	120.32	C	3.5		F	15 MI. SOUTH OF COALINGA; IV AT CRESTON AND PASO ROBLES.
09/22/1953	07-36-58	36.40	121.20	D	3.8			NORTH OF KING CITY.
09/23/1953	06-21-51	35.70	121.10	D	3.5		F	NEAR SAN SIMEON; V AT BRYSON.
10/01/1953	03-56-15	36.25	121.83	C	3.4		F	25 MI. S OF MONTEREY; IV AT BIG SUR.
10/16/1953	03-45-35	35.95	120.53	C	3.4			SOUTHWEST OF COALINGA.
10/21/1953	16-02-38	34.32	119.70	B	4.0		F	OFF SANTA BARBARA; V AT SANTA BARBARA AND VICINTIY, AND IV AT GOLETA AND LOS PRIETOS RANGER STATION.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
10/24/1953	13-24-30	35.90	121.10	D	3.6			SOUTH OF KING CITY.
10/25/1953	08-43-25	36.50	121.50	D	3.2			NORTHWEST OF KING CITY.
11/02/1953	-?-52-06	36.40	121.30	D	3.4			NORTHWEST OF KING CITY.
01/04/1954	23-03-11	36.12	120.63	B	3.2			14 MI. WEST OF COALINGA.
01/05/1954	-?-23-23	35.93	120.00	C	3.0			SOUTHEAST OF COALINGA.
01/15/1954	22-02-18	36.50	121.23	C	2.6			NORTH OF KING CITY.
01/24/1954	19-06-45	35.78	121.08	C	3.1			30 MI. SOUTH OF KING CITY.
01/26/1954	09-43-22	34.50	120.33	C	3.8		F	W OF LAS CRUCES; III AT SANTA YNEZ.
03/09/1954	19-55-30	35.90	120.50	D	3.6		F	16 MI. SSE OF COALINGA; FELT NEAR PARKFIELD.
03/15/1954	22-43-50	35.00	120.70	D	3.4			
03/18/1954	12-07-53	35.40	120.90	D	3.0			NORTHWEST OF SAN LUIS OBISPO.
04/01/1954	12-04-38	36.05	120.20	C	3.3			6 MI. SOUTHEAST OF COALINGA.
04/09/1954	07-38-23	35.78	121.08	D	3.1			10 MI. NORTHEAST OF SAN SIMEON.
04/09/1954	14-58--?	35.90	121.00	D			F	IV AT BRYSON (PLEYTO SCHOOL); SECOND SHOCK REPORTED FELT AT 23-40--?.
04/20/1954	09-32-18	36.63	121.03	D	2.6			12 MI. NORTHEAST OF KING CITY.
05/10/1954	14-24-28	36.08	120.80	C	3.1		F	NE OF SAN ARDO - SLIGHT AT KING CITY.
06/04/1954	11-58-38	36.45	121.13	C	3.5			16 MI. SOUTHWEST OF LLANADA.
07/05/1954	07-25-39	36.20	121.80	D	3.2			30 MI. SOUTH OF MONTEREY.
08/13/1954	13-36-44	34.25	120.50	C	3.2			
08/13/1954	13-44-23	34.25	120.50	C	3.2			
08/19/1954	11-45-08	34.25	120.50	C	3.2			
08/21/1954	22-50-49	35.47	121.33	B	3.3			40 MI. SOUTH OF HOLLISTER.
08/22/1954	08-34-40	34.33	120.67	C	3.8			
08/22/1954	12-36-07	34.33	120.67	C	3.8			
12/22/1954	21-12-24	36.00	121.00	D	3.7		F	SE OF KING CITY; III AT KING CITY.
12/22/1954	21-12-28	36.00	120.60	D	3.8			
01/07/1955	14-50-22	34.40	119.60	D	3.0			
01/18/1955	13-30--?	36.20	121.85	D			F	IV REPORTED FELT AT BIG SUR.
02/05/1955	07-10-19	35.80	121.40	C	3.3			WEST OF SAN SIMEON.
02/27/1955	03-17-51	36.25	120.83	C	2.9		F	EAST OF KING CITY; IV IN PRIEST VALLEY.
03/02/1955	03-30--?	36.00	120.70	D			F	IV REPORTED FELT IN INDIAN VALLEY.
03/02/1955	15-59-01	36.00	120.93	B	4.8		F	18 MI. SE OF KING CITY; FELT OVER 7000 SQ. MI. OF W CENTRAL CALIF. USCGS MAG. 5.1. VI AT ADELAIDA, BRYSON, INDIAN VALLEY, SAN ARDO, SAN LUCAS, AND TEMPLETON.
03/02/1955	20-02-53	36.00	120.93	B	3.7			AFTERSHOCK OF QUAKE AT 15-59-01.
03/05/1955	08-46-36	36.10	121.10	D	2.0			SOUTH OF KING CITY.
03/06/1955	10-47-32	35.92	120.90	D	3.2			SOUTHEAST OF KING CITY.
04/04/1955	20-56-56	36.08	121.00	C	3.2			SOUTHEAST OF KING CITY.
04/27/1955	09-28-08	35.90	121.20	D	2.8			SOUTHWEST OF KING CITY.
05/14/1955	20--?--?	36.35	121.85	D			F	IV REPORTED FELT AT BIG SUR AND SANTA CRUZ.
05/16/1955	18-22-52	35.92	120.58	C	3.0			SOUTHWEST OF COALINGA.
05/30/1955	09-38-29	36.25	121.25	C	3.0			WEST OF KING CITY.
05/31/1955	01-45-53	36.40	121.25	B	3.0			NORTH OF KING CITY.
06/13/1955	14-55-12	36.30	121.30	C	2.5			NORTH OF KING CITY.
06/19/1955	05-36-33	35.62	121.10	C	2.5			SOUTHEAST OF SAN SIMEON.
07/06/1955	11-29-18	36.50	121.42	C	3.4			SOUTH OF HOLLISTER.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
07/06/1955	13-18-53	36.50	121.50	D	2.7			SOUTH OF HOLLISTER.
07/28/1955	12-07-52	36.50	121.40	D	2.6			SOUTH OF HOLLISTER.
09/21/1955	18-06-52	36.50	121.00	D	3.3			NORTH OF KING CITY.
10/22/1955	07-04-18	36.22	120.33	C	4.2		F	V AT AND 14 MI. NW OF COALINGA.
11/02/1955	19-40-06	36.00	120.92	A	5.2		F	55 MI. NNW OF SAN LUIS OBISPO; FELT OVER 7000 SQ. MI. OF COASTAL W CENTRAL CALIF. VI AT ADELAIDA RD. (14 MI. W OF PASO ROBLES), BRYSON, KING CITY, PASO ROBLES, SAN ARDO, SAN LUCAS, AND SAN MIGUEL.
11/18/1955	09-03-30	35.90	120.50	D	2.9			SOUTHWEST OF COALINGA.
11/19/1955	07-20--?	34.50	119.65	D			F	REPORTED FELT AT SANTA BARBARA.
11/19/1955	10-59-41	36.03	120.90	C	3.3			SOUTHEAST OF KING CITY.
11/21/1955	21-14-18	36.10	119.90	D	3.5			
12/11/1955	20-10-38	36.27	120.72	C	3.5			NORTHWEST OF COALINGA.
12/16/1955	14-43-11	36.03	120.87	C	3.8		F	SOUTHWEST OF KING CITY; FELT AT ATASCADERO, PASO ROBLES, AND SAN MIGUEL.
12/29/1955	13-33-17	36.45	121.25	C	3.4			NORTH OF KING CITY.
02/14/1956	22-15-08	36.50	121.10	D	2.8			SOUTHWEST OF LLANADA.
03/15/1956	15-26-11	36.50	121.20	D	2.6			SOUTHEAST OF HOLLISTER.
04/03/1956	09-26-02	36.45	121.23	B	2.7			SOUTH OF HOLLISTER.
04/10/1956	11-24-21	36.43	121.48	C	2.9			SOUTHEAST OF MONTEREY.
04/10/1956	20-53-21	36.30	121.00	D	2.9			NORTHEAST OF KING CITY.
05/01/1956	15-06-33	36.50	121.00	D	2.5			SOUTH OF HOLLISTER.
05/04/1956	08-16-14	35.75	121.07	B	3.1			NORTHEAST OF SAN SIMEON.
05/04/1956	08-16-16	35.95	120.93	D	3.5			
05/15/1956	10-45--?	34.90	120.40	D			F	REPORTED FELT AT SANTA MARIA.
06/11/1956	-?-48-37	36.00	120.97	C	3.2			SOUTHEAST OF KING CITY.
06/15/1956	23-42-03	36.30	121.80	D	2.8			SOUTH OF MONTEREY.
07/09/1956	23-15--?	35.10	120.50	D			F	III REPORTED FELT NEAR HUASNA.
07/23/1956	08-03-48	36.30	121.30	D	4.7		F	NW OF KING CITY; FELT OVER 4000 SQ. MI. OF COASTAL CENTRAL CALIF. V AT BIG SUR, CHUALAR, GONZALES, GREENFIELD, 7.5 MI. S OF HOLLISTER, KING CITY, PASO ROBLES, SAN BENITO, AND SAN JUAN BAUTISTA.
07/23/1956	08-20-37	36.50	121.40	D	3.1			AFTERSHOCK OF QUAKE AT 08-03-48.
07/31/1956	-?-40-43	34.15	119.60	C	3.2			
07/31/1956	17-25--?	35.10	120.50	D			F	IV REPORTED FELT AT HUASNA.
08/09/1956	-?-08-49	34.37	119.80	B	4.0		F	OFF SANTA BARBARA; IV AT LOS PRIETOS RANGER STATION.
08/10/1956	23-24-03	35.90	121.30	D	3.0			SOUTHWEST OF KING CITY.
08/20/1956	05-10-33	36.48	121.48	B	3.2		F	NEAR GONZALES; IV AT PINNACLES NATIONAL MONUMENT.
09/15/1956	-?-34-37	36.30	120.30	D	2.7			NORTH OF COALINGA.
10/10/1956	20-02-24	34.70	121.00	D	3.8			
11/12/1956	10-13--?	36.30	120.10	C	3.3			
11/16/1956	03-23-09	35.95	120.47	B	5.0		F	SW OF COALINGA; FELT OVER 8000 SQ. MI. FROM HOLY CITY TO BETTERAVIA TO FIREBAUGH. VI AT KING CITY, MEE RANCH (LONOAK), AND SAN LUCAS.
11/19/1956	13-53-53	35.98	120.57	C	3.3		F	SOUTHWEST OF COALINGA; III AT ADELAIDA (15 MI. WEST OF PASO ROBLES).
11/20/1956	03-42-44	34.70	120.50	C	3.6		F	IV AT LOS ALAMOS; III FELT AT 07-42--?, 11/21/1956.

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MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
12/11/1956	10-56-53	35.88	120.47	C	4.1			NEAR PARKFIELD.
12/28/1956	13-39-37	35.90	121.10	D	2.6			NORTHEAST OF SAN SIMEON.
01/01/1957	09-25--?	35.50	120.65	D			F	REPORTED FELT AT ATASCADERO.
01/29/1957	21-19-53	35.87	122.12	C	4.9		F	OFF COAST NW OF SAN SIMEON; FELT OVER 5000 SQ. MI. OF COASTAL CENTRAL CALIF. V AT BIG SUR, CAMBRIA, CARMEL VALLEY, HARMONY, KING CITY, LUCIA, MARINA, AND SEASIDE, AND IV GENERALLY FROM MOSS LANDING TO 20 MI. W OF COALINGA TO SAN LUIS OBISPO.
02/03/1957	07-57-12	34.50	121.20	C	3.9			
02/08/1957	04-45-38	36.50	121.20	D	2.8			NORTH OF KING CITY.
02/08/1957	21-20--?	36.50	122.00	D			F	SHARP SHOCK FELT MONTEREY PEN. (BSSA).
02/09/1957	08-10--?	35.50	120.65	D			F	IV REPORTED FELT AT ATASCADERO.
02/14/1957	-?-31-30	35.10	119.80	D	2.4			
02/14/1957	10-30-27	36.00	120.60	C	3.6			
02/16/1957	11-43-50	34.30	119.53	C	3.5			
03/09/1957	14-38-28	34.70	119.60	C	2.9			
03/09/1957	14-59-21	34.70	119.60	C	2.4			
04/05/1957	-?-40--?	34.75	120.25	D			F	IV REPORTED FELT AT LOS ALAMOS.
06/21/1957	20-46-42	35.10	120.90	D	3.7		F	OFF COAST; FELT AT SAN LUIS OBISPO AND MORRO BAY.
07/02/1957	09-18-22	34.37	119.88	B	3.4		F	W OF SANTA BARBARA; FELT AT SANTA BARBARA.
07/02/1957	12-59-05	34.37	119.88	B	3.3			
07/02/1957	13-58-28	34.37	119.88	B	3.2			
07/21/1957	01-29-20	36.43	121.22	B	3.1			NORTH OF KING CITY.
08/03/1957	09-31-22	36.25	120.88	C	2.5			EAST OF KING CITY.
08/18/1957	03-05-25	34.47	120.13	C	3.4			
08/18/1957	11-08-23	34.47	120.13	C			F	N OF GAVIOTA; FELT AT CACHUMA RESERVOIR.
08/21/1957	07-36-54	36.47	121.52	C	3.6			NORTHWEST OF KING CITY.
08/28/1957	01-13-57	34.58	121.00	C	3.5			
09/12/1957	21-36--?	35.50	121.00	D			F	II FELT AT P G AND E PLANT, MORRO BAY.
09/21/1957	06-54-26	36.40	121.10	D	2.8			NORTH OF KING CITY.
09/21/1957	15-32--?	35.50	121.00	D			F	II FELT AT P G AND E PLANT, MORRO BAY.
09/25/1957	23-33-31	36.50	121.50	D	2.7			SOUTH OF HOLLISTER.
10/01/1957	12-55-57	36.47	121.23	C	3.3			SOUTHWEST OF LLANADA.
10/05/1957	14-42--?	34.75	120.25	D			F	IV REPORTED FELT AT LOS ALAMOS.
10/19/1957	-?-04-38	36.10	120.87	B	3.3			SOUTHEAST OF KING CITY.
10/28/1957	11-41-02	34.33	120.00	C	2.8			
11/05/1957	23-50-52	34.72	120.33	C	3.4			
11/18/1957	01-11-42	36.38	121.23	C	3.1			NORTHWEST OF KING CITY.
11/18/1957	07-26-32	36.50	121.70	D	3.3			SOUTHEAST OF MONTEREY.
12/31/1957	22-32-55	36.40	121.00	D	2.9			NORTHEAST OF KING CITY.
01/07/1958	17-13-16	35.70	120.80	D	3.0			NORTH OF SAN LUIS OBISPO.
01/18/1958	08-12--?	35.55	120.65	D			F	REPORTED FELT AT PASO ROBLES.
01/21/1958	21-22-08	36.40	120.50	D	2.9			NORTHWEST OF COALINGA.
01/23/1958	07-06-46	34.38	119.58	B	2.6		F	E OF SANTA BARBARA; IV AT SANTA BARBARA.
01/28/1958	07-12-54	36.50	121.10	D	2.2			SOUTHWEST OF LLANADA.
03/26/1958	13-12-30	36.20	120.30	D	2.4			NEAR COALINGA.
03/27/1958	20-26-14	35.90	121.50	D	2.8			NORTHWEST OF SAN SIMEON.

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MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
03/31/1958	17-38-23	36.50	121.10	D	2.7			SOUTHWEST OF LLANADA.
04/10/1958	08-32-33	36.45	121.12	C	2.9			SOUTHWEST OF LLANADA.
06/05/1958	17-12-50	36.40	121.10	D	3.1			NORTH OF KING CITY.
06/15/1958	07-02-33	36.50	121.38	C	2.9			FORESHOCK OF QUAKE AT 07-05-34.
06/18/1958	07-05-34	36.50	121.38	C	3.3			SOUTH OF HOLLISTER.
06/21/1958	01-03-31	36.40	120.40	D	2.1			SOUTHWEST OF FRESNO.
07/02/1958	17-56-26	36.50	121.30	D	2.8			SOUTHWEST OF LLANADA.
08/08/1958	18-43-01	36.30	121.20	D	2.7			FORESHOCK OF 13-43-15 - RECORDS MIXED.
08/08/1958	13-43-15	36.30	121.20	D	3.9		F	NORTHWEST OF KING CITY; IV AT BIG SUR.
08/18/1958	05-30-42	35.80	121.30	D	3.4			NEAR SAN SIMEON.
09/01/1958	11-31-42	36.10	120.80	D	3.2			SOUTHEAST OF KING CITY.
09/21/1958	07-24-55	36.35	121.12	C	4.0		F	NORTH OF KING CITY; VI AT SAN BENITO; ALSO FELT AT SOLEDAD.
09/21/1958	14-23-01	36.50	121.05	C	2.7			SOUTHWEST OF LLANADA.
10/03/1958	04-25-51	34.37	119.50	B	3.7		F	FROM CARPINTERIA TO GOLETA.
10/10/1958	13-05-16	35.93	120.50	B	4.5		F	SOUTHWEST OF COALINGA; FELT OVER AN AREA OF APPROXIMATELY 3500 SQ. MI. OF THE SOUTHWEST-CENTRAL REGION OF CALIFORNIA - APPEARS TO HAVE BEEN FELT MORE STRONGLY AT PARKFIELD THAN ELSEWHERE; V AT ADELAIDA, CAMP ROBERTS, COALINGA, HARMONY, LONE PINE INN, OILFIELD, PARKFIELD, PASO ROBLES, AND SAN ARDO.
10/15/1958	16-16-44	35.50	121.20	D	3.2			NEAR SAN SIMEON.
11/06/1958	20-11-57	36.08	120.88	C	3.1			SOUTHEAST OF KING CITY.
11/16/1958	09-34-04	34.50	119.83	C	4.0		F	NW OF SANTA BARBARA; FELT OVER 600 SQ. MI. FROM SANTA YNEZ TO VENTURA; V AT CARPINTERIA, GOLETA, AND SANTA BARBARA.
11/27/1958	06-04-26	36.37	121.15	C	3.9		F	WEST OF LLANADA; FELT SLIGHTLY AT CARMEL.
11/27/1958	13-39-01	36.20	120.80	D	3.1			EAST OF KING CITY.
12/15/1958	14-58-49	36.20	120.40	D	3.0			NEAR COALINGA.
12/15/1958	15-24-01	36.20	120.40	D	3.0		F	NEAR COALINGA; IV AT COALINGA.
12/30/1958	01-34-15	35.92	119.80	C	3.2			
01/11/1959	05-18-26	36.20	120.80	D	2.5			WEST OF COALINGA.
02/07/1959	05-51-02	36.10	120.00	D	3.0			SOUTHEAST OF KING CITY.
02/27/1959	21-35-01	36.25	120.75	C	3.1			SOUTHEAST OF LLANADA.
03/13/1959	02-44-27	35.80	120.30	D	2.5			SOUTH OF COALINGA.
03/14/1959	02-43-41	35.70	121.30	D	3.6			WEST OF SAN SIMEON.
03/20/1959	05-12-09	36.48	121.17	B	2.9			SOUTHWEST OF LLANADA.
03/25/1959	05-34-17	34.25	119.58	C	2.5		F	SANTA BARBARA CHANNEL; IV AT CARPINTERIA.
04/08/1959	07-41-57	36.37	121.20	B	3.4			NORTH OF KING CITY.
04/09/1959	14-03-11	36.38	121.15	C	2.5			NORTH OF KING CITY.
04/21/1959	09-36-23	36.40	120.40	D	3.0			NORTH OF COALINGA.
04/21/1959	12-31-10	36.10	121.10	D	2.2			NEAR KING CITY.
04/22/1959	19-04-25	36.20	120.90	D	2.6			NEAR KING CITY.
05/13/1959	14-28-10	36.48	121.03	C	2.6			SOUTHWEST OF LLANADA.
05/14/1959	01-34-09	36.50	121.20	D	2.4			SOUTHWEST OF LLANADA.
05/20/1959	10-15-55	36.30	120.40	D	2.6			NORTHWEST OF COALINGA.
06/01/1959	03-47-24	36.50	121.23	C	2.4			SOUTHWEST OF LLANADA.
06/20/1959	15-01-17	36.50	121.30	D	2.9			SOUTH OF VINEYARD.

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MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
06/21/1959	09-24-07	34.32	119.67	B	3.3			
07/18/1959	01-11-47	36.50	121.30	D	2.5			SOUTH OF VINEYARD.
08/05/1959	03--?-34	35.95	120.48	C	3.5		F	SOUTHEAST OF COALINGA (NEAR PARKFIELD; FELT STRONGEST AT PARKFIELD; IV FELT AT PASO ROBLES).
09/05/1959	05-45-34	36.50	121.70	D	3.8			SOUTHWEST OF VINEYARD.
10/01/1959	04-35-35	34.43	120.57	B	4.5		F	OFF POINT CONCEPTION; VI AT GAVIOTA PASS AND V AT GAVIOTA, GOLETA, AND LOMPOC.
10/01/1959	05-52-55	34.20	119.50	C	3.2			
10/11/1959	02-03-09	36.45	121.12	C	4.1		F	SOUTHWEST OF LLANADA; FELT AT SALINAS.
10/24/1959	23-12-54	36.47	121.40	C	3.2			SOUTH OF HOLLISTER.
10/25/1959	03-33-13	36.50	121.20	D	2.4			SOUTHEAST OF VINEYARD.
10/25/1959	03-34-02	36.50	121.32	C	3.0			SOUTH OF VINEYARD.
10/26/1959	09-56-01	36.40	121.10	D	3.0			SOUTHEAST OF VINEYARD.
11/25/1959	09-28-22	35.20	121.20	D	3.5			SOUTH OF KING CITY.
11/26/1959	07-02-05	36.40	121.40	D	2.7			SOUTH OF VINEYARD.
12/11/1959	05-55-26	35.60	120.60	D	3.5			SOUTHEAST OF VINEYARD.
12/25/1959	20-38-28	36.00	120.60	D	3.1			SOUTHEAST OF VINEYARD.
12/29/1959	14-53-08	35.75	120.30	C	3.5		F	NEAR CHOLAME; FELT AT PASO ROBLES.
01/02/1960	22-51-48	35.40	121.20	D	4.0			NW OF SAN LUIS OBISPO.
01/04/1960	12-18-20	36.20	120.70	D	3.2			WEST OF COALINGA.
02/14/1960	08-34-30	35.80	121.70	D	2.8			WEST OF SAN SIMEON.
02/25/1960	06-34-31	36.50	121.20	D	2.7			SOUTHWEST OF LLANADA.
02/28/1960	02-55-32	34.33	119.95	C	3.1			
03/21/1960	20-46-39	36.50	120.73	C	2.5			SOUTHEAST OF LLANADA.
03/26/1960	21-39-21	36.22	121.00	C	2.7			EAST OF KING CITY.
03/29/1960	11-46-42	36.50	121.10	C	2.4			SOUTHEAST OF VINEYARD.
03/31/1960	08-35-09	36.40	121.20	D	2.6			SOUTHEAST OF VINEYARD.
04/02/1960	13-02-10	35.97	120.33	C	2.7			SOUTH OF COALINGA.
04/02/1960	19-01-12	36.20	120.60	D	3.4			WEST OF COALINGA.
04/09/1960	08-01-14	36.50	121.13	B	3.6			SOUTHEAST OF HOLLISTER.
05/04/1960	09-44-32	36.42	120.72	C	3.4			SOUTHEAST OF LLANADA.
05/15/1960	06-07-23	36.43	121.27	C	2.5			SOUTH OF VINEYARD.
06/11/1960	17-39-48	36.30	120.90	D	3.7			SOUTHEAST OF VINEYARD, DIABLO RANGE.
06/19/1960	19-51-20	36.20	121.90	D	2.6			SOUTHWEST OF BIG SUR.
06/24/1960	18-13-12	36.45	121.22	B	3.5			SOUTHEAST OF VINEYARD.
07/14/1960	03-22-23	35.60	120.40	D	3.0			NORTHEAST OF SAN LUIS OBISPO.
07/20/1960	-?-59-36	35.80	119.80	D	2.8			NORTHEAST OF SAN LUIS OBISPO.
07/30/1960	02-16-29	36.43	120.28	C	2.5			SOUTHWEST OF FRESNO.
08/09/1960	08-59-47	36.20	120.20	D	3.2			EAST OF COALINGA.
08/10/1960	03-03-50	36.47	121.40	D	3.2			SOUTH OF VINEYARD.
08/26/1960	08-57-24	38.33	121.13	C	3.0			SOUTHEAST OF VINEYARD.
09/10/1960	01-18-22	36.47	121.05	C	2.7			SOUTHEAST OF HOLLISTER.
09/10/1960	20-49-12	36.45	121.28	D	2.8			SOUTHWEST OF LLANADA.
10/08/1960	-?-02-29	36.50	121.67	C	3.0			SOUTHWEST OF VINEYARD.
11/03/1960	07-13-40	36.43	121.07	C	2.7			SOUTH-SOUTHWEST OF LLANADA.
11/18/1960	04-36-44	36.38	121.20	C	3.0			NORTH-NORTHWEST OF KING CITY.

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MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
12/01/1960	14-23-49	34.33	119.85	B	3.2			OFF SANTA BARBARA.
12/15/1960	08-28-08	36.40	121.30	D	3.0			SOUTH OF HOLLISTER.
12/27/1960	03-57-55	36.00	121.10	D	3.3			SOUTH OF KING CITY.
01/06/1961	20-46-36	35.80	120.20	D	3.4			SE OF PARKFIELD.
02/02/1961	12-31--?	36.35	121.20	D	2.2			NORTHWEST OF KING CITY.
02/21/1961	15-46-58	34.37	119.53	C	2.8			SE OF SANTA BARBARA.
03/14/1961	04-15--?	36.40	121.20	D	3.4			SOUTHEAST OF VINEYARD.
03/29/1961	16--?-11	36.50	121.50	D	2.5			SOUTH OF VINEYARD.
04/07/1961	12-21-19	36.20	120.40	D	2.9			NORTH OF COALINGA.
04/08/1961	04-55-26	36.00	121.20	D	2.7			SOUTH OF KING CITY.
04/08/1961	09-29-47	36.10	120.43	B	3.4			NEAR COALINGA.
04/08/1961	12-52-16	36.12	120.43	C	2.7			AFTERSHOCK OF QUAKE AT 09-29-47.
04/11/1961	09-08-11	36.00	120.10	D	2.7			SOUTHEAST OF KING CITY.
04/12/1961	04-59-08	35.92	120.50	C	2.6			SOUTHWEST OF COALINGA.
04/19/1961	18-16-35	36.40	121.58	C	3.3			SOUTHEAST OF MONTEREY.
05/25/1961	14-19-05	36.33	121.00	C	3.4			NORTHEAST OF KING CITY.
05/25/1961	14-19-35	36.33	121.00	B	3.4			NORTHEAST OF KING CITY.
06/01/1961	06-47-20	36.33	121.32	B	2.7			NORTHWEST OF KING CITY.
06/01/1961	14-11-30	36.45	121.20	C	2.6			NORTH OF KING CITY.
06/18/1961	12-50-59	36.18	120.83	C	2.1			EAST OF KING CITY.
06/25/1961	13-15-26	36.48	121.35	C	3.6		F	SOUTH OF HOLLISTER; FELT IN HOLLISTER AREA. INTENSITY IV 7.5 MI. SOUTH OF HOLLISTER AT HARRIS RANCH.
06/26/1961	11-30-22	35.77	122.00	C	2.5			OFF SAN SIMEON COAST.
07/22/1961	18-01-55	36.40	121.20	C	4.0		F	NORTHEAST OF PARAISO; FELT AT PINNACLES NATIONAL MONUMENT (ABOUT 25 MI. SOUTHEAST OF HOLLISTER).
07/31/1961	-?-07-09	35.82	120.37	C	4.7		F	SAN LUIS OBISPO; FELT OVER AN AREA OF 5000 SQ. MI. OF WEST CENTRAL CALIFORNIA. INTENSITY V AT ATASCADERO, CHOLAME, CRESTON, PARKFIELD, SAN LUIS OBISPO, AND TEMPLETON.
08/01/1961	06-12-54	36.43	120.85	C	3.1			SOUTH OF LLANADA.
08/17/1961	17-14-45	36.33	120.95	B	3.1			NORTHEAST OF KING CITY.
09/14/1961	15-12-20	34.32	119.63	C	2.7			
09/14/1961	15-14-38	34.32	119.63	C	2.8			
09/27/1961	02-02-06	36.33	121.25	C	2.7			EAST OF PARAISO.
09/29/1961	15-39-58	36.33	120.88	B	2.4			SOUTH OF LLANADA.
10/12/1961	06-31-11	35.80	121.30	D	2.3			NORTH OF SAN SIMEON.
10/29/1961	11-47-33	36.33	120.92	C	2.0			EAST OF PARAISO.
11/05/1961	10-43-57	36.03	120.10	D	2.0			EAST OF LLANADA.
11/29/1961	04-49-03	35.15	120.13	C	3.0			SOUTHEAST OF KING CITY.
12/06/1961	03-27-30	36.43	121.85	B	2.4			SOUTH OF MONTEREY.
12/14/1961	07-28-44	36.48	121.08	B	2.1			SOUTHWEST OF LLANADA.
01/04/1962	03-56-10	36.40	121.40	C	3.0	11		NORTHWEST OF KING CITY.
01/31/1962	08-33-15	34.88	120.68	C	3.6			
02/01/1962	06-37-57	34.88	120.68	C	4.5		F	WEST OF GUADALUPE; FELT OVER AN AREA OF 3000 SQ. MI. V AT ARROYO GRANDE, AVILA BEACH, CASMALIA, GROVER CITY, GUADALUPE, HALCYON, OCEANO, POINT ARGUELLO, AND SHELL
02/01/1962	07-58-12	34.38	120.68	C	3.7			
02/04/1962	11-43-34.1	36.42	121.27	C	3.2	12		

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
02/07/1962	13--?-70	34.30	122.10	D	3.9			
03/05/1962	07-44-01	34.60	121.60		4.5		F	OFF COAST NEAR LOMPOC; V AT MORRO BAY AND PISMO BEACH.
03/06/1962	03-40-22	34.60	121.60	D	3.6			
03/10/1962	08-07-21	34.60	121.60	D	4.2			OFF COAST NEAR LOMPOC.
03/10/1962	13-40-48	34.60	121.60	D	4.0			OFF COAST NEAR LOMPOC.
03/10/1962	15-24-21	34.60	121.60	D	3.5			
03/12/1962	21-32-09	34.60	121.60	D	3.9			
03/23/1962	22-10-18	34.28	120.20	C	2.9			
03/24/1962	03-38-41.8	36.20	119.78	B	3.4	19		SOUTH OF FRESNO.
04/02/1962	03-06-03.2	36.25	120.10	B	3.7	16	F	EAST OF COALINGA; V IN TEHACHAPI.
04/15/1962	08-41-02.3	36.42	120.62	B	4.7	23	F	SOUTHEAST OF LLANADA; V AT IDRIA.
05/04/1962	20-52-32	35.27	119.55	B	2.8			
05/05/1962	-?-55-20	34.20	121.50	D	3.3			
09/03/1962	17-53-33.1	36.47	121.07	C	2.6	8	F	SOUTHWEST OF LLANADA; FELT IN HOLLISTER.
09/11/1962	01-34-31	36.03	121.23	B	3.3	16		SOUTHWEST OF KING CITY.
09/16/1962	18-12-35	34.48	119.68	B	4.0		F	NEAR SANTA BARBARA; V AT LOS PRIETOS.
09/16/1962	18-17-09	34.48	119.68	C	2.2			
09/16/1962	18-31-17	34.52	119.77	B	2.9			
09/21/1962	05-07-18	34.47	119.58	B	3.0			
09/29/1962	19-47-32	34.47	119.70	B	2.9			
10/13/1962	17-49-39.5	36.35	120.42	B	3.7	17		NORTHEAST OF PRIEST.
12/15/1962	-?-40-20.9	36.47	120.63	B	2.9	13		NORTH OF PRIEST.
01/09/1963	06-04-25.7	35.98	120.35	B	3.2	14	F	SE OF PRIEST; III AT WHEELER RIDGE.
02/09/1963	02-52-14.5	35.98	121.69	C	2.8	8		OFF COAST S OF BIG SUR.
02/12/1963	03-44-30.9	36.50	121.32	B	2.6	10		S OF VINEYARD.
02/22/1963	15-56-21.9	35.11	121.44	C	3.3	15		OFF COAST, SW OF MORRO BAY.
02/22/1963	15-56-36.0	35.67	120.83	D	3.6			
04/04/1963	01--?-58	35.80	121.50		2.5	6		NW OF SAN SIMEON.
04/10/1963	01-38-56.8	36.42	121.05		2.9	11		SW OF LLANADA.
04/11/1963	14-02-31.8	36.20	120.87		2.9	13		NW OF PRIEST.
04/20/1963	16-37-33.0	36.38	120.96		3.0	14		SOUTH OF LLANADA.
05/10/1963	10-17-57.1	36.37	120.98		2.5	9		SOUTH OF LLANADA.
06/01/1963	05-19--0.2	34.33	119.54	B	2.0			
07/02/1963	12--?-24.9	34.86	119.80	C	2.0			
07/04/1963	03-20-41.0	34.77	120.02	C	3.2			
07/06/1963	23-32-30.4	34.78	120.63	B	3.3			
08/15/1963	21-02-32.2	35.97	121.02		3.6	15		NEAR JOLON; FORESHOCK OF FOLLOWING--
08/15/1963	21-21-32.1	35.91	121.06		3.9	18	F	NEAR JOLON; FELT AT HARRIS RANCH.
08/16/1963	08-12-13.6	36.06	121.01		3.2	10		NEAR JOLON; AFTERSHOCK OF PRECEDING.
09/06/1963	03-54-34	36.22	121.48		2.6	8		WEST OF PARAISO.
11/01/1963	14-05-56.0	35.56	120.23		3.4	9		EAST OF ATASCADERO.
11/01/1963	14-06--0.4	35.75	120.47	C	3.2			
11/18/1963	07-31-38.5	36.22	120.30	C	3.5		F	IV 15 MI. NE OF SAN MIGUEL.
11/18/1963	10-54-45.4	36.38	120.32		2.7	11		NE OF COALINGA.
11/19/1963	03-33-09.2	36.42	121.03		2.9	10		SW OF LLANADA.
12/12/1963	17-10-48.5	34.98	119.51	C	3.1			
02/10/1964	05-47-25.0	35.75	120.94		3.9	19		NE OF PASO ROBLES.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
03/20/1964	13-15-51.0	36.40	121.03		2.6	7		SW OF LLANADA.
04/28/1964	15-01-48.3	36.23	121.08		2.8	7		NEAR KING CITY.
05/07/1964	17-53-58.3	36.43	120.54		2.5	5		N OF PRIEST.
06/06/1964	11-47-39.0	34.63	121.40	D	4.3			
06/20/1964	09-21-51.4	34.13	120.67	C	3.1			
07/24/1964	07-09-35.9	36.47	121.18		2.9	15		NE OF PARAISO.
08/30/1964	03-41-10.4	36.29	121.94		2.9	7		OFF COAST NW OF POINT SUR.
09/12/1964	01-45-53.5	36.08	120.49		3.1	10		SE OF PRIEST.
10/17/1964	23-43-22.6	36.21	120.92		3.3	14		NW OF PRIEST.
11/08/1964	01-19-19.0	36.00	120.00		4.0	15		E OF AVENAL.
11/08/1964	13-45-51.1	36.34	121.32		3.1	16		NEAR PARAISO.
11/18/1964	01-47-34.0	35.98	121.13		2.7	8		SW OF KING CITY.
11/25/1964	12-49-41.8	36.21	120.78		2.8	15		NW OF PRIEST.
12/05/1964	13-55-57.5	36.02	121.08		2.6	12		W OF SAN ARDO.
12/11/1964	03-35-38.8	34.24	119.76	B	3.5			
12/25/1964	11-21-13.2	35.97	121.18		2.6	5		N OF LAKE NACIMIENTO.
12/27/1964	18-58-59.4	36.46	121.06		2.6	7		SW OF LLANDA.
01/13/1965	04-20-48.2	36.45	120.58		2.6	9		NE OF PRIEST.
01/26/1965	08-34-30.7	35.72	120.54		3.0	12		SE OF PRIEST.
01/26/1965	08-36-36.6	35.92	120.27	C	3.1			
01/26/1965	08-38-16.4	36.04	120.26	C	3.1			
02/21/1965	18-39-18.3	35.67	120.43		3.1	12		E OF PASO ROBLES.
03/28/1965	02-32-21.0	36.20	120.40		3.5			(USCGS)
04/06/1965	20-49-24.4	35.95	121.46		2.5	7		N OF SAN SIMEON.
04/08/1965	01-05-40.6	36.03	121.40		3.0	10		N OF SAN SIMEON.
04/09/1965	12-50-19.3	36.03	120.64		3.0	10		S OF PRIEST.
04/18/1965	03-58-52.4	36.50	121.23		2.7	7		NEAR PINNACLES NATIONAL MONUMENT
04/24/1965	07-29-47.1	34.91	120.14	C	3.6			
05/12/1965	17-55-08.7	35.49	121.17		3.0	6		SW OF SAN SIMEON.
06/07/1965	15-06-47.6	36.50	121.13		2.5	10		NEAR PINNACLES NATIONAL MONUMENT.
06/20/1965	02-56-43.5	36.33	120.37		2.7	11		N OF COALINGA.
06/30/1965	15-21-27.7	36.35	120.71		2.5	9		N OF PRIEST.
07/23/1965	05-31-52.7	35.71	121.23		3.4	13		N OF SAN SIMEON.
07/24/1965	15-25-57.4	36.36	120.98		2.5	7		SW OF LLANADA.
08/01/1965	06-47-27.3	36.23	120.85		2.5	7		NW OF PRIEST.
08/01/1965	13-28-32.9	36.23	120.84		2.5	6		AFTERSHOCK OF 06-47-27.3.
08/13/1965	07-36-08.4	36.46	121.08		2.6	9		SW OF LLANADA.
08/13/1965	13-46-16.5	34.35	119.63	B	3.7		F	IV AT CARPINTERIA AND SANTA BARBARA.
08/13/1965	21-28-51.8	36.48	121.13		2.4	8		W OF LLANADA.
08/15/1965	23-06-52.5	36.00	120.20		4.0		F	AT PAICINES.
08/21/1965	20-09-35.4	36.46	121.07		2.5	8		SW OF LLANADA.
09/06/1965	18--?-57.8	35.96	120.36	C	3.4			
09/12/1965	08-50-05.5	36.49	121.12		2.5	7		W OF LLANADA.
09/19/1965	15-42-07.8	35.98	120.34	C	4.8		F	V AT ARMONA, AVENAL, CHOLAME, KETTLEMAN CITY, AND STRATFORD.
10/22/1965	02-29-22	36.00	121.70		2.7	6		OFF COAST, W OF KING CITY.
12/02/1965	22-29-13.0	36.20	121.68		2.8	9		W OF PARAISO.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
01/28/1966	01-49-47.4	35.83	120.45		3.0		F	PARKFIELD SEQUENCE; MC EVILLY, ET AL, (1967) THE PARKFIELD, CALIFORNIA EARTHQUAKE OF 1966, BULL. SEISM. SOC. AM.
02/01/1966	-?-20-44.3	36.03	120.57		2.9			PARKFIELD SEQUENCE - SEE 01/28/1966 AT 01-49-47.4.
02/14/1966	-?-24-03.9	36.02	120.57		2.4			PARKFIELD SEQUENCE - SEE 01/28/1966 AT 01-49-47.4.
02/25/1966	01-34-38.0	36.05	120.63		2.4			PARKFIELD SEQUENCE - SEE 01/28/1966 AT 01-49-47.4.
03/31/1966	21-38-45.2	36.05	120.60		2.5			PARKFIELD SEQUENCE - SEE 01/28/1966 AT 01-49-47.4.
04/05/1966	20-44-58.7	36.24	120.85		2.7	9		10 KM NW OF PRIEST (UC BERKELEY SEISMOGRAPH STATION (SS)).
04/12/1966	15-31-39.8	36.07	120.70		2.3			PARKFIELD SEQUENCE.
05/11/1966	17-37-01.1	35.98	120.57		2.3			PARKFIELD SEQUENCE.
05/23/1966	08-07-37.6	36.02	120.57		2.5			PARKFIELD SEQUENCE.
05/23/1966	08-11-07.0	36.02	120.57		2.2			PARKFIELD SEQUENCE.
05/27/1966	15-36-03.7	35.98	120.49		2.7			PARKFIELD SEQUENCE.
06/18/1966	16-32-17.6	35.96	120.53		2.0			PARKFIELD SEQUENCE.
06/20/1966	23-19-18.8	36.33	120.96		2.8	9		NE OF KING CITY.
06/24/1966	21-42-50.4	36.50	120.85		3.1	10		SE OF LLANADA.
06/28/1966	01--?-31.5	35.95	120.52		3.1		F	PARKFIELD SEQUENCE; FELT AT CHOLAME, PARKFIELD, VALLETON, AND WORK RANCH.
06/28/1966	01-14-55	35.95	120.50		1.8			PARKFIELD SEQUENCE.
06/28/1966	04-08-55.2	35.97	120.50		5.1			PARKFIELD SEQUENCE FIRST MAIN SHOCK (FELT REPORTS FOR THE 2 MAIN SHOCKS ARE NOT SEPARATED.) FELT OVER 20,000 SQ. MI., MINOR SURFACE FAULTING ALONG SAN ANDREAS FAULT FROM PARKFIELD TO CHOLAME (20 MI.), MAXIMUM DISPLACEMENT 4 IN. VII AT CHOLAME AND PARKFIELD, VI AT ANNETTE, BITTERWATER VALLEY, COALINGA, HIDDEN VALLEY RANCH, PASO ROBLES, SAN LUIS OBISPO, SAN MIGUEL, SHAFTER, SHANDON, SLACK CANYON, VALLETON, WAITI RANCH, AND WORK RANCH, AND V AT ADELAIDA, ALPAUGH, ARROYO GRANDE, ATASCADERO, AVILA BEACH, BAKERSFIELD, BAYWOOD PARK, BRYSON, BURREL, BUTTONWILLOW, EARLIMART, FELLOWS, FRAZIER PARK, GREENFIELD, HARMONY, INDIAN VALLEY, KETTLEMAN CITY, KING CITY, LAPANZA, LOST MARICOPA, MEE RANCH, MORRO BAY, MOSS LANDING, MUSICK, NIPOMO, OCEANO, OLD RIVER, PANOCHE, PINE CANYON, PISMO BEACH, POZO, PRIEST VALLEY, SAN ARDO, SAN JOAQUIN, SAN LUCAS, SAN SIMEON, SIMMLER, STRATFORD, TEMPLETON, AND VANDENBURG A.F.B.
06/28/1966	04-09-53	35.95	120.50					PARKFIELD SEQUENCE.
06/28/1966	04-18-34.0	35.95	120.53		2.6		F	PARKFIELD SEQUENCE - FELT AT CANTUA CREEK AND SOQUEL.
06/28/1966	04-26-13.4	35.95	120.50		5.5		F	PARKFIELD SEQUENCE - SECOND MAIN SHOCK.
06/28/1966	04-26-28	35.95	120.50					PARKFIELD SEQUENCE.
06/28/1966	04-26-34	35.95	120.50					PARKFIELD SEQUENCE.
06/28/1966	04-27-37	35.95	120.50					PARKFIELD SEQUENCE.
06/28/1966	04-27-58	35.95	120.50					PARKFIELD SEQUENCE.
06/28/1966	04-28-19	35.95	120.50					PARKFIELD SEQUENCE.
06/28/1966	04-28-36	35.95	120.50		4.5			PARKFIELD SEQUENCE.
06/28/1966	04-28-46	35.95	120.50					PARKFIELD SEQUENCE.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
06/28/1966	04-29-13	35.95	120.50					PARKFIELD SEQUENCE.
06/28/1966	04-31-55	35.95	120.50		3.0			PARKFIELD SEQUENCE.
06/28/1966	04-32-50	35.95	120.50		3.5		F	PARKFIELD SEQUENCE - FELT AT CANTUA CREEK, CHOLAME, AND HERNANDEZ.
06/28/1966	04-34-59.1	35.81	120.40		3.0			PARKFIELD SEQUENCE.
06/28/1966	04-39-08.1	35.95	120.50		3.0		F	PARKFIELD SEQUENCE - FELT AT PARKFIELD AND WORK RANCH.
06/28/1966	04-42-33.6	35.83	120.38		2.4			PARKFIELD SEQUENCE.
06/28/1966	04-43-54.8	35.95	120.57		2.7			PARKFIELD SEQUENCE.
06/28/1966	04-46-22	35.95	120.50		3.0			PARKFIELD SEQUENCE.
06/28/1966	04-51-43	35.95	120.50		2.4			PARKFIELD SEQUENCE.
06/28/1966	05--?-59.5	35.85	120.40		3.1			PARKFIELD SEQUENCE.
06/28/1966	05-03-44.7	35.88	120.45		2.4			PARKFIELD SEQUENCE.
06/28/1966	05-09-48.3	35.83	120.13		2.5			PARKFIELD SEQUENCE.
06/28/1966	05-12-42.5	35.92	120.47		2.9			PARKFIELD SEQUENCE.
06/28/1966	05-17-05	35.95	120.50		2.1			PARKFIELD SEQUENCE.
06/28/1966	05-21-05	35.95	120.50		2.0			PARKFIELD SEQUENCE.
06/28/1966	05-29-14.9	35.92	120.48		2.1			PARKFIELD SEQUENCE.
06/28/1966	05-37-04.6	35.88	120.44		2.5			PARKFIELD SEQUENCE.
06/28/1966	05-40-19.4	35.94	120.48		2.7			PARKFIELD SEQUENCE.
06/28/1966	05-45-59.1	35.75	120.33		3.2			PARKFIELD SEQUENCE.
06/28/1966	05-48-26	35.95	120.50		2.2			PARKFIELD SEQUENCE.
06/28/1966	05-51-34.0	35.86	120.44		2.1			PARKFIELD SEQUENCE.
06/28/1966	05-52-06	35.95	120.50		2.3			PARKFIELD SEQUENCE.
06/28/1966	05-52-58	35.95	120.50		2.4			PARKFIELD SEQUENCE.
06/28/1966	05-56--?	35.95	120.50		2.1			PARKFIELD SEQUENCE.
06/28/1966	06-11-03.5	35.81	120.35		2.6			PARKFIELD SEQUENCE.
06/28/1966	06-32-17.9	35.94	120.52		3.4		F	PARKFIELD SEQUENCE - FELT AT CHOLAME, COALINGA, AND PARKFIELD.
06/28/1966	06-35-11.4	35.80	120.38		3.0			PARKFIELD SEQUENCE.
06/28/1966	06-39-31.2	35.90	120.47		2.2			PARKFIELD SEQUENCE.
06/28/1966	07-01-03.8	35.92	120.48		2.2			PARKFIELD SEQUENCE.
06/28/1966	07-33-52.7	35.90	120.45		2.7			PARKFIELD SEQUENCE.
06/28/1966	07-41-43	35.95	120.50		2.3			PARKFIELD SEQUENCE.
06/28/1966	07-45-48.3	35.90	120.47		3.0		F	PARKFIELD SEQUENCE - FELT AT CHOLAME AND PARKFIELD.
06/28/1966	08-14-48.6	35.83	120.42		2.4			PARKFIELD SEQUENCE.
06/28/1966	08-47-52.4	35.85	120.42		2.0			PARKFIELD SEQUENCE.
06/28/1966	08-54-49.5	35.92	120.50		2.3			PARKFIELD SEQUENCE.
06/28/1966	08-59-52.3	35.85	120.42		2.5			PARKFIELD SEQUENCE.
06/28/1966	09-31-26.5	35.77	120.35		2.4			PARKFIELD SEQUENCE.
06/28/1966	09-35-54.3	35.77	120.36		2.2			PARKFIELD SEQUENCE.
06/28/1966	09-56-09.7	35.83	120.40		2.5			PARKFIELD SEQUENCE.
06/28/1966	10-15-53.3	35.92	120.53		2.1			PARKFIELD SEQUENCE.
06/28/1966	10-20-16.4	35.85	120.42		2.3			PARKFIELD SEQUENCE.
06/28/1966	10-23-22.8	35.55	120.42		2.0			PARKFIELD SEQUENCE.
06/28/1966	10-23-22.8	35.94	120.48		2.5			PARKFIELD SEQUENCE.
06/28/1966	10-46-22.9	35.94	120.50		2.0			PARKFIELD SEQUENCE.
06/28/1966	11-15-13.9	35.85	120.42		2.0			PARKFIELD SEQUENCE.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
06/28/1966	11-28-41.4	35.85	120.38		2.0			PARKFIELD SEQUENCE.
06/28/1966	11-30-14.0	35.90	120.47		2.2			PARKFIELD SEQUENCE.
06/28/1966	12-31-52.1	35.94	120.48		2.5			PARKFIELD SEQUENCE.
06/28/1966	12-52-22.0	35.97	120.53		2.3			PARKFIELD SEQUENCE.
06/28/1966	13-48-22	35.97	120.53		2.7			PARKFIELD SEQUENCE.
06/28/1966	14-13-09.3	35.94	120.48		2.6			PARKFIELD SEQUENCE.
06/28/1966	14-21-36.3	35.94	120.48		2.2			PARKFIELD SEQUENCE.
06/28/1966	14-51-53.6	35.90	120.47		2.3			PARKFIELD SEQUENCE.
06/28/1966	18-12-19.4	35.92	120.50		2.3			PARKFIELD SEQUENCE.
06/28/1966	18-22-32.4	35.92	120.50		2.0			PARKFIELD SEQUENCE.
06/28/1966	18-54-55.3	35.88	120.45		2.5			PARKFIELD SEQUENCE.
06/28/1966	19-59-37.8	35.92	120.47		2.8			PARKFIELD SEQUENCE.
06/28/1966	20--?-38.7	35.92	120.48		2.5			PARKFIELD SEQUENCE.
06/28/1966	20-46-56.4	35.77	120.40		3.1		F	PARKFIELD SEQUENCE - FELT AT BAR B RANCH AND WORK RANCH.
06/28/1966	22-01-13.9	35.85	120.44		2.0			PARKFIELD SEQUENCE.
06/28/1966	22-37-56.7	35.88	120.42		2.0			PARKFIELD SEQUENCE.
06/28/1966	23-57-22.3	35.77	120.35		2.5			PARKFIELD SEQUENCE.
06/29/1966	-?-17-32.6	35.85	120.44		2.3			PARKFIELD SEQUENCE.
06/29/1966	02-19-39.9	35.92	120.52		3.6		F	PARKFIELD SEQUENCE - FELT AT CHOLAME, PARKFIELD, AND WORK RANCH.
06/29/1966	04-06-40.3	35.92	120.53		2.8			PARKFIELD SEQUENCE.
06/29/1966	07-28-59.4	35.92	120.48		2.3			PARKFIELD SEQUENCE.
06/29/1966	08-55-52.4	35.88	120.45		2.9			PARKFIELD SEQUENCE.
06/29/1966	09-20-50.1	35.78	120.36		2.5			PARKFIELD SEQUENCE.
06/29/1966	10-13-44.0	35.97	120.50		2.3			PARKFIELD SEQUENCE.
06/29/1966	10-56-58.8	35.75	120.33		3.0			PARKFIELD SEQUENCE.
06/29/1966	12-30-09.0	35.94	120.50		2.4			PARKFIELD SEQUENCE.
06/29/1966	13-11-59.7	35.82	120.38		3.1		F	PARKFIELD SEQUENCE - FELT AT CHOLAME AND PARKFIELD.
06/29/1966	15-18-38.9	35.95	120.33		2.0			PARKFIELD SEQUENCE.
06/29/1966	15-34-22.2	35.92	120.48		2.3			PARKFIELD SEQUENCE.
06/29/1966	16-03-30.1	35.86	120.45		2.1			PARKFIELD SEQUENCE.
06/29/1966	17-10-28.3	35.82	120.36		2.0			PARKFIELD SEQUENCE.
06/29/1966	19-53-25.9	35.95	120.53		5.0		F	PARKFIELD SEQUENCE - FELT AT ADELAIDA, BITTERWATER, CHOLAME, COALINGA, FRESNO, MEE RANCH, MORRO BAY, SAN LUIS OBISPO, SAN MIGUEL, SANTA MARGARITA, SHANDON, AND WORK RANCH.
06/29/1966	20-44-40.0	35.74	120.28		2.5			PARKFIELD SEQUENCE.
06/29/1966	23-48-12.0	35.74	120.28		2.3			PARKFIELD SEQUENCE.
06/30/1966	01-17-36.1	35.86	120.45		4.1			PARKFIELD SEQUENCE.
06/30/1966	03-36-16.8	35.92	120.47		2.6			PARKFIELD SEQUENCE.
06/30/1966	05-04-12.9	35.88	120.45		2.0			PARKFIELD SEQUENCE.
06/30/1966	06-07-21.5	35.94	120.48		2.4			PARKFIELD SEQUENCE.
06/30/1966	06-23-32.4	35.90	120.47		2.1			PARKFIELD SEQUENCE.
06/30/1966	07-37-12.1	35.90	120.47		2.0			PARKFIELD SEQUENCE.
06/30/1966	08-01-38.4	35.90	120.47		2.9			PARKFIELD SEQUENCE.
06/30/1966	11-07-55.1	35.78	120.33		2.8			PARKFIELD SEQUENCE.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
06/30/1966	13-26-05.7	35.78	120.35		2.3			PARKFIELD SEQUENCE.
06/30/1966	13-29-56.6	35.86	120.40		2.0			PARKFIELD SEQUENCE.
06/30/1966	13-40-50.9	35.83	120.38		2.1			PARKFIELD SEQUENCE.
06/30/1966	16-05-02.7	35.97	120.50		2.3			PARKFIELD SEQUENCE.
06/30/1966	19-06-17.5	35.86	120.42		2.1			PARKFIELD SEQUENCE.
07/01/1966	09-41-21.9	35.94	120.52	3.2			F	PARKFIELD SEQUENCE - FELT AT WORK RANCH.
07/02/1966	12-08-34.8	35.79	120.33		3.7		F	PARKFIELD SEQUENCE - FELT AT PARKFIELD.
07/02/1966	12-16-15.8	35.81	120.35		3.4		F	PARKFIELD SEQUENCE - FELT AT PARKFIELD.
07/02/1966	12-25-06.8	35.80	120.35		3.1		F	PARKFIELD SEQUENCE - FELT AT PARKFIELD.
07/05/1966	18-54-54.5	35.92	120.48		3.0		F	PARKFIELD SEQUENCE - FELT AT PARKFIELD.
07/25/1966	22-49-39	36.40	120.30		2.5	4		NE OF COALINGA.
07/27/1966	08-12- 0.2	35.90	120.48		3.0			PARKFIELD SEQUENCE.
08/03/1966	12-39-05.8	35.80	120.38		3.4		F	PARKFIELD SEQUENCE; V AT CHOLAME, PARKFIELD, AND WORK RANCH.
08/04/1966	-?-54-24.5	35.74	121.35		3.0	8		NW OF SAN SIMEON.
08/07/1966	17-03-24.9	35.94	120.55		3.0			PARKFIELD SEQUENCE.
08/19/1966	22-51-20.1	35.90	120.45		3.3			PARKFIELD SEQUENCE.
09/07/1966	-?-20-50.5	35.83	119.94		3.2	9		SE OF COALINGA.
09/18/1966	15-09-55.7	35.74	120.35		3.1			PARKFIELD SEQUENCE.
10/27/1966	12-06-03.9	35.94	120.50		3.8		F	PARKFIELD SEQUENCE; V AT ATASCADERO, AVENAL, COALINGA, PARKFIELD, SAN MIGUEL, TEMPLETON, AND WORK RANCH.
11/05/1966	13-31-31.2	35.94	120.50		3.3			PARKFIELD SEQUENCE.
11/18/1966	23-39-42.3	35.75	120.33		3.3			PARKFIELD SEQUENCE.
12/30/1966	10-23-48	36.47	120.40		2.5	4		N OF COALINGA.
01/08/1967	23-03-50.9	35.90	120.40		2.8	8		35 KM SE OF PRIEST (UC BERKELEY SS).
01/09/1967	23-18-59.5	35.86	120.10		3.1	9		SE OF COALINGA.
02/01/1967	13-55-54.1	35.70	120.25		3.0	8		NE OF SAN LUIS OBISPO.
02/26/1967	15-17-53.9	36.40	121.06		2.5	9		SW OF LLANADA.
03/13/1967	21-59-48.4	36.00	120.61		3.1	8	F	15 KM S OF PRIEST (UC BERKELEY SS). IV AT SAN MIGUEL; FELT AT INDIAN VALLEY AND RANCHITO CANYON.
03/21/1967	02-24-28.3	36.21	120.85		2.8	8		17 KM NW OF PRIEST (UC BERKELEY SS).
03/23/1967	11-39-56.4	36.16	120.18		3.0	5		20 KM E OF COALINGA.
04/13/1967	09-06-42.5	36.15	120.80		2.7	8		13 KM W OF PRIEST (UC BERKELEY SS).
05/17/1967	14-16-52.2	35.95	120.73		3.0	6		30 KM S OF PRIEST (UC BERKELEY SS).
06/03/1967	20-10-53.0	35.71	121.48		2.6	7		OFF COAST NW OF SAN SIMEON.
06/06/1967	06-11-38.5	35.81	120.43		3.0	10	F	40 KM SE OF PRIEST (UC BERKELEY SS); IV AT WORK RANCH; FELT IN INDIAN VALLEY, SOUTHERN MONTEREY COUNTY, AND VINEYARD CANYON.
06/13/1967	12-54-10.7	35.81	121.50		3.3	10		OFF COAST, 35KM NW OF SAN SIMEON.
07/24/1967	07-08-52.9	35.96	120.50		3.7	9		PARKFIELD AREA.
07/28/1967	14-44-40.1	35.75	121.38		3.0	6		NEAR SAN SIMEON.
08/01/1967	22-14-13.0	35.75	121.40		2.7	6		NW OF SAN SIMEON.
08/08/1967	18-11-20.3	36.42	120.42		2.5	7		N OF COALINGA.
08/12/1967	18-57-40.4	35.80	120.45		4.1	18	F	PARKFIELD AREA; V AT ESTRELLA AREA, HOG CANYON ROAD TO PARKFIELD, AND SHANDON, AND IV AT CHOLAME.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
08/12/1967	23-21-07.8	36.11	120.80		2.8	6		SE OF KING CITY.
08/12/1967	23-22-05.3	36.13	120.76		2.5	7		SE OF KING CITY.
08/17/1967	23-12-02.7	35.91	121.50		2.6	5		NW OF SAN SIMEON.
08/25/1967	02-28-14.4	35.81	121.27		2.7	6		NW OF SAN SIMEON.
08/25/1967	16-35-27.8	36.05	120.00		3.2	7		SE OF COALINGA.
08/25/1967	16-40-50.2	36.01	119.95		3.0	7		SE OF COALINGA.
08/31/1967	18-10-40.4	35.86	121.35		2.8	7		NW OF SAN SIMEON.
09/09/1967	21-35-05.6	35.81	121.63		2.4	3		OFF SHORE SAN SIMEON.
10/14/1967	12-02-43.6	36.50	120.61		2.7	5		NEAR MT. CIERVO.
10/21/1967	12-05-21.8	35.83	120.46		3.1	7		PARKFIELD AREA.
10/25/1967	23-05-30.5	35.73	121.45		2.6	4		NEAR SAN SIMEON.
11/11/1967	22-10-06.8	36.50	120.81		3.3	9		S OF PANOCHE VALLEY.
11/11/1967	22-33-47.5	36.48	120.78		2.8	6		S OF PANOCHE VALLEY.
11/12/1967	07-11-20.4	36.48	120.80		2.6	7		S OF PANOCHE VALLEY.
11/14/1967	-?--?-51.7	35.78	120.53		3.1	3		PARKFIELD.
11/25/1967	15-27-43.4	36.46	121.06		2.5	6		BEAR VALLEY.
12/21/1967	05-13-11.3	35.36	120.85		2.6	3		S OF SAN SIMEON.
12/21/1967	19-08-53.8	35.91	119.53		3.1	5		NW OF DELANO.
12/21/1967	23-58-60.2	35.93	120.56		3.0	3		PARKFIELD.
12/31/1967	23-48-13.5	35.75	120.45		4.3	3	F	PARKFIELD AREA; V AT CRESTON, PARKFIELD, SALINAS DAM, SAN MIGUEL, SHANDON, TEMPLETON, AND WORK RANCH.
02/03/1968	19-07-26.4	35.73	121.25		2.8	5		NEAR SAN SIMEON.
02/23/1968	20-20-57.9	35.86	121.31		2.5	7		EAST OF HOLLISTER.
03/25/1968	11-32-07.4	36.37	120.70		3.6	8	F	SE OF LLANADA; MAXIMUM INTENSITY V.
03/28/1968	04-53-26.5	36.36	120.19		3.1	5	F	SE OF COALINGA; FELT AT AVENAL - INTENSITY IV.
04/14/1968	06-20-54.6	36.18	121.65		2.5	6		SE OF MONTEREY.
04/23/1968	15-09-14.9	35.52	120.82		3.4	7		SE OF SAN SIMEON.
04/27/1968	14-32-37.4	36.22	120.83		2.7	7		NW OF PRIEST (UC BERKELEY SS).
04/28/1968	06-31-32.9	35.46	120.83		3.5	7		NW OF SAN LUIS OBISPO.
05/31/1968	07-07-37.9	35.80	120.60		3.0	5		S OF COALINGA.
06/11/1968	11-43-28.1	35.90	121.70		3.3	9		OFFSHORE, NW OF SAN SIMEON.
06/22/1968	12-50-50.1	36.43	121.04		2.9	9		S OF LLAN
07/03/1968	17-52-52	35.80	121.50		2.5	7		NW OF SAN SIMEON.
07/29/1968	04-27-51.9	36.38	120.69		2.7	9		N OF PRIEST (UC BERKELEY SS).
07/29/1968	05-29-19.9	36.37	120.70		2.8	9		N OF PRIEST (UC BERKELEY SS).
07/31/1968	-?-49-25.4	36.37	120.70		2.9	9		N OF PRIEST (UC BERKELEY SS).
08/19/1968	16-30-18.2	36.40	121.91		3.3	9		S OF CARMEL.
09/01/1968	21-56-24.4	36.45	121.02		2.7	8		E OF PINNACLES NATIONAL MONUMENT.
11/06/1968	08-58-23.2	35.88	120.45		2.8	10	F	NEAR PARKFIELD; FELT NEAR SAN MIGUEL.
11/10/1968	04-06-03.9	35.70	121.18		3.2	9		NEAR SAN SIMEON.
11/17/1968	01-03-47.0	36.29	120.94		3.0	6		NEAR KING CITY.
12/11/1968	12-19-52.4	35.81	120.48		3.0	10		NEAR PARKFIELD.
12/16/1968	01-14-10.9	36.17	120.85		2.7	7		W OF PRIEST (UC BERKELEY SS).
01/09/1969	09-42-47.2	35.94	120.57		3.8	7	F	CHOLAME VALLEY; FELT IN PARKFIELD AND SLACK CANYON - MAXIMUM INTENSITY V.
02/04/1969	-?-45-25	36.40	120.38		3.0	4		NORTH OF COALINGA.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
06/19/1969	07-05-08	36.12	119.58		3.5	8	F	NEAR TULARE; FELT IN CORCORAN, DINUBA, HANFORD, IVANHOE, LEMON COVE, STRATHMORE, AND TIPTON. MAXIMUM INTENSITY IV.
06/24/1969	14-25-37	36.42	120.13		3.0	4		SOUTHWEST OF FRESNO.
07/16/1969	04-06-35	35.83	120.28		3.2	7		15 KM SOUTHEAST OF PARKFIELD.
09/06/1969	13-44-45	35.30	121.10		3.8	10	F	50 KM WEST OF SAN LUIS OBISPO.
09/16/1969	03-32-24	36.18	120.80		2.5	8		13 KM WEST OF PRIEST (UC BERKELEY SS).
10/02/1969	06--?-58.9	36.32	120.32		3.3	10		10 KM NORTH OF COALINGA.
11/17/1969	20-49-10.4	36.43	121.05		4.4	10	F	NNE OF KING CITY; FELT IN MONTEREY - SWAYED BUILDINGS IN SALINAS
11/19/1969	06-23-50	36.45	121.52		4.2	8	F	GONZALES AND SALINAS VALLEY; FELT IN SALINAS AND SANTA CRUZ - RATTLED WINDOWS IN MONTEREY.
11/26/1969	-?-06-59	36.48	120.60		2.5	6		50 KM NORTHEAST OF KING CITY.
11/30/1969	15-11-54	35.30	120.90		2.5	10		20 KM EAST OF KING CITY; 2 SMALL FORESHOCKS RECORDED.
12/10/1969	13-25-31	35.75	120.40		3.5	7		40 KM SOUTH OF COALINGA.
12/14/1969	19-07-57	35.92	120.68		3.2	9		20 KM NORTH OF PASO ROBLES.
01/29/1970	02-49-12.9	36.11	120.99		2.5	6		20 KM SOUTHWEST OF KING CITY.
02/01/1970	21-19-45.7	36.41	121.08		2.6	12		30 KM EAST OF PARAISO.
02/08/1970	-?-14-13.3	36.40	120.97		2.7	13		25 KM SOUTH OF LLANADA.
02/09/1970	16--?-46.1	35.77	120.35		3.1	16		60 KM SOUTH OF PRIEST (UC BERKELEY SS).
02/14/1970	15-44-58.0	36.09	120.64		2.8	14		5 KM SOUTH OF PRIEST (UC BERKELEY SS).
04/18/1970	13-16-53.4	36.49	120.01		3.0	15		35 KM SOUTHWEST OF FRESNO.
04/21/1970	22-29-25.9	35.66	120.43		3.0	8		65 KM SOUTH OF PRIEST (UC BERKELEY SS).
04/23/1970	03-25-18.9	35.97	121.45		2.5	10		25 KM SOUTHWEST OF KING CITY.
05/27/1970	10-42-19.3	35.99	120.91		3.4	8		40 KM SOUTHWEST OF PRIEST (UC BERKELEY SS).
07/20/1970	23-24-55	35.95	121.57		2.5	5		8 KM SOUTH OF LOPEZ POINT - OFFSHORE.
07/21/1970	05-24-16.1	35.99	121.57		2.5	5		5 KM SOUTHEAST OF LOPEZ POINT.
08/05/1970	06-47-36.4	35.82	119.94		2.9	8		KETTLEMAN HILLS.
08/05/1970	16-51-45.7	36.23	121.69		3.0	11		25 KM SOUTHWEST OF PARAISO.
08/13/1970	05-06-19.8	36.17	121.70		3.7	11		20 KM WEST OF LOPEZ POINT.
09/05/1970	11-29-11	36.20	120.10		3.1	4		EAST-NORTHEAST OF COALINGA.
09/10/1970	23-45-59	36.40	120.50		3.2	11		30 KM NORTHWEST OF COALINGA.
09/11/1970	15-20-08	35.98	120.05		3.3	9		8 KM EAST OF AVENAL.
09/16/1970	18-22-10.7	35.96	121.27		2.6	7		NEAR MILPITAS.
10/07/1970	17-57-06.3	36.30	121.40		2.5	9		30 KM NORTHWEST OF KING CITY.
12/01/1970	06-05-59	35.38	121.13		3.3	7	F	25 KM WEST OF MORRO BAY; INTENSITY V AT BRYSON - NO DAMAGE.
12/12/1970	22-29-20	35.65	121.55		2.5	6		30 KM WEST OF SAN SIMEON.
01/02/71	06-27-37.5	35°55.1'	120°32.2'		3.0			10 km NW of Parkfield
01/16/71	05-33-27.8	36°00'	120°12'		3.1			Kettleman Hills
01/26/71	21-53-53	35°12'	120°42'		3.0			Near San Luis Obispo.
01/31/71	12-22-49.5	35°55.6'	120°30.6'		3.0			NW of Parkfield; sharp, rapid jolting at Shandon.
04/05/71	01-40-34.2	36°24.8'	120°59.0'		3.0			20 km SE of Pinnacles National Monument.
04/19/71	09-35-58.8	36°13.7'	120°50.3'		3.0			25 km E of King City.
04/29/71	02-13-15.7	36°30.3'	120°32.5'		3.0			40 km NW of Coalinga.
06/20/71	12-41-39.8	35°3'	120°20'		3.4			Near Cholame.
07/06/71	09-24-35	35°34'	121°35'		3.0			SW of San Simeon.

TABLE 2.5-1

MM/DD/YY	HR/MN/SE	NORTH LAT	WEST LONG	QUALITY	MAG.	STA. REC.	FELT	MAXIMUM INTENSITY - COMMENTS
07/21/71	09-14-26.2	36°13.7'	120°50.8'		3.2			Near Coalinga.
08/06/71	20-03-16.3	36°00.8'	120°02.2'		3.0			Near Coalinga.
10/06/71	14-43-30.6	35°51.3'	120°22.5'		3.5			S of Coalinga; intensity IV at Cholame, Parkfield, and Shandon.
10/21/71	22-09-45.4	35°58.8'	120°50.2'		3.7			SE of King City; intensity V at San Ardo (small objects shifted) and intensity IV at Jolon, King City, Lockwood, Pine Canyon, and San Lucas.
11/07/71	14-03-30.4	35°31.2'	119°50.2'		4.0			SE of Coalinga.
11/18/71	04-03-52.4	36°14.5'	120°50.6'		3.4			NE of King City.
11/30/71	09-45-42.8	36°03.6'	119°53.4'		3.0			SE of Coalinga.

END OF SELECTED EARTHQUAKES

END OF QUAKES PROGRAM FOR SELECTION OF EARTHQUAKES

TABLE 2.5-2

SUMMARY, REVISED EPICENTERS OF REPRESENTATIVE SAMPLES OF EARTHQUAKES OFF THE COAST OF CALIFORNIA NEAR SAN LUIS OBISPO

Date	Event Number	Original Hypocenter Revised Hypocenter Lat.	Long.	Distance Hypocenter Moved, km	Error Ellipse km	Mag., M_L
May 27, 1935	1	35.370 35.621	120.960 121.639	66NW	7 x 14	3.0
Sept. 7, 1939	6	35.420 35.459	121.070 121.495	40W	8 x 8	3.0
Oct. 6, 1939	7	35.800 36.232	121.500 121.763	54NW	16 x 31	3.5
July 11, 1945	8	35.670 35.809	121.250 121.408	21NW	7 x 24	4.0
Mar. 23, 1947	12	35.150 34.577	121.300 121.137	66S	12 x 24	3.7
Mar. 27, 1947	15	35.000 34.739	121.000 120.896	32SW	20 x 20	4.2
Dec. 20, 1948	9	35.800 35.683	121.500 121.364	16SE	9 x 38	4.5
Dec. 31, 1948	10	35.670 35.598	121.400 121.226	17SE	8 x 29	4.6
Nov. 22, 1952 Bryson Earthquake	17	35.730 35.830 35.836	121.190 121.170 121.204	U.C. Berkeley Richter (1969) 12N	7 x 24	6.0
Mar. 13, 1954	21	35.000 34.960	120.690 120.490	19E	9 x 18	3.4
Mar. 5, 1955	23	35.600 35.863	121.400 121.149	38NE	15 x 29	3.3
June 21, 1957	25A	35.100 35.255	120.900 120.951	15NW	10 x 19	3.7
Jan. 2, 1960	26	35.400 35.778	121.190 121.066	44NE	15 x 29	4.0
Feb. 1, 1962	52	34.880 35.031	120.670 120.846	22NW	6 x 16	4.5

TABLE 2.5-2

Date	Event Number	Original Hypocenter Revised Hypocenter Lat.	Long.	Distance Hypocenter Moved, km	Error Ellipse km	Mag., M_L
Mar. 5, 1962	54	34.600 34.622	121.590 121.416	17E	8 x 10	4.5
Mar. 10, 1962	54A	34.600 34.667	121.590 121.372	22NE	6 x 20	4.2
Feb. 22, 1963	28	35.110 34.730	121.440 121.400	42S	7 x 28	3.3
Sept. 6, 1969	31	35.300 35.355	121.090 121.033	9NE	5 x 10	3.6
Oct. 22, 1969	56	34.830 34.649	121.340 121.471	23SW	14 x 50	5.4

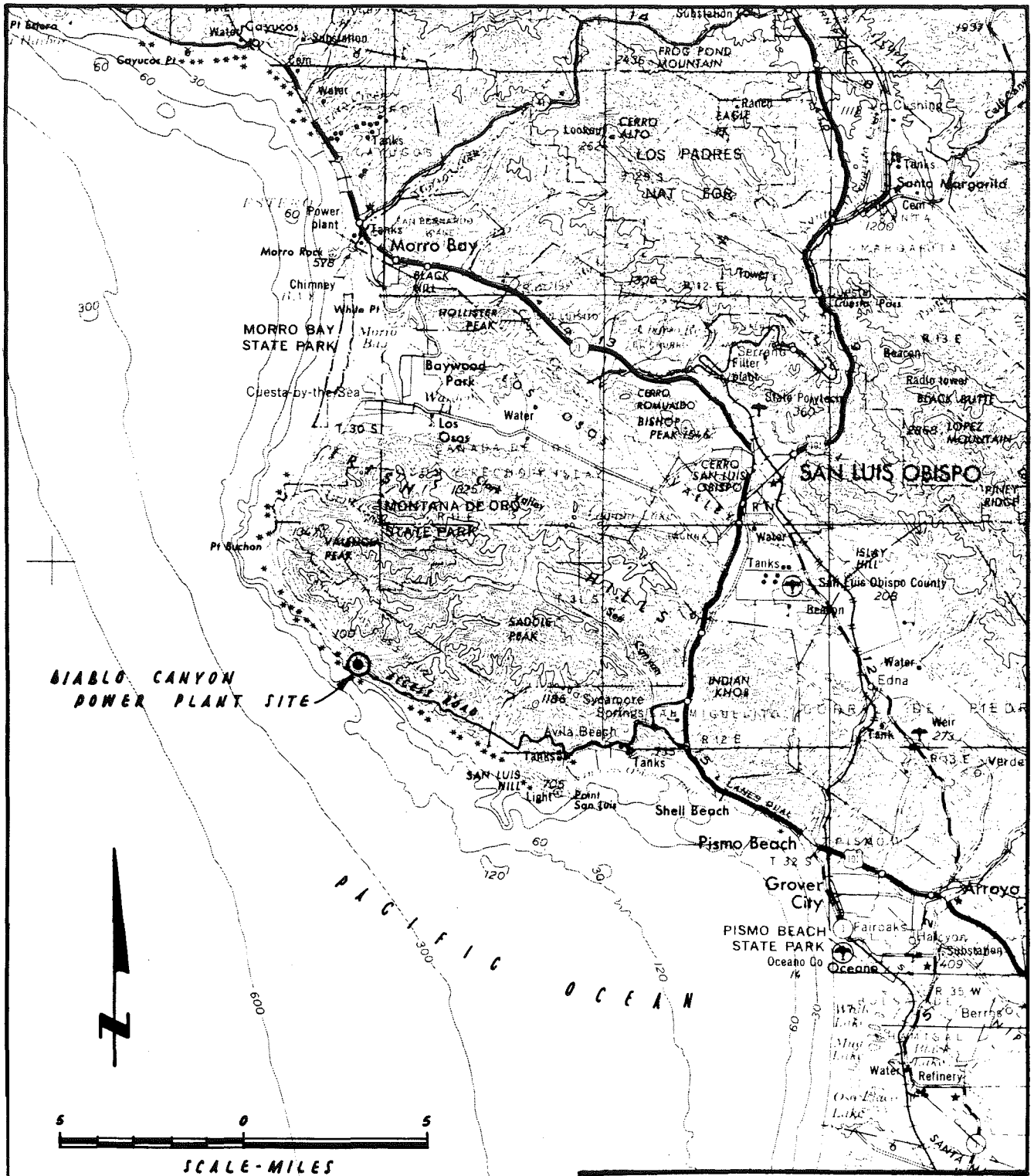
TABLE 2.5-3

DISPLACEMENT HISTORY OF FAULTS IN THE SOUTHERN COAST RANGES OF CALIFORNIA

Fault	Distance From Diablo Site, miles	Time of Principal Activity	Youngest Formation Cut By Fault	Oldest Formation Capping Fault
San Andreas	45	Mid-Tertiary - present		Currently active
Faults in ground between San Andreas and Sur-Nacimiento-Rinconada, La Panza, Cuyama, Red Hills, East Huasna	18-45	Tertiary	Pleistocene (possible Holocene) (Ref. 14)	Not Known
Sur-Nacimiento (zone)	18	Late Mesozoic, (Benioff-subduction zone)	Pleistocene (possible Holocene) (Ref. 14)	Late Quaternary terrace deposits (Ref. 11)
West Huasna-Suey	11	Late Tertiary	Post late-Miocene	Late Quaternary terrace deposits (Ref. 36)
Edna	4.5	Late Tertiary	Plio-Pleistocene (Paso Robles Fm)	Late Pleistocene (Ref. 20)
Miguelito	5	Late Tertiary	Early Pliocene (Miguelito Member of Careaga Fm) (Ref. 21)	Poss. capped by mid-Pliocene Squire Member of Careaga Fm; Plio-Pleistocene Paso Robles Fm

TABLE 2.5-3

Fault	Distance From Diablo Site, miles	Time of Principal Activity	Youngest Formation Cut By Fault	Oldest Formation Capping Fault
Faulting in the Mesozoic rocks near Pt. San Luis	4	Mesozoic	Mesozoic	Late Pleistocene (Ref. 20)
Unnamed faults near Pt. San Simeon	35	Probable Tertiary	Not known; possible Holocene	Not known
Offshore structural zone	4.5	Late Tertiary	Possible Holocene (Ref. 19) (northern part)	Holocene-upper Pliocene (Ref. 19) (southern part)
Faults in the Santa Maria Basin	40	Not known	Possible Pleistocene (orcutt Fm) (Ref. 23)	Pleistocene-Holocene



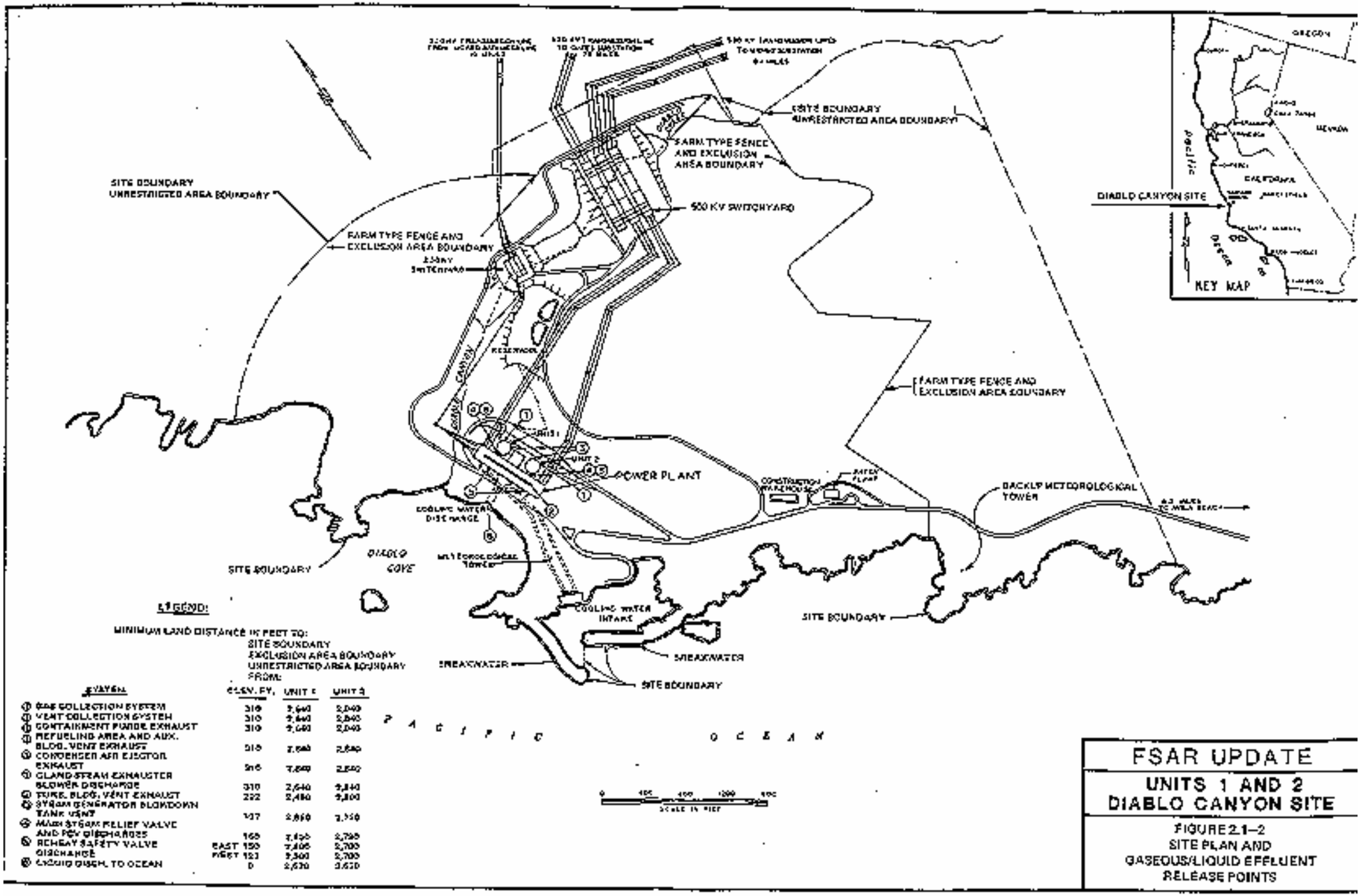
FSAR UPDATE

UNITS 1 AND 2 DIABLO CANYON SITE

FIGURE 2.1–1

SITE LOCATION MAP

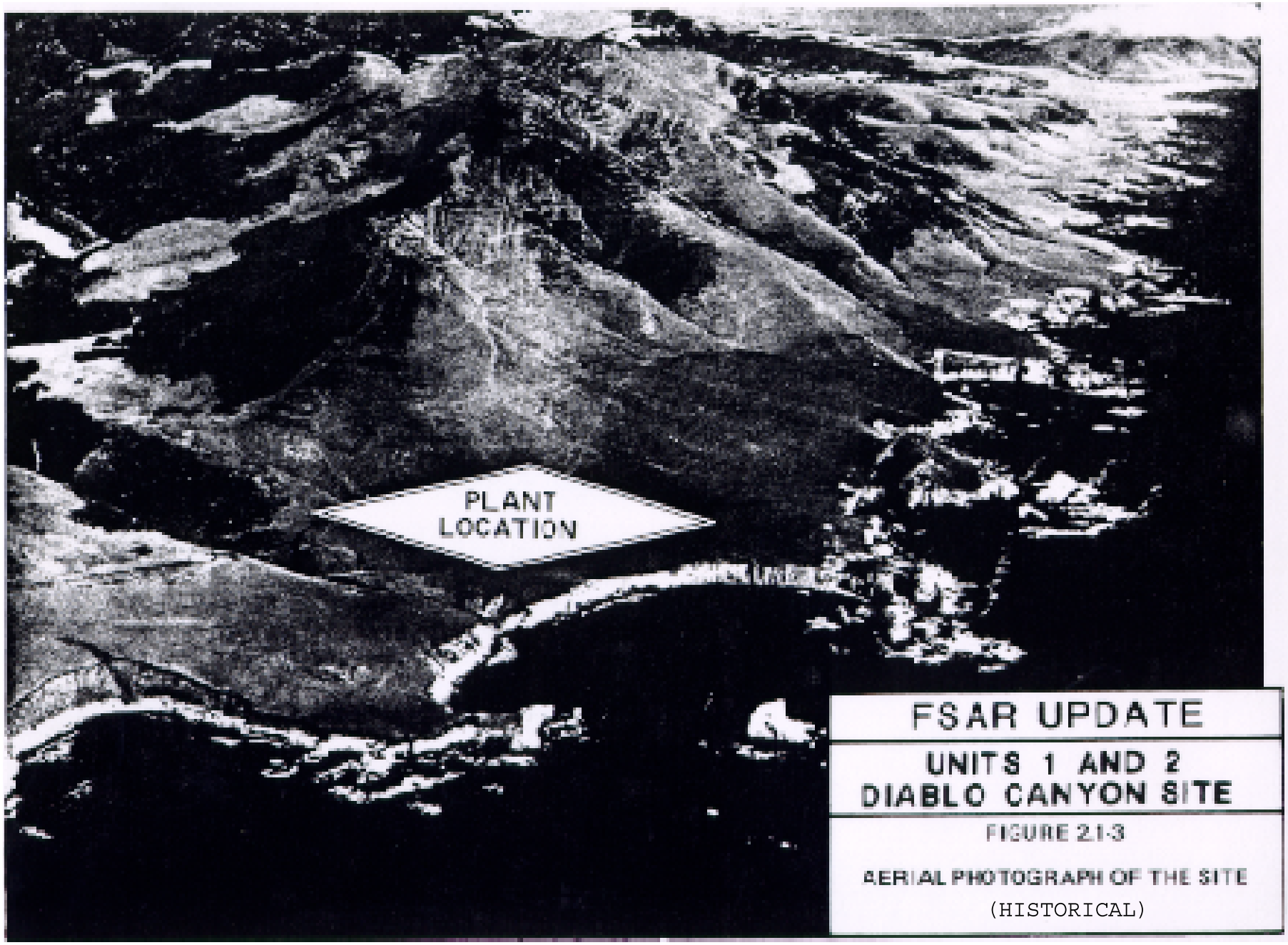
(HISTORICAL)



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.1–2
SITE PLAN AND
GASEOUS/LIQUID EFFLUENT
RELEASE POINTS

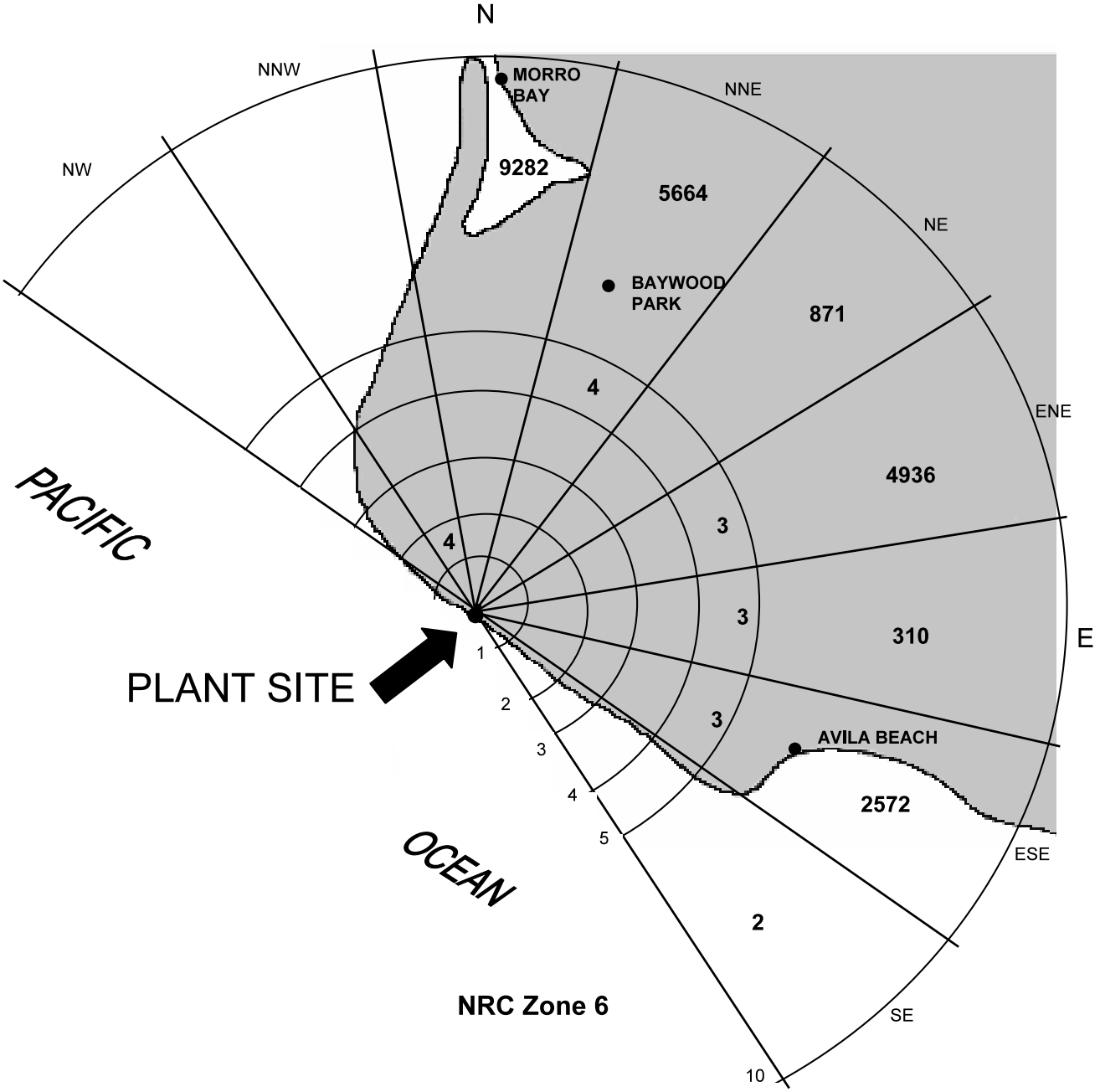


FSAR UPDATE

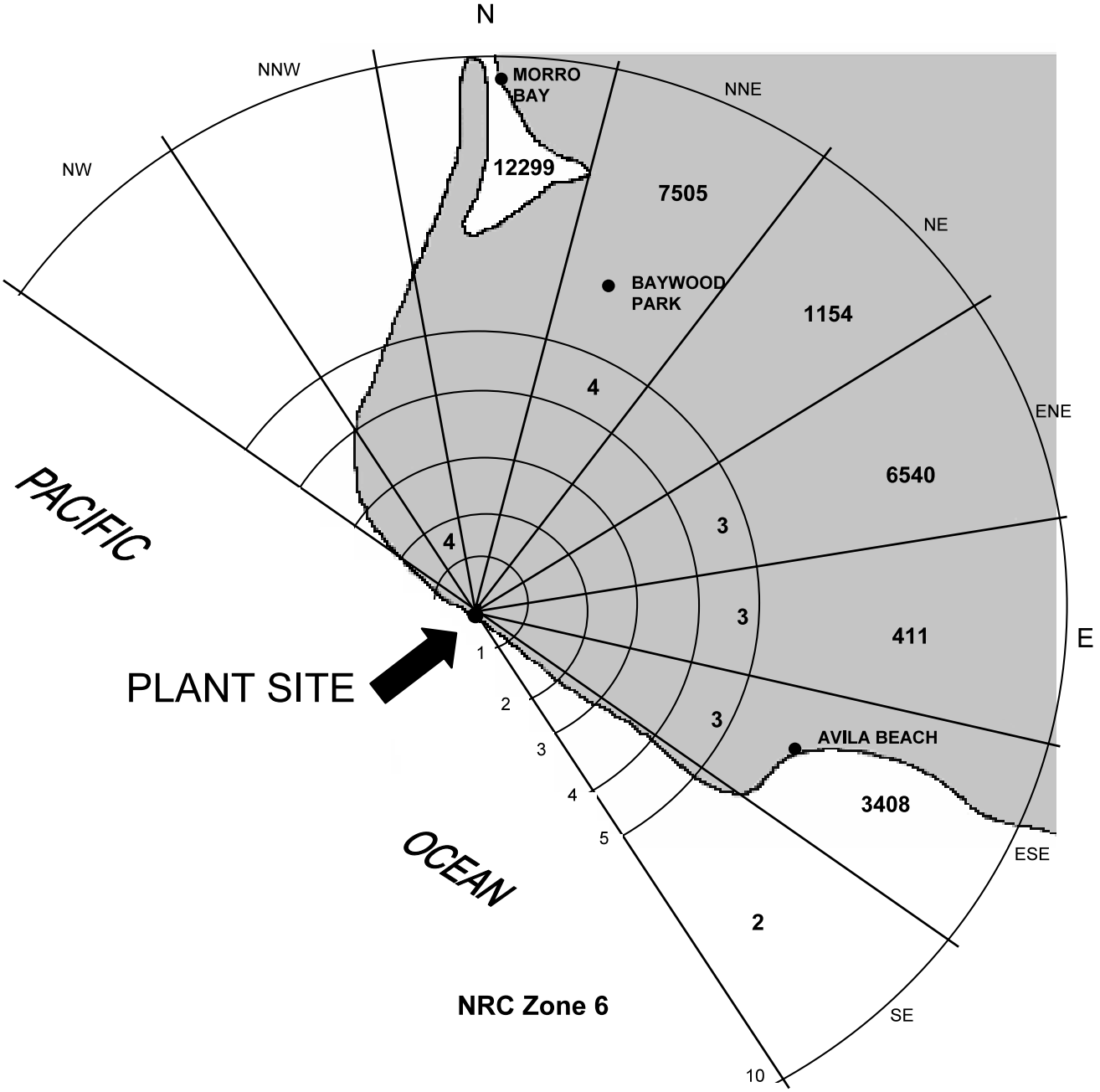
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.1-3

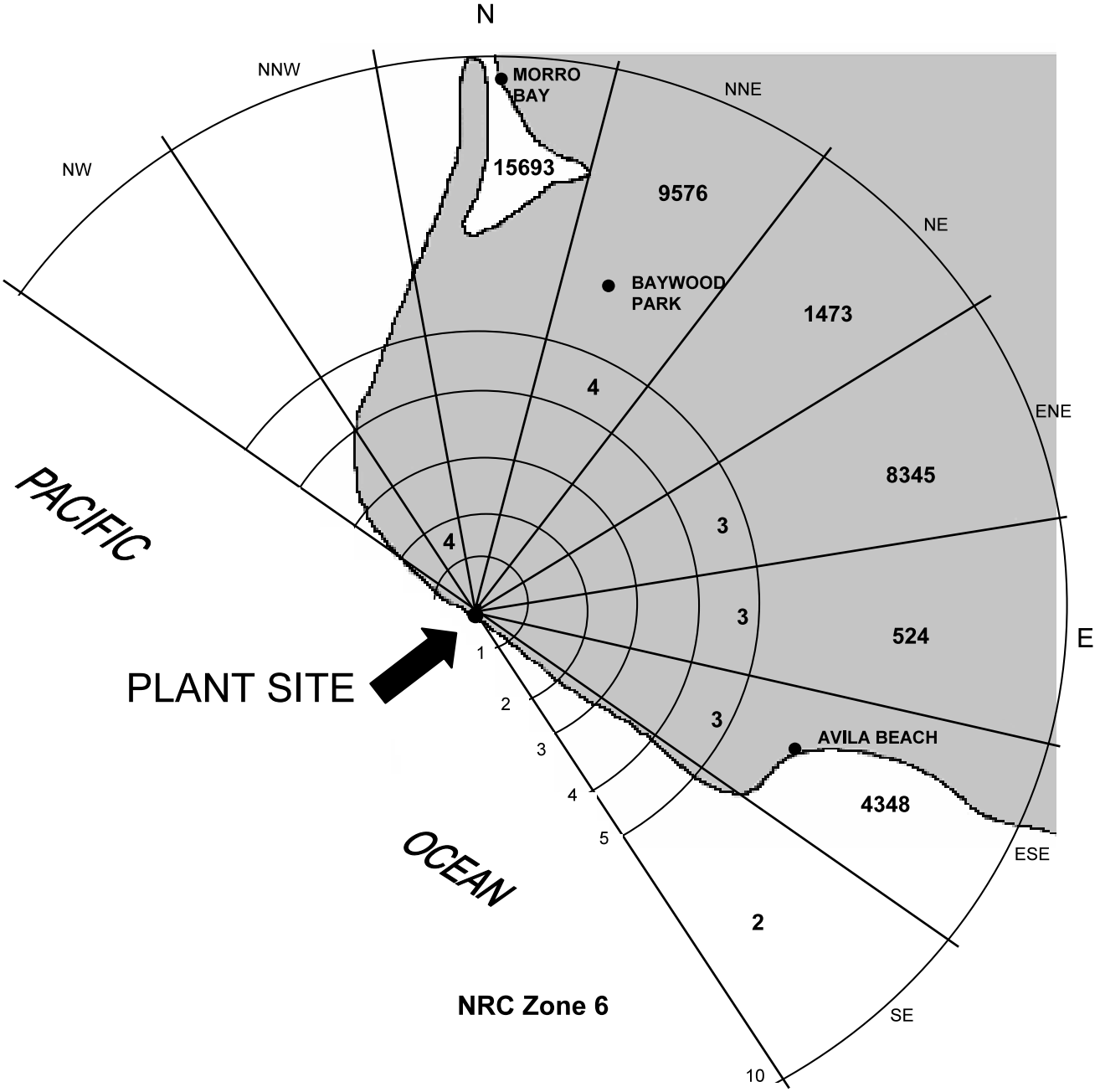
AERIAL PHOTOGRAPH OF THE SITE
(HISTORICAL)



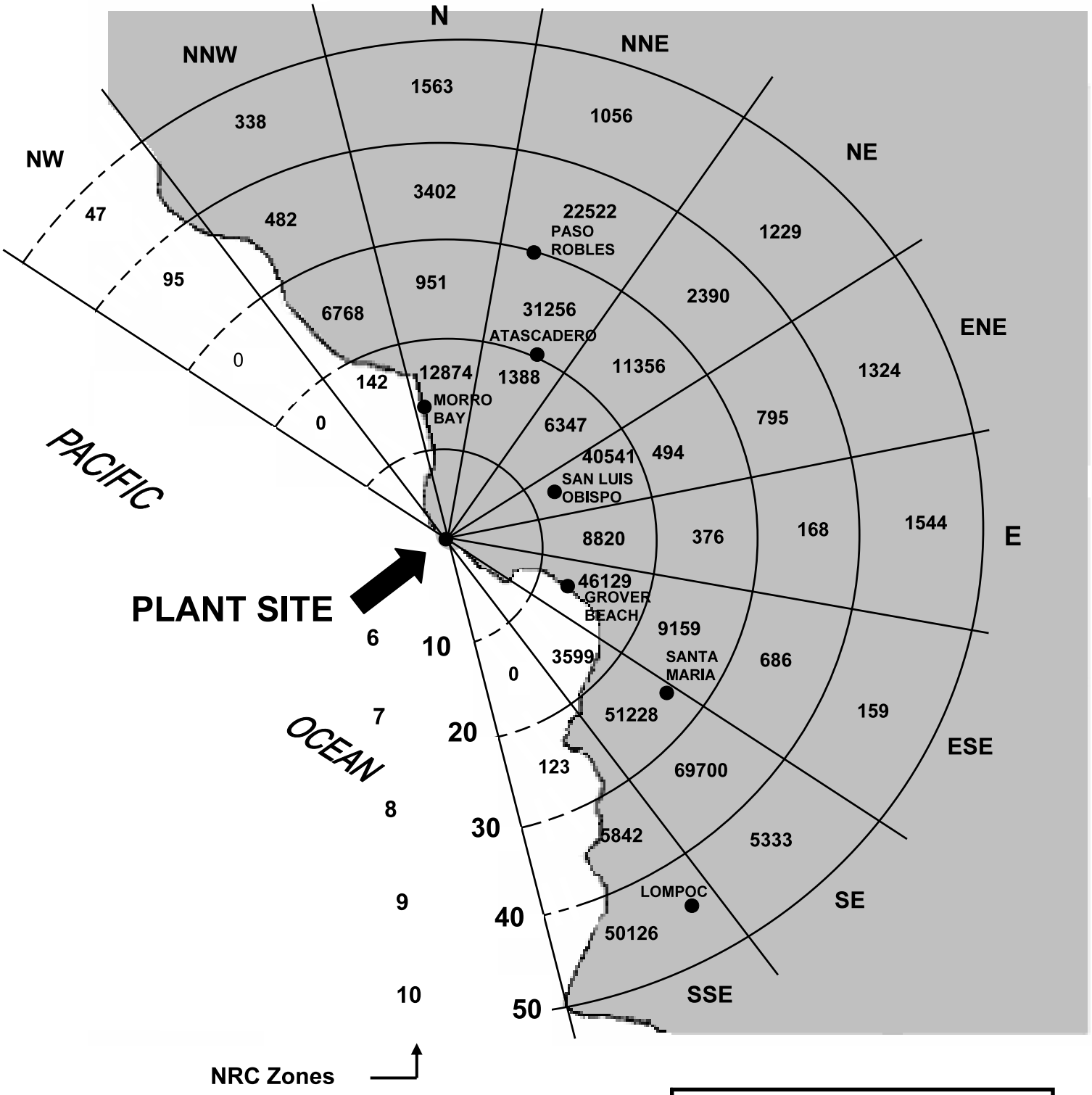
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.1-4 POPULATION DISTRIBUTION 0 TO 10 MILES 2000 CENSUS (HISTORICAL)



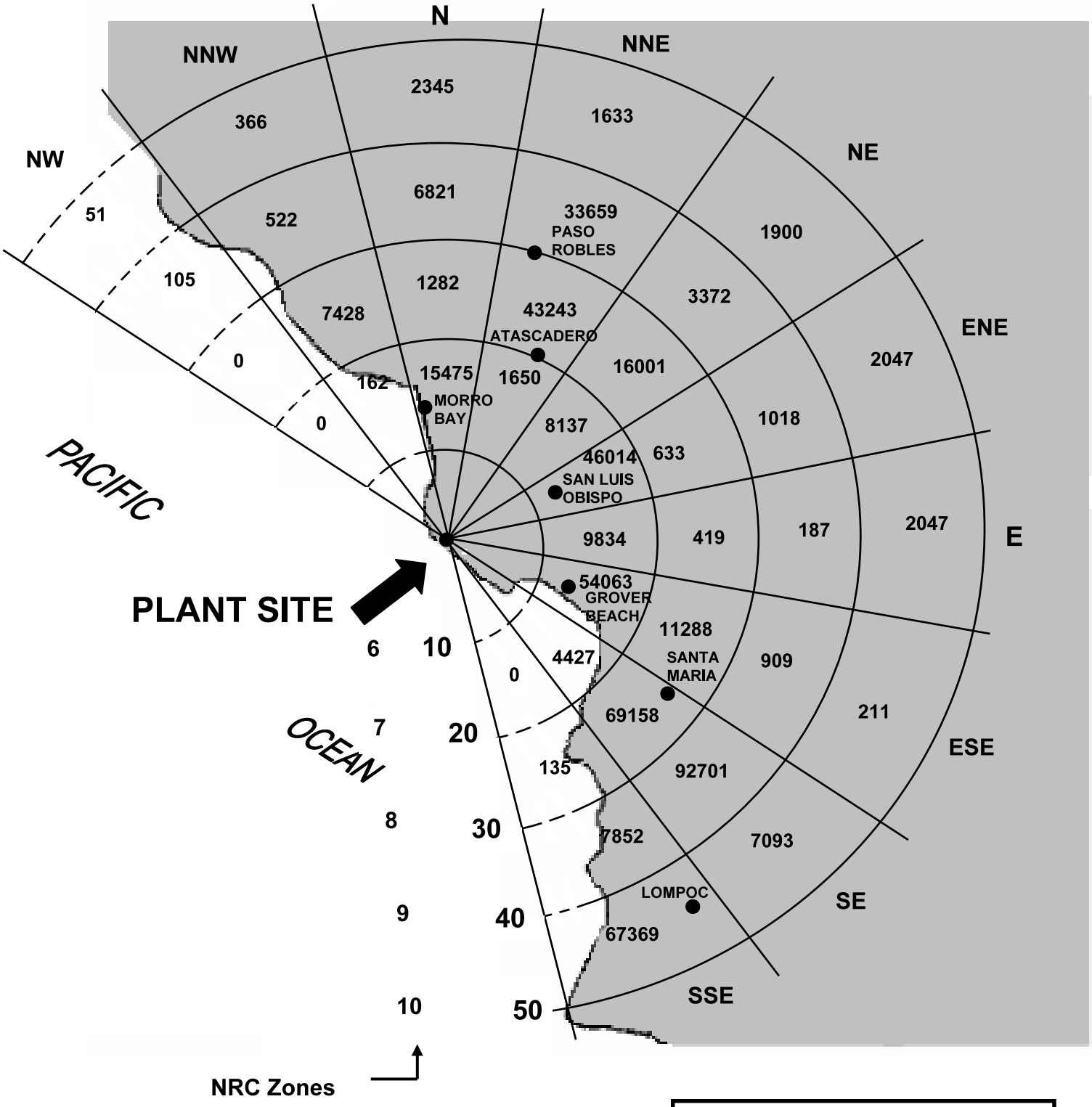
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.1-5 POPULATION DISTRIBUTION 0 TO 10 MILES 2010 PROJECTED (HISTORICAL)



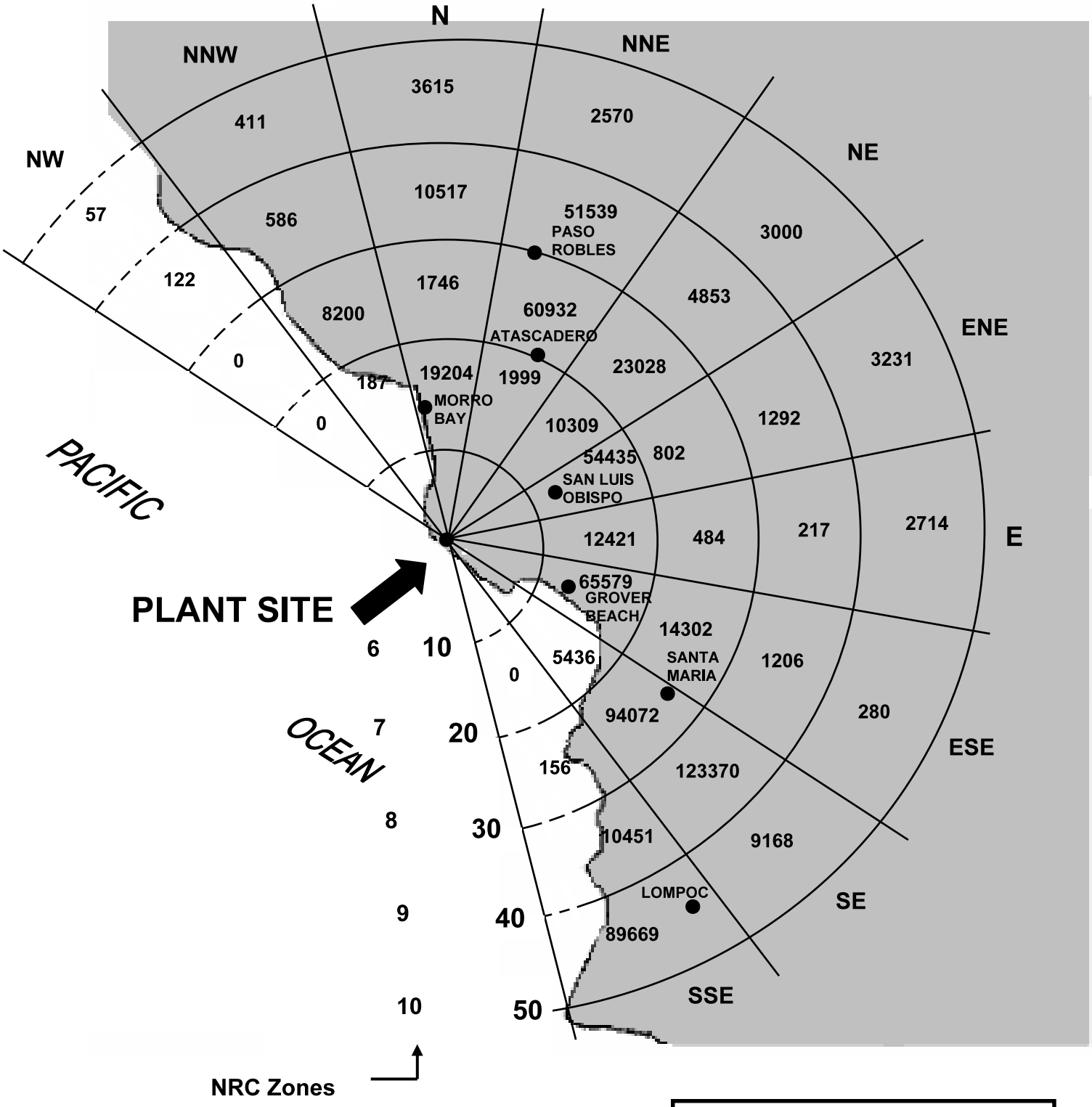
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.1-6 POPULATION DISTRIBUTION 0 TO 10 MILES 2025 PROJECTED (HISTORICAL)



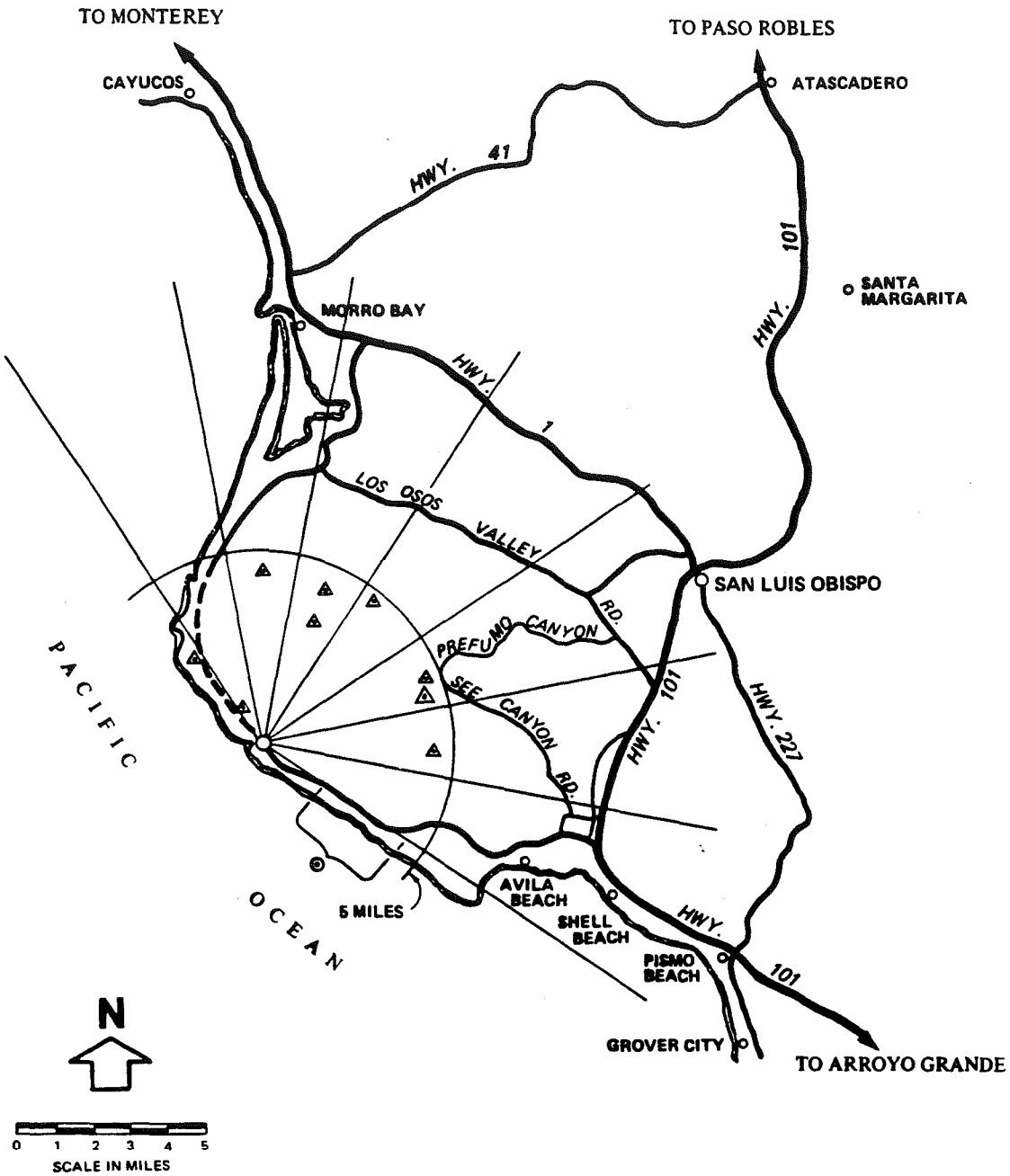
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.1-7 POPULATION DISTRIBUTION 10 TO 50 MILES 2000 CENSUS (HISTORICAL)



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.1-8 POPULATION DISTRIBUTION 10 TO 50 MILES 2010 PROJECTED (HISTORICAL)



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.1-9 POPULATION DISTRIBUTION 10 TO 50 MILES 2025 PROJECTED (HISTORICAL)



LEGEND

⊙ GARDENS OR FARM

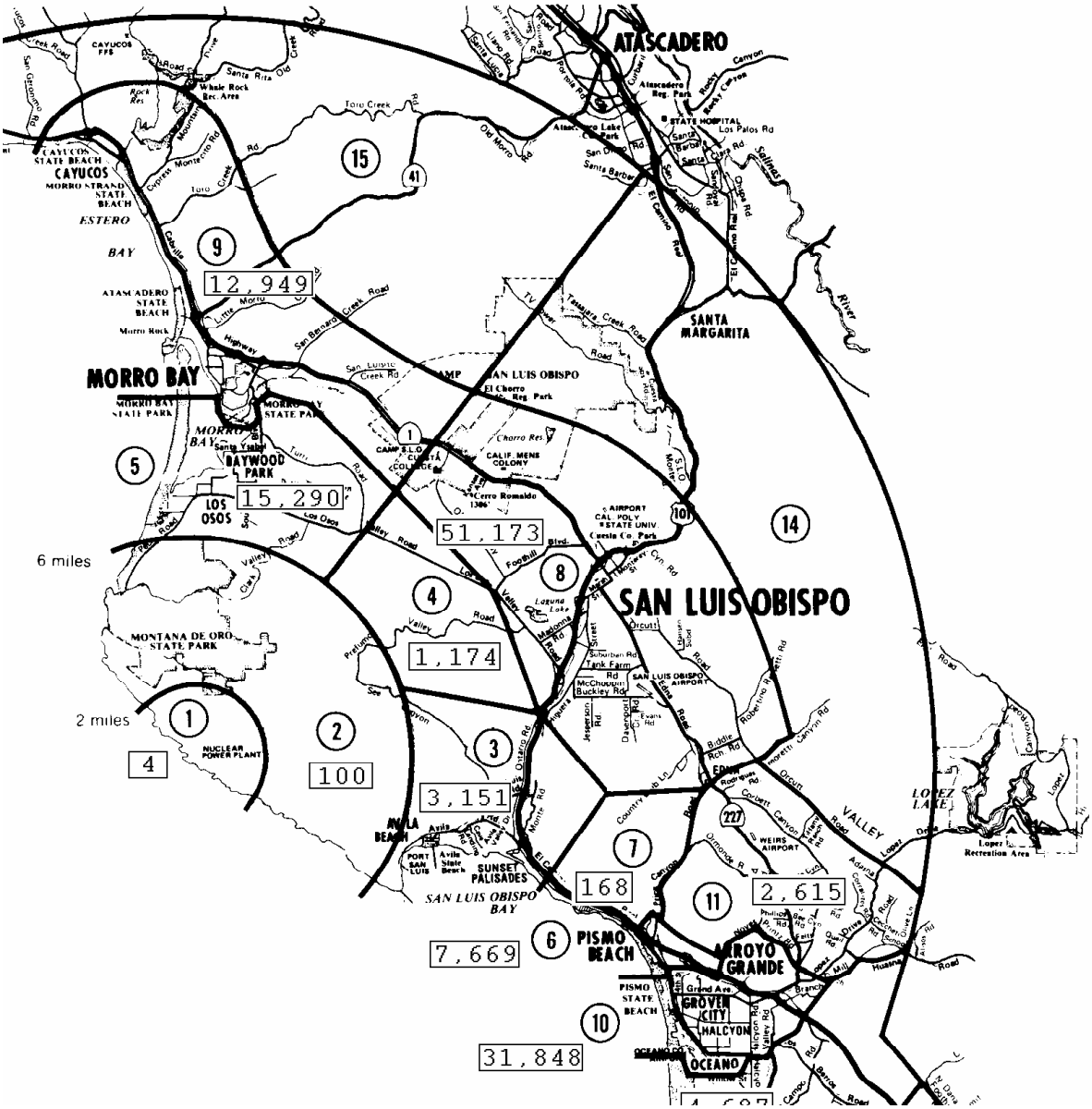
△ RESIDENCES

FSAR UPDATE

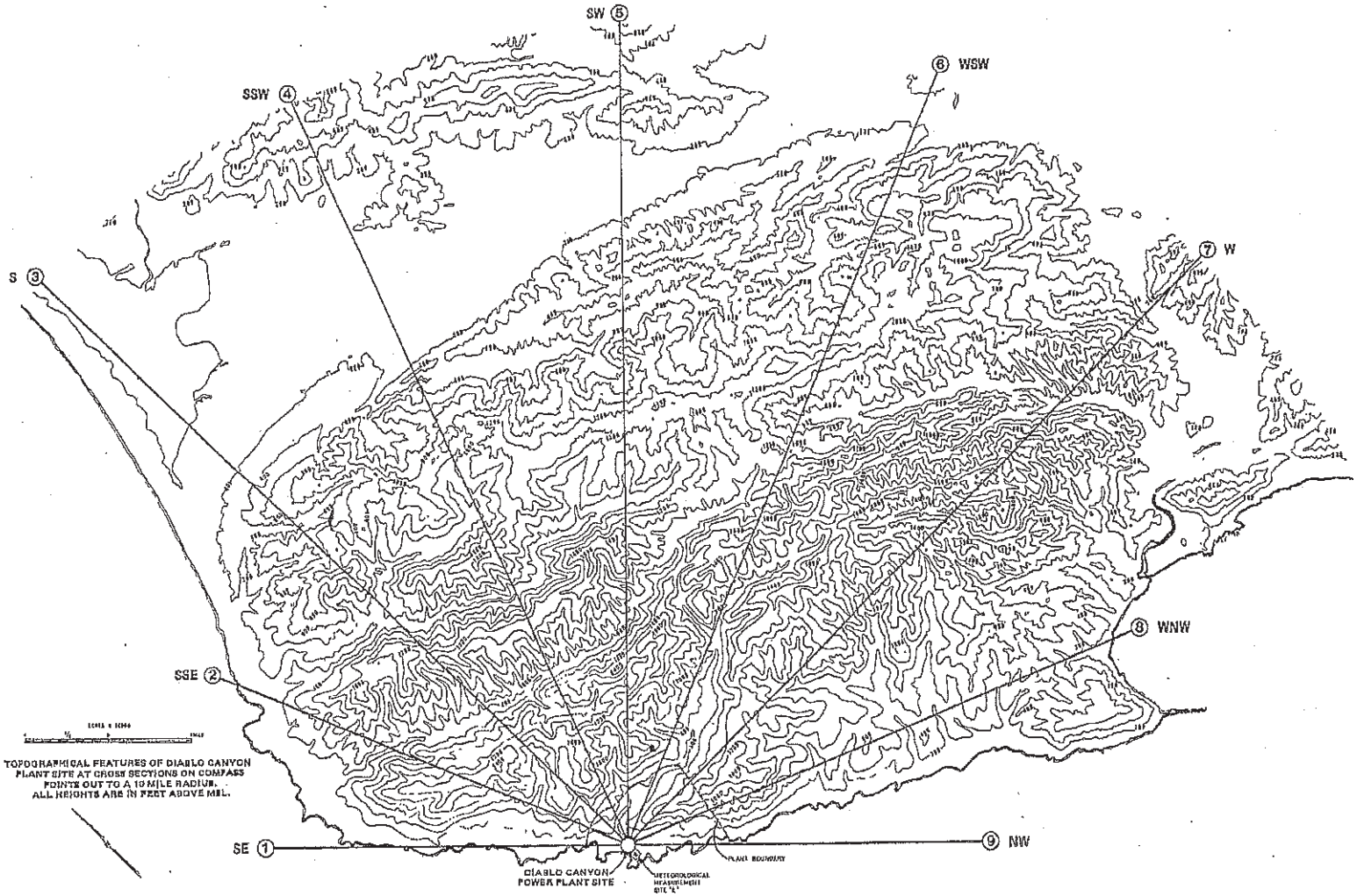
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.1–14.

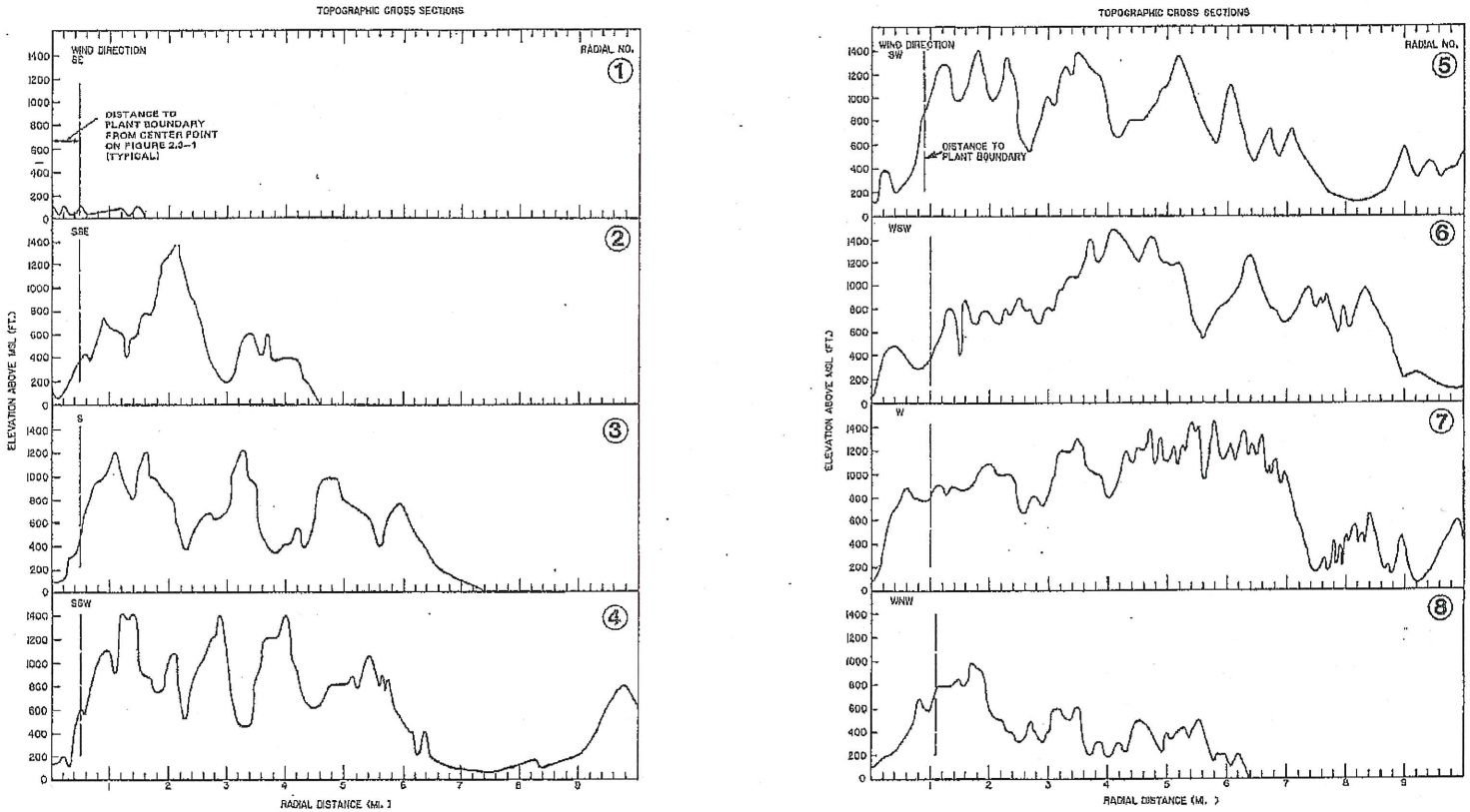
1985 LAND USE CENSUS
(HISTORICAL)



FSAR Update
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.1-15 LOW POPULATION ZONE (HISTORICAL)

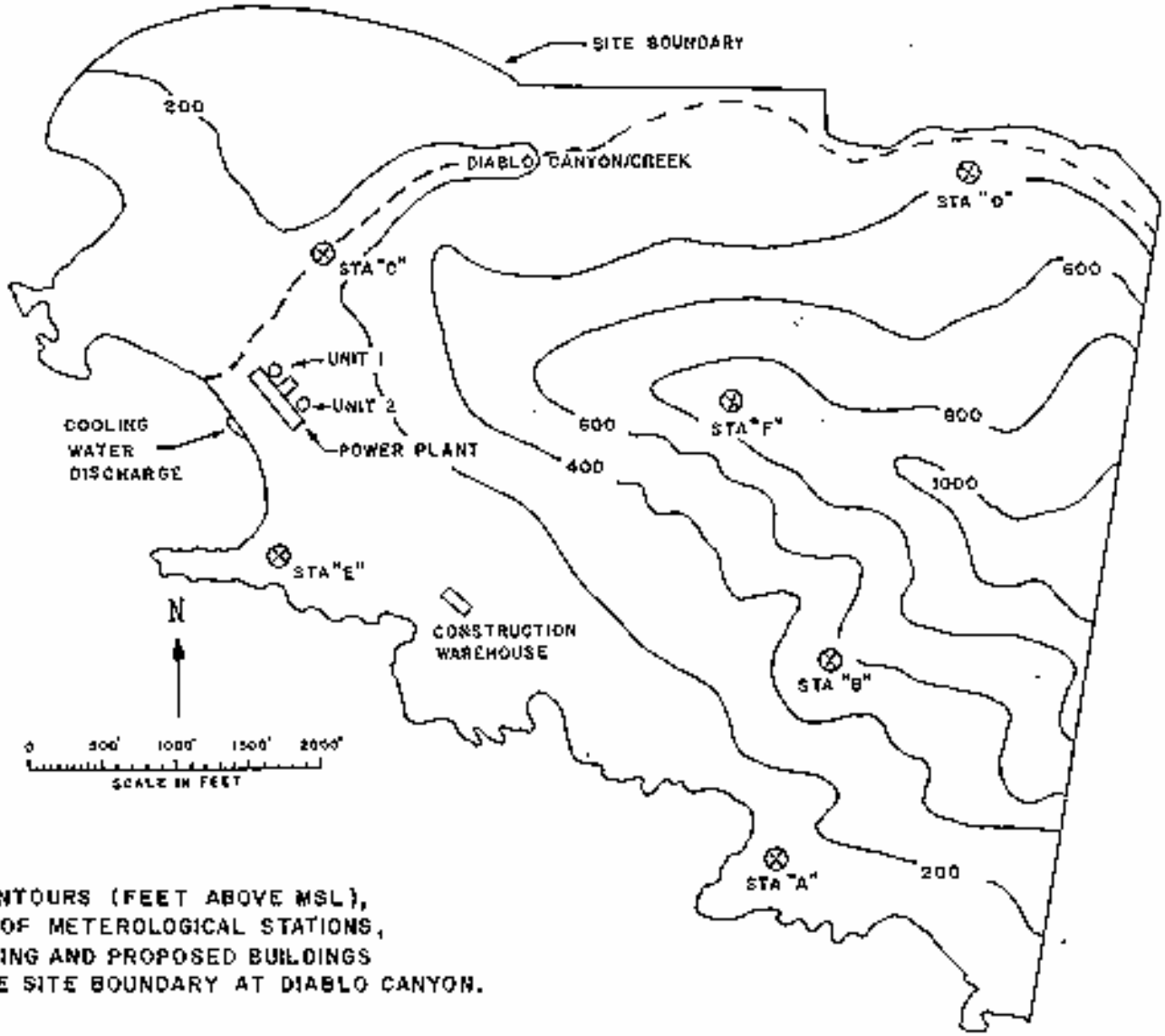


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.3-1 TOPOGRAPHICAL FEATURES AT CROSS SECTIONS TO A 10 MILE RADIUS (SECTIONS SHOWN ON FIGURE 2.3-2)



TOPOGRAPHICAL FEATURES OF DIABLO CANYON PLANT SITE AT CROSS SECTIONS ON COMPASS POINTS OUT TO A 10 MILE RADIUS. ALL HEIGHTS ARE IN FEET ABOVE MSL.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.3-2
TOPOGRAPHICAL FEATURES AT CROSS SECTIONS TO A 10 MILE RADIUS (SECTIONS CUT ON FIGURE 2.3-1)



NOTE:

HEIGHT CONTOURS (FEET ABOVE MSL), LOCATION OF METEROLOGICAL STATIONS, AND EXISTING AND PROPOSED BUILDINGS WITHIN THE SITE BOUNDARY AT DIABLO CANYON.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

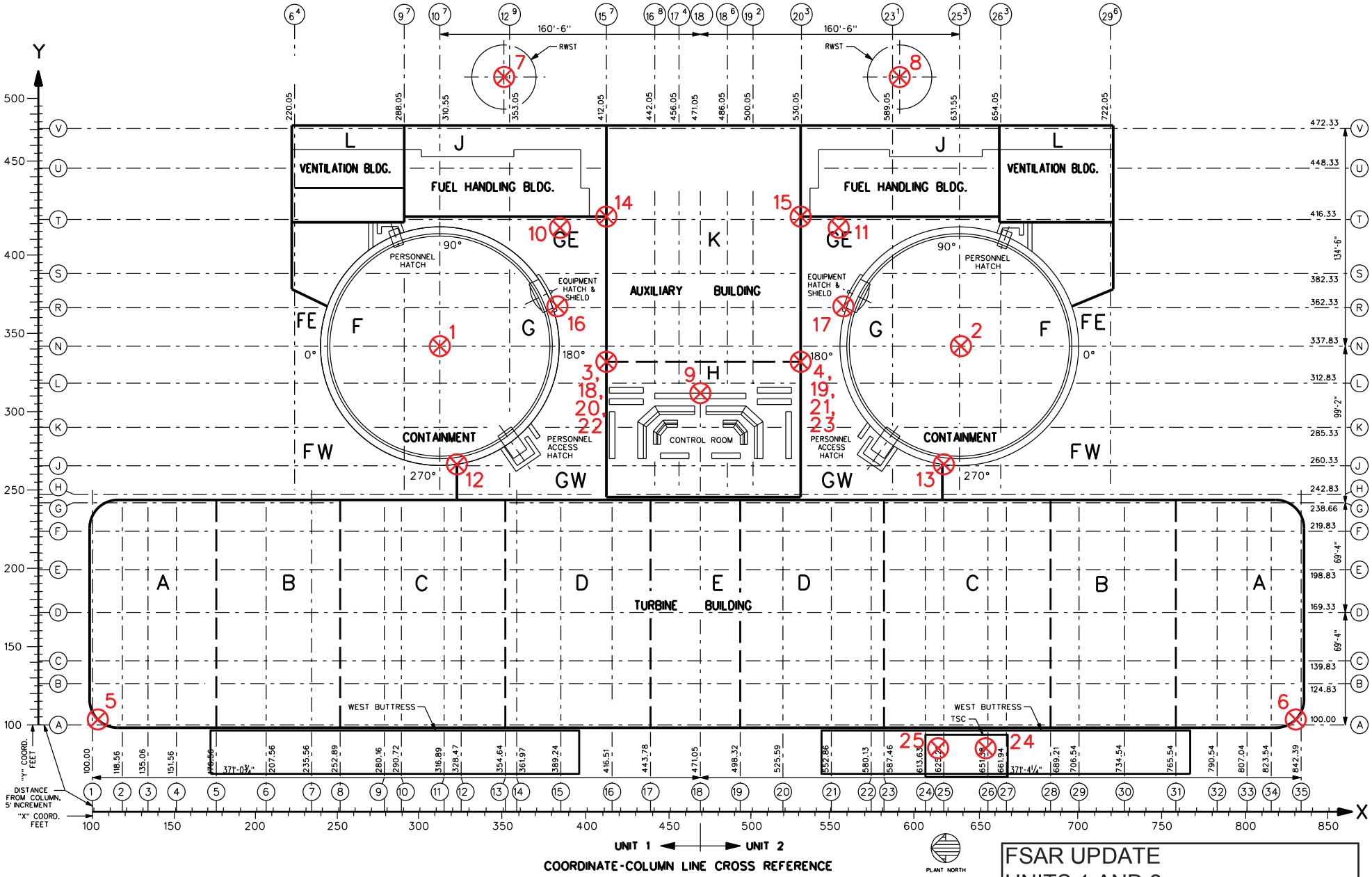
FIGURE 2.3-3

LOCATION OF METEROLOGICAL STATIONS WITHIN THE SITE BOUNDARY

Revision 11 November 1996

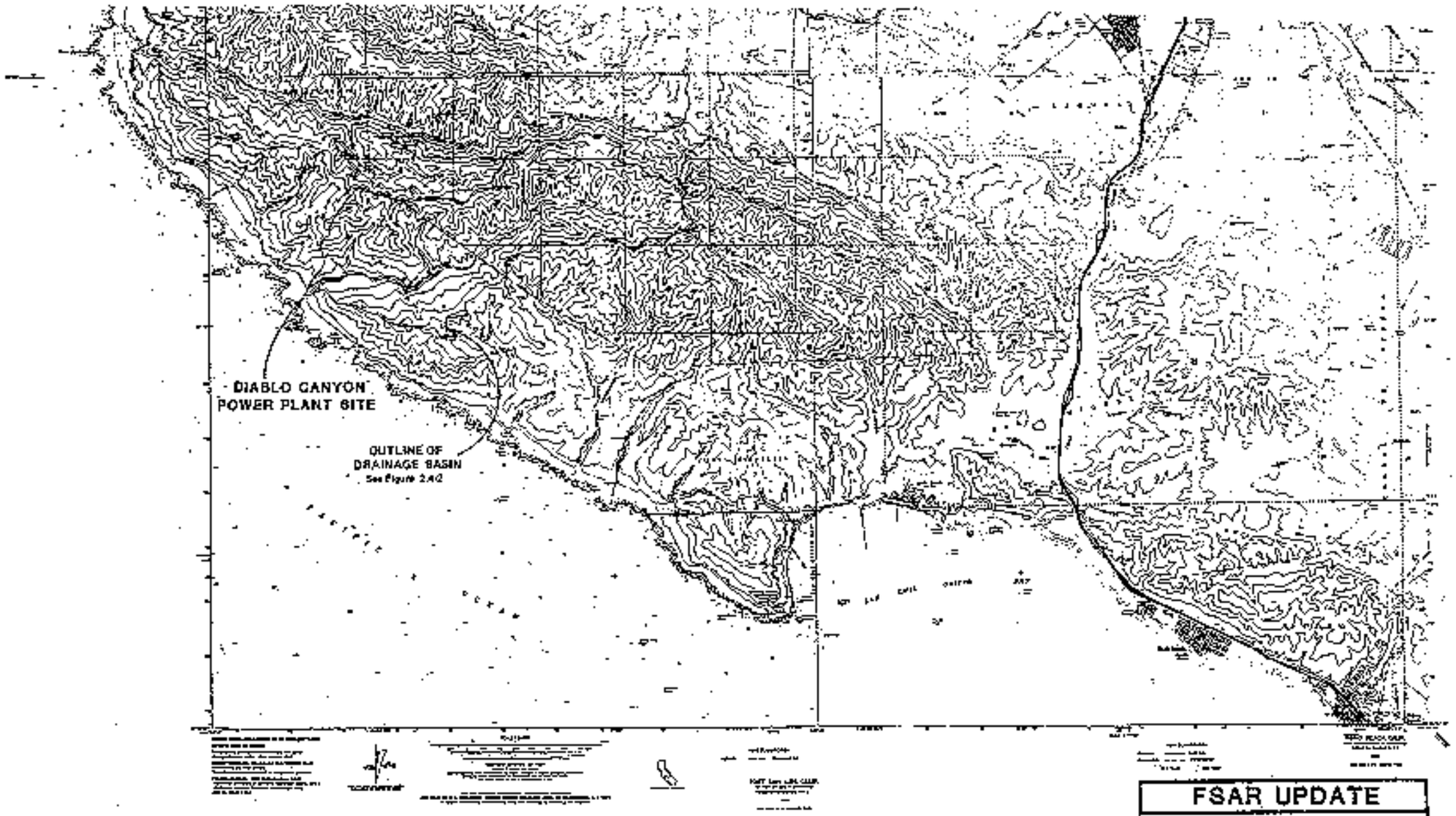
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.3-4 LOCATION OF METEOROLOGICAL MEASUREMENT SITES AT DIABLO CANYON AND VICINITY

Revision 20 November 2011



Revision 24 September 2018

FSAR UPDATE
UNITS 1 AND 2
DIABLO CANYON SITE
FIGURE 2.3-5
Post-Accident Environmental
Release Point / Receptor Location



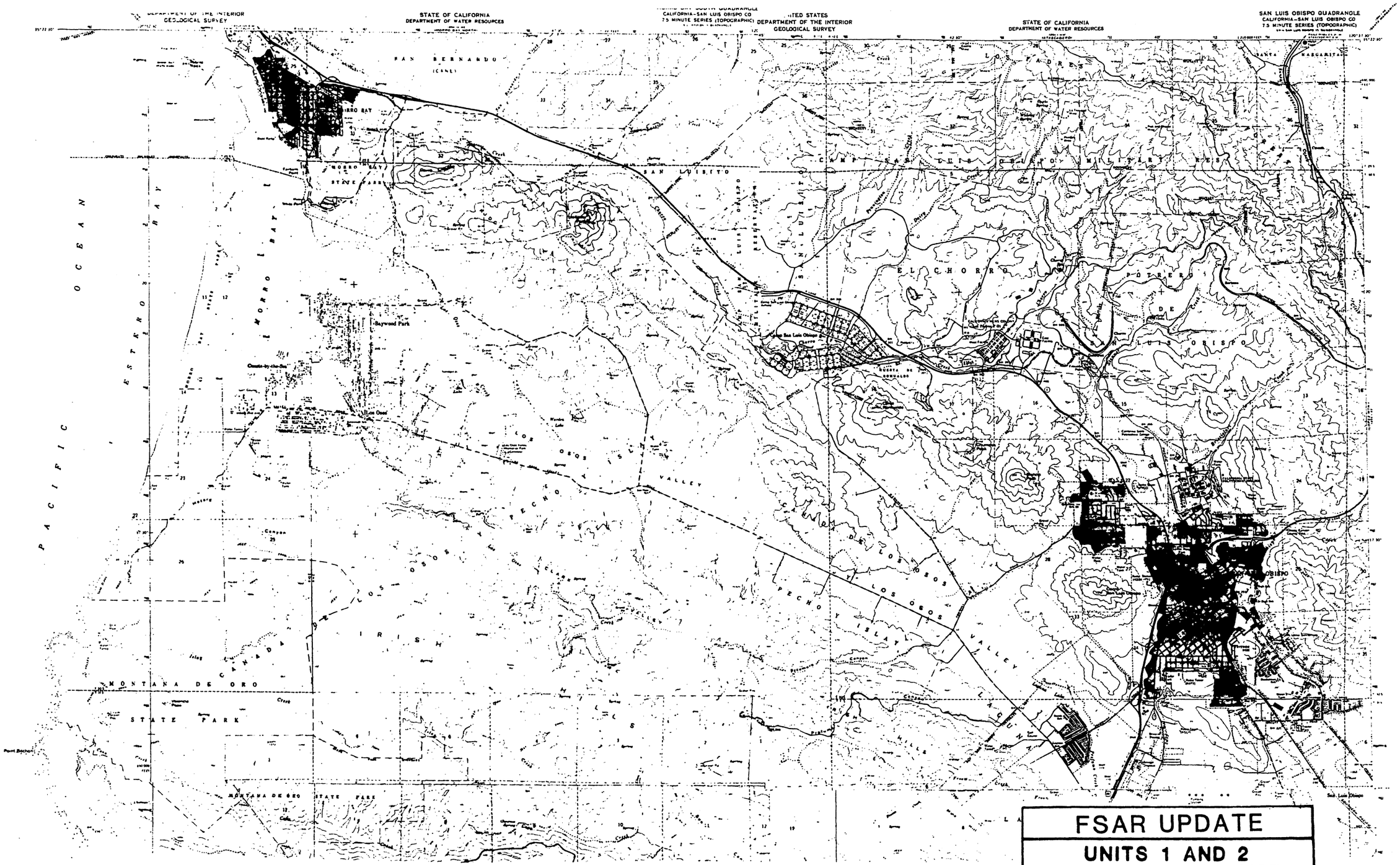
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.4-1

PLANT SITE LOCATION
DRAINAGE AND TOPOGRAPHY
(SHEET 1 OF 2)

Revision 11 November 1996

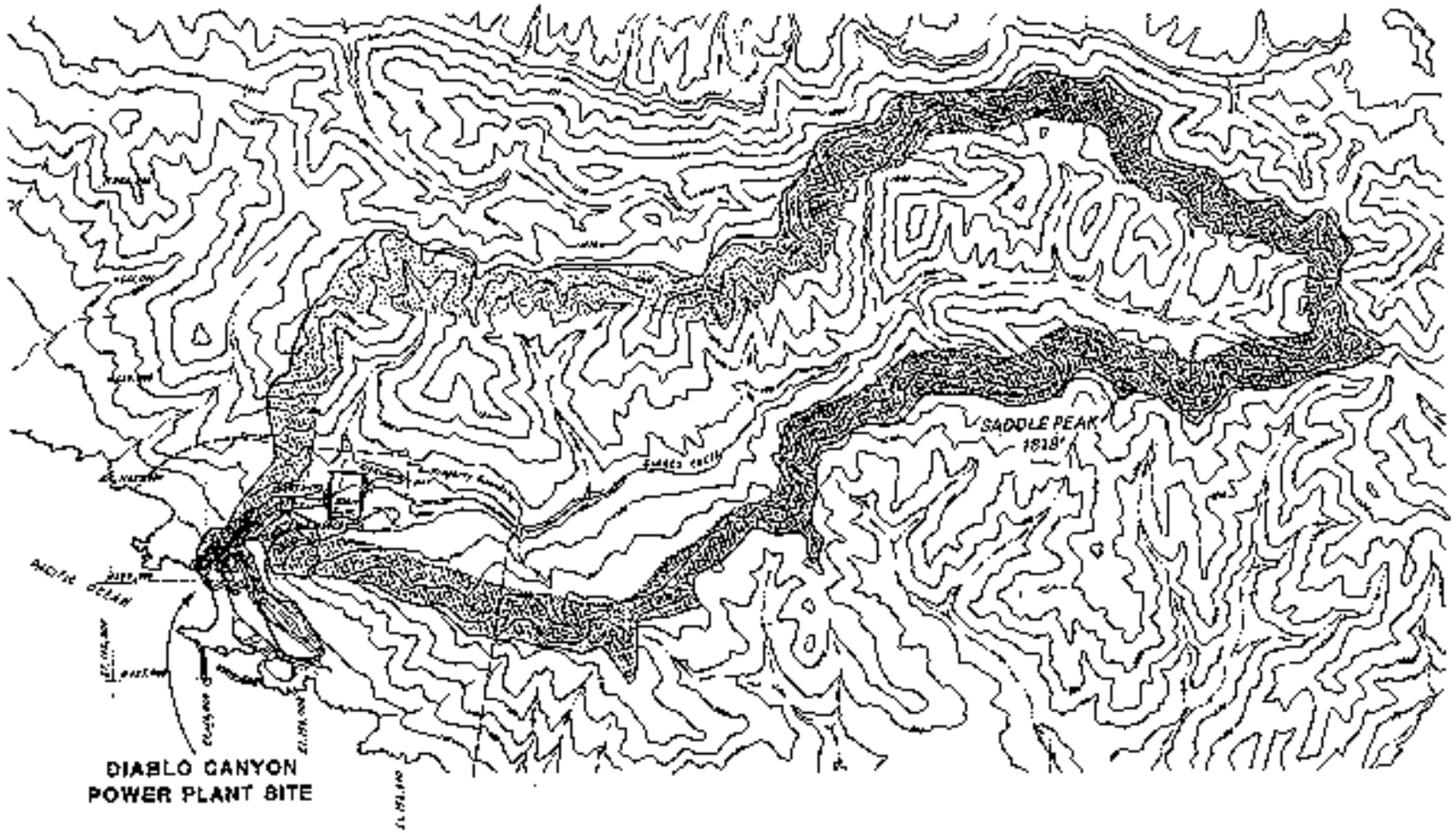


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.4-1

PLANT SITE LOCATION
DRAINAGE AND TOPOGRAPHY
(SHEET 2 OF 2)



SURFACE DRAINAGE PLAN

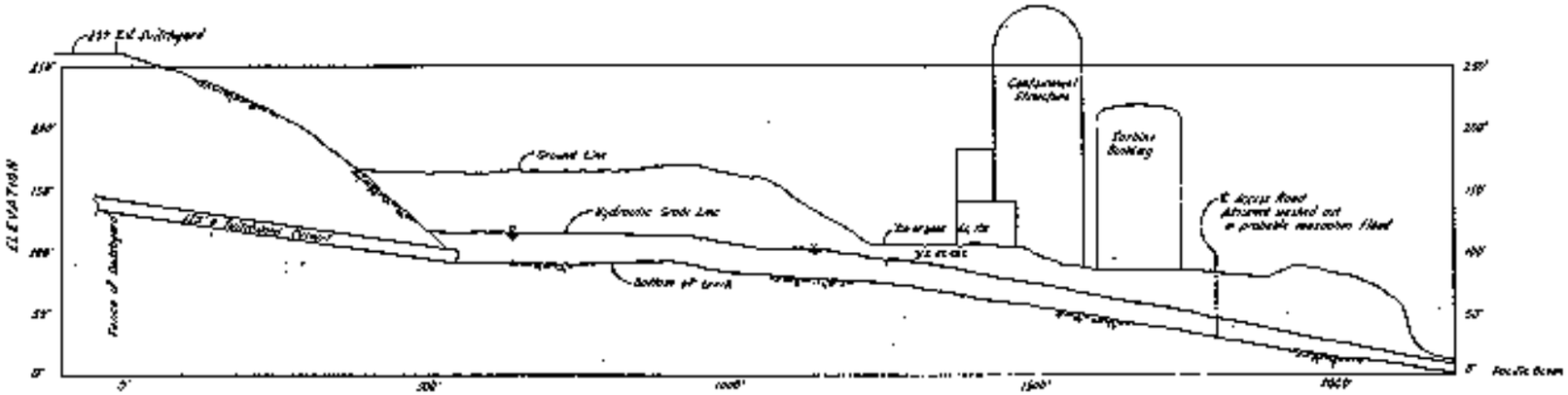
NOTES:
1. GRID COORDINATES SHOWN ARE BASED ON EACH STATE CHROMATIC SYSTEM
2. DATUM FOR ELEVATIONS SHOWN IS MEAN SEA LEVEL (L.A.D.)
3. ARROW (→) INDICATES DIRECTION OF FLOW OFF.
4. TOPOGRAPHY PHOTOGRAMMETRICALLY REPRODUCED FROM USGS PORT SAN LUIS 7.5 MINUTE QUADRANGLE, 1967

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

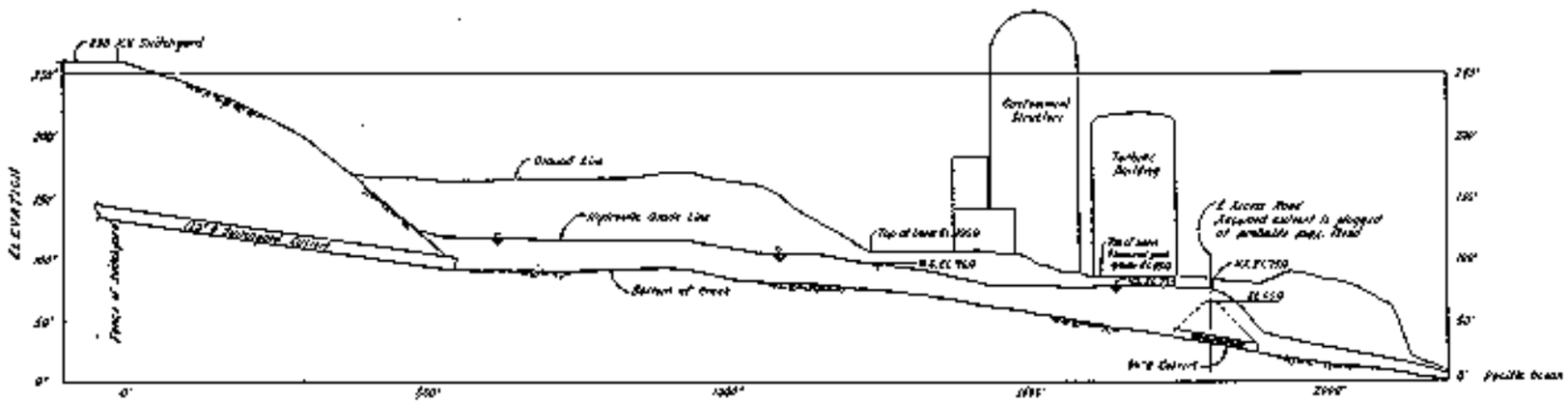
FIGURE 2.4-2

SURFACE DRAINAGE PLAN



PROFILE - DIABLO CREEK
FROM FOOT OF 230 KV SWITCHYARD TO PACIFIC OCEAN

NOTES:
1. The hydraulic grade lines shown are for an assumed flow of 10,000 cfs.
2. The average velocity in channel for assumed flow is 1.00 fps.
3. The roughness factor of Diablo Creek is assumed to be n = .04 in Manning's formula $Q = \frac{1.49}{n} A R^{2/3} S^{1/2}$
4. Bottom for alignment shown is taken as from 24 cfs.



PROFILE - DIABLO CREEK
FROM FOOT OF 230 KV SWITCHYARD TO PACIFIC OCEAN

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.4-3

DIABLO CREEK FROM FOOT OF 230 KV SWITCHYARD TO PACIFIC OCEAN

DIABLO CANYON PROJECT JAN. 19-20, 1969 OPTIMIZATION
RUNOFF FROM LOS BERROS CREEK
RAIN FROM DIABLO & 250 TOWER

INPUT DATA

NHT	M	IPLOT	NCLRK
1	0	1	0

DA	TR	VAR1	VAR2	VAR3	VAR4	VAR5	VAR6	VAR7	QRECSN
15.00	60.	1.42	0.0	0.0	0.0	0.0	0.0	0.0	240.

FLAG1	FLAG2	FLAG3	FLAG4	FLAG5	FLAG6	FLAG7	FLGNH1	FLGNH2	RTIOR
0.	0.	0.	0.	0.	0.	0.	0.	0.	1.56

INPUT DATA

NP	VARNH1	VARNH2	STRTQ	NQO	IQA	RQA	IQB	RQB	N
21	0.0	0.0	15.	66	0	0.0	0	0.0	1

MODIFIED INPUT DATA

NP	VARNH1	VARNH2	STRTQ	NQO	IQA	RQA	IQB	RQB	N
21	0.50	0.50	15.	66	0	0.0	0	0.0	1

DA	TR	VAR1	VAR2	VAR3	VAR4	VAR5	VAR6	VAR7	QRECSN
15.00	60.	1.42	1.00	1.50	0.0	2.00	0.03	0.30	240.

FLAG1	FLAG2	FLAG3	FLAG4	FLAG5	FLAG6	FLAG7	FLGNH1	FLGNH2	RTIOR
0.	0.	0.	0.	0.	0.	0.	0.	0.	1.56

OPTIMIZATION RESULTS

DA	TR	VAR1	VAR2	VAR3	VAR4	VAR5	VAR6	VAR7	QRECSN
15.00	60.	2.44	2.02	1.00	0.0	4.24	0.02	0.29	240.

FLAG1	FLAG2	FLAG3	FLAG4	FLAG5	FLAG6	FLAG7	FLGNH1	FLGNH2	RTIOR
0.	0.	0.	0.	0.	0.	0.	0.	0.	1.56

UNIT HYD.NO= 27 LAGS 2.595 CP= 0.366

366.	1031.	1367.	1274.	1039.	848.	691.	564.	460.	375.
306.	250.	204.	166.	135.	110.	90.	73.	60.	49.
40.	33.	27.	22.	18.	14.	12.			

NP	VARNH1	VARNH2	STARTQ	NQO	IQA	RQA	IQB	RQB	STRTK
21	0.14	0.59	15.	66	0	0.0	0	0.0	0.14

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.4-4
OPTIMIZATION OF FIT
DIABLO - LOS BERROS
(SHEET 1 OF 3)

LOS BERROS CREEK OPTIMIZATION

PERIOD	RAIN	LOSS	EXCESS	Q(30) C	Q(4) C
1	0.00	0.01	0.0	34.	35.
2	0.01	0.10	0.0	34.	36.
3	0.02	0.02	0.0	33.	40.
4	0.08	0.06	0.0	33.	45.
5	0.07	0.07	0.0	33.	49.
6	0.27	0.14	0.13	51.	51.
7	0.11	0.09	0.01	154.	140.
8	0.05	0.05	0.0	203.	190.
9	0.06	0.07	0.01	261.	234.
10	0.02	0.02	0.0	307.	280.
11	0.03	0.03	0.0	154.	118.
12	0.07	0.03	0.0	170.	115.
13	0.15	0.04	0.07	161.	112.
14	0.05	0.05	0.0	161.	160.
15	0.20	0.03	0.17	210.	215.
16	0.07	0.06	0.01	273.	300.
17	0.03	0.03	0.0	291.	322.
18	0.12	0.08	0.04	280.	450.
19	0.21	0.07	0.19	361.	502.
20	0.16	0.06	0.04	571.	575.
21	0.02	0.02	0.0	611.	600.
22				535.	500.
23				483.	426.
24				394.	335.
25				322.	345.
26				264.	329.
27				240.	295.
28				230.	285.
29				220.	240.
30				216.	215.
31				201.	220.
32				192.	210.
33				184.	197.
34				176.	187.
35				161.	178.
36				163.	170.
37				154.	162.
38				143.	156.
39				141.	152.
40				132.	145.
41				124.	141.
42				123.	135.
43				118.	128.
44				113.	122.
45				108.	118.
46				103.	114.
47				99.	109.
48				94.	105.
49				90.	100.
50				86.	95.
51				83.	90.
52				79.	85.
53				76.	80.
54				72.	75.
55				69.	70.
56				66.	65.
57				63.	60.
58				60.	55.
59				58.	50.
60				55.	45.
61				52.	45.
62				51.	35.
63				48.	30.
64				46.	28.
65				44.	25.
66				42.	20.
TOTAL	5.03	4.32	0.71	1534.	1114.

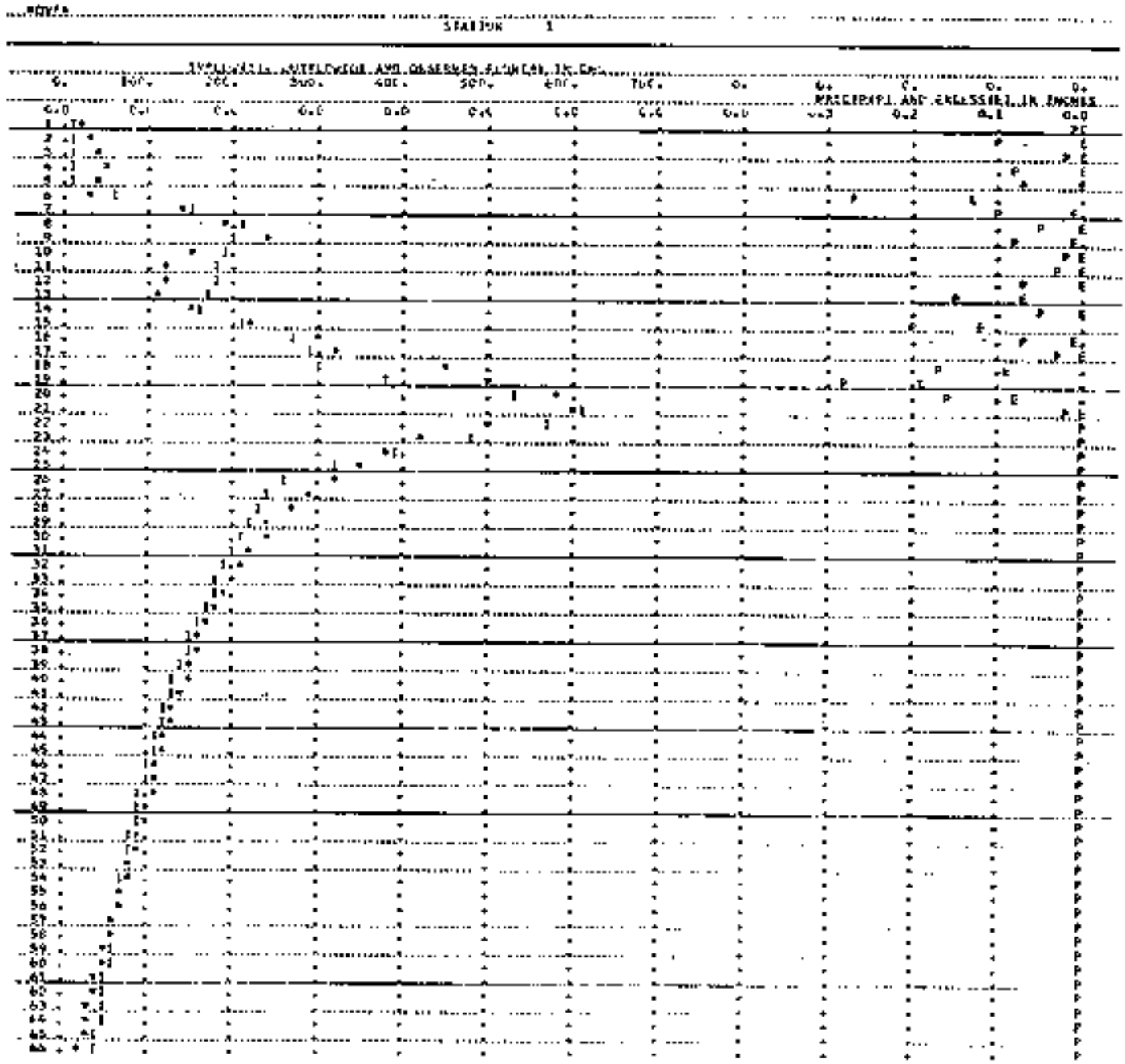
PEAK RECEIVED = 400.60 PEAK NO. = 21
PEAK COMPUTED = 411.03 PEAK NO. = 23

COMPUTED VOL. = [illegible] (CFS) AC.FT.
RECEIVED VOL. = [illegible] VOL. AC.FT.
RATIO OF VOL. FIT = 1.4
RATIO OF PEAK FIT = 0.98
ROOT PERCENTAGE = 82.62

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.4-4
OPTIMIZATION OF FIT
DIABLO – LOS BERROS
(SHEET 2 OF 3)



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.4-4
OPTIMIZATION OF FIT
DIABLO - LOS BERROS
(SHEET 3 OF 3)

D E S I G N F L O O D H Y D R O G R A P H

DIABLO CANYON CREEK 24HR PMP
LOSS RATES EQUAL 50% OF OPTIMIZED RESULTS
RAIN AND RAINFALL DISTRIBUTION FROM HMS 36

INPUT DATA - BASIN CHARACTERISTICS

DA	TB	VAR1	VAR2	VAR3	VAR4	VAR5	VAR6	VAR7	DSECSN
5.19	60.	0.96	2.02	1.00	0.0	8.48	0.01	0.29	240.

NP	NCLRX	VARNH1	VARNH2	STARTQ	STRTK	RTIOR
25	0	0.07	0.30	0.0	0.07	1.56

OUTPUT

UNIT HGR.NO= 11 LAG= 1.735 CP= 0.549

686.	1091.	644.	380.	224.	132.	78.	46.	27.	16.
9.									

DESIGN FLOOD HYDROGRAPH DIABLO CANYON CREEK 24HR PMP

PERIOD	RAIN	LOSS	EXCESS	COMP Q
1	0.30	0.09	0.21	142.
2	0.30	0.07	0.23	383.
3	0.50	0.07	0.43	678.
4	0.70	0.07	0.63	1131.
5	0.60	0.06	0.54	1474.
6	0.40	0.05	0.35	1681.
7	0.30	0.05	0.25	1287.
8	0.30	0.05	0.25	1108.
9	0.40	0.05	0.35	1089.
10	0.60	0.05	0.55	1355.
11	0.60	0.05	0.55	1493.
12	0.70	0.06	0.66	1690.
13	1.00	0.06	0.94	2081.
14	4.30	0.09	4.21	4757.
15	1.80	0.07	1.73	6878.
16	0.70	0.05	0.65	5485.
17	0.60	0.05	0.55	4173.
18	0.50	0.05	0.45	3148.
19	0.40	0.04	0.36	2410.
20	0.40	0.04	0.36	1908.
21	0.40	0.04	0.36	1611.
22	0.30	0.04	0.26	1370.
23	0.30	0.04	0.26	1162.
24	0.20	0.04	0.16	972.
25				643.
26				381.
27				240.
28				230.
29				220.
30				210.
31				201.
32				192.
33				184.
34				176.
35				168.
TOTAL	16.60	1.34	15.26	52191.

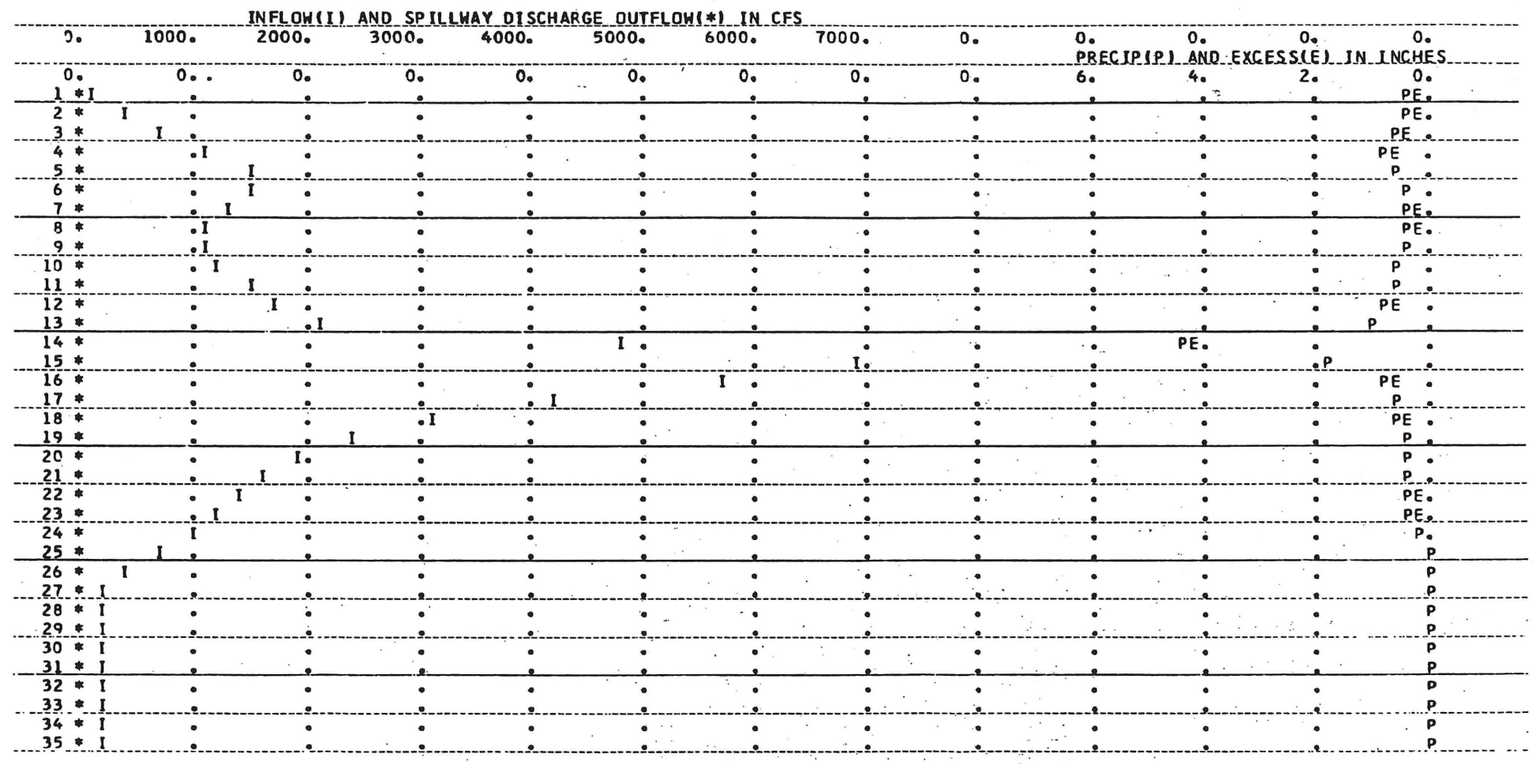
PERCENT LOSS = 8.08 %
PERIOD OF MAXIMUM INFLOW = 15
MAXIMUM INFLOW = 6878. CFS
UNIT MAXIMUM INFLOW = 1325. CFS/SQ.MILE

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.4-5
DESIGN FLOOD HYDROGRAPH
(SHEET 1 OF 3)

INFLOW-OUTFLOW HYDROGRAPHS DIABLO CANYON CREEK 24HR PMP



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.4-5
DESIGN FLOOD HYDROGRAPH
(SHEET 2 OF 3)

Revision 11 November 1996

DEFINITION OF SYMBOLS

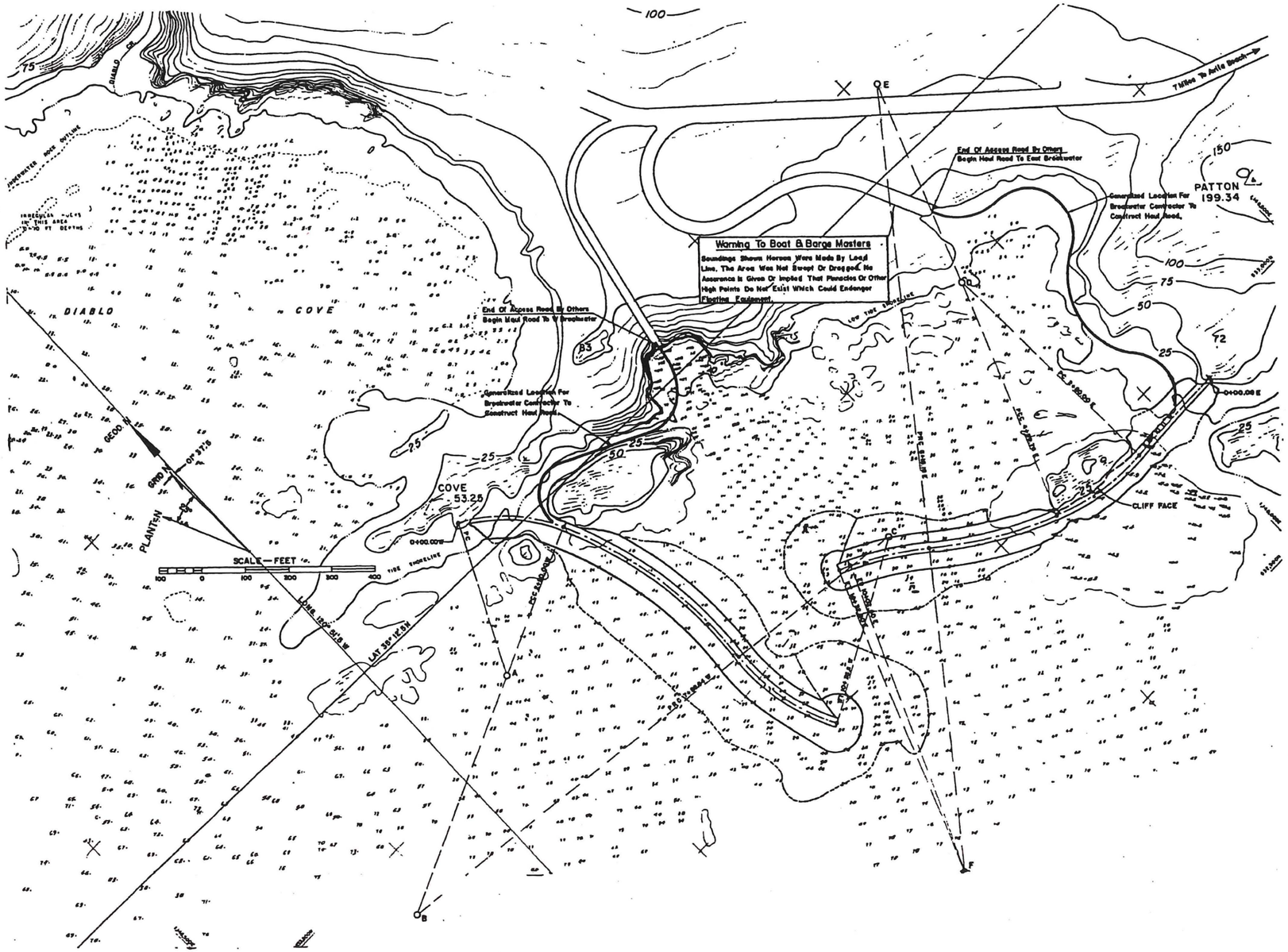
DA	- CONTRIBUTING DRAINAGE AREA IN SQUARE MILES
TR	- RAINFALL AND RUNOFF INTERVAL IN MINUTES
VAR 1	- CLARK'S TIME OF CONCENTRATION T_C IN HOURS
VAR 2	- RATIO OF CLARK'S R TO T_C
VAR 3	- SHAPE FACTOR FOR SYNTHETIC TIME-AREA CURVE
VAR 4	- RATIO OF IMPERVIOUSNESS OF DRAINAGE AREA
VAR 5	- RATIO OF K ON STRAIGHT LINE PORTION OF LOSS RATE CURVE TO K AT 10 INCHES MORE ACCUMULATED LOSS
VAR 6	- RECOVERY LOSS INDEX IN INCHES, SUBTRACTED FROM ACCUMULATED LOSS EVERY PERIOD
VAR 7	- EXPONENT OF RAIN IN LOSS COMPUTATION
QRECSN	- FLOW BELOW WHICH RECESSION RATES ARE MAINTAINED AS A MINIMUM
NP	- NUMBER OF OBSERVED PRECIPITATION PERIODS IN STORM
NCLRK	- INDICATOR, CALCS FOR THE NUMBER OF TIME-AREA ORDINATES
VAR NH1	- LOSS RATE INDEX - VALUE OF K ON STRAIGHT LINE PORTION OF LOSS RATE CURVE WHEN ACCUMULATED LOSS IS 1/2 OF STORM LOSS. ALSO KNOWN AS VAR 8
VAR NH2	- ACCUMULATED LOSS INCREMENT DURING INITIAL LOSS PERIOD. ADDS AN INCREMENT OF 0.2(VAR(NH2)) TO K WHEN ACCUMULATED LOSS IS ZERO, DECREASING TO ZERO WHEN ACCUMULATED LOSS IS VAR(NH2). ALSO KNOWN AS VAR 9
STRTQ	- FLOW IN CFS AT START OF FIRST TR PERIOD OF STORM
RTIOR	- RATIO OF RECESSION FLOW TO THAT 10 TR UNITS LATER
LAG	- SNYDER'S T_P IN HOURS
	- TIME IN HOURS FROM CENTER OF MASS OF EXCESS RAINFALL TO PEAK OF UNIT HYDROGRAPH
CP	- SNYDER'S C_P

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.4-5
DESIGN FLOOD HYDROGRAPH
DEFINITION OF SYMBOLS
(SHEET 3 OF 3)

INTAKE BASIN BREAKWATERS
FOR DIABLO CANYON SITE
PACIFIC GAS & ELECTRIC COMPANY



NOTES—

1. Soundings refer to Mean Lower Low Water Datum.
2. Contours shown above "Low Tide Shoreline" refer to Sea Level Datum and are from an aerial survey made before power plant excavation was started. Bidders shall ascertain by visit to the site, before submitting bids, what effect the site excavations have, if any, on the cost of the work to be done in building the breakwaters.
3. To convert elevations from one datum to the other, apply the following: $Elev_{MLLW} = Elev_{SLD} + 2.6$ Ft.
4. Coordinate positions shown refer to California Coordinate System, Zone 5, a Lambert Conformal Projection. Conversion of arbitrary Plant Grid System is made as follows:
   $N_L = 576{,}067.06 + .9205049\ N_P + .3907311\ D_P$
   $D_L = 1{,}161{,}806.12 + .9205049\ D_P - .3907311\ N_P$

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

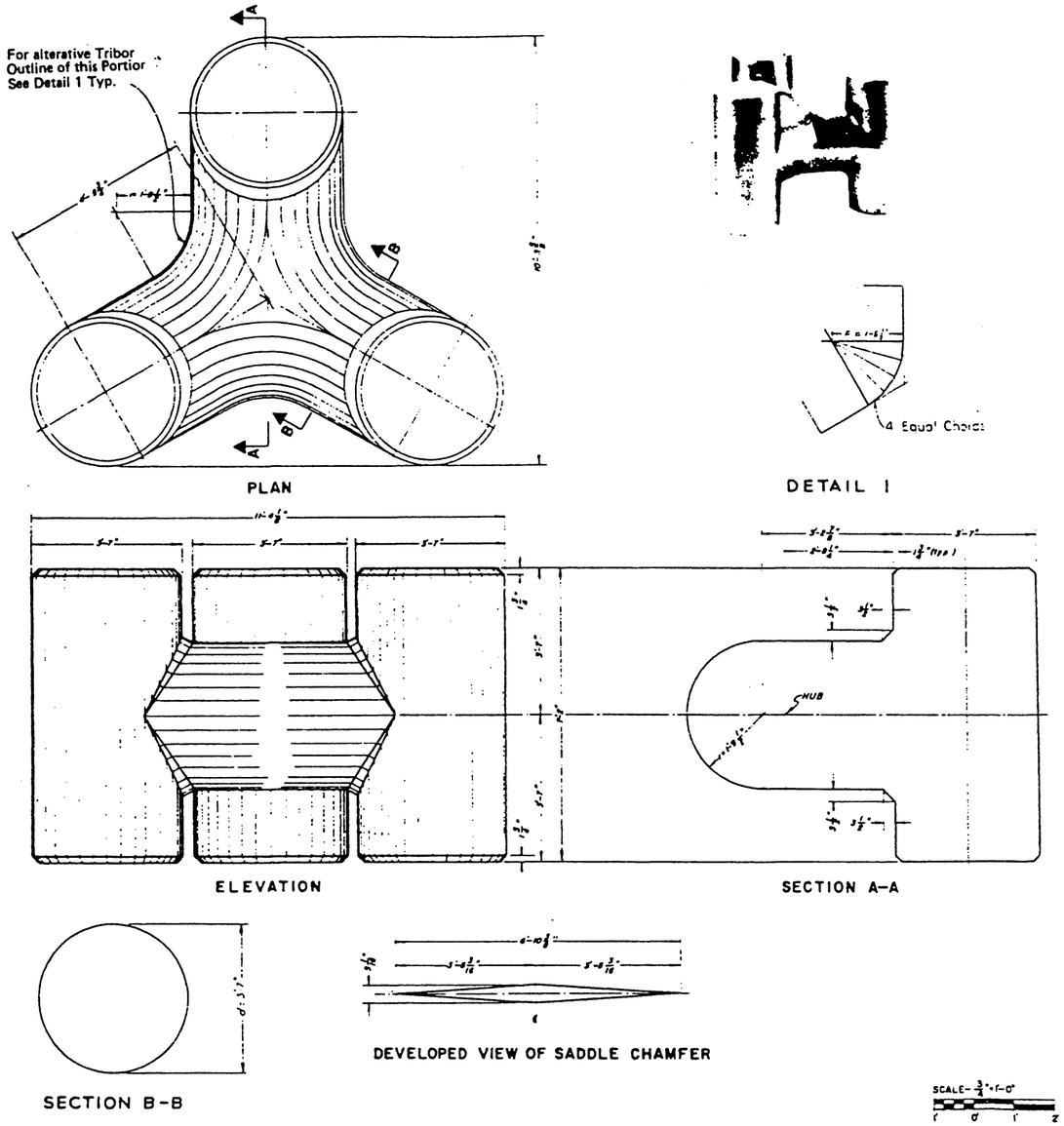
FIGURE 2.4–6
GENERAL LAYOUT OF BREAKWATERS
(Sheet 1 of 2 – SOUNDINGS)

FSAR UPDATE

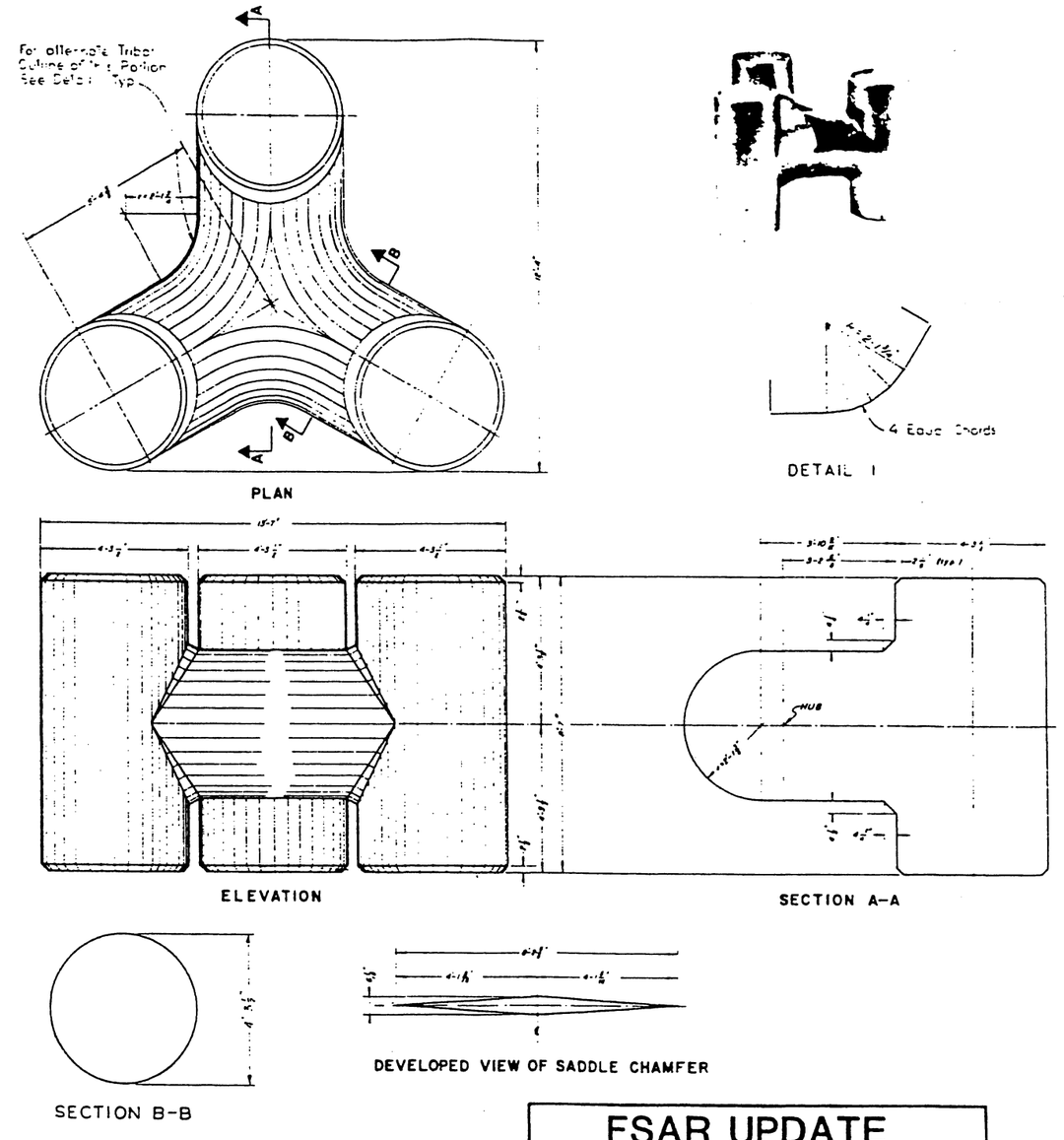
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.4–6
GENERAL LAYOUT OF BREAKWATERS
(Sheet 2 of 2 – CONTOURS)

TRIBAR DIMENSIONS



TRIBAR DIMENSIONS, OVERSIZE

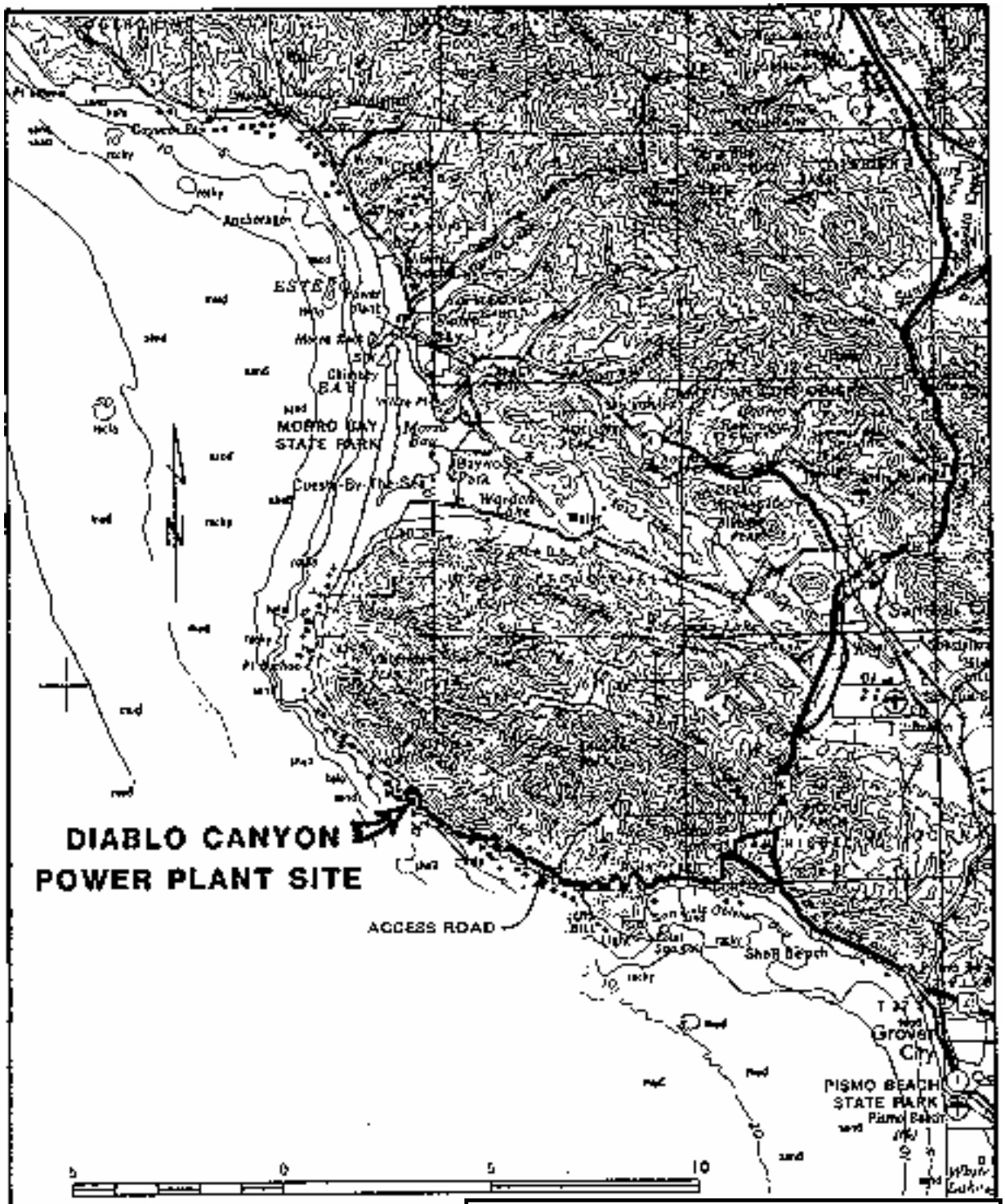


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.4-9

DIMENSIONS FOR TRIBARS

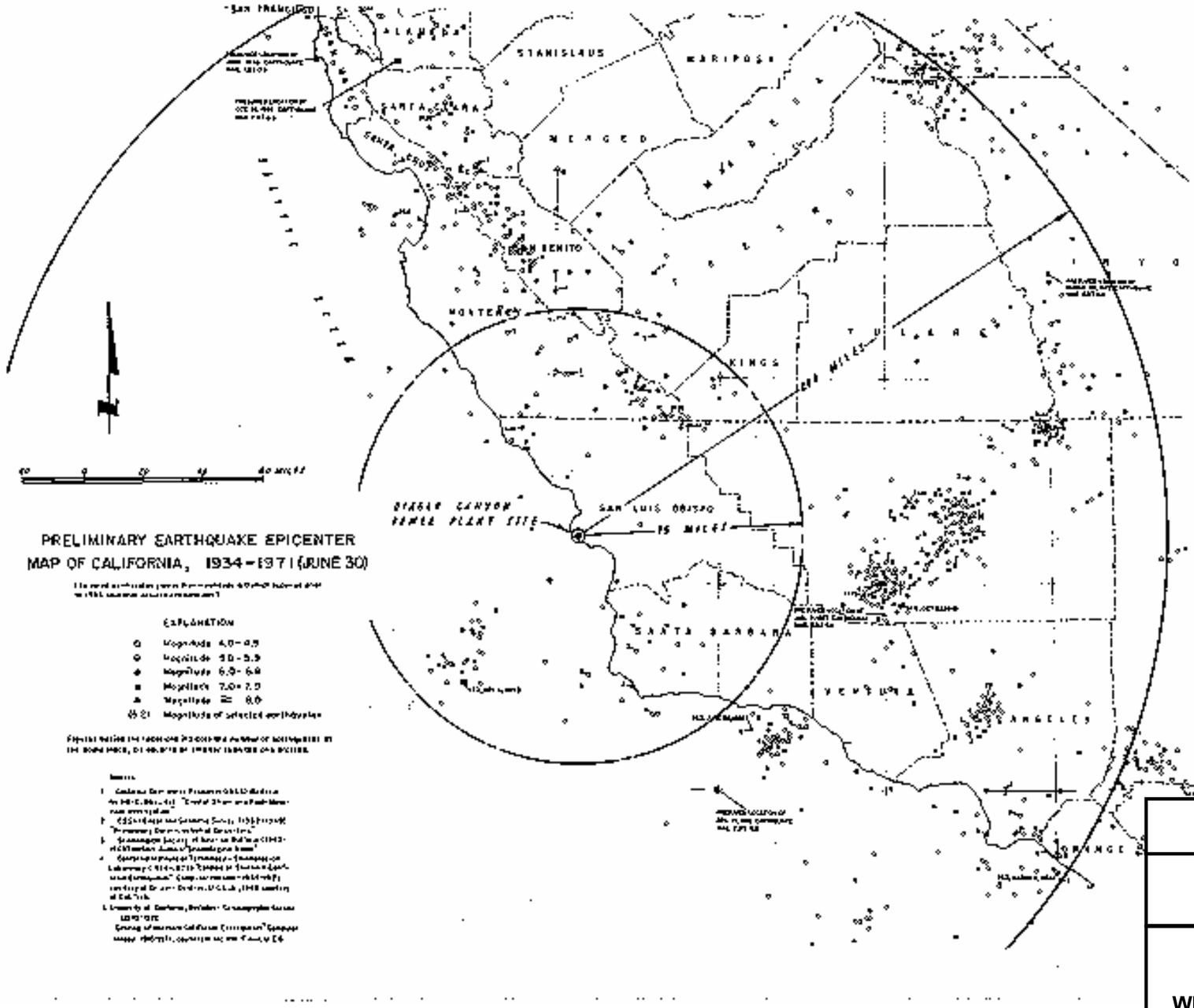


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.5-1

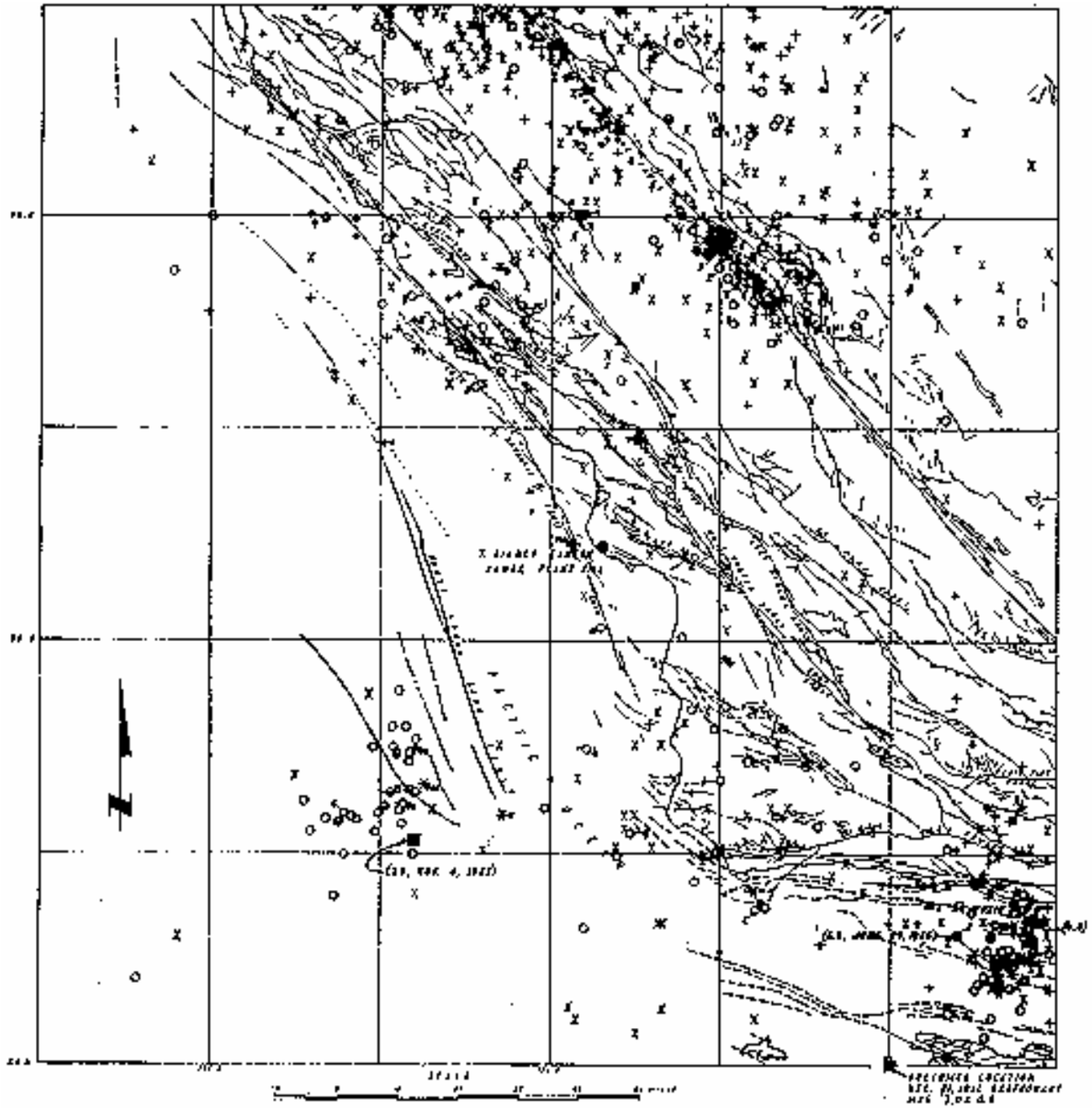
PLANT SITE LOCATION
AND TOPOGRAPHY



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.5-2
EARTHQUAKE EPICENTERS
WITHIN 200 MILES OF PLANT SITE



EXPLANATION

EARTHQUAKE EPICENTER DATA

INSTRUMENTALLY LOCATED AND LARGE HISTORICAL SEISMICITY EARTHQUAKE EPICENTERS WITHIN 75 MILES OF THE DIABLO CANYON SITE, 1840-1972

SYMBOL	MAGNITUDE	
■	7.9 ≥ M ≥ 7.0	MAGNITUDE 7.0 AND ABOVE CRITICAL
●	6.9 ≥ M ≥ 6.0	
◐	5.9 ≥ M ≥ 5.0	
□	4.9 ≥ M ≥ 4.0	
X	3.9 ≥ M ≥ 3.0	
+	2.9 ≥ M ≥ 2.0	

(FIGURE 2.5-3 INDICATES NUMBER OF EPICENTERS RECORDED AT SAME LOCATION)

SOURCES FOR FAULT AND EARTHQUAKE EPICENTER DATA ARE AS FOLLOWS:

1. FAULT DATA FROM JENNINGS, C.W., 1972, GEOLOGIC MAP OF CALIFORNIA, SCALE 1:1,000,000. (PRELIMINARY)
2. FOR EARTHQUAKES M ≥ 2.0 MAGNITUDE OCCURRING DURING THE TIME INTERVAL 1934 THRU JUNE 30, 1970: CALIFORNIA DIVISION OF MINES AND GEOLOGY PRELIMINARY EARTHQUAKE EPICENTER MAP, SCALE 1:1,000,000, 1972.
3. FOR EARTHQUAKES M ≥ 2.0 MAGNITUDE OCCURRING DURING THE TIME INTERVAL 1932 THRU 1970; BUT NOT INCLUDED EARTHQUAKES OVER DATA DO INTENSITY (FELT) SEISMOGRAPHIC STATION DATA (UNCERTAINTY OF EPICENTER, ACCURACY).
4. FOR LARGE EARTHQUAKES OCCURRING DURING THE TIME INTERVAL 1800 THRU 1931, IN WHICH ESTIMATED MAGNITUDE RATHER THAN ACCURATE ACCELEROGRAPH RECORDS ARE AVAILABLE: CALIFORNIA DIVISION OF MINES AND GEOLOGY, PROVISIONAL EARTHQUAKE EPICENTER MAP, SCALE 1:1,000,000, 1970.
5. FOR EARTHQUAKES M ≥ 5.0 MAGNITUDE OCCURRING DURING THE TIME INTERVAL JULY 30 THRU DEC. 31, 1972: SEISMOGRAPHIC OBSERVATORY OF CALIFORNIA. (CALIFORNIA INSTITUTE OF TECHNOLOGY).

NOTES FOR REVISED FAULT AND EPICENTER DATA

A. FAULT DATA REVISED IN ACCORDANCE WITH NOTE 6, FIGURE 5, APPENDIX 2.5D

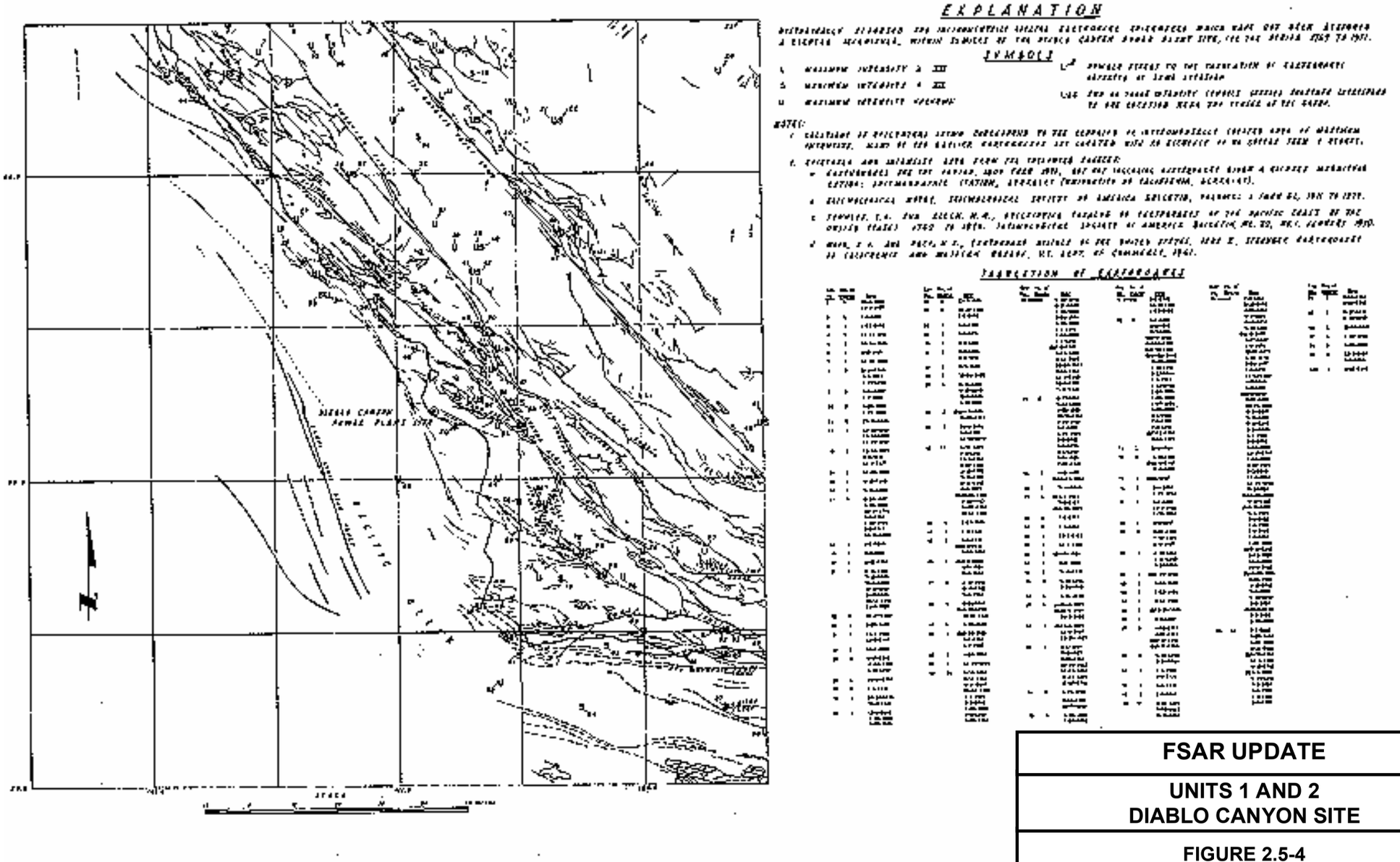
B. EPICENTERS OF 19 SELECTED EARTHQUAKES, RECOMPUTED BY D. W. SMITH (1974). EPICENTER–MAGNITUDE SYMBOL OF THESE EVENTS IS INDICATED BY HORIZONTAL DASHES ($\mathbb{X}$ = $\mathbb{X}_{16}$; NUMBER SUBSCRIPT INDICATES EVENT NUMBER

C. ∘–EPICENTERS MAGNITUDE ≤ 4.0 RECORDED AND LOCATED BY WOLFIAN GANTNER (1970). AS DESCRIBED IN "PRELIMINARY REPORT ON A SHORT TERM SEISMIC STUDY OF THE SAN LUIS OBISPO REGION (MAY, 1973)."

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

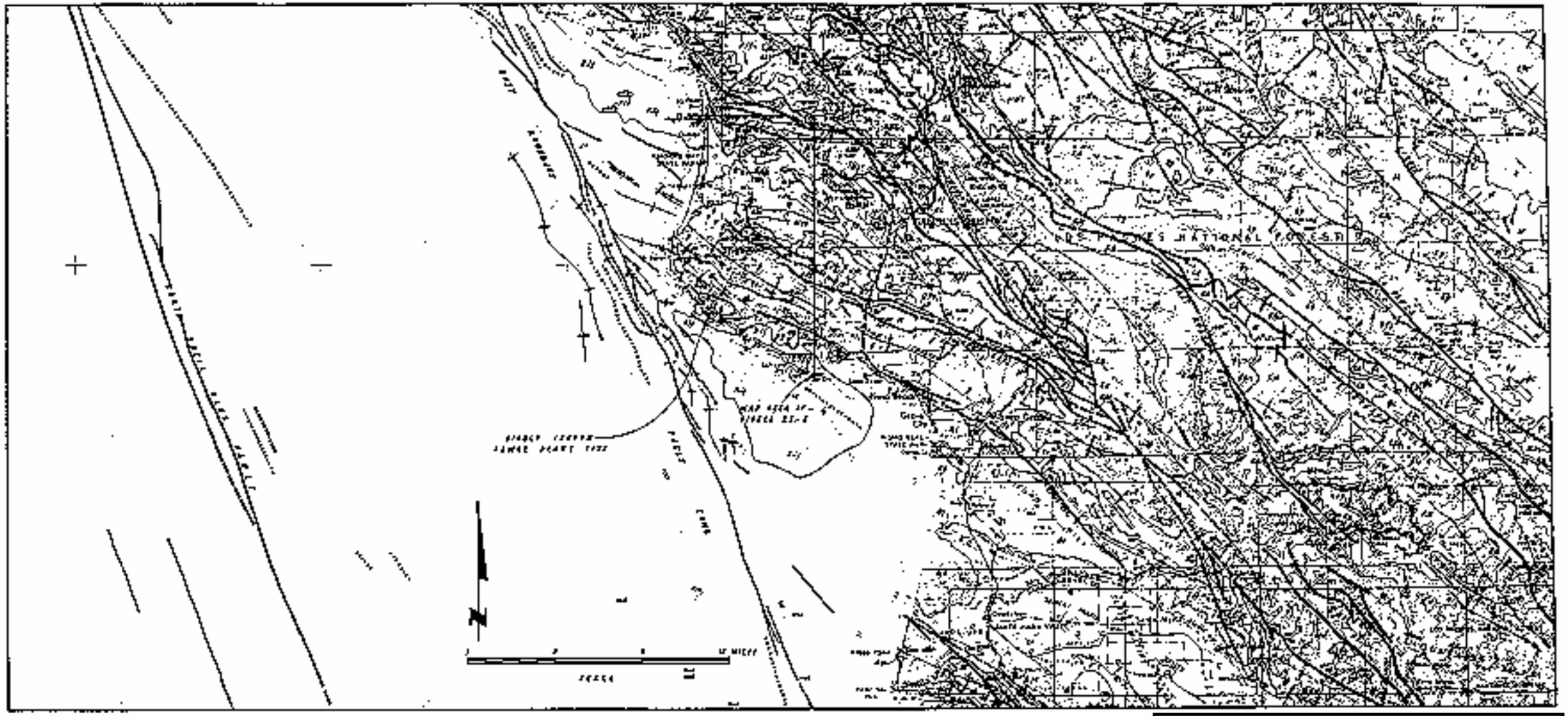
FIGURE 2.5-3
FAULTS AND EARTHQUAKE EPICENTERS WITHIN 75 MILES OF PLANT SITE (FOR EARTHQUAKES WITH ASSIGNED MAGNITUDES)



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.5-4
FAULTS AND EARTHQUAKE EPICENTERS WITHIN 75 MILES OF PLANT SITE (FOR EARTHQUAKES WITH ASSIGNED INTENSITIES ONLY)



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.5-5
GEOLOGIC AND TECTONIC MAP OF SOUTHERN COAST RANGES IN THE REGION OF PLANT SITE
(SHEET 1 OF 2)

EXPLANATION

GEOLOGIC UNITS

CENOZOIC

SEDIMENTARY DEPOSITS AND ROCKS

- **Q** — HOLOCENE AND PLEISTOCENE NONMARINE (INCLUDES ALLUVIAL AND MARINE DEPOSITS, UNDIVIDED.
- **Qls** — LARGE LANDSLIDES, WHERE MAPPED SEPARATELY.
- **Qt** — DUNE SAND DEPOSITS, WHERE MAPPED SEPARATELY.
- **QPc** — PLIO-PLEISTOCENE AND PLIOCENE NONMARINE.
- **P** — PLIOCENE MARINE
- **M** — MIOCENE MARINE
- **Oc** — OLIGOCENE NONMARINE
- **E** — EOCENE MARINE
- **Ep** — PALEOCENE MARINE

VOLCANIC ROCKS

- **Tv** — TERTIARY VOLCANIC ROCKS
- **Tvp** — TERTIARY PYROCLASTIC ROCKS, (INCLUDING VOLCANIC MUDFLOW DEPOSITS.
- **Ti** — TERTIARY INTRUSIVE ROCKS.

MESOZOIC

SEDIMENTARY AND METAMORPHIC ROCKS

- **Ku** — UPPER CRETACEOUS MARINE ROCKS
- **Kl** — LOWER CRETACEOUS MARINE ROCKS
- **Kfj** — FRANCISCAN ASSEMBLAGE (PREDOMINANTLY SEDIMENTARY AND META-SEDIMENTARY ROCKS. INCLUDES FRANCISCAN MELANGE)
- **J** — JURASSIC MARINE ROCKS (INCLUDES NIPOMO FORMATION)
- **M** — METAMORPHIC ROCKS OF PRE-TERTIARY AGE, UNDIVIDED.

METAVOLCANIC ROCKS

- **Mzv** — MESOZOIC METAVOLCANIC ROCKS (INCLUDING FRANCISCAN VOLCANIC ROCKS).

PLUTONIC ROCKS

- **grMz** — MESOZOIC GRANITIC ROCKS
- **UMz** — MESOZOIC ULTRAMAFIC ROCKS

EXPRESSED CONTOUR IN "OVER COMPLEXES"

SYMBOLS

GEOLOGIC CONTACT, DASHED WHERE APPROXIMATE OR WHERE QUATERNARY DEPOSITS ARE INVOLVED.

FAULT (SOLID LINE WHERE LOCATION IS WELL DEFINED; DASHED LINE WHERE APPROXIMATE OR INFERRED; DOTTED WHERE CONCEALED.

ANTICLINAL AXIS - WITH PLUNGE INDICATED. (SOLID LINE WHEN LOCATION IS WELL DEFINED; DASHED WHERE APPROXIMATE OR INFERRED; DOTTED WHERE CONCEALED.

SYNCLINAL AXIS - WITH PLUNGE INDICATED. (SOLID LINE WHERE LOCATION IS WELL DEFINED; DASHED WHERE APPROXIMATE OR INFERRED; DOTTED WHERE CONCEALED.

NOTES

1. MAP BASE FROM PARTS OF SAN LUIS OBISPO AND SANTA MARIA SHEETS, U.S. GEOLOGICAL SURVEY 1:250,000 SCALE TOPOGRAPHIC MAP SERIES
2. GEOLOGIC DATA FROM:

   "GEOLOGIC MAP OF CALIFORNIA" 1958, (SCALE 1:750,000); PRELIMINARY, UNPUBLISHED, CALIFORNIA DIVISION OF MINES AND GEOLOGY. (COMPILED BY C.W. JENNINGS)

   LOCALLY SUPPLEMENTED WITH DATA FROM:

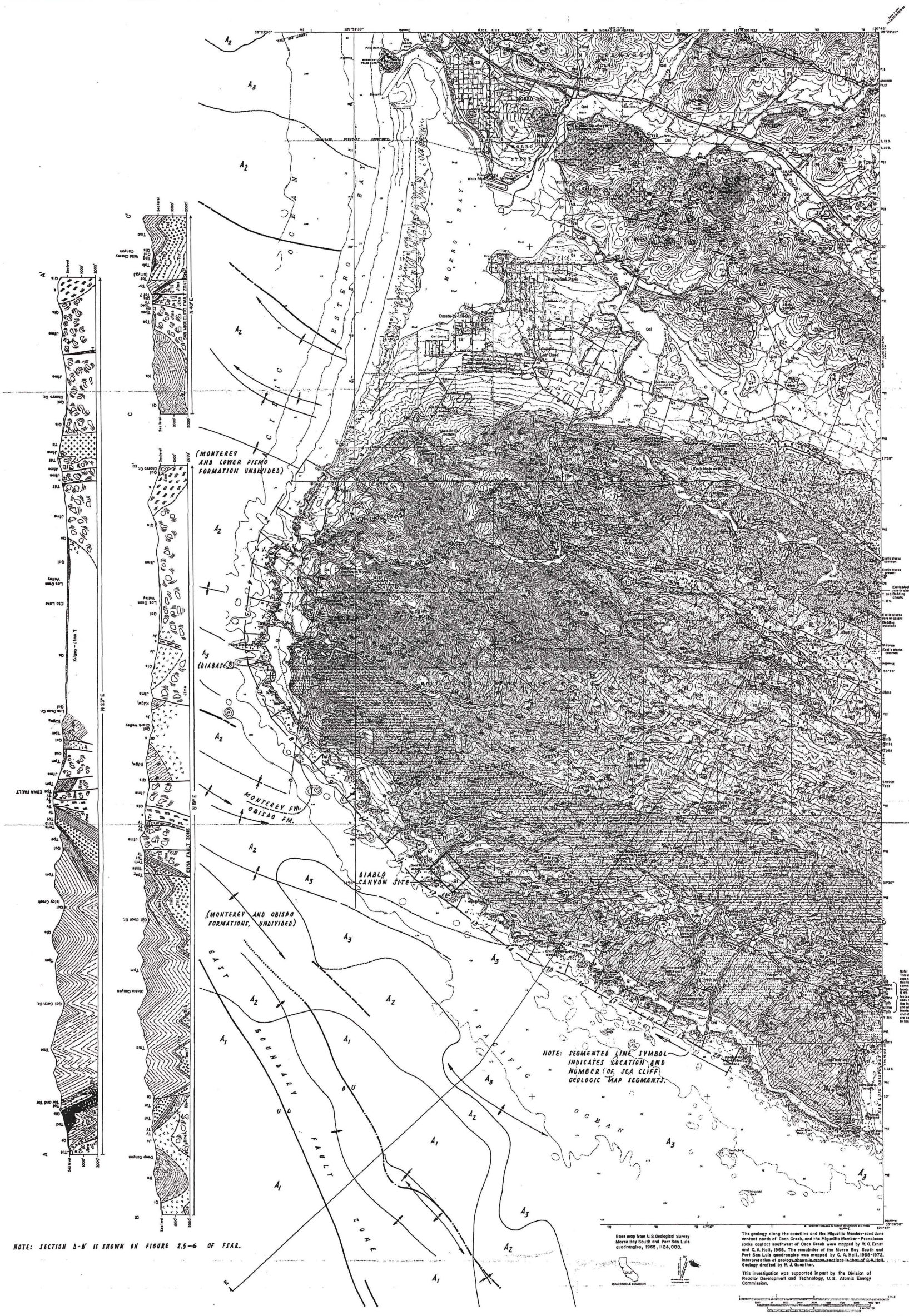
   - BERKLEY, L.E., 1965, GEOLOGY OF THE COASTAL PORTION OF THE SAN LUIS RANGE, SAN LUIS OBISPO COUNTY, CALIF., UNPUBLISHED M.S. THESIS, UNIV. SOUTHERN CALIF.
   - JAHNS, R.H., 1966, GEOLOGY OF THE DIABLO CANYON POWER PLANT SITE, SAN LUIS OBISPO COUNTY, CALIFORNIA; 1967 SUPPLEMENTARY REPORTS I AND II; 1968 SUPPLEMENTARY REPORT III, UNPUBLISHED, REPORT TO THE PACIFIC GAS AND ELECTRIC COMPANY.
   - HALL, C.A., 1973, U.S.G.S. MAP OF SLO.
   - EARTH SCIENCES ASSOCIATES, 1974, OFFSHORE INVESTIGATION.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.5-5
GEOLOGIC AND TECTONIC MAP OF SOUTHERN COAST RANGES IN THE REGION OF PLANT SITE
(SHEET 2 OF 2)

(SHEET 2 OF 2)



Base map from U.S. Geological Survey Morro Bay South and Port San Luis quadrangles, 1965, 1:24,000.

The geology along the coastline and the Miguelito Member-sand dune contact north of Coon Creek, and the Miguelito Member - Franciscan rocks contact southwest of Coon Creek were mapped by W. G. Ernst and C. A. Hall, 1968. The remainder of the Morro Bay South and Port San Luis quadrangles was mapped by C. A. Hall, 1958-1972. Interpretation of geology shown in cross sections is that of C. A. Hall. Geology drafted by M. J. Guenther.

This investigation was supported in part by the Division of Reactor Development and Technology, U.S. Atomic Energy Commission.

ON-SHORE GEOLOGY AND GEOLOGIC CROSS SECTIONS BY CLARENCE A. HALL, 1973, PUBLISHED AS USGS MAP MF 511, 1973.

OFF SHORE GEOLOGY BY EARTH SCIENCES ASSOCIATES, 1974.

EXPLANATION

QUATERNARY

Holocene

Qal — Alluvial deposits
Cobble-pebble gravel, sand, silt, and clay

Pleistocene and Holocene

Qs — Sand dune deposits
Unconsolidated white to brown, windblown sand. Includes older stabilized sand dune deposits

Qls — Landslide deposits
Lithology dependent on source material

Qt — Terrace deposits
Unconsolidated sand, silt, clay, and gravel. Marine and stream terrace deposits

UNCONFORMITY

Pleistocene

Qpr — Paso Robles(?) Formation
Sandstone, siltstone, claystone, and Monterey clast conglomerate. Poorly to well consolidated. Partly or entirely marine

UNCONFORMITY

TERTIARY

Pliocene — Pismo Formation

Tps — Squire Member
Massive white to tan calcareous arkosic sandstone; more calcareous and resistant near base; 75% to 80% quartz, 15% to 20% feldspar, less than 5% mafic mineral grains. Fine- to medium-grained; grains subrounded to subangular, moderately well sorted. Finer grained in west, where it grades into siltstone and claystone with some sandstone. Contains *Lyropecten cerrosensis* (Gabb). Upper Pliocene. Marine. Hall (1973)

Tpb — Bellevlew Member
Interbedded buff to gray claystone and fine-grained sandstone. Claystone is spheroidally fractured. Upper Pliocene. Marine. Hall (1973)

Tpg — Gragg Member
Massive resistant to soft medium-grained sandstone. White, weathering buff; 65% quartz, 30% feldspar, 4% clay, 1% mafic minerals. Contains *Lyropecten cerrosensis* (Gabb). Upper Pliocene. Marine. Hall (1973)

Miocene and Pliocene

Tpm — Miguelito and Edna Members
Tpm, brown claystone and siltstone; beds 2 to 4 in. thick, but commonly 1/2 to 3 in. thick; towards top and southwest porcelaneous shale, opaline shale, diatomite or diatomaceous shale; relatively soft well-bedded siltstone; locally tuffaceous near base in north, absent southwest; locally bituminous (*Bif*) or friable sandstone; conglomerate locally near base. Claystone and siltstone beds grade laterally into sandstone toward east (Arroyo Grande quadrangle). Contains *Anadara montereyana* (Osmont) and, in adjoining Arroyo Grande quadrangle, *Aequipecten discus* (Conrad). Mohnian and Delmontian. Marine. Hall (1973)
Tps, nonbituminous sandstone and silty sandstone, fine- to medium-grained, friable, gray to brown; 80% to 90% quartz, less than 5% to 15% feldspar
Tpss, nonbituminous buff to gray sandy siltstone; where bituminous (*Bif*)
Tpsc, conglomerate of predominantly hard clasts of fine-grained Obispo tuff (65% to 90%) and others of Franciscan chert
Edna Member contains *Astrodapsis spatiosus* (Kew) and *Patinopecten jahni* (Hertlein) in adjoining Arroyo Grande quadrangle Mohnian and Delmontian. Marine. Hall (1973)

UNCONFORMITY

Tmts — Monterey Formation
Tmc, resistant hard siliceous shale and interbedded chert. Color variable but commonly white and brown to gray and reddish-brown, weathering chalky white. Brittle with subconchoidal fracture. Beds 1/2 to 6 in. thick, commonly 1/2 to 1 in. thick. Laminations less than 1/4 in. thick; color banding common, reddish-brown and black chert in west, brown and cream-colored chert in east. Commonly fractured and sheared. Locally interlaminated and interbedded with diatomaceous siltstone. Contains *Patinopecten propatulus* (Conrad) in diatomaceous facies in Arroyo Grande quadrangle. Mohnian. Marine
Tmts, tuffaceous siltstone; locally dolomitic siltstone with some opaline chert. Absent in southwest
Tmb, siltstone or blocky dolomitic claystone and siliceous siltstone; tan to yellowish-white in color; locally tuffaceous or interbedded with cherty shale. Beds 2 to 8 in. thick. Near Diablo Canyon unconformably overlain by Tmc. Possibly equivalent to Point Sal Formation of Santa Maria area. Relizian and Luisian. Marine

Miocene

UNCONFORMITY

Tof — Obispo Formation
Tod, diabase, greenish-black to gray. Occurs as dikes, sills, and basalt flows
Tbf, yellow to brown tuffaceous siltstone and claystone. Locally contains reddish-brown chert and glassy volcanic lenses. Contains *Amaurolopecten vanvleeki* (Arnold). Lithologically equivalent in part to Point Sal Formation of Santa Maria area
Tcr, fine-grained zeolitized or silicified vari-colored very resistant tuff
Tbt, fine- to coarse-grained white tuff; subangular clasts of pumice, perlite, white to dark gray glass shards, and feldspar in a vitric matrix. Ashy matrix commonly altered to clay. Locally intrusive into fine-grained tuffaceous siltstone (Tbf)
Tcp, perlitic glass and breccia
Radiometric ages of tuff, 15.3 ± 0.5 to 16.5 ± 0.6 m.y. (Turner, 1970). Upper Saucesian and lower Relizian

Tr — Rincon Shale
Dark brown, weathering light tan, siltstone or silty claystone, poorly to well-bedded. Locally includes thin beds or lenses of yellow or buff colored dolomite. Saucesian. Marine

Oligocene

Tv — Vaqueros Sandstone
Tan, gray, or dark reddish-brown sandstone. Poorly to well indurated, rounded to subangular grains, 40% to 60% quartz, 5% to 15% feldspar, 30% to 50% rock fragments. Contains *Chlamys* cf. *C. fucanus* (Dall) and *Chlamys* cf. *C. sespeensis* (Arnold). Zemorrian. Marine

UNCONFORMITY

Td — Dacite
Td, porphyritic dacite; Islay Hill - Morro Rock complex, 50% of rock composed of phenocrysts with modal composition 44.8% strongly zoned andesine, 15% biotite and clay, 10% hornblende, 5% partially resorbed quartz, and 5% magnetite, apatite, and zeolites. The groundmass makes up the other 50% of the rock and consists of altered plagioclase microlites, biotite, glass, quartz, and hornblende. Flow banding common
Tdf, fine-grained dacite or flow facies; phenocrysts are absent or rare and flow banding common
Potassium-argon age determinations of dacite: Morro Rock, 22.1 ± 0.9 m.y.; Black Hill, 26.4 ± 0.8 m.y.; near Hallister Peak, 26.4 ± 0.8 m.y., Turner (1968) and Turner, et al. (1970). Relizian and Zemorrian

CRETACEOUS(?)

Upper Cretaceous(?)

Ku — Unnamed sedimentary rocks
Interbedded white, gray, tan, 60% to 70% brown or dark greenish-brown hard arkosic wacke sandstone and 30% to 40% greenish-brown or black claystone and siltstone, conglomerate with pebbles and cobbles of black chert and quartzite. Massive to moderately well-bedded. Sandstone commonly not as altered, sheared, or weathered as Franciscan graywacke, grain boundaries more distinct. Thick-bedded sandstone composed of 50% to 70% quartz, 10% to 20% altered plagioclase and K-feldspar, 10% rock fragments of claystone (predominant) and chert, 5% biotite and muscovite. Locally hard gray altered siliceous sandstone, e.g., near Port San Luis. Unit may be correlative with Upper Cretaceous Great Valley-type clastic rocks elsewhere in Coast Ranges. Marine

JURASSIC OR CRETACEOUS

Serpentinite and serpentinized ultrabasic rocks

Franciscan rocks

Kdpw₂, interbedded very fine-grained graywacke or claystone and greenish-brown medium-grained graywacke composed of 60% to 70% quartz, 15% to 25% plagioclase, 2% to 5% K-feldspar, 2% to 5% biotite, 10% rock fragments of dark gray siltstone. Exotic blocks absent
Kdpw₁, mostly dark brown massive graywacke and greenish-brown or gray micrograywacke or claystone. Bedding commonly chaotic. Exotic blocks rare or absent, otherwise similar to Kdpw₂
These units of presumed Jurassic or Cretaceous age are petrologically similar and have been differentiated only on the basis of relative abundance or absence of exotic blocks and the degree of shearing. The units apparently represent different ages of tectonism or degrees of tectonism
Jv, weathered diabase and basalt associated with red chert (*ch*) and altered cream-colored fine-grained tuff (?) (*uf*). Jv is presumably everywhere above mélange and below units Kdpw₁ and Kdpw₂. The contacts between these units are everywhere inferred to be faults. Probably Jurassic
Jfm, mélange of graywacke (*gw*), pervasively sheared and in large part composed of sheared green claystone. Includes exotic blocks of conglomerate (*cg*), blue schist (*bs*), schist (*sch*), metavolcanic rocks or greenstone (*mv*) and volcanic rocks (*v*), white, red or green chert (*ch*), and serpentinite (*s*). Probably Jurassic
No stratigraphic order can be determined with certainty for the mélange, volcanic rocks, and graywacke (Kdpw₁ and Kdpw₂). However, because the mélange contains exotic blocks and is pervasively sheared, the inference can be made that the age of tectonism of the Franciscan mélange is older than the basalt (Jv) and graywacke (Kdpw₁ and Kdpw₂)

GEOLOGIC SYMBOLS

Contact
Dashed where approximately located, queried where doubtful

High-angle fault
Dashed where approximately located or inferred, dotted where concealed

Thrust or reverse fault
Dashed where approximately located or inferred, dotted where concealed; queried where presence is doubtful. Saw-teeth on upper plate. Dip of fault plane between 30° and 80°

Anticline
Showing axis at surface. Dashed where approximately located, dotted where concealed

Syncline
Showing axis at surface. Dashed where approximately located, dotted where concealed

Horizontal — Inclined — Vertical
Strike and dip of beds

Strike and dip of flow banding

Inferred general direction of landslide movement

Megafossil locality
U.C.L.A. locality number

Abandoned well drilled for oil

Siltstone
Tuff
Marker beds

REFERENCES CITED

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———, 1970, Potassium-argon dating of Pacific Coast Miocene foraminiferal stages: Geol. Soc. America Spec. Paper 124, p. 91-129
———, Burdam, R. C., and Hall, C. A., 1970, The Obispo Formation and associated volcanic rocks in central California Coast Ranges — K-Ar ages and biochronologic significance: Geol. Soc. America Abstracts with programs, Cordilleran Sec., 66th Annual Meeting, v. 2, no. 2, p. 155

GEOLOGIC MAP OF THE MORRO BAY SOUTH AND PORT SAN LUIS QUADRANGLES, SAN LUIS OBISPO COUNTY, CALIFORNIA

EXPLANATION FOR GEOLOGIC MAP OF THE OFFSHORE AREA

MAP ACOUSTIC UNIT	MAP UNITS — STRATIGRAPHIC EQUIVALENT
A_1	UPPER PART OF PISMO FORMATION (ABOVE MIGUELITO AND EDNA NUMBERS).
A_2	MONTEREY FORMATION AND LOWER PART OF PISMO FORMATION (MIGUELITO AND EDNA NUMBERS), INCLUDES OBISPO FORMATION IN THE AREA OFFSHORE FROM DIABLO CANYON.
A_3	FRANCISCAN AND GREAT VALLEY SEQUENCE BASEMENT ROCKS, UNDIVIDED. LOCALLY MAY INCLUDE SOME OBISPO FORMATION.

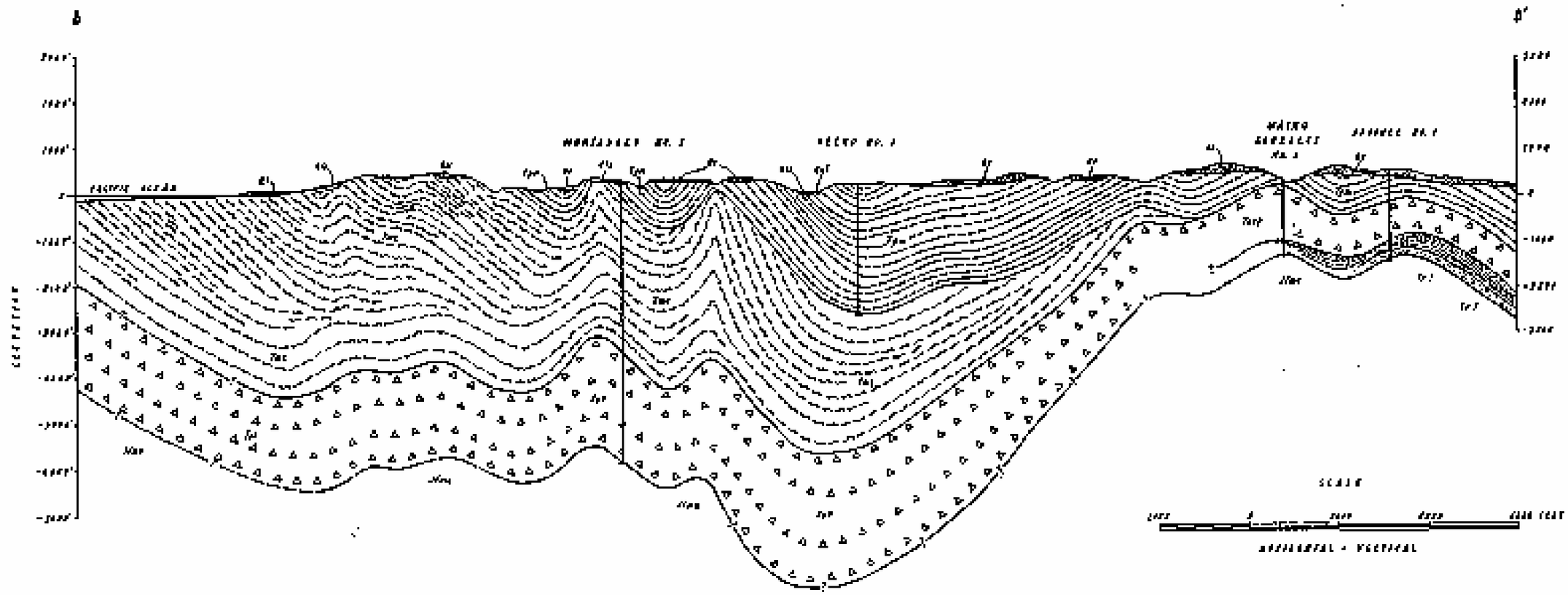
MAP SYMBOLS

- CONTACT, DASHED WHERE POORLY CONTROLLED.
- FAULT, DASHED WHERE POORLY CONTROLLED.
- BURIED FAULT
- ANTICLINE
- SYNCLINE

FSAR UPDATE
UNITS 1 AND 2
DIABLO CANYON SITE
FIGURE 2.5 – 6
GEOLOGIC MAP OF THE MORRO BAY SOUTH AND PORT SAN LUIS QUADRANGLES, SAN LUIS OBISPO COUNTY, CALIFORNIA, AND ADJACENT OFFSHORE AREA.
Revision 11 November 1996

(ORIGINALLY: PLATE VIII APPENDIX 2.5D)

FSAR UPDATE
UNITS 1 AND 2
DIABLO CANYON SITE
FIGURE 2.5 – 6
GEOLOGIC MAP OF THE MORRO BAY SOUTH AND PORT SAN LUIS QUADRANGLES, SAN LUIS OBISPO COUNTY, CALIFORNIA, AND ADJACENT OFFSHORE AREA.

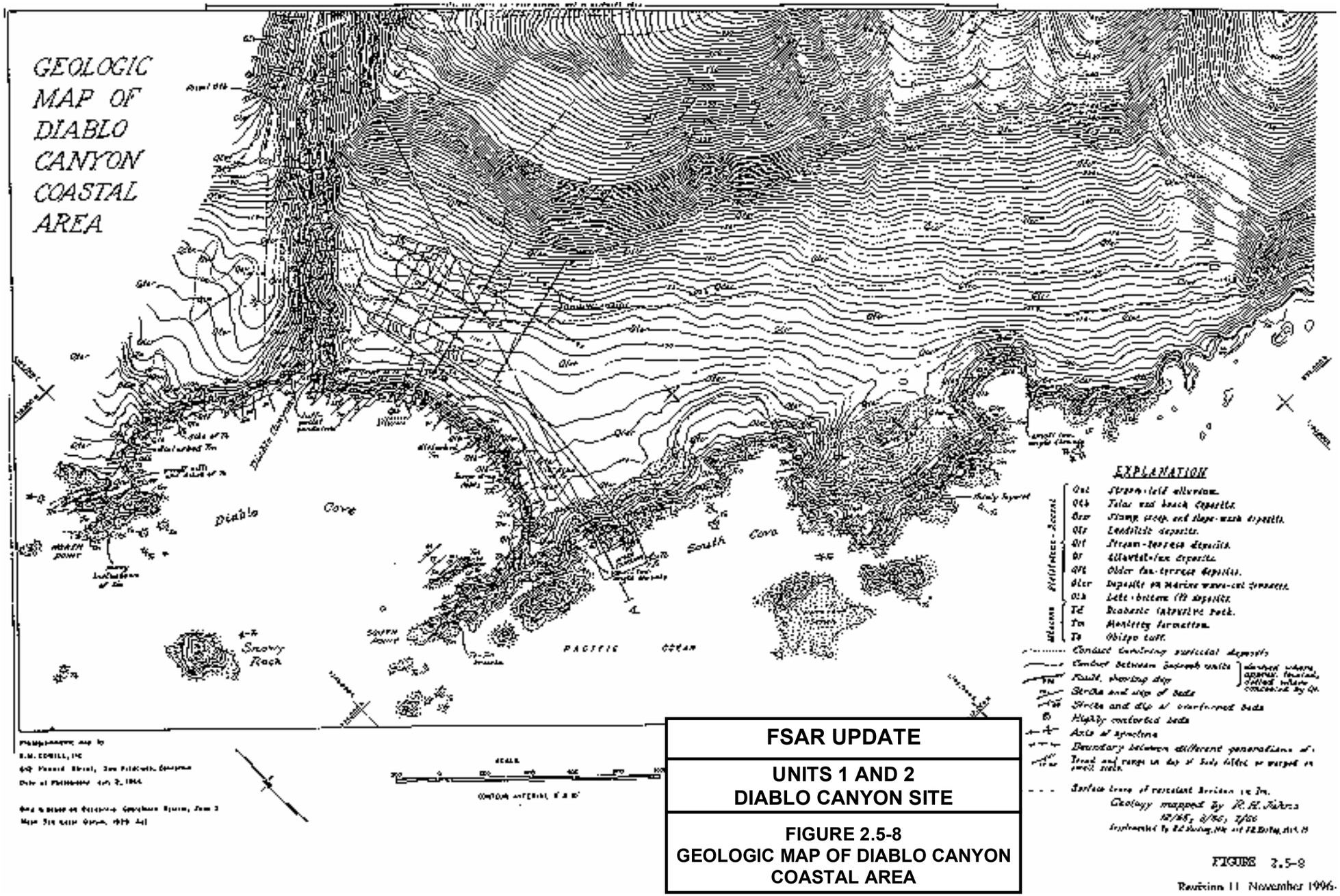


SECTION B-B'
TAKING EXPLORATORY OIL WELLS AND
GEOLOGIC RELATIONSHIPS IN THE SAN LUIS RANGE
VIEW WEST-NORTHWEST

NOTE: SEE FIGURE 2.5-6 FOR LOCATION OF THIS
SECTION AND EXPLANATION OF SYMBOLS.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.5-7 GEOLOGIC SECTION THROUGH EXPLORATORY OIL WELLS IN THE SAN LUIS RANGE

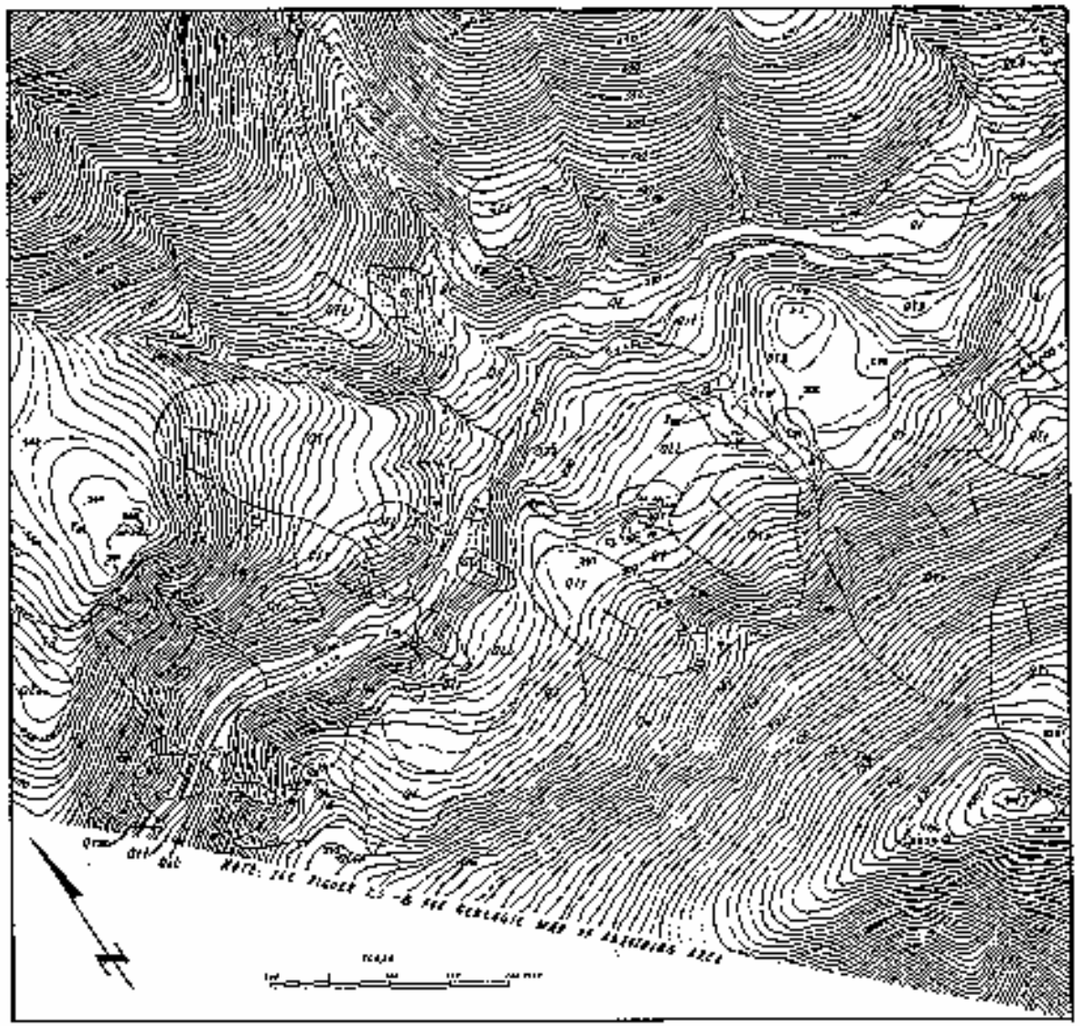
Revision 11 November 1996



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.5-8
GEOLOGIC MAP OF DIABLO CANYON COASTAL AREA



EXPLANATION

PLEISTOCENE – RECENT

- Qal — STREAM-LAID ALLUVIUM
- Qsw — SLUMP, CREEP, AND SLOPE-WASH DEPOSITS
- Qls — LANDSLIDE DEPOSITS.
- Qst — STREAM-TERRACE DEPOSITS
- Qf — ALLUVIAL-FAN DEPOSITS
- Qft — OLDER FAN-TERRACE DEPOSITS
- Qtmr — DEPOSITS ON MARINE WAVE-CUT TERRACES.
- Qlb — LAKE-BOTTOM (?) DEPOSITS

MIOCENE

- Td — DIABASIC INTRUSIVE ROCK
- Tm — MONTEREY FORMATION.

CONTACT INVOLVING SURFICIAL DEPOSITS.

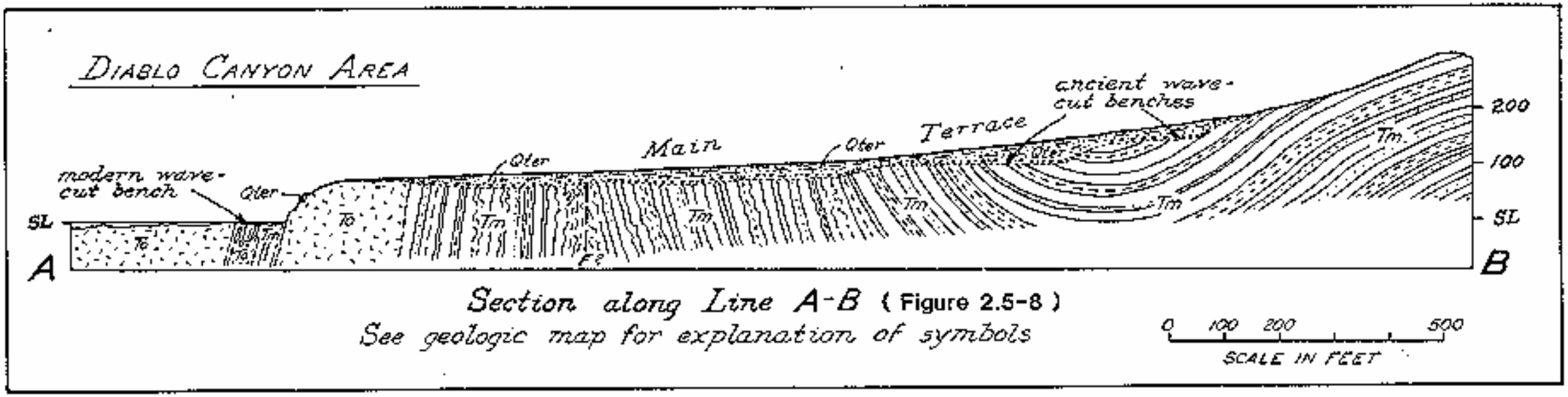
CONTACT BETWEEN BEDROCK UNITS. DASHED WHERE APPROX. LOCATED; DOTTED WHERE CONCEALED BY QCWT.

70 — STRIKE AND DIP OF BEDS

40-70 — TRUE AND RANGE IN DIP OF BEDS TOO SMALL TO BE MAPPED ON A SMALL SCALE.

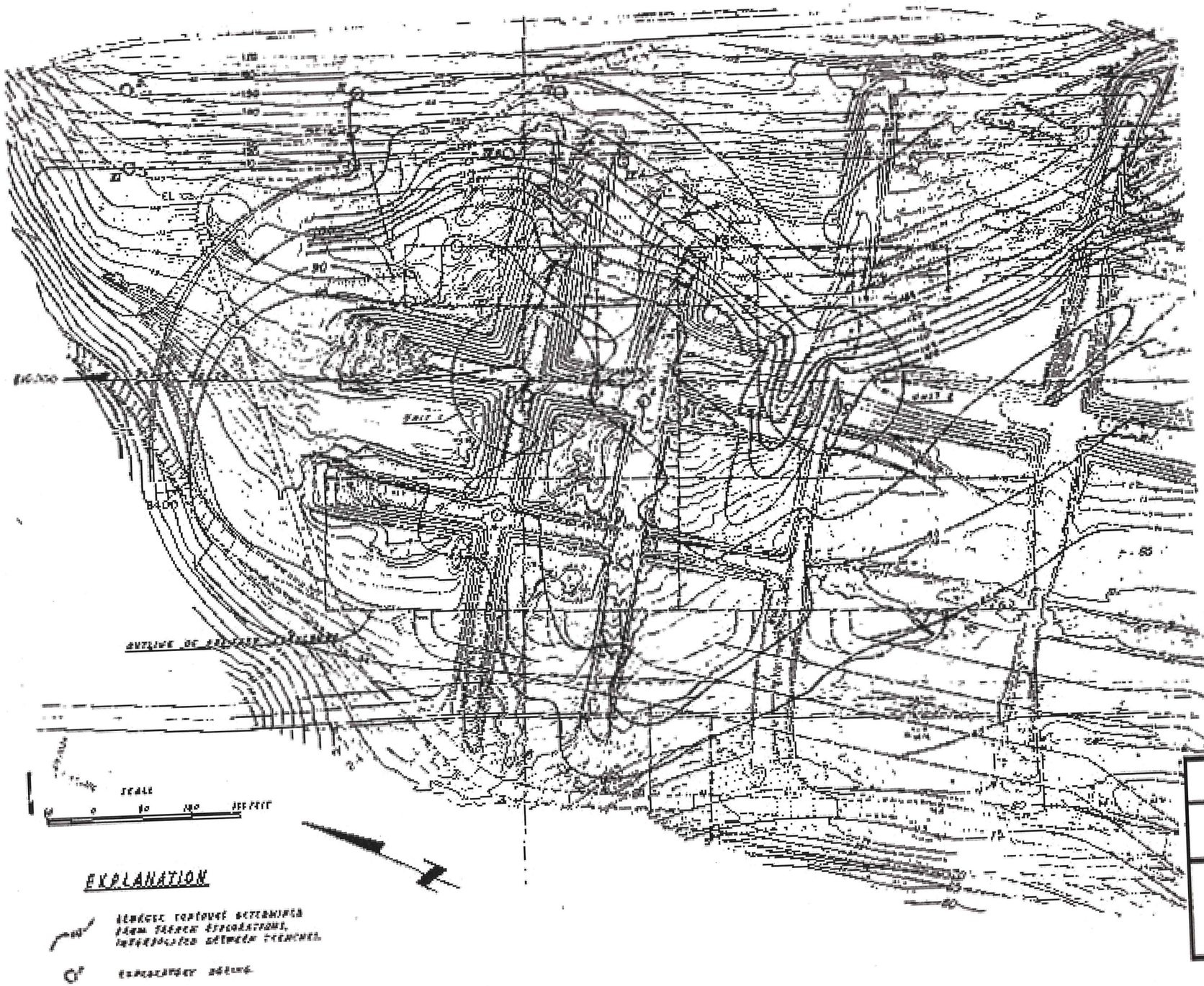
GEOLOGY MAPPED BY E.W. JAHNS AND A.M. JOHNSON, 1961, SUPPLEMENTED BY J.R. EVERNDEN, 1969.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.5-9 GEOLOGIC MAP OF SWITCHYARD AREA



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.5-10 GEOLOGIC SECTION THROUGH THE PLANT SITE

Revision 11 November 1996

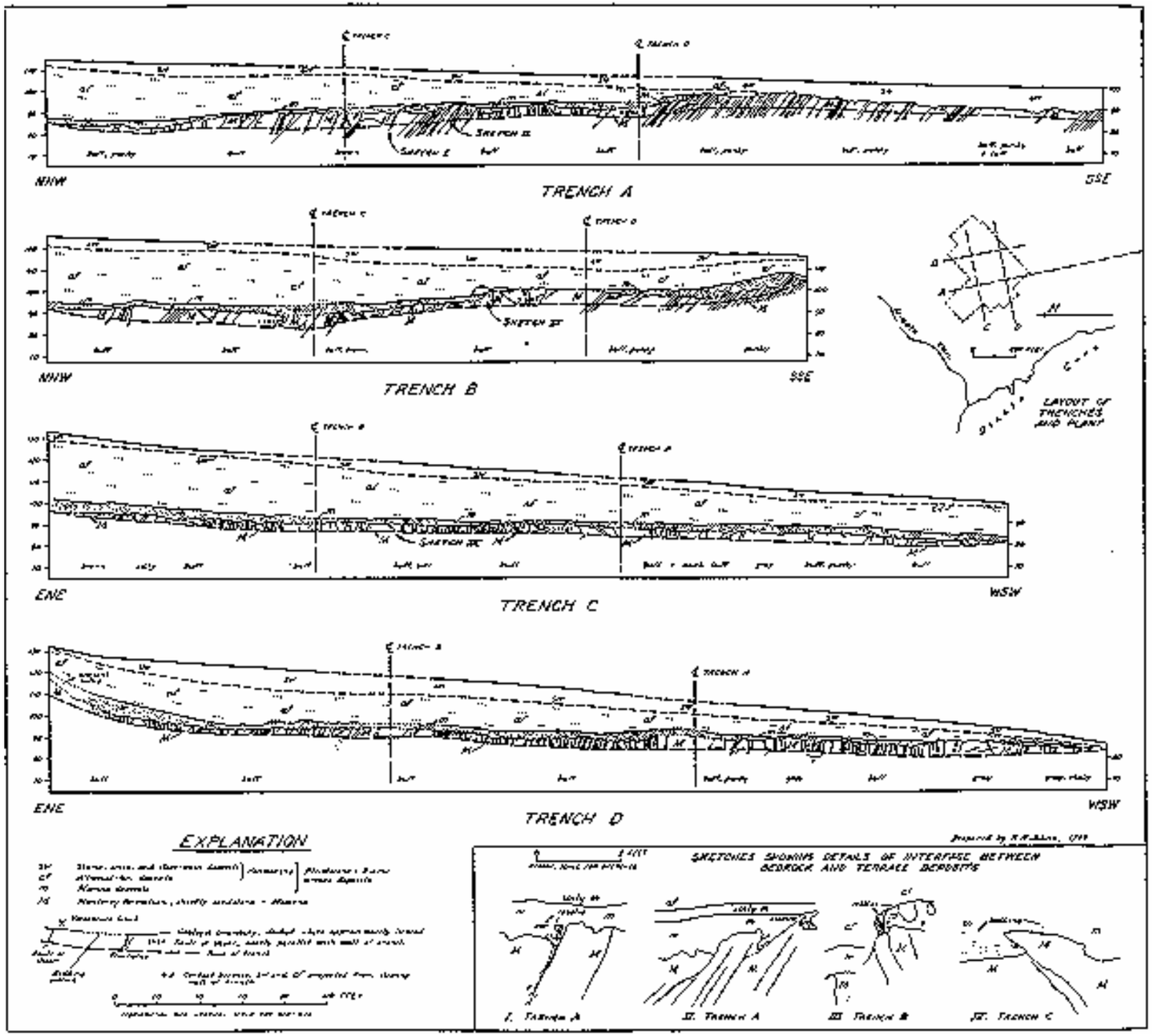


FSAR UPDATE

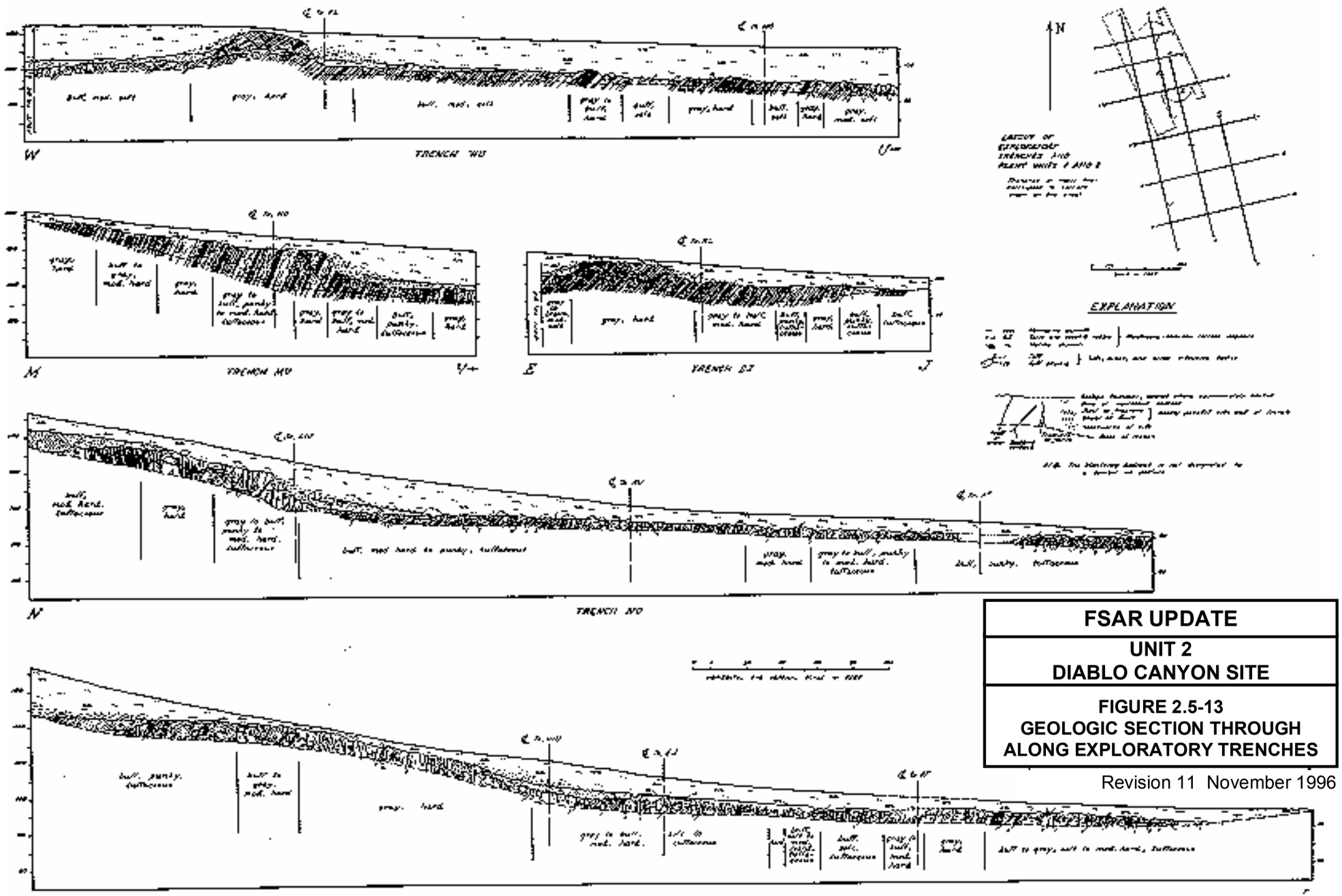
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.5-11
SITE EXPLORATION FEATURES AND BEDROCK CONTOURS

Revision 11 November 1996



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 2.5-12 GEOLOGIC SECTIONS AND SKETCHES ALONG EXPLORATORY TRENCHES

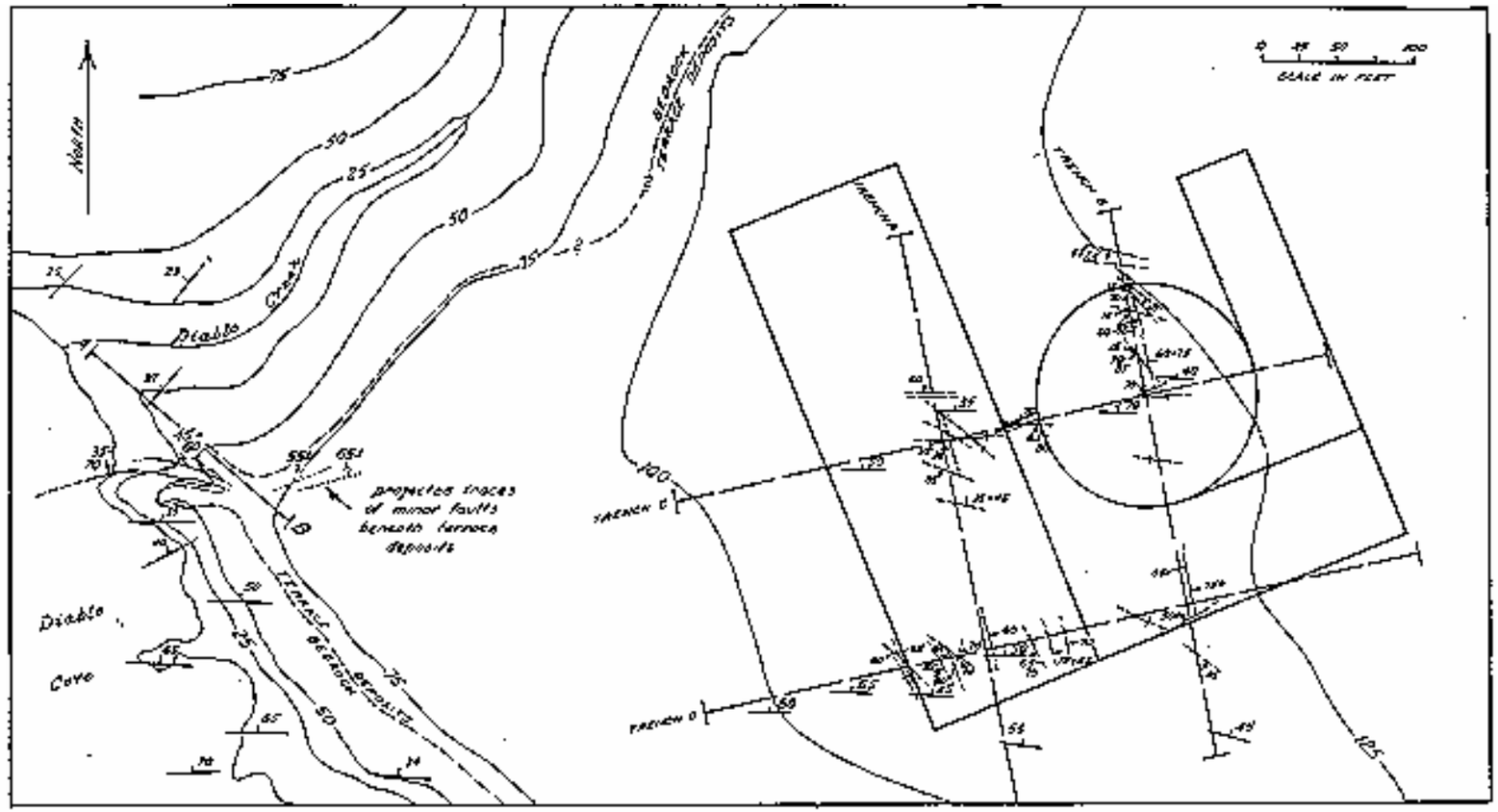


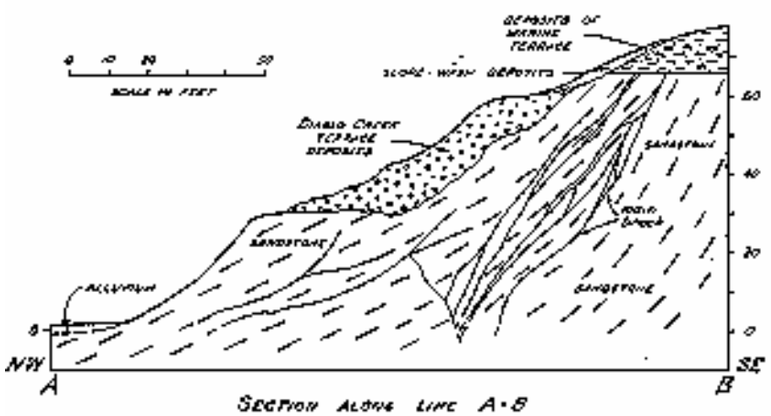
FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

FIGURE 2.5-13
GEOLOGIC SECTION THROUGH ALONG EXPLORATORY TRENCHES

Revision 11 November 1996

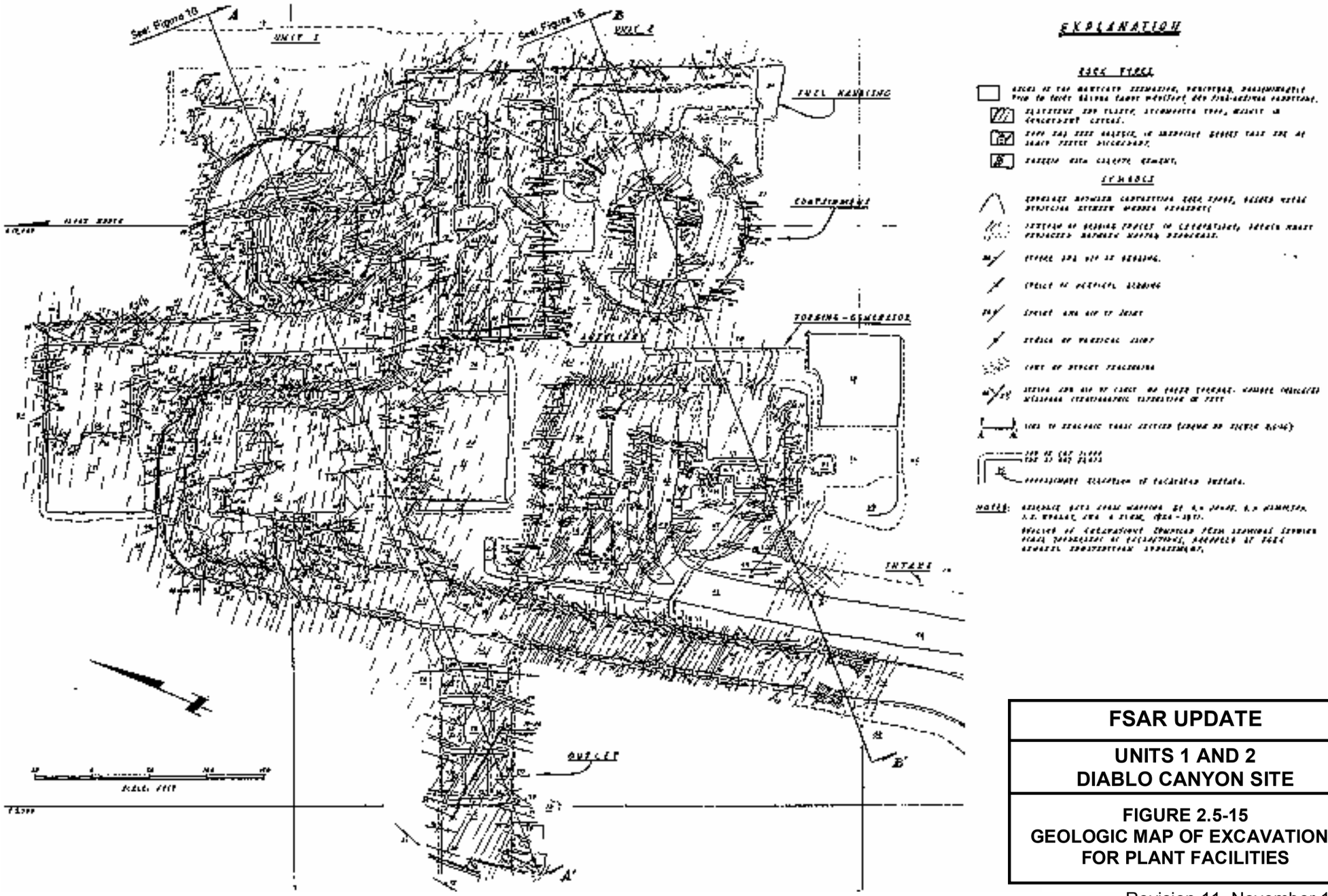




EXPLANATION

- Strike and dip of beds
- Generalized trace of bedding (in section only)
- Fault or shear, showing dip and trend and plunge of slickensides
- Vertical fault or shear
- Center line of exploratory trench
- Outline of power plant structure

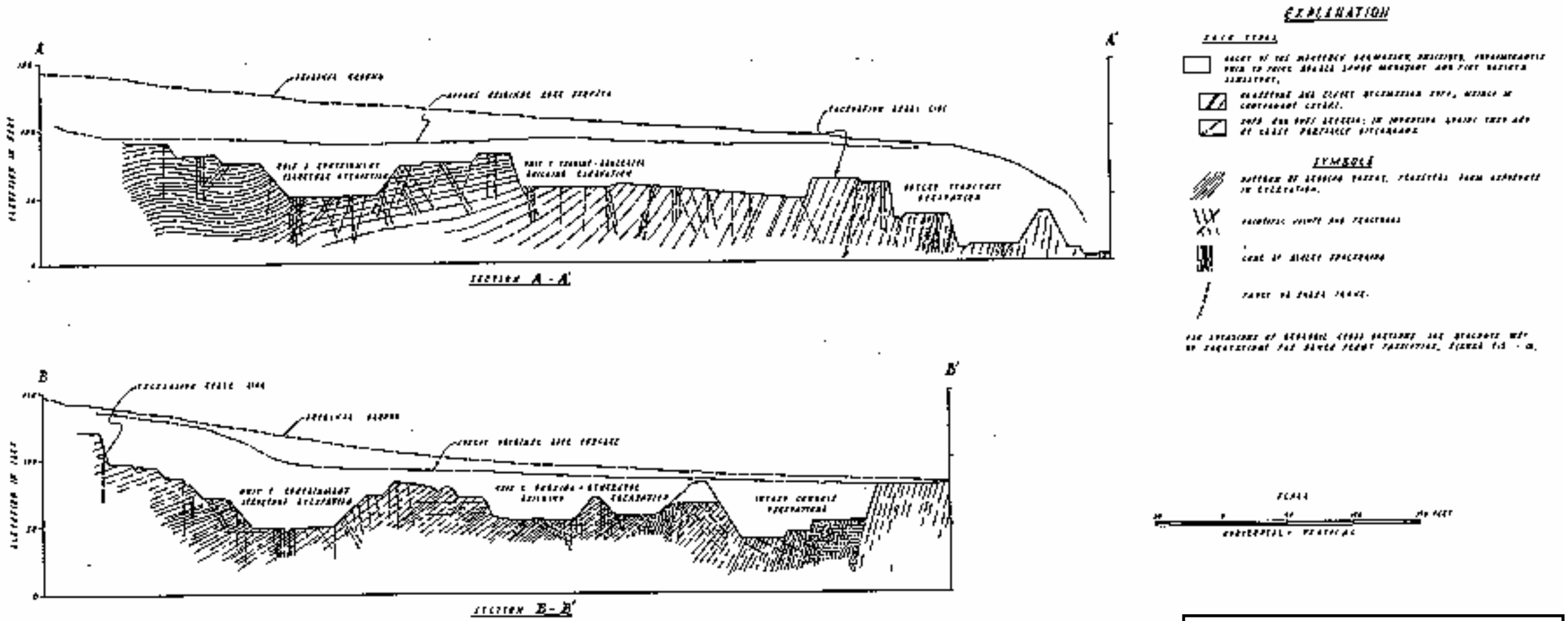
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.5-14 RELATIONSHIPS OF FAULTS AND SHEARS AT PLANT SITE



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.5-15
GEOLOGIC MAP OF EXCAVATIONS FOR PLANT FACILITIES

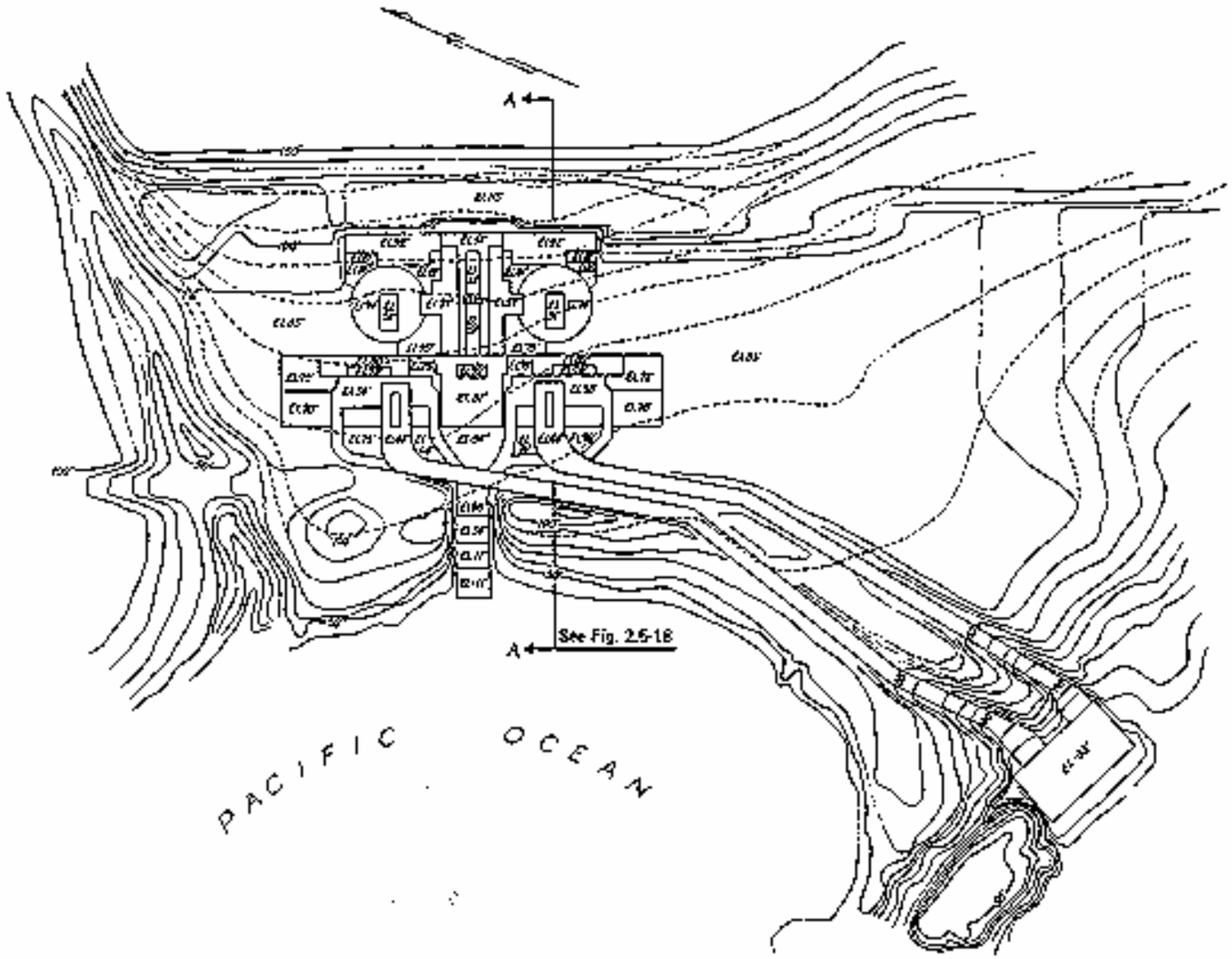


FSAR UPDATE

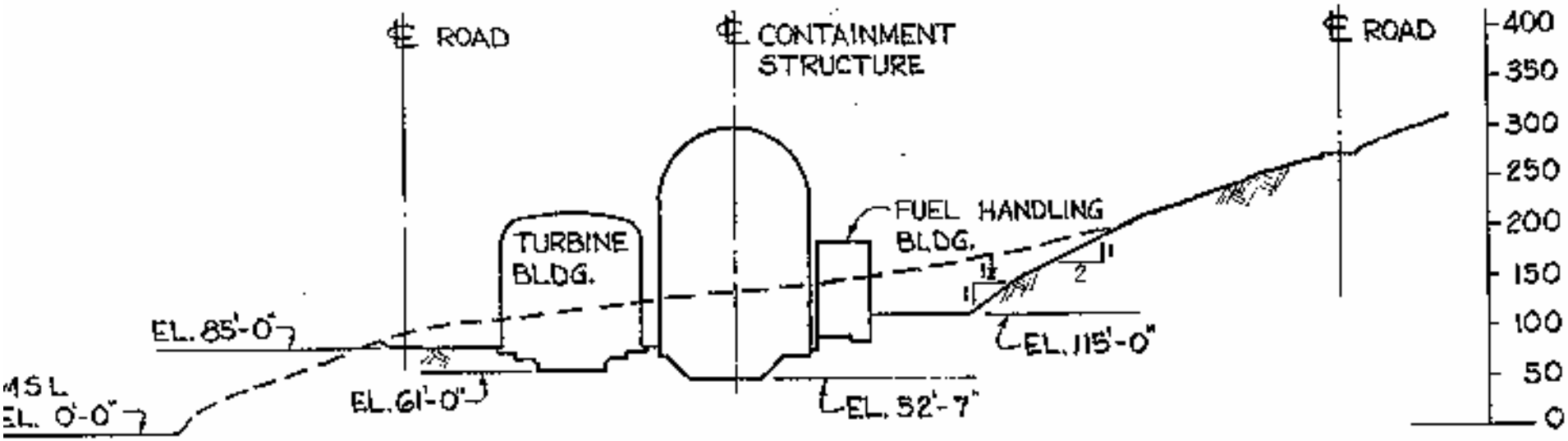
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.5-16
GEOLOGIC SECTIONS THROUGH EXCAVATIONS FOR PLANT FACILITIES

Revision 11 November 1996



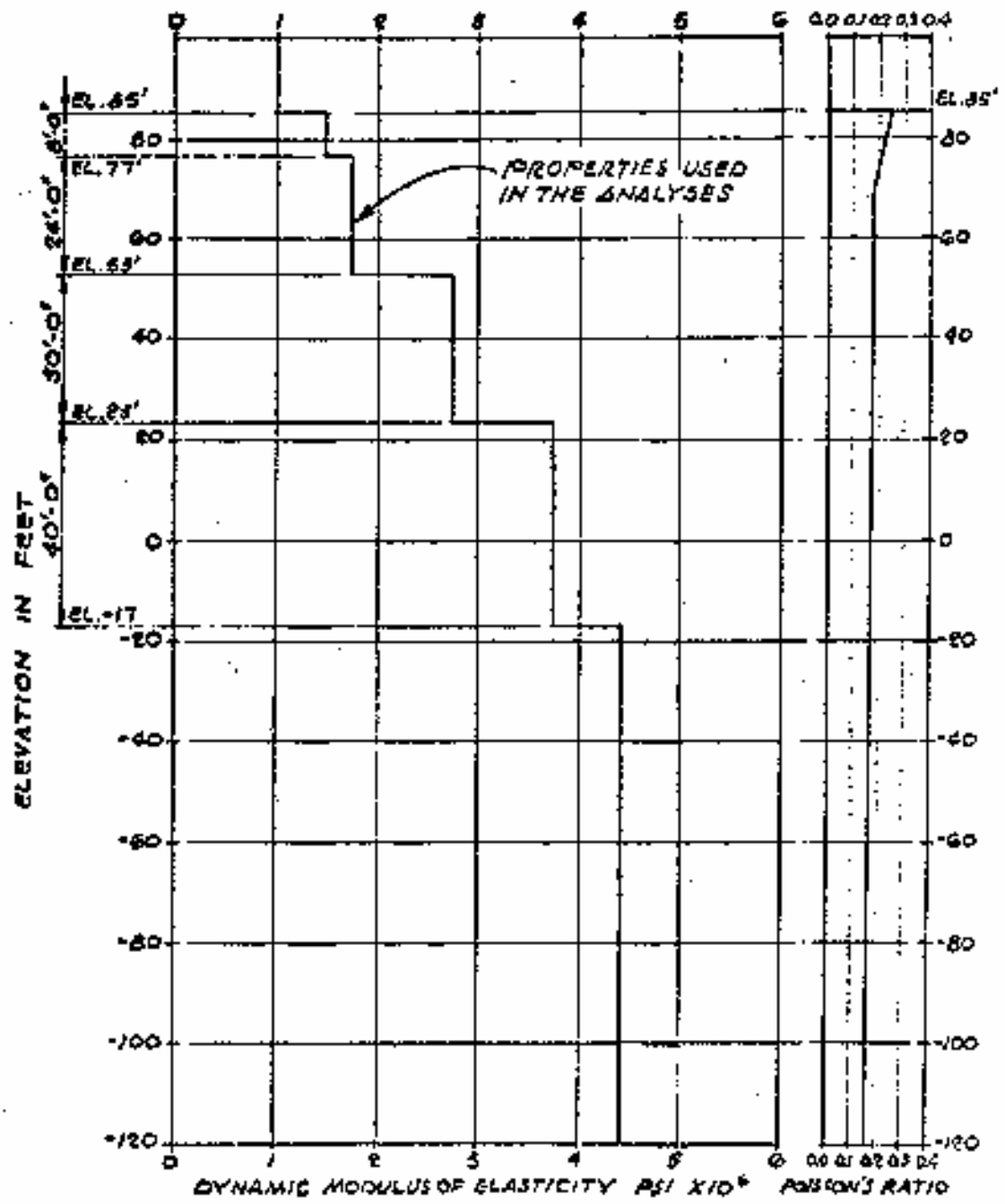
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.5-17 PLAN OF EXCAVATION AND BACKFILL



SECTION A-A

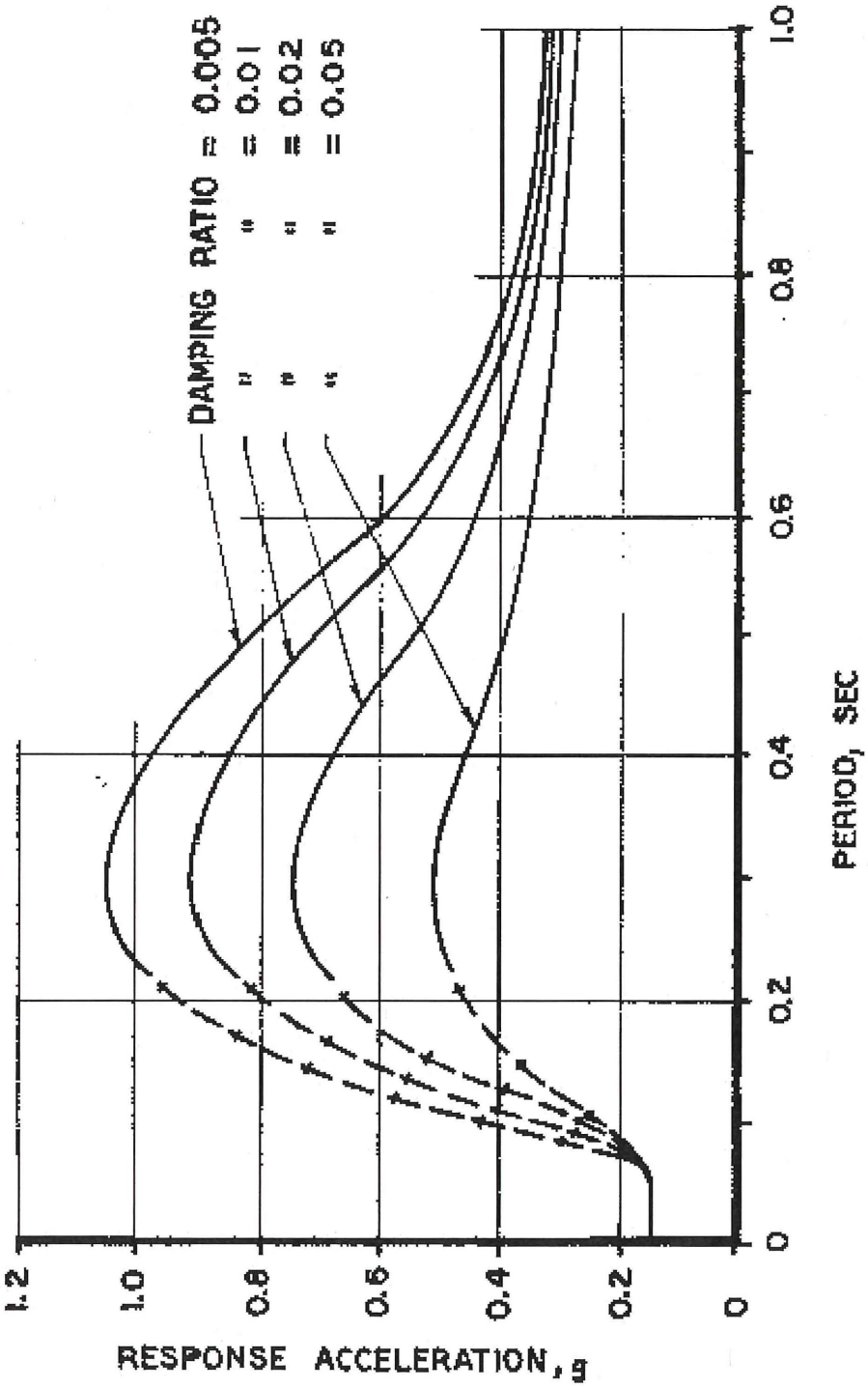
FROM FIGURE 2.5-17

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.5-18 SECTION A-A EXCAVATION AND BACKFILL

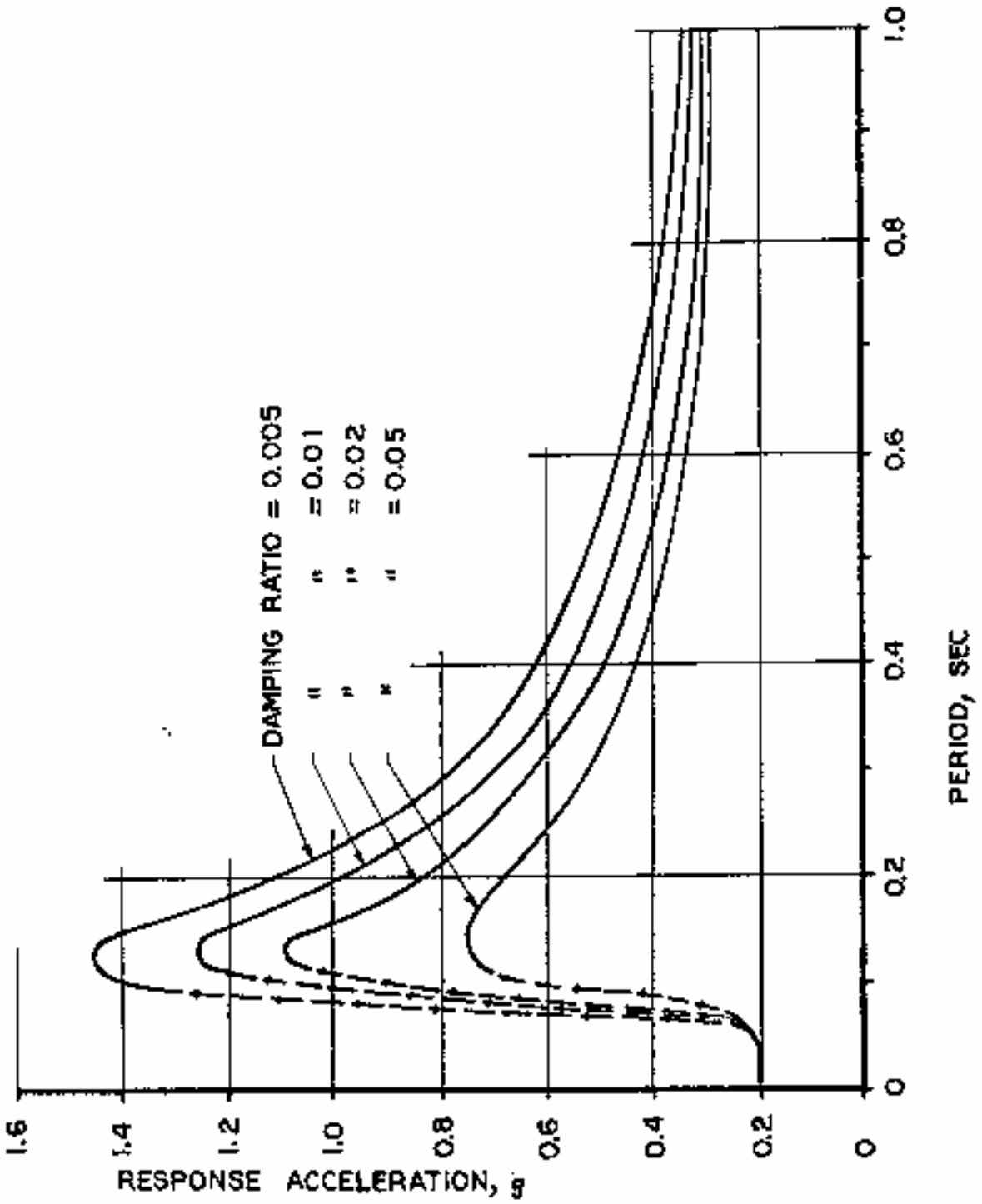


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.5-19 SOIL MODULE OF ELASTICITY AND POISSON'S RATIO

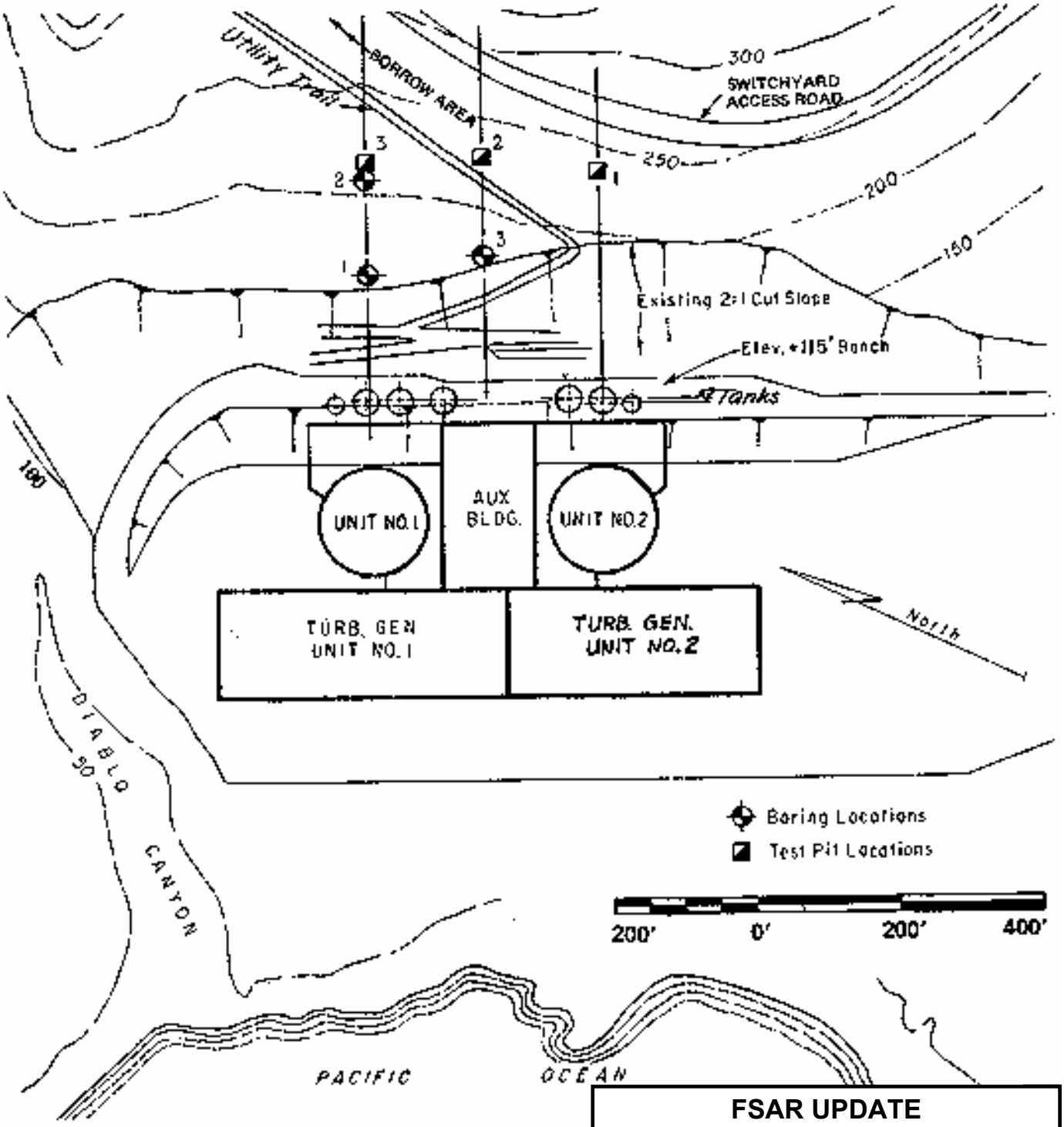
Revision 11 November 1996



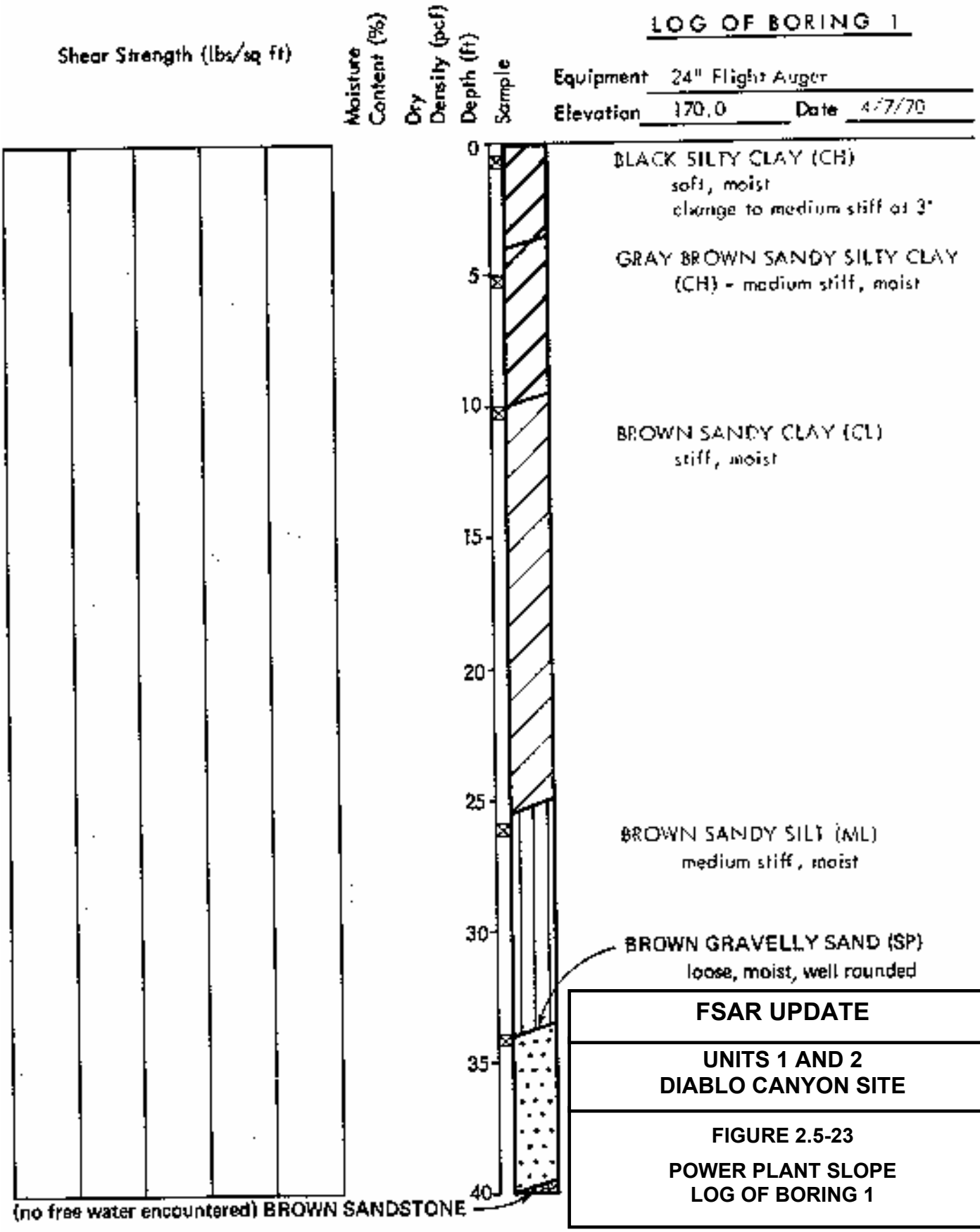
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.5-20 SMOOTH RESPONSE ACCELERATION SPECTRA – EARTHQUAKE "B"



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.5-21 SMOOTH RESPONSE ACCELERATION SPECTRA – EARTHQUAKE "D" MODIFIED



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.5-22 POWER PLANT SLOPE PLAN

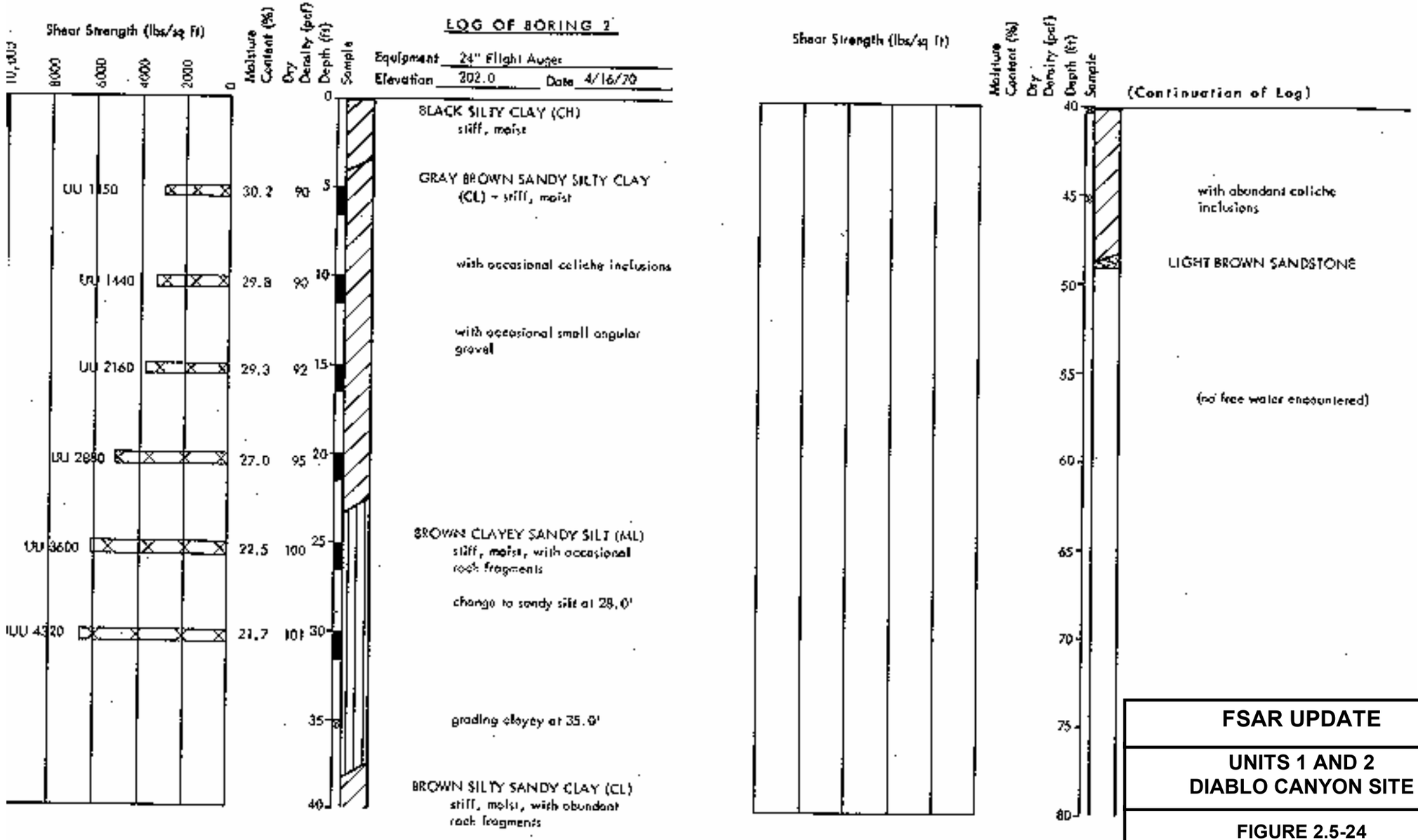


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.5-23

POWER PLANT SLOPE
LOG OF BORING 1

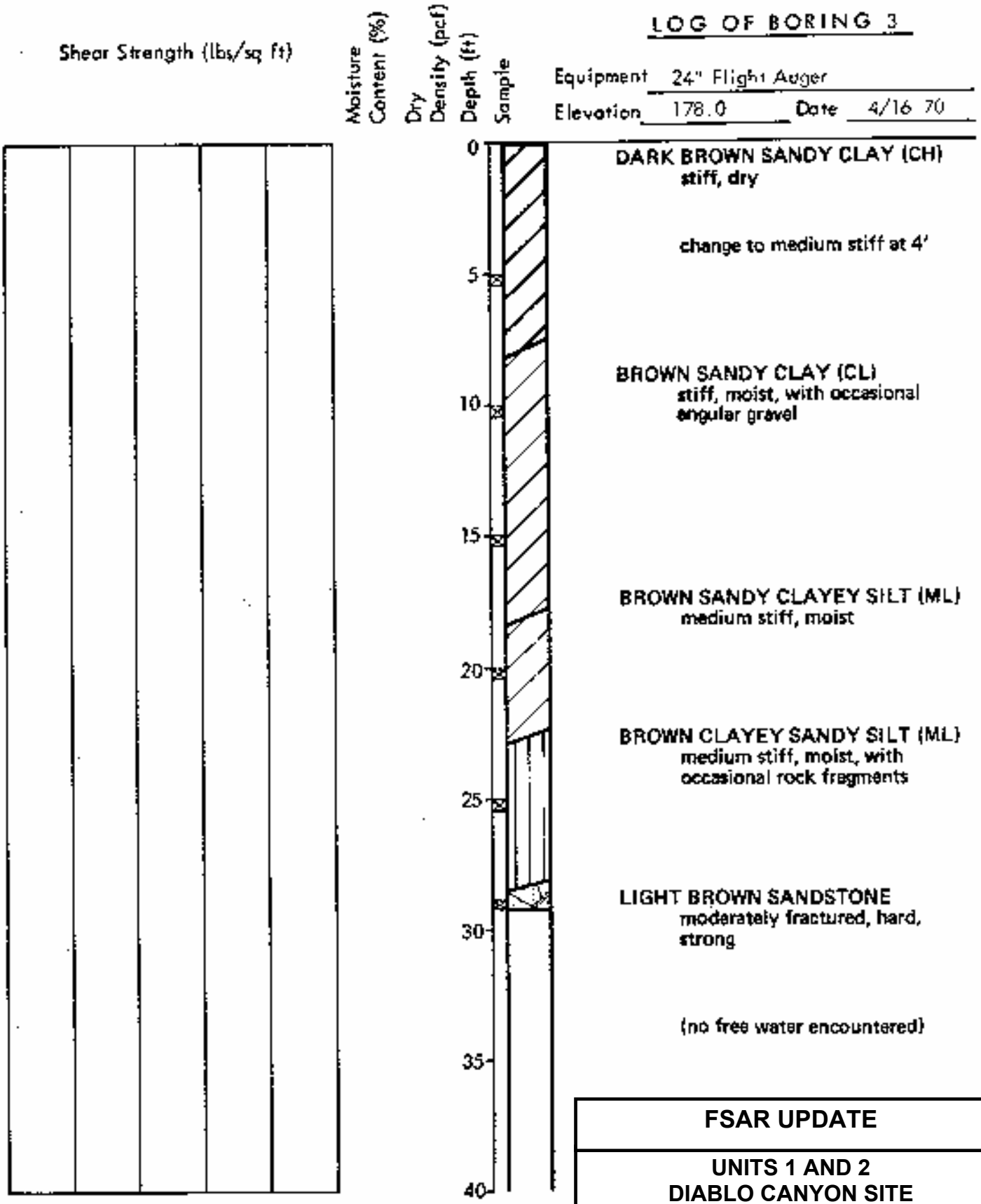


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.5-24

POWER PLANT SLOPE
LOG OF BORING 2

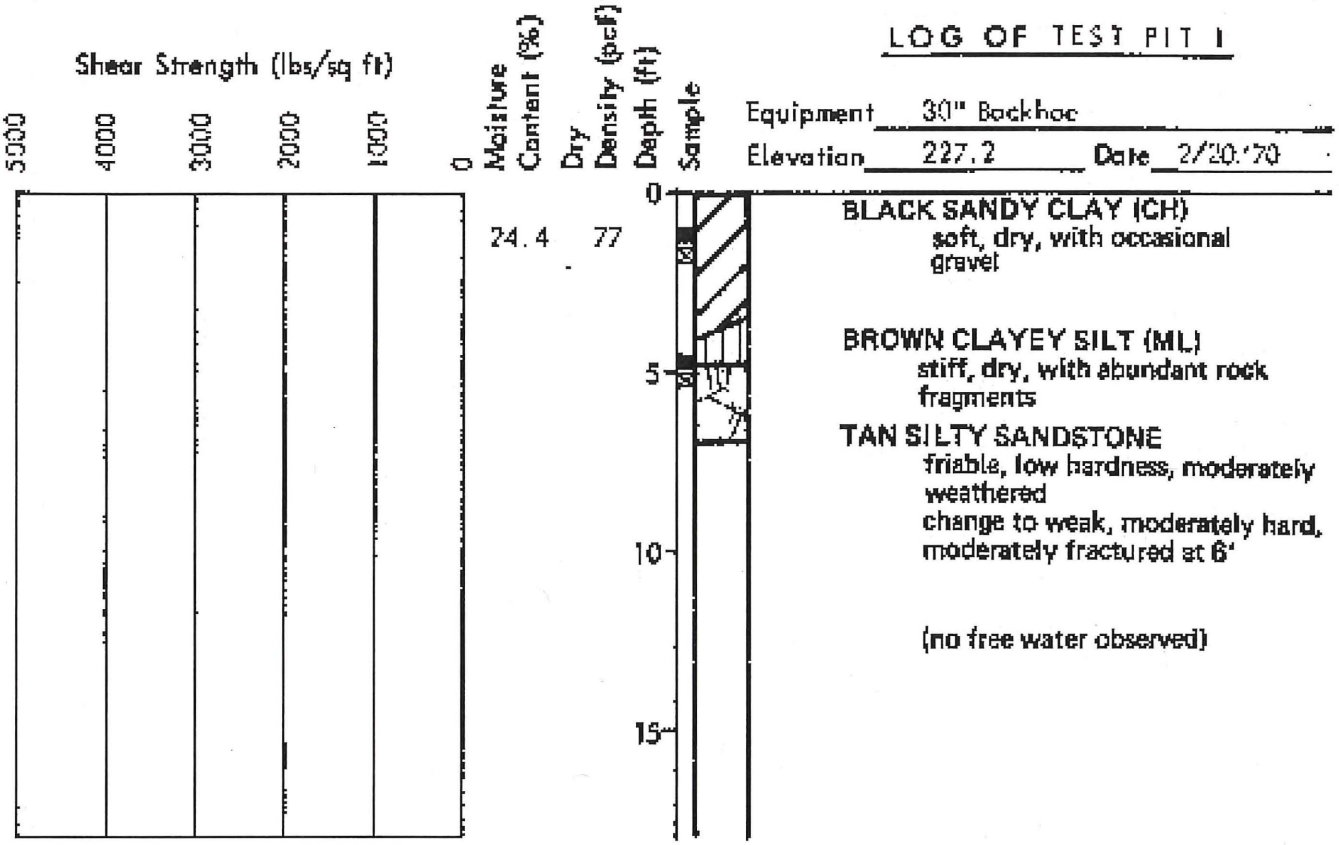


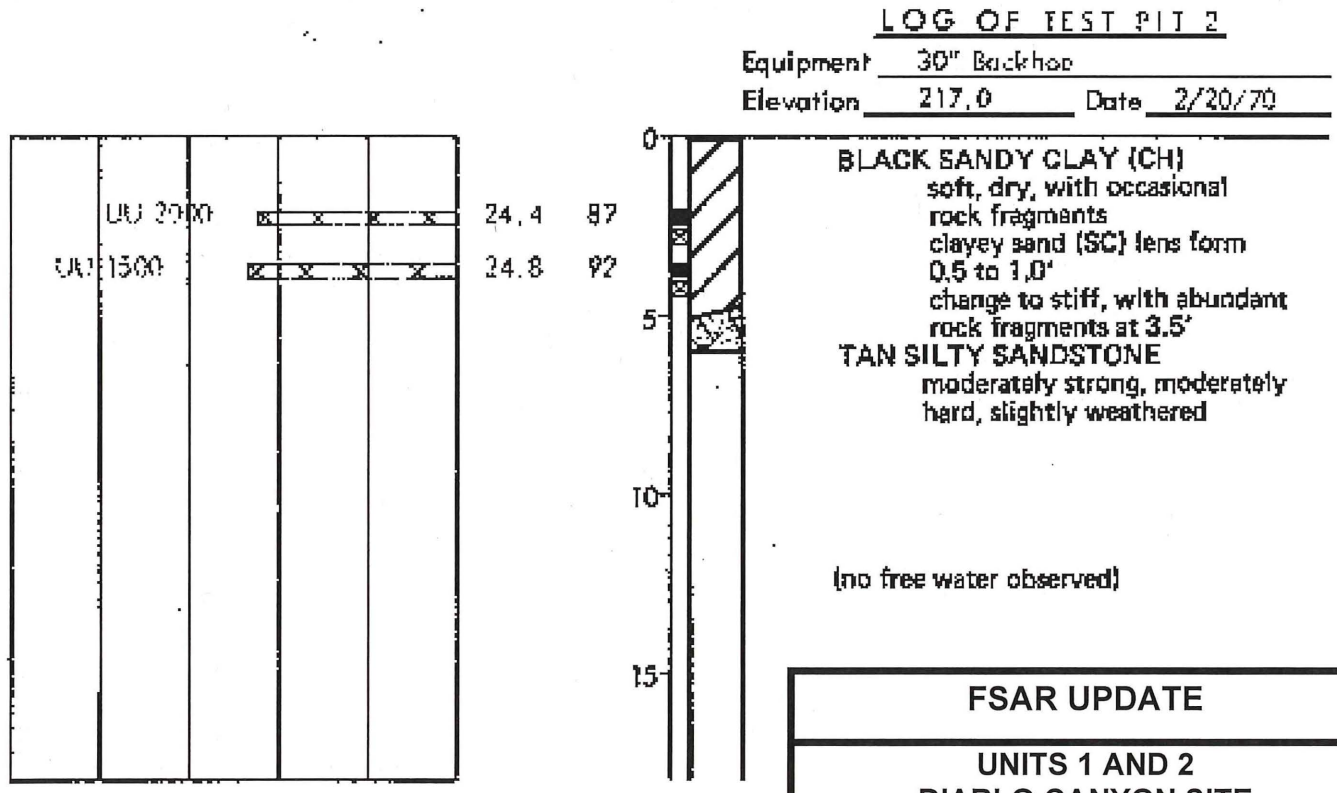
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.5-25

POWER PLANT SLOPE
LOG OF BORING 3



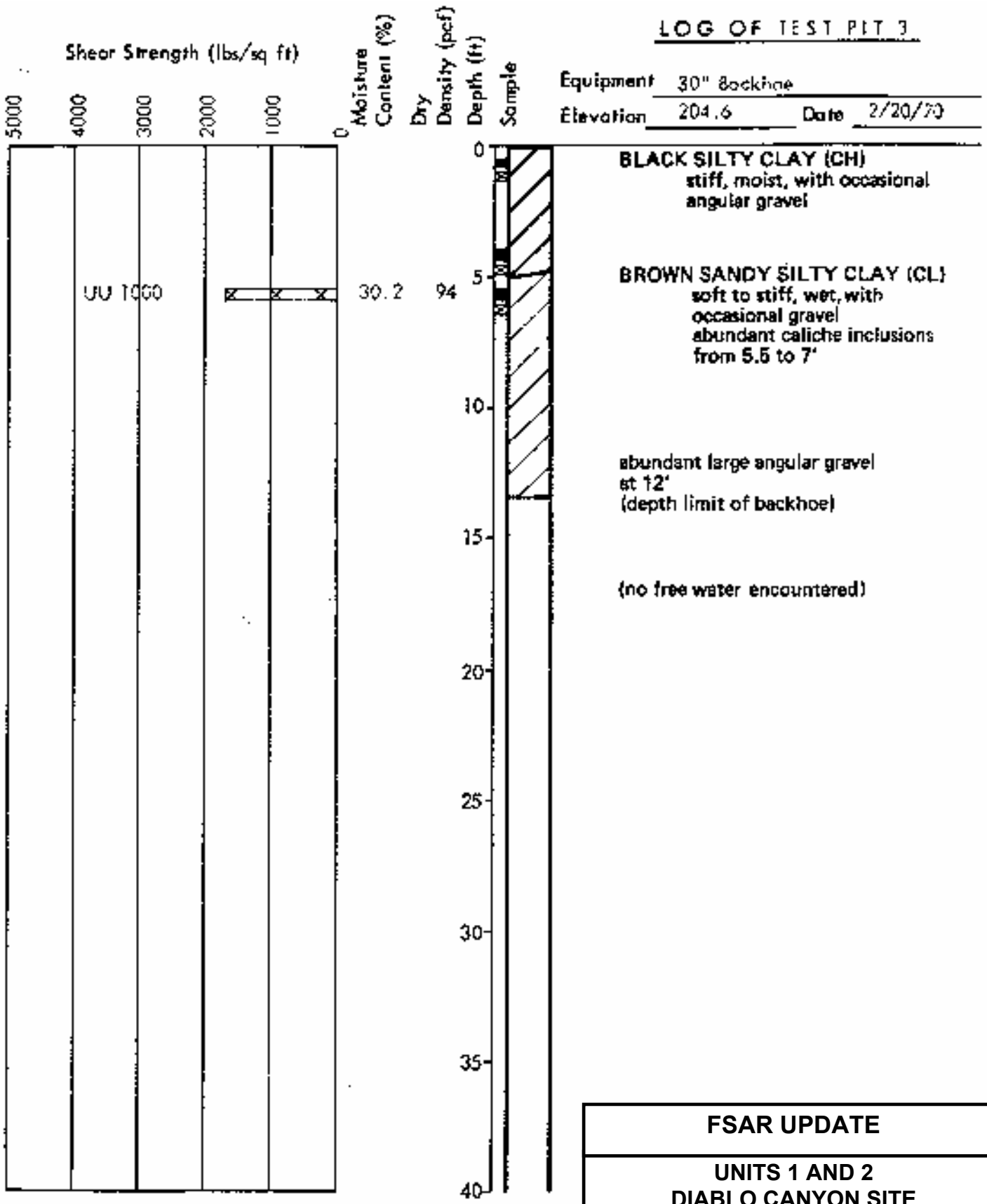


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.5-26

POWER PLANT SLOPE
LOG OF TEST PITS 1 & 2



FSAR UPDATE

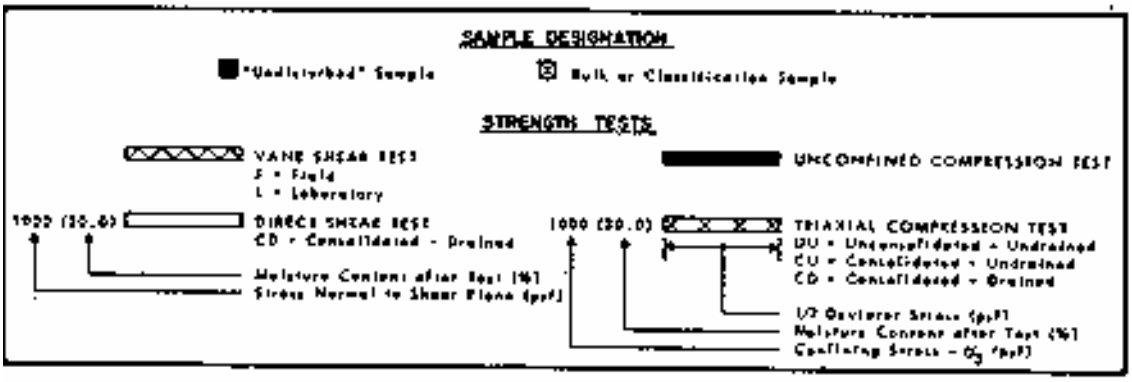
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 2.5-27

POWER PLANT SLOPE
LOG OF TEST PIT 3

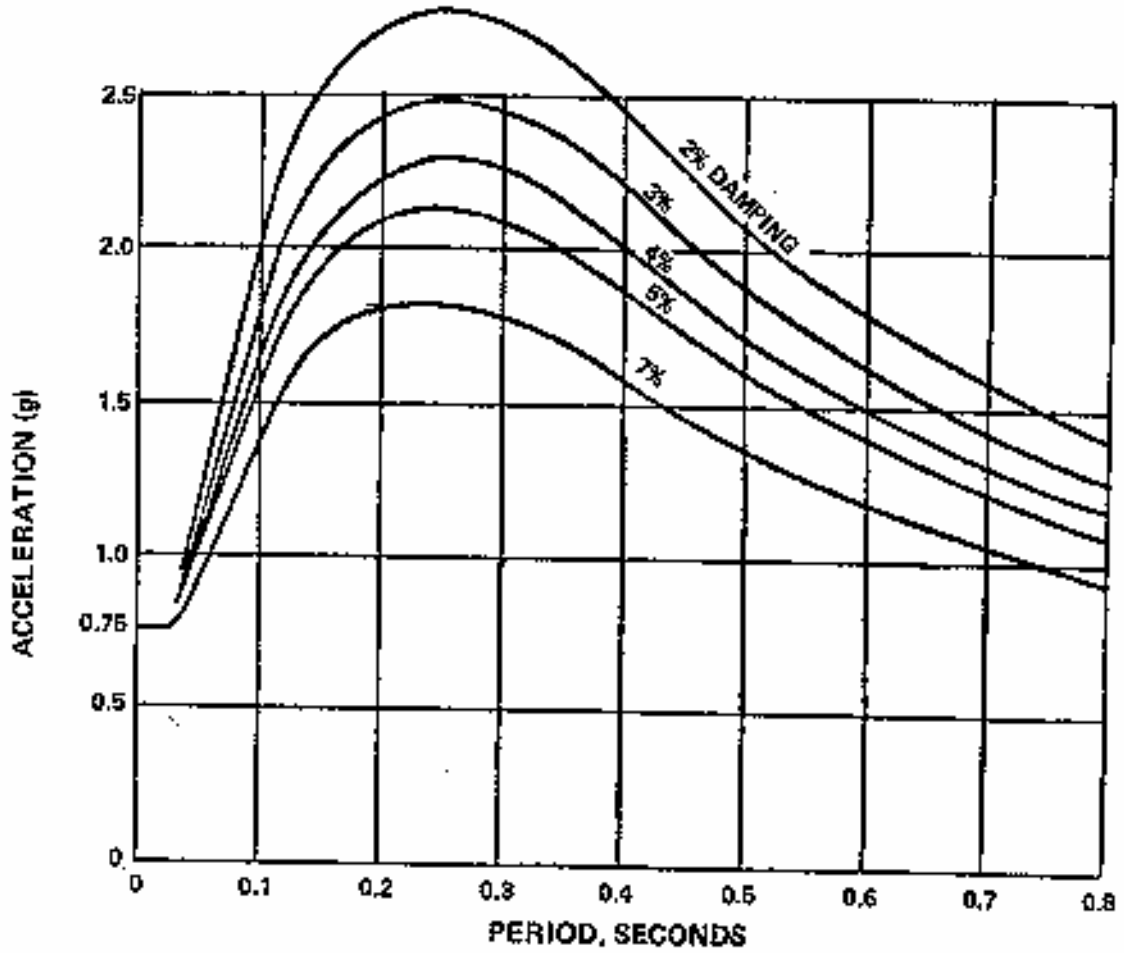
MAJOR DIVISIONS				TYPICAL NAMES
COARSE GRAINED SOILS (MORE THAN HALF IS LARGER THAN #200 SIEVE)	GRAVELS (MORE THAN HALF COARSE FRACTION IS LARGER THAN NO. 4 SIEVE SIZE)	CLEAN GRAVELS WITH LITTLE OR NO FINES	GW	WELL GRADED GRAVELS, GRAVEL – SAND MIXTURES
			GP	POORLY GRADED GRAVELS, GRAVEL – SAND MIXTURES
		GRAVELS WITH OVER 12% FINES	GM	SILTY GRAVELS, POORLY GRADED GRAVEL – SAND – SILT MIXTURES
			GC	CLAYEY GRAVELS, POORLY GRADED GRAVEL – SAND – CLAY MIXTURES
	SANDS (MORE THAN HALF COARSE FRACTION IS SMALLER THAN NO. 4 SIEVE SIZE)	CLEAN SANDS WITH LITTLE OR NO FINES	SW	WELL GRADED SANDS, GRAVELLY SANDS
			SP	POORLY GRADED SANDS, GRAVELLY SANDS
		SANDS WITH OVER 12% FINES	SM	SILTY SANDS, POORLY GRADED SAND – SILT MIXTURES
			SC	CLAYEY SANDS, POORLY GRADED SAND – CLAY MIXTURES
FINE GRAINED SOILS (MORE THAN HALF IS SMALLER THAN #200 SIEVE)	SILTS AND CLAYS (LIQUID LIMIT LESS THAN 50)		ML	INORGANIC SILTS AND VERY FINE SANDS, ROCK FLOUR, SILTY OR CLAYEY FINE SANDS, OR CLAYEY SILTS WITH SLIGHT PLASTICITY
			CL	INORGANIC CLAYS OF LOW TO MEDIUM PLASTICITY, GRAVELLY CLAYS, SANDY CLAYS, SILTY CLAYS, LEAN CLAYS
			OL	ORGANIC CLAYS AND ORGANIC SILTY CLAYS OF LOW PLASTICITY
	SILTS AND CLAYS (LIQUID LIMIT GREATER THAN 50)		MH	INORGANIC SILTS, MICACEOUS OR DIATOMACEOUS FINE SANDY OR SILTY SOILS, ELASTIC SILTS
			CH	INORGANIC CLAYS OF HIGH PLASTICITY, FAT CLAYS
			OH	ORGANIC CLAYS OF MEDIUM TO HIGH PLASTICITY, ORGANIC SILTS
HIGHLY ORGANIC SOILS			Pt	PEAT AND OTHER HIGHLY ORGANIC SOILS

UNIFIED SOIL CLASSIFICATION SYSTEM



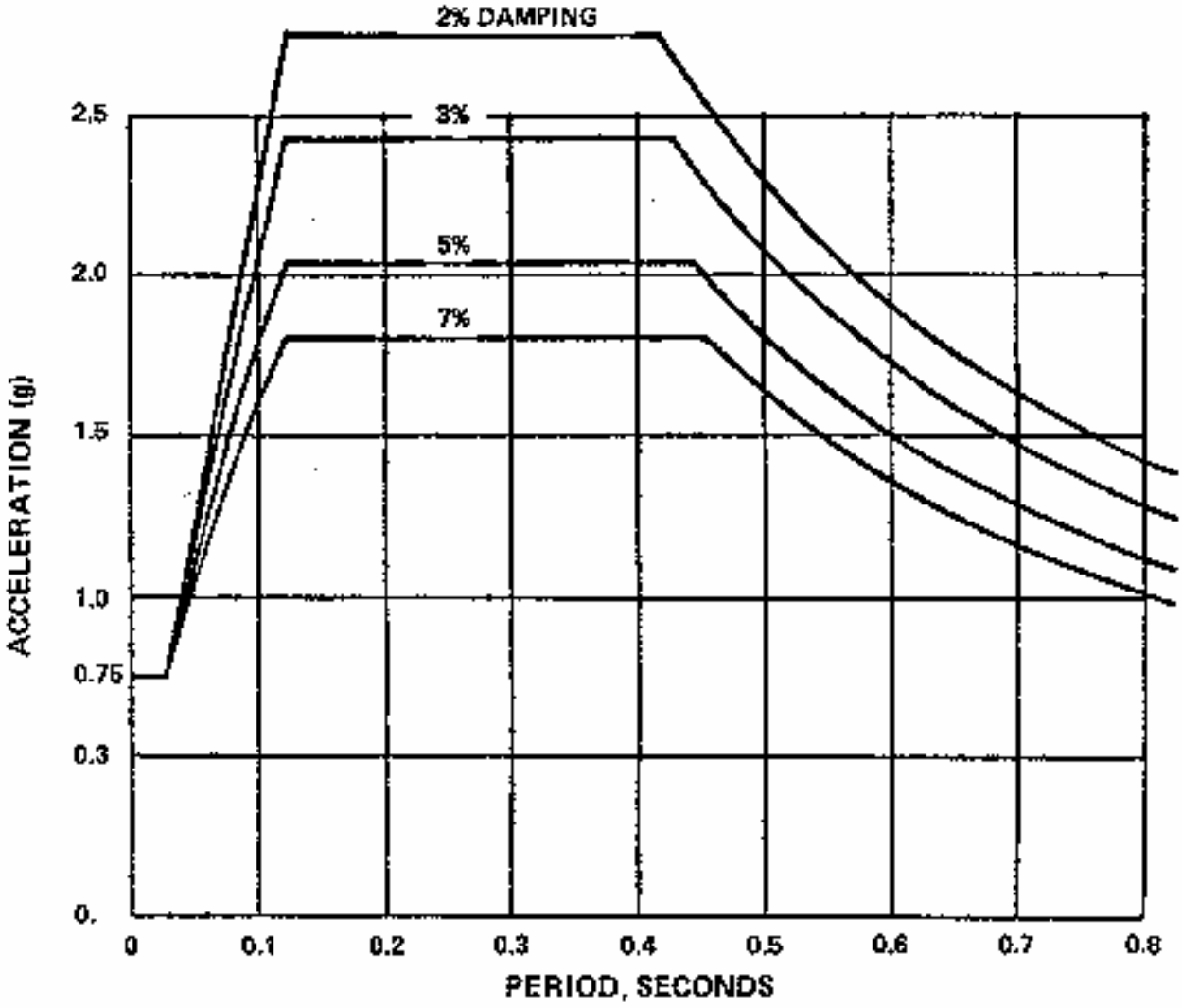
KEY TO TEST DATA

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.5-28 POWER PLANT SLOPE SOIL CLASSIFICATION CHART AND KEY TO TEST AREA

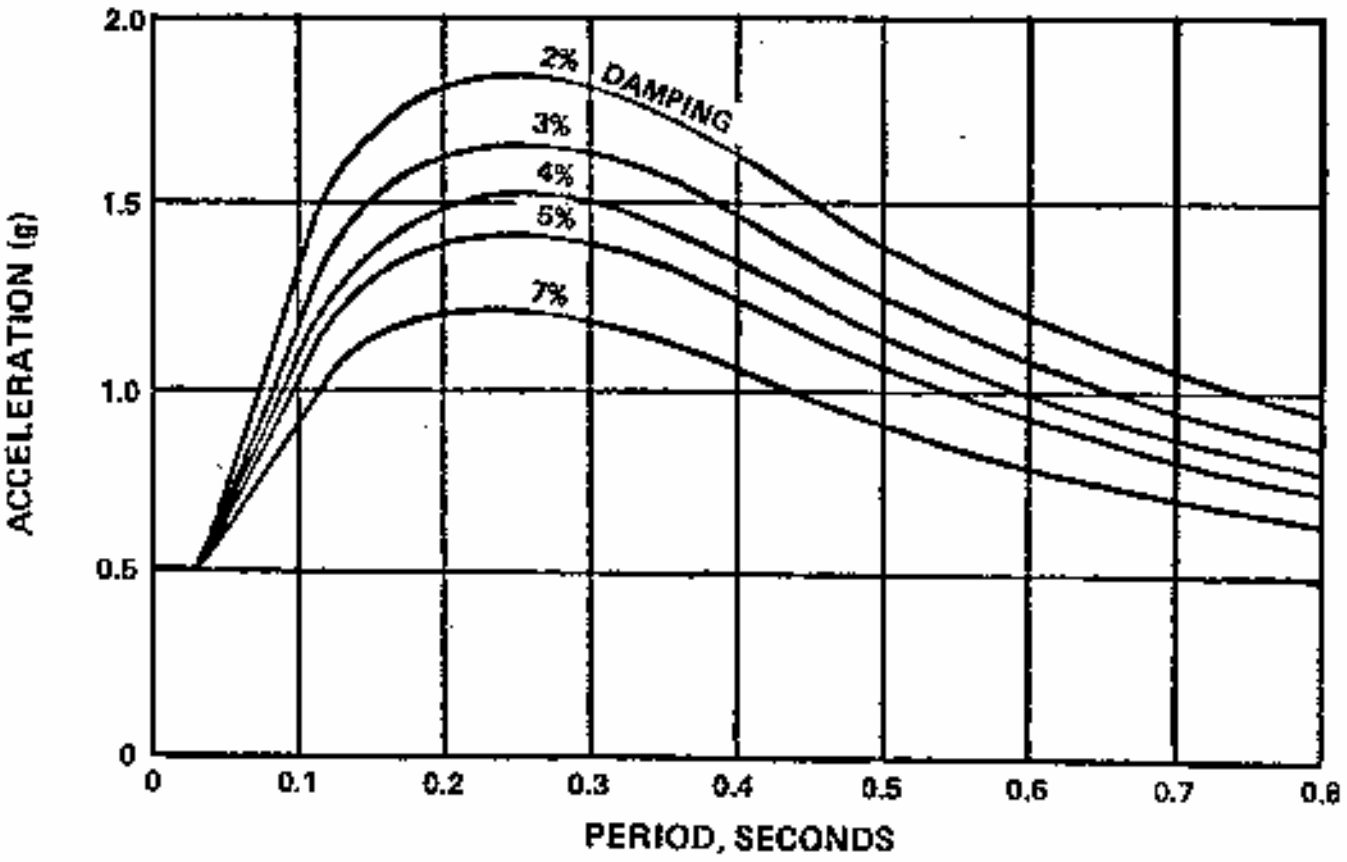


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.5-29 FREE FIELD SPECTRA HORIZONTAL HOSGRI 7.5M/BLUME

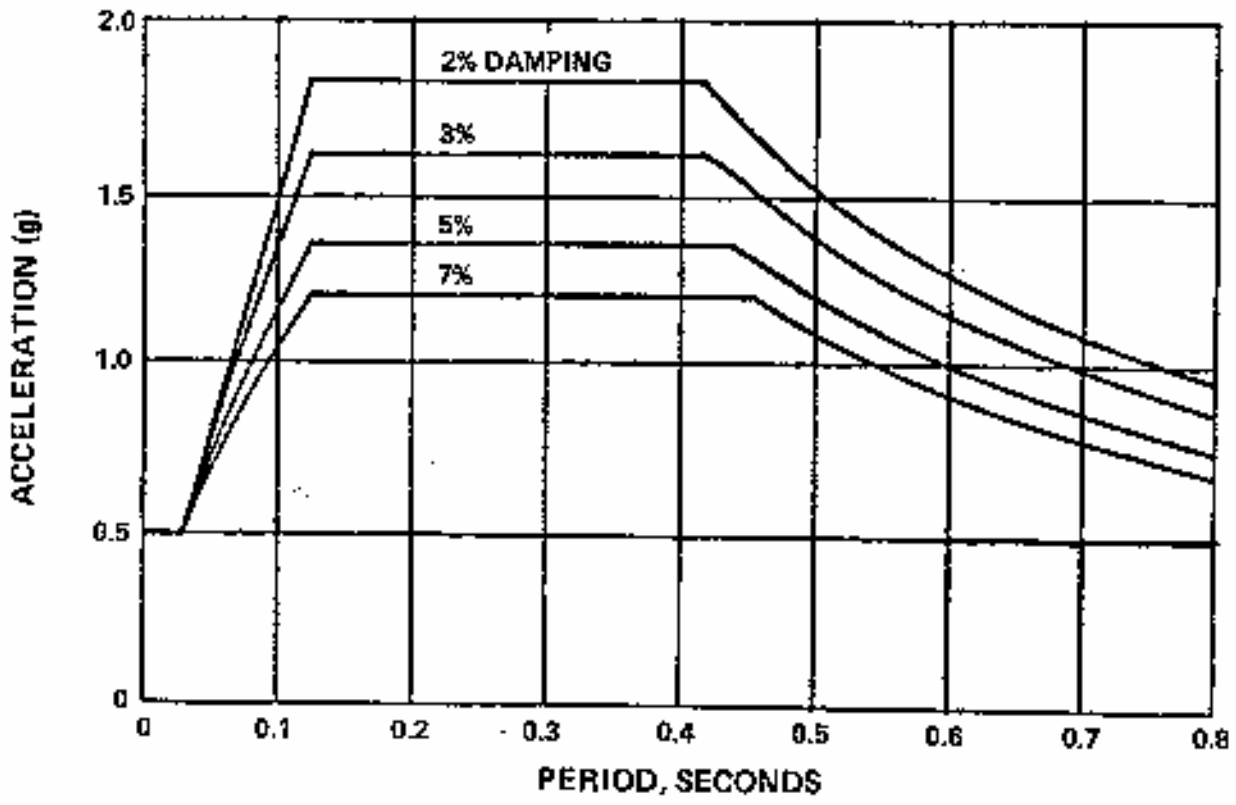
Revision 11 November 1996



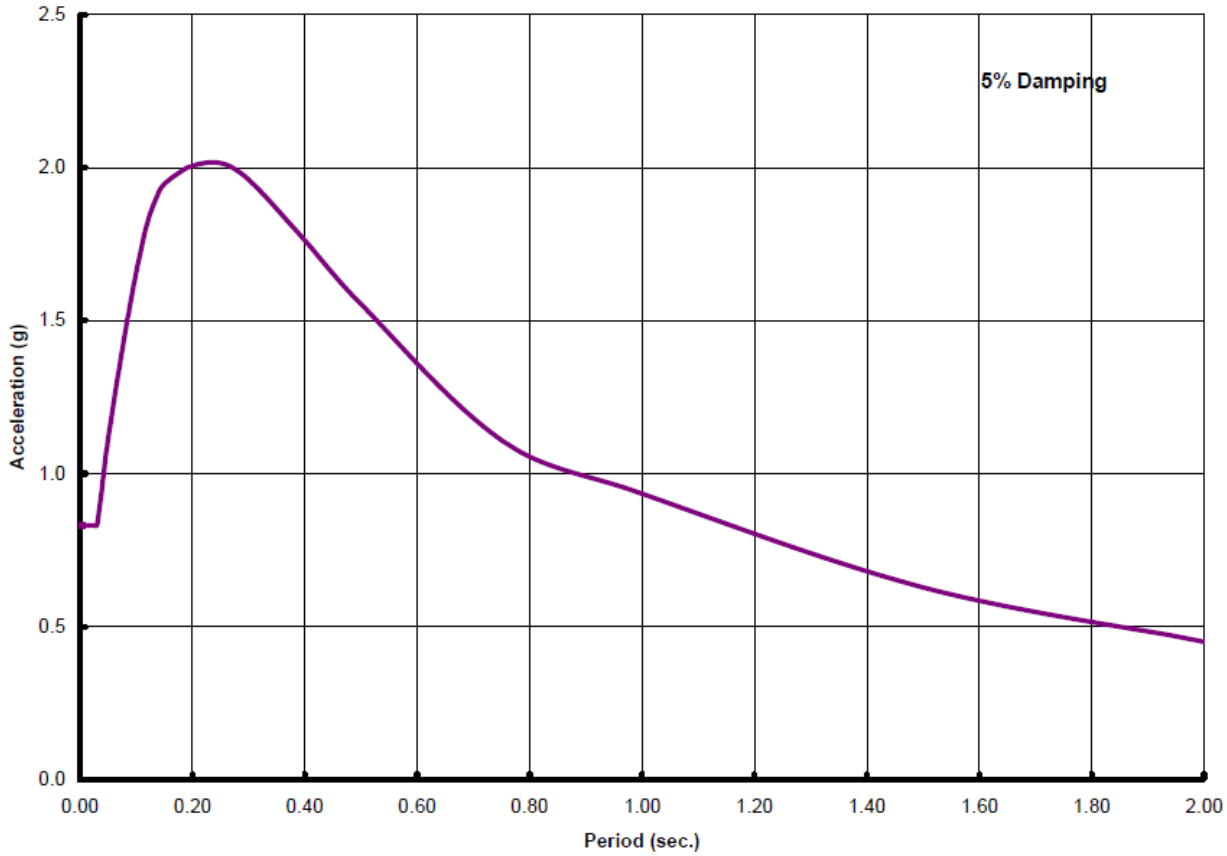
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.5-30 FREE FIELD SPECTRA HORIZONTAL HOSGRI 7.5M/NEWMARK



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.5-31 FREE FIELD SPECTRA VERTICAL HOSGRI 7.5M/BLUME



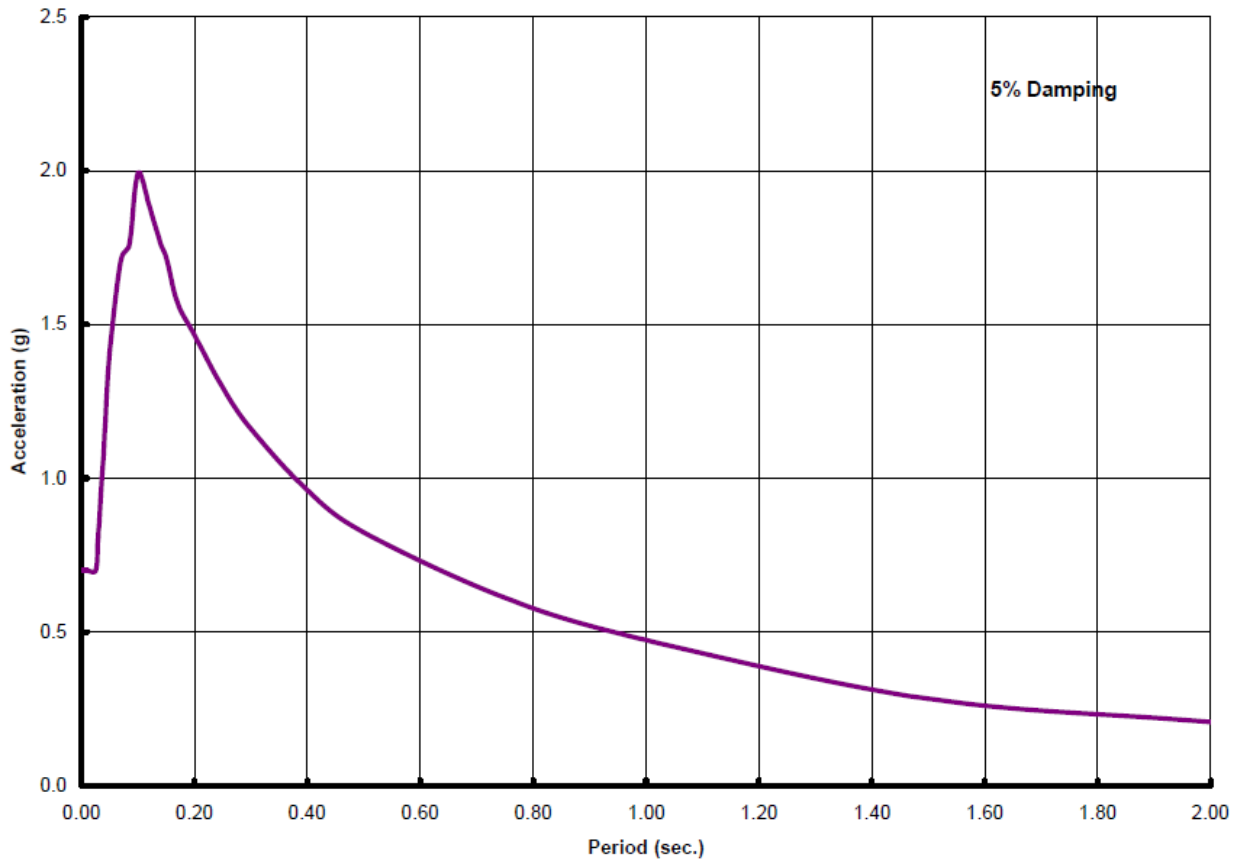
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.5-32 FREE FIELD SPECTRA VERTICAL HOSGRI 7.5M/NEWMARK



NOTES:

1. This figure is based on Reference 42, Figure 2.4

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.5-33 FREE FIELD SPECTRUM HORIZONTAL 1991 LTSP (84TH PERCENTILE NON-EXCEEDANCE) AS MODIFIED PER SSER-34



NOTES:

1. This Figure is based on Reference 42, Figure 2.5.

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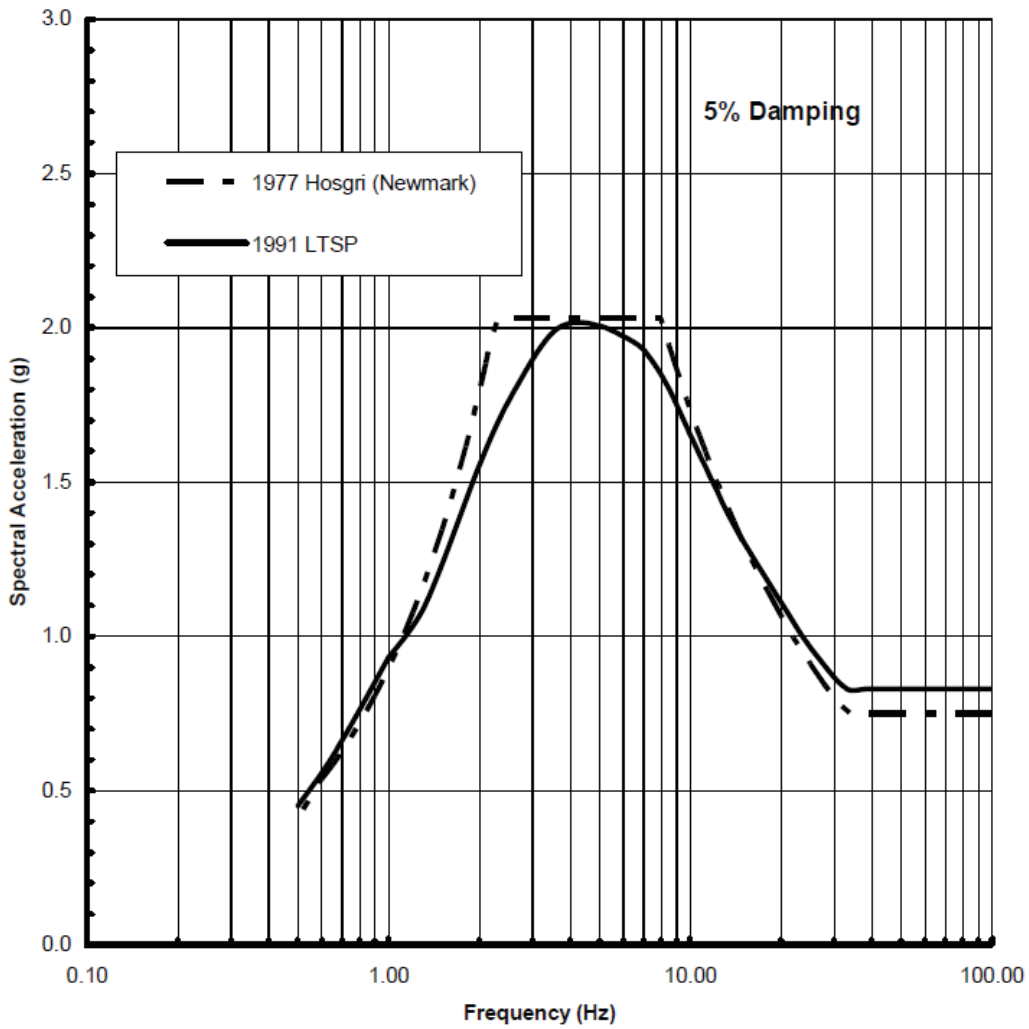
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.5-34 FREE FIELD SPECTRUM VERTICAL 1991 LTSP (84TH PERCENTILE NON-EXCEEDANCE) AS MODIFIED PER SSER-34



NOTES:

1. This Figure is based on Reference 40, Figure 7-2; however, the LTSP response spectrum has been adjusted in accordance with Reference 42, Figure 2.5.
2. This Figure is for comparison purposes only. Do not use for design.
3. Legend: 1977 Hosgri (Newmark) corresponds to the spectrum shown in Figure 2.5-30
   (Frequency range of 0.5 Hz to 1.25 Hz is an extrapolation)
   1991 LTSP corresponds to the spectrum shown in Figure 2.5-33

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UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.5-35 FREE FIELD SPECTRA HORIZONTAL LTSP (PG&E 1998) GROUND MOTION VS. HOSGRI (NEWMARK 1977)

NOTE:

1. This figure is based on Reference 52, Figure 1-1.

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UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 2.5-36 MAP OF SHORELINE FAULT STUDY AREA

Revision 21 September 2013

Chapter 3

DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

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3.8-27	Containment Structure, Membrane Forces Dead Load and Pressure
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3.8-46[a]	Auxiliary Building, Concrete Outline – Plan at El 115 ft Areas J, GE, and GW
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3.8-48[a]	Auxiliary Building, Concrete Outline – Section Areas J and K
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Figure	Title
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3.8-52[a]	Auxiliary Building, Concrete Reinforcing – Plan at El 115 and 140 ft – Area L
3.8-53[a]	Auxiliary Building, Concrete Reinforcing – Miscellaneous Sections – Area K
3.8-54[a]	Auxiliary Building, Concrete Reinforcing – Sections Areas H, K, and GE
3.8-55[a]	Auxiliary Building, Control Room – Sections
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3.8-57[a]	Auxiliary Building, Crane Support Structure – Elevations and Details
3.8-58[a]	Auxiliary Building, Crane Support Structure – Section and Details
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3.8-60	Auxiliary Building, Floor Plan El 100 ft
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3.8-63	Auxiliary Building, Load Dissipation to Foundation, Hosgri N-S
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3.8-65[a]	PG&E Design Class I Tanks Concrete Foundations
3.8-66	Turbine Building Plan El 85 ft
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3.8-83[a]	Safety Related Masonry Walls, Turbine Bldg – Unit 1
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3.9-1	Vibration Checkout, Functional Test Inspection Data - Unit 1
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3.9-3	Thermal Shield, Modal Shape n=4 Obtained from Shaker Test - Unit 1
3.9-4	Thermal Shield, Maximum Amplitude of Vibration During Preoperational Test - Unit 1

FIGURES (Continued)

Figure	Title

NOTE:

[a] This figure corresponds to a controlled engineering drawing that is incorporated by reference into the FSAR Update. See Table 1.6-1 for the correlation between the FSAR Update figure number and the corresponding controlled engineering drawing number.

APPENDICES

Appendix	Title
3.1A	AEC GENERAL DESIGN CRITERIA -1971
3.11A	Deleted in Revision 7

Chapter 3

DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

3.1 CONFORMANCE WITH U.S. ATOMIC ENERGY COMMISSION GENERAL DESIGN CRITERIA

The Diablo Canyon Power Plant (DCPP) units are designed to comply with the Atomic Energy Commission (AEC) (now the Nuclear Regulatory Commission, or NRC) General Design Criteria (GDC) for Nuclear Power Plant Construction Permits, published in July 1967. Sections 3.1.1 through 3.1.10, therefore, provide a listing of these criteria and a discussion of conformance. The DCPP design basis is the 1967 GDCs. Subsequent commitments to GDCs issued later (e.g., 1971 GDC, and the 1987 revision to GDC 4) are noted in the discussion of the related 1967 GDCs beginning in Section 3.1.2 and as detailed in other sections specific to systems and detailed analysis.

The GDCs are discussed in sections. Sections 3.1.2 through 3.1.10 are grouped as presented in the proposed 10 CFR Part 50 Appendix A 1967 Groups. Note that where later editions of the GDC were implemented in the DCPP licensing basis, they have been incorporated in the Sections 3.1.2 through 3.1.10 related to the 1967 Group. Table 3.1-1, at the end of this section, provides a quick reference to the current license basis applicability of the GDCs. Although regulatory correspondence often refers to the 1971 criteria because NRC review is typically based on the current GDCs at the time, the DCPP licensing basis remains the 1967 GDCs except as follows:

GDC 3, 1971 - Fire Protection
GDC 4, 1987 Revision – Environmental and Missile Design Basis (Leak-Before-Break)
GDC 10, 1971 - Reactor Design
GDC 11, 1971 - Reactor Inherent Protection
GDC 12, 1971 - Suppression of Reactor Power Oscillations
GDC 17, 1971 - Electric Power Systems
GDC 18, 1971 - Inspection and Testing of Electric Power Systems
GDC 19, 1999 - Control Room Habitability (Accident Dose)
GDC 25, 1971 - Protection System Requirements for Reactivity Control Malfunctions
GDC 26, 1971 - Reactivity Control System Redundancy and Capability
GDC 28, 1971 - Reactivity Limits
GDC 29, 1971 - Protection Against Anticipated Operational Occurrences
GDC 54, 1971 - Piping Systems Penetrating Containment
GDC 55, 1971 - Reactor Coolant Pressure Boundary Penetrating Containment
GDC 56, 1971 - Primary Containment Isolation
GDC 57, 1971 - Closed System Isolation Valves

Table 3.1-2 provides a matrix listing of the 1971 criteria to related 1967 criteria.

Submittal of the FSAR using Regulatory Guide 1.70, Revision 1 format and content was expected by the NRC as part of the initial DCPP licensing process, even though the NRC acknowledged in NUREG-0675 (SER-00) that the DCPP design basis was the 1967 GDCs. DCPP included, as part of the original FSAR, Appendix 3.1A, "AEC General Design Criteria – 1971", which was a summary of the extent to which the original DCPP principal design features (the 1967 GDCs plus additional design features) for plant structures, systems and components (SSCs) conformed to the intent of the AEC "General Design Criteria for Nuclear Power Plants" published in February 1971 as Appendix A to 10 CFR Part 50 (i.e., the 1971 GDCs).

Appendix 3.1A provides a summary discussion for each criterion of how the DCPP principal design features (the 1967 GDCs plus additional design features) conform to the intent of the 1971 GDCs. Any exceptions to the 1971 GDCs that DCPP identified and the NRC approved in writing resulting from earlier DCPP design or construction commitments are identified in the discussion of the corresponding criterion in Appendix 3.1A.

The summary provided in the original FSAR in Appendix 3.1A was reviewed by the NRC to conclude that DCPP's design conformed to the intent of the 1971 GDCs. The degree to which the DCPP design (the 1967 GDCs plus additional design features) conforms to the intent of the 1971 GDCs, as summarized in Appendix 3.1A, establishes additional DCPP licensing basis which must be reviewed when evaluating facility changes.

3.1.1 SINGLE FAILURE CRITERIA

Each of the engineered safety features (ESFs) is designed to tolerate a single failure during the period of recovery following an accident without loss of its protective function. This period of recovery consists of two segments: the short-term period and the long-term period. During the short-term period, the single failure is limited to a failure of an active component to complete its function as required. Should the single failure occur during the long-term period rather than the short-term, the related engineered safety system is designed to tolerate an active failure or a passive failure without loss of its protective function.

3.1.1.1 Definitions

The following definitions apply to the single failure criterion and to the GDCs:

(1) Active Failure - The failure of a powered component, such as a piece of mechanical equipment, component of the electrical supply system, or instrumentation and control equipment, to act on command to perform its design function.

Examples include the failure of a (MOV) to move to its correct position, the failure of an electrical breaker or relay to respond, the failure of a pump, fan, or (DG) to start, etc.

(2) Passive Failure - The structural failure of a static component that limits the component's effectiveness in carrying out its design function. When applied to a fluid system, this means a break in the pressure boundary resulting in abnormal leakage not exceeding 50 gpm for 30 minutes. Such leak rates are assumed for residual heat removal (RHR) pump seal failure.

(3) Accident - Any natural or accidental event of infrequent occurrence and its related consequences which affect the plant operation and require the use of ESFs. Such events, analyzed independently and not assumed to occur simultaneously, include the loss-of-coolant accident (LOCA), steam line ruptures, steam generator tube ruptures, etc. A loss of normal (main generator) and all offsite ac power may be an isolated occurrence or may be concurrent with any event requiring ESF use if the event should cause turbine trip and grid failure.

(4) Short-term - The first 24 hours following the incident, during which time automatic actions are performed, system responses are checked, type of incident is identified, and preparations for long-term recovery operation are made.

(5) Long-term - The remainder of the recovery period following the short-term. In comparison with the short-term where the main concern is to remain within NRC specified site criteria, the long-term period of operation involves bringing the plant to cold shutdown conditions.

(6) Recovery Period - The time necessary to bring the plant to a cold shutdown. The recovery period is the sum of the short- and long-term periods defined above.

3.1.1.2 Applicability

The single failure criterion applies to the following safety-related fluid systems discussed in this UFSAR:

System	Section
Containment Isolation Systems	6.2.4
Emergency Core Cooling System	6.3
Containment Spray System	6.2.2
Containment Fan Coolers	6.2
Auxiliary Feedwater (AFW) System	6.5
Auxiliary Saltwater (ASW) System	9.2.7

Component Cooling Water System	9.2.2
Chemical and Volume Control System (Boric Acid Injection Portion)	9.3.4
Diesel Fuel Oil System	9.5.4

3.1.2 OVERALL PLANT REQUIREMENTS

GDCs related to the overall plant are presented in this section. A summary discussion of conformance follows each 1967 criterion in the following Sections, 3.1.2 through 3.1.10. The detailed conformance of the GDCs are further discussed in the other sections specific to systems and analyses.

3.1.2.1 Criterion 1, 1967 - Quality Standards (Category A)

Those systems and components of reactor facilities that are essential to the prevention of accidents which could affect the public health and safety, or mitigation of their consequences, shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes or standards on design, materials, fabrication, and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to ensure a quality product in keeping with the safety functions, they shall be supplemented or modified as necessary. Quality assurance (QA) programs, test procedures, and inspection acceptance levels to be used shall be identified. A showing of sufficiency and applicability of codes, standards, QA programs, test procedures, and inspection acceptance levels used is required.

Discussion

All systems and components of DCPP Unit 1 and Unit 2 are classified according to their importance in the prevention and mitigation of accidents. Those items vital to safe shutdown and isolation of the reactor, or whose failure might cause or increase the severity of a LOCA, or result in an uncontrolled release of excessive amounts of radioactivity, are designated PG&E Design Class I. Those items important to the reactor operation, but not essential to safe shutdown and isolation of the reactor or control of the release of substantial amounts of radioactivity, are designated PG&E Design Class II. Those items not related to reactor operation or safety are designated PG&E Design Class III.

PG&E Design Class I systems and components are essential to the protection of the health and safety of the public. Consequently, they are designed, fabricated, inspected, erected, and the materials selected to the applicable provisions of recognized codes, good nuclear practice, and to quality standards that reflect their importance. Discussions of applicable codes and standards as well as code classes are given in Section 3.2 for the major items and components. The QA program conforms with the requirements of 10 CFR Part 50 Appendix B, Quality Assurance Criteria for Nuclear Power Plants. Details of

the QA program are provided in the Diablo Canyon Quality Assurance Program Description.

3.1.2.2 Criterion 2, 1967 - Performance Standards (Category A)

Those systems and components of reactor facilities that are essential to the prevention of accidents which could affect the public health and safety, or to mitigation of their consequences, shall be designed, fabricated, and erected to performance standards that will enable the facility to withstand, without loss of the capability to protect the public, the additional forces that might be imposed by natural phenomena such as earthquakes, tornadoes, flooding conditions, winds, ice, and other local site effects. The design bases so established shall reflect (a) appropriate consideration of the most severe of these natural phenomena that have been recorded for the site and the surrounding area, and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design.

Discussion

All systems and components designated PG&E Design Class I are designed so that there is no loss of function for ground acceleration associated with two times the Design Earthquake (DE) acting in the horizontal and vertical directions simultaneously. The ESF is included in the above. The working stresses for Class I items are kept within code allowable values for the DE. Similarly, measures are taken in the plant design to protect against possible effects of tsunamis, lightning storms, strong winds, and other natural phenomena.

The site characteristics are discussed in Chapter 2. Wind design criteria and flood design criteria are found in Sections 3.3 and 3.4, respectively.

3.1.2.3 Criterion 3, 1971 - Fire Protection

SSCs important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat resistant materials shall be used wherever practical throughout the unit, particularly in locations such as the containment and control room. Fire detection and fighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on SSCs important to safety. Firefighting systems shall be designed to assure that their rupture or inadvertent operation does not significantly impair the safety capability of these SSCs.

Discussion

GDC 3 (1971) is invoked by 10 CFR 50.48, Fire Protection. The fire protection program for DCPP satisfies the requirements of GDC 3 (1971) by complying with 10 CFR 50.48(a) and (c) as stipulated by Operating License Conditions for 2.C(5) and

2.C(4) for Units 1 and 2, respectively. Federal Regulation 10 CFR 50.48(c) endorses, with exceptions, NFPA 805, Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants (2001).

The probability and effect of fires and explosions is minimized by identifying the fire protection systems and features required to achieve the nuclear safety performance criteria in Section 1.5 of NFPA 805 (2001). Once the determination was made that the fire protection system or feature was required to achieve this performance criteria, the design and qualification of that system or feature was reviewed to ensure that any applicable requirements of NFPA 805, Chapter 3 are met. This process satisfies the GDC 3 requirement to design and locate SSCs important to safety in order to minimize the probability and effects of fires and explosions.

Documenting the basis for compliance for each of the fire protection program and design elements given in Chapter 3 of NFPA 805 is required by 10 CFR 50.48(c). The following sections of Chapter 3 of NFPA 805 support the use of non-combustible and heat resistant materials as required by GDC 3. Specifically:

- Section 3.3.2: Structural
- Section 3.3.3: Interior Finishes
- Section 3.3.4: Insulation Materials
- Section 3.11.4: Through Penetration Fire Stops

The capacity and capability of fire detection and fighting systems provided and designed to minimize the adverse effects of fires on structures, systems, and components important to safety are verified by first identifying the fire protection systems and features required to achieve the nuclear safety performance criteria in Section 1.5 of NFPA 805. Once the determination was made that a fire protection system or feature was required to achieve the performance criteria of Section 1.5, its design and qualification was reviewed to ensure that any applicable requirements of NFPA 805, Chapter 3 were met. This process satisfies the GDC 3 requirement to provide fire detection and fighting systems of appropriate capacity and capability to minimize the adverse effects of fires on structures, systems, and components important to safety.

It was assured that the rupture or inadvertent operation of firefighting systems does not significantly impair the safety capability of these structures, systems, and components through documentation of the basis of compliance for each of the fire protection program and design elements with the requirements given in Chapter 3 of NFPA 805 (2001). The following sections of Chapter 3 of NFPA 805 address the design of firefighting systems. Specifically:

- Section 3.4: Industrial Fire Brigade
- Section 3.5: Water Supply
- Section 3.6: Standpipe and Hose Stations
- Section 3.7: Fire Extinguishers
- Section 3.8: Fire Alarm and Detection Systems

- Section 3.9: Automatic and Manual Water-Based Fire Suppression Systems
- Section 3.10: Gaseous Fire Suppression Systems

The process satisfies the GDC 3 requirement to design firefighting systems to ensure that their rupture or inadvertent operation does not significantly impair the safety capability of structures, systems, and components important to safety.

3.1.2.4 Criterion 4, 1967 - Sharing of Systems (Category A)

Reactor facilities shall not share systems or components unless it is shown safety is not impaired by the sharing.

Discussion

Those systems or components that are shared, either between the two units or functionally within a single unit, are designed in such a manner that plant safety is not impaired by the sharing. A list of shared systems and components is provided in Section 1.2.2.10.

3.1.2.5 Criterion 5, 1967 - Records Requirements (Category A)

Records of the design, fabrication, and construction of essential components of the plant shall be maintained by the reactor operator or under its control throughout the life of the reactor.

Discussion

Records of the design, fabrication, construction, and testing of PG&E Design Class I components of the plant will be maintained by Pacific Gas and Electric Company (PG&E) or kept under its control throughout the life of the plant. The Diablo Canyon Quality Assurance Program Description describes the procedures for keeping these records. Operating records to be maintained throughout the life of the plant are described in Chapter 13.

3.1.3 PROTECTION BY MULTIPLE FISSION PRODUCT BARRIERS

GDCs related to prevention of fission product release are presented in this section. A discussion of conformance follows each criterion.

3.1.3.1 Criterion 6, 1967 - Reactor Core Design (Category A)

The reactor core shall be designed to function throughout its design lifetime, without exceeding acceptable fuel damage limits which have been stipulated and justified. The core design, together with reliable process and decay heat removal systems, shall provide for this capability under all expected conditions of normal operation with appropriate margins for uncertainties and for transient situations which can be anticipated, including

the effects of the loss of power to recirculation pumps, tripping out of a turbine generator set, isolation of the reactor from its primary heat sink, and loss of all offsite power.

Discussion

Each reactor core with its related control and protection systems is designed to function throughout its design lifetime without exceeding acceptable fuel damage limits. Core design, together with reliable process and decay heat removal systems, provides for this capability under all expected conditions of normal operation with appropriate margins for uncertainties and anticipated transient situations, including the effects of the loss of reactor coolant flow, trip of the turbine-generator, loss of normal feedwater, and loss of offsite power.

The reactor control and protection instrumentation systems are designed to initiate a reactor shutdown for any anticipated combination of plant conditions when necessary to assure a minimum departure from nucleate boiling ratio (DNBR) equal to or greater than the applicable limit value (refer to Sections 4.4.4.1 and 4.4.3.3) and fuel center temperatures below the melting point of UO_2.

Criterion 6, 1967 is applicable to the process and decay heat removal systems such as the reactor coolant system (RCS), RHR system, and reactor core control and protection systems. GDC 10, 1971 supersedes Criterion 6, 1967 with respect to the design of the reactor core. Refer to Section 3.1.3.1.1 for further discussion.

3.1.3.1.1 Criterion 10, 1971 - Reactor Design

The reactor core and associated coolant, control, and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

Discussion

Each reactor core with its related control and protection systems is designed to function throughout its design lifetime without exceeding acceptable fuel damage limits. Core design, together with reliable process and decay heat removal systems, provides for this capability under all expected conditions of normal operation with appropriate margins for uncertainties and anticipated transient situations, including the effects of the loss of reactor coolant flow, trip of the turbine-generator, loss of normal feedwater, and loss of offsite power.

Chapter 4 discusses the design bases and design evaluation of reactor components. The details of the control and protection instrumentation systems' design and logic are discussed in Chapter 7. This information supports the accident analyses presented in Chapter 15.

GDC 10, 1971 supersedes GDC 6, 1967 with respect to the design of the reactor core.

3.1.3.2 Criterion 7, 1967 - Suppression of Power Oscillations (Category B)

Criterion 7, 1967 is no longer part of the DCPP license basis and has been replaced by GDC 12, 1971.

3.1.3.2.1 Criterion 12, 1971 - Suppression of Reactor Power Oscillations

The reactor core and associated coolant, control and protection systems shall be designed to assure that power oscillations which can result in conditions exceeding specified acceptable fuel design limits are not possible or can be reliably and readily detected and suppressed.

Discussion

The DCPP Unit 1 and Unit 2 designs include provisions to detect and control those power oscillations that might exceed acceptable fuel design limits during operation.

Oscillations in total core power, from whatever cause, are readily detected by loop temperature sensors and by nuclear instrumentation. Unacceptable power increases result in a reactor trip, thus preserving margins to fuel design limits.

The core is designed so that diametral and azimuthal oscillations due to spatial xenon effects are self-damping, and no operator action or control action is required to suppress them. Additionally, thermohydraulic oscillations do not occur under Condition I and Condition II events for Westinghouse pressurized water reactors (PWRs).

The stability of the cores against xenon-induced power oscillations and the functional requirements of instrumentation for monitoring and measuring core power distributions are discussed in Section 4.3. Thermohydraulic stability characteristics are discussed in Section 4.4. Details of the instrumentation design and logic are discussed in Chapter 7.

3.1.3.3 Criterion 8, 1967 - Overall Power Coefficient (Category B)

Criterion 8, 1967 is no longer part of the DCPP license basis and has been replaced by GDC 11, 1971.

3.1.3.3.1 Criterion 11, 1971 - Reactor Inherent Protection

The reactor core and associated coolant systems shall be designed so that in the power operating range the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity.

Discussion

A negative reactivity coefficient in the power operating range is a basic feature of each design. Prompt compensatory reactivity feedback effects are ensured when each reactor is critical by the negative fuel temperature effect (Doppler effect) and by the operational limit on moderator temperature coefficient of reactivity. The negative Doppler coefficient of reactivity is ensured by the inherent design using low-enrichment fuel. The limits on moderator temperature coefficient of reactivity are ensured by administratively controlling the dissolved neutron absorber concentration and control rod position.

These reactivity coefficients are discussed in Section 4.3.

3.1.3.4 Criterion 9, 1967 - Reactor Coolant Pressure Boundary (Category A)

The reactor coolant pressure boundary (RCPB) shall be designed and constructed so as to have an exceedingly low probability of gross rupture or significant leakage throughout its design lifetime.

Discussion

The RCS boundaries are designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation, including all anticipated transients, and to maintain the stresses within applicable stress limits. The RCPB materials selection and fabrication techniques ensure a low probability of gross rupture or significant leakage. Additional details are presented in Section 5.2.

In addition to the loads imposed on the system under normal operating conditions, abnormal loading conditions, such as seismic loading and pipe rupture, are also considered, as discussed in Sections 3.6 and 3.7. The systems are protected from overpressure by means of pressure-relieving devices as required by applicable codes.

Means are provided to detect significant uncontrolled leakage from either RCPB with indication in the control room as discussed in Section 5.2. Each RCS boundary has provisions for inspection, testing, and surveillance of critical areas to assess the structural and leaktight integrity. The details of these provisions are given in Section 5.2. For each reactor vessel, a material surveillance program conforming to applicable codes is provided. Additional details are provided in Section 5.4.

The materials of construction of the pressure-retaining boundary of the RCS are protected by control of coolant chemistry from corrosion that might otherwise reduce the system structural integrity during its service lifetime. In addition, secondary side water chemistry is controlled to minimize steam generator tube degradation and protect the RCPB as discussed in Sections 10.4.6, 10.4.8 and 10.4.9.

3.1.3.5 Criterion 10, 1967 - Containment (Category A)

Containment shall be provided. The containment structure shall be designed to sustain the initial effects of gross equipment failures, such as a large coolant boundary break, without loss of required integrity and, together with other ESFs as may be necessary, to retain for as long as the situation requires the functional capability to protect the public.

Discussion

The reactor containment is a reinforced concrete structure with a steel liner that is capable of withstanding the pressure buildup resulting from a major LOCA.

The reactor containment, together with the containment spray system (CSS) and the containment fan cooler system, are described in Chapter 6. The structural design criteria are presented in Chapter 3. The consequences of major LOCAs are analyzed in Chapter 15.

3.1.4 NUCLEAR AND RADIATION CONTROLS

GDCs related to nuclear and radiation controls are presented in this section. A discussion of conformance follows each criterion.

3.1.4.1 Criterion 11, 1967 - Control Room (Category B)

The facility shall be provided with a control room from which actions to maintain safe operational status of the plant can be controlled. Adequate radiation protection shall be provided to permit access, even under accident conditions, to equipment in the control room or other areas as necessary to shut down and maintain safe control of the facility without radiation exposures of personnel in excess of 10 CFR Part 20 limits. It shall be possible to shut the reactor down and maintain it in a safe condition if access to the control room is lost due to fire or other cause.

Discussion

The plant is provided with a centralized control room common to both units that contains the controls and instrumentation necessary for operation of both units under normal and accident conditions.

The control room is continuously occupied by the operating personnel under all operating and accident conditions. Sufficient shielding, distance, and containment are provided to ensure that the control room personnel are not subject to radiation exposures in excess of 10 CFR Part 20 limits. Adequate radiation protection is provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem, total effective dose equivalent (TEDE) for the duration of the accident to meet the requirements of GDC 19, 1999. Control room

shielding is described in Section 12.1, and post-accident control room exposures are described in Section 15.5.

The control room ventilation system (CRVS) is described in Section 9.4.1. It consists of a dual system providing a large percentage of recirculated air. In the event of fire in the control room, provisions are made for 100 percent outside air makeup operation. In the event of airborne toxic gas outside the control room, provisions are made for operation with 100 percent recirculated air. In the event of airborne radioactivity outside the control room, provisions are made to isolate and pressurize the control room.

The risk of fire is minimized by the use of noncombustible and fire retardant materials in the construction of the control room and its furnishings. Fire fighting equipment is located in the control room, and the use and storage of combustible supplies are minimized.

Provisions are made to enable plant operators to readily shut down and maintain the plant at safe shutdown (Mode 3) by means of controls located outside the control room.

3.1.4.1.1 Criterion 19, 1999 – Control Room

A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in a safe condition under accident conditions, including LOCAs. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident. Holders of operating licenses using an alternative source term under 10 CFR 50.67 shall meet the requirements of this criterion, except that with regard to control room access and occupancy, adequate radiation protection shall be provided to ensure that radiation exposures shall not exceed 0.05 Sv (5 rem) total effect dose equivalent (TEDE) as defined in 10 CFR 50.2 for the duration of the accident.

Discussion

Adequate radiation protection is provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE for the duration of the accident to meet the requirements of GDC 19, 1999. The DCPP design includes use of alternative source terms in accordance with 10 CFR 50.67, and Regulatory Guide 1.183, July 2000. Refer to Sections 6.4 and 15.5.

3.1.4.2 Criterion 12, 1967 - Instrumentation and Control Systems (Category B)

Instrumentation and controls shall be provided as required to monitor and maintain variables within prescribed operating ranges.

Discussion

Reactor, control rod, boron concentration, pressurizer pressure and level, feedwater, steam dump, and turbine instrumentation and controls are provided to monitor and maintain variables within prescribed operating ranges. Reactor protection systems that receive plant instrumentation signals and automatically actuate alarms, inhibit control rod withdrawal, initiate load cutback, and/or trip the reactors as prescribed limits are approached or reached are also provided. These systems are discussed in Chapter 7.

3.1.4.3 Criterion 13, 1967 - Fission Process Monitors and Controls (Category B)

Means shall be provided for monitoring and maintaining control over the fission process throughout core life and for all conditions that can reasonably be anticipated to cause variations in reactivity of the core, such as indication of position of control rods and concentration of soluble reactivity control poisons.

Discussion

Control over the fission process for each reactor will be maintained throughout the core life by the combination of control rods and chemical shim (boration). Adequate indication of the core reactivity status is provided by the nuclear instrumentation system (NIS). Periodic samples of boron concentration and continuous indication of RCS temperature and control rod position provide additional fission process information.

During operation, the shutdown rod banks are fully withdrawn. The control rod system automatically maintains a programmed average reactor temperature compensating for reactivity effects associated with scheduled and transient load changes. The shutdown rod banks along with the control banks are designed to shut down the reactor under conditions of normal operation and anticipated operational occurrences.

The boron system maintains the reactor in the cold shutdown state independent of the position of the control rods and can compensate for all xenon burnout transients.

The reactivity control and NIS are discussed in Chapters 4 and 7.

3.1.4.4 Criterion 14, 1967 - Core Protection Systems (Category B)

Core protection systems, together with associated equipment, shall be designed to act automatically to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits.

Discussion

Operational limits for the core protection systems are defined by analyses of all plant operating and fault conditions requiring rapid rod insertion to prevent or limit core damage. The protection system design bases for all anticipated transients or faults are:

(1) Minimum DNBR shall be the applicable limit value (refer to Sections 4.4.4.1 and 4.4.3.3)

(2) Cladding strain on the fuel element shall not exceed 1 percent

(3) Center melt shall not occur in the fuel elements

A region of permissible core operation is defined in terms of power, axial power distribution, and coolant flow and temperature. The protection systems monitor these process variables (as well as many other process and plant variables). If the region limits are approached during operation, the protection systems automatically actuate alarms, initiate load runback, prevent control rod withdrawal, and/or trip the reactor. Operation within the permissible region and complete core protection is ensured by the overtemperature ΔT and overpower ΔT reactor trips over the system pressure range defined by the pressurizer high-pressure and pressurizer low-pressure reactor trips, provided that the transient is slow with respect to piping delays from the core to the temperature sensors. High neutron flux and low coolant flow reactor trips provide core protection against transients that are faster than the ΔT response. Also, thermal transients are anticipated and avoided by reactor trips actuated by turbine trip and primary coolant pump circuit breaker position. The protection systems are discussed in Section 7.2.

3.1.4.5 Criterion 15, 1967 - Engineered Safety Features Protection Systems (Category B)

Protection systems shall be provided for sensing accident situations and initiating the operation of necessary ESFs.

Discussion

An important safety function of the reactor protection system is that of processing signals used for ESF actuation and generation of the actuation demand. ESFs are discussed in Chapter 6 and Section 7.3.

3.1.4.6 Criterion 16, 1967 - Monitoring Reactor Coolant Pressure Boundary (Category B)

Means shall be provided for monitoring the RCPB to detect leakage.

Discussion

All RCS components are designed, fabricated, inspected, and tested in conformance with the ASME Boiler and Pressure Vessel Code.

Leakage is detected by an increase in the amount of makeup water required to maintain a normal level in the pressurizer. The reactor vessel closure joint is provided with a temperature monitored leakoff between double gaskets.

Leakage into the reactor containment is drained to the reactor building sump where the level is monitored.

Leakage is also detected by measuring the airborne activity and quantity of the condensate drained from each reactor containment fan cooler unit.

These leakage detection methods are described in detail in Section 5.2.

3.1.4.7 Criterion 17, 1967 - Monitoring Radioactivity Releases (Category B)

Means shall be provided for monitoring the containment atmosphere, the facility effluent discharge paths, and the facility environs for radioactivity that could be released from normal operations, from anticipated transients and from accident conditions.

Discussion

The containment atmosphere, the plant vents, and the liquid and gaseous waste systems effluent discharge paths are monitored for radioactivity concentrations during all modes of operations. The monitoring systems are described in Section 11.4. The offsite radiological monitoring program is described in Section 11.6.

Waste handling systems are incorporated in each facility design for processing and/or retention of normal operation radioactive wastes with appropriate controls and monitors to ensure that releases do not exceed the limits of 10 CFR Part 20. The facilities are also designed with provisions to monitor radioactivity release during accidents and to prevent releases from causing exposures in excess of the guideline levels specified in 10 CFR 100.11 (for tank rupture accidents) or 10 CFR 50.67 (for accidents analyzed using AST methodology).

3.1.4.8 Criterion 18, 1967 - Monitoring Fuel and Waste Storage (Category B)

Monitoring and alarm instrumentation shall be provided for fuel and waste storage and handling areas for conditions that might contribute to loss of continuity in decay heat removal and to radiation exposures.

Discussion

The fuel and waste storage and handling areas are provided with monitoring and alarm systems for radioactivity, and the plant vents are monitored for radioactivity during all operations. The monitoring systems are described in Section 11.4.

The spent fuel pool (SFP) cooling system is equipped with adequate instrumentation for normal operation. Water temperatures in the pool and at the outlet of the heat exchanger are indicated locally, and high pool temperature is alarmed in the control room. The SFP cooling system is described in Section 9.1.

3.1.5 RELIABILITY AND TESTABILITY OF PROTECTION SYSTEMS

GDCs related to reliability and testing of protection systems are presented in this section. A discussion of conformance follows each criterion.

3.1.5.1 Criterion 19, 1967 - Protection Systems Reliability (Category B)

Protection systems shall be designed for high functional reliability and in-service testability commensurate with the safety functions to be performed.

Discussion

The protection systems are designed for high functional reliability and inservice testability. Each design employs redundant logic trains and measurement and equipment diversity. Sufficient redundancy is provided to enable individual end-to-end channel tests with each reactor at power without compromise of the protective function. Built-in semiautomatic testers provide means to test the majority of system components very rapidly. The protection systems are described in Section 7.2.

3.1.5.2 Criterion 20, 1967 - Protection Systems Redundancy and Independence (Category B)

Redundancy and independence designed into protection systems shall be sufficient to assure that no single failure or removal from service of any component or channel of a system will result in loss of the protection function. The redundancy provided shall include, as a minimum, two channels of protection for each protection function to be served. Different principles shall be used where necessary to achieve true independence of redundant instrumentation components.

Discussion

Sufficient redundancy and independence is designed into the protection systems to ensure that no single failure nor removal from service of any component or channel of a system will result in loss of the protection function. The minimum redundancy is exceeded in each protection function that is active with the reactor at power.

Functional diversity and consequential location diversity are designed into the systems. DCPP uses the Westinghouse Eagle 21 Process Protection System, which is discussed in detail in Section 7.2.

3.1.5.2.1 Criterion 29, 1971 - Protection Against Anticipated Operational Occurrences

The protection and reactivity control systems shall be designed to assure an extremely high probability of accomplishing their safety functions in the event of anticipated operational occurrences.

Discussion

If power to the stationary gripper coils of the control rod drive mechanisms (CRDMs) is cut off, the combined weight of the drive rod assembly and the rod cluster control assembly (RCCA) is sufficient to move latches out of the drive rod assembly groove. The RCCA falls by gravity into the core.

3.1.5.3 Criterion 21, 1967 - Single Failure Definition (Category B)

Multiple failures resulting from a single event shall be treated as a single failure.

Discussion

When evaluating the protection systems, the ESF, and their support systems, multiple failures resulting from a single event are treated as a single failure. The ability of each system to perform its function with a single failure is discussed in the sections describing the individual systems. The single failure criterion is discussed further at the beginning of Section 3.1.1.

3.1.5.4 Criterion 22, 1967 - Separation of Protection and Control Instrumentation Systems (Category B)

Protection systems shall be separated from control instrumentation systems to the extent that failure or removal from service of any control instrumentation system component or channel, or of those common to control instrumentation and protection circuitry, leaves intact a system satisfying all requirements for the protection channels.

Discussion

The protection systems comply with the requirements of IEEE 279-1971, Criteria for Protection Systems for Nuclear Power Generating Stations, although construction permits for the DCPP units were issued prior to issuance of the 1971 version of the standard. Each protection system is separate and distinct from the respective control systems. The control system is dependent on the protection system in that control signals are derived from protection system measurements, where applicable. These signals are transferred to the control system by isolation amplifiers that are classified as protection system components. The adequacy of system isolation has been verified by testing or analysis under conditions of all postulated credible faults. Isolation devices that serve to protect PG&E Instrument Class IA instrument loops have all been tested. For certain applications

where the isolator is protecting an PG&E Instrument Class IB instrument loop, and the isolation device is a simple linear device with no complex failure modes, the analysis was used to verify the adequacy of the isolation device. The failure or removal of any single control instrumentation system component or channel, or of those common to the control instrumentation system component or channel and protection circuitry, leaves intact a system that satisfies the requirements of the protection system. The protection systems and control systems are discussed in Chapter 7.

3.1.5.5 Criterion 23, 1967 - Protection Against Multiple Disability of Protection Systems (Category B)

The effects of adverse conditions to which redundant channels or protection systems might be exposed in common, either under normal conditions or those of an accident, shall not result in loss of the protection function.

Discussion

Physical separation and electrical isolation of redundant channels and subsystems, functional diversity of subsystems, and safe failure modes are employed in design of the reactors as defenses against functional failure through exposure to common causative factors. The redundant logic trains, reactor trip breakers, and ESF actuation devices are physically separated and electrically isolated. Physically separate channel trays, conduits, and penetrations are maintained upstream from the logic elements of each train.

The protection system components have been qualified by testing under extremes of the normal environment. In addition, components are tested and qualified according to individual requirements for the adverse environment specific to their location that might result from postulated accident conditions. The protection systems are discussed in Section 7.2.

3.1.5.6 Criterion 24, 1967 - Emergency Power for Protection Systems (Category B)

In the event of loss of all offsite power, sufficient alternate sources of power shall be provided to permit the required functioning of the protection systems.

Discussion

The facility is supplied with normal and standby emergency power to provide for the required functioning of the protection systems.

In the event of loss of normal power, emergency ac power is supplied by six DGs, as described in Chapter 8. Only four diesels are required to supply the power requirements with one unit in an accident situation and to bring the other to the shutdown condition from full power.

The instrumentation and controls portions of the protection systems are supplied initially from the station batteries and subsequently from the emergency DGs. A single failure of any one component will not prevent the required functioning of protection systems.

3.1.5.7 Criterion 25, 1967 - Demonstration of Functional Operability of Protection Systems (Category B)

Means shall be included for testing protection systems while the reactor is in operation to demonstrate that no failure or loss of redundancy has occurred.

Discussion

All reactor protection channels employed in power operation are sufficiently redundant so that individual testing and calibration, without degradation of the protection function or violation of the single failure criterion, can be performed with the reactors at power. Such testing discloses failures or reduction in redundancy that may have occurred. Removal from service of any single channel or component does not result in loss of minimum required redundancy. For example, a two-out-of-three function becomes a one-out-of-two function when one channel is removed.

Semiautomatic testers are built into each of the two logic trains in the reactor protection system. These testers have the capability of testing the major part of the protection system very rapidly while the reactor is at power. Between tests, the testers continuously monitor a number of internal protection system points, including the associated power supplies and fuses. Outputs of the monitors are logically processed to provide alarms for failures in one train and automatic reactor trip for failures in both trains. A self-testing provision is designed into each tester. Additional details can be found in Section 7.2.

3.1.5.8 Criterion 26, 1967 - Protection Systems Fail-Safe Design (Category B)

The reactor protection systems shall be designed to fail into a safe state or into a state established as tolerable on a defined basis if conditions such as disconnection of the system, loss of energy (e.g., electric power, instrument air), or adverse environments (e.g., extreme heat or cold, fire, steam, or water) are experienced.

Discussion

The protection systems are designed with due consideration of the most probable failure modes of the components under various perturbations of the environment and energy sources. Each reactor trip channel is designed on the de-energize-to-trip principle, so loss of power, disconnection, open channel faults, and the majority of internal channel short circuit faults cause the channel to go into its tripped mode. Additional defenses against loss of function are discussed under Criterion 23. The protection system details can be found in Section 7.2.

3.1.6 REACTIVITY CONTROL

GDCs related to reactivity control are presented in this section. A discussion of conformance follows each criterion.

3.1.6.1 Criterion 27, 1967 - Redundancy of Reactivity Control (Category A)

Criterion 27, 1967 is no longer part of the DCPP license basis and has been replaced by GDC 26, 1971.

3.1.6.1.1 Criterion 26, 1971 - Reactivity Control System Redundancy and Capability

Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margins for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions.

Discussion

Two independent reactivity control systems of different design principles are provided for each reactor. These are RCCAs and chemical shim (boration). The boron system is capable of maintaining the reactor in a subcritical status under cold shutdown conditions and is capable of controlling the rate of reactivity change resulting from planned normal power changes including xenon burnout. The rod control system maintains a programmed average reactor temperature with scheduled and transient load changes. The RCCAs are inserted into the core by the force of gravity.

The RCCA system is capable of making and holding the core subcritical from all operating and hot shutdown conditions sufficiently fast to prevent exceeding acceptable fuel damage limits. The chemical shim control is also capable of making and holding the core subcritical, but at a slower rate, and is not employed as a means of compensating for rapid reactivity transients. The RCCA system is, therefore, used in protecting each core from fast transients. Details of the construction of the RCCA are included in Section 4.2, with the operation discussed in Chapter 7. The means of controlling the boric acid concentration is described in Section 9.3.4.

Criterion 26, 1971 supplements Criterion 28, 1967, with respect to the boron system, specifically for the ability of the boron system to hold the reactor core subcritical under cold conditions. Refer to Section 3.1.6.2 for further discussion.

3.1.6.2 Criterion 28, 1967 - Reactivity Hot Shutdown Capability (Category A)

At least two of the reactivity control systems provided shall be capable of independently making and holding the core subcritical from any hot standby or hot operating condition, including those resulting from power changes, sufficiently fast to prevent exceeding acceptable fuel damage limits.

Discussion

The chemical shim control is capable of making and holding the core subcritical, but at a slower rate, and is not employed as a means of compensating for rapid reactivity transients. Details of the operation and effectiveness of this system is included in Chapters 4 and 9.

Criterion 28, 1967 is applicable with respect to the boron system only. Criterion 26, 1971 supplements Criterion 28, 1967 specifically for the ability of the boron system to hold the reactor core subcritical under cold conditions; and Criterion 26, 1971 supersedes Criterion 28, 1967 with respect to the design of the RCCA system. Refer to Section 3.1.6.1.1 for further discussion.

3.1.6.3 Criterion 29, 1967 - Reactivity Shutdown Capability (Category A)

At least one of the reactivity control systems provided shall be capable of making the core subcritical under any condition (including anticipated operational transients) sufficiently fast to prevent exceeding acceptable fuel damage limits. Shutdown margins greater than the maximum worth of the most effective control rod when fully withdrawn shall be provided.

Discussion

As discussed in Chapter 4, the reactors may be made subcritical by the RCCA systems sufficiently fast to prevent exceeding acceptable fuel damage limits, under all anticipated conditions, with the most reactive RCCA fully withdrawn.

3.1.6.4 Criterion 30, 1967 - Reactivity Holddown Capability (Category B)

At least one of the reactivity control systems provided shall be capable of making and holding the core subcritical under any conditions with appropriate margins for contingencies.

Discussion

The boron reactivity (chemical shim) control systems are capable of making and holding the core subcritical under any anticipated condition and with appropriate margin for contingencies. These means are discussed in detail in Chapters 4 and 9. Normal reactivity shutdown capability is provided by rapid control rod insertion. The chemical shim

control system permits the necessary shutdown margin to be maintained during long-term xenon decay and plant cooldown.

3.1.6.5 Criterion 31, 1967 - Reactivity Control Systems Malfunction (Category B)

The reactivity control systems shall be capable of sustaining any single malfunction, such as, unplanned continuous withdrawal (not ejection) of a control rod, without causing a reactivity transient which could result in exceeding acceptable fuel damage limits.

Discussion

Reactor shutdown by RCCA insertion is completely independent of the normal control function, since the trip breakers interrupt power to the drive mechanisms regardless of existing control signals. The protection system is designed to limit reactivity transients so that DNBR will exceed the applicable limit value (refer to Sections 4.4.4.1 and 4.4.3.3) for any single malfunction in either reactor control system.

The analysis presented in Chapter 15 shows that for postulated dilution during refueling, startup, or manual or automatic operation at power, the operator has ample time to determine the cause of dilution, terminate the source of dilution, and initiate reboration before the shutdown margin is lost. The facility reactivity control systems are discussed further in Chapter 7, and analyses of the effects of the other possible malfunctions are discussed in Chapter 15. The analyses show that acceptable fuel damage limits are not exceeded in the event of a single malfunction of either system.

3.1.6.5.1 Criterion 25, 1971 - Protection System Requirements for Reactivity Control Malfunctions

The protection system shall be designed to assure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods.

Discussion

Reactivity addition associated with an accidental withdrawal of a control bank (or banks) is limited by the maximum rod speed (or travel rate) and by the worth of the bank(s). For this reactor the maximum control rod speed is 45 inches per minute and the maximum rate of reactivity change considering two control banks moving is less than 75 pcm/sec. The reactivity rate used in the boron dilution analysis at power is discussed in Section 15.2.4.

3.1.6.6 Criterion 32, 1967 - Maximum Reactivity Worth of Control Rods (Category A)

Limits, which include considerable margin, shall be placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot: (a) rupture the RCPB, or (b) disrupt the core, its support structures, or other vessel internals sufficiently to impair the effectiveness of emergency core cooling.

Discussion

The maximum reactivity worth of control rods and the maximum rates of reactivity insertion employing control rods and boron removal are limited to values that could not cause rupture of the RCS boundary or disruptions of the core or vessel internals to a degree that could impair the effectiveness of emergency core cooling.

The appropriate reactivity insertion rate for the withdrawal of RCCA and the dilution of the boric acid in the RCS are determined by safety analyses for the facility. The analyses include appropriate graphs that show the permissible manual withdrawal limits and overlap of function of the several RCCA banks as a function of power. These data on reactivity insertion rates, dilution, and withdrawal limits are also discussed in Section 4.3. The capability of the chemical and volume control system (CVCS) to avoid an inadvertent excessive rate of boron dilution is discussed in Chapter 9. The relationship of the reactivity insertion rates to plant safety is discussed in Chapter 15.

Assurance of core cooling capability following accidents, such as rod ejection, steam line break, etc., is provided by keeping the RCPB stresses within faulted condition limits as specified by applicable ASME codes. Structural deformations are also checked and are limited to values that do not jeopardize the operation of needed safety features.

3.1.6.6.1 Criterion 28, 1971 - Reactivity Limits

The reactivity control systems shall be designed with appropriate limits on the potential amount and rate of reactivity increase to assure that the effects of postulated reactivity accidents can neither (1) result in damage to the RCPB greater than limited local yielding nor (2) sufficiently disturb the core, its support structures or other reactor pressure vessel (RPV) internals to impair significantly the capability to cool the core. These postulated reactivity accidents shall include consideration of rod ejection (unless prevented by positive means), rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition.

Discussion

The RCCA system is designed with appropriate limits on the potential amount and rate of reactivity increase to assure that the effects of postulated reactivity accidents can neither (1) result in damage to the RCPB greater than limited local yielding nor (2) sufficiently disturb the core, its support structures or other RPV internals to impair

significantly the capability to cool the core. These postulated reactivity accidents shall include consideration of rod ejection (unless prevented by positive means), rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition.

The maximum control rod reactivity worth and the maximum rates of reactivity insertion using control rods are limited to preclude either rupture of the coolant pressure boundary or disruption of the core internals to a degree that would impair core cooling capacity in the event of a rod withdrawal or ejection accident (refer to Chapter 15).

Following any Condition IV event (such as rod ejection and steam line break), the reactor can be brought to the shutdown condition and the core will maintain acceptable heat transfer geometry. These means are discussed in detail in Section 4.3.

3.1.7 REACTOR COOLANT PRESSURE BOUNDARY

GDCs related to the RCPB are presented in this section. A discussion of conformance follows each criterion.

3.1.7.1 Criterion 33, 1967 - Reactor Coolant Pressure Boundary Capability (Category A)

The RCPB shall be capable of accommodating without rupture, and with only limited allowance for energy absorption through plastic deformation, the static and dynamic loads imposed on any boundary components as a result of any inadvertent and sudden release of energy to the coolant. As a design reference, this sudden release shall be taken as that which would result from a sudden reactivity insertion such as rod ejection (unless prevented by positive mechanical means), rod dropout, or cold water addition.

Discussion

Each reactor coolant boundary is shown in Chapter 15 to be capable of accommodating, without rupture, the static and dynamic loads imposed as a result of a sudden reactivity insertion such as a rod ejection.

The operation of each reactor is such that the severity of an ejection accident is inherently limited. Since control rod clusters are used to control load variations and core depletion is followed with boron dilution, only the RCCAs in the controlling groups are inserted in the core at power, and these rods are only partially inserted. Rod insertion limit monitors are provided as an administrative aid to the operator to ensure that this condition is met.

3.1.7.2 Criterion 34, 1967 - Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention (Category A)

The RCPB shall be designed to minimize the probability of rapidly propagating type failures. Consideration shall be given: (a) to the notch-toughness properties of materials extending to the upper shelf of the Charpy transition curve, (b) to the state of stress of materials under static and transient loadings, (c) to the quality control specified for materials and component fabrication to limit flaw sizes, and (d) to the provisions for control over service temperature and irradiation effects that may require operational restrictions.

Discussion

Close control is maintained over material selection and fabrication for the RCS. RCS materials exposed to the coolant are corrosion-resistant stainless steel or Inconel. The nil ductility transition (NDT) temperature of the reactor vessel material samples are established by Charpy V-notch and drop weight tests. The materials testing is consistent with 10 CFR Part 50, Appendices G and H. These tests also ensure that only materials with adequate toughness properties are used.

As part of the reactor vessel specification, certain additional tests, not specified by the applicable ASME codes, are performed:

(1) Ultrasonic Testing

In addition to code requirements, the performance of a 100 percent volumetric ultrasonic test of reactor vessel plate for shear wave and a post-hydrotest ultrasonic map of all welds in the pressure vessel are required. Cladding bond ultrasonic inspection to more restrictive requirements than code is also required to preclude interpretation problems during inservice inspection.

(2) Radiation Surveillance Program

In the surveillance programs, the evaluation of the radiation damage is based on pre-irradiation and post-irradiation testing of Charpy V-notch and tensile specimens. These programs are directed toward evaluation of the effect of radiation on the fracture toughness of reactor vessel steels based on the transition temperature approach and the fracture mechanics approach, and are in accord with ASTM-E-185, Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels.

The fabrication and quality control techniques used in the fabrication of each RCS, described in Section 5.2, are equivalent to those used for the reactor vessel. The inspections of reactor vessel, pressurizer, piping, pumps, and steam generator are governed by ASME code requirements.

The allowable heatup and cooldown rates as well as the static loading stresses during plant life are predicted, using conservative values for the change in ductility transition temperature due to irradiation.

3.1.7.3 Criterion 35, 1967 - Reactor Coolant Pressure Boundary Brittle Fracture Prevention (Category A)

Under conditions where RCPB system components constructed of ferritic materials may be subjected to potential loadings, such as a reactivity-induced loading, service temperatures shall be at least 120°F above the NDT temperature of the component material if the resulting energy release is expected to be absorbed by plastic deformation, or 60°F above the NDT temperature of the component material if the resulting energy release is expected to be absorbed within the elastic strain energy range.

Discussion

Sufficient testing and analysis of materials employed in RCS components have been performed to ensure that the required NDT temperature limits specified in the criterion are met. Removable test capsules installed in the reactor vessel are removed and tested at various times in the plant lifetime to determine the effects of operation on system materials. Details of the testing and analysis programs are included in Chapter 5. Close control is maintained over material selection and fabrication for the RCS. Materials exposed to the coolant are corrosion-resistant stainless steel or Inconel. Materials testing consistent with 10 CFR Part 50 ensures that only materials with adequate toughness properties are used.

The fabrication and quality control techniques used in the fabrication of the RCS are equivalent to those used for the reactor vessel. The inspections of reactor vessel, steam generators, pressurizer, pumps, and piping are governed by ASME code requirements.

3.1.7.4 Criterion 36, 1967 - Reactor Coolant Pressure Boundary Surveillance (Category A)

RCPB components shall have provisions for inspection, testing, and surveillance by appropriate means to assess the structural and leaktight integrity of the boundary components during their service lifetime. For the reactor vessel, a material surveillance program conforming with ASTM-E-185-66 shall be provided.

Discussion

The design of the RCPB provides for accessibility during service life to the entire internal surface of the reactor vessel and certain external zones of the vessel, including the nozzle to reactor coolant piping welds and the top and bottom heads, except where control rod drive or instrument penetrations prevent access. The reactor arrangement within each containment provides sufficient space for inspection of the external surfaces of the reactor coolant piping, except for the area of pipe within the primary shielding concrete. The

inspection capability complements the leakage detection systems in assessing the pressure boundary components' integrity.

Monitoring of the NDT temperature properties of each core region plate, forging, weldment, and associated heat-treated zones are performed in accordance with ASTM-E-185, Recommended Practice for Surveillance Tests on Structural Materials in Nuclear Reactors. Samples of reactor vessel plate materials are retained and cataloged in case future engineering development shows the need for further testing.

The material properties surveillance program includes not only the conventional tensile and impact tests, but also fracture mechanics specimens. The observed shifts in NDT temperature of the core region materials with irradiation are used to confirm the calculated limits to startup and shutdown transients.

To define permissible operating conditions below NDT temperature, a pressure range is established that is bounded by a lower limit for pump operation and an upper limit that satisfies reactor vessel stress criteria. To allow for thermal stresses during heatup or cooldown of the reactor vessel, an equivalent pressure limit is defined to compensate for thermal stress as a function of rate of change of coolant temperature. Since the normal operating temperature of the reactor vessel is well above the maximum expected NDT temperature brittle fracture during normal operation, it is not considered to be a credible mode of failure. Additional details can be found in Section 5.2.

3.1.8 ENGINEERED SAFETY FEATURES

GDCs related to ESFs are presented in this section. A discussion of conformance follows each criterion.

3.1.8.1 Criterion 37, 1967 - Engineered Safety Features Basis for Design (Category A)

ESFs shall be provided in the facility to back up the safety provided by the core design, the RCPB, and their protection systems. As a minimum, such ESFs shall be designed to cope with any size RCPB break up to and including the circumferential rupture of any pipe in that boundary assuming unobstructed discharge from both ends.

Discussion

ESFs are provided to cope with any size reactor coolant pipe break up to and including the circumferential rupture of any pipe in that boundary assuming unobstructed discharge from both ends, and to cope with any steam or feedwater line break up to and including the main steam or feedwater headers.

Limiting the release of fission products from the reactor fuel is accomplished by the emergency core cooling system (ECCS) which, by cooling the core, keeps the fuel in place and substantially intact and limits the metal-water reaction to an acceptable amount. A

reinforced concrete, steel-lined containment structure is provided and encloses the entire RCS. It is designed to sustain, without loss of required integrity, all effects of gross equipment failures up to and including the rupture of the largest pipe in the RCS. ESFs are described in Chapter 6.

3.1.8.2 Criterion 38, 1967 - Reliability and Testability of Engineered Safety Features (Category A)

All ESFs shall be designed to provide high functional reliability and ready testability. In determining the suitability of a facility for a proposed site, the degree of reliance upon and acceptance of the inherent and engineered safety afforded by the systems, including ESFs, will be influenced by the known and the demonstrated performance capability and reliability of the systems, and by the extent to which the operability of such systems can be tested and inspected where appropriate during the life of the plant.

Discussion

A comprehensive program of testing has been formulated for all equipment and instrumentation vital to the functioning of ESFs. The program consists of startup tests of system components and integrated tests of the system. Periodic tests of the activation circuitry and system components, throughout the station lifetime, with maintenance performed as necessary, ensure that the initially high reliability will be maintained and that the system will perform on demand. Details of the test program are provided in the Technical Specifications (Reference 1). The ESFs are described in Chapter 6.

3.1.8.3 Criterion 39, 1967 - Emergency Power for Engineered Safety Features (Category A)

Criterion 39, 1967 is no longer part of the DCPP license basis and has been replaced by GDC 17, 1971 and GDC 18, 1971.

3.1.8.3.1 Criterion 17, 1971 - Electric Power Systems

An onsite electric power system and an offsite electric power system shall be provided to permit functioning of SSCs important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the RCPB are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate

rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the RCPB are not exceeded. One of these circuits shall be designed to be available within a few seconds following a LOCA to assure that core cooling, containment integrity, and other vital safety functions are maintained.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.

Discussion

The DCPP offsite power system is designed to supply offsite electrical power by two physically independent circuits. The 230-kV system provides startup and standby power, and is immediately available following a design basis accident (DBA) to assure that core cooling, containment integrity, and other vital safety functions are maintained. The 500-kV system provides for transmission of the plant's electric power output. The 500-kV connection also provides a delayed access source of offsite power after the main generator is disconnected. A combination of the 230-kV and the 500-kV circuits provides independent sources of offsite power as required by GDC 17, 1971.

The onsite emergency power source consists of three DGs for each unit.

Both offsite and onsite systems have sufficient independence, capacity, and testability to permit the operation of the ESFs assuming a failure of a single active component in each power system. The combination of two 230-kV lines plus the 500-kV system provides a high degree of assurance that offsite power will be available when required. The 230-kv and 500-kV systems meet the requirements of GDC 17, 1971. Further details are provided in Chapter 8.

3.1.8.3.2 Criterion 18, 1971 - Inspection and Testing of Electric Power Systems

Electric power systems important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features, such as wiring, insulation, connections, and switchboards, to assess the continuity of the systems and the condition of their components. The systems shall be designed with a capability to test periodically (1) the operability and functional performance of the components of the systems, such as onsite power sources, relays, switches, and buses, and (2) the operability of the systems as a whole and, under conditions as close to design as practical, the full operation sequence that brings the systems into operation, including operation of applicable portions of the protection system, and the transfer of power among the nuclear power unit, the offsite power system, and the onsite power system.

Discussion

The electric power system and its components have provisions for periodic inspection and testing. Electric power components have been provided with convenient and safe features for inspecting and testing to meet the requirements of GDC 18, 1971.

3.1.8.4 Criterion 40, 1967 - Missile Protection (Category A)

Protection for ESFs shall be provided against dynamic effects and missiles that might result from plant equipment failures.

Discussion

Use of conservative design methods, segregated routing of piping, provision of missile shield walls, and use of engineered hangers and pipe restraints are incorporated in the design to accommodate dynamic effects of postulated accidents. The various sources of missiles that might affect ESFs have been identified, and protective measures have been devised to minimize these effects (refer to Section 3.5).

Electrical raceways containing circuits for the ESFs have not been installed in zones where provision against dynamic effects must be made, with a few exceptions. When routing through such zones was necessary, metallic conduits only were used, and conduits containing redundant circuits were separated physically as far as practical.

3.1.8.4.1 Criterion 4, 1987 - Environmental and Dynamic Effects Design Bases

SSCs important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including LOCAs. These SSCs shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analyses reviewed and approved by the Commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

Discussion

GDC 4, 1987 revision, "Environmental and dynamic effects design bases," states in part, that

> ...dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analyses reviewed and

approved by the Commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

The leak-before-break (LBB) methodology was applied to the primary loops of DCPP Unit 1 and Unit 2. The following postulated breaks were eliminated: the six terminal ends in the cold, hot, and crossover legs; a split in the steam generator inlet elbow; and the loop closure weld in the crossover leg. Reference PG&E letter dated March 16, 1992 (DCL-92-059).

The NRC allows the application of LBB technology on the primary piping systems under the broad-scope revision to 10 CFR Part 50, Appendix A, GDC 4 revision (52 FR 4128841295; October 27, 1987). Use of LBB at DCPP has been approved by the NRC in a safety evaluation dated March 2, 1993.

3.1.8.5 Criterion 41, 1967 - Engineered Safety Features Performance Capability (Category A)

ESFs such as emergency core cooling and containment heat removal systems shall provide sufficient performance capability to accommodate partial loss of installed capacity and still fulfill the required safety function. As a minimum, each ESF shall provide this required safety function assuming a failure of a single active component.

Discussion

The overall capacity of the ESF meets the requirements of 10 CFR 50.67 for the occurrence of any rupture of a reactor coolant or steam system pipe, including the double-ended rupture of a reactor coolant pipe, known as the DBA. Additional details can be found in Chapters 6 and 15.

3.1.8.6 Criterion 42, 1967 - Engineered Safety Features Components Capability (Category A)

ESFs shall be designed so that the capability of each component and system to perform its required function is not impaired by the effects of a LOCA.

Discussion

Instrumentation, motors, cables, and penetrations located inside the containment are selected to meet the most adverse accident conditions to which they may be subjected. These items are either protected from containment accident conditions or are designed to withstand, without failure, exposure to the worst combination of temperature, pressure, and humidity expected during the required operational period.

The ECCS pipes serving each loop are anchored at the missile barrier in each loop area to restrict potential accident damage to the portion of piping beyond this point. The

anchorage is designed to withstand, without failure, the thrust force exerted by any branch line severed from the reactor coolant pipe and discharging fluid to the atmosphere, and to withstand a bending moment equivalent to that producing failure of the piping under the action of a free-end discharge to atmosphere or motion of the broken reactor coolant pipe to which the emergency core cooling pipes are connected. This prevents possible failure at any point upstream from the support point including the branch line connection into the piping header. Chapter 6 contains the details of the containment structure and ESFs.

3.1.8.7 Criterion 43, 1967 - Accident Aggravation Prevention (Category A)

ESFs shall be designed so that any action of the ESFs that might accentuate the adverse aftereffects of a loss of normal cooling is avoided.

Discussion

The reactor is maintained subcritical following a pipe rupture accident. Introduction of borated cooling water into the core does not result in a net positive reactivity addition. The control rods insert and remain inserted. The supply of water by the ECCS to cool hot core cladding does not produce significant water-metal reactions. The delivery of cold emergency core cooling water to the reactor vessel following accidental expulsion of reactor coolant does not cause further loss of integrity of the RCS boundary. The ESFs are discussed in detail in Chapter 6.

3.1.8.8 Criterion 44, 1967 - Emergency Core Cooling Systems Capability (Category A)

At least two ECCSs, preferably of different design principles, each with a capability for accomplishing abundant emergency core cooling,shall be provided. Each ECCS and the core shall be designed to prevent fuel and clad damage that would interfere with the emergency core cooling function and to limit the clad metal-water reaction to negligible amounts for all sizes of breaks in the RCPB, including the double-ended rupture of the largest pipe. The performance of each ECCS shall be evaluated conservatively in each area of uncertainty. The systems shall not share active components and shall not share other features or components unless it can be demonstrated that (a) the capability of the shared feature or component to perform its required function can be readily ascertained during reactor operation, (b) failure of the shared feature or component does not initiate a LOCA, and (c) capability of the shared feature or component to perform its required function is not impaired by the effects of a LOCA and is not lost during the entire period this function is required following the accident.

Discussion

By combining the use of passive accumulators with two centrifugal charging pumps (CCP1 and CCP2), two safety injection (SI) pumps, and two RHR pumps, emergency core cooling is provided even if there should be a failure of any single component in any system. The ECCS employs a passive system of accumulators that do not require any

external signals or source of power for their operation to cope with the short-term cooling requirements of large reactor coolant pipe breaks. Two independent and redundant high-pressure flow and pumping systems, each capable of the required emergency cooling, are provided for small break protection and to keep the core submerged after the accumulators have discharged following a large break. These systems are arranged so that the single failure of any active component does not interfere with meeting the short-term cooling requirements.

Borated water is injected into the RCS by accumulators, SI pumps, RHR pumps, and charging pumps. Pump design includes consideration of fluid temperature and containment pressure in accordance with Safety Guide 1. The failure of any single active component or the development of excessive leakage during the long-term cooling period does not interfere with the ability to meet necessary long-term cooling objectives with one of the systems.

The primary function of the ECCS is to deliver borated cooling water to the reactor core in the event of a LOCA. This limits the fuel cladding temperature and thereby ensures that the core will remain intact and in place, with its essential heat transfer geometry preserved. This protection is afforded for:

(1) All pipe break sizes up to and including the hypothetical circumferential rupture of a reactor coolant loop (RCL)

(2) A loss of coolant associated with a rod ejection accident

The basic criteria for LOCA evaluations are (a) no cladding melting will occur, (b) zirconium-water reactions will be limited to an insignificant amount, and (c) the core geometry will remain essentially in place and intact so that effective cooling of the core will not be impaired. The zirconium-water reactions will be limited to an insignificant amount so that the accident:

(1) Does not interfere with the emergency core cooling function to limit cladding temperatures

(2) Does not produce hydrogen in an amount that, when burned, would cause the containment pressure to exceed the design value

For any rupture of a steam pipe and the associated uncontrolled heat removal from the core, the ECCS adds shutdown reactivity so that with a stuck rod, no offsite power, and minimum ESF, there is no consequential damage to the primary system and the core remains in place and intact. With no stuck rod, offsite power, and all equipment operating at design capacity, there is insignificant cladding rupture. The ECCS is described in Section 6.3. Chapter 15 provides the analysis for the LOCA.

3.1.8.9 Criterion 45, 1967 - Inspection of Emergency Core Cooling Systems (Category A)

Design provisions shall be made to facilitate physical inspection of all critical parts of the ECCS, including reactor vessel internals and water injection nozzles.

Discussion

Design provisions facilitate access to the critical parts of the reactor vessel internals, injection nozzles, pipes, and valves for visual or nondestructive inspection.

The components outside containment are accessible for leaktightness inspection during operation of the reactor.

Details of the inspection program for the reactor vessel internals are included in Section 5.4. Information on inspection for the ECCS is provided in Section 6.3.

3.1.8.10 Criterion 46, 1967 - Testing of Emergency Core Cooling System Components (Category A)

Design provisions shall be made so that active components of the ECCS, such as pumps and valves, can be tested periodically for operability and required functional performance.

Discussion

The design provides for periodic testing of both active and passive components of the ECCS for operability and functional performance.

Preoperational performance tests of the components were performed in the manufacturer's shop. Initial system flow tests demonstrate proper functioning of the system. Thereafter, periodic tests demonstrate that components are functioning properly.

Each active component of the ECCS may be individually actuated on the normal power source at any time during plant operation to demonstrate operability. The centrifugal charging pumps are part of the charging system, and this system is in continuous operation during plant operation. The test of the SI pumps employs the minimum flow recirculation test line that connects back to the refueling water storage tank (RWST). Remotely operated valves are exercised and actuation circuits tested. The automatic actuation circuitry, valves, and pump breakers also may be checked during integrated system tests performed during a planned cooldown of the RCS.

Details of the ECCS are found in Section 6.3. Performance under accident conditions is evaluated in Chapter 15. Periodic testing procedures are listed in Section 13.5.

3.1.8.11 Criterion 47, 1967 - Testing of Emergency Core Cooling Systems (Category A)

A capability shall be provided to test periodically the delivery capability of the ECCS at a location as close to the core as is practical.

Discussion

Design provisions include special instrumentation, testing, and sampling lines to perform tests during plant shutdown to demonstrate proper operation of the ECCS. A test signal is applied to initiate automatic action. The test demonstrates the operation of the valves, pump circuit breakers, and automatic circuitry. In addition, the periodic recirculation to the RWST can verify that the SI pumps attain required discharge heads. During a refueling outage the full flow capability of each injection pump can be verified.

Details of the ECCS are found in Section 6.3. Performance under accident conditions is evaluated in Chapter 15.

3.1.8.12 Criterion 48, 1967 - Testing of Operational Sequence of Emergency Core Cooling Systems (Category A)

A capability shall be provided to test under conditions as close to design as practical the full operational sequence that would bring the ECCS into action, including the transfer to alternate power sources.

Discussion

The design provides for capability to test initially, to the extent practical, the full operational sequence up to design conditions, including transfer to alternative power sources for the ECCS, to demonstrate the state of readiness and capability of the system. This functional test is performed with the RCS initially cold and at low pressure (LP). The ECCS valving is set to initially simulate the system alignment for plant power operation.

Details of the ECCS are found in Section 6.3.

3.1.8.13 Criterion 49, 1967 - Containment Design Basis (Category A)

The containment structure, including access openings and penetrations, and any necessary containment heat removal systems shall be designed so containment structure can accommodate, without exceeding the design leakage rate, pressures and temperatures resulting from the largest credible energy release following a LOCA, including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of ECCSs.

Discussion

The containment, including access openings and penetrations, has a design pressure of 47 psig. The greatest transient peak pressure associated with a postulated rupture of the piping in the RCS and the calculated effects of metal-water reaction do not exceed this value. The containment is strength tested at 54 psig.

The reactor containment structure and penetrations, with the aid of containment heat removal systems, are designed to limit radiation doses resulting from leakage of radioactive fission products from the containment to below 10 CFR 50.67 values, assuming the largest credible energy release following a LOCA, including a margin to cover the effects of metal-water or other undefined energy sources. The containment design is described in detail in Section 3.8.2.1.

3.1.8.14 Criterion 50, 1967 - NDT Requirement for Containment Material (Category A)

Principal load carrying components of ferritic materials exposed to the external environment shall be selected so that their temperatures under normal operating and testing conditions are not less than 30°F above NDT temperature.

Discussion

The selection and use of containment structure materials comply with the applicable codes and standards.

The NDT temperature requirement of Criterion 50 reflects the requirements of the ASME BPVC Section III-1968 Edition for Class B (containment) vessels. Section N-1210 requires an NDT temperature at least 30°F below the lowest service temperature. NDT temperature may be determined either by Charpy V-notch test or dropweight test. Using the Charpy V-notch test, acceptance criteria specified by the Code depend on the material specification and range from 15 to 20 ft-lbs minimum average.

During construction, Charpy V-notch test temperature for material exposed to external environments was established by subtracting 30°F from the lowest service temperature. The lowest service temperature was taken to be the design 24-hour mean-low ambient temperature for the site of 30°F. Thus the Charpy V-notch test temperature was 0°F.

The containment liner is enclosed within the containment structure and thus not directly exposed to the temperature of the external environment and not subject to Criterion 50, 1967. Nevertheless, the design specification required Charpy V-notch tests at 20°F for the containment liner. This corresponds to a lowest service temperature of 50°F during operation.

During construction, compliance with Criterion 50, 1967 and the ASME Code was ensured by specifying appropriate test temperatures and minimum acceptance values for Charpy

V-notch tests as part of the material specification. Mill test reports showing the Charpy V-notch test results were provided as documentation.

ASME Section III requirements have evolved over the years to reflect the industry's better understanding of the behavior of ferritic steel materials. The current ASME Code requirements for notch toughness testing for metallic containment vessels are contained in Subsection NE-2300. ASME has determined that an adequate level of toughness is ensured by performing the Charpy V-notch tests at or below the lowest service temperature rather than 30°F below the lowest service temperature as previously required. Acceptance criteria are based on material thickness rather than material specification and range from 20 to 25 ft-lbs minimum average or 20-25 mils lateral expansion minimum average. Notch toughness testing is not required for material 5/8 inch or less in thickness. For repair, replacement, or alteration or ferritic containment material subject to Criterion 50, 1967, the notch toughness testing requirements of NE-2300 will be used in lieu of the original requirements. Charpy V-notch testing will be performed at or below the lowest service temperature and materials 5/8 inch or less in thickness will be exempt from Charpy V-notch testing.

The concrete containment structure is not susceptible to a low temperature brittle fracture.

Further information on containment structure materials appears in Section 3.8.2.1.

3.1.8.15 Criterion 51, 1967 - Reactor Coolant Pressure Boundary Outside Containment (Category A)

If part of the RCPB is outside the containment, appropriate features as necessary shall be provided to protect the health and safety of the public in case of an accidental rupture in that part. Determination of the appropriateness of features such as isolation valves and additional containment shall include consideration of the environmental and population conditions surrounding the site.

Discussion

The RCPB is defined as those piping systems and components that contain reactor coolant at design pressure and temperature. With the exception of the reactor coolant sampling lines, the entire RCPB, as defined above, is located entirely within the containment structure. All sampling lines are provided with remotely operated valves for isolation in the event of a failure. These valves also close automatically on a containment isolation signal. Sampling lines are only used during infrequent sampling and can readily be isolated.

All other piping and components that may contain reactor coolant are low-pressure, low temperature systems which would yield minimal environmental doses in the event of failure.

The sampling system and low-pressure systems are described in Chapter 9. An analysis of malfunctions in these systems is included in Chapter 15.

3.1.8.16 Criterion 52, 1967 - Containment Heat Removal Systems (Category A)

Where active heat removal systems are needed under accident conditions to prevent exceeding containment design pressure, at least two systems, preferably of different principles, each with full capacity, shall be provided.

Discussion

Two separate heat removal systems, the CSS and the containment fan coolers, are provided to remove heat from the containment following an accident. The design cooling rates of the two systems at the containment design pressure and temperature conditions are the same. The heat removal capability of either system is sufficient to rapidly reduce the containment pressure following an accident.

A second purpose served by the CSS is to remove radioactive iodine isotopes from the containment atmosphere should these fission products be released in the event of an accident. The system is designed to deliver enough sodium hydroxide mixed with the borated spray water from the RWST to provide pH control for iodine removal when mixed with the other sources of water in the containment recirculation sump. The containment heat removal systems are described in Section 6.2.

3.1.8.17 Criterion 53, 1967 - Containment Isolation Valves (Category A)

Penetrations that require closure for the containment function shall be protected by redundant valving and associated apparatus.

Discussion

Penetrations that require closure for the containment function are provided with at least two barriers. Additional details can be found in Section 6.2.

The containment isolation system is designed to meet the 1971 GDC requirements with exceptions. The component cooling water (CCW) penetration to the excess letdown heat exchanger is an exception that does not meet the 1971 GDC because of commitments to design and construction made prior to the issuance of the 1971 GDC; this penetration does comply with the 1967 GDC (refer to Section 6.2.4).

3.1.8.17.1 Criterion 54, 1971 - Piping Systems Penetrating Containment

Piping systems penetrating primary reactor containment shall be provided with leak detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. Such piping systems shall be designed with a capability to test periodically

the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

Discussion

The containment isolation design provides for a double barrier at the containment penetration in those fluid systems that are not required to function following a design basis event. Piping systems penetrating the containment are provided with test vents and test connections or have other provisions to allow periodic leakage testing.

Those automatic isolation valves that do not restrict normal plant operation are periodically tested to ensure operability. Refer to Section 6.2.4 for further discussion and details of the capability for periodic leakage rate testing.

3.1.8.17.2 Criterion 55, 1971 - Reactor Coolant Pressure Boundary Penetrating Containment

Each line that is part of the RCPB and that penetrates primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:

(1) One locked closed isolation valve inside and one locked closed isolation valve outside containment; or

(2) One automatic isolation valve inside and one locked closed isolation valve outside containment; or

(3) One locked closed isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment; or

(4) One automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Other appropriate requirements to minimize the probability or consequences of an accidental rupture of these lines or of lines connected to them shall be provided as necessary to assure adequate safety. Determination of the appropriateness of these requirements, such as higher quality in design, fabrication, and testing, additional provisions for inservice inspection, protection against more severe natural phenomena,

and additional isolation valves and containment, shall include consideration of the population density, use characteristics, and physical characteristics of the site environs.

Discussion

The RCPB is defined as those piping systems and components that contain reactor coolant at design pressure and temperature. With the exception of the reactor coolant sampling lines, the entire RCPB, as defined above, is located entirely within the containment structure. All sampling lines are provided with remotely operated valves for isolation in the event of a failure. These valves also close automatically on a containment isolation signal. Sampling lines are only used during infrequent sampling and can readily be isolated. Further details are provided in Section 6.2.4.

3.1.8.17.3 Criterion 56, 1971 - Primary Containment Isolation

Each line that connects directly to the containment atmosphere and penetrates primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:

(1) One locked closed isolation valve inside and one locked closed isolation valve outside containment; or

(2) One automatic isolation valve inside and one locked closed isolation valve outside containment; or

(3) One locked closed isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment; or

(4) One automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Discussion

Each Line that connects directly to the containment atmosphere and penetrates the primary reactor containment is provided with containment isolation valves or other acceptable barriers, as required. Refer to Section 6.2.4 for further discussion.

3.1.8.17.4 Criterion 57, 1971 - Closed System Isolation Valves

Each line that penetrates primary reactor containment and is neither part of the RCPB nor connected directly to the containment atmosphere shall have at least one containment isolation valve which shall be either automatic, or locked closed, or capable of remote manual operation. This valve shall be outside containment and located as close to the containment as practical. A simple check valve may not be used as the automatic isolation valve.

Discussion

Each line that penetrates the reactor containment in each unit, and is neither part of the RCPB nor connected directly to the containment atmosphere, has at least one containment isolation valve located outside the containment as close to the containment as practicable. Refer to Section 6.2.4 for further discussion.

3.1.8.18 Criterion 54, 1967 - Containment Leakage Rate Testing (Category A)

Containment shall be designed so that an integrated leakage rate test can be conducted at design pressure after completion and installation of all penetrations and the leakage rate measured over a sufficient period of time to verify its conformance with required performance.

Discussion

The containment structure design permits preoperational leakage rate tests, including an integrated leakage rate test of the containment structure and sensitive leakage rate tests of the penetrations and weld channels.

The integrated leakage rate test, which is at design pressure and could extend to a period of at least 24 hours, verifies that the structure leakage rate is less than the allowable value. Subsequent leakage tests are conducted at a pressure greater than or equal to 25 psig. A sensitive leakage rate test can be performed by pressurizing the double penetrations, the spaces between resilient seals on penetrations, and the weld channels at slightly above design pressure. This test would be conducted with the containment structure at atmospheric pressure.

The leakage rate tests and the sensitive leakage rate test demonstrate the integrity of the double leakage barriers provided by the penetrations and the overall integrity of the containment structure. The criterion for acceptance is that the measured leakage rate be less than 0.10 percent of the containment free volume per day.

Further details of the integrated leakage rate test and the sensitive leakage rate test provisions appear in Section 3.8.

3.1.8.19 Criterion 55, 1967 - Containment Periodic Leakage Rate Testing (Category A)

The containment shall be designed so that integrated leakage rate testing can be done periodically at design pressure during plant lifetime.

Discussion

The containment structure is provided with testable weld channels and penetrations so that periodic sensitive leakage rate tests at design pressure can be made of those areas where leakage may occur. The containment structure is designed to permit periodic full integrated leakage rate tests at reduced pressure.

3.1.8.20 Criterion 56, 1967 - Provisions for Testing of Penetrations (Category A)

Provisions shall be made for testing penetrations which have resilient seals or expansion bellows to permit leaktightness to be demonstrated at design pressure at any time.

Discussion

All penetrations are provided with a volume that can be pressurized to test for leaktightness. There are three configurations used: (a) weld channels over the penetration welds, (b) an annular space between the penetration insert and the sleeve, which is sealed at both ends, and (c) double resilient seals with a gap between the seals.

Further details appear in Section 3.8.

3.1.8.21 Criterion 57, 1967 - Provisions for Testing of Isolation Valves (Category A)

Capability shall be provided for testing functional operability of valves and associated apparatus essential to the containment function for establishing that no failure has occurred and for determining that valve leakage does not exceed acceptable limits.

Discussion

Capability is provided to the extent practical for testing the functional operability of valves and associated apparatus and the leakage during periods of reactor shutdown.

Initiation of containment isolation employs coincidence circuits that allow checking of the operability and calibration of one channel at a time. Removal or bypass of one signal channel places that channel in the tripped mode. Section 6.2 describes in detail the testing of isolation valves.

3.1.8.22 Criterion 58, 1967 - Inspection of Containment Pressure-Reducing Systems (Category A)

Design provisions shall be made to facilitate the periodic physical inspection of all important components of the containment pressure-reducing systems, such as, pumps, valves, spray nozzles, torus, and sumps.

Discussion

The containment heat removal systems (CHRS) is comprised of the containment fan cooler system (CFCS) and the containment spray system (CSS). Where practicable, all active components and passive components of the CHRS are inspected periodically to demonstrate system readiness. The pressure-containing systems are inspected for leaks from pump seals, valve packing, flanged joints, and safety valves (SVs). During operational testing of the containment spray pumps, the portions of the system subjected to pump pressure are inspected for leaks. The containment fan coolers are normally in use, which provides an additional check on the readiness of the system. Five fan coolers are provided. Each is sized for one-quarter the capacity needed to maintain the containment temperature below 120°F during normal plant operation. Following a LOCA, two of the five fan coolers provide sufficient capacity to maintain containment pressure below design value when used in conjunction with one containment spray pump during the injection phase.

Additional details are found in Section 6.2.

3.1.8.23 Criterion 59, 1967 - Testing of Containment Pressure-Reducing Systems Components (Category A)

The containment pressure-reducing systems shall be designed so that active components, such as pumps and valves, can be tested periodically for operability and required functional performance.

Discussion

To the extent practicable, active components of the containment fan coolers are given preoperational performance tests after installation. Since these coolers are in use during normal operation, they are continually subjected to operational tests. The same is true of the CCW system that supplies the cooling water for the fan coolers. Each unit can be isolated during plant operation and subjected to a leak test to determine that the leaktight integrity of the unit has not been lost.

Similarly, active components in the CSS are given preoperational performance tests after installation. Periodic tests demonstrate that components are functioning properly. Tests are performed after any component maintenance affecting operability. The containment systems are described in detail in Section 6.2.

3.1.8.24 Criterion 60, 1967 - Testing of Containment Spray Systems (Category A)

A capability shall be provided to test periodically the delivery capability of the CSS at a position as close to the spray nozzles as is practical.

Discussion

Permanent test lines for all the containment spray loops are located so that all components up to the isolation valves at the containment can be tested.

The air test lines for checking that spray nozzles are not obstructed are connected upstream of the spray ring isolation valves. Airflow through the nozzles is monitored by positive means. Details of the CSS are found in Section 6.2.

3.1.8.25 Criterion 61, 1967 - Testing of Operational Sequence of Containment Pressure-Reducing Systems (Category A)

A capability shall be provided to test under conditions as close to the design as practical the full operational sequence that would bring the containment pressure-reducing systems into action, including the transfer to alternate power sources.

Discussion

The design provides for capability to test, to the extent practicable, the full operational sequence for the CSS and the containment fan coolers to demonstrate the state of readiness for those sections of the systems not normally functioning during plant operation. Containment systems are described in detail in Section 6.2.

3.1.8.26 Criterion 62, 1967 - Inspection of Air Cleanup Systems (Category A)

Design provisions shall be made to facilitate physical inspection of all critical parts of containment air cleanup systems, such as, ducts, filters, fans, and dampers.

Discussion

The CSS, utilizing sodium hydroxide, serves as the air cleanup system. Where practical, all components of the CSS are inspected periodically to demonstrate system readiness. Special attention is given to critical parts such as pipes, pumps, nozzles, and storage facilities for sodium hydroxide. Additional details are found in Section 6.2.

3.1.8.27 Criterion 63 , 1967- Testing of Air Cleanup Systems Components (Category A)

Design provisions shall be made so that active components of the air cleanup systems, such as fans and dampers, can be tested periodically for operability and required functional performance.

Discussion

The CSS, utilizing sodium hydroxide, serves as the air cleanup system. The active components in the CSS are given preoperational performance tests after installation. Permanent test lines for all containment spray loops are located so that all components up to the isolation valves at the containment may be tested. The nozzles are tested by airflow that is monitored by positive means. The fan coolers are normally in use, which provides a check on the operability of the system. Additional details are found in Section 6.2.

3.1.8.28 Criterion 64, 1967 - Testing Air Cleanup Systems (Category A)

A capability shall be provided for in situ periodic testing and surveillance of the air cleanup systems to ensure: (a) filter bypass paths have not developed and (b) filter and trapping materials have not deteriorated beyond acceptable limits.

Discussion

The CSS water flow can be tested through the permanent test lines, permitting the test of the system up to the isolation valves at the containment. Permanent air testing lines, connected upstream of the containment isolation valves, permit operability testing of piping and nozzles beyond the isolation valves. Periodically, a sample of the sodium hydroxide solution is tested to ensure proper concentration. The fan coolers are normally in use and, therefore, the readiness of the system is verified. Additional details are found in Section 6.2.

3.1.8.29 Criterion 65, 1967 - Testing of Operational Sequence of Air Cleanup Systems (Category A)

A capability shall be provided to test, under conditions as close to design as practical, the full operational sequence that would bring the air cleanup systems into action, including the transfer to alternate power sources and the design air flow delivery capability.

Discussion

The CSS design provides for the capability to test initially, to the extent practicable, the full operational sequence from the CSS to demonstrate the state of readiness of the system. The fan cooler system is normally in use, which verifies its readiness. Details are contained in Section 6.2.

3.1.9 FUEL AND WASTE STORAGE SYSTEMS

GDC for fuel and waste storage systems are presented in this section. A discussion of conformance follows each criterion.

3.1.9.1 Criterion 66, 1967 - Prevention of Fuel Storage Criticality (Category B)

Criticality in new and spent fuel storage shall be prevented by physical systems or processes. Such means as geometrically safe configurations shall be emphasized over procedural controls.

Discussion

During reactor vessel head removal and while loading and unloading fuel from the reactor, the boron concentration in the refueling water and the SFP is maintained at not less than that required to shut down the core to a $k_{eff} = 0.95$.

Borated water is used to fill the spent fuel storage pools at a concentration comparable to that used in the reactor cavity and refueling canal during refueling operations. The fuel is stored vertically in an array with sufficient center-to-center distance between assemblies to ensure that, including uncertainties, a k_{eff} of less than or equal to 0.95 if the fuel racks are flooded with borated water, and a $k_{eff} < 1.0$, even if unborated water is used to fill the pool. The fuel storage and handling details are found in Section 9.1.

3.1.9.2 Criterion 67, 1967 - Fuel and Waste Storage Decay Heat (Category B)

Reliable decay heat removal systems shall be designed to prevent damage to the fuel in storage facilities that could result in radioactivity release to plant operating areas or the public environs.

Discussion

Refueling water provides a reliable and adequate cooling medium for spent fuel transfer, and heat removal is provided by an auxiliary cooling system. Natural radiation and convection is adequate for cooling the holdup tanks. The auxiliary systems are discussed in detail in Chapter 9.

3.1.9.3 Criterion 68, 1967 - Fuel and Waste Storage Radiation Shielding (Category B)

Shielding for radiation protection shall be provided in the design of spent fuel and waste storage facilities as required to meet the requirements of 10 CFR Part 20.

Discussion

The SFP is designed to provide a sufficient depth of water over the top of the active portion of a spent fuel assembly during handling operations so that, in all cases, operator dose levels will be within the requirements of 10 CFR Part 20.

Fuel handling and storage is described in Chapter 9. Shielding design is described in Chapter 12.

3.1.9.4 Criterion 69, 1967 - Protection Against Radioactivity Release from Spent Fuel and Waste Storage (Category B)

Containment of fuel and waste storage shall be provided if accidents could lead to release of undue amounts of radioactivity to the public environs.

Discussion

The spent fuel area is enclosed and maintained under negative pressure. All ventilation air is passed through high-efficiency particulate air (HEPA) filters prior to being released to the plant vent. In the event of an accident, high activity would be detected by the radiation monitor (refer to Section 11.4), and the exhaust air would be diverted through charcoal filters. For radioactive waste storage, refer to the detailed discussion in Chapter 11. Failure of a gas decay tank has been postulated and analyzed in Chapter 15.

3.1.10 PLANT EFFLUENTS

The GDC related to plant effluents is presented in this section. A discussion of conformance follows the criterion.

3.1.10.1 Criterion 70, 1967 - Control of Releases of Radioactivity to the Environment (Category B)

The facility design shall include those means necessary to maintain control over the plant radioactive effluents, whether gaseous, liquid, or solid. Appropriate holdup capacity shall be provided for retention of gaseous, liquid, or solid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control shall be justified (a) on the basis of 10 CFR Part 20 requirements for normal operations and for any transient situation that might reasonably be anticipated to occur and (b) on the basis of 10 CFR Part 100 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence except that reduction of the recommended dosage levels may be required where high population densities or very large cities can be affected by the radioactive effluents.

Discussion

Waste handling systems are incorporated in the facility design for processing and/or retention of radioactive wastes from normal operation, with appropriate controls and monitors to ensure that releases do not exceed the limits of 10 CFR Part 20. The radioactive waste processing system, the design criteria, and amounts of estimated releases of radioactive effluents to the environment are described in Chapter 11. Details of the monitoring system are found in Section 11.4.

The facility is designed to prevent radioactivity release during accidents from exceeding the limits of 10 CFR 100.11 (for tank rupture accidents) or 10 CFR 50.67 (for accidents analyzed using AST methodology). The containment system, which forms a barrier to the escape of fission products should a loss of coolant occur, is described in Section 6.2. Postulated accidents that could release radioactivity to the environment are analyzed in Chapter 15.

3.1.11 REFERENCES

1. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

2. Deleted in Revision 3.

3. Deleted in Revision 3.

4. Deleted in Revision 20

5. Diablo Canyon Plant Units 1 and 2 Final Safety Analysis Report (FSAR), July 1973.

6. Diablo Canyon Plant Units 1 and 2 FSAR Amendment 85, 1980.

3.2 CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS

This section describes the DCPP classification system for SSCs that is used to implement quality standards in conformance with GDC 1, 1967.

It is recognized that during the design and construction of DCPP Unit 1 and Unit 2, significant industry and regulatory changes were made in establishing common methods of classification, e.g., American National Standards Institute (ANSI) standard N18.2, Draft August 1970 (Reference 1), Safety Guide 26, March 1972 (Reference 2), and Safety Guide 29, June 1972 (Reference 3). However these methods all differ slightly in detail from those used for DCPP. Although these regulatory and industry documents are similar, these are not the DCPP Licensing Basis.

DCPP utilizes three primary classification categories (PG&E Design Class, PG&E Quality Assurance Classification and PG&E Quality/Code Class) as defined in Section 3.2.2. Although this section makes comparisons to the above documents, it is clear that the DCPP Licensing Basis is the PG&E classification categories.

GDC 1, 1967, requires that SSCs important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed.

3.2.1 DESIGN BASES

3.2.1.1 General Design Criterion 1, 1967 - Quality Standards

DCPP SSCs that are essential to the prevention of accidents which could affect the public health and safety, or mitigation of their consequences are identified and designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed.

3.2.1.2 General Design Criterion 2, 1967 - Performance Standards

DCPP SSCs that are essential to prevention of accidents which could affect the public health and safety, or to mitigation of their consequences are designed, fabricated, and erected to withstand the effects of or are protected against natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

3.2.1.3 10 CFR 50.55a - Codes and Standards

Title 10 of the U.S. Code of Federal Regulations, Section 50.55a (10 CFR 50.55a), requires that certain components of the RCPB be designed, fabricated, erected, and tested in accordance with the requirements for Class A components of Section III of the ASME Boiler and Pressure Vessel Code, or the most recently available industry codes and standards at the time of construction authorization application. PG&E Quality/Code Class I is applied to those components of the RCPB and implements the quality

standards that satisfy the requirements of 10 CFR 50.55a. PG&E Quality/Code Class I components of the RCPB are listed in Table 3.2-3, along with the industry codes and standards used for their design, fabrication, erection, and test.

3.2.1.4 10 CFR Part 50 Appendix B - Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants

Classification of SSCs includes the basis of Appendix B to 10 CFR Part 50, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants, which requires that SSCs important to safety be designed and constructed in accordance with the QA requirements described in Appendix B. Therefore, the requirements of the DCPP QA Program apply to all SSCs classified as PG&E Design Class I. This ensures that plant features important to safety have met the requirements of Appendix B. Specific QA requirements may also be applied to selected PG&E Design Class II features.

3.2.2 CLASSIFICATION CATEGORIES

DCPP SSCs are classified using three primary categories: PG&E Design Class, PG&E Quality Assurance Classification, and PG&E Quality/Code Class. The requirements and interrelationships of these categories are described in the sections below and Table 3.2-1.

The general applicability and requirements of the various PG&E classification categories are provided in Tables 3.2-1, 3.2-2 and 3.2-4.

The classifications of specific SSCs are provided in Table 3.2-3. Piping schematic drawings are illustrated in controlled engineering drawings in Figures 3.2-1 through 3.2-27 in Table 1.6-1.

3.2.2.1 PG&E Design Class

This section describes the PG&E design classes that are used to classify individual SSCs.

The design class for individual SSCs, including specific requirements and exceptions, are identified in Table 3.2-3.

Note that there is no direct correlation between the design class of an SSC and the seismic design requirements. Refer to Section 3.2.2.4 for the discussion of seismic qualification requirements.

3.2.2.1.1 PG&E Design Class I

PG&E Design Class I is applicable to SSCs that are important to safety, including SSCs required to assure the following:

(a) The integrity of the RCPB.

(b) The capability to shut down the reactor and maintain it in a safe shutdown condition.

(c) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to the guideline exposures of 10 CFR 100.11 (for tank rupture accidents) or 10 CFR 50.67 (for accidents analyzed using AST methodology).

(d) All plant features designated as PG&E Design Class I are designed to remain functional when subjected to the additional forces associated with the design basis earthquakes that they are required to withstand: the DE, the Double Design Earthquake (DDE) and/or the Hosgri Earthquake (HE). Refer to Section 3.2.2.4 for additional information regarding the earthquake requirements for the design of SSCs.

The following SSCs, including their foundations and supports, are classified as PG&E Design Class I:

(1) The RCPB

(2) The reactor core and reactor vessel internals

(3) Systems (refer to Notes (i) and (iii) below) or portions of systems that are required for emergency core cooling, post-accident containment heat removal, or post-accident containment atmosphere cleanup (refer to Note (iv) below)

(4) Systems or portions of systems that are required for reactor shutdown and RHR

(5) Those portions of the main steam, feedwater, and steam generator blowdown systems extending from and including the secondary side of the steam generators up to and including the outermost containment isolation valves, and connected piping up to and including the first valve (including a safety or relief valve) that is either normally closed or capable of automatic closure during all modes of normal reactor operation (refer to Note (iv) below)

(6) ASW, CCW, and AFW systems or portions of these systems that are required for emergency core cooling, post-accident containment heat removal, post-accident containment atmosphere cleanup, and RHR

(7) CCW system and seal water systems, or portions of these systems that are required to function to support other systems or components important to safety

(8) Those portions of systems (other than the radioactive waste management systems) that contain or may contain radioactive material and whose postulated failure could result in conservatively calculated potential offsite exposures in excess of 0.5 rem whole body (or its equivalent to parts of the body) at the site boundary or beyond

(9) Systems or portions of systems that are required to supply fuel for emergency equipment

(10) Systems or portions of systems that are required for (a) post-accident monitoring (PAM) of Regulatory Guide 1.97, Revision 3 (Reference 11), Category 1 variables and (b) actuation of systems important to safety (refer to Table 7.5-1)

(11) The protection system (refer to Note (ii) below)

(12) The spent fuel storage pool structure, including the spent fuel racks

(13) The reactivity control systems that are required to achieve safe shutdown of the plant; i.e., control rods, control rod drivers, and boron injection system

(14) The control room, including its associated vital equipment and life support systems, and any structures or equipment inside or outside of the control room whose failure could result in an incapacitating injury to the operators

(15) Reactor containment structure, including penetrations (refer to Note (iv) below)

(16) Systems or portions of systems that are required to provide heating, ventilating, and/or air conditioning for safety-related equipment/areas

(17) Portions of the onsite electric power system, including the onsite electric power sources, that provide the emergency electric power needed for functioning of SSCs included in Items (1) through (16) above

(18) Portions of the SFP cooling system used to remove spent fuel decay heat from the SFP, and portions of the refueling water purification system used to recirculate and cleanup the contents of the RWST

Notes:

(i) A PG&E Design Class I boundary includes those portions of the system required to accomplish the specified PG&E Design Class I safety function and connected piping up to and including the first valve (including a safety or relief valve) that is either normally closed or capable of automatic closure when the PG&E Design Class I safety function is required. Specific PG&E Design Class I boundaries (PG&E Quality/Code Class II components outside the reactor coolant pressure boundary or PG&E Quality/Code Class III components) with no valve or an open valve not capable of automatic closure were also qualified on the basis that it has been demonstrated that a failure of any of the lower-classification components does not impair the minimum PG&E Design Class I function or result in an uncontrollable release to the environment of gaseous activity normally required to be held for decay.

(ii) For purposes of these criteria, the protection system encompasses all electrical and mechanical devices and circuitry (from sensors to actuation device input terminals) involved in generating those signals associated with the protective function. These signals include those that actuate reactor trip and, in the event of a serious reactor accident, that actuate ESFs such as containment isolation, SI, pressure reduction, and air cleaning.

(iii) SSCs that form interfaces between PG&E Design Class I and PG&E Design Class II or III SSCs are designed to PG&E Design Class I requirements.

(iv) Certain valves in these systems that are used for accident mitigation only, and do not support safe shutdown following an HE, are qualified for active function for an HE to provide increased conservatism in accordance with Reference 7. Refer to the active valve list, Table 3.9-9.

While some portions of the FPS components are designated PG&E Design Class I, the system is not required to ensure the integrity of the RCPB or to shut down the reactor and maintain it in a safe shutdown condition. Fire protection SSCs meet the requirements defined in NFPA 805 (Reference 5, refer to Section 9.5.1) and, where designated in Table 3.2-3 as PG&E Design Class I, are designed to withstand the effects of an HE.

3.2.2.1.2 PG&E Design Class II

PG&E Design Class II is applicable to SSCs that are important to reactor operation but not essential to safe shutdown and isolation of the reactor, and failure of which would not result in the release of substantial amounts of radioactivity.

Seismic qualification of certain PG&E Design Class II SSCs for the DE, the DDE and/or the HE is required to satisfy licensing basis commitments. These SSCs, along with their seismic qualification requirements, are identified in Table 3.2-3. Refer to Section 3.2.2.4 for additional information.

(a) Those fluid systems and fluid system components that contain or may contain radioactive material, but whose failure would not result in calculated potential exposures in excess of 0.5 rem whole body (or its equivalent to parts of the body) at the site boundary. These fluid systems and fluid system components are designed to the accepted industry codes and standards in effect during the design and construction of DCPP.

(b) Power and auxiliary service piping systems (as defined in ANSI standard B31.1 , - Paragraph 100.1), which might otherwise be considered as PG&E Design Class III (refer to Section 3.2.2.1.3), are classified as PG&E Design Class II (i.e., PG&E Design Class III is not used for power and auxiliary service piping systems).

3.2.2.1.3 PG&E Design Class III

PG&E Design Class III is applicable to SSCs that are not related to reactor operation or safety.

Seismic qualification of certain PG&E Design Class III SSCs for the DE, the DDE and/or the HE is required to satisfy licensing basis commitments. These SSCs, along with their seismic qualification requirements, are identified in Table 3.2-3. Refer to Section 3.2.2.4 for additional information.

3.2.2.2 PG&E Quality Assurance Classification

Appendix B to 10 CFR Part 50, Quality Assurance Criteria for Nuclear Power Plants requires that SSCs important to safety be designed and constructed in accordance with the QA requirements and establishes such requirements for the design, manufacture, construction, and operation of these SSCs. 10 CFR Part 50, Appendix B, Criterion III, Design Control, states: “Measures shall be established to assure that applicable regulatory requirements and the design basis, as defined in 10 CFR 50.2 and as specified in the license application, for those SSCs to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions." DCPP QA Program, as described in the Diablo Canyon Quality Assurance Program Description, satisfies the requirements of Appendix B to 10 CFR Part 50.

PG&E Design Class I SSCs are subject to the requirements of the QA Program, in order to ensure that SSCs important to safety meet the requirements of 10 CFR Part 50, Appendix B. The QA Program also includes several graded quality programs that apply to specific PG&E Design Class II and III SSCs.

As described in Section 13.5.2.24, the NRC staff approved License Amendments 247 and 249 (Reference 12), that authorized PG&E to implement the provisions of 10 CFR 50.69 for DCPP. The provisions of 10 CFR 50.69 divides the existing "safety-related" and "nonsafety-related" classifications into two subcategories based on high or low safety significance through a categorization process. The categorization process does not replace the existing "safety-related" and "nonsafety-related" classifications. 10 CFR 50.69 allows alternative treatments to be implemented for SSCs that perform low safety significant functions in lieu of the special treatments (including the special treatment QA provisions of Appendix B to 10 CFR Part 50).

The following are PG&E QA Classes:

QA Class	Definition
Q	Equipment and structures to which the QA provisions of Appendix B to 10 CFR Part 50 apply for design, procurement, and construction.
"Blank"	PG&E Design Class II or III equipment that is not subject to nuclear QA requirements.
R	Those radioactive waste management items that require application of graded QA requirements.
G	Those portions of the FPSs and emergency lighting and communication equipment that require application of a quality program as described in NFPA 805 (Reference 5).
S	Equipment within the scope of the seismic configuration control program as defined in Inter-Department Administrative Procedure (IDAP) CF3.ID11. This PG&E Design Class II or III equipment requires seismic qualification to satisfy licensing or UFSAR commitments, or to assure the functionality of PG&E Design Class I components. Refer to Section 3.2.2.4 for additional information.
T	Regulatory Guide 1.97, Revision 3, Category 2 and 3 instrumentation that requires application of the graded QA Program as defined in IDAP CF3.ID12. (Note: Other Regulatory Guide 1.97 Category 2 and 3 instrumentation which is within the Environmental Qualification [EQ] Program, is part of the pressure boundary of a PG&E Design Class I System, or is a Class 1E electrical device, is PG&E QA Class Q.)

X Safety-related SSCs that the 10 CFR 50.69 categorization process has determined the SSC performs low safety significant functions.

The DCPP Q-List (Reference 8), indicates the QA Class associated with each SSC, along with the industry codes and standards used for their design, fabrication, erection, and testing. In addition, specific requirements dictated by the quality standards applicable to the respective commercial code classes (i.e., ASME, ANSI, or ASA) are identified.

In addition to the graded QA programs described above, there are other QA programs that do not directly relate to the design, fabrication, procurement, construction, modifications or installation of DCPP SSCs (e.g., Emergency Preparedness, Fitness for Duty, and Security [refer to Program Directive OM5, Attachment 4]). Reference to these other programs is not included in the Q-List.

3.2.2.3 PG&E Quality/Code Class for Fluid Systems and Fluid Components

This section describes the PG&E Quality/Code classes that are used to implement quality standards that satisfy GDC 1, 1967, for DCPP fluid systems and fluid system components. The interrelationship between the PG&E Quality/Code class, the PG&E Design Class (Section 3.2.2.1), the PG&E Piping Symbol (Section 3.2.2.3.4), and applicable codes and standards, is illustrated in Table 3.2-2.

A comparison of the PG&E Quality/code classes to the recommendations of ANSI N18.2, Draft 1970, Safety Guide 26, March 1972, and Safety Guide 29, June 1972 is provided in Table 3.2-4. PG&E is not committed to the classification categories described in these documents.

3.2.2.3.1 PG&E Quality/Code Class I Fluid Systems and Fluid System Components

10 CFR 50.55a requires that certain components of the RCPB be designed, fabricated, erected, and tested (Inservice Inspection and Inservice Testing [IST] per 10 CFR 50.55a) in accordance with the requirements for Class A[(a)] components of Section III of the ASME Boiler and Pressure Vessel Code, or the most recently available industry codes and standards. PG&E Quality/Code Class I is applied to those components of the RCPB and implements the quality standards that satisfy the requirements of 10 CFR 50.55a. PG&E Quality/Code Class I components of the RCPB are listed in Table 3.2-3, along with the industry codes and standards used for their design, fabrication, erection, and testing (refer to Table 3.2-2).

[(a)] The 1971 edition of the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, uses the term Class I in lieu of Class A.

The following provides a discussion of the PG&E Licensing Basis as compared to the other relevant regulatory and industry documents for comparison information only:

The PG&E Quality/Code Class I generally includes the fluid systems and components identified as Safety Class I in ANSI standard N18.2, Draft 1970, and Quality Group A in Safety Guide 26, March 1972. However, the classification and quality standards for DCPP fluid systems and components were established prior to the existence of these documents and, therefore, do not always fall within their strict definitions. All PG&E Quality/Code Class I fluid systems and components are in accordance with the accepted industry codes and standards that were in effect during the design and construction of DCPP. If fluid systems and components were designed and constructed to codes and standards outside of the requirements of the above-mentioned documents, additional quality standards have normally been applied.

3.2.2.3.2 PG&E Quality/Code Class II Fluid Systems and Fluid System Components

Generally, PG&E Quality/Code Class II is applied to fluid systems and fluid system components that are:

(1) Part of the reactor coolant boundary, but excluded from PG&E Quality/Code Class I requirements by 10 CFR 50.55a

(2) Not part of the RCPB, but part of:

(a) Systems or portions of systems[(b)] that are required for emergency core cooling, post-accident containment heat removal, or post-accident containment atmosphere cleanup

(b) Systems or portions of systems that are required for reactor shutdown and RHR

(c) Those portions of the main steam, feedwater, and steam generator blowdown systems extending from and including the secondary side of steam generators up to and including the outermost containment isolation valves, and connected piping up to and including the first valve (including a safety or relief valve) that are either normally closed or capable of automatic closure during all modes of normal reactor operation

(d) Systems or portions of systems that are connected to the RCPB and are not capable of being isolated from the boundary during all

[(b)] The system boundary includes those portions of the system required to accomplish the specified safety function and connected piping up to and including the first valve (including a safety or relief valve) that is either normally closed or capable of automatic closure when the safety function is required.

modes of normal reactor operation by two valves, each of which is either normally closed or capable of automatic closure

PG&E Quality/Code Class II fluid systems and fluid system components are listed in Table 3.2-3, along with the industry codes and standards used for their design, fabrication, erection, and testing (refer to Table 3.2-2).

The following provides a discussion of the PG&E Licensing Basis as compared to the other relevant regulatory and industry documents for comparison information only:

The PG&E Quality/Code Class II generally includes the fluid systems and components identified as Safety Class 2a in ANSI standard N18.2, Draft 1970, and Quality Group B in Safety Guide 26, March 1972. However, the classification and quality standards for DCPP fluid systems and components were established prior to the existence of these documents and, therefore, do not always fall within their strict definitions. All PG&E Quality/Code Class II fluid systems and components are in accordance with the accepted industry codes and standards that were in effect during the design and construction of DCPP. If fluid systems and components were designed and constructed to codes and standards outside of the requirements of the above-mentioned documents, additional quality standards have normally been applied.

3.2.2.3.3 PG&E Quality/Code Class III Fluid Systems and Fluid System Components

Generally, PG&E Quality/Code Class III is applied to fluid systems and fluid system components that are not part of the RCPB, nor included in PG&E Quality/Code Class II, but that are part of:

(1) ASW, CCW, and AFW systems, or portions of these systems that are required for (a) emergency core cooling, (b) post-accident containment heat removal, (c) post-accident containment atmosphere cleanup, or (d) RHR from the reactor

(2) Systems or portions of systems that are connected to the RCPB and are capable of being isolated from the boundary during all modes of normal reactor operation by two valves, each of which is either normally closed or capable of automatic closure

(3) Those portions of systems other than radioactive waste management systems that contain or may contain radioactive material, and whose postulated failure could result in conservatively calculated potential offsite exposures in excess of 0.5 rem whole body (or its equivalent to parts of the body) at the site boundary or beyond

(4) CCW system and seal water systems, or portions of these systems, that are required to function to support other systems or components important to safety

(5) Portions of the SFP cooling system required for spent fuel cooling, and the refueling water purification system whose postulated failure could result in a loss of RWST inventory

PG&E Quality/Code Class III fluid systems and fluid system components are listed in Table 3.2-3, along with the industry codes and standards used for their design, fabrication, erection, and testing (refer to Table 3.2-2).

The following provides a discussion of the PG&E Licensing Basis as compared to the other relevant regulatory and industry documents for comparison information only:

The PG&E Quality/Code Class III generally includes the fluid systems and components identified as Safety Classes 2b and 3 in ANSI standard N18.2 Draft 1970, and Quality Group C in Safety Guide 26, March 1972. However, the classification and quality standards for DCPP fluid systems and components were established prior to the existence of these documents and, therefore, do not always fall within their strict definitions. All PG&E Quality/Code Class III fluid systems and components are in accordance with the accepted industry codes and standards that were in effect during the design and construction of DCPP. If fluid systems and components were designed and constructed to codes and standards outside of the requirements of the above-mentioned documents, additional quality standards have normally been applied.

An exception exists to the above for PG&E Quality/Code Class III, Piping Symbol D piping. These are systems or portions of systems that were originally constructed as PG&E Design Class II and were subsequently upgraded to PG&E Design Class I, usually because a later requirement was updated. For such piping, the design analysis is in accordance with PG&E Design Class I criteria. All construction, repair, or replacement performed after the upgrade is in accordance with PG&E QA Class Q requirements.

3.2.2.3.4 PG&E Piping Symbol System

A system of PG&E piping symbols are used on all piping schematics and drawings to indicate the fabrication, erection, seismic qualification requirements and test criteria applicable to specific portions of each piping system. The PG&E piping symbols, including their correlation with PG&E Design Class and PG&E Quality/Code Class, are listed in Table 3.2-2.

3.2.2.4 Additional Classifications

3.2.2.4.1 Seismic Classifications

GDC 2, 1967 requires that nuclear power plant SSCs essential to the prevention of accidents be designed to withstand the effects of earthquakes. The seismic design classification of SSCs is not explicitly defined for DCPP. Instead, the seismic design requirements for an SSC are determined based on the combination of the DCPP specific classification categories:

(1) PG&E Design Class (refer to Section 3.2.2.1)

(2) PG&E Quality Assurance Classification (refer to Section 3.2.2.2)

(3) PG&E Quality/Code Class of Fluid Systems and Fluid Components (refer to Section 3.2.2.3)

(4) PG&E Piping Symbol (refer to Section 3.2.2.3.4)

(5) PG&E Instrument System Classifications (refer to Section 3.2.2.5)

(6) PG&E Electrical System Classifications (refer to Section 3.2.2.6)

Table 3.2-3 identifies the seismic qualification requirements for individual SSCs. For an SSC that requires seismic qualification, one or more of the following design basis earthquakes is included in the applicable load combinations:

(1) The Design Earthquake, as described in Section 3.7.1.2.1

(2) The Double Design Earthquake, as described in Section 3.7.1.2.2

(3) The Hosgri Earthquake, as described in Section 3.7.1.2.3

The acceptance criteria for an SSC that requires seismic qualification are based on maintaining structural/pressure boundary integrity (PBI) and may also include the ability to perform an active function, depending on the design basis function of the SSC.

The following general guidelines apply to the seismic qualification requirements for an SSC, specific details and exceptions are provided in Table 3.2-3:

(1) All SSCs designated as PG&E Design Class I are designed to remain functional when subjected to DE, DDE, and HE seismic loads.

(2) Most SSCs designated as PG&E Design Class II or III are not designed to remain functional when subjected to DE, DDE, or HE seismic loads.

(3) Based on specific licensing requirements, certain SSCs designated as PG&E Design Class II or III are designed to remain functional when subjected to DE, DDE, and/or HE seismic loads. These licensing requirements are addressed in Sections 3.2.2.1 and 3.2.2.3 and in Tables 3.2-1through 3.2-3, as applicable.

PG&E Design Class II or III may have some seismically qualified components (as defined in Table 3.2-3) and have no PG&E Quality/Code Class designation. However, some PG&E Design Class II components have been seismically designed; e.g., items in the Seismically Induced Systems Interaction (SISI) Program, specific components required for post-HE shutdown, (e.g., CCW header C components), and items that were designed for the DE (for specific SSC classifications refer to Table 3.2-3). For this reason, there is not a direct correlation between PG&E Design Class and the level of seismic qualification (except that PG&E Design Class I SSCs have seismically qualified components). In addition, the classification of seismically qualified components does not indicate which of the three design basis earthquakes the SSC has been qualified for, nor whether that qualification is for passive or active function. The design basis function of the equipment determines the type of seismic qualification required. These classifications and their relationships are summarized in Tables 3.2-1 and 3.2-2.

The definitions of the three DCPP Earthquakes are included below:

Design Earthquake

The DE (0.2g) is defined as the maximum size earthquake that can be expected to occur at DCPP during the life of the reactor. The DE is the equivalent of the operating basis earthquake, as described in 10 CFR Part 100, Appendix A.

Double Design Earthquake

The DDE (0.4g) is defined as the hypothetical earthquake that would produce accelerations twice those of the DE. The DDE is the equivalent of the safe shutdown earthquake, as described in 10 CFR Part 100, Appendix A.

Hosgri Earthquake

The HE (0.75g) is defined as the predicted ground motion at DCPP due to a Richter magnitude 7.5 earthquake on the offshore Hosgri fault. The HE does not correspond to an operating basis earthquake or safe shutdown earthquake.

Safe shutdown for DCPP is Hot Standby (MODE 3) and is achieved with PG&E Design Class I equipment qualified for DE, DDE, and HE. Cold shutdown for the Hosgri earthquake (refer to Section 3.7.6) may be achieved using equipment that is seismically qualified.

3.2.2.5 PG&E Instrument System Classifications

DCPP Instrumentation is classified as PG&E Instrument Class IA, IB, IC, ID, and II depending upon the function performed. PG&E Instrument Class IA, IB, IC and ID devices have PG&E Design Class I functions or other special requirements. PG&E Instrument Class II devices have PG&E Design Class II functions. Instrument classes are defined as follows:

(1) PG&E Instrument Class IA - PG&E Instrument Class IA instruments and controls are those that initiate and maintain safe shutdown of the reactor, mitigate the consequences of an accident, or prevent exceeding off-site dose limits in 10 CFR 100.11 (for tank rupture accidents) or 10 CFR 50.67 (for accidents analyzed using AST methodology. Class IA instruments and controls enable the PG&E Design Class I systems to automatically accomplish their appropriate safety functions, or they enable operating personnel to manually accomplish appropriate safety actions when a monitored condition reaches a preset level.

(2) PG&E Instrument Class IB – PG&E Instrument Class IB instruments and controls are those that are required for PAM of Category 1 and 2 variables in accordance with Regulatory Guide 1.97, Revision 3 (refer to Table 7.5-6). Regulatory Guide 1.97, Revision 3, Category 3 instruments required for PAM are PG&E Instrument Class II. PAM instrumentation enables operating personnel to:

(a) Determine when a condition monitored by PG&E Design Class I instruments and controls reaches a level requiring manual action

(b) Assess the accomplishment of plant safety functions

(c) Assess fission product barrier integrity

(d) Provide information to indicate the operability of individual systems important to safety

(e) Assess the magnitude of radioactive materials releases from the plant

PAM instruments are further divided into five variable types (A through E) as detailed in Regulatory Guide 1.97, Revision 3. These are further detailed in Section 7.5.

(3) PG&E Instrument Class IC – PG&E Instrument Class IC instruments and controls have the passive function of maintaining the PBI of PG&E Design Class I piping systems. Passive valve operators that are within PG&E Design Class I piping systems are PG&E Instrument Class IC and are

seismically analyzed to assure structural and PBI of the valve operator assembly. This classification also includes instruments installed in PG&E Design Class I heating, ventilation and air-conditioning (HVAC) ducting that are required to maintain PBI. In addition, this classification is used for instruments that are part of seismically qualified, PG&E Design Class II systems and denotes that the instruments are required to maintain their PBI.

(4) PG&E Instrument Class ID – PG&E Instrument Class ID instruments and controls are components that have certain PG&E Design Class I attributes, but do not require conformance with all PG&E Instrument Class IA, IB or IC requirements. The PG&E Instrument Class ID designation signifies that only certain design requirements are imposed for a component. The specific requirements for the PG&E Instrument Class ID instruments are provided on a case-by-case basis in the DCPP Q-List (Reference 8).

PG&E Instrument Class ID components are defined as:

Active components that have certain PG&E Instrument Class I attributes and are relied upon to satisfy licensing commitments or safety analyses, but do not require conformance with all PG&E Instrument Class IA and IB requirements, or Components that are electrically, mechanically or pneumatically coupled with, and whose failure may have an adverse impact on the operation of equipment with an active safety function, but do not themselves have an active safety function. These components have certain PG&E Instrument Class I requirements imposed on them to preclude their failure.

(5) PG&E Instrument Class II – PG&E Instrument Class II instruments and controls have PG&E Design Class II functions. However, certain PG&E Instrument Class II components are subjected to some graded QA requirements. This classification also includes instruments fulfilling Regulatory Guide 1.97, Revision 3, Category 3 PAM functions (refer to Table 7.5-6).

PG&E Instrument Classifications IA, IB and IC are not mutually exclusive. More than one classification may apply to a single instrument device. Where such multiple choices exist, the highest classification is assigned to the device.

3.2.2.6 PG&E Electrical System Classifications

Class 1E: The electrical equipment and components supporting PG&E Design Class I functions are shown in Table 3.2-1.

Non-Class 1E: The electrical equipment and components supporting PG&E Design Class II SSCs functions are shown in Table 3.2-1.

3.2.2.7 Summary and Comparison of PG&E Classification Systems

Generally, codes and standards were applied for construction prior to issuance of the latest codes and standards; i.e., prior to the 1971 edition of the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components. For these fluid systems and fluid system components, the design specifications specified the accepted industry codes and standards in effect during the design and construction of DCPP (refer to Table 3.2-2).

Table 3.2-2 shows the relationship among the following: PG&E Design Class, PG&E Quality/Code Class, PG&E Piping Symbols, seismically qualified components, and the Original Design/Construction Codes and Standards. Table 3.2-4 shows the relationship between DCPP classification categories and non-licensing basis regulatory and industry documents.

DCPP is committed to the PG&E classification categories (PG&E Design Class, PG&E Quality/Code, seismically qualified components, etc) as described in this section.

3.2.3 SAFETY EVALUATION

3.2.3.1 General Design Criterion 1, 1967 - Quality Standards

As discussed in Section 3.2.2, the DCPP classification system implements quality standards that satisfy the requirements of GDC 1, 1967.

3.2.3.2 General Design Criterion 2, 1967 - Performance Standards

As discussed in Sections 3.2.2.1 and 3.2.2.4, seismically qualified components at DCPP implement performance standards that satisfy the requirements of GDC 2, 1967, with respect to earthquakes.

3.2.3.3 10 CFR 50.55a - Codes and Standards

As discussed in Sections 3.2.2.2 and 3.2.2.3 the DCPP quality/code classification system includes codes and standards that satisfy the requirements of 10 CFR 50.55(a).

3.2.3.4 10 CFR Part 50 Appendix B - Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants

As discussed in Section 3.2.2.2, the DCPP QA Program ensures that the quality/code classification category includes requirements that satisfy 10 CFR Part 50, Appendix B.

3.2.4 REFERENCES

1. Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants. N18.2 American Nuclear Society, August 1970 Draft.

2. Quality Group Classifications and Standards for Water, Steam, and Radioactive Waste Containing Components of Nuclear Power Plants, Safety Guide 26, March 1972, Atomic Energy Commission.

3. Seismic Design Classification, Safety Guide 29, June 1972, US Atomic Energy Commission.

4. Spent Fuel Storage Facility Design Basis, Regulatory Guide 1.13, Nuclear Regulatory Commission.

5. 10 CFR 50.48(c), National Fire Protection Association Standard NFPA 805, Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants, 2001 Edition.

6. Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants, Regulatory Guide 1.143, October 1979, Revision 1, Nuclear Regulatory Commission.

7. PG&E Letter to the NRC, DCL-92-198 (LER 1-92-015).

8. Classification of Structures, Systems, and Components for Diablo Canyon Power Plant Units 1 and 2 (Q-List), PG&E.

9. Letter from NRC (L. F. Miller) to PG&E (G. M. Rueger), dated December 13, 1993, Subject: NRC Inspection of Diablo Canyon Units 1 and 2 (Report No. 50-275, 50-323/93-31) [pages 1 and 2].

10. Letter from NRC (A. W. Beach) to PG&E (G. M. Rueger), dated August 15, 1994, Subject: NRC Inspection Report 50-275/94-18; 50-323/94-18 (Notice of Violation) [pages 14 and 15].

11. Criteria for Accident Monitoring Instrumentation for Nuclear Power Plants, Regulatory Guide 1.97, May 1983, Revision 3, Nuclear Regulatory Commission.

12. Letter from Samson Lee (NRC) to Paula Gerten (PG&E), "Diablo Canyon Power Plant, Units 1 and 2 – Issuance of Amendment Nos. 247 and 249 RE: Adoption of 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors," dated December 11, 2024.

3.2.5 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

3.3 WIND AND TORNADO LOADINGS

PG&E Design Class I structures exposed to wind forces have been designed to meet wind loading criteria (refer to Section 3.3.1). The tornado resistance capabilities of PG&E Design Class I structures and certain PG&E Design Class II structures have been established (refer to Section 3.3.2).

3.3.1 WIND LOADINGS

3.3.1.1 Design Bases

3.3.1.1.1 General Design Criterion 2, 1967 – Performance Standards

PG&E Design Class I structures and certain PG&E Design Class II structures that can be postulated to have an effect on PG&E Design Class I structures are designed to withstand the additional forces imposed by natural phenomena such as wind.

3.3.1.2 Safety Evaluation

3.3.1.2.1 General Design Criterion 2, 1967 – Performance Standards

PG&E Design Class I structures and the turbine building have been designed to withstand the effects of design wind.

The design wind specified has a velocity of 80 mph based on a recurrence interval of 100 years and is in accordance with Reference 8. Section 2.3 gives information on winds recorded at the site during the period of operation of the meteorological facility. A gust factor of 1.1 was applied to the design wind. The resulting dynamic pressures, q, for the design wind velocity distribution, developed in accordance with Reference 1, are given in Table 3.3-1.

3.3.1.2.2 Containment Structure

Wind loads for the containment structure were developed in accordance with Reference 1 for the design wind. Methods and results of force calculations are discussed in Section 3.8.

3.3.1.2.3 Turbine Building

Since the PG&E Design Class II turbine building could potentially be a hazard to adjacent PG&E Design Class I structures, the turbine building is designed to withstand a design wind velocity essentially the same as that used for PG&E Design Class I structures. Due to the turbine building's unique size, shape, and configuration, International Conference of Building Officials Uniform Building Code (UBC-1967) and ASCE Transaction Paper Number 3269 (ASCE 3269) (Reference 1) criteria are not used to derive wind pressures for this building. The magnitude and distribution of wind

pressure loads on the turbine building are based on recommendations given in the United States Navy Design Manual DM-2 (Reference 10), except for the following conservatisms:

- The base for the vertical wind distribution is taken at sea level, rather than the ground elevation at the structure as specified in DM-2.

- A uniform wind pressure based on the average elevation of the roof is considered, rather than using the wind pressure variation with height specified in DM-2.

The turbine building design wind pressures, acting on the exterior surfaces of the building, are as follows:

Main Framing	
Windward side	25 psf
Leeward side	15 psf suction
Roof	20 psf suction
Girts and Purlins	
Windward side	35 psf
Leeward side	30 psf suction
Roof	35 psf suction

3.3.1.2.4 Other Buildings

Wind loads for buildings other than the containment structure and the turbine building were developed in accordance with the UBC-1967. This code designates the site as being in a 20 pound per square foot (psf) zone. To provide added conservatism, it was assumed for design purposes that the site is in a 25 psf zone. This resulted in the following distribution of wind loading with height above ground (the ground - or the base for wind distribution - was conservatively assumed to be at sea level):

Height Above Sea Level, feet	Wind Load (On Flat Surfaces), psf
0-29	20
30-49	25
50-99	30
100-499	40

These wind pressures were considered to act upon the gross area of the vertical projection of each PG&E Design Class I structure measured above the average level of the adjoining ground. The roof of each PG&E Design Class I structure was designed for an uplift pressure equal to three fourths of the wind pressure for the vertical projection, assumed to act over the entire roof area.

A comparison of the UBC-1967 wind pressure values with those obtained for the design wind, using the recommendations of ASCE 3269, is shown for the auxiliary building in Table 3.3-1. Wind values using ASCE 3269 are shown in the table column labeled "1.3q" (1.3 is the drag coefficient recommended by ASCE 3269). The top of the building is 105 feet above the ground surface. The comparison shows that the UBC-1967 wind pressures are greater than those recommended by ASCE 3269 up to about 70 feet above the ground surface. At greater heights, ASCE 3269 wind pressures are more than the UBC-1967 pressures. Design of the building considering both the UBC-1967 and ASCE 3269 wind pressures is discussed in Section 3.8.

3.3.2 TORNADO LOADINGS

Although the reported tornado probabilities are significantly less than the threshold for a credible event, the evaluation of DCPP's tornado effects is still considered as part of DCPP's design and licensing bases.

A tornado design criterion was not required as a condition for granting a construction permit for DCPP. However, the NRC required establishment of tornado design criteria, as a condition for granting an operating license that includes conservatively estimated translational and rotational wind velocities, atmospheric pressure drop and consideration of appropriate missiles (Reference 18). Additionally, the NRC required discussion of the effects of failure of structures or components caused by these loadings on the ability to achieve safe shutdown (Reference 18).

The Staff subsequently clarified their request for the tornado review. They asked that the review concentrate on identifying the capability of major structures to withstand a tornado and demonstrate that the plant can be safely shut down following the tornado, assuming that all offsite power is lost. A simultaneous accident such as a LOCA did not need to be considered, unless it was a direct result of the tornado.

The tornado resisting capabilities of plant SSCs determined by the review are summarized in Table 3.3-2. The consequences of failure of items with low to intermediate tornado resistance were then analyzed to determine their impact on the ability to achieve safe shutdown (Hot Shutdown, Mode 4) and if required, Cold Shutdown (Mode 5).

The methodology, assumptions and results of the above tornado review were discussed at an Advisory Committee for Reactor Safeguards meeting (Reference 19). PG&E presented an overview of the tornado review and its result as follows:

- ASCE Paper No. 3269, 1961 and BC-TOP-3 (References 1 and 2) were the basic technical references employed in the tornado capability review;

- Three hypothetical tornado-borne missiles were considered in the tornado review. They are currently listed in Section 3.3.2.3.2;

- An expanded inventory of missiles was analyzed to determine the maximum velocity attained and the thickness of concrete necessary to prevent perforation or generation of secondary missiles;

- The major findings of the tornado analysis currently provided in Section 3.3.2.5.1 were presented.

The NRC Staff also presented their position on DCPP tornado protection. The Staff concluded that the plant has substantial capability for tornado missiles, with the exception of three vulnerable areas: 1) the Class 1E 4.16-kV cable spreading and switchgear rooms in the turbine building; 2) the DGs and their radiators; 3) component cooling surge tank and associated exterior piping.

Subsequently, DG tornado missile barriers were added, along with modifications to the turbine building steel framing as currently described in Section 3.3.2.5.1(6) to reduce these vulnerabilities.

The NRC documented their review and acceptance of the DCPP design, including areas vulnerable to tornado missile damage, in SSER 07, SSER 16, and SSER 17. The NRC review concluded that the probability of tornado missile damage to these limited vulnerable areas was sufficiently low to be acceptable.

Based on the following evaluations performed subsequent to the initial review, PG&E has demonstrated that there is a low probability of tornadoes occurring at DCPP:

(1) The station blackout evaluation (Reference 11), using the methodology of NUMARC 8700 (Reference 12), determined that the annual expectation of tornadoes of severity f2 or greater (i.e., wind speeds greater than or equal to 113 mph) in events per square mile for DCPP is equal to 1.0×10^{-7}. As a result, a tornado has not been considered an initiator for a station blackout. The NRC's acceptance of the station blackout evaluation is documented in Reference 13.

(2) The Individual Plant Examination for External Events (IPEEE) (Reference 14) determined that the annual frequency of excessive tornado winds (i.e., wind speeds greater than or equal to 200 mph) was less than 3.2×10^{-7} per year. As a result, it was judged that a tornado wind-induced scenario is an insignificant contributor to overall core damage frequency and there are no plant vulnerabilities to high winds. The NRC's acceptance of the IPEEE evaluation is documented in Reference 15.

Subsequent inspections by PG&E identified several SSCs that did not have the necessary level of protection from tornado missiles. These SSCs were considered to be adequately protected since either the consequences of failure were no more significant than a tornado missile striking components within a 4.16 kV switchgear room, or because adequate shielding was afforded by adjacent structures; however, those conclusions had not been accepted by the NRC. These SSCs are associated with the emergency power system and are listed in Section 3.3.2.5.1(6), items (c) through (f). The use of the Tornado Missile Risk Evaluator (TMRE, NEI 17-02 Rev. 1B, Reference 20) concluded that the safety significance associated with the current exposure of these SSCs is sufficiently low such that additional physical protection from tornado missiles is not required.

3.3.2.1 Design Bases

3.3.2.1.1 General Design Criterion 2, 1967 – Performance Standards

PG&E Design Class I structures and certain PG&E Design Class II structures that can be postulated to have an effect on PG&E Design Class I SSCs are designed to withstand the additional forces imposed by natural phenomena such as tornadoes, including hypothetical consequential missiles.

3.3.2.1.2 Tornado Loadings Safety Function Requirements

(1) <u>Safe Shutdown</u>

Other than specific vulnerable areas approved by the NRC, DCPP provides shielding of SSCs or equipment separation to ensure that safe shutdown (Hot Shutdown Mode 4), and if required, Cold Shutdown (Mode 5), can be achieved and maintained in the event of a tornado and associated design basis missiles.

3.3.2.2 Methods and Assumptions

3.3.2.2.1 Tornado Resistance Capability Analysis

The tornado resistance capabilities of structures are determined using the following methods and assumptions:

- References 1 and 2 are the basic technical references employed in the tornado capability review;
- The tornado wind loads are determined using the method given in Section 3.3.2.4.1. The tornado capability considers both the wind and atmospheric loads on the structure as well as overall stability;
- The tornado missile loads are determined using the method given in Section 3.3.2.4.2. Tornado missile impact loads are combined with wind loads only where exterior walls protect PG&E Design Class I components;
- Three hypothetical tornado-borne missiles listed in Section 3.3.2.3.2 are used for structural response. The expanded list of missiles given in Section 3.3.2.7 are only evaluated for determination of maximum velocity and the thickness of concrete required to prevent perforation or generation of secondary missiles;
- Structures involved in the generation of electricity are designed to prevent collapse on PG&E Design Class I structures and to prevent generation of more severe missiles than the three hypothetical tornado-borne missiles listed in Section 3.3.2.3.2;
- Structures that are not directly involved in the generation of electricity are designed to lesser wind velocities.
- The three hypothetical missiles only act on vertical surfaces (i.e., vertical missiles need not be considered)
- Wind and pressure and associated pressure drop effects are applied to the element of the structure with the minimum capability in determining the safewind velocity.

3.3.2.2.2 Tornado Failure Consequence Analysis

The tornado failure consequence analysis is discussed in Section 3.3.2.5. The method and assumptions used in the analysis are as follows:

- A separate event, such as a LOCA, does not need to be postulated concurrent with a tornado unless it is a direct result of the tornado;

- Both units are operating at full power when the tornado strikes, with no prior initiation of shutdown procedures;
- The tornado causes a loss of offsite power and turbine trip;
- The plant is assumed to proceed to hot shutdown and then proceeds to cold shutdown, if necessary.

3.3.2.3 Applicable Design Parameters

3.3.2.3.1 Tornado Winds

There is no DCPP commitment to a specific design basis tornado windspeed. However, the NRC, in the evaluation of PG&E's tornado design criteria, used the methodology of WASH-1300, Technical Basis for Internal Regional Tornado Criteria, dated May 1974, to develop a conservative estimate of a tornado windspeed appropriate for DCPP. The NRC estimated that the design basis tornado windspeed (at a probability level of 10^{-7} per year) is about 200 miles per hour for the region at the plant site. The 200 mph tornado includes a 157 mph rotational component, a 43 mph translational component, and a differential pressure of 0.86 psi applied at a rate of 0.36 psi per second. However, DCPP used a safewind velocity as described in Section 3.3.2.5 and given in Table 3.3-2. Due to the low probability, the postulated tornado is unlikely to strike the site.

The general equation for tornado loads is:

$$W' = \left(C_p\, q_f + C_{pi}\, q_m\right) A + P_m \qquad (3.3\text{-}1)$$

where:

A = area exposed to wind
C_p = effective external pressure coefficient
C_{pi} = internal pressure coefficient
q_f = effective external velocity pressure
q_m = effective velocity pressure for calculating internal pressure
p_m = equivalent elastic missile impact loading

No gust factors or variation of wind velocity with height are assumed for tornadoes in evaluating overall response. However, in evaluating small structures (plan dimension less than 80 feet, and area less than 6400 square feet) or critical portions of large structures, an appropriate gust factor is used. Pressure coefficients are taken from Bechtel Corporation Topical Report BC-TOP-3 (Reference 2). The internal pressure coefficients used in the review include the combined effects on internal pressures from both wind and atmospheric pressure drop. The magnitude and sign of the internal pressure coefficient selected depends on the ratio of open to solid area of the exterior walls, and on which of the following combinations is critical:

(1) Maximum wind load alone

(2) Maximum wind + one-half maximum pressure drop without building depressurization

(3) Maximum pressure drop with building depressurization

(4) Maximum wind + one-half maximum pressure recovery without building repressurization

These combinations conservatively represent the effects of the transient atmospheric pressure history. In cases (2) and (4), no building internal pressure equalization is assumed in combining maximum wind with pressure drop or pressure recovery. It is physically impossible for maximum atmospheric pressure drop to occur simultaneously with maximum wind.

The coefficients relating atmospheric pressure drop to velocity pressure are applied to the resultant (rotational plus translational) wind component. This procedure is conservative because only the rotational component causes an atmospheric pressure drop.

The maximum atmospheric pressure drop depends on the wind speed and relative structure size:

- For large structures, the pressure drop is 2.1q, where q is the velocity pressure, corresponding to a pressure range of 1.2 psi to 3.4 psi for tornado wind speeds of 175 mph to 300 mph.

- For small structures and local portions of large structures, the pressure drop is 3.4q, corresponding to a pressure range of 1.9 psi to 5.4 psi for tornado wind speeds of 175 mph to 300 mph.

Velocity pressures (q) are converted to wind speeds (V) using the formula:

$$q = 0.00256\ V^2 \qquad (3.3\text{-}2)$$

where:

q = velocity pressure (psf)
V = wind speed (mph)

3.3.2.3.2 Tornado Missiles

Hypothetical tornado borne missiles considered for structural response are:

(1) 108 pound, 4- x 12-inch x 10 feet board at tornado wind velocity

(2) 76-pound, 3-inch x 10 feet schedule 40 pipe at one-third tornado wind velocity

(3) 4000 pound auto up to 25 feet above ground - frontal area 20 square feet at one-sixth tornado wind velocity

Only one missile is assumed to act at a time. Additional site-specific tornado missiles, such as siding, are evaluated to determine if they are more severe than the three listed hypothetical missiles.

3.3.2.4 Determination of Forces on Structures

3.3.2.4.1 Tornado Wind Forces

The basic technical references employed in the tornado review are ASCE Paper No. 3269 (Reference 1) and Topical Report BC-TOP-3 (Reference 2). BC-TOP-3 requires designing structures, which are directly involved in the generation of electricity, to prevent collapse on PG&E Design Class I structures and to prevent the generation of more serious missiles than the three hypothetical missiles defined in Section 3.3.2.3.2. BC-TOP-3 requires other structures that are not directly involved in the generation to be designed for lesser wind loads.

The safewind force capability is conservatively determined by deriving the uniform static load applied over the full height of the structure's projected area combined with atmospheric pressure drop at which induced stress in the critical element equals 0.9 F_y in bending and tension and 0.5 F_y in shear in the case of steel, or American Concrete Institute (ACI) 318-71 stress levels in the case of concrete structures. For the combined effect of wind and tornado-borne missiles, 1.0 F_y in bending and tension and 0.6 F_y in shear are used. Additionally, overall stability is checked by comparing the overturning moment of the wind forces to the resisting moment due to dead load only. Live and dead loads are considered to act simultaneously with tornado loadings. A load factor of unity is used in this load combination and is justified by the short duration and low probability of tornado loads.

3.3.2.4.2 Forces Derived From Tornado Missile Loading

Guidelines for this determination include the derived capability of structures or components for wind loads and an evaluation of the weight, weight to maximum cross-sectional area, and weight to minimum impact area of the potential missile. Tornado missiles produce impulsive load effects that are converted to equivalent elastic loads to

be combined with wind loads only at locations where exterior walls protect interior PG&E Design Class I components. Missile penetration capabilities are evaluated using the modified Petry formula for concrete, and the Ballistic Research Laboratories and Stanford formula for steel. For concrete structures, the missile impact load is converted to an equivalent elastic load, P_m, using the following procedures:

(1) Estimate average impact force:

$$F_i = \frac{W V^2}{2 g X} \qquad (3.3\text{-}3)$$

where:

W = missile weight
V = missile impact velocity
X = impact penetration as determined by modified Petry formula
g = acceleration of gravity

(2) Calculate duration of impact force:

$$t_i = \frac{2X}{V} \qquad (3.3\text{-}4)$$

(3) Determine dynamic load factor (DLF) versus the ratio of t_i/T, where T is the target period and a rectangular impulse is assumed

(4) Calculate equivalent static load as the product of impact force, F_i, and the DLF

(5) Calculate equivalent elastic load P_m:

Pm = Fi x DLF/10 for bending (3.3-5)

Pm = Fi x DLF/7.5 for shear (3.3-6)

The elastic indices of 10 for bending and 7.5 for shear are based on tests (3) that indicate that when using an elastic impulsive analysis, very high fictitious elastic stress will result. These tests indicate that the fictitious stresses corresponding to an elastic impulsive analysis are generally more than 10 times the usual static ultimate values.

(6) Calculate the ultimate buckling load of the missile, P_b. If P_m is less than P_b, use P_m. If P_m is greater than P_b, use P_b in evaluating structural capability.

For steel structures, missile impact loads are converted to equivalent static loads and structural response is evaluated using conventional methods, such as conservation of momentum and energy balance techniques, with due consideration for type of impact (elastic or plastic).

3.3.2.4.3 Piping Analysis

PG&E Design Class I piping in locations exposed to the weather is evaluated against the following tornado-related effects: (1) tornado wind loading, and (2) impact by tornado-borne missiles. Primary stresses associated with the first loading is evaluated on limiting pipe spans between supports against 120 percent of the normal allowable stress, as specified by the ANSI B31.1 piping code (refer to Section 3.9.2.2.3). Active piping supports (i.e., seismic snubbers) are assumed to resist the tornado wind effects. The second effect, tornado-borne missile impact, is evaluated via the methods described in ANSI 177-1974 (Reference 4). This evaluation considers the impact interaction energy to determine:

(a) Crushing of the pipe wall;

(b) Crushing of the missile;

(c) Penetration of the pipe wall.

The first two effects are evaluated against material yield strength, and the penetration effect is evaluated via the Ballistic Research Laboratory formula as described in “Design of Structures for Missile Impact,” Topical Report BC-TOP-9A, Revision 2, Bechtel Power Corporation, September 1974 (Reference 17).

3.3.2.4.4 Tornado Resisting Capability

Table 3.3-2 lists tornado resisting capabilities in terms of safewind velocities for PG&E Design Class I structures and PG&E Design Class II structures containing PG&E Design Class I components. In all cases, the safewind velocity includes wind pressure and associated atmospheric pressure drop effects, and is based on the element of the structure with the minimum capability. For almost all cases, the capability to resist the combined effects of a tornado and the most severe of the tornado-borne missiles is also given in terms of safewind velocity in Table 3.3-2. An expanded list of tornado-borne missiles has also been evaluated for maximum velocity developed and penetration and spalling of reinforced concrete missile barriers. This supplementary analysis is discussed in Section 3.3.2.7.

3.3.2.5 Tornado Analysis

The consequences of failure of items in Table 3.3-2 with low or intermediate resistance to tornadoes and tornado-borne missiles have been analyzed. The purpose of this

analysis is to determine whether such failure would compromise the capability of shutting the plant down safely.

In this determination, it is conservatively assumed that both units are operating at full power when the tornado strikes, with no prior initiation of shutdown procedures. The tornado is generally assumed to first cause complete loss of offsite power and a turbine trip, as described in Sections 15.2.9 and 8.3.1.1.3.3.5 (refer to Tables 8.3-2 and 8.3-3). The plant is assumed to proceed to hot shutdown and then to cold shutdown (if necessary), in accordance with procedures for loss of offsite power operation. The effects of failure of items in Table 3.3-2 have been analyzed for two cases: (a) following loss of offsite power, and (b) as the initiating event for plant shutdown.

Recorded tornadoes in California, and in the continental US in general, have traveled from the south or southwest to the north or northeast. In the analysis of consequences, this direction is postulated as the tornado path; and credit is taken qualitatively for protection afforded to external equipment or exposed components by structures in the postulated path.

3.3.2.5.1 Major Findings of the Tornado Analysis

The following are the major findings of the tornado analysis:

(1) The maximum postulated tornado wind velocity (300 mph) will not cause a LOCA or structural damage impairing containment integrity.

(2) All PG&E Design Class I structures, or structures housing PG&E Design Class I components, are capable of withstanding the wind effects of at least a 225 mph tornado without failure of major structural elements. Their resistance to the tornado-borne missiles corresponds to at least a 150 mph wind velocity. Structures are arranged on the plant site and protected in such a manner that the collapse of structures that do not have tornado-resisting capability will not affect those that must withstand the tornado effects.

(3) At calculated safewind velocities of equipment and structures, no missiles more severe than the three hypothetical missiles are generated.

(4) Loss of the following PG&E Design Class I equipment, with low or intermediate tornado resistance, will not compromise the capability of shutting down the plant safely:

    (a) Outdoor tanks

    (b) Plant vent

    (c) CRVS

(d) Auxiliary building and fuel handling area ventilation systems

(e) Miscellaneous instrumentation controls and instrument conduits associated with steam and feedwater lines of steam generators 1 and 2

(f) Piping and instrumentation on the CCW system surge tank.

(g) Auxiliary feedwater (AFW) system piping, valves and instrumentation in Area FE and Area FW

(h) 480-V switchgear and 125-Vdc inverter room ventilation system

(i) Containment penetrations

(j) 4.16-kV switchgear/cable spreading room HVAC system

(k) 10 percent atmospheric dump valves (PCV-19 to PCV-22)

(l) Containment penetration area GE/GW ventilation system

(5) The externally located PG&E Design Class I relief valves on the main steam system are susceptible to damage in the highly unlikely event of a direct impact from one of the tornado-borne missiles. The vulnerability of these valves was accepted by the NRC with no additional tornado missile protection required.

(6) The following components of the emergency power system were evaluated for tornado-borne damage:

(a) Diesel generators

(b) 4.16-kV Class 1E switchgear and cable spreading rooms.

Such damage would not be expected to affect more than one DG or more than one Class 1E 4.16-kV bus. This degree of damage will not affect the shutdown capability of the plant, even if all offsite power is lost. However, tornado missile barriers have been provided to preclude tornado-borne damage to the DGs.

Additional girts have been added to the turbine building steel framing at the 4.16-kV switchgear and cable spreading rooms to prevent the exterior siding from becoming a missile during a 200 mph tornado. The turbine building framing modifications are shown in Figures 3.3-1 and 3.3-2.

The following components have been concluded to not require additional physical protection from tornado missiles based on the low safety significance associated with their exposures as determined by the TMRE method (see Section 3.3.2.6.3):

(c) Diesel generator engine exhaust lines

(d) Diesel generator ventilation system exhaust plenums

(e) Large Diameter 4.16 kV raceways routed through the 12 kV switchgear rooms

(f) Class 1E raceways containing Diesel Generator 2-3 circuits routed along the 140' elevation of the Unit 2 Turbine Building and through the 12 kV switchgear room

3.3.2.5.2 Detailed Results of the Tornado Analysis

3.3.2.5.2.1 Auxiliary Building

The tornado resistance capabilities of the major portions of the auxiliary building are given by Table 3.3-2, Item 1(a). The tornado resistance capabilities of the rooms housing the Class 1E 125-Vdc battery room ventilation supply and exhaust fans at elevation 163 feet are given by Table 3.3-2, Item 1(b). All PG&E Design Class I equipment within the building is behind concrete walls or within concrete enclosures. The CCW surge tank and the Class 1E 480-V switchgear and Class 1E 125-Vdc inverter room ventilation system located on the roof of the auxiliary building are evaluated for tornado effects in Sections 3.3.2.5.2.2 and 3.3.2.5.2.12, respectively.

Venting to limit effects of atmospheric pressure drop was not included in the design of the auxiliary building, nor assumed in the subsequent analysis of the structure. With the assumption of no venting and the selection of corresponding internal pressure coefficients, the building is conservatively shown to be capable of sustaining at least a 3.4 psi pressure drop. If venting through openings and louvers were assumed, the capability would exceed 300 mph.

The auxiliary building houses equipment for three PG&E Design Class I ventilation systems. Air intake or exhaust louvers for these systems have limited tornado-resisting capability. The PG&E Design Class I ventilation systems within the auxiliary building potentially affected by tornado are: (a) the main ABVS (refer to Section 9.4.2), (b) the CRVS (refer to Section 9.4.1), and (c) the fuel handling building ventilation system (FHBVS) (refer to Section 9.4.4). Section 3.3.2.5.2.3 has additional information on FHBVS tornado capabilities. The consequences of tornado damage affecting these ventilation systems are discussed below.

The main auxiliary building ventilation equipment that is potentially vulnerable to tornado damage is located in the auxiliary building at elevation 140 feet. Air intake openings and equipment access panels create potential tornado vulnerability for this area, although the containment, turbine building, and fuel handling building structures provide protection from tornado missiles. Separation of the redundant auxiliary building ventilation supply fans ensures that cooling air to safe shutdown equipment would be available should a tornado generated missile damage one supply fan. Damage to the ventilation control components could cause inlet vane dampers to fail open, but supply fans would continue to run. Although intake louvers will yield and could be forced inward at tornado wind speeds, blockage of the auxiliary building intake openings is considered highly unlikely.

CRVS equipment is located in the auxiliary building at approximate elevation 154 feet in a mechanical equipment room. Rooms to the east of the mechanical equipment room contain condenser units required for control room cooling, but not required for ventilation.

Three types of louvers are part of the CRVS (refer to Figure 9.4-1): (a) inlet louvers tied by ductwork to dampers and inlet filter banks, (b) exhaust louvers tied by ductwork to dampers, and (c) inlet and outlet louvers associated with the air-cooled condensers.

At a wind speed of about 100 mph, the louver yields in bending, or the louver attachment to the louver frame yields. A deformed louver assembly could be blown inward at a higher wind speed and could damage related components, such as filters and dampers, or buckle attached ductwork. The redundant supply fans are not considered vulnerable to such damage because of their physical location in relation to the inlet and exhaust louvers, and because of the number of components (dampers, filters, etc.) in the ductwork between the louvers and the fans. Complete blockage of the ducts by the damaged louvers is highly unlikely. As a result, the CRVS is most likely to continue operation in Mode 1 following a tornado.

Without a simultaneous control room fire or accident, operation of other components is not required to maintain adequate temperature conditions for personnel or instrumentation in the control room during post-tornado shutdown. The redundant air-cooled condensers are not considered vulnerable to damage from being hit by displaced louvers. A condenser could be damaged by a tornado-borne missile penetrating through the louvers.

Multiple missiles would be required to render inoperative more than one of the four condensers serving the CRVS of the two units. Even if all inlet ducts were blocked by damage or by loss of air to the pneumatic dampers, and if all air-cooled condensers were rendered inoperative, operators would take appropriate action based on plant conditions.

FHBVS equipment located in Area L of the auxiliary building at elevation 100 feet is potentially vulnerable to tornado damage because of supply fan air intake openings.

These air intake openings are fully shielded to the south (Unit 1) and north (Unit 2) by the containment structures. Significant shielding is afforded these air intakes by the pipeway structure and turbine building to the west. The FHBVS supply fans are located in a compartment beneath the air intakes and are not vulnerable to the effects of a tornado-borne missile. In the unlikely event that a missile were to enter the FHBVS equipment through the air intake, supply fan discharge ducting and dampers could be impacted. While damage to the ducting could occur that could degrade system performance, the supply fans would still be expected to provide adequate air flow to the fuel handling building PG&E Design Class I equipment.

The Class 1E 125-Vdc battery room ventilation equipment in the fan rooms on the auxiliary building roof on approximate elevation 163 feet is PG&E Design Class II and damage to this equipment due to a tornado does not affect the safe shutdown capability of the plant.

3.3.2.5.2.2 Component Cooling Water System Surge Tank

The surge tank of the CCW system (refer to Section 9.2.2) is supported horizontally at the L-line on the roof of the auxiliary building (refer to Figures 1.2-21 and 1.2-25). A baffle at the tank's mid-length extends about 40 percent up the tank volume to divide it into two compartments. Each compartment has its own liquid level instrumentation (refer to Figure 3.2-14) and a 6-inch surge line to one of the two independent trains of the CCW system. Each surge line is fed by a makeup line with an air-operated level control valve. This connection is made inside the auxiliary building. The high-level alarm actuates above the top of the tank divider.

The tornado resistance capability of the tank is given by Table 3.3-2, Item 1(e). The weakest element of the tank structure is the anchorage, which fails in bearing on concrete and results in only minor displacement of the tank. It is highly unlikely that such displacement would result in either rupture of the relief valve header or surge lines.

The surge lines run from beneath the surge tank, along the auxiliary building roof, and down the outside wall to elevation 140 feet, where they enter the auxiliary building. These lines are exposed to tornado-borne missiles after they exit from beneath the surge tank until they enter the auxiliary building. The relief valve header, the vent and valve, and the two sets of liquid level instrumentation are on the east side of the surge tank and are susceptible to damage by tornado-borne missiles. Tubing, valves, and instrumentation added for surge tank nitrogen/air pressurization are also susceptible to damage by tornado-borne missiles. The tank does provide considerable protection in the postulated path of the tornado, particularly to instrumentation taps located below the operating liquid level of the tank. An exposed raceway carries the common Class 1E conduit from the surge tank to the control room.

Failures of the raceway, the liquid level instrumentation, the nitrogen/air pressurization components, and pipes and valves are analyzed in Table 3.3-3. This analysis

demonstrates that the CCW system would continue to operate satisfactorily even with postulated tornado damage. The CCW system surge tank is readily accessible from the control room, so immediate assessment of any damage following a tornado is possible.

Failure of the surge lines are analyzed in Table 3.3-3.

3.3.2.5.2.3 Fuel Handling Area

Analysis of the basic structure of the fuel handling area, with partial loss of siding, provides a conservative estimate of capability to withstand a wind velocity given by Table 3.3-2, Item 2a. The worst case analysis, based on elastic behavior, shows tornado wind and missile resistance capability given by Table 3.3-2, Item 2a. Because of the conservatism inherent in the assumptions for these calculations, the resistance to tornado-induced missiles is believed to be considerably higher.

Purlins, girts, siding, roofing, doors, and louvers are damaged at lower wind velocities. They are not essential to the overall structural integrity of the fuel handling area and do not produce missiles more severe than the hypothetical missiles. The metal siding and roofing do not provide significant missile protection for the building contents.

Analysis of potential water loss from the SFP shows that the water cover remaining over the fuel provides adequate protection against both fuel damage and pool liner penetration from tornado-borne missiles. Water lost from the SFP can be replenished from on-site water supplies (refer to Section 9.1.3). The FHBVS exhaust ducts and fuel handling area radiation monitors have limited tornado resisting capability. Failure of these components does not affect safe shutdown capability. Since damage to the spent fuel does not occur, the capability of the FHBVS to maintain a negative pressure in the fuel handling area is not required after a tornado.

3.3.2.5.2.4 Containment Structure

The tornado resistance capability of the containment structure, including equipment, personnel, and escape hatches are given by Table 3.3-2, Items 3a and 3b. The tornado resistance capability of the containment pipeway structure is given by Table 3.3-2, Item 3h.

Containment pipe penetrations for main steam and feedwater lines for steam generators 1 and 2 and some non-Class 1E and spare electrical penetrations are located within the pipeway structure. No other containment penetrations are exposed to the effects of a tornado. As described in Section 3.3.2.5.2.7, the tornado resistance capability of the main steam and feedwater piping is given by Table 3.3-2, Item 3e. The non-Class 1E circuits within the electrical penetrations are not required for safe shutdown of the plant. The electrical penetrations for both Unit 1 and Unit 2 are significantly shielded by the turbine building, containment structure, and the auxiliary building. In addition, the pipeway structure affords additional local protection for these penetrations. Therefore,

tornado induced damage to these penetrations is considered extremely unlikely and would not affect safe shutdown capability.

3.3.2.5.2.5 Plant Vent

The plant vent is anchored securely to the containment and can withstand loads from a wind velocity of greater than 300 mph. The internal framing supporting the duct will yield at a wind velocity of about 125 mph, but the duct remains functional at higher wind velocities. The tornado-borne missiles would damage and penetrate the vent. The plant vent handles exhaust from the auxiliary building, fuel handling areas, and penetration area ventilation fans, steam air ejector and gland steam condenser, containment purge system, and gas decay system. The plant vent contains sample probes for the plant vent gas and particulate radiation monitor. The containment purge, steam ejector line, and the gas decay system have radiation monitors prior to discharge to the plant vent (refer to Sections 9.4.2, 9.4.3, 9.4.4, and 9.4.5).

The FHBVS and penetration area ventilation systems do not need to be operated while the plant is brought to a safe shutdown condition. The damage to the plant vent will not prevent the ABVS from exhausting. The containment purge system is normally operated only during extended plant shutdowns, and operation during safe shutdown procedures is not necessary. The remaining process flows exhausted through the plant vent are not necessary for and are unrelated to attaining safe shutdown capability. It is therefore concluded that the plant can be safely shut down even if the plant vent and its radiation monitoring capabilities are damaged by a tornado.

3.3.2.5.2.6 PG&E Design Class I Raceways and Instrumentation

Exposed PG&E Design Class I raceways are attached to the support structure for the main steam and feedwater lines outside the containment (refer to Figure 3.3-3). These raceways carry control wiring to actuate various mechanical components of the steam, feedwater, and AFW systems. These items are shadowed from two directions as indicated in Figure 3.3-3. Some of this equipment is located in exposed instrumentation panels on the outside of the containment. The NRC approved these main steam, feedwater, and auxiliary feedwater raceways without additional tornado missile protection on the basis that the probability of tornado generated missiles striking the small vulnerable areas is small enough to be negligible.

A failure analysis has been performed on these raceways and panels. Two cases were examined: (a) failure with the plant operating normally, and (b) failure with the plant already being shut down due to loss of all offsite power caused by the tornado. The results of this analysis, given in Table 3.3-4, indicate that the plant can be shut down safely.

Main steam pressure transmitters, main feedwater flow transmitters, and AFW flow transmitters associated with steam generators 1 and 2 are located within mechanical panels at elevation 85 feet underneath the pipeway structure. The equivalent

transmitters for steam generators 3 and 4 are within the auxiliary building structure and are not vulnerable to tornado damage. In addition, main steam line radiation monitors are located adjacent to main steam lines 1 and 2 near the containment pipe penetrations.

The steam generator pressure transmitters (PT-514 to PT-516 and PT-524 to PT-526) provide a SI and main steam isolation signal on low steam generator pressure using two-out-of-three logic. A SI signal will be actuated only upon loss of at least two of the three redundant pressure transmitters associated with each steam line. The SI signal can be classified as spurious and is a Condition II fault discussed in Section 15.2.15. Steam generator pressure indicators for steam generators 3 and 4 are not affected by the tornado, and these steam generators would be used to attain safe shutdown.

The main feedwater system would receive isolation signals as a result of the SI signal being produced. With the main feedwater isolation valves (MFIVs) closed and the feedwater pumps tripped, the main feedwater flow transmitters (FT-510, FT-511, FT-520 and FT-521) do not provide relevant information. These transmitters, while conservatively designated as PG&E Instrument Class IA, do not have any PG&E Design Class I functions.

The AFW transmitters (FT-50 and FT-77) provide control room indication and do not have any protective functions. If these transmitters are lost, steam generator level (especially wide range steam generator level, which is recorded) would provide an assessment of the status of the AFW system to steam generators 1 and 2. If steam generator 1 and/or 2 level cannot be controlled due to damage to AFW system components in the pipeway structure, AFW to steam generator 1 and/or 2 can be secured and the plant can be safely shutdown using steam generators 3 and 4.

The main steam line radiation monitors are provided to detect primary-to-secondary radiation releases resulting from a steam generator tube rupture accident. Such an accident condition is not assumed to occur concurrently with extreme weather conditions. Therefore, tornado-induced failure of these instruments is of no consequence and does not affect safe shutdown capability.

A seismic trip sensor located in the pipeway area is one of three sensors that generate a reactor trip signal if seismic accelerations exceed a predetermined level using two-out-of-three logic. Loss of power to these sensors will not result in a trip signal. Damage to this instrument and its resultant output signal is of no consequence and does not affect safe shutdown capability.

3.3.2.5.2.7 External PG&E Design Class I Piping and Valves

Main steam lines 1 and 2, and associated feedwater piping, penetrate the containment at elevation 129 feet. This piping is carried to the turbine building at approximate elevation 112 feet on a support structure external to the containment (refer to Figures 1.2-5 and 1.2-21 for Unit 1, and Figures 1.2-10 and 1.2-28 for Unit 2). This piping and

associated steam relief valves are PG&E Design Class I up to and including the first isolation valves outside the containment. On main steam lines 1 and 2, the relief valves are located directly on the piping. On main steam lines 3 and 4, which are enclosed within the auxiliary building, the relief valves are located on separate headers on the roof of the enclosure at elevation 143 feet (refer to Figures 1.2-4 and 1.2-21).

The tornado resistance capability for the main steam and feedwater piping is given by Table 3.3-2, Item 3e. At this wind velocity, the piping is capable of supporting all loadings associated with the most severe tornado-borne missile without penetration of the pipe wall.

The outdoor 4-inch main steam piping to the AFW pump turbine is vulnerable to damage from a tornado missile. A break in this piping would be considered a minor secondary pipe break, which is a Condition III fault discussed in Section 15.3.2. A breach in this 4-inch main steam piping could cause a loss of the AFW pump 1 turbine. The motor-driven AFW pump 3 supplying steam generators 3 and 4 would still be available for plant shutdown. In addition, AFW pump 2 would be available, although there is a potential for wind induced damage to its level control valves as discussed below.

The steam generator safety relief valve spindles are considered vulnerable to direct impact by a missile. Such impact could result in severance of the spindle. However, this is not expected to result in a valve discharge or pressure boundary leakage. The relief valves represent extremely small targets for a missile and a direct hit is considered extremely unlikely. The relief valve headers for lines 3 and 4 of both Unit 1 and Unit 2 are almost completely protected by the containment and auxiliary building concrete structures, particularly from the south and southwest. The containment for Unit 1 also provides considerable protection from those directions to the relief valves on main steam lines 1 and 2 for that unit. The NRC approved the main steam relief valve spindles without additional tornado missile protection on the basis that the probability of tornado generated missiles striking these small vulnerable areas is small enough to be negligible.

The mechanical portions of other externally located valves associated with main steam lines 1 and 2 are not considered susceptible to tornado or tornado missile damage. The following other events related to these valves are considered:

(a) loss of air supply to main steam isolation valve;

(b) rupture of the bypass line around a main steam isolation valve;

(c) failure of the motor operator on a MFIV;

(d) loss of air supply to main feedwater control and bypass valves

The main steam isolation valve is held open by compressed air. The valve has an integral pneumatic supply to hold the valve open (or to open it one time, if closed), upon loss of the main air supply. Such loss would, therefore, have no consequences. If the integral pneumatic supply is damaged, the valve is driven shut by an internally mounted spring. The inadvertent closing of a main steam isolation valve is similar to the inadvertent closing of a turbine stop valve, a Condition II fault whose consequences are discussed in Section 15.2.7.

The bypass around a main steam isolation valve is a 3-inch line. Its rupture by missile impact qualifies as a minor secondary system pipe break, as analyzed in Section 15.3.2. The consequences of such a break are considerably less than those of a 6-inch-diameter break, which is the limiting case in that section and is equivalent to the inadvertent opening of a steam relief valve.

Failure of the motor operator on a MFIV causes the valve to remain as is. The valve is normally open during plant operation. A PG&E Design Class I feedwater control/bypass valve and a PG&E Design Class I check valve are installed upstream of each MFIV. These valves provide additional means of isolating the feedwater line and provide the pressure boundary for operation of the AFW system if the isolation valve were to fail open. Therefore damage to the isolation valve operator or a loss of power that would cause it to fail as-is would have no affect on the integrity of the feedwater line or operation of the AFW system.

The air operators on the main feedwater control and bypass valves fail in the closed position upon loss of air or loss of dc power to the trip solenoid. The isolation valve and check valve installed downstream of each control/bypass valve provide additional means of isolating each feedwater line. A malfunction of the feedwater control or bypass valves, such as accidental full opening, is a highly unlikely consequence of tornado damage since these valves fail closed. However, this type of malfunction (a Condition II fault) is discussed in Section 15.2.10.

The AFW system piping and valves located in Area FE and Area FW, at approximately 130 feet elevation (supply to steam generators 1 and 2), were identified as potentially vulnerable to tornado wind and induced missile effects. This piping has been analyzed to withstand over 300 mph wind velocity. Hence, it is very unlikely that these components will be damaged due to tornado winds. However, the AFW piping and valves in these areas are still susceptible to tornado-borne missile damage. On the basis that only one missile will occur at a time, such damage is limited to only one train of the AFW system. Thus, there will be no complete loss of AFW system function because redundant trains are available.

The following events related to AFW valves have been considered:

(a) Failure of the motor operator on an AFW control valve;

(b) Failure of the electro-hydraulic AFW level control valves;

(c) Failure of the motor-operated steam supply valve to the turbine-driven AFW pump.

The motor-operated AFW level control valves (LCV-106 and LCV-107) for the turbine-driven AFW pump are normally open. These valves are used for remote manual throttling to maintain an appropriate steam generator level if the turbine-driven AFW pump is utilized. In case of loss of power to these valves, the turbine-driven AFW pump can be secured if necessary and secondary system decay heat removal can be accomplished using steam generators 3 and 4 and motor-driven AFW pump 3. None of these components are vulnerable to tornado damage as they are contained within the auxiliary building structure.

The electro-hydraulic AFW level control valves (LCV-110 and LCV-111) for the motor-driven pump that supplies AFW to steam generators 1 and 2 fail in the open position on loss of power. These valves are used for remote manual throttling to maintain an appropriate steam generator level if the motor-driven AFW pump to steam generators 1 and 2 is utilized. In case of loss of power to these valves, the motor-driven AFW pump can be secured if necessary and secondary system decay heat removal can be accomplished using steam generators 3 and 4 and motor-driven AFW pump 3. None of these components are vulnerable to tornado damage since they are contained within the auxiliary building structure.

Loss of remote manual control to the above noted AFW level control valves may result in some excess in feedwater injection from the AFW system. A much greater excess in feedwater injection, such as results from inadvertent full opening of a main feedwater supply valve, is a Condition II fault discussed in Section 15.2.10.

Failure of the motor operator on the steam supply valve to the turbine-driven AFW pump (FCV-37) causes the normally open valve to remain in the as-is position. The valve is not required to change position for operation of the AFW system. Therefore, damage to this valve operator or its electrical circuitry does not affect safe shutdown capability.

Loss of air supply or power to the 10 percent atmospheric dump valves (PCV-19 to PCV-22) will cause the valves to remain in their closed position. This is the preferred failure mode, as opposed to the 10 percent atmospheric dump valves failing open causing uncontrolled depressurization of the steam generators. Steam generator pressure transmitters PT-516A and PT-526A provide non-PG&E Design Class I control signals to the 10 percent atmospheric dump valves and could be damaged by a tornado. If the control schemes for these valves are damaged, the plant would remain at hot standby using the steam generator safety relief valves for secondary system heat removal until the secondary system is depressurized by manual operation of these valves using their handwheels. Therefore, tornado-borne damage to the 10 percent atmospheric dump valve control scheme does not adversely affect safe shutdown capability.

The steam generator blowdown tank vent condenser and the 3/4-inch CCW supply and return piping are located outdoors at elevation 140 feet above the auxiliary building. This piping is part of CCW Header C and as such is a non-essential heat load. Tornado damage to the supply lines, return lines, or the steam generator blowdown tank vent condenser was evaluated to confirm that the CCW system leakage will be significantly less than the maximum acceptable system leakage. Therefore, tornado-borne damage to these components does not adversely affect CCW system operation.

Four-inch diameter containment hydrogen purge lines are located outdoors at elevation 140 feet above the auxiliary building. This system is used if accident conditions produce potentially explosive hydrogen concentrations inside containment. Given that extreme weather conditions do not have the capability to result in inside-containment accidents, the use of these lines would not be required after a tornado. Therefore, tornado-borne damage to these lines is of no consequence.

3.3.2.5.2.8 Turbine Building

Analysis of the basic structure of the turbine building, with partial loss of siding, provides a conservative estimate of tornado resistance capability given by Table 3.3-2, Item 4a.

The tornado resistance capability of the 24-inch concrete walls of the turbine building is given by Table 3.3-2, Item 4b. The corresponding tornado resistance capability for 12-inch concrete walls is given by Table 3.3-2, Item 4b.

Purlins, girts, siding, roofing, doors, and louvers are potentially damaged by tornado wind velocities less than 175 mph. The tornado resistance capability of the siding system at the exterior walls (north and east sides for Unit 1, south and east sides for Unit 2) protecting the Class 1E 4.16-kV switchgear and cable spreading rooms is given by Table 3.3-2, Item 4d. The roofing, siding, and louvers cannot withstand the tornado-borne missiles discussed in Section 3.3.2.3.2.

The turbine building contains major components of the standby power supply, described in Chapter 8, which are:

(a) the three 4.16-kV Class 1E buses (buses F, G, and H) for Unit 1 and Unit 2 including associated switchgear;

(b) the six DGs, three for each unit.

The possibility of tornado-related damage to these standby power system components, and the potential effect on safe shutdown capability, has been considered and are discussed below. Such damage has potential impact on safe shutdown capability only if all offsite power is lost.

Class 1E 4.16-kV switchgear for the standby power supply is located at elevation 119 feet between column lines D and G (refer to Figures 1.2-14 and 1.2-18). Cable

spreading rooms associated with this switchgear are located immediately below the switchgear at elevation 107 feet (refer to Figures 1.2-15 and 1.2-19). Both the switchgear and the cable spreading rooms are located above the concrete portion of the turbine building wall. Exterior turbine building walls in these areas consist of steel siding installed on a structural steel framework. Separation between components associated with each of the bus sections is provided by reinforced 8-inch concrete block partitions, as shown in Figure 3.3-4.

As shown in Figures 1.2-2 through 1.2-32, the turbine building structure provides protection from tornado-generated missiles above, below, and on two sides of the 4.16-kV switchgear and cable spreading rooms. The remaining two sides (north and east side for Unit 1, south and east side for Unit 2) are enclosed by steel siding on a structural steel framework. Some protection is provided by the structural steel, but tornado-generated missiles could penetrate the siding and damage standby power supply components. On the north and south sides (north side for Unit 1, south side for Unit 2), only components associated with bus H are directly exposed to such damage. On the east side, the ends of compartments housing components associated with buses F, G, and H are similarly exposed to tornado-generated missiles.

Concrete block partitions between Class 1E buses minimize the possibility that tornado-generated missiles penetrating the north or south (north side for Unit 1, south side for Unit 2) turbine building walls would damage components associated with buses F and G.

The containment building for each unit and the auxiliary building provide a substantial amount of tornado missile protection for the east turbine building wall. In addition, the topography of the site reduces the likelihood that tornado-generated missiles would damage standby power supply components by penetrating the east wall of the turbine building.

Tornado-related damage would not be expected to affect more than one Class 1E 4.16-kV bus. Such damage would not affect the capability for safe shutdown, even with the loss of offsite power.

The DGs are located in the west side of the turbine building, three between column lines 1 and 5 (refer to Figure 1.2-16) and three between column lines 31 and 35 (refer to Figure 1.2-20). The DGs in each group are separated from each other by 10-inch concrete walls. The exterior walls to the north, south, and east protecting the DGs are capable of withstanding 200 mph tornado wind and missile loads. Openings in the west walls of the turbine building between these column lines, and between floor elevations 85 and 107 feet, for DGs are protected by tornado missile barriers. The tornado missile barriers, consisting of closely spaced beams, are provided to protect the DG compartments and their air intakes at elevation 85 feet at the west wall of the turbine building. The barriers are designed to withstand the combined effects of a 200 mph wind and tornado missiles.

The DG compartment ventilation system (refer to Section 9.4.7) uses the DG silencer rooms and an external plenum as the exhaust air flow path to the atmosphere. The external plenum, located at the west wall of the building, is integral with the turbine building structural framing and is enclosed on three sides and the bottom with corrugated metal siding. The east side of the plenum is open to the DG silencer rooms at elevation 107 feet and the top is open to the atmosphere. The plenum was added in order to improve the operation of the ventilation system when the diesel engines are operating under extreme weather conditions.

The external plenum, including the steel framing, girts, siding, and turning vanes, is designed for the effects of 200 mph tornado wind loads. The design is performed in accordance with the methodology given in BC-TOP-3. The tornado wind speed corresponds to that used for the design of the added girts, which support the siding at the Class 1E 4.16-kV switchgear and cable spreading rooms (refer to Section 3.3.2.5.1 and Table 3.3-2).

Due to its exposed location, the exhaust air plenum may be vulnerable to damage by a tornado-generated missile. The impact of a missile on the plenum could result in localized damage to the framing, which supports the plenum, or puncture of the siding, which forms the exterior boundary of the plenum. However, the plenum represents a small vulnerable area for missile impact, and is not designed for missile loads. The exhaust plenum was determined not to require any additional physical protection from tornado missiles due to low safety significance of its exposure as determined by the TMRE method.

The diesel exhaust lines routed above elevation 107 feet are potentially vulnerable to tornado wind loads if the turbine building siding is blown off. Analyses demonstrate that the exhaust lines will not be affected by tornado wind loads. The diesel exhaust lines were determined not to require any additional physical protection from tornado missiles due to low safety significance of their exposure as determined by the TMRE method.

The electrical conduits for DG 2-3 at elevation 140 feet are routed close to the concrete floor and are shielded from tornado influences to some extent by control room pressurization system (CRPS) piping and other raceways, but are exposed and potentially vulnerable to tornado missiles. These conduits were determined not to require any additional physical protection from tornado missiles due to low safety significance of their exposure as determined by the TMRE method.

Banks of large diameter conduits from the 4.16-kV cable spreading rooms routed through the non-Class 1E 12-kV switchgear room are separated by electrical division and are encased in rigid fireproofed vaults that afford some protection against tornado debris and minor missiles. This room is constructed of 12-inch reinforced concrete capable of withstanding tornado wind and missile loads. However, exhaust air louvers in the east wall provide a pathway for a tornado missile to strike banks of conduits routed directly in front of the wall penetrations. These banks of large diameter conduits were determined not to require any additional physical protection from tornado missiles

due to the low safety significance of their exposure as determined by the TMRE method.

The 4.16-kV switchgear room/cable spreading room ventilation system supply fans and supply ducting at elevation 119 feet and exhaust ducting at elevation 140 feet could be vulnerable to the effects of a tornado if the building siding is blown off. Compartment heatup analyses demonstrate that loss of this ventilation equipment does not jeopardize electrical equipment in these compartments due to elevated temperatures. Therefore, this ventilation system equipment is not required for safe shutdown of the plant.

The CCW heat exchangers and associated CCW and ASW piping, valves, and instrumentation are protected from the effects of tornado because of their location within the turbine building.

Plant protection system inputs from the main turbine first stage pressure are protected from the effects of tornado wind and missiles. The process tubing is routed in protected areas within the turbine building and is enclosed within a protective barrier. The sensing transmitters and signal circuitry are contained within the CCW heat exchanger room.

3.3.2.5.2.9 Outdoor PG&E Design Class I Tanks

PG&E Design Class I tanks located at the east end of the auxiliary building (refer to Figure 1.2-2) include the condensate storage tank (CST), the fire water storage and transfer tank, and the RWST. The tornado resistance capability of these concrete-protected steel tanks is given by Table 3.3-2, Item 5. These capabilities do not take credit for the concrete encasement. When the concrete encasement is considered, these tanks are capable of withstanding a wind velocity of 300 mph. The anchorages that prevent the tanks from overturning have a design capacity greater than a 300 mph wind load. Based on these considerations, a tank failure producing an instantaneously large leak and flood is extremely unlikely, particularly as the tanks are concrete-protected. The 5-million-gallon PG&E Design Class II raw water reservoir provides a backup source of water supply.

The RWST (refer to Section 6.3.2.4.2) is normally used to supply borated water to the refueling canal for refueling operations when the plant is already in a safe shutdown condition. Its PG&E Design Class I function is to supply borated water to ECCS pumps and containment spray pumps following a SI signal.

The fire water storage and transfer tank, with a 300,000 gallon capacity (refer to Section 9.5.1), is the shared backup source of fire water. The normal source of fire water is the shared raw water reservoir. The fire water storage and transfer tank inventory may also be used to supplement the CST for AFW and as a source of makeup water to the SFP. While tornado-borne damage to the fire water storage and transfer tank is considered extremely unlikely, such damage would not affect safe shutdown capability of Unit 1 and

Unit 2. The raw water reservoir provides an alternate capability for the functions performed by this tank.

The CST (refer to Section 9.2.6) supplies normal makeup and rejection requirements of the steam plant. Its PG&E Design Class I function is to provide 200,000 gallons for Unit 1 and 166,000 gallons for Unit 2 (out of a total capacity of 425,000 gallons) for the AFW system during the plant cooldown to 350°F. While tornado-borne damage to the CST is considered extremely unlikely, such damage would not affect safe shutdown capability. The raw water reservoir provides an alternate capability for the function performed by this tank.

The raw water reservoir is the backup source of AFW. The reservoir (refer to Section 9.2.3) is below grade, concrete- and PVC-lined, and divided into two compartments to permit maintenance without removing the reservoir from service.

The total potential demand on the reservoir resulting from total loss of water inventory in the CST's for Unit 1 and Unit 2 is 392,000 gallons. This amount of water represents less than 10 percent of the capacity of both compartments in the reservoir and about 16 percent of one compartment. Based on APED-5696, Tornado Protection for the Spent Fuel Storage Pool (Reference 5), a relatively large and shallow pool, such as the raw water reservoir, is susceptible to partial dewatering by a tornado of specific size and path. A detailed analysis of water loss has not been made since simultaneous, essentially complete loss of water from both tanks and from the reservoir is not considered credible.

3.3.2.5.2.10 Intake Structure

The tornado resistance capability of the intake structure and the ASW pump room vent shaft extensions are given by Table 3.3-2, Item 6. The gantry crane for servicing equipment within the structure is susceptible to overturning at a wind velocity above 110 mph in its anchored position. In this position the crane is located near the north end of the craneway approximately 80 feet from the vent shaft above the intake structure; damage to the structure or to its components from the crane is considered extremely unlikely. The crane is kept in its anchored position when not in use.

3.3.2.5.2.11 PG&E Design Class II Outdoor Electrical Equipment

In addition to the structures listed in Table 3.3-2, the tornado-resisting capability of PG&E Design Class II outdoor electrical equipment has been evaluated. This capability ranges from greater than 250 mph for main transformers, to about 100 mph for such equipment as the isophase bus duct structure. No missiles more severe than the hypothetical missiles are generated by a tornado-induced failure of this equipment. In addition, no PG&E Design Class I equipment is endangered by any such failure.

3.3.2.5.2.12 480-V Switchgear and Class 1E 125-Vdc Inverter Room Ventilation System

The portion of the ventilation system for the Class 1E 480-V switchgear and Class 1E 125-Vdc inverter rooms (refer to Section 9.4.9) located on the auxiliary building roof is potentially vulnerable to the effects of a tornado. Potentially affected equipment includes the redundant supply and exhaust fans, dampers, ducting, and instrumentation and electrical raceways supporting the operation of the ventilation system.

If the ventilation system is completely lost due to a tornado, alternate cooling (propping open doors and starting portable fans) would be provided to the affected rooms in sufficient time, before electrical equipment necessary to complete safe shutdown operations is affected from overheating. Compartment heatup analyses demonstrate that sufficient time is available for plant personnel to take these actions before safe shutdown equipment overheats. Therefore, loss of the ventilation system following a tornado does not compromise the capability to safely shutdown the plant.

3.3.2.5.2.13 Containment Penetration Area GE/GW Ventilation System

The Design Class I portion of the containment penetration area GE/GW ventilation system is anchored securely to the containment and connected to the plant vent. The system must have the same tornado and wind resistant capabilities as the plant vent. The containment penetration area GE/GW ventilation system can withstand loads from a wind velocity of 300 mph. The framing supporting the duct will yield at a wind velocity of about 125 mph, but the duct remains functional at higher wind velocities. The tornado-borne missiles would damage and penetrate the duct. Operation of the containment penetration area GE/GW ventilation system is not necessary for and is unrelated to attaining safe shutdown capability. It is therefore concluded that the plant can be safely shut down without additional radiation exposure to the public, even if the containment penetration area GE/GW ventilation system is damaged by a tornado.

3.3.2.5.2.14 Outdoor Hatch Covers

Several outdoor pull box and hatch covers are not anchored for tornado winds in accordance with Topical Report BC-TOP-3 (Reference 2). Some of these pull box and hatch covers have been determined to be more serious missiles than the three hypothetical missiles defined in Reference 2 and in Section 3.3.2.3.2. Use of the Tornado Missile Risk Evaluator (TMRE) method, NEI 17-02, Rev. 1B (Reference 20), considers the pull box and hatch covers in the site missile population. TMRE concludes that the safety significance associated with the unsecured pull box and hatch covers is sufficiently low that deviation from BC-TOP-3 methodology is acceptable and that additional physical protection from these covers becoming potential tornado missiles is not required.

3.3.2.6 Safety Evaluation

3.3.2.6.1 General Design Criterion 2, 1967 – Performance Standards

The total effect of the tornado on PG&E Design Class I structures was determined by combining the individual effects of the tornado wind pressure, pressure drop and hypothetical missiles (refer to Section 3.3.2.4). The results of this review indicate that the maximum postulated tornado wind velocity (300 mph) will not cause a LOCA or structural damage which would impair containment integrity (refer to Section 3.3.2.5). All other PG&E Design Class I structures or structures housing PG&E Design Class I components are capable of withstanding the effects of at least a 225 mph tornado without failure of major structural elements. Their resistance to the hypothetical missiles corresponds to a 150 mph wind velocity. Structures are arranged at DCPP and protected such that the collapse of structures which do not have tornado resistance capability does not affect those which must withstand the tornado effects (refer to Section 3.3.2.5). The use of these design criteria provides assurance that the structural integrity and safety function of PG&E Design Class I structures will not be impaired as a result of a tornado. Table 3.3-2 lists tornado resisting capabilities in terms of safewind velocities for PG&E Design Class II structures containing PG&E Design Class I components. Failure of the PG&E Design Class II turbine building and PG&E Design Class I components located outdoors does not affect the plant's ability to achieve safe shutdown (refer to Section 3.3.2.5).

The effects of tornado missile impact on PG&E Design Class I structures and missile barriers are determined by analysis (refer to Section 3.3.2.4). The analysis first determines the potential damage done in the vicinity of impact by estimating the depth of missile penetration. The overall response of the structure when impacted by the design basis missiles is determined by methods of impactive analysis. The analysis provides assurance that the integrity of PG&E Design Class I structures will not be impaired or degraded as a result of design basis missiles striking the structure. PG&E Design Class I systems and components located within these PG&E Design Class I structures are thereby protected from the effects of missiles (refer to Sections 3.3.2.2 and 3.3.2.3).

3.3.2.6.2 Tornado Loadings Safety Function Requirements

(1) <u>Safe Shutdown</u>

The tornado analysis demonstrates that existing shielding and separation assures that safe shutdown (Hot Shutdown Mode 4), and if required proceed to Cold Shutdown (Mode 5) can be achieved and maintained in the event of a tornado and associated design basis missiles. Consequences of failure of items with low or intermediate resistance to tornadoes and the design basis tornado missiles do not compromise the ability of DCPP to achieve and maintain safe shutdown.

3.3.2.6.3 Tornado Missile Risk Evaluator (TMRE)

The Tornado Missile Risk Evaluator (TMRE) method (NEI 17-02 Rev. 1B, Reference 20) is an NRC-approved method to determine whether SSC protection from tornado-generated missiles is required. The SSCs identified in Section 3.3.2.5.1(6), items (c) through (f) have been determined to not require additional protection from tornado missiles based on the TMRE method. The TMRE method may only be used to demonstrate that existing conditions do not require additional physical protection from tornado missiles. It cannot be used in place of physical protection in future plant modifications.

3.3.2.7 Supplementary Analysis of Additional Tornado Missiles: Estimated Maximum Missile Velocity, Required Barrier Thickness

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

The following expanded list of tornado-borne missiles has also been analyzed to determine the maximum velocity attained and the thickness of a reinforced concrete missile barrier necessary to preclude perforation or the generation of secondary missiles. The previously discussed three hypothetical missiles (refer to Section 3.3.2.3.2) are approximately the same as items (1), (6), and (7) in the following list:

(1) 4- x 12-inch plank, 12 feet long, with a density of 50 lb/ft^3

(2) Utility pole 13.5 inches in diameter by 35 feet long with a density of 43 lb/ft^3

(3) 1-inch solid steel rod, 3 feet long, with a density of 490 lb/ft^3

(4) 6-inch Schedule 40 pipe, 15 feet long, with a density of 490 lb/ft^3

(5) 12-inch Schedule 40 pipe, 15 feet long, with a density of 490 lb/ft^3

(6) 3-inch Schedule 40 pipe, 15 feet long, with a density of 490 lb/ft^3

(7) 4000-pound automobile with a volume of 1.67 x 6 x 17 ft^3

The analysis employed in developing the maximum missile velocity is based on methods described in Reference 6. The tornado characteristics used as initial conditions include a constant tangential wind speed of 250 mph.

A three-dimensional (3-D), right-circular-cylinder representation is assumed for the funnel cloud. Vertical and radial velocity components are taken from Bates & Swanson (Reference 7).

The vertical component varies with elevation. The radial component varies from a peak value at the outside surface and drops abruptly to zero at the inside surface of the funnel cloud. With this model, the tornado missile forcing function and, consequently, the potential missile destructive forces do not significantly vary with elevation, since the vertical velocity component and its variation with elevation are small relative to the tangential velocity component.

The calculation of the ejection velocity of the postulated missile from the tornado vortex described above is based on solving the equation of motion for the missile. The missile is assumed to accelerate as it follows the path of the maximum tangential wind speed at the surface of the funnel cloud. It is ejected when the pressure differential and aerodynamic forces acting on the missile are overcome by centrifugal forces. Further assumptions are: (a) the missiles do not tumble, and present the maximum value of $C_d A/W$ *while in flight, and (b) the ejection velocity thus determined is the maximum velocity attained by the missile.*

Modified missile velocities are calculated for those missiles incapable of being sustained after initial injection into the tornado wind field. Injection is calculated by assuming a 0.2-second impulse due to the aerodynamic lift force. From this calculation, an initial height for missile injection can be determined. Subsequent suspension and increase or decrease in elevation is determined by a new force balance including lift and gravity forces acting on the missile at the initial injection height. For the nonsustained missile, the modified horizontal velocity upon its return to the elevation of origin is then computed. Horizontal and vertical velocity components are decoupled in this latter calculation for simplicity. This approach is justified because the vertical wind speed is small compared to its horizontal component.

The required thickness of a reinforced concrete barrier to preclude perforation due to end-on impact of the additional tornado-borne missiles is computed by the modified Petry formula. The estimated thickness required to prevent the formation of secondary missiles is conservatively taken as 1.5 times the thickness required to preclude perforation. This approximation is based on a comparison of the thickness required to prevent perforation and spalling of concrete targets. These thicknesses were determined for various missile types with velocities ranging from 40 to 250 fps. Calculations were based on the Army Corps of Engineers and National Defense Research Committee formulas. Although these formulas are applicable for missile velocities exceeding 500 fps, they represented the only available basis for estimating the thickness required to prevent secondary missile generation.

The results of the supplementary analysis of additional missiles are presented in Tables 3.3-5 and 3.3-6.

3.3.3 REFERENCES

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12. Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors, Nuclear Management and Resources Council, NUMARC 8700, Revision 0.

13. NRC Letter to PG&E, Supplemental Safety Evaluation of PG&E Response to Station Blackout Rule (10 CFR 50.63) for Diablo Canyon (TAC Nos. M68537 and M68538), May 29, 1992.

14. PG&E Letter DCL-94-133 to the NRC, Response to Generic Letter 88-20, Supplement 4, Individual Plant Examination of External Events for Severe Accident Vulnerabilities, June 27, 1994.

15. NRC Letter to PG&E, Review of Diablo Canyon Individual Plant Examination of External Events (IPEEE) Submittal (TAC Nos. M83614 and M83615), December 4, 1997.

16. Deleted.

17. Design of Structures for Missile Impact, Topical Report BC-TOP-9A, Bechtel Corporation, Revision 2, September 1974.

18. NRC Letter to PG&E, FSAR Deficiencies and Additional Requirements, August 13, 1973.

19. Advisory Committee on Reactor Safeguards, 182nd General Meeting Proceedings, June 5, 1975.

20. NEI 17-02 Rev. 1B, Tornado Missile Risk Evaluator (TMRE) Industry Guidance Document, The Nuclear Energy Institute, September 2018.

3.4 WATER LEVEL (FLOOD) DESIGN

PG&E Design Class I SSCs are designed to withstand the effects of potential external flooding.

PG&E Design Class I SSCs are also protected against the effects of internal flooding, which may result from piping breaks and equipment/component failures.

3.4.1 DESIGN BASES

3.4.1.1 General Design Criterion 2, 1967 – Performance Standards

PG&E Design Class I structures and certain PG&E Design Class II structures that can be postulated to have an effect on PG&E Design Class I SSCs are designed to withstand the effects of, or are protected against, natural phenomena such as flooding.

3.4.1.2 Water Level (Flood) Design Safety Function Requirement

(1) Internal Flooding Protection

PG&E Design Class I SSCs are protected against the effects of internal flooding, which may result from leakage or rupture of piping or equipment.

3.4.2 SAFETY EVALUATION

3.4.2.1 General Design Criterion 2, 1967 – Performance Standards

External flood elevations, phenomena considered in design load calculations, flood force application, and flood protection are addressed in the following subsections.

3.4.2.1.1 Flood Elevations

PG&E Design Class I components are located in the intake structure, turbine building, auxiliary building, fuel handling building, and containment building, and in the plant yard. The intake structure top deck nominal elevation is 17.5 feet mean sea level (MSL). The turbine, auxiliary, fuel handling, and containment buildings are all at nominal elevation 85 feet MSL, and the PG&E Design Class I structures in the yard (outdoor water storage tanks) are at nominal elevation 115 feet MSL.

As discussed in Section 2.4, the design combination tsunami-storm wave run-up is elevation 48 feet mean lower low water (MLLW) (45.4 feet MSL). In addition, wave action may result in water splashing to elevations in excess of 52 feet MLLW (49.4 feet MSL). These elevations affect the intake structure, but are well below and do not affect the turbine building, auxiliary building, fuel handling building, containment building, or outdoor water storage tanks located in the plant yard at the 85 foot level or higher.

As discussed in Section 2.4 Diablo Creek is adequate to handle the probable maximum flood (PMF), and yard and roof drainage designs are such that it is not possible to develop sufficient ponding to flood PG&E Design Class I buildings. Thus, the depth of water at the plant location for the PMF is zero.

3.4.2.1.2 Phenomena Considered in Design Load Calculations

As discussed above, the intake structure is the only structure that contains PG&E Design Class I equipment and that is affected by the design combination tsunami-storm wave run-up for DCPP. Section 2.4 discusses the characteristics of the tides, storm waves, storm surge, and tsunami waves that were considered in the development of the design loading on the intake structure and the PG&E Design Class I components contained within it.

3.4.2.1.3 Flood Force Application

The hydraulic forces on the intake structure resulting from the design flood conditions and when the breakwaters are assumed to be degraded to MLLW were determined by hydraulic scale model tests and reported in References 1, 2, and 3.

3.4.2.1.4 Flood Protection

Sections 2.4.5 and 2.4.6 describe flooding protection provisions for PG&E Design Class I SSCs associated with sea wave activity and tsunami. Section 3.8.5.1 discusses the adequacy of the design of the intake structure with respect to the associated flood force application.

The intake structure is designed with an elevated air intake so that the PG&E Design Class I ASW pumps can operate during the design combination tsunami-storm wave run-up. As discussed in Section 2.4.6.7, analysis of wave splash-up from the hydraulic scale model tests was performed as documented in Reference 4 to demonstrate that ingestion of sufficient seawater through the intake structure snorkels into the ASW pump rooms is extremely unlikely to jeopardize operation of the ASW pumps. These pumps are located below elevation zero feet MSL. The pumps are mounted at a nominal floor elevation -2.1 feet MSL, and each pump is housed in a separate watertight compartment. The ASW pump compartment is provided with a watertight door, and a back flow preventer in the room drain line. Associated alarms in the control room are discussed in Section 9.2.7.5. The location and arrangement of this equipment are shown in Figure 9.2-2.

Underground cables located in cable vaults are inspected and maintained in accordance with plant administrative controls to prevent degradation that could be caused by submergence of the cables.

During excavation for the Unit 1 containment structure, some seepage of ground water was encountered. Since the flow of water into the excavation was slight, no special provisions for the base slab were considered necessary. However, to provide the

capability to detect the presence of water in the future, two collector loops were installed under each containment structure: one at approximate elevation 52 feet (bottom of the reactor cavity), and one at approximate elevation 74 feet (bottom of the base slab). The loops at each containment structure are connected to observation wells. The observation wells are capped to contain radon gas emitted from the wells. Provisions are made on the cap plate to be able to monitor the wells, and, if water should accumulate, to allow groundwater to be pumped from the wells.

3.4.2.2 Water Level (Flood) Design Safety Function Requirement

3.4.2.2.1 Internal Flooding Protection

Protection of PG&E Design Class I SSCs from the effects of internal flooding due to pipe rupture is discussed in Section 3.6. Potential sources of flooding, the consequences of postulated flooding, and other precautions to prevent such flooding are more specifically discussed in subsections on systems with a potential for causing flooding, including:

(1) Auxiliary saltwater system (refer to Section 9.2.7)

(2) Service cooling water system (refer to Section 9.2.1)

(3) Component cooling water system (refer to Section 9.2.2)

(4) Makeup water system (refer to Section 9.2.3)

(5) Condensate storage facilities (refer to Section 9.2.6)

(6) Fire protection water system (refer to Section 9.5.1)

(7) Circulating water system (refer to Section 10.4.5)

(8) Condensate and feedwater system (refer to Section 10.4.7)

(9) Chilled water system, for cable spreading room air conditioning system (refer to Section 9.4.9)

3.4.2.2.2 Internal Flooding Detection

The operator would be alerted to equipment failure or pipe rupture leading to flooding by the annunciation of the faulted system's pressure, temperature, flow, level, overcurrent, etc., alarms (located in the control room) in addition to the auxiliary building high-sump level alarm. High-flow alarms are installed in the fire water and makeup water systems since they are high-capacity nonradioactive systems. The location of failures in radioactive systems would be aided by the control room annunciation of area radiation monitors located throughout the auxiliary building as described in Section 11.4. The operator would be alerted to incipient failures by routine visual observation of sight

glasses provided for the drainage header of each zone. These sight glasses are located in the corridor adjacent to the auxiliary building sump.

3.4.3 REFERENCES

1. O. J. Lillevang, et al., The Height Limiting Effect of Sea Floor Terrain Features and of Hypothetically Extensively Reduced Breakwaters on Wave Action at Diablo Canyon Sea Water Intake, March 15, 1982.

2. F. Raichlen, The Investigation of Wave-Structure Interactions for the Cooling Water Intake Structure of the Diablo Canyon Nuclear Power Plant, December 1982.

3. E.N. Matsuda, Wave Effects on the Intake Structure at Diablo Canyon, Units 1 and 2, January 1983.

4. P. J. Ryan, Investigation of Seawater Ingestion into the Auxiliary Salt Water Pump Room Due to Splash Runup During the Design Flood Events at Diablo Canyon, January 1983.

3.5 MISSILE PROTECTION

The DCPP design provides protection for PG&E Design Class I systems and components, including ESFs, from internally and externally generated missiles. This section discusses the design bases for DCPP missile protection and includes information on missile barriers and loadings, missile selection, selected missiles, barrier design procedures and missile barrier features.

3.5.1 DESIGN BASES

3.5.1.1 General Design Criterion 40, 1967 – Missile Protection

ESFs are designed to be protected against missiles generated inside and outside of containment that might result from plant equipment failures.

3.5.1.2 Missile Protection Safety Function Requirements

(1) Protection From Missiles

PG&E Design Class I SSCs inside and outside of containment are protected against the effects of missiles, which may result from equipment failures and from events and conditions outside the nuclear power unit.

3.5.2 SYSTEM DESCRIPTION

3.5.2.1 Missile Barriers and Loadings

DCPP was designed and built with structures, shields, and barriers that are designed to withstand missile effects.

3.5.2.1.1 Missiles Generated Within the Containment

The principle design bases for missiles generated within the containment are that missiles generated coincident with a LOCA shall not cause loss of function of any ESF, PG&E Design Class I equipment or cause a loss of containment integrity (refer to Section 3.6). The containment is defined as the containment structure, liner and penetrations, the steam generator shell, the steam generator steam-side instrumentation connections, and the steam, feedwater, blowdown, and steam generator drain piping within the containment structure.

Other than the ECCS lines that must circulate cooling water to the reactor vessel, the ESFs are located outside the crane wall. The ECCS lines are routed outside of the crane wall so that the penetrations are in the vicinity of the loop to which they are attached. Physical separation together with barrier protection provided by the refueling cavity walls and various structural beams serve to minimize the potential for missiles generated in one loop from damaging adjacent loops. The portion of the steam and

feedwater lines within the containment has been routed behind barriers that separate them from all reactor coolant piping.

The lower steam generator shell connecting lines are routed so that they are not in the direct path of any postulated missile.

The systems located inside the containment structure have been examined to identify and classify potential missiles. The basic approach is to ensure design adequacy against generation of missiles, rather than to allow missile formation and then try to contain their effects.

Catastrophic failure of the reactor vessel, steam generators, pressurizer, reactor coolant pump (RCP) casings, or piping leading to generation of missiles is not considered credible. Massive and rapid failure of these components is not credible because of the material characteristics, inspections, quality control during fabrication, erection, operation, conservative design, and prudent operation as applied to the particular component (refer to Section 3.6). The RCP flywheel is not considered a source of missiles for the reasons discussed in Sections 5.2.3.20 and 5.2.3.2.1. Nuts and bolts are of no concern because of the small amount of stored elastic energy.

Components considered to have a potential for missile generation inside the reactor containment are listed as follows:

(1) CRDM, drive shaft, and the drive shaft and drive mechanism latched together

(2) Certain valve bonnets

(3) Temperature and pressure sensor assemblies

(4) Pressurizer heaters

The structures designed to withstand missile effects within the containment are:

(1) The integrated head assembly (IHA) missile shield provided over the CRDMs is intended to block missiles defined in Tables 3.5-2 and 3.5-3.

(2) The pressurizer enclosure is designed to block missiles listed in Tables 3.5-4 through 3.5-6.

(3) The polar crane wall, fuel transfer canal walls, and operating floor at elevation 140 feet constitute barriers for temperature elements and valve bonnets as described in Tables 3.5-4, 3.5-5 and 3.5-6, to prevent them from reaching the containment liner.

3.5.2.1.2 Missiles Generated Outside the Containment

The ESF and PG&E Design Class I systems located outside the containment structure have been reviewed to determine the possible sources and consequences of missiles. Catastrophic failure of pressure vessels and system piping outside the containment structure is not considered credible as a source of missiles because of the conservative design, material characteristics, inspection during erection, and prudent operation. Pressurized gas containers of significant quantities are summarized in Table 3.9-11. Thrust loads resulting from a postulated failure of the largest connected pipe or manifold have been calculated to produce stresses no larger than yield in the container hold-down structure; therefore, no significant missiles are postulated from any of these containers. As shown in Table 3.9-11, other protective measures to prevent the loss of function of ESF and PG&E Design Class I equipment include compliance with Occupational Safety and Health Administration regulations in 29 CFR Part 1910. Many of the tanks listed in Table 3.9-11 are in locations remote from such ESF and PG&E Design Class I SSCs.

Components considered to have a potential for missile generation outside the containment structure are:

(1) Main turbine

(2) Main feedwater pump turbine

(3) Auxiliary feedwater pump turbine

3.5.2.1.2.1 Missiles from the Main Turbines

Based on the main turbine design, factory test procedures, the redundancy in control systems, and routine plant testing and inspection, the probability of the generation of main turbine missiles is so remote that turbine missiles are not considered credible events. See Section 3.5.2.2.2.1 for a discussion of the main turbine missile analysis.

3.5.2.1.2.2 Missiles from the Main Feedwater Pump Turbines

Due to the location of the main feedwater pump turbines on the west side of the turbine building at elevation 85 feet, failure of these turbines and the subsequent release of a missile would not prevent PG&E Design Class I SSCs, including ESFs, from performing their design function. Protection from missiles for Class 1E cables and equipment is discussed in Section 8.3.1.4.10.2.

3.5.2.1.2.3 Missiles from the Auxiliary Feedwater Pump Turbine

For DCPP Unit 1 or Unit 2, the only ESF or PG&E Design Class I equipment in the area of the turbine-driven AFW pump are the two make-up water transfer pumps and the two motor-driven auxiliary feed pumps.

A missile barrier is provided over the pump turbines to contain any potential missiles generated by disk failure.

3.5.2.1.3 Missiles Generated by Natural Phenomena

Tornado-generated missiles and protection from tornado-generated missiles are discussed in Section 3.3.2.

3.5.2.1.4 Site Proximity Missiles

Nearby industrial, transportation, and military facilities are described in Section 2.2. There are no such facilities within 5 miles of the site. The probability of missiles originating from these facilities striking PG&E Design Class I structures or components on the site is so small that missile loadings from this source have not been included in structure or component design bases.

3.5.2.2 Missile Selection

The missiles selected for each structure and the basis for their selection are discussed below.

3.5.2.2.1 Missiles Generated Within the Containment

Gross failure of a CRDM housing sufficient to allow a control rod to be rapidly ejected from the core is not considered credible for the following reasons:

(1) All CRDMs are shop pressure-tested at 3107 psig, whereas the RCS operates at 2235 psig.

(2) The pressure housings were individually hydrotested. The lower latch housing to nozzle connection is hydrotested during hydrotest of the completed reactor vessel closure head (RVCH).

(3) Stress levels in the mechanisms are not affected by system transients at power, or by thermal movement+ of the coolant loops.

(4) The mechanism housings are made of Type 304 stainless steel. This material exhibits excellent fracture notch toughness at all temperatures that will be encountered.

(5) The CRDM housing plug is an integral part of the rod travel housing.

However, if it is postulated that the top of the rod travel housing portion of the CRDM becomes ruptured and is forced upward by the water jet, the following sequence of events is assumed. The drive shaft and control rod cluster are forced out of the core by

the differential pressure of 2500 psi across the drive shaft. (The drive shaft and control rod cluster, latched together, are assumed fully inserted when the accident starts.) After approximately 12 feet of travel, the rod cluster control spider hits the underside of the upper support plate. Upon impact, the flexure arms in the coupling joining the drive shaft and control cluster fracture, freeing the drive shaft from the control rod cluster. The control cluster is stopped by the upper support plate, but the drive shaft continues to be accelerated upward to be stopped by the IHA missile shield.

Valve stems are not considered a credible source of missiles. All of the isolation valves installed in the RCS have stems with backseats. This effectively eliminates the possibility of ejecting valve stems even if the stem threads fail.

Valves are designed against bonnet-body connection failure and subsequent bonnet ejection by means of:

(1) using the design practice of ASME BPVC Section VIII-1968 for bolting

(2) using the design practice of ASME BPVC Section VIII-1968 for flange design

(3) controlling the torque load during the bonnet body connection stud tightening process

The pressure-containing parts are designed in accordance with requirements of either ANSI B16.5 or MSS SP 66, except for the accumulator check valves which are designed to ASME BPVC Section III-1968.

Valve missiles are not generally postulated due to the above discussion. However, the valves in the region where the pressurizer extends above the operating deck are capable of generating missiles. The valves in this region are the pressurizer SVs, the motor-operated isolation valves in the relief line, and the air-operated relief valves. Although failure of these valves is also not considered credible, failure of the valve bonnet-body bolts is postulated and provisions are made to ensure integrity of the containment liner from the resultant bonnet missile.

The only credible source of jet-propelled missiles from the reactor coolant piping and piping systems connected to the RCS are the temperature and pressure sensor element assemblies. The resistance temperature element assemblies are considered to be "with well" (i.e., with the piping thermowell attached) and "without well" (without the piping thermowell attached).

A temperature sensor element is installed on the RCPs close to the radial bearing assembly. A hole is drilled in the gasket and sealed on the internal end by a steel plate. In evaluating missile potential, it is assumed that this plate could break and the pipe plug on the external end of the hole could become a missile.

In addition, it is assumed that the weldment between the instrumentation well and the pressurizer wall could fail and the well and sensor assembly could become a jet-propelled missile.

Finally, it is assumed that the pressurizer heaters could become loose and become jet-propelled missiles.

3.5.2.2.2 Missiles Generated Outside the Containment

3.5.2.2.2.1 Main Turbine

The high pressure (HP) turbines and the generators for DCPP Unit 1 and Unit 2 are manufactured by Siemens-Westinghouse Electric Corporation. The LP turbines A, B, and C, originally supplied by Siemens-Westinghouse, have been retrofitted with Alstom rotors and casings.

Factory test procedures, redundancy in the control system, routine testing of the main steam valves and the mechanical overspeed protection system, make generation of missiles that might penetrate the turbine casing due to a turbine overspeed highly improbable. The Alstom LP rotor inspection program ensures that the integrity of the LP rotors is maintained and the rotor failure probability is below the applicable NRC allowable of 10^{-5} failures per year for an unfavorably oriented turbine. This is based on the Alstom evaluation methodology as accepted by the NRC that establishes that the probability of turbine missile generation is the same as the probability of rotor failure.

Three important criteria contribute to preventing destructive overspeed of a turbine:

(1) Factory test procedures

Destructive testing is performed on material specimens taken from forgings in addition to an ultrasonic test of each forging following major heat treatment. These test procedures ensure sound forgings with mechanical properties (tensile strength, yield strength, ductility, and impact strength), which meet specified levels.

(2) Redundancy in the control system

The overspeed protection control (OPC) system controls turbine overspeed in the event of a partial or complete loss of load, or if the turbine reaches or exceeds 103 percent of rated speed. A mechanical overspeed trip device is also provided that will automatically trip the unit at 111 percent of rated speed. An electronic trip signal is generated by the digital electrohydraulic control system at 111.5 percent of rated speed, as redundant

overspeed protection. This trip signal is set approximately 10 rpm higher than the mechanical overspeed device.

(3) Routine testing of the main steam valves and the mechanical overspeed protection system

Functional tests of the main turbine steam inlet valves are performed at a frequency that maintains acceptable rotor failure probability while the unit is carrying load, per Siemens-Westinghouse instructions for the DCPP steam turbines.

References 9, 10, 11, and 12 contain an update on the industry turbine valve failure rates and assessment of the turbine destructive overspeed probabilities, and forms the basis of the turbine valve testing frequency for DCPP.

A routine LP rotor inspection program for DCPP Unit 1 and Unit 2 assures that the integrity of LP rotors is maintained. The Alstom LP rotor inspection intervals are based upon fleet and industry experience. The Alstom recommended inspection intervals for DCPP's Alstom LP rotors conservatively bounds the worst case hypothetical stress corrosion cracking (SCC) failure mechanisms, crack initiation, size and growth rates as determined by the Alstom LP turbine missile analysis (Reference 20).

The resulting DCPP LP turbine rotor inspection program intervals, minimizes the potential for operational development of a crack to a critical depth, while maintaining conservative margin to the allowable rotor failure probability of 10^{-5} failures per year for unfavorably oriented turbine rotors, as established in the Alstom LP turbine missile analysis methodology accepted by the NRC (Reference 20). Rotor forgings are subject to inspection and testing both at the forging suppliers and manufacturer's facilities. Thus, an LP rotor failure at a speed less than or equal to the design overspeed is not considered a credible event.

Because of the extensive overspeed and backup controls, routine testing of the turbine inlet valves and overspeed protection system, acceleration beyond design overspeed (120 percent of rated speed) to the destructive overspeed (approximately 151 percent for Alstom rotors) is not considered a credible event.

Because of the LP rotor inspection program and preoperational forging inspection described in Section 3.5.2.2.2.1, generation of a missile at design overspeed or less is not considered a credible event.

The possibility that a postulated crane fall or falling debris could damage elements of the turbine trip system in an earthquake has been considered in relation to the main turbine failure probability. The turbine building crane is parked away from the steam inlet valves during turbine operation to preclude damage to the valves from a postulated crane fall. Review of the vulnerability of the main turbine inlet valves and the overspeed

trip system to falling debris indicates that no postulated debris could prevent a trip for the following reason:

(1) The siding and roofing of the turbine building are constructed to withstand design wind loads, which are in excess of the loads they would experience during an earthquake. The structural support for attachment of the panels, as well as attached overhead equipment, such as lighting or public address speakers, have been evaluated for design basis seismic loads and will maintain structural integrity during a seismic event. Therefore, falling corrugated metal roofing, siding, or overhead equipment due to an earthquake is not considered a credible event.

In summary, the probability of generation of an HP turbine missile by speed in excess of the design overspeed, or of an LP turbine missile of any kind, is extremely remote. These are not considered credible events.

3.5.2.2.2.1.1 Potential Missiles

Analyses and tests regarding the generation and effects of missiles caused by the main turbine accelerating to design overspeed have been carried out by both Alstom and Siemens-Westinghouse Electric Corporation. The analyses and tests described below consider the potential sources of missiles resulting from postulated failures of the HP turbine rotor and the LP turbine rotor or last stage blade (LSB) loss at design overspeed (120 percent of rated speed) and the capability of the turbine casings to contain the postulated missiles.

Experimental Results

Siemens-Westinghouse conducted a test program at its research laboratories to evaluate the missile-containing ability of its steam turbines. The tests involved spinning alloy steel discs to failure within various carbon steel containments. The discs were notched to ensure failure in a given number of segments at the desired speed. Test results were correlated with various parameters descriptive of the missile momentum and energy and the geometry of the missile and containment.

The containments were of varying geometry but all were axisymmetric and concentric with the rotation axis of the disc. They ranged in complexity from a circular cylinder to containments that approximated actual turbine construction.

From these tests, logical criteria were evolved for predicting the missile-containing ability of various turbine structures. In addition, the tests also served to determine the mode of failure that certain structural shapes common to turbine construction undergo when hit by a missile. This is important since the mode of failure has a great influence on the amount of energy absorbed by the containment.

Fracture of the Siemens-Westinghouse discs into 90, 120, and 180° segments was considered. Calculations show that the 90° fragments pose the greatest threat as external missiles.

A 120° segment has an initial translational kinetic energy 12.5 percent greater than that of a 90° segment; however it also has a 33 percent greater rim periphery, resulting in greater energy loss when penetrating the turbine casing. Therefore, 90° and 120° segments have nearly equal kinetic energy leaving the turbine casing; but since a 90° segment has smaller impact area, it represents a more severe missile.

The initial translational kinetic energy of a half disc is equal to that of a quarter disc. Because of kinematic considerations, a half disc segment will always impact with the rotor after fracture. The 180° segment, due to its larger size, will subject the stationary parts to greater deformation. As a result, the 180° segment will leave the turbine casing with lower energy than the 90° segment.

For the purpose of evaluating the missile-containing ability of the turbine structure, the discs have been postulated to fail in four quarters. Before failure, a disc has a total energy, which is purely rotational, of $1/2(I\omega^2)$, where I is the mass moment of inertia of the disc about its axis of rotation and ω is the angular velocity of the turbine at the postulated failure speed. After failure, the mass center of each fragment translates at a velocity of ωr, r being the distance from the rotation axis of the disc to the mass center of the fragment. In addition, the fragment rotates about its center of mass with an angular velocity of ω. The initial rotational energy of the disc is partitioned into both the translational and rotational kinetic energy of the fragments.

Test results and analytical considerations indicate that the translational kinetic energy of a fragment is of much greater importance than the rotational kinetic energy in predicting the ability of the fragment to penetrate the turbine casing. Rotational kinetic energy tends to be dissipated as a result of friction forces developed between the fragment surfaces and stationary parts.

These principles apply to fragments that would be generated by failure of the HP turbine rotor.

High-Pressure Turbine Analysis

The HP turbine element is of double-flow design. Steam enters at the center of the turbine element through four inlet pipes, two in the base and two in the cover. These pipes feed four double-flow nozzle chambers flexibly connected to the turbine casing. Steam leaving the nozzle chambers passes through the Rateau control stage and flows through the reaction blading. The reaction blading is mounted in the blade rings which in turn are mounted in the turbine casing. The main body of the rotor weighs approximately 100,000 pounds.

Calculations were performed to determine the effects of a postulated failure of the HP turbine rotor at design overspeed (120 percent of rated speed). These calculations show that all fragments generated by any postulated failure of the HP turbine rotor would be contained by the HP turbine blade rings and casing.

Low Pressure Turbine Analysis

Alstom has also evaluated the probability of generating LP turbine missiles, providing finite element analyses, inspection results and operating experience in References 14 through 20. Alstom rotors are far less vulnerable to SCC, as compared to the Siemens-Westinghouse rotors, due to improved design features, materials, manufacturing, and factory inspection techniques. Therefore, the Alstom recommended rotor inspection intervals are longer than the original Siemens-Westinghouse intervals.

In Reference 14, Alstom presents criterion governing nuclear LP rotor inspection intervals. Since there are no field failures or indications of SCC in the relevant directions which might produce a missile, Alstom developed hypothetical cases to set criteria governing crack growth rate, critical crack size, and fraction of crack size allowed. In this manner, Alstom's missile analysis is equivalent to the methodology used by Siemens-Westinghouse.

From this analysis, Alstom produced an inspection interval versus missile generation probability chart (Figure 2, Reference 20). This shows that the maximum allowable inspection interval could be as long as 21 years, and the turbine missile generation probability would still meet the 10^{-5} per year criteria for unfavorably oriented turbine rotors with a 95 percent confidence level, as established in the Alstom methodology accepted by the NRC (Reference 20). The LP turbine rotor inspection program for DCPP Unit 1 and Unit 2 assures that the integrity of the LP rotors is maintained with conservative margin to the applicable 10^{-5} per year acceptance criteria. The Alstom criteria governing LP turbine rotor inspection sets forth recommendations based on crack growth rate, critical crack size, and fraction of critical crack size allowed.

The DCPP LP turbine program inspection frequency is derived from the Alstom turbine missile analysis (Reference 20), which governs the maximum interval between inspections. The DCPP LP turbine inspection intervals maintain conservative margin to the Alstom turbine missile analysis.

The Alstom (single) inner cylinder does not enclose the LSBs making loss of a LSB an unacceptable event. Given the blade mass and projected exit velocity during a hypothetical blade loss event, it is likely the blade would penetrate the outer housing. Alstom has incorporated several LSB design features, such as tangential fir tree entry, snubber location and design, and blade frequency tuning to prevent resonant conditions which might lead to high cycle fatigue crack growth. Additionally, operational avoidance regions are procedurally enforced, improved ultrasonic testing factory inspection techniques will detect manufacturing defects, and routine maintenance inspections will preclude undetected crack propagation. A fracture mechanics deterministic analysis

presented in Reference 15 substantiates that this type of missile generation from a LSB loss is not a credible event.

3.5.2.2.2.2 Auxiliary Feedwater Pump Turbine

The DCPP Unit 1 and Unit 2 turbine-driven AFW pumps are driven by Terry Steam Turbine Company turbines with a casing constructed of cast steel. The turbine disc is a solid forging.

When required to operate, the turbines run at speeds ranging from 4000 to 4260 rpm. The overspeed trip on the turbine is a centrifugal weight type, which is set at 4950 plus or minus 50 rpm.

The construction and periodic testing of the turbine make it an improbable source of missiles. It is calculated that the probability of missile generation is less than 10^{-7} events per year. Hence, using NRC criteria, such an event need not be postulated. However, if failure of the turbine did occur, the most severe missile generated is assumed to be a 90° segment of the rotor.

3.5.2.3 Selected Missiles

The characteristics for each selected missile, such as origin, weight, dimensions, impact velocity and orientation, and material composition, are described below.

3.5.2.3.1 Missiles Generated Within the Containment

The characteristics of the control rod drive shaft (with the disconnect rod) missile are given in Table 3.5-2. The characteristics of the control rod drive shaft and the disconnect rod latched to the drive mechanism are given in Table 3.5-3.

The missile characteristics of the bonnets of the valves in the region where the pressurizer extends above the operating deck are given in Table 3.5-4.

The missile characteristics of the piping temperature element sensor assemblies are given in Table 3.5-5. A 10 degree expansion half-angle water jet has been assumed. The missile characteristics of the piping pressure element assemblies are less severe than those shown in Table 3.5-5.

The missile characteristics of the RCP temperature element, the instrumentation well of the pressurizer, and the pressurizer heaters are given in Table 3.5-6. A 10-degree expansion half-angle water jet has been assumed.

3.5.2.3.2 Missiles Generated Outside the Containment

3.5.2.3.2.1 Auxiliary Feedwater Pump Turbine

As noted in Section 3.5.2.2.2.2, the probability of generating a missile from the AFW turbine is less than the NRC threshold value for credible events. While not required, an evaluation of the AFW turbine's ability to generate a missile has resulted in the following conclusions. A disc rupture at the maximum turbine speed, consistent with a single failure of the turbine control system, will not generate a missile capable of penetrating the turbine casing. However, the postulation of multiple control system failures leads to the rupture of the turbine disc at an assumed speed of 9,000 rpm (first critical speed). The resulting missile is capable of penetrating the turbine casing. The missile characteristics are as follows:

Velocity	=	459 fps
Impact area	=	54.2 in^2
Weight	=	42.5 lb (includes 12.5 lb for the turbine casing)

3.5.2.4 Barrier Design Procedures

The barriers are designed to prevent penetration by the postulated missiles. The design procedures are described below:

3.5.2.4.1 Missiles Generated Within the Containment

The steam generator shell for the original steam generators (OSGs) was calculated to resist penetration of the postulated missiles using the method illustrated in ORNL-NSIC-5. The shells for the replacement steam generators (RSGs) are fabricated with materials similar to or in some cases improved from those used for the OSGs. In addition, the RSG shells are approximately as thick as the OSG shells, are made from SA-508 forging material that is equivalent to the SA-533 plate material used in the OSG shells, and do not have longitudinal weld seams in the cylindrical sections as do the OSGs.

In conclusion, the RSGs are evaluated to be at least as resistive to missile penetration as the OSGs.

The missile shield structure over the CRDMs was evaluated using a formula derived from the Ballistic Research Laboratories formula:

$$T = \frac{\left(E_k\right)^{2/3}}{670\ d} \qquad (3.5\text{-}11)$$

where:

T = required steel wall thickness, in.

E_k = kinetic energy of missile, ft-lb
d = diameter of missile, in.

The governing missile, a 1.75-inch-diameter control rod drive shaft with a maximum kinetic energy of 60,200 foot-pounds (shield located 4 feet above housing), requires a shield thickness of 1.31 inches. However, a 2.0 inch-thick shield was provided.

The pressurizer housing and other concrete structures were evaluated for perforation by a missile using Ballistic Research Laboratories formula:

$$P = \frac{427}{(f_c')^{1/2}} \times \frac{W}{d^2} d^{1/5} \times \left(\frac{V}{1000}\right)^{4/3} \qquad (3.5\text{-}12)$$

where:

P = required thickness of concrete slab, in.
fc' = compressive strength of concrete, psi
W, d, V = weight (lb), diameter (in.), and velocity (ft/sec) of missile, respectively

The most powerful missile among those listed in Tables 3.5-4 through 3.5-6 is the 3-inch motor-operated isolation valve bonnet, weighing 400 pounds and having a velocity of 135 ft/sec and a 28 square inch impact area. This missile could perforate 6.7 inches of 5000 psi strength concrete; the minimum thickness of the target is 24 inches.

In addition to the check for perforation, the overall structural response is evaluated by using the method of Reference 4. For this purpose, the penetration depth is calculated by using the modified Petry formula (Reference 2):

$$D = K_1 A_p V' \qquad (3.5\text{-}13)$$

where:

D = depth of penetration, ft
K_1 = experimentally obtained material coefficient
A_p = weight to impact area ratio, lb/ft
V' = $\lg\left(1 + \frac{V^2}{215000}\right)$ = velocity factor
V = missile velocity, ft/sec

The calculation procedure is illustrated below for a missile believed to produce the largest response:

Missile - 3-in. motor-operated isolation valve bonnet

Weight - W = 400 lb
Impact area - A = 28 in^2 = 0.195 ft^2
Velocity - V = 135 fps

$$K_1 = 2.82 \times 10^{-3} \ ft^3/lb$$

$$A_p = \frac{W}{A} = 2{,}050 \ lb/ft^2$$

$$D = 2.82 \times 10^{-3} \times 2{,}050 \ Lg \left(1 + \frac{135^2}{215{,}000} \right) = 0.205 \ ft$$

Because the velocity is assumed to reduce linearly from the initial value of V, the time t_1 of the impulse or the duration of the dynamic force F_1 is determined by the equation:

$$t_1 = \frac{2D}{V} = \frac{2 \times 0.205}{135} = 0.003 \ sec \qquad (3.5\text{-}14)$$

The dynamic force is calculated by the equation:

$$F_i = \frac{W V^2}{2gD} = \frac{0.4 \times (135)^2}{2 \times 32.2 \times 0.205} = 550 \ kips \qquad (3.5\text{-}15)$$

The factor K, by which the value of F_i can be reduced to determine an equivalent static load P, is given by the equation:

$$K = \frac{(2\mu - 1)^{0.5} T}{\pi t_1} + \frac{1 - \frac{0.5}{\mu}}{1 + \frac{0.7T}{t_1}} = \frac{(6-1)^{0.5} (0.03)}{p(0.003)} + \frac{1 - \frac{0.5}{3}}{1 + \frac{(0.7)(0.03)}{0.003}} = 7.22 \qquad (3.5\text{-}16)$$

where:

the ductility ratio μ = 3, and the structure's natural period T = 0.03 sec

The value of the static load is then:

$$P = \frac{550}{7.22} = 76 \ kips \qquad (3.5\text{-}17)$$

3.5.2.4.2 Loadings for Missiles Generated Outside the Containment

Although the original design of certain PG&E Design Class I reinforced concrete structures outside containment included consideration of potential missile penetration

and spalling effects, subsequent analyses and evaluations have determined that the generation of main turbine missiles outside of the turbine casing are not credible events.

3.5.2.5 Missile Barrier Features

The structures designed to protect SSCs from the effects of missiles generated within the containment are:

(1) A missile shield is provided over the CRDMs. The shield is located 4 feet above the CRDM housing and consists of a primary shielding element made of 2-inch steel plate that is part of the IHA structure (refer to Figure 3.5-1).

(2) The pressurizer housing, shown in Figure 3.5-2, consists of 12-inch- and 18-inch-thick reinforced concrete walls forming an irregular polygon and a 24-inch-thick concrete slab above the top of pressurizer. A 66-inch by 105-inch opening is provided in the top slab to prevent pressure buildup. The opening is covered with grating to preclude penetration by potential missiles.

(3) The polar crane wall, fuel transfer canal walls, and operating floor at elevation 140 feet are shown on the concrete outline drawings referenced in Section 3.8.2.1.

A missile shield barrier is provided over the AFW pump turbines. The Unit 1 missile shield is a barrel-vault design and is formed from 1-inch-diameter bars sandwiched between 1/2 x 2 x 25-inch plates as shown in Figure 3.5-6. The Unit 2 missile shield is formed from horizontal layers of 4 x 1/2-inch steel bars supported on 12-inch-thick concrete walls. Analysis of the missile shields indicate that they are capable of retaining the missile postulated in Section 3.5.2.3.2.1.

3.5.3 SAFETY EVALUATION

3.5.3.1 General Design Criterion 40, 1967 – Missile Protection

Protection for ESFs inside and outside of containment is provided against missiles that might result from plant equipment failures (refer to Sections 3.5.2.1 through 3.5.2.5).

3.5.3.2 Missile Protection Safety Function Requirement

(1) <u>Protection From Missiles</u>

PG&E Design Class I SSCs, both inside and outside of containment, are protected against the effects of missiles, which may result from equipment failures and from events and conditions outside the nuclear power unit (refer to Sections 3.5.2.1 through 3.5.2.5).

3.5.4 TESTS AND INSPECTIONS

A routine LP rotor inspection program for DCPP Unit 1 and Unit 2 ensures that the integrity of LP rotors is maintained. The LP turbine rotors are inspected in order to identify cracks which may lead to missile generation. The inspection interval is based on maintaining a missile generation probability below the NRC guidance of 10^{-7} events per year. Section 3.5.2.2.2.1 discusses LP turbine inspection.

The turbine overspeed protection system helps ensure that the turbine does not accelerate to destructive overspeed should a failure occur. Section 3.5.2.2.2.1 discusses testing of the main steam intercept valves and other turbine overspeed protection devices.

3.5.5 REFERENCES

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18. Alstom Study: “Diablo Canyon Stress Corrosion Cracking (SCC) Initiation at the Bottom of Rotor Grooves”, DC 6020487-43.

19. Alstom Study: “Diablo Canyon – 1200 MW @ 1800 RPM; Stress Analysis of the LP-Rotors”, DC 6020487-29.

20. Alstom Report STD0023609, “Diablo Canyon LP Retrofit Missile Analysis – Comparison of Methodology with Main Yankee”, August 2014.

3.5.6 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

3.6 PROTECTION AGAINST DYNAMIC EFFECTS ASSOCIATED WITH THE POSTULATED RUPTURE OF PIPING

Special measures have been taken in the design and construction of the plant to protect the public against the consequences of dynamic effects associated with postulated piping ruptures both inside and outside the containment. The plant is designed so that a postulated piping failure will not cause the loss of needed functions of essential equipment and structures, and so that the plant can be safely shut down in the event of such failure. For moderate energy systems, protection from the jet spray and flooding effects due to critical cracks is incorporated into the design. This section presents the design bases and design measures established for DCPP for protection against these dynamic effects.

Essential equipment are those PG&E Design Class I systems and components required to achieve safe (cold) shut down and mitigate the consequences of a postulated piping failure. All essential equipment inside and outside the containment, particularly components of the RCPB and other PG&E Design Class I components, are protected against the effects resulting from the postulated rupture of piping.

3.6.1 DESIGN BASES

3.6.1.1 General Design Criterion 4, 1987 – Environmental and Dynamic Effects Design Bases

The dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analyses reviewed and approved by the Commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

3.6.1.2 General Design Criterion 40, 1967 – Missile Protection

The DCPP ESF systems and components designed to be are protected against dynamic effects and missiles that may result from plant equipment failures.

3.6.1.3 Protection Against Pipe Rupture Effects Safety Function Requirements

(1) Protection from High Energy Pipe Rupture Effects - Outside Containment

PG&E Design Class I structures and essential systems and components (outside containment) are designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure (pipe whipping, jet impingement, compartment pressurization, flooding, and environmental effects) to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(2) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

Essential equipment (outside containment) required to safely bring the plant to cold shutdown conditions are located or protected to accommodate the fluid spray effects of a postulated moderate energy piping failure.

(3) Protection from Jet Impingement – Inside Containment

The containment and essential equipment within the containment are protected against high-energy pipe break jet impingement effects.

(4) Protection from Flooding Effects – Outside Containment

Equipment required to safely bring the plant to cold shutdown conditions are located or protected to accommodate the flooding effects of a postulated high energy or moderate energy piping failure.

3.6.1.4 Regulatory Guide 1.46, May 1973 - Protection Against Pipe Whip Inside Containment

For high-energy piping inside containment, the selection of break locations and determining the measures that are taken for restraint against pipe whipping that may result from such breaks conforms with or is equivalent to the guidance in Regulatory Guide 1.46, May 1973.

3.6.1.5 Generic Letter 87-11, June 1987– Relaxation in Arbitrary Intermediate Pipe Rupture Requirements

Generic Letter 87-11, June 1987 allows the elimination of all dynamic effects (missile generation, pipe whipping, pipe break reaction forces, jet impingement forces, compartment, subcompartment and cavity pressurizations and decompression waves within the ruptured pipe) and all environmental effects (pressure, temperature, humidity and flooding) resulting from arbitrary intermediate pipe ruptures in high-energy piping inside and outside containment. Arbitrary intermediate breaks are no longer described in Branch Technical Position MEB 3-1, Revision 2.

3.6.1.6 Branch Technical Position MEB 3-1, Revision 1, July 1981 – Postulated Break and Leakage Locations in Fluid System Piping Inside and Outside Containment

High-energy break locations in fluid system piping inside and outside containment are postulated based on stress level as recommended in Branch Technical Position MEB 3-1, Revision 1. For jet impingement effects inside containment and pipe whip and traveling jet effects for small lines inside containment not restrained as a result of the original review of pipe break dynamic effects, break type, orientation and cross-

sectional area at each non- RCL break location are postulated based upon Branch Technical Position MEB 3-1, Revision 1 criteria.

3.6.2 PIPE RUPTURE CRITERIA

3.6.2.1 General Criteria

The criteria used in defining the type, location and geometry of postulated pipe breaks may vary depending upon (1) the pressure and temperature of the fluid in the piping system under normal operating conditions, (2) the location of the piping system (i.e., inside or outside containment), and (3) the nominal pipe diameter. The matrix below is a summary of the current DCPP pipe rupture criteria.

P (psig)[2]		T (°F)[3]	Pipe Size	Piping Location[1]	Break Type[4,5]	Break Geometry
>275	and	>200	>1"	IC	HELB	Circumferential[8]
>275	and	>200	≥4"	IC	HELB	Circumferential[8] and longitudinal[8]
>275	or[6]	>200	>1"	IC	HELB	Circumferential[8]
>275	or[6]	>200	≥4"	IC	HELB	Circumferential[8] and longitudinal[8]
>275	and	>200	>1"	OC	HELB	Circumferential[8,9]
>275	and	>200	≥4"	OC	HELB	Circumferential[8,9] and longitudinal[8,9]
>275	or	>200	>1"	OC	HELB	Crack[7, 9]
≤275	and	≤200	>1"	IC	MELB	Crack[7]
≤275	and	≤200	>1"	OC	MELB	Crack[7]

Notes:

1. IC = Inside Containment; OC=Outside Containment
2. P = Maximum operating pressure, psig (this corresponds to the NRC's HELB pressure criterion terminology in References 1 and 4)
3. T = Maximum operating temperature, °F (this corresponds to the NRC's HELB temperature criterion terminology in References 1 and 4)
4. HELB = High Energy Line Break
5. MELB = Moderate Energy Line Break
6. Jet Impingement effects only
7. ½" pipe diameter in length and ½" the wall thickness in width

8. Breaks postulated when fluid conditions exist for more than 1% of the plant operating time.
9. Breaks postulated only if piping is pressurized during startup, shutdown, or normal plant operating conditions.

3.6.2.1.1 High-Energy Piping Inside Containment

The containment and all essential equipment within the containment, particularly components of the RCPB and other safety-related components, are protected against the dynamic and environmental effects of pipe whip resulting from postulated rupture of piping. The criteria for minimizing these effects are described in Section 3.6.5. In March 1993, the DCPP LBB evaluation (Reference 11) was accepted by the NRC (Reference 12), so that the dynamic effects associated with breaks in the main RCL piping are no longer part of the DCPP design basis and no longer need to be protected against, although protection from the dynamic effects of RCS branch line and other HELBs must still be provided (refer to Section 3.6.2.1.1.1).

ESFs are provided for core cooling and boration, pressure reduction, and activity confinement in the event of a loss of reactor coolant or a steam or feedwater line break accident, to ensure that the public is protected in accordance with 10 CFR 50.67 guidelines. These safety systems have been designed to provide protection for an RCS pipe rupture of a size up to and including a double-ended severance of an RCS main loop.

The following systems have been evaluated with regard to the dynamic effects of pipe whip and blowdown reactive forces associated with a ruptured pipe:

(1) Reactor coolant system

(a) RCL branch line breaks (refer to Section 3.6.2.1.1.1)

(b) Pressurizer surge line

(c) Pressurizer spray line

(d) Pressurizer relief and SV lines

(e) Drains greater than 1-inch in diameter

(2) Chemical and volume control system

(a) Charging line and auxiliary spray line

(b) RCPs seal water injection

(c) Letdown line

(d) Excess letdown line

(e) RCPs - seal vent and leakoff, greater than 1 inch in diameter

(3) Safety injection system

(a) Accumulator injection lines

(b) Safety injection lines

(4) RHR system

(a) RHR supply

(b) RHR return

(5) Turbine steam supply system

(a) Main steam lines

(b) Feedwater lines

(c) Steam generator blowdown lines

3.6.2.1.1.1 Reactor Coolant System Main Loop Piping (Leak-Before-Break)

In November 1984, the NRC issued NUREG-1061 assessing the applicability of LBB analysis to nuclear power plant piping systems. Effective May 1986, the NRC revised 1971 General Design Criterion 4 to allow the use of LBB methodology for excluding the dynamic effects of postulated ruptures in RCL piping in PWRs from the design basis. A draft revision to Standard Review Plan 3.6.3 was subsequently issued outlining the scope of the plant specific evaluation required to obtain NRC acceptance of the use of LBB. Westinghouse performed the required evaluation for the DCPP main RCLs (Reference 11), and PG&E submitted the evaluation to the NRC on March 16, 1992, requesting elimination of the dynamic effects of postulated ruptures in the main RCL piping from the DCPP design basis. On March 2, 1993, the NRC accepted the analysis and granted permission to eliminate the dynamic effects of those breaks from the DCPP design basis.

The scope of application of LBB at DCPP is limited in nature. It applies to the dynamic effects of breaks in the main RCL piping only, and can be used only for purposes of eliminating consideration of the dynamic loads resulting from such breaks in the equipment and structural design bases, and for eliminating consideration of the dynamic effects of those breaks in the protection of equipment. The application of LBB does not apply to breaks in branch lines attached to the main loop lines. Hence, the effects of

pipe whip, pipe break reaction forces, jet impingement, decompression waves within the ruptured pipe, missile generation, and dynamic subcompartment pressurization due to main loop piping breaks no longer have to be considered in the DCPP design basis (Reference 13); however, those effects resulting from branch line breaks still must be considered. The inclusion of pipe whip restraints and jet impingement barriers in the design of the plant to protect equipment in containment from the dynamic effects of main RCL pipe breaks is no longer required. In addition, dynamic LOCA loads resulting from main RCL breaks may be excluded from the dynamic load combinations for equipment and structural analyses, although the dynamic effects resulting from branch line breaks must still be included. However, the use of LBB is specifically not allowed for purposes of accident analysis or for purposes of EQ of equipment. Static post-LOCA peak containment pressure resulting from main RCS loop breaks must still be included in load combinations where that pressure is a consideration in the structural design. The ECCS and ESF systems must still be capable of mitigating the effects resulting from the original design basis double-ended guillotine breaks in the main RCLs, and the equipment required to mitigate a LOCA must still be environmentally qualified to the conditions resulting from such breaks.

In Amendments 221 and 223, the NRC approved the ability to perform the fuel assembly structural analyses, that satisfy NUREG-0800, Standard Review Plan Section, 4.2, “Fuel System Design,” Appendix A, “Evaluation of Fuel Assembly Structural Response to Externally Applied Forces,” based on a pipe break location that considers the application of LBB. The results of the fuel assembly structural analyses, which are performed to determine if any fuel grid deformation occurs, are used as an input to demonstrate compliance with 50.46(b)(4), fuel coolable geometry requirements in accordance with the NRC approved best estimate LOCA methodology for DCPP.

The acceptability of the LBB evaluation is based on a number of RCS design and operating characteristics which are expected to remain fairly constant over the life of the plant and which are controlled by procedures and licensing and design basis documents. These include main coolant loop piping materials and mechanical properties, as-built configuration, assumed seismic loads and load combinations, RCS chemistry, and RCS operating parameters. To maintain the validity of the LBB evaluation, these characteristics should not change significantly in a nonconservative direction. If such a change occurs or is made by design or procedure change, its effect on the assumptions made in the LBB analysis should be evaluated. The LBB analysis also assumes that the DCPP RCS leak detection system has the capability to detect an increase in RCS leakage into the containment of 1 gpm (refer to Section 5.2.3.23). Operability of this system is controlled by the plant Technical Specifications.

3.6.2.1.1.2 Reactor Coolant System Connected Piping

The piping connections to the primary RCLs fall into the general categories illustrated in Figure 3.6-1. These categories are defined by the direction of flow to or from the primary RCLs and by the associated valve configuration. A rupture of these lines

conceivably could cause uncontrolled loss of reactor coolant depending on the precise location of the break and the line configuration.

In establishing the dynamic effects criterion, uncontrolled loss of reactor coolant is assumed to occur for a pipe break out to the restraint of the second automatic isolation valve (refer to Case II, Figure 3.6-1) on outgoing lines, and out to and including the second check valve on incoming lines normally with flow (refer to Case III, Figure 3.6-1). This criterion takes credit for only one of the two valves performing its intended function. However, for the letdown line pipe break analysis, credit for successful closure of isolation valves LCV-459 and LCV-460 is not required (they would be considered to be fail-as-is valves in Figure 3.6-1, Case II). The HELB analysis showed that accident mitigation and plant shutdown could be successfully accomplished for a letdown line break downstream of these valves even in the event they should not close. For normally closed isolation or incoming check valves (refer to Cases I and IV, Figure 3.6-1), uncontrolled loss of reactor coolant is assumed to occur for pipe breaks on the reactor side of the valve.

It is assumed that a break of the piping associated with ESFs does not occur during the injection phase following a loss of coolant. During the recirculation phase, a leak or equivalent break resulting in a maximum flow of 50 gpm is assumed. This value is based on the flow that could result from the complete failure of a RHR pump seal. The radiation dose analysis for this seal failure is discussed in Section 15.5.17.2.8.

3.6.2.1.1.3 Other High-Energy Piping Inside Containment

Originally, breaks were postulated at all terminal ends and all locations, regardless of stress level, where plastic hinges could form and endanger essential systems or components. This criterion conservatively bounds Regulatory Guide 1.46, May 1973 (Reference 1) criteria of break postulation at all terminal ends and all high stress points.

Subsequent to receipt of NRC approval on March 13, 1987, break locations were postulated based on stress level as recommended in Branch Technical Position MEB 3-1, Revision 1 (Reference 8). Subsequent to the issuance of Generic Letter 87-11, June 1987, arbitrary intermediate breaks are not postulated (no longer mentioned) in Branch Technical Position MEB 3-1, Revision 2 (Reference 9). This NRC guideline allows DCPP to eliminate the dynamic effects (missile generation, pipe whipping, pipe break reaction forces, jet impingement forces, sub-compartment and cavity pressurizations and decompression waves within the ruptured pipe) and the environmental effects (pressure, temperature, humidity and flooding) resulting from arbitrary intermediate pipe breaks or breaks satisfying the stress criteria.

3.6.2.1.2 High-Energy Piping Outside Containment

The criteria that apply to the outside the containment high-energy pipe rupture postulation and evaluation of the associated dynamic effects were originally in accordance with those given in References 4, 5, and 6. Subsequent to receipt of NRC approval on March 13, 1987, break locations were postulated based on stress level as recommended in Branch Technical Position MEB 3-1, Revision 1 (Reference 8)and arbitrary intermediate breaks were eliminated in accordance with Generic Letter 87-11, June 1987 (Reference 9). Section 3.6.2.2.2.1 provides the current criteria for the postulation of pipe breaks outside containment.

The systems that contain high-energy lines located outside of the containment in which both open crack and design bases breaks are postulated to occur are:

(1) Condensate system

(2) Feedwater system

(3) Turbine steam supply system (main steam, steam generator blowdown system, and AFW turbine steam supply piping up to stop valve FCV-95)

(4) Extraction steam and heater drip system

(5) Chemical and volume control system

(6) Turbine and generator associated systems

(7) Auxiliary steam system (crack, T>200°F)

(8) AFW pump discharge piping (crack, P>275 psig)

No design basis breaks or crack breaks are postulated downstream of stop valve FCV-95 in the AFW pump turbine steam supply because it is not pressurized during startup, shutdown, or normal plant operating conditions.

3.6.2.1.3 Moderate-Energy Piping

Through-wall cracks are postulated to occur in moderate energy systems, i.e., any pipe larger than 1-inch in diameter with fluid maximum operating temperature less than or equal to 200°F and maximum operating pressure less than or equal to 275 psig, to determine the effect of resulting spray or flooding on essential equipment. The crack breaks are assumed at the worst location with respect to the equipment required for safe (cold) shutdown. The effects of water spray on the equipment and potential compartment flooding are considered.

The high energy portions of the RHR and its associated normally pressurized branch piping only exceed the 200°F/275 psig moderate energy piping criterion during normal plant operational conditions during a portion of plant shutdown. The amount of time this system is high energy as compared to the total operational lifetime of the plant is expected to be less than one percent. Therefore the probability that a crack will occur in one of these systems and propagate to a full design basis break during the short time these systems are high energy is expected to be considerably less than the probability of a design basis break in a system with a more frequency usage. For this reason, design basis breaks are not postulated to occur in this system. The system is also PG&E Design Class I, dual-purpose, designed and constructed to meet ANSI B31.7-1969 with 1970 Addendum, Class II requirements for PG&E Design Class I portions.

3.6.2.2 Specific Criteria

The specific criteria for determining pipe break location, type, and area are discussed below.

3.6.2.2.1 High-Energy Piping Inside Containment

3.6.2.2.1.1 Break Locations

Based on the general criteria described in Sections 3.6.2.1 and 3.6.2.1.1.3, piping breaks are postulated to occur in each piping run or branch run:

(1) At the terminal ends

(2) At all (intermediate) locations where the primary plus secondary stress exceeds the stress level of 0.8 ($1.2S_h + S_A$)

3.6.2.2.1.2 Break Types, Break Orientation and Break Area (Non-Reactor Coolant Loop Piping)

The pipe break types (circumferential and longitudinal) are defined in Section 3.6.2.1 tabulation.

For jet impingement effects inside containment and pipe whip and traveling jet effects for small lines inside containment not restrained as a result of the original review of pipe break dynamic effects, longitudinal and circumferential break orientation and break area for non-RCL high-energy piping are in accordance with Branch Technical Position MEB 3-1, Revision 1. For other effects inside the containment, longitudinal and circumferential break orientation and break area for non-RCL high-energy piping are equivalent to the criteria for piping inside containment set forth in with Regulatory Guide 1.46, May 1973.

3.6.2.2.2 High-Energy Piping Outside Containment

3.6.2.2.2.1 Break Locations

The selection of design basis breaks in each of the systems identified in Section 3.6.2.1.2 is generally based on results of the piping stress analyses. These analyses consider effects of pressure, deadweight, thermal expansion during normal operation, upset and test conditions, and the DE.

Based on the general criteria described in Sections 3.6.2.1 and 3.6.2.1.2, piping breaks are postulated to occur in each piping run or branch run:

(1) At the terminal ends

(2) At all (intermediate) locations where the primary plus secondary stress exceeds the stress level of 0.8 ($1.2S_h + S_A$)

(3) Crack breaks are postulated at all potentially adverse locations for all high energy piping systems

(4) For piping runs where stress analyses are not available, design basis breaks are postulated at locations where pipe break would yield most severe consequences in such systems. Breaks are postulated to occur at each location of potential high stress or fatigue, such as pipe fittings (elbows, tees, reducers, etc.), valves, flanges and welded attachments. However, at valve weldments along straight sections of seamless pipe, only circumferential breaks are postulated.

(5) Piping that is either encased in concrete or protected by barriers from PG&E Design Class I structures, systems, or essential equipment is not considered for evaluation of dynamic effects.

(6) Piping physically located so that unrestrained motion (pipe whip) in any direction about a plastic hinge formed after a pipe rupture, but that could not impact any PG&E Design Class I structures, systems, or essential equipment is not considered for evaluation of dynamic effects.

3.6.2.2.2.2 Break Types, Orientation, and Break Area

The pipe break types (circumferential, longitudinal, and crack) are defined in Section 3.6.2.1.

Design basis breaks in straight or curved pipe 4 inches in diameter or greater are assumed to be longitudinal or circumferential, with the break area equal to the flow area of the pipe. Longitudinal breaks may have any orientation around the circumference of the pipe. Design basis breaks in pipe greater than 1 inch and less than 4 inches in

diameter are assumed to be circumferential only, with break area equal to flow area of the pipe. Design basis breaks at ·branch points are assumed to be circumferential in branch lines and longitudinal in run lines, with break area equal to flow area of the branch.

Crack breaks are assumed to have a flow area equal to one-half the pipe diameter times one-half the pipe thickness and are postulated in the most adverse orientations and locations throughout the piping.

3.6.2.2.3 Moderate-Energy Piping

Through-wall cracks are assumed to have an area equal to ½ d x ½ t, where "d" is the nominal pipe diameter and "t" is the nominal pipe wall thickness. Refer to Section 3.6.2.1.3 for postulated break locations.

The control room ventilation and pressurization system is not required to be protected from moderate-energy pipe breaks from either unit. In the event that an MELB occurs, and the control room becomes uninhabitable due to the impairment of the HVAC system, safe shutdown can be controlled from the hot shutdown panel. Cold shutdown can be achieved after an assessment of plant conditions following a MELB to establish procedures for making any physical modifications to instrumentation and control equipment in order to attain cold shutdown (refer to Section 7.4.2.3).

3.6.3 DESIGN LOADING COMBINATIONS

3.6.3.1 High-Energy Piping Breaks Inside Containment

The design loading combinations, the design condition categories, and design stress limits applied to components, supports, and pipe whip restraints of essential components and piping of high-energy fluid systems within the containment, are described in Sections 3.9 and 5.2. Section 5.2 addresses RCPB components while Section 3.9 addresses the remaining components. A discussion of potential missiles is presented in Section 3.5.

The RCL pipe rupture load analysis considered double-ended circumferential breaks in the RHR, SI (accumulator line), pressurizer surge line connections to the RCL piping, the main steam line at the steam generator steam outlet nozzle, and the feedwater line at the steam generator feedwater inlet nozzle (refer to Section 5.2.2.1.10.1).Dynamic analyses for RCS branch line breaks, MSLB, and feedwater line break are considered for the support structure design discussed in the following three subsections.

3.6.3.1.1 Reactor Vessel Support Structure

The reactor vessel support structure is designed to resist thrusts that are considered to originate from the following three sources: (a) the reactions of the blowdown forces in the primary RCL piping that are eventually transmitted to the reactor nozzles, (b) the

forces within the RPV shell acting on the reactor internals and shell wall, and (c) the effects of reactor vessel cavity asymmetric pressurization.

The superposition of these effects, in time-history form, permits accurate determination of the loads transmitted to the reactor vessel support structure. The design and details of the reactor vessel support structure are further discussed in Sections 5.2.2.1.10 and 5.5.13.

3.6.3.1.2 Steam Generator Support Structure

The steam generators are supported in a manner that allows for thermal expansion of the equipment from cold to operating condition. Each steam generator is supported such that the rupture of steam, feedwater, blowdown, or instrument piping as a result of thrust forces created by the rupture of a RCL branch line is prevented. The steam generators are also supported in a manner that prevents rupture of a primary RCL pipe as a result of thrust forces created by the rupture of a steam or feedwater line.

Guides and restraints are employed, where required, to limit the motion of the steam generators under the reaction forces that result from a RCL branch line break, to a distance that is compatible with the flexibility of the steam and feedwater piping. Also, the motion of the steam generators, under the reaction forces due to a steam or feedwater pipe break, is limited to a distance that is compatible with the flexibility of the primary reactor coolant piping. The design and details of the steam generator support structures are further discussed in Sections 5.2.2.1.10 and 5.5.13.

3.6.3.1.3 Reactor Coolant Pump Support Structure

Each RCP is supported in a manner that would limit its displacement short of the primary shield, secondary shield, steam generator, steam generator supports, equipment and piping in adjacent loops, and hot leg of the affected loop as a result of a RCL branch line break. The design and details of the RCP support structures are further discussed in Section 5.5.13.

3.6.3.2 High-Energy Piping Breaks Outside Containment

Piping response analyses are performed on high-energy piping systems at those postulated break locations for which unrestrained pipe motion about a plastic hinge could impact or endanger essential systems. Factors and criteria that are considered are:

(1) The dynamic nature of the loading.

(2) Pipe impact effects due to gaps in piping restraints.

(3) Nonlinear (elastic-plastic) pipe and restraint material properties and the effect of rapid strain rate on material properties.

(4) For circumferential breaks in a pipe, whip occurs upon attainment of 50 percent of uniform ultimate strain at a plastic hinge due to loading from the blowdown reactive forces. The pipe whip is characterized by unrestrained motion of the pipe about the hinge in the direction governed by the vector thrust of the break force.

(5) For longitudinal breaks, failure occurs upon attainment of a hinge mechanism with 50 percent of uniform ultimate strain on each hinge.

(6) Lower-bound piping material properties are used for the prediction of pipe whips.

(7) Both lower- and upper-bound piping material properties are used for the prediction of loads on anchors and restraints.

(8) Piping loads on the rupture restraints are limited to the equivalent of 50 percent of uniform ultimate strain in the restraint materials. The nonlinear material properties of the restraint are considered.

(9) The load combinations and allowable limits used in evaluating PG&E Design Class I concrete structures for the effects of the postulated high-energy pipe breaks are discussed in Section 3.8.

(10) Load combinations and allowable limits used in evaluating those PG&E Design Class I steel structures outside the containment whose function is to provide protection against the effects of the postulated high-energy pipe break are discussed in Section 3.8.

3.6.4 DYNAMIC ANALYSES

The dynamic effects of pipe breaks described previously in Sections 3.6.1 and 3.6.2 were analyzed using the methods described below. Refer to Section 5.2.2.1.10 for discussion of dynamic analysis of the RCL.

3.6.4.1 Reactor Coolant Loop Branch Line Piping Breaks

The primary coolant loop branch line pipe break hydraulic analysis described below in Sections 3.6.4.1.1 and 3.6.4.1.2 was performed to determine the resulting dynamic asymmetric pressure, dynamic thrust, and jet impingement forces.

3.6.4.1.1 Asymmetric Pressure Loading

Pressure differentials may develop between structural subcompartments as a result of reactor coolant pipe breaks. Evaluation of these pressure differentials is given in Section 6.2.1.

3.6.4.1.2 Dynamic Thrust and Jet Impingement Forces - Inside Containment

Dynamic thrust (blowdown) forces and jet impingement forces due to the postulated piping breaks in lines inside containment (other than the RCLs) were calculated from the formula:

$$F_B = C_T \text{ PoA (refer to Reference 2)} \qquad (3.6\text{-}1)$$

where:

F_B = steady state blowdown force, lb
CT = steady state thrust coefficient
= ranges from 1.26 for saturated steam/water to 2.0 for subcooled water (refer to References 2 and 20)
Po = line pressure at time 0
A = cross-sectional flow area of pipe with a full-area break

Moments required to form a plastic hinge were calculated from the formula:

$$M_p = \frac{K\,S_y\,I}{R_o} \qquad (3.6\text{-}2)$$

where:

M_p = plastic moment
K = M_p/M_y where M_y is the moment to produce yielding on the extreme fiber
S_y = yield stress of material at temperature
I = moment of inertia of piping = $\pi/4\ (R_o^4 - R_i^4)$
R_o = outside radius of pipe
R_i = inside radius of pipe
K = 2.5 for materials in the piping systems

3.6.4.2 High-Energy Piping Breaks Outside Containment

The Unit 1 analysis to determine the effects of a rupture of high-energy piping breaks outside containment was originally documented in Reference 7. Differences in pipe break protection features between Unit 1 and Unit 2 are documented in Reference 15. Pipe break effects analyzed include pipe whip, jet impingement, compartment pressurization, water flooding, and the environmental effects of pressure, temperature, and humidity.

The general safety evaluation criteria applied in the determination of the acceptability of the consequences of a HELB outside containment are (Reference 7):

(1) The most consequential single failure of an active component is assumed to occur coincidentally with the damage resulting from the effects of the pipe break.

(2) Concurrent LOOP is assumed if the postulated rupture results in a reactor or turbine trip.

(3) Required redundancy must be preserved in those protection systems, electrical systems, engineered safety feature equipment, and their interconnecting cables and cable penetrations necessary to mitigate the consequences of the pipe break and place the reactor in a safe shutdown condition.

(4) For those environmentally induced failures caused by either an open crack or a design basis pipe break which would not of itself result in protective action but which does disable protection functions, a loss of redundancy is acceptable but the minimum required function of the system must be preserved.

(5) The failure of any structure caused by the pipe break must not damage any structure containing safety and shutdown equipment to the extent that the capability to mitigate the consequences of the pipe break and bring the reactor to a cold shutdown condition is impaired.

(6) The integrity of the control room must be preserved.

(7) The ability to bring the reactor to a safe (cold) shutdown condition from the control room or from outside the control room must be preserved.

The analyses on pipe whip, jet impingement, and water flooding were reverified to reflect the current as-built condition, and modifications were made as necessary. In this reanalysis, in addition to the method used in Reference 21, the methods as described in ANSI/ANS 58.2-1980 (Reference 20) are also used to verify the jet impingement temperature.

The analyses have been performed on compartment pressurization and the environmental effects of pressure, temperature and humidity. These analyses and their results are reported in Sections 3.6.4.2.2 and 3.6.4.2.3. Because of the similarity of Unit 1 and Unit 2, these results can also apply to Unit 2.

3.6.4.2.1 Blowdown Forces

Fluid blowdown thrust time-histories resulting from a pipe rupture are determined using PRTHRUST, a computer code derived from RELAP3. The assumptions used for these analyses together with representative mathematical models and typical results are presented in Reference 7.
Pipe whip analyses of the main steam and feedwater piping, between the containment and the turbine building, resulting from ruptures at the identified locations were determined using computer program PIPERUP. PIPERUP determines the nonlinear,

elastic-plastic response of 3-D piping restraint systems to the fluid blowdown force time-histories defined above. Gaps between the piping and rupture restraints, as well as nonlinear properties of the restraints are included in the analysis. A description of the analytical methods used in the analyses, mathematical models of the piping systems, and representative results are also presented in Reference 7 and supporting analyses. The original analyses are supplemented by added considerations introduced by the operating license review (Reference 22).

3.6.4.2.2 Compartment Pressurization

A definition of the worst case overpressure condition is required for the areas subjected to high-energy line breaks in order to evaluate the structural capability of essential structures required to maintain their integrity following the break. The potentially affected areas of the plant were modeled as compartments connected by vent paths that communicate with the break compartment in the multicompartment computer program FLUD, PCFLUD, or GOTHIC. This program calculates the conditions that will exist in the compartments over the duration of release of mass and energy from the postulated break. Figures 3.6-5 through 3.6-15 illustrate the compartment designations for the various models used in the analysis. Because of the similarity between Unit 1 and Unit 2, the compartment designations also apply to Unit 2.

3.6.4.2.2.1 Main Steam and Feedwater Piping

The controlling design basis break locations in the main steam piping between the containment and turbine stop valves in regard to compartment overpressure are as follows:

(1) Auxiliary building, Area GW, containment penetration

(2) Auxiliary building, Area GW, G-line anchor

(3) Turbine building, Area D, elevation 85 feet

(4) Turbine building, Area D, elevation 140 feet

Mass and energy release were calculated for each of the above breaks assuming the worst case operating conditions with the flow constrictions at the containment penetration and G-line anchor considered in addition to the available means of detection and automatic isolation. The consequent pressurization of compartments was determined and the results are illustrated in Figures 3.6-16 through 3.6-19. Pressurization effects due to feedwater line breaks are bounded by the above results for the main steam lines.

3.6.4.2.2.2 Other High-Energy Piping

The controlling break locations for other high-energy lines are as follows:

(1) Chemical and volume control system (double-ended rupture in letdown line)

- Auxiliary building, Area K, letdown heat exchanger room

(2) Auxiliary steam supply system (crack)

- Auxiliary building, Area J, AFW pump rooms

- Auxiliary building, Area K, elevation 100 feet open area

(3) Turbine steam supply system (double-ended rupture in line 593)

- Auxiliary building, Area L, radiation monitor room

Mass and energy release were calculated for each of the above breaks assuming the worst case operating conditions and considering the available means of detection and isolation system. In the case of the CVCS break, an automatic detection/isolation system as described in Section 7.6 is utilized to minimize the release. The consequent pressurization of compartments was determined and the results are illustrated in Figures 3.6-20 through 3.6-26. Pressurization effects due to other high-energy line breaks in Area GE and Area GW and the turbine building are bounded by the results for the MSLBs.

3.6.4.2.3 Environmental Conditions

A definition of the worst case environmental conditions of temperature and humidity is required for the area subjected to the high-energy line breaks to evaluate essential equipment required to shutdown the plant following the break.

3.6.4.2.3.1 Main Steam and Feedwater Piping

The controlling break locations in the main steam piping between the containment and turbine stop valves for consideration of adverse environmental effects are as follows:

(1) Auxiliary building, Area GW, elevation 115 feet (crack break)

(2) Turbine building, Area D, elevation 85 feet (double-ended rupture)

(3) Turbine building, Area D, elevation 140 feet (crack break)

Mass and energy releases were calculated for each of the above breaks assuming the worst case operating conditions utilizing the computer program LOFTRAN..

The consequent compartment temperatures and relative humidity values were determined using the computer program FLUD, PCFLUD, or GOTHIC. Bounding temperature profiles for the affected areas are illustrated in Figures 3.6-28 through 3.6-30 for the turbine building and Figure 3.6-32 for the auxiliary building. Additionally for the GE/GW area, peak instantaneous temperatures, as determined over the analysis time duration (2000 second maximum time duration), for the limiting case for each analyzed compartment, are:

Compartment	Peak Temperature, °F
GW 115 feet	453.7
GE 115 feet	329.1
GW 100 feet	356.5
GE 100 feet	306.3
GW 85 feet	261.7
Pipeway	425.5

3.6.4.2.3.2 Other High-Energy Piping

The controlling break locations for the other high-energy lines for consideration of adverse environmental effects are those identified in Section 3.6.4.2.2.2. The consequent temperature and relative humidity in the affected compartments were determined in the FLUD or GOTHIC analysis. Bounding temperature profiles for the affected areas are illustrated in Figures 3.6-34 through 3.6-44. The maximum relative humidity of 100 percent was applied in the evaluation of essential equipment.

3.6.5 PROTECTIVE MEASURES

3.6.5.1 Piping Breaks

3.6.5.1.1 High-Energy Piping Breaks Inside Containment

It is essential that the equipment support structures (RPV, steam generators, pressurizer and RCPs) be protected from the impact of large whipping pipes or be designed to resist such impact. This protection is accomplished by separation of equipment and piping, or by providing pipe restraints to prevent the formation of a plastic hinge mechanism. With the acceptance of the DCPP LBB analysis by the NRC (Reference 12), protection of equipment and support structures from the whipping of main RCL piping is no longer required, although protection from the dynamic effects of RCS branch line and other HELBs must still be provided. If any branch pipes are supported from equipment support structures, the reaction force resulting from a rupture of these lines is considered in designing the equipment supports. Small pipes are assumed to cause no significant damage to equipment supports.

To ensure the continued integrity of the essential components and the engineered safety systems, consideration is given to the consequential effects of the pipe break itself in order to meet the following criteria:

(1) The minimum performance capabilities of the engineered safety systems must not be reduced below that required to protect against the postulated break.

(2) The containment (defined here as the containment structure liner and penetrations, the steam generator shell including instrumentation connections, the feedwater, blowdown, and steam generator drain lines within the containment structure) leaktightness must not be decreased below the design value, if the break leads to a loss of reactor coolant.

(3) An RCS pipe break must not cause a steam-feedwater system pipe break and vice versa.

The fluid discharge from ruptured piping would produce reaction and thrust forces in the piping systems. The effects of these forces have been considered in ensuring that the general criteria and performance of engineered safety systems are satisfied.

In addition to the three criteria on the consequential effects of the pipe break itself, as given above, propagation of damage must be limited in type and/or degree as follows:

(1) A pipe break that is not a loss of reactor coolant must not cause a loss of reactor coolant, or a steam or feedwater line break.

(2) Branch lines connected to the RCS are defined as "large" if they have an inside diameter (ID) greater than 4 inches.

Large piping is restrained so that:

(a) propagation of the break to the unaffected loops is prevented

(b) propagation of the break in the affected loop is permitted to occur but must not exceed 20 percent of the area of the line that initially ruptured

(3) Branch lines connected to the RCS are defined as "small" if they have an ID equal to or less than 4 inches.

Small lines are restrained or arranged to meet the following requirements in addition to (1) and (2) above:

(a) Break propagation must be limited to the affected leg.

(b) Propagation of the break in the affected leg is permitted, but must be limited to a total break area of 12.5 square inches (4-inch ID).

(c) Damage to the high-head SI lines connected to the other leg of the affected loop or to the other loops must be prevented.

(d) Propagation of the break to high-head SI lines connected to the affected leg must be prevented if the line break results in a loss of core cooling capability due to a spilling injection line.

(4) Where restraints are necessary to prevent impact causing unacceptable damage to essential systems and components, they are installed such that a plastic hinge (unrestrained rotation) on the pipe at the two support points closest to the break will not be formed (refer to Section 3.6.5.2). Pipes are allowed to form plastic hinges in areas or arrangements where:

(a) Whipping free sections cannot reach equipment or other pipes for which protection is required.

(b) Protective barriers prevent the whipping pipe from impacting components or pipes requiring protection.

(c) The internal energy of the pipe is insufficient to impair the function of any equipment or structure, i.e., the maximum operating temperature is less than 200°F and the maximum operating pressure is below 275 psig.

Pursuant to Regulatory Guide 1.46, May 1973, lines hitting equal or larger size lines of the same schedule will not cause failure of the line being hit, e.g., failure of a 2-inch line will not cause subsequent failure of another 2-inch line or a line of larger size. The reverse, however, is assumed to be probable; i.e., a 4-inch line, should it fail and whip as a result of the fluid discharged through the break, is assumed to cause failure of smaller lines, such as neighboring 3-inch or 2-inch lines, unless additional justification is provided.

3.6.5.1.2 High-Energy Piping Breaks Outside Containment

The PG&E Design Class I structures and essential equipment requiring protection from high-energy pipe breaks outside containment are discussed in Reference 7.

3.6.5.2 Pipe Whip Restraint Design Criteria

3.6.5.2.1 Inside Containment

Where the requirements as outlined above cannot be satisfied by judicious routing of the piping, pipe whip restraints are designed and located as outlined below. Note that with the acceptance of the DCPP main RCS loop LBB analysis by the NRC (Reference 12), pipe whip restraints are not required on main RCL piping since breaks in this piping are no longer assumed to occur for evaluation of dynamic effects. Pipe

whip effects due to breaks in RCS branch lines and other high energy lines must still be evaluated.

3.6.5.2.1.1 Location of Pipe Whip Restraints

Restraints are located at each zone of the piping over 1 inch in size where formation of a plastic hinge could endanger a PG&E Design Class I structure or essential equipment. Design was completed prior to issuance of Regulatory Guide 1.46, May 1973. The piping design on all of these systems is based on ANSI B31.1-1967.

3.6.5.2.1.2 Design of Restraint Structures

Restraint structures consist of steel rods, U-bolts, crushable bumpers, and steel frames. In determining their design load, the pipe rupture restraints are considered independent of dead and live load supports and of seismic restraints.

In equation form,

$$Y = Y_r \qquad (3.6\text{-}6)$$

where:

Y = section strength required to resist design loads

Y_r = the equivalent static load on a pipe rupture restraint generated by the reaction on the broken high-energy pipe during a postulated break. The load, Y_r, includes a dynamic impact factor (DIF). The DIF equals 2 for restraints where rods, U-bolts, or crushable bumpers are provided, and 3 for restraints without U-bolts, rods, or crushable bumpers and a gap larger than 1/2 inch; Y_r = (DIF) (K)(P)(A), where K is the thrust coefficient.

Maximum strain of steel rods and U-bolts is limited to 50 percent of the strain corresponding to the maximum tested ultimate strength of the material. Crushable bumper deformation is limited to two-thirds of the effective crushing length of the bumper. For nonlinear analysis of steel frames, the allowable stress is the minimum specified yield stress of the material. Due to the high rate of strain that the restraint would experience after pipe rupture, the static yield strength of the frame material is increased by 5 percent.

3.6.5.2.1.3 Summary of Pipe Whip Effects

Lines that are classified as high-energy have been evaluated against Regulatory Guide 1.46, May 1973 as the minimum design criteria. Tables 3.6-1 and 3.6-2 are checklists of pipe whip effects from postulated pipe ruptures inside the containment.

3.6.5.2.2 High-Energy Piping Breaks Outside Containment

Pipe restraint design criteria for high-energy piping outside containment are given in Reference 7.

3.6.5.3 Protective Provisions for Essential Equipment

3.6.5.3.1 High-Energy Piping Breaks Inside Containment

The piping is routed so that whipping of two free sections cannot reach equipment or other pipes for which protection is required. Barriers are used, where available, to prevent the whipping pipe from impacting equipment or piping requiring protection. For example, the crane wall, operating floor, and refueling cavity walls serve as barriers between the RCLs and the containment liner. Subsequent to the acceptance of LBB evaluation by the NRC (Reference 12) pipe whip effects due to breaks in RCS branch lines and other high energy lines must still be evaluated. Except for ECCS lines attached to main RCLs, the ESFs are located outside of the crane wall. The ECCS lines that penetrate the crane wall are routed outside of the crane wall so as to penetrate it in the vicinity of the loop to which they are attached. The results of analyses demonstrate that pipe whip resulting from a postulated break in an ECCS line inside the crane wall will not cause damage in excess of that allowed by the established criteria.

3.6.5.3.2 High-Energy Piping Breaks Outside Containment

The piping anchors, rupture restraints, and restraint attachments are analyzed as described in Reference 7 and supporting analyses. The original analyses are supplemented by added considerations introduced by the operating license review (Reference 22).

PG&E Design Class I building structures are analyzed in accordance with the design load combinations described in Section 3.8.
The design of the structures includes calculation of the effects of forces from postulated pipe ruptures transmitted through pipe restraints and equipment supports and jet forces from postulated pipe ruptures.

The enclosure over the annular space between the containment wall and auxiliary building roof at Elevation 140 feet is provided with blow-out type bellows to provide a steam relief flow path during a HELB accident.

Affected equipment and conduits have also been investigated to ensure their operability in the post-break temperature, pressure, and humidity environment.

3.6.5.3.3 Moderate-Energy Piping Breaks

All equipment required to safely bring the plant from full power to cold shutdown conditions was identified and evaluated for the effects of MELBs. The effects of spray or flooding from postulated ruptures of moderate-energy piping were evaluated to indicate probable loss of function of any essential equipment. If the loss of function of the equipment could be tolerated due to system redundancies, equipment EQ, etc., no action was required. If the loss of function could not be tolerated, a design modification was required to protect the vulnerable equipment. Following a detailed review and plant walkdown as described above, no modifications were required (Reference 10).

3.6.5.4 Pipe Whip Restraints and Spray Barriers

3.6.5.4.1 Inside Containment

For piping inside containment, the analysis shows that the locations of restraints are adequate to prevent unacceptable damage from whips that could result from postulated breaks (refer to Figure 3.6-2 and Tables 3.6-1 and 3.6-2). Restraint structures consist of ASTM A304 steel rods or U-bolts, or crushable bumpers, and steel frames of ASTM A36, ASTM A441, or ASTM A516 Grade 70 material. Bumpers are 1-1/2 inch square, thin-walled A151 Grade 1010 carbon steel tubing welded together to form a multi-cell cross-section. Typical restraint structures are shown in Figures 3.6-3A through 3.6-3C. Tested properties of the ASTM A304 material are as follows:

Elastic modulus	28,000 ksi
Yield strength	34 to 46 ksi
Tensile strength	76 to 94 ksi

3.6.5.4.2 Outside Containment

For piping outside the containment, the analysis shows that the locations of restraints are adequate to prevent unacceptable damage from all whips that could result from postulated breaks. A typical restraint is shown in Figure 3.6-3.

3.6.5.4.3 Moderate-Energy Piping Breaks

Based on a detailed review and a plant walkdown, it was determined that no impingement shields (i.e., barriers) were necessary to protect essential equipment from moderate-energy pipe breaks (Reference 10). Due to system redundancy and equipment EQ, the postulated MELBs would not affect the capability to achieve a safe (cold) shutdown.

3.6.5.5 Differences Between Unit 1 and Unit 2 Pipe Break Protection Features Outside Containment

DCPP Unit 1 and Unit 2 were designed to be mirror images of each other. This similarity allowed use of the same type of analysis to determine the consequence of a pipe break outside containment. The two units were not built simultaneously, which accounts for some of the design differences between them.

The major difference in protection on Unit 2 was that, for several locations, jet impingement barriers were eliminated from the Unit 2 design. However, for these locations, essential equipment was separated from piping systems whose failure could produce jets. Other main differences are in the change in the Unit 2 reheater drain system and location of essential equipment, instrumentation, and electrical conduit.

The reheater drain piping systems of Unit 1 and Unit 2 in the turbine building are not mirror images of each other.

Table 3.6-6, Pipe Break Protection Features on Unit 2 Different from Unit 1, describes the design features of the units that are different, compares the protection features of the units, and justifies the protection features employed for Unit 2.

3.6.6 SAFETY EVALUATION

3.6.6.1 General Design Criterion 4, 1987 – Environmental and Dynamic Effects Design Bases

Protection from dynamic effects associated with postulated pipe ruptures in the main reactor coolant piping are not considered because DCPP has invoked LBB methodology/analyses by demonstrating that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping system. Refer to Sections 3.6.2.1.1.1, 3.6.5.1.1, and 3.6.5.3.1 for details.

3.6.6.2 General Design Criterion 40, 1967 – Missile Protection

Protection for ESFs inside and outside of containment is provided against dynamic effects that might result from plant equipment failures. For details, refer to:

(1) Sections 3.6 and 3.6.2.1 for the general criteria for the postulation of high-energy line breaks

(2) Section 3.6.2.1.1 for the list of systems evaluated for the effects of pipe whip and blowdown reactive forces associated with pipe rupture inside containment.

(3) Sections 3.6.2.1.1.2 and 3.6.5.1.1 for the RCS connected piping break criteria applicable to DCPP.

(4) Sections 3.6.2.1.1.3, 3.6.2.2.1.1, and 3.6.2.2.1.2 for the break criteria that apply to other high-energy piping inside containment. Originally, breaks were postulated at all terminal ends and all locations, regardless of stress level, where plastic hinges could form and endanger essential systems or components. Currently, intermediate breaks are postulated in accordance with MEB 3-1, Revision 1 except for arbitrary intermediate breaks which were eliminated per guidance from Generic Letter 87-11, June 1987.

(5) Sections 3.6.2.1.2, 3.6.2.2.1.2, and 3.6.2.2.2.1 for the break location criteria that apply to high-energy piping outside containment. Originally, breaks were postulated in accordance with References 4, 5, and 6. Currently, intermediate breaks are postulated in accordance with MEB 3-1, Revision 1 except for arbitrary intermediate breaks which were eliminated per guidance from Generic Letter 87-11, June 1987. This section identifies the systems that contain high-energy lines located outside of the containment in which both open crack and design bases breaks are postulated to occur based on the before mentioned criteria.

(6) Section 3.6.2.2.2.2 for break types, orientation, and break area criteria that apply to high-energy piping outside containment.

(7) Section 3.6.3.2 for the factors and criteria in the piping response analysis of high-energy pipe breaks outside containment.

(8) Section 3.6.4.1.2 for the piping other than RCL, and RCL branch lines, inside containment high-energy pipe break blowdown and jet impingement forces calculation methodology.

(9) Sections 3.6.4.2, 3.6.4.2.2.1, 3.6.4.2.2.2, 3.6.4.2.3, 3.6.4.2.3.1, and 3.6.4.2.3.2 for the reverification of pipe whip, jet impingement, and water flooding to reflect the current as-built condition. In the reanalysis, methods as described in ANSI/ANS 58.2-1980 are also used to verify the jet impingement temperature.

(10) Sections 3.6.4.2.1, 3.6.4.2.2, 3.6.4.2.3.1 and 3.6.4.2.3.2 for the computer programs used to determine the fluid blowdown forces and compartment pressurization conditions associated with high-energy pipe breaks outside containment.

(11) Sections 3.6.5.1.1, 3.6.5.1.2, 3.6.5.2.1.1, 3.6.5.2.1.2, 3.6.5.2.1.3, and 3.6.5.2.2 for the high-energy line break propagation criteria (inside containment), pipe whip restraint design criteria, and jet impingement assessment criteria.

(12) Sections 3.6.5.3.1 and 3.6.5.4.1 for protective measures from pipe whip effects.

(13) Section 3.6.5.5 for the differences between Unit 1 and Unit 2 Pipe Break Protection Features Outside Containment.

3.6.6.3 Protection Against Pipe Rupture Effects Safety Function Requirements

(1) Protection from High Energy Pipe Rupture Effects - Outside Containment

DCPP can achieve and maintain safe shutdown in the event of a rupture of piping outside of containment containing high-energy fluid. PG&E Design Class I structures and essential systems and components are designed and located to accommodate the dynamic effects of such a postulated pipe failure (pipe whipping, jet impingement, compartment pressurization, and environmental effects) to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained. For details, refer to:

(a) Sections 3.6 and 3.6.4.2 for the reverification of pipe whip, jet impingement, and water flooding to reflect the current as-built condition. In the reanalysis, methods as described in ANSI/ANS 58.2-1980 are also used to verify the jet impingement temperature.

(b) Sections 3.6.4.2.1 and 3.6.4.2.2 for the computer programs used to determine the fluid blowdown forces and compartment pressurization conditions associated with high-energy pipe breaks outside containment.

(c) Sections 3.6.5.1.2 and 3.6.5.2.2 for the high-energy line break propagation criteria (outside containment), pipe whip restraint design criteria, and jet impingement assessment criteria.

(d) Sections 3.6.5.3.2 and 3.6.5.4.2 for protective measures from pipe whip effects.

(2) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

DCPP can achieve cold shutdown in the event of a rupture of piping outside of containment containing moderate energy fluid. Essential equipment required to safely bring the plant to cold shutdown conditions are located or protected to accommodate the effects of such a postulated piping failure (fluid spray). Refer to Sections 3.6, 3.6.2.1.3, 3.6.2.2.3, 3.6.5.3.3 and 3.6.5.4.3 for details.

(3) Protection from Jet Impingement – Inside Containment

The containment and essential equipment within the containment are protected against HELB jet impingement effects. The DCPP jet impingement assessment inside containment conforms with the following:

(a) Pipe breaks resulting in jet impingement for fluid piping systems are postulated for systems with a maximum operating pressure greater than or

equal to 275 psig or the maximum operating temperature greater than or equal to 200°F. Refer to Sections 3.6 and 3.6.2.1 for details.

(b) For jet impingement effects inside containment and pipe whip and traveling jet effects for small lines inside containment not restrained as a result of the original review of pipe break dynamic effects, longitudinal and circumferential break orientation and break area for non-RCL high-energy piping are in accordance with Branch Technical Position MEB 3-1, Revision 1. Refer to Section 3.6.2.2.1.2 for details.

(c) Jet impingement forces due to the postulated piping breaks in lines inside containment (other than the RCLs) were calculated from the formula:

$$F_B = C_T \, PoA$$

Refer to Section 3.6.4.1.2 for details.

(4) Protection from Flooding Effects – Outside Containment

DCPP can achieve cold shutdown in the event of a rupture of piping outside of containment. Essential equipment required to safely bring the plant to cold shutdown conditions are located or protected to accommodate flooding associated with postulated high-energy and moderate energy piping failures. Refer to Sections 3.6, 3.6.2.1.1.3, 3.6.2.1.3, 3.6.4.2, and 3.6.5.3.3 for details.

3.6.6.4 Regulatory Guide 1.46, May 1973 - Protection Against Pipe Whip Inside Containment

The DCPP criteria for the postulation of high-energy pipe break locations inside containment are equivalent to or in accordance with Regulatory Guide 1.46, May 1973. The following summarizes the application of Regulatory Guide 1.46, May 1973:

(1) For high-energy piping inside containment (except for RCL), breaks were originally postulated at all terminal ends and all locations, regardless of stress level, where plastic hinges could form and endanger safety systems or components. This criterion conservatively bounds Regulatory Guide 1.46, May 1973 criteria of break postulation. Subsequently, guidance from Regulatory Guide 1.46, May 1973 was used to postulate intermediate breaks at all high stress points. Refer to Section 3.6.2.1.1.3 for more details.

(2) Longitudinal and circumferential break orientation and break area for non-RCL high-energy piping inside containment are equivalent to the criteria for piping inside containment set forth in Regulatory Guide 1.46, May 1973. Refer to Section 3.6.2.2.1.2 for more details.

(3) Pursuant to Regulatory Guide 1.46, May 1973, high-energy lines inside containment hitting equal or larger size lines of the same schedule will not cause failure of the line being hit. Targeted lines not meeting this criterion are assumed to fail unless additional justification is provided. Refer to Section 3.6.5.1.1 for more details.

(4) Pipe whip effects from postulated high-energy pipe ruptures inside the containment have been evaluated against Regulatory Guide 1.46, May 1973 as the minimum design criteria. Refer to Section 3.6.5.2.1.3 for more details.

3.6.6.5 Generic Letter 87-11, June 1987 – Relaxation in Arbitrary Intermediate Pipe Rupture Requirements

Arbitrary intermediate pipe ruptures are no longer postulated in high-energy piping inside and outside containment as recommended by Generic Letter 87-11, June 1987 (no longer mentioned in Branch Technical Position MEB 3-1 (Reference 9). Dynamic effects have been eliminated (missile generation, pipe whipping, pipe break reaction forces, jet impingement forces, sub-compartment and cavity pressurizations and decompression waves within the ruptured pipe) and the environmental effects (pressure, temperature, humidity and flooding) resulting from arbitrary intermediate pipe breaks. Refer to Section 3.6.2.1.1.3 and 3.6.2.1.2 for details.

3.6.6.6 Branch Technical Position MEB 3-1, July 1981 – Postulated Break and Leakage Locations in Fluid System Piping Inside and Outside Containment

Pipe breaks inside and outside containment are postulated to occur at all (intermediate) locations where the primary plus secondary stress exceeds the stress level of $0.8(1.2S_h + S_A)$ as described in Sections 3.6.2.1.1.3, 3.6.2.1.2, 3.6.2.2.1.1, and 3.6.2.2.2.1. For jet impingement effects inside containment and pipe whip and traveling jet effects for small lines inside containment not restrained as a result of the original review of pipe break dynamic effects, the pipe break types, break orientation and break area for non-RCL high-energy piping are in accordance with Branch Technical Position MEB 3-1, Revision 1 as described in Sections 3.6.2.1 and 3.6.2.2.1.2.

3.6.7 REFERENCES

1. Regulatory Guide 1.46, Protection Against Pipe Whip Inside Containment, May 1973.

2. Moody, ASME Paper 69-HT-31, 1969.

3. WCAP-8082, Pipe Breaks for the LOCA Analysis of the Westinghouse Primary Coolant Loop, Westinghouse Nuclear Energy Systems, June 1973.

4. Letter dated December 18, 1972, including the attachment, General Information Required for Consideration of the Effects of a Piping System Break Outside Containment, (Docket Nos. 50-275 and 50-323) from A. Giambusso of the AEC to F. T. Searls of PG&E.

5. Letter dated January 29, 1973, including the errata sheet, General Information Required for Consideration of the Effects of a Piping System Break Outside Containment, (Docket Nos. 50-275 and 50-323) from P. Kniel of the AEC to F. T. Searls of PG&E.

6. Enclosure 3 to letter dated August 13, 1973, Structural Design Criteria for Evaluating the Effects of High Energy Pipe Breaks on Category I Structures Outside Containment, (Docket Nos. 50-275 and 50-323) from A. Giambusso of the AEC to F. T. Searls of PG&E.

7. Nuclear Services Corporation, PGE-01-02, Evaluation for Effects of Postulated Pipe Break Outside Containment for Diablo Canyon Unit 1, Revision 3, April 13, 1977.

8. Branch Technical Position MEB 3-1, Revision 1, Postulated Break and Leakage Locations in Fluid System Piping Inside and Outside Containment, July 1981.

9. Generic Letter 1987-11 dated June 19,1987, Relaxation in Arbitrary Intermediate Pipe Rupture Requirements and attached Branch Technical Position MEB 3-1 Revision 2, Postulated Rupture Locations in Fluid System Piping Inside and Outside Containment, June 1987.

10. PG&E Memorandum, Reanalysis of Moderate Energy Line Break (MELB) Requirements, Unit 1 January 18, 1991.

11. WCAP-13039, Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for DCPP Units 1 and 2, Westinghouse Electric Corporation, November 1991.

12. Letter dated March 2, 1993, Leak-Before-Break Evaluation of Reactor Coolant System Piping for DCPP Units 1 and 2, (Docket Nos. 50-275 and 50-323), from Sheri R. Peterson of the NRC to Gregory M. Rueger of PG&E.

13. Modification of General Design Criterion 4 Requirements for Protection Against Dynamic Effects of Postulated Pipe Ruptures, Federal Register, Volume 51, No. 70 dated April 11, 1986 and Federal Register, Volume 52, No. 207 dated October 27, 1987.

14. Deleted in Revision 19

15. Letter dated October 10, 1977, Pipe Break Protection Features on Unit 2 Different from Unit 1…Reply to Question No. 31.107 (Docket Nos. 50-275 and 50-323), from Phillip A. Crane of PG&E to John F. Stolz of the NRC.

16. Letter dated April 09, 1984, Jet Impingement Evaluations, (Docket Nos. 50-275 and 50-323), from J. O. Schuyler of PG&E to Mr. Harold R. Denton of the NRC.

17. Letter dated February 14, 1985, Jet Impingement Evaluation, (Docket No. 50-323), from J. D. Shiffer of PG&E to Mr. George W. Knighton of the NRC.

18. Letter dated September 14, 1979, Diablo Canyon Plant Evaluation for Moderate Energy Line Breaks, (Docket Nos. 50-275 and 50-323), from Philip A. Crane of PG&E to John F. Stoltz of the NRC.

19. Letter dated December 28, 1979, Evaluation of the Diablo Canyon Plant Design for the Effects of Moderate Energy Line Breaks on Equipment Required for Safe Shutdown, (Docket Nos. 50-275 and 50-323), from Philip A. Crane of PG&E to John F. Stoltz of the NRC.

20. ANSI/ANS-58.2-1980, Design Basis for Protection of Light Water Nuclear Power Plants Against the Effects of Postulated Pipe Rupture

21. Nuclear Services Corporation, PGE-01-29, Jet Effects Analysis of postulated Pipe Break Outside Containment at Diablo Canyon Unit 1, April 15, 1975

22. PG&E, Phase I Final Report - Design Verification Program, Diablo Canyon Power Plant, Revision 14, transmitted via letter dated October 14, 1983, J. O. Schuyler (PG&E) to D. G. Eisenhut (NRC).

3.6.8 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

3.7 SEISMIC DESIGN

3.7.1 SEISMIC INPUT

This section describes the DE, the DDE, and the HE.

In addition to the above three design-basis earthquakes, PG&E conducted a program to reevaluate the seismic design for DCPP in response to License Condition 2.C(7) of the DCPP Unit 1 Operating License (DPR-80), which stated, in part: "PG&E shall develop and implement a program to reevaluate the seismic design bases used for the Diablo Canyon Power Plant."

PG&E's reevaluation effort in response to the license condition was titled the "Long Term Seismic Program" (LTSP). PG&E prepared and submitted to the NRC the "Final Report of the Diablo Canyon Long Term Seismic Program" in July 1988 (Reference 19). The NRC reviewed the Final Report between 1988 and 1991, and PG&E prepared and submitted written responses to NRC questions resulting from that review. In February 1991, PG&E issued the "Addendum to the 1988 Final Report of the Diablo Canyon Long Term Seismic Program" (Reference 20). In June 1991, the NRC issued Supplement 34 to the Diablo Canyon SER (Reference 21), in which the NRC concluded that PG&E had satisfied License Condition 2.C(7) of DPR-80. In the SSER the NRC requested certain confirmatory analyses from PG&E, and PG&E subsequently submitted the requested analyses. The NRC's final acceptance of the 1991 LTSP is documented in a letter to PG&E dated April 17, 1992 (Reference 22

The 1991 LTSP contains extensive databases and analyses that update the basic geologic and seismic information. However, the 1991 LTSP material does not alter the design bases for DCPP. In SSER 34 (Reference 21), the NRC states, "The Staff notes that the seismic qualification basis for Diablo Canyon will continue to be the original design basis plus the Hosgri evaluation basis, along with associated analytical methods, initial conditions, etc."

PG&E committed to the NRC in a letter dated July 16, 1991 (Reference 23), that certain future plant additions and modifications, as identified in that letter, would be checked against insights and knowledge gained from the 1991 LTSP to verify that the plant margins remain acceptable.

A completed listing of bibliographic references to the 1991 LTSP reports and other documents are provided in References 19, 20, and 21.

As indicated in Section 2.5.7, the close-out of the 1991 LTSP included a commitment to keep abreast of new geological, seismic, and seismic engineering information and evaluate it with respect to its significance to Diablo Canyon. The process for the evaluation of this new information is described in Section 2.5.7.2, which was implemented in PG&E's response to the request for information pursuant to 10 CFR 50.54(f) Regarding Recommendation Nos. 2.1, 2.3, and 9.3 of the Near-Term Task

Force Review of Insights from the Fukushima Dai-Ichi Accident (Reference 43). PG&E's response to this request (Reference 44) included a change to the commitment associated with the 1991 LTSP regarding future plant additions and modifications to assess future plant additions and modifications to verify that the plant seismic risk remains acceptable (i.e., lowered or no significant increase), using the insights from the updated seismic hazard evaluation and updated seismic probabilistic risk assessment, described in Sections 2.5.7.2.1.1 and 2.5.7.2.1.2, respectively (Enclosure 2 to Reference 44). The NRC's review and acceptance of PG&E's response to the request for information is documented in Reference 45.

3.7.1.1 Design Bases

The regulatory requirements listed below constitute additional Design Bases as defined in 10 CFR 50.2 and NEI 97-04, Appendix B (2000) and include: GDCs, applicable federal regulations, and system safety functional requirements.

3.7.1.1.1 General Design Criterion 2, 1967 - Performance Standards

Those systems and components of reactor facilities that are essential to the prevention of accidents which could affect the public health and safety, or to mitigation of their consequences, shall be designed, fabricated, and erected to performance standards that will enable the facility to withstand, without loss of the capability to protect the public, the additional forces that might be imposed by natural phenomena such as earthquakes. The design bases so established shall reflect (a) appropriate consideration of the most severe of these natural phenomena that have been recorded for the site and the surrounding area, and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design.

Subject matter related to meeting GDC 2, 1967 falls under the following general categories:

Seismic Input

- Design Response Spectra
- Design Response Spectra Derivation
- Critical Damping Values
- Bases for Site Dependent Analysis
- Soil-Supported Category I Structures
- Soil-Structure Interaction

Seismic System Analysis

The seismic system analyses address the following considerations:

- Seismic Analysis Methods

- Natural Frequencies and Response Loads
- Procedures Used to Lump Masses
- Rocking and Translation Response Summary
- Methods Used to Couple Soil with Seismic-System Structures
- Development of Floor Response Spectra
- Differential Seismic Movement of Interconnected Components
- Effects of Variations on Floor Response Spectra
- Use of Constant Vertical Load Factors
- Methods Used to Account for Torsional Effects
- Comparison of Responses
- Methods to Determine PG&E Design Class I Structure Overturning Moments
- Analysis Procedure for Damping
- Combination of Components of Earthquake Motion for Structures

Seismic Subsystem Analysis

The seismic subsystem analyses address the following considerations:

- Determination of number of earthquake cycles
- Basis for selection of forcing frequencies
- Procedure for combining modal responses
- Root mean square basis
- Design criteria and analytical procedures for piping
- Basis for computing combined response
- Amplified seismic responses
- Use of simplified dynamic analysis
- Modal period variation
- Torsional effects of eccentric masses
- Piping outside Containment Structure
- Interaction of other piping with PG&E Design Class I Piping
- Field location of supports and restraints
- Seismic analyses for fuel elements, control rod Assemblies and control rod drives

Seismic Instrumentation Program

The seismic instrumentation program, addresses the following:

- Safety Guide 12, March 10, 1971, “Instrumentation for Earthquakes”
- Location and description of instrumentation
- Control Room operator notification
- Comparison of Measured and Predicted Responses

Seismic Design Control

- Equipment Purchased Directly by PG&E
- Equipment Supplied by Westinghouse

3.7.1.1.2 Seismic Design Safety Function Requirement

(1) Design Earthquake and Double Design Earthquake Damping Values

The damping values provided in Section 3.7.1.4 shall be used for the seismic evaluation of PG&E Design Class I SSCs for the DE and DDE.

3.7.1.1.3 Safety Guide 12, March 10, 1971 – Instrumentation for Earthquakes

The seismic instrumentation is designed to fulfill the requirements of Safety Guide 12, March 10, 1971.

3.7.1.1.4 Regulatory Guide 1.61, October 1973 - Damping Values for Seismic Design of Nuclear Power Plants

As noted in Section 3.7.1.4, it is acceptable to use the damping values that are defined in the section Table, consistent with the recommendations of Regulatory Guide 1.61, October 1973, "Damping Values for Seismic Design of Nuclear Power Plants," for the seismic evaluation of PG&E Design Class I SSCs for the HE, and the RCL piping for the DE and DDE.

3.7.1.1.5 Regulatory Guide 1.61, Revision 1, March 2007 - Damping Values for Seismic Design of Nuclear Power Plants

Damping values for the seismic design and analysis of the IHA and CRDM pressure housings that are consistent with the recommendations of Regulatory Guide 1.61, Revision 1, “Damping Values for Seismic Design of Nuclear Power Plants,” are used in the seismic qualification.

3.7.1.1.6 NUREG-0660 (Item II.C.3), May 1980 - NRC Action Plan Developed as a Result of the TMI-2 Accident

Item II.C.3 - Review of Safety Classifications and Qualifications: The object of the DCPP SISI Program is to identify and eliminate any potential undesirable, seismically-induced interactions between PG&E defined targets and sources.

3.7.1.1.7 License Condition 2.C(7) of DCPP Facility Operating License DPR-80 Revision 44 (Long Term Seismic Program), Element (4)

License Condition 2.C(7), “Seismic Design Bases Reevaluation Program (SSER 27 Section IV.5)” requires that PG&E shall develop and implement a program to reevaluate the seismic design bases used for the Diablo Canyon Nuclear Power Plant.

Elements 1, 2 and 3 of this license condition apply to the geological and seismological aspects of seismic sources and motion and are discussed in Section 2.5

Element 4 of this license condition requires that PG&E shall assess the significance of conclusions drawn from the seismic reevaluation studies in Elements 1, 2 and 3, utilizing a probabilistic risk analysis and deterministic studies, as necessary, to assure adequacy of seismic margins.

3.7.1.1.8 ASME Code Case N-411

The use of damping values from ASME Code Case N-411 is acceptable for piping reanalysis associated with the snubber reduction program and for future pipe stress analysis work, with certain restrictions as set forth in the NRC letter dated April 7, 1986.

3.7.1.2 Design Response Spectra

Section 2.5.3 provides a discussion of the earthquakes postulated for the DCPP site and the effects of these earthquakes in terms of maximum free-field ground motion accelerations and corresponding response spectra at the plant site. Since the development of the seismic inputs for DCPP predates the issuance of 10 CFR Part 100, Appendix A, “Seismic and Geologic Siting Criteria for Nuclear Power Plants,” the following DCPP earthquakes are plant specific.

3.7.1.2.1 Design Earthquake

The maximum vibratory accelerations at the plant site associated with the DE would result from either Earthquake B or Earthquake D-modified, depending on the natural period of the vibrating body. Response acceleration spectra curves for horizontal free-field ground motion at the plant site from Earthquake B and Earthquake D-modified are presented in Figures 2.5-20 and 2.5-21, respectively.

For design purposes, the response spectra for each damping value from Earthquake B and Earthquake D-modified are combined to produce an envelope spectrum. The acceleration value for any period on the envelope spectrum is equal to the larger of the two values from the Earthquake B spectrum and the Earthquake D-modified spectrum. Vertical free field ground accelerations, and the vertical free-field ground motion response spectra are assumed to be two-thirds of the corresponding horizontal spectra.

The DE is the hypothetical earthquake that would produce these horizontal and vertical vibratory accelerations. The DE corresponds to the operating basis earthquake (OBE), as described in 10 CFR Part 100, Appendix A (Reference 7).

3.7.1.2.2 Double Design Earthquake

To ensure adequate reserve energy capacity, PG&E Design Class I structures and equipment are reviewed for the DDE. The DDE is the hypothetical earthquake that would produce accelerations twice those of the DE. The DDE corresponds to the SSE, as described in 10 CFR Part 100, Appendix A (Reference 7).

3.7.1.2.3 Hosgri Earthquake

PG&E was requested by the NRC to evaluate the plant's capability to withstand a Richter magnitude 7.5 earthquake centered along an offshore zone of geologic faulting, generally referred to as the Hosgri Fault. This evaluation is discussed in the various chapters when it is specifically referred to as the Hosgri evaluation or Hosgri event evaluation.

Acceleration response spectra curves for horizontal and vertical free field ground motion at the plant site from the HE are the Newmark and Blume spectra described in Section 2.5 and presented in Figures 2.5-29 through 2.5-32. The vertical free field response spectra are two-thirds of the corresponding horizontal spectra.

3.7.1.3 Design Response Spectra Derivation

3.7.1.3.1 Design Earthquake

The free-field ground motion acceleration time-histories used in the dynamic analyses of the containment structure, auxiliary building, turbine building, and intake structure, for the DE, are developed by the following procedure: The response spectra for 2 percent damping for Earthquake B and Earthquake D-modified are enveloped to produce a single response spectrum (DE intensity). A time-history is then developed that produces a spectrum with no significant deviation from the smooth DE-envelope spectrum. This procedure eliminates undesirable peaks and valleys that exist in the response spectrum calculated directly from Earthquake B and Earthquake D-modified records.

3.7.1.3.2 Double Design Earthquake

A similar procedure is used to obtain a free-field ground motion acceleration time-history for the DDE. The free-field ground motion acceleration time-histories for the DE and DDE are shown in Figures 3.7-1 and 3.7-2, respectively. Comparison of the response spectrum computed from the time-history with the smoothed envelope spectrum is shown in Figure 3.7-3 (2 percent damping) and in Figure 3.7-4 (5 percent damping). These spectra are calculated at period intervals of 0.01 seconds, which adequately define the spectra.

3.7.1.3.3 Hosgri Earthquake

For the HE evaluation of containment structure, auxiliary building, turbine building, and intake structure acceleration time-histories were derived from the smooth spectra by utilizing an iterative procedure computer program. The horizontal input motions are reduced from free-field motions to account for the presence of the structures that have large foundations. These reduced inputs have been derived by spatial averaging of acceleration across the foundations of each structure by the Tau filtering procedure (Reference 12). The resulting horizontal response spectra for these structures are shown in Figures 3.7-4A through 3.7-4F. The Blume and Newmark spectra were used as the basic horizontal inputs while the vertical input corresponded to the Newmark free field response spectrum.

For HE evaluation of outdoor water storage tanks and smaller structures, the horizontal design response spectra are the free-field horizontal response spectra. HE vertical design response spectra are the free-field vertical response spectra. For design purposes, the Newmark spectra are used, or alternately the Blume spectra are used, with adjustment in certain frequency ranges as necessary so that they do not fall below the corresponding Newmark spectra.

Acceleration time-histories used in the analysis of the containment and intake structures, auxiliary building, and turbine building are shown in Figures 3.7-4G through 3.7-4M. Comparison of the response spectrum computed from each time-history with the corresponding design response spectrum for 7 percent damping is shown in Figures 3.7-4N through 3.7-4T.

3.7.1.4 Critical Damping Values

The specific percentages of critical damping used for PG&E Design Class I SSCs, and the PG&E Design Class II turbine building and intake structure are listed in the following table:

Type of Structure	% of Critical Damping		
	DE	DDE	HE
Containment structures and all internal concrete structures	2.0	5.0	7.0
Other conventionally reinforced concrete structures above ground, such as shear walls or rigid frames[j]	5.0	5.0	7.0
Welded structural steel assemblies	1.0	1.0	4.0
Bolted or riveted steel assemblies	2.0	2.0	7.0
Mechanical components (PG&E purchased)	2.0	2.0	4.0

Type of Structure	% of Critical Damping		
	DE	DDE	HE
Vital piping systems (except RCL)[a]	0.5	0.5	3.0[b]
RCL[a][c]	2.0	3.0	4.0
Reactor Pressure Vessel	0.5[i]	1.0[i]	4.0
Pressurizer	1.0[i]	1.0[i]	4.0
Reactor Coolant Pumps	2.0[i]	2.0[i]	4.0
Replacement Steam Generators[f]	2.0	4.0	4.0
IHA[g]	4.9	6.85	6.85
CRDMs[h]	5.0	5.0	5.0
Foundation rocking (containment structure only)[d]	5.0	5.0	NA[e]

[a] ASME Code Case N-411 damping may be used provided it is applied to all earthquake cases and used in response spectrum modal superposition analysis. When used, pipe displacements are checked for adequacy of clearances and pipe mounted equipment accelerations are verified against project qualification criteria.
For equipment and components modeled inline, damping should be consistent with Regulatory Guide 1.61, October 1973; a composite damping value may be used for the analysis of these piping systems.

A log of calculations is kept that indicates which calculations have used Code Case N-411 damping.

Request for NRC approval for the use of ASME Code Case N-411 was made in Letter DCL-86-009, dated January 22, 1986. NRC approval was granted by Letter on April 7, 1986

[b] Two percent of critical damping is used for piping less than or equal to 12 inches in diameter.

[c] The damping values of 2% and 3% are used for DE and DDE, respectively, and are consistent with the maximum permissible damping values for DE and DDE specified in Regulatory Guide 1.61, October 1973. The NRC approved a higher damping value (4%) for the HE. Damping values of greater than 4 percent have been measured experimentally for the RCL in full-size power plants (Reference 8). These testing programs have been reviewed and approved by the NRC. [d] Five percent of critical damping is used for structures founded on rock for the purpose of computing the response in the rocking mode,

and 7 percent of critical damping is used for the purpose of computing the response in the translation mode.

(e) Analysis utilizes fixed base.

(f) These values are valid for replacement steam generator (RSG) internals and shell components including up to the RSG nozzle to pipe/tube connections for the RCS, main steam, and feedwater systems. It also includes the interface between the RSG shell and the RSG supports (upper lateral, lower lateral, and lower vertical support). The restrictions imposed by WCAP 7921-AR (Reference 8) shall be observed when applying these values. (Reference 27)

(g) Damping values for the IHA are based on Regulatory Guide 1.61, Revision 1 (Reference 31), Tables 1 and 2, using a weighted average for "Welded Steel or Bolted Steel with Friction Connections" and "Bolted Steel with Bearing Connections". See PG&E Document 6023227-19 (Reference 30) for computation of weighted average value. Computation of weighted average value was approved in Reference 32.

(h) Damping values for the CRDMs are based on Regulatory Guide 1.61, Revision 1, (Reference 31) as approved in Reference 33.

(i) Damping values for the Reactor Pressure Vessel, Pressurizer, and Reactor Coolant Pumps are taken from Regulatory Guide 1.61, October 1973 and Westinghouse Specification DC-SDC-1, “Seismic Design for Westinghouse Seismic Class I Equipment for the Diablo Canyon Power Plant, as corrected by Westinghouse Letter PGE-06-90, dated August 24, 2006.”

(j) The Intake Structure and Turbine Building collapse analyses are based on the Hosgri Earthquake with 7 percent critical damping (refer to Section 3.7.2.2.2). However, for seismic qualification of the PG&E Design Class I components within these buildings, DE and DDE In-Structure Response Spectra (ISRS) are generated using 5 percent and 2 percent critical damping factors for the concrete and steel building materials, respectively.

3.7.1.5 Bases for Site-Dependent Analysis

Site conditions used to develop the shape of site seismic design response spectra are described in Section 2.5.2.

3.7.1.6 Soil-Supported PG&E Design Class I Structures

All PG&E Design Class I plant structures are founded on rock or on concrete fill.

3.7.1.7 Soil-Structure Interaction

Soil-structure interaction effects are considered as described in Section 3.7.2.2.

3.7.1.8 Hosgri Evaluation

The criteria and methods used to review the major structures for response to the HE are discussed in this chapter. A comparison of the DE and the DDE criteria with the HE evaluation criteria is given in Table 3.7-1 for the containment and auxiliary building, Table 3.7-1A for the turbine building, Table 3.7-1B for the intake structure, and Table 3.7-1C for the outdoor water storage tanks, respectively.

3.7.2 SEISMIC SYSTEM ANALYSIS

In accordance with Regulatory Guide 1.70, Revision 1, paragraphs under the headings below Seismic Analysis Methods and Description of Seismic Analyses, apply to all seismic analysis performed, i.e., both seismic system analysis and seismic subsystem analysis. Paragraphs under subsequent headings in this section provide discussion of specific topics applicable to seismic system analysis. Discussion of specific topics applicable to seismic subsystem analysis is provided in Section 3.7.3. The seismic analyses of PG&E Design Class I SSCs are based on the input motions associated with the DE, DDE, and HE described in Section 3.7.1.

3.7.2.1 Seismic Analysis Methods

Primarily, four dynamic methods of seismic analysis are used for the evaluation of PG&E Design Class I SSCs: time-history modal superposition, response spectrum modal superposition, response spectrum single-degree-of-freedom, and the method for rigid equipment and piping. The concept of modal analysis and each of the four methods of seismic analysis listed above are discussed in subsequent sections.

In cases where a different method of analysis is used a description of the analysis method is provided in the UFSAR section associated with its application. Specific exceptions include:

(1) Mechanical equipment whose seismic adequacy is verified by testing as described in Section 3.9

(2) Electrical and instrumentation equipment whose seismic adequacy is verified as described in Section 3.10

(3) Certain PG&E Design Class I piping less than 2-1/2 inches in diameter that is restrained according to criteria described in Section 3.7.2.2.4

(4) Reactor internals, fuel elements, control rod drive assemblies, and control rod drives, as described in Section 3.7.3.15.

3.7.2.1.1 Modal Analysis

The structure, system, or component is represented as a mathematical model that is in the form of lumped masses interconnected by springs or finite elements. The mathematical model typically has one, two, or three degrees of freedom for each lumped mass or node point, but could have as many as six degrees of freedom for each lumped mass or node point.

Each multiple-degree-of-freedom (multidegree) system has the same number of normal modes as it has degrees of freedom. The characteristics of a normal mode of vibration is that, under certain conditions, the multidegree system could vibrate freely in that mode alone, and during such vibration the ratio of displacements of any two masses is constant with time. These ratios define the characteristic shape of the mode. For any vibration of the multidegree system, the motion in any of the individual normal modes can be treated as an independent single-degree-of-freedom system, and the complete motion of the multidegree system can be obtained by superimposing the independent motions of the individual modes.

The natural frequencies and characteristic shapes are determined by solution of the equations of motions for free vibrations.

3.7.2.1.2 Time-History Modal Superposition

The time-history of response in each mode is determined from the acceleration time-history input by integration of the equations of motion. The modal responses are combined by algebraic sum to produce an accurate summation at each step.

3.7.2.1.3 Response Spectrum Modal Superposition

The response spectrum is a plot, for all periods of vibration, of the maximum acceleration experienced by a single-degree-of-freedom vibrating body during a particular earthquake. The response spectrum modal superposition method of analysis applies to multidegree systems and is based on the concept of modal analysis. The modal equation of motion for a multidegree system is analogous to the equation of motion for a single degree of freedom. The maximum response in each mode is calculated, and modal responses (displacements, accelerations, shears, moments, etc.) are combined by the square root of the sum of the squares (SRSS) method.

3.7.2.1.4 Response Spectrum, Single-Degree-of-Freedom

Many components can be accurately represented by a single-degree-of-freedom mathematical model. The response spectrum method of analysis is applicable and the concept of modal analysis is not required.

3.7.2.1.5 Method for Rigid Equipment and Piping

When it can be shown that a sub-system is rigid, a static analysis may be performed. The zero period acceleration obtained from the applicable response spectra curve may be used in static calculations.

3.7.2.2 Description of Seismic Analyses

3.7.2.2.1 PG&E Design Class I Structures

Dynamic analyses by the time-history modal superposition method were performed for the containment structure and the auxiliary building to generate acceleration time-histories at specific points in the structures, and response spectra were calculated from these. In order to provide for possible variations in the parameters used in the dynamic analyses, such as mass values, material properties, and material sections, the calculated spectra were modified. For DE and DDE analyses, it is estimated that the calculated period of the structure could vary by approximately 10 percent, and to account for this the peaks of the spectra were correspondingly widened. Similarly, for HE analyses, peaks of the spectra are widened 5 percent on the high frequency side, due to a lesser need for peak broadening as the structural stiffnesses based on the actual material strengths are used, and 15 percent on the low frequency side. The modified spectra, known as "smooth spectra," are used in the design of PG&E Design Class I equipment and piping located in the containment structure and auxiliary building.

A detailed analytical static model of the auxiliary building was used to distribute the seismic inertial forces and moments to various walls, diaphragms, and columns, as described in Section 3.8.2.3.4.

In addition to the containment structure and auxiliary building, the dynamic analyses of the PG&E Design Class I containment polar crane, pipeway structure, and outdoor water storage tanks are discussed in the following subsections.

Allowable stresses for PG&E Design Class I structures are presented in Section 3.8.

3.7.2.2.1.1 Containment Structure Model

(1) DE and DDE events

The containment structure calculations relative to responses to DE and DDE events are performed with a computer program for analysis of axisymmetric structures by the finite element method. The foundation rock mass and the containment structure are modeled as one structure system to consider the effect of rock-structure interaction, as shown in Figure 3.7-5. The boundary dimensions of the model are selected such that they do not have a significant effect on the response of the structure. The exterior shell and internal structure are modeled using shell elements

with four degrees of freedom at each nodal point. The weight of mechanical equipment in the structure is included in the calculation of equivalent mass density for the structure elements. Values of elastic constants for the rock mass and their variation with depth are based on field measurements made at the plant site (refer to Section 2.5).

In the seismic analysis of the finite element model, for DE and DDE, the motions at the boundary of the rock mass are required as input. These boundary motions are derived using procedures described in the following steps:

(a) The finite element model of the rock mass only (without the structure) is subjected to a unit impulse acceleration acting at the rock mass boundaries. As a result, the acceleration time-history (impulse response that reflects the rock mass properties) is obtained at the center nodal point on the surface of the rock mass.

(b) The impulse response function, together with the desired free-field ground motion, is used as input to a deconvolution program. The required boundary motion is obtained as the output. This boundary motion, when used as input to the nodes along the horizontal and vertical boundaries of the rock mass model, produces a time-history at the center nodal point on the surface of the model that is equivalent to the free-field motion. To check the accuracy of the derived boundary motion, the rock mass without the structure is analyzed using this motion as input, and the computed free-field ground motion at the center nodal point on the surface of the rock mass is obtained. The computed free-field spectrum is calculated for this surface motion and compared with the DE- or DDE-smoothed spectrum. Due to approximations involved in the analytical methods used to derive the boundary motions, the computer spectra show slight deviations from the desired smoothed spectra. To account for these deviations, the structural response results are then conservatively scaled upward by appropriate correction factors.

The boundary motions derived from the procedure described above are used to complete the analysis of the containment structure.

To substantiate that the coupling effect is small at the RPV elevation, two floor response spectra were generated for a decoupled interior concrete structure model and a coupled RPV and the interior concrete structure model, respectively. The RPV model is a simplified one-degree-of-freedom system, with its natural frequency matching the fundamental mode of the DCPP vessel. The RPV model is attached to

Node 2 of the interior concrete structure model at the vessel support elevation by the spring of the vessel model.

Floor response spectra for the decoupled and the coupled models were very similar, indicating that the coupling effect at this low elevation is very small. More importantly, the response spectra magnitude of the decoupled model is consistently higher than the coupled model between 0.05 to 0.40 seconds, and is equal at all other natural periods. This shows that, indeed, the decoupled model is more conservative.

(2) HE event

The dynamic analysis for HE is performed for exterior shell, interior concrete structures, and the annulus steel structure. The description of these structural components is given in Section 3.8.2.1.

The elements used in the analysis of exterior shell consist of annular rings of shell elements as shown in Figure 3.7-5A. A typical shell element has four degrees-of-freedom as shown in Figure 3.7-7. The axisymmetric model is used to compute the translational response of the structure due to the horizontal and vertical ground motion. The horizontal base motion inputs are applied directly at the top of the base mat. A response spectrum analysis of the axisymmetric model is used to determine the maximum shell forces and moments, as shown in Section 3.7.2.2. The appropriate responses of the exterior structure from the horizontal and vertical components of the ground motion were combined at the mid-thickness of the shell on a SRSS basis. Since the center of mass and the center of rigidity coincide, the translational analysis does not yield any torsional response. The torsional responses are obtained from separate lumped mass models as shown in Figure 3.7-5B. These lumped mass models account for actual (geometric) eccentricity as well as 5 percent and 7 percent accidental eccentricities (refer to Section 3.7.2.11).

The dynamic analysis of containment internal structure is divided into two parts: concrete interior structure and annulus steel structure.

(a) The concrete interior structure mainly comprised of reactor cavity walls and crane wall is represented by an axisymmetric model as shown in Figure 3.7-5A. The weight of mechanical equipment in the structure is included in the calculation of equivalent mass density for the structure elements. Because the center of mass and the center of rigidity coincide, the analysis does not yield torsional modes. Therefore, a separate lumped mass model, as shown in Figure 3.7-5C, is used to consider torsional response.

Figure 3.7-5D is used to compute vertical responses of the concrete interior structures due to the HE. The lumped mass stick with model points 1, 7, 18, 29, and 40 represent the concrete walls. The annulus steel is modeled by five frames located along the circumference as shown. This model was developed at an early stage of the project to estimate vertical responses of both annulus steel and concrete structures from the HE. However, subsequently detailed models were developed for the annulus steel as described later and the model of Figure 3.7-5D is used for the vertical analysis of the concrete interior structures only. The vertical response is determined by a time-history, modal superposition analysis.

The models of Figures 3.7-5A, 3.7-5C, and 3.7-5D represent concrete interiors up to elevation 140 feet which is the operating floor of the containment. The secondary shield walls housing the steam generators do extend above elevation 140 feet; however, the mass of these walls above elevation 140 feet is small compared to the total concrete mass and, therefore, lumping the mass at elevation 140 feet of the walls that extend above elevation 140 feet has little effect on the dynamic behavior of concrete internals below elevation 140 feet.

(b) Several models are developed for the vertical dynamic analysis of the annulus steel. Each model represents a steel frame with a column at the outside perimeter, crane wall at the inside perimeter, and the radial beam. Figure 3.7-5E represents a typical model.

The horizontal responses of the annulus steel are considered to be the same as the concrete interior structures as computed from model of Figure 3.7-5A. This consideration is supported by:

- The study results showing that the amplification above 20 Hz for the annulus steel is negligible; and

- The modal analysis of steel frames shows that the first mode of vibration, which is the predominant mode, is approximately 20 Hz.

For the HE, the analytical models are considered fixed as shown in Figures 3.7-5A through 3.7-5D. The fixed base assumption for the Containment Structure uncouples the exterior and interior structure responses and allows a separate, independent analysis of each structure. The analysis is performed using the input motions as specified in Section 3.7.1. These spectra are to be used for all equipment placed on top of the base slab at elevation 91 feet.

3.7.2.2.1.2 Containment Polar Crane

The polar crane, as described in Sections 9.1.4 and 3.8.4.3, is an overhead gantry crane, supported by the crane wall inside the containment.

The polar crane does not perform a safety function; however, its structural elements are classified as PG&E Design Class I to preclude consequential damage to the containment structure or to PG&E Design Class I components inside containment caused by the failure of the polar crane. The polar crane structural elements, therefore, are evaluated for their capability to withstand seismic loads. For the DE, DDE, and HE, nonlinear time-history analyses are performed for the crane to consider the possibility of wheel uplift and/or slack in the hook cable. The crane structure model is shown in Figure 3.7-7A. Structural members are represented as beam elements; wheel assemblies as nonlinear gap elements with compression stiffness only, and a hook cable is represented as a truss element with no compression capability. A step-by-step integration procedure is employed to determine the response. The time-step for integration is 0.005 sec. Seismic input is provided by simultaneous, independent time-histories in three directions (two horizontal and one vertical). These time-histories are developed at the top of the crane wall from the dynamic analysis described in Section 3.7.2.2.1.1 above.

3.7.2.2.1.3 Pipeway Structure

To obtain seismic responses in the pipeway structure, a combined model is used consisting of containment exterior shell, pipeway-framing members, and the mainsteam and feedwater piping which are supported by the framing members. The 3-D pipeway structure model consists of steel platforms supported on structural steel columns, containment shell and auxiliary and turbine buildings. This structure is represented in the model by beam elements. Oversized holes are provided to support pipeway structure beams on the auxiliary and turbine buildings. Accordingly, the model is decoupled from auxiliary and turbine buildings in the horizontal direction. The horizontal coupling between pipeway framing model and containment model is achieved by rigid links. The main steam and feedwater lines are included in the model since they represent significant masses for the pipeway structure.

The combined containment-pipeway structure model was excited by acceleration time-history at the containment base.

(1) DE and DDE events

Equivalent static analyses of the pipeway structure are performed for the DE and DDE events as described in Section 3.8.2.2. The adequacy of these analyses is confirmed by a time-history dynamic analysis.

(2) HE event

The response spectra are generated using the time-history dynamic analysis method. The effect of accidental torsion is included as discussed for the containment structure model in Section 3.7.2.2.1.1. These response spectra are used for qualification of equipment and components. The structural qualification is performed using the response spectrum dynamic modal superposition method for the Unit 1 pipeway structure and using the equivalent static method for the Unit 2 pipeway structure.

3.7.2.2.1.4 Auxiliary Building

For the DE, DDE, and HE dynamic time-history analyses of the auxiliary building are performed with a computer program for analysis of a spring and lumped mass model. Two horizontal models and a vertical model, shown in Figure 3.7-13, are used. Each model is fixed at the base (elevation 85 feet). The part of the structure between elevations 60 ft and 85 ft is below grade and therefore is not lumped as a separate mass but it is assumed to be part of the foundation mass. Each horizontal model consists of five lumped masses with two degrees of freedom at each mass point, one translational degree of freedom in the horizontal direction, and one rotational degree of freedom about the vertical axis.

For HE the Blume and Newmark acceleration time histories correspond to the smooth response spectra used to represent the east-west and north-south horizontal components of the Hosgri base-motion inputs to the auxiliary building. The vertical model for HE evaluation consists of five lumped masses with one translational degree of freedom in the vertical direction at each mass point. The vertical input is represented by the Newmark free-field acceleration time history, which corresponds to the smooth response spectra used as the vertical component of the Hosgri ground motion.

For DE, DDE, and HE the masses are represented as the mass of the slab plus one-half of the walls immediately above and below the slab, with an appropriate live load on each floor to account for the effect of small pieces of equipment, concrete pads for equipment, tanks, pumps, and incidental weight not otherwise considered. Weights of cranes, storage tanks, and other large pieces of equipment are included at the appropriate mass points. Location of the centers of masses and rigidities are calculated to consider torsional modes of vibration. It was found that the centers of mass and rigidity at each level were very close for the east-west and vertical directions. Hence these small eccentricities were ignored in the model. The actual eccentricities in the structure for the north-south direction were more substantial, and these were included in the model. The inclusion of both actual and accidental eccentricity into the horizontal model for HE requires that the torsional mass moment of inertia be included. The vertical model requires that the rotational mass be included. Mass moments of inertia and torsional rigidities are calculated by conventional structural analysis methods.

For DE, DDE, and HE the soil at elevation 100 feet is represented by soil springs as shown in Figure 3.7-13. The stiffnesses of these foundation springs are derived by considering the case of a rigid plate on a semi-infinite elastic half-space with a horizontal surface (References 2, 3, and 4). The auxiliary building is a broad-based and comparatively low-rise structure, and therefore rocking is insignificant.

For HE evaluation, dynamic time-history analysis of flexible floor slabs is performed using finite element models composed of plate elements. Columns supporting the slabs are represented by springs. In each model, masses of slab, equipment, piping, and other items are concentrated at appropriate nodal points. A typical flexible slab model is shown in Figure 3.7-13A. Input excitation is the vertical acceleration time-history at the slab supports, obtained from the vertical analysis of the auxiliary building model.

Dynamic time-history analyses of the fuel handling area crane support structure for the DE, DDE, and HE are performed using one model to represent six end-bay frames and a second model to represent six middle bay frames. Each model is fixed at its base and uses beam and truss elements to represent all significant structural members. Structure masses are concentrated at appropriate nodal points. The model representing the middle bay frames is shown in Figure 3.7-13B. Input excitations are translational and rotational acceleration time-histories at elevation 140 feet obtained from analysis of the auxiliary building model.

3.7.2.2.1.5 Outdoor Water Storage Tanks

The CSTs, RWSTs, and firewater and transfer tank are PG&E Design Class I steel tanks with exterior concrete encasements.

(a) HE event

The axisymmetric and 3-D SAP IV mathematical models used in the HE finite element analysis are shown in Figures 3.7-14, 3.7-15, 3.7-15A, and 3.7-15B. The axisymmetric model using the AXIDYN computer program is used to analyze the effects of gravity loading, hydrostatic pressure, structure inertial forces, and hydrodynamic loads consisting of impulsive and convective pressures caused by the seismic event. The fluid impulsive effects are modeled as effective fluid inertia masses attached to appropriate concrete elements (Reference 13). The 3-D SAP IV model is used to assess the effects of the nonaxisymmetric vault opening on the stresses in and around the opening area. The loads determined from dynamic analysis using axisymmetric model are input as static loads in the 3-D SAP IV model. All tanks except the firewater and transfer tank are analyzed as fixed base models.

The exterior tank of the firewater and transfer tank is analyzed as a fixed base, whereas the inner steel tank is pinned at the base in the finite-element analyses.

For horizontal direction, a response spectrum, modal superposition analysis is performed with an axisymmetric model to determine the combined dynamic effects of structure inertial forces and impulsive pressures due to the horizontal earthquake. Gravity, hydrostatic pressure, and convective pressure loads are analyzed statically. The tanks analyzed are RWST and firewater and transfer tank. No additional analysis is done for condensate tank since it is similar to RWST.

For the SAP IV nonaxisymmetric model, an equivalent, static, lateral load analysis based on accelerations computed from the axisymmetric model analysis is performed for the RWST to determine the structure response maxima. The results of this analysis are applicable to other outdoor water storage tanks because they have similar vault openings and are of comparable size. The axisymmetric analyses have shown that responses of these tanks are generally similar to refueling tank.

Since the fundamental period is approximately 0.033 sec in the vertical direction, the empty tanks are determined to be rigid in that direction. Considering the possibility that fluid may not act as a rigid mass during vertical motion, effects of the vertical earthquake are obtained by scaling the results of the analysis for gravity loading and hydrostatic pressure by a factor of 1.0 for the HE (2/3 x 0.75 x amplification factor of 2).

(b) DE and DDE events

For the DE and the DDE, HE finite-element analysis results are used as the basis for evaluation. The HE responses are adjusted by the ratio of peak spectral accelerations for the DE, or the DDE, and by appropriate damping ratios.

3.7.2.2.2 PG&E Design Class II Structures Containing PG&E Design Class I Equipment

The turbine building and the intake structure are primarily PG&E Design Class II structures. However, PG&E Design Class I equipment is located inside:

(a) Turbine building: CCW heat exchangers, 4.16-kV Class 1E switchgear, emergency DGs, CRPS, and other PG&E Design Class I systems

(b) Intake structure: ASW pumps, piping, and instrumentation

In order to provide assurance that the function of the PG&E Design Class I equipment will not be adversely affected, these structures are reviewed to ensure that they would not collapse in the unlikely event of a DDE or an HE. The vulnerability of the main

turbine steam valves to seismically induced falling debris was reviewed and is described in Section 3.5.

The structural evaluation of the turbine building and intake structure for the HE was performed using the response spectrum dynamic modal superposition method. The HE analysis bounds DDE. In addition, a time-history dynamic analysis was performed to generate DE, DDE, and HE response spectra for evaluation of the PG&E Design Class I equipment.

3.7.2.2.2.1 Turbine Building

Turbine building horizontal analyses use one model to represent the Unit 1 portion of the building, which extends from column line 1 to 19, and a second model to represent the Unit 2 portion of the building, which extends from column line 19 to 35. The models are fixed at the base and are composed of truss, beam, and plane stress elements. The Unit 1 horizontal model is shown in Figures 3.7-15C and 3.7-15D. The Unit 2 horizontal model is similar.

Four models representing different areas of the building are used to represent the building in the vertical direction. The models are fixed at the base and consist of plate, beam, and truss elements. Three of the models are 3-D extending the full building height and width, and together represent the building from column lines 1 to 17 and 19 to 35. The fourth model is two-dimensional extending to elevation 140 feet only and represents the building between column lines 17 and 19. The vertical model used to represent the building between lines 1 and 5 and between lines 31 and 35 is shown in Figures 3-7-15E and 3.7-15F. Additional models are used to represent bridge crane effects. Analyses consider that both the Unit 1 and the Unit 2 bridge cranes may be located in the Unit 1 or the Unit 2 portion of the building with one of the cranes lifting 135 tons.

In generating the floor response spectra for PG&E Design Class I equipment for the HE, two analyses are made, elastic and inelastic using the lower bound of material strength. The final floor response spectrum is the envelope of the two spectra.

Structural evaluation of the turbine pedestal for the HE earthquake is performed using the response spectrum dynamic modal superposition method. The evaluation has shown the available gap between the turbine pedestal and the turbine building is adequate to prevent component interaction during a seismic event. Three-dimensional fixed base models are used to evaluate loading of the pedestals in the horizontal and vertical directions. The model shown in Figure 3.7-15G represents the Unit 1 turbine pedestal. The Unit 2 model is similar. Pedestal members are modeled as beam elements with rigid joints to account for the stiff zones at beam-column intersections. Pedestal and turbine-generator masses are included at appropriate nodal points.

The turbine building crane, either loaded or unloaded, is seismically qualified for the HE.

3.7.2.2.2.2 Intake Structure

The seismic analysis of the intake structure was carried out by initially separating the structure into two basic parts: (a) the pump-deck base, consisting of the massive land-side portion of the structure, from elevation -31.5 feet to the -2.1-foot pump-deck level; and (b) the remainder of the structural system. The analysis demonstrated that the massive pump-deck base below the 2.1-foot level would not amplify the ground motion. Hence, the pump-deck base need not be considered in the analysis of the remainder of the structure.

The 3-D mathematical model is used for the north-south and east-west/vertical analysis. Figures 3.7-15H and 3.7-15I show a typical finite element model. The model is fixed at the base and uses typical finite-element methods of discretization suitable for the structural system. Floor slabs and walls are modeled as flat-plate elements primarily to capture in-plane behavior. The slabs are shown to be rigid in the vertical direction by a separate simplified analysis. Some thick shear walls near the symmetry plane of the structure in the east-west direction are modeled as 3-D solid elements. There are six degrees of freedom for each node - three translational and three rotational degrees of freedom.

For the north-south analysis, the effect of the virtual mass of contained water has been considered by including the total mass of water tributary to the transverse flow straighteners (or piers). This method is considered reasonable because the relatively short distance between piers inhibits the tendency of the water to slosh and thereby reduce its virtual mass. A high-tide condition, with sea level at elevation +3.4 feet MSL, is assumed for the analysis.

For the east-west/vertical analysis, the effect of water due to an earthquake is considered negligible because it is assumed that the water can flow in and out of the structure and will exert relatively little force on the structure.

Static and dynamic lateral earth pressures on the east wall of the intake structure are considered in the calculation of the in-place shear stress for the east-west walls and roof slabs. The earth pressure influence is combined by SRSS method with the seismic forces.

The intake structure crane, either loaded or unloaded, is seismically qualified for the HE.

3.7.2.2.3 PG&E Design Class I Mechanical Equipment

3.7.2.2.3.1 Reactor Coolant Loop

The RCLs and their support systems are analyzed for seismic loads (DE, DDE, and HE) based on a 3-D, multi-mass elastic dynamic model, as discussed in Section 5.2. Table 3.7-24 shows the fundamental mode frequency ranges for RCL primary equipment (steam generator, RCP, and RPV). The stress analyses for faulted condition loadings of these components are provided in Section 5.2.2.1.15. The analyses of the reactor internals, fuel elements, control rod drive assemblies, and control rod drives are described in Section 3.7.3.15.

3.7.2.2.3.2 Other PG&E Design Class I Mechanical Equipment

PG&E Design Class I mechanical equipment is grouped into: (a) equipment purchased directly by PG&E, and (b) equipment supplied by Westinghouse.

(1) Equipment purchased directly by PG&E

Equipment is considered rigid if all natural periods are equal to or less than 0.05 seconds for the DE and the DDE, and 0.03 seconds for the HE. Rigid equipment is designed for the maximum acceleration of the supporting structure at the equipment location. Flexible equipment is analyzed by response spectrum methods. Hydrodynamic analysis of tanks as rigid bodies is performed using the methods described in Reference 6 and as flexible bodies by the methods described in Reference 13. A half-sine vibration configuration, the most conservative of three configurations suggested by Reference 13, was used in the hydrodynamic analysis of tanks as flexible bodies.

Load combinations and allowable stresses for PG&E Design Class I equipment are given in Section 3.9.

(2) Equipment supplied by Westinghouse Electric Corporation

The seismic response of PG&E Design Class I piping and components is determined by response spectrum methods. The system is evaluated for the simultaneous occurrence of one horizontal and the vertical seismic input motions. For each mode, the results for the vertical excitation are added absolutely to the separate results for the horizontal (e.g., north-south or east-west) directions. The larger of the two values so determined at each point in the model is considered as the earthquake response. Details of the response spectrum analyses are as follows:

(a) If a component falls within one of the many categories that has been previously analyzed using a multi-degree-of-freedom model

and shown to be relatively rigid, the equipment specification for the component is checked to ensure that the equivalent static g-values specified are larger than the building floor response spectrum values and therefore are conservative. Equipment is considered to be rigid relative to the building if all natural periods are equal to or less than 0.05 seconds for the DE and the DDE, and 0.03 seconds for the HE.

(b) If the component cannot be categorized as similar to a previously analyzed component that has been shown to be relatively rigid, an analysis is performed as described below.

PG&E Design Class I mechanical equipment, including heat exchangers, pumps, tanks, and valves, are analyzed using a multi-degree-of-freedom modal analysis. Appendages, such as motors attached to MOVs, are included in the models. The natural frequencies and normal modes are obtained using analytical techniques developed to solve eigenvalue-eigenvector problems. A response spectrum analysis is then performed using horizontal and vertical umbrella spectra that encompass the appropriate floor response spectra developed from the building time-history analyses.

The simultaneous occurrence of horizontal and vertical motions are included in the analyses. These response spectra are combined with the modal participation factors and the mode shapes to give the structural response for each mode from which the modal stresses are determined. The combined total seismic response is obtained by adding the individual modal responses utilizing the SRSS method.

Under certain conditions, the natural frequency of the equipment is not calculated. Under those conditions, using the appropriate damping value, the peak value of acceleration response curve is used to calculate the inertia forces. This method of calculation is termed the pseudo-dynamic method.

Components and supports of the RCS are designed for the loading combinations given in Section 5.2. Components are designed in complete accordance with the ASME BPVC Section III, Nuclear Vessels, and the USAS Code for Pressure Piping (refer to Section 5.2 for details of code years and addenda to specific components). The allowable stress limits for these components and supports are also given in Section 5.2. The loading combinations and stress limits for other components and supports are given in Section 3.9.

The Hosgri evaluation of the RCS is discussed in Section 5.2. All loop piping, components and supports of the RCS satisfy criteria demonstrating qualification for the HE.

3.7.2.2.4 PG&E Design Class I Piping

3.7.2.2.4.1 Criteria

The following criteria determine the type of seismic analysis performed for PG&E Design Class I piping:

(1) 2-1/2 inches in diameter and larger

Seismic analysis is performed by the response spectrum, modal superposition method.

(2) Less than 2-1/2 inches in diameter

Seismic analysis is performed by the response spectrum modal superposition method for all Unit 2 piping. In Unit 1, piping less than 2-1/2 inches in diameter was analyzed by sampling criteria in which systems representing the worst case configurations or reflecting generic concerns were selected for analysis by the response spectrum modal superposition method. The remainder was qualified by criteria that limit the periods of free vibration to values that assure only moderate amplification of piping responses.

3.7.2.2.4.2 Modeling

Three dimensional mathematical models are used in the response spectrum modal superposition analyses. A typical mathematical model is shown in Figure 3.7-26.

Valves and valve operators are included where appropriate in the piping models as eccentric masses. Pipe supports, restraints and equipment having a natural frequency of 20 Hz or greater are modeled as being rigid restraints. Where PG&E Design Class II piping connects to PG&E Design Class I piping, sufficient PG&E Design Class II piping is included in the model to assure qualification of the PG&E Design Class I piping and code boundary.

3.7.2.2.4.3 Allowable Stresses

Load combinations and allowable stresses for PG&E Design Class I piping are given in Section 3.9.

3.7.2.3 Natural Frequencies and Response Loads

The natural frequencies and seismic response results summarized in the following sections for the major plant structures are representative of the seismic analyses performed for the operating license review (Reference 18), but may not reflect minor changes associated with subsequent plant modifications.

3.7.2.3.1 Containment Structure

(1) DE and DDE

The natural periods for all significant modes of the containment structure are listed in Table 3.7-2. The corresponding mode shapes are shown in Figure 3.7-6. The shell forces and moments in a typical element of the model are defined in Figure 3.7-7.

The containment structure seismic analysis provides acceleration time-histories, maximum absolute accelerations, displacements, shell forces and moments, total shears, and total overturning moments. These maximum response values are listed in Tables 3.7-3 through 3.7-8 for the nodal points indicated in Figure 3.7-5.

Acceleration response spectra for the containment are calculated from the acceleration time-histories, and corresponding smooth spectra are prepared. Typical smooth spectra are shown in Figures 3.7-8 through 3.7-12.

(2) HE

The natural periods and significant modes of vibration are listed in Table 3.7-8A. Modes having a period of vibration less than 0.03 sec (frequency greater than 33 Hz) are considered to be insignificant. The percentage of the modal participation factors is defined as:

$$\%PF_i = \frac{PF_i}{\sum_{i=1}^{n} PF_i} \times 100$$

where:

$\%PF_i$ = percent participation factor in ith mode
PF_i = participation factor in ith mode
n = number of significant modes used in the analysis

As shown in Table 3.7-8A three sets of periods are given for the exterior shell:

(a) Translational mode determined from model of Figure 3.7-5A

(b) Torsional and translational mode determined from Figure 3.7-5B

(c) Vertical modes determined from Figure 3.7-5D

Table 3.7-8B gives the horizontal and vertical maximum absolute accelerations and Table 3.7-8C gives the maximum relative horizontal and vertical displacement. Table 3.7-8D gives the maximum shell forces and moments. Tables 3.7-8E and 3.7-8F give the maximum total shear forces, overturning moments, torsional moments, and axial forces for the containment shell.

The horizontal floor response spectra, including the effects of accidental torsion of the structure, at the inside face of the exterior shell are shown in Figures 3.7-12A and 3.7-12B. To develop these spectra, the translational spectra are combined with the torsional spectra from the 5 percent and 7 percent accidental eccentricities. The combined translational and torsional spectra are then combined on an SRSS basis with the horizontal component due to the vertical input to yield the spectra shown in Figures 3.7-12A and 3.7-12B. The horizontal floor response spectra are applicable in any horizontal direction due to the axisymmetry of the structure.

The vertical floor spectra are shown in Figures 3.7-12C and 3.7-12D. These spectra are based on a dynamic vertical analysis of the exterior structure using a vertical ground motion equal to 2/3 the Newmark 7.5M Hosgri free-field (tau = 0) ground motion combined with the vertical components resulting from each of the Blume and Newmark horizontal ground motion inputs. Tables 3.7-8G and 3.7-8H show the accelerations, displacements, stress, and moments for the containment interior structures as a result of the horizontal dynamic analysis.

For the interior structure, the Newmark input generally produces a higher structure response than does the Blume input. Figures 3.7-12E through 3.7-12G show the response spectra for the interior structure at elevation 140 feet, which is the operating floor for the containment. The spectra are for the horizontal, torsional, and vertical response. The horizontal and torsional response spectra at the Containment centerline are applicable to both the north-south and the east-west directions due to the assumed axisymmetry of the structure. However, for points located away from the centerline, the horizontal acceleration in the tangential direction is based on the combination of the horizontal and torsional response spectra as follows:

$$A_{MAX\,TANG} = |A_{HORIZONTAL}| + \left|\frac{X}{g}\,A_{TORSION}\right|$$

Where:

$A_{MAX\ TANG}$ = Maximum horizontal acceleration applied tangentially at the location under consideration in g's.

$A_{HORIZONTAL}$ = Maximum horizontal acceleration of the center of mass in g's.

$A_{TORSION}$ = Torsional acceleration at the center of mass in radians/sec^2.

X = Distance in feet from the center of mass of the Containment Interior Structure to the location under consideration perpendicular to the direction of $A_{MAX\ TANG}$.

g = Gravitational constant of 32.2 ft./sec^2.

For $A_{MAX\ RADIAL}$ (Maximum horizontal acceleration applied radially at the location under consideration) there is no torsional component and $A_{MAX\ RADIAL} = A_{HORIZONTAL}$.

The same procedure is used to calculate maximum relative horizontal displacements, as well the horizontal response for the seismic analysis of equipment and piping supported on the interior structure.

The vertical floor response spectra are based on a dynamic vertical analysis of the interior structure using a vertical input equal to 2/3 the Newmark 7.5M Hosgri free-field ground motion.

For the annulus structural steel frames, a separate vertical dynamic analysis is carried out for each frame as shown in Figures 3.7-12H and 3.7-12I for Unit 1 and Unit 2, respectively. Tables 3.7-8I and 3.7-8J list the frequencies and participation factors for frame number 6 which is a typical annulus steel radial frame. After the response spectra are generated in the vertical direction for each radial frame, they are enveloped according to their locations. As shown in Figures 3.7-12H and 3.7-12I, the annulus is divided into the five major sectors (called sector frames) and the response spectra for any sector frame at a given elevation are derived from enveloping the response spectra of radial frames located in that sector. Typical enveloped response spectra are shown in Figures 3.7-12J and 3.7-12K. As discussed earlier, the annulus structure does not amplify the horizontal motion of the interior concrete.

Therefore, the horizontal spectra for the concrete interior structures are used for the annulus steel. Table 3.7-8K lists the natural frequencies for horizontal seismic motion. As mentioned in Section 3.7.2.2, the first mode frequencies are approximately 20 Hz or higher and, therefore, for the rationale given earlier, the annulus is considered rigid in the horizontal direction.

3.7.2.3.2 Containment Polar Crane

Maximum displacements for various nodes for the polar crane are given in Table 3.7-8L. The member forces and bending moments are shown in Tables 3.7-8M and Table 3.7-8N. The typical response spectra are shown in Figures 3.7-12L and 3.7-12M.

3.7.2.3.3 Pipeway Structure

The modal analysis indicates that the minimum frequency of the model is 1.6 Hz and there are 100 modes below 33 Hz indicating many closely spaced modes. The containment structure and the piping modes are included in the results since a composite model is analyzed as discussed in Section 3.7.2.2. The mode shapes indicate there are no global structural modes of the pipeway structure itself; instead, there are many local modes.

The input horizontal acceleration time-histories are scaled up by a factor of 1.06 to approximate the accidental eccentricity of masses. Five input cases are considered for the seismic analysis: The Blume horizontal time-history in E-W and N-S direction, the Newmark horizontal time-history in E-W and N-S direction, and the Newmark time-history in the vertical direction. Typical response spectra for pipeway structure are shown in Figures 3.7-12N through 3.7-12S.

3.7.2.3.4 Auxiliary Building

The natural periods for all significant modes of the auxiliary building are listed in Tables 3.7-9 through 3.7-11. Frequencies for significant modes of the fuel handling crane support structure are listed in Tables 3.7-11A and 3.7-11B.

Acceleration response spectra for the auxiliary building are calculated from the acceleration time-histories at the mass points and corresponding smooth spectra are developed. Typical spectra are shown in Figures 3.7-16 through 3.7-25 and 3.7-21A through 3.7-21I.

Maximum absolute accelerations, relative displacements, story shears, overturning moments, and torsional moments in the auxiliary building are listed in Tables 3.7-12 through 3.7-23. Maximum absolute accelerations and relative displacements in the fuel handling crane support structure are listed in Tables 3.7-8O and 3.7-8P; the

displacements are obtained from static analysis of the detailed model described in Section 3.8.2.3.4.

3.7.2.3.5 Turbine Building

Natural frequencies of vibration in the horizontal direction in all significant modes of the Unit 1 portion of the building, for the condition where two bridge cranes are centered near column line 10.6, are listed on Table 3.7-23A. Corresponding horizontal frequencies for the Unit 2 portion of the building are similar. Natural frequencies of vibration in the vertical direction for all significant modes of the building between column lines 1 and 5 are listed on Table 3.7-23B. Corresponding vertical frequencies for the Unit 2 portion of the building are similar.

HE floor acceleration response spectra for the turbine building are calculated from acceleration time-histories at the mass points using both the Blume and Newmark ground motion as the horizontal input, and the Newmark ground motion as the vertical input. Typical spectra are shown in Figures 3.7-25A through 3.7-25M.

Maximum absolute accelerations and relative displacements in the Unit 1 portion of the building are listed in Tables 3.7-23C and 3.7-23D. Corresponding accelerations and displacements in the Unit 2 end of the building are similar.

Natural periods for all significant modes of the turbine pedestal model are listed in Table 3.7-23E. Maximum relative displacements of the pedestal model are listed in Table 3.7-23F.

3.7.2.3.6 Intake Structure

The natural periods and participation factors for all significant modes of the intake structure having periods of vibration less than 0.03 sec (frequency greater than 33 Hz) are listed in Tables 3.7-23G. Acceleration response spectra for the intake structure are calculated from the acceleration time-histories at the selected mass points, and corresponding smooth spectra are developed as specified in Figure 3.7-4A. Typical spectra are shown in Figures 3.7-25N through 3.7-25T. Maximum absolute acceleration, relative maximum displacements are listed in Table 3.7-23H.

3.7.2.3.7 Outdoor Water Storage Tanks

The natural periods for significant modes of the RWSTs and fire water and transfer tank are listed in Tables 3.7-23I and 3.7-23J.

3.7.2.4 Procedures Used to Lump Masses

3.7.2.4.1 Structures

The mass of the structure is assumed to be concentrated at particular locations on the model. These locations coincide with either floor levels, significant points where dynamic response is required as input for piping and equipment, nodal points in the finite element model, or any other points required to accurately define the natural frequencies and mode shapes for the significant modes. The torsional effect for containment, auxiliary building, turbine building, and intake structure is considered as discussed in Section 3.7.2.11.

3.7.2.4.2 Equipment and Piping

The mass of the equipment and piping systems is assumed to be concentrated at particular locations on the model. These locations coincide with either actual masses such as pumps, motors, valve restraints and anchors, or any other points required to accurately define the natural frequencies and mode shapes of the significant modes.

3.7.2.5 Rocking and Translational Response Summary

Methods used to consider soil-structure interaction for PG&E Design Class I structures are described in Section 3.7.2.2.

3.7.2.6 Methods Used to Couple Soil with Seismic-System Structures

The procedures used to represent the containment structure and surrounding rock mass as a finite element model, and the procedures used to derive the stiffnesses of foundation springs for the auxiliary building are described in Sections 3.7.2.2.1.1 and 3.7.2.2.1.4, respectively.

3.7.2.7 Development of Floor Response Spectra

Floor response spectra are developed using time-history modal superposition analyses as described in Section 3.7.2.3.

3.7.2.8 Differential Seismic Movement of Interconnected Components

Components and supports of the RCS are designed for the loading combinations and stress limits given in Section 5.2. The loading combinations and stress limits for other components and supports are given in Section 3.9.

3.7.2.9 Effects of Variations on Floor Response Spectra

Consideration of the effects on floor response spectra of possible variations in the parameters used for the structural analysis is discussed in connection with the development of smooth spectra in Section 3.7.2.2.1.

3.7.2.10 Use of Constant Vertical Load Factors

The PG&E Design Class I structures are heavy, massive, reinforced concrete, rigid-type structures and are founded on competent hard rock. For such structures, insignificant amplification of vertical motions can be expected, the critical factor in design being the response of the structures to horizontal earthquake motions. The containment structure and auxiliary building including Class I systems and components are designed for DE and DDE, using a vertical static coefficient equal to two-thirds of the peak horizontal ground motion, unless otherwise noted. For the HE, a dynamic analysis in the vertical direction is carried out as discussed in Sections 3.7.2.2.1.1 and 3.7.2.2.1.4.

3.7.2.11 Method Used to Account for Torsional Effects

The containment structure is essentially axisymmetric and therefore has insignificant torsional response. The torsional response of the auxiliary building is calculated by use of a combined translational and torsional mathematical model in the seismic system time-history modal superposition analysis, as described in Section 3.7.2.2.1.4.

For the HE evaluation of PG&E Design Class I structures, the effect of accidental torsion is included as an additional eccentricity in the mathematical models. The greater of these two cases is considered for accidental torsion:

(a) torsional response due an eccentricity equal 5 percent of the building dimension in the direction perpendicular to the applied loads combined with the translational response by the absolute summation method

(b) torsional response due an eccentricity equal 7 percent of the building dimension in the direction perpendicular to the applied loads combined with the translational response by the SRSS method

For HE evaluation of the PG&E Design Class II turbine building, turbine pedestals and the intake structure, a torsional response is calculated by the use of finite element models which include both translation and torsion. In addition, the effect of accidental eccentricity is accounted for by a 10 percent increase in the structural responses for the turbine building and intake structure. For the turbine pedestal, a static torsional moment corresponding to a 5 percent eccentricity is added to the dynamic analysis in each horizontal direction.

3.7.2.12 Comparison of Responses

Time-history analyses only are performed for PG&E Design Class I structures. Response spectrum analyses are not performed because the time-history produces spectra that represent reasonably the criteria response spectra.

3.7.2.13 Methods for Seismic Analysis of Dams

There are no dams associated with the DCPP.

3.7.2.14 Methods to Determine PG&E Design Class I Structure Overturning Moments

The maximum overturning moments for PG&E Design Class I structures are determined as part of the time-history modal superposition analyses. Vertical earthquake is considered to act concurrently with the maximum horizontal overturning moments.

3.7.2.15 Analysis Procedure for Damping

Structures are analyzed using modal superposition techniques, and element or material-associated damping ratios are given in Section 3.7.1.4. "Composite" or modal damping ratios in structural systems comprised of different element material types are selected based on an inspection of the significant mode shapes, and on the assumption that the contribution of each material to the composite effective modal damping is proportional to the elastic energy induced in each material. The following criteria and procedures are applied on a-mode-by mode basis to evaluate and conservatively determine composite damping values:

(1) Where a particular mode primarily indicates response of a single element type, the damping ratio corresponding to that element type is assigned to that mode. Where all but a negligible amount of the elastic energy is induced in, for example, concrete or rock, the damping ratio appropriate to these materials is applied. Similarly, where a lightly damped material exhibits a major portion of the elastic energy of the mode, a conservative choice is made to use the damping ratio of that material for that mode. In most cases for this plant, the modes are well defined according to material types; composite damping values can be selected on the basis of a visual inspection of mode shapes and no additional numerical computations are required.

(2) In a few instances, the above criteria cannot be applied because a particular mode indicates response of several element types. The damping ratio for that mode is conservatively estimated based on the degree of participation of the different elements. Table 3.7-10 lists the participation factors for the auxiliary building. The elastic energy induced

in the different elements is estimated and the composite damping values assigned in proportion to the elastic energy.

(3) Mass-weighted composite modal-damping is used for the DE and DDE analysis of the turbine building.

The approach described above is consistent with currently accepted techniques, and in all cases the damping values are selected conservatively. The use of this approach results in design that can conservatively resist the seismic motions postulated for the DCPP.

3.7.2.16 Combination of Components of Earthquake Motion For Structures

For DE and DDE analysis maximum structural response due to one horizontal and the vertical component of earthquake motion are combined by the absolute sum method. For HE analysis the maximum structural responses due to each of the three components of earthquake motion are typically combined by the SRSS method. For the PG&E Design Class I Containment Structure and Auxiliary Building the two horizontal components are taken as equal, although it is generally recognized that the second component is smaller than the first. Alternately, the maximum structural response due to one horizontal component of earthquake motion is combined with the vertical component by the absolute sum method if it can be shown that the results of this combination are essentially equivalent to the results determined by the SRSS combination method.

3.7.3 SEISMIC SUBSYSTEM ANALYSIS

3.7.3.1 Determination of Number of Earthquake Cycles

Where fatigue is a criterion, it is assumed that there are 20 occurrences of the DE, each producing 20 cycles of maximum response.

3.7.3.2 Basis for Selection of Forcing Frequencies

PG&E Design Class I equipment and piping is analyzed by the response spectrum method or the pseudo-dynamic method, using floor response spectra, unless it can be shown to be rigid, as discussed in Section 3.7.2.1. Accordingly, a special procedure to avoid certain frequencies is not needed.

3.7.3.3 Procedure for Combining Modal Responses

The method and procedure for combining modal responses are described in Sections 3.7.2.1.3 and 3.7.3.4.

3.7.3.4 Square Root of the Sum of the Squares

When PG&E Design Class I piping systems are analyzed by the response spectrum modal superposition method, all modal responses, including closely spaced modes, are combined by the SRSS method to obtain total response.

A study was conducted to evaluate the effects of combining modes with closely spaced modal frequencies by the absolute sum method. For closely spaced modes, the combined total response was obtained by taking the absolute sum of the closely spaced modes and then taking the SRSS with all other modes. Twenty-nine piping systems were studied, representing approximately 10 percent of the total number of piping systems analyzed. Of these 29 piping systems, 8 systems had no closely spaced frequencies and 8 systems had closely spaced frequencies which were in the rigid period range and therefore required no further study.

The remaining 13 systems had some modal frequencies in the flexible range that could be termed closely spaced. Of these, 5 systems had low seismic stresses with an adequate margin of safety, so that any possible increase in seismic stresses due to a combination of closely spaced frequencies by the absolute sum method would not affect the safety of the piping systems. In addition, 6 systems had closely spaced frequencies, but study of the mode shapes revealed that the seismic stresses would not be significantly affected by the absolute sum of these modal responses.

For the 2 remaining systems, it was not possible to positively conclude that the effects of combining the modes with closely spaced frequencies by absolute sum would be minimal by inspecting the stresses or mode shapes. Therefore, these 2 systems were reanalyzed by computer, and it was found that if the seismic responses of the modes with closely spaced frequencies were combined by the absolute sum method, the increase in stress would be less than 1 percent.

It was therefore concluded that the combination of modal responses of piping systems by the SRSS method is adequate and conservative.

3.7.3.5 Design Criteria and Analytical Procedures for Piping

Stresses induced in PG&E Design Class I piping from relative movement of anchor points (points where all degrees of freedom are fixed), whether due to building or equipment movement, are considered with stresses calculated in the piping response spectrum modal superposition analyses.

PG&E has developed specific guidelines for the design of PG&E Design Class I pipe supports that account for such items as allowable deflections, forces, gaps, and moments imposed on the supports. Allowable stresses and loads are described in more detail in Section 3.9.

A study (Reference 9) has also been performed to evaluate the stresses in piping systems, assuming failure of a single hydraulic or mechanical pipe snubber during a seismic event. Results of the study indicate that the probability of a snubber failing to snub and causing a pipe failure was sufficiently low that no additional design restraints had to be imposed.

As an additional control, hydraulic snubbers are visually inspected and functionally tested. These surveillance requirements are detailed in the DCPP Equipment Control Guidelines (refer to Chapter 16).

At the request of the NRC in April 18, 1984, in its order to modify Facility Operating License No. DPR-76, PG&E developed a program to review the small and large bore pipe supports for the specific concerns raised by that order.

The specific items requested by the NRC were as follows:

(1) PG&E shall complete the review of all small-bore piping supports which were reanalyzed and requalified by computer analysis. The review shall include consideration of the additional technical topics, as appropriate, contained in License Condition No. 7 below.

(2) PG&E shall identify all cases in which rigid supports are placed in close proximity to other rigid supports or anchors. For these cases PG&E shall conduct a program that assures loads shared between these adjacent supports and anchors result in acceptable piping and support stresses. Upon completion of this effort, PG&E shall submit a report to the NRC Staff documenting the results of the program.

Design procedures were revised to address this issue.

(3) PG&E shall identify all cases in which snubbers are placed in close proximity to rigid supports and anchors. For these cases, utilizing snubber lock-up motion criteria acceptable to the staff, PG&E shall demonstrate that acceptable piping and piping support stresses are met. Upon completion of this effort, PG&E shall submit a report to the NRC Staff documenting the results.

Design procedures were revised to address this issue.

(4) PG&E shall identify all pipe supports for which thermal gaps have been specifically included in the piping thermal analyses. For these cases the licensee shall develop a program for periodic inservice inspection to assure that these thermal gaps are maintained throughout the operating life of the plant. PG&E shall submit to the NRC Staff a report containing the gap-monitoring program.

Rather than establishing a gap-monitoring program, the piping analysis and procedures were modified to eliminate the thermal gaps in the analyses.

(5) PG&E shall provide to the NRC the procedures and schedules for the hot walkdown of the main steam system piping. PG&E shall document the main steam hot walkdown results in a report to the NRC Staff.

(6) PG&E shall conduct a review of the "Pipe Support Design Tolerance Clarification" program (PSDTC) and "Diablo Problem" system (DP) activities. The review shall include specific identification of the following:

(a) Support changes, which deviated from the defined PSDTC program scope;

(b) Any significant deviations between as-built and design configurations stemming from the PSDTC or DP activities; and

(c) Any unresolved matters identified by the DP system.

The purpose of this review is to ensure that all design changes and modifications have been resolved and documented in an appropriate manner. Upon completion PG&E shall submit a report to the NRC Staff documenting the results of this review.

(7) PG&E shall conduct a program to demonstrate that the following technical topics have been adequately addressed in the design of small and large-bore piping supports:

(a) Inclusion of warping normal and shear stresses due to torsion in those open sections where warping effects are significant.

(b) Resolution of differences between the American Institute of Steel Construction (AISC) Code and Bechtel criteria with regard to allowable lengths of unbraced angle sections in bending.

(c) Consideration of lateral/torsional buckling under axial loading of angle members.

(d) Inclusion of axial and torsional loads due to load eccentricity where appropriate.

(e) Correct calculation of pipe support fundamental frequency by Rayleigh's method.

(f) Consideration of flare bevel weld effective throat thickness as used on structural steel tubing with an outside radius of less than 2T.

The above considerations were incorporated in the applicable design procedures.

All of the above specific concerns were addressed and resolved to the satisfaction of the NRC.

3.7.3.6 Basis for Computing Combined Response

As a minimum, mechanical equipment is designed for a vertical static coefficient equal to 2/3 of the peak horizontal ground motion for DE and DDE analysis. For HE analysis, specific vertical floor response spectra are used. Horizontal and vertical responses are combined by absolute sum. The responses of PG&E Design Class I equipment analyzed with the response spectrum method are combined by SRSS for HE.

Equipment is reviewed for a vertical force determined from a response spectrum, as described in Sections 3.7.2.2.3, 3.7.3 and 5.2.

The horizontal and vertical responses of PG&E Design Class I piping are determined from the two-dimensional response spectrum modal superposition analyses described in Section 3.7.2.2.4. Response spectra at the applicable piping support attachment elevations are enveloped to obtain the final design response spectra. The vertical and one horizontal response are combined by absolute sum on the modal level. Modal responses are combined by the SRSS method. The two two-dimensional results are then enveloped to obtain the total response. Figure 3.7-26 shows a typical piping mathematical model. Figure 3.7-29 illustrates the derivation of the design response spectra for a typical piping system.

In many cases, earthquake piping stresses due to DDE are not directly calculated. Instead, the results from the DE piping analysis are doubled to represent the DDE. This approach was chosen because review of the design spectra showed that the DDE accelerations did not exceed twice the DE accelerations. Since pipe stress is linear with accelerations, this approach is conservative.

3.7.3.7 Amplified Seismic Responses

Components that can be adequately characterized as a single-degree-of-freedom system are considered to have a modal participation of one.

3.7.3.8 Use of Simplified Dynamic Analysis

All methods of seismic analysis used for PG&E Design Class I structures, components, systems, and piping are described in Section 3.7.2.

Two methods of dynamic seismic analysis are used for PG&E Design Class I components and piping that are different than multiple-degree-of-freedom, modal analysis methods. The first of these is the response spectrum, single-degree-of-freedom method used for components whose dynamic behavior can be accurately represented by a single-degree-of-freedom mathematical model. The second of these is the method for rigid components where the component is designed for the maximum acceleration experienced by the supporting structure at the location of support, if all natural periods of the component are less than, or equal to, 0.05 seconds for DE and DDE, or 0.03 seconds for HE in piping analysis.

The pseudo-dynamic method of analysis is used for certain items of mechanical equipment as described in Section 3.7.2. The basis for this method is described in Section 3.7.2.2.3.

Certain Unit 1 PG&E Design Class I piping less than 2-1/2 inches in diameter is restrained according to criteria described in Section 3.7.2.2.4.

3.7.3.9 Modal Period Variation

Consideration of the effects on floor response spectra of possible variations in the parameters used for structural analysis is discussed in connection with the development of smooth spectra in Section 3.7.2.2.1.

3.7.3.10 Torsional Effects of Eccentric Masses

Where appropriate, valves and valve operators are included as eccentric masses in the mathematical models for piping seismic analysis, as described in Section 3.7.2.2.4.

3.7.3.11 Piping Outside Containment Structure

The procedures used to determine piping stresses resulting from relative movement between anchor points (points where all degrees-of-freedom are fixed) are discussed in Section 3.7.3.5. The forces exerted by piping on anchor points, including the containment structure penetrations, are included in the evaluation of stresses for PG&E Design Class I structures.

Buried PG&E Design Class I piping is described in Sections 9.2.7.2.4 and 9.5.4.2. The piping material is ASTM A-53 or A-106 carbon steel.

3.7.3.12 Interaction of Other Piping With PG&E Design Class I Piping

Mathematical models for PG&E Design Class I piping seismic analyses normally originate and terminate at anchor points. Where PG&E Design Class II piping connects to PG&E Design Class I piping sufficient PG&E Design Class II piping is included in the mathematical model to assure qualification of the PG&E Design Class I piping and code boundary.

3.7.3.13 Seismically Induced Systems Interaction Program

PG&E developed a program to consider seismically-induced physical interactions between PG&E Design Class II or III SSCs and PG&E Design Class I SSCs. The methodology and results of the original interaction study are presented in Reference 10 and are summarized as follows. The objective of the program was to establish confidence that when subjected to seismic events of severity up to and including the HE, SSCs important to safety shall not be prevented from performing their intended safety functions as a result of physical interactions caused by seismically induced failures of PG&E Design Class II or III SSCs. In addition, safety-related SSCs shall not lose the redundancy required to compensate for single failures as a result of such interactions.

To accomplish the program, PG&E defined as targets all SSCs required to safely shut down the plant and maintain it in a safe shutdown condition, and certain accident-mitigating systems. Initial plant operating modes of normal operation, shutdown, and refueling were considered in the selection of the target equipment. All PG&E Design Class II or III SSCs were defined as sources.

Interactions between source and target equipment were postulated by an interdisciplinary Interaction Team. The Interaction Team postulated interactions during walkdowns of the target equipment, using previously established guidelines and criteria. The Interaction Team also recommended resolutions to the postulated interactions. The findings of the Interaction Team were evaluated during a subsequent office-based technical evaluation. Any modifications deemed necessary were reviewed after completion by the Interaction Team to ensure that no new interactions were created by the modifications themselves.

The program was subjected to an independent audit by PG&E's Quality Assurance Department and a review by an Independent Review Board which reported its findings to a managing consultant who, in turn, reported his findings to PG&E management. The NRC documented acceptance of the SISI Program in SSER 31(Reference 41).

To ensure that the objective of the SISI Program is met on an ongoing basis, plant modifications and housekeeping and maintenance activities are reviewed for their potential to create SISIs. The SISI Program Manual (Reference 40) provides the technical guidance to perform SISI evaluations.

3.7.3.14 Field Location of Supports and Restraints

Seismic supports and restraining devices for PG&E Design Class I piping are located as follows:

3.7.3.14.1 Two Inches in Diameter and Less

Field-routed and vendor-furnished piping 2 inches and less in diameter is supported by the piping installation contractor's field personnel in accordance with criteria supplied by PG&E's engineering staff on Approved for Construction drawings. These criteria specify size, type, spacing, and permissible locations for seismic supports and restraining devices. Prior to initial fuel loading, the completed installation of this piping was reviewed by an experienced piping engineer from PG&E's engineering staff to ensure compliance with the criteria and the observance of good design practice.

3.7.3.14.2 Larger Than 2 Inches in Diameter

The size, type, and location of each support or restraining device on each line is shown on Approved for Construction drawings.

The procedures followed during development of the Approved for Construction drawings provide assurance that the field location and the seismic design of supports and restraining devices are consistent with the assumptions made in the seismic analysis. These procedures are:

(1) The locations of supports and restraining devices are established on preliminary drawings.

(2) The locations shown on the preliminary drawings are used to develop the mathematical model for the seismic analysis, and the seismic analysis is performed. If the results show piping stresses higher than allowable, adjustments are made in the location, and/or the type of support or restraining device, and the seismic analysis is repeated.

(3) The reactions calculated as part of the seismic analysis, combined with other loads, are used for final design of piping supports and restraining devices.

(4) When the design is complete, drawings are issued as Approved for Construction to the piping installation contractor. Installation of supports and restraining devices is in accordance with Approved for Construction drawings.

3.7.3.15 Seismic Analyses for Fuel Elements, Control Rod Assemblies, Control Rod Drives, and Integrated Head Assembly

3.7.3.15.1 Reactor Vessel Internals Evaluation - DE, DDE, and HE

Nonlinear dynamic seismic analysis of the RPV system includes the development of the system finite element model and the synthesized time history accelerations. Both of these developments for the seismic time history analysis are discussed below.

The basic mathematical model for seismic analysis is essentially similar to a LOCA model in that the seismic model includes the hydrodynamic mass matrices in the vessel/barrel downcomer annulus to account for the fluid-solid interactions. On the other hand, the fluid-solid interactions in the LOCA analysis are accounted through the hydraulic forcing functions generated by MULTIFLEX Code 3.0 (Reference 42). Another difference between the LOCA and seismic models is the difference in loop stiffness matrices. The seismic model uses the unbroken loop stiffness matrix, whereas the LOCA model uses the broken loop stiffness matrix. Except for these two differences, the RPV system seismic model is identical to that of LOCA model.

The RPV system finite element model for the nonlinear time history dynamic analysis consists of three concentric structural sub-models connected by nonlinear impact elements and linear stiffness matrices. The first sub-model, shown in Figure 3.7-27A, represents the reactor vessel shell and its associated components. The reactor vessel is restrained by four reactor vessel supports (situated beneath alternate nozzles) and by the attached primary coolant piping. Also shown in Figure 3.7-27A is a typical RPV support mechanism.

The second sub-model, shown in Figure 3.7-27B, represents the reactor core barrel, thermal shield, lower support plate, tie plates, and the secondary support components for Unit 1 (PGE); whereas, for Unit 2 (PEG) the second sub-model is shown in Figure 3.7-27C (core barrel with neutron pads instead of thermal shield).

These sub-models are physically located inside the first, and are connected to them by stiffness matrices at the vessel/internals interfaces. Core barrel to reactor vessel shell impact is represented by nonlinear elements at the core barrel flange, upper support plate flange, core barrel outlet nozzles, and the lower radial restraints.

The third and innermost sub-model, shown in Figure 3.7-27D, represents the upper support plate assembly consisting of guide tubes, upper support columns, upper and lower core plates, and the fuel. The fuel assembly simplified structural model incorporated into the RPV system model preserves the dynamic characteristics of the entire core. For each type of fuel design the corresponding simplified fuel assembly model is incorporated into the system model. The third sub-model is connected to the first and second by stiffness matrices and nonlinear elements.

As mentioned earlier, fluid-structure or hydroelastic interaction is included in the RPV model for seismic evaluations. The horizontal hydroelastic interaction is significant in the cylindrical fluid flow region between the core barrel and the reactor vessel annulus. Mass matrices with off-diagonal terms (horizontal degrees-of-freedom only) attach between nodes on the core barrel, thermal shield and the reactor vessel. The mass matrices for the hydroelastic interactions of two concentric cylinders are developed using the work of Reference 36. The diagonal terms of the mass matrix are similar to the lumping of water mass to the vessel shell, thermal shield, and core barrel. The off-diagonal terms reflect the fact that all the water mass does not participate when there is

no relative motion of the vessel and core barrel. It should be pointed out that the hydrodynamic mass matrix has no artificial virtual mass effect and is derived in a straight-forward, quantitative manner.

The matrices are a function of the properties of two cylinders with the fluid in the cylindrical annulus, specifically, inside and outside radius of the annulus, density of the fluid, and length of the cylinders. Vertical segmentation of the reactor vessel and the core barrel allows inclusion of radii variations along their heights and approximates the effects beam mode deformation. These mass matrices were inserted between the selected nodes on the core barrel, thermal shield, and the reactor vessel as shown in Figure 3.7-27E. The thermal shield is not used and does not apply to Unit 2. The neutron panels for Unit 2 are accounted for by adjusting the properties of the core barrel for Unit 2 accordingly.

The seismic evaluations are performed by including the effects of simultaneous application of time history accelerations in three orthogonal directions. For the DE, DDE and HE, the Westinghouse generated synthesized time history accelerations at the reactor vessel support were used.

The ANSYS computer code, which is used to determine the response of the reactor vessel and its internals, is a general-purpose finite element code. A full transient dynamic analysis of the model is performed by direct integration solution using the full system matrices. In the finite element approach, the structure is divided into a finite number of discrete members or elements. The inertia and stiffness matrices, as well as the force array, are first calculated for each element in the local coordinates. Employing appropriate transformations, the element global matrices and arrays are assembled into global structural matrices and arrays, and used for dynamic solution of the system equations.

The results of the nonlinear seismic dynamic analyses include the transient displacements and impact loads for various elements of the mathematical model. These displacements, impact loads, and linear component loads (forces and moments) are then used by cognizant organizations for detailed component evaluations to assess the structure of the reactor vessel, reactor internals, and the fuel.

3.7.3.15.2 Fuel Assembly Evaluation

The fuel assembly design adequacy under DDE and HE conditions was assessed through a combination of mechanical tests and analyses. The information obtained from the fuel assembly and component structural tests provided the fundamental mechanical constants for the finite element model used in the fuel analysis.

The analysis of the fuel is performed in two steps. The first step involves analysis of the detailed reactor core model, which includes the reactor vessel, internals, and a simplified model of the fuel (refer to Figures 3.7-27A thru 3.7-27E). This dynamic analysis uses seismic time history motion at the reactor vessel support elevation

(Elevation 102 feet). The second step of the fuel analysis involves running a detailed fuel assembly model using the WEGAP code. This detailed model (refer to Figure 3.7-27F) conservatively represents an entire row of full-length fuel assemblies (15 total). WEGAP analysis predicts grid-to-grid impact forces and fuel assembly lateral displacements at each grid elevation.

The fuel assembly model consists of a series of beam elements with torsional springs located at the various fuel assembly grid elevations to simulate the fuel assembly dynamic characteristics. The values of the mechanical constants such as the rigidity modulus and the torsional stiffness were selected to accurately represent the experimentally determined fuel assembly modal stiffness and natural frequencies.

The time history motion for the upper and lower core plates and core barrel are simultaneously applied to the simulated fuel assembly model as illustrated in Figure 3.7-27F. These input motions were obtained from the time history analysis of the reactor vessel and internals finite element model.

The maximum grid impact forces and the fuel assembly maximum deflection are determined with the reactor core model.

Because of the basic fuel assembly design configuration, the assembly impacts are restricted to the grid locations. The seismic and LOCA loads at each grid were combined using the SRSS method to obtain the design maximum loads. These loads are compared with the allowable grid load, which is determined based on the test data using 95 percent confidence level on the true mean criteria. Refer to Sections 4.2.1.3.2.5 and 4.2.1.5.4 for additional information.

3.7.3.15.3 Control Rod Drive Mechanism Evaluation

The CRDMs were evaluated using a combination of linear and nonlinear finite element models which included the CRDM housings, RVCH head adapters, and the IHA (refer to Section 3.7.3.15.4). The following models and analysis methods were employed for the specified earthquakes:

The DE, DDE, and HE horizontal direction seismic loads, acting on the CRDMs, were determined using finite element models and nonlinear seismic time history methods. The finite element models included nonlinear spring elements to represent the gaps and contact between the seismic plates (near the tops of the CRDM rod travel housings) and to represent the contact between the outer seismic plates and the seismic stop plates. A linear spring was also included to represent the combined tie-rod and IHA stiffness connection to the wall. The IHA was included in the models as a vertical beam connecting the RVCH to the tie-rod spring. An IHA horizontal beam was included to connect the IHA vertical beam to the seismic stop plates.

Time history input motions for the CRDM DE, DDE, and HE horizontal earthquake analyses were developed at the RVCH elevation and at the 140-foot elevation corresponding to the tie-rod/IHA connection to the wall. The time history inputs and

CRDM models were used with the ANSYS structural analysis program to determine seismic forces acting on the CRDMs along their lengths due to DE, DDE, and HE horizontal direction earthquakes.

The vertical direction seismic forces for DE, DDE, and HE were determined using linear elastic response spectra methods. The vertical direction seismic analyses used response spectra at the RVCH elevation, since the CRDMs are supported vertically only at the RVCH elevation. To account for gaps between the seismic plates, a static analysis was also performed using a forced horizontal direction displacement at the CRDM seismic plate elevation that corresponds to the maximum cumulative gap.

For the DE and DDE horizontal earthquakes analyzed, the maximum of the results for the two horizontal earthquake directions (X or Z) were used when combining results with vertical earthquake results. For the Hosgri horizontal earthquakes analyzed, the results for each of the two horizontal earthquake directions (X and Z) were combined by SRSS with vertical earthquake results. The time history inputs and CRDM models were used with the ANSYS structural analysis program to determine seismic forces acting on the CRDMs along their lengths due to DE, DDE, and HE earthquakes.

Analyses show the CRDM fundamental frequency range is 5 to 8 Hz and the dominant frequencies of response are below 10 Hz.

3.7.3.15.4 Integrated Head Assembly Evaluation

For seismic loading, a uniform linear elastic response spectrum analysis of the IHA was performed using the spectra at the 140 foot elevation of the cavity walls and the spectra at the center of gravity (CG) of the RVCH to obtain enveloped spectra. These enveloped spectra are applied at both the tie rod attachments to the cavity walls as well as at the IHA ring beam attachments at the RVCH. Tension only capability of the tie rods was modeled. Modal responses were combined by the SRSS method consistent with Section 3.7.2.1.3.

Critical damping values used for the IHA components are provided in 3.7.1.4, “Critical Damping Values” and were approved in Reference 32. The combinations of the spatial components of earthquake motion are in accordance with Section 3.7.2.16. The seismic loadings were used as inputs to the IHA structural analysis presented in Section 5.2.2.1.14.1(3).

3.7.4 SEISMIC INSTRUMENTATION PROGRAM

3.7.4.1 Safety Guide 12, March 1971, “Instrumentation for Earthquakes”

The seismic monitoring system instrumentation consists of strong motion triaxial accelerometers that sense and record ground motions, and the amplified seismic response of various locations in the plant structures. The licensing basis for the seismic

monitoring system instrumentation is in accordance with Safety Guide 12, March 1971 (Reference 39). Enhancements to the seismic instrumentation have been made to improve the system effectiveness. The enhancements include additional accelerometers and rapid processing of the ground motion data. The enhancements exceed the intent of Safety Guide 12, March 1971, and are not considered part of the licensing basis. The seismic trip system is discussed in Section 7.2.

3.7.4.2 Location and Description of Instrumentation

Seismic instrumentation is provided in accordance with Safety Guide 12, March 1971. All instruments are rigidly mounted so their records can be related to movement of the structures and ground motion. All are accessible for periodic servicing and for obtaining readings.

3.7.4.2.1 Strong Motion Triaxial Accelerometers

Strong motion triaxial accelerometers provide time-histories of acceleration for each of three orthogonal directions. These histories are recorded in the accelerometer housings. The instruments start recording upon actuation of a seismic trigger which has an adjustable threshold. Seven strong motion triaxial accelerometers are provided in accordance with Safety Guide 12, March 1971. Additional accelerometers provide ground motion data beyond the regulatory guidance and are not part of the licensing commitment.

3.7.4.3 Control Room Operator Notification

Operation of the strong motion triaxial accelerometers (ESTA01 or ESTA28) will activate an annunciator in the control room and provide indications on the earthquake force monitor (EFM) in the Rack Seismic Instrument panel. The EFM will display the acceleration levels for all areas of both the Unit 1 containment base sensor (ESTA01) and the free field sensor (ESTA28). For the Emergency Plan event classification, it also provides a status of level exceedance for any axis on both sensors within a few minutes. The setpoint thresholds are set in accordance with Emergency Plan Action Levels.

3.7.4.4 Comparison of Measured and Predicted Responses

In the event of an earthquake that produces significant ground motions, all seismic instruments are read and the readings compared to the corresponding design values. This comparison, together with information provided by other plant instrumentation and an inspection of safety-related systems, forms the basis for a judgment on severity, level, and the effects of the earthquake.

3.7.5 SEISMIC DESIGN CONTROL

3.7.5.1 Equipment Purchased Directly by PG&E

The position of PG&E's engineering staff in the corporate structure is shown in the Diablo Canyon Quality Assurance Program Description. The procedures for specifying technical and PG&E QA requirements in purchase orders and specifications are included in Sections 4, 5, and 8 of the Diablo Canyon Quality Assurance Program Description.

The seismic design requirements developed from the structure seismic system analysis are included in the purchase order or specification for PG&E Design Class I equipment. The purchase order or specification requires that the manufacturer submit seismic qualification data of the equipment to be furnished, for review by the responsible PG&E engineer. The procurement is approved only when all seismic design criteria are met.

3.7.5.2 Equipment Supplied by Westinghouse

The following procedure is implemented for PG&E Design Class I mechanical equipment that falls within one of the many categories analyzed as described in Section 3.7.2 and shown to be rigid (fundamental frequency > 20Hz for DE and DDE and > 33 Hz for HE).

(1) Equivalent static acceleration factors for the horizontal and vertical directions must be checked against those in the Design Criteria Memoranda. Westinghouse must certify the adequacy of the equipment to meet the seismic requirements as described in Section 3.7.2 for DE, DDE, and HE.

(2) Westinghouse must check to ensure that the given equivalent static acceleration factors are less than or equivalent to those given in the equipment analysis.

(3) Westinghouse must perform the necessary reanalysis to the procedures and criteria presented herein for those cases, where required, due to revised DE, DDE, and HE seismic response spectra.

All other PG&E Design Class I equipment must be analyzed or tested as described in Sections 3.7.2 and 3.10.

Design control measures and design documentation for all PG&E Design Class I SSCs are in accordance with formalized QA procedures. These procedures are presented in the Diablo Canyon Quality Assurance Program Description.

3.7.6 SEISMIC EVALUATION TO DEMONSTRATE COMPLIANCE WITH THE HOSGRI EARTHQUAKE REQUIREMENTS UTILIZING A DEDICATED SHUTDOWN FLOWPATH

The evaluation of DCPP for the effects of the HE, as described in the "Seismic Evaluation for Postulated 7.5 M Hosgri Earthquake, Unit 1 and Unit 2, Diablo Canyon Site" was performed in the following phases:

(a) Phase I of the evaluation addressed the seismic qualification of a minimum subset of essential equipment needed to maintain the plant in hot standby, and then go to cold shutdown, assuming offsite power was not available for the loads associated with the HE. This subset of equipment is defined as the dedicated shutdown flowpath.

(b) Phase II of the evaluation addressed the seismic qualification of all remaining PG&E Design Class I equipment, with the exception of radwaste handling systems, for the loads associated with the HE.

As a result of the completion of Phase II of the evaluation, the dedicated post-Hosgri safe shutdown flow path, previously identified in this subsection, is no longer required. Post-Hosgri safe shutdown is now accomplished per existing plant procedures using the appropriate seismically qualified equipment. The PG&E Design Class I fire water tank is credited as an alternate supply of auxiliary feedwater in lieu of the non-seismically qualified raw water storage reservoir (Reference 25).

3.7.7 SAFETY EVALUATION

3.7.7.1 General Design Criterion 2, 1967 - Performance Standards

The DCPP seismic design ensures that PG&E Design Class I SSCs can withstand the effects of loads associated with the DE, the DDE, and the HE and maintain their design basis functions.

Subject matter related to meeting GDC 2, 1967 falls under the following general categories:

Seismic Input

- Design Response Spectra (refer to Section 3.7.1.2)
- Design Response Spectra Derivation (refer to Section 3.7.1.3)
- Critical Damping Values (refer to Sections 3.7.1.1 and 3.7.1.4)
- Bases for Site Dependent Analysis (refer to Section 3.7.1.5)
- Soil-Supported Category I Structures (refer to Section 3.7.1.6)
- Soil-Structure Interaction (refer to Section 3.7.1.7)

Seismic System Analysis

The seismic system analyses address the following considerations:

- Seismic Analysis Methods (refer to Section 3.7.2.1)
- Natural Frequencies and Response Loads (refer to Section 3.7.2.3)
- Procedures Used to Lump Masses (refer to Section 3.7.2.4)
- Rocking and Translation Response Summary (refer to Section 3.7.2.5)
- Methods Used to Couple Soil with Seismic-System Structures (refer to Section 3.7.2.6)
- Development of Floor Response Spectra (refer to Section 3.7.2.7)
- Differential Seismic Movement of Interconnected Components (refer to Section 3.7.2.8)
- Effects of Variations on Floor Response Spectra (refer to Section 3.7.2.9)
- Use of Constant Vertical Load Factors (refer to Section 3.7.2.10)
- Methods Used to Account for Torsional Effects (refer to Section 3.7.2.11)
- Comparison of Responses (refer to Section 3.7.2.12)
- Methods to Determine PG&E Design Class I Structure Overturning Moments (refer to Section 3.7.2.14)
- Analysis Procedure for Damping (refer to Section 3.7.2.15)
- Combination of Components of Earthquake Motion for Structures (refer to Section 3.7.2.16)

Seismic Subsystem Analysis

The seismic subsystem analyses address the following considerations:

- Determination of number of earthquake cycles (refer to Section 3.7.3.1)
- Basis for selection of forcing frequencies (refer to Section 3.7.3.2)
- Procedure for combining modal responses (refer to Section 3.7.3.3)
- Root mean square basis (refer to Section 3.7.3.4)
- Design criteria and analytical procedures for piping (refer to Section 3.7.3.5)
- Basis for computing combined response (refer to Section 3.7.3.6)
- Amplified seismic responses (refer to Section 3.7.3.7)
- Use of simplified dynamic analysis (refer to Section 3.7.3.8)
- Modal period variation (refer to Section 3.7.3.9)
- Torsional effects of eccentric masses (refer to Section 3.7.3.10)
- Piping outside Containment Structure (refer to Section 3.7.3.11)
- Interaction of other piping with PG&E Design Class I Piping (refer to Section 3.7.3.12)
- Field location of supports and restraints (refer to Section 3.7.3.14)
- Seismic analyses for fuel elements, control rod assemblies, and control rod drives (refer to Section 3.7.3.15)

Seismic Instrumentation Program

The seismic instrumentation program, addresses the following:

- Safety Guide 12, March 10, 1971, “Instrumentation for Earthquakes” (refer to Section 3.7.4.1)
- Location and description of instrumentation (refer to Section 3.7.4.2)
- Control Room operator notification (refer to Section 3.7.4.3)
- Comparison of Measured and Predicted Responses (refer to Section 3.7.4.4)

Seismic Design Control

- Equipment Purchased Directly by PG&E (refer to Section 3.7.5.1)
- Equipment Supplied by Westinghouse (refer to Section 3.7.5.2)

3.7.7.2 Seismic Design Safety Function Requirement

(1) Design Earthquake and Double Design Earthquake Damping Values

Section 3.7.1.4 describes the damping values for the seismic evaluation of PG&E Design Class I SSCs for the DE and DDE.

3.7.7.3 Safety Guide 12, March 10, 1971 – Instrumentation for Earthquakes

Section 3.7.4 describes the use of Safety Guide 12, March 10, 1971, for the design of DCPP seismic monitoring instrumentation system.

3.7.7.4 Regulatory Guide 1.61, October 1973 - Damping Values for Seismic Design of Nuclear Power Plants

Section 3.7.1.4 describes the use of Regulatory Guide 1.61, October 1973, damping values for the seismic evaluation of PG&E Design Class I SSC for the HE.

3.7.7.5 Regulatory Guide 1.61, Revision 1, March 2007 - Damping Values for Seismic Design of Nuclear Power Plants

Section 3.7.1.4 describes the use of Regulatory Guide 1.61, Revision 1, damping values for the seismic qualification of the IHA and CRDM pressure housings for the DE, the DDE, and the HE.

3.7.7.6 NUREG-0660 (Item II.C.3), May 1980 - NRC Action Plan Developed as a Result of the TMI-2 Accident

Item II.C.3 – Review of Safety Classifications and Qualifications: Section 3.7.3.13 describes the implementation of NUREG-0660, Item II.C.3 - Review of Safety Classifications and Qualifications, through the SISI Program. This program ensures that

SSCs required for safe shutdown of the plant, as well as certain accident mitigating systems, will not be impaired from performing their safety function as a result of seismically induced interactions.

3.7.7.7 License Condition 2.C(7) of DCPP Facility Operating License DPR-80 Revision 44 (Long Term Seismic Program), Elements (4)

DCPP Unit 1 Facility Operating License No. DPR-80, License Condition 2.C(7), stated, in part: "PG&E shall develop and implement a program to reevaluate the seismic design bases used for the Diablo Canyon Power Plant."

PG&E's reevaluation effort in response to the license condition was titled the "Long Term Seismic Program". PG&E prepared and submitted to the NRC the "Final Report of the Diablo Canyon Long Term Seismic Program" in July 1988. Between 1988 and 1991, the NRC performed an extensive review of the Final Report, and PG&E prepared and submitted written responses to formal NRC questions. In February 1991, PG&E issued the "Addendum to the 1988 Final Report of the Diablo Canyon Long Term Seismic Program". In June 1991, the NRC issued Supplement Number 34 to the Diablo Canyon SSER in which the NRC concluded that PG&E had satisfied License Condition 2.C(7) of Facility Operating License DPR-80. In the SSER the NRC requested certain confirmatory analyses from PG&E, and PG&E subsequently submitted the requested analyses. The NRC's final acceptance of the 1991 LTSP is documented in a letter to PG&E dated April 17, 1992.

3.7.7.8 ASME Code Case N-411

Section 3.7.1.4 describes the use of ASME Code Case N-411 damping values for piping analyses.

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3.8 DESIGN OF PG&E DESIGN CLASS I STRUCTURES

Figures 1.2-1 and 1.2-2 show the location of all structures for DCPP Unit 1 and Unit 2. The design classification of plant structures is given in Table 3.2-3.

This section addresses the design of the following groups of structures:

(1) PG&E Design Class I structures (refer to Section 3.8.2)

(a) The design of the containment structure, including the interior concrete and steel annulus structure, is discussed in Section 3.8.2.1

(b) The design of the pipeway structures is discussed in Section 3.8.2.2

(c) The design of the auxiliary building, including the fuel handling area crane support structure, is discussed in Section 3.8.2.3

(d) The design of the outdoor water storage tanks, including the condensate storage, refueling water storage, and fire water tanks, is discussed in Section 3.8.2.4

(e) The foundations and concrete supports of PG&E Design Class I structures are discussed in Section 3.8.2.5

(2) PG&E Design Class II structures Containing PG&E Design Class I Equipment (refer to Section 3.8.3)

(a) The design of the turbine building, including the turbine pedestal, is discussed in Section 3.8.3.1

(b) The design of the intake structure is discussed in Section 3.8.3.2.

(3) PG&E Design Class I structures located inside other structures (refer to Section 3.8.4)

(a) The design of masonry walls is discussed in Section 3.8.4.1

(b) The design of the spent fuel storage racks is discussed in Section 3.8.4.2

(c) The design of the containment polar cranes is discussed in Section 3.8.4.3

Note that the analytical results summarized in the following sections for the major plant structures are representative of the evaluations performed for the operating license review (Reference 31), but are not revised to reflect minor changes associated with

plant modifications. The DCPP design calculation control procedure ensures that adequate margin is maintained for these structures.

3.8.1 DESIGN BASES

3.8.1.1 General Design Criterion 2, 1967 – Performance Standards

The DCPP PG&E Design Class I structures and PG&E Design Class II structures that contain PG&E Design Class I components are designed to withstand the effects of, or are protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects. Masonry walls in proximity to, or have attachments to, PG&E Design Class I components are designed to be capable of withstanding all postulated loads and load combinations, as required by Bulletin 80-11.

3.8.1.2 General Design Criterion 3, 1971 – Fire Protection

The DCPP PG&E Design Class I structures and PG&E Design Class II structures that contain PG&E Design Class I components are designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

3.8.1.3 General Design Criterion 4, 1967 – Sharing of Systems

The PG&E Design Class I structures and PG&E Design Class II structures that contain PG&E Design Class I components are not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

3.8.1.4 General Design Criterion 10, 1967 – Containment

DCPP Unit 1 and Unit 2 are provided with containment structures designed to sustain the initial effects of gross equipment failures, such as a LOCA, without loss of required integrity. The containment, together with other ESFs, is designed to retain for as long as the situation requires the functional capability to protect the public.

3.8.1.5 General Design Criterion 11, 1967 – Control Room

The PG&E Design Class I personnel access hatch control system and emergency personnel access hatch indication are designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room and from a remote location.

3.8.1.6 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the PG&E Design Class I personnel access hatch control system and emergency personnel access hatch indication variables within prescribed operating ranges.

3.8.1.7 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

The containment structure is designed to provide back-up to the safety provided by the core design, the RCPB, and their protection systems. The ECCS is designed to cope with any size RCPB break, up to and including the circumferential rupture of any pipe in that boundary, assuming unobstructed discharge from both ends.

3.8.1.8 General Design Criterion 40, 1967 – Missile Protection

DCPP Unit 1 and Unit 2 PG&E Design Class I structures are designed to provide protection for ESFs against dynamic effects and missiles that might result from plant equipment failure.

3.8.1.9 General Design Criterion 42, 1967 – Engineered Safety Features Components Capability

The containment structure is designed so its capability to perform its required ESF function is not impaired by the effects of a LOCA.

3.8.1.10 General Design Criterion 49, 1967 – Containment Design Basis

The containment structure, including access openings and penetrations, is designed to support the containment design basis such that the containment structure accommodates without exceeding the design leakage rate, the pressures and temperatures following a LOCA.

3.8.1.11 General Design Criterion 50, 1967 – NDT Requirement for Containment Material

The DCPP Unit 1 and Unit 2 containment penetration sleeves, being principal load carrying components of ferritic material exposed to the external environment, were selected so that their temperatures, under normal operating and testing conditions, are not less than 30 °F above the NDT temperature.

3.8.1.12 General Design Criterion 54, 1967 – Containment Leakage Rate Testing

The DCPP Unit 1 and Unit 2 containment structures are designed so that an integrated leakage rate testing can be conducted at design pressure and the leakage rate

measured over a sufficient period of time to verify its conformance with required performance.

3.8.1.13 General Design Criterion 56, 1967 – Provisions for Testing of Penetrations

The DCPP Unit 1 and Unit 2 containment structures are designed with provisions for testing penetrations which have resilient seals or expansion bellows to permit leak tightness to be demonstrated at design pressure at any time.

3.8.1.14 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The PG&E Design Class I structures shall include those means necessary to maintain control over the plant radioactive effluents, whether gaseous, liquid or solid. Appropriate holdup capacity shall be provided for retention of gaseous, liquid or solid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control shall be justified:

(a) On the basis of 10 CFR Part 20 requirements for normal operations and for any transient situation that might reasonably be anticipated to occur.

(b) On the basis of 10 CFR Part 100 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence except that reduction of the recommended dosage levels may be required where high population densities or very large cities can be affected by the radioactive effluents.

3.8.1.15 Design of PG&E Design Class I Structures Safety Function Requirements

(1) <u>Protection from Missiles and Dynamic Effects</u>

The non-ESF portions of PG&E Design Class I Structures are designed to be protected against internal missiles generated inside and outside containment and dynamic effects that might result from plant equipment failures.

3.8.1.16 Safety Guide 13, March 1971 – Fuel Storage Facility Design Basis

The fuel handling building, auxiliary building and containment structure shall be designed to assure adequate safety under normal and postulated accident conditions and that these systems be designed with appropriate containment, confinement and filtering systems and be designed to prevent significant reduction in the coolant inventory to the storage facility under accident conditions.

3.8.1.17 Safety Guide 18, October 1971 – Structural Acceptance Test for Concrete Primary Reactor Containments

The DCPP Unit 1 and Unit 2 containment structures were subjected to an acceptance test in accordance with the recommendations given in Safety Guide 18, October 1971, "Structural Acceptance Test for Concrete Primary Reactor Containments."

3.8.1.18 Regulatory Guide 1.55, June 1973 – Concrete Placement in Category I Structures

The DCPP PG&E Design Class I auxiliary building and containment structure shall be designed and constructed in accordance with quality requirements Regulatory Guide 1.55, June 1973.

3.8.1.19 Regulatory Guide 1.63, Revision 1, May 1977 – Electrical Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Plants

Circuits routed through containment electrical penetrations are designed to the requirements of Regulatory Guide 1.63, Revision 1 regarding installation of redundant or backup fault current protection devices to limit fault current to less than that which the penetration can withstand, assuming a single random failure of the circuit overload protective device.

3.8.2 PG&E DESIGN OF CLASS I STRUCTURES

3.8.2.1 Containment Structures

This section addresses the overall containment structures, including the following substructures:

(a) Exterior concrete shell

(b) Liner

(c) Penetrations/hatches

(d) Base slab

(e) Internal concrete structure

(f) Steel annulus structures

3.8.2.1.1 Description of the Containment

The containment structure for each unit is a steel-lined, reinforced concrete building of cylindrical shape with a dome roof that completely encloses the reactor and RCS. It ensures that essentially no leakage of radioactive materials to the environment would result even if gross failure of the RCS were to occur simultaneously with a DDE or a HE.

The containment structures for Unit 1 and Unit 2 are essentially identical, but are mirror images. The following discussion applies to either unit:

The concrete outline and equipment locations are shown in Chapter 1. The exterior shell consists of a 142-foot-high cylinder, topped with a hemispherical dome. The minimum thickness of the concrete walls is 3.6 feet, and the minimum thickness of the concrete roof is 2.5 feet. Both have a nominal ID of 140 feet and a nominal inside height of 212 feet. The concrete base slab is 153 feet in diameter with a minimum thickness of 14.5 feet, with the reactor cavity near the center. The inside of the dome, cylinder, and base slab is lined with welded steel plate, which forms a leak-tight membrane. The nominal thickness of the steel liner is 3/8-inch on the wall and dome and the nominal thickness of the steel liner on the base slab is 1/4-inch.

The containment is designed and will be maintained for a maximum internal pressure of 47 psig and a temperature of 271°F (refer to Section 6.2.2), coincident with a DDE or HE.

The 271°F containment temperature is the peak containment design temperature not exceeded during a LOCA (refer to Section 6.2.2). A containment atmospheric temperature of greater than 271°F may occur during a MSLB accident. The containment structure was not analyzed for MSLBs, which were not considered design basis for containment structural design.

The internal concrete structure approximates a 106-foot-diameter, 51-foot-high cylinder, with a slab on top. However, there are multiple openings and walls, such as the reactor shield wall and the stainless steel lined refueling canal, which complicate the shape. The walls and top slab are generally 3 feet thick. This structure provides support for the reactor and components of the RCS, provides radiation shielding, and provides protection for the liner from postulated missiles originating from the RCS (refer to Section 3.5 and Chapter 12).

A polar crane is mounted on top of the internal concrete cylinder wall. The polar crane, its connection to the concrete, and provisions to resist seismic forces are described in Sections 3.8.4.3 and 9.1.4.

The piping and electrical connections between equipment inside the containment structure and other parts of the plant are made through specially designed, leak-tight penetrations. In addition to the piping and electrical penetrations, other penetrations are

the 18-foot 6-inch diameter equipment hatch, the 9-foot 7-inch diameter personnel hatch, the 5-foot 6-inch diameter personnel emergency hatch, and the fuel transfer tube. Refer to Section 3.8.2.1.1.3 for descriptions of the penetrations present in the containment structure.

The plant vent (6-foot 7-inch by 13-foot ventilation duct) is attached to the outside of the structure, extending from an elevation 25 feet above the base slab to the top of the dome (refer to Section 9.4.2). The duct is fabricated from steel plate with stiffeners.

A system of lightning rods is installed on the dome to protect against lightning damage.

The following paragraphs describe the various parts of the structure:

3.8.2.1.1.1 Exterior Shell

(1) Reinforcing Steel

The reinforcing steel arrangement is designed to provide continuous reinforcement for tensile and shear membrane forces in the cylinder and dome. The reinforcing in the cylinder wall consists of horizontal hoop bars, and inclined bars, oriented 60° from the horizontal. In Figure 3.8-1, layers (4) and (6) are the Number 18 hoop bars, spaced at 8-1/2 inches center-to-center vertically, and layers (3) and (5) are the inclined Number 18 bars spaced at 8-1/2 inches center-to-center, all spacing measured normal to the bars.

The dome reinforcing is accomplished by extending the inclined bars past the springline and over the dome. After crossing the dome, the same bar once again becomes an inclined bar in the cylinder. A layer (3) bar becomes a layer (5) bar after crossing the dome, as shown in Figure 3.8-2. No inclined bars are terminated at the springline or in the dome.

The dome reinforcing steel layout is based on the division of a sphere into 20 equilateral spherical triangles, as shown in Figure 3.8-3. At the springline, two sides of the triangles make an angle of 30° with the vertical. Thus, an inclined cylinder bar is parallel to the sides of the triangles at the springline. The inclined cylinder bars are extended into the dome so that they are always parallel to one side of a spherical triangle.

Figure 3.8-4 shows the five types of bars in the dome. When these five types are superimposed, there are three layers of reinforcing steel at every point above the pentagon identified as ABCDE in Figure 3.8-3. Below pentagon ABCDE, the inclined bars make up two layers at every point, and bars similar to the cylinder hoop bars are used to provide reinforcing in the third direction.

Layers (1) and (2) (Figure 3.8-1) are inclined at 30° to the vertical and extend from the base slab to elevation 172 feet. These bars, spaced at 17 inches center-to-center, provide additional capacity to resist earthquake forces. Above elevation 170 feet, Number 4 bars are spaced at 12 inches center-to-center horizontally and vertically.

(2) Splices

All Number 18 bars are spliced by Cadwelding using "T-Series" sleeves, designed to develop the full tensile strength of the bar. As a general rule, splices are staggered a minimum of 3 feet.

For all penetrations except the equipment and personnel hatches, the Number 18 reinforcing bars are bent around openings. For the equipment and personnel hatch openings, a 2.5-inch-thick hexagonal collar, widened to 4 inches thick at the edges, is provided to transfer the reinforcing bar forces around the opening as shown in Figures 3.8-12 and 3.8-13. The reinforcing bars are Cadwelded to special studs threaded into the 4-inch edge of the hexagonal collar.

3.8.2.1.1.2 Dome and Cylinder Liner

All liner seams are full penetration butt-welded, and are covered with steel channels welded to the inside of the structure. These "leak chase" channels provide a sensitive and accurate means of detecting leakage. They are arranged in zones so that one zone at a time may be pressurized to test the integrity of the liner plate welds.

The liner in the dome and cylinder wall is anchored by welded studs that extend into the concrete wall past the innermost layers of reinforcing steel. Three types of studs are used: a 3/8-inch diameter with an 8-1/2-inch shaft and a plain 4-inch "L" shaped arm, a 3/8-inch diameter with an 8-1/2-inch shaft and a threaded end, and a 1/2-inch diameter with an 11-inch shaft and a threaded end. All threaded studs are provided with an anchorage at the threaded end, and provide resistance to pullout that is equal to or greater than the 3/8-inch stud with a 4-inch arm. The studs are spaced a maximum of 19.6 inches on center (plus a placement tolerance of 1/2 inch) in a pattern that is compatible with the reinforcing steel, as shown in Figure 3.8-5.

For all penetrations in the exterior shell, a thickened plate is welded into the liner.

3.8.2.1.1.3 Penetrations

In general, a penetration consists of a sleeve embedded in the concrete wall and welded to the containment structure liner. The pipe, electrical conductor cartridge, duct, or access hatch passes through the embedded sleeve and one or both ends of the resulting annulus are closed off by welded end plates, bolted flanges, or flued heads. Typical electrical and piping penetrations are shown in Figures 3.8-6 through 3.8-10, and the fuel transfer tube penetration is shown in Figure 3.8-11. The penetrations are designed to maintain the same high degree of leak-tight integrity afforded by the containment structure itself.

3.8.2.1.1.3.1 Electrical Penetrations

Electrical penetrations are either canister types or feed-through modules that allow electrical conductors to pass through the containment boundary. Penetrations are qualified for a single seal pressure boundary. The canister and feed-through modules are connected to the header plate, which is welded to the containment penetration sleeve. All penetrations are provided with a connection to allow periodic leak testing. The weld connecting the sleeve to the liner plate is provided with a leak chase channel for leak testing. Typical electrical containment penetrations are shown in Figures 3.8-8 and 3.8-9.

3.8.2.1.1.3.2 Piping Penetrations

Piping penetrations are provided for all piping passing through the containment boundary. Typical piping penetrations are shown in Figures 3.8-6 and 3.8-7. Several small pipes may pass through a single embedded sleeve to minimize the number of penetrations required. Welded end plates or flued heads are used to provide end closure. The welded joints are covered with a leak chase channel to allow periodic testing. The weld connecting the sleeve to the liner plate also has a leak chase channel.

Pipes carrying hot fluids through penetrations are designed to maintain the temperature of the concrete adjacent to the sleeve below 200°F under normal operating conditions.

Pipes and penetrations are anchored, as required, to resist the forces and movements incident at the penetration under normal and accident conditions, and to limit the loads imposed on the containment structure liner. Piping loads are transferred to the penetration sleeve and thence to anchors in the concrete wall rather than to the containment structure liner.

3.8.2.1.1.3.3 Equipment and Personnel Access Hatches

The equipment hatch is furnished with a double o-ring flange and bolted dished door. Equipment up to a diameter of approximately 18 feet can be transferred into and out of the containment structure through this hatch. The hatch barrel is embedded in the containment structure wall and welded to the liner. Provision is made for pressurizing the space between the double o-rings of the door flanges and the weld seam leak chase channels at the sleeve-to-liner joint.

The two personnel hatches are double door, mechanically-latched, welded steel assemblies.

A quick-acting type equalizing valve connects each personnel hatch with the interior of containment for the purpose of equalizing pressure in the two systems when entering or leaving. The personnel hatch doors are interlocked to prevent simultaneous opening. Remote indicating lights and annunciators situated in the control room indicate the door operational status. Provision is made to permit bypassing the door interlocking system to allow doors to be left open during a plant cold shutdown. Each door hinge is capable of independent 3-D adjustment to assist proper seating. A lighting and communication system operating from an external supply is provided in the airlock interior. Access, to either the inner door from the containment interior, or to the outer door from outside, is possible by the use of handwheels and lever arms. All doors on the personnel hatches are double o-ring sealed and provided with fittings to allow pressurization of the space between the double o-rings.

3.8.2.1.1.3.4 Special Penetrations

(1) Fuel Transfer Tube Penetration

A fuel transfer tube penetration is provided for fuel movement between the refueling canal in the containment structure and the SFP. The penetration consists of a 20-inch-diameter stainless steel pipe installed inside a 24-inch-diameter pipe sleeve as shown in Figure 3.8-11. The inner pipe acts as the transfer tube and is fitted with a quick-opening hatch in the refueling canal and a standard gate valve in the SFP. This arrangement prevents leakage through the transfer tube in the event of an accident. The outer pipe is welded to the containment liner and provision is made, by use of a special seal ring to permit pressure testing all welds essential to the integrity of the penetration. Bellows expansion joints are provided on the pipes to compensate for any differential movement between the two pipes or other structures.

(2) Containment Supply and Exhaust Purge Ducts

The ventilation system purge duct is equipped with two quick-acting tight-sealing valves (one inside and one outside the containment) to be used for isolation purposes (refer to Section 9.4.5). These valves are normally closed during reactor operation. They are manually opened for containment purging but are automatically closed upon a signal of high containment pressure or high containment radiation level (via the SI and phase A circuitry). The space between the valves can be pressurized to check the integrity of the penetration. In addition, the shaft seals of the purge valves are equipped with double seals with provision for testing the space between.

(3) Spare Penetrations

Capped spare penetrations are provided. The welds between the sleeve and the liner and between the sleeve and the cap are covered with leak chase channels.

All spaces that are equipped for pressurization of penetrations and penetration sleeves are included in the same system of pressurization zones as the liner seam leak chase channels.

Several spare penetrations are also provided with capped, blind flanged or valved and capped end connections. These are 10 CFR Part 50 Appendix J Type B penetrations and are leak tested in accordance with Appendix J, Option B, as modified by approved exemptions (refer to Section 6.2.1.4).

(4) Mini-Equipment Hatches (Penetrations 58 and 60)

The mini-equipment hatch penetrations are provided to facilitate the passage of electrical cables and compressed air/water hoses into containment during refueling outages to support maintenance activities. Each of the two penetrations are comprised of flange connections on both sides of containment. The in-containment flanges are equipped with double O-Rings, which form a double containment isolation boundary. The in-containment blind flanges are provided with pressure test connections to permit pressure testing between the O-Rings. During plant outages, a temporary configuration is used to provide a containment pressure seal while the penetration blind flange is removed from service. Both the O-Rings and temporary blind flange assemblies prevent leakage through the penetrations in the event of an accident.

(5) Recirculation Sump Suction Penetrations (Penetrations 28 and 29)

There are two penetrations through the containment base slab for the containment sump suction lines. These are similar to the piping penetrations in the exterior shell (refer to Section 3.8.2.1.1.3.2). The weld seams between the liner and the penetration sleeve and between the penetration sleeve and internal, are covered with leak chase channels. The volume in the end of the penetration internal has a fitting for pressurization. These leak chase channels and the volume in the end of the penetration internal are connected in the zones of pressurization used for liner leak chase channels.

3.8.2.1.1.4 Base Slab and Shell-Base Slab Connection

The reinforced concrete base slab acts as the foundation for the containment structure, supporting the exterior shell, the internal structure, and the annulus structures. A recessed area in the center of the base slab acts as the reactor cavity. The upper surface of the base slab, including the reactor cavity, has a steel liner plate, similar to that for the dome and cylinder walls (refer to Section 3.8.2.1.1.2). The seams on the base slab and reactor cavity liner are full penetration butt-welded and are covered with leak chase channels. The leak chase channels are arranged in zones in the same manner as those on the exterior shell liner.

The detail of the shell-base slab connection is shown in Figure 3.8-14. The vertical wide flange steel beams provide a gradual transition of load carrying elements between the base slab and the cylinder, and resist the radial bending moments and shears. The beams are keyed and grouted in a groove at the base slab and extend approximately 20 feet up the wall. They do not participate in resisting either uplift due to pressure, or shear and tension forces due to earthquake.

The 3-foot 8-inch thick cylinder wall is designed to offer minimum bending resistance at the junction with the base slab. To achieve this the wall is divided into three layers, with the contact surface between the layers designed as a slip surface. The 12-inch inner layer, next to the liner plate, provides stiffness to the liner plate. The L-shaped stud anchors, welded to the liner plate, and layers (1) and (2) of the wall reinforcing bars are in this layer. The middle layer is the wide flange steel beams. The voids between the beam webs are filled with concrete. The outer layer is 20 inches thick. Layers (3) through (6) of the wall reinforcing bars are in this layer. The slip surface between layers is provided by covering both flanges of the steel beams with two sheets of Johns-Manville #60 asbestos sheet packing. This packing is graphite coated on one side, and the two sheets are placed with the graphite-coated sides in contact. PG&E has successfully used this means of providing sliding supports on penstock piers. The inert nature of the material, and the fact that it is completely isolated from the atmosphere by a minimum of 20 inches of concrete, combine to ensure that it will be fully effective throughout the lifetime of the plant.

The detail at the bottom of each of these three layers is shown in Figure 3.8-14. The innermost and outermost layers have a 1-inch neoprene pad to allow slight rotation

without crushing of the concrete. The center layers, consisting of the beams, have a 5-inch-deep pocket in which the beams are placed and grouted.

The diagonal wall reinforcing extends to the bottom of the base slab for anchorage, as shown in Figure 3.8-15. The base slab bars are bent up at 45° and passed through the diagonal bars. The ends of the base slab bars are provided with a mechanical anchorage consisting of a Cadweld sleeve and a steel plate.

The shell liner is anchored to the base slab by Number 14 rebar welded to the bottom course liner plate, which is 3/4-inch-thick. These bars are embedded 8-1/2 feet in the base slab concrete.

3.8.2.1.1.5 Internal Structure

The internal structure shown in Figures 3.8-16 through 3.8-22 consists of the following parts:

(1) The lower operating floor at elevation 91 feet is a 2-foot-thick concrete slab placed over the containment structure base slab liner.

(2) The circular crane wall is a 3-foot-thick, 106-foot outside diameter (OD) reinforced concrete wall, concentric with the exterior shell, and extending vertically from the containment structure base slab liner at elevation 89 feet to the main operating floor at elevation 140 feet. The runway for the 200-ton polar gantry crane is located on top of the circular crane wall. This wall is anchored to the containment structure base slab by Number 18 reinforcing bars. This anchorage is developed through the containment structure base slab liner by means of Cadweld sleeves welded to each side of the liner at the same locations. The polar crane is shown in Figure 3.8-23.

(3) The reactor shield wall is a 34-foot OD, 17-foot ID reinforced concrete wall. This wall is anchored to the containment structure base slab in the same manner as the circular crane wall.

(4) The fuel transfer canal is a stainless steel lined cavity that can be filled with water during refueling. The vertical walls of the fuel transfer canal are 4 feet thick.

(5) The main operating floor at elevation 140 feet is a 3-foot-thick concrete slab supported by the circular crane wall and the fuel transfer canal walls. This slab is thickened locally up to 7 feet near openings.

(6) Main steam line restraint towers are reinforced concrete buttresses extending from the main operating floor at elevations 140 to 184 feet.

(7) Annulus platforms are structural steel platforms at elevations 117 and 140 feet, located between the circular crane wall and the exterior shell. Steel framing is also provided at elevations 106 feet 8 inches and 101 feet 5 inches for support of piping. Figures 3.8-21 and 3.8-22 provide the structural steel framing details for these platforms.

3.8.2.1.2 Applicable Codes, Standards, and Specifications

3.8.2.1.2.1 Codes and Standards

The following codes and standards were used, insofar as they are applicable, in the design and/or construction of the containment structure:

Note: Exceptions to these codes are discussed in the sections below where the particular code is discussed.

(1) American Concrete Institute Standard Building Code Requirements for Reinforced Concrete (ACI 318-1963)

(2) Manual of Standard Practice for Detailing Reinforced Concrete Structures (ACI 315-1965)

(3) Recommended Practice for Evaluation of Compression Test Results of Field Concrete (ACI 214-1965)

(4) Inspection of the Cadweld Rebar Splice (Erico Products, Inc., RB-5M 768)

(5) Recommended Practices for Welding Reinforcing Steel, Metal Inserts, and Connections in Reinforced Concrete Construction, American Welding Society (AWS) D12.1-1961

(6) American Institute of Steel Construction Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, February 1969

(7) Construction of the containment structure liner conforms to the applicable parts of Part UW, "Requirements for Unfired Pressure Vessels Fabricated by Welding," ASME BPVC Section VIII-1968 including Addenda through Summer 1968

(8) Those parts of penetration insert plates, penetration sleeves, airlocks, and access hatches, which form part of the pressure boundary, conform to Class B requirements of ASME BPVC Section III-1968, including Addenda through Summer 1968

(9) Code for Welding in Building Construction, AWS D1.0-1969. Work performed prior to December 12, 1969 is in accordance with the earlier

edition, AWS D1.0-1966. For inspection of non-ASME structural welds or new non-ASME work performed after January 1, 1988, the guidelines of Nuclear Construction Issues Group (Visual Weld Acceptance Criteria, Vol. 1-3, EPRI Report No. NP-5380, September 1987) (Reference 27) may be used except for those cases where:

(a) Fatigue is a governing design condition

(b) The weld allowables are permitted to be higher than those allowed by AWS D1.1 (such as the full penetration welds evaluation for the HE) [(a)]

(c) The weld is part of work performed in the ASME BPVC Section XI Inservice Inspection Program.

(10) Stud welding is in accordance with the Supplement to AWS Specifications AWS D1.0-1966 and AWS D2.0-1966 on Requirements for Stud Welding

(11) Materials, and the quality control tests for materials conform to American Society for Testing and Materials standards

(12) Pressure tests of the containment structure, leak chase channels, double penetration volumes, volumes between double seals, and volumes between double isolation valves are in accordance with the requirements of ANSI N45.4-1972, Leakage Rate Testing of Containment Structures for Nuclear Reactors, dated March 16, 1972

(13) Safety Guide 12, March 1971, Instrumentation for Earthquake (refer to Section 3.7.4)

(14) Safety Guide 18, October 1971, Structural Acceptance Test for Concrete Primary Reactor containments

(15) ASME BPVC Section III-1980, Division 2

(16) ASME BPVC Section III-1974, Division 1, Subsection NE

(17) American Petroleum Institute Code 650, Welded Steel Tanks for Oil Storage

(18) United States of America Standards Institute – Standard No. N6.2 Safety Standard for the Design, Fabrication and Maintenance of Steel Containment Structures, for Stationary Nuclear Power Reactors

Note:

(a) PG&E identified that some of the welds in this category had been inspected using the visual weld acceptance criteria contained in EPRI Report No. NP-5380. PG&E evaluated the impacts of this weld inspection criteria deviation and determined that the welds are acceptable as-is.

3.8.2.1.2.2 Safety Guides/Regulatory Guides

The following guidance documents were issued after construction at the DCPP was partially completed. The following guidance documents are not the DCPP Licensing Basis. Tables 3.8-1 through 3.8-3 provide a comparison for information only.

(1) Safety Guide 10, March 1971, Mechanical (Cadweld) Splices in Reinforcing Bars of Concrete Containments

(2) Regulatory Guide 1.15, Revision 1, Testing of Reinforcing Bars for Category I Concrete Structures

(3) Safety Guide 19, August 1972, Nondestructive Examination of Primary Containment Liner Welds

DCPP is committed to the following guidance document:

(4) Regulatory Guide 1.55, June 1973, Concrete Placement in Category I Structures

Because the corresponding programs for the DCPP were conservatively formulated, the inspection provided essentially equals, and in many cases exceeds, that provided by the regulatory position in the guides. Detailed comparisons of the program used for the DCPP with the regulatory position of Regulatory Guide 1.15, Revision 1; Safety Guide 10, March 1971; and Safety Guide 19, August 1972 are presented in Tables 3.8-1 through 3.8-3, respectively. The comparisons in Table 3.8-1, Table 3.8-2, and Table 3.8-3 are provided for information only. The regulatory guidance documents compared in the tables are not the DCPP Licensing Basis. The PG&E Design Class I containment structures are in accordance with the accepted industry codes and standards that were in effect during the design and construction of DCPP. The QA program for the DCPP meets the requirements of Regulatory Guide 1.55, Revision 1. In regard to Regulatory Guide 1.55, June 1973, the references used for guidance are those listed in Appendix A of the regulatory guide, as they existed at the time of the Preliminary Safety Analysis Report (PSAR).

3.8.2.1.2.3 ACI-ASME for Containments

The technical requirements of ACI Standard 359-1975 (Reference 3) were derived from the Building Code Requirements for Reinforced Concrete (ACI 318-1971), from ASME BPVC Section III, Division 1, and from other codes and standards commonly applied to containment structure design, fabrication, and examination. The requirements for the

DCPP containment structures are based on those same codes and standards, except that in many cases an earlier edition was applied to DCPP.

Tables 3.8-1, 3.8-2, and 3.8-3 compare the DCPP programs for reinforcing steel, Cadweld splices, and nondestructive examination of the liner with the regulatory position in Regulatory Guide 1.15, Revision 1; Safety Guide 10, March 1971; and Safety Guide 19, August 1972, respectively.

The general requirements of the code require third party inspection for all containment structure fabrication and construction. For DCPP, third party inspection was provided for fabrication and installation of all containment structure penetrations in accordance with the Class B requirements of ASME BPVC Section III.

3.8.2.1.3 Loads and Loading Combinations

3.8.2.1.3.1 Design Loads

The following loads were considered in the design of the containment structure:

3.8.2.1.3.1.1 Dead Loads

Dead loads consist of the weight of concrete, reinforcing steel, steel liner, structural steel, and permanent equipment loads. Equipment loads are supplied by the manufacturers.

3.8.2.1.3.1.2 Live Loads

Live loads consist of temporary equipment loads and a uniform load to account for the miscellaneous temporary loadings that may be placed on the structure.

3.8.2.1.3.1.3 Internal Pressure Due to Loss-of-Coolant Accident

The design peak internal pressure used for design purposes is 47 psig, which is greater than any of the peak pressures calculated in the detailed analysis reported in Chapter 6.

For design purposes, a maximum pressure differential of 15 psi due to the hypothetical LOCA was assumed to exist between the volume within the circular crane wall and the surrounding containment structure volume. The pressurizer enclosure maximum pressure differential was assumed to be 4 psi due to the vent openings provided. These values are greater than the values calculated in the detailed analysis reported in Chapter 6.

3.8.2.1.3.1.4 Loads Due to Thermal Expansion

These are loads resulting from the internal temperatures associated with normal operation and the hypothetical LOCA. The maximum internal atmospheric temperature

during normal operation is 120°F. The temperature transients associated with the LOCA pressure and temperature are shown in Appendix 6.2D. The analyses of Appendix 6.2D correspond to a design load factor of 1.0. To determine the temperature transients for load factors equal to 1.25 and 1.5, steam tables are used.

3.8.2.1.3.1.5 Loads Due to Postulated Pipe Ruptures and Missile Impact

Design of the internal structure includes calculation of the effects of forces from postulated pipe ruptures transmitted through pipe restraints and equipment supports, jet forces for postulated pipe ruptures, and forces resulting from postulated missile impact. The forces from postulated pipe ruptures are calculated as described in Section 3.6. The forces from postulated missile impact are calculated as described in Section 3.5.

3.8.2.1.3.1.6 Earthquake Loads

Earthquake loads are based on a time-history modal superposition analysis of the containment structure and surrounding rock mass, as appropriate, as described in Section 3.7.2.

3.8.2.1.3.1.7 Wind Loads

Wind loads are determined in accordance with the criteria presented in Section 3.3.

3.8.2.1.3.1.8 Test Pressure

Internal pressure was applied to test the structural integrity of the containment vessel up to 115 percent of the design pressure. For this structure, the test pressure is 54 psig.

3.8.2.1.3.1.9 Negative Pressure

Negative pressure consists of loading from an internal negative pressure of 3.5 psig. This negative pressure has taken into account the Technical Specification limit on lower bound containment pressure and on inadvertent containment spray actuations, which would result in a 70°F temperature decrease.

3.8.2.1.3.2 Loading Combinations

The following loading combinations are used in design of the containment structure elements.

3.8.2.1.3.2.1 Operating Conditions

(1) Exterior Structure and Base Slab

Dead load, thermal load, DE, and negative pressure are considered as follows:

$$C = D + T_O + DE + NP \quad (3.8\text{-}1)$$

where:

C	=	required capacity of section based on the methods described in Section 3.8.2.2.5.1
D	=	dead load of structure and equipment loads
T_O	=	thermal loads during normal operating conditions
DE	=	loads resulting from the DE
NP	=	load due to negative pressure

(2) Internal Structure

For concrete structures, dead load, live load, thermal load, and DE load are considered as follows:

$$C = D + L + T_O + DE \quad (3.8\text{-}2)$$

For annulus steel structures, the load combinations are:

$$C = D + T_O + TH + FL \quad (3.8\text{-}3)$$

$$C = D + T_O + TH + FV + RVOT + DE \quad (3.8\text{-}4)$$

where:

FL	=	friction loads applied in the direction of thermal movements
FV	=	fast valve closure load
L	=	live load
RVOT	=	relief valve opening thrust load
TH	=	restrained thermal loads of the supported piping

3.8.2.1.3.2.2 Accident Conditions

(1) Exterior Shell and Base Slab

$$U = 1.0D \pm 0.05D + 1.5P_A + 1.0T'' \quad (3.8\text{-}5)$$

$$U = 1.0D \pm 0.05D + 1.25P_A + 1.0T' + 1.25DE \quad (3.8\text{-}6)$$

$$U = 1.0D \pm 0.05D + 1.0P_A + 1.0T + 1.0DDE \quad (3.8\text{-}7)$$

$$U = 1.0D \pm 0.05D + 1.0P_A + 1.0T + 1.0HE \quad (3.8\text{-}8)$$

where:

U	=	required load capacity of section based on the methods described in Section 3.8.2.2.5.2
P_A	=	load due to accident pressure
T	=	load due to maximum temperature associated with $1.0P_A$
T'	=	load due to maximum temperature associated with $1.25P_A$
T"	=	load due to maximum temperature associated with $1.5P_A$
DDE	=	loads resulting from the DDE
HE	=	loads resulting from the HE

For structural steel and concrete elements designed by normal working strength method, the allowable stresses determined by AISC and ACI 318-1963 codes, respectively, are increased by 1.6 for the DDE and 1.7 for the HE, except for shear in structural steel which is determined by the Von Mises criterion as outlined in the commentary of the AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, February 1969.

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(2) Internal Structure

For concrete structures, dead load, live load, earthquake load, compartment pressurization, pipe reactions associated with a postulated pipe rupture, jet forces, and missile loads are considered wherever occurring as follows:

$$U = D + L + DDE + CP + R + J + M \quad (3.8\text{-}9)$$

$$U = D + L + HE + CP + R + J + M \quad (3.8\text{-}10)$$

For annulus steel structures, the load combinations are:

$$U = D + DDE + THA + FV + RVOT \quad (3.8\text{-}11)$$

$$U = D + HE \quad (3.8\text{-}12)$$

where:

CP	=	compartment pressurization associated with a pipe break
R	=	pipe reactions associated with a postulated pipe rupture
J	=	jet impingement load
M	=	missile impact load
THA	=	restrained thermal expansion loads of the supported piping

3.8.2.1.4 Design and Analysis Procedures

3.8.2.1.4.1 Analysis of Containment Cylinder and Dome

For the loading conditions described in Section 3.8.2.3.3, the exterior wall is subjected to membrane forces and moments. These forces and moments are shown in Figures 3.8-27 through 3.8-34, and have been calculated based on the overall elastic behavior of containment exterior wall and dome in accordance with the conventional close form solution. An exception is that at the juncture of cylinder wall and base slab, the meridional moment and shear forces are computed as described in Section 3.8.2.1.3.1.4.

The stresses in the reinforcing steel and concrete subject to the above membrane forces and moments are computed by assuming that the concrete cracks under tension. This involved resolving compatibility and equilibrium equations by an iterative method. The stress analysis is performed with two sets of assumptions: (a) the effect of the liner plate is neglected, and (b) the liner plate is included as a stress-carrying element. Since the thicknesses of the cylinder and dome are small in comparison with the radii of curvature, they are analyzed as a thin walled shell structure.

(1) Internal pressure and dead load

The calculated membrane forces due to axisymmetric loads, such as internal pressure and dead load, are shown in Figure 3.8-27.

(2) Earthquake

Membrane forces are from the finite element, time-history modal superposition analysis described in Section 3.7.2. The plots of these membrane forces in the cylinder and dome due to the DE, DDE, and HE are shown in Figures 3.8-28 and 3.8-29, respectively. Shear forces in the dome due to the vertical input were calculated. Vertical input produces only radial shear, but no membrane shear. Radial shears were negligible when compared to membrane shears.

(3) Wind

Membrane forces from wind are shown in Figure 3.8-34. These are less than the membrane forces due to an earthquake.

(4) Temperature

Temperature loads are considered thermal gradients in the reinforced section, including the liner plate. The analysis procedure for thermal load is described in Section 3.8.2.1.4.4.

The combined membrane forces for the four accident loading conditions are shown in Figures 3.8-30 through 3.8-33.

3.8.2.1.4.2 Liner Anchors to Concrete Exterior Shell

The liner anchors are designed so that they have sufficient strength and flexibility to withstand any combination of liner stress and deformation that can be reasonably assumed to occur under accident loading conditions. The liner plate system is evaluated by developing allowable loads for attached threaded studs to support the mechanical or piping system. The load transfer mechanism from the external mechanical loads through the liner plate to the concrete stud system is developed to ensure the transfer of all loads into the concrete shell with all elements remaining elastic, while maintaining the leak-tight boundary.

The liner anchors are capable of accommodating the displacement of the liner plate under the operating and accident loading conditions.

3.8.2.1.4.3 Equipment and Personnel Hatch Openings

Membrane forces are transferred around the equipment hatch and personnel hatch openings by means of hexagonal-shaped steel collars to which the reinforcing steel is attached.

The analysis of the equipment hatch and personnel hatch openings takes into account the following:

(1) Direct membrane forces in the shell

(2) Force concentrations in the shell

(3) Bending effect in the shell

The area of the containment shell adjacent to the opening is extended beyond the opening far enough to make the effects of the opening negligible. This area is represented by a finite element mesh consisting of three parallel layers of plate elements which are interconnected by transverse beam elements representing the transverse normal and shear stiffness of concrete wall. The outer surface represents the hexagonal plate and outside reinforcement, the inner surface represents the sleeve, the liner plate and the inner reinforcement, and the intermediate layer represents the additional reinforcement around the opening. The hexagonal plate, sleeve, and liner plate are modeled by isotropic plate elements, and the reinforcement by orthotropic elements, in which the principal directions coincide with the directions of the reinforcement. The stiffness of concrete in the membrane directions is not included, because under tension the concrete is assumed to be cracked. The finite element model is shown in Figure 3.8-35. The analysis is performed by using BSAP/CE 800 computer program.

For axisymmetric loading, the vertical boundaries are restrained in the hoop direction. For the application of tangential shear force, the lower horizontal boundaries are restrained in the vertical and tangential directions. The vertical movement of the lower horizontal boundary is always restrained.

The internal pressure is applied to a large area of the shell wall adjacent to the opening and on the hatch. Since the hatch is not a part of the model, this pressure is transferred to the nodal point around the opening as nodal loads. The pressure on the containment shell and the nodal loads around the opening are applied in the radial direction. By examining the equilibrium of the sector of the wall isolated for modeling, having boundary conditions as described above, hoop membrane forces are induced to the model at the boundary conditions in which the following equation of equilibrium is met:

$$N\Theta = pR \qquad (3.8\text{-}13)$$

where:

$N\Theta$ = hoop force
p = internal pressure
R = radius of cylinder

The isostress plots are shown in Figures 3.8-40 through 3.8-42. These stresses are the results of the load combination shown by Equation 3.8-5, which controls the stress evaluation.

3.8.2.1.4.4 Juncture of Cylinder and Base Slab

At the base of the cylinder, radial expansion from internal pressure is considered compatible with the stiffness of the base slab. In this region, the cylinder undergoes a transition from a very small radial displacement at the base slab to full membrane displacement a short distance up from the base slab. This displacement results in longitudinal curvature in the cylinder.

A system consisting of structural steel wide flange beams, embedded in the bottom 20 feet of the concrete cylinder wall and keyed into the base slab, as shown in Figure 3.8-14, provides radial shear strength. These structural steel beams are located continuously around the circumference of the cylinder and provide bending and shear strength adequate to ensure the integrity of the wall in the transition region.

3.8.2.1.4.5 Base Slab

The containment base slab is evaluated by performing static analysis of the model shown in Figure 3.8-43. The model is divided into discrete segments represented by beam elements in the two horizontal directions, which simulate the two way action of the base slab. The interconnecting nodal points are supported by horizontal and vertical

springs which represent the properties of the underlying foundation rock. The horizontal and vertical stiffness of the containment shell, crane wall, and the reactor cavity are also represented by beams in the respective directions. The base slab model is analyzed for load combinations pertaining to the containment exterior structure as described in Sections 3.8.2.1.3.2.1 and 3.8.2.1.3.2.2.

The seismic loads resulting from the containment and the interior structures are applied at the appropriate nodal points. When these loads cause tension at the supports, the springs are released and an iterative analysis is performed until equilibrium is achieved. The results of the analyses are shown in Table 3.8-4, along with the corresponding allowable values.

3.8.2.1.4.6 Internal Structure

3.8.2.1.4.6.1 Concrete Structure

The principal structural features and design methods of the containment internal concrete structure are as follows:

The operating deck at elevation 140 feet is supported by the 3-foot-thick, 106-foot OD cylindrical crane wall, 4-foot-thick fuel transfer canal walls, and structural steel columns placed on the periphery next to the containment wall, which are a portion of the annulus framing structure. The slab within the circular crane wall is, in general, 3 feet thick. Because of irregular shape, it is represented by approximate models with negative moments based on clamped edges and positive moments based on hinged edges. Because of large openings, it was necessary to thicken parts of the slab to 7 feet, and these parts are treated as beams spanning between the circular crane wall and fuel transfer canal walls. Outside the circular crane wall the operating deck consists of a 1-foot 6-inch-thick concrete slab supported on the circular crane wall and on steel beams on the periphery; steel grating is placed over steel beams. Lateral forces are transmitted to the circular crane wall through diaphragm action of concrete slabs. The circular crane wall provides support for the operating floor at elevation 140 feet and also acts as a primary system transmitting lateral loads into the base.

Maximum stress ratios for selected elements of the containment internal structure are listed in Table 3.8-5.

3.8.2.1.4.6.2 Annulus Structure

The principal structural features and design methods of the annulus structure are:

The structure consists of four main framing levels at elevations 140, 117, 106, and 101 feet. This framing system is located between the circular crane wall and the containment exterior shell. The operating deck at elevation 140 feet consists mainly of a 1-foot 6-inch-thick concrete slab supported on the circular crane wall and on steel

beams by columns on the periphery near the exterior containment shell. Portions of the floor consist of steel grating supported on steel beams.

The framing system is anchored to the crane wall which provides all lateral support; lateral forces are transmitted to the circular crane wall through diaphragm action of the concrete slab at elevation 140 feet, and by structural framing system at other floor elevations. Vertical support is provided by the crane wall around the inner perimeter and by the concrete base slab at elevation 91 feet around the outer perimeter of the annulus. The annulus framing system is not attached to the exterior shell of the containment.

The annulus structure is modeled with 3-D computer models and analyzed with the BSAP computer program for Unit 1 and the GT STRUDL and SAP2000 computer programs for Unit 2, using a method of equivalent static loads to represent seismic forces. Maximum stresses for selected structural steel elements are listed in Table 3.8-5.

3.8.2.1.4.7 Computer Programs

The main computer programs used for static and dynamic analyses of containment structure are listed in Table 3.8-6. The table also describes the general function of the programs and their respective verification measures.

3.8.2.1.5 Structural Acceptance Criteria

The structural acceptance criteria for the containment structure exterior shell and internal structure are as follows:

3.8.2.1.5.1 Operating Conditions

For operating conditions, the containment structure is designed for the allowable stresses of the applicable code such as ACI 318-1963, AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, February 1969, and ASME BPVC, except that the increase in allowable stress or decrease in load factor usually allowed for load combinations involving earthquake or wind forces is not used.

3.8.2.1.5.2 Accident Conditions

For accident conditions, the containment structure is designed for overall elastic behavior under all load combinations, except at the juncture of containment exterior wall and base slab where inelastic analysis was performed by taking into consideration cracking of concrete under tension.

For structural elements designed by strength method, the yield stress of the material is reduced by ϕ factors, which are determined as follows:

Exterior shell reinforcing, structural steel embedded in exterior shell, and liner plate	ϕ= 0.95
Other structural steel	ϕ= 0.90[a]
Reinforced concrete in base slab and internal structure	ϕ factor in accordance with ACI 318-1963

The yield strength values of material under a non-Hosgri event are governed by the following codes:

Reinforced concrete	ACI 318-1963
Structural steel	AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, February 1969
Hexagonal collars of equipment and personnel hatches	ASME BPVC Section III, Div. 2, and ASME BPVC Section III, Div. 1
Penetration sleeves	ASME BPVC Section III, Div. 1
Liner plate	Table CC-3720-1[b] ASME BPVC Section III, Div. 2

Note:

(a) Refer to note in discussion of loading combinations in Section 3.8.2.3.

(b) Table CC-3720-1 is referred to establish acceptable design strain levels for the liner plate. The construction of the liner plate is pursuant to the specifications of Section 3.8.2.1.2.1(7).

The yield strength of steel and the ultimate strength of concrete for load combinations that include the HE are taken as the average values of properly substantiated test results. However, in no case are the yield values used in strength computations of structural steel greater than 70 percent of the corresponding average ultimate strength values determined by the tests (Reference 36). The ϕ factors described above are applicable in the HE. The average strength values for concrete are shown in Table 3.8-6A. The minimum and average yield and ultimate strength values for reinforcing and structural steel are shown in Table 3.8-6B.

For structural steel elements designed by normal working strength method, the allowable stresses determined by AISC and ACI 318-1963 codes, respectively, are increased by 1.6 for the DDE and 1.7 for the HE, except for shear in structural steel

which is determined by the Von Mises criterion as outlined in the commentary of AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, February 1969.

3.8.2.1.5.3 Factors of Safety

The factors of safety for the exterior shell and internal structure of the containment structure are at least as great as indicated by the load factors given in Section 3.8.2.1.3.2. The calculated stresses for the exterior shell are given in Figures 3.8-37 through 3.8-39, and the calculated stresses for the internal structure are given in Table 3.8-5.

Separations between the containment structure and the auxiliary building are adequate to ensure these structures will not impact each other when subject to design load combinations. Calculated displacements, separations, and factors of safety against impact are shown in Table 3.8-5B.

The relative seismic displacements between the containment structure exterior shell and the internal structure have been calculated as the sum of the maximum seismic displacement of each structure. Except for a few localized areas, the minimum cold gap between the internal structure and the exterior shell is 2 inches. The factors of safety against contact for all areas, including the localized areas, are greater than 2.33 for the governing seismic event, the DDE, after thermal effects on the size of gap are considered. The calculated factors of safety for the HE are greater than those for the DDE.

3.8.2.1.6 Materials, Quality Control, and Special Construction Techniques

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During the first 16 months of construction, a PG&E civil engineer was assigned to the construction site on a full-time basis. This engineer was familiar with, and had participated in, the design of the containment structure. For the period he was on site, he was part of the Quality Assurance Department (described in Chapter 17) and his responsibilities included performing audits on the various construction QA programs. This engineer was qualified as ANSI Level II for radiographic, magnetic particle, ultrasonic, and dye penetrant methods of nondestructive testing. In addition, other engineers from PG&E who were involved in the design of the containment structure maintained daily contact with the site by telephone calls, and made periodic visits to the site during construction.

Inspectors from PG&E's engineering staff performed regularly scheduled shop inspections on materials and components for the containment structure.

PG&E's construction staff provided a complete staff of resident engineers, field engineers, quality control engineers, and inspectors for supervision and inspection of

construction operations at the site. Their responsibilities for quality control of the containment structure were as follows:

(1) To inspect materials delivered to the jobsite and examine supplier's certified test reports of physical and chemical properties

(2) To inspect handling and placing of concrete, reinforcing bars, embedded items, and forms

(3) To maintain an adequate force of qualified supervisory personnel at all times

(4) To maintain qualified personnel, as a part of its field engineering force, to perform a thorough inspection of each significant construction operation

(5) To supervise and be fully responsible for the quality of work performed by contractors

(6) To maintain records of inspections that were performed

Many of PG&E's construction personnel at the site attended a formal course of instruction in radiographic, magnetic particle, ultrasonic, and dye penetrant methods of nondestructive testing. PG&E technicians staffed the onsite materials laboratory where tests on cement, aggregate, concrete, and reinforcing steel were performed.

3.8.2.1.6.1 Concrete

Concrete is a dense, durable mixture of sound aggregate, cement, water, and such admixtures as may be found advantageous. The concrete design strengths used in the containment structure are:

Exterior Shell	3,000 psi
Base Slab	5,000 psi
Internal Structures	5,000 psi

The concrete compressive strength and the modulus of elasticity values used in the analysis for load combinations, including the HE, are given in Table 3.8-6A.

Concrete construction meets, as a minimum, the requirements of ACI 318-1963, Building Code Requirements for Reinforced Concrete.

(1) Cement

Cement is clean, fresh, Type II, low alkali, moderate heat, Portland cement conforming to the specifications of ASTM C 150, except that the PG&E specification is more stringent in requiring that the compressive

strengths for any mill-run or bin be not less than 1,700 psi at 3 days, 2,700 psi at 7 days, and 4,000 psi at 28 days, and that the loss on ignition be less than 2 percent. In addition, the following Optional Chemical Requirements of ASTM C 150 are required by PG&E specification:

(a) Total alkalis of the cement, calculated as the percent of Na_2O + 0.658 times the percent of K_2O, is limited to 0.60 percent.

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(b) The sum of tricalcium silicate and tricalcium aluminate is limited to 58 percent. During manufacture, samples of cement were taken once each shift, or at the rate of one sample for every 2,000 barrels. After the quality history was established, in accordance with Section 5 of the Federal Test Method Standard Number 158a, testing was performed at the reduced testing rate specified in that standard. A report of the tests made on each sample was sent to PG&E engineering research staff. In addition, each shipment of cement was accompanied by a mill certificate, and a report of the average of all the individual tests was sent with the initial delivery from each new lot or grind.

Cement shipped to the batch plant was not placed in a plant bin unless it had been accepted by PG&E. In addition to the tests the cement manufacturer performed, PG&E made the following tests on each new lot to ensure conformance with ASTM C 150:

- ASTM C 109: Compressive Strength of Hydraulic Cement Mortars (using 2-inch cube specimens)

- ASTM C 114: Chemical Analysis of Hydraulic Cement

- ASTM C 151: Autoclave Expansion of Portland Cement

- ASTM C 191: Time of Setting of Hydraulic Cement by Vicat Needle

- ASTM C 204: Fineness of Portland Cement by Air Permeability Apparatus

The tests prescribed in ASTM C 114 were also performed periodically during storage to check for any effect on cement characteristics. These tests supplemented visual inspection during storage.

(2) Aggregates

Aggregates consist of inert materials that are clean, hard, durable, free from organic matter, not coated with clay or dirt, and conforming to ASTM Designation C 33, Standard Specification for Concrete Aggregates. In addition to the requirements of ASTM C 33, the PG&E specification requires that:

(a) Sodium Sulfate Test for Soundness (ASTM C 88). For fine aggregate, the portion retained on a Number 50 screen, be limited to a weighted average loss of no more than 8 percent after 5 cycles. For coarse aggregate, the weighted average loss after 5 cycles be no more than 10 percent

(b) Sand Equivalent Test (California Division of Highways Test Method Number California 217). Sand equivalent value be at least 75

(c) The fineness modulus be within the limits of 2.6 to 2.9

(d) Los Angeles Rattler Test (ASTM C 131) for coarse aggregate. Loss by weight using Grading A, be a maximum of 10 percent by weight at 100 revolutions and 40 percent by weight at 500 revolutions

(e) Cleanness Value (California Division of Highways Test Method Number California 227-B) for coarse aggregate. Cleanness value be at least 75

(f) Specific Gravity (ASTM C 127) for coarse aggregate. Specific gravity on a saturated surface dry basis be at least 2.60

(g) The chloride content of aggregate be no more than 440 ppm

The following tests were performed by the aggregate supplier at the frequency indicated:

Test	ASTM Destination	Frequency
Screen Analysis and Fineness Modulus	C 136	B
Clay Lumps and Friable Particles	C 142	D
Minus 200 Mesh Sand Only	C 117	D
Organic Impurities	C 40	D

Test	ASTM Destination	Frequency
Soft Particles	C 235	D
Lightweight Particles	C 123	D
Specific Gravity	C 127 & 128	C
Absorption	C 127 & 128	C
Unit Weight	C 29	C
Los Angeles Abrasion (coarse)	C 131	E
Soundness	C 88	E
Effect of Organic Impurities in Fine Aggregate on Strength of Mortar	C 87	F
Petrographic	C 295	F
Sand Equivalent Test	California Test Method 217	A
Cleanness Value	California Test Method 227-B	C

Frequency:

(a) Once each 100 tons, but not more than 10, nor less than one per day of production

(b) Once each 2,000 tons, but not less than one test per week during production

(c) Every 10,000 tons, or once every 10 days of production

(d) Every 20,000 tons, or once every 20 days of production

(e) Once for initial source approval, then once per 30,000 tons

(f) One per deposit

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All tests except the Soundness Test (ASTM C 88) and Soft Particles (ASTM C 235) were also performed by PG&E on a periodic basis.

Samples were taken at the place where the aggregate entered the batch bin.

(3) Admixtures

Admixtures conformed to the following ASTM standards:

(a)	*Pozzolan*	*ASTM C 618*	
(b)	*Air Entraining Agent*	*ASTM C 260*	
(c)	*Water Reducing Agent*	*ASTM C 494*	*1.1.1, Type A*

A certificate of compliance accompanied each load of admixture delivered to the construction site.

(4) Water

Water is clean and free from deleterious amounts of silt, oil, acids, alkali, salts, and organic substances. Chlorides, calculated as Cl, are limited to 1,000 ppm, and sulfates, calculated as SO_4, are limited to 1,000 ppm.

(5) Concrete Mixing, Placing, and Testing

The contractor was required to submit concrete mix designs meeting PG&E specification requirements. The mixes were designed in accordance with Method 2, Section 308, of ACI 301-1966. PG&E's material testing laboratory made sample batches of the proposed mixes and tested them according to:

(a) ASTM C 192, Making and Curing Concrete Test Specimens in the Laboratory

(b) ASTM C 39, Compressive Strength of Molded Concrete Cylinders

(c) ASTM C 143, Slump of Portland Cement Concrete by the Pressure Method

For each design mix, 7-day and 28-day compressive strength tests were made on 6 x 12 inch cylindrical samples in the laboratory.

The contractor was required to submit lift drawings, which showed the location of all construction joints and embedded items, for approval by PG&E. The lift drawings were approved prior to concrete placement. At construction joints in all structural concrete, the surface of the hardened concrete was roughened to expose the coarse aggregate by either bush hammering, wet sandblasting, or cutting with an air-water jet. Prior to

placing the next lift of concrete, the surface of the hardened, cleaned concrete was wetted and given a 1/2-inch coat of bonding mortar on all horizontal joints. The bonding mortar had the same sand-cement ratio as the concrete mix, and had a water-cement ratio such as to make a thick slurry but, at most, no greater than that for the concrete. Vertical joints in walls were provided with shear keys. Vertical joints were staggered by at least 6 inches.

The concrete was batched and mixed in an automatic batching and mixing plant located at the construction site. Approved concrete mixes were punched on cards, and the appropriate card was inserted into the control console to initiate batching. The console automatically printed out the quantities of each material in the batch, and the time, date, batch number, and mix identification for each batch. Prior to plant startup, all weighing equipment was certified. This equipment was periodically checked to ensure continuing accuracy.

A full-time PG&E inspector checked the batching and mixing operation. The maximum temperature of concrete at placement was as follows:

(1) 55°F, base slab

(2) 70°F, internal structure and exterior shell

The concrete was placed within 45 minutes after introduction of water to the mix.

Concrete placement was inspected by PG&E inspectors. The concrete was either maintained in a moist condition for 7 days by approved methods, or coated with an approved curing compound.

Concrete was sampled at the frequency required by ACI 301-1966. Sampling concrete and making, curing, and testing specimens was in accordance with:

(1)	*ASTM C 172*	*Sampling Fresh Concrete*
(2)	*ASTM C 31*	*Making and Curing Concrete Compressive and Flexural Strength Test Specimens in the Field*
(3)	*ASTM C 39*	*Compressive Strength of Molded Concrete Cylinders*
(4)	*ASTM C 143*	*Slump of Portland Cement Concrete*
(5)	*ASTM C 231*	*Air Content of Freshly Mixed Concrete by the Pressure Method*

All taking and testing of concrete samples was done by qualified PG&E personnel.

Compressive strength tests were evaluated in accordance with ACI 214-1965. PG&E specifications required that 95 percent of all cylinders tested meet or exceed the specified strength for 5000 psi concrete, and 90 percent meet or exceed the specified strength for 3000 psi concrete. The correlation between field specimens and design strengths was evaluated continuously during construction.

The average strengths and coefficients of variations of concrete tested were:

Mix	Design, psi	Cement[(a)], sacks/yd	Average Strength, psi	Coefficient of Variation	Number of Tests
Unit 1					
7AP	5000	7.5	6500	4.3%	11
8	5000	7.5	6400	6.5%	134
8A	5000	7.0	6220	8.3%	18
8AP	5000	6.6	6120	6.4%	43
9BP	3000	6.0	3800	7.0%	87
Unit 2					
8A	5000	7.0	6680	6.7%	40
8AP	5000	6.6	6200	7.1%	101

Notes:

(a) Cement and pozzolan

These coefficients of variation represent "excellent control" as defined in Table 2 of ACI 214-1965.

Concrete in Unit 1 and Unit 2 containments is Class AP for base slab and interior concrete and Class BP for cylinder and dome. Mixes designated 7AP, 8, 8A, and 8AP are Class AP. Mix 9BP is Class BP.

3.8.2.1.6.2 Reinforcing Steel

Reinforcing steel is deformed billet-steel bar conforming to ASTM Designation A 615. All reinforcing bars in the containment structure are Grade 60, except for the following, which are Grade 40:

(1) Liner anchorages in the base slab

(2) Anchorages on the structural steel beams embedded at the base of the containment structure wall

Table 3.8-1 compares the program for testing of reinforcing bars at the DCPP to the requirements of Regulatory Guide 1.15, Revision 1, which was issued after construction

at DCPP was partially complete. Table 3.8-1 also indicates those areas where the PG&E specification is more stringent than ASTM A 615.

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Heat number identification was maintained on reinforcing steel from the start of manufacture through placement in the structure.

Physical and chemical test results were sent to the construction site with the first load of steel from each heat. Test values were checked by PG&E inspectors or quality control engineers.

Detailing was in accordance with ACI Standard 315-1965, Manual of Standard Practice for Detailing Reinforced Concrete Structures. Bars to be bent were cold bent around pins of the following minimum diameters:

(1) Stirrups and ties - four times the bar diameter

(2) Number 8 bars or smaller - six times the bar diameter

(3) Numbers 9, 10, and 11 - eight times the bar diameter

(4) Numbers 14 and 18 - ten times the bar diameter

Fabrication tolerances were as follows:

(1)	*Cut length:*	
	Number 14 and 18 bars	*0 inch, -3/8 inch*
	All other bars	*±1 inch*
(2)	*Depth of truss bars:*	
	Number 18 bars	*±2 inch*
	All other bars	*0 inch, -1/2 inch*
(3)	*Stirrups, ties, and spirals:*	*±1/2 inch*
(4)	*All other bends:*	
	Number 14 and 18 bars	*±1/2 inch*
	All other bars	*±1 inch*

Placement tolerances were as follows:

(1) Concrete cover to formed surfaces:

Number 14 and 18 bars	*–1/2 inch, +2 inch*
All other bars	*±1/2 inch*

(2) Longitudinal location of bends:

Number 14 and 18 bars	*±2 inch*
All other bars	*±1 inch*

(3) Depth of bars in slabs:

8 inches or less in thickness	*±1/4 inch*
Over 8 inches in thickness	*±1/2 inch*

(4) Lateral location in the plane of reinforcing: ±2 inch

Occasionally, reinforcing steel bars had to be moved to avoid interferences. In this situation, a bar could be moved, within the plane of the reinforcing layer or curtain, up to one-half the specified spacing. If this was not sufficient, the resulting arrangement was submitted to PG&E for approval. Also, if the bar had to be moved out of the reinforcing layer or curtain to avoid an interference by more than one bar diameter or the above tolerances, whichever was greater, the resulting arrangement was submitted to PG&E for approval.

Tack welding to reinforcing bars was not permitted.

Reinforcing steel placement was inspected by contractor quality control inspectors and by PG&E inspectors.

The average and minimum properties of the tested Number 18 bars in the containment structure were as follows (these values [Yield and Tensile] are also shown in Table 3.8-6B):

(1)	*Yield*	*- minimum*	*61,750 psi*
		- average	*66,854 psi*
(2)	*Tensile*	*- minimum*	*93,750 psi*
		- average	*105,992 psi*
(3)	*Elongation*	*- minimum*	*7.0%*
		- average	*9.4%*

3.8.2.1.6.3 Splices

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

(1) Cadweld Splices

Cadweld splices were used at all locations for primary reinforcing in the exterior shell and base slab. Cadweld splices were used in a few locations in the internal structure.

Quality control procedures for Cadweld splices are described in Table 3.8-2 that compares the program used at the DCPP to that required by Safety Guide 10, March 1971. Safety Guide 10, March 1971 was issued after construction at DCPP was partially complete.

The average and minimum strengths of tested Cadweld tensile samples were:

(a)	*Minimum tensile strength*	*85,000 psi*
(b)	*Average tensile strength*	*97,725 psi*
(c)	*Number of tests*	*641*
(d)	*Number of Cadwelds placed*	*19,068*

(2) Butt-welded Splices

Butt-welded splices were used in a few locations where there was insufficient room to properly mount the Cadweld crucible. The quality control measures applied are the same as those described in Section 3.8.2.3.6.3 for butt-welded splices.

(3) Lap Splices

Lap splices are in accordance with ACI 318-1963.

3.8.2.1.6.4 Liner, Penetration Sleeves, and Penetration Internals

The containment structure liner is carbon steel, conforming to ASTM A 516, Carbon Steel Plates for Pressure Vessels for Moderate and Lower Temperature Service, Grade 70. This steel has a minimum yield strength of 38,000 psi, a minimum tensile strength of 70,000 psi, and a minimum elongation of 17 percent in an 8-inch gage length at failure.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Charpy V-notch impact tests were performed at +20°F, in accordance with ASTM A 370.

Penetration sleeves conform to one of the following three material specifications:

(1) ASTM A 106, Seamless Carbon Steel Pipe for High Temperature Service, Grade B, with the additional requirement that Charpy V-notch impact tests be performed at 0°F

(2) ASTM A 333, Seamless and Welded Steel Pipe for Low Temperature Service, Grade 1, except that Charpy V-notch impact tests are performed at 0°F

(3) ASTM A 516, Carbon Steel Plates for Pressure Vessels for Moderate and Lower Temperature Service, Grade 70, to ASTM A 300, except that Charpy V-notch impact tests were performed at 0°F

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

For all three material specifications, the Charpy impact tests were in accordance with the requirements of Paragraph N-330 of ASME BPVC Section III-1968.

Penetration internals conform to the following material specifications:

(1) Equipment and personnel hatches are ASME SA 516, Grade 70, to SA 300 with Charpy impact values at 0°F, in accordance with paragraph N-330 of ASME BPVC Section III-1968

(2) Carbon steel flued heads are ASME SA 105, Grade II, with Charpy impact tests at 0°F, in accordance with paragraph NB-2300 of ASME BPVC Section III-1971. Ultrasonic and magnetic particle inspections are performed in accordance with Paragraphs NB 2542 and NB 2545, respectively

(3) Stainless steel flued heads are ASME SA 182, Grade F 304. Ultrasonic and liquid penetrant inspections are performed in accordance with Paragraphs NB 2542 and NB 2546, respectively

Welded studs attached to the liner meet the requirements of ASTM A 108, Grade 1015-1018.

The Charpy impact test temperatures stated in the paragraphs above were selected to be at least 30°F below the lowest service temperature in accordance with ASME BPVC Section III-1968 for Class B (containment) vessels. For future repair, replacement, or alteration of ferritic containment pressure boundary material, the notch toughness test requirements of Section III, NE-2300 will be used in lieu of the original requirements.

Charpy impact tests will be performed at or below the lowest service temperature and material 5/8 inch or less in thickness will be exempt from notch toughness testing. Further information on notch toughness testing of containment materials appears in Section 3.1.8.14.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Mill test reports certifying the physical and chemical properties of the liner plate delivered to the jobsite were required from the steel supplier. The average and minimum properties of liner plate are as follows:

The Charpy impact test temperature for the hexagonal collars was selected to be at least 30°F below the lowest service temperature in accordance with ASME BPVC Section III-1968 for Class B (containment) vessels. For future repair, replacement, or alteration of the hexagonal collars, the notch toughness test requirements of Section III, NE-2300 will be used in lieu of the original requirements. Charpy impact tests will be performed at or below the lowest service temperature and material 5/8 inch or less in thickness will be exempt from notch toughness testing. Further information on notch toughness testing of containment testing materials appears in Section 3.1.8.14.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Reactor Pit and Floor Plates		*Unit 1*	*Unit 2*
Yield Strength	*- minimum*	*43,800 psi*	*39,800 psi*
	- average	*51,400 psi*	*55,100 psi*
Tensile Strength	*- minimum*	*71,000 psi*	*74,000 psi*
	- average	*76,500 psi*	*78,900 psi*
Elongation	*- minimum*	*19%*	*17%*
	- average	*25%*	*24%*
Total number of heats		*16*	*11*
Total number of slabs		*58*	*62*
Total number of tests		*58*	*62*

Cylinder and Dome		*Unit 1*	*Unit 2*
Yield Strength	*- minimum*	*41,900 psi*	*38,100 psi*
	- average	*48,800 psi*	*46,100 psi*
Tensile Strength	*- minimum*	*70,200 psi*	*70,100 psi*
	- average	*74,900 psi*	*73,681 psi*

Cylinder and Dome		*Unit 1*	*Unit 2*
Elongation	*- minimum*	*19%*	*18%*
	- average	*26.5%*	*25.4%*
Total number of heats		*23*	*22*
Total number of slabs		*251*	*255*
Total number of tests		*251*	*255*

Fabrication of the containment structure liner conforms to the applicable parts of Part UW, Requirements for Unfired Pressure Vessels Fabricated by Welding, ASME BPVC Section VIII-1968.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

All of the welds were visually examined by contractor quality control inspectors. All field welds were also visually examined by PG&E inspectors.

Table 3.8-3 compares the program for nondestructive testing of containment structure liner welds, including penetration sleeves and inserts, used on the DCPP to that required by Safety Guide 19, August 1972, which was issued after construction at DCPP was partially complete.

Erection tolerances for the liner were as follows:

The liner of the completed structure shall be substantially round. At points not more than 4 inches above the base, the radius of the 3/4-inch liner shall be 69 feet 11-13/16 inches plus or minus 1/2-inch. The maximum diameter of the 3/8-inch liner shall not exceed 140 feet 4 inches and the minimum diameter shall not be less than 139 feet 8 inches.

The liner shall be erected true and plumb. At any point the out-of-plumb shall not exceed 1/240 of the height of the point above the base. For any plate (10 feet ± in height), the out-of-plumbness shall not exceed 1/120.

Flat spots or local out-of-roundness shall not exceed 2 inches in 15 feet of arc.

The base liner shall not deviate from a plane surface between anchorages by more than 1/240.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Stud welding was in accordance with the Supplement to AWS Specification D1.0-1966. The tolerance of the location of each stud was ± 1/2-inch. At the beginning of each work day, each welder attached at least two test studs that were then tested by bending the stud approximately 45 percent toward the plate to demonstrate the integrity of the stud-to-plate weld. If failure occurred in the weld, the welding procedure or technique was corrected and two successive studs successfully welded and tested before further studs were attached to the liner plate. These test studs were allowed to remain in place but are not considered as a part of the regular stud pattern required by the design. A 100 percent visual inspection of liner and stud anchors was made prior to pouring concrete.

3.8.2.1.6.5 Structural Steel

Hexagonal collars at the equipment hatch and personnel hatch meet the requirements of ASTM A 516, Grade 70, and ASTM A 300, except that Charpy V-notch impact tests were performed at 20°F.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

The following quality control procedures were followed in the fabrication of the hexagonal steel collars at the equipment hatch and personnel hatch openings:

(1) The 4-inch-thick plate for the edge pieces was ultrasonically examined in accordance with ASTM A 435, except that scanning covered 100 percent of the surface.

(2) Fabrication conformed to the applicable parts of Part UW, Requirements for Unfired Pressure Vessels Fabricated by Welding, ASME BPVC Section VIII. All welds are full penetration butt welds and were 100 percent radiographed in accordance with Paragraph UW-51.

(3) The reinforcement plates were heat treated after fabrication in accordance with Paragraph UCS-56, Requirements for Postweld Heat Treatment, ASME BPVC Section VIII.

3.8.2.1.7 Testing and Inservice Surveillance Requirements

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

After each containment structure was complete, with liner, concrete, and all electrical and piping penetrations, equipment hatch and personnel locks in place, tests were performed as discussed in the following sections.

3.8.2.1.7.1 Structural Integrity Test

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

The structural integrity test was performed by pressurizing the containment structure with air up to 115 percent of design pressure, or 54 psig. During this test, structural deflections were measured, crack patterns in the concrete were measured and photographed, and strains in the liner and reinforcing steel measured electrically and recorded. The deflections, crack patterns, and strains were compared to the theoretical predictions to verify the structural integrity of the containment structure. The structural integrity test of each containment structure meets the requirements of Safety Guide 18, October 1971, Structural Acceptance Test for Concrete Primary Reactor Containments.

The Unit 1 containment structure is a prototype concrete primary reactor containment, as defined in Safety Guide 18, October 1971.

For the structural integrity test, the pressure was increased in increments to the maximum of 54 psig. Measurements were made at 0, 15, 25, 35, 47, and 54 psig during pressurization and again during depressurization. At each pressure level, the deflection and strain gage readings were made after a 1-hour wait to allow adjustment of strains. The crack patterns were recorded both before and immediately after the test and at the maximum pressure level achieved during the test.

The instrumentation for Unit 1 was as follows:

The radial and vertical growth was measured by means of calibrated targets attached to the exterior shell and sighted by means of high magnification theodolites. Radial deflections were measured at three points on each of six equally spaced meridians: at the springline, at mid-height of the cylinder, and at the top of the base slab. Vertical deflections were measured at the springline and at the top of the dome.

The radial and tangential deflections of the containment structure wall were measured at twelve locations adjacent to the equipment hatch, which is the largest opening.

The pattern of cracks that exceed 0.01-inch in width were mapped or photographed near the base-wall intersection, at mid-height of the wall, at the springline of the dome, and around the equipment hatch. At each location, an area of at least 40 square feet was mapped or photographed.

Strain measurements were made at the following locations, in accordance with the requirements for prototype containment structures:

(1) In the wall at the top of the base mat

(2) In the wall at the equipment hatch, with one gauge located approximately 0.5 times the wall thickness from the edge of the opening

(3) In the wall at the level of the springline

(4) In the wall where pure membrane stress is anticipated, i.e., where there are no discontinuities

Inasmuch as the concrete is assumed cracked, and the tensile strength of the concrete is neglected, strain measurements were made on the reinforcing steel and liner, rather than on the concrete. At the equipment hatch, additional strain measurements were made on the structural steel hexagonal collar. In the wall at the top of the base slab, additional strain measurements were made on the structural steel wide flange beams.

The method used for attaching strain gauges to Number 18 reinforcing bars is shown in Figure 3.8-44.

In evaluating the results of the structural integrity test, the deflection measurements were considered the most reliable result.

Strains, deflections, and crack patterns were compared to the theoretical predictions. The acceptance criterion was that actual readings had to be within 20 percent of the predicted values. This criterion was based on an evaluation of:

(1) Residual stress due to concrete shrinkage

(2) Measurement errors

(3) Temperature variations

(4) As-built deviations of the containment shell from a circular shape

(5) Actual results of other structural integrity tests (primarily at the R. E. Ginna plant)

The deflection measurement and crack mapping program for Unit 2 was identical to that for Unit 1.

3.8.2.1.7.2 Overall Integrated Leakage Rate Tests

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

During the depressurization phase of the structural integrity test, the sequence was stopped at 47 psig to conduct an overall integrated leakage rate test at design pressure.

During the overall integrated leakage rate tests, the double penetration and weld seam leak chase channel zones were open to the atmosphere inside the containment structure.

All leakage tests are conducted and evaluated in accordance with 10 CFR Part 50 Appendix J, Option B, as modified by approved exemptions (refer to Sections 6.2.1 and 6.2.4).

3.8.2.1.7.3 Sensitive Leakage Rate Tests

A sensitive leakage rate test can be performed with only the volume of the weld seam leak chase channels and double penetrations included in the test. This sensitive leakage rate test would be performed with penetrations and leak chase channels at not less than the peak calculated containment internal pressure (Pa), and with the containment structure at atmospheric pressure.

3.8.2.1.7.4 Inservice Surveillance Requirements

Periodic leakage rate testing is performed in accordance with the requirements of 10 CFR Part 50 Appendix J. Inservice surveillance to ensure continued containment integrity is discussed in Section 6.2.1.3.8. Instrumentation employed to monitor containment status is described in Section 6.2.1.5.

3.8.2.2 Pipeway Structures

3.8.2.2.1 Description of Pipeway Structures

The pipeway structure for each unit is a steel frame structure attached to the outside of the containment shell, the auxiliary building, and the turbine building as shown in Figure 3.8-80. The pipeway structure in one unit is essentially a mirror image of the other. The primary function of the pipeway structure is to support main steam and feedwater piping. The pipeway structure has five major platforms located at elevations 109, 114, 118, 127, and 138 feet. Connections between the pipeway structure and the auxiliary and turbine buildings are provided with slotted holes oriented such that horizontal motions cannot be transmitted between the structures.

3.8.2.2.2 Applicable Codes, Standards, and Specifications

3.8.2.2.2.1 Codes

The following codes and standards are used, insofar as they are applicable, in the design and/or construction of the pipeway structure.

(1) AISC Specification for Design, Fabrication, and Erection of Structural Steel for Buildings, February 1969

(2) ACI Standard Building Code Requirements for Reinforced Concrete (ACI-318-1963)

(3) Standard code for welding in building construction (AWS D1.0-1969). For inspection of non-ASME structural welds or new non-ASME work performed after January 1, 1988, the guidelines of Nuclear Construction Issues Group (Visual Weld Acceptance Criteria, Vol. 1-3, EPRI Report No. NP-5380, September 1987) may be used except for those cases where:

a) Fatigue is a governing design condition.

b) The weld allowables are permitted to be higher than those allowed by AWS D1.1 (such as the full penetration weld evaluation for the HE). [(a)]

c) The weld is part of work performed in the ASME BPVC Section XI Inservice Inspection Program.

(4) Materials, and the quality control tests for materials, conform primarily to ASTM and ASME standards. Additional materials and supplemental QA requirements conform to ANSI standards

Note:

(a) PG&E identified that some of the welds in this category had been inspected using the visual weld acceptance criteria contained in EPRI Report No. NP-5380. PG&E evaluated the impacts of this weld inspection criteria deviation and determined that the welds are acceptable as-is.

3.8.2.2.3 Loads and Loading Combinations

3.8.2.2.3.1 Design Loads

The following loads are considered in the design of the pipeway structure.

3.8.2.2.3.1.1 Dead Loads

Dead loads consist of the weight of the structure, piping, pipe rupture restraints, electrical raceways, and equipment.

3.8.2.2.3.1.2 Live Loads

Live loads are temporary loads that may be placed on the structure. These are considered small in relative magnitude and, therefore, are considered negligible.

3.8.2.2.3.1.3 Earthquake Loads

Earthquake loads are as described in Section 3.7.2.3.

3.8.2.2.3.1.4 Wind Loads

Wind loads are determined in accordance with the criteria presented in Section 3.3. However, the forces due to wind are much less than those due to earthquake; consequently, seismic loads, rather than wind, are entered into the load combination equations.

3.8.2.2.3.1.5 Thermal Loads

Thermal loads are those induced by thermal growth of the main steam and feedwater pipes through the support system. These loads are considered negligible.

3.8.2.2.3.2 Loading Combinations

The following loading combinations are used in the design of the pipeway structure.

3.8.2.2.3.2.1 Normal Conditions

Dead loads and DE are considered as follows:

$$S = D + DE \tag{3.8-35}$$

where:

S = required section strength based on elastic design methods and allowable stresses defined in Part 1 of the AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, February 1969
D = dead load
DE = loads resulting from the DE

3.8.2.2.3.2.2 Abnormal Conditions

Where elastic working stress design methods are used:

$$1.6S = D + DDE \tag{3.8-36}$$

$$1.7S = D + DDE + Yr \tag{3.8-37}$$

$$1.7S = D + 1.25DE + Yr \tag{3.8-38}$$

$$1.7S = D + HE \tag{3.8-39}$$

Where plastic design methods are used:

$$1.0Y = D + DDE + Yr \quad (3.8\text{-}40)$$

$$1.0Y = D + 1.25DE + Yr \quad (3.8\text{-}41)$$

where:

DDE = loads resulting from the DDE
HE = loads resulting from the HE
Yr = reaction on structure from a broken pipe, generated by a postulated pipe break, including an appropriate DLF
Y = required section strength based on plastic design methods described in Part 2 of the AISC specification referenced in Section 3.8.2.2.2.1

3.8.2.2.4 Design and Analysis Procedures

3.8.2.2.4.1 Hosgri Event

Seismic forces from the response spectrum dynamic analysis described in Section 3.7.2.3 are used in the stress evaluation of the Unit 1 pipeway structure. The Unit 2 pipeway structure is evaluated using a detailed 3-D model and the static equivalent method of seismic analysis described in Section 3.7.2.3. The calculated stress ratios for the most critical members are given in Table 3.8-5A.

3.8.2.2.4.2 Design Earthquake and Double Design Earthquake

Member forces are calculated using corresponding Hosgri forces adjusted in proportion to ratios of DE or DDE to HE spectral accelerations. These forces are used in the stress evaluation of the Unit 1 and Unit 2 pipeway structures. Stresses obtained by this method are confirmed by time-history dynamic analysis described in Section 3.7.2.3. Calculated stress ratios for the most critical members are given in Table 3.8-5A.

3.8.2.2.4.3 Computer Programs

Computer programs used in the structural analysis and the verification measures are listed in Table 3.8-6.

3.8.2.2.5 Structural Acceptance Criteria

For DE and DDE load combinations in the absence of pipe break loads (Yr), the minimum specified yield strength for structural steel is considered. For load combinations including HE or Yr, the average yield strength of structural steel, based on properly substantiated test results, is used. However, in no case are the yield values used in strength computations of structural steel greater than 70 percent of the corresponding average ultimate strength values determined by the tests (Reference 36). In addition, the following conditions apply.

3.8.2.2.5.1 Normal Conditions

For normal conditions, the pipeway structure is designed to the allowable working stresses in Part 1 of the AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, February 1969; however, the increase in allowable stress usually allowed for load combinations involving earthquake forces is not used.

3.8.2.2.5.2 Abnormal Conditions

For abnormal conditions, the pipeway structure, in general, is designed for overall elastic behavior. For load combinations (3.8-37), (3.8-38), (3.8-40), and (3.8-41) of Section 3.8.2.2.3.2.2, the acceptance criteria described therein should be satisfied first without considering the effect of Yr. When considering the effect of Yr, local section strength capacities may be exceeded provided there is no loss of function of any safety-related system.

3.8.2.2.5.3 Factors of Safety

The calculated capacity-to-demand ratio for the most critical members of the pipeway structure are given in Table 3.8-5A. In all cases these ratios are greater than the minimum allowable value of 1.0. Therefore, all structural elements satisfy the criteria.

3.8.2.2.6 Materials, Quality Control, and Construction Techniques

Structural steel is ASTM A441 and ASTM A516 Grade 70. ASTM minimum specified values are used with DE and DDE load combinations in the absence of Yr. Average test values, properly substantiated test results, are used with load combinations that include HE or Yr (Reference 36). Minimum and average values are as follows:

	ASTM A441	ASTM A516
Minimum yield strength, psi	45,000	38,000
Average yield strength, psi	51,600	51,040

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

High strength bolts, nuts, and washers used for connections are predominantly ASTM A490. Some ASTM A325 bolts are also used when found acceptable.

Impact tests for structural steel and high strength bolts were performed in accordance with ASTM Standard Method A370 at 0°F.

Welding electrodes conform to ASTM A233, E70 series low hydrogen.

Where indicated on drawings, nondestructive testing was performed as required utilizing ultrasonic or magnetic particle techniques.

Approved substitute for ASTM A441 structural steel is ASTM A572 Grade 42. For any new construction after May 2004, the structural steel used may be A572 Grade 42. The impact test is required for this new steel.

3.8.2.3 Auxiliary Building and Fuel Handling Building

3.8.2.3.1 Description of the Auxiliary Building

The auxiliary building is located between the Unit 1 and Unit 2 containment structures. It contains the control room that includes consoles and a fuel handling building for each unit. In addition, the auxiliary building contains equipment for the CVCSs, the SI systems, the RHR systems, the CCW systems, the liquid radwaste systems, the gaseous radwaste system, and others.

The main floor levels in the auxiliary building are at elevations 85, 100, 115, and 140 feet. Elevations 55, 60 and 73 feet are below ground level, which is at elevation 85 feet, except for the east side of the building where ground level is at elevation 115 feet. Floor plans at elevations 100, 115, and 140 feet are shown in Figures 3.8-60 through 3.8-62.

The foundation of the auxiliary building is divided between 3 elevations. The structure is supported at elevations 85 feet (Areas GE, GW, and L) 100 feet (Area J), and elevation 60 feet (Areas H and K).

Figure 1.2-2, Plant Layout, shows relative locations of the plant buildings. The general arrangement of equipment in the auxiliary building, including the fuel handling areas, is shown in Figures 1.2-4 through 1.2-11, Figures 1.2-21 through 1.2-26, and Figures 1.2-29 and 1.2-30. Generally, one-half of the auxiliary building is a mirror image of the other, with each half of the structure containing equipment for one unit. The control room is located at elevation 140 feet. The two fuel handling areas that contain the SFPs, the fuel handling cranes, fuel racks, and related equipment are located on each side of the east end of the auxiliary building with the top of the SFPs at elevation 140 feet.

The auxiliary building is a reinforced concrete shear wall structure, except for the fuel handling area crane support structure which is a structural steel moment resisting and braced frame structure supported on elevation 140 feet and extending up to elevation 188 feet. The shear walls and slabs of the auxiliary building are generally 2 feet thick.

The walls of the SFPs are 6 feet thick except for local areas around the fuel transfer tubes. The foundation slabs under the SFPs have a minimum thickness of 5 feet. The SFP sides and bottoms are lined with stainless steel, 1/4-inch-thick on the bottoms and 1/8-inch nominal thickness on the sides. Representative concrete outlines, reinforcing steel arrangements, and structural steel details for the auxiliary building are shown in Figures 3.8-45 through 3.8-59.

The 125-ton overhead crane in the fuel handling area, shown in Figure 3.8-59, is equipped with restraints that prevent derailing from motions associated with an earthquake.

The only connections between the auxiliary building and other structures are the fuel transfer tube, miscellaneous piping, and attachments to the pipeway structure. The fuel transfer tube is fitted with expansion bellows that allow relative movement between the auxiliary building, the containment structure exterior shell, and the internal structure of the containment structure. The design of the expansion bellows considers the maximum axial and lateral relative deflection. Piping systems are analyzed for the maximum relative displacements of the auxiliary building and other structures, and the piping anchor points in the structures are designed to withstand the resulting forces.

3.8.2.3.2 Applicable Codes, Standards, and Specifications

The following codes and standards are used in the design, construction, inspection, and testing of the auxiliary building and fuel handling area crane support structure:

(1) ACI Standard Building Code Requirements for Reinforced Concrete (ACI 318-1963), except that design loading combinations are as described in Section 3.8.2.2.3.2

(2) Manual of Standard Practice for Detailing Reinforced Concrete Structures (ACI 315-1965)

(3) Recommended Practice for Evaluation of Compression Test Results of Field Concrete (ACI 214-1965)

(4) Inspection of the Cadweld Rebar Splice (Erico Products, Inc., RB-5M768)

(5) Recommended Practices for Welding Reinforcing Steel, Metal Inserts, and Connections in Reinforced Concrete Construction, AWS D12.1-1961

(6) AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, February 1969

(7) Code for Welding in Building Construction, AWS D1.0-1969. Work performed prior to December 12, 1969 is in accordance with the earlier edition, AWS D1.0-1966. For inspection of non-ASME structural welds or

new non-ASME work performed after January 1, 1988, the guidelines of Nuclear Construction Issues Group (Visual Weld Acceptance Criteria, Vol. 1-3, EPRI Report No. NP-5380, September 1987) may be used except for those cases where:

(a) Fatigue is a governing design condition.

(b) The weld allowables are permitted to be higher than those allowed by AWS D1.1 (such as the full penetration welds evaluation for HE). [a]

(c) The weld is part of work performed in the ASME BPVC Section XI Inservice Inspection Program.

(8) Stud welding is in accordance with the Supplement to AWS Specifications AWS D1.0-1966 and AWS D2.0-1966 on Requirements for Stud Welding

(9) Materials and the quality control tests for materials conform to ASTM standards

Regulatory Guide 1.15, Revision 1, Testing of Reinforcing Bars for Category I Concrete Structures (dated December 28, 1972), and Regulatory Guide 1.55, June 1973, Concrete Placement in Category I Structures (dated June 1973), were issued after construction of the DCPP was nearly complete. A comparison of the program used for the DCPP with the regulatory position of Regulatory Guide 1.15, Revision 1, is presented in Table 3.8-1. The comparisons in Tables 3.8-1 through 3.8-3 are provided for information only. PG&E is not committed to the regulatory guidance documents compared in the tables. The PG&E Design Class I auxiliary building is in accordance with the accepted industry codes and standards that were in effect during the design and construction of DCPP. The QA program for the DCPP meets the requirements of Regulatory Guide 1.55, June 1973. In regard to Regulatory Guide 1.55, June 1973, the references used for guidance are those listed in Appendix A of the regulatory guide, as they existed at the time of the PSAR.

Note:

(a) PG&E identified that some of the welds in this category had been inspected using the visual weld acceptance criteria contained in EPRI Report No. NP-5380. PG&E evaluated the impacts of this weld inspection criteria deviation and determined that the welds are acceptable as-is.

3.8.2.3.3 Loads and Loading Combinations

3.8.2.3.3.1 Design Loads

The following loads are considered in the design of the auxiliary building and the fuel handling area crane support structure.

3.8.2.3.3.1.1 Dead Loads

Dead loads consist of the weight of the structure, and permanent equipment loads.

3.8.2.3.3.1.2 Live Loads

Live loads consist of temporary equipment loads and a uniform load to account for the miscellaneous temporary loadings that may be placed on the structure.

3.8.2.3.3.1.3 Earthquake Loads

Earthquake loads are based on a time-history modal superposition analysis. This analysis is described in Section 3.7.2.

3.8.2.3.3.1.4 Wind Loads

Wind loads are determined in accordance with the criteria presented in Section 3.3. However, considering the UBC and ASCE Paper 3269 pressures, the forces due to wind are much less than those due to earthquake; consequently, seismic loads, rather than wind, are entered into the load combination equations.

3.8.2.3.3.1.5 Thermal Loads

Thermal loads are loads induced by local increases in temperature. Thermal loads result from normal operating conditions and from postulated accident conditions.

3.8.2.3.3.1.6 Pipe Reaction Loads

Pipe reactions that result from hydraulic forces, thermal expansion, and seismic events, are transferred to the structure through pipe supports. Pipe reaction loads result from normal operating conditions and postulated accident conditions.

3.8.2.3.3.1.7 Jet and Missile Loads

Jet and missile loads are localized forces on structures in the immediate vicinity of a postulated pipe break. Jet forces result from the impingement of high energy fluid on an object. Missile forces result when a part possessing kinetic energy strikes an object.

Missile forces are calculated by the methods described in Section 3.5. Jet forces and pipe reactions from a postulated broken pipe are calculated as described in Section 3.6.

3.8.2.3.3.1.8 Pressure Loads

Pressure loads are forces generated by a postulated pipe break. Pressures from a postulated broken pipe are calculated as described in Section 3.6.

3.8.2.3.3.2 Loading Combinations

3.8.2.3.3.2.1 Normal Conditions

Dead load, live load, loads from the DE, thermal loads, and pipe reactions are considered in all possible combinations. Inasmuch as working stress design is used for normal operating loads, the factored load approach is not used. For each structural member, the combination of these loads that produces the maximum stress is used for design. Stated in equation form:

$$C = D + L + DE + T_o + R_o \qquad (3.8\text{-}14)$$

where:

C	=	required capacity of member based on the methods described in Section 3.8.2.2.5.1
D	=	dead load of structure and equipment loads
L	=	live load
DE	=	loads resulting from the DE
T_o	=	thermal loads during normal operating conditions
R_o	=	pipe reactions during normal operating conditions

3.8.2.3.3.2.2 Abnormal Conditions

Dead load, live load, earthquake loads, and loads associated with accidental pipe rupture are considered in the following combinations; for each structural member, the combination that produces the maximum stress is used for design:

Concrete Structural Elements

$$U = D + L + T_A + R_A + 1.5\ P_A \qquad (3.8\text{-}15)$$

$$U = D + L + T_A + R_A + 1.25\ P_A + 1.0\ (Y_j + Y_m + Y_r) + 1.25\ DE \qquad (3.8\text{-}16)$$

$$U = D + L + T_A + R_A + 1.0\ P_A + 1.0\ (Y_j + Y_m + Y_r) + DDE \qquad (3.8\text{-}17)$$

$$U = D + L + T_A + R_A + 1.0\ P_A + 1.0\ (Y_j + Y_m + Y_r) + HE \qquad (3.8\text{-}18)$$

where:

T_A = thermal loads on structure generated by a postulated pipe break, including T_O

R_A = pipe reactions on structure from unbroken pipe generated by postulated pipe break conditions, including R_O

PA = pressure load within or across a compartment and/or building generated by a postulated pipe break, and including an appropriate DLF to account for the dynamic nature of the load

Y_j = jet load on structure generated by a postulated pipe break, including an appropriate DLF

Y_m = missile impact load on a structure generated by, or during, a postulated pipe break, such as a whipping pipe, including an appropriate DLF

Y_r = reaction on structure from broken pipe generated by a postulated pipe break, including an appropriate DLF

U = ultimate strength required to resist design loads based on the methods described in ACI 318-1963. Refer to Section 3.8.2.2.5.2 for equation 3.8-16 through 3.8-18

DDE = loads resulting from the DDE

HE = loads resulting from an HE

Steel Structural Elements

Where elastic working stress design methods are used[(a)(b)]:

$$1.6S^{(a)} = D + L + T_A^{(b)} + R_A + P_A \quad (3.8\text{-}19)$$

$$1.6S^{(a)} = D + L + T_A^{(b)} + R_A + P_A + 1.0\left(Y_j + Y_m + Y_r\right) + DE \quad (3.8\text{-}20)$$

$$1.6\mathrm{S}^{(a)} = \mathrm{D} + \mathrm{L} + \mathrm{T}_A^{(b)} + \mathrm{R}_A + \mathrm{P}_A + 1.0\left(\mathrm{Y}_j + \mathrm{Y}_m + \mathrm{Y}_r\right) + \mathrm{DDE} \quad (3.8\text{-}21)$$

$$1.7S = D + L + T_A^{(b)} + R_A + 1.0P_A + 1.0\left(Y_j + Y_m + Y_r\right) + HE \quad (3.8\text{-}22)$$

Where plastic design methods are used:

$$0.90Y^{(a)} = D + L + T_A^{(b)} + R_A + 1.5P_A \quad (3.8\text{-}23)$$

$$0.90Y^{(a)} = D + L + T_A^{(b)} + R_A + 1.25P_A + 1.0(Y_a + Y_m + Y_r) + 1.25DE \quad (3.8\text{-}24)$$

$$0.90Y^{(a)} = D + L + T_A^{(b)} + R_A + 1.0P_A + 1.0(Y_j + Y_m + Y_r) + DDE \quad (3.8\text{-}25)$$

$$1.0Y = D + L + T_A^{(b)} + R_A + 1.0P_A + 1.0(Y_j + Y_m + Y_r) + HE \quad (3.8\text{-}26)$$

where:

S = required section strength based on elastic design methods and the allowable stresses[(c)] defined in Part 1 of the AISC Specifications for the Fabrication and Erection of Structural Steel for Buildings, February 1969

Y = required section strength based on plastic design methods[(c)] described in Part 2 of AISC Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, February 1969

For both concrete and steel structural elements, both cases of L having its full value present during the postulated pipe rupture, or being completely absent, are checked.

Notes:

(a) For existing structures, the 1.6 factor applied to the required section strength, S, and the 0.90 reduction factor applied to the required section strength, Y, are increased to 1.7 and 1, respectively. In such situations, however, it is verified that deflections will not result in the loss of function of any safety-related system.

(b) Thermal loads are neglected when it can be shown that they are secondary and self-limiting in nature and where the material is ductile.

(c) Refer to Section 3.8.2.2.5 regarding material properties used in conjunction with load combinations including HE.

3.8.2.3.4 Design and Analysis Procedures

Structural analysis of the auxiliary building is performed by the traditional methods of engineering analysis for structural steel and reinforced concrete structures. These methods are based on the principles of equilibrium, compatibility of deformations, and predictions of material strength by the methods of the AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, February 1969 (AISC Code), and the ACI Standard Building Code Requirements for Reinforced Concrete (ACI Code).

The use of these codes is discussed in Section 3.8.2.2.5. The following sections discuss the specific design methods used for the structural steel and concrete parts of the auxiliary building.

3.8.2.3.4.1 Structural Steel

The fuel handling area crane support structure is a 370 x 60 x 50-foot high steel framed structure clad with metal siding and covered by metal decking and built-up roofing. The structure is supported on concrete walls at elevation 140 feet on the eastern side of the auxiliary building. Lateral forces are resisted by steel cross-braced frames in the north-south direction, moment resisting frames in the east-west direction, and by the roof, which is a trussed and cross-braced diaphragm covered with metal decking. Slotted holes are provided at certain structural connections to relieve an uneven distribution of forces throughout the structure.

Acceleration profiles and forces from the analyses described in Section 3.7.2 are applied to a detailed static model of the entire fuel handling area crane support structure to obtain forces for the stress evaluation of the structural members and connections and to obtain structural displacements. Various crane and lifted load positions are considered. The stress evaluation is carried out for the load combinations described in Section 3.8.2.3.3. Stresses are evaluated against the criteria in Section 3.8.2.3.5. The calculated stress ratios for the most critical members are given in Table 3.8-7.

3.8.2.3.4.2 Concrete

The vertical and the lateral load-resisting system of the auxiliary building consists of reinforced concrete columns and walls tied together with reinforced concrete slabs. The evaluation of these elements is carried out for the loading combinations given in Section 3.8.2.2.3, according to the criteria in Section 3.8.2.2.5.

The seismic forces and moments are based on the response of the auxiliary building seismic models described in Section 3.7. A detailed analytical model of the auxiliary building is then developed to distribute forces and moments to the various walls, diaphragms, and columns.

Slabs

Slabs are evaluated separately for out-of-plane loads and in-plane loads.

For out-of-plane loads, shear stresses and moments are calculated assuming one-way or two-way slab action as appropriate. Out-of-plane capacity-to-demand ratios for selected slabs are shown in Tables 3.8-8 through 3.8-10. The slab in-plane capacities are investigated at critical sections. The selection of these sections is based on the location of numerous openings across the entire section of the diaphragm and the magnitudes of shear, moment, and axial forces on the entire section. The in-plane

capacity-to-demand ratios for the concrete slabs are shown in Tables 3.8-11 through 3.8-13.

Walls

The critical wall elements are selected based on the magnitude of demand loads and presence of openings. The forces and moments for the governing load combination in those elements are compared to their respective capacities, and the capacity-to-demand ratios are shown in Tables 3.8-14 through 3.8-16.

Concrete Columns

The concrete columns are evaluated for axial and flexural loads. Flexural loads on columns due to the vertical loads are determined by considering frame action with the slabs. Flexural loads include the effect of minimum eccentricity specified by ACI 318-1963. Column moments due to inter-story drift are found to be negligible. Capacity-to-demand ratios for selected columns are shown in Table 3.8-17.

3.8.2.3.4.3 Load Dissipation to the Foundation

The adequacy of the structural system, at and below elevation 85 feet, to dissipate lateral loads to the rock foundation is evaluated for the load combinations given in Section 3.8.2.2.3.2. The results, given in Tables 3.8-18 through 3.8-23, and illustrated for HE loads in Figures 3.8-63 and 3.8-64, indicate the adequacy of the system to dissipate the loads.

3.8.2.3.4.4 Computer Programs

Computer programs used in the structural analysis, and the verification measures used, are listed in Table 3.8-6.

3.8.2.3.5 Structural Acceptance Criteria

For DE and DDE load combinations, the nominal design strength for concrete and specified yield strength for reinforcing and structural steel are considered. For load combinations including HE, however, the average material properties, based on properly substantiated test results, are used (Reference 36). Refer to Sections 3.8.3.1.6.1, 3.8.3.1.6.2, and 3.8.3.1.6.3 for material properties associated with concrete, reinforcing steel, and structural steel, respectively. Refer to Section 3.8.2.3.6.5 for allowable stresses for bolted connections. Ductility, when applied for HE load combinations, is in accordance with Table 3.8-24.

3.8.2.3.5.1 Normal Loads

For normal loads, the auxiliary building is designed for the allowable working stresses of ACI 318-1963, as supplemented by Section 3.8.2.3.3.2.1, and Part 1 of the AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, February 1969, except that the increase in allowable stress usually allowed for load combinations involving earthquake forces is not used.

3.8.2.3.5.2 Abnormal Loads

For abnormal loads, the auxiliary building is designed for overall elastic behavior. For concrete elements, the strength design method of ACI 318-1963 applies, as supplemented by Section 3.8.2.3.5.3. For the evaluation of steel elements using elastic design methods, the allowable stresses are defined in Part 1 of AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, February 1969. For the evaluation of steel elements using "plastic design," Part 2 of the same AISC February 1969 specification applies.

The capacity for the various concrete structural elements is based on the yield strength of the material, reduced by a factor, f, which provides for the possibility that small, adverse variations in material strengths, workmanship, dimensions, and control, while individually within required tolerances and the limits of good practice, occasionally may be additive. The f-factors used are in accordance with ACI 318-1963.

For load combinations involving Y_j, Y_m, and Y_r, local stresses due to these concentrated loads may exceed the allowable provided there is no loss of function. Refer to Reference 6, Enclosure Number 3, Document (B), for more detailed information concerning the acceptance criteria for these load combinations.

3.8.2.3.5.3 In-Plane Loads on Concrete Elements

The design of slab diaphragms and shear walls for in-plane forces is not explicitly covered by ACI 318-1963. Section 104 of ACI 318-1963 allows criteria based on test data to be used for the design of elements not covered by its provisions. Consequently, the document entitled "Recommended Evaluation Criteria for Diablo Canyon Nuclear Power Plant Auxiliary Building Walls and Diaphragms" (Reference 7) is developed to provide criteria for evaluation of auxiliary building shear walls and floor diaphragms for in-plane seismic forces, including the simultaneous effects of out-of-plane forces.

Accordingly, the structural elements are evaluated as follows:

(1) The columns are evaluated by the provisions of ACI 318-1963 for all loading conditions.

(2) The slabs and walls are evaluated for out-of-plane loads according to ACI 318-1963, and for in-plane loads according to Reference 7.

3.8.2.3.5.4 Factors of Safety

The calculated capacity-to-demand ratio for selected structural elements of the auxiliary building are given in Tables 3.8-7 through 3.8-17. In all cases, these ratios are greater than the minimum allowable value of 1. Therefore, all structural elements satisfy the criteria.

The gap between the auxiliary building and the containment structure, as well as the factor of safety against the structure impacting during a seismic event, is discussed in Section 3.8.2.1.5.3. Separations between the auxiliary building and the turbine building are adequate to ensure these structures will not impact each other when subject to design load combinations. Calculated displacements, separations, and factors of safety against impact are shown in Table 3.8-23A.

3.8.2.3.6 Materials, Quality Control, and Special Construction Techniques

Sections 3.8.2.1.6.1 and 3.8.2.1.6.2 for the containment structure also apply to the auxiliary building, except as superseded by information in the following paragraphs.

3.8.2.3.6.1 Concrete

Concrete strengths are shown below.

Walls and slabs below elevation 85 feet; slabs 4 feet and thicker at elevation 85 feet; slab at elevation 85 feet bounded by column lines 16.8 - 19.2 - L - H:

Design f'c = 3000 psi (DE and DDE combinations)

All other concrete:

Design f'c = 5000 psi (DE and DDE combinations)

Average 28-day strengths are used with HE load combinations (Reference 36). The average strengths of representative mixes are as follows:

Design Strength	Average 28-day Strength	Number of Tests
3000 psi	3920 psi	167
5000 psi	5650 psi	368

3.8.2.3.6.2 Reinforcing Steel

Reinforcing steel is ASTM A 615, Grade 40, except in some locations where Grade 60 is used. ASTM minimum values are used with DE and DDE load combinations.

Average test values, based on properly substantiated test results, are used with HE load combinations (Reference 36). The average and minimum properties of representative bar sizes, are as follows:

	#8		#11	
	Grade 40	Grade 60	Grade 40	Grade 60
Design Yield Strength, psi	40,000	60,000	40,000	60,000
Average Yield Strength, psi	49,655	66,189	48,302	68,582
Minimum Yield Strength, psi	41,200	60,250	42,950	61,710
Average Tensile Strength, psi	82,236	102,403	81,074	105,822
Minimum Tensile Strength, psi	74,392	96,500	72,940	94,390
Average Elongation, %	18.9	13.94	14.82	14.41
Minimum Elongation, %	13.0	11.0	8.5	9.4
Total Number of Heats	67	18	91	56

3.8.2.3.6.3 Splices

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

The majority of splices in the auxiliary building are lap splices, made in accordance with ACI 318-1963. Cadweld splices are used in some locations in the auxiliary building. The quality control procedures described for Cadweld splices in the containment structure also apply to Cadweld splices in the auxiliary building.

Butt-welded splices are used where a section of wall has to be temporarily left open for access, and in certain other locations. Butt-welded splices are made in accordance with ACI 318-1963, and the American Welding Society's Recommended Practices for Welding Reinforcing Steel, Metal Inserts, and Connections in Reinforced Concrete Construction, using the "short-arc" process or low hydrogen stick electrodes by the shielded arc process. Both processes have minimum preheat and interpass temperatures of 400°F. Completed welds are wrapped with a protective blanket of insulating material to avoid rapid cooling.

Procedure qualification and welder qualification are as follows:

(1) A welding procedure qualification test is made for each position and for each grade and size of bar. The test consists of two tension tests and one nick break test. Bars may not be rolled during welding.

(2) Welder qualification tests are made for each position, type of electrode, grade and size of bar, and joint design. Qualification for one size of bar is considered qualification for all smaller sizes. Each test consists of one tension and one nick break test. Bars may not be rolled during welding.

(3) Tension specimens are tested to failure and must comply with the minimum tensile requirements for the grade of reinforcing steel.

(4) The nick break specimen is broken and visually examined for soundness. The specimen must exhibit the following: the sum of the longest dimension of all inclusions visible in any one joint must not exceed ½-inch; no inclusion may be closer to the weld surface than a distance equal to the largest dimension of the inclusion; there must be no incomplete fusion or lack of penetration or cracks in the weld or base metal.

Testing percentages applicable to butt-welded splices for each welder, position, and grade of bar are as follows:

(1) Two out of the first ten splices

(2) Six out of the next 90 splices

(3) Four out of second and subsequent 100 splice units

Qualification for one size of bar is considered as qualification for all smaller sizes.

3.8.2.3.6.4 Structural Steel

Structural steel is ASTM A 36 and ASTM A 441; ASTM minimum values are used with DE and DDE load combinations, and average test values, based on properly substantiated tests, are used with HE load combinations. However, in no case are the yield values used in strength computations of structural steel greater than 70 percent of the corresponding average ultimate strength values determined by the tests (Reference 36). Minimum and average values are as follows:

	ASTM A36	ASTM A441
Design Yield (ksi)	36	42

Testing of structural steel installed through 1977 gave the following:

	ASTM A36	ASTM A441
Average Test Yield (ksi)	43.95	51.62
Average Test Ultimate (ksi)	68.04	75.91

Charpy impact tests were performed on all structural steel at the following temperature:

Framing for pipe rupture restraints	40°F
Structural steel	20°F

3.8.2.3.6.5 Structural Bolts

Structural bolts are ASTM A307, A325, and A490, allowable stresses per Table 1.5.2.1 of the AISC Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, February 1969, are used with the DE, DDE, and HE load combinations. However, it is acceptable to increase the allowable stresses for the HE load combinations, based on the results of properly substantiated testing (References 34 through 38).

3.8.2.4 PG&E Design Class I Outdoor Water Storage Tanks

3.8.2.4.1 Description of the Outdoor Water Storage Tanks

The PG&E Design Class I outdoor water storage tanks, located adjacent to the east side of the auxiliary building, are steel studded tanks with concrete shielding, as shown in Figure 3.8-65, Sheets 1 and 2.

There are two RWSTs and two CSTs, one to service each unit of the plant. The firewater and transfer tank, which serves both Unit 1 and Unit 2, is made up of two concentric cylindrical steel tanks connected by a common dome roof. The inner cylindrical tank is the firewater tank and the outer tank is the transfer tank. The structural configuration of the CSTs is similar to that of the RWSTs.

The PG&E Design Class I outdoor water storage tanks are supported on concrete fill down to bed rock and are anchored to bed rock with rock anchors as shown in Figure 3.8-65, Sheet 2.

3.8.2.4.2 Applicable Codes, Standards, and Specifications

The following codes and standards are used in the design, construction, inspection, and testing of the outdoor water storage tanks.

(1) ACI Standard Building Code Requirements for Reinforced Concrete (ACI 318-1963, and ACI 318-1971)

(2) Manual of Standard Practice for Detailing Reinforced Concrete Structures (ACI 315-1965)

(3) Recommended Practices for Welding Reinforcing Steel, Metal Inserts, and Connections in Reinforced Concrete Construction, AWS D12.1-1975

(4) AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, April 1963, and AISC, February 1969

(5) Code for Welding in Building Construction, AWS D1.1-1977, Revision 2. Work performed prior to (December 12, 1969) is in accordance with the

earlier edition, AWS D1.0-1966. For inspection of non-ASME structural welds or new non-ASME work performed after January 1, 1988, the guidelines of Nuclear Construction Issues Group (Visual Weld Acceptance Criteria, Vol. 1-3, EPRI Report No. NP-5380, September 1987) may be used except for those cases where:

(a) Fatigue is a governing design condition.

(b) The weld allowables are permitted to be higher than those allowed by AWS D1.1-1977 (such as full penetration weld evaluation for the HE). [(a)]

(c) The weld is part of work performed in the ASME BPVC Section XI Inservice Inspection Program.

(6) Stud loading is in accordance with the Supplement to AWS Specifications AWS D1.0-1966 and AWS D2.0-1966 on Requirements for Stud Welding

(7) Materials and quality control tests for materials conform to ASTM standards

(8) ASME BPVC Section VIII-1974, Division 2

(9) AWWA D100-1967, American Waterworks Association, Standard to Steel Tanks, Standpipes Reservoirs and Elevated Tanks for Water Storage

Note:

(a) PG&E identified that some of the welds in this category had been inspected using the visual weld acceptance criteria contained in EPRI Report No. NP-5380. PG&E evaluated the impacts of this weld inspection criteria deviation and determined that the welds are acceptable as-is.

3.8.2.4.3 Loads and Loading Combinations

3.8.2.4.3.1 Normal Conditions

$$C = D + HS + 1.0\ DE + 1.0\ R_O \qquad (3.8\text{-}27)$$

where:

C	=	required load capacity of section as described in Section 3.8.2.3.5.1
D	=	dead load of tank
HS	=	hydrostatic load
DE	=	loads resulting from DE
R_O	=	pipe reactions during normal operating conditions, including dead,

thermal, and DE loads.

3.8.2.4.3.2 Abnormal Conditions

$$U = D + HS + 1.0\ DDE + 1.0\ R_A \quad (3.8\text{-}28)$$

$$U = D + HS + 1.0\ HE + 1.0\ R_A \quad (3.8\text{-}29)$$

where:

D and HS are defined in Section 3.8.2.4.3.1, and

U	=	strength required to resist abnormal loads as described in Section 3.8.2.2.5.2
DDE	=	loads resulting from the DDE
HE	=	loads resulting from the HE
R_A	=	pipe reactions during abnormal conditions, including dead, thermal, and DDE or HE loads

3.8.2.4.4 Design and Analysis Procedures

CSTs, the RWSTs, and the fire water and transfer water tanks were originally designed to meet the criteria based on the DE, DDE, and HE. The code used in designing the tanks was AWWA D100-1967, with stress allowables restricted to those permitted by ASME BPVC Section VIII-1974, Division 2. Revised security criteria called for additional resistance to bullet penetration and explosives and required all the above steel tanks to be modified with minimum reinforced concrete protection as determined by Argonne National Laboratory. The PG&E Design Class I tanks with concrete protection were reevaluated for DE, DDE, and HE using finite-element computer models as described in Section 3.7.

The stresses in the stiffeners and the steel liner plate around the vault openings were determined by hand calculation and compared with the stress allowables. The forces, moments, and stresses in the RWST resulting from dead load, hydrostatic pressure, hydrodynamic loads, and seismic loads are listed in Table 3.8-25. These values are within the allowable limits as described in Section 3.8.2.4.5.

3.8.2.4.5 Structural Acceptance Criteria

3.8.2.4.5.1 Normal Loads

For normal loads, the outdoor water storage tanks are designed for the allowable working stresses of the ACI 318-1963 for concrete, Part 1 of the AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, April 1963, for structural steel components, and ASME BPVC Section VIII-1974, Division 2, for steel liner plates.

3.8.2.4.5.2 Abnormal Loads

For abnormal loads, the outdoor water storage tanks are designed for overall elastic behavior. For concrete elements the strength design method of ACI 318-1963 applies for DDE loads and of ACI 318-1971 for HE loads. For the evaluation of structural steel elements using elastic design methods, for the loading condition including DDE loads, 1.6 times AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, April 1963, Part 1 allowables are used; whereas, for the HE load combination, Part 2 of AISC, February 1969, the Plastic Design method applies.

The steel liner plates are evaluated by using stress intensities as defined in ASME BPVC Section VIII-1974, Division 2, and applying a factor of 0.9 to the minimum specified yield strength for DDE, and 1.0 to the yield strength based on properly substantiated test results for HE load conditions (Reference 36). For local stress intensities around nozzles in the vault opening area for DDE loads, a factor of 1.0 to the minimum specified yield strength applies, whereas for HE loads, a factor of 2.4 to the ASME BPVC Section VIII-1974, Division 2, allowable values applies.

3.8.2.4.5.3 Factors of Safety

The calculated capacity-to-demand ratios for critical structural elements of the outdoor water storage tanks are greater than the minimum allowable value of 1. Therefore, all structural elements satisfy the criteria.

3.8.2.4.6 Materials, Quality Control, and Special Construction Techniques

The quality control measures discussed in Sections 3.8.2.1.6.1 and 3.8.2.1.6.2 for the containment structure also apply to PG&E Design Class I tanks.

3.8.2.4.6.1 Materials Tank Walls and Roof Dome

Condensate and Inner and Outer Tank Walls of Firewater and Transfer Tank	-	Carbon steel liner plates and stiffeners conform to ASTM A-516 GR 60. The CSTs are coated with an epoxy coating and the Fire Water and Transfer Tank is coated with Vinyl Paint. Carbon steel studs conform to ASTM A108 GR 1015-1018.
Refueling Water Tank	-	Stainless steel liner plates and stiffeners conform to ASTM A-240 Type 304L. Stainless steel studs conform to ASTM A276 type 304 annealed.

All Tanks, Except Inner Tank of Firewater and Transfer Tank:

- Concrete strength (minimum specified) f_c = 4 ksi

- Rebar conforms to ASTM A615, GR 60, fy = 60 ksi (minimum specified)

3.8.2.5 PG&E Design Class I Foundations and Concrete Supports

The foundation structures for the containment and the auxiliary building are included in Sections 3.8.2.1 and 3.8.2.3, respectively. The pipeway structure is supported from the containment structure, auxiliary building, and turbine building, so it does not have an independent foundation. The foundations of the PG&E Design Class I outdoor water storage tanks are described in this section. Concrete and structural steel supports for RCS components are described and evaluated in Section 5.5.14. Loading combinations for these supports are discussed in Section 5.2.

3.8.2.5.1 Foundations for PG&E Design Class I Outdoor Water Storage Tanks

The following PG&E Design Class I concrete-protected steel tanks are located adjacent to the east side of the auxiliary building on reinforced concrete foundation slabs:

(1) Condensate storage tank (one for each unit)

(2) Refueling water storage tank (one for each unit)

(3) Fire water and transfer tank (common to both units)

3.8.2.5.1.1 Description of the Foundation Slabs

Each of the CSTs and RWSTs has a separate, circular foundation slab. The fire water and transfer tank, which serves both units, are concentric tanks on a common circular foundation slab. Each of the foundation slabs is shown in Figure 3.8-65 and consists of a 1-foot-thick reinforced concrete slab with an integral edge beam tied to a reinforced concrete wall. Each of the tanks, except for the fire water tank, is anchored to its foundation slab with ASTM A 193, Grade B7 anchor bolts. The bolt diameters are 1-1/4 inches for the CSTs and the transfer tank, and 1-3/8 inches for the RWSTs. The wall of the fire water tank is welded to an insert plate in the foundation.

The tank foundation slabs are resting on concrete fill anchored to bedrock with rock anchors. The reinforced concrete protective walls of the steel tanks are anchored to bedrock as shown in Figure 3.8-65, Sheet 2.

3.8.2.5.1.2 Applicable Codes, Standards, and Specifications

The foundation slabs for the PG&E Design Class I outdoor storage tanks listed are designed and constructed in accordance with the ACI 318-1963.

3.8.2.5.1.3 Loads and Loading Combinations

The foundation slabs for the PG&E Design Class I outdoor water storage tanks are designed for dead loads, hydrostatic load, and seismic load:

$$C = DL + HS + EQ + R \qquad (3.8\text{-}30)$$

where:

C	=	total load on foundation
DL	=	dead load of tank
HS	=	hydrostatic load
EQ	=	maximum seismic loads including inertial, impulsive, and convective loads
R	=	pipe reaction load including dead, thermal, and seismic loads

3.8.2.5.1.4 Design and Analysis Procedures

The foundation slabs with concrete fill are designed to prevent overturning and sliding of the tank and limit bearing pressure to 80 ksf. The rock anchors attaching the tank to the foundation are designed so that the maximum uplift force is within the allowable capacity provided in Figure 3.8-65, Sheet 2.

3.8.2.5.1.5 Structural Acceptance Criteria

Stresses in the reinforced concrete foundation slabs are limited to the allowable values in ACI 318-1963.

3.8.2.5.1.6 Materials, Quality Control, and Special Construction Techniques

The quality control measures discussed in Sections 3.8.2.1.6.1 and 3.8.2.1.6.2 for the containment structure also apply to the PG&E Design Class I tank foundations.

Material strengths for the PG&E Design Class I tank foundation slabs are as follows:

(1) Concrete strength of foundation slab and concrete fill is 3000 psi.

(2) Reinforcing steel in foundation slab is ASTM A 615, Grade 40.

(3) Rock anchors conform to VSL 28, strand #ER5-28, with double corrosion protection and are fully grouted with grout strength of 4000 psi.

3.8.3 PG&E DESIGN CLASS II STRUCTURES CONTAINING PG&E DESIGN CLASS I EQUIPMENT

The turbine building and the intake structure are primarily PG&E Design Class II structures that contain PG&E Design Class I equipment.

The turbine building contains the CCW heat exchangers, emergency DGs, 4.16-kV Class 1E switchgear, CRPS, and other PG&E Design Class I systems. Area A of the turbine building, that houses this equipment, is PG&E Design Class I as are structural portions of the turbine building that protect this equipment such as missile and jet impingement barriers (refer to Table 3.2-3).

The turbine building also encompasses the on-site technical support center (TSC) which is located in the Unit 2 turbine building buttress and is designed for Hosgri seismic loads. The TSC houses portions of the PG&E Design Class I CRPS supply duct.

The intake structure contains the PG&E Design Class I ASW pumps, piping, and instrumentation. The capability of the intake structure to protect the ASW system during design flood events is evaluated to ensure this capability, as described in Sections 2.4 and 3.4.

To ensure that the PG&E Design Class I equipment would not be affected by failure of the PG&E Design Class II structures, both the turbine building and the intake structure were evaluated for seismic events as described in Section 3.7.2.2.2.

3.8.3.1 Turbine Building

3.8.3.1.1 Description

The turbine building was originally designed as a PG&E Design Class II structure using static equivalent seismic loads. Subsequently, the building was dynamically analyzed and designed to assure that it would not collapse and impair the function of PG&E Design Class I equipment located inside the building during a DDE coincident with a pipe rupture. Later, during the Hosgri evaluation, the building was re-evaluated and upgraded to withstand the Hosgri seismic loads. As a result of the Hosgri evaluation, buttresses and concrete walls were added to the turbine building, and internal modifications, such as reinforcing main columns, strengthening floor diaphragms, and roof and wall bracing, were made.

The turbine pedestal was originally designed as a PG&E Design Class II structure, using static equivalent seismic loads. During the Hosgri evaluation, the pedestal was reevaluated and upgraded to withstand the Hosgri seismic loads. As a result of the Hosgri evaluation, six of the twelve piers were post-tensioned and the pedestal-to-building separations were increased along the east and west sides of the pedestal.

The turbine building is located adjacent to the west side of the auxiliary building as shown in Figure 1.2-2, Plant Layout. The general layout of equipment in the turbine building, including the turbine generators, is shown in Figures 1.2-13 through 1.2-20, Figures 1.2-24 through 1.2-27, and Figures 1.2-30 through 1.2-32. Generally, the Unit 1 and Unit 2 portions of the turbine building are opposite hand and similar to the other, with each portion of the structure containing equipment for one unit. Exceptions are the presence of a machine shop and material storage area common to both units in the Unit 1 portion, and the on-site TSC in the Unit 2 portion of the structure.

Main floor levels in the turbine building are at elevations 85, 104, 119, and 140 feet. The foundation of the building is at elevation 85 feet. Representative plans at the main floor levels roof truss lower chord level, and a typical section are shown in Figures 3.8-66 through 3.8-71.

The turbine building is a reinforced concrete shear wall structure except for the superstructure, which is a structural steel moment resisting and braced frame structure extending from elevation 140 feet to elevation 217 feet. Shear walls generally range from 16 to 29 inches thick. Floors are 10- to 12-inch-thick reinforced concrete slabs or 1/2-inch-thick steel plate, supported on steel framing and steel columns. The reinforced concrete foundation mat is generally 3 feet thick except under the turbine pedestal, where the thickness is 10 feet. Reinforced concrete turbine pedestals, one for each unit, are located in the building; six piers of each pedestal are post-tensioned. The pedestals are structurally isolated from the building floors and extend from the common foundation slab, elevation 85 feet, to elevation 140 feet. Two 135-ton overhead cranes are located in the building.

3.8.3.1.2 Applicable Codes, Standards, and Specifications

The following codes and standards are used in the HE evaluation, and in the design, construction, inspection, and testing of HE modifications to the turbine building:

(1) ACI Standard Building Code Requirements for Reinforced Concrete (ACI 318-1971) except that, for the HE evaluation and design, the 1973 Supplement to ACI 318 is used and design load combinations are as described in Section 3.8.3.1.3

(2) Manual of Standard Practice for Detailing Reinforced Concrete Structures (ACI 315-1974)

(3) Recommended Practice for Evaluation of Compression Test Results of Field Concrete (ACI 214-1965)

(4) Recommended Lateral Force Requirements, 1974 Seismology Committee Structural Engineers Association of California (SEAOC)

(5) Recommended Practices for Welding Reinforcing Steel, Metal Inserts, and Connections in Reinforced Concrete Construction, AWS D12.1-1975

(6) AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, February 1969, is generally used for steel structures. AISC, November 1978, is also used for evaluating selected connections.

(7) Code for Welding in Building Construction (AWS D1.1-1977 Revision 2). For inspection of non-ASME structural welds or new non-ASME work performed after January 1, 1988, the guidelines of Nuclear Construction Issues Group (Visual Weld Acceptance Criteria, Vol. 1-3, EPRI Report No. NP-5380, September 1987) may be used except for those cases where:

(a) Fatigue is a governing design condition

(b) The weld allowables are permitted to be higher than those allowed by AWS D1.1-1977 (such as full penetration weld evaluation for the HE) [(a)]

(c) The weld is part of work performed in the ASME BPVC Section XI Inservice Inspection Program

(8) Materials and the quality control tests for materials conform to ASTM standards

Note:

(a) PG&E identified that some of the welds in this category had been inspected using the visual weld acceptance criteria contained in EPRI Report No. NP-5380. PG&E evaluated the impacts of this weld inspection criteria deviation and determined that the welds are acceptable as-is.

3.8.3.1.3 Loads and Loading Combinations

3.8.3.1.3.1 Design Loads

The following loads are considered in the HE evaluation of the turbine building.

3.8.3.1.3.1.1 Dead Loads

Dead loads consist of the weight of the structure, permanent attachments and permanent equipment.

3.8.3.1.3.1.2 Live Loads

Live loads consist of any actual live loads acting on the element considered.

3.8.3.1.3.1.3 Seismic Loads

Seismic loads are based on a response spectrum modal superposition analysis. This analysis is described in Section 3.7.2.

3.8.3.1.3.2 Loading Combination

Concrete Structural Elements

$$U = D + L + HE \qquad (3.8\text{-}31)$$

where:

U = Strength determined in accordance with the methods described in ACI 318-1971 and 1973 Supplement, except strength of shear walls is based on method described in Section 3(c) of the Recommended Lateral Force Requirements, 1974 Seismology Committee of SEAOC. (refer to Section 3.1.5)

D = dead load
L = live load
HE = loads resulting from an HE

Steel Structural Elements

Where plastic design methods are used:

$$Y = D + L + HE \qquad (3.8\text{-}32a)$$

Where elastic working stress design methods are used:

$$1.7S = D + L + R_A + HE \qquad (3.8\text{-}32b)$$

where:

S = required section strength based on elastic design methods and the allowable stresses defined in Part 1 of the AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, February 1969

Y = required section strength based on plastic design methods described in Part 2 of AISC Specification for the Design,

Fabrication, and Erection of Structural Steel for Buildings, February 1969 (refer to Section 3.8.3.1.5)

R_A = pipe reactions during abnormal conditions

3.8.3.1.4 Design and Analysis Procedures

Structural analysis of the turbine building is based on the traditional methods of engineering analysis for structural steel and reinforced concrete structures. These methods are based on the principles of equilibrium, compatibility of deformations, and predictions of material strength by the methods of the AISC Code and the ACI Code. The use of these codes is discussed in Section 3.8.3.1.5.

The lateral force resisting system of the turbine building above elevation 140 feet consists of moment resisting bents, formed by steel roof trusses and steel plate columns, steel cross-brace frames at exterior walls, and a steel bracing system in the plane of the roof truss lower chords. At and below elevation 140 feet, lateral resistance is provided by concrete and steel plate floors acting as diaphragms; by concrete shear walls; by concrete buttresses along the east and west sides of the building; and by steel cross-braced frames above elevation 104 feet at the north and south ends of the building. Vertical forces are transmitted to the foundation by the steel plate columns, concrete walls, and interior steel columns which support the steel floor framing system.

HE forces on the lateral force resisting system of the turbine building and the turbine pedestal are based on the response of the turbine building and pedestal seismic models described in Section 3.7.2.3.5. In some cases detailed analytical models are developed to calculate building member forces. Structural evaluation of members is performed for the load combinations described in Section 3.8.3.1.3. The evaluation considers bridge crane location and lifted load as described in Section 3.7. Members are evaluated against the acceptance criteria in Section 3.8.3.1.5. Results of the evaluation are shown in Tables 3.8-26 and 3.8-27.

Computer programs used in the structural analysis and the verification measures are listed in Table 3.8-6.

3.8.3.1.5 Structural Acceptance Criteria

For HE load combinations average material properties, based on properly substantiated test results, are used (Reference 36). Lateral force resisting elements are allowed inelastic deformation subject to the ductility limits shown in Table 3.8-24. The strength of concrete elements is determined in accordance with the methods of ACI 318-1971 and the 1973 Supplement. Strength of concrete shear walls is determined in accordance with Section 3(c) of Recommended Lateral Force Requirements, 1974 Seismology Committee of SEAOC. Strength of steel elements is determined in accordance with the AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, February 1969.

Calculated forces and capacities for selected structural elements of the turbine building and turbine pedestals are compared in Tables 3.8-26 and 3.8-27. Generally, the predicted forces in combination with earthquake effect do not exceed member strengths. A limited number of members are found to exhibit inelastic behavior which does not exceed the allowable ductility limits of Table 3.8-24. Therefore, all structural elements satisfy the criteria.

Separations between the turbine building's primary structure and the turbine pedestal are adequate to ensure these structures will not impact each other when subject to the HE load combination. The relative displacements between these structures are summarized in Table 3.8-27A.

3.8.3.1.6 Materials, Quality Control, and Special Construction Techniques

The turbine building, including the turbine pedestals, was originally constructed prior to 1978. Following the HE evaluation of the plant, modifications to the turbine building and the turbine pedestals were made during the period 1978 to 1979. Additional modifications to the turbine building were required for the installation of DG 2-3 during the period 1991 to 1993. Materials installed during these three periods are described in the following paragraphs.

3.8.3.1.6.1 Concrete

Design strengths of concrete are as follows:

	Age, days	Compressive Strength, psi
Original construction:		
East-west walls	28	5000
Elevation 140 feet floor	60	5000
All other concrete	28	3000
Hosgri Modifications:		
Concrete above elevation 85 feet	28	5000
All other concrete	28	3000
Modifications for installation diesel generator no. 2-3, all associated concrete	28	4000

Average strengths, based on properly substantiated test results, are used with the HE load combination (Reference 36). The average strengths are as follows:

	Age, days (except as noted)	Compressive Strength, psi

Original Construction:		
Turbine pedestal	6 years[(a)]	6000
East-west walls	28	5500
Elevation 140 feet floor	60	6590
All other concrete	28	3870
Hosgri Modifications:		
Concrete above elevation 85 feet	28	5680
All other concrete	28	4260

Note:

(a) Turbine pedestal concrete strength is based on cylinder tests of 6-year-old stored specimens. The strength is verified by rebound hammer tests and by tests of concrete core samples.

3.8.3.1.6.2 Reinforcing Steel

Reinforcing steel is ASTM A615, Grade 40, except in some locations where grade 60 is used. Average test values, based on properly substantiated test results, are used with HE load combinations (Reference 36). Properties of the reinforcing steel are as follows:

	Grade 40	Grade 60
Design yield strength, psi	40,000	60,000
Original construction		
Average yield strength, psi	51,400	65,900
Average tensile strength, psi	80,600	101,400
Hosgri Modifications		
Average yield strength, psi	51,900	67,000
Average tensile strength, psi	81,300	106,500

3.8.3.1.6.3 Structural Steel

Structural steel is ASTM A36 except for reinforcing bars installed at flanges of some columns along column lines A and G where ASTM A572 Grade 50, is used. Properties of the structural steel are as follows:

	ASTM A36	ASTM A572, Gr 50
Design yield strength, psi	36,000	50,000
Original construction		

	ASTM A36	ASTM A572, Gr 50
Average yield strength, psi	44,000	
Average tensile strength, psi	68,000	
Hosgri Modifications		
Elevation 140 and 119 feet floor plate		
Average yield strength, psi	40,800	
Average tensile strength, psi	69,300	
Other structural steel		
Average yield strength, psi	44,500	55,200
Average tensile strength, psi	68,200	87,400

3.8.3.2 Intake Structure

3.8.3.2.1 Description of Intake Structure

The intake structure was originally designed as a PG&E Design Class II structure. The intake structure is a reinforced concrete building constructed with 3,000 psi minimum-specified-strength concrete. The structure has plan dimensions of approximately 240 x 100 feet. The long dimension corresponds to the north-south direction, and is parallel to the seaward face of the structure. The intake structure is backfilled by rock on three sides, and has water on the fourth (western) side. The top deck of the structure has a maximum elevation of +17.5 feet. A concrete ventilation tower with steel coaxial ventilation pipe extends to an elevation of +49.4 feet, which provides the cooling air associated with the ASW watertight compartments (this is also referred to as the Snorkel). The structure is supported by a concrete mat foundation at elevation -31.5 feet. Figures 3.8-72 through 3.8-74 illustrate plans at elevations +17.5, -2.1, and -31.5 feet; Figures 3.8-75 through 3.8-77 illustrate representative sections through the structure.

The top level of the structure consists of an 18-inch-thick concrete slab, except for the roadway area where it is 24 inches thick. Openings, as shown in Figure 3.8-72, are provided to allow removal of pumps, screens, and gates. The pump deck floor at elevation -2.1 feet supports the four main circulating water pumps and the four PG&E Design Class I ASW pumps. The PG&E Design Class I ASW equipment is located in ventilated watertight compartments. The structure is symmetric about a vertical plane in the east-west direction through its centerline.

3.8.3.2.2 Applicable Codes, Standards, and Specifications

The following codes and standards were used in the Hosgri evaluation and the design, construction, inspection, and testing of the intake structure.

(1) ACI Standard Building Code Requirements for Reinforced Concrete (ACI 318-1963, ACI 318-1971, ACI 318-1977)

(2) Manual of Standard Practice for Detailing Reinforced Concrete Structures (ACI 315-1965)

(3) Recommended Practices for Welding Reinforcing Steel, Metal Inserts and Connections in Reinforced Concrete Construction, AWS D12.1-1975

(4) AISC Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, February 1969, and AISC, November 1978

(5) Code for Welding in Building Construction, AWS D1.1-1977, Revision 2. For inspection of non-ASME structural welds or new non-ASME work performed after January 1, 1988, the guidelines of Nuclear Construction Issues Group (Visual Weld Acceptance Criteria, Vol. 1-3, EPRI Report No. NP-5380, September 1987) may be used except for those cases where:

(a) Fatigue is a governing design condition

(b) The weld allowables are permitted to be higher than those allowed by AWS D1.1-1977 (such as the full penetration welds evaluation for the HE) [(a)]

(c) The weld is part of work performed in the ASME BPVC Section XI Inservice Inspection Program

(6) Recommended Lateral Force Requirements 1974 Seismology Committee, Structural Engineers Association of California (SEAOC)

(7) Materials and quality control tests for materials conform to ASTM standards

Note:

(a) PG&E identified that some of the welds in this category had been inspected using the visual weld acceptance criteria contained in EPRI Report No. NP-5380. PG&E evaluated the impacts of this weld inspection criteria deviation and determined that the welds are acceptable as-is.

3.8.3.2.3 Loads and Loading Combination

Seismic Load Combination

$$U = D + L + HE \qquad (3.8\text{-}33)$$

where:

D	=	dead load of the structure and equipment loads
L	=	live load
HE	=	loads resulting from HE
U	=	strength required to resist design loads as described in Section 3.8.3.2.5

Wave Load Combination

$$U = D + L + W_f \quad (3.8\text{-}34)$$

where:

U, D, and L are as defined in (1) above

W_f = wave force associated with breakwater degraded to MLLW

3.8.3.2.4 Design and Analysis Procedures

3.8.3.2.4.1 General

Structural analysis of the intake structure is performed by the traditional methods of engineering analysis for structural steel and reinforced concrete structures. These methods are based on the principles of equilibrium, compatibility of deformations, and predictions of material strength by the methods of the AISC Code, and the ACI Code. The use of these codes is discussed in Section 3.8.3.2.5.

3.8.3.2.4.2 Seismic Forces

A time-history dynamic analysis is performed with a computer program to determine the structure response spectra. A response spectrum dynamic modal superposition analysis is performed to determine structure response maxima. The analytical procedure using modal superposition methods is described in Section 3.7.2.

The demands resulting from the combination of north-south, east-west, and vertical components of the HE, in conjunction with dead loads, actual live loads, and soil pressures, are less than the yield capacity of the major portion of the structure, including the area housing the PG&E Design Class I ASW equipment. The only exceptions are some of the flow straighteners (or piers) that exhibit stresses beyond code values.

However, these piers demonstrate ductility properties that would preclude structural failure. The ductilities are within allowables as stated in Section 3.8.3.2.5. Table 3.8-28 presents the results of the analysis.

The intake structure is reviewed to verify that there is an adequate factor of safety against sliding and overturning, and the foundation pressure is within the allowable value of 50 ksf as described in Reference 13.

3.8.3.2.4.3 Wave Forces

As shown in Figures 3.8-78 and 3.8-79, a scaled, 3-D physical model of the cooling water intake basin, the intake structure, and a hypothetically damaged breakwater was constructed to examine the wave effects on the intake structure as described in References 8 and 9.

Based on the test results, the intake structure was modified to mitigate wave slam (high magnitude, high frequency) pressure behind the curtain wall and to withstand the pressures measured on the bottom of the slab during the testing.

The ASW pump compartments were modified to provide the required ventilation for the PG&E Design Class I equipment and to prevent flooding due to combined tsunami and storm wave runup conditions as described in Section 2.4.7.6.

A risk analysis, as described in Reference 14, was performed to determine the frequency of vessel impact with the intake structure which houses the ASW pumps (refer to Section 2.2). In the analysis, the breakwater was assumed to be degraded to the MLLW level. The analysis considered only large vessels (greater than 250 tons displacement), since impact on the intake structure by smaller vessels was concluded, on the basis of a deterministic analysis, to be inconsequential to the safety-related function of the ASW pumps.

The results of risk analysis for frequency of impact indicate a frequency of 6.7×10^{-6} breakwater boundary crossings per year for storm-independent analysis. The probability of large vessels, therefore, crossing the degraded breakwater and impacting the intake structure is quite low. Refer to Section 2.2.3.1 for discussion regarding the analysis of marine vessels impacting the intake structure.

3.8.3.2.5 Structural Acceptance Criteria

For the load combinations given in Section 3.8.3.2.3, the intake structure is designed so that it does not sustain damage that would adversely affect the function of the PG&E Design Class I ASW system and prevent it receiving an adequate supply of water.

For load combinations with seismic force, strength is based on Recommended Lateral Force Requirements, 1974 Seismology Committee of SEAOC for concrete shear walls; ACI 318-1963 and ACI 318-1971 for other concrete members; and AISC, Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, February 1969, Part 2 for steel members. Lateral force resisting elements are allowed inelastic deformation consistent with ductility factors indicated in Table 3.8-24. For these elements, the allowable stress limitations given in the codes above need not apply.

For load combinations with wave forces, strength is based on ACI 318-1971 and AISC Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, February 1969, Part 2 for all structural members except for ASW pump compartment modifications. For the latter, strength is based on ACI 318-1977 and 1.6 times AISC Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, November 1978, Part 1 allowable values.

3.8.3.2.6 Materials, Quality Control, and Special Construction Techniques

The intake structure was originally constructed prior to 1981. As a result of January 1981 storm damage to the west-breakwater, hydraulic model studies of wave effects on the intake structure were conducted in 1982 (References 8 through 12), and the intake structure was modified to withstand these wave effects.

The material strengths for these periods are provided below:

Concrete

Prior to 1981	Minimum specified fc'	=	3000 psi @ 28 days
	Average test values fc'	=	3630 psi
1981 modifications	Minimum specified fc'	=	5000 psi @ 28 days

Reinforcing Steel

Prior to 1981	ASTM A615, Grade 40;	Minimum specified fy	= 40 ksi
		Average test values fy	= 49.6 ksi
1981 Modifications	ASTM A615, Grade 60;	Minimum specified fy	= 60 ksi

Structural Steel

Prior to and after 1981	ASTM A36;	Minimum specified fy	= 36 ksi

3.8.4 PG&E DESIGN CLASS I STRUCTURES LOCATED INSIDE OTHER STRUCTURES

3.8.4.1 PG&E Design Class I Masonry Walls

In accordance with Reference 28, PG&E Design Class I masonry walls (refer to Section 3.8.4.1.1) have been reevaluated and modified as necessary using conservative design and analysis procedures, and structural acceptance criteria as specified in Sections 3.8.4.1.4 and 3.8.4.1.5. Design and analysis methods and structural acceptance criteria are in accordance with Reference 29. NRC Staff acceptance of the wall reevaluation design and analysis methods is documented in Reference 30.

3.8.4.1.1 Description of PG&E Design Class I Masonry Walls

Masonry walls that perform a PG&E Design Class I function are those walls which support PG&E Design Class I piping or equipment. Masonry walls that do not perform a PG&E Design Class I function but that are in proximity to PG&E Design Class I components and whose failure could prevent a PG&E Design Class I system from performing its intended safety function are addressed by the SISI Program (refer to Section 3.7.3.13). PG&E Design Class I walls are located in the auxiliary and turbine buildings at locations identified in Figures 3.8-83 through 3.8-85, and are evaluated in accordance with Reference 29. These walls are fire walls or nonbearing partitions serving various functions and are not required to resist tornado or missile loads and are not part of the buildings lateral force resisting system. Some of the walls support small piping, conduits, or instrumentation tubing. A few walls support concrete or metal deck ceilings.

All walls are single width, 8 or 12 inches thick, fully grouted, and reinforced in the horizontal and vertical directions with steel reinforcing bars. The bottoms of all walls are tied to the building structure.

In general, walls extend to the underside of the floor structure, where lateral support is provided by a structural supporting system. A separation joint filled with compressible material is provided at the top and side boundaries of all walls where they abut the building structure floors or columns. Walls are braced with steel members. The bottoms of some walls are connected to the floor with bolted steel angles. Some walls are strengthened by steel plates bolted to each face of the wall.

3.8.4.1.2 Applicable Codes, Standards, and Specifications

The following codes and standards are used in the design, construction, inspection, and testing of PG&E Design Class I masonry walls:

(1) Building Code Requirements for Concrete Masonry Structures (ACI 531-1979) and Commentary (ACI 531R-1979)

(2) AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, February 1969

(3) Materials and quality control tests for materials conform to the applicable ASTM standards

3.8.4.1.3 Loads and Loading Combinations

3.8.4.1.3.1 Design Loads

The following loads are considered in the evaluation of PG&E Design Class I masonry walls:

3.8.4.1.3.1.1 Dead Loads

Dead loads consist of the weight of the wall and supported items.

3.8.4.1.3.1.2 Live Loads

Live loads consist of occupancy loads, if any, acting on the wall.

3.8.4.1.3.1.3 Earthquake Loads

Earthquake loads are those resulting from the HE. The loads are based on the response spectrum, single-degree-of-freedom method described in Section 3.7.2.1. The percentage of critical damping used is 7 percent.

3.8.4.1.3.1.4 Thermal Loads

Thermal loads are loads induced by local increases in temperature resulting from normal operating and from postulated accident conditions.

3.8.4.1.3.1.5 Pipe Reaction Loads

Pipe reactions result from hydraulic forces, thermal expansion, and seismic events. These loads are transferred to the structure through pipe supports and result from normal operating conditions and postulated accident conditions.

3.8.4.1.3.1.6 Pressure Loads

Pressure loads are forces generated by a postulated pipe break. Pressures from a postulated broken pipe are calculated as described in Section 3.6.

3.8.4.1.3.1.7 Loads and Loading Combinations

The following load combinations are used in evaluation of PG&E Design Class I masonry walls:

$$U = D + L + To + Ro + HE$$

$$U = D + L + Ta + Ra + 1.5Pa$$

$$U = D + L + Ta + Ra + 1.0Pa + HE$$

where:

U	=	strength determined using acceptance criteria described in Section 3.8.4.1.5
D	=	dead load
L	=	live load
To	=	thermal loads during normal operating conditions
Ro	=	pipe reactions during normal operating conditions
HE	=	loads resulting from an HE
Ta	=	thermal loads generated by a postulated pipe break, including To
Pa	=	pressure load generated by a postulated pipe break
Ra	=	pipe reactions from unbroken pipes generated by postulated pipe break conditions, including Ro

3.8.4.1.4 Design and Analysis Procedures

Evaluation of PG&E Design Class I masonry walls is performed using traditional methods of engineering analysis. Proper consideration is given to boundary conditions, cracking of sections, and the dynamic behavior of the walls. Both in-plane and out-of-plane loads and inter-story drift effects are considered.

HE forces on the walls are based on applicable building floor response spectra generated by the analysis described in Section 3.7.2.1. In some cases, detailed models of the walls and supporting steel members are used to calculate forces and stresses in the walls.

HE forces on the walls including wall reactions are calculated by linear elastic analysis. Applied forces on the walls include the combined effects of vertical loads and horizontal out-of-plane wall deflections (P-Δ effect). Masonry wall stiffnesses are based on best estimate (median) properties, which are:

E_m = 750 f'm
f'_m = 1950 psi
f_r = $4(f'_m)^{0.5}$

The stiffness and strength of walls strengthened with steel plates on each face are based on wall panel tests. Dry-pack grout at the top of the walls is treated as unreinforced and is not relied upon to withstand earthquake loads. An additional evaluation of the walls is performed to address the variability of material properties, workmanship, and construction tolerances.

Computer programs used in the structural analysis and the verification measures are listed in Table 3.8-6.

3.8.4.1.5 Structural Acceptance Criteria

In the evaluation of PG&E Design Class I masonry walls for load combinations, including HE or pipe break loads, average material properties, based on properly substantiated test results, may be used. However, in no case are the yield values used in strength computations of structural steel greater than 70 percent of the corresponding average ultimate strength values determined by the tests (Reference 36).

The moment capacity of a masonry wall is not less than the moment produced by the applied loads. Moment capacity of the masonry wall is determined using the strength design method, with a strength reduction factor, ϕ, equal to 1.0. Allowable masonry shear stress is 1.3 x 1.1 $(f'_m)^{0.5}$, where f'_m is as defined in Section 3.8.4.1.4. Allowable masonry bearing stress is 2.5 x 0.25 (f'_m). Analysis of the behavior of masonry walls strengthened with steel plates is substantiated by tests. Allowable forces on steel members are based on 1.6 times allowable stresses defined in the AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, February 1969, Part 1, or 0.9 times member strengths defined in the AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, February 1969, Part 2.

3.8.4.1.6 Materials, Quality Control, and Special Construction Techniques

3.8.4.1.6.1 Masonry Units

Masonry units are hollow, load-bearing, open-ended lightweight units of ASTM Designation C90, Grade A. The average compressive test strength of masonry units is 3400 psi on the net area.

3.8.4.1.6.2 Reinforcing Steel

In general reinforcing steel is ASTM A615, Grade 40. The average yield strength by test is 51,400 psi.

In limited areas, reinforcing steel is ASTM A615, Grade 60. The average yield strength by test is 64,200 psi.

3.8.4.1.6.3 Core Fill

Grout having a minimum specified compressive strength of 2000 psi is placed in all masonry unit cells. The average tested compressive strength is 3285 psi.

3.8.4.1.6.4 Mortar

Mortar is ASTM Designation C270, Type S.

3.8.4.1.6.5 Construction Inspection

Inspection procedures meet the intent of Section 4.5 of Building Code Requirements for Concrete Masonry Structures (ACI 531-1979).

3.8.4.2 Spent Fuel Storage Racks

3.8.4.2.1 Description of the Spent Fuel Pool and Racks

The description of the SFP, which is located in the fuel handling area of the auxiliary building, is provided in Sections 3.8.2.3.1 and 9.1.2.2. Each fuel pool has 16 high density fuel rack modules as shown in Figure 9.1-2. They are free-standing and consist of individual cells with an 8.85 by 8.85-inch square cross-section, each of which stores a single Westinghouse PWR fuel assembly. The number of cells varies from 34 to 110 per module. The cells are fabricated by welding two formed stainless steel channels, which are welded together by stainless steel gap channels to provide the required predetermined distance between the cells. Typically, each module is provided with four support legs, three of which are adjustable and one fixed. The adjustable support legs are used to achieve a leveled free-standing position on the pool floor. For ease of installation and to reduce potential interferences with liner seam welds, each rack support leg is supported on a bridge plate. Typically, each rack module is equipped with girdle bars located near the top, which are designed to accommodate seismically induced impact loads.

3.8.4.2.2 Applicable Codes, Standards, and Specifications

The following codes and standards are used in the design and construction of the racks.

(1) AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, February 1969

(2) ASME BPVC Section III-1983 and Subsection NF

(3) Safety Guide 13, March 1971 "Fuel Storage Facility Design Basis," (refer to Section 9.1.2.3.11)

(4) Westinghouse Fuel Assembly, Storage and Refueling Equipment Design Interface Specification No. F-8, Revision 8

(5) NRC "OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications," April 14, 1978, and "Modifications to the OT Position," January 18, 1979, letters from B. K. Grimes to All Power Reactor Licensees

(6) Appendix D to Standard Review Plan (NUREG-0800), Section 3.8.2.4, "Technical Position on Spent Fuel Pool Racks," Revision 0, July 1981, NRC

3.8.4.2.3 Loads and Loading Combinations

The loads and loading combinations and the corresponding acceptance criteria are as follows (Reference 20):

	Loading Combination	Stress Limit
(a)	D $D + T_o$ $D + T_o + E$	Level A service limits
(b)	$D + T_a + E$ $D + T_o + P_f$	Level B service limits
(c)	$D + T_a + E'$ $D + F_d$	Level D service limits (The functional capability of the fuel racks should be demonstrated)

where:

D	=	Dead weight-induced stresses (including fuel assembly weight)
F_d	=	Force caused by the accidental drop of the heaviest load from the maximum possible height
P_f	=	Upward force on the racks caused by postulated stuck fuel assembly
E	=	DE
E'	=	HE
T_o	=	Differential temperature induced loads (normal or upset condition)
T_a	=	Differential temperature induced loads (abnormal design conditions)

3.8.4.2.4 Design and Analysis of Racks

3.8.4.2.4.1 Design Basis Rack Model

The racks are analyzed using a nonlinear dynamic model as shown in Figure 3.8-81. The model simulates the rack as a single stick supported on a rigid base with supports. Impact springs are provided at the girdle bar and the baseplate locations to account for rack-to-rack and/or rack-to-wall impact. The legs are represented by 4 impact springs to account for the impact as well as frictional sliding. The rattling of the fuel assemblies in cells is considered by the use of additional impact springs. The model includes 2 mass points comprising 8 degrees of freedom. Mass 1 is located in the rack module

and has 6 degrees of freedom, (i.e., 3-D space with 3 linear translations and 3 rotations). Mass 2 is located at the top of the fuel and moves with 2 translational degrees of freedom. The lower mass point of the fuel assembly is lumped with the rack module mass (Reference 20).

3.8.4.2.4.2 Design Basis Rack Analysis and Results

Due to the complexity of the nonlinear time-history analysis, the racks, in general, are analyzed using a single rack model (refer to Figure 3.8-81) that uses conservative model parameters. The seismic input motions are provided in the form of three orthogonal time histories at the fuel pool liner location. A minimum value of 0.2 and a maximum value of 0.8 are used for the range of friction coefficients between the rack supports and the pool liner (Reference 23). The effects of fluid are considered in accordance with the method advanced by Fritz (Reference 24). The impact springs are set at values to produce conservative impact forces. Parametric studies have been performed to evaluate the effects of various design variables such as friction coefficients, size of rack, fuel loading (partially loaded, fully loaded, or empty) on rack, spacing between racks (corner rack vs. non-corner rack), fabrication tolerance, etc. The bounding loads are obtained from those parametric analyses, which are then used for the design of rack components.

The racks have been analyzed to store LOPAR, VANTAGE 5, and ZIRLO fuel assemblies. The impact loads between the cell wall and the fuel assemblies are less than those provided by Westinghouse.

3.8.4.2.4.3 Multi-Rack Confirmatory Model

The design basis analysis, described in Section 3.8.4.2.4.2 includes several conservative assumptions applied to a single rack model to obtain conservative impact loads. To confirm the adequacy of this methodology, additional multi-rack analyses have been performed (References 21 and 22).

Figure 3.8-82 shows the two-dimensional dynamic model used in this analysis. Each rack is represented by four degrees of freedom simulating fuel rattling, translation, and rocking of the racks. The parameters for the model are developed in a manner similar to those used for the design basis model, except more realistic assumptions are made to compute the fluid coupling coefficients and spring constants.

3.8.4.2.4.4 Multi-Rack Confirmatory Analysis and Results

The analyses are performed using the nonlinear time history method. The governing horizontal (east-west) and vertical ground motions are applied simultaneously to the model. Parametric studies have been performed to evaluate the effects of various friction coefficients, fuel loading on racks, sizes of racks, lateral gaps, and fabrication tolerances. The results of the analysis demonstrate that the use of conservative model

parameters in the design basis analysis (Reference 20) yields conservative rack and fuel assembly impact loads.

3.8.4.2.5 Materials, Quality Control, and Special Construction Techniques

The materials for rack modules are:

Stainless steel sheet and plate	ASTM A-240-304L
Weld filler material	ASME SFA-5-9 Type 308L and 308LSI
Top part of support	ASTM 479-S21800
Bottom part of support	ASTM SA564-630

3.8.4.2.6 Design and Analysis of Spent Fuel Pool Structure

The SFP structure, which is an integral part of the PG&E Design Class I auxiliary building, was evaluated for postulated interactions of the rack modules with the structure as a result of the design basis seismic events (DE, DDE and HE). The effect of the change in fuel rack mass on global dynamic response of the pool structure was considered. The change in global mass was determined to be on the order of 1 percent to 2 percent, therefore, the change in dynamic response is insignificant.

The pool walls were evaluated for the out-of-plane effects due to hydrostatic, hydrodynamic, thermal, and seismic loads. They adequately meet the loading combinations and acceptance criteria in Sections 3.8.2.3.3.2 and 3.8.2.3.5, respectively. The walls were also checked for additional impact loads that may result from the rack-to-wall impact and they meet the acceptance criteria of Section 3.8.2.3.5.

The liner was evaluated for the maximum vertical impact load and maximum horizontal sliding load and was determined to be adequate for leak tightness. The concrete slab that supports the liner was evaluated for the floor impact load using the allowable values specified in ACI 349-1980 (Reference 25). The liner in-plane loadings that result from the sliding of the rack and thermal effects were evaluated in accordance with the allowable strains and anchor displacements as specified in ASME BPVC Section III-1983, Division II (Reference 26).

The design of the fuel handling area crane and the travel limitations placed on it are discussed in Section 9.1.4.3.

3.8.4.3 Containment Polar Cranes

3.8.4.3.1 Description of the Containment Polar Cranes

The containment polar crane (one for each unit) is an overhead gantry crane with a 200 ton capacity main hook and a 35 ton capacity auxiliary hook. Each polar crane travels along a circular rail in the crane runway, which is located on top of the 3-foot thick, 106-

foot outside diameter cylindrical crane wall, as described in Sections 3.8.2.1.4.6.1 and 3.8.2.1.1.5. The supports for the polar crane, the connection of the crane rail to the concrete, and the provisions to resist seismic forces are shown in Figure 3.8-23 and described in Section 9.1.4.2.1.5. Seismic analysis for the polar crane is discussed in Section 3.7.2.

Each polar crane is a structural steel frame consisting of:

(1) Two main box girders 120 feet long, 10 feet deep and 4 feet wide, spaced 24 feet apart

(2) Four gantry legs, 52 feet long and made of tapered box sections supporting the girders

(3) Two sill beams, 28 feet long with box sections to connect the gantry legs

(4) Four tie beams connecting main girders and gantry legs

The sill beams are supported by two wheel assemblies each and are restrained by guide struts. These struts allow the wheels to uplift during a seismic event but guide the wheels back on to the rail.

3.8.4.3.2 Applicable Codes, Standards, and Specifications

The following codes and standards were used, insofar as they are applicable, in the design and/or construction of the polar crane:

(1) AISC Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, February 1969

(2) Code for Welding in Building Construction, AWS D1.0-1969. Work performed prior to December 12, 1969 is in accordance with the earlier edition, AWS D1.0-1966.

(3) Materials, and the quality control tests for materials conform to ASTM standards

3.8.4.3.3 Loads and Loading Combinations

3.8.4.3.3.1 Design Loads

The following loads were considered in the design of the polar crane (Reference 40):

3.8.4.3.3.1.1 Dead Loads

Dead loads consist of the weight of crane and accessories.

3.8.4.3.3.1.2 Live Loads

Live loads consist of the lifted load on the crane's main hoist (200-ton) or auxiliary hoist (35-ton).

3.8.4.3.3.1.3 Crane Operating Loads

Crane-operating loads include:

(1) Live load impact = (LI) = 0.2L

(2) Lateral operating load = (LAT) = 0.1 (L+TD)

(3) Longitudinal operating load = (LONG) = 0.1 (L+TD)

where:

L = Crane rated live load
TD = Trolley dead weight

3.8.4.3.3.1.4 Earthquake Loads

The seismic analysis of the polar crane is described in Section 3.7.2.2.1.2.

3.8.4.3.3.2 Loading Combinations

The following loading combinations are used in design of the containment structure elements.

3.8.4.3.3.2.1 Operating Conditions

C = D + TD + L + LI

C = D + TD + L + LAT

C = D + TD + L + LONG

C = D + TD + DE

where:

C = required capacity of section based on the methods described in Section 3.8.4.3.5.1
D = dead load of structure and equipment loads
L = crane rated live load

TD = trolley dead weight
LI = live load impact = 0.2L
LAT = lateral operating load = 0.1 (L+TD)
LONG = longitudinal operating load = 0.1 (L+TD)

3.8.4.3.3.2.2 Accident Conditions

$U = D + TD + DDE + T_O$

$U = D + TD + L + HE$

where:

D = dead load of structure and equipment loads
L = crane rated live load
TD = trolley dead weight
T_O = thermal load induced by the temperature differential between the crane structure and supporting concrete structure, during operating condition
U = capacity of the section as determined from an increase of allowable stresses by a factor of 1.7
DDE = loads resulting from the DDE
HE = loads resulting from the HE

3.8.4.3.4 Design and Analysis Procedures

3.8.4.3.4.1 Structural Analysis of Polar Crane

The polar crane is analyzed using a conventional frame analysis technique. The seismic analysis is described in Section 3.7.2. The resulting forces and moments in selected structural members are summarized in Tables 3.7-8M and 3.7-8N.

3.8.4.3.4.2 Computer Programs

The main computer programs used for the analyses of polar crane are listed in Table 3.8-6. The table also describes the general function of the programs and their respective verification measures.

3.8.4.3.5 Structural Acceptance Criteria

The structural acceptance criteria for the polar crane are as follows:

3.8.4.3.5.1 Operating Conditions

For operating conditions, the polar crane is designed for the allowable stresses of the applicable code such as AISC Specification for the Design, Fabrication, and Erection of

Structural Steel for Buildings, February 1969, except that the increase in allowable stress or decrease in load factor usually allowed for load combinations involving earthquake or wind forces is not used.

3.8.5 SAFETY EVALUATION

3.8.5.1 General Design Criterion 2, 1967 – Performance Standards

PG&E Design Class I structures (refer to Sections 3.8.2.1 through 3.8.2.5, and 3.8.4.1 through 3.8.4.3), and PG&E Design Class II structures containing PG&E Design Class I SSCs (refer to Sections 3.8.3.1 and 3.8.3.2) are designed to withstand the effects of winds and tornadoes (refer to Section 3.3.1), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other natural phenomena, and to protect SSCs to ensure their safety-related functions and designs are maintained. The auxiliary building, fuel handling building, and firewater and transfer tank are designed to remain functional following a DBA, DE, DDE, or HE event. The turbine building and intake structure are seismically qualified for the HE, protecting the PG&E Design Class I systems or components contained within. Masonry walls that support, or are in the vicinity of, PG&E Design Class I equipment (refer to Section 3.8.4.1) meet the requirements of NRC Bulletin 80-11.

3.8.5.2 General Design Criterion 3, 1971 – Fire Protection

The PG&E Design Class I structures, and PG&E Design Class II structures that contain PG&E Design Class I SSCs are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

3.8.5.3 General Design Criterion 4, 1967 – Sharing of Systems

The auxiliary building, fuel handling building, and the firewater and transfer tank are the only PG&E Design Class I structures that are shared between units. The turbine building and intake structure are the only PG&E Design Class II structures containing PG&E Design Class I systems or components that are shared between units. These structures are designed to ensure that safety is not impaired by the sharing.

3.8.5.4 General Design Criterion 10, 1967 – Containment

The containment structure is designed to withstand the effects of a DBA as discussed in Section 3.8.2.1.3.

3.8.5.5 General Design Criterion 11, 1967 – Control Room

PG&E Design Class I controls and indications for the personnel access hatches and emergency personnel access hatches are provided to support actions to maintain containment isolation.

A control room alarm is provided to indicate when a personnel access hatch or an emergency personnel access hatch is opened. A light above each access hatch provides local indication for when an access hatch is opened. Additionally, a control room alarm is provided to indicate when personnel air lock leakage exceeds administratively controlled setpoints.

3.8.5.6 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided to indicate the operational status of the PG&E Design Class I personnel access hatches and emergency personnel access hatches to ensure that containment isolation is maintained. A control room alarm is provided for personnel access hatch and emergency personnel access hatch indication as discussed in Section 3.8.5.5.

3.8.5.7 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

Refer to Section 3.8.2.1.3 for discussion regarding the design loading for the containment structure. The containment structure is designed to withstand the pressures and temperatures resulting from a rupture of the RCPB (i.e., a LOCA).

3.8.5.8 General Design Criterion 40, 1967 – Missile Protection

The containment internal concrete structure protects ESF SSCs (refer to Section 1.2.2.3 for a list of ESFs) inside containment, including the containment liner, from postulated missiles and dynamic effects originating inside containment (refer to Section 3.5.2.1.1). The IHA includes a missile shield provides protection from failure of a CRDM (refer to Section 3.5.2.1.1). There are no credible missiles outside of containment resulting from plant equipment failure that would prevent ESF systems or components located outside containment from performing their design functions (refer to Section 3.5.2.1.2). Refer to Section 3.8.2.1.3.1.5 for a description of the missile and dynamic effects loading considered for the containment structure.

3.8.5.9 General Design Criterion 42, 1967 – Engineered Safety Features Components Capability

The containment structure is designed to withstand the effects of a DBA (including the effects of a LOCA) as discussed in Section 3.8.2.1.3.

3.8.5.10 General Design Criterion 49, 1967 – Containment Design Basis

The containment structure, including access openings and penetrations, is designed and analyzed to withstand the pressures and temperatures that could result from a LOCA without exceeding design leakage rates as discussed in Section 3.8.2.1.3.

3.8.5.11 General Design Criterion 50, 1967 – NDT Requirement for Containment Material

Refer to Sections 3.1.8.14 and 3.8.2.1.6.4 for description of the Charpy V-notch impact test temperatures fur for the containment liner, penetration sleeves, and hatch hexagonal collar. For all future repairs, replacements, or alterations of these components, the notch toughness test requirements of Section III, NE-2300 will be used in lieu of the original requirements as discussed in Sections 3.1.8.14 and 3.8.2.1.6.4.

3.8.5.12 General Design Criterion 54, 1967 – Containment Leakage Rate Testing

The containment structure is designed to meet the requirements of the integrated leakage rate test and the sensitive leakage rate test provisions as discussed in Sections 3.8.2.1.7.2 and 3.8.2.1.7.3, respectively.

3.8.5.13 General Design Criterion 56, 1967 – Provisions for Testing of Penetrations

All containment penetrations are provided with a volume that can be pressurized to test for leak tightness. Refer to Section 3.8.2.1.7.3 for test provisions involving containment penetrations.

3.8.5.14 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The PG&E Design Class I containment, auxiliary building, and fuel handling building structures are designed to maintain control over plant radioactive effluents, whether gaseous, liquid, or solid.

The containment structure is designed to withstand the effects of a DBA (refer to Section 3.8.2.1.3), ensuring that the offsite radiological exposures resulting from a LOCA are within the limits of 10 CFR 50.67. Refer to Section 15.5 for a discussion of offsite radiological exposures resulting from a LOCA.

A negative pressure environment during fuel handling activities ensures that gaseous and particulate radioactive effluents are directed through the FHBVS in the event of a fuel handling accident in the fuel handling building. Refer to Section 9.4.4 for a discussion of the FHBVS.

The ABVS is designed to provide a controlled pathway for volatile radioactive materials released in the event of a leak in the RHR circulation loop following a LOCA or in the event of a rupture of a gas decay tank or the volume control tank. This reduces the

amount of the radioactive effluents released to the environment in such an event. Refer to Section 9.4.2 for a discussion of the ABVS.

The release of liquid effluents from inside the containment structure, fuel handling building, and the auxiliary building is controlled by the liquid radwaste system. Refer to Section 11.2 for a discussion of the liquid radwaste system.

3.8.5.15 Design of PG&E Design Class I Structures Safety Function Requirements

(1) Protection from Missiles and Dynamic Effects

PG&E Design Class I structures are protected against the effects of missiles and dynamic effects which may result from equipment failures located outside the containment structure (refer to Section 3.5.2.1.2). The non-ESF PG&E Design Class I SSCs inside containment are protected from postulated missiles and dynamic effects originating inside containment as discussed Section 3.5.2.1.1. Refer to Sections 3.8.2.1.3.1.5, 3.8.2.2.3.2.2, and 3.8.2.3.3.1.7 for a description of the missile and dynamic effects loading considered for the containment structures, pipeway structures, and auxiliary building, respectively.

3.8.5.16 Safety Guide 13, March 1971 – Fuel Storage Facility Design Basis

Regulatory Position 1:

The spent fuel storage facilities, including the auxiliary building and fuel handling area of the auxiliary building, are PG&E Design Class I.

Regulatory Position 2:

The auxiliary building and fuel handling building are designed to prevent tornado winds and tornado generated missiles from causing a loss of watertight integrity of the SFP or from causing damage to fuel assemblies stored in the SFP. Refer to Section 3.8.5.1 for a discussion of the DCPP environmental protections provided by the structures used for fuel storage.

Regulatory Position 4:

The fuel handling building provides a controlled leakage enclosure so that any potential release of radioactive materials will be directed to the appropriate ventilation and filtration system (refer to Section 9.4.4).

Regulatory Position 5:

The SFP, which is a part of the auxiliary building structure, is designed to withstand, without leakage which could uncover the fuel, the impact of the heaviest load to be carried by the fuel handling area crane (refer to Section 9.1.4.3.10).

3.8.5.17 Safety Guide 18, October 1971 – Structural Acceptance Test for Concrete Primary Reactor Containments

Acceptance testing of the containment structure was conducted as described in Section 3.8.2.1.7.1.

3.8.5.18 Regulatory Guide 1.55, June 1973 – Concrete Placement in Category I Structures

The DCPP QA program implemented for the placement of concrete for the PG&E Design Class I auxiliary building and containment structures meets the requirements of Regulatory Guide 1.55, June 1973. The references used for establishing the DCPP QA program are the same as the references listed in Appendix A of Regulatory Guide 1.55, June 1973 (as they existed at the time of the PSAR).

3.8.5.19 Regulatory Guide 1.63, Revision 1, May 1977 – Electrical Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Plants

Electrical circuits routed through containment electrical penetrations are designed with protective systems to prevent heat rises in the containment electrical penetrations from compromising the integrity of the containment structure. Refer to Sections 3.8.2.1.1.3.1, 8.3.1.1.5.3.11 and 8.3.1.4.8 for additional electrical penetration details and discussion of their protective systems.

3.8.6 REFERENCES

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3. Code for Concrete Reactor Vessels and Containments, ACI Standard 359-1975.

4. PG&E's response to Governor George Deukmejian's and Joint Intervenors' first set of interrogatories (Docket Nos. 50-275 and 50-323): Interrogatory Number 2 – Unit 1; Interrogatory Number 3 - Unit 2.

5. PG&E's first supplemental response to Governor Deukmejian's and Joint Intervenors' first set of interrogatories. (Docket Nos. 50-275 and 50-323.)

6. Letter dated August 13, 1973, with enclosures, (Docket Nos. 50-275 and 50-323) from A. Giambusso of the AEC to F. T. Searls of PG&E.

7. Recommended Evaluation Criteria for Diablo Canyon Nuclear Power Plant Auxiliary Building Walls and Diaphragms, by Jack R. Benjamin and Associates, Inc., dated February 11, 1983, prepared for Bechtel Power Corporation, San Francisco, California.

8. The Height Limiting Effects of Sea Floor Terrain Features and of Hypothetically Extensively Reduced Breakwaters on Wave Action at Diablo Canyon Sea Water Intake, by Omar J. Lillevang, Fredric Raichlen, Jack C. Cox, March 15, 1982.

9. The Investigation of Wave-Structure Interactions for the Cooling Water Intake Structure of the Diablo Canyon Nuclear Power Plant, by Fredric Raichlen, December 1982.

10. Criteria for Selection of Critical Wave Directions, Omar J. Lillevang, November 2, 1982.

11. Wave Effects on Intake Structure at Diablo Canyon Units 1 and 2, E. N. Matsuda, January 1983.

12. Investigation of Seawater Injection into the Auxiliary Saltwater Pump Room Due to the Splash Runup During the Design Flood Events at Diablo Canyon, P. J. Ryan, January 1983.

13. Geotechnical Studies on Intake Structure, Water Storage Tanks, Diesel Fuel Oil Storage Tanks, for Diablo Canyon Power Plant, San Luis Obispo County, California, by Harding-Lawson Associates, April 12, 1978.

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21. "Additional Information on Rack to Rack Interaction," Enclosure 1 to PG&E Letter No. DCL-87-070, dated April 7, 1987.

22. "Three-Dimensional Studies (ACORN 10 and ACORN 12)," Enclosure to PG&E Letter No. DCL-87-082, dated April 23, 1987.

23. Rabinowicz, E., Friction Coefficient Value for a High Density Fuel Storage System, Report to General Electric Nuclear Energy Program Division, November 23, 1977.

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25. ACI Standard 349-1980, Code Requirements for Nuclear Safety Related Concrete Structures, American Concrete Institute, Detroit, Michigan.

26. ASME BPVC Section III-1983, American Society of Mechanical Engineers, Division II.

27. EPRI NP-5380 Final Report, Visual Weld Acceptance Criteria, Volumes 1-3 (Nuclear Construction Issues Group (NCIG) NCIG-01, Revision 2, NCIG-02 Revision 2, and NCIG-03 Revision 1), September 1987.

28. PG&E Letter DCL-90-289, with enclosure, from J.D. Shiffer to NRC, December 14, 1990.

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30. Letter dated September 18, 1991, with enclosure, (Docket Nos. 50-275 and 50-323) from R.P. Zimmerman of NRC to J.D. Shiffer of PG&E.

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35. J. W. Fisher and Associates, "Review Comments on Position Paper on Shear Strength of A325 Bolts as Specified by the 7th Edition of the AISC Manual," dated July 10, 2008.

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39. PG&E Calculation 9000009056, "Model 1.0 Reconstruction, Benchmarking and Re-Evaluation of FHBSS for Single-Failure-Proof (S-F-P) Upgrade of FHB Crane and Only Two Movable Partition Wall Panels (MPWPs)," Legacy Calc. No. 52.15.7.1.1.15.

40. PG&E Calculation No. 2252 C-1 (SAP Calc. No. 9000041231), "Polar Crane ANSR Model Reconstruction and Benchmarking."

3.8.7 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

3.9 MECHANICAL SYSTEMS AND COMPONENTS

This section discusses the design of PG&E Design Class I mechanical systems and components for DCPP Unit 1 and Unit 2.

3.9.1 DESIGN BASES

3.9.1.1 General Design Criterion 1, 1967 – Quality Standards

The PG&E Design Class I mechanical systems and components that are essential to the prevention of accidents which could affect the public health and safety, or mitigation of their consequences, shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed.

3.9.1.2 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I mechanical systems and components are designed to withstand the effects of, or are protected against, natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

3.9.1.3 General Design Criterion 4, 1987 – Environmental and Dynamic Effects Design Bases

Consideration of the dynamic effects associated with postulated pipe ruptures of RCL piping (i.e., hot, cold, and crossover leg) are excluded from the DCPP Unit 1 and Unit 2 design basis with the approval of LBB methodology by demonstrating that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping systems.

3.9.1.4 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The DCPP Unit 1 and Unit 2 RCPB is designed to have an exceedingly low probability of gross rupture or significant leakage throughout its design lifetime.

3.9.1.5 General Design Criterion 33, 1967 – Reactor Coolant Pressure Boundary Capability

The DCPP Unit 1 and Unit 2 RCPB is capable of accommodating without rupture, and with only limited allowance for energy absorption through plastic deformation, the static and dynamic loads imposed on any boundary components as a result of any inadvertent and sudden release of energy to the coolant.

3.9.1.6 General Design Criterion 40, 1967 – Missile Protection

The PG&E Design Class I mechanical systems and components ESFs are designed to be protected against dynamic effects and missiles that might result from plant equipment failure.

3.9.1.7 10 CFR 50.55a – Codes and Standards

The PG&E Quality/Code Class I mechanical systems and components of the RCPB are designed, fabricated, erected, and tested in accordance with the requirements for Class A components of Section III of the ASME Boiler and Pressure Vessel Code.

3.9.1.8 10 CFR 50.55a(f) – Inservice Testing Requirements

The ASME Code components (i.e., active pumps and valves) are tested to the requirements of 10 CFR 50.55a(f)(4) and a(f)(5) to the extent practical.

3.9.1.9 Safety Guide 20, December 1971 – Vibration Measurements on Reactor Internals

The DCPP Unit 1 and Unit 2 reactor internals were subjected to confirmatory vibration testing and subsequent visual inspection as part of the preoperational tests to provide added confirmation of the capability of the structural elements of the reactor internals to sustain flow-induced vibrations.

3.9.1.10 NUREG-0737 (Item II.D.1), November 1980 - Clarification of TMI Action Plan Requirements

Item II.D.1 – Relief and Safety Valve Test Requirements: PG&E is required to demonstrate that the DCPP Unit 1 and Unit 2 pressurizer SVs, power operated relief valves (PORVs), PORV block valves, and all associated discharge piping will function adequately under conditions predicted for design basis transients and accidents.

3.9.2 MECHANICAL SYSTEMS AND COMPONENTS DESCRIPTION

3.9.2.1 Dynamic System Analysis and Testing

A mechanical design description of the internals and core components showing the differences and similarities between the two DCPP units is presented in Section 4.2.2. The dynamic analysis techniques and methods used to determine and confirm the dynamic response of the reactor internals are presented in the following section. Detailed information of the dynamic system analysis and testing is presented in the reports listed in References Section 3.9.4. Chapter 14 describes the plant initial tests and operation.

A description of the analyses used in the design of PG&E Design Class I mechanical equipment, such as pumps and heat exchangers, to withstand the DE, DDE, and HE-seismic loadings is provided in Section 3.7.

3.9.2.1.1 Vibration Operational Test Programs

This section describes the nature of flow-induced vibrations in the RCLs and the analyses performed to ensure such vibrations are at an acceptable level.

3.9.2.1.1.1 Main Piping System, Flow-Induced Vibration

Pressure pulses, from the RCP impeller are prevented from resulting in flow-induced vibrations in the main piping systems of the RCL. The RCP perturbing frequency is quite high when compared to the piping natural frequency. Frequency separation, therefore, ensures a very small probability of self-excited or sympathetic vibration.

3.9.2.1.1.2 Reactor Internals Flow-Induced Vibration

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

The dynamic behavior of reactor components has been studied using experimental data obtained from operating reactors along with results of model tests and static and dynamic tests. The following procedures have been performed in the study of thermal shield vibration:

(1) During a test program performed with a 1/7th-scale model, the natural frequencies of the thermal shield in water and the maximum vibration amplitude were measured.

(2) Shaker test programs performed on a prototype thermal shield with the actual boundary conditions provided full-scale natural frequencies and mode shapes in air. These modes were established by measuring accelerations at the center, top (support elevation), and bottom of the shield. In Figure 3.9-3, the results obtained are plotted for n = 4 and correspond to a thermal shield with eight supports which are indicated on the same figure. The amplitudes of vibration are fitted with a curve y = A sin 4q.

(3) Maximum displacements were measured during the preoperational reactor test and were correlated with the information obtained in the 1/7th-scale model and shaker test.

(4) In Figure 3.9-4, the maximum amplitudes of vibration are plotted as measured on a thermal shield with six supports. The experimental points have been least-square fitted with a curve y = A sin 3q.

In general, the study follows two parallel procedures. Frequencies and spring constants are derived analytically, and these values are confirmed from the results of the tests. Damping coefficients are established experimentally, and forcing functions are estimated from pressure fluctuations measured during operation and in models. In parallel, the responses of important reactor structures were measured during preoperational reactor tests and the frequencies and mode shapes of the structures obtained. Once all the dynamic parameters were obtained as explained above, the forcing functions could be estimated. Internals behavior during reactor operation is measured using mechanical devices and nuclear noise methods.

Some components, such as control rod guide tubes, fuel rods, and incore instrumentation tubes are subjected to cross flow and parallel flow with respect to the axis of the structure. For both cases, cross and parallel, the response is obtained after the forcing function and the damping of the system are determined.

3.9.2.1.1.3 Vibration Monitoring

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Since internals of four loop reactors are designed and manufactured to essentially the same procedures, processes, and similar drawings, the response of these structures is similar. Performance data from the instrumentation of actual reactors, as well as mechanical and flow scale models, are available (References 2, 4, and 5). The pre- and post-operational flow test examinations of the Indian Point II Plant internals, the four loop prototype plant, have been completed indicating that all the components performed as predicted. No evidence or sign of damage or incipient failure was found.

The testing programs consisted of measurements of the stresses, deflections, and responses of selected key points in the internals structures during hot functional and low power physics tests. The main purpose of this testing program was to ensure that no unexpected large amplitudes of vibration existed in the internals structure during operation. The tests were extended to provide data and results on what were assumed to be indicators of overall core support structure performance and to verify particular stress and deflection quantities.

3.9.2.1.2 Dynamic Testing Procedure

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

During startup functional testing, piping, including supports and restraints, of certain systems was observed carefully by experienced startup personnel. At selected points of calculated maximum movement, visual inspection and/or measurements were taken and compared with those calculated to establish that stress limits are not exceeded.

If vibration was noted to cause piping or supports movements beyond those allowed, corrective action in the form of additional or redesigned supports, snubbers, etc. was

taken and the system was retested to determine that vibrations have been reduced to an acceptable level. Stress analysis on the system was rerun if deemed necessary by the designer. The systems and transients included in this program are listed below:

(1) RCPs start

(2) RCPs trip

(3) Main steam turbine stop valves trip

(4) Steam dump to condenser valves open

(5) Main steam safety and relief valves lift and blowdown

(6) Pressurizer relief valves lift and blow down (Unit 1 only)

(7) AFW pump turbine stop valve trip

(8) Charging pumps start and trip

(9) SI pumps start and trip

(10) RHR pumps start and trip

(11) Containment spray pumps start and trip

(12) Accumulators discharge to loops

(13) Pressurizer spray valves open and trip closed

(14) Pressurizer power relief valves open

Locations of observation points for piping movements for preoperational piping vibration tests for the above systems were determined from dynamic analysis performed on the piping systems, with system stiffness and restraint locations taken into account. Observed deflections were compared with code allowable values.

3.9.2.1.3 Dynamic System Analysis Methods for Reactor Equipment

To verify structural adequacy of reactor internal components and the reactor core for DCPP Unit 1 and Unit 2, nonlinear LOCA and seismic dynamic analyses are performed. These dynamic analyses are performed for both LOCA branch line break, as well as for seismic excitations of DDE and HE.

For faulted conditions, the response of reactor internals due to DDE or HE and LOCA conditions are additive by the SRSS method. The methods and techniques for these dynamic analyses are described below.

3.9.2.1.3.1 Reactor Equipment System Model

The LOCA and seismic dynamic analyses of the reactor vessel and internals were performed using reactor equipment system models (RESMs). The RESMs for Unit 1 and Unit 2 are shown in Figure 3.7-27E. The reactor and internals components are modeled with beam/pipe elements. Components are connected at various interfaces with concentric and unidirectional gap elements, as well as horizontal, vertical, and rotary spring elements, etc. As shown in the figure, the RESM consists of several connected sub-models, including reactor vessel, vessel support, thermal shield (Unit 1 only), core barrel, upper support structure, and fuel sub-models. In addition, the IHA and CRDM sub-model were incorporated into the RESMs.

The models used for the LOCA and seismic analyses are identical except that the LOCA model does not contain hydrodynamic mass elements between the core barrel and reactor vessel. The fluid-solid interaction in the annulus between the core barrel and reactor vessel is accounted for during the generation of the LOCA hydraulic forces.

Modal analyses for the Unit 1 and Unit 2 RESMs were completed, and mode shapes examined to ensure the frequencies predicted by the models are reasonable.

Reactor Vessel Submodel

The reactor vessel submodel consists of 3-D pipe elements to represent the reactor vessel cylindrical shell and 3-D lumped masses at the CG for the closure head, vessel flange, nozzles, and lower dome. The reactor vessel submodel is connected to ground by the vessel support submodel.

Vessel Support Submodel

The vessel support submodel consists of 12x12 stiffness matrices that connect the node on the vessel at the vessel/nozzle centerline to nodes at the geometric center of the bottom of each support pad. Each stiffness matrix represents the stiffness of the inlet or outlet nozzle at that location plus the local rotational stiffness of the reactor vessel shell. Vertical impact elements and horizontal linear spring elements connect each support pad node to ground. A 12x12 loop piping stiffness matrix also connects the reactor vessel to ground.

Thermal Shield Submodel (Unit 1 Only)

The thermal shield submodel consists of 3-D pipe elements that are coupled to the core barrel at the top and bottom. Unit 2 has neutron pads instead of a thermal shield. The neutron pads are accounted for by adjusting the properties of the core barrel for Unit 2 accordingly.

Core Barrel Submodel

The core barrel submodel consists of 3-D pipe elements to represent the core barrel cylindrical shell. Lumped masses are included at the center of gravity of the barrel flange, at the core barrel nozzle elevation, and at the CG of the lower support plate. The core barrel submodel is connected to the reactor vessel submodel at the top with nonlinear cylindrical gap elements in the horizontal direction, with nonlinear friction and impact elements in the vertical direction, and with linear rotary springs about the horizontal axes. Unidirectional gap elements are used at each outlet nozzle interface (i.e., between the barrel outlet nozzles and vessel outlet nozzles). At the bottom of the core barrel, the lower radial keys are modeled with a combination of linear gap elements and nonlinear spring elements in series and in parallel.

Upper Support Structure Submodel

The upper support structure submodel consists of rigid links to represent the upper support plate and deep beam and 3-D beam elements to represent the different types of upper support columns and also the guide tubes. Lumped masses are included at the upper core plate (UCP) and at the upper support plate CG. The upper support structure submodel is connected to the reactor vessel submodel with horizontal concentric gap elements, vertical friction and impact elements, and rotary springs about the horizontal axes in the same way that the core barrel submodel is connected to the vessel submodel. The upper support submodel is also connected to the core barrel submodel by nonlinear vertical springs (preloaded and open gap) and linear rotary springs about the horizontal axes (to represent the lower internals hold-down spring). The UCP is connected to the core barrel horizontally by a combination of concentric gap elements and nonlinear spring elements.

Fuel Submodel

The fuel submodel consists of 3-D beam elements and rotational spring elements. The simplified beam model accurately represents the dynamic characteristics of a fuel assembly at normal operating conditions. Each grid elevation is connected to the core barrel with a horizontal cylindrical gap element. The top fuel nozzle is coupled to the UCP in the horizontal (translational and rotational) degrees of freedom. The top fuel nozzle is also connected to the UCP in the vertical direction by nonlinear impact elements (preloaded and open gap). The bottom fuel nozzle is coupled to the lower core plate in the horizontal (translational and rotational) degrees of freedom. The bottom fuel nozzle is also connected to the lower core plate in the vertical direction by a nonlinear

impact element. The lower core plate is coupled in the horizontal (translational and rotational) degrees of freedom to the core barrel. The lower core plate is connected to the lower support plate in the vertical direction by a linear spring (to represent the lower support columns).

Integrated Head Assembly and Control Rod Drive Mechanism Submodels

The IHA model is a simple beam and lumped-mass model that represents the mass and dynamic characteristics of the IHA. The model used for the CRDMs is identical to the model for a standard Westinghouse-developed L106-A CRDM.

3.9.2.1.3.2 Time-History Loss-of-Coolant Accident and Seismic Input

For a seismic event, the RESM is excited by acceleration time histories in three orthogonal directions simultaneously. The following seismic events are considered for DCPP:

1. Design earthquake
2. Double design earthquake
3. Hosgri earthquake

For a LOCA event, the RESM is excited by time-history horizontal and vertical forces generated by the MULTIFLEX 3.0 (Reference 9) computer code (a Westinghouse-developed code for LOCA analysis). The LOCA events considered include accumulator line break in the cold leg, pressurizer surge line break in the hot leg, and RHR line break in the hot leg. For Unit 2, the RHR line was not analyzed because the RHR and pressurizer surge lines are the same size and virtually at the same break location.

3.9.2.1.3.3 Dynamic Analysis

The dynamic analysis of the RESM is completed in ANSYS by performing a full transient dynamic analysis of the model (direct integration solution using the full system matrices). In addition to the damping in local nonlinear impact elements, proportional damping is applied to the model. The use of proportional damping results in a nonlinear relationship between damping and frequency. The structure is overdamped for frequencies below the first significant mode of the internals that is not a fuel assembly mode (since the fuel assembly first mode is very highly damped), then underdamped over a broad frequency range, and finally overdamped for very high frequencies.

The results of the time-history analysis include, but are not limited to, the following:

1. Reactor vessel closure head time-history motions. These are used to generate acceleration response spectra.

2. Time-history core plate motions. These are used for the dynamic analysis of the core to generate fuel assembly grid impact loads.

3. Time-history vessel motions. These are used for the dynamic analysis of the primary RCL piping.

4. Loads at various internals-internals and vessel-internals component interfaces.

3.9.2.1.3.4 Reactor Internals Components Subjected to Horizontal Excitations (Reactor Internals Stress Report)

The following sections describe the reactor internals analysis methodology that includes LOCA analysis for the RCS branch line breaks. The response of reactor internals components due to an excitation produced by complete severance of a branch line pipe is analyzed. Assuming a pipe break occurs in a very short period of time, e.g., 1 millisecond, the rapid drop of pressure at the break produces a disturbance that propagates along the primary loop and excites the internal structures.

Analytical Methods

The RPV system finite element model as described in Section 3.9.2.1.3.1 was used to perform the LOCA analysis. Following a postulated LOCA pipe rupture, forces are imposed on the reactor vessel and its internals. These forces result from the release of the pressurized primary system coolant. The release of pressurized coolant results in traveling depressurization waves in the primary system. These depressurization waves are characterized by a wave front with low pressure on one side and high pressure on the other. The wave front translates and reflects throughout the primary system until the system is completely depressurized. The rapid depressurization results in transient hydraulic loads on the mechanical equipment of the system.

The LOCA loads applied to the RPV system consist of: (1) reactor internal hydraulic loads (vertical and horizontal), and (2) reactor coolant mechanical loads. All loads are calculated individually and combined in a time-history manner.

RPV Internal Hydraulic Loads

Depressurization waves propagate from the postulated break location into the reactor vessel through either a hot leg or a cold leg nozzle. After a postulated break in the cold leg, the depressurization path for waves enter the reactor vessel through the inlet nozzle into the region between the core barrel and reactor vessel. This region is called the downcomer annulus. The initial waves propagate up, around, and down the downcomer annulus, then up through the region circumferentially enclosed by the core barrel, that is, the fuel region.

The region of the downcomer annulus close to the break depressurizes rapidly, but because of restricted flow areas and finite wave speed (approximately 3,000 feet per second) the opposite side of the core barrel remains at a high pressure. This results in a net horizontal force on the core barrel and RPV. As the depressurization wave

propagates around the downcomer annulus and up through the core, the barrel differential pressure reduces, and similarly, the resulting hydraulic forces drop.

In the case of postulated break in the hot leg, the waves follow dissimilar depressurization path, passing through the outlet nozzle and directly into the upper internals region, depressurizing the core and entering the downcomer annulus from the bottom exit of the core barrel. Thus, after a break in the hot leg, the downcomer annulus would be depressurized with very little difference in pressure across the outside diameter of the core barrel.

A hot leg break produces less horizontal force because the depressurization wave travels directly to the inside of the core barrel (so that the downcomer annulus is not directly involved) and internal differential pressures are not as large as for a cold leg break. Since the differential pressure is less for a hot leg break, the horizontal force applied to the core barrel is less for a hot leg break than for a cold leg break. For breaks in both the hot leg and cold leg, the depressurization waves would continue to propagate by reflection and translation through the reactor vessel and loops.

The MULTIFLEX 3.0 computer code (Reference 3) calculates the hydraulic transients within the entire primary coolant system. It considers the subcooled transition, and two-phase (saturated) blow-down regimes. The MULTIFLEX 3.0 program employs the method of characteristics to solve the conservation laws, and assumes one-dimensionality of flow and homogeneity of the liquid-vapor mixture.

The MULTIFLEX 3.0 code considers a coupled fluid-structure interaction by accounting for the deflection of constraining boundaries, which are represented by separate spring-mass oscillator systems. A beam model of the core support barrel is developed from the structural properties of the core barrel. In this model, the cylindrical barrel is vertically divided into various segments and the pressure, as well as the wall motions, are projected onto the plane parallel to the broken inlet nozzle. Horizontally, the barrel is divided into segments; each segment consists of three separate walls. The spatial pressure variation at each time step is transformed into 10 horizontal forces that act on the 10 mass points of the beam model. Each flexible wall is bounded on either side of the hydraulic flow path. The motion of the flexible walls is determined by solving the global equations of motion for the masses representing the forced vibration of a damped beam.

RCL Mechanical Loads

The RCL mechanical loads are applied to the RPV nozzles by the primary coolant loop piping. The loop mechanical loads result from the release of normal operating forces present in the pipe prior to the separation as well as transient hydraulic forces in the RCS. The magnitudes of the loop release forces are determined by performing a RCL analysis for normal operating loads (pressure, thermal, and deadweight). The loads existing in the pipe at the postulated break location are calculated and are “released” at the initiation of the LOCA transient by application of the loads to the broken piping ends.

These forces are applied with the ramp time of 1 millisecond because of the assumed instantaneous break opening time. For breaks in the branch lines, the force applied at the reactor vessel would be insignificant. The restraints on the main coolant piping would eliminate any force to the reactor vessel caused by a break in the branch line.

Results of the Analysis

The severity of a postulated break in a reactor vessel is related to three factors: the distance from the reactor vessel to the break location, the break opening area, and the break opening time. The nature of the decompression following a LOCA, as controlled by the internals structural configuration previously discussed, results in larger reactor internal hydraulic forces for pipe breaks in the cold leg than in the hot leg (for breaks of similar area and distance from the RPV). Pipe breaks farther away from the reactor vessel are less severe because the pressure wave attenuates as it propagates toward the reactor vessel. The LOCA hydraulic and mechanical loads described in the previous sections were applied to the model of the RPV system.

The results of LOCA analysis include time-history displacements and nonlinear impact forces for all major components. The time-history displacements of the UCP, lower core plate, and core barrel at the UCP elevation are provided as inputs for the reactor core evaluations. The impact forces calculated at the vessel / internals interfaces are used to evaluate the structural integrity of the reactor vessel and its internals. Component linear forces are also calculated using the appropriate post-processors.

3.9.2.1.4 Correlation of Test and Analytical Results

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

The program used to establish the integrity of reactor internals has involved extensive design analysis, model testing, and post-hot functional inspection. Additionally, a full-size reactor has been instrumented to measure the dynamic behavior of a plant the size and type of DCPP. Measured values have been compared to predicted values.

The Indian Point II reactor has been established as the prototype for the DCPP Unit 1 internals verification program. The Trojan plant (Portland General Electric Company) provides additional internals verification for Unit 2. (Unit 1 has a thermal shield similar to Indian Point II; Unit 2 has neutron panels similar to Trojan.)

The only significant differences between the DCPP units' internals and Indian Point II are the modifications resulting from the use of a 17 x 17 fuel array in place of 15 x 15, and the replacement of the annular thermal shield with neutron shield panels. The change to neutron shield panels applies only to Unit 2. The change to 17 x 17 applies to both Unit 1 and Unit 2.

The only structural changes in the internals resulting from the design change from the 15 x 15 to the 17 x 17 fuel assembly are in the support columns and assembly guide tubes. The new 17 x 17 guide tubes are stronger and more rigid, hence they are less susceptible to flow-induced vibration problems. The fuel assembly itself is relatively unchanged in mass and spring rate, and thus no significant deviation is expected from the 15 x 15 fuel assembly vibration characteristics.

The remainder of the core structure design is identical to the prototypes that have been tested and proven to be well within design expectations and limits.

The Trojan plant is the lead plant featuring neutron panels and 17 x 17 fuel assemblies.

The Trojan plant internals were instrumented for strain measurements on the core barrel and on the guide tube subject to highest cross flow. The data obtained provided verification of Westinghouse analysis and scale model predictions of neutron panels and 17 x 17 internals behavior in a full-size plant.

The Four Loop Internals Assurance Program conducted on Indian Point II, supplemented by the Trojan data on neutron shield panels and 17 x 17 fuel assemblies, satisfy Safety Guide 20, December 1971 (Reference 12) with respect to adequate plant testing of internals similar to those employed at DCPP. The core support structures received, in addition, the normal pre- and post-hot functional testing examination for integrity in accordance with Paragraph D, "Regulations for Reactor Internals Similar to the Prototype Design," of Safety Guide 20, December 1971. This examination included the points shown in Figure 3.9-1 for Unit 1 and Figure 3.9-2 for Unit 2, and also:

(1) All major load bearing elements of the reactor internals relied on to retain the core structure in place

(2) The lateral, vertical, and torsional restraints provided within the vessel

(3) Those locking and bolting devices whose failure could adversely affect the structural integrity of the internals

(4) Those other locations on the reactor internal components that are similar to those which were examined on the prototype Indian Point II and Trojan designs

The interior of the reactor vessel was also examined for evidence of loose parts or foreign material. Specifically, the inside of the vessel was inspected before and after the hot functional tests, with all the internals removed, to verify that no loose parts or foreign materials were in evidence.

Lower Internals

A particularly close inspection was made on the following items or areas, using a 5x or 10x magnifying glass or penetrant test where applicable. The locations of these areas are shown in Figures 3.9-1 and 3.9-2 for Unit 1 and Unit 2, respectively:

(1) Upper barrel flange and girthweld

(2) Upper barrel to lower barrel girthweld

(3) UCP aligning pin (examine for any shadow marks, burnishing, buffing, or scoring; check for the soundness of lockwelds)

(4) Irradiation specimen basket welds

(5) Baffle assembly locking devices (check for lockweld integrity)

(6) Lower barrel to core support girthweld

(7) For Unit 1, the flexible tie connections (flexures) at the lower end of the thermal shield

(8) For Unit 2, the neutron shield panel locking devices and dowel pin cover plate welds (examine the connections for evidence of change in tightness of lockweld integrity)

(9) Radial support key welds to barrel

(10) Insert locking devices (examine soundness of lockwelds)

(11) Core support columns and instrumentation guide tubes (check all the joints for tightness and soundness of the locking devices)

(12) Secondary core support assembly welds

(13) Lower radial support lugs and inserts (Examine for any shadow marks, burnishing, buffing, or scoring. Checking the integrity of the lockwelds: these members supply the radial and torsional constraint of the internals at the bottom relative to the reactor vessel while permitting axial growth between the two. One would expect to see, on the bearing surfaces of the key and keyway, burnishings, buffing, or shadowing marks that would indicate pressure loading and relative motion between the two parts. Some scoring of engaging surfaces is also possible and acceptable.)

(14) For Unit 1, mounting blocks thermal shield to core barrel (examine the connections for evidence of change in tightness or lockweld integrity)

(15) For Unit 1 and Unit 2, gaps at baffle joints (check for gaps between baffle and top former and at baffle-to-baffle joints)

Upper Internals

A particularly close inspection was made on the following items or areas, using a magnifying glass of 5x or 10x magnification where necessary:

The locations of these areas are shown in Figures 3.9-1 and 3.9-2 for Unit 1 and Unit 2, respectively.

(1) Thermocouple conduits, clamps, and couplings

(2) Guide tube, support column, and thermocouple column assembly locking devices

(3) Support column and conduit assembly clamp welds

(4) UCP alignment inserts (Examine for any shadow marks, burnishing, buffing or scoring. Check for tightness and lock device integrity)

(5) Connections of the support columns, mixing devices, and orifice plates to the UCP (check for tightness and lock device integrity)

(6) Thermocouple conduit gusset and clamp welds

(7) Thermocouple end-plugs (check for tightness)

(8) Guide tube closure welds, tube-transition plate welds, and card welds

Acceptance standards are the same as required in the shop by the original design drawings and specifications.

During the hot functional test, the internals were subjected to a total operating time at greater than normal full flow conditions (four pumps operating) of at least 10 days. This provides a cyclic loading of approximately 10^7 cycles on the main structural elements of the internals. In addition, there was some operating time with only one, two, and three pumps operating. No signs of abnormal wear were found, no harmful vibrations were detected, and no apparent structural changes took place; therefore, the four loop core support structures are considered to be structurally adequate and sound for operation.

3.9.2.1.5 Analysis Methods Under Loss-of-Coolant Accident Loadings

The analysis methods used to confirm the structural design adequacy of the RCS under LOCA loadings are described in Section 5.2.2.1.11. Since the breaks postulated for the original analyses are more severe than those that are now required to be considered, the original analyses are conservative.

3.9.2.1.6 Analytical Methods for ASME Code Class 1 Components

Plastic instability allowable limits given in ASME Section III are not used when dynamic analysis is performed, except as noted in Section 5.2.2.1.11. The analysis methods have the limits established by the ASME Section III for Normal, Upset, and Emergency conditions. For these cases, the limits are sufficiently low to ensure that the analysis is not invalidated. For ASME Code Class 1 components, the stress limits for faulted loading conditions are specified in Section 5.2. For ASME components other than Class I and components not covered by the ASME Code, the stress limits for faulted loading conditions are specified in Sections 3.9.2.2 and 3.9.2.3, respectively. These faulted condition limits are established in such a manner that there is an equivalence with the adopted elastic limits and consequently will not invalidate the elastic system analysis.

3.9.2.1.7 Design and Analysis Details for the Pressurizer Safety and Relief System

The method of analysis for SVs and relief valves suitably accounts for the time-history of loads acting during and subsequent to valve opening (i.e., less than one second). The fluid-induced forcing functions are calculated for pertinent SV and relief valve discharge cases using one-dimensional equations for the conservation of mass, momentum, and energy.

The calculated forcing functions are applied at locations along the associated piping. Application of these forcing functions to the associated piping model constitutes the dynamic time-history analysis.

The dynamic response of the piping system is determined for the input forcing functions. Therefore, a dynamic amplification factor is inherently accounted for in the analyses.

Snubbers or strut-type restraints are used as required. The stresses resulting from the loads produced by the sudden opening of a relief or SV are combined with stresses due to other pertinent loads and are shown to be less than the allowable limits of the ANSI B31.1-1967 PG&E Quality/Code Class I and ANSI B31.7-1969 with 1970 Addenda for PG&E Quality/Code Class II and III pressurizer safety and relief system components. Also, the analyses show that the loads applied to the nozzles of the safety and relief valves do not exceed the maximum loads specified by the manufacturer.

The pressurizer safety and relief valve (PSRV) discharge piping systems provide overpressure protection for the RCS. The three spring-loaded SVs, located on top of the

pressurizer, are designed to prevent system pressure from exceeding design pressure by more than 10 percent. The three PORVs, also located on top of the pressurizer, are designed to prevent system pressure from exceeding the normal operating pressure by more than 100 psi. The valve outlet side is sloped to prevent the formation of water pockets. The SVs have been converted from water-seated to steam-seated, and the water loop seal was eliminated by providing a continuous drain.

The pressurizer SVs, manufactured by Crosby, are self-actuated, spring-loaded valves with backpressure compensation. The PORVs, manufactured by Masoneilan, are air-operated globe valves, capable of automatic operation via HP signal or remote manual operation. The SVs and relief valves are located in the pressurizer cubicle and are supported by the attached piping. If the pressure exceeds the setpoints, the valves open. Even though the water loop seal has been eliminated, the analysis has not been revised to reflect any added margins because the valve discharge conditions without the water slug are less severe than those originally considered with the water slug. With a pressurizer SV water loop seal (now eliminated), the water slug from the loop seal discharges and the water slug, driven by high system pressure, generates transient thrust forces at each location where a change in flow direction occurs. The valve discharge conditions are considered in the analysis of the PSRV piping systems as follows: (a) the three SVs remain closed, and (b) the three relief valves open simultaneously while the SVs are closed. In addition to these two cases, which consider water seal discharge (water slug followed by steam), solid water from the pressurizer (cold overpressure) is also investigated.

For each pressurizer safety and relief piping system, an analytical hydraulic model is developed. The piping from the pressurizer nozzle to the relief tank nozzle is modeled as a series of single pipes. The pressurizer is modeled as a reservoir which contains steam at constant pressure (approximately 2500 psia for safety system and approximately 2350 psia for relief system) and at constant temperature of approximately 680°F. The pressurizer relief tank is modeled as a sink which contains steam and water mixture.

Fluid acceleration inside the pipe generates reaction forces on all segments of the line which are bounded at either end by an elbow or bend. Reaction forces resulting from fluid pressure and momentum variations are calculated. These forces are defined in terms of the fluid properties for the transient hydraulic analysis. Unbalanced forces are calculated for each straight segment of pipe from the pressurizer to the relief tank. The time histories of these forces are used for the subsequent structural analysis of the pressurizer safety and relief lines.

The structural model used in the seismic analysis of the safety and relief lines is modified for the valves thrust analysis to represent the safety and relief valve discharge. The time-history hydraulic forces are applied to the piping system lump mass points. The dynamic solution for the valve thrust is obtained by using a modified predictor-corrector-integration technique and normal mode theory.

The time-history solution is performed in subprogram FIXFM3. The input to this subprogram consists of the natural frequencies and normal modes, applied forces, and nonlinear elements. The natural frequencies and normal modes for the modified pressurizer safety and relief line dynamic model are determined with the WESTDYN program. The support loads are computed by multiplying the support stiffness matrix and the displacement vector at each support point. The time-history displacements of the FIXFM3 subprogram are used as input to the WESDYN2 subprogram to determine the internal forces, deflections, and stresses at each end of the piping elements.

The loading combinations and acceptance criteria considered in the analysis of the PSRV piping are given in Table 3.9-1. These load combinations are consistent with the final recommendations of the piping subcommittee of the Electric Power Research Institute PWR PSRV performance test program.

3.9.2.2 ASME Code Class 2 and 3 Components

This section discusses the design criteria for PG&E Quality/Code Class II and III components. The design of these components is based on the requirements of various codes and standards that were in effect when the items were purchased. These codes and standards have been widely used by the nuclear industry and were, to a large extent, incorporated or referenced in the 1971 edition of the ASME BPVC Section III. If the 1971 edition of the ASME BPVC Section III, had been available during the design of DCPP, all these PG&E Quality/Code Class II and III components would have been in accordance with the requirements for ASME Code Class 2 and 3 components.

Table 3.2-3 lists the codes and standards to which PG&E Quality/Code Class II and III components were designed. The quality group classifications for DCPP mechanical systems and components are described in Section 3.2.2.

3.9.2.2.1 Plant Conditions and Design Loading Combinations

Design pressure, temperature, and other loading conditions that provide the bases for design of mechanical systems or components are presented in the corresponding sections that describe the components and systems; refer to Chapters 6, 7, 9, and 11. Design codes, standards, and their applicability to systems and components are presented in Section 3.2.2 and Table 3.2-3.

3.9.2.2.2 Design Loading Combinations

Design Criteria for Westinghouse supplied PG&E Quality/Code Class II and III components, are provided in Tables 3.9-2 through 3.9-7. Table 3.9-8 provides design information for selected tanks.

The loading combinations and acceptance criteria used for piping (except for PSRV piping) primary equipment, and primary equipment supports in the Westinghouse scope

of analysis are provided in Tables 5.2-5, 5.2-6, 5.2-6a, 5.2-7, and 5.2-8, and also in Tables 3.9-2 through 3.9-7.

3.9.2.2.3 Design Stress Limits

Stress limits for Westinghouse supplied PG&E Quality/Code Class II and III components are provided in Tables 3.9-2 through 3.9-7. Stress limits were selected to comply with the intent of ASME Code Section III and are sufficiently low to provide assurance that no gross deformation will occur in active components and that the active components will operate as required following the event. Active components are those whose operability is relied upon to perform a safety function such as safe shutdown of the reactor or mitigation of the consequences of a postulated pipe break in the RCPB. The limits established for passive (inactive) components are intended to ensure that violation of the pressure retaining boundary will not occur. Passive components are those whose operability (e.g., valve opening or closing, pump operation, or trip) are not relied upon to perform a safety function.

The designs of the CSTs, RWSTs, and the fire water and transfer tank are based on the AWWA D100, 1967 Code, with stress allowables restricted to those permitted by ASME Code Section VIII, Division 1. The design basis of these tanks is discussed in Section 3.8.2.4.

Load combinations and allowable stresses were taken from ANSI B31.1-1973 Summer Addenda. This code was used since the earlier codes did not address these load combinations and allowable stresses.

Piping stresses resulting from the seismic analyses are combined with deadload stresses, pressure stresses, and other stresses caused by other sustained loads, as suggested in ANSI B31.1-1973 Summer Addenda by the following equations:

$$\frac{PDo}{4t_n} + \frac{0.75iM_A}{Z} \leq 1.0S_h \qquad (3.9\text{-}1)$$

$$\frac{PDo}{4t_n} + \frac{0.75iM_A}{Z} + \frac{0.75iM_B}{Z} \leq 1.2S_h \qquad (3.9\text{-}2)$$

$$\frac{PDo}{4t_n} + \frac{0.75iM_A}{Z} + \frac{0.75iM_B'}{Z} \leq 1.8S_h \qquad (3.9\text{-}3)$$

$$\frac{PDo}{4t_n} + \frac{0.75iM_A}{Z} + \frac{0.75iM_B''}{Z} \leq 2.4S_h \qquad (3.9\text{-}4)$$

$$\frac{iMc}{Z} \leq S_A \qquad (3.9\text{-}5)$$

where:

S_h	=	basic material allowable stress at operating temperature, psi
P	=	internal pressure, psig
Do	=	outside diameter of pipe, in
t_n	=	nominal wall thickness of pipe, in
Z	=	section modulus, in^3
i	=	stress intensification factor. The product of 0.75 x i shall never be taken as less than 1
M_A	=	resultant moment loading on cross-section due to deadload and other sustained loads, in-lb
M_B	=	one-half of the resultant moment due to DE loads plus one-half of the full range of the resultant moment due to DE seismic anchor movements if not included in Equations 3.9-5 or 3.9-6
M_B'	=	same as M_B except that moments from DDE are used instead of DE and anchor movements due to DDE are excluded
M_B''	=	same as M_B except the moments from HE are used instead of DE and anchor movements due to HE are excluded
M_C	=	the larger of (a) the full range of resultant moment due to seismic anchor movements, or (b) the range of resultant moment due to normal thermal expansion and anchor movements plus one-half of the full range of resultant moment due to seismic anchor movements, in-lb
S_A	=	f (1.25 S_c + 0.25 S_h)
S_c	=	basic allowable stress at cold (ambient) temperature, psi
f	=	stress range reduction factor for cyclic loading = 1 (There are no events causing more than 7000 loading cycles for DCPP)

If Equation 3.9-5 is not satisfied, then the following equation must be satisfied:

$$\frac{PDo}{4t_n} + \frac{0.75iM_A}{Z} + \frac{iM_C}{Z} \leq (S_h + S_A) \qquad (3.9\text{-}6)$$

For hydrodynamic loadings the following stress equations must be satisfied:

$$\frac{PDo}{4t_n} + \frac{0.75iM_A}{Z} + \frac{0.75iM_D}{Z} \leq 1.2S_h \qquad (3.9\text{-}7)$$

$$\frac{PDo}{4t_n} + \frac{0.75iM_A}{Z} + \frac{0.75i}{Z}(M_B{}^2 + M_D{}^2)^{1/2} \leq 1.8S_h \qquad (3.9\text{-}8)$$

where:

M_D	=	Resultant moment due to hydrodynamic loads

All PG&E Design Class I pipe stresses were found to be within allowable limits specified in Equations 3.9-1 to 3.9-8.

Maximum allowable stresses for various loading combinations on hangers within B31.1 Code jurisdiction are as follows:

	DE	DDE	HE
Tension	0.417 Fy	0.9 Fy	Least of 1.2 Fy or 0.7 Fu
Shear	0.694 Fv	1.44 Fv	1.44 Fv
Compression	0.694 Fa	1.33 Fa	1.33 Fa
Bending	0.694 Fb	1.5 Fb	1.88 Fb
Bearing	0.625 Fy	Not Applicable	Not Applicable

where Fy, Fu, Fv, Fa, and Fb are from Section 1.5 of the AISC Steel Construction Manual, 7th Edition.

Supporting structures (supplemental steel) are in accordance with the 7th Edition of the AISC Steel Construction Manual. The stress limits and load combinations used by PG&E for equipment and equipment supports for their scope of analysis are:

DE Seismic Event

Component	Stress Limits (see notes a, b, c, d)
(Except cast iron) (active or inactive)	$Q_m \leq 1.1\ S$ $(Q_m \text{ or } Q_L) + Q_b \leq 1.65\ S$
Inactive cast iron, pressure-retaining components	$Q_p \leq 0.1\ S_u$ $(Q_m \text{ or } Q_L) + Q_b \leq 1.5 \times 0.1\ S_u$
Inactive cast iron, nonpressure-retaining components	$(Q_m \text{ or } Q_L) + Q_b \leq 1.0 \times 0.2\ S_u$
Support Element	
Plate and shell (see note e)	$Q_m \leq 1.0\ S$ $Q_m + Q_b \leq 1.5\ S$
Linear (see note f)	1974 ASME Code, Section III, Appendix XVII and Subsection NF
Bolts	1974 ASME Code, Section III, Appendix XVII and/or Code Case 1644, and/or AISC Manual, 7th Edition

DDE/HE Seismic Event

Component	Stress Limits (see notes a, b, c, f, h)
Inactive (Except cast iron)	$Q_m \leq 2.0\ S$ $(Q_m \text{ or } Q_L) + Q_b \leq 2.4\ S$
Active (Except cast iron)	$Q_m \leq 1.2\ S$ $(Q_m \text{ or } Q_L) + Q_b \leq 1.8\ S$
Inactive cast iron, pressure-retaining components	$Q_p \leq 0.1\ S_u$ $(Q_m \text{ or } Q_L) + Q_b \leq 2.4 \times 0.1\ S_u$
Inactive cast iron, nonpressure-retaining components	$(Q_m \text{ or } Q_L) + Q_b \leq 2.0 \times 0.2\ S_u$
Support Elements	
Plate and shell (see note e) (active components)	$Q_m \leq 1.2\ S$ $(Q_m + Q_b) \leq 1.8\ S$
Plate and shell (inactive components)	$Q_m \leq 2.0\ S$ $(Q_m + Q_b) \leq 2.4\ S$
Linear	1974 ASME Code, Section III, Appendix XVII, (see note f) Subsection NF and Appendix F (Stresses not to exceed S_y [see note g] for active components)
Bolts	1974 ASME Code, Section III, Appendix XVII and/or Code Case 1644 plus Appendix F and/or AISC Manual, 7th Edition

(a) Q_m = general membrane stress, ksi. This stress is equal to the average stress across the solid section under consideration. It excludes discontinuities and concentrations and is produced only by pressure and other mechanical loads.

(b) Q_L = local membrane stress, ksi. This stress is the same as Q_m except that it includes the effect of discontinuities.

(c) Q_b = bending stress, ksi. This stress is equal to the linear varying portion of the stress across the solid section under consideration, excludes discontinuities and concentration, and is produced only by mechanical loads.

(d) S = material allowable stress listed in either 1971 or 1974 ASME Code, Section III, or the code the component was purchased and manufactured under, allowable stress values. The allowable stress shall correspond to the highest metal temperature at the section under consideration during the condition under consideration.

(e) Plate and shell type supports: Plate and shell type component supports are supports such as vessel skirts and saddles that are fabricated from plate and shell elements and are normally subjected to a biaxial stress field.

(f) S_u = material minimum tensile strength listed in either the code the component was purchased and manufactured under, or ASME Code Section III.

(g) S_y = material allowable stress listed in either 1971 or 1974 ASME Code, Section III, or the code the component was purchased and manufactured under, minimum yield stress. The yield stress shall correspond to the highest metal temperature at the section under consideration during the condition under consideration.

(h) Q_p = local membrane stress, ksi. This stress is equal to the average stress across the solid section under consideration. It excludes discontinuities and concentrations and is produced only by pressure.

Load Combinations

(3.1.1) $DE + P_n + T_n + D + N + O$

(3.1.2) $DDE + P_a + T_a + D + N + O$

(3.1.3) $HE + P_n + D + N + O$

where the following loads apply, as applicable:

HE	=	loads from Hosgri earthquake
P_n	=	Pressure, normal
P_a	=	Pressure, accident
T_n	=	Temperature, normal
T_a	=	Temperature, accident
DE	=	DE
DDE	=	DDE
D	=	Deadweight
N	=	Nozzle
O	=	Operating

3.9.2.2.4 Analytical and Empirical Methods for the Design of Pumps and Valves

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The PG&E Quality/Code Class II and III pumps and valves were designed and constructed to PG&E Design Class I standards and manufactured under approved QA programs. *PG&E inspectors routinely performed audits, inspections, and witnessed testing of Quality Code Class II and III components as they were manufactured.*

The PG&E Quality/Code Class II and III pumps and valves were designed in accordance with the codes and standards listed in Tables 3.2-2 and 3.2-3. These were the codes and standards that were in effect when the items were purchased. The stress limits selected are sufficiently low to provide assurance that no gross deformations will occur in active components; therefore, the active components will perform as required.

The pumps purchased by Westinghouse were analyzed for the forces resulting from seismic accelerations in the horizontal and vertical directions applied simultaneously. The pumps were designed to have a natural frequency in excess of 30 Hz to eliminate any amplification of the seismic floor accelerations in the pump support structures.

The Westinghouse pumps were subjected to a series of tests prior to installation in the plant. The in-shop tests included (a) hydrostatic tests to 150 percent of the design pressure, (b) seal leakage tests, (c) net positive suction head tests to develop the minimum suction head necessary to allow operation, and (d) functional performance tests.

The pumps purchased by PG&E were designed in accordance with ASME standards or PG&E power plant pump standards. The design standards required were determined for each pump by reviewing the pump service conditions. Seismic calculations provided by the manufacturers were reviewed by PG&E to ensure that the loads developed from the combination of the design seismic horizontal and vertical acceleration did not exceed those allowed by applicable codes or standard engineering practices. Seismic calculations were not requested when the seismic adequacy could be ensured by testing or a comparative review of pump design. Hydrostatic tests to 150 percent of design pressure were performed on the pumps purchased by PG&E. The pumps also were subjected to performance tests consistent with the requirements of the Hydraulic Institute Standards or PG&E's power plant pump standards.

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In addition to the above described tests, which were performed prior to installation in the plant, numerous tests were performed on the pumps during the preoperational test period. Cold hydrostatic pressure tests, hot functional qualification tests, periodic inservice inspections, and periodic inservice operational tests are performed on PG&E Quality/Code Class II and III pumps after installation in the plant. These tests verify the

functional ability of the pumps and ensure the operability of active safety-related pumps for the design life of the plant.

The supports of all PG&E Quality/Code Class II and III pumps were designed to withstand the effects of the DE and reviewed for the DDE and HE. These considerations prevent supports of active safety-related pumps from deflecting and impairing the operability of the pump.

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Active pumps were qualified for operability by first being subjected to rigid tests both prior to installation in the plant and after installation in the plant. The in-shop test included (a) hydrostatic tests of pressure-retaining parts to 150 percent of the product of the design pressure times the ratio of material allowable stress at room temperature to the allowable stress value at the design temperature, (b) seal leakage tests, and (c) performance tests to determine total developed head, minimum and maximum head, net positive suction head requirements and other pump parameters. Bearing temperature and vibration levels were monitored during these operating tests. Bearing temperature limits and vibration levels were established by the manufacturer based on bearing materials, clearances, oil type and rotational speed. After a pump was installed in the plant, it underwent cold hydrostatic tests, and hot functional tests, and will undergo the required periodic inservice inspection operation. These tests demonstrated that a pump will function as required during all normal operating conditions for the design life of the plant.

In addition to these tests, the active pumps were qualified for operability by assuring that they will start, continue operating and not be damaged during the HE.

It was shown that the pumps will perform their design functions when subjected to loads imposed by the maximum seismic accelerations and maximum nozzle loads. It was required that test or analysis be used to show that the lowest natural frequency of each pump was greater than 33 Hz. A pump having a natural frequency above 33 Hz was considered rigid. This consideration avoids amplification between the component and structure for all seismic areas. A static shaft deflection analysis of rotors was performed with horizontal and vertical accelerations acting simultaneously. The deflections, determined from the static shaft analyses, were compared to the allowable rotor clearances. Pump and motor bearing loads were determined and shown to be below the manufacturer's specified levels.

To avoid damage during the postulated earthquake, the stresses caused by the combination of normal operating loads, earthquake, and dynamic system loads were limited to the limits indicated in Table 3.9-2. Pump casing stresses caused by the maximum nozzle loads were limited to the stresses outlined in Table 3.9-2. The maximum seismic nozzle loads combined with the loads imposed by the seismic accelerations were considered in the analysis of pump supports. Furthermore, calculated misalignment was shown to be less than that which could hinder pump

operation. The stresses in the supports were below those of Table 3.9-3. Therefore, support distortion is elastic and of short duration (no longer than the duration of the seismic event).

Performing these analyses with the loads and the stress limits of Tables 3.9-2 and 3.9-3, assures that critical parts of pumps will not be damaged during the postulated earthquake.

If the natural frequency was found to be below 33 Hz, an analysis was performed to determine the amplified input accelerations necessary to perform the static analysis. The adjusted accelerations were determined with the same conservatisms used for rigid structures. The static analysis was performed using the adjusted accelerations; the stress limits stated in Tables 3.9-2 and 3.9-3 were satisfied.

To complete the seismic qualifications procedures, the pump motors were qualified for operation during the maximum seismic event. Any auxiliary equipment which is vital to the operation of the pump or pump motor, and which was not qualified for operation with the pump or motor was qualified separately.

The above program gives assurance that the active pumps and motors would not be damaged and would continue operating under seismic loadings. These requirements demonstrate that the active pumps will perform their intended functions.

Since it has been demonstrated that the pumps would not be damaged during the earthquake, the functional ability of the active pumps after the earthquake is assured. Normal operating loads and steady state nozzle loads are the most probable conditions following an earthquake. The ability of the pumps to function under these loads is demonstrated during normal plant operation.

The PG&E Quality/Code Class II and III valves purchased by Westinghouse were designed to the pressure and temperature requirements of the American Standard Association (ASA) B16.5 or the Manufacturers Standardization Society Standard Practice No. 66 (MSS SP66). The valves were tested to the requirements of MSS SP61. These tests included hydrostatic shell and seat leakage tests.

The PG&E Quality/Code Class II and III valves purchased by PG&E were designed, manufactured, and tested in accordance with the Draft ASME Code for Pumps and Valves for Nuclear Power, November 1968 or later editions, the ASME Code, Section III-1974, ANSI B16.5, and/or the MSS SP66.

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In situ seismic testing of five representative valves was performed at the DCPP site. The purpose of this testing was to demonstrate that valves would indeed function when subjected to simulated seismic loads. Each valve was subjected to a static load applied at the center of gravity of the extended structure. The load was applied in the direction

that would yield the largest deflection for the given load. While the valve was held in the deflected position, the valve was stroked. Any differences in deflected valve stroking time, line voltage, and motor current (as compared to the undeflected readings) would indicate the effect of a seismic event on valve operability. The valve was again stroked open and closed after removal of the static load to demonstrate that the valve had returned to its initial condition.

The five selected valves tested by this method performed satisfactorily while subjected to the simulated load. The operability indicators of motor current, voltage, and valve stroke time were essentially the same for both the deflected and undeflected tests. During the preoperational piping dynamics effects test program described in Section 3.9.2.1.2, any excessive piping deflections and vibrations were noted and corrected. Since all valves are supported as part of adjoining piping, this program ensures that the deflections by the pipe (and valve) supports will not impair the operability of active safety-related valves. The attention given to the design, manufacture, and testing of the Quality Code Class II and III pumps and valves ensures that the components will operate as required during or following any expected plant transient.

An evaluation and tabulation of all active valves is presented in Table 3.9-9. An active valve is a valve that must perform a mechanical motion in order to shut down the plant or mitigate the consequences of a postulated event. Check valves with flow through the valves secured are considered passive devices. Check valves designed to close without operator action following an accident are considered active devices. The position each valve assumes on power failure is listed in this table.

The design approach and criteria used to ensure the protection of all critical systems and containment from the effects of pipe whip, are presented in Section 3.6. Section 3.6 also presents the criteria for postulated pipe breaks.

3.9.2.2.5 Design and Installation Criteria, Pressure-Relieving Devices

The main steam SVs are located outside the primary containment directly on main steam leads 1 and 2, and on external headers on main steam leads 3 and 4. Five SVs are provided for each steam generator, for a total of 20 SVs. The SV headers and main steam lead connections were designed to ANSI B31.1-1967. Fabrication and erection were in accordance with the ASME BPVC Section I-1968.

The SVs are of the single discharge type and were built in accordance with ASME BPVC Section III. The valve discharge consists of an elbow attached to the SV outlet. The elbow discharges into a stack that is structurally independent of the valve and is oriented at approximately 36° to the vertical centerline of the SV. The stacks are supported to restrain the discharge reactions. Provisions are made to ensure that the SV discharge elbow and stack have adequate clearances during all phases of operation.

With the above SV discharge arrangement, the sustained blow force developed during valve operation intersects the vertical centerline of the SV header nozzle and the base of

the header nozzle extrusion. The SV nozzles on the headers and on the main steam leads have been analyzed to ensure that the sustained forces developed during valve operation will not develop stresses in excess of those allowed by ANSI B31.1-1967.

The main steam leads are anchored by the main steam flued heads which are structurally located in the reactor containment wall and are supported for the deadweight, thermal, seismic, and SV forces that may develop within the PG&E Design Class I portion. The two external SV headers on main steam leads 3 and 4 are independently supported in a similar fashion.

3.9.2.2.6 Mechanical Equipment Seismic Qualification

Table 3.9-12 identifies PG&E Design Class I equipment that has been seismically qualified. The location, qualification method, seismic spectra, and damping values are part of the qualification.

3.9.2.2.7 Small Bore Piping Systems

DCPP Unit 1 and Unit 2 small bore PG&E Design Class I piping is analyzed by computer or designed using simplified spacing criteria.

3.9.2.3 Components Not Covered by ASME Code

3.9.2.3.1 Core and Internals Integrity Analysis (Mechanical Analysis)

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Stainless steel clad silver-indium-cadmium alloy absorber rods are resistant to radiation and thermal damage, thereby ensuring their effectiveness under all operating conditions. *Rods of similar design have been successfully used in the original and reload cores of San Onofre, Connecticut Yankee, and others.*

Two burnable poison rods (Reference 6) of smaller length but similar in design to those used in DCPP were exposed to in-pile test conditions in the Saxton Test Reactor in October 1967. A visual examination of the rods was made in early June 1968 and a visual and profilometer examination was made on July 30, 1968, after an exposure of 1900 effective full power hours (approximately 25 percent B^{10} depletion). The rods were found to be in excellent condition and profilometry results showed no dimensional variation from the initial condition.

An experimental verification of the reactivity worth calculations for borosilicate glass tubing has been accomplished. Similar rods have been successfully operated in the Ginna Reactor (Reference 7) with no evidence of deficiency.

Manufacturing defects did not appear during the hot functional tests because any manufacturing defects were detected in the shop or during the assembly period. The

basic program that is currently being used to ensure adequacy of manufacturing practices consists of:

(1) Extremely thorough nil ductility temperature and QA programs at the internals vendors

(2) Extensive visual examination at the plant site prior to hot functional testing of the primary system

(3) Running the hot functional test with full flow for 240 hours that accumulates approximately 10^7 cycles on the majority of the core structure components

(4) *Reexamining all areas of the internals after the 240-hour hot functional test*

The response of the reactor core and vessel internals under excitation produced by a simultaneous complete severance of a reactor coolant pipe and seismic excitation for a typical Westinghouse PWR plant internals was determined. The following mechanical functional performance requirements applied:

(1) Following the DBA, the basic operational or functional requirement to be met for the reactor internals is that the plant shall be shut down and cooled in an orderly fashion so that fuel cladding temperature is kept within specified limits. This implies that the deformation of certain critical reactor internals must be kept sufficiently small to allow core cooling.

(2) For large breaks, the reduction in water density greatly reduces the reactivity of the core, thereby shutting down the core whether the rods are tripped or not. The subsequent reflooding of the core by the ECCS with borated water maintains the core in a subcritical state. Therefore, the main requirement is to ensure effectiveness of the ECCS. Insertion of the control rods, although not needed, gives further assurance of the ability to shut the plant down and keep it in a safe shutdown condition.

(3) The functional requirements for the core structures during the DBA are shown in Table 3.9-10. The inward upper barrel deflections are controlled to ensure no contacting of the nearest rod cluster control guide tube. The outward upper barrel deflections are controlled in order to maintain an adequate annulus for the coolant between the vessel inner diameter and core barrel outer diameter.

(4) The rod cluster control guide tube deflections are limited to ensure operability of the control rods.

(5) To ensure no column loading of rod cluster control guide tubes, the UCP deflection is limited to the value shown in Table 3.9-10.

(6) The reactor has mechanical provisions that are sufficient to maintain the design core and internals and to ensure that the core is intact with acceptable heat transfer geometry following transients arising from the DBA operating conditions (References 2, 8, and 13).

(7) The core internals are designed to withstand mechanical loads arising from DE, DDE, HE and pipe ruptures (References 2, 4, 8, and 13). Note these loads are combined as described in Section 3.9.2.3.3.

3.9.2.3.2 Faulted Conditions (Reactor Internals Stress Report)

This section describes the reactor internals analysis methodology that includes LOCA analysis for the RCS branch line breaks, consistent with the reactor internals stress report.

The following events were considered in the faulted conditions category:

(1) Loads produced by the RCS branch line breaks.

(2) Bounding seismic loads are applied in the reactor internals stress analysis; DDE and HE are not specifically considered. The DCPP analyses reconcile plant specific seismic loads with the generic loads used in the analysis.

(3) Most unfavorable combination of DDE or HE and LOCA. Maximum stresses obtained from the seismic and LOCA load analyses were combined using the SRSS.

Maximum stress intensities are compared with allowables for each condition. When fatigue is of concern, the applicable stress concentrations factors are utilized and peak stresses are used to establish the usage factor. Elastic analysis is used to obtain the response of the structure and the stress analysis for each component is performed on an elastic basis. For faulted conditions, stresses are above yield in a few locations. For these cases only, when deformation requirements exist, a plastic analysis is independently performed to ensure that functional requirements are maintained (guide tubes deflections and core barrel expansions). The elastic limit allowable stresses are used to compare with the results of the analysis. No inelastic stress limits are used.

These analyses showed that the stresses and deflections that would result following a faulted condition are less than those that would adversely affect the integrity of the structures. Also, the natural and applied frequencies were such that resonance problems should not occur.

3.9.2.3.3 Reactor Internals Response Under LOCA and Seismic Excitations

Dynamic analyses were performed for the LOCA and seismic design conditions of DE, DDE, and HE.

The ANSYS computer code is used to determine the response of the RESM. ANSYS is a general purpose finite element code that is commonly used to perform dynamic analysis. In the finite element approach, the structure is divided into a finite number of discrete members (or elements). The inertia and stiffness matrices, as well as the force array, are first calculated for each element in the local coordinates. Employing appropriate transformations, the element global matrices and arrays are assembled into global structural matrices and arrays, and used for dynamic solution of the differential equation of motion for the structure. ANSYS uses the direct time integration method to solve the nonlinear model. An initial deadweight run is made to set the initial vertical interface gaps. The first time step performs the static solution of operating hydraulic forces.

3.9.2.3.3.1 Reactor Internals Response Under Seismic Excitations.

Refer to Sections 3.7.3.15.1 and 3.9.2.1.3.2 for discussion of the reactor internals seismic evaluation.

3.9.2.3.3.2 Reactor Pressure Vessel Internal Hydraulic Loads

Depressurization waves propagate from the postulated break location into the reactor vessel through either a hot leg or a cold leg branch line nozzle. After a postulated cold leg break, the depressurization path for waves entering the reactor vessel is through the nozzle that contains the broken pipe and into the region between the core barrel and the reactor vessel (that is, the downcomer region). The initial wave propagates up, around, and down the downcomer annulus, then up through the region circumferentially enclosed by the core barrel, that is, the fuel region. In the case of a cold leg break, the region of the downcomer annulus close to the break depressurizes rapidly but, because of the restricted flow areas and finite wave speed (approximately 3000 feet per second), the opposite side of the core barrel remains at a HP. This results in a net horizontal force on the core barrel and the reactor vessel. As the depressurization wave propagates around the downcomer annulus and up through the core, the core barrel differential pressure reduces and, similarly, the resulting hydraulic forces drop.

In the case of a postulated break in the hot leg, the wave follows a similar depressurization path, passing through the outlet nozzle and directly into the upper internals region depressurizing the core and entering the downcomer annulus from the bottom exit of the core barrel. Thus, after a hot leg break, the downcomer annulus would be depressurized with very little difference in pressure forces across the outside diameter of the core barrel. A hot leg break produces less horizontal force because the depressurization wave travels directly to the inside of the core barrel (so that the downcomer annulus is not directly involved), and internal differential pressures are not as large as for a cold leg break of the same size. Since the differential pressure is less for a hot leg break, the horizontal force applied to the core barrel is less for hot leg break than for a cold leg break. For breaks in both the hot leg and cold leg, the

depressurization waves continue to propagate by reflection and translation through the reactor vessel and loops.

3.9.2.3.3.2.1 Reactor Vessel and Internals Response During Loss-of-Coolant-Accident Conditions

Following a postulated LOCA pipe rupture, forces are imposed on the reactor vessel and its internals. These forces result from the release of the pressurized primary system coolant. The release of pressurized coolant results in traveling depressurization waves in the primary system. These depressurization waves are characterized by a wave-front with LP on one side and HP on the other. The wave-front translates and reflects throughout the primary system until the system is completely depressurized. The rapid depressurization results in transient hydraulic loads on the mechanical equipment of the system. The release of coolant resulting from a postulated LOCA pipe rupture also results in a pressure increase in the region surrounding the postulated break. Refer to Section 6.2.1.2.2 for discussion of LOCA subcompartment pressurization.

The loads on the RPV and internals that result from the depressurization of the system and from the pressurization of the area around the break may be categorized as: (a) reactor internal hydraulic loads (vertical and horizontal), and (b) RCL mechanical loads.

The DCPP Unit 1 and Unit 2 LOCA vessel forces analyses and Unit 2 guide tube loads were analyzed. The Unit 1 analysis conservatively assumed a limiting full power RCS cold leg temperature of 526.7°F (including uncertainty) which bounds the minimum cold leg temperature of 531.7°F (excluding uncertainty) for Unit 1 operation. The Unit 2 analysis conservatively assumed a limiting full power RCS cold leg temperature of 526.9°F (including uncertainty) which bounds the minimum cold leg temperature of 531.9°F (excluding uncertainty) for Unit 2. These conditions bound the most severe operating conditions. The break locations analyzed for Unit 1 and Unit 2 are consistent with standard methodology.

3.9.2.3.4 MULTIFLEX Analysis of Blowdown Forces

A USNRC approved FORTRAN-IV computer program called MULTIFLEX (Reference 3) was originally used to calculate the local fluid pressure, flow, and density transients that occur during a LOCA.

MULTIFLEX 3.0 (Reference 9) is an extension of MULTIFLEX 1.0 (Reference 3) and models a more realistic downcomer hydraulic network and a more realistic core barrel structural model that accounts for non-linear boundary conditions and vessel motion. Generally, this improved modeling results in lower, more realistic, but still conservative hydraulic forces on the core barrel. The NRC staff has accepted (Reference 10) the use of MULTIFLEX 3.0 for calculating the hydraulic forces on reactor vessel internals (Reference 11).

The MULTIFLEX 3.0 computer code (Reference 9) calculates the hydraulic transients within the entire primary coolant system. It considers subcooled, transition, and two-phase (saturated) blowdown regimes. The MULTIFLEX 3.0 code employs the method of characteristics to solve the conservation laws, and assumes one-dimensionality of flow and homogeneity of the liquid-vapor mixture. The MULTIFLEX 3.0 code considers a coupled fluid-structure interaction by accounting for the deflection of constraining boundaries, which are represented by separate spring-mass oscillator system. A beam model of the core support barrel has been developed from the structural properties of the core barrel; in this model, the pressure as well as the wall motions are projected onto the plane parallel to the broken nozzle. The spatial pressure variation at each time step is transformed into ten horizontal forces, which act on the ten mass points of the beam model. Each flexible wall is bounded on either side by a hydraulic flow path. The motion of the flexible walls is determined by solving the global equations of motion for the masses representing the forced vibration of a damped beam.

The analysis is performed for the subcooled decompression period of the transient, where the hydraulic loads are the greatest. These loads are used for the structural evaluation of the RPV support system, in conjunction with other loads associated with a LOCA and with a safe shutdown earthquake (SSE).

3.9.2.3.4.1 FORCE2 and LATFORC Models for Blowdown

The MULTIFLEX 3.0 code (Reference 9) evaluates the pressure and velocity transients throughout the RCS. These pressure and velocity transients are made available to the programs FORCE2 and LATFORC, which utilize detailed geometric descriptions in evaluating the loadings on the reactor internals.

LATFORC (Reference 3) is used to calculate the horizontal force components on the vessel, core barrel, and thermal shield as a function of elevation and time using the MULTIFLEX 3.0 hydraulic data. The force components significant to the horizontal forces are primarily a function of the pressure times area.

FORCE2 (Reference 3) is used to calculate the vertical force components acting on the reactor vessel and internals. Each reactor component for which FORCE2 calculations are required is designated as an element and assigned an element number. Forces acting on each of the elements are calculated summing the effects of:

(1) The pressure differential across the element.

(2) Flow stagnation on, and unrecovered orifice losses across, the element.

(3) Friction losses along the element.

The most significant assumption made for the analysis is that the thermal-hydraulic analysis has been performed to include mechanical structural models of the core barrel,

which allows for fluid structure interaction in the downcomer region of the vessel to decrease the peak pressures calculated on the core barrel and vessel. No other fluid structure interaction has been modeled in the vessel LOCA forces calculation.

3.9.2.3.4.2 Reactor Coolant Loop Mechanical Loads

The loop mechanical loads result from the release of normal operating forces present in the pipe prior to the separation as well as transient hydraulic forces in the RCS. The magnitudes of the loop release forces are determined by performing a RCL analysis for normal operating loads (that is, pressure, thermal, and deadweight). The loads existing in the pipe at the postulated break location are calculated and are "released" at the initiation of the LOCA transient by application of the loads to the broken piping ends. These forces are applied with a ramp time of one millisecond because of the assumed instantaneous break opening time.

3.9.2.3.4.3 Reactor Cavity Pressurization Loads

Reactor cavity forces arise from the steam and water that are released into the reactor cavity through the annulus around the broken pipe. These forces occur for postulated breaks in certain RCS branch lines. The reactor cavity is pressurized asymmetrically, with HPs on the side adjacent to the break. The horizontal differences in pressure across the reactor cavity result in horizontal forces on the reactor vessel. Vertical forces on the reactor vessel arise from similar variations in pressures on the upper and lower head and the tapered parts of the vessel. Refer also to Section 6.2.1.2.

3.9.2.3.4.4 Jet Impingement Loads

The jet impingement load is an axial force along the broken pipe centerline that is caused by the pressure of the escaping jet of coolant acting on the exposed pipe cross-section at the break location. The jet force is calculated by multiplying the saturation pressure corresponding to the temperature of the coolant at break location times the cross-sectional area of the pipe. This force is applied with a ramp time of one millisecond.

3.9.2.3.5 Acceptance Criteria

3.9.2.3.5.1 Structural Adequacy of Reactor Internal Components

The reactor internal components of DCPP Unit 1 and Unit 2 are not ASME Code components because Sub section NG did not exist in the ASME Boiler and Pressure Code. The allowable stress limits for the DBA for core support structures are based on limits specified in the ASME Code, Subsection NG, 1971 Edition through Winter 1973 Addenda.

3.9.2.3.5.2 Allowable Deflection and Stability Criteria.

The criterion for acceptability in regard to mechanical integrity analyses is that adequate core cooling and core shutdown must be ensured. This implies that the deformation of reactor internals must be sufficiently small so that the geometry remains substantially intact. Consequently, the limitations established on the reactor internals are concerned principally with the maximum allowable deflections and stability of the components.

For faulted conditions, deflections of critical internal structures are limited to values given in Table 3.9-10. In a hypothesized vertical displacement of internals, energy absorbing devices limit the displacement to 1.25 inches by contacting the vessel bottom head.

Upper Core Barrel

The upper core barrel has the following deformation limits:

(1) To ensure shutdown and cooldown of the core during cold leg blowdown, the basic requirement is a limitation on the outward deflection of the barrel at the locations of the inlet nozzles connected to unbroken lines. A large outward deflection of the upper barrel in front of the inlet nozzles, accompanied with permanent strains, could close the inlet area and restrict the cooling water coming from the accumulators. Consequently, a permanent barrel deflection in front of the unbroken inlet nozzles larger than a certain limit, called “no loss of function” limit, could impair the efficiency of the ECCS.

(2) During the hot leg break, the rarefaction wave enters through the outlet nozzle into the upper internals region and thus depressurizes the core and then enters the downcomer annulus from the bottom exit of the core barrel. This depressurization of the annulus region subjects the core barrel to external pressures and this condition requires a stability check of the core barrel during hot leg break. Therefore, to ensure rod insertion and to avoid disturbing the control rod cluster guide structure, the barrel should not interfere with the guide tubes.

Control Rod Cluster Guide Tubes

The deflection limits of the guide tubes were established from test data (refer to Table 3.9-10).

Upper Package

The local vertical deformation of the UCP, where a guide tube is located, shall be less than 0.100 inch. This deformation will cause the plate to contact the guide tube, since the clearance between the plate and the guide tube is 0.100 inch. This limit will prevent

the guide tubes from undergoing compression. For a plate local deformation of 0.150 inch, the guide tube will be compressed and deformed transversely to the upper limit previously established. Consequently, the value of 0.150 inch is adopted as the no loss function local deformation with an allowable limit of 0.100 inch. These limits are given in Table 3.9-10.

3.9.2.3.6 Methods of Analysis

The LBB analysis (Reference 14) allows for exclusion of main loop piping breaks from the design basis, so credit has been taken for the smaller branch line areas in the current reactor vessel LOCA forces analyses for Unit 1 and Unit 2. When credit for this break area reduction is taken, it provides substantial margin relative to the original DBA loads.

For the vessel forces analyses, the pressurizer surge line break (103.87 in^2) and RHR line break (98.31 in^2) on the hot leg and the accumulator line break (60.13 in^2) on the cold leg were analyzed for Unit 1. The pressurizer surge line break (98.31 in^2) on the hot leg and the accumulator line break (60.13 in^2) on the cold leg were analyzed for Unit 2. All breaks were analyzed using the MULTIFLEX 3.0 code (Reference 9). The analyses used a 1 millisecond BOT, consistent with the MULTIFLEX licensing requirements. All break cases used flexible beam modeling for the core barrel. The analysis conservatively assumed limiting full power RCS temperatures. These conditions bound the most severe operating conditions.

3.9.2.3.6.1 Reactor Vessel/Internals/Fuel Analysis Under LOCA Conditions

The 3-D LOCA analysis of the RPV system (i.e., reactor vessel/internals/fuel) is discussed in Sections 3.9.2.1.3.1 and 3.9.2.1.3.2 and provides insight into the description of major core support components during LOCA transients.

3.9.2.3.6.2 Reactor Vessel/Internals/Fuel Analysis Under Seismic Conditions

The 3-D seismic analysis of the RPV system (i.e., reactor vessel/internals/fuel) is discussed in Section 3.7.2, and the methods of analyses for seismic loads of major subsystems are discussed in Section 3.7.3.

3.9.2.3.6.3 Methods and Results (Mechanical)

To verify structural adequacy of the reactor internal components and the core under LOCA and seismic loading, nonlinear time history dynamic analyses of the RPV system were performed to generate component interface loads as well as the time history displacements of the lower core plate, UCP, and the core barrel. These time history displacements of the core plates and the barrel were then used to determine the fuel grid impact loads and the structural adequacy of the core components.

The results of RPV system LOCA and seismic analyses demonstrate that the reactor internals component interface loads for DCPP Unit 1 and Unit 2 for LOCA and seismic loading are bounded by those of the reactor internals stress report (refer to Section 3.9.2.3.2). In the reactor internals stress report, the four-loop reactor internals components are analyzed to meet the ASME Code Subsection NG 1974 stress requirements.

The results also indicate that the maximum deflections in the critical structures are below the established allowable limits (refer to Table 3.9-10). The design evaluation of the internals structure is presented in Section 4.2.2.

3.9.2.3.7 Control Rod Drive Mechanisms

The CRDMs are PG&E Quality/Code Class I components designed to meet the stresses of the ASME Boiler and Pressure Vessel Code and therefore are presented in Section 4.2.3.

3.9.2.4 Non-Design Class I Components

Several PG&E Design Class II and III components were also seismically qualified to preclude seismic interaction with PG&E Design Class I equipment and/or to ensure structural integrity of the CCW system.

3.9.2.5 Miscellaneous Pressurized Gas Containers

Table 3.9-11 provides a summary of storage tanks located outside containment containing significant quantities of gas under pressure in excess of 100 psig.

3.9.3 SAFETY EVALUATION

3.9.3.1 General Design Criterion 1, 1967 – Quality Standards

The PG&E Design Class I mechanical systems and components, as discussed in Section 3.2.2 and the Diablo Canyon Quality Assurance Program Description implements quality standards that satisfy the requirements of GDC 1, 1967 (refer to Section 3.9.1.1).

3.9.3.2 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I mechanical systems and components are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other natural phenomena, and to protect SSCs to ensure their safety-related functions and designs are maintained. Refer to Sections 3.9.2.1 through 3.9.2.3 for detailed discussion of the mechanical components design basis.

3.9.3.3 General Design Criterion 4, 1987 – Environmental and Dynamic Effects Design Bases

Refer to Section 3.6.2.1.1.1 for discussion of the LBB methodology and application to the primary loops of DCPP Unit 1 and Unit 2. As discussed in Sections 3.9.2.1.3.4 and 3.9.2.3.2, the reactor internals stress report is based on the RCS large main loop breaks. However the application of LBB was applied to generate dynamic LOCA loads from RCS branch line breaks and these loads were compared to the reactor internals stress report as discussed in Section 3.9.2.3.6.3.

3.9.3.4 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The PG&E Quality/Code Class I mechanical systems and components of the RCPB are designed to have an exceedingly low probability of gross rupture or significant leakage throughout its design lifetime as described in Section 5.2. The loads imposed on the RCPB under normal operating conditions, abnormal loading conditions, such as seismic loading and pipe rupture are considered and discussed in Sections 3.6 and 3.7. Refer to Sections 3.9.2.1.5, 3.9.2.1.6, and 3.9.2.1.7 for additional information.

3.9.3.5 General Design Criterion 33, 1967 – Reactor Coolant Pressure Boundary Capability

The capability of the RCPB is described in Section 5.2.

3.9.3.6 General Design Criterion 40, 1967 – Missile Protection

The PG&E Design Class I mechanical systems and components ESFs as discussed in Sections 3.5, 3.6.3, 3.9.2.1.3 and 3.9.2.3 are designed to or are provided with protection from dynamic effects that might result from plant equipment failure.

3.9.3.7 10 CFR 50.55a - Codes and Standards

PG&E Quality/Code Class I is applied to those components of the RCPB and implements the quality standards that satisfy the requirements of 10 CFR 50.55a. PG&E Quality/Code Class I components of the RCPB are listed in Table 3.2-3, along with the industry codes and standards used for their design, fabrication, erection, and testing (refer to Table 3.2-2).

3.9.3.8 10 CFR 50.55a(f) – Inservice Testing Requirements

The IST requirements for the PG&E Design Class I mechanical systems and components (i.e., active pumps and valves) are contained in the DCPP Unit 1 and Unit 2 IST Program Plan. Refer to Section 3.9.2.2.4 for analytical and empirical methods for design of pumps and valves. Refer to Table 3.9-9 for an evaluation and tabulation of all active valves.

3.9.3.9 Safety Guide 20, December 1971 - Vibration Measurements on Reactor Internals

DCPP Unit 1 and Unit 2 reactor internals, as discussed in Table 14.1-1, following hot functional testing, the reactor internals were removed and inspected for signs of excessive vibration. Refer to Section 3.9.2.1.4 for additional discussion about preoperational testing of reactor internals.

3.9.3.10 NUREG-0737 (Item II.D.1), November 1980 - Clarification of TMI Action Plan Requirements

Item II.D.1 – Relief and Safety Valve Test Requirements: DCPP Unit 1 and Unit 2 participated in the Electric Power Research Institute Test Program performance testing of the relief and SVs and associated piping and supports which demonstrated the ability of the RCS PORVs, PORV block valves, SVs, and associated piping to function under expected operating conditions for design basis transients and accidents. Refer to Section 3.9.2.1.7 for additional information.

3.9.4 REFERENCES

1. Deleted in Revision 1.

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4. Moore, Westinghouse PWR Core Behavior Following a Loss-of-Coolant Accident, WCAP-7422, September 1971.

5. Bohm, and J. P. Lafaille, Reactor Internals Response under a Blowdown Accident, First Intl. Conf. on Structural Mech. in Reactor Tech., Berlin, September 20-24, 1971.

6. Wood et al., Use of Burnable Poison Rods in Westinghouse Pressurized Water Reactors, WCAP-7113, October 1967.

7. Barry et al., Topical Report - Power Distribution Monitoring in the R.E. Ginna PWR, WCAP-7756, September 1971.

8. Gesinski, Fuel Assembly Safety Analysis for Combined Seismic and Loss-of-Coolant Accident, WCAP-7950, July 1972.

9. Takeuchi, K. et al., MULTIFLEX 3.0, A FORTRAN IV Computer Program for Analyzing Thermal-Hydraulic-Structural System Dynamics Advanced Beam Model," WCAP-9735, Revision 2, Westinghouse Proprietary Class 2/WCAP-9736, Revision 1, Non-Proprietary, February 1998.

10. Letter, T. H. Essig (USNRC) to Lou Liberatori (WOG), Safety Evaluation of Topical Report WCAP-15029, "Westinghouse Methodology for Evaluating the Acceptability of Baffle-Former-Barrel Bolting Distributions Under Faulted Load Conditions", (TAC No. MA1152)," November 10, 1998 (Enclosure 1 – Safety Evaluation Report.

11. Schwirian, R. E., et al., Westinghouse Methodology for Evaluating the Acceptability of Baffle-Former-Barrel Bolting Distributions Under Faulted Load Conditions, WCAP-15029-P-A, Westinghouse Proprietary Class 2 / WCAP-15030-NP-A, Revision 0, Non-Proprietary, January 1999.

12. Safety Guide 20, Vibration Measurements on Reactor Internals, December 19, 1971.

13. PG&E Letter DCL-88-288, LAR 88-08, Request to Use VANTAGE 5 Fuel Assemblies, November 29, 1989.

14. Letter dated March 2, 1993, Leak-Before-Break Evaluation of Reactor Coolant System Piping for DCPP Units 1 and 2, (Docket Nos. 50-275 and 50-323), from Sheri R. Peterson of the NRC to Gregory M. Rueger of PG&E.

15. Deleted in Revision 23.

16. Deleted in Revision 21.

17. Deleted in Revision 23.

18. WCAP-8172-A, Pipe Breaks for the LOCA Analysis of the Westinghouse Primary Coolant Loop, January 1975.

19. Deleted in Revision 23.

20. Deleted in Revision 22.

3.10 SEISMIC DESIGN OF PG&E DESIGN CLASS I INSTRUMENTATION, HVAC, AND ELECTRICAL EQUIPMENT

3.10.1 DESIGN BASES

3.10.1.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I instrumentation, HVAC, and electrical equipment have been designed and analyzed to withstand those forces that might result from the most severe natural earthquake phenomena.

The guidance of IEEE 535-1979 Qualification of Class 1E Lead Storage Batteries for Nuclear Power Generating Stations is required for the qualification of the Class 1E batteries.

3.10.1.2 Regulatory Guide 1.100, Revision 1, August 1977 – Seismic Qualification of Electric Equipment for Nuclear Power Plants

PG&E Design Class I electrical equipment are seismically qualified in accordance with Regulatory Guide 1.100, Revision 1.

3.10.1.3 Regulatory Guide 1.100, Revision 2, June 1988 – Seismic Qualification of Electric and Mechanical Equipment for Nuclear Power Plants

New PG&E Design Class I electrical equipment not previously seismically qualified may be qualified in accordance with Regulatory Guide 1.100, Revision 2.

3.10.2 SEISMIC DESIGN CRITERIA

The PG&E Design Class I instrumentation, HVAC, and electrical equipment are capable of performing their nuclear safety functions during and after a DDE or HE. The seismic levels for DDE and HE are given in Section 3.7. PG&E Instrument Class IA instrumentation is capable of performing its active nuclear safety functions during and after a DDE or HE. PG&E Instrument Class IB Category 1 instrumentation is capable of performing its active nuclear safety functions after a DDE or HE. Other PG&E Design Class I instrumentation is capable of performing the passive function of maintaining Class I PBI during and after a DDE or HE. In addition, some of the PG&E Design Class I instrumentation may have active seismic qualification; these instruments are identified on a case-by-case basis. For the requirements of PG&E instrumentation refer to Section 3.2.2.5 and Table 3.2-1.

Performance criteria for PG&E Design Class I instrumentation, HVAC, and electrical equipment are as follows: (a) The reactor protection system shall be able to shut down the unit and maintain it in safe shutdown condition. (b) The electrical equipment is able to perform its required functions of providing electrical power, control, instrumentation,

and protection for the ESF. (c) No device shall fail to initiate and maintain its safety function, nor shall it prevent other safety devices from performing their safety function.

The original seismic qualification of most equipment was done in accordance with IEEE 344-1971 (Reference 1) for DDE levels. As a result of changes in spectra the PG&E Design Class I equipment has been reevaluated, based on response spectra derived from the HE as well as the DDE levels discussed in Section 3.7. In the process of reevaluation, some equipment had to be requalified because: (a) its previous qualification was not adequate to envelop the HE input, or (b) concerns had been raised about the adequacy of the justification for the previous qualification methods. Requalification of the equipment, according to the guidance contained in IEEE 344-1975 (Reference 2) and Regulatory Guide 1.100, Revision 1 (Reference 3) was performed where necessary. New electrical equipment not previously seismically qualified may be qualified in accordance with IEEE 344-1987.

Tables 3.10-1 and 3.10-2 list instrumentation and electrical equipment that have been seismically qualified. The tables provide references to appropriate sections where qualification is described. Table 3.10-3 lists HVAC equipment that has been seismically qualified. Design and acceptance criteria for HVAC equipment are discussed in Section 3.10.3.33.

The seismic qualification of the equipment is based on the free-field ground motions described in Section 3.7.1. Effects of amplification of ground accelerations due to the response of the building at the location of the equipment were derived from the time-history modal superposition analyses made for the structures, as described in Section 3.7.

In addition to direct seismic effects on PG&E Design Class I equipment, PG&E has also given consideration to possible seismically induced physical interactions between PG&E Design Class II & III SSCs and PG&E Design Class I SSCs. The methodology and results of this interaction study are presented in Reference 4, and are provided in summary form in Section 3.7.3.13. Appropriate design modifications were performed where the study indicated safety functions of PG&E Design Class I equipment might be affected due to seismic interaction.

3.10.3 SEISMIC ANALYSES, TESTING PROCEDURES, AND RESTRAINT MEASURES

The effects of seismic accelerations were determined either by physical tests, mathematical analyses, or engineering judgment. Mathematical analyses of structural elements were made for PG&E Design Class I exposed electrical raceways, for equipment supports, and also for some equipment. Physical tests of equipment were made either on one of the units being supplied or on one of a similar type. Choice of method used to determine seismic capability of the equipment and devices was based on the supplier's judgment of what would be adequate and appropriate.

For a discussion of the seismic design bases at DCPP refer to Sections 2.5, 3.2.2.4 and 3.7.1.

3.10.3.1 Nuclear Reactor Instrumentation and Protection Systems

The seismic testing of Westinghouse-supplied electrical and control equipment is documented in Reference 5. The testing conforms to the procedures of IEEE 344-1971. The radiation monitoring cabinet and the Tracerlab scintillation detector and liquid sampler equipment are not PG&E Design Class I, and these portions of Reference 5 are not applicable. The radiation monitoring system (RMS) cabinet at DCPP has been upgraded to PG&E Design Class I (refer to Section 3.10.3.26).

Typical items of equipment have been type tested under simulated seismic motion in the form of sine beats. This testing was done with conservatively large accelerations over a range of applicable frequencies and conformed to the procedures given in IEEE 344-1971. The peak test input accelerations used in those tests were checked to verify that they are larger than the requirements derived by structural analyses of DDE and HE levels. Westinghouse Electric Company, the supplier, made dynamic tests of typical samples of this equipment to confirm its seismic adequacy. Included in this test program were the racks for the NIS; the process control and protection sets; the solid-state protection system cabinets and its safeguards test cabinets and auxiliary safeguards cabinets; the inverters for the power supply; pressure and differential pressure transmitters; the reactor trip switchgear; and main coolant loop resistance temperature detectors (RTDs). Details of these tests are given in Table 3.10-1 and in Sections 3.10.3.1.1 to 3.10.3.1.9.

3.10.3.1.1 Nuclear Instrumentation

As described in Reference 5, a typical two-cabinet unit of the Westinghouse NIS and RMS has been seismically tested. The NIS equipment was contained in one cabinet and the RMS equipment was mounted in the other cabinet. The two cabinets were attached and mounted on a two-cabinet base to simulate the support of adjoining cabinets. A typical NIS installation consists of four cabinets.

The NIS cabinet contained one source range channel, one intermediate range channel, and one power range channel located and mounted in the same configuration as the plant installation. Since any DBA can be terminated within acceptable limits by the power range channels, only the power range channel was energized and monitored. The other NIS channels mounted in the cabinet served to simulate the mass distribution and weight in an actual installation.

Shutdown procedures contain the following provisions in the event that the source range channels are rendered inoperative due to a seismic event:

(1) The operator will take appropriate action to preclude boron dilution

(2) Prior to cooldown, boric acid will be added to the reactor coolant to ensure that the concentration is sufficient to maintain the reactor in a subcritical state

During seismic testing an external test signal was applied to the equipment so that the power range output signal was 100 percent full power. The test input signals, analog output signals, and bistable output signals were monitored during test. The tripping action of the bistable amplifier circuitry was checked after each series of tests to insure that the simulated earthquake had not impaired this function.

Only one instance of mechanical malfunction occurred as a result of this level of testing. Drawer latch damage occurred during side-to-side testing at higher g levels. A new fastening mechanism has been designed and the design submitted to the NRC (Reference 6). This modification was implemented at DCPP. A demonstration test for seismic operability of the NIS equipment was performed with multiple frequency, multiple axis inputs. The test, reported in Reference 7, indicated that the equipment will operate during a seismic event as required.

The neutron detector for the NIS power range channel has been tested using sinusoidal inputs in both the horizontal and vertical directions at accelerations at least equal to those calculated for the DCPP. Neutron current measurements were made during the tests, and current, resistance and capacitance checks were made after the tests. No significant changes were found and there was no mechanical damage to the detector.

In addition, a two-section power range excore neutron detector was tested using multiple frequency, multiple axis inputs in a support assembly which simulated a detector holder. The multiple frequency inputs were developed in accordance with the guidelines set forth in Reference 8. The test response spectra envelope the DDE and HE inputs.

During the multiple frequency test, the detector was energized from a high voltage power supply, and an ac signal was imposed in each of the two signal electrodes to determine proper electrical operability.

At the completion of the tests, there was no observable mechanical damage and the electrical recordings revealed only a transient type electrical disturbance of one of the two signals. The signal perturbations were small in amplitude and would not cause any loss of protection capability of the NIS during normal operation. Subsequent detector acceptance tests performed by the detector manufacturer did not disclose any abnormal permanent change in the electrical or neutron sensitivity characteristics. Thus the NIS Power Range Detector will operate as required during and after the DCPP seismic events.

3.10.3.1.1.1 Radiation Monitoring

Qualification of the radiation monitoring panels in the control room is based on shake table tests performed on the panels for Victoreen. The racks were shake table tested with the monitoring equipment in place (refer to Section 3.10.3.26).

3.10.3.1.2 Solid State Protection System

The three-bay, two-train solid state protection system (SSPS) was seismically tested as described in Section 2.5 of Reference 5. During the seismic test, a typical reactor trip matrix and typical safeguards actuation matrix were energized and monitored. Before each test, the circuitry was placed in a pre-trip condition. During the actual shaking, the circuitry was deliberately tripped and changed to a post-trip condition. The functional integrity of the system was thus demonstrated by observing a satisfactory change of state on demand. Relay contact positions necessary to show the operability were recorded during the tests.

No mechanical problems occurred during the vertical axis tests. In the side-to-side axis test at lower "g" levels, the two lefthand cabinet-to-base bolts repeatedly loosened and were deformed until it became necessary to replace these with more hardened bolts. During subsequent testing at these levels in the side-to-side axis, these bolts failed completely on the last sine-beat test. Before performing the front-to-back test, twelve additional cabinet-to-base bolts were installed making a total of 24 bolts fastening the cabinet to its base. This change has been incorporated into the SSPS cabinets at DCPP.

The functions monitored by recorders were: undervoltage trip, train trouble, and SI signal. Test switches were operated during the third sine beat simulating a reactor trip and safeguards actuation, causing a change in amplitude of the recorded signals for under voltage trip and SI.

During the front-to-back axis test, the signal indicated several momentary trips (contact closures) before the test switches were operated. Also, at 7 Hz and 9.5 Hz, this signal indicated a momentary trip and then a permanent change of state (latch up) on the first bounce on the output (slave) relays. The permanent change of state was caused by the armature of the same relays bouncing closed. This closing allowed their mechanical latch mechanism to operate. These maloperations could have initiated safeguards actuation. However, they would not have negated a valid safeguard actuation or reactor trip. Although SI was prematurely actuated, the under voltage coil tripped when called upon to do so.

The duration of the momentary contact closure was probably short enough not to cause a false SI signal. The probability of spurious initiation of SI due to any earthquake is therefore very small. The seismic tests performed have demonstrated that the seismic event will not prevent a legitimate SI signal from being actuated, either during or after the event. Reference 9 presents an analysis of the consequences of seismic-induced

actuation of protection system relays by considering the possible actuation of each contact of the relays studied and describing the resulting effect of inadvertent equipment actuation.

The relays which exhibited contact bounce and mechanical latching were replaced by a new type of relay which was seismically qualified by single-axis sine-beat and multiple frequency sine-beat testing. Input levels for the tests were determined from the measured acceleration response at the cabinet during the cabinet tests described in Section 2.5 of Reference 5. Seismic qualification of these replacement relays is documented in Reference 10.

Due to obsolescence issues, the original SSPS printed circuit boards can be replaced with newer vintage boards supplied by Westinghouse. The replacement printed circuit boards have been seismically qualified by Westinghouse. The seismic qualification is documented in Reference 49.

3.10.3.1.3 Process Control and Protection Equipment

The Eagle 21 system has been seismically qualified on a generic basis by Westinghouse (References 40 through 42) in accordance with requirements from References 43 and 44. A site-specific seismic analysis was also performed to ensure that the Eagle 21 generic testing performed by Westinghouse encompasses the DCPP installed condition (Reference 45), which included the effects of the top entry conduit stiffness.

The Hagan process control system in instrument racks 17 through 32 (RNO1A through RNO4E) was replaced with a programmable logic controller (PLC) based system manufactured by Triconex (DDP 1000000237 and DDP 1000000501). The system chassis, input/output and hardware have been seismically qualified by Triconex (Reference 55). As part of the design change process, a site-specific seismic evaluation and seismic calculation file was completed for the installed condition.

Supporting process control system equipment, such as loop power supplies, signal isolators, circuit breakers, terminal boards and line filters that support PG&E Design Class I equipment, was seismically qualified in accordance with References 56, 57 and 58.

3.10.3.1.4 Instrument AC Inverters

A prototype uninterruptible power supply (UPS) and regulating transformer of the DCPP UPS system was tested as described in PG&E engineering seismic file No. ES-68-1.

The UPS and regulating transformer were tested while loaded at 20-kVA; and the ac output voltage, current and frequency were monitored during the seismic test. The presence of a continuous ac output voltage both during and after the test formed the basis for determining the functional integrity of the UPS system.

During seismic testing the static inverter maintained structural integrity and functional operability. No variation or loss of 120-Vac output voltage was observed during or after the test. Therefore, the static inverter will perform its PG&E Design Class I functions during and after the DCPP seismic events.

3.10.3.1.5 Pressure and Differential Pressure Transmitters (Westinghouse)

Westinghouse supplied pressure and differential pressure transmitters are no longer in service. Refer to Section 3.10.3.11 for the qualification of pressure and differential pressure transmitters.

3.10.3.1.6 Reactor Trip Switchgear

Seismic testing of a typical reactor trip switchgear was performed as described in Reference 16. The basis for determining the functional integrity of the equipment was the following: (a) the breakers should trip open on loss of voltage to the undervoltage trip device during the testing sequence, and (b) all breaker outputs, including secondary contact outputs to the various protection system, should maintain proper contact condition of open or closed position.

The electrical functions of the equipment were monitored both during and after the seismic test (Reference 16) to ensure that the equipment was operating properly and performing the required PG&E Design Class I functions. This monitoring consisted of recording output signal voltages, and the input signal voltage to the undervoltage trip. The tripping action of each breaker through the undervoltage trip circuitry was checked during and after each series of tests to verify that the simulated earthquake had not impaired this function.

The recordings of all electrical signals indicated proper and complete functioning of the equipment both during and after all testing. No secondary contact chattering, no false breaker closing and no false breaker opening was observed.

The test results show that the functions of this equipment were maintained within the established criteria, both during and after each simulated seismic condition. During seismic testing a modification kit was installed within the reactor trip switchgear to enhance its seismic capabilities. This modification kit has been installed in the DCPP reactor trip switchgear.

3.10.3.1.7 Resistance Temperature Detectors

RTDs are ruggedly built devices designed to withstand the high temperature and pressure of the fluid in the RCS. They are also designed to withstand severe seismically induced vibration, and the reactor coolant RTDs are designed to withstand the flow-induced vibration from the reactor coolant flow.

The RTDs are mounted in the reactor coolant piping, on the containment sump wall, and on rigid support structures. The reactor coolant RTDs are installed in thermowells mounted into the main reactor coolant piping.

The seismic testing described in Reference 35 was performed on the Weed reactor coolant RTDs. The test inputs were random frequency, biaxial sine wave vibrations for a range of 1 through 1000 Hz. During the test, the RTDs were operated and their input/output signals were monitored. No mechanical damage was observed, and the input/output signals remained within acceptable limits.

The seismic testing described in Reference 36 was performed on the Conax RTDs. The test inputs were random frequency, biaxial sine wave vibrations for a range of 1 through 200 Hz. During the test, the RTDs were operated and their input/output signals were monitored. No mechanical damage was observed, and the input/output signals remained within acceptable limits.

3.10.3.1.8 Safeguards Test Cabinet

As described in Reference 19, sine-beat testing was performed on a typical engineered safeguard test cabinet. The engineered safeguards test cabinet completed seismic testing without sustaining physical damage. The only functional anomaly observed during testing was the momentary opening of the normally closed contacts of certain test selection switches at particular frequencies.

These switches are used to set up and initiate individual tests. The normally closed contacts are used exclusively to reset the blocking relays of the engineered safeguards test cabinet upon completion of a test. When the blocking circuit is not in the test mode, the blocking relay is in the reset state. A momentary opening of the normally closed contacts, therefore, will have no effect on the state of the blocking relay.

Therefore, based on the seismic testing performed, the engineered safeguard test cabinet will perform its PG&E Design Class I function during and after the DCPP seismic events.

3.10.3.1.9 Auxiliary Safeguards Cabinet

The auxiliary safeguards cabinet is structurally identical to the safeguards test cabinet (refer to Section 3.10.3.1.8) and the component layout of the two cabinets is essentially the same. Therefore the results obtained from the test of the safeguards test cabinet were applied to the auxiliary safeguards cabinet.

The auxiliary safeguards cabinet was analyzed by time history analysis to qualify the use of the rotary relay in the cabinet. This analysis is described in Reference 20.

The rotary relays have been tested separately using single axis, multiple frequency inputs. These tests are described in Reference 10.

The analysis response spectra of the auxiliary safeguards cabinet, at relay mount locations, was found to be enveloped by the relay test response spectra. Therefore both the auxiliary safeguards cabinet and relays will function properly during and after the DCPP seismic event.

3.10.3.2 Main Control Board and Console

The main control board (MCB) is located within the control room at elevation 140 feet in the auxiliary building. It has two major structures: MCB section and control console.

Seismic qualification of the MCB and central console is demonstrated by analysis as described in Reference 21. The analysis consisted of the following tasks:

(1) Modeling of the MCB so that its analytical frequencies correlate to those obtained from the field test

(2) Response spectrum analysis of the model using the given spectra to evaluate structural adequacy

(3) Modification of MCB to address overstress condition

(4) Response spectrum analysis of the modified MCB model to compute loads for structural evaluation

(5) Transient dynamic analysis of the modified model to generate in-equipment response spectra (IERS) for device qualification

The MCB section and central console are modeled using the general purpose finite element computer code, WECAN (Reference 22). The MCB is modeled as a linearly elastic system of beam, plate and lumped mass elements.

In addition, in-situ testing of the unmodified structure was performed to identify local panel modes. This consisted of tap tests of the vertical and bench panels as described in Reference 23.

Response spectrum analyses were performed to compute structural loads using DDE and HE required response spectra (RRS). Two dimensional shocks were considered in the evaluation. Maximum elemental stresses were obtained from the two sets of response spectrum analyses.

The structural analyses of the unmodified design indicated some overstress which is a result of the changes in spectra from the original HE loadings. To reconcile the overstressed conditions and simultaneously provide the additional advantage of increasing the overall structural frequencies to above the peak of the floor response spectra, modifications have been done on top of the MCB. These modifications lead to

a much lower stress condition and increase the board's overall structural frequencies to values exceeding the peak of the input spectra.

The results of stress analyses for the modified design show that the maximum member stress is about 85 percent of allowable. A comparison of the required and as-built weldments demonstrates that the existing weldments exceed the required weldments. Buckling stability of all MCB structural members has also been evaluated. There exists, at least a factor of safety of three against buckling.

Transient dynamic analyses of the modified structural model was performed to obtain the IERS for use in qualifying board mounted devices. Two sets of transient analyses are performed using two directional seismic excitation with one horizontal and one vertical direction. The synthesized floor excitation is employed in a transient dynamic analysis using the modal superposition integration procedure. Five percent of critical damping is assumed in the analyses.

The central console is a U-shaped electrical cabinet consisting of three bolted sections, welded to the main control room floor. The structure is modeled using WECAN, similar to the MCB. Results of modal analyses of the console structural model show the lowest overall fundamental frequency to be 70 Hz.

Since the console model has no frequencies below 33 Hz, it is classified as a rigid structure, and stress evaluations are performed using the static method. Uniform static acceleration equal to the floor response spectra zero period acceleration are applied to the console structural model. Stresses computed by the SRSS method are observed to be well below the allowables. No weldments and buckling evaluations are performed due to the obvious integrity apparent from the low stress conduit.

As all console frequencies are in the rigid range, the IERS for console mounted devices are the floor response spectra.

The IERS obtained from MCB and console analysis were used for seismically qualifying the MCB mounted devices as described in Reference 24. Qualification tests were performed to determine if the structural integrity and functional operability of the devices are maintained for the seismic level.

Devices tested were supplied by PG&E and are representative of all the PG&E Design Class I devices used in the MCB. Indicators, recorders, switches, power supply, and light box were tested. The seismic qualification was achieved by subjecting the devices to multiple frequency, multiple axis seismic testing such that the response spectrum envelops the IERS obtained from analysis. It was concluded from the tests that all of the PG&E Design Class I devices will maintain their structural integrity and functional operability during and after the seismic event. In addition, three displays have been located in the central console. Seismic tests were performed to insure that these displays will not become missile sources.

3.10.3.3 Hot Shutdown Panel and Associated Panels

The hot shutdown panel is a backup panel used if the control room must be evacuated and the plant brought to a hot shutdown condition. It contains indicators, control switches, and hand-auto stations for proportional control. These give indication and control over various pumps and valves in the AFW, CCW, boration control, safety injection, chemical and volume control, and containment fan cooler systems. Additionally, the 10 percent atmospheric dump valves are controlled from the hot shutdown panel, but the control loops for that function are not PG&E Design Class I.

3.10.3.3.1 Qualification of the Panel

The main hot shutdown panel consists of an enclosure 5 feet 10 inches wide, 6 feet 6 inches high, and 3 feet deep, with two panels inside, one on a vertical plane, the other tilted up 30° from the horizontal. The enclosure is mounted on four channels which are welded to a box comprised of 10-inch WF beams. This box is welded to steel plates embedded in the concrete floor of the auxiliary building at elevation 100 feet.

A sub-panel installed as a wing to the main panel's bench board provides non-safety related backup indications of parameters that are required to comply with NFPA 805. A second sub-panel installed as a wing to the main panel's bench board provides safety related and non-safety related SI and CVCS valve control switches and position indications that are required to comply with NFPA 805.

A 3-D response spectra analyses have been performed on finite element models developed for the hot shutdown panel, sub-panels and associated transfer switch panels. These analyses have shown the subject panels are qualified for DE, DDE, and HE seismic events.

3.10.3.3.2 Qualification of Individual Instruments

The types of components in the panel that are Class 1E are indicators (Westinghouse Model VX252), control switches (Cutler-Hammer Type 10250T), and hand-auto control stations. Other devices (e.g., Westinghouse Type KA-241 indicators) are non-Class 1E and have no need to meet seismic qualifications. These devices are separated from Class 1E devices by a barrier.

All required devices (VX252 indicators, W-2 switches, 10250T switches) were qualified by test using multifrequency biaxial shake tests. The devices were mounted to closely simulate their mounting conditions on the panel. The indicator was calibrated before and after the tests to ensure that the tests had not affected the calibration. During the tests, an input was applied that produced a midscale output. The outputs were monitored for fluctuation, and no fluctuation or calibration shift greater than required accuracy was noted.

Replacement valve manual/auto hand stations manufactured by NUS were seismically qualified in accordance with References 59, 60 and 61.

Control switches, transfer switches, indicating lights, fuse blocks, fuses, and terminal blocks installed in the hot shutdown switch sub-panel and the associated transfer switch and cut-out switch panels were qualified by test using multifrequency triaxial shake tests.

The control switches were tested in both the neutral and the "switched" positions. The contacts were monitored for chatter during the event, and were tested for proper operation afterwards. (The safety function of these devices is to give the operator manual control of various devices, and the operator will not be expected to change switch position during the seismic event; therefore, no requirement exists to change inputs during the event.) No malfunction of the switches were noted.

3.10.3.4 Local Instrument Panels

Local instrument panels are used as enclosures for PG&E Design Class I and PG&E Design Class II and III instrumentation throughout the plant. The panels perform no PG&E Design Class I function except to provide support for the PG&E Design Class I devices. The panels are supported at the top by fastening them to a wall or other suitable structure. The bottom is fastened to the floor or to the same structure as the top.

The panels were originally qualified by analysis performed by the panel vendor. The criteria for the panels are that they have a resonant frequency greater than 20 Hz, and that all stresses be below allowables.

Due to the large number of panels requiring qualification, a worst case analytical method was used. It was based on determination of the panel having the highest calculated stresses resulting from simultaneous horizontal and vertical seismic accelerations. Subsequent to their installation in the plant, several of the panels were modified to increase their stiffness.

The qualification of the panels is based on finite element models of several representative panels which include the effect of equipment mounted in the panel. The analysis took into account the various sizes, configurations, and locations, using an envelope of 2 percent DDE and 4 percent HE spectra.

The results of the analyses show that all panel stresses are below allowables. In addition, the panel response at PG&E Design Class I transmitter locations was derived for comparison with the test response spectra for PG&E Design Class I transmitters in the panels (refer to Section 3.10.3.11).

3.10.3.5 Instrument Panels PIA, PIB, and PIC

These instrument panels house various devices used to power plant transmitters and perform the necessary signal conditioning to provide alarm functions and send linear

signals to indicators on the MCB. The typical parameters involved are CCW flows and heat exchanger DP, and RWST level, etc. The panels are mounted on reinforced concrete columns at about the 132-foot elevation in the cable spreading room.

The relays were qualified by comparison with the same relays installed in the ventilating control panel, physically installed nearby.

The panels were analyzed for the current seismic criteria for both the DDE and the HE. In addition, the seismic qualifications of the devices within the panels have been reviewed to the same seismic criteria. The analysis and the review have demonstrated that the instrument panels PIA, PIB, and PIC are seismically qualified to perform their safety function after the seismic conditions.

Subsequent to the original qualification testing, replacement or additional devices to the panels have been installed. These devices are qualified by testing, analyses, or a combination of the two. Their qualification is documented in the engineering seismic files associated with the panels and/or devices.

Moore (CPT) PC-programmable temperature transmitter and signal isolators/converters included in the process control system perform the functions of the original direct current alarms, thermocouple transmitters, square root transmitters, and signal conditioners removed from PIA, PIB, and PIC. The Moore CPTs were seismically qualified by NLI per References 56, 57 and 58.

3.10.3.6 Diesel Generator Excitation Cubicle and Control Cabinet

The DG excitation cubicle and the control cabinet for DGs 1-1, 1-2, 1-3, 2-1, and 2-2, were shake table tested and qualified to the DE, DDE, and HE levels described in Section 3.7.

Both the excitation cubicle and the control cabinet will perform their safety function during and after the specified seismic conditions.

The sixth excitation cubicle and control cabinet for DG 2-3 have been seismically qualified by shake table testing.

3.10.3.7 PG&E Design Class I AC Electrical Distribution Equipment

The following sections describe the seismic qualification of Class 1E ac electrical distribution equipment.

3.10.3.7.1 4.16-kV Metal-Clad Switchgear

The 4.16-kV metal-clad switchgear with Yaskawa SF6 circuit breakers, converted by NTS/PDS to fit the existing 4.16-kV switchgear, was seismically qualified by a combination of testing and analyses.

The circuit breakers were seismically qualified by shake table testing (NTS report No. TR60431-95N-FR). The shake table testing was intended to achieve the following objectives.

(1) Demonstrate the structural integrity and functionality of the Yaskawa breakers.

(2) Demonstrate the structural integrity of as-installed 4.16-kV switchgear cubicles at DCPP with the Yaskawa breakers.

(3) Demonstrate the functional performance of the existing components (i.e., various relays and switches) installed in the existing 4.16-kV switchgear cubicles with replacement Yaskawa breakers.

(4) Instrument the test 4.16-kV switchgear cubicles with sufficient number of accelerometers to obtain accurate information on the dynamic response (response frequencies, test response spectra) at various cubicle locations. This information is to be used for further/future testing and analyses.

(5) Take immediate corrective actions to address significant anomalies observed during the test.

The initial seismic testing was performed at Wyle Laboratories in Huntsville, Alabama. Three seismic mock-up 4.16-kV switchgear cubicles were built to duplicate the design, material, and construction of cubicles G-5, G-12, and G-13 of Unit 1. A total of 18 OBE and SSE test runs were performed, including three runs of resonance search. Test results showed that the new breakers and mock-up cubicles successfully passed the minimum required 5 OBE tests.

For the SSE tests performed at Wyle Laboratories, excessive relay chatter at certain frequencies were noted. The excessive chatter was due to over-testing the equipment, which in turn was a result of Wyle Laboratories being unable to accurately control the test table response at 10 Hz and above due to resonance of the table. The over-test produced a significant amount of relay chatter, which caused the tripping and closing of breakers. The post test functional check showed that the breakers were functioning properly and had no structural damage.

To properly test the relays, supplemental SSE testing was performed at Farwell and Hendricks Laboratories. The upper front doors of the G-12 and G-13 cubicles, where a majority of relays are mounted, were mounted on the Farwell and Hendricks rigid test fixture. One 1200A breaker and one 2000A breaker, located adjacent to the test table, were fed by the relays. The SSE RRS obtained at relay locations on the G-12 and G-13 cubicles from the previous Wyle testing were reduced with the appropriate scaling factor to eliminate unnecessary over-testing. The supplemental SSE testing was successful. However, certain modifications (such as adding chokes to the breakers and

removing the seal-ins from certain relays) were made when the new breakers were installed in the 4.16-kV switchgear.

Based on the above, the switchgear and its contents are qualified for the DE, DDE, HE, and LTSP seismic events at DCPP.

3.10.3.7.2 Potential Transformers 4.16-kV/120-Vac

There are a total of four potential transformers associated with each 4.16-kV Class 1E switchgear. There is a potential transformer for each feeder; auxiliary, startup and the DG and one for the bus itself. Potential transformers are normally an integral mechanical and electrical part of metal clad switchgear. However, the auxiliary and startup potential transformers were removed from the top of the 4.16-kV metal clad switchgear during the initial qualification testing performed in 1978. In 1978, a potential transformer representing the auxiliary and startup potential transformer was separately shake table tested and qualified for the HE. A potential transformer representing the DG and bus potential transformer was shake table tested using a mock-up of cubicle H-7.

In 1995, a potential transformer was mounted above a mock-up of cubicle G-12 and a dummy weight, representing the weight of a potential transformer, was mounted above a mock-up of cubicle G-5. These two cubicles were included in the shake table testing at Wyle Laboratories during the seismic qualification of the new SF6 breakers described in Section 3.10.3.7.1.

The auxiliary and startup potential transformers that were originally at the 90-inch level of the Class 1E switchgear have been relocated to rigid stands adjacent to the respective switchgear lineups. Electrically, they are still an integral part of the switchgear. The DG and bus potential transformers located below the 90-inch level are still physically attached to the switchgear, with the exception of the DG potential transformer on Unit 1 Bus F that was also moved to a rigid stand adjacent to the switchgear.

The seismic qualification has been reviewed for the DDE and HE levels. The comparison of the earlier test data with current seismic requirements and additional analysis demonstrate that the potential transformers are qualified to perform their safety function during and after the specified seismic conditions.

3.10.3.7.3 Safeguard Relay Boards

One safeguard relay board from Unit 1 was shake table tested to qualify the relay boards for the seismic requirements of the DDE. As a result of the 1978 HE reevaluation, one relay board of the six installed was shake table tested to higher levels than the original test.

The qualification of the relay boards has been reviewed to the DDE and HE levels. Based on this review, it is concluded that the safeguard relay boards are seismically qualified to perform their safety function.

3.10.3.7.4 Class 1E 480-V Load Centers

The Class 1E 480-V load centers were originally qualified for the DDE based on seismic tests on similar equipment conducted by the manufacturer. As a result of the 1978 HE reevaluation, the equipment was further qualified by shake table testing. During the testing, the draw-out modules of the load center were equipped with hold-down brackets to prevent slamming of the modules and subsequent chatter of contacts. Chatter was detected also on the deenergized high-speed contactors of the Unit 2 fan cooler controllers while the low-speed contactor was energized.

As a result, all draw-out modules of the 480-V Class 1E load centers have been equipped with hold-down brackets. The containment fan cooler motor controllers have been equipped with mechanical interlocks that prevent inadvertent closure of the deenergized high-speed contactor when the low-speed contactor is energized, and likewise prevent closure of the low-speed contactor when the high-speed is energized.

The load centers were qualified using a certain type of kickout spring. Subsequently, all load center contactors in question were checked in the field and the proper kickout springs (the one used in the qualification testing) were installed where necessary.

The qualification of the load centers has been reviewed to new 1983 seismic criteria for both the DDE and the HE event described in Section 3.7. The comparison of the earlier test data with current seismic requirements and additional analysis demonstrates that the Class 1E 480-V load centers are seismically qualified to perform their safety function during and after the specified seismic conditions. The qualification meets the requirements of IEEE 344-1975 and Regulatory Guide 1.100, Revision 1.

3.10.3.7.5 Class 1E Load Center Transformer

The Class 1E load center transformers were originally seismically qualified for the DDE based on shake table testing of a similar, but larger power transformer. A comparison was made which demonstrated that the test of the 1500-kVA transformers is applicable to qualify the 1000-kVA Class 1E load center transformers installed.

A further review of the original test with regard to current seismic requirements for both the DDE and HE concluded that the Class 1E load center transformers are qualified for the DDE and HE.

3.10.3.7.6 480-V Class 1E Load Center Auxiliary Relay Panels

To qualify the Class 1E load center auxiliary relay panels and electrical components for the 1978 HE requirements, two typical panels were shake table tested. This requalified all relay panels.

The qualification of the relay panels has been reviewed to current seismic criteria for both the DDE and the HE. The comparison of the earlier test data with the current seismic requirements and additional analysis demonstrates that the Class 1E load center auxiliary relay panels are qualified to perform their safety function.

3.10.3.7.7 Instrument Power AC Panelboards

The instrument power ac panelboards (including mounting and attached components) have been qualified to the DDE and HE criteria by a combination of analysis, seismic testing (including multifrequency sine beat and resonant frequency), and comparison of test data.

3.10.3.8 PG&E Design Class I DC Electrical Equipment

The following subsections describe the seismic qualification of Class 1E dc electrical equipment.

3.10.3.8.1 Batteries

There are six Class 1E "batteries" at DCPP, three in each unit. Each "battery" consists of 60 battery cells (refer to Section 8.3.2.2.2.3 for 59-cell configuration). All Class 1E batteries are C&D Model LCUN-33 cells.

The battery cells were tested using a rigid test rack. The test rack held four cells. The battery cells were qualified by shake table testing for DE, DDE, and HE. They have also been evaluated for the LTSP requirements and were found to satisfy the LTSP acceptance criteria.

Two separate LCUN-33 tests were performed. First, unaged cells were tested to qualify the cells for installation in outage 1R5 and for a 5-year life. Next, another group of LCUN-33 cells were artificially aged and tested. The second test qualified the LCUN-33 cells for a 15-year life. The qualification was performed using the guidance of IEEE 535-1986 (Reference 51) and Regulatory Guide 1.158, February 1989 (Reference 52). The qualified life of the C&D LCUN-33 battery was extended to achieve a 20 year mean service life in 2006. Qualified life is determined per IEEE 535-1986 and is documented in the seismic calculation file (Reference 53).

Preventive maintenance is in place to replace the batteries before the expiration of their qualified life.

It is concluded that the station batteries C&D Model LCUN-33 will perform their safety function during and after DCPP design basis seismic events.

3.10.3.8.2 Station Battery Racks

Each Class 1E battery (60 cells – refer to Section 8.3.2.2.2.3 for 59-cell configuration) is located in its own room in the auxiliary building at elevation 115 feet. In each battery room, there are currently four battery racks. Three of the racks are single-tier racks that hold 12 cells each. The fourth is a two-step rack that holds 24 cells.

Both the single-tier and the two-step racks have been seismically qualified by analysis and are qualified for DCPP design basis seismic events.

3.10.3.8.3 Battery Chargers

Shake table testing has been done on one of the battery chargers to current seismic requirement. The testing demonstrated that the battery charger will perform its safety function during and after the postulated seismic events. The testing qualifies all Class 1E battery chargers for both DDE and HE.

3.10.3.8.4 125-Vdc Switchgear

The 125-Vdc switchgear was originally qualified for the DDE based on seismic tests performed on similar equipment conducted by the manufacturer.

As part of the 1978 HE reevaluation, a 125-Vdc switchgear from DCPP was shake table tested. This switchgear is identical to the other five 125-Vdc Class 1E switchgears installed in the plant. This test demonstrated the adequacy of the equipment's safety function during and after the seismic condition.

The qualification of the dc switchgears has been re-reviewed to current seismic requirements for both the DDE and HE. The review confirms the adequacy of the qualification by comparison of the 1978 equipment test data to the current criteria. Based on the review, it is concluded that the 125-Vdc switchgears are qualified to perform their function during and after the DDE and the HE.

3.10.3.8.5 Motor Controller, 125-Vdc, for Valve FCV 95

The 125-Vdc motor controllers were installed at Unit 1 and Unit 2 in 1982. They have been seismically qualified to the seismic requirements of both the DDE and HE described in Section 3.7 by shake table testing of one unit. The controller met all the test requirements; therefore, it is concluded that the motor controllers will perform their safety function during and after the specified seismic events.

3.10.3.9 Main Annunciator

The main annunciator cabinets have been analyzed and meet the requirements of the DDE and HE. Components of the visual annunciator were shake table tested and meet the requirements of the DDE and HE.

The original Sequence of Events Recorder was replaced with a seismically qualified touch screen and a computer (PC) interfacing with a nonseismically qualified desktop printer. The PC and touch screen were qualified by testing. After a seismic event, the operators will be able to view the alarms on the touch screen. Any compatible desktop printer can be obtained and used to print the data.

The main annunciator communicates via data link to remote multiplexers and visual annunciator drivers associated with the main generator, which are not seismically qualified. There is no failure mechanism of the data link, remote multiplexer, or remote visual annunciator drivers that can adversely impact the function of the main annunciator system following an earthquake. The main generator alarms provided by the multiplexers are PG&E Design Class II and are not needed to maintain the plant in a safe shutdown condition or to mitigate the consequences of seismic events (Reference 46).

The main annunciator system is considered to be important to plant operation. However, the main annunciator system is not required for safe shutdown of the reactor. To achieve high reliability, the main annunciator system is designed to remain functional during and after a HE, and to operate during a momentary or extended loss of offsite power. However, since the main annunciator system is not designed to meet the single failure criterion, the system is classified as PG&E Design Class II.

3.10.3.10 Electrical Penetrations

Electrical penetrations of the containment structure must withstand the forces caused by a LOCA. The header plates are made of forged steel welded to the containment steel liner and therefore have considerably more strength than is needed to meet seismic conditions. The penetrations are approximately 5 feet long and contain insulated electrical conductors of stranded copper. These conductors are supported within the penetration and at the terminal boxes attached to each end of the penetration.

The electrical penetrations were originally seismically qualified for the DDE by static analysis, meeting the requirements of paragraph 3.1.3 of IEEE 344-1971. A further seismic analysis was made for penetration of similar configurations for the Pilgrim 1 and Fitzpatrick 1 units. This analysis was used to qualify the penetration for the 1978 HE reevaluation.

Seismic testing performed by the manufacturer and a new analysis was used to qualify the penetrations to current requirements of the DDE and HE. The analysis

demonstrates that the electrical penetrations will perform their safety function during and after the specified seismic conditions.

3.10.3.11 Pressure and Differential Pressure Transmitters

Seismic tests were performed on Barton Model 763 and 764 transmitters and Rosemount Model 1151, 1152, 1153, and 1154 transmitters as part of an environmental test programs conducted by their respective manufacturers. The transmitters were subjected to simultaneous independent biaxial excitation using a random test input. The test included a resonant search, 5-DEs, and 1-DDE, in each of two test positions.

The transmitters were pressurized and operational throughout the test. The output of each transmitter was monitored during the test to verify proper operation. The results of the test verified that the transmitters will operate properly for both DDE and HE excitation.

The seismic qualification of Rosemount Model 1154 transmitters is based on similarity between Model 1154 and Model 1153 Series D transmitters (Reference 37, paragraph 7.2). As documented in References 38 and 39, the Model 1153 Series D transmitters were shake table tested per IEEE 344-1975 to DCPP seismic requirements.

During the seismic testing leak test, calibration check and voltage variation tests were performed.

All tested transmitters successfully met the acceptance criteria. Anomalies observed were determined not to have an impact on the transmitters' qualification. The test response spectra curves enveloped the applicable DCPP-RRS curves (Reference 39).

Seismic testing and analysis (Reference 50) was performed to qualify Rosemount 'Smart' transmitter model 3051C for use in PG&E Instrument Class IC Systems as defined in Section 3.2.2.5 (3). The seismic testing and analysis in Reference 50 also qualifies the use of Rosemount 'Smart' transmitter model 3051N for use in PG&E Instrument Class IA Systems as defined in Section 3.2.2.5 (1).

Seismic tests were also performed on two typical models of Barton transmitters, Models 368 and 369, pressurized to mid-range operation. The tests were performed at Wyle Laboratories on a biaxial shaking table. Results show that the requirements were met. The transmitters operated throughout the tests without malfunctioning. A helium leak test was made on the pressure boundary of the transmitter after the seismic tests. No leakage was detected. The instruments were qualified in conformance to the requirements of IEEE 344-1971, Paragraph 3, Method 2, simulated seismic test.

Seismic tests were performed on Rosemount Model 3152N transmitters during manufacturer qualification for safety related applications per IEEE Standard 323-

1974/1983/2003, IEEE Standard 344-1975/1987/2004 and Regulatory Guide 1.180 Rev 1.

3.10.3.12 Raceway Supports

The Class 1E raceway systems (PG&E Design Class I) consist of conduits, cable trays, and pull boxes supported by approximately 27,000 supports in each unit. The raceway supports are constructed primarily of bolted assemblies of cold-formed channel sections either of "Superstrut" (more than 90 percent) or "Unistrut" (approximately 10 percent) brand, which are spaced at 8-1/2 feet or less, unless otherwise approved by an engineering evaluation. The supports are attached to concrete or structural steel by bolted connections or welding. Based on the similarity of structural configuration, the raceway supports are grouped into more than 400 generic types.

3.10.3.12.1 Design and Acceptance Criteria

The raceway supports are required to withstand loads from DDE or HE. The supports, in their as-built conditions, are evaluated to ensure that they meet the following criteria.

Loading Combination

The horizontal component of seismic load (DDE or HE) either transverse or longitudinal to the raceways that results in the highest stress on the member under consideration is combined, by absolute sum, with the stresses or forces due to dead load and vertical seismic load.

Response Acceleration of Support System

Unless otherwise justified the floor response spectra where supports are located are used for evaluation. The horizontal response is taken as the greater of the building responses due to either the east-west or the north-south ground motion combined by absolute sum, with the corresponding torsional response, as appropriate.

Acceptance Criteria

The specifications used to review the design of the steel members are the AISI "Specification for Design of Cold Formed Steel Structural Members" (Reference 32, Section 3.10.5) and Part 1 of the AISC "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings," 7th Edition (Reference 33, Section 3.10.5) applicable to hot-rolled members. The allowable stress given in the AISC "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings," 7th Edition is increased by 60 percent as recommended by Standard Review Plan Section 3.8.4 (Reference 34, Section 3.10.3.12.3). The allowable stress for AISI is increased so that the margin against yielding is 1.0 or greater with the allowance for local yielding at connections.

The allowable slip-shear capacity of bolted connections on strut members are established by statically testing support connections with various combination of nuts and bolt torque values. The design allowable is based on the support connection containing the type of nut (98 percent of the nuts actually used in the plant exhibit superior behavior) and the bolt torque value (more than 90 percent of the connections have significantly higher values) which very conservatively represent the as-built condition. In addition, a qualification criterion was established by performing dynamic tests on specimens having representative support configuration in determining acceptable shear capacity of the in-situ bolts. In some cases, the slip-shear capacities are based on manufacturer's recommended values. These shear capacities are for appropriate combination of nut types, bolt torque, and strut which have been verified by additional tests.

Permissible loads on conduit clamps are kept below 90 percent of the ultimate values. Clamps are also checked for interaction of pull-out and slip (either in transverse or longitudinal direction). The acceptance limit on fillet welds on cold-formed steel members is 60 percent greater than the allowable given in Section 4.2.1 of the AISI Specification. Spot-welds in composite superstrut channels are checked against allowable shear values developed from a testing program.

3.10.3.12.2 Evaluation

The electrical raceway systems are evaluated for seismic loading in the transverse, longitudinal, and vertical directions by following the methodology stated below.

Transverse Seismic Analysis

Each of the support types are evaluated against the acceptance criteria. The seismic loads used in the evaluation of the supports are based on system frequency of the support and adjacent span of the raceway. The damping value used for conduit supports is 7 percent. For cable tray supports, two separate frequency analyses are made to determine the spectral response. In the first analysis, the system frequency is obtained based on support frequency alone and 7 percent damping is used. In the second analysis, the system frequency is generated by combining the support frequency and the tray frequency. The seismic response is obtained based on 15 percent damped floor spectra. The second analysis is confirmatory and not a basis for the license. The larger of the two spectral values is used for evaluation.

Each support type is first evaluated for the generic case based on design, which results in maximum support response. Any support that cannot be qualified for its generic case is investigated for its as-built condition.

Longitudinal Seismic Analysis

All Class 1E raceway systems are walked down and documented. The longitudinal seismic load is generated based on raceway system frequency and 7 percent damping.

The peak response acceleration is used if the system frequency is less than 33 Hz; otherwise, the zero period acceleration is used. The seismic load is distributed among the supports in proportion to their longitudinal stiffness. The individual supports are evaluated for structural adequacy.

Vertical Seismic Analysis

The vertical seismic analysis uses the same methodology as the transverse seismic analysis.

3.10.3.13 Fire Pump Controller

The fire pump controllers for the plant interior system were upgraded to Class 1E when the FPS was upgraded. One controller was shake table tested and qualified to 1978 HE seismic requirements.

The qualification has been reviewed to the current seismic criteria for both the DDE and HE. The comparison of earlier test data with the current seismic requirements demonstrates that the fire pump controllers are seismically qualified to perform their safety function during and after the specified seismic conditions.

3.10.3.14 Local Starters

Local starters were originally seismically qualified for the DDE based on shake table testing by the manufacturer. As a result of the 1978 HE reevaluation, three representative starters were shake table tested. The testing qualified all local starters for their respective locations. Other starters of different manufacture used for the HVAC systems were qualified by comparison to the starters tested. The qualification of the local starters has been reviewed to current seismic criteria for both the DDE and HE.

For the review of the qualification to current seismic requirements, the local starters were broken down into four groups:

(1) Starters located in the auxiliary and fuel handling buildings were qualified by comparison of the 1978 test data to the current seismic criteria. This includes contactors installed since the 1978 shake table testing.

(2) Starters located at the turbine building 119-foot elevation were qualified by comparison of the 1978 test data to the current seismic criteria and by comparison to identical starters shake table tested for the turbine building 140-foot elevation.

(3) Starters located at the turbine building 140-foot elevation were installed after the 1978 electrical equipment testing program. One of these starters was shake table tested to qualify the starters for the current seismic criteria.

(4) Starters located at the auxiliary building 154-foot elevation, some of which are of different manufacture, have been qualified by comparison to the starters tested. The starters tested were qualified to spectra with much higher accelerations than are required for the 154-foot elevation of the auxiliary building.

The aforementioned review of the earlier seismic testing to current criteria for both the DDE and HE and additional testing demonstrates that all local starters are qualified to perform their safety function during and after the specified seismic conditions.

3.10.3.15 Ventilation Control Logic and Relay Cabinet

The ventilation control logic and relay cabinets were originally vibration-tested in July 1973, and seismically qualified for the DDE. The cabinets were found to be rigid. As part of the 1978 HE reevaluation, components of the cabinets were shake table tested again and qualified for the HE.

The seismic qualification of the ventilating control logic and relay cabinet and their components has been reviewed to the current seismic requirements of both the DDE and the HE. Based on the review, it has been concluded that the ventilation control logic and relay cabinets are seismically qualified to perform their safety function during and after the DDE and the HE.

As part of the Unit 1 and Unit 2 auxiliary and fuel handling buildings ventilation system control system replacement, a new PLC system was installed. The seismic qualification of the Plant Operating Vent (POV) panels, POV1 and POV2, and their components were reviewed to the current seismic requirements of both the DDE and the HE. The POV panels were evaluated using analytical evaluation and the PLC was shake table tested by the supplier. Based on the review, it was concluded that the POV1 and POV2 cabinets are seismically qualified to perform their intended safety function during and after the DCPP design basis seismic events.

3.10.3.16 Fan Cooler Motors

The fan cooler units were qualified for seismic adequacy by a combination of analysis and testing. A seismic analysis of the fan cooler unit, including the motor, was made to verify that the units will not exceed the allowable stresses or deflections. The response spectrum method of analysis was used.

The fan motor assembly natural frequencies were calculated using a lumped mass model. Because of high natural frequencies (after adding stiffeners to the fan cooler assemblies), this system was analyzed as a rigid structure and equivalent static loads were applied. An additional unbalanced load of 1 g was assumed to occur in all rotating assemblies.

Limit values were in accordance with the elastic provisions of the AISC "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings," 7th Edition. Bearing limits were taken as failure by brinelling under dynamic load (basic rating) from the manufacturer's catalog.

An analysis and an impact test were also made on an end bell of the motor. Based on these results, Westinghouse concluded that the containment fan-motor-cooler assembly structure could withstand the combination of required loads.

3.10.3.17 Pump Motors

Electric motors for PG&E Design Class I pumps were procured with the pumps to equipment specifications that covered the pump/motor assembly as a unit. These equipment specifications required that the equipment be adequately designed to accommodate seismic accelerations appropriate for the DE, DDE, and HE.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

At the time of procurement of this equipment, there were no industry standards for seismic qualification of electric motors. However, methods and criteria employed in the design of large, integral horsepower electric motors lead to motor designs that are inherently capable of tolerating high seismic loadings without loss of function. Design considerations for motors of this type include maximum torque, critical shaft speed, bearing life, vibration, and cyclical loading. These considerations lead to motor designs that would not be governed by the application of seismic loads in the range of those appropriate for DCPP. Experience with such motors in applications subject to severe vibration and shock provides additional confirmation of seismic adequacy. Based on these considerations, it is the consensus of competent engineering practice that these motors are adequately designed to perform their safety function before, during, and after the DDE or HE.

In the case of the ASW pumps, which are vertically mounted, calculations indicated that seismic bracing in the horizontal direction was necessary to ensure that the first vibrational mode of the pump-and-motor assembly would be in the rigid range of the design spectra. Other pump-and-motor assemblies have natural frequencies well within the rigid range.

Analyses of pump and motor assemblies representative of those considered here have been performed and have shown substantial margin in stresses, deflections, and bearing loads for seismic loadings in the range of those appropriate for DCPP. Selected pump-and-motor assemblies for DCPP have also been analyzed using the appropriate floor response spectra and both static and dynamic analysis methods. For all cases analyzed, seismic adequacy has been verified.

3.10.3.18 Electric Cables

Electric cables interconnecting pieces of equipment depend on raceways for support during seismic activity. Seismic criteria for raceway supports are described in Section 3.10.3.12. These cables are flexible and are fully supported along their entire length in conduit or tray. Adequate slack is provided to impose little or no tension on the wires. Where relative shifts between structures can occur, raceways are provided with flexible joints or are routed with adequate flexibility to ensure that the conductors remain undamaged and their associated supports meet their acceptance criteria. (Note that use of trays for Class 1E circuits is very limited [refer to Chapter 8]).

3.10.3.19 Motor-Operated Valves

PG&E-purchased MOVs, whose only safety function is to maintain a pressure boundary, and which are not required to change position during or after an accident (passive valves), and those whose safety function includes both maintaining a pressure boundary and changing position during or after an accident (active valves), were qualified to acceleration levels less than or equal to allowable acceleration levels provided by the vendor or established by analysis. All Westinghouse-purchased MOVs were qualified to acceleration levels less than or equal to allowable acceleration levels provided by Westinghouse.

Limitorque MOV operators of the type installed on active PG&E Design Class I valves in DCPP Unit 1 and Unit 2 have also been seismically qualified by test. The shaker table tests were conducted on various sized operators to meet the requirements of IEEE 344-1975 seismic accelerations.

Operators were tested both while operating and while energized and not operating. The testing employed was biaxial, multifrequency testing as well as single axis, single frequency testing, performed along each of three mutually perpendicular major axes. The test excitations were adequately severe and meet or exceed the recommendations of IEEE 344-1975 and Regulatory Guide 1.100, Revision 1 for qualification of all Limitorque valve actuators.

The test results for the MOV operators have been considered in the analysis of piping systems. The mass and resonant frequency of the operator is used as input in the piping analysis. The resulting acceleration levels are compared to the allowable levels to verify that the operator will function as required.

3.10.3.20 Control Room Ventilation System

The control relay and power panels are seismically qualified to the current seismic requirements for both the DDE and the HE. The qualification of the power panels is based on: shake table testing on the similar equipment performed by the manufacturer, onsite resonance frequency test on the similar panelboard, extensive shake table testing of electro-mechanical equipment containing circuit breakers or circuit breaker panelboards and testing of circuit breakers to the extent of the shake table limit.

The qualification of the control relay panels is based on the actual shake table testing of similar ventilation control relay cabinet installed in DCPP, containing the same control relays. Timing relays not found in this shake test are seismically qualified based on the qualification of 4.16-kV switchgear equipment in which the identical timing relays were installed.

Test specimens similar to the installed equipment were evaluated for their adequacy of qualification. By comparison of the test data from those shake table tests to the current seismic requirements, the test results of these equipment demonstrate that the specified seismic criteria are met for both the DDE and HE. It should be noted that the equipment is only needed for the control room ventilation and pressurization (CRVP) after an earthquake and not during the earthquake. Therefore it is concluded that the CRVP control relay and power panels are qualified to perform their safety function after the seismic events such as the DDE and the HE.

The radiation and chlorine monitoring panel has been qualified by seismic simulation testing of a test specimen similar to the panel installed at the DCPP. The panel test specimen was welded to the test table and bolted to an adjacent structure in order to simulate the actual plant mounting conditions. The panel test specimen contained the following instruments: one radiation rate readout (Nuclear Measurements Corporation Model GA-2TMO), one radiation rate readout (Technical Associates Model FML-554), one chlorine analyzer (Capital Controls Model 1030), and one switch reset module. Dummy weights were used to simulate random biaxial seismic simulation tests in accordance with IEEE 344-1975. The function of the instruments was verified before and after the testing. The test response spectra have been verified to envelop the DDE and HE RRS. The chlorine detection function has been eliminated and the detectors have been removed.

The radiation detector associated with the Nuclear Measurements radiation rate readout described above was also subjected to random biaxial seismic simulation tests. The test specimen was bolted to a rigid steel plate in order to simulate the mounting arrangement used at DCPP. The function of the device was verified before and after the test. The test table response spectra have been verified to envelop the DDE and HE RRS.

The radiation detector associated with the Technical Associates radiation readout and the chlorine detector associated with the Capitol Controls chlorine analyzer have also

been submitted to random biaxial seismic simulation tests. These two detectors were mounted into a 14-inch steel duct in order to simulate the mounting arrangement used at the DCPP. The function of the detectors was verified before and after the tests. The test response spectra envelops the RRS for both the DDE and HE cases. The chlorine detection function has been eliminated and the detectors have been removed.

3.10.3.21 Subcooled Margin Monitors

The subcooled margin monitors (SCMMs) are located in PAM Panels 3 and 4. Subcooled margin is calculated and displayed by the reactor vessel level instrumentation system (RVLIS); therefore, seismic qualification of each SCMM is covered by the seismic qualification of the RVLIS cabinets (refer to Section 3.10.3.31).

Train A of the SCMM provides output to a recorder on PAM1. PAM1 seismic qualification is addressed in Section 3.10.3.22.

Train B of the SCMM provides output to a display on VB2. This display was qualified by testing.

3.10.3.22 Post-accident Monitoring Panels PAM1 and PAM2

These panels are located in the main control room and house various indicators and recorders used for PAM. Typical parameters involved are reactor vessel level, containment hydrogen gas concentration, containment gross activity, etc. The panels were manufactured for PG&E by Trayer Engineering, Inc. PG&E Design Class I indicators and recorders were manufactured by Westinghouse and other qualified suppliers.

Panel PAM1, with its associated instruments, was qualified by random biaxial seismic simulation tests. The tests were performed at Wyle Laboratories. The function of the devices was verified before and after seismic testing. The test response spectra have been verified to envelop the DDE and HE RRS.

Panel PAM2 has been qualified by an analysis that showed that the panel is rigid, with no resonant frequencies below 33 Hz. In addition, a static analysis was performed that showed that the combined seismic stresses do not exceed the allowable limits. The PG&E Design Class I instruments mounted in PAM2 have been qualified by seismic simulation tests. The test response spectra obtained from these random biaxial tests have been verified to envelop the DDE and HE spectra.

3.10.3.23 Pilot Solenoid Valves

Pilot solenoid valves are used to control the air supply to air-operated control valves. The pilot valves can be mounted either on or off the control valve actuator. The required acceleration level for the pilot valves is 9 g's, which is based on the maximum allowable response for control valve actuators having PG&E Design Class I pilot valves.

The pilot solenoid valves have been qualified by tests performed on a variety of valve models by both the vendor, ASCO, and PG&E. The tests consisted typically of sine beat tests performed over the frequency range of 1 to 33 Hz. The minimum acceleration value met or exceeded the required level for the valves except at low frequencies, where the level was limited by testing machine capabilities. The function of the valves was verified before and after the testing.

3.10.3.24 Process Solenoid Valves

PG&E Design Class I process solenoid valves are used as containment isolation valves in the post-LOCA sampling system and containment hydrogen monitoring system (CHMS) (refer to Table 6.2-39). The valves were manufactured by Valcor Engineering.

The valves are located both inside and outside of containment. The valves inside containment are mounted to the annulus steel structure. The valves outside of containment are mounted to the exterior of the containment structure. The required acceleration level for the valves is an envelope of the DDE- and HE-RRS for both these locations.

The valves were qualified by a test performed by the vendor as part of an EQ program. The test used a random biaxial input, with the devices mounted to the test table simulating an actual installation. The test procedure conformed with IEEE 344-1975. The test levels were sufficient to qualify the valves to their required acceleration level. The function of the valves was verified before and after the testing.

3.10.3.25 Containment Hydrogen Monitoring System

The CHMS consists of two redundant systems each consisting of an analyzer panel and a remote control panel. The analyzer panels are anchored to the floor in plant Area GE at elevation 100 feet. The remote control panels for both systems are mounted in a remote containment hydrogen monitoring control (RCHMC) panel located in the post-LOCA sampling room in plant Area GE at elevation 85 feet.

The containment hydrogen analyzer panels are PG&E Design Class II, PG&E Instrument Class II, Type C, Category 3. The analyzer panels have been seismically evaluated. The RCHMC panel is PG&E Design Class I, PG&E Instrument Class IA with Class 1E circuits powering the related containment isolation valves.

The RCHMC panel has been structurally analyzed which includes the seismic mounting of PG&E Design Class II panel inserts. A detailed stress analysis was conducted that showed that the rack assembly is structurally adequate to withstand the DDE and HE loads.

3.10.3.26 Containment Purge Exhaust

Each monitor consists of a detector assembly and a Local Radiation Processor (LRP) located in Area L at elevation 100 feet. The remote readout is located in the Radiation Monitoring System panel (RNRMS) in the control room. The detectors and LRPs are qualified by analysis based on a test simulation performed on similar equipment. The control room mounted equipment is qualified based on shake table tests on the RNRMS panels performed for Victoreen (refer to Section 3.10.3.1.1.1).

3.10.3.27 Limit Switches

Limit switches are used to detect the position of control valves. Limit switches for MOVs that are an integral part of the actuator are qualified as part of the assembly (refer to Section 3.10.3.19). Limit switches for air-operated valves and for MOVs that are mounted on the valve actuator are qualified separately. The required acceleration level for these limit switches is 9 g, which is based on the maximum response allowable for valves having Class 1E limit switches.

Class 1E limit switches have been qualified by testing performed on several different styles. Tests have been performed by both the vendor and PG&E. These tests typically consisted of sine beats or sine dwells at 9 g peak acceleration over the frequency range of 1 to 33 Hz. Test acceleration levels met or exceeded the required level except at low frequency ranges where the level was limited to test machine capabilities. The test specimens were functionally tested before and after the vibration testing.

3.10.3.28 Containment High-Range Radiation Monitoring System

The containment high-range RMS is used to monitor ambient gamma radiation in the containment following a LOCA. The system consists of two redundant detectors located in the containment at elevation 145 feet and a remote readout located in the PAM panel PAM2 in the main control room. The system was supplied and qualified by Victoreen.

The radiation detectors and readouts have been qualified by random biaxial seismic simulation tests that were conducted as part of an EQ test program. The test response spectra have been verified to envelop the required DDE and HE response spectra. There were no malfunctions experienced throughout the seismic tests. The test conformed to IEEE 344-1975.

3.10.3.29 Pressurizer Safety Relief Valve Position Indication

The pressurizer safety relief valve position indication system is an acoustic flow detection system that verifies valve position by sensing flow through the pressurizer relief lines. There are three channels, one for each relief valve. The system consists of four components: detector, charge converter, signal conditioner, and remote readout. The detector is an accelerometer attached to the pressurizer relief line by a metal strap.

The charge converters for all three channels are housed in a stainless steel enclosure, which is mounted to the wall adjacent to the pressurizer at elevation 145 feet in the containment. The signal conditioner is located in panel RCRM in the main control room. The remote readout is mounted in the MCB. All components of the system were supplied and qualified by Technology for Energy Corporation.

The equipment comprising the system was qualified as part of an EQ program conducted by the vendor. The seismic portion of the testing was conducted in accordance with IEEE 344-1975. All of the system components were qualified by tests consisting of random input, independent triaxial excitation. Tests were conducted at Structural Dynamics Research Corporation. The test response spectra from these tests have been verified to envelop the applicable DDE and HE spectra. The function of the devices was verified before and after the testing.

3.10.3.30 Electric Hydrogen Recombiner System

The model B electric hydrogen recombiner system (EHRS) is designed to control and reduce post-LOCA containment hydrogen levels. The system consists of three components; control panel, power supply, and recombiner. Two model B EHRSs are provided for the DCPP site.

The recombiner was subjected to multiple frequency multiple axis testing in accordance with IEEE 344-1975. The results of the seismic testing are provided in Reference 25. The recombiner was energized and at operating temperature before, during, and after each seismic test. Following the entire testing, the recombiner was inspected for damage. No disabling damage was found. An air flow test was conducted after testing and the results show no loss of air flow. The test response spectra were checked to envelope the DDE and HE response spectra, to confirm its seismic adequacy.

The power supply and control panel were tested at the same time as documented in Reference 26. Testing was done with conservatively large accelerations over a range of applicable frequencies and conformed to the procedures given in IEEE 344-1971. The peak test input accelerations used in the power supply and control panel tests were checked to verify that they are larger than the requirements derived by DDE and HE loadings.

After each seismic test the power supply was visually inspected for structural integrity and functional operability. Both units were found to operate satisfactorily.

3.10.3.31 Reactor Vessel Level Instrumentation System

The RVLIS consists of the following instrumentation:

- RVLIS/incore thermocouple cabinets (including remote display)
- Reactor coolant level differential pressure transmitters (refer to Section 3.10.3.1.5)

- Surface mounted RTDs
- High volume sensors
- Differential pressure indicating switches (hydraulic isolators)

Typical items of the above instrumentation and electronic equipment have been type tested using multiple frequency, multiple axis seismic testing. Testing was performed in accordance with the procedures given in IEEE 344-1975. The test response spectra obtained from those tests were checked to envelope the DDE and HE response spectra.

3.10.3.31.1 Reactor Vessel Level Instrumentation System/Incore Thermocouple Cabinets

Two RVLIS/incore thermocouple cabinets (PAMs 3 and 4) are provided for DCPP application. Located within each cabinet are the microprocessor electronics, RCP status panel, and a remote display. The above RVLIS instrumentation is only required to operate normally before and after seismic excitation. The RCP status panel assembly is shown to be operational by the signals recorded during testing and the functional checks made after each simulated SSE. The remote display electronics must function normally by providing microprocessor output display formatted information.

The results of seismic testing of the original RVLIS/incore thermocouple cabinets are provided in Reference 27. The original remote display was not included in the cabinet tested. The original remote display was tested later to worst-case (maximum) in-cabinet response for the RVLIS/incore thermocouple cabinets. The seismic testing of the original remote display is documented in Reference 28.

Because the original Westinghouse-supplied system is obsolete and due to the lack of availability of replacement components, the obsolete RVLIS/incore thermocouple systems were replaced. The replacement processors, signal conditioners, and displays are seismically qualified by testing and analysis as documented in References 47, 48, 54 and PG&E Calculation IS-66.

3.10.3.31.2 Surface Mounted Resistance Temperature Detectors

There are 14 surface mounted RTDs used in RVLIS to measure the temperature of the reference leg impulse lines. The surface mounted RTDs were subjected to single frequency, multiple axis sinusoidal tests and multiple frequency, multiple axis seismic tests. The RTDs tested were operational throughout all phases of the test sequence. Measurement of performance was by an evaluation of the recorded RTD output and periodic static calibrations to ensure numerous insulation surface mounted RTDs maintain their structural integrity and functional accuracy as required.

3.10.3.31.3 High Volume Sensors

The high volume sensors are bellows designed for large volumetric displacement to accommodate thermal expansion postulated post-accident environment. The PG&E Design Class I performance requirement is that the sensor must maintain this pressure boundary and sensing interface between the process and filled pressure/differential pressure system without introducing any sensing errors.

The results of seismic testing are provided in Reference 30. Based upon the information provided therein, the high volume pressure sensor can successfully fulfill its PG&E Design Class I requirements during and after seismic testing.

3.10.3.31.4 Differential Pressure Indication Switches

The differential pressure indicating switches (hydraulic isolators) are used to seal off full process pressure in either direction and will actuate switches to indicate an unbalanced condition. The PG&E Design Class I performance requirement for RVLIS is that the switch provide the isolation function without contributing a sensing error to the accuracy of a downstream pressure or differential pressure transmitter.

During the seismic test, adherence to this requirement is verified by monitoring the output of two reference transmitters receiving the pressure signal. While no PG&E Design Class I use is made of the switch contacts in the reactor vessel level indicating system, testing was designed to demonstrate the suitability of indicating switch use for other applications.

Seismic testing of the hydraulic isolators is provided in Reference 31. The hydraulic isolators sustained no physical damage during the seismic testing and performed their process sensing line isolation function successfully, with no leakage of the water fill.

3.10.3.32 Incore Flux Mapping Cabinets and Transfer Device

The incore flux mapping cabinets and flux mapping transfer device are PG&E Design Class II, but have been seismically qualified for structural integrity for HE loadings.

The incore flux mapping cabinet is structurally identical to the NIS cabinets (refer to Section 3.10.3.1.1). The weight distribution of equipment within the cabinet would produce essentially the same dynamic results. Therefore the results obtained from the test of the NIS cabinets are applicable for the incore flux mapping cabinet structure.

The flux mapping transfer device is an assembly used to support control equipment to drive detectors into and out of thimbles in the reactor core. The flux mapping transfer device has been evaluated to maintain its structural integrity to withstand the HE for DCPP.

3.10.3.33 Heating, Ventilation, and Air Conditioning Equipment

The qualification of PG&E Design Class I HVAC equipment is reviewed according to DE, DDE, and HE criteria. This HVAC equipment is associated with the following PG&E Design Class I systems:

(1) Forced draft shutter

(2) DG compartment ductwork

(3) ASW compartment ventilation

(4) 4.16-kV switchgear ventilation

(5) 480-V switchgear ventilation

(6) Auxiliary building and fuel handling building ventilation

(7) Control room ventilation and pressurization system

(8) Containment penetration area GE/GW ventilation

The equipment and components of PG&E Design Class I HVAC systems are listed in Table 3.10-3. They have been reviewed for seismic qualification in accordance with the spectra, defined in Section 3.7.

The equipment listed in the table is organized into qualifying groups consisting of similar types of equipment. The component subject to the worst-case qualifying condition in each group has been reviewed for compliance with acceptance criteria. This worst-case analysis in turn envelops the other components in the respective groups.

All the items in the table were reviewed for identification of the qualifying spectra. Where the most current spectra exceed the conditions under which the component was previously analyzed, a new analysis was initiated. The results of the analysis confirmed the qualification of the component or identified a physical modification. Where analysis is not appropriate, equipment testing was used to demonstrate the design performed under the qualifying seismic conditions.

3.10.3.33.1 Heating, Ventilation, and Air-Conditioning Duct and Duct Supports

The PG&E Design Class I HVAC duct system consists of ducts and approximately 2,000 supports in both units. HVAC ducts are made of cold-formed steel conforming to ASTM A525, A526, and A527 with the thickness varying depending upon the duct size. The duct supports are mostly structural steel angles. Supports are attached to concrete or structural steel by bolted connections or by welding. The ducts are fastened to the supports by means of screws, rivets, or stitch welds.

3.10.3.33.1.1 Design and Acceptance Criteria

The duct and duct supports are evaluated in their as-built condition to meet the following criteria:

Loading Combination

The ducts are evaluated for the concurrent dead weight, seismic load, and pressure load. The duct supports are evaluated for dead weight and seismic load. The pressure load is the negative operating pressure of the HVAC system and is not included in the evaluation of the duct supports. The seismic loads evaluated are DDE and HE loads. The horizontal component of seismic load (DDE or HE), either transverse or longitudinal to the ducts, that results in the highest stress in the member under consideration is combined, by absolute sum, with the stresses due to vertical seismic load. As an alternative, the seismic loads from each of the three directions are combined by the SRSS method.

Response Acceleration of Support System

The applicable floor response spectra where the supports are located are used for evaluation of HVAC duct and duct supports. The corresponding horizontal spectra are combined, by absolute sum, with the corresponding torsional response, as appropriate.

Acceptance Criteria

The AISI "Specification for Design of Cold-formed Steel Structural Members" is used to evaluate the design of cold-formed steel members, and part 1 of the AISC "Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings," 7th Edition is used for the design of hot-rolled members. The allowable stresses given in AISI and AISC "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings," 7th Edition are increased by 60 percent.

3.10.3.33.1.2 Evaluation

For duct supports, the seismic loading is evaluated for vertical plus transverse horizontal loads and vertical plus longitudinal horizontal loads. The frequency of the coupled duct and duct support system is used in determining the spectral response. The damping values used are 2 percent for DDE and 7 percent for HE.

3.10.4 SAFETY EVALUATION

3.10.4.1 General Design Criterion 2, 1967 – Performance Standards

As discussed in Section 3.10.2, the PG&E Design Class I instrumentation, HVAC, and electrical equipment are designed to withstand the effects of earthquakes. Historically, the analyses of the PG&E Design Class I instrumentation and electrical equipment were performed to the standards of IEEE 344-1971. The qualification of individual components to withstand the effects of earthquakes is discussed in detail in Sections 3.10.3 through 3.10.3.33.

The guidance of IEEE 535-1979 Qualification of Class 1E Lead Storage Batteries for Nuclear Power Generating Stations is required for the qualification of the Class 1E batteries. Refer to Section 3.10.3.8 for a one time usage of IEEE 535-1986 Qualification of Class 1E Lead Storage Batteries for Nuclear Power Generating Stations.

3.10.4.2 Regulatory Guide 1.100, Revision 1, August 1977 – Seismic Qualification of Electric Equipment for Nuclear Power Plants

As discussed in Section 3.10.2, the PG&E Design Class I instrumentation, HVAC, and electrical equipment have been qualified to withstand the effects of earthquakes with procedures in conformance with Regulatory Guide 1.100, Revision 1. In accordance with Regulatory Guide 1.100, Revision 1 the design and analyses are performed to the standards of IEEE 344-1975.

3.10.5 REFERENCES

1. The Institute of Electrical and Electronic Engineers, Inc., IEEE Standard 344-1971, Trial Use Guide For Seismic Qualification of Class I Electric Equipment for Nuclear Power Generating Stations.

2. IEEE Standard 344-1975, Recommended Practices for Seismic Qualification of Class IE Equipment for Nuclear Power Generating Stations.

3. USNRC Regulatory Guide 1.100, Revision 1, Seismic Qualification of Electrical Equipment for Nuclear Power Plants, August 1977.

4. Description of the Systems Interactions Program for Seismically Induced Events, Revision 4, August 1980.

5. Seismic Testing of Electrical and Control Equipment (PG&E Plants), WCAP-8021, May 1973.

6. Letter No. NS-CE-1609, Eicheldinger (Westinghouse) to Stolz (NRC), Subject: “Drawer Securing Method for NIS Rack,” November 1977.

7. Seismic Operability Demonstration Testing of the Nuclear Instrumentation System Bistable Amplifier, WCAP-8830, October 1976.

8. General Method of Developing Multifrequency Biaxial Test Inputs for Bistables, WCAP-8624, September 1975.

9. Consequences of Seismic-Induced Actuation of Protection Systems Relays on the Diablo Canyon Nuclear Plant, Westinghouse Electric Corporation, July 1975.

10. Seismic Qualification of the Rotary Relay for Use in the Solid State Protection System, WCAP-8694, January 1976.

11. Deleted in Revision 21.

12. Deleted.

13. Seismic Testing of Electrical and Control Equipment, High Seismic Plants, WCAP-8921, December 1971.

14. Equipment Qualification Test Report Pressure Sensor, WCAP-8687, Supplement 2-E21A, Revision 1, March 1982.

15. Equipment Qualification Test Report Barton Differential Pressure Transmitter - Qualification Group B, WCAP-8687, Supplement 2-E04A, Revision 2, March 1983.

16. Seismic Testing of Electrical and Control Equipment, Type DB Reactor Trip Switchgear, WCAP-8821, Supplement 4, August 1974.

17. Deleted.

18. Deleted.

19. Seismic Testing of Electrical and Control Equipment Engineering Safeguards Test Cabinet for PG&E Plants, WCAP-8021, Supplement 1, May 1977.

20. Seismic Qualification of the Rotary Relay for Use in the Trojan and Diablo Canyon Auxiliary Safeguard Cabinets, WCAP-8941, February 1977.

21. Seismic Qualification of the Diablo Canyon Main Control Board, Central Console, WCAP-10358, August 1983.

22. Benchmark Problem Solutions Employed for Verification of the WECAN Code, WCAP-8929, June 1977.

23. Forced Vibration Testing of the Diablo Canyon Unit 1 Main Control Board, ANCO Engineers Inc., Document No. A-000047, May 1983.

24. Seismic Qualification Test Report for Diablo Canyon Main Control Board and Central Console Mounted Class 1E Devices, WCAP-10359, August 1983.

25. Qualification Testing for Model B Electric Hydrogen Recombiner, WCAP-9346, July 1978.

26. Electric Hydrogen Recombiner for PWR Containments Equipment Qualification Report, WCAP-7709-L, Supplement 2, September 1973.

27. Equipment Qualification Test Report, Reactor Vessel Level Instrumentation System/Incore Thermocouple Cabinet With 8080 Microprocessor Electronics and Reactor Cabinet Pump Station Panel, WCAP-8687, Supplement 2-E51A, July 1984.

28. Equipment Qualification Test Report, Remote Digital Display for the 8080 Microprocessor Electronics, WCAP-8687, Supplement 2-E46A, July 1984.

29. Equipment Qualification Test Report, Surface Mounted RTDs, WCAP-8687, Supplement 2-E48A, January 1983.

30. Equipment Qualification Test Report, High Volume Sensor-Group A, WCAP-8687, Supplement 2-E48A, January 1983.

31. Equipment Qualification Test Report, Differential Pressure Indicating Switch-Group, WCAP-8687, Supplement 2-E49A, January 1983.

32. American Iron and Steel Institute, Specification for the Design of Cold-Rolled Steel Structural Members, AISI, Washington, D.C., 1968.

33. American Institute of Steel Construction, Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, AISC, Chicago, IL, Seventh Edition.

34. Office of Nuclear Reactor Regulation, Standard Review Plan, Section 3.8.4, NRC, Washington, D.C. (November 1975).

35. Seismic Confirmation of Weed Resistance Temperature Detectors For Diablo Canyon Unit 1 and Unit 2 Bypass Elimination System, WCAP-12714, Revision 2, February 1993.

36. Seismic Qualification Test Report of Class IE RTD and Thermocouple Temperature Sensors for Conax Corp., Report No. IPS-1165, Revision A, June 18, 1984.

37. Rosemount Report D8400102, Qualification Report for Pressure Transmitter Model 1154, (PG&E DC 6000784-117).

38. Rosemount Report D8300040, Qualification Report for Pressure Transmitters Rosemount Model 1153 Series D, (PG&E DC 6000784-7-1).

39. PG&E Seismic Calculation No. IS-35, “Seismic Qualification of Rosemount Transmitters.”

40. Equipment Qualification Test Report, Eagle 21 Process Protection System (Environmental and Seismic Testing), WCAP-8687, Supplement 2-E69A, Revision 0, May 1988.

41. Equipment Qualification Test Report, Eagle 21 Process Protection System (Environmental and Seismic Testing), WCAP-8687, Supplement 2-E69B, Revision 0, February 1990.

42. Equipment Qualification Test Report, Eagle 21 Process Protection System (Environmental and Seismic Testing), WCAP-8687, Supplement 2-E69C, Revision 0, February 1991.

43. Seismic Qualification of Electrical Equipment for Nuclear Power Plants, NRC Regulatory Guide 1.100, Revision 2, June 1988.

44. Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations, IEEE 344-1987.

45. Seismic Conformation of Eagle 21 Digital Process Protection System Upgrade for Pacific Gas and Electric Company Diablo Canyon Power Plant Units 1 and 2, WCAP-13384, Revision 0, PG&E, September 1992.

46. PG&E Specification 1021-J-NPG, “Specification for Furnishing and Delivering Remote Multiplexer and Visual Annunciator Equipment Associated with the Main Annunciator Systems for Diablo Canyon Power Plant, Units 1 and 2.”

47. Trentec Test Report No. 8Q017.0, dated 11/98.

48. Altran Calculation No. 98250-C-001, Revision 0, dated May 1999.

49. PG&E Seismic Calculation No. ES-66, "Seismic Qualification of Westinghouse Supplied SSPS Cabinets."

50. PG&E Seismic Calculation No. IS-88, "Seismic Qualification of Model 3015C/3015N Rosemount Transmitters."

51. IEEE Standard 535-1986, IEEE Standard for Qualification of Class 1E Lead Storage Batteries for Nuclear Power Generating Stations.

52. USNRC Regulatory Guide 1.158, Revision 0, Qualification of Safety-Related Lead Acid Storage Batteries for Nuclear Power Plants, February 1989.

53. PG&E Seismic Calculation No. ES-15-1, "C&D Model LCUN-33 Vital Batteries and Two Steps Battery Rack."

54. QualTech Test Report No. S1203.0, Revision 0, dated 02/24/2012.

55. Triconex Tricon v10 Seismic Test Report Document No. 9600164-526, Revision 1.

56. Qualification of Rack Mounted Electrical Components at Process Control Racks RNO1A through RNO4D, Specification 10101-M-NPG, Revision 3.

57. NLI Qualification Report QR-01913272-1 Revision 5(PG&E Document Number 663222-267).

58. NLI Supplemental Qualification Report SQR-01913272-1, Revision 3 (PG&E Document Number 663222-268).

59. Specification for Furnishing and Delivering Manual/Auto Stations for Diablo Canyon Power Plant Units 1 & 2 10083-J-NPG, Revision 4.

60. AMS826, AMS826/1 and AMS826/2 Qualification Report Revision 3 (PG&E Document Number 6021767-6).

61. AMS827 Qualification Report Revision 2 (PG&E Document Number 6021767-8).

3.11 ENVIRONMENTAL DESIGN OF MECHANICAL AND ELECTRICAL EQUIPMENT

Postulated nuclear plant accidents can result in significant increases in environmental parameters (temperature, pressure, humidity, radiation, chemical spray, and submergence). Established engineering specification and design practices, backed up by a comprehensive QA program and years of actual operating experience (in the nuclear as well as other industries), afford high confidence that equipment will perform satisfactorily in its normal service environment.

Additional assurance of Class 1E equipment operability in accident environments is warranted. Therefore, an EQ Program is established to demonstrate, through appropriate testing and/or analyses, that the DCPP equipment within the scope of the EQ Program will function, as required, during and after postulated accident conditions. This section provides the acceptance criteria and design criteria for the DCPP EQ Program.

3.11.1 DESIGN BASES

3.11.1.1 Environmental Design of Mechanical and Electrical Equipment Safety Function Requirements

(1) Identification of Active Equipment Required to Function During and Subsequent to a Design Basis Event

The active mechanical and electrical equipment, located inside and outside containment, required to function during and subsequent to a design basis event are identified. For equipment located inside containment, the following are identified: (1) the device is used only to initiate a safeguards action, or (2) the device must maintain its function for long term monitoring in a severe environment.

(2) Implementation of a Comprehensive Testing Program for Equipment and System Controls Necessary for the Functioning of Engineered Safety Features Systems

A comprehensive testing program for equipment and system controls necessary for the functioning of ESF systems is implemented. The program consists of performance tests of individual pieces of equipment conducted by the manufacturer and DCPP, integrated tests of the system as a whole, and periodic inspection tests of the Class 1E equipment and circuits to assure reliable performance upon demand throughout the plant lifetime.

(3) Area Temperature Monitoring

The ambient air temperatures in areas outside containment containing Class 1E electrical equipment are monitored continuously where excessive temperature could possibly occur. Air temperatures exceeding those allowed for the equipment's environment are recorded along with the times, and an alarm is transmitted to the

control room. The cause and effects of the high temperature are investigated and corrected as necessary to maintain safe operation.

The criteria for monitoring air temperature are given below:

(1) Where only one Class 1E redundant train or division of electrical equipment is in a given room or area and the ventilation there is neither redundant nor PG&E Design Class I, the ambient air temperature monitoring system is redundant. The temperature monitor meets Class 1E requirements for supply and separation or has two reliable and redundant non-Class 1E supplies

(2) Where only one Class 1E redundant train or division is in a given room or area and the ventilation is PG&E Design Class I, but is not redundant within the area, one temperature monitor is used to monitor the area ambient temperature. The temperature monitor meets Class 1E requirements for supply and separation or has two reliable and redundant non-Class 1E supplies. When demonstrated that passive ventilation is able to support a Class 1E train or division of electrical equipment in a given room or area, the cooling function in that area is considered equally reliable as PG&E Design Class 1 ventilation.

(3) Where one or more Class 1E redundant trains or divisions are in a given room or area and the ventilation is PG&E Design Class I and redundant, one non-redundant temperature monitor is supplied.

The area temperature monitoring systems are PG&E Design Class II; however, high quality components are utilized. The systems are testable; QA procedures are utilized in design, procurement, and installation; and conductors are routed in seismically qualified raceways. Whenever the qualification temperature of monitored equipment is exceeded for more than eight hours, an evaluation is performed to demonstrate the continued acceptability of the affected equipment.

3.11.1.2 10 CFR 50.49 - Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

The DCPP EQ Program provides qualification of the electric equipment defined in 10 CFR 50.49 (Reference 16) paragraph (b). 10 CFR 50.49(b) identifies three categories of electric equipment important to safety covered by the regulation: (1) safety-related electrical equipment, as defined in 10 CFR 50.49(b)(1); (2) nonsafety-related electrical equipment whose failure under postulated environmental conditions could prevent satisfactory accomplishment of the safety functions defined above by the safety-related equipment; and (3) certain PAM equipment (10 CFR 50.49, Footnote 4, states that specific guidance concerning the types of variables to be monitored is provided in Regulatory Guide 1.97, Revision 3).

10 CFR 50.49(k) states that applicants for and holders of operating licenses are not required to requalify electric equipment important to safety in accordance with the provisions of 10 CFR 50.49 if the Commission has previously required qualification of the equipment in accordance with "Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors," November 1979 (DOR Guidelines), or NUREG-0588, For Comment version, December 1979 (Reference 7).

10 CFR 50.49(l) states that replacement equipment must be qualified in accordance with the provisions of 10 CFR 50.49 unless there are sound reasons to the contrary.

3.11.1.3 Regulatory Guide 1.89, November 1974 - Qualification of Class 1E Equipment for Nuclear Power Plants

The subcooling margin monitoring system, except for the backup analog recorder and the incore thermocouple inputs, the containment narrow range water level measurement instrumentation, and the high range containment radiation monitors are qualified in accordance with Regulatory Guide 1.89, November 1974 (Reference 6).

3.11.1.4 Regulatory Guide 1.89, Revision 1, June 1984 - Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants

Replacement electric equipment within the scope of 10 CFR 50.49, installed after (and including) February 22, 1983, is required to be environmentally qualified in accordance with the provisions of 10 CFR 50.49, unless there are sound reasons to the contrary. Acceptable sound reasons for the use of replacement equipment previously qualified in accordance with NUREG-0588, For Comment version, December 1979, are delineated in Regulatory Guide 1.89, Revision 1.

3.11.1.5 NUREG-0588, For Comment Version, December 1979 - Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment

DCPP complies with IEEE 323-1971 requirements and the Category II positions of NUREG-0588, For Comment version, December 1979.

3.11.2 CLASS 1E ENVIRONMENTAL QUALIFICATION PROGRAM DESCRIPTION

3.11.2.1 Bounding List Development

In determining the Class 1E electrical equipment that would require EQ, DCPP considered the following items:

(1) Accidents and transients analyzed in the UFSAR

(2) Electrical equipment required to achieve or support:

(a) emergency reactor shutdown

(b) containment isolation

(c) containment and reactor heat removal

(d) prevention of a significant release of radioactive material to the environment

(3) Electrical equipment required to perform PG&E Design Class I actions noted in emergency procedures

At DCPP, a PG&E Instrument Class IA classification is assigned to instrumentation required to perform a PG&E Design Class I function (including, but not limited to, the protection system and the ESF system). This encompasses Class 1E instrumentation. In addition, DCPP assigns a Class 1E classification to electrical equipment other than instrumentation (e.g., cables, motors, etc.). Section 3.2 defines the design classification criteria and lists the classification associated with DCPP mechanical, electrical, and instrumentation and control systems and components.

To develop the bounding list of equipment that would be considered for EQ, DCPP prepared a list of all PG&E Instrument Class IA functions at DCPP, a list of the systems needed to perform the PG&E Design Class I functions, and a list of the electrical equipment needed for those systems to operate. The equipment list was developed by integrating the PG&E Instrument Class IA list with the Class 1E list of electrical equipment other than instrumentation for the required systems.

DCPP also conducted a review of its emergency operating procedures to identify all of the equipment included in these procedures. The instruments (for Regulatory Guide 1.97, Revision 3 [Reference 17] Type A/Category 1 variables only) identified in this review, combined with the integrated IA/1E classification listing discussed above, were used as the base list of equipment eligible for EQ at DCPP. (Note that activities related to compliance with Regulatory Guide 1.97, Revision 3 [Reference 17], proceeded independently and resulted in other instruments being added to the EQ list.)

3.11.2.2 Exemptions

DCPP then performed case-by-case evaluations to determine which of the identified equipment items may be exempted from qualification. In making these determinations, DCPP utilized certain evaluation criteria that were provided as guidelines by the NRC Staff. The list of exempt devices was developed by verifying whether specific equipment meets any of the following three criteria:

(1) The equipment does not perform PG&E Design Class I functions in a harsh environment, and any failure of such equipment in a harsh environment will not impact PG&E Design Class I functions or mislead an operator.

(2) The equipment performs its function before it is exposed to a harsh environment, the sufficiency of any time margin provided is adequately justified, and the subsequent failure of the equipment as a result of the exposure to the harsh environment does not degrade other safety functions or mislead the operator.

(3) The PG&E Design Class I function of a particular piece of equipment can be accomplished by some other designated equipment that has been adequately qualified and satisfies the single failure criterion.

DCPP identified a number of devices that satisfied the above criteria and, therefore, could be exempted from EQ.

3.11.2.3 Cable and Terminations

Consideration was also given to the wiring and terminations associated with each equipment item that was required to be qualified. As part of the initial NUREG-0588, For Comment version, December 1979 (Reference 7) qualification effort, DCPP chose the following course of action related to sealing for wiring and terminations.

All devices qualified to function in a harsh environment have environmentally qualified electrical sealing assemblies added unless they are qualified with their own sealing system, or do not require seals to maintain their EQ (for example, equipment qualified for a harsh radiation environment only). All Class 1E wiring terminations for environmentally qualified equipment inside containment are made by means of environmentally qualified splices, thus avoiding terminal blocks, except for (a) terminal blocks within devices that have the sealing assemblies mentioned above, and (b) terminal blocks inside vendor-supplied equipment assemblies that were procured and environmentally qualified as an assembly. Connections between circuit conductors and the electrical containment penetrations, both inside and outside containment, are also made by means of qualified splices.

Wire and cable used for Class 1E application inside containment and in areas with potential for harsh environment outside containment were generically qualified to perform their PG&E Design Class I function while being exposed to the postulated accident environment. Cable EQ files are segregated according to cable manufacturer. DCPP's procedures assure that only such qualified wire and cable are used for Class 1E application in these areas.

Class 1E cables and associated cable devices (penetrations, splices, seals, etc.) requiring EQ were identified by a search of purchase documents and added to the list of equipment items requiring qualification.

3.11.2.4 Class 1E Electrical Equipment Environmental Qualification Master List Maintenance

The Unit 1 and Unit 2 components within the scope of DCPP's EQ Program are identified in the EQ Master List. To facilitate maintaining the DCPP EQ Master List as a living document (i.e., to maintain it current on an ongoing basis), the "Systems, Applications, and Products in Data Processing" (SAP) database Functional Locations, along with controlled drawing 050909, constitute the DCPP "Class 1E Electrical Equipment Qualification List." A hardcopy output of this EQ Master List information is available as a living document. Controlled drawing 050909 lists the EQ equipment that does not have tag numbers (i.e., electrical cables, connectors, splices) and provides guidance to print a hardcopy of the EQ Master List Information and a report of changes since the last EQ Master List review.

There are two important "notes" that may be assigned to equipment on the EQ Master List:

(1) "Note 11" - identifies devices that are located in a mild area; EQ is not required.

(2) "Note 16" - identifies devices that are located in an area subject to a harsh environment but that are not required to function for accident mitigation or PAM of the event that causes the harsh environment. Note 16 is also ascribed to devices that complete their required PG&E Design Class I function prior to being exposed to the harsh environment.

Changes to the EQ Master List can occur as a result of plant design changes, maintenance, or as a consequence of revised post-accident environment analyses. For example:

(1) Design changes that add new equipment to the plant will result in additions to the list if the equipment is within the scope of 10 CFR 50.49(b).

(2) Design changes or re-analyses that add or eliminate areas of harsh environment can result in changes in the list.

(3) Design changes that change equipment location (either to a harsh environment from a mild environment, or vice versa) can result in changes in the list.

(4) Design changes (or analyses) that change equipment functional requirements can result in additions to or deletions from the list, or in changes to the "Note 16" assignments.

(5) Maintenance activities can result in equipment replacement/upgrade with consequent changes to the list (new vendor, model number, etc.).

Design and maintenance activities are procedurally controlled to ensure that any associated impact on EQ Program implementation is identified, evaluated, and tracked.

3.11.2.5 Accident Environments

Fundamental to the EQ of equipment is the determination of the changes in environmental parameters to which the equipment would be subjected in the event of an accident. The environmental parameters considered are pressure, temperature, humidity, radiation, caustic spray, and submergence. Extensive modeling has been performed to determine the time-dependent behavior of these parameters following postulated accidents. This information is compiled and maintained.

The post-accident environmental radiation levels are determined using source term guidance provided in NUREG-0737, Item II.B.2 (Reference 29). Radiation environments inside containment are developed using guidance provided in NUREG-0588, Appendix D for radioactivity transport (Reference 7). The post-accident radiation environments established using the above regulatory guidance is utilized for environmental equipment qualification of PG&E Design Class I components (Reference 30).

Changes in this information can occur as a result of plant design changes or new/revised analyses, and are evaluated for EQ impact. Consequent actions are taken as required to assure that equipment required to be environmentally qualified remains environmentally qualified. The effect of changes in fuel design, enrichment and burnup implemented since the issuance of Reference 30 have been incorporated into the EQ Program.

It is noted that DCPP has incorporated a full implementation of Alternative Source Terms (AST) as defined in Regulatory Guide 1.183, July 2000, Section 1.2.1. However, the post-LOCA integrated doses utilized for radiological environmental qualification of PG&E Design Class I equipment continue to be based on TID-14844 assumptions. This approach is acceptable based on Section 1.3.5 of Regulatory Guide 1.183 and NUREG-0933, Section 3.0, Item 187 which concluded that there is no clear basis for a requirement to modify the design basis for EQ to adopt AST since there would be no discernible risk reduction associated with adopting AST for EQ.

3.11.2.6 Normal Environments

Normal service environments are of concern with respect to EQ because of their effect on equipment's qualified life.

Equipment items requiring qualification typically comprise various different materials: metals, plastics, elastomers, etc. The non-metallic materials are often susceptible to slow degradation over time as a result of exposure to elevated temperatures or radiation. This degradation can limit the capability of an equipment item to fulfill its design function in an accident environment. Qualified life is thus defined as "the period of time for which satisfactory performance can be demonstrated for a specific set of service conditions" (Reference 5). Qualified life does not include the time period for which the equipment item would be required to perform during and following an accident; EQ testing and analyses are based on the assumption that the accident for which the item would be required would occur right at the end of the item's qualified life. Thus, an item having a ten-year qualified life, for example, can be relied on until the very end of the tenth year.

The normal environments used for equipment EQ are specified. A qualified life has been determined for every equipment item that requires EQ. Equipment having a qualified life less than the 40-year life of the plant is replaced or refurbished, in accordance with applicable maintenance procedures, prior to the end of its qualified life. Procedures also ensure that any other required maintenance on an environmentally qualified equipment item be performed such that the item remains qualified.

DCPP uses 10^3 rads total integrated dose (TID) outside containment as the threshold gamma exposure above which qualification for a radiation environment is required (Reference 14). Note that the basis for the radiation environment qualification of non-electronic electrical devices subject to a gamma TID of between 10^3 and 10^4 rads is documented.

3.11.2.7 Loss of Ventilation

Safety provisions of the HVAC systems are discussed in Section 9.4.

3.11.2.8 Mechanical Components

The scope of the EQ Program encompasses mechanical components that are integral to, and required for, the operation of electromechanical devices (e.g., switches, relays, valve operators, solenoid valves, and pressure detectors). Mechanical sealing devices for electrical equipment (including terminations, splices, conduit connections, and penetrations) are within the scope of the EQ Program if they are required to demonstrate the EQ of the associated electrical equipment.

The EQ Program does not specifically address purely mechanical components; they are addressed through the DCPP preventative maintenance programs.

3.11.3 SAFETY EVALUATION

3.11.3.1 Environmental Design of Mechanical and Electrical Equipment Safety Function Requirements

(1) Identification of Active Equipment Required to Function During and Subsequent to a Design Basis Event

Active mechanical and electrical equipment, located inside and outside containment, required to function during and subsequent to a design basis event, is identified.

For equipment located inside containment, it was determined that either: (1) the device is used only to initiate a safeguards action, or (2) the device must maintain its function for long term monitoring in a severe environment.

(2) Implementation of a Comprehensive Testing Program for Equipment and System Controls Necessary for the Functioning of Engineered Safety Features Systems

The qualification tests of individual components in conjunction with integrated testing of ESF systems ensure that the systems perform as designed and the actuation circuitry functions properly. Maintenance activities required as a result of routine periodic testing ensure components function properly and within their prescribed limits for their qualified life.

(3) Area Temperature Monitoring

The DCPP Equipment Control Guidelines identify rooms/areas monitored by the area temperature monitoring systems, along with their corresponding temperature limits. The ambient air temperatures in these areas are monitored continuously. Air temperatures exceeding the established setpoints are recorded along with the times. An alarm is also transmitted to the control room. The cause and effects of high temperature are investigated and corrected in accordance with the DCPP Equipment Control Guidelines.

The area temperature monitoring systems meet the criteria for monitoring air temperature, as follows:

(1) Where only one Class 1E redundant train or division of Class 1E electrical equipment is in a given room or area and the ventilation there is neither redundant nor PG&E Design Class I, the ambient air temperature monitoring system is redundant. The temperature monitor meets Class 1E requirements for supply and separation or has two reliable and redundant non-Class 1E supplies.

(2) Where only one Class 1E redundant train or division is in a given room or area and the ventilation is PG&E Design Class I, but is not redundant within the area, one temperature monitor is used to monitor the area ambient temperature. The temperature monitor meets Class 1E requirements for supply and separation or has two reliable and redundant non-Class 1E supplies.

(3) Where one or more Class 1E redundant trains or divisions are in a given room or area and the ventilation is PG&E Design Class I and redundant, one non-redundant temperature monitor is supplied.

The area temperature monitoring systems are designated as PG&E Design Class II. Area temperature monitoring system components are subject to the QA program for balance of plant equipment important to reliable plant operation. Procedures have been established to test the area temperature monitoring systems. Conductors are routed in seismically qualified raceways.

3.11.3.2 10 CFR 50.49 - Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

Equipment within the scope of 10 CFR 50.49 installed before February 22, 1983, is, at a minimum, environmentally qualified in accordance with the standards contained in IEEE 323-1971 (Reference 4) supplemented by the Category II positions contained in NUREG-0588, For Comment version, December 1979 (Reference 7).

New (i.e., non-replacement) equipment within the scope of 10 CFR 50.49 installed after (and including) February 22, 1983, is environmentally qualified in accordance with the standards contained in IEEE 323-1974 (Reference 5) supplemented by the Category I positions contained in NUREG-0588, For Comment version, December 1979 (Reference 7).

Replacement equipment, for equipment within the scope of 10 CFR 50.49, installed after (and including) February 22, 1983, is environmentally qualified in accordance with the standards contained in IEEE 323-1974 (Reference 5) supplemented by the Category I positions contained in NUREG-0588, For Comment version, December 1979 (Reference 7), unless there are sound reasons to the contrary.

The Unit 1 and Unit 2 components within the scope of DCPP's EQ Program are identified in the EQ Master List. The EQ Master List identifies Class 1E equipment, both in the balance-of-plant scope and the nuclear steam supply scope, which may be required to function in a severe environment. This list includes the following information for each component listed: manufacturer, model number, location in the plant, and specific reference to the qualification report(s) for each piece of equipment (refer to Section 3.11.2.4).

EQ testing and analyses have demonstrated that components identified as requiring EQ are qualified to 10 CFR 50.49 and are capable of fulfilling their PG&E Design Class I functions despite exposure to harsh accident environment conditions.

Dedicated EQ files have been established to document the EQ of equipment based on the results of testing and analyses. The files are segregated on a discipline basis and according to manufacturer. The files include qualification summaries, test reports, applicable correspondence, and information that associates the installed equipment with the qualification documents.

The EQ files are prepared and maintained in accordance with procedures and are readily available to engineering and maintenance personnel. They are maintained as quality records (Reference 24).

3.11.3.3 Regulatory Guide 1.89, November 1974 - Qualification of Class 1E Equipment for Nuclear Power Plants

The subcooling margin monitoring system is environmentally qualified in accordance with Regulatory Guide 1.89, November 1974, except for the backup analog recorder, which is not subject to a harsh environment (Reference 26), and the incore thermocouple inputs, which meet the requirements of Regulatory Guide 1.97, Revision 3 (Reference 17).

The high range containment radiation monitors are environmentally qualified in accordance with Regulatory Guide 1.89, November 1974 (Reference 27).

The containment narrow range water level measurement instrumentation is qualified in accordance with Regulatory Guide 1.89, November 1974 (Reference 28).

3.11.3.4 Regulatory Guide 1.89, Revision 1, June 1984 - Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants

Replacement electric equipment within the scope of 10 CFR 50.49, installed after (and including) February 22, 1983, is environmentally qualified in accordance with the provisions of 10 CFR 50.49 unless there are sound reasons to the contrary. Acceptable sound reasons for the use of replacement equipment previously qualified in accordance with NUREG-0588, For Comment version, December 1979, are delineated in Regulatory Guide 1.89, Revision 1 (Reference 18), and are documented, if invoked, in the applicable EQ file.

3.11.3.5 NUREG-0588, For Comment Version, December 1979 - Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment

DCPP Unit 1 and Unit 2 components within the scope of the EQ Program conform with the Category II requirements of NUREG-0588, For Comment version, December 1979 (Reference 7).

3.11.4 REFERENCES

1. Deleted in Revision 23.

2. Deleted in Revision 23.

3. Deleted in Revision 23.

4. IEEE Trial-Use Standard 323-1971, General Guide for Qualifying Class I Electric Equipment for Nuclear Power Generating Stations, dated April 1971.

5. IEEE Standard 323-1974, IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations, dated December 1973.

6. Regulatory Guide 1.89, Qualification of Class 1E Equipment for Nuclear Power Plants, AEC, dated November 1974.

7. NRC, Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment, NUREG-0588, For Comment version, dated December 1979.

8. Deleted in Revision 23.

9. Deleted in Revision 23.

10. Deleted in Revision 23.

11. Deleted in Revision 23.

12. Deleted in Revision 23.

13. Deleted in Revision 23.

14. DCPP Environmental Qualification Report, Revision 1, dated September 1981, attached to PG&E (Mr. Philip A Crane, Jr.) Letter to NRC (Mr. Frank J. Maglia, Jr., Chief, Licensing Branch No. 3, Division of Licensing, Office of Nuclear Reactor Regulation),dated September 2, 1981.

15. Deleted in Revision 23.

16. Title 10 of the U.S. Code of Federal Regulations, Section 50.49 (10 CFR 50.49), "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants," promulgated in the Federal Register on January 21, 1983 (refer to 48FR2729), effective February 22, 1983.

17. Regulatory Guide 1.97, Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident, NRC, Revision 3, dated May 1983.

18. Regulatory Guide 1.89, Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants, NRC, Revision 1, dated June 1984.

19. Deleted in Revision 23.

20. Deleted in Revision 23.

21. Deleted in Revision 23.

22. Deleted in Revision 24.

23. Deleted in Revision 23.

24. PG&E (Mr. J. O. Schuyler) Letter DCL-84-088 to NRC (Mr. John B. Martin, Regional Administrator, NRC Region V) dated March 1, 1984, re: "Response to NRC Inspection Report 50-275/83-40."

25. Deleted in Revision 23.

26. PG&E (Mr. Philip A. Crane, Jr.) Letter to NRC (Mr. Frank J. Miraglia, Jr., Chief, Licensing Branch No. 3, Division of Licensing, Office of Nuclear Reactor Regulation), dated March 19, 1981, “Additional Clarification of PG&E’s Submittal Regarding Item II.F.2 of NUREG-0737.”

27. PG&E (Mr. Philip A. Crane, Jr.) Letter to NRC (Mr. A. Schwencer, Acting Chief, Licensing Branch No. 3, Office of Nuclear Reactor Regulation), dated September 22, 1980, “Additional Information Regarding Shielding Review, Containment Monitors, and Iodine Sampling.”

28. PG&E (Mr. Philip A. Crane, Jr.) Letter to NRC (Mr. Harold R. Denton, Director, Office of Nuclear Reactor Regulation), dated November 2, 1979, “PG&E Response to NRC Letters Regarding Staff Follow-up Actions to the TMI Unit 2 Accident.”

29. NUREG-0737, Clarification of TMI Plan Requirements, USNRC, November 1980.

30. Diablo Canyon Units 1 and 2 Radiation Shielding Review, Rev. 3, including Supplement 1, June 1984.

TABLE 3.1-1

GENERAL DESIGN CRITERIA APPLICABILITY

1967 GDC GROUP	1967 GDC	1971 GDC	1987 GDC	1999 GDC
Overall Plant Requirements	1			
	2			
		3 [a]		
	4			
	5			
Protection by Multiple Fission Product Barriers	6	10 [b]		
		12 [c]		
		11 [d]		
	9			
	10			
Nuclear and Radiation Controls	11			19 [e]
	12 to 18			
Reliability and testability of protection systems	19	29 [f]		
	20	29 [f]		
	21 to 26			
Reactivity Control		26 [g]		
	28	26 [g]		
	29	26 [g]		
	30	26 [g]		
	31	25 [h]		
	32	28 [i]		
Reactor Coolant Pressure Boundary	33 to 36			
Engineered Safety features	37			
	38			
		17 [i]		
		18 [j]		
	40		4 [k]	
	41 to 52			
	53	54 [l]		
		55 [l]		
		56 [l]		
		57 [l]		
	54 to 65			
Fuel and Waste Storage Systems	66 to 69			

TABLE 3.1-1

1967 GDC GROUP	1967 GDC	1971 GDC	1987 GDC	1999 GDC
Plant Effluents	70			

(a) GDC 3, 1971 replaces GDC 3, 1967
(b) GDC 10, 1971 replaces GDC 6, 1967 for the design of the reactor core.
(c) GDC 12, 1971 replaces GDC 7, 1967
(d) GDC 11, 1971 replaces GDC 8, 1967
(e) GDC 11, 1967 is supplemented by GDC 19, 1999 for Dose
(f) GDCs 19, 1967 and GDC 20, 1967 are supplemented by GDC 29, 1971.
(g) GDC 26, 1971 replaces GDC 27, 1967 and supplements GDCs 28, 29, and 30, 1967.
(h) GDC 31, 1967 is supplemented by GDC 25, 1971 for reactivity insertion rate limits.
(i) GDC 32, 1967 is supplemented by GDC 28, 1971.
(j) GDC 17, 1971 and GDC 18, 1971 replace GDC 39, 1967
(k) GDC 40, 1967 is supplemented by GDC 4, 1987 for LBB only.
(l) GDC 53, 1967 is supplemented by GDC 54 to 57, 1971.

TABLE 3.1-2

MATRIX OF 1971 GDCs to ASSOCIATED 1967 GDCs

1971 GDC Number	1971 GDC Title	Associated 1967 GDC	1967 GDC Title
1	Quality Standards and Records	1	Quality Standards.
		5	Records Requirements.
2	Design Basis for Protection Against Natural Phenonema	2	Performance Standards.
3	Fire Protection	3	Fire Protection
4	Environmental and Missile Design Bases	40	Missile Protection.
5	Sharing of Structures, Systems, and Components	4	Sharing of Systems.
6 to 9	(Not issued, not used).	---	---
10	Reactor Design.	6	Reactor Core Design.
11	Reactor Inherent Protection.	8	Overall Power Coefficient
12	Suppression of Reactor Power Oscillations.	7	Suppression of Power Oscillations.
13	Instrumentation and Control.	12	Instrumentation and Control Systems.
		13	Fission Process Monitors and Controls.
		14	Core Protection Systems.
		15	Engineered Safety Features Protection Systems.
14	Reactor Coolant Pressure Boundary.	9	Reactor Coolant Pressure Boundary.
15	Reactor Coolant System Design.	No direct association with 1967 GDC.	---
16	Containment Design.	10	Containment.
		49	Containment Design Basis.

TABLE 3.1-2

MATRIX OF 1971 GDCs to ASSOCIATED 1967 GDCs

1971 GDC Number	1971 GDC Title	Associated 1967 GDC	1967 GDC Title
17	Electric Power Systems.	39 (Superseded by 1971 Criterion 17 and 18).	Emergency Power for Engineered Safety Features.
18	Inspection and Testing of Electric Power Systems.	39 (Superseded by 1971 Criterion 17 and 18).	---
19	Control Room.	11	Control Room.
20	Protection System Functions.	14	Core Protection Systems.
		15	Engineered Safety Features Protection Systems.
		20	Protection Systems Redundancy and Independence. Single Failure Definition.
		21	Demonstration of Functional Operability of Protection Systems.
		25	
21	Protection System Reliability and Testability.	19	Protection Systems Reliability.
22	Protection System Independence.	20	Protection Systems Redundancy and Independence. Single Failure Definition.
		21	Separation of Protection and Control Instrumentation Systems.
		22	Protection Against Multiple Disability of Protection Systems.
		23	
23	Protection System Failure Modes.	26	Protection Systems Fail-Safe Design.
24	Separation of Protection and Control Systems.	22	Separation of Protection and Control Instrumentation Systems.

TABLE 3.1-2

MATRIX OF 1971 GDCs to ASSOCIATED 1967 GDCs

1971 GDC Number	1971 GDC Title	Associated 1967 GDC	1967 GDC Title
25	Protection System Requirements for Reactivity Control Malfunctions.	31	Reactivity Control Systems Malfunction.
26	Reactivity Control System Redundancy and Capability.	27	Redundancy of Reactivity Control.
		28	Reactivity Hot Shutdown Capability.
		29	Reactivity Shutdown Capability.
		30	Reactivity Holddown Capability.
27	Combined Reactivity Control Systems Capability.	30	Reactivity Holddown Capability.
28	Reactivity Limits.	32	Reactivity Holddown Capability.
29	Protection Against Anticipated Operational Occurrences.	19	Protection Systems Reliability.
		20	Reactivity Shutdown Capability.
30	Quality of Reactor Coolant Pressure Boundary.	9	Reactor Coolant Pressure Boundary.
		16	Monitoring Reactor Coolant Pressure Boundary.
31	Fracture Prevention of Reactor Coolant Pressure Boundary.	34	Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention.
		35	Reactor Coolant Pressure Boundary Brittle Fracture Prevention.
32	Inspection of Reactor Coolant Pressure Boundary.	36	Reactor Coolant Pressure Boundary Surveillance.
33	Reactor Coolant Makeup.	No direct association with 1967 GDC.	---
34	Residual Heat Removal.	No direct association	---

TABLE 3.1-2

MATRIX OF 1971 GDCs to ASSOCIATED 1967 GDCs

1971 GDC Number	1971 GDC Title	Associated 1967 GDC	1967 GDC Title
		with 1967 GDC.	
35	Emergency Core Cooling.	37	Engineered Safety Features Basis for Design.
		44	Emergency Core Cooling Systems Capability.
36	Inspection of Emergency Core Cooling System.	45	Inspection of Emergency Core Cooling Systems.
37	Testing of Emergency Core Cooling System.	38	Reliability and Testability of Engineered Safety Features.
		46	Testing of Emergency Core Cooling System Components.
		47	Testing of Emergency Core Cooling Systems.
		48	Testing of Operational Sequence of Emergency Core Cooling Systems.
38	Containment Heat Removal.	49	Containment Design Basis.
		52	Containment Heat Removal Systems.
39	Inspection of Containment Heat Removal System.	58	Inspection of Containment Pressure-Reducing Systems.
40	Testing of Containment Heat Removal System.	59	Testing of Containment Pressure-Reducing Systems.
		60	Testing of Containment Spray Systems.
		61	Testing of Operational Sequence of Containment Pressure-Reducing Systems.
41	Containment Atmosphere Cleanup.	37	Engineered Safety Features Basis for Design.
42	Inspection of Containment Atmosphere Cleanup	62	Inspection of Air Cleanup Systems.

TABLE 3.1-2

MATRIX OF 1971 GDCs to ASSOCIATED 1967 GDCs

1971 GDC Number	1971 GDC Title	Associated 1967 GDC	1967 GDC Title
	Systems.		
43	Testing of Containment Atmosphere Cleanup Systems.	63 64 65	Testing of Air Cleanup Systems Components. Testing of Air Cleanup Systems. Testing of Operational Sequence of Air Cleanup Systems.
44	Cooling Water.	No direct correlation with 1967 GDC.	---
45	Inspection of Cooling Water System.	No direct association with 1967 GDC.	---
46	Testing of Cooling Water System.	No direct association with 1967 GDC.	---
47 to 49	(Not issued, not used).	---	---
50	Containment Design Basis.	49	Containment Design Basis.
51	Fracture Prevention of Containment Pressure Boundary.	50	NDT Requirement for Containment Material.
52	Capability for Containment Leakage Rate Testing.	54 55	Containment Leakage Rate Testing. Containment Periodic Leakage Rate Testing.
53	Provisions for Containment Testing and Inspection.	56	Provisions for Testing Penetrations.
54	Piping Systems Penetrating Containment.	57	Provisions for Testing of Isolation Valves.

TABLE 3.1-2

MATRIX OF 1971 GDCs to ASSOCIATED 1967 GDCs

1971 GDC Number	1971 GDC Title	Associated 1967 GDC	1967 GDC Title
55	Reactor Coolant Pressure Boundary Penetrating Containment.	51 57	Reactor Coolant Pressure Boundary Outside Containment. Provisions for Testing Isolation Valves.
56	Primary Containment Isolation.	53	Containment Isolation Valves.
57	Closed System Isolation Valves.	53	Containment Isolation Valves.
58 to 59	(Not issued, not used).	---	---
60	Control of Releases of Radioactive Materials to the Environment.	17 70	Monitoring Radioactivity Releases. Control of Releases of Radioactivity to the Environment.
61	Fuel Storage and Handling and Radioactivity Control.	68 69	Fuel and Waste Storage Radiation Shielding. Protection Against Radioactivity Release from Spent Fuel and Waste Storage.
62	Prevention of Criticality in Fuel Storage and Handling.	66	Prevention of Fuel Storage Criticality.
63	Monitoring Fuel and Waste Storage.	18	Monitoring Fuel and Waste Storage.
64	Monitoring Radioactivity Releases.	17	Monitoring Radioactivity Releases.

TABLE 3.2-1

DESIGN CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS (SSCs) Sheet 1 of 2

PG&E Design Class I	PG&E Design Class II	PG&E Design Class III
Applicability		
SSCs important to safety, including SSCs required to assure (1) the integrity of the reactor coolant pressure boundary, (2) the capability to shut down the reactor and maintain it in a safe shutdown condition, or (3) the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to the guideline exposures of 10 CFR Part 100.	SSCs important to reactor operation, but not essential to safety, including plant features not required to be PG&E Design Class I.	SSCs not related to reactor operation or safety.

TABLE 3.2-1

PG&E Design Class I		PG&E Design Class II		PG&E Design Class III
Requirements				
1. Quality Standards - SSCs required to meet AEC GDC 1, 1967.		1. Quality Standards – SSCs not required to meet AEC GDC 1, 1967.		1. Quality Standards - SSCs not required to meet AEC GDC 1, 1967.
2. Quality Assurance - SSCs required to meet Appendix B to 10 CFR Part 50.		2. Quality Assurance - SSCs not required to meet Appendix B to 10 CFR Part 50. Specific QA requirements may be applied to selected features. Refer to the DCPP Q-List for further details.		2. Quality Assurance – SSCs not required to meet Appendix B to 10 CFR Part 50. Specific QA requirements may be applied to selected features. Refer to the Q-List for further details.
3. Seismic Design – SSCs required to meet AEC GDC 2, 1967. SSCs are designed to maintain their structural/ pressure boundary integrity, may be designed to perform an active function, when subjected to loading associated with the double design earthquake (DDE) and the Hosgri earthquake (HE). Refer to the DCPP Q-List for the requirements associated with individual SSCs.		3. Seismic Design - SSCs not required to meet AEC GDC 2, 1967. SSCs not designed to withstand effects of design basis earthquakes, except where specifically designated in the Q-list.		3. Seismic Design – SSCs not required to meet AEC GDC 2, 1967. SSCs not designed to withstand effects of design basis earthquakes, except where specifically designated in the DCPP Q-list.

TABLE 3.2-2

PG&E DESIGN CLASS QUALITY/CODE CLASS, AND PIPING SYMBOL vs. INDUSTRY CODE FOR FLUID SYSTEMS – Note (a)(1)

PG&E Design Class	PG&E Engineering PG&E Quality/Code Class	PG&E Piping Symbol	Original Code Classification: Orig. Design Codes & Standards	Original Code Classification: Orig. Fab., Erection, & Inspection Code	Remarks/Notes
I	I	NONE	ASA B31.1-1955	ASME B&PV Code, Section III-1971	Note (b), (p), (r), (t)
I	I	A	ANSI B31.1-1967	ANSI B31.7-1969 w/ 1970 Addenda, Class I	Note (h), (p), (r), (t), (u)
I	II	B	ANSI B31.7-1969 with 1970 Addenda, Class II	ANSI B31.7-1969 with 1970 Addenda, Class II	Note (p), (r), (t), (u)
I	II	@	ANSI B31.1-1967	ASME B&PV Code Section I-1968; Section III - 1968	Note (g), (n), (p), (r), (t), (u)
I	III	C	ANSI B31.7- 1969 with 1970 Addenda, Class III	ANSI B31.7-1969 With 1970 Addenda, Class III	Note (p), (r), (t), (u)
I	III	D	ANSI B31.1- 1967; ANSI B 31.7-1969 with 1970 Addenda, Class III	ANSI B31.1- 1967; ANSI B 31.7-1969 with 1970 Addenda, Class III	Note (i), (p), (q), (r), (t), (u)
II	-	G	ANSI B31.1-1967 and NFPA Standards	ANSI B31.1-1967 and NFPA Standards	Note (d), (j), (p), (t), (u)
I	III	J	ANSI B31.1-1967	ANSI B31.1-1967	Note (k), (p), (r), (t), (u)
II	-	E	ANSI B31.1-1967	ANSI B31.1-1967	Note (p), (t), (u)
II	-	F	ANSI B31.1-1967	ANSI B31.1-1967	Note (e), (c), (p), (t), (u)

PG&E Design Class	PG&E Engineering PG&E Quality/Code Class	PG&E Piping Symbol	Original Code Classification: Orig. Design Codes & Standards	Original Code Classification: Orig. Fab., Erection, & Inspection Code	Remarks/Notes
II	-	G1	NFPA Standards	NFPA Standards	Note (d), (p), (s), (t)
II	-	H	ANSI B31.1-1967	ANSI B31.1-1967	Note (c), (p), (t), (u)
II	-	-	Applicable industry codes and standards	Applicable industry codes and standards	Note (o), (p), (t)
III	-	-	Applicable industry codes and standards	Applicable industry codes and standards	Note (o), (p), (t)
II	-	@	ASME B&PV Code, Section I-1980	ASME B&PV Code, Section I-1980	Note (m), (n), (p), (t)

Notes:

(a) Deleted.

(a)(1) It is recognized that during the design and construction of DCPP Units 1 and 2, significant industry and regulatory changes were made in establishing common methods of classification, e.g., ANSI N18.2 (Reference 1), Safety Guide 26 March 1972 (Reference 2), and Safety Guide 29 June 1972 (Reference 3). However, these methods all differ slightly in detail from those used for the DCPP. Although the form and intent of these regulatory and industry documents are similar, these are not the DCPP Licensing Basis.

(b) Reactor coolant loop and pressurizer surge line piping. Design to ASA B31.1-1955 using Nuclear (N) Code Cases N-7, N-9, and N-10. Fabrication, erection, and inspection to ASME Boiler and Pressure Vessel (B&PV) Code Section III-1971.

(c) Radioactive system (PG&E QA Class R). Future activities such as repair, replacement, maintenance, or testing shall be performed per Regulatory Guide 1.143, Revision 1 (Reference 6) for those portions of the systems designated as PG&E Piping Symbol F or H on the piping schematics.

(d) Certain portion of the fire protection system have not been designed or constructed under a quality assurance program meeting all requirements of 10 CFR 50, Appendix B. However, activities such as repair, replacement, maintenance, or testing shall be performed in accordance with the QA recommendations described in NFPA 805, 2001 Edition and PG&E Program Directive (PD) OM8 (PG&E QA Class G). Quality requirements administered shall be commensurate with the safety function of the SSC.

(e) Piping is seismically qualified for the Design Earthquake.

(f) Deleted

(g) Feedwater piping from the (final) main feedwater check valve to the steam generator; auxiliary feedwater from the main feedwater line back to the second check valve; main steam piping from the steam generator to the main steam isolation valve; steam generator blowdown piping from the steam generator to the first valve outside containment; design to ANSI B31.1-1967; fabrication, erection, and inspection to ASME B&PV Code Section I-1968. Requirements for the main steam safety valves are in accordance with ASME B&PV Code Section III-1968.

(h) Design to ANSI B31.1-1967. Fabrication, erection, and inspection to ANSI B31.7-1969 with 1970 Addenda, Class I.

(i) This PG&E Piping Symbol applies to: (1) the spent fuel pool cooling loop; (2) the auxiliary feedwater pump suction piping from the fire water storage tank; and (3) the refueling water purification loop from and to the refueling water storage tank. This piping was upgraded from Design Class II, Piping Symbol E. ANSI B31.1 applies for work performed prior to the upgrade. ANSI B31.7 applies to work performed after the upgrade.

(j) Piping is seismically qualified for the Hosgri earthquake.

(k) Piping originally installed as Design Class II, but has been upgraded to require seismic qualification for the Hosgri earthquake. All repair, replacement, and new construction shall be in accordance with the requirements for QA Class Q SSCs.

(l) Deleted.

(m) Auxiliary Boiler No. 0-2 and its external piping conforms to ASME B&PV Code Section I-1980 through summer 1980 Addenda.

(n) The PG&E Piping Symbol '@' is referred to in the UFSAR and the Q-List. However, this symbol is not used on the piping schematics for designation purposes; instead, the line is bubbled (i.e., -0-0-) and the notes describe the applicable code(s).

(o) Refer to the HVAC system schematics for the symbols used for ductwork

(p) Refer to PG&E Drawings 102028 (Unit 1) and 104628 (Unit 2) for ASME Code Boundaries for Inservice Inspection.

(q) Original design, fabrication, construction, and testing of Piping Symbol D piping was performed in accordance with ANSI B31.1, 1967. ANSI B31.7 applies for new work. Refer to mechanical component drawings for codes and standards applicable to the component.

(r) The design, fabrication, construction, and testing of all PG&E Quality/Code Class I fluid systems and components are in accordance with the accepted industry codes and standards that were in effect during the design and construction of DCPP. If fluid systems and components were designed and constructed in accordance with codes and standards outside of the requirements of the above-mentioned documents, additional quality standards have normally been applied.

The design, fabrication, construction, and testing of all PG&E Quality/Code Class II fluid systems and components are in accordance with the accepted industry codes and standards that were in effect during the design and construction of DCPP. If fluid systems and components were designed and constructed in accordance with codes and standards outside of the requirements of the above-mentioned documents, additional quality standards have normally been applied.

The design, fabrication, construction, and testing of all PG&E Quality/Code Class III fluid systems and components are in accordance with the accepted industry codes and standards that were in effect during the design and construction of DCPP. If fluid systems and components were designed and constructed in accordance with codes and standards outside of the requirements of the above- mentioned documents, additional quality standards have normally been applied.

An exception exists to the above for PG&E Quality Code Class III, Piping Symbol D piping. These are systems or portions of systems which were originally constructed as Design Class II and were subsequently upgraded to Design Class I, usually because a change in the requirements for the system. For such piping, the design analysis is in accordance with PG&E Design Class I criteria. All construction, repair, or replacement performed after the upgrade is in accordance with PG&E Quality Assurance Class I requirements.

(s) Piping Symbol G1 applies to the South Site Fire Water System (SSFWS).The SSFWS was not installed under the QA Class G (fire protection system) program.

(t) The “Orig. Design Code & Standards” and the “Orig. Fab., Erection, & Inspection Code” columns list the title and year of the code or standard (e.g., ASME, ANSI, NFPA) that were approved for the design, fabrication, erection, and testing of the fluid systems in the original operating licenses for DCPP Units 1 & 2. Modifications implemented since the original licensing may meet newer codes and standards, which have been accepted through the code reconciliation process or through the NRC approval of License Amendments.

(u) Piping design stress equations are not defined in ANSI B31.1-1967, therefore, stress equations from ANSI B31.1-1973 Summer Addenda apply. Since ANSI B31.7 for PG&E Quality Class II and III piping refers to ANSI B31.1, the same stress equations must be met for piping designed to ANSI B31.7. Furthermore, for PG&E Piping Code Class G, the satisfaction of the given ANSI B31.1 equations is not meant to replace conformance to the applicable NFPA Codes and Standards.

TABLE 3.2-3

CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS

Structure, System, Component	Design Class	Design, Fabrication, Erection, and Test Code
SECTION I - STRUCTURES, BUILDINGS, AND FACILITIES		
Containment Structure and Facilities		
Structure and Components		
Containment exterior concrete	I	
Containment base slab	I	
Containment liner	I	ASME BPVC Section VIII[a] (no code stamp)
Containment penetrations & air locks	I	ASME BPVC Section III (no code stamp)
Containment piping rupture restraints	I	
Containment interior concrete	I	
Containment interior annulus steel	I	
Reactor cavity liner	II	
Containment pipeway structure	I	
Containment penetration flued heads	I	Based on ASA B31.1-1955[b]
Reactor Coolant System Equipment Supports		
Reactor vessel support structure	I	
Steam generator support	I	

(a) Containment liner fabrication conforms to the applicable parts of ASME BPVC Section VIII, Part UW, "Requirements for Unfired Pressure Vessels Fabricated by Welding."
(b) Welders qualified per ASME BPVC Section VIII.

TABLE 3.2-3

Structure, Component, and System	Design Class	Design, Fabrication, Erection, and Test Code
SECTION I (CONTD.)		
Containment Structure and Facilities (contd.)		
Steam generator hydraulic support struts	I	
Reactor coolant pump supports	I	
Reactor coolant piping restraints	I	
Pressurizer support	I	
Facilities		
Containment structure polar crane	I[(a)]	
Polar crane cables and hooks	II	
Reactor vessel internals support stands	II	
Containment dome service crane	III[(c)]	
Ventilation and Air Conditioning		
Containment fan cooling units	I	
Containment fan cooling system annular ring and ductwork	II[(e)]	
Containment penetration isolation valves	I	
CRDM ventilation system	II[(d)]	
Iodine removal system	II	
Plant exhaust vent	I	

(a) Cranes are PG&E Design Class I only for those aspects necessary to prevent the crane itself from falling during a DE, DDE, or HE seismic event.
(b) Not used.
(c) Evaluated to demonstrate crane structure either loaded or unloaded will not fail as a result of the Hosgri event.
(d) Equipment support analyzed to Seismic Category I criteria.
(e) Duct and duct supports are qualified to Seismic Category I criteria.

TABLE 3.2-3

Structure, Component, and System	Design Class	Design, Fabrication, Erection, and Test Code
SECTION I (CONTD.)		
Containment Structure and Facilities (contd.)		
Forced draft shutter dampers	I	
Containment hydrogen purge system	I	
Containment normal purge system	II	
Containment purge valve debris screens	I	
Hydrogen recombiners	I	
Containment pressure indication system	I	
Containment water level indication system	I	
Containment hydrogen indication system	II	
Containment recirculation sump, strainer, trash rack, and vortex suppressor	I	
Auxiliary & Fuel Handling Buildings & Facilities		
Building and Components		
Auxiliary building	I	
Fuel handling area of the auxiliary building	I	
Control room	I	
Spent fuel pool concrete	I	
Building and Components		
Spent fuel pool liner	II[(a)]	
PG&E Design Class I masonry walls	I	
Missile barriers which protect PG&E Design Class I items	I	
Radiation shielding	II	

(a) Evaluated for its capability to withstand spent fuel rack reactions resulting from the Hosgri event.

TABLE 3.2-3

Structure, Component, and System	Design Class	Design, Fabrication, Erection, and Test Code
SECTION I (CONTD.)		
Auxiliary & Fuel Handling Buildings & Facilities (cont'd.)		
Facilities		
Fuel handling building crane	II[c]	
Fuel handling building crane trolley “Critical Items”	I[c]	
Auxiliary building elevators	II	
Spent fuel storage racks	I	
New fuel storage racks	I[a]	
Ventilation and Air Conditioning		
125-Vdc/480-Vac switchgear area ventilation system	I	
Control room HVAC system (except exhaust fans)	I	
Ventilation system - non-Class 1E	II	
Post-Accident sampling room HVAC system	II[b]	
Auxiliary building ventilation system -Class 1E	I	
Fuel handling building ventilation system -Class 1E	I	
Communications room air conditioning system	II	

(a) Classification made prior to realization that failure might result in a fuel array that could support a nuclear reaction. The fuel racks have been designed to PG&E Design Class I criteria, but without quality assurance documentation. Any modifications or repairs will be conducted under the Operational Quality Assurance Program.

(b) All ducts and duct supports have been evaluated to Seismic Category I criteria. Normal air conditioning units have been evaluated to remain in place after a Hosgri event but not necessarily remain functional. Emergency filtration equipment has been evaluated for a Hosgri event; calculated stresses are within the allowables for the PG&E Design Class I criteria.

(c) Structural adequacy unloaded has been demonstrated by seismic qualification for the DE and DDE earthquake; unloaded and loaded for HE and LTSP. Portions of the crane defined as “Critical" by ASME NOG-1 are subject to additional quality requirements as documented in the “Critical Items List.”

TABLE 3.2-3

Structure, Component, and System	Design Class	Design, Fabrication, Erection, and Test Code
SECTION I (CONTD.)		
Auxiliary & Fuel Handling Buildings & Facilities (cont'd.)		
GE/GW area ventilation system	II[c]	
Access control ventilation system	II	
Battery rooms & cable spreading rooms ventilation system	II	
Control room pressurization system	I	
Gaseous radwaste filter	II	
Turbine Generator Building and Facilities		
Building and Components		
Turbine generator building	II[a]	
Turbine pedestal	II[a]	
Machine shop	III	
Facilities		
Turbine building crane	II[b]	
Machine shop crane	II	
Freight elevator	II	

(a) The turbine building and the turbine pedestal are PG&E Design Class II structures, except for those areas of the turbine building that are designated as PG&E Design Class I in Section 3.8.3.1. The PG&E Design Class I portions of the turbine building have been evaluated for their capability to withstand high energy line break (HELB) effects. In addition, the PG&E Design Class II portions of the turbine building that house or support PG&E Design Class I equipment are evaluated for the DDE, seismically qualified to Hosgri criteria and controlled by the seismic configuration control program (SCCP) in accordance with CF3.ID11.

(b) Evaluated to demonstrate the crane structure either loaded or unloaded will not fail as a result of the Hosgri event.

(c) The GE/GW area ventilation system is a PG&E Design Class II system, which provides non-safety related cooling to the GE/GW area. The two series system isolation dampers and duct, which connect the GE/GW area ventilation system to the plant vent are PG&E Design Class I.

The Design Class I portion of the system has been evaluated for the DE, DDE, and Hosgri criteria to ensure the pressure boundary integrity of the plant vent is maintained.

TABLE 3.2-3

Structure, Component, and System	Design Class	Design, Fabrication, Erection, and Test Code
SECTION I (CONTD.)		
Turbine Generator Building and Facilities (cont'd)		
Ventilation		
4.16-kV Class 1E switchgear supply system	I[c]	
Ventilation systems & equipment	II	
Diesel generator room ventilation	I	
Technical support center ventilation system	II[b]	
Intake and Discharge Structures and Facilities		
Structures and Components		
Intake structure	II[a]	
Discharge structure	II	
Circulating water conduits	II[a]	
Auxiliary saltwater conduits	I	
Breakwaters	II	
Facilities		
Intake structure crane	II[d]	
Bar racks	II	
Intake structure watertight door	I	

(a) PG&E Design Class I components located in the intake structure and supported by the circulating water conduits are protected by evaluating the structure for the DDE and evaluating the structure and the circulating water conduits to Hosgri earthquake criteria so that auxiliary saltwater flow is assured.
(b) Equipment supports, duct, and duct supports, have been evaluated to Seismic Category I criteria.
(c) The design intent of the system is to remain intact and functional for accidents or events such as LOCA, LOOP and earthquake in order to provide operational margin. It is not required to be PG&E Design Class I for the purposes of supporting the operability of the 4.16-kV switchgear.
(d) Evaluated to demonstrate the crane structure either loaded or unloaded will not fail as a result of the Hosgri event.

Structure, Component, and System	Design Class	Design, Fabrication, Erection, and Test Code
SECTION I (CONTD.)		
Intake and Discharge Structures and Facilities (contd.)		
Ventilation		
Auxiliary saltwater pump room ventilation system	I	
Intake structure control building ventilation system	II	
Reservoirs		
Raw water storage reservoir	II	
Solid Radwaste Storage Facility and Laundry Facility		
Structures		
Solidified radioactive waste storage areas	II	
Laundry facility	II	
Dry active waste storage areas	II	
Contaminated lube oil storage area	II	
Components		
Traveling bridge cranes	II	

Structure, Component, and System	Design Class	Design, Fabrication, Erection, and Test Code
SECTION I (CONTD.)		
Solid Radwaste Storage Facility and Laundry Facility (contd.)		
Shielded transport railcar	II	
Respirator cleaning equipment	II	
Washers	III	
Dryers	III	
Water heaters	III	
Radwaste Storage Building		
Structures		
Solidified and/or dewatered waste storage areas	II	
Dry active waste storage area	II	
Components		
Traveling bridge cranes	II	

TABLE 3.2-3

Structure, Component, and System	Design Class	Design, Fabrication, Erection, and Test Code
SECTION I (CONTD.)		
Radwaste Storage Building (contd.)		
Shielded transport rail car	II	
Liner inspection and decontamination equipment	II	
Freon recycle system	II	
Emergency Support Facilities		
Facilities[a]		
Technical support center	III[b]	
Operations support center	III	
Emergency operations facilities	III	

(a) The appropriate requirements of the operational Quality Assurance (QA) program will be applied to the PG&E Design Class I features of these facilities and their assorted equipment to assure continued compliance with applicable regulatory requirements. These requirements are currently specified in NUREG-0696, February, 1981, "Functional Criteria for Emergency Program Facilities."

(b) NUREG-0696, February 1981, “Functional Criteria for Emergency Program Facilities,” requires the TSC to be housed in a well-engineered structure but need not meet Seismic Category I criteria. To implement these guidelines, the TSC is designed for Hosgri seismic loads.

SECTION II - MECHANICAL EQUIPMENT AND COMPONENTS

The following general notes apply to the Mechanical Equipment and Component sheets:

(1) All mechanical equipment and components have been assigned PG&E Design Class I, II, or III, in accordance with the seismic classification system (refer to Section 3.2.2.1 and Table 3.2-2.).

(2) Mechanical equipment and components, which form part of a fluid system pressure boundary and which are designated PG&E Design Class I, are assigned Code Class I, II, or III, in accordance with the system quality group classification system.

(3) Mechanical equipment and components which form part of a fluid system pressure boundary, and which are PG&E Design Class II or III, are not assigned a code class.

(4) Mechanical equipment and components which do not form part of a fluid system pressure boundary are not assigned a code class.

(5) Pumps and valves have been designed, fabricated, erected, and tested in accordance with specific requirements of numerous standards and codes, e.g., ANSI B16.5, ANSI B16.11, ANSI B31.1.0, MSS-SP-67, ASME BPVC Section III, and ASME BPVC Section VIII. This was industry practice during the design and construction of DCPP, i.e., prior to the issuing of the Draft ASME Code for Pumps and Valves, and ASME BPVC Section III-1971.

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION II - MECHANCIAL EQUIPMENT AND COMPOENTS			
Condensate System			
Condenser and Associated Items			
Main condenser	II	-	
Condenser tubes	II	-	ASTM B-338-73 Grade 2
Condenser-turbine expansion joints	II	-	
Condenser steam jet air ejector	II	-	
Condenser-circulating water expansion joints	II	-	
Pumps			
Condensate pump	II	-	
Condensate booster pump	II	-	
Condenser vacuum pump	II	-	
Seal water	II	-	
Pump for condenser vacuum pump			
(Main Feedwater) Hydrazine & ETA injection pumps	II		

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION II - (CONT'D)			
Condensate System (contd.)			
Heat Exchangers			
Feedwater heater Nos. 5 & 6	II	-	ASME BPVC Section VIII
Feedwater heater Nos. 2, 3, & 4	II	-	ASME BPVC Section VIII
Condensate cooler	II	-	ASME BPVC Section VIII
Tanks			
Miscellaneous condensate return tank	II	-	ASME BPVC Section VIII (no code stamp)
Hydrazine tank	II	-	(a)
Main Feedwater ETA tank	II	-	(a)
Vacuum pump sump tank	II	-	
ETA Storage tank	II	-	ASME BPVC Section VIII, Division I
Feedwater System			
Steam generator feedwater pump	II	-	
Auxiliary feedwater pump (motor driven)[b]	I	III	
Auxiliary feedwater pump (turbine-driven)	I	III	
Auxiliary feedwater Hydrazine & ETA injection pump	II	-	
Feedwater heater No.1	II	-	ASME BPVC Section VIII
Auxiliary feedwater Hydrazine & ETA tanks	II	-	(a)

(a) Welders qualified per ASME BPVC Section VIII.
(b) Motors are Class 1E for PG&E Design Class I pumps.

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION II - (CONT'D)			
Turbine Steam Supply System			
Main turbine - HP element	II	-	
Main turbine - LP elements	II	-	
Auxiliary feed pump turbine	I	III	
Steam generator feed pump turbine	II	-	
Moisture separator reheater	II	-	ASME BPVC Section VIII
Steam generator blowdown tank	II	-	ASME BPVC Section VIII
Reheater drain tank	II	-	ASME BPVC Section VIII
Extraction Steam and Heater Drips Systems			
Heater No.2 drain tank pump	II	-	
Heater No.2 drain tank	II	-	ASME BPVC Section VIII
Heater No.6 drain tank	II	-	ASME BPVC Section VIII
Heater No.6 drain cooler	II	-	ASME BPVC Section VIII
Auxiliary Steam System			
Package boiler blowdown tempering tank	II	-	
Auxiliary boiler	II		ASME BPVC Section I
Auxiliary boiler feed pumps	II	-	
Auxiliary boiler deaerator	II	-	ASME BPVC Section VIII

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION II - (CONT'D)			
Auxiliary Steam System (contd.)			
Auxiliary steam drain receiver	II	-	ASME BPVC Section VIII (no code stamp)
Auxiliary steam drain receiver pump	II	-	
Reboiler	II	-	ASME BPVC Section VIII and TEMA Standards, Class C
Building heating drain receiver	II	-	
Building heating drain receiver pumps	II	-	
Reactor Coolant System			
Reactor Vessel and Associated Items			
Reactor vessel	I	I	ASME BPVC Section III-A
Vessel insulation	II	-	

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION II - (CONT'D)			
Reactor Coolant System (contd.)			
Integrated head assembly (IHA)	I	-	
Reactor vessel upper internals	I	-	
Reactor vessel lower internals	I	-	
Incore Flux Mapping Associated Items			
Instrument conduit & couplings	I	I	ANSI B31.7
Seal table & parts	I	I	
Flux thimble tubing	I	I	
RCS vent	I	-	
Instrumentation to detect inadequate core cooling	I	-	
Control Rod Drive Mechanisms			
CRDM pressure housings	I	I	ASME BPVC Section III-A
Fuel and Rod Control Cluster Assemblies			
Fuel assemblies	I	II	
Rod control cluster assemblies	I	II	
Fuel Transfer System and Associated Items			
Fuel transfer system (except tube)	III[(a)]	-	
Fuel transfer tube	I	-	ASME BPVC Section VIII

(a) Classification made prior to realization that failure of certain components might result in release of radioactivity normally held up. Certain PG&E Design Class I requirements for these components have been met.

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION II - (CONT'D)			
Reactor Coolant System (contd.)			
Other Components			
New fuel elevator	III[d]	-	
Spent fuel pool bridge crane & hoist	II[a]	-	
Reactor cavity manipulator crane	II[a]	-	
Fuel inspection fixture	II	-	
Steam generator, primary side	I	I	ASME BPVC Section III
Steam generator, secondary side	I	II	ASME BPVC Section III
Reactor coolant pump	I[b] [c]	I	
Reactor coolant pump oil collection system	II[e]		
Pressurizer	I	I	ASME BPVC Section III-A
Pressurizer heaters	I	-	
Pressurizer relief tank	II	-	ASME BPVC Section III-C (design and construction)
RCPB leak detection system	II		
Chemical and Volume Control System			
Pumps			
Boric acid transfer pump	I	III	ASME BPVC Section III, 2001 Edition through 2003 Addenda.

(a) Classification made prior to realization that failure might result in release of radioactivity normally held up. Evaluated to demonstrate crane structure either loaded or unloaded will not fail as a result of the Hosgri event.
(b) RCP motor is non-Class 1E with augmented seismic requirements to sustain the DDE and Hosgri loads without loss of structural integrity or coastdown function during a concurrent loss of power. Flywheel and CCW pressure boundary are PG&E Design Class I.
(c) RCP casing is in accordance with ASME BPVC Section III-A.
(d) New fuel elevator evaluated for DDE and Hosgri earthquake concurrent with a maximum lifted load attached.
(e) RCP oil collection system including the overflow piping is qualified to DDE.

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION II - (CONT'D)			
Chemical and Volume Control System (contd.)			
Pumps (contd.)			
Centrifugal charging pump	I	II	Draft ASME Code for Pumps and Valves
Gas stripper feed pump	II	-	Draft ASME Code for Pumps and Valves
Boric acid reserve tank pump	II	-	Draft ASME Code for Pumps and Valves
Liquid holdup tanks recirculation pump	II	-	Draft ASME Code for Pumps and Valves
Boric acid reserve tank recirculation pumps	II	-	
Heat Exchangers			
Excess letdown heat exchanger	I	II	Tubeside - ASME BPVC Section III-C
	I	III	Shellside - ASME BPVC Section VIII, and TEMA Standards, Class R

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION II - (CONT'D)			
Chemical and Volume Control System (contd.)			
Heat Exchangers (contd.)			
Non-regenerative (letdown) heat exchangers	I	II	Tubeside - ASME BPVC Section III-C
	I	III	Shellside - ASME BPVC Section VIII, and TEMA Standards, Class R
Regenerative heat exchanger	I	II	ASME BPVC Section III-C
Seal water heat exchanger	I	II	Tubeside - ASME BPVC Section III-C
	I	III	Shellside - ASME BPVC Section VIII, and TEMA Standards, Class R
Tanks			
Boric acid batch tank & heater	II	-	ASME BPVC Section VIII (no code stamp)
Chemical mixing tank	II	-	ASME BPVC Section VIII (no code stamp)
Resin fill tank	III	-	ASME BPVC Section VIII (no code stamp)
Volume control tank	I	II	ASME BPVC Section III-C
Boric acid tank & heaters	I	III	ASME BPVC Section VIII (no code stamp)
Liquid holdup tanks	II	-	ASME BPVC Section III-C
Boric acid reserve tanks	II	-	ASME BPVC Section VIII-(no code stamp)
Demineralizers			
Cation bed demineralizer	I	II	ASME BPVC Section III-C, 1965
Deborating demineralizer	I	II	ASME BPVC Section III-C, 1965
Evaporator feed ion exchanger	II	-	ASME BPVC Section III-C
Mixed bed demineralizer	I	II	ASME BPVC Section III-C

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION II - (CONT'D)			
Chemical and Volume Control System (contd.)			
Filters			
Boric acid filter	I	III	ASME BPVC Section III-C
Ion exchange filter	II	-	ASME BPVC Section III-C
Reactor coolant filter	I	II	ASME BPVC Section III-C
Redundant reactor coolant filter	I	II	ASME BPVC Section III-B
Seal water injection filter	I	II	ASME BPVC Section III-C
Seal water return filter	I	II	ASME BPVC Section III-C
Other Items			
Boric acid tank orifice	I	III	
Charging pump recirculation orifice	I	II	
Chemical mixing tank orifice	II	-	
Letdown orifice	I	II	
Reactor coolant pump seal bypass orifice	I	II	
Reactor coolant pump seal standpipe orifice	II	-	
Reactor coolant pump seal standpipe	II	-	ASME BPVC Section VIII (no code stamp)[a]
Boric acid blender	I	II	ASME BPVC Section VIII
Boric acid reserve tank recirculation heater	II		ASME BPVC Section VIII

(a) ASME BPVC Section VIII, allowable stresses used for design.

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION II - (CONT'D)			
Safety Injection System			
Safety injection pump	I	II	
Safety injection pump recirculation orifice	I	II	
Safety injection accumulator tank	I	II	ASME BPVC Section III-C
Refueling water storage tank	I	II	AWWA Standard D100[b]
Residual Heat Removal System			
Residual heat removal pump	I	II	Draft ASME Code for Pumps and Valves
Residual heat removal heat exchanger	I	II	Tubeside - ASME BPVC Section III-C Shellside - ASME BPVC Section VIII
NSS Sampling System			
NSSS sample heat exchangers	II[a]		Tubeside -- ASME BPVC Section III Shellside -- ASME BPVC Section VIII
NSSS sample vessels	II[a]		

(a) RCS hot leg sample heat exchanger, RCS sample vessel, and sample hood & sink are seismically qualified to Hosgri criteria to allow post-earthquake RCS sampling capability to confirm RCS boron concentration.
(b) ASME BPVC Section VIII, allowable stresses used for design.

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION II - (CONT'D)			
NSS Sampling System (contd.)			
Post-accident sampling system	II		
Sample vessel	II		
Sample hood & sink	II[a]	-	
Radiation Monitoring Equipment			
Personnel radiation monitoring equipment	II		
Radiation monitoring equipment (fixed and portable)	II		
Accident-related decontamination facilities	II		
Respiratory protecting equipment	II		
Accident related contamination control	II		
Meteorological data collection equipment	II		
Noble gas effluent radiological monitor	II		
Iodine and particulates effluent monitors	II		
Containment high range radiation monitors	I		
Containment Spray System			
Containment spray pump	I	III	
Spray additive tank	I	III	ASME BPVC Section VIII (no code stamp)
Spray eductor	I	III	
Spray nozzle	I	II	

(a) RCS hot leg sample heat exchanger, RCS sample vessel, and sample hood and sink are seismically qualified to Hosgri criteria to allow post-earthquake RCS sampling capability to confirm RCS boron concentration.

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION II - (CONT'D)			
Spent Fuel Pool Cooling System[a]			
Spent fuel pool pump	I	III	Draft ASME Code for Pumps and Valves, Class III
Spent fuel pool skimmer pump	III	-	Draft ASME Code for Pumps and Valves, Class III
Refueling water purification pump	I[b]	-	Draft ASME Code for Pumps and Valves, Class III
Spent fuel pool heat exchanger	I	III	Tubeside - ASME BPVC Section III-C Shellside - ASME BPVC Section VIII
Spent fuel pool demineralizer	I[b]	-	ASME BPVC Section III-C
Spent fuel pool filter	II	-	ASME BPVC Section III-C
Spent fuel pool skimmer filter	III	-	ASME BPVC Section III-C
Spent fuel pool resin trap filter	I[b]	-	ASME BPVC Section VIII
Refueling water purification filter	I[b]	-	ASME BPVC Section VIII
Spent fuel pool skimmer	III	-	
Spent fuel pool strainer	III	-	
Spent fuel pool skimmer strainer	III	-	ASME BPVC Section VIII

(a) Refer to general note (17), of Section III.
(b) PG&E Design Class I except for flow balancing accessories.

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION II - (CONT'D)			
Component Cooling Water System			
CCW pump	I	III	ASME BPVC Section VIII
CCW heat exchanger	I	III	ASME BPVC Section VIII, and TEMA Standards, Class R
CCW surge tank	I	III	ASME BPVC Section VIII
CCW chemical additive tank	II	-	
Service Cooling Water System			
Service cooling water pump	II	-	
Service cooling water heat exchanger	II	-	ASME BPVC Section VIII, and TEMA Standards, Class C
Service cooling water head tank	II	-	
Makeup Water System			
Pumps			
Primary makeup water pump	II	-	
Makeup water transfer pump	I	III	

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION II - (CONT'D)			
Makeup Water System (contd.)			
Tanks			
Primary water storage tank	II	-	AWWA Standard D100[a]
Condensate storage tank	I	III	AWWA Standard D100[a]
Transfer storage tank	I	III	AWWA Standard D100[a]
Acid storage tank	II	-	ASME BPVC Section VIII
Caustic storage tank	II	-	ASME BPVC Section VIII
Saltwater Systems			
Pumps			
Circulating water pump	II	-	
Auxiliary saltwater pump	I	III	ASME BPVC Section VIII, Division I
Screen wash pump	II	-	
Screen refuse pump	II	-	
Intake cooler pump	II	-	

(a) ASME BPVC Section VIII, allowable stresses used for design.

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION II - (CONT'D)			
Saltwater Systems (cont'd)			
Other Items			
Condensate transition spool	II	-	
Circulating water conduits	II[b]	-	
Circulating water pump discharge valve	II	-	
Traveling water screen	II	-	
Screen wash water strainer	II	-	
Intake cooler	II	-	ASME BPVC Section VIII, and TEMA Standards, Class C
Intake structure cooling water head tank	II	-	
Chlorination equipment	II	-	
Sawdust injection tank	III	-	
Auxiliary saltwater gate operators	I[a]	-	
Components for Buried Bypass Piping			
Concrete thrust blocks	I		
Soil bedding and soil envelope materials	II[c]		
Trench soil backfill materials	II[d]		
Ground slope east of intake structure	II		
Wave protection measures	II		

(a) ASW gate operators and stems shall remain structurally intact. Operators not required to operate during any design basis accidents.
(b) Evaluated to Hosgri earthquake criteria to protect the supported auxiliary saltwater conduits and assure auxiliary saltwater flow.
(c) To protect the ASW system buried bypass piping, the bedding and envelope materials are required to support the piping during a Hosgri seismic event. To ensure that the seismic function of the bedding and envelope materials is not compromised as a result of any engineering, construction, or plant operations activity, these materials are classified as seismic graded quality features under QA Class S.
(d) The backfill material does not have a seismic resisting function; however, its weight is accounted for in the seismic analysis of the piping.

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION II - (CONT'D)			
Fire Protection System			
Fire pump	II	-	NFPA Standard 20[b]
Firewater storage and transfer tank	I	III	AWWA Standard D 100[a], NFPA Standard 22
CO_2 storage tank	II	-	NFPA Standard 12
CO_2 storage bottles for circulating water pump motor	II	-	
Liquid Radwaste System			
Pumps			
Reactor coolant drain tank pump	II	-	
Miscellaneous equipment drain pump	II	-	
Equipment drain receiver pump	II	-	
Floor drain receiver pump	II	-	
Chemical drain, laundry & hot shower pumps	II	-	
Containment structure sump pump	II	-	
Reactor cavity sump pump	II	-	
Auxiliary building sump pump	II	-	
Residual heat removal pump vault sump pump	II	-	

(a) ASME BPVC Section VIII, allowable stresses used for design.
(b) Seismic qualification for Hosgri event is required. Refer to SSER 8. In addition, equipment is qualified to DE and DDE.

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION II - (CONT'D)			
Liquid Radwaste System (cont'd)			
Tanks			
Reactor coolant drain tank	II	-	ASME BPVC Section III-C
Equipment drain receiver tank	II	-	ASME BPVC Section VIII (no code stamp)
Floor drain receiver tank	II	-	ASME BPVC Section VIII (no code stamp)
Processed waste receiver	II	-	ASME BPVC Section VIII (no code stamp)
Laundry & hot shower tanks	II	-	ASME BPVC Section VIII (no code stamp)
Chemical drain tank	II	-	ASME BPVC Section VIII (no code stamp)
Spent resin storage tank	II	-	ASME BPVC Section III-C
Demineralizer regenerant receiver tank	II	-	ASME BPVC Section VIII (no code stamp)
Other Items			
Radwaste ion exchangers	II	-	ASME BPVC Section VIII (no code stamp)
Radwaste multimedia filters	II	-	ASME BPVC Section VIII (no code stamp)
Radwaste cartridge filter vessels	II	-	ASME BPVC Section III-C
Radioactive resin removal system	II	-	
Spent filter handling & packaging system	II	-	
Miscellaneous equipment drain tank	II	-	
Auxiliary building sump	II	-	
Residual heat removal sump	II	-	
Reverse osmosis skid	II	II	

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION II - (CONT'D)			
Lube Oil Distribution and Purification Systems			
Lube oil reservoir	II	-	
Lube oil coolers	II	-	
Lube oil transfer pump	II	-	
Lube oil centrifuge	II	-	
Dirty & clean lube oil storage tanks	II	-	
Lube oil overflow tank	II	-	ASME BPVC Section VIII
Diesel Engine Generating Systems			
Diesel fuel oil transfer pump	I	III	
Diesel engine generator unit	I	-	
Engine starting air compressors	II	-	
Engine starting air receivers	I	-	ASME BPVC Section VIII
Engine intake air filter	I	III	
Engine intake air silencer	I	III	
Engine exhaust silencer	I	III	
Diesel fuel oil storage tanks	I	III	UL Standard No. 58[(a)]
Diesel fuel oil transfer filters	I	III	ASME BPVC Section VIII

(a) Welders qualified per ASME BPVC Section IX.

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION II - (CONT'D)			
Turbine and Generator-Associated Systems			
Turbine-generator unit	II	-	
Electrohydraulic control unit	II	-	
Gland steam condenser (shell side)	II	-	
Gland steam condenser air exhauster	II	-	
Seal oil unit	II	-	
Stator coil cooling unit	II	-	
Hydrogen coolers	II	-	
Gaseous Radwaste System			
Waste gas compressors	II[(a)]	-	
Waste gas decay tanks	II[(a)]	-	ASME BPVC Section III-C
Waste gas analyzers	II	-	
Compressed Air System			
Plant air compressor	II	-	
Plant air dryer	II	-	
Plant air receiver	II	-	ASME BPVC Section VIII
Plant air filter	II	-	

(a) Qualification required for DE only per, Regulatory Guide 1.143, Revision 1, October 1979.

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION II - (CONT'D)			
Compressed Air System (contd.)			
Instrument air backup receiver	II	-	
Instrument air accumulators	II	-	
Breathing air system	II	-	
Nitrogen and Hydrogen Supply System			
Nitrogen storage cylinders	II	-	
Hydrogen storage cylinders	II	-	-
Oily Water Separator and Turbine Building Sump System			
Turbine building sump pump	II	-	
Oily water separator	II	-	
Oily water separator holding tank	II	-	AWWA D-100

SECTION III - PIPING SYSTEMS

The following general notes apply to the Piping Systems sheets:

(1) The Reactor Coolant System (RCS) boundary extends to, and includes, the second valve which serves to isolate the RCS from connecting systems. Therefore, all portions of connecting piping, fittings and valves, up to the second valve, are considered to be part of the RCS. For a check valve to qualify as the RCS boundary, it must be located inside the Containment.

(2) All piping that connects to a system or portion of a system is the same code and class up to the first isolation valve, except for the RCS, as noted above.

(3) Piping noted as being ANSI B31.7, Nuclear Power Piping, Class I, is fabricated, erected, and tested in accordance with all the requirements of that code and class (1969 Edition with 1970 Addenda), but design is to ASA B31.1-1955, Power Piping with Nuclear Code Cases, for Unit 1, and USAS B31.1.0-1967 for Unit 2. For this reason, this piping will not have code stamping, but shall receive third party inspection.

(4) Piping noted as being ANSI B31.7, Nuclear Power Piping, Class II, is designed, fabricated, erected, and tested in accordance with all the requirements of that code and class (1969 Edition with 1970 Addenda), is code stamped, and receives third party inspection.

(5) Piping noted as being ANSI B31.7, Nuclear Power Piping, Class III, is designed, fabricated, erected, and tested in accordance with all the requirements of that code and class (1969 Edition with 1970 Addenda). Portions of Unit 2 RCS will have third party inspection and code stamping.

(6) Piping noted as being ANSI B31.1, Nuclear Power Piping, is in accordance with all the requirements of that code and class (1967 Edition with 1971 Addenda).

(7) Piping noted as being ASME Boiler and Pressure Vessel Code, Section I, is in accordance with all the requirements of that code(1968 Edition; 1980 Edition and Summer 1980 Addenda for Auxiliary Boiler 0-2). This piping shall receive third party inspection. The main steam, auxiliary steam, feedwater, auxiliary feedwater, and steam generator blowdown shall be code stamped, but the reactor coolant pipe will not be stamped, because design is to ASA B31.1.

(8) Valves noted as being ASME Boiler and Pressure Vessel Code, Section III, or Section VIII (1968 Editions), and the Draft ASME Nuclear Pump & Valve Code (1968 Editions), is in accordance (with as many as possible), of the design, fabrication, erection, and test requirements of those codes. Valves have been designed, fabricated, erected, and tested in accordance with specific requirements of numerous standards and codes, e.g., ANSI B16.5, ANSI B16.11, ANSI B31.1.0, MSS-SP-67, ASME BPVC Section III, and ASME BPVC Section VIII. This was industry practice during the design and construction of Diablo Canyon, i.e., prior to the issuing of the Draft ASME Code for Pumps and Valves, and ASME BPVC Section III, 1971 Edition. New and replacement valves may be purchased/installed in accordance with later editions of the ASME BPVC. For replacement elastomer diaphragms for diaphragm valves, the requirements of code case N-31 (1540-2) are used; the manufacturer's recommended service life is used as a guideline for replacement. All valves shall be installed in accordance with the requirements of the applicable piping code and class. Valve operators for PG&E Design Class I valves are also considered as PG&E Design Class I for pressure and seismic integrity. However, the electrical and control design for the valve operator can be PG&E Design Class II based on its functional requirement and is specified in the instrument schematics.

(9) The Piping Schematic Drawings, Figures 3.2-1 through 3.2-27, indicate more accurately the limits of piping classes by the application of the piping symbols.

(10) Local stress evaluations due to welded rectangular lug attachments are performed using Welding Research Council Bulletin No. 107 and the ASME Code Case N-318. The method of lug attachment is either by full penetration weld or fillet weld, depending on the application. Attachments are installed on the PG&E Design Class I piping systems.

SECTION III

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(11) Feedwater Piping, Isolation Valves to Steam Generators:

This is 16-inch piping (carbon steel, SA 106) and was furnished with Charpy impact testing to ASTM for each heat. Minimum value of 15 ft-lb, (3 tests), average of 20 ft-lb when tested at 0°F. Supplementary tests S-1 through S-6 of SA 106 were performed on one length of pipe from each heat or lot of steel for piping 8-inches and over.

Piping for modifications or replacements shall conform to SA-106, manufactured in accordance with ASME BPVC Section III, Class 2 requirements, in lieu of supplementary testing. For all future applications, impact testing shall conform to ASME BPVC Section III, Subsection NC, requirements using Charpy V-Notch method at a test temperature at or below the lowest service metal temperature of 32°F.

Chemical and physical test reports were furnished. All welding per Section IX. All welds received full nondestructive testing (NDT) requirements in accordance with B31.7 Class II, 100% radiography of butt welds plus magnetic particle inspection of fillet and socket welds. Stamping and inspection per Section I requirements plus the above.

Auxiliary Feedwater Piping - Check Valves, to Main Feedwater Piping

Same as (11) above except for size.

(12) Main Steam Piping - Steam Generator to Isolation Valves:

Specification 8707 required -- made from SA 516 Grade 70 plate, rolled and welded. Inspection per Section I Boiler Code 1968. 100% radiographed seam welds on pipe and fittings per Section I requirements. All welding to Section IX requirements.

Ladle analysis of each heat of steel, plus laboratory analysis of chemical and physical properties. Charpy impact testing per ASTM A370, 3 tests per heat or lot, no test to be less than 15 ft-lb at 0°F, average to be 20 ft-lb.

Hardness tests to be performed on both ends of one length of pipe from each heat. Transverse tension and bend test specimens are to be made per SA 155.

Piping for modifications or replacements shall be manufactured in accordance with ASME BPVC Section III, Subsection NC, requirements. For all future applications, impact testing shall conform to ASME BPVC Section III, Subsection NC, requirements using Charpy V-Notch method at a test temperature at or below the lowest service metal temperature of 32°F.

100% magnetic particle examination to be made on all welds per B31.7 Class II. All butt welds have 100% radiographic examination per B31.7, Class II requirements.

(13) Steam Generator Blowdown Sample Piping:

This piping (and tubing) complies in all respects with ANSI B31.1 requirements, including welding, NDT, etc. 100% radiograph on all butt welds, magnetic particle or liquid penetrant examination on all socket and fillet welds. Section I (1968) is referenced for blowdown piping as inspection code only.

(14) General Note:

All the piping outlined above was fabricated by M. W. Kellogg Company, using approved QA manuals per Section III requirements. All material and all filler metal used for welding was documented.

(15) The ANSI B31.7 Code Class III classification for (1) accumulator piping, except for nitrogen supply line, (2) injection water supply piping, from the refueling water storage tank to the suction of the system pumps, and (3) containment spray piping, except for portions that may recirculate reactor coolant from residual heat removal system connection to the spray nozzles, is in accordance with ANSI N18.2, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants", American Nuclear Society, August 1970 Draft. This document was the basis for determining the Diablo Canyon piping system classification and boundaries, and it was the accepted industry-wide standard for classification of fluid systems and components at the start of Diablo Canyon piping design and fabrication. Subsequently, revisions to ANSI 18.2, as well as Regulatory Guide 1.26, Revision 3, February 1976, have been issued. Refer to Section 3.2.2 for the description of Diablo Canyon System Quality Group classifications.

The ANSI B31.7 Code Class III accumulator piping, injection water supply piping, and containment spray piping, have been fabricated and erected in accordance with the same quality assurance program and design requirements as ANSI B31.7 Code Class II. All material, fabrication, erection and NDE was performed to ANSI B31.7 Code Class III requirements.

The maximum operating conditions for these portions of accumulator, injection water supply, and containment spray piping are all less than 650 psig and 200°F.

All shop and field welds for this piping were completely liquid penetrant, examined in accordance with the procedures and acceptance criteria of ANSI B31.7, Code Class III requirements.

Repairs shall be in accordance with ASME BPVC Section XI, IWA-4000 for Class 2 systems. Alterations, additions, modifications and replacements shall be in accordance with IWA-7000 for Class 2 systems. As allowed by ASME BPVC Section XI this work may be performed in accordance with the requirements of the original construction code, or any other construction code permitted by ASME BPVC Section XI, and as approved in 10CFR50.55a. Therefore, additions, modifications, alterations, or repairs are to be in accordance with ANSI B31.7 Code Class III requirements for design and ANSI B31.7 code Class III or ASME BPVC Section III Class 3 requirements for material, fabrication, and NDE. Inservice inspection for this piping will be performed, insofar as practicable, in accordance with the requirements for ASME BPVC Section XI Code Class 2 Systems. Refer to Section 5.2.3.15 for a description of the Inservice Inspection Program.

Since this piping is low pressure and temperature, the quality assurance and nondestructive examination considerations accomplished to date, as well as the future inservice inspection, give assurance that this piping will maintain pressure boundary integrity and perform its intended function in event of a loss-of-coolant-accident (LOCA).

(16) Deleted in Revision 1

(17) The PG&E Design Class II classification for the spent fuel pool cooling system is in accordance with the seismic design criteria approved during the licensing for construction of Diablo Canyon. After the design, fabrication, and erection of Diablo Canyon piping had commenced, Regulatory Guide 1.29, Revision 3, September 1978 was issued with the recommendation that the cooling loop of the spent fuel pool cooling system be Seismic Category I. The original, single, spent fuel pool cooling loop had been fabricated and erected by the same contractor who installed Code Class I, II, and III piping; its design was upgraded in accordance with PG&E Design Class I seismic criteria and a random sample of piping welds (shop and field welds) examined by liquid penetrant testing to ensure a level of quality consistent with Piping Code Class C requirements. Since this piping operates at low pressures and temperatures (a maximum of 150 psig and 218°F), the measures taken, including seismic design analysis to PG&E Design Class I, Code Class III piping criteria, the liquid penetrant examinations, and the piping being included in the inservice inspection program make it highly unlikely that the pressure boundary of this piping will fail during any plant condition. Provisions for dealing with failures of the spent fuel pool cooling system are described in FSAR Update Section 9.1.3.3.6. Any additions, modifications, alterations, or repairs, will be in accordance with a level of quality equivalent to the standards of Seismic Category I and Quality Group C, including seismic design, quality assurance, and nondestructive examination.

(18) Loading combinations for containment spray piping are specified in the piping stress calculations. (Refer to Section 6.2.2.3.1).

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION III - PIPING SYSTEMS			
Condensate System (Figure 3.2-2)			
Condensate system piping	II	-	ANSI B31.1
Condensate system valves	II	-	ANSI B16.5, ASME BPVC Section VIII
Feedwater System (Figure 3.2-3)			
Steam generator feedwater piping, from containment isolation valves through containment penetrations to steam generators	I	II(11,14)*	ANSI B31.1 for design, ASME BPVC Section I for fabrication, erection
Valves for above portion of system	I	II	Draft ASME Code for Pumps and Valves, Class II
Auxiliary feedwater piping, from raw water supply valves and condensate storage tank through auxiliary feedwater pumps to the second check valve away from the steam generator feedwater piping	I	III	ANSI B31.7, Class III
Valves for above portion of system	I	III	Draft ASME Code for Pumps and Valves, Class III
Auxiliary feedwater piping from makeup water header to raw water supply valves	I	III	ANSI B31.1 prior to upgrade, ANSI B31.7, Class III for repair, replacement, and new construction.

* Refer to Notes (11, 14).

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION III - (CONT'D)			
Feedwater System (Figure 3.2-3) (contd.)			
Valves for above portion of system	I	III	ANSI B16.5, prior to upgrade, Draft ASME Code for Pumps and Valves, Class III, for repair, replacement and new construction
Remainder of feedwater system piping	II[(a)]	-	ANSI B31.1
Remainder of feedwater system valves	II	-	ANSI B16.5, ASME BPVC Section VIII
Turbine Steam Supply (Figure 3.2-4)			
Main steam piping, from steam generators through containment penetrations to main steam isolation valves	I	II[(12,14)*]	ANSI B31.1 for Design; ASME BPVC Section I for fabrication, erection
Valves for above portion of system including safety relief valves, and including 10% atmosphere dump valves	I	II	Draft ASME Code for Pumps and Valves, Class II ASME BPVC Section III, ANSI B16.5
Steam generator blowdown & blowdown sample piping, from steam generators through containment penetrations to isolation valves	I	II[(13,14)*]	ANSI B31.1 for fabrication and erection ASME BPVC Section I for inspection
Valves for above portion of system	I	II	Draft ASME Code for Pumps and Valves, Class II
Remainder of Turbine Steam Supply System piping	II[(b)]	-	ANSI B31.1
Remainder of Turbine Steam Supply System valves	II	-	ANSI B16.5 ASME BPVC Section VIII

(a) The PG&E Design Class II MFW piping and valves (except FCV-510, 520, 530, 540, 1510, 1520, 1530, and 1540, which are PG&E Design Class I) from the column line G anchor in the turbine building continuing downstream to the MFW check valves (connection to PG&E Design Class I MFW piping) are seismically analyzed to DE, DDE and HE to assure the PG&E Design Class I function of the control valves.

(b) Main Steam Piping downstream of the MSIVs is classified as PG&E Design Class II, but seismic analyses for the piping up to the column line G pipe anchor have determined that a DE, DDE or HE seismic event will not prevent the MSIVs from performing their PG&E Design Class I isolation function.

* Refer to Notes (12-14).

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION III - (CONT'D)			
Turbine Steam Supply (Figure 3.2-4) (contd.)			
Auxiliary feedwater pump turbine steam piping, from main steam piping to auxiliary feedwater pump turbine & exhaust line	I	III	ANSI B31.7, Class III
Valves for above portion of system	I	III	Draft ASME Code for Pumps and Valves, Class III
Extraction Steam and Heater Drips System (Figure 3.2-5)			
Extraction steam & heater drip system piping	II	-	ANSI B31.1
Extraction steam & heater drip system valves	II	-	ANSI B16.5
Auxiliary Steam System (Figure 3.2-6)			
Portions of system piping between containment isolation valves	I	II	ANSI B31.7, Class II
Valves for above portions of system	I	II	
Other auxiliary steam system piping	II	-	ANSI B31.1
Other auxiliary steam system valves	II	-	ANSI B16.5

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION III - (CONT'D)			
Reactor Coolant System (Figure 3.2-7)			
Reactor coolant loop piping and pressurizer surge line piping (design only)	I	I	ASA B31.1-1955 with Nuclear Code Cases for Unit 1, USAS B31.1.0-1967 for Unit 2
Reactor coolant loop piping and pressurizer surge line piping (fabrication, erection, & test)	I	I	ASME BPVC Section III[(a)]
Pressurizer relief valve line piping up to safety and power relief valves, pressurizer RCS spray line piping, and piping connecting the reactor coolant loops to other systems, all if greater than 1/2 inch in diameter	I	I	ANSI B31.7, Class I for fabrication and erection ANSI B31.1 for design
Portions of system piping that penetrate containment; reactor vessel head vent and RCS piping - 1/2 inch and less	I	II	ANSI B31.7, Class II
Safety and power relief valve discharge line to the pressurizer relief tank	I	III	ANSI B31.7, Class III
Remainder of system piping that connects other systems to the pressurizer relief tank	II	-	ANSI B31.1
Reactor coolant system valves - including safety valve, PORV, PORV block valves and their actuators	I & II	I, II, & none	ANSI B16.5, ASME BPVC Section III (Pressurizer Safety Valves)

(a) ASA B31.1, Code Cases N7, N9, and N10 (for weld NDE).

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION III - (CONT'D)			
Chemical and Volume Control System (Figure 3.2-8)			
Letdown & charging (makeup) loop piping; reactor coolant pump seal water supply and return line piping; excess letdown line piping	I	II	ANSI B31.7, Class II
Portion of system piping that provides boric acid to letdown & charging loop, from boric acid tanks through the transfer pumps to the suction of the charging pumps	I	III	ANSI B31.7,Class III
Portion of the system piping between the boric acid reserve tanks and pumps to the liquid hold-up tanks, or to the liquid radwaste system	II	-	ANSI B31.1
Chemical & volume control system valves	I & II	II, III, & none	ANSI B16.5

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION III - (CONT'D)			
Safety Injection System (Figure 3.2-9)			
Portion of system piping that provides injection and may recirculate reactor coolant from the suction of the safety injection, residual heat removal and centrifugal charging pumps to the reactor coolant system; containment sump recirculation piping, from containment sump to residual heat removal pumps suction; portion of accumulator nitrogen supply line that penetrates containment; and portion of system test line that penetrates containment.	I	II	ANSI B31.7, Class II
Accumulator piping, except for nitrogen supply Line; injection water supply piping, from the refueling water storage tank to the suction of the system pumps; and system test piping.	I	III(15,17)*	ANSI B31.7, Class III
Accumulator nitrogen supply line, except for portion that penetrates containment	II	-	ANSI B31.1
Safety injection system valves	I & II	II, III, & none	ANSI B16.5

* Refer to Notes (15-17)

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION III - (CONT'D)			
Residual Heat Removal System (Figure 3.2-10)			
Residual heat removal system piping	I	II	ANSI B31.7, Class II
Residual heat removal system valves	I	II	ANSI B16.5
Nuclear Steam Supply Sampling System (Figure 3.2-11)			
Portions of system piping connecting from the reactor coolant system and accumulators through containment penetration; and, portions of system piping connecting to residual heat removal and chemical volume control system	I	II	ANSI B31.7, Class II
Valves for above portion of system	I	II	ANSI B16.5
Remainder of system piping	II[a]	-	ANSI B31.1
Remainder of NSSS system valves	II	-	ANSI B16.5

(a) RCS hot leg sample line from outboard containment isolation valve to NSSS sample station and PM-80 (including hot shutdown panel in Unit 1) is seismically qualified for the Hosgri event to allow post-earthquake RCS sampling capability to confirm RCS boron concentration at the NSSS sample station.

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION III - (CONT'D)			
Containment Spray System (Figure 3.2-12)			
Portions of system piping that may recirculate reactor coolant, from the residual heat removal system connection to the spray nozzles	I	II(18)*	ANSI B31.7, Class II
Remainder of containment spray system piping	I	III(15)*	ANSI B31.7, Class III
Containment spray system valves	I	II, III	ANSI B16.5
Spent Fuel Pool Cooling System (Figure 3.2-13)			
Spent fuel pool cooling loop	I(17)*	III(17)*	ANSI B31.7, Class III for repair, replacement, and new construction, ANSI B31.1 prior to upgrade
Spent fuel pool cooling system piping, excluding the cooling loop, the portion from the makeup water transfer pump to the spent fuel pool, and the refueling water purification system piping	II		
Spent fuel pool cooling system valves in the cooling loop	I	III	ANSI B16.5

*Refer to Notes (15, 17, & 18)

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION III - (CONT'D)			
Spent Fuel Pool Cooling System (Figure 3.2-13) (contd.)			
Spent fuel pool cooling system valves other than those in the cooling loop and refueling water purification system	II		ANSI B16.5
Component Cooling Water System (Figure 3.2-14)			
Portions of system piping that penetrate containment	I	II	ANSI B31.7, Class II
Valves for above portions of system	I	II	Draft ASME Code for Pumps and Valves, Class II
Remainder of system piping	I	III	ANSI B31.7, Class III
Valves for above portion of system	I	III	Draft ASME Code for Pumps and Valves, Class III
Piping to and from chemical addition tanks, post-accident sample cooler, steam generator blowdown tank vent condenser for chemical or radioactivity sample.	II[(a)]		ANSI B31.1

(a) PG&E Design Class II piping to and from the post-accident sample cooler and S.G. Blowdown tank vent shall be analyzed to PG&E Design Class I criteria.

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION III - (CONT'D)			
Service Cooling Water System (Figure 3.2-15)			
Service cooling water system piping	II	-	ANSI B31.1
Service cooling water system valves	II	-	
Makeup Water System (Figure 3.2-16)			
Component cooling water system supply piping, from condensate storage tank through makeup water transfer pumps to CCW system;	I	III	ANSI B31.7 Class III
Valves for above portions of system	I	III	Draft ASME Code for Pumps and Valves , Class III
Fire water and demineralizer water supply crosstie to the auxiliary feedwater pumps used for long-term cooling system	I	III	ANSI B31.1 for design, ANSI B31.7, Class III for repair, replacement, and new construction
Valves for above portions of system	I	III	ANSI B16.5, Draft ASME Code for Pumps and Valves, Class III for repair, replacement, and new construction
Piping from fire water tank to crosstie connection to auxiliary feedwater pumps used for long-term cooling system	II[(a)]		
Portions of the raw water storage reservoir discharge header, from reservoir to fire water - Auxiliary Feedwater cross tie	II		ANSI B31.1, for Design ANSI B31.7, Class III for repair, replacement, and new construction
Valves for above portion of system	II		ANSI B16.5, prior to upgrade, Draft ASME Code for Pumps and Valves, Class III, for repair, replacement, and new construction

(a) Seismic qualification for Hosgri event is required. Refer to SSER 8.

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION III - (CONT'D)			
Makeup Water System (Figure 3.2-16) (contd.)			
Auxiliary feedwater pump turbine bearing cooler supply & recirculation piping to the condensate storage tank	I	III	
Auxiliary feedwater pump turbine bearing cooler supply from transfer tank	II		
Remainder of system piping	II	-	ANSI B31.1
Valves for above portion of system	II	-	
Saltwater Systems (Figure 3.2-17)			
Auxiliary saltwater system piping	I	III	ANSI B31.7, Class III
Valves for above portion of system	I	III	Draft ASME Code for Pumps and Valves, Class III
Circulating water system conduits	II[(a)]	-	
Valves for above portion of system	II	-	

(a) Evaluated to Hosgri earthquake criteria to protect the supported auxiliary saltwater conduits and assure auxiliary saltwater flow.

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION III - (CONT'D)			
Fire Protection Systems (Figure 3.2-18)			
Portion of water system piping that penetrates containment	I	II	ANSI B31.7, Class II
Valves for above portion of system	I	II	Draft ASME Code for Pumps and Valves, Class II
Underground loop water system piping in yard and supplying piping from raw water reservoir	II	-	ASTM C-296 & C-541 (Mat'l), AWWA C-100, C110 C-203 (Fittings), NFPA Standard 24 (Testing)
Valves for above portion of system	II	-	
CO_2 system piping	II	-	NFPA Standard 12 ANSI B31.1
Valves for above portion of system	II	-	
Water system piping for hose reels in areas containing PG&E Design Class I equipment.	II[(a)]	-	NFPA Standard 14 ANSI B31.1
Valves for above portion of system	II[(a)]	-	
Remainder of systems piping, including deluge and sprinkler system	II	-	NFPA Standards 12, 13, 14, 15, 20
Valves for above portion of systems	II	-	
Liquid Radwaste System (Figure 3.2-19)			
Portions of system piping between containment isolation valves	I	II	ANSI B31.7, Class II
Valves for above portions of system	I	II	Draft ASME Code for Pumps and Valves, Class II

(a) Seismically qualified for Hosgri earthquake.

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION III - (CONT'D)			
Liquid Radwaste System (Figure 3.2-19) (contd.)			
Portions of system piping from reactor coolant drain tank and pump to chemical and volume control system (liquid holdup tanks), to safety injection system (refueling water storage tank), and to equipment drain receivers; piping from miscellaneous equipment drain tank and pumps to equipment drain receivers and pumps and radioactive resins removal system piping	II		ANSI B31.7, Class III (originally), ANSI B31.1 / Regulatory Guide 1.143, Revision 1, October 1979 for changes
Valves for above portions of system	II		Draft ASME Code for Pumps and Valves, Class II (originally), ANSI B31.1 / Regulatory Guide 1.143, Revision 1, October 1979 for changes
Remainder of system piping	II	-	ANSI B31.1 /Regulatory Guide 1.143, Revision 1, October 1979 for changes
Valves for above portion of system	II	-	ANSI B31.1 / Regulatory Guide 1.143, Revision 1, October 1979 for changes

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION III - (CONT'D)			
Lube Oil Distribution and Purification System (Figure 3.2-20)			
Lube oil distribution and purification system piping	II	-	ANSI B31.1
Lube oil distribution and purification system valves	II	-	ANSI B16.5
Diesel Engine-Generator Systems (Figure 3.2-21)			
Diesel fuel oil system piping; engine starting air system piping; turbo-charger boost air system piping; and engine crankcase vent line piping (excluding air dryer system)	I	III	ANSI B31.7 Class III
Valves for above portions of system	I	III	Draft ASME Code for Pumps and Valves, Class III
Engine combustion air intake and exhaust piping	II	-	ANSI B31.1, Seismically Qualified for Hosgri and upgraded to PG&E Design Class I, ANSI B31.7, Class III for repair, replacement, and new construction.
Starting and turbocharger air dryer piping and portions of diesel fuel system piping	II	-	
Turbine and Generator-Associated Systems (Figure 3.2-22)			
Turbine & generator-associated system piping	II	-	ANSI B31.1
Turbine & generator-associated system valves	II	-	ANSI B16.5

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION III - (CONT'D)			
Containment Hydrogen Purge System (Figure 3.2-23)			
Containment isolation valves	I	II	ASME BPVC Section III, Class II[(a)]
Portions of piping between containment isolation valves	I	II	ANSI B31.7, Class II
Piping systems outside the containment isolation valves (including piping/connections for external hydrogen recombiners)	I	III	ANSI B31.7, Class III
Valves in piping systems outside the containment isolation valves	I	III	Draft ASME Code for Pumps and Valves, Class III, or ASME BPVC Section III, Class II
Gaseous Radwaste System (Figure 3.2-24)			
Gaseous radwaste system piping	II	-	ANSI B31.7, Class III (originally), ANSI B31.1 / Regulatory Guide 1.143, Revision 1, October 1979 for changes
Gaseous radwaste system valves	II	-	Draft ASME Code for Pumps and Valves , Class III[(a)] (originally), ANSI B31.1 / Regulatory Guide 1.143, Revision 1, October 1979 for changes

(a) The containment hydrogen purge supply system check valves and Unit 2 radiation monitoring system check valves were designed and fabricated in accordance with the Draft ASME Code for Pumps and Valves, Class III. An alternative quality assurance plan was implemented to inspect and test the valves in accordance with Class II Requirements.

TABLE 3.2-3

Structure, Component, and System	Design Class	Code Class	Design, Fabrication, Erection, and Test Code
SECTION III - (CONT'D)			
Compressed Air Systems (Figure 3.2-25)			
Portions of systems' piping between containment isolation valves	I	II	ANSI B31.7, Class II
Valves for above portions of system	I	II	Draft ASME Code for Pumps and Valves, Class II
Remainder of system piping	II	-	ANSI B31.1
Valves for above portion of system	II	-	ANSI B16.5
Nitrogen and Hydrogen Systems (Figure 3.2-26)			
Nitrogen and hydrogen systems piping[(a)]	II	-	ANSI B31.1
Nitrogen and hydrogen systems valves	II	-	ANSI B16.5

(a) Guard pipes seismically qualified to Hosgri criteria, are required around hydrogen piping in PG&E Design Class I areas.

Structure, Component, and System	Design Class	Design, Fabrication, Erection, and Test Code
SECTION IV - ELECTRICAL SYSTEMS AND EQUIPMENT		
Main Generator and Associated Equipment		
Main generator (includes all auxiliary systems such as excitation, seal oil, hydrogen, stator cooling, etc.)	II	
Isolated phase bus	II	
Generator neutral transformer & resistor	II	
Generator relay boards	II	
12-kV System and Equipment		
12-kV System	II	
25-kV / 12-kV auxiliary transformers	II	
12-kV grounding transformers	II	
12-kV fuse cabinets	II	
12-kV grounding resistors	II	
12-kV metaclad switchgear & buses	II[(a)]	
Startup relay board	II	

(a) The 12-kV reactor coolant pump motor breaker position switches and switchgear are seismically qualified for DE, DDE, and HE loads without loss of structural integrity.

TABLE 3.2-3

Structure, Component, and System	Design Class	Design, Fabrication, Erection, and Test Code
SECTION IV - (CONT'D)		
4.16-kV Systems and Equipment		
4.16-kV system - Class 1E	I	
4.16-kV system - non-Class 1E	II	
25-kV / 4.16-kV auxiliary transformers	II	
12-kV / 4.16-kV standby/startup transformers	II	
4.16-kV grounding resistors	II	
4.16-kV metaclad switchgear - Class 1E	I	
4.16-kV metaclad switchgear - non-Class 1E	II	
4.16-kV metaclad bus ducts (all)	II	
Emergency diesel engine generator (includes all auxiliary systems, excitation, voltage, regulation, governing, etc.)	I	
Station electric relay boards - non-Class 1E	II[(a)]	
Safeguard relay boards - Class 1E	I	
480-Vac Systems and Equipment		
480-Vac system - Class 1E	I	
480-Vac system - non-Class 1E	II	
480-Vac motor control centers - Class 1E	I	
480-Vac load centers - non-Class 1E	II	
480-Vac motor control centers - non-Class 1E	II	
480-Vac circuit breaker panel boards	II	
480-Vac Class 1E MCC auxiliary relay cabinets	I	

(a) The 12-kV bus undervoltage and underfrequency relays located in the station electrical relay boards (RVHD and RVHE) are required to be seismically qualified for DE, DDE, and HE loads without loss of structural integrity.

Structure, Component, and System	Design Class	Design, Fabrication, Erection, and Test Code
SECTION IV - (CONT'D)		
120-V Instrument AC Systems and Equipment		
120-Vac instrument system - Class 1E	I	
120-Vac instrument system - non-Class 1E	II	
120-Vac Class 1E instrument circuit breaker panel boards	I	
Uninterruptible power supplies	I	
Computer power inverters	II	
125-Vdc and 250-Vdc Systems and Equipment		
125-Vdc instrument system - Class 1E	I	
125-Vdc / 250-Vdc instrument system - non-Class 1E	II	
125-Vdc dist. panel boards	I	
250-Vdc motor control center	II	
Station storage batteries	I	
Battery chargers	I	
Lighting System and Equipment		
Lighting system (dc)	II	
125-Vdc lighting circuit breaker panels	II	
Lighting system - non-Class 1E (ac)	II	
AC lighting panel boards	II	
Lighting power centers	II	
Emergency lighting battery packs	II[(a)]	

(a) Emergency lighting battery packs in PG&E Design Class I buildings are seismically qualified as follows: Battery-operated emergency lighting units required to meet commitments stated in the Hosgri Report (Section 10.3.32) are seismically qualified to DE, DDE, and HE. However, those units that are not necessary to perform post-seismic operator actions or to illuminate access/egress routes to the operator action location are exempted from the requirement. The battery operated lights in the following areas

are exempted: the technical support center, outage access control areas, the auxiliary boiler 0-2 room, laundry facility, outage coordination center, cold machine shop offices, and the central alarm station facility including the fire brigade room.

TABLE 3.2-3

Structure, Component, and System	Design Class	Design, Fabrication, Erection, and Test Code
SECTION IV - (CONT'D)		
Wire, Cable, and Raceways		
Insulated electrical conductors - Class 1E system	I	
Insulated electrical conductors - non-Class 1E system	II	
Electrical penetrations of containment - Class 1E	I	
Electrical penetrations of containment - non-Class 1E	I	
Embedded electrical raceways - Class 1E	II[(a)]	
Non-embedded electrical raceways - Class 1E	II[(a)]	
Embedded electrical raceways - non-Class 1E	II	
Non-embedded electrical raceways - non-Class 1E	II	
Raceway fire stops and seals	II	

(a) Conduits, trays, and junction boxes by themselves are not Class 1E. However, special supports have been provided for raceways carrying Class 1E circuits. These supports meet Class 1E seismic criteria and are designed to remain functional when subjected to DE, DDE, and HE seismic loads. No such supports are required for buried or embedded conduits.

TABLE 3.2-3

Structure, Component, and System	Design Class	Design, Fabrication, Erection, and Test Code
SECTION IV - (CONT'D)		
230-kV System and Equipment		
230-kV system	II	
230-kV / 12-kV standby startup transformer	II	
230-kV circuit breakers	II	
230-kV air switches	II	
230-kV carrier relays	II	
230-kV line carrier coupling equipment	II	
230-kV post type insulators	II	
230-kV suspension insulators	II	
230-kV duplex switchboard in switchyard	II	
Circuit breaker panel boards in switchyard	II	
Conductor for switchyard	II	
500-kV System and Equipment		
500-kV system	II	
Main transformers (500-kV / 25-kV)	II	
500-kV circuit breakers	II	
500-kV air switches	II	
500-kV carrier relays	II	
500-kV line carrier coupling equipment	II	
500-kV switchyard insulators	II	
500-kV signal & line suspension insulators	II	
500-kV duplex switchboards in switchyard	II	
Circuit breaker panelboards in switchyard	II	
500-kV line protective gap devices	II	
Conductor for switchyard	II	
Computer recording system in 500-kV switchyard	II	
Switchyard control boards in control room	II	

TABLE 3.2-3

Structure, Component, and System	Design Class	Design, Fabrication, Erection, and Test Code
SECTION IV - (CONT'D)		
Other Systems and Equipment		
125-Vdc batteries for 230-kV switchyard	II	
125-Vdc batteries for 500-kV switchyard	II	
125-Vdc battery chargers for switchyards	II	
4.16-kV & 480-V metaclad switchgear in switchyard	II	
Grounding, lightning protection, & cathodic protection systems	II	
Communication & signaling system (excluding annunciation systems)	II	
Heat tracing system - non-Class 1E	II	

TABLE 3.2-4

PG&E DESIGN CLASS, QUALITY/CODE CLASS, AND PIPING SYMBOL COMPARISON TO ANSI N 18.2; SAFETY GUIDE 26; AND SAFETY GUIDE 29 - Notes (a) and (b)

PG&E CURRENT LICENSING BASIS (CLB) - Notes (b) and (h)		COMPARISON TO NON-CLB STANDARD AND SAFETY GUIDES - Note (b)			
PG&E Design Class	**PG&E Quality/Code Class**	**ANSI N 18.2 Safety Group**	**SG 26 Quality Group**	**SG 29 Category**	**Notes**
I	I	1	A	Category I	Note (c)
I	I	1	A	Category I	-
I	II	2	B	Category I	-
I	II	2	B	Category I	Note (d)
I	III	3	C	Category I	-
I	III	3	C	Category I	-
I	-	-	-	Category I	Note (e)
II	-	NNS	-	Non-Category I	-
II	-	NNS	D	Non-Category I	Note (d), (g)
II	-	-	-	Category I	-
II	-	-	-	Non-Category I	-
II	-	NNS	D	Non-Category I	Note (f)
II	-	NNS	-	Non-Category I	-
II	-	-	-	Non-Category I	-
III	-	-	-	Non-Category I	-

Notes:

(a) American Nuclear Society, Standard No. ANSI N18.2, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," draft August 1970 (Reference 1); Atomic Energy Commission, Safety Guide 26, "Quality Group Classifications and Standards for Water, Steam, and Radioactive Waste Containing Components of Nuclear Power Plants," March 1972 (Reference 2), and Atomic Energy Commission, Safety Guide 29, "Seismic Design Classification," June 1972 (Reference 3).

TABLE 3.2-4

(b) It is recognized that during the design and construction of DCPP Units 1 and 2, significant industry and regulatory changes were made in establishing common methods of classification; e.g., ANSI N18.2, Draft August 1970 (Reference 1), Safety Guide 26, March 1972 (Reference 2), and Safety Guide 29, June 1972. However, these methods all differ slightly in detail from those used for the DCPP. Although the form and intent of these NRC documents are similar, these are not the DCPP Licensing Basis.

(c) Reactor coolant loop and pressurizer surge line piping.

(d) Feedwater piping from the (final) main feedwater check valve to the steam generator; auxiliary feedwater from the main feedwater line back to the second check valve; main steam piping from the steam generator to the main steam isolation valve; steam generator blowdown piping from the steam generator to the first valve outside containment.

(e) Piping originally installed as Design Class II, but has been upgraded to require seismic qualification for the Hosgri earthquake.

(f) Radioactive system (PG&E QA Class R).

(g) Piping is seismically qualified for the Design Earthquake.

(h) Refer to Table 3.2-2 for Piping Symbols

Table 3.3-1

COMPARISON OF AUXILIARY BUILDING WIND PRESSURE VALUES,
UNIFORM BUILDING CODE, AND ASCE PAPER 3269

Height Above Ground Surface[a]	UBC Wind Pressure[c]	Dynamic Pressure[d]	
		q	1.3 q
30	40.0	19.8	25.8
50	40.0	25.7	33.4
70	40.0	30.5	39.7
90	40.0	34.7	45.1
100	40.0	36.6	47.6
150	40.0	45.0	NA[b]
200	40.0	52.1	NA[b]
212	40.0	53.7	NA[b]

(a) Ground surface (plant grade) is 85 feet above mean sea level (MSL).

(b) Not applicable because the highest part of the auxiliary building is 105 feet above the ground surface.

(c) UBC pressure is based on 1967 Edition, considering the site to be in a 25 psf zone instead of the code prescribed 20 psf zone and considering the ground surface to be at MSL instead of the actual ground surface at the structure.

(d) Dynamic pressure is based on ASCE paper #3269, considering a design wind speed of 80 mph and a gust factor of 1.1.

TABLE 3.3-2

TORNADO RESISTING CAPABILITY OF STRUCTURES, SYSTEMS AND COMPONENTS

Structure or No. Component	SAFE WIND VELOCITY: More than 300 mph		300 mph		250 mph		200 mph		175 mph		Less than 175 mph[a]	
	Wind	Wind & Missile	Wind	Wind & Missile	Wind	Wind & Missile	Wind	Wind & Missile	Wind	Wind & Missile	Wind	Wind & Missile
1. Auxiliary Bldg.												
(a) Reinforced concrete between approximate El. 85' & 165'	X	X										
(b) Battery room ventilation system fan room					X	X						
(c) Control room	X	X										
(d) Doors & louvers											X	
(e) Component cooling water surge tank					X			X				
(f) Auxiliary building supply fan room equipment											X	
(g) Control room ventilation equipment											X	
(h) Fuel handling building supply fan room equipment											X	
2. Fuel Handling Area												
(a) Steel frame[b]					260							150
(b) Roof purlins									X			
(c) Girts, siding, roofing											X	

TABLE 3.3-2

Structure or No. Component	SAFE WIND VELOCITY: More than 300 mph		300 mph		250 mph		200 mph		175 mph		Less than 175 mph[a]	
	Wind	Wind & Missile	Wind	Wind & Missile	Wind	Wind & Missile	Wind	Wind & Missile	Wind	Wind & Missile	Wind	Wind & Missile
(d) Doors & Louvers											X	
(e) Fuel handling building ventilation equipment											X	
3. Containment												
(a) Reinforced concrete	X	X										
(b) Equipment., personnel & escape hatches			X	X								
(c) Exhaust vent											125	
(d) Exterior Class I raceway and instruments											X	
(e) Main steam and feedwater piping	X	X										
(f) Auxiliary feedwater piping			X									
(g) Pipe penetrations			X	X								
(h) Pipeway							X					
4. Turbine Bldg.												
(a) Steel frame[b]							225			X		
(b) Exterior concrete walls:												
12" thick							X	X				
24" thick	X	X										

TABLE 3.3-2

Structure or No. Component	SAFE WIND VELOCITY: More than 300 mph		300 mph		250 mph		200 mph		175 mph		Less than 175 mph[a]	
	Wind	Wind & Missile	Wind	Wind & Missile	Wind	Wind & Missile	Wind	Wind & Missile	Wind	Wind & Missile	Wind	Wind & Missile
(c) Girts, louvers siding, purlins											X	
(d) Siding in 4.16-kV switchgear and cable spreading room areas							X					
(e) 4.16-kV switchgear/cable spreading room HVAC system											X	
5. Outdoor Tanks												
(a) Condensate storage[b]			X									150
(b) Refueling water storage[b]			X									150
(c) Fire water and transfer storage[b]			X									150
6. Intake Structure												
(a) Reinforced concrete incl. ASW pumps compartment	X					X						
(b) ASW pump room shaft extensions								240				
7. Miscellaneous PG&E Design Class I Piping												
(a) CCW piping to SG blowdown tank[b]											X	

TABLE 3.3-2

Structure or No. Component	SAFE WIND VELOCITY More than 300 mph Wind	More than 300 mph Wind & Missile	300 mph Wind	300 mph Wind & Missile	250 mph Wind	250 mph Wind & Missile	200 mph Wind	200 mph Wind & Missile	175 mph Wind	175 mph Wind & Missile	Less than 175 mph[a] Wind	Less than 175 mph[a] Wind & Missile
(b) Containment hydrogen purge lines[b]											X	
8. 480-V Switchgear and 125-Vdc Inverter Room Ventilation System											X	

Notes:

[a] Structures, systems and components with an “X” in the “Less than 175 safewind velocity” typically do not have quantified analyses of tornado wind and missile resisting capability.

[b] A safe-wind velocity of combined wind and missile of less than 200 mph is acceptable for this SSC.

TABLE 3.3-3

TORNADO FAILURE ANALYSIS - COMPONENT COOLING WATER SURGE TANK AND RELATED INSTRUMENTATION

Component & Failure	Consequences
(1) Loss of vital conduit to control room	(a) Loss of liquid level indication and annunciators in control room. Any makeup to CCW system still indicated by annunciator on supply valves (LCV-69 and LCV-70).
	(b) Loss of automatic and manual actuation to, and position indication from vent valve (RCV-16). Valve fails closed and any overflow from CCW system discharges through relief valve to auxiliary building sump.
(2) Loss of control air to makeup valve (LCV-69 or LCV-70)	(a) One or both of the normally closed valves fail closed.
	(b) Makeup is not required during a tornado event and CCW system is maintained in normal operating mode.
	(c) Manual makeup bypass valves may be used.
(3) Loss of air supply to level controllers (LC-59 or LC-60) and control air to vent valve (RCV-16)	(a) One or both of the normally closed makeup valves (LCV-69 and LCV-70) fail closed.
	(b) Normally open RCV-16 fails closed.
	(c) Makeup is not required during a tornado event and CCW system is maintained in normal operating mode.
	(d) Tank overpressure protection is maintained by surge tank relief valve (RV-45).
(4) Loss of level instrumentation (one set)	(a) Makeup valve fails closed. Makeup to CCW system through redundant valve, which annunciates in the control room.
	(b) Loss of liquid level indication and annunciator on one compartment of CCW system surge tank.
	(c) Any leakage from instrument taps close to tank flows to the auxiliary building sump; other breaks leak to roof drains.
	(d) Operate on redundant system. Manually isolate compartment with damaged instrumentation, if possible.

TABLE 3.3-3

Component & Failure	Consequences
	(e) Potential loss of N_2 pressurization – (refer to item 10).
(5) Break in vent line, isolation valve or back-pressure regulator	(a) A break between the back-pressure regulator and vent isolation valve will cause surge tank pressure to decrease and the low surge tank pressure alarm to annunciate in the control room. This break can be isolated from the surge tank by closing the vent isolation valve.
	(b) A break upstream of the vent isolation valve will cause surge tank pressure to decrease and the low surge tank pressure alarm to annunciate in the control room. The CCW system will continue to operate, but surge tank pressure must be restored to declare the system operable.
(6) Break in relief valve or header	(a) Surge tank pressure will decrease and low surge tank pressure annunciate in the control room. CCW system will continue to operate; surge tank pressure will have to be restored to declare the system operable.
	(b) Pressurization required to mitigate consequences of LOCA. LOCA not postulated simultaneously with a tornado.
(7) Break in one redundant surge line	(a) A maximum of 6,200 gallons of liquid discharged to the yard drains via the 164 feet and 140 feet roof drains.
	(b) Manually isolate that compartment of the surge tank.
	(c) Operate within an action statement with the redundant side of the surge tank and makeup water system until the faulted condition can be repaired.
	(d) Potential loss of N2 pressurization – (refer to item 10).
(8) Break in two redundant surge lines	(a) A maximum of 8,100 gallons of liquid discharged to the yard drains via the 164 feet and 140 feet roof drains.
	(b) Technical Specifications require CFCUs (and hence the CCW system) be operable in Modes 1-4. Commence plant shutdown to Mode 5 (cold shutdown) and remain in cold shutdown until both surge lines have been repaired.

TABLE 3.3-3

Component & Failure	Consequences
(9) Loss of all level instrumentation	(a) Makeup valves fail closed. (b) Loss of liquid level indication and annunciators in the control room. (c) Instrument tap breaks close to tank leak to auxiliary building sump; other breaks leak to roof drains. (d) Some inventory probably remains in surge tank. System continues to operate satisfactorily with no makeup required. (e) Backup indication of adequate liquid level from pressure measurement at CCW pump discharge with low pressure annunciator in control room. (f) Alternate makeup through manual bypass valves around makeup valves. (g) Potential loss of N_2 pressurization – (refer to item 10).
(10) Loss of nitrogen/ instrument air pressurization	(a) CCW system continues to function normally; CCW surge tank pressure annunciated in the control room. (b) Pressure required to mitigate the consequences of a LOCA; a LOCA is not postulated simultaneously with a tornado. (c) Failure of nitrogen/instrument air supply pressure regulators will not cause CCW system over-pressurization or prevent normal CCW system operation.

TABLE 3.3-4

TORNADO REVIEW - FAILURE ANALYSIS FOR EXPOSED RACEWAYS AND INSTRUMENTATION

Component					
No.	Dwg. No. [a]	Description	Normal Mode	Failure Mode	Consequences
FCV-24 FCV-25	3.2-04(51-B) 3.2-04(51-A) (7.3.42)	SG 1 and 2 main steam isolation bypass valves	Close	Close	None - not involved in plant shutdown
FCV-37	3.2-04(50-B) (7.3-18)	SG 2 steam supply valve turbine-driven AFW pump	Open	In place	None - backed up by FCV-38 coming from main steam line from SG 3
FCV-41 FCV-42	3.2-04(51-A) 3.2-04(51-B) (7.3-42)	SG 1 and 2 main steam isolation valves (redundant solenoid valves)	Open	Open	None - not involved in plant shutdown unless there is a steam line break
FCV-438 FCV-439	3.2-03(47-A) 3.2-03(47-A)	SG 1 and 2 main feedwater isolation valves (redundant solenoid valves)	Open	In place	None - backed up by FCV-510 and FCV-520 and MFP trip
FCV-510 FCV-520	3.2-03(33A-E) 3.2-03(33A-E)	SG 1 and 2 main feedwater regulating valves (redundant solenoid valves)	Open	Close	Closing causes reactor trip followed by turbine trip
FCV-1510 FCV-1520	3.2-03(33A-E) 3.2-03(33A-E)	SG 1 and 2 feedwater bypass valves	Close	Close	None
LCV-106 LCV-107	3.2-03(46-C) 3.2-03(46-C)	SG 1 and 2 supply valves from turbine driven AFW pumps	Open	As-is	Simultaneous loss of signal to valves LCV-106, 107, 110, and 111 results in inability to modulate AFW flow and may result in some excess feedwater addition
LCV-110 LCV-111	3.2-03(46-D) 3.2-03(46-D)	SG 1 and 2 supply valves from motor-driven AFW pumps	Open	Open	

TABLE 3.3-4

Component					
No.	Dwg. No. [a]	Description	Normal Mode	Failure Mode	Consequences
PCV-19 PCV-20 PCV-21 PCV-22	3.2-04 (51A) 3.2-04 (51-C) 3.2-04 (31D) 3.2-04 (31-E)	10 percent atmospheric dump valves	Close	Close	Backed up by main steam safety valves
FT-50 FT-77	3.2-03(48-C) 3.2-03(48-C)	AFW lead 1 and 2 flow transmitters			Other indication available to monitor SG level; backup - shutdown with SGs 3 and 4
FT-510 FT-511 FT-520 FT-521	3.2-03(35A-E) (7.2-1,Sh.13) 3.2-03(35A-C)	SG 1 and 2 main feedwater flow transmitters (redundant)			None - if already switched to AFW by loss of all offsite power
PT-514 PT-515 PT-516 PT-524 PT-525 PT-526	3.2-04(51-A) 3.2-04(31-B) 3.2-04(51-C)	SG 1 and 2 steam pressure transmitters			Loss of two pressure transmitters on either loop to initiate safety injection signal and steam line isolation signal
PT-516A PT-526A	3.2-04(51-A) (7.2-1,Sh.13) 3.2-04(51-B)	SG 1 and 2 steam pressure transmitters for 10 percent atmospheric dump logic			Loss of transmitters causes loss of automatic control of the 10 percent atmospheric dump valve; backed up by main steam safety valve

(a) 3.2-04 denotes P&ID; (31-A) is grid location of P&ID; (7.3-42) denotes instrumentation logic diagram common to SG 1 and 2 components

TABLE 3.3-5

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

SUMMARY OF THE VELOCITY CHARACTERISTICS OF ADDITIONAL TORNADO-BORNE MISSILES FOR 250 MPH TORNADO WIND VELOCITY

	Input Data						*Result*				
Additional Tornado-borne Missile	C_l	C_d	A_p	ρ_m	W	*Ejection Velocity, fps*	*Injection Height, ft*	*Missile Suspension ft*	*Modified Missile Velocity, fps*	*Design Missile Velocity, fps*	*Maximum Missile Elevation, ft*
Plank 4 x 12 x 12 ft ρ = 50 lb/ft^3	0.5	1.0	12.0	1.55	200	247	14	Yes	-	247	68
Utility Pole 13.5 in. ϕ x 35 ft lg. ρ = 43 lb/ft^3	0.7	0.37	39.4	1.34	1500	144	5	No	65	65	5
1 in. ϕ Solid$_{Stl.\ Rod}$ 3 ft Lg. ρ = 490 lb/ft^2	0.7	1.12	0.25	15.20	8	203	7	Yes	-	203	92
6 in. ϕ Pipe Sch. 40, 15 ft lg. ρ = 490 lb/ft^3	0.7	0.37	8.29	2.47	285	149	6	No	84	84	6
12" ϕ Pipe Sch. 40, 15 ft lg. ρ = 490 lb/ft^3	0.7	0.38	15.9	1.74	744	134	3	No	42	42	3
3 in. ϕ Pipe Sch. 40, 15 ft lg. ρ = 490 lb/ft3	0.7	0.37	4.38	3.54	114	165	11	Yes		165	24
4000# Auto 1.67 x 6 x 17 ft	0.7	0.70	102	0.73	4000	165	5	Yes		165	37

TABLE 3.3-5

LEGEND:

C_1 = *Lift coefficient (dimensionless)*
C_d = *Drag coefficient (dimensionless)*
A_p = *Maximum projected area of the missile* (ft^2)
ρ_m = $W/g \times 1/V_1 = \rho/g$ ($slug/ft^3$)
W = *Total weight of the missile (lb)*
V_1 = *Total volume of the missile* (ft^3)
g = $32.2\ ft/sec^2$

TABLE 3.3-6

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
REQUIRED THICKNESS OF A REINFORCED CONCRETE MISSILE BARRIER
TO PRECLUDE MISSILE PERFORATION OR THE CREATION OF SECONDARY MISSILES

	Input Data For 250 MPH Tornado			*Results (Inches)*			
Additional Tornado-Borne Missile	*Missile Velocity, ft/sec*	*Weight of Missile, lbs*	*Min. Impact Area, ft^2*	*Penetration Into An Infinite Thick Conc.*	*Just Perforated Thickness*	*Thickness Without Creating Secondary Missiles*	*Min. Design Thickness, in.*
Plank	*247*	*200*	*0.333*	*2.7*	*5.5*	*8.2*	*9*
Utility Pole	*65*	*1500*	*0.93*	*0.6*	*1.2*	*1.7*	*6*
1 in. ϕ Solid Stl Rod	*203*	*8*	*0.00545*	*4.7*	*9.4*	*14.1*	*15*
6 in. ϕ Pipe	*84*	*285*	*0.239*	*0.7*	*1.4*	*2.1*	*6*
12 in. ϕ Pipe	*42*	*744*	*0.885*	*0.1*	*0.3*	*0.4*	*6*
3 in. ϕ Pipe	*165*	*114*	*0.0667*	*3.7*	*7.4*	*11.2*	*12*
4000 lb Auto	*165*	*4000*	*10.0*	*0.9*	*1.7*	*2.6*	*6*

TABLE 3.5-2

CONTROL ROD DRIVE SHAFT - MISSILE CHARACTERISTICS

Diameter = 1.75 inches
Length = 300 inches
Weight = 120 pounds

Drive Shaft Travel Outside Housing[a] ft	Drive Shaft Velocity ft/sec	Drive Shaft Kinetic Energy ft-lb
1	151	42,900
2	162	49,000
3	171	55,000
4	179	60,200
5	189	66,500

(a) Distance from top of rod travel housing to bottom of missile shield

TABLE 3.5-3

CONTROL ROD DRIVE SHAFT AND MECHANISM - MISSILE CHARACTERISTICS

Missile weight: 1500 pounds
Impact OD: 3.75 inches

Travel ft	Drive Shaft Velocity ft/sec	Drive Shaft Kinetic Energy ft-lb
1	14.3	4,600
2	20.2	9,200
3	24.8	13,800
4	28.6	18,400
5	32.0	23,000

TABLE 3.5-4

VALVE - MISSILE CHARACTERISTICS

Missile Description	Weight lb	Flow Discharge Area, in^2	Thrust Area, in^2	Impact Area, in^2	Wt. to Imp. Area Ratio	Velocity fps
Safety relief valve bonnet, (3 in. x 6 in. x 6 in.)	350	2.86	80	24	14.6	110
3 in. motor-operated isolation valve bonnet (plus motor and stem) (3 in.)	400	5.5	113	28	14.1	135
2 in. air-operated relief valve bonnet (plus stem)	75	1.8	20	20	3.75	115
3 in. air-operated spray valve bonnet (plus stem)	120	5.5	50	50	2.4	190
4 in. air-operated spray valve bonnet	200	9.3	50	50	4.0	190

TABLE 3.5-5

PIPING TEMPERATURE ELEMENT ASSEMBLY - MISSILE CHARACTERISTICS

1. For a radial fracture around the weld between the thermowell (well) and the pipe:

Characteristics	"without well"	"with well"
Flow discharge area, in^2	0.11	0.60
Thrust area, in^2	7.1	9.6
Missile weight, lb	11.0	15.2
Area of impact, in^2	3.14	3.14
$\left(\frac{\text{Missile weight}}{\text{Impact area}}\right)$, psi	3.5	4.84
Velocity, fps	20.0	120.0

2. For a radial fracture at the junction between the temperature element assembly and the thermowell for the "without well" element and at the junction between the thermowell and the well for the "with well" element:

Characteristics	"without well"	"with well"
Flow discharge area, in^2	0.11	0.60
Thrust area, in^2	3.14	3.14
Missile weight, lb	4.0	6.1
Area of impact, in^2	3.14	3.14
$\left(\frac{\text{Missile weight}}{\text{Impact area}}\right)$, psi	1.27	1.94
Velocity, fps	75.0	120.0

TABLE 3.5-6

CHARACTERISTICS OF OTHER MISSILES
POSTULATED WITHIN REACTOR CONTAINMENT

	Reactor Coolant Pump Temperature Element	Instrument Well of Pressurizer	Pressurizer Heaters
Weight, lb	0.25	5.5	15.0
Discharge area, in^2	0.50	0.442	0.80
Thrust area, in^2	0.50	1.35	2.4
Impact area, in^2	0.50	1.35	2.4
$\left(\frac{\text{Missile weight}}{\text{Impact area}}\right)$, psi	0.5	4.1	6.25
Velocity, fps	260.0	100.0	55.0

TABLE 3.6-1

CHECKLIST OF DYNAMIC EFFECTS FROM POSTULATED RUPTURE OF PIPE CONNECTED TO THE REACTOR COOLANT SYSTEM

Large Break (>4 in. ID) Resulting in a Loss of Coolant	Location Description	Loop	Size in.	Is the Contain-ment Liner Protected?	Is Break Propagation Prevented and Low-head Safety Injection Maintained to the Un-affected Loops?	Is Break Propagation in the Affected Loop Limited to 20%?	Is Damage to Steam System Prevented?						Is the Integrity of Supports Maintained?		Is Line Restrained to Meet Criteria with Regulatory Guide 1.46 as a Minimum?[g]
							Steam Line	Feed Line	Aux Feed	Blow-down	Level Taps	Sample Line	SG	Pump	
Pressurizer surge (16)[a]	Hot leg to pressurizer	2	14	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Accumulator injection (253)	Check valve 8948A to cold leg	1	10	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Accumulator injection (254)	Check valve 8948B to cold leg	2	10	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Accumulator injection (255)	Check valve 8948C to cold leg	3	10	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Accumulator injection (256)	Check valve 8948D to cold leg	4	10	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Residual heat removal supply (109)	Hot leg to valve 8702	4	14	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Low-head safety injection (235)	Loop to check valve	1	6	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

TABLE 3.6-1

Large Break (>4 in. ID) Resulting in a Loss of Coolant	Location Description	Loop	Size in.	Is the Contain-ment Liner Protected?	Is Break Propagation Prevented and Low-head Safety Injection Maintained to the Un-affected Loops?	Is Break Propagation in the Affected Loop Limited to 20%?	Is Damage to Steam System Prevented?						Is the Integrity of Supports Maintained?		Is Line Restrained to Meet Criteria with Regulatory Guide 1.46 as a Minimum? [g]
							Steam Line	Feed Line	Aux Feed	Blow-down	Level Taps	Sample Line	SG	Pump	
Low-head safety injection (236)	Loop to check valve	2	6	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Low-head safety injection (237)	Loop to check valve	3	6	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Low-head safety injection (238)	Loop to check valve	4	6	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Pressurizer relief line (730)	Pressurizer to 1171 takeoff	-	6	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(b)
Pressurizer safety lines (727, 728, 729)	Pressurizer to safety valves	-	6	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(b)
Accumulator injection (253, 1294)	Accumulator to check valve 8948A to cold leg	1	10	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Accumulator injection (254, 1295)	Accumulator to check valve 8938B to cold leg	2	10	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

TABLE 3.6-1

Large Break (>4 in. ID) Resulting in a Loss of Coolant	Location Description	Loop	Size in.	Is the Contain-ment Liner Protected?	Is Break Propagation Prevented and Low-head Safety Injection Maintained to the Un-affected Loops?	Is Break Propagation in the Affected Loop Limited to 20%?	Is Damage to Steam System Prevented?						Is the Integrity of Supports Maintained?		Is Line Restrained to Meet Criteria with Regulatory Guide 1.46 as a Minimum? [g]
							Steam Line	Feed Line	Aux Feed	Blow-down	Level Taps	Sample Line	SG	Pump	
Accumulator injection (255, 1296)	Accumulator to check valve 8948C to cold leg	3	10	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Loop 4 only	Yes
Accumulator injection (256, 1297)	Accumulator to check valve 8948D to cold leg	4	10	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Loop 3 only	Yes
Residual heat removal supply (109, 927)	Valve 8702 to cont. pen. 27	4	14	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Residual heat removal return (2576, 120)	Accumulator disch. to cont. pen. 26	3	8, 14	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	(e)
Residual heat removal return (2575, 120)	Accumulator disch. to cont. pen. 26	4	8, 12	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	(e)
Low-head safety injection (235)	Loop isol. valve to cont. pen. 24	-	6	Yes	-	-	-	-	-	-	-	-	-	-	(c)
Low-head safety injection (236)	Loop isol. valve to cont. pen. 24	-	6	Yes	-	-	-	-	-	-	-	-	-	-	(c)

TABLE 3.6-1

arge Break (>4 in. ID) Resulting in a Loss of Coolant	Location Description	Loop	Size in.	Is the Contain-ment Liner Protected?	Is Break Propagation Prevented and Low-head Safety Injection Maintained to the Un-affected Loops?	Is Break Propagation in the Affected Loop Limited to 20%?	Is Damage to Steam System Prevented?						Is the Integrity of Supports Maintained?		Is Line Restrained to Meet Criteria with Regulatory Guide 1.46 as a Minimum? [g]
							Steam Line	Feed Line	Aux Feed	Blow-down	Level Taps	Sample Line	SG	Pump	
Low-head safety injection (237)	Loop isol. valve to cont. pen. 25	-	6	Yes	-	-	-	-	-	-	-	-	-	-	(c)
Low-head safety injection (238)	Loop isol. valve to cont. pen. 25	-	6	Yes	-	-	-	-	-	-	-	-	-	-	(c)
Pressurizer relief line (17)	From 4x6 to header (23)	-	6	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(d)
Pressurizer safety line (19, 20, 21)	Safety valve to header (23)	-	6	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(d)
Pressurizer spray (12, 15)	Cold Leg to pressurizer	1	4	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Pressurizer spray (14)	Cold leg to pressurizer	2	4	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

TABLE 3.6-1

Large Break (>4 in. ID) Resulting in a Loss of Coolant	Location Description	Loop	Size in.	Is the Contain-ment Liner Protected?	Is Break Propagation Prevented and Low-head Safety Injection Maintained to the Un-affected Loops?	Is Break Propagation in the Affected Loop Limited to 20%?	Is Damage to Steam System Prevented?						Is the Integrity of Supports Maintained?		Is Line Restrained to Meet Criteria with Regulatory Guide 1.46 as a Minimum? [g]
							Steam Line	Feed Line	Aux Feed	Blow-down	Level Taps	Sample Line	SG	Pump	
Charging (50)	Check valve 8379A to RC piping	3	3	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Loop 4 only	Yes
Charging (246)	Check valve 8379B to RC piping	4	3	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Loop 3 only	Yes
Auxiliary spray (51)	Check valve 8377 to line (15)	-	2	Yes	Yes	-	-	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(e)
RC pump seal water injection (54)	Check valve 8368 to RC pump	1	2	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(e)
RC pump seal water injection (55)	Check valve 8368 to RC pump	2	2	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(e)
RC pump seal water injection (58)	Check valve 8368 to RC pump	3	2	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(e)

TABLE 3.6-1

Large Break (>4 in. ID) Resulting in a Loss of Coolant	Location Description	Loop	Size in.	Is the Contain-ment Liner Protected?	Is Break Propagation Prevented and Low-head Safety Injection Maintained to the Un-affected Loops?	Is Break Propagation in the Affected Loop Limited to 20%?	Is Damage to Steam System Prevented?						Is the Integrity of Supports Maintained?		Is Line Restrained to Meet Criteria with Regulatory Guide 1.46 as a Minimum? [g]
							Steam Line	Feed Line	Aux Feed	Blow-down	Level Taps	Sample Line	SG	Pump	
RC pump seal water injec-tion (57)	Check valve 8368 to RC pump	4	2	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(e)
Letdown (24)	RC piping to to support downstream of valve LCV 460	2	3	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(e)
Excess letdown (63)	RC piping to to support downstream of valve LCV 8167	2	1	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(e)
RC seal vent (1495)	Pump to valve	-	-	-	-	-	-	-	-	-	-	-	-	-	(d)
RC seal vent (1496)	Pump to valve	-	-	-	-	-	-	-	-	-	-	-	-	-	(d)
RC seal vent (1497)	Pump to valve	-	-	-	-	-	-	-	-	-	-	-	-	-	(d)
RC seal vent (1498)	Pump to valve	-	-	-	-	-	-	-	-	-	-	-	-	-	(d)
RC leakoff (58)		-	-	-	-	-	-	-	-	-	-	-	-	-	(d)

TABLE 3.6-1

Large Break (>4 in. ID) Resulting in a Loss of Coolant	Location Description	Loop	Size in.	Is the Contain-ment Liner Protected?	Is Break Propagation Prevented and Low-head Safety Injection Maintained to the Un-affected Loops?	Is Break Propagation in the Affected Loop Limited to 20%?	Is Damage to Steam System Prevented?						Is the Integrity of Supports Maintained?		Is Line Restrained to Meet Criteria with Regulatory Guide 1.46 as a Minimum? [g]
							Steam Line	Feed Line	Aux Feed	Blow-down	Level Taps	Sample Line	SG	Pump	
RC leakoff (59)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(d)
RC leakoff (60)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(d)
RC leakoff (61)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(d)
Drain 958	RC piping downstream of valve	1	2	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(e)
Drain 959	RC piping downstream of valve	2	2	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(e)
Drain 960	RC piping downstream of valve	3	2	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(e)
Drain 961	RC piping downstream of valve	4	2	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(e)
Pressurizer relief lines (1171, 1172, 1195)	1171 take off to valve (N.C.)	3	2	Yes	-	-	-	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Charging high-head SIS (50, 49)	Upstream of check valve 8379A	3	3	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(e)

TABLE 3.6-1

Large Break (>4 in. ID) Resulting in a Loss of Coolant	Location Description	Loop	Size in.	Is the Contain-ment Liner Protected?	Is Break Propagation Prevented and Low-head Safety Injection Maintained to the Un-affected Loops?	Is Break Propagation in the Affected Loop Limited to 20%?	Is Damage to Steam System Prevented?						Is the Integrity of Supports Maintained?		Is Line Restrained to Meet Criteria with Regulatory Guide 1.46 as a Minimum? [g]
							Steam Line	Feed Line	Aux Feed	Blow-down	Level Taps	Sample Line	SG	Pump	
Charging high-head SIS (246)	Upstream of check valve 8379B	4	3	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(e)
Auxiliary spray (51)	Charging line to isolation valve	-	2	-	-	-	-	-	-	-	-	-	-	-	(d)
RC pump seal water injec-tion (54)	Upstream of check valve	1	-	-	-	-	-	-	-	-	-	-	-	-	(d)
RC pump seal water injec-tion (55)	Upstream of check valve	2	-	-	-	-	-	-	-	-	-	-	-	-	(d)
RC pump seal water injec-tion (56)	Upstream of check valve	3	-	-	-	-	-	-	-	-	-	-	-	-	(d)
RC Pump seal water injec-tion (57)	Upstream of check valve	4	-	-	-	-	-	-	-	-	-	-	-	-	(d)
Letdown (24)	Beyond re-straint downstream of isolation valve	2	3	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

TABLE 3.6-1

Large Break (>4 in. ID) Resulting in a Loss of Coolant	Location Description	Loop	Size in.	Is the Contain-ment Liner Protected?	Is Break Propagation Prevented and Low-head Safety Injection Maintained to the Un-affected Loops?	Is Break Propagation in the Affected Loop Limited to 20%?	Is Damage to Steam System Prevented?						Is the Integrity of Supports Maintained?		Is Line Restrained to Meet Criteria with Regulatory Guide 1.46 as a Minimum? [g]
							Steam Line	Feed Line	Aux Feed	Blow-down	Level Taps	Sample Line	SG	Pump	
Excess letdown (63)	Beyond re-straint downstream of isolation valve	2	1	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(f)
Pressurizer relief lines (1171, 1172, 1195)	Downstream of valves (N.C.)	-	3	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

(a) PG&E line number.

(b) Affected area limited by enclosure.

(c) Operates only during the injection and recirculation phase following a LOCA. Rupture not postulated.

(d) Due to pressure and flow conditions in these pipes during operation of these lines, whipping is not assumed to occur.

(e) Whipping allowed with no services affected.

(f) Whipping allowable with no services affected with restraints at valves to prevent LOCA.

(g) For high-energy piping inside containment (except for the RCL), breaks were originally postulated at all terminal ends and all locations, regardless of stress level, where plastic hinges could form and endanger safety systems or components. This commitment was later relaxed as allowed by MEB 3-1, July 1981, where pipe breaks inside containment (except for the RCL) are required to be postulated to occur at intermediate locations only where the primary plus secondary stress exceeds the stress level of $0.8(1.2S_h + S_A)$. This commitment was further relaxed as allowed by Generic Letter 87-11, June 1987 where the requirement for the postulation of all arbitrary intermediate pipe ruptures was eliminated (refer to Sections 3.6.6.4, 3.6.6.5, and 3.6.6.6).

TABLE 3.6-2

CHECKLIST OF DYNAMIC EFFECTS OF OTHER POSTULATED PIPE RUPTURES INSIDE THE CONTAINMENT

Steam System Break Not Resulting in a Loss of Coolant	Location Description	Loop	Size	Is Loss of Coolant Prevented From Occurring?	Is Break Propagation Prevented to Steam Piping in the Unaffected Loops?	Is Safety Injection Maintained to All RC Loops?	Is the Contain-ment Liner Protected?	Is Inte-grity of the Steam Generator Maintained?	Is Boration Capability Maintained?	Is Cold Shutdown Capability Maintained?	Is Line Restrained to Meet Criteria with Regulatory Guide 1.46 as a Minimum? [c]
Main steam line (225)[a]	From steam generator nozzle to containment penetration	4	28	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Main steam line (226)	From steam generator nozzle to containment penetration	3	28	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Main steam line (227)	From steam generator nozzle to containment penetration	2	28	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Main steam line (228)	From steam generator nozzle to containment penetration	1	28	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Feedwater line (554)	From steam generator nozzle to containment penetration	1	16	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Feedwater line (555)	From steam generator nozzle to containment penetration	2	16	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

TABLE 3.6-2

Steam System Break Not Resulting in a Loss of Coolant	Location Description	Loop	Size	Is Loss of Coolant Prevented From Occurring?	Is Break Propagation Prevented to Steam Piping in the Unaffected Loops?	Is Safety Injection Maintained to All RC Loops?	Is the Contain-ment Liner Protected?	Is Inte-grity of the Steam Generator Maintained?	Is Boration Capability Maintained?	Is Cold Shutdown Capability Maintained?	Is Line Restrained to Meet Criteria with Regulatory Guide 1.46 as a Minimum? [c]
Feedwater line (556)	From steam generator nozzle to containment penetration	4	16	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Feedwater line (557)	From steam generator nozzle to containment penetration	3	16	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Steam generator blowdown line (1059)	From steam generator nozzle to containment penetration	1	2	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(b)
Steam generator blowdown line (1060)	From steam generator nozzle to containment penetration	2	2	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(b)
Steam generator blowdown line (1061)	From steam generator nozzle to containment penetration	3	2	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(b)
Steam generator blowdown line (1062)	From steam generator nozzle to containment penetration	4	2	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(b)

TABLE 3.6-2

Steam System Break Not Resulting in a Loss of Coolant	Location Description	Loop	Size	Is Loss of Coolant Prevented From Occurring?	Is Break Propagation Prevented to Steam Piping in the Unaffected Loops?	Is Safety Injection Maintained to All RC Loops?	Is the Contain-ment Liner Protected?	Is Inte-grity of the Steam Generator Maintained?	Is Boration Capability Maintained?	Is Cold Shutdown Capability Maintained?	Is Line Restrained to Meet Criteria with Regulatory Guide 1.46 as a Minimum? [c]

(a) PG&E line number.
(b) In case of pipe rupture, pipe is allowed to whip with no services affected.
(c) For high-energy piping inside containment (except for the RCL), breaks were originally postulated at all terminal ends and all locations, regardless of stress level, where plastic hinges could form and endanger safety systems or components. This commitment was later relaxed as allowed by MEB 3-1, July 1981, where pipe breaks inside containment (except for the RCL) are required to be postulated to occur at intermediate locations only where the primary plus secondary stress exceeds the stress level of $0.8(1.2S_h + S_A)$. This commitment was further relaxed as allowed by Generic Letter 87-11, June 1987 where the requirement for the postulation of all arbitrary intermediate pipe ruptures was eliminated (refer to Sections 3.6.6.4, 3.6.6.5, and 3.6.6.6).

TABLE 3.6-6

PIPE BREAK PROTECTION FEATURES ON UNIT 2 DIFFERENT FROM UNIT 1

Area	Description	Protection Feature Used
Turbine	Reheater drain system has different configuration, due to piping layout, causing different line numbers to appear for Unit 2.	Protection features used were the same as for Unit 1. The same vital structures, equipment, etc., were protected from pipe whip and jet impingement.
GE/GW	Cables and conduits servicing vital equipment were routed below the floor at el. 115 feet and returned through floor penetrations.	Protection was accomplished through separation.
GE/GW	Elimination of containment barrier plates, two on MS and two on FW.	Vital conduits affected by jet impingement were rerouted.
GE/GW	Elimination of impingement barrier surrounding the main steam line riser pipes.	Vital conduits were rerouted, vital equipment was relocated away from the jet impingement.
GE/GW	Elimination of impingement sleeve end barriers on main steam and feedwater line. Required only on MS nodes 4070 and 3180, and FW node 1403.	Conduits and instrumentation were relocated away from sleeve end jet impingement.
FW	Elimination of sleeve and barriers on main steam and feedwater lines. Required only on MS nodes 1180 and 2187, and FW nodes 1213 and 1113.	Conduits were rerouted away from sleeve end jet impingement.

TABLE 3.7-1

CONTAINMENT AND AUXILIARY BUILDING
CRITERIA COMPARISON

Parameters	HE	DE	DDE
Seismic input, horizontal	0.75g	0.2g	0.4g
Seismic input, vertical	2/3 of horizontal dynamic amplification considered	Static - 2/3 of horizontal ground spectra	Static-2/3 of horizontal ground spectra
Accidental torsion	5% and 7% eccentri-city	Not considered	Not considered
Foundation filtering	Tau = 0.040[a]	Not applicable	Not applicable
Response combination	3-D SRSS	2-D ABSUM	2-D ABSUM
Damping values	7%	2% concrete[b] 2% steel	5% concrete 2% steel
Ductility	Allowed in some areas	Not considered	Not considered
Material properties	Based on test values	Min specified values	Min specified values
Response spectra broadening (based on frequency)	+5%, -15%	±10%	±10%
Response spectra peaks clip		10% (for containment only)	10% (for containment only)

(a) 0.052 for auxiliary building.

(b) 5% for auxiliary building.

TABLE 3.7-1A

TURBINE BUILDING
CRITERIA COMPARISON

Parameters	HE	DE and DDE[a]
Seismic input, horizontal	0.75g	0.2g (DE) 0.4g (DDE)
Seismic input, vertical	2/3 of horizontal dynamic amplification Considered	Static - 2/3 of horizontal ground spectra
Accidental torsion	5% and 7% eccentricity, or equivalent Note (b)	Not considered
Foundation filtering	Tau = 0.080 (Blume input) Tau = 0.067 (Newmark input)	Not applicable
Response combination	3-D SRSS	2-D ABSUM
Damping values	7%	5% concrete 2% steel
Ductility	Concrete 1.3 Steel 3 (6 locally)	Not considered
Material properties	Based on test values	Min specified values
Response spectra broadening (based on frequency)	+5%, -15%	±10%
Response spectra peaks clip		10%

(a) DE and DDE analysis is performed only to generate response spectra for systems qualification.

(b) Equivalent method is used as described in Section 3.7.2.10.

TABLE 3.7-1B

INTAKE STRUCTURE
CRITERIA COMPARISON

Parameters	Hosgri	DE and DDE for Systems Qualifications Only
Seismic input, horizontal	Hosgri 7.5M	DE (0.20g) DDE (0.40g)
Seismic input, vertical	2/3 of horizontal spectra with Tau = 0.0 Dynamic amplification Considered	Static 2/3 of ground horizontal spectra
Accidental torsion	Horizontal floor response spectra increased by 10%	Not considered
Foundation filtering	Tau - 0.04	Not applicable
Response combination	3-D-SRSS	Not applicable
Damping values % critical	7%	5%
Ductility	Concrete 1.3; Steel 3, with up to 6 locally[(a)]	Not considered
Material properties	Based on test values	Minimum specified values
Floor response spectra broadening (based on frequency)	+5%, -15%	Structural peaks clipped 10% and widened by ± 10%

(a) Or as may be required to demonstrate that function of Design Class I equipment will not be adversely affected.

TABLE 3.7-1C

OUTDOOR STORAGE TANKS
CRITERIA COMPARISON

Parameters	Hosgri	DE and DDE
Seismic input, horizontal	Hosgri 7.5M	DE (0.20g) DDE (0.40g)
Seismic input, vertical	2/3 ZPA (0.75g) of horizontal spectra with Amplification considered Tau = 0.0	Static 2/3 ZPA of horizontal ground spectra
Accidental torsion	Not applicable	Not applicable
Response combination	3-D SRSS	2-D ABSUM
Damping	7%-All tanks with concrete cover 4%-Firewater tank without concrete cover	5%-All tanks with concrete cover 1%-Firewater tank without concrete cover
Material properties	Based on test values	Minimum specified values

TABLE 3.7-2

CONTAINMENT STRUCTURE
PERIODS OF VIBRATION

Mode No.	Period, T, in sec
1	0.255
2	0.093
3	0.088
4	0.073
5	0.060
6	0.058
7	0.057
8	0.051
9	0.051

Table 3.7-3

CONTAINMENT STRUCTURE
MAXIMUM ABSOLUTE ACCELERATIONS

Structure	Nodal Point[a]	Elevation, ft	Maximum Absolute Acceleration, g	
			DE Analysis	DDE Analysis
Exterior structure	2	301.64	1.275	2.083
	8	274.37	1.032	1.736
	10	258.27	0.907	1.567
	14	231.00	0.743	1.177
	17	205.58	0.837	1.358
	23	181.08	0.911	1.369
	26	155.83	0.866	1.292
	34	130.58	0.713	1.080
	37	109.67	0.492	0.793
Interior structure	19-22	140.00	0.735	1.195
	24	127.00	0.597	0.982
	27-30	114.00	0.478	0.773
	32	110.00	0.455	0.726
	38	102.00	0.384	0.601
Base slab	47-58	88.58	0.291	0.483

(a) See Figure 3.7-5.

Table 3.7-4

CONTAINMENT STRUCTURE
MAXIMUM DISPLACEMENTS

Structure	Nodal Point[a]	Elevation, ft	Maximum Displacement Inches	
			DE Analysis	DDE Analysis
Exterior structure	2	301.64	0.666	1.063
	8	274.37	0.602	0.967
	10	258.27	0.562	0.911
	14	231.00	0.480	0.807
	17	205.58	0.389	0.695
	23	181.08	0.314	0.587
	26	155.83	0.248	0.459
	34	130.58	0.180	0.327
	37	109.67	0.115	0.212
Interior structure	19-22	140.00	0.083	0.139
	24	127.00	0.069	0.114
	27-30	114.00	0.056	0.090
	32	110.00	0.053	0.084
	38	102.00	0.043	0.068
Base slab	47-58	88.58	0.030	0.050

(a) See Figure 3.7-5.

Table 3.7-5

CONTAINMENT STRUCTURE
MAXIMUM SHELL FORCES AND MOMENTS[a] - DE ANALYSIS

Nodal[b] Point	Elevation, ft	Shell Moments, kip-ft/ft			Shell Forces, kips/ft		
		M_{SS}	M_{TT}	M_{ST}	F_{SS}	F_{TT}	F_{ST}
2	301.64	0.21	0.21	28.99	2.74	3.84	3.75
8	274.37	0.33	0.44	2.96	14.47	32.07	23.85
10	258.27	1.76	0.91	1.63	21.04	40.91	32.80
14	231.00	9.17	2.94	0.36	37.68	42.73	48.97
17	205.58	5.74	1.26	0.27	63.59	33.27	66.44
23	181.08	7.58	2.54	0.31	91.25	37.79	79.59
26	155.83	5.69	1.49	0.50	110.72	36.31	91.43
34	130.58	4.31	1.01	0.27	151.69	31.20	108.65
37	109.67	8.26	2.75	0.19	174.13	18.99	122.66
57	88.58	1.01	0.14	2.23	209.79	63.73	127.22

(a) See Figure 3.7-7.

(b) See Figure 3.7-5.

Table 3.7-6

CONTAINMENT STRUCTURE
MAXIMUM SHELL FORCES AND MOMENTS[a] - DDE ANALYSIS

Nodal[b] Point	Elevation, ft	Shell Moments, kip-ft/ft			Shell Forces, kips/ft		
		M_{SS}	M_{TT}	M_{ST}	F_{SS}	F_{TT}	F_{ST}
2	301.64	0.36	0.37	47.17	4.30	6.33	6.04
8	274.37	0.62	0.76	4.77	22.00	53.37	39.37
10	258.27	2.71	1.46	2.63	32.58	67.71	54.58
14	231.00	15.29	4.92	0.50	60.01	71.93	83.06
17	205.58	8.14	1.64	0.37	103.39	53.31	110.30
23	181.08	11.39	3.96	0.45	154.79	56.72	132.95
26	155.83	8.27	2.21	0.77	190.50	54.24	162.53
34	130.58	6.07	1.36	9.42	251.35	46.24	195.36
37	109.67	15.95	5.31	0.34	282.88	30.75	217.34
57	88.58	1.74	0.23	4.18	338.73	110.90	220.62

(a) See Figure 3.7-7.

(b) See Figure 3.7-5.

Table 3.7-7

CONTAINMENT STRUCTURE
MAXIMUM TOTAL SHEARS

Structure	Associated[a] Nodel Point	Elevation, ft	Maximum Shears, kips x 10^3 DE Analysis	DDE Analysis
Exterior structure	2	301.64	0.19	0.66
	8	274.37	5.81	9.38
	10	258.27	8.49	13.91
	14	231.00	11.39	19.55
	17	205.58	15.00	25.02
	23	181.08	17.95	29.98
	26	155.83	20.63	36.66
	34	130.58	24.53	44.18
	37	109.67	27.83	49.42
	57	88.58	29.55	51.39
Interior structure	19 & 22	140.00	8.06	13.23
	27 & 30	114.00	10.27	16.87
	49 & 54	88.58	18.85	30.96
Total base shear	49, 54, & 57	88.58	35.05	59.99

(a) See Figure 3.7-5.

Table 3.7-8

CONTAINMENT STRUCTURE
MAXIMUM TOTAL OVERTURNING MOMENTS

Structure	Associated[a] Nodel Point	Elevation, ft	Maximum Overturning Moment kips-ft x 10^6 DE Analysis	DDE Analysis
Exterior structure	2	301.64	0.00	0.00
	8	274.37	0.12	0.18
	10	258.27	0.27	0.41
	14	231.00	0.61	0.97
	17	205.58	1.03	1.67
	23	181.08	1.48	2.50
	26	155.83	1.79	3.08
	34	130.58	2.45	4.07
	37	109.67	2.82	4.58
	57	88.58	3.39	5.48
Interior structure	19 & 22	140.00	0.06	0.10
	27 & 30	114.00	0.20	0.33
	49 & 54	88.58	0.76	1.24
Total O.T.M. at base	49, 54 & 57	88.58	3.48	5.62

(a) See Figure 3.7-5.

TABLE 3.7-8A

PERIODS OF VIBRATION AND PERCENT PARTICIPATION FACTORS

	Containment Exterior Structure					
	Translational[a] Horizontal Model		Coupled Translation[b] Plus Torsion Model		Vertical Model	
Mode No	Period (sec)	Percent Participation Factor	Period (sec)	Percent Participation Factor	Period (sec)	Participation Factor
1	0.225	44.97	0.217	58.85	0.081	51.72
2	0.081	22.75	0.109	0.32	0.051	16.72
3	0.053	3.73	0.074	25.86	0.046	2.62
4	0.053	7.88	0.041	12.35	0.046	3.81
5	0.047	1.96	0.039	5.63	0.044	11.84
6	0.045	0.043			0.043	0.05
7	0.043	9.91			0.040	7.96
8	0.041	1.66			0.038	3.15
9	0.037	1.70			0.035	1.25
10	0.036	1.71			0.035	0.88
11	0.033	1.18				
12	0.032	2.12				

(a) Axisymmetric model (see Figure 3.7-5A).
(b) Lumped-mass model with 5% accidental eccentricity (see Figure 3.7-5B).

TABLE 3.7-8B

CONTAINMENT EXTERIOR STRUCTURE
MAXIMUM ABSOLUTE HORIZONTAL AND VERTICAL ACCELERATIONS

Nodal[b] Point	Elevation (ft)	Absolute Horizontal Acceleration (g) Blume-Hosgri[a] Horizontal Input	Absolute Horizontal Acceleration (g) Vertical Input	Absolute Vertical Acceleration (g) Blume-Hosgri Horizontal Input	Absolute Vertical Acceleration (g) Vertical Input
2	301.64	2.21	0.02	0.075	1.600
8	274.37	2.07	0.15	0.450	1.020
10	258.27	1.95	0.28	0.511	0.882
14	231.00	1.70	0.28	0.532	0.810
17	205.58	1.44	0.11	0.475	0.759
19	181.08	1.23	0.14	0.416	0.703
20	155.83	1.00	0.17	0.334	0.633
22	130.58	0.80	0.18	0.228	0.575
23	109.67	0.75	0.16	0.122	0.538

(a) Effective horizontal acceleration at containment shell due to absolute sum of horizontal response and torsional response from 5% eccentricity.

(b) See Figure 3.7-5A.

TABLE 3.7-8C

CONTAINMENT EXTERIOR STRUCTURE
MAXIMUM HORIZONTAL AND VERTICAL DISPLACEMENTS

Nodal[a] Point	Elevation (ft)	Horizontal Displacement (in.) Blume-Hosgri Horizontal Input[b]	Horizontal Displacement (in.) Vertical Input	Vertical Displacement (in.) Blume-Hosgri Horizontal Input	Vertical Displacement (in.) Vertical Input
2	301.64	1.124	0.002	0.032	0.108
8	274.37	1.036	0.009	0.198	0.076
10	258.27	0.969	0.020	0.228	0.066
14	231.00	0.828	0.020	0.240	0.056
17	205.58	0.665	0.008	0.221	0.049
19	181.08	0.534	0.009	0.196	0.041
20	155.83	0.394	0.011	0.158	0.031
22	130.58	0.262	0.012	0.109	0.020
23	109.67	0.156	0.012	0.058	0.010

(a) Refer to Figure 3.7-5A.
(b) Effective horizontal acceleration at Containment Shell due to absolute sum of translational response and torsional response from 5% eccentricity.

TABLE 3.7-8D

CONTAINMENT EXTERIOR STRUCTURE
MAXIMUM SHELL FORCES AND MOMENTS

Nodal[b] Point	Elevation (ft)	Shell Forces (kip/ft)[a] Blume-Hosgri Horizontal Input			Shell Forces (kip/ft)[a] Vertical Input			Shell Moments (kip-ft/ft)[a] Blume-Hosgri Horizontal Input			Shell Moments (kip-ft/ft)[a] Vertical Input		
		F_{SS}	F_{TT}	F_{ST}	F_{SS}	F_{TT}	F_{ST}	M_{SS}	M_{TT}	M_{ST}	M_{SS}	M_{TT}	M_{ST}
2	301.64	4.48	7.35	6.85	26.04	10.32	0	0.80	0.39	57.55	3.68	2.94	0
8	274.37	23.05	59.90	44.80	27.97	28.90	0	0.72	0.86	5.87	2.66	1.09	0
10	258.27	34.80	77.10		31.00	28.24	0	2.85	1.59	3.24	3.12	1.36	0
				63.15									
14	231.00	65.60	86.55	101.00	42.95	9.45	0	17.40	5.42	0.64	11.24	1.24	0
17	205.58	118.00	51.40	143.00	57.41	13.38	0	7.80	1.27	0.23	5.86	1.12	0
19	181.08	185.50	47.00	173.50	63.95	11.60	0	11.75	3.86	0.32	3.14	1.40	0
20	155.83	235.00	40.15	200.00	65.85	7.89	0	12.40	2.96	0.69	3.51	1.37	0
22	130.58	325.50	37.80	219.50	66.95	10.76	0	5.99	1.13	0.27	2.08	2.32	0
23	109.67	376.00	36.25	240.50	67.06	8.78	0	19.05	6.26	0.26	6.99	2.78	0

(a) Refer to Figure 3.7-7.

(b) Refer to Figure 3.7-5A.

TABLE 3.7-8E

CONTAINMENT EXTERIOR STRUCTURE
MAXIMUM TOTAL SHEARS AND MAXIMUM OVERTURNING MOMENTS

Nodal[b] Point	Elevation (ft)	Maximum Shear Force (kips x 10^3)[a] Blume-Hosgri Horizontal Input	Maximum Overturning Moment (kip-ft x 10^6)[a] Blume-Hosgri Horizontal Input
2	301.64	0.34	--
8	274.37	10.50	0.18
10	258.27	15.94	0.44
14	231.00	23.67	1.06
17	205.58	32.49	1.91
19	181.08	39.44	3.00
20	155.83	45.39	3.80
22	130.58	49.70	5.26
23	109.67	55.05	6.08
27	88.58	55.81	7.31

(a) Vertical Input does not produce a net shear force.

(b) See Figure 3.7-5A.

TABLE 3.7-8F

CONTAINMENT EXTERIOR STRUCTURE
MAXIMUM TOTAL TORSIONAL MOMENTS AND AXIAL FORCES

Nodal[b] Point	Elevation (ft)	Blume-Hosgri Total Torsional Moment (kip-ft x 10^3)[a] Horizontal Input	Axial Force(kips x 10^3)[c]
2	301.64	5.49	1.52
8	274.37	67.61	9.93
10	258.27	136.94	12.82
14	231.00	216.36	19.36
17	205.58	293.17	25.88
19	181.08	353.32	28.83
20	155.83	400.00	29.69
22	130.58	427.78	30.18
23	109.67	439.99	30.23

(a) Vertical input does not produce a net torque.

(b) See Figure 3.7-5A.

(c) Due to vertical input.

TABLE 3.7-8G

CONTAINMENT INTERIOR STRUCTURE
MAXIMUM ABSOLUTE HORIZONTAL ACCELERATIONS AND DISPLACEMENTS

		Newmark-Hosgri			
Nodal[a] Point	Elevation (ft)	Horizontal Acceleration (g)	Torsional Acceleration (rad/sec^2)	Displacement (in.)	Rotation (rad x 10^{-5})
28	140.00	0.92	0.07	0.06	1.21
34	114.00	0.70	0.05	0.03	0.82

(a) See Figure 3.7-5A.

TABLE 3.7-8H

CONTAINMENT INTERIOR STRUCTURE
MAXIMUM TOTAL SHEARS, OVERTURNING MOMENTS,
AND TORSIONAL MOMENTS[a]

Nodal[b] Point	Elevation (ft)	Shear (kips x 10^3) Blume-Hosgri	Shear (kips x 10^3) Newmark-Hosgri	Overturning Moment (kip-ft x 10^3) Blume-Hosgri	Overturning Moment (kip-ft x 10^3) Newmark-Hosgri	Torsional Moment[c] (kip-ft x 10^3) Blume-Hosgri	Torsional Moment[c] (kip-ft x 10^3) Newmark-Hosgri
34	114.00	6.52	6.64	74.55	78.82	136.68	146.48
37	114.00	10.80	11.23	227.89	239.55		
48	88.58	10.08	10.40	219.60	229.31	266.06	283.99
49	88.58	13.26	13.73	544.10	560.76		

(a) Due to horizontal input only.

(b) See Figure 3.7-5A.

(c) Values obtained from lumped-mass model shown in Figure 3.7-5C.

TABLE 3.7-8I

UNIT 1
VERTICAL DYNAMIC ANALYSIS - FRAME NO. 6
SUMMARY OF MODAL PARTICIPATION FACTORS AND FREQUENCIES

Mode	Frequency	X-Direction	Y-Direction	Z-Direction	X-Rotation	Y-Rotation	Z-Rotation
1	11.4	0.00	0.00	0.71	0.0	-541.0	0.0
2	16.8	0.00	0.00	0.09	0.0	-63.0	0.0
3	20.6	0.00	0.00	-0.08	0.0	54.0	0.0
4	21.9	0.00	0.00	0.09	0.0	-65.0	0.0
5	24.1	0.00	0.00	0.03	0.0	-31.0	0.0
6	24.4	0.00	0.00	-0.01	0.0	13.0	0.0
7	24.9	0.00	0.00	-0.03	0.0	22.0	0.0
8	26.2	0.00	0.00	-0.01	0.0	-5.0	0.0
9	28.4	0.00	0.00	-0.50	0.0	304.0	0.0
10	29.3	0.00	0.00	0.20	0.0	-124.0	0.0
11	33.2	0.00	0.00	-0.04	0.0	30.0	0.0

NOTE: X is in the Radial direction.
Y is in the Longitudinal direction.
Z is in the Vertical direction.

TABLE 3.7-8J

UNIT 2
VERTICAL DYNAMIC ANALYSIS - ANNULUS FRAME 6
SUMMARY OF MODAL PARTICIPATION FACTORS AND FREQUENCIES

Mode	Frequency	X-Direction	Y-Direction	Z-Direction	X-Rotation	Y-Rotation	Z-Rotation
1	11.6	.00	0.70	.00	.00	.00	82.0
2	16.0	.00	-0.09	.00	.00	.00	-7.7
3	16.46	.00	0.07	.00	.00	.00	6.6
4	22.9	.00	-0.07	.00	.00	.00	-13.0
5	23.87	.00	0.02	.00	.00	.00	-2.0
6	24.0	.00	0.00	.00	.00	.00	7.0
7	27.8	.00	0.00	.00	.00	.00	-8.1
8	32.28	.00	0.08	.00	.00	.00	-15.0

NOTE: X is in the Radial direction.
Y is in the Longitudinal direction.
Z is in the Vertical direction.

TABLE 3.7-8K

CONTAINMENT ANNULUS STRUCTURES UNITS 1 AND 2
NATURAL FREQUENCIES FOR HORIZONTAL
SEISMIC GROUND MOTION

Unit	Elevation	Mode	Frequency (cps)
1	101	1	20.95
		2	21.69
	106	1	20.16
		2	21.47
	117	1	20.24
		2	22.78
2	101	1	22.46
		2	22.79
	106	1	19.98
		2	22.20
	117	1	19.98
		2	25.79

TABLE 3.7-8L

POLAR GANTRY CRANE
MIXIMUM DISPLACEMENTS, HOSGRI
(UNIT 1)

Condition	Node	Longitudinal Direction (in.)	Transverse Direction (in.)	Vertical Direction (in.)
Unloaded	31	6.16	6.11	1.77
	32	6.29	6.11	2.10
	39	6.16	5.27	1.49
	40	6.30	5.28	1.47
	47	6.16	5.40	1.71
	48	6.29	5.40	1.81
	75	-	-	1.57
	76	-	-	1.92
	77	-	-	1.71
	78	-	-	1.81
Loaded, 200 tons	31	6.61	5.22	1.69
	32	6.67	5.22	1.74
	39	6.62	4.76	2.12
	40	6.68	4.76	2.09
	47	6.62	4.56	1.12
	48	6.67	4.56	1.24
	75	-	-	1.49
	76	-	-	1.34
	77	-	-	1.12
	78	-	-	1.26

Notes:

1. All displacements are measured relative to base of crane.
2. For node numbers, refer to Figure 3.7-7A.
3. See PG&E Calculation No. 2252C-2 (Reference 37).

TABLE 3.7-8L

POLAR GANTRY CRANE
MAXIMUM DISPLACEMENTS, HOSGRI
(UNIT 2)

Condition	Node	Longitudinal Direction (in.)	Transverse Direction (in.)	Vertical Direction (in.)
Unloaded	31	6.16	6.11	1.77
	32	6.29	6.11	2.10
	39	6.16	5.27	1.49
	40	6.30	5.28	1.47
	47	6.16	5.40	1.71
	48	6.29	5.40	1.81
	75	-	-	1.57
	76	-	-	1.92
	77	-	-	1.71
	78	-	-	1.81
Loaded, 200 tons	31	6.61	5.22	1.69
	32	6.67	5.22	1.74
	39	6.62	4.76	2.12
	40	6.68	4.76	2.09
	47	6.62	4.56	1.12
	48	6.67	4.56	1.24
	75	-	-	1.49
	76	-	-	1.34
	77	-	-	1.12
	78	-	-	1.26

Notes:

1. All displacements are measured relative to base of crane.
2. For node numbers, refer to Figure 3.7-7A.
3. See Civil Calculation 2252C-4 (Reference 39).

TABLE 3.7-8M

POLAR GANTRY CRANE
MAXIMUM FORCES,
HOSGRI - UNLOADED CONDITION
(UNIT 1)

Type of Element	Element	Node	Axial Force (kips)	Bending Moment About Axis Y (kip-in.)	Bending Moment About Axis Z (kip-in.)
Girder Beam	13	35	212	111,700	17,950
Girder Beam	18	36	172	122,900	18,100
Gantry Leg	2	11	679	23,240	15,810
Gantry Leg	3	15	637	24,660	81,950
Gantry Leg	6	12	635	24,020	16,270
Gantry Leg	7	16	575	25,060	86,170
Gantry Leg	29	59	646	27,740	81,400
Gantry Leg	28	63	720	26,000	16,140
Gantry Leg	33	60	679	26,140	80,930
Gantry Leg	32	64	703	24,080	16,590
Sill Beam	11	9	38	28,800	2,652
Sill Beam	26	68	39	29,470	2,914
Leg Tie BM	10	20	15	28,640	7,176
Leg Tie BM	25	57	6	26,750	4,227
Girder Tie BM	9	34	9	8,853	12,080
Girder Tie BM	24	50	8	14,280	13,480
Trolley	22	71	56	23,280	3,480

Notes:

1. For node and element numbers, refer to Figure 3.7-7A.
2. See PG&E Calculation No. 2252C-3 (Reference 38).
3. Y-axis represents the major axis of cross section. Z-axis represents the minor axis.

TABLE 3.7-8M

POLAR GANTRY CRANE
MAXIMUM FORCES,
HOSGRI - UNLOADED CONDITION
(UNIT 2)

Type of Element	Element	Node	Axial Force (kips)	Bending Moment About Axis Y (kip-in.)	Bending Moment About Axis Z (kip-in.)
Girder Beam	13	35	212	111,700	17,950
Girder Beam	18	36	172	122,900	18,100
Gantry Leg	2	11	679	23,240	15,810
Gantry Leg	3	15	637	24,660	81,950
Gantry Leg	6	12	635	24,020	16,270
Gantry Leg	7	16	575	25,060	86,170
Gantry Leg	29	59	646	27,740	81,400
Gantry Leg	28	63	720	26,000	16,140
Gantry Leg	33	60	679	26,140	80,930
Gantry Leg	32	64	703	24,080	16,590
Sill Beam	11	9	38	28,800	2,652
Sill Beam	26	68	39	29,470	2,914
Leg Tie BM	10	20	15	28,640	7,176
Leg Tie BM	25	57	6	26,750	4,227
Girder Tie BM	9	34	9	8,853	12,080
Girder Tie BM	24	50	8	14,280	13,480
Trolley	22	71	56	23,280	3,480

Notes:

1. For node and element numbers, refer to Figure 3.7-7A.
2. See PG&E Calculation No. 2252C-4 (Reference 39).
3. Y-axis represents the major axis of cross section. Z-axis represents the minor axis.

TABLE 3.7-8N

POLAR GANTRY CRANE
MAXIMUM FORCES,
HOSGRI - LOADED CONDITION
(UNIT 1)

Type of Element	Element	Node	Axial Force (kips)	Bending Moment About Axis Y (kip-in.)	Bending Moment About Axis Z (kip-in.)
Girder Beam	14	39	190	210,700	25,310
Girder Beam	19	40	181	219,000	25,570
Gantry Leg	3	15	824	27,550	105,000
Gantry Leg	4	21	698	10,750	114,700
Gantry Leg	7	16	881	28,290	107,000
Gantry Leg	8	22	675	10,380	115,700
Gantry Leg	30	51	670	11,710	149,700
Gantry Leg	29	59	762	26,430	113,900
Gantry Leg	34	52	681	11,570	147,900
Gantry Leg	33	60	738	25,230	112,100
Sill Beam	11	9	45	34,760	2,410
Sill Beam	26	68	47	30,560	2,370
Leg Tie BM	10	20	15	36,710	7,683
Leg Tie BM	25	58	6	24,640	4,626
Girder Tie BM	9	33	9	11,530	13,550
Girder Tie BM	24	50	7	15,900	14,850
Trolley	22	71	57	88,950	3,269

Notes:

1. For node and element numbers, refer to Figure 3.7-7A.
2. See PG&E Calculation No. 2252C-3 (Reference 38).
3. Y-axis represents the major axis of cross section. Z-axis represents the minor axis.

TABLE 3.7-8N

POLAR GANTRY CRANE
MAXIMUM FORCES,
HOSGRI - LOADED CONDITION
(UNIT 2)

Type of Element	Element	Node	Axial Force (kips)	Bending Moment About Axis Y (kip-in.)	Bending Moment About Axis Z (kip-in.)
Girder Beam	14	39	190	210,700	25,310
Girder Beam	19	40	181	219,000	25,570
Gantry Leg	3	15	824	27,550	105,000
Gantry Leg	4	21	698	10,750	114,700
Gantry Leg	7	16	881	28,290	107,000
Gantry Leg	8	22	675	10,380	115,700
Gantry Leg	30	51	670	11,710	149,700
Gantry Leg	29	59	762	26,430	113,900
Gantry Leg	34	52	681	11,570	147,900
Gantry Leg	33	60	738	25,230	112,100
Sill Beam	11	9	45	34,760	2,410
Sill Beam	26	68	47	30,560	2,370
Leg Tie BM	10	20	15	36,710	7,683
Leg Tie BM	25	58	6	24,640	4,626
Girder Tie BM	9	33	9	11,530	13,550
Girder Tie BM	24	50	7	15,900	14,850
Trolley	22	71	57	88,950	3,269

Notes:

1. For node and element numbers, refer to Figure 3.7-7A.
2. See PG&E Calculation No. 2252C-4 (Reference 39).
3. Y-axis represents the major axis of cross section. Z-axis represents the minor axis.

TABLE 3.7-8O

FUEL HANDLING CRANE SUPPORT STRUCTURE
MAXIMUM ABSOLUTE ACCELERATIONS

Load Case	Location	Acceleration,[a] g		
		NS	EW	Vertical
HE	El 188 ft	1.7	1.6	1.1
	Columns, El 166 ft	1.6	1.3	0.6
DE	El 188 ft	0.8	0.5	(b)
	Columns, El 166 ft	0.7	0.4	(b)

(a) Accelerations are average of accelerations from models 2.1 and 2.2.

(b) DE vertical equivalent static analysis coefficient is 0.13 g.

TABLE 3.7-8P

FUEL HANDLING CRANE SUPPORT STRUCTURE
MAXIMUM RELATIVE DISPLACEMENTS

Load Case	Location	Displacements[a], in. NS	EW
HE	El 188 ft	2.0	8.8
	Columns, El 166 ft	1.8	7.1
DE	El 188 ft	0.9	2.8
	Columns, El 166 ft	0.9	2.3

(a) Displacements are from static analysis of detailed fuel handling crane support structure model described in Section 3.8.2.3.4. Displacements are relative to elevation 140 ft.

TABLE 3.7-9

AUXILIARY BUILDING
PERIODS OF VIBRATION - DE ANALYSIS

	N-S Direction		E-W Direction	
Mode No.	Period, T, (sec)	Translational Participation Factor	Period, T, (sec)	Translational Participation Factor
1[a]	0.641	0.0	0.688	8.6
2[a]	0.327	8.9	0.641	0.0
3	0.073	48.1	0.072	68.7
4	0.059	48.7	0.065	0.0
5	0.037	20.0	0.040	20.6
6	0.031	1.5	0.031	0.0

(a) Steel superstructure modes (one translational and the other torsional).

TABLE 3.7-10

AUXILIARY BUILDING HORIZONTAL MODEL
PERIODS AND PARTICIPATION FACTORS - HE ANALYSIS

COUPLED - TRANSLATIONAL PLUS TORSION

	North-South Model with 5% Eccentricity to East		North-South Model with 5% Eccentricity to West		East-West Model with 5% Eccentricity	
Mode No.	Period (sec)	Translation Participation Factor	Period (sec)	Translation Participation Factor	Period (sec)	Translation Participation Factor
1[a]	.641	-0.0	.641	0.0	.688	8.6
2[a]	.327	8.9	.327	8.9	.641	0.0
3	.070	-41.2	.075	-47.6	.074	60.2
4	.061	54.7	.056	49.4	.062	33.2
5	.036	-19.7	.037	-19.4	.039	-20.8
6	.030	-3.8	.030	7.0	.030	3.1
7	.025	-15.3	.026	14.6	.028	-17.9
8	.024	19.6	.023	-19.2	.023	14.8
9	.015	2.8	.016	-7.8	.017	11.3
10	.014	13.9	.014	-11.7	.014	9.0

(a) Steel superstructure modes (one translational and the other torsional).

TABLE 3.7-11

AUXILIARY BUILDING VERTICAL MODEL
PERIODS AND PARTICIPATION FACTORS - HE ANALYSIS

Mode Number[a]	Period (sec)	Participation Factor
1[b]	0.085	-6.0
2	0.033	67.9

(a) Only modes below 33 Hz are listed.

(b) Steel superstructure roof mode.

TABLE 3.7-11A

FUEL HANDLING CRANE SUPPORT STRUCTURE
HORIZONTAL MODELS FREQUENCIES OF VIBRATION[a]

DE, DDE, AND HE ANALYSES

First[b] Fundamental Modal Direction	Model 2.1		Model 2.2	
	Frequency (cps)	Modal Effective Mass %	Frequency (cps)	Modal Effective Mass (%)
E-W	1.6	85.0	1.6	86.0
N-S	3.1	88.0	2.7[a]	92.0

(a) For Model 2.2 see Figure 3.7-13B. Model 2.1 represents six end bay frames and is similar.

(b) Other modes have insignificant contributions, and are not included.

TABLE 3.7-11B

FUEL HANDLING CRANE SUPPORT STRUCTURE
VERTICAL MODEL FREQUENCIES OF VIBRATION[(a)(b)]

DE, DDE, AND HE ANALYSES

Model 2.1		Model 2.2	
Frequency (hz)	Modal Effective Mass (% of roof)	Frequency (hz)	Modal Effective Mass (% of roof)
10.6	19	10.1	23
16.9	23	16.6	26
20.7	2	22.8	1

(a) Only significant modes with frequencies less than 33 hz are shown. For models 2.1 and 2.2, 99 modes and 105 modes were extracted, respectively, with frequencies up to 105 hz.

(b) For model 2.2, see Figure 3.7-13B. Model 2.1 represents six end bay frames and is similar.

TABLE 3.7-12

AUXILIARY BUILDING
MAXIMUM ABSOLUTE ACCELERATIONS-DE ANALYSIS

		Maximum Absolute Accelerations		
		N-S Direction		E-W Direction
Mass[a] Point	Elevation, ft	Horizontal Acceleration, g	Rotational Acceleration rad/sec^2	Horizontal Acceleration, g
6	188.0	0.554	0.0004	0.313
1	163.0	0.375	0.0217	0.435
2	140.0	0.300	0.0187	0.324
3	115.0	0.259	0.0115	0.291
4	100.0	0.230	0.0055	0.257

(a) See Figure 3.7-13.

TABLE 3.7-13

AUXILIARY BUILDING
MAXIMUM RELATIVE DISPLACEMENTS-DE ANALYSIS

		Maximum Relative Displacement		
		N-S Direction		E-W Direction
Mass[a] Point	Elevation, ft	Horizontal Translation, in.	Rotation radians x 10^{-6}	Horizontal Translation, in.
6	188.0	0.575	1.624	1.447
1	163.0	0.022	4.087	0.025
2	140.0	0.015	3.308	0.018
3	115.0	0.009	2.014	0.012
4	100.0	0.004	0.975	0.006

(a) See Figure 3.7-13.

TABLE 3.7-14

AUXILIARY BUILDING
MAXIMUM STORY SHEARS-DE ANALYSIS

Element[a]	Maximum Story Shears, kips x 10^3	
	N-S Direction	E-W Direction
5	1.3	0.7
1	3.8	4.8
2	26.3	24.6
3	40.0	42.7
4	28.5	28.4

(a) See Figure 3.7-13.

TABLE 3.7-15

AUXILIARY BUILDING
MAXIMUM OVERTURNING MOMENTS-DE ANALYSIS

Element[a]	Maximum O.T. Moments, kips - ft x 10^6	
	N-S Direction	E-W Direction
5	0.06	0.04
1	0.08	0.10
2	0.74	0.68
3	1.32	1.30
4	1.76	1.74

(a) See Figure 3.7-13.

TABLE 3.7-16

AUXILIARY BUILDING
MAXIMUM TORSIONAL MOMENTS DUE TO
EARTHQUAKE IN N-S DIRECTION-DE ANALYSIS

Element[a]	Maximum Torsional Moments, kip - ft x 10^5
5	0.004
1	0.265
2	14.080
3	19.810
4	9.139

(a) See Figure 3.7-13.

TABLE 3.7-17

AUXILIARY BUILDING
MAXIMUM ABSOLUTE ACCELERATIONS - HE ANALYSIS
EARTHQUAKE IN N-S DIRECTION

Mass[a] Point	Elevation, ft	Blume-Hosgri Horizontal Acceleration, g		Newmark-Hosgri Horizontal Acceleration, g		Blume-Hosgri Rotational Acceleration, rad/sec^2		Newmark-Hosgri Rotational Acceleration, rad/sec^2	
		5% E	5% W	5% E	5% W	5% E	5% W	5% E	5% W
6	188.0	1.57	1.56	1.37	1.36	-	-	-	-
1	163.0	1.13	1.10	1.25	1.21	.0981	.1477	.1102	.1646
2	140.0	0.84	0.77	0.90	0.84	.0604	.0895	.0710	.1018
3	115.0	0.71	0.70	0.72	0.66	.0370	.0516	.0431	.0590
4	100.0	0.67	0.66	0.58	0.61	.0175	.0239	.0206	.0275

(a) See Figure 3.7-13.

TABLE 3.7-18

AUXILIARY BUILDING
MAXIMUM ABSOLUTE ACCELERATIONS - HE ANALYSIS
EARTHQUAKE IN E-W DIRECTION

Mass[a] Point	Elevation, ft	Blume-Hosgri Horizontal Acceleration, g	Newmark-Hosgri Horizontal Acceleration, g	Blume-Hosgri Rotational Acceleration, rad/sec^2	Newmark-Hosgri Rotational Acceleration, rad/sec^2
6	188.0	1.11	1.24	.0015	.0017
1	163.0	1.11	1.22	.1162	.1292
2	140.0	0.94	1.00	.0769	.0881
3	115.0	0.72	0.75	.0452	.0527
4	100.0	0.66	0.62	.0213	.0246

(a) See Figure 3.7-13.

TABLE 3.7-19

AUXILIARY BUILDING
MAXIMUM RELATIVE DISPLACEMENTS - HE ANALYSIS
EARTHQUAKE IN N-S DIRECTION

Mass[a] Point	Elevation, ft	Blume-Hosgri Horizontal Translation, in.		Newmark-Hosgri Horizontal Translation, in.		Blume-Hosgri Rotation radians x 10^{-6}		Newmark-Hosgri Rotation radians x 10^{6}	
		5% E	5% W	5% E	5% W	5% E	5% W	5% E	5% W
6	188.0	1.63	1.62	1.42	1.42	-	-	-	-
1	163.0	0.06	0.06	0.06	0.07	9.589	18.901	10.961	21.001
2	140.0	0.04	0.04	0.04	0.04	8.034	14.091	9.135	15.472
3	115.0	0.02	0.02	0.02	0.02	4.785	8.530	5.468	9.361
4	100.0	0.01	0.01	0.01	0.01	2.256	4.044	2.576	4.444

(a) See Figure 3.7-13.

TABLE 3.7-20

AUXILIARY BUILDING
MAXIMUM RELATIVE DISPLACEMENTS - HE ANALYSIS
EARTHQUAKE IN E-W DIRECTION

Mass[a] Point	Elevation, ft	Blume-Hosgri Horizontal Translation, in.	Newmark-Hosgri Horizontal Translation in.	Blume-Hosgri Rotation radians x 10^{-6}	Newmark-Hosgri Rotation radians x 10^{6}
6	188.0	5.08	5.63	6.153	6.897
1	163.0	0.07	0.07	14.616	16.354
2	140.0	0.05	0.05	11.219	12.484
3	115.0	0.03	0.03	7.078	7.873
4	100.0	0.02	0.02	3.471	3.854

(a) See Figure 3.7-13.

TABLE 3.7-21

AUXILIARY BUILDING
MAXIMUM STORY SHEARS - HE ANALYSIS

	Earthquake in N-S Direction				Earthquake in E-W Direction	
	Blume-Hosgri Shear kips x 10^3		Newmark-Hosgri Shear kips x 10^3		Blume-Hosgri Shear kips x 10^3	Newmark-Hosgri Shear kips x 10^3
Element[a]	5% E	5% W	5% E	5% W	±5%	±5%
5	3.6	3.6	3.2	3.2	2.6	2.9
1	12.4	12.4	13.7	13.6	12.3	13.6
2	65.6	58.4	71.9	63.3	71.0	76.2
3	106.2	100.0	115.2	101.5	115.0	122.5
4	84.5	86.7	90.2	85.8	75.8	80.2

(a) See Figure 3.7-13.

TABLE 3.7-22

AUXILIARY BUILDING
MAXIMUM OVERTURNING MOMENTS - HE ANALYSIS

	Earthquake in N-S Direction				Earthquake in E-W Direction	
	Blume-Hosgri Moment kips x 10^6		Newmark-Hosgri Moment kips x 10^6		Blume-Hosgri Moment kips x 10^6	Newmark-Hosgri Moment kips x 10^6
Element[a]	5% E	5% W	5% E	5% W	±5%	±5%
5	0.18	0.17	0.15	0.15	0.12	0.14
1	0.27	0.27	0.30	0.29	0.27	0.29
2	1.85	1.66	2.05	1.74	1.96	2.11
3	3.41	3.12	3.73	3.21	3.65	3.90
4	4.68	4.42	5.11	4.46	4.82	5.15

(a) Refer to Figure 3.7-13.

TABLE 3.7-23

AUXILIARY BUILDING
MAXIMUM TORSIONAL MOMENTS - HE ANALYSIS

	Earthquake in N-S Direction				Earthquake in E-W Direction	
	Blume-Hosgri Torsional Moment kips x 105		Newmark-Hosgri Torsional Moment kips x 10^5		Blume-Hosgri Torsional Moment kips x 10^5	Newmark-Hosgri Torsional Moment kips x 10^5
Element[a]	5% E	5% W	5% E	5% W	±5%	±5%
5	0.01	0.02	0.01	0.02	0.01	0.02
1	0.82	1.71	0.89	1.88	1.30	1.45
2	35.36	60.41	39.93	66.53	44.98	50.14
3	48.24	85.27	55.16	93.73	68.81	76.67
4	21.14	38.00	24.14	41.73	32.59	36.19

(a) See Figure 3.7-13.

TABLE 3.7-23A

TURBINE BUILDING HORIZONTAL MODEL (LOADED CRANE CASE 2)[a]
FREQUENCIES OF VIBRATION[b] - HE ANALYSIS[d]

Mode No.	Frequency Hz	Participation Factor North-South	Participation Factor East-West
1[c]	1.39	0.00	3.01
4[c]	3.32	2.59	0.00
18	5.81	-4.75	0.77
19	5.86	-0.02	-3.32
21	6.03	-0.32	-2.29
22	6.19	0.76	-2.60
23	6.37	-1.16	0.81
24	6.43	-2.66	-0.66
26	6.78	0.24	-1.74
27	7.10	-2.02	0.50
28	7.18	1.08	-1.32
29	7.32	-2.13	0.62
30	7.36	1.02	-0.03
31	7.43	-1.51	-0.61
32	7.57	0.44	-2.59
33	7.62	1.83	1.42
36	7.99	-2.04	-0.95
38	8.32	-1.70	-0.94
39	8.38	-3.16	-0.70
40	8.47	2.47	1.17
44	9.09	0.30	-1.78
56	10.71	0.28	-1.54
65	11.52	1.54	-0.14
82	13.10	-0.39	2.02
83	13.15	0.29	-1.43
89	14.02	0.01	1.79
92	14.32	-0.11	1.87
93	14.78	0.33	1.04
100	16.60	-0.31	1.54
101	16.74	0.13	2.00
102	16.81	0.52	-1.78
103	17.03	1.65	-0.22
104	17.26	-1.46	-0.54
111	18.16	0.12	1.11
115	18.93	-1.68	-0.10
147	22.29	1.00	-0.41
165	23.89	-0.89	0.49

TABLE 3.7-23A

(a) For Case 2, the Unit 1 crane has a 15-ton load and is located at column line 9, and the Unit 2 crane has a 50-ton load and is located at column line 12.2.

(b) 210 modes were extracted with frequencies ranging from 1.39 Hz to 33.01 Hz. Shown above are the modes with the twenty highest participation factors in each direction. The cumulative modal masses of the 210 modes represent 95% of the total weight of the building.

(c) Modes 1 and 4 are the principal modes of the superstructure.

(d) Note that the results in this table correspond with the seismic analysis performed for the operating license review (Reference 18) and may not reflect the latest as-built configuration of the turbine building.

TABLE 3.7-23B

TURBINE BUILDING VERTICAL MODEL NO. 1
FREQUENCIES OF VIBRATION[a] - HE ANALYSIS[c]

Mode No.	Frequency Hz	Participation Factor
1[b]	2.80	0.65
2[b]	2.80	0.38
5[b]	5.07	-0.48
15	7.48	2.00
17	7.75	-1.55
21	8.71	1.04
23	9.16	-0.55
33	10.70	-0.40
35	10.87	0.52
40	11.38	0.53
54	13.34	-0.36
59	14.02	0.43
61	14.23	0.57
62	14.40	0.31
63	14.46	-0.87
64	14.56	0.28
78	16.68	0.30
83	17.36	-0.65
89	18.29	0.48
115	22.03	-0.29

(a) 187 modes were extracted, ranging from 2.80 Hz to 33.01 Hz. Shown above are the modes with the 20 highest participation factors. The cumulative modal mass of the 187 modes represents 94% of the total weight of the building.

(b) Modes 1, 2, and 5 represent significant modes for the superstructure and overhead crane.

(c) Note that the results in this table correspond to the seismic analysis performed for the operating license review (Reference 18) and may not reflect the latest as-built configuration of the turbine building.

TABLE 3.7-23C

TURBINE BUILDING MODEL
LOADED CRANE CASES
MAXIMUM ABSOLUTE ACCELERATIONS - HE ANALYSIS[b]

Elevation, ft	Location		Acceleration[a], g		
	Bent	Line	N-S	E-W	Vertical
104 & 107	1 to 5	A-G	--	1.16	1.54
	5 to 15	A-G	--	1.18	1.99
	15 to 17	A-G	--	1.06	2.49
	17 to 19	A-G	--	1.11	--
	1 to 19	A-G	1.22	--	--
119 & 123	1 to 5	A-G	--	1.84	2.16
	5 to 15	A-G	--	2.08	2.35
	15 to 17	A-G	--	1.83	2.43
	17 to 19	A-G	--	1.68	1.30
	1 to 19	A-G	2.20	--	--
140	1 to 5	A-G	--	1.37	1.68
	5 to 15	A-G	--	2.19	1.91
	15 to 17	A-G	--	1.24	1.29
	17 to 19	A-G	--	1.11	1.32
	1 to 19	A-G	1.91	--	--
159	1.9 to 4.8	G	--	1.29	0.73
	5.7 to 15	G	--	2.51	0.70
	16 to 19	G	--	1.51	0.59
	1.9 to 19	G	1.57	--	--
193	1.9 to 4.8	A, G	--	--	0.91
	5.7 to 15	A, G	--	--	0.70
	16 to 19	A, G	--	--	0.59
Roof	1 to 1.9	A-D	3.97	1.60	

TABLE 3.7-23C

(a) Acceleration values are zero period accelerations of floor response spectra. At and below elevation 140 feet, values are for the case of a single unloaded crane; values for the case of two cranes with one crane loaded are similar.

(b) Note that the results in this table correspond to the seismic analysis performed for the operating license review (Reference 18) and may not reflect the latest as-built configuration of the turbine building.

TABLE 3.7-23D

TURBINE BUILDING MODELS
LOADED CRANE CASES
MAXIMUM RELATIVE DISPLACEMENTS - HE ANALYSIS[b]

Elevation, ft	Location		Displacement[a], in.		
	Bent	Line	N-S	E-W	Vertical
104 & 107	1 to 5	A-G	0.08	0.07	0.25
	5 to 15	A-G	0.07	0.16	0.75
	15 to 17	A-G	0.04	0.13	1.31
	17 to 19	A-G	0.06	0.68	--
119, 123, & 125	1 to 5	A-G	0.25	0.23	0.52
	5 to 15	A-G	0.60	0.42	0.82
	15 to 17	A-G	0.80	0.35	0.62
	17 to 19	A-G	0.90	1.02	0.45
140	1 to 5	A-G	0.22	0.18	0.37
	5 to 15	A-G	0.20	0.58	0.03
	15 to 17	A-G	0.20	0.28	0.13
	17 to 19	A-G	0.20	0.83	0.42
159	1 to 5	G	0.42	2.06	0.39
	5 to 15	G	0.42	3.22	0.31
	15 to 17	G	0.41	2.97	0.06
	17 to 19	G	0.42	3.98	--
193	1 to 5	A-G	1.92	5.89	0.13
	5 to 15	A-G	1.09	8.76	0.05
	15 to 17	A-G	1.21	9.64	0.08
	17 to 19	A-G	1.32	11.46	--
Roof	1 to 1.9	A-D	2.60	3.64	--

(a) Displacement values are based on response spectrum analysis.

(b) Note that the results in this table correspond to the seismic analysis performed for the operating license review (Reference 18) and may not reflect the latest as-built configuration of the turbine building.

TABLE 3.7-23E

TURBINE PEDESTAL MODEL
FREQUENCIES OF VIBRATION[a] - HE ANALYSIS

Mode No.	Frequency (Hz)	Participation Factor N-S	Participation Factor E-W	Participation Factor Vertical
1	3.09	--	87.5	--
2	3.55	--	1.8	--
3	4.22	89.9	--	--
11	14.9	--	--	23.7
12	16.16	--	--	8.2
21	20.96	--	--	17.7
22	21.19	--	0.5	--
26	22.32	--	--	6.0
27	22.37	0.3	2.1	--
28	23.15	--	--	6.0
29	23.36	0.2	0.5	--
32	24.27	--	--	2.6
42	29.06	0.4	--	3.8
43	29.59	0.5	0.3	--
44	30.39	0.9	0.2	--
47	31.34	1.7	--	2.3

(a) 50 modes were extracted, ranging in frequency from 3.09 Hz to 32.26 Hz. Shown above are the modes with the five highest participation factors for each direction.

TABLE 3.7-23F

TURBINE PEDESTAL MODEL
MAXIMUM RELATIVE DISPLACEMENTS - HE ANALYSIS[a]

Nodal Point[b]	North-South Direction (in.)	East-West Direction (in.)
124(U2)	1.10[c](N)	
36(U2)	1.06[c](S)	
82(U2)		2.24[c](E)
81(U2)		2.24[c](W)

(a) Displacements are an envelope of the results for the Unit 1 and Unit 2 Pedestals.

(b) Refer to Figure 3.7-15G (Unit 2 model is a mirror image, reflected at frame 6)

(c) Displacements are increased by a ductility factor of 1.3 to account for Blume response

TABLE 3.7-23G

SIGNIFICANT PERIODS OF VIBRATION AND PERCENT PARTICIPATION FACTORS
INTAKE STRUCTURE

	North-South Model		East-West Vertical Model		
Mode Number	Period (sec)	Percent Participation Factor	Period (sec)	East-West Percent Participation Factor	Vertical Percent Participation Factor
2	0.081	0.5	0.081	0.0	0.1
3	0.081	0.1	0.081	0.0	0.0
4	0.081	0.2	0.081	0.0	0.0
5	0.080	1.1	0.080	0.0	0.0
6	0.079	2.5	0.079	0.0	0.3
7	0.078	0.8	0.078	0.0	0.1
9	0.069	0.1	0.065	0.1	0.1
10	0.066	2.1	0.065	0.4	0.0
11	0.065	3.5	0.064	0.2	0.0
12	0.064	0.2	0.064	0.0	0.0
13	0.064	0.4	0.064	0.0	0.0
14	0.064	0.0	0.064	0.0	0.0
15	0.064	0.2	0.063	0.4	0.1
17	0.063	0.0	0.063	0.1	0.1
18	0.063	0.3	0.062	0.4	0.0
19	0.060	0.7	0.060	0.1	0.9
21	0.049	0.8	0.049	1.7	0.7
22	0.049	1.4	0.048	2.1	0.6
23	0.048	1.1	0.048	0.3	0.0
24	0.047	2.7	0.047	2.4	0.6
25	0.047	2.1	0.046	3.4	1.4
33	0.034	1.4	0.033		7.4
35	0.032	1.6	0.032	3.0	5.4
36	0.031	3.4	0.031	1.3	4.7

TABLE 3.7-23H

MAXIMUM RELATIVE DISPLACEMENTS AND
MAXIMUM ABSOLUTE ACCELERATIONS (HOSGRI)
INTAKE STRUCTURE

Nodal Point[a]	Elevation (ft)	North-South Displacement (in.)	East-West Displacement (in.)	Vertical Displacement (in.)	North-South Acceleration (g)	East-West Acceleration (g)	Vertical Acceleration (g)
330	+32.0	0.025	0.044	0.010	2.36	2.15	0.65
312	+24.4	0.016	0.029	0.008	1.50	1.55	0.65
71	+17.5	0.120	0.011	0.010	1.58	0.66	0.61
73	+17.5	0.065	0.011	0.007	0.94	0.66	0.54
74	+17.5	0.058	0.011	0.005	0.85	0.66	0.51
284	+17.5	0.009	0.019	0.007	0.64	1.00	0.62
363	+11.0	0.008	0.012	0.003	0.64	0.87	0.54
80	-2.1	0.133	0.007	0.010	1.71	0.70	0.59
83	-2.1	0.066	0.005	0.006	0.98	0.71	0.52
87	-16.8	0.251	0.003	0.005	3.14	0.72	0.52
89	-16.8	0.050	0.002	0.003	1.12	0.73	0.50

(a) See Figure 3.7-15F.

TABLE 3.7-23I

OUTDOOR WATER STORAGE TANKS
SUMMARY OF SIGNIFICANT PERIODS AND PERCENT PARTICIPATION FACTORS
REFUELING WATER STORAGE TANK

Mode No.	Period (sec)	Modal Participation Factor %
1	0.132	50.7
2	0.052	22.6

TABLE 3.7-23J

OUTDOOR WATER STORAGE TANKS
SUMMARY OF SIGNIFICANT PERIODS AND PERCENT PARTICIPATION FACTORS
FIREWATER AND TRANSFER TANK

	Load Case 1[a]		Load Case 2[b]	
Mode No.	Period (sec.)	Modal Participation Factor %	Period (sec.)	Modal Participation Factor %
1	0.12124	54.91	0.1234	48.4
2	0.04985	21.26	0.06318	6.21

(a) Load Case 1: Inner and outer tanks are filled with water up to design level
(b) Load Case 2: Inner tank is filled to design level, outer tank is empty

Table 3.7-24

FUNDAMENTAL MODE FREQUENCY RANGES
FOR RCL PRIMARY EQUIPMENT

	Frequency, Hz
Steam Generator	6.7 – 9.0
Reactor coolant pump	6.7 - 7.2
Reactor pressure vessel	16.8 - 17.0

TABLE 3.8-1

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TESTING OF REINFORCING BARS FOR PG&E DESIGN CLASS I CONCRETE STRUCTURES
COMPARISON OF PROGRAM USED ON DIABLO CANYON POWER PLANT WITH REGULATORY GUIDE 1.15, DECEMBER 1972

Diablo Canyon Power Plan	*Regulatory Guide 1.15, December 1972*
The number of test specimens required for acceptance is in accordance with ASTM A 615, Deformed Billet-Steel Bars for Concrete-Reinforcement, American Society for Testing and Materials. Additional samples were tested as part of the splice testing program. The requirements for acceptance testing are more stringent than ASTM A 615 in that all tests must be conducted using the full section of the bar.	*At least one full-diameter specimen from each bar size should be tested for each 50 tons or fraction thereof of reinforcing bars that are produced from each heat and used in Category I structures.*
Test procedures are in accordance with ASTM A 615-68.	*The test procedures should be in accordance with ASTM A 370-68, Standard Methods and Definitions for Mechanical Testing of Steel Products, American Society for Testing and Materials.*
Acceptance standards are in accordance with ASTM A 615-68 using full sections of the bars as rolled. Bend test requirements described in Item 3, Sheet 2 of 2, are more stringent than those in Supplemental Requirements (S-1) of ASTM A 615-72.	*The acceptance standards should be in accordance with ASTM A 615-72, Standard Specification for Deformed Billet-Steel Bars for Concrete Reinforcement, American Society for Testing and Materials, including Supplemental Requirement (S-1)[a] using full sections of the bars as rolled.*

TABLE 3.8-1

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Diablo Canyon Power Plan	*Regulatory Guide 1.15, December 1972*
In addition to the requirements of ASTM A 615, the Company specification requires the following: *1. Grade 60 bars be limited in carbon and manganese content to a maximum of 0.45% and 1.3% respectively.* *2. Performance of a check analysis, which is listed as an option in ASTM A 615.* *3. No. 14 and No. 18 bars be subjected to a 90° bend test using a pin having a diameter eight times the diameter of the bar.*	*Where any material property such as yield strength to tensile strength ratio, ductility, weldability or other similar property is relied upon by the designer or constructor, then the reinforcing bar chemistry should be controlled to the extent required to achieve the desired material property, and confirmatory testing should be performed.*
Deformations were inspected during production to ensure conformance with ASTM A 615.	*Deformations of the reinforcing bars should be inspected to assure their compliance with ASTM A 615-72 and with the licensee's specifications pertinent to bonding and other purposes which are dependent on the deformation characteristics.*
Adequacy of deformations for splicing was demonstrated by the tensile tests of the Cadweld splices. See Table 3.8-2.	*Adequacy of deformations for splicing will be demonstrated by the tensile tests of the splices. See Safety Guide 10, "Mechanical (Cadweld) Splices in Reinforcing Bars of Category I Concrete Structures."*

(a) Supplemental Requirement (S-1) is for a 90° bend test, using a pin diameter 10 times the bar diameter, on No. 14 and No. 18 bars.

TABLE 3.8-2
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

MECHANICAL (CADWELD) SPLICES IN REINFORCING BARS OF CONCRETE CONTAINMENTS
COMPARISON OF PROGRAM USED ON DIABLO CANYON POWER PLANT WITH SAFETY GUIDE 10, MARCH 1971

Diablo Canyon Power Plant	*Safety Guide 10, March 1971*
Prior to production splicing, each operator was instructed by a representative of the manufacturer.	1. *Crew Qualification - Each member of splicing crew (or each crew if the members work as a crew) should prepare two qualification splices for each of the splice positions (e.g., horizontal, vertical, diagonal) to be used. The qualification splices should be made using the same materials (e.g., bar, sleeve, powder) as those to be used in the structure. The completed qualification splices should meet the requirements specified by the designer of the containment structure and approved by the licensee, pass visual inspection as provided by Paragraph 2 below, and meet the tensile tests as provided by Paragraph 3 below.*
Each operator (a crew consisted of an operator and a helper) prepared one qualification splice for each of the splice positions for which he was qualified. The qualification splice was made using the same materials as those used in the structures. The completed qualification splices had to pass visual inspection and develop the minimum tensile strength of the reinforcing steel. A manufacturer's representative was present for at least the first 20 production splices for each crew to verify that proper procedures were being used and quality splices obtained.	
All completed splices were visually inspected in accordance with the recommendations of the Erico Co. inspection manual RB-5M 768, Inspection of the Cadweld Rebar Splice. This visual inspection included both ends of the sleeve, the tap hole, and measurement of void area.	2. *Visual Inspection - All completed mechanical splices should be inspected at both ends of the splice sleeve and at the tap hole in the center of the splice sleeve in accordance with the requirements specified by the designer of the containment structure and approved by the licensee.*
In addition, at least twice daily for each Cadweld crew, an inspector observed the entire splicing operation including cleaning of rebar ends, spacing of rebar, centering of rebar ends, loading the crucible,	*Among the items should be included in these specifications are longitudinal centering of sleeve on the spliced ends, allowable voids in filler metal, extent of leaking of filler metal,*

TABLE 3.8-2
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Diablo Canyon Power Plant	*Safety Guide 10, March 1971*
and firing the charge. The Cadweld procedure specified for the DCPP includes placing a mark 12 inches ± 1/4-inch back from the end of the bar. This line was used as a reference to determine if the bar ends are centered in the sleeve.	*permissible gap between rebar ends, cartridge size, gas blowout, amount of packing and slag at the tap hole. Splices that fail to pass visual inspection should be discarded and replaced, and should not be used as tensile test samples.*
Acceptance criteria for splice tensile tests is as follows:	*3. Tensile Testing - Splice samples may be production splices (i.e., those cut directly from in place reinforcing) or sister splices (i.e., those removable splices made in-place next to production splices and under the same conditions).*
No splice in the test series may have a tensile value below 125% of the specified yield point stress, and no more than 5 % of the splices tested may have an ultimate tensile strength less than 85% of that specified. The average tensile strength of all splices in the test series must equal or exceed the ASTM specified minimum ultimate strength.	*Splice samples should be subjected to tensile tests in accordance with the sampling frequency specified in Paragraph 4a or Paragraph 4b below, to determine conformance with the following acceptance standards:*
	a. The tensile strength of each sample tested should be equal or exceed 125 percent of the minimum yield strength specified in the ASTM standard appropriate for the grade of reinforcing bar using loading rates set forth in ASTM Specification A 370 dated August 15, 1968.
	b. The average tensile strength of each group of 15 consecutive samples should equal or exceed the guaranteed ultimate tensile strength specified for the reinforcing bar.

TABLE 3.8-2
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Diablo Canyon Power Plant	*Safety Guide 10, March 1971*
	If any sample tested fails to meet the provisions of Paragraph 3a above, the procedure of Paragraph 5a below should be followed. *If the average tensile strength of the 15 samples tested fails to meet the provisions of Paragraph 3b above, the procedure of Paragraph 5b below should be followed.*
Testing frequency for each crew, position, and grade of bar was as follows: *One out of the first 10 splices. This splice must be a production splice for No. 18, Grade 60 bars and a sister splice for other sizes and grades of bar.* *Three out of the next 90 splices for No. 18, Grade 60 bars and one out of the next 90 splices for all other sizes and grades of bar.* *Three out of second and subsequent 100 splice units for No. 18, Grade 60 bars and one out of second and subsequent 100 splice units for all other sizes and grades of bar.* *At least 25% of the total number of No. 18, Grade 60 test splices must be made by cutting out*	*4. <u>Tensile Test Frequency</u> - Separate test cycles should be established for mechanical splices in horizontal, vertical, and diagonal bars, for each bar size, and for each splicing crew as follows:* *a. Test Frequency for Production Splice Test Samples. If only production splices are tested, the sample frequency should be:* *1 of the first 10 splices* *1 of the next 90 splices* *2 of the next and subsequent units of 100 splices* *b. Test Frequency for Combinations of Production and Sister Splices. If production and sister splices are tested, the sample frequency should be:*

TABLE 3.8-2
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Diablo Canyon Power Plant	*Safety Guide 10, March 1971*
production splices on a random basis. The remaining test splices may be made by having test bars tie wired alongside the production bars and spliced in sequence with those bars. The minimum length of the spliced bars is 3 feet.	*1 production splice of the first 10 production splices* *1 production and 3 sister splices, for the next 90 production splices* *3 splices, either production or sister splices, for the next and subsequent units of 100 splices.* *At least 1/4 of the total number of splices tested should be production splices.*
In the event a splice should fail the tensile test criteria, the specimen was to be examined by a testing laboratory. Based on the results of this investigation, additional splices by the crew responsible, as directed by the Engineer, were to be taken from the structure to ensure that there are no other defective splices. The procedures of the crew responsible for making the failed splice were to be reviewed, and if necessary, the crew retrained and requalified.	*5. <u>Procedure for Substandard Tensile Test Results</u>* *a. If any production or sister splice tested fails to meet the tensile test specification of Paragraph 3a and the observed rate of splices that fail the tensile test at that time does not exceed 1 for each 15 consecutive test samples, the sampling procedure should be started anew.* *If any production or sister splice used for testing fails to meet the tensile test specification in Paragraph 3a, and the observed rate of splices that fail the tensile test exceeds 1 for each 15 consecutive test samples, mechanical splicing should be stopped. In addition, the adjacent production splices on each side of the last failed splice and 4 other splices distributed uniformly throughout the balance of the 100 production splices under investigation should be tested,*

TABLE 3.8-2
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Diablo Canyon Power Plant	*Safety Guide 10, March 1971*
	and an independent laboratory analysis should be made to identify the cause of all failures. The results of these tests should be evaluated by the designer of the containment structure and the licensee to determine the required corrective action. The designer and the licensee should specify the extent of repairs necessary and the actions required to prevent further failures from the identified causes.
	b. If two or more splices from any of these 6 additional splice samples fail to meet the tensile test specification of Paragraph 3a, the balance of the 100 production splices under investigation should be rejected and replaced.
	When mechanical splicing is resumed, the sampling procedure should be started anew.
	If the average tensile strength of the 15 consecutive samples fails to meet the provisions of paragraph 3b above, the designer of the containment structure and the licensee should evaluate and assess the acceptability of the reduced average tensile strength with respect to the required strength at the location from which the samples were taken.

TABLE 3.8-3

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

NONDESTRUCTIVE EXAMINATION OF PRIMARY CONTAINMENT LINER WELDS
COMPARISON OF PROGRAM USED ON DIABLO CANYON POWER PLANT WITH SAFETY GUIDE 19, AUGUST 1972

Diablo Canyon Power Plant	*Safety Guide 19, August 1972*
	1. Nondestructive Examination of Liner Seam Welds
For each welder and welding position, the first 10 feet of weld was examined radiographically. Thereafter, a minimum of 10% of the welding (to at least include all intersections of joints) was progressively examined radiographically as welding was performed. This was done on a random basis with the location specified in such a manner that an approximately equal number of radiographs were taken from the work of each welder. The techniques of radiographic examination of welds were in accordance with Paragraph UW-51 of Section VIII, ASME Boiler and Pressure Vessel Code (ASME B&PV Code). See Notes 1 and 2.	*a. For each welder and welding position (flat, horizontal, and overhead), the first 10 feet of weld, and one spot (not less than 12 inches in length) in each additional 50 foot increment of weld (weld test unit) or fraction thereof should be examined radiographically in accordance with the techniques prescribed in Section V, "Nondestructive Examination," of the ASME Boiler and Pressure Vessel Code (ASME B&PV Code). In any case, a minimum of 2 percent of all liner seam welds should be examined by radiography.*
Where radiographic examination of liner seal welds was not feasible, a minimum 10% of the welding (to at least include all locations where there are welded backing strip splices and intersections) was examined by magnetic particle or liquid penetrant testing. Magnetic particle testing was in accordance with Appendix VI of Section VIII, ASME B&PV Code. Liquid penetrant testing was in accordance with Appendix VIII of Section VIII, ASME B&PV Code. See Notes 1 and 2.	*b. Where radiographic examination of liner seam welds is not feasible or where the weld is located in areas which will not be accessible after construction, the entire length of weld should be examined by the magnetic particle method or by the ultrasonic method in accordance with the techniques prescribed in Section V of the ASME BPVC for such examination methods.*

TABLE 3.8-3

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Diablo Canyon Power Plant	*Safety Guide 19, August 1972*
All liner seam welds were tested for leaktightness in accordance with the following method:	*c. All liner seam welds should be tested for leaktightness in accordance with the following method (or other methods of equivalent sensitivity):*
Immediately preceding the test, a soap solution is applied to the weld. The application of the soap solution must not precede the vacuum box by more than 3 minutes. The vacuum box, which contains a viewing window, is placed over the area to be tested and evacuated to a 5 psi differential with the atmospheric pressure.	*Immediately preceding the test, a soap solution (or other appropriate solution) should be applied to the weld. A vacuum box containing a viewing window should be placed over the area to be tested and evacuated to produce at least 5 psi differential with the atmospheric pressure. Leaks in welds, if present, should be detected by formation of bubbles. The solution used for the test should have bubble formation properties adequate for identification of leaks. The test solution should be checked every hour, with a suitable test leak to verify the bubble formation property of the solution used.*
Leak chase channels are installed over the liner welds. Upon completion of one zone of leak chase channels, the zone was tested at the containment structure design pressure of 47 psi. The acceptance criteria is that there be no loss of pressure within 2 hours as indicated by a pressure gauge.	*d. Where leak chase system channels are installed over liner welds, channel-to-liner plate welds should be tested for leak- tightness by pressurizing the channels to containment design pressure. If any indicated loss of channel test pressure occurs within 2 hours, as evidenced by a test gauge, the channel-to-liner welds should be soap bubble tested in accordance with the above procedure.*

TABLE 3.8-3

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Diablo Canyon Power Plant	*Safety Guide 19, August 1972*
All welds in penetration, airlocks, and access openings that are not backed by concrete were fully examined in accordance with Class B requirements of Section III, ASME B&PV Code. See Notes 1, 2, 3, and 4. *All welds between flued heads and pipelines were fully examined in accordance with the Class II requirements of ANSI B 31.7, Nuclear Power Piping.* *Welds backed by concrete in the vicinity of penetrations were examined as follows:* *1. Welds between the penetration sleeve and insert plate were fully examined in accordance with the Class B requirements of Section III, ASME B&PV Code. See Notes 1, 2, and 4.* *2. Welds between the insert plate and the liner were examined under the same criteria as liner seam welds.* *All welds backed by concrete in the containment structure are carbon steel.*	*2. <u>Nondestructive Examination of Penetration, Airlock, and Access Opening Welds</u>* *a. All welds in penetration, airlocks, and access openings that are not backed by concrete, such as welds between penetrations and flued fittings and pipelines, should be fully examined in accordance with examination methods of NE-5120 of Section III of the ASME B&PV Code employing the techniques prescribed in Section V of that code.* *b. All welds in the vicinity of penetrations and access openings that are backed by concrete, such as welds between penetration and reinforcing plate,[(a)] penetration and liner, reinforcing plate and liner, liner insert and liner, reinforcing plate and frames for airlocks and access openings, and liners and frames for airlocks and access openings, should be fully examined (1) in accordance with Paragraph 2a above or (2) by magnetic particle, or liquid penetrant when a nonmagnetic weld is used, in accordance with the techniques prescribed in Section V of the ASME B&PV Code.*

(a) Thickened liner insert which provides local reinforcement.

TABLE 3.8-3

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Diablo Canyon Power Plant	*Safety Guide 19, August 1972*
Examination of welds in penetrant assemblies and in the vicinity of penetrations is described in the preceding paragraphs.	*c. All welds in bellow type expansion joints provided in penetration assemblies or appurtenances to the containment vessel should be magnetic-particle or liquid-penetrant tested when a nonmagnetic weld is used, in accordance with the techniques prescribed in Section V of ASME B&PV Code for such examination methods.*
	3. Qualification of Welders and Welding Procedures
The qualification of welders, welding machine operators, and welding procedures was in accordance with Section IX, "Welding Qualifications," of the ASME B&PV Code. See Note 2.	*The qualification of welders, welding machine operators, and welding procedures should be in accordance with Section IX, "Welding Qualifications," of the ASME B&PV Code.*
	4. Qualification of Nondestructive Examination Personnel
Nondestructive examinations were performed by personnel qualified in accordance with the appropriate parts of the ASME B&PV Code. See Notes 1 and 2.	*Nondestructive examination should be performed by personnel designated by the licensee or his agent and qualified in accordance with the provisions of Section V of the ASME B&PV Code.*
	5. Selection of Spots for Radiographic Examination
The spots of liner seam welds to be radiographically examined were selected on a random basis with the locations selected such that all intersections	*The spots of liner seam welds to be radiographically examined should be randomly selected, but no two spots in adjacent weld test units*

TABLE 3.8-3

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Diablo Canyon Power Plant	*Safety Guide 19, August 1972*
of joints were examined, and an approximately equal number of radiographs were taken from the work of each welder. The location covered by each radiograph was recorded.	*should be closer than 10 feet and their locations should be recorded.*
	6. Time of Examination
Nondestructive examinations were done progressively as welding was performed.	*All examinations should be performed as soon as practicable after the linear increment of weld to be examined is completed.*
	7. Acceptance Standards
	a. Containment Liner Seam Welds Examined by Radiography
Where a spot in the seam weld is judged acceptable in accordance with Paragraph UW-51 of Section VIII, ASME B&PV Code, the entire weld test unit represented by this spot radiograph is considered acceptable. See Notes 2 and 3.	*Where a spot in the seam weld is judged acceptable in accordance with the referenced standards of NE-5120 of Section III of the ASME B&PV Code, the entire weld test unit represented by this spot radiograph is considered acceptable.*
	b. Containment Liner Seam Welds Examined by Ultrasonic or Magnetic Particle
Where a spot in the seam weld examined by magnetic particle or liquid penetrant method is judged	*Seam welds examined by ultrasonic or magnetic particle methods are considered acceptable*

TABLE 3.8-3

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Diablo Canyon Power Plant	*Safety Guide 19, August 1972*
acceptable, in accordance with the acceptance criteria referenced in Section VIII, ASME B&PV Code, the entire weld seam represented by the examination is considered acceptable. See Notes 2 and 3.	*provided the examinations meet the acceptance standards referenced for such examination methods in NE-5120 of Section III of the ASME B&PV Code.*
The acceptance criterion for the vacuum box test is that no leaks be detected.	*c. Soap Bubble Leak Tests of Containment Liner Welds* *Liner welds are considered acceptable provided no leakage is detected by soap bubble tests (or by other methods of equivalent sensitivity).*
Penetration, airlock, and access opening welds that are not backed by concrete are considered acceptable provided the examinations meet the acceptance standards referenced for Class B vessels in Section III, ASME B&PV Code. See Notes 2, 3, and 4. *Welds between flued heads and pipelines are considered acceptable provided the examinations meet the acceptance standards referenced for Class II piping in ANSI B31.7, Nuclear Power Piping.*	*d. Penetration, Airlock, and Access Opening Welds* *Penetration, airlock, and access opening welds are considered acceptable provided the examinations meet the acceptance standards referenced in NE-5120 of Section III of the ASME B&PV Code. Welds in bellows type expansion joints are considered acceptable if the examinations meet the acceptance standards referenced in magnetic particle and liquid penetrant methods in NE-5120 of Section III.*

TABLE 3.8-3

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Diablo Canyon Power Plant	*Safety Guide 19, August 1972*
Welds between the penetration sleeve and insert plate are considered acceptable provided the examinations meet the acceptance standards referenced for Class B vessels in Section III, ASME B&PV Code. See Note 2.	
	8. Repair and Reexamination
	a. Containment Liner Seam Welds Examined by Radiography
If a radiographed spot failed to meet the specified acceptance standards, two additional spots of the same length were radiographically examined in the same weld seam at locations away from the original spot, but in welds performed by the same welder or welder operator. The locations of these additional spots were determined as provided for the original spot examination.	*When a radiographed spot fails to meet the specified acceptance standards, two additional spots should be radiographically examined in the same weld test unit at locations at least one foot removed (on each side) from the original spot. The locations of these additional spots should be determined by the examiner using the same procedure followed in the selection of the original spot for examination and the examination results should determine the following corrective actions:*
If the two additional spots examined showed welding that meets the specified acceptance standards, the entire weld represented by the three radiographs is judged acceptable. The defective welding disclosed by the first of the three radiographs was removed and repaired.	*(1) If the two additional spots examined meet the specified acceptance standards, the entire weld unit represented by the three spot radiographs is considered acceptable. However, the defective welding disclosed by the first of the three radiographs should be repaired by welding.*

TABLE 3.8-3

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Diablo Canyon Power Plant	*Safety Guide 19, August 1972*
If either of the two additional spots examined showed welding that does not comply with the specified acceptance standards, the entire portion of the seam represented was considered unacceptable or, optionally, the entire weld represented was completely radiographed and defective welding corrected to meet the specific acceptance standards.	*(2)If either of the two additional spots examined fails to meet the specified acceptance standards, the entire weld test unit is considered unacceptable.* *The entire weld should be removed and the joint should be rewelded or, optionally, the entire weld unit may be completely radiographed and defective welding only need be repaired.*
Repair welding was performed using a qualified procedure. The rewelded joints or weld repaired areas were completely reradiographed and meet the specified acceptance standards.	*(3)Repair welding should be performed using a procedure as specified under regulatory position 3. above. The weld repaired areas in each weld test unit should be spot radiographed at one selected location to meet the acceptance criteria specified in regulatory position 7.a. or 8.a. (1). above.*
	b.Containment Liner Seam Welds Examined by Ultrasonic or Magnetic Particle
If a weld that had been examined did not comply with the specified acceptance standards, additional examination was performed to the same extent as required for radiography. The weld was repaired and reexamined in accordance with the provisions of Section VIII of the ASME B&PV Code. See Notes 2 and 3.	*When a weld which has been examined does not comply with the specified acceptance standards, the weld should be repaired and reexamined in accordance with the provisions of Section III of the ASME B&PV Code.*

TABLE 3.8-3

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Diablo Canyon Power Plant	*Safety Guide 19, August 1972*
	c. Soap Bubble Tests of Containment Liner Welds
If a weld was judged unacceptable because leakage is repaired. Repair welding was performed using a procedure qualified as specified for production welds. The weld repaired areas were reexamined by soap bubble leakage retesting.	*Welds judged unacceptable because leakage is detected by the soap bubble test (see regulatory position 7.c. above) should be repaired. Repair welding should be performed using a qualified procedure as specified under regulatory position 3. above. The weld repaired areas should be reexamined by soap bubble leakage retesting.*
	d. Penetration, Airlock and Access Opening Welds
If a weld was judged unacceptable on a penetration sleeve airlock, or access opening, the weld was repaired and reexamined in accordance with the provisions for Class B vessels of Section III of the ASME B&PV Code. See Notes 2 and 3.	*Welds judged acceptable in accordance with regulatory position 7.d. should be repaired and reexamined in accordance with the provisions of Section III of the ASME B&PV Code.*
	9. Records
Retention of records is discussed in Chapter 17.	*Records of radiographs and other nondestructive examinations including those for repaired defective welds should be retained by the licensee in compliance with the provisions of Section XVII, "Quality Assurance Records," of Appendix B to 10 CFR Part 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants."*

TABLE 3.8-3

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Notes:

1. *Section V, ASME B&PV Code, which provides techniques for nondestructive examination applicable to all sections of the ASME B&PV Code, was first published in July 1971. Although it may eventually replace the corresponding parts of other sections of the ASME B&PV Code, the individual sections still contain techniques for nondestructive examinations.*

2. *References in the table to ASME B&PV Code for the Diablo Canyon plant refer to 1968 Edition, including addenda through Summer 1968.*

3. *NE-5120, Section III, ASME B&PV Code, requires examination technique and acceptance criteria in accordance with Section VIII, ASME B&PV Code (Paragraph UW-51 for radiography).*

4. *Class B requirements of Section III, ASME B&PV Code, specify radiographic examination and acceptance criteria in accordance with Paragraph UW-51, Section VIII, ASME B&PV Code.*

TABLE 3.8-4

CONTAINMENT BUILDING
BASE SLAB STRESS RATIOS[a]

Beam No.[b]	Operating Moment Demand (ft-k)	Operating Moment Capacity (ft-k)	Accident Moment Demand (ft-k)	Accident Moment Capacity (ft-k)	Accident With Hosgri Moment Demand (ft-k)	Accident With Hosgri Moment Capacity (ft-k)	Stress Ratio
62	15,293	37,640	12,827	36,925	20,134	41,250	
	--	-50,600	-37,772	-156,900	-44,967	-175,875	2.05
225	59,630	88,835	75,492	279,275	109,844	314,000	
	--	-18,275	--	-54,375	--	-61,083	1.49
43	12,126	51,880	56,623	167,925	69,444	188,124	
	--	-18,275	--	-54,375	--	-61,083	2.71
24	14,483	25,940	64,157	83,963	68,263	94,062	
	--	-9,138	--	-27,188	--	-30,541	1.31
129	23,425	88,835	76,480	279,275	93,238	314,000	
	--	-18,275	--	-54,375	--	-61,083	3.65
216	23,013	37,640	19,780	36,925	26,007	41,250	
	--	-50,600	-21,785	-156,900	-67,471	-175,875	1.59
171	1,898	6,675	--	22,155	5,831	24,750	
	-6,884	-30,360	-37,497	-94,140	-55,206	-105,525	1.91

(a) Stress Ratio = $\frac{\text{Capacity}}{\text{Demand}}$

(b) See Figure 3.8-38: + = Tension on bottom - = Tension on top

TABLE 3.8-5

CONTAINMENT BUILDING INTERNAL STRUCTURE
STRESS RATIOS IN SELECTED ELEMENTS

Description of Member	Location of Member	Load Combination[a]	Demand	Capacity	Stress Ratio[b]
Rebar in 3-ft concrete wall	Crane wall:				
	1. Vertical bar	D + L + DDE + CP + R + J + M	58 ksi	60 ksi	1.03
	2. Hoop bar		54 ksi	60 ksi	1.11
4-ft concrete wall	Fuel transfer canal:				
	1. Wall @ N & S from el 113 ft-1 1/2 in. to el 140 ft	D + L + DDE + CP + R + J + M	343 k-ft	381 k-ft	1.11
	2. Wall @ W from el 113 ft-1 1/2 in. to el 140 ft	D + L + DDE + CP + R + J + M	162 k-ft	216 k-ft	1.33
Rebar in 2-ft concrete wall	Fuel transfer canal wall @ W from el 88 ft to el 113 ft-1 1/2 in.	D + L + DDE + CP + R + J + M	22 ksi	60 ksi	2.72
3-ft concrete slab	Fuel transfer canal floor @ el 113 ft-1 1/2 in.	D + L + DDE + CP + R + J + M	258 k-ft	269 k-ft	1.04
4-ft Concrete Slab	Fuel transfer canal floor @ el 104 ft	D + L + DDE + CP + R + J + M	306 k-ft	381 k-ft	1.24
Rebar in 6-ft concrete wall	Reactor cavity wall:				
	1. Vertical bar	D+L+DDE+CP+R+J+M	15 ksi	60 ksi	4.0
	2. Hoop bar	D + L + DDE + CP + R + J + M	26 ksi	60 ksi	2.3
3-ft concrete slab	Floor @ el 140 ft	D + L + DE + T	46 k-ft	93 k-ft	2.02

(a) Load combinations with Hosgri do not govern.
(b) Stress Ratio $= \frac{\text{Capacity}}{\text{Demand}}$

TABLE 3.8-5

Description of Member	Location of Member	Load Combination[a]	Demand	Capacity	Stress Ratio[b]
4 ft 6 in. concrete slab	Floor @ el 140 ft	D + L + DE + T	156 k-ft	229 k-ft	1.46
5 ft concrete slab	Floor @ el 140 ft	D + L + DDE + CP + R + J + M	328 k-ft	500 k-ft	1.52
10 in. concrete slab	Annulus platform @ el 130 ft	D + L + DE + T	10 k-ft	39 k-ft	3.90
1 ft 6 in. concrete slab	Annulus platform @ el 140 ft	D + L + DE + T	35 k-ft	57 k-ft	1.62
W21x73	Annulus platform @ el 130 ft	D + L + DE + T + TH + FV + RVOT	22 ksi	24 ksi	1.09
W21x62	"	"	8 ksi	22 ksi	2.75
W12x40	"	"	9 ksi	22 ksi	2.44
W12x65	Annulus platform column	"	124 k (Unit 1)	268 ksi	2.16
W12x65	"	"	205 k (Unit 2)	268 ksi	1.31
W12x99	"	"	212 k (Unit 1)	366 k	1.73
W21x55	Annulus platform @ el 140 ft	"	24 ksi (Unit 1)	27 ksi	1.12
W21x82	"	"	11 ksi (Unit 1)	22 ksi	2.00
W21x68	"	"	17 ksi (Unit 1)	22 ksi	1.29
W21x96	"	"	23 ksi (Unit 1)	27 ksi	1.17

TABLE 3.8-5

Description of Member	Location of Member	Load Combination[a]	Demand	Capacity	Stress Ratio[b]
W24x100	Annulus platform @ el 140 ft	D + DDE + THA + FV + RVOT	28 (Unit 2)	37.4	1.34
W21x96	"	"	18 (Unit 2)	37.4	2.08
W21x68	"	"	21 (Unit 2)	37.4	1.78
W21x55	"	"	16 (Unit 2)	37.4	2.33
W24x100	"	D + HE	21 (Unit 2)	44.8	2.13
W21x96	"	"	20 (Unit 2)	44.8	2.21
W21x68	"	"	17 (Unit 2)	44.8	2.64
W21x55	"	"	13 (Unit 2)	44.8	3.45
W12x65	Annulus platform column	D + DDE + THA + FV + RVOT	260 (Unit 2)	45.6	1.75
W12x99	"	"	270 (Unit 2)	45.6	1.69
W12x65	"	D + HE	357 (Unit 2)	55.7	1.56
W12x99	"	D + HE	365 (Unit 2)	55.7	1.53

TABLE 3.8-5A

CONTAINMENT BUILDING PIPEWAY STRUCTURE STRESS RATIOS IN SELECTED MEMBERS

Description of Membe r	Location of Member Unit	Location of Member Elevation	Load Combination	Stress Ratio[a]
W8 x 40	1	114	D + DE	1.10
W8 x 40	1	114	D + DE	1.07
W8 x 40	1	114	D + DE	1.07
W14 x 111	2	109	D + DE	1.72
W14 x 111	2	109	D + DE	1.79
W14 x 111	2	109	D + DE	1.59
W8 x 40	1	114	D + DDE	1.11
W8 x 40	1	114	D + DDE	1.20
W8 x 40	1	114	D + DDE	1.20
W14 x 111	2	109	D + DDE	2.78
W14 x 111	2	109	D + DDE	1.89
W14 x 111	2	109	D + DDE	1.92
W8 x 40	1	114	D + DDE + Yr	1.06
W14 x 111	1	119	D + DDE + Yr	1.27
W14 x 202	1	119	D + DDE + Yr	1.32
W14 x 202	2	114	D + DDE + Yr	1.52
W8 X 17	2	109	D + DDE + Yr	1.11
W14 x 111	2	109	D + DDE + Yr	1.25
W8 x 40	1	114	D + HE	1.05
W8 x 40	1	114	D + HE	1.09
W8 x 40	1	114	D + HE	1.05
W14 x 111	2	109	D + HE	1.03
W10 x 31	2	109	D + HE	1.06
W12 x 106	2	138	D + HE	1.11

(a) Stress ratio = $\frac{\text{Capacity}}{\text{Demand}}$

TABLE 3.8-5B

CONTAINMENT AND AUXILIARY BUILDINGS COMPARISON OF DISPLACEMENTS AND SEPARATIONS

	Maximum Relative Seismic Displacement[a]			
Elevation (ft)	DDE	HE	Minimum Separation (in.)[c]	Minimum Factor of Safety Against Contact[e]
188	6.76	9.59	22	2.06
140	0.44	0.37	8	5.29
115	0.27	0.23	2[d]	3.05
100	0.17	0.11	1.25[d]	4.12

(a) Maximum relative seismic displacements are calculated as sum of maximum containment and auxiliary building displacements.

(b) Not Used.

(c) Minimum separation is measured at normal ambient temperature and pressure.

(d) Except for a few localized areas, the minimum separation is 4 inches at elevations 100 ft and 115 ft.

(e) The factor of safety is determined from the relative seismic displacements after the thermal and pressure effects are conservatively accounted for.

TABLE 3.8-6

VERIFICATION OF COMPUTER PROGRAMS

Program Name	General Function	Verification Measure
AISCBM/CE401	Analysis, design, and investigation of structural steel framing system in accordance with AISC specification	Bechtel Verification Manual
ANSR	Linear/nonlinear static and dynamic analysis finite-element program	URS/Blume QA Manual
AXIDYN	Static and dynamic analysis of axisymmetric structures	URS/Blume QA Manual
BLUME SAP IV	General-purpose linear elastic finite-element static and dynamic analysis	URS/Blume QA Manual
BSAP/CE800	General-purpose linear elastic finite-element static and dynamic analysis	Bechtel Verification Manual
BSAP-POST/ CE201&CE217	Postprocessing for BSAP computer program	Bechtel Verification Manual
CECAP/CE987	Computes stress in rebars and liner plate by considering cracking in concrete	Bechtel Verification Manual
Drain-2D	Nonlinear 2-D static and dynamic analysis	URS/Blume QA Manual
FINEL/CE801	Performs finite element static analysis by considering cracking and yielding	Bechtel Verification Manual
LOCAL STRESS/ME210	Calculates local stress in cylindrical shells due to external loading	Bechtel Verification Manual
SMIS	Matrix manipulation program	URS/Blume QA Manual
SPECTRA/CE802	Computes response spectra from acceleration time-histories	Bechtel Verification Manual
STAND/ME425	Design and evaluation of pipe support base plate with concrete anchor bolt assemblies	Bechtel Verification Manual

TABLE 3.8-6

Program Name	General Function	Verification Measure
THERMAL STRESS/ ME643	Performs thermal and stress analysis for 2-D plane or axisymmetric structures	Bechtel Verification Manual
BECHTEL ANSYS/ CE798	Large general-purpose linear/nonlinear static and dynamic analysis	Bechtel Verification Manual
BECHTEL STRUDL/ CE901	Finite element static/dynamic analysis, and design of structures	Bechtel Verification Manual
EASE2/E2SPEC	Linear elastic finite-element static and dynamic analysis computer program	Verification by Control Data Corporation
PG&E STRUDL	General purpose static and dynamic structural analysis	Partial verification of program as originally received. Complete verification performed on a case-by-case basis for each application.
GTSTRUDL/CE701	General-purpose static and dynamic finite element code	Verification by Control Data Corporation
PIPERUP	Performs nonlinear elastic/plastic analysis of 3-D piping system subject to static/dynamic time-history forcing functions	Nuclear Services Corporation Verification Manual
STARDYNE/CE991	General-purpose finite-element static and dynamic analysis	Bechtel Verification Verification
RAP	Pipe whip restraint design program	Nuclear Services Corporation Verification Manual
WECAN	Modal superposition time history analysis and static analysis of structure	Westinghouse Verification Manual

TABLE 3.8-6

Program Name	General Function	Verification Measure
SAP90	General-purpose linear elastic finite-element static and dynamic analysis	Computers and Structures, Inc. Verification Manual
SAP2000	General-purpose linear and non-linear finite-element program for static and dynamic analysis	Computers and Structures, Inc. Verification Manual
PC-SPECTRA	Pre- and post-processor for response spectra data	PG&E Nuclear Computer Program Acceptance Report
PC-ANSR	Linear/Nonlinear static and dynamic analysis finite-element program	PG&E Calculation No. 2252C-1 (Reference 40)

TABLE 3.8-6A

AVERAGE CONCRETE STRENGTH

CONTAINMENT AND INTERIOR STRUCTURE

Component	Average f_c' (test value) (psi)	E_c[(a)] (psi)
Base slab to elevation 87 ft	6330	4.53×10^6
Skin pour at elevation 89 ft	6330	4.53×10^6
Interior	6330	4.53×10^6
Skin pour	3850	3.54×10^6
Soldier beams	3850	3.54×10^6
Exterior walls	3850	3.54×10^6
Dome	3850	3.54×10^6

(a) $E_c = 57{,}000\ (f_c')^{1/2}$ per AC1 318-71, in psi

TABLE 3.8-6B

STEEL STRENGTH DATA

CONTAINMENT AND INTERIOR STRUCTURE

Structure	Designation of Steel	Yield (psi) Minimum	Yield (psi) Average	Ultimate (psi) Minimum	Ultimate (psi) Average
		Reinforcing Steel			
Containment (1 and 2) Exterior #18s	ASTM 615, Grade 60	61,750	66,854	93,750	105,992
Containment (1 and 2) Interior #11s	Grade 60	62,820	68,079	96,795	105,556
		Structural Steel			
ASTM	A36	36,100	43,950	58,200	68,040
ASTM	A441	42,100	51,620	67,200	75,910
ASTM	A516	45,800	51,040	72,200	79,170

TABLE 3.8-7

AUXILIARY BUILDING
FUEL HANDLING CRANE SUPPORT STRUCTURE
STRUCTURAL MEMBERS AND ANCHORAGES STRESS RATIOS

Description Of Members And Their Functions		Stress Ratios[(a) (b)] Hosgri	DDE	DE
BRACES	Top Chord Roof	1.7	1.5	1.9
	Bottom Chord Roof	1.1	1.2	1.3
	East-West Elevation Diagonals	1.1	1.1	1.4
	N-S Truss Diagonals, West and East Exterior/Interior	1.9	≥ 1.6	≥ 2.0
	East-West Truss Diagonals	1.1	≥ 1.3	≥ 1.1
	East-West Truss Knee	1.1	≥ 1.3	≥ 1.5
CHORDS	North South Trusses, Top	3.4	4.0	4.2
	North South Trusses, Bottom	3.2	4.0	4.3
	East-West Trusses, Top	1.1	1.6	1.9
	East-West Trusses, Bottom	1.1	1.4	1.8
LATERAL & VERTICAL	Frame Horizontals, West and East Sides	4.5	4.8	5.9
	Vertical Columns	1.0	1.1	1.0
	East-West Truss Struts	1.2	1.4	1.6
BASE ANCHORAGE	Axial Tensions	1.0	1.1	1.6
	Axial Compressions	1.3	1.4	1.7
	Lateral Shears	1.9	2.2	2.3

(a) Stress Ratio = $\frac{\text{Capacity}}{\text{Demand}}$

(b) Refer to Reference 39 for stress ratios.

TABLE 3.8-8

AUXILIARY BUILDING SLABS STRESS RATIOS[a][b]
OUT-OF-PLANE LOADS (DE)

Slab Location	Member	Shear, psi Demand	Shear, psi Capacity	Moment, kips-ft Demand	Moment, kips-ft Capacity	Stress Ratio
El 73 ft						
Area bounded by column[c]	Slab	49	60	24	30	1.2
lines H, U, 15.7, 16.8	Beam	48	60	100	140	1.2
El 85 ft						
Area bounded by column lines H, U, 16.8, 19.2	Slab	64	78	82	120	1.2
El 100 ft & 115 ft						
Area bounded by column[c]	Slab	48	78	75	88	1.2
lines H, T, 10.7, 15.7	Beam	70	120	340	470	1.4
El 115 ft						
Area bounded by column lines U, V, 15.7, 20.3	Slab	45.0	78.0	27.0	32.00	1.2
El 115 ft						
Area bounded by column	Slab	59	78	56	67	1.2
lines H, L.5, 15.7, 20.3	Beam	170	210	2,000	2,400	1.2
El 140 ft						
Area bounded by column[c]	Slab	120	130	2,050	2,390	1.1
lines H, T, 10.7, 15.7	Beam	130	140	1450	1640	1.1
El 140 ft						
Area bounded by column[c]	Slab	55	78	59	77	1.3
lines R, V, 15.7, 17.4	Beam	89	97	2,010	2,240	1.1
El 140 ft						
Area bounded by column lines H, L, 15.7, 20.3	Slab	57.0	78.0	382.0	455.00	1.2
El 154-1/2 ft						
Area bounded by column	Slab	30	78	14	17	1.2
lines L, R, 15.7, 17.4	Beam	60	78	76	100	1.3
El 163-1/3 ft						
Area bounded by column lines H, L, 15.7, 20.3	Composite[d] Beam	9,300	14,000	2,260	2,300	1.02

(a) Stress ratio = $\frac{\text{Capacity}}{\text{Demand}}$ for shear or moment, whichever is smaller.
(b) This does not include the effects of pipe break loads which are evaluated locally in accordance with provisions of Reference 6.
(c) Counterpart in Unit 2 is similar.
(d) These values are for structural steel beams embedded in the slab.

TABLE 3.8-9

AUXILIARY BUILDING SLABS STRESS RATIOS[a][b]
OUT-OF-PLANE LOADS (DDE)

Slab Location	Member	Shear, psi Demand	Shear, psi Capacity	Moment, kips-ft Demand	Moment, kips-ft Capacity	Stress Ratio
El 73 ft						
Area bounded by column[c]	Slab	53	91	27	56	1.7
lines H, U, 15.7, 16.8	Beam	53	93	110	260	1.8
El 85 ft						
Area bounded by column lines H, U, 16.7, 19.2	Slab	72	120	93	220	1.7
El 100 ft & 115 ft						
Area bounded by column[c]	Slab	51	120	81	167	2.1
lines H, T, 10.7, 15.7	Beam	130	200	360	900	1.5
El 115 ft						
Area bounded by column lines U, V, 15.7, 20.3	Slab	49	120	30	62	2.1
El 115 ft						
Area bounded by column	Slab	66	120	63	130	1.8
lines H, L.5, 15.7, 20.3	Beam	190	330	2,200	4,600	1.7
El 140 ft						
Area bounded by column[c]	Slab	120	190	2,110	4,310	1.6
lines H, T, 10.7, 15.7	Beam	130	200	1,500	3,140	1.5
El 140 ft						
Area bounded by column[c]	Slab	56	120	60	150	2.1
lines R, V, 15.7, 17.4	Beam	93	150	2,110	4,030	1.9
El 140 ft						
Area bounded by column lines H, L, 15.7, 20.3	Slab	61	120	411	858	2.0
El 154-1/2 ft						
Area bounded by column	Slab	32	120	15	33	2.2
lines L, R, 15.7, 17.4	Beam	64	120	81	190	1.6
El 163-1/3 ft						
Area bounded by column lines H, L, 15.7, 20.3	Composite[d] Beam	11,000	20,000	2,200	3,100	1.4

(a) Stress ratio = $\frac{\text{Capacity}}{\text{Demand}}$ for shear or moment, whichever is smaller.
(b) This does not include the effects of pipe break loads which are evaluated locally in accordance with provisions of Reference 6.
(c) Counterpart in Unit 2 is similar.
(d) These values are for structural steel beams embedded in the slab.

TABLE 3.8-10

AUXILIARY BUILDING SLABS STRESS RATIOS[a][b]
OUT-OF-PLANE LOADS (HE)

Slab Location	Member	Shear, psi Demand	Shear, psi Capacity	Moment, kips-ft Demand	Moment, kips-ft Capacity	Stress Ratio
El 73 ft						
Area bounded by column[c]	Slab	65	110	32	56	1.7
lines H, U, 15.7, 16.8	Beam	63	110	130	260	1.7
El 85 ft						
Area bounded by column lines H, U, 16.8, 19.2	Slab	91	130	120	270	1.4
El 100 ft & 115 ft						
Area bounded by column[c]	Slab	68	130	110	200	1.8
lines H, T, 10.7, 15.7	Beam	170	220	480	1,100	1.3
El 115 ft						
Area bounded by column lines U, V, 15.7, 20.3	Slab	60.0	130.00	36.0	74.00	2.0
El 115 ft						
Area bounded by column	Slab	100	130	120	150	1.2
lines H, L.5, 15.7, 20.3	Beam	300	360	4,300	5,500	1.2
El 140 ft						
Area bounded by column[c]	Slab	160	200	2,720	5,220	1.3
lines H, T, 10.7, 15.7	Beam	170	200	2,140	3,770	1.2
El 140 ft						
Area bounded by column[c]	Slab	72	130	79	180	1.8
lines R, V, 15.7, 17.4	Beam	145	160	3,280	4,870	1.1
El 140 ft						
Area bounded by column lines H, L, 15.7, 20.3	Slab	105.0	130.00	710.0	1,062.00	1.2
El 154-1/2 ft						
Area bounded by column[c]	Slab	65	130	29	41	1.4
lines L, R, 15.7, 17.4	Beam	92	130	150	230	1.4
El 163-1/3 ft						
Area bounded by column lines H, L, 15.7, 20.3	Composite[d] Beam	16,000	24,000	3,900	4,200	1.1

(a) Stress ratio = $\frac{\text{Capacity}}{\text{Demand}}$ for shear or moment, whichever is smaller.
(b) This does not include the effects of pipe break loads which are evaluated locally in accordance with provisions of Reference 6.
(c) Counterpart in Unit 2 is similar.
(d) These values are for structural steel beams embedded in the slab.

TABLE 3.8-11

AUXILIARY BUILDING SLABS STRESS RATIOS[f]
IN-PLANE LOADS (DE)

Elevation, ft	Section[e][g] Number	Shear[c], kip		Moment[d], k-ft		Stress Ratio
		Demand	Capacity[a]	Demand	Capacity[b]	
100	1-a	60	2,200	2,650	25,300	9.5
100	1-b	170	2,300	5,700	21,600	3.8
100	2-a	320	2,880	9,500	91,900	9.0
100	2-b	110	1,060	700	6,350	9.1
100	2-c	10	220	50	600	>10.0
115	1	300	2,240	7,350	23,200	3.2
115	2-a	240	4,350	200	50,900	>10.0
115	2-b	120	490	2,100	4,100	2.0
115	3-a	260	1,260	2,650	7,700	2.9
115	3-b	280	1,280	2,150	18,100	4.6
115	4	1,460	8,100	29,700	289,000	5.5
140	1	380	2,240	2,500	4,800	1.9
140	2-a	320	4,130	5,100	64,000	>10.0
140	2-b	270	2,100	3,050	13,800	4.5
140	3-a	160	430	1,950	4,950	2.5
140	3-b	390	1,530	5,900	16,300	2.8
140	4	1,840	8,580	39,500	443,000	4.7

(a) Shear capacity is calculated for the section subjected to demand moment and axial force.
(b) Moment capacity is calculated for the section subjected to demand axial force.
(c) Shear capacities and demands are rounded to the nearest 10 kips or 3 significant digits.
(d) Moment capacities and demands are rounded to the nearest 50 ft-kips or 3 significant digits.
(e) Section location is shown on Figures 3.8-60 through 3.8-62.
(f) Stress ratio = $\frac{\text{Capacity}}{\text{Demand}}$ for shear or moment, whichever is smaller
(g) Component in Unit 2 is similar.

TABLE 3.8-12

AUXILIARY BUILDING SLABS STRESS RATIOS[f]
IN-PLANE LOADS (DDE)

Elevation, ft	Section[e][g] Number	Shear[c], Kip		Moment[d], k-ft		Stress Ratio
		Demand	Capacity[a]	Demand	Capacity[b]	
100	1-a	110	3,710	3,400	73,300	>10.0
100	1-b	310	3,770	9,850	63,100	6.4
100	2-a	610	4,800	14,900	303,000	7.9
100	2-b	200	1,770	1,250	17,000	8.9
100	2-c	10	370	50	1,100	>10.0
115	1	500	3,730	15,400	88,700	5.8
115	2-a	430	7,240	3,550	167,000	>10.0
115	2-b	240	1,130	4,500	16,500	3.7
115	3-a	330	2,090	2,900	12,000	4.1
115	3-b	450	2,140	2,350	42,600	4.8
115	4	2,920	13,500	60,000	1,000,000	4.6
140	1	750	3,730	4,250	43,300	5.0
140	2-a	840	6,890	6,150	200,000	8.2
140	2-b	510	3,500	5,550	36,200	6.5
140	3-a	240	720	2,550	10,300	3.0
140	3-b	590	2,550	8,900	46,400	4.3
140	4	3,700	14,300	79,000	1,110,000	3.9

(a) Shear capacity is calculated for the section subjected to demand moment and axial force.
(b) Moment capacity is calculated for the section subjected to demand axial force.
(c) Shear capacities and demands are rounded to the nearest 10 kips or 3 significant digits.
(d) Moment capacities and demands are rounded to the nearest 50 ft-kips or 3 significant digits.
(e) Section location is shown on Figures 3.8-60 through 3.8-62.
(f) Stress ratio = $\frac{\text{Capacity}}{\text{Demand}}$ for shear or moment, whichever is smaller
(g) Component in Unit 2 is similar.

TABLE 3.8-13

AUXILIARY BUILDING SLABS STRESS RATIOS[f]
IN-PLANE LOADS (HE)

Elevation, ft	Section[e][g] Number	Shear[c], Kip		Moment[d], k-ft		Stress Ratio
		Demand	Capacity[a]	Demand	Capacity[b]	
100	1-a	170	4,350	3,650	86,100	>10.0
100	1-b	510	4,500	13,000	65,000	5.0
100	2-a	930	5,580	18,500	180,000	6.0
100	2-b	290	1,830	1,500	13,300	6.3
100	2-c	20	360	100	1,250	>10.0
115	1	770	3,730	25,000	88,500	3.5
115	2-a	710	7,700	11,300	231,000	>10.0
115	2-b	400	1,120	8,050	16,400	2.0
115	3-a	480	2,330	3,100	14,500	4.7
115	3-b	820	2,500	3,200	48,900	3.0
115	4	3,940	15,500	117,000	1,170,000	3.9
140	1	1,120	3,870	9,200	38,000	3.5
140	2-a	1,170	8,010	7,300	240,000	6.8
140	2-b	900	4,150	7,750	43,100	4.6
140	3-a	450	830	3,250	13,800	1.8
140	3-b	970	3,010	11,300	50,700	3.1
140	4	5,210	14,500	157,000	1,160,000	2.8

(a) Shear capacity is calculated for the section subjected to demand moment and axial force
(b) Moment capacity is calculated for the section subjected to demand axial force
(c) Shear capacities and demands are rounded to the nearest 10 kips or 3 significant digits
(d) Moment capacities and demands are rounded to the nearest 50 ft-kips or 3 significant digits
(e) Section location is shown on Figures 3.8-60 through 3.8-62
(f) Stress ratio = $\frac{\text{Capacity}}{\text{Demand}}$ for shear or moment, whichever is smaller
(g) Component in Unit 2 is similar

TABLE 3.8-14

AUXILIARY BUILDING CONCRETE WALLS
STRESS RATIOS (DE)[a]

Wall Location	Elev., ft	Shear, psi Demand	Shear, psi Capacity[b]	Moment 10^3, k-ft Demand	Moment 10^3, k-ft Capacity[b]	Stress Ratio
On line H (15.7-20.3)	100	120	230	57	188	1.9
	85	160	330	9	173	1.9
On line J (11.7-15.7)[c]	100	130	270	35	126	2.0
	85	150	280	47	126	1.8
On line T(6.4-15.7)[c]	100	75	200	141	343	2.4
	85	85	220	164	664	2.6
On line T (16.8-19.2)	100[d]	55	210	15	65	3.8
On line U.5 (10.3-12.9)[c]	100[d]	45	155	20	113	3.4
On line V (15.7-20.3)	100	50	100	32	250	2.0
	85	50	90	67	245	1.8
On line V (6.4-15.7)[c]	100[d]	70	360	82	200	2.4
On line 6.4 (V-S)[c]	100	80	250	85	158	1.9
	85	100	340	20	31	1.6
On line 10.3 (T-V)[c]	100[d]	80	250	54	146	2.7
On line 12.9 (T-V)[c]	100[d]	80	240	54	145	2.7
On line 15.7 (H-T.6)[c]	100	110	250	382	782	2.1
	85	110	220	481	818	1.7
On line 15.7 (H-T.6)[c]	100	110	260	7	19	2.3
	85	60	170	12	19	1.6

(a) Stress ratio = $\frac{\text{Capacity}}{\text{Demand}}$ for shear or moment, whichever is smaller
(b) Axial demand effect is included in the capacities
(c) Counterpart in Unit 2 is similar
(d) Wall does not extend below elevation 100 ft

TABLE 3.8-15

AUXILIARY BUILDING CONCRETE WALLS
STRESS RATIOS (DDE)[a]

Wall Location	Elev., ft	Shear, psi Demand	Shear, psi Capacity[b]	Moment 10^3, k-ft Demand	Moment 10^3, k-ft Capacity[b]	Stress Ratio
On line H (15.7-20.3)	100	240	390	114	407	1.6
	85	310	550	178	556	1.8
On line J (11.7-15.7)[c]	100	250	450	62	253	1.8
	85	290	460	90	253	1.6
On line T (6.4-15.7)[c]	100	140	340	273	987	2.4
	85	170	370	316	1086	2.2
On line T (16.8-19.2)	100[d]	110	350	31	147	3.2
On line U.5(10.3-12.9)[c]	100[d]	85	260	40	244	3.0
On line V (15.7-20.3)	100	90	170	63	394	1.9
	85	100	150	133	327	1.5
On line V (6.4-15.7)[c]	100[d]	140	600	133	400	3.0
On line 6.4 (V-S)[c]	100	160	420	141	333	2.4
	85	190	570	34	92	2.7
On line 10.3 (T-V)[c]	100[d]	160	420	105	280	2.6
On line 12.9 (T-V)[c]	100[d]	160	410	106	268	2.5
On line 15.7 (H-T.6)[c]	100	220	420	553	1205	1.9
	85	220	370	740	1155	1.6
On line 15.7 (U-V)[c]	100	220	430	13	32	1.9
	85	115	290	23	30	1.3

(a) Stress ratio = $\frac{\text{Capacity}}{\text{Demand}}$ for shear or moment, whichever is smaller
(b) Axial demand effect is included in the capacities
(c) Counterpart in Unit 2 is similar
(d) Wall does not extend below elevation 100 ft

TABLE 3.8-16

AUXILIARY BUILDING CONCRETE WALLS
STRESS RATIOS (HE)[a]

Wall Location	Elev., ft	Shear, psi Demand	Shear, psi Capacity[b]	Moment 10^3, k-ft Demand	Moment 10^3, k-ft Capacity[b]	Stress Ratio
On line H (15.7-20.3)	100	400	480	176	504	1.2
	85	510	630	270	682	1.2
On line J (11.7-15.7)[c]	100	390	500	107	313	1.3
	85	440	580	145	313	1.3
On line T (6.4-15.7)[c]	100	190	310	438	860	1.6
	85	230	320	493	979	1.4
On line T (16.8-19.2)	100[d]	150	350	42	168	2.3
On line U.5 (10.3-12.9)[c]	100[d]	130	190	60	197	1.5
On line V (15.7-20.3)	100	140	200	90	489	1.4
	85	150	170	182	405	1.15
On line V (6.4-15.7)[c]	100[d]	220	640	291	500	1.7
On line 6.4 (V-S)[c]	100	380	460	301	434	1.2
	85	390	450	63	84	1.15
On line 10.3 (T-V)[c]	100[d]	330	480	220	339	1.4
On line 12.9 (T-V)[c]	100[d]	270	460	199	324	1.6
On line 15.7 (H-T.6)[c]	100	330	520	666	1494	1.6
	85	320	450	859	1425	1.4
On line 15.7 (U-V)[c]	100	340	480	19	36	1.4
	85	160	300	30.5	32.6	1.07

(a) Stress ratio = $\frac{\text{Capacity for shear or moment, whichever is smaller}}{\text{Demand}}$
(b) Axial demand effect is included in the capacities
(c) Counterpart in Unit 2 is similar
(d) Wall does not extend below elevation 100 ft

TABLE 3.8-17

AUXILIARY BUILDING COLUMNS STRESS RATIOS[a]

Column Location[b]	Stress Ratio		
	DE	DDE	HE
14 - J.7	2.9	3.7	2.6
15 – N	5.3	7.7	4.8
15 - R.8	3.6	3.3	2.5
15 - J.7	1.04	1.8	1.3
15 – S	1.9	2.9	2.3

(a) Stress ratio = $\frac{\text{Capacity}}{\text{Demand}}$

(b) Counterpart in Unit 2 is similar

TABLE 3.8-18

AUXILIARY BUILDING SHEAR DISSIPATION TO FOUNDATION (DE NORTH-SOUTH)

Building Portion Location[a]	Shear Demand at Elevation 85 ft.					Remarks
	Shear from Upper Level			Inertial Load at El 85 ft, kips	Total, kips	
	Direct Shear, kips	Torsional Shear, kips[b]	Torsional + Direct Shear, kips			
Central Portion	23,600	1,800	25,400	4,400	29,800	Capacity is 57,900 kips
North Wing	2,300 900 200 4,700 600	500 100	2,800 1,000 200 4,700 600	600 600 400	10,900	Load is directly dissipated to the foundation
South Wing	2,300 900 200 4,700 600	500 100	2,800 1,000 200 4,700 600	600 600 400	10,900	Load is directly dissipated to the foundation

Shear Capacity at Elevation 85 ft (Central Portion)

Capacity of diaphragm to dissipate shear force to the foundation at elevation 85 ft (kips)	by bearing	4,700 + 18,000 = 22,700
	by rebar tension	1,100 + 1,100 = 2,200
Shear capacity of walls below elevation 85 ft (kips)		33,000
Total shear capacity at and below elevation 85 ft (kips)		57,900

(a) For building portion location only, see Figures 3.8-63 and 3.8-64
(b) Torsional shears on only one side of the center of rigidity are considered

TABLE 3.8-19

AUXILIARY BUILDING SHEAR DISSIPATION TO FOUNDATION (DE EAST-WEST)

Building Portion Location[a]	Shear Demand at Elevation 85 ft.					Remarks
	Shear from Upper Level			Inertial Load at El 85 ft, kips	Total, kips	
	Direct Shear, kips	Torsional Shear, kips	Torsional + Direct Shear, kips			
Central Portion	35,500	-0-	35,500	4,400	39,900	Capacity is 76,200 kips
North Wing	900 1,100 400 400	-0-	900 1,100 400 400	600 600 400	4,400	Load is directly dissipated to the foundation
South Wing	900 1,100 400 400	-0-	900 1,100 400 400	600 600 400	4,400	Load is directly dissipated to the foundation

Shear Capacity at Elevation 85 ft (Central Portion)

Capacity of diaphragm to dissipate shear force to the foundation at elevation 85 ft (kips)	4,100 4,100
Shear capacity of walls below elevation 85 ft (kips)	68,000
Total shear capacity at and below elevation 85 ft (kips)	76,200

(a) For building portion location only, see Figures 3.8-63 and 3.8-64

TABLE 3.8-20

AUXILIARY BUILDING SHEAR DISSIPATION TO FOUNDATION (DDE NORTH-SOUTH)

Building Portion Location[a]	Shear Demand at Elevation 85 ft.					Remarks
	Shear from Upper Level			Inertial Load at El 85 ft, kips	Total, kips	
	Direct Shear, kips	Torsional Shear, kips[b]	Torsional + Direct Shear, kips			
Central Portion	46,500	3,700	50,200	9,200	59,400	Capacity is 115,700 kips
North Wing	4,300 1,600 400 9,100 1,200	1,000 300 100	5,300 1,900 500 9,100 1,200	1,100 1,100 800	21,000	Load is directly dissipated to the foundation
South Wing	4,300 1,600 400 9,100 1,200	1,000 300 100	5,300 1,900 500 9,100 1,200	1,100 1,100 800	21,000	Load is directly dissipated to the foundation

Shear Capacity at Elevation 85 ft (Central Portion)

Capacity of diaphragm to dissipate shear force to the foundation at elevation 85 ft (kips)	by bearing	11,100 + 42,800 = 53,900
	by rebar tension	1,900 + 1,900 = 3,800
Shear capacity of walls below elevation 85 ft (kips)		58,000
Total shear capacity at and below elevation 85 ft (kips)		115,700

(a) For building portion location only see Figures 3.8-63 and 3.8-64
(b) Torsional shears on only one side of the center of rigidity are considered

TABLE 3.8-21

AUXILIARY BUILDING SHEAR DISSIPATION TO FOUNDATION (DDE EAST-WEST)

Building Portion Location[a]	Shear Demand at Elevation 85 ft.					Remarks
	Shear from Upper Level			Inertial Load at El 85 ft, kips	Total, kips	
	Direct Shear, kips	Torsional Shear, kips	Torsional + Direct Shear, kips			
Central Portion	68,700	-0-	68,700	9,200	77,900	Capacity is 128,000 kips
North Wing	1,600 2,100 900 700	-0-	1,600 2,100 900 700	1,100 1,100 800	8,300	Load is directly dissipated to the foundation
South Wing	1,600 2,100 900 700	-0-	1,600 2,100 900 700	1,100 1,100 800	8,300	Load is directly dissipated to the foundation

Shear Capacity at Elevation 85 ft (Central Portion)

Capacity of diaphragm to dissipate shear force to the foundation at elevation 85 ft (kips)	7,000 7,000
Shear capacity of walls below elevation 85 ft (kips)	114,000
Total shear capacity at and below elevation 85 ft (kips)	128,000

(a) For building portion location only see Figures 3.8-63 and 3.8-64

TABLE 3.8-22

AUXILIARY BUILDING SHEAR DISSIPATION TO FOUNDATION (HE NORTH-SOUTH)[(a)]

Building Portion Location[(a)]	Shear Demand at Elevation 85 ft.					Remarks
	Shear from Upper Level			Inertial Load at El 85 ft, kips	Total, kips	
	Direct Shear, kips	Torsional Shear, kips[(b)]	Torsional + Direct Shear, kips			
Central Portion	63,000	9,000	72,000	12,500	84,500	Capacity is 136,800 kips
North Wing	5,700 2,100 500 12,200 1,700	2,300 500 300	8,000 2,600 800 12,200 1,700	1,600 1,600 1,000	29,500	Load is directly dissipated to the foundation
South Wing	5,700 2,100 500 12,200 1,700	2,300 500 300	8,000 3,600 800 12,200 1,700	1,600 1,600 1,000	29,500	Load is directly dissipated to the foundation

Shear Capacity at Elevation 85 ft (Central Portion)

Capacity of diaphragm to dissipate shear force to the foundation at elevation 85 ft (kips)	by bearing	14,600 + 48,400 = 63,000
	by rebar tension	2,940 + 2,400 = 4,800
Shear capacity of walls below elevation 85 ft (kips)		69,000
Total shear capacity at and below elevation 85 ft (kips)		136,800

(a) For illustration, see Figures 3.8-63 and 3.8-64.
(b) Torsional shears on only one side of the center of rigidity are considered.

TABLE 3.8-23

AUXILIARY BUILDING SHEAR DISSIPATION TO FOUNDATION (HE EAST-WEST)[a]

Building Portion Location[a]	Shear Demand at Elevation 85 ft.					Remarks
	Shear from Upper Level			Inertial Load at El 85 ft, kips	Total, kips	
	Direct Shear, kips	Torsional Shear, kips[b]	Torsional + Direct Shear, kips			
Central Portion	84,700	5,300	90,000	12,500	102,500	Capacity is 154,200 kips
North Wing	2,000 2,500 1,100 900	1,600 1,900 600 100	3,600 4,400 1,700 1,000	1,600 1,600 1,000	14,900	Load is directly dissipated to the foundation
South Wing	2,000 2,500 1,100 900		2,000 2,500 1,100 900	1,600 1,600 1,000	10,700	Load is directly dissipated to the foundation

Shear Capacity at Elevation 85 ft (Central Portion)

Capacity of Diaphragm to Dissipate Shear Force to the Foundation at Elevation 85 ft (kips)	8,600 8,600
Shear Capacity of Walls Below Elevation 85 ft (kips)	137,000
Total Shear Capacity at and Below Elevation 85 ft (kips)	154,200

(a) For illustration, see Figures 3.8-63 and 3.8-64.
(b) Torsional shears on only one side of the center of rigidity are considered.

TABLE 3.8-23A

AUXILIARY BUILDING AND TURBINE BUILDING
COMPARISON OF DISPLACEMENTS AND SEPARATIONS

Elevation (ft)	Maximum Total Displacement (in.)[a] DDE	HE	Separation (in.)	Minimum Factor of Safety Against Contact
163	2.7	4.5	8.0	1.78
140	0.9	0.9	8.0	8.89
115	0.7	1.1	8.0	7.27
100	0.5	0.7	3.0	4.29

(a) Displacements are calculated as sum of maximum auxiliary and turbine building displacements.

TABLE 3.8-24

DUCTILITY[a]

Structure	Blume Ductility	Newmark Ductility	
Containment	1.3[b]	1.0[b]	
Auxiliary Building	1.3[b]	1.0[b]	
		Class I	Class II
Turbine Building	[c]	1.0[b]	[c]
Intake	[c]	1.0[b]	[c, d]

(a) Ductilities are on story basis; however, floor response spectra were, in general, computed on an elastic analysis basis.

(b) Under normal conditions Newmark ductility is 1.0 maximum; higher ductility may be considered for special cases where supporting evidence justifies its use. Blume ductility for Class I structures is 1.3, and may be used only in specific situations.

(c) Concrete 1.3; steel 3, with up to 6 locally.

(d) Or as may be required to demonstrate that function of PG&E Design Class I equipment will not be adversely affected.

TABLE 3.8-25

REFUELING WATER STORAGE TANK
STRESS RATIO[a]

		DL + HS + DE + R_A			DL + HS + DDE + R_A			DL + HS + HE + R_A		
Force Component	Material	Demand	Capacity	Stress Ratio	Demand	Capacity	Stress Ratio	Demand	Capacity	Stress Ratio
Longitudinal force, Kips/ft	Concrete	63.5	96.0	1.51	121.2	216.0	1.78	133.3	216.0	1.62
Circumferential force, kips/ft	Concrete	54.4	96.0	1.76	71.5	216.0	3.02	79.6	216.0	2.71
In plane shear force, kips/ft	Concrete	26.1	45.5	1.74	52.1	77.4	1.49	58.9	77.4	1.31
Longitudinal moment, Kips-ft/ft	Concrete	40.4	78.2	1.94	56.3	179.7	3.19	58.6	179.7	3.07
Stress intensity outside vault opening area, Kips/in^2	Steel	6.4	16.7	2.61	11.2	22.5	2.01	15.4	40.6	2.64
Stress intensity within vault opening area, Kips/in^2	Steel	12.1	16.7	1.38	20.5	22.5	1.10	34.0	40.6	1.19

(a) Stress Ratio = $\frac{\text{Capacity}}{\text{Demand}}$

TABLE 3.8-26

TURBINE BUILDING
STRUCTURAL STEEL MEMBERS
STRESS RATIOS (HE)

Member Description	Stress Ratios[a]
Exterior columns, lines A and G	[b]
East-west roof trusses – chords	1.2[c]
East-west roof trusses – diagonals	1.0[c]
North-south walls diagonal tension bracing	1.1[c]
North-south walls diagonal compression bracing	1.0[c]
Crane runway girder	[b]
Floor beams	[b]

(a) Stress Ratio = $\frac{\text{Capacity}}{\text{Demand}}$

(b) Inelastic deformation occurs, ductility meets limits of Table 3.8-24.

(c) Effects of force redistribution are included.

TABLE 3.8-27

TURBINE BUILDING
CONCRETE MEMBERS
STRESS RATIOS (HE)[a]

Member	Location	Stress Ratios[b]
Wall, line A	Elev. 85 ft (20-30.3)	1.9
Wall, line G	Elev. 85 ft (20-30.3)	1.3
Wall, line 19	Elev. 123 ft (A-G)	1.1
Buttress, line 27	Elev. 85 ft	1.5
Floor slab	Elev. 140 ft line 21 (A-C), line C (19-21)	1.2 1.5[c]
Turbine Pedestal	Frame 6 (See Figure 3.7-15G)	1.0[d]

(a) Stress Ratio = $\frac{\text{Capacity}}{\text{Demand}}$ for shear or moment, whichever is smaller.

(b) Axial demand effect is included in the capacity.

(c) Effects of concrete cracking are considered.

(d) Effects of force distribution are included.

TABLE 3.8-27A

TURBINE BUILDING AND TURBINE PEDESTAL (UNITS 1 & 2)[a]
COMPARISON OF DISPLACEMENTS AND SEPARATIONS AT EL 140 FT
HE ANALYSIS

Side of Pedestal Location	Maximum Calculated Displacement, in.[b]			Minimum Separation, in.[c]	Factor of Safety Against Contact
	Building	Pedestal	Total		
East(U1)	0.53	2.21	2.74	2.88	1.05
West(U1)	0.58	2.21	2.79	3.00	1.08
North(U1)	0.20	0.93	1.13	1.25	1.11
South(U2)	0.21	0.99	1.20	1.31	1.09

(a) Values shown are for Unit 1 or Unit 2, whichever has the lowest factor of safety.

(b) Displacements are an envelope of maximum displacements calculated using envelope of Hosgri Newmark and Blume design response spectra.

(c) Separations are an envelope of minimum as-built separations.

TABLE 3.8-28

INTAKE STRUCTURE
CAPACITIES AND DUCTILITIES OF FLOW STRAIGHTENERS (OR PIERS)[1]

Pier	P (Tension)	M	M_{allow}	U (Ductility)
1	129.0	10,600	15,600	N/A
2	81.5	14,300	15,900	N/A
3	44.6	15,700	16,100	N/A
4	24.1	16,400	16,200	1.24
5	39.1	17,300	16,100	1.33
6	141.0	17,700	15,500	1.44
7	146.0	16,300	15,400	1.32

Notes:

(1) These values are due to the Newmark earthquake, which governs for all piers:

P = Axial tension, kips

M = Moment, in.-kips (value of M based on linear analysis)

M_{allow} = Factored (0=0.90) ultimate moment capacity including tension effects

u = Ductility of tensile steel (ratio between calculated strain to yield strain)

TABLE 3.9-1

LOAD COMBINATIONS AND ACCEPTANCE CRITERIA FOR PRESSURIZER SAFETY AND RELIEF VALVE PIPING

Combination	Plant/System Operation Condition	Load Combination	Piping Allowable Stress Intensity
Upstream of Valves			
1	Normal	N	1.0 S_h
2	Upset	N + DE + SOT_U	1.2 S_h
3	Emergency	N + SOT_E	1.8 S_h
4	Faulted	N + MAX(DDE, HOSGRI) + SOT_F	2.4 S_h
5	Faulted	N + LOCA + MAX(DDE, HOSGRI) + SOT_F	2.4 S_h
Downstream of Valves(Note 1)			
1	Normal	N	1.0 S_h
2	Upset	N + SOT_U	1.2 S_h
3	Upset	N + DE + SOT_U	1.8 S_h
4	Emergency	N + SOT_E	1.8 S_h
5	Faulted	N + MAX(DDE, HOSGRI) + SOT_F	2.4 S_h
6	Faulted	N + LOCA + MAX(DDE, HOSGRI) + SOT_F	2.4 S_h

TABLE 3.9-1

NOTES:

(1) This table is applicable to the seismically designed portion of downstream PG&E Design Class II and III piping necessary to isolate the response, and to assure acceptable valve loading on the discharge nozzle.

(2) Refer to SOT definitions and other load abbreviations.

(3) The bounding number of valves (and discharge sequence if setpoints are significantly different) for the applicable system operating transient defined on this sheet should be used.

(4) Use SRSS for combining dynamic load responses.

Abbreviations

N	=	Sustained loads during normal plant operation
SOT	=	System Operating Transient
SOT_U	=	Relief Valve Discharge Transient
SOT_E	=	Safety Valve Discharge Transient
SOT_F	=	Max (SOT_U; SOT_E)
DE	=	Design Earthquake
DDE	=	Double Design Earthquake
HOSGRI	=	Hosgri earthquake
LOCA	=	Loss-of-coolant accident
S_h	=	Basic material allowable stress at maximum (hot) temperature

TABLE 3.9-2

HOSGRI AND DDE SEISMIC LOADING COMBINATIONS AND STRUCTURAL CRITERIA MECHANICAL EQUIPMENT[1]

COMPONENT (2, 3)	LOADING COMBINATIONS (4)	CRITERIA (7, 8, 9, 10, 11, 12, 13, 14)	
Tanks, Heat Exchangers, Filters, Demineralizers	Deadweight + Pressure + HOSGRI/DDE + Nozzle/Piping Loads	σ_m	$\leq 2.0S$
		$(\sigma_m$ or $\sigma_L) + \sigma_b$	$\leq 2.4S$
Active Pumps	Deadweight + Pressure + HOSGRI/DDE + Nozzle/Piping Loads + Operating Loads	σ_m	$\leq 1.2S$
		$(\sigma_m$ or $\sigma_L) + \sigma_b$	$\leq 1.8S$
Inactive Pumps	Deadweight + Pressure + HOSGRI/DDE + Nozzle/Piping Loads + Operating Loads	σ_m	$\leq 2.0S$
		$(\sigma_m$ or $\sigma_L) + \sigma_m$	$\leq 2.4S$
Active Valves	Deadweight + Pressure + HOSGRI/DDE + Nozzle/Piping Loads + Operating Loads[12]	Extended Structure:	$\sigma_m \leq 1.2S$ $(\sigma_m$ or $\sigma_L)$ $+ \sigma_b \leq 1.8S$ or S_y (higher of)
		Pressure Boundary: Valve Nozzles:	ANSI B16.5 or MSS-SP-66 [5]
		Bolting:	$\sigma_m \leq 2.0S$
Inactive Valves	Deadweight + Pressure + HOSGRI/DDE + Nozzle/Piping Loads + Operating Loads[12]	Extended Structure:	$\sigma_m \leq 2.0S$ $(\sigma_m$ or $\sigma_L)$ $+ \sigma_b \leq 2.4S$
		Pressure Boundary: Valve Nozzles:	ANSI B16.5 or MSS-SP-66 [6]
		Bolting:	$\sigma_m \leq 2.0S$

TABLE 3.9-2

COMPONENT (2, 3)	LOADING COMBINATIONS (4)	CRITERIA (7, 8, 9, 10, 11, 12, 13, 14)	
Inactive Cast Iron Pressure Retaining Components	Deadweight + Pressure + HOSGRI/DDE + Nozzle/Piping Loads + Operating Loads(12)	σ_p	$0.1\ S_u$
		$(\sigma_m$ or $\sigma_L) + \sigma_b$	$\leq 2.4 \times 0.1\ S_u$
Inactive Cast Iron Non-pressure Retaining Components	Deadweight + Pressure + HOSGRI/DDE + Nozzle/Piping Loads + Operating Loads(12)	$(\sigma_m$ or $\sigma_L) + \sigma_b$	$\leq 2.0 \times 0.2\ S_u$

Notes:

(1) Refer to Chapter 5 Table 5.2-8 for structural components.

(2) Active: Mechanical equipment which is needed to go from normal full power operation to safe shutdown following the earthquake and which must perform mechanical motions during the course of accomplishing its design function. For DCPP, safe shutdown is defined as Mode 5 following a Hosgri earthquake.

(3) Inactive: Mechanical Equipment which is not required to perform mechanical motions in taking the plant from normal full power operation to safe shutdown following the earthquake. For DCPP, safe shutdown is defined as Mode 5 following a Hosgri earthquake.

(4) Nozzle loads shall include piping loads transmitted to the component during the HOSGRI/DDE earthquake.

(5) Piping loads at piping/active-valve interfaces shall be limited such that maximum fiber stresses in the piping at the interface are less than the piping yield strength at temperature (S_y).

(6) Valves, being stronger than the attached piping and having a proven history without any gross failures of pressure boundaries, can safely transmit piping loads without compromising their pressure retaining integrity. Therefore piping integrity assures valve integrity.

(7) σ_m = General membrane stress. This stress is equal to the average stress across the solid section under consideration, excludes discontinuities and concentrations and is produced only by mechanical loads.

TABLE 3.9-2

Notes: (Cont'd)

(8) σ_L = Local membrane stress. This stress is equal to the same as σ_m except that it includes the effect of discontinuities.

(9) σ_b = Bending stress. This stress is equal to the linear varying portion of the stress across the solid section under consideration, excludes discontinuities and concentrations, and is produced only by mechanical loads.

(10) S = 1971 or 1974 ASME Code allowable stress. The allowable stress shall correspond to the highest metal temperature at the section under consideration during the condition consideration.

(11) S_y = 1971 or 1974 ASME Code minimum yield stress. The yield stress shall correspond to the highest metal temperature at the section under consideration during the condition consideration.

(12) Except racked-out valves.

(13) σ_p = Local membrane stress. This stress is equal to the average stress across the solid section under consideration. It excludes discontinuities and concentrations and is produced only by pressure.

(14) S_u = Material minimum tensile strength listed in either the code the component was purchased and manufactured under, or ASME Code Section III.

TABLE 3.9-3

HOSGRI AND DDE SEISMIC LOADING COMBINATIONS AND
STRUCTURAL CRITERIA MECHANICAL EQUIPMENT
SUPPORTS AND STRUCTURAL COMPONENT[1]

ELEMENT	LOADING COMBINATIONS (4, 5)	CRITERIA (6, 7, 8, 9, 10, 11, 12, 13)	
Linear[3]	Deadweight + HOSGRI/DDE + Nozzle/Piping Loads	1974 ASME Code Appendix XVII, Subsection NF, and Appendix F or AISC Manual, 7th Edition[11] (Stresses not to exceed S_y for active components supports)	
Plate and shell[2] (active components)	Deadweight + HOSGRI/DDE + Nozzle/Piping Loads	σ_m	$\leq 1.2S$
		$(\sigma_m + \sigma_b)$	$\leq 1.8S$ or S_y
Plate and shell (inactive components)	Deadweight + HOSGRI/DDE + Nozzle/Piping Loads	σ_m	$\leq 2.0S$
		$(\sigma_m + \sigma_b)$	$\leq 2.4S$
Bolts	Deadweight + HOSGRI/DDE + Nozzle/Piping Loads	1974 ASME Code Section III, Appendix XVII, Code Case 1644-6 and Appendix F, or AISC Manual, 7th Edition	

Notes:

(1) Includes reactor cavity manipulator crane, spent fuel pit bridge crane, flux mapping transfer devices and RCS seal table and parts. Qualification of flux mapping transfer device, not required for DDE (required for HOSGRI only in order to insure structural integrity and preclude seismic interaction).

(2) Plate and shell type supports: Plate and shell type components supports are supports such as vessel skirts and saddles which are fabricated from plate and shell elements and are normally subjected to a biaxial stress field.

TABLE 3.9-3

Notes (Continued):

(3) Linear type support: A linear type component support is defined as acting under essentially as single components of direct stress. Such elements may also be subjected to shear stresses. Examples of such structural elements are: tension and compression struts, beams and columns subjected to bending, trusses, frames, rings, arches, and cables.

(4) Nozzle loads shall be those nozzle loads acting on the supported components during the HOSGRI/DDE earthquake.

(5) Plus operating loads, as applicable.

(6) σ_m = General membrane stress. This stress is equal to the average stress across the solid section under consideration, excludes discontinuities and concentrations and is produced only by mechanical loads.

(7) σ_b = Bending stress. This stress is equal to the linear varying portion of the stress across the solid section under consideration, excludes discontinuities and concentrations, and is produced only by mechanical loads.

(8) S = 1971 or 1974 ASME Code allowable stress value. The allowable stress shall correspond to the highest metal temperature at the section under consideration during the condition under consideration.

(9) S_y = 1971 or 1974 ASME Code minimum yield stress. The yield stress shall correspond to the highest metal temperature at the section under consideration during the condition under consideration.

(10) For the reactor cavity manipulator crane, the spent fuel pit bridge crane, and the flux mapping transfer device, the stress limits for the above loading combinations are obtained by increasing the normal condition allowable stresses by a factor of 1.7.

(11) The reference, "AISC Manual, 7th Edition," where used in this section, refers to the AISC Code, Part 5, "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings," 1969 version.

(12) σ_p = Local membrane stress. This is equal to the average stress across the solid section under consideration. It excludes discontinuities and concentrations and is produced only by pressure.

(13) S_u = Material minimum tensile strength listed in either the code the component was purchased and manufactured under, or ASME Code Section III.

TABLE 3.9-4

DE SEISMIC LOADING COMBINATIONS AND
STRUCTURAL CRITERIA MECHANICAL EQUIPMENT[1]

COMPONENT (2, 3)	LOADING COMBINATIONS (4)	CRITERIA (7, 8, 9, 10, 11, 12, 13, 14)	
Tanks, heat-exchangers filters, demineralizers	Deadweight + Pressure + DE + Nozzle/Piping Loads.	σ_m	$\leq 1.0S$[13]
		$(\sigma_m$ or $\sigma_L) + \sigma_b$	$\leq 1.65S$
Active pumps	Deadweight + Pressure + DE + Nozzle/Piping Loads + Operating Loads.	σ_m	$\leq 1.1S$
		$(\sigma_m$ or $\sigma_L) + \sigma_b$	$\leq 1.65S$
Inactive pumps	Deadweight + Pressure + DE + Nozzle/Piping Loads + Operating Loads.	σ_m	$\leq 1.1S$
		$(\sigma_m$ or $\sigma_L) + \sigma_b$	$\leq 1.65S$
Active valves	Deadweight + Pressure + DE + Nozzle/Piping Loads + Operating Loads.[11]	Extended structure:	$\sigma_m \leq 1.1S$ $(\sigma_m$ or $\sigma_L)$ $+ \sigma_b \leq 1.0S_y$
		Pressure boundary: valve nozzles:	ANSI B16.5 or MSS-SP-66 [6]
		bolting:	$\sigma_b \leq 2.0S$
Inactive valves	Deadweight + Pressure + DE + Nozzle/Piping Loads + Operating Loads.[11]	Extended structure:	$\sigma_b \leq 1.1S$ $(\sigma_m$ or $\sigma_L)$ $+ \sigma_b \leq 1.0S_y$
		Pressure boundary: valve nozzles:	ANSI B16.5 or MSS-SP-66 [6]
		bolting:	$\sigma_m \leq 2.0S$

TABLE 3.9-4

COMPONENT (2, 3)	LOADING COMBINATIONS (4)	CRITERIA (7, 8, 9, 10, 11, 12, 13, 14)	
Inactive cast iron, pressure retaining components	Deadweight + Pressure + DE + Nozzle/Piping Loads + Operating Loads(11)	σ_p	$\leq 0.1\ S_u$
		$(\sigma_m$ or $\sigma_L) + \sigma_b$	$\leq 1.5 \times 0.1\ S_u$
Inactive cast iron non-pressure retaining Components	Deadweight + Pressure + DE + Nozzle/Piping Loads + Operating Loads(11)	$(\sigma_m$ or $\sigma_L) + \sigma_b$	$\leq 1.0 \times 0.2\ S_u$

Notes:

(1) Refer to Chapter 5, Table 5.2.8 for structural components.

(2) Active: Mechanical equipment which is needed to go from normal full power operation to safe shutdown following the earthquake and which must perform mechanical motions during the course of accomplishing its design function. For DCPP, safe shutdown is defined as Mode 5 following a Hosgri earthquake.

(3) Inactive: Mechanical equipment which is not required to perform mechanical motions in taking the plant from normal full power operations to safe shutdown following the earthquake. For DCPP, safe shutdown is defined as Mode 5 following a Hosgri earthquake.

(4) Nozzle loads shall include piping loads transmitted to the component during the DE earthquake.

(5) Deleted.

(6) Valves, being stronger than the attached piping and having a proven history without any gross failures of pressure boundaries, can safely transmit piping loads without compromising their pressure retaining integrity. Therefore, piping integrity assures valve integrity.

(7) σ_m = General membrane stress. This stress is equal to the average stress across the solid section under consideration, excludes discontinuities and concentrations and is produced only by mechanical loads.

(8) σ_L = Local membrane stress. This stress is the same as σ_m except that it includes the effect of discontinuities.

TABLE 3.9-4

Notes (Continued):

(9) σ_b = Bending stress. The stress is equal to the linear varying portion of the stress across the solid section under consideration, excludes discontinuities and concentrations, and is produced only by mechanical loads.

(10) S = 1971 or 1974 ASME code allowable stress value. The allowable stress shall correspond to the highest metal temperature at the section under consideration during the condition under consideration.

(11) Except racked-out valves.

(12) The primary membrane stress limit for pressure vessels under DE loading is conservatively selected to be lower than the level permitted by the present ASME Code, in order to insure that it is also conservative with respect to earlier editions of the code of which these components were designed.

(13) σ_p = Local membrane stress. This is equal to the average stress across the solid section under consideration. It excludes discontinuities and concentrations and is produced only by pressure.

(14) S_u = Material minimum tensile strength listed in either the code the component was purchased and manufactured under, or ASME Code Section III.

(15) S_y = 1971 or 1974 ASME Code minimum yield stress. The yield stress shall correspond to the highest metal temperature at the section under consideration during the condition under consideration.

TABLE 3.9-5

DE SEISMIC LOADING COMBINATION
STRUCTURAL CRITERIA MECHANICAL EQUIPMENT SUPPORTS
AND STRUCTURAL COMPONENTS[1]

ELEMENT (2, 3)	LOADING COMBINATIONS (4,5)	CRITERIA (6,7, 8)
Linear[3]	Deadweight + DE + Nozzle/Piping Loads	1974 ASME Code Section III Appendix XVII, Subsection NF or AISC Manual, 7th Edition.
Plate and shell[2] (active components)	Deadweight + DE + Nozzle/Piping Loads	$\sigma_m \leq 1.0S$ $(\sigma_m + \sigma_b) \leq 1.5S$
Plate and shell (inactive components)	Deadweight + DE + Nozzle/Piping Loads	$\sigma_m \leq 1.0S$ $(\sigma_m + \sigma_b) \leq 1.5S$
Bolts	Deadweight + DE + Nozzle/Piping Loads	1974 ASME Code Section III Appendix XVII, Code Case 1644-6 or AISC Manual, 7th Edition.

TABLE 3.9-5

Notes:

(1) Includes RCS seal table and parts. Qualification of reactor cavity manipulator crane and spent fuel pit bridge crane and flux mapping transfer device not required for DE. Structural integrity insured by HOSGRI qualification.

(2) Plate and shell type supports: Plate and shell type component supports are supports such as vessel skirts and saddles which are fabricated from plate and shell elements and are normally subjected to a biaxial stress field.

(3) Linear type support: A linear type component support is defined as acting under essentially a single component of direct stress. Such elements may also be subjected to shear stresses. Examples of such structural elements are: tension and compression struts, beams and columns subjected to bending, trusses, frames, rings, arches, and cables.

(4) Nozzle loads shall be those nozzle loads acting on the supported component during the DE earthquake.

(5) Plus Operating Loads, as applicable.

(6) σ_m = General membrane stress. This stress is equal to the average stress across the solid section under consideration, excludes discontinuities and concentrations and is produced only by mechanical loads.

(7) σ_b = Bending stress. This stress is equal to the linear varying portion of the stress across the solid section under consideration, excludes discontinuities and concentrations, and is produced only by mechanical loads.

(8) S = 1971 or 1974 ASME code allowable stress value. The allowable stress shall correspond to the highest metal temperature at the section under consideration during the condition under consideration.

TABLE 3.9-6

NORMAL CONDITIONS LOADING COMBINATIONS AND
STRUCTURAL CRITERIA MECHANICAL EQUIPMENT[1]

COMPONENT (2, 3)	LOADING COMBINATIONS (4)	CRITERIA (7, 8, 9, 10, 11, 12, 13)	
Tanks, heat-exchangers filters, demineralizers	Deadweight + Pressure + Nozzle/ Piping Loads.	σ_m $(\sigma_m$ or $\sigma_L) + \sigma_b$	$\leq 1.0S$ $\leq 1.5S$
Active pumps	Deadweight + Pressure + Nozzle/ Piping Loads + Operating Loads.	σ_m $(\sigma_m$ or $\sigma_L) + \sigma_b$	$\leq 1.0S$ $\leq 1.5S$
Inactive pumps	Deadweight + Pressure + Nozzle/ Piping Loads + Operating Loads.	σ_m $(\sigma_m$ or $\sigma_L) + \sigma_b$	$\leq 1.0S$ $\leq 1.5S$
Active valves	Deadweight + Pressure + Nozzle/ Piping Loads + Operating Loads.	Extended Structure:	$\sigma_m \leq 1.0S$ $(\sigma_m$ or $\sigma_L)$ + $\sigma_b \leq 1.5S$
		Pressure Boundary: Valve Nozzles: Bolting:	ANSI B16.5 or MSS-SP-66 (6) $\sigma_m \leq 2.0S$
Inactive valves	Deadweight + Pressure + Nozzle/ Piping Loads + Operating Loads.	Extended Structure:	$\sigma_m \leq 1.1S$ $(\sigma_m$ or $\sigma_L)$ $+ \sigma_b \leq 1.5S$
		Pressure Boundary: Valve Nozzles: Bolting:	ANSI B16.5 or MSS-SP-66 (6) $\sigma_m \leq 2.0S$

TABLE 3.9-6

COMPONENT (2, 3)	LOADING COMBINATIONS (4)	CRITERIA (7, 8, 9, 10, 11, 12, 13)	
Inactive cast iron, pressure retaining Components	Deadweight + Pressure + Nozzle/Piping Loads + Operating Loads(12)	σ_p $(\sigma_m$ or $\sigma_L) + \sigma_b$	$\leq 0.1\ S_u$ $\leq 1.5 \times 0.1\ S_u$
Inactive cost iron non-pressure retaining Components	Deadweight + Pressure + Nozzle/Piping Loads + Operating Loads(12)	$(\sigma_m$ or $\sigma_L) + \sigma_b$	$\leq 1.0 \times 0.2\ S_u$

Notes:

(1) Refer to Chapter 5, Table 5.2.8 for structural components.

(2) Active: Mechanical equipment which is needed to go from normal full power operation to safe shutdown following the earthquake and which must perform mechanical motions during the course of accomplishing its design function. For DCPP, safe shutdown is defined as Mode 5 following a Hosgri earthquake.

(3) Inactive: Mechanical equipment which is not required to perform mechanical motions in taking the plant from normal full power operations to safe shutdown following the earthquake. For DCPP, safe shutdown is defined as Mode 5 following a Hosgri earthquake.

(4) Nozzle loads shall include piping loads transmitted to the component during the normal conditions.

(5) Deleted.

(6) Valves, being stronger than the attached piping and having a proven history without any gross failures of pressure boundaries, can safely transmit piping loads without compromising their pressure retaining integrity. Therefore, piping integrity assures valve integrity.

TABLE 3.9-6

Notes (Continued):

(7) σ_m = General membrane stress. This stress is equal to the average stress across the solid section under consideration, excludes discontinuities and concentrations and is produced only by mechanical loads.

(8) σ_L = Local membrane stress. This stress is the same as σ_m except that it includes the effect of discontinuities.

(9) σ_b = Bending stress. The stress is equal to the linear varying portion of the stress across the solid section under consideration, excludes discontinuities and concentrations, and is produced only by mechanical loads.

(10) S = 1971 or 1974 ASME code allowable stress value. The allowable stress shall correspond to the highest metal temperature at the section under consideration during the condition under consideration.

(11) S_y = 1971 or 1974 ASME code yield stress value. The yield stress shall correspond to the highest metal temperature at the section under consideration during the condition under consideration.

(12) S_p = Local membrane stress. This is equal to the average stress across the solid section under consideration. It excludes discontinuities and concentrations and is produced only by pressure.

(13) S_u = Material minimum tensile strength listed in either the code the component was purchased and manufactured under, or ASME Code Section III.

TABLE 3.9-7

NORMAL CONDITIONS LOADING COMBINATIONS AND
STRUCTURAL CRITERIA MECHANICAL EQUIPMENT SUPPORTS
AND STRUCTURAL COMPONENTS[1]

ELEMENT	LOADING COMBINATIONS (4, 5)	CRITERIA (6, 7, 8)	
Linear[3]	Deadweight + Nozzle/Piping Loads	1974 ASME Code Appendix XVII, Subsection NF or AISC Manual, 7th Edition	
Plate and shell[2] (active components)	Deadweight + Nozzle/Piping Loads	σ_m $(\sigma_m + \sigma_b)$	$\leq$ 1.0S (and/or 1974 ASME Code, $\leq$ 1.5S Subsection NF)
Plate and shell (inactive components)	Deadweight + Nozzle/Piping Loads	σ_m $(\sigma_m + \sigma_b)$	$\leq$ 1.0S (and/or 1974 ASME Codes, $\leq$ 1.5S Subsection NF)
Bolts	Deadweight + Nozzle/Piping Loads	1974 ASME Code Appendix XVII, Code Case 1644-6 or AISC Manual, 7th Edition	

TABLE 3.9-7

Notes:

(1) Includes RCS seal table and parts. Qualification of reactor cavity manipulator crane and spent fuel pit bridge crane and flux mapping transfer device not required for DE. Structural integrity insured by HOSGRI qualification.

(2) Plate and shell type supports: Plate and shell type component supports are supports such as vessel skirts and saddles which are fabricated from plate and shell elements and are normally subjected to a biaxial stress field.

(3) Linear type support: A linear type component support is defined as acting under essentially a single component of direct stress. Such elements may also be subjected to shear stresses. Examples of such structural elements are: tension and compression struts, beams and columns subjected to bending, trusses, frames, rings, arches, and cables.

(4) Nozzle loads shall be those nozzle loads acting on the supported component during the normal conditions.

(5) Plus Operating Loads, as applicable.

(6) σ_m = General membrane stress. This stress is equal to the average stress across the solid section under consideration, excludes discontinuities and concentrations and is produced only by mechanical loads.

(7) σ_b = B ending stress. This stress is equal to the linear varying portion of the stress across the solid section under consideration, excludes discontinuities and concentrations, and is produced only by mechanical loads.

(8) S = 1971 or 1974 ASME code allowable stress value. The allowable stress shall correspond to the highest metal temperature at the section under consideration during the condition under consideration.

TABLE 3.9-8

TANK DESIGN

Storage Function	Design Code	Tank Plate Material	ASME Code Allowable Design Stress, (psi)	Code
Boric acid	ASME Sec. VIII, Div. 1 (no code stamp)	ASTM A240 T304	16,000	ASME Sec. VIII, Div. 1
Liquid holdup	ASME Sec. III, Class C	ASTM A240 T304	16,000	ASME Sec. VIII, Div. 1
Component cooling water surge	ASME Sec. VIII,	ASTM A285 Gr. C	13,750	ASME Sec. VIII, Div. 1
Waste gas decay	ASME Sec. III, Class C	ASTM A285 Gr. C	13,750	ASME Sec. VIII, Div. 1
Diesel fuel oil storage (underground)	UL 58	ASTM A36	12,650	ASME Sec. VIII, Div. 1
Volume control	ASME Sec. III, Class C	ASTM A240 T304	16,000	ASME Sec. VIII, Div. 1

TABLE 3.9-8

Storage Function	Design Code	Tank Plate Material	ASME Code Allowable Design Stress, (psi)	Code
Accumulator	ASME Sec. III, Class C	ASTM A516 Gr. 70 W/ A240 T304 Cladding	17,500	ASME Sec. VIII, Div. 1
Spray additive	ASME Sec. VIII, Div. 1 (no code stamp)	ASTM A240 T304	16,000	ASME Sec. VIII, Div. 1
Transfer storage & firewater	AWWA D100	ASTM A516 Gr. 60	19,500	ASME Sec. VIII, Div. 2
Reactor coolant drain tank	ASME Sec. III, Class C	ASTM A240 T304	16,000	ASME Sec. VIII, Div. 1
Waste concentrates holding	ASME Sec. III, Class C	ASTM A240 T304	16,000	ASME Sec. VIII, Div. 1

TABLE 3.9-8

Storage Function	Design Code	Tank Plate Material	ASME Code Allowable Design Stress, (psi)	Code
Spent Resin Storage	ASME Sec. III, Class C	ASTM A240 T304	16,000	ASME Sec. VIII, Div. 1
Equipment Drain Receiver	ASME Sec. VIII, Div. 1 (no code stamp)	ASTM A240 T304	16,000	ASME Sec. VIII, Div. 1

1. ASME Section III - American Society of Mechanical Engineers, Boiler and Pressure Vessel, Section III (1968, 1971).
2. ASME Section VIII - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section VIII (1968, 1971) Div. 1.
3. UL-58 - Underwriters Standards, Steel Underground Tanks for Flammable and Combustible Liquids.
4. AWWAD100 - American Waterworks Association, Standard for Steel Tanks, Standpipes Reservoirs and Elevated Tanks for Water Storage.
5. Waste concentrates holding tank abandoned in place.

TABLE 3.9-9

LIST OF ACTIVE VALVES

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
AUX FW PUMP 1 TURBINE GOV	FCV-15	3.2-4	Globe	-	Speed Governor	NA	Open	11
MSIV BYPASS – LEAD 4	FCV-22	3.2-4	Globe	3	Air	Closed	Closed	
MSIV BYPASS – LEAD 3	FCV-23	3.2-4	Globe	3	Air	Closed	Closed	
MSIV BYPASS – LEAD 2	FCV-24	3.2-4	Globe	3	Air	Closed	Closed	
MSIV BYPASS – LEAD 1	FCV-25	3.2-4	Globe	3	Air	Closed	Closed	
MAIN STM LEAD 2 TO AUX FW PUMP 1 TURBINE	FCV-37	3.2-4	Gate	4	Motor	FAI	Operable	10, 25
MAIN STM LEAD 3 TO AUX FW PUMP 1 TURBINE	FCV-38	3.2-4	Gate	4	Motor	FAI	Operable	10, 25
MAIN STEAM ISOL LEAD 1	FCV-41	3.2-4	Swing Check	28	Air	Refer to Note 7	Closed	7
MAIN STEAM ISOL LEAD 2	FCV-42	3.2-4	Swing Check	28	Air	Refer to Note 7	Closed	7
MAIN STEAM ISOL LEAD 3	FCV-43	3.2-4	Swing Check	28	Air	Refer to Note 7	Closed	7

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
MAIN STEAM ISOL LEAD 4	FCV-44	3.2-4	Swing Check	28	Air	Refer to Note 7	Closed	7
MN STM TO AUX FW PUMP 1 TURBINE	FCV-95	3.2-4	Gate	4	Motor	FA	Open	11
BORIC ACID BLENDER INLET	FCV-110A	3.2-8	Globe	2	Air	Open	Open	23
STEAM GEN NO. 1 TO BLOWDN TANK	FCV-151	3.2-8	Globe	3	Air	Closed	Closed	
AUX FP TURB 1 STM INLET	FCV-152	3.2-4	Globe	4	Manual	NA	Open	11
STEAM GEN NO. 2 TO BLOWDN TANK	FCV-154	3.2-4	Globe	3	Air	Closed	Closed	
STEAM GEN NO. 3 TO BLOWDN TANK	FCV-157	3.2-4	Globe	3	Air	Closed	Closed	
STEAM GEN NO. 4 TO BLOWDN TANK	FCV-160	3.2-4	Globe	3	Air	Closed	Closed	
CTMT H_2 SAMPLE SUPPLY IN CTMT	FCV-235	3.2-23	Globe	3/8	Solenoid	Closed	Operable	
CTMT H_2 SAMPLE SUPPLY OUT CTMT	FCV-236	3.2-23	Globe	3/8	Solenoid	Closed	Operable	

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
CTMT H_2 SAMPLE RETURN OUT CTMT	FCV-237	3.2-23	Globe	3/8	Solenoid	Closed	Operable	
CTMT H_2 SAMPLE SUPPLY IN CTMT	FCV-238	3.2-23	Globe	3/8	Solenoid	Closed	Operable	
CTMT H_2 SAMPLE SUPPLY OUT CTMT	FCV-239	3.2-23	Globe	3/8	Solenoid	Closed	Operable	
CTMT H_2 SAMPLE RETURN OUT CTMT	FCV-240	3.2-23	Globe	3/8	Solenoid	Closed	Operable	
STM GEN 4 BD SAMPLE OS CNTMT	FCV-244	3.2-4	Globe	¾	Air	Closed	Closed	
STM GEN 3 BD SAMPLE OS CNTMT	FCV-246	3.2-4	Globe	¾	Air	Closed	Closed	
STM GEN 2 BD SAMPLE OS CNTMT	FCV-248	3.2-4	Globe	¾	Air	Closed	Closed	
STM GEN 1 BD SAMPLE OS CNTMT	FCV-250	3.2-4	Globe	¾	Air	Closed	Closed	
RC DRN PPS DISCH IN CNTMT	FCV-253	3.2-19	Ball	2-1/2	Air	Closed	Closed	
RC DRN PPS DISCH OUT CNTMT	FCV-254	3.2-19	Ball	2-1/2	Air	Closed	Closed	

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
RC DRN TANK VENT HEADER IN CONTAINMENT	FCV-255	3.2-19	Ball	3/4	Air	Closed	Closed	
RC DRN TANK VENT HEADER OUT CONTAINMENT	FCV-256	3.2-19	Ball	3/4	Air	Closed	Closed	
RC DRN TANK GAS ANALYZER OUT CONTAINMENT	FCV-257	3.2-19	Ball	1/2	Air	Closed	Closed	
RC DRN TANK GAS ANALYZER IN CONTAINMENT	FCV-258	3.2-19	Ball	1/2	Air	Closed	Closed	
RC DRN TANK N2 SUPPLY OUT CONTAINMENT	FCV-260	3.2-19	Ball	3/4	Air	Closed	Closed	
CCW SUPPLY HEADER C	FCV-355	3.2-14	B'fly	20	Motor	FAI	Closed	
CCW TO RC PUMPS	FCV-356	3.2-14	B'fly	10	Motor	FAI	Closed	
RCP THERMAL BARRIER CCW RETURN	FCV-357	3.2-14	Globe	6	Motor	FAI	Closed	
EXCESS LETDOWN HT EXCH CCW RETURN	FCV-361	3.2-14	B'fly	4	Air	Closed	Closed	
RCP OIL COOLER CCW RETURN	FCV-363	3.2-14	B'fly	6	Motor	FAI	Closed	
RHR HT EXCHANGER 2 CCW RETURN	FCV-364	3.2-14	B'fly	12	Air	21	Functional	10

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
RHR HT EXCHANGER 3 CCW RETURN	FCV-365	3.2-14	B'fly	12	Air	21	Functional	10
CCW SUPPLY HEADER A	FCV-430	3.2-14	B'fly	30	Motor	FAI	Open	
CCW SUPPLY HEADER B	FCV-431	3.2-14	B'fly	30	Motor	FAI	Open	
RAW WATER STG RES AUX FEED PUMP 1	FCV-436	3.2-3	B'fly	8	Manual	FAI	Functional	
RAW WATER STG RES AUX FEED PUMPS 2 & 3	FCV-437	3.2-3	B'fly	8	Manual	FAI	Functional	
MAIN FEEDWATER ISOLATION LEAD 1	FCV-438	3.2-3	Gate	16	Motor	FAI	Closed	5
MAIN FEEDWATER ISOLATION LEAD 2	FCV-439	3.2-3	Gate	16	Motor	FAI	Closed	5
MAIN FEEDWATER ISOLATION LEAD 3	FCV-440	3.2-3	Gate	16	Motor	FAI	Closed	5
MAIN FEEDWATER ISOLATION LEAD 4	FCV-441	3.2-3	Gate	16	Motor	FAI	Closed	5
AUX SALTWATER PUMPS CROSS	FCV-495	3.2-17	B'fly	24	Motor	FAI	Operable	
AUX. SALTWATER PUMPS CROSS	FCV-496	3.2-17	B'fly	24	Motor	FAI	Operable	

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
CNT BLDG SUMP PP DISCHARGE IN CNTMT	FCV-500	3.2-19	Ball	2	Air	Closed	Closed	
CNT BLDG SUMP PP DISCHARGE OUT CNTMT	FCV-501	3.2-19	Ball	2	Air	Closed	Closed	
STEAM GEN 1 MAIN FW SUPPLY	FCV-510	3.2-3	Globe	16	Air	Closed	Closed	
STEAM GEN 2 MAIN FW SUPPLY	FCV-520	3.2-3	Globe	16	Air	Closed	Closed	
STEAM GEN 3 MAIN FW SUPPLY	FCV-530	3.2-3	Globe	16	Air	Closed	Closed	
STEAM GEN 4 MAIN FW SUPPLY	FCV-540	3.2-3	Globe	16	Air	Closed	Closed	
CNT WEST INSTRUMENT AIR	FCV-584	3.2-25	Ball	2	Air	Closed	Closed	
AUX SW TO CCW HT EXCH NO. 1	FCV-602	3.2-17	B'fly	24	Air	Open	21, 22	
AUX SW TO CCW HT EXCH NO. 2	FCV-603	3.2-17	B'fly	24	Air	Open	21, 22	
CNTMT FIRE WATER ISOLATION	FCV-633	3.2-18	Globe	3	Air	Closed	Closed 21	

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
RHR PUMP 1 RECIRC	FCV-641A	3.2-10	Globe	2	Motor	FAI	Functional	
RHR PUMP 2 RECIRC	FCV-641B	3.2-10	Globe	2	Motor	FAI	Functional	
CNTMT ISO CHPS EXHAUST	FCV-658	3.2-23	Gate	4	Motor	FAI	Functional	
CNTMT ISO CHPS EXHAUST	FCV-659	3.2-23	Gate	4	Motor	FAI	Functional	
CONT PURGE SUPPLY IC	FCV-660	3.2-23	B'fly	48	Air	Closed	Closed	
CONT PURGE SUPPLY OC	FCV-661	3.2-23	B'fly	48	Air	Closed	Closed	
CONT VAC/PRESS RELIEF 1C	FCV-662	3.2-23	B'fly	12	Air	Closed	Closed	
CONT PRESSURE RELIEF OC	FCV-663	3.2-23	B'fly	12	Air	Closed	Closed	
CONT VACUUM RELIEF OC	FCV-664	3.2-23	B'fly	12	Air	Closed	Closed	
CNTMT ISO CHPS EXHAUST	FCV-668	3.2-23	Gate	4	Motor	FAI	Functional	
CNTMT ISO CHPS EXHAUST	FCV-669	3.2-23	Gate	4	Motor	FAI	Functional	
CNT AIR SAMPLE (INSIDE CNT)	FCV-678	3.2-23	Ball	1	Air	Closed	Closed	5
CNT AIR SAMPLE (OUTSIDE CNT)	FCV-679	3.2-23	Ball	1	Air	Closed	Closed	5

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
CNT AIR SAMPLE (OUTSIDE CNT)	FCV-681	3.2-23	Ball	1	Air	Closed	Closed	5
POST-LOCA SAMPLING SYST	FCV-696	3.2-19	Globe	3/8	Solenoid	Closed	Closed	5
POST-LOCA SAMPLING SYST	FCV-697	3.2-19	Globe	3/8	Solenoid	Closed	Closed	5
POST-LOCA SAMPLING SYST	FCV-698	3.2-23	Globe	3/8	Solenoid	Closed	Closed	5
POST-LOCA SAMPLING SYST	FCV-699	3.2-23	Globe	3/8	Solenoid	Closed	Closed	5
POST-LOCA SAMPLING SYST	FCV-700	3.2-23	Globe	3/8	Solenoid	Closed	Closed	5
RCP OIL COOLER CCW RETURN	FCV-749	3.2-14	B'fly	6	Motor	FAI	Closed	
RCP THERMAL BARRIER CCW RETURN	FCV-750	3.2-14	Globe	6	Motor	FAI	Closed	
STEAM GEN NO. 1 BLOWDOWN AND SAMPLE	FCV-760	3.2-4	Globe	3	Air	Closed	Closed	
STEAM GEN NO. 2 BLOWDOWN AND SAMPLE	FCV-761	3.2-4	Globe	3	Air	Closed	Closed	
STEAM GEN NO. 3 BLOWDOWN AND SAMPLE	FCV-762	3.2-4	Globe	3	Air	Closed	Closed	

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
STEAM GEN NO. 4 BLOWDOWN AND SAMPLE	FCV-763	3.2-4	Globe	3	Air	Closed	Closed	
STEAM GEN NO. 1 MAIN FW SUPPLY BY-PASS	FCV-1510	3.2-3	Globe	6	Air	Closed	Closed	
STEAM GEN NO. 2 MAIN FW SUPPLY BY-PASS	FCV-1520	3.2-3	Globe	6	Air	Closed	Closed	
STEAM GEN NO. 3 MAIN FW SUPPLY BY-PASS	FCV-1530	3.2-3	Globe	6	Air	Closed	Closed	
STEAM GEN NO. 4 MAIN FW SUPPLY BY-PASS	FCV-1540	3.2-3	Globe	6	Air	Closed	Closed	
CHG PUMPS DISCH TO REGEN HT EXCH	HCV-142	3.2-4	Globe	3	Air	Closed	21	23
RHR TO COLD LEGS 3 & 4	HCV-637	3.2-10	Ball	8	Air	Open	Open	
RHR TO COLD LEGS 1 & 2	HCV-638	3.2-10	Ball	8	Air	Open	Open	
DSL FO DAY TK 1-2 HEADER B	LCV-85	3.2-21	Ball	1-1/2	Air	Closed	Functional	
DSL FO DAY TK 2-1 HEADER B	LCV-86	3.2-21	Ball	1-1/2	Air	Closed	Functional	
DSL FO DAY TK 1-3 HEADER B	LCV-87	3.2-21	Ball	1-1/2	Air	Closed	Functional	
DSL FO DAY TK 1-2 HEADER A	LCV-88	3.2-21	Ball	1-1/2	Air	Closed	Functional	

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
DSL FO DAY TK 2-1 HEADER A	LCV-89	3.2-21	Ball	1-1/2	Air	Closed	Functional	
DSL FO DAY TK 1-3 HEADER A	LCV-90	3.2-21	Ball	1-1/2	Air	Closed	Functional	
AUX FEEDWATER FROM TURB AFW PP TO SG 1	LCV-106	3.2-3	Globe	2	Motor	FAI	Operable	4
AUX FEEDWATER FROM TURB AFW PP TO SG 2	LCV-107	3.2-3	Globe	2	Motor	FAI	Operable	4
AUX FEEDWATER FROM TURB AFW PP TO SG 3	LCV-108	3.2-3	Globe	2	Motor	FAI	Operable	4
AUX FEEDWATER FROM TURB AFW PP TO SG 4	LCV-109	3.2-3	Globe	2	Motor	FAI	Operable	4
AUX FEEDWATER FROM MOTOR AFW PP TO SG 1	LCV-110	3.2-3	Globe	2	Electro Hydraulic	Open	Operable	4
AUX FEEDWATER FROM MOTOR AFW PP TO SG 2	LCV-111	3.2-3	Globe	2	Electro Hydraulic	Open	Operable	4
VOLUME CONTROL TANK TO CHARG PUMPS	LCV-112B	3.2-8	Gate	4	Motor	FAI	Closed	5
VOLUME CONTROL TANK TO CHARG PUMPS	LCV-112C	3.2-8	Gate	4	Motor	FAI	Closed	5
AUX FEEDWATER FROM MOTOR AFW PP TO SG 4	LCV-113	3.2-3	Globe	2	Electro Hydraulic	Open	Operable	4

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
AUX FEEDWATER FROM MOTOR AFW PP TO SG 3	LCV-115	3.2-3	Globe	2	Electro Hydraulic	Open	Operable	4
STEAM GEN 1 10% ATM DUMP	PCV-19	3.2-4	Globe	8	Air	Closed	Functional 21	
STEAM GEN 2 10% ATM DUMP	PCV-20	3.2-4	Globe	8	Air	Closed	Functional 21	
STEAM GEN 3 10% ATM DUMP	PCV-21	3.2-4	Globe	8	Air	Closed	Functional 21	
STEAM GEN 4 10% ATM DUMP	PCV-22	3.2-4	Globe	8	Air	Closed	Functional 21	
PRESSURIZER POWER-OPERATED RELIEF	PCV-455C	3.2-7	Globe	2	Air	Closed	Functional 21	8,12
PRESSURIZER POWER-OPERATED RELIEF	PCV-456	3.2-7	Globe	2	Air	Closed	Functional 21	8,12
CONT PURGE EXHAUST 1C	RCV-11	3.2-23	B'fly	48	Air	Closed	Closed	
CONT PURGE EXHAUST OC	RCV-12	3.2-23	B'fly	48	Air	Closed	Closed	
MAIN STM SAFETY LEAD 1	RV-3	3.2-4	Relief	6	Spring	NA	Operable	9
MAIN STM SAFETY LEAD 1	RV-4	3.2-4	Relief	6	Spring	NA	Operable	9

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[(a)]	Failure Analysis Comments
MAIN STM SAFETY LEAD 1	RV-5	3.2-4	Relief	6	Spring	NA	Operable	9
MAIN STM SAFETY LEAD 1	RV-6	3.2-4	Relief	6	Spring	NA	Operable	9
MAIN STM SAFETY LEAD 2	RV-7	3.2-4	Relief	6	Spring	NA	Operable	9
MAIN STM SAFETY LEAD 2	RV-8	3.2-4	Relief	6	Spring	NA	Operable	9
MAIN STM SAFETY LEAD 2	RV-9	3.2-4	Relief	6	Spring	NA	Operable	9
MAIN STM SAFETY LEAD 2	RV-10	3.2-4	Relief	6	Spring	NA	Operable	9
MAIN STM SAFETY LEAD 3	RV-11	3.2-4	Relief	6	Spring	NA	Operable	9
MAIN STM SAFETY LEAD 3	RV-12	3.2-4	Relief	6	Spring	NA	Operable	9
MAIN STM SAFETY LEAD 3	RV-13	3.2-4	Relief	6	Spring	NA	Operable	9
MAIN STM SAFETY LEAD 3	RV-14	3.2-4	Relief	6	Spring	NA	Operable	9
CCW SURGE TK RV	RV-45	3.2-14	Relief	3	Spring	NA	Operable	
MAIN STM SAFETY LEAD 4	RV-58	3.2-4	Relief	6	Spring	NA	Operable	9
MAIN STM SAFETY LEAD 4	RV-59	3.2-4	Relief	6	Spring	NA	Operable	9
MAIN STM SAFETY LEAD 4	RV-60	3.2-4	Relief	6	Spring	NA	Operable	9

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
MAIN STM SAFETY LEAD 4	RV-61	3.2-4	Relief	6	Spring	NA	Operable	9
MAIN STM SAFETY LEAD 1	RV-222	3.2-4	Relief	6	Spring	NA	Operable	9
MAIN STM SAFETY LEAD 2	RV-223	3.2-4	Relief	6	Spring	NA	Operable	9
MAIN STM SAFETY LEAD 3	RV-224	3.2-4	Relief	6	Spring	NA	Operable	9
MAIN STM SAFETY LEAD 4	RV-225	3.2-4	Relief	6	Spring	NA	Operable	9
FIRE WATER TANK CROSSTIE	FP-0-306	3.2-18	Gate	8	Manual	NA	Functional	
FIRE WATER TANK CROSSTIE BYPASS	FP-0-307	3.2-18	Gate	8	Manual	NA	Functional	
PRESSURIZER POWER RELIEF ISO	8000A	3.2-7	Gate	3	Motor	FAI	Operable	
PRESSURIZER POWER RELIEF ISO	8000B	3.2-7	Gate	3	Motor	FAI	Operable	
PRESSURIZER POWER RELIEF ISO	8000C	3.2-7	Gate	3	Motor	FAI	Operable	
PRESSURIZER SAFETY	8010A	3.2-7	Relief	6	Spring	NA	Functional	9
PRESSURIZER SAFETY	8010B	3.2-7	Relief	6	Spring	NA	Functional	9

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
PRESSURIZER SAFETY	8010C	3.2-7	Relief	6	Spring	NA	Functional	9
PRESSURIZER RELIEF TK PRIMARY WTR	8029	3.2-7	Ball	3	Air	Closed	Closed	
PRESSURIZER RELIEF TK GAS ANALYZER IC	8034A	3.2-7	Globe	3/8	Air	Closed	Closed	
PRESSURIZER RELIEF TK GAS ANALYZER OC	8034B	3.2-7	Globe	3/8	Air	Closed	Closed	
PRESSURIZER RELIEF TK N2 SUPPLY	8045	3.2-7	Dia-phragm	3/4	Air	Closed	Closed	
REACTOR VESSEL HEAD VENT SYS	8078A	3.2-7	Globe	1	Solenoid	Closed	Operable	
REACTOR VESSEL HEAD VENT SYS	8078B	3.2-7	Globe	1	Solenoid	Closed	Operable	
REACTOR VESSEL HEAD VENT SYS	8078C	3.2-7	Globe	1	Solenoid	Closed	Operable	
REACTOR VESSEL HEAD VENT SYS	8078D	3.2-7	Globe	1	Solenoid	Closed	Operable	
REACTOR COOL PPS SEAL WTR RET	8100	3.2-7	Gate	4	Motor	FAI	Closed	

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
BORIC ACID TO CHARGING PPS	8104	3.2-8	Globe	2	Motor	FAI	Operable	
CENTRIFUGAL I CHG PPS RECRC	8105	3.2-8	Globe	2	Motor	FAI	Functional	5
CENTRIFUGAL CHG PPS RECRC	8106	3.2-8	Globe	2	Motor	FAI	Functional	5
CHG PPS DISCH TO LETDOWN HX	8107	3.2-8	Gate	3	Motor	FAI	Functional	
CHG PPS DISCH TO LETDOWN HX	8108	3.2-8	Gate	3	Motor	FAI	Functional	
REACT COOL PPS SEAL WTR RET	8112	3.2-8	Gate	4	Motor	FAI	Closed	
LETDOWN LINE RV	8117	3.2-8	Relief	2	Spring	Open	Closed	
RCP SEAL WTR RTN RV	8121	3.2-8	Relief	2	Spring	Open	Closed	
SEAL WTR HX INLET RV	8123	3.2-8	Relief	2	Spring	Open	Closed	
CHARGING PUMP SUCTION HEADER	8125	3.2-8	Relief	3/4	Spring	Open	Closed	
PRESSURIZER AUX SPRAY	8145	3.2-8	Globe	2	Air	Closed	Operable 21	

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
CHG PUMP TO LOOP 4 COLD LEG	8146	3.2-8	Globe	3	Air	Open	Operable 21	
CHG PUMP TO LOOP 3 COLD LEG	8147	3.2-8	Globe	3	Air	Open	Operable 21	
RCS PRESSURIZER AUX SPRAY	8148	3.2-8	Globe	2	Air	Closed	Operable 21	
LETDOWN LINE ISOL	8149A	3.2-8	Globe	2	Air	Closed	Closed	
LETDOWN LINE ISOL	8149B	3.2-8	Globe	2	Air	Closed	Closed	
LETDOWN LINE ISOL	8149C	3.2-8	Globe	2	Air	Closed	Closed	
LETDOWN LINE ISOL	8152	3.2-8	Globe	2	Air	Closed	Closed	
CCP 1 FCV-128 MANUAL BYPASS	8387B	3.2-8	Globe	3	Manual	NA	Functional	23
CCP 2 FCV-128 MANUAL BYPASS	8387C	3.2-8	Globe	3	Manual	NA	Functional	23
HCV-142 MANUAL BYPASS	8403	3.2-8	Globe	3	Manual	NA	Functional	23
MANUAL EMERGENCY BORATE VALVE	8471	3.2-08	Diaphragm	2	Manual	NA	Functional	23

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
BA TRANSFER PUMP SUCTION CROSSTIE	8476	3.2-8	Diaphragm	2	Manual	NA	Functional	23
RHR PP 1 SUCT	8700A	3.2-10	Gate	14	Motor	FAI	Operable	
RHR PP 2 SUCT	8700B	3.2-10	Gate	14	Motor	FAI	Operable	
RHR SUCTION FROM LOOP 4 HOT LEG	8701	3.2-10	Gate	14	Motor	FAI	Operable	23
RHR SUCTION FROM LOOP 4 HOT LEG	8702	3.2-10	Gate	14	Motor	FAI	Operable	23
RHR DISCHARGE TO HOT LEGS 1 & 2	8703	3.2-10	Gate	12	Motor	FAI	Functional	10, 19
RHR SUCTION PIPING RV	8707	3.2-10	Relief	3	Spring	Open	Closed	
RHR COOLDOWN LINE RV	8708	3.2-10	Relief	3/4	Spring	Open	Closed	
RHR HT EXCH 1 TO RCS HOT LEGS 1 & 2	8716A	3.2-10	Gate	8	Motor	FAI	Operable	
RHR HT EXCH 2 TO RCS HOT LEGS 1 & 2	8716B	3.2-10	Gate	8	Motor	FAI	Operable	
CHARGING INJECT LINE DISCHARGE	8801A	3.2-9	Gate	4	Motor	FAI	Open	

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
CHARGING INJECT LINE DISCHARGE	8801B	3.2-9	Gate	4	Motor	FAI	Open	
SAFETY INJECT PUMP 1 DISCH TO HOT LEGS 1 & 2	8802A	3.2-9	Gate	4	Motor	FAI	Operable	19
SAFETY INJECT PUMP 2 DISCH TO HOT LEGS 3 & 4	8802B	3.2-9	Gate	4	Motor	FAI	Operable	19
CHARG PUMPS TO CHARGING INJECT LINE	8803A	3.2-9	Gate	4	Motor	FAI	Open	10
CHARG PUMPS TO CHARGING INJECT LINE	8803B	3.2-9	Gate	4	Motor	FAI	Open	10
RHR HT EXCH 1 TO CHG PPS SUCT	8804A	3.2-9	Gate	8	Motor	FAI	Functional	13
RHR HT EXCH 2 TO CHG PPS SUCT	8804B	3.2-9	Gate	8	Motor	FAI	Functional	13
RWST TO CHARG PUMP SUCT	8805A	3.2-9	Gate	8	Motor	FAI	Open	10
RWST TO CHARG PUMP SUCT	8805B	3.2-9	Gate	8	Motor	FAI	Open	10
CHARGING PPS SIS PPS SUC CROSSTIE	8807A	3.2-9	Gate	4	Motor	FAI	Functional	10, 13

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
CHARGING PPS SIS PPS SUC CROSSTIE	8807B	3.2-9	Gate	4	Motor	FAI	Functional	10, 13
RHR HT EXCH 1 TO COLD LEGS 1 & 2	8809A	3.2-9	Gate	8	Motor	FAI	Functional	20
RHR HT EXCH 2 TO COLD LEGS 3 & 4	8809B	3.2-9	Gate	8	Motor	FAI	Functional	20
SIS PUMP 1 DISCH TO COLD LEGS	8821A	3.2-9	Gate	4	Motor	FAI	Functional	
SIS PUMP 2 DISCH TO COLD LEGS	8821B	3.2-9	Gate	4	Motor	FAI	Functional	
SIS PUMP DISCH TO COLD LEGS	8835	3.2-9	Gate	4	Motor	FAI	Open	14
SI PUMP DISCHARGE RV	8851	3.2-9	Relief	¾	Spring	Open	Closed	
SI PUMP DISCHARGE RV	8853A	3.2-9	Relief	¾	Spring	Open	Closed	
SI PUMP DISCHARGE RV	8853B	3.2-9	Relief	¾	Spring	Open	Closed	
ACCUM RV	8855A	3.2-9	Relief	1	Spring	Open	Closed	
ACCUM RV	8855B	3.2-9	Relief	1	Spring	Open	Closed	
ACCUM RV	8855C	3.2-9	Relief	1	Spring	Open	Closed	

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
ACCUM RV	8855D	3.2-9	Relief	1	Spring	Open	Closed	
RHR HT EXCH OUTLET RELIEF RV	8856A	3.2-10	Relief	2	Spring	Open	Closed	
RHR HT EXCH OUTLET RELIEF	8856B	3.2-10	Relief	2	Spring	Open	Closed	
SI PUMP SUCT HEADER RV	8858	3.2-9	Relief	3/4	Spring	Open	Closed	
ACCUM TEST IN CTMT	8871	3.2-9	Globe	3/4	Air	Closed	Closed	
ACCUM N2 SUPPLY HEADER	8880	3.2-9	Globe	1	Air	Closed	Closed	
SAFETY INJECTION TEST LINE	8883	3.2-9	Globe	3/4	Air	Closed	Closed	5
SAFETY INJECT PUMP NO. 1 SUCT	8923A	3.2-9	Gate	6	Motor	FAI	Operable	
SAFETY INJECT PUMP NO. 2 SUCT	8923B	3.2-9	Gate	6	Motor	FAI	Operable	
ACCUM TEST OUTSIDE CONTAINMENT	8961	3.2-9	Globe	3/4	Air	Closed	Closed	
SAFETY INJECT PUMP MIN. RECIRC. VALVES	8974A	3.2-9	Globe	2	Motor	FAI	Operable	
SAFETY INJECT PUMP MIN. RECIRC. VALVES	8974B	3.2-9	Globe	2	Motor	FAI	Operable	

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
RWST TO SAFETY INJECTION PUMP SUCT	8976	3.2-9	Gate	8	Motor	FAI	Open	14
RWST TO RHR PUMP SUCTION	8980	3.2-9	Gate	12	Motor	FAI	Operable	14
CNTMT SUMP TO RHR PP1 SUCT	8982A	3.2-10	Gate	14	Motor	FAI	Operable	
CNTMT SUMP TO RHR PP2 SUCT	8982B	3.2-10	Gate	14	Motor	FAI	Operable	
SPRAY ADDITIVE SYSTEM	8987	3.2-12	Relief	3/4	Spring	Open	Close	
SPRAY ADD TK OUT ISOL	8994A	3.2-12	Gate	3	Motor	FAI	Open	10
SPRAY ADD TK OUT ISOL	8994B	3.2-12	Gate	3	Motor	FAI	Open	10
CNTMT SPRAY PP 1 DISCHG	9001A	3.2-12	Gate	8	Motor	FAI	Open	10
CNTMT SPRAY PP 2 DISCHG	9001B	3.2-12	Gate	8	Motor	FAI	Open	10
RHR HT EXCH 1 TO CONT SPRAY	9003A	3.2-12	Gate	8	Motor	FAI	Operable	10
RHR HT EXCH 2 TO CONT SPRAY	9003B	3.2-12	Gate	8	Motor	FAI	Operable	10

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
RCS SAMPLE	9351A	3.2-11	Globe	3/8	N_2	Closed	Closed 21	23
RCS SAMPLE	9351B	3.2-11	Globe	3/8	N_2	Closed	Closed 21	23
PRESS STEAM SPACE IN CONTMT	9354A	3.2-7	Globe	3/8	Air	Closed	Closed	
PRESS STEAM SPACE OUT CONTMT	9354B	3.2-7	Globe	3/8	Air	Closed	Closed	
PRESS LIQUID SPACE IN CONTMT	9355A	3.2-7	Globe	3/8	Air	Closed	Closed	
PRESS LIQUID SPACE OUT CONTMT	9355B	3.2-7	Globe	3/8	Air	Closed	Closed	
HOT LEGS 1 & 4 IN CONTMT SAMPLE	9356A	3.2-7	Globe	3/8	N_2	Closed	Closed 21	
HOT LEGS 1 & 4 IN CONTMT SAMPLE	9356B	3.2-7	Globe	3/8	N_2	Closed	Closed 21	
ACCUM SAMPLE HDR IN CONTAINMENT	9357A	3.2-9	Globe	3/8	Air	Closed	Closed	
ACCUM SAMPLE HDR OUT CONTAINMENT	9357B	3.2-9	Globe	3/8	Air	Closed	Closed	

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[a]	Failure Analysis Comments
CCW PUMP SUCT CROSSTIE VALVE (2 VALVES ON LINES 97 & 2285)	CCW-4 & -5	3.2-14	B'fly	20	Manual	NA	Operable	
CCW PUMP 2 DISCH ISOLATION (TO HDR B)	CCW-16	3.2-14	B’fly	20	Manual	NA	Operable	
CCW PUMP 3 DISCH ISOLATION (TO HDR B)	CCW-17	3.2-14	B'fly	20	Manual	NA	Operable	
CCW PUMP 1 DISCH ISOLATION (TO HDR A)	CCW-18	3.2-14	B'fly	20	Manual	NA	Operable	
CCW PUMP 2 DISCH ISOLATION (TO HDR A)	CCW-19	3.2-14	B'fly	20	Manual	NA	Operable	
CCW HDR C SUPPLY FROM HDR A	CCW-23	3.2-14	B'fly	24	Manual	NA	Operable	
CCW HDR C SUPPLY FROM HDR B	CCW-24	3.2-14	B'fly	24	Manual	NA	Operable	
MAIN STEAM LEAD ONE 10% ATM DUMP ISOLATION	MS-1015	3.2-4	Gate	8	Manual	NA	Operable 24	
MAIN STEAM LEAD TWO 10% ATM DUMP ISOLATION	MS-2015	3.2-4	Gate	8	Manual	NA	Operable 24	
MAIN STEAM LEAD THREE 10% ATM DUMP ISOLATION	MS-3015	3.2-4	Gate	8	Manual	NA	Operable 24	

TABLE 3.9-9

System or Service Description	Valve Identification	FSAR Fig. No.	Body Type	Size in.	Actuator Type	Valve Position On Failure	Position for Safe Shutdown[(a)]	Failure Analysis Comments
MAIN STEAM LEAD FOUR 10% ATM DUMP ISOLATION	MS-4015	3.2-4	Gate	8	Manual	NA	Operable 24	

(a) The valves whose positions are listed in this column are those valves whose operability is relied on to perform an active function such as safe shutdown of the reactor or mitigation of the consequences of a Design Basis Accident coincidental with loss of offsite power. An entry of "functional" or equivalently "operable" means that the valve must be capable of being opened and/or closed to perform its active function. For DCPP, safe shutdown is defined as Mode 3 following an accident (SSER 7 and SSER 22), Mode 5 following a Hosgri earthquake, and Mode 3, following a fire (10 CFR 50.48(c)).

Failure Analysis Comment Notes:

1. Deleted in Revision 9.
2. Deleted in Revision 9.
3. Deleted in Revision 9.
4. Valve is provided for control. Failure, open or close, is remedied by redundant train and EOP RNO actions.
5. Valve provides isolation. Failure to close is remedied by valve in series.
6. Deleted in Revision 9.
7. Locally mounted air accumulators protected against compressed air system failure by check valves can hold open the main steam isolation valves for a short duration of time after the compressed air system is lost. In the event of loss of all air to the main steam isolation valves, the valves will fail closed.
8. These valves are provided for controlled steam release. Failure to open is remedied by redundant valves. Failure to close is remedied by closure of series valve or system shutdown.
9. These valves provide vessel protection. Failure to open is remedied by redundant valves in parallel. Valve size limits flow on failure to close.
10. Valve provides isolation. Failure to close (or stay closed) is remedied by a redundant valve in series. Failure to open (or stay open) is remedied by a redundant line (or system).
11. Valve opens to start device. Failure to open is remedied by use of redundant system.
12. Air-operated valve operation is not required for safe shutdown.
13. Used during recirculation mode.

Failure Analysis Comment Notes (continued)

14. Valve provides isolation. Failure to stay open could defeat system function. "Hot" short could close valve, but is not considered credible.

15. Deleted in Revision 9.

16. Deleted in Revision 9.

17. Deleted in Revision 9.

18. Deleted in Revision 9.

19. Valves operated (opened) during changeover from cold leg recirculation to hot leg injection. Failure to stay closed during cold leg injection or cold leg recirculation could defeat system function. "Hot" short could open valve but is not considered credible.

20. Valve 8809A operated (closed) during the changeover from cold leg injection to cold leg recirculation. Valve 8809B operated (closed) during the changeover from cold leg recirculation to hot leg recirculation. Failure of one valve to stay open during cold leg injection remedied by redundant system.

21. Air operated valves required to operate or maintain position after a loss of the compressed air system are supplied with compressed gas from the backup air/nitrogen supply system. Refer to Section 9.3.1.6 for details.

22. If one of the CCW heat exchangers is valved out-of-service, then backup air is supplied to the respective CCW heat exchanger saltwater inlet valve to maintain the valve closed. This ensures all ASW flow is directed to in-service CCW heat exchangers.

23. Valve does not have an active safety function to support accident mitigation or Mode 3 safe shutdown. Valve is active to support achieving post-Hosgri cold shutdown. Valve needs to be seismically qualified for active function for Hosgri only.

24. Valve has an active safety function to support accident mitigation or Mode 3 safe shutdown. Valve is passive to support achieving post-Hosgri cold shutdown.

25. Normal position for Safe Shutdown is Open. For Containment Isolation and the condition described in Section 6.5.3.9 (Rupture of a Steam Supply Line to the Turbine-Driven AFW Pump), valve must be Operable.

Abbreviations:

FCV	=	Flow control valve	RCP	=	Reactor coolant pump	B'fly	=	Butterfly
LCV	=	Level control valve	FAI	=	Fail as is	RC	=	Reactor coolant
PCV	=	Pressure control valve	PP & PPS	=	Pump(s)	CCW	=	Component cooling water
HCV	=	Hand control valve	CNT	=	Containment	RHR	=	Residual heat removal
RV	=	Relief valve	CHG	=	Charging	AFW	=	Auxiliary feedwater
TCV	=	Temperature control valve	DSL FO	=	Diesel fuel oil	NA	=	Not applicable
RCV	=	Radiation control valve	MS	=	Main steam			

TABLE 3.9-10

MAXIMUM DEFLECTIONS ALLOWED FOR REACTOR INTERNAL SUPPORT STRUCTURES FOR FAULTED CONDITIONS

Component	Allowable Deflection, Inches	No Loss of Function Deflection, Inches
Upper Barrel		
Radial inward	4.1	8.2
Radial outward	1.0	1.0
Upper Core Plate	0.100[a]	0.150
Rod Cluster Control Guide Tubes	1.0	1.75

(a) Only to ensure that the plate will not touch a guide tube.

TABLE 3.9-11

PRESSURIZED GAS CONTAINERS LOCATED OUTSIDE CONTAINMENT (Above 100 psig)

Vessel	PG&E Design Class	Design Code	Design Pressure	Vessel Operating Pressure	Vessel Volume	Type Relief Device[a]	Relief Set-point	Stored Energy ft-lb(ea)	Attached Piping Vessel Location	Attached Piping PG&E Design Class	Attached Piping Largest Size	Deviations from OSHA 29 CFR Section 1910
CO_2 storage tanks (Cardox)	I	ASME B&PV Code Sec. VIII	363 psig	300 psig	7.5 ton	Relief valve Pop safety	341 psig 357 psig	N.A.[b]	Turbine building	II	6 in.	None
Diesel generator starting air receivers	I	ASME B&PV Code Sec. VIII	342 psig	250 psig	53 cu ft	Relief valve	260 psig	3×10^6	Turbine building	I	2 in.	None
Diesel generator turbocharger booster air receivers	I	ASME B&PV Code Sec. VIII	342 psig	250 psig	106 cu ft	Relief valve	260 psig	5.9×10^6	Turbine building	I	2 in.	None
Air plant receiver	II	ASME B&PV Code Sec. VIII-Div. I	120 psig	110 psig	650 cu ft	Relief valve	115 psig	14.8×10^6	Turbine building	III	4 in.	None
N_2 storage vessels	II	ASME B&PV Code Sec. VIII Case 1205	2450 psig	2200 psig	51 cu ft per vessel	Relief valve	2450 psig	34.8×10^6	Yard vault	III	3/4 in.	None
Instrument air receivers	II	ASME B&PV Code Sec. VIII	120 psig	105 psig per receiver 2 receivers	152 cu ft	Relief valve	110 psig	3.5×10^6	Auxiliary building & intake Structure	III	2 in.	None
H_2 storage vessels	II	ASME B&PV Code Sec VIII Case1205	2450 psig	2200 psig	51 cu. ft. per vessel 6 vessels	Relief Valve	2450 psig	34.8×10^6	Yard Vault	III	3/4 in.	None

TABLE 3.9-11

Vessel	PG&E Design Class	Design Code	Design Pressure	Vessel Operating Pressure	Vessel Volume	Type Relief Device[a]	Relief Set-point	Stored Energy ft-lb(ea)	Attached Piping: Vessel Location	Attached Piping: PG&E Design Class	Attached Piping: Largest Size	Deviations from OSHA 29 CFR Section 1910
H_2 bottles standard commercial bottles (rental)	II	ICC Std. 3A	3225 psig	2000 psig	6.7 cu. ft. bottle 4 bottles	Relief Valve	3200 psig	6,000	Turbine Building	II	3/4 in.	None
CO_2 bottles standard commer-cial bottles (rental)	II	ICC Std. 3A	3225 psig	2000 psig	75 lb $C0_2$ per vessel 11 vessels	Relief Valve	3200 psig	2.245×10^6 (Calc. M-634)	Intake Structure	III	1/2 in.	None
Compressed breath air storage vessels	II	ASME B&PV Code Sec. VIII	6667 psig	6000 psig	17.6 cu. ft. per vessel 9 vessels	Relief Valve	6667 psig	34.97×10^6 (Ref. calc. M-110)	Unit 2 Turbine Building	III	3/4 in.	None
Breathing Air Compressor Internal Storage Cylinders	II	ASME B&PV Code Section VIII	6600 psig	6000 psig	1.44 cu. ft per bottle 12 bottles	Relief Valve	6500 psig	2.78×10^6 (Ref. calc. M-110)	E. Buttress Area (x8) 85' Aux Bldg (x4)	II	½ in.	None
Carbon dioxide Storage bottles	II	ICC Std. 3AA-2265	2265 psig	2000 psig	1.5 cu. ft. per bottle 16 bottles	Relief Valve	2200 psig		Turbine Building Elev. 85'	II	2 in.	None
N_2 storage bottles	II	ICC Std. 3AA-3500	3500 psig	2800 psig	1.5 cu. ft. per bottle 4 bottles	Relief Valve	3000 psig		Aux Bldg	II	1 in.	None
Argon storage bottles	II	ICC Std. 3AA-2015	2015 psig	2000 psig	1.5 cu. ft. per bottle 5 bottles	Relief Valve	2015 psig		Penetration Area	II	1 in.	None
Air/N2	I	ASTM A106	1415 psig	850 psig	1.0 cu ft	Relief Valve	1000 psig	2.6×10^5	Aux Bldg	I	1/2in	

TABLE 3.9-11

Accumulator For HCV-142		Grade B							GE Area 100'		
Air/N2 Accumulator For 9356B	I	ASTM A106 Grade B	1415 psig	850 psig	0.8 cu ft	Relief Valve	1000 psig	2.1 X 10^5	Aux Bldg GE Area 85'	I	1/2in

(a) Relief setpoint and capacity based on the applicable design code.

(b) Filled with liquid, which requires heat input to flash.

TABLE 3.9-12

MECHANICAL EQUIPMENT SEISMIC
QUALIFICATION RESULTS

Equipment	Location Building/ Elevation, ft	Qualification Method	Qualifying Spectra HE, DDE, DE	Damping Value Used
Feedwater System				
AFW Pump (Motor Driven)	Aux/100	A	DE	R
			DDE	R
			HE	R
AFW Pump Motor	Aux/100	A	DE	R
			DDE	R
			HE	R
AFW Pump (Turbine-driven)	Aux/100	A	DE	R
			DDE	R
			HE	R
AFW Pump Turbine	Aux/100	A	DE	R
			DDE	R
			HE	R
CVC System				
Boric Acid Tank and Heater	Aux/115	A	DE	2
			DDE	2
			HE	4
Safety Injection System				
SI Pump Lube Oil Filter Stand	Aux/85	A	DE	R
			DDE	R
			HE	R

TABLE 3.9-12

Equipment	Location Building/ Elevation, ft	Qualification Method	Qualifying Spectra HE, DDE, DE	Damping Value Used
Component Cooling System				
CCW Pump	Aux/73	A	DE	R
			DDE	R
			HE	R
CCW Pump Motor	Aux/73	A	DE	R
			DDE	R
			HE	R
CCW Heat Exchanger	Turb/85	A	DE	2
			DDE	2
			HE	4
CCW Surge Tank	Aux/163	A	DE	R
			DDE	R
			HE	R
CCW Pump Lube Oil Cooler	Aux/73	A	DE	R
			DDE	R
			HE	R
Makeup Water System				
Makeup Water Transfer Pump and Motor	Aux/100	A	DE	R
			DDE	R
			HE	R

TABLE 3.9-12

Equipment	Location Building/ Elevation, ft	Qualification Method	Qualifying Spectra HE, DDE, DE	Damping Value Used
Saltwater System				
ASW Pump and Motor	Intake/-2	A	DE	R
			DDE	R
			HE	4
Fire Protection System				
Fire Pump	Aux/115	A	DE	R
			DDE	R
			HE	R
Fire Pump Motor	Aux/115	A	DE	R
			DDE	R
			HE	R
Portable Fire Pump (diesel)	MSS/85	A, T	DE	R
			DDE	R
			HE	R
Diesel Generator System				
Diesel Generator	Turb/85	A, T	DE	2
			DDE	2
			HE	4

TABLE 3.9-12

Equipment	Location Building/ Elevation, ft	Qualification Method	Qualifying Spectra HE, DDE, DE	Damping Value Used
Diesel Transfer Pump	MSS/77	A	DE	R
			DDE	R
			HE	R
Diesel Transfer Pump Motor	MSS/77	A	DE	R
			DDE	R
			HE	R
Diesel Transfer Filter	MSS/77	A	DE	R
			DDE	R
			HE	R
Diesel Transfer Strainer	MSS/77	A	DE	R
			DDE	R
			HE	R
Priming Tank	Turb/85	A	DE	R
			DDE	R
			HE	R
Starting Air Receiver	Turb/85	A	DE	2
			DDE	2
			HE	4
Turbocharger Air Receiver	Turb/85	A	DE	R
			DDE	R
			HE	R

TABLE 3.9-12

Equipment	Location Building/ Elevation, ft	Qualification Method	Qualifying Spectra HE, DDE, DE	Damping Value Used
Ventilation System				
Containment H_2 Purge Supply Filters	Aux/100	A	DE	R
			DDE	R
			HE	R
Containment H_2 Purge Exhaust Filters	Aux/115	A	DE	R
			DDE	R
			HE	R
Containment Fan Cooler Box	Cont/140	A	DE	R
			DDE	R
			HE	R
Gaseous Radwaste System				
Waste Gas Compressor	Aux/60	A	DE[(a)]	R
Waste Gas Moisture Separator	Aux/60	A	DE[(a)]	R
Waste Gas Decay Tank	Aux/60	A	DE[(a)]	R

(a) Qualified for DE only per Table 3.2-2 Note (c).

(b) Legend:

A = Qualification by analysis (Qualification Method Column)
T = Qualification by testing
R = Rigid

TABLE 3.10-1

WESTINGHOUSE SUPPLIED CLASS IE INSTRUMENTATION AND ELECTRICAL EQUIPMENT SEISMIC CAPABILITIES

Equipment	Elev./Bldg.	Qualification Method	Qualifying Spectra HE, DDE, DE	FSAR Reference
Nuclear Instrumentation System Cabinet	140'/Aux.	T / A	HE, DDE, DE	3.10.3.1.1
Radiation Monitoring System Cabinets	140'/Aux.	T	HE, DDE, DE	3.10.3.1.1.1
Two-section Power Range Excore Neutron Detector	102'/Cont.	T	HE, DDE, DE	3.10.3.1.1
Solid State Protection System	140'/Aux.	T	HE, DDE, DE	3.10.3.1.2
Process Control and Protection System	128'/Aux.	T / A	HE, DDE, DE	3.10.3.1.3
Cont. Pressure Transmitter				
- Transmitter	109.67'/Cont. Exterior	T	HE, DDE, DE	3.10.3.1.5
- Sensor	109.67'/Cont.	T	HE, DDE, DE	3.10.3.1.5
Reactor Coolant Level Differential Pressure Transmitter	100'/Aux.	T	HE, DDE, DE	3.10.3.1.5
Reactor Trip Switchgear	115'/Aux.	T	HE, DDE, DE	3.10.3.1.6
Main Coolant Loop Resistance Temperature Detectors	117'/Cont.	T	HE, DDE, DE	3.10.3.1.7
Safeguards Test Cabinet	140'/Aux.	T	HE, DDE, DE	3.10.3.1.8
Aux. Safeguards Cabinet	128'/Aux.	T / A	HE, DDE, DE	3.10.3.1.9
Main Control Board	140'/Aux.	T / A	HE, DDE, DE	3.10.3.2
Electric Hydrogen Recombiner	140'/Cont.	T	HE, DDE, DE	3.10.3.30

TABLE 3.10-1

Equipment	Elev./Bldg.	Qualification Method	Qualifying Spectra HE, DDE, DE	FSAR Reference
Hydrogen Recombiner Control Panel and Power Supply	100'/Aux.	T	HE, DDE, DE	3.10.3.30
Reactor Vessel Level Instrumentation System/Incore Thermocouple Cabinets (PAMS 3 & 4)	140'/Aux.	T	HE, DDE, DE	3.10.3.31
Surface Mounted Resistance Temperature Detectors	140'/Cont.	T	HE, DDE, DE	3.10.3.31.2
High Volume Sensors	127'/Cont.	T	HE, DDE, DE	3.10.3.31.3
Hydraulic Isolators	89'/GW	T	HE, DDE, DE	3.10.3.31.4
Flux Mapping Transfer Device	127'/Cont.	A	HE	3.10.3.32
Incore Flux Mapping Cabinets	140'/Cont.	A	HE	3.10.3.32

A = Qualification by analysis (Qualification Method Column)
T = Qualification by testing
DE = Design Earthquake
DDE = Double Design Earthquake
HE = Hosgri Earthquake

TABLE 3.10-2

EQUIPMENT SEISMIC QUALIFICATION RESULTS:
ELECTRICAL, INSTRUMENTATION, AND CONTROLS

Equipment	Bldg./Elev.	Qualification Method	Qualifying Spectra HE, DDE, DE	FSAR Reference
Main annunciator	Aux/128	T / A	HE, DDE, DE	3.10.3.9
Battery chargers	Aux/115	T	HE, DDE, DE	3.10.3.8.3
Station battery	Aux/115	T / A	HE, DDE, DE	3.10.3.8.1
DC switchgear	Aux/115	T / A	HE, DDE, DE	3.10.3.8.4
Diesel generators a) Excitation cabinet b) Engine control cabinet	 Turb/85 Turb/85	 T / A T / A	HE, DDE, DE	3.10.3.6
Electrical penetrations	Cont/Various	A	HE, DDE, DE	3.10.3.10
Emergency light packs	Various	T	HE, DDE, DE	--
Fire pump controller	Aux/115	T	HE, DDE, DE	3.10.3.13
Hot shutdown panel and sub-panels	Aux/100	T / A	HE, DDE, DE	3.10.3.3
Transfer switch and cut-out switch panels	Aux/100 and 115	T / A	HE, DDE, DE	3.10.2.3.1
Heat trace distribution panel	Aux/Various	A	HE, DDE, DE	N/A
Instrument power ac panelboards	Aux/115	T / A	HE, DDE, DE	3.10.3.7.7

TABLE 3.10-2

Equipment	Bldg./Elev.	Qualification Method	Qualifying Spectra HE, DDE, DE	FSAR Reference
Instrument panels PIA, PIB & PIC	Aux/128	A	HE, DDE, DE	3.10.3.5
Instrument (Panels A & B)	Aux/128	T / A		
Local instrument panels	Various	A	HE, DDE, DE	3.10.3.4
Local starters (LPF 36)	Turb/119	T	HE, DDE, DE	3.10.3.14
Local starters (LPS 96)	Turb/140	T	HE, DDE, DE	3.10.3.14
Local starters (LPG 66) E1 100/J	Aux/ Various	T / A	HE, DDE, DE	3.10.3.14
Local starter 125 Vdc (FCV 95)	Aux/100	T	HE, DDE, DE	3.10.3.8.5
Limit switches	Various	T	HE, DDE, DE	3.10.3.27
P&ΔP transmitters	Various	T	HE, DDE, DE	3.10.3.11
Safeguards relay board	Turb/119	T / A	HE, DDE, DE	3.10.3.7.3
Ventilation control				
a) Logic cabinet (POV1, POV2)	Aux/140	T / A	HE, DDE, DE	3.10.3.15
b) Relay cabinet (RCV1, RCV2)	Aux/128	T / A	HE, DDE, DE	3.10.3.15
c) Electro-mechanical devices	Aux/Various	T / A	HE, DDE, DE	3.10.3.15
Vital load center (480 Vac MCC)	Aux/100	T / A	HE, DDE, DE	3.10.3.7.4

TABLE 3.10-2

Equipment	Bldg./Elev.	Qualification Method	Qualifying Spectra HE, DDE, DE	FSAR Reference
Vital load center transformer (480 V)	Aux/100	T / A	HE, DDE, DE	3.10.3.7.5
Auxiliary relay panels (SPF, SPG, SPH)	Aux/100	T / A	HE, DDE, DE	3.10.3.7.6
Fan cooler starter	Aux/100	T / A		
Vital switchgear (4.16 kV)	Turb/119	T / A	HE, DDE, DE	3.10.3.7.1
Potential transformers	Turb/119	T / A	HE, DDE, DE	3.10.3.7.2
Air circuit breaker (pressurizer heaters)	Aux/100	A	HE, DDE, DE	--
Solenoid valves	Various	T	HE, DDE, DE	3.10.3.23
Postaccident monitor panels and instrument (PAMs 1 & 2)	Aux/140	T / A	HE, DDE, DE	3.10.3.22
Containment H2 monitors	GW/85 GE/100	T / A	HE, DDE, DE	3.10.3.25
Containment high-range radiation detector	F/145	T	HE, DDE, DE	3.10.3.28
Containment purge exhaust detectors and LRP	L/100	T / A	HE, DDE, DE	3.10.3.26
Instrument AC UPS	Aux/115	T	HE, DDE, DE	3.10.3.1.4

TABLE 3.10-2

Equipment	Bldg./Elev.	Qualification Method	Qualifying Spectra HE, DDE, DE	FSAR Reference
Control room air supply radiation monitors	H/158	T	HE, DDE, DE	3.10.3.20
Control room pressurization	Turb/145	T	HE, DDE, DE	3.10.3.20
Radiation monitors	H/140	T	HE, DDE, DE	3.10.3.20
Control room vent & press. control & power panels	Various	T / A	HE, DDE, DE	3.10.3.20
Pressurizer SRV	F/146	T	HE, DDE, DE	3.10.3.29
Position margin monitor	H/140			
Sub-cooled margin monitor (calculators)	H/140	T	HE, DDE, DE	3.10.3.21
Process solenoid valves	G/110 GW/110	T	HE, DDE, DE	3.10.3.24

A = Qualification by analysis (Qualification Method Column)
T = Qualification by testing
DE = Design Earthquake
DDE = Double Design Earthquake
HE = Hosgri Earthquake

TABLE 3.10-3

HVAC EQUIPMENT SEISMIC QUALIFICATION SPECTRA RESULTS

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Supply Fan 1 (S-1)	L/85	A	HE, DDE, DE	(b)
Supply Fan 1 (2S-1)	L/85	C	HE, DDE, DE	(b)
Supply Fan 2 (S-2)	L/85	A	HE, DDE, DE	(b)
Supply Fan 2 (2S-2)	L/85	C	HE, DDE, DE	(b)
Supply Fan 31 (S-31)	K/140	A	HE, DDE, DE	(b)
Supply Fan 32 (S-32)	K/140	A	HE, DDE, DE	(b)
Supply Fan 33 (S-33)	K/140	C	HE, DDE, DE	(b)
Supply Fan 34 (S-34)	K/140	C	HE, DDE, DE	(b)
Supply Fan 39 (S-39)	K/156	A	HE, DDE, DE	(b)
Supply Fan 40 (S-40)	K/156	A	HE, DDE, DE	(b)
Supply Fan 41 (S-41)	K/156	C	HE, DDE, DE	(b)
Supply Fan 42 (S-42)	K/156	C	HE, DDE, DE	(b)
Exhaust Fan 1 (E-1)	L/128	A	HE, DDE, DE	(b)
Exhaust Fan 1 (2E-1)	L/128	C	HE, DDE, DE	(b)
Exhaust Fan 2 (E-2)	L/128	A	HE, DDE, DE	(b)
Exhaust Fan 2 (2E-2)	L/128	C	HE, DDE, DE	(b)
Exhaust Fan 4 (E-4)	L/140	A	HE, DDE, DE	(b)
Exhaust Fan 4 (2E-4)	L/140	C	HE, DDE, DE	(b)
Exhaust Fan 5 (E-5)	L/140	A	HE, DDE, DE	(b)
Exhaust Fan 5 (2E-5)	L/140	C	HE, DDE, DE	(b)
Exhaust Fan 6 (E-6)	L/140	A	HE, DDE, DE	(b)
Exhaust Fan 6 (2E-6)	L/140	C	HE, DDE, DE	(b)
Exhaust Fan 101 (E-101)	ISA/15	A	HE, DDE, DE	(b)
Exhaust Fan 102 (E-102)	ISA/15	A	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Exhaust Fan 103 (E-103)	ISA/15	A	HE, DDE, DE	(b)
Exhaust Fan 104 (E-104)	ISA/15	A	HE, DDE, DE	(b)
Supply Fan 43 (S-43)	H/163	A	HE, DDE, DE	(b)
Supply Fan 44 (S-44)	H/163	A	HE, DDE, DE	(b)
Supply Fan 45 (S-45)	H/163	C	HE, DDE, DE	(b)
Supply Fan 46 (S-46)	H/163	C	HE, DDE, DE	(b)
Exhaust Fan 43 (E-43)	H/163	A	HE, DDE, DE	(b)
Exhaust Fan 44 (E-44)	H/163	A	HE, DDE, DE	(b)
Exhaust Fan 45 (E-45)	H/163	C	HE, DDE, DE	(b)
Exhaust Fan 46 (E-46)	H/163	C	HE, DDE, DE	(b)
Supply Fan 35 (S-35)	K/157	A	HE, DDE, DE	(b)
Supply Fan 36 (S-36)	K/157	A	HE, DDE, DE	(b)
Supply Fan 37 (S-37)	K/157	C	HE, DDE, DE	(b)
Supply Fan 38 (S-38)	K/157	C	HE, DDE, DE	(b)
Supply Fan 67 (S-67)	A/119	A	HE, DDE, DE	(b)
Supply Fan 67 (2S-67)	A/119	C	HE, DDE, DE	(b)
Supply Fan 68 (S-68)	A/119	A	HE, DDE, DE	(b)
Supply Fan 68 (2S-68)	A/119	C	HE, DDE, DE	(b)
Supply Fan 69 (S-69)	A/119	A	HE, DDE, DE	(b)
Supply Fan 69 (2S-69)	A/119	C	HE, DDE, DE	(b)
Compressor Unit 35 (CP-35)	K/156	A	HE, DDE, DE	(b)
Compressor Unit 36 (CP-36)	K/156	A	HE, DDE, DE	(b)
Compressor Unit 37 (CP-37)	K/156	C	HE, DDE, DE	(b)
Compressor Unit 38 (CP-38)	K/156	C	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Condenser Unit 35 (CR-35)	K/157	A	HE, DDE, DE	(b)
Condenser Unit 36 (CR-36)	K/157	A	HE, DDE, DE	(b)
Condenser Unit 37 (CR-37)	K/157	C	HE, DDE, DE	(b)
Condenser Unit 38 (CR-38)	K/157	C	HE, DDE, DE	(b)
Mode Damper 78 in. (1A)	L/128	A	HE, DDE, DE	(b)
Mode Damper 78 in. (2-1A)	L/128	C	HE, DDE, DE	(b)
Mode Damper 78 in. (1B)	L/128	A	HE, DDE, DE	(b)
Mode Damper 78 in. (2-1B)	L/128	C	HE, DDE, DE	(b)
Mode Damper 132x144 (3)	L/122	A	HE, DDE, DE	(b)
Mode Damper 132x144 (2-3)	L/122	C	HE, DDE, DE	(b)
Mode Damper 96x144 (5A)	L/107	A	HE, DDE, DE	(b)
Mode Damper 96x144 (2-5A)	L/107	C	HE, DDE, DE	(b)
Mode Damper 96x144 (5B)	L/107	A	HE, DDE, DE	(b)
Mode Damper 96x144 (2-5B)	L/107	C	HE, DDE, DE	(b)
Mode Damper 108x144 (6)	L/122	A	HE, DDE, DE	(b)
Mode Damper 108x144 (2-6)	L/122	C	HE, DDE, DE	(b)
Mode Damper 108x144 (9)	L/122	A	HE, DDE, DE	(b)
Mode Damper 108x144 (2-9)	L/122	C	HE, DDE, DE	(b)
Backdraft Damper for Supply Fan S-31 96x72	K/146	A	HE, DDE, DE	(b)
Backdraft Damper for Supply Fan S-32 96x72	K/146	A	HE, DDE, DE	(b)
Backdraft Damper for Supply Fan S-33 96x72	K/146	C	HE, DDE, DE	(b)
Backdraft Damper for Supply Fan S-34 96x72	K/146	C	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Backdraft Damper for Exhaust Fan E-1 90x66	L/121	A	HE, DDE, DE	(b)
Backdraft Damper for Exhaust Fan 2E-1 90x66	L/121	C	HE, DDE, DE	(b)
Backdraft Damper for Exhaust Fan E-2 90x66	L/121	A	HE, DDE, DE	(b)
Backdraft Damper for Exhaust Fan 2E-2 90x66	L/121	C	HE, DDE, DE	(b)
Backdraft Damper for Exhaust Fan E-4 56x44	L/143	A	HE, DDE, DE	(b)
Backdraft Damper for Exhaust Fan 2E-4 56x44	L/143	A	HE, DDE, DE	(b)
Backdraft Damper for Exhaust Fan E-5 56x44	L/154	A	HE, DDE, DE	(b)
Backdraft Damper for Exhaust Fan 2E-5 56x44	L/154	A	HE, DDE, DE	(b)
Backdraft Damper for Exhaust Fan E-6 56x44	L/154	A	HE, DDE, DE	(b)
Backdraft Damper for Exhaust Fan 2E-6 56x44	L/154	A	HE, DDE, DE	(b)
Forced Draft Shutter Damper 30x48	G/96	A	HE, DDE, DE	(b)
Forced Draft Shutter Damper 30x48	G/96	C	HE, DDE, DE	(b)
Fire Damper 46x14 (FD-4)	H/125	A	HE, DDE, DE	(b)
Fire Damper 46x14 (2FD-4)	H/125	C	HE, DDE, DE	(b)
Fire Damper 46x14 (FD-5)	H/125	A	HE, DDE, DE	(b)
Fire Damper 46x14 (2FD-5)	H/125	C	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Fire Damper 46x14 (FD-6)	H/125	A	HE, DDE, DE	(b)
Fire Damper 46x14 (2FD-6)	H/125	C	HE, DDE, DE	(b)
Carbon Tray Filters (EFC-1)	L/115	A	HE, DDE, DE	(b)
Carbon Tray Filters (2EFC-1)	L/115	C	HE, DDE, DE	(b)
Carbon Tray Filters (EFC-5)	L/148	A	HE, DDE, DE	(b)
Carbon Tray Filters (2EFC-5)	L/148	C	HE, DDE, DE	(b)
Carbon Tray Filters (EFC-6)	L/148	A	HE, DDE, DE	(b)
Carbon Tray Filters (2EFC-6)	L/148	C	HE, DDE, DE	(b)
Astrocel-Hepa Filters (EFH-1)	L/126	A	HE, DDE, DE	(b)
Astrocel-Hepa Filters (2EFH-1)	L/126	C	HE, DDE, DE	(b)
Astrocel-Hepa Filters (EFH-2a)	L/126	A	HE, DDE, DE	(b)
Astrocel-Hepa Filters (2EFH-2a)	L/126	C	HE, DDE, DE	(b)
Astrocel-Hepa Filters (EFH-2b)	L/105	A	HE, DDE, DE	(b)
Astrocel-Hepa Filters (2EFH-2b)	L/105	C	HE, DDE, DE	(b)
Astrocel-Hepa Filters (EFH-4)	L/150	A	HE, DDE, DE	(b)
Astrocel-Hepa Filters (2EFH-4)	L/150	C	HE, DDE, DE	(b)
Astrocel-Hepa Filters (EFH-5)	L/148	A	HE, DDE, DE	(b)
Astrocel-Hepa Filters (2EFH-5)	L/148	C	HE, DDE, DE	(b)
Astrocel-Hepa Filters (EFH-6)	L/148	A	HE, DDE, DE	(b)
Astrocel-Hepa Filters (2EFH-6)	L/148	C	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Varicel-Roughing Filter (EFR-4)	L/154	A	HE, DDE, DE	(b)
Varicel-Roughing Filter (2EFR-4)	L/154	C	HE, DDE, DE	(b)
Varicel-Roughing Filter (EFR-5)	L/154	A	HE, DDE, DE	(b)
Varicel-Roughing Filter (2EFR-5)	L/154	C	HE, DDE, DE	(b)
Varicel-Roughing Filter (EFR-6)	L/154	A	HE, DDE, DE	(b)
Varicel-Roughing Filter (2EFR-6)	L/154	C	HE, DDE, DE	(b)
Filter Housing With Filters (FU-39)	K/155	A	HE, DDE, DE	(b)
Filter Housing With Filters (FU-41)	K/155	C	HE, DDE, DE	(b)
Filter Box (FB-29)	H/163	A	HE, DDE, DE	(b)
Filter Box (2FB-29)	H/163	C	HE, DDE, DE	(b)
Electric Duct Heater (EH-30)	L/137	A	HE, DDE, DE	(b)
Chromalox Model TDH-54C (2EH-30)	J/138	C	HE, DDE, DE	(b)
Supply Fan 96 for CRPS (OS-96)	A/140	C	HE, DDE, DE	(b)
Supply Fan 97 for CRPS (OS-97)	A/140	C	HE, DDE, DE	(b)
Supply Fan 98 for CRPS (OS-98)	A/140	A	HE, DDE, DE	(b)
Supply Fan 99 for CRPS (OS-99)	A/140	A	HE, DDE, DE	(b)
Mode Damper 72 in. ϕ and Actuator (2A)	L/132	A	HE, DDE, DE	(b)
Mode Damper 72 in. ϕ and Actuator (2-2A)	L/132	C	HE, DDE, DE	(b)
Mode Damper 72 in. ϕ and Actuator (2B)	L/132	A	HE, DDE, DE	(b)
Mode Damper 72 in. ϕ and Actuator (2-2B)	L/132	C	HE, DDE, DE	(b)
Mode Damper 90x66 and Actuator (7)	L/102	A	HE, DDE, DE	(b)
Mode Damper 90x66 and Actuator (2-7)	L/102	C	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Mode Damper 10 in. ϕ (13A)	K/97	A	HE, DDE, DE	(b)
Mode Damper 10 in. ϕ (2-13A)	K/97	C	HE, DDE, DE	(b)
Mode Damper 10 in. ϕ (13B)	K/97	A	HE, DDE, DE	(b)
Mode Damper 10 in. ϕ (2-13B)	K/97	C	HE, DDE, DE	(b)
Mode Damper 10 in. ϕ (14A)	GE/81	A	HE, DDE, DE	(b)
Mode Damper 10 in. ϕ (2-14A)	GE/81	C	HE, DDE, DE	(b)
Mode Damper 10 in. ϕ (14B)	GE/81	A	HE, DDE, DE	(b)
Mode Damper 10 in. ϕ (2-14B)	GE/81	C	HE, DDE, DE	(b)
Mode Damper 14 in. ϕ (15A)	GE/70	A	HE, DDE, DE	(b)
Mode Damper 14 in. ϕ (2-15A)	GE/70	C	HE, DDE, DE	(b)
Mode Damper 14 in. ϕ (15B)	GE/70	A	HE, DDE, DE	(b)
Mode Damper 14 in. ϕ (2-15B)	GE/70	C	HE, DDE, DE	(b)
Isolation Damper 40 in. ϕ (1-FCV-5160)	L/140	A	HE, DDE, DE	(b)
Isolation Damper 40 in. ϕ (2-FCV-5160)	L/140	A	HE, DDE, DE	(b)
Isolation Damper 40 in. ϕ (1-FCV-5161)	L/140	A	HE, DDE, DE	(b)
Isolation Damper 40 in. ϕ (2-FCV-5161)	L/140	A	HE, DDE, DE	(b)
Mode Damper 48 in. ϕ (35)	L/107	A	HE, DDE, DE	(b)
Mode Damper 48 in. ϕ (2-35)	L/107	C	HE, DDE, DE	(b)
Mode Damper 54 in. ϕ and Actuator (29)	L/150	A	HE, DDE, DE	(b)
Mode Damper 54 in. ϕ and Actuator (2-29)	L/150	C	HE, DDE, DE	(b)
Mode Damper 54 in. ϕ and Actuator (30)	L/150	A	HE, DDE, DE	(b)
Mode Damper 54 in. ϕ and Actuator (2-30)	L/150	C	HE, DDE, DE	(b)
Mode Damper 54 in. ϕ and Actuator (31)	L/150	A	HE, DDE, DE	(b)
Mode Damper 54 in. ϕ and Actuator (2-31)	L/150	C	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Mode Damper 72x100 (4A)	L/107	A	HE, DDE, DE	(b)
Mode Damper 72x100 (2-4A)	L/107	C	HE, DDE, DE	(b)
Mode Damper 72x100 (4B)	L/107	A	HE, DDE, DE	(b)
Mode Damper 72x100 (2-4B)	L/107	C	HE, DDE, DE	(b)
Mode Damper 72x75 (8A)	L/133	A	HE, DDE, DE	(b)
Mode Damper 72x75 (2-8A)	L/133	C	HE, DDE, DE	(b)
Mode Damper 72x75 (8B)	L/115	A	HE, DDE, DE	(b)
Mode Damper 72x75 (2-8B)	L/115	C	HE, DDE, DE	(b)
Mode Damper 90x66 (10)	L/110	A	HE, DDE, DE	(b)
Mode Damper 90x66 (2-10)	L/110	C	HE, DDE, DE	(b)
Mode Damper 40x84 (12)	K/90	A	HE, DDE, DE	(b)
Mode Damper 40x84 (2-12)	K/90	C	HE, DDE, DE	(b)
Mode Damper 46x40 (16A)	K/95	A	HE, DDE, DE	(b)
Mode Damper 46x40 (2-16A)	K/95	C	HE, DDE, DE	(b)
Mode Damper 46x40 (16B)	K/95	A	HE, DDE, DE	(b)
Mode Damper 46x40 (2-16B)	K/95	C	HE, DDE, DE	(b)
Mode Damper 26x54 (17A)	K/94	A	HE, DDE, DE	(b)
Mode Damper 26x54 (2-17A)	K/94	C	HE, DDE, DE	(b)
Mode Damper 26x54 (17B)	K/94	A	HE, DDE, DE	(b)
Mode Damper 26x54 (2-17B)	K/94	C	HE, DDE, DE	(b)
Mode Damper 96x72 (20)	K/146	A	HE, DDE, DE	(b)
Mode Damper 96x72 (2-24)	K/146	C	HE, DDE, DE	(b)
Mode Damper 96x72 (21)	K/146	A	HE, DDE, DE	(b)
Mode Damper 96x72 (2-21)	K/146	C	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Mode Damper 54x100 (22A)	K/141	A	HE, DDE, DE	(b)
Mode Damper 54x100 (2-22A)	K/141	C	HE, DDE, DE	(b)
Mode Damper 54x100 (22B)	K/132	A	HE, DDE, DE	(b)
Mode Damper 54x100 (2-22B)	K/132	C	HE, DDE, DE	(b)
Mode Damper 40x40 (23)	K/135	A	HE, DDE, DE	(b)
Mode Damper 40x40 (2-23)	K/135	C	HE, DDE, DE	(b)
Mode Damper 40x40 (23B)	K/135	A	HE, DDE, DE	(b)
Mode Damper 40x40 (2-23B)	K/135	C	HE, DDE, DE	(b)
Mode Damper 14x44 (24)	K/111	A	HE, DDE, DE	(b)
Mode Damper 14x44 (2-24)	K/111	C	HE, DDE, DE	(b)
Mode Damper 14x44 (24B)	K/111	A	HE, DDE, DE	(b)
Mode Damper 14x44 (2-24B)	K/111	C	HE, DDE, DE	(b)
Mode Damper 48x40 (26A)	K/87	A	HE, DDE, DE	(b)
Mode Damper 48x40 (2-26A)	K/87	C	HE, DDE, DE	(b)
Mode Damper 48x40 (26B)	K/87	A	HE, DDE, DE	(b)
Mode Damper 48x40 (2-26B)	K/87	C	HE, DDE, DE	(b)
Mode Damper 30x48 (25)	K/95	A	HE, DDE, DE	(b)
Mode Damper 30x48 (2-25)	K/95	C	HE, DDE, DE	(b)
Mode Damper 30x48 (25B)	K/95	A	HE, DDE, DE	(b)
Mode Damper 30x48 (2-25B)	K/95	C	HE, DDE, DE	(b)
Mode Damper 42x64 (33)	L/108	A	HE, DDE, DE	(b)
Mode Damper 42x64 (2-33)	L/108	C	HE, DDE, DE	(b)
Mode Damper 42x64 (34)	L/105	A	HE, DDE, DE	(b)
Mode Damper 42x64 (2-34)	L/105	C	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Backdraft Damper for Supply Fan S-1 64x42	L/95	A	HE, DDE, DE	(b)
Backdraft Damper for Supply Fan 2S-1 64x42	L/95	C	HE, DDE, DE	(b)
Backdraft Damper for Supply Fan S-2 64x42	L/95	A	HE, DDE, DE	(b)
Backdraft Damper for Supply Fan 2S-2 64x42	L/95	C	HE, DDE, DE	(b)
Backdraft Damper 14 in. ϕ (OBD-1)	A/149	A	HE, DDE, DE	(b)
Backdraft Damper 14 in. ϕ (OBD-2)	A/149	A	HE, DDE, DE	(b)
Backdraft Damper 14 in. ϕ (OBD-3)	A/149	C	HE, DDE, DE	(b)
Backdraft Damper 14 in. ϕ (OBD-4) A/149	A/149	C	HE, DDE, DE	(b)
Quadrant Damper (QD 10 in. ϕ)	K/110	A	HE, DDE, DE	(b)
Quadrant Damper (QD 20 in. ϕ)	K/82	A	HE, DDE, DE	(b)
Quadrant Damper (QD 14 in. ϕ)	K/82	A	HE, DDE, DE	(b)
Quadrant Damper (QD 14 in. ϕ)	K/111	A	HE, DDE, DE	(b)
Quadrant Damper (QD 16 in. ϕ)	K/111	A	HE, DDE, DE	(b)
Quadrant Damper (QD 12 in. ϕ)	K/112	A	HE, DDE, DE	(b)
Quadrant Damper (QD 12 in. ϕ)	K/130	A	HE, DDE, DE	(b) (e)
Quadrant Damper (QD 10 in. ϕ)	K/132	A	HE, DDE, DE	(b) (e)
Quadrant Damper (QD 14 in. ϕ)	K/132	A	HE, DDE, DE	(b) (e)
Quadrant Damper (QD 12 in. ϕ)	K/134	A	HE, DDE, DE	(b) (e)
Quadrant Damper (QD 16 in. ϕ)	K/134	A	HE, DDE, DE	(b) (e)
Quadrant Damper (QD 16 in. ϕ)	K/131	A	HE, DDE, DE	(b) (e)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Quadrant Damper (QD 20 in. ϕ)	K/134	A	HE, DDE, DE	(b) (e)
Quadrant Damper (QD 14 in. ϕ)	K/134	A	HE, DDE, DE	(b) (e)
Quadrant Damper (QD 14 in. ϕ)	K/70	A	HE, DDE, DE	(b)
Quadrant Damper (QD 14 in. ϕ)	GE/70	A	HE, DDE, DE	(b)
Quadrant Damper (QD 14 in. ϕ)	H/79	A	HE, DDE, DE	(b)
Quadrant Damper (QD 20 in. ϕ)	H/65	A	HE, DDE, DE	(b)
Quadrant Damper (QD 28 in. ϕ)	J/132	A	HE, DDE, DE	(b)
Quadrant Damper (QD 16 in. ϕ)	L/141	A	HE, DDE, DE	(b)
Quadrant Damper (QD 14 in. ϕ)	GE/70	A	HE, DDE, DE	(b)
Quadrant Damper (QD 18 in. ϕ)	K/132	C	HE, DDE, DE	(b)
Quadrant Damper #52 (QD 48x24)	J/111	A	HE, DDE, DE	(b)
Quadrant Damper #2-52 (QD 48x24)	J/111	A	HE, DDE, DE	(b)
Quadrant Damper #54 (QD 42x42)	J/134	A	HE, DDE, DE	(b)
Quadrant Damper #2-54 (QD 42x42)	J/134	A	HE, DDE, DE	(b)
Quadrant Damper #46 (QD 38x14)	J/123	A	HE, DDE, DE	(b)
Quadrant Damper #2-46 (QD 38x14)	J/123	A	HE, DDE, DE	(b)
Quadrant Damper #33 (QD 40x40)	K/135	A	HE, DDE, DE	(b)
Quadrant Damper #2-33 (QD 40x40)	K/135	A	HE, DDE, DE	(b)
Quadrant Damper #34 (QD 14x10)	K/136	A	HE, DDE, DE	(b)
Quadrant Damper #2-34 (QD 14x10)	K/136	A	HE, DDE, DE	(b)
Quadrant Damper #35 (QD 46x14)	K/134	A	HE, DDE, DE	(b)
Quadrant Damper #2-35 (QD 46x14)	K/134	A	HE, DDE, DE	(b)
Quadrant Damper #24 (QD 14x14)	K/109	A	HE, DDE, DE	(b)
Quadrant Damper #2-24 (QD 14x14)	K/109	A	HE, DDE, DE	(b)
Quadrant Damper #31 (QD 54x100)	K/132	A	HE, DDE, DE	(b)
Quadrant Damper #2-31 (QD 54x100)	K/132	C	HE, DDE, DE	(b)
Quadrant Damper #25 (QD 14x30)	K/111	A	HE, DDE, DE	(b)
Quadrant Damper #2-25 (QD 14x30)	K/111	A	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Quadrant Damper #66 (QD 24x44)	K/92	A	HE, DDE, DE	(b)
Quadrant Damper #2-67 (QD 24x44)	K/92	A	HE, DDE, DE	(b)
Quadrant Damper #5 (QD 58x32)	K/81	A	HE, DDE, DE	(b)
Quadrant Damper #2-5 (QD 58x32)	K/81	C	HE, DDE, DE	(b)
Quadrant Damper #64 (QD 44x32)	K/81	A	HE, DDE, DE	(b)
Quadrant Damper #2-64 (QD 44x32)	K/81	A	HE, DDE, DE	(b)
Quadrant Damper #6 (QD 24x32)	K/81	A	HE, DDE, DE	(b)
Quadrant Damper #2-6 (QD 24x32)	K/81	A	HE, DDE, DE	(b)
Quadrant Damper #4 (QD 44x26)	K/82	A	HE, DDE, DE	(b)
Quadrant Damper #2-4 (QD 44x26)	K/82	A	HE, DDE, DE	(b)
Quadrant Damper #53 (QD 72x100)	L/100	A	HE, DDE, DE	(b)
Quadrant Damper #2-53 (QD 72x100)	L/100	C	HE, DDE, DE	(b)
Volume Damper (VD 24x24)	H/123	A	HE, DDE, DE	(b)
Volume Damper (VD 24x24)	H/124	A	HE, DDE, DE	(b)
Volume Damper (VD 27x21)	H/124	A	HE, DDE, DE	(b)
Quadrant Damper #19 (QD 38x44)	K/96	A	HE, DDE, DE	(b)
Quadrant Damper #2-19 (QD 38x44)	K/96	A	HE, DDE, DE	(b)
Quadrant Damper #15 (QD 20x12)	K/97	A	HE, DDE, DE	(b)
Quadrant Damper #2-15 (QD 20x12)	K/97	A	HE, DDE, DE	(b)
Quadrant Damper #20 (QD 20x44)	K/97	A	HE, DDE, DE	(b)
Quadrant Damper #2-20 (QD 20x44)	K/97	A	HE, DDE, DE	(b)
Quadrant Damper #14 (QD 72x24)	K/96	A	HE, DDE, DE	(b)
Quadrant Damper #2-14 (QD 72x24)	K/96	A	HE, DDE, DE	(b)
Quadrant Damper #28 (QD 18x16)	K/113	A	HE, DDE, DE	(b)
Quadrant Damper #2-28 (QD 18x16)	K/113	A	HE, DDE, DE	(b)
Quadrant Damper #29 (QD 16x18)	K/112	A	HE, DDE, DE	(b)
Quadrant Damper #2-29 (QD 16x18)	K/112	A	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Quadrant Damper #37 (QD 32x30)	K/132	A	HE, DDE, DE	(b)
Quadrant Damper #2-37 (QD 32x30)	K/132	A	HE, DDE, DE	(b)
Quadrant Damper #45 (QD 38x38)	J/120	A	HE, DDE, DE	(b)
Quadrant Damper #2-45 (QD 38x38)	J/120	A	HE, DDE, DE	(b)
Quadrant Damper (QD 24x24)	H/130	C	HE, DDE, DE	(b) (f)
Quadrant Damper (QD 18x24)	H/130	C	HE, DDE, DE	(b) (f)
Quadrant Damper #36 (QD 22x30)	K/131	A	HE, DDE, DE	(b)
Quadrant Damper #2-36 (QD 22x30)	K/131	A	HE, DDE, DE	(b)
Quadrant Damper #10 (QD 46x30)	K/78	A	HE, DDE, DE	(b)
Quadrant Damper #2-10 (QD 46x30)	K/78	A	HE, DDE, DE	(b)
Quadrant Damper #11 (QD 18x30)	K/79	A	HE, DDE, DE	(b)
Quadrant Damper #2-11 (QD 18x30)	K/79	A	HE, DDE, DE	(b)
Quadrant Damper #12 (QD 6x30)	K/79	A	HE, DDE, DE	(b)
Quadrant Damper #2-12 (QD 6x30)	K/79	A	HE, DDE, DE	(b)
Quadrant Damper #3 (QD 20x32)	K/69	A	HE, DDE, DE	(b)
Quadrant Damper #2-3 (QD 20x32)	K/69	A	HE, DDE, DE	(b)
Quadrant Damper #55 (QD 30x12)	H/61	A	HE, DDE, DE	(b)
Quadrant Damper #2-55 (QD 30x12)	H/61	A	HE, DDE, DE	(b)
Quadrant Damper #40 (QD 16x40)	J/152	A	HE, DDE, DE	(b)
Quadrant Damper #2-40 (QD 16x40)	J/152	A	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Quadrant Damper #27 (QD 40x42)	K/110	A	HE, DDE, DE	(b)
Quadrant Damper #2-27 (QD 40x42)	K/110	A	HE, DDE, DE	(b)
Quadrant Damper #26 (QD 36x42)	K/110	A	HE, DDE, DE	(b)
Quadrant Damper #2-26 (QD 36x42)	K/110	A	HE, DDE, DE	(b)
Quadrant Damper #18 (QD 40x26)	K/97			
Quadrant Damper #2-18 (QD 40x26)	K/97			
Quadrant Damper #2 (QD 30x66)	H/69	A	HE, DDE, DE	(b)
Quadrant Damper #2-2 (QD 30x66)	H/69	A	HE, DDE, DE	(b)
Quadrant Damper #1 (QD 24x72)	K/69	A	HE, DDE, DE	(b)
Quadrant Damper #2-1 (QD 24x72)	K/69	A	HE, DDE, DE	(b)
Quadrant Damper #43 (QD 86x48)	K/132	A	HE, DDE, DE	(b)
Quadrant Damper #2-43 (QD 86x48)	K/132	C	HE, DDE, DE	(b)
Quadrant Damper #42 (QD 36x18)	K/132	A	HE, DDE, DE	(b)
Quadrant Damper #2-42 (QD 36x18)	K/132	A	HE, DDE, DE	(b)
Quadrant Damper #8 (QD 36x18)	K/81	A	HE, DDE, DE	(b)
Quadrant Damper #2-8 (QD 36x18)	K/81	A	HE, DDE, DE	(b)
Quadrant Damper #9 (QD 36x18)	K/81	A	HE, DDE, DE	(b)
Quadrant Damper #2-9 (QD 36x18)	K/81	A	HE, DDE, DE	(b)
Quadrant Damper #41 (QD 56x50)	L/143	A	HE, DDE, DE	(b)
Quadrant Damper #2-41 (QD 56x50)	L/143	C	HE, DDE, DE	(b)
Quadrant Damper #65 (QD 60x30)	J/152	A	HE, DDE, DE	(b)
Quadrant Damper #2-65 (QD 60x30)	J/152	C	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Quadrant Damper #49 (QD 38x30)	J/156	A	HE, DDE, DE	(b)
Quadrant Damper #2-49 (QD 38x30)	J/156	C	HE, DDE, DE	(b)
Quadrant Damper #7 (QD 84x72)	K/85	A	HE, DDE, DE	(b)
Quadrant Damper #2-7 (QD 84x72)	K/85	C	HE, DDE, DE	(b)
Quadrant Damper #13 (QD 54x48)	K/86	A	HE, DDE, DE	(b)
Quadrant Damper #2-13 (QD 54x48)	K/86	C	HE, DDE, DE	(b)
Quadrant Damper #32 (QD 37x78)	K/131	A	HE, DDE, DE	(b)
Quadrant Damper #2-32 (QD 37x78)	K/131	A	HE, DDE, DE	(b)
Motorized Damper 24 in. ϕ (2)	H/156	A	HE, DDE, DE	(b)
Motorized Damper 24 in. ϕ (2-2)	H/156	A	HE, DDE, DE	(b)
Motorized Damper 24 in. ϕ (2A)	H/160	A	HE, DDE, DE	(b)
Motorized Damper 24 in. ϕ (2-2A)	H/160	A	HE, DDE, DE	(b)
Motorized Damper 18 in. ϕ (3)	H/156	A	HE, DDE, DE	(b)
Motorized Damper 18 in. ϕ (2-3)	H/156	A	HE, DDE, DE	(b)
Motorized Damper 18 in. ϕ (3A)	H/160	A	HE, DDE, DE	(b)
Motorized Damper 18 in. ϕ (2-3A)	H/160	A	HE, DDE, DE	(b)
Motorized Damper 24 in. ϕ (7)	H/161	A	HE, DDE, DE	(b)
Motorized Damper 24 in. ϕ (2-7)	H/161	A	HE, DDE, DE	(b)
Motorized Damper 24 in. ϕ (7A)	H/159	A	HE, DDE, DE	(b)
Motorized Damper 24 in. ϕ (2-7A)	H/159	A	HE, DDE, DE	(b)
Motorized Damper 18 in. ϕ (8)	H/163	A	HE, DDE, DE	(b)
Motorized Damper 18 in. ϕ (2-8)	H/163	A	HE, DDE, DE	(b)
Motorized Damper 18 in. ϕ (8A)	H/163	A	HE, DDE, DE	(b)
Motorized Damper 18 in. ϕ (2-8A)	H/163	A	HE, DDE, DE	(b)
Motorized Damper 14 in. ϕ for CRPS (1)	A/143	A	HE, DDE, DE	(b)
Motorized Damper 14 in. ϕ for CRPS (2-1)	A/143	C	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Motorized Damper 14 in. ϕ for CRPS (1A)	A/149	A	HE, DDE, DE	(b)
Motorized Damper 14 in. ϕ for CRPS (2-1A)	A/149	C	HE, DDE, DE	(b)
Motorized Damper 14 in. ϕ for CRPS (1B)	A/143	A	HE, DDE, DE	(b)
Motorized Damper 14 in. ϕ for CRPS (2-1B)	A/143	C	HE, DDE, DE	(b)
Motorized Damper 14 in. ϕ for CRPS (1C)	A/149	A	HE, DDE, DE	(b)
Motorized Damper 14 in. ϕ for CRPS (2-1C)	A/149	C	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (2)	H/156	T	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (2-2)	H/156	T	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (2A)	H/160	T	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (2-2A)	H/160	T	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (3)	H/156	T	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (2-3)	H/156	T	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (3A)	H/160	T	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (2-3A)	H/161	T	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (7)	H/160	T	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (2-7)	H/161	T	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (7A)	H/159	T	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (2-7A)	H/159	T	HE, DDE, DE	(b)
Limitorque Actuator for	H/163	T	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Motorized Damper (8)				
Limitorque Actuator for Motorized Damper (2-8)	H/163	T	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (8A)	H/163	T	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (2-8A)	H/163	T	HE, DDE, DE	(b)
Motorized Damper 18x16 (4)	H/163	A	HE, DDE, DE	(b)
Motorized Damper 18x16 (2-4)	H/163	C	HE, DDE, DE	(b)
Motorized Damper 36x24 (5)	H/163	A	HE, DDE, DE	(b)
Motorized Damper 36x24 (2-5)	H/163	C	HE, DDE, DE	(b)
Motorized Damper 36x24 (6)	H/159	A	HE, DDE, DE	(b)
Motorized Damper 36x24 (2-6)	H/159	C	HE, DDE, DE	(b)
Motorized Damper 70x16 (9)	H/159	A	HE, DDE, DE	(b)
Motorized Damper 70x16 (2-9)	H/159	C	HE, DDE, DE	(b)
Motorized Damper 70x16 (9A)	H/159	A	HE, DDE, DE	(b)
Motorized Damper 70x16 (2-9A)	H/159	C	HE, DDE, DE	(b)
Motorized Damper 70x20 (10)	H/157	A	HE, DDE, DE	(b)
Motorized Damper 70x20 (2-10)	H/157	C	HE, DDE, DE	(b)
Motorized Damper 70x20 (10A)	H/157	A	HE, DDE, DE	(b)
Motorized Damper 70x20 (2-10A)	H/157	C	HE, DDE, DE	(b)
Motorized Damper 70x16 (11)	H/159	A	HE, DDE, DE	(b)
Motorized Damper 70x16 (2-11)	H/159	C	HE, DDE, DE	(b)
Motorized Damper 70x16 (11A)	H/159	A	HE, DDE, DE	(b)
Motorized Damper 70x16 (2-11A)	H/159	C	HE, DDE, DE	(b)
Motorized Damper 70x20 (12)	H/157	A	HE, DDE, DE	(b)
Motorized Damper 70x20 (2-12)	H/157	C	HE, DDE, DE	(b)
Motorized Damper 70x20 (12A)	H/157	A	HE, DDE, DE	(b)
Motorized Damper 70x20 (2-12A)	H/157	C	HE, DDE, DE	(b)
Motorized Damper 22x12 (13)	H/159	A	HE, DDE, DE	(b)
Motorized Damper 22x12 (2-13)	H/159	C	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Motorized Damper 22x12 (14)	H/159	A	HE, DDE, DE	(b)
Motorized Damper 22x12 (2-14)	H/159	C	HE, DDE, DE	(b)
Balancing Damper 14 in. ϕ (1-15)	H/163	A	HE, DDE, DE	(b)
Balancing Damper 14 in. ϕ(2-15)	H/163	C	HE, DDE, DE	(b)
Balancing Damper 14 in. ϕ (1-16)	A/141	A	HE, DDE, DE	(b)
Balancing Damper 14 in. ϕ (2-16)	A/141	C	HE, DDE, DE	(b)
Shut-off Damper (48X48) (HD-43)	H/168	A	HE, DDE, DE	(b)
Shut-off Damper (48X48) (HD-44)	H/168	A	HE, DDE, DE	(b)
Shut-off Damper (48X48) (HD-45)	H/168	C	HE, DDE, DE	(b)
Shut-off Damper (48X48) (HD-46)	H/168	C	HE, DDE, DE	(b)
Back Draft Damper (E-21)	GW/96	A	HE, DDE, DE	(b)
Back Draft Damper (48X48) (BDD-43)	H/168	A	HE, DDE, DE	(b)
Back Draft Damper (48X48) (BDD-44)	H/168	A	HE, DDE, DE	(b)
Back Draft Damper (48X48) (BDD-45)	H/168	C	HE, DDE, DE	(b)
Back Draft Damper (48X48) (BDD-46)	H/168	C	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper 4	K/166	T	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper 2-4	K/166	C	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper 5	K/166	T	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper 2-5	K/166	C	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper 6	K/166	T	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Barber Colman Actuator for Motorized Damper 2-6	K/166	C	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper (9)	K/159	T	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper (2-9)	K/159	T	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper (9A)	K/159	T	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper (2-9A)	K/159	T	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper (10)	H/157	T	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper (2-10)	H/157	T	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper (10A)	H/157	T	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper (2-10A)	H/157	T	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper (11)	K/159	T	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper (2-11)	K/159	T	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper (11A)	K/159	T	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper (2-11A)	K/159	T	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper (12)	H/157	T	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper (2-12)	H/157	T	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper (12A)	H/157	T	HE, DDE, DE	(b)
Barber Colman Actuator for	H/157	T	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Motorized Damper (2-12A)				
Barber Colman Actuator for Motorized Damper (13)	K/159	T	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper (2-13)	K/159	T	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper (14)	K/159	T	HE, DDE, DE	(b)
Barber Colman Actuator for Motorized Damper (2-14)	K/159	T	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (1)	A/143	T	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (2-1)	A/143	C	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (1A)	A/149	T	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (2-1A)	A/149	C	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (1B)	A/143	T	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (2-1B)	A/143	C	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (1C)	A/149	T	HE, DDE, DE	(b)
Limitorque Actuator for Motorized Damper (2-1C)	A/149	C	HE, DDE, DE	(b)
Pneumatic Contromatics Operator for Fan S-1	L/91	T	HE, DDE, DE	(b)
Pneumatic Contromatics Operator for Fan 2S-1	L/91	C	HE, DDE, DE	(b)
Pneumatic Contromatics Operator for Fan S-2	L/91	T	HE, DDE, DE	(b)
Pneumatic Contromatics Operator for Fan 2S-2	L/91	C	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Pneumatic Contromatics Operator for Fan S-31	K/150	T	HE, DDE, DE	(b)
Pneumatic Contromatics Operator for Fan S-33	K/150	C	HE, DDE, DE	(b)
Pneumatic Contromatics Operator for Fan S-32	K/150	T	HE, DDE, DE	(b)
Pneumatic Contromatics Operator for Fan S-34	K/150	C	HE, DDE, DE	(b)
Pneumatic Contromatics Operator for Fan E-1	L/135	T	HE, DDE, DE	(b)
Pneumatic Contromatics Operator for Fan 2E-1	L/135	C	HE, DDE, DE	(b)
Pneumatic Contromatics Operator for Fan E-2	L/135	T	HE, DDE, DE	(b)
Pneumatic Contromatics Operator for Fan 2E-2	L/135	C	HE, DDE, DE	(b)
Pneumatic Contromatics Operator for Fan E-4	L/146	T	HE, DDE, DE	(b)
Pneumatic Contromatics Operator for Fan 2E-4	L/146	C	HE, DDE, DE	(b)
Pneumatic Contromatics Operator for Fan E-5	L/146	T	HE, DDE, DE	(b)
Pneumatic Contromatics Operator for Fan 2E-5	L/146	C	HE, DDE, DE	(b)
Pneumatic Contromatics Operator for Fan E-6	L/146	T	HE, DDE, DE	(b)
Pneumatic Contromatics Operator for Fan 2E-6	L/146	C	HE, DDE, DE	(b)
Fire Damper 12x14 (FD-128)	K/73	A	HE, DDE, DE	(b)
Fire Damper 12x14 (2FD-128)	K/73	C	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Motor for Supply Fan OS-96 (CRPS)	A/140'	A	HE, DDE, DE	(b)
Motor for Supply Fan OS-97 (CRPS)	A/140'	A	HE, DDE, DE	(b)
Motor for Supply Fan OS-98 (CRPS)	A/140'	A	HE, DDE, DE	(b)
Motor for Supply Fan OS-99 (CRPS)	A/140'	A	HE, DDE, DE	(b)
Fire Damper 46x14 (FD-1)	H/111	A	HE, DDE, DE	(b)
Fire Damper 46x14 (2FD-1)	H/111	C	HE, DDE, DE	(b)
Fire Damper 46x14 (FD-2)	H/111	A	HE, DDE, DE	(b)
Fire Damper 46x14 (2FD-2)	H/111	C	HE, DDE, DE	(b)
Fire Damper 46x14 (FD-3)	H/110	A	HE, DDE, DE	(b)
Fire Damper 46x14 (2FD-3)	H/110	C	HE, DDE, DE	(b)
Fire Damper 32x68 (FD-24)	J/100	A	HE, DDE, DE	(b)
Fire Damper 32x68 (2FD-24)	J/100	C	HE, DDE, DE	(b)
Motors for Fans E-43, E-44, S-43 and S-44	H/163	A	HE, DDE, DE	(b)
Motors for Fans E-45, E-46, S-45 and S-46	H/163	C	HE, DDE, DE	(b)
Fire Damper 42x24 (FD-25)	A/135	A	HE, DDE, DE	(b)
Fire Damper 42x24 (2FD-25)	A/135	C	HE, DDE, DE	(b)
Fire Damper 42x24 (FD-26)	A/135	A	HE, DDE, DE	(b)
Fire Damper 42x24 (2FD-26)	A/135	C	HE, DDE, DE	(b)
Fire Damper 42x24 (FD-27)	A/135	A	HE, DDE, DE	(b)
Fire Damper 42x24 (2FD-27)	A/135	C	HE, DDE, DE	(b)
Fire Damper 36x39 (FD-19)	A/140	A	HE, DDE, DE	(b)
Fire Damper 36x39 (2FD-19)	A/140	C	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Fire Damper 36x39 (FD-20)	A/140	A	HE, DDE, DE	(b)
Fire Damper 36x39 (2FD-20)	A/140	C	HE, DDE, DE	(b)
Fire Damper 36x39 (FD-21)	A/140	A	HE, DDE, DE	(b)
Fire Damper 36x39 (2FD-21)	A/140	C	HE, DDE, DE	(b)
Fire Damper 14x10 (FD-26)	H/151	T	HE, DDE, DE	(b)
Fire Damper 14x10 (2FD-26)	H/151	T	HE, DDE, DE	(b)
Fire Damper 20x10 (FD-27)	H/153	T	HE, DDE, DE	(b)
Fire Damper 20x10 (2FD-27)	H/153	T	HE, DDE, DE	(b)
Fire Damper 12x12 (FD-28)	H/158	T	HE, DDE, DE	(b)
Fire Damper 12x12 (2FD-28)	H/158	T	HE, DDE, DE	(b)
Varicel-Roughing Filter (EFR-1)	L/120	A	HE, DDE, DE	(b)
Varicel-Roughing Filter (2EFR-1)	L/120	C	HE, DDE, DE	(b)
Varicel-Roughing Filter (EFR-2a)	L/122	A	HE, DDE, DE	(b)
Varicel-Roughing Filter (2EFR-2a)	L/122	C	HE, DDE, DE	(b)
Varicel-Roughing Filter (EFR-2b)	L/104	A	HE, DDE, DE	(b)
Varicel-Roughing Filter (2EFR-2b)	L/104	C	HE, DDE, DE	(b)
Electric Duct Heater (EH-27)	H/163	A	HE, DDE, DE	(b)
Electric Duct Heater (2EH-27)	H/163	A	HE, DDE, DE	(b)
Electric Duct Heaters (OEH-28A & 28B)	Tech. Support Center/109	A	HE, DDE, DE	(a) (b)
Mode Damper 8 in. dia (0-17)	Tech. Support Center/109	A	HE, DDE, DE	(a) (b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Ceiling Registers & Diffusers Wall Registers & Diffusers(Unit 1)	Aux./Varies	A	HE, DDE, DE	(b)
Ceiling Registers & Diffusers Wall Registers & Diffusers (Unit 2)	Aux./Varies	A, C	HE, DDE, DE	(b)
Aluminum Air Outlets (26" wide or less) "Metalaire"	Aux./Varies	A	HE, DDE, DE	(b)
Aluminum Air Outlets (26" wide or less) "Metalaire" for Unit 2	Aux./Varies	C	HE, DDE, DE	(b)
Air Monitors (AM FE-5001, 5013, 5015, 5016, 5018A, 5018B, 5019 and 5020) and Flow Evaluators (FE-5014, 5017A and 5017B).	Aux./Varies	A	HE, DDE, DE	(b)
Air Monitors (AM 2-FE-5001, 5002, 5003, 5004, 5005, 5006, 5007, 5008, 5009, 5010, 5011, 5012, 5013, 5015, 5019 and 5020) and Flow Evaluators (2-FE-5014, 5017A, 5017B, 5018A, 5018B).	Aux./Varies	C	HE, DDE, DE	(b)
Air Flow Controllers Johnson Service R-317-1 for Fans	Aux./Varies	T	HE, DDE, DE	(b)
Pressure Reducing Valve Johnson Service R-130-A for Fan & Dampers	Aux./Varies	T	HE, DDE, DE	(b) (g)
Restrictors Johnson Service T-5210-100 for Fans	Aux./Varies	T	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Solenoid Valves ASCO HT-8316-B15, C15 and D45; HT-8320-A20, A24 and A185; HT-8331-A45, and NP8320A172 for Fans & Dampers	Aux./Varies L/140	T	HE, DDE, DE	(b)
Speed Controllers ASCO VO221	Aux./Varies	T	HE, DDE, DE	(b)
Speed Controllers ASCO V0222 and VO223	Aux./Varies	C	HE, DDE, DE	(b)
Position Switches NAMCO D-2400-X-R2-WS for Dampers	Aux./Varies	T, C	HE, DDE, DE	(b)
Brandt Air Flow Controller (Pi-DPT-2000)	Aux./Varies	T, A	HE, DDE, DE	(b)
Portion of Refrigerant Piping with Solenoid Valve Exp. Valve with Sight Glass	H/158	T	HE, DDE, DE	(b)
Position Switches Allen-Bradley 802T-HW1 for Dampers	Aux./Varies	T	HE, DDE, DE	(b)
Position Switches Allen-Bradley 802T-HW1 for Dampers	Aux./Varies	C	HE, DDE, DE	(b)
Air Flow Switches Dwyer 1638, 1639, and 1640 for Fans	Aux./Varies, Turbine bldg., Technical Support Center/Varies, L/140	T, A	HE, DDE, DE	(a) (b)
Air Flow Switches McDonald-Miller AF1-S for Fans	Aux./Varies	T, A	HE, DDE, DE	(a) (b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Thermostats Honeywell T8400C1057 or TH5110D1006	H/145	T	HE, DDE, DE	(b)
Thermostats Penn A28AA	K/145	T	HE, DDE, DE	(b)
Thermostats Penn T26J-2	A/124	T	HE, DDE, DE	(b)
Thermostats Penn T26S-18	A/124	C	HE, DDE, DE	(b)
Thermostats Johnson Controls T26S-18C	A/124	C	HE, DDE, DE	(h)
Control Relay Cabinets for CRC-1 and CRC-3	H/157	T, A	HE, DDE, DE	(b)
Control Relay Cabinets for CRC-6 and CRC-8	H/157	T, A	HE, DDE, DE	(b)
Common Control Relay Cabinets for CCRC-2	H/157	T, A	HE, DDE, DE	(b)
Common Control Relay Cabinets for CCRC-7	H/157	T, A	HE, DDE, DE	(b)
Control Panels for Compressors CP-35 & CP-36	H/156	T	HE, DDE, DE	(b)
Control Panels for Compressors CP-37 & CP-38	H/156	T	HE, DDE, DE	(b)
Heating Relay in Cabinet 3	H/157	T	HE, DDE, DE	(b)
Thermostat Honeywell Model T675A1565 & T6031A1029	H/154	T	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Motors for Fans S-1, S-2, S-31, S-32, S-39, S-40, E-1, E-2, E-4, E-5, E-6, E-101, E-102, E-103 and E-104	Aux./Varies Intake Structure/Varies	T	HE, DDE, DE	(b)
Motors for Fans 2S-1, 2S-2, S-33, S-34, S-41, S-42, 2E-1, 2E-2, 2E-4, 2E-5 and 2E-6	Aux./Varies Intake Structure/Varies	C	HE, DDE, DE	(b)
Motors for Fans CR-35, CR-36, S-35, S-36, S-67, S-68, S-69	Aux./Varies & Turbine /Varies	T, C, A	HE, DDE, DE	(b)
Motors for Fans CR-37, CR-38, S-37, S-38, 2S-67, 2S-68, 2S-69	Aux./Varies & Turbine/Varies	C, A	HE, DDE, DE	(b)
Flex connection in 48-in. ϕ Purge Air Supply Duct FC-1 & FC-2	L/Varies	A	HE, DDE, DE (Bldg. Displ. Per DCM C-28)	(b)
Flex connection in 48-in. ϕ Purge Air Supply Duct 2FC-1 & 2FC-2	L/Varies	C	HE, DDE, DE (Bldg. Displ. per DCM C-28)	(b)
Flex connection in 12-in. ϕ Excess Pressure Relief Duct FC-3 & FC-4	L/Varies	A	HE, DDE, DE (Bldg. Displ. per	(b)
Flex connection in 12-in. ϕ Excess Pressure Relief Duct 2FC-3 & 2FC-4	L/Varies	C	HE, DDE, DE (Bldg. Displ. per	(b)
Flex Connections in 14-in. Pipes OFC-11, through OFC-16, OFC-18 through OFC-21	Turbine bldg. /varies	A	HE, DDE, DE (Bldg. Displ. per DCM C-28)	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Flex Connection in 14-in. Pipe OFC-17	Between Aux. bldg. & Turbine bldg./ 167	A	HE, DDE, DE (Bldg. Displ. per DCM C-28)	(b)
Flex Connection in 14-in. Pipe OFC-22	Aux. bldg./163	A	HE, DDE, DE (Bldg. Displ. Per DCM C-28)	(b) (d)
Flex Connection in 14-in. Pipe OFC-22 Unit 2	Aux. bldg./163	A	HE, DDE, DE (Bldg. Displ. Per DCM C-28)	(b) (d)
Nutherm/Cleveland Airflow Switches Model AFS-951-1 for over heater in CRPS	H/169	T, A	HE, DDE, DE	(a) (b)
Motors for Compressors CP-35 and CP-36	H/154	A	HE, DDE, DE	(b)
Motors for Compressors CP-37 and CP-38	H/154	C	HE, DDE, DE	(b)
Fire Damper 24x12 (FD-7)	H/110	A	HE, DDE, DE	(b)
Fire Damper 24x12 (2FD-7)	H/110	C	HE, DDE, DE	(b)
Fire Damper 24x12 (FD-8)	H/110	A	HE, DDE, DE	(b)
Fire Damper 24x12 (2FD-8)	H/110	C	HE, DDE, DE	(b)
Fire Damper 24x12 (FD-9)	H/110	A	HE, DDE, DE	(b)
Fire Damper 24x12 (2FD-9)	H/110	C	HE, DDE, DE	(b)
Fire Damper (FD-34)	H/127	T	HE, DDE, DE	(b)
Fire Damper (2FD-34)	H/127	C	HE, DDE, DE	(b)
Fire Damper (FD-36)	H/127	T	HE, DDE, DE	(b)
Fire Damper (2FD-36)	H/127	C	HE, DDE, DE	(b)
Fire Damper (FD-38)	H/126	T	HE, DDE, DE	(b)
Fire Damper (FD-39)	H/126	T	HE, DDE, DE	(b)
Fire Damper (FD-40)	H/123	T	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Fire Damper (FD-43)	A/119	T	HE, DDE, DE	(b)
Fire Damper (2FD-43)	A/119	C	HE, DDE, DE	(b)
Fire Damper (FD-44)	A/119	T	HE, DDE, DE	(b)
Fire Damper (2FD-44)	A/119	C	HE, DDE, DE	(b)
Fire Damper (FD-45)	A/119	T	HE, DDE, DE	(b)
Fire Damper (2FD-45)	A/119	C	HE, DDE, DE	(b)
Fire Damper (FD-10)	H/121	A	HE, DDE, DE	(b)
Fire Damper (2FD-10)	H/121	C	HE, DDE, DE	(b)
Fire Damper (FD-11)	H/121	A	HE, DDE, DE	(b)
Fire Damper (2FD-11)	H/121	C	HE, DDE, DE	(b)
Fire Damper (FD-12)	H/121	A	HE, DDE, DE	(b)
Fire Damper (2FD-12)	H/121	C	HE, DDE, DE	(b)
Smoke Damper (SD-26)	H/151	A	HE, DDE, DE	(b)
Smoke Damper (2SD-26)	H/151	C	HE, DDE, DE	(b)
Smoke Damper (SD-27)	H/151	A	HE, DDE, DE	(b)
Smoke Damper (2SD-27)	H/151	C	HE, DDE, DE	(b)
Smoke Damper (SD-35)	H/127	A	HE, DDE, DE	(b)
Smoke Damper (2SD-35)	H/127	C	HE, DDE, DE	(b)
Smoke Damper (SD-37)	H/127	A	HE, DDE, DE	(b)
Smoke Damper (2SD-37)	H/127	C	HE, DDE, DE	(b)
Pneumatic Bettis Actuator for Damper (4A)	Aux/Varies	T	HE, DDE, DE	(b)
Pneumatic Bettis Actuator for Damper (2-4A)	Aux/Varies	T	HE, DDE, DE	(b)
Pneumatic Bettis Actuator for Damper (4B)		T	HE, DDE, DE	(b)
Pneumatic Bettis Actuator for Damper (2-4B)	Aux/Varies	T	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Pneumatic Bettis Actuator for Damper (8A)		T	HE, DDE, DE	(b)
Pneumatic Bettis Actuator for Damper (2-8A)	Aux/Varies	T	HE, DDE, DE	(b)
Pneumatic Bettis Actuator for Damper (8B)		T	HE, DDE, DE	(b)
Pneumatic Bettis Actuator for Damper (2-8B)	Aux/Varies	T	HE, DDE, DE	(b)
Pneumatic Bettis Actuator for Damper (10)		T	HE, DDE, DE	(b)
Pneumatic Bettis Actuator for Damper (2-10)	Aux/Varies	T	HE, DDE, DE	(b)
Pneumatic Bettis Actuator for Damper (1-FCV-5160)	L/140	T	HE, DDE, DE	(b)
Pneumatic Bettis Actuator for Damper (2-FCV-5160)	L/140	T	HE, DDE, DE	(b)
Pneumatic Bettis Actuator for Damper (1-FCV-5161)	L/140	T	HE, DDE, DE	(b)
Pneumatic Bettis Acutator For Damper (2-FCV-5161)	L/!40	T	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (12)	Aux/Varies	T	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (16A)		T	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (2-16A)	Aux/Varies	C	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (16B)		T	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (2-16B)	Aux/Varies	C	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (17A)		T	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Power Regulator Co. Actuator for Damper (2-17A)	Aux/Varies	C	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (17B)		T	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (2-17B)	Aux/Varies	C	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (20)		T	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (2-20)	Aux/Varies	C	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (21)	Aux/Varies	T	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (2-21)	Aux/Varies	C	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (22A)		T	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (2-22A)	Aux/Varies	C	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (22B)		T	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (2-22B)	Aux/Varies	C	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (23A)		T	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (2-23)	Aux/Varies	C	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (23B)		T	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (2-23B)	Aux/Varies	C	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (24A)		T	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Power Regulator Co. Actuator for Damper (2-24)	Aux/Varies	C	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (24B)		T	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (2-24B)	Aux/Varies	C	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (25A)		T	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (2-25)	Aux/Varies	C	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (25B)		T	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (2-25B)	Aux/Varies	C	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (26A)		T	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (2-26A)	Aux/Varies	C	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (26B)		T	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (2-26B)	Aux/Varies	C	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (33)		T	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (2-33)	Aux/Varies	C	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (34)		T	HE, DDE, DE	(b)
Power Regulator Co. Actuator for Damper (2-34)	Aux/Varies	C	HE, DDE, DE	(b)
Pneumatic Parker-Hannifin Actuator for Mode Damper (1A)	L/127	A	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Pneumatic Parker-Hannifin Actuator for Mode Damper (2-1A)	L/127	A	HE, DDE, DE	(b)
Pneumatic Parker-Hannifin Actuator for Mode Damper (1B)	L/131	C	HE, DDE, DE	(b)
Pneumatic Parker-Hannifin Actuator for Mode Damper (2-1B)	L/131	C	HE, DDE, DE	(b)
Pneumatic Parker-Hannifin Actuator for Damper (13A)	K/97	A	HE, DDE, DE	(b)
Pneumatic Parker-Hannifin Actuator for Damper (2-13A)	K/97	C	HE, DDE, DE	(b)
Pneumatic Parker-Hannifin Actuator for Damper (13B)	K/97	A	HE, DDE, DE	(b)
Pneumatic Parker-Hannifin Actuator for Damper (2-13B)	K/97	C	HE, DDE, DE	(b)
Pneumatic Parker-Hannifin Actuator for Damper (14A)	K/81	A	HE, DDE, DE	(b)
Pneumatic Parker-Hannifin Actuator for Damper (2-14A)	K/81	C	HE, DDE, DE	(b)
Pneumatic Parker-Hannifin Actuator for Damper (14B)	K/81	A	HE, DDE, DE	(b)
Pneumatic Parker-Hannifin Actuator for Damper (2-14B)	K/81	C	HE, DDE, DE	(b)
Pneumatic Parker-Hannifin Actuator for Damper (15A)	Aux/70	A	HE, DDE, DE	(b)
Pneumatic Parker-Hannifin Actuator for Damper (2-15A)	Aux/70	C	HE, DDE, DE	(b)
Pneumatic Parker-Hannifin Actuator for Damper (15B)	Aux/70	A	HE, DDE, DE	(b)
Pneumatic Parker-Hannifin Actuator for Damper (2-15B)	Aux/70	C	HE, DDE, DE	(b)

TABLE 3.10-3

Equipment	Location[c] Building/ Elevation, ft	Qualification Method[c]	Qualifying Spectra[c]	Notes
Position Switches NAMCO SL-3B1W, SL-170D, and EA180- for Dampers	L/115 L/140	T	HE, DDE, DE	(b)

(a) Turbine building, Unit 2, response spectra applicable for Qualification Spectra of equipment in the Technical Support Center.

(b) Envelope of 4% HE and 2% DDE Acceleration used in Qualification Spectra. Per DCM T-10 acceptance criteria, DE stresses shall not exceed the maximum allowable stress values specified in building codes (Uniform Building Code, 1973 and AISC, 1969). Increase in allowable stresses, permitted by code for seismic loads, shall not be used. In lieu of these, DDE and Hosgri stresses shall not exceed 90% of the yield strength and 150% of the AISC allowable stress, respectively.

(c) Legend:

ISA = Intake structure area
A = Qualification Spectra by analysis (Qualification Method column)
T = Qualification Spectra by testing
C = Comparison with similarly qualified equipment
DE = Design Earthquake
DDE = Double Design Earthquake
HE = Hosgri Earthquake

The letters in the Location column refer to standard area designations as defined in Figure 1.2-3, Piping and Mechanical Area Location Plan.

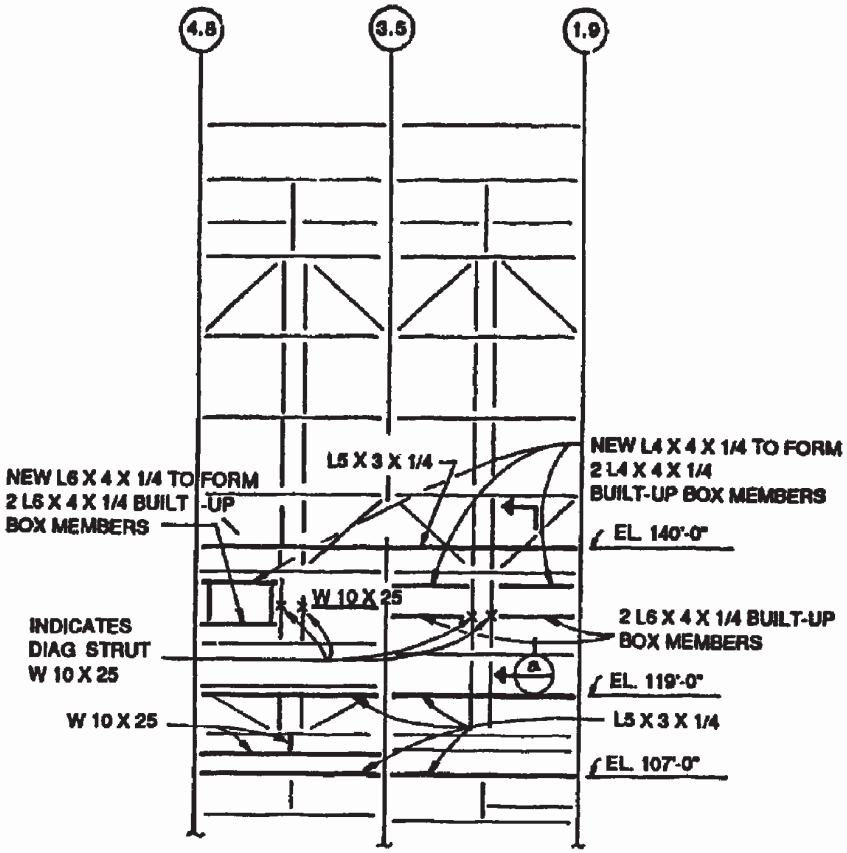
(d) Tag number of flexible connection OFC-22 has been duplicated.

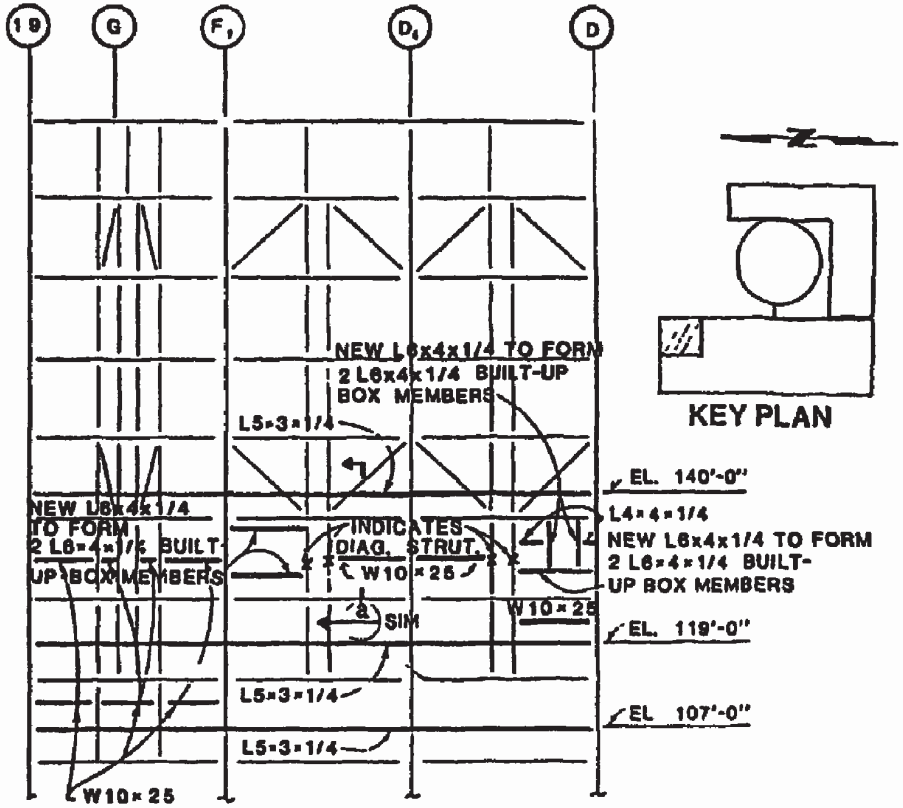
(e) Quadrant dampers supported on flexible slab.

(f) Applicable to Units 1 and 2.

(g) Due to obsolescence of Johnson air pressure reducing regulators, Fisher 67CSR regulators may be installed.

(h) Due to obsolescence of Penn thermostats, Johnson Controls T26S-18C thermostats may be installed.





NORTH ELEV. GIRT FRAMING ALONG 1

1/16" = 1'-0"

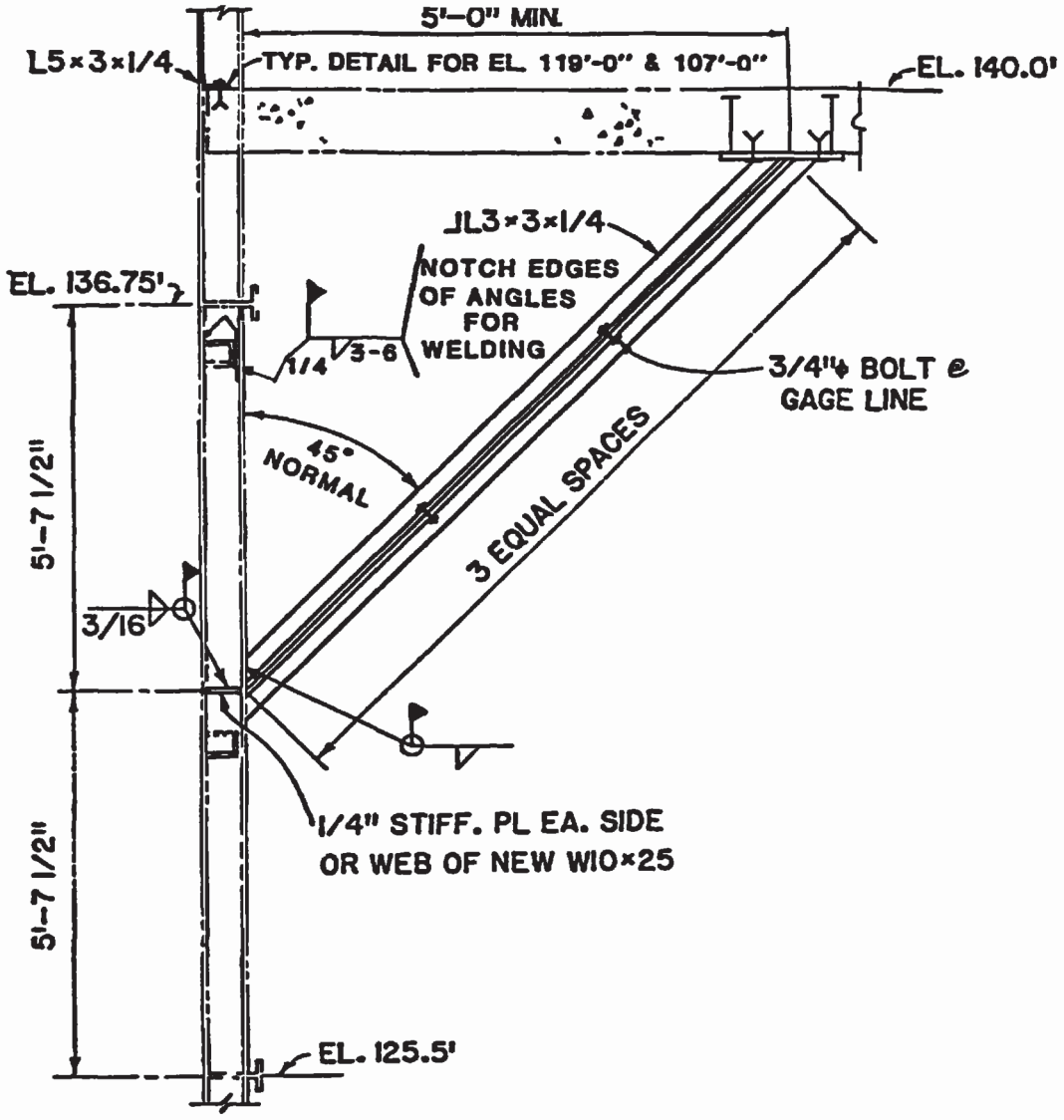
NOTES:

1. NEW MEMBERS ARE INDICATED BY HEAVY, DARK LINES
2. MODIFICATIONS AT NORTH AND EAST SIDE OF UNIT 1 ARE SHOWN. MODIFICATIONS AT SOUTH AND EAST SIDE OF UNIT 2 ARE IDENTICAL.

EAST ELEV. GIRT FRAMING ALONG G

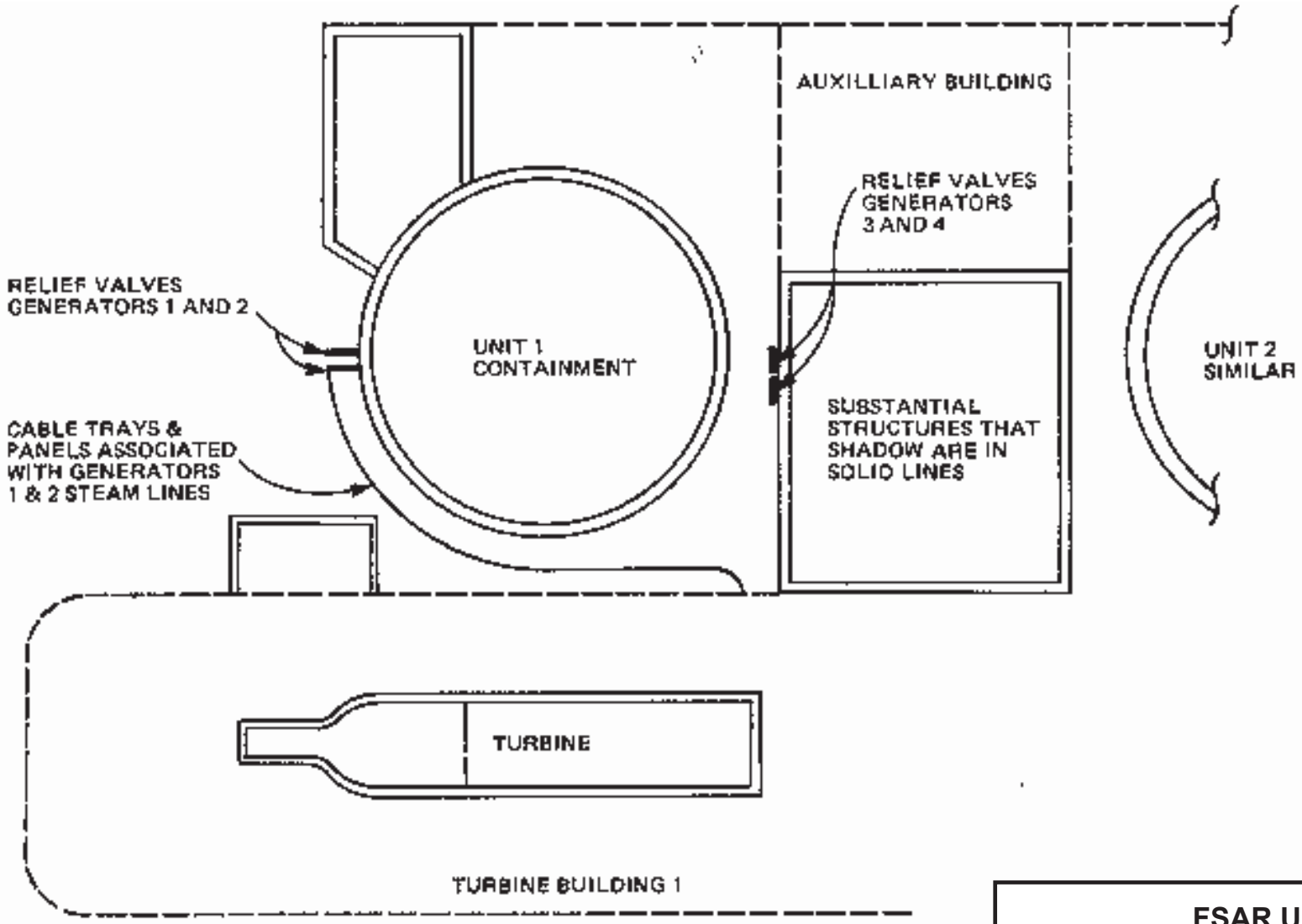
1/16" 1'-0"

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.3-1 TURBINE BUILDING FRAMING MODIFICATIONS FOR TORNADO RESISTANCE - ELEVATION

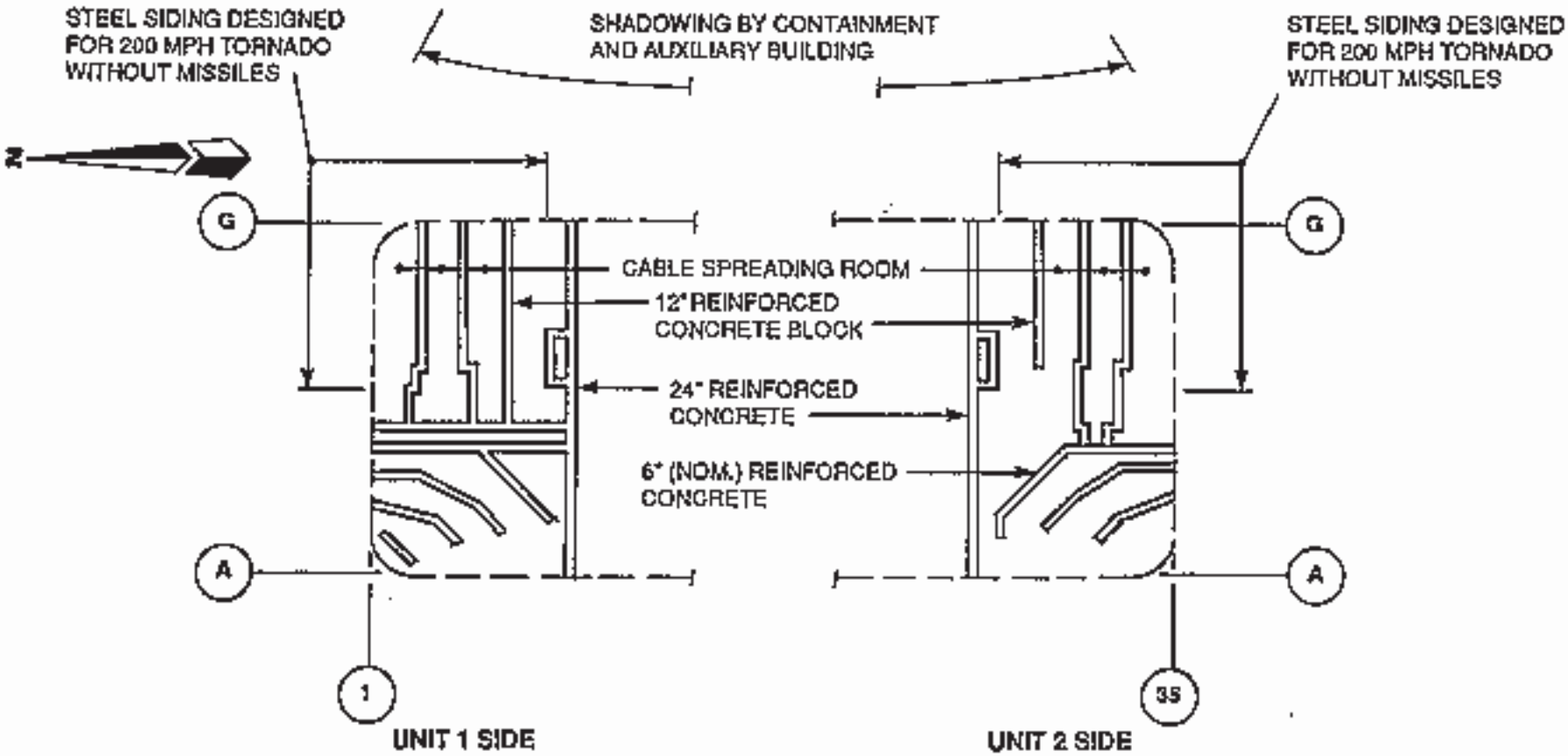


SECTION a
1/2"= 1'-0"

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.3-2 TURBINE BUILDING FRAMING MODIFICATIONS FOR TORNADO RESISTANCE - SECTION



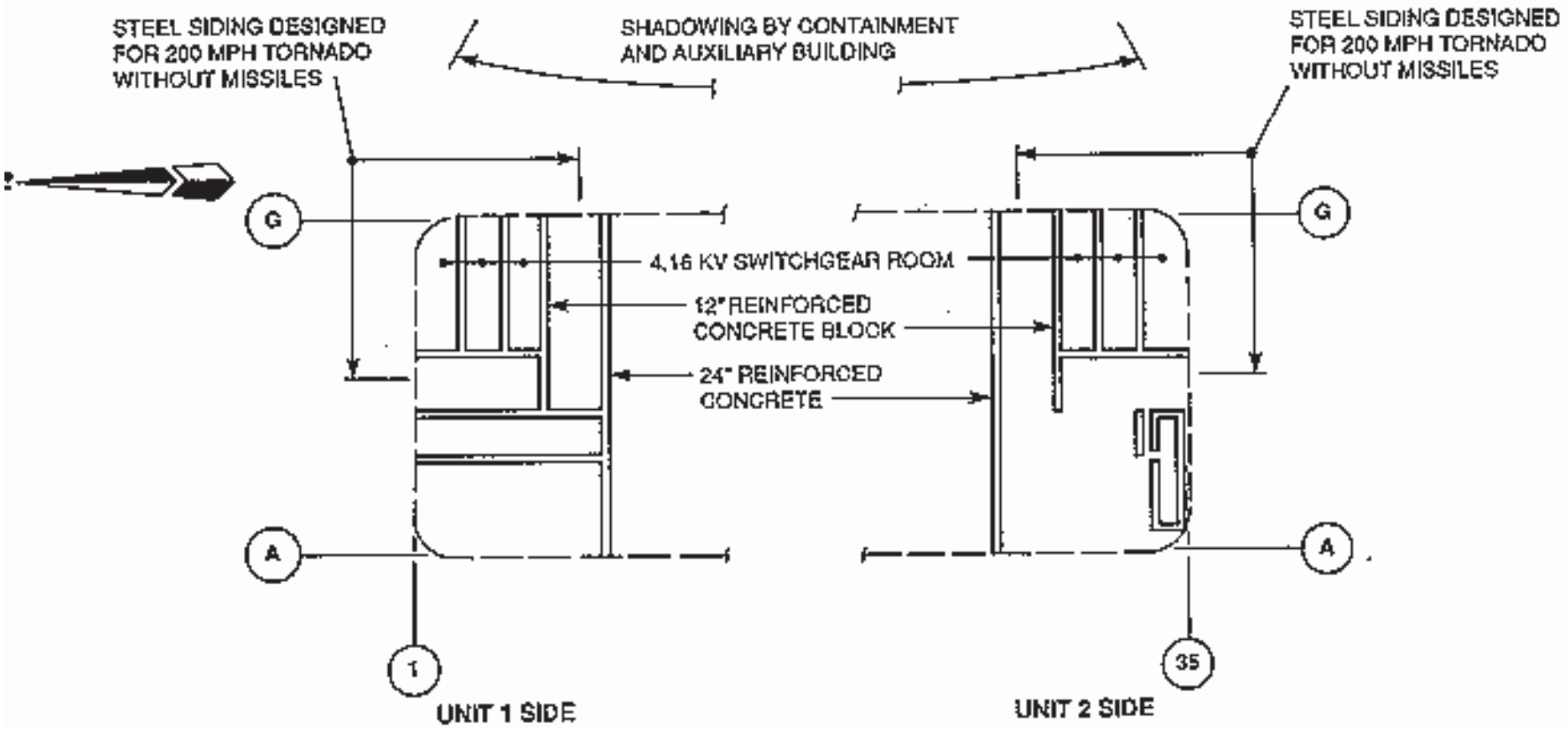
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.3-3 LAYOUT OF VULNERABLE MAIN STEAM RELIEF VALVES AND CABLE TRAY OUTSIDE OF PLANT



PLAN @ EL 107'-0"

1. CABLE SPREADING ROOMS HAVE 10" REINFORCED CONCRETE FLOORS ABOVE AND BELOW.
2. ALL WALLS SHOWN ARE 8" REINFORCED CONCRETE MASONRY EXCEPT AS NOTED.

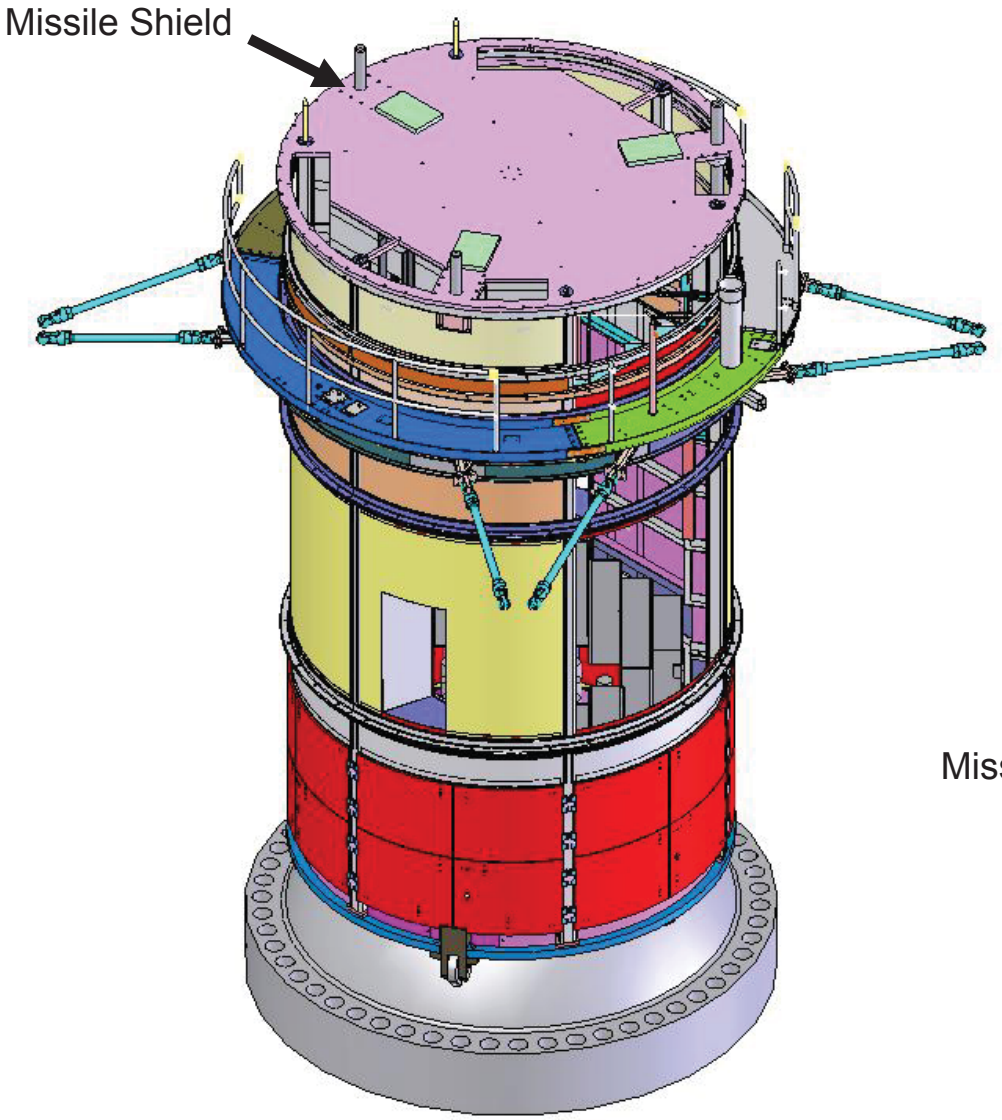
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.3-4 (SHEET 1 OF 2) SCHEMATIC LAYOUT OF CABLE SPREADING AND SWITCHGEAR ROOMS IN THE TURBINE BUILDING

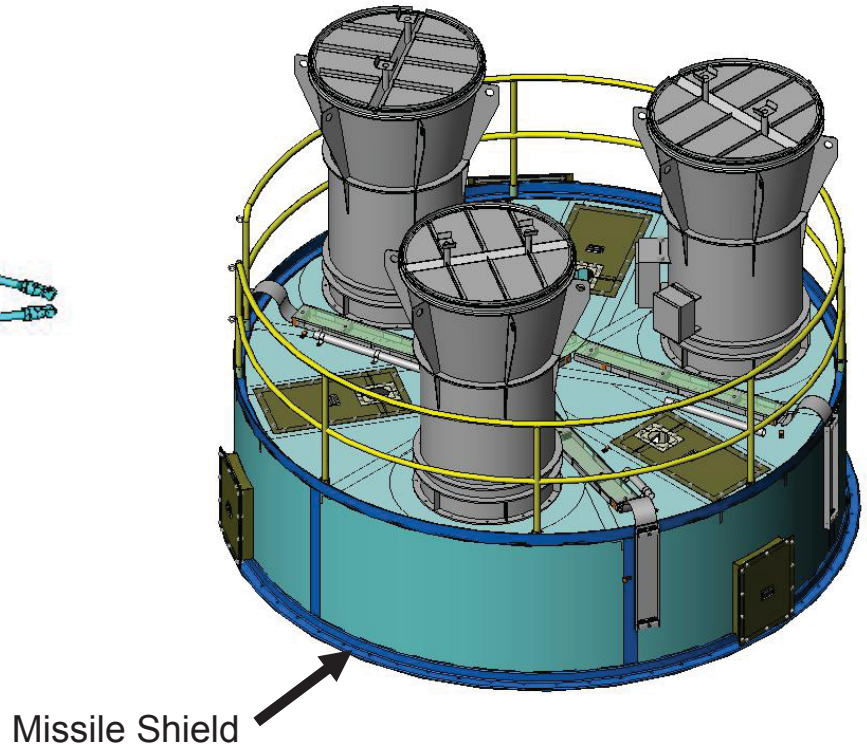


PLAN @ EL 119'-0"

1. SWITCHGEAR ROOMS HAVE 12" REINFORCED CONCRETE FLOORS ABOVE AND 10" REINFORCED CONCRETE FLOORS BELOW.
2. ALL WALLS SHOWN ARE 8" REINFORCED CONCRETE MASONRY EXCEPT AS NOTED

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.3-4 (SHEET 2 OF 2) SCHEMATIC LAYOUT OF CABLE SPREADING AND SWITCHGEAR ROOMS IN THE TURBINE BUILDING





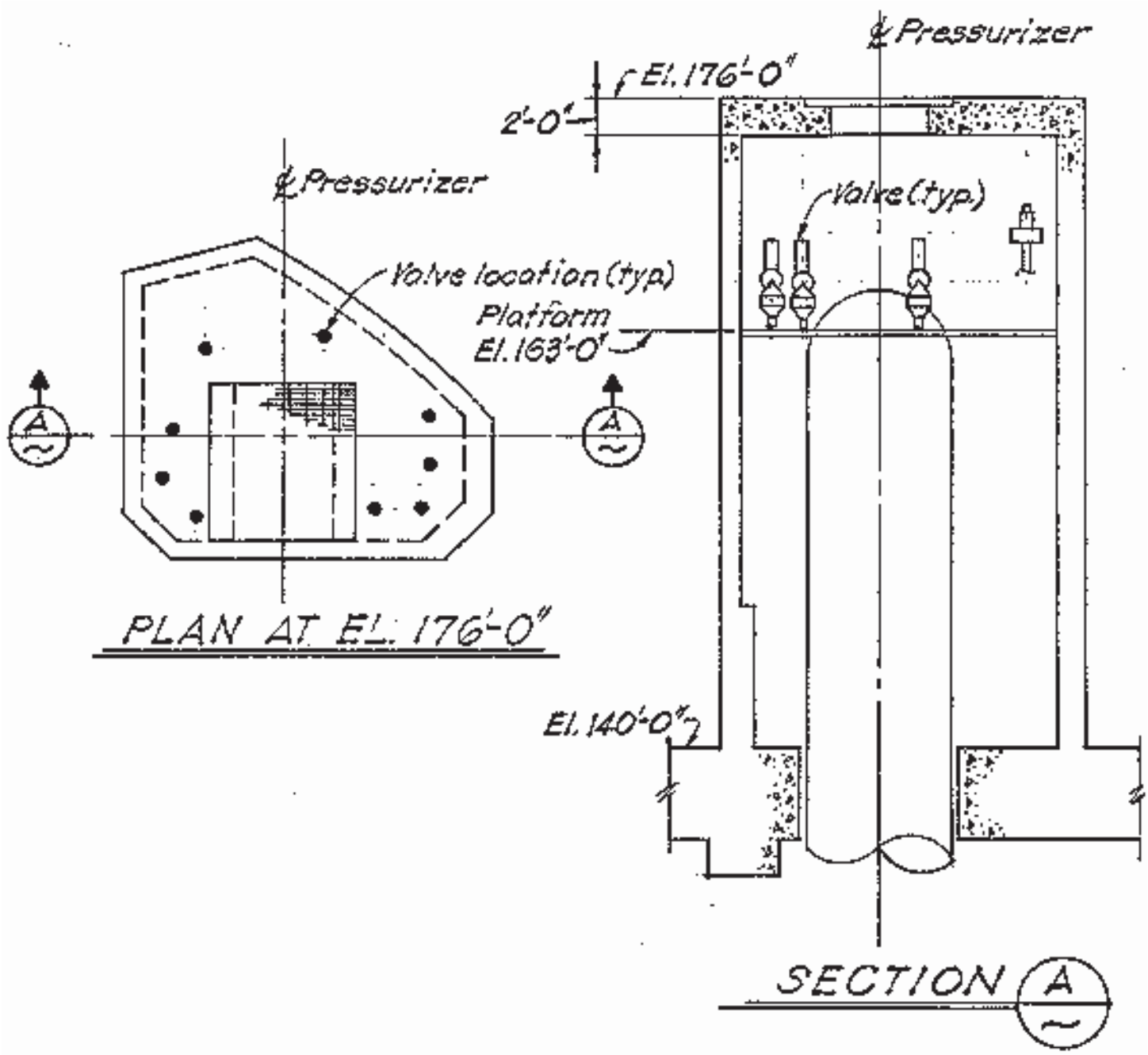
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.5-1

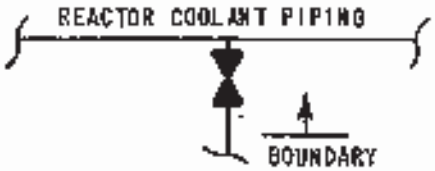
INTEGRATED HEAD ASSEMBLY
REACTOR MISSILE SHIELD

Revision 20 November 2011



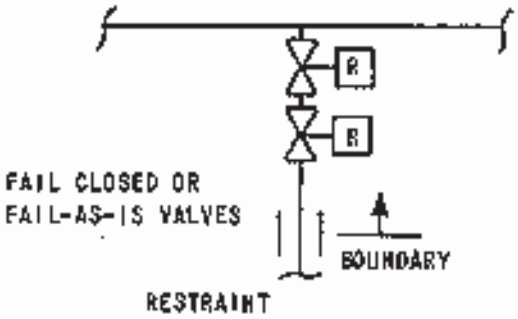
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.5-2 CONTAINMENT STRUCTURE PRESSURIZER MISSILE SHIELD

CASE I — OUTGOING LINES WITH NORMALLY CLOSED VALVE



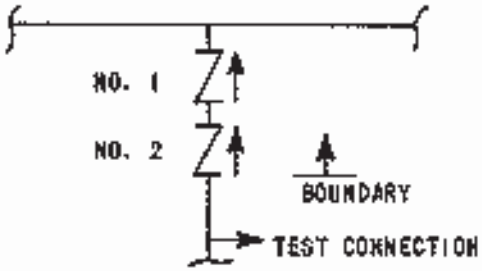
NOTE: PRESSURIZER SAFETY VALVES ARE INCLUDED UNDER THIS CASE.

CASE II — OUTGOING LINES WITH NORMALLY OPEN VALVES

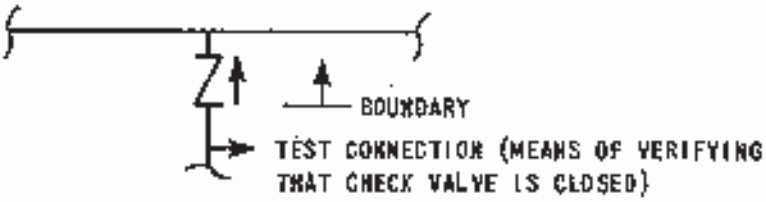


NOTE: THE REACTOR COOLANT PUMP NO. 1 SEAL IS ASSUMED TO BE EQUIVALENT TO FIRST VALVE

CASE III — INCOMING LINES NORMALLY WITH FLOW

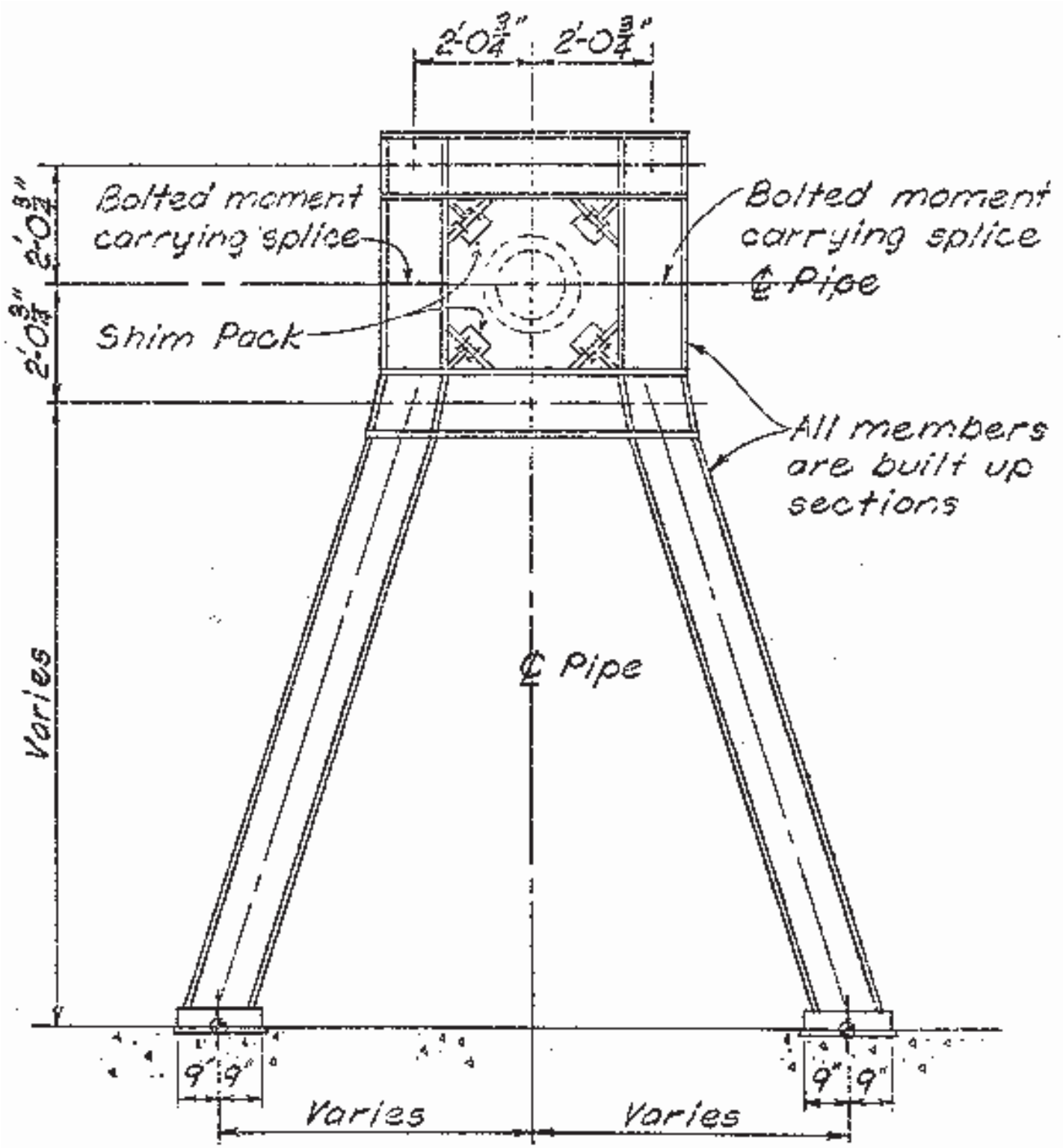


CASE IV — INCOMING LINES NORMALLY WITHOUT FLOW

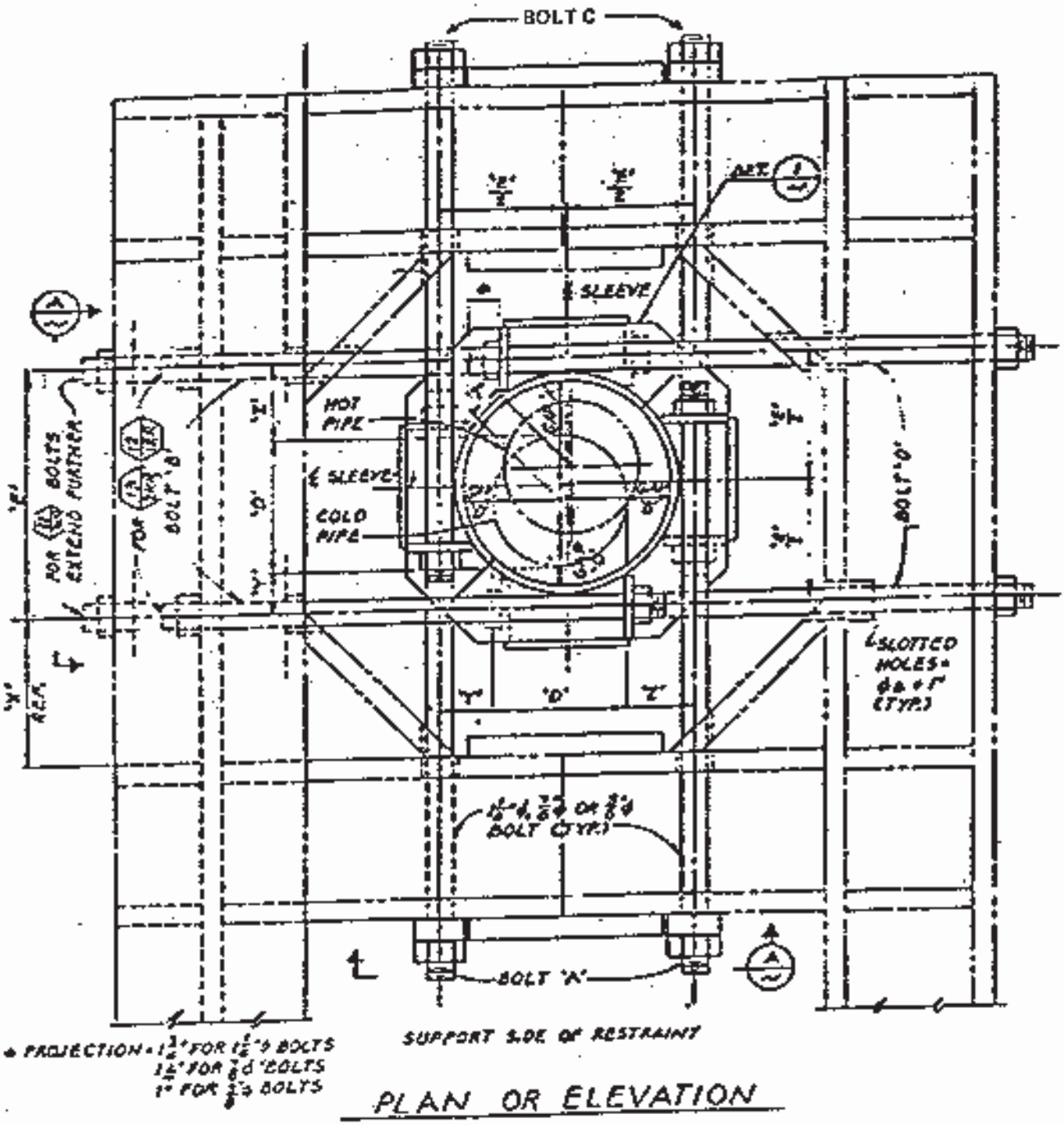


CASE V — ALL INSTRUMENTATION TUBING AND INSTRUMENTS CONNECTED DIRECTLY TO THE REACTOR COOLANT SYSTEM ARE CONSIDERED A BOUNDARY. HOWEVER, A BREAK WITHIN THIS BOUNDARY RESULTS IN A RELATIVELY SMALL FLOW WHICH CAN NORMALLY BE MADE UP WITH THE CHARGING SYSTEM.

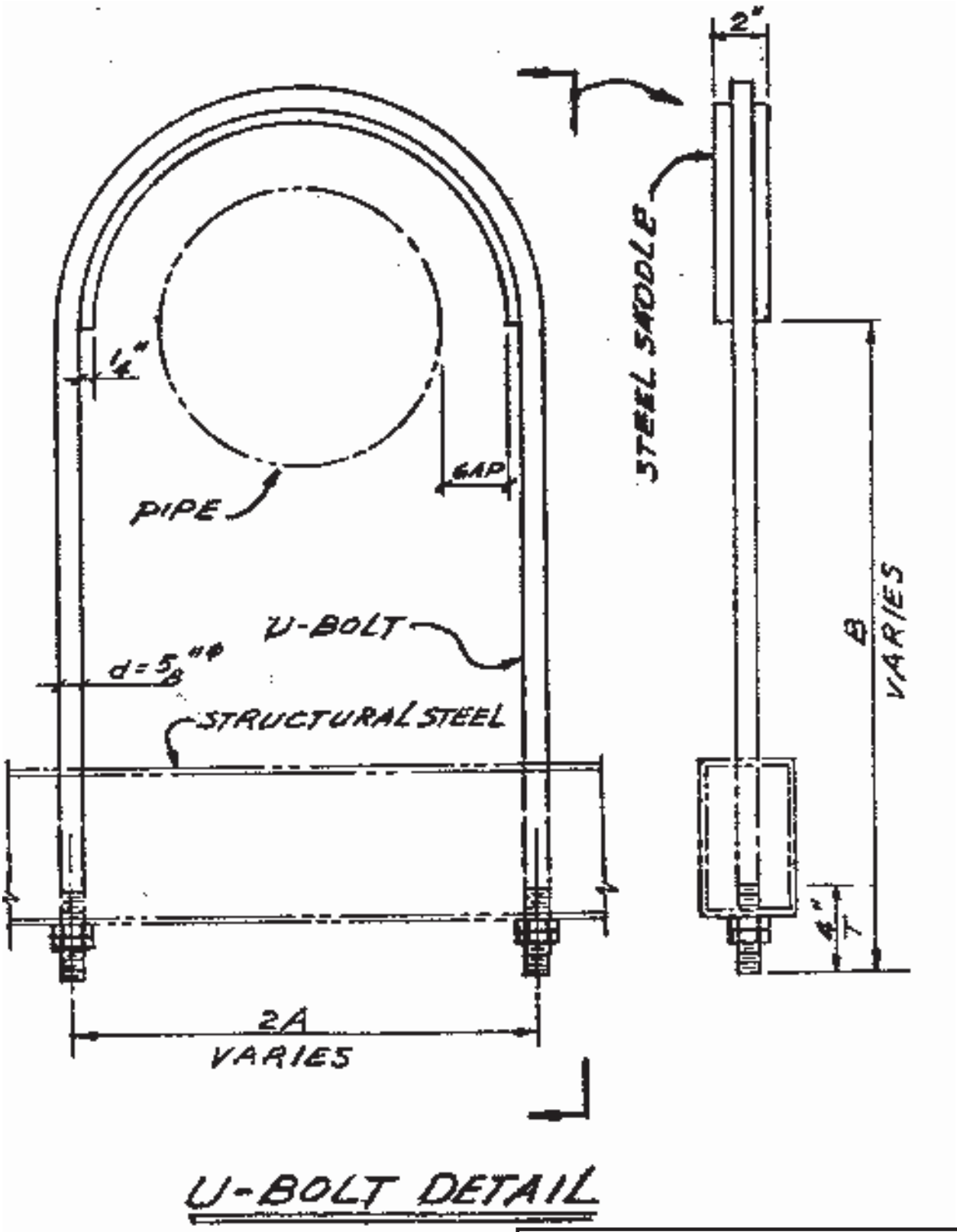
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.6-1 LOSS OF COOLANT ACCIDENT BOUNDARY LIMITS



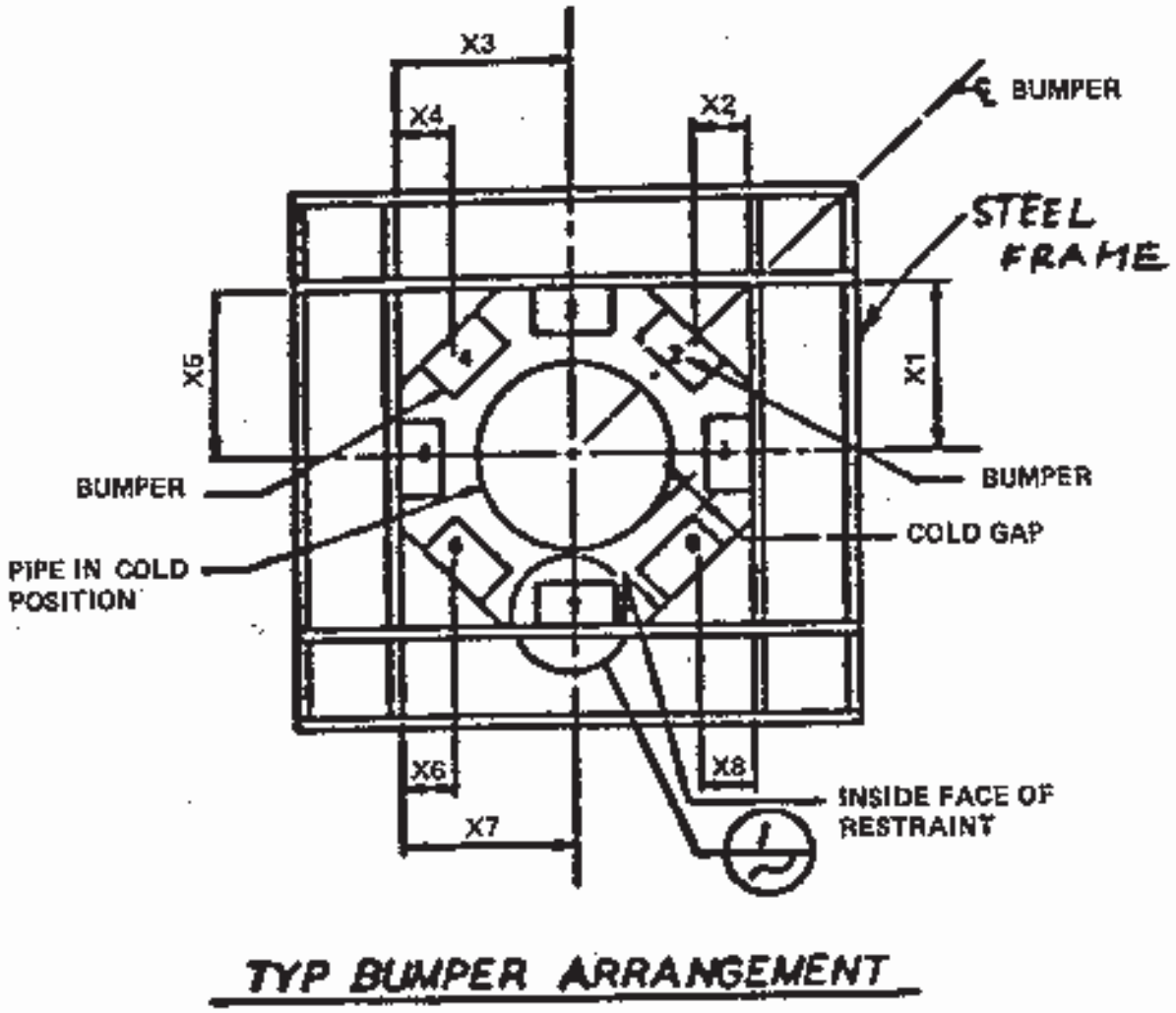
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.6-3 TYPICAL PIPE RUPTURE RESTRAINT



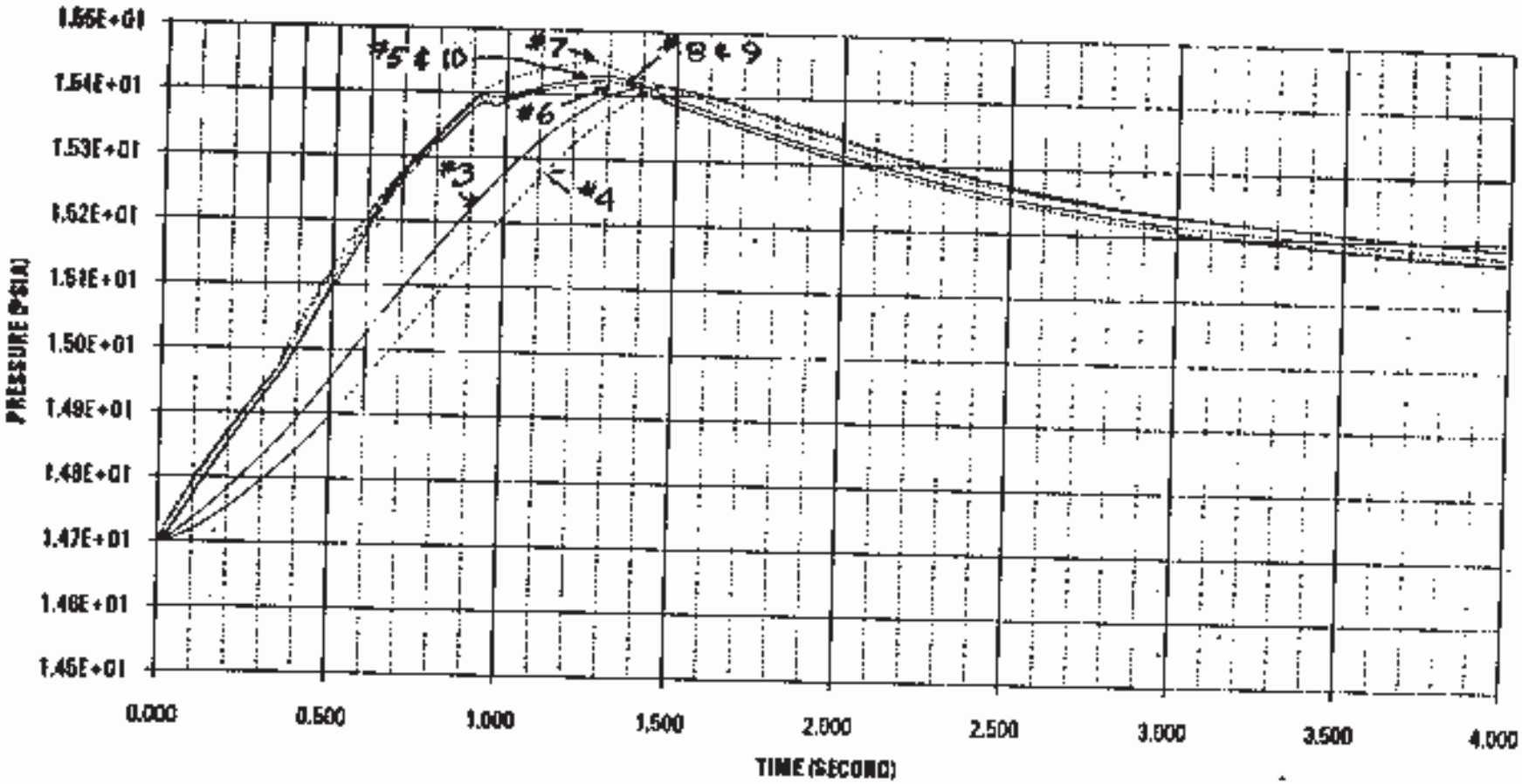
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.6-3A PIPE RUPTURE RESTRAINT TYPICAL ROD ARRANGEMENT



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.6-3B PIPE RUPTURE RESTRAINT TYPICAL U-BOLT



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.6-3C PIPE RUPTURE RESTRAINT CRUSHABLE BUMPER ARRANGEMENT

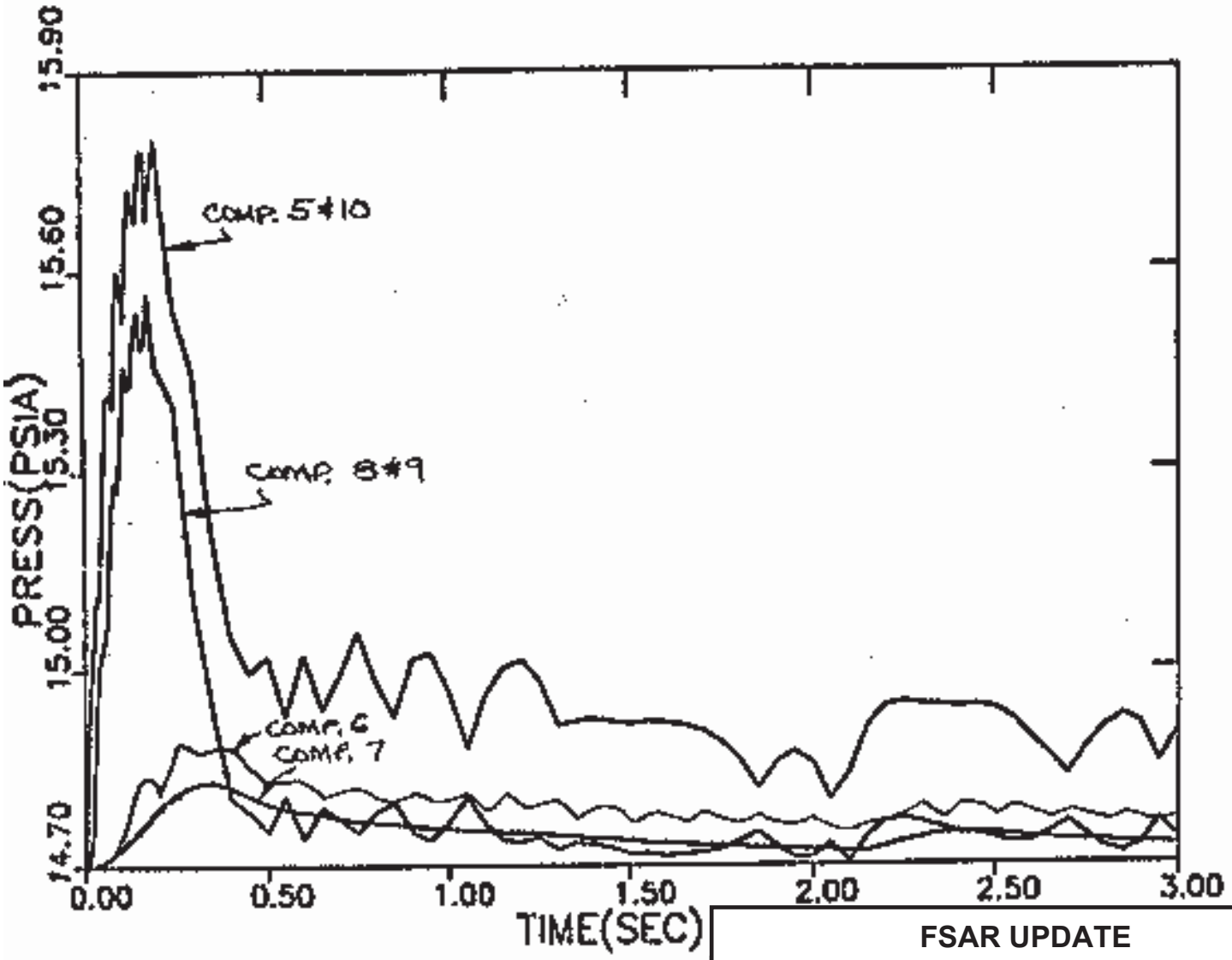


FSAR UPDATE

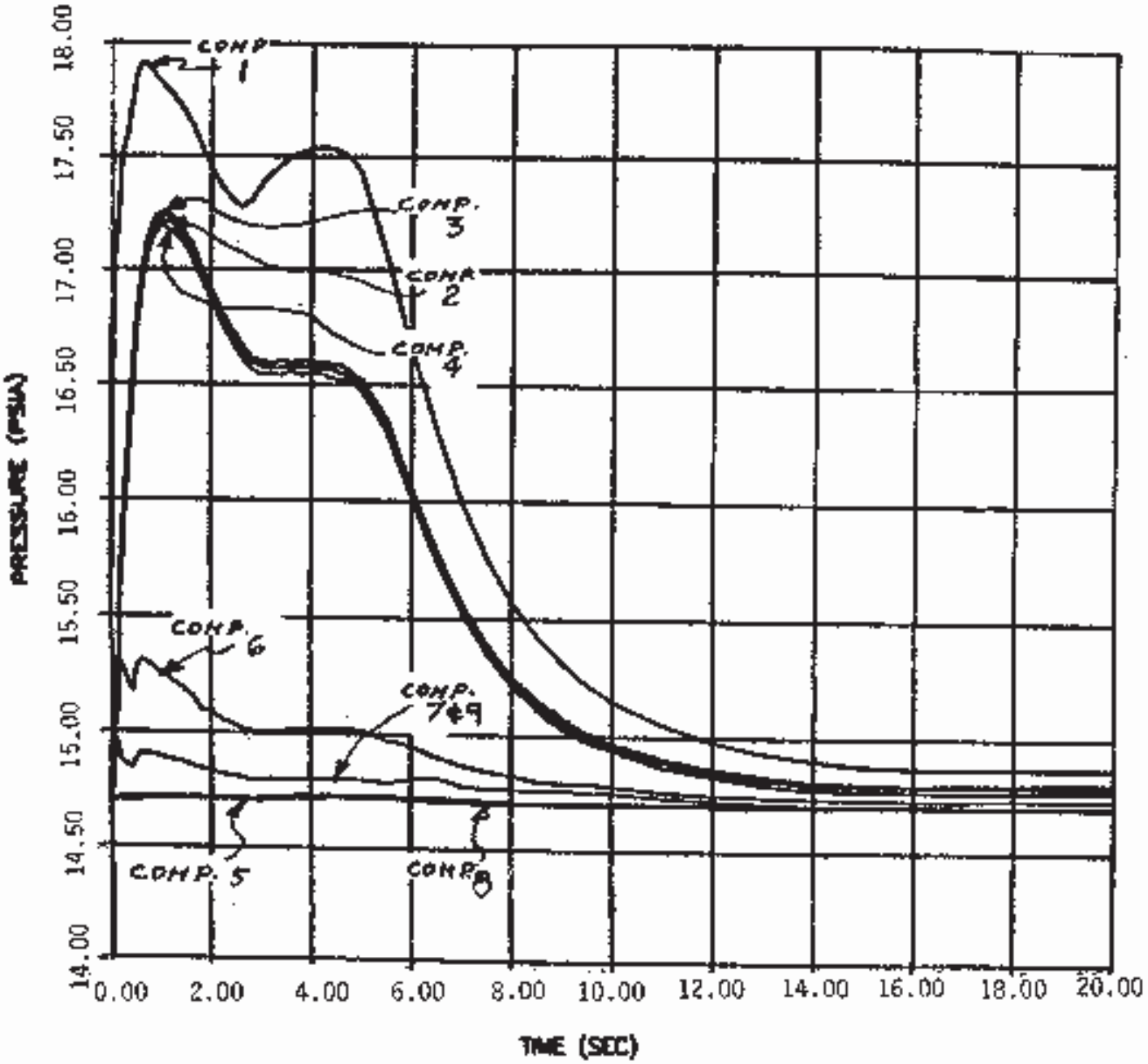
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.6-16

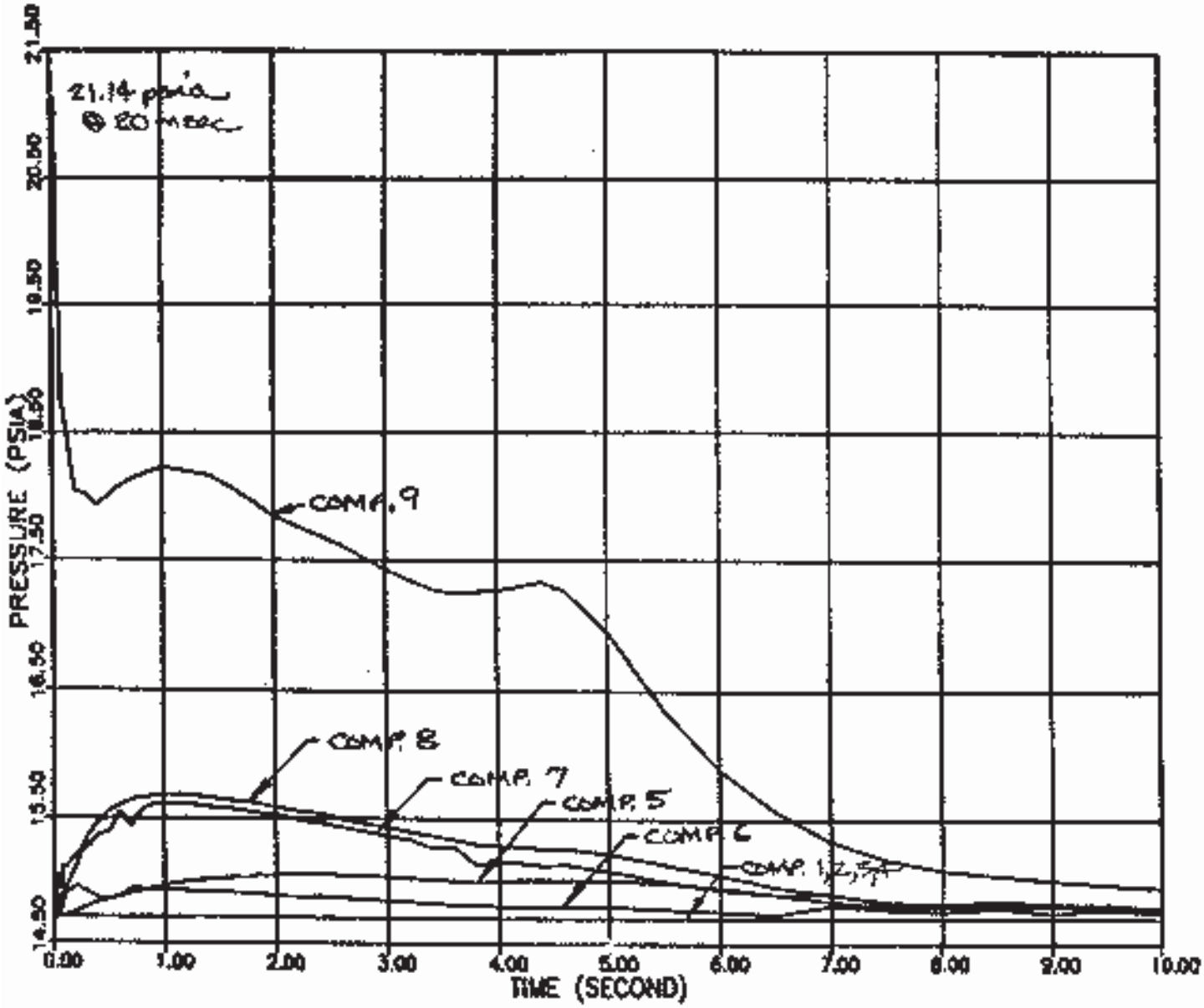
TURBINE BUILDING
PRESSURE vs. TIME RESPONSE
MSLB AT ELEVATION 140'
(DER) STEAM WITH ENTRAINMENT



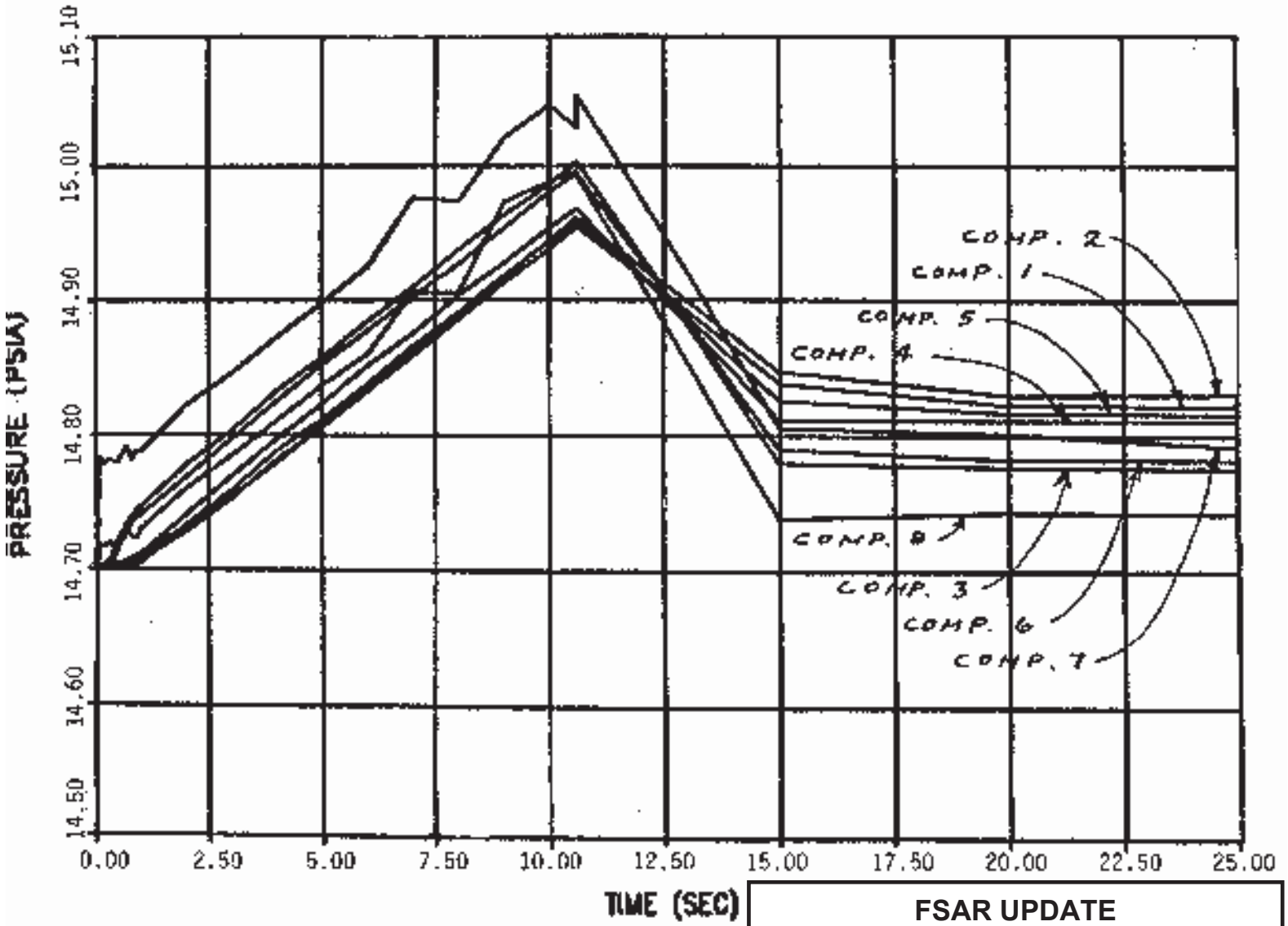
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.6-17 TURBINE BUILDING PRESSURE vs. TIME RESPONSE MSLB AT ELEVATION 85' (DER) STEAM WITH ENTRAINMENT



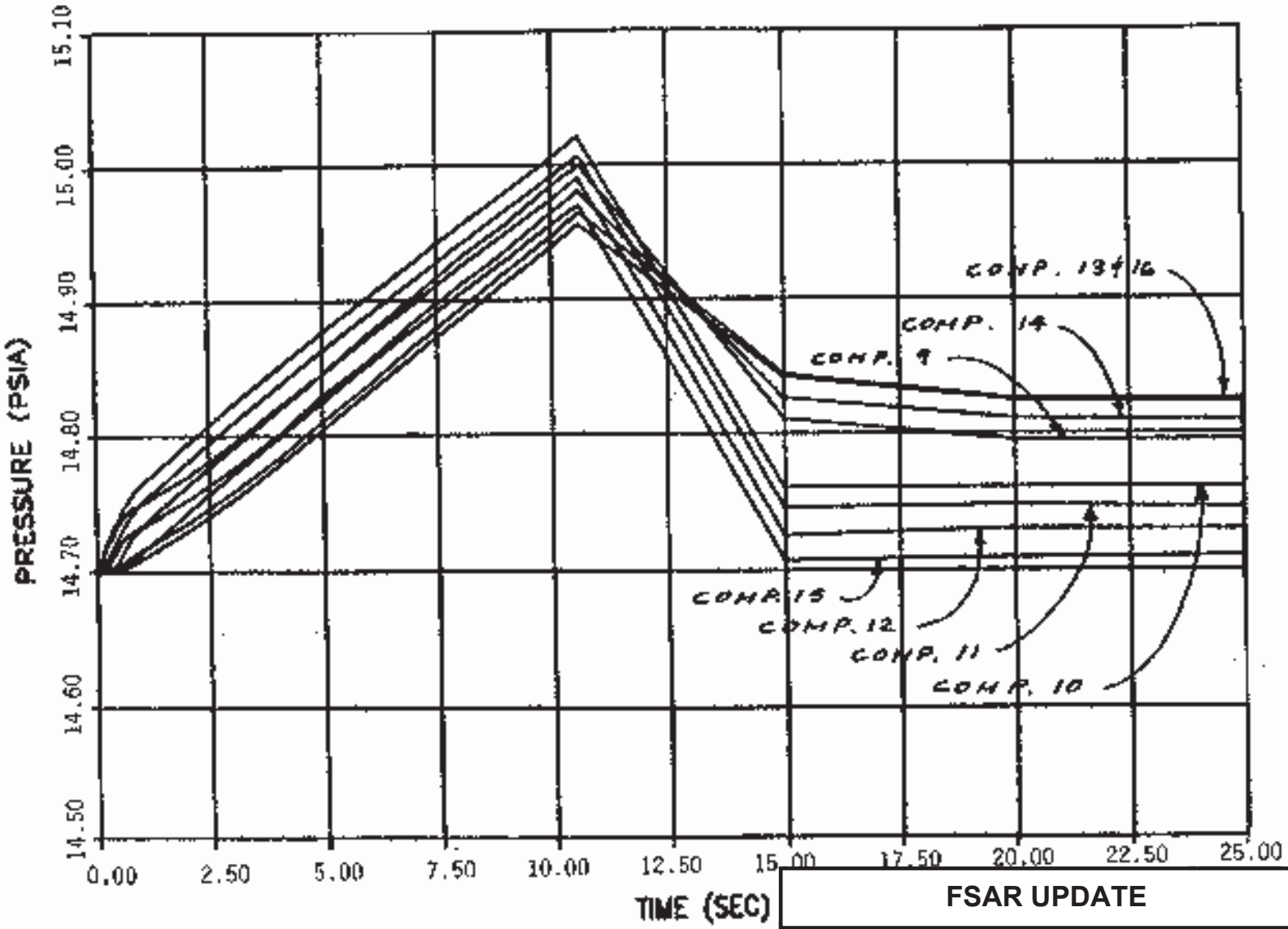
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.6-18 AREA GE/GW PRESSURE vs. TIME RESPONSE MSLB AT ELEVATION 115' (DER) STEAM WITH ENTRAINMENT



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.6-19 AREA GE/GW PRESSURE vs. TIME RESPONSE MSLB AT G-ROW ANCHOR (DER) STEAM WITH ENTRAINMENT



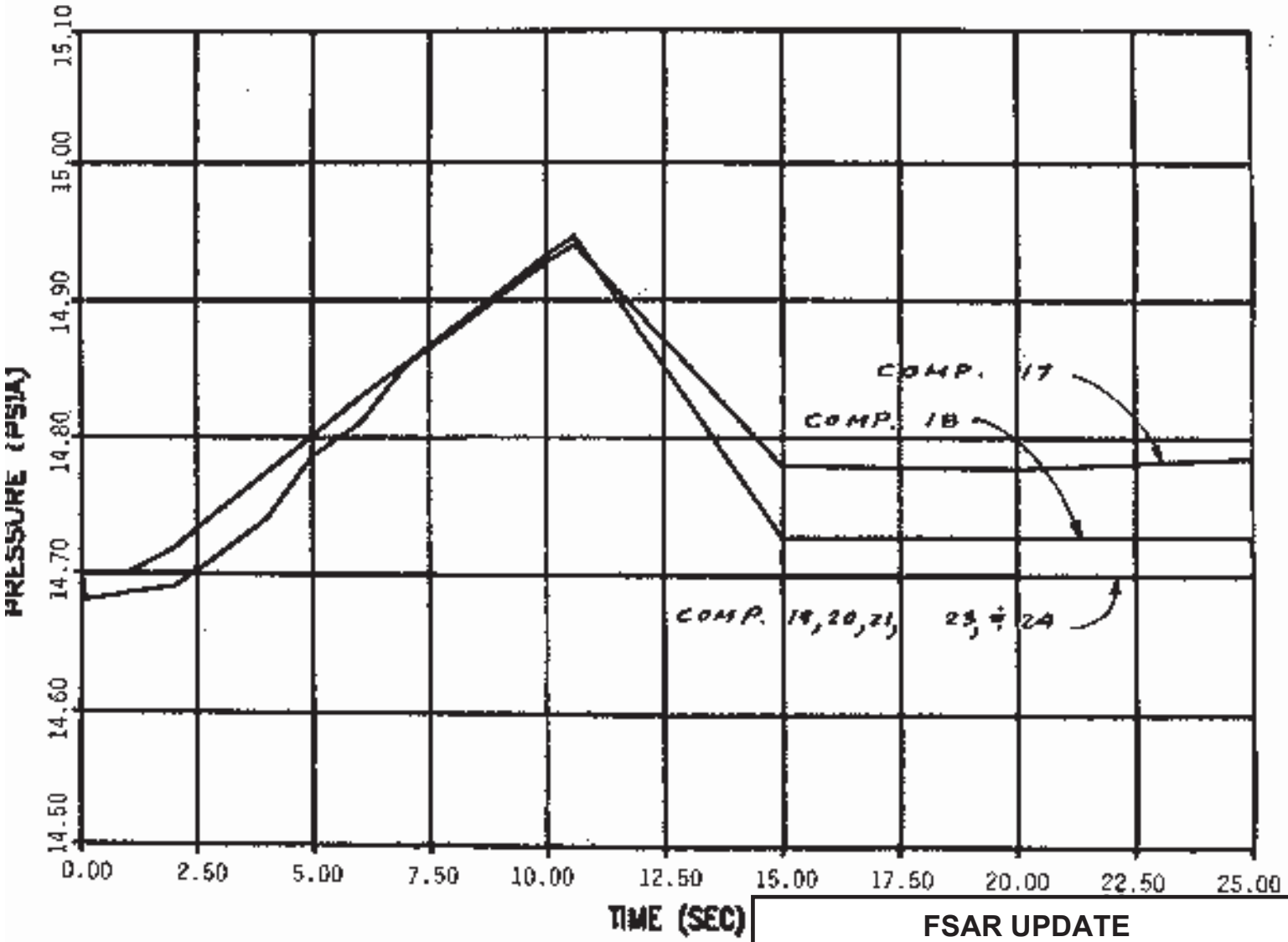
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.6-20 AREA H, K PRESSURE vs. TIME RESPONSE CVCS LETDOWN LINE IN AREA K AT ELEVATION 85' (DER)



FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

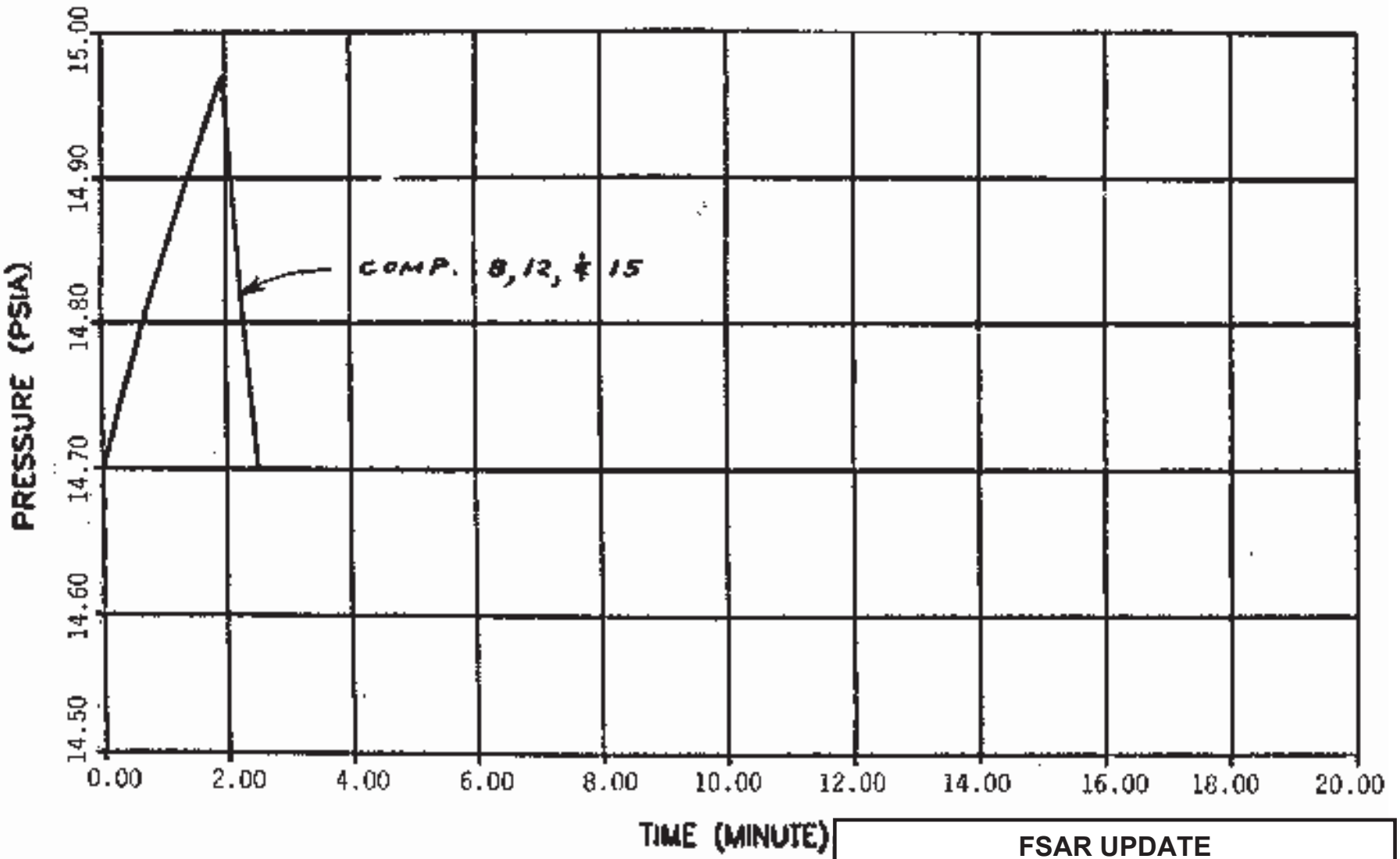
FIGURE 3.6-21
AREA H, K
PRESSURE vs. TIME RESPONSE
CVCS LETDOWN LINE IN AREA K
AT ELEVATION 85' (DER)



FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

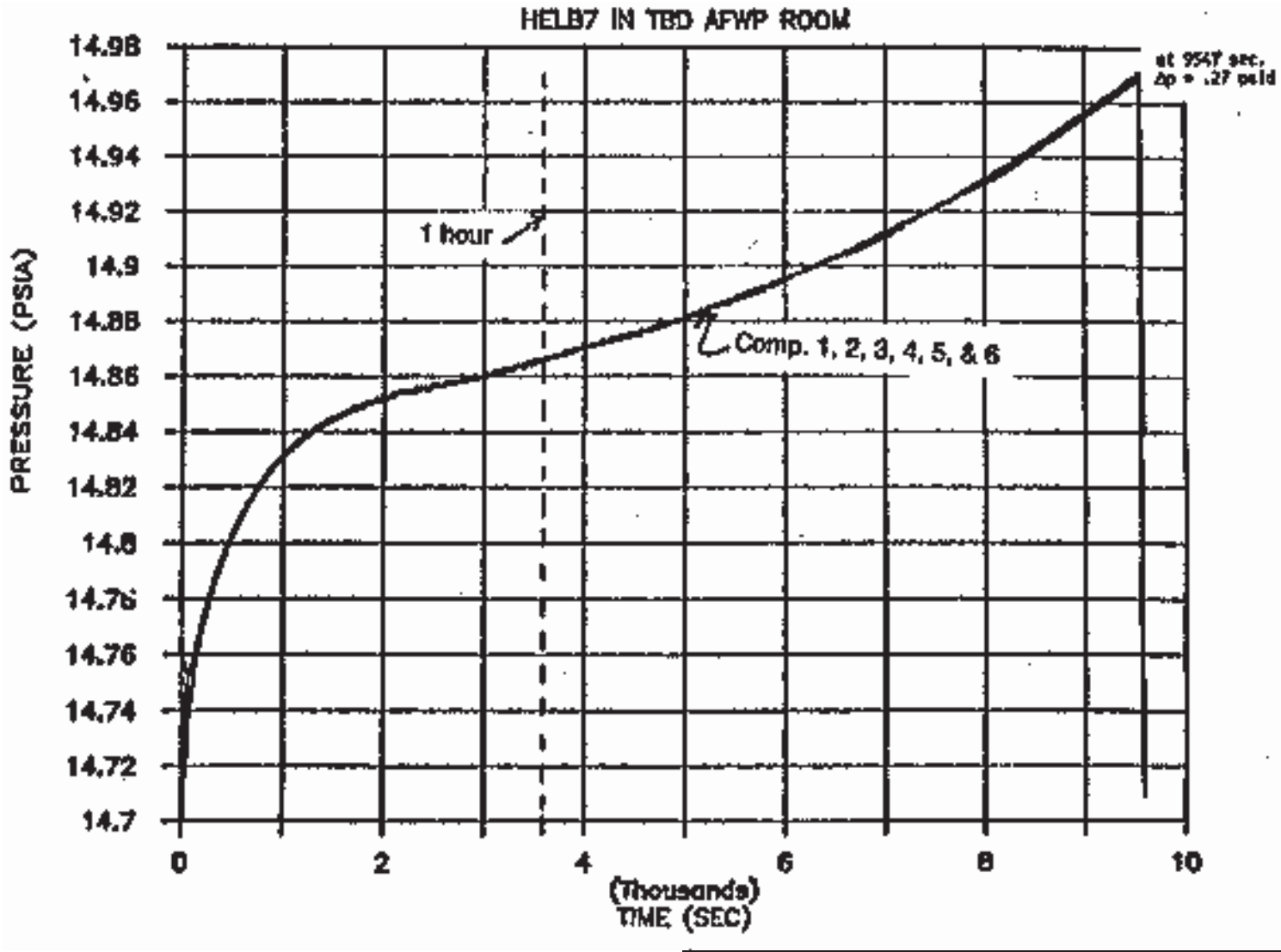
FIGURE 3.6-22
AREA H, K
PRESSURE vs. TIME RESPONSE
CVCS LETDOWN LINE IN AREA K
AT ELEVATION 85' (DER)



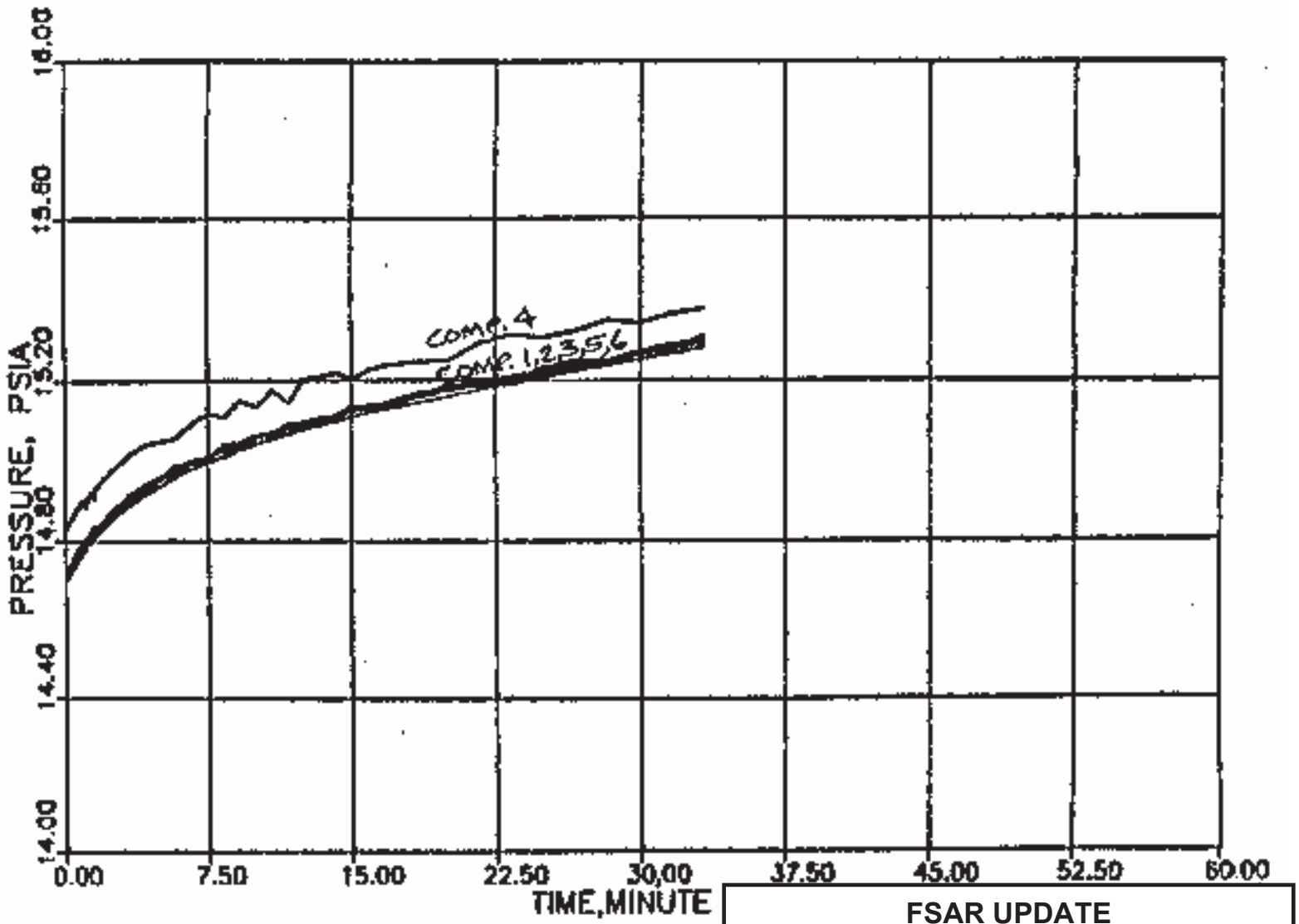
FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 3.6-23
AREA H, K
PRESSURE vs. TIME RESPONSE
AUXILIARY STEAM LINE IN AREA K
AT ELEVATION 100' (CRACK BREAK)



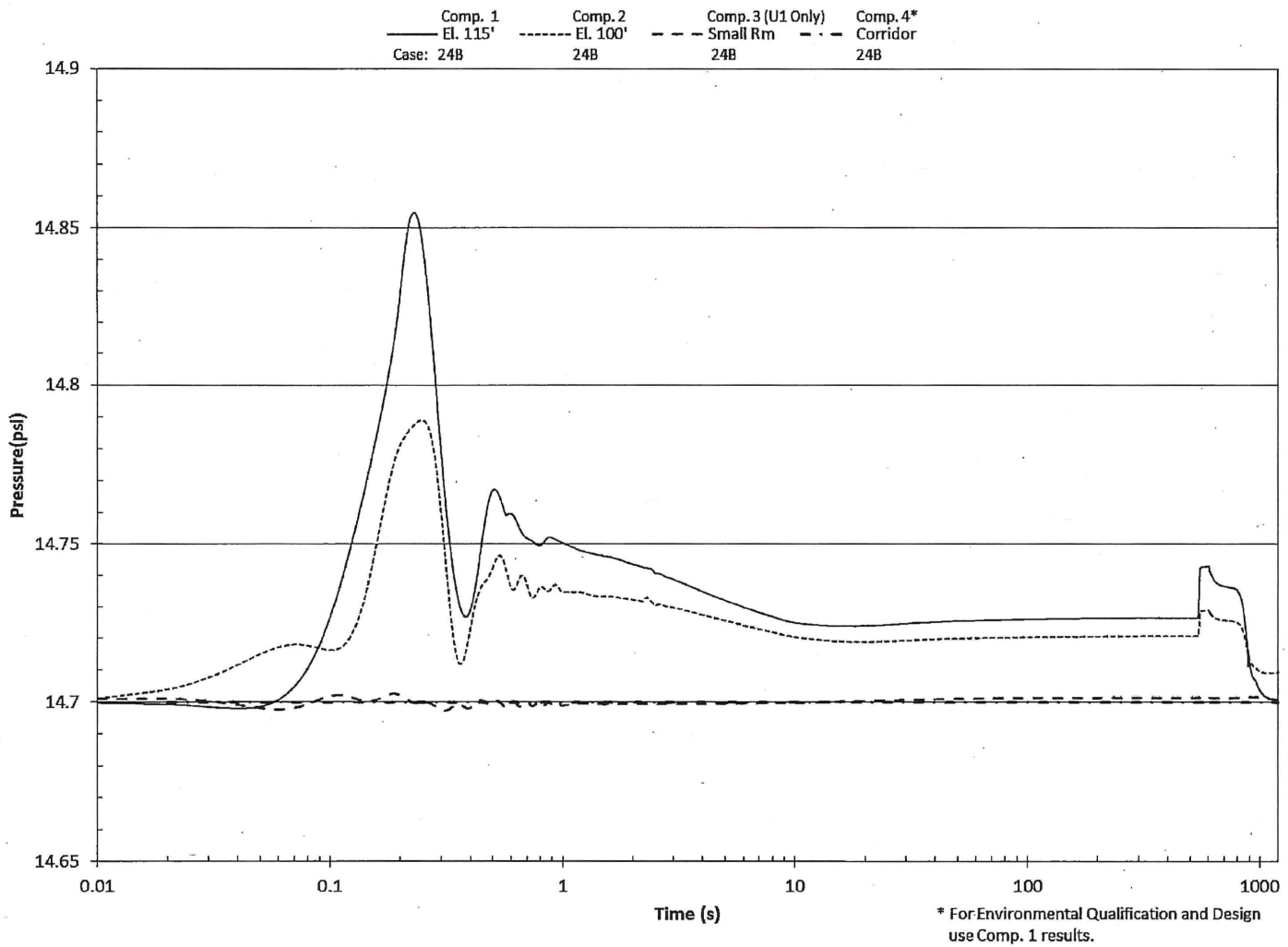
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.6-24 AREA J PRESSURE vs. TIME RESPONSE AUXILIARY STEAM LINE IN TURBINE DRIVEN AUXILIARY FW PUMP ROOM (CRACK BREAK)



FSAR UPDATE

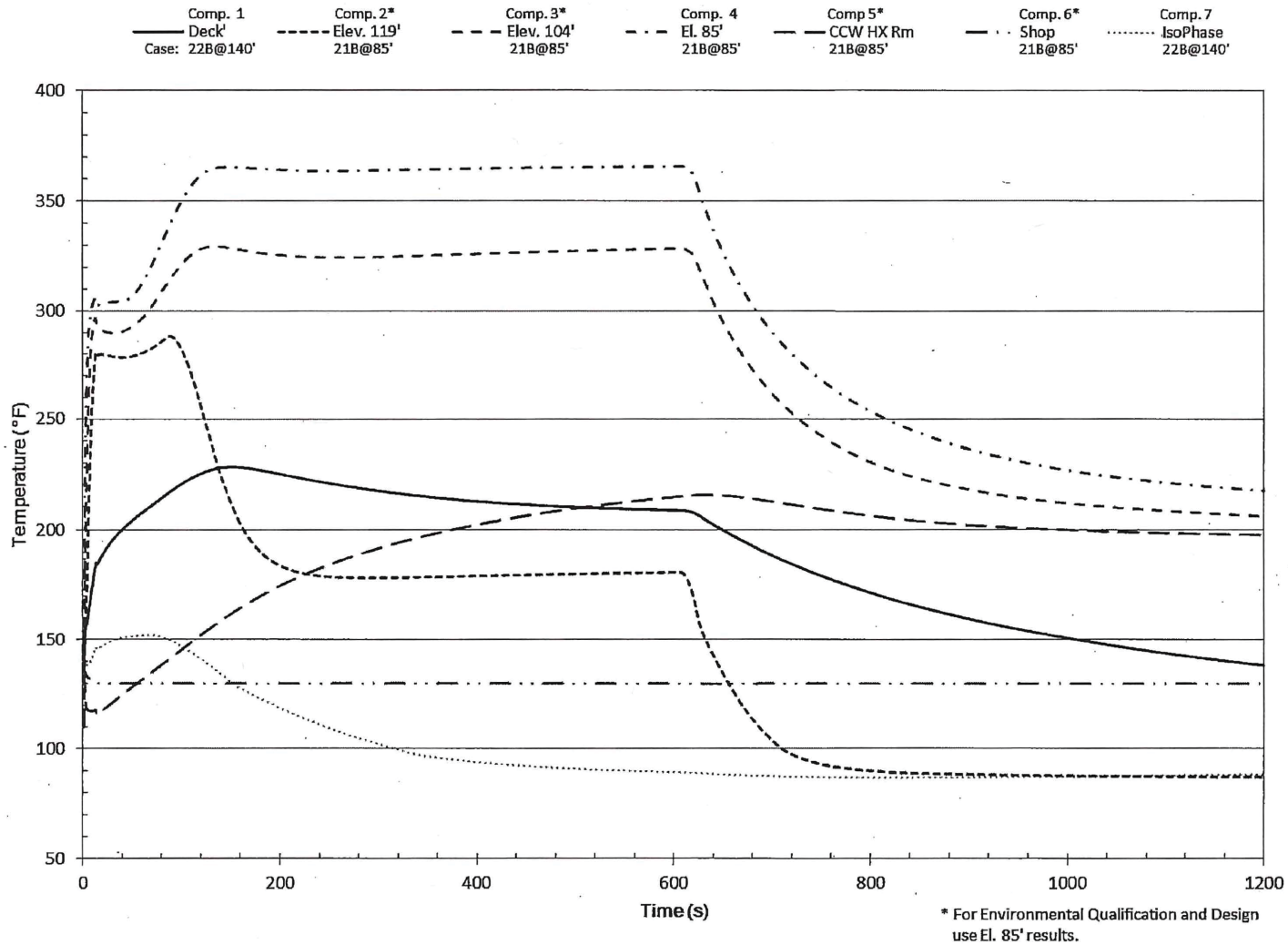
UNIT 1
DIABLO CANYON SITE

FIGURE 3.6-25
AREA J
PRESSURE vs. TIME RESPONSE
AUXILIARY STEAM LINE IN MOTOR DRIVEN
AUXILIARY FW PUMP ROOM, (CRACK BREAK)

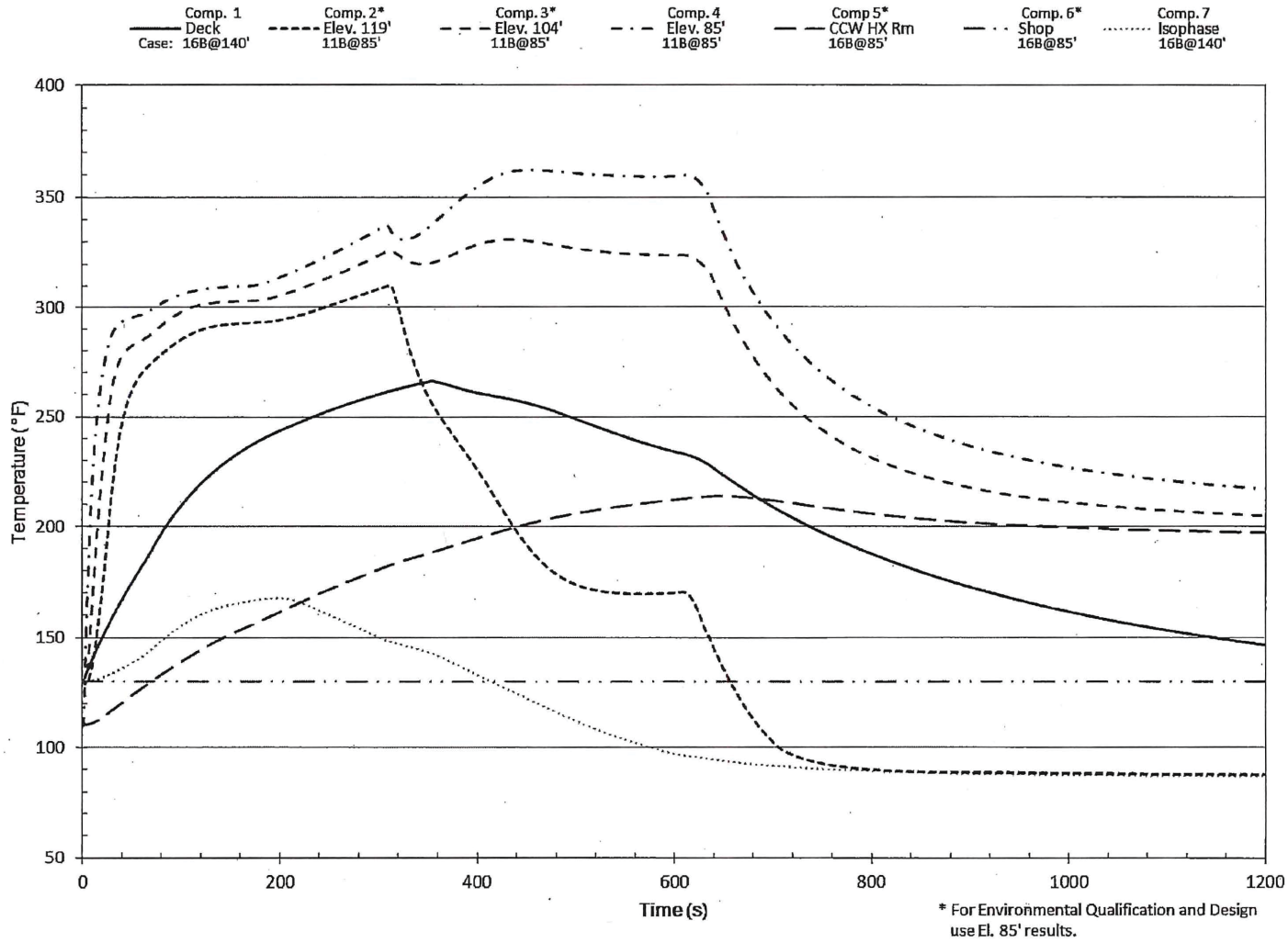


FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.6-26 AREA L PRESSURE vs. TIME RESPONSE AFW PUMP STEAM SUPPLY LINE AT ELEVATION 115' (DER)

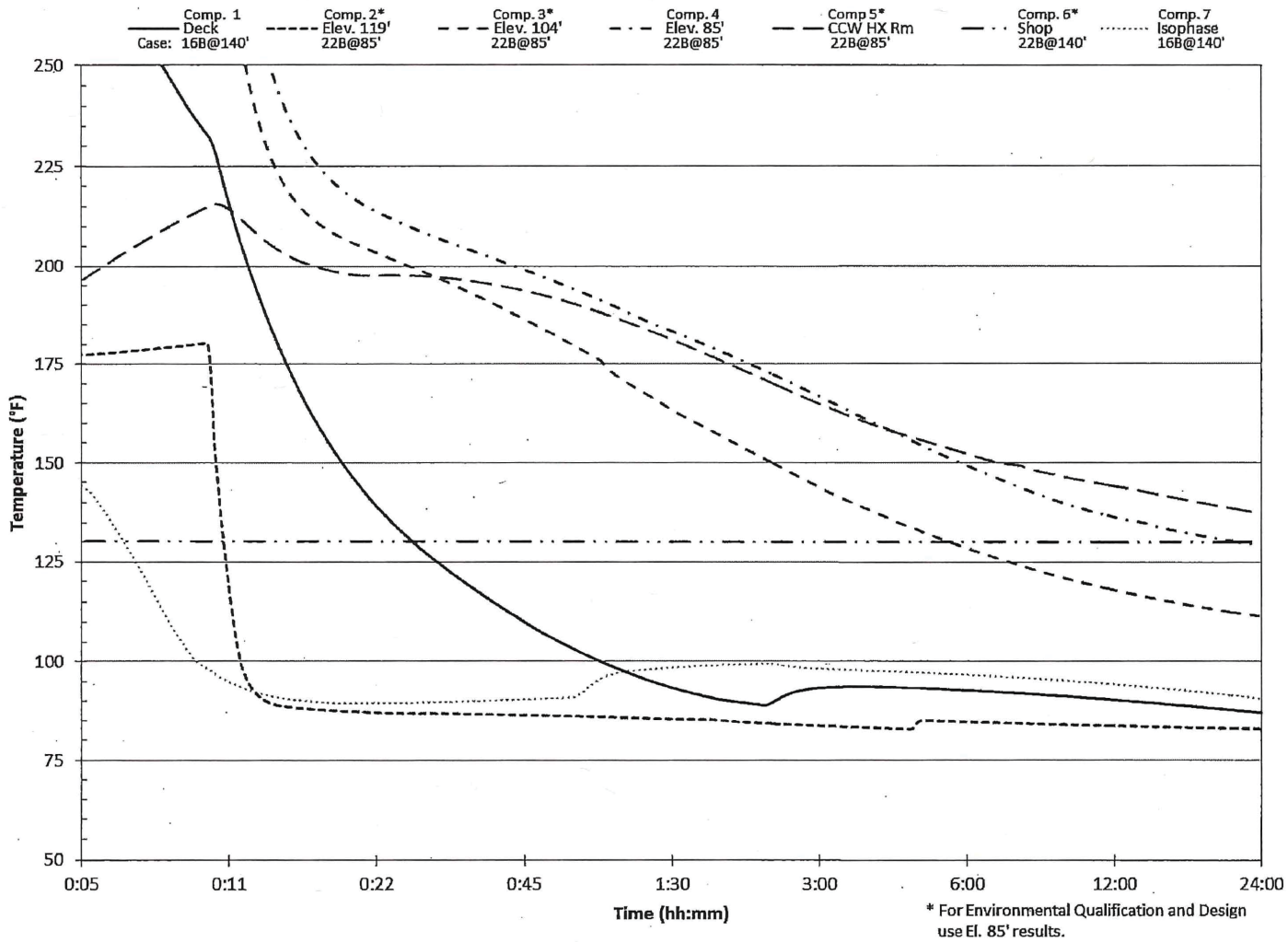
Revision 22 May 2015



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.6-28 TURBINE BUILDING TEMPERATURE vs. TIME RESPONSE MSLB (DER)

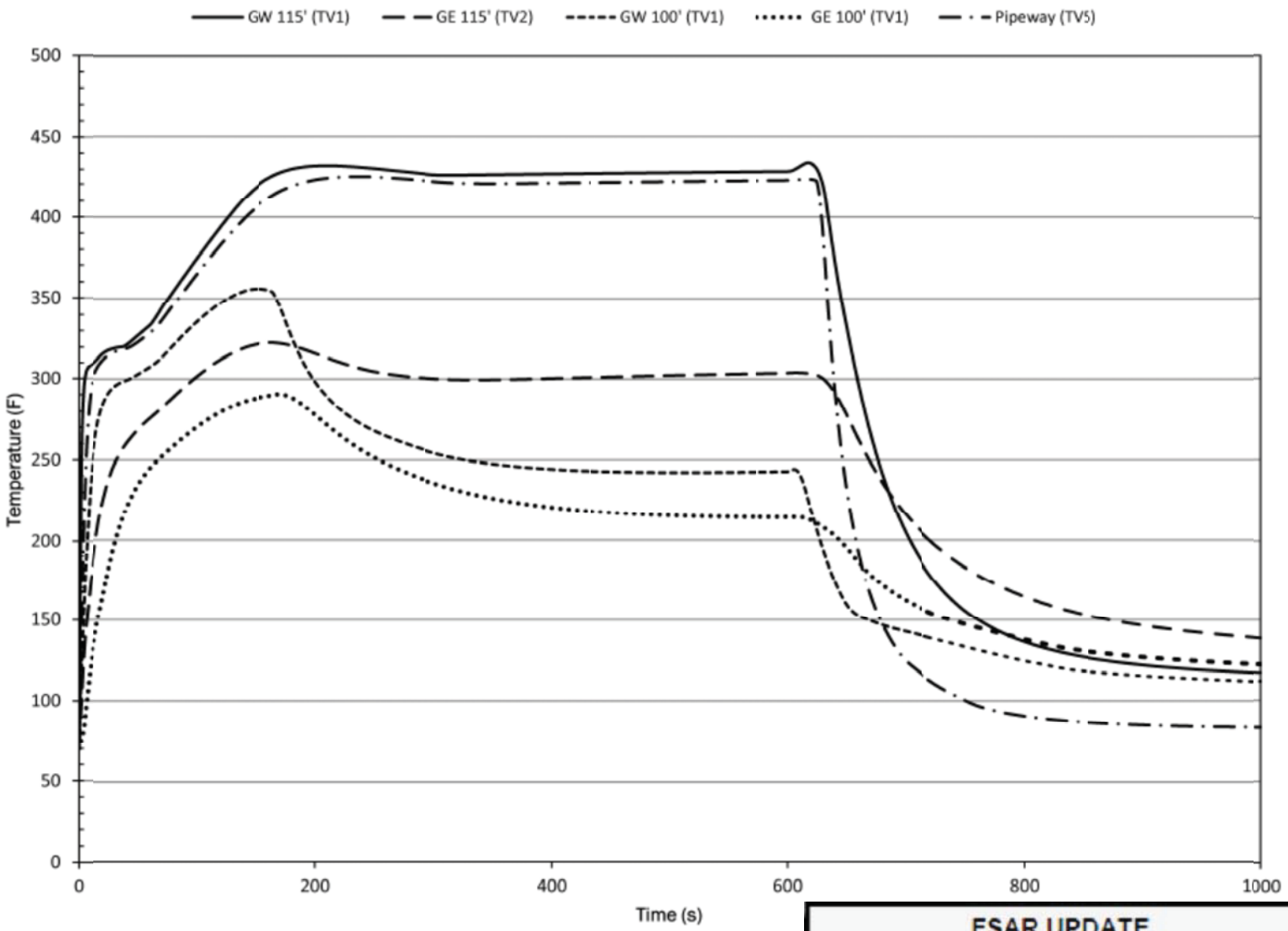


FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.6-29 TURBINE BUILDING TEMPERATURE vs. TIME RESPONSE MSLB (SPLIT RUPTURE)

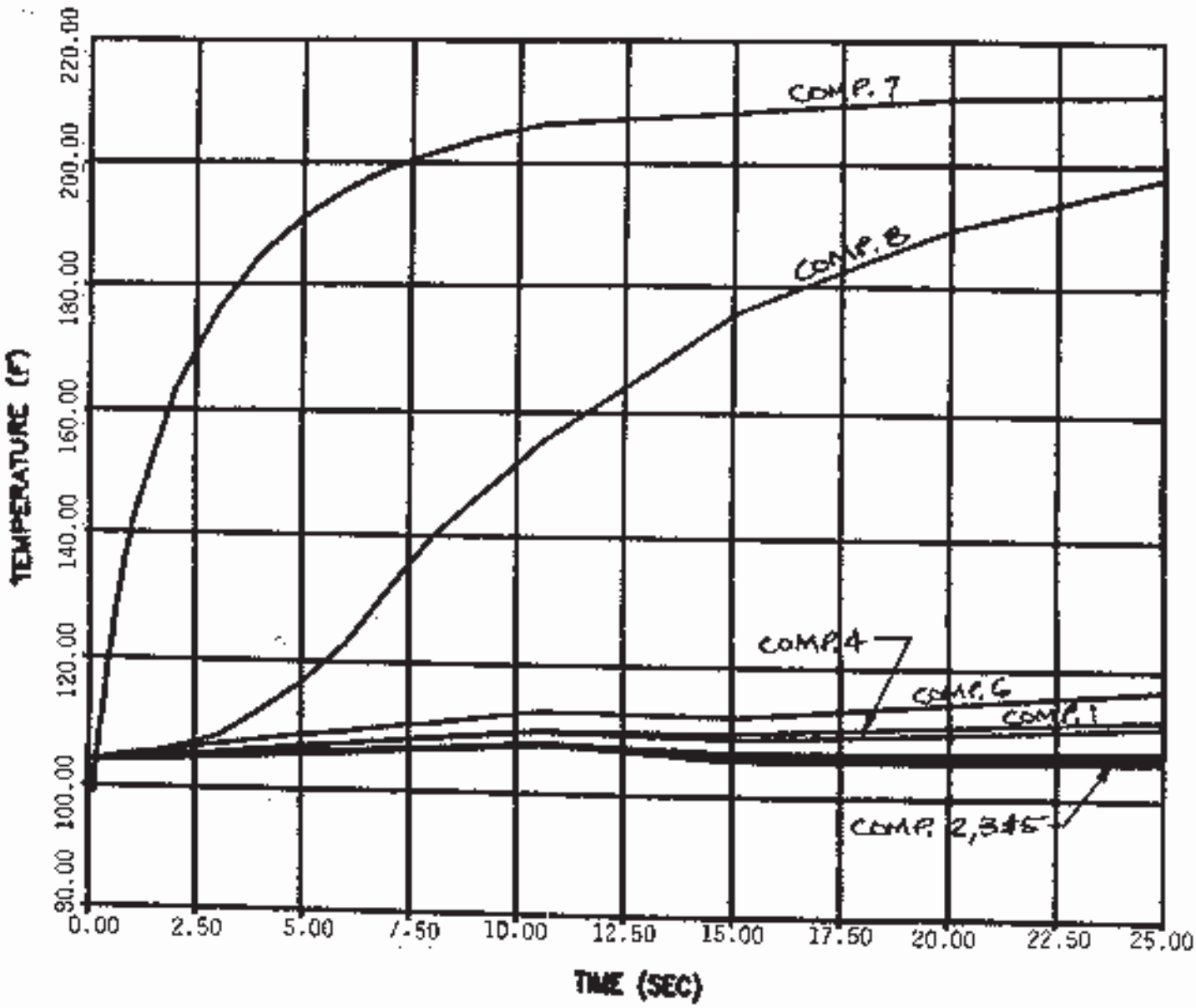


FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.6-30 TURBINE BUILDING LONG TERM TEMPERATURE vs. TIME RESPONSE

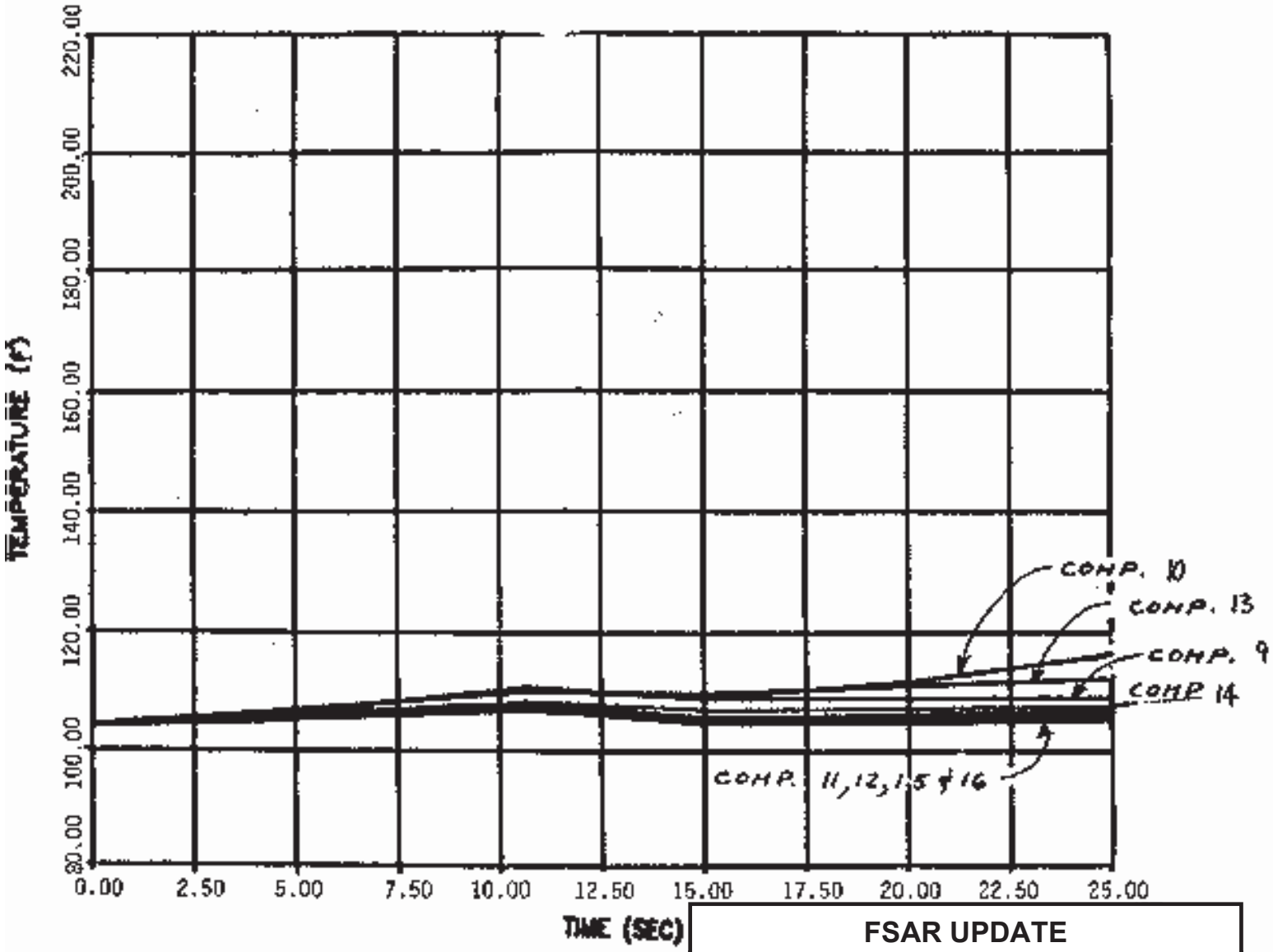
Revision 22 May 2015



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.6-32 AREA GE/GW TEMPERATURE vs. TIME RESPONSE MSLB AT ELEVATION 115' (SPLIT RUPTURE)



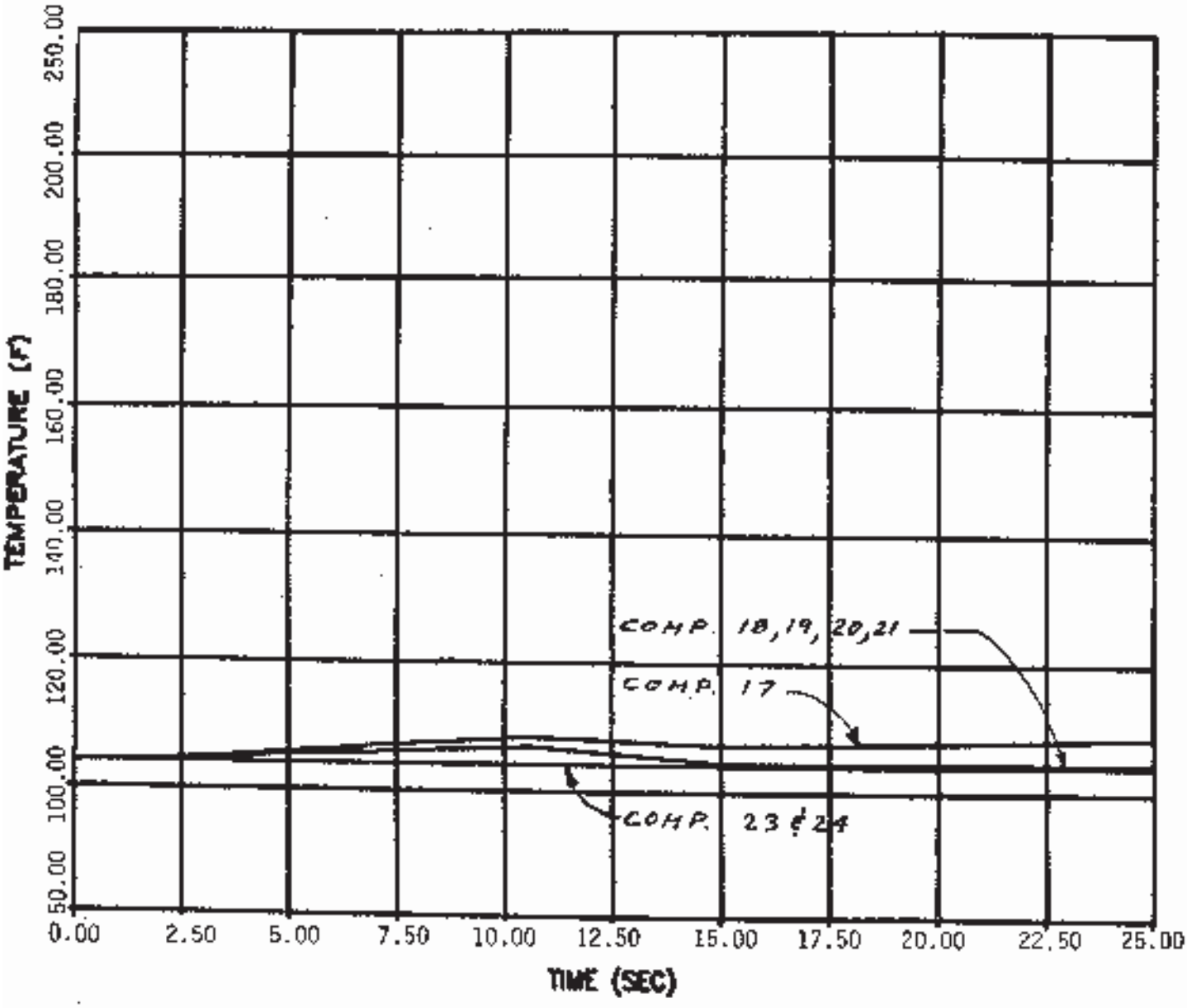
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.6-34 AREA H, K TEMPERATURE vs. TIME RESPONSE CVCS LETDOWN LINE BREAK IN AREA K AT ELEVATION 85', (DER)



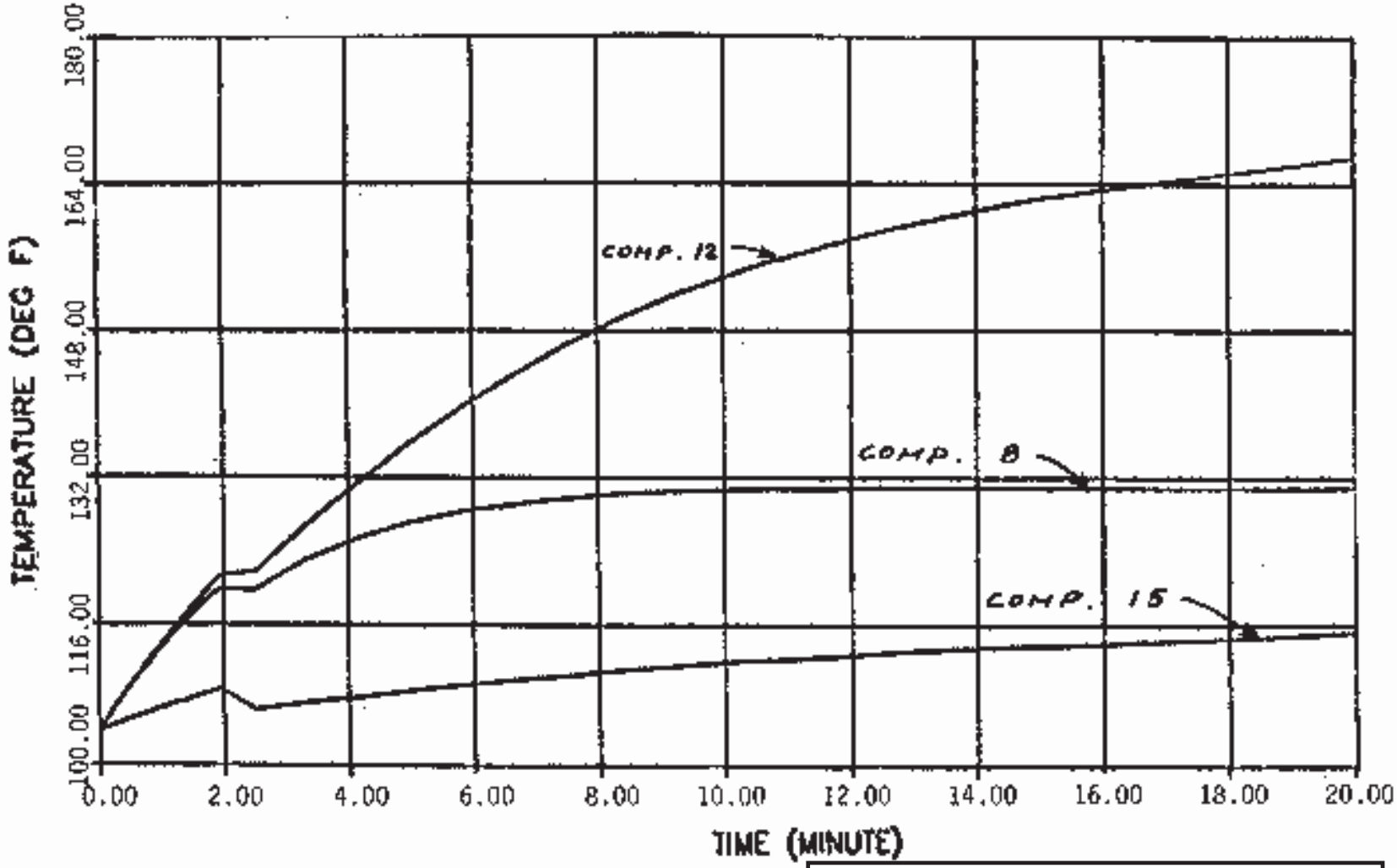
FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

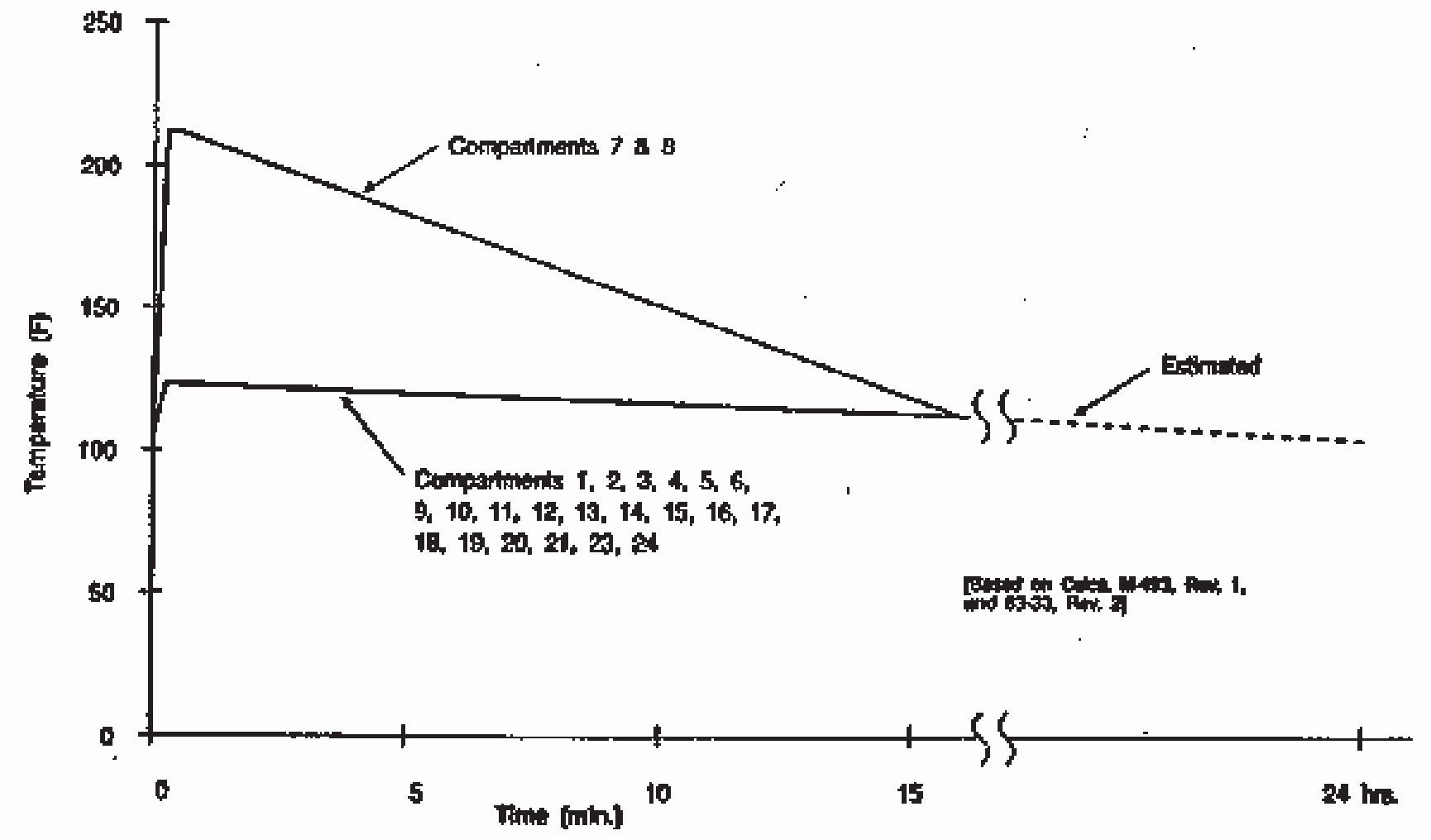
FIGURE 3.6-35
AREA H, K
TEMPERATURE vs. TIME RESPONSE
CVCS LETDOWN LINE IN AREA K
AT ELEVATION 85', (DER)



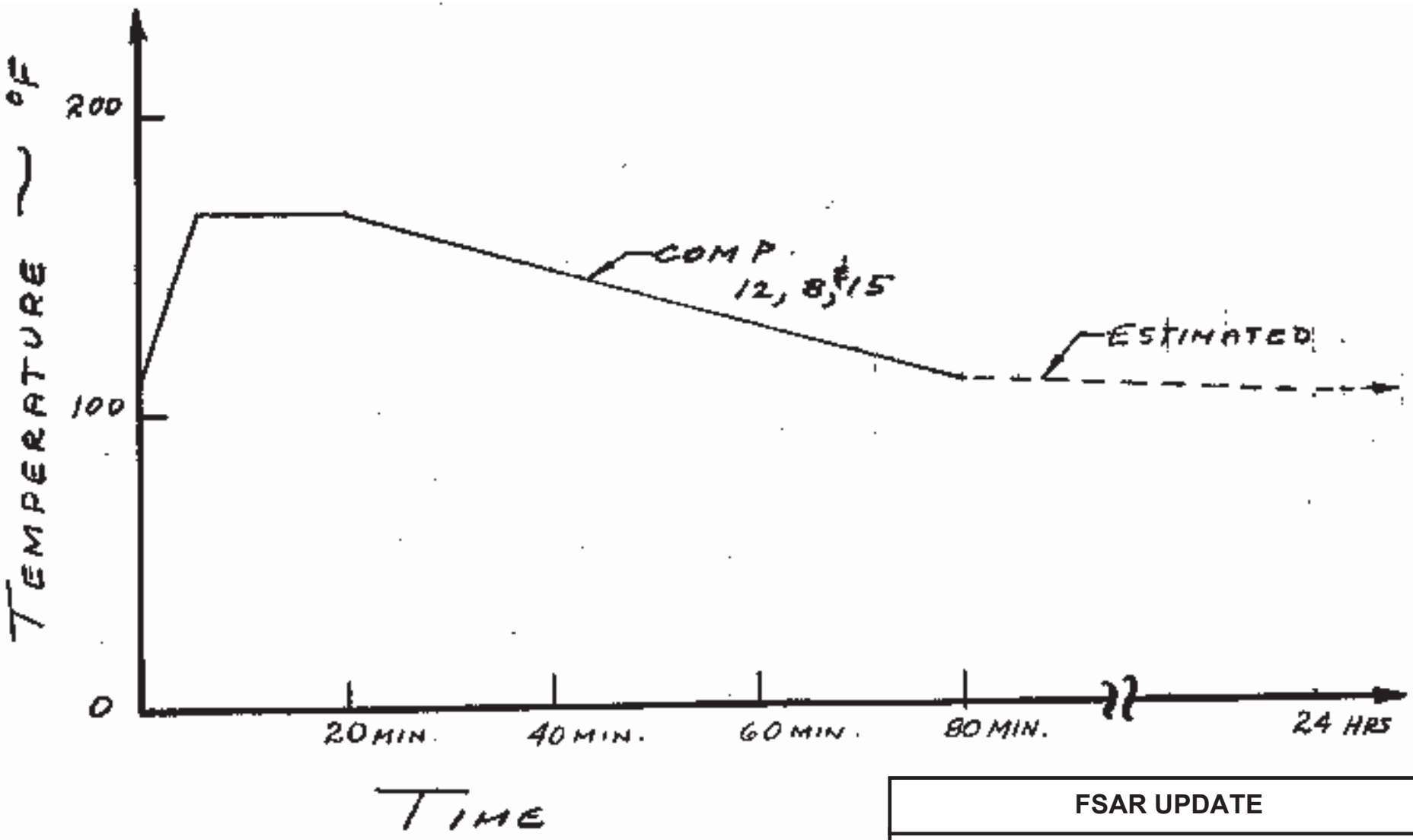
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.6-36 AREA H, K TEMPERATURE vs. TIME RESPONSE CVCS LETDOWN LINE IN AREA K AT ELEVATION 85' (DER)



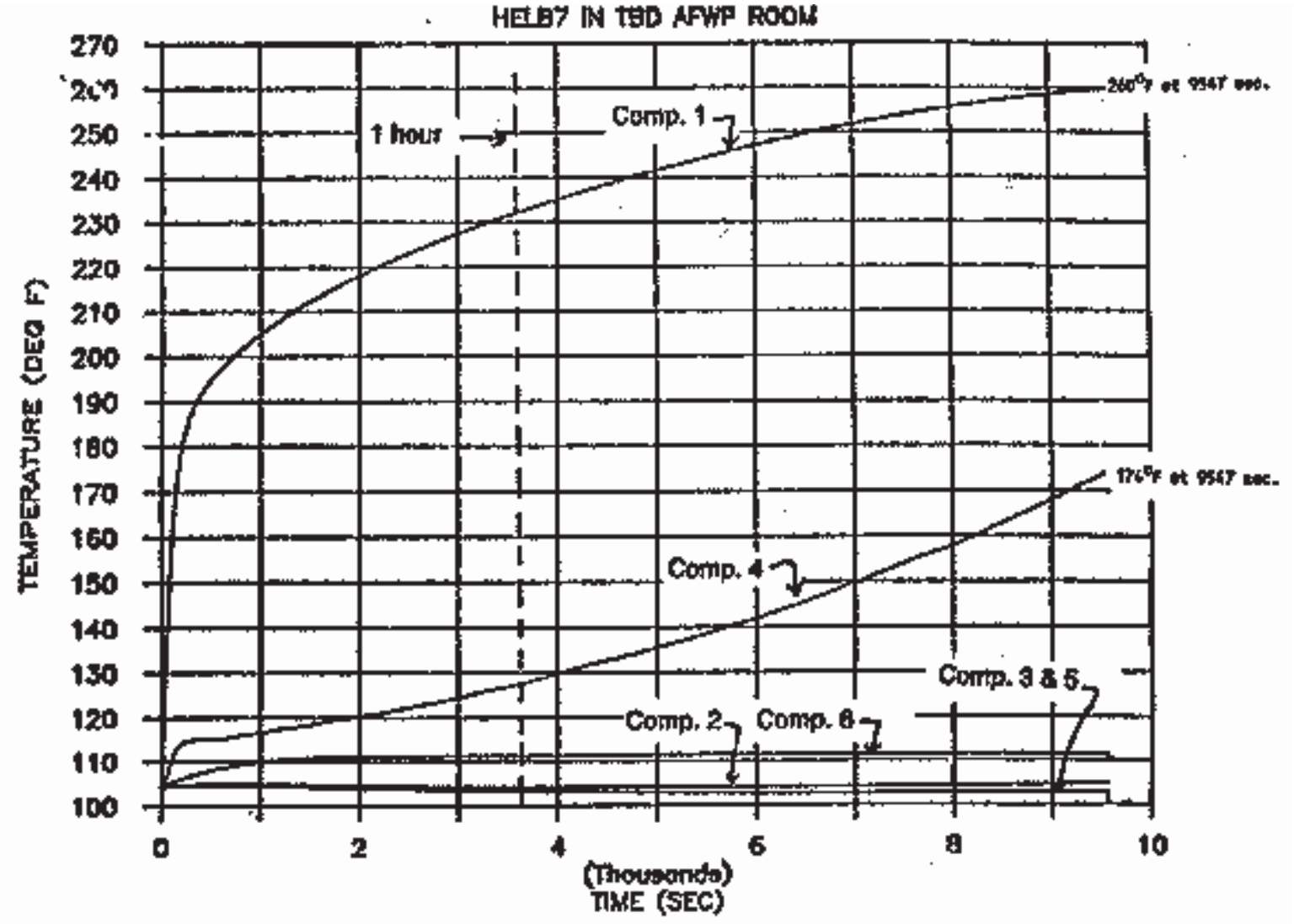
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.6-37 AREA H, K TEMPERATURE vs. TIME RESP0NSE AUXILIARY STEAM LINE IN AREA K AT ELEVATION 100' (CRACK BREAK)



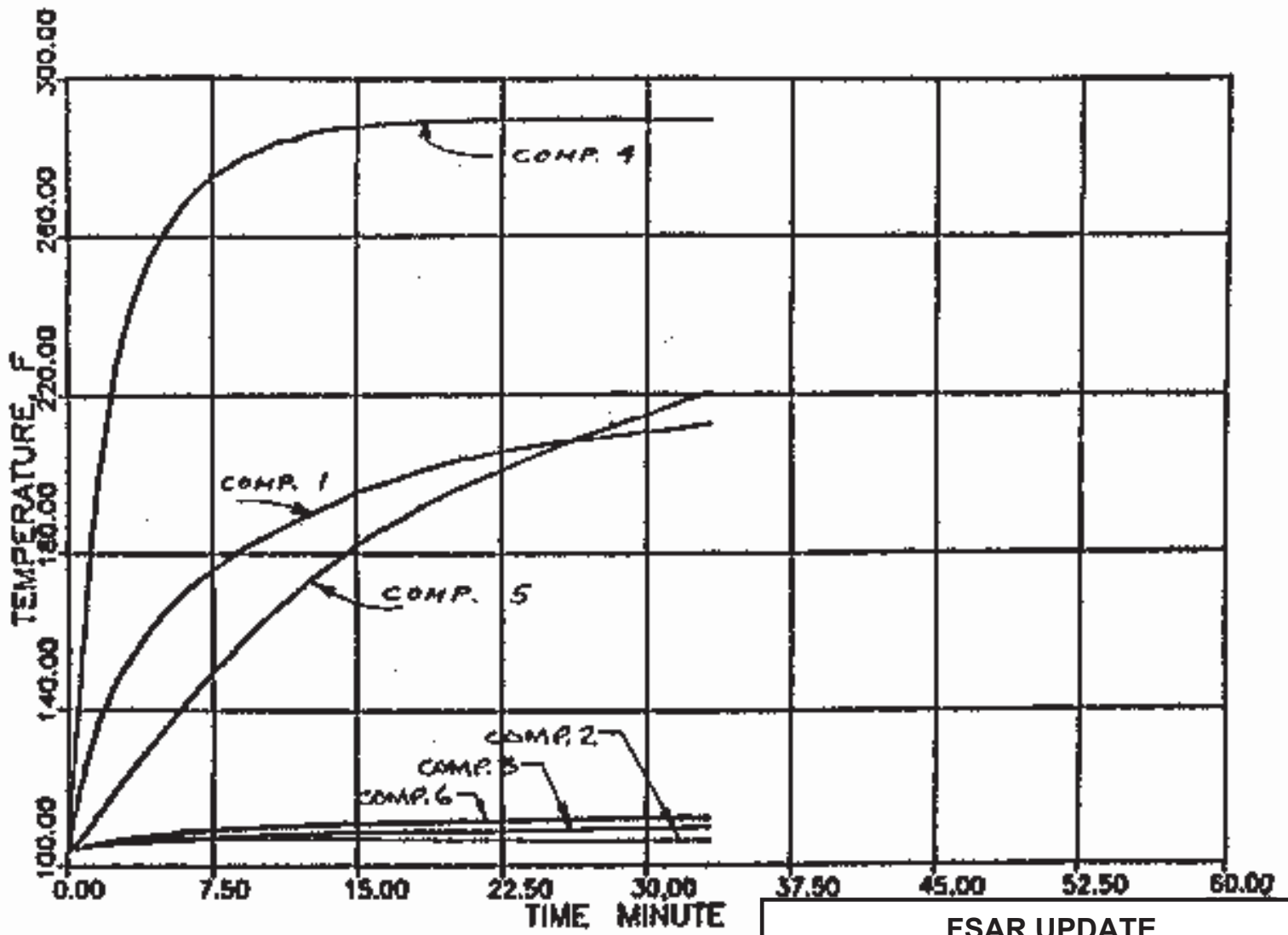
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.6-38 AREA H, K LONG TERM TEMPERATURE vs. TIME RESPONSE CVCS LETDOWN LINE IN AREA K AT ELEVATION 85 FT (DER)



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.6-39 AREA H, K LONG TERM TEMPERATURE vs. TIME RESP0NSE AUXILIARY STEAM LINE IN AREA K AT ELEVATION 100' (CRACK BREAK)



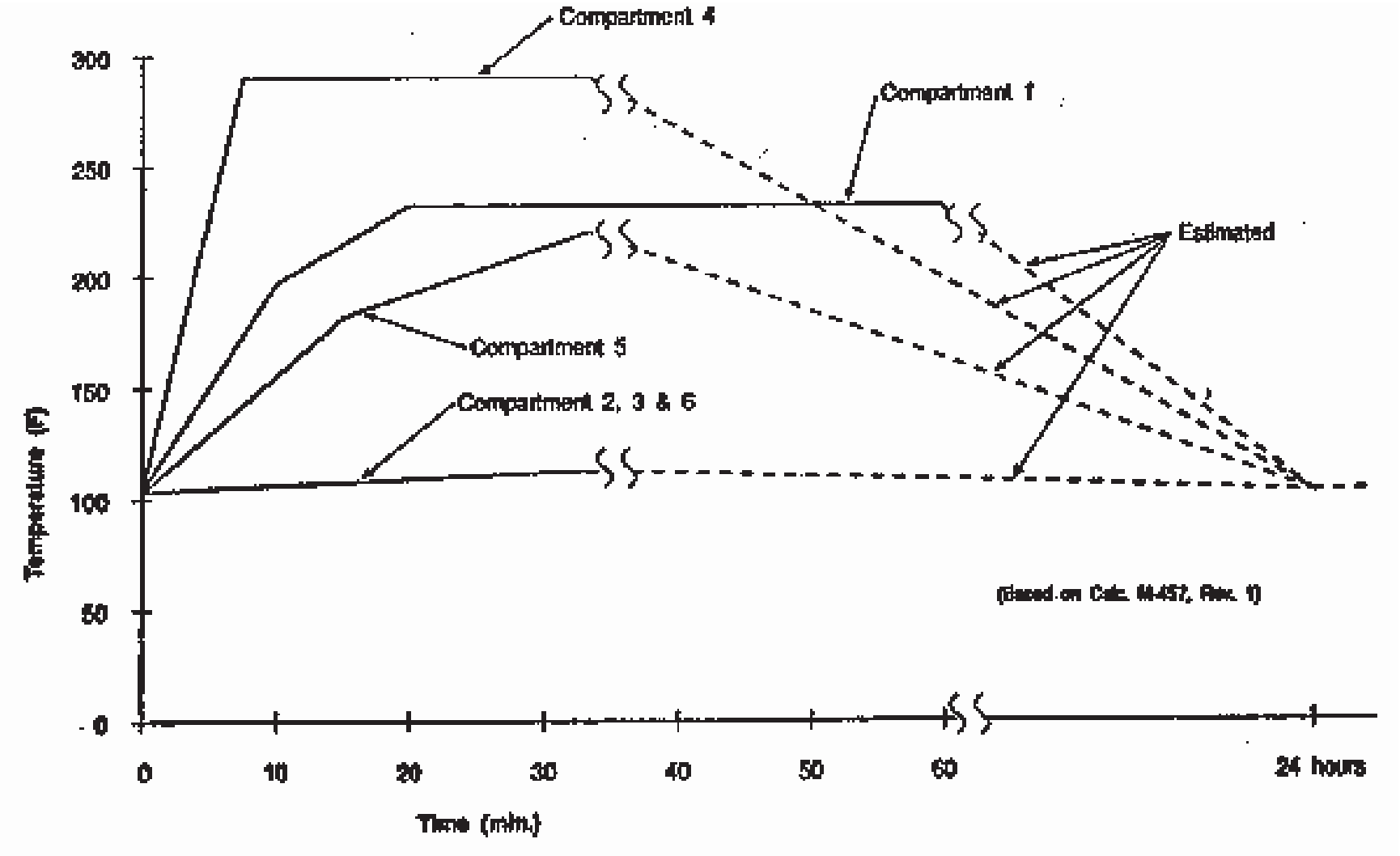
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.6-40 AREA J TEMPERATURE vs. TIME RESPONSE AUXILIARY STEAM LINE IN TURBINE DRIVEN AUXILIARY FW PUMP ROOM (CRACK BREAK)



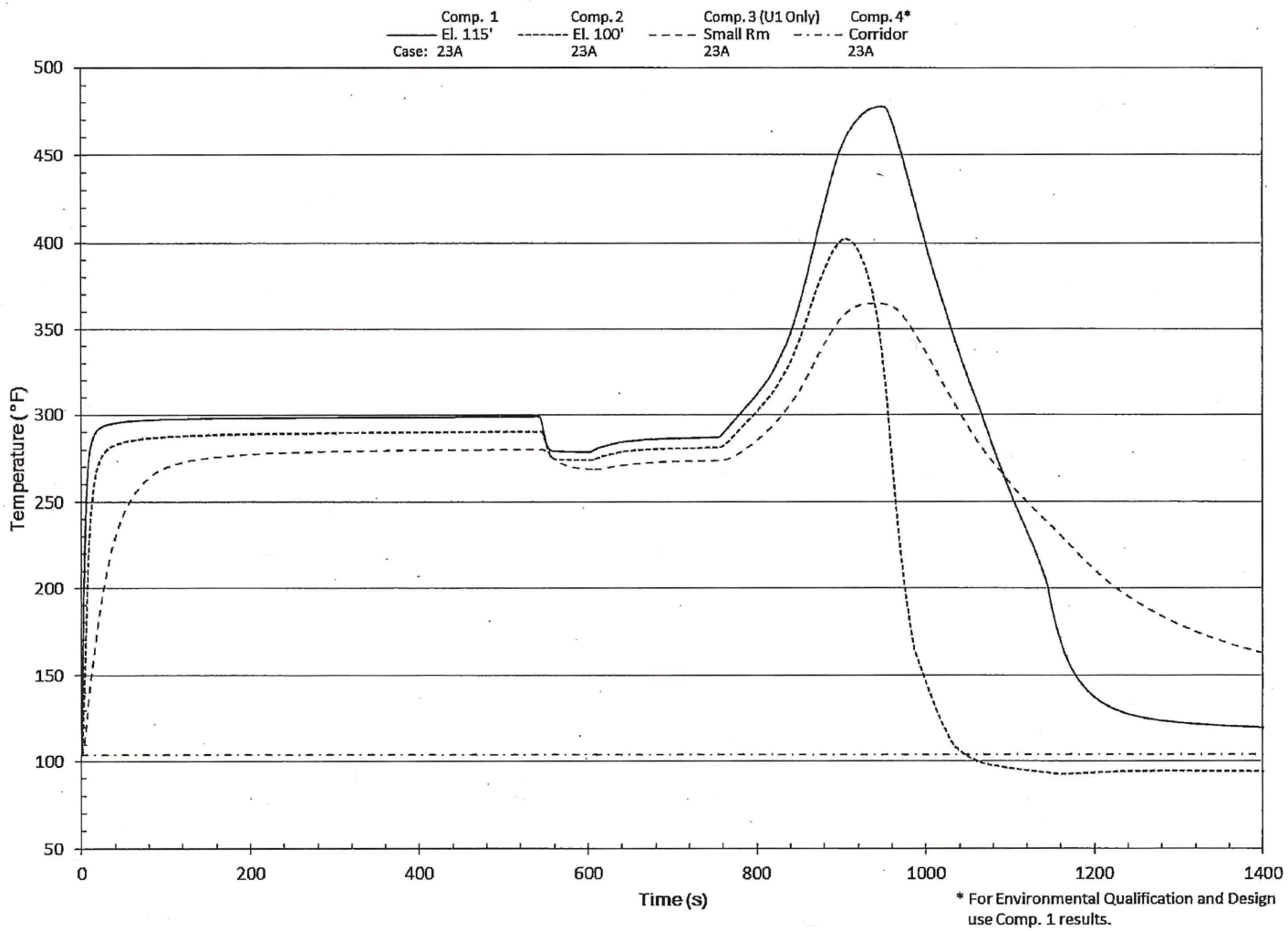
FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

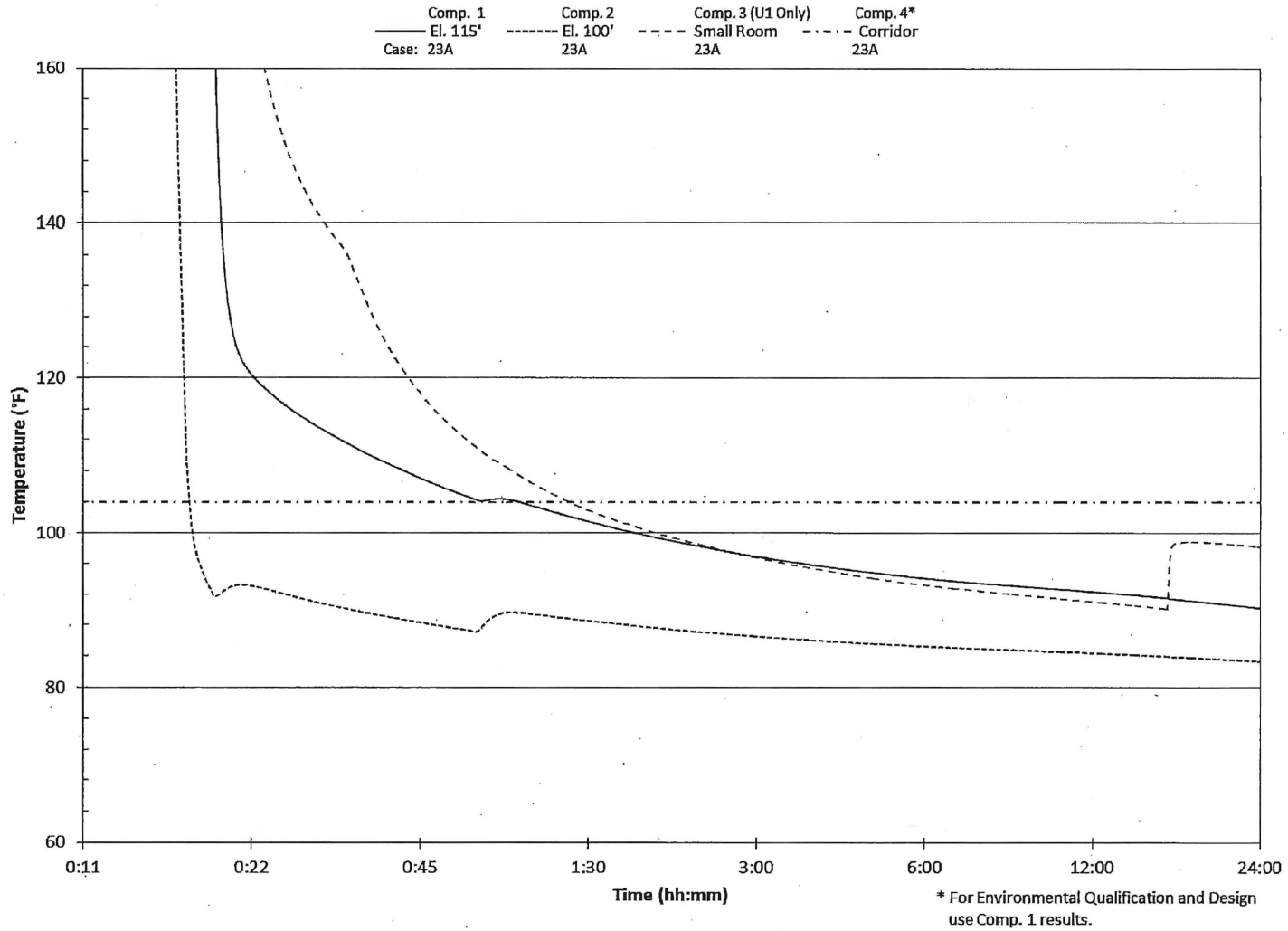
FIGURE 3.6-41
AREA J
TEMPERATURE vs. TIME RESP0NSE
AUXILIARY STEAM LINE IN MOTOR DRIVEN
AUXILIARY FW PUMP ROOM, (CRACK BREAK)



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.6-42 AREA J LONG TERM TEMPERATURE vs. TIME RESPONSE

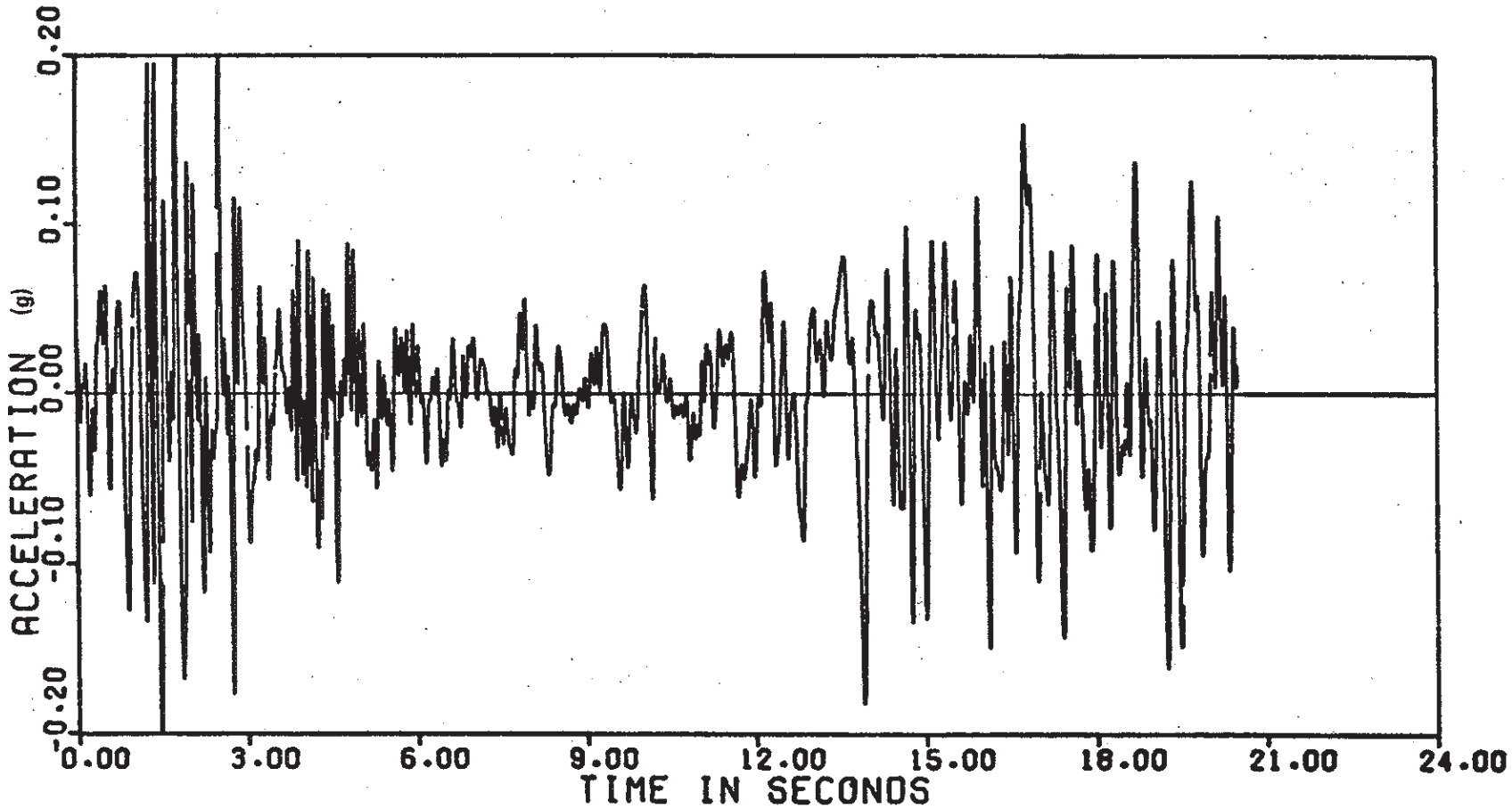


FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.6-43 AREA L TEMPERATURE vs. TIME RESPONSE AFW PUMP STEAM SUPPLY LINE AT ELEVATION 115' (DER)

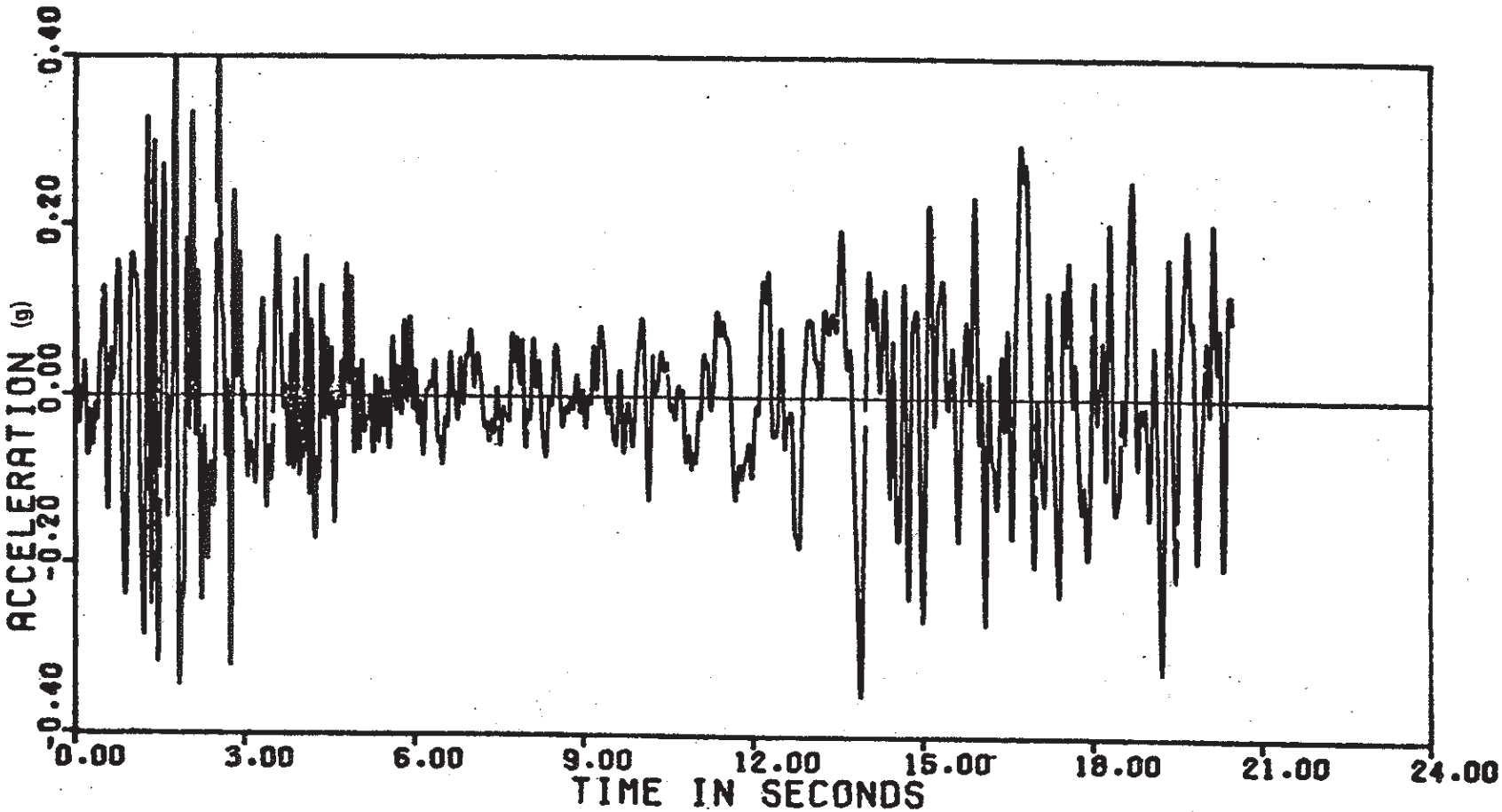


FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.6-44 AREA L LONG TERM TEMPERATURE vs. TIME RESPONSE AFW PUMP STEAM SUPPLY LINE AT ELEVATION 115' (DER)

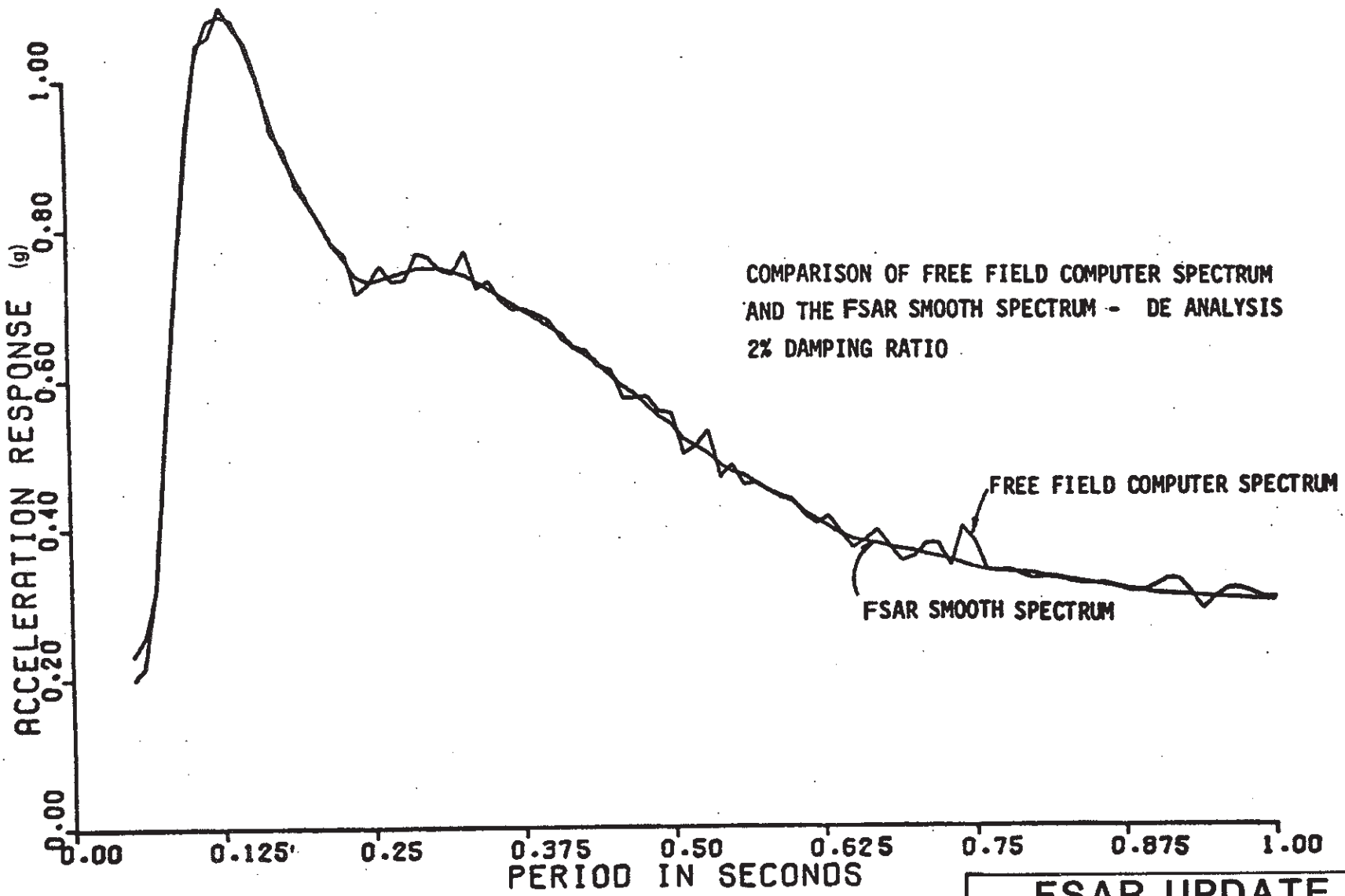
Revision 22 May 2015



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.7-1 FREE FIELD GROUND MOTION DE ANALYSIS



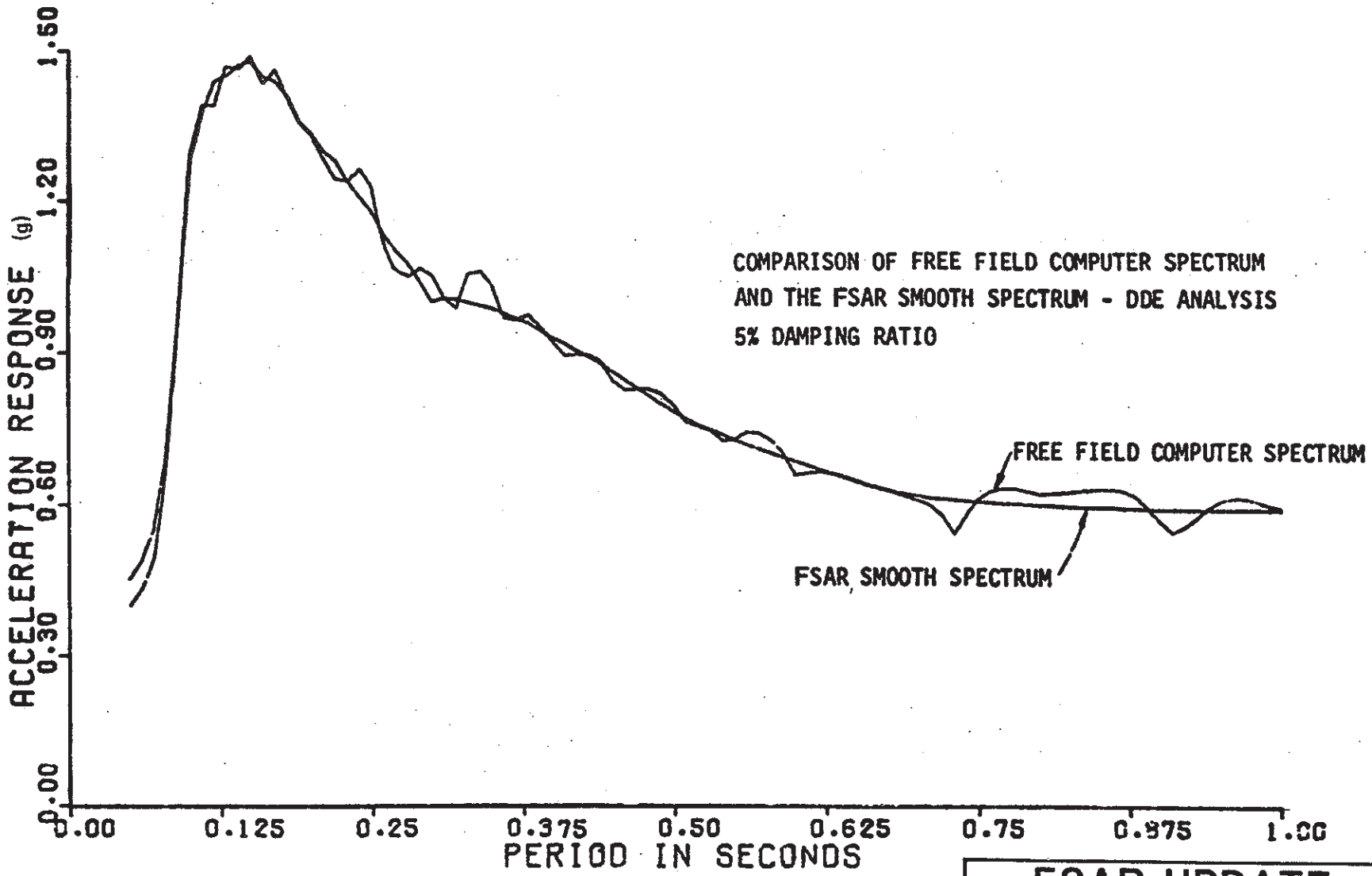
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.7-2 FREE FIELD GROUND MOTION DDE ANALYSIS



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

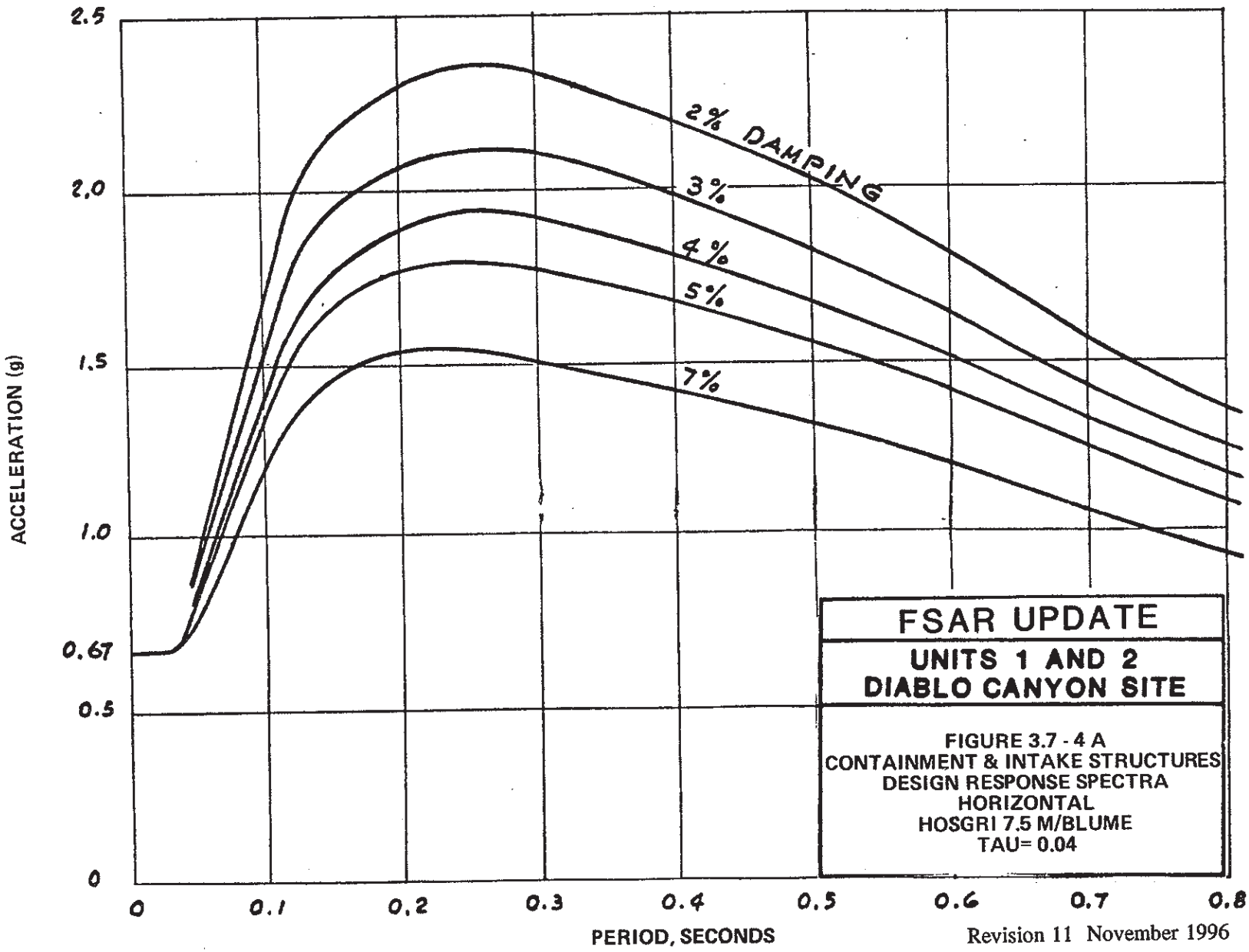
FIGURE 3.7-3
COMPARISON OF SPECTRA
2% DAMPING RATIO



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

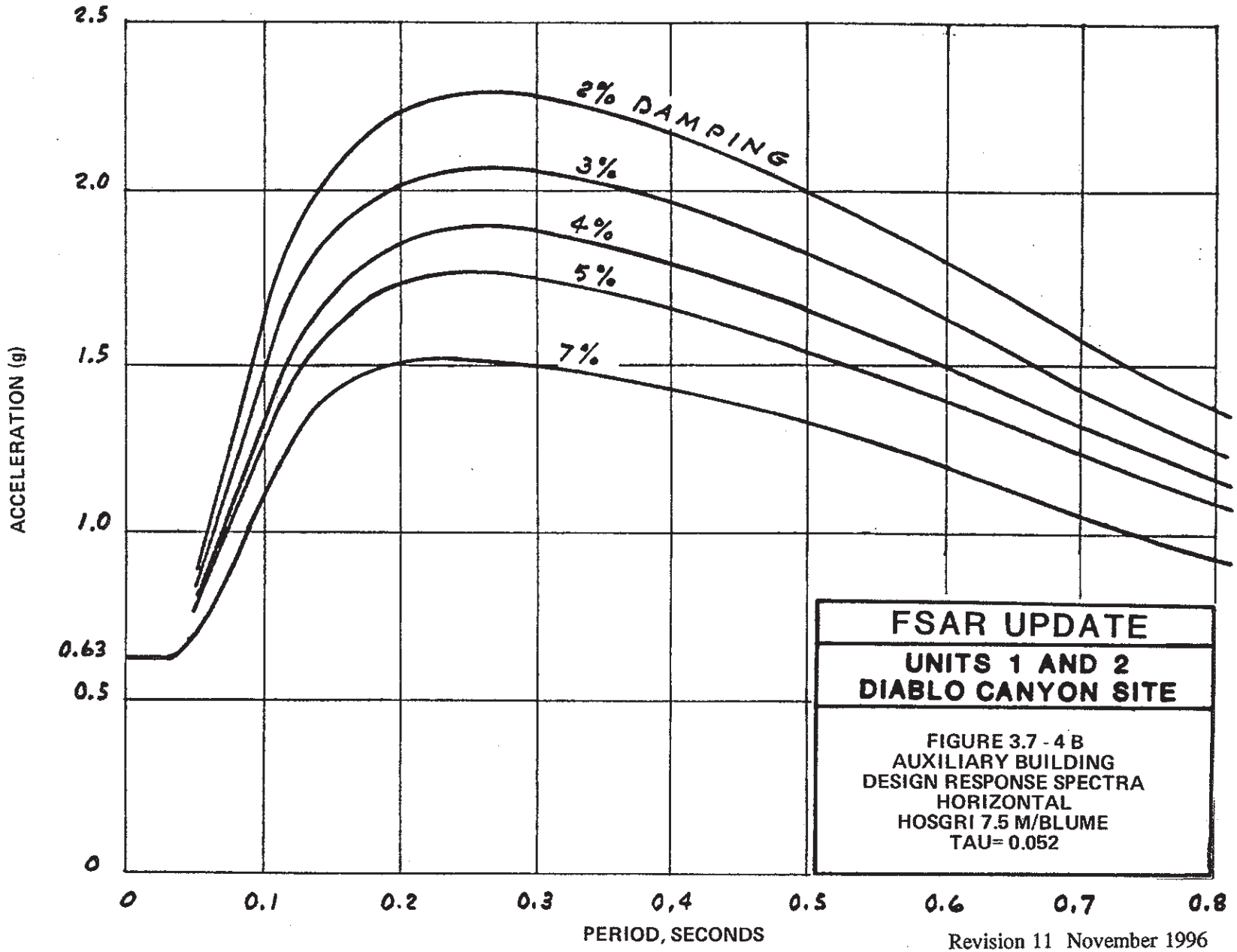
FIGURE 3.7-4
COMPARISON OF SPECTRA
5% DAMPING RATIO



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

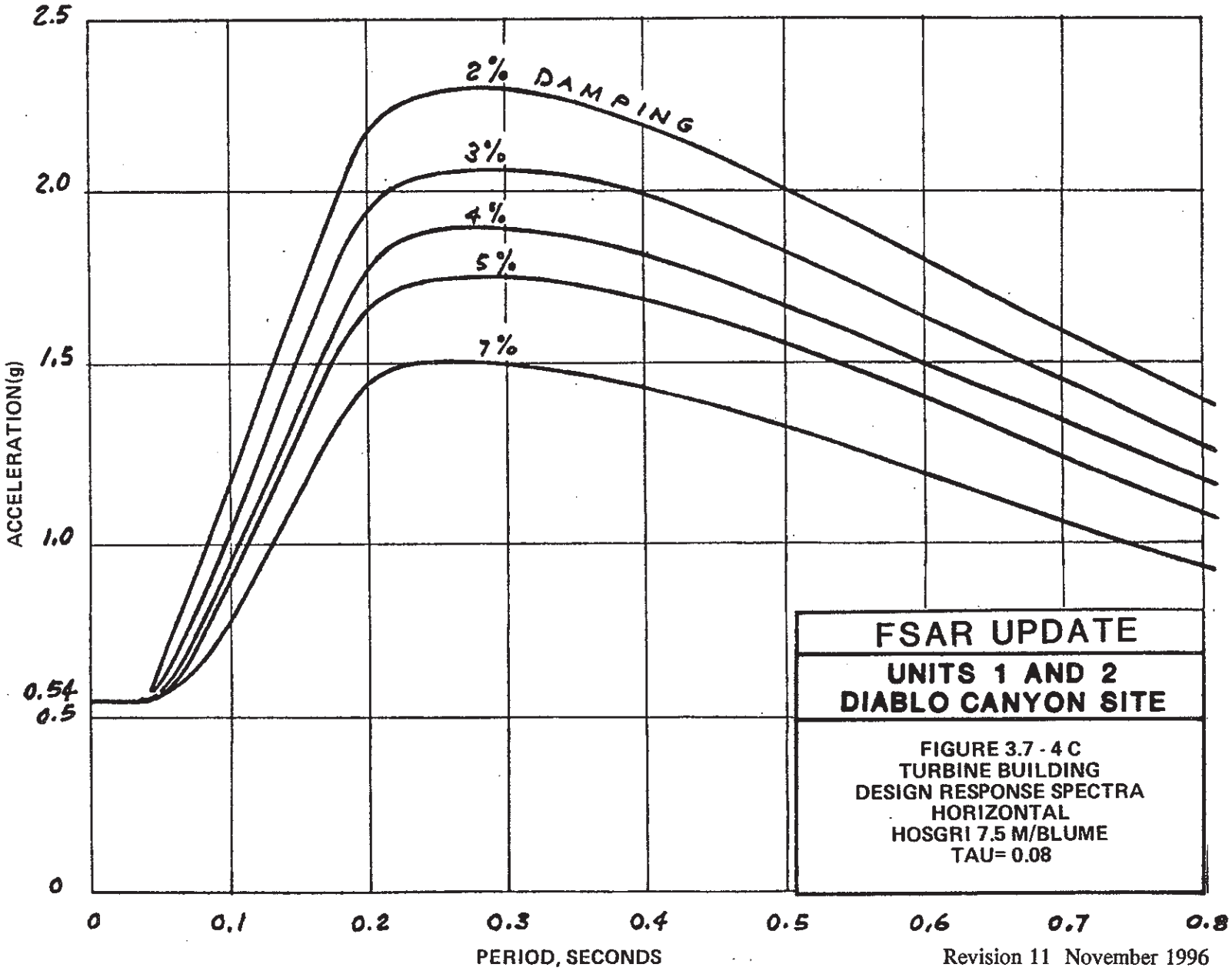
FIGURE 3.7 - 4 A
CONTAINMENT & INTAKE STRUCTURES
DESIGN RESPONSE SPECTRA
HORIZONTAL
HOSGRI 7.5 M/BLUME
TAU= 0.04



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

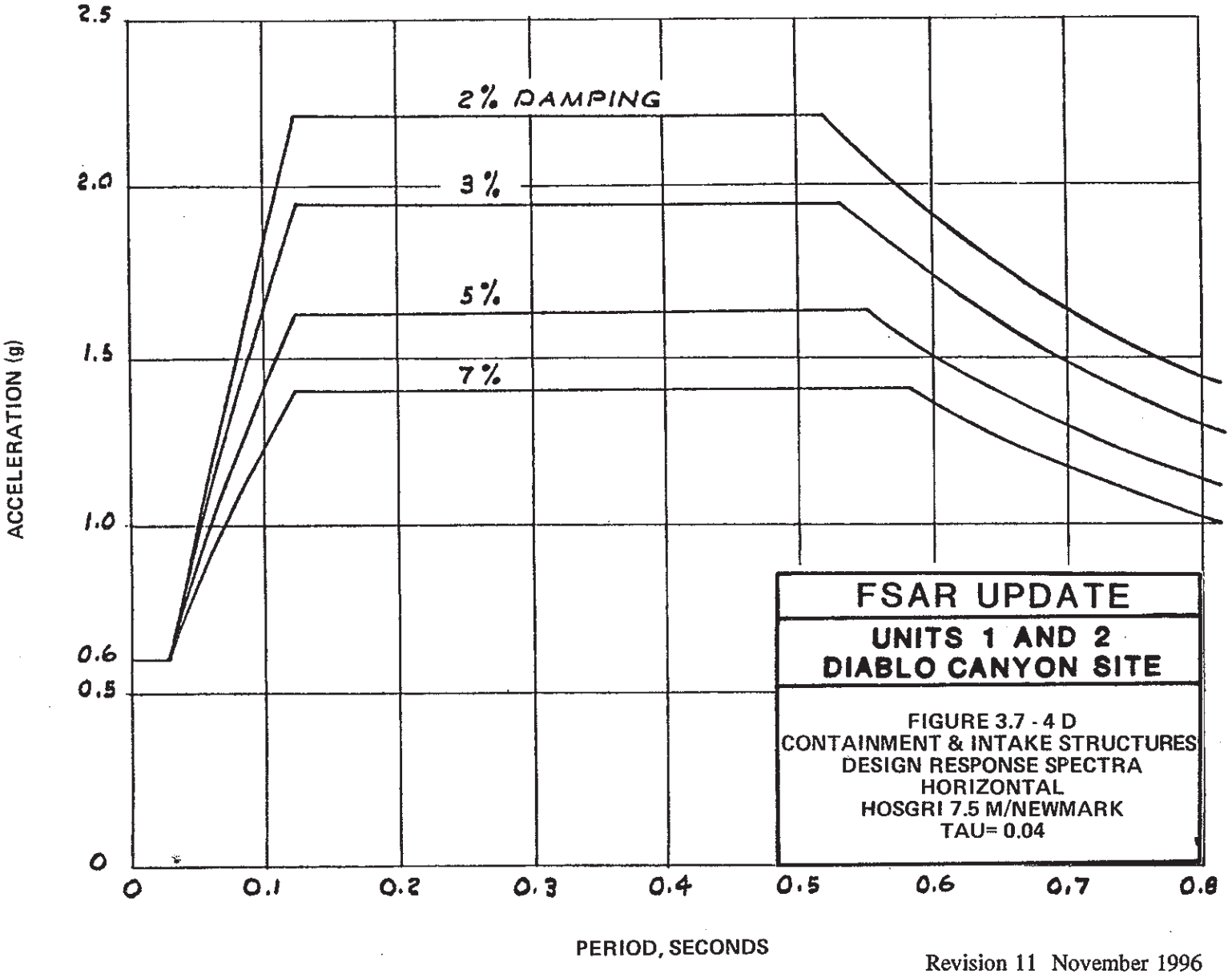
FIGURE 3.7 - 4 B
AUXILIARY BUILDING
DESIGN RESPONSE SPECTRA
HORIZONTAL
HOSGRI 7.5 M/BLUME
TAU= 0.052



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

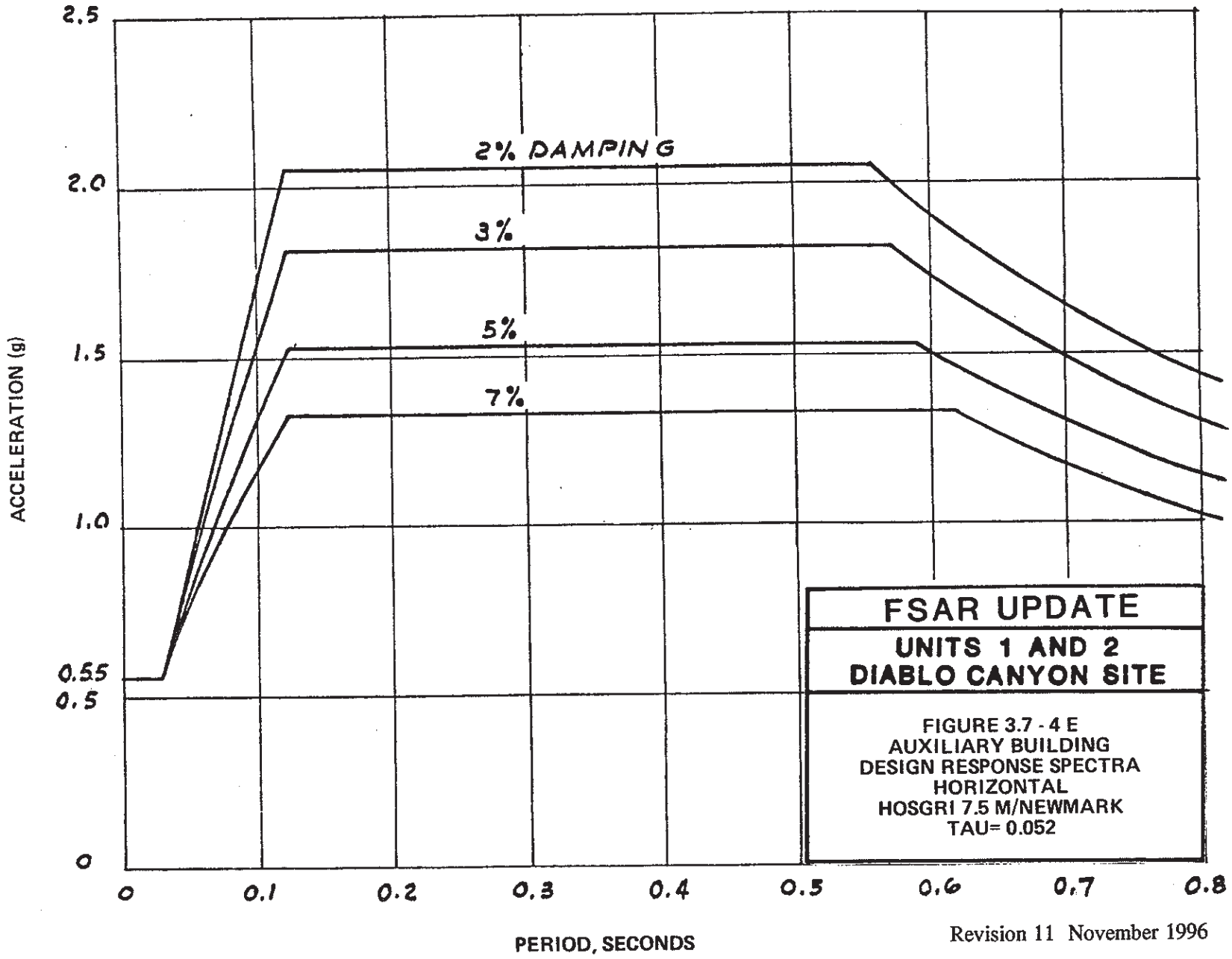
FIGURE 3.7 - 4 C
TURBINE BUILDING
DESIGN RESPONSE SPECTRA
HORIZONTAL
HOSGRI 7.5 M/BLUME
TAU= 0.08



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

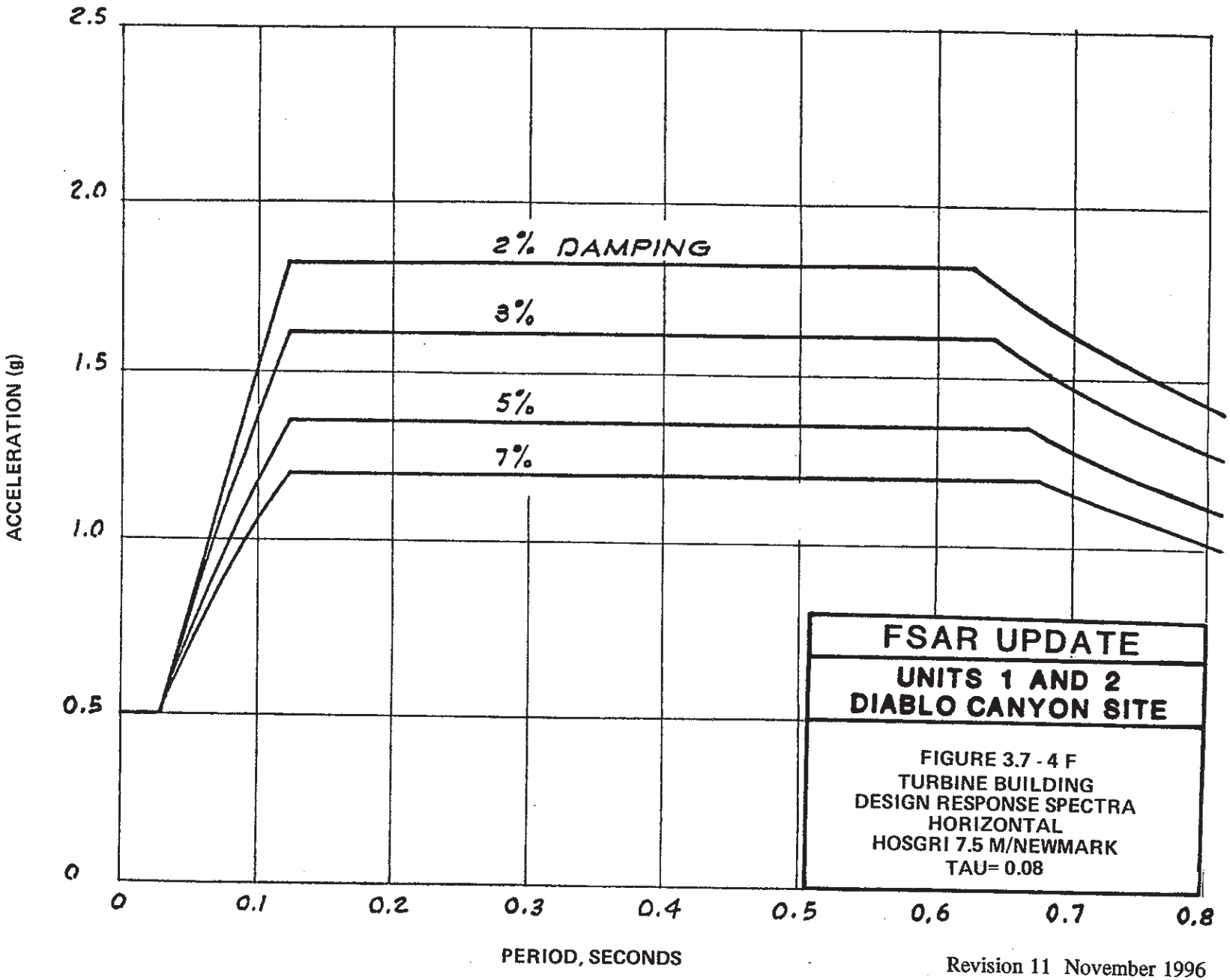
FIGURE 3.7 - 4 D
CONTAINMENT & INTAKE STRUCTURES
DESIGN RESPONSE SPECTRA
HORIZONTAL
HOSGRI 7.5 M/NEWMARK
TAU= 0.04



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

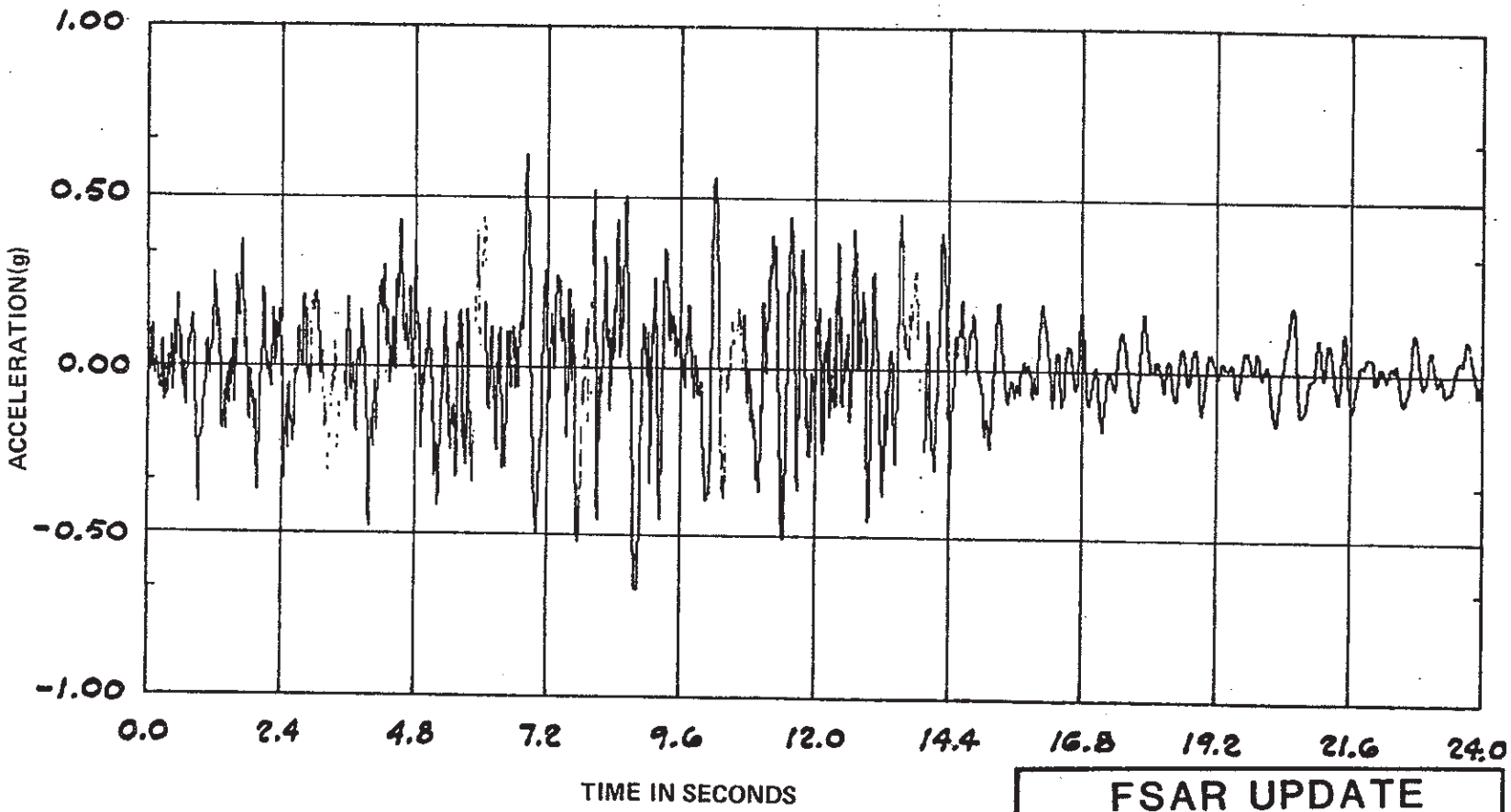
FIGURE 3.7 - 4 E
AUXILIARY BUILDING
DESIGN RESPONSE SPECTRA
HORIZONTAL
HOSGRI 7.5 M/NEWMARK
TAU= 0.052



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

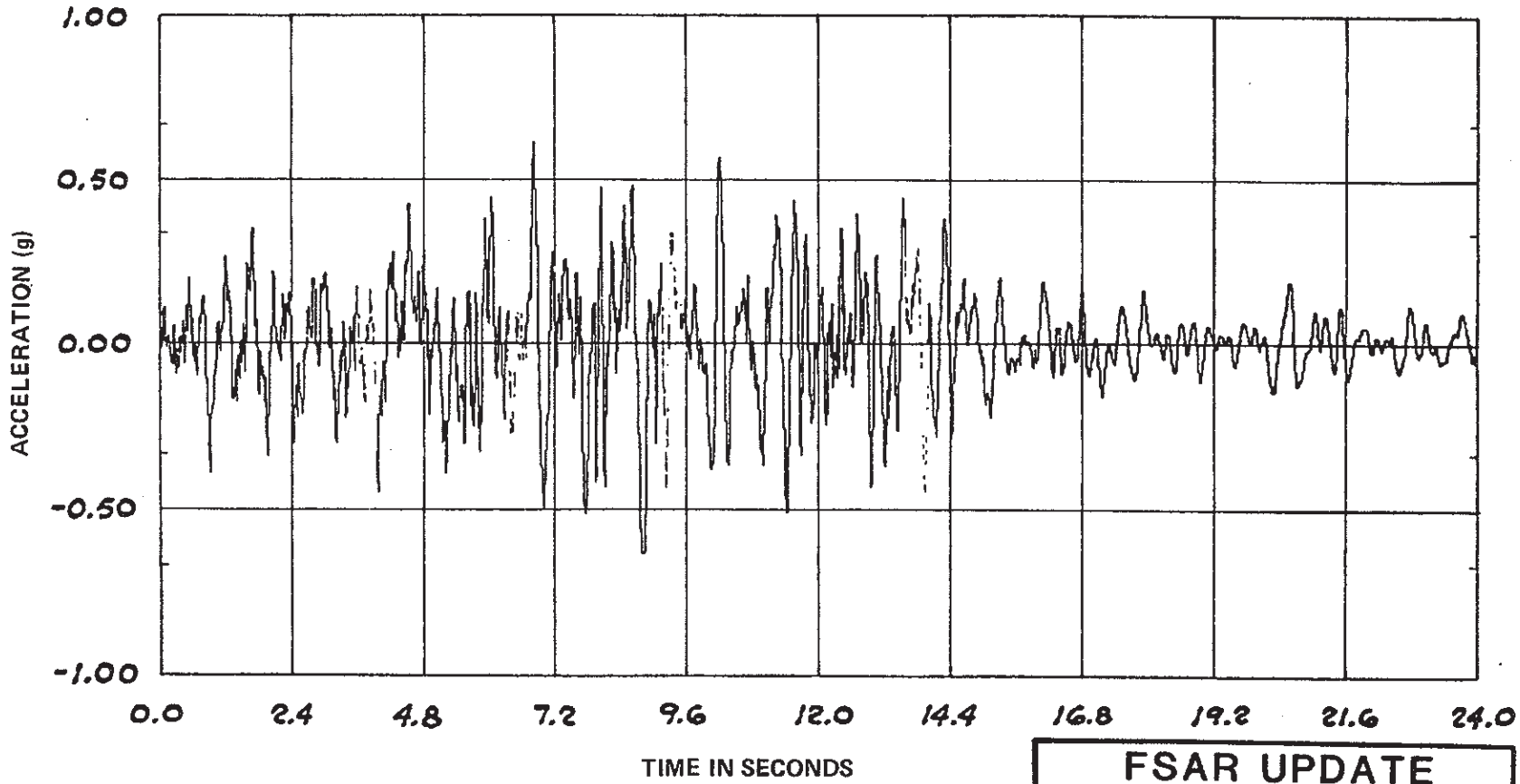
FIGURE 3.7 - 4 F
TURBINE BUILDING
DESIGN RESPONSE SPECTRA
HORIZONTAL
HOSGRI 7.5 M/NEWMARK
TAU= 0.08



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

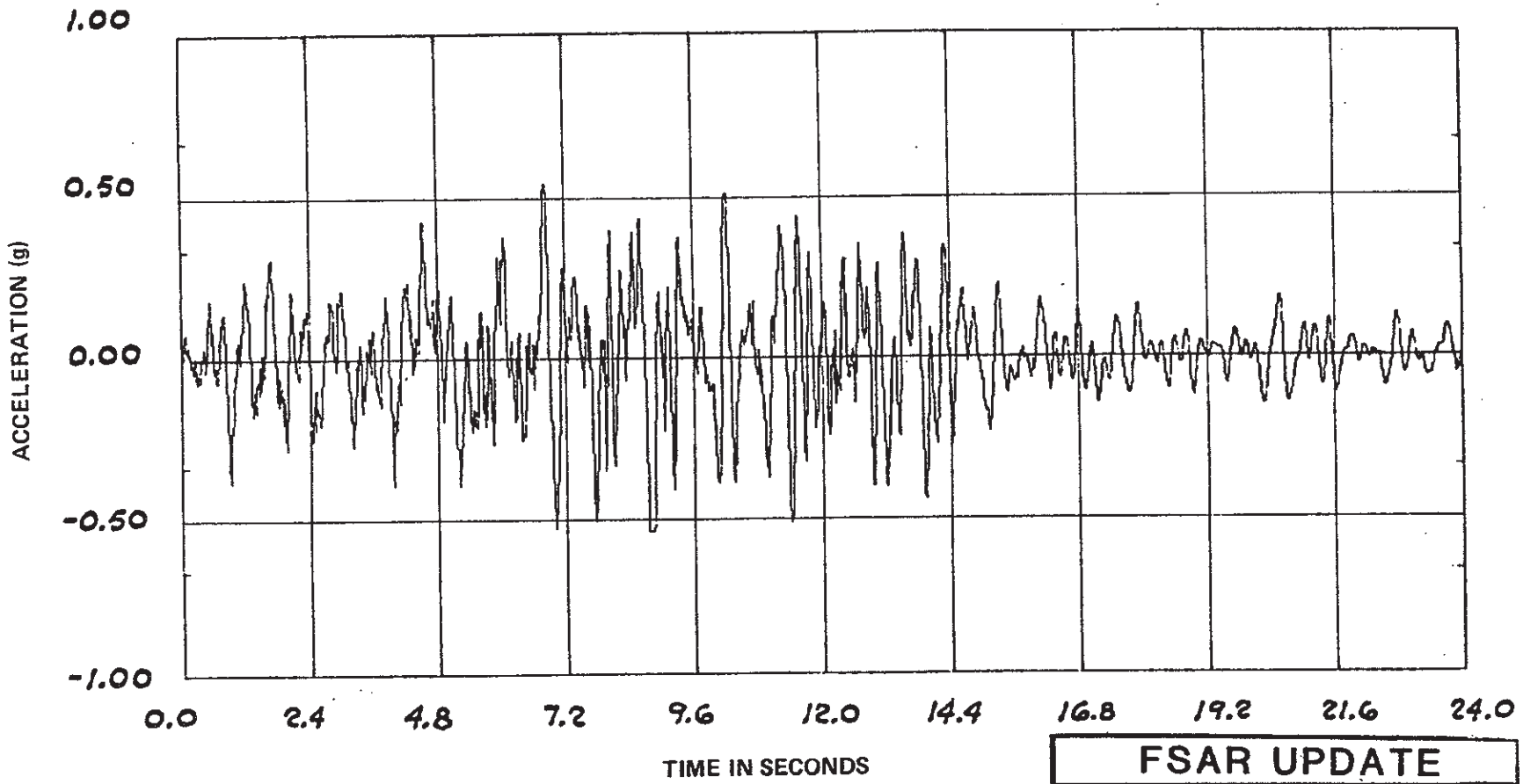
FIGURE 3.7 - 4 G
CONTAINMENT & INTAKE STRUCTURES
HORIZONTAL TIME - HISTORY
HOSGRI 7.5M/BLUME
TAU = 0.04



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

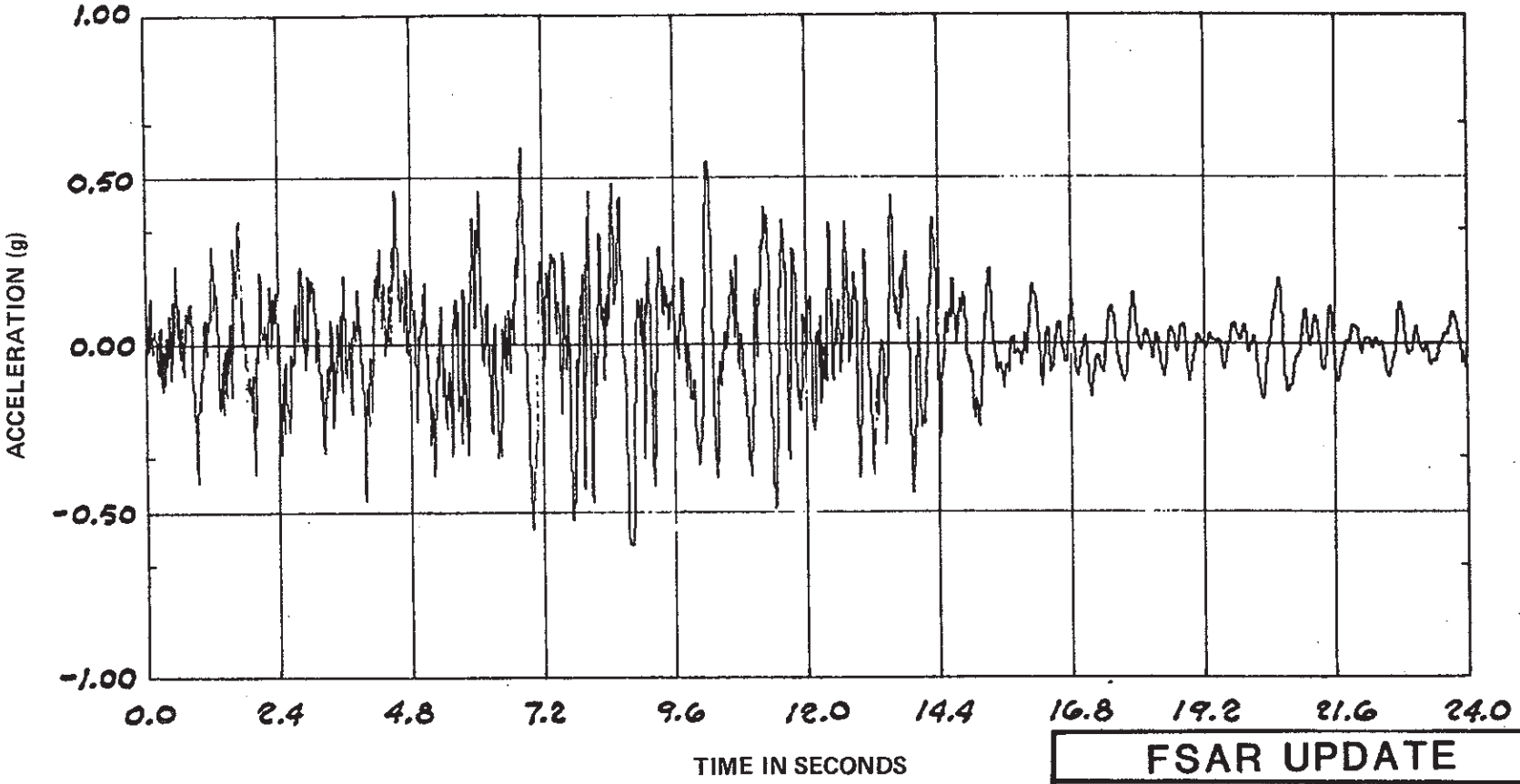
FIGURE 3.7 - 4 H
AUXILIARY BUILDING
HORIZONTAL TIME - HISTORY
HOSGRI 7.5 M/BLUME
TAU= 0.052



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

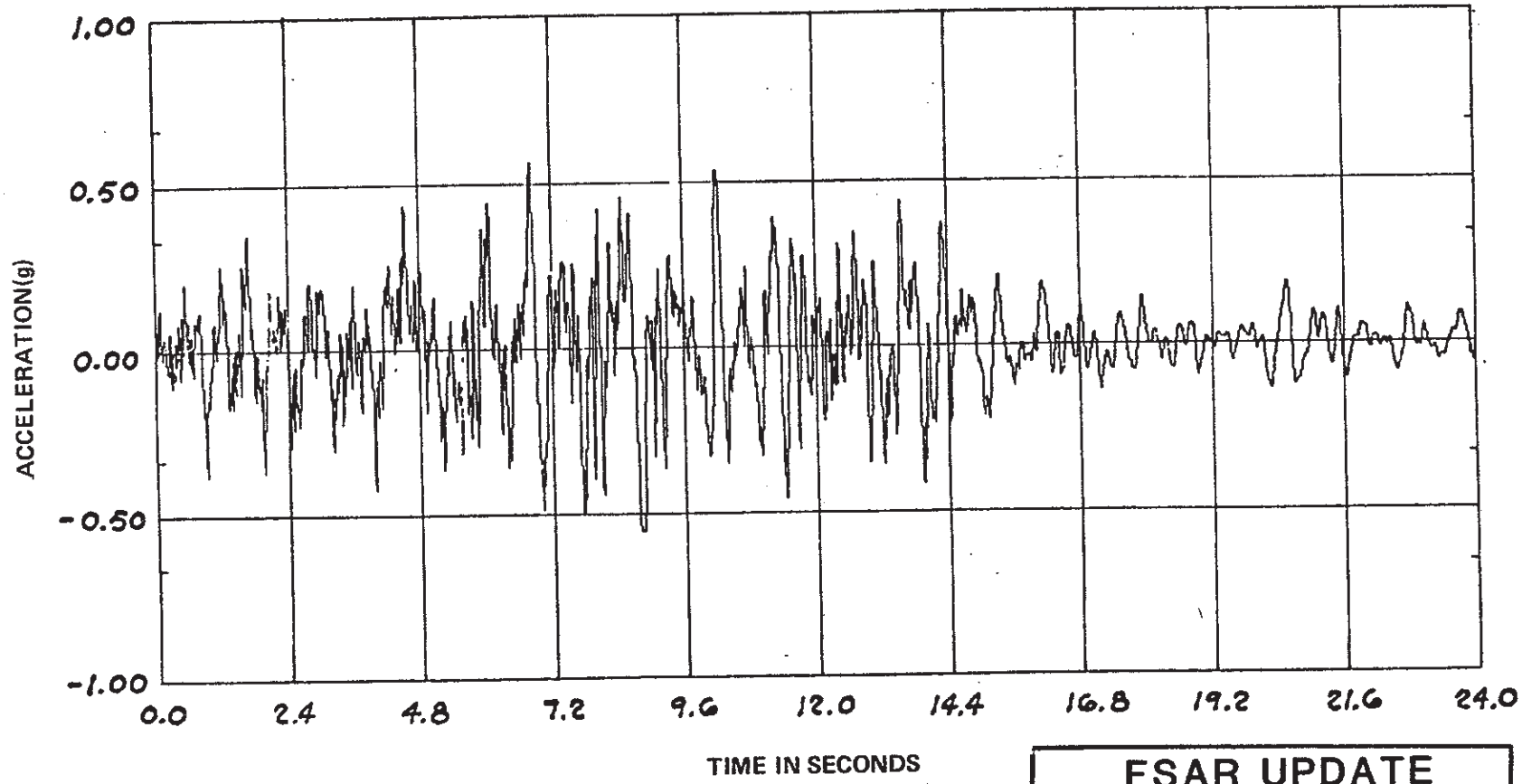
FIGURE 3.7 - 4 I
TURBINE BUILDING
HORIZONTAL TIME - HISTORY
HOSGRI 7.5 M/BLUME
TAU= 0.080



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

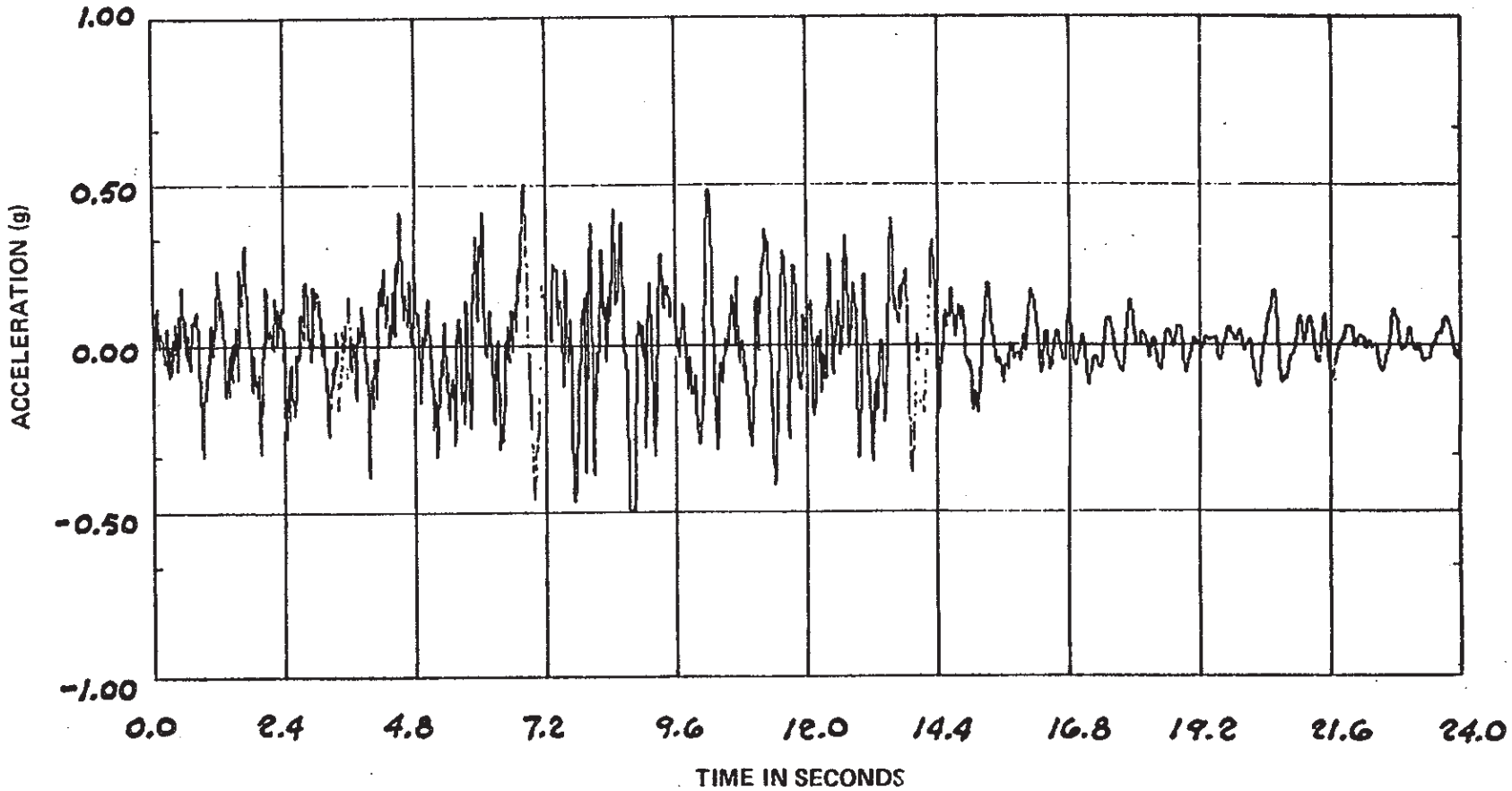
FIGURE 3.7 - 4 J
CONTAINMENT & INTAKE STRUCTURES
HORIZONTAL TIME - HISTORY
HOSGRI 7.5M/NEWMARK
TAU = 0.04



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

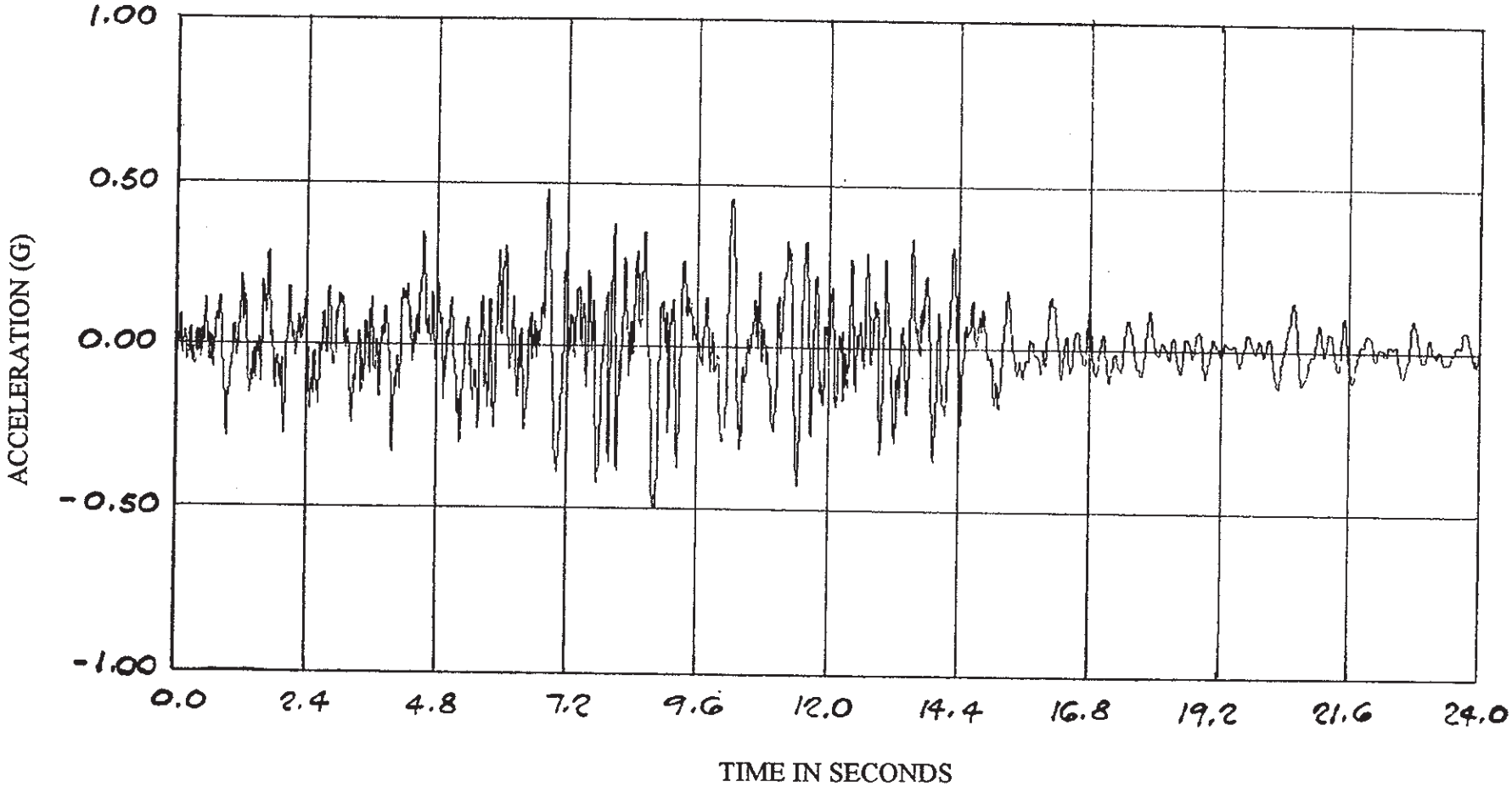
FIGURE 3.7 - 4 K
AUXILIARY BUILDING
HORIZONTAL TIME - HISTORY
HOSGRI 7.5M/NEWMARK
TAU= 0.052



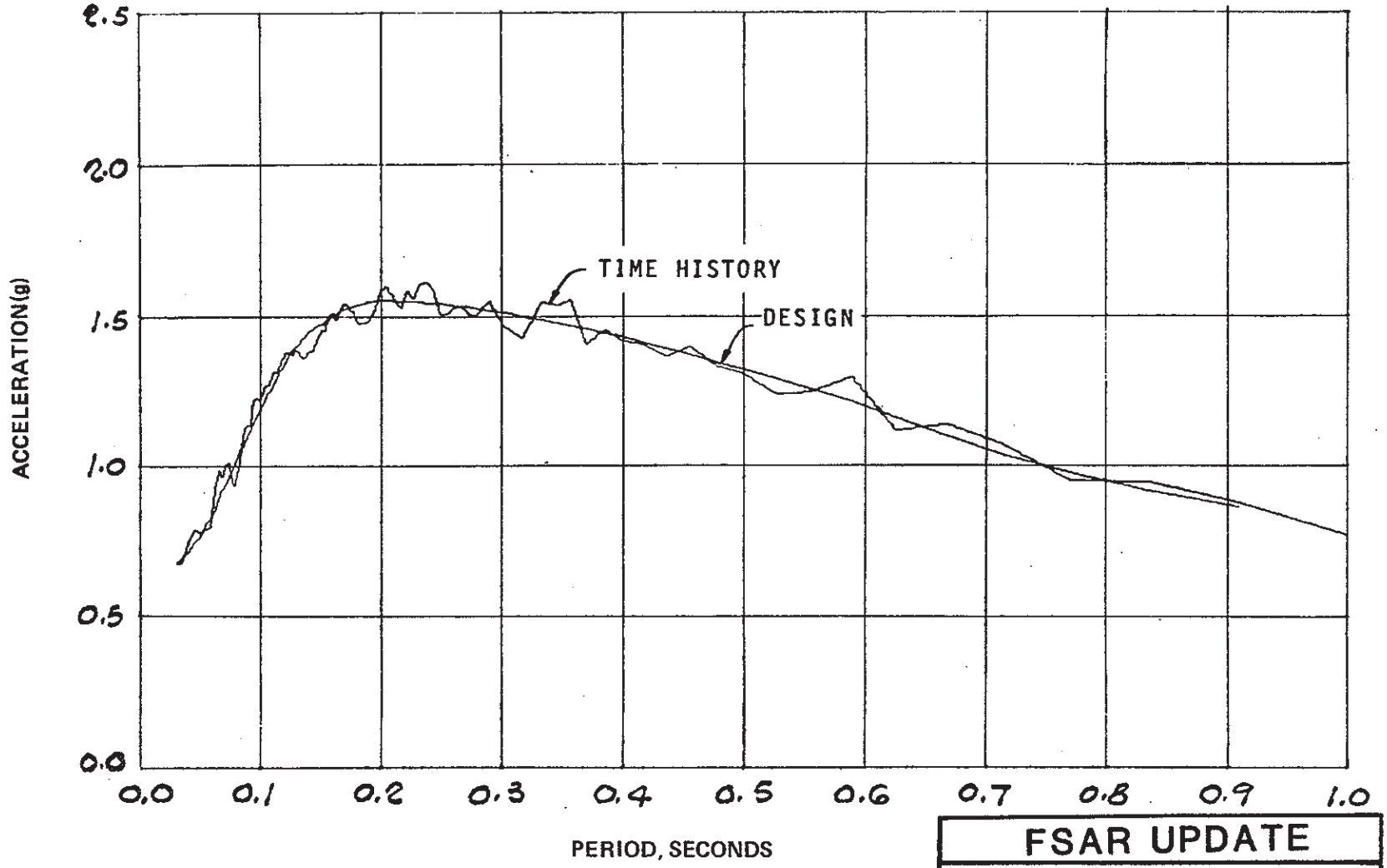
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7 - 4 L
TURBINE BUILDING
HORIZONTAL TIME - HISTORY
HOSGRI 7.5M/NEWMARK
TAU = 0.067



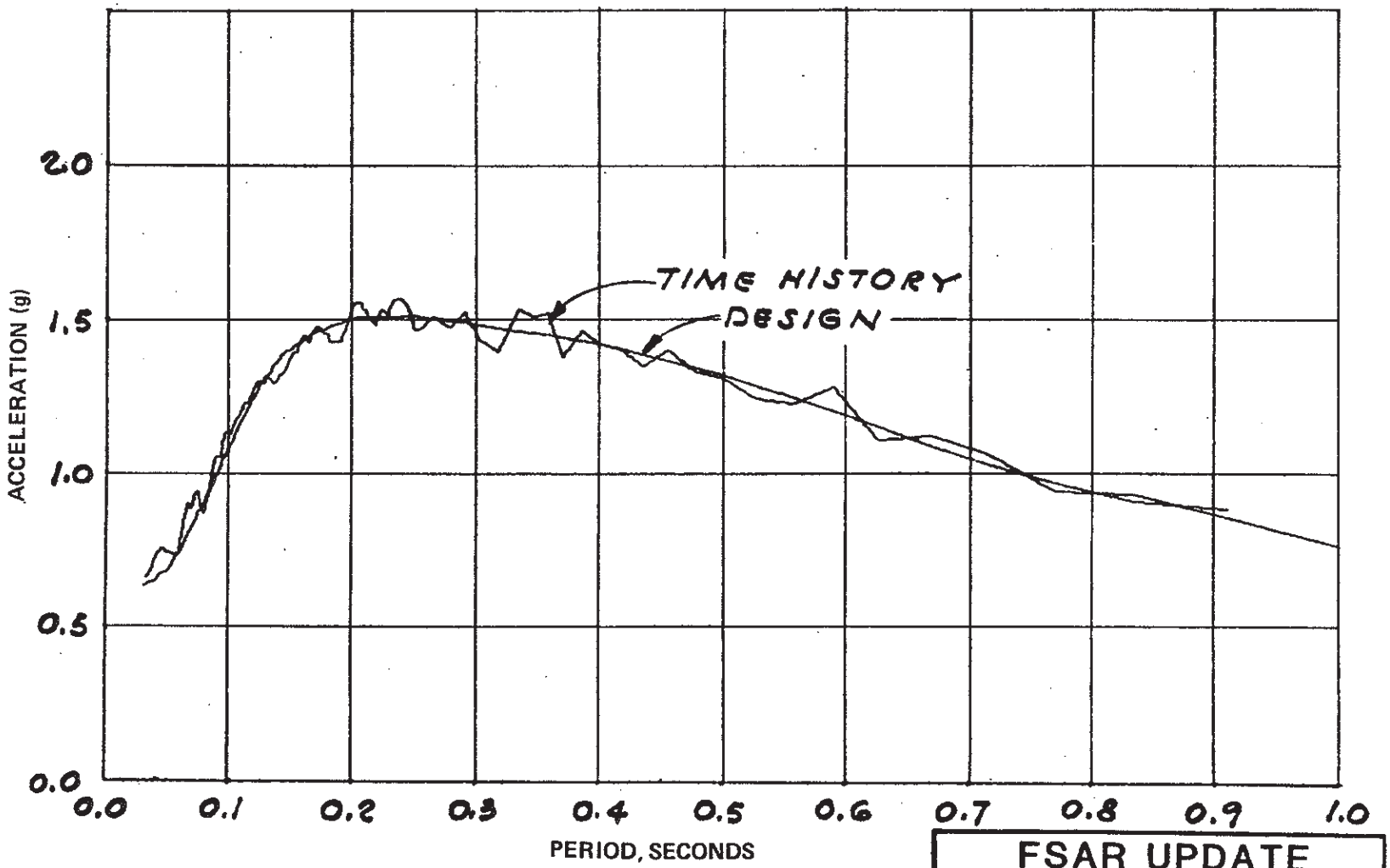
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.7 - 4 M VERTICAL TIME HISTORY HOSGRI 7.5M/NEWMARK TAU = 0.0



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

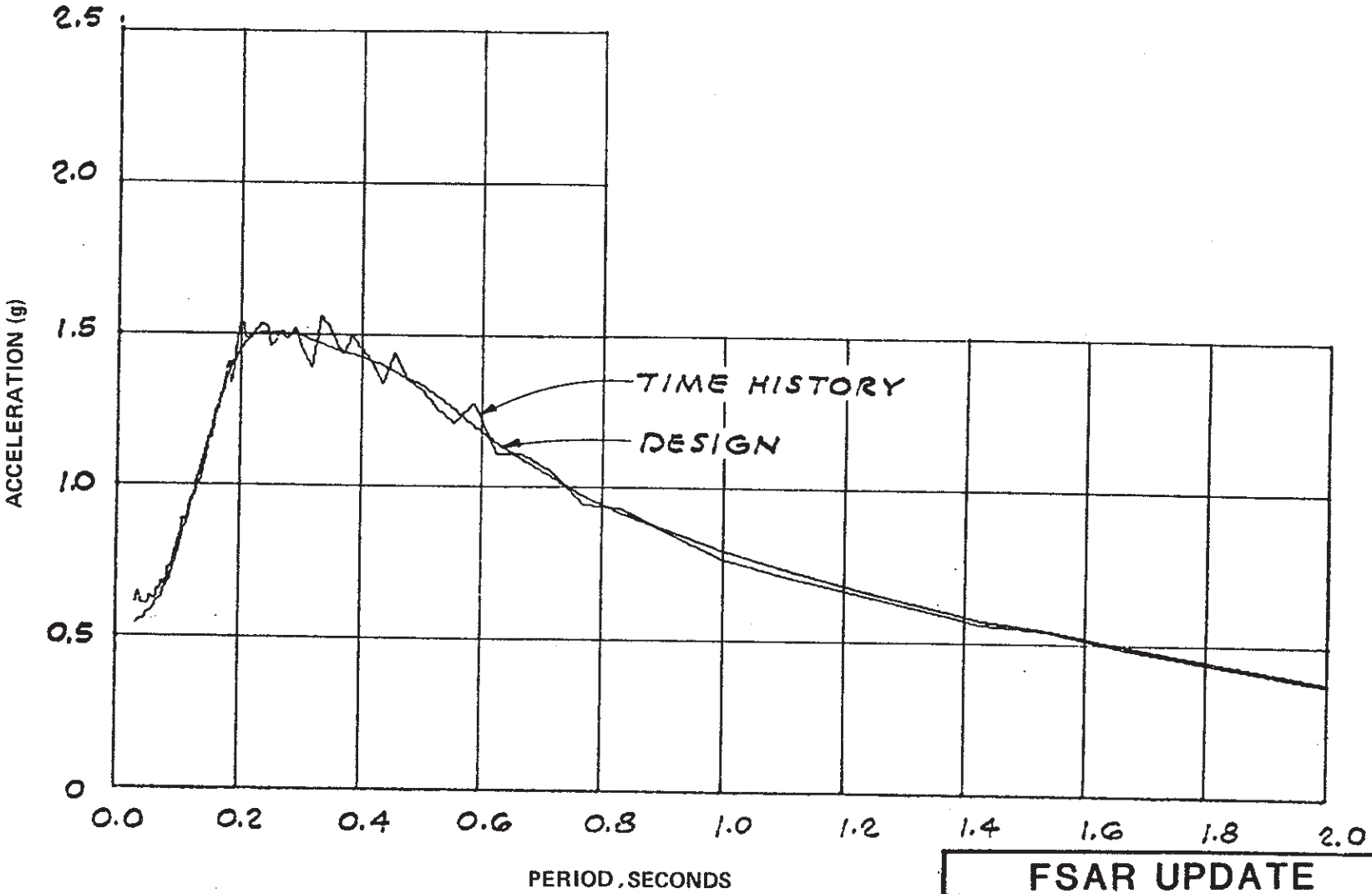
FIGURE 3.7 - 4 N
CONTAINMENT & INTAKE STRUCTURES
COMPARISON OF SPECTRA
HORIZONTAL
HOSGRI 7.5 M/BLUME
TAU= 0.04, 7% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

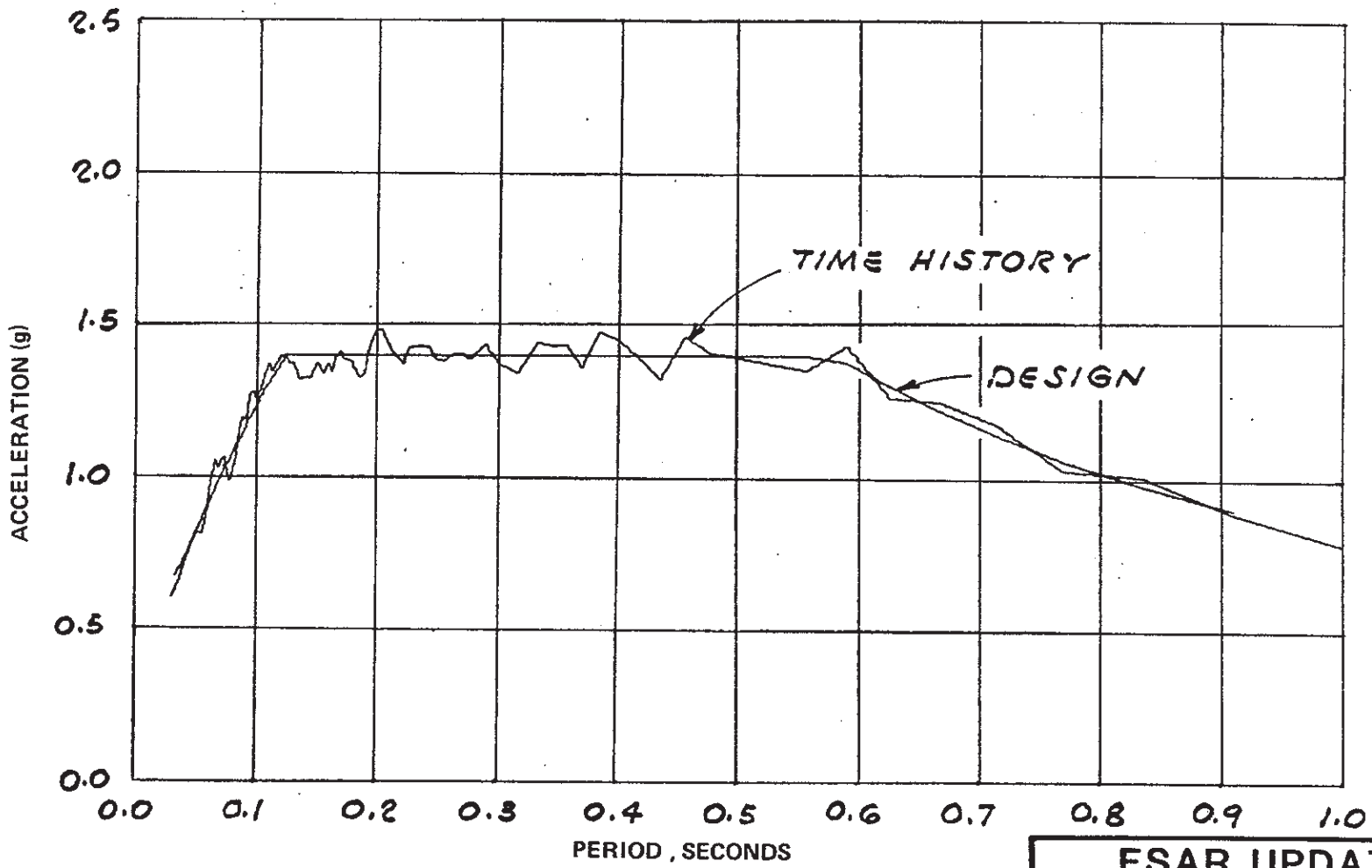
FIGURE 3.7 - 4 O
AUXILIARY BUILDING
COMPARISON OF SPECTRA
HORIZONTAL
HOSGRI 7.5M/BLUME
TAU= 0.052, 7% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

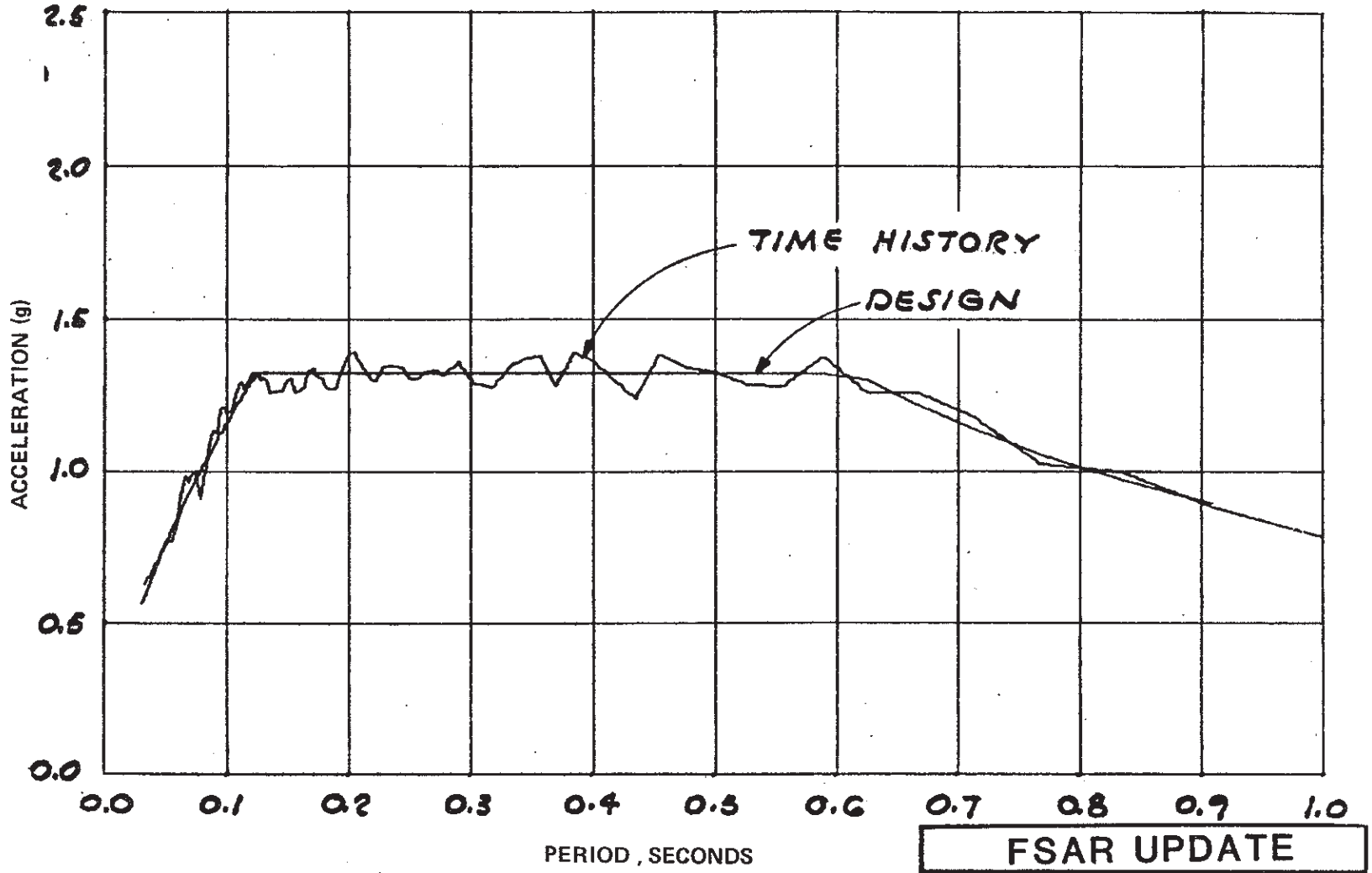
FIGURE 3.7 - 4 P
TURBINE BUILDING
COMPARISON OF SPECTRA
HORIZONTAL
HOSGRI 7.5 M/BLUME
TAU = 0.080, 7% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

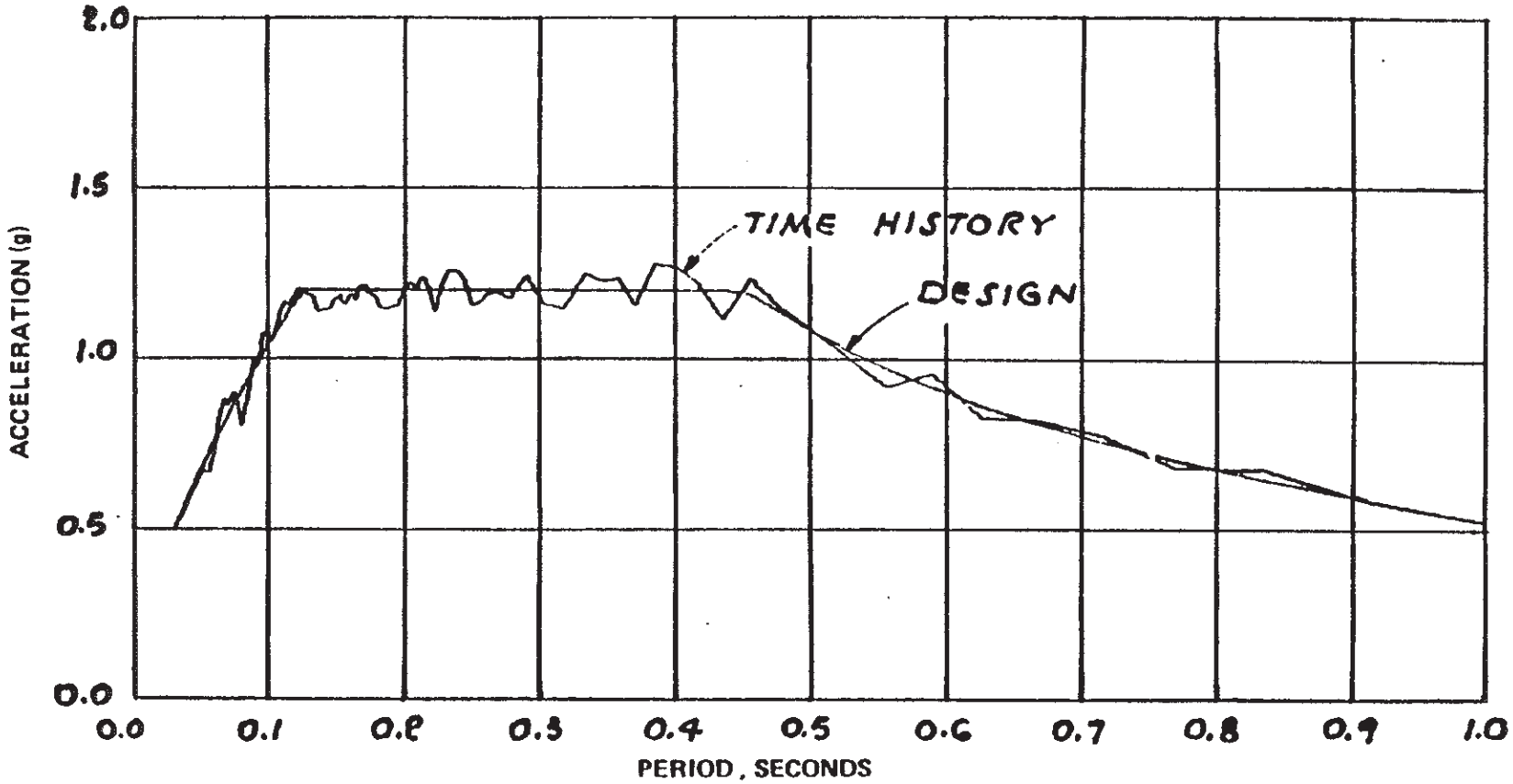
FIGURE 3.7 - 4 Q
CONTAINMENT AND INTAKE
STRUCURES
COMPARISON OF SPECTRA
HORIZONTAL
HOSGRI 7.5 M/NEWMARK
TAU = 0.04, 7% DAMPING



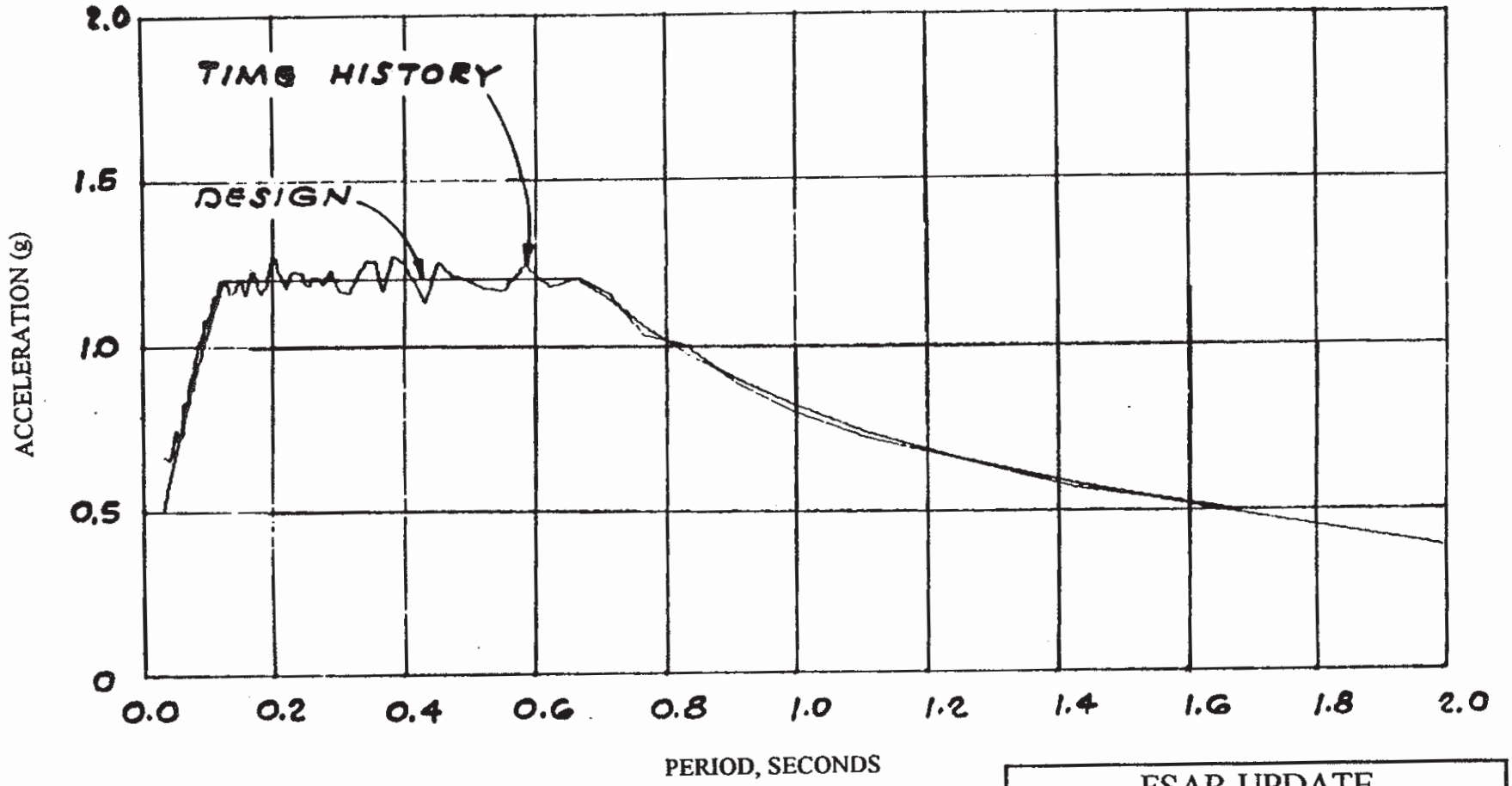
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7 - 4 R
AUXILIARY BUILDING
COMPARISON OF SPECTRA
HORIZONTAL
HOSGRI 7.5 M/NEWMARK
TAU= 0.052, 7% DAMPING



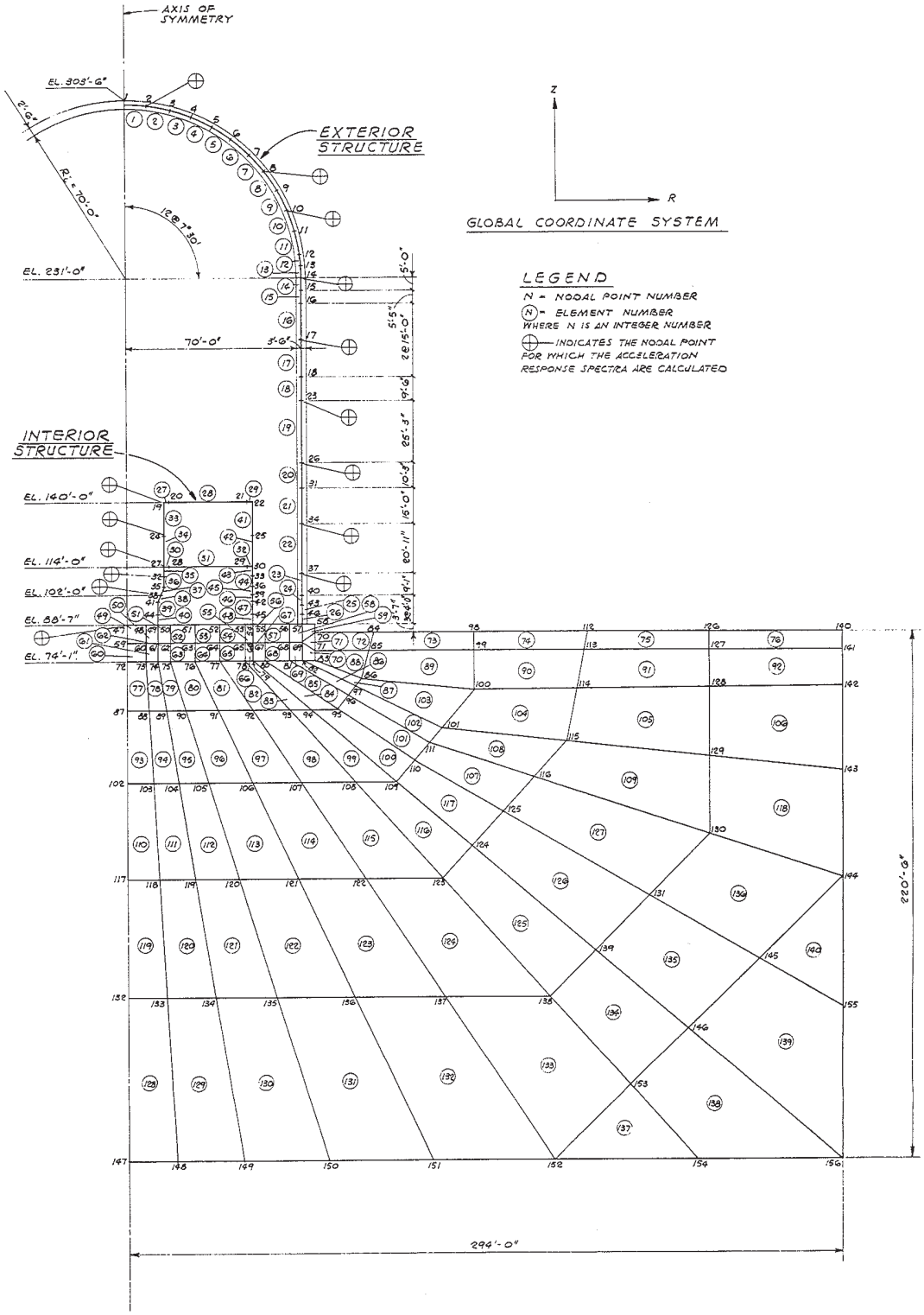
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.7 - 4S COMPARISON OF SPECTRA VERTICAL HOSGRI 7.5 M/NEWMARK TAU = 0.0, 7% DAMPING



FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 3.7 - 4 T
TURBINE BUILDING
COMPARISON OF SPECTRA
HORIZONTAL
HOSGRI 7.5M/NEWMARK
TAU = 0.067, 7% DAMPING



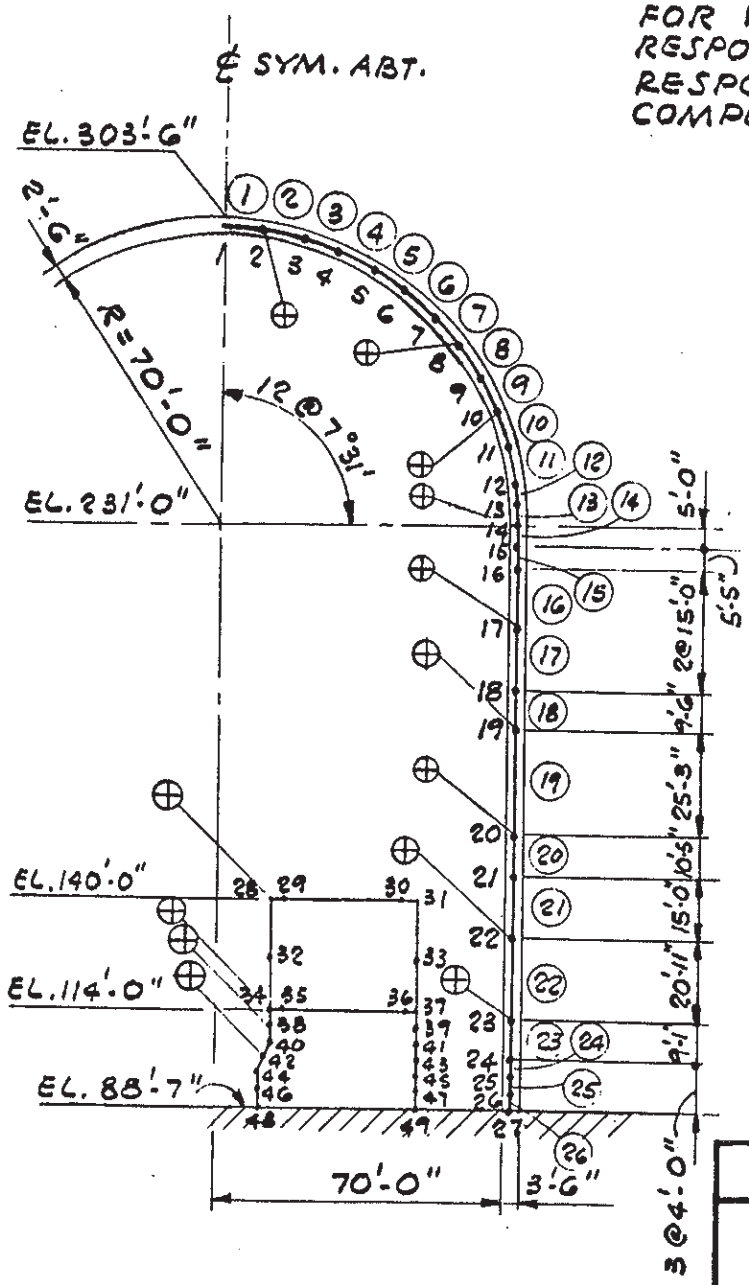
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.7-5 CONTAINMENT STRUCTURE FINITE ELEMENT MODEL

LEGEND

10 NODAL POINT NUMBER

(7) ELEMENT NUMBER

⊕ INDICATES NODAL POINTS FOR WHICH STRUCTURE RESPONSES AND ACCELERATION RESPONSE SPECTRA ARE COMPUTED

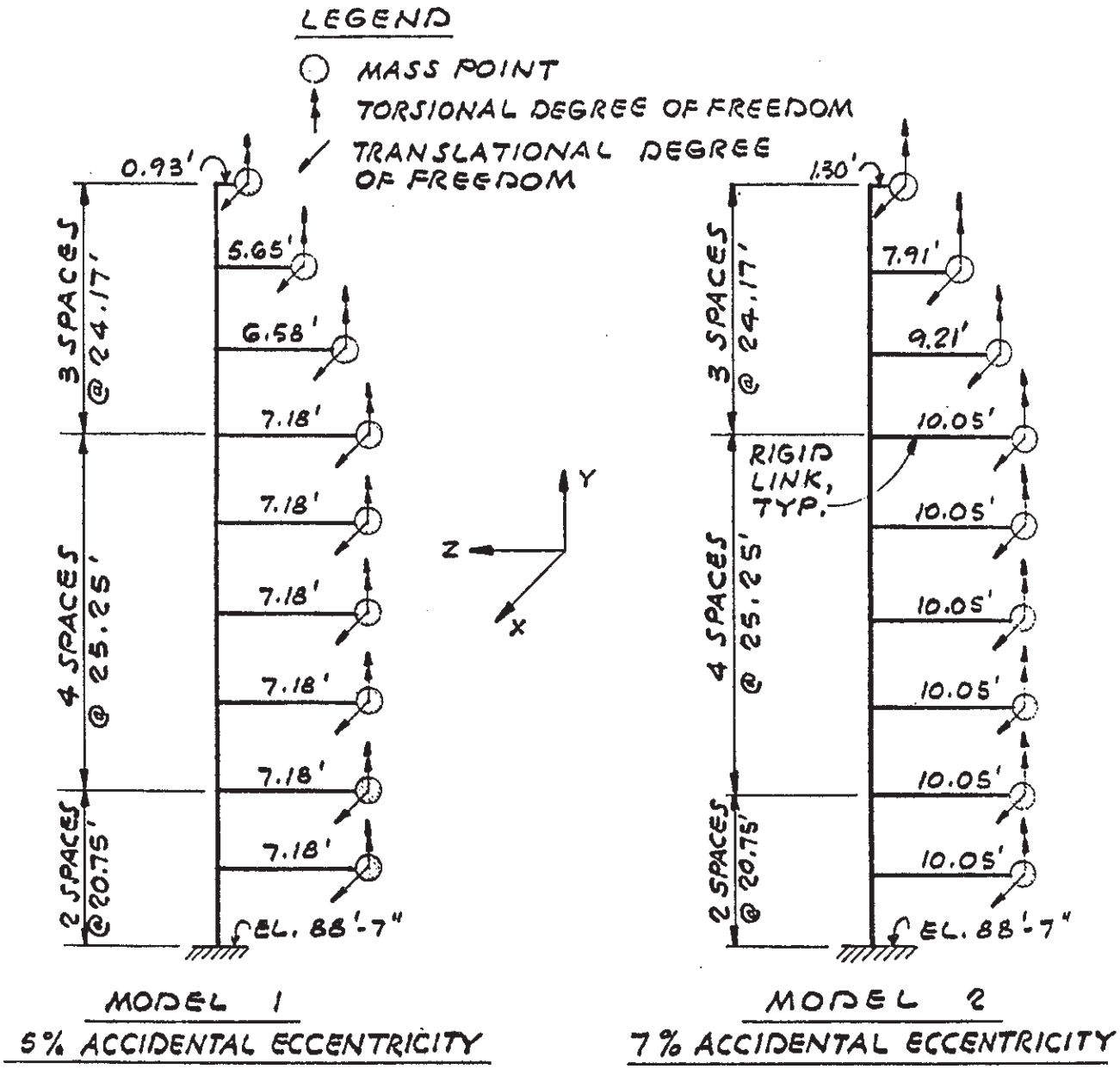


Note: Used for horizontal and vertical analysis of exterior shell and horizontal analysis of internal structure

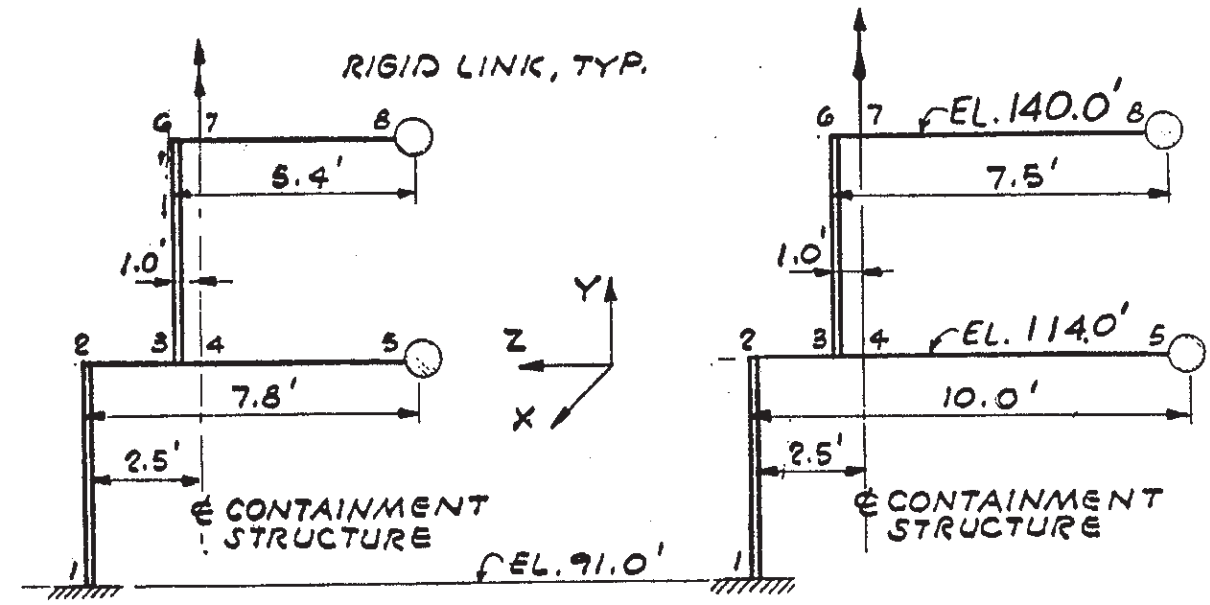
FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 3.7 - 5 A
CONTAINMENT STRUCTURE
FINITE ELEMENT MODEL



FSAR UPDATE
UNIT 1 **DIABLO CANYON SITE**
FIGURE 3.7 - 5 B CONTAINMENT STRUCTURE EXTERIOR SHELL MATHEMATICAL MODELS FOR TORSIONAL ANALYSIS



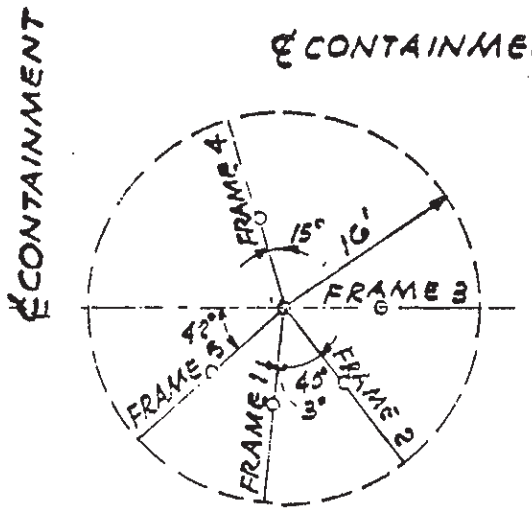
MODEL 1
5% ACCIDENTAL ECCENTRICITY

MODEL 2
7% ACCIDENTAL ECCENTRICITY

FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 3.7 - 5 C
CONTAINMENT INTERIOR STRUCTURE
MATHEMATICAL MODEL FOR
HORIZONTAL AND TORSIONAL
ANALYSIS



LEGEND:

[1] — ELEMENT NUMBER

2 — NODE NUMBER

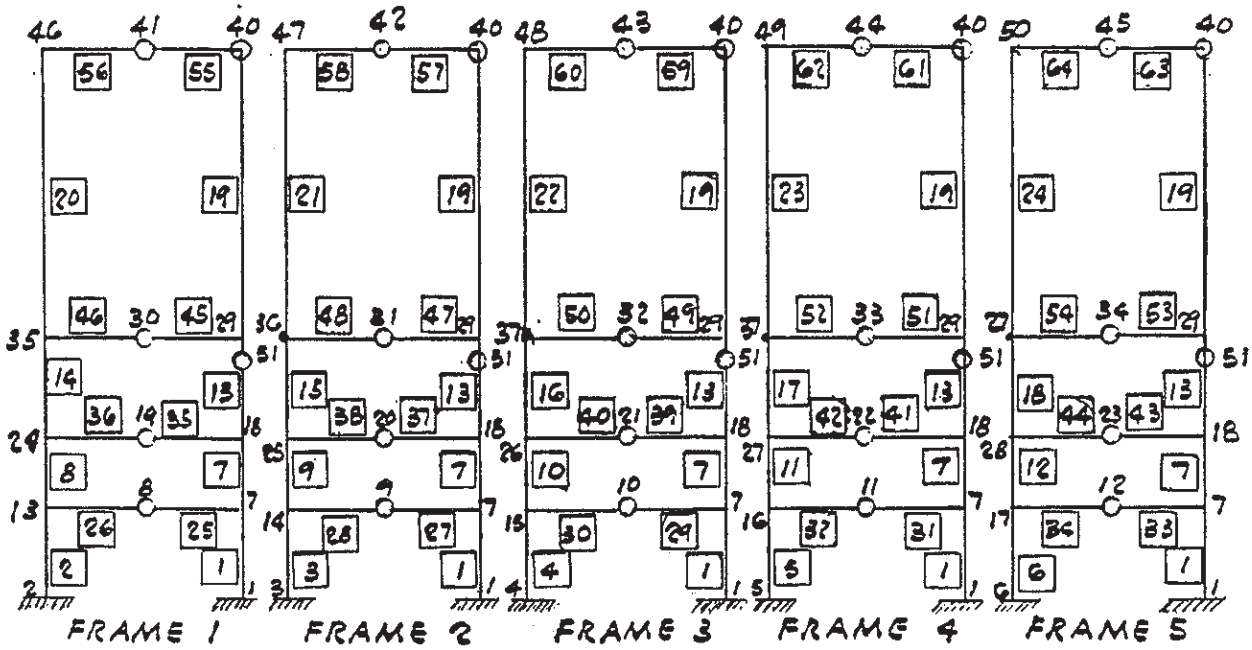
○ — MASS POINT

NOTE:

NODES 1, 7, 18, 29, 40 & 51 ARE ALONG ℄ OF STRUCTURE AND ARE COMMON TO ALL FIVE FRAMES

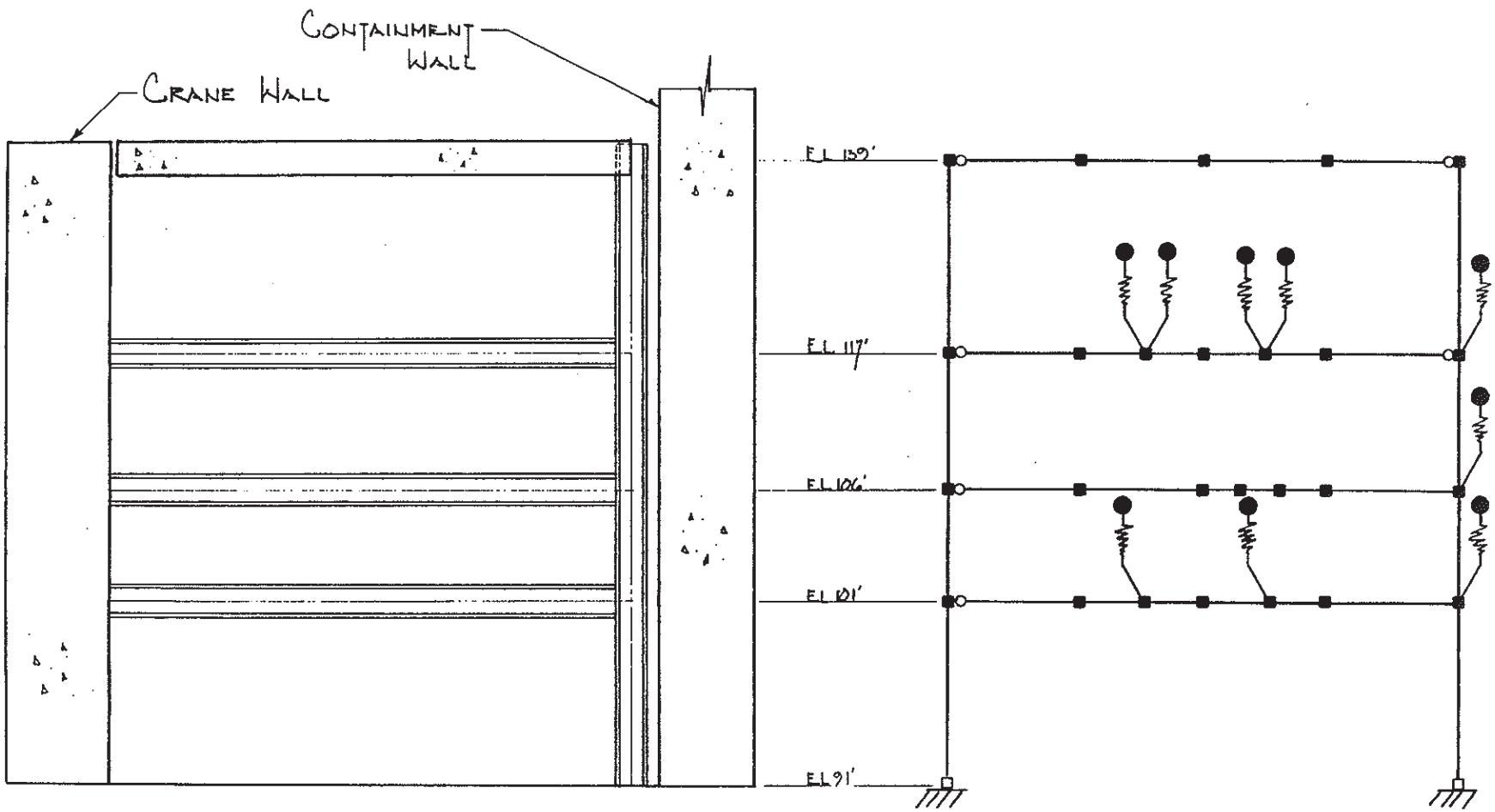
PLAN

UNIT 2



ELEVATIONS

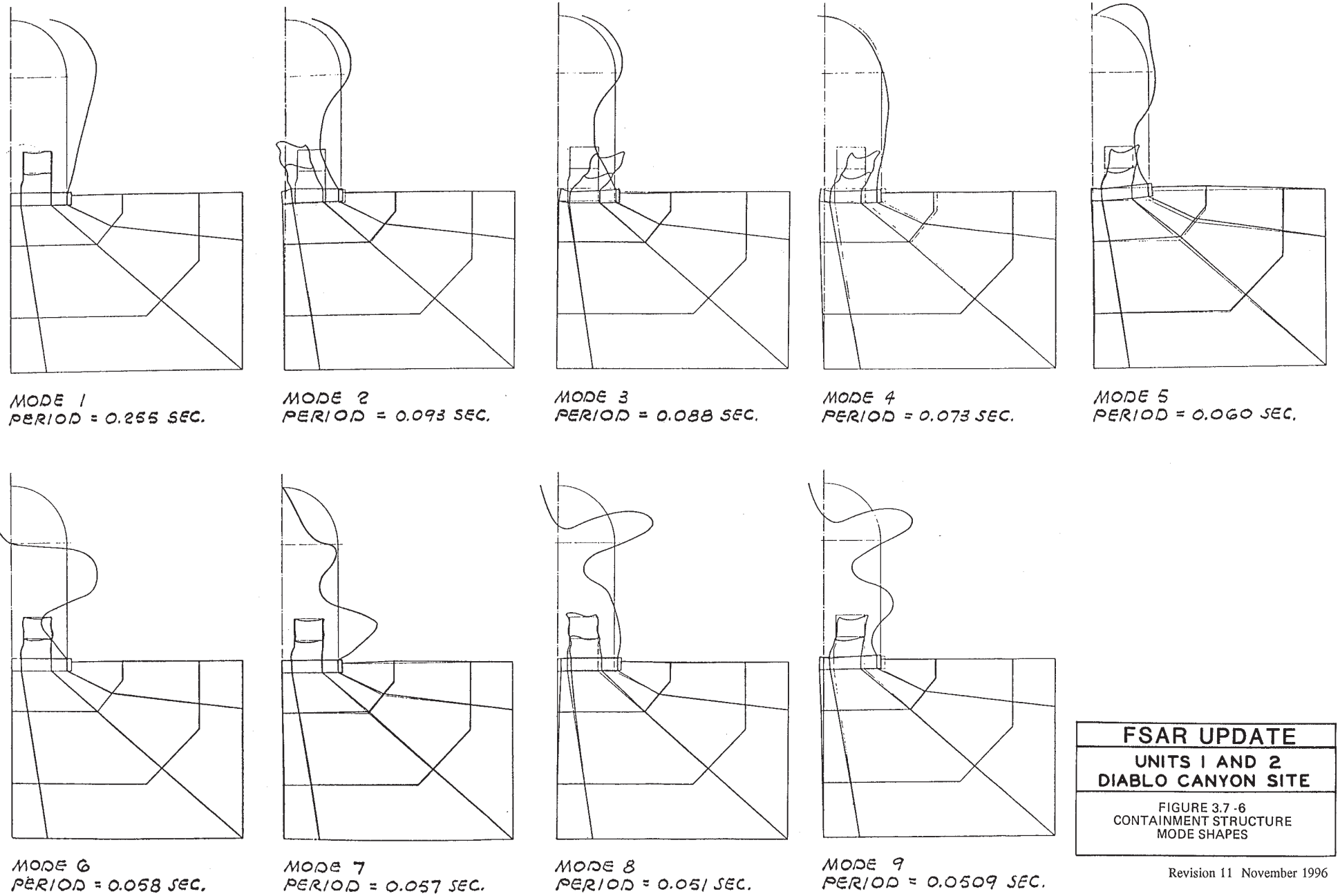
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 3.7 - 5 D MATHEMATICAL MODEL FOR VERTICAL ANALYSIS OF CONTAINMENT INTERIOR STRUCTURE



FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

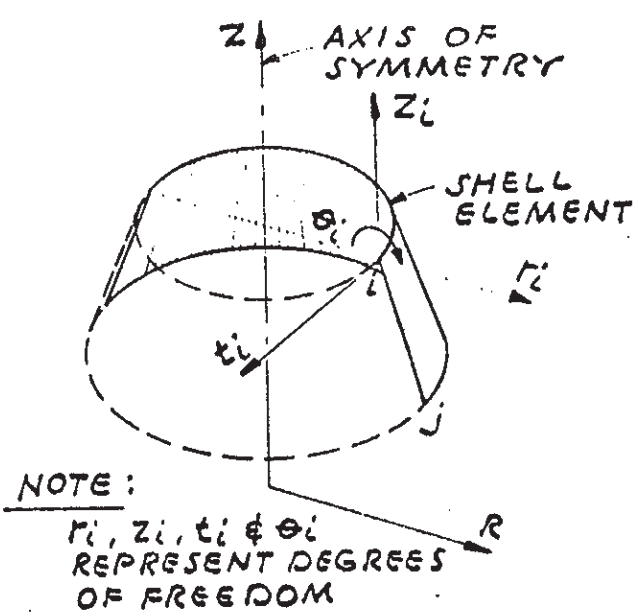
FIGURE 3.7 - 5 E
FRAME ANALYSIS FOR
VERTICAL RESPONSE
COLUMN LINE 6
(FRAME 6)



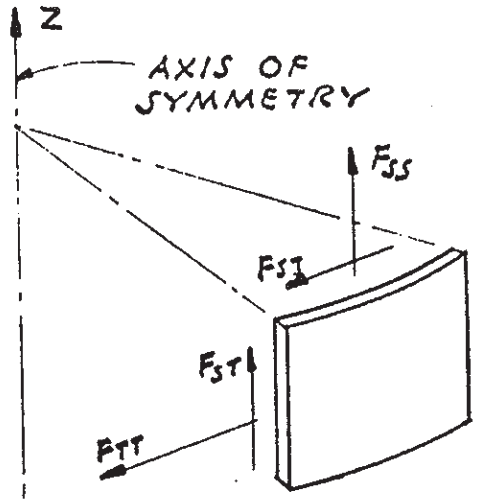
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

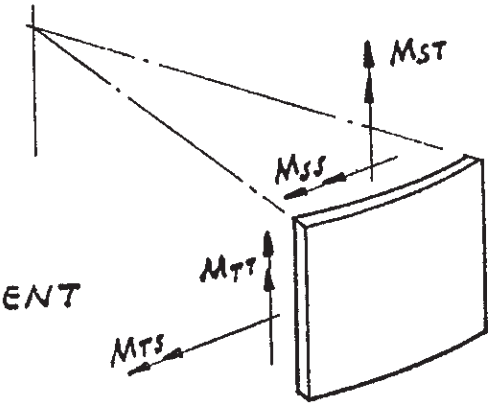
FIGURE 3.7-6
CONTAINMENT STRUCTURE
MODE SHAPES



DEGREES OF FREEDOM



SHELL FORCES

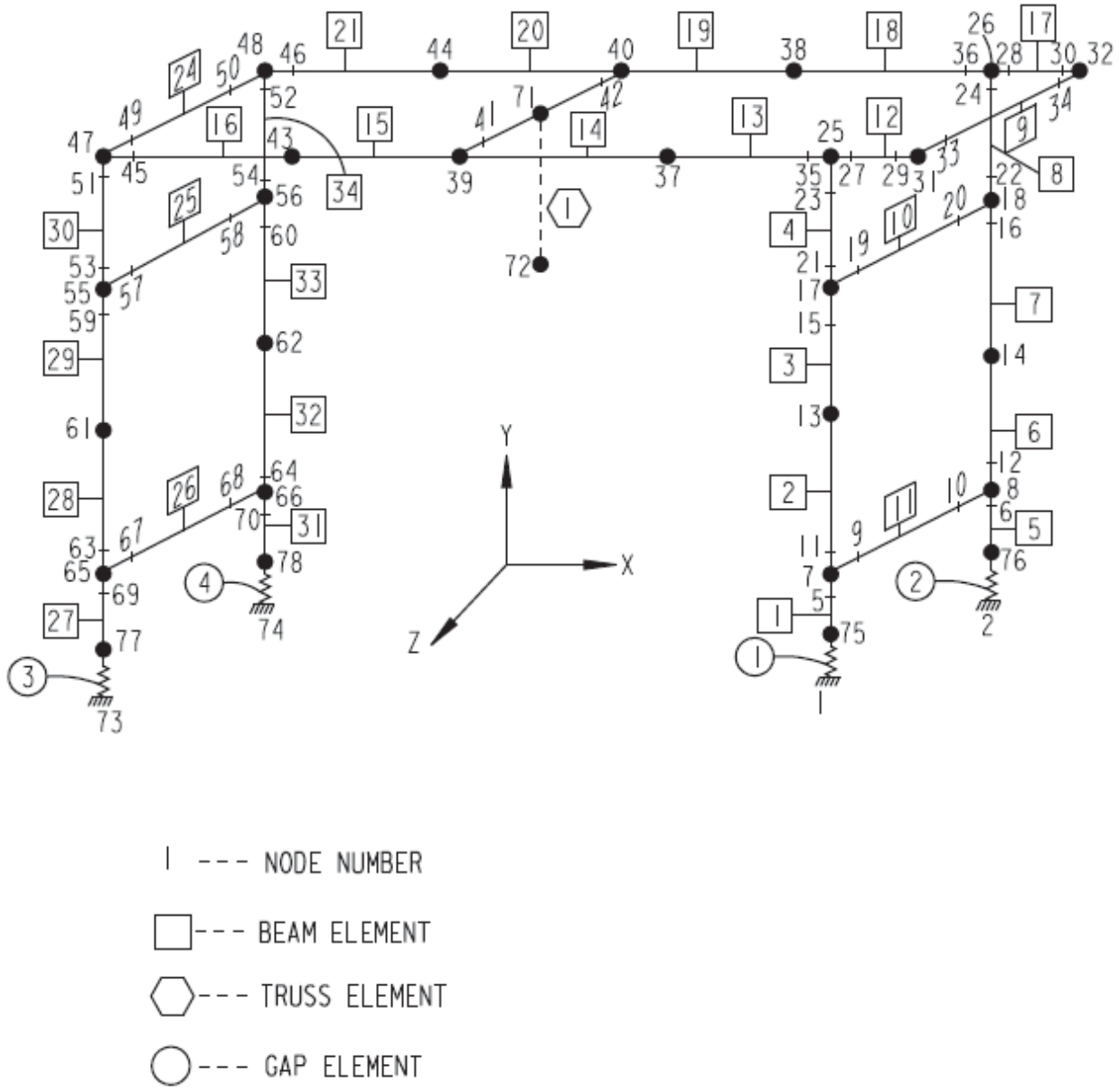


SHELL MOMENTS

LEGEND:

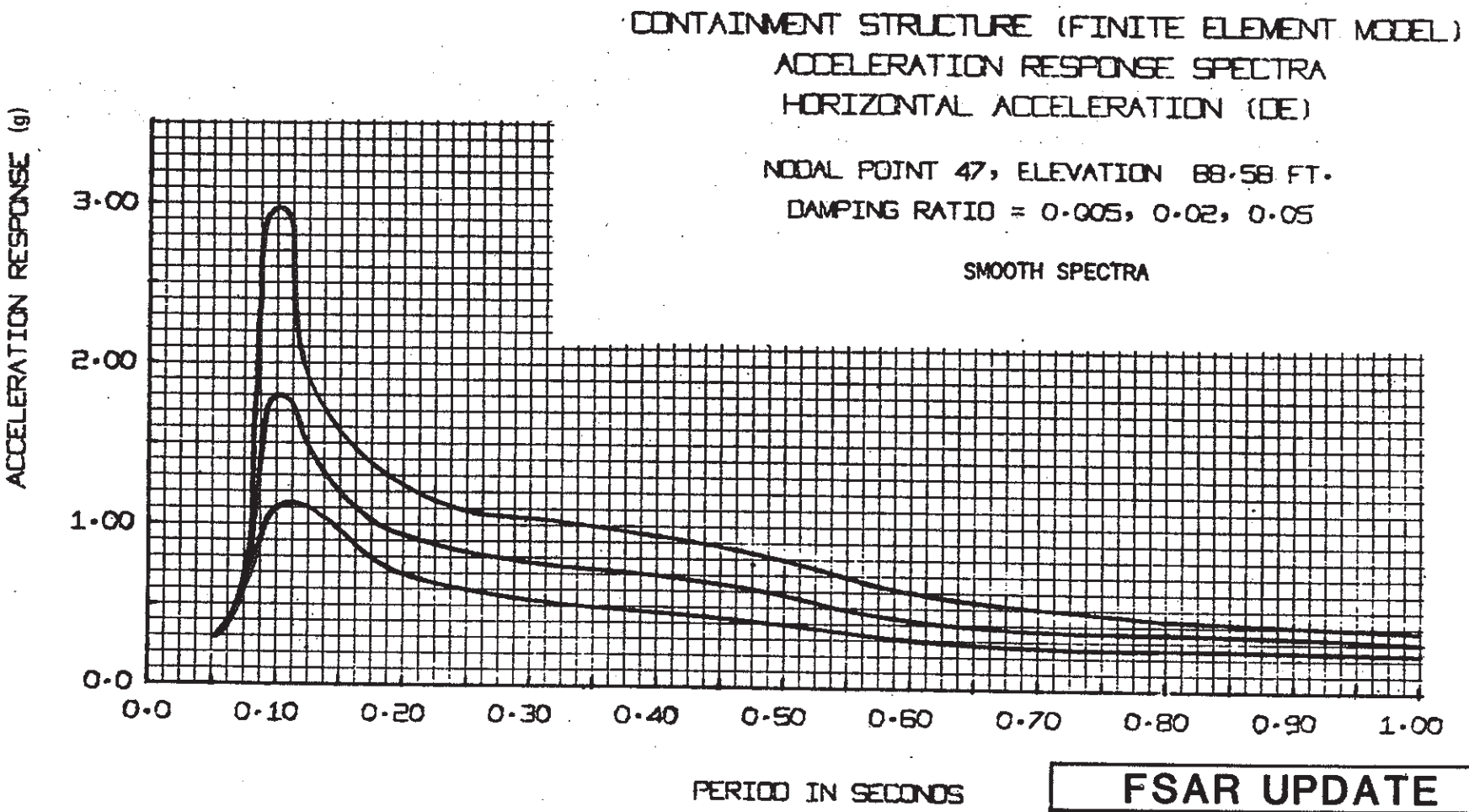
F_{SS} - LONGITUDINAL FORCE
F_{TT} - HOOP FORCE
F_{ST} - SHEAR FORCE
M_{SS} - LONGITUDINAL MOMENT
M_{TT} - CIRCUMFERENTIAL MOMENT
M_{ST} - CROSS MOMENT

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.7-7 CONTAINMENT STRUCTURE SHELL FORCES AND MOMENTS AND ELEMENT DEGREES OF FREEDOM



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.7-7A POLAR CRANE THREE DIMENSIONAL NONLINEAR MODEL

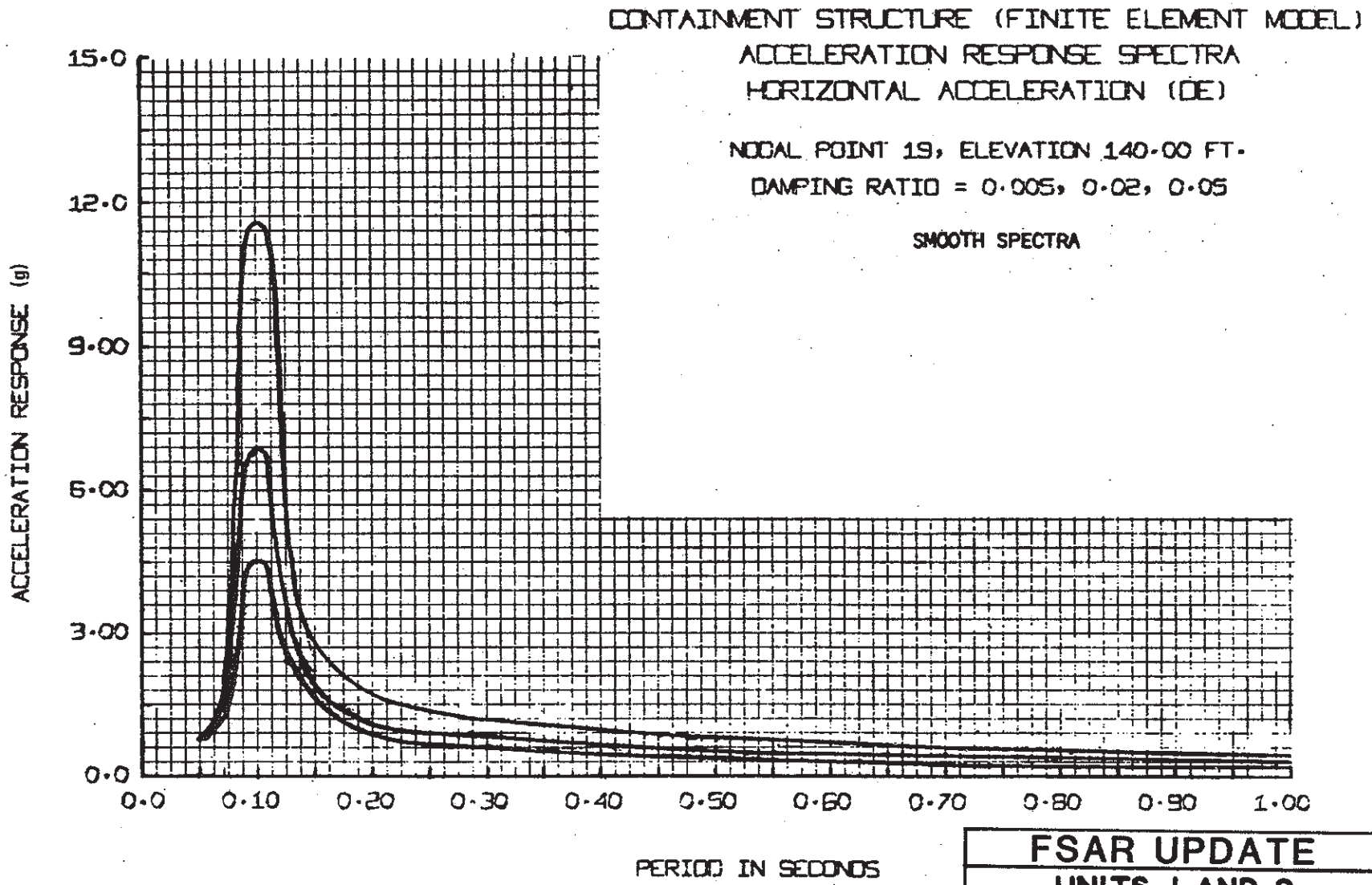
Revision 21 September 2013



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

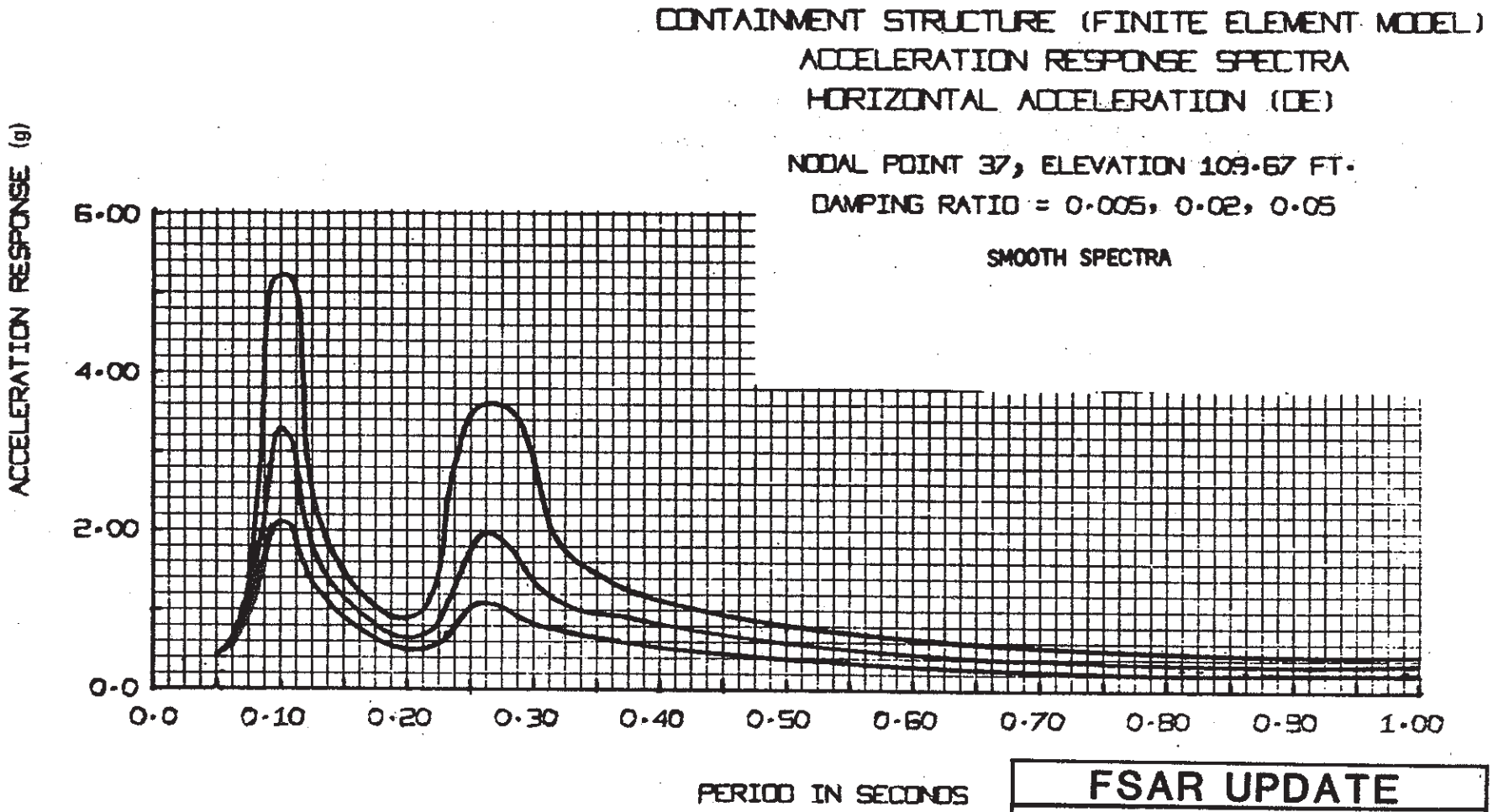
FIGURE 3.7-8
CONTAINMENT STRUCTURE
TYPICAL SPECTRA



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

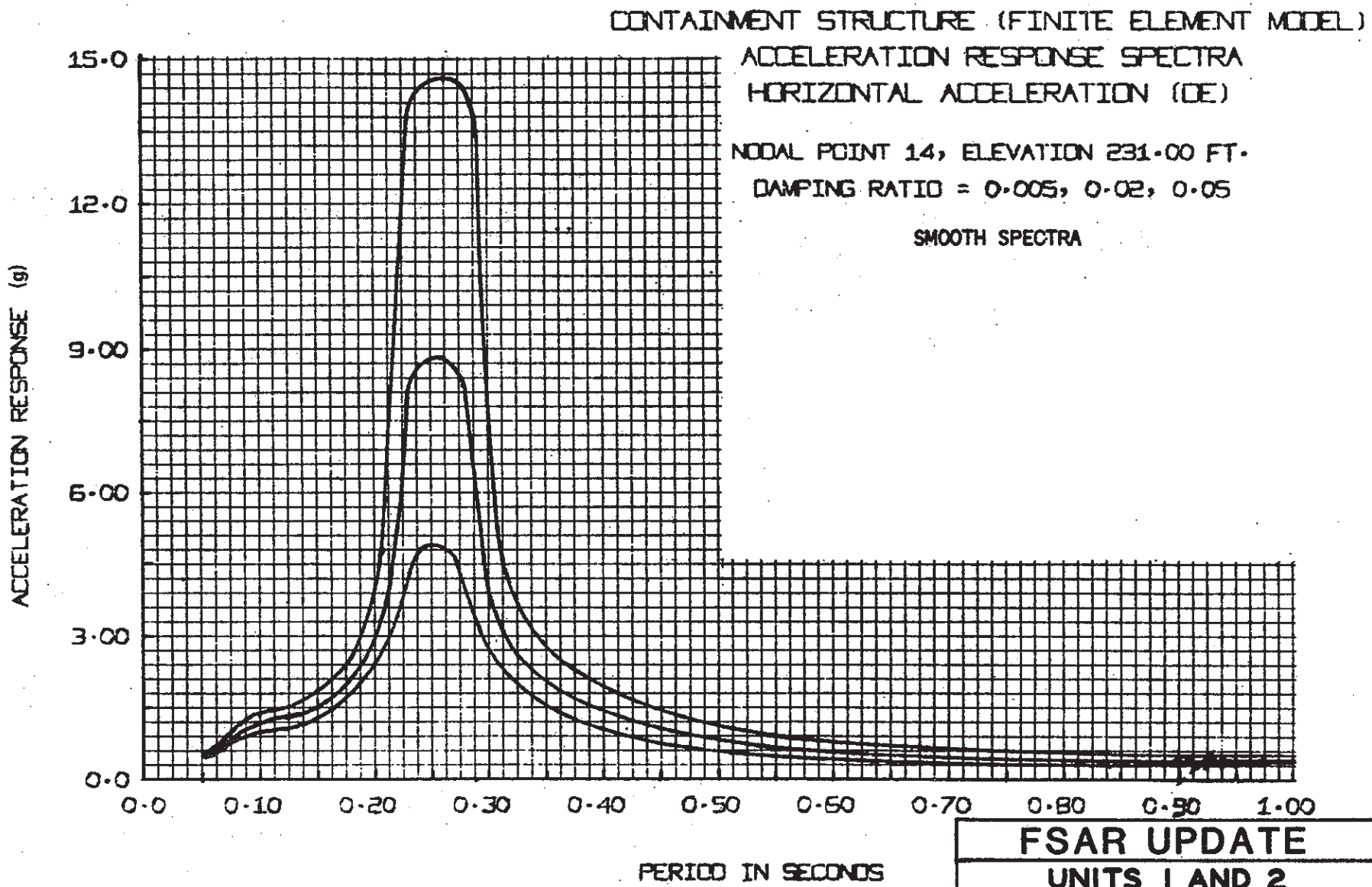
FIGURE 3.7 - 9
CONTAINMENT STRUCTURE
TYPICAL SPECTRA



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

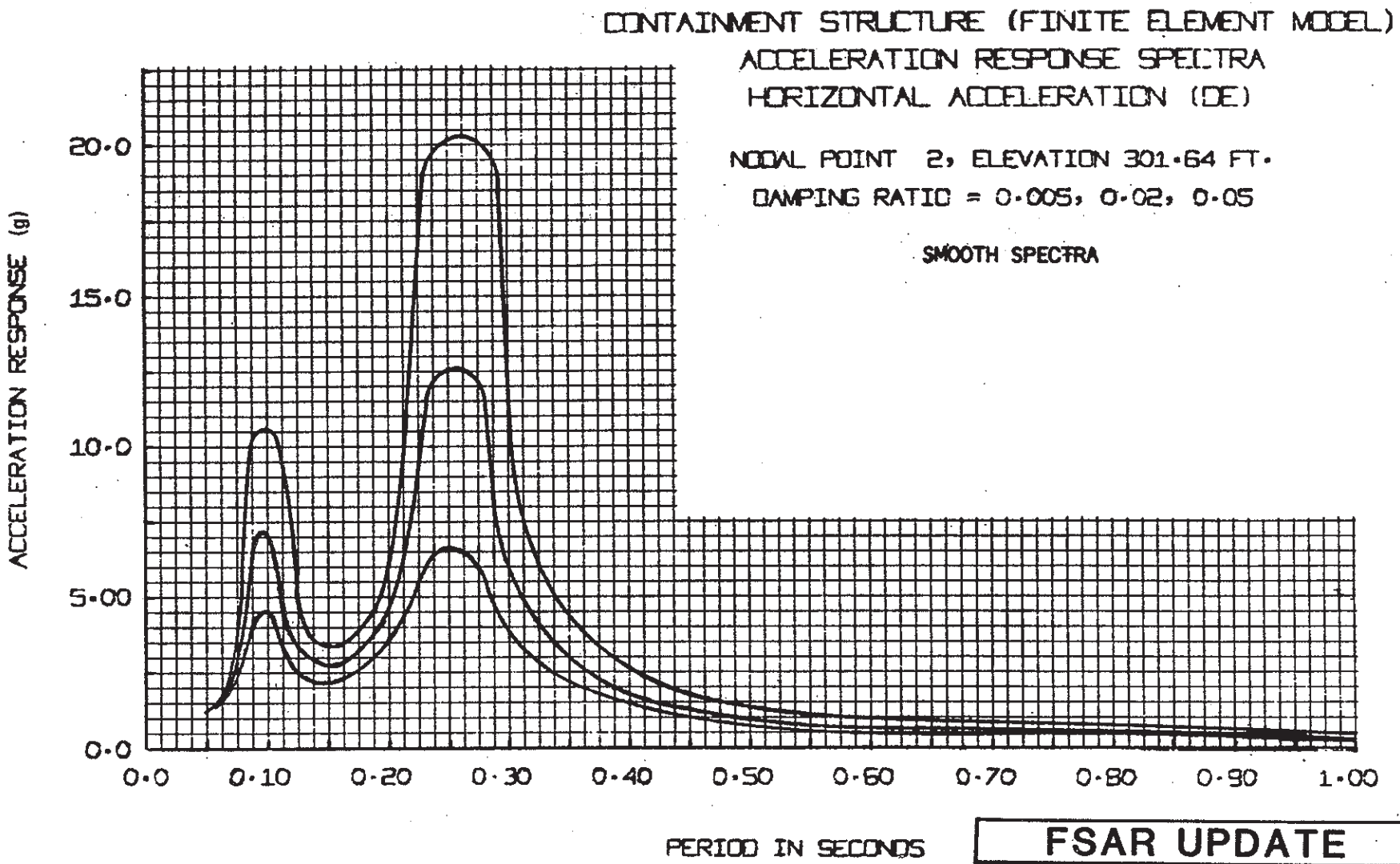
FIGURE 3.7 - 10
CONTAINMENT STRUCTURE
TYPICAL SPECTRA



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

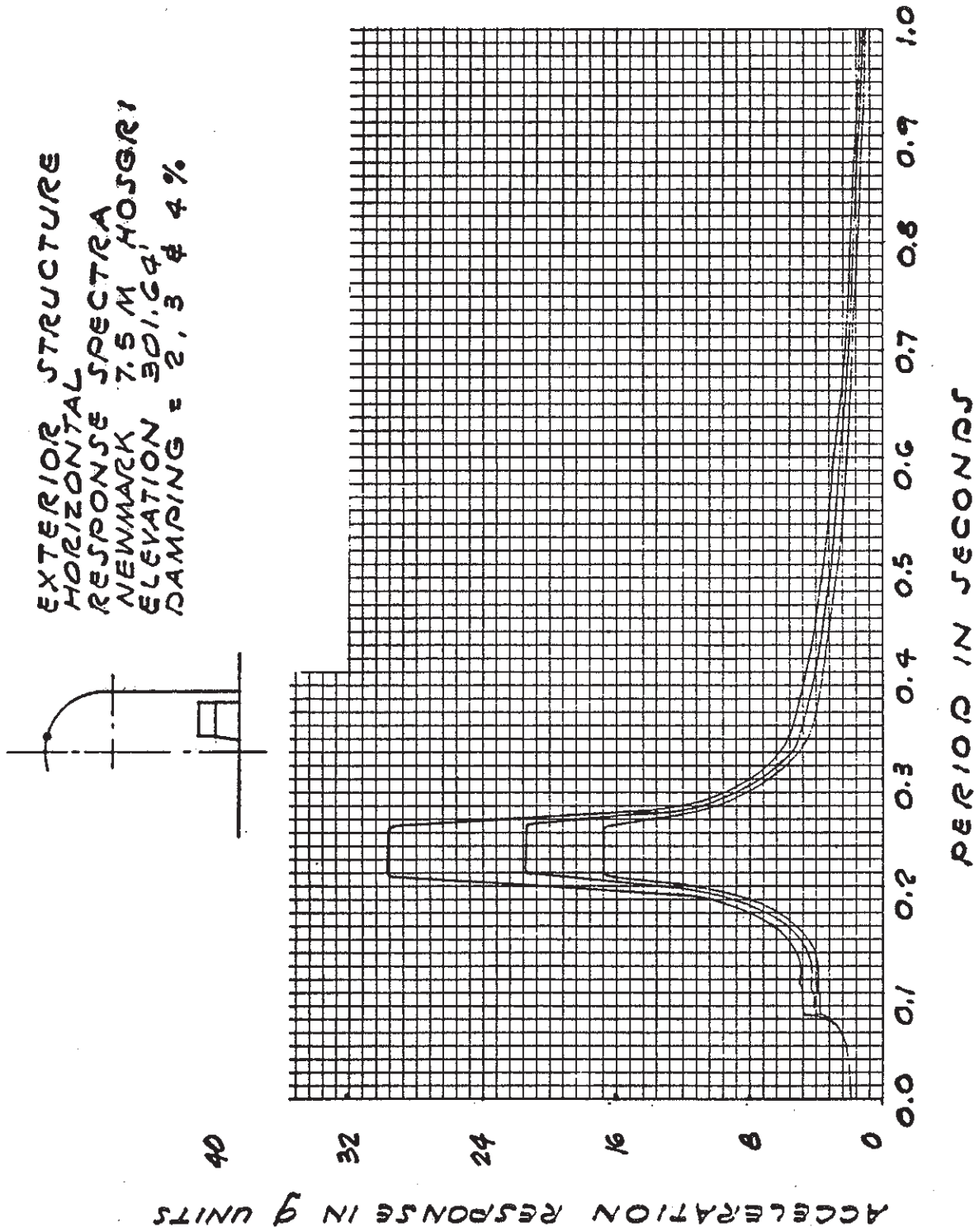
FIGURE 3.7 - 11
CONTAINMENT STRUCTURE
TYPICAL SPECTRA



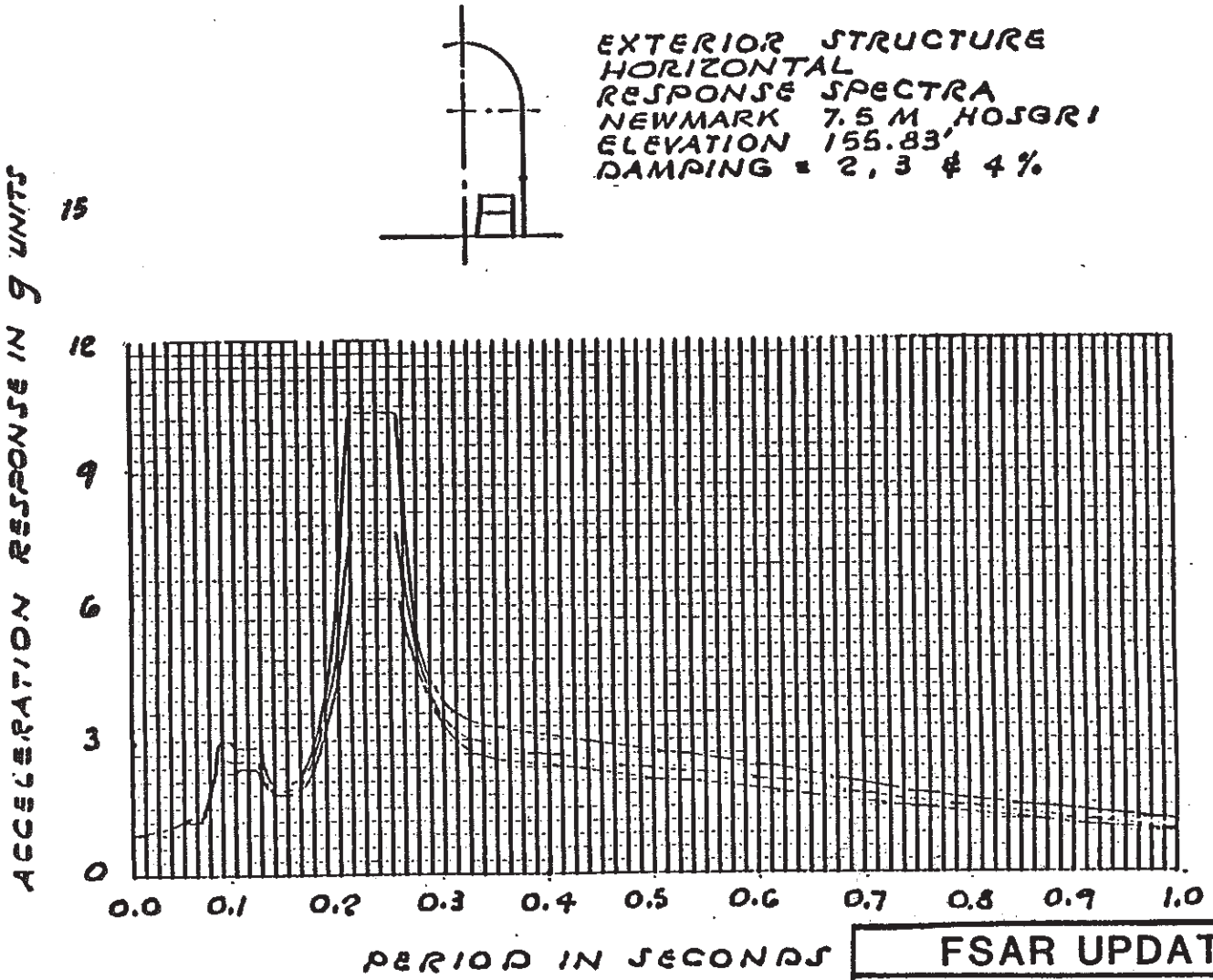
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7 - 12
CONTAINMENT STRUCTURE
TYPICAL SPECTRA



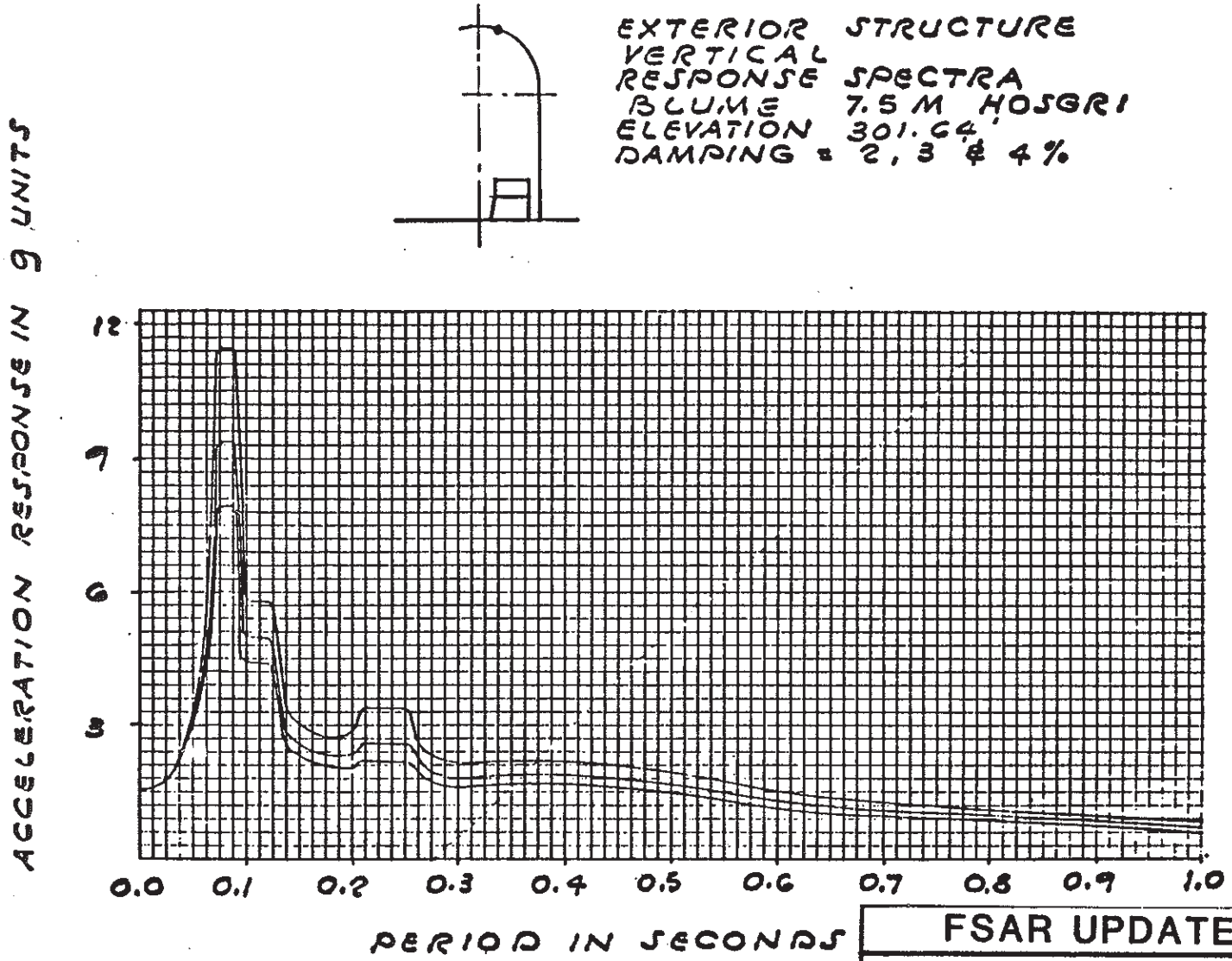
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.7 - 12A CONTAINMENT STRUCTURE



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

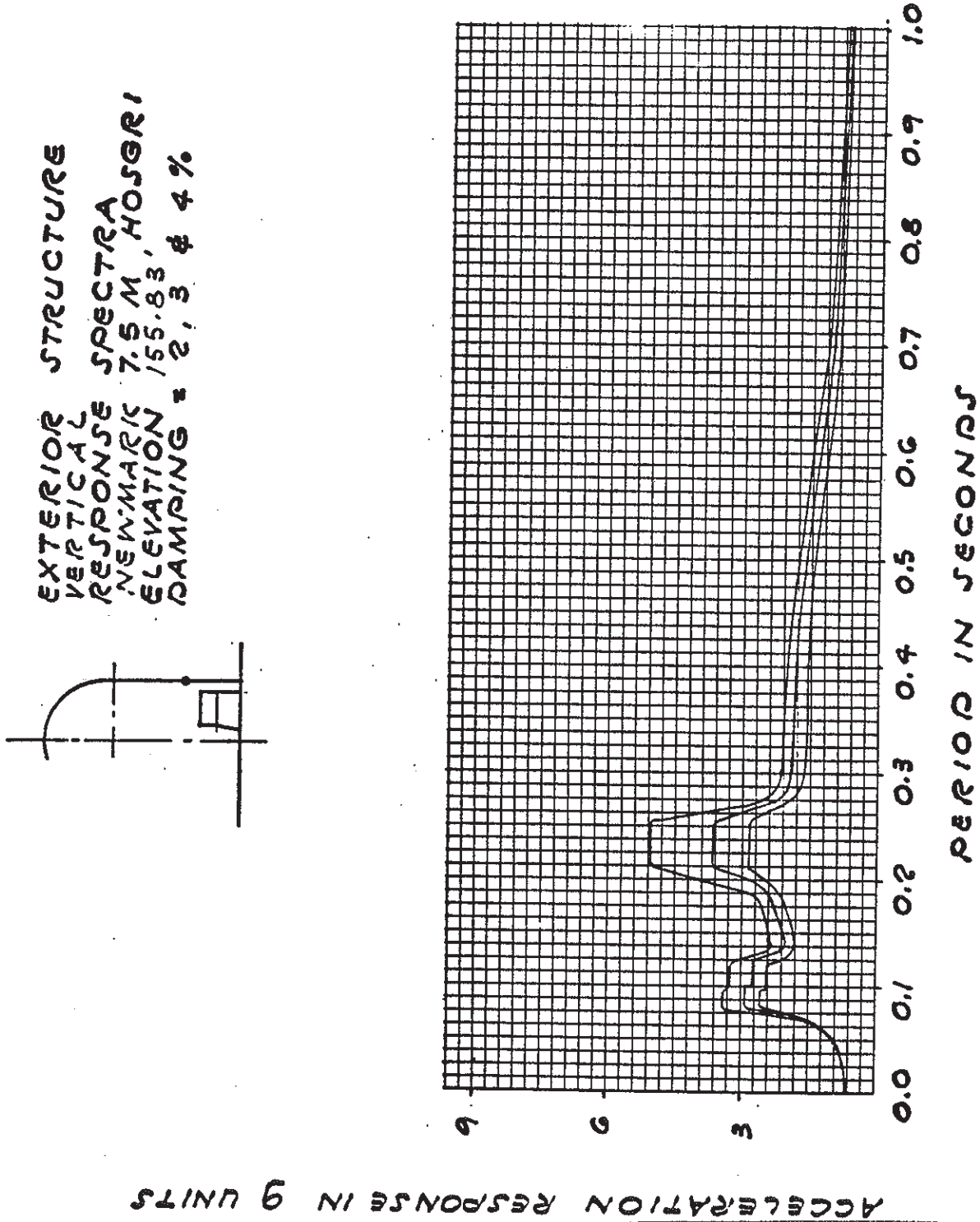
FIGURE 3.7 - 12B
CONTAINMENT STRUCTURE



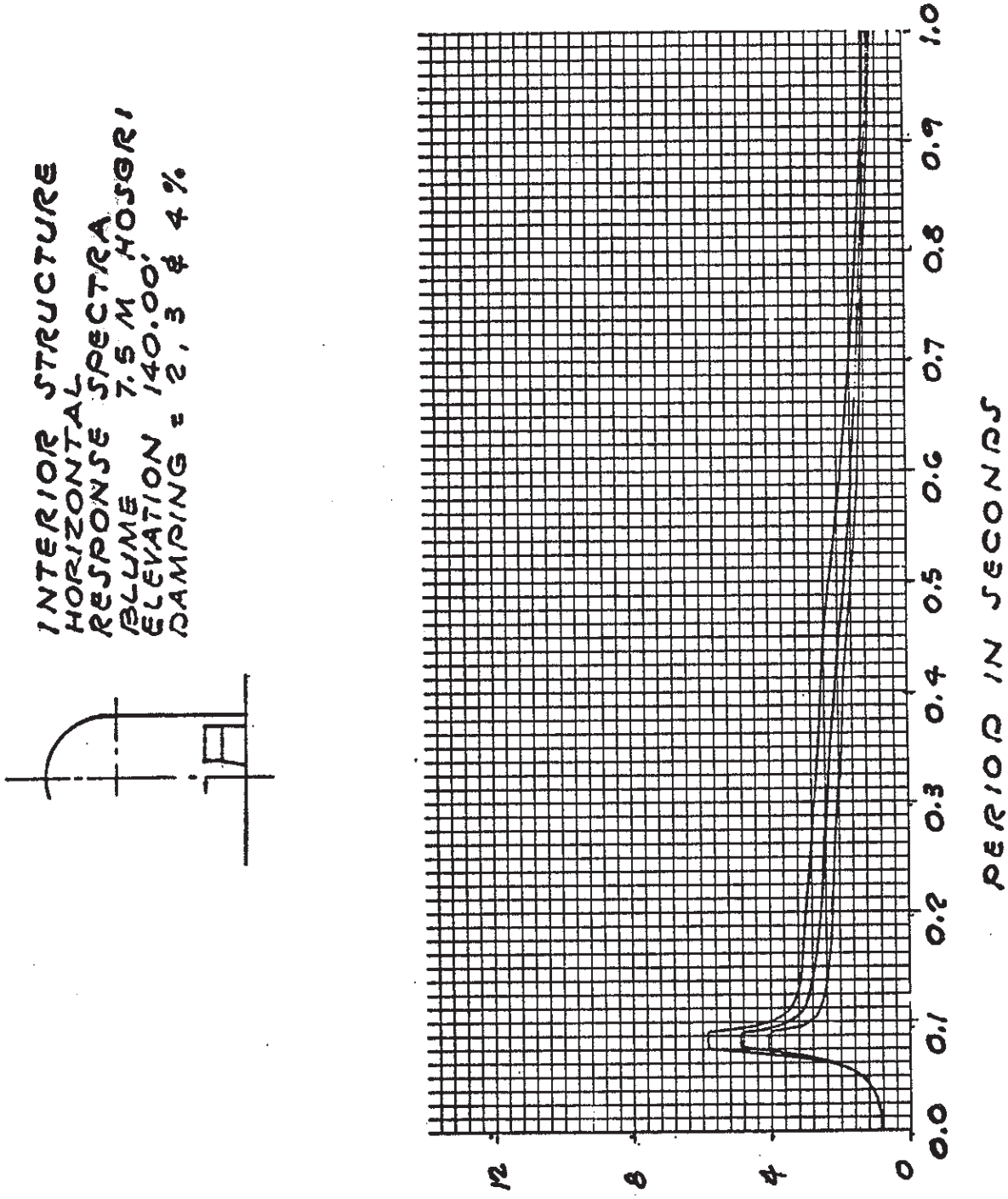
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7 - 12C
CONTAINMENT STRUCTURE



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.7 - 12D CONTAINMENT STRUCTURE



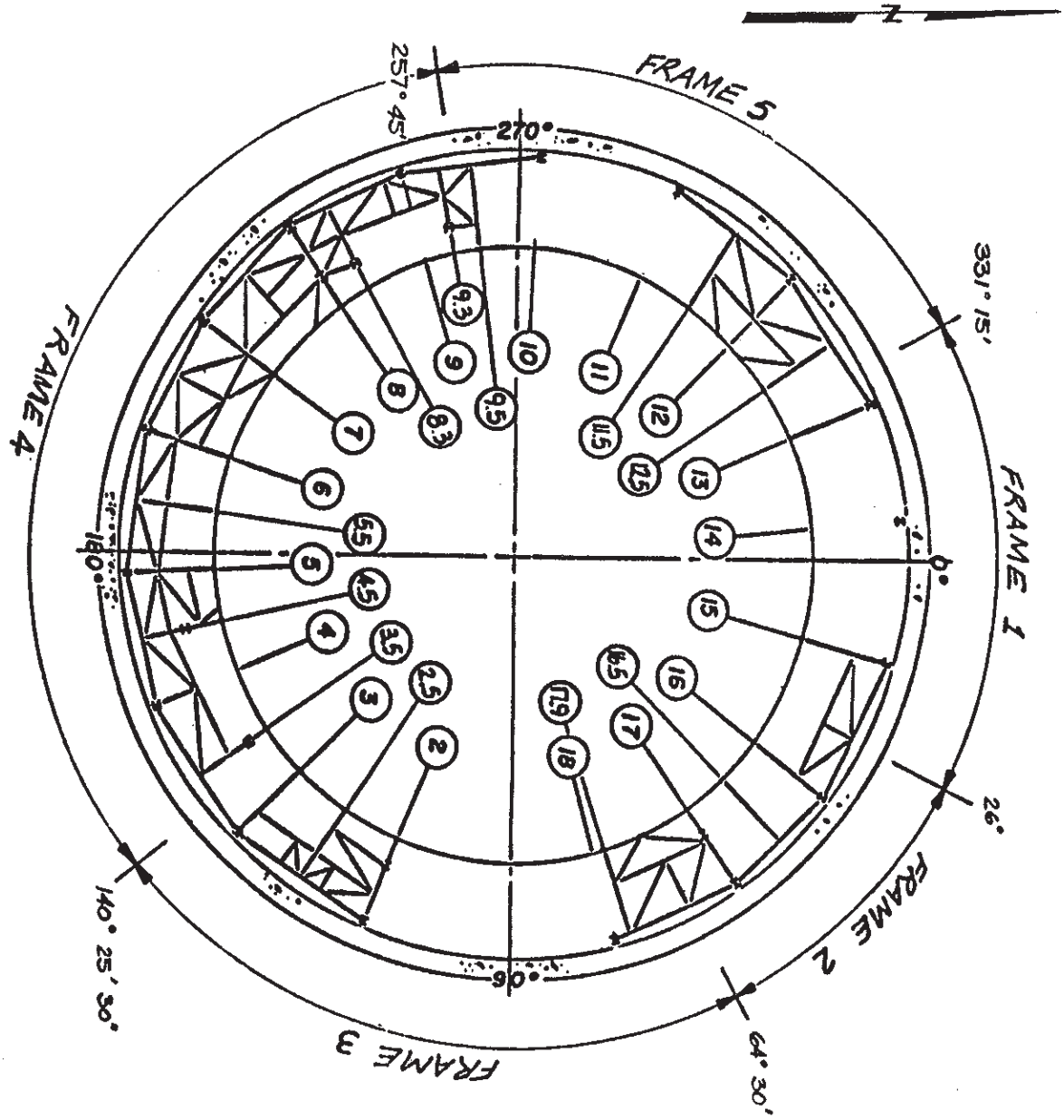
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.7 - 12E CONTAINMENT STRUCTURE

FSAR UPDATE

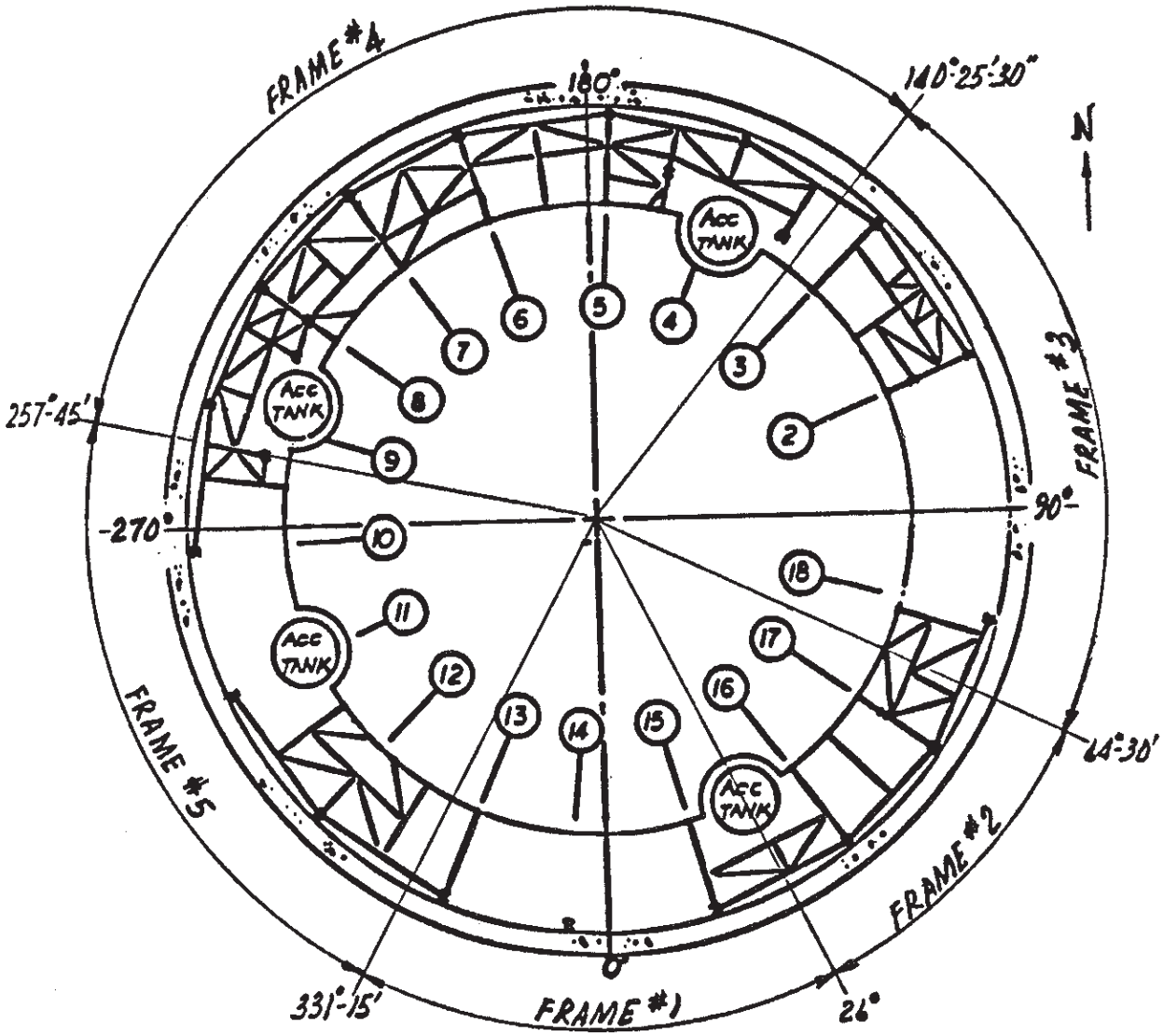
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7 - 12 F
CONTAINMENT STRUCTURE

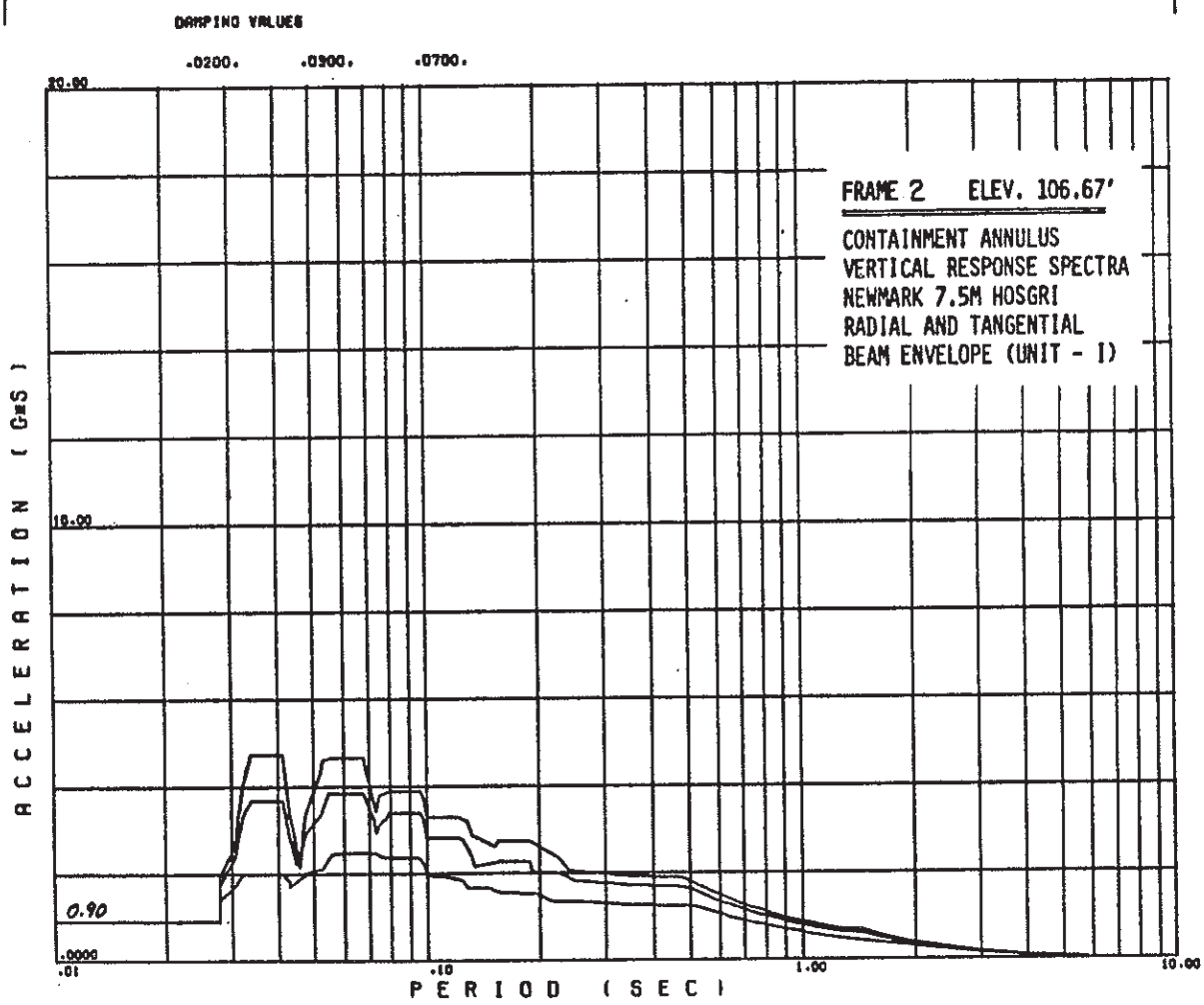
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.7 - 12G CONTAINMENT STRUCTURE



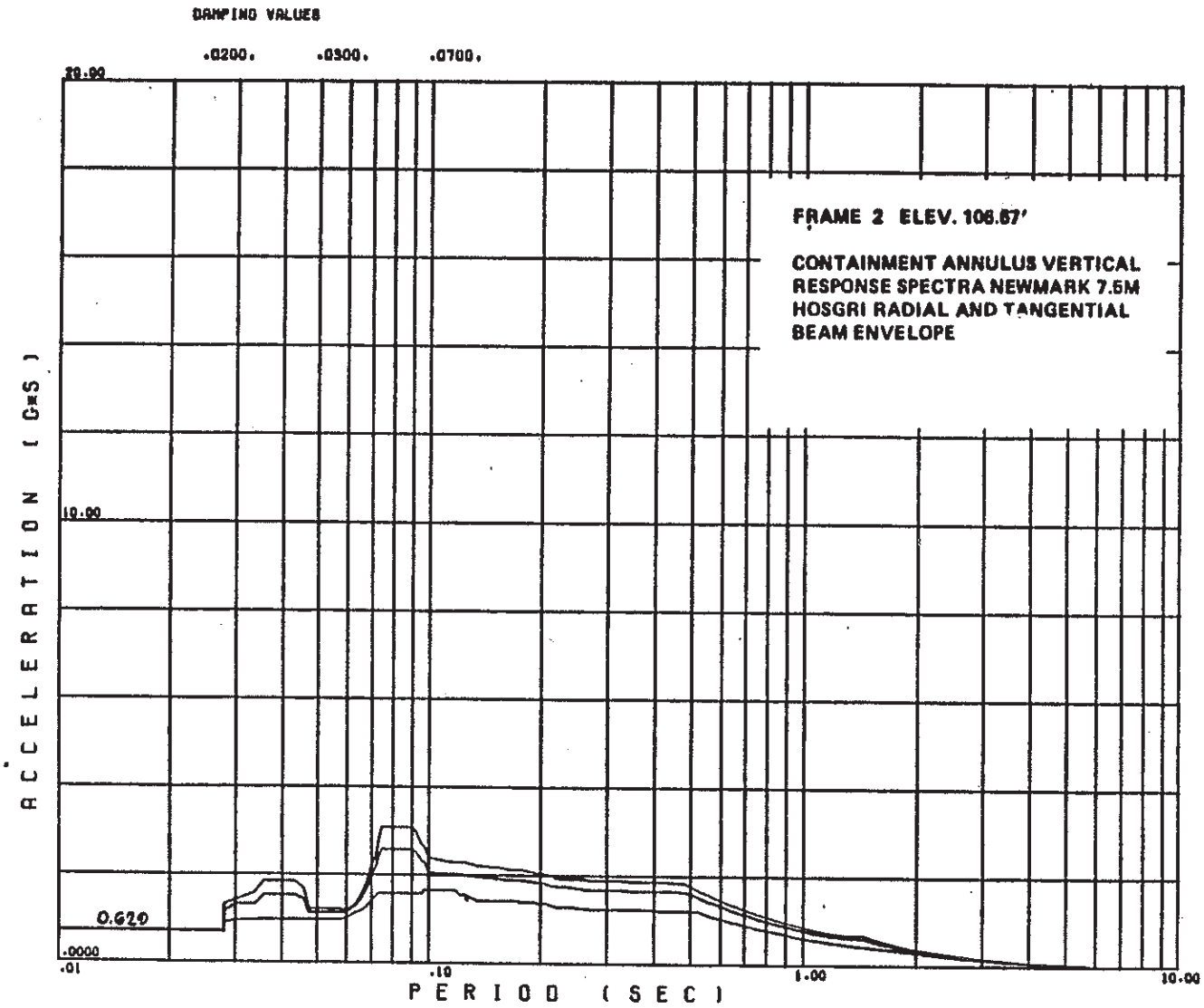
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.7 - 12 H CONTAINMENT – ANNULUS STRUCTURE



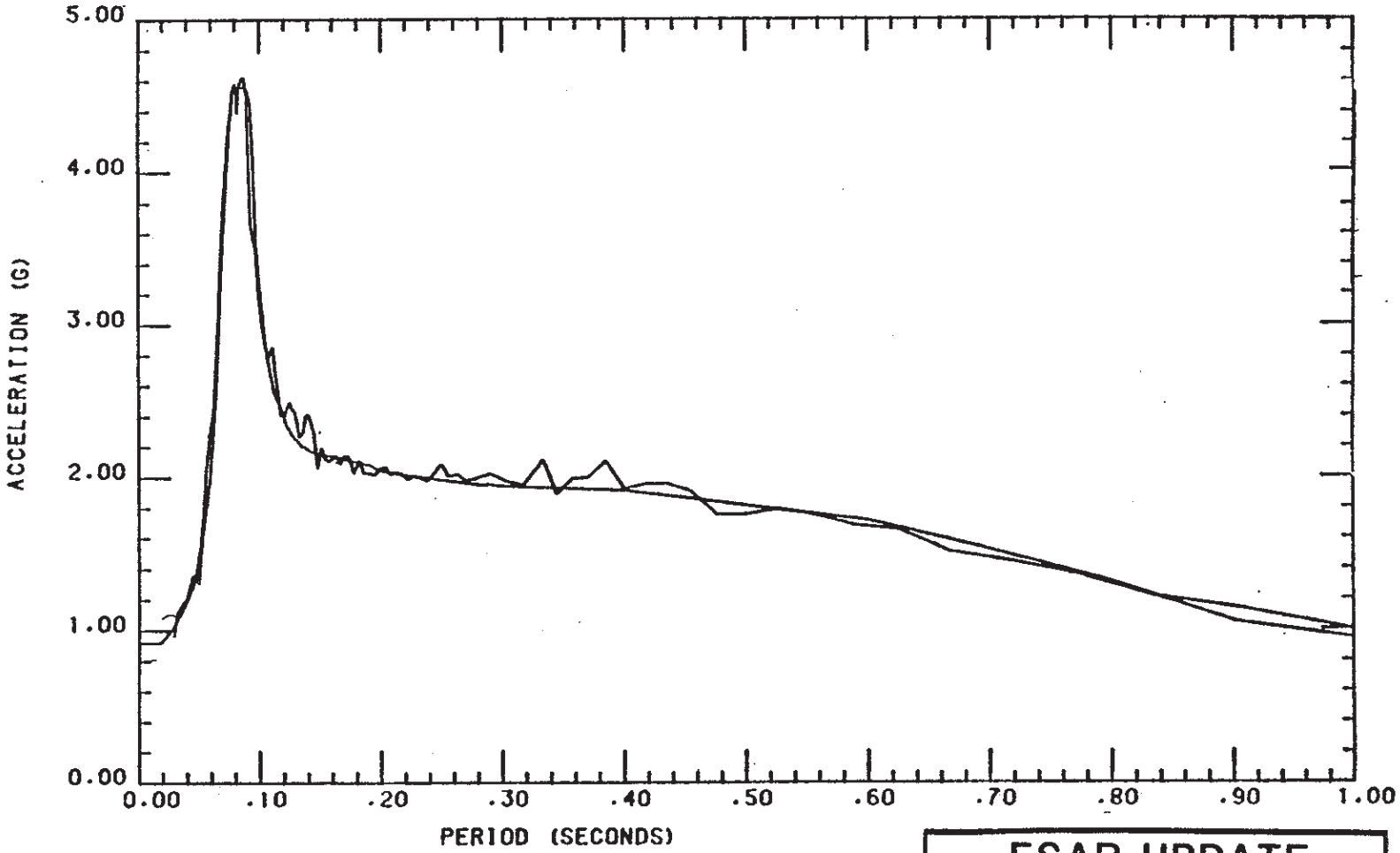
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 3.7 - 121 CONTAINMENT – ANNULUS STRUCTURE



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.7 - 12 J CONTAINMENT ANNULUS SPECTRA



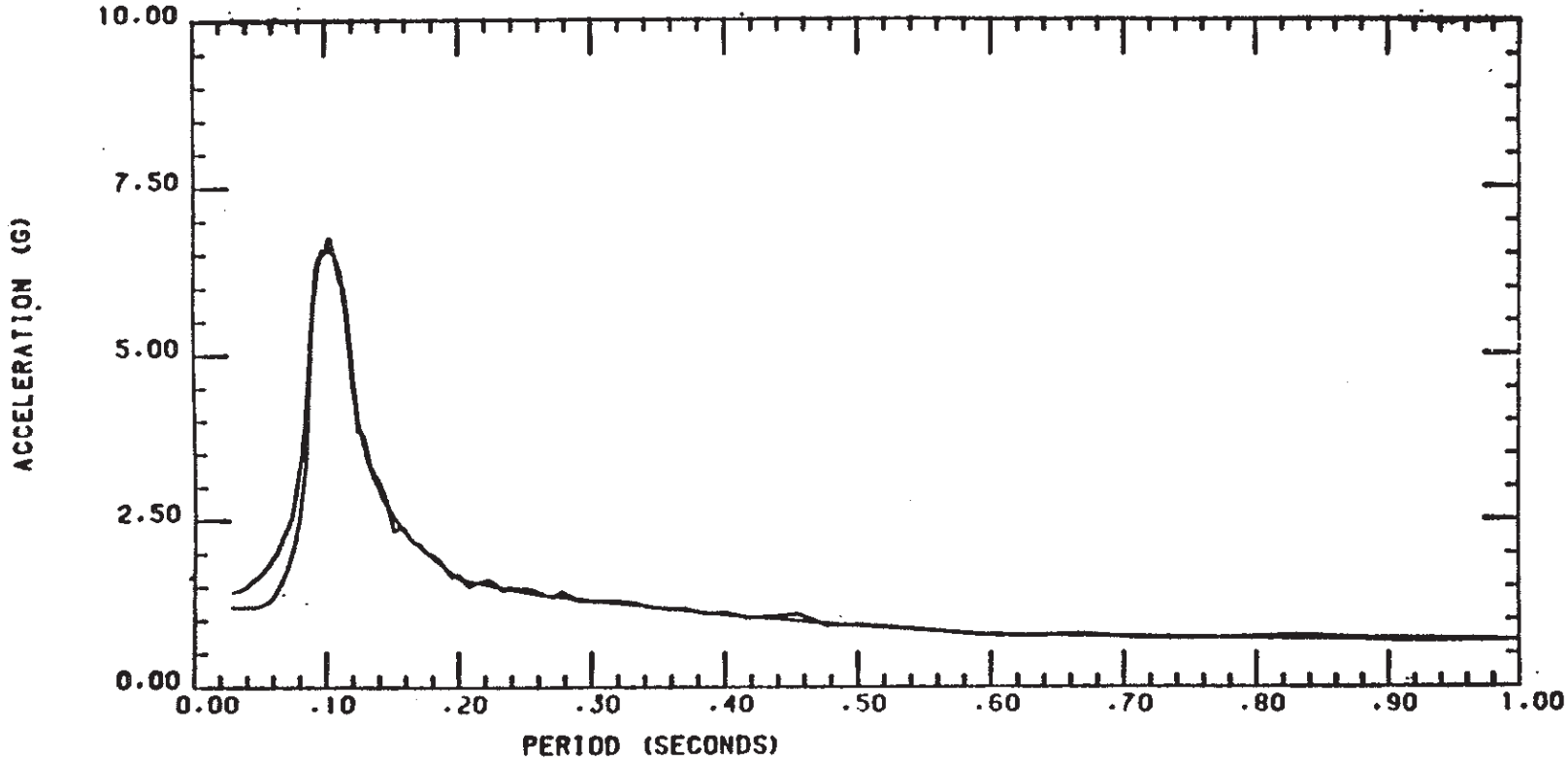
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 3.7 - 12K CONTAINMENT ANNULUS SPECTRA



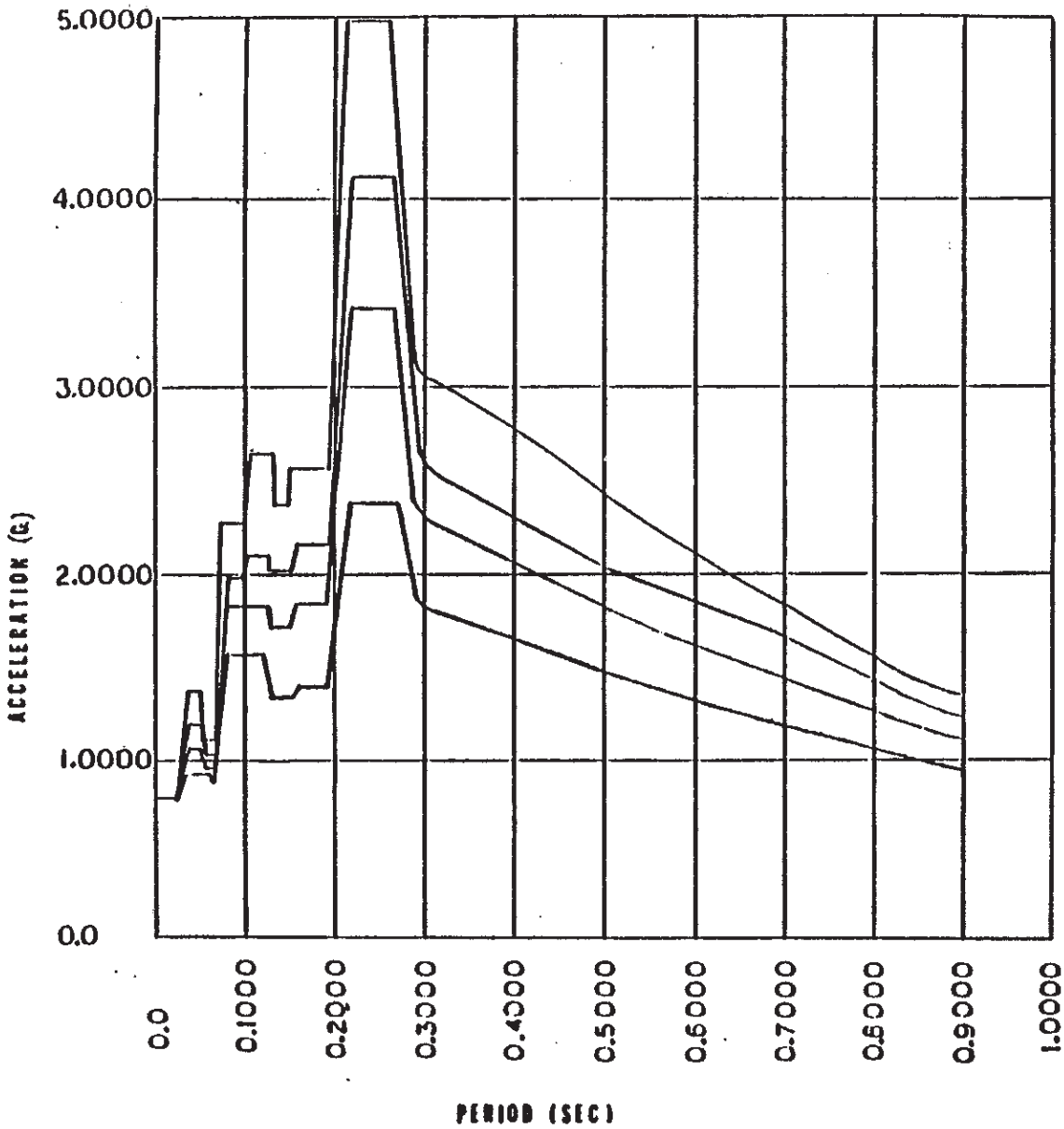
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

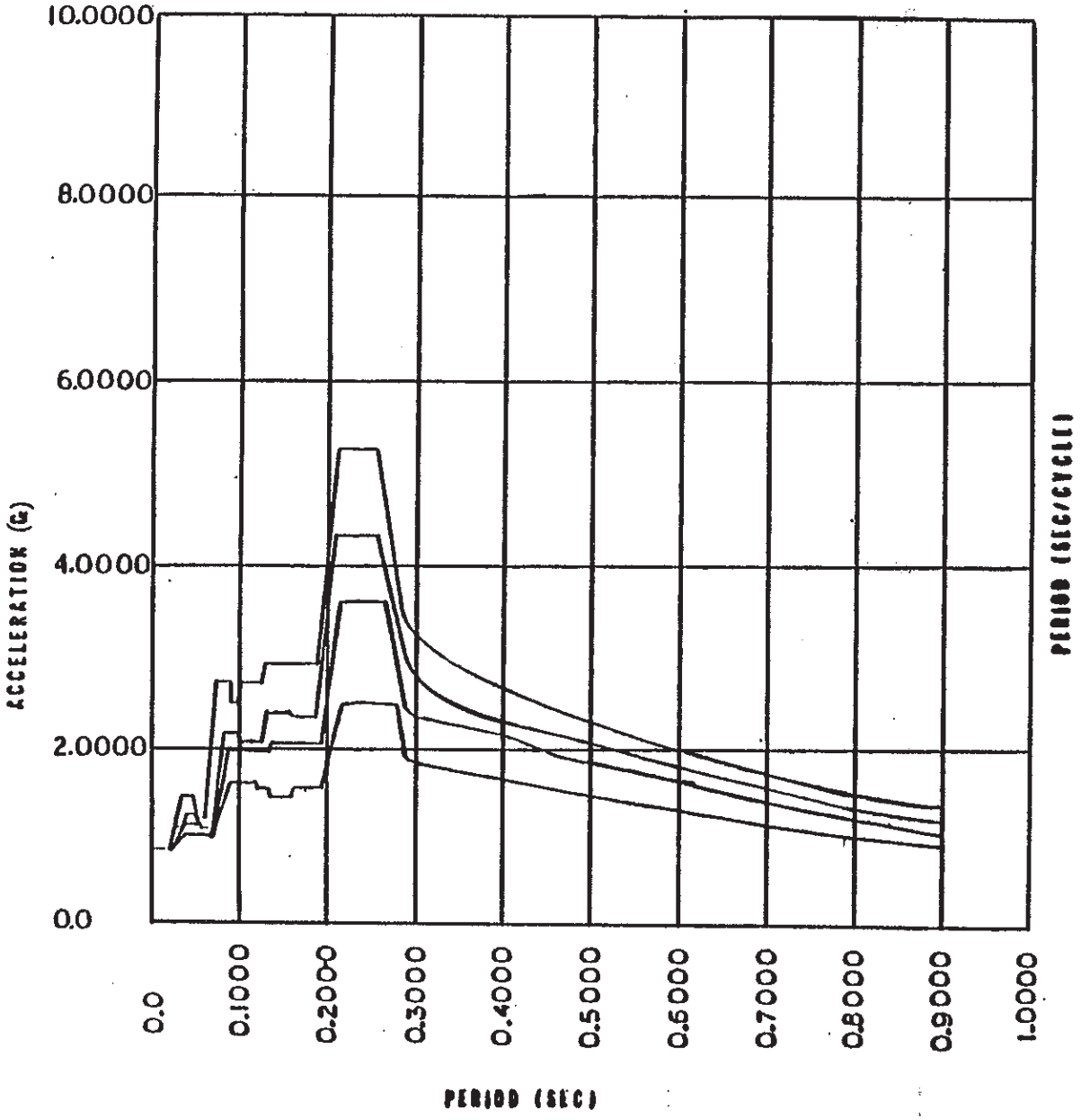
FIGURE 3.7 - 12 L
POLAR CRANE HOSGRI HORIZONTAL SPECTRUM IN X DIRECTION WITH 4% DAMPING AT EL. 140'



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.7 - 12 M POLAR CRANE DDE HORIZONTAL SPECTRUM IN Z DIRECTION WITH 5% DAMPING AT EL. 140'



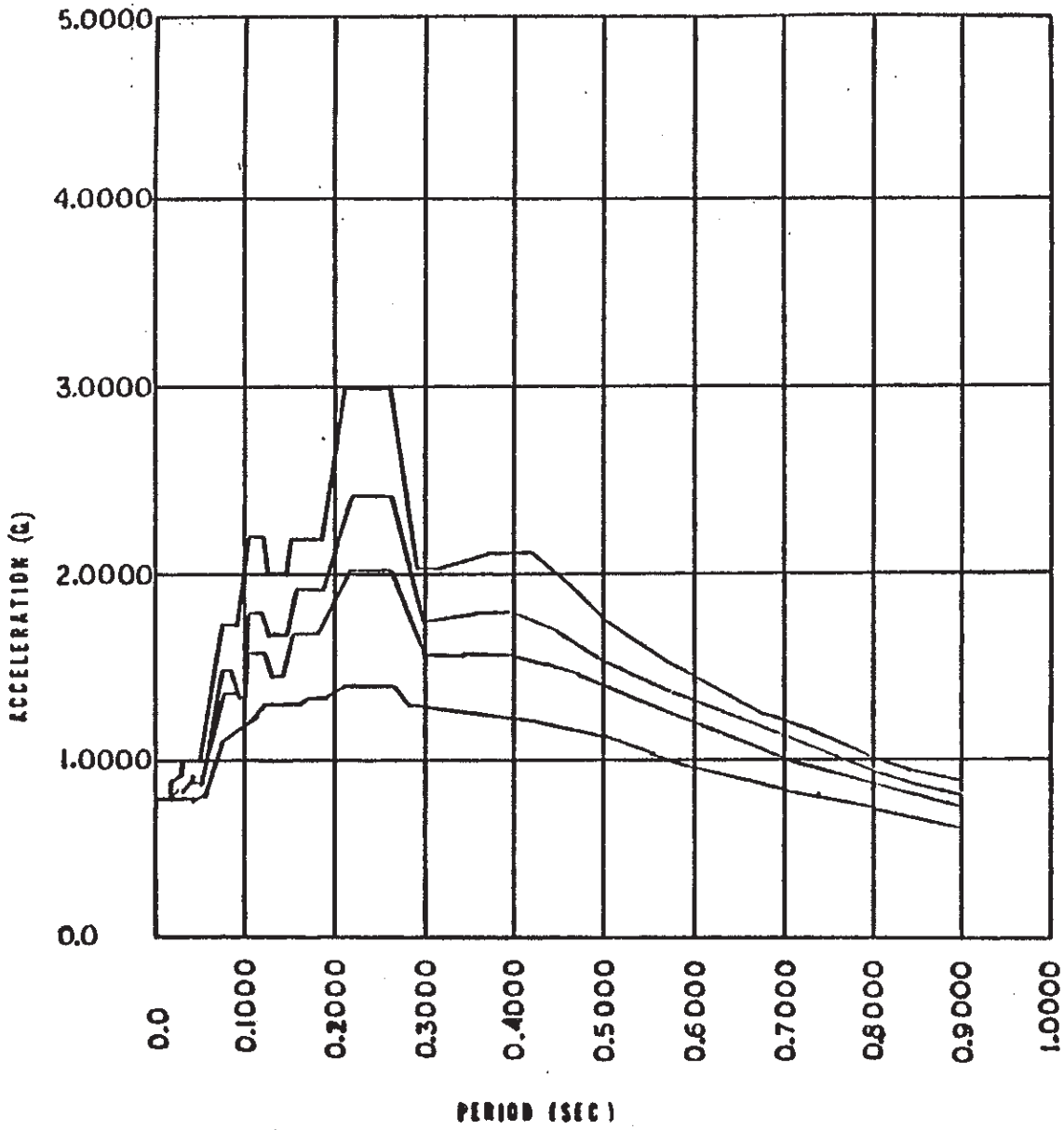
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.7 - 12 N PIPEWAY STRUCTURE HOSGRI BLUME N-S RESPONSE SPECTRA % DAMPING 2,3,4,7 ELEVATION 109'4" NODE 893



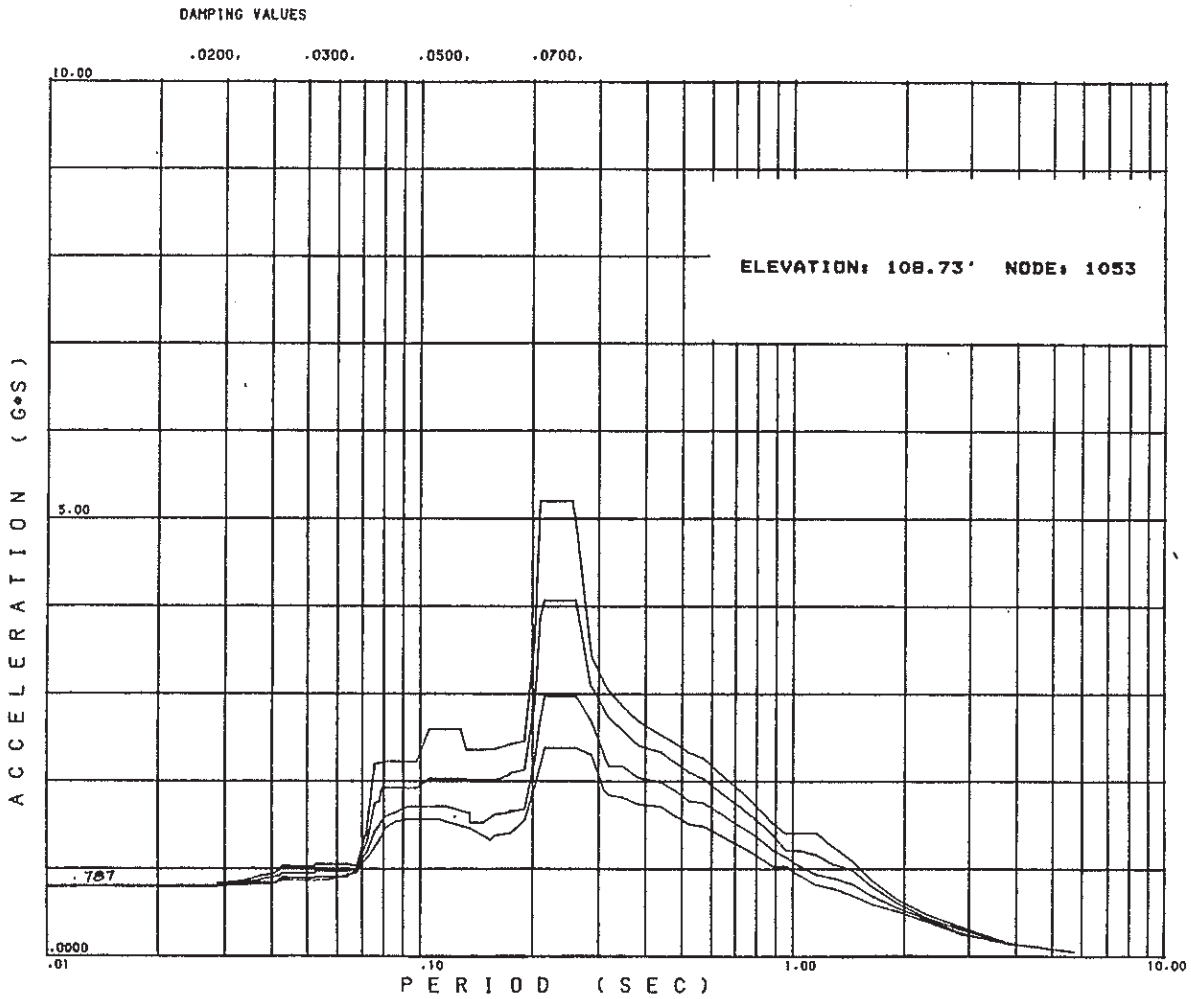
FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

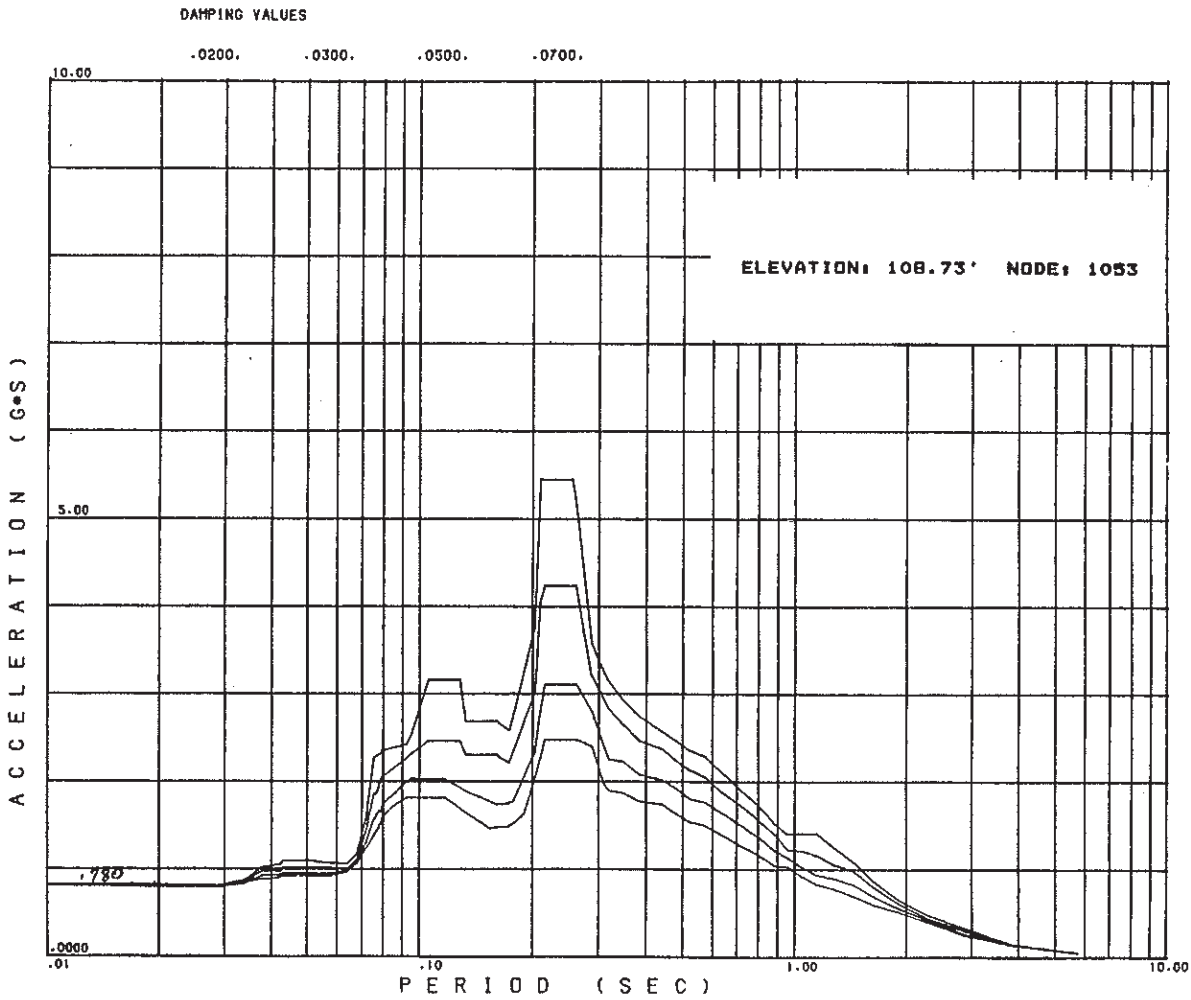
FIGURE 3.7 - 12 O
PIPEWAY STRUCTURE
HOSGRI BLUME E-W
RESPONSE SPECTRA
% DAMPING 2, 3 , 4, 7
ELEVATION 109'- 4"
NODE 893



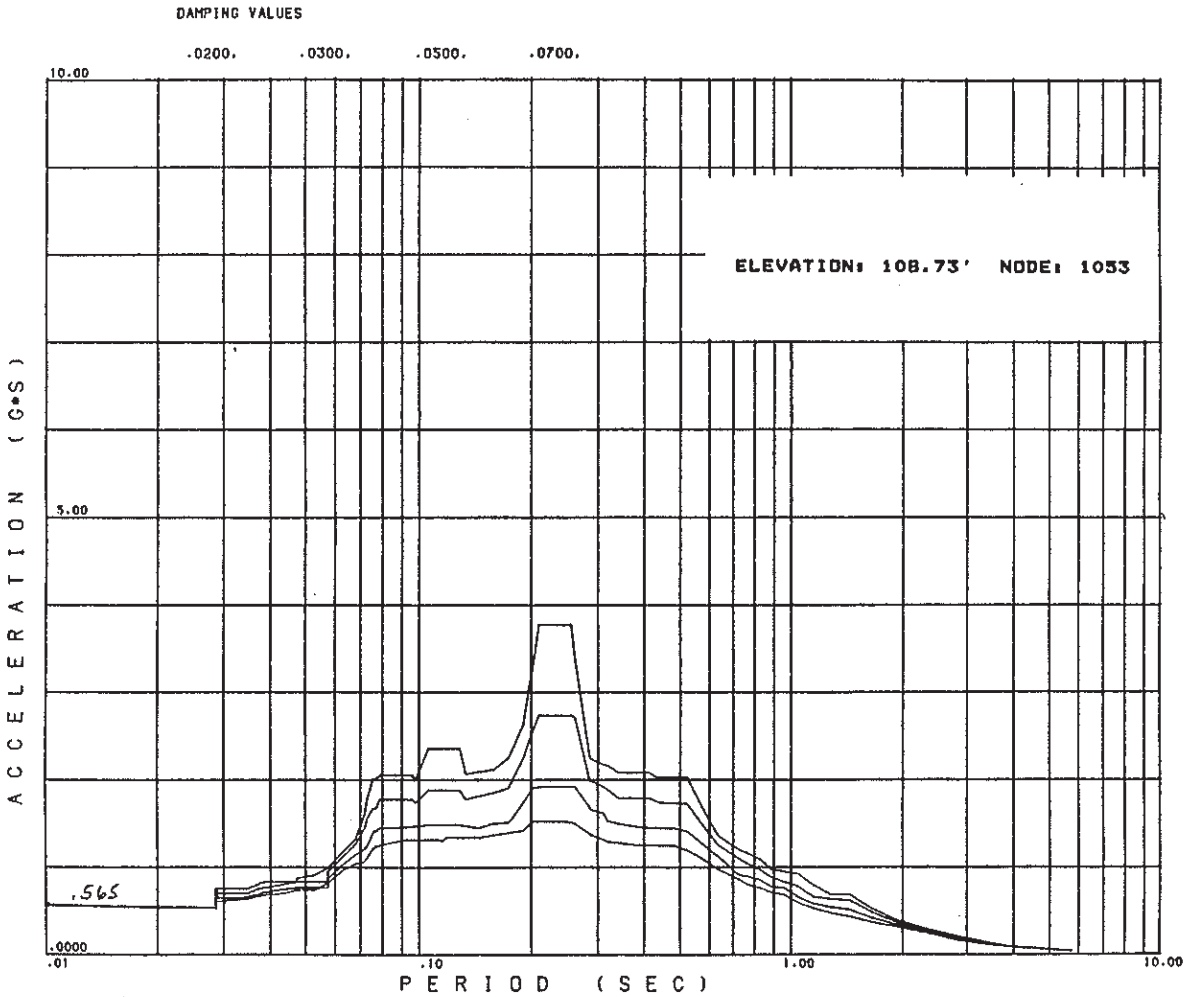
FSAR UPDATE
UNIT 1 **DIABLO CANYON SITE**
FIGURE 3.7 - 12 P PIPEWAY STRUCTURE HOSGRI BLUME VERTICAL RESPONSE SPECTRA % DAMPING 2,3,4,7 ELEVATION 109'-4" NODE 893



FSAR UPDATE
UNIT 2 **DIABLO CANYON SITE**
FIGURE 3.7 - 12Q PIPEWAY STRUCTURE HOSGRI BLUME N-S RESPONSE SPECTRA



FSAR UPDATE
UNIT 2 **DIABLO CANYON SITE**
FIGURE 3.7 - 12R PIPEWAY STRUCTURE HOSGRI BLUME E- W RESPONSE SPECTRA



FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

FIGURE 3.7 - 12 S
PIPEWAY STRUCTURE
HOSGRI BLUME VERTICAL
RESPONSE SPECTRA

LEGEND:

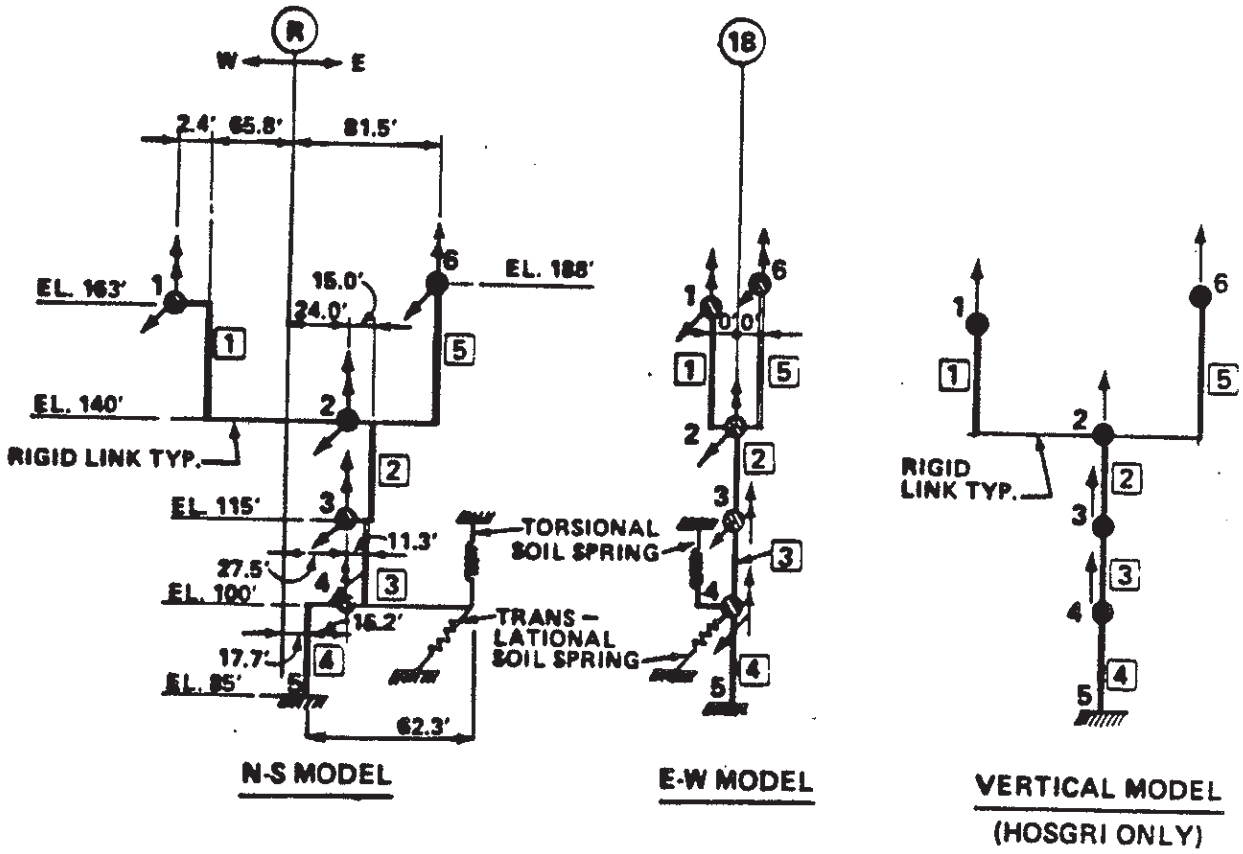
2 – NODE NUMBER

1 – ELEMENT NUMBER

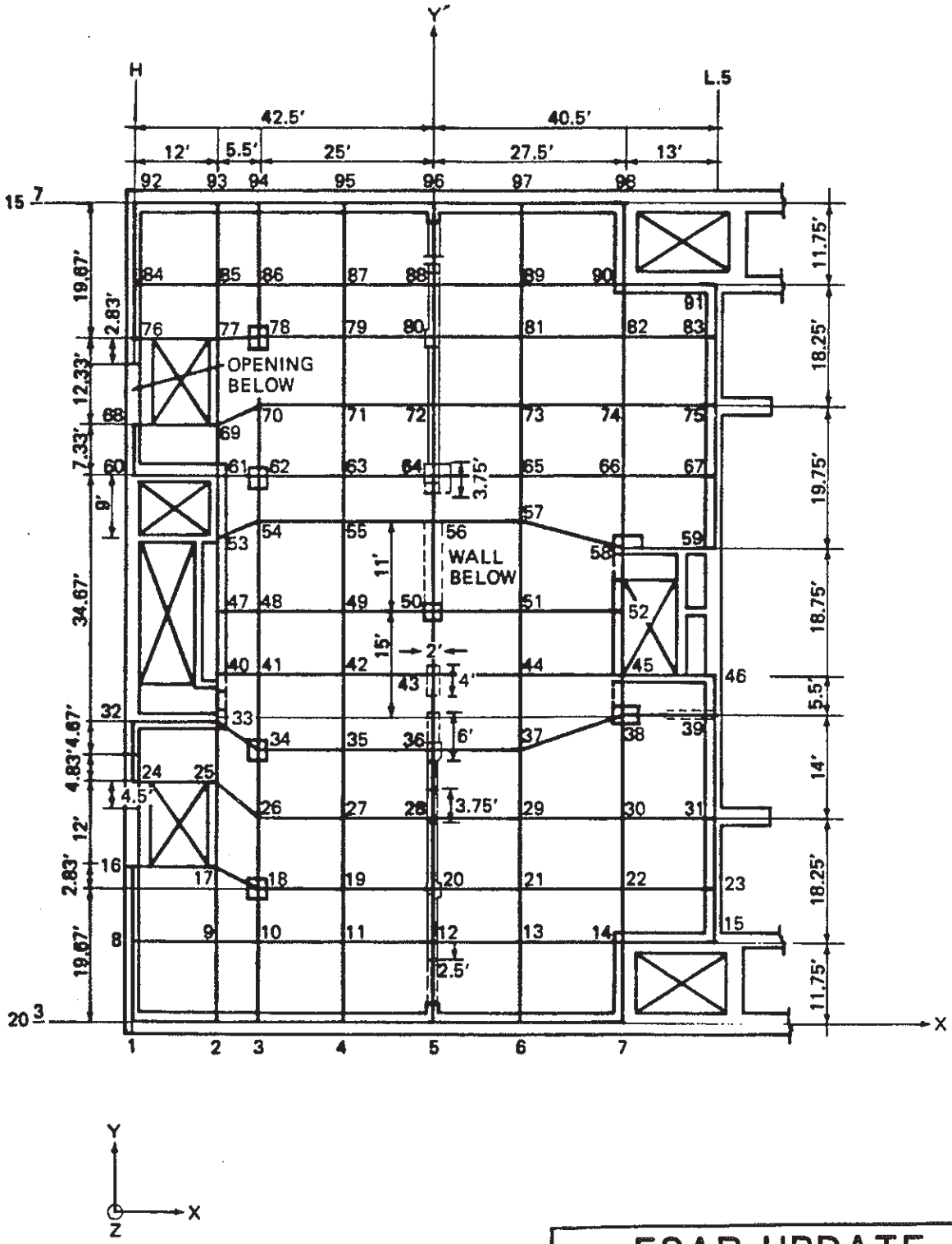
– ROTATIONAL DEGREE OF FREEDOM

– TRANSLATIONAL DEGREE OF FREEDOM

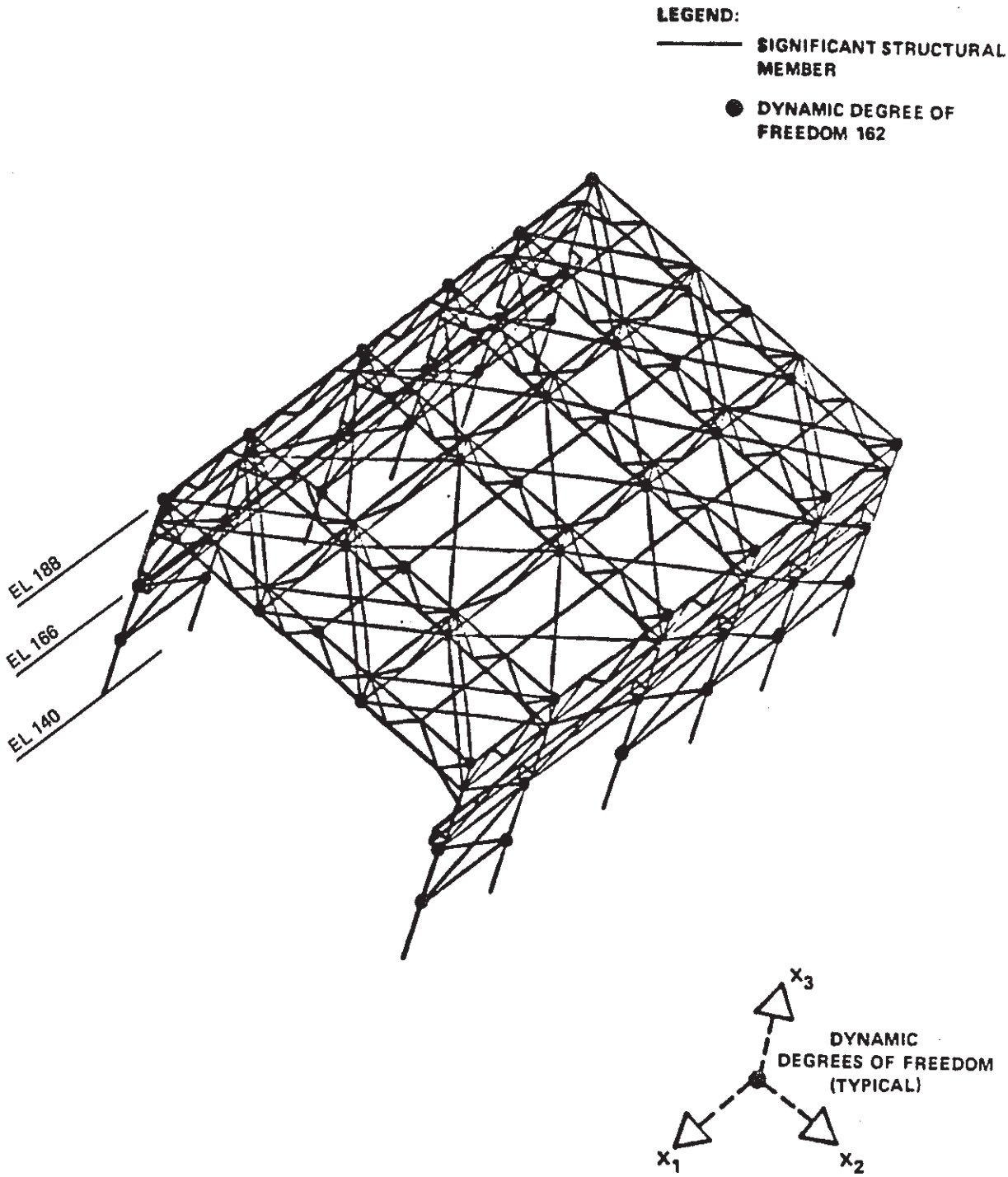
– MASS POINT



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.7 -13 AUXILIARY BUILDING MATHEMATICAL MODEL



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.7–13A AUXILIARY BUILDING FLEXIBLE SLAB MODEL

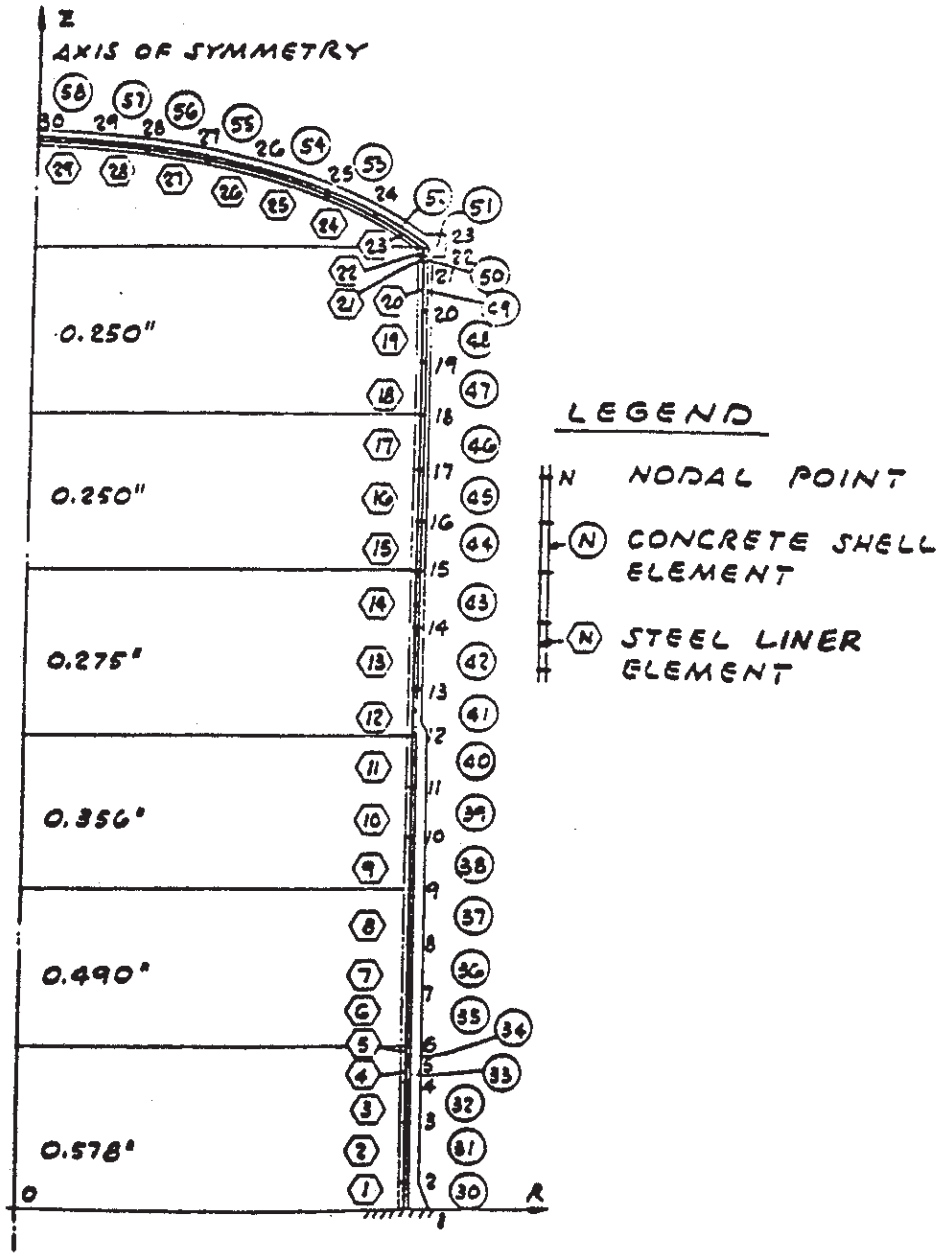


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7–13B

AUXILIARY BUILDING
FUEL HANDLING
CRANE SUPPORT STRUCTURE
MODEL NO. 2.2

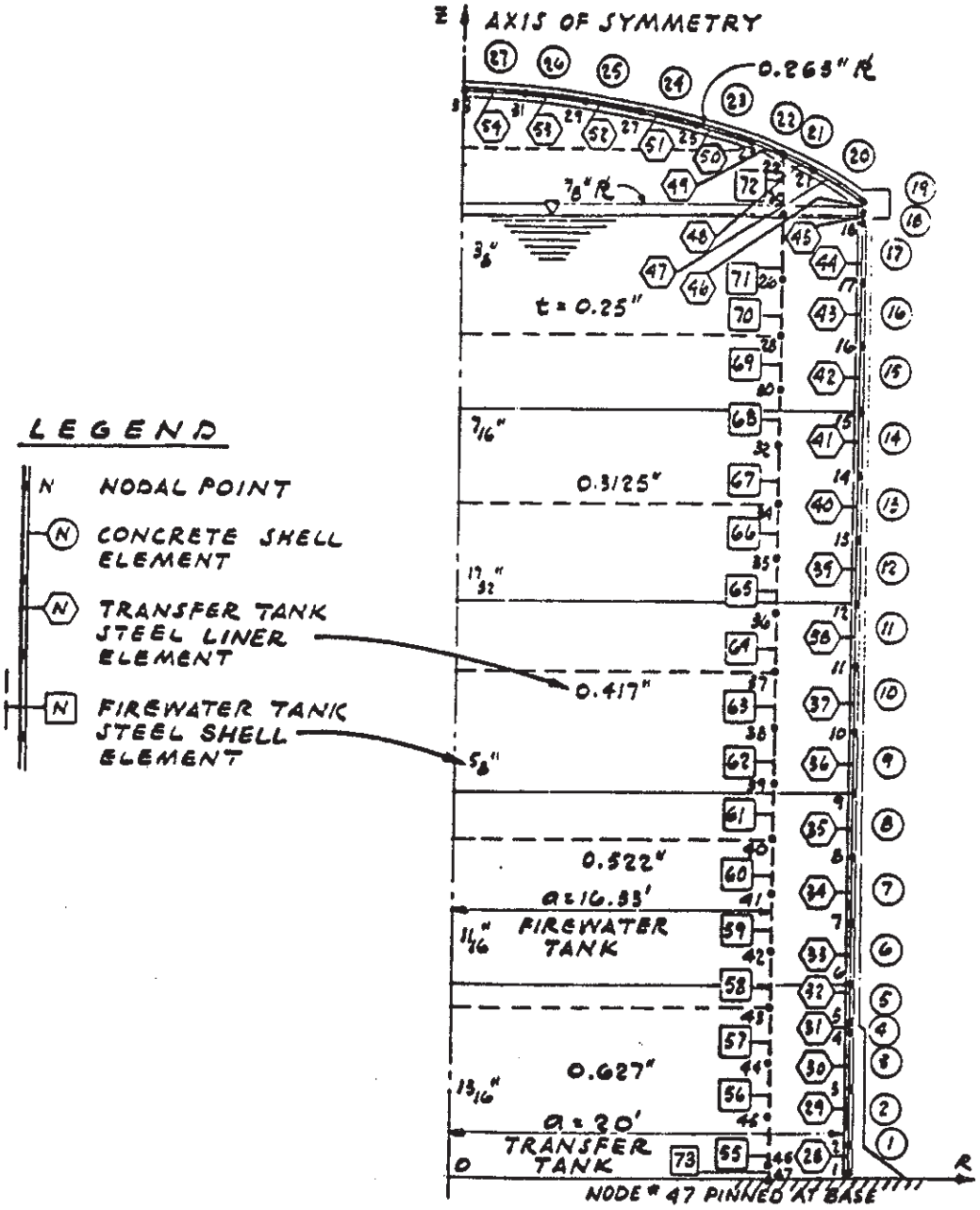


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7-14

OUTDOOR WATER STORAGE TANKS: REFUELING WATER TANK, AXISYMMETRIC MODEL

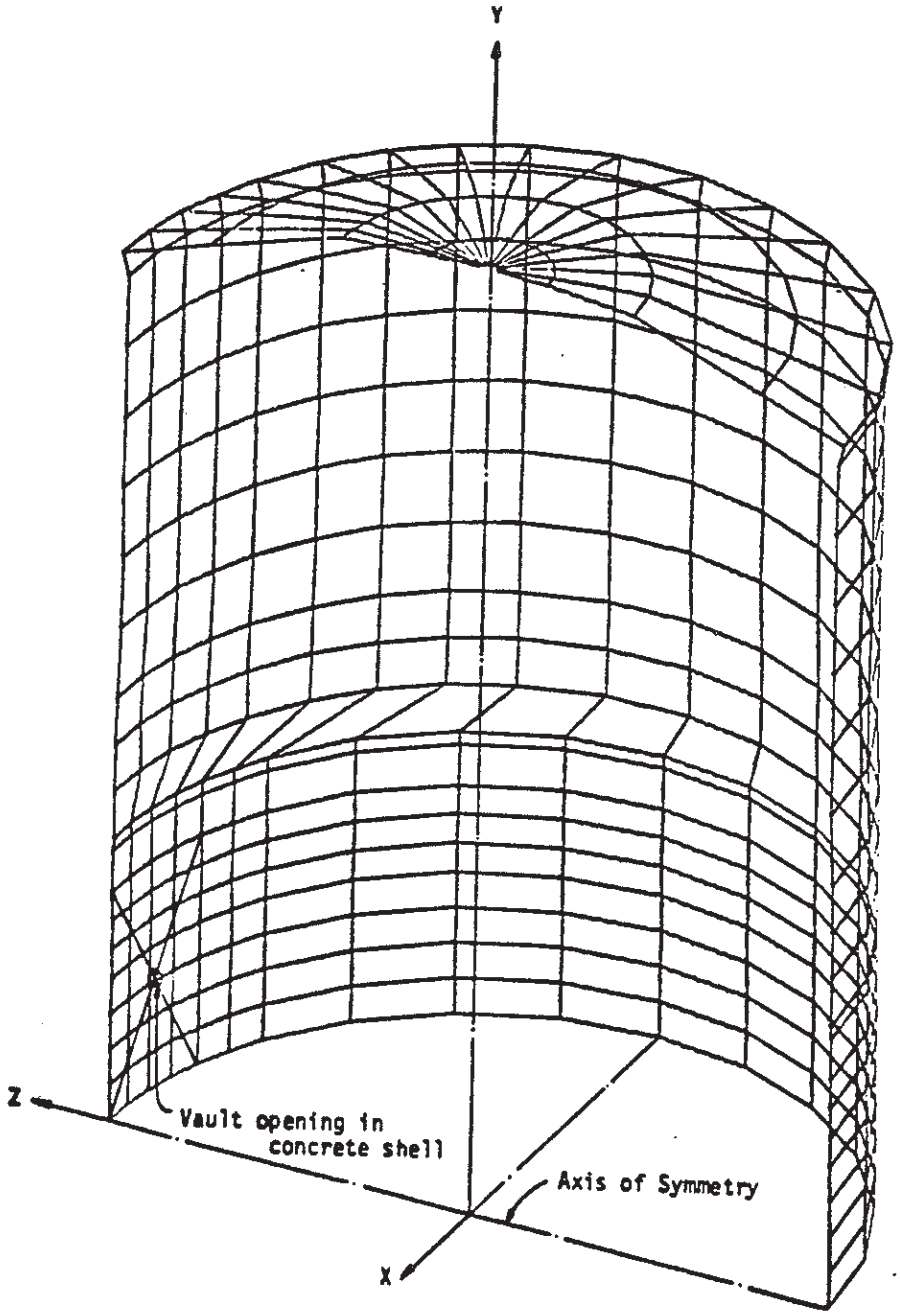


FSAR UPDATE

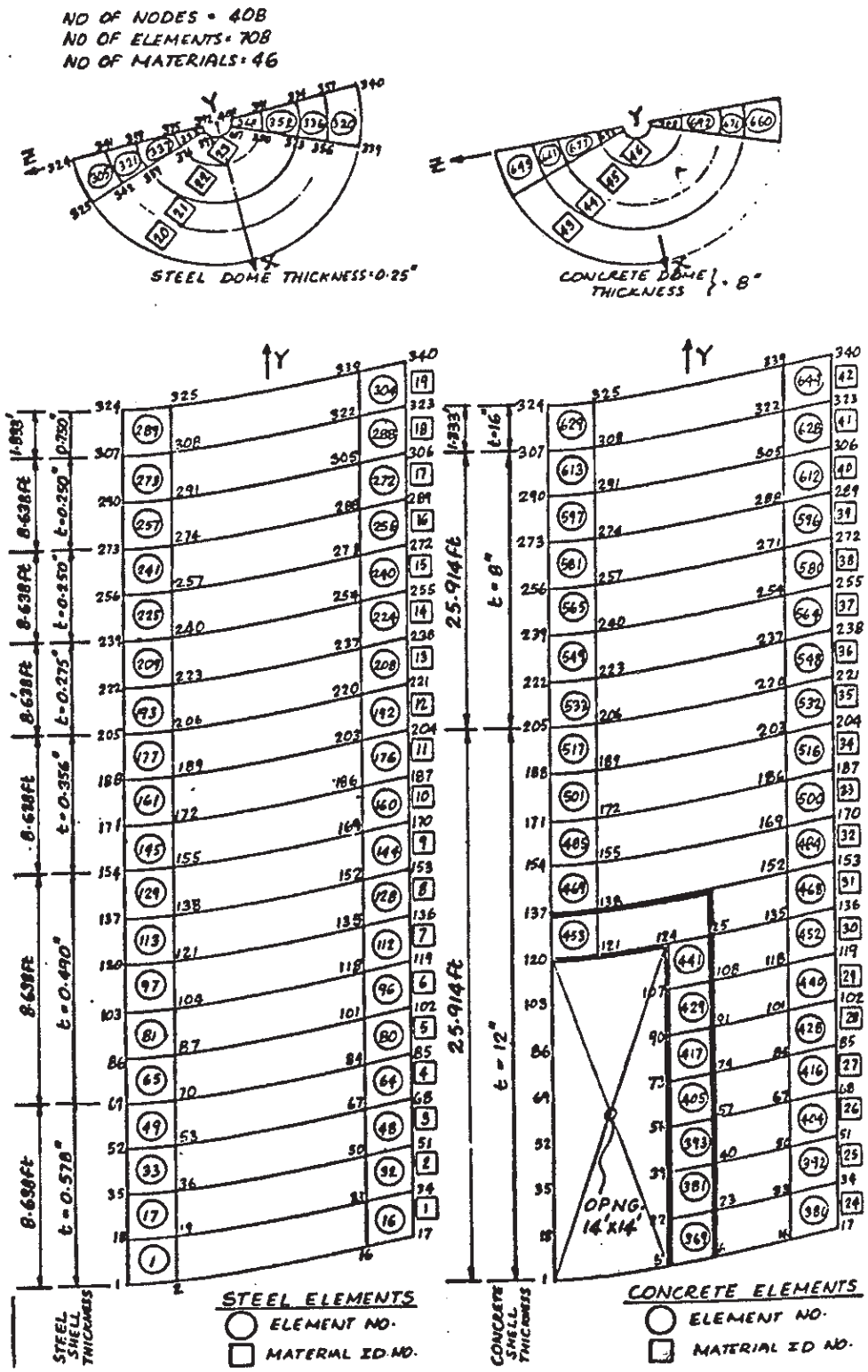
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7-15

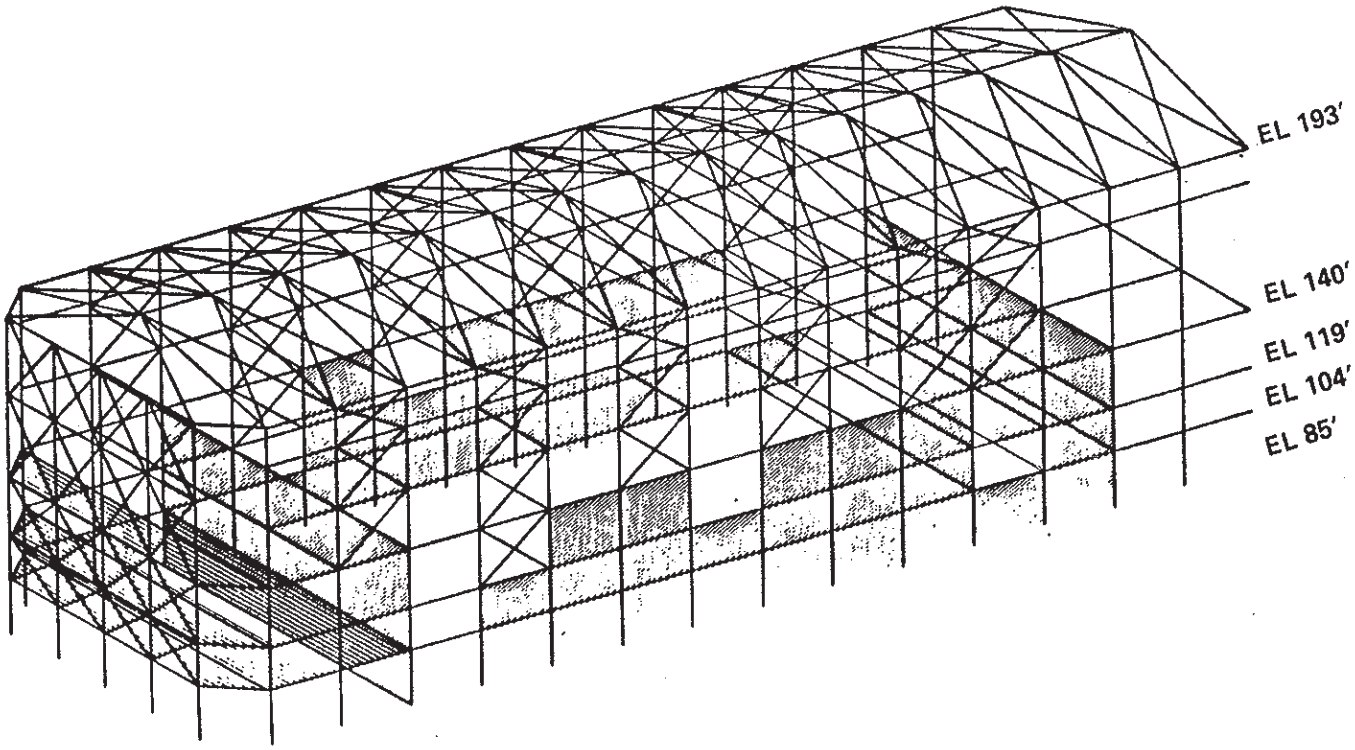
OUTDOOR WATER STORAGE TANKS: FIREWATER AND TRANSFER TANK, AXISYMMETRIC MODEL



FSAR UPDATE
UNIT 1 **DIABLO CANYON SITE**
FIGURE 3.7 - 15 A OUTDOOR WATER STORAGE TANKS: REFUELING WATER TANK, PERSPECTIVE VIEW OF HALF-TANK MODEL



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.7 - 15 B HALF-TANK COMPUTER MODEL

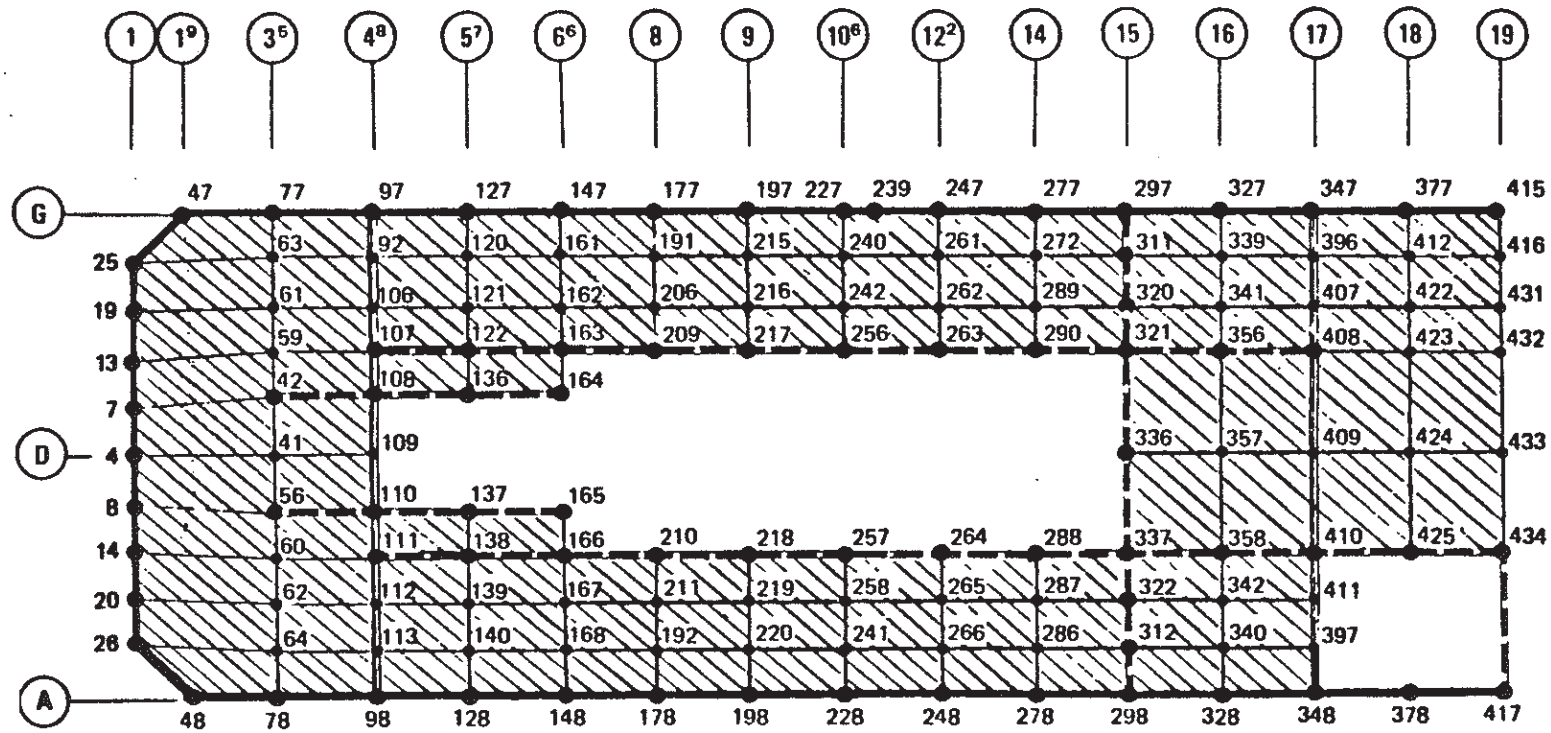


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7 - 15C
TURBINE BUILDING
UNIT 1 PORTION
HORIZONTAL MODEL
ISOMETRIC

Revision 11 November 1996

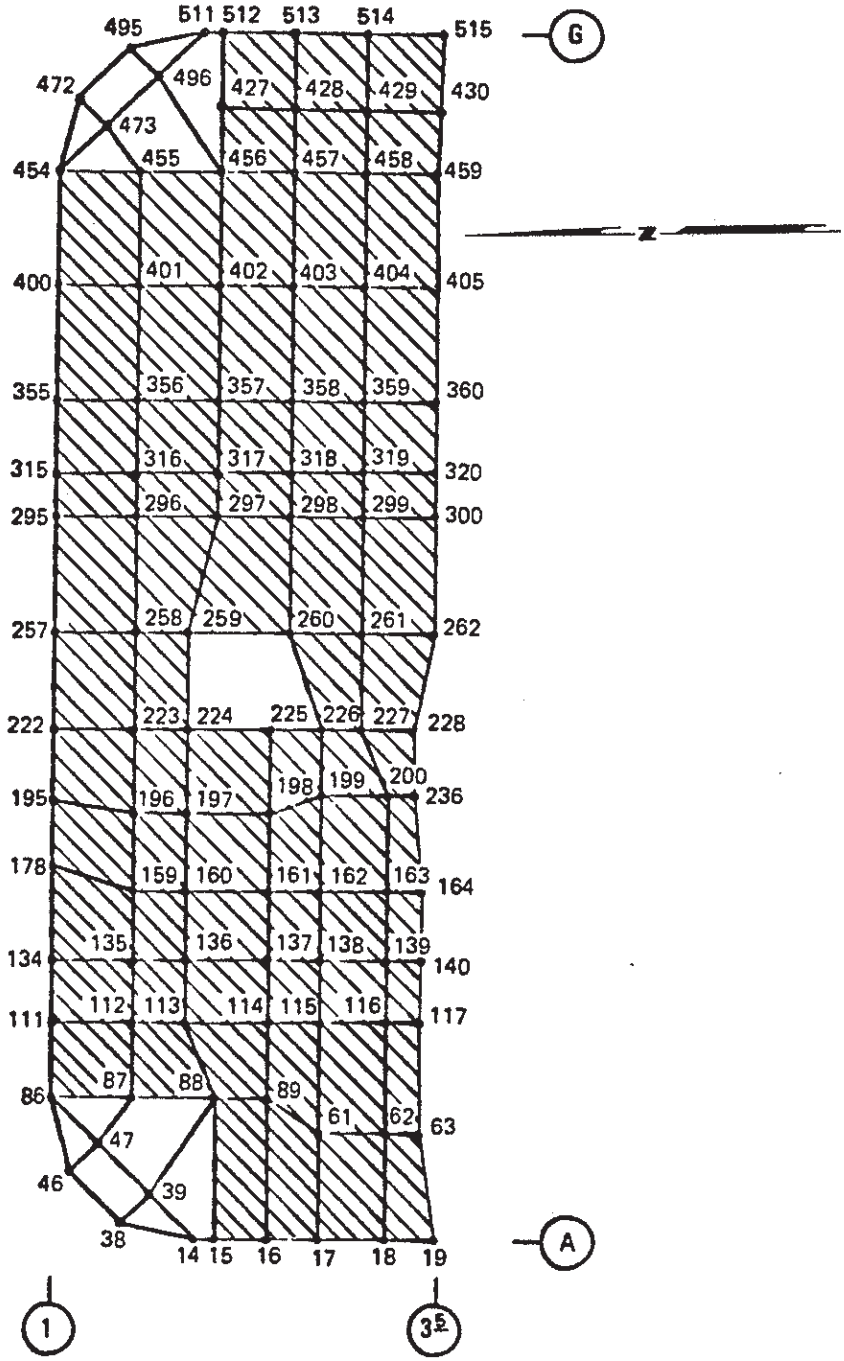


TRUSS ELEMENTS
BEAM ELEMENTS
PLANE STRESS ELEMENTS

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7 - 15 D
TURBINE BUILDING UNIT 1
PORTION HORIZONTAL
MODEL PLAN AT ELEV. 140′

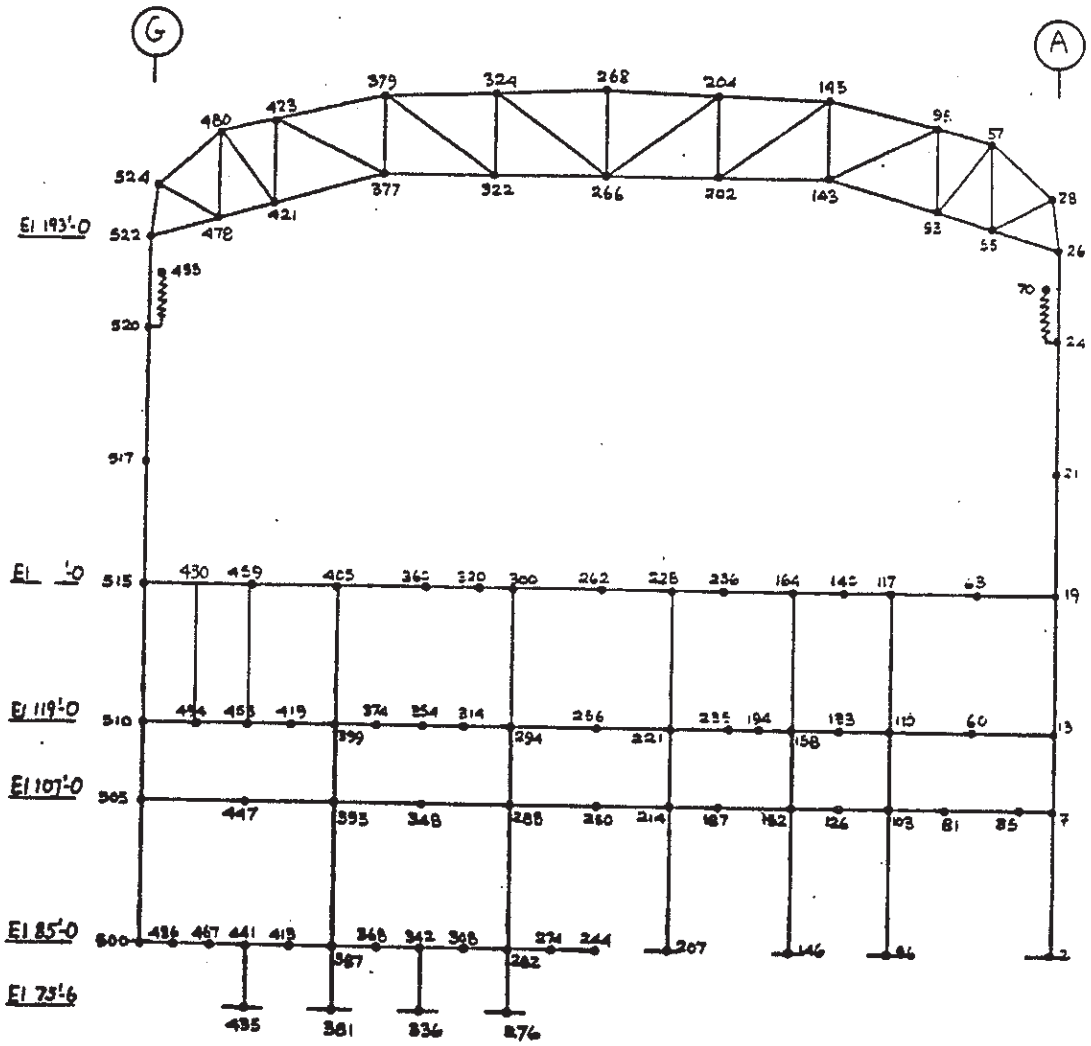


ELEMENT

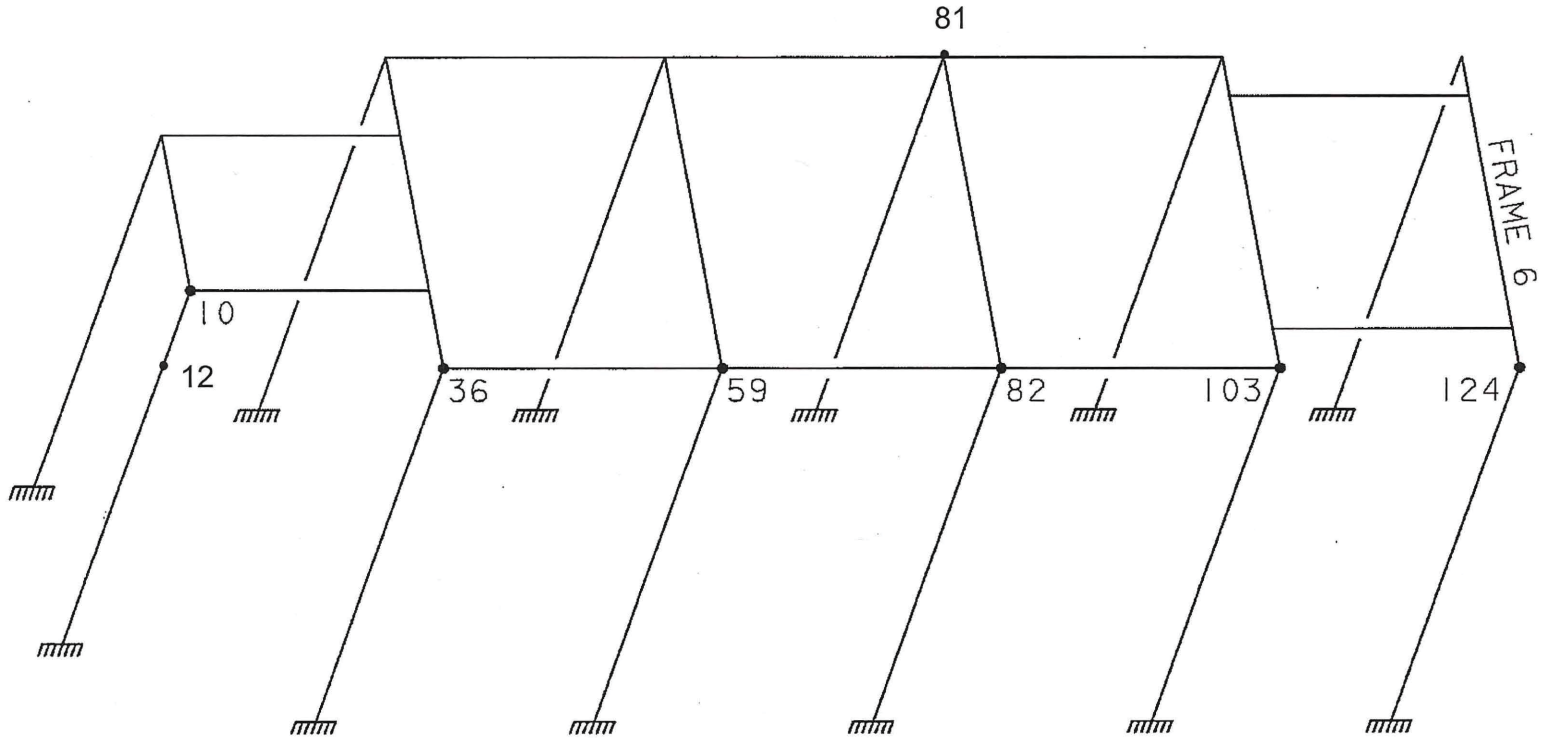
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7-15E
TURBINE BUILDING
VERTICAL MODEL NO. 1
PLAN AT ELEVATION 140'

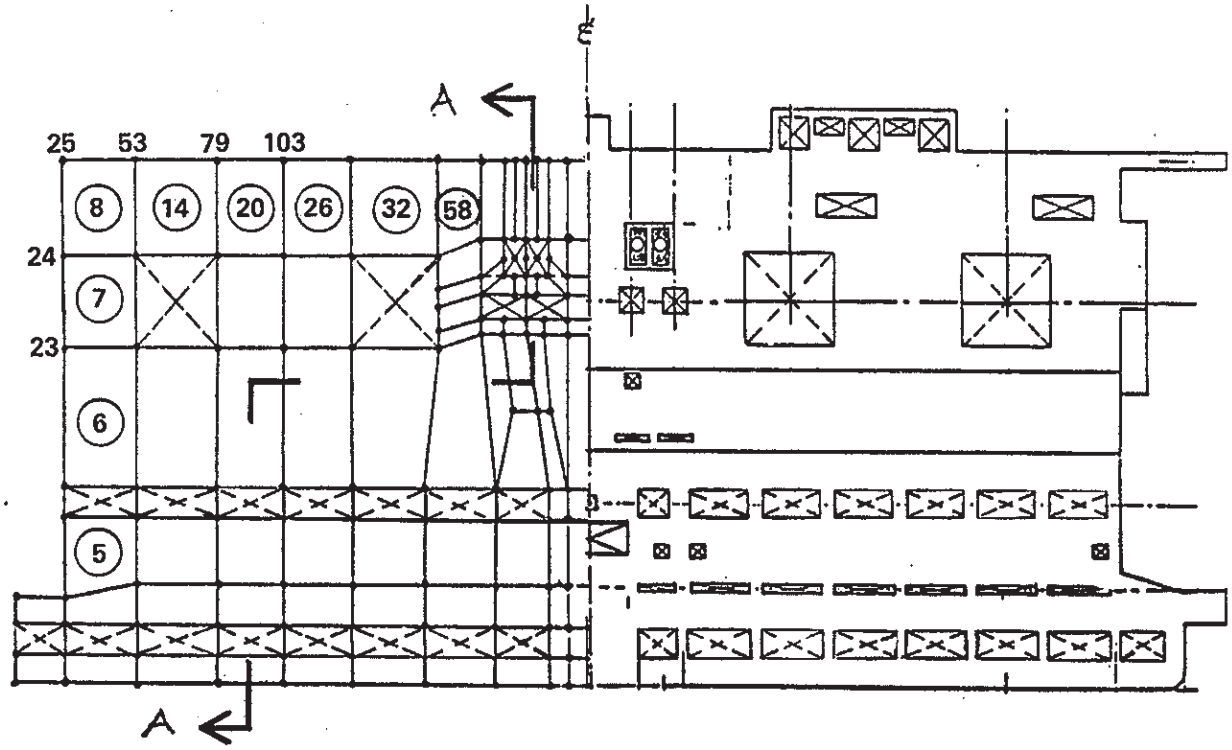


FSAR UPDATE
UNIT 1 **DIABLO CANYON SITE**
FIGURE 3.7 - 15 F TURBINE BUILDING VERTICAL MODEL NO.1 ELEVATION AT LINE 3.5

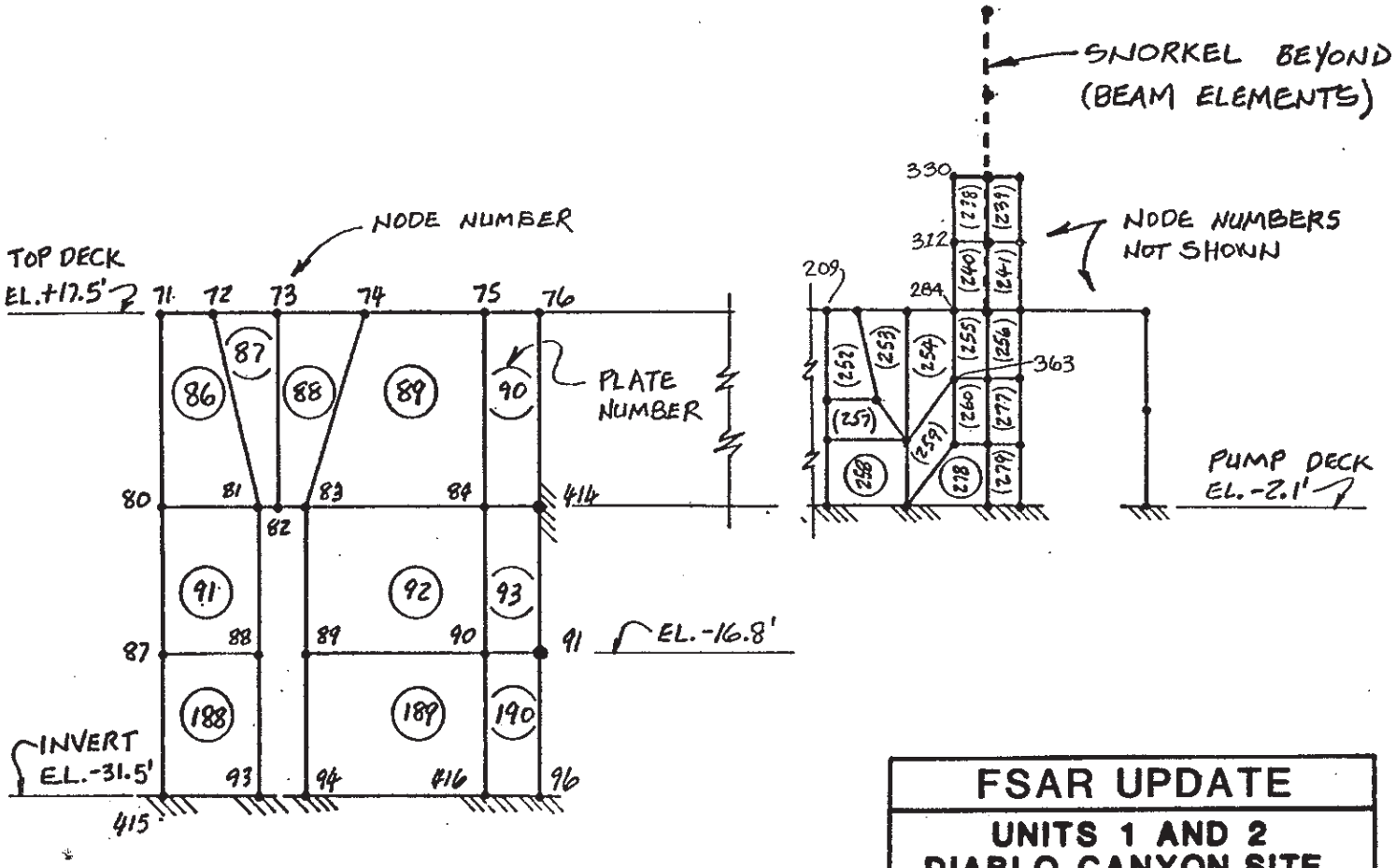


<------ NORTH

FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.7-15G TURBINE PEDESTAL SEISMIC ANALYSIS MODEL



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.7 - 15 H INTAKE STRUCTURE TOP DECK MATHEMATICAL MODEL, ELEVATION + 17.5 FT.

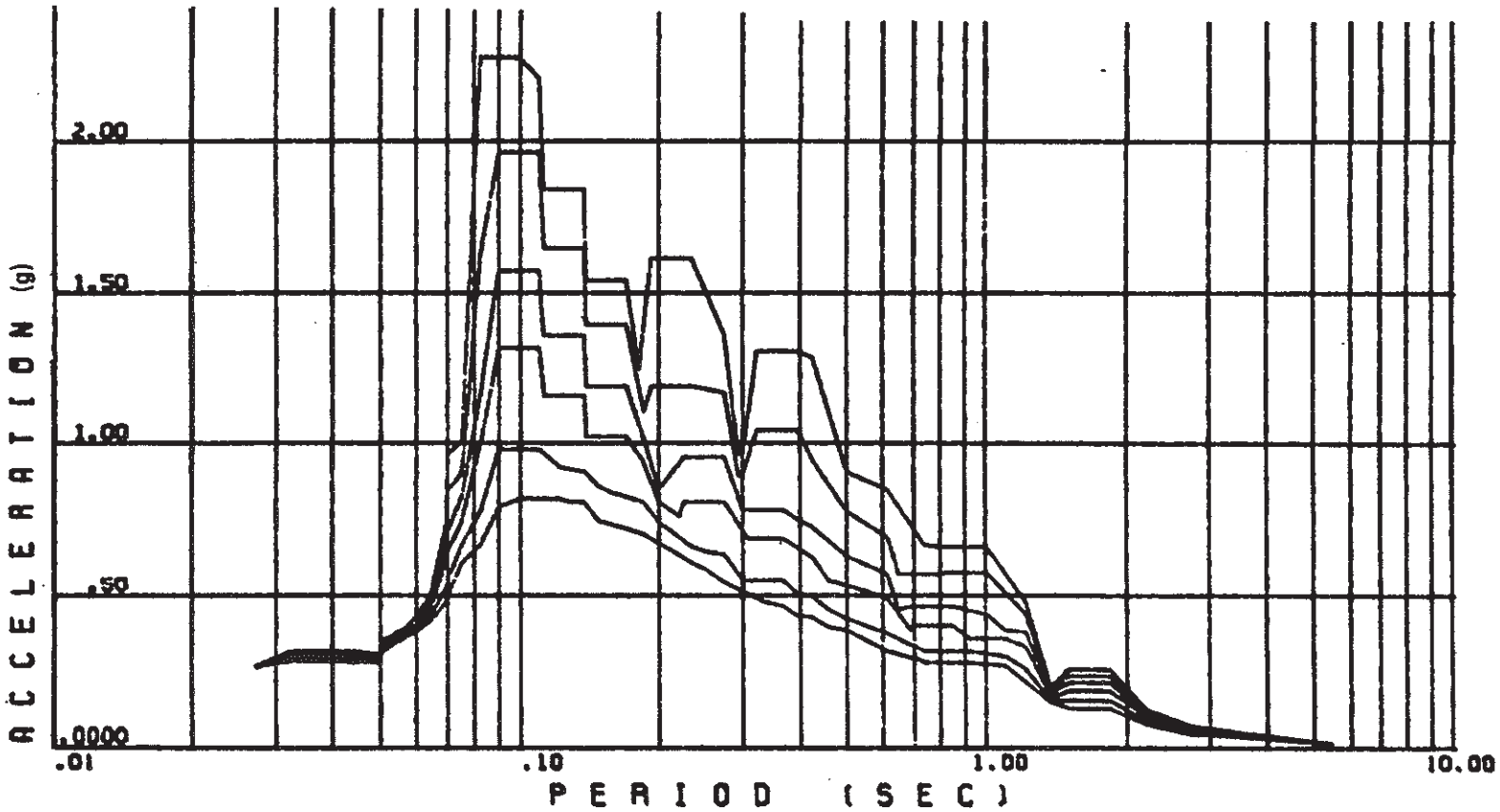


SEE FIG. 3.7-15 H FOR
LOCATION OF
SECTION A–A

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

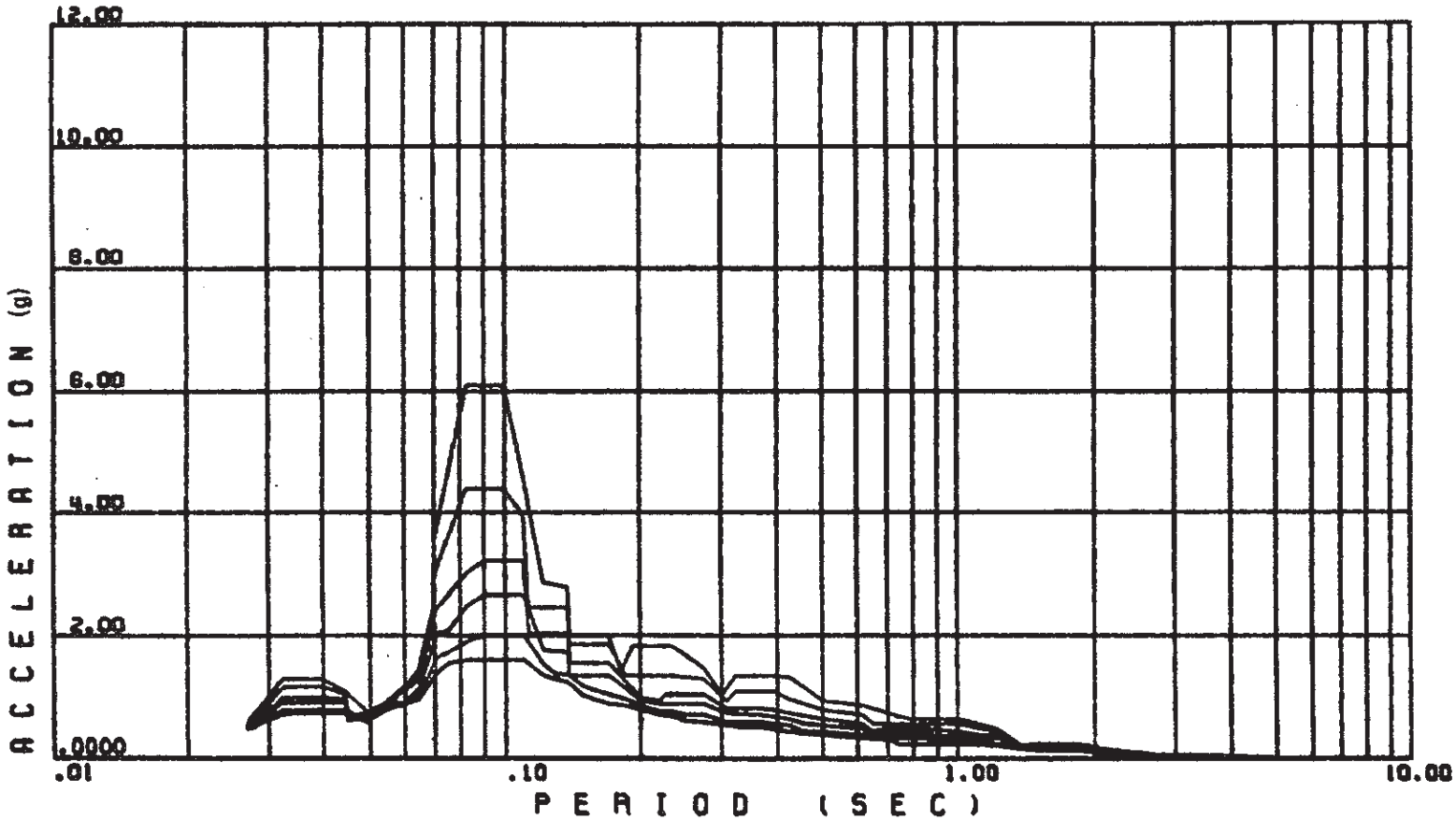
FIGURE 3.7-15 I
INTAKE STRUCTURE
TRANSVERSE SECTION A-A
MATHEMATICAL MODEL



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

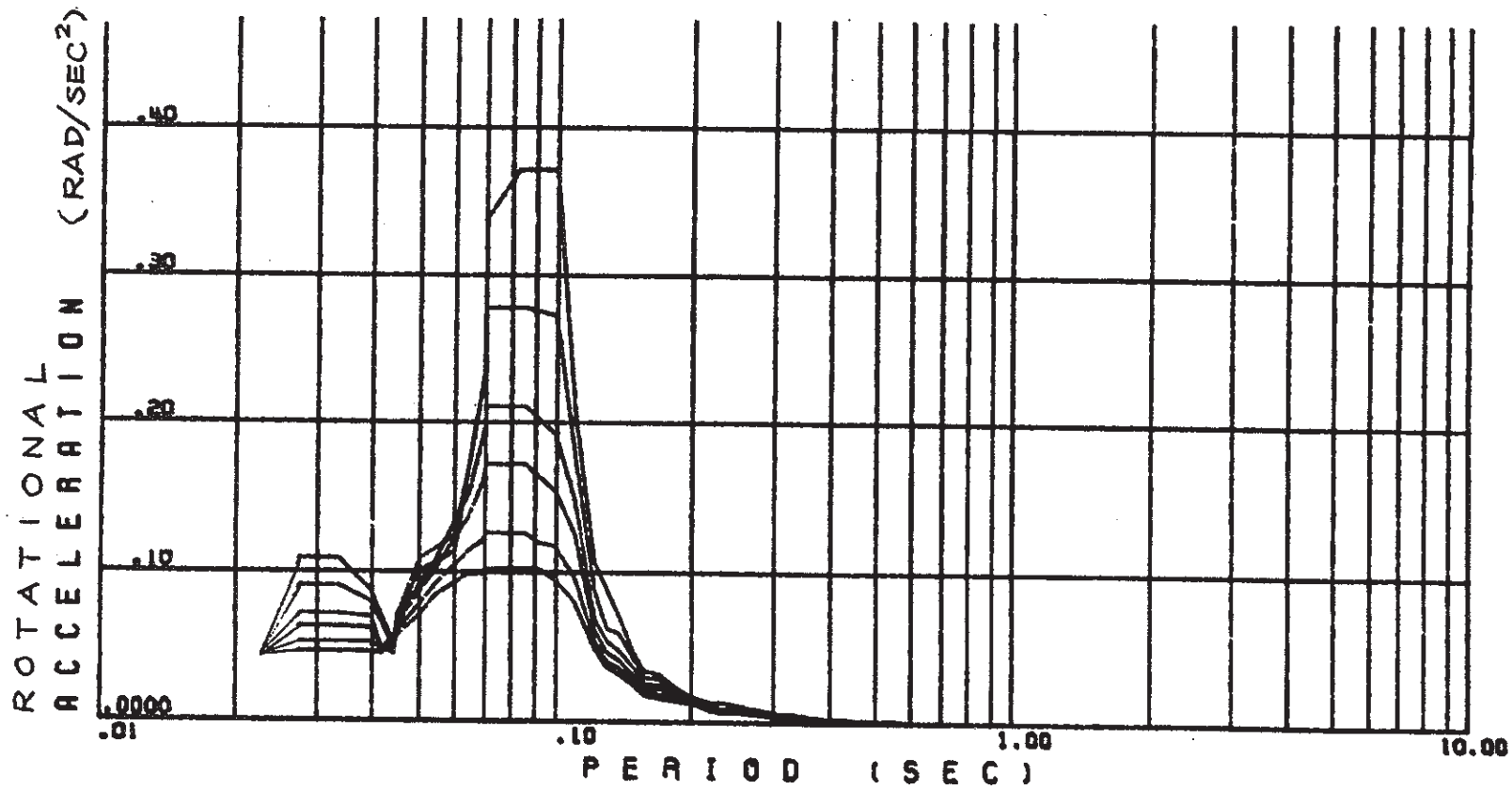
FIGURE 3.7-16
AUXILIARY BUILDING
FLOOR ELEV. 100'–0" N–S
HORIZONTAL SPECTRA
DESIGN EARTHQUAKE
½, 1, 2, 3, 5, 7% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

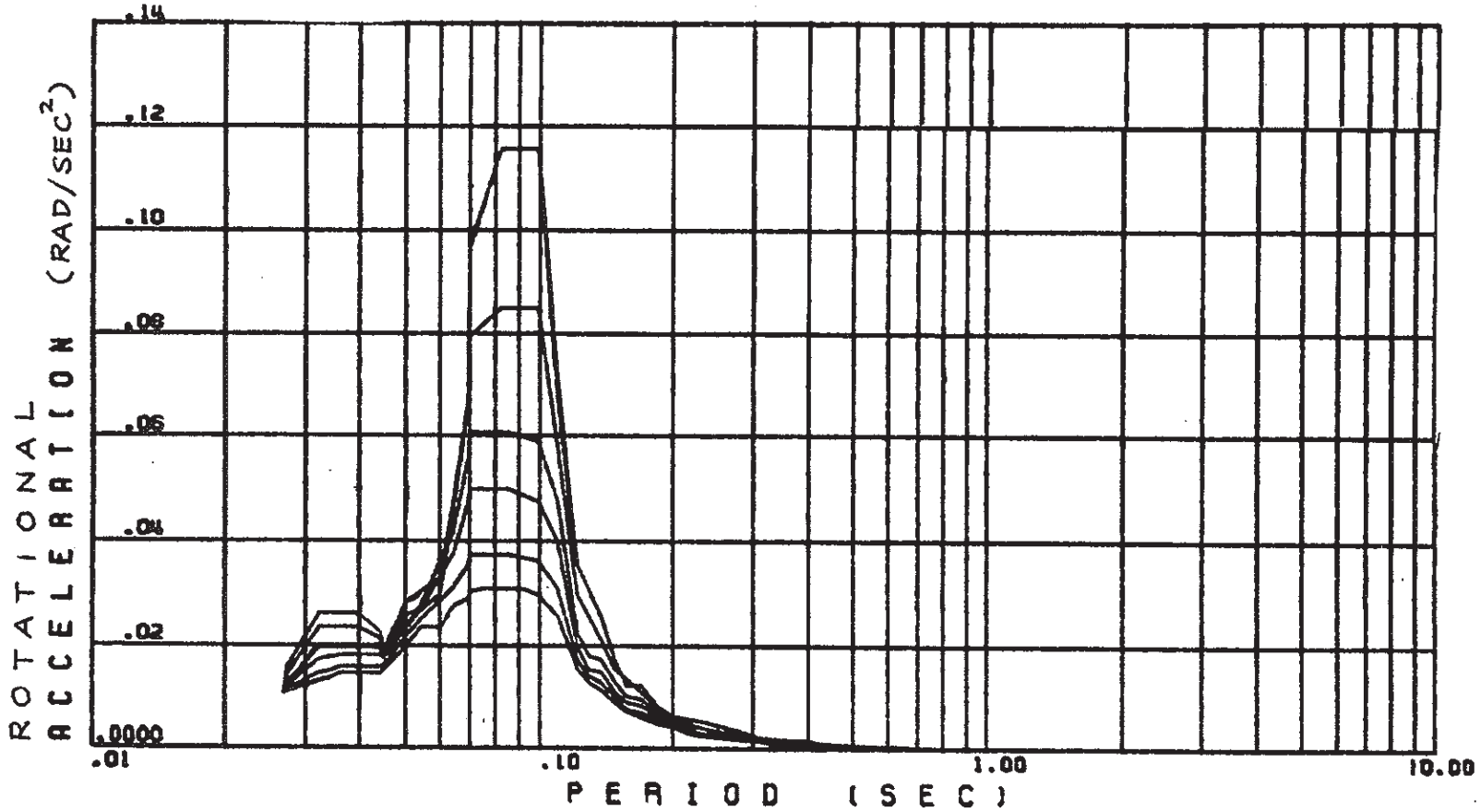
FIGURE 3.7-17
AUXILIARY BUILDING
FLOOR ELEV. 163'–0" N–S
HORIZONTAL SPECTRA
DESIGN EARTHQUAKE
½, 1, 2, 3, 5, 7% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

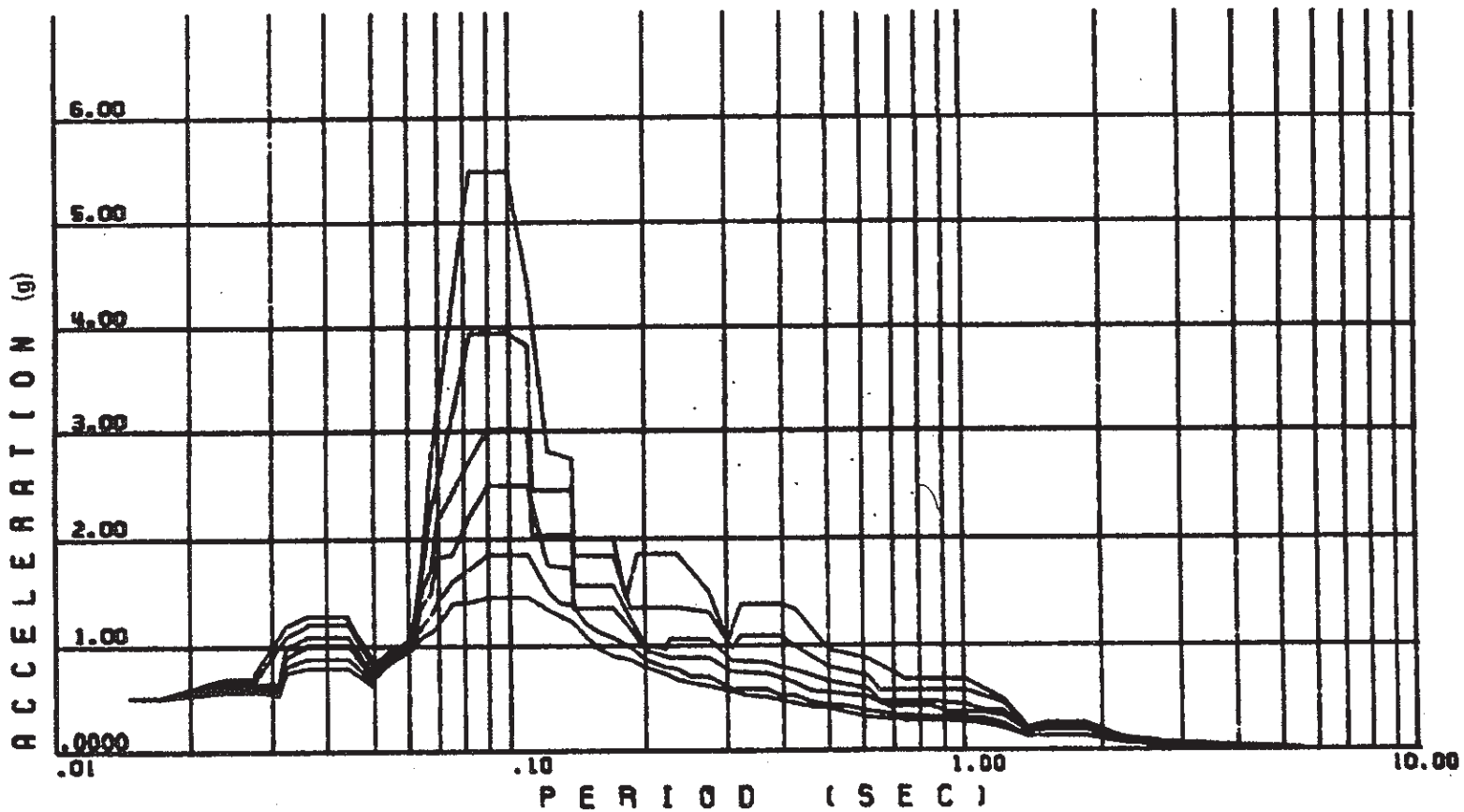
FIGURE 3.7-18
AUXILIARY BUILDING
FLOOR ELEV. 163'–0"
N–S TORSIONAL SPECTRA
DESIGN EARTHQUAKE
½, 1, 2, 3, 5, 7% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

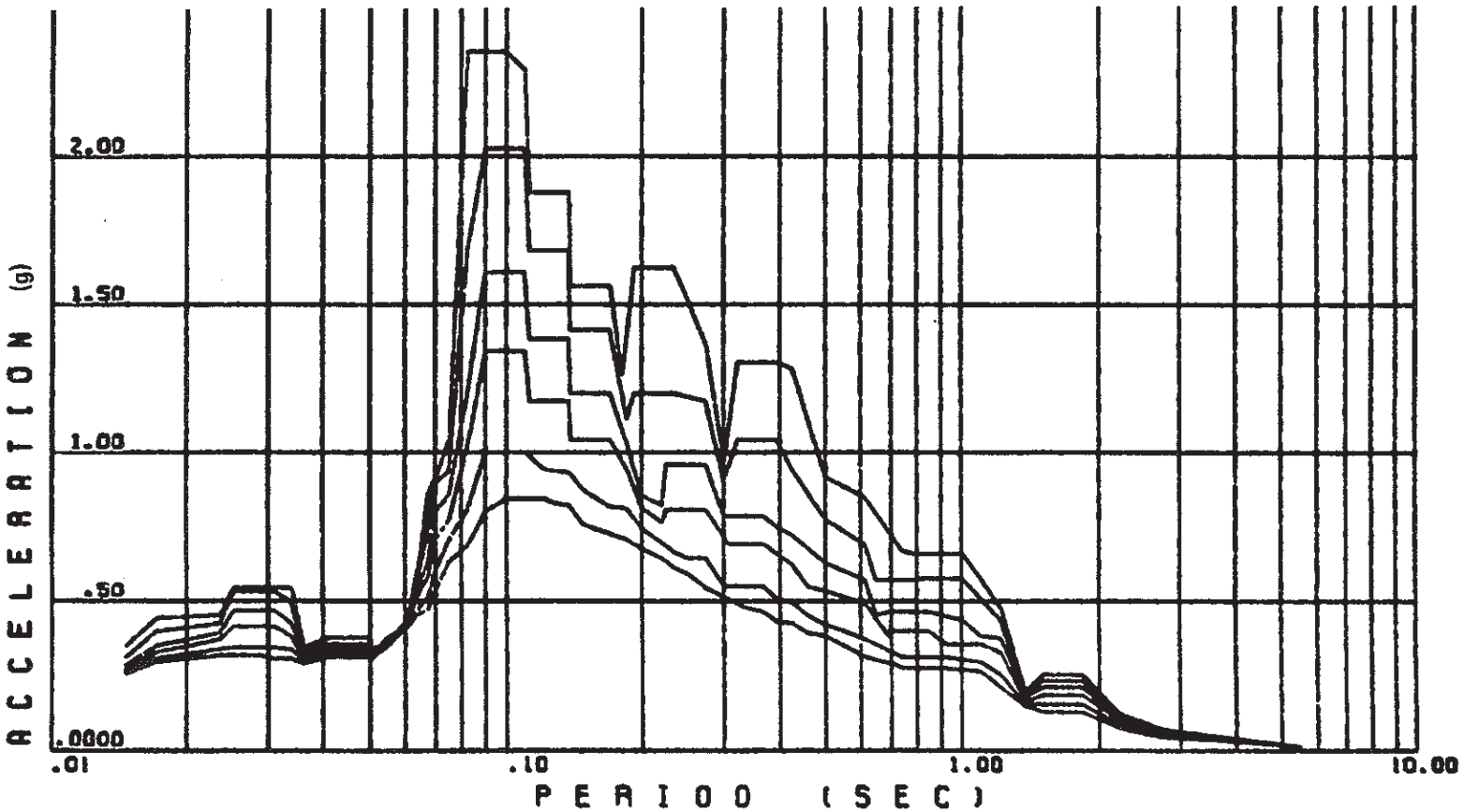
FIGURE 3.7-19
AUXILIARY BUILDING
FLOOR ELEV. 100'–0"
N–S TORSIONAL SPECTRA
DESIGN EARTHQUAKE
½, 1, 2, 3, 5, 7% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

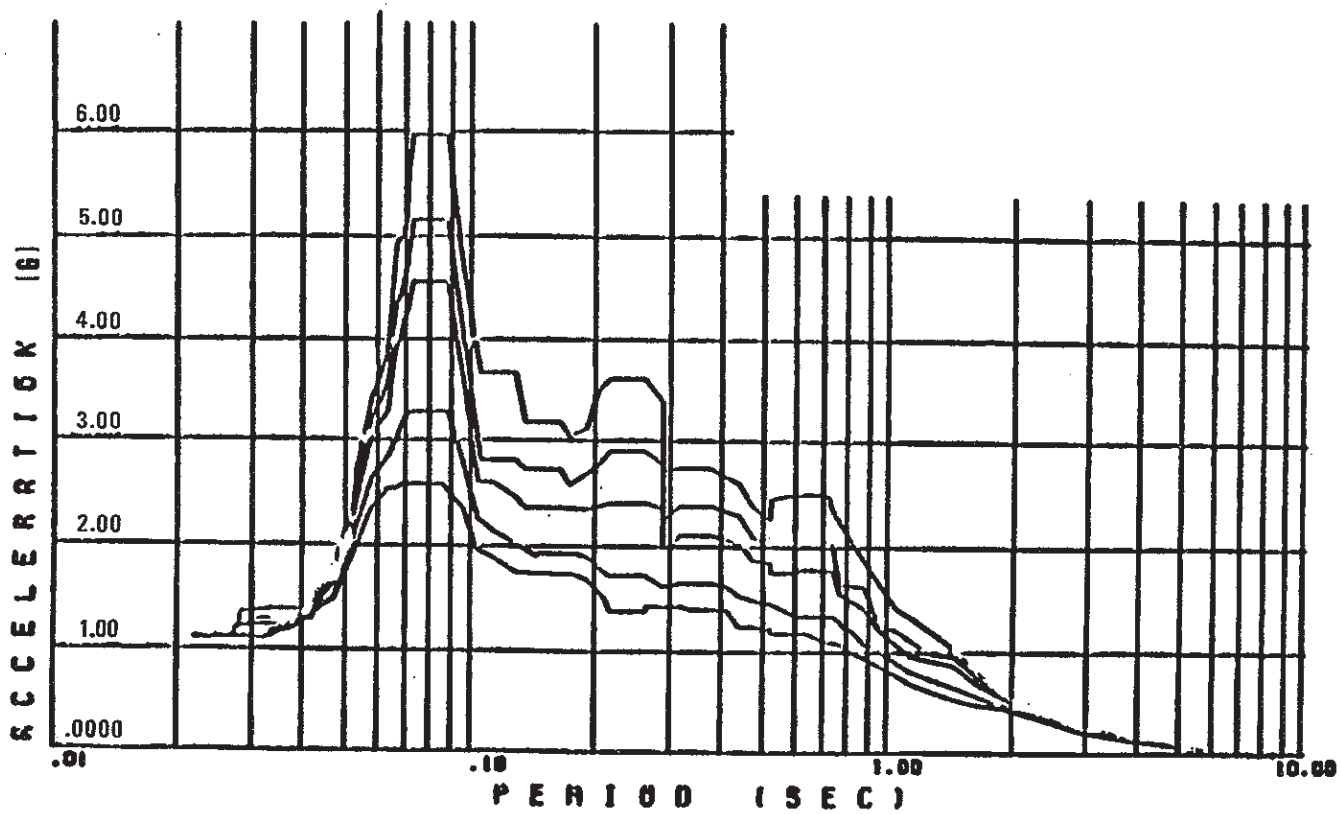
FIGURE 3.7-20
AUXILIARY BUILDING
FLOOR ELEV. 163'–0" E–W
HORIZONTAL SPECTRA
DESIGN EARTHQUAKE
½, 1, 2, 3, 5, 7% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7-21
AUXILIARY BUILDING
FLOOR ELEV. 100'–0"
E–W HORIZONTAL SPECTRA
DESIGN EARTHQUAKE
½, 1, 2, 3, 5, 7% DAMPING

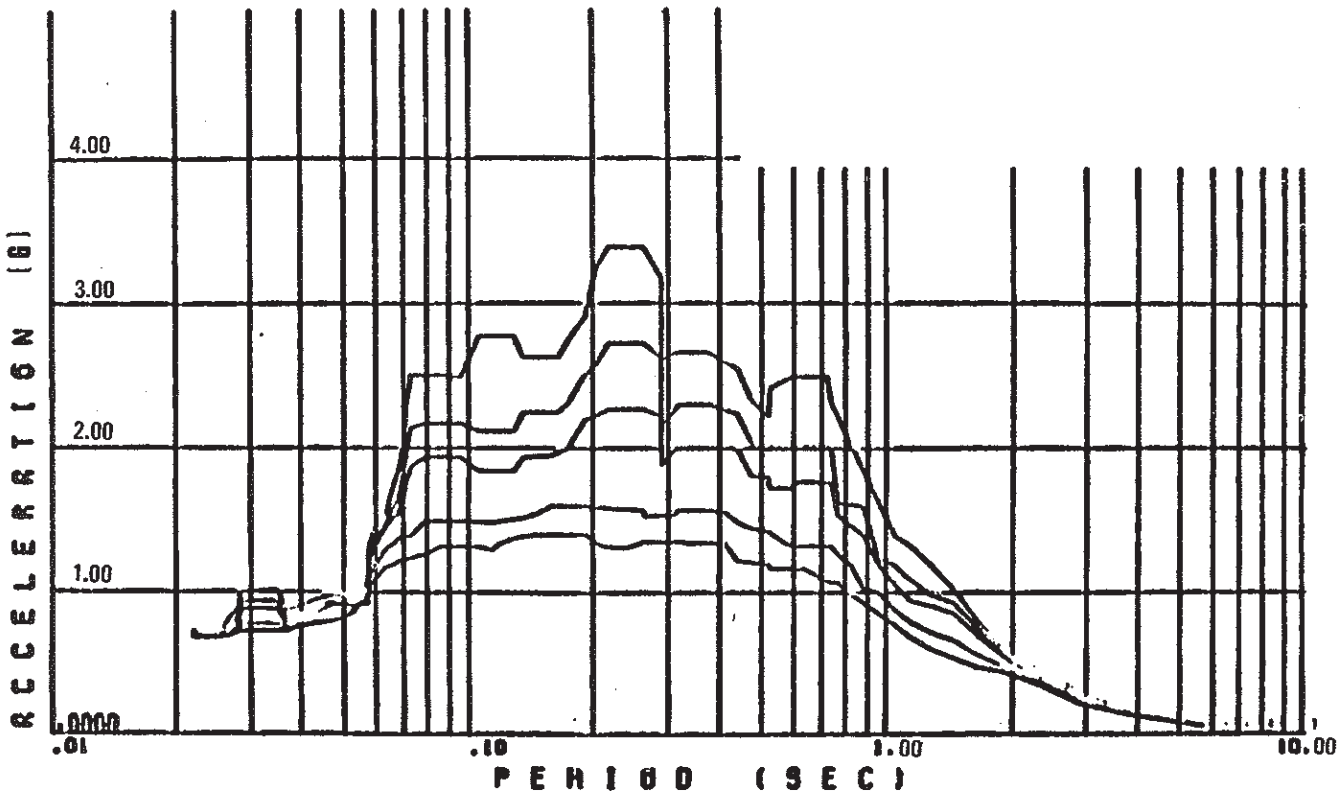


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7–21A

AUXILIARY BUILDING
E–W HOSGRI
HORIZONTAL FLOOR SPECTRA
AT EL 140′–0″
2,3,4,7, AND 10% DAMPING

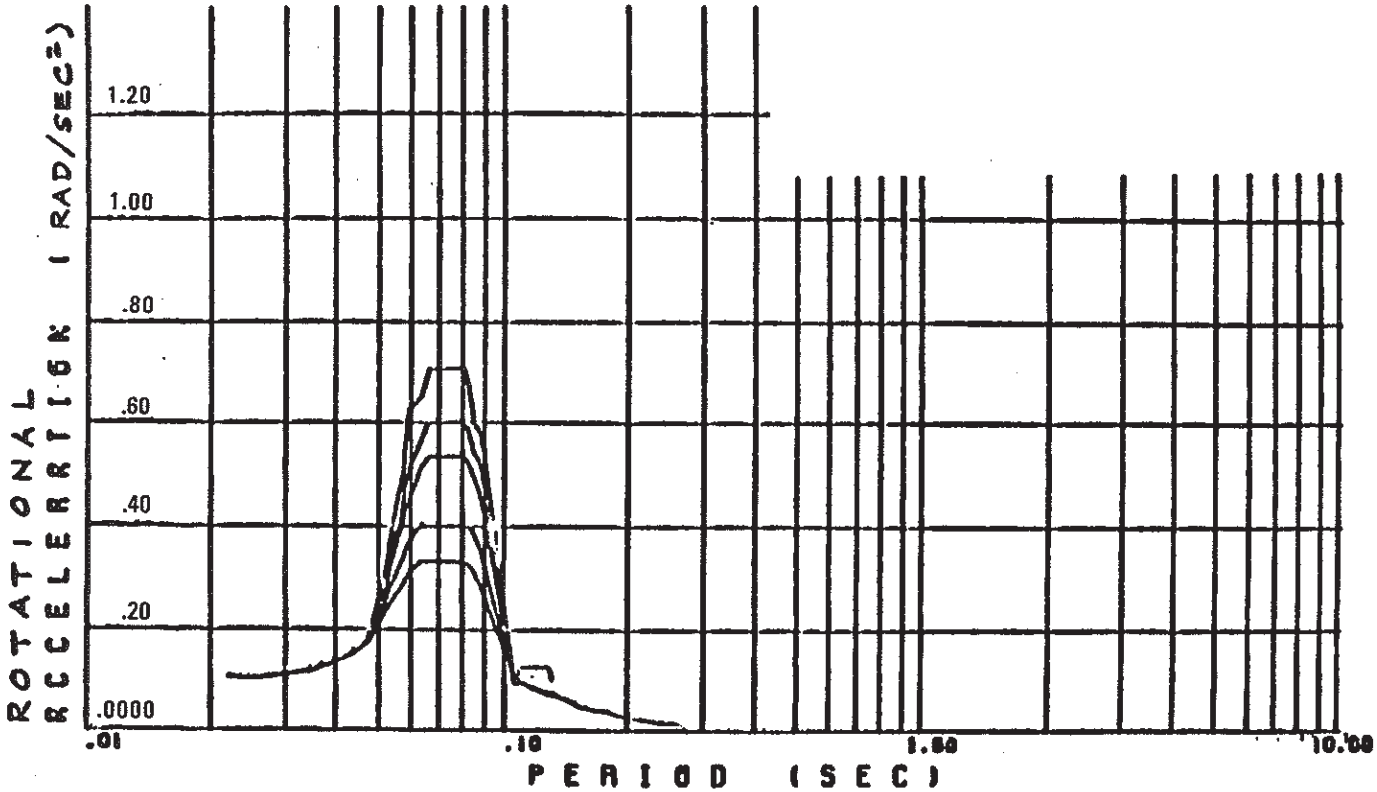


FSAR UPDATE

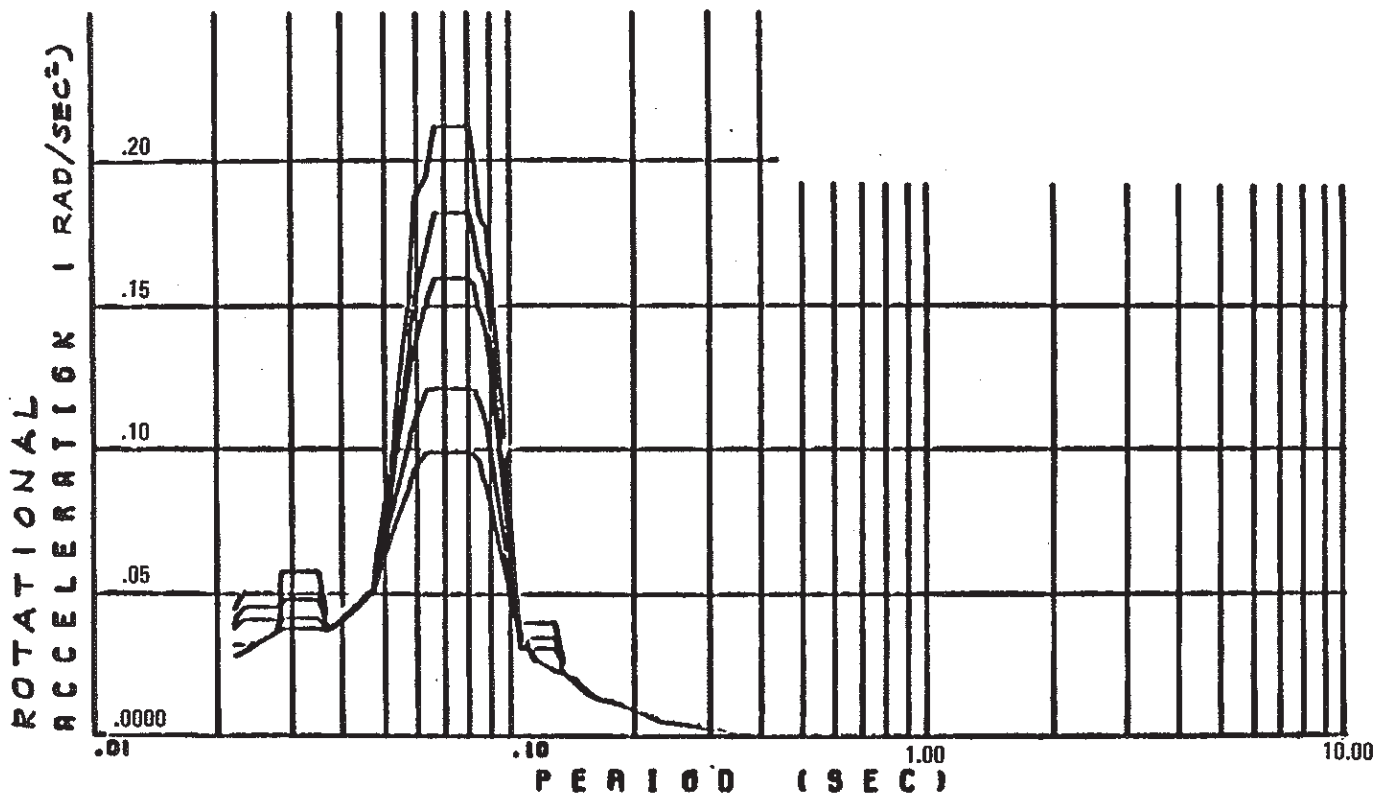
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7–21B

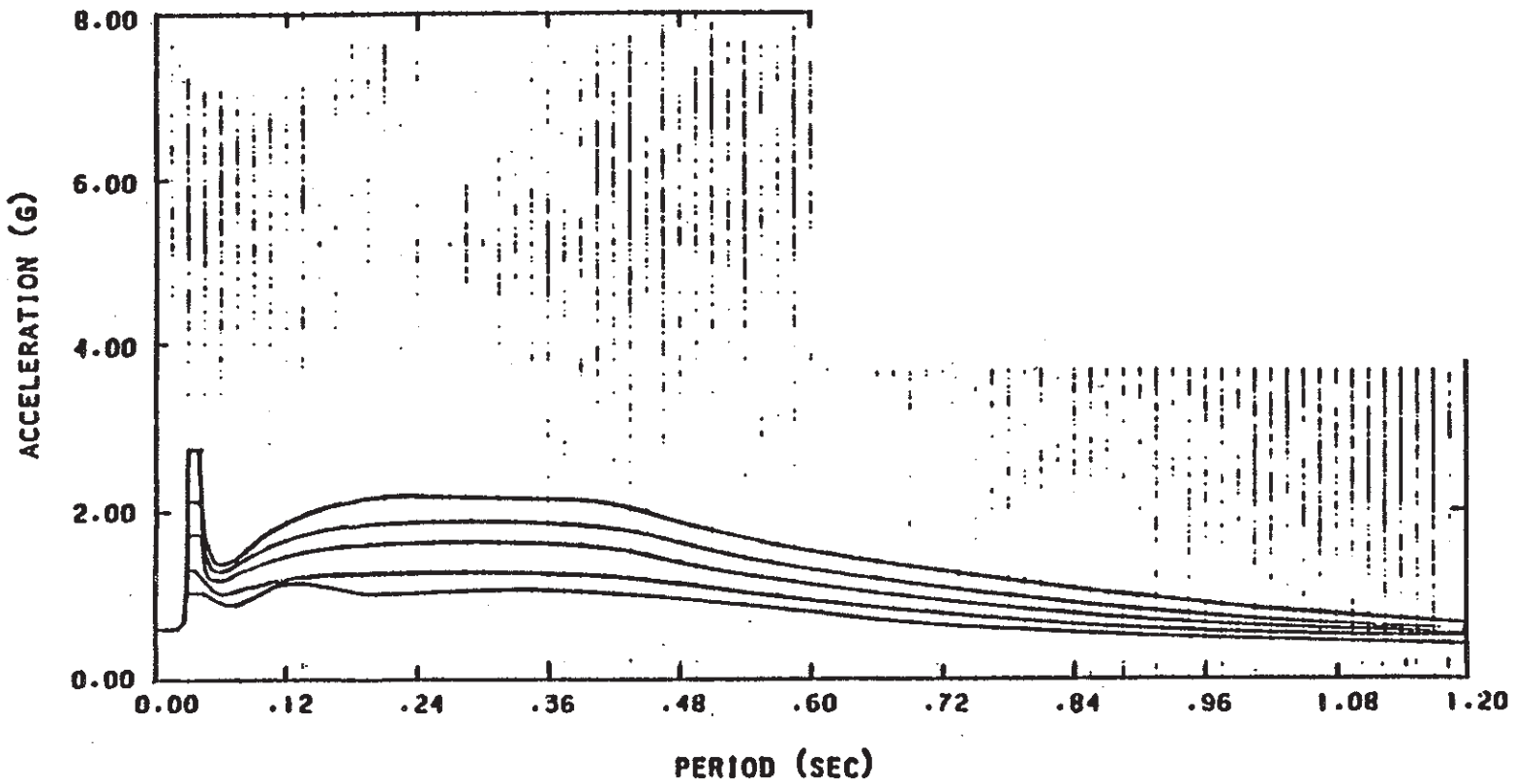
AUXILIARY BUILDING
E–W HOSGRI
HORIZONTAL FLOOR SPECTRA
AT EL 100′–0″
2,3,4,7, AND 10% DAMPING



FSAR UPDATE
UNITS 1 AND 2 **DIABLO CANYON SITE**
FIGURE 3.7–21C **AUXILIARY BUILDING** **E–W HOSGRI** **TORSIONAL FLOOR SPECTRA** **AT EL 140'–0"** **2,3,4,7 and 10% DAMPING**



FSAR UPDATE
UNITS 1 AND 2 **DIABLO CANYON SITE**
FIGURE 3.7–21D **AUXILIARY BUILDING** **E–W HOSGRI** **TORSIONAL FLOOR SPECTRA** **AT EL 100′–0″** **2,3,4,7, AND 10% DAMPING**

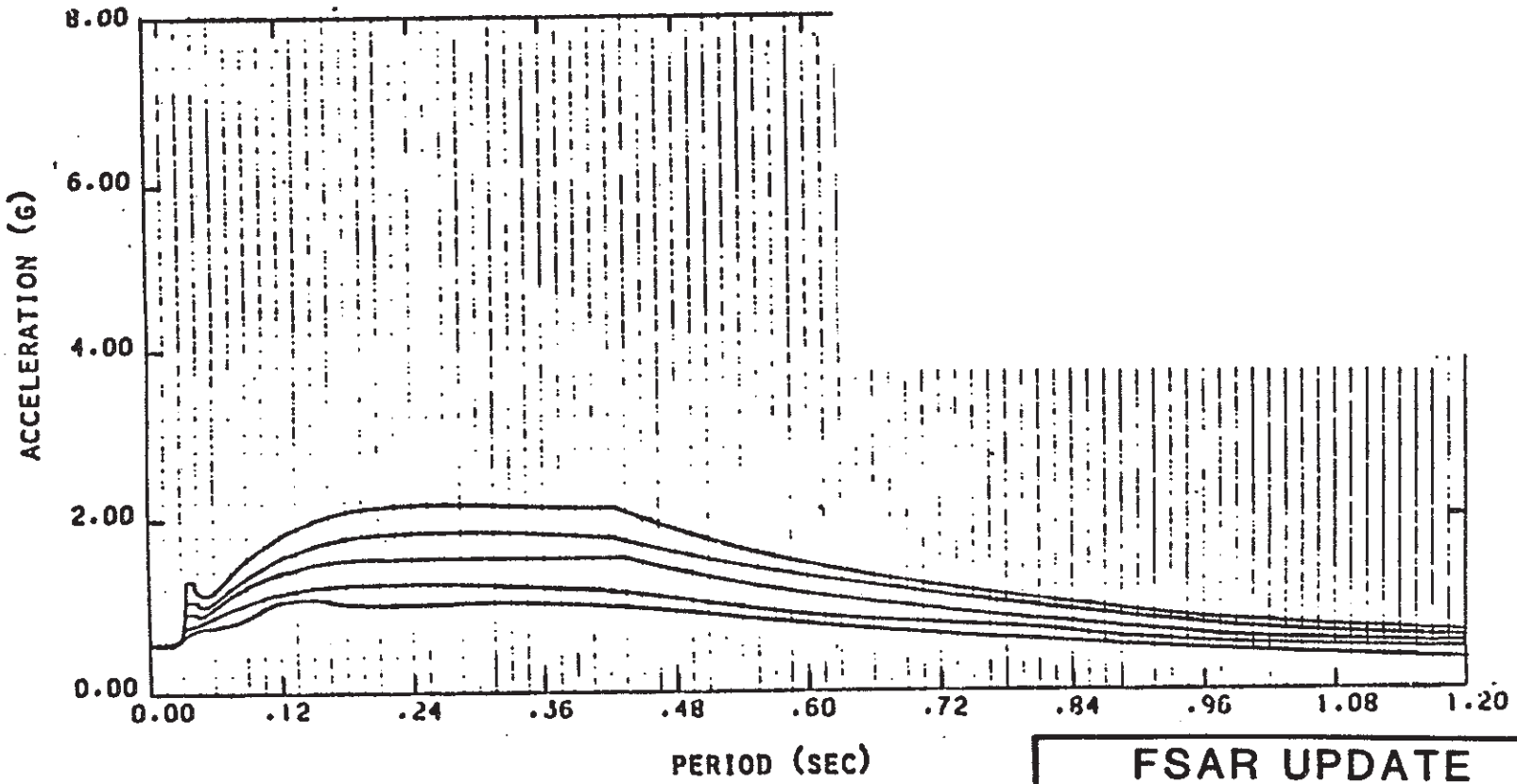


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7–21E

AUXILIARY BUILDING
HOSGRI VERTICAL SPECTRA
AT EL 140'–0"
2,3,4,7, AND 10% DAMPING

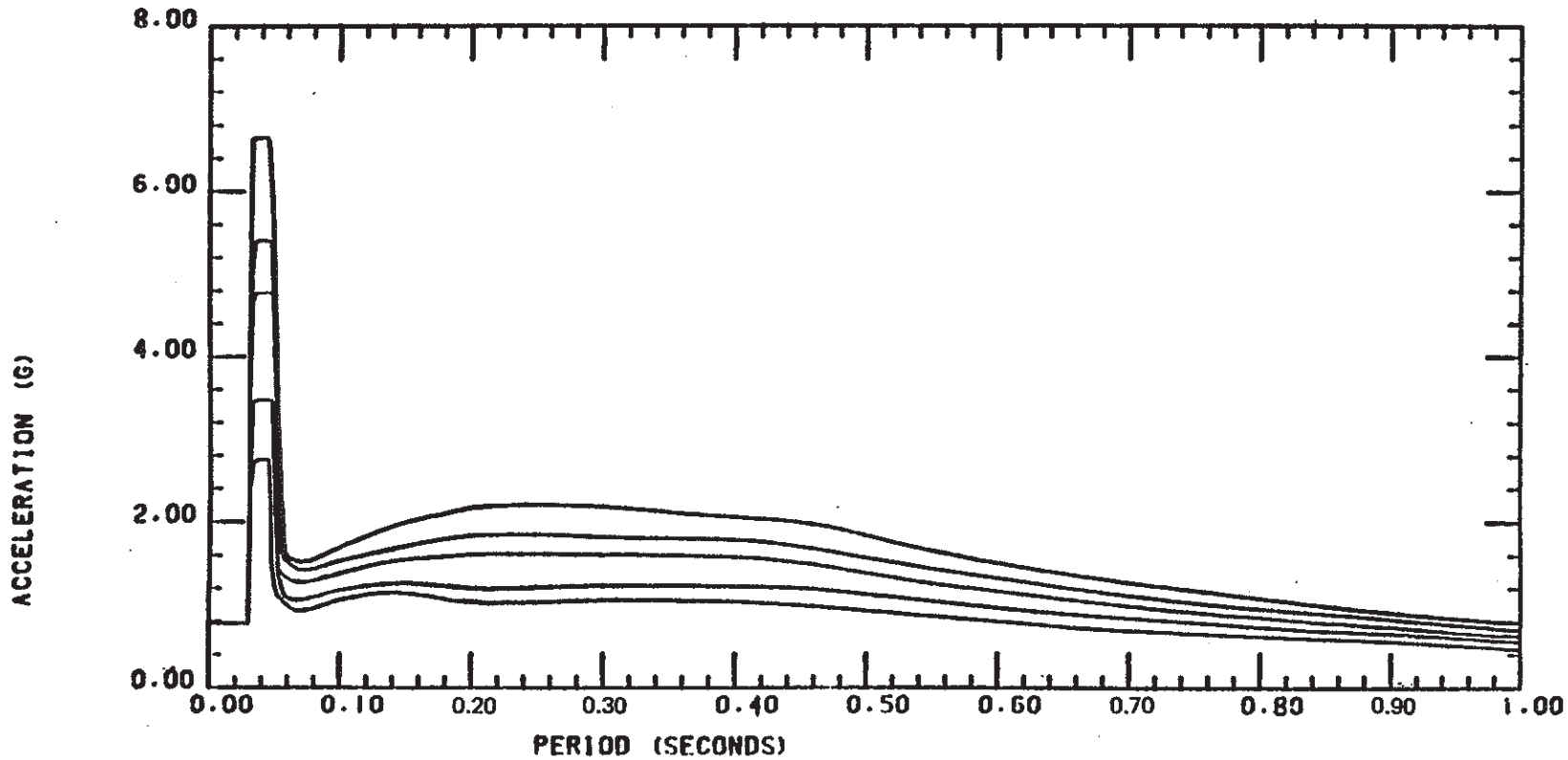


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7–21F

AUXILIARY BUILDING
HOSGRI VERTICAL SPECTRA
AT EL 100′–0″
2,3,4,7, AND 10% DAMPING

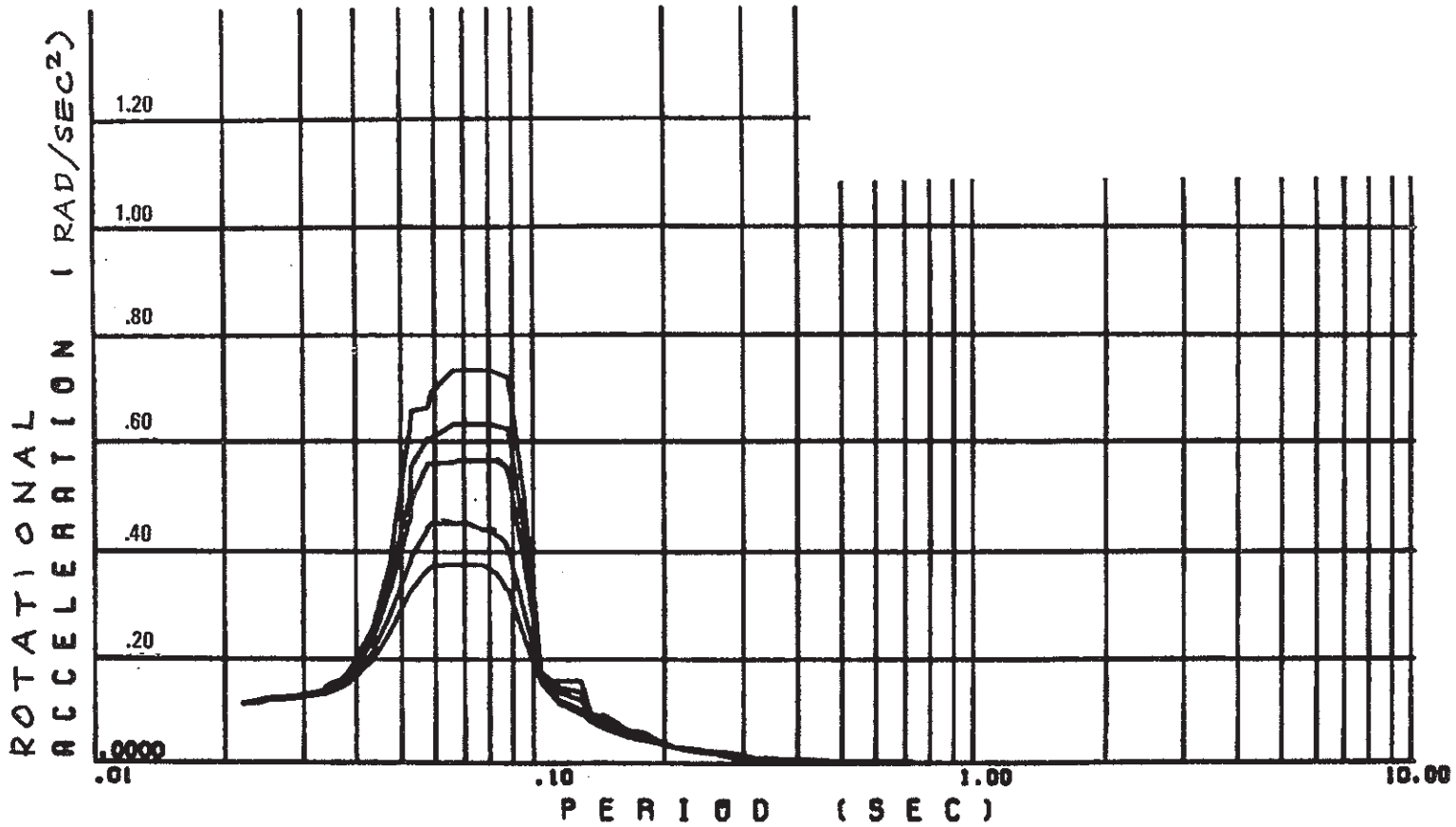


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7–21G

AUXILIARY BUILDING
HOSGRI VERTICAL SPECTRA
EL 100'–0" SLAB 2 NODE 51
2,3,4,7, AND 10%

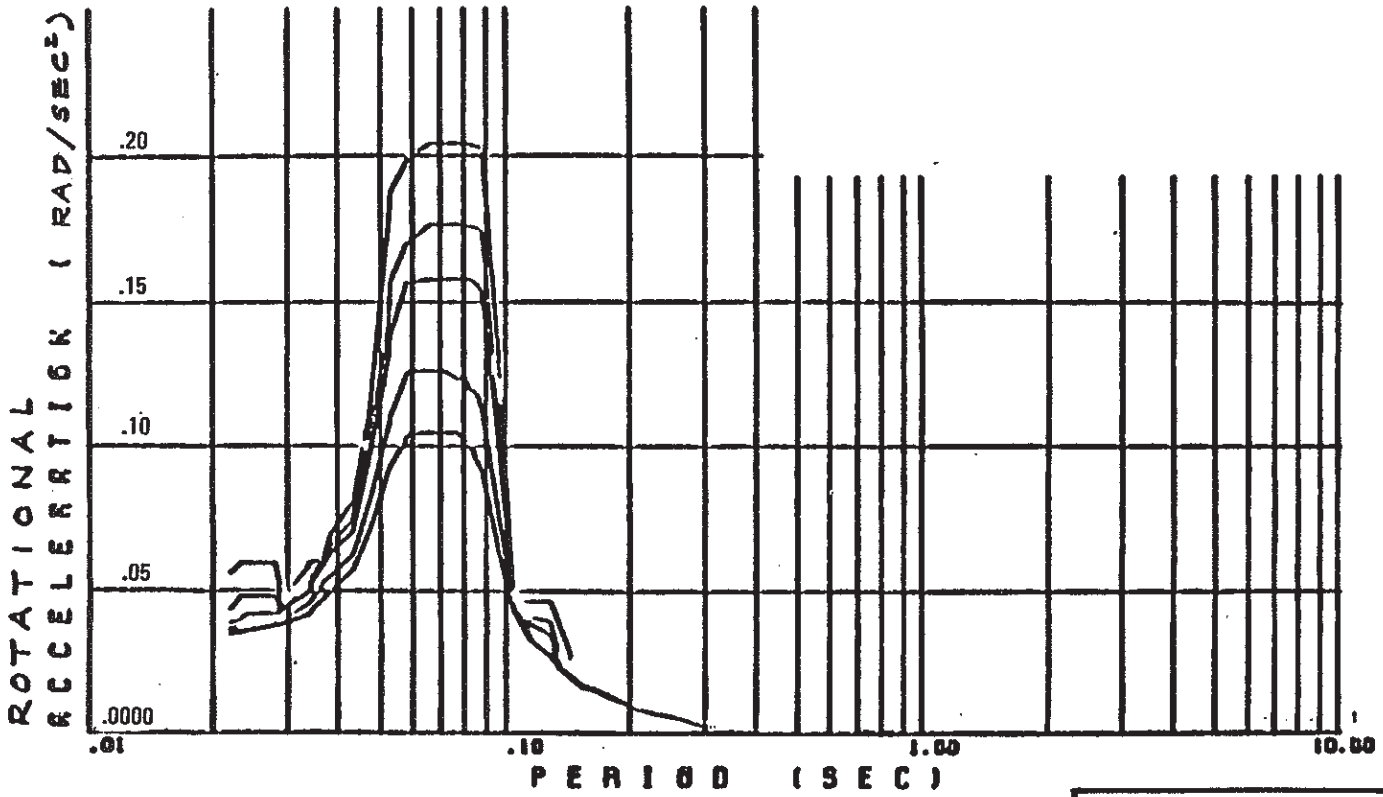


FSAR UPDATE

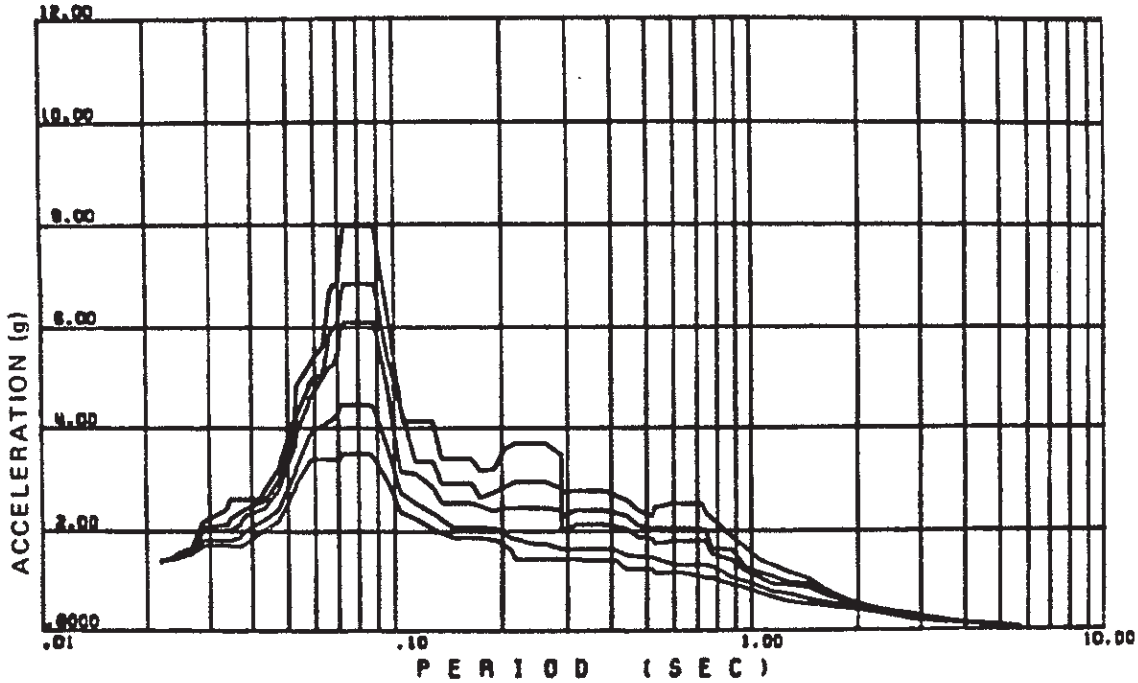
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7–21H

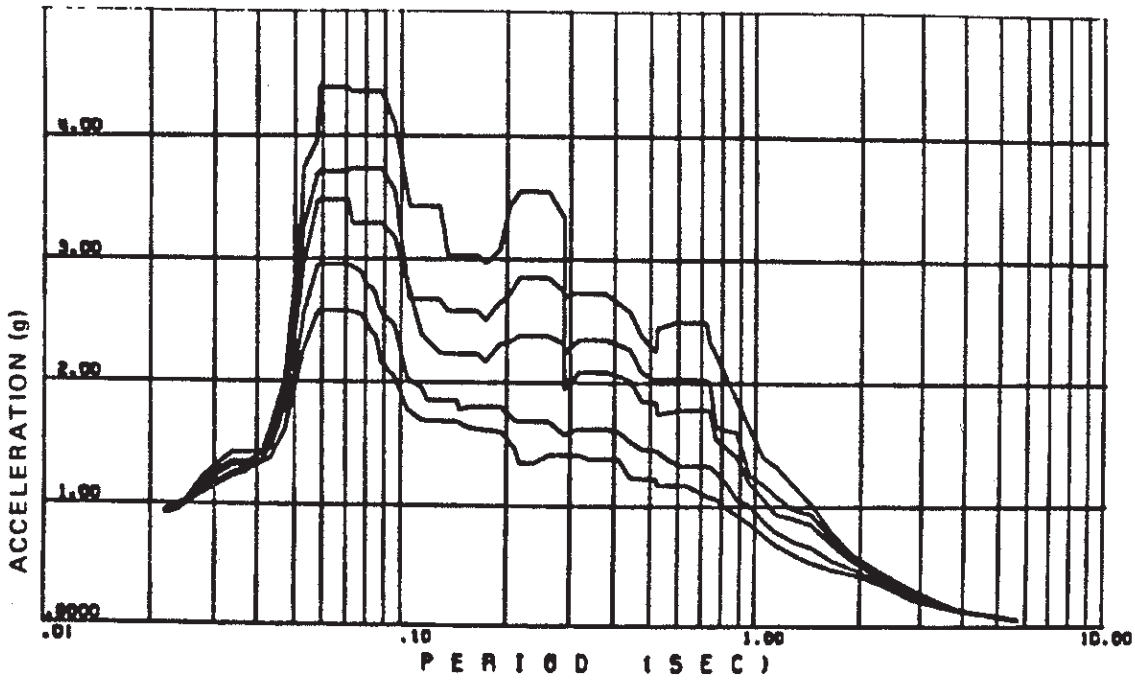
AUXILIARY BUILDING
N–S HOSGRI
TORSIONAL FLOOR SPECTRA
AT EL 140'–0"
2,3,4,7, AND 10% DAMPING



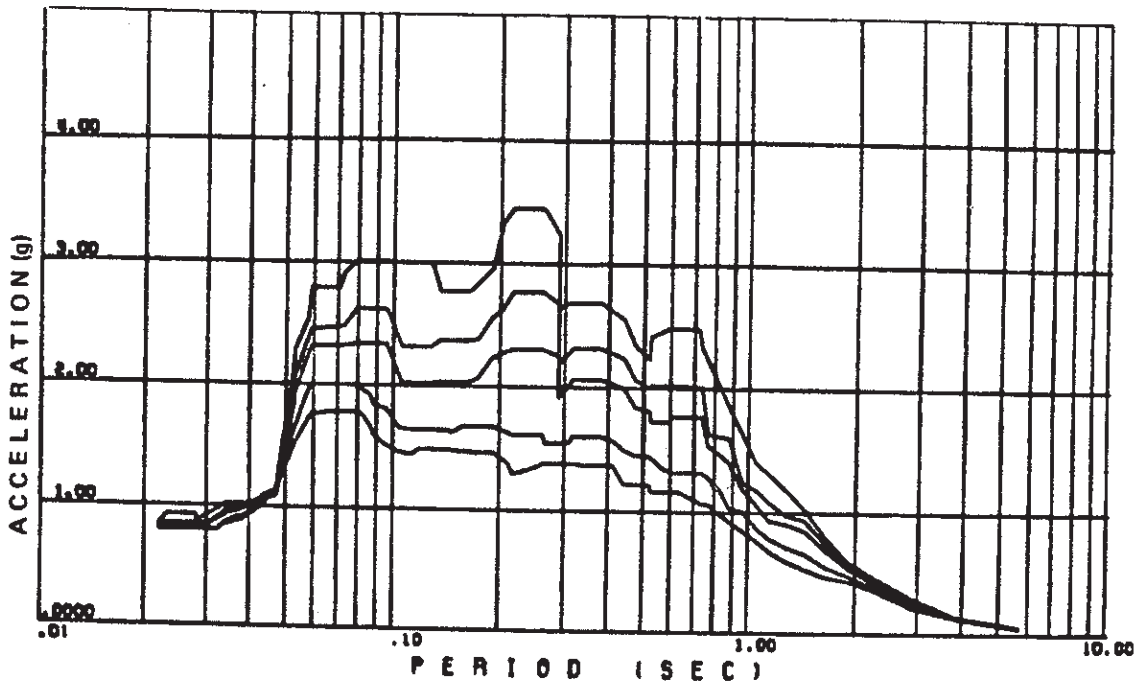
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.7–21I AUXILIARY BUILDING N–S HOSGRI TORSIONAL FLOOR SPECTRA AT EL 100′–0″ 2,3,4,7,AND 10% DAMPING



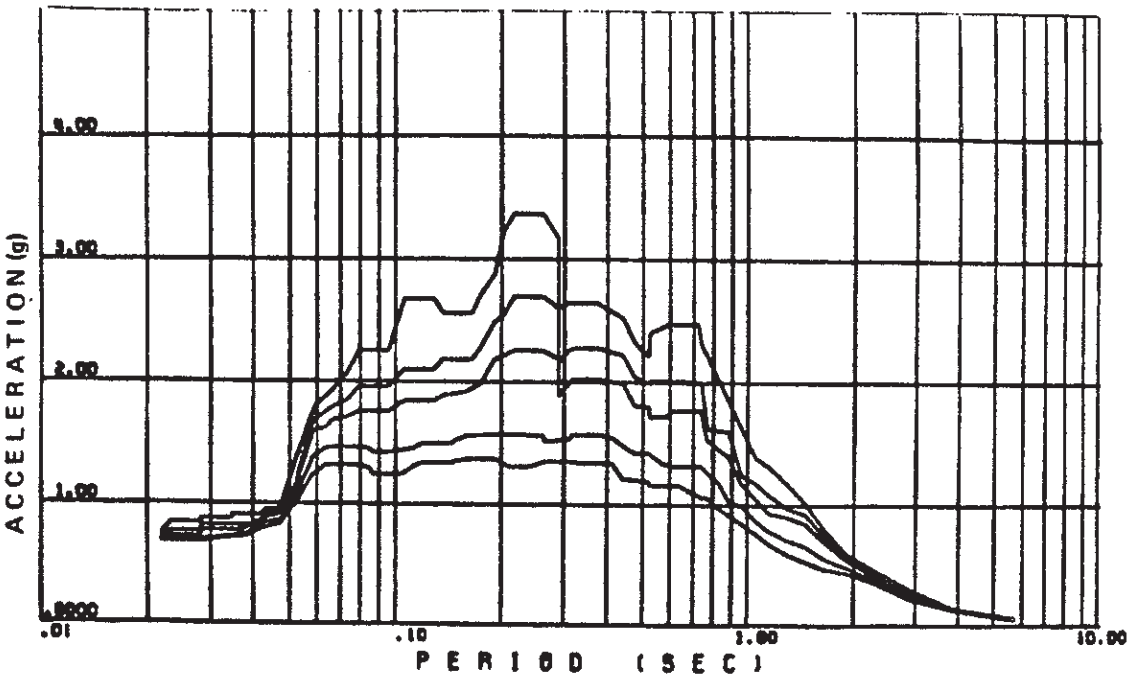
FSAR UPDATE
UNITS 1 AND 2 **DIABLO CANYON SITE**
FIGURE 3.7-22 AUXILIARY BUILDING N–S HOSGRI HORIZONTAL FLOOR SPECTRA AT EL 163'-0" NODE 1 2, 3, 4, 7, AND 10% DAMPING



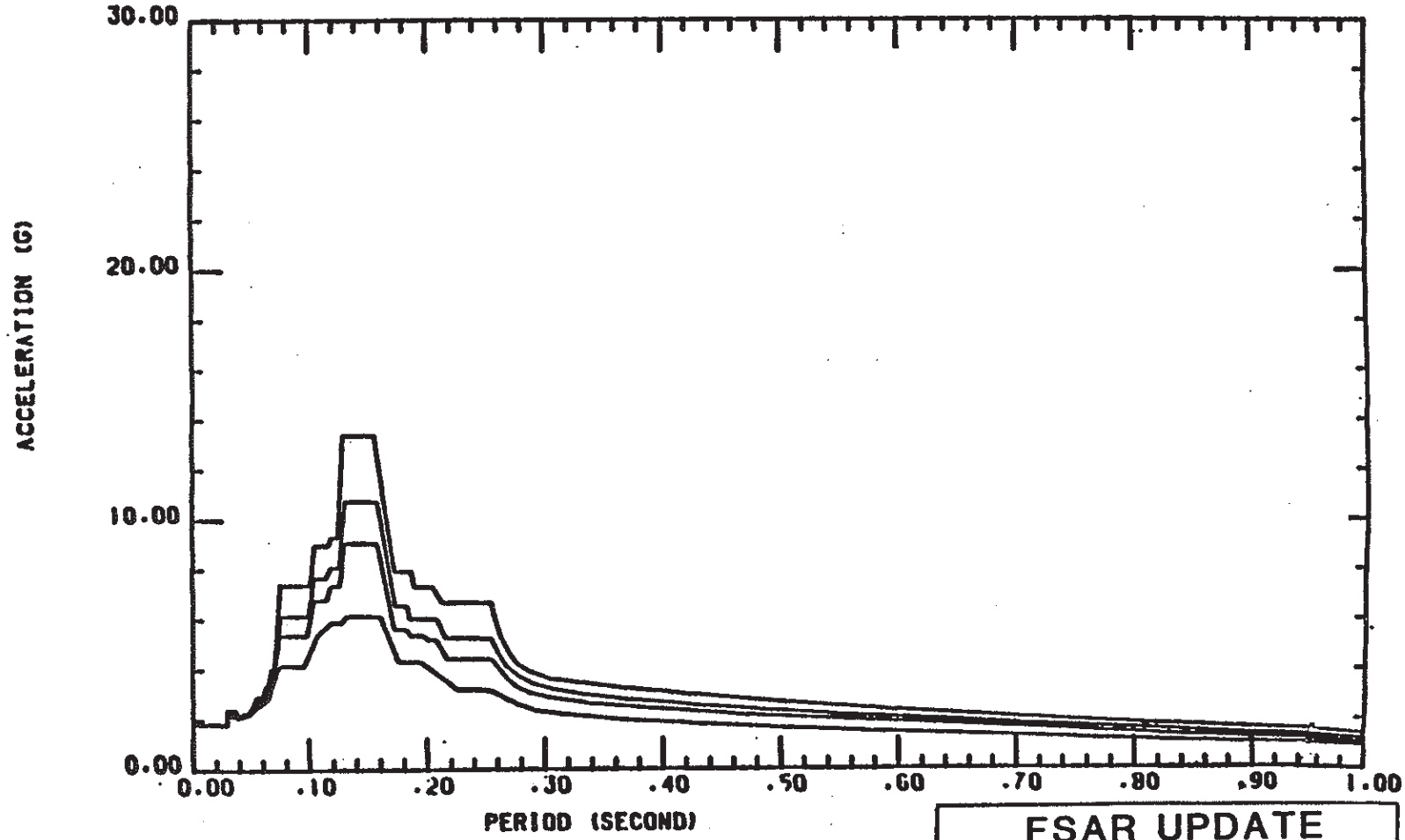
FSAR UPDATE
UNITS 1 AND 2 **DIABLO CANYON SITE**
FIGURE 3.7-23 AUXILIARY BUILDING N–S HOSGRI HORIZONTAL FLOOR SPECTRA AT EL 140'-0" NODE 2 2, 3, 4, 7, AND 10% DAMPING



FSAR UPDATE
UNITS 1 AND 2 **DIABLO CANYON SITE**
FIGURE 3.7-24 AUXILIARY BUILDING N–S HOSGRI HORIZONTAL FLOOR SPECTRA AT EL 115'-0" NODE 3 2, 3, 4, 7, AND 10% DAMPING



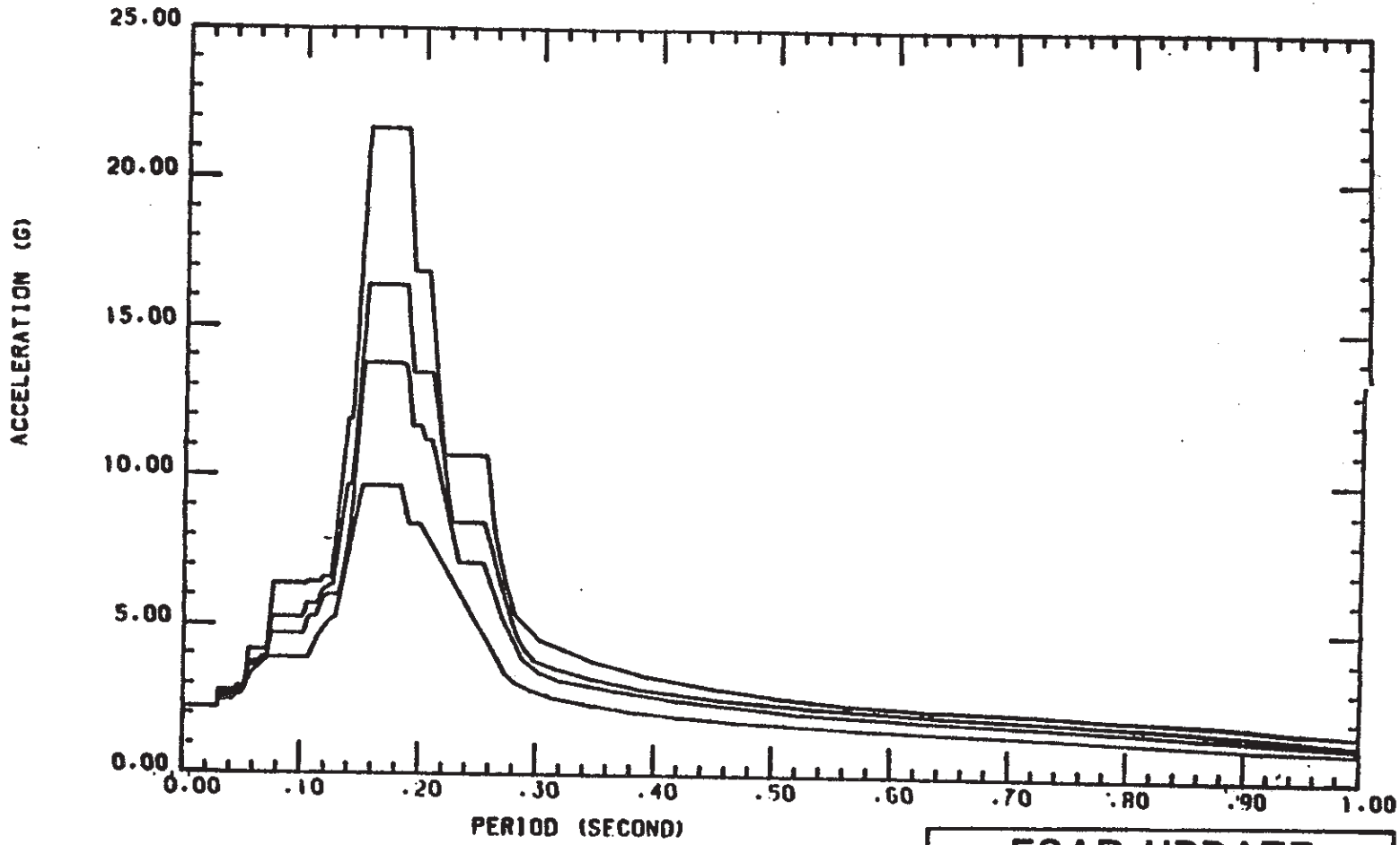
FSAR UPDATE
UNITS 1 AND 2 **DIABLO CANYON SITE**
FIGURE 3.7-25 AUXILIARY BUILDING N–S HOSGRI HORIZONTAL FLOOR SPECTRA AT EL 100'-0" NODE 4 2, 3, 4, 7, AND 10% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

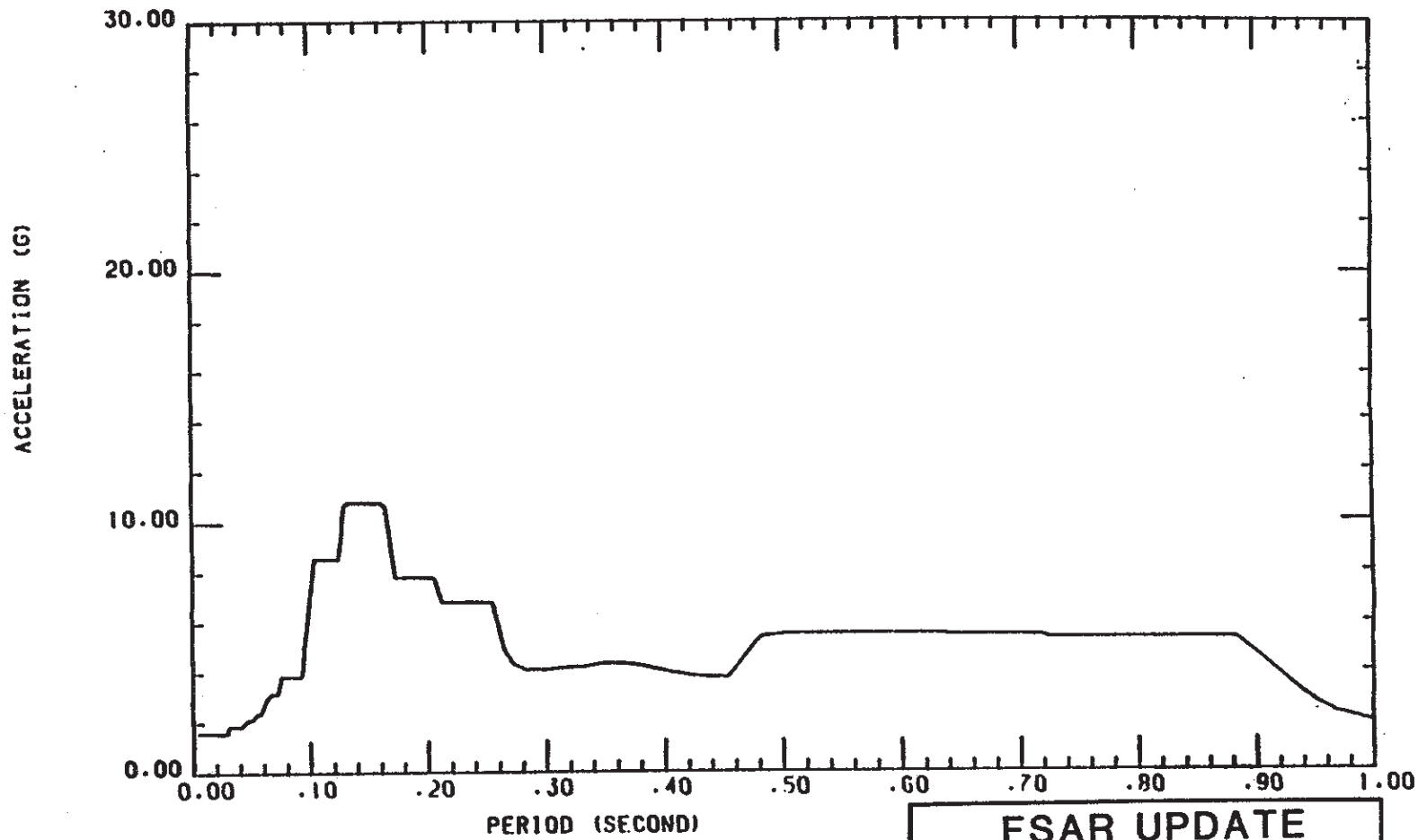
FIGURE 3.7 - 25 A
TURBINE BUILDING
EL. 119'
4 KV SWITCHGEAR AREA
COLUMN LINES 1-4, D-G
HOSGRI E-W SPECTRA
2,3,4,7% DAMPING



FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

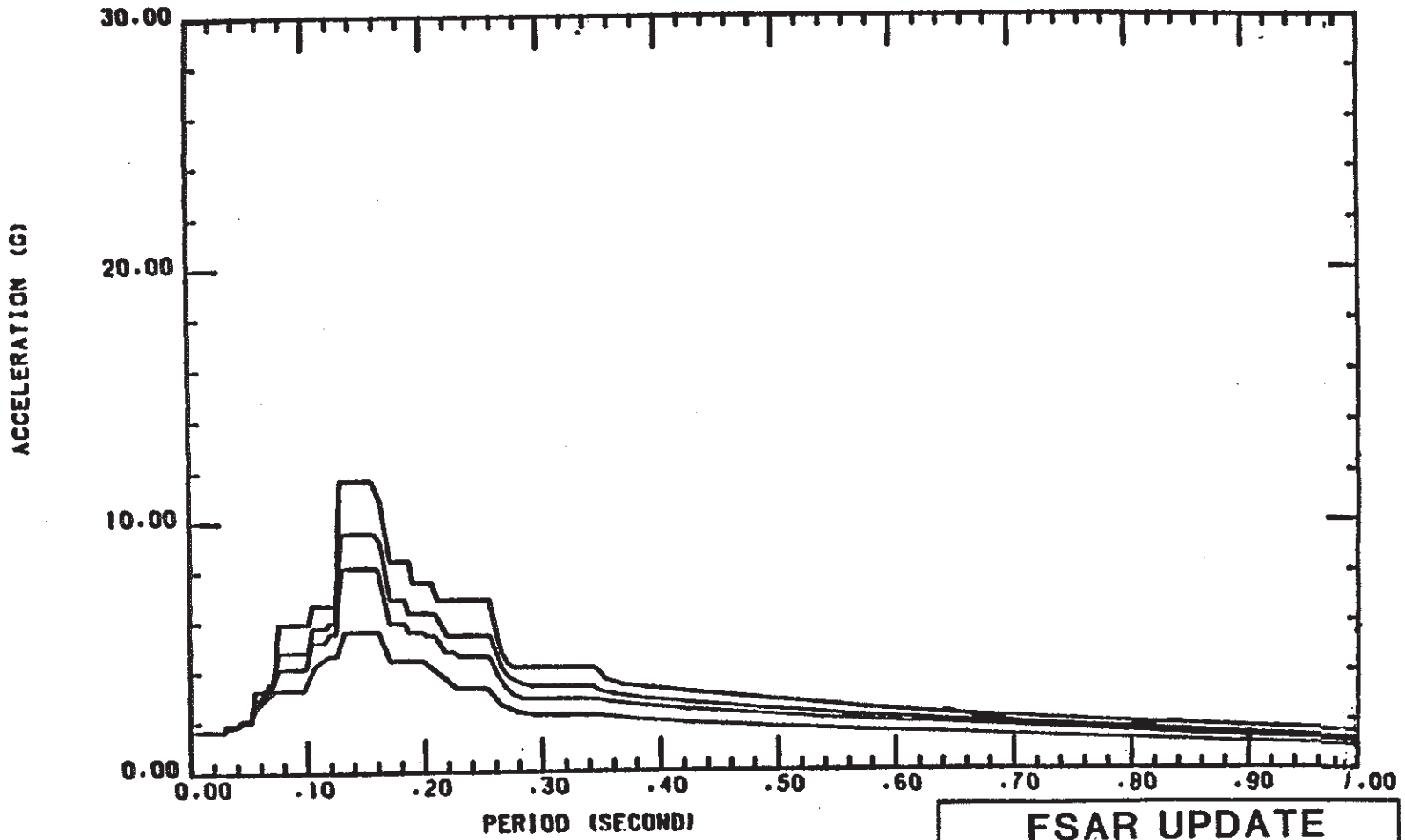
FIGURE 3.7 - 25B
TURBINE BUILDING EL. 140'
COLUMN LINES 5-15
HOSGRI E-W SPECTRA
2, 3, 4, 7% DAMPING



FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

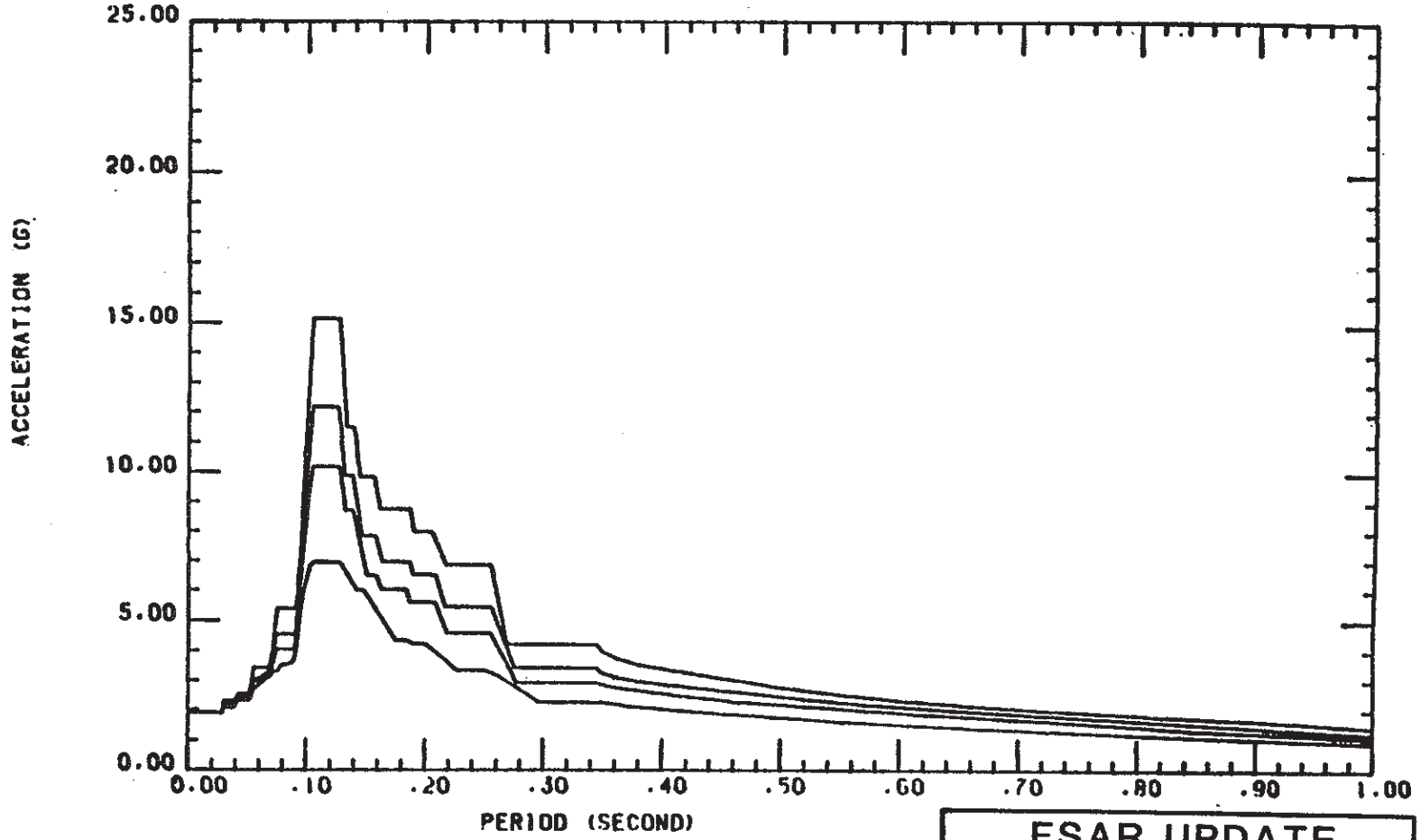
FIGURE 3.7 - 25 C
TURBINE BUILDING
ROOF LEVEL
COLUMN LINES 1 to 1.9, A-D
HOSGRI E - W SPECTRA
3% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

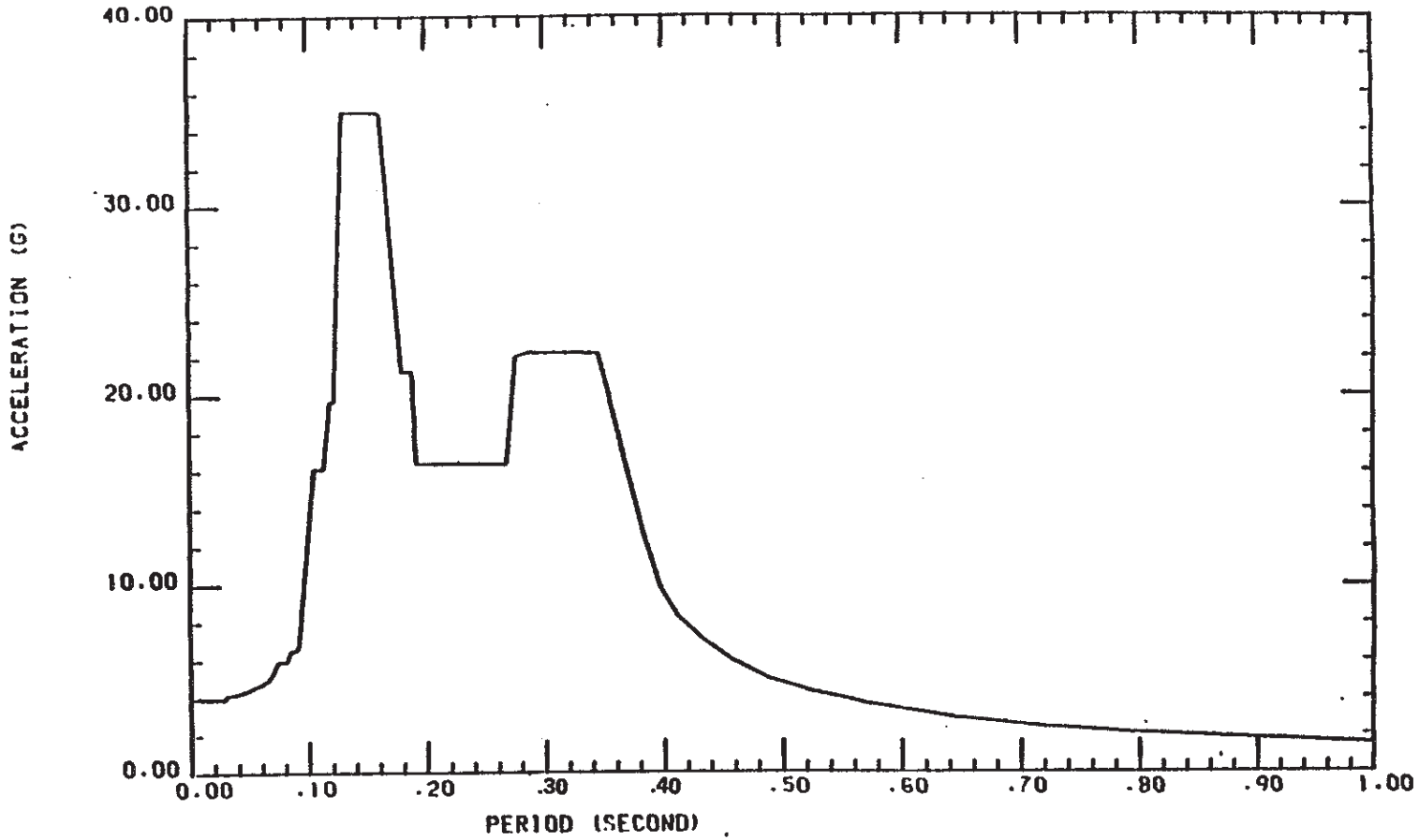
FIGURE 3.7 - 25 D
TURBINE BUILDING
EL. 119'
4 KV SWITCHGEAR AREA
COLUMN LINES 1-4. D-G
HOSGRI N-S SPECTRA
2, 3, 4, 7% DAMPING



FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 3.7 - 25 E
TURBINE BUILDING
EL. 140'
COLUMN LINES 1-19
HOSGRI N-S SPECTRA
2, 3, 4, 7% DAMPING

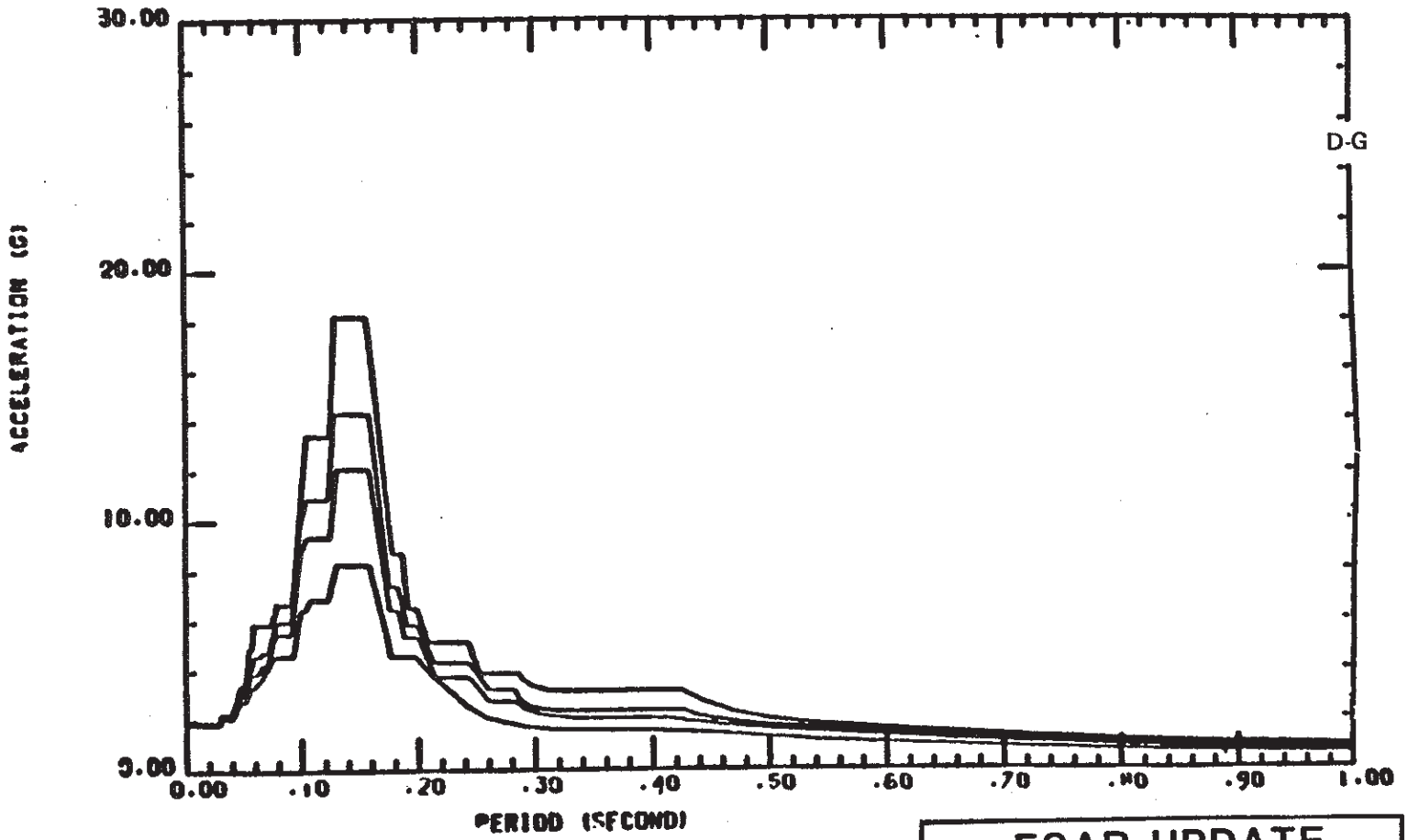


*Spectrum Enveloping the Spectra at Four Locations:
Column Lines 1 & D, El. 193'
Column Lines 1 & A', El. 193'
Column Lines 1' & A, El. 193'
Column Lines 1' & D, El. 210.69'

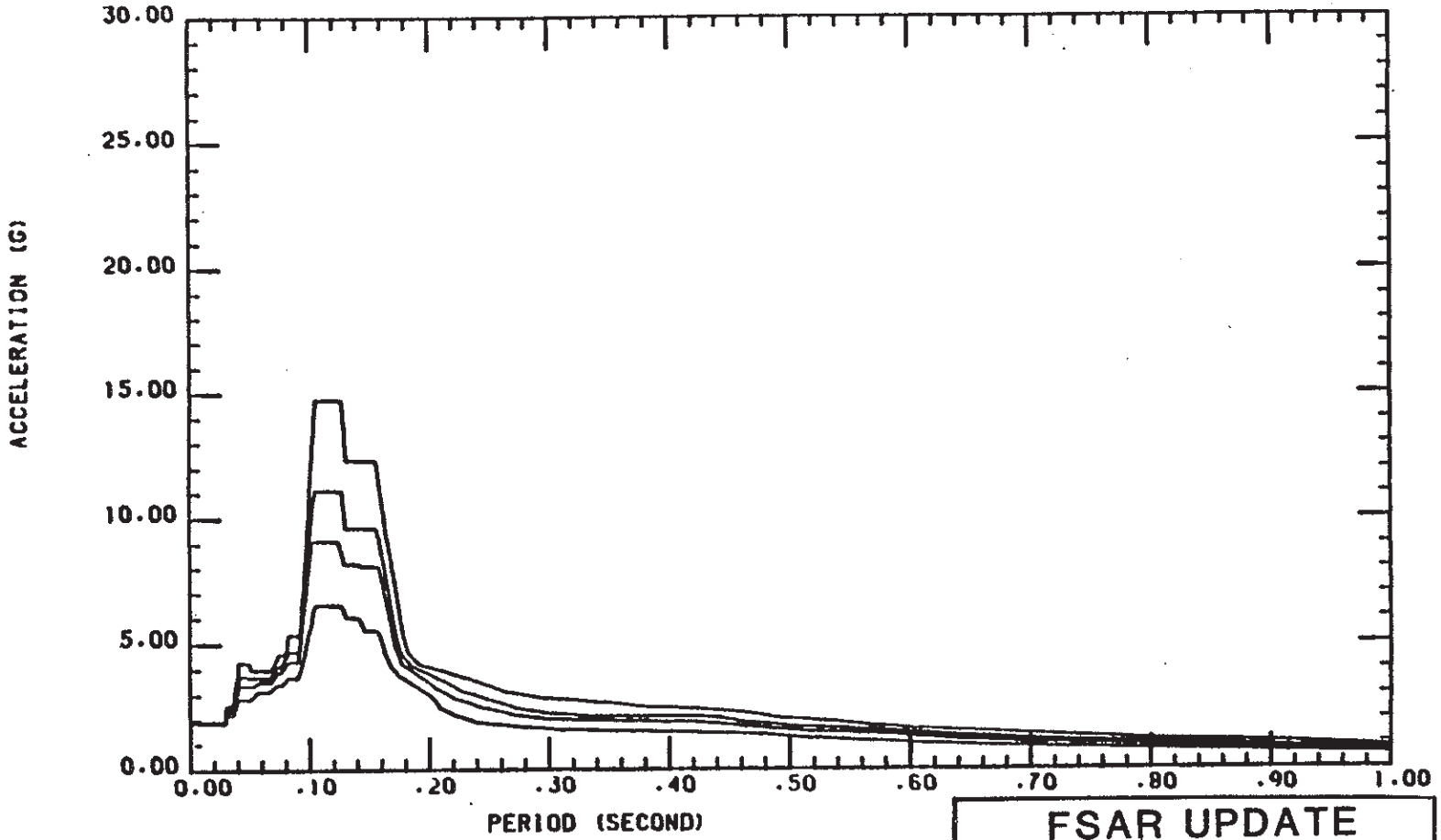
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7 - 25 F
TURBINE BUILDING ROOF LEVEL
COLUMN LINES 1 to 1.9, A-D
HOSGRI N-S SPECTRA 3% DAMPING



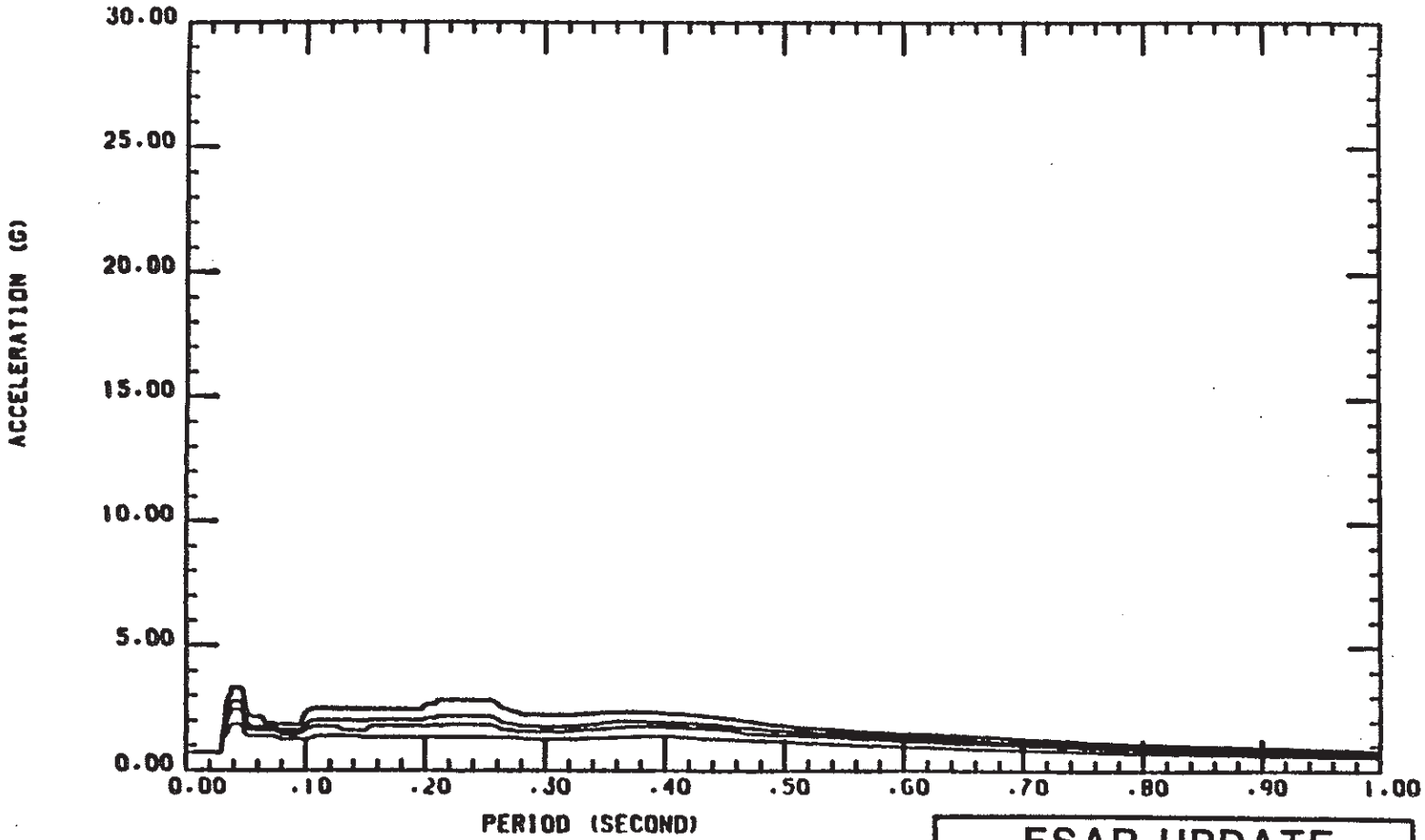
FSAR UPDATE
UNITS 1 AND 2 **DIABLO CANYON SITE**
FIGURE 3.7 - 25 G TURBINE BUILDING EL.119' COLUMN LINES 1-4 & 32-35 D G 4 KV SWITCHGEAR AREA HOSGRI VERTICAL SPECTRA 2, 3. 4, 7% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

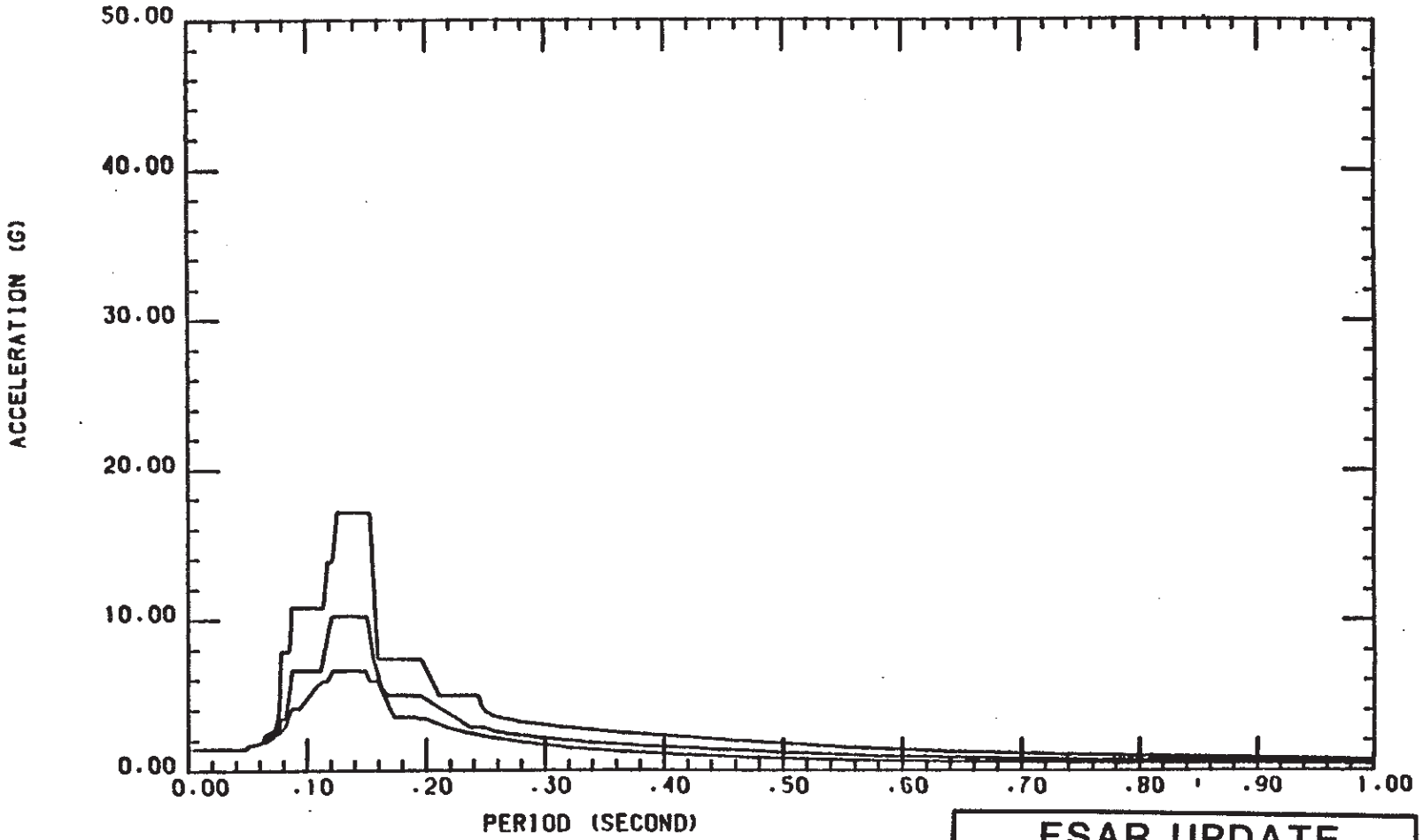
FIGURE 3.7 - 25 H
TURBINE BUILDING
EL. 140'
COLUMN LINES
5- 15, 21 -31
HOSGRI VERTICAL SPECTRA
2, 3, 4, 7% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

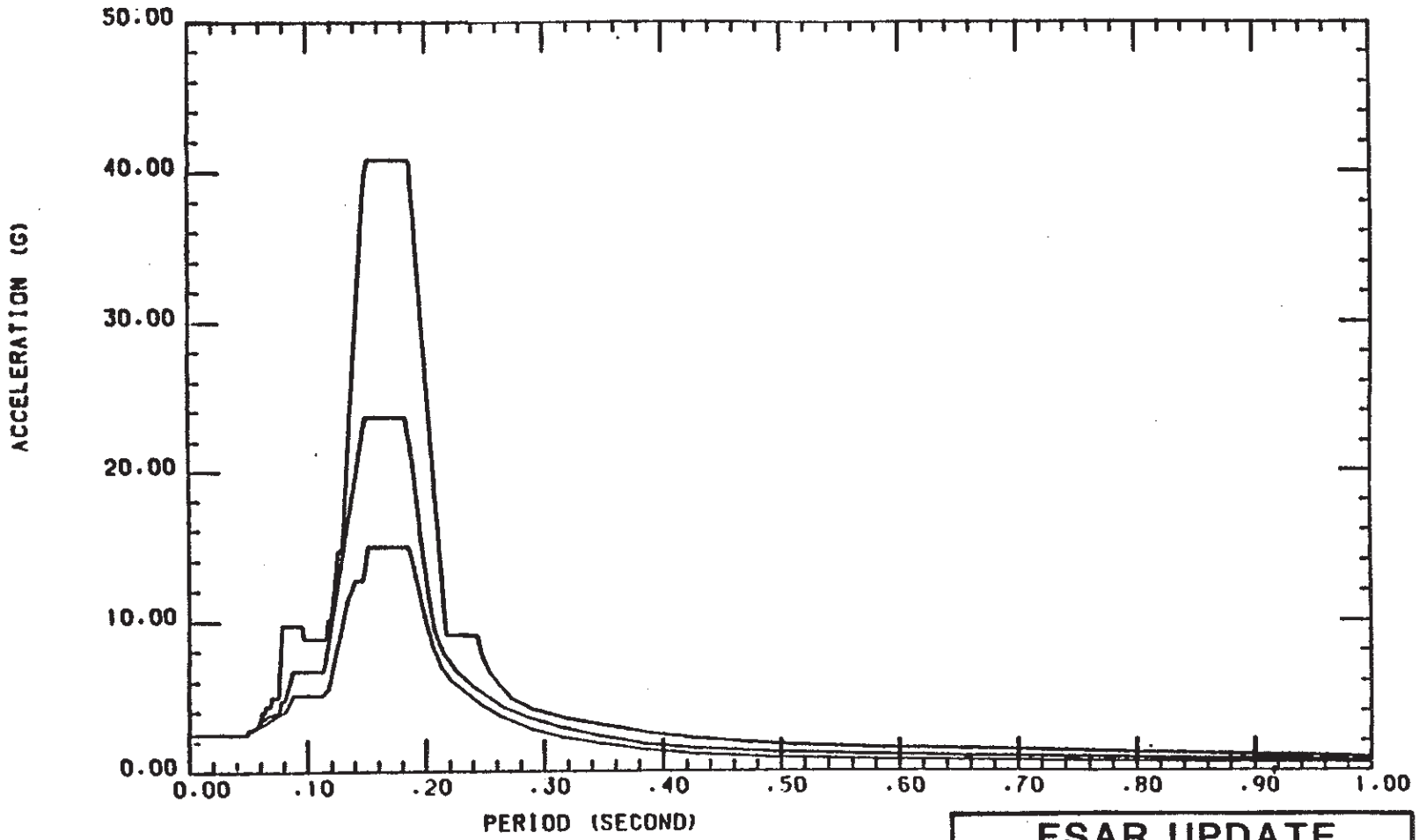
FIGURE 3.7-25I
TURBINE BUILDING
EL. 193'
BUILT UP COLUMNS ON LINE
A&G FROM 5.7 TO 15 & 21 TO 30.3
HOSGRI VERTICAL SPECTRA
2, 3, 4, 7% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

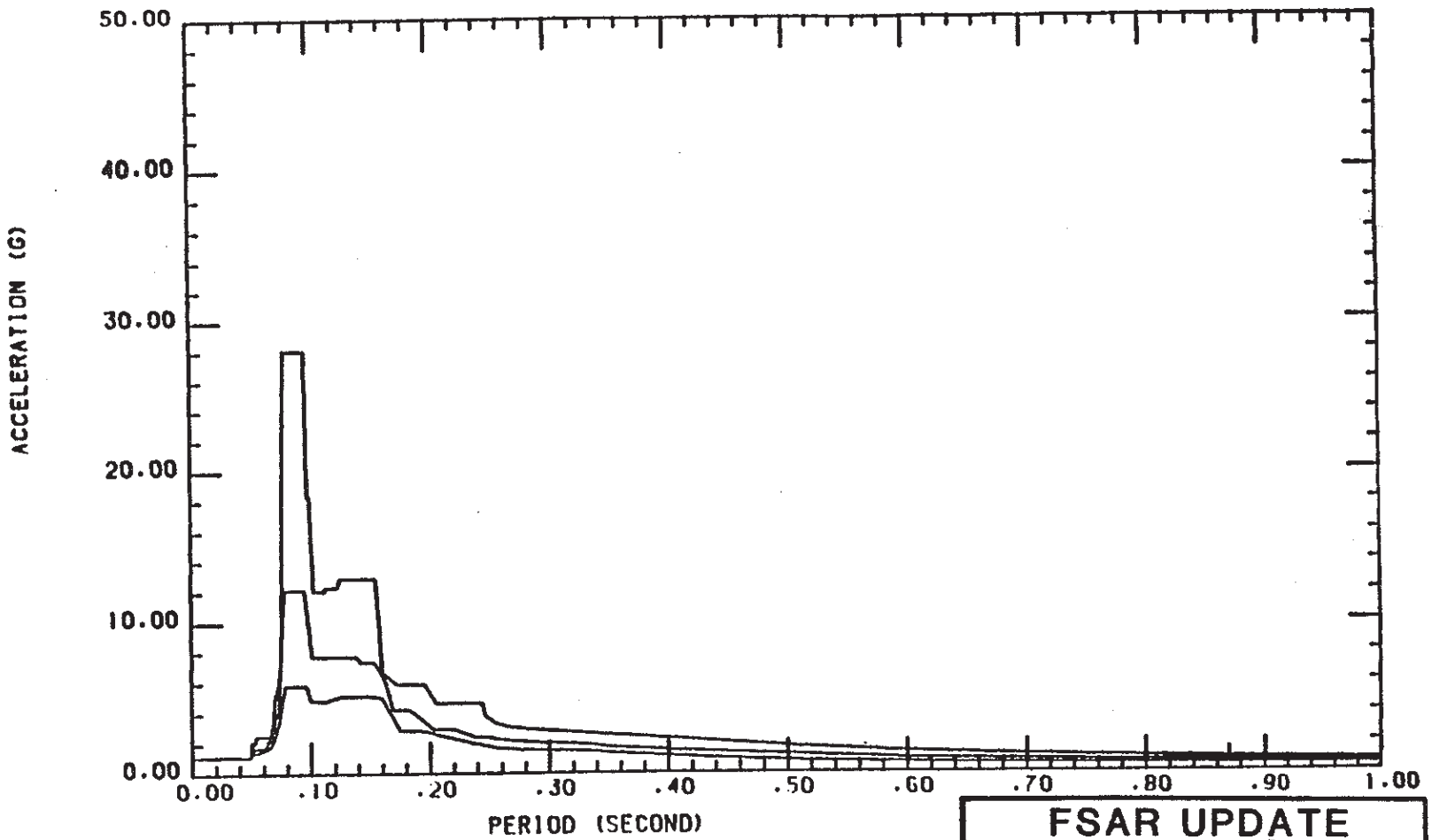
FIGURE 3.7 - 25 J
TURBINE BUILDING
ELEV. 104'
COLUMN LINES 5 to 15
DDE E-W SPECTRA
1/2, 2, 5% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

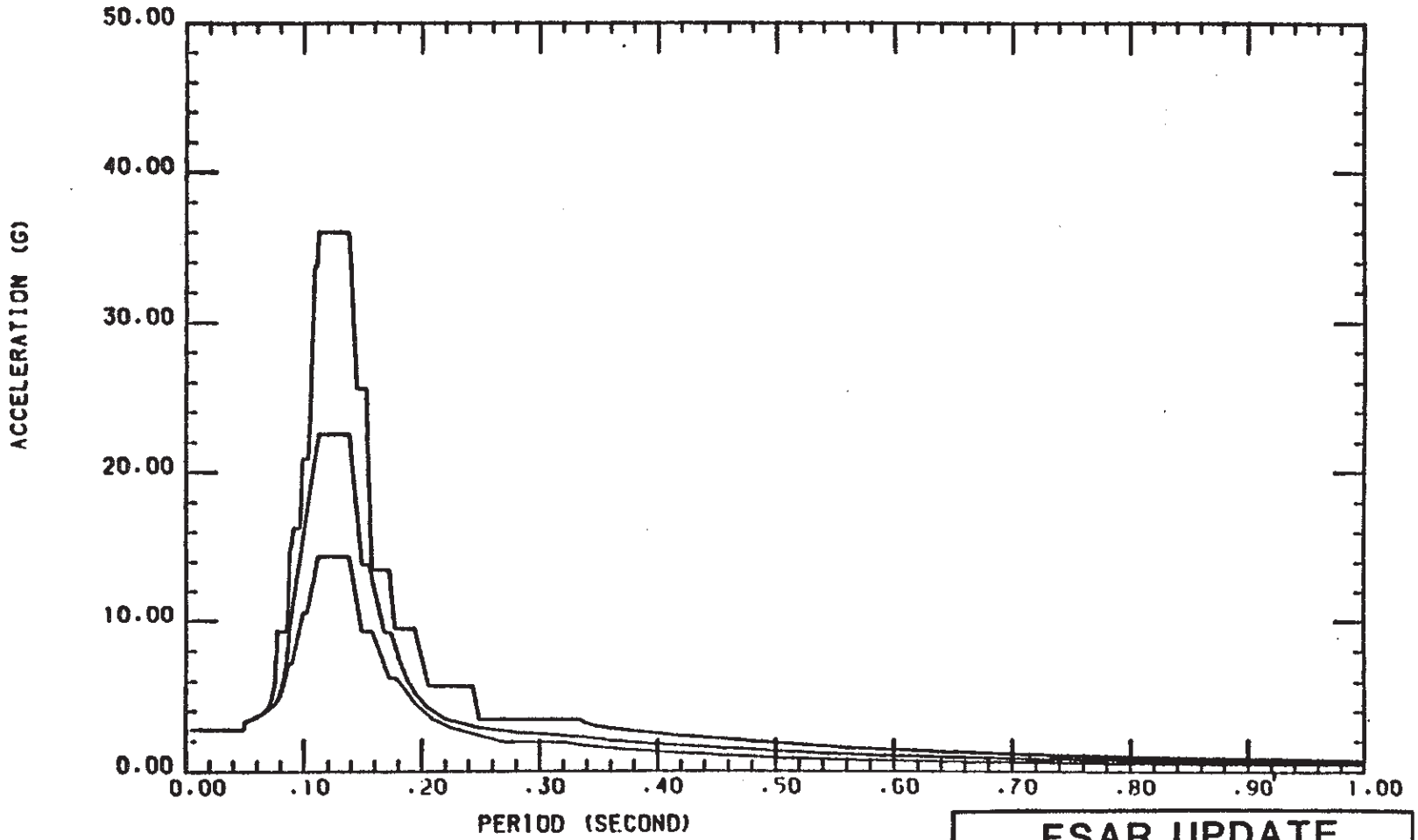
FIGURE 3.7 - 25 K
TURBINE BUILDING
ELEV. 140′
COLUMN LINES 5-15
DDE E-W SPECTRA
1/2,2,5% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

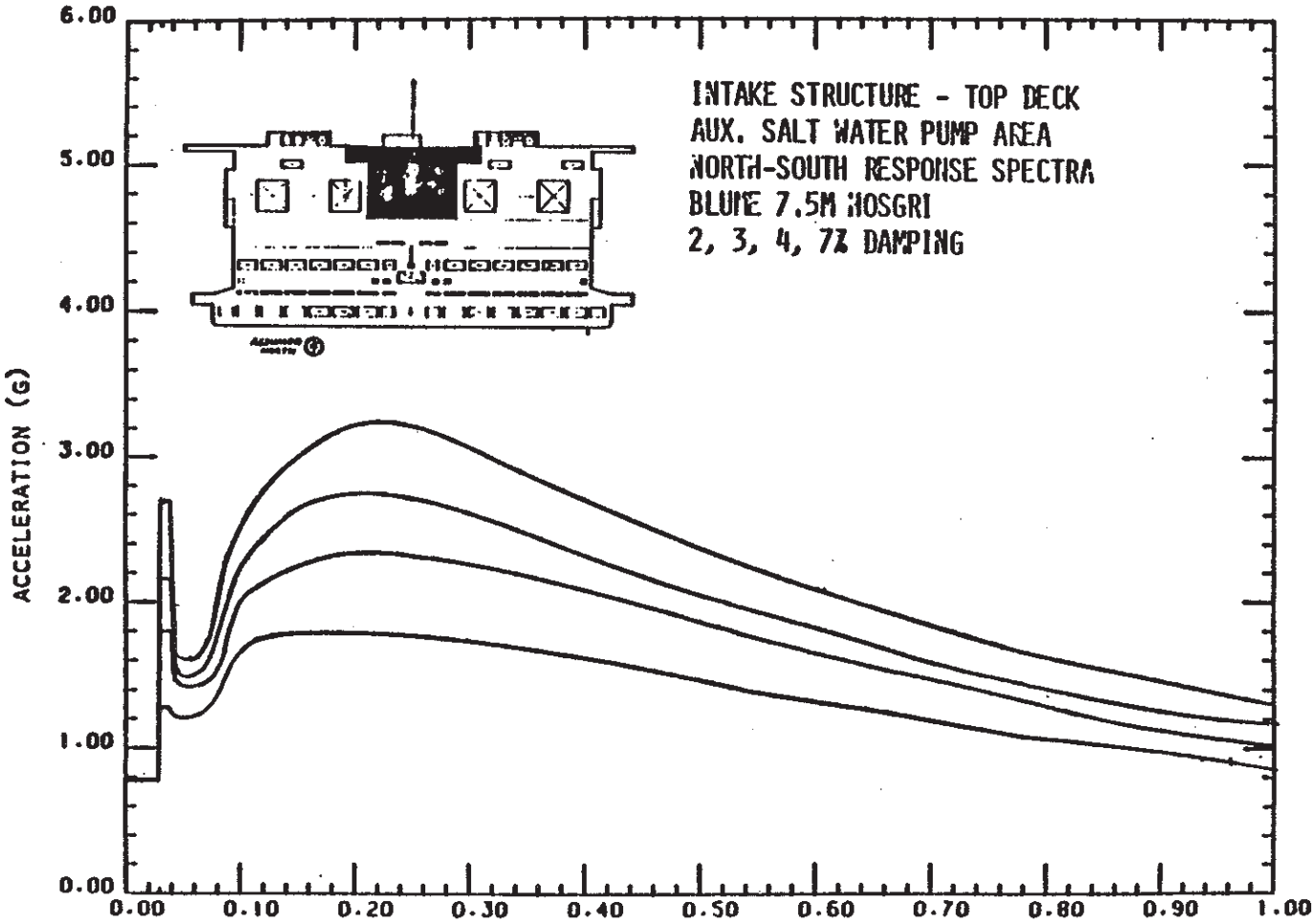
FIGURE 3.7 - 25 L
TURBINE BUILDING
ELEV 104' & 107'
COLUMN LINES 1-19
DDE N-S SPECTRA
1/2, 2, 5% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

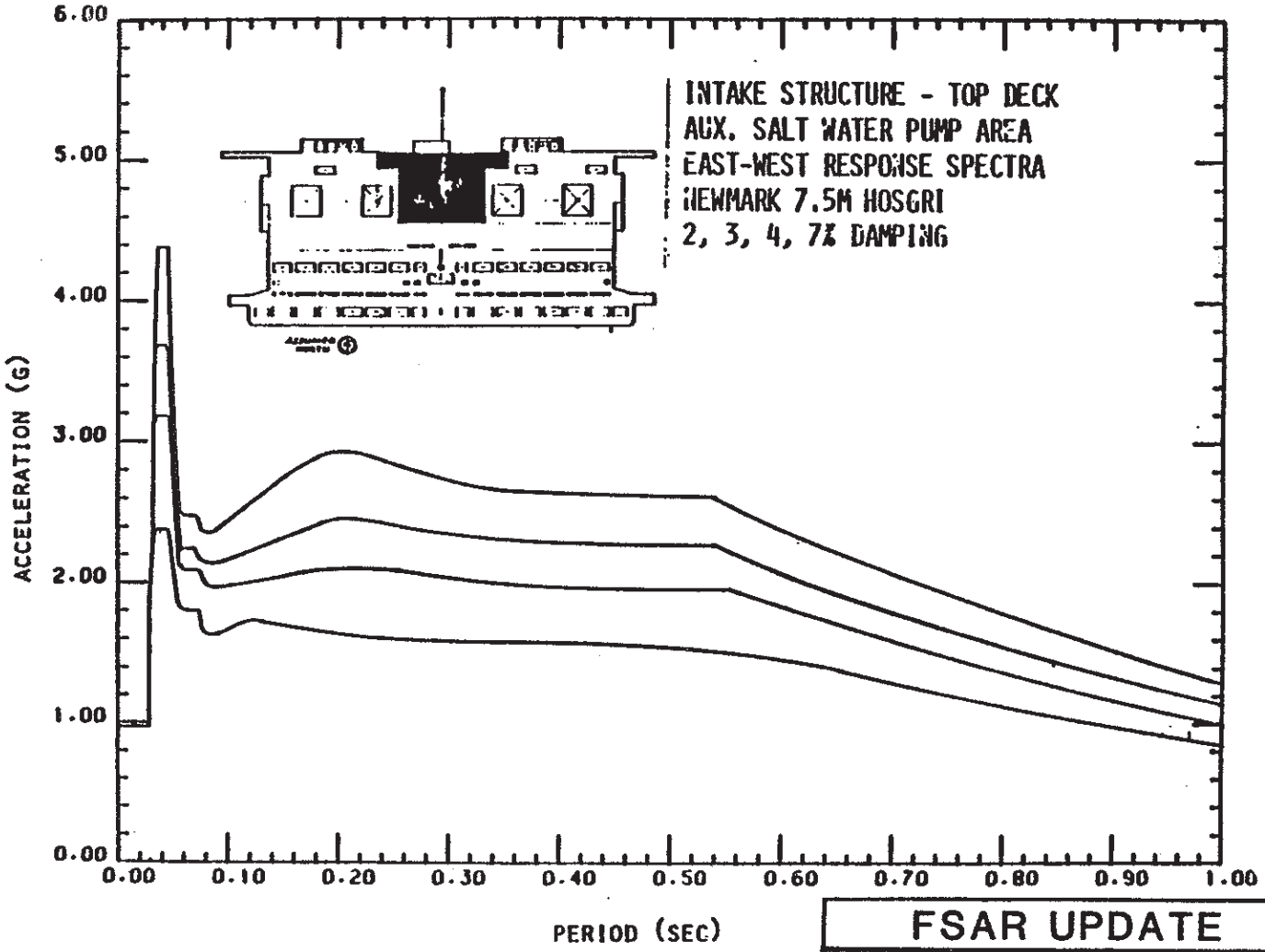
FIGURE 3.7 - 25 M
TURBINE BUILDING
ELEV 140'
COLUMN LINES 1-19
DDE N-S SPECTRA
1/2, 2, 5% DAMPING



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

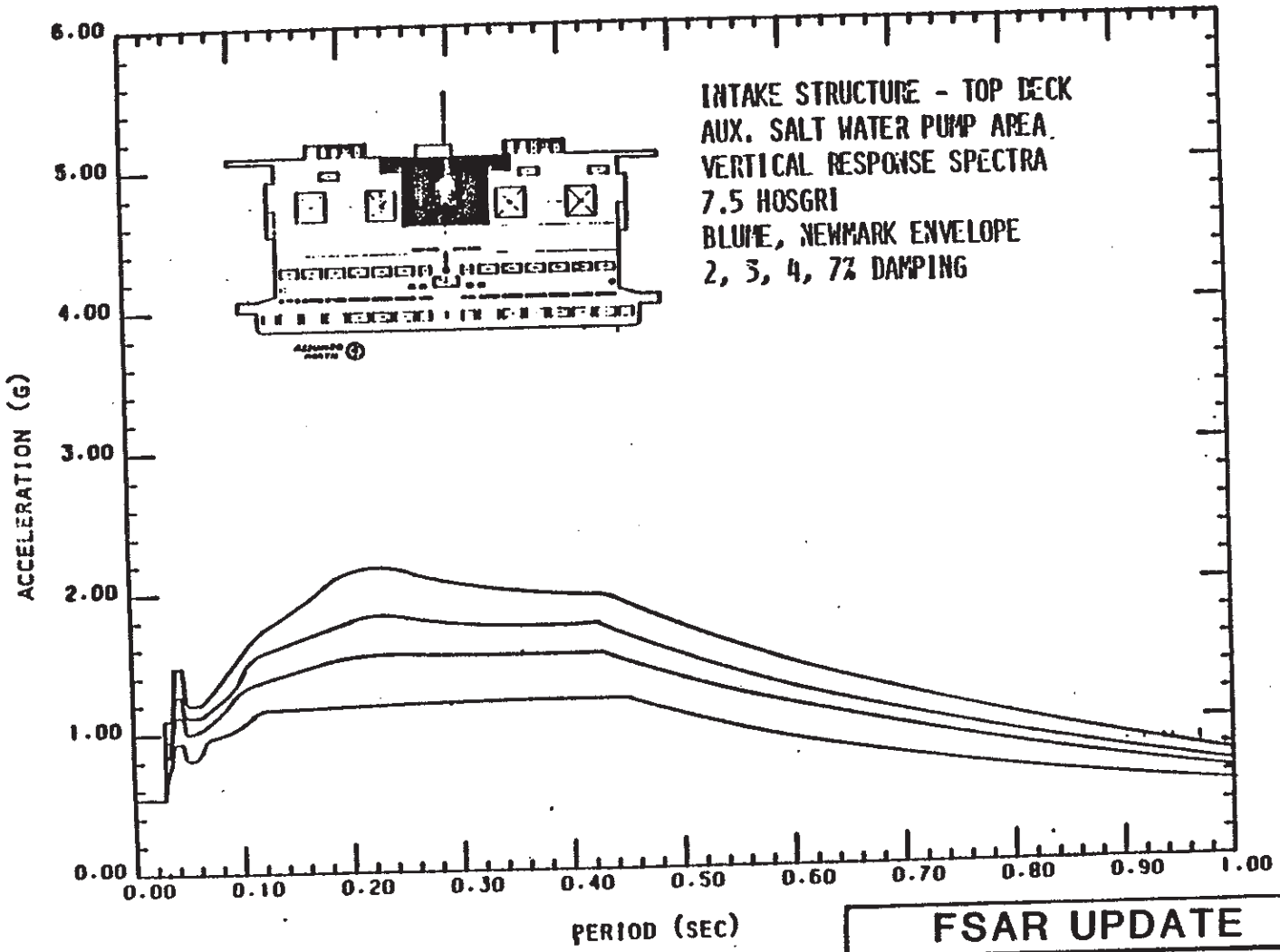
FIGURE 3.7 - 25 N
INTAKE STRUCTURE
RESPONSE SPECTRA
BLUME 7.5 M HOSGRI



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

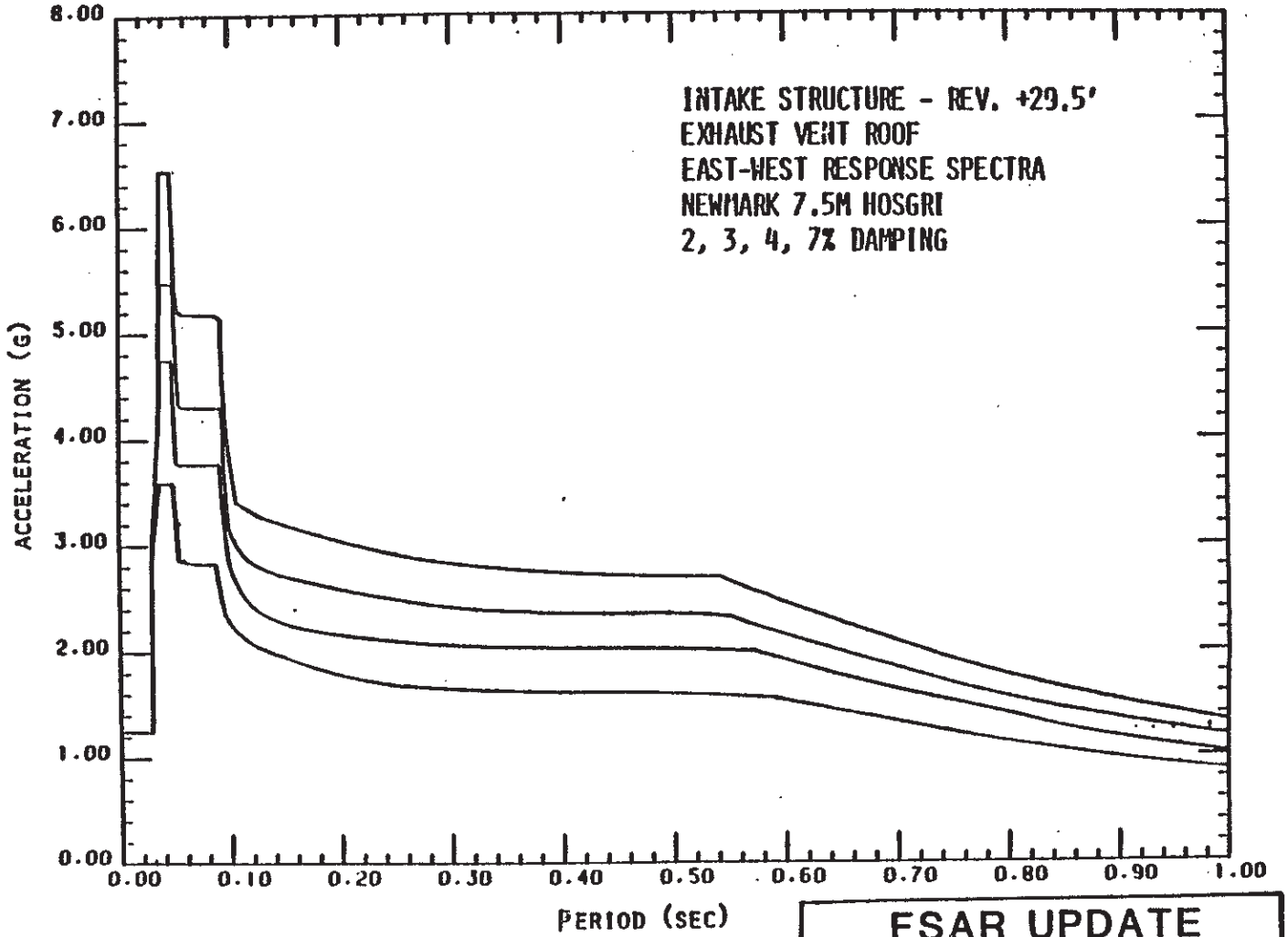
FIGURE 3.7 - 25 O
INTAKE STRUCTURE
RESPONSE SPECTRA
NEWMARK 7.5 M HOSGRI



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

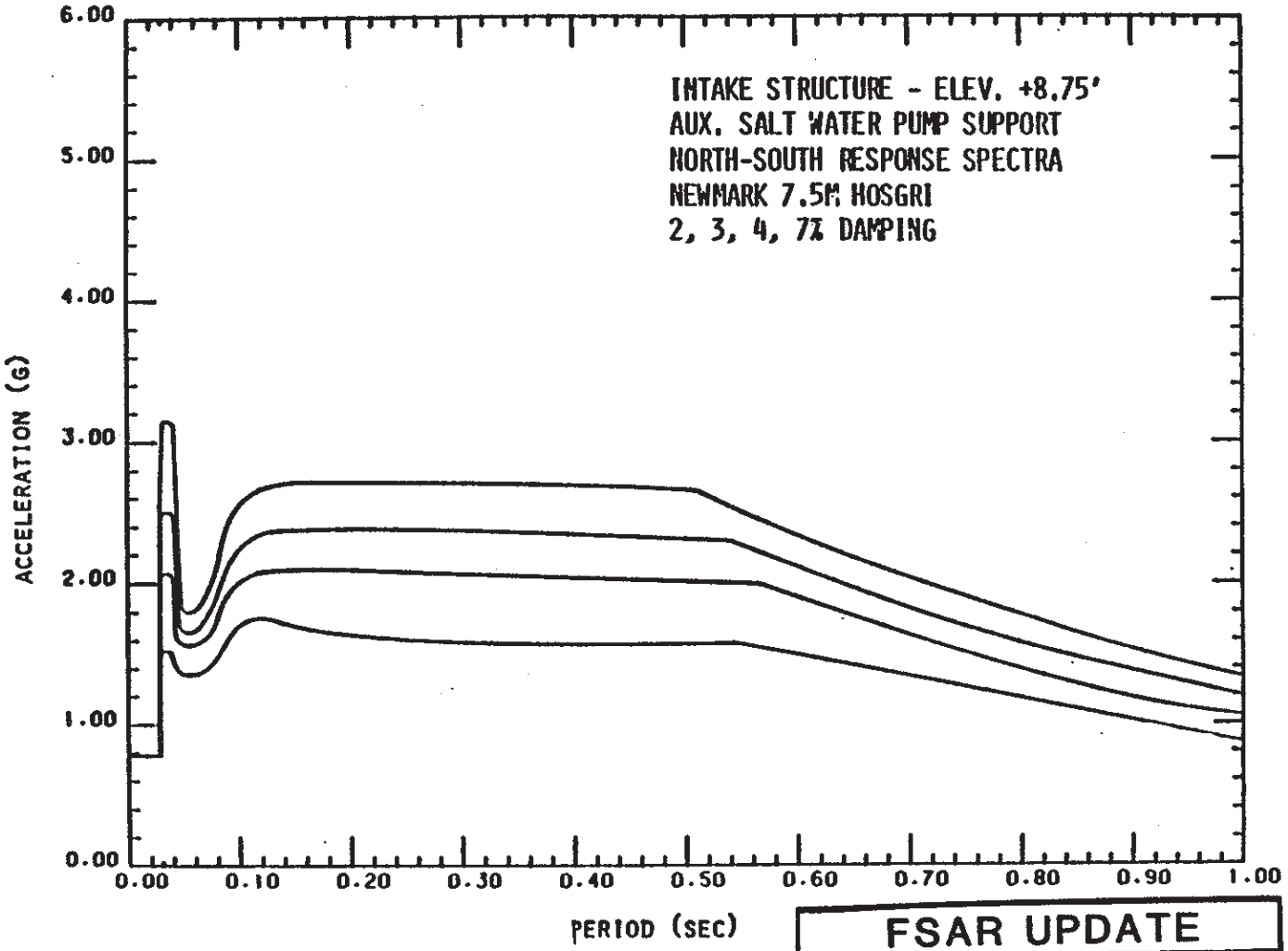
FIGURE 3.7 - 25 P
INTAKE STRUCTURE VERTICAL
RESPONSE SPECTRA 7.5M/HOSGRI
BLUME, NEWMARK ENVELOPE



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

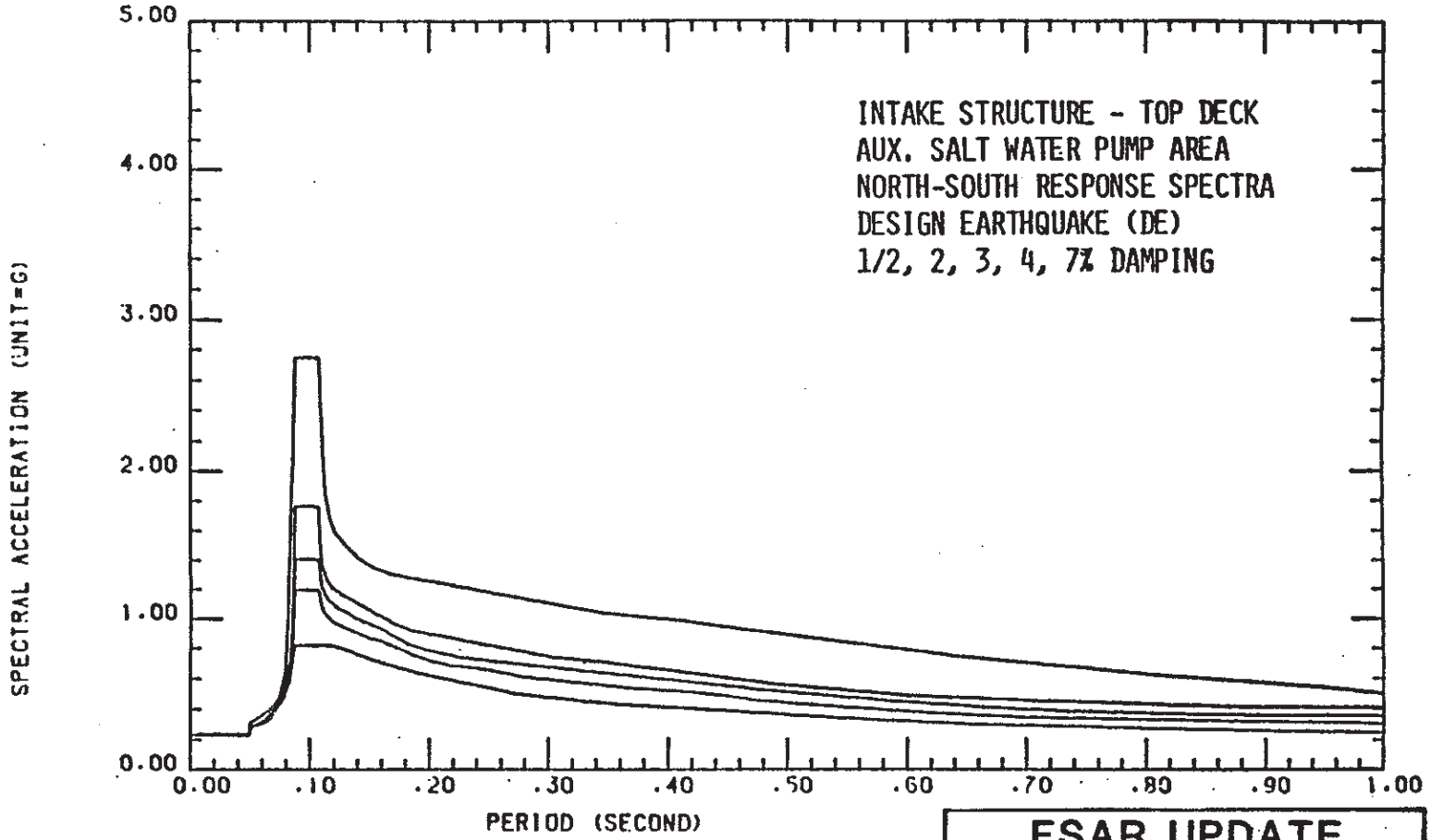
FIGURE 3.7 - 25 Q
INTAKE STRUCTURE
RESPONSE SPECTRA
NEWMARK 7.5 M HOSGRI



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

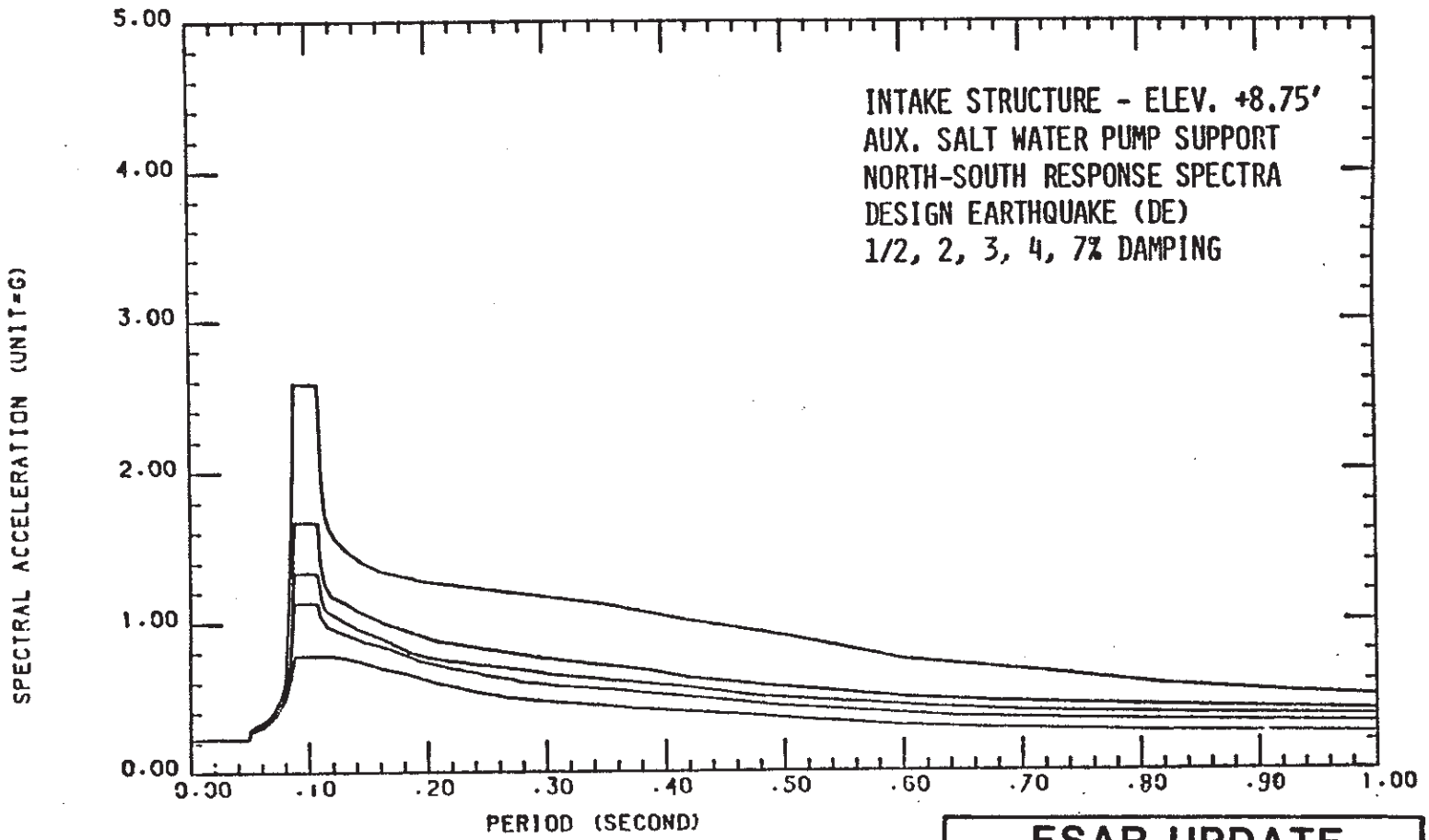
FIGURE 3.7-25 R
INTAKE STRUCTURE
RESPONSE SPECTRA
NEWMARK 7.5 M HOSGRI



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

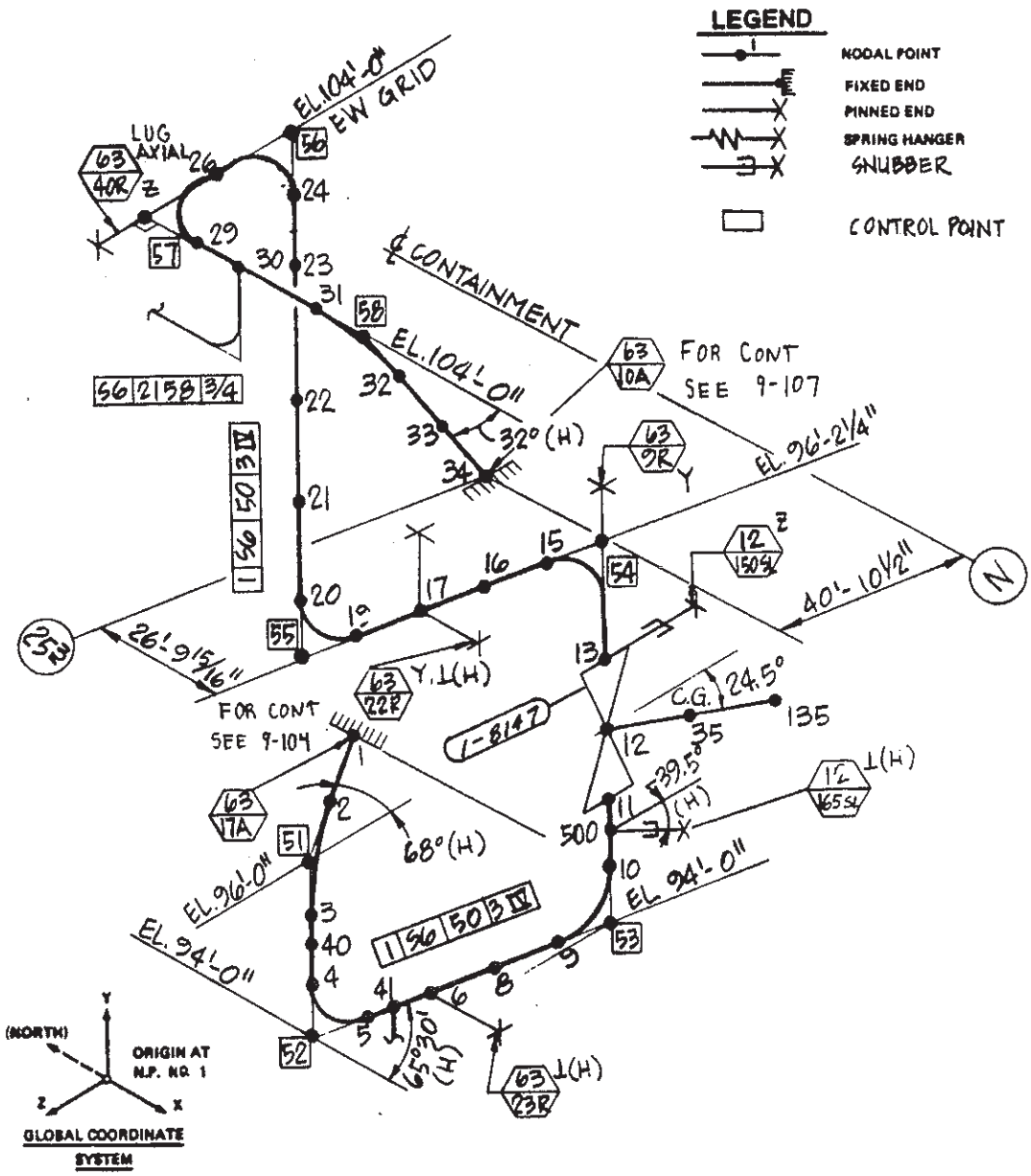
FIGURE 3.7 - 25 S
INTAKE STRUCTURE
RESPONSE SPECTRA
DESIGN EARTHQUAKE (DE)



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7 - 25 T
INTAKE STRUCTURE
RESPONSE SPECTRA
DESIGN EARTHQUAKE (DE)

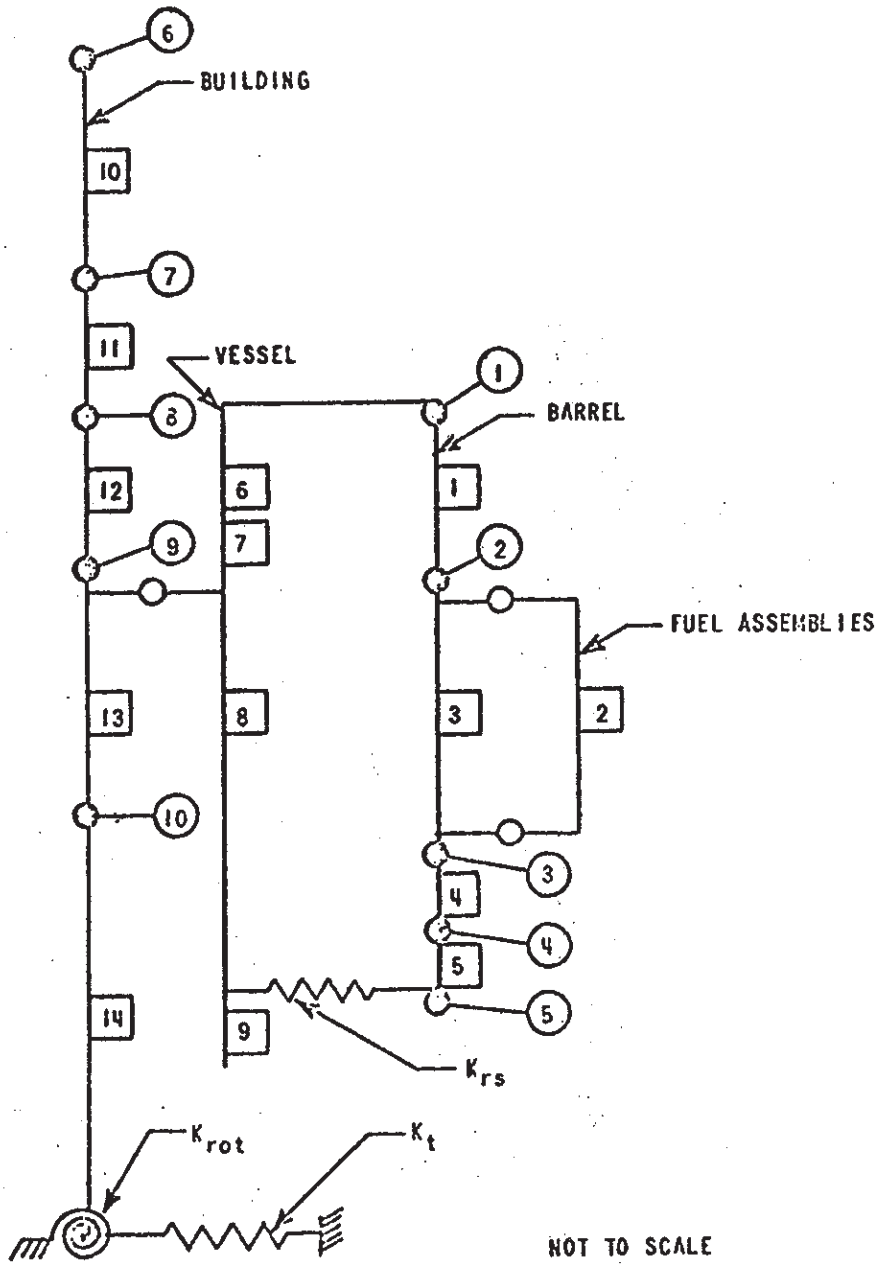


FSAR UPDATE
UNIT 1 **DIABLO CANYON SITE**
FIGURE 3.7-26 TYPICAL PIPING MATHEMATICAL MODEL

K_{rs} = RADIAL SUPPORT SPRING CONSTANT

K_{rot} = ROTATIONAL GROUND SPRING CONSTANT

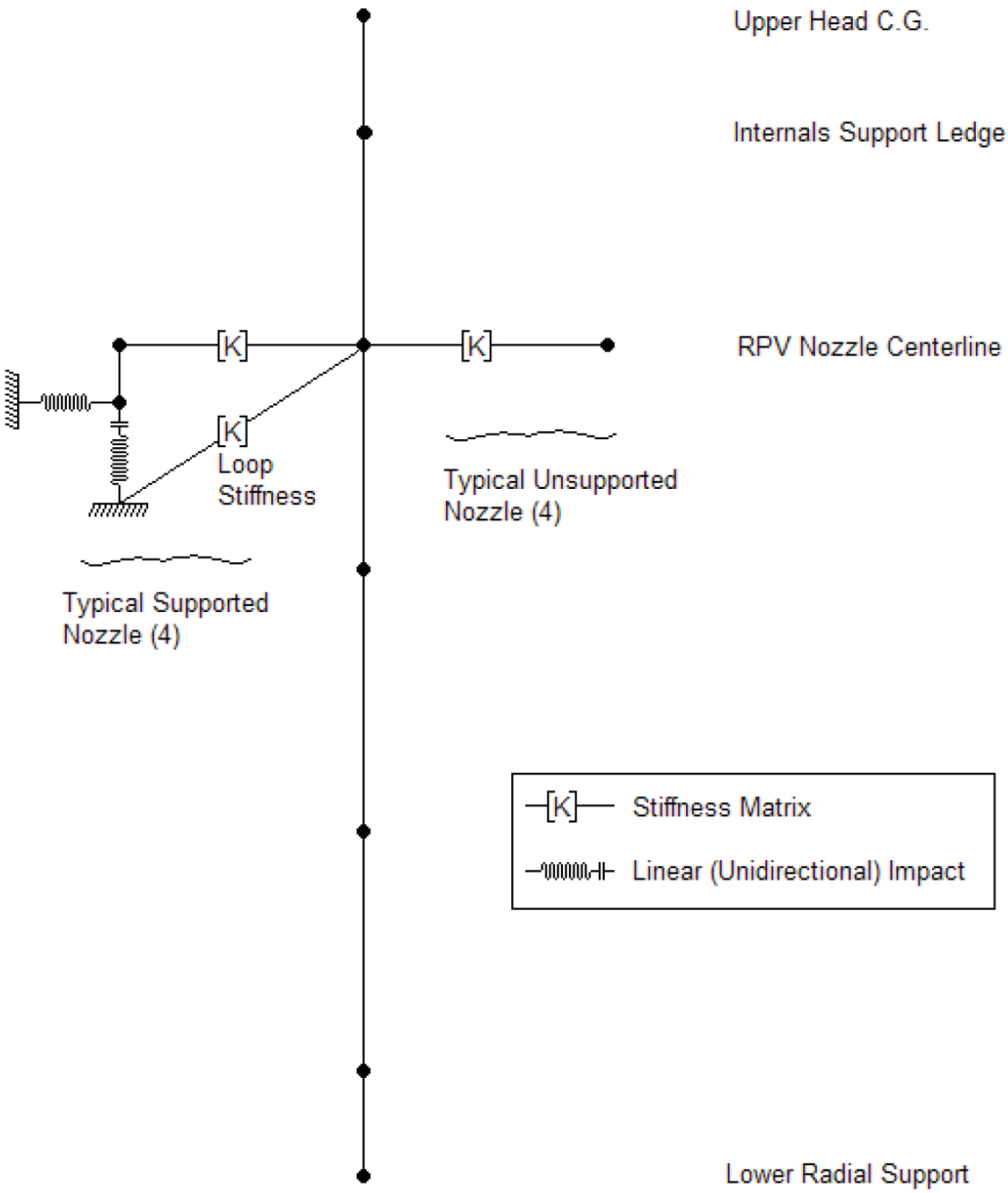
K_t = TRANSLATIONAL GROUND SPRING CONSTANT



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7-27
REACTOR INTERNALS
MATHEMATICAL MODELS



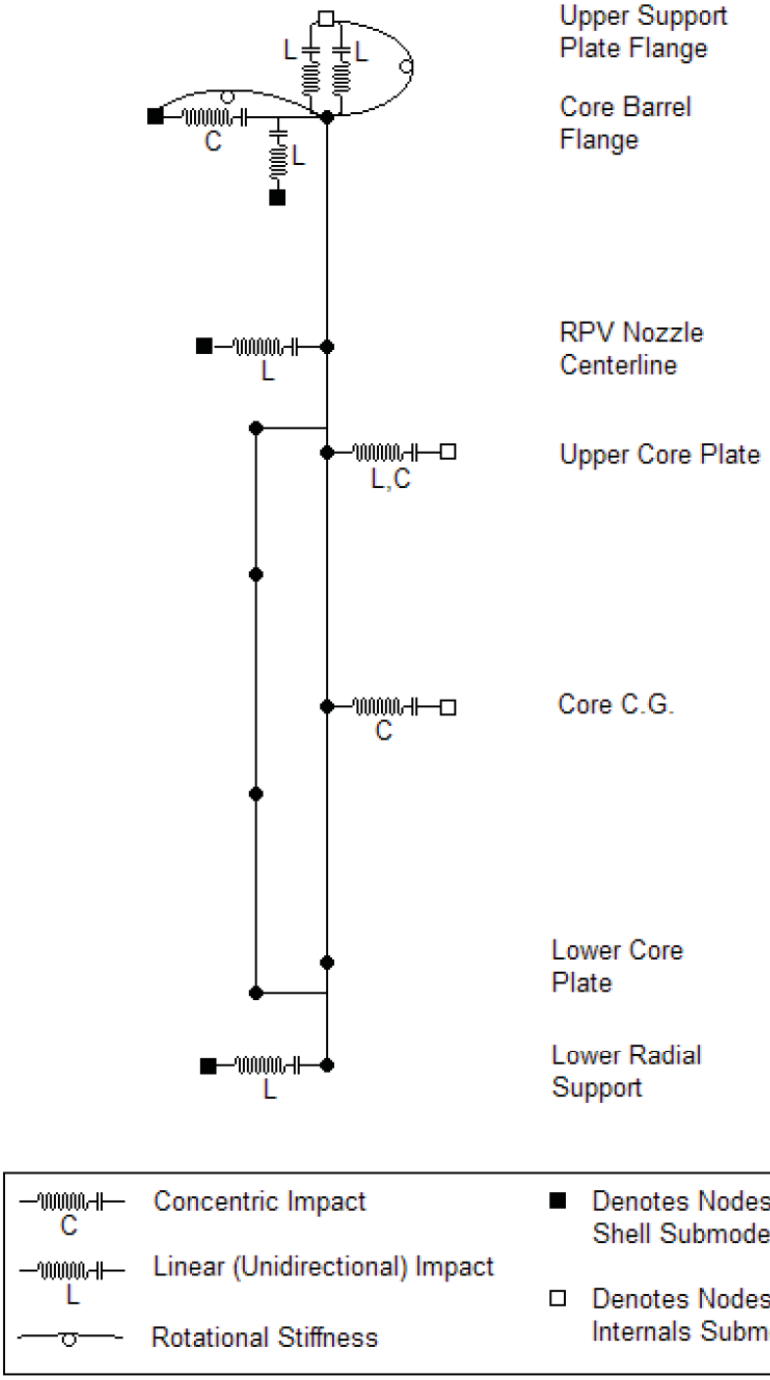
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7-27A

REACTOR PRESSURE VESSEL SHELL SUBMODEL

Revision 20 November 2011



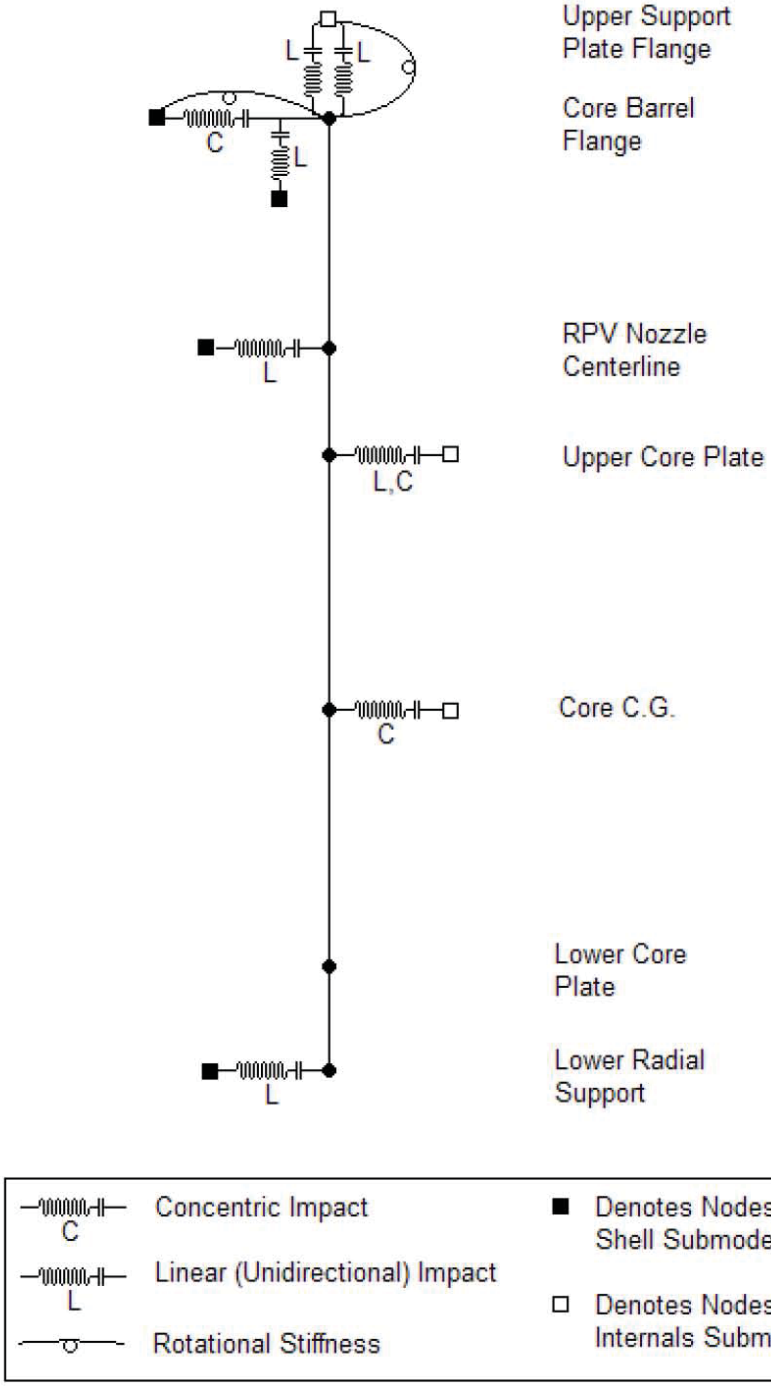
FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

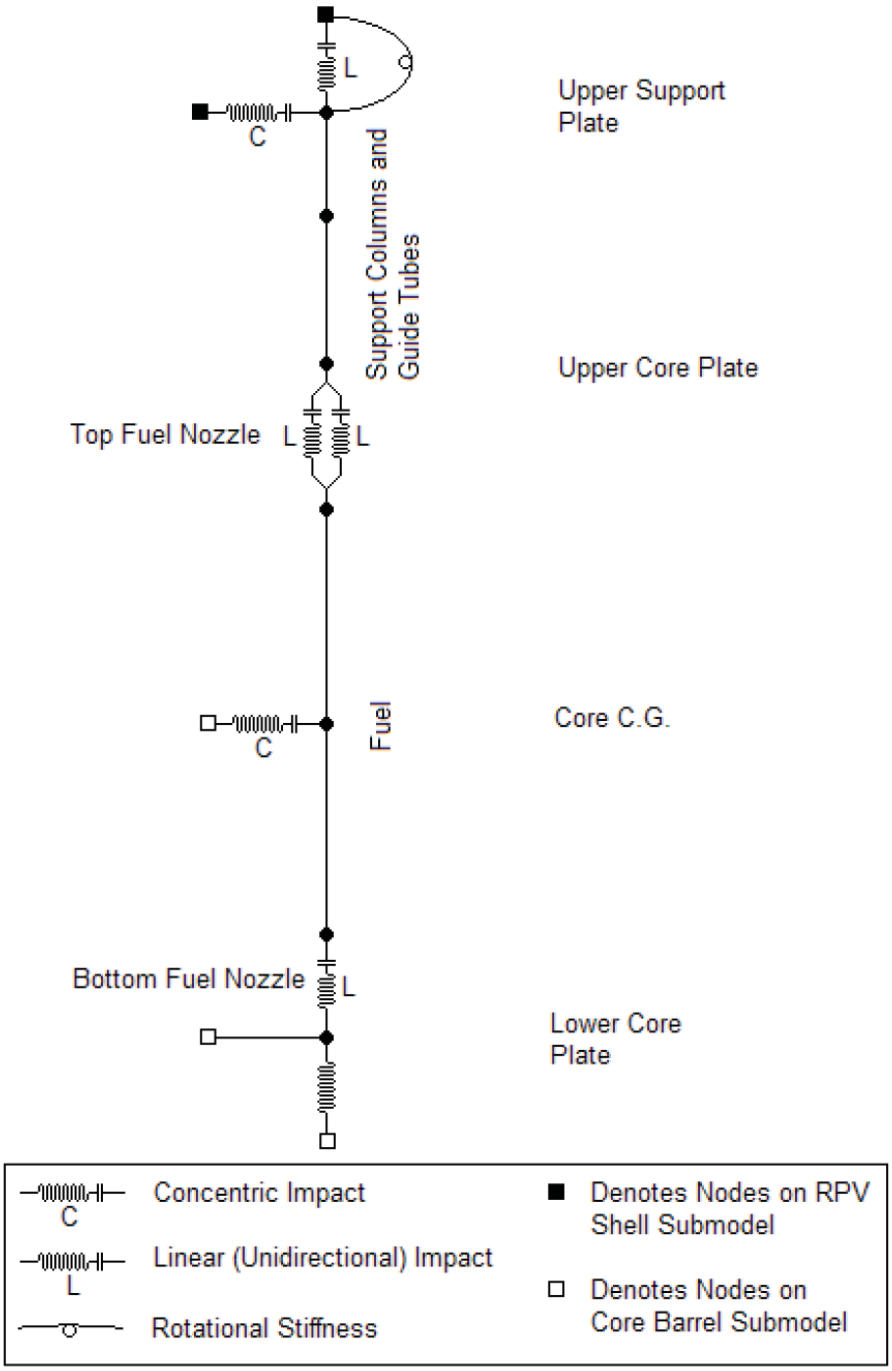
FIGURE 3.7-27B

CORE BARREL SUBMODEL

Revision 20 November 2011



FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 3.7-27C CORE BARREL SUBMODEL



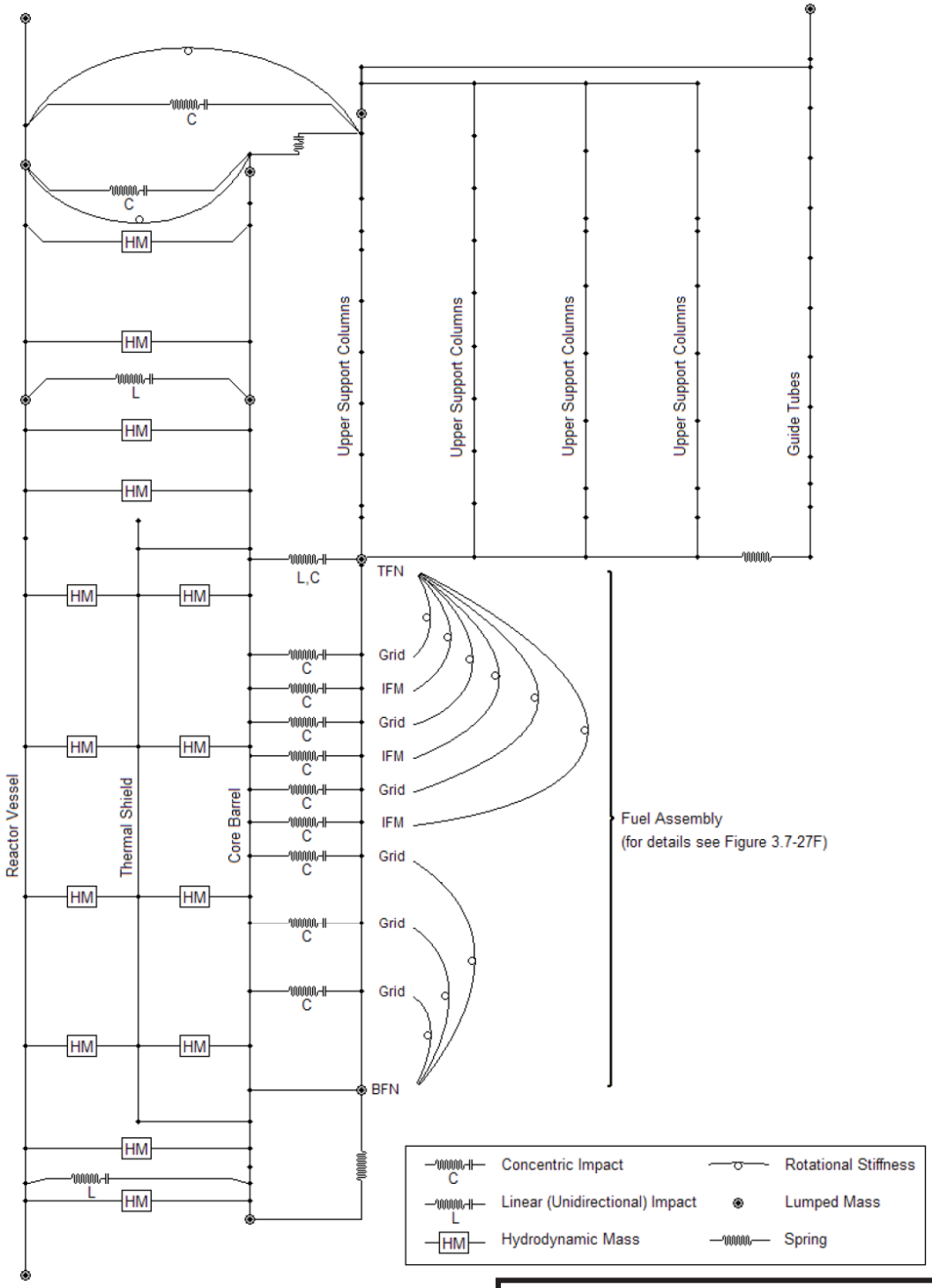
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7-27D

INTERNALS (INNERMOST) SUBMODEL

Revision 20 November 2011

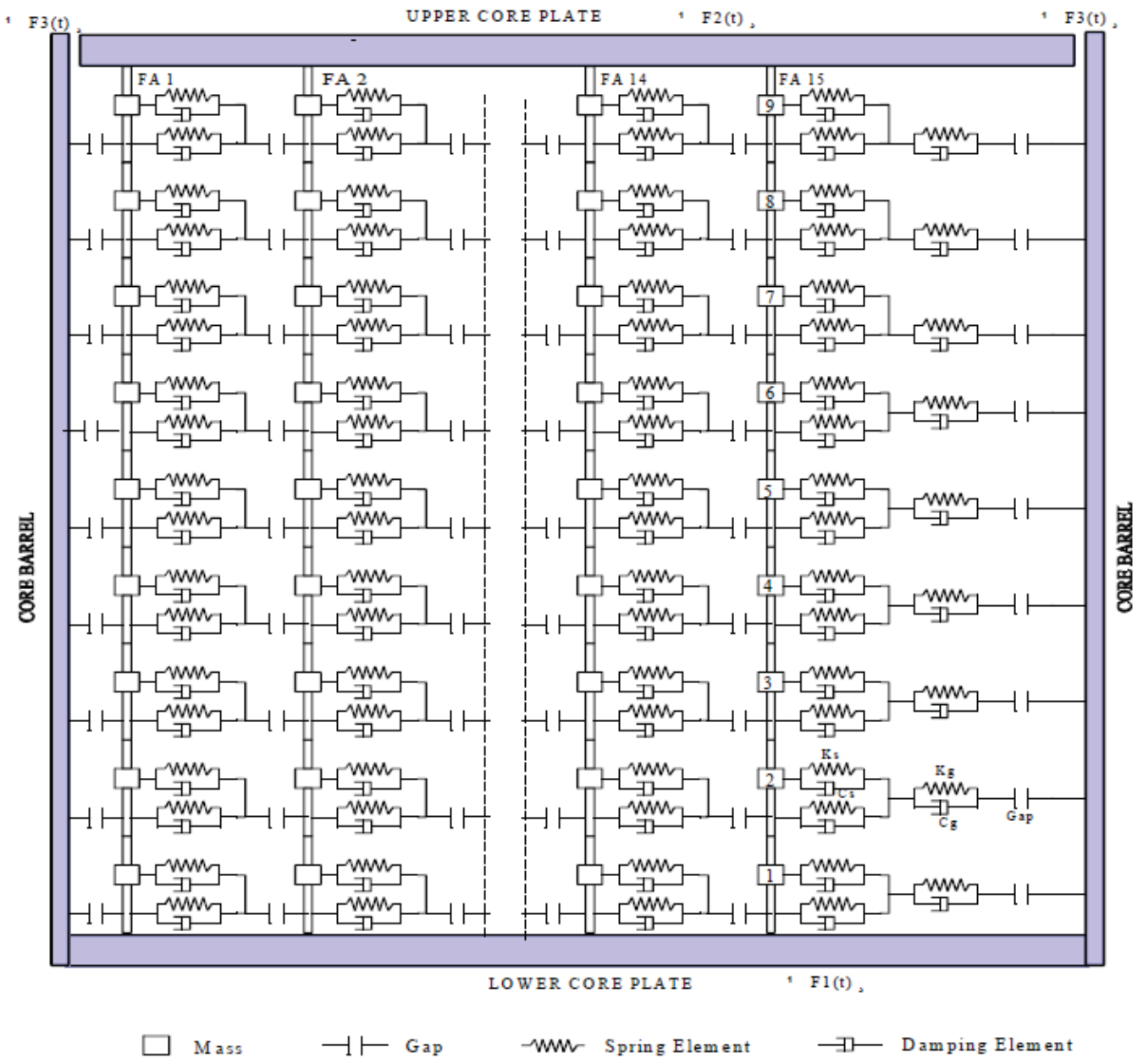


FSAR UPDATE

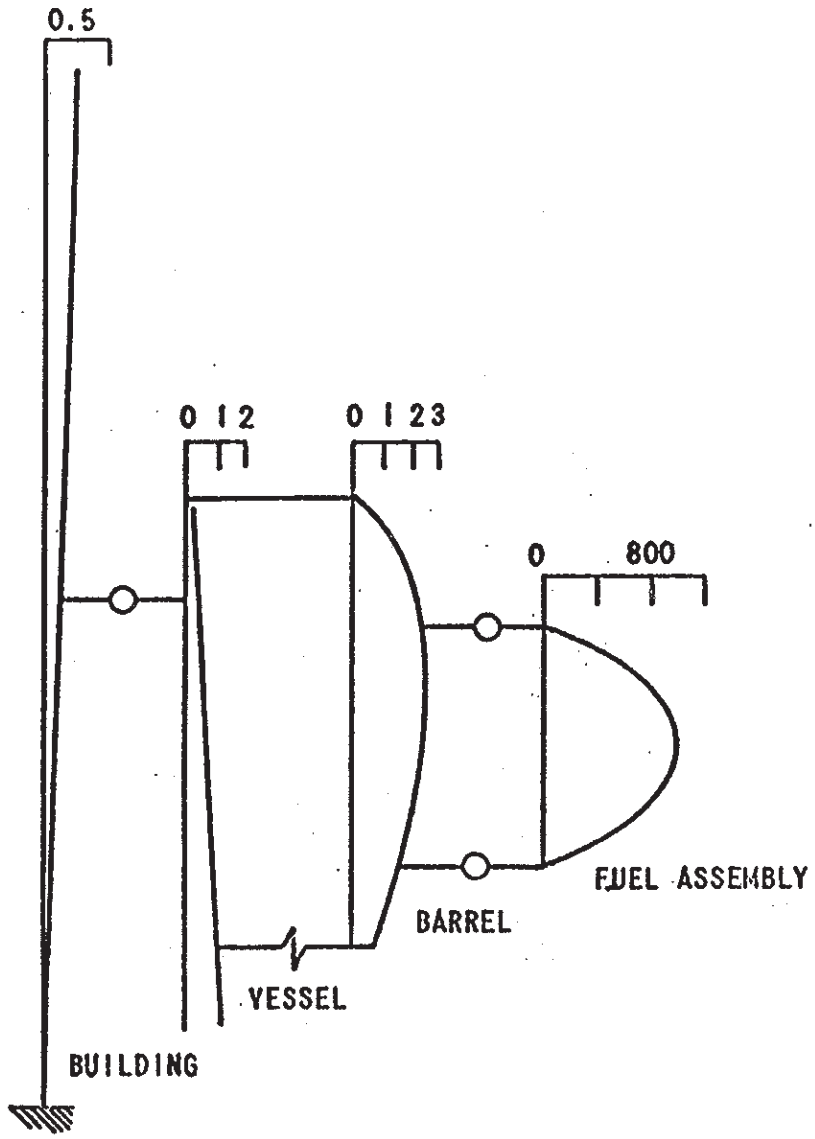
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7-27E

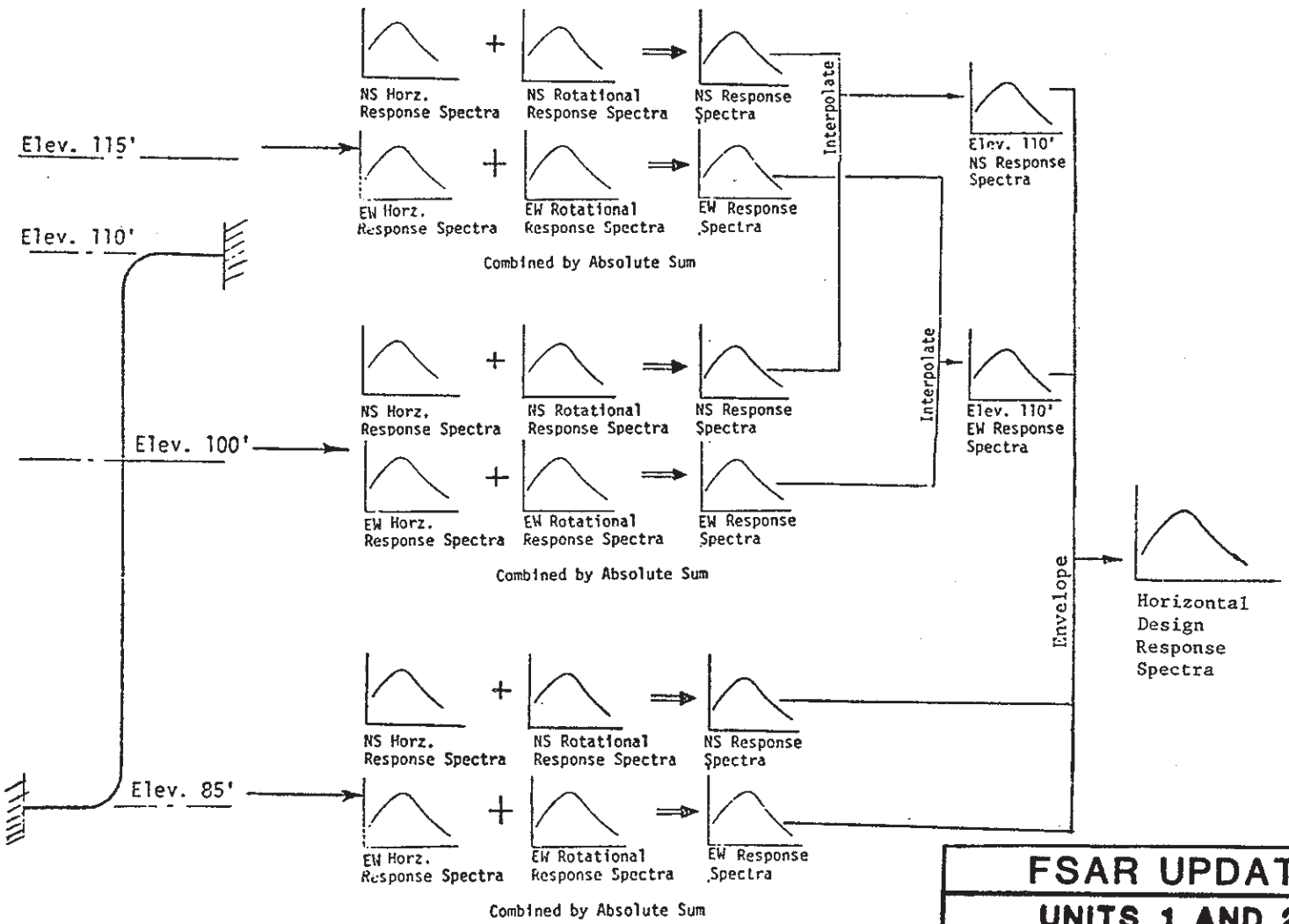
ASSEMBLED FINITE ELEMENT SYSTEM MODEL



FSAR UPDATE
UNIT 1 AND UNIT 2 DIABLO CANYON SITE
FIGURE 3.7-27F SCHEMATIC REPRESENTATION OF COMPUTER MODEL USED TO ANALYZE CORE DYNAMIC RESPONSE



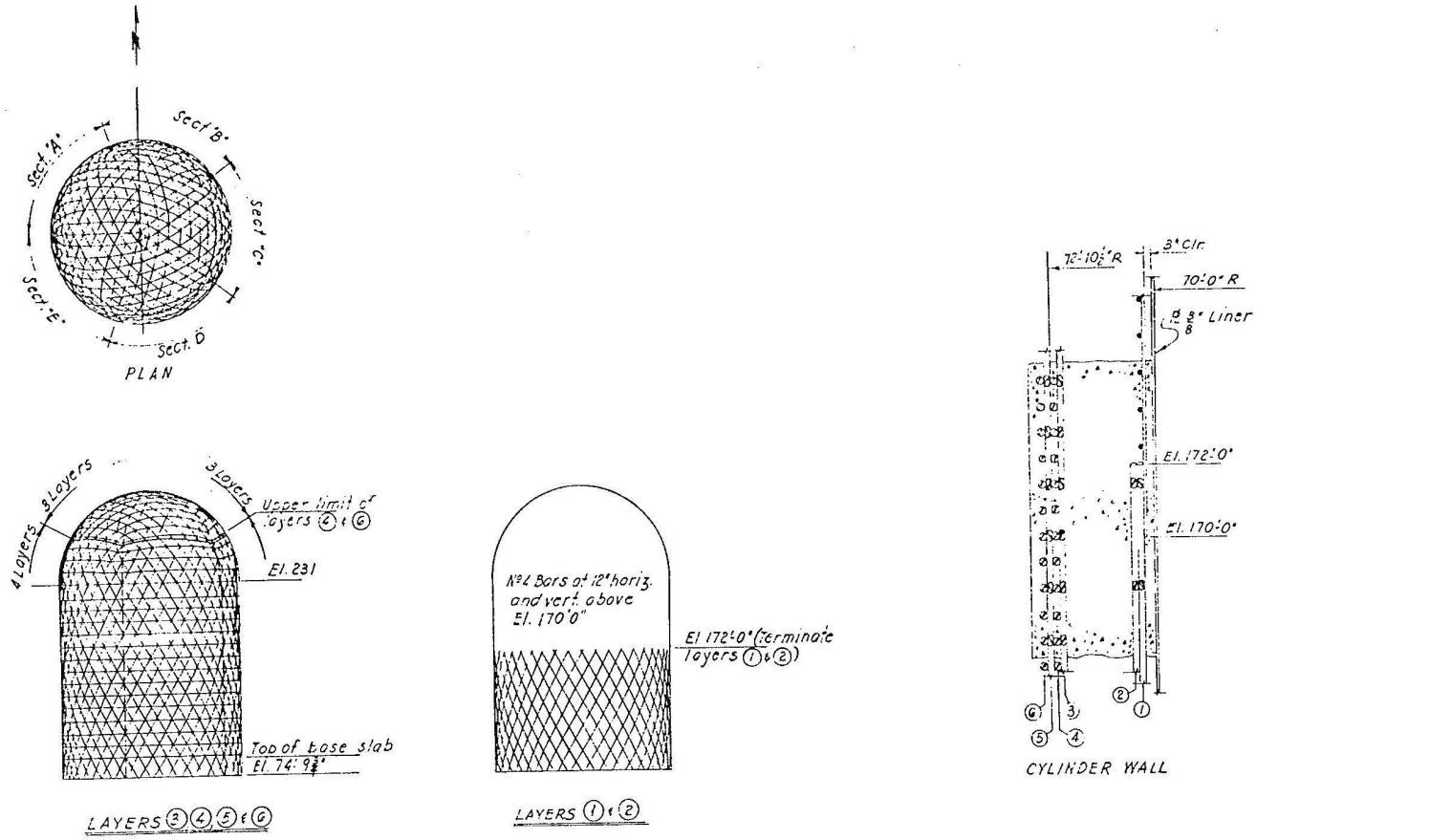
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.7-28 REACTOR INTERNALS FIRST MODE OF VIBRATION



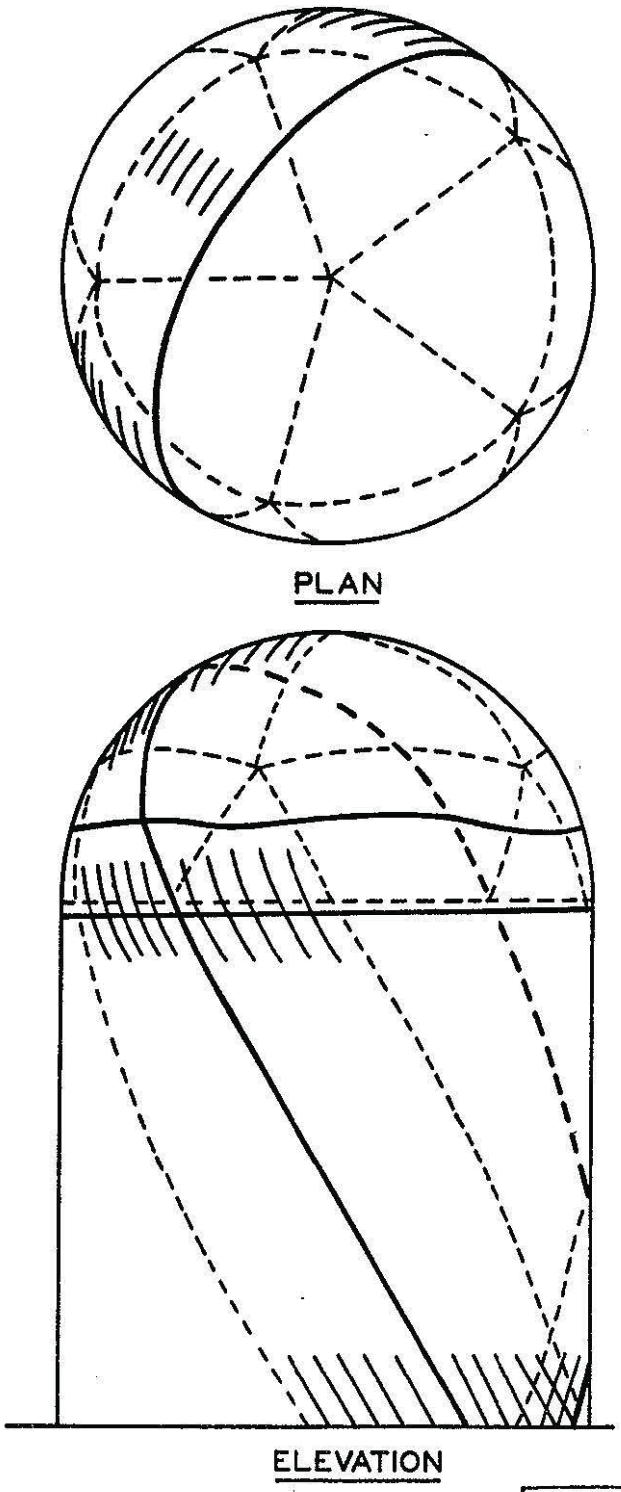
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.7–29
DERIVATION OF
DESIGN RESPONSE SPECTRA
FOR A TYPICAL PIPING SYSTEM



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.8-1 CONTAINMENT STRUCTURE REINFORCING STEEL ARRANGEMENT **(HISTORICAL)**



FSAR UPDATE

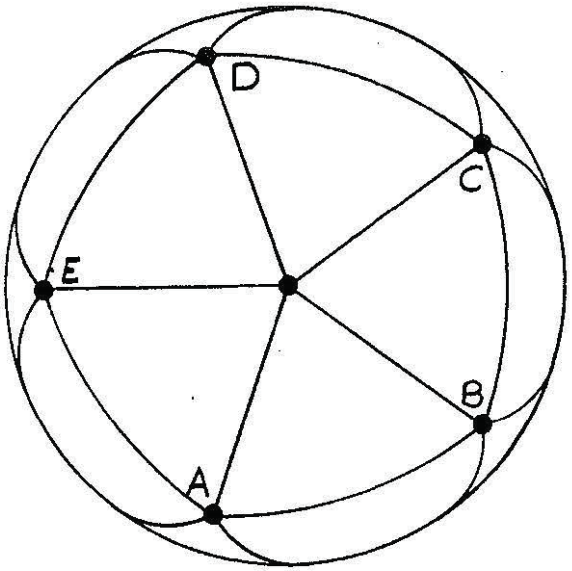
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-2

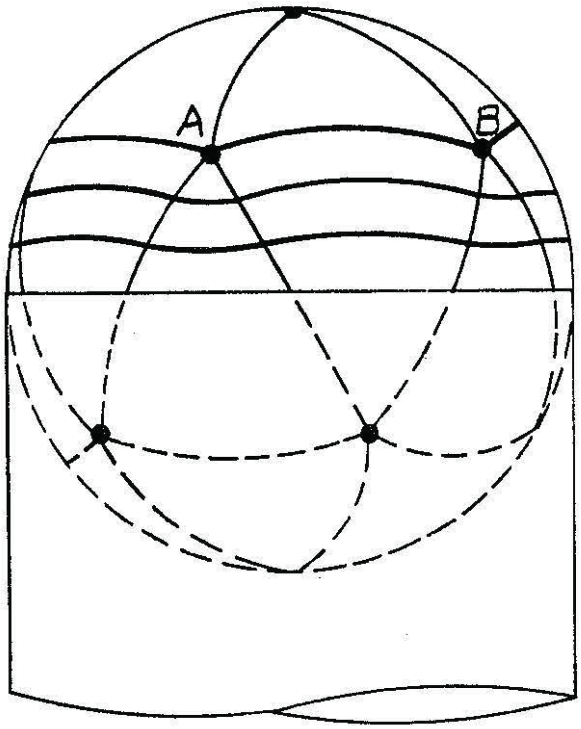
CONTAINMENT STRUCTURE

TYPICAL REINFORCING LOOP

(HISTORICAL)



SKETCH 1



SKETCH 2

FSAR UPDATE

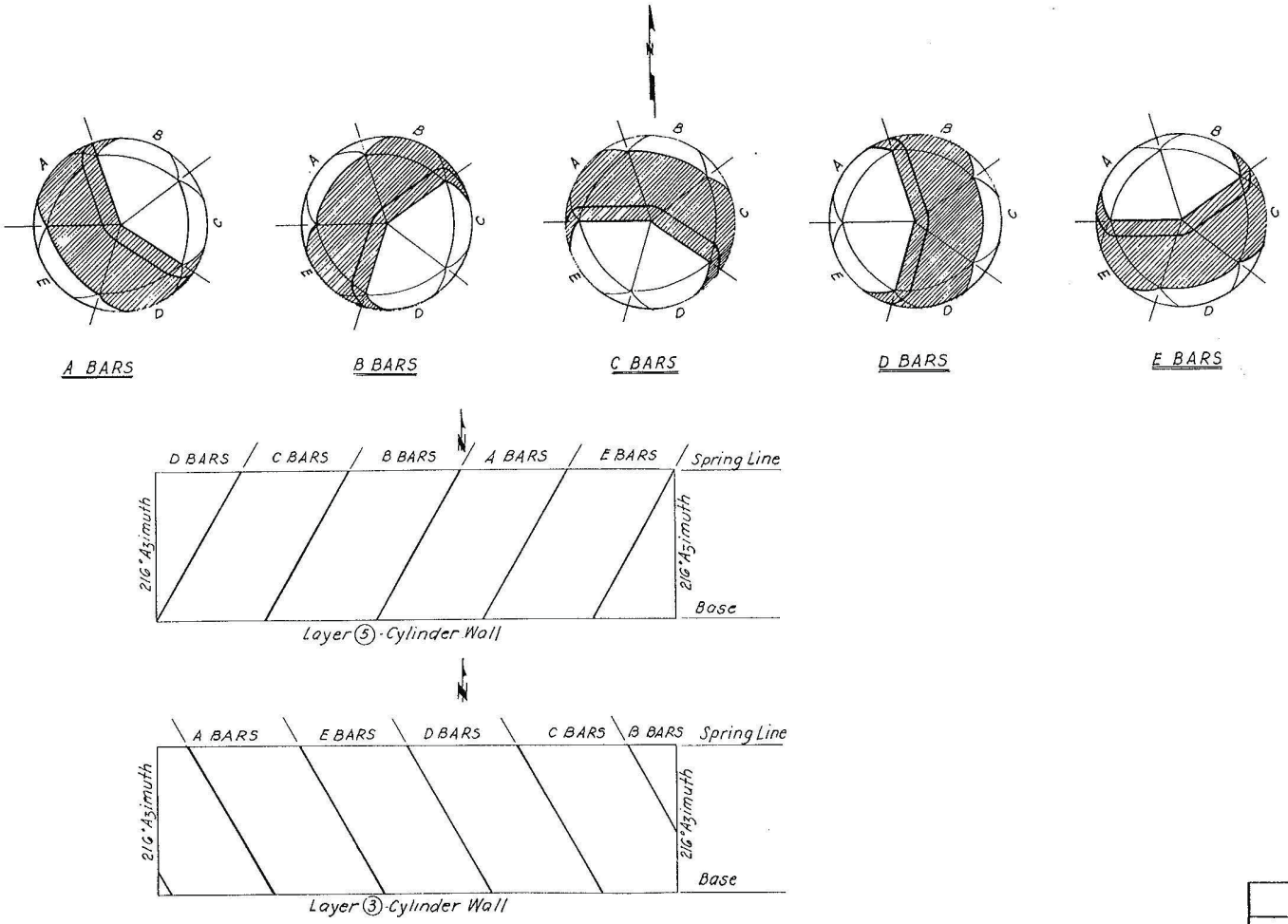
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-3

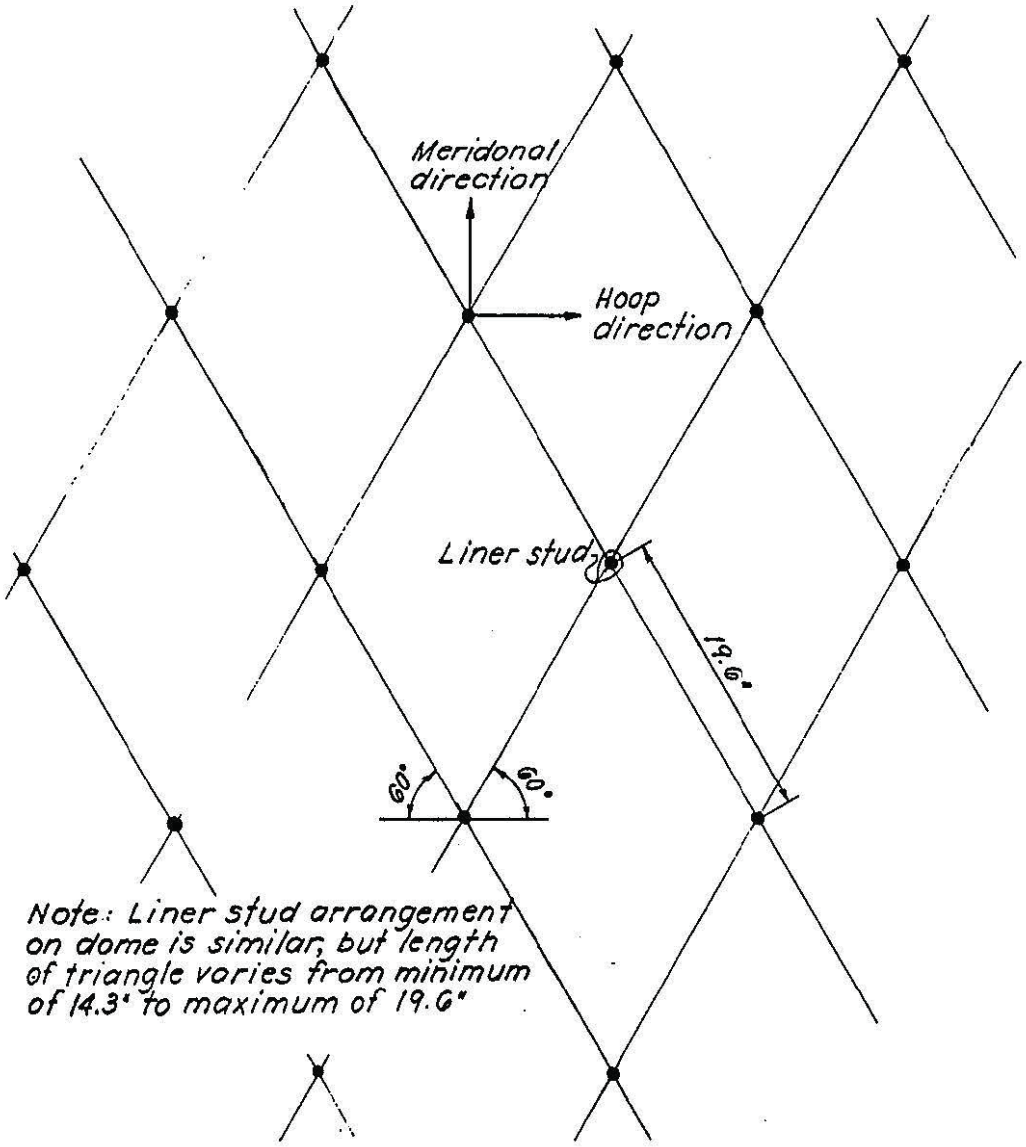
CONTAINMENT STRUCTURE

DOME SPHERICAL TRIANGLES

(HISTORICAL)



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.8-4 CONTAINMENT STRUCTURE DOME AND CYLINDER BARS **(HISTORICAL)**



FSAR UPDATE

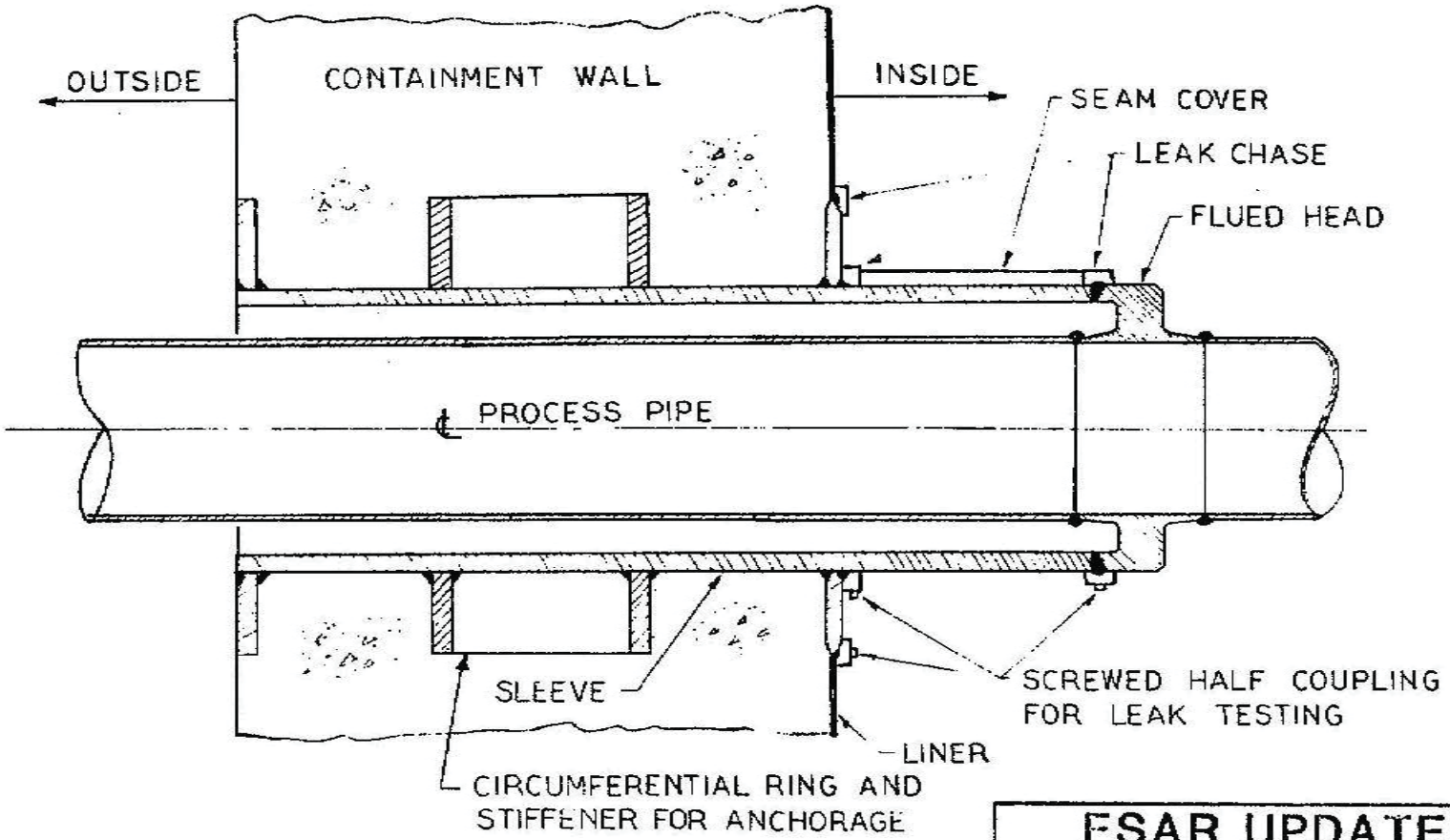
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-5

CONTAINMENT STRUCTURE

LINER STUD ARRANGEMENT

(HISTORICAL)



FSAR UPDATE

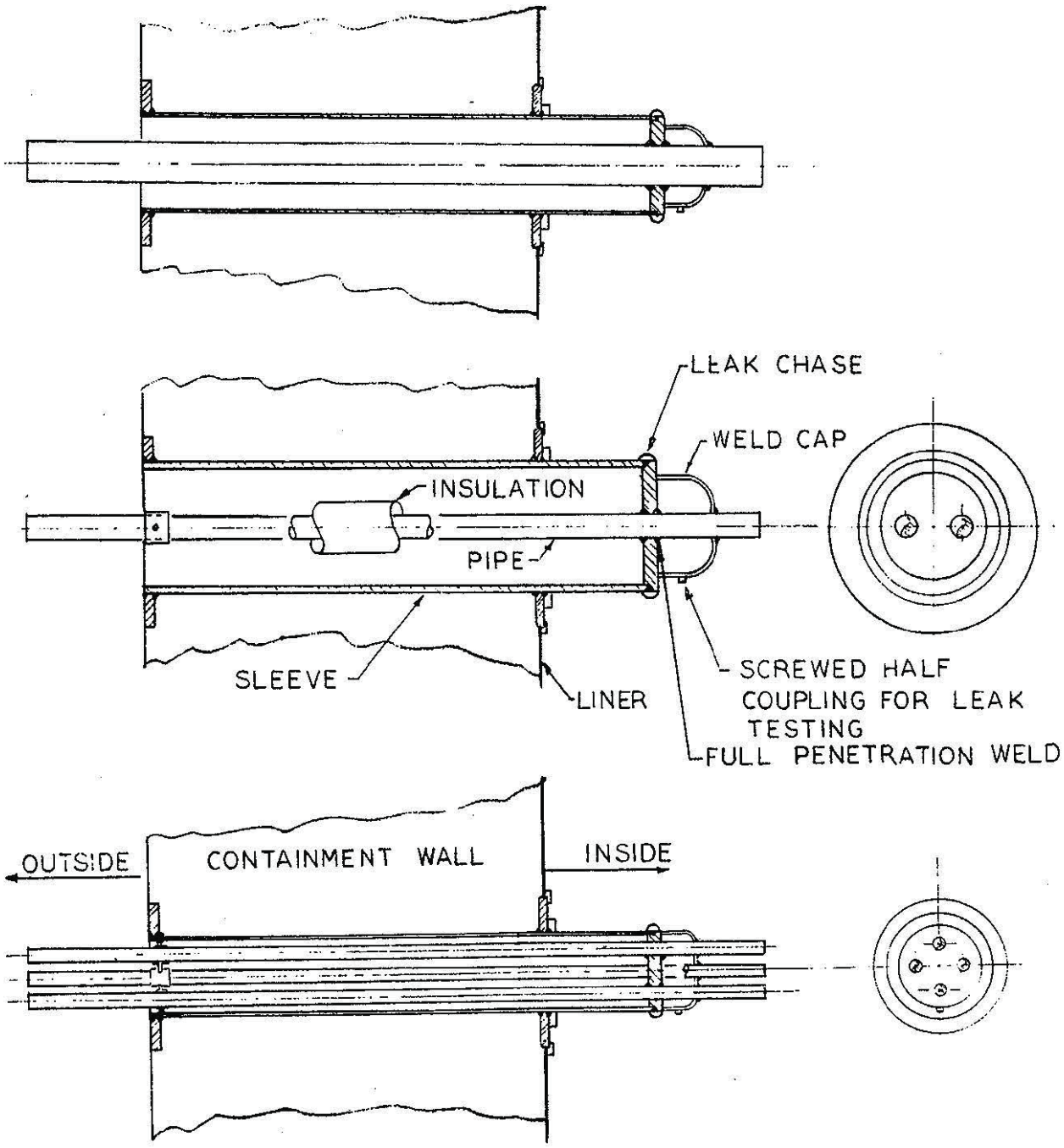
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-6

CONTAINMENT STRUCTURE

TYPICAL PIPING PENETRATION

(HISTORICAL)



FSAR UPDATE

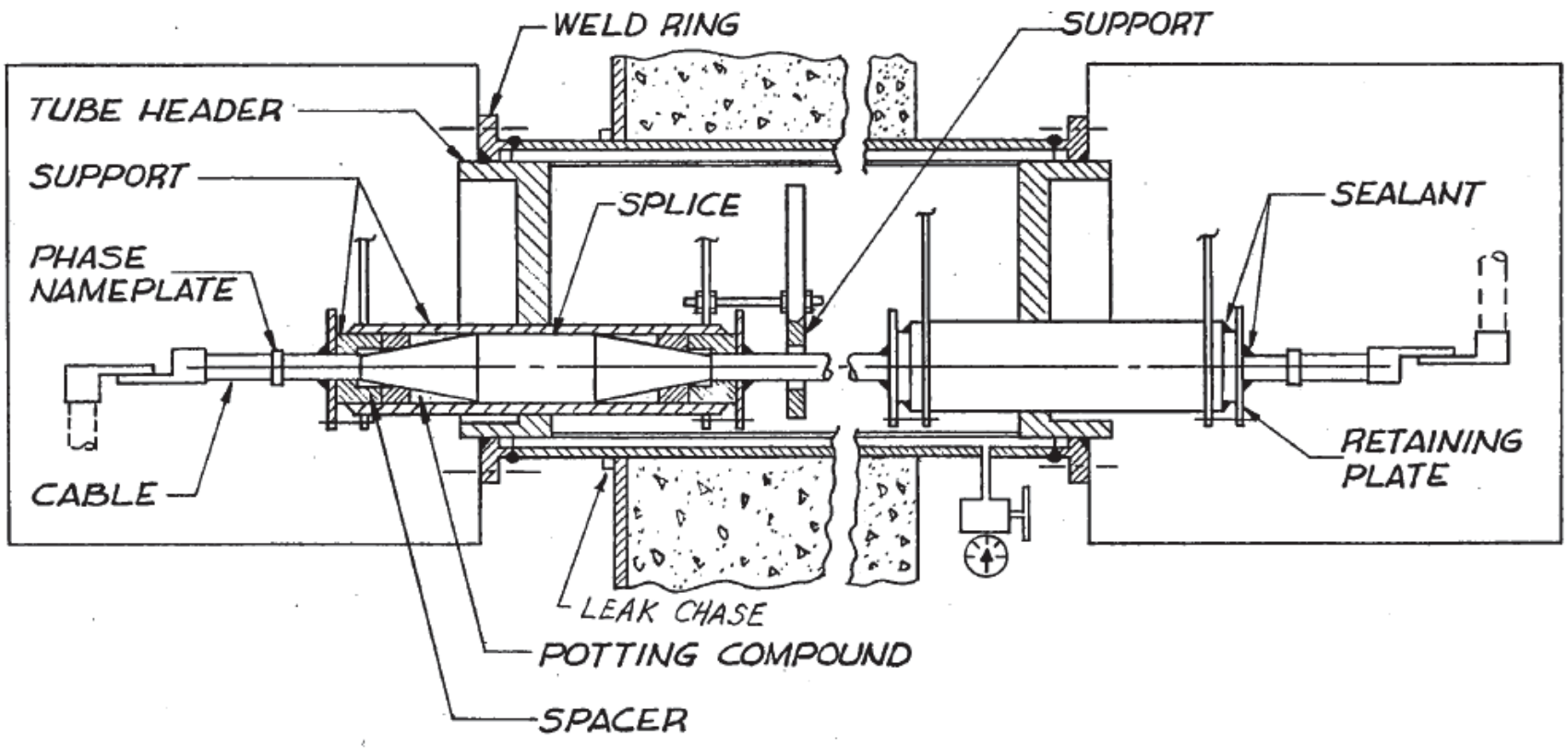
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-7

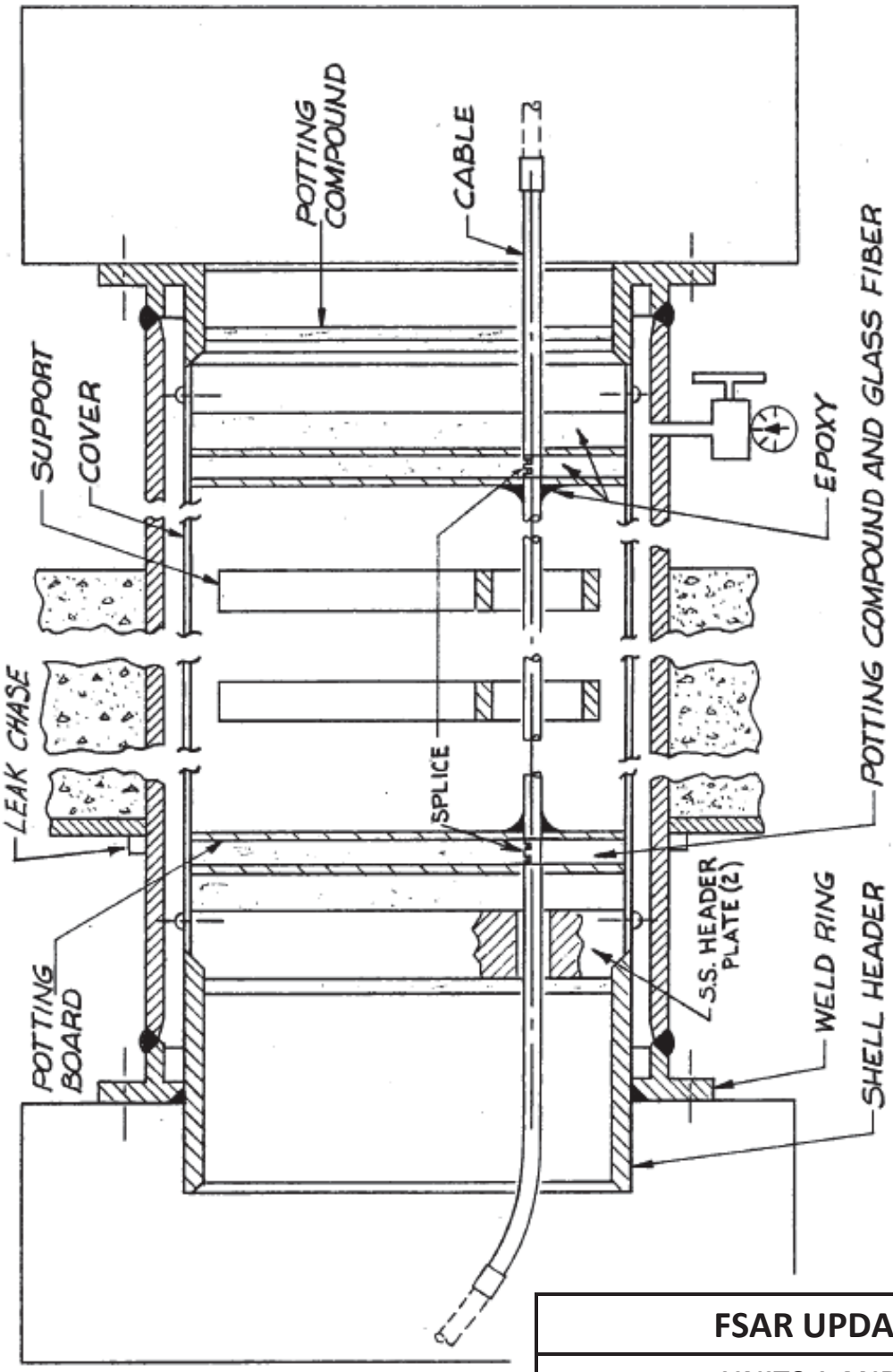
CONTAINMENT STRUCTURE

TYPICAL PIPING PENETRATION

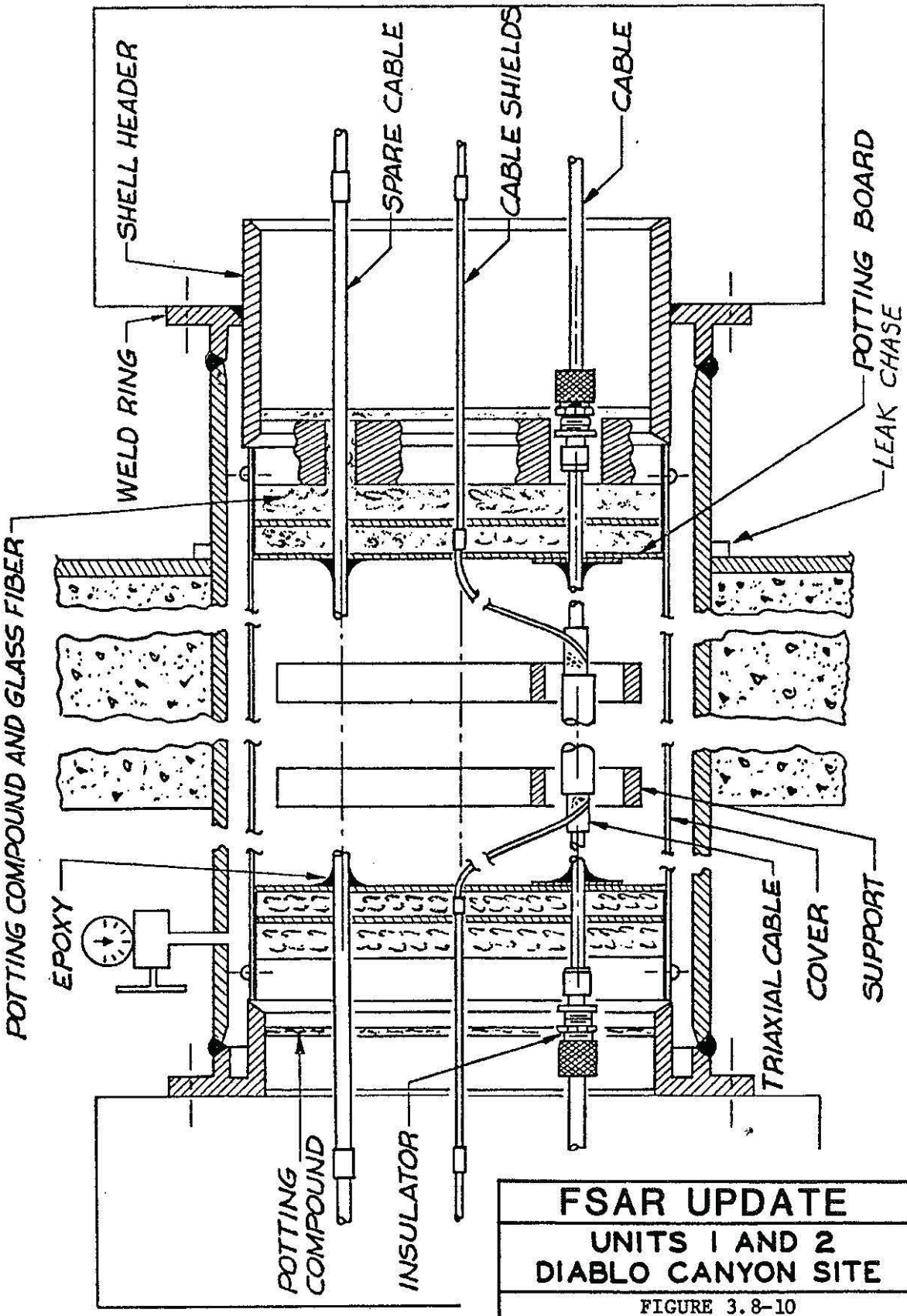
(HISTORICAL)



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.8-8 CONTAINMENT STRUCTURE TYPICAL 12 KV POWER PENETRATION (HISTORICAL)



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.8-9 CONTAINMENT STRUCTURE TYPICAL LOW VOLTAGE PENETRATION (HISTORICAL)

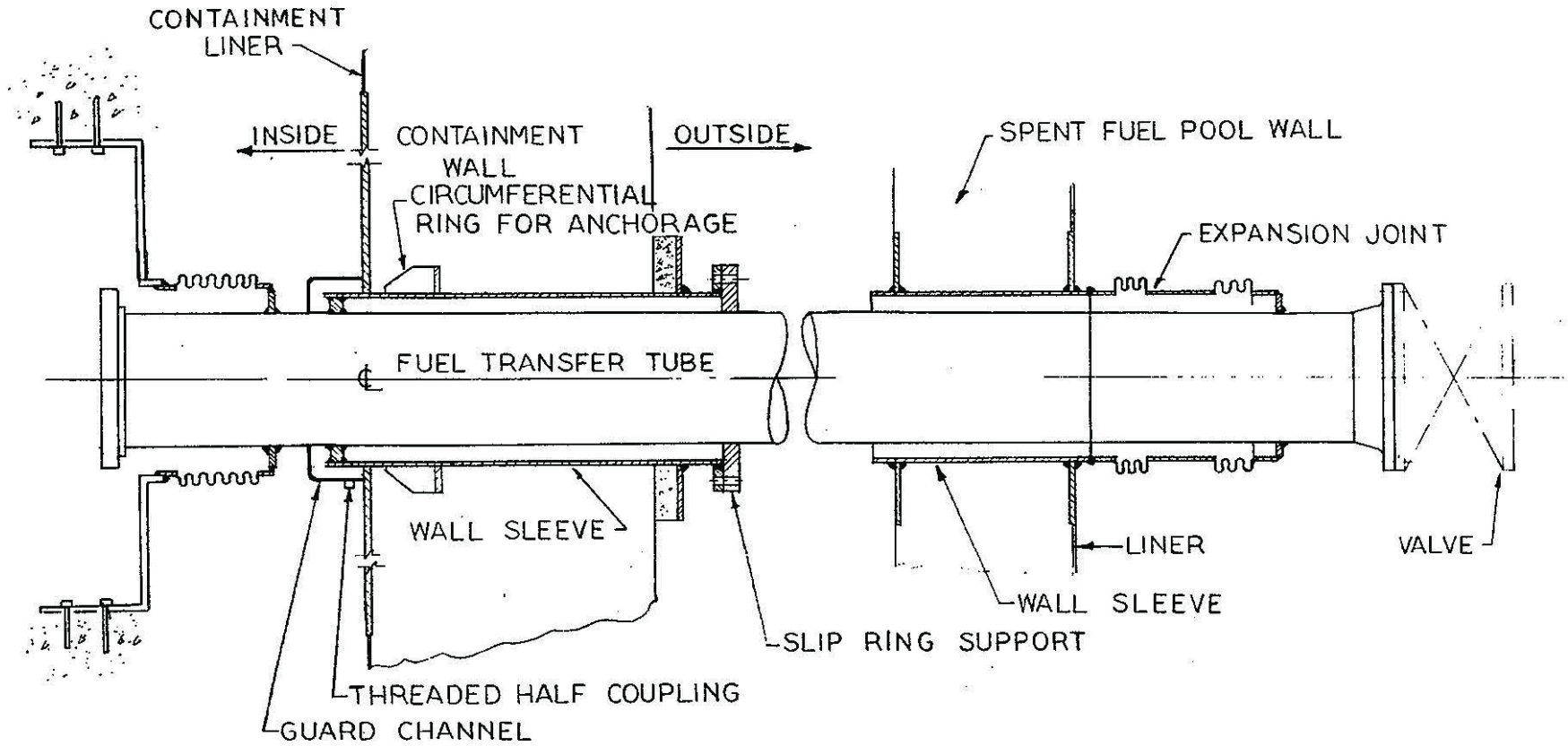


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-10

CONTAINMENT STRUCTURE
TYPICAL INSTRUMENTATION PENETRATION
(HISTORICAL)



FSAR UPDATE

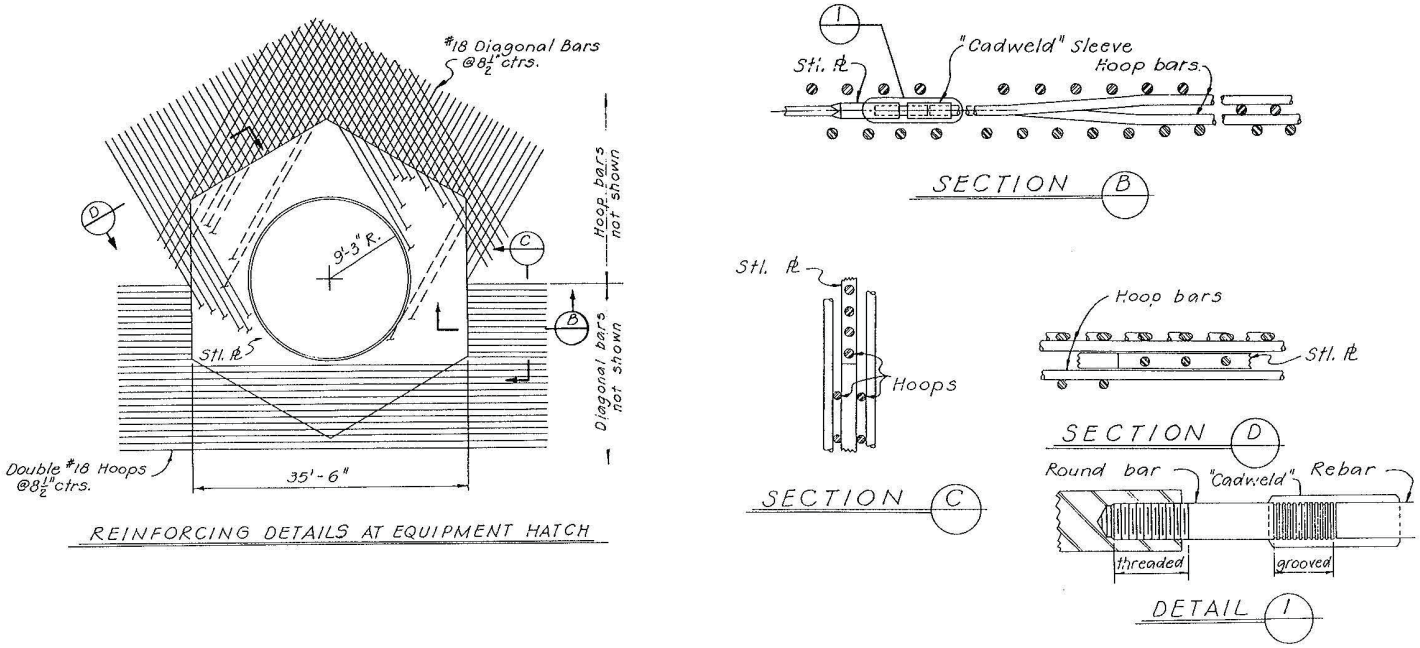
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-11

CONTAINMENT STRUCTURE

FUEL TRANSFER TUBE PENETRATION

(HISTORICAL)



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

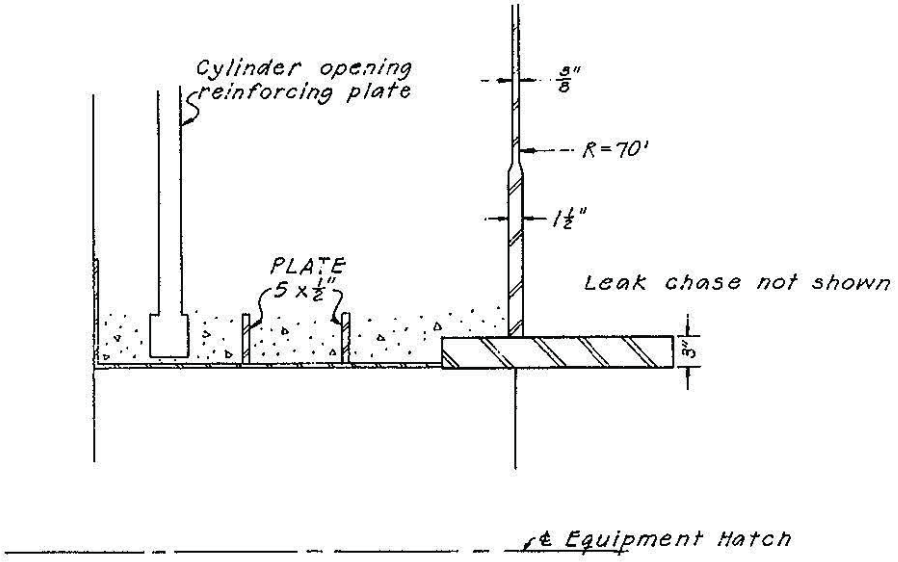
FIGURE 3.8-12

CONTAINMENT STRUCTURE

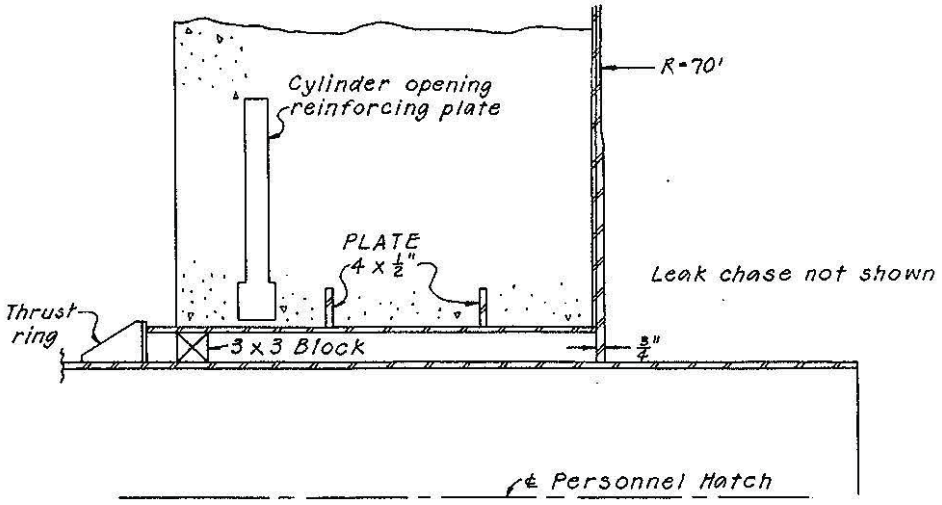
HEXAGONAL COLLARS

(HISTORICAL)

Revision 23 December 2016

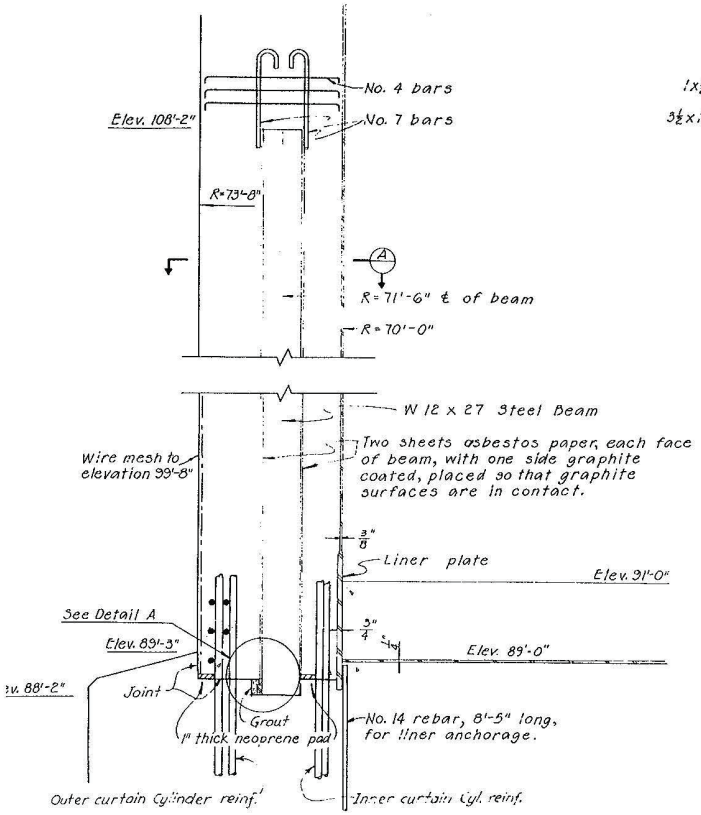


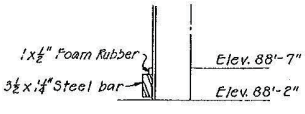
EQUIPMENT HATCH



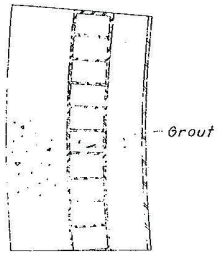
Unit 1 PERSONNEL HATCH

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.8-13 CONTAINMENT STRUCTURE ACCESS HATCH SLEEVES (HISTORICAL)





DETAIL A



SECTION A

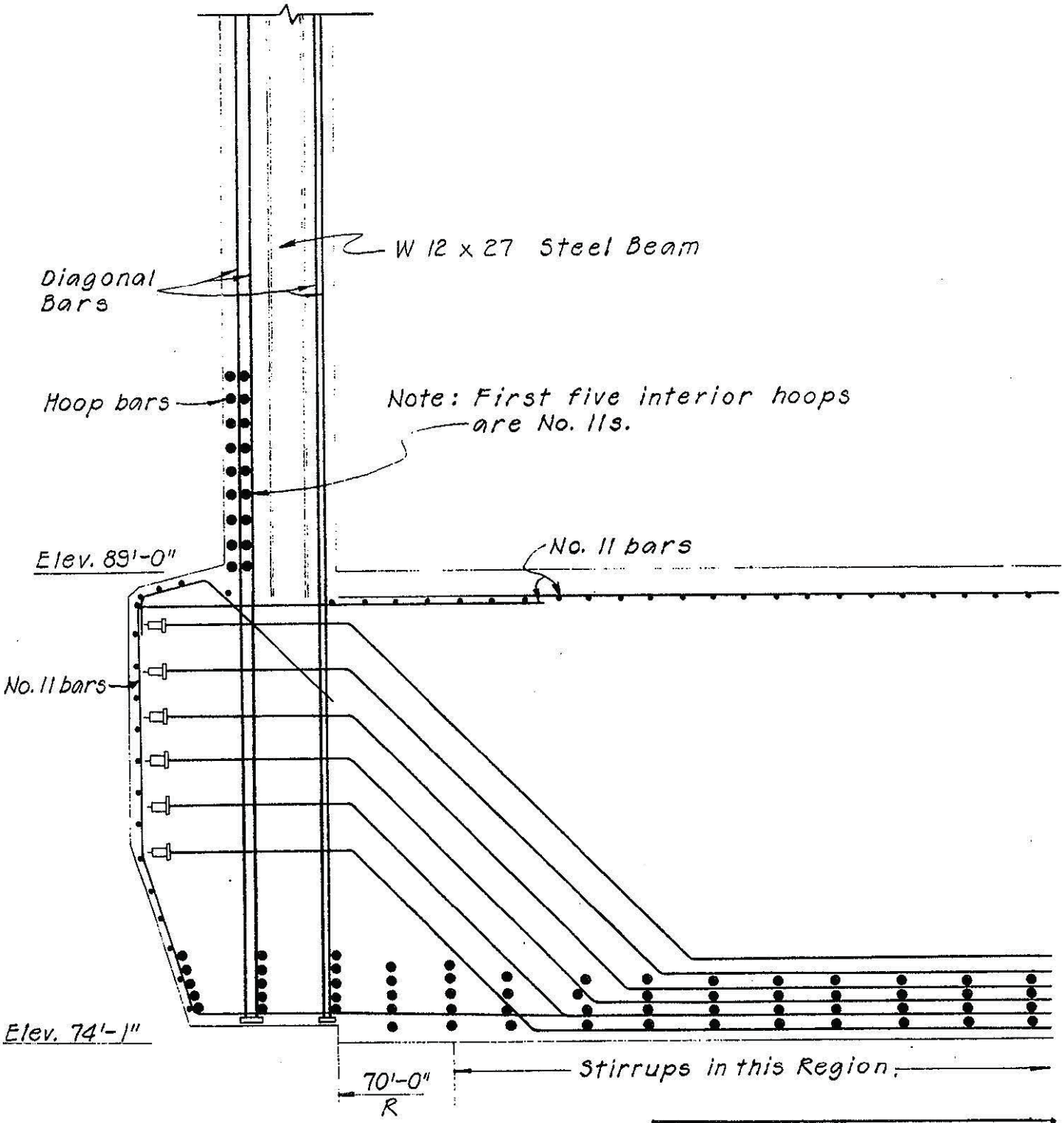
NOTES :

SEE FIGURE 3.8-15 FOR REINFORCING STEEL IN THIS REGION.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-14
CONTAINMENT STRUCTURE
EMBEDDED BEAMS
CYLINDER-BASE SLAB JUNCTURE
(HISTORICAL)

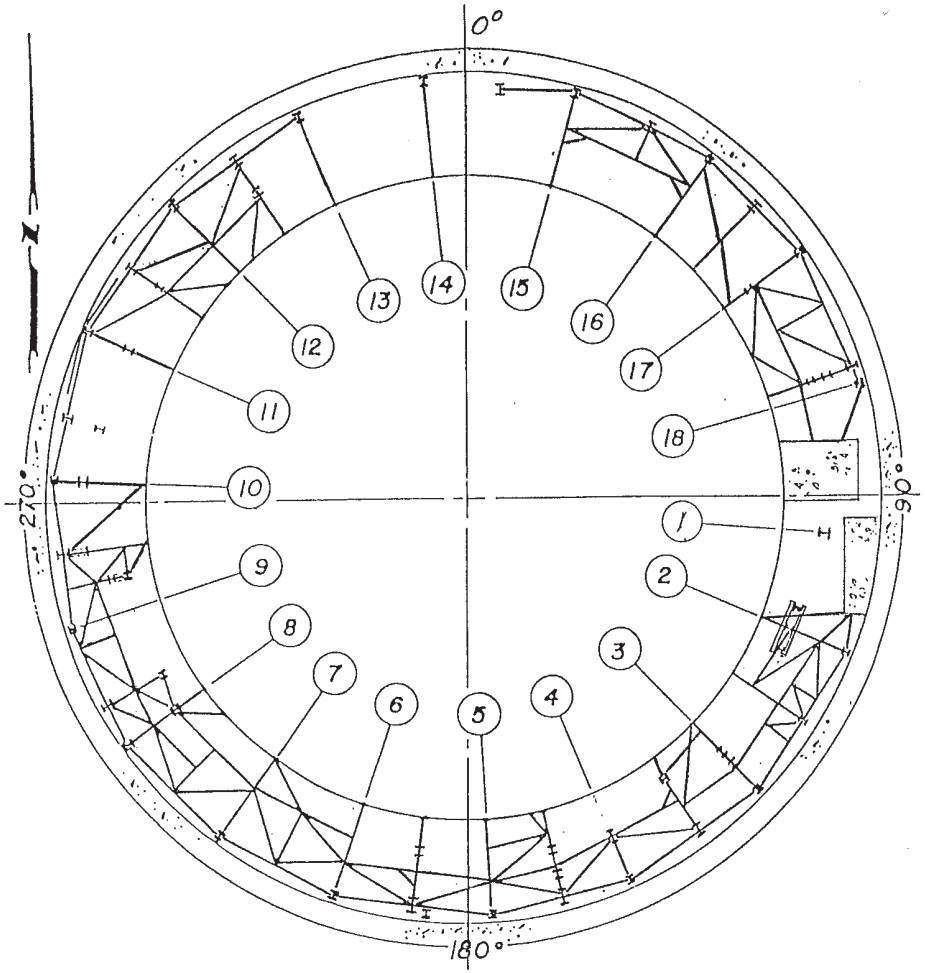


Bars are No. 18 unless noted.

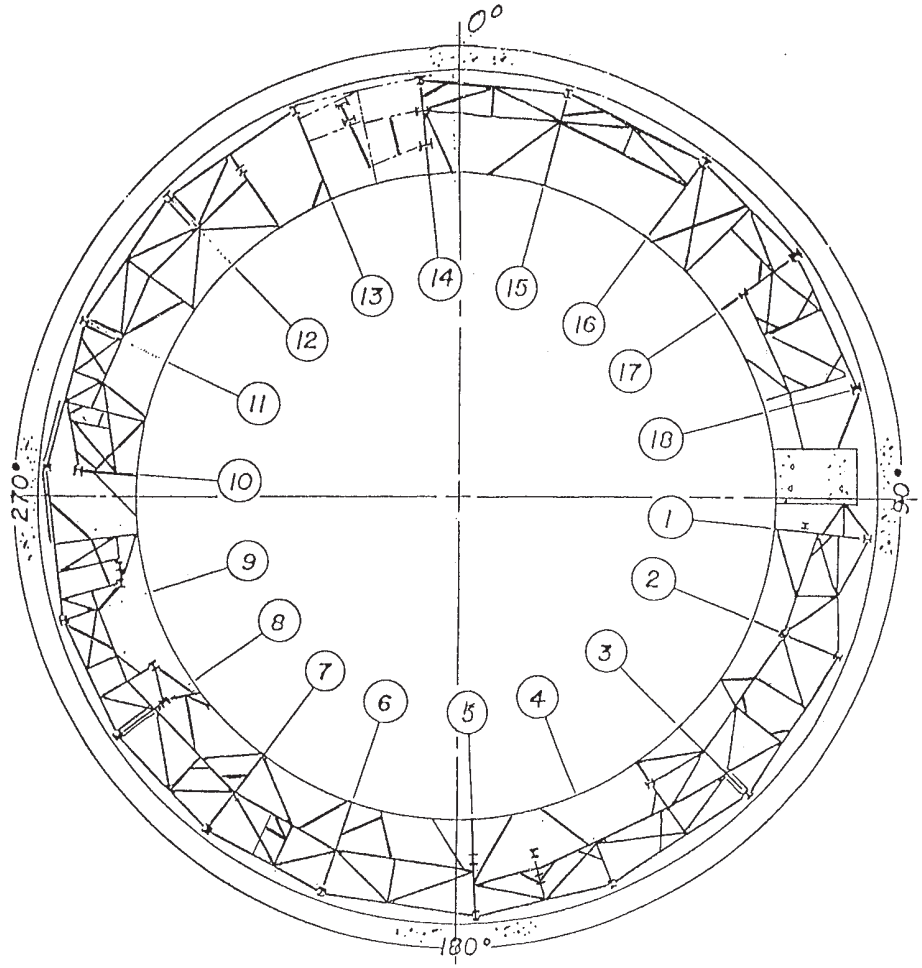
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-15
CONTAINMENT STRUCTURE
REINFORCING STEEL
BASE SLAB AND WALL
(HISTORICAL)



FRAMING PLAN T.O.S. EL 101'-4 1/2"



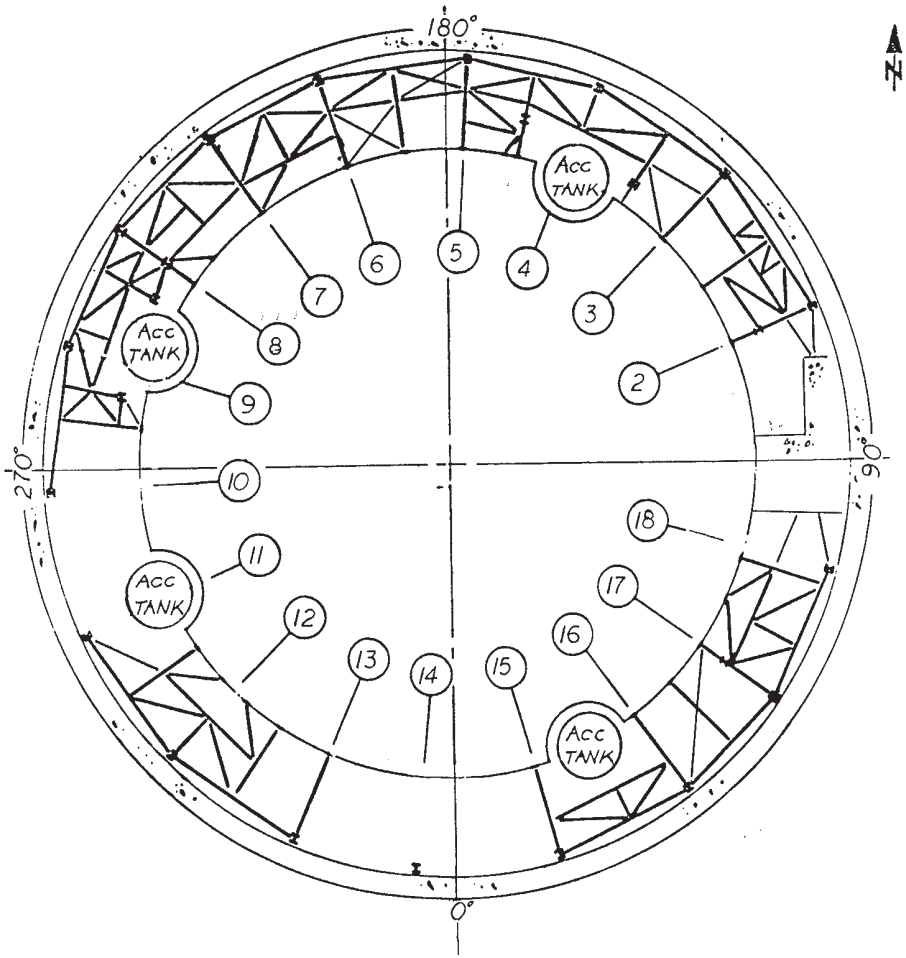
FRAMING PLAN T.O.S. EL 106'-8"

FSAR UPDATE

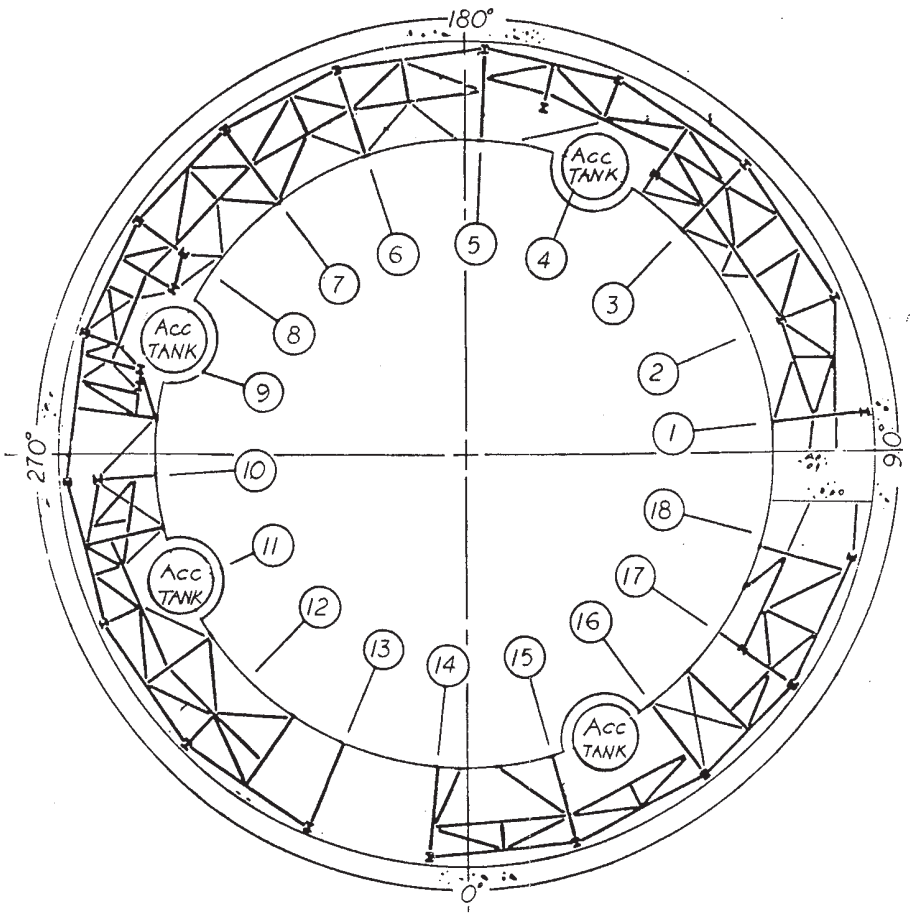
UNIT 1
DIABLO CANYON SITE

FIGURE 3.8-21, (Sheet 1 of 2)

INTERNAL STRUCTURE
ANNULUS PLATFORM
ELEVATIONS 101' AND 106'



FRAMING PLAN T.O.S. EL. 101'-4½"



FRAMING PLAN T.O.S. EL. 106'-8"

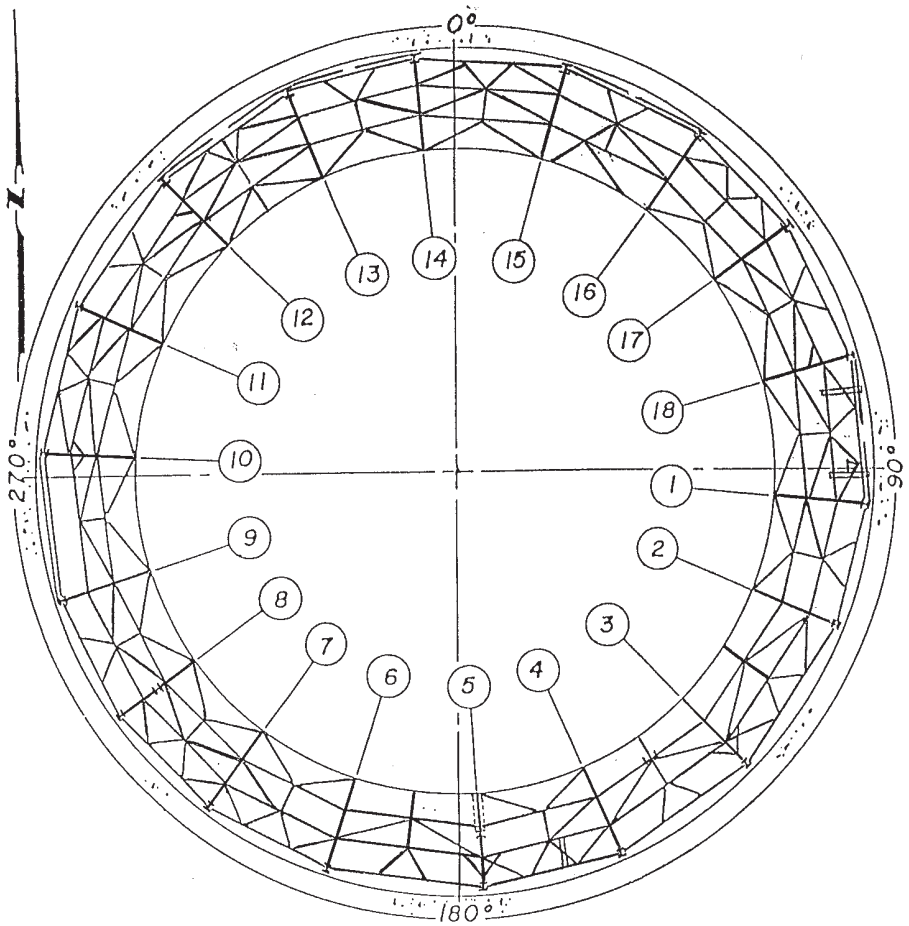
FSAR UPDATE

UNIT 2

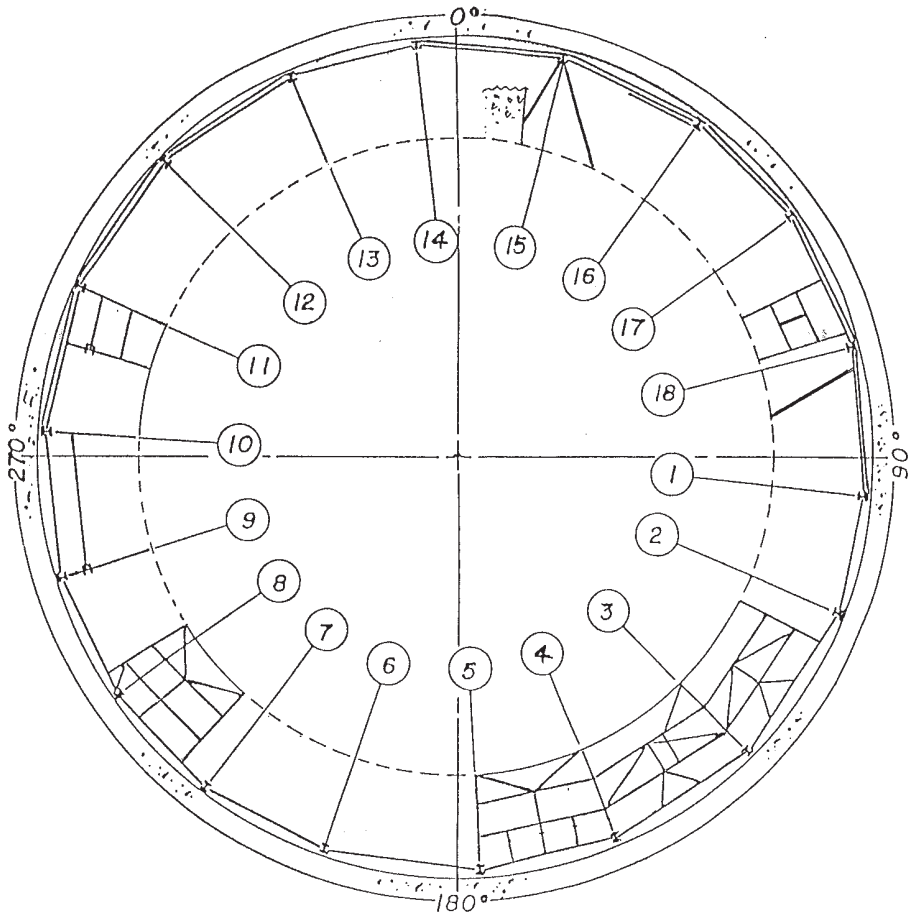
DIABLO CANYON SITE

FIGURE 3.8-21, (Sheet 2 of 2)

INTERNAL STRUCTURE
ANNULUS PLATFORM
ELEVATIONS 101 AND 106'

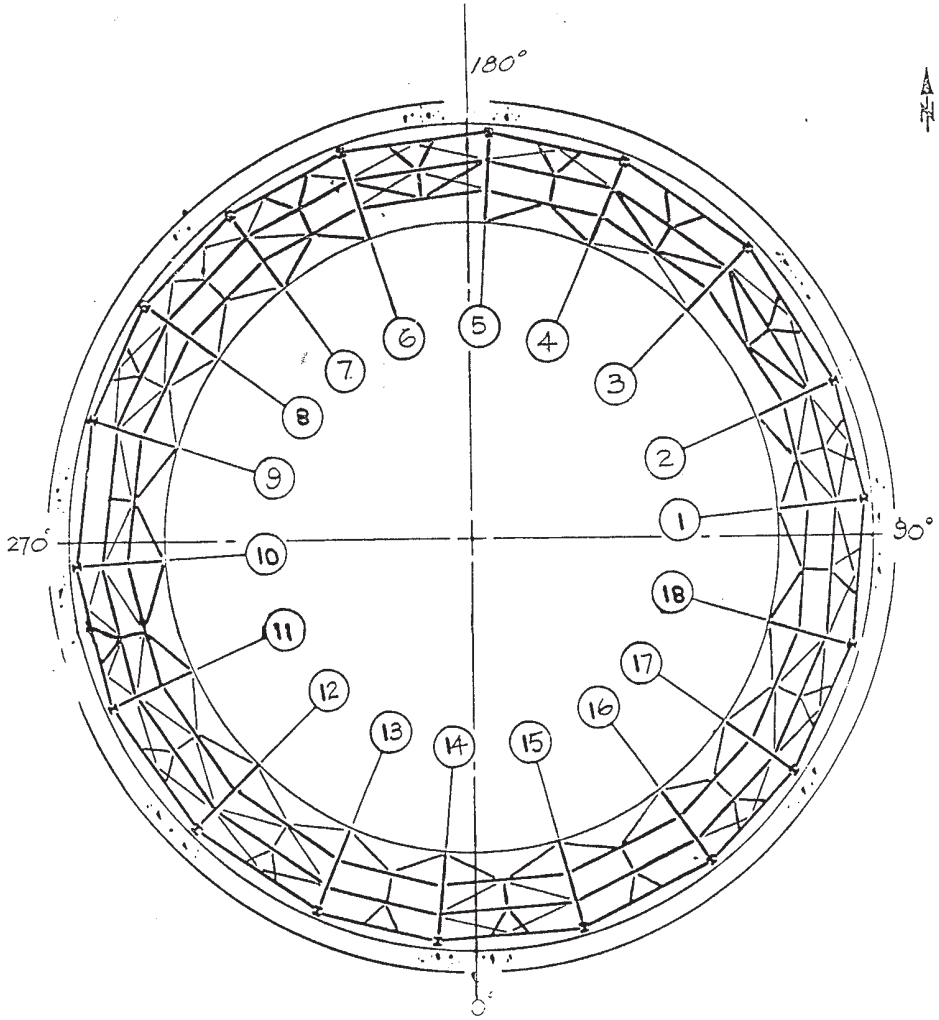


FRAMING PLAN T.O.S. EL 116'-10 3/4"

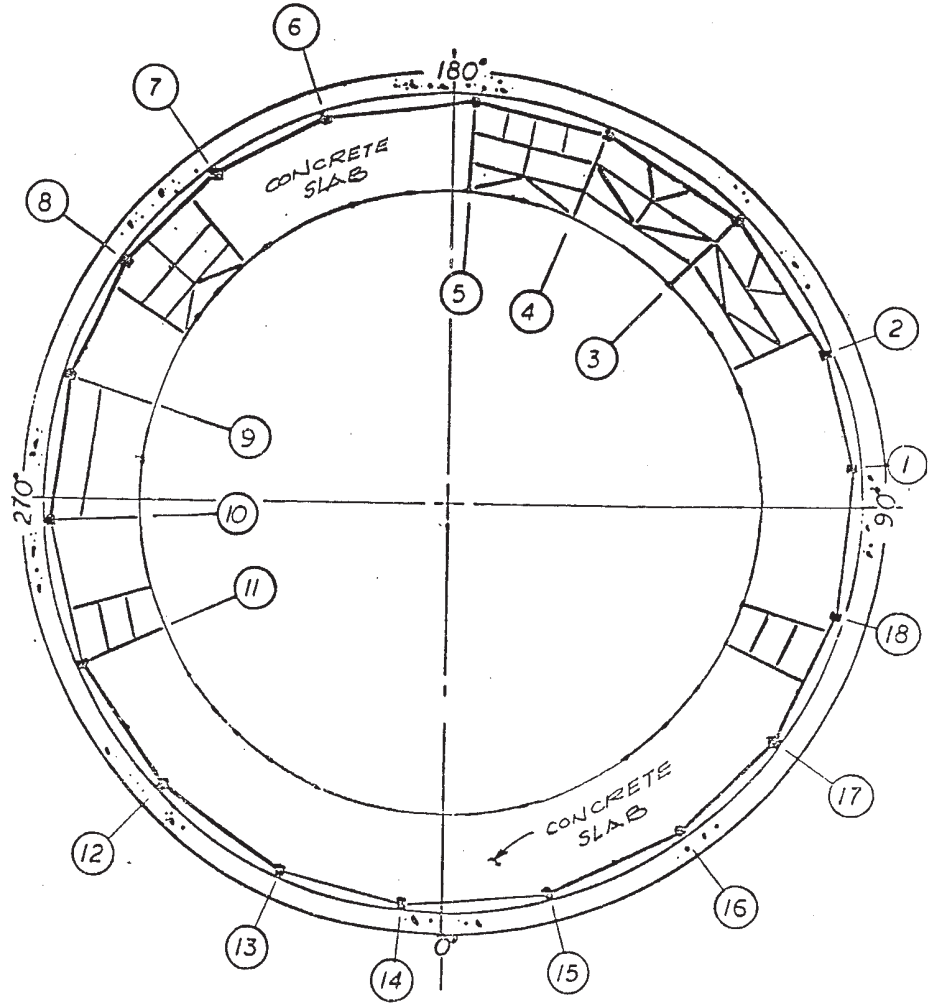


FRAMING PLAN T.O.S. EL 139'-10 3/4"

FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.8-22 (Sheet 1 of 2) INTERNAL STRUCTURE ANNULUS PLATFORM ELEVATIONS 117 AND 140'

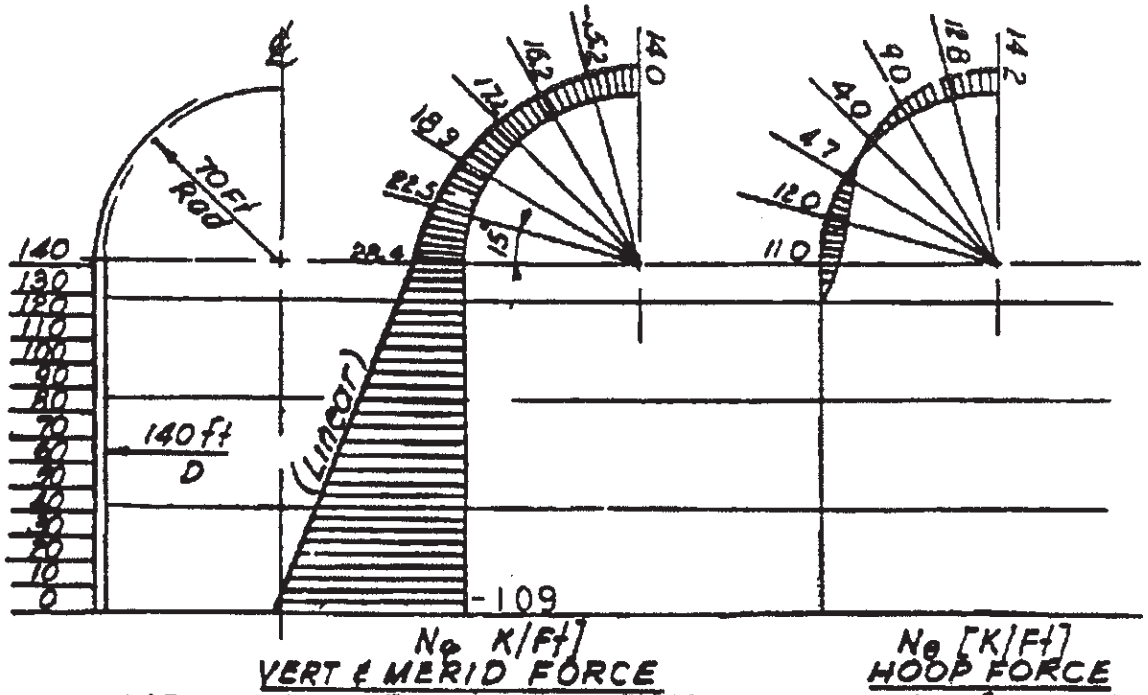


FRAMING PLAN T.O.S. EL. 116'-10¾"



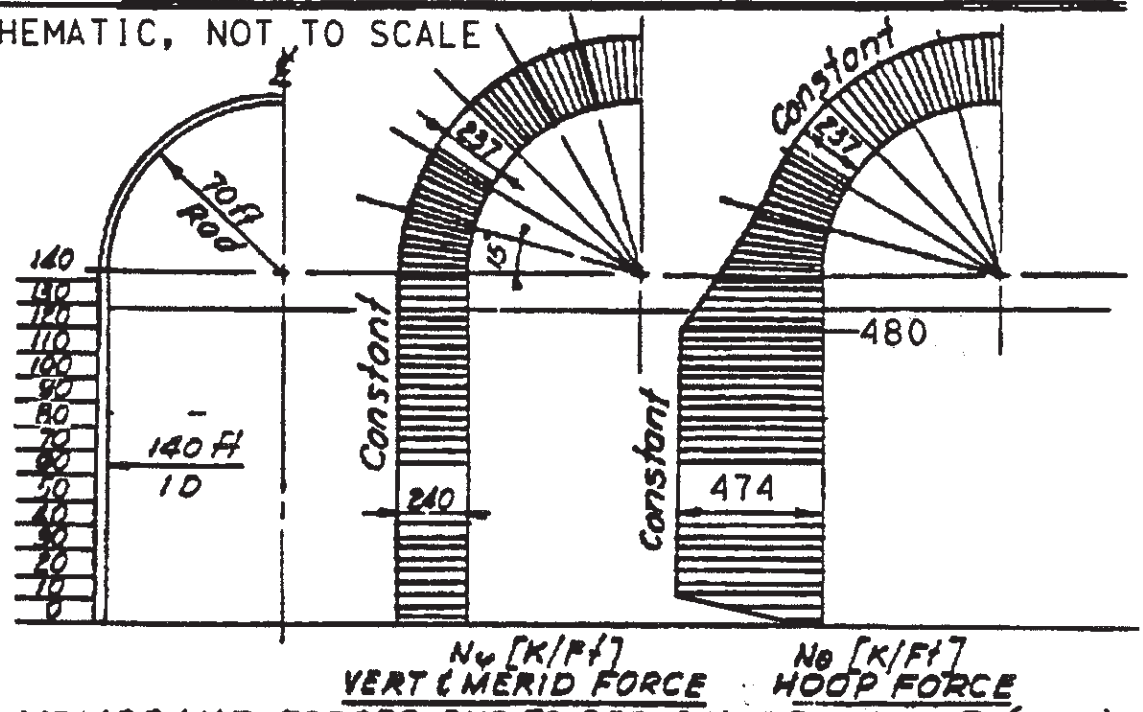
FRAMING PLAN AT EL. 140'-0"

FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 3.8-22 (Sheet 2 of 2) INTERNAL STRUCTURE ANNULUS PLATFORM ELEVATIONS 117 AND 140'



MEMBRANE FORCES DUE TO DEAD LOAD (1.00 D)

SCHEMATIC, NOT TO SCALE



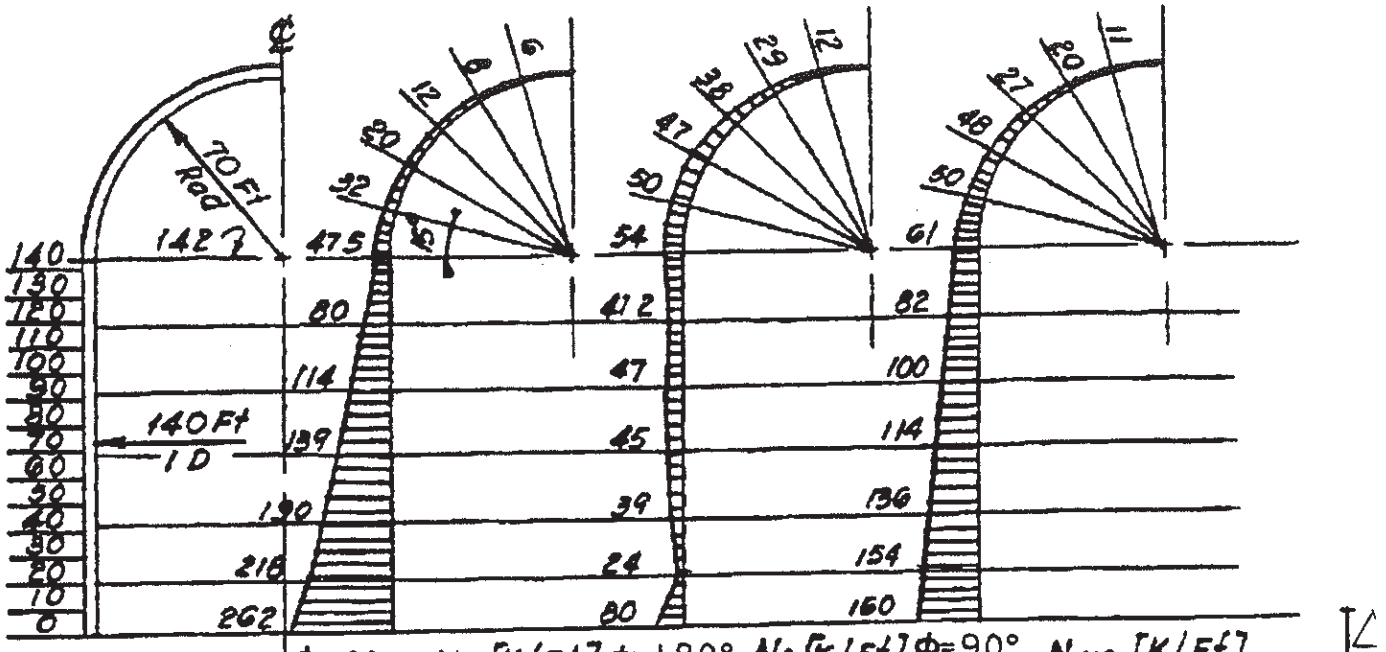
MEMBRANE FORCES DUE TO DESIGN PRESSURE (1.0 P)

SCHEMATIC, NOT TO SCALE

FSAR UPDATE

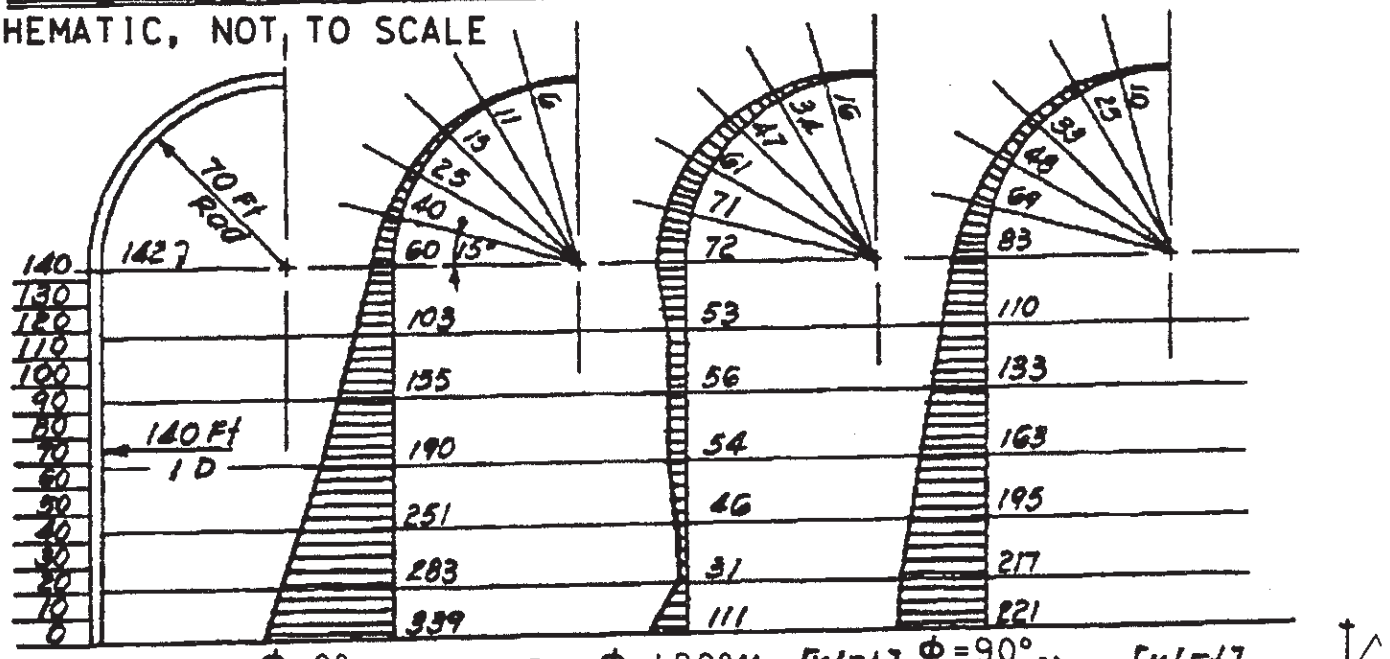
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-27
CONTAINMENT STRUCTURE
MEMBRANE FORCES
DEAD LOAD AND PRESSURE



MEMBRANE FORCES DUE TO 125x DESIGN EARTHQUAKE (125 DE)

SCHEMATIC, NOT TO SCALE



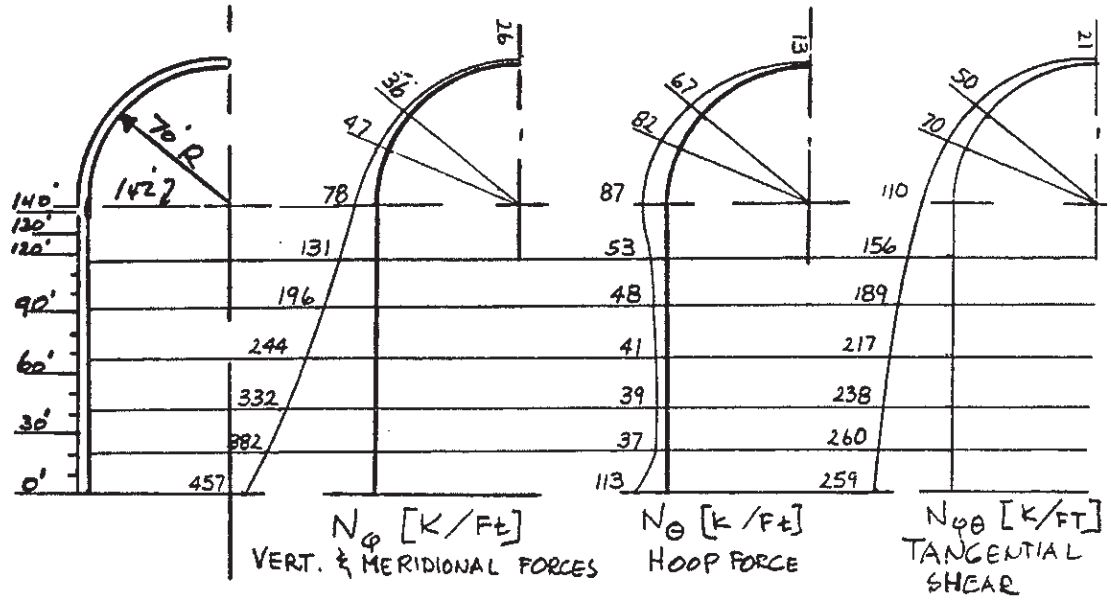
MEMBRANE FORCES DUE TO DOUBLE DESIGN EARTHQUAKE (DDE)

SCHEMATIC, NOT TO SCALE

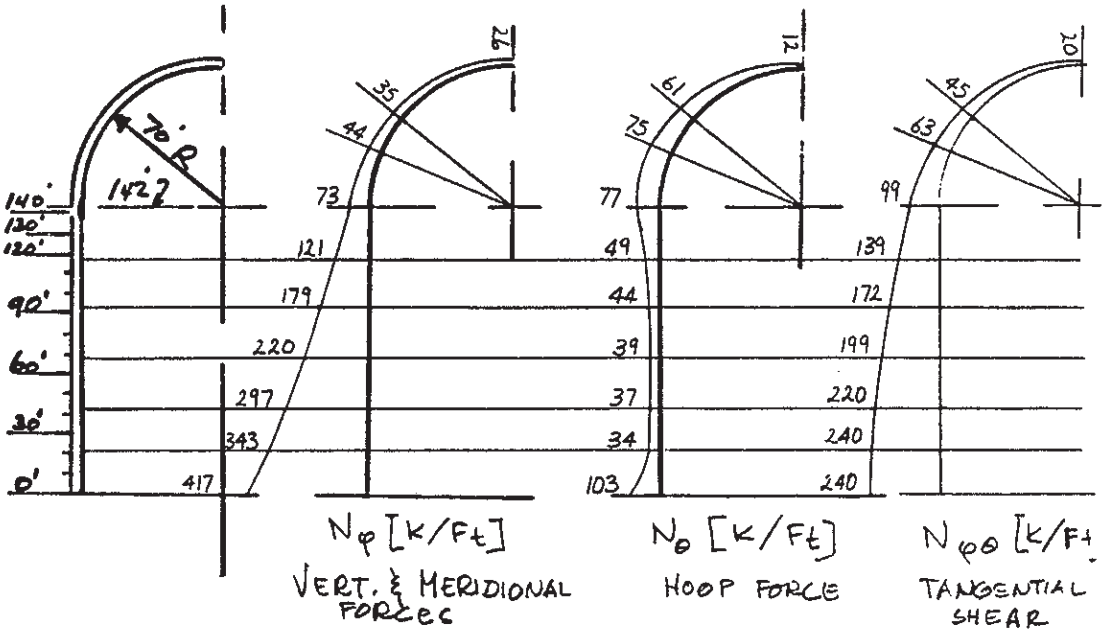
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8.28
CONTAINMENT STRUCTURE
MEMBRANE FORCES
DE and DDE EARTHQUAKES-B

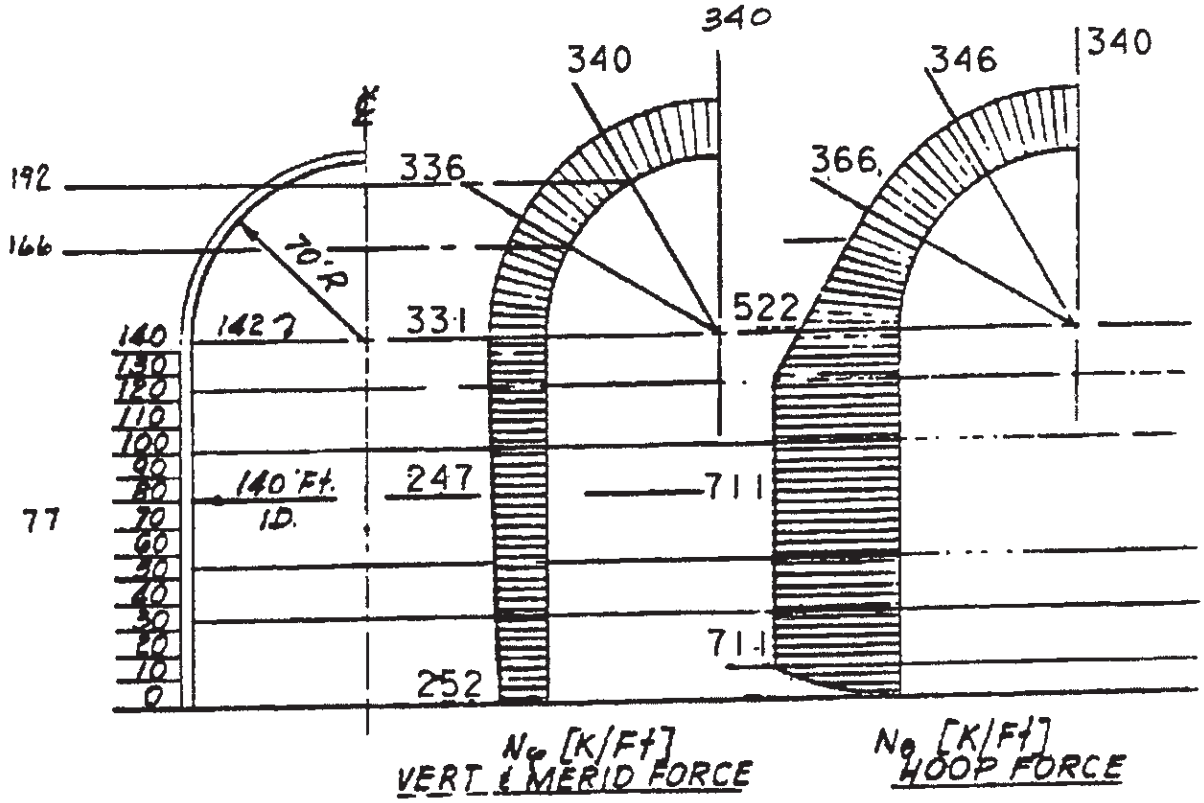


MEMBRANE FORCES DUE TO HOSGRI (BLUME) EARTHQUAKE



MEMBRANE FORCES DUE TO HOSGRI [NEWMARK] EARTHQUAKE

FSAR UPDATE
UNITS 1 AND 2 **DIABLO CANYON SITE**
FIGURE 3.8-29 CONTAINMENT STRUCTURE MEMBRANE FORCES HOSGRI EARTHQUAKE



MAMBRANE FORCES

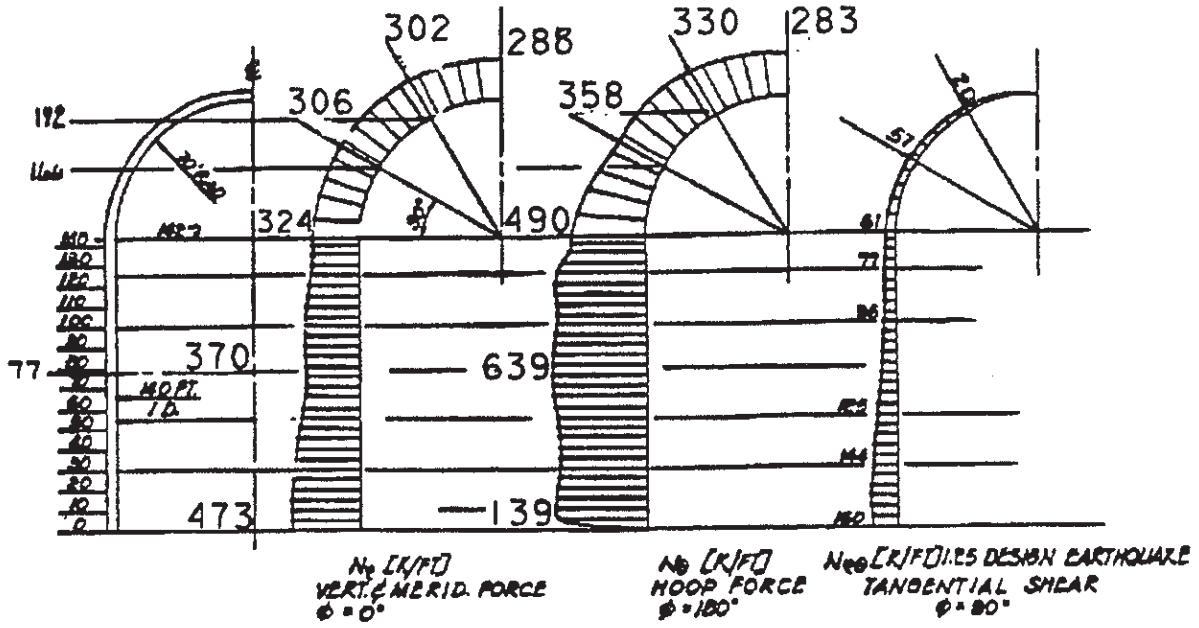
DUE TO LOAD CONDITION (1) U = 1.0D ± .05D + 1.5P +1.0T"

SCHEMATIC NOT TO SCALE

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-30
CONTAINMENT STRUCTURE
MEMBRANE FORCES
ACCIDENT CONDITION 1



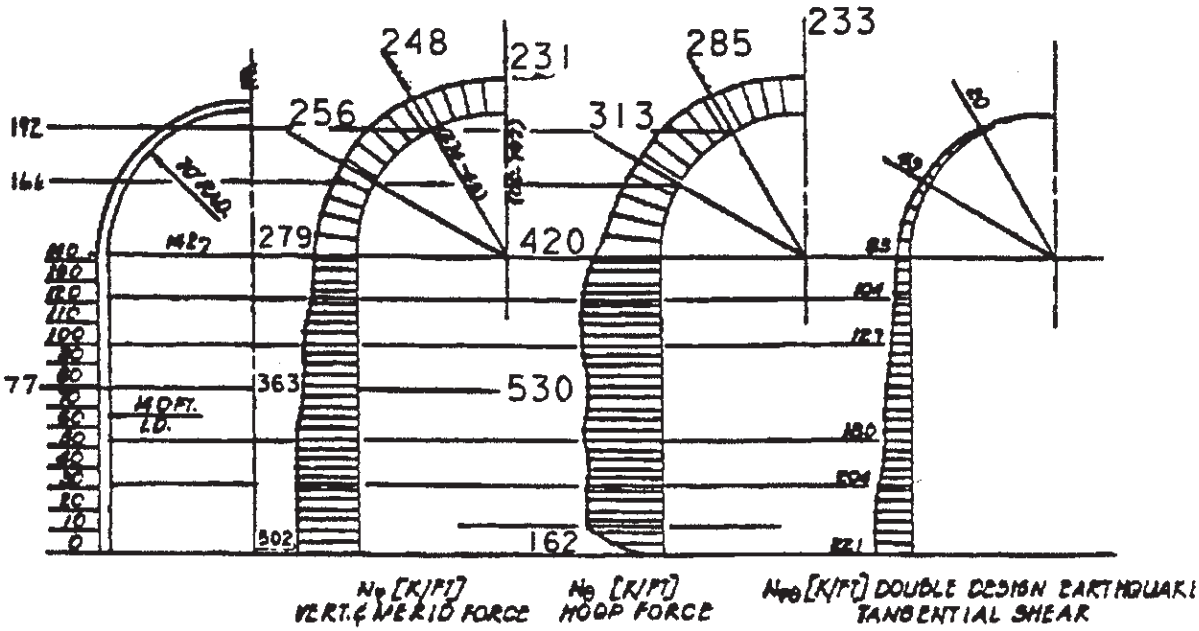
MEMBRANE FORCES

DUE TO LOAD CONDITION (2) U = 1.0D ± .05D + 1.25P + 1.25DE + T'

SCHEMATIC NOT TO SCALE

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.8-31 CONTAINMENT STRUCTURE MEMBRANE FORCES ACCIDENT CONDITION 2

Revision 24 September 2018



MAMBRANE FORCES

NOTE VALUES ARE FORCES IN REBAR

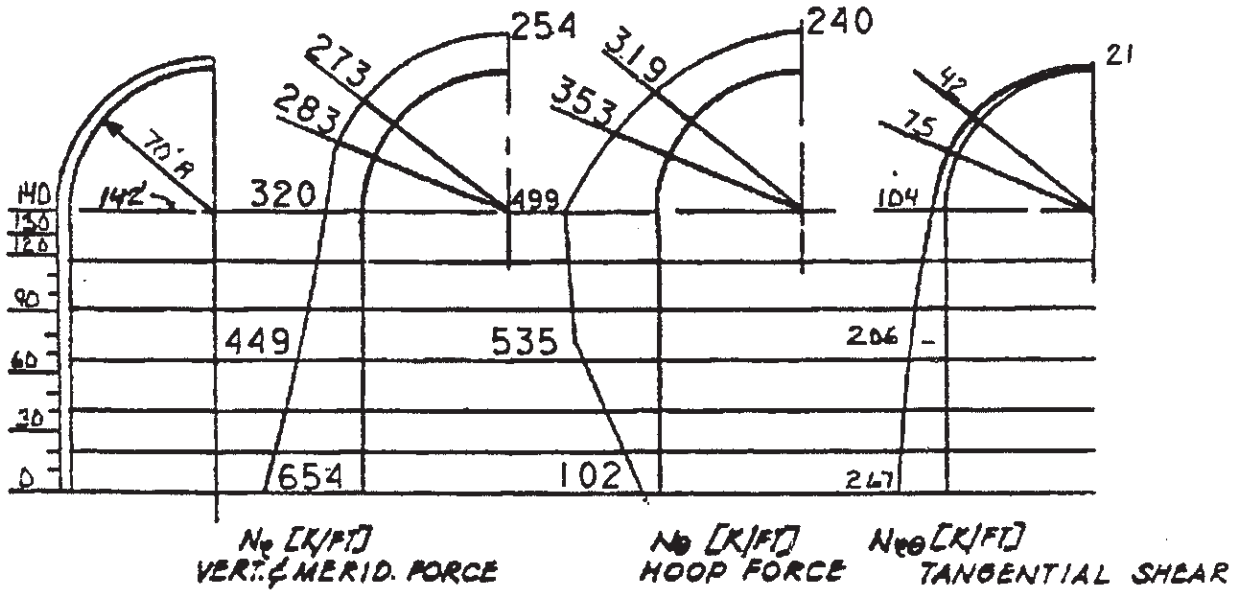
FORCES DUE TO LOAD CONDITION (3) U = 1.0D ± .05D + 1.0P + 1.0T + 1.0DDE

SCHEMATIC NOT TO SCALE

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-32
CONTAINMENT STRUCTURE
MEMBRANE FORCES
ACCIDENT CONDITION 3



MEMBRANE FORCES

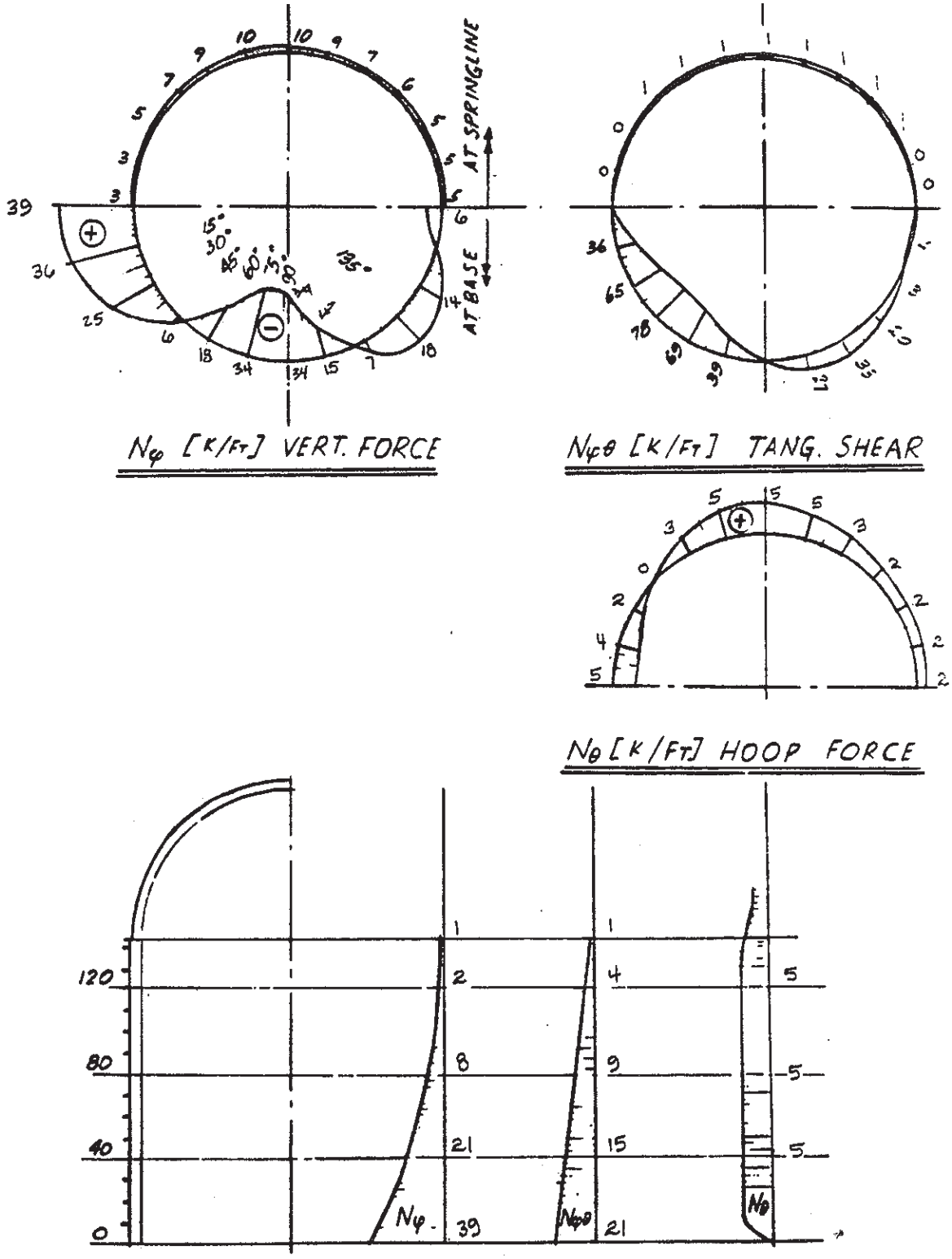
FORCES DUE TO LOAD CONDITION (4): U= (1 ± .05) D + P_A + T +HE

SCHEMATIC NOT TO SCALE

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-33
CONTAINMENT STRUCTURE
MEMBRANE FORCES
ACCIDENT CONDITION 4

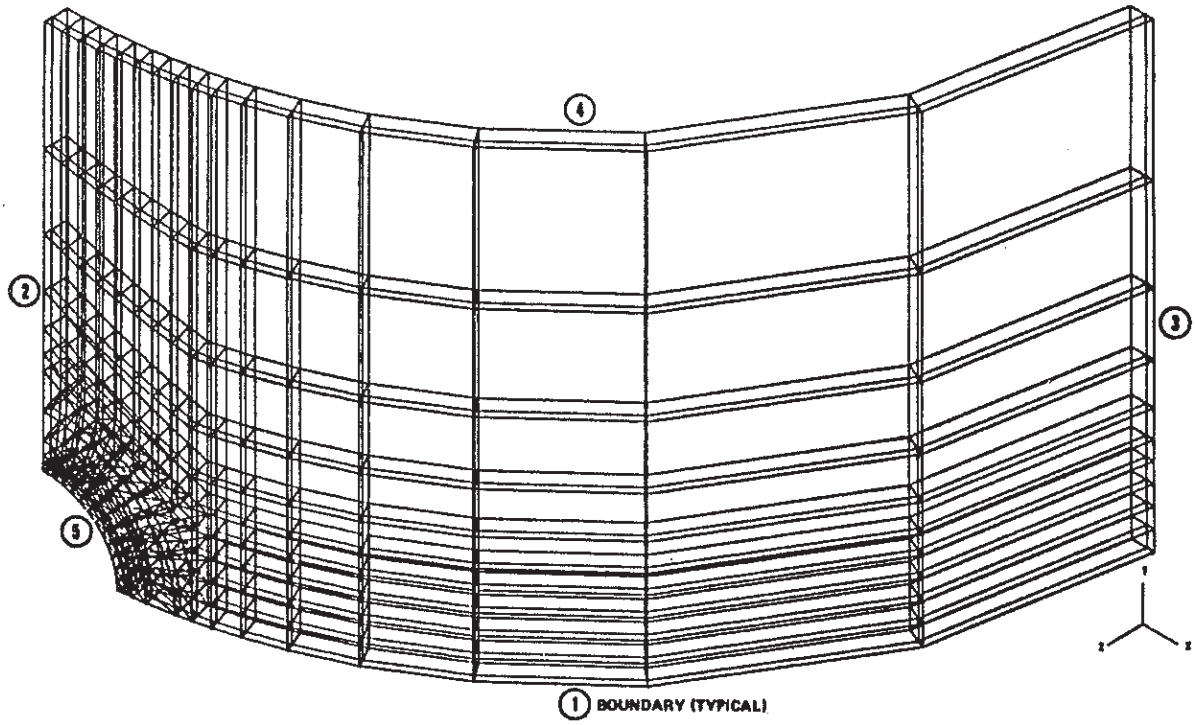


MEMBRANE FORCES DUE TO 80 MPH WIND

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-34
CONTAINMENT STRUCTURE
MEMBRANE FORCES
WIND LOAD



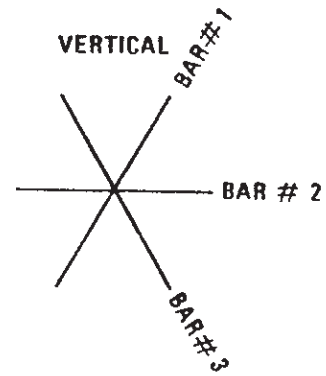
FSAR UPDATE
UNITS 1 AND 2 **DIABLO CANYON SITE**
FIGURE 3.8-35 CONTAINMENT STRUCTURE EQUIPMENT HATCH ANALYTICAL MODEL ISOMETRIC VIEW

Revision 11 November 1996

CRACKED SECTION

CONDITION (a) C = 1.0D + 0.05D + 1.5P + 1.0 T "

ALLOWABLE STRESS ELEVATION (ABOVE BASE SLAB)		LINER NOT CONSIDERED REBAR STRESSES 1	2	3	LINER CONSIDERED REBAR STRESSES 1	2	3	LINER STRESS σ_{MAX}	σ_{MIN}
		57.0	57.0	57.0	57.0	57.0	57.0		
DOME	212				42.8	42.8	42.8	-5.1	-5.1
DOME	185				42.8	44.5	42.8	-3.4	-5.2
DOME	169				42.3	41.0	42.3	-5.6	-7.0
CYLINDER	142	38.7	52.6	38.7	42.2	50.3	42.2	2.1	-6.5
CYLINDER	83	34.3	54.4	34.3	39.7	51.9	39.7	2.7	-10.2
CYLINDER	0	19.0	0	19.0	31.6	0	31.6	-23.8 (*)	-52.7 (*)



ALL STRESSES IN KIPS/SQUARE INCH

MINUS SIGN INDICATES COMPRESSION

(*) Maximum strain levels for the liner plate are within acceptable limits.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

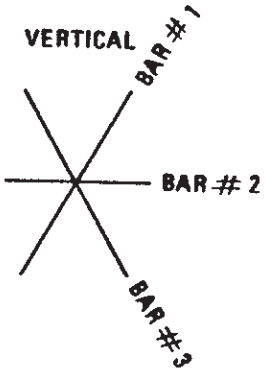
FIGURE 3.8-37
CONTAINMENT STRUCTURE
EXTERIOR SHELL STRESSES
ACCIDENT CONDITION 1

CRACKED SECTION – LINER CONSIDERED

CONDITION	$U = 1.0D \pm 0.05D + 1.25P + 1.0T' + 1.25DE$					$U = 1.0D \pm 0.05D + 1.0P + 1.0T' + 1.0DDE$				
	REBAR STRESSES			LINER STRESS		REBAR STRESSES			LINER STRESS	
ALLOWABLE STRESS ELEVATION (ABOVE BASE SLAB)	1	2	3	σ_{MAX}	σ_{MIN}	1	2	3	σ_{MAX}	σ_{MIN}
	57.0	57.0	57.0			57.0	57.0	57.0		
212	38.7	38.3	37.7	-8.4	-8.5	32.1	31.6	30.9	-8.6	-8.6
185	41.7	40.7	35.5	-5.9	-8.1	36.0	34.1	27.9	-6.0	-8.2
169	42.7	37.6	34.2	-9.0	-8.0	37.6	31.7	26.2	-8.1	-8.3
142	45.2	44.9	32.9	-1.6	-7.8	41.0	37.5	24.2	-2.4	-7.4
83	50.1	45.1	31.0	-.9	-5.7	48.9	36.7	22.7	-2.0	-2.9
0	43.8	0	29.3	-10.4 (*)	-47.2 (*)	46.6	0	22.9	-4.8 (*)	-39.1 (*)

DOME

CYLINDER



ALL STRESSES IN KIPS/SQUARE INCH

MINUS SIGN INDICATES COMPRESSION

NOTE:
REBAR STRESSES FOR REBAR IN OUTER LAYER ONLY.

(*) Maximum strain levels for the liner plate are within acceptable limits.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-38

CONTAINMENT STRUCTURE
EXTERIOR SHELL STRESSES
ACCIDENT CONDITIONS 2 AND 3

CRACKED SECTION

ALLOWABLE STRESS ELEVATION (FT) (ABOVE BASE SLAB)	CONDITION (c) C = 1.0D ± 0.05D + 1.0P + 1.0T + 1.0 HE					
	REBAR STRESSES *				LINER PLATE * STRESS	
	1	2	3		MAX	MIN
	63.5	63.5	63.5			
213	33.6	31.4	32.2		-6.4	-8.6
185	37.7	34.7	28.4		-4.9	-6.7
169	39.6	31.9	26.1		-6.7	-7.7
142	44.2	36.8	23.0		-2.6	-6.0
83	53.4	37.5	18.4		-1.2	-2.8
83	61.2	38.1	11.0			
0	49.5	0	24.8		-1.0 (*)	-38.1 (*)

DOME

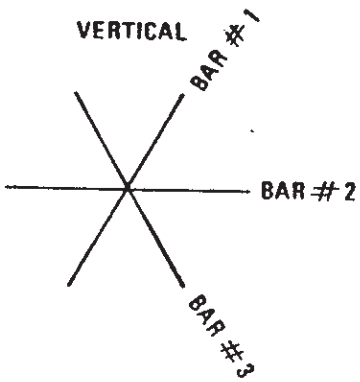
CYLINDER

WITH LINER PLATE

WITHOUT LINER PLATE

WITH LINER PLATE

(*) Maximum strain levels for the liner plate are within acceptable limits.



ALL STRESSES IN KIPS/SQUARE INCH

MINUS SIGN INDICATES COMPRESSION

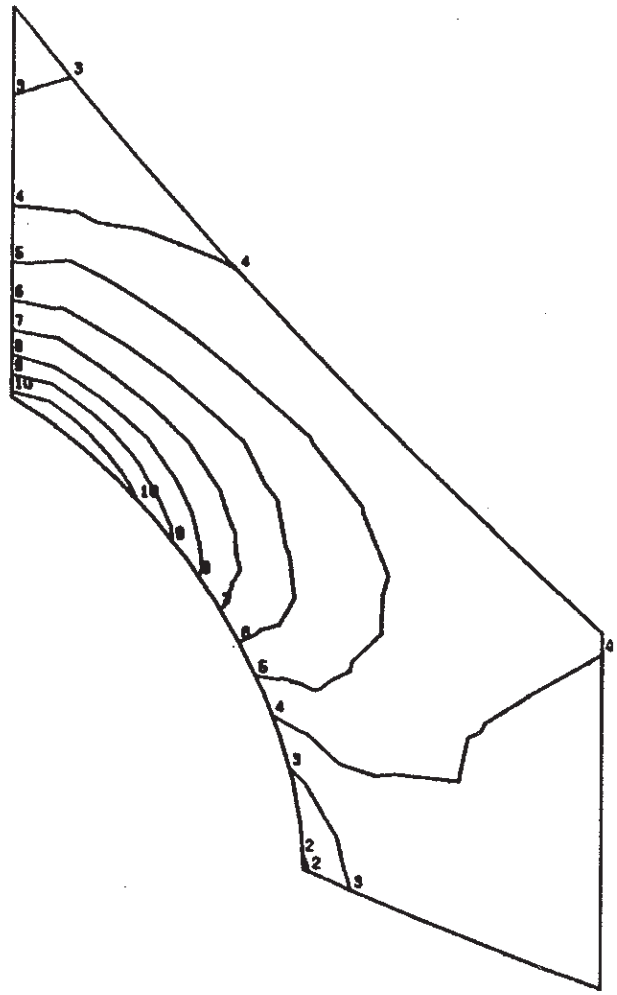
* STRESSES ARE MAXIMUM OR MINIMUM AT ANY SECTION:

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

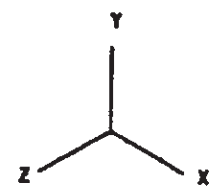
FIGURE 3.8-39

CONTAINMENT STRUCTURE, EXTERIOR SHELL STRESSES – ACCIDENT CONDITION 4



CONTOURING INFORMATION

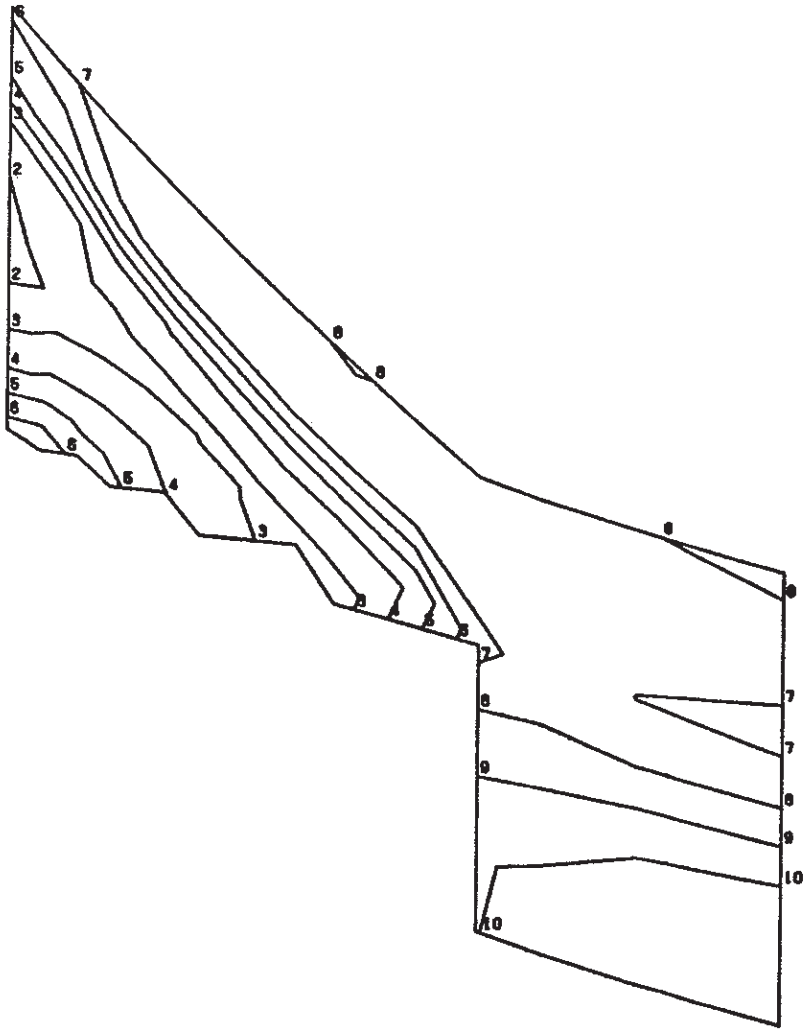
LEVEL	VALUE
1	.13600+05
2	.17000+05
3	.20400+05
4	.23800+05
5	.27200+05
6	.30600+05
7	.34000+05
8	.37400+05
9	.40800+05
10	.44200+05



FSAR UPDATE

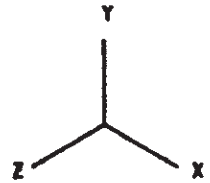
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-40
EQUIPMENT HATCH HEXAGONAL PLATE MAXIMUM STRESSES
(1.05D + 1.5P + T")



CONTOURING INFORMATION

LEVEL	VALUE
1	.15200+05
2	.19000+05
3	.22800+05
4	.26600+05
5	.30400+05
6	.34200+05
7	.38000+05
8	.41800+05
9	.45600+05
10	.49400+05

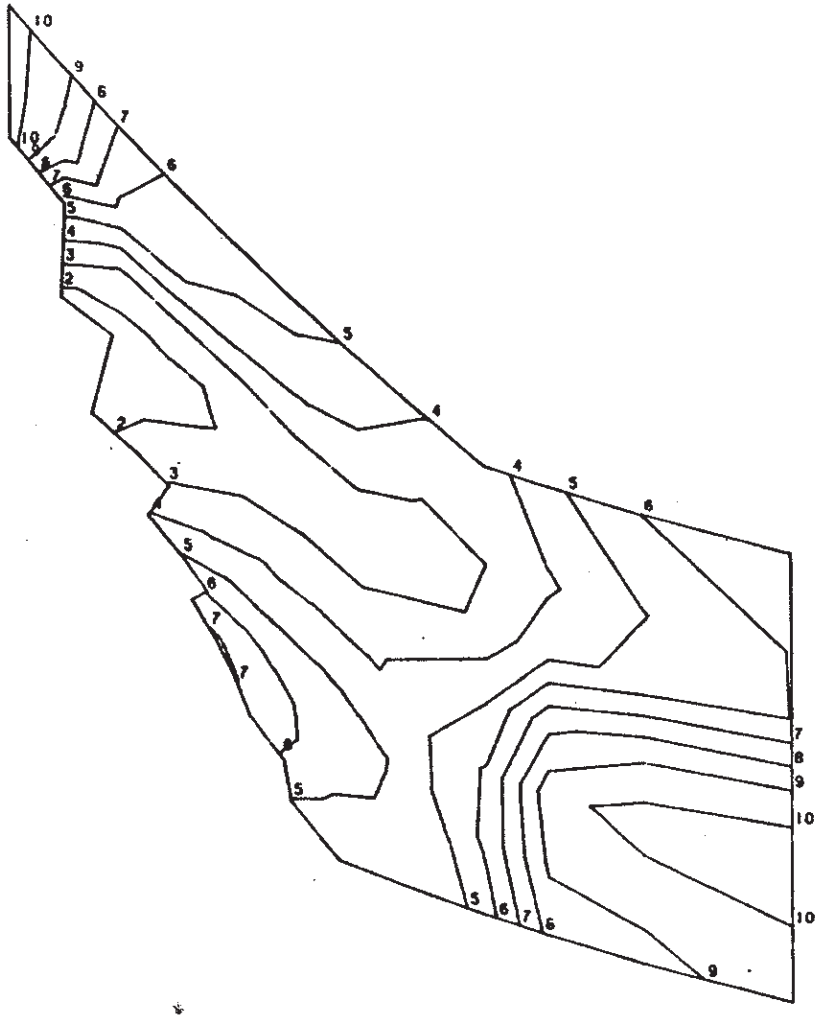


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

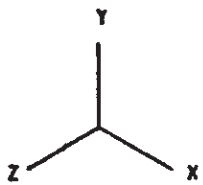
FIGURE 3.8-41

EQUIPMENT HATCH HOOP
REINFORCEMENT STRESSES
(1.05D + 1.5P + T″)



CONTOURING INFORMATION

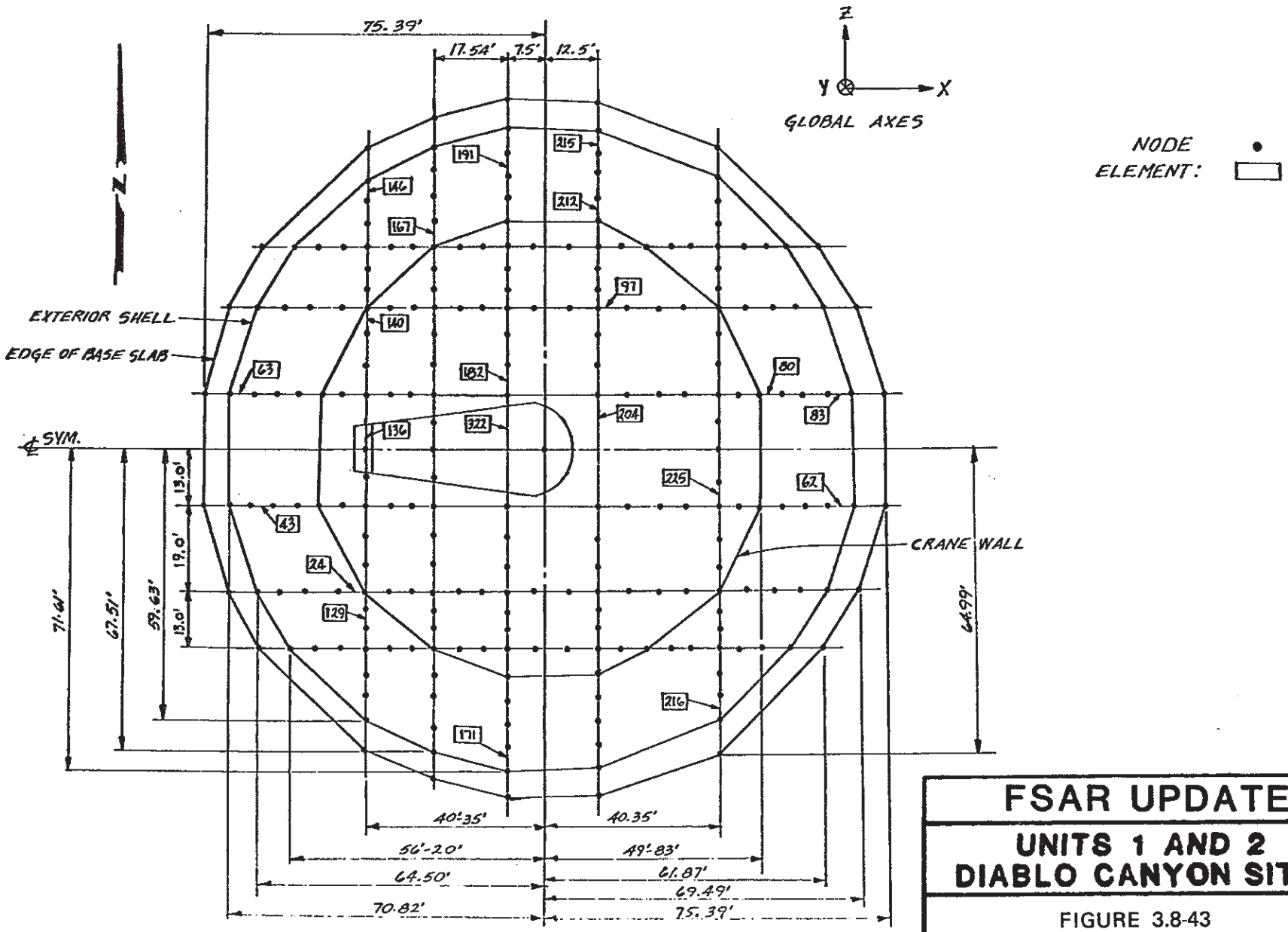
LEVEL	VALUE
1	.96000+04
2	.12000+05
3	.14400+05
4	.16800+05
5	.19200+05
6	.21600+05
7	.24000+05
8	.26400+05
9	.28800+05
10	.31200+05



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-42
EQUIPMENT HATCH DIAGONAL REINFORCEMENT STRESSES
(1.05D + 1.5P + T″)



FSAR UPDATE

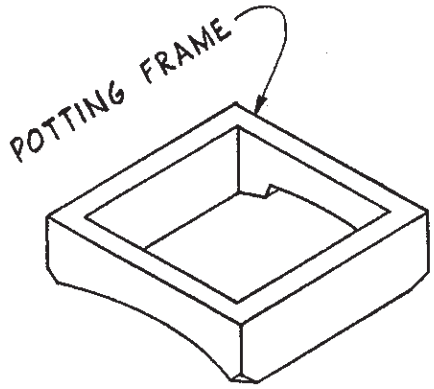
UNITS 1 AND 2
DIABLO CANYON SITE

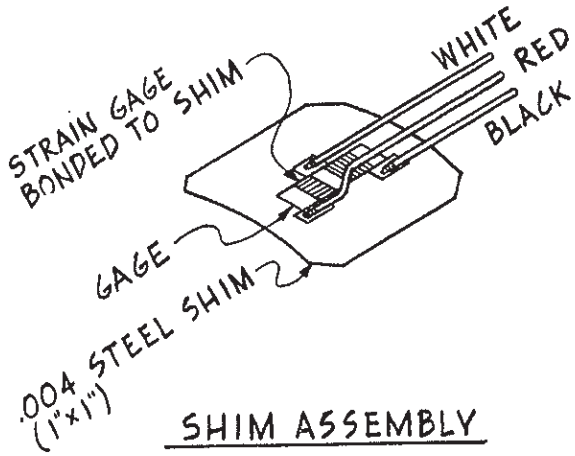
FIGURE 3.8-43

CONTAINMENT
BASE SLAB MODEL

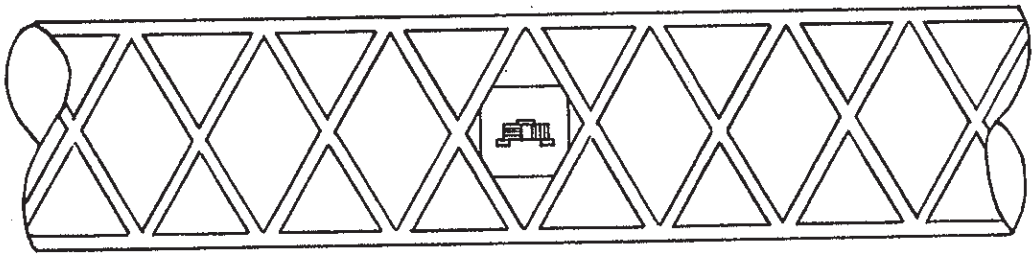
NOTES FOR FIELD INSTALLATION

1. REMOVE MILL SCALE AND POLISH REBAR SURFACE INSIDE OF DIAMOND AREA
2. BOND SHIM ASSEMBLY TO POLISHED REBAR
3. PLACE SEALANT AND PROTECTIVE COVER OVER SHIM ASSEMBLY.

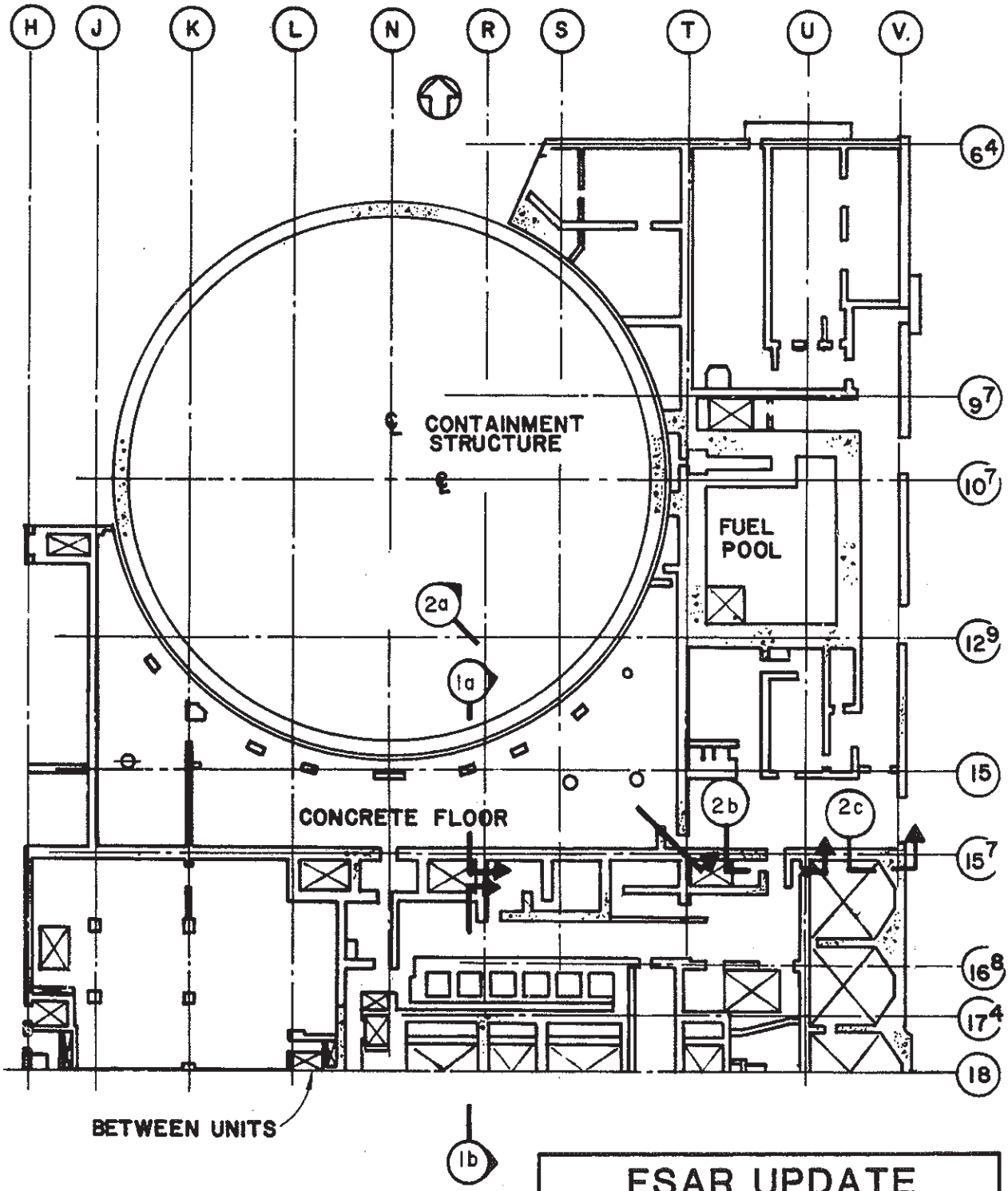




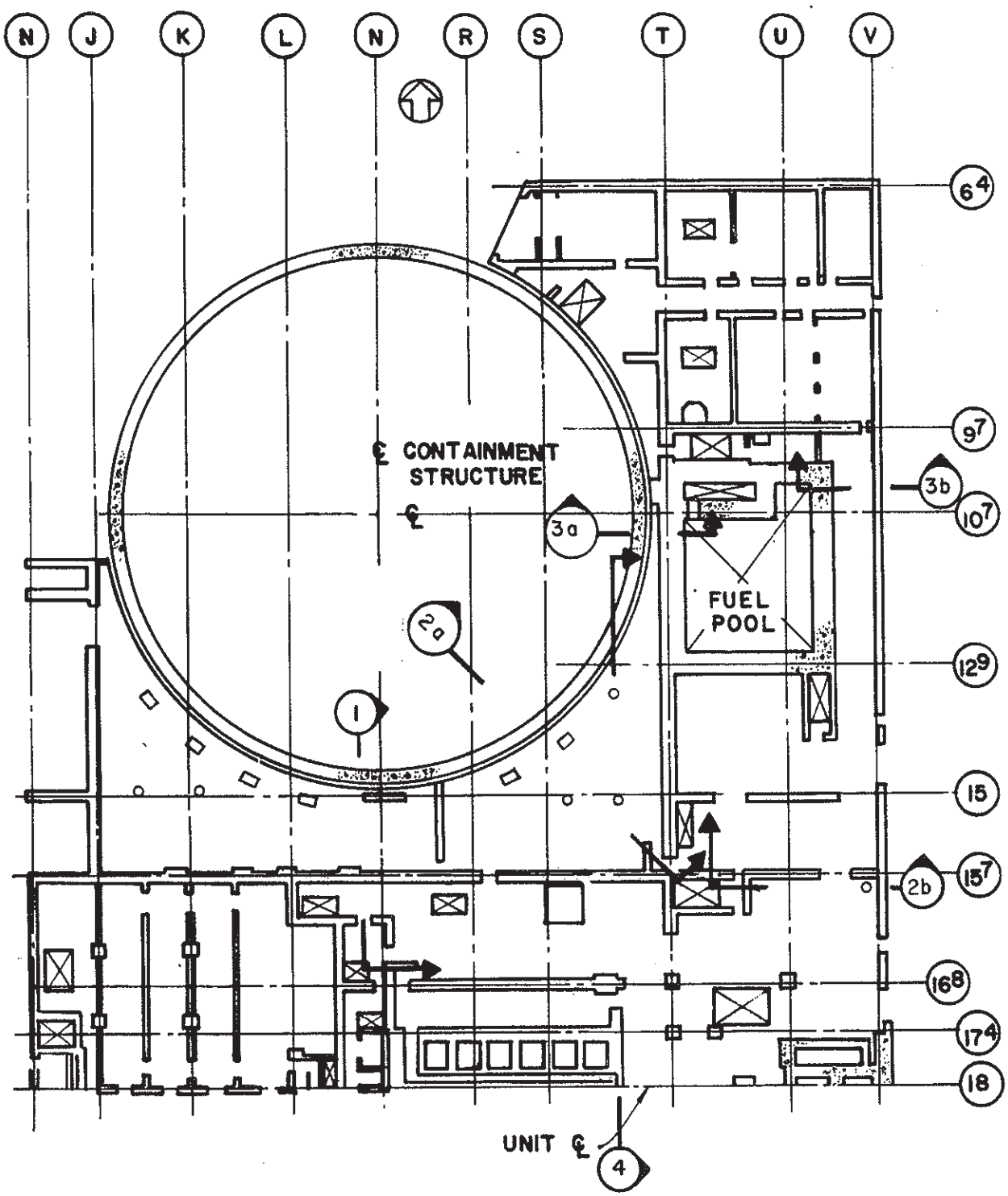
SHIM ASSEMBLY



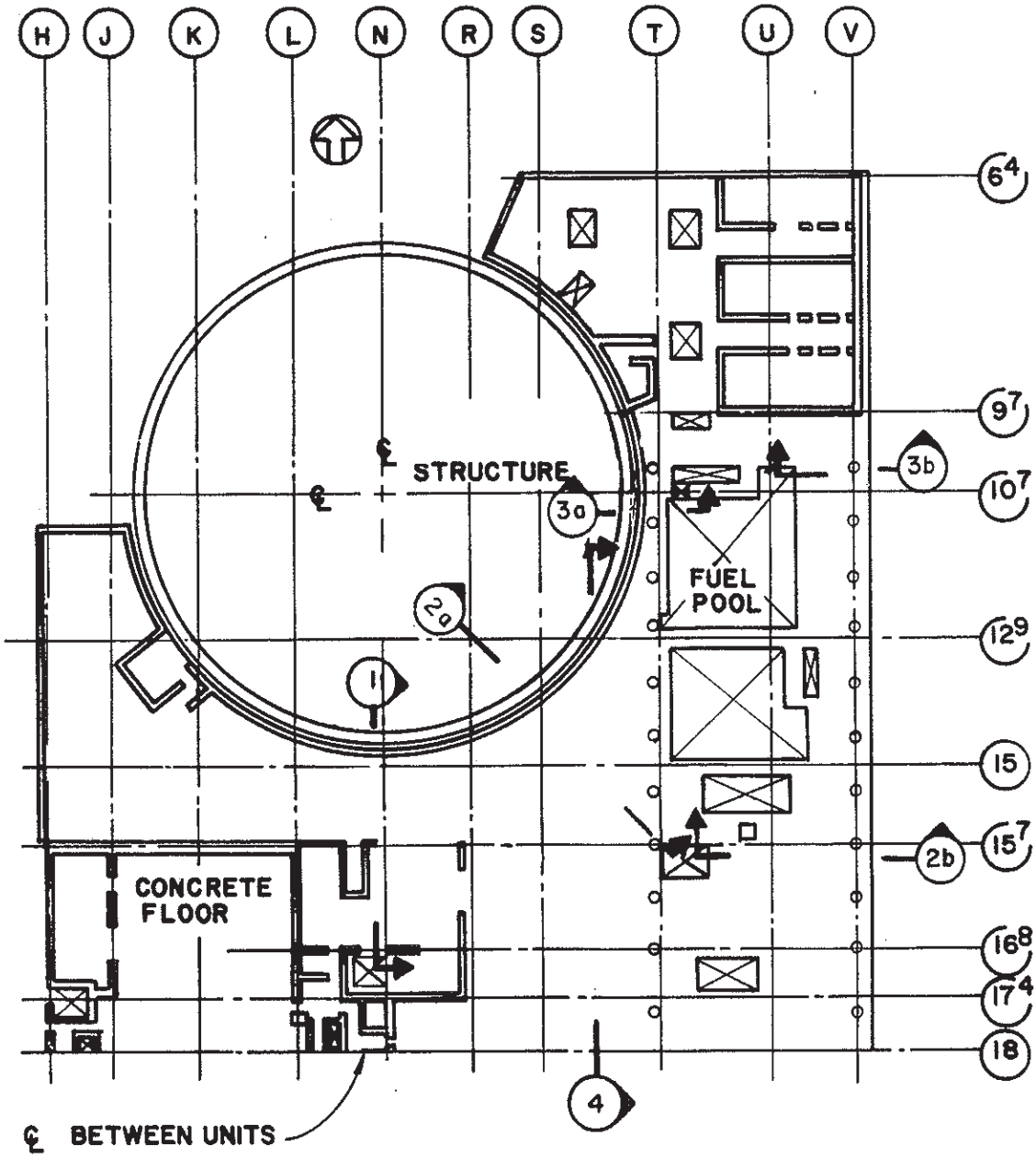
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.8-44 CONTAINMENT STRUCTURE TYPICAL REBAR STRAIN GAUGE



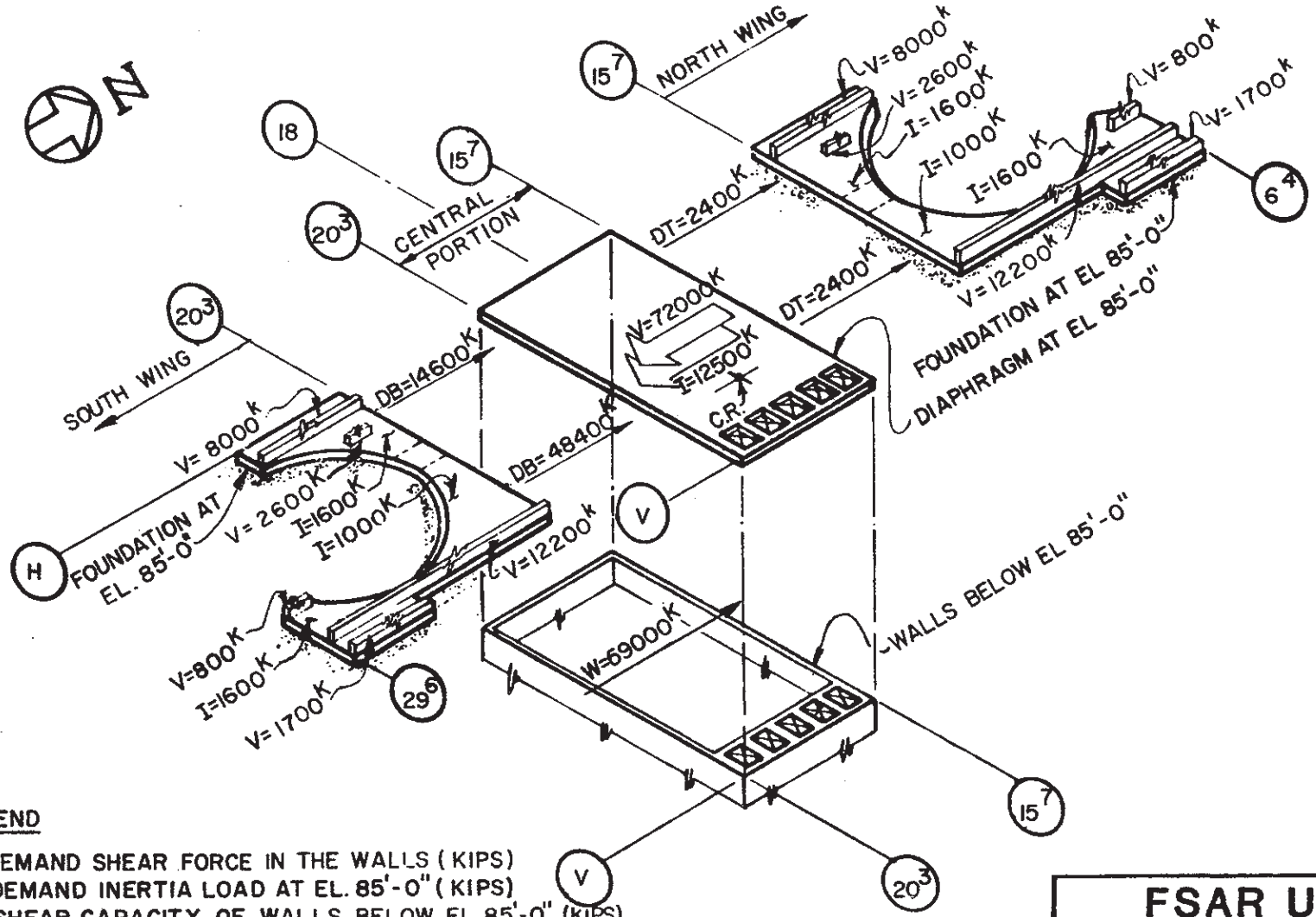
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.8-60 AUXILIARY BUILDING FLOOR PLAN AT EL 100'-0"



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.8-61 AUXILIARY BUILDING FLOOR PLAN AT EL 115'-0"



FSAR UPDATE
UNIT 1 **DIABLO CANYON SITE**
FIGURE 3.8-62 AUXILIARY BUILDING FLOOR PLAN AT EL 140'-0"



LEGEND

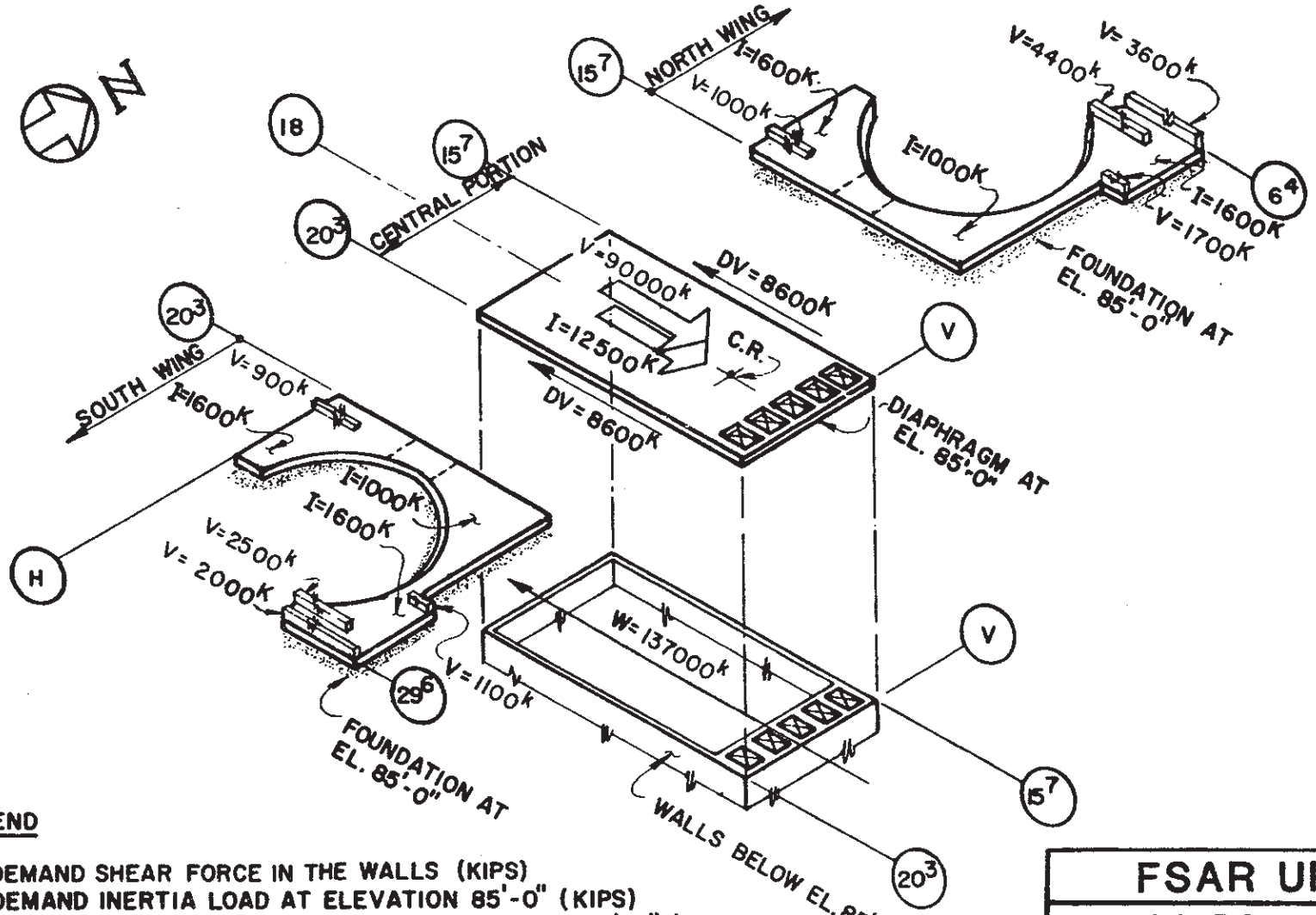
V = DEMAND SHEAR FORCE IN THE WALLS (KIPS)
I = DEMAND INERTIA LOAD AT EL. 85'-0" (KIPS)
W = SHEAR CAPACITY OF WALLS BELOW EL. 85'-0" (KIPS)
DT = CAPACITY THROUGH DIAPHRAGM REBAR TENSION (KIPS)
DB = CAPACITY THROUGH DIAPHRAGM BEARING (KIPS)

NOTE: DEMAND SHEARS IN WALLS WEST OF CENTER OF RIGIDITY CONSIDER DIRECT PLUS POSITIVE TORSIONAL SHEARS. THOSE IN WALLS EAST OF CENTER OF RIGIDITY CONSIDER ONLY DIRECT SHEARS.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-63
AUXILIARY BUILDING
LOAD DISSIPATION TO FOUNDATION
HOSGRI N – S



LEGEND

V= DEMAND SHEAR FORCE IN THE WALLS (KIPS)
I = DEMAND INERTIA LOAD AT ELEVATION 85'-0" (KIPS)
W= SHEAR CAPACITY OF WALLS BELOW ELEVATION 85'-0" (KIPS)
DV= SHEAR CAPACITY OF DIAPHRAGM (KIPS)

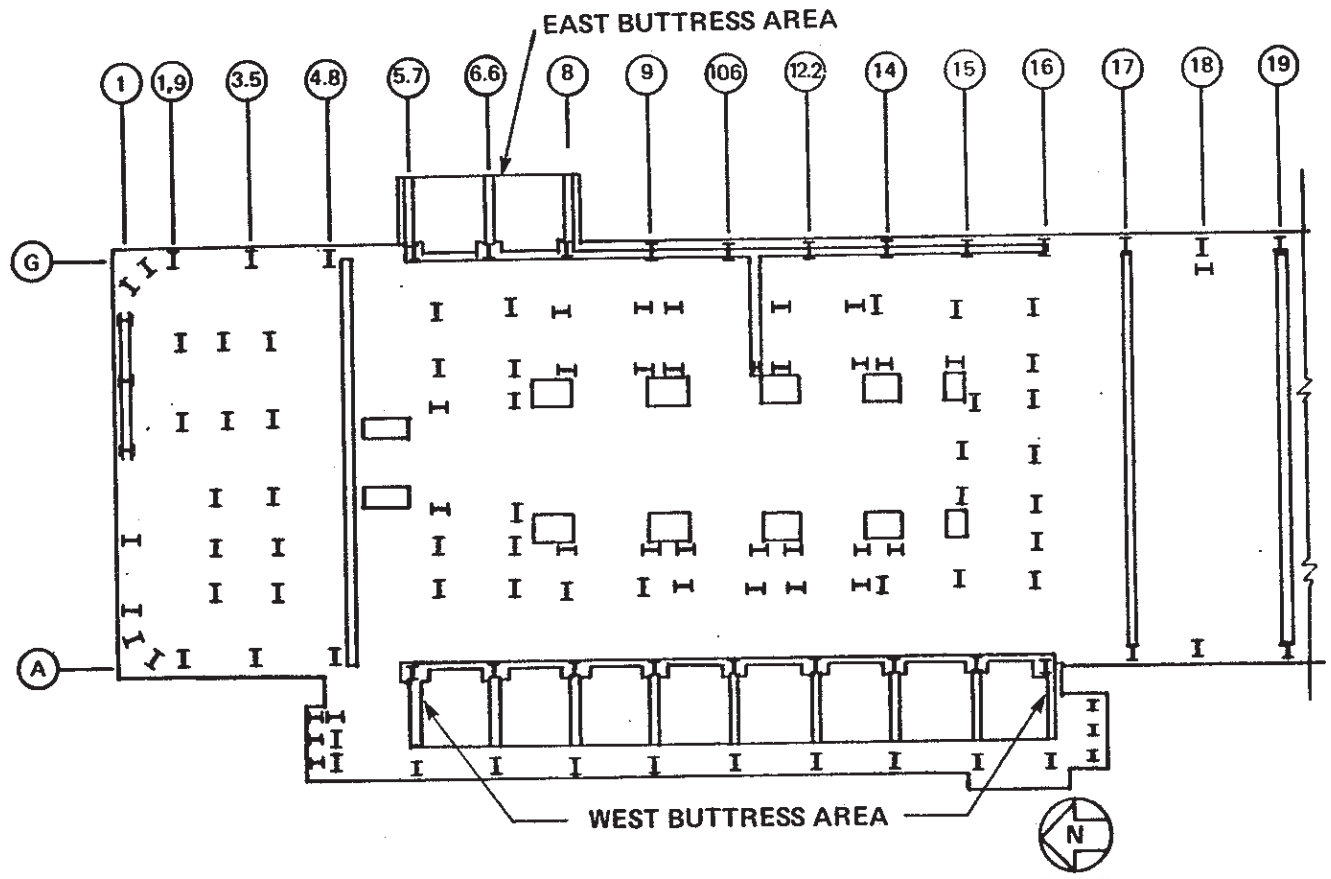
NOTE: WALLS NORTH OF LINE 18 CONSIDER DIRECT PLUS POSITIVE TORSIONAL EFFECT AND THOSE SOUTH OF LINE 18 CONSIDER ONLY DIRECT SHEARS.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8-64

AUXILIARY BUILDING
LOAD DISSIPATION TO FOUNDATION
HOSGRI E – W

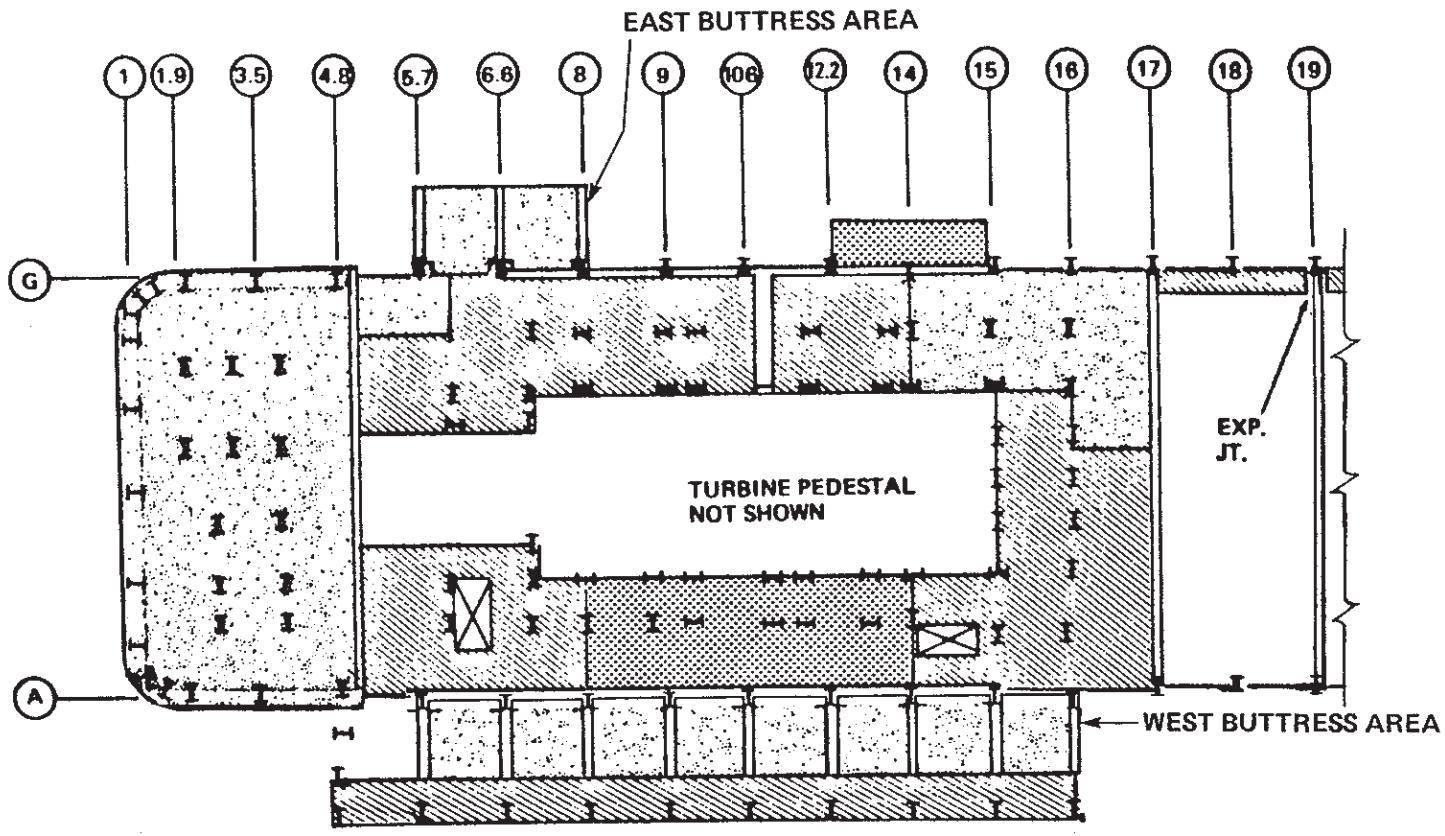


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8–66

TURBINE BUILDING
PLAN AT EL. 85'



CONC.

GRATING

STEEL CHECKERED PL

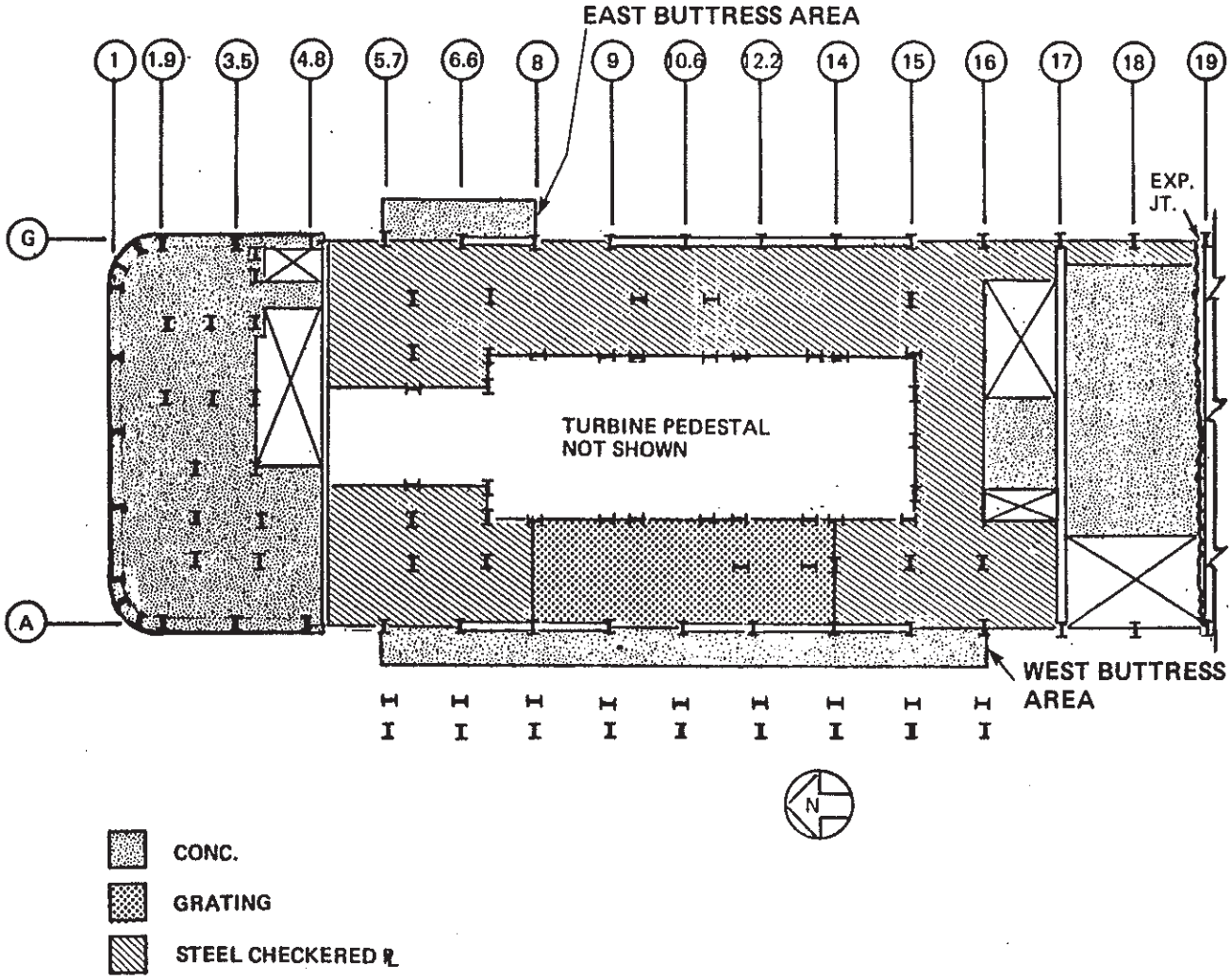
N

FSAR UPDATE

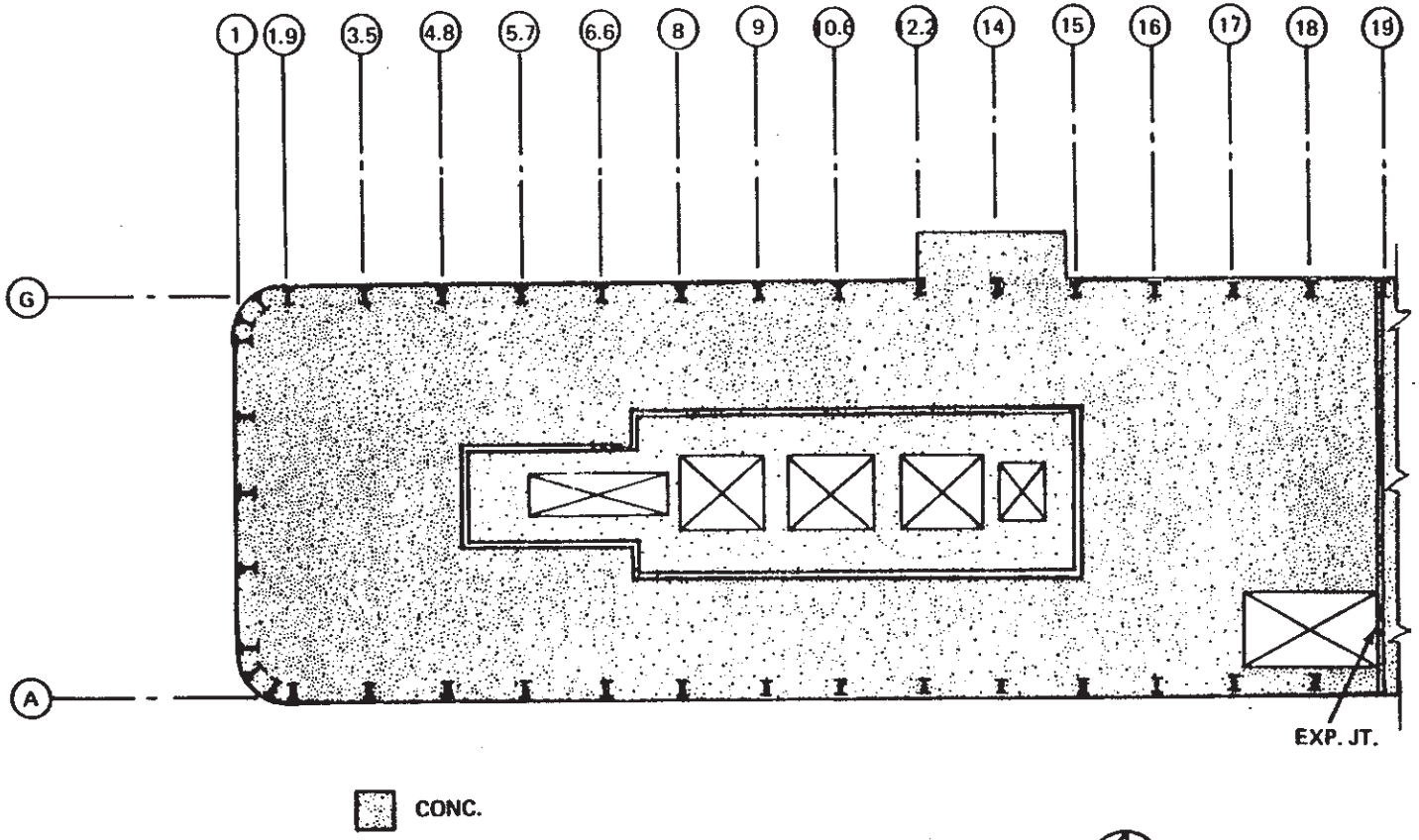
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8–67

TURBINE BUILDING
PLAN AT EL. 104'



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.8–68 TURBINE BUILDING PLAN AT EL. 119'

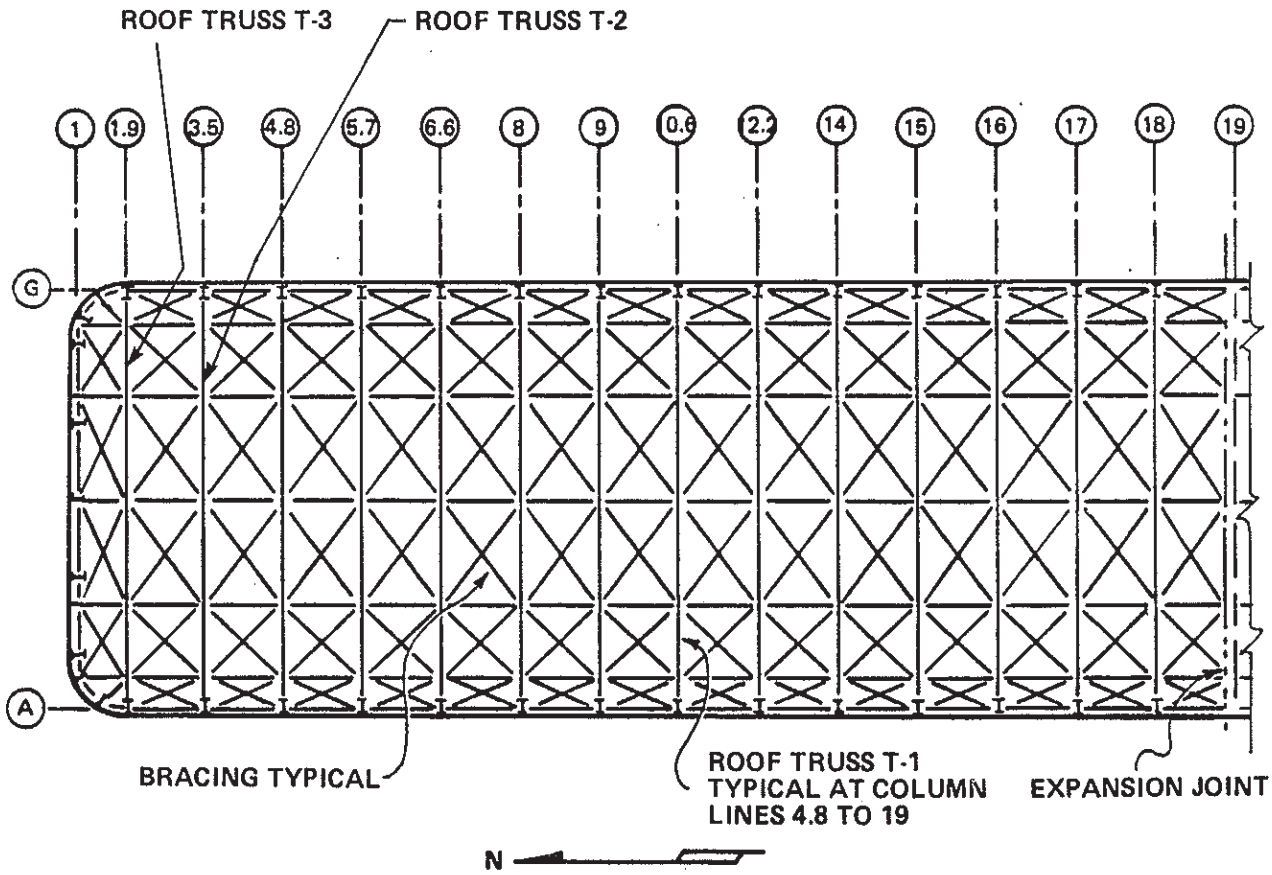


FSAR UPDATE

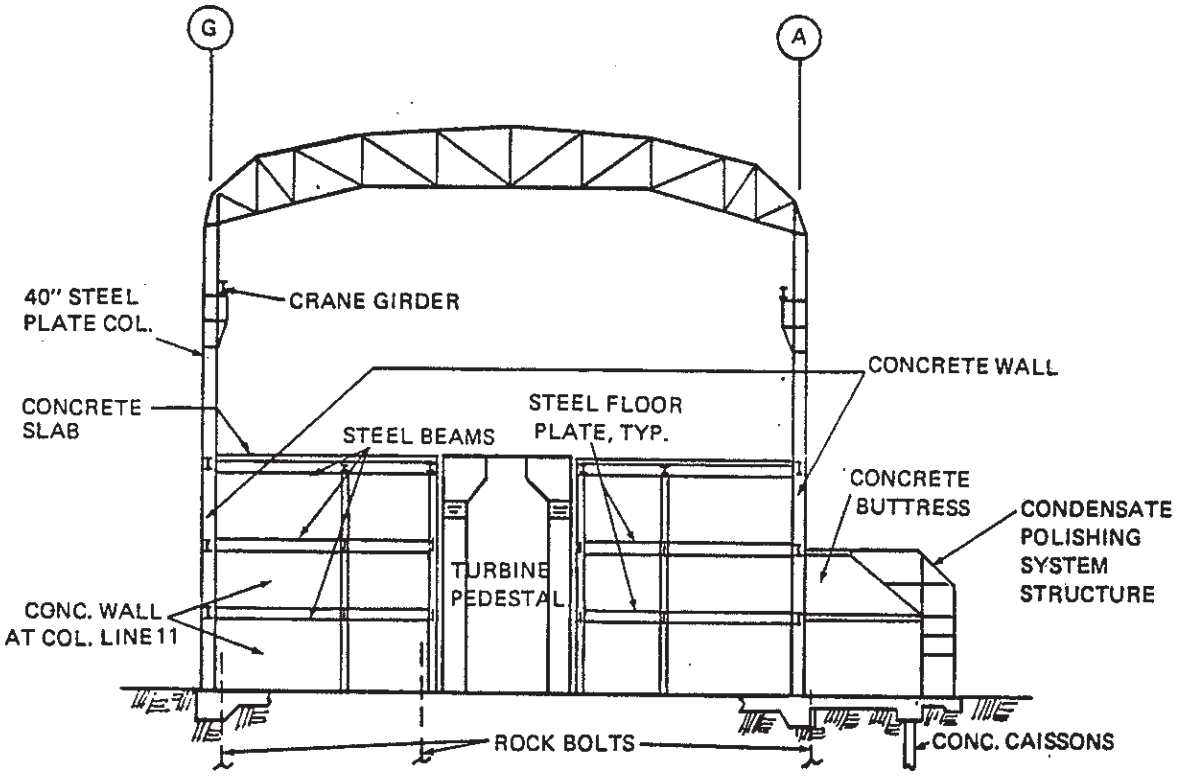
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8–69

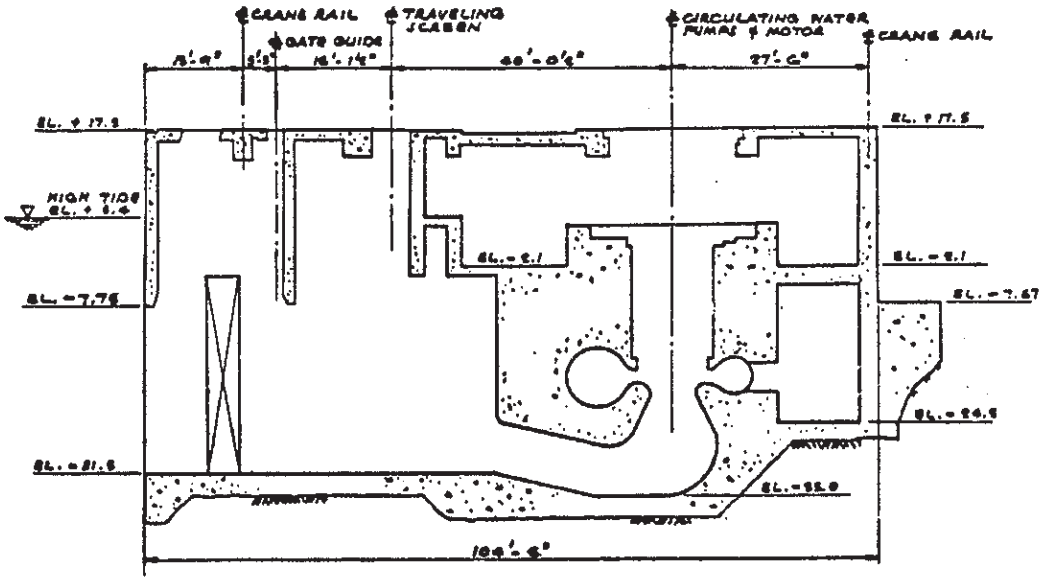
TURBINE BUILDING
PLAN AT EL. 140'



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.8–70 TURBINE BUILDING PLAN AT LOWER CHORD OF ROOF TRUSS

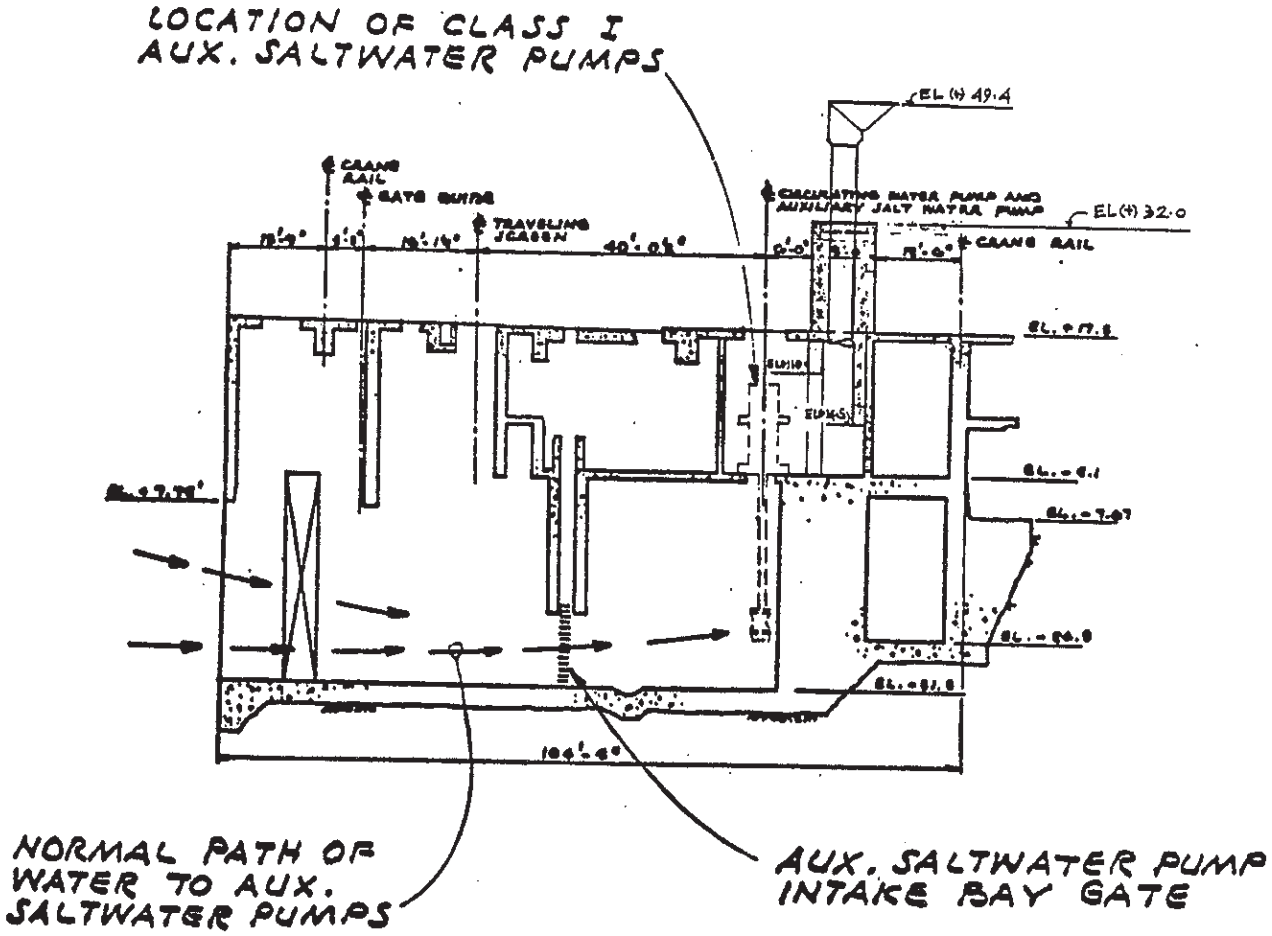


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.8–71 TURBINE BUILDING TYPICAL SECTION

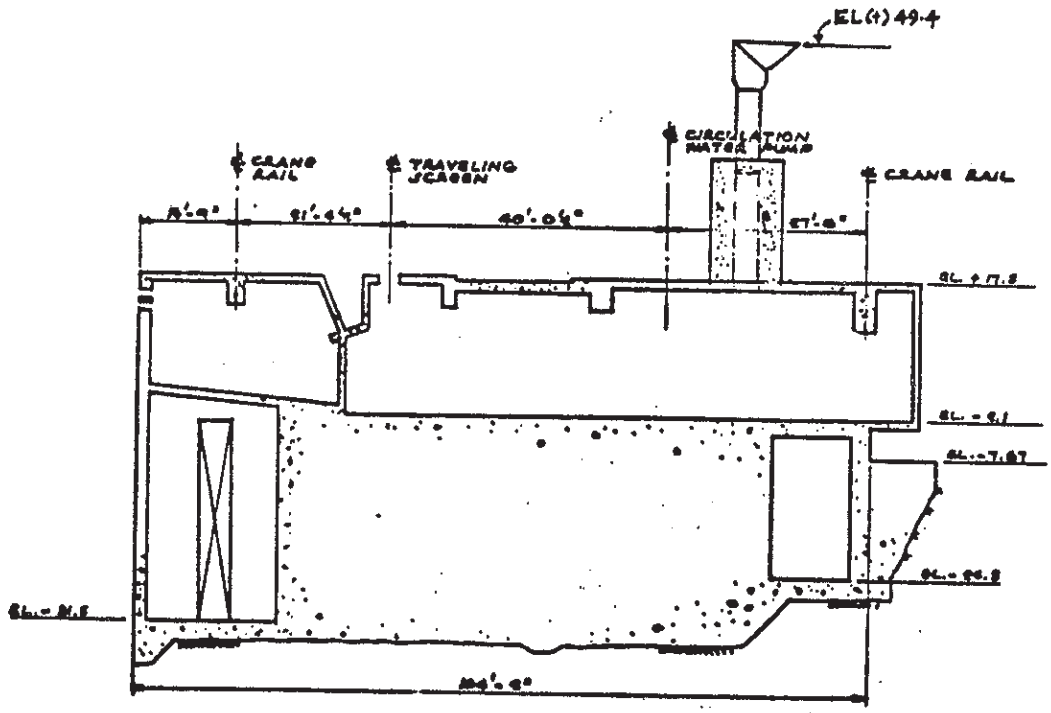


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.8–75 INTAKE STRUCTURE TRANSVERSE SECTION A

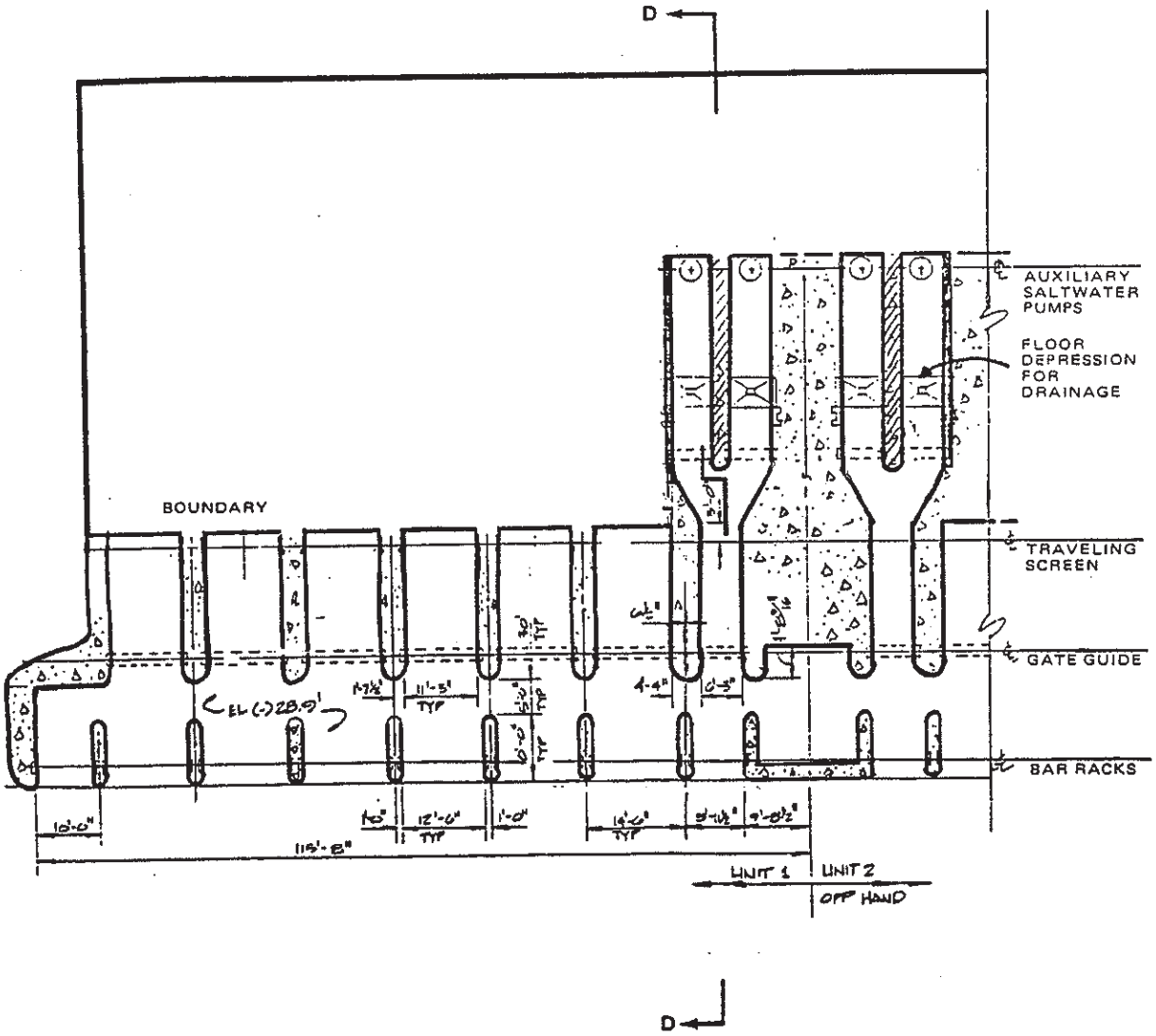
Revision 11 November 1996



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.8–76 INTAKE STRUCTURE TRANSVERSE SECTION B



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 3.8–77 INTAKE STRUCTURE TRANSVERSE SECTION C

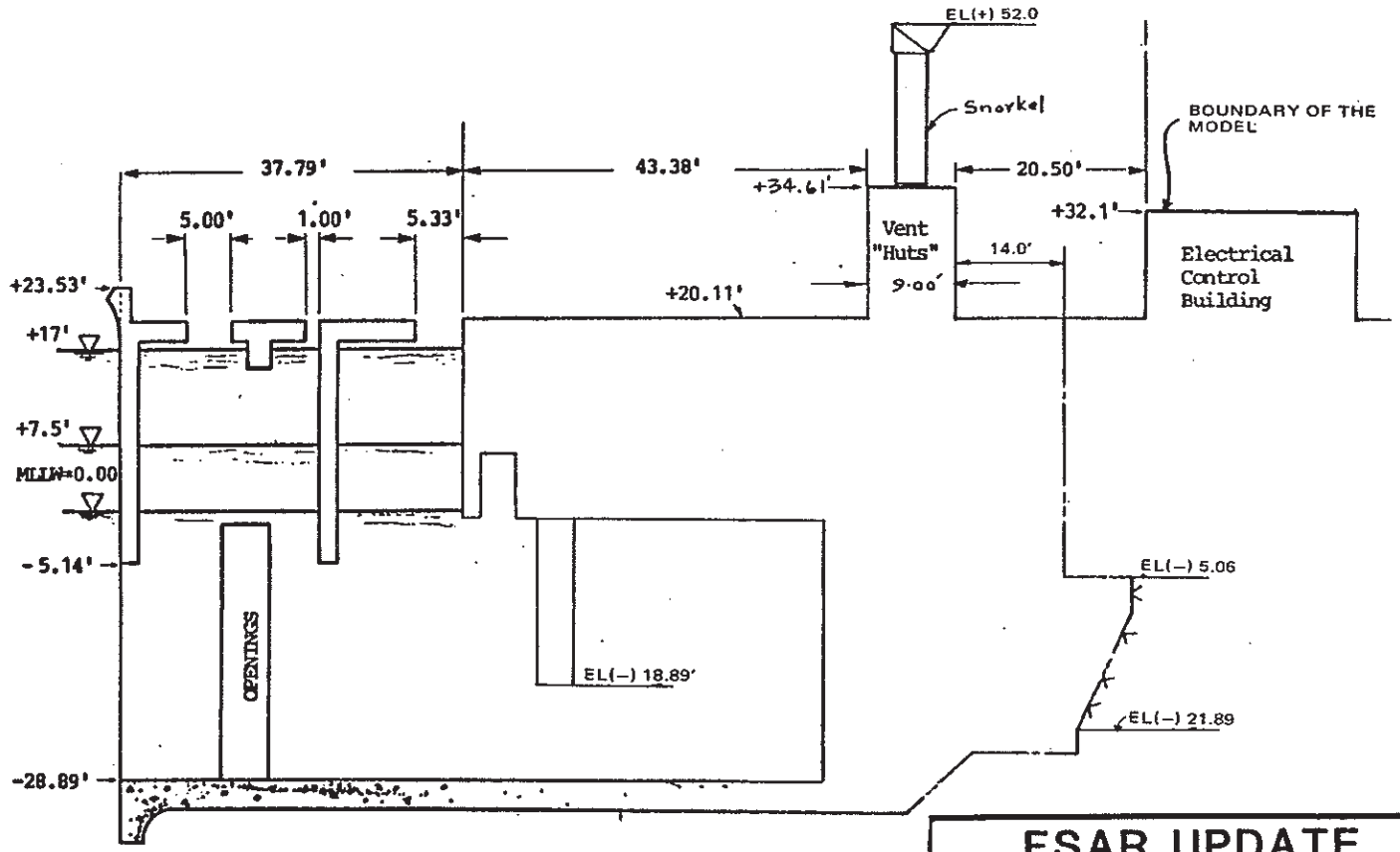


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8–78

INTAKE STRUCTURE
WAVE SCALE MODEL
PLAN-INVERT (UNIT 1)
NTS



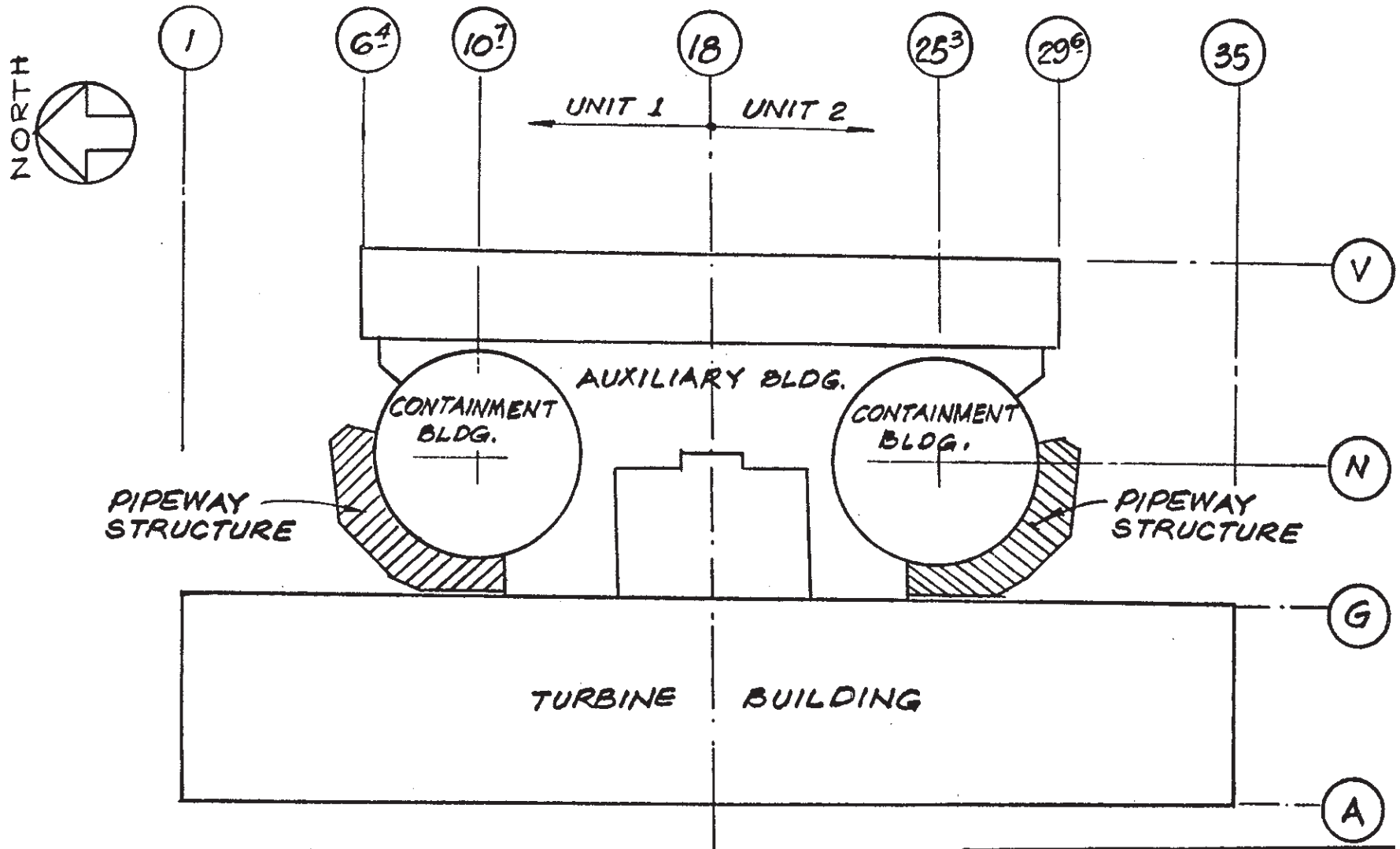
NOTE: (All Elevations Refer to Mean Lower Low Water Datum)

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8–79

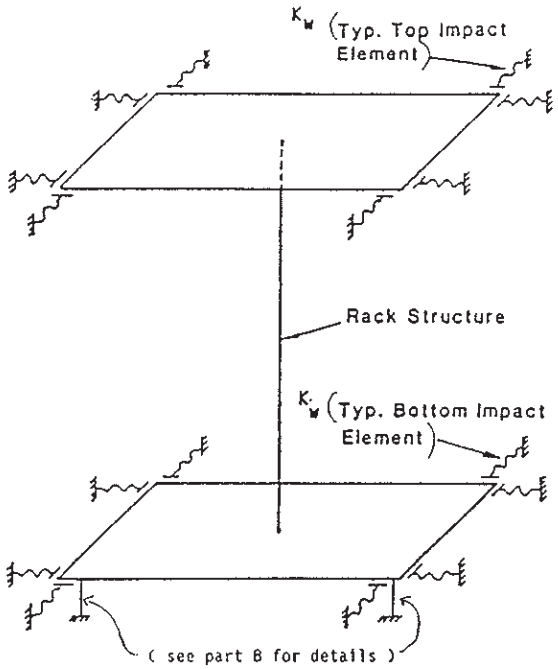
INTAKE STRUCTURE
WAVE SCALE MODEL
TRANSVERSE SECTION D



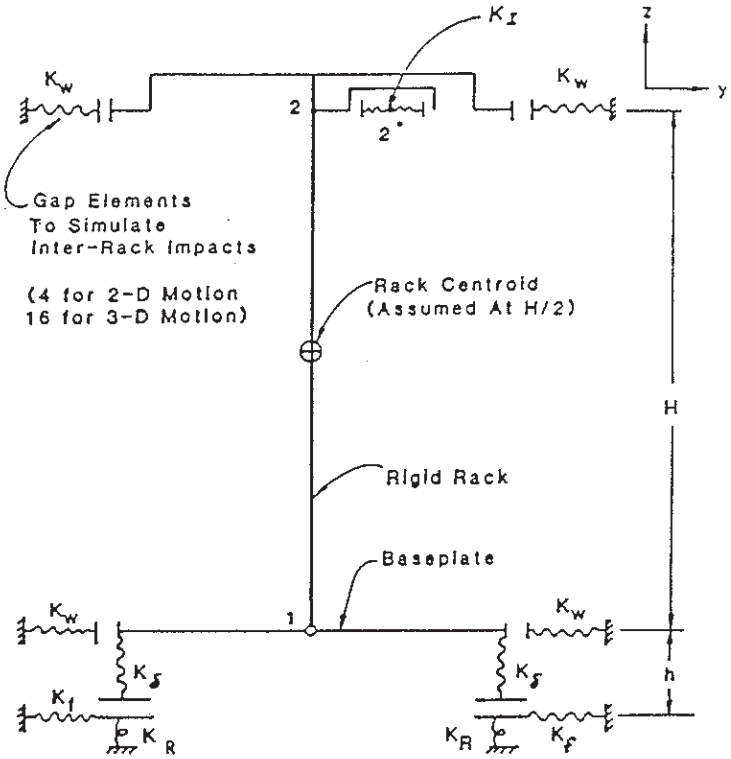
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 3.8–80
PIPEWAY STRUCTURE LAYOUT

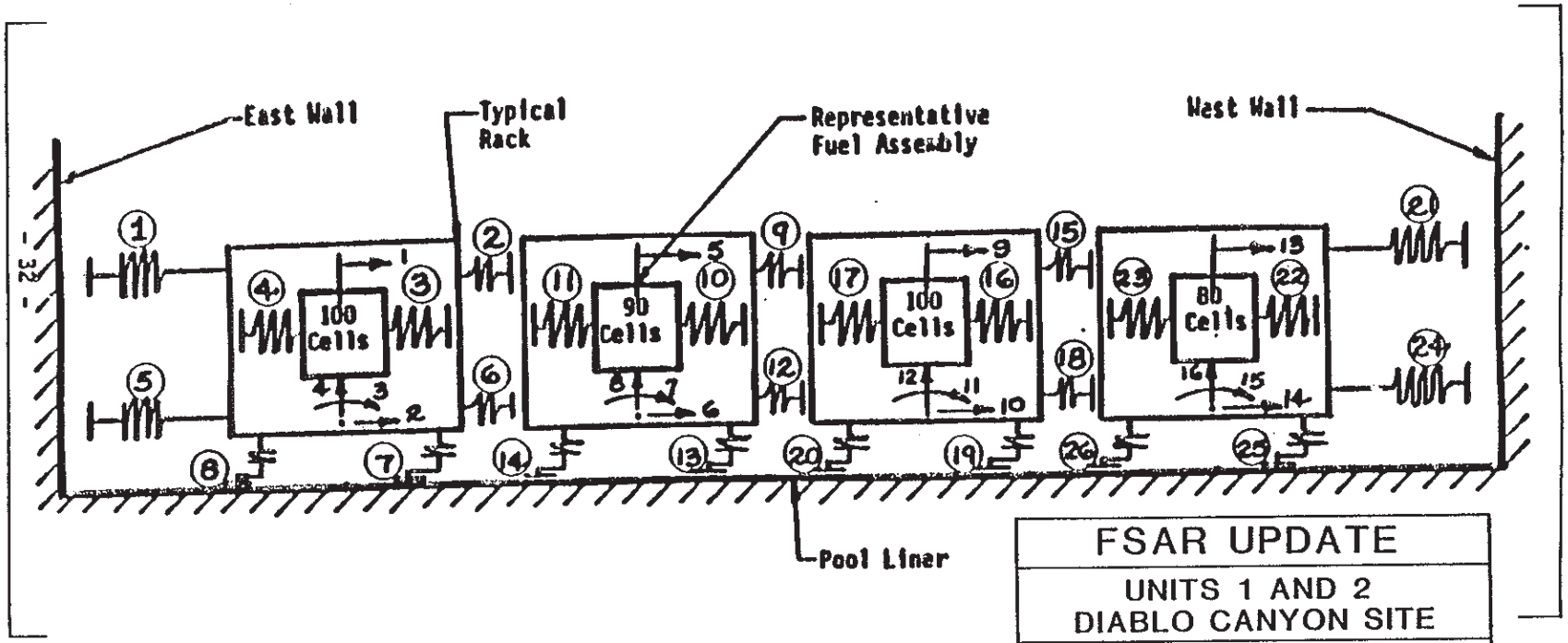


Part A. Three-Dimensional Representation of Rack Dynamic Model



Part B. Two-Dimensional Representation of Rack Dynamic Model

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
Figure 3.8-81. Rack Dynamic Model

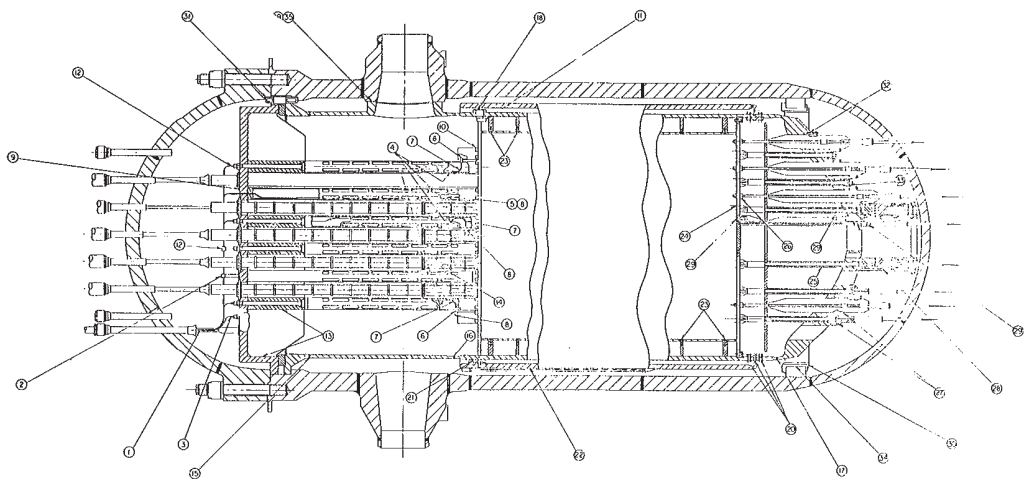


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

Figure 3.8-82.

MULTI-RACK MODEL



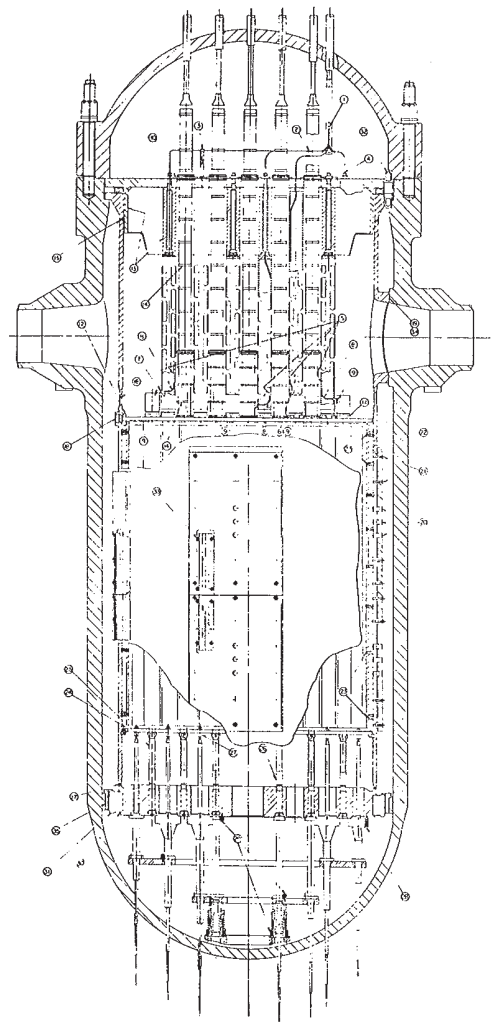
		FEATURES TO BE EXAMINED	COMMENTS AND OBSERVATIONS BEFORE FUNCTIONAL TEST
UPPER INTERNALS	1	THERMOCOUPLE CONDUIT CLAMPS INSIDE THE THERMOCOUPLE COLUMN.	
	2	CLAMP ARRANGEMENTS AT THE MOUNTING BRACKET LOCATIONS.	
	3	PLUG TO CONDUIT WELD AT THE FIVE SUPPORT COLUMNS ADJACENT TO THE THERMOCOUPLE COLUMNS.	
	4	ACCESSIBLE ANGLE CONDUIT CLAMPS INSIDE THE UPPER SUPPORT COLUMNS.	
	5	ACCESSIBLE WELD JOINTS AT THE THERMOCOUPLE STOP FOR THE SELF INSTRUMENTED COLUMNS.	
	6	WELD JOINTS ON ACCESSIBLE SUPPORT COLUMN AND MIXING DEVICE GUSSETS. (THERMOCOUPLE SUPPORT HARDWARE)	
	7	RIGIDITY OF EXPOSED PORTION OF THERMOCOUPLE CONDUIT RUNS, AT ACCESSIBLE LOCATIONS. (INSIDE SUPPORT COLUMNS - LOWER END)	
	8	RIGIDNESS OF THE ACCESSIBLE PROTRUDING THERMOCOUPLE TIPS	
	9	THERMOCOUPLE COLUMN AND GUIDE TUBE SCREW LOCKING DEVICES.	
	10	ACCESSIBLE SUPPORT COLUMN MIXING DEVICE, ORIFICE PLATE, AND CORE PLATE INSERT SCREW LOCKING DEVICES.	
	11	UPPER CORE PLATE INSERTS.	
	12	CONDUIT CONNECTOR FITTINGS AND CROSS RUN CLAMP ARRANGEMENTS.	
	13	DEEP BEAM WELDS AT THE SKIRT AND AT THE OUTER HOLLOW ROUNDS.	
	14	ACCESSIBLE GUIDE TUBE WELDS.	
LOWER INTERNALS	15	UPPER BARREL TO FLANGE GIRTH WELD.	
	16	UPPER BARREL TO LOWER BARREL GIRTH WELD.	
	17	LOWER BARREL TO CORE SUPPORT GIRTH WELD.	
	18	UPPER CORE PLATE ALIGNING PIN WELDS AND BEARING SURFACES.	
	19	OUTLET NOZZLE INTERFACE SURFACE CONDITION.	
	20	THERMAL SHIELD FLEXURE ARM, ATTACHMENTS TO BARREL, AND WELD TO THE THERMAL SHIELD. DYE PENETRANT INSPECT ALL SIX.	
	21	THERMAL SHIELD INTERFACE AT THE HANG OFF PADS.	
	22	IRRADIATION SPECIMEN BASKET WELDS.	
	23	BAFFLE ASSEMBLY SCREW LOCKING ARRANGEMENTS AT THE TWO TOP AND THE TWO BOTTOM FORMER ELEVATIONS.	
	24	CORE SUPPORT COLUMN TO LOWER CORE PLATE SCREW LOCKING DEVICES. (24 RANDOMLY CHOSEN)	
	25	CORE SUPPORT COLUMN ADJUSTING SLEEVES.	
	26	ACCESSIBLE (2) INSTRUMENTATION GUIDE COLUMN LOCKING COLLARS NEAREST THE WALKWAY.	
	27	LOCKING DEVICES OF THE BOTTOM INSTRUMENTATION GUIDE COLUMNS.	
	28	LOCKING DEVICES OF THE SECONDARY CORE SUPPORT.	
	29	ACCESSIBLE LOCKING DEVICES OF THE OFF-SET INSTRUMENTATION COLUMN (UPPER AND LOWER ENDS)	
	30	RADIAL SUPPORT KEY LOCKING ARRANGEMENTS AND BEARING SURFACES.	
	31	HEAD AND VESSEL ALIGNING PIN SCREW LOCKING DEVICES AND BEARING SURFACES.	
	32	CONTACT AT INTERFACE OF THE ACCESSIBLE INSTRUMENTATION GUIDE COLUMNS.	
	33	CONTACT AT INTERFACE OF THE ACCESSIBLE CORE SUPPORT COLUMN NUTS.	
VESSEL	34	VESSEL CLEVIS LOCKING ARRANGEMENTS AND BEARING SURFACES	
	35	VESSEL NOZZLE INTERFACE SURFACE CONDITION.	

FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 3.9-1
VIBRATION CHECKOUT - FUNCTIONAL
TEST INSPECTION DATA

Revision 11 November 1996



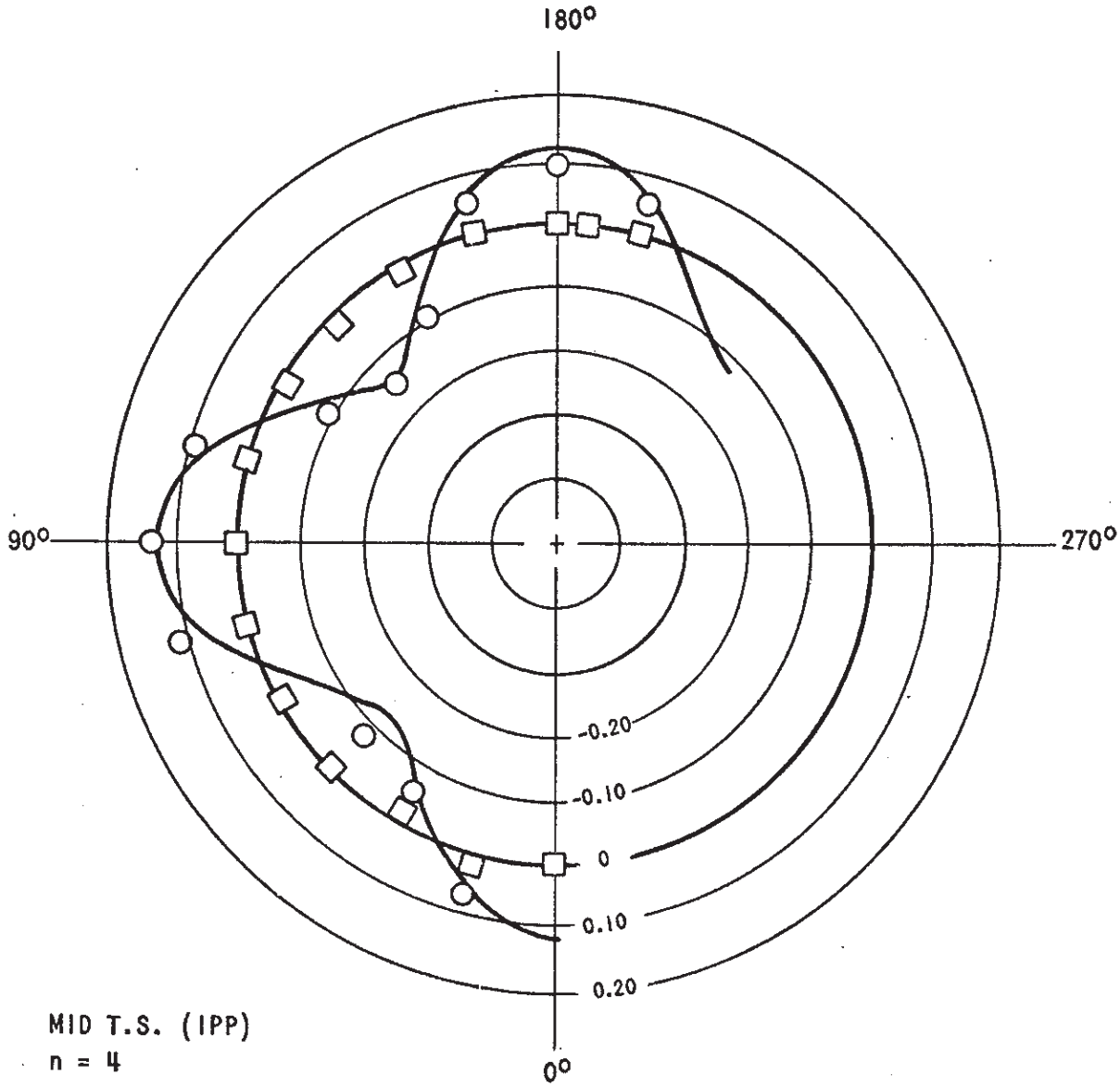
	FEATURES TO BE EXAMINED	COMMENTS AND OBSERVATIONS BEFORE FUNCTIONAL TEST	COMMENTS AND OBSERVATIONS AFTER FUNCTIONAL TEST
1	THERMOCOUPLE CONDUIT CLAMPS INSIDE THE THERMOCOUPLE COLUMN.		
2	CONDUIT SWAGELOK FITTINGS, THEIR BANDINGS, AND THE FAB TYPE LOCKS.		
3	CLAMP ARRANGEMENTS AT THE MOUNTING BRACKET LOCATIONS.		
4	PLUG "O CONDUIT WELD AT THE FOUR SUPPORT COLUMNS ADJACENT TO THE THERMOCOUPLE COLUMNS.		
5	ACCESSIBLE ANGLE CONDUIT CLAMPS INSIDE THE UPPER SUPPORT COLUMNS.		
6	ACCESSIBLE WELD JOINTS AT THE THERMOCOUPLE STOP FOR THE SELF INSTRUMENTED COLUMNS.		
7	WELD JOINTS ON ACCESSIBLE SUPPORT COLUMN AND MIXING DEVICE GUSSETS (THERMOCOUPLE SUPPORT HARDWARE.)		
8	RIGIDITY OF EXPOSED PORTION OF THERMOCOUPLE CONDUIT RUNS, AT ACCESSIBLE LOCATIONS, (INSIDE SUPPORT COLUMNS LOWER END.)		
9	RIGIDNESS OF THE ACCESSIBLE PROTRUDING THERMOCOUPLE TIPS.		
10	THERMOCOUPLE COLUMN AND GUIDE TUBE SCREW LOCKING DEVICES.		
11	ACCESSIBLE SUPPORT COLUMN, MIXING DEVICE, ORIFICE PLATE, AND CORE PLATE INSERT SCREW LOCKING DEVICES.		
12	UPPER CORE PLATE INSERTS.		
13	DEEP BEAM WELDS AT THE SKIRT AND AT THE OUTER HOLLOW ROUNDS.		
14	ACCESSIBLE GUIDE TUBE WELDS.		
15	UPPER BARREL TO FLANGE GIRTH WELD.		
16	UPPER BARREL TO LOWER BARREL GIRTH WELD.		
17	LOWER BARREL TO CORE SUPPORT GIRTH WELD.		
18	UPPER CORE PLATE ALIGNING PIN WELDS AND BEARING SURFACE'		
19	OUTLET NOZZLE INTERFACE SURFACE CONDITION.		
20	NEUTRON SHIELD PANEL COWL PIN COVER PLATE WELDS.		
21	NEUTRON SHIELD PANEL SCREW LOCKING DEVICES.		
22	INTERFACE SURFACES AT THE SPACER PADS ALONG THE TOP AND BOTTOM ENDS OF THE NEUTRON PANELS.		
23	BAFFLE ASSEMBLY SCREW LOCKING ARRANGEMENTS AT THE TWO TOP AND THE TWO BOTTOM FORMER ELEVATIONS.		
24	LOWER CORE PLATE TO CORE BARREL FLANGE SCREW LOCKING DEVICES ACCESSIBLE AT THE 0°, 90°, 180°, AND 270° AXES.		
25	CORE SUPPORT COLUMNS AND THEIR SCREW LOCKING DEVICES.		
26	CORE SUPPORT COLUMN ADJUSTING SLEEVES.		
27	ACCESSIBLE (2) INSTRUMENTATION GUIDE COLUMN LOCKING COLLARS NEAREST THE MANWAY.		
28	LOCKING DEVICES AND CONTACT OF THE CRUCIFORM SHAPED BOTTOM INSTRUMENTATION GUIDE COLUMNS WHERE ATTACHED TO THE CORE SUPPORT AND TIE PLATES.		
29	LOCKING DEVICES OF THE SECONDARY CORE SUPPORT BUTT COLUMNS AT THE CORE SUPPORT, TIE PLATE AND BASE PLATE.		
30	RADIAL SUPPORT KEY WELDS		
31	RADIAL SUPPORT KEY LOCKING ARRANGEMENTS AND BEARING SURFACES.		
32	HEAD AND VESSEL ALIGNING PIN SCREW LOCKING DEVICES AND BEARING SURFACES.		
33	IRRADIATION SPECIMEN GUIDE SCREW LOCKING DEVICES AND COWL PINS		
34	VESSEL NOZZLE INTERFACE SURFACE CONDITION.		
35	VESSEL CLEVIS LOCKING ARRANGEMENTS AND BEARING SURFACES.		

FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

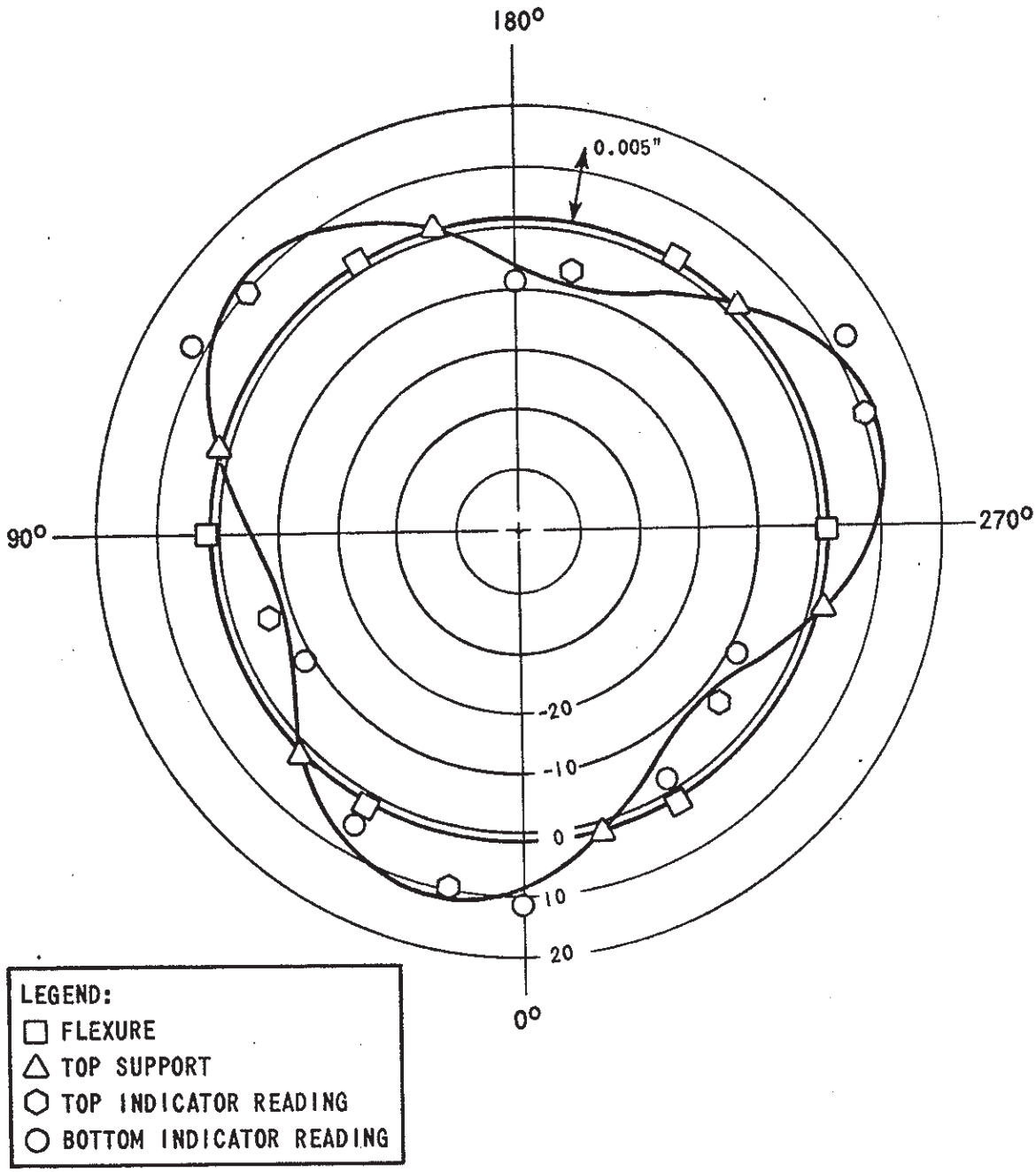
FIGURE 3.9-2
VIBRATION CHECKOUT - FUNCTIONAL
TEST INSPECTION DATA

SHOP TEST ACCELEROMETER DATA



MID T.S. (IPP)
n = 4
f = 72 H_z FORCE = 6 LB
CURVE = 0.12 COS 49 (LEAST SQUARE)
○ MIDDLE □ BOTTOM

FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 3.9-3 THERMAL SHIELD, MODEL SHAPE n=4 OBTAINED FROM SHAKER TEST



FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 3.9-4
THERMAL SHIELD, MAXIMUM AMPLITUDE OF VIBRATION DURING PREOPERATIONAL TEST

APPENDIX 3.1A

AEC
GENERAL DESIGN CRITERIA - 1971

Appendix 3.1A

AEC GENERAL DESIGN CRITERIA - 1971

As stated and described in DCPP Updated Final Safety Analysis Report (UFSAR) Section 3.1, the DCPP units are designed to comply with the "General Design Criteria for Nuclear Power Plant Construction Permits," published by the AEC in July, 1967. Appendix 3.1A briefly discusses the extent to which the original DCPP principal design features (the 1967 GDCs plus additional design features) for plant SSCs conform to the intent of the AEC "General Design Criteria for Nuclear Power Plants" published in February 1971 as 10 CFR Part 50 Appendix A (i.e., the 1971 GDCs). Submittal of the FSAR using Regulatory Guide 1.70, Revision 1 format and content was expected by the NRC as part of the initial DCPP licensing process, even though the NRC acknowledged in NUREG-0675 (SER-00) that the DCPP design basis was the 1967 GDCs.

Each 10 CFR Part 50, Appendix A 1971 GDC is addressed below including a summary of how the DCPP principal design features (the 1967 GDCs plus additional design features) demonstrates conformance to the intent of or exceptions to the criterion. The discussion of each GDC refers to sections of the FSAR presenting the details of the DCPP Unit 1 and Unit 2 designs. FSAR Table 3.1-2 provides a matrix listing of the 1971 GDC to the related 1967 GDC. Any exceptions to the 1971 GDCs that DCPP identified and the NRC approved in writing resulting from earlier DCPP design or construction commitments are identified in the discussion of the corresponding criterion in this appendix.

The discussion of how the plant design conformed to the intent of the 1971 GDCs was included in the original FSAR in Appendix 3.1A, and was reviewed by the NRC to conclude that DCPP's design conformed to the intent of the 1971 GDCs. The degree to which the DCPP design conforms to the intent of the 1971 GDCs, as summarized in this appendix, establishes additional DCPP licensing basis which must be reviewed when evaluating facility changes.

Criterion 1, 1971 - Quality Standards and Records

SSCs important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy, and sufficiency and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function. A QA program shall be established and implemented in order to provide adequate assurance that these SSCs will satisfactorily perform their safety function. Appropriate records of the design, fabrication, erection and testing of SSCs important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 1. SSCs have been designed, fabricated, erected, and tested to quality levels commensurate with their relationship to safety. The appropriate codes employed for various items have been supplemented where required. A QA program consistent with the 10 CFR Part 50, Appendix B, requirements has been employed and appropriate records have been made and are being maintained directly by PG&E or are under PG&E's control.

All systems and components of DCPP Unit 1 and Unit 2 are classified according to their importance in the prevention and mitigation of accidents. Those items vital to safe shutdown and isolation of the reactor, or whose failure might cause or increase the severity of a LOCA, or result in an uncontrolled release of excessive amounts of radioactivity, are designated PG&E Design Class I. Those items important to the reactor operation, but not essential to safe shutdown and isolation of the reactor or control of the release of substantial amounts of radioactivity, are designated PG&E Design Class II. Those items not related to reactor operation or safety are designated PG&E Design Class III.

PG&E Design Class I systems and components are essential to the protection of the health and safety of the public. Consequently, they are designed, fabricated, inspected, erected, and the materials selected to the applicable provisions of recognized codes, good nuclear practice, and to quality standards that reflect their importance. Discussions of applicable codes and standards as well as code classes are given in Section 3.2 for the major items and components. The QA program conforms to the requirements of 10 CFR Part 50 Appendix B, Quality Assurance Criteria for Nuclear Power Plants. Details of the QA program are provided in the Diablo Canyon Quality Assurance Program Description.

Records of the design, fabrication, construction and testing of PG&E Design Class I components of the plant will be maintained by PG&E or under its control throughout the life of the plant. The Diablo Canyon Quality Assurance Program Description describes the procedures for keeping these records. Operating records to be maintained throughout the life of the plant are described in Chapter 13.

This criterion is associated with 1967 GDCs 1 and 5.

Criterion 2, 1971 - Design Basis for Protection Against Natural Phenomena

SSCs important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches without loss of capability to perform their safety functions. The design bases for these SSCs shall reflect:

(1) Appropriate consideration of the most severe of the natural phenomena that have been historically reported for the site and surrounding area, with

sufficient margin for the limited accuracy, quantity, and period of time in which the historical data have been accumulated,

(2) Appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena, and

(3) The importance of the safety functions to be performed.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 2. The components, structures and systems important to safety have been designed to accommodate without loss of capability the most severe natural phenomena recorded for the site and surrounding areas with appropriate combinations of postulated accidents and natural phenomena. The importance of the safety functions of the various items has been considered.

The site characteristics are discussed in Chapter 2. Wind design criteria and flood design criteria are found in Sections 3.3 and 3.4, respectively. Seismic design is discussed in Section 3.7.

This criterion is associated with 1967 GDC 2.

Criterion 3, 1971 - Fire Protection

SSCs important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat-resistant materials shall be used wherever practical throughout the unit, particularly in locations such as the containment and control room. Fire detection and fighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on SSCs important to safety. Firefighting systems shall be designed to assure that their rupture or inadvertent operation does not significantly impair the safety capability of these SSCs.

Discussion

GDC 3 (1971) is invoked by 10 CFR 50.48, Fire Protection. The fire protection program for DCPP satisfies the requirements of GDC 3 (1971) by complying with 10 CFR 50.48(a) and (c) as stipulated by Operation License Conditions for 2.C(5) and 2.C(4) for Units 1 and 2, respectively. Federal Regulation 10 CFR 50.48(c) endorses, with exceptions, NFPA 805, Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants (2001).

The probability and effect of fires and explosions is minimized by identifying the fire protection systems and features required to achieve the nuclear safety performance criteria in Section 1.5 of NFPA 805 (2001). Once the determination was made that the

fire protection system or feature was required to achieve this performance criteria, the design and qualification of that system or feature was reviewed to ensure that any applicable requirements of NFPA 805, Chapter 3 are met. This process satisfies the GDC 3 requirement to design and locate SSCs important to safety in order to minimize the probability and effects of fires and explosions.

Documenting the basis for compliance for each of the fire protection program and design elements given in Chapter 3 of NFPA 805 is required by 10 CFR 50.48(c). The following section of Chapter 3 of NFPA 805 support the use of non-combustible and heat resistant material as required by GDC 3. Specifically:

- Section 3.3.2: Structural
- Section 3.3.3: Interior Finishes
- Section 3.3.4: Insulation Materials
- Section 3.11.4: Through Penetration Fire Stops

The capacity and capability of fire detection and fighting systems provided and designed to minimize the adverse effects of fires on structures, systems, and components important to safety are verified by first identifying the fire protection systems and features required to achieve the nuclear safety performance criteria in Section 1.5 of NFPA 805. Once the determination was made that a fire protection system or feature was required to achieve the performance criteria of Section 1.5, its design and qualification was reviewed to ensure that any applicable requirements of NFPA 805, Chapter 3 were met. This process satisfies the GDC 3 requirement to provide fire detection and fighting systems of appropriate capacity and capability to minimize the adverse effects of fires on structures, systems, and components important to safety.

It was assured that the rupture or inadvertent operation of firefighting systems does not significantly impair the safety capability of these structures, systems, and components through documentation of the basis of compliance for each of the fire protection program and design elements with the requirements given in Chapter 3 of NFPA 805 (2001). The following sections of Chapter 3 of NFPA 805 address the design of firefighting systems. Specifically:

Section 3.4: Industrial Fire Brigade
Section 3.5: Water Supply
Section 3.6: Standpipe and Hose Stations
Section 3.7: Fire Extinguishers
Section 3.8: Fire Alarm and Detection Systems
Section 3.9: Automatic and Manual Water-Based Fire Suppression Systems
Section 3.10: Gaseous Fire Suppression Systems

This process satisfies the GDC 3 requirement to design firefighting systems to ensure that their rupture or inadvertent operation does not significantly impair the safety capability of structures, systems, and components important to safety.

This criterion is associated with 1967 GDC 3.

Criterion 4, 1971 - Environmental and Missile Design Bases

SSCs important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including LOCAs. These SSCs shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 4. The safety-related SSCs are designed to accommodate all normal or routine environmental conditions as well as those associated with postulated accidents. The designs include provisions to protect, where appropriate, those safety-related items from dynamic effects resulting from component failures and specific credible outside events and conditions.

Use of conservative design methods, segregated routing of piping, provision of missile shield walls, and use of engineered hangers and pipe restraints are incorporated in the design to accommodate dynamic effects of postulated accidents. The various sources of missiles that might affect ESFs have been identified, and protective measures have been devised to minimize these effects (refer to Section 3.5).

The basic approach for protection of Class 1E equipment and cables from missiles is to ensure design adequacy against generation of missiles. Where missiles cannot be contained within parent equipment, missile protection is attained by routing or placing Class 1E cables and equipment in non-missile prone areas or by shielding the equipment.

This criterion is associated with 1967 GDC 40.

Criterion 5, 1971 - Sharing of Structures, Systems and Components

SSCs important to safety shall not be shared between nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 5. Those SSCs that are shared are designed in such a manner that plant safety is not impaired by the sharing. A list of shared components and systems is given in Section 1.2.

This criterion is associated with 1967 GDC 4.

Criterion 10, 1971 - Reactor Design

The reactor core and associated coolant, control, and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to Criterion 10, 1971 instead of 1967 GDC 6, with respect to the design of the reactor core. This is an exception to the commitments to 1967 GDCs. Appropriate fuel margins are included in each design.

Each reactor core with its related control and protection systems is designed to function throughout its design lifetime without exceeding acceptable fuel damage limits. Core design, together with reliable process and decay heat removal systems, provides for this capability under all expected conditions of normal operation with appropriate margins for uncertainties and anticipated transient situations, including the effects of the loss of reactor coolant flow, trip of the turbine generator, loss of normal feedwater and loss of offsite power.

The reactor control and protection instrumentation systems are designed to initiate a reactor shutdown for any anticipated combination of plant conditions when necessary to assure a minimum DNBR equal to or greater than the applicable limit value (refer to Sections 4.4.4.1 and 4.4.3.3) and fuel center temperatures below the melting point of UO_2.

Chapter 4 discusses the design bases and design evaluation of reactor components. The details of the control and protection instrumentation systems design and logic are discussed in Chapter 7. This information supports the accident analyses presented in Chapter 15.

This criterion supersedes 1967 GDC 6 with respect to the design of the reactor core.

Criterion 11, 1971 - Reactor Inherent Protection

The reactor core and associated coolant systems shall be designed so that in the power operating range the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to Criterion 11, 1971 instead of 1967 GDC 8. This is an exception to the commitments to 1967 GDCs. A negative reactivity coefficient is a basic feature of each design.

Prompt compensatory reactivity feedback effects are ensured when each reactor is critical by the negative fuel temperature effect (Doppler effect) and by the operational limit on moderator temperature coefficient of reactivity. The negative Doppler coefficient of reactivity is ensured by the inherent design using low-enrichment fuel. The limits on moderator temperature coefficient of reactivity are ensured by administratively controlling the dissolved neutron absorber concentration and control rod position. These reactivity coefficients are discussed in Section 4.3.

This criterion supersedes 1967 GDC 8.

Criterion 12, 1971 - Suppression of Reactor Power Oscillations

The reactor core and associated coolant, control and protection systems shall be designed to assure that power oscillations which can result in conditions exceeding specified acceptable fuel design limits are not possible or can be reliably and readily detected and suppressed.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to Criterion 12, 1971 instead of 1967 GDC 7. This is an exception to the commitments to 1967 GDCs. The designs include provisions to detect and control those power oscillations that might exceed acceptable fuel design limits during operation.

Oscillations in total core power, from whatever cause, are readily detected by loop temperature sensors and by nuclear instrumentation. Unacceptable power increases result in a reactor trip, thus preserving margins to fuel design limits.

The core is designed so that diametral and azimuthal oscillations due to spatial xenon effects are self-damping, and no operator action or control action is required to suppress them. Additionally, thermohydraulic oscillations do not occur under Condition I and Condition II events for Westinghouse PWRs.

The stability of the cores against xenon-induced power oscillations and the functional requirements of instrumentation for monitoring and measuring core power distributions are discussed in Section 4.3. Thermohydraulic stability characteristics are discussed in Section 4.4. Details of the instrumentation design and logic are discussed in Chapter 7.

This criterion supersedes 1967 GDC 7.

Criterion 13, 1971 - Instrumentation and Control

Instrumentation shall be provided to monitor variables and systems over their anticipated range for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the RCPB, and the containment and its associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 13. Appropriate instrumentation and control systems have been provided to monitor and control pertinent variables and systems over normal range of operation and postulated accident conditions.

Reactor, control rod, boron concentration, pressurizer pressure and level, feedwater, steam dump, and turbine instrumentation and controls are provided to monitor and maintain variables within prescribed operating ranges. Reactor protection systems that receive plant instrumentation signals and automatically actuate alarms, inhibit control rod withdrawal, initiate load cutback, and/or trip the reactors as prescribed limits are approached or reached are also provided. These systems are discussed in Chapter 7. The reactivity control and NIS are discussed in Chapters 4 and 7.

This criterion is associated with 1967 GDCs 12, 13, 14, and 15.

Criterion 14, 1971 - Reactor Coolant Pressure Boundary

The RCPB shall be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 14. The design, fabrication, erection, and testing employed on each RCPB and the extensive quality control measures employed during each of the above phases ensure that these pressure boundaries have extremely low probabilities of abnormal leakage, rapidly propagating failure, and gross rupture.

In addition to the loads imposed on the system under normal operating conditions, abnormal loading conditions, such as seismic loading and pipe rupture, are also considered, as discussed in Sections 3.6 and 3.7. The systems are protected from overpressure by means of pressure-relieving devices as required by applicable codes.

Means are provided to detect significant uncontrolled leakage from either RCPB with indication in the control room as discussed in Section 5.2. Each RCS boundary has provisions for inspection, testing, and surveillance of critical areas to assess the structural and leaktight integrity. The details of these provisions are given in Section 5.2. For each reactor vessel, a material surveillance program conforming to applicable codes is provided. Additional details are provided in Section 5.4.

The materials of construction of the pressure-retaining boundary of the RCS are protected by control of coolant chemistry from corrosion that might otherwise reduce the system structural integrity during its service lifetime.

This criterion is associated with 1967 GDC 9.

Criterion 15, 1971 - Reactor Coolant System Design

The RCS and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including anticipated operational occurrences.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 15. Each RCS design and associated pertinent systems include sufficient margin to assure that the appropriate design limits of the RCPB are not exceeded during normal operation, including transients as defined in Chapter 15. Reactor internals analysis and testing are described in Section 3.9. The RCS is discussed in Chapter 5.

No direct association exists with the 1967 GDC for this criterion.

Criterion 16, 1971 - Containment Design

Reactor containment and associated systems shall be provided to establish an essentially leaktight barrier against the uncontrolled release of radioactivity to the environment and to assure that the containment design conditions important to safety are not exceeded for as long as postulated accident conditions require.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 16. The reactor containment is a reinforced concrete structure with a steel liner that provides an essentially leaktight barrier against the uncontrolled release of radioactivity to the environment under any postulated accident condition.

The reactor containment structure and penetrations, with the aid of containment heat removal systems, are designed to limit radiation doses resulting from leakage of

radioactive fission products from the containment to below 10 CFR Part 100 values, assuming the largest credible energy release following a LOCA, including a margin to cover the effects of metal water or other undefined energy sources. The containment design is described in detail in Section 3.8.2.1.

This criterion is associated with 1967 GDCs 10 and 49.

Criterion 17, 1971 - Electric Power Systems

An onsite electric power system and an offsite electric power system shall be provided to permit functioning of SSCs important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the RCPB are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the RCPB are not exceeded. One of these circuits shall be designed to be available within a few seconds following a LOCA to assure that core cooling, containment integrity, and other vital safety functions are maintained.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to Criterion 17 instead of 1967 GDC 39. This is an exception to the commitments to 1967 GDCs.

The DCPP offsite power system is designed to supply offsite electrical power by two physically independent circuits. The 230-kV system provides startup and standby power, and is immediately available following a DBA to assure that core cooling,

containment integrity, and other vital safety functions are maintained. The 500-kV system provides for transmission of the plant's electric power output. The 500-kV connection also provides a delayed access source of offsite power after the main generator is disconnected. A combination of the 230-kV circuits and the 500-kV circuits provides independent sources of offsite power as required by GDC 17, 1971.

The onsite emergency power source consists of three DGs for each unit.

Both offsite and onsite systems have sufficient independence, capacity, and testability to permit the operation of the ESFs assuming a failure of a single active component in each power system. The combination of two 230-kV lines plus the 500-kV system provides a high degree of assurance that offsite power will be available when required. The 230-kV and 500-kV systems meet the requirements of 1971 GDC 17. Further details are provided in Chapter 8.

This criterion supersedes 1967 GDC 39.

Criterion 18, 1971 - Inspection and Testing of Electric Power Systems

Electric power systems important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features, such as wiring, insulation, connections, and switchboards, to assess the continuity of the systems and the condition of their components. The systems shall be designed with a capability to test periodically (1) the operability and functional performance of the components of the systems, such as onsite power sources, relays, switches, and buses, and (2) the operability of the systems as a whole and, under conditions as close to design as practical, the full operational sequence that brings the systems into operation, including operation of applicable portions of the protection system, and the transfer of power among the nuclear power unit, the offsite power system, and the onsite power system.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to Criterion 18.

The electric power system and its components have provisions for periodic inspection and testing. Electric power components have been provided with convenient and safe features for inspecting and testing to meet the requirements of GDC 18, 1971. Further details are provided in Chapter 8.

Criterion 19, 1971 - Control Room

A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in a safe condition under accident conditions including LOCAs. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without

personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 19. A centralized control room common to both units contains the controls and instrumentation necessary for operation of both units under normal and accident conditions, including LOCAs. Adequate radiation protection is provided to ensure that control room personnel are not subject to radiation exposures in excess of 10 CFR Part 20 limits. Provisions are made so that plant operators can readily maintain the plant at safe shutdown (MODE 3) condition from a location outside the control room.

The DCPP Unit 1 and Unit 2 designs conform to Criterion 19 for accident dose. The DCPP design also incudes use of alternative source terms in accordance with 10 CFR 50.67 and Regulatory Guide 1.183, July 2000. Adequate radiation protection is provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent (TEDE) for the duration of the accident to meet the requirements of GDC 19, 1999 (refer to Section 6.4).

This criterion is associated with 1967 GDC 11.

Criterion 20, 1971 - Protection System Functions

The protection system shall be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of systems and components important to safety.

Discussion

The DCPP Unit 1 and Unit 2 protection system designs comply with the intent of Criterion 20. The systems will automatically actuate alarms, inhibit control rod withdrawal, initiate load cutback, or trip the reactor as a result of anticipated operational occurrences. The systems will also sense accident conditions and initiate ESFs operation if required. ESF and the protection systems are discussed in Chapters 6 and 7, respectively.

Operational limits for the core protection systems are defined by analyses of all plant operating and fault conditions requiring rapid rod insertion to prevent or limit core damage. The protection systems are discussed in Section 7.2.

This criterion is associated with 1967 GDCs 14, 15, 20, 21, and 25.

Criterion 21, 1971 - Protection System Reliability and Testability

The protection system shall be designed for high functional reliability and inservice testability commensurate with the safety functions to be performed. Redundancy and independence designed into the protection system shall be sufficient to assure that (1) no single failure results in loss of protection function and (2) removal from service of any component or channel does not result in loss of the required minimum redundancy unless the acceptable reliability of operation of the protection system can be otherwise demonstrated. The protection system shall be designed to permit periodic testing of its functioning when the reactor is in operation, including a capability to test channels independently to determine failures and losses of redundancy that may have occurred.

Discussion

The DCPP Unit 1 and Unit 2 protection system designs comply with the intent of Criterion 21. Each protection system is comprised of redundant independent logic trains of high functional reliability capable of tolerating a single failure without loss of the protection function, or removal from service of a single component or channel without loss of required minimum redundancy. Independent end-to-end channel tests can be performed with the reactor at power. The majority of system components can be tested very rapidly by use of built-in semiautomatic testers. Removal from service of any single channel or component does not result in loss of minimum required redundancy. For example, a two-of-three function becomes a one-of-two function when one channel is removed.

Semiautomatic testers are built into each of the two logic trains in a protection system. These testers have the capability of testing the major part of the protection system very rapidly while the reactor is at power. Between tests, the testers continuously monitor a number of internal protection system points including the associated power supplies and fuses. Outputs of the monitors are logically processed to provide alarms for failures in one train and automatic reactor trip for failures in both trains. Additional details can be found in Section 7.2.

This criterion is associated with 1967 GDC 19.

Criterion 22, 1971 - Protection System Independence

The protection system shall be designed to assure that the effects of natural phenomena, and of normal operating, maintenance, testing, and postulated accident conditions on redundant channels do not result in loss of the protection function, or shall be demonstrated to be acceptable on some other defined basis. Design techniques, such as functional diversity or diversity in component design and principles of operation, shall be used to the extent practical to prevent loss of the protection function.

Discussion

The DCPP Unit 1 and Unit 2 protection system designs comply with the intent of Criterion 22. Independent, redundant, and separate subsystems have been provided. Extensive measurement, equipment, and location diversity is employed in each design. These design techniques are defenses against loss of the protective function through the effects of natural phenomena, normal operation, maintenance, and testing.

Physical separation and electrical isolation of redundant channels and subsystems, functional diversity of subsystems, and safe failure modes are employed in design of the reactors as defenses against functional failure through exposure to common causative factors. The redundant logic trains, reactor trip breakers, and ESF actuation devices are physically separated and electrically isolated. Physically separate channel trays, conduits, and penetrations are maintained upstream from the logic elements of each train.

The protection system components have been qualified by testing under extremes of the normal environment. In addition, components are tested and qualified according to individual requirements for the adverse environment specific to their location that might result from postulated accident conditions. The protection systems are discussed in Section 7.2.

This criterion is associated with 1967 GDCs 20, 21, 22, and 23.

Criterion 23, 1971 - Protective System Failure Modes

The protection system shall be designed to fail into a safe state or into a state demonstrated to be acceptable on some other defined basis if conditions such as disconnection of the system, loss of energy (e.g., electric power, instrument air), or postulated adverse environments (e.g., extreme heat or cold, fire, pressure, steam, water, and radiation) are experienced.

Discussion

The DCPP Unit 1 and Unit 2 protection system designs comply with the intent of Criterion 23. Each system is designed with due consideration of the most probable failure modes of the components under various perturbations of energy sources and environment. Each trip channel is designed to trip on de-energization. Loss of power, disconnection, open channel faults, and the majority of internal channel short circuit faults cause a channel to go into its tripped mode. Components of each system are qualified by testing for the environments that might result from postulated accident conditions. The protection system details can be found in Section 7.2.

This criterion is associated with 1967 GDC 26

Criterion 24, 1971 - Separation of Protection and Control Systems

The protection system shall be separated from control systems to the extent that failure of any single control system component or channel, or failure or removal from service of any single protection system component or channel which is common to the control and protection systems leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection system. Interconnection of the protection and control systems shall be limited so as to assure that safety is not significantly impaired.

Discussion

The DCPP Unit 1 and Unit 2 protection and control system designs comply with the intent of Criterion 24. Failure of or removal from service of any single component or channel of either the protection system or the control system leaves intact a system satisfying the reliability, redundancy, and independence requirements of the protection system. The protection system is separate and distinct from the control system.

The control system is dependent on the protection system in that control system signals are derived from protection system measurements where applicable. Interconnection is through isolation amplifiers that are classified as protection system components. The adequacy of systems isolation has been verified by testing under the conditions of maximum credible faults.

The protection systems comply with the requirements of IEEE Standard 279-1971 "Criteria for Protection Systems for Nuclear Power Generation Stations" although construction permits for the Diablo Canyon units were issued prior to issuance of the 1971 version of the standard. The protection systems and control systems are discussed in Chapter 7.

This criterion is associated with 1967 GDC 22.

Criterion 25, 1971 - Protection System Requirements for Reactivity Control Malfunctions

The protection system shall be designed to assure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods.

Discussion

The DCPP Unit 1 and Unit 2 designs comply with the intent of Criterion 25, 1971.

Reactor shutdown with control shutdown rods is completely independent of control functions. The reactor trip breakers interrupt power to all CRDMs regardless of the status of existing control signals. The design is such that the systems can withstand

accidental withdrawal of control groups or unplanned dilution of soluble boron without exceeding acceptable fuel design limits.

The facility reactivity control systems are discussed further in Chapter 7, and analyses of the effects of the other possible malfunctions are discussed in Chapter 15. The analyses show that acceptable fuel damage limits are not exceeded in the event of a single malfunction of either system.

The DCPP Unit 1 and Unit 2 designs conform to Criterion 25, 1971 for reactivity insertion rate limits. Reactivity addition associated with an accidental withdrawal of a control bank (or banks) is limited by the maximum rod speed (or travel rate) and by the worth of the bank(s). For this reactor the maximum control rod speed is 45 inches per minute and the maximum rate of reactivity change considering two control banks moving is less than 75 pcm/sec. The reactivity rate used in the boron dilution analysis at power is discussed in Section 15.2.4.

This criterion is associated with 1967 GDC 31.

Criterion 26, 1971 - Reactivity Control System Redundancy and Capability

Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margins for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to, with the possible exception of the preferred rod insertion means, Criterion 26, 1971 instead of 1967 GDC 27. This is an exception to the commitments to 1967 GDCs.

Two independent reactivity control systems of different design principles are provided for each reactor design. One of the systems uses control rods; the other system uses dissolved boron. The boron system is capable of maintaining the reactor in a subcritical status under cold shutdown conditions. The rod control system maintains a programmed average reactor temperature with scheduled and transient load changes; the boron system is capable of controlling the rate of reactivity change resulting from planned normal power changes including xenon burnout. The control rods are inserted by gravity.

The RCCA system is capable of making and holding the core subcritical from all operating and hot shutdown conditions sufficiently fast to prevent exceeding acceptable fuel damage limits. The chemical shim control is also capable of making and holding the core subcritical, but at a slower rate, and is not employed as a means of compensating for rapid reactivity transients. The RCCA system is, therefore, used in protecting each core from fast transients. Details of the construction of the RCCA are included in Section 4.2, with the operation discussed in Chapter 7. The means of controlling the boric acid concentration is described in Section 9.3.4.

This criterion supersedes 1967 GDC 27 and is associated with 1967 GDCs 28, 29 and 30. Criterion 26, 1971 supplements Criterion 28, 1967 specifically for the ability of the boron system to hold the reactor core subcritical under cold conditions.

Criterion 27, 1971 - Combined Reactivity Control Systems Capability

The reactivity control systems shall be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes to assure that under postulated accident conditions and with appropriate margin for stuck rods the capability to cool the core is maintained.

Discussion

The DCPP Unit 1 and Unit 2 designs comply with the intent of Criterion 27. Appropriate reactivity margin is available for each unit under postulated accident conditions to ensure that the capability to cool the core is maintained. Such margin includes an allowance for the most reactive rod control cluster being stuck out of the core.

The boron reactivity (chemical shim) control systems are capable of making and holding the core subcritical under any anticipated conditions and with appropriate margin for contingencies. These means are discussed in detail in Chapters 4 and 9. Normal reactivity shutdown capability is provided by rapid control rod insertion. The chemical shim control system permits the necessary shutdown margin to be maintained during long-term xenon decay and plant cooldown.

This criterion is associated with 1967 GDC 30.

Criterion 28, 1971 - Reactivity Limits

The reactivity control systems shall be designed with appropriate limits on the potential amount and rate of reactivity increase to assure that the effects of postulated reactivity accidents can neither (1) result in damage to the RCPB greater than limited local yielding nor (2) sufficiently disturb the core, its support structures or other RPV internals to impair significantly the capability to cool the core. These postulated reactivity accidents shall include consideration of rod ejection (unless prevented by positive means), rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition.

Discussion

The DCPP Unit 1 and Unit 2 designs comply with the intent of Criterion 28, 1971. For each unit, the maximum rate of reactivity insertion employing boron removal is limited to values that prevent rupture of the coolant pressure boundary or disruption of the core or internals to a degree that could impair the effectiveness of the ECCS. The appropriate reactivity insertion rate for the dilution of boron in the coolant system is discussed in Chapter 15.

The boron reactivity (chemical shim) control systems are capable of making and holding the core subcritical under any anticipated condition and with appropriate margin for contingencies. These means are discussed in detail in Chapters 4 and 9.

The DCPP Unit 1 and Unit 2 designs conform to Criterion 28, 1971. The reactivity control system employing control rods is designed with appropriate limits on the potential amount and rate of reactivity increase to assure that the effects of postulated reactivity accidents can neither (1) result in damage to the RCPB greater than limited local yielding nor (2) sufficiently disturb the core, its support structures or other RPV internals to impair significantly the capability to cool the core. These postulated reactivity accidents shall include consideration of rod ejection (unless prevented by positive means), rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition.

The maximum control rod reactivity worth and the maximum rates of reactivity insertion using control rods are limited to preclude either rupture of the coolant pressure boundary or disruption of the core internals to a degree that would impair core cooling capacity in the event of a rod withdrawal or ejection accident (refer to Chapter 15).

Following any Condition IV event (such as rod ejection and steam line break), the reactor can be brought to the shutdown condition and the core will maintain acceptable heat transfer geometry. These means are discussed in detail in Section 4.3.

This criterion is associated with 1967 GDC 32.

Criterion 29, 1971 - Protection Against Anticipated Operational Occurrences

The protection and reactivity control systems shall be designed to assure an extremely high probability of accomplishing their safety functions in the event of anticipated operational occurrences.

Discussion

The DCPP Unit 1 and Unit 2 designs comply with the intent of Criterion 29, 1971.

The protection and reactivity control systems for each plant are designed to ensure an extremely high probability of fulfilling their intended functions. The design principles of diversity and redundancy coupled with a rigorous QA program support this probability as does operating experience in plants using the same basic design. The protection systems are described in Section 7.2.

The DCPP Unit 1 and Unit 2 CRDM designs conform to Criterion 29, 1971. If power to the stationary gripper coil of the CRDM is cut off, the combined weight of the drive rod assembly and the RCCA is sufficient to move latches out of the drive rod assembly groove. The control rod falls by gravity into the core.

This criterion is associated with 1967 GDCs 19 and 20.

Criterion 30, 1971 - Quality of Reactor Coolant Pressure Boundary

Components which are part of the RCPB shall be designed, fabricated, erected, and tested to the highest quality standards practical. Means shall be provided for detecting and, to the extent practical, identifying the location of the source of reactor coolant leakage.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 30. The quality levels employed in the design, fabrication, erection and testing for each RCPB are extremely comprehensive. Systems are included in the plant to detect and, to the extent practical, to locate leakage.

All RCS components are designed, fabricated, inspected, and tested in conformance with the ASME Boiler and Pressure Vessel Code.

Leakage is detected by an increase in the amount of makeup water required to maintain a normal level in the pressurizer. The reactor vessel closure joint is provided with a temperature monitored leakoff between double gaskets.

Leakage into the reactor containment is drained to the reactor building sump where the level is monitored.

Leakage is also detected by measuring the airborne activity and quantity of the condensate drained from each reactor containment fan cooler unit. These leakage detection methods are described in detail in Section 5.2.

This criterion is associated with 1967 GDCs 9 and 16.

Criterion 31, 1971 - Fracture Prevention of Reactor Coolant Pressure Boundary

The RCPB shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (1) the boundary behaves in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions and the uncertainties in determining (1) material properties, (2) the effects of irradiation on material properties, (3) residual, steady-state and transient stresses, and (4) size of flaws.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 31. Each reactor coolant boundary is designed so that, for all normal operating and postulated accident modes, the boundary behaves in a nonbrittle manner and so that the probability of rapidly propagating failure is minimized. Service temperature and pressure, irradiation, cyclic loading, seismic, blowdown and thermal forces from postulated accidents, residual stresses, and code allowable material discontinuities have all been considered in the design, with appropriate margins for each.

Sufficient testing and analysis of materials employed in RCS components have been performed to ensure that the required NDT temperature limits specified in the criterion are met. Removable test capsules installed in the reactor vessel are removed and tested at various times in the plant lifetime to determine the effects of operation on system materials. Details of the testing and analysis programs are included in Chapter 5.

Close control is maintained over material selection and fabrication for the RCS. Materials exposed to the coolant are corrosion-resistant stainless steel or Inconel. Materials testing consistent with 10 CFR Part 50 ensures that only materials with adequate toughness properties are used.

The fabrication and quality control techniques used in the fabrication of the RCS are equivalent to those used for the reactor vessel. The inspections of reactor vessel, steam generators, pressurizer, pumps, and piping are governed by ASME code requirements.

This criterion is associated with 1967 GDCs 34 and 35.

Criterion 32, 1971 - Inspection of Reactor Coolant Pressure Boundary

Components which are part of the RCPB shall be designed to permit (1) periodic inspection and testing of important areas and features to assess their structural and leaktight integrity, and (2) an appropriate material surveillance program for the RPV.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 32. Each RCPB is periodically inspected under the provisions of ASME Section XI. The DCPP Inservice Inspection and Testing Program plans for the first ten-year interval conformed to the extent practicable with the 1977 Edition of Section XI with Addenda through Summer 1978. The Inservice Inspection Program plan for the second ten-year interval conformed to the extent practicable with the 1989 Edition of Section XI without Addenda. The Inservice Inspection Program plan for the third ten-year interval will conform to the extent practicable with the 2001 Edition of Section XI with 2002 and 2003 Addenda. A reactor vessel metal surveillance program will be employed in accordance with ASTM 185, Recommended Practice for Surveillance Tests on Structural Materials in Nuclear Reactors.

Monitoring of the NDT temperature properties of each core region plate, forging, weldment, and associated heat-treated zones are performed in accordance with ASTM E 185, Recommended Practice for Surveillance Tests on Structural Materials in Nuclear Reactors. Samples of reactor vessel plate materials are retained and cataloged in case future engineering development shows the need for further testing.

The material properties surveillance program includes not only the conventional tensile and impact tests, but also fracture mechanics specimens. The observed shifts in NDT temperature of the core region materials with irradiation are used to confirm the calculated limits to startup and shutdown transients.

To define permissible operating conditions below NDT temperature, a pressure range is established that is bounded by a lower limit for pump operation and an upper limit that satisfies reactor vessel stress criteria. To allow for thermal stresses during heatup or cooldown of the reactor vessel, an equivalent pressure limit is defined to compensate for thermal stress as a function of rate of change of coolant temperature. Because the normal operating temperature of the reactor vessel is well above the maximum expected NDT temperature brittle fracture during normal operation, it is not considered to be a credible mode of failure. Additional details can be found in Section 5.2.

This criterion is associated with 1967 GDC 36.

Criterion 33, 1971 - Reactor Coolant Makeup

A system to supply reactor coolant makeup for protection against small breaks in the RCPB shall be provided. The system safety function shall be to assure that specified acceptable fuel design limits are not exceeded as a result of reactor coolant loss due to leakage from the RCPB and rupture of small piping or other small components which are part of the boundary. The system shall be designed to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety

function can be accomplished using the piping, pumps, and valves used to maintain coolant inventory during normal reactor operation.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 33. The normal flowpath for each RCS charging system can be used to ensure appropriate makeup protection against small breaks. The RCS charging system is discussed in Section 9.3.

No direct association exists with the 1967 GDC.

Criterion 34, 1971 - Residual Heat Removal

A system to remove residual heat shall be provided. The system safety function shall be to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the RCPB are not exceeded.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 34. Each RHR system, consisting of two redundant trains of pumps and heat exchangers, has appropriate heat removal capacity to ensure fuel protection. This system supplements the normal steam and power conversion system which is used for the first cooldown. The AFW system complements the steam and power conversion system in this function. The systems together accommodate the single failure criteria.

The RHR system is discussed in Section 5.5.

No direct association exists with the 1967 GDC.

Criterion 35, 1971 - Emergency Core Cooling

A system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant at a rate such that (1) fuel and clad damage that could interfere with continued effective core cooling is prevented and (2) clad metal-water reaction is limited to negligible amounts.

Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 35. Appropriate core cooling systems have been designed for each plant so as to provide for the removal of core thermal loads and for the limiting of metal-water reactions to an insignificant level. Suitable redundancy is provided in core cooling systems. The charging accumulator and SI systems will accommodate a single active failure and still fulfill their intended safety function. The RHR system will accommodate a single passive or active failure and still fulfill its intended safety function.

By combining the use of passive accumulators with two centrifugal charging pumps (CCP1 and CCP2), two SI pumps, and two RHR pumps, emergency core cooling is provided even if there should be a failure of any single component in any system. The ECCS employs a passive system of accumulators that do not require any external signals or source of power for their operation to cope with the short-term cooling requirements of large reactor coolant pipe breaks. Two independent and redundant high-pressure flow and pumping systems, each capable of the required emergency cooling, are provided for small break protection and to keep the core submerged after the accumulators have discharged following a large break. These systems are arranged so that the single failure of any active component does not interfere with meeting the short-term cooling requirements.

Borated water is injected into the RCS by accumulators, SI pumps, RHR pumps, and charging pumps. Pump design includes consideration of fluid temperature and containment pressure in accordance with Safety Guide 1, November 1970. The failure of any single active component or the development of excessive leakage during the long term cooling period does not interfere with the ability to meet necessary long-term cooling objectives with one of the systems.

The primary function of the ECCS is to deliver borated cooling water to the reactor core in the event of a LOCA. This limits the fuel cladding temperature and thereby ensures that the core will remain intact and in place, with its essential heat transfer geometry preserved. This protection is afforded for:

(1) All pipe break sizes up to and including the hypothetical circumferential rupture of a RCL

(2) A loss-of-coolant associated with a rod ejection accident

The basic criteria for LOCA evaluations are (a) no cladding melting will occur, (b) zirconium-water reactions will be limited to an insignificant amount, and (c) the core geometry will remain essentially in place and intact so that effective cooling of the core will not be impaired. The zirconium-water reactions will be limited to an insignificant amount so that the accident:

(1) Does not interfere with the emergency core cooling function to limit cladding temperatures

(2) Does not produce hydrogen in an amount that, when burned, would cause the containment pressure to exceed the design value

For any rupture of a steam pipe and the associated uncontrolled heat removal from the core, the ECCS adds shutdown reactivity so that with a stuck rod, no offsite power, and minimum ESF, there is no consequential damage to the primary system and the core remains in place and intact. With no stuck rod, offsite power, and all equipment operating at design capacity, there is insignificant cladding rupture. The ECCS is described in Section 6.3. Chapter 15 provides the analysis for the LOCA.

This criterion is associated with 1967 GDCs 37 and 44.

Criterion 36, 1971 - Inspection of Emergency Core Cooling System

The ECCS shall be designed to permit appropriate periodic inspection of important components, such as spray rings in the RPV, water injection nozzles, and piping, to assure the integrity and capability of the system.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 36. They provide for inspection of the emergency core cooling branch line connections to the RCS for each plant in accordance with the provision of ASME Section XI. These are the areas of principal stress in the system due to temperature gradients. The remainder of the systems are verified as to integrity and functioning by means of periodic testing as described in the Technical Specifications.

Design provisions facilitate access to the critical parts of the reactor vessel internals, injection nozzles, pipes, and valves for visual or nondestructive inspection. The components outside containment are accessible for leaktightness inspection during operation of the reactor.

Details of the inspection program for the reactor vessel internals are included in Section 5.4. Information on inspection for the ECCS is provided in Section 6.3.

This criterion is associated with 1967 GDC 45.

Criterion 37, 1971 - Testing of Emergency Core Cooling System

The ECCS shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leaktight integrity of its components, (2) the operability and performance of the active components of the system, and (3) the operability of the system as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 37. Periodic tests demonstrate the integrity, operability, and performance of each active component. Each system as a whole, and the entire operational sequence of actuation, power transfer, and cooling water operation are tested in several phases rather than in one phase during periodic testing.

The design provides for periodic testing of both active and passive components of the ECCS for operability and functional performance. Preoperational performance tests of the components were performed in the manufacturer's shop. Initial system flow tests demonstrate proper functioning of the system. Thereafter, periodic tests demonstrate that components are functioning properly.

Each active component of the ECCS may be individually actuated on the normal power source at any time during plant operation to demonstrate operability. The centrifugal charging pumps are part of the charging system, and this system is in continuous operation during plant operation. The test of the SI pumps employs the minimum flow recirculation test line that connects back to the RWST. Remotely operated valves are exercised and actuation circuits tested. The automatic actuation circuitry, valves, and pump breakers also may be checked during integrated system tests performed during a planned cooldown of the RCS. Details of the ECCS are found in Section 6.3. Performance under accident conditions is evaluated in Chapter 15.

Design provisions include special instrumentation, testing, and sampling lines to perform tests during plant shutdown to demonstrate proper operation of the ECCS. A test signal is applied to initiate automatic action. The test demonstrates the operation of the valves, pump circuit breakers, and automatic circuitry. In addition, the periodic recirculation to the RWST can verify that the SI pumps attain required discharge heads. During a refueling outage the full flow capability of each injection pump can be verified.

This criterion is associated with 1967 GDCs 38, 46, 47, and 48.

Criterion 38, 1971 - Containment Heat Removal

A system to remove heat from the reactor containment shall be provided. The system safety function shall be to reduce rapidly, consistent with the functioning of other associated systems, the containment pressure and temperature following any LOCA and maintain them at acceptably low levels.

Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 38. Two diverse heat removal systems, each composed of redundant components, are provided. These are the CSS (100 percent capacity pumping systems) and the containment fan cooler system (five units provided, two required for accident heat removal).

The reactor containment structure and penetrations, with the aid of containment heat removal systems, are designed to limit radiation doses resulting from leakage of radioactive fission products from the containment to below 10 CFR Part 100 values, assuming the largest credible energy release following a LOCA, including a margin to cover the effects of metal water or other undefined energy sources. The containment design is described in detail in Section 3.8.2.1.

Two separate heat removal systems, the CSS and the containment fan coolers, are provided to remove heat from the containment following an accident. The design cooling rates of the two systems at the containment design pressure and temperature conditions are the same. The heat removal capability of either system is sufficient to rapidly reduce the containment pressure following an accident. The containment heat removal systems are described in Section 6.2.

This criterion is associated with 1967 GDCs 49 and 52.

Criterion 39, 1971 - Inspection of Containment Heat Removal System

The containment heat removal system shall be designed to permit appropriate periodic inspection of important components, such as the torus, pumps, spray nozzles, and piping to assure the integrity and capability of the system.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 39 except for limited areas. Four or fewer fan cooler units are continually operating and are rotated in

service to provide continuous verification of operability and integrity. Access for routine maintenance and inspection has been provided.

The CSS integrity will be verified by means of periodic testing as described in the Technical Specifications. Access has been provided for routine maintenance and inspection except for the spray ring headers and nozzles for which no inspection provision was made, except that provisions were made to smoke or air test these headers and nozzles periodically.

Where practicable, all active components and passive components of the containment cooling system are inspected periodically to demonstrate system readiness. The pressure containing systems are inspected for leaks from pump seals, valve packing, flanged joints, and SVs. During operational testing of the containment spray pumps, the portions of the system subjected to pump pressure are inspected for leaks. The containment fan coolers are normally in use, which provides an additional check on the readiness of the system. Additional details are found in Section 6.2.

This criterion is associated with 1967 GDC 58.

Criterion 40, 1971 - Testing of Containment Heat Removal System

The containment heat removal system shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leaktight integrity of its components, (2) the operability and performance of the active components of the system, and (3) the operability of the system as a whole, and, under conditions as close to the design as practical, the performance of the full operational sequence that brings the system into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 40. Periodic tests demonstrate the integrity, operability, and performance of the containment heat removal systems.

To the extent practicable, active components of the containment fan coolers are given preoperational performance tests after installation. Since these coolers are in use during normal operation, they are continually subjected to operational tests. The same is true of the CCW system that supplies the cooling water for the fan coolers. Each unit can be isolated during plant operation and subjected to a leak test to determine that the leaktight integrity of the unit has not been lost.

Similarly, active components in the CSS are given preoperational performance tests after installation. Periodic tests demonstrate that components are functioning properly. Tests are performed after any component maintenance affecting operability.

Permanent test lines for all the containment spray loops are located so that all components up to the isolation valves at the containment can be tested.

The air test lines for checking that spray nozzles are not obstructed are connected upstream of the spray ring isolation valves. Airflow through the nozzles is monitored by positive means.

The containment systems are described in detail in Section 6.2.

This criterion is associated with 1967 GDCs 59, 60, and 61.

Criterion 41, 1971 - Containment Atmosphere Cleanup

Systems to control fission products, hydrogen, oxygen, and other substances which may be released into the reactor containment shall be provided as necessary to reduce, consistent with the functioning of other associated systems, the concentration and quality of fission products released to the environment following postulated accidents, and to control the concentration of hydrogen or oxygen and other substances in the containment atmosphere following postulated accidents to assure that containment integrity is maintained.

Each system shall have suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) its safety function can be accomplished, assuming a single failure.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 41. The CSS and containment fan coolers, provide controls on, and means for, reduction of fission products and other substances.

The CSS removes radioactive iodine isotopes from the containment atmosphere should these fission products be released in the event of an accident. The system is designed to deliver enough sodium hydroxide mixed with the borated spray water from the RWST to provide pH control for iodine removal when mixed with the other sources of water in the containment recirculation sump.

The CSS, including required auxiliary systems, is designed to tolerate a single active failure during the injection phase following a LOCA or steam line break without loss of protective function. The containment spray pumps are of the horizontal centrifugal type and are driven by electric motors. The motors are powered from separate vital buses.

The containment fan cooler system consists of five identical fan coolers, each including cooling coils, fan and drive motor, locked open air flow dampers and pressure relief dampers, duct distribution system, instrumentation, and control.

The containment fan cooler system and the CSS operate during the injection phase following a LOCA to reduce the containment ambient temperature and pressure. While performing this cooling function, the containment heat removal system also helps limit offsite radiation levels by reducing the pressure differential between containment and outside atmosphere, thus reducing the driving force for leakage of fission products from the containment atmosphere.

The fan cooler units are powered from vital buses and have a standby unit. Used in conjunction with one another during the injection phase, one containment spray pump and two containment fan cooler units will provide the heat removal capability to maintain the post-accident containment pressure below the design value of 47 psig.

The containment systems are described in Section 6.2. Diversity of electric power supplies is discussed in Chapter 8.

This criterion is associated with 1967 GDC 37.

Criterion 42, 1971 - Inspection of Containment Atmosphere Cleanup Systems

The containment atmosphere cleanup systems shall be designed to permit appropriate periodic inspection of important components, such as filter frames, ducts, and piping to assure the integrity and capability of the systems.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 42.

Nondestructive examination is performed on the components of the systems in accordance with the requirements of the applicable codes as described in Section 3.2.

The CSS is designed so that component surveillance can be performed periodically to demonstrate system readiness. The pressure-containing portions of the system are tested periodically to check for leakage. This testing includes the portions of the system that would circulate radioactive water from the containment sump, if recirculation spray was required.

Access is available for visual inspection of the fan cooler components, including fans, cooling coils, enclosure dampers, and ductwork. Because these units are in use during power operation, continuous checks of their status are available. Additional details are found in Section 6.2.

This criterion is associated with 1967 GDC 62.

Criterion 43, 1971 - Testing of Containment Atmosphere Cleanup Systems

The containment atmosphere cleanup systems shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leaktight integrity of its components, (2) the operability and performance of the active components of the systems such as fans, filters, dampers, pumps, and valves and (3) the operability of the systems as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the systems into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of associated systems.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 43. Periodic tests demonstrate the integrity, operability, and performance of the containment atmosphere cleanup systems.

The CSS, utilizing sodium hydroxide, serves as the air cleanup system. The active components in the CSS are given preoperational performance tests after installation. Permanent test lines for all containment spray loops are located so that all components up to the isolation valves at the containment may be tested. The nozzles are tested by airflow that is monitored by positive means. The fan coolers are normally in use, which provides a check on the operability of the system. Additional details are found in Section 6.2.

Design provisions have been made, to the extent practicable, to facilitate access for periodic visual inspection of all important components of the containment fan cooler system. Testing of any components, after maintenance or as a part of a periodic inspection program, may be performed at any time, since the containment fan cooler system units are in operation on an essentially continuous schedule during normal plant operation.

This criterion is associated with 1967 GDCs 63, 64, and 65.

Criterion 44, 1971 - Cooling Water

A system to transfer heat from SSCs important to safety, to an ultimate heat sink shall be provided. The system safety function shall be to transfer the combined heat load of these SSCs under normal operating and accident conditions.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric

power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 44. A PG&E Design Class I CCW system is provided to transfer heat from reactor coolant, ESFs, and the containment to the PG&E Design Class I ASW system. The latter system discharges to the Pacific Ocean, which is the ultimate heat sink.

The CCW system is designed to provide cooling water to vital and nonvital components and to operate in all plant operating modes, including normal power operation, plant cooldown, and emergencies, including a LOCA or main steam line break (MSLB). Safety analyses for containment peak pressure demonstrate that only one ASW pump and one CCW heat exchanger is required to provide sufficient heat removal from containment to mitigate a MSLB or LOCA.

The CCW system is designed to continue to perform its safety function following an accident assuming a single active failure during the short-term recovery period and either a single active or passive failure during the long-term recovery period. Refer to Section 3.1.1 for a description of DCPP single failure criteria and definition of terms. During normal operation and up to 24 hours after an accident (the short-term recovery period), the CCW headers are crosstied. This configuration will withstand a single active failure without the loss of safety function. For a passive failure (up to a 200 gpm leak for 20 minutes), operator mitigation action (consisting of valve manipulations) is credited to stop leaks. The CCW piping design includes valving for isolating cooling water flow associated with individual components and for complete isolation of a header. The CCW system components that are considered vital are redundant. The three CCW pump motors are on separate vital 4.16-kV buses that have DG standby power sources. A radiation monitor associated with each of the two CCW pump discharge headers monitors the CCW system for radioactive in-leakage.

Additional details are found in Section 9.2.

No direct correlation exists with the 1967 GDC.

Criterion 45, 1971 - Inspection of Cooling Water System

The cooling water system shall be designed to permit appropriate periodic inspection of important components, such as heat exchangers and piping, to assure the integrity and capability of the system.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 45. The CCW pumps, heat exchangers, associated valves, large piping, and instrumentation are

located outside the containment and are therefore accessible for maintenance and inspection during power operation. Cooling water systems are discussed in Section 9.2.

No direct association exists with the 1967 GDC.

Criterion 46, 1971 - Testing of Cooling Water System

The cooling water system shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leaktight integrity of its components, (2) the operability and the performance of the active components of the system, and (3) the operability of the system as a whole and under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation for reactor shutdown and for LOCAs, including operation of applicable portions of the protection system and the transfer between normal and emergency power sources.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 46. System design permits periodic hydrostatic testing of the cooling water system during plant shutdown. The system is pressurized during power operation. The emergency control functions can be tested out to the final actuated device as described in Chapter 7.

No direct association exists with the 1967 GDC.

Criterion 50, 1971 - Containment Design Basis

The reactor containment structure, including access openings, penetrations, and the containment heat removal system shall be designed so that the containment structure and its internal compartments can accommodate, without exceeding the design leakage rate and, with sufficient margin, the calculated pressure and temperature conditions resulting from any LOCA. This margin shall reflect consideration of (1) the effects of potential energy sources which have not been included in the determination of the peak conditions, such as energy in steam generators and energy from metal-water and other chemical reactions that may result from degraded emergency core cooling functioning, (2) the limited experience and experimental data available for defining accident phenomena and containment responses, and (3) the conservatism of the calculational model and input parameters.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 50. The containment structure has been designed with sufficient margins to accommodate the calculated pressure and temperature conditions resulting from any LOCA.

The containment, including access openings and penetrations, has a design pressure of 47 psig. The greatest transient peak pressure associated with a postulated rupture of the piping in the RCS and the calculated effects of metal-water reaction do not exceed this value. The containment is strength tested at 54 psig.

The reactor containment structure and penetrations, with the aid of containment heat removal systems, are designed to limit radiation doses resulting from leakage of radioactive fission products from the containment to below 10 CFR Part 100 values, assuming the largest credible energy release following a LOCA, including a margin to cover the effects of metal water or other undefined energy sources. The containment design is described in detail in Section 3.8.2.1.

This criterion is associated with 1967 GDC 49.

Criterion 51, 1971 - Fracture Prevention of Containment Pressure Boundary

The reactor containment boundary shall be designed with sufficient margin to assure that under operating, maintenance, testing, and postulated accident conditions (1) its ferritic materials behave in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the containment boundary material during operation, maintenance, testing, and postulated accident conditions, and the uncertainties in determining (1) material properties, (2) residual, steady-state, and transient stresses, and (3) size of flaws.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 51. The concrete containment structure is not susceptible to low-temperature brittle fracture. The independence of the reinforcing steel minimizes the possibility of rapidly propagating fracture. The steel liner is not directly exposed to the temperature of the environs.

The selection and use of containment structure materials comply with the applicable codes and standards.

The containment liner is enclosed within the containment structure and thus not directly exposed to the temperature of the external environment and not subject to Criterion 50, 1967. Nevertheless, the design specification required Charpy V notch tests at 20°F for the containment liner. This corresponds to a lowest service temperature of 50°F during operation. Further information on containment structure materials appears in Section 3.8.

This criterion is associated with 1967 GDC 50.

Criterion 52, 1971 - Capability for Containment Leakage Rate Testing

The reactor containment and other equipment which may be subjected to containment test conditions shall be designed so that periodic integrated leakage rate testing can be conducted at containment design pressure.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 52. The containment design will accommodate both initial strength testing at 1.15 times design pressure and periodic leakage rate testing. The containment is provided with testable weld channels and penetrations so that sensitive leakage rate tests can be made of these areas where leakage could occur. Periodic leakage rate testing will be performed over the life of the units in accordance with the requirements of 10 CFR Part 50 Appendix J, Option B, as modified by approved exemptions.

The leakage rate tests and the sensitive leakage rate test demonstrate the integrity of the double leakage barriers provided by the penetrations and the overall integrity of the containment structure. The criterion for acceptance is that the measured leakage rate be less than 0.10 percent of the containment free volume per day. Further details of the integrated leakage rate test and the sensitive leakage rate test provisions appear in Section 3.8.

This criterion is associated with 1967 GDCs 54 and 55.

Criterion 53, 1971 - Provisions for Containment Testing and Inspection

The reactor containment shall be designed to permit (1) appropriate periodic inspection of all important areas, such as penetrations, (2) an appropriate surveillance program, and (3) periodic testing at containment design pressure of the leaktightness of penetrations which have resilient seals and expansion bellows.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 53. The containment design includes provision for testing and inspecting penetrations, liner plate areas, and areas of seals and expansion bellows.

All penetrations are provided with a volume that can be pressurized to test for leaktightness. There are three configurations used: (a) weld channels over the penetration welds, (b) an annular space between the penetration insert and the sleeve, which is sealed at both ends, and (c) double resilient seals with a gap between the seals. Further details appear in Section 3.8.

Periodic leakage rate testing is performed in accordance with the requirements of 10 CFR Part 50 Appendix J. Applicable surveillance requirements for such testing are included in the Technical Specifications.

This criterion is associated with 1967 GDC 56.

Criteria 54, 1971 - Piping Systems Penetrating Containment

Piping systems penetrating primary reactor containment shall be provided with leak detection, isolation, and containment capabilities having redundance, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. Such piping systems shall be designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to Criterion 54 except where specifically indicated in Section 6.2.4. The containment isolation design provides for a double barrier at the containment penetration in those fluid systems that are not required to function following a design basis event. Piping systems penetrating the containment are provided with test vents and test connections or have other provisions to allow periodic leakage testing. Those automatic isolation valves that do not restrict normal plant operation are periodically tested to ensure operability. Section 6.2.4 describes in detail the testing of isolation valves.

This criterion is associated with 1967 GDC 57.

Criterion 55, 1971 - Reactor Coolant Pressure Boundary Penetrating Containment

Each line that is part of the RCPB and that penetrates primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:

(1) One locked closed isolation valve inside and one locked closed isolation valve outside containment; or

(2) One automatic isolation valve inside and one locked closed isolation valve outside containment; or

(3) One locked closed isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment; or

(4) One automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Other appropriate requirements to minimize the probability or consequences of an accidental rupture of these lines or of lines connected to them shall be provided as necessary to assure adequate safety. Determination of the appropriateness of these requirements, such as higher quality in design, fabrication, and testing, additional provisions for inservice inspection, protection against more severe natural phenomena, and additional isolation valves and containment, shall include consideration of the population density, use characteristics, and physical characteristics of the site environs.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to Criterion 55 except where specifically indicated in Section 6.2.4. The RCPB is defined as those piping systems and components that contain reactor coolant at design pressure and temperature. With the exception of the reactor coolant sampling lines, the entire RCPB, as defined above, is located entirely within the containment structure. All sampling lines are provided with remotely operated valves for isolation in the event of a failure. These valves also close automatically on a containment isolation signal. Sampling lines are only used during infrequent sampling and can readily be isolated. Refer to Section 6.2.4 for details on conformance.

This criterion is associated with 1967 GDCs 51 and 57.

Criterion 56, 1971 - Primary Containment Isolation

Each line that connects directly to the containment atmosphere and penetrates primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:

(1) One locked closed isolation valve inside and one locked closed isolation valve outside containment; or

(2) One automatic isolation valve inside and one locked closed isolation valve outside containment; or

(3) One locked closed isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment; or

(4) One automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to Criterion 56 except where specifically indicated in Section 6.2.4. Each line that connects directly to the containment atmosphere and penetrates the primary reactor containment is provided with containment isolation valves as required. Refer to Section 6.2.4 for further discussion.

This criterion is associated with 1967 GDC 53.

Criterion 57, 1971 - Closed System Isolation Valves

Each line that penetrates primary reactor containment and is neither part of the RCPB nor connected directly to the containment atmosphere shall have at least one containment isolation valve which shall be either automatic, or locked closed, or capable of remote manual operation. This valve shall be outside containment and located as close to the containment as practical. A simple check valve may not be used as the automatic isolation valve.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to Criterion 57 except where specifically indicated in Section 6.2.4. Each line that penetrates the reactor containment in each unit, and is neither part of the RCPB nor connected directly to the containment atmosphere, has at least one containment isolation valve located outside the containment as close to the containment as practicable. The CCW penetration to the excess letdown heat exchanger is an exception that does not meet the 1971 GDC because of commitments to design and construction made prior to the issuance of the 1971 GDC; this penetration does comply with the 1967 GDC 53. Refer to Section 6.2.4 for details on conformance.

This criterion is associated with 1967 GDC 53.

Criterion 60, 1971 - Control of Releases of Radioactive Materials to the Environment

The nuclear power unit design shall include means to control suitably the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational

occurrences. Sufficient holdup capacity shall be provided for retention of gaseous and liquid effluents containing radioactive materials, particularly where unfavorable site environmental conditions can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 60. An extensive treatment system has been incorporated in the design for processing liquid wastes. Gaseous wastes are processed by appropriate holdup. Solid wastes are solidified in concrete (except for clothing, paper, etc.) for eventual disposition in licensed burial grounds.

The containment atmosphere, the plant vents, and the liquid and gaseous waste systems effluent discharge paths are monitored for radioactivity concentrations during all modes of operations. The monitoring systems are described in Section 11.4. The offsite radiological monitoring program is described in Section 11.6.

Waste handling systems are incorporated in each facility design for processing and/or retention of normal operation radioactive wastes with appropriate controls and monitors to ensure that releases do not exceed the limits of 10 CFR Part 20. The facilities are also designed with provisions to monitor radioactivity release during accidents and to prevent releases from causing exposures in excess of the guideline levels specified in 10 CFR Part 100.

The containment system, which forms a barrier to the escape of fission products should a loss-of-coolant occur, is described in Section 6.2. Postulated accidents that could release radioactivity to the environment are analyzed in Chapter 15.

This criterion is associated with 1967 GDCs 17 and 70.

Criterion 61, 1971 - Fuel Storage and Handling and Radioactivity Control

The fuel storage and handling, radioactive waste, and other systems which may contain radioactivity shall be designed to assure adequate safety under normal and postulated accident conditions. These systems shall be designed (1) with a capability to permit appropriate periodic inspection and testing of components important to safety, (2) with suitable shielding for radiation protection, (3) with appropriate containment, confinement, and filtering systems, (4) with a RHR capability having reliability and testability that reflects the importance to safety of decay heat and other RHR, and (5) to prevent significant reduction in fuel storage coolant inventory under accident conditions.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 61. The fuel storage facility meets the requirements of Safety Guide 13, March 1971. Radioactive

waste treatment systems that contain or confine leakage under normal and accident conditions are located in the auxiliary building. Adequate shielding is provided. The associated ventilation equipment includes charcoal filtration that minimizes radioactive material release associated with a postulated fuel handling accident.

The spent fuel area is enclosed and maintained under negative pressure. All ventilation air is passed through HEPA filters prior to being released to the plant vent. In the event of an accident, high activity would be detected by the radiation monitor (refer to Section 11.4), and the exhaust air would be diverted through charcoal filters. For radioactive waste storage, refer to the detailed discussion in Chapter 11. Failure of a gas decay tank has been postulated and analyzed in Chapter 15.

Waste handling systems are incorporated in the facility design for processing and/or retention of radioactive wastes from normal operation, with appropriate controls and monitors to ensure that releases do not exceed the limits of 10 CFR Part 20. The radioactive waste processing system, the design criteria, and amounts of estimated releases of radioactive effluents to the environment are described in Chapter 11. Details of the monitoring system are found in Section 11.4.

Refueling water provides a reliable and adequate cooling medium for spent fuel transfer, and heat removal is provided by an auxiliary cooling system. Natural radiation and convection is adequate for cooling the holdup tanks.

Active components of the SFP cooling and cleanup system are either in continuous or intermittent use during normal system operation. Periodic visual inspection and preventive maintenance are conducted using normal industry practice.

System piping is arranged so that failure of any pipeline cannot inadvertently drain the SFP below the water level required for radiation shielding. Demineralized makeup water can be added directly to the SFP by a PG&E Design Class I source.

This criterion is associated with 1967 GDCs 68 and 69.

Criterion 62, 1971 - Prevention of Criticality in Fuel Storage and Handling

Criticality in the fuel storage and handling system shall be prevented by physical systems or processes, preferably by use of geometrically safe configurations.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 62. Fuel storage and transfer systems are configured to preclude criticality.

During reactor vessel head removal and while loading and unloading fuel from the reactor, the boron concentration in the refueling water and the SFP is maintained at not less than that required to shut down the core to a k_{eff} = 0.95.

Borated water is used to fill the spent fuel storage pools at a concentration comparable to that used in the reactor cavity and refueling canal during refueling operations. The fuel is stored vertically in an array with sufficient center-to-center distance between assemblies to ensure that, including uncertainties, a k_{eff} of less than or equal to 0.95 if the fuel racks are flooded with borated water, and a $k_{eff} < 1.0$, even if unborated water is used to fill the pool. The fuel storage and handling details are found in Section 9.1.

This criterion is associated with 1967 GDC 66.

Criterion 63, 1971 - Monitoring Fuel and Waste Storage

Appropriate systems shall be provided in fuel storage and radioactive waste systems and associated handling area (1) to detect conditions that may result in loss of RHR capability and excessive radiation levels and (2) to initiate appropriate safety actions.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 63. Failure in the SFP cooling system and high radiation level in the SFP or radioactive waste areas are alarmed locally and in the control room.

The fuel and waste storage and handling areas are provided with monitoring and alarm systems for radioactivity, and the plant vents are monitored for radioactivity during all operations. The monitoring systems are described in Section 11.4.

The SFP cooling system is equipped with adequate instrumentation for normal operation. Water temperatures in the pool and at the outlet of the heat exchanger are indicated locally, and high pool temperature is alarmed in the control room. The SFP cooling system is described in Section 9.1.

This criterion is associated with 1967 GDC 18.

Criterion 64, 1971 - Monitoring Radioactivity Releases

Means shall be provided for monitoring the reactor containment atmosphere, spaces containing components for recirculation of LOCA fluids, effluent discharge paths, and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and from postulated accidents.

Discussion

The DCPP Unit 1 and Unit 2 designs conform to the intent of Criterion 64. The containment atmospheres, the plant vents, and the waste effluents are monitored for radioactivity concentration during all operations.

Radiation detection instruments are located in areas of the plant that house equipment containing or processing radioactive materials. These instruments continually detect, compute, and record operating radiation levels.

The data from the offsite monitoring program are reported annually. The reports include the basic data on sampling locations, organism collected, counting data, gross activity levels, identification of gamma emitting isotopes, and the associated counting errors. The monitoring systems are described in Section 11.4. The offsite radiological monitoring program is described in Section 11.6.

This criterion is associated with 1967 GDC 17.

Chapter 4

Reactor

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NOTE:

(a) This figure corresponds to a controlled engineering drawing that is incorporated by reference into the UFSAR. Refer to Table 1.6-1 for the correlation between the UFSAR figure number and the corresponding controlled engineering drawing number.

Chapter 4

REACTOR

This chapter describes the design for the reactors at Diablo Canyon Power Plant (DCPP) Unit 1 and Unit 2, and evaluates their capabilities to function safely under all operating modes expected during their lifetimes.

4.1 SUMMARY DESCRIPTION

This chapter describes the following subjects: (a) the mechanical components of the reactor and reactor core, including the fuel rods and fuel assemblies, reactor vessel internals, and the control rod drive mechanisms (CRDMs), (b) the nuclear design, and (c) the thermal-hydraulic design.

The reactor core of each unit consists of VANTAGE+ fuel assemblies.

The significant mechanical design features of the VANTAGE+ design, as defined in Reference 1, include the following:

- Integral fuel burnable absorber (IFBA)
- Intermediate flow mixer (IFM) grids
- Protective grid assemblies (P-Grid)
- Reconstitutable top nozzle (RTN)
- Axial blanket
- Debris filter bottom nozzle (DFBN)

The core is cooled and moderated by light water at a nominal pressure of 2250 psia to preclude bulk boiling under normal operating conditions. The coolant uses boron as a neutron absorber. Boron concentration in the coolant is varied as required to control relatively slow reactivity changes, such as those associated with the fuel burnup. Additional boron, in the form of IFBA or burnable absorber rods may be employed to limit the moderator temperature coefficient (MTC) and/or the local power peaking that can be achieved.

A fuel assembly consists of up to 264 mechanically joined fuel rods in a 17 x 17 square array. The fuel rods are supported at intervals along their length by grid assemblies that maintain the lateral spacing between the rods throughout the design life of the assembly. The grid assembly consists of an "egg-crate" arrangement of interlocked straps. The straps contain springs and dimples for maintaining fuel rod lateral and axial support, as well as mixing vanes at the top of the straps for coolant mixing. The fuel

rods consist of enriched UO_2 cylindrical pellets contained in zirconium alloy tubing that is plugged and seal-welded at the ends. To increase fatigue life, all fuel rods are pressurized with helium during fabrication to reduce stress and strain.

The center position of the fuel assembly contains an instrument tube; the remaining 24 positions in the array are equipped with guide thimbles joined to the grids and the top and bottom nozzles. Depending on assembly position in the core, the guide thimbles are used as core locations for rod cluster control assemblies (RCCAs), neutron source assemblies, and burnable absorber rods (if used).

The DFBN is a box-like structure that serves as a bottom structural element of the fuel assembly and directs the coolant flow to the assembly. The pattern and size of the flow holes in the bottom nozzle are designed to reduce the possibility of fuel rod damage due to debris-induced fretting. This feature is discussed in Section 4.2.1.3.2.1.

The top nozzle assembly functions as the upper structural element of the fuel assembly in addition to providing a partial protective housing for the RCCA or other components.

Each RCCA consists of a group of individual absorber rods fastened at the top end to a common hub or spider assembly.

The CRDMs for the RCCA are of the magnetic latch type. The latches are controlled by three magnetic coils. Upon a loss of power to the coils, the RCCA is released and falls by gravity to shut down the reactor.

Components of the reactor vessel internals are divided into three parts: (a) the lower core support structure (including the entire core barrel, the Unit 1 thermal shield, and the Unit 2 neutron shield pad assembly), (b) the upper core support structure, and (c) the incore instrumentation support structure. Reactor vessel internals support the core, maintain fuel alignment, limit fuel assembly movement, maintain alignment between fuel assemblies and CRDMs, direct coolant flow past the fuel assemblies to the pressure vessel head, provide gamma and neutron shielding, and provide guides for incore instrumentation.

The nuclear design analyses and evaluations establish physical locations for fuel assemblies, control rods, burnable absorber, and physical parameters such as fuel enrichments and boron concentration in the coolant. These characteristics, together with the reactor control and protection systems and the emergency core cooling system (ECCS), provide adequate reactivity control even if the RCCA with the highest reactivity worth is stuck in the fully withdrawn position ensuring that the reactor performance and safety criteria specified in Section 4.2 are met.

The thermal-hydraulic design analyses and evaluations establish coolant flow parameters that ensure adequate heat transfer between fuel cladding and reactor coolant. The thermal-hydraulic design takes into account local variations in dimensions, power generation, flow distribution, mixing and the IFM grids in the VANTAGE+ fuel

assembly. The mixing vanes incorporated in the fuel assembly spacer grid design induce additional flow mixing between the various flow channels within a fuel assembly as well as between adjacent assemblies.

Instrumentation is provided in and out of the core to monitor the nuclear, thermal-hydraulic, and mechanical performance of the reactor, and to provide input signals to control and protection functions and to the plant computer.

Table 4.1-1 presents a comparison of the reactor design parameters for the DCPP Unit 1 and Unit 2 reactor cores fueled with VANTAGE+ fuel assemblies. The analysis techniques employed in the core design are tabulated in Table 4.1-2. Design loading conditions for reactor core components are tabulated in Table 4.1-3.

4.1.1 REFERENCES

1. S. L. Davidson (Ed.), et al., VANTAGE+ Fuel Assembly Reference Core Report, WCAP-12610-P-A, April 1995.

4.2 MECHANICAL DESIGN

For design purposes, the DCPP conditions are divided into four categories, in accordance with their anticipated frequency of occurrence and risk to the public, as follows:

(1) Condition I - Normal Operation

(2) Condition II - Incidents of Moderate Frequency

(3) Condition III - Infrequent Faults

(4) Condition IV - Limiting Faults

In general, Condition I occurrences are accommodated with margin between any plant parameter and the value of that parameter which would require either automatic or manual protective action. Condition II incidents are accommodated with, at most, a shutdown of the reactor with the plant capable of returning to operation after corrective action.

The release of radioactive material due to Condition III incidents should not be sufficient to interrupt or restrict public use of areas outside the exclusion area. Furthermore, a Condition III incident shall not, by itself, generate a Condition IV fault or result in a consequential loss of function of the reactor coolant system (RCS) or reactor containment barriers.

Condition IV occurrences are faults that are not expected to occur, but are defined as limiting faults that must be considered in design. Condition IV faults shall not cause a release of radioactive material that results in an undue risk to public health and safety.

The reactor is designed so that its components meet the following performance and safety criteria:

(1) The mechanical design of the reactor core components and their physical arrangement, together with corrective actions by the reactor control, protection, and emergency cooling systems (when applicable) ensure that:

(a) Fuel damage is not expected during Conditions I and II events, although a very small number of fuel rod failures is anticipated. This number of failures is within the capability of the plant cleanup system and is consistent with the plant design bases. Fuel damage is defined as penetration of the fission product barrier (i.e., the fuel rod cladding).

(b) The reactor can be brought to a safe state following a Condition III event with only a small number of fuel rods damaged, although sufficient fuel damage may occur to preclude resumption of operation without considerable outage time.

(c) The reactor can be brought to a safe state and the core can be kept subcritical with acceptable heat transfer geometry, following transients arising from Condition IV events.

(2) The fuel assemblies are designed to withstand loads induced during shipping, handling, and core loading without exceeding the criteria of Section 4.2.1.3.2.5.

(3) The fuel assemblies are designed to accept control rod insertions to provide the reactivity control required for power operations and shutdown conditions (if in such core locations).

(4) All fuel assemblies have provisions for the insertion of the incore instrumentation necessary for plant operation (if in such core locations).

(5) The reactor internals, in conjunction with the fuel assemblies, direct reactor coolant through the core to achieve acceptable flow distribution and to restrict bypass flow so that the heat transfer performance requirements can be met for all modes of operation. In addition, internals provide core support and distribute coolant flow to the pressure vessel head. The distribution of flow into the vessel head minimizes axial and circumferential temperature gradients, thus precluding excessive rotation or warpage that could result in leakage past the O-ring gaskets during Conditions I and II operations. Required inservice inspections can be carried out since the internals are removable and provide access to the inside of the pressure vessel.

4.2.1 FUEL

The fuel assembly and fuel rod design data are listed in Table 4.1-1. U.S. Nuclear Regulatory Commission (NRC) approval of the VANTAGE+ design is given in Reference 29. Figure 4.2-1 shows a cross-section of the fuel assembly array, and Figure 4.2-2 shows a fuel assembly full-length outline. The fuel rods are loaded into the fuel assembly structure so that there is clearance between the fuel rod ends and the top and bottom nozzles.

Each fuel assembly is installed vertically in the reactor vessel and stands upright on the lower core plate, which is fitted with alignment pins to locate and orient the assembly. After all fuel assemblies are set in place, the upper support structure is installed. Alignment pins, built into the upper core plate, engage and locate the upper ends of the

fuel assemblies. The upper core plate then bears downward against the fuel assemblies' top nozzles, via the holddown springs, to hold the fuel assemblies in place.

4.2.1.1 Design Bases

4.2.1.1.1 General Design Criterion 2, 1967 – Performance Standards

The reactor core is designed to withstand, without fuel and/or clad damage that could interfere with continued effective core cooling, the effects of, or is protected against, natural phenomena such as earthquakes.

4.2.1.1.2 General Design Criterion 10, 1971 – Reactor Design

The fuel is designed with appropriate margin to assure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

4.2.1.1.3 Safety Function Requirements

(1) Loads During Handling

The fuel assemblies are designed to accommodate conditions expected to exist as a result of handling during assembly, inspection, and refueling operations, as well as shipping loads.

4.2.1.1.4 10 CFR 50.46(b)(4) – Coolable Geometry

The fuel is designed with appropriate margin to assure that following a postulated loss-of-coolant accident (LOCA) the calculated core geometry remains amenable to cooling by the ECCS. The calculated core geometry allows adequate ECCS cooling to assure the peak cladding temperature does not exceed 2200˚F and the maximum cladding oxidation nowhere exceeds 0.17 times the total cladding thickness before the start of significant oxidation during the event.

4.2.1.2 Fuel Rods

4.2.1.2.1 Fuel Rods Acceptance Criteria

To meet GDC 10, 1971 and ensure their integrity, fuel rods are designed to prevent excessive fuel temperatures, excessive internal gas pressures due to fission gas buildup, and excessive cladding stresses and strains. To this end, the following conservative design bases are adopted for Condition I and Condition II events:

(1) Fuel Pellet Temperatures - The center temperature of the hottest pellet is to be below the melting temperature of the UO_2. The melting point of un-irradiated UO_2 is 5080°F (Reference 1). Irradiation reduces the melting

point of UO_2 by 58°F per 10,000 megawatt days/metric ton of uranium (MWD/MTU). While a limited amount of center melting can be tolerated, the design conservatively precludes center melting. A calculated centerline fuel temperature of 4700°F has been selected as the overpower limit. This provides sufficient margin for uncertainties.

(2) Internal Gas Pressure - The fuel rod internal gas pressure remains below the value that can cause the fuel-cladding diametral gap to increase due to outward cladding creep during steady state operation. Rod pressure is also limited so that extensive departure from nucleate boiling (DNB) propagation does not occur during normal operation and accident events (Reference 14). Also, cladding flattening (Reference 15) will not occur during the fuel rod incore life.

(3) Cladding Stress and Strain - The design limit for the fuel rod clad strain is the total plastic tensile creep strain due to:

- uniform clad creep,
- uniform cylindrical fuel pellet expansion due to swelling, and
- thermal expansion

is less than 1% from the un-irradiated condition.

The design limit for the fuel rod clad stress is that the volume average effective stress calculated with the von Mises equation considering interference due to uniform cylindrical pellet-clad contact, caused by:

- pellet thermal expansion,
- pellet swelling and uniform clad creep, and
- pressure differences

is less than the ZIRLO® 0.2% offset yield stress, with due consideration to temperature and irradiation effects under Condition I and Condition II events.

While the clad has some capability for accommodating plastic strain, the yield stress has been established as a conservative design limit.

(4) Cladding Tensile Strain - The total tensile strain due to uniform cylindrical pellet thermal expansion during a transient is less than 1% from the pre-transient value.

(5) Strain Fatigue - The fuel system will not be damaged due to excessive clad fatigue. The fatigue life usage factor is limited to less than 1.0 to prevent reaching the material fatigue limit.

(6) Fuel Clad Oxidation and Hydriding - Fuel rod damage will not occur due to excessive clad oxidation and hydriding. In order to limit metal-oxide formation to acceptable values, the ZIRLO® metal-oxide interface temperature is limited for Condition I and Condition II events. The clad and structural component hydrogen pickup is limited at end of life (EOL) to preclude loss of ductility due to hydrogen embrittlement by the formation of zirconium hydride platelets.

(7) Fuel Clad Wear - The fuel system will not be damaged due to fuel rod clad fretting. A design wall thickness reduction of 10% is a general guide in evaluating clad imperfections including fretting wear marks.

(8) Fuel Clad Flattening - Fuel clad flattening is the long-term creep collapse of the fuel rod into the axial gap between fuel pellet columns. No clad flattening occurs in Westinghouse fuel designs (Reference 33).

(9) Fuel Rod Axial Growth - The fuel rods will be designed with adequate clearance between the fuel rod ends and the top and bottom nozzles to accommodate the differences in the growth of fuel rods and the growth of the fuel assembly.

The preceding fuel rod acceptance criteria and other supplementary fuel design criteria/limits are given in Reference 29. Reference 25 provides the methodology for peak rod burnup in excess of 50,000 MWD/MTU. The above requirements impact design parameters such as pellet size and density, cladding-pellet diametral gap, gas plenum size, and helium pre-pressurization. The design also considers effects such as fuel density changes, fission gas release, cladding creep, and other physical properties that vary with burnup.

An extensive irradiation testing and fuel surveillance operational experience program has been conducted to verify the adequacy of the fuel performance and design bases. This program is discussed in Section 4.2.1.4.

4.2.1.2.2 Fuel Rods Description

The fuel rods consist of zirconium alloy tubing that is plugged and seal-welded at the ends. The VANTAGE+ fuel rods contain enriched uranium dioxide fuel pellets and may also include axial blanket (natural or enriched uranium dioxide) pellets, and/or an IFBA coating on some of the enriched fuel pellets. The VANTAGE + design is capable of achieving extended burnup operation. Fuel rod schematics are shown in Figure 4.2-3.

The fuel pellets are right circular cylinders consisting of uranium dioxide powder that has been compacted by cold pressing and then sintered to the required density. The ends of each pellet are dished slightly to allow greater axial expansion at the center of the pellets.

The axial blanket reduces power at the ends of the rods and causes a slight increase in axial power peaking. Axial blankets reduce neutron leakage and improve fuel utilization. Certain fuel assemblies utilize annular fuel pellets in the axial blanket region of the fuel rods. The use of this feature provides additional margin to the fuel rod internal pressure design limits. The axial blankets typically are a nominal 6 inches of natural or enriched fuel pellets at each end of the fuel rod pellet stack. However, the option exists to increase the top axial blanket length to a nominal 7 inches. The axial blankets utilize pellets, which are physically different from the non-axial blanket pellets to prevent accidental mixing during manufacturing.

The IFBA coated fuel pellets are identical to the enriched uranium dioxide pellets except for the addition of a thin ZrB_2 coating on the pellet cylindrical surface. Coated pellets may occupy the central portion of the fuel column. The number and pattern of IFBA rods within an assembly may vary depending on specific application. An evaluation and test program for the IFBA design features is given in Section 2.5 in Reference 26.

The IFBA flattens the axial power distribution and reduces the local peaking as it burns out during irradiation. The net result of axial blankets and IFBA is a slight increase in power peaking during core operation.

The new fuel regions incorporate assemblies whose non-IFBA rods contain fully enriched solid fuel pellets in the blanket region.

All fuel rods are internally pressurized with helium during the welding process to minimize compressive cladding stresses and creep due to coolant operating pressures. Fuel rod pressurization depends on the planned fuel burnup, as well as other fuel design parameters and fuel characteristics. To avoid overstressing of the cladding or seal welds, void volume and clearances are provided within the rods to accommodate fission gases released from the fuel, differential thermal expansion between the cladding and the fuel, and fuel density changes during burnup. Shifting of the fuel within the cladding during handling or shipping prior to core loading is prevented by a helical spring within the fuel rod that bears on top of the fuel.

4.2.1.2.2.1 Materials - Fuel Cladding

VANTAGE+ fuel has ZIRLO® fuel cladding. Reference 29 provides additional details on ZIRLO® fuel cladding.

Metallographic examination of irradiated commercial fuel rods has shown occurrences of fuel/cladding chemical interaction. Reaction layers of 1 mil in thickness have been observed between fuel and cladding at limited points around the circumference. These data give no indication of propagation of the layer and eventual cladding penetration.

Stress corrosion cracking is another postulated phenomenon related to fuel/cladding chemical interaction. Out-of-reactor tests have shown that in the presence of high cladding tensile stresses, large concentrations of iodine can chemically attack the fuel

cladding and lead to eventual cladding cracking. Westinghouse has no evidence that this mechanism is operative in commercial fuel.

4.2.1.2.2.2 Materials - Fuel Pellets

Sintered, high-density UO_2 reacts only slightly with the cladding at core operating temperatures and pressures. In the event of cladding defects, the high resistance of uranium dioxide to attack by water protects against fuel deterioration, although limited fuel erosion can occur. Operating experience and extensive experimental work reveal that the thermal design parameters conservatively account for changes in the thermal performance of the fuel elements due to pellet fracture that may occur during power operation. The consequences of defects in the cladding are greatly reduced by the ability of uranium dioxide to retain fission products, including those that are gaseous or highly volatile.

Improvements in fuel fabrication techniques, based on extensive analytical and experimental work (References 9 and 33), have eliminated or minimized the fuel pellet densification effect that had previously been observed in fuel irradiated in operating Westinghouse pressurized water reactors (PWRs) (References 5 and 8).

Fuel densification is considered in the nuclear and thermal-hydraulic design of the reactor, as described in Sections 4.3.3.2.5 and 4.4.3.2.1, respectively.

Some fuel pellets are fabricated with a thin boride coating on the pellet outside surface for reactivity control (refer to Section 4.2.1.2.2).

4.2.1.2.2.3 Materials - Strength Considerations

One of the most important limiting factors in fuel element duty is the mechanical interaction of fuel and cladding. This fuel-cladding interaction produces cyclic stresses and strains in the cladding, and these in turn consume cladding fatigue life. To reduce fuel-cladding interaction, which is a principal goal of design, and enhance the cyclic operational capability of the fuel rod, pre-pressurized fuel rods are used.

Pre-pressurized fuel rods partially offset the effect of the coolant external pressure and reduce the rate of cladding creep toward the surface of the fuel. Fuel rod pre-pressurization delays the time at which substantial fuel-cladding interaction and hard contact occur. This significantly reduces the number and extent of cyclic stresses and strains experienced by the cladding, both before and after fuel-cladding contact. These factors increase the fatigue life margin of the cladding and lead to greater cladding reliability. If gaps should form in the fuel stacks, cladding flattening will be prevented by the rod pre-pressurization so that the flattening time will be greater than the fuel core life.

To minimize fuel-cladding interaction during startup, following handling of irradiated fuel assemblies during a refueling, or a cold shutdown, limitations in power increase rates are instituted.

4.2.1.2.2.4 Steady State Performance Evaluation

In the calculation of the steady state performance of a nuclear fuel rod, the following interacting factors must be considered:

(1) Cladding creep and elastic deflection

(2) Pellet density changes, thermal expansion, gas release, and thermal properties as a function of temperature and fuel burnup

(3) Internal pressure as a function of fission gas release, rod geometry, and temperature distribution

These effects are evaluated using the fuel rod design model of Reference 34. The model modifications for time-dependent fuel densification are given in Reference 34. The model determines fuel rod performance characteristics for a given rod geometry, power history, and axial power shape. In particular, internal gas pressure, fuel and cladding temperatures, and cladding deflections are calculated. The fuel rod is divided lengthwise into several sections and radially into a number of annular zones. Fuel density changes, cladding stresses, strains and deformations, and fission gas releases are calculated separately for each segment. These effects are then integrated to obtain the total internal pressure.

Subject to the design criteria of Section 4.2.1.2.1, the initial rod internal pressure is selected to delay fuel-cladding mechanical interaction and to avoid the potential for flattened rod formation.

The gap conductance between the pellet surface and the cladding inner diameter is calculated as a function of the composition, temperature, and pressure of the gas mixture, and the gap size or contact pressure between cladding and pellet. After computing the fuel temperature for each pellet's annular zone, the fractional fission gas release is calculated based on local fuel temperature and burnup. Finally, the gas released is summed over all zones and the pressure is calculated.

The PAD 4.0 code shows good agreement in fit for a variety of published and proprietary data on fission gas release, fuel temperatures, and cladding deflection (Reference 34). Included in this spectrum are variations in power, time, fuel density, and geometry.

Typical fuel cladding inner diameter and the fuel pellet outer diameter as a function of exposure are presented in Figure 4.2-4. The cycle-to-cycle changes in the pellet outer diameter represent the effects of power changes as the fuel is moved into different

positions during refueling. The gap size at any time is given by the difference between cladding inner radius and pellet outer radius. Total cladding-pellet surface contact occurs between 600 and 800 effective full power days (EFPD). Figure 4.2-4 represents hot fuel dimensions for a fuel rod operating at the power level shown in Figure 4.2-5. Figure 4.2-5 also illustrates representative fuel rod internal gas pressure and linear power for the lead burnup rod versus irradiation time. In addition, it outlines the typical operating range of internal gas pressures that is applicable to the total fuel rod population within a region. The plenum height of the fuel rod, in conjunction with other characteristics, is designed to ensure that the maximum internal pressure of the fuel rod remains below the value that causes the fuel-cladding diametral gap to increase due to outward cladding creep (Reference 29).

Cladding stresses during steady state operation are low. Compressive stresses are created by the pressure differential between the coolant pressure and the rod internal gas pressure.

The design fuel rod internal pressure limit which precludes gap increase is up to 1150 psi above system pressure for ZIRLO® rods, based on the ZIRLO® creep rate. Stresses due to the temperature gradient are not included because their contribution to the cladding volume average stress is small and decreases with time during steady state operation due to stress relaxation. The stress due to pressure differential is highest in the minimum power rod at the beginning of life (BOL) (due to low internal gas pressure), and the thermal stress is highest in the maximum power rod (due to the steep radial temperature gradient).

Tensile stresses could be created once the cladding comes in contact with the pellet. These stresses would be induced by the fuel pellet swelling during irradiation. As shown in Figure 4.2-4, there is very limited cladding pushout after pellet-cladding contact. Fuel swelling can result in small cladding strains (<1% for expected discharge burnups but the associated cladding stresses are very low because of cladding creep thermal and irradiation-induced creep). The 1% strain criterion is extremely conservative for fuel-swelling driven cladding strain because the strain rate associated with solid fission products swelling is very slow.

4.2.1.2.2.5 Transient Evaluation Method

The PAD 4.0 code (Reference 34) is the principal design tool for fuel rod performance evaluations. PAD 4.0 iteratively calculates the interrelated effects of temperature, pressure, cladding elastic and plastic behavior, fission gas release, and fuel densification and swelling as a function of time and linear power as a function time and linear power.

Westinghouse uses the PAD 4.0 code to show that the VANTAGE+ fuel design meets pellet cladding interaction (PCI) acceptance criteria, 1) less than 1% transient-induced cladding strain, and 2) no centerline fuel melting. The NRC has found PAD 4.0 acceptable for application to the

VANTAGE+ design with changes in the cladding creep model for ZIRLO® cladding and changes in the rod growth model for the rod pressure calculation (Reference 34).

Pellet thermal expansion due to power increases in a fuel rod is considered the only mechanism by which significant stresses and strains can be imposed on the cladding. Such power increases in commercial reactors can result from fuel shuffling, reactor power escalation following extended reduced power operation, and control rod movement. In the mechanical design model, depletion of lead rods is calculated using best estimate power histories as determined from core physics calculations. During the depletion, the diametral gap closure is evaluated using the pellet expansion-cracking model, cladding creep model, and fuel swelling model. At various times during the depletion, the power is increased locally on the rod to the burnup-dependent attainable power density, as determined by core physics calculation. The radial, tangential, and axial cladding stresses resulting from the power increase are combined into a volume average effective cladding stress.

The von Mises' criterion, described in Section 4.2.1.2.3, is used to determine if the cladding yield stress has been exceeded. The yield stress correlation is that for irradiated cladding, since fuel-cladding interaction occurs at high burnup. Furthermore, the effective stress is increased by an allowance that accounts for stress concentrations in the cladding adjacent to radial cracks in the pellet, prior to the comparison with the yield stress. This allowance was evaluated using a two-dimensional (r, θ) finite element model.

Since slow transient power increases can result in large cladding strains without exceeding the cladding yield stress due to cladding creep and stress relaxation, a criterion on allowable cladding positive strain is necessary. Based on high strain rate burst and tensile test data for irradiated tubing, 1 percent strain was adopted as the lower limit on irradiated cladding ductility.

It is recognized that a possible limitation to the satisfactory behavior of the fuel rods in a reactor that is subjected to daily load follow is the failure of the cladding by low cycle strain fatigue. During their normal residence time in a reactor, the fuel rods may be subjected to 1000 cycles with typical changes in power level from 50 to 100 percent of their steady state values.

The ZIRLO® cladding fatigue analyses have been performed using the Zircaloy-4 fatigue model. Fatigue properties of materials can be generally correlated with tensile properties, and are frequently described in terms of the fatigue ratio, defined as the ratio of the fatigue limit to the tensile strength. While the ratio is considered to be an approximation, it can serve as a useful tool to predict fatigue properties within a given alloy system. At room temperature, ZIRLO® cladding has an average tensile strength equivalent to Zircaloy-4 cladding. At elevated temperatures, ZIRLO® cladding has a higher tensile strength than Zircaloy-4 cladding. On this basis, it is conservative to assume that the fatigue properties of ZIRLO® cladding are equivalent to those of Zircaloy-4 cladding, and that on a best estimate basis, ZIRLO® cladding has a higher fatigue strength than does Zircaloy-4 cladding at elevated temperatures.

The evaluation of the fatigue life usage factor for extended burnup operation conservatively assumes daily load follow operation over the life of the fuel rod, plus ten (10) cold shutdowns per cycle. The Westinghouse fuel performance code, PAD 4.0, (Reference 34) is used to determine the strain range for the fatigue life usage analysis.

PAD 4.0, is used to determine the strain range for the fatigue usage analysis of the VANTAGE+ fuel design. The Langer-O'Donnell fatigue model is used with the calculated strains from PAD 4.0 to assure that the above criterion is met for VANTAGE+.

The Westinghouse analytical approach to strain fatigue results from evaluating several strain-fatigue models and the results of the Westinghouse experimental programs. In conclusion, the approach defined by Langer-O'Donnell (Reference 12) was retained, and the empirical factors of their correlation were modified to conservatively bound the results of the Westinghouse testing program.

The Langer-O'Donnell empirical correlation has the following form:

$$S_a = \frac{E}{\sqrt[4]{\left(N_f\right)}} \ln\left(\frac{100}{100-RA}\right) + S_e \qquad (4.2\text{-}1)$$

where:

S_a = 1/2 $E\Delta\varepsilon_\tau$ = pseudo-stress amplitude that causes failure in N_f cycles, lb/in^2
$\Delta\varepsilon_\tau$ = total strain range, in./in
E = Young's Modulus, lb/in^2
N_f = number of cycles to failure
RA = reduction in area at fracture in a uniaxial tensile test, %
S_e = endurance limit, lb/in^2

Both RA and S_e are empirical constants that depend on the type of material, the temperature, and the irradiation.

The results of the Westinghouse test programs provided information on different cladding conditions, including the effect of irradiation, hydrogen level, and temperature.

The Westinghouse design equations followed the concept for the fatigue design criterion according to the ASME BPVC Section III, namely:

(1) The calculated pseudo-stress amplitude (Sa) includes a safety factor of 2.

(2) The allowable cycles for a given Sa are 5 percent of Nf or a safety factor of 20 on cycles.

The lesser of the two allowable numbers of cycles is selected. The cumulative fatigue life fraction is then computed as:

$$\sum_{1}^{k} \frac{n_k}{N_{fk}} \leq 1 \qquad (4.2\text{-}2)$$

where:

n_k = number of diurnal cycles of mode k

4.2.1.2.3 Fuel Rod Design Evaluation

The fuel rod design ensures that the design bases are satisfied.

(1) Fuel Pellet Temperatures – The temperature of the VANTAGE+ fuel pellets is evaluated by the same methods as are used for all Westinghouse fuel designs. Rod geometries, thermal properties, heat fluxes, and temperature differences are modeled to calculate the temperature at the surface and centerline of the fuel pellets. Fuel centerline temperatures are calculated as a function of local power and rod burnup. To preclude fuel melting, the peak local power experienced during Condition I and Condition II events can be limited to a maximum value which is sufficient to ensure that the fuel centerline temperatures remain below the melting temperature at all burnups. Design scoping evaluations for Condition I and Condition II events show that fuel melting will not occur for achievable local powers and extended burnups (refer to Section 4.2.1.2.1).

(2) Internal Gas Pressure – The rod internal pressure of the VANTAGE+ fuel rod is evaluated in the same manner as is used for other Westinghouse fuel types. Gas inventories, gas temperature, and rod internal volumes are modeled and the resulting rod internal pressure is compared to the design limit. VANTAGE+ design evaluations to extended burnup levels verify that the fuel rod internal pressure as calculated will meet the design basis. This evaluation is discussed in detail in Appendix B, Section B.2.2 of Reference 29.

(3) Cladding Stress and Strain - Radial, tangential, and axial stress components due to pressure differential and fuel cladding contact pressure are combined into an effective stress using the maximum-distortion-energy theory. The von Mises criterion (Reference 22) is used to evaluate whether or not the yield strength has been exceeded. The criterion states that an isotropic material under multiaxial

stress will begin to yield plastically when the effective stress (i.e., combined stress using maximum-distortion-energy theory) becomes equal to the material yield stress in simple tension, as determined by a uniaxial tensile test. Since general yielding is prohibited, the volume average effective stress determined by integrating across the cladding thickness is increased by an allowance for local nonuniformity effects before the stress is compared to the yield strength. The yield strength correlation is appropriate for irradiated cladding since the irradiated properties are attained at low exposure, whereas the fuel/cladding interaction conditions, which can lead to minimum margin to the design basis limit, always occur at much higher exposures. The clad stresses in the VANTAGE+ fuel rod clad caused by power transients are evaluated (refer to Section 4.2.1.2.2.5). These evaluations show that the clad stresses and clad strains for VANTAGE+ fuel rod designs (IFBA and non-IFBA) meet the design limits.

(4) Cladding Tensile Strain – Section 4.2.1.2.2.5 shows that the cladding tensile strain stresses for the VANTAGE+ fuel rod designs meet the design limits.

(5) Strain Fatigue – Clad fatigue for the VANTAGE+ fuel rod design is evaluated by the same methods as are used for other Westinghouse fuel designs. Computer modeling of the fuel rod simulates a daily load follow cycling scheme 100-15-100% power and 12-3-6-3 hour intervals for residence times of more than 60 months. Design evaluations have shown that the cumulative fatigue usage factor for the VANTAGE+ fuel rod will meet the design criterion. Details regarding this evaluation are presented in Reference 29, Section B.2.3.

(6) Fuel Clad Oxidation and Hydriding - The clad surface temperature and hydriding of the VANTAGE+ fuel rod is evaluated by the same methods as are used for other Westinghouse fuel designs. The coolant temperature rise over the length of the fuel rod and temperature rise through the film, crud and oxide layer are calculated and the temperature at the metal-oxide interface is determined. Calculations show that the clad surface temperature and hydriding of the VANTAGE+ fuel rod meet the design limits.

(7) Fuel Clad Wear - The design criteria with regard to clad fretting wear are met for VANTAGE+ to its design burnup. Details regarding this evaluation are presented in Reference 29, Section B.2.5.1.

(8) Fuel Clad Flattening - Calculations for VANTAGE+ fuel show that predicted clad flattening time exceeds residence times expected for extended burnup fuel management. The evaluation is discussed in detail in Reference 29, Section B.2.4.

(9) Fuel Rod Axial Growth - The fuel assembly design is sized to provide sufficient fuel-rod-to-nozzle gaps, as discussed in Reference 29, Section 2.3.1.1. Sufficient top and bottom nozzle-to-fuel rod gaps are provided to assure that fuel rod growth is accommodated during the fuel design lifetime.

4.2.1.3 Fuel Assembly Structure

4.2.1.3.1 Fuel Assembly Structure Acceptance Criteria

4.2.1.3.1.1 Fuel Assembly Structural Integrity

The VANTAGE+ fuel assembly must maintain its structural integrity in response to seismic and LOCA loads (refer to Sections 3.7.3.15.2 and 4.2.1.5.4). The stresses and deformations due to various loads on the fuel assemblies are discussed in Section 4.2.1.3.2.5, including the effects of Seismic/LOCA loads.

4.2.1.3.1.2 Fuel Assembly Shipping and Handling Loads

The design acceleration limit for the fuel assembly handling and shipping loads are 6g lateral and 4g axial.

4.2.1.3.1.3 Top Nozzle

The top nozzle is required to transmit 4g shipping and handling loads without permanent deformation. The joints must transmit the same loads and be capable of disconnecting using a special disassembly tool.

4.2.1.3.1.4 Fuel Assembly Holddown Springs

The fuel assembly holddown springs, Figure 4.2-2, are designed to keep the fuel assemblies resting on the lower core plate under transients associated with Condition I and Condition II events with the exception of the turbine overspeed transient associated with a loss of external load. The holddown springs are designed to tolerate the possibility of a deflection associated with fuel assembly liftoff for this case and provide contact between the fuel assembly and the lower core plate following this transient.
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4.2.1.3.2 Fuel Assembly Structure Description

The fuel assembly structure consists of a bottom nozzle, top nozzle, guide thimbles, and grids, as shown in Figure 4.2-2.

4.2.1.3.2.1 Bottom Nozzle

The bottom nozzle is a box-like structure that serves as a bottom structural element of the fuel assembly and directs the coolant flow distribution to the assembly. The square nozzle is fabricated from Type 304 stainless steel. The legs form a plenum for the inlet coolant flow. The plate prevents a downward ejection of the fuel rods. The bottom nozzle is fastened to the fuel assembly guide tubes by locked screws that penetrate through the nozzle and mate with an inside fitting in each guide thimble tube.

The bottom nozzle design, known as the DFBN, reduces the possibility of fuel rod damage due to debris-induced fretting. The holes in the bottom nozzle plate are sized to minimize passage of debris particles large enough to cause damage while providing sufficient flow area, comparable pressure drop, and continued structural integrity of the nozzle. Tests to measure pressure drop and demonstrate structural integrity have been performed to verify that the DFBN meets the applicable mechanical design criteria for both Condition I and Condition II events.

The bottom nozzle design has a reconstitution feature that permits remote unlocking, removing, and relocking of the thimble screws. Coolant flow through the fuel assembly is directed from the plenum in the bottom nozzle upward through the penetrations in the plate to the channels between the fuel rods.

The weight and axial loads (holddown) imposed on the fuel assembly are transmitted through the bottom nozzle to the lower core plate. Indexing and positioning of the fuel assembly is controlled by alignment holes in two diagonally opposite bearing plates that mate with locating pins in the lower core plate. Any lateral loads on the fuel assembly are transmitted to the lower core plate through the locating pins.

Westinghouse has developed the standardized debris filter bottom nozzle (SDFBN) for use on its 17x17 fuel designs, including the 17x17 VANTAGE+ fuel design. The SDFBN improves the debris mitigation performance of the bottom nozzle by eliminating the side skirt communication flow holes. This nozzle has been evaluated and meets all of the applicable mechanical design criteria. In addition, there is no adverse effect on the thermal hydraulic performance of the SDFBN either with respect to the pressure drop or with respect to DNB. The SDFBN was implemented at Diablo Canyon beginning with Unit 2 Region 20 (Cycle 18 feed) and Unit 1 Region 21 (Cycle 19 feed).

Beginning with Region 28 (Cycle 26), the Diablo Canyon units implemented the 17x17 OFA PRIME fuel assembly bottom nozzle design. This advanced bottom nozzle design has a two chamfer inlet flow hole design to improve the pressure drop. The PRIME bottom nozzle design also lowers the side skirts to improve the debris filtering capability of the bottom nozzle by eliminating the large lateral flow path between the bottom nozzle legs in the SDFBN design. In addition, small flow holes are added to the side skirts to ensure that there is adequate lateral flow to the baffle barrel region of the core to ensure that the reactor vessel former plates are cooled.

4.2.1.3.2.2 Top Nozzle

The RTN assembly functions as the upper structural element of the fuel assembly in addition to providing a partial protective housing for the RCCA. It consists of an adapter plate, enclosure, top plate, and pads. The integral welded assembly has holddown springs mounted on the assembly, as shown in Figure 4.2-2. The springs are made of Inconel® 718. The other components are made of Type 304 stainless steel.

The square adapter plate is provided with round penetrations and semicircular-ended slots that permit the flow of coolant upward through the top nozzle. Other round holes are provided to accept sleeves that are welded to the adapter plate and mechanically attached to the thimble tubes. The ligaments in the plate cover the tops of the fuel rods and prevent their upward ejection from the fuel assembly. The enclosure is a box-like structure that sets the distance between the adapter plate and the top plate. The top plate has a large square hole in the center to permit access for the control rods and the control rod spiders. Holddown springs are mounted on the top plate and are fastened in place by bolts and clamps located at two diagonally opposite corners. The Westinghouse integral nozzle (WIN) design provides a wedged joint for transfer of the fuel assembly hold-down forces into the top nozzle structure. On the other two corners, integral pads contain alignment holes to locate the upper end of the fuel assembly.

In the removable top nozzle design, a stainless steel nozzle insert is mechanically connected to the top nozzle adapter plate by means of a pre-formed circumferential bulge near the top of the insert. The insert engages a mating groove in the wall of the adapter plate thimble tube thru-hole. The insert has 4 equally spaced axial slots which allow the insert to deflect inwardly at the elevation of the bulge thus permitting the installation or removal of the nozzle. The insert bulge is positively held in the adapter plate mating groove by placing a lock tube, with a uniform ID identical to that of the thimble tube, into the insert. The lock tube is secured in place by locally deforming it into the concave side of the bulge in the insert.

The full complement of these joints comprises the structural connection between the top nozzle and the remainder of the fuel assembly. The nozzle insert-to-adapter plate bulge joints replace the uppermost grid sleeve-to-adapter plate welded joints found in current fuel assemblies. The nozzle insert-to-thimble tube multiple 4-lobe bulge joint located in the lower portion of the insert represents the structural connection between the insert and the remainder of the fuel assembly below the elevation of the insert.

4.2.1.3.2.3 Guide and Instrument Thimbles

Guide thimbles are structural members that also provide channels for the neutron absorber rods, burnable poison rods, or neutron source assemblies. Each guide thimble is fabricated from zirconium alloy tubing having two different diameters. The larger tube diameter at the top provides the annular area necessary to permit rapid insertion of the control rods during a reactor trip. The lower portion of the guide thimble has a reduced diameter to produce a dashpot action near the end of the control rod

travel during a reactor trip. Four holes are provided on the thimble tube above the dashpot to reduce the rod drop time. The dashpot is closed at the bottom by an end plug and thimble screw that is provided with a small flow port to avoid fluid stagnation in the dashpot volume during normal operation.

The central instrumentation tube, fabricated from zirconium alloy tubing, is constrained by its seating in counterbores of each nozzle. Incore neutron detectors pass through the bottom nozzle's large counterbore into the center instrumentation tube.

The VANTAGE+ guide thimble tube ID provides an adequate nominal diametral clearance of 0.061 inches for the control rods. The VANTAGE+ thimble tube ID also provides sufficient diametral clearance for burnable absorber rods, source rods, and dually compatible thimble plugs.

The VANTAGE+ instrumentation tube allows sufficient diametral clearance for the flux thimble to traverse the tube without binding.

4.2.1.3.2.4 Grid Assemblies

The fuel rods, as shown in Figure 4.2-2, are supported laterally at eight intervals along their length by grid assemblies that maintain the lateral spacing between the rods by the combination of support dimples and springs. The grid assembly consists of individual slotted straps interlocked and brazed or welded in an "egg-crate" arrangement to join the straps permanently at their points of intersection. The straps contain springs and support dimples. The outside straps on all grids contain mixing vanes which, in addition to their mixing function, help guide the grids and fuel assemblies past projecting surfaces during fuel handling or core loading and unloading.

Inconel® 718 and zirconium alloys were chosen as the grid materials because of corrosion resistance, neutron economy, and high strength properties. The grids are connected to the thimble tube with 4-lobe bulge joints similar to the top nozzle (refer to Section 4.2.1.3.2.2). The magnitude of the grid restraining force on the fuel rod is set high enough to minimize possible fretting, without overstressing the cladding at the points of contact. The grid assemblies also allow axial thermal expansion of the fuel rods to prevent their buckling or distortion.

VANTAGE+ fuel assemblies have four types of grid assemblies: top and bottom grids, Mid-grids, IFM grids, and protective grids (P-Grid). Each fuel assembly has a total of twelve grids: one bottom and one top grid, six Mid-grids, three IFM grids, and one P-Grid.

The most critical grids from a standpoint of preventing fretting of fuel rods are the bottom and top grids (i.e., the end grids). The bottom and top grid assemblies do not include mixing vanes on the inner straps. The material of these grid assemblies is Inconel® 718, chosen because of its corrosion resistance and high strength. These grid

assemblies, being at the ends of the fuel assembly, are in the lower flux regions of the fuel assembly.

The Mid-grid assemblies consist of zirconium alloy straps arranged as described above and permanently joined by welding at their points of intersection. This material is primarily chosen for its low neutron absorption properties. These grids are used in the high heat flux region of the fuel assemblies. The inner straps include mixing vanes that project into the coolant stream and promote mixing of the coolant.

The IFM grids, as shown in Figure 4.2-2, are located between the three uppermost spans between the Mid-grids and incorporate a similar mixing vane array. Their prime function is mid-span flow mixing in the hottest fuel assembly spans. Each IFM grid cell contains four dimples which are designed to prevent mid-span channel closure in the spans containing IFMs and fuel rod contact with the mixing vanes. This simplified cell arrangement allows short grid cells so that the IFM can accomplish its flow mixing objective with minimal pressure drop. The IFM grids are fabricated from Zircaloy. This material was selected to take advantage of the material's inherent low neutron capture cross-section.

The P-Grid, configured with the same “egg crate” support matrix and other internal structures as the other grid assemblies, is added to the bottom of the fuel assembly to provide an additional debris barrier thereby improving fuel reliability. This protective or “P” grid is thinner (i.e., shorter) than the normal grid to accommodate the gap between the bottom nozzle and the fuel rods. It has no mixing vanes and has shorter inner straps comprising the support matrix compared to the top and bottom grids. The P-Grid is composed of Inconel® 718 material.

4.2.1.3.2.5 Stresses and Deflections

Structural integrity of fuel assemblies is ensured by setting limits on stresses and deformations due to various loads, and by determining that the assemblies do not interfere with other components' functionality.

These stress and deformation limits are applied to the design and evaluation of the top and bottom nozzles, the guide thimbles, the grids, and the thimble joints.

The design bases for evaluating the structural integrity of the fuel assemblies are:

(1) Nonoperational - 6g lateral and 4g axial loading with dimensional stability in both lateral and axial directions.

(2) Normal Operation (Condition I) and Incidents of Moderate Frequency (Condition II). The fuel assembly component structural design criteria are classified into two material categories: austenitic steels and zirconium alloys. Although not strictly fuel assembly components, reactor core elements that are made of stainless steel and are closely related to the

fuel assembly design include the top and bottom nozzle, the RCCA cladding, and some burnable absorber rod's cladding.

The stress categories and strength theory presented in the ASME BPVC Section III, are used as a general guide.

Zirconium alloy structural components, which consist of guide thimbles and fuel tubes, are in turn subdivided into two categories because of material differences and functional requirements. The fuel tube design criteria are covered separately in Section 4.2.1.2.3. For the guide thimble design, the stress intensities, the design stress intensities and the stress intensity limits are calculated using the same methods as for the austenitic steel structural components. Un-irradiated zirconium alloy properties are used to define the stress limits.

The maximum shear stress theory (Tresca criterion {Reference 22}) for combined stresses is used to determine the stress intensities for the austenitic steel components. The stress intensity is defined as the numerically largest difference between the various principal stresses in a three-dimensional field. The allowable stress intensity value for austenitic stainless steel is given by the lowest of the following:

(a) One-third of the specified minimum tensile strength, or two-thirds of the minimum yield strength, at room temperature.

(b) One-third of the tensile strength or 90 percent of the yield strength, at temperature, but not to exceed two-thirds of the specified minimum yield strength at room temperature.

The stress intensity limits for the austenitic steel components are:

Stress Intensity Limits

Categories	Limit
General Primary Membrane Stress Intensity	1.0 S_m
Local Primary Membrane Stress Intensity	1.5 S_m
Primary Membrane plus Bending Stress Intensity	1.5 S_m
Total Primary plus Secondary Stress Intensity Range	3.0 S_m

where S_m is the membrane stress.

(3) Abnormal Loads during Conditions III or IV - Worst cases are represented by combined seismic and blowdown loads. However, with NRC approval of the DCPP leak-before-break (LBB) analysis (Reference 30) and Amendments 221 and 223, to perform the fuel assembly structural analyses based on postulated pipe break locations that consider the

application of LBB (Reference 32), the blowdown loads resulting from pipe rupture events in the main reactor coolant loop piping no longer have to be considered in the structural design basis analysis. Only the much smaller blowdown loads from RCS branch line breaks have to be considered (see Section 3.6.2.1.1.1).

(a) Deflections of components cannot interfere with reactor shutdown or emergency cooling of fuel rods.

(b) The fuel assembly structural component stress under faulted conditions are evaluated using primarily the methods outlined in Appendix F of the ASME BPVC Section III. Since the current analytical methods utilize elastic analysis, the stress allowables are defined as the smaller value of 2.4 S_m or 0.70 Su (ultimate stress) for primary membrane and 3.6 S_m or 1.05 Su for primary membrane plus primary bending. For the austenitic steel fuel assembly components, the stress intensity is defined in accordance with the rules described in the previous section for normal operating conditions. For the Zircaloy components the stress intensity limits are set at two-thirds of the material yield strength, Sy, at reactor operating temperature. This results in Zircaloy stress limits being the smaller of 1.6 Sy or 0.70 Su for primary membrane and 2.4 Sy or 1.05 Su for primary membrane plus bending. For conservative purposes, the Zircaloy unirradiated properties are used to define the stress limits. The grid component strength criteria are based on experimental tests. For both Zircaloy and Inconel® grids, the limit is the 95 percent confidence level on the true mean as taken from the distribution of measurements at operating temperature.

Stresses in the fuel rod due to thermal expansion and fuel cladding irradiation growth are limited by the relative motion of the rod as it slips over the grid spring and dimple surfaces. Clearances between the fuel rod ends and nozzles are provided so that fuel cladding irradiation growth does not produce interferences. Stresses due to hold-down springs opposing the hydraulic lift force are limited by the deflection characteristic of the springs. Stresses in the fuel assembly caused by tripping of the RCCA have little influence on fatigue because of the small number of events during the life of an assembly. Welded joints in the fuel assembly structure are considered in the structural analysis of the assembly. Appropriate material properties of welds ensure that the design bases are met. Assembly components and prototype fuel assemblies made from production parts were subjected to structural tests to verify that the design bases requirements were met.

Precautions are taken during fuel handling operations to minimize fuel assembly grid strap damage. These precautions include proper training of operators, confirmation of proper functioning and alignment of the fuel handling and transfer equipment,

implementation of appropriate handling precautions, and Westinghouse recommendations.

The fuel assembly design loads for shipping have been established at 6g lateral and 4g axial. Trip accelerometers, permanently mounted on the shipping container, are placed to detect shocks in the lateral direction and axially in the longitudinal direction of the fuel assembly to monitor accelerations experienced by the shipping container. The accelerometer setpoints are established by the fuel supplier based on the fuel assembly orientation in the shipping container. Exceeding the limits requires re-inspection of the fuel assembly. Tests on various fuel assembly components such as the grid assembly, sleeves, inserts, and structure joints have been performed to ensure that the shipping design limits do not result in impairment of fuel assembly function.

The seismic/LOCA analysis methodology for fuel assembly analysis is presented in Reference 27. Specific seismic/LOCA analyses have been performed for Diablo Canyon and have demonstrated that all Condition II, III and IV load requirements are satisfied for the VANTAGE+ fuel design. The seismic analyses are performed for Design Earthquake (DE) (Condition II) and for both the Double Design Earthquake (DDE) and Hosgri Earthquake (HE) (Condition III and IV).The LOCA analysis is performed for the largest RCS branch lines (accumulator, pressure surge, residual heat removal). In all cases, the combined faulted condition seismic/LOCA grid impact forces were less than the grid strength and all stress values were found to be acceptable. Fuel assembly stresses and deflections meet the acceptance criteria for all loading conditions, as described in Section 4.2.1.3.2.5. Therefore, no fuel rod fragmentation will occur, long term core coolable geometry is maintained and RCCA insertability is maintained.

4.2.1.3.2.6 Dimensional Stability

The dimensional stability of coolant flow channels is maintained by the grids and guide thimbles structure. The lateral spacing between fuel rods is controlled by the support dimples of adjacent grid cells plus the spring force and the internal moments generated between the spring and the support dimples.

No interference with control rod insertion into thimble tubes will occur during a postulated LOCA transient due to fuel rod swelling, thermal expansion, or bowing. In the early phase of the event, the high axial loads, which could be potentially generated by the difference in thermal expansion between fuel cladding and thimbles, are relieved by slippage of the fuel rods through the grids. The relatively low drag force restraint on the fuel rods will induce only minor thermal bowing, not enough to close the fuel rod-to-thimble tube gap. This rod-to-grid slip mechanism occurs simultaneously with control rod drop. Subsequent to the control rod insertion, the transient temperature increase of the fuel rod cladding can result in sufficient swelling to contact the thimbles.

4.2.1.3.2.7 Vibration and Wear

The effect of a flow-induced vibration on the fuel assembly and individual fuel rods is minimal. Both fretting and vibration have been experimentally investigated. The cyclic stress range associated with deflections of such small magnitude is insignificant and has no effect on the structural integrity of the fuel rod.

The conclusion that the effect of flow-induced vibrations on the fuel assembly and fuel rod is minimal is based on test results and analysis documented in WCAP-8279 (Reference 13), which considered conditions normally encountered in reactor operation.

The reaction on the grid support due to vibrational motions is correspondingly small and much less than the spring preload. Firm contact is therefore maintained. No significant cladding or grid support wear is expected during the life of the fuel assembly, as described in Section 4.2.1.4.

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During the mid-1970s, unexpected degradation of guide thimble tube walls was observed during examination of irradiated fuel assemblies taken from several operating PWRs. It was later determined that coolant up-flow through the guide thimble tubes and turbulent cross-flow above the fuel assemblies were responsible for inducing vibratory motion in normally fully withdrawn ("parked") control rods. When these vibrating rods were in contact with the inner surface of the thimble wall, a fretting wear of the thimble wall occurred. The extent of the observed wear is both time and nuclear steam supply system (NSSS) design-dependent and has been observed, in some non-Westinghouse cases, to extend through the guide tube walls, resulting in the formation of holes.

Guide thimble tubes function as the main structural members of the fuel assembly and as channels to guide and decelerate tripped control rods. Significant loss of mechanical integrity due to wear or hole formation could: (a) result in the inability of the guide thimble tubes to withstand their anticipated loadings for fuel handling accidents and transients, and (b) hinder RCCA trip.

The susceptibility and impact of guide thimble tube wear in Westinghouse plants of the DCPP design have been assessed in References 17 through 20. Included is a mechanistic wear model and the impact of the model's wear predictions on plant designs such as for DCPP.

Accordingly, the DCPP fuel design will experience less wear than that reported for other NSSS designs because the DCPP fuel design uses thinner, more flexible control rods that have relatively more lateral support in the guide tube assembly of the upper core structure. Such a design provides the housing and guide path for the RCCA above the core, and thus restricts control rod vibration due to lateral exit flow. The wear model is also believed to conservatively predict guide thimble tube wear and even with the worst

anticipated wear conditions (both in the degree of wear and the location of wear), the guide thimble tubes will be able to fulfill their design functions.

Pacific Gas and Electric Company (PG&E) participated in a surveillance program to obtain data related to guide tube thimble wear (References 20 and 21). Data obtained from surveillance program examinations confirmed that guide thimble tubes used in DCPP meet design requirements.

4.2.1.3.3 Fuel Assembly Structure Design Evaluation

4.2.1.3.3.1 Structural Integrity Design Evaluation

Structural integrity of fuel assemblies is ensured by setting limits on stresses and deformations due to various loads and by determining that the assemblies do not interfere with other components' operability (refer to Section 4.2.1.3.2.5). No interference with control rod insertion into thimble tubes will occur during a postulated LOCA transient due to fuel rod swelling, thermal expansion, or bowing (refer to Section 4.2.1.3.2.6). Deflections of components have been determined not to interfere with reactor shutdown or emergency cooling of fuel rods (refer to Section 4.2.1.3.2.5).

4.2.1.3.3.2 Fuel Assembly Shipping and Handling Loads Design Evaluation

Fuel handling accelerations at both the manufacturing facility and reactor sites have been determined to be well below the fuel assembly design load limits. Extensive over-the-road tests with shipping containers containing dummy (lead weighted) fuel assemblies were made during the current shipping container design development. Road conditions were selected to ensure that the most realistic adverse conditions such as jumping curbs, railroad tracks, rough roads, etc. were encountered. Recording accelerometers confirmed that accelerations experienced by the fuel assembly are further attenuated as compared with the accelerations experienced by the shipping container.

4.2.1.3.3.3 Top Nozzle Design Evaluation

Finite element analyses of the nozzle have been performed which show that the design is more than adequate to resist the 4g loading. Structural testing has verified this result. The RTN feature was tested both as individual joints and functionally as part of the fuel assembly flow test assembly (refer to Appendix A, Sections A.1.0 and A.3.0 of Reference 26). The results of these tests demonstrate that the joint strength exceeds the structural (4g) and functional requirement.

4.2.1.3.3.4 Fuel Assembly Holddown Springs Design Evaluation

The results of the flow testing serve as the basis for optimizing the spring force with due consideration of fuel assembly growth and holddown spring relaxation and holddown force requirements (refer to Appendix A, Section A.1.0 of Reference 26).

4.2.1.4 Operational Experience

The operational experience of Westinghouse cores is presented in WCAP-8183 (Reference 8).

4.2.1.5 Safety Evaluation

4.2.1.5.1 General Design Criterion 2, 1967 – Performance Standards

The seismic analyses for the fuel assemblies documents that the fuel assembly design can withstand the additional forces that might be imposed under DDE and HE conditions without fuel or clad damage that could interfere with continued effective core cooling (refer to Section 3.7.3.15.2).

4.2.1.5.2 General Design Criterion 10, 1971 – Reactor Design

Section 4.2.1.2.1 provides the conservative design bases of the fuel rods adopted for Condition I and Condition II events. Section 4.2.1.2.3 describes how the fuel rods are designed to ensure that the design bases are satisfied for Condition I and Condition II events.

Section 4.2.1.3.1 provides the design bases to ensure the structural integrity of the fuel assembly adopted for Condition I and Condition II events. Section 4.2.1.3.3 describes how the fuel assembly meets its design basis.

4.2.1.5.3 Safety Function Requirements

(1) Loads During Handling

Section 4.2.1.3.3.2 documents that the fuel assembly shipping and handling load safety function requirements are met.

4.2.1.5.4 10 CFR 50.46(b)(4) – Coolable Geometry

The fuel is designed with appropriate margin to assure that following a postulated LOCA, the calculated core geometry remains amenable to cooling by the ECCS. The calculated core geometry allows adequate ECCS cooling to assure the peak cladding temperature does not exceed 2200˚F and the maximum cladding oxidation nowhere exceeds 0.17 times the total cladding thickness prior to oxidation (refer to Sections 4.2.1.3.3.1 and 15.4.1).

Plant specific analyses were performed using the approved methodology in WCAP-9401 (Reference 27) to demonstrate structural integrity of fuel assemblies, in accordance with NUREG-0800, Standard Review Plan (SRP) for the Review of Safety Analysis Reports for Nuclear Power Plants, Section 4.2, Appendix A.

4.2.1.6 Tests and Inspections

4.2.1.6.1 Quality Assurance Program

The Quality Assurance Program for Westinghouse nuclear fuel is summarized in the latest edition of the Westinghouse Nuclear Fuel Division Quality Assurance Program Plan, as listed in the PG&E Qualified Suppliers List.

4.2.1.6.2 Manufacturing

The Westinghouse quality control philosophy during manufacturing is described in the Westinghouse Nuclear Fuel Division Quality Assurance Program Plan, as listed in the PG&E Qualified Suppliers List.

4.2.1.6.3 Onsite Inspection

Onsite inspection of fuel assemblies, control rods, and reactor vessel internals is performed in accordance with the inspection program requirements discussed in the Diablo Canyon Quality Assurance Program Description.

Surveillance of fuel and reactor performance is routinely conducted on Westinghouse reactors. Power distribution is monitored using the excore fixed and incore movable detectors. Coolant activity and chemistry are followed, which permit early detection of any fuel cladding defects.

Visual examinations are routinely conducted during refueling outages. Additional fuel inspections are dependent on results of the operational monitoring and the visual examinations. Onsite examinations, if required, could include fuel integrity or other fuel performance evaluation examinations.

4.2.1.6.4 Removable Fuel Rod Assembly

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As part of a continuing Westinghouse fuel performance evaluation program, one surveillance fuel assembly containing 88 removable fuel rods was included in Region 3 of the initial DCPP Unit 1 and Unit 2 core loading. The objective of this program was to facilitate interim and EOL fuel evaluation as a function of exposure. The rods could be removed, nondestructively examined, and reinserted at the end of intermediate fuel cycles. The rods could be removed easily and subjected to a destructive examination at EOL.

The overall dimensions, rod pitch, number of rods, and material are the same as for other Region 3 assemblies. These fuel rods were fabricated in parallel with the regular Region 3 rods using selected Region 3 cladding and pellets fabricated to the same

manufacturing tolerance limits. Mechanically, the special assemblies differ from other Region 3 assemblies only in those features that facilitate removal and reinsertion.

Figure 4.2-6 compares the mechanical design of a removable fuel rod to a standard rod. Figure 4.2-7 shows the removable rod fuel assembly, the modified upper nozzle adapter plate, and thimble plug assembly; it may be compared to the standard assembly shown in Figure 4.2-2. The location of the removable rods within the fuel assembly is shown in Figure 4.2-8. Fuel handling with removable fuel rods has been done routinely and without difficulty in many operating plants.

4.2.2 REACTOR VESSEL INTERNALS

4.2.2.1 Design Bases

4.2.2.1.1 General Design Criterion 2, 1967 – Performance Standards

The reactor internals are designed to withstand the effects of, or are protected against, natural phenomena such as earthquakes.

4.2.2.1.2 General Design Criterion 4, 1987 – Environmental and Dynamic Effects Design Bases

Consideration of the dynamic effects associated with main reactor coolant loop (RCL) piping postulated pipe ruptures are excluded from the DCPP design basis with the approval of leak-before-break (LBB) methodology by demonstrating that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

4.2.2.1.3 General Design Criterion 10, 1971 – Reactor Design

The reactor vessel internals are designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

4.2.2.1.4 Safety Function Requirements

(1) <u>Core Flow Distribution</u>

The reactor vessel internals, in conjunction with the fuel assemblies, direct reactor coolant through the core to achieve acceptable flow distribution and to restrict bypass flow so that the heat transfer performance requirements are met for all modes of operation. In addition, required cooling for the pressure vessel head is provided so that the temperature differences between the vessel flange and head do not result in leakage from the flange during reactor operation.

(2) Protection of the Reactor Pressure Vessel from Neutron Exposure

In addition to neutron shielding provided by the reactor coolant, a thermal shield in Unit 1 and a neutron pad (Reference 7) assembly in Unit 2 limit the neutron exposure of the pressure vessel. Additionally, provisions are made to install the vessel material test specimens for the reactor pressure vessel material surveillance program (refer to Section 5.2).

(3) Incore Instrumentation

Provisions are made to install incore instrumentation for plant operation.

4.2.2.2 Acceptance Criteria

The acceptance criteria for the mechanical design of the reactor vessel internals components are:

(1) The core internals were designed to withstand mechanical loads arising from the DE, DDE, HE, and pipe ruptures (refer to Sections 3.7.3.15 and 3.9.2.1.3). The seismic and pipe rupture design of core internals is further discussed in Sections 3.7.3 and 3.9.3. This addresses GDC 2, 1967.

(2) The reactor has mechanical provisions to adequately support the core and internals and to ensure that the core is intact with acceptable heat transfer geometry following transients arising from abnormal operating conditions. This addresses GDC 10, 1971.

(3) Following the design basis accident, the plant shall be capable of being shut down and cooled in an orderly fashion so that fuel cladding temperature is kept within 10 CFR 50.46 limits. This implies that the deformation of certain critical reactor internals must be kept sufficiently small to allow core cooling (refer to Section 3.9.2.3.1).

4.2.2.3 Reactor Vessel Internals Description

The components of the reactor vessel internals consist of the lower core support structure (including the entire core barrel, the thermal shield on Unit 1, and the neutron shield pad assembly on Unit 2), the upper core support structure, and the incore instrumentation support structure. The reactor vessel internals support the core, maintain fuel alignment, limit fuel assembly movement, maintain alignment between fuel assemblies and CRDMs, direct coolant flow past the fuel elements, direct coolant flow to the pressure vessel head, and provide gamma and neutron shielding and guides for incore instrumentation.

In DCPP Unit 1, the coolant flows from the vessel inlet nozzles down the annulus between the core barrel and the vessel wall around the thermal shield. Most of the

coolant then enters the plenum at the bottom of the vessel. The coolant then reverses and flows up through the core support and lower core plate. A small portion of the coolant passes through core barrel flow holes and flows downward between the core barrel and the baffle plate, providing additional cooling of the barrel, and enters the core between the bottom of the baffle plate and the top of the lower support plate. The coolant coming up through the lower core plate and the coolant coming out to the baffle region then passes through the core. After passing through the core, the coolant enters the upper support structure and flows radially to the core barrel outlet nozzles and directly through the vessel outlet nozzles. Additionally, a small amount of the entering flow is directed into the vessel head plenum and exits through the vessel outlet nozzles.

In DCPP Unit 2, all the flow entering the core barrel from the inlet nozzle flows downward around the thermal neutron pads into the lower plenum. The coolant then reverses and flows upwards through the lower core plate and into the core and the baffle barrel region. After passing through the core, the coolant enters the upper support structure and flows radially to the core barrel outlet nozzles and directly through the vessel outlet nozzles. A small portion passes up between the core barrel and the baffle plate, providing additional cooling of the barrel, and enters the upper support structure through flow holes in the baffle region top plate. Also for Unit 2, an additional modification has been made to reduce the upper head bulk fluid temperature to approximately T-cold. In this modification, reactor upper and lower internals were modified to provide additional flow in the upper head region.

The major material for the reactor vessel internals is Type 304 stainless steel. Parts not fabricated from Type 304 stainless steel include bolts and dowel pins, which are fabricated from Type 316 stainless steel, the radial support clevis inserts which are fabricated from alloy 600, and insert bolts, which are fabricated from alloy X-750. The Unit 1 reactor vessel internals hold-down springs are Type 304 stainless steel. The Unit 2 reactor vessel internals hold-down springs are made of Type 403 stainless steel treated in accordance with ASME BPVC-1971, Case Number 1337 to have a yield stress greater than 90,000 psi. Undue susceptibility to intergranular stress corrosion cracking is prevented by not using sensitized stainless steel, as recommended in Regulatory Guide 1.44, May 1973 (Reference 23).

All reactor vessel internals are removable, thus permitting inspection of the vessel internal surface.

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With respect to previous plants, there is no change in the design configuration of reactor vessel internals and the reactor vessel internals core support structures. Moreover, since their mechanical properties (e.g., fuel assembly weight, beam stiffness) are virtually the same, the response of the reactor vessel internals core support structure will not change.

The qualification of identical plants by the first-of-a-kind analysis is further verified by the Internals Vibration Assurance Program discussed in Section 3.9.2.1.

4.2.2.3.1 Lower Core Support Structure

The reactor vessel internals support member is the lower core support structure shown in Figures 4.2-9 and 4.2-10 for DCPP Unit 1 and Unit 2, respectively. This support structure assembly consists of the core barrel, the core baffle, the lower core plate and support columns, the thermal shield on Unit 1, and the neutron shield pad assembly on Unit 2 (the transition from a thermal shield to neutron shield pad assembly is explained in WCAP-7870 {Reference 7}), and the core support, which is welded to the core barrel. All the major material for this structure is Type 304 stainless steel. The lower core support structure is supported at its upper flange from a ledge in the reactor vessel and its lower end is restrained from transverse motion by a radial support system attached to the vessel wall. Within the core barrel are an axial baffle and a lower core plate, both of which are attached to the core barrel wall and form the enclosure periphery of the core. The lower core support structure and core barrel provide passageways and direct the coolant flow. The lower core plate is positioned at the bottom level of the core below the baffle plates and provides support and orientation for the fuel assemblies.

The lower core plate contains the necessary flow distribution holes for each fuel assembly. On Unit 2, adequate coolant distribution is obtained through the use of the lower core plate and the flat core support. Unit 1 has a domed core support plate. Adequate coolant distribution is obtained through the use of an intermediate flow diffuser plate and the lower core plate.

On Unit 1, the one-piece thermal shield is fixed to the core barrel at the top with rigid bolted connections. The bottom of the thermal shield is connected to the core barrel by means of axial flexures. Rectangular specimen guides in which material samples can be inserted, held by a preloaded spring device, and irradiated during reactor operation, are welded to the thermal shield.

On Unit 2, the neutron shield pad assembly, shown in Figure 4.2-11, consists of four panels, constructed of Type 304 stainless steel, that are bolted and pinned to the outside of the core barrel. Rectangular specimen guides in which material surveillance samples are inserted, held by a preloaded spring device, and irradiated during reactor operation, are bolted and pinned to the panels. Additional details of the neutron shielding pads and irradiation specimen holders are given in Reference 7.

Vertically downward loads from weight, fuel assembly preload, control rod dynamic loading, hydraulic loads, and earthquake acceleration are carried by the lower core plate into the lower core plate support flange on the core barrel shell, and through the lower support columns to the core support and then through the core barrel shell to the core barrel flange supported by the vessel flange. Transverse loads from earthquake acceleration, coolant cross flow, and vibration are carried by the core barrel shell and distributed between the lower radial support to the vessel wall and to the vessel flange.

Transverse loads of the fuel assemblies are transmitted to the core barrel shell by direct connection of the lower core plate to the barrel wall, and by upper core plate alignment pins that are welded into the core barrel.

The radial support system of the core barrel is accomplished by "key" and "keyway" joints to the reactor vessel wall. At six equally spaced points around the circumference, an Inconel® clevis block is welded to the vessel inner diameter. An Inconel® insert block is bolted to each of these clevis blocks, and has a keyway geometry. Opposite each of these is a key that is welded to the lower core support. During assembly, as the internals are lowered into the vessel, the keys engage the keyways in the axial direction.

Radial and axial expansions of the core barrel are accommodated, but this design restricts transverse movement of the core barrel. With this system, cyclic stresses in the internal structures are within the ASME BPVC Section III limits. In the event of an abnormal downward vertical displacement of the internals following a hypothetical failure, the load is transferred through energy absorbing devices of the lower internals to the vessel. The number and design of these absorbers are determined so as to limit the stresses imposed on all components (except the energy absorber) to less than yield stress (ASME BPVC Section III values).

To prevent fuel rod damage as a result of water jetting through lower internals baffle gaps in Unit 2, edge bolts have been added along the full length of the center injection baffle plate joints and the gaps have been peened after bolting. Unit 1 has edge bolts along the entire length of all corner and center injection baffle plate joints.

In addition, if baffle jetting is detected in Unit 2, anti-baffle jetting fuel clips may be used to dampen the amplitude of the fuel rod vibrations.

4.2.2.3.2 Upper Core Support Assembly

The upper core support assembly, shown in Figures 4.2-12through 4.2-14, consists of the upper support assembly and the upper core plate between which are contained support columns and guide tube assemblies. The support columns establish the spacing between the upper support assembly and the upper core plate, and transmit the mechanical loadings between the upper support and upper core plate. The guide tube assemblies shield and guide the control rod drive shafts and control rods. Flow restrictors are installed in the guide tubes that formerly housed the part length CRDM drive shafts.

The upper core support assembly, which is removed as a unit during the refueling operation, is positioned in its proper orientation with respect to the lower support structure by slots in the upper core plate. Fuel assembly locating pins protrude from the bottom of the upper core plate and engage the fuel assemblies as the upper assembly is lowered into place, thus ensuring proper alignment of the lower core support structure, the upper core support assembly, the fuel assemblies, and control rods. The

upper core support assembly is restrained from any axial movements by a large circumferential spring that rests between the upper barrel flange and the upper core support assembly. The spring is compressed when the reactor vessel head is installed on the pressure vessel.

Vertical loads from weight, earthquake acceleration, hydraulic loads, and fuel assembly preload are transmitted through the upper core plate, via the support columns, to the upper support assembly and then into the reactor vessel head. Transverse loads from coolant cross flow, earthquake acceleration, and possible vibrations are distributed by the support columns to the upper support and upper core plate. The upper support plate is particularly stiff to minimize deflection.

4.2.2.3.3 Incore Instrumentation Support Structures

The incore instrumentation support structures consist of an upper system to convey and support thermocouples penetrating the vessel through the head, and a lower system to convey and support flux thimbles penetrating the vessel through the bottom (Figure 7.7-9 shows the basic flux-mapping system).

The upper system utilizes the reactor vessel head penetrations. Instrumentation port columns are slip-connected to in-line columns that are, in turn, fastened to the upper support plate. These port columns protrude through the head penetrations. The thermocouple conduits, made of Type 304 stainless steel, are supported from the columns of the upper core support system.

In addition to the upper incore instrumentation, there are reactor vessel bottom port columns that carry the retractable, cold-worked stainless steel flux thimbles that are pushed upward into the reactor core. Conduits extend from the bottom of the reactor vessel down through the concrete shield area and up to a thimble seal table. The thimbles are closed at the leading ends and serve as the pressure barrier between the reactor pressurized water and the containment atmosphere.

Mechanical seals between the retractable thimbles and conduits are provided at the seal table. During normal operation, the retractable thimbles are stationary and move only during refueling or for maintenance, at which time a space of approximately 15 feet above the seal table is cleared for the retraction operation.

The incore instrumentation support structure is designed for adequate support of instrumentation during reactor operation and is sturdy enough to resist damage or distortion under the conditions imposed by handling during the refueling sequence. Reactor vessel surveillance specimen capsules are covered in Section 5.2.2.4.

4.2.2.4 Reactor Vessel Internals Design Evaluation

The following show the acceptance criteria in Section 4.2.2.2 are satisfied.

4.2.2.4.1 Design Loading Conditions

The design loading conditions for the reactor vessel internals are:

(1) Fuel assembly weight

(2) Fuel assembly spring forces

(3) Internals weight

(4) Control rod scram (equivalent static load)

(5) Differential pressure

(6) Spring preloads

(7) Coolant flow forces (static)

(8) Temperature gradients

(9) Differences in thermal expansion

  (a) Due to temperature differences

  (b) Due to expansion of different materials

(10) Interference between components

(11) Vibration (mechanically or hydraulically induced)

(12) One or more loops out of service

(13) All operational transients listed in Table 5.2-4

(14) Pump overspeed

(15) Seismic loads (DE, DDE and HE)

(16) Blowdown forces (due to RCS branch line breaks)

Combined seismic and blowdown forces are included in the stress analysis by assuming the maximum amplitude of each force to act concurrently. In the original analyses, the blowdown forces were those resulting from breaks in the RCS cold and hot legs. However, with the acceptance of the DCPP LBB analysis by the NRC (Reference 30), the blowdown forces resulting from pipe rupture events in the main RCL piping no longer have to be considered in the design basis analyses. Only the much

smaller loads from RCS branch line breaks have to be considered (refer to Section 3.6.2.1.1.1).

The design analysis ensures that allowable stress limits are not exceeded, that adequate design margin exists, and establishes deformation limits that are concerned primarily with components' operability. The stress limits are established not only to ensure that peak stresses do not reach unacceptable values, but also to limit the amplitude of the oscillatory stress component in consideration of material fatigue characteristics. Both low and high cycle fatigue stresses are considered when the allowable amplitude of oscillation is established. Dynamic analysis on the reactor internals is provided in Section 3.9.2.3.

As part of the evaluation of design loading conditions, extensive testing and inspections are performed from the initial selection of raw materials up to and including component installation and plant operation. Among these tests and inspections are those performed during component fabrication, plant construction, startup and checkout, and plant operation.

4.2.2.4.2 Design Loading Categories

The combination of design loadings fits into either the normal, upset, or faulted conditions (refer to Table 5.2-4). The reactor vessel internals are designed to withstand stresses originating from RCS design transients, as summarized in Table 5.2-6.

Loads and deflections imposed on components due to shock and vibration are determined analytically and experimentally in both scaled models and operating reactors. The cyclic stresses due to these dynamic loads and deflections are combined with the stresses imposed by loads from component weights, hydraulic forces, and thermal gradients for the determination of the total stresses of the internals.

The scope and methodology of the stress analysis problem is discussed in Section 3.9.2.3.

4.2.2.4.3 Allowable Deflections

For normal operating conditions, downward vertical deflection of the lower core support plate is negligible.

Limiting deflection values from the LOCA plus the earthquake (larger of the DDE or HE), and for the deflection criteria of critical internal structures, are given in Section 3.9.2.3 and Table 3.9-10.

The criteria for the core drop accident are based on determining the total downward displacement of the internal structures following a hypothesized core drop resulting from loss of supports. The initial clearance between the secondary core support structures and the reactor vessel lower head in the hot condition is approximately ½ inch. An

additional displacement of approximately ¾ inch would occur due to strain of the energy absorbing devices of the secondary core support; thus the total drop distance is about 1-¼ inches, which is insufficient to permit the tips of a fully withdrawn RCCA to come out of the guide thimble.

Specifically, the secondary core support is a device that will never be used, except during a hypothetical accident of the core support (core barrel, barrel flange, etc.). There are four supports in each reactor. This device limits the fall of the core and absorbs the energy of the fall that otherwise would be imparted to the vessel. The energy of the fall is calculated assuming a complete and instantaneous failure of the primary core support and is absorbed during the plastic deformation of the controlled stainless steel volume loaded in tension.

4.2.2.4.4 Design Criteria Bases

The structural adequacy of the reactor vessel internals is discussed in Section 3.9.2.3.5.1.

4.2.2.5 Safety Evaluation

4.2.2.5.1 General Design Criterion 2, 1967 – Performance Standards

The design loading conditions for the reactor vessel internals include the additional forces that may be imposed by earthquakes. The design analysis ensures that allowable stress limits are not exceeded and establishes deformation limits that are concerned primarily with components' operability (refer to Section 4.2.2.4.1). Allowable deflections for normal operating conditions and the limiting deflection values from the LOCA plus the earthquake are discussed in Section 3.9.2.3.3.

Section 3.7.3.15.1 provides a detailed discussion of the seismic analyses for the reactor vessel internals.

4.2.2.5.2 General Design Criterion 4, 1987 – Environmental and Dynamic Effects Design Bases

Protection from the dynamic effects of the most limiting breaks of auxiliary lines is considered. RCS branch line breaks and other high energy line breaks are provided. Refer to Section 3.9.3.3 for additional discussion of LBB methodology and application.

The LOCA dynamic analyses are based on the accumulator, pressurizer surge, and residual heat removal system RCS branch line breaks credited LBB (Reference 32).

4.2.2.5.3 General Design Criterion 10, 1971 – Reactor Design

The reactor vessel internals are designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the

effects of anticipated operational occurrences. Section 4.2.2.4.2 documents that the reactor vessel internals are designed to withstand stresses originating from design transients. Section 3.9.2.3 discusses the design criteria used for normal operating conditions to evaluate calculated static and dynamic stresses. These calculated allowable stresses are considered appropriate and conservative.

4.2.2.5.4 Safety Function Requirements

(1) Core Flow Distribution

The components of the reactor vessel internals direct coolant flow past the fuel elements and direct coolant flow to the pressure vessel head (refer to Section 4.2.2.3).

The design loading conditions for the reactor vessel internals include temperature gradients and differences in thermal expansion due to temperature differences and the expansion of different materials (refer to Section 4.2.2.4.1).

(2) Protection of the Reactor Pressure Vessel from Neutron Exposure

The Unit 1 one-piece thermal shield is fixed to the core barrel at the top with rigid bolted connections. The bottom of the thermal shield is connected to the core barrel by means of axial flexures. Rectangular specimen guides in which material samples can be inserted, held by a preloaded spring device, and irradiated during reactor operation, are welded to the thermal shield (refer to Section 4.2.2.3.1).

The Unit 2 neutron shield pad assembly consists of four panels, constructed of Type 304 stainless steel, that are bolted and pinned to the outside of the core barrel (refer to Figure 4.2-11). Rectangular specimen guides in which material surveillance samples are inserted, held by a preloaded spring device, and irradiated during reactor operation, are bolted and pinned to the panels. Additional details of the neutron shielding pads and irradiation specimen holders are given in Reference 7.

The reactor vessel internals have provisions to install material test specimens for the reactor vessel material surveillance program (refer to Section 5.2.2.4.4).

(3) Incore Instrumentation

The reactor vessel internals have provisions to install incore instrumentation. The incore instrumentation support structure is designed for adequate support of instrumentation during reactor operation (refer to Section 4.2.2.3.3).

4.2.3 REACTIVITY CONTROL SYSTEM

4.2.3.1 Design Bases

4.2.3.1.1 General Design Criterion 2, 1967 – Performance Standards

The CRDMs are designed to withstand the effects of, or are protected against, natural phenomena, such as earthquakes.

4.2.3.1.2 General Design Criterion 4, 1987 – Environmental and Dynamic Effects Design Bases

Consideration of the dynamic effects associated with main RCL piping postulated pipe ruptures are excluded from the DCPP design basis with the approval of LBB methodology by demonstrating that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

4.2.3.1.3 General Design Criterion 25, 1971 – Protection System Requirements for Reactivity Control Malfunctions

The reactivity control system is designed to assure that no single malfunction (this does not include rod ejection) causes a violation of the acceptable fuel design limits.

4.2.3.1.4 General Design Criterion 26, 1971 – Reactivity Control System Redundancy And Capability

The reactivity control system is provided with redundancy and capability such that two independent reactivity control systems of different design principles and capabilities of reliably controlling reactivity changes under conditions of normal operation, including anticipated operational occurrences, to assure acceptable fuel design limits are not exceeded.

In addition, one of the systems is capable of holding the reactor core subcritical under cold conditions. To meet this requirement the rod control system is designed to provide sufficient operational control and reliability during reactivity changes during normal and anticipated transients and the chemical and volume control system (CVCS) regulates the concentration of chemical neutron absorber in the reactor coolant to control reactivity changes.

4.2.3.1.5 General Design Criterion 29, 1971 – Protection Against Anticipated Operational Occurrences

The reactivity control system is designed to ensure an extremely high probability of functioning during anticipated operational occurrences.

4.2.3.1.6 General Design Criterion 30, 1967 – Reactivity Holddown Capability

At least one of the reactivity control systems provided is capable of making and holding the core subcritical under any conditions with appropriate margins for contingencies.

4.2.3.2 Reactivity Control System Acceptance Criteria

4.2.3.2.1 Design Stresses Acceptance Criteria

The reactivity control system is designed to withstand stresses originating from the operating transients summarized in Table 5.2-4.

Allowable stresses for normal operating conditions are in accordance with ASME BPVC Section III. All components are analyzed as Class I components under Article NB-3000.

The cyclic stresses due to dynamic loads and deflections are combined with the stresses imposed by loads from component weights, hydraulic forces, and thermal gradients to determine the total stresses of the reactivity control system.

4.2.3.2.2 Material Compatibility Acceptance Criteria

Materials are selected for compatibility in a PWR environment, adequate mechanical properties at room and operating temperature, resistance to adverse property changes in a radioactive environment, and compatibility with interfacing components.

4.2.3.2.3 Absorber Rods Acceptance Criteria

The following design conditions, based on Article NB-3000 of the ASME BPVC Section III-1973, are considered.

(1) The external pressure equal to the RCS operating pressure

(2) The wear allowance equivalent to 1000 reactor trips

(3) Bending of the rod due to a misalignment in the guide tube

(4) Forces imposed on the rods during rod drop

(5) Loads caused by accelerations imposed by the CRDM

(6) Radiation exposure for maximum core life.

The absorber material temperature shall not exceed its melting temperature (1470°F for silver-indium-cadmium absorber material {Reference 2}).

4.2.3.2.4 Burnable Absorber Rods Acceptance Criteria

The burnable absorber rod cladding (Zircaloy-4 for the wet annular burnable absorber {WABA} design) is designed as a Class I component under Article NB-3000 of the ASME BPVC Section III-1973, for Conditions I and II. For Conditions III and IV loads, code stresses are not considered limiting. Failures of the burnable absorber rods during these conditions must not interfere with reactor shutdown or emergency cooling of the fuel rods.

The structural elements of the burnable absorber rod are designed to maintain absorber geometry. The rods are designed so that the Al_2O_3-B_4C material is below 1200°F during normal operation or overpower transients.

4.2.3.2.5 Neutron Source Rods Acceptance Criteria

The neutron source rods are designed to withstand:

(1) An external pressure equal to the RCS operating pressure

(2) An internal pressure equal to the pressure generated by gases released over the neutron source rod life.

4.2.3.2.6 Thimble Plug Assembly Acceptance Criteria

The thimble plug assemblies:

(1) Accommodate the differential thermal expansion between fuel assembly and core internals

(2) Maintain positive contact with the fuel assembly and the core internals

(3) Can be inserted into, or withdrawn from, the fuel assembly by a force not exceeding 65 pounds.

4.2.3.2.7 Control Rod Drive Mechanism Acceptance Criteria

The CRDMs were designed to meet the following basic operational requirements:

(1) 5/8-inch per step

(2) 142.5-inch travel (nominal)

(3) 360 pounds-force maximum load

(4) Step in or out at 45 inches per minute (72 steps per minute) maximum

(5) Power interruption shall initiate release of drive rod assembly

(6) Trip delay of 150 milliseconds or less - Free fall of drive rod assembly shall begin less than 150 milliseconds after power interruption, no matter what holding or stepping action is being executed, with any load and coolant temperatures between 100°F and 650°F.

(7) 50-year design life with normal refurbishment

(8) 13,200 complete travel excursions equaling 6 million steps with normal refurbishment

4.2.3.3 Reactivity Control System Description

Reactivity control is provided by neutron absorbing rods and a soluble chemical neutron absorber (boric acid). The boric acid concentration is varied to control long-term reactivity changes such as:

(1) Fuel depletion and fission product buildup

(2) Cold to hot, zero power reactivity change

(3) Reactivity change produced by intermediate-term fission products such as xenon and samarium

(4) Burnable poison depletion

The concentration of boric acid in the reactor coolant is regulated by the CVCS, as described in Section 9.3.4.

The RCCAs provide reactivity control for:

(1) Shutdown

(2) Reactivity changes due to coolant temperature changes in the power range

(3) Reactivity changes associated with the power coefficient of reactivity

(4) Reactivity changes due to void formation

The neutron source assemblies provide a means of verifying that the neutron instrumentation performs its function during periods of low neutron activity. They also provide the required count rate during startup.

The most effective reactivity control component is the RCCA and its corresponding drive rod assemblies. Figure 4.2-15 identifies the rod cluster control and drive rod assembly, in addition to the interfacing fuel assembly, guide tubes, and CRDM.

Guidance for the control rod cluster is provided by the guide tube, as shown in Figure 4.2-15. The guide tube provides two types of guidance:

(1) In the lower section, a continuous guidance system provides support immediately above the core. This system protects the rod against excessive deformation and wear due to hydraulic loading.

(2) The region above the continuous section provides support and guidance at uniformly spaced intervals.

The support envelope is determined by the RCCA pattern, as shown in Figure 4.2-16. The guide tube ensures alignment and support of the control rods, spider body, and drive rod while maintaining trip times at or below required limits.

4.2.3.3.1 Reactivity Control Components Description

The reactivity control components are subdivided into two categories:

(1) Permanent devices used to control or monitor the core

(2) Optional burnable absorber assemblies

The permanent type components are the RCCAs, control rod drive assemblies, and neutron source assemblies. Although the optional thimble plug assembly does not directly contribute to the reactivity control of the reactor, it is presented as a reactivity control system component in this document because it is used to restrict bypass flow through those thimbles not occupied by absorber, source or burnable poison rods.

The purpose of the optional burnable absorber assemblies is to control assembly power and ensure that the temperature coefficient of reactivity is less positive under normal operating conditions.

4.2.3.3.2 Rod Cluster Control Assembly Description

The RCCA banks are divided into two categories: control and shutdown. Two criteria have been employed for selection of the control groups. First, the total reactivity worth must be adequate to meet the nuclear requirements. Second, because some of these rods may be partially inserted at power operation, the total power peaking factor should be low enough to ensure that the power capability is met. The control and shutdown groups provide adequate shutdown margin (SDM) which is defined as: the

instantaneous amount of reactivity by which the reactor is subcritical, or would be subcritical from its present condition, assuming

(1) all RCCAs are fully inserted, except for the single RCCA of highest reactivity worth which is assumed to be fully withdrawn (with any RCCA not capable of being fully inserted, the reactivity worth of the RCCA must be accounted for in the determination of SDM) and

(2) when in MODE 1 or 2, the fuel and moderator temperatures are changed to the hot zero power temperatures.

An RCCA comprises a group of individual neutron absorber rods fastened at the top end to a common spider assembly, as illustrated in Figure 4.2-16.

The absorber material used in the control rods is a silver-indium-cadmium alloy that is essentially "black" to thermal neutrons and has sufficient additional resonance absorption to significantly increase its worth. The alloy is in the form of extruded rods that are sealed in stainless steel tubes to prevent the rods from coming in direct contact with the coolant. The silver-indium-cadmium rods are inserted into cold-worked stainless steel tubing. It is sealed at the bottom and top by welded end plugs, as shown in Figure 4.2-17. Sufficient diametral and end clearance is provided to accommodate relative thermal expansions.

The bullet-nosed bottom plugs reduce the hydraulic drag during reactor trip and guide the absorber rods smoothly into the dashpot section of the fuel assembly guide thimbles. The upper plug is threaded for assembly to the spider and has a reduced end section to make the joint more flexible.

The spider assembly is in the form of a central hub with radial vanes containing cylindrical fingers from which the absorber rods are suspended. Handling detents and detents for connection to the drive rod assembly are machined into the upper end of the hub. Coiled springs inside the spider body absorb the impact energy at the end of a trip insertion. All components of the spider assembly are made from various types and grades of stainless steel compatible with the service conditions. The absorber rods are fastened securely to the spider to ensure trouble-free service.

The overall length is such that when the assembly is withdrawn through its full travel, the tips of the absorber rods remain engaged in the guide thimbles so that alignment between rods and thimbles is always maintained. Because the rods are long and slender, they are relatively free to conform to any small misalignments with the guide thimble.

4.2.3.3.3 Burnable Absorber Assembly Description

Each burnable absorber assembly consists of WABA burnable absorber rods attached to a hold down assembly.

A WABA rod (refer to Figure 4.2-18a) consists of annular pellets of alumina-boron carbide (Al_2O_3-B_4C) burnable absorber material contained within two concentric Zircaloy tubes. These Zircaloy tubes, which form the inner and outer cladding for the WABA rod, are plugged and welded at each end to encapsulate the annular stack of absorber material. The assembled rod is then internally pressurized to 650 psig and seal welded. The absorber stack lengths are positioned axially within the WABA rods by the use of Zircaloy bottom-end spacers. An annular plenum is provided within the rod to accommodate the helium gas released from absorber material depletion during irradiation. The reactor coolant flows inside the inner tube and outside the outer tube of the annular rod. Further design details are given in Section 3.0 of Reference 28.

The burnable absorber rods are statically suspended and positioned in selected guide thimbles within the fuel assemblies. The absorber rods in each assembly are attached together at the top end of the rods to a hold down assembly by a flat, perforated retaining plate which fits within the fuel assembly top nozzle and rests on the adapter plate. The absorber rod assembly is held down and restrained against vertical motion through a spring pack which is attached to the plate and is compressed by the upper core plate when the reactor upper internals assembly is lowered into the reactor. This arrangement ensures that the absorber rods cannot be ejected from the core by flow forces. Each rod is permanently attached to the base plate by a nut, which is locked into place.

4.2.3.3.4 Neutron Source Assembly Description

The neutron source assembly provides a base neutron level to ensure that the detectors are operational and responding to core multiplication neutrons. Because there is very little neutron activity during core loading, refueling, hot and cold shutdown, and approach to criticality, neutron sources are placed in the reactor to help determine if source range detectors are properly responding.

During core loading, it is verified that active source assemblies provide the responding source range detectors with a sufficient count rate. For normal source range detectors (N-31 and N-32), and for alternate source range detectors (N-51 and N-52), the following count rate requirements must be met after an installed active source is neutronically coupled to a detector:

(1) For N-31 and N-32:

The count rate shall be equal to or greater than the maximum of the following count rates:

- Twice the background radiation in counts per second (CPS), or
- 0.5 CPS + background radiation in CPS, or
- 1.0 CPS.

(2) For N-51 and N-52:

The count rate shall be equal to or greater than the maximum of the following count rates:

- Twice the background radiation in CPS, or
- 0.05 CPS + background radiation in CPS, or
- 0.1 CPS.

The differences in required count rates are due to differences in detector sensitivity between the proportional counters (N-31 and N-32) and the fission chambers (N-51 and N-52).

The source assembly also permits detection of changes in the core multiplication factor during core loading, refueling, and approach to criticality. This can be done since the multiplication factor is related to an inverse function of the detector count rate. Therefore, a change in the multiplication factor can be detected during addition of fuel assemblies while loading the core, a change in control rod positions, and changes in boron concentration.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

The DCPP Unit 1 and Unit 2 reactor cores each employed two primary source assemblies and two secondary source assemblies in the first core. Each primary source assembly contained one primary source rod and between zero and twenty-three burnable absorber rods. The primary source rod, containing californium-252, spontaneously fissions and emits neutrons. After the primary source rod decays beyond the desired neutron flux level, neutrons are then supplied by the secondary source rod.

The secondary source rod contains a mixture of approximately half antimony and half beryllium by volume, which is activated by neutron bombardment during reactor operation. Activation of antimony results in the subsequent release of neutrons by the (γ,n) reaction in beryllium. This becomes a source of neutrons during periods of low neutron flux, such as during refueling and subsequent startups.

Each of the two secondary source assemblies has six secondary source rods and no burnable poison rods (refer to Figure 4.2-21).

Neutron source assemblies are located at diametrically opposite sides of the core. The assemblies are inserted into the guide thimbles at selected unrodded locations.

The secondary source rods utilize slightly cold worked 304 SS material. The secondary source rods contain about 500 grams of stacked antimony-beryllium pellets, and the rod is internally pre-pressurized to 625 ± 50 psig. The rods in each assembly are permanently fastened at the top end to a hold down assembly, which is identical to that of the burnable absorber assemblies.

The other structural members are fabricated from Type 304 and 308 stainless steel except for the springs exposed to the reactor coolant. They are wound from an age hardened nickel base alloy for corrosion resistance and high strength.

4.2.3.3.5 Thimble Plug Assembly Description

Thimble plug assemblies are utilized, if desired, to further limit bypass flow through the guide thimbles in fuel assemblies that do not contain either control rods, source rods, or burnable absorber rods.

The thimble plug assemblies shown in Figure 4.2-22 consist of a flat base plate with short rods suspended from the bottom surface and a spring pack assembly. The 24 short rods, called thimble plugs, project into the upper ends of the guide thimbles to reduce the bypass flow area. Similar short rods may be also used on the source assemblies and burnable absorber assemblies to plug the ends of all vacant fuel assembly guide thimbles.

All components in the thimble plug assembly, except for the springs, are fabricated from Type 304 stainless steel. The springs are wound from an age-hardened nickel base alloy for corrosion resistance and high strength.

4.2.3.3.6 Control Rod Drive Mechanism Description

All parts exposed to reactor coolant are made of metals that resist the corrosive action of the water. Three types of metals are used exclusively: stainless steels, nickel alloy, and cobalt-based alloys. Wherever magnetic flux is carried by parts exposed to the main coolant, 400 series stainless steel is used. Cobalt-based alloys are used for the pins and latch tips. Nickel alloy is used for the springs of the latch assemblies, and Type 304 stainless steel for all pressure-containing parts. Hard chrome plating provides wear surfaces on the sliding parts and prevents galling between mating parts.

A position indicator assembly slides over the CRDM rod travel housing. This position indicator assembly detects the drive rod assembly position by means of 42 discrete coils that magnetically sense the entry and presence of the rod drive line through its centerline over the normal length of the drive rod travel.

The CRDMs are located on the head of the reactor vessel. They are coupled to RCCAs. A CRDM schematic is shown in Figure 4.2-24.

The primary function of the CRDM is to insert or withdraw RCCAs into or from the core to control average core temperature and to shut down the reactor. The CRDM is a magnetically operated jack. A magnetic jack is an arrangement of three electromagnets that are energized in a controlled sequence by a power cycler to insert or withdraw the RCCAs of the reactor core in discrete steps. The CRDM consists of the pressure vessel, coil stack assembly, the latch assembly, and the drive rod assembly:

(1) The pressure vessel includes a one-piece integrated latch housing / head adaptor. A seal weld is located between the integrated latch housing and the rod travel housing. The integrated latch housing is butt welded to the CRDM nozzle; however, the butt weld is not part of the pressure housing assembly.

The latch housing is the lower portion of the vessel and contains the latch assembly. The rod travel housing is the upper portion of the vessel and provides space for the drive rod during its upward movement as the control rods are withdrawn from the core.

(2) The coil stack assembly includes the coil housings, an electrical conduit and connector, and three operating coils: (a) the stationary gripper coil, (b) the movable gripper coil, and (c) the lift coil.

Energizing the operation coils causes movement of the pole pieces and latches in the latch assembly.

(3) The latch assembly includes the guide tube, stationary pole pieces, movable pole pieces, and two sets of latches: (a) the movable gripper latch, and (b) the stationary gripper latch.

The latches engage grooves in the drive rod assembly. The movable gripper latches are moved up or down in 5/8-inch steps by the lift pole to raise or lower the drive rod. The stationary gripper latches hold the drive rod assembly while the movable gripper latches are repositioned for the next 5/8-inch step.

(4) The drive rod assembly includes a flexible coupling, a drive rod, a disconnect button, a disconnect rod, and a locking button.

The drive rod has 5/8-inch grooves that receive the latches during holding or moving of the drive rod.

The disconnect button, disconnect rod, and locking button provide positive locking of the coupling to the RCCA and permit remote disconnection.

The CRDM has a trip design. Tripping can occur during any part of the power cycler sequencing if power to the coils is interrupted.

The mechanism can handle a 360-pound load, including the drive rod weight, at a rate of 45 inches per minute (72 steps per minute). Withdrawal of the RCCA is accomplished by magnetic forces while insertion is by gravity.

The mechanism internals are designed to operate in 650°F reactor coolant. The three operating coils are designed to operate at 392°F with forced air cooling required to maintain that temperature.

The CRDM, shown schematically in Figure 4.2-24, withdraws and inserts its control rod as electrical pulses are received by the operator coils. Position of the control rod is measured by 42 discrete coils mounted on the position indicator assembly surrounding the rod travel housing. Each coil magnetically senses the entry and presence of the top of the ferromagnetic drive rod assembly as it moves through the coil centerline.

During plant operation, the stationary gripper coil of the drive mechanism holds the control rod withdrawn from the core in a static position until the movable gripper coil is energized.

If power to the stationary gripper coil is cut off, the combined weight of the drive rod assembly and the RCCA is sufficient to move latches out of the drive rod assembly groove. The control rod falls by gravity into the core. The trip occurs as the magnetic field, holding the stationary gripper plunger half against the stationary gripper pole, collapses, and the stationary gripper plunger half is forced down by the weight acting upon the latches. After the drive rod assembly is released by the mechanism, it falls freely until the control rods enter the buffer section of their guide tubes.

4.2.3.4 Reactivity Control System Design Evaluation

4.2.3.4.1 Reactivity Control Components Design Evaluation

The components are analyzed for loads corresponding to normal, upset, emergency, and faulted conditions. The analysis performed depends on the mode of operation under consideration.

The scope of the analysis requires many different techniques and methods, both static and dynamic.

Some of the loads that are considered on each component, where applicable, are:

(1) Control rod scram (equivalent static load)

(2) Differential pressure

(3) Spring preloads

(4) Coolant flow forces (static)

(5) Temperature gradients

(6) Differences in thermal expansion

(a) Due to temperature differences

(b) Due to expansion of different materials

(7) Interference between components

(8) Vibration (mechanically or hydraulically induced)

(9) All operational transients listed in Table 5.2-4

(10) Pump overspeed

(11) Seismic loads (refer to Section 3.7.3.15)

(12) Post-LOCA Rod Insertion (seismic plus LOCA loads)

The main objective of the analysis is to ensure that allowable stress limits are not exceeded, that an adequate design margin exists, and to establish deformation limits that are concerned primarily with the components' functioning. The stress limits are established not only to ensure that peak stresses will not reach unacceptable values, but also to limit the amplitude of the oscillatory stress component in consideration of fatigue characteristics of the materials. Standard methods of strength of materials are used to establish the stresses and deflections of these components. The dynamic behavior of the reactivity control components has been studied using experimental test data and experience from operating reactors.

The design of reactivity component rods provides sufficient cold void volume within the source rods to limit internal pressures to a value that satisfies the criteria in Section 4.2.1.2.3. The WABA rods have an annular plenum within the rod to accommodate the helium gas released from the absorber material during boron depletion (refer to Figure 4.2-18a). The internal pressure of source rods continues to increase from ambient until EOL; the internal pressure never exceeds that allowed by the criteria in Section 4.2.1.2.3. The stress analysis for the WABA rods assumed a maximum 30 percent gas release, consistent with Reference 28.

The WABA rod cladding and rod initial internal pressure have been designed so that the clad will not rely upon the pellets for support under all Condition I and Condition II events. Rodlet pre-pressurization will support the outer clad against irradiation induced creep collapse in the event of 0% gas release (worst case) from the Al_2O_3-B_4C for the design life. Calculations also verify the clad integrity under Condition I and Condition II events with a conservative maximum gas release.

Thermal analyses have shown that the maximum absorber temperature is less than 1200°F for both normal operation (Condition I) and for Condition II upset events. This provides assurance that the He gas release will not exceed limits for the WABA rod's

mechanical design life of 18,000 EFPH. This also assures that the Zircaloy clad strain limit is satisfied. A conservatively large heating rate was used in the thermal analyses. The actual heating rate would be less for the reference design due to the lower B_{10} loading.

An evaluation of the WABA rod design is given in Reference 28.

Analysis of the RCCA spider indicates it is structurally adequate to withstand the various operating loads, including the higher loads that occur during the drive mechanism stepping action and rod drop. Verification of the spider structural capability has been experimentally demonstrated.

The material was selected on the basis of resistance to irradiation damage and compatibility with the reactor environment. No apparent degradation of construction material has occurred in operating plants with the DCPP reactivity control design.

Regarding material behavior in a radioactive environment, it should be noted that at high fluences, the austenitic material increases in strength with a corresponding decreased ductility (as measured by tensile tests), but energy absorption (as measured by impact tests) remains quite high. Corrosion of the material exposed to the coolant is quite low, and proper control of Cl^- and O_2 in the coolant prevents stress corrosion. All of the austenitic stainless steel base material used is processed and fabricated to preclude sensitization.

Analysis of the RCCA shows that if the drive mechanism housing ruptures, the RCCA will be ejected from the core by the pressure differential of the operating pressure and ambient pressure across the drive rod assembly. The ejection is also predicated on the failure of the drive mechanism to retain the drive rod/RCCA position. It should be pointed out that a drive mechanism housing rupture causes the ejection of only one RCCA with the other assemblies remaining in the core. For the Westinghouse RCCA only, analysis also showed that a pressure drop in excess of 4000 psi must occur across a two-fingered vane to break the vane/spider body joint, causing ejection of two neutron absorber rods from the core. Since the highest normal pressure of the primary system coolant is only 2250 psi, with the safety valves set to lift at 2485 psig, a pressure drop in excess of 4000 psi is not expected. Thus, ejection of the neutron absorber rods is not possible.

Ejection of a burnable absorber or thimble plug assembly is conceivable if one postulates that the hold-down bar fails and that the base plate and burnable absorber rods are severely deformed. In the unlikely event of hold-down bar failure, the upward displacement of the burnable absorber assembly only permits the base plate to contact the upper core plate. Since this displacement is small, the major portion of the absorber material remains positioned within the core. In the case of the thimble plug assembly, the thimble plugs will partially remain in the fuel assembly guide thimbles, thus maintaining a majority of the desired flow impedance. Further displacement or complete ejection would necessitate that the square base plate and burnable absorber

rods be forced, thus plastically deformed, to fit up through a smaller diameter hole. As expected, this condition requires a substantially higher force or pressure drop than that of the hold-down bar failure.

To ensure subcriticality during hot leg recirculation following a LOCA (refer to Section 15.4.1.3.2), control rod insertion analyses and evaluations are performed that demonstrate that the control rods will insert under combined LOCA and seismic conditions for the applicable limiting design basis cold leg breaks.

Experience with control rods, burnable absorber rods, and source rods is discussed in Reference 8.

The mechanical design of the reactivity control components provides for the protection of the active elements to prevent the loss of control capability and functional failure of critical components. The components have been reviewed for potential failure and consequences of a functional failure of critical parts. The results of the review are summarized below.

4.2.3.4.2 Rod Cluster Control Assembly Design Evaluation

(1) The basic absorbing material is sealed from contact with the primary coolant and the fuel assembly and guidance surfaces by a high quality stainless steel cladding. Potential loss of absorber mass or reduction in reactivity control material due to mechanical or chemical erosion or wear is therefore reliably prevented.

(2) A breach of the cladding for any postulated reason does not result in serious consequences. The silver-indium-cadmium absorber material is relatively inert and would still remain remote from high coolant velocity regions. Rapid loss of material resulting in significant loss of reactivity control material would not occur.

(3) The individually clad absorber rods are robustly secured to the retaining spider vane by threaded joints and welds. A failure of the joint would result in the insertion of the individual rod into the core. This results in reduced core reactivity which is a fail-safe condition.

(4) The RCCA spiders are either one-piece or two-piece assemblies that include vanes and fingers, a failure of which could result in insertion of the individual rod into the core.

Failure of the vane-to-hub joint of a single rod vane could potentially result in failure of the separated vane and rod insertion. This could occur only at withdrawal elevation where the spider is above the continuous guidance section of the guide tube (in the upper internals). A rotation of the disconnected vane could cause it to hang on one of the guide cards in the

intermediate guide tube. Such an occurrence would be evident from the failure of the RCCA to insert below a certain elevation, but with free motion above this point.

This possibility is considered extremely remote because the single rod vanes are subjected to only vertical loads and very light lateral reactions from the rods even during a seismic event (refer to Section 3.7.3.15). The consequences of such a failure are not considered critical since only one drive line of the reactivity control system would be involved. This condition is readily observed and can be cleared at shutdown.

(5) The spider hub, being of single unit cylindrical construction, is very rugged and has extremely low potential for damage. Should some unforeseen event cause fracture of the hub above the vanes, the lower portion with the vanes and rods attached would insert by gravity into the core causing reactivity decrease, again a fail-safe condition.

(6) The RCCA rods are provided a clear channel for insertion by the guide thimbles of the fuel assemblies. All fuel rod failures are protected against by providing this physical barrier between the fuel rod and the intended insertion channel. Distortion of the fuel rods by bending cannot apply sufficient force to damage or significantly distort the guide thimble. Fuel rod distortion by swelling, though precluded by design, would be terminated by fracture before contact with the guide thimble occurs. If such were not the case, a force reaction at the point of contact would cause a slight deflection of the guide thimble. The radius of curvature of the deflected shape of the guide thimbles would be sufficiently large to have a negligible influence on rod cluster control insertion.

4.2.3.4.3 Burnable Absorber Assemblies Design Evaluation

The burnable absorber assemblies are static temporary reactivity control elements. The axial position is ensured by the holddown assembly that bears against the upper core plate. Their lateral position is maintained by the guide thimbles of the fuel assemblies.

The individual rods are shouldered against the underside of the retainer plate and securely fastened at the top by a threaded nut that is then locked in place. The square dimension of the retainer plate is larger than the diameter of the flow holes through the core plate. Therefore, failure of the holddown bar or spring pack does not result in ejection of the burnable absorber rods from the core.

The only incident that could result in ejection of the burnable absorber rods is a multiple fracture of the retainer plate. This is not considered credible because of the light loads borne by this component.

The burnable absorber rods are clad with either stainless steel or Zircaloy 4. The burnable absorber is Al_2O_3-B_4C annular pellets contained within two concentric Zircaloy tubes. Burnable absorber rods are placed in static assemblies and are not subjected to motion which might damage the rods. Further, the guide thimble tubes of the fuel assembly afford additional protection from damage.

During the accumulated thousands of years of burnable absorber rodlet operating experience, only one instance of penetration of the stainless steel burnable absorber cladding has been observed. The consequences of cladding breach are also small. It is anticipated that upon cladding breach, the B_4C would be leached by the coolant water and that localized power peaking of a few percent would occur; no design criteria would be violated. Additional information on the consequences of postulated WABA rod failures is presented in Reference 28.

4.2.3.4.4 Drive Rod Assemblies Design Evaluation

All postulated failures of the drive rod assemblies, either by fracture or uncoupling, lead to the fail-safe condition. If the drive rod assembly fractures at any elevation, that portion remaining coupled falls with, and is guided by, the RCCA. This always results in a reactivity decrease.

4.2.3.4.5 Control Rod Drive Mechanism Design Evaluation

The CRDMs are Code Class I components designed to meet the stress requirements for normal operating conditions of the ASME BPVC Section III, Division I, 2001 Edition through 2003 Addenda.

Structural analysis of the CRDMs was performed for normal and faulted conditions as described in Section 5.2.2.1.15.7.

4.2.3.4.5.1 Material Selection Design Evaluation

Materials for all pressure-containing CRDM components comply with ASME BPVC Section III and were fabricated from austenitic (Type 304) stainless steel.

Magnetic pole pieces are fabricated from Type 410 stainless steel. All nonmagnetic parts, except pins and springs, are fabricated from Type 304 stainless steel. Cobalt alloy is used to fabricate link pins. Springs are made from nickel alloy. Latch arm tips are clad with Stellite 6 or ERCoCrA to provide improved wearability. Hard chrome plate and Stellite 6 or ERCoCrA are used selectively for bearing and wear surfaces.

The cast coil housings require a magnetic material. The choice was the ductile iron used in the CRDM. The finished housings are zinc-plated to provide corrosion resistance.

Coils are wound on bobbins of molded Dow Corning 302 material, with double glass-insulated copper wire. Coils are then vacuum-impregnated with silicon varnish. A wrapping of mica sheet is secured to the coil outer surface. The result is a well-insulated coil capable of sustained operation at 200°C.

The drive rod assembly uses a Type 410 stainless steel drive rod. The coupling is machined from Type 403 stainless steel. Other parts are Type 304 stainless steel with the exception of the springs, which are Inconel®-X, and the locking button, which is Haynes 25.

4.2.3.4.5.2 Radiation Damage Design Evaluation

As required by the equipment specification, the CRDMs are designed to accommodate a radiation dose rate of 10 rad/hr. The above radiation level, which amounts to 1.753×10^6 rads in 20 years, will not limit CRDM life.

4.2.3.4.5.3 Positioning Requirements Design Evaluation

The mechanism has a step length of 5/8 inch that determines the positioning capabilities of the CRDM. (Note: Positioning requirements are determined by reactor physics.)

4.2.3.4.5.4 Evaluation of Materials' Adequacy Design Evaluation

The ability of the pressure housing components to perform throughout the design lifetime as defined in the equipment specification is confirmed by the stress analysis report required by the ASME BPVC Section III.

The CRDM latch assembly may be significantly worn and should be replaced after 6 million individual steps.

4.2.3.4.5.5 Results of Dimensional and Tolerance Analysis

With respect to the CRDM systems as a whole, critical clearances are present in the following areas:

(1) Latch assembly (diametral clearances)

(2) Latch arm-drive rod clearances

(3) Coil stack assembly-thermal clearances

(4) Coil fit in coil housing

These clearances have been proven by life tests and actual field performance at operating plants:

(1) Latch Assembly - Thermal Clearances - The magnetic jack has several clearances where parts made of Type 410 stainless steel fit over parts made from Type 304 stainless steel. Differential thermal expansion is therefore important.

(2) Latch Arm - Drive Rod Clearances - The CRDM incorporates a load transfer action. The movable or stationary gripper latch is not under load during engagement due to load transfer action.

Figure 4.2-25 shows latch clearance variation with the drive rod at minimum and maximum temperatures. Figure 4.2-26 shows clearance variations over the design temperature range.

(3) Coil Stack Assembly - Thermal Clearances - The assembly clearance of the coil stack assembly over the latch housing was selected so that the assembly could be removed under all anticipated conditions of thermal expansion.

(4) Coil Fit in Coil Housing - CRDM and coil housing clearances are selected so that coil heatup results in a close or tight fit. This facilitates thermal transfer and coil cooling in a hot CRDM.

4.2.3.5 Safety Evaluation

4.2.3.5.1 General Design Criterion 2, 1967 – Performance Standards

A dynamic seismic analysis is performed on the CRDMs to confirm their ability to trip under a postulated seismic disturbance while maintaining resulting stresses under allowable values (refer to Section 5.2.2.1.15.7).

Additionally, seismic loads (DE, DDE, and HE) are considered on each component, where applicable (refer to Section 3.7.3.15.3).

The containment building, in which the CRDMs are located, is a PG&E Design Class I structure (refer to Section 3.8). As such it is designed to withstand the effects of winds (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7). This design protects the CRDMs, ensuring their safety function will be performed.

4.2.3.5.2 General Design Criterion 4, 1987 – Environmental and Dynamic Effects Design Bases

The LBB methodology was applied to the primary loops of DCPP Unit 1 and Unit 2. The following postulated breaks were eliminated: the six terminal ends in the RCS cold, hot, and crossover legs; a split in the steam generator inlet elbow; and the loop closure weld

in the crossover leg. Protection from the dynamic effects of the most limiting breaks of auxiliary lines is considered. RCS branch line breaks and other high energy line breaks are provided. Refer to Section 5.2 for additional discussion of LBB methodology and application.

The LOCA dynamic analyses are based on the accumulator, pressurizer surge, and residual heat removal system RCS branch line breaks credited LBB (Reference 32).

4.2.3.5.3 General Design Criterion 25, 1971 – Protection System Requirements for Reactivity Control Malfunctions

The maximum reactivity insertion rate due to withdrawal of RCCAs, or by boron dilution, is limited as discussed in Section 4.3.4.4.

4.2.3.5.4 General Design Criterion 26, 1971 – Reactivity Control System Redundancy and Capability

The rod control system relies on gravity to insert the rods into the core (refer to Section 4.2.3.3.6). The mechanical design of the reactivity control components provides for the protection of the active elements to prevent the loss of control capability and functional failure of critical components. The components have been reviewed for potential failure and consequences of a functional failure of critical parts (refer to Section 4.2.3.4).

The CVCS regulates the concentration of chemical neutron absorber in the reactor coolant to control reactivity changes resulting from the change in reactor coolant temperature between cold shutdown and hot full power (HFP) operation, burnup of fuel and burnable poisons, and xenon transients (refer to Section 9.3.4).

This documents that the reactivity control system is provided with redundancy and capability such that two independent reactivity control systems of different design principles and capable of reliably controlling reactivity changes under conditions of normal operation, including anticipated operational occurrences to assure acceptable fuel design limits are not exceeded and that one is capable of holding the reactor core subcritical under cold conditions.

4.2.3.5.5 General Design Criterion 29, 1971 – Protection Against Anticipated Operational Occurrences

During plant operation, the stationary gripper coil of the drive mechanism holds the control rod withdrawn from the core in a static position until the movable gripper coil is energized. If power to the stationary gripper coil is cut off, the combined weight of the drive rod assembly and the RCCA is sufficient to move latches out of the drive rod assembly groove. The control rod falls by gravity into the core. After the drive rod assembly is released by the mechanism, it falls freely until the control rods enter the buffer section of their thimble tubes.

4.2.3.5.6 General Design Criterion 30, 1967 – Reactivity Holddown Capability

The control and shutdown rod groups provide adequate SDM (refer to Section 4.2.3.3.2) which is defined as: the instantaneous amount of reactivity by which the reactor is subcritical, or would be subcritical from its present condition, assuming

(1) All RCCAs are fully inserted, except for the single RCCA of highest reactivity worth which is assumed to be fully withdrawn (with any RCCA not capable of being fully inserted, the reactivity worth of the RCCA must be accounted for in the determination of SDM) and

(2) When in MODE 1 or 2, the fuel and moderator temperatures are changed to the hot zero power temperatures.

4.2.3.6 Tests and Inspections

4.2.3.6.1 Reactivity Control Components

Tests and inspections are performed on each reactivity control component to verify its mechanical characteristics. For the RCCA, prototype testing has been conducted and both manufacturing tests/inspections and functional testing are performed at the plant site.

During the component manufacturing phase, material procurement, testing, and inspections are controlled in accordance with the vendors 10 CFR 50 Appendix B compliant QA program.

Rod drop tests following refueling outages are performed in accordance with the DCPP Technical Specifications (Reference 24) requirements.

4.2.3.6.2 Control Rod Drive Mechanisms

The quality assurance program and testing for the CRDMs is discussed in the CRDM component design specification.

It is expected that all CRDMs will meet specified operating requirements for the duration of plant life with normal refurbishment. Technical Specifications define actions to be taken for rod group misalignment and rod inoperability.

To demonstrate continuous free movement of the RCCA and to ensure acceptable core power distributions during operation, partial-movement checks are performed in accordance with Technical Specifications. In addition, periodic drop tests of the RCCAs are performed at each refueling shutdown to demonstrate continued ability to meet trip time requirements. During these tests, the acceptable trip time of each assembly is not greater than the requirements listed in the Technical Specifications at full flow and operating temperature, from decay of the stationary gripper voltage to dashpot entry.

Periodic tests are also conducted during plant operation in accordance with the Technical Specifications.

4.2.3.7 Instrumentation Applications

Instrumentation for determining reactor coolant average temperature is provided to create demand signals for moving groups of RCCAs to provide load follow (determined as a function of turbine impulse pressure) during normal operation, and to counteract operational transients. The hot and cold leg resistance temperature detectors (RTDs) are described in Section 7.2. The reactor control system, which controls the reactor coolant average temperature by regulation of control rod bank position, is described in Section 7.7.

Rod position indication instrumentation is provided to sense the actual position of each control rod so that it may be displayed to the operator. Signals are also supplied by this system as input to the rod deviation comparator. The rod position indication system is described in Chapter 7. The CVCS, one of whose functions is to permit adjustment of the reactor coolant boron concentration for reactivity control (as well as to maintain the desired operating fluid inventory in the volume control tank), consists of a group of instruments arranged to provide a manually preselected makeup composition that is borated or diluted, as required, to the charging pump suction header or the volume control tank. This system, as well as other systems, including boron sampling provisions that are part of the CVCS, is described in Section 9.3.4.

When the reactor is critical, the normal indication of reactivity status in the core is the position of the control bank in relation to reactor power (as indicated by the RCS loop ΔT) and coolant average temperature. These parameters are used to calculate insertion limits for the control banks to warn the operator of excessive rod insertion. Monitoring of the neutron flux for various phases of reactor power operation, as well as of core loading, shutdown, startup, and refueling is by means of the nuclear instrumentation system. The monitoring functions and readout and indication characteristics for the following reactivity monitoring systems are included in the discussion on the safety parameter display system (SPDS) in Section 7.5:

(1) Nuclear instrumentation system

(2) Temperature indicators

  (a) T average (measured)

  (b) ΔT (measured)

  (c) Auctioneered T average

(3) Demand position of RCCA group

(4) Actual rod position indicator.

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4.3 NUCLEAR DESIGN

The nuclear design of the reactors for DCPP Unit 1 and Unit 2, including fuel and reactivity control systems, is described in this section; the analytical methods used in reactor design and evaluation are also discussed.

Before discussing the nuclear design bases, a brief review of the four major plant operation conditions, categorized in accordance with their anticipated frequency of occurrence and risk to the public, (refer to Section 4.2) are as follows:

(1) Condition I - Normal Operation

(2) Condition II - Incidents of Moderate Frequency

(3) Condition III - Infrequent Faults

(4) Condition IV - Limiting Faults

In general, Condition I occurrences are accommodated with margin between any plant parameter and the value of that parameter which would require either automatic or manual protective action. Condition II incidents are accommodated with, at most, a shutdown of the reactor with the plant capable of returning to operation after corrective action. Fuel damage (penetration of the fission product barrier; i.e., the fuel rod cladding) is not expected during Conditions I and II events. It is not possible, however, to preclude a very small number of rod failures. These are within the capability of the plant cleanup system and are consistent with the plant design bases.

Condition III incidents shall not cause more than a small fraction of the fuel elements in the reactor to be damaged, although sufficient fuel element damage might occur to preclude immediate resumption of operation. The release of radioactive material due to Condition III incidents should not be sufficient to interrupt or restrict public use of those areas beyond the exclusion radius. Furthermore, a Condition III incident shall not, by itself, generate a Condition IV fault or result in a consequential loss of function of the RCS or reactor containment barriers. Condition IV occurrences are faults that are not expected to occur, but are defined as limiting faults that must be considered in design. Condition IV faults shall not cause a release of radioactive material that results in an undue risk to public health and safety.

The core design power distribution limits related to fuel integrity are met for Condition I occurrences through conservative design, and maintained by the action of the control system. The requirements for Condition II occurrences are met by providing an adequate protection system that monitors reactor parameters. The control and protection systems are described in Chapter 7 and the consequences of Conditions II, III, and IV occurrences are discussed in Chapter 15.

4.3.1 DESIGN BASES

The design bases and functional requirements for the nuclear design of the fuel and reactivity control system, and the relationships of these design bases to the GDC of July 1971, are presented in this section. Where appropriate, supplemental criteria, such as 10 CFR 50.46, are addressed.

4.3.1.1 General Design Criterion 10, 1971 – Reactor Design

The reactor core and associated coolant, control and protection systems are designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

4.3.1.2 General Design Criterion 11, 1971 – Reactor Inherent Protection

The reactor core is designed so that in the power operating range, the prompt inherent nuclear feedback characteristics tend to compensate for a rapid increase in reactivity.

4.3.1.3 General Design Criterion 12, 1971 – Suppression of Reactor Power Oscillations

The reactor core is designed to assure that power oscillations that could result in conditions exceeding SAFDLs are not possible or can be reliably and readily detected and suppressed.

4.3.1.4 General Design Criterion 25, 1971 – Protection System Requirements for Reactivity Control Malfunctions

The reactivity control system is designed to assure that no single malfunction (this does not include rod ejection) causes a violation of the acceptable fuel design limits.

4.3.1.5 General Design Criterion 26, 1971 – Reactivity Control System Redundancy and Capability

Two independent reactivity control systems of different design principles are provided. Each system has the capability to control the rate of reactivity changes resulting from planned, normal power changes. One of the systems is capable of reliably controlling anticipated operational occurrences. In addition, one of the systems is capable of holding the reactor core subcritical under cold conditions.

4.3.1.6 General Design Criterion 28, 1971 – Reactivity Limits

The reactivity control systems are designed to assure that the effects of postulated reactivity accidents neither result in damage to the reactor coolant pressure boundary greater than limited local yielding nor cause sufficient damage to significantly impair the capability to cool the core.

4.3.2 NUCLEAR DESIGN ACCEPTANCE CRITERIA

4.3.2.1 Fuel Burnup

Sufficient reactivity should be incorporated in the fuel to attain a desired region average discharge burnup.

4.3.2.2 Control of Power Distribution

The nuclear design basis, with at least a 95 percent confidence level, is as follows:

(1) The fuel will not be operated at greater than 14.3 kW/ft under normal operating conditions, including an allowance of 2 percent for calorimetric error and not including the power spike factor due to densification effects (Reference 31).

(2) Under abnormal conditions, including the maximum overpower condition, the fuel peak power will not cause melting as defined in Section 4.4.2.2.

(3) The fuel will not operate with a power distribution that violates the DNB design basis (i.e., the departure from nucleate boiling ratio {DNBR} shall not be less than the design limit DNBR, as discussed in Section 4.4.2) under Conditions I and II events, including the maximum overpower condition.

(4) Fuel management will be such as to produce fuel rod powers and burnups consistent with the assumptions in the fuel rod mechanical integrity analysis of Section 4.2.

4.3.2.3 Negative Reactivity Feedbacks (Reactivity Coefficients)

The fuel temperature coefficient of reactivity will be negative, and the MTC of reactivity will be nonpositive for full power operating conditions, thus providing negative reactivity feedback characteristics over the operating range. Below 70 percent power, an MTC of up to +5 pcm (percent mille)/°F is allowed. From 70 percent to 100 percent the MTC limit decreases linearly from +5 to 0 pcm/°F.

4.3.2.4 Stability

Spatial power oscillations within the core, with a constant core power output, should they occur, can be reliably and readily detected and suppressed.

4.3.2.5 Maximum Controlled Reactivity Insertion Rate

The maximum reactivity insertion rate due to withdrawal of RCCAs, or by boron dilution, is limited. This limit, expressed as a maximum reactivity change rate (75 pcm/sec) is set such that the peak heat generation rate does not exceed the maximum allowable, and DNBR is not below the minimum allowable at overpower conditions (refer to Note (b) of Table 4.3-1).

4.3.2.6 Shutdown Margins

Minimum SDM, as specified in the Core Operating Limits Reports, is required in all operational modes.

In all analyses involving reactor trip, the single, highest worth RCCA is postulated to remain untripped in its full-out position (stuck rod criterion).

4.3.3 DESCRIPTION

4.3.3.1 Nuclear Design Description

The reactor core consists of 193 fuel assemblies arranged in a pattern that approximates a right circular cylinder. Each fuel assembly contains a 17 x 17 rod array composed of 264 fuel rods, 24 RCCA guide tubes, and an incore instrumentation thimble. Each rod is held in place by spacer grids and top and bottom nozzles. The fuel rods are constructed of zirconium alloy tubing containing enriched UO_2 fuel pellets. A limited substitution of fuel rods by filler rods of zirconium alloy or stainless steel may be made for a particular design if justified by a cycle-specific reload analysis. Figure 4.2-1 shows a cross-sectional view of a fuel assembly and the related RCCA locations. The fuel assembly design is discussed in Section 4.2.1.

All the fuel rods within a given assembly generally have the same nominal uranium enrichment. The exceptions are that the top and bottom portions of the rods may contain a low enriched or natural uranium blanket and that some assemblies may contain more than one enrichment as a result of reconstitution operations. Figure 4.3-1 shows a typical equilibrium 18-month cycle core loading of fresh and burned fuel assemblies. This "typical" loading pattern is modified for fuel cycles of longer length to accommodate the needed additional cycle energy.

A typical reload pattern employs low leakage fuel management in which more highly burned fuel is placed on the core periphery. Reload cores will operate approximately 12 months to 24 months between refuelings. The feed fuel enrichment is determined by the amount of fissionable material required to provide the desired core lifetime and energy production. Reactivity losses due to U-235 depletion and the buildup of fission products are partially offset by the buildup of plutonium produced by the capture of neutrons in U-238, as shown in Figure 4.3-2. At the beginning of any cycle, an excess reactivity to compensate for these losses over the specified cycle life must be "built" into

the reactor. This excess reactivity is controlled by removable neutron absorbing material in the form of boron dissolved in the primary coolant and burnable absorber rods or boron coated fuel pellets.

Boric acid concentration in the primary coolant is varied to control and to compensate for long-term reactivity requirements, such as those due to fuel burnup, fission product poisoning, including xenon and samarium, burnable absorber material depletion, and the cold-to-operating moderator temperature change. Using its normal makeup path, the CVCS is capable of inserting negative reactivity at a rate of approximately 30 pcm/min when the reactor coolant boron concentration is 100 ppm. In an emergency, the CVCS can insert negative reactivity at approximately 65 pcm/min when the reactor coolant concentration is 1000 ppm, and 75 pcm/min when the reactor coolant boron concentration is 100 ppm. The peak xenon burnout rate is 25 pcm/min (Section 9.3.4 discusses the capability of the CVCS to counteract xenon decay). Rapid transient reactivity requirements and safe shutdown requirements are met with control rods.

As the boron concentration increases, the MTC becomes less negative. Using soluble poison alone would result in a positive MTC at BOL at full power operating conditions. Therefore, burnable absorber and IFBA rods are used to reduce the soluble boron concentration sufficiently to ensure that the MTC is not positive for full power operating conditions. During operation, the absorber content in these rods is depleted, thus adding positive reactivity to offset some of the negative reactivity from fuel depletion and fission product buildup. The depletion rate of the burnable absorber material is not critical since chemical shim is always available and flexible enough to cover any possible deviations in the expected burnable absorber depletion rate. Figure 4.3-3 shows typical core depletion curves with burnable absorbers.

In addition to reactivity control, the burnable absorbers are strategically located to provide a favorable radial power distribution. Figures 4.3-4 and 4.3-5 show the typical burnable absorber distribution within a fuel assembly for the several burnable absorber patterns used for both discrete and IFBAs. The burnable absorber loading pattern for a typical equilibrium cycle reload core is shown in Figure 4.3-6.

Tables 4.1-1, and 4.3-1 through 4.3-3, summarize the reactor core design parameters for a typical reload fuel cycle, including reactivity coefficients, delayed neutron fraction, and neutron lifetimes.

4.3.3.2 Power Distribution

DCPP employs two methods for performing core power distribution calculations: the power distribution monitoring system (PDMS) and the movable incore detector system (MIDS).

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The PDMS generates a continuous measurement of the core power distribution using the methodology documented in References 32 and 33. The measured core power

distribution is used to determine the most limiting core peaking factors, which are used to verify that the reactor is operating within the design limits.

The PDMS requires information on current plant and core conditions in order to determine the core power distribution using the core peaking factor measurement and measurement uncertainty methodology described in References 32 and 33. The core and plant condition information is used as input to the continuous core power distribution measurement software that continuously and automatically determines the current core peaking factor values. The core power distribution calculation software provides the measured peaking factor values at nominal one-minute intervals to allow operators to confirm that the core peaking factors are within design limits. In order for the PDMS to accurately determine the peaking factor values, the core power distribution measurement software requires accurate information about the current reactor power level average reactor vessel inlet temperature, control bank positions, the power range detector currents, and the core exit thermocouples.

Data obtained from the MIDS, described in Section 7.7.2.9.2, are used to calibrate the PDMS, and may also be used independent of the PDMS to generate a flux map of the core power distribution. The accuracy of these power distribution calculations has been confirmed under conditions similar to those expected for DCPP, as discussed in References 1 and 3 and in Section 4.3.3.2.7.

4.3.3.2.1 Definitions

Power distributions are quantified in terms of hot channel factors. These factors are a measure of the peak pellet power within the reactor core and the total energy produced in a coolant channel and are expressed in terms of quantities related to the nuclear or thermal design; namely:

Power density is the thermal power produced per unit volume of the core (kW/liter).

Linear power density is the thermal power produced per unit length of active fuel (kW/ft). Since fuel assembly geometry is standardized, this is the unit of power density most commonly used. For all practical purposes, it differs from kW/liter by a constant factor that includes geometry effects and the fraction of the total thermal power which is generated in the fuel rods.

Average linear power density is the total thermal power produced in the fuel rods divided by the total active fuel length of all rods in the core.

Local heat flux is the heat flux at the surface of the cladding (Btu $ft^{-2}hr^{-1}$). For nominal fuel rod parameters, this differs from linear power density by a constant factor.

Rod power or *rod integral power* is the linear power density in one rod integrated over its length (kW).

Average rod power is the total thermal power produced in the fuel rods divided by the number of fuel rods.

The hot channel factors used in the discussion of power distributions in this section are defined as follows:

F_Q^T , *heat flux hot channel factor*, is defined as the maximum local heat flux on the surface of a fuel rod divided by the average fuel rod heat flux, allowing for manufacturing tolerances on fuel pellets and rods.

F_Q^N, *nuclear heat flux hot channel factor*, is defined as the maximum local fuel rod linear power density divided by the average fuel rod linear power density, assuming nominal fuel pellet and rod parameters. (No densification effects included.)

F_Q^E, *engineering heat flux hot channel factor*, is the allowance on heat flux required for manufacturing tolerances. The engineering factor allows for local variations in enrichment, pellet density and diameter, surface area of the fuel rod, and eccentricity of the gap between pellet and clad.

Combined statistically, the net effect is a factor of 1.03 to be applied to the fuel rod surface heat flux.

$F_{\Delta H}^N$, *nuclear enthalpy rise hot channel factor*, is defined as the ratio of the integral of linear power along the rod with the highest integrated power to the average rod power.

Manufacturing tolerances, hot channel power distribution, and surrounding channel power distributions are treated explicitly in the calculation of DNBR described in Section 4.4.

For the purposes of discussion, it is convenient to define subfactors of F_Q^T; design limits are set, however, in terms of the total peaking factor:

$$F_Q^T = \text{Total peaking factor or heat flux hot channel factor}$$

$$= \frac{\text{Maximum kW/ft}}{\text{Average kW/ft}} \qquad (4.3\text{-}1)$$

without densification effects.

$$F_Q^T = F_Q^N \times F_Q^E$$

$$= \max\,[F_{XY}^N(z) \times P(z)] \times F_U^N \times F_Q^E \qquad (4.3\text{-}2)$$

where:

F_Q^N and F_Q^E are defined above.

F_U^N = the measurement uncertainty associated with a full core flux map with movable detectors or PDMS

$F_{XY}^N(z)$ = ratio of peak power density to average power density in the horizontal plane of peak local power

P(z) = ratio of the power per unit core height in the horizontal plane at elevation Z to the average value of power per unit core height

4.3.3.2.2 Radial Power Distributions

The power shape in horizontal sections of the core at full power is a function of the fuel and burnable absorber loading patterns, and the presence or absence of a single bank of control rods. Thus, at any time in the cycle, any horizontal section of the core can be characterized as unrodded, or with control banks inserted. These two situations, combined with burnup effects, determine the radial power shapes that can exist in the core at full power. The effects on radial power shapes of power level, xenon, samarium, and moderator density effects are also considered, but these are smaller. While radial power distributions in various planes of the core are often illustrated, the core radial enthalpy rise distribution, as determined by the power integral of each channel, is of greater interest. Figures 4.3-7 through 4.3-12 show representative radial power distributions for one-eighth of the core for representative operating conditions during the initial cycle, as follows:

Figure	Conditions
4.3-7	HFP at BOL unrodded no xenon
4.3-8	HFP at BOL unrodded equilibrium xenon
4.3-9	HFP at BOL Bank D in equilibrium xenon – Unit 1
4.3-10	HFP at BOL Bank D in equilibrium xenon – Unit 2
4.3-11	HFP at middle of life (MOL) unrodded equilibrium xenon, and
4.3-12	HFP at EOL unrodded equilibrium xenon.

Since hot channel location varies from time to time, a single reference radial design power distribution is selected for DNB calculations. This reference power distribution, normalized to core average power, is chosen conservatively to concentrate power in one area of the core, minimizing the benefits of flow redistribution.

4.3.3.2.3 Assembly Power Distributions

For the purpose of illustration, assembly power distributions for the BOL and EOL conditions corresponding to Figures 4.3-8 and 4.3-12 are given for the same assembly in Figures 4.3-13 and 4.3-14, respectively.

Since the detailed power distribution surrounding the hot channel varies from time to time, a conservatively flat assembly power distribution is assumed in the DNB analysis, described in Section 4.4, with the rod of maximum integrated power artificially raised to the design value of $F^N_{\Delta H}$. The nuclear design considers all fuel cycles and all operating conditions to ensure that a flatter assembly power distribution does not occur with limiting values of $F^N_{\Delta H}$.

4.3.3.2.4 Axial Power Distributions

The shape of the power profile in the axial direction is largely under the control of the operator through the manual operation of the control rods or the automatic motion of the control rods responding to manual operation of the CVCS. Nuclear effects that cause variations in the axial power shape include moderator density, Doppler effect on resonance absorption, spatial xenon variations, fuel and burnable absorber material distribution and burnup. Automatically controlled variations in total power output and control rod motion are also important in determining the axial power shape at any time. Signals are available to the operator from the excore ion chambers that run parallel to the axis of the core. Separate signals are taken from the top and bottom halves of the chambers. The difference between top and bottom signals for each of four pairs of detectors is called the flux difference, $\Delta\phi$. If it deviates from the flux difference target band, an alarm is actuated.

Calculations of core average peaking factor for many plants and measurements from operating situations are associated with either $\Delta\phi$ or axial offset (AO) to place an upper bound on the peaking factor. For these correlations, AO is defined as:

$$AO = \frac{\phi_t - \phi_b}{\phi_t + \phi_b} \qquad (4.3\text{-}4)$$

where:

ϕ_t and ϕ_b are the top and bottom detector readings.

Representative axial power shapes for BOL, MOL, and EOL conditions covering a wide range, including power shape changes achieved by skewing xenon distributions, are shown in Figures 4.3-15 through 4.3-17.

4.3.3.2.5 Local Power Peaking

Fuel densification causes fuel pellets to shrink both axially and radially. Pellet shrinkage combined with random hang-up of fuel pellets results in gaps in the fuel column when the pellets below the hung-up pellet settle in the fuel rod. The gaps vary in length and location in the fuel rod. Because of decreased neutron absorption in the vicinity of the gap, power peaking occurs in the adjacent fuel rods resulting in an increased power peaking factor. A quantitative measure of this local power peaking is given by the power spike factor S(z) where z is the axial location in the core.

In previous analyses of power peaking factors for DCPP Unit 1 and Unit 2, it was necessary to apply a penalty on calculated overpower transient F_Q values to allow for interpellet gaps caused by pellet hang-ups and pellet shrinkage due to densification (Reference 22). This penalty is known as the densification spike factor. However, studies have shown (Reference 31) that this penalty can be eliminated for the fuel type present in the DCPP Unit 1 and Unit 2 cores.

4.3.3.2.6 Limiting Power Distributions

As discussed in Section 4.3, Condition I occurrences are those expected frequently or regularly in the course of power operation, maintenance, or maneuvering of the plant. Condition I occurrences are accommodated with margin between any plant parameter and the value of that parameter that would require either automatic or manual protective action. Since they occur frequently or regularly, Condition I occurrences affect the consequences of Conditions II, III, and IV events. Analysis of each fault condition is generally based on a conservative set of initial conditions corresponding to the most adverse set of conditions that can occur during a Condition I event.

The list of steady state and shutdown conditions, permissible deviations, and operational transients is given in Section 15.1. Implicit in the definition of normal operation is proper and timely action by the reactor operator. That is, the operator follows recommended operating procedures for maintaining appropriate power distributions and takes any necessary remedial actions when alerted to do so by plant instrumentation. Thus, as stated above, the worst or limiting power distribution that can occur during normal operation is considered as the starting point for analysis of Conditions II, III, and IV events.

Improper procedural actions or errors by the operator are assumed in the design as occurrences of moderate frequency (Condition II). The limiting power shapes that result from such Condition II events are, therefore, those power shapes, which deviate from the normal operating condition at the recommended AO band. Power shapes that fall in this category are used to determine reactor protection system setpoints in order to maintain margin to overpower or DNB limits.

Maintaining power distributions within the required hot channel factor limits is discussed in the Technical Specifications. A complete discussion of power distribution control in

Westinghouse PWRs is included in References 2, 29, and 30. Detailed background information on the following design constraints on local power density in a Westinghouse PWR, on the defined operating procedures, and on the measures taken to preclude exceeding design limits is presented in References 23, 29, and 30.

The upper bound on peaking factors, F_Q^T and $F_{\Delta H}^N$, includes all of the nuclear effects that influence the radial and/or axial power distributions throughout core life for various modes of operation, including load follow, reduced power operation, and axial xenon transients.

Radial power distributions are calculated for full power, and fuel and moderator temperature feedback effects are included for the average enthalpy plane of the reactor. Steady state nuclear design calculations are done for normal flow with the same mass flow in each channel and flow redistribution is calculated explicitly where it is important to the DNB analysis of accidents. The effect of xenon on radial power distribution is small (compare Figures 4.3-7 and 4.3-8), but is included as part of the normal design process.

The core average axial profile can experience significant changes that can occur rapidly as a result of rod motion and load changes, and more slowly due to xenon distribution. To study points of closest approach to axial power distribution limits, several thousand cases are examined. Since the nuclear design properties dictate what axial shapes can occur, the limits of interest can be set in terms of parameters that are readily observed. Specifically, the following nuclear design parameters are significant to the axial power distribution analysis:

(1) Core power level

(2) Core height

(3) Coolant temperature and flow

(4) Coolant temperature program as a function of reactor power

(5) Fuel cycle lifetimes

(6) Rod bank worths

(7) Rod bank overlaps

Normal plant operation assumes compliance with the following conditions:

(1) Control rods in a single bank move together with no individual rod insertion differing by more than 12 steps (indicated) from the bank demand position

(2) Control banks are sequenced with overlapping banks

(3) Control bank insertion limits are not violated

(4) Axial power distribution procedures, which are given in terms of flux difference control and control bank position, are observed.

The above axial power distribution procedures are part of the normal plant operating procedures. Briefly, they require control of the AO (refer to Equation 4.3-4) at all power levels, within a permissible operating band. This minimizes xenon transient effects on the axial power distribution, since the procedures essentially keep the xenon distribution in phase with the power distribution.

Calculations are performed for normal reactor operation at beginning, middle, and end of cycle conditions. Different operation histories are implicitly included in the methodology. These different histories cover both base loaded operation and extensive load following.

These cases represent many possible reactor states in the life of one fuel cycle. They are considered to be necessary and sufficient to generate a local power density limit which, when increased by 5 percent for conservatism, will not be exceeded with a 95 percent confidence level. Many of the points do not approach the limiting envelope. However, they are generated as part of the process that leads to the shapes, which do define the envelope.

Thus, it is not possible to single out any transient or steady state condition that defines the most limiting case. It is not even possible to separate out a small number, which form an adequate analysis. The process of generating a myriad of shapes is essential to the philosophy that leads to the required level of confidence. A set of parameters that produces a limiting case for one reactor fuel cycle (defined as approaching the line of Figure 4.3-23) is not necessarily a limiting case for another reactor or fuel cycle with different control bank worths or insertion limits, enrichments, burnup, reactivity coefficient, etc. The shape of the axial power distribution calculated for a particular time depends on the operating history of the core up to that time, and on the manner in which the operator conditioned xenon in the days immediately before that time.

The calculated points are synthesized from axial calculations combined with the radial factors appropriate for rodded and unrodded planes. In these calculations, the effects on the radial peak of xenon redistribution that occur, following the withdrawal of a control bank (or banks) from a rodded region, are obtained from three-dimensional calculations. The factor to be applied to the radial peak is obtained from calculations in which the xenon distribution is preconditioned by the presence of control rods and then allowed to redistribute for several hours. A detailed discussion of this effect may be found in References 23 and 29. In addition to the 1.05 conservatism factor, the calculated values are increased by a factor of 1.03 for the engineering factor F_Q^E.

The envelope drawn over the calculated (max F_Q^T x Power) points, as shown in Figure 4.3-23 is an example of an upper bound envelope on local power density versus elevation in the core. Cycle-specific values are calculated each cycle.

Finally, this upper bound envelope is based on operation within an allowed range of axial flux difference limits. These limits are detailed in the Core Operating Limits Reports and rely only on excore surveillance supplemented by the required normal monthly power distribution measurement. If the axial flux difference exceeds the allowable range, an alarm is actuated.

Allowing for fuel densification, the average linear power is 5.445 kW/ft for both units at 3,411 MWt. The conservative upper bound value of normalized local power density, including uncertainty allowances, is 2.58, corresponding to a peak linear power of 14.3 kW/ft at 102 percent power.

To determine reactor protection system setpoints, with respect to power distributions, three categories of events are considered: rod control equipment malfunctions, operator errors of commission, and operator errors of omission. In evaluating these three categories, the core is assumed to be operating within the four constraints described above.

The first category is uncontrolled rod withdrawal (with rods moving in the normal bank sequence). Also included are motions of the banks below their insertion limits, which could be caused, for example, by uncontrolled dilution or primary coolant cooldown. Power distributions were calculated, assuming short-term corrective action. That is, no transient xenon effects were considered to result from the malfunction. The event was assumed to occur from typical normal operating situations, which include normal xenon transients. It was also assumed that the total power level would be limited by the reactor trip to below 118 percent. Results are given in Figure 4.3-21 in units of kW/ft. The peak power density, which can occur in such events, assuming reactor trip at or below 118 percent, is less than that required for fuel centerline melt, including uncertainties.

The second category, also appearing in Figure 4.3-21, assumes that the operator mispositions the rod bank in violation of insertion limits and creates short-term conditions not included in normal operating conditions.

The third category assumes that the operator fails to take action to correct a flux difference violation. The results shown in Figure 4.3-22 are F_Q^T multiplied by 102 percent power, including an allowance for calorimetric error. The peak linear power does not exceed 22.0 kW/ft, provided the operator's error does not continue for a period which is long compared to the xenon time constant. It should be noted that a reactor overpower accident is not assumed to occur coincident with an independent operator error. Additional detailed discussion of these analyses is presented in Reference 23.

Analyses of possible operating power shapes for the DCPP reactor show that the appropriate hot channel factors F_Q^T and $F_{\Delta H}^N$ for peak local power density, and for DNB analysis at full power, are the values given in Table 4.3-1 and addressed in the Technical Specifications.

The maximum allowable F_Q^T can increase with decreasing power, as shown in the Technical Specifications. Increasing $F_{\Delta H}^N$ with decreasing power is permitted by the DNB protection setpoints and allows radial power shape changes with rod insertion to the insertion limits, as described in Section 4.4.3.13. The allowances for increased $F_{\Delta H}^N$ permitted is:

$$F_{\Delta H}^N = 1.65\,[1 + 0.3\,(1-P)] \text{ for VANTAGE+ fuel} \qquad (4.3\text{-}5)$$

This becomes a design basis criterion, which is used for establishing acceptable control rod patterns and control bank sequencing. Likewise, fuel loading patterns for each cycle are selected with consideration of this design criterion. The worst values of $F_{\Delta H}^N$ for possible rod configurations occurring in normal operation are used in verifying that this criterion is met. Typical radial factors and radial power distributions are shown in Figures 4.3-7 through 4.3-12. The worst values generally occur when the rods are assumed to be at their insertion limits. As discussed in Reference 3, it has been determined that the Technical Specification limits are met, provided the above conditions (1) through (4) are observed. These limits are taken as input to the thermal-hydraulic design basis, as described in Section 4.4.3.13.1.

If the possibility exists during normal operation of local power densities exceeding those assumed as the precondition for a subsequent hypothetical accident, but which would not itself cause fuel failure, administrative controls and alarms are provided to return the core to a safe condition. These alarms are described in Chapter 7 and in the Technical Specifications.

4.3.3.2.7 Experimental Verification of Power Distribution Analysis

This subject, which is discussed in depth in Reference 1, is summarized here.

To measure the peak local power density, F_Q^T, with the movable detector system described in Sections 4.4.7 and 7.7.2.9.2, the following uncertainties are considered:

(1) Reproducibility of the measured signal

(2) Errors in the calculated relationship between detector current and local flux

(3) Errors in the calculated relationship between detector flux and peak rod power some distance from the measurement thimble

Allowance for (1) has been quantified by repetitive measurements made with several intercalibrated detectors using the common thimble features of the incore detector system. This system allows more than one detector to access any thimble. Item (2) above is quantified to the extent possible by using the fluxes measured at one thimble location to predict fluxes at another location, which is also measured. Local power distribution predictions are verified in critical experiments on arrays of rods with simulated guide thimbles, control rods, burnable poisons, etc.

Reference 1 concludes that the uncertainty associated with the peak nuclear heat flux factor, F_Q^T, is 4.58 percent at the 95 percent confidence level with only 5 percent of the measurements greater than the inferred value.

In comparing measured power distributions (or detector currents) against the calculations for the same situations, it is not possible to subtract out the detector reproducibility. Thus, a comparison between measured and predicted power distributions must consider measurement error. Such a comparison is illustrated in Figure 4.3-25 for one of the maps of Reference 1, which is similar to hundreds of maps taken since then on various reactors, confirming the adequacy of the 5 percent uncertainty allowance on F_Q^T.

A similar analysis for the uncertainty in $F_{\Delta H}^N$ (rod integral power) measurements results in an allowance of 3.68 percent at the equivalent of a 2σ confidence level. For historical reasons, an 8 percent uncertainty factor is allowed in the nuclear design basis; that is, the predicted rod integrals at full power must not exceed the design $F_{\Delta H}^N$ less 8 percent. This 8 percent may be reduced in final design to 4 percent to allow a wider range of acceptable axial power distributions in the DNB analysis and still meet the acceptance criteria of Section 4.3.2.2.

A measurement in the second cycle of a 121-assembly, 12-foot core, was compared with a simplified one-dimensional core average axial calculation in Figure 4.3-26. This calculation does not give explicit representation to the fuel grids.

The accumulated data on power distributions in actual operation is basically of three types:

(1) Much of the data is obtained in steady state operation at constant power in the normal operating configuration.

(2) Data with unusual values of AO are obtained as part of the excore detector calibration exercise which is performed monthly.

(3) Special tests have been performed in load follow and other transient xenon conditions which have yielded useful information on power distributions.

These data are presented in detail in Reference 3. Figure 4.3-27 contains a summary of measured values of F_Q^T as a function of AO for five plants from that report.

4.3.3.2.8 Testing

An extensive series of physics tests is performed on first cores. These tests and the criteria for satisfactory results are described in detail in Chapter 14. Since not all limiting situations can be created at BOL, the main purpose of the tests is to provide a check on the calculation methods used in the predictions for the conditions of the test. Physics testing is also performed at the beginning of each reload cycle to ensure that the operating characteristics of the core are consistent with design predictions.

4.3.3.2.9 Monitoring Instrumentation

The adequacy of instrument numbers, spatial deployment, and required correlations between readings and peaking factors, calibration, and errors is described in References 1, 2, and 3. The relevant conclusions are summarized in Sections 4.3.3.2.7 and 4.4.7.

References 32 and 33 describe the instrumentation requirements and calibration of the PDMS, and the uncertainties applied to the calculated peaking factors.

If the limitations given in Section 4.3.3.2.6 on rod insertion and flux difference are observed, the excore detector system provides adequate monitoring of power distributions.

Further details of specific limits on the observed rod positions and flux difference are given in the Core Operating Limits Reports, together with a discussion of their bases.

Limits for alarms, reactor trip, etc., are given in the Technical Specifications. System descriptions are provided in Section 7.7.

4.3.3.3 Reactivity Coefficients

Reactor core kinetic characteristics determine the response of the core to changing plant conditions, or to operator adjustments made during normal operation, as well as the core response during abnormal or accidental transients. These kinetic characteristics are quantified in reactivity coefficients. The reactivity coefficients reflect changes in the neutron multiplication due to varying plant conditions such as power, moderator or fuel temperatures, or, less significantly, due to a change in pressure or void conditions. Since reactivity coefficients change during the life of the core, ranges of coefficients are employed in transient analysis to determine the response of the plant throughout life. The analytical methods and calculational models used in calculating the reactivity coefficients are given in Section 4.3.3.10.

4.3.3.3.1 Fuel Temperature (Doppler) Coefficient

The fuel temperature (Doppler) coefficient is defined as the change in reactivity per degree change in effective fuel temperature and is primarily a measure of the Doppler broadening of U-238 and Pu-240 resonance absorption peaks. Doppler broadening of other isotopes such as U-236, Np-237, etc., are also considered, but their contributions to the Doppler effect is small. An increase in fuel temperature increases the effective resonance absorption cross-sections of the fuel and produces a corresponding reduction in reactivity.

The fuel temperature coefficient is calculated by two-group two or three-dimensional calculations. Moderator temperature is held constant and the power level is varied. Spatial variation of fuel temperature is taken into account by calculating the effective fuel temperature as a function of power density, as discussed in Section 4.3.3.10.1.

A typical Doppler temperature coefficient is shown in Figure 4.3-28 as a function of the effective fuel temperature (at BOL and EOL conditions). The effective fuel temperature is lower than the volume averaged fuel temperature since the neutron flux distribution is nonuniform through the pellet and gives preferential weight to the surface temperature. A typical Doppler-only contribution to the power coefficient (defined later) is shown in Figure 4.3-29 as a function of percent core power. The integral of the differential curve in Figure 4.3-29 is the Doppler contribution to the power defect and is shown in Figure 4.3-30 as a function of percent power. The Doppler coefficient changes as a function of core life, representing the combined effects of the fuel temperature reduction with burnup and the buildup of Pu-240 (refer to Section 4.3.3.10.1). The upper and lower limits of Doppler coefficient used in accident analyses are given in Chapter 15.

4.3.3.3.2 Moderator Coefficients

The moderator coefficient is a measure of the change in reactivity due to a change in specific coolant parameters such as density, temperature, pressure, or void.

4.3.3.3.2.1 Moderator Density and Temperature Coefficients

The MTC (density) is defined as the change in reactivity per degree change in the moderator temperature. Generally, the effect of the changes in moderator density, as well as the temperature, are considered together. A decrease in moderator density means less moderation which results in a negative MTC. An increase in coolant temperature, keeping the density constant, leads to a hardened neutron spectrum resulting in greater resonance absorption in U-238, Pu-240, and other isotopes. The hardened spectrum also causes a decrease in the fission to capture ratio in U-235 and Pu-239. Both of these effects make the MTC more negative. Since water density decreases as temperature increases, the MTC (density) becomes more negative with increasing temperature.

The soluble boron also affects the MTC (density) since its density, like that of water, also decreases when the coolant temperature rises. Therefore, an increase in the soluble poison concentration will result in an increase to the moderator coefficient. Indeed, if the concentration of soluble poison is large enough, the net value of the coefficient may be positive. With the burnable poison rods present, however, the initial hot boron concentration is sufficiently low, making the MTC negative at full power operating temperatures. The effect of control rods is to make the moderator coefficient more negative by reducing the required soluble boron concentration and by increasing "leakage" from the core.

With burnup, the MTC normally becomes more negative primarily as a result of boric acid dilution, but also, to a significant extent, from the effects of plutonium and fission products buildup.

The MTC is calculated for various plant conditions by performing two-group two or three dimensional calculations, varying the moderator temperature (and density) by about ±5°F about each of the mean temperatures. The MTC is shown in Figures 4.3-31 through 4.3-33 as a function of core temperature and boron concentration for a typical reload unrodded and rodded core. The temperature range covered is from cold (68°F) to about 600°F. The contribution due to Doppler coefficient (because of change in moderator temperature) has been subtracted from these results. Figure 4.3-34 shows the hot, full power MTC as a function of cycle lifetime for the critical boron concentration condition based on the design boron letdown condition (refer to Figure 4.3-3) for a typical reload cycle.

4.3.3.3.2.2 Moderator Pressure Coefficient

The moderator pressure coefficient relates the change in moderator density, resulting from a reactor coolant pressure change, to the corresponding effect on neutron production. This coefficient is of much less significance than the MTC. A change of 50 psi in pressure has approximately the same effect on reactivity as a half-degree change in moderator temperature. This coefficient can be determined from the MTC by relating change in pressure to the corresponding change in density. The moderator pressure coefficient is negative over a portion of the moderator temperature range at BOL (-0.004 pcm/psi, BOL) but is always positive at operating conditions and becomes more positive during life (+0.3 pcm/psi, EOL).

4.3.3.3.2.3 Moderator Void Coefficient

The moderator void coefficient relates the change in neutron multiplication to the presence of voids in the moderator. In a PWR, this coefficient is not very significant because of the low void content in the coolant. The core void content is less than one-half of 1 percent and is due to local or statistical boiling. The void coefficient varies from 50 pcm/% void at BOL and low temperatures to -250 pcm/% void at EOL and at operating temperatures. The negative void coefficient at operating temperature becomes more negative with fuel burnup.

4.3.3.3.3 Power Coefficient

The combined effect of moderator temperature and fuel temperature change as the core power level changes is called the total power coefficient, and is expressed in terms of reactivity change per percent power change. A typical power coefficient at BOL, MOL, and EOL conditions is given in Figure 4.3-35. It becomes more negative with burnup, reflecting the combined effect on moderator and fuel temperature coefficients of burnup. A typical power defect (integral reactivity effect) at BOL, MOL, and EOL is given in Figure 4.3-36.

4.3.3.3.4 Comparison of Calculated and Experimental Reactivity Coefficients

The accuracy of the current analytical model is discussed in Section 4.3.3.10.3.

Experimental verification of the calculated coefficients was performed during the physics startup tests described in Chapter 14.

4.3.3.3.5 Reactivity Coefficients Used in Transient Analysis

Table 4.3-1 gives representative ranges for the reactivity coefficients used in the transient analysis. The exact values of the coefficient used in the analysis depend on whether the transient of interest is examined at the BOL or EOL, whether the most negative or the most positive (least negative) coefficients are appropriate, and whether spatial nonuniformity must be considered in the analysis. Conservative values of coefficients are always used in the transient analysis, as described in Chapter 15.

The values listed in Table 4.3-1, and illustrated in Figures 4.3-29 through 4.3-36, apply to the core shown in Figure 4.3-1. Appropriate coefficients for use in other cycles depend on the core's operating history, the number and enrichment of fresh fuel assemblies, the loading pattern of burned and fresh fuel, and the number and location of any burnable poison rods. The need for a reevaluation of any accident in a subsequent cycle is contingent on whether or not the coefficients for that cycle fall within the range used in the analysis presented in Chapter 15. For information only, control rod requirements are given in Tables 4.3-2 and 4.3-3 for a hypothetical equilibrium cycle.

4.3.3.4 Control Requirements

To ensure SDM availability under cooldown to ambient temperature conditions, concentrated soluble boron is added to the coolant. Boron concentrations for several core conditions are listed in Table 4.3-1. They are all well below the solubility limit. The RCCAs are employed to bring the reactor to the hot shutdown condition. The minimum SDM required is given in the Core Operating Limits Reports.

The ability to shut down from hot conditions is demonstrated in Tables 4.3-2 and 4.3-3 by comparing the difference between the reactivity available in the RCCA, allowing for the rod with the highest worth being stuck, with that required for control and protection. The SDM allows 10 percent for analytic uncertainties (refer to Section 4.3.3.4.9). The largest reactivity control requirement appears at EOL when the MTC reaches its peak negative value as reflected in the larger power defect.

Control rods are required to provide sufficient reactivity to compensate for the power defect from full power to zero power and the required SDM. The reactivity addition resulting from power reduction consists of contributions from Doppler, variable average moderator temperature, flux redistribution, and reduction in void content.

4.3.3.4.1 Doppler

Control requirements to compensate for the Doppler effect are listed in Tables 4.3-2 and 4.3-3, for DCPP Unit 1 and Unit 2, respectively.

4.3.3.4.2 Variable Average Moderator Temperature

When the core is shut down to the hot zero power condition, the average moderator temperature changes from the equilibrium full load value, determined by the steam generator and turbine characteristics (such as steam pressure, heat transfer, and tube fouling), to the equilibrium no-load value, which is based on the steam generator shell side design pressure. The design change in temperature is conservatively increased by 4°F to account for control dead band measurement errors.

Since the moderator coefficient is negative, there is a reactivity addition with power reduction. The MTC becomes more negative as the fuel depletes because the boron concentration decreases. This effect is the major contribution to the increased requirement at EOL.

4.3.3.4.3 Redistribution

During full power operation, the coolant density decreases with core height and this, together with partial insertion of control rods, results in less fuel depletion near the top of the core. Under steady state conditions, the relative power distribution will be slightly asymmetric towards the bottom of the core. On the other hand, at hot zero power conditions, the coolant density is uniform and there is no flattening due to Doppler. The result is a flux distribution that at zero power can be skewed toward the top of the core. The reactivity insertion due to the skewed distribution is calculated with an allowance for the most adverse effects of xenon distribution.

4.3.3.4.4 Void Content

A small void content in the core is due to nucleate boiling at full power. The void collapse that results from a power reduction makes a small reactivity contribution.

4.3.3.4.5 Rod Insertion Allowance

At full power, the control bank is operated within a prescribed travel band to compensate for small periodic changes in boron concentration, temperature, and very small changes in the xenon concentration not compensated for by a change in boron concentration. When the control bank reaches either limit of this band, a change in boron concentration is required to compensate for additional reactivity changes. Since the insertion limit is set by a rod travel limit, a conservatively high calculation of the inserted worth is made which exceeds the normally inserted reactivity.

4.3.3.4.6 Burnup

Excess reactivity of 10 percent $\Delta\rho$ to 25 percent $\Delta\rho$ (hot) is installed at the beginning of each cycle to provide sufficient reactivity to compensate for fuel depletion and fission products buildup throughout the cycle. This reactivity is controlled by the addition of soluble boron to the coolant and by burnable absorber. Representative soluble boron concentrations for several core configurations and the boron coefficient in the primary coolant are given in Table 4.3-1. Since the excess reactivity for burnup is controlled by soluble boron and/or burnable absorbers, it is not included in control rod requirements.

4.3.3.4.7 Xenon and Samarium Poisoning

Changes in xenon and samarium concentrations in the core occur at a sufficiently slow rate, even following rapid power level changes, so that the resulting reactivity change is controlled by changing the soluble boron concentration.

4.3.3.4.8 pH Effects

Changes in reactivity due to a change in coolant pH, if any, are sufficiently small in magnitude and occur slowly enough to be controlled by the boron system. Further details are available in Reference 4.

4.3.3.4.9 Experimental Confirmation

The most appropriate assessment of the experimental confirmation of the analytical methods calls for comparison of key physics parameter predictions against directly measured plant data. A total of seven reactor cores covering a diversified range of advanced fuel product features, modern fuel management schemes, and different reactor loop types formulate the basis for the qualification assessment. Three-dimensional Advanced Nodal Code (ANC) models employing PHOENIX-P based cross-sections were developed to predict all relevant physics parameters. To encompass the

entire range of available measured quantities, hot zero power physics predictions are compared against measured data in addition to full power core analyses. Refer to Reference 27 for additional details of the experimental confirmation.

These and other measurements demonstrate the ability of the methods described in Section 4.3.3.10 to accurately predict the total shutdown reactivity of the core.

4.3.3.5 Control

Core reactivity is controlled by means of a chemical neutron absorber (chemical shim) dissolved in the coolant, RCCAs, and burnable poison rods as described below.

4.3.3.5.1 Chemical Shim

Boron in solution as boric acid is used to control relatively slow reactivity changes associated with:

(1) The moderator temperature defect in going from cold shutdown at ambient temperature to the hot operating temperature at zero power

(2) Transient xenon and samarium poisoning, such as that following power changes or changes in RCCA position

(3) The excess reactivity required to compensate for the effects of fissile inventory depletion and buildup of long-life fission products

(4) The burnable absorber depletion

The boron concentrations for various core conditions are presented in Table 4.3-1.

4.3.3.5.2 Rod Cluster Control Assemblies

As shown in Table 4.1-1, 53 RCCAs are used in these reactors. The RCCAs are used for shutdown and control purposes to offset fast reactivity changes associated with:

(1) The required SDM in the hot zero power, stuck rods condition

(2) The increase in power above hot zero power (power defect including Doppler and moderator reactivity changes)

(3) Unprogrammed fluctuations in boron concentration, coolant temperature, or xenon concentration (with rods not exceeding the allowable rod insertion limits)

(4) Reactivity ramp rates resulting from load changes

Control bank reactivity insertion at full power is limited to maintain shutdown capability. As the power level is reduced, control rod reactivity requirements are reduced and more rod insertion is allowed. The control bank position is monitored and the operator is notified by an alarm if the limit is approached. The determination of the insertion limit uses conservative xenon distributions and axial power shapes. In addition, the RCCA withdrawal pattern obtained from these analyses is used in determining power distribution factors, and in determining the maximum reactivity worth during an ejection accident of an inserted RCCA. The Technical Specifications discuss rod insertion limits.

Power distribution, rod ejection, and rod misalignment analyses are based on the arrangement of the shutdown and control RCCA groups shown in Figures 4.3-37 and 4.3-38, for Unit 1 and Unit 2, respectively. All shutdown RCCAs are withdrawn before control banks withdrawal is initiated. In going from zero to 100 percent power, control banks A, B, C, and D are withdrawn sequentially. Rod position limits and the basis for rod insertion limits are provided in the Core Operating Limits Reports.

4.3.3.5.3 Burnable Absorber Rods

Burnable absorber rods (either discrete or integral type) provide partial control of excess reactivity during the fuel cycle. These rods prevent the MTC from being positive at normal operating conditions. They perform this function by reducing the requirement for soluble boron in the moderator at the beginning of the fuel cycle, as described above. The burnable absorber patterns, used together with a typical number of rods per assembly, are shown in Figure 4.3-6. The arrangements within an assembly for discrete and integral absorber types are displayed in Figures 4.3-4 and 4.3-5 respectively. The critical concentration of soluble boron resulting from the slow burnup of boron in the rods is such that the MTC remains negative at all times for full power operating conditions.

4.3.3.5.4 Peak Xenon Startup

Peak xenon buildup is compensated by the boron control system. Startup from the peak xenon condition is accomplished with a combination of rod motion and boron dilution. Boron dilution may be made at any time, including the shutdown period, provided the SDM is maintained.

4.3.3.5.5 Load Follow Control and Xenon Control

The DCPP units are usually base loaded; however, it is expected that during certain times of certain years some load following may be required.

Should load following become a desired mode of operation, then, during load follow maneuvers, power changes would be accomplished using control rod motion, dilution or boration by the boron systems as required, and reductions in coolant average temperature. Control rod motion limitations are discussed in Section 4.3.3.5.2 and the

Technical Specifications. Reactivity changes due to the changing xenon concentration can be controlled by rod motion and/or soluble boron concentration changes.

4.3.3.5.6 Burnup

The excess reactivity available for burnup is controlled with soluble boron and/or burnable absorbers. The boron concentration must be limited during operating conditions to ensure the MTC is negative at full power. Sufficient burnable absorbers are installed at the beginning of a cycle to give the desired cycle lifetime without exceeding the boron concentration limit. The practical minimum boron concentration is 10 ppm.

4.3.3.6 Control Rod Patterns and Reactivity Worths

The RCCAs are designated by function as the control groups and the shutdown groups. The terms "group" and "bank" are used synonymously throughout this chapter to describe a particular grouping of control assemblies. The RCCA patterns are displayed in Figures 4.3-37 and 4.3-38 for Unit 1 and Unit 2, respectively. These patterns are not expected to change during the life of the units. The control banks are labeled A, B, C, and D, and the shutdown banks are labeled SA, SB, SC and SD.

The two criteria used to select the control groups are: (a) the total reactivity worth must be adequate to meet the requirements specified in Tables 4.3-2 and 4.3-3, and (b) because these rods may be partially inserted at power operation, the total power peaking factor should be low enough to ensure that power capability requirements are met. Analyses indicate that the first requirement can be met by one or more banks whose total worth equals at least the required amount. Since the shape of the axial power distribution would be more peaked following movement of a single group of rods worth 3 to 4 percent $\Delta\rho$, four banks, each worth approximately 1 percent $\Delta\rho$, were selected.

The position of control banks for criticality under any reactor condition is determined by the boron concentration in the coolant. On an approach to criticality, boron is adjusted to ensure criticality will be achieved with control rods above the insertion limit set by shutdown and other considerations (refer to the Technical Specifications). Early in the cycle there may also be a withdrawal limit at low power to maintain an MTC more negative than the Technical Specification limit. Usual practice is to adjust boron to ensure that the rod position lies within the so-called maneuvering band so that an escalation from zero power to full power does not require further adjustment of boron concentration.

Ejected rod worths are given in Section 15.4.6 for several different conditions. Experimental confirmation of ejected rod worths can be found by reference to startup test reports such as Reference 5.

Allowable deviations due to misaligned control rods are discussed in the Technical Specifications.

A representative calculation for two banks of control rods withdrawn simultaneously (rod withdrawal accident) at EOL is shown in Figure 4.3-39. Calculation of control rod reactivity worth versus time following reactor trip involves both control rod velocity and differential reactivity worth. Rod position versus time of travel after rod release is shown in Figure 4.3-40. The reactivity worth versus rod position is calculated by a series of steady state calculations at various control rod positions assuming all rods out of the core as the initial position to minimize the initial reactivity insertion rate. To be conservative, the rod of highest worth is assumed stuck out of the core and the flux distribution (and thus reactivity importance) is assumed to be skewed to the bottom of the core. The result of these calculations is shown in Figure 4.3-41.

The shutdown groups provide additional negative reactivity to ensure an adequate SDM. SDM is defined as the instantaneous amount of reactivity by which the reactor is subcritical, or would be subcritical from its present condition, assuming:

(1) all RCCAs are fully inserted except for the single RCCA of highest reactivity worth, which is assumed to be fully withdrawn (with any RCCA not capable of being fully inserted, the reactivity worth of the RCCA must be accounted for in the determination of SDM) and

(2) when in MODE 1 or 2, the fuel and moderator temperatures are changed to the hot zero power temperatures.

The loss of control rod worth due to material irradiation is negligible, since only bank D rods may be in the core under full power operating conditions.

Tables 4.3-2 and 4.3-3 show that the available reactivity in withdrawn RCCAs provides the design bases minimum SDM allowing for the highest worth cluster to be at its fully withdrawn position in DCPP Unit 1 and Unit 2, respectively. An allowance for uncertainty in the calculated worth of N-1 rods is made before determination of the SDM.

4.3.3.7 Criticality of Fuel Assemblies

Criticality of fuel assemblies outside the reactor is precluded by adequate design of fuel transfer and fuel storage facilities, and by administrative control procedures (refer to Section 9.1.1).

Verification that appropriate shutdown criteria, including uncertainties, are met during refueling is achieved using standard Westinghouse reactor design methods. Core subcriticality during refueling is continuously monitored as described in the Technical Specifications.

4.3.3.8 Stability

4.3.3.8.1 Introduction

The stability of PWR cores against xenon-induced spatial oscillations, and the control of such transients, is discussed extensively in References 2, 6, 7, and 8.

Due to the negative power coefficient of reactivity, PWR cores are inherently stable to oscillations in total power. In a large reactor core, however, xenon-induced oscillations can take place with no corresponding change in total core power. The oscillation may be caused by a power shift in the core that occurs rapidly in comparison with the xenon-iodine time constants. Such a power shift occurs in the axial direction when a plant load change is made by control rod motion, and results in a change in the moderator density and fuel temperature distributions. Such a power shift in the diametral plane of the core could result from abnormal control action.

4.3.3.8.2 Stability Index

Power distributions, either in the axial direction or in the X-Y plane, can undergo oscillations due to perturbations introduced in the equilibrium distributions without changing total core power. The xenon-induced oscillations are essentially limited to the first flux overtones in the current PWRs, and the stability of the core against xenon-induced oscillations can be determined in terms of the eigenvalues of the first flux harmonics. Writing the eigenvalue of the first flux harmonic, either in the axial direction or in the X-Y plane, as:

$$\xi = b + ic, \left(i^2 = -1\right); \tag{4.3-6}$$

where b is defined as the stability index and T = $2\pi/c$ as the oscillation period of the first harmonic. The time-dependence of the first harmonic in the power distribution can now be represented as:

$$\delta\phi(t) = A\,e^{\xi t} = ae^{bt}\cos ct \tag{4.3-7}$$

where A and a are constants. The stability index can also be obtained approximately by:

$$b = \frac{1}{T}\ln\left[\frac{A_{n+1}}{A_n}\right] \tag{4.3-8}$$

where A_n, A_{n+1} are the successive peak amplitudes of the oscillation, and T is the time period between the successive peaks.

4.3.3.8.3 Prediction of the Core Stability

The stability of the DCPP cores in relation to xenon-induced spatial oscillations is expected to be equal to that of earlier designs because: (a) the overall core size is unchanged and spatial power distributions are similar, (b) the MTC is expected to be similar, and (c) the Doppler coefficient of reactivity is expected to be similar at full power.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

4.3.3.8.4 Stability Measurements

(1) Axial Measurements

Two axial xenon transient tests conducted in a PWR with a core height of 12 feet and 121 fuel assemblies, at approximately 10 and 50 percent of cycle life, are reported in Reference 9.

The AO of power was obtained as a function of time for both tests as shown in Figure 4.3-42. The total core power was maintained constant during these spatial xenon tests, and the stability index and the oscillation period were obtained from a least-square fit of the AO data to Equation 4.3-8. The conclusions of the tests are as follows:

(a) The core was stable against induced axial xenon transients both at the core average burnups of 1550 MWD/MTU and 7700 MWD/MTU.

(b) The reactor core becomes less stable as fuel burnup progresses, and the axial stability index was essentially zero at 12,000 MWD/MTU.

(2) Measurements in the X-Y Plane

Two X-Y xenon oscillation tests were performed at a PWR plant with a core height of 12 feet and 157 fuel assemblies. This plant had the highest power output of any Westinghouse PWR operating in 1972. The first test was conducted at a core average burnup of 1540 MWD/MTU and the second at a core average burnup of 12900 MWD/MTU. Both of the X-Y xenon tests show that the core was stable in the X-Y plane at both burnups. The second test shows that the core became more stable as the fuel burnup increased and all Westinghouse PWRs with 121 and 157 assemblies are expected to be stable throughout their burnup cycles.

In each of the two X-Y tests, a perturbation was introduced to the equilibrium power distribution through an impulse motion of one RCCA located along the diagonal axis. Following the perturbation, the

uncontrolled oscillation was monitored using the movable detector and thermocouple system and the excore power range detectors. The quadrant tilt difference (QTD) is the quantity that properly represents the diametral oscillation in the X-Y plane of the reactor core in that the difference of the quadrant average powers over two symmetrically opposite quadrants essentially eliminates the contribution to the oscillation from the azimuthal mode. The QTD data were least-square fitted to the form of Equation 4.3-8. A stability index of -0.076 hr-1 with a period of 29.6 hours was obtained from the thermocouple data shown in Figure 4.3-43.

In the second X-Y xenon test, the PWR core with 157 fuel assemblies became more stable due to increased fuel depletion.

4.3.3.8.5 Comparison of Calculations with Measurements

Axial xenon transient tests were analyzed in an axial slab geometry using a flux synthesis technique. The PANDA code (Reference 11) was used for direct simulation of the AO data. X-Y xenon transient tests analyses were performed with the modified TURTLE code (Reference 12). Both the PANDA and TURTLE codes solve the two-group time-dependent neutron diffusion equation with time-dependent xenon and iodine concentrations. The fuel temperature and moderator density feedback is limited to a steady state model. All the X-Y calculations were performed in an average enthalpy plane.

The basic nuclear cross-sections used in this study were generated from a unit cell depletion program that evolved from the codes LEOPARD (Reference 13) and CINDER (Reference 14). The detailed experimental data during the tests, including the reactor power level, enthalpy rise, and the impulse motion of the control rod assembly, as well as the plant follow burnup data, were closely simulated in the study.

The results of the stability calculation for the axial tests are compared with the experimental data in Table 4.3-4. The calculations show conservative results for both of the axial tests with a margin of approximately 0.01 hr^{-1} in the stability index.

An analytical simulation of the first X-Y xenon oscillation test shows a calculated stability index of -0.081 hr^{-1}, in good agreement with the measured value of -0.076 hr^{-1}. As indicated earlier, the second X-Y xenon test showed that the core had become more stable compared to the first test. The increase in the core stability in the X-Y plane due to increased fuel burnup is due mainly to the increased magnitude of the negative MTC.

Previous studies of the physics of xenon oscillations, including three-dimensional analysis, are reported in References 6, 7, 8, 9, and Section 1 of Reference 10.

4.3.3.8.6 Stability Control and Protection

The excore detector system provides indications of xenon-induced spatial oscillations. The readings from the excore detectors are available to the operator and also form part of the protection system.

(1) Axial Power Distribution

To maintain proper axial power distributions, the operator is instructed to maintain an AO within a prescribed operating band, based on the excore detector readings. Should the AO move far enough outside this band, the protection limit will be reached and the power will be automatically cut back.

(2) Radial Power Distribution

The DCPP cores are calculated to be stable with respect to xenon-induced oscillations in the X-Y plane during the plant's lifetime.

The X-Y stability of large PWRs has been further verified as part of the startup physics test program at a PWR core with 193 fuel assemblies. The measured X-Y stability of the PWR core with 157 assemblies, and the good agreement between the calculated and measured stability index for this core, as discussed in Sections 4.3.3.8.4 and 4.3.3.8.5, make it very unlikely that a sustained X-Y oscillation can occur in a core with 193 assemblies. In the unlikely event that X-Y oscillations occur, backup actions are possible and would be implemented, if necessary, to increase the natural stability of the core until tests demonstrate a suitable stability, by making the MTC more negative.

A more detailed discussion of the power distribution control in PWR cores is presented in Reference 2.

4.3.3.9 Vessel Irradiation

Pressure vessel irradiation and the corresponding material surveillance program are discussed in Sections 5.2.2.4 and 5.4.1. A brief review of the methodology used to determine neutron and gamma flux attenuation between the core and pressure vessel follows.

The primary shielding material used to attenuate high energy neutron and gamma flux originating in the core consists primarily of the core baffle, core barrel, the thermal shield for Unit 1 and the neutron pads for Unit 2, and associated water annuli, all of which are within the region between the core and the pressure vessel.

In general, few group neutron diffusion theory and nodal analysis codes are used to determine flux and fission power density distributions within the active core, and the accuracy of these analyses is verified by incore measurements on operating reactors. Refer to Section 5.2.2.4 for methods used outside the active core.

The neutron flux distribution and spectrum in the various structural components varies significantly from the core to the pressure vessel. Representative values of the neutron flux distribution and spectrum are presented in Table 4.3-5. The values listed are based on equilibrium cycle reactor core parameters and power distributions and are thus suitable for long-term neutron fluence projections and for correlation with radiation damage estimates.

4.3.3.10 Analytical Methods

Calculations required in nuclear design consist of the following three distinct types, which are performed in sequence:

(1) Determination of effective fuel temperatures

(2) Generation of macroscopic few-group parameters

(3) Space-dependent, few-group diffusion calculations

4.3.3.10.1 Fuel Temperature (Doppler) Calculations

Temperatures vary radially within the fuel rod, depending on heat generation rate in the pellet, the conductivity of the materials in the pellet, gap and cladding, and coolant temperature.

The FIGHTH code (Reference 34) performs a simplified calculation of effective temperatures in low enrichment, sintered UO_2 fuel rods for use in nuclear design. The model includes radial variations of heat generation rate, thermal conductivity, and thermal expansion in the fuel pellet, elastic deflection of the cladding, and a pellet-clad gap conductance which depends on the kind of initial fill gas, the hot open gap dimension, and the fraction of the pellet circumference over which the gap is effectively closed due to pellet cracking. The steady-state radial temperature distribution in the fuel rod is calculated at a specified burnup, given the local value of the linear heat generation rate in the pellet and the moderator temperature and flow rate. The effective resonance temperatures of U-238 and Pu-240 are obtained by appropriate radial weighting of the temperature distribution. An effective flat pellet temperature for expansion which reproduces the hot pellet outer radius is also determined.

The observed burnup dependence of the Doppler defects and Doppler coefficients in operating plants was used to construct an empirical model of progressive pellet cracking which, primarily through the increased gap conductance due to gap closure, produces effective temperatures which lead to adequate predictions of the measurements. The

effects of fission gas release, clad creep, and pellet swelling are not treated explicitly in this simplified model, described in Section 4.2.1.2.2.5.

Fuel temperatures for use in some past nuclear design Doppler calculations were obtained from a simplified version of the Westinghouse fuel rod design model described in Section 4.2.1.2.2, which considers the effect of radial variation of pellet conductivity, expansion-coefficient and heat generation rate, elastic deflection of the cladding, and a gap conductance which depends on the initial fill gas, the hot open gap dimension, and the fraction of the pellet over which the gap is closed. The fraction of the gap assumed closed represents an empirical adjustment to produce good agreement with observed reactivity data at BOL. Further gap closure occurs with burnup and accounts for the decrease in Doppler defect with burnup which has been observed in operating plants. For detailed calculations of the Doppler coefficient, such as for use in xenon stability calculations, a more sophisticated temperature model is used which accounts for the effects of fuel swelling, fission gas release, and plastic cladding deformation.

Radial power distributions in the pellet as a function of burnup were obtained from LASER (Reference 15) calculations.

The effective U-238 temperature for resonance absorption was obtained from the radial temperature distribution by applying a radially dependent weighting function. The weighting function was determined from REPAD (Reference 16) Monte Carlo calculations of resonance escape probabilities in several steady state and transient temperature distributions. In each case, a flat pellet temperature was determined which produced the same resonance escape probability as the actual distribution. The weighting function was empirically determined from these results.

The effective Pu-240 temperature for resonance absorption was determined by a convolution of the radial distribution of Pu-240 number densities from LASER burnup calculations and the radial weighting function. The resulting temperature is burnup dependent, but the difference between U-238 and Pu-240 temperatures, in terms of reactivity effects, is small.

The effective pellet temperature for pellet dimensional change is that value which produces the same outer pellet radius in a virgin pellet as that obtained from the temperature model. The effective cladding temperature for dimensional change is its average value.

The temperature calculational model has been validated by plant Doppler defect data as shown in Table 4.3-6 and Doppler coefficient data as shown in Figure 4.3-44. Stability index measurements also provide a sensitive measure of the Doppler coefficient near full power (refer to Section 4.3.3.8). It can be seen that Doppler defect data are typically within 0.2 percent $\Delta\rho$ of prediction.

4.3.3.10.2 Macroscopic Group Constants

There are two lattice codes used for the generation of macroscopic group constants for use in the spatial few group diffusion codes. They are a version of the LEOPARD and CINDER codes and PHOENIX-P. A detailed description of each follows. Macroscopic few-group constants and analogous microscopic cross-sections (needed for feedback and microscopic depletion calculations) can be generated for fuel cells by a Westinghouse version of the LEOPARD and CINDER codes, which are linked internally and provide burnup-dependent cross-sections. Normally, a simplified approximation of the main fuel chains is used; however, where needed, a complete solution for all the significant isotopes in the fuel chains from Th-232 to Cm-244 is available (Reference 17). Cross-section library tapes contain microscopic cross-sections from the ENDF/B (Reference 18) library, with a few exceptions, where other data provide better agreement with critical experiments, isotopic measurements, and plant critical boron values.

The effect on the unit fuel cell of nonlattice components in the fuel assembly is obtained by supplying an appropriate volume fraction of these materials in an extra region which is homogenized with the unit cell in the fast (MUFT) and thermal (SOFOCATE) flux calculations. In the thermal calculation, the fuel rod, cladding, and moderator are homogenized by energy-dependent disadvantage factors derived from an analytical fit to integral transport theory results.

Group constants for burnable absorber cells, guide thimbles, instrument thimbles, and interassembly gaps are generated in a manner analogous to the fuel cell calculation. Reflector group constants are taken from infinite medium LEOPARD calculations. Baffle group constants are calculated from an average of core and radial reflector microscopic group constants for stainless steel.

Group constants for control rods are calculated in a linked version of the HAMMER (Reference 19) and AIM (Reference 20) codes to provide an improved treatment of self-shielding in the broad resonance structure of the appropriate isotopes at epithermal energies than is available using LEOPARD. The Doppler broadened cross-sections of the control rod material are represented as smooth cross-sections in the 54-group LEOPARD fast group structure and in 30 thermal groups. The four-group constants in the rod cell and appropriate extra region are generated in the coupled space-energy transport HAMMER calculation. A corresponding AIM calculation of the homogenized rod cell with extra region is used to adjust the absorption cross-sections of the rod cell to match the reaction rates in HAMMER. These transport-equivalent group constants are reduced to two-group constants for use in space-dependent diffusion calculations. In discrete X-Y calculations only one mesh interval per cell is used, and the rod group constants are further adjusted for use in this standard mesh by reaction rate matching the standard mesh unit assembly to a fine-mesh unit assembly calculation.

Validation of the cross-section method is based on analysis of critical experiments (refer to Table 4.3-7), isotopic data (refer to Table 4.3-8), plant critical boron (C_B) values at hot

zero power (HZP), BOL (refer to Table 4.3-9), and at HFP as a function of burnup (refer to Figures 4.3-45 through 4.3-47). Control rod worth measurements are shown in Table 4.3-10. Confirmatory critical experiments on burnable absorbers are described in Reference 21.

The PHOENIX-P computer code is a two-dimensional, multi-group, transport based lattice code capable of providing all necessary data for PWR analysis. Being a dimensional lattice code, PHOENIX-P does not rely on pre-determined spatial/spectral interaction assumptions for a heterogeneous fuel lattice, hence, will provide a more accurate multi-group flux solution than versions of LEOPARD/CINDER. The PHOENIX-P computer code is approved by the USNRC as the lattice code for generating macroscopic and microscopic few group cross-sections for PWR analysis (Reference 27).

The solution for the detailed spatial flux and energy distribution is divided into two major steps in PHOENIX-P (Reference 27). In the first step, a two-dimensional fine energy group nodal solution is obtained which couples individual subcell regions (pellet, cladding and moderator) as well as surrounding pins. PHOENIX-P uses a method based on the Carlvik's collision probability approach and heterogeneous response fluxes which preserves the heterogeneity of the pin cells and their surroundings. The nodal solution provides accurate and detailed local flux distribution, which is then used to spatially homogenize the pin cells to fewer groups.

The second step in the solution process solves for the angular flux distribution using a standard S4 discrete ordinates calculation. This step is based on the group-collapsed and homogenized cross-sections obtained from the first step of the solution. The S4 fluxes are then used to normalize the detailed spatial and energy nodal fluxes. The normalized nodal fluxes are used to compute reaction rates, power distribution and to deplete the fuel and burnable absorbers. A standard B1 calculation is employed to evaluate the fundamental mode critical spectrum and to provide an improved fast diffusion coefficient for the core spatial codes.

The PHOENIX-P code employs an energy group library, which has been derived mainly from ENDF/B (Reference 18) files. The PHOENIX-P cross-sections library was designed to properly capture integral properties of the multi-group data during group collapse, and enabling proper modeling of important resonance parameters. The library contains all neutronic data necessary for modeling fuel, fission products, cladding and structural data, coolant, and control/burnable absorber materials present in Light Water Reactor cores.

Group constants for burnable absorber cells, guide thimbles, instrument thimbles, control rod cells and other non-fuel cells can be obtained directly from PHOENIX-P without any adjustments such as those required in the cell or 1D lattice codes.

4.3.3.10.3 Spatial Few-Group Diffusion Calculations

Spatial few-group diffusion calculations have primarily consisted of two group X-Y calculations using an updated version of the TURTLE code, and two-group axial calculations using an updated version of the PANDA code. However, with the advent of VANTAGE+ and hence axial features such as axial blankets and part length burnable absorbers, there is a greater reliance on three-dimensional nodal codes such as 3D PALADON (Reference 25) and APOLLO code (Reference 35) which performs one-dimensional, two group calculations using typical finite difference techniques, and 3D ANC (References 26 and 27) which provides both the radial and axial power distributions.

Nodal three-dimensional calculations are carried out to determine the critical boron concentrations and power distributions. The moderator coefficient is evaluated by varying the inlet temperature in the same calculations used for power distribution and reactivity predictions.

Axial calculations are used to determine differential control rod worth curves (reactivity versus rod insertion) and axial power shapes during steady state and transient xenon conditions. Group constants are obtained from three-dimensional nodal calculations homogenized by flux volume weighting.

Validation of the spatial codes for calculating power distributions involves the use of incore and excore detectors, and is discussed in Section 4.3.3.2.7.

The agreement in the PHOENIX-P methodology and PHOENIX-P/ANC core model qualification demonstrates the high accuracy of the PHOENIX-P/ANC advanced design system for multidimensional nuclear analysis of PWR cores. This qualification data base demonstrates the performance of this system for a wide range of applications performed in the design, safety, licensing and operational follow of PWR cores. Refer to Reference 27 for additional details on experimental verification.

The accuracy of APOLLO predictions for reactivity and axial power shapes is comparable to that for 3D ANC-based calculations (References 26 and 27).

4.3.4 SAFETY EVALUATION

4.3.4.1 General Design Criterion 10, 1971 – Reactor Design

The reactor core and associated coolant, control, and protection systems are designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

4.3.4.1.1 Fuel Burnup

Fuel burnup is a measure of fuel depletion that represents the integrated energy output of the fuel (MWD/MTU) and is a convenient means for quantifying fuel exposure.

The core design lifetime or design discharge burnup is achieved by installing sufficient initial excess reactivity in each fuel region, and by following a fuel replacement program (such as that described in Section 4.3.3) that meets all safety-related criteria in each cycle of operation.

Initial excess reactivity in the fuel, although not a design basis, must be sufficient to maintain core criticality at full power operating conditions throughout cycle life with equilibrium xenon, samarium, and other fission products present. The end of design cycle life is defined to occur when the chemical shim concentration is essentially zero, with control rods present to the degree necessary for operational requirements (e.g., the controlling bank at the "bite" position). In terms of chemical shim boron concentration, this represents approximately 10 ppm with no control rod insertion.

4.3.4.1.2 Control of Power Distribution

Calculation of the extreme power shapes that affect fuel design limits is performed with proven methods as described in Section 4.3.3.10 and verified frequently with results from measurements in operating reactors. The conditions under which limiting power shapes are assumed to occur are chosen conservatively with regard to any permissible operating state.

Even though there is good agreement between peak power calculations and measurements, a nuclear uncertainty margin is applied to calculated peak local power. Such a margin is provided both for the analysis of normal operating states and for anticipated transients.

4.3.4.2 General Design Criterion 11, 1971 – Reactor Inherent Protection

The reactor core and associated coolant systems is designed so that in the power operating range the net effect of the prompt inherent nuclear feedback characteristics tend to compensate for a rapid increase in reactivity.

When compensation for a rapid increase in reactivity is considered, there are two major effects. These are the resonance absorption effects (Doppler) associated with changing fuel temperature, and the spectrum effect resulting from changing moderator density. These basic physics characteristics are often identified by reactivity coefficients. The use of slightly enriched uranium ensures that the Doppler coefficient of reactivity, which provides the most rapid reactivity compensation, is negative. The core is also designed to have an overall negative MTC of reactivity at full power so that average coolant temperature or void content provides another, slower, compensatory effect. A small positive MTC is allowed at low power. The negative MTC at full power can be achieved

through use of fixed burnable absorbers and/or boron coated fuel pellets and/or control rods by limiting the reactivity held down by soluble boron.

Burnable absorber content (quantity and distribution) is not stated as a design basis other than as it relates to achieving a nonpositive MTC at power operating conditions, as discussed above.

4.3.4.3 General Design Criterion 12, 1971 – Suppression of Reactor Power Oscillations

The reactor core and associated coolant, control, and protection systems are designed to assure that power oscillations which can result in conditions exceeding SAFDLs are not possible or can be reliably and readily detected and suppressed.

Oscillations in total core power output, from whatever cause, are readily detected by loop temperature sensors and by nuclear instrumentation. If power increased unacceptably, a reactor trip would occur, thus preserving margins to fuel design limits. The stability of the turbine/steam generator/core systems and the reactor control system ensure that core power oscillations do not normally occur. Protection circuits' redundancy ensures an extremely low probability of exceeding design power levels.

The core is designed so that diametral and azimuthal oscillations due to spatial xenon effects are self-damping, and no operator action or control action is required to suppress them. Stability against diametral oscillations is so great that this excitation is highly improbable. Convergent azimuthal oscillations can be excited by prohibited motion of individual RCCAs. Such oscillations are readily observable and alarmed, using the excore long ion chambers. Indications are also continuously available from incore thermocouples and loop temperature measurements. The MIDS can be activated to provide more detailed information. In all presently proposed cores, these horizontal plane oscillations are self-damping by virtue of reactivity feedback effects designed into the core.

Axial xenon spatial power oscillations can be excited by power level changes or by control rod motion/misalignments. The oscillations are inherently convergent at the beginning of core life, but become divergent as the core ages. The time in core life when oscillations may become divergent depends on core characteristics. Xenon oscillations studies performed for plants similar to DCPP concluded that oscillations can diverge as early as 50 EFPD. The magnitude of oscillations increases with increasing core burnup, although the period is unaffected. The type of oscillation (convergence or divergence) does not depend on the amplitude of the initial oscillation but is a function of initial conditions at the start of the transient.

The excore detectors provide monitoring of axial power distribution. The operator actions (control rod movement or power level changes) are expected to suppress and control axial xenon transients.

The limits on measured axial flux difference assure that the fuel design limits (F_q) are not exceeded during either normal operation or a xenon transient. The measured axial flux difference is also used as an input to the OTΔT trip function so that the DNB design bases are not exceeded.

4.3.4.4 General Design Criterion 25, 1971 – Protection System Requirements for Reactivity Control Malfunctions

The protection system is designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods.

Reactivity addition associated with an accidental withdrawal of a control bank (or banks) is limited by the maximum rod speed (or travel rate) and by the worth of the bank(s). For this reactor the maximum control rod speed is 45 inches per minute and the maximum rate of reactivity change considering two control banks moving is less than 75 pcm/sec. The reactivity rate used in the boron dilution analysis at power is discussed in Section 15.2.4.3.4.

4.3.4.5 General Design Criterion 26, 1971 – Reactivity Control System Redundancy and Capability

Two independent reactivity control systems are provided: control rods and soluble boron in the coolant.

The control rod system can compensate for the reactivity effects of the fuel and water temperature changes accompanying power level changes over the range from full load to no load. In addition, the control rod system provides the minimum SDM under Condition I events and is capable of making the core subcritical rapidly enough to prevent exceeding acceptable fuel damage limits, assuming that the highest worth control rod is stuck out upon trip.

The boron system can compensate for all xenon burnout reactivity changes and will maintain the reactor in cold shutdown. Thus, backup and emergency shutdown provisions are provided by a mechanical and a chemical shim control system.

When fuel assemblies are in the pressure vessel and the vessel head is not in place, k_{eff} will be maintained at or below 0.95 with control rods and soluble boron. Further, the fuel will be maintained sufficiently subcritical that removal of all RCCAs will not result in criticality.

4.3.4.6 General Design Criterion 28, 1971 – Reactivity Limits

The reactivity control system is designed with appropriate limits on the potential amount and rate of reactivity increase to assure that the effects of postulated reactivity accidents can neither (1) result in damage to the reactor coolant pressure boundary

greater than limited local yielding nor (2) sufficiently disturb the core, its support structures or other reactor pressure vessel internals to impair significantly the capability to cool the core. These postulated reactivity accidents shall include consideration of rod ejection (unless prevented by positive means), rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition.

The maximum control rod reactivity worth and the maximum rates of reactivity insertion using control rods are limited to preclude either rupture of the coolant pressure boundary or disruption of the core internals to a degree that would impair core cooling capacity in the event of a rod withdrawal or ejection accident (refer to Chapter 15).

Following any Condition IV event (such as rod ejection and steam line break), the reactor can be brought to the shutdown condition and the core will maintain acceptable heat transfer geometry.

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4.4 THERMAL AND HYDRAULIC DESIGN

This section discusses the thermal and hydraulic design of the DCPP reactors.

The objective of the thermal and hydraulic design of the reactor core is to provide adequate heat transfer that is compatible with the heat generation distribution in the core, so that heat removal by the RCS or the ECCS (when applicable) meets the following performance and safety criteria:

(1) Fuel damage is not expected during normal operation and operational transients (Condition I) or any transient conditions arising from faults of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of rod failures. These will be within the capability of the plant cleanup system and are consistent with the plant design bases.

(2) The reactor can be brought to a safe state following a Condition III event with only a small fraction of fuel rods damaged although sufficient fuel damage might occur to preclude resumption of operation without considerable outage time.

(3) The reactor can be brought to a safe state and the core can be kept subcritical with acceptable heat transfer geometry following transients arising from Condition IV events.

Note that fuel damage as used here is defined as penetration of the fission product barrier (i.e., the fuel rod cladding).

4.4.1 DESIGN BASES

4.4.1.1 General Design Criterion 10, 1971 – Reactor Design

The reactor core is designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation or anticipated operational occurrences.

4.4.1.2 General Design Criterion 12, 1971 – Suppression of Reactor Power Oscillations

The reactor core is designed to assure that power oscillations that could result in conditions exceeding SAFDLs are not possible or can be reliably and readily detected and suppressed.

4.4.2 THERMAL AND HYDRAULIC DESIGN ACCEPTANCE CRITERIA

4.4.2.1 Departure from Nucleate Boiling Acceptance Criteria

There will be at least a 95 percent probability that DNB will not occur on the limiting fuel rods during normal operation and operational transients and any transient conditions arising from faults of moderate frequency (Conditions I and II events) at a 95 percent confidence level.

4.4.2.2 Fuel Temperature Acceptance Criteria

During Condition I and Condition II events, the maximum fuel temperature shall be less than the melting temperature of UO_2. The UO_2 melting temperature for at least 95 percent of the peak kW/ft fuel rods will not be exceeded at the 95 percent confidence level.

4.4.2.3 Core Flow Acceptance Criteria

A minimum of 92.5 percent (Unit 1) and 91 percent (Unit 2) of the thermal flowrate (refer to Section 5.1) will pass through the fuel rod region of the core and be effective for fuel rod cooling. Coolant flow through the thimble tubes, as well as leakage from the core barrel-baffle region into the core, is not effective for heat removal.

4.4.2.4 Hydrodynamic Stability Acceptance Criteria

Modes of operation associated with Condition I and Condition II events shall not lead to hydrodynamic instability.

4.4.3 SYSTEM DESCRIPTION

4.4.3.1 Summary Comparison

The core design parameters of the DCPP Unit 1 and Unit 2 reactors are presented in Table 4.1-1.

The reactor core is designed to a minimum DNBR greater than or equal to the design limit DNBR as well as no fuel centerline melting during normal operation, operational transients, and faults of moderate frequency.

4.4.3.2 Fuel Cladding Temperatures

A discussion of fuel cladding integrity is presented in Section 4.2.1.2.2.

The thermal-hydraulic design ensures that the maximum fuel pellet temperature is below the melting point of UO_2 (refer to Section 4.4.2.2). To preclude center melting and establish overpower protection system setpoints, a calculated centerline fuel

temperature of 4700°F has been selected as the overpower limit. The temperature distribution within the fuel pellet is predominantly a function of the local power density and UO_2 thermal conductivity. However, the computation of radial fuel temperature distributions combines crud, oxide, cladding, gap, and pellet conductances. The factors that influence these conductances, such as gap size (or contact pressure), internal gas pressure, gas composition, pellet density, and radial power distribution within the pellet, etc., have been combined into a semiempirical thermal model (refer to Section 4.4.3.2.4) with modifications for time-dependent fuel densification (Reference 68). The temperature predictions have been compared to incore fuel temperature measurements (References 3 through 9) and melt radius data (References 10 and 11) with good results.

4.4.3.2.1 Effect of Fuel Densification on Fuel Rod Temperatures

Fuel densification results in fuel pellet shrinkage. This affects the fuel temperatures in the following ways:

(1) Pellet radial shrinkage increases the pellet diametral gap that results in increased thermal resistance of the gap and thus higher fuel temperatures (refer to Section 4.2.1.2.2).

(2) Pellet axial shrinkage may produce pellet-to-pellet gaps that result in local power spikes, described in Section 4.3.3.2.1, and thus higher total heat flux hot channel factor, F_Q^T and local fuel temperatures. However, studies have shown that this penalty can be eliminated for the fuel type present in the DCPP Unit 1 and Unit 2 cores (refer to Section 4.3.3.2.5).

(3) Pellet axial shrinkage results in a fuel stack height reduction and an increase in the linear power generation rate (kW/ft) for a constant core power level. Using the methods of Reference 68, the increase in linear power for the fuel rod specifications listed in Table 4.1-1 is 0.2 percent.

Fuel rod thermal parameters (fuel centerline, average, and surface temperatures) are determined throughout its lifetime considering time-dependent densification. Maximum fuel average and surface temperatures, shown in Figure 4.4-1 as a function of linear power density (kW/ft), are peak values attained during the fuel lifetime. Similarly, Figure 4.4-2 presents the peak value of fuel centerline temperature versus linear power density, attained during its lifetime. The maximum linear power density throughout the lifetime of the fuel is maintained below the value that would cause UO_2 fuel centerline melt.

The maximum pellet temperature at the hot spot during full power steady state and at the maximum overpower ΔT trip point is shown in Table 4.1-1 for Unit 1 and Unit 2. The principal factors employed in fuel temperature determinations are discussed below.

4.4.3.2.2 UO_2 Thermal Conductivity

The thermal conductivity of UO_2 was evaluated from data reported in References 7 and 12 through 24.

At the higher temperatures, thermal conductivity is best obtained by utilizing the integral conductivity to melt, which can be determined with more certainty. From an examination of the data, it has been concluded that the best estimate for the value of $\int_0^{2800^\circ C} k dT$ is 93 watts/cm. This conclusion is based on the integral values reported in References 10 and 24 through 28.

The design curve for the thermal conductivity is shown in Figure 4.4-3. The section of the curve at temperatures between 0 and 1300°C is in excellent agreement with the recommendation of the International Atomic Energy Agency (IAEA) panel (Reference 29). The section of the curve above 1300°C is derived for an integral value of 93 watts/cm (Reference 89).

Thermal conductivity for UO_2 at 95 percent theoretical density can be represented best by the following equation:

$$k = \frac{1}{(11.8 + 0.0238T)} + 8.775 \times 10^{-13} \; T^3 \qquad (4.4\text{-}1)$$

where:

k is in watts/cm-°C, and T is in °C

4.4.3.2.3 Radial Power Distribution in UO_2 Fuel Rods

An accurate radial power distribution as a function of burnup is needed to determine the power level for incipient fuel melting and other important performance parameters, e.g., pellet thermal expansion, fuel swelling, and fission gas release rates.

This UO_2 fuel rods radial power distribution as a function of core burnup is determined using a 3D ANC calculation (refer to Sections 4.3.3.10.3 and 15.1.2.4) or with the neutron transport theory LASER (Reference 81) code that has been validated by comparing code predictions on radial burnup and isotopic distributions with measured radial microdrill data (References 30 and 31). "Microdrill data" are data obtained from the physical examination of irradiated pellets in a hot cell. Small core samples are removed from different radial positions in a pellet (using a "microdrill"). Isotopic measurements of the fuel samples determine actual UO_2 burnups at the sample points. A "radial power depression factor," f, is determined using radial power distribution predicted by LASER (Reference 81).

4.4.3.2.4 Gap Conductance

The temperature drop across the pellet-cladding gap is a function of the gap size and the thermal conductivity of the gas in the gap. The gap conductance model is selected such that when combined with the UO_2 thermal conductivity model, the calculated fuel centerline temperatures reflect the inpile temperature measurements. A more detailed discussion of the gap conductance model is presented in Reference 101.

4.4.3.2.5 Surface Heat Transfer Coefficients

The fuel rod surface heat transfer coefficients during subcooled forced convection and the outer cladding wall temperature for the onset of nucleate boiling is presented in Section 4.4.3.8.1.

4.4.3.2.6 Fuel Cladding Temperatures

The fuel rod outer surface at the hot spot operates at a temperature of approximately 660°F for steady state operation at rated power throughout core life, due to the onset of nucleate boiling. At BOL, this temperature is that of the cladding metal outer surface.

During operation over the life of the core, the buildup of oxides and crud on the fuel rod cladding outer surface causes the cladding surface temperature to increase. Allowance is made in the fuel center melt evaluation for this temperature rise. The thermal-hydraulic DNB limits ensure that adequate heat transfer is provided between the fuel cladding and the reactor coolant so that cladding temperature does not limit core thermal output. Figure 4.4-4 shows the axial variation of average cladding temperature for a representative average power rod both at BOL and EOL.

4.4.3.2.7 Treatment of Peaking Factors

The total heat flux hot channel factor, F_Q^T, is defined by the ratio of the maximum to core average heat flux. The design value of F_Q^T for normal operation is 2.58, allowing for fuel densification effects, as shown in Table 4.3-1. This results in a peak local linear power density of 14.3 kW/ft at full power. The corresponding peak local power at the maximum overpower trip point (118 percent total power) is 16.6 kW/ft. Centerline temperature at this kW/ft must be below the UO_2 melt temperature over the lifetime of the rod including allowances for uncertainties. From Figure 4.4-2, the centerline temperature at the maximum overpower trip point is well below that required to produce melting. The maximum linear power density throughout the lifetime of the fuel is maintained below the value that would cause UO_2 fuel centerline melt. Fuel centerline and average temperature at rated (100 percent) power and at the maximum overpower trip point for Unit 1 and Unit 2 are presented in Table 4.1-1.

4.4.3.3 Departure from Nucleate Boiling Ratio

The minimum DNBRs for the rated power, and anticipated transient conditions are given in Table 4.1-1 for Unit 1 and Unit 2. The minimum DNBR in the limiting flow channel will occur downstream of the peak heat flux location (hot spot) due to the increased downstream enthalpy rise.

DNBRs are calculated by using the correlation and definitions described in Section 4.4.3.3.1. The THINC-IV (Reference 47) computer code (discussed in Section 4.4.3.15.1) determines the flow distribution in the core and the local conditions in the hot channel for use in the DNB correlation. The use of hot channel factors is discussed in Section 4.4.3.13.1 (nuclear hot channel factors) and in Section 4.4.3.3.4 (engineering hot channel factors).

4.4.3.3.1 Departure from Nucleate Boiling Technology

The WRB-2 DNB correlation (Reference 85) was developed to take credit for the VANTAGE+ fuel assembly mixing vane design. A DNBR limit of 1.17 is also applicable for the WRB-2 correlation. Figure 4.4-20 shows measured critical heat flux (CHF) plotted against predicted CHF using the WRB-2 correlation.

In several cases, the W-3 DNB correlation is used where the WRB-2 is not applicable. For example, Section 15.2.14.1 uses the W-3 DNB correlation since the system pressure for the limiting statepoint is below 1,000 psia.

The W-3 DNB correlation, and several modifications, have been used in Westinghouse CHF calculations. The W-3 DNB was originally developed from single tube data (Reference 34), but was subsequently modified to apply to the 0.422 inch, OD rod low parasitic reinforced grid (R-grid) (References 35 and 92) and low parasitic grid (L-grid) (Reference 36), as well as the 0.374 inch OD (References 37 and 38) rod bundle data. These modifications to the W-3 DNB correlation have been demonstrated to be adequate for reactor rod bundle design.

A description of the 17 x 17 fuel assembly test program and a summary of the results are described in detail in Reference 37.

Figure 4.4-5 shows the data obtained in this test program. The test results indicate that a reactor core using this geometry may operate with a minimum DNBR of 1.28 and satisfy the design criterion.

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The WRB-1 correlation (Reference 84) was developed based exclusively on the large bank of mixing vane grid rod bundle CHF data (over 1100 points) that Westinghouse has collected. The WRB-1 correlation, based on local fluid conditions, represents the rod bundle data with better accuracy over the wide range of variables than the previous

correlation used in design. This correlation accounts directly for both typical and thimble cold wall cell effects, uniform and non-uniform heat flux profiles, and variations in rod heated length and in grid spacing.

Figure 4.4-19 shows measured CHF plotted against predicted CHF using the WRB-1 correlation.

CHF tests which model the 17x17 optimized fuel assembly have been performed with the results described in detail in Reference 87. It was concluded that the CHF characteristics of the 17x17 optimized fuel assembly design are not significantly different from those of 17x17 LOPAR design, and can be adequately described by the "R" grid form of the WRB-1 CHF correlation. Furthermore, the new data can be incorporated into the "R" grid data base such that the WRB-1 correlation can be applied to 17x17 LOPAR fuel design without changing the DNBR design criterion of 1.17.

4.4.3.3.2 Definition of Departure from Nucleate Boiling Ratio

The DNBR, as applied to this design for both typical and thimble cold wall cells is:

$$\mathrm{DNBR} = \frac{q''_{\mathrm{DNB,\,Predicted}}}{q''_{\mathrm{actual}}} \tag{4.4-5}$$

For the W-3 DNB (R-Grid) correlation,

$$q''_{\mathrm{DNB,Predicted}} = \frac{q''_{\mathrm{EU,W-3}} \times F'_S}{F} \tag{4.4-6}$$

when all flow cell walls are heated and $q''_{\mathrm{EU,\,W\text{-}3}}$ is the uniform DNB heat flux as predicted by W-3 DNB correlation and F is the flux shape factor which accounts for non-uniform axial heat flux distributions (Reference 39) with the "C" term modified as in Reference 34.

F'_S is the modified spacer factor described in Reference 37 using an axial grid spacing coefficient, K_S = 0.046, and a thermal diffusion coefficient (TDC) of 0.038, based on the 26-inch grid spacing data. Since the actual grid spacing is approximately 20 inches, these values are conservative since the DNB performance was found to improve and TDC increase as axial grid spacing is decreased (References 35 and 40).

When a cold wall is present for the W-3 DNB correlation,

$$q''_{\mathrm{DNB,Predicted}} = q''_{\mathrm{EU,W-3,CW}} \times F'_S \tag{4.4-7}$$

where:

$$q''_{EU,W-3,CW} = \frac{q''_{EU,W-3,Dh}}{F} \times CWF \qquad (4.4\text{-}7A)$$

$q''_{EU,W-3,Dh}$ is the uniform DNB heat flux as predicted by the W-3 DNB cold wall correlation (Reference 34) when not all flow cell walls are heated (thimble cold wall cell). The cold wall factor (CWF) is provided in References 34 and 39. For the WRB-2 correlation,

$$q''_{DNB,Predicted} = \frac{q''_{WRB-2}}{F} \qquad (4.4\text{-}8)$$

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$$q''_{DNB,Predicted} = \frac{q''_{WRB-1}}{F} \qquad \textit{for WRB-1 correlation}$$

where:

F is the same flux shape factor that is used with the W-3 DNB correlation.

4.4.3.3.3 Mixing Technology

The rate of heat exchange by mixing between flow channels is proportional to the difference in the local mean fluid enthalpy of the respective channels, the local fluid density, and the flow velocity. The proportionality is expressed by the dimensionless TDC, which is defined as:

$$TDC = \frac{w'}{\rho V a} \qquad (4.4\text{-}9)$$

where:

w' = flow exchange rate per unit length, lbm/ft-sec
ρ = fluid density, lbm/ft^3
V = fluid velocity, ft/sec
a = lateral flow area between channels per unit length, ft^2/ft

The application of the TDC in the THINC analysis for determining the overall mixing effect or heat exchange rate is presented in Reference 41.

The TDC is determined by comparing the THINC code predictions with the measured subchannel exit temperatures. Data for 26-inch axial grid spacing are presented in Figure 4.4-6 where the TDC is plotted versus the Reynolds number. The TDC is found

to be independent of the Reynolds number, mass velocity, pressure, and quality over the ranges tested.

The two-phase data (local and subcooled boiling) fell within the scatter of the single-phase data. The effect of two-phase flow on the value of TDC has been demonstrated by Cadek (Reference 40), Rowe and Angle (References 42 and 43), and Gonzalez-Santalo and Griffith (Reference 44). In the subcooled boiling region, the values of TDC were indistinguishable from the single-phase values. In the quality region, Rowe and Angle show that in the case with rod spacing similar to that in PWR reactor core geometry, the value of TDC increased with quality to a point and then decreased but never below the single-phase value. Gonzalez-Santalo and Griffith showed that the mixing coefficient increased as the void fraction increased.

The data from these tests on the R-grid showed that a design TDC value of 0.038 (for 26 inch grid spacing) can be used in determining the effect of coolant mixing in the THINC analysis. A mixing test program similar to the one described above was conducted at Columbia University for the 17 x 17 geometry and mixing vane grids on 26-inch spacing (Reference 45). The mean value of TDC obtained from these tests was 0.059, and all data were well above the current design value of 0.038.

Because the reactor grid spacing is approximately 20 inches, additional margin is available for this design, as the value of TDC increases as grid spacing decreases (Reference 40).

The inclusion of three IFM grids in the upper span of the VANTAGE+ fuel assembly results in a grid spacing of approximately 10 inches. Therefore, the design value of 0.038 for TDC is a conservatively low value for use in VANTAGE+ to determine the effect of coolant mixing in the core thermal performance analysis.

4.4.3.3.4 Hot Channel Factors

The total hot channel factors for heat flux and enthalpy rise are defined as the maximum-to-core average ratios of these quantities. The heat flux hot channel factor considers the local maximum linear heat generation rate at a point (the "hot spot"), and the enthalpy rise hot channel factor involves the maximum integrated value along a channel (the "hot channel").

Each of the total hot channel factors considers a nuclear hot channel factor (refer to Section 4.4.3.13) describing the neutron power distribution and an engineering hot channel factor, which allows for variations in flow conditions and fabrication tolerances. The engineering hot channel factors are made up of subfactors that account for the influence of the variations of fuel pellet diameter, density, enrichment and eccentricity; fuel rod diameter pitch and bowing; inlet flow distribution; flow redistribution; and flow mixing.

4.4.3.3.4.1 Heat Flux Engineering Hot Channel Factor, F_Q^E

The heat flux engineering hot channel factor is used to evaluate the maximum heat flux. This subfactor is determined by statistically combining the tolerances for the fuel pellet diameter, density, enrichment, eccentricity, and the fuel rod diameter, and has a value of 1.03. Measured manufacturing data on Westinghouse fuel verify that this value was not exceeded for 95 percent of the limiting fuel rods at a 95 percent confidence level. As shown in Reference 99, no DNB penalty need be taken for the short, relatively low intensity heat flux spikes caused by variations in the above parameters.

4.4.3.3.4.2 Enthalpy Rise Engineering Hot Channel Factor, $F_{\Delta H}^E$

The effect of variations in flow conditions and fabrication tolerances on the hot channel enthalpy rise is directly considered in the THINC core thermal subchannel analysis (refer to Section 4.4.3.15.1) under any reactor operating condition. The following items contribute to the enthalpy rise engineering hot channel factor:

(1) Pellet Diameter, Density and Enrichment, Fuel Rod Diameter, Pitch, and Bowing

Design values employed in the THINC analysis are based on applicable limiting tolerances such that design values are met for 95 percent of the limiting channels at a 95 percent confidence level. The effect of variations in pellet diameter and enrichment is employed in the THINC analysis as a direct multiplier on the hot channel enthalpy rise, while the fuel rod diameter, pitch, and bowing variation, including incore effects, enter in the preparation of the THINC input values.

(2) Inlet Flow Maldistribution

Inlet flow maldistribution in the core thermal performances is discussed in Section 4.4.3.12.2. A design basis of 5 percent reduction in coolant flow to the hot assembly is used in the THINC-IV analysis.

(3) Flow Redistribution

The flow redistribution accounts for the flow reduction in the hot channel resulting from the high flow resistance in the channel due to the local or bulk boiling. The effect of the non-uniform power distribution is inherently considered in the THINC analysis.

(4) Flow Mixing

The subchannel mixing model incorporated in the THINC code and used in reactor design is based on experimental data (Reference 46), as discussed in Section 4.4.3.15.1. The mixing vanes incorporated in the

spacer grid design induce additional flow mixing between the various flow channels in a fuel assembly, as well as between adjacent assemblies. This mixing reduces the enthalpy rise in the hot channel resulting from local power peaking or unfavorable mechanical tolerances.

4.4.3.3.5 Effects of Rod Bow on Departure from Nucleate Boiling Ratio

The phenomenon of fuel rod bowing, as described in Reference 79, must be accounted for in the DNBR safety analysis of Condition I and Condition II events for each plant application. Applicable generic credits for margin resulting from retained conservatism in the evaluation of DNBR and/or margin obtained from measured plant operating parameters (such as $F^N_{\Delta H}$ or core flow), which are less limiting than those required by the plant safety analysis, can be used to offset the effect of rod bow.

The safety analysis for DCPP cores maintains sufficient margin between the safety analysis DNBR limits and the design DNBR limits. The design DNBR limits are shown below to accommodate full flow and low flow DNBR penalties identified in Reference 80, which are applicable to 17x17 VANTAGE+ fuel assembly analysis utilizing the WRB-2 correlation.

However, for the upper assembly span of VANTAGE+ fuel where additional restraint is provided with the IFM grids, the grid-to-grid spacing in DNB limiting span is approximately 10 inches . Using the rod bow topical report methods (Reference 79), and scaling with the NRC approved factor results in predicted channel closure in the limiting spans of less than 50 percent closure; no rod bow DNBR penalty is required in the 10 inch spans in the VANTAGE+ safety analyses.

	VANTAGE+
Design Limit	
Typical Cell	1.34
Thimble Cell	1.32
Safety Limit	
Typical Cell	1.71
Thimble Cell	1.68

The maximum rod bow penalties accounted for in the design safety analysis are based on an assembly average burnup of 24,000 MWD/MTU based on Reference 100. At burnups greater than 24,000 MWD/MTU, credit is taken for the effect of $F^N_{\Delta H}$ burndown. Due to the decrease in fissionable isotopes and the buildup of fission product inventory, no additional rod bow penalty is required.

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4.4.3.3.6 Transition Core

The Westinghouse transition core DNB methodology is given in References 89 and 90 and has been approved by the NRC via Reference 91. Using this methodology, transition cores are analyzed as if they were full cores of one assembly type (full LOPAR or full VANTAGE 5), applying the applicable transition core penalties. This penalty was included in the safety analysis limit DNBRs such that sufficient margin over the design limit DNBR existed to accommodate the transition core penalty and the appropriate rod bow DNBR penalty. However, since the transition to a full VANTAGE 5 core has been completed, various analyses, such as large break and small LOCA analysis, have assumed a full VANTAGE 5 core and no longer assume a transition core penalty.

The LOPAR and VANTAGE 5 designs have been shown to be hydraulically compatible in Reference 85.

4.4.3.4 Flux Tilt Considerations

Significant quadrant power tilts are not anticipated during normal operation since this phenomenon is caused by asymmetric perturbations. A dropped or misaligned RCCA could cause changes in hot channel factors. These events are analyzed separately in Chapter 15.

Other possible causes for quadrant power tilts include X-Y xenon transients, inlet temperature mismatches, enrichment variations within tolerances, and so forth.

In addition to unanticipated quadrant power tilts, other readily explainable asymmetries may be observed during calibration of the excore detector quadrant power tilt alarm. During operation, at least one power distribution measurement is taken per effective-full-power month. Each of these power distribution measurements is reviewed for deviations from the expected power distributions. The acceptability of an observed asymmetry, planned or otherwise, depends solely on meeting the required accident analyses assumptions. In practice, once acceptability has been established by review of the power distribution measurements, the quadrant power tilt alarms and related instrumentation are adjusted to indicate zero quadrant tilt, 1.00 quadrant power tilt ratio, as the final step in the calibration process. Proper functioning of the quadrant power tilt alarm is significant because no allowances are made in the design for increased hot channel factors due to unexpected developing flux tilts since all likely causes are prevented by design or procedures or specifically analyzed. Finally, in the event that unexplained flux tilts do occur, the Technical Specification (Reference 82) stipulates appropriate corrective actions to ensure continued safe operation of the reactor.

4.4.3.5 Void Fraction Distribution

The calculated core average and the hot subchannel maximum and average void fractions are presented in Tables 4.4-1 and 4.4-2 for operation at full power with design hot channel factors for Unit 1 and Unit 2, respectively. The void fraction distribution in the core is presented in Reference 47. The void fraction as a function of thermodynamic quality is shown in Figure 4.4-10. The void models used in the THINC-IV computer code are described in Section 4.4.3.8.3.

4.4.3.6 Core Coolant Flow Distribution

Coolant enthalpy rise and flow distributions are shown for the 4-foot elevation (1/3 of core height) in Figure 4.4-7, 8-foot elevation (2/3 of core height) in Figure 4.4-8, and at the core exit in Figure 4.4-9. These distributions correspond to a representative Westinghouse 4-loop plant. The THINC code analysis for this case utilized a uniform core inlet enthalpy and inlet flow distribution.

4.4.3.7 Core Pressure Drops and Hydraulic Loads

4.4.3.7.1 Core Pressure Drops

The analytical model and experimental data used to calculate the pressure drops, for the full power conditions given in Table 4.1-1, are described in Section 4.4.3.8.2. The core pressure drop consists of the fuel assembly, lower core plate, and upper core plate pressure drops. These pressure drops are based on the best estimate flow, as described in Section 5.1.6. Section 5.1.6 also defines the thermal design flow (minimum flow), which is the basis for reactor core thermal performance, and the mechanical design flow (maximum flow), which is used in the mechanical design of the reactor vessel internals and fuel assemblies. Since the best estimate flow is that which is most likely to exist in an operating plant, the calculated core pressure drops in Table 4.1-1 are greater than pressure drops previously quoted using the thermal design flow. The relation between best estimate flow, thermal design flow, and mechanical design flow is illustrated in Figure 5.1-2.

4.4.3.7.2 Hydraulic Loads

Maximum flow conditions are limiting because hydraulic loads are a maximum. The most adverse flow conditions occur during a LOCA, as discussed in Section 15.4.1.

Hydraulic loads at normal operating conditions are calculated considering the best estimate flow and accounting for the best estimate core bypass flow. Core hydraulic loads at cold plant startup conditions are based on the cold best estimate flow, but are adjusted to account for the coolant density difference. Conservative core hydraulic loads for a pump overspeed transient, which are based on flowrates 20 percent greater than the mechanical design flow (refer to Section 5.1.6), are evaluated to be greater than twice the fuel assembly weight.

The hydraulic verification tests are discussed in References 48 and 87.

4.4.3.8 Correlation and Physical Data

4.4.3.8.1 Surface Heat Transfer Coefficients

Forced convection heat transfer coefficients are obtained from the familiar Dittus-Boelter correlation (Reference 49), with the properties evaluated at bulk fluid conditions:

$$\frac{hD_e}{k} = 0.023\left(\frac{D_e G}{\mu}\right)^{0.8}\left(\frac{C_p \mu}{k}\right)^{0.4} \qquad (4.4\text{-}10)$$

where:

- h = heat transfer coefficient, Btu/hr-ft^2-°F
- D_e = equivalent diameter, ft
- k = thermal conductivity, Btu/hr-ft-°F
- G = mass velocity, lbm/hr-ft^2
- μ = dynamic viscosity, lbm/ft-hr
- Cp = heat capacity, Btu/lbm-°F

This correlation has been shown to be conservative (Reference 50) for rod bundle geometries with pitch-to-diameter ratios in the range used by PWRs.

The onset of nucleate boiling occurs when the cladding wall temperature reaches the amount of superheat predicted by Thom's (Reference 51) correlation. After this occurrence, the outer cladding wall temperature is determined by:

$$\Delta T_{sat} = [0.072 \exp(-P/1260)]\,(q'')^{0.5} \qquad (4.4\text{-}11)$$

where:

- ΔT_{SAT} = wall superheat, $T_w - T_{sat}$, °F
- q'' = wall heat flux, Btu/hr-ft^2
- P = pressure, psia
- T_w = outer cladding wall temperature, °F
- T_{SAT} = saturation temperature of coolant at P, °F

4.4.3.8.2 Total Core and Vessel Pressure Drop

Pressure losses occur as a result of viscous drag (friction) and/or geometry changes (form) in the fluid flowpath. The flow field is assumed to be incompressible, turbulent, single-phase water. Two-phase considerations are neglected in the vessel pressure

drop evaluation because the core average void is negligible (refer to Section 4.4.3.5 and Tables 4.4-1 and 4.4-2).

Two-phase flow considerations in the core thermal subchannel analyses are considered and the models are discussed in Section 4.4.3.12.3. Core and vessel pressure losses are calculated by equations of the form:

$$\Delta P_L = \left(K + \frac{FL}{D_e}\right) \frac{\rho V^2}{2g_c(144)} \qquad (4.4\text{-}12)$$

where:

ΔP_L = pressure drop, lb_f/in^2
ρ = fluid density, lbm/ft^3
L = length, ft
D_e = equivalent diameter, ft
V = fluid velocity, ft/sec
g_c = $32.174 \frac{1b_m - ft}{1b_f - sec^2}$
K = form loss coefficient, dimensionless
F = friction loss coefficient, dimensionless

Fluid density is assumed to be constant at an appropriate value for each component in the core and vessel. Because of the complex core and vessel flow geometry, precise analytical values for the form and friction loss coefficients are not available. Therefore, experimental values for these coefficients are obtained from geometrically similar models.

The results of full-scale tests of core components and fuel assemblies were utilized in developing the core pressure loss characteristics. The pressure drop for the vessel was obtained by combining the core pressure loss with correlation of 1/7th scale model hydraulic test data on a number of vessels (References 52 and 53) and form loss relationships (Reference 54). Moody (Reference 55) curves were used to obtain the single-phase friction factors.

Tests of the primary coolant loop flowrates are made (refer to Section 4.4.6.1) prior to initial criticality to verify that the flowrates used in the design are conservative.

4.4.3.8.3 Void Fraction Correlation

Three separate void regions are considered in flow boiling in a PWR as illustrated in Figure 4.4-10. They are the wall void region (no bubble detachment), the subcooled boiling region (bubble detachment), and the bulk boiling region.

In the wall void region, local boiling begins at the point where the cladding temperature reaches the amount of superheat predicted by Thom's (Reference 51) correlation (refer to Section 4.4.3.8.1). The void fraction in this region is calculated using Maurer's (Reference 56) relationship. The bubble detachment point, where the superheated bubbles break away from the wall, is determined by using Griffith's (Reference 57) relationship.

The void fraction in the subcooled boiling region (i.e., after the detachment point) is calculated from the Bowring (Reference 58) correlation. This correlation predicts the void fraction from the detachment point to the bulk boiling region.

The void fraction in the bulk boiling region is predicted by using homogeneous flow theory and assuming no slip. The void fraction in this region is, therefore, a function of steam quality only.

4.4.3.9 Thermal Effects of Operational Transients

DNB core safety limits are generated as a function of coolant temperature, pressure, core power, and axial power imbalance. Steady state operation within these safety limits ensures that the minimum DNBR is not less than the safety limit DNBR.

Figure 15.1-1 shows lines at the safety limit DNBR and the resulting overtemperature ΔT trip lines (which are part of the Technical Specifications), plotted as ΔT versus T-average for various pressures. This system provides adequate protection against anticipated operational transients that are slow with respect to fluid transport delays in the primary system. In addition, for fast transients (e.g., uncontrolled rod bank withdrawal at power incident) (refer to Section 15.2.2), specific protection functions are provided as described in Section 7.2; their use is described in Chapter 15 (refer to Table 15.1-2). Fuel rod thermal response is discussed in Section 4.4.3.18.

4.4.3.10 Uncertainties in Estimates

4.4.3.10.1 Uncertainties in Fuel and Cladding Temperatures

As discussed in Section 4.4.3.2, the fuel temperature is a function of crud, oxide, cladding, gap, and pellet conductance. Uncertainties in the fuel temperature calculation are essentially of two types: fabrication uncertainties, such as variations in the pellet and cladding dimensions and the pellet density; and model uncertainties, such as variations in the pellet conductivity and the gap conductance. These uncertainties have been quantified by comparison of the thermal model to the incore thermocouple measurements (References 3 through 9), by out-of-pile measurements of the fuel and cladding properties (References 7 and 12 through 23), and by measurements of the fuel and cladding dimensions during fabrication. The effect of densification on fuel temperature uncertainties is presented in Reference 68.

In addition, the measurement uncertainty in determining the local power, and the effect of density and enrichment variations on local power, are considered in establishing the heat flux hot channel factor.

Uncertainty in determining cladding temperature results from uncertainties in the crud and oxide thickness. Because of the excellent heat transfer between the surface of the rod and the coolant, the film temperature drop does not appreciably contribute to the uncertainty.

Reactor trip setpoints, as specified in the Technical Specifications, include allowance for instrument and measurement uncertainties such as calorimetric error, instrument drift, and channel reproducibility.

4.4.3.10.2 Uncertainties in Pressure Drops

Core and vessel pressure drops based on the best estimate flow, as described in Section 5.1, are quoted in Table 4.1-1. The uncertainties quoted are based on the uncertainties in both the test results and the analytical extension of these values to the reactor application.

4.4.3.10.3 Uncertainties Due to Inlet Flow Maldistribution

Uncertainties in the inlet flow maldistribution criteria used in the core thermal analyses are discussed in Section 4.4.3.12.2.

4.4.3.10.4 Uncertainty in Departure from Nucleate Boiling Correlation

The uncertainty in the DNB correlation (refer to Section 4.4.3.3) can be written as a statement on the probability of not being in DNB based on the DNB data statistics. This is discussed in Section 4.4.3.3.2.

4.4.3.10.5 Uncertainties in Departure from Nucleate Boiling Ratio Calculations

The uncertainties in the DNBRs calculated by THINC analysis (refer to Section 4.4.3.15.1) due to uncertainties in the nuclear peaking factors are accounted for by applying conservatively high values of the nuclear peaking factors and including measurement error allowances in the statistical evaluation of the limit DNBR (refer to Section 4.4.4.1) using the Improved Thermal Design Procedure (ITDP) (Reference 86). In addition, conservative values for the engineering hot channel factors are used (refer to Section 4.4.3.3.4). The results of a sensitivity study with THINC-IV show that the minimum DNBR in the hot channel is relatively insensitive to variations in the core-wide radial power distribution (for the same value of $F^N_{\Delta H}$).

The ability of the THINC-IV computer code to accurately predict flow and enthalpy distributions in rod bundles is discussed in Section 4.4.3.15.1 and in Reference 59. The sensitivity of the minimum DNBR in the hot channel to the void fraction correlation (refer to Section 4.4.3.8.3), the inlet velocity and exit pressure distributions, and the grid pressure loss coefficients have been studied (Reference 47). The results show that the minimum DNBR in the hot channel is relatively insensitive to variations in these parameters.

4.4.3.10.6 Uncertainties in Flowrates

The uncertainties associated with loop flowrates are discussed in Section 5.1. For core thermal performance evaluations, a thermal design loop flow is used which is less than the best estimate loop flow (by approximately 4 percent). In addition, another 7.5 percent (Unit 1) and 9.0 percent (Unit 2) of the thermal design flow is assumed to be ineffective for core heat removal capability because it bypasses the core through the various available flowpaths described in Section 4.4.3.12.1.

4.4.3.10.7 Uncertainties in Hydraulic Loads

As discussed in Section 4.4.3.7.2, hydraulic loads on the fuel assembly are evaluated for a pump overspeed transient that creates flowrates 20 percent greater than the mechanical design flow.

4.4.3.10.8 Uncertainty in Mixing Coefficients

The value of the mixing coefficient, TDC, used in THINC analyses for this application is 0.038. The mean value of TDC obtained in the R-grid mixing tests described in Section 4.4.3.3.2 was 0.042 (for 26-inch grid spacing). The value of 0.038 is one standard deviation below the mean value and 90 percent of the data gives values of TDC greater than 0.038 (Reference 40).

The results of the mixing tests discussed in Section 4.4.3.3.3, had a mean TDC value of 0.059 and standard deviation of $\sigma = 0.007$. Hence, the current design TDC value is almost three standard deviations below the mean for 26-inch grid spacing.

Since the value of TDC increases as grid spacing decreases, the design value of 0.038 for TDC is a conservatively low value for use in VANTAGE+ to determine the effect of coolant mixing in the core thermal performance analysis. Refer to Section 4.4.3.3.3 for a discussion of the current reactor grid spacing of approximately 20 inches and IFM grid spacing of approximately 10 inches.

4.4.3.11 Plant Configuration Data

Plant configuration data for the thermal-hydraulic and fluid systems external to the core are provided in Chapters 5, 6, and 9. Implementation of the ECCS is discussed in Chapters 6 and 15. Some specific areas of interest are:

(1) Total coolant flow rate for the RCS is provided in Table 5.1-1.

(2) Total RCS volume is given in Table 5.1-1.

(3) The flowpath length through each volume is calculated from physical data and the component pressure drops as provided in Table 5.1-1.

(4) The height of fluid in each component of the RCS may be determined from the physical data and data provided in Table 5.1-1. The RCS components are water-filled during power operation with the pressurizer being approximately 60 percent water-filled.

(5) ECCS components are located to meet the criteria for net positive suction head described in Section 6.3.

(6) Line lengths and sizes for the safety injection system are determined so as to guarantee a total system resistance that will provide, as a minimum, the fluid delivery rates assumed in the safety analyses described in Chapter 15.

(7) The design data for RCS components, including volumes (diameter), flows, and pressure and temperature, are presented in Section 5.5.

(8) RCS steady state pressure and temperature distribution are presented in Table 5.1-1.

4.4.3.12 Core Hydraulics

4.4.3.12.1 Flowpaths Considered in Core Pressure Drop and Thermal Design

The following flowpaths are considered:

(1) Flow through the spray nozzles into the upper head for cooling purposes

(2) Flow entering the RCCA guide thimbles to cool core components

(3) Leakage flow from the vessel inlet nozzle directly to the vessel outlet nozzle through the gap between vessel and barrel

(4) Flow entering the core from the baffle-barrel region through the gaps between the baffle plates

(5) Flow introduced between baffle and barrel to cool these components

(6) Flow through the empty guide thimble tubes

The above contributions are evaluated to confirm that the design basis value of 7.5 percent (Unit 1) and 9.0 percent (Unit 2) core bypass flow is met.

4.4.3.12.2 Inlet Flow Distribution

Data from several 1/7 scale hydraulic reactor model tests (References 52, 53, and 60) have been considered in arriving at the core inlet flow maldistribution criteria to be used in the THINC analyses (refer to Section 4.4.3.15.1). THINC (Reference 41) analyses have indicated that a conservative design basis is to consider a 5 percent reduction in the flow to the hot assembly (Reference 61).

The experimental error in the inlet velocity distribution has been estimated in Reference 47. The sensitivity of changes in inlet velocity distributions to hot channel thermal performance is shown to be small.

The effect of the total flowrate on the inlet velocity distribution was studied in the experiments of Reference 52. As expected, no significant variation could be found in inlet velocity distribution with reduced flowrate.

4.4.3.12.3 Empirical Friction Factor Correlations, F_Q^E

Two empirical friction factor correlations are used in the THINC-IV computer code (refer to Section 4.4.3.15.1).

The friction factor in the axial direction, parallel to the fuel rod axis, uses the Novendstern-Sandberg (Reference 62) correlation. This correlation consists of the following:

(1) For isothermal conditions, this correlation uses the Moody (Reference 55) friction factor, including surface roughness effects.

(2) Under single-phase heating conditions, a factor is applied based on the values of the coolant density and viscosity at the temperature of the heated surface and at the bulk coolant temperature.

(3) Under two-phase flow conditions, the homogeneous flow model proposed by Owens (Reference 63) is used with a modification to account for a mass velocity and heat flux effect.

The flow in the lateral directions, normal to the fuel rod axis, views the reactor core as a large tube bank. Thus, the lateral friction factor proposed by Idel'chik (Reference 54) is applicable. This correlation is of the form:

$$F_L = ARe_L^{-0.2} \qquad (4.4\text{-}13)$$

where:

A is a function of the rod pitch and diameter as given in Reference 54
Re_L is the lateral Reynolds number based on rod diameter

Extensive comparisons of THINC-IV predictions using these correlations to experimental data are given in Reference 59, and verify the applicability of these correlations in PWR design.

4.4.3.13 Influence of Power Distribution

The core power distribution, which at BOL is largely established by fuel enrichment, loading pattern, and core power level, is also a function of variables such as control rod worth and position and fuel depletion throughout lifetime. Although radial power distributions in various planes of the core are often illustrated for general interest, the core radial enthalpy rise distribution, as determined by the integral of power over each channel, is of greater importance for DNB analyses. These radial power distributions, characterized by $F^N_{\Delta H}$ (defined in Section 4.3.3.2.2), as well as axial heat flux profiles, are discussed in the following two sections.

4.4.3.13.1 Nuclear Enthalpy Rise Hot Channel Factor, $F^N_{\Delta H}$

Given the local power density q' (kW/ft) at a point x, y, z in a core with N fuel rods and height H:

$$F^N_{\Delta H} = \frac{\text{hot rod power}}{\text{average rod power}} = \frac{\text{Max}\int_o^H q'(x_o, y_o, z)dz}{\frac{1}{N}\sum_{\substack{\text{all}\\ \text{rods}}} \int_o^H q'(x,y,z)dz} \qquad (4.4\text{-}14)$$

The location of minimum DNBR depends on the axial profile and its magnitude depends on the enthalpy rise up to that point. The maximum value of the rod integral is used to identify the most likely rod for minimum DNBR. An axial power profile is obtained which, when normalized to the design value of $F^N_{\Delta H}$, recreates the axial heat flux along the limiting rod. The surrounding rods are assumed to have the same axial profile with rod average powers that are typical of distributions found in hot assemblies. In this manner, worst case axial profiles can be combined with worst case radial distributions for reference DNB calculations.

Local heat fluxes are obtained by using hot channel and adjacent channel explicit power shapes which take into account variations in horizontal power shapes throughout the core. The sensitivity of the THINC-IV analysis to radial power shapes is discussed in Reference 47.

For operation at a fraction P of full power, the design $F^N_{\Delta H}$ is given by:

$$F^N_{\Delta H} = 1.59\ [1 + 0.3\ (1\text{-}P)]\ (\text{VANTAGE+}) \qquad (4.4\text{-}15)$$

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$$\textit{F}^N_{\Delta H} = \textit{1.56 [1 + 0.3 (1-P)] (LOPAR)}$$

The permitted relaxation of $F^N_{\Delta H}$ is included in the DNB protection setpoints and allows radial power shape changes with rod insertion to the insertion limits (Reference 64), thus allowing greater flexibility in the nuclear design.

4.4.3.13.2 Axial Heat Flux Distributions

As discussed in Section 4.3.3.2, the axial heat flux distribution can vary as a result of rod motion, power change, or due to spatial xenon transients that may occur in the axial direction. Consequently, it is necessary to measure the axial power imbalance by means of the excore nuclear detectors (refer to Section 4.3.3.2.7) and protect the core from excessive axial power imbalance. The reactor trip system provides automatic reduction of the trip setpoint in the overtemperature ΔT channels on excessive axial power imbalance, i.e., when an extremely large AO corresponds to an axial shape that could lead to a DNBR, which is less than that calculated for the reference DNB design axial shape.

The reference DNB design axial shape is a chopped cosine with a peak-to-average ratio of 1.55.

4.4.3.14 Core Thermal Response

A general summary of the steady state thermal-hydraulic design parameters including thermal output, flowrates, etc., is provided in Table 4.1-1. As stated in Section 4.4.2, the acceptance criteria are to prevent DNB and to prevent fuel melting for Conditions I and II events. The protective systems described in Chapter 7 (Instrumentation and Controls) are designed to meet these bases. The response of the core to Condition II transients is given in Chapter 15.

4.4.3.15 Analytical Techniques

4.4.3.15.1 Core Analysis

The objective of reactor core thermal analysis is to determine the maximum heat removal capability in all flow subchannels, and to show that the core safety limits, as presented in the Technical Specifications, are not exceeded. The thermal design considers local variations in dimensions, power generation, flow redistribution, and mixing. THINC-IV is a realistic three-dimensional matrix model developed to account for hydraulic and nuclear effects on the enthalpy rise in the core (References 47 and

59). The behavior of the hot assembly is determined by superimposing the power distribution among the assemblies upon the inlet flow distribution, while allowing for flow mixing and distribution between assemblies. The average flow and enthalpy in the hottest assembly is obtained from the core-wide assembly-by-assembly analysis. The local variations in power, fuel rod and pellet fabrication, and mixing within the hottest assembly are then superimposed on the average conditions of the hottest assembly to determine conditions in the hot channel.

The following sections describe the use of the THINC code in the thermal-hydraulic design evaluation.

4.4.3.15.1.1 Steady State Analysis

The THINC-IV computer program determines coolant density, mass velocity, enthalpy, vapor void, static pressure, and DNBR distributions along parallel flow channels within a reactor core under all expected operating conditions. The core region being studied is made up of a number of contiguous elements in a rectangular array extending the full length of the core. An element may represent any region of the core from a single assembly to a subchannel.

The momentum and energy exchange between elements in the array are described by the conservation of energy and mass equations, the axial momentum equation, and two lateral momentum equations that couple each element with its neighbors. The momentum equations used in THINC-IV incorporate frictional loss terms that represent the combined effects of frictional and form drag due to the presence of the grids and fuel assembly nozzles in the core. The cross flow resistance model used in the lateral momentum equations was developed from experimental data for flow normal to tube banks (Reference 54). The energy equation for each element also contains additional terms that represent the energy gain or loss due to the cross flow between elements.

The unique feature in THINC-IV is that lateral momentum equations, which include both inertial and cross flow resistance terms, are incorporated into the calculation scheme. Another important consideration in THINC-IV is that the entire velocity field is solved, en masse, by a field equation. The solution method is complex and some simplifying techniques must be employed. Because the reactor flow is chiefly in the axial direction, the core flow field is primarily one-dimensional, and it is reasonable to assume that the lateral velocities and the parameter gradients are larger in the axial direction than the lateral direction. Thus, a perturbation technique is used to represent separately the axial and lateral parameters in the conservation equations.

Three THINC-IV computer runs constitute one design run: a core-wide analysis, a hot-assembly analysis, and a hot subchannel analysis.

The first computation is a core-wide assembly-by-assembly analysis that uses an inlet velocity distribution modeled from experimental reactor models (References 52, 53, and 60) (refer to Section 4.4.3.12.2). The core is made up of a number of contiguous fuel

assemblies divided axially into increments of equal length. The system of perturbed and unperturbed equations is solved for this array giving the flow, enthalpy, pressure drop, temperature, and void fraction in each assembly. This computation determines the inter-assembly energy and flow exchange at each elevation for the hot assembly. THINC-IV stores this information, then uses it for the subsequent hot assembly analysis.

In the second computation, each computational element represents one-fourth of the hot assembly. The inlet flow and the amount of momentum and energy interchange at each elevation are known from the previous core-wide calculation. The same solution technique is used to solve for the local parameters in the hot one-quarter assembly.

The third computation further divides the hot assembly into channels consisting of individual fuel rods to form flow channels. The local variations in power, fuel rod and pellet fabrication, fuel rod spacing and mixing (engineering hot channel factors) within the hottest assembly are imposed on the average conditions of the hottest fuel assembly to determine the conditions in the hot channel. Engineering hot channel factors are described in Section 4.4.3.3.4.

4.4.3.15.1.2 Experimental Verification

An experimental verification (Reference 59) of the THINC-IV analysis for core-wide assembly-by-assembly enthalpy rises, as well as enthalpy rises in a non-uniformly heated rod bundle, have been obtained. In these tests, system pressure, inlet temperature, mass flowrate, and heat fluxes were typical of present PWR core designs.

During reactor operation, various incore monitoring systems obtain measured data indicating core performance. Assembly power distributions and assembly mixed mean temperature are measured and can be converted into the proper three-dimensional power input needed for the THINC programs. These data can then be used to verify the Westinghouse thermal-hydraulic design codes.

One standard startup test is the natural circulation test in which the core is held at a very low power (2 percent) and the pumps are turned off. The core will then be cooled by the natural circulation currents created by the power differences in the core. During natural circulation, a thermal siphoning effect occurs, resulting in the hotter assemblies gaining flow, thereby creating significant inter-assembly cross flow. Tests with significant cross flow are of more value in code verification.

Inter-assembly cross flow is caused by radial variations in pressure that are caused in turn by variations in the axial pressure drops in different assemblies. Under normal operating conditions (subcooled forced convection), the axial pressure drop is due mainly to friction losses. Because all assemblies have the same geometry, all assemblies have nearly the same axial pressure drops, and cross flow velocities are small. However, under natural circulation conditions (low flow) the axial pressure drop is due primarily to the difference in elevation head (or coolant density) between assemblies. This phenomenon can result in relatively large radial pressure gradients

and, therefore, in higher cross flow velocities than at normal reactor operating conditions.

Incore instrumentation was used to obtain the assembly-by-assembly core power distribution during a natural circulation test. Assembly exit temperatures during the natural circulation test on a 157-assembly three-loop plant were predicted using THINC-IV. The predicted data points were plotted as assembly temperature rise versus assembly power, and a least squares fitting program was used to generate an equation that best fits the data. The result is the straight line presented in Figure 4.4-11 and is predicted closely by THINC-IV. This agreement verifies the lateral momentum equations and the cross flow resistance model used in THINC-IV.

Data have been obtained for Westinghouse plants operating from 67 to 101 percent of full power. A representative cross-section of the data obtained from a two-loop and a three-loop reactor was analyzed to verify the THINC-IV predictions that are compared with the experimental data in Figures 4.4-12 and 4.4-13.

The predicted assembly exit temperatures were compared with the measured exit temperatures for each data run. The standard deviations of the measured and predicted assembly exit temperatures are compared for both THINC-IV and THINC-I, and are given in Table 4.4-3. THINC-IV generally fits the data somewhat more accurately than THINC-I. Both codes are conservative and predict exit temperatures higher than measured values for the high-powered assemblies. Experimental verification of the THINC-IV subchannel calculation has been obtained from exit temperature measurements in a non-uniformly heated rod bundle (Reference 66).

Figure 4.4-14 compares, for a typical run, the measured and predicted temperature rises as a function of the power density in the channel. The THINC-IV results correctly predict the temperature gradient across the bundle.

In Figure 4.4-15, the measured and predicted temperature rises are compared for a series of runs at different pressures, flows, and power levels. Again, the measured points represent the average of the measurements taken in the various quadrants. The THINC-IV predictions provide a good representation of the data.

Thus, the THINC-IV analysis provides a realistic evaluation of the core performance and is used in the thermal analyses as described above.

4.4.3.15.1.3 Transient Analysis

The THINC-III thermal-hydraulic computer code (Reference 41) is the third section of the THINC program and has transient DNB analysis capability.

The conservation equations needed for the transient analysis are included in THINC-III by adding the necessary accumulation terms to the conservation equations used in the

steady state analysis. The input description must now include one or more of the following time arrays:

(1) Inlet flow variation

(2) Heat flux distribution

(3) Inlet pressure history

At the beginning of the transient, the calculation procedure is carried out as in the steady state analysis. The THINC-III code is first run in the steady state mode to ensure conservatism with respect to THINC-IV and to provide the steady state initial conditions at the start of the transient. The time is incremented by an amount determined either by the user or by the program. At each new time step, the accumulation terms are evaluated using the information from the previous time step. This procedure is continued until a preset maximum time is reached.

At various times during the transient, steady state THINC-IV is applied to show that the application of THINC-III is conservative. The THINC-III code does not have the capability for evaluating fuel rod thermal response. This is treated by the methods described in Section 15.1.9.

4.4.3.15.2 Fuel Temperatures

As discussed in Section 4.4.3.2, fuel rod behavior is evaluated with a semiempirical thermal model that considers, in addition to the thermal aspects, such items as cladding creep, fuel swelling, fission gas release, release of absorbed gases, cladding corrosion, elastic deflection, and helium solubility.

A detailed description of the thermal model can be found in References 67 and 83 with the modifications for the time-dependent densification given in Reference 68.

4.4.3.16 Hydrodynamic and Flow-Power Coupled Instability

Boiling flow may be susceptible to thermohydrodynamic instabilities (Reference 69). These instabilities may cause a change in thermo-hydraulic conditions that may lead to a reduction in the DNB heat flux relative to that observed during a steady flow condition, or to undesired forced vibrations of core components. Thus, the thermo-hydraulic design criterion states that operation during Condition I and Condition II events shall not lead to thermohydrodynamic instabilities.

Two specific types of flow instabilities are considered by Westinghouse for PWR operation. These are the Ledinegg, or flow excursion, type of static instability and the density wave type of dynamic instability.

A Ledinegg instability involves a sudden change in flowrate from one steady state to another. This instability occurs (Reference 69) when the slope of the RCS pressure drop-flowrate curve becomes algebraically smaller than the slope of the loop supply (pump head) pressure drop-flowrate curve. The Westinghouse pump head curve has a negative slope whereas the RCS pressure drop-flow curve has a positive slope over the Conditions I and II operational ranges. Thus, Ledinegg instability will not occur.

The mechanism of density wave oscillations in a heated channel has been described by Lahey and Moody (Reference 70).

The method developed by Ishii (Reference 71) for parallel closed channel systems evaluates if a given condition is stable with respect to the density wave type of dynamic instability. This method had been used to assess the stability of typical Westinghouse reactor designs (References 72, 73, and 74) under operating Conditions I and II. The results indicate that a large margin to density wave instability exists (e.g., an increase in the order of 200 percent of rated reactor power would be required) for the inception of this type of instability.

Flow instabilities that have been observed have occurred almost exclusively in closed channel systems operating at low pressures relative to the Westinghouse PWR operating pressures. Kao, Morgan, and Parker (Reference 75) analyzed parallel closed channel stability experiments simulating a reactor core flow. These experiments were conducted at pressures up to 2200 psia. The results showed that for flow and power levels typical of power reactor conditions, no flow oscillations could be induced above 1200 psia. Additional evidence that flow instabilities do not adversely affect thermal margin is provided by data from rod bundle DNB tests.

In summary, it is concluded that thermo-hydrodynamic instabilities will not occur under Conditions I and II events for Westinghouse PWR designs. A large power margin exists to predicted inception of such instabilities. Analysis has been performed and shows that minor plant-to-plant differences in Westinghouse reactor designs such as fuel assembly arrays, core power flow ratios, fuel assembly length, etc., will not result in gross deterioration of the above power margins.

4.4.3.17 Temperature Transient Effects Analysis

Waterlogging damage of a fuel rod could occur as a consequence of a power increase on a rod after water has entered the fuel rod through a cladding defect and will continue until the fuel rod internal pressure equals the reactor coolant pressure. A subsequent power increase raises the temperature and, hence, could raise the pressure of the water contained within the fuel rod. Zirconium alloy-clad fuel rods, which have failed due to waterlogging (References 76 and 77) indicate that very rapid power transients are required for fuel failure. Normal operational transients are limited to about 40 cal/gm-min. (peak rod) while the Spert tests (Reference 76) indicate that 120 to 150 cal/gm is required to rupture the clad even with very short transients (5.5 msec. period). Release of the internal fuel rod pressure is expected to have a minimal effect on the

RCS (Reference 76) and is not expected to result in failure of additional fuel rods (Reference 77). Ejection of fuel pellet fragments into the coolant stream is not expected (References 76 and 77). A cladding breach due to waterlogging is thus expected to be similar to any fuel rod failure mechanism that exposes fuel pellets to the reactor coolant stream. Waterlogging has not been identified as the mechanism for cladding distortion or perforation of any Westinghouse Zirconium alloy-clad rods.

An excessively high fuel rod internal gas pressure could cause cladding failure. During operational transients, fuel rod cladding rupture due to high internal gas pressure is precluded by adopting a design basis that the fuel rod internal gas pressure remains below the value that causes the fuel-cladding diametral gap to increase due to outward cladding creep.

4.4.3.18 Potentially Damaging Temperature Effects During Transients

A fuel rod experiences many operational transients (intentional maneuvers) while in the core. Several thermal effects must be considered when designing and analyzing fuel rod performance.

The cladding can be in contact with the fuel pellet at some time in the fuel lifetime. Cladding-pellet interaction occurs if fuel pellet temperature is increased after the cladding is in contact with the pellet. Cladding-pellet interaction is discussed in Section 4.2.1.2.3.

Increasing fuel temperature results in an increased fuel rod internal pressure. One of the fuel rod acceptance criteria is that the fuel rod internal pressures remain below values that can cause the fuel-cladding diametral gap to increase due to outward cladding creep (refer to Section 4.2.1.2.1).

The potential effects of operation with waterlogged fuel were discussed in Section 4.4.3.17, which concluded that waterlogging is not a concern during operational transients.

Clad flattening, as noted in Section 4.2.1.2.3, has been observed in some operating power reactors. Thermal expansion (axial) of the fuel rod stack against a flattened section of cladding could cause cladding failure. This is no longer a concern because clad flattening is precluded by pre-pressurization.

A differential thermal expansion between the fuel rods and the guide thimbles can occur during a transient. Excessive bowing of fuel rods can occur if the grid assemblies do not allow axial movement of the fuel rods relative to the grids. Thermal expansion of fuel rods is considered in the grid design so that axial loads imposed on the fuel rods during a thermal transient will not result in excessively bowed fuel rods (refer to Section 4.2.1.3.2).

4.4.3.19 Energy Release During Fuel Element Burnout

As discussed in Section 4.4.3.14, the core is protected from going through DNB over the full range of possible operating conditions. At full power operation, the typical minimum DNBR was calculated for VANTAGE+ fuel for Unit 1 and for Unit 2 and is listed in Table 4.1-1. This means that, for these conditions, the probability of a rod going through DNB is less than 0.1 percent at 95 percent confidence level based on the statistics of the WRB-2 correlations (References 84 and 85). In the extremely unlikely event that DNB should occur, cladding temperature will rise due to steam blanketing the rod surface and the consequent degradation in heat transfer. During this time a potential for a chemical reaction between the cladding and the coolant exists. Because of the relatively good film boiling heat transfer following DNB, the energy release from this reaction is insignificant compared to the power produced by the fuel.

These results have been confirmed in DNB tests conducted by Westinghouse (References 66 and 78).

4.4.3.20 Energy Release During Rupture of Waterlogged Fuel Elements

A full discussion of waterlogging including energy release is contained in Section 4.4.3.17.

4.4.3.21 Fuel Rod Behavior Effects from Coolant Flow Blockage

Coolant flow blockage can occur within the coolant channels of a fuel assembly or external to the reactor core. The effect of coolant flow blockage within the fuel assembly on fuel rod behavior is more pronounced than external blockages of the same magnitude. In both cases, the flow blockages cause local reductions in coolant flow. The amount of local flow reduction, its location in the reactor, and how far downstream reduction persists, are considerations that influence fuel rod behavior. Coolant flow blockage effects in terms of maintaining rated core performance are determined both by analytical and experimental methods. The experimental data are usually used to augment analytical tools such as the THINC-IV program. Inspection of the DNB correlation (refer to Section 4.4.3.3) shows that the predicted DNBR depends on local values of quality and mass velocity.

The THINC-IV code can predict the effects of local flow blockages on DNBR within the fuel assembly on a subchannel basis, regardless of where the flow blockage occurs. THINC-IV accurately predicts the flow distribution within the fuel assembly when the inlet nozzle is completely blocked (Reference 59). For the DCPP reactors operating at nominal full power conditions as specified in Table 4.1-1, the effects of an increase in enthalpy and decrease in mass velocity in the lower portion of the fuel assembly would not result in the reactor reaching the safety limit DNBR.

The analyses, which assume fully developed flow along the full channel length, show that a reduction in local mass velocity greater than approximately 53 percent would be

required before the safety limit DNBRs are reached. In reality, a local flow blockage is expected to promote turbulence and thus would likely not affect DNBR.

Coolant flow blockages induce local cross flows as well as promoting turbulence. Fuel rod vibration could occur, caused by this cross flow component, through vortex shedding or turbulent mechanisms. If the cross flow velocity exceeds the limit established for fluid elastic stability, large amplitude whirling will result in, and can lead to, mechanical wear of the fuel rods at the grid support locations. The limits for a controlled vibration mechanism are established from studies of vortex shedding and turbulent pressure fluctuations. Fuel rod wear due to flow-induced vibration is considered in the fuel rod fretting evaluation (refer to Section 4.2.1.3.2.7).

4.4.4 THERMAL AND HYDRAULIC DESIGN EVALUATION

4.4.4.1 Departure from Nucleate Boiling

DNB will not occur on at least 95 percent of the limiting fuel rods during normal operation and operational transients and any transient conditions arising from faults of moderate frequency (Condition I and Condition II events) at a 95 percent confidence level.

This criterion has been conservatively met by adhering to the following thermal design basis: there must be at least a 95 percent probability that the minimum DNBR of the limiting power rod during Condition I and II events is greater than or equal to the DNBR limit of the DNB correlation being used. The DNBR limit for the correlation is established based on the variance of the correlation such that there is a 95 percent probability with 95 percent confidence that DNB will not occur when the calculated DNBR is at the DNBR limit.

Historically, this DNBR limit has been 1.30 for Westinghouse applications. In this application the WRB-1 correlation (Reference 84) for LOPAR fuel and the WRB-2 correlation (Reference 85) for VANTAGE 5 fuel are employed (refer to Section 15.1.4.2). With the significant improvement in the accuracy of the CHF prediction by using these correlations instead of previous DNB correlations, a DNBR limit of 1.17 is applicable in this application. For 17 x 17 VANTAGE+ fuel, a DNBR limit of 1.17 is applicable to thermal-hydraulic analyses performed with the WRB-2 correlation.

The design method employed to meet the DNB design basis is the ITDP (Reference 86). Uncertainties in plant operating parameters, nuclear and thermal parameters, and fuel fabrication parameters are considered statistically such that there is at least a 95 percent probability that the minimum DNBR will be greater than or equal to 1.17 for the limiting power rod. Plant parameter uncertainties are used to determine the plant DNBR uncertainties. These DNBR uncertainties, combined with the DNBR limit, establish a design DNBR value, which must be met in plant safety analyses. Since the parameter uncertainties are considered in determining the design DNBR value, the plant safety analyses are performed using values of input parameters without

uncertainties. Table 4.4-4 lists the Chapter 15 non-LOCA accident analyses and the applicable DNB design method.

This design procedure is illustrated in Figure 4.4-18. For this application, the minimum required DNBR design limits for the VANTAGE+ fuel analysis are 1.32 for thimble cells (three fuel rods and a thimble tube) and 1.34 for typical cells (four fuel rods).

In addition to the above considerations, a plant-specific DNBR margin has been considered in the analyses. In particular, safety analysis DNBR limits of 1.68 for thimble cells and 1.71 for typical cells for the VANTAGE+ fuel, were employed in the safety analyses. The plant allowance available between the DNBRs used in the safety analyses and the design DNBR values is not required to meet the design basis discussed earlier. This allowance is used for the flexibility in the design, operation, and analyses of DCPP.

By preventing DNB, adequate heat transfer is ensured between the fuel cladding and the reactor coolant, thereby preventing cladding damage. Maximum fuel rod surface temperature is not a design basis because it will be within a few degrees of coolant temperature during operation in the nucleate boiling region. Limits provided by the nuclear control and protection systems are such that this design basis will be met for transients associated with Condition II events including overpower transients. The DNBR margin at rated power operation and during normal operating transients is substantially larger (refer to Table 4.1-1).

4.4.4.2 Fuel Temperature

During Conditions I and II events, the maximum fuel temperature shall be less than the melting temperature of UO_2. The UO_2 melting temperature for at least 95 percent of the peak kW/ft fuel rods will not be exceeded at the 95 percent confidence level.

The melting temperature of UO_2 is taken as 5080°F (Reference 1) unirradiated, and decreasing 58°F per 10,000 megawatt days per metric ton of uranium (MWD/MTU). By precluding UO_2 melting, the fuel geometry is preserved and possible adverse effects of molten UO_2 on the cladding are eliminated. To preclude center melting and establish overpower protection system setpoints, a calculated centerline fuel temperature of 4700°F has been selected as the overpower limit, thus providing sufficient margin for uncertainties. The peak linear power value used in the design evaluation is 22.0 kW/ft. This value corresponds to a peak centerline temperature which is less than 4700°F.

Fuel rod thermal evaluations are performed at rated power, maximum overpower, and during transients at various burnups. These analyses ensure that this design basis, as well as the fuel integrity design bases given in Section 4.2, are met. They also provide input for the evaluation of Conditions III and IV faults given in Chapter 15.

4.4.4.3 Core Flow

A minimum of 92.5 percent (Unit 1) and 91 percent (Unit 2) of the thermal flowrate (refer to Section 5.1) will pass through the fuel rod region of the core and be effective for fuel rod cooling. Coolant flow through the thimble tubes, as well as leakage from the core barrel-baffle region into the core, is not effective for heat removal.

Core cooling evaluations are based on the thermal flowrate (minimum flow) entering the reactor vessel. On Unit 1 the design core bypass flow is 7.5%, which accounts for thimble plugs removed, intermediate flow mixing vanes, and allowance for possible future upflow conversion. On Unit 2 the design core bypass flow is 9.0%, which accounts for thimble plugs removed, intermediate flow mixing vanes, upflow conversion and upper head temperature reduction.

4.4.4.4 Hydrodynamic Stability

Operation during Condition I and Condition II events shall not lead to hydrodynamic instability.

4.4.5 SAFETY EVALUATION

4.4.5.1 General Design Criterion 10, 1971 – Reactor Design

The preceding evaluations show that the SAFDLs are not exceeded during any condition of normal operation or anticipated operational occurrence. Specifically:

- Section 4.4.4.1 shows that the DNB limits are not exceeded;
- Section 4.4.4.2 shows that the maximum fuel temperature limits are not exceeded; and
- Section 4.4.4.3 shows that the minimum core flow is met.

The above design bases, together with the fuel cladding and fuel assembly design bases given in Section 4.2.1.1, are sufficient. Fuel cladding integrity criteria cover possible effects of cladding temperature limitations. As noted in Section 4.2.1.2.3, the fuel rod conditions change with time. A single cladding temperature limit for Conditions I or II events is not appropriate since of necessity it would be overly conservative. A cladding temperature limit is applied to the LOCA (refer to Section 15.4.1), control rod ejection accident (Reference 2), and locked rotor accident (Reference 67).

4.4.5.2 General Design Criterion 12, 1971 – Suppression of Reactor Power Oscillations

Thermo-hydrodynamic instabilities (i.e., oscillations) will not occur under Condition I and Condition II events for DCPP. A large power margin exists to predicted inception of

such instabilities. Analyses have been performed and show that in Westinghouse reactor designs, parameters such as fuel assembly arrays, core power flow ratios, fuel assembly length, etc., do not result in gross deterioration of the above power margins (refer to Section 4.4.3.16).

4.4.6 TESTS AND INSPECTIONS

4.4.6.1 Testing Prior to Initial Criticality

Reactor coolant flow tests, as noted in Tests 3.9 and 3.10 of Table 14.1-2, are performed following fuel loading, but prior to initial criticality. Coolant loop pressure drop data are obtained in this test. These data, in conjunction with coolant pump performance information, allow determination of the coolant flowrates at reactor operating conditions. This test verifies that proper coolant flowrates have been used in the core thermal and hydraulic analysis.

4.4.6.2 Initial Power Plant Operation

Core power distribution measurements are made at several core power levels (refer to Section 4.3.3.2.7) during startup and initial power operation. These tests are used to verify that conservative peaking factors were used in the core thermal and hydraulic design and analysis.

4.4.6.3 Component and Fuel Inspections

Inspections performed on the manufactured fuel are delineated in Section 4.2.1.6. Fabrication measurements critical to thermal and hydraulic analysis are obtained to verify that the engineering hot channel factors employed in the design analyses (refer to Section 4.4.3.3.4) are met.

4.4.7 INSTRUMENTATION APPLICATIONS

4.4.7.1 Incore Instrumentation

Instrumentation is located in the core so that by correlating movable neutron detector information with fixed thermocouple information the radial core characteristics may be obtained for all core quadrants.

The incore instrumentation system is comprised of thermocouples, positioned to measure fuel assembly coolant outlet temperatures at preselected positions, and movable fission chamber detectors positioned in guide thimbles that run the length of selected fuel assemblies to measure the neutron flux distribution. Figures 4.4-16 and 4.4-17 show the number and location of instrumented assemblies in the core for Unit 1 and Unit 2, respectively. In the Unit 1 reactor, four of these thermocouples have been moved to the upper head for monitoring conditions in the upper head.

The core exit thermocouples provide a backup for the flux monitoring instrumentation to monitor power distribution. The routine, systematic collection of thermocouple readings provides a data base. From this data base, abnormally high or abnormally low readings, quadrant temperature tilts, or systematic departures from a prior reference map can be deduced.

The movable incore neutron detector system is used for more detailed mapping should the thermocouple system indicate an abnormality. These two complementary systems are more useful when taken together than taken alone. The incore instrumentation system is described in more detail in Section 7.7.2.9.

Incore instrumentation is provided to obtain data from which fission power density distribution in the core, coolant enthalpy distribution in the core, and fuel burnup distribution may be determined.

4.4.7.2 Overtemperature and Overpower ΔT Instrumentation

The overtemperature ΔT trip protects the core against low DNBR. The overpower ΔT trip protects against excessive power (fuel rod rating protection).

As discussed in Section 7.2.2.1.2, factors included in establishing the overtemperature ΔT and overpower ΔT trip setpoints include the reactor coolant temperature in each loop. The axial distribution of core power, as determined by the two-section (upper and lower) excore neutron detectors, is also a factor in establishing the overtemperature ΔT trip.

4.4.7.3 Instrumentation to Limit Maximum Power Output

The output of the three ranges (source, intermediate, and power) of detectors, with the associated nuclear instrumentation electronics, is used to limit the maximum power output of the reactor.

Eight instrument wells are located around the reactor periphery in the primary shield, 45° apart from each other, at an equal distance from the reactor vessel.

Two of the positions, on opposite flat portions of the core, directly across from the secondary neutron source positions, each contain a BF_3 proportional counter to cover the source range, and a compensated ionization chamber for the intermediate range. The source range detector is located at an elevation of approximately one-fourth of the core height; the compensated ionization chambers are positioned at an elevation corresponding to one-half of the core height. The two positions opposite the other two flat portions of the core house the post-accident neutron flux monitor detectors.

Four dual-section uncompensated ionization chamber assemblies are installed vertically in the instrumentation wells directly across from the four corners of the core. They are used as power range detectors. To minimize neutron flux pattern distortions, they are placed within 1 foot of the reactor vessel. Each dual-section uncompensated ionization

chamber assembly provides two signals that correspond to the neutron flux in the upper and in the lower positions of a core quadrant, thus permitting the determination of relative axial power production.

Signals from the detectors in the three ranges (source, intermediate, and power) provide inputs which, when combined, monitor neutron flux from a completely shutdown condition to 120 percent of full power, with the capability of recording overpower excursions up to 200 percent of full power.

The difference in neutron flux readings between the upper and lower sections of the power range detectors is used to limit the overtemperature ΔT and overpower ΔT trip setpoints and to provide the operator with an indication of the core power AO. In addition, the output of the power range channels is used as follows:

(1) For the rod speed control function

(2) To alert the operator to an excessive power unbalance between the quadrants

(3) To protect the core against rod ejection accidents

(4) To protect the core against adverse power distributions resulting from dropped rods

Details of the neutron detectors and nuclear instrumentation design and the control and trip logic are given in Chapter 7. The limits on neutron flux operation and trip setpoints are given in the Technical Specifications.

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TABLE 4.1-1

REACTOR DESIGN COMPARISON

Thermal and Hydraulic Design Parameters (Using ITDP)[a]	Unit 1	Unit 2
Reactor Core Heat Output, MWt	3,411	3,411
Reactor Core Heat Output, 10^6 Btu/hr	11,639	11,639
Heat Generated in Fuel, %	97.4	97.4
Reactor Coolant Pressure, psia	2,250	2,250
Fuel Type	Vantage+	Vantage+
Design DNBR Limit		
Typical Cell	1.34	1.34
Thimble Cell	1.32	1.32
Safety Analysis DNBR Limit		
Typical Cell	1.71	1.71
Thimble Cell	1.68	1.68
DNB Correlation	WRB-2	WRB-2

TABLE 4.1-1

		Unit 1	Unit 2
Vessel Minimum Measured Flow Rate (including Bypass) gpm		359,200	362,500
Vessel Thermal Design Flow[e] Rate (including Bypass) gpm		350,800	354,000
Thermal and Hydraulic Design Parameters (Based on Thermal Design Flow)			
Core Flow Rate (excluding Bypass)			
10^6 lbm/hr		122.3	123.4
gpm		324,490	327,450
Effective Core Flow Area for Heat Transfer, ft^2		54.13	54.13
Average Velocity along Fuel[k] Rods, ft/sec		14.0	14.2
Core Inlet Mass Velocity, 10^6 lbm/hr-ft	(V-5)	2.26	2.28

TABLE 4.1-1

	Unit 1	Unit 2
Nominal Vessel/Core Inlet Temperature, °F	531.7 - 544.5	531.9 -545.1
Vessel Average Temperature, °F	565.0 - 577.3	565.0 - 577.6
Core Average Temperature, °F	569.1 - 581.5	569.6 - 582.3
Vessel Outlet Temperature, °F	598.3 - 610.1	598.1 - 610.1
Average Temperature Rise in Vessel, °F	66.6 - 65.6	66.2 - 65.0
Average Temperature Rise in Core, °F	71.6 - 70.4	72.1 - 70.7
Heat Transfer		
Active Heat Transfer Surface Area, ft^2	57,505	57,505
Average Heat Flux, Btu/hr-ft^2	197,180	197,180
Maximum Heat Flux for Normal[h] Operation, Btu/hr-ft^2	508,720	508,720
Average Linear Power, kW/ft	5.445	5.445
Peak Linear Power for Normal Operation,[h] kW/ft	14.3	14.3
Peak Linear Power for Prevention of Centerline Melt, kW/ft	22.0[i]	22.0[i]
Pressure Drop[j] Across Core, psi *	25.5 + 2.6	27.2 + 2.7
Across Vessel,[n] including nozzle, psi *	52.8 + 5.3	48.2 + 4.8
Thermal and Hydraulic Design Parameters (Fuel Rod Design)		
Heat Flux Hot Channel Factor, F_Q^T	2.58	2.58
Temperature at Peak Linear Power for Prevention of Centerline Melt, °F	4,700	4,700
Fuel Centerline Temperature, °F		
Peak at 102% power	<3,360	<3,360
Peak at maximum thermal output for maximum overpower DT trip point	<3,770	<3,770

* Pressure drop values for mechanical design flow and low inlet temperatures of 531.7°F and 531.9°F for Unit 1 and Unit 2.

TABLE 4.1-1

Core Mechanical Design Parameters	Unit 1	Unit 2
Fuel Assemblies		
Design	RCC Canless	RCC Canless
Number of fuel assemblies	193	193
Rod array	17 X 17	17 X 17
$U0_2$ rods per assembly	264	264
Rod pitch, in	0.496	0.496
Overall dimensions, in	8.424 x 8.424	8.424 x 8.424
Fuel weight (as UO_2) lb	200,720/205,159	200,720/205,159
Zirconium alloy weight, lb	51,917	51,917
Number of grids per assembly	12	12
	2 non-mixing vane type	2 non-mixing vane type
	6 mixing vane type	6 mixing vane type
	3 IFM; 1 P-Grid	3 IFM; 1 P-Grid
Composition of grids	Inconel® Alloy 718 or ZIRLO®	Inconel® Alloy 718 or ZIRLO®
Weight of grids, lb	1841/2820	1841/2820
Number of guide thimbles per assembly	24	24
Composition of guide thimbles	ZIRLO®	ZIRLO®
Diameter of guide thimbles (ID x OD), in.		
Upper part	0.442 x 0.474	0.442 x 0.474
Lower part	0.397 x 0.430	0.397 x 0.430
Diameter of instrument guide thimbles, in.	0.442 x 0.474	0.442 x 0.474

TABLE 4.1-1

Core Mechanical Design Parameters (Cont'd)	Unit 1	Unit 2
Fuel Rods		
Number	50,952	50,952
Outside diameter, in	0.360	0.360
Diametral gap, in	0.0062	0.0062
Cladding thickness, in	0.0225	0.0225
Cladding material	ZIRLO®	ZIRLO®
Gap material	Helium	Helium
Fuel Pellets		
Material	UO_2 sintered	UO_2 sintered
Density, % of theoretical	95	95
Diameter, in	0.3088 ± 0.0005	0.3088 ± 0.0005
Length, in		
Enriched or IFBA Pellets	0.370 ± 0.025	0.370 ± 0.025
Axial Blanket Pellets (refer to Section 4.2.1.2.2)	0.500 ± 0.025	0.500 ± 0.025
Mass of UO_2, lb/ft of fuel rod	0.334	0.334
Rod Cluster Control Assemblies		
Neutron absorber,	Ag-In-Cd	Ag-In-Cd
Composition	80%, 15%, 5%	80%, 15%, 5%
Diameter, in	0.341 ± 0.001*	0.341 ± 0.001*
Nominal length of absorber material, in.	142	142
Density, lb/in^3	0.367	0.367
Cladding material		
Framatome RCCAs	Ion-nitrided, cold worked, Type 316L SS	Ion-nitrided, cold worked, Type 316L SS
Westinghouse RCCAs	Chrome Plated, cold worked, Type 304 SS	Chrome Plated, cold worked, Type 304 SS
Cladding thickness, in	0.0185	0.0185
Number of RCCAs	53	53
Number of absorber rods per cluster	24	24
Core Structure		
Core barrel, ID/OD, in	148.0/152.5	148.0/152.5
Thermal shield, ID/OD, in	158.5/164.0	Neutron pad Design

* Diameter reduced to 0.336 $\pm$ 0.001 over bottom 12 inches.

TABLE 4.1-1

Nuclear Design Parameters	Unit 1	Unit 2
Structure Characteristics		
Core diameter, in (equivalent)	132.7	132.7
Core average active fuel height, in.	144	144
Reflector Thickness and Composition		
Top - water plus steel, in.	~10	~10
Bottom - water plus steel, in.	~10	~10
Side - water plus steel, in	~15	~15
H_2O/U, cold molecular ratio lattice	2.73	2.73
Fuel Enrichment, Wt%		
Maximum feed enrichment	5.0	5.0
Burnable Absorbers		
Type	IFBA	IFBA
Number (typical range)	2000 - 15000	2000 - 15000
Material	ZrB_2	ZrB_2
B10 Loading, mg/inch (typical)	2.25	2.25

(a) Includes the effect of fuel densification

(b) Deleted

(c) Based on T_{in} = 545.1°F (Unit 1) and T_{in} = 545.7°F (Unit 2) corresponding to Minimum Measured Flow of each unit

(d) Deleted

(e) Includes 0 to 10 percent steam generator tube plugging

(f) Deleted

(g) Deleted

(h) This limit is associated with the value of F_Q^T = 2.58

(i) Refer to Section 4.3.3.2.6

(j) Based on best estimate reactor flow rate(refer to Section 5.1)

(k) At core average temperature

(l) Deleted

(m) Deleted

(n) Deleted

TABLE 4.1-2

ANALYTICAL TECHNIQUES IN CORE DESIGN

Analysis	Technique	Computer Code	Section Referenced
Mechanical Design of Core Internals			
Loads, deflections, and stress analysis	Static and dynamic modeling	WECAN; ANSYS; MULTIFLEX 3.0; BLODWN-2; LATFORC; WEGAP	3.7, 3.9
Fuel Rod Design			
Fuel performance characteristics (temperature, internal pressure, cladding stress, etc.)	Semiempirical thermal model of fuel rod with consideration of fuel density changes, heat transfer, fission gas release, etc.	Westinghouse fuel rod design model; PAD 4.0	4.2.1.2.2.5 4.4.3.15.2

TABLE 4.1-2

Analysis	Technique	Computer Code	Section Referenced
Nuclear Design			
(1) Cross sections and group constants	Microscopic data	Modified ENDF/B library	4.3.3.10.2
	Macroscopic constants for homogenized core regions	LEOPARD /CINDER type and PHOENIX-P	4.3.3.10.2
	Group constants for control rods with self-shielding	HAMMER-AIM and PHOENIX-P/ANC	4.3.3.10.2 4.3.3.10.3
(2) X-Y power distributions, fuel depletion, critical boron concentrations, X-Y xenon distributions, reactivity coefficients and control rod worths	2-D, 2-group diffusion theory	TURTLE and ANC	4.3.3.10.3
(3) X-Y-Z power distributions, fuel depletion, critical boron concentrations, X-Y-Z xenon distributions, reactivity coefficients and control rod worths	3-D, 2-group diffusion theory	3D PALADON and ANC	4.3.3.10.3
(4) Axial power distributions and axial xenon distributions	1-D, 2-group diffusion theory	PANDA/APOLLO	4.3.3.10.3
(5) Fuel rod power	Integral transport theory	LASER / 3D ANC	4.4.3.2.3
(6) Effective resonance temperature	Radial weighting function	REPAD / FIGHTH	4.3.3.10.1

TABLE 4.1-2

Analysis	Technique	Computer Code	Section Referenced
Thermal-Hydraulic Design			
(1) Steady state	Subchannel analysis of local fluid conditions in rod bundles, including inertial and crossflow resistance terms, solution progresses from core-wide to hot assembly to hot channel	THINC-IV	4.4.3.3 4.4.3.5 4.4.3.10.5 4.4.3.12 4.4.3.13 4.4.3.15 4.4.3.21
(2) Transient DNB analysis	Subchannel analysis of local fluid conditions in rod bundles during transients by including accumulation terms in conservation equations; solution progresses from core-wide to hot assembly to hot channel	THINC-III	4.4.3.15.1.3

TABLE 4.1-3

DESIGN LOADING CONDITIONS FOR REACTOR CORE COMPONENTS

(1) Fuel assembly weight
(2) Fuel assembly spring forces
(3) Internals weight
(4) Control rod scram (equivalent static load)
(5) Differential pressure
(6) Spring preloads
(7) Coolant flow forces (static)
(8) Temperature gradients
(9) Differences in thermal expansions
    (a) Due to temperature differences
    (b) Due to expansion of different materials
(10) Interference between components
(11) Vibration (mechanically or hydraulically induced)
(12) One or more loops out of service
(13) All operational transients listed in Table 5.2-4
(14) Pump overspeed
(15) Seismic loads (DE and DDE)
(16) Blowdown forces (due to RCS branch line breaks)[a]

(a) In the original analysis, the blowdown forces used were those resulting from breaks in the RCS cold and hot legs. However, with the acceptance of the DCPP leak-before-break analysis by the NRC, the blowdown forces resulting from pipe rupture events in the main reactor coolant loop piping no longer have to be considered in the design basis structural analyses and included in the loading combinations. Only the much smaller forces from RCS branch line breaks have to be considered (see Section 3.6.2.1.1.1).

TABLE 4.3-1

NUCLEAR DESIGN PARAMETERS
(Typical)

Core Average Linear Power, kW/ft, including densification effects	5.445[a]
Total Heat Flux Hot Channel Factor, F_Q^T	2.58
Nuclear Enthalpy Rise Hot Channel Factor, $F_{\Delta H}^N$	1.65 VANTAGE+
Reactivity Coefficients	
Doppler coefficient	Refer to 4.3-29
Moderator temperature coefficient at operating conditions, pcm/°F[b]	+5 to -40
Boron coefficient in primary coolant, pcm/ppm	-16 to -8
Delayed Neutron Fraction and Lifetime	
β_{eff} BOL, (EOL)	0.0069, (0.0051)
l^* BOL, (EOL), µsec	19.2, (18.6)
Control Rod Worths	
Rod requirements	Refer to Table 4.3-2
Maximum bank worth, pcm	< 2000
Maximum ejected rod worth	Refer to Chapter 15

TABLE 4.3-1

Boron Concentrations (ppm)	
Refueling	≥ 2000
k_{eff} = 0.95, cold, rod cluster control assemblies in	≥ 2000
Full power, no xenon, k_{eff} = 1.0, hot, rod cluster control assemblies out	1876[d]
Full power, equilibrium xenon, k_{eff} = 1.0, hot, rod cluster control assemblies out	1536[d]
Reduction with fuel burnup Typical reload cycle, ppm/GWD/MTU[c]	Refer to Figure 4.3-3

(a) Data in table based on Unit 1 and Unit 2

(b) 1 pcm = percent mille
= 10^{-5} $\Delta\rho$ where $\Delta\rho$ is calculated from two state point values of k_{eff} by ln (k_2/k_1)

(c) Gigawatt day (GWD) = 1000 megawatt days (1000 MWD)

(d) These values are representative values used for analytical purposes only.

TABLE 4.3-2

UNIT 1 - REACTIVITY REQUIREMENTS FOR ROD CLUSTER CONTROL ASSEMBLIES

Reactivity Effects, %Δρ	HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED *Beginning of Life (First Cycle)*	*End of Life (First Cycle)*	End of Life (Equilibrium Cycle) (Typical)
1. Control Requirements			
Fuel temperature (Doppler)	*1.39*[(a)]	*1.12*[(a)]	1.00
Moderator temperature(includes void)	*0.16*	*0.89*	0.80
Redistribution	*0.50*	*0.85*	0.90
Rod insertion allowance	*0.50*	*0.50*	0.50
2. Total Control	*2.55*	*3.36*	3.20
3. Estimated Rod Cluster Control Assembly Worth (53 Rods) All but one (highest worth) assemblies inserted	*7.18*	*7.05*	6.50
4. Estimated Rod Cluster Control Assembly-Credit with 10% adjustment to accommodate uncertainties	*6.46*	*6.34*	5.85
5. Shutdown Margin Available (Section 4.2)	*3.91*	*2.98*	2.65[(b)]

(a) Includes 0.1 percent Δρ uncertainty

(b) The design basis minimum shutdown margin is 1.6% Δρ

TABLE 4.3-3

UNIT 2 - REACTIVITY REQUIREMENTS FOR ROD CLUSTER CONTROL ASSEMBLIES

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Reactivity Effects, %Δρ	*Beginning of Life (First Cycle)*	*End of Life (First Cycle)*	End of Life (Equilibrium Cycle) (Typical)
1. Control Requirements			
Fuel temperature (Doppler)	*1.39*[a]	*1.12*[a]	1.00
Moderator temperature (includes void)	*0.29*	*0.96*	0.94
Redistribution	*0.50*	*0.85*	0.90
Rod insertion allowance	*0.50*	*0.50*	0.50
2. Total Control	*2.68*	*3.43*	3.34
3. Estimated Rod Cluster Control Assembly Worth (53 Rods) All but one (highest worth) assemblies inserted	*6.48*	*6.38*	5.70
4. Estimated Rod Cluster Control Assembly (Credit with 10% adjustment to accommodate uncertainties	*5.83*	*5.74*	5.13
5. Shutdown Margin Available (Section 4.2)	*3.15*	*2.31*	1.79[b]

(a) Includes 0.1% Δρ uncertainty

(b) The design basis minimum shutdown margin is 1.6% Δρ

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

TABLE 4.3-4

AXIAL STABILITY INDEX
PWR CORE WITH A 12-FT HEIGHT

Burnup (MWD/MTU)	*F_Z*	*C_B (ppm)*	*Stability Index, hr^{-1}*	
			Exp.	*Calc.*
1550	*1.34*	*1065*	*-0.041*	*-0.032*
7700	*1.27*	*700*	*-0.014*	*-0.006*
		Difference:	*+0.027*	*+0.026*

TABLE 4.3-5

TYPICAL NEUTRON FLUX LEVELS (n/cm^2-sec) AT FULL POWER

	$E > 1$ MeV	5.53 keV $\leq E \leq 1$ MeV	0.625 eV $\leq E < 5.53$ keV	$E < 0.625$ eV $(nv)_0$
Core center	6.51×10^{13}	1.12×10^{14}	8.50×10^{13}	3.00×10^{13}
Core outer radius at midheight	3.23×10^{13}	5.74×10^{13}	4.63×10^{13}	8.60×10^{12}
Core top, on axis	1.53×10^{13}	2.42×10^{13}	2.10×10^{13}	1.63×10^{13}
Core bottom, on axis	2.36×10^{13}	3.94×10^{13}	3.50×10^{13}	1.46×10^{13}
Pressure vessel inner wall, azimuthal peak, core midheight	2.77×10^{10}	5.75×10^{10}	6.03×10^{10}	8.38×10^{10}

TABLE 4.3-6

COMPARISON OF MEASURED AND CALCULATED DOPPLER DEFECTS

Plant	Fuel Type	Core Burnup (MWD/MTU)	Measured (pcm)[a]	Calculated (pcm)
1	Air filled	1800	1700	1710
2	Air filled	7700	1300	1440
3	Air and helium filled	8460	1200	1210

(a) pcm = $10^{-5}\ \Delta\rho$. See footnote in Table 4.3-1

TABLE 4.3-7

BENCHMARK CRITICAL EXPERIMENTS

Description of Experiments	No. of Experiments	LEOPARD k_{eff} Using Experimental Bucklings
UO_2		
Al clad	14	1.0012
SS clad	19	0.9963
Borated H_2O	7	0.9989
Total	40	0.9985
U-metal		
Al clad	41	0.9995
Unclad	20	0.9990
Total	61	0.9993
Grand Total	101	0.9990

TABLE 4.3-8

SAXTON CORE II ISOTOPICS
ROD MY, AXIAL ZONE 6

Atom Ratio	Measured	2σ Precision, %	LEOPARD Calculation
U-234/U	4.65×10^{-5}	$\pm$ 29	4.60×10^{-5}
U-235/U	5.74×10^{-3}	$\pm$ 0.9	5.73×10^{-3}
U-236/U	3.55×10^{-4}	$\pm$ 5.6	3.74×10^{-4}
U-238/U	0.99386	$\pm$ 0.01	0.99385
Pu-238/Pu	1.32×10^{-3}	$\pm$ 2.3	1.222×10^{-3}
Pu-239/Pu	0.73971	$\pm$ 0.03	0.74497
Pu-240/Pu	0.19302	$\pm$ 0.2	0.19102
Pu-241/Pu	6.014×10^{-2}	$\pm$ 0.3	5.74×10^{-2}
Pu-242/Pu	5.81×10^{-3}	$\pm$ 0.9	5.38×10^{-3}
Pu/U[(a)]	5.938×10^{-2}	$\pm$ 0.7	5.970×10^{-2}
Np-237/U-238	1.14×10^{-4}	$\pm$ 15	0.86×10^{-4}
Am-241/Pu-239	1.23×10^{-2}	$\pm$ 15	1.08×10^{-2}
Cm-242/Pu-239	1.05×10^{-4}	$\pm$ 10	1.11×10^{-4}
Cm-244/Pu-239	1.09×10^{-4}	$\pm$ 20	0.98×10^{-4}

(a) Weight ratio

TABLE 4.3-9

CRITICAL BORON CONCENTRATIONS, AT HZP, BOL

Plant Type	Measured	Calculated
2-loop, 121 assemblies, 10-foot core	1583	1589
2-loop, 121 assemblies, 12-foot core	1625	1624
2-loop, 121 assemblies, 12-foot core	1517	1517
3-loop, 157 assemblies, 12-foot core	1169	1161
3-loop, 157 assemblies, 12-foot core	1344	1319
4-loop, 193 assemblies, 12-foot core	1370	1355
4-loop, 193 assemblies, 12-foot core	1321	1306

TABLE 4.3-10

COMPARISON OF MEASURED AND CALCULATED ROD WORTH

2-Loop Plant, 121 Assemblies, 10-foot core	Measured, pcm	Calculated, pcm
Group B	1885	1893
Group A	1530	1649
Shutdown group	3050	2917
ESADA Critical, 0.69-in pitch, 2 wt.% PuO_2, 8% Pu^{240}, 9 Control Rods		
6.21-in rod separation	2250	2250
2.07-in rod separation	4220	4160
1.38-in rod separation	4100	4010

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

TABLE 4.3-11

COMPARISON OF MEASURED AND CALCULATED MODERATOR TEMPERATURE COEFFICIENTS AT HZP, BOL

Plant Type/Control Bank Configuration	*Measured α_{iso}[(a)] pcm/°F*	*Calculated α_{iso} pcm/°F*
3-Loop, 157 Assemblies, 12-foot core		
D at 160 steps	*-0.50*	*-0.50*
D in, C at 190 steps	*-3.01*	*-2.75*
D in, C at 28 steps	*-7.67*	*-7.02*
B, C, and D in	*-5.16*	*-4.45*
2-Loop, 121 Assemblies, 12-foot core		
D at 180 steps	*+0.85*	*+1.02*
D in, C at 180 steps	*-2.40*	*-1.90*
C and D in, B at 165 steps	*-4.40*	*-5.58*
B, C, and D in, A at 174 steps	*-8.70*	*-8.12*

(a) Isothermal coefficients, which include the Doppler effect in the fuel

$$\alpha_{iso} = 10^5 \ln\left(\frac{k_2}{k_1}\right)/\Delta T(°F)$$

TABLE 4.4-1

UNIT 1
VOID FRACTIONS AT NOMINAL REACTOR CONDITIONS WITH
DESIGN HOT CHANNEL FACTORS

		Average	Maximum
Core	(VANTAGE+)	0.17%	--
Hot subchannel	(VANTAGE+)	0.89%	2.11%

TABLE 4.4-2

UNIT 2
VOID FRACTIONS AT NOMINAL REACTOR CONDITIONS WITH
DESIGN HOT CHANNEL FACTORS

		Average	Maximum
Core	(VANTAGE+)	0.19%	--
Hot subchannel	(VANTAGE+)	3.92%	14.51%

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

TABLE 4.4-3

COMPARISON OF THINC-IV AND THINC-I PREDICTIONS WITH DATA FROM REPRESENTATIVE WESTINGHOUSE TWO- AND THREE-LOOP REACTORS

Reactor	*Power, MWt*	*% Full Power*	*Measured Inlet Temp, °F*	*σ_{rms}, °F THINC-I*	*σ, °F THINC-IV*	*Improvement, °F for THINC-IV over THINC-1*
Ginna	*847*	*65.1*	*543.7*	*1.97*	*1.83*	*0.14*
	854	*65.7*	*544.9*	*1.56*	*1.46*	*0.10*
	857	*65.9*	*543.9*	*1.97*	*1.82*	*0.15*
	947	*72.9*	*543.8*	*1.92*	*1.74*	*0.18*
	961	*74.0*	*543.7*	*1.97*	*1.79*	*0.18*
	1091	*83.9*	*542.5*	*1.73*	*1.54*	*0.19*
	1268	*97.5*	*542.0*	*2.35*	*2.11*	*0.24*
	1284	*98.8*	*240.2*	*2.69*	*2.47*	*0.22*
	1284	*98.9*	*541.0*	*2.42*	*2.17*	*0.25*
	1287	*99.0*	*544.4*	*2.26*	*1.97*	*0.29*
	1294	*99.5*	*540.8*	*2.20*	*1.91*	*0.29*
	1295	*99.6*	*542.0*	*2.10*	*1.83*	*0.27*
Robinson	*1427.0*	*65.1*	*548.0*	*1.85*	*1.88*	*0.03*
	1422.6	*64.9*	*549.4*	*1.39*	*1.39*	*0.00*
	1929.0	*88.0*	*550.0*	*2.35*	*2.34*	*0.01*
	2207.3	*100.7*	*534.0*	*2.41*	*2.41*	*0.00*
	2213.9	*101.0*	*533.8*	*2.52*	*2.44*	*0.08*

TABLE 4.4-4

NON-LOCA DNB ANALYSIS METHOD

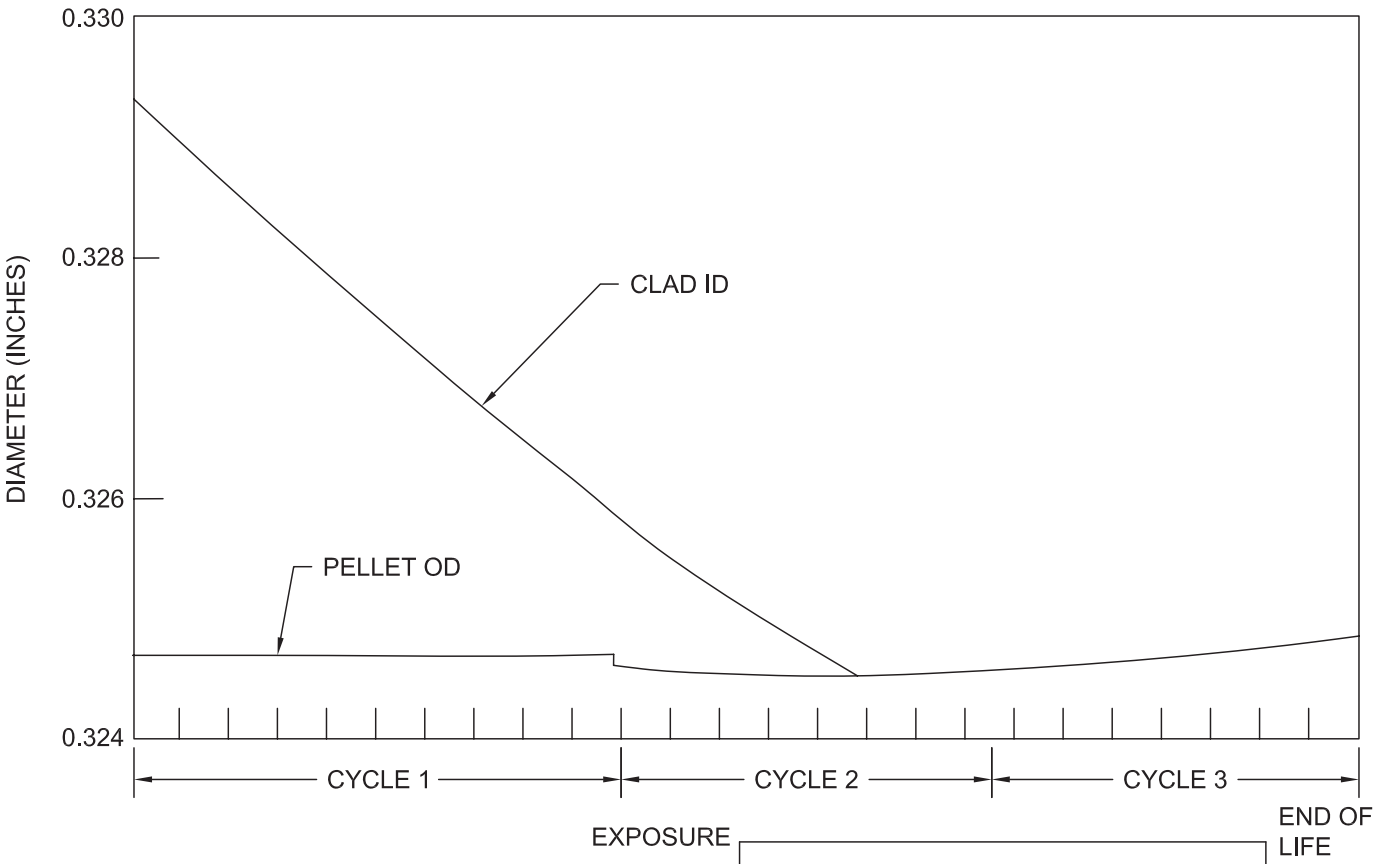
UFSAR Section(s)	Event	DNB Analysis Method[a]
15.2.1	RCCA Bank Withdrawal from Subcritical	Non-ITDP
15.2.2	RCCA Bank Withdrawal at Power	ITDP
15.2.3	RCCA Misoperation (Dropped Rod)	ITDP
15.2.4	Uncontrolled Boron Dilution	Not Applicable[b]
15.2.5	Partial Loss of Flow	ITDP
15.2.6	Startup of an Inactive Loop[c]	Non-ITDP
15.2.7	Loss of Electrical Load / Turbine Trip	ITDP
15.2.8, 15.2.9	Loss of Normal Feedwater / Loss of Offsite Power	Not Applicable (Non-DNB)
15.2.10	Feedwater Malfunction (excess flow)	ITDP
15.2.11	Sudden Feedwater Temperature Reduction	ITDP
15.2.12	Excessive Load Increase	ITDP
15.2.13	Accidental RCS Depressurization	ITDP
15.2.14	Accidental MSS Depressurization[d]	Non-ITDP
15.2.15	Spurious SI Actuation at Power	ITDP
15.3.4	Complete Loss of Flow	ITDP
15.3.5	Single RCCA Withdrawal at Power	ITDP
15.4.2.1	Rupture of a Main Steam Line (HZP)	Non-ITDP
15.4.2.2	Rupture of a Main Feedwater Pipe	Not Applicable (Non-DNB)
15.4.2.3	Steam Break at Full Power	ITDP
15.4.4	Locked Rotor	ITDP
15.4.6	RCCA Ejection	Not Applicable (Non-DNB)

(a) The DNB analysis method specified (ITDP or non-ITDP) refers to the method used to analyze for the DNB criterion. This is not applicable for cases analyzed for other acceptance criteria (e.g., peak RCS pressure) or for events that are not explicitly analyzed for DNB.

(b) For the time period from the start of dilution until reactor trip the Boron Dilution at Power case with the reactor in manual control is bounded by the DNB analysis for RCCA Bank Withdrawal at Power (refer to Section 15.2.2).

(c) Precluded by Technical Specifications; no longer analyzed.

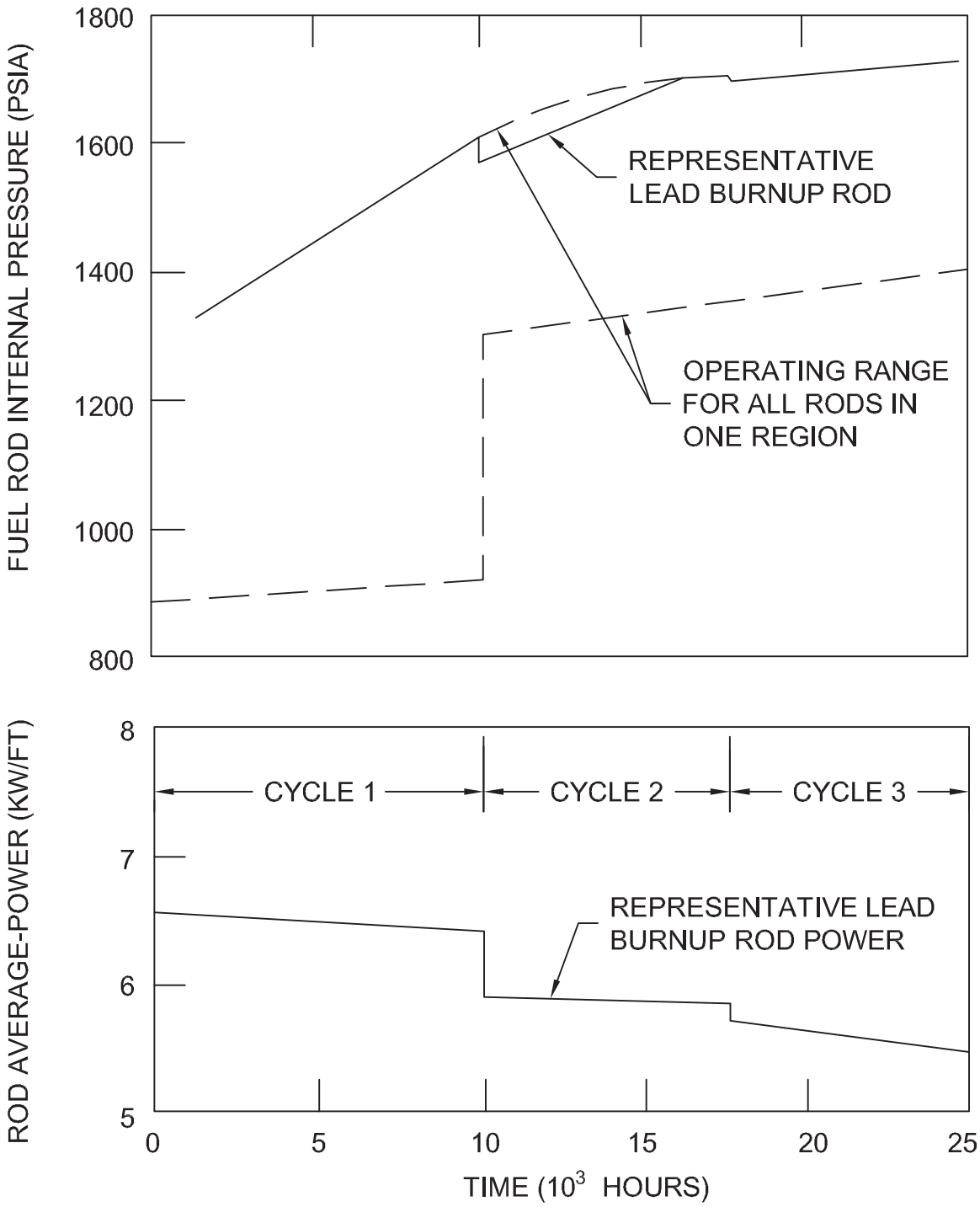
(d) Bounded by Section 15.4.2.1; no longer analyzed.



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

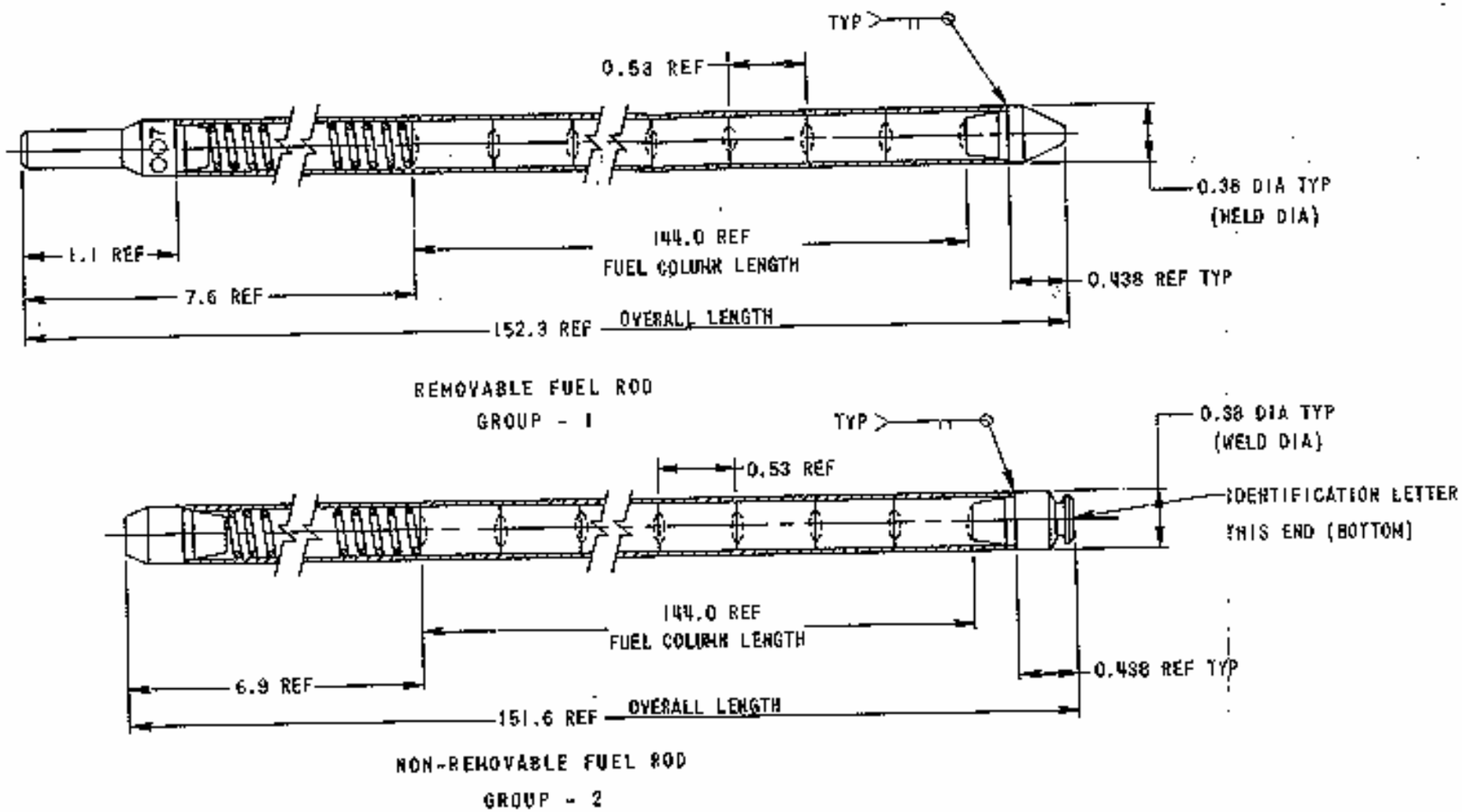
FIGURE 4.2-4
TYPICAL CLAD AND PELLET DIMENSIONS
AS A FUNCTION OF EXPOSURE



FSAR UPDATE

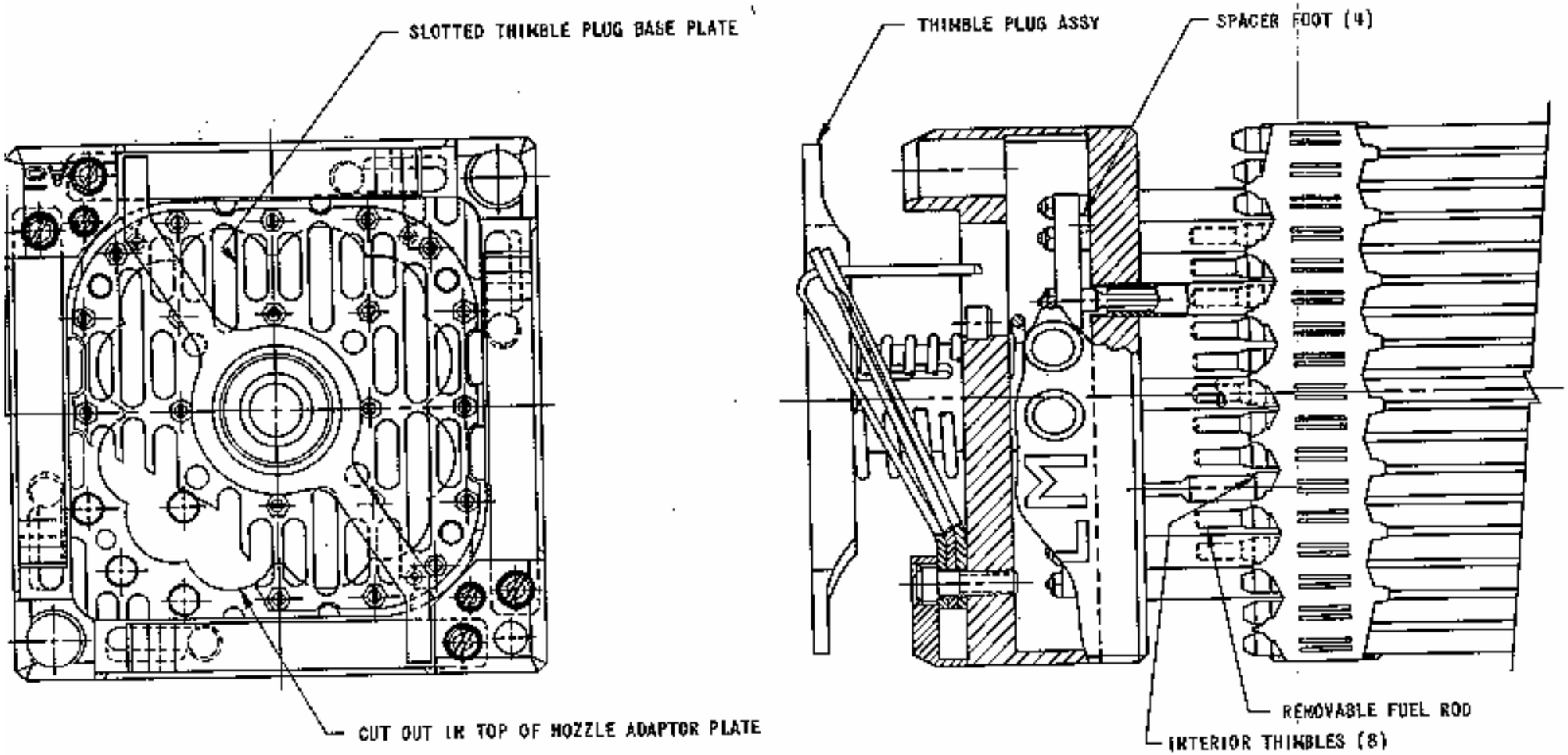
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.2-5
REPRESENTATIVE FUEL ROD INTERNAL PRESSURE AND LINEAR POWER DENSITY FOR THE LEAD BURNUP ROD AS A FUNCTION OF TIME



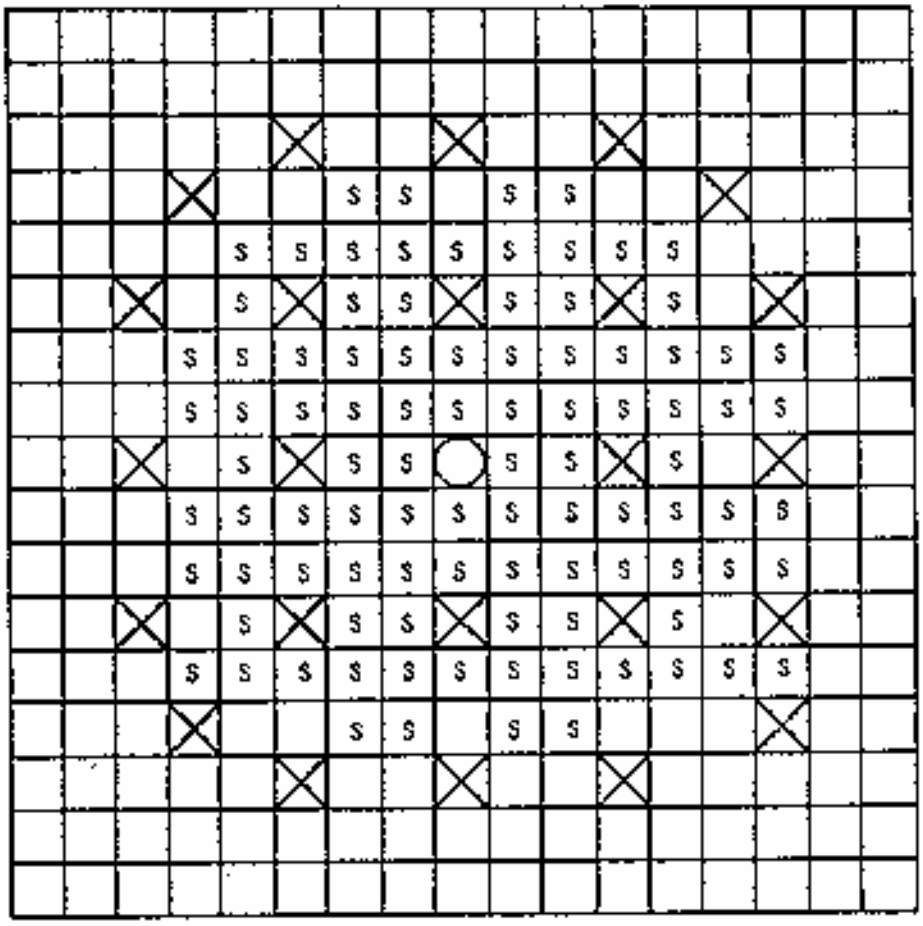
HISTORICAL

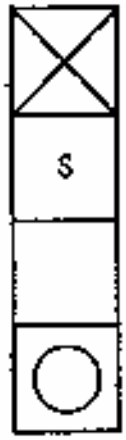
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.2-6 REMOVABLE ROD COMPARED TO STANDARD ROD



HISTORICAL

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.2-7 REMOVABLE FUEL ROD ASSEMBLY OUTLINE





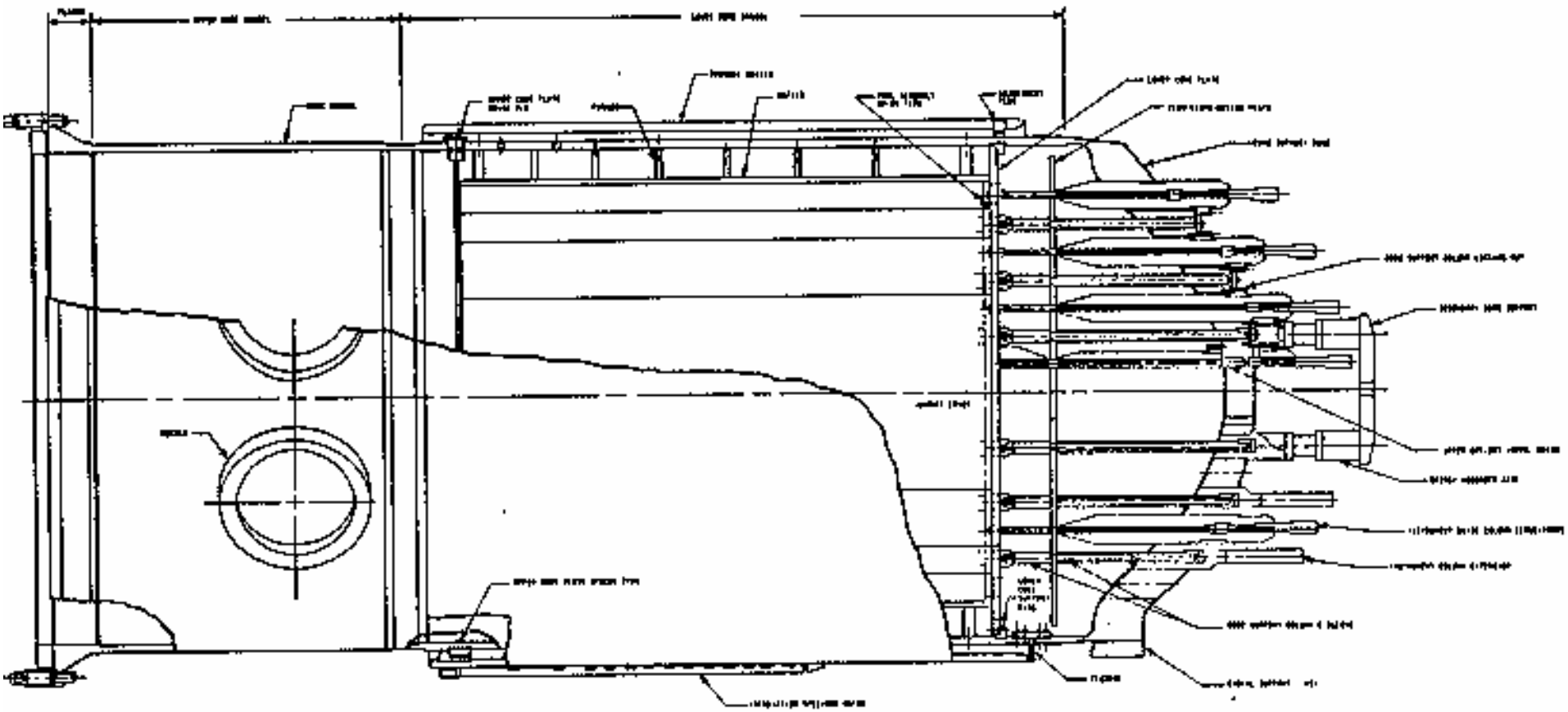
THIMBLE

REMOVABLE FUEL RODS

REGULAR FUEL RODS

INSTRUMENTATION TUBE

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.2-8 LOCATION OF REMOVABLE RODS WITHIN AN ASSEMBLY

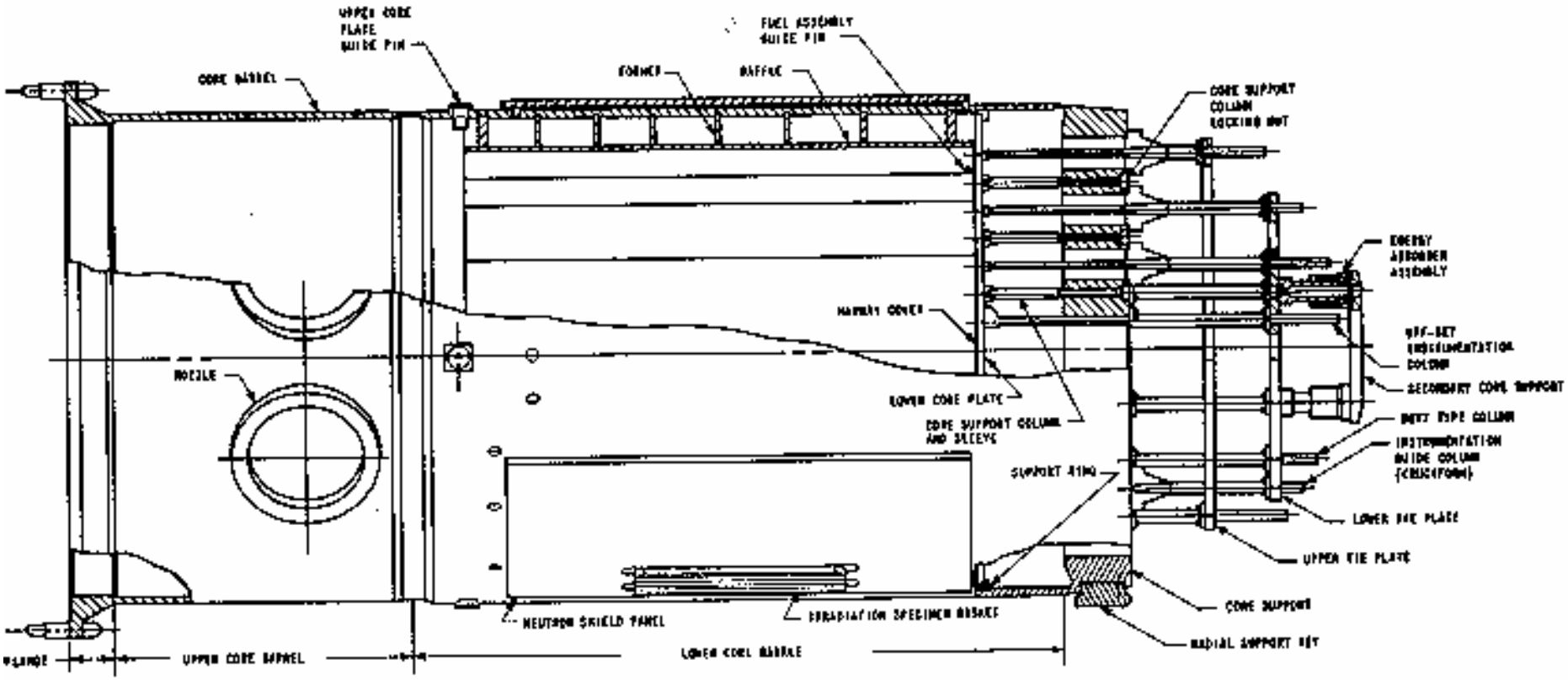


FSAR UPDATE

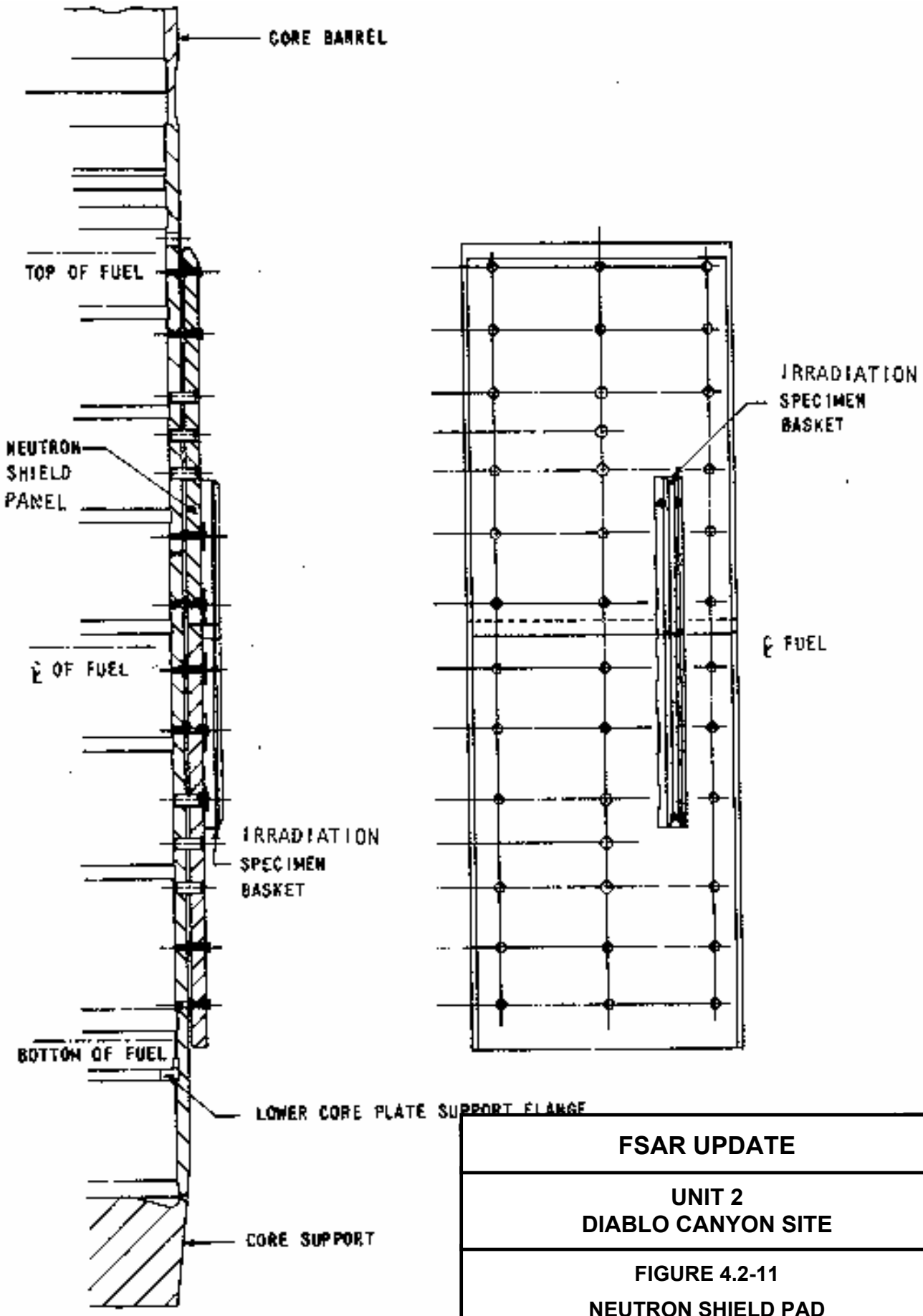
UNIT 1
DIABLO CANYON SITE

FIGURE 4.2-9

LOWER CORE SUPPORT ASSEMBLY



FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 4.2-10 LOWER CORE SUPPORT ASSEMBLY

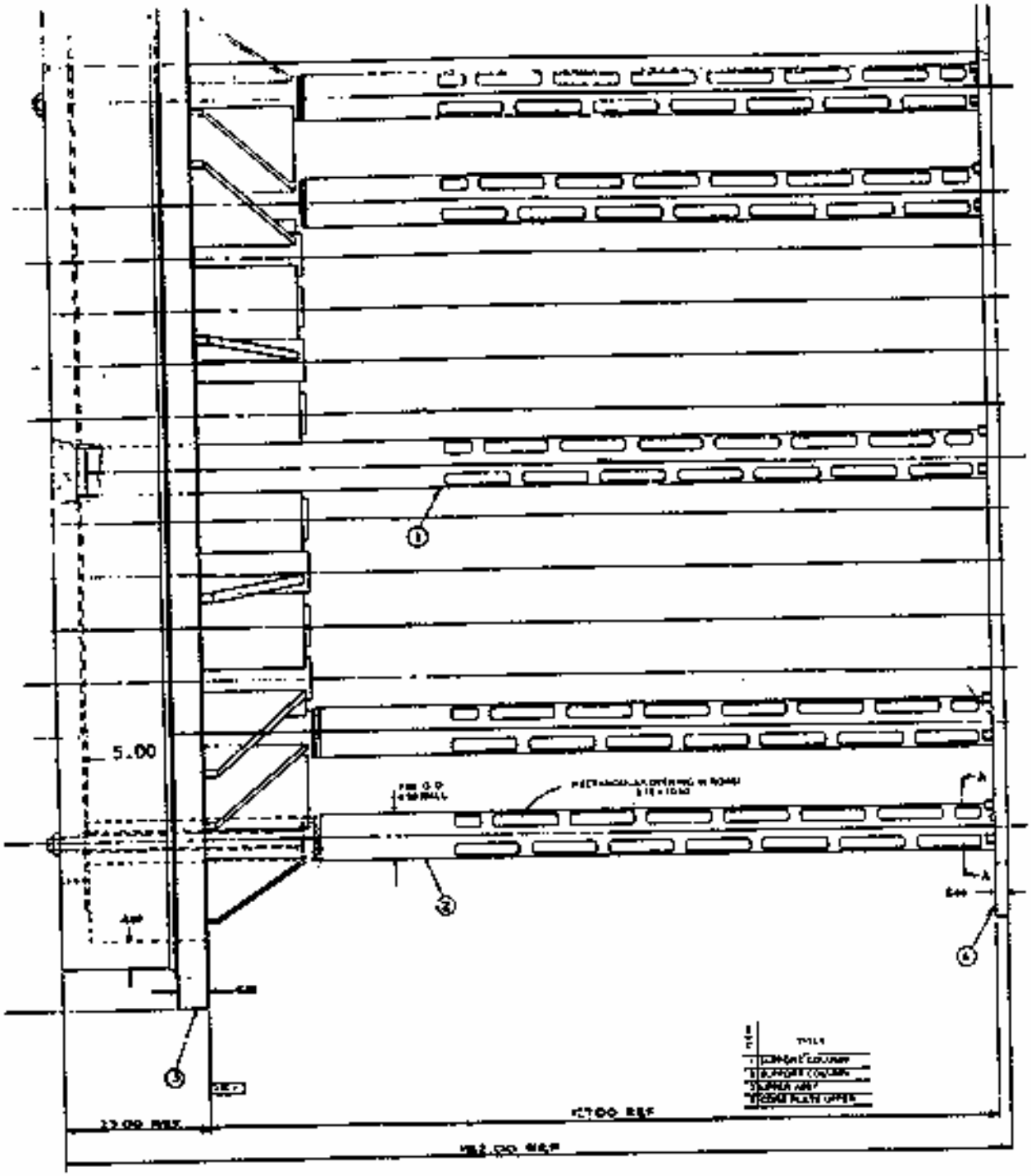


FSAR UPDATE

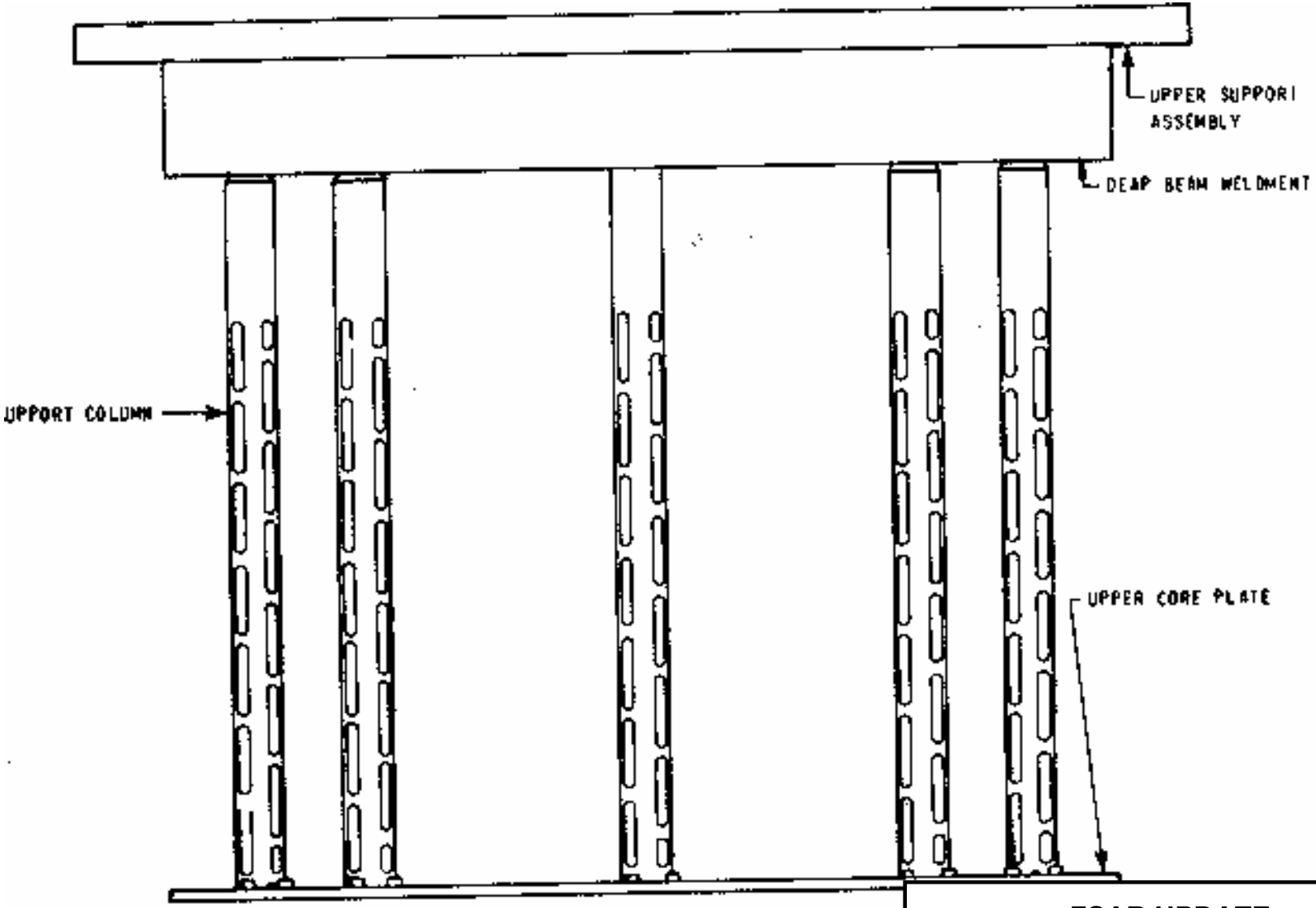
UNIT 2
DIABLO CANYON SITE

FIGURE 4.2-11

NEUTRON SHIELD PAD
LOWER CORE SUPPORT STRUCTURE



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 4.2-12 UPPER CORE SUPPORT STRUCTURE

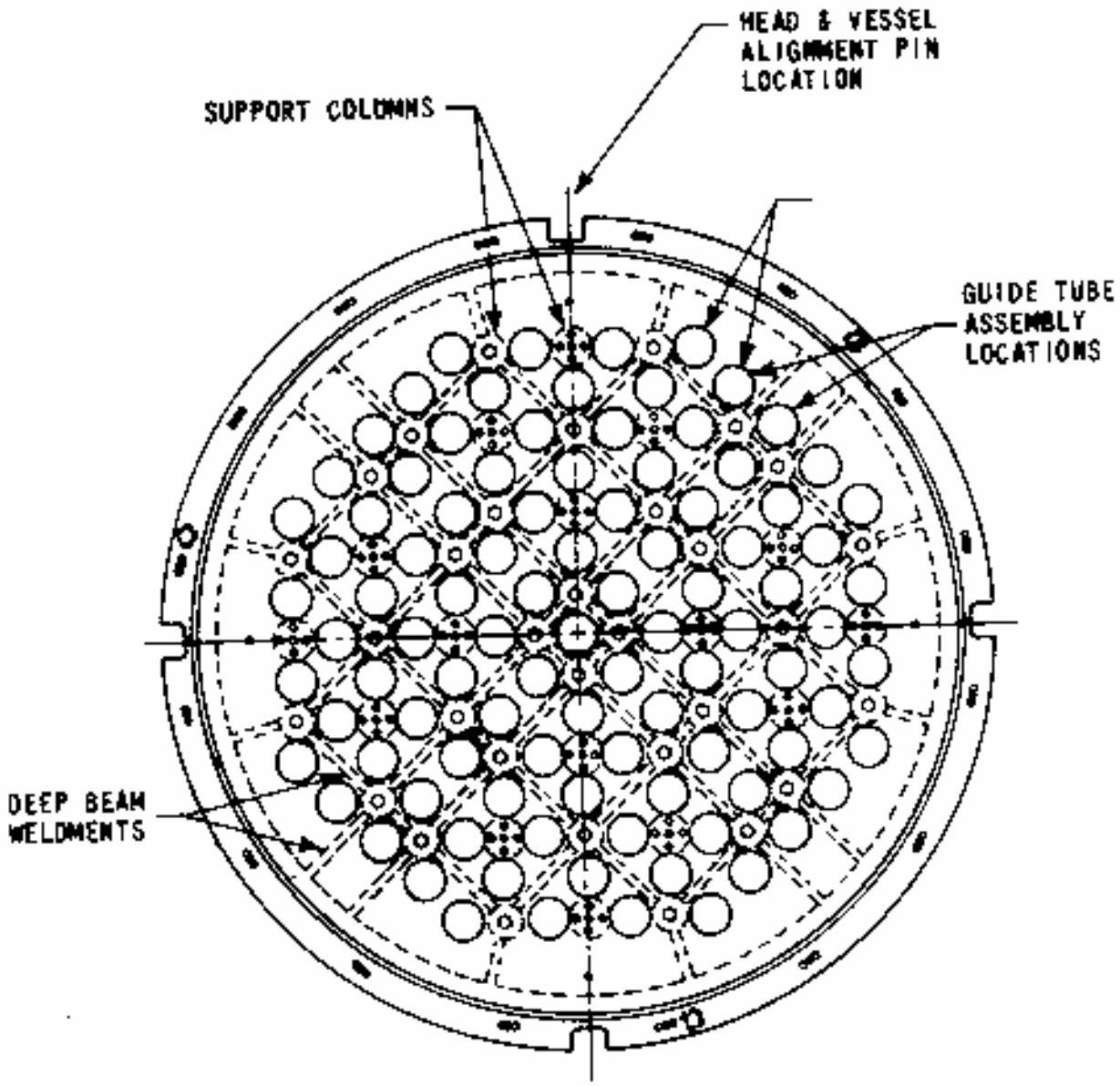


FSAR UPDATE

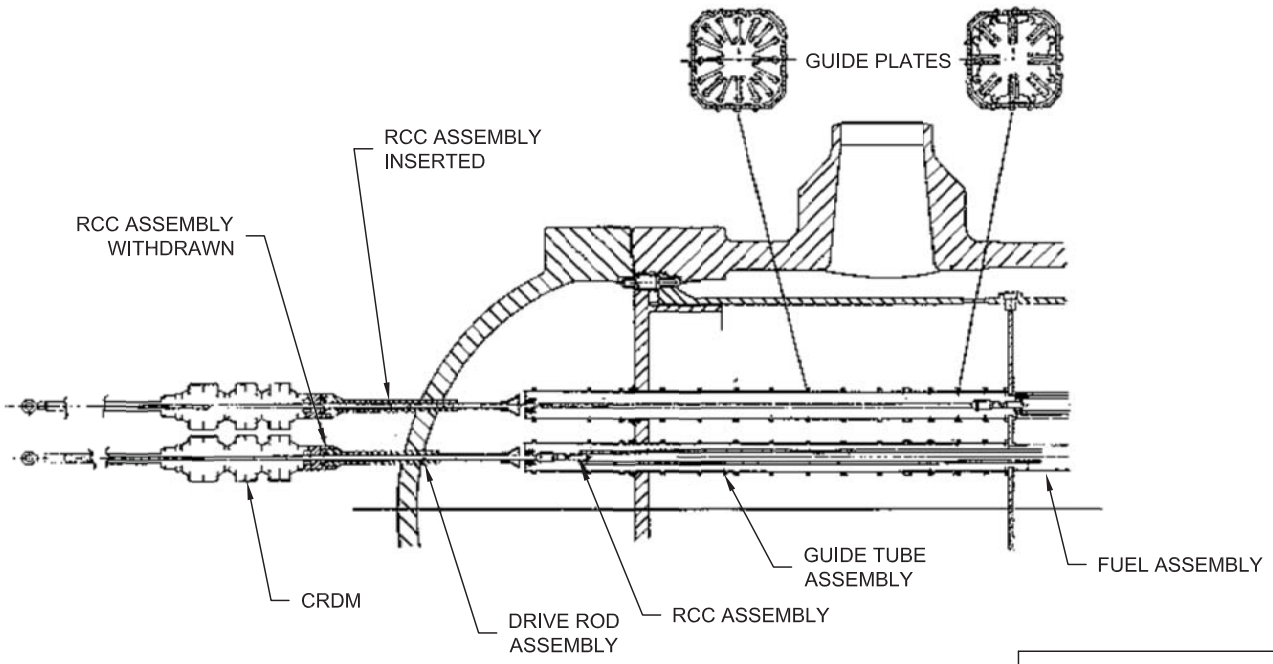
UNIT 2
DIABLO CANYON SITE

FIGURE 4.2-13

UPPER CORE SUPPORT STRUCTURE

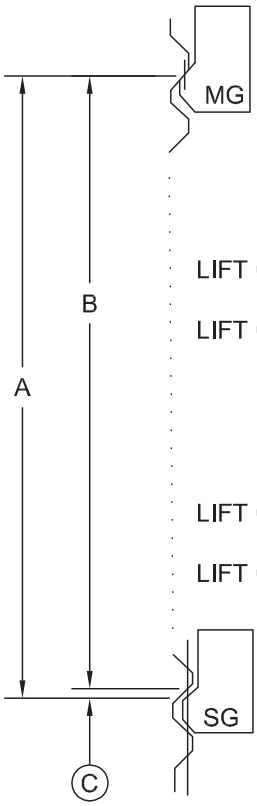


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.2-14 PLAN VIEW OF UPPER CORE SUPPORT STRUCTURE



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.2-15 ROD CLUSTER CONTROL AND DRIVE ROD ASSEMBLY WITH INTERFACING COMPONENTS

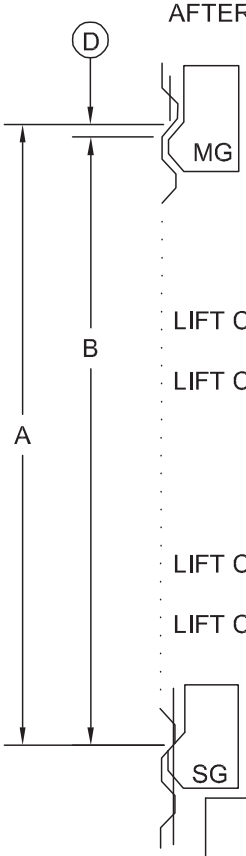
BEFORE LOAD TRANSFER



	AT 70°		
	A	B	C
LIFT COIL OFF	15.640	15.625	0.015
LIFT COIL ON	16.265	16.250	0.015

	AT 650°		
	A	B	C
LIFT COIL OFF	15.725	15.679	0.046
LIFT COIL ON	16.375	16.387	0.068

AFTER LOAD TRANSFER



	AT 70°		
	A	B	D
LIFT COIL OFF	15.625	15.578	0.047
LIFT COIL ON	16.258	16.203	0.047

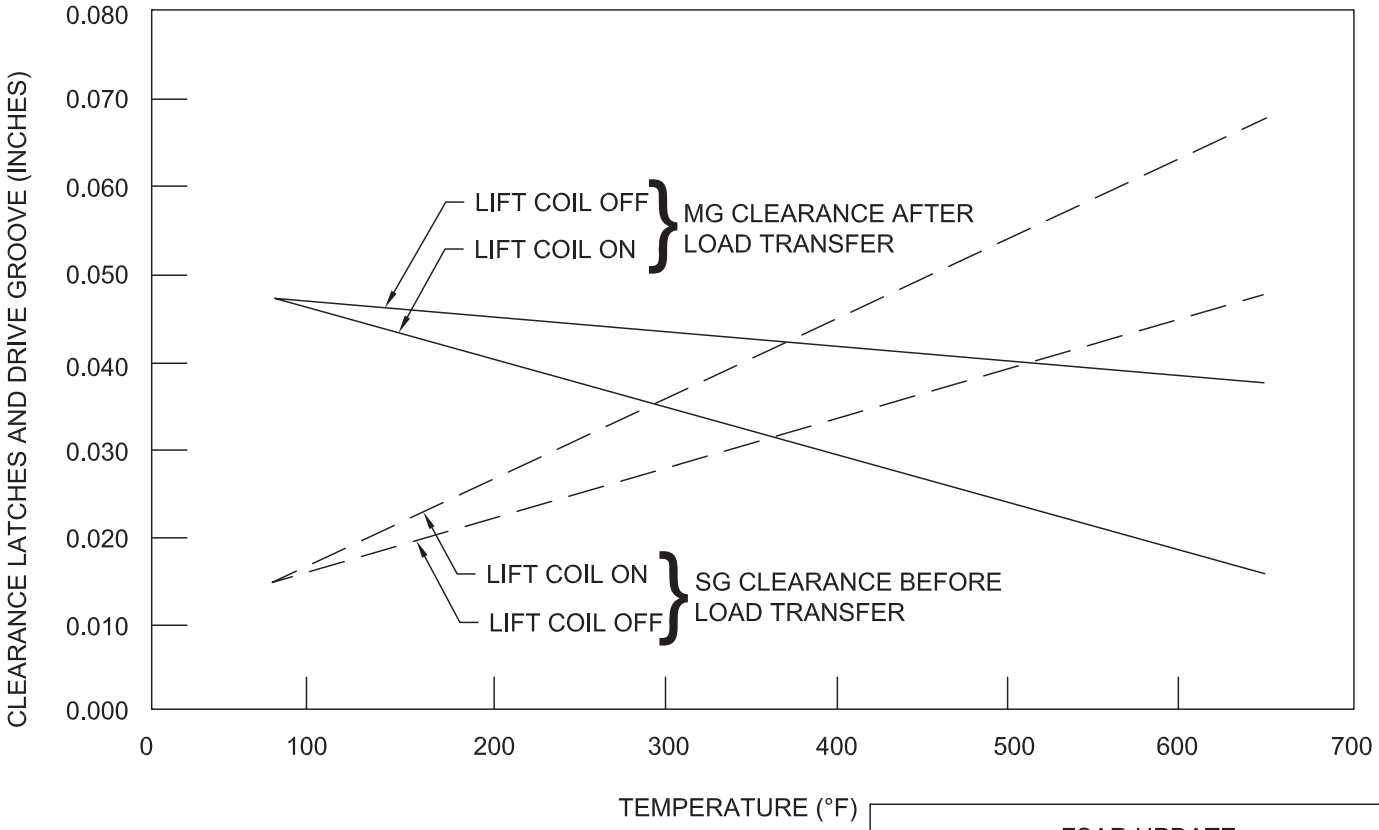
	AT 650°		
	A	B	D
LIFT COIL OFF	15.679	15.641	0.038
LIFT COIL ON	16.387	16.291	0.016

NOTE:
UNITS IN TABLES ARE INCHES.

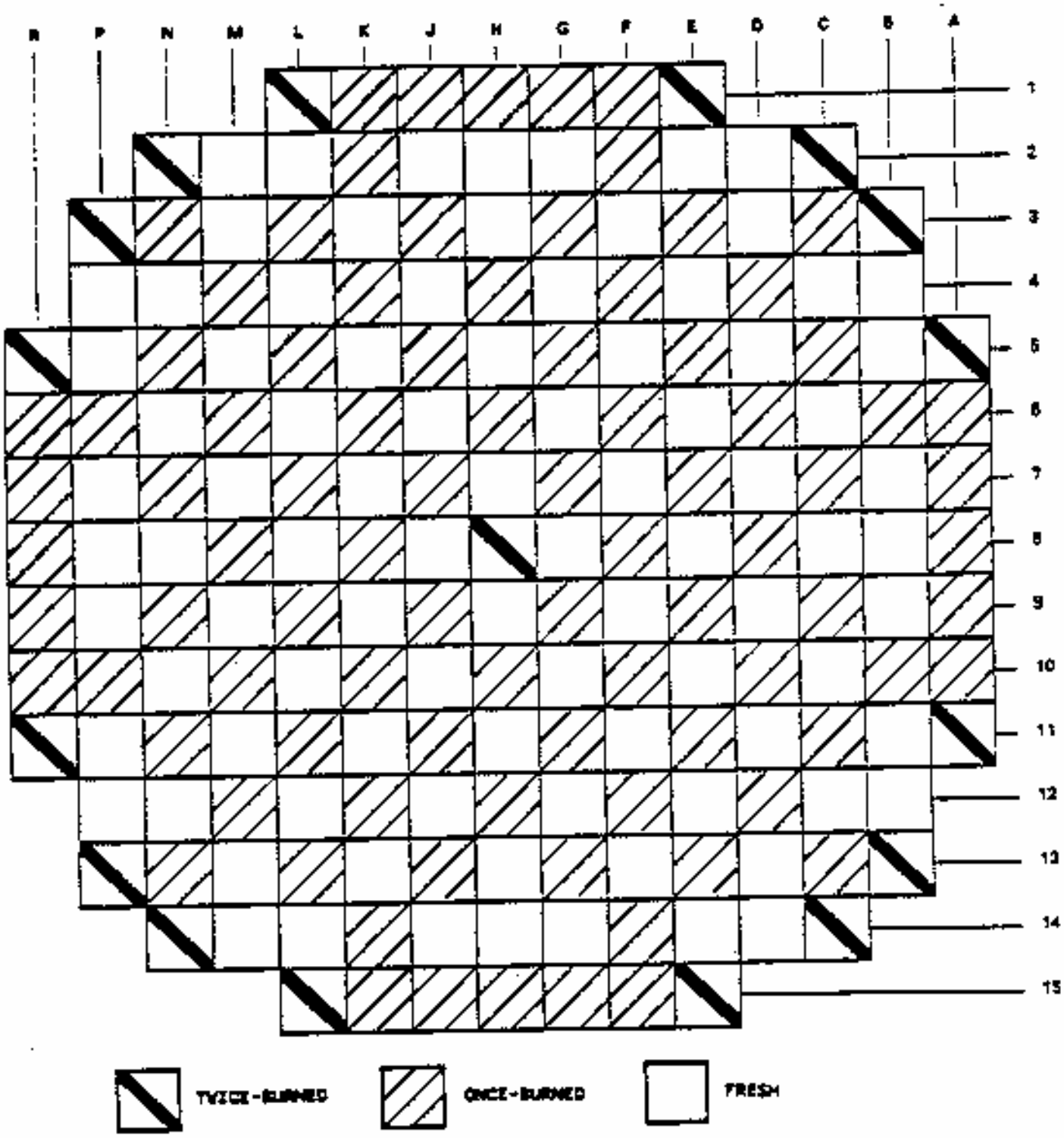
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

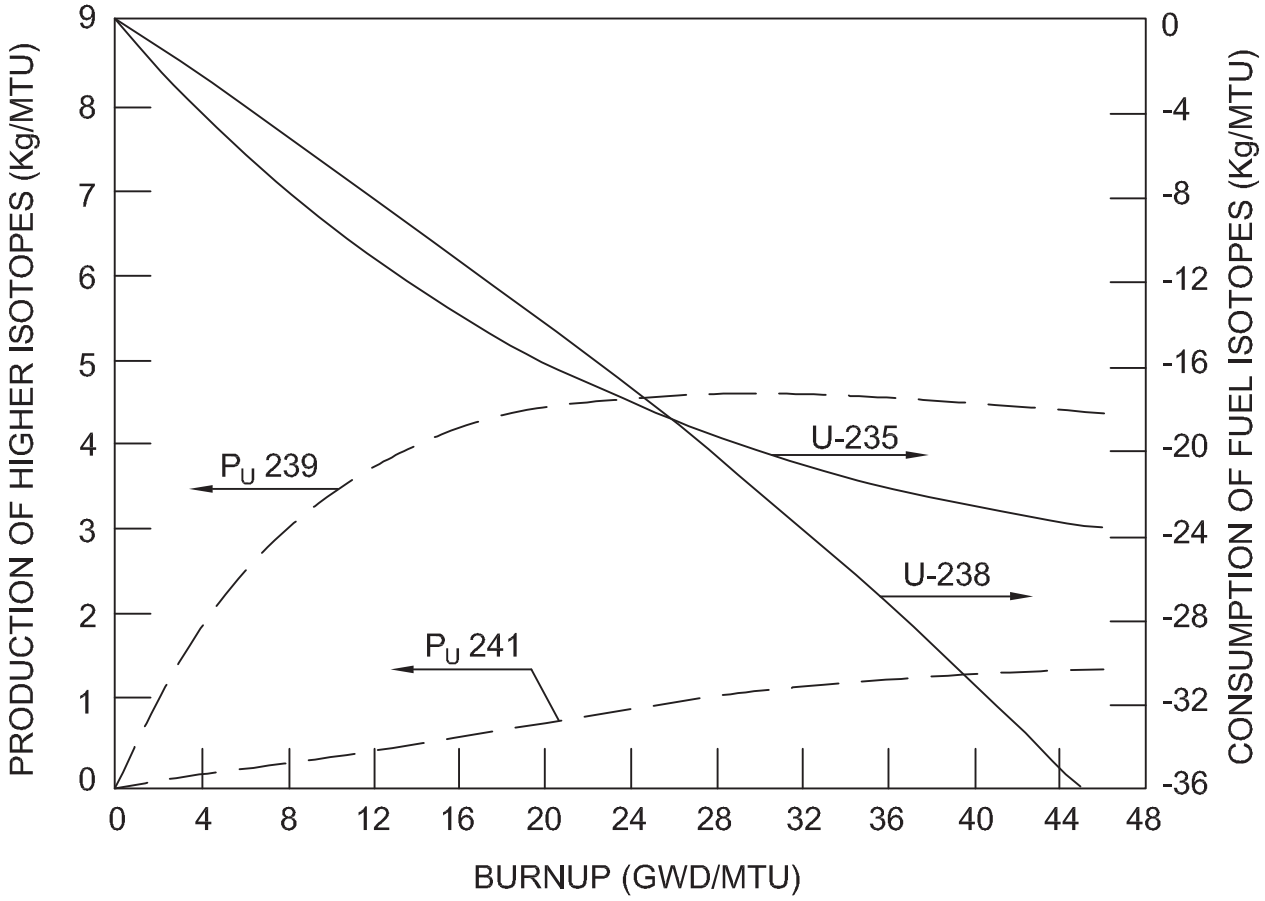
FIGURE 4.2-25
NOMINAL LATCH
CLEARANCE AT MINIMUM
AND MAXIMUM TEMPERATURE



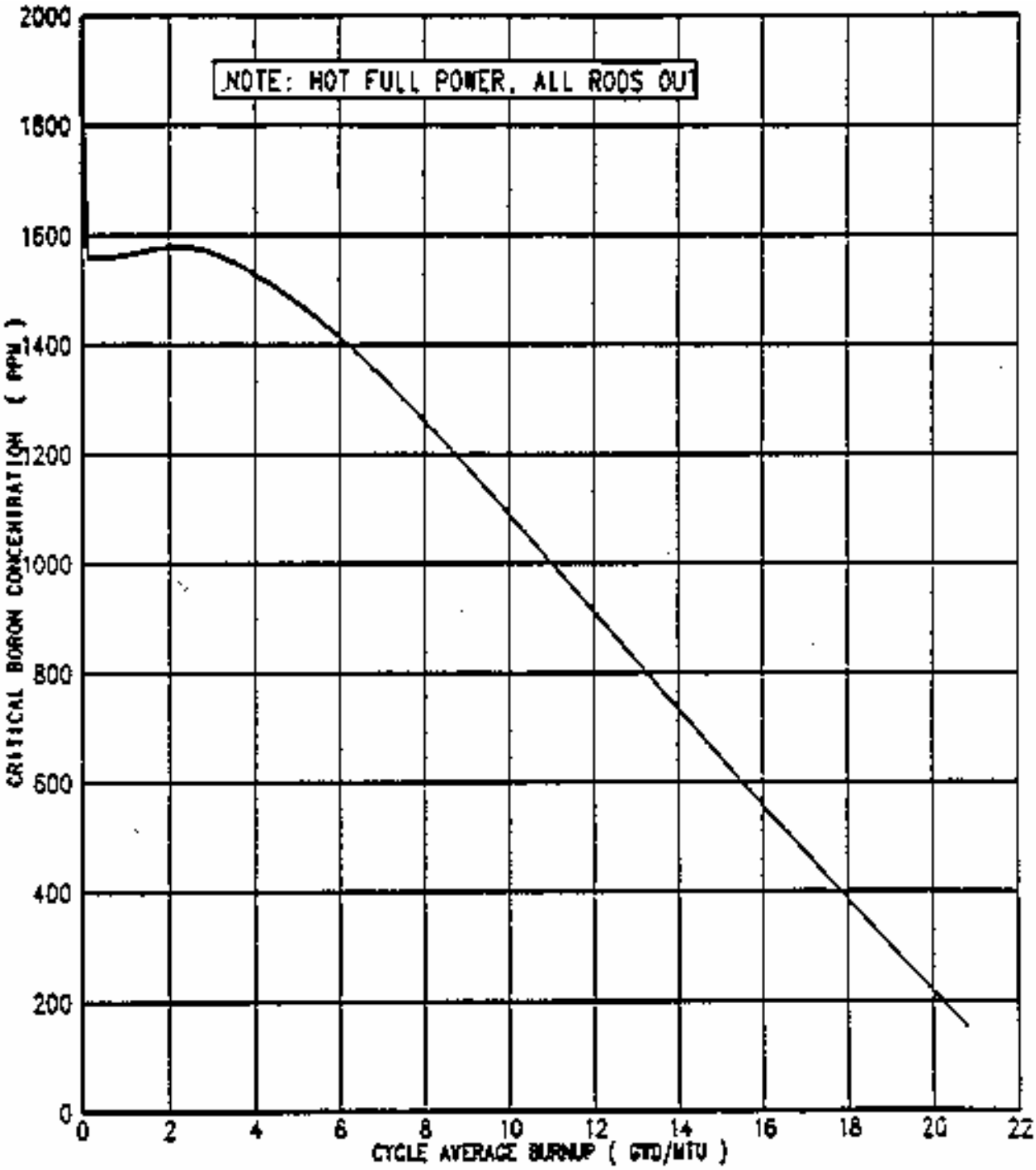
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.2-26 CONTROL ROD DRIVE MECHANISM LATCH CLEARANCE THERMAL EFFECT



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-1 FUEL LOADING ARRANGEMENT



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-2 PRODUCTION AND CONSUMPTION OF HIGHER ISOTOPES



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-3 BORON CONCENTRATION VS CYCLE BURNUP WITH BURNABLE ABSORBER RODS

17 x 17 Default Burnable Absorber Patterns

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
1	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○
2	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○
3	○	○	○	○	○	3	○	○	5	○	○	3	○	○	○	○	○
4	○	○	○	1	○	○	○	○	○	○	○	○	○	1	○	○	○
5	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○
6	○	○	4	○	○	6	○	○	2	○	○	6	○	○	4	○	○
7	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○
8	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○
9	○	○	5	○	○	2	○	○	7	○	○	2	○	○	5	○	○
10	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○
11	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○
12	○	○	4	○	○	6	○	○	2	○	○	6	○	○	4	○	○
13	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○
14	○	○	○	1	○	○	○	○	○	○	○	○	○	1	○	○	○
15	○	○	○	○	○	3	○	○	5	○	○	3	○	○	○	○	○
16	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○
17	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○

No IFBAs.
Shows guide tube / discrete BA sets.

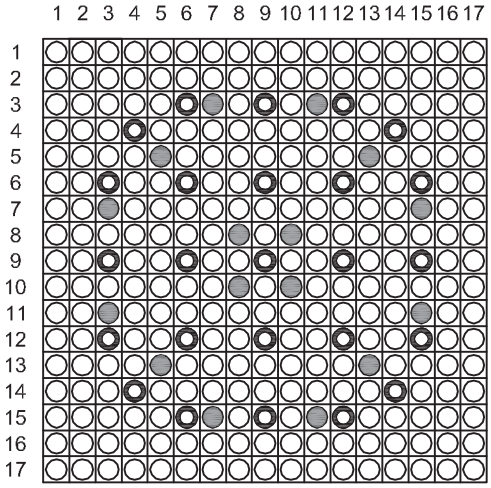
○ Fuel
● IFBA
1 Guide tube or discrete BA (Set 1)
2 Guide tube or discrete BA (Set 2)
3 Guide tube or discrete BA (Set 3)
4 Guide tube or discrete BA (Set 4)
5 Guide tube or discrete BA (Set 5)
6 Guide tube or discrete BA (Set 6)
7 Instrument tube

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-4 BURNABLE ABSORBER ROD ARRANGEMENT WITHIN AN ASSEMBLY (1 OF 2)

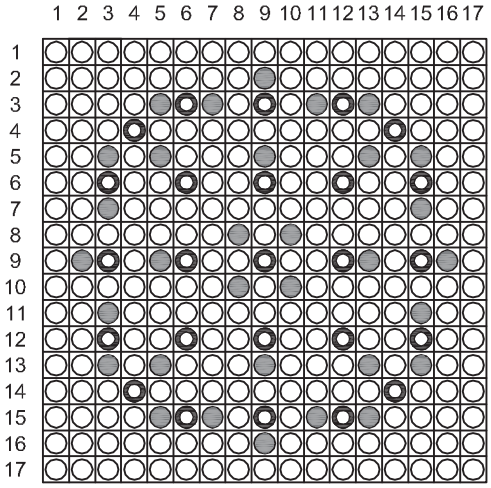
Discrete BA Placement Specification

Pattern Name	Guide Tube Set Numbers
4A	1
4B	2
4C	5
4D	6
8A	1, 2
8B	1, 5
8C	1, 6
8D	2, 5
8E	2, 6
8F	3, 4
8G	5, 6
12A	1, 2, 5
12B	1, 2, 6
12C	1, 3, 4
12D	1, 5, 6
12E	2, 3, 4
12F	2, 5, 6
12G	3, 4, 5
12H	3, 4, 6
16A	1, 2, 3, 4
16B	1, 2, 5, 6
16C	1, 3, 4, 5
16D	1, 3, 4, 6
16E	2, 3, 4, 5
16F	2, 3, 4, 6
16G	3, 4, 5, 6
20A	1, 2, 3, 4, 5
20B	1, 2, 3, 4, 6
20C	1, 3, 4, 5, 6
20D	2, 3, 4, 5, 6
24	1, 2, 3, 4, 5, 6

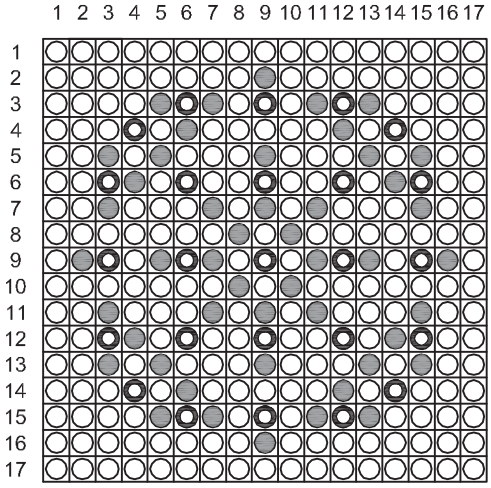
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-4 BURNABLE ABSORBER ROD ARRANGEMENT WITHIN AN ASSEMBLY (2 OF 2)



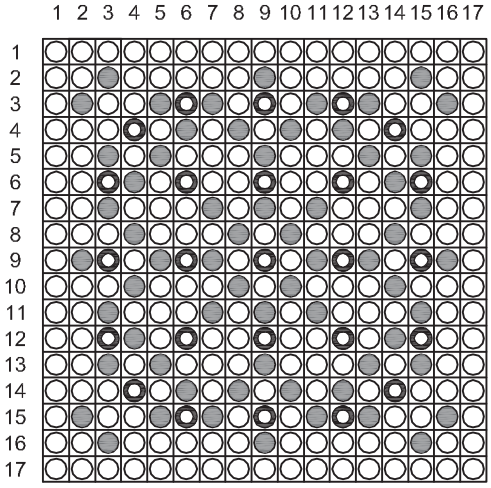
16 IFBAs



32 IFBAs

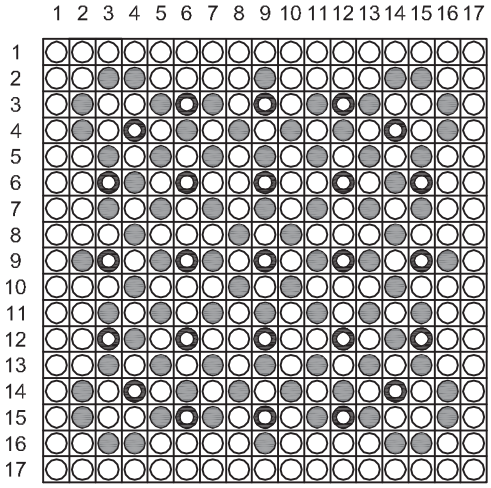


48 IFBAs

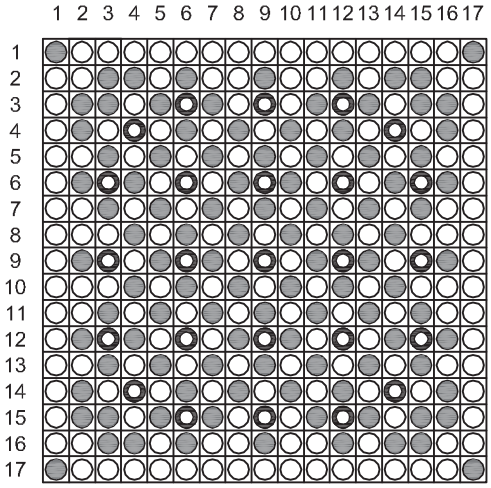


64 IFBAs

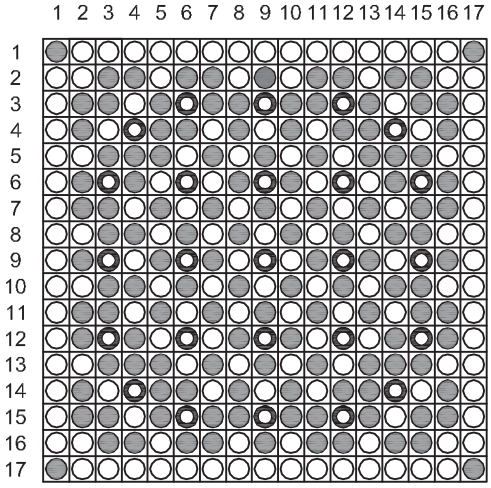
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-5 TYPICAL INTEGRAL FUEL BURNABLE ABSORBER ROD ARRANGEMENT WITHIN AN ASSEMBLY (1 OF 4)



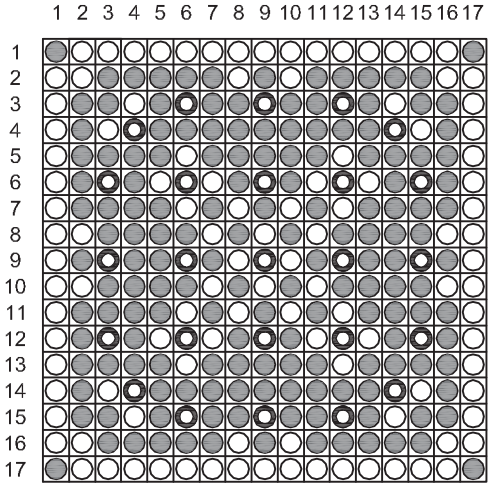
80 IFBAs



104 IFBAs

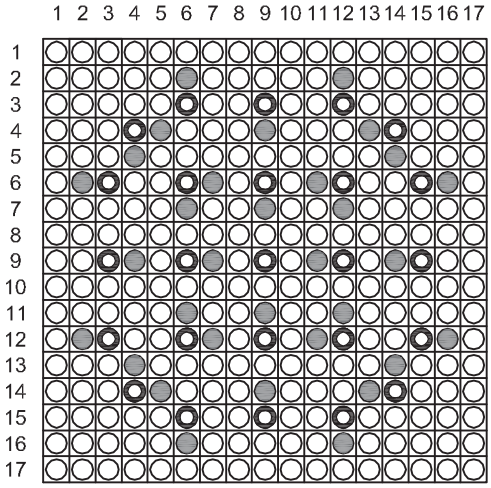


128 IFBAs

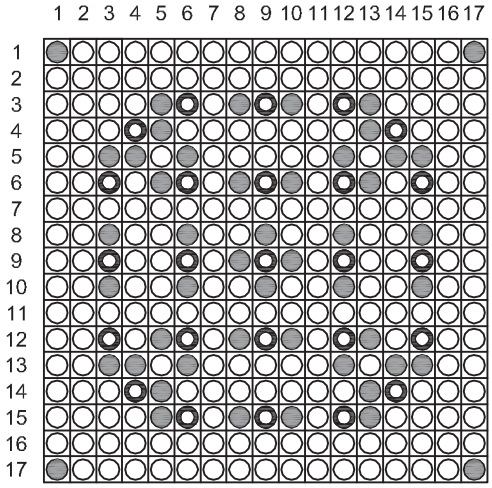


156 IFBAs

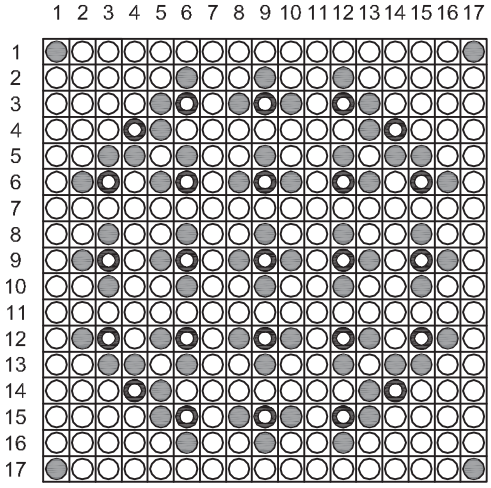
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-5 TYPICAL INTEGRAL FUEL BURNABLE ABSORBER ROD ARRANGEMENT WITHIN AN ASSEMBLY (2 OF 4)



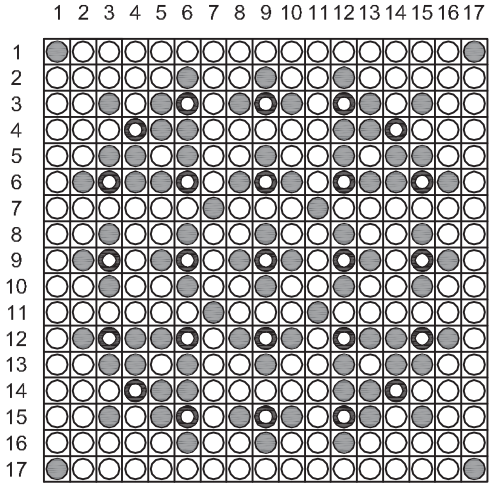
32 IFBAs



48 IFBAs

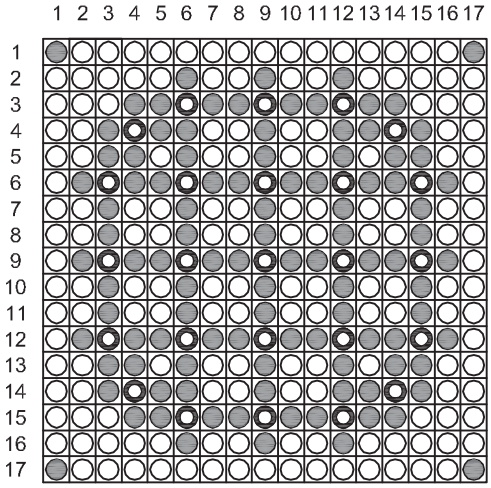


64 IFBAs

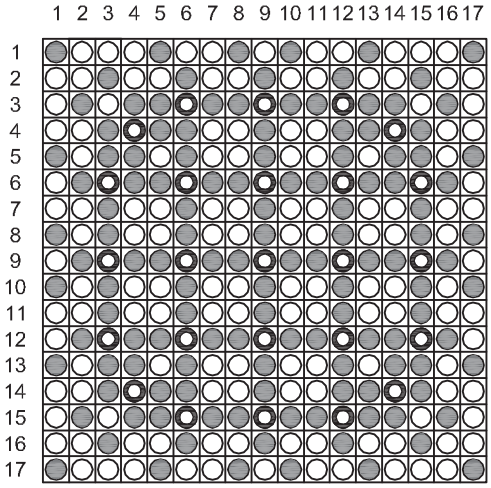


80 IFBAs

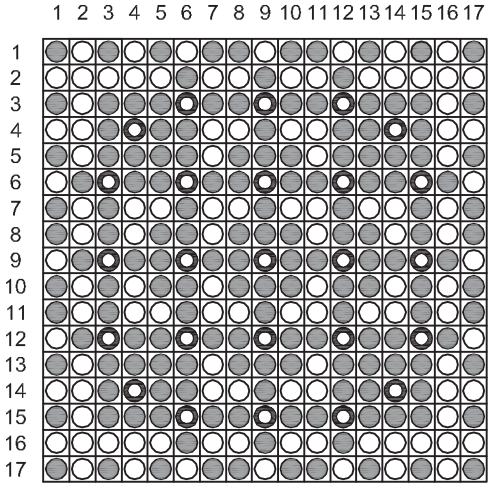
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-5 TYPICAL INTEGRAL FUEL BURNABLE ABSORBER ROD ARRANGEMENT WITHIN AN ASSEMBLY (3 OF 4)



104 IFBAs

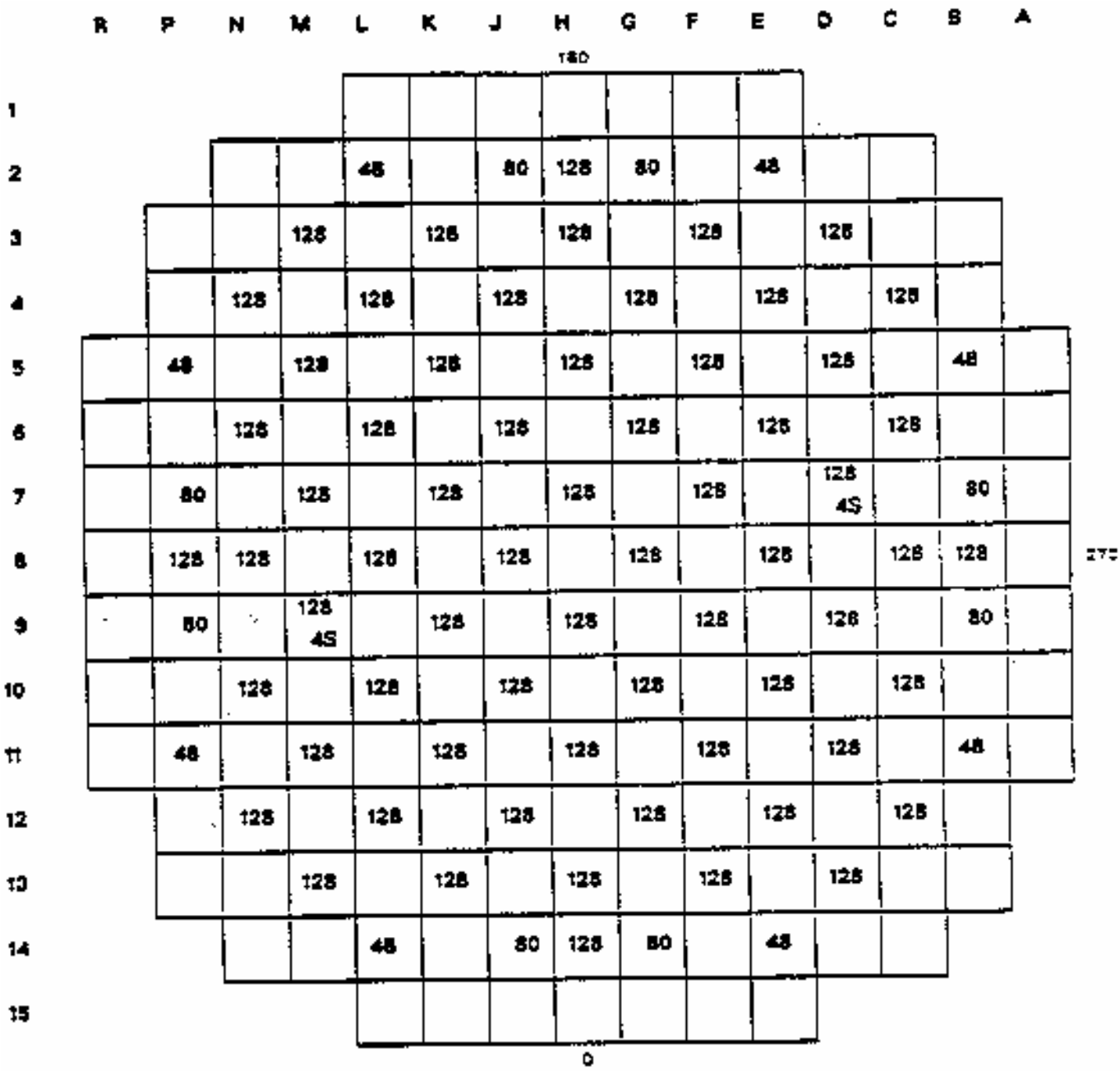


128 IFBAs



156 IFBAs

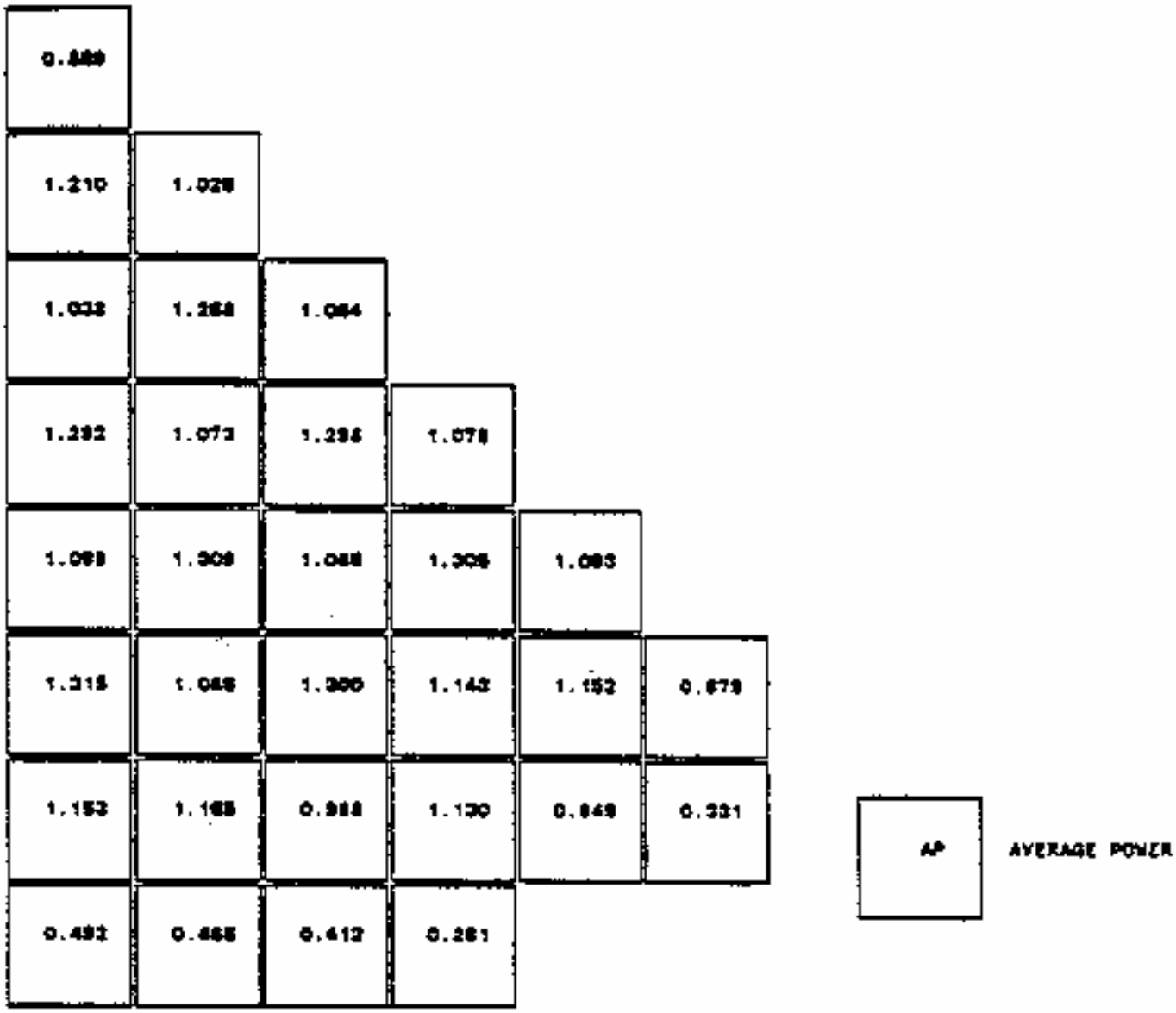
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-5 TYPICAL INTEGRAL FUEL BURNABLE ABSORBER ROD ARRANGEMENT WITHIN AN ASSEMBLY (4 OF 4)



number indicates number of IFBA rods.

S indicates secondary source rod.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-6 BURNABLE ABSORBER LOADING PATTERN

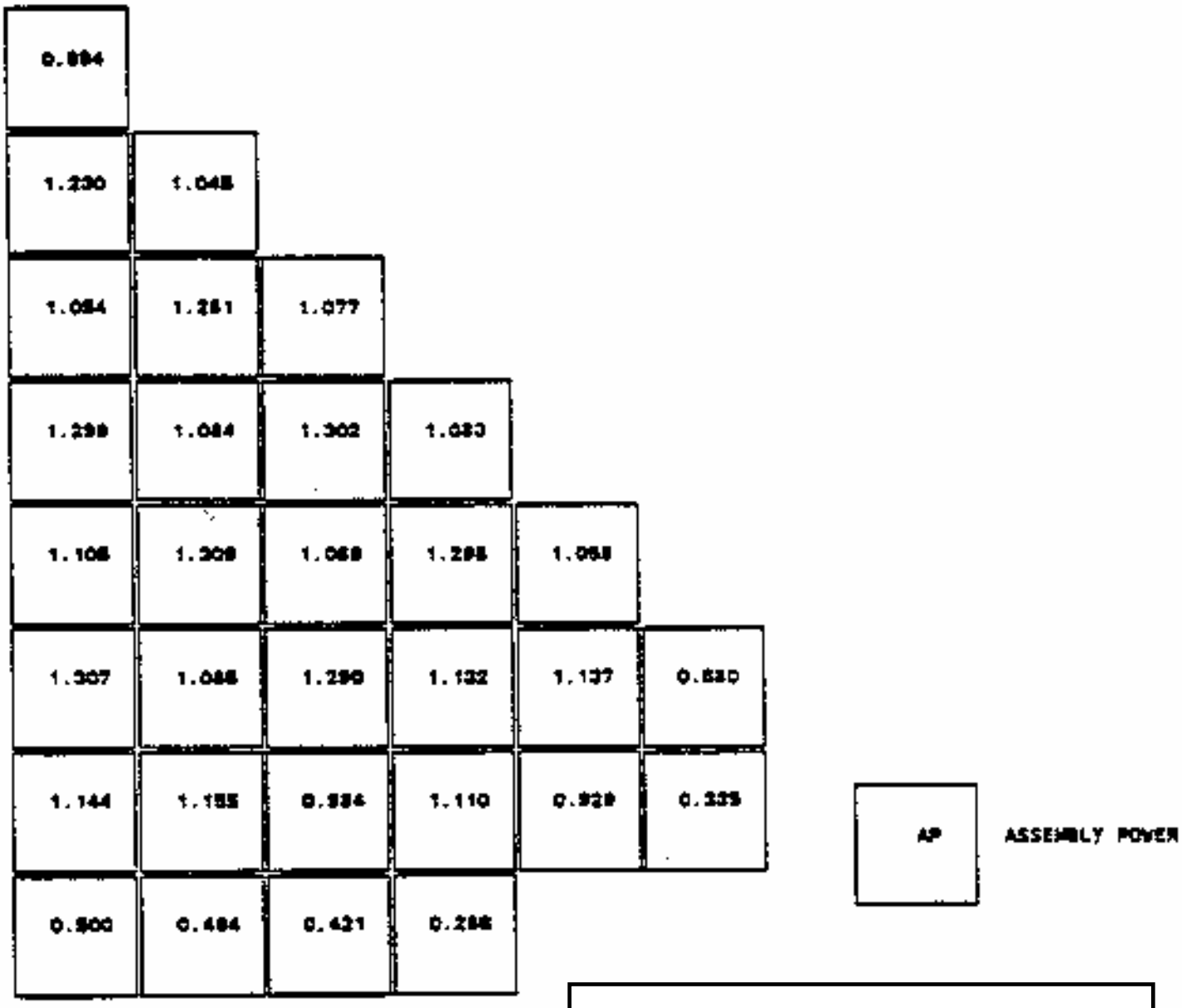


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-7

NORMALIZED POWER DENSITY DISTRIBUTION NEAR BEGINNING OF LIFE (BOL), UNRODDED CORE, HOT FULL POWER, NO XENON

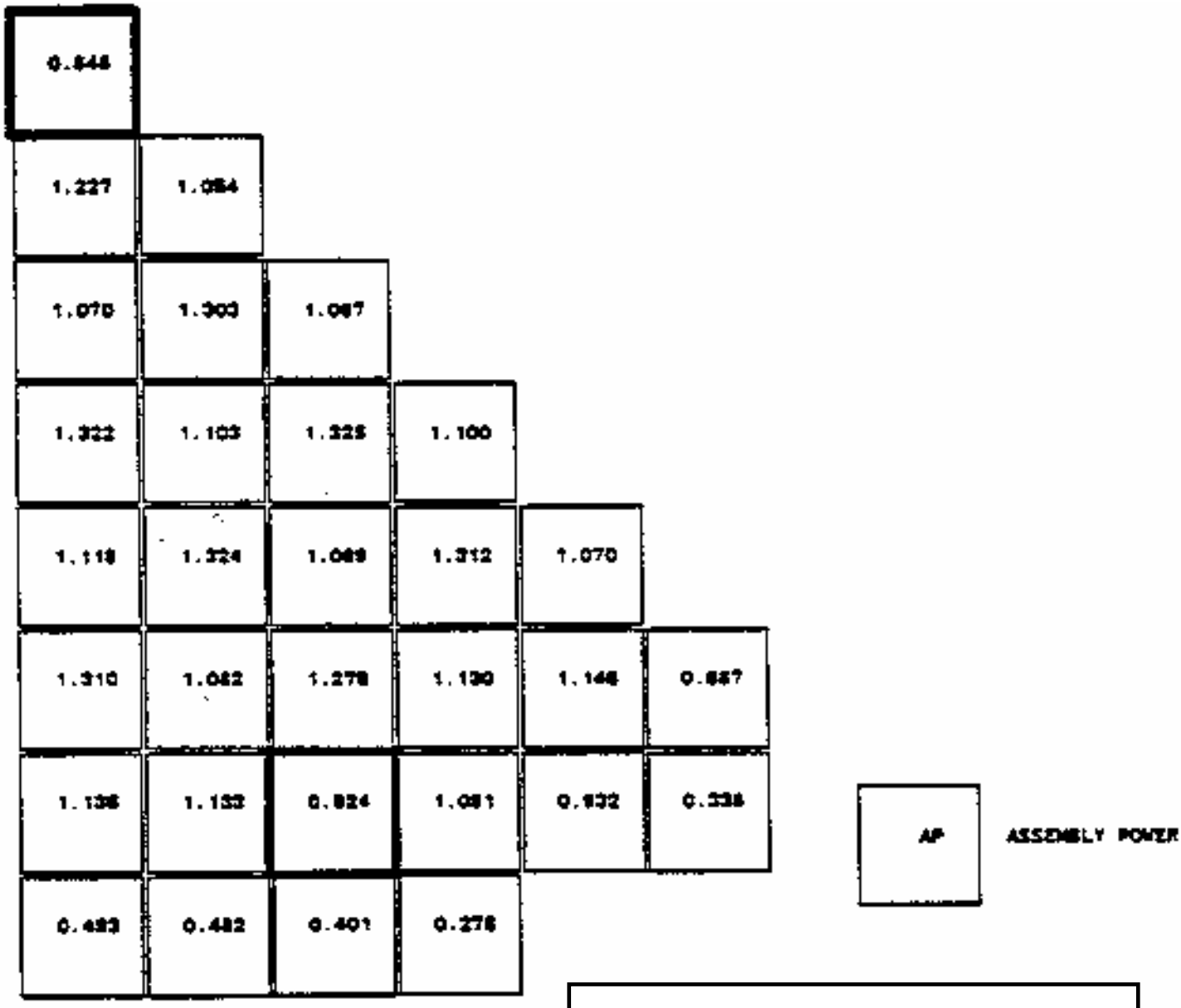


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-8

NORMALIZED POWER DENSITY DISTRIBUTION NEAR BOL UNRODDED CORE, HOT FULL POWER, EQUILIBRIUM XENON

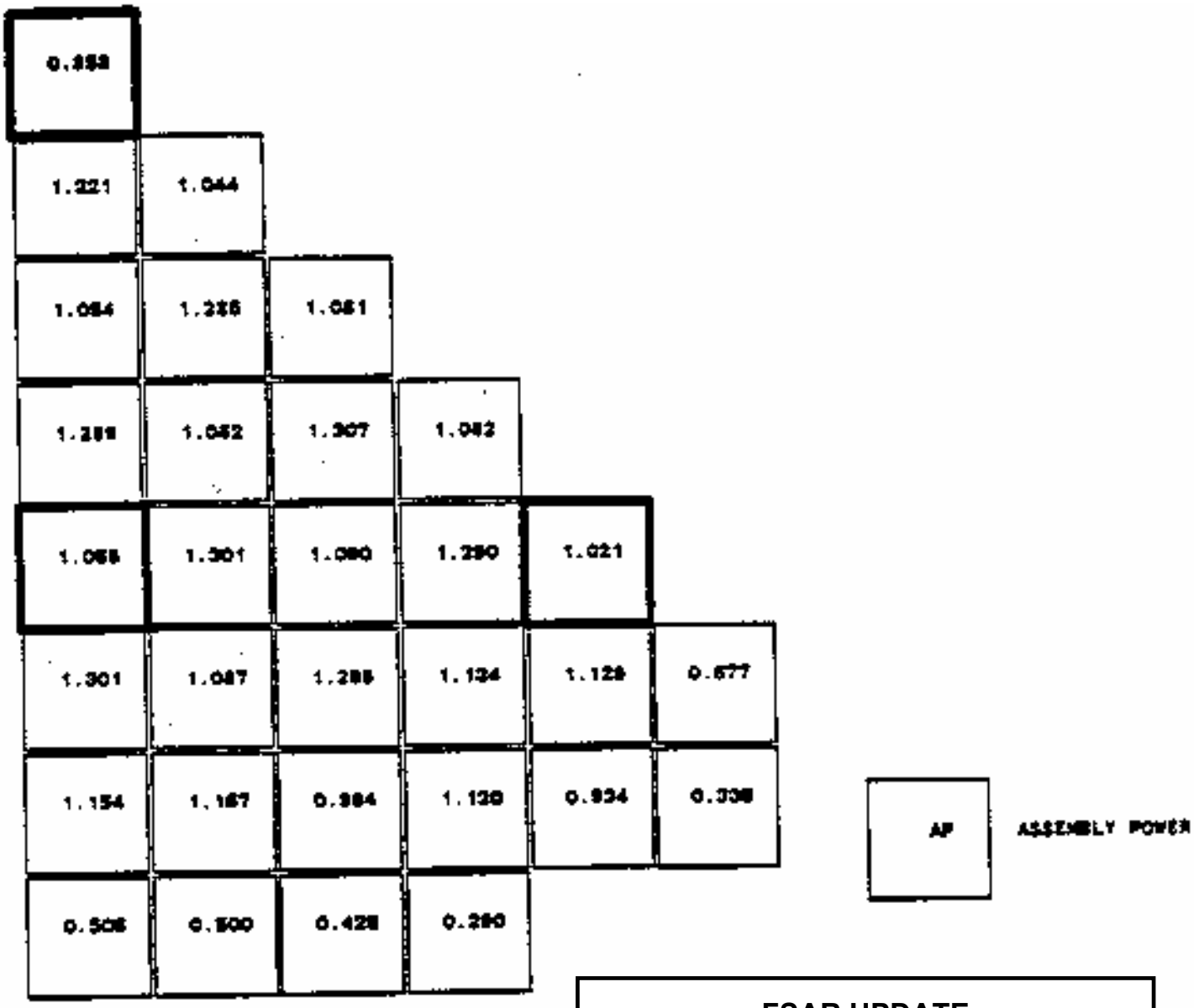


FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

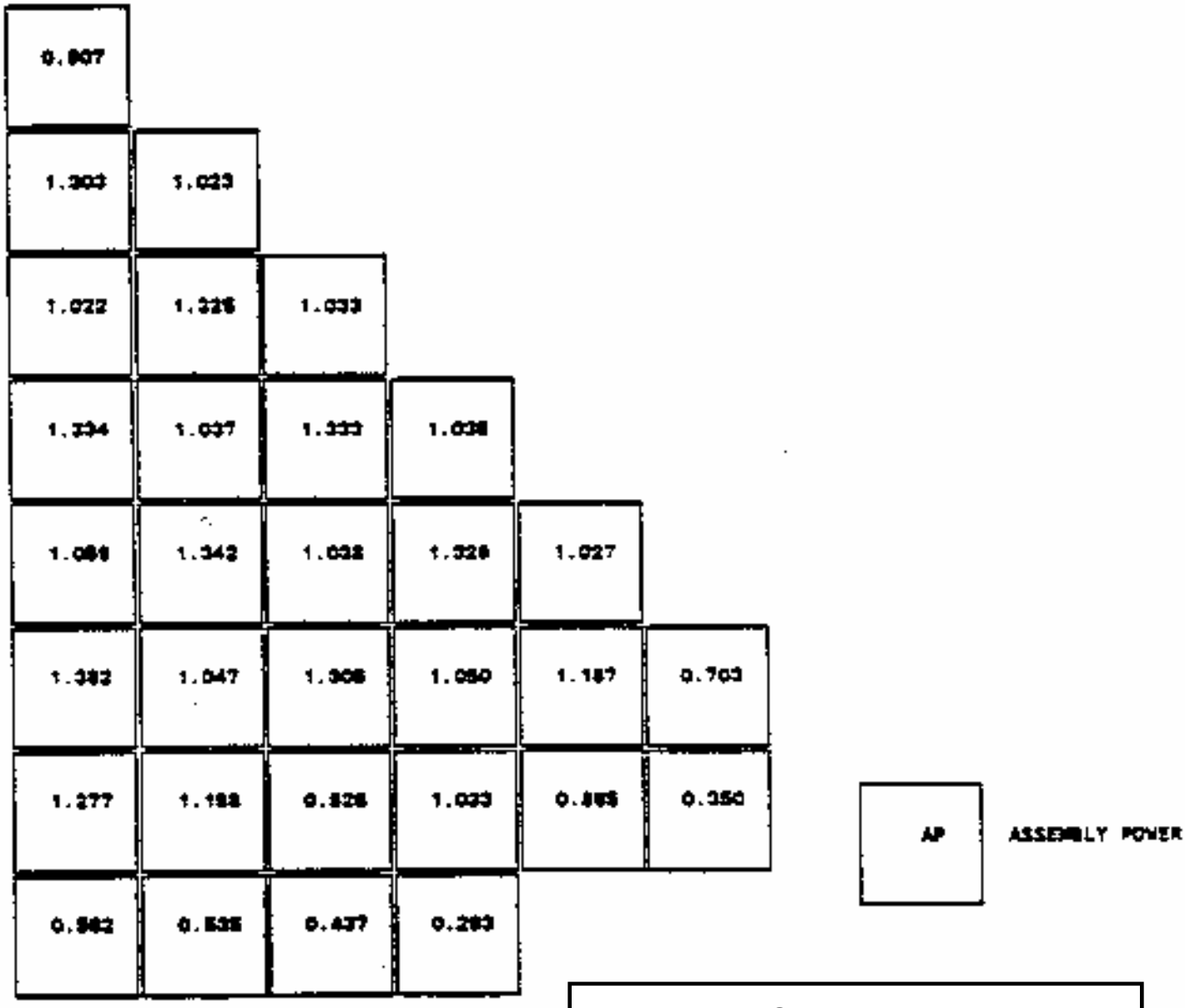
FIGURE 4.3-9

NORMALIZED POWER DENSITY DISTRIBUTION NEAR BOL GROUP D AT INSERTION LIMIT, HOT FULL POWER, EQUILIBRIUM XENON



FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 4.3-10 NORMALIZED POWER DENSITY DISTRIBUTION NEAR BOL GROUP D AT INSERTION LIMIT, HOT FULL POWER, EQUILIBRIUM XENON

Revision 11 November 1996

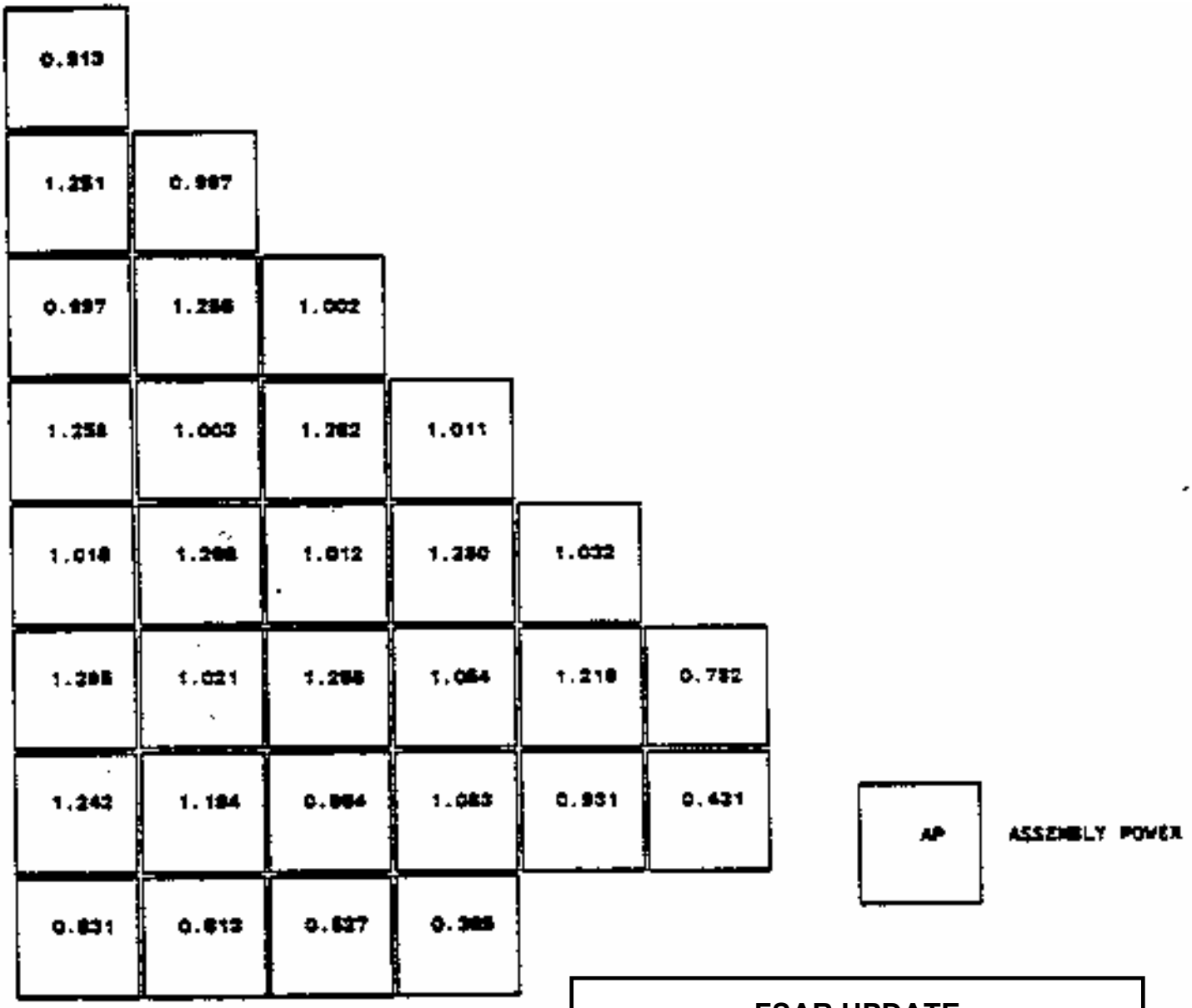


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-11

NORMALIZED POWER DENSITY DISTRIBUTION NEAR MIDDLE OF LIFE (MOL) UNRODDED CORE, HOT FULL POWER, EQUILIBRIUM XENON



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-12 NORMALIZED POWER DENSITY DISTRIBUTION NEAR END OF LIFE (EOL) UNRODDED CORE, HOT FULL POWER, EQUILIBRIUM XENON

1.240	1.208	1.141	1.208	1.163	1.241	1.172	1.234	1.185	1.235	1.177	1.248	1.172	1.220	1.154	1.224	1.258
1.210	1.124	1.139	1.182	1.177	1.282	1.183	1.186	1.281	1.188	1.188	1.289	1.185	1.162	1.135	1.138	1.227
1.143	1.124	1.184	1.290	1.320		1.305	1.302		1.305	1.308		1.329	1.300	1.163	1.137	1.158
1.211	1.184	1.291		1.345	1.328	1.208	1.204	1.311	1.208	1.212	1.345	1.354		1.309	1.167	1.227
1.187	1.180	1.322	1.346	1.292	1.338	1.213	1.208	1.318	1.211	1.217	1.342	1.360	1.336	1.334	1.182	1.181
1.248	1.236		1.340	1.336		1.333	1.322		1.334	1.327		1.344	1.350		1.298	1.260
1.177	1.187	1.308	1.211	1.218	1.224	1.215	1.215	1.325	1.216	1.218	1.330	1.221	1.220	1.318	1.189	1.190
1.240	1.191	1.307	1.207	1.213	1.323	1.216	1.217	1.327	1.218	1.219	1.328	1.218	1.214	1.317	1.202	1.253
1.191	1.287		1.315	1.321		1.326	1.328		1.328	1.329		1.327	1.323		1.298	1.202
1.244	1.184	1.310	1.210	1.215	1.327	1.218	1.220	1.330	1.221	1.221	1.331	1.220	1.217	1.319	1.204	1.255
1.184	1.184	1.315	1.218	1.221	1.331	1.221	1.221	1.331	1.222	1.224	1.335	1.337	1.225	1.334	1.203	1.195
1.257	1.297		1.351	1.347		1.333	1.331		1.339	1.336		1.352	1.355		1.306	1.267
1.181	1.183	1.336	1.350	1.285	1.348	1.226	1.221	1.330	1.222	1.226	1.353	1.370	1.367	1.344	1.201	1.190
1.229	1.170	1.308		1.363	1.356	1.224	1.218	1.326	1.219	1.227	1.360	1.368		1.318	1.178	1.238
1.163	1.143	1.177	1.310	1.341		1.324	1.331		1.322	1.326		1.345	1.316	1.183	1.150	1.171
1.234	1.146	1.148	1.174	1.193	1.308	1.204	1.206	1.302	1.207	1.206	1.308	1.202	1.178	1.150	1.152	1.242
1.267	1.225	1.166	1.232	1.187	1.265	1.196	1.296	1.206	1.257	1.196	1.268	1.191	1.238	1.171	1.241	1.275

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-13

RODWISE POWER DISTRIBUTION IN A TYPICAL ASSEMBLY (G-10) NEAR BOL, HOT FULL POWER, EQUILIBRIUM XENON, UNRODDED CORE

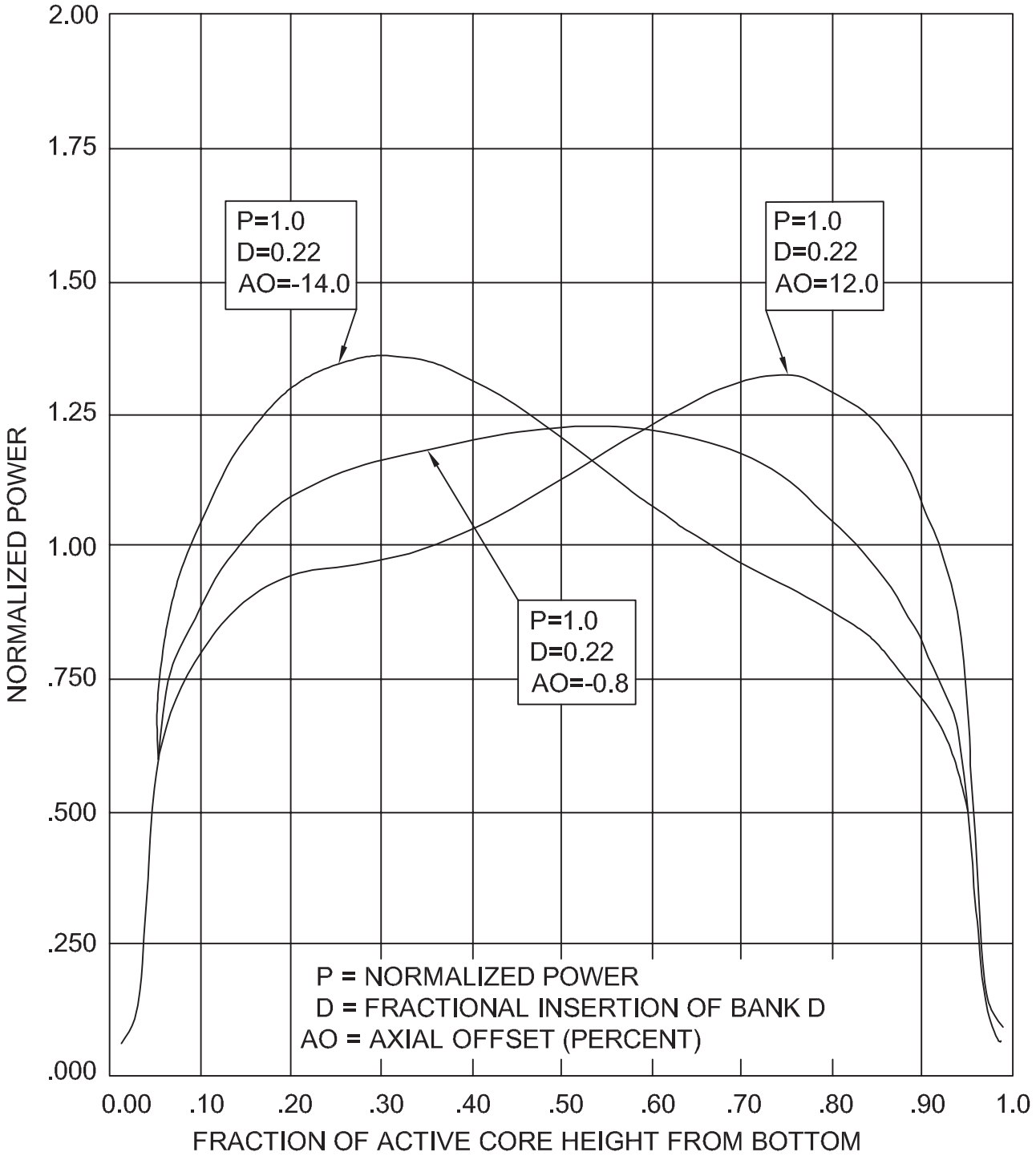
1.218	1.199	1.215	1.205	1.237	1.226	1.244	1.223	1.250	1.223	1.244	1.227	1.236	1.206	1.219	1.200	1.230
1.199	1.199	1.202	1.220	1.237	1.246	1.243	1.243	1.247	1.240	1.243	1.246	1.238	1.221	1.202	1.200	1.200
1.214	1.202	1.223	1.247	1.264		1.258	1.257		1.257	1.258		1.265	1.248	1.223	1.204	1.220
1.208	1.220	1.247		1.277	1.275	1.258	1.258	1.262	1.255	1.258	1.276	1.278		1.248	1.221	1.206
1.237	1.237	1.264	1.277	1.281	1.275	1.261	1.259	1.267	1.259	1.262	1.276	1.282	1.278	1.265	1.239	1.238
1.226	1.248		1.275	1.275		1.270	1.270		1.270	1.271		1.276	1.276		1.247	1.228
1.244	1.243	1.258	1.258	1.261	1.270	1.263	1.263	1.272	1.264	1.263	1.271	1.262	1.259	1.259	1.244	1.245
1.223	1.243	1.257	1.255	1.258	1.270	1.263	1.264	1.273	1.265	1.264	1.270	1.260	1.256	1.258	1.245	1.225
1.251	1.247		1.262	1.267		1.272	1.273		1.273	1.272		1.268	1.263		1.248	1.252
1.223	1.243	1.257	1.255	1.258	1.270	1.264	1.265	1.273	1.265	1.264	1.271	1.260	1.256	1.258	1.245	1.225
1.244	1.244	1.259	1.258	1.262	1.271	1.264	1.264	1.272	1.264	1.264	1.272	1.263	1.258	1.260	1.245	1.246
1.227	1.247		1.276	1.276		1.271	1.271		1.271	1.272		1.277	1.277		1.248	1.229
1.238	1.238	1.265	1.278	1.282	1.276	1.262	1.260	1.268	1.260	1.263	1.277	1.282	1.278	1.266	1.240	1.240
1.206	1.221	1.248		1.276	1.276	1.258	1.256	1.263	1.256	1.260	1.277	1.278		1.249	1.223	1.208
1.220	1.204	1.223	1.246	1.265		1.259	1.256		1.258	1.260		1.266	1.248	1.225	1.205	1.222
1.200	1.200	1.204	1.221	1.239	1.247	1.244	1.245	1.248	1.245	1.245	1.248	1.240	1.222	1.205	1.202	1.202
1.219	1.200	1.219	1.206	1.238	1.227	1.245	1.224	1.251	1.224	1.245	1.228	1.239	1.207	1.221	1.202	1.221

FSAR UPDATE

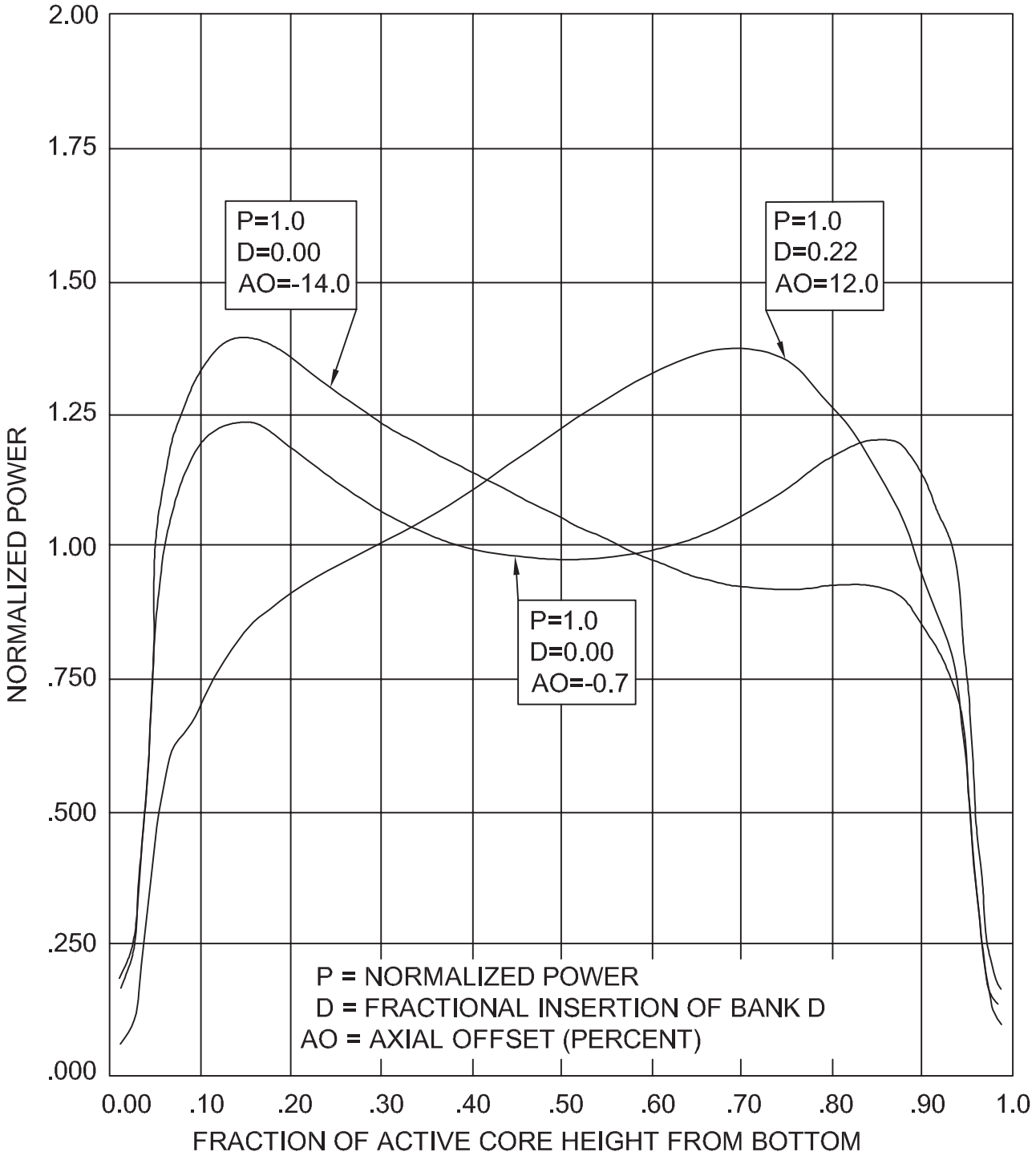
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-14

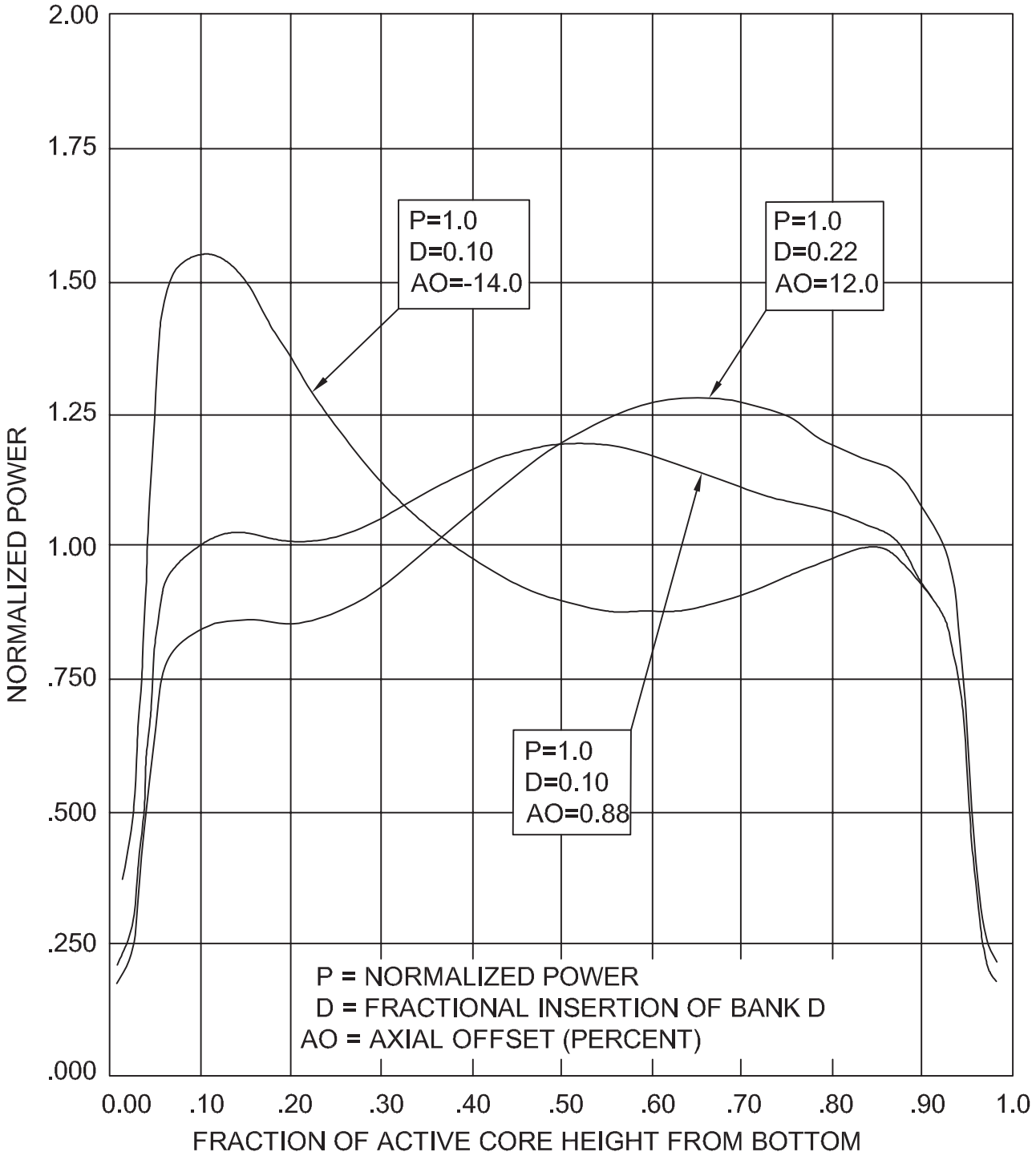
RODWISE POWER DISTRIBUTION IN A TYPICAL ASSEMBLY (G-10) NEAR EOL, HOT FULL POWER, EQUILIBRIUM XENON, UNRODDED CORE



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-15 POSSIBLE AXIAL POWER SHAPES AT BOL DUE TO ADVERSE XENON DISTRIBUTIONS

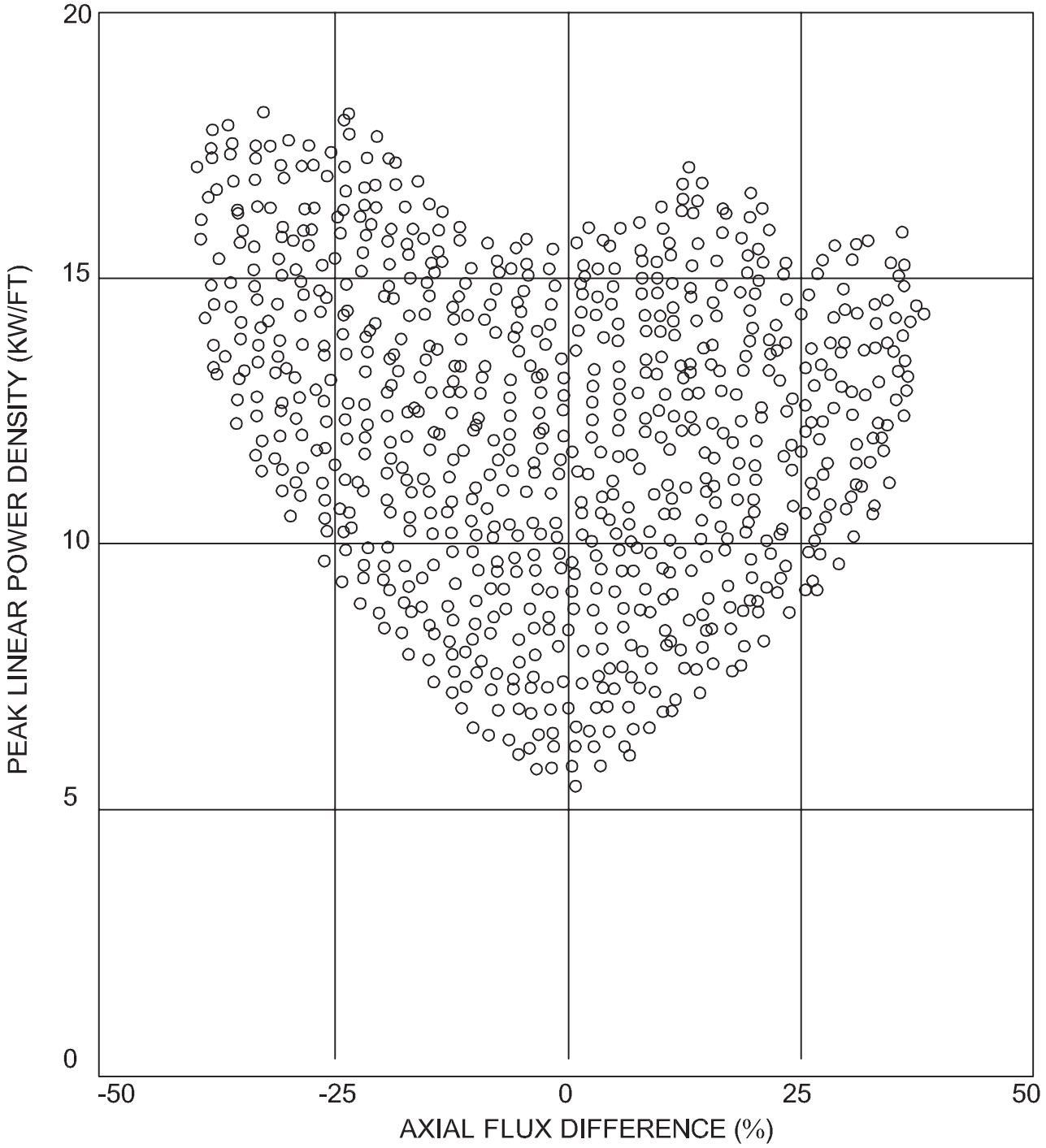


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-16 POSSIBLE AXIAL POWER SHAPES AT MOL DUE TO ADVERSE XENON DISTRIBUTIONS

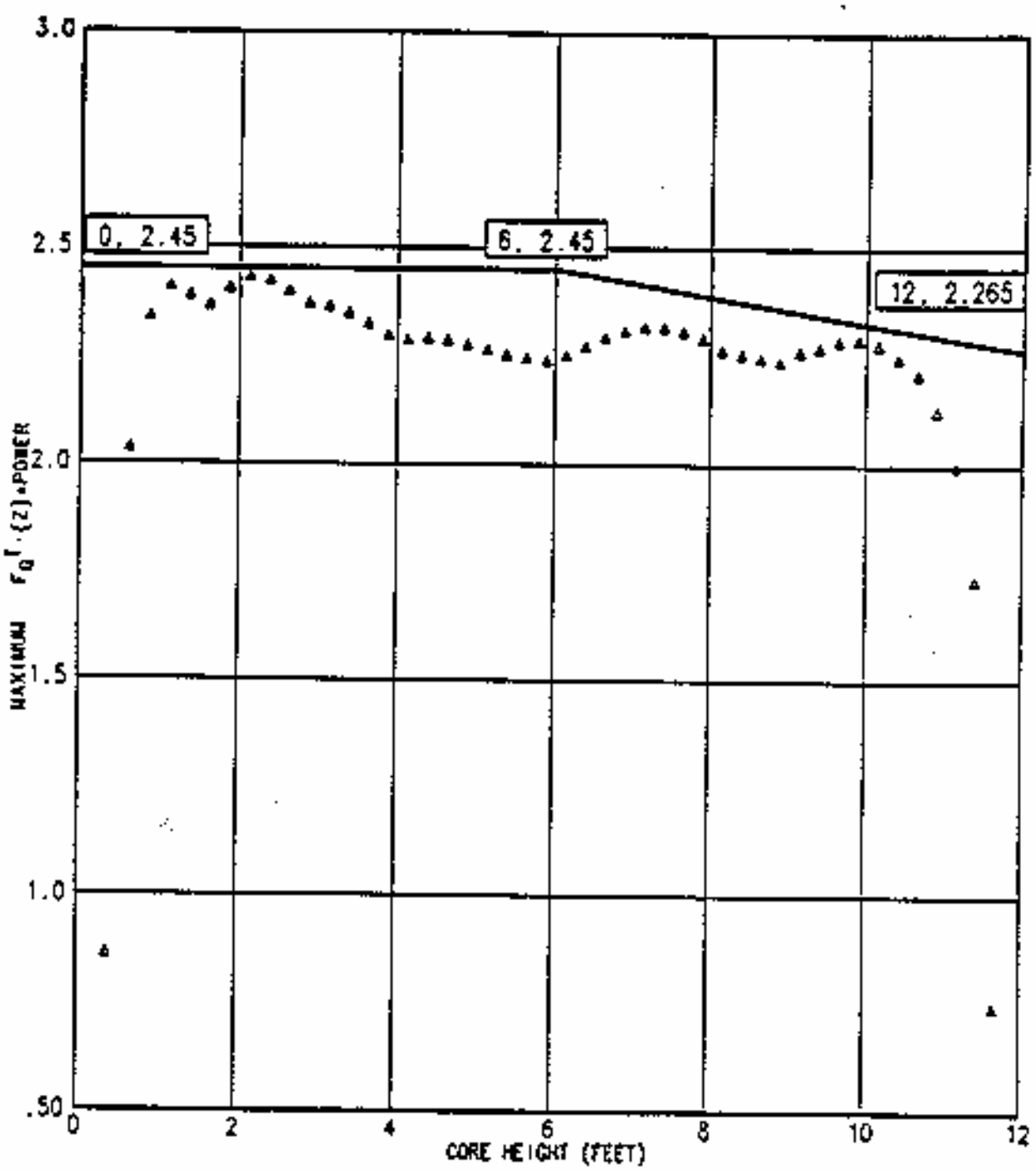


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-17 POSSIBLE AXIAL POWER SHAPES AT EOL DUE TO ADVERSE XENON DISTRIBUTIONS

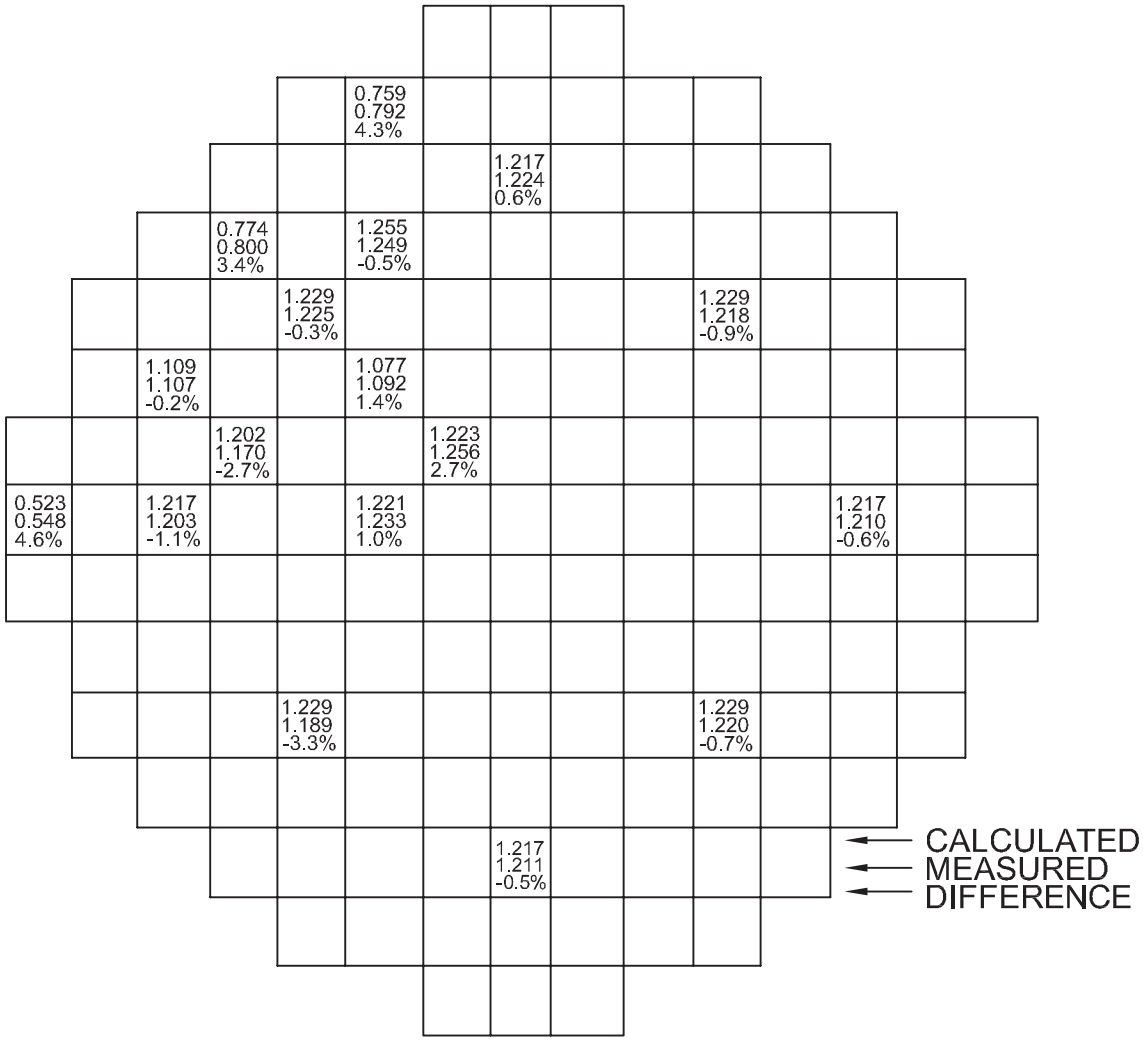
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-21 PEAK POWER DENSITY DURING CONTROL ROD MALFUNCTION OVERPOWER TRANSIENTS



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-22 PEAK LINEAR POWER DURING BORATION / DILUTION OVERPOWER TRANSIENTS



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-23 MAXIMUM $F_Q^T x$ POWER vs AXIAL HEIGHT DURING NORMAL OPERATIONS



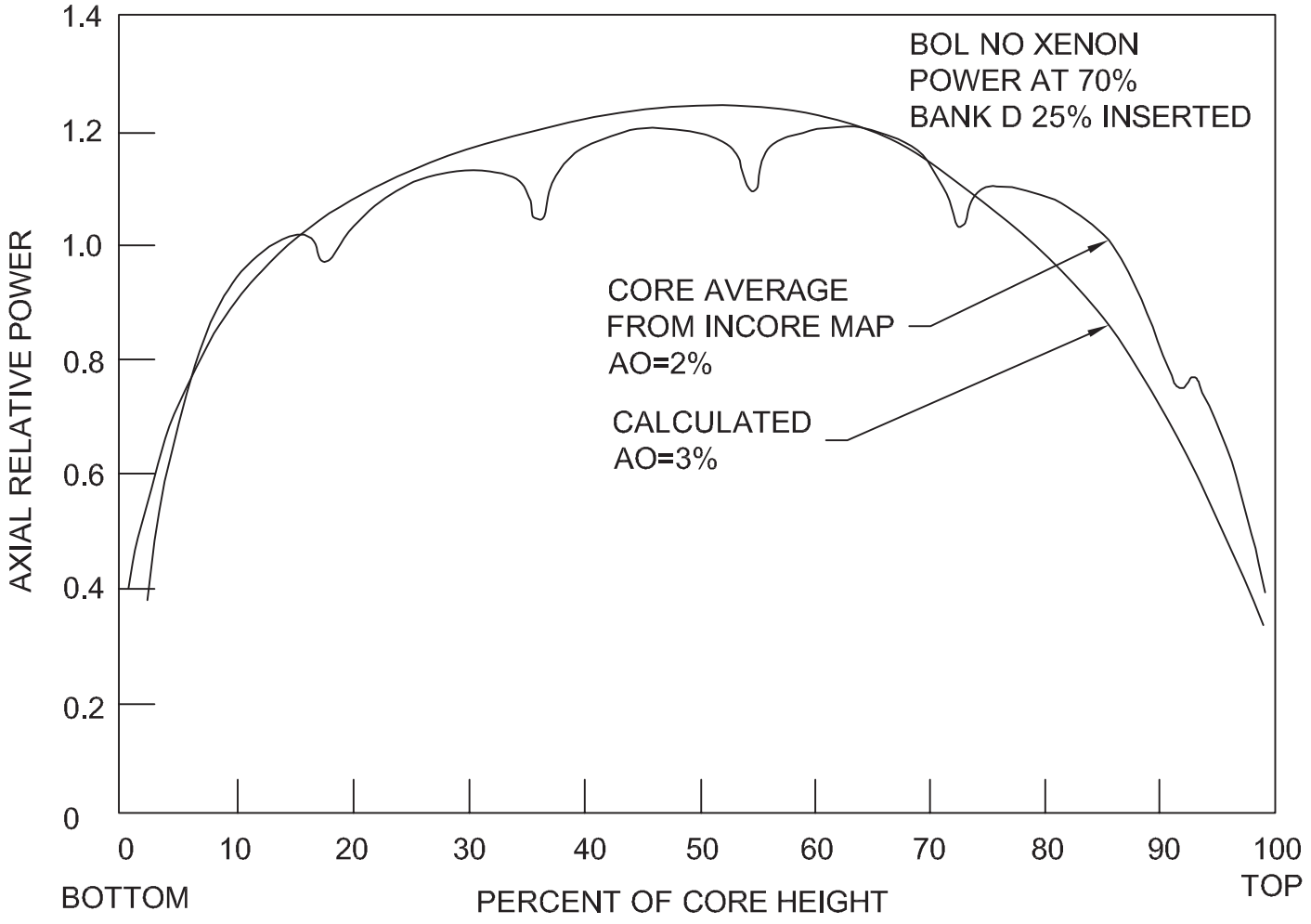
PEAKING FACTORS

$\bar{F}_Z$ = 1.5

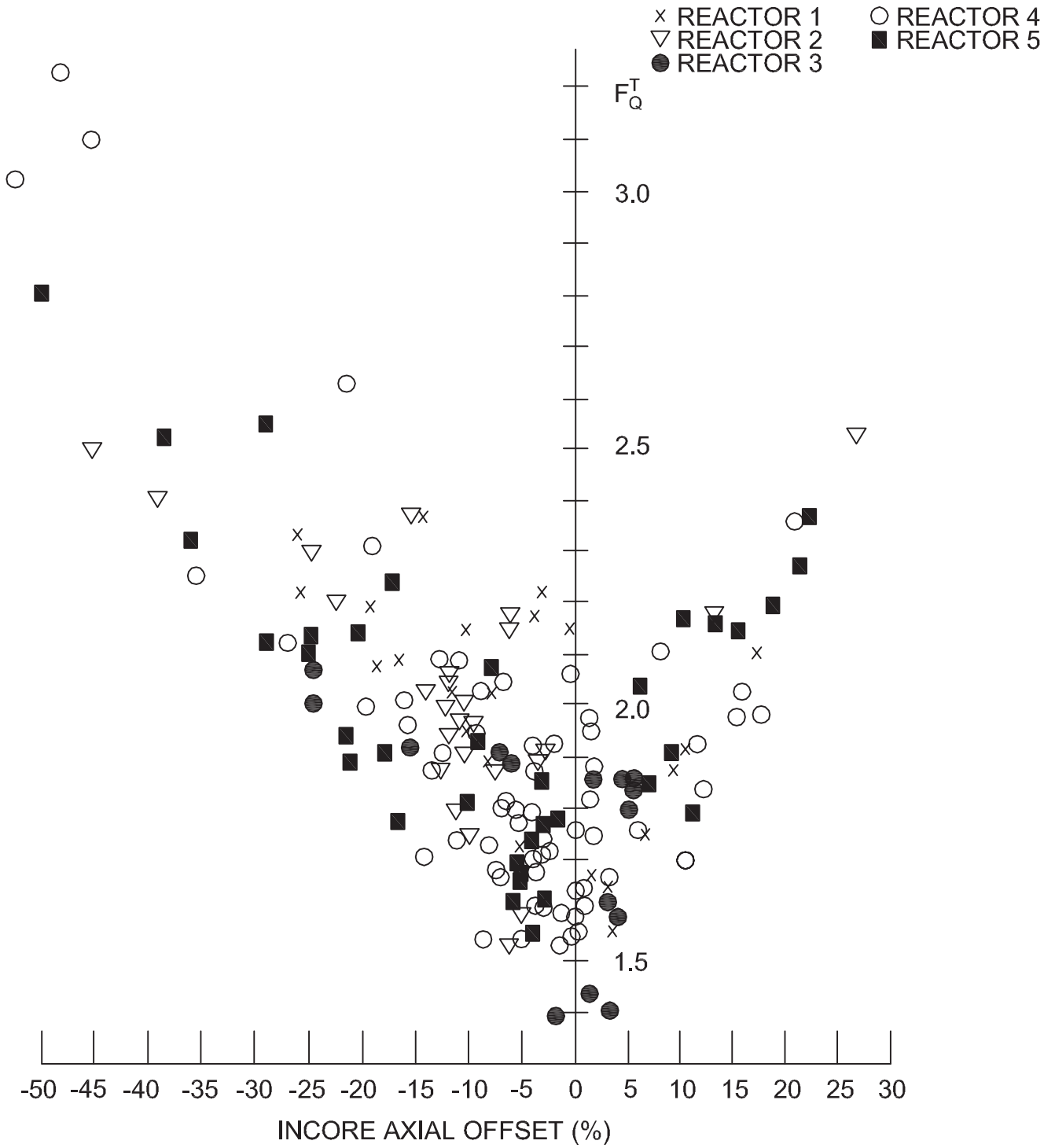
$F^N_{\Delta H}$ = 1.357

F^N_Q = 2.07 LOCATED AT M-8 SOUTH

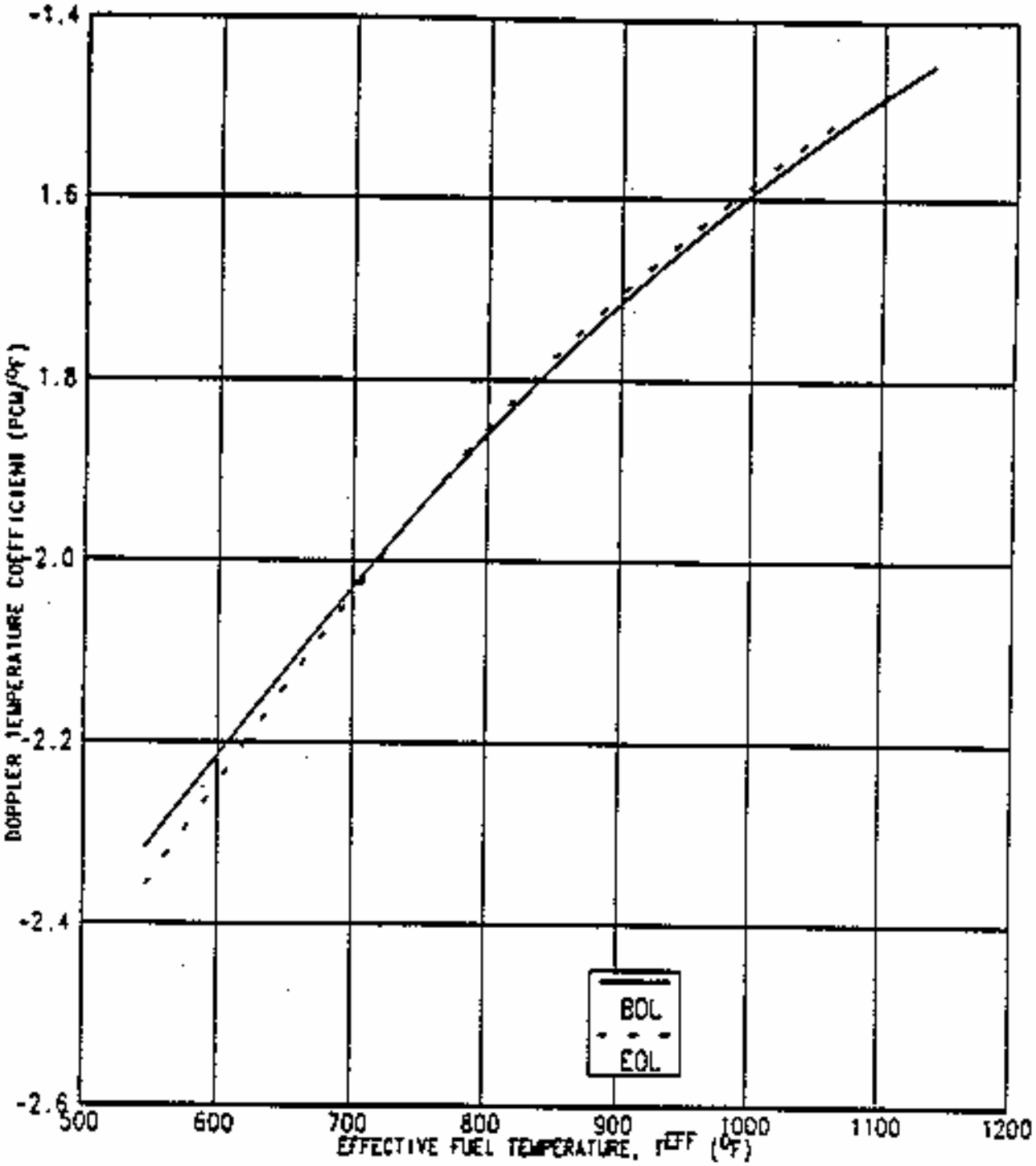
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-25 COMPARISON BETWEEN CALCULATED AND MEASURED RELATIVE FUEL ASSEMBLY POWER DISTRIBUTION



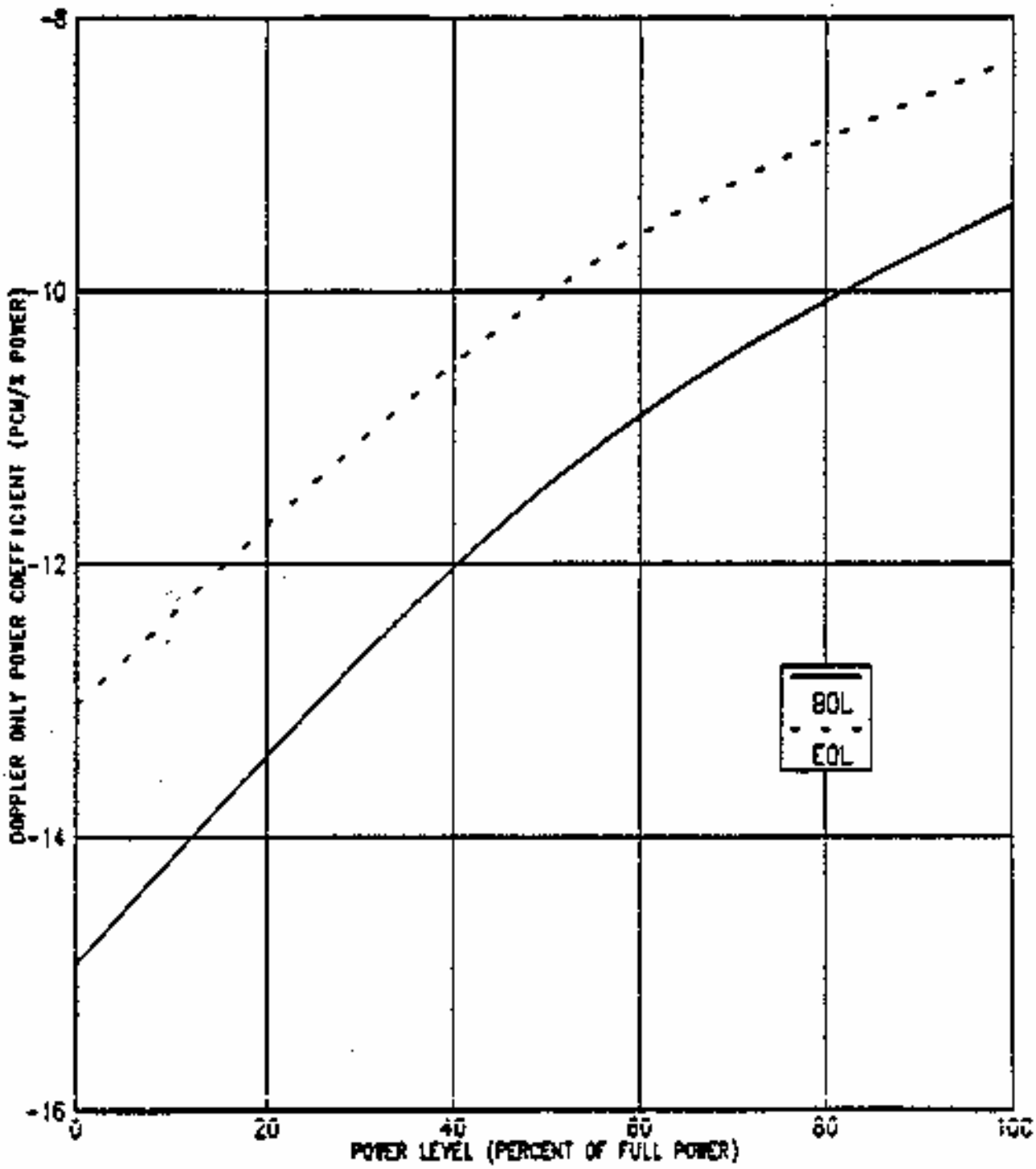
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-26 COMPARISON OF CALCULATED AND MEASURED AXIAL SHAPE



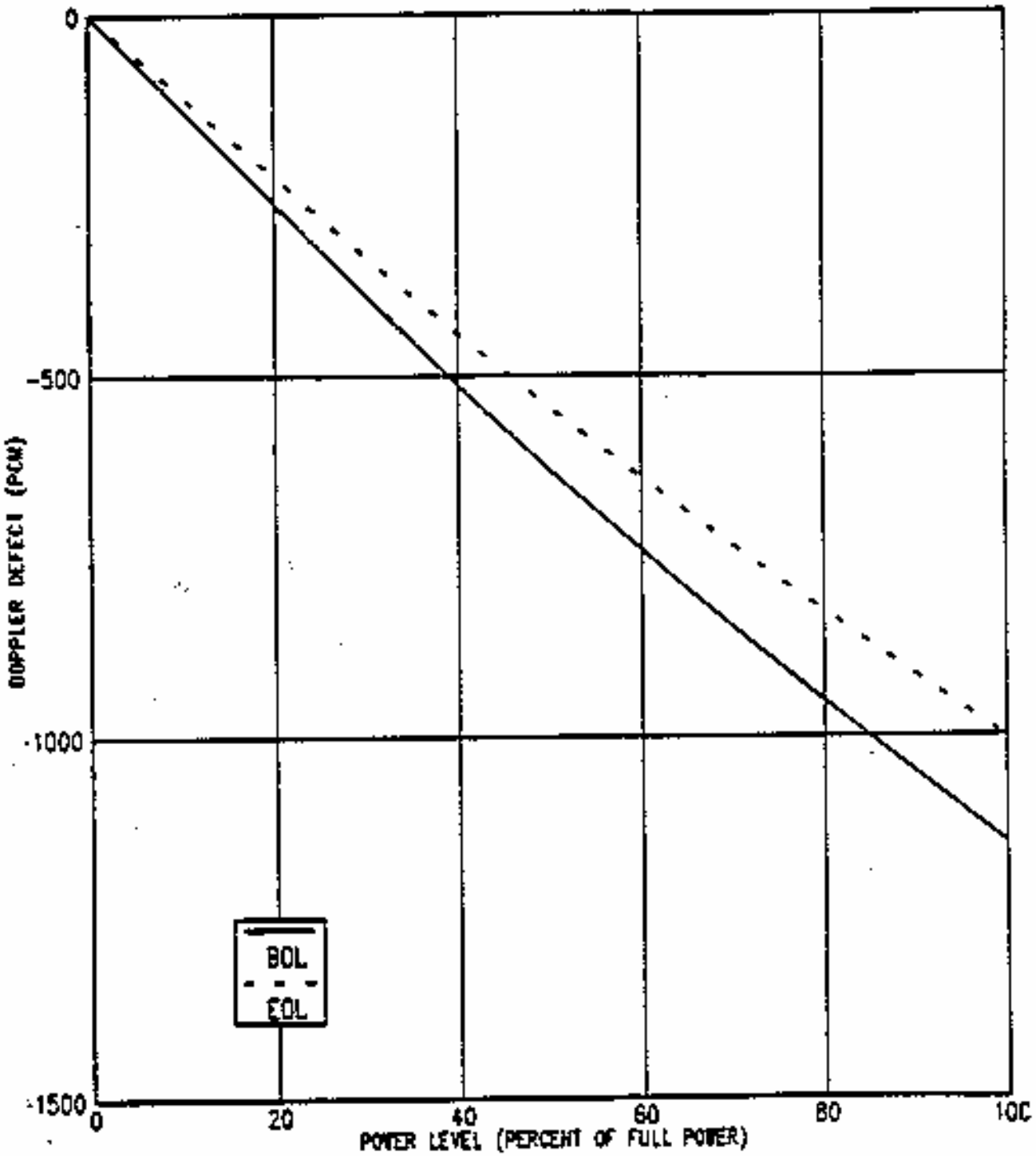
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-27 MEASURED VALUES OF F_Q^T FOR FULL POWER ROD CONFIGURATIONS



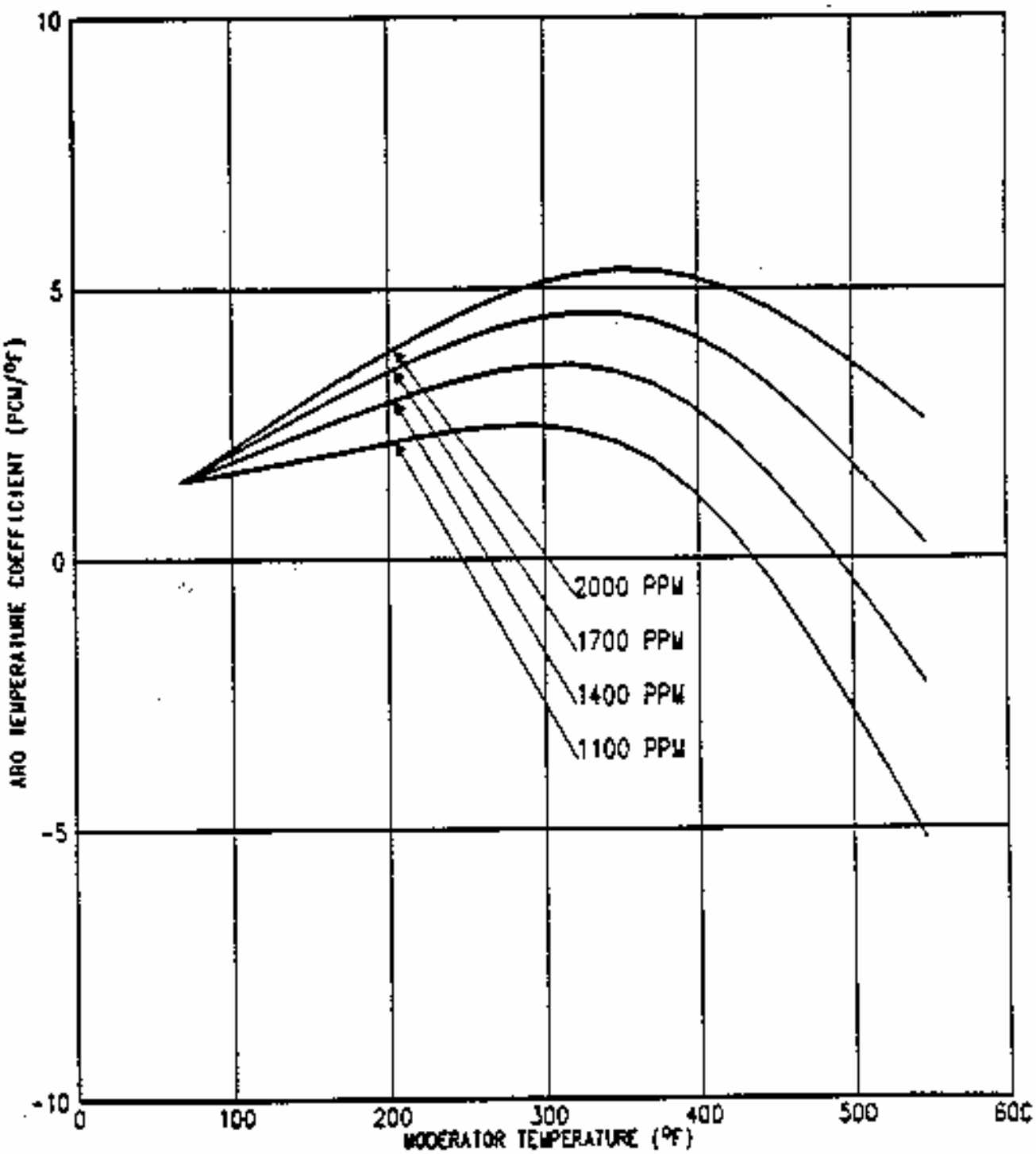
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-28 DOPPLER TEMPERATURE COEFFICIENT AT BOL AND EOL



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-29 DOPPLER ONLY POWER COEFFICIENT AT BOL AND EOL



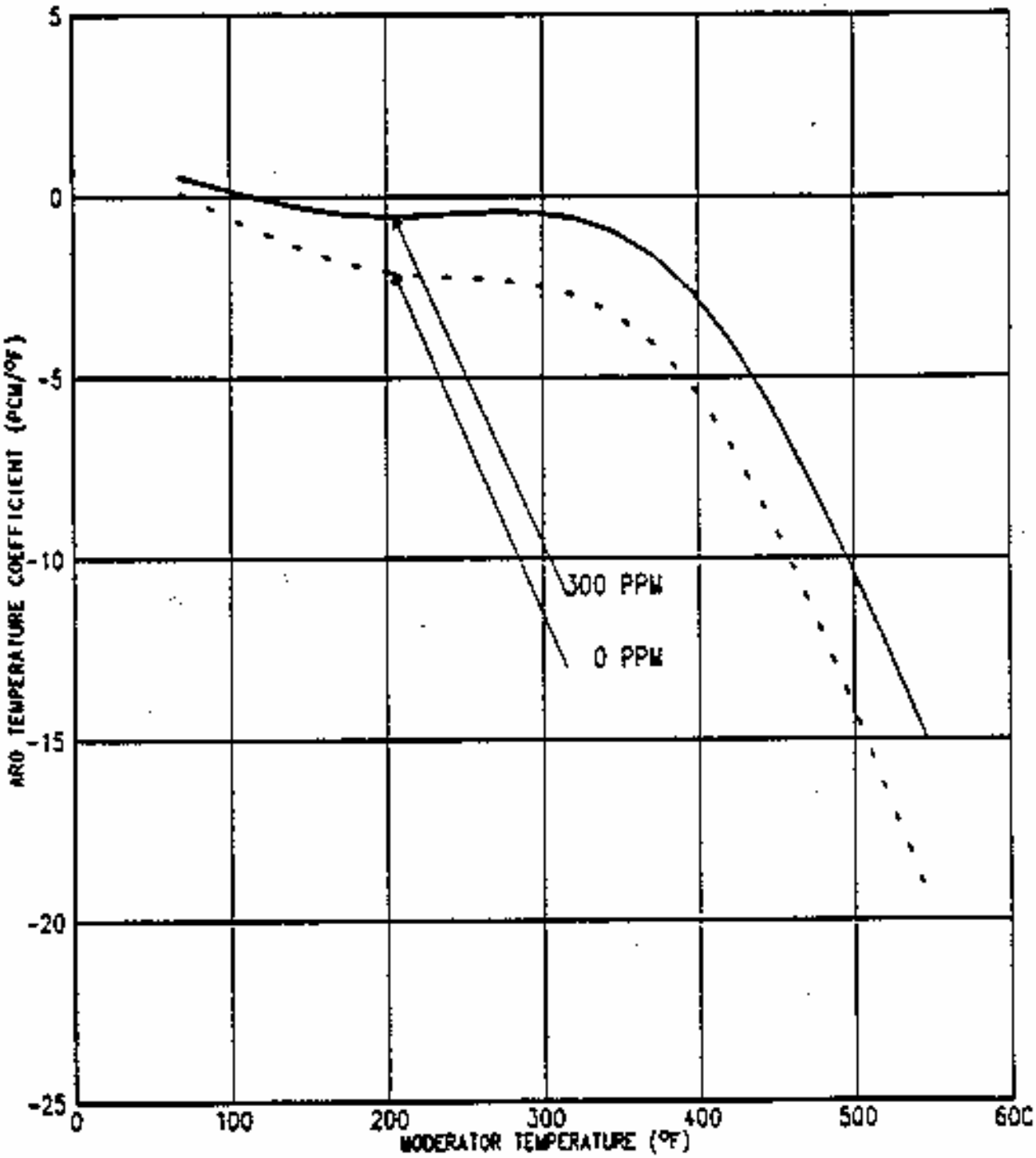
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-30 DOPPLER ONLY POWER DEFECT AT BOL AND EOL



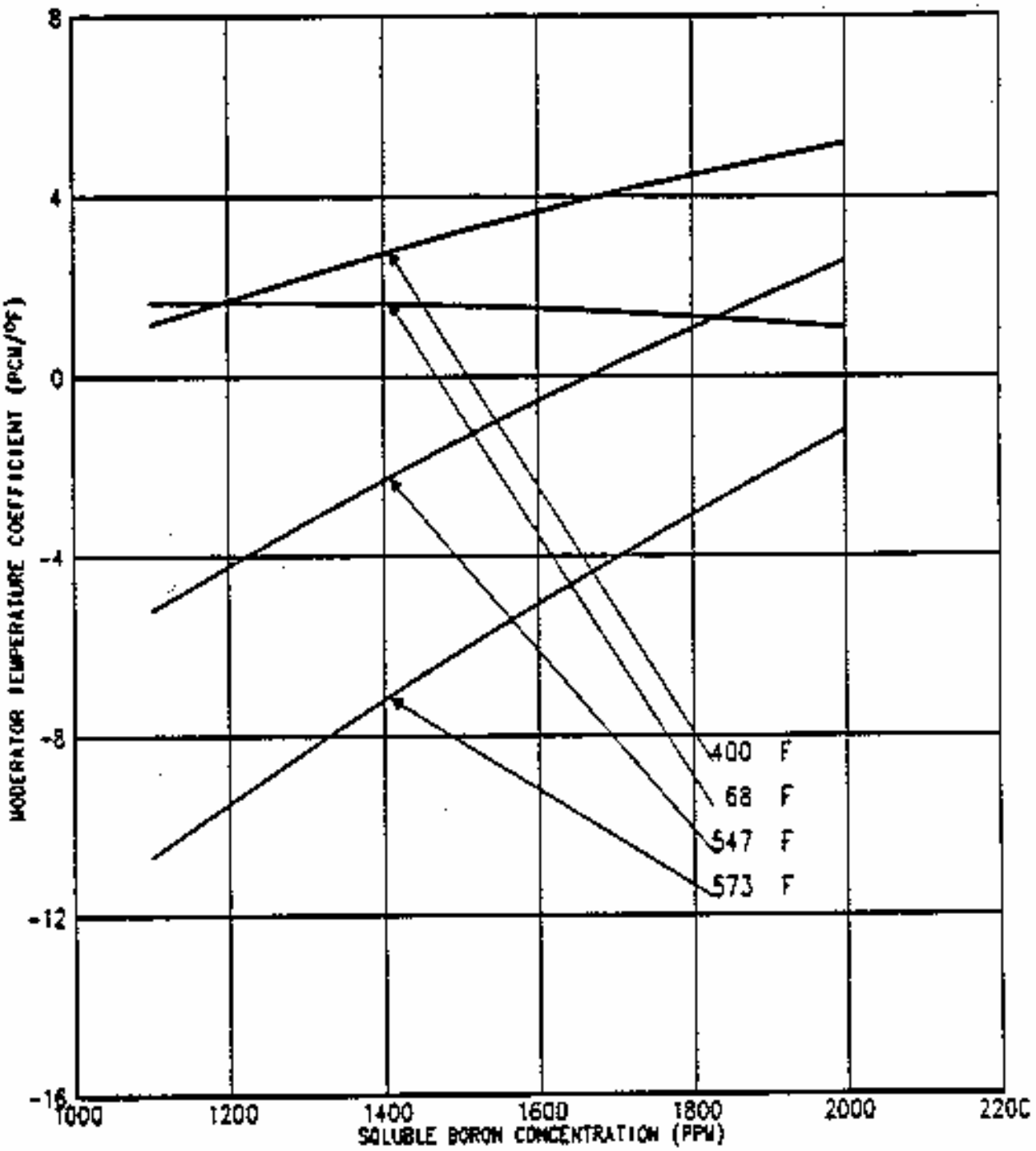
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

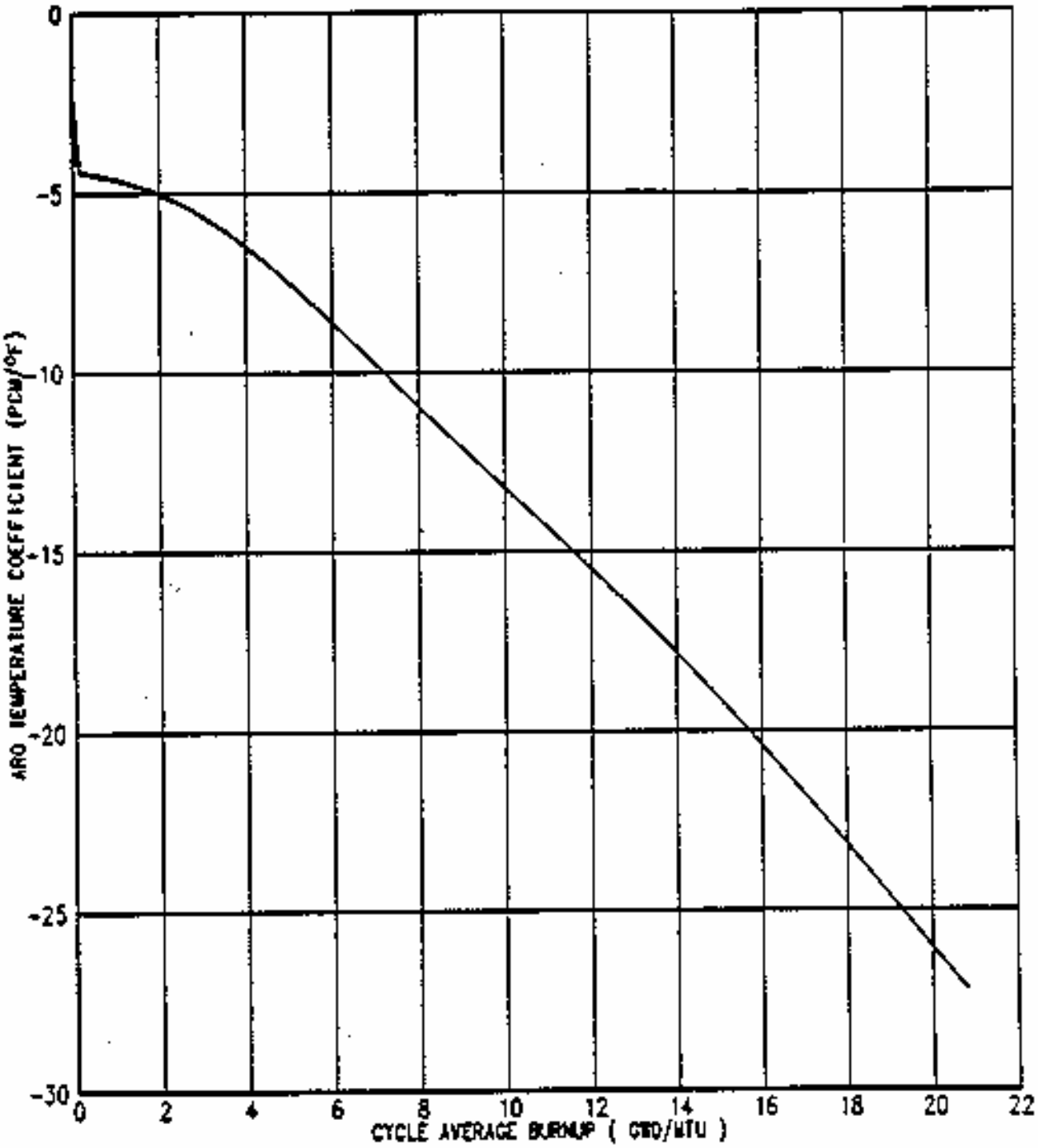
FIGURE 4.3-31
MODERATOR TEMPERATURE COEFFICIENT AT BOL, NO RODS



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-32 MODERATOR TEMPERATURE COEFFICIENT AT EOL



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-33 MODERATOR TEMPERATURE COEFFICIENT AS A FUNCTION OF BORON CONCENTRATION AT BOL, NO RODS

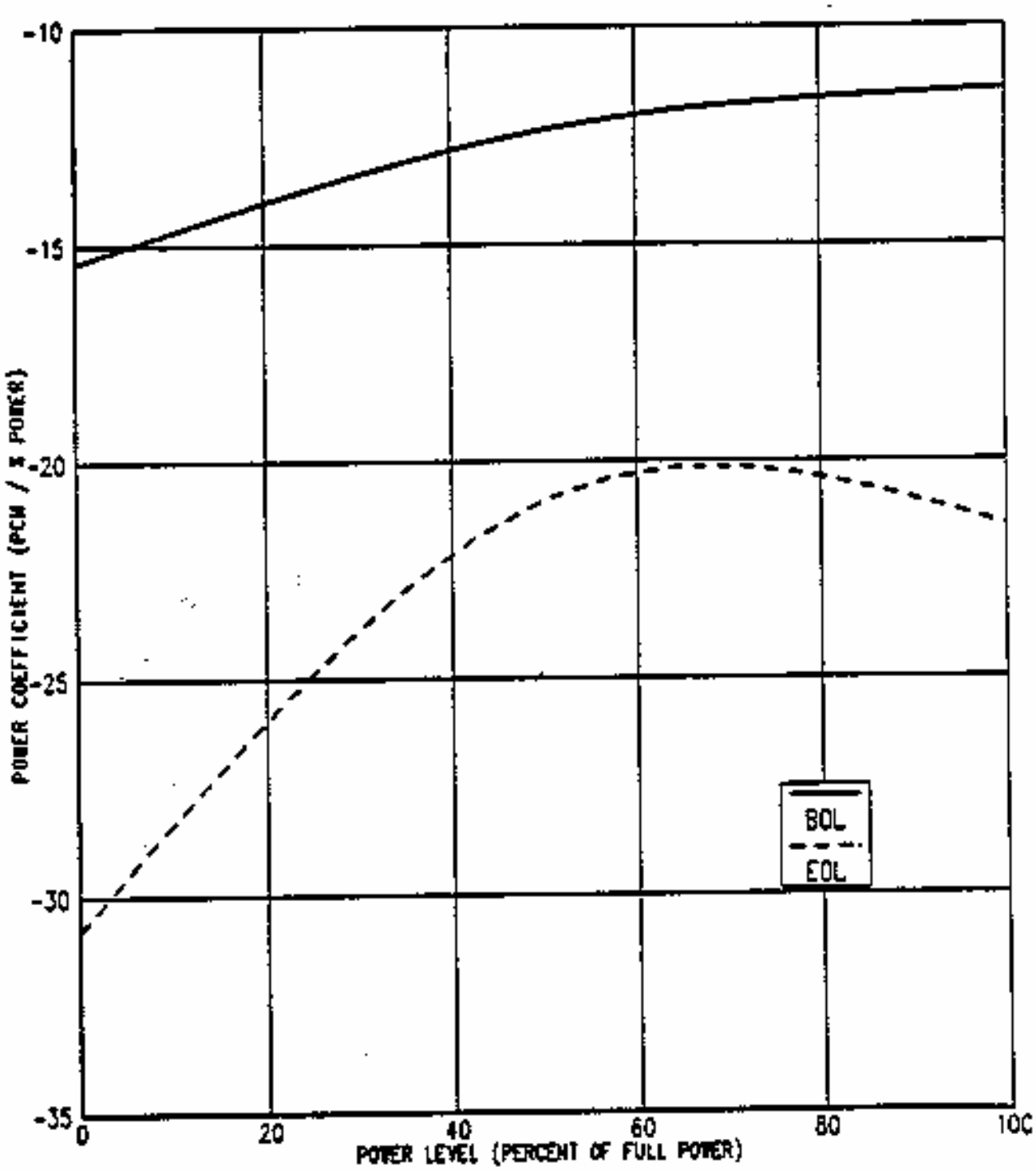


FSAR UPDATE

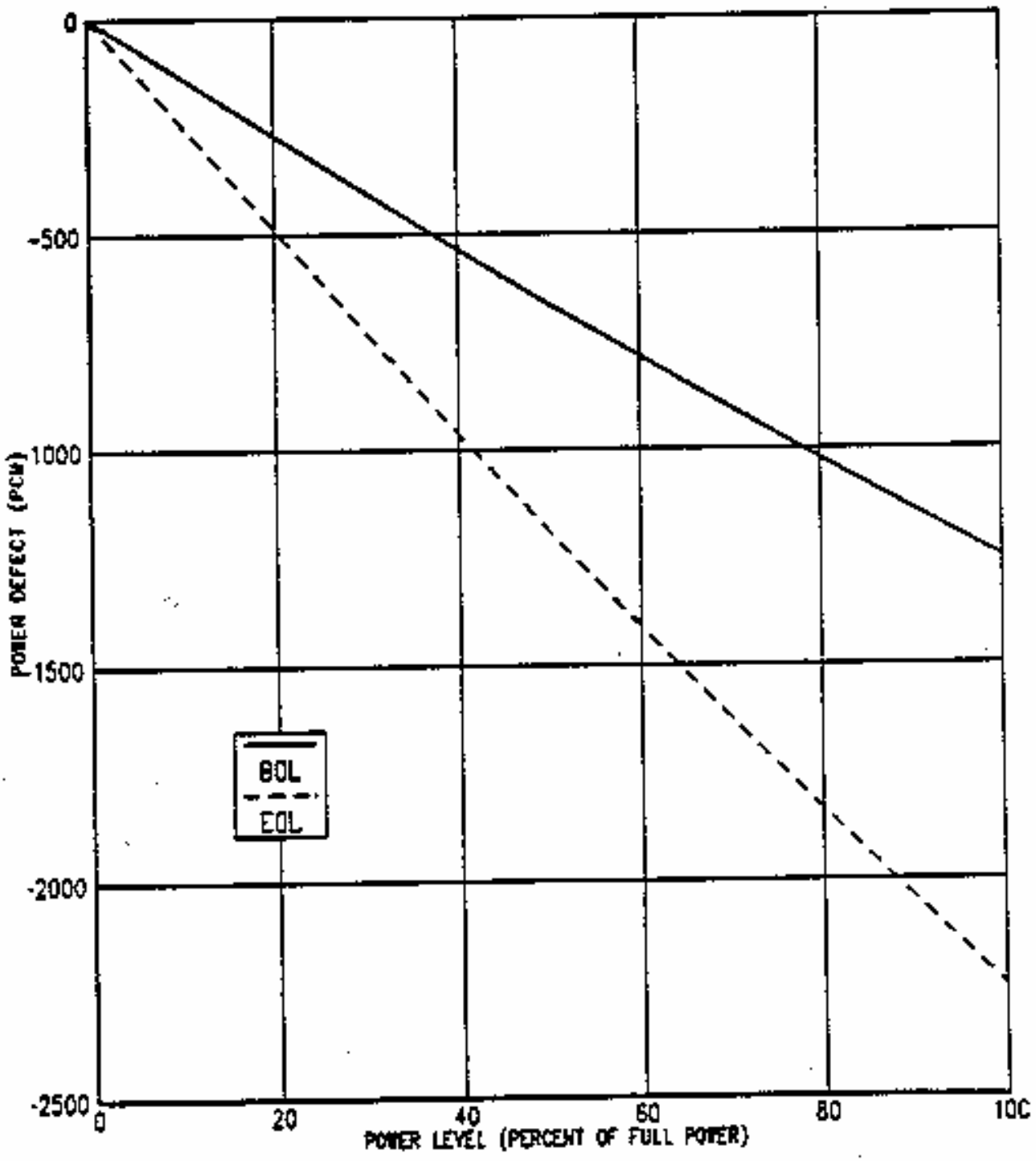
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-34

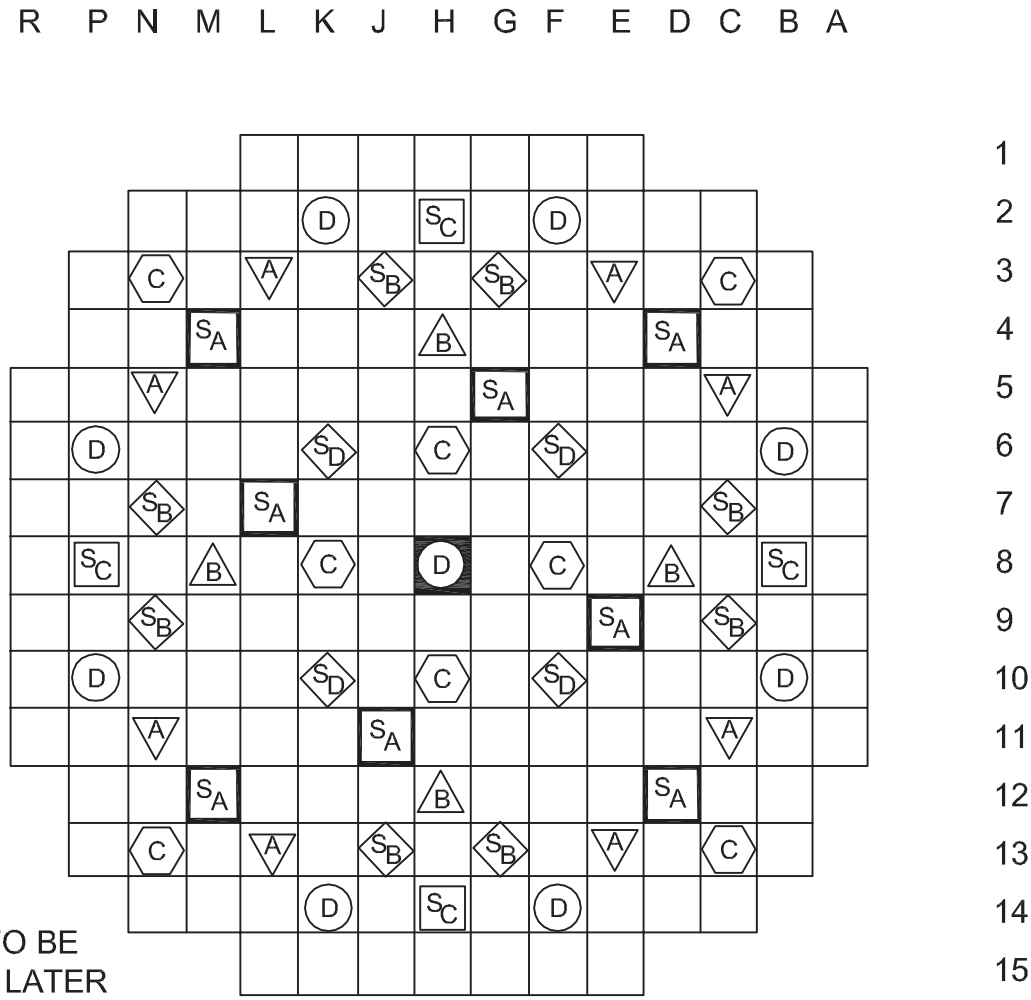
HOT FULL POWER
MODERATOR TEMPERATURE COEFFICIENT
FOR CRITICAL BORON CONCENTRATION



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-35 TOTAL POWER COEFFICIENT AT BOL AND EOL



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-36 TOTAL POWER DEFECT AT BOL AND EOL



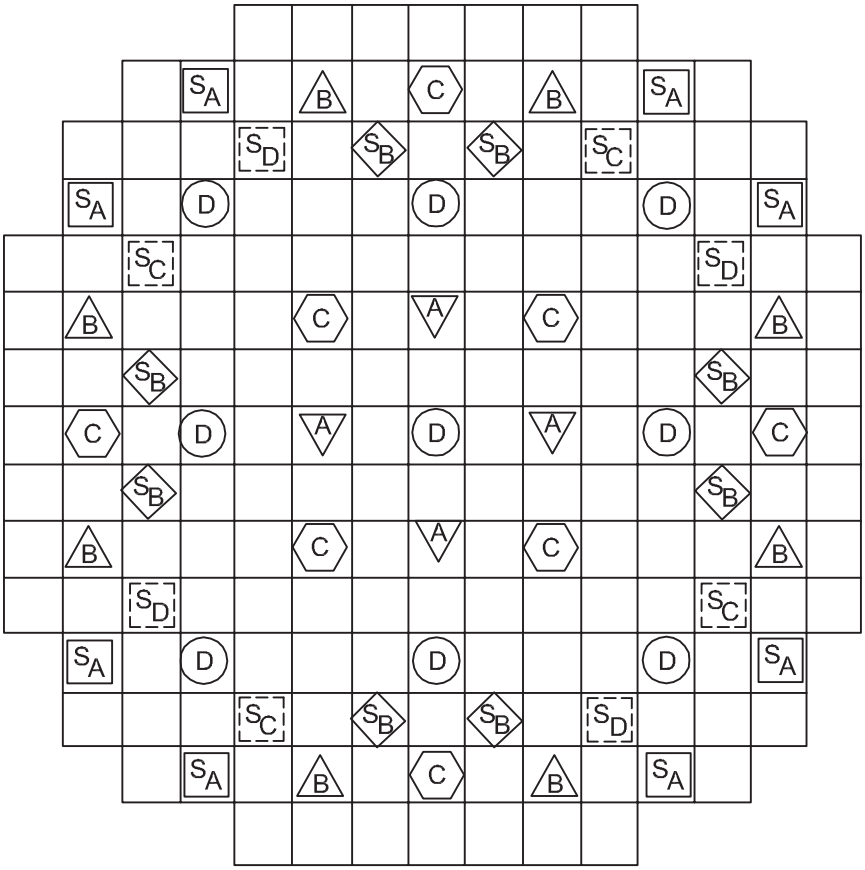
LOCATIONS TO BE TAPPED FOR LATER ACCOMMODATION OF ORIFICE PLATE

	FUNCTION	SYMBOL	NUMBER OF ROD CLUSTERS
SHUTDOWN BANK	S_A	▣	8
SHUTDOWN BANK	S_B	◇	8
SHUTDOWN BANK	S_C	□	4
SHUTDOWN BANK	S_D	◇	4
CONTROL BANK	A	▽	8
CONTROL BANK	B	△	4
CONTROL BANK	C	⬡	8
CONTROL BANK	D	○	9

FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 4.3-37
ROD CLUSTER
CONTROL ASSEMBLY PATTERN

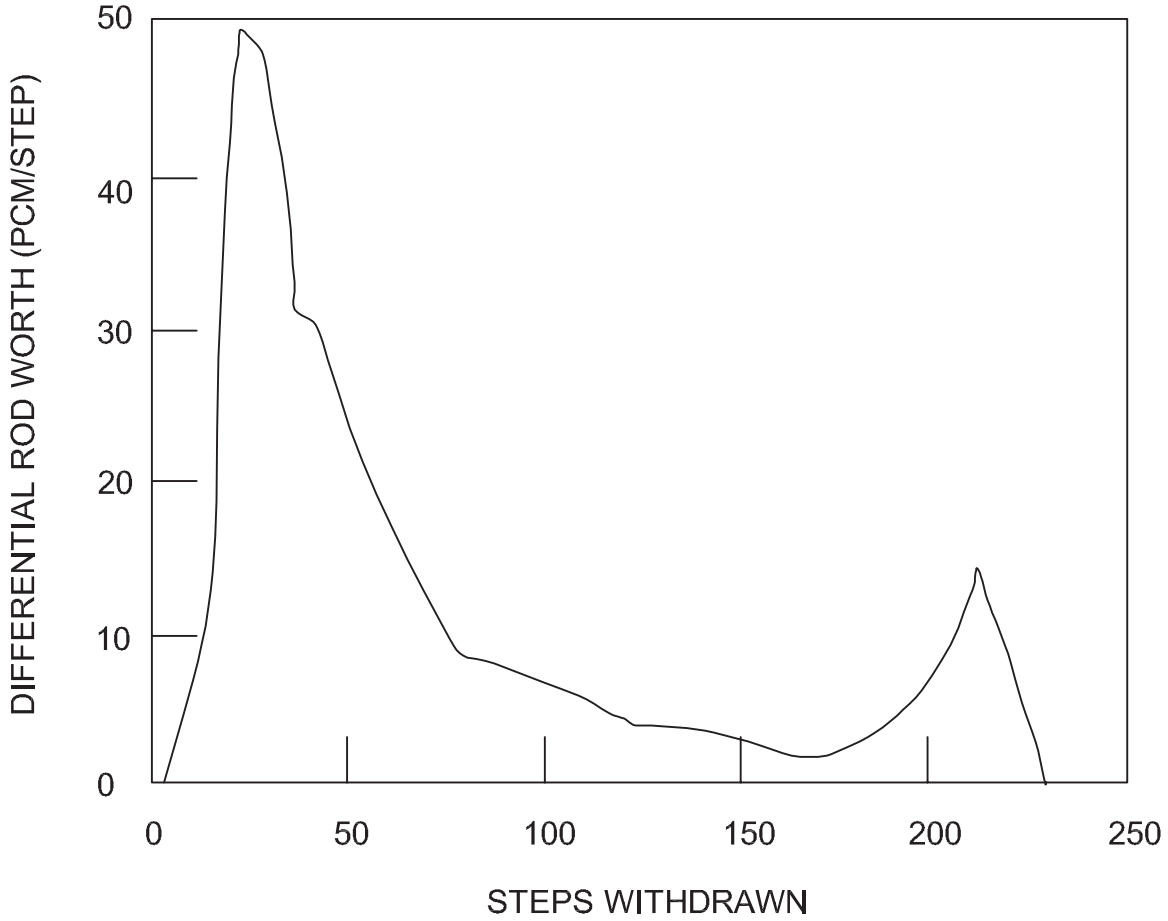


	FUNCTION	SYMBOL	NUMBER OF ROD CLUSTERS
SHUTDOWN BANK	S_A	□	8
SHUTDOWN BANK	S_B	◇	8
SHUTDOWN BANK	S_C & S_D	⬚	4 & 4
CONTROL BANK	A	▽	4
CONTROL BANK	B	△	8
CONTROL BANK	C	⬡	8
CONTROL BANK	D	○	9

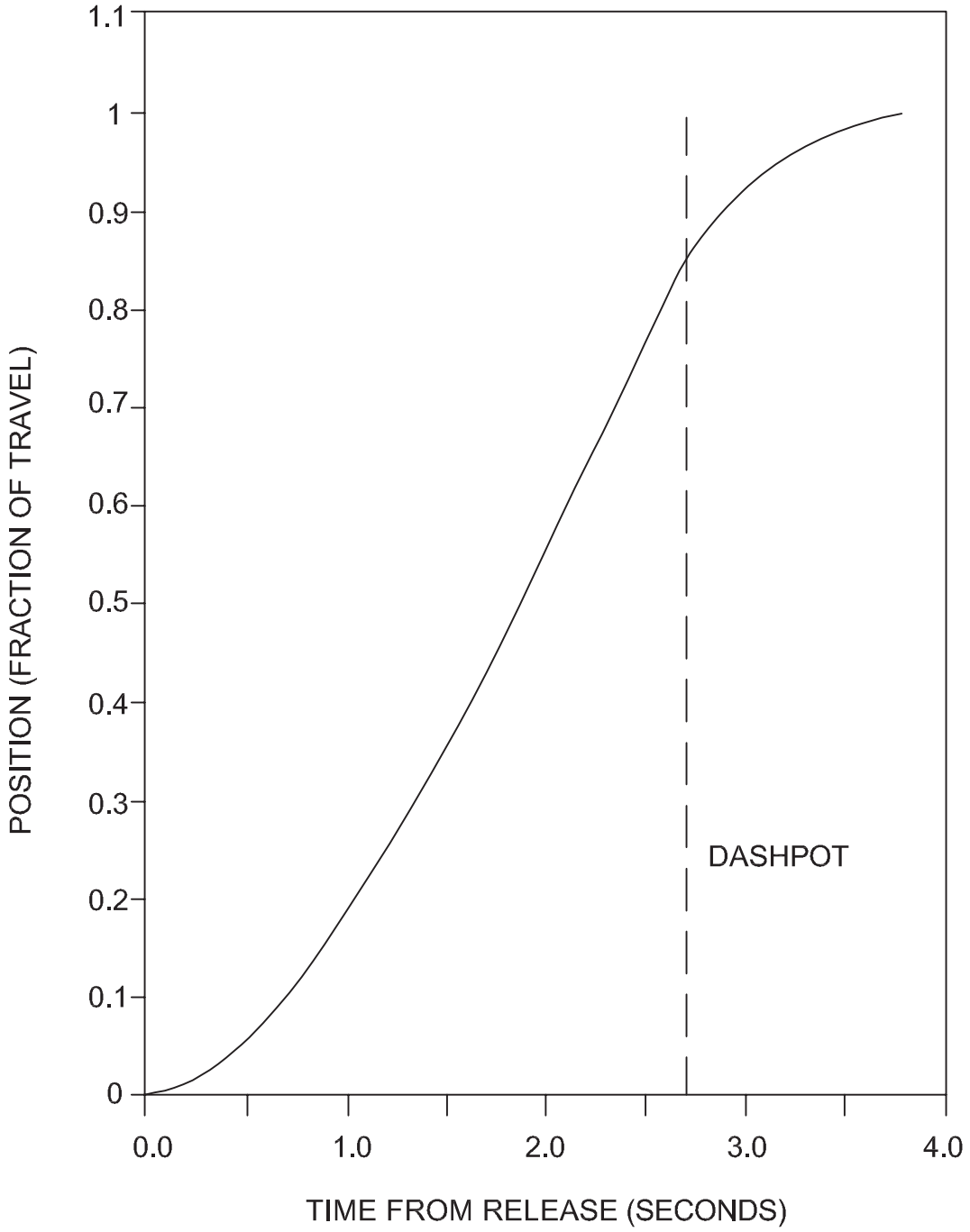
FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

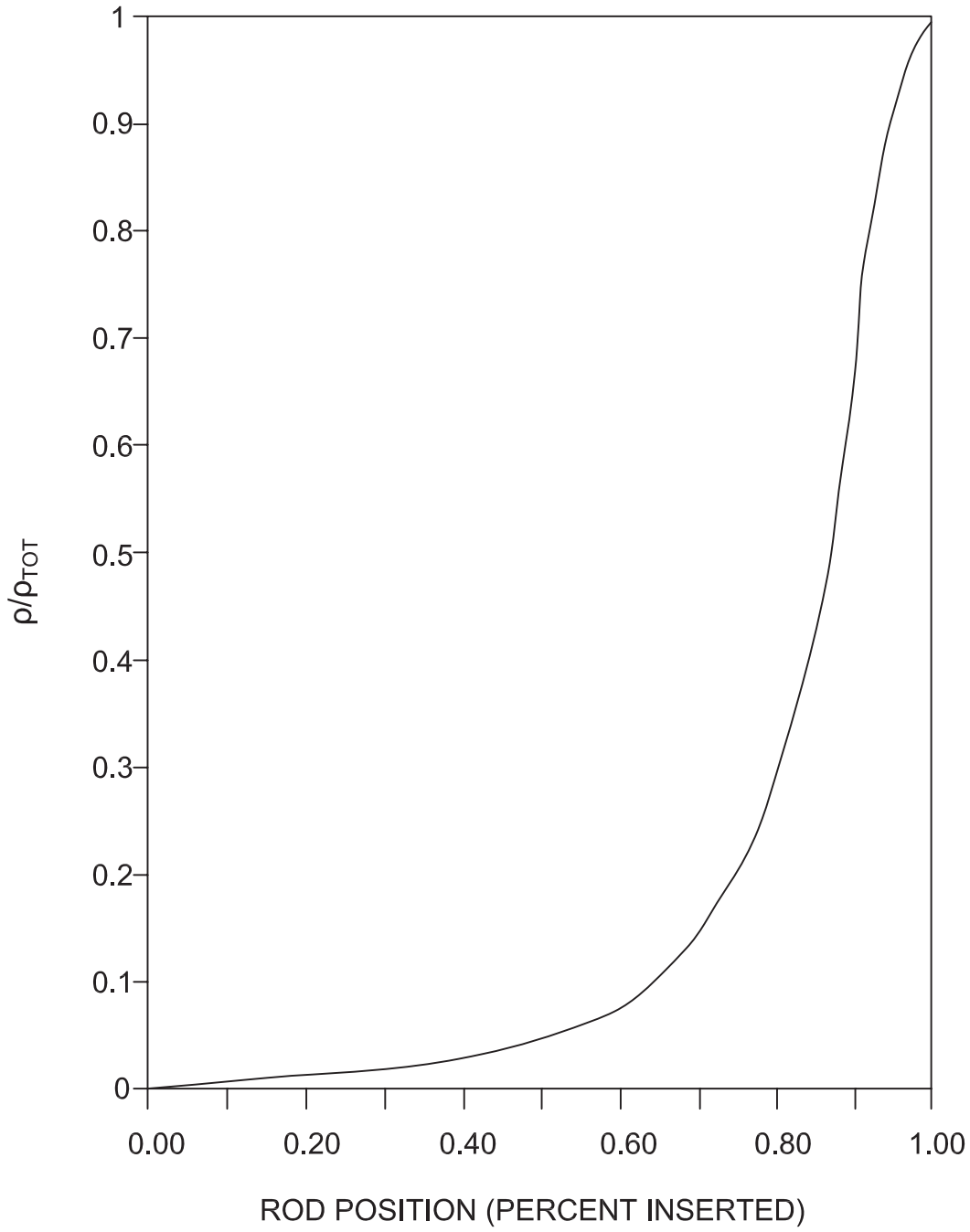
FIGURE 4.3-38
ROD CLUSTER
CONTROL ASSEMBLY PATTERN



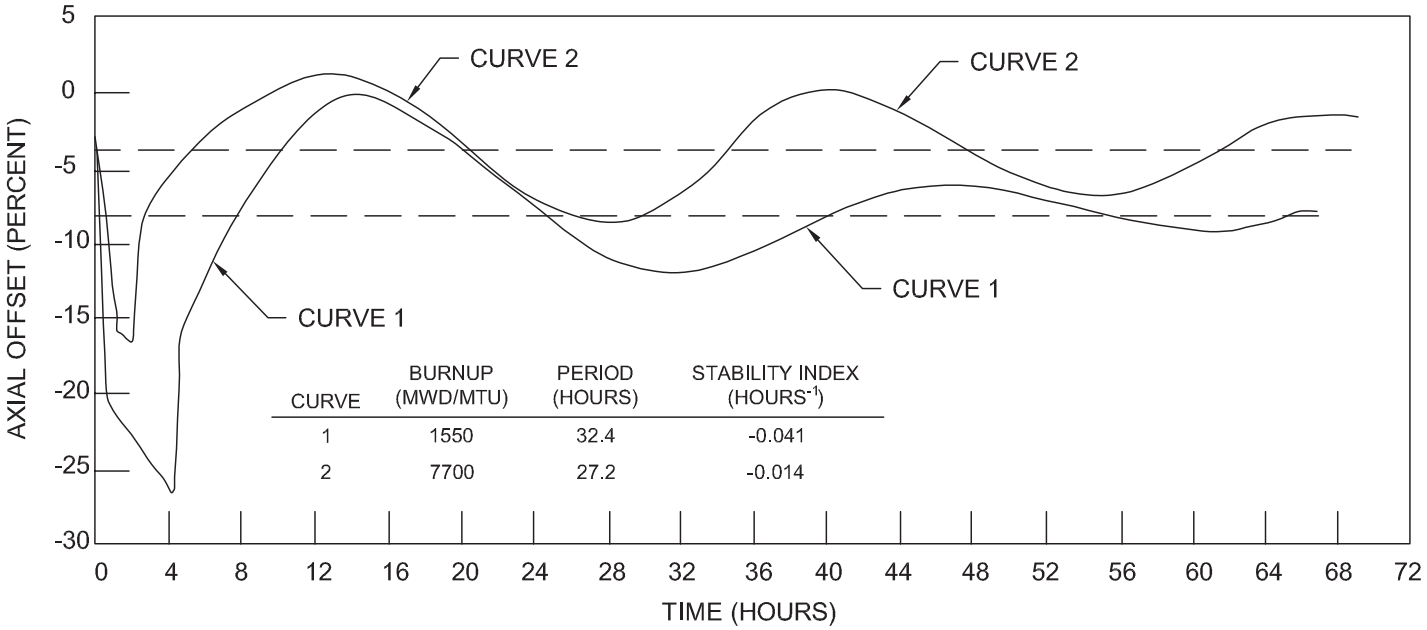
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-39 ACCIDENTAL SIMULTANEOUS WITHDRAWAL OF TWO CONTROL BANKS EOL, HZP BANKS B AND D MOVING IN THE SAME PLANE



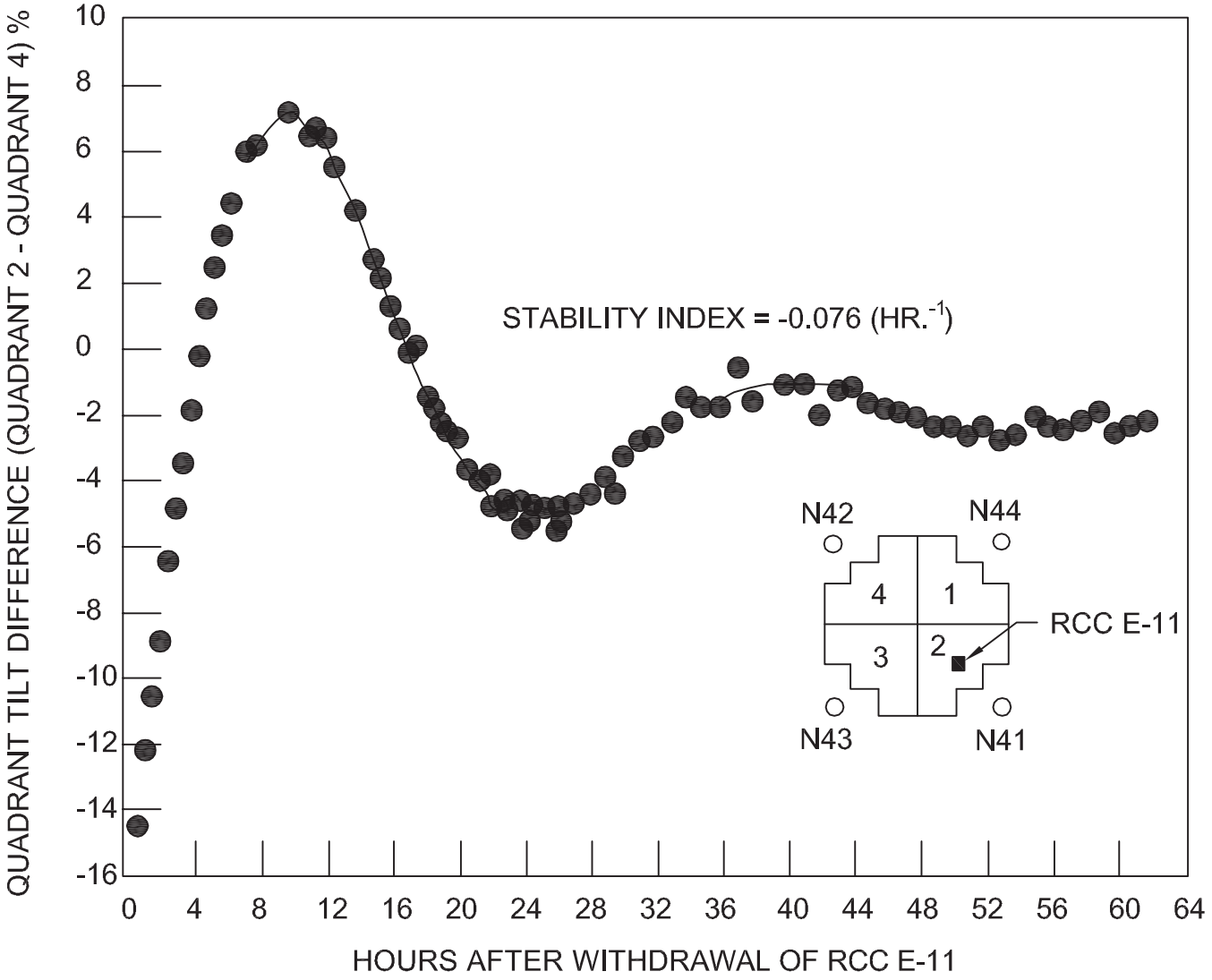
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-40 DESIGN - TRIP CURVE



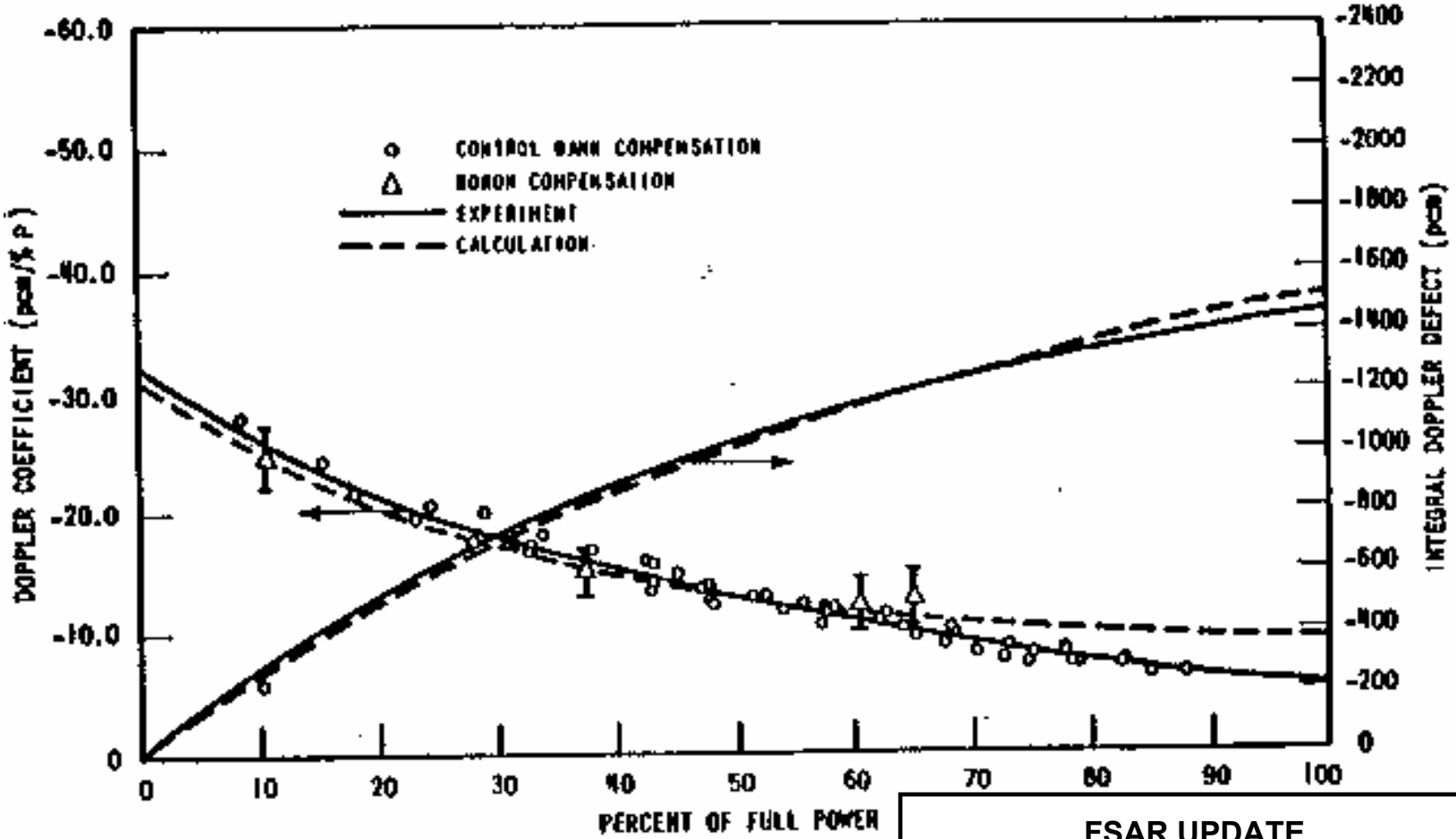
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-41 NORMALIZED ROD WORTH vs. PERCENT INSERTION, ALL RODS BUT ONE



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-42 AXIAL OFFSET vs. TIME PWR CORE WITH A 12-FT CORE HEIGHT AND 121 ASSEMBLIES



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-43 XY XENON TEST THERMOCOUPLE RESPONSE QUADRANT TILT DIFFERENCE vs. TIME

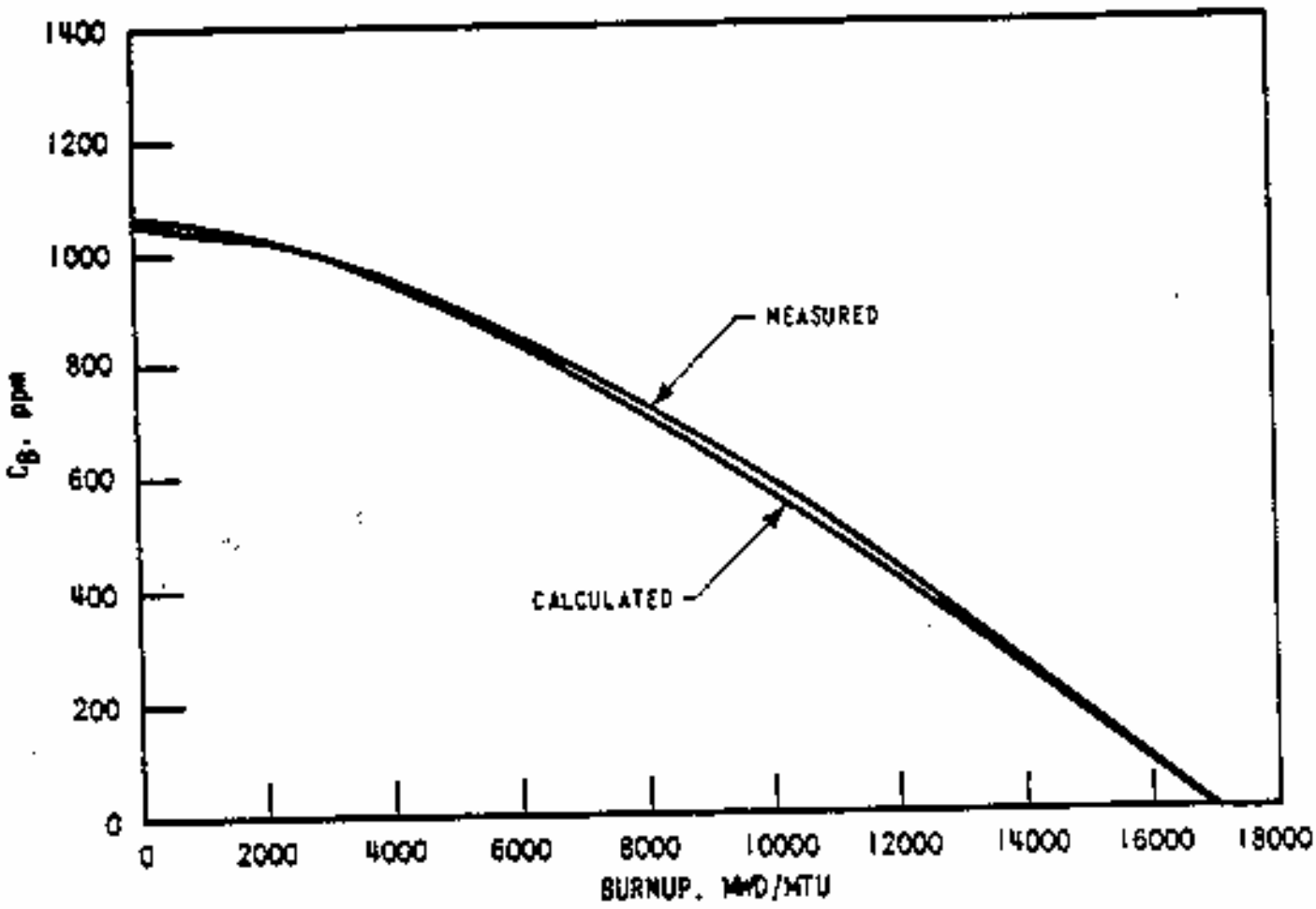


FSAR UPDATE

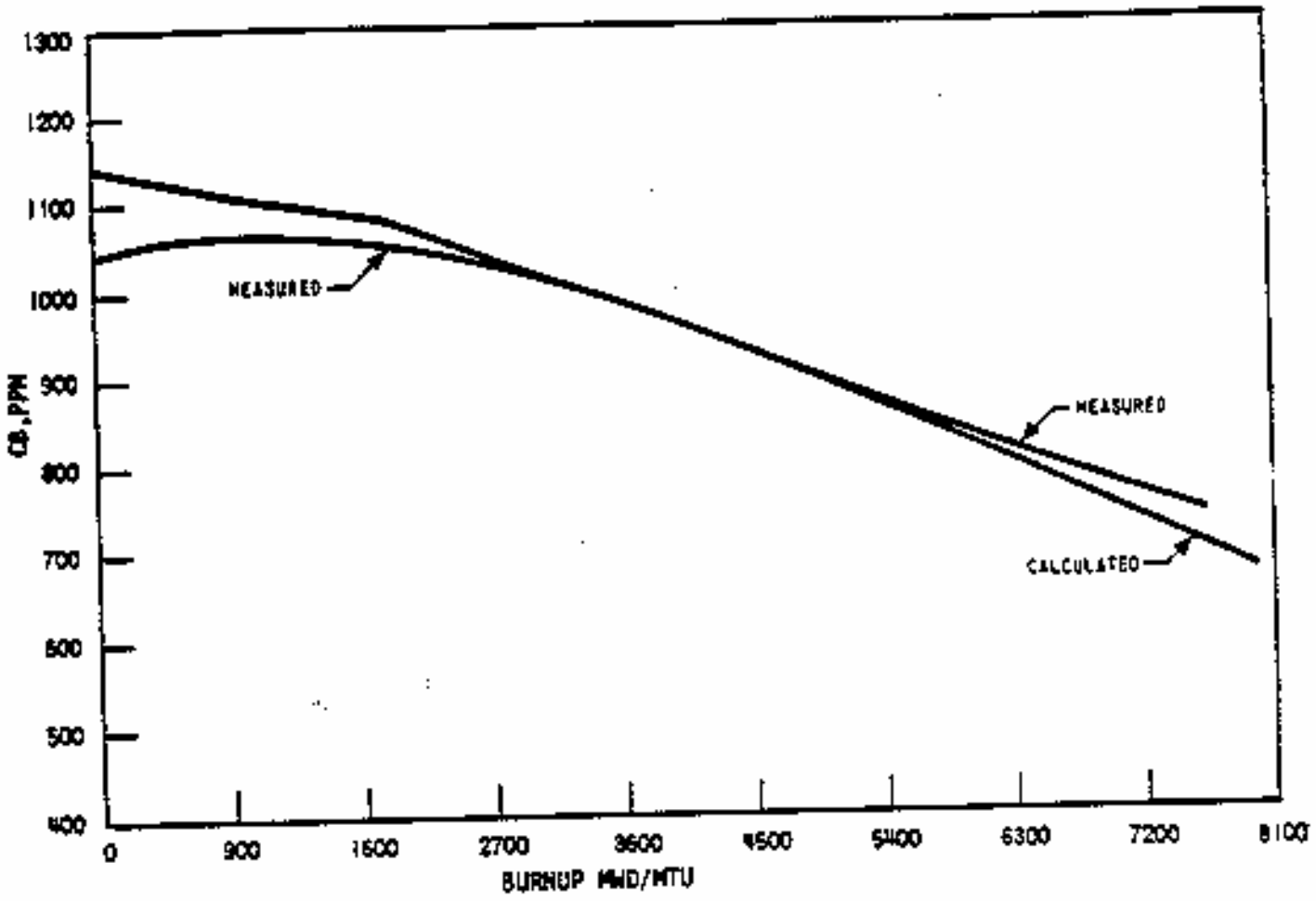
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.3-44

CALCULATED AND MEASURED DOPPLER DEFECT AND COEFFICIENTS AT BOL, FOR A TWO-LOOP PLANT WITH A 12-FT CORE HEIGHT AND 121 ASSEMBLIES

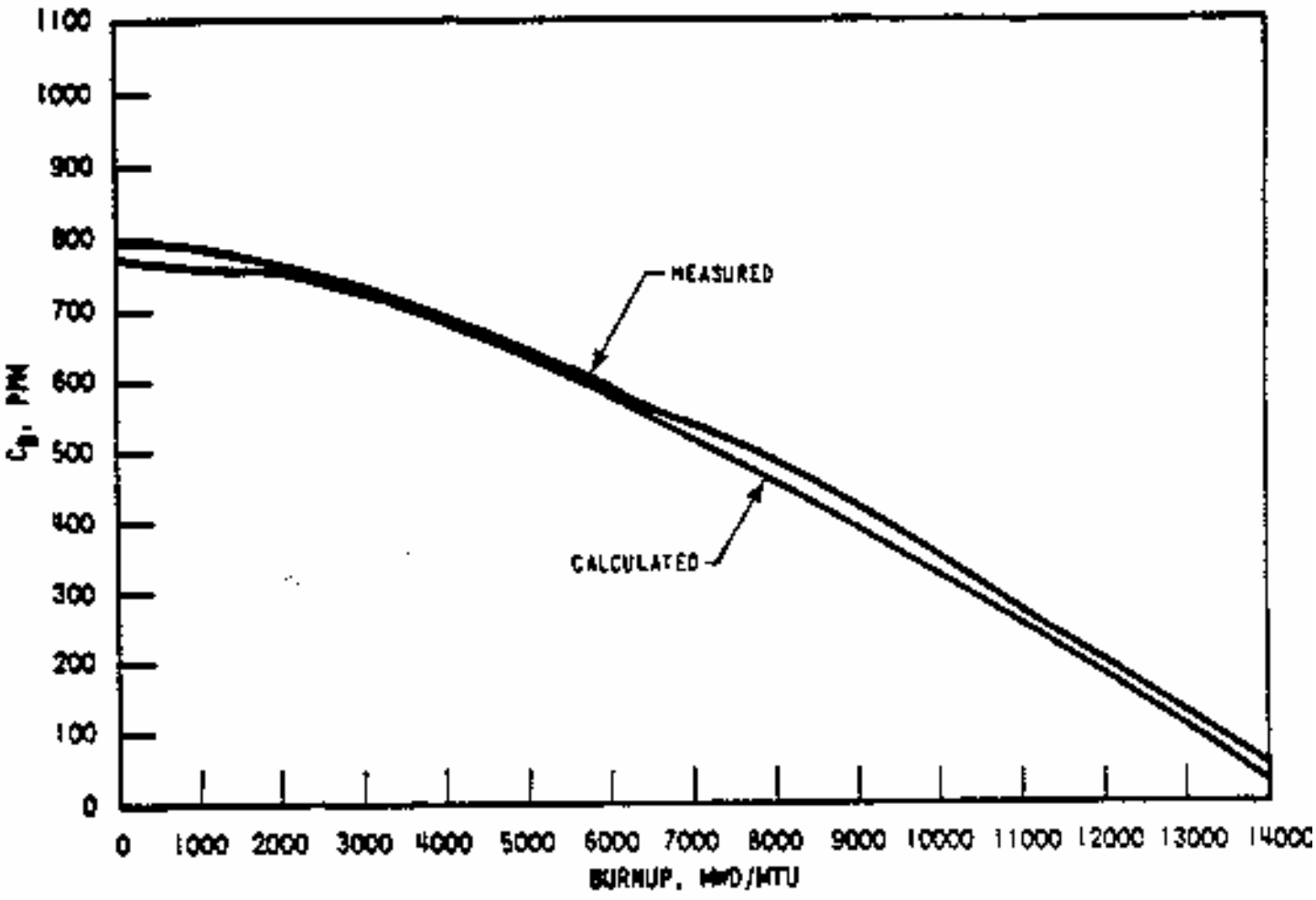


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-45 COMPARISON OF CALCULATED AND MEASURED BORON CONCENTRATION FOR A TWO-LOOP PLANT WITH A 12-FT CORE HEIGHT AND 121 ASSEMBLIES



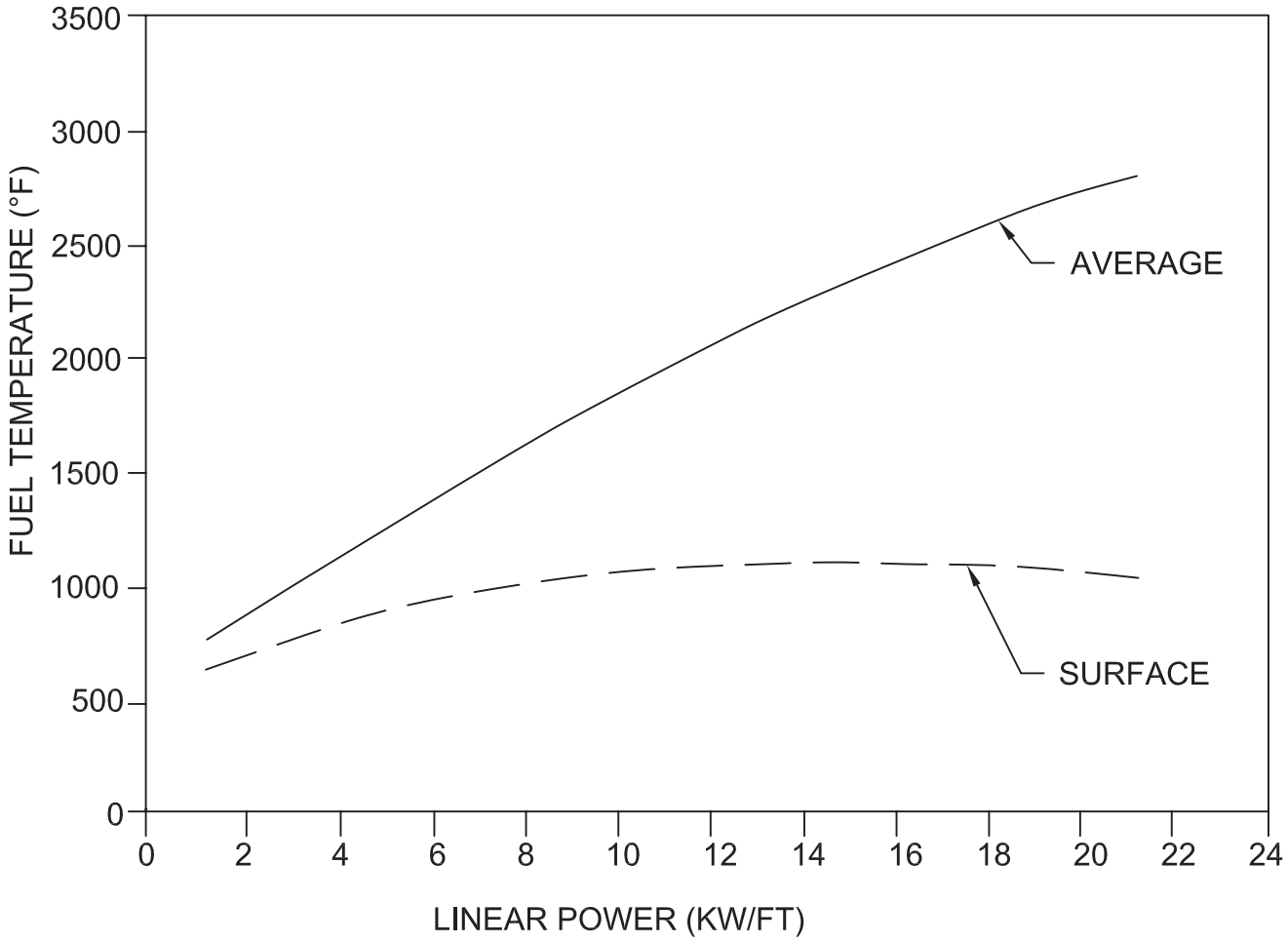
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-46 COMPARISON OF CALCULATED AND MEASURED BORON FOR A TWO LOOP PLANT WITH A 12-FT CORE HEIGHT AND 121 ASSEMBLIES

Revision 11 November 1996

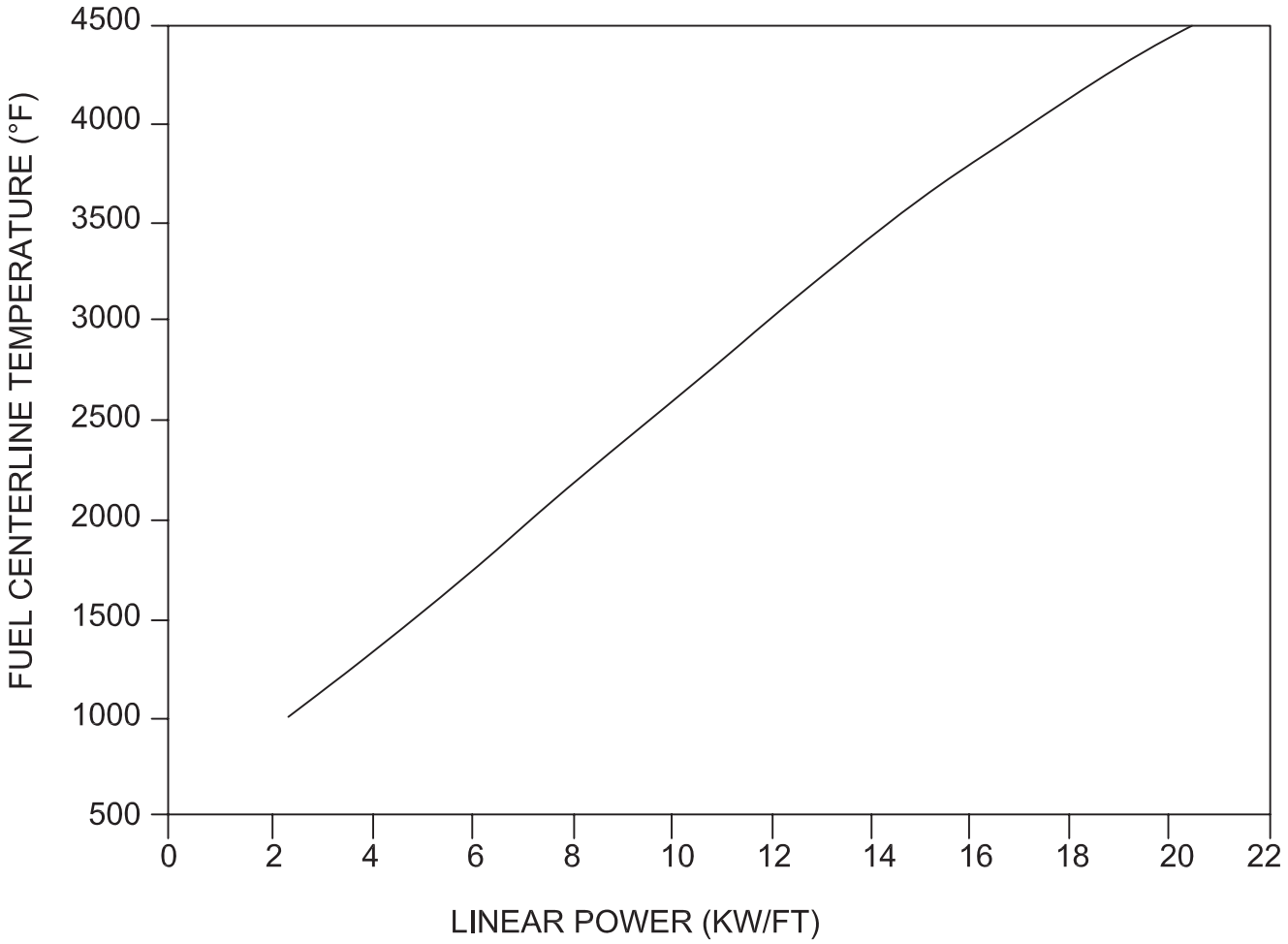


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.3-47 COMPARISON OF CALCULATED AND MEASURED BORON IN A 3-LOOP PLANT WITH A 12-FT CORE HEIGHT AND 157 ASSEMBLIES

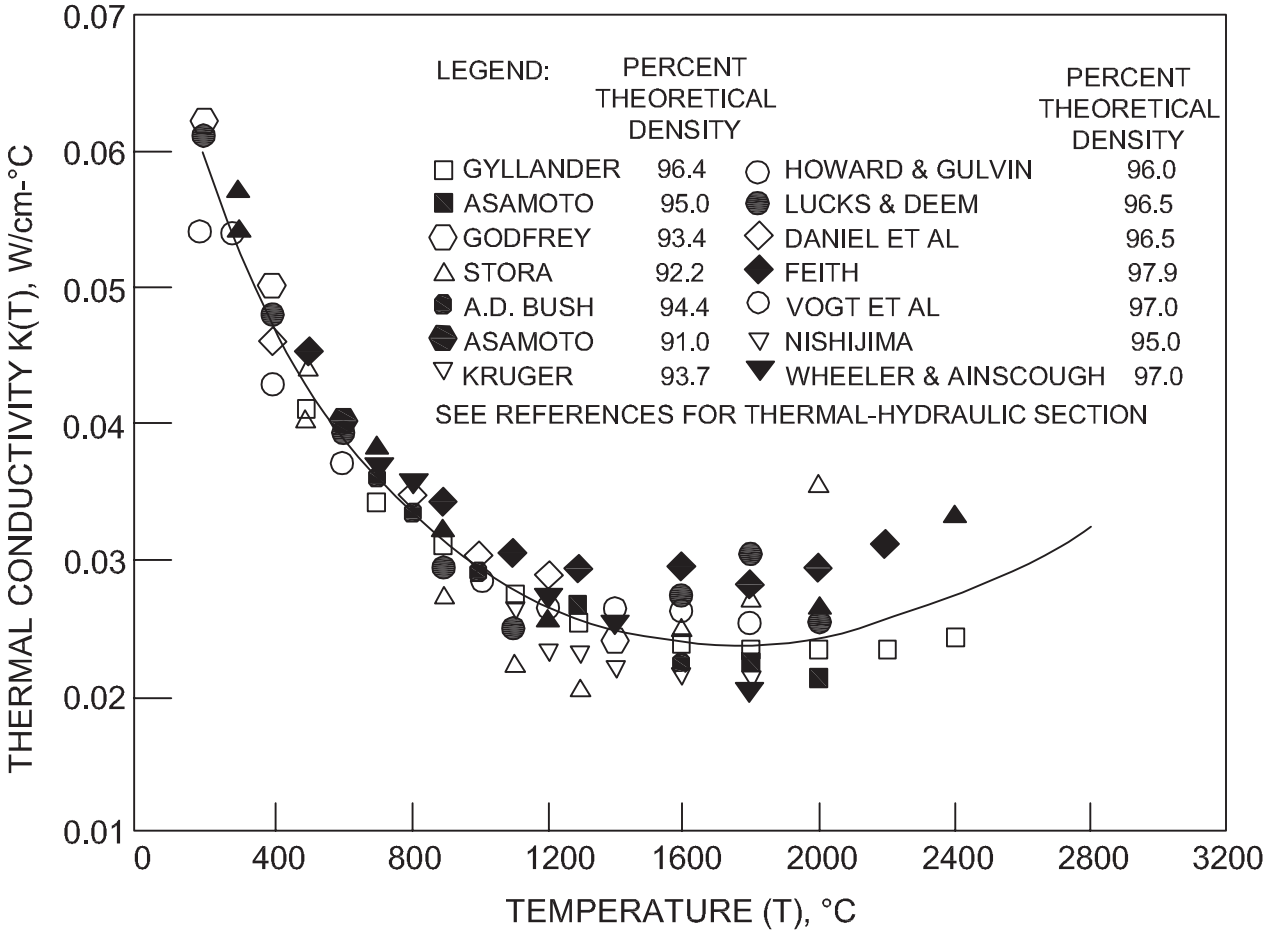
Revision 11 November 1996



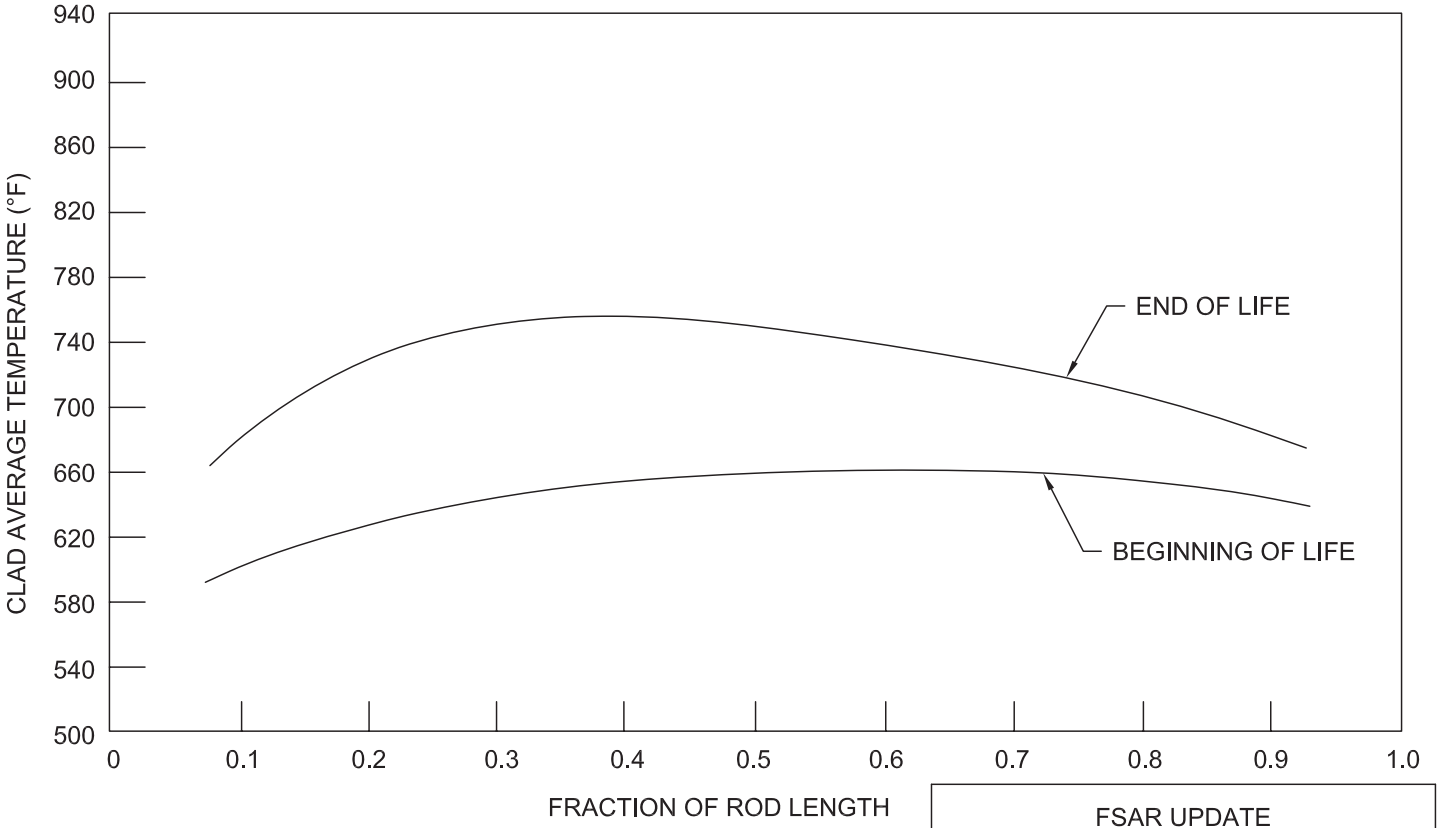
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.4-1 PEAK FUEL AVERAGE AND SURFACE TEMPERATURES DURING FUEL ROD LIFETIME vs. LINEAR POWER DENSITY



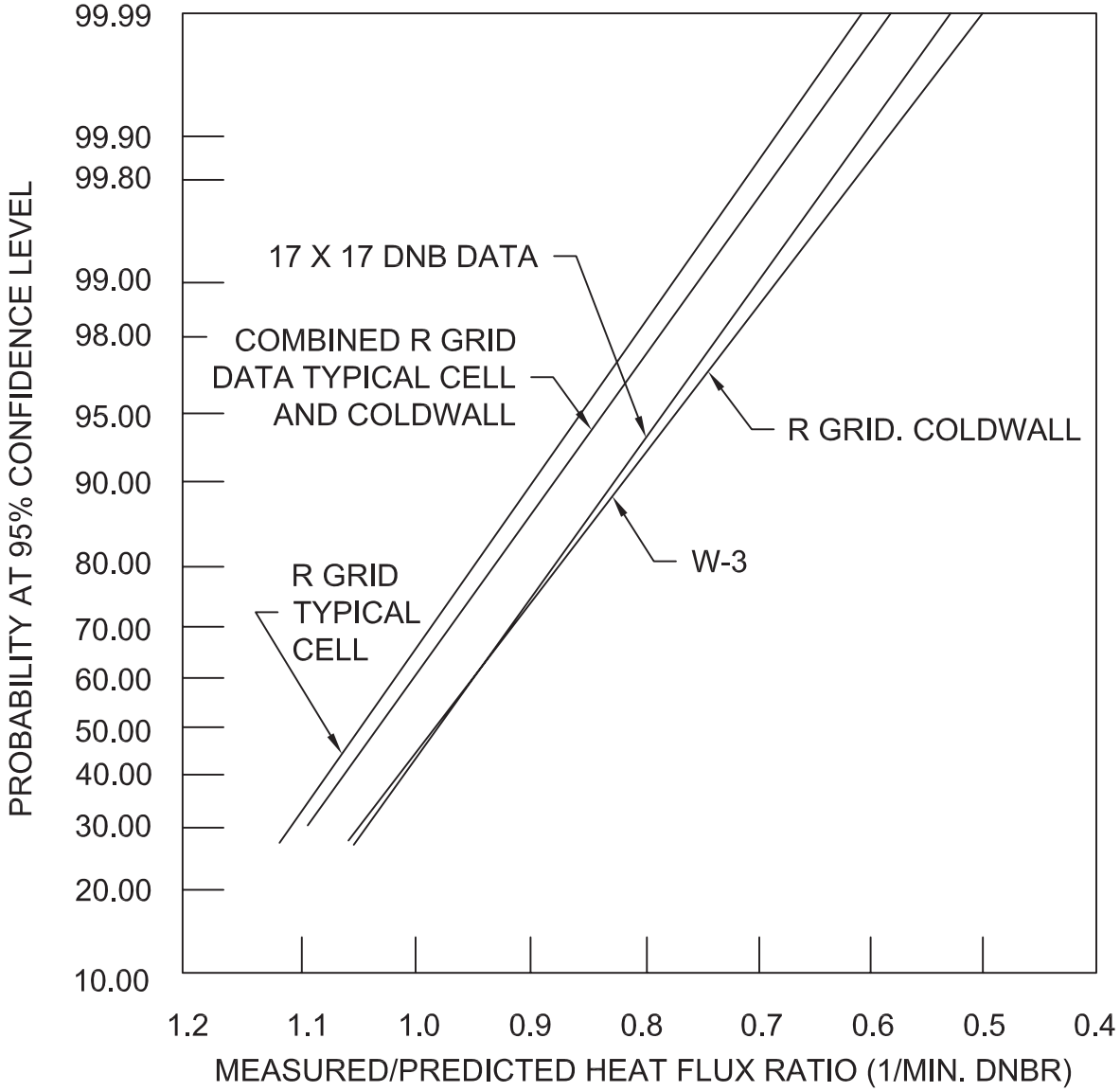
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.4-2 PEAK FUEL CENTERLINE TEMPERATURE DURING FUEL ROD LIFETIME vs. LINEAR POWER DENSITY



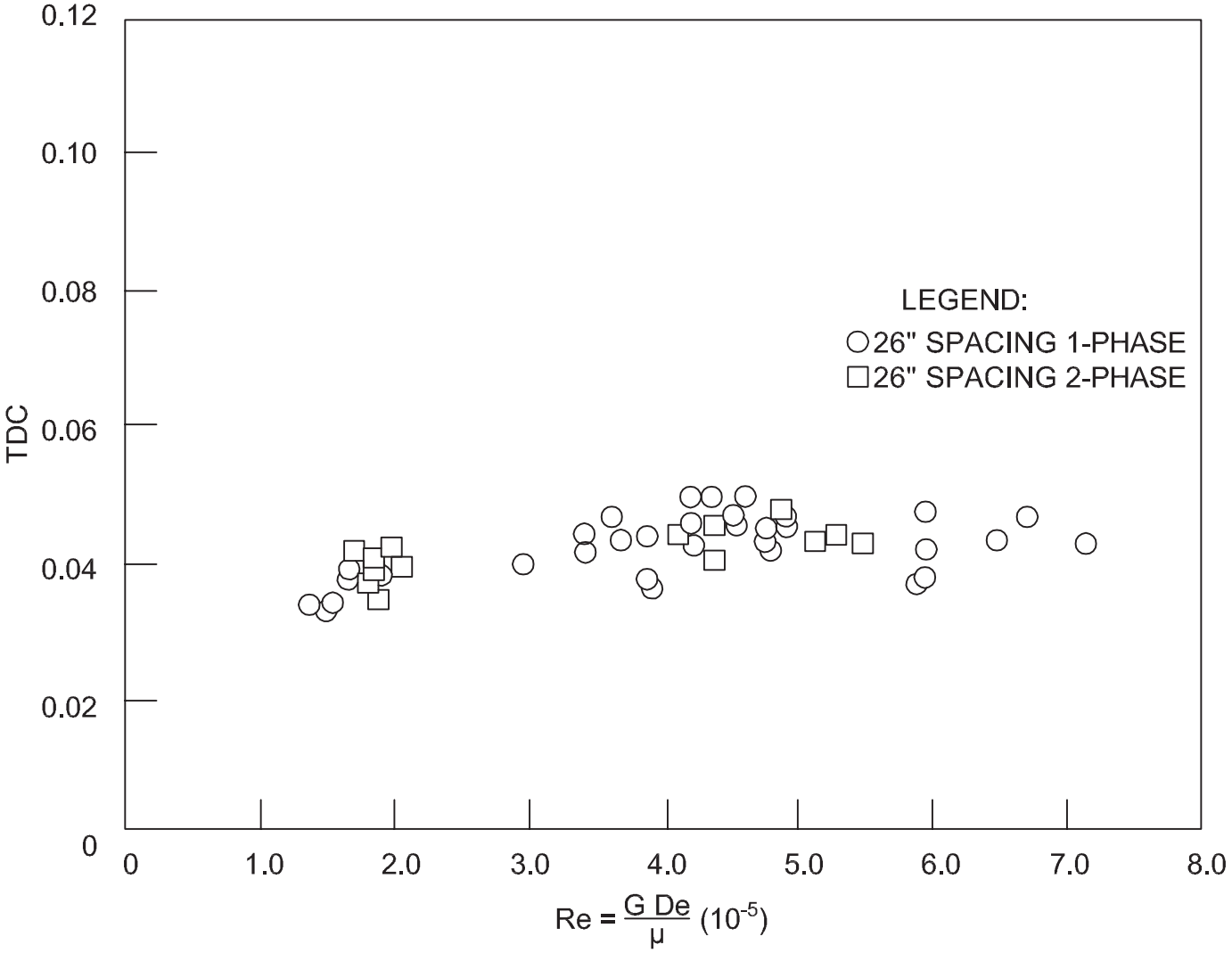
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.4-3 THERMAL CONDUCTIVITY OF UO_2 (DATA CORRECTED TO 95% THEORETICAL DENSITY)



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.4-4 AXIAL VARIATION OF AVERAGE CLAD TEMPERATURE FOR ROD OPERATING AT 5.43 KW/FT



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.4-5 PROBABILITY CURVES FOR W-3 AND R GRID DNB CORRELATIONS



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.4-6 TDC vs. REYNOLDS NUMBER FOR 26-INCH GRID SPACING

KEY:
$\Delta H/\overline{\Delta H}$
$G/\overline{G}$

	H	G	F	E	D	C	B	A
8	1.151 0.997	1.012 1.000	1.161 0.999	1.091 0.999	1.181 0.998	1.071 0.999	1.041 1.000	0.763 1.001
9	1.012 1.000	1.141 0.999	1.012 1.000	1.151 0.999	1.022 1.000	1.141 0.999	0.992 1.000	0.703 1.001
10	1.161 0.999	1.012 1.000	1.121 0.999	0.972 1.000	1.131 0.999	0.992 1.000	1.071 1.000	0.882 1.001
11	1.091 0.999	1.151 0.999	0.972 1.000	1.041 1.000	1.021 1.000	1.111 0.999	0.972 1.001	0.674 1.002
12	1.181 0.998	1.022 1.000	1.131 0.999	1.021 1.000	1.111 0.999	0.932 1.001	0.932 1.001	
13	1.071 0.999	1.141 0.999	0.992 1.000	1.111 0.999	0.932 1.001	1.140 0.999	0.624 1.002	
14	1.041 1.000	0.992 1.000	1.071 1.000	0.972 1.001	0.932 1.001	0.624 1.002		
15	0.762 1.001	0.703 1.001	0.882 1.001	0.674 1.002				

FOR RADIAL POWER DISTRIBUTION NEAR BEGINNING OF LIFE UNRODDED CORE, HOT FULL POWER, EQUILIBRIUM XENON.
CALCULATED $F_{\Delta H} = 1.36$

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 4.4-7
NORMALIZED RADIAL FLOW
AND ENTHALPY DISTRIBUTION
AT 4-FT ELEVATION

KEY:
$\Delta H/\overline{\Delta H}$
$G/\overline{G}$

	H	G	F	E	D	C	B	A
8	1.146 0.994	1.012 1.000	1.163 0.993	1.093 0.997	1.184 0.992	1.073 0.998	1.042 0.999	0.762 1.009
9	1.012 1.000	1.143 0.994	1.012 1.000	1.153 0.994	1.022 1.000	1.143 0.994	0.992 1.001	0.702 1.011
10	1.163 0.993	1.012 1.000	1.122 0.995	0.972 1.001	1.132 0.995	0.992 1.001	1.072 0.998	0.882 1.004
11	1.093 0.997	1.153 0.994	0.972 1.001	1.041 0.999	1.022 1.000	1.112 0.996	0.972 1.001	0.673 1.012
12	1.184 0.992	1.022 1.000	1.132 0.995	1.022 1.000	1.112 0.996	0.932 1.002	0.931 1.003	
13	1.073 0.998	1.143 0.994	0.992 1.001	1.112 0.996	0.932 1.002	1.142 0.994	0.624 1.014	
14	1.042 0.999	0.992 1.001	1.072 0.998	0.972 1.001	0.931 1.003	0.624 1.014		
15	0.762 1.009	0.702 1.011	0.882 1.004	0.673 1.012				

FOR RADIAL POWER DISTRIBUTION NEAR BEGINNING OF LIFE UNRODDED CORE, HOT FULL POWER, EQUILIBRIUM XENON.
CALCULATED $F_{\Delta H} = 1.36$

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

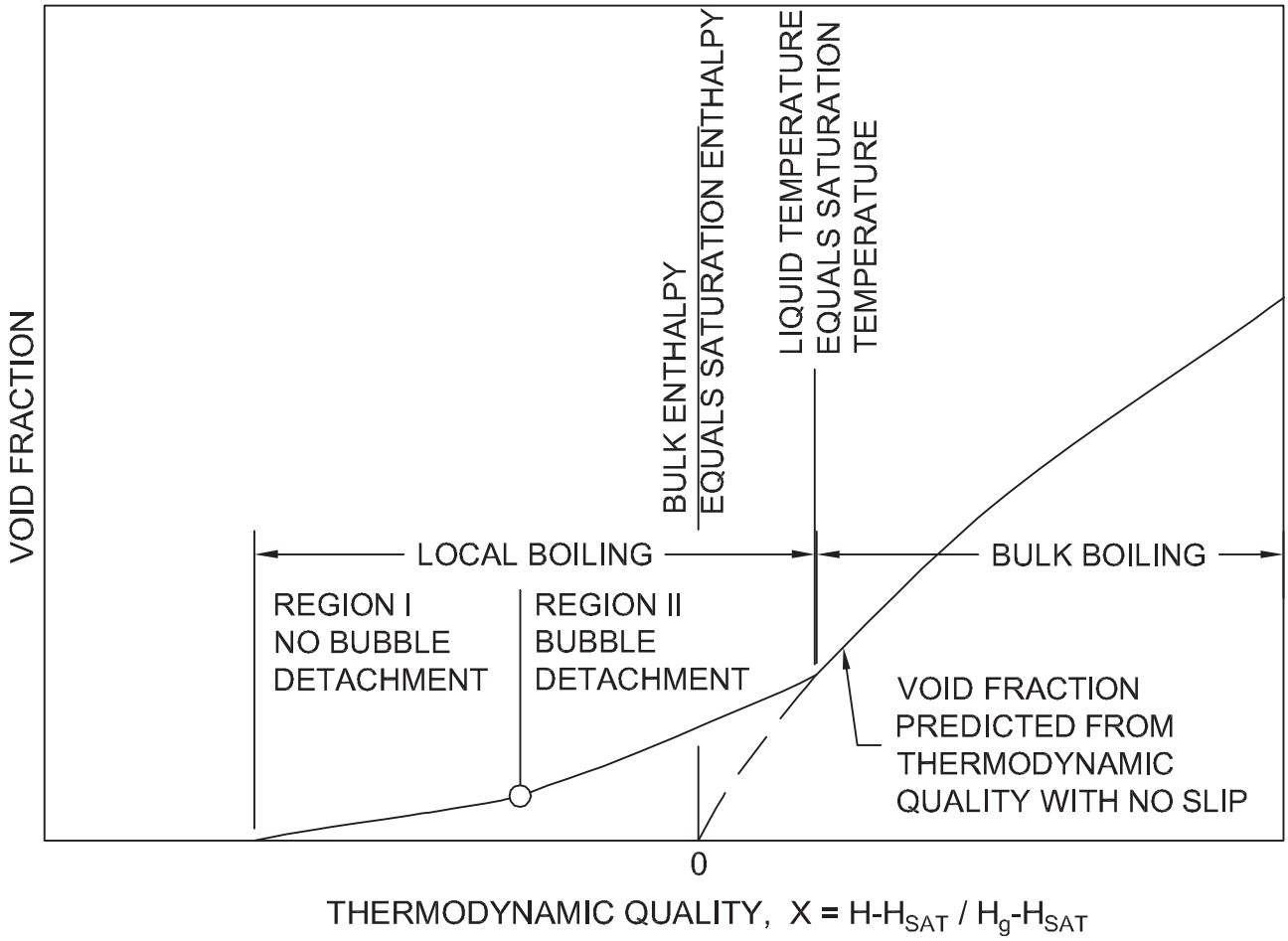
FIGURE 4.4-8
NORMALIZED RADIAL FLOW
AND ENTHALPY DISTRIBUTION
AT 8-FT ELEVATION

KEY:
$\Delta H/\overline{\Delta H}$
$G/\overline{G}$

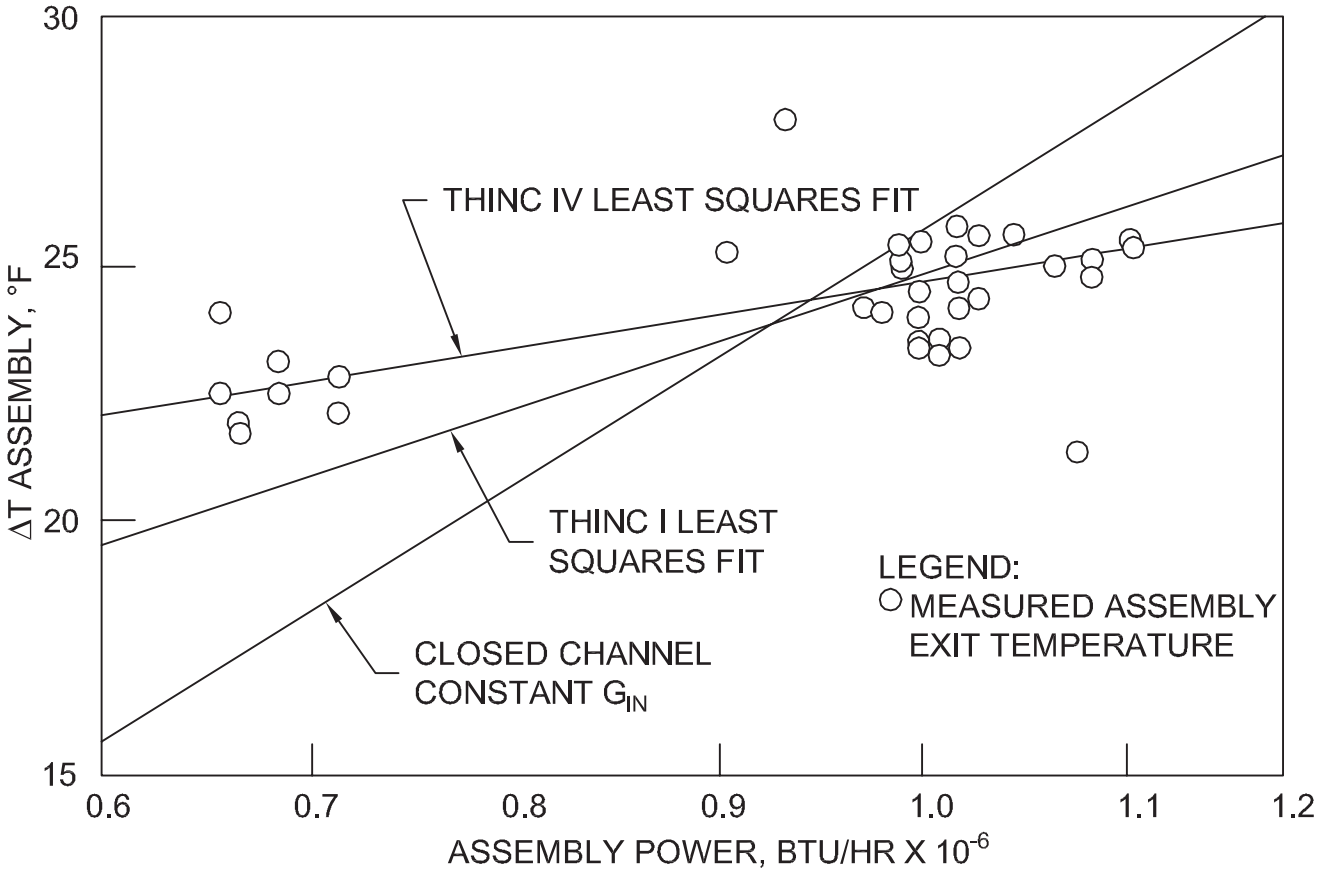
	H	G	F	E	D	C	B	A
8	1.147 0.993	1.012 0.999	1.166 0.992	1.094 0.995	1.186 0.991	1.074 0.996	1.042 0.998	0.761 1.013
9	1.012 0.999	1.145 0.993	1.012 0.999	1.155 0.992	1.023 0.998	1.144 0.993	0.992 1.000	0.701 1.016
10	1.166 0.992	1.012 0.999	1.124 0.994	0.927 1.001	1.134 0.994	0.992 1.000	1.072 0.997	0.881 1.006
11	1.094 0.995	1.155 0.992	0.972 1.001	1.042 0.998	1.022 0.999	1.113 0.995	0.972 1.001	0.671 1.017
12	1.186 0.991	1.023 0.998	1.134 0.994	1.022 0.999	1.113 0.995	0.932 1.003	0.930 1.004	
13	1.074 0.996	1.144 0.993	0.992 1.000	1.113 0.995	0.932 1.003	1.142 0.994	0.624 1.020	
14	1.042 0.998	0.992 1.000	1.072 0.997	0.972 1.001	0.930 1.004	0.624 1.020		
15	0.761 1.013	0.701 1.016	0.881 1.006	0.671 1.017				

FOR RADIAL POWER DISTRIBUTION NEAR BEGINNING OF LIFE UNRODDED CORE, HOT FULL POWER, EQUILIBRIUM XENON.
CALCULATED $F_{\Delta H} = 1.36$

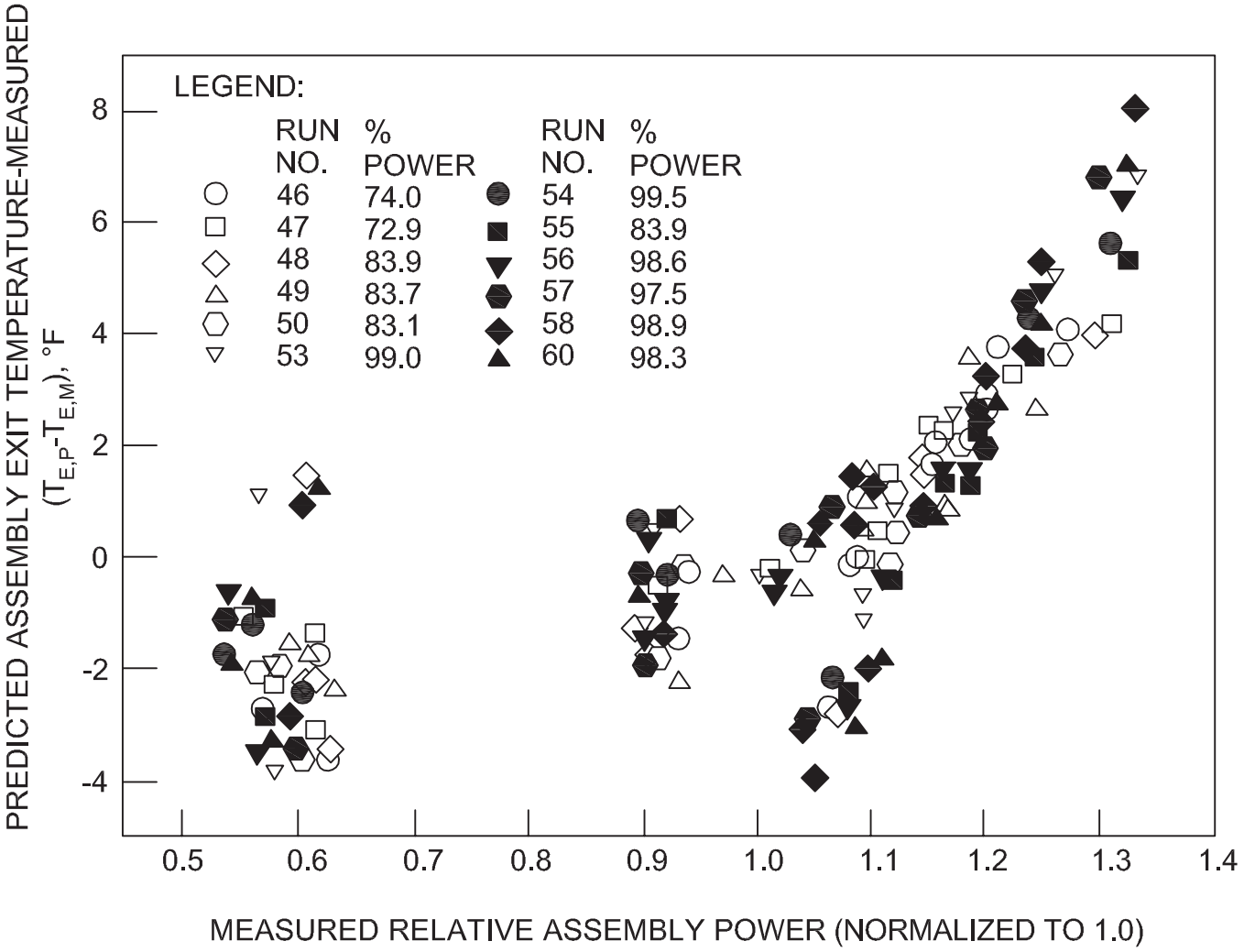
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.4-9 NORMALIZED RADIAL FLOW AND ENTHALPY DISTRIBUTION AT 12-FT ELEVATION



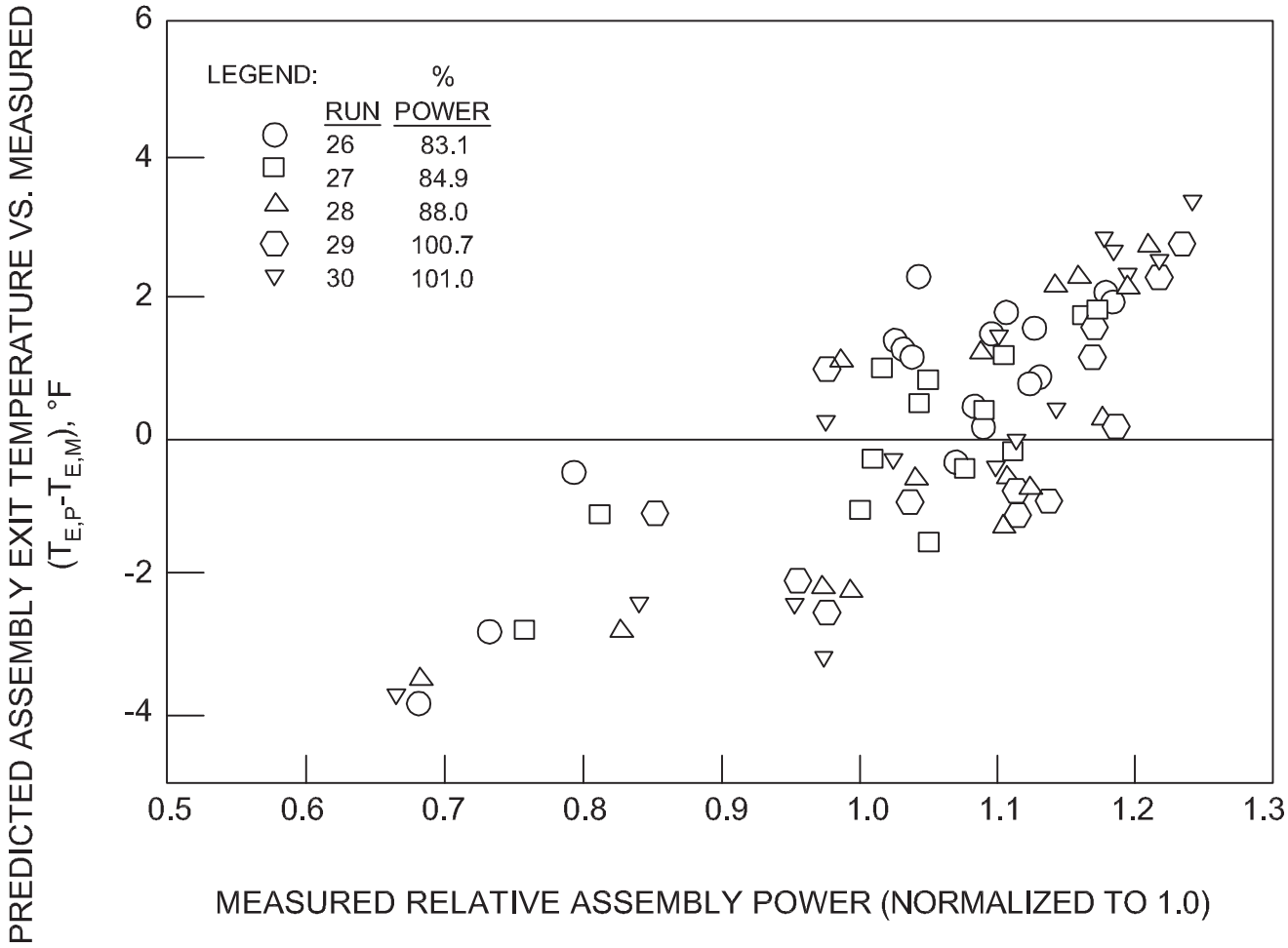
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.4-10 VOID FRACTION vs. THERMODYNAMIC QUALITY $H-H_{SAT}/H_G-H_{SAT}$



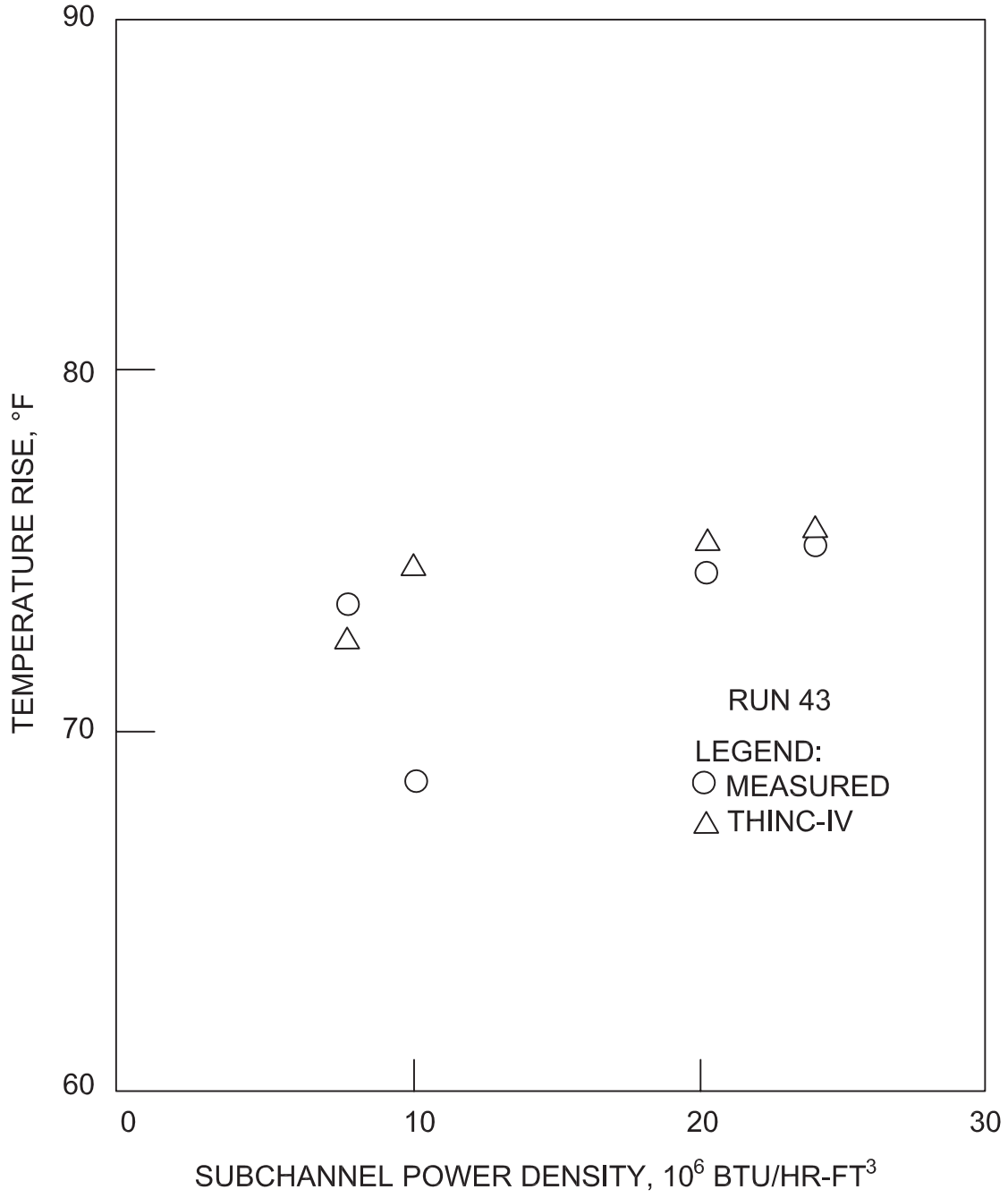
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.4-11 PWR NATURAL CIRCULATION TEST



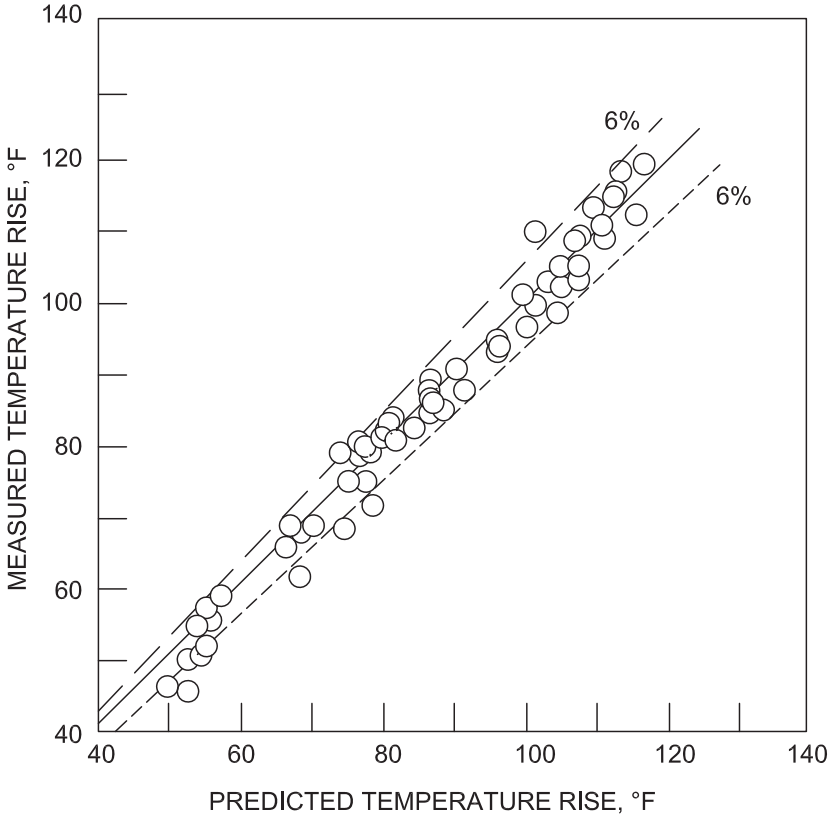
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.4-12 COMPARISON OF A REPRESENTATIVE W TWO-LOOP REACTOR INCORE THERMOCOUPLE MEASUREMENTS WITH THINC-IV PREDICTIONS

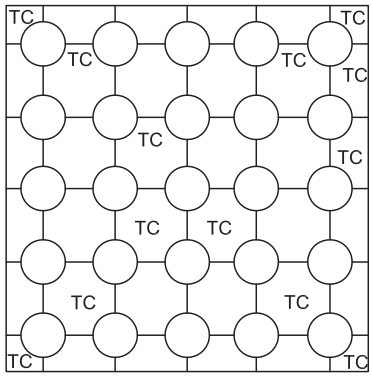


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.4-13 COMPARISON OF A REPRESENTATIVE W THREE-LOOP REACTOR INCORE THERMOCOUPLE MEASURMENTS WITH THINC-IV PREDICTIONS



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.4-14 HANFORD SUBCHANNEL TEMPERATURE DATA COMPARISON WITH THINC-IV

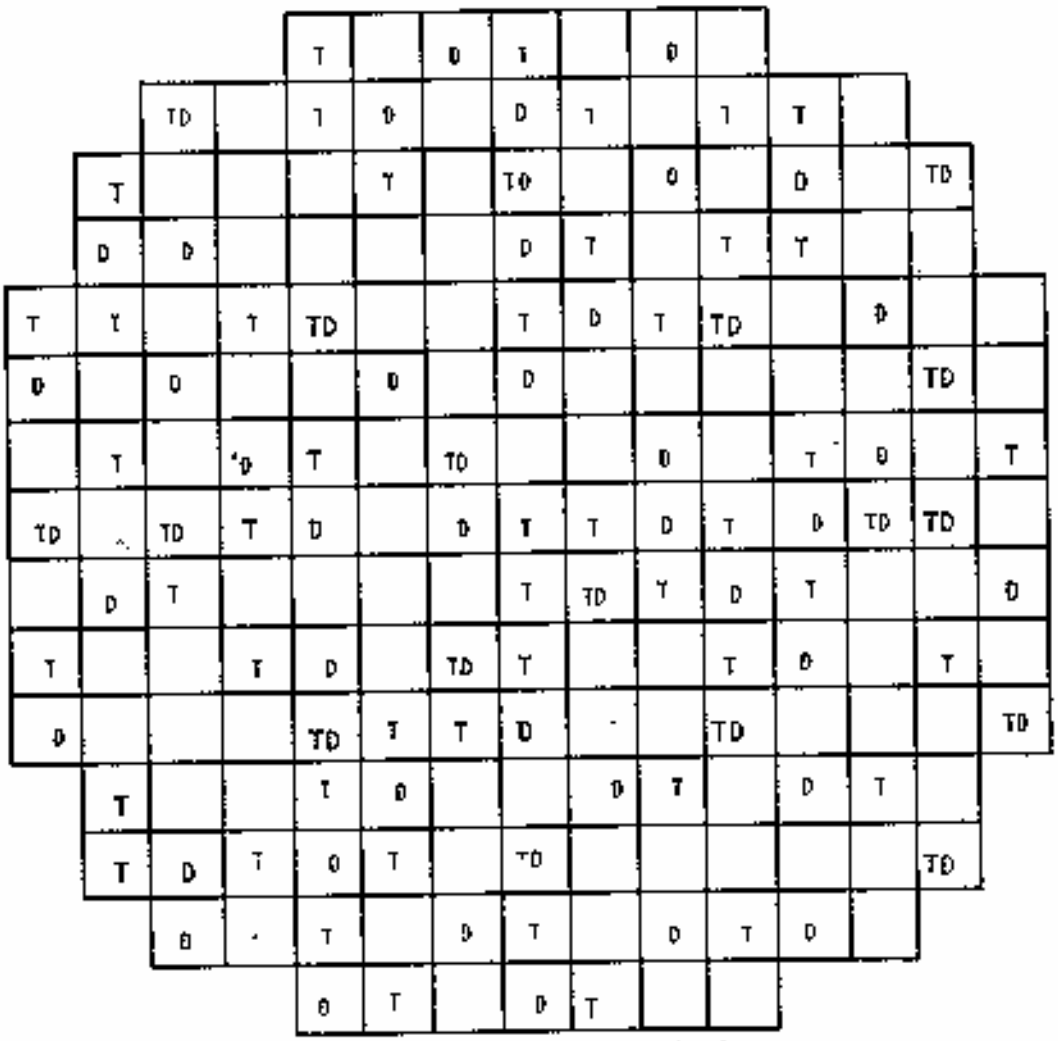




PRESSURE	2014 PSIA
MASS FLOW	$0.5\text{-}2.2 \times 10^6$ LB/$_M$FT^2-HR
ROD DIAMETER	0.422 INCHES
ROD PITCH	0.555 INCHES
HEATED LENGTH	84 INCHES
HEAT FLUX DISTRIBUTION	
INNER ROD: OUTER ROD	1.204: 1.0

TC - THERMOCOUPLE LOCATION

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.4-15 HANFORD SUBCRITICAL TEMPERATURE DATA COMPARISON WITH THINC-IV



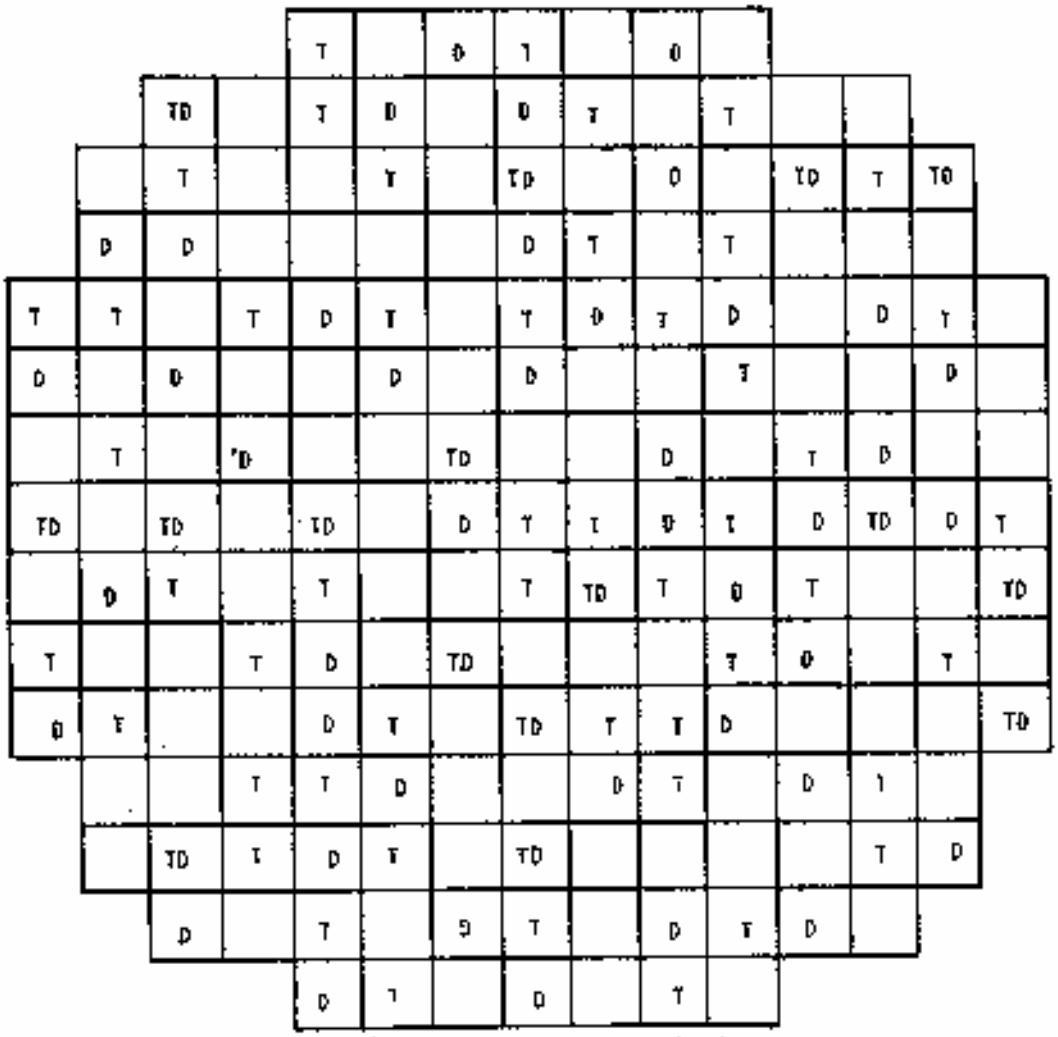
T = THERMOCOUPLE (65)

D = MOVABLE INCORE DETECTOR (58 LOCATIONS)

SAME ORIENTATION AS FIGURE 4.3-1

FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 4.4-16 DISTRIBUTION OF INCORE INSTRUMENTATION

Error! Not a valid embedded object.



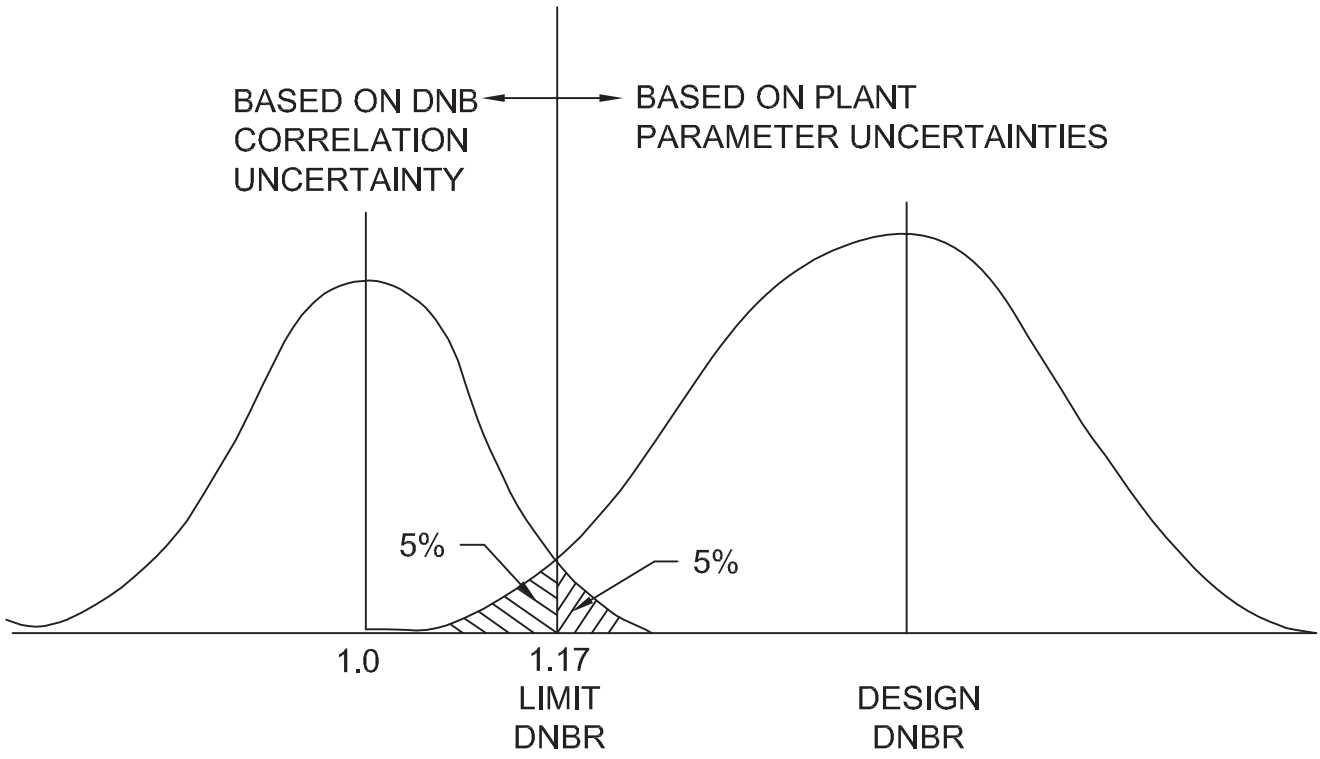
T = THERMOCOUPLE (65)

D = MOVABLE INCORE DETECTOR (58 LOCATIONS)

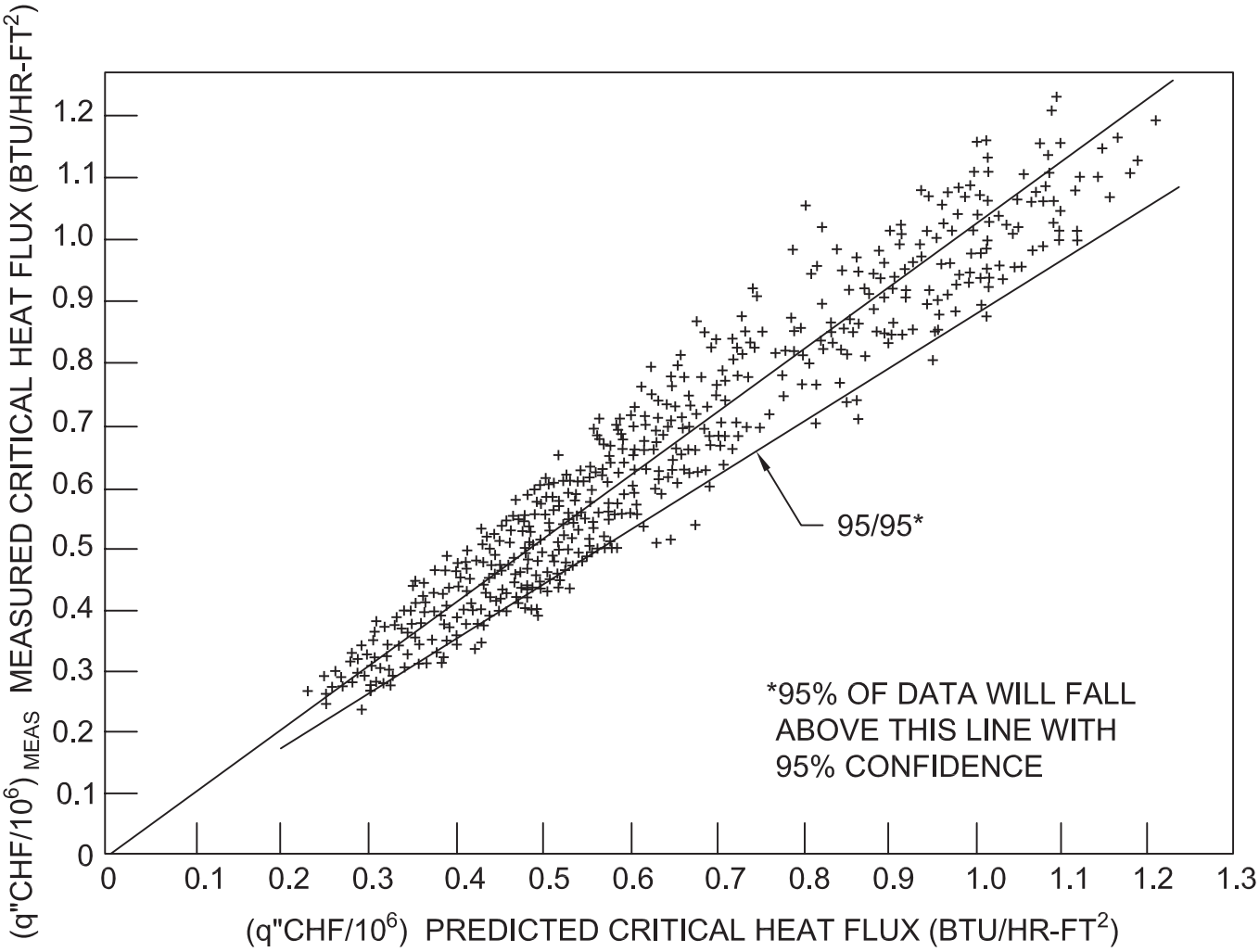
SAME ORIENTATION AS FIGURE 4.3-1

FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 4.4-17 DISTRIBUTION OF INCORE INSTRUMENTATION

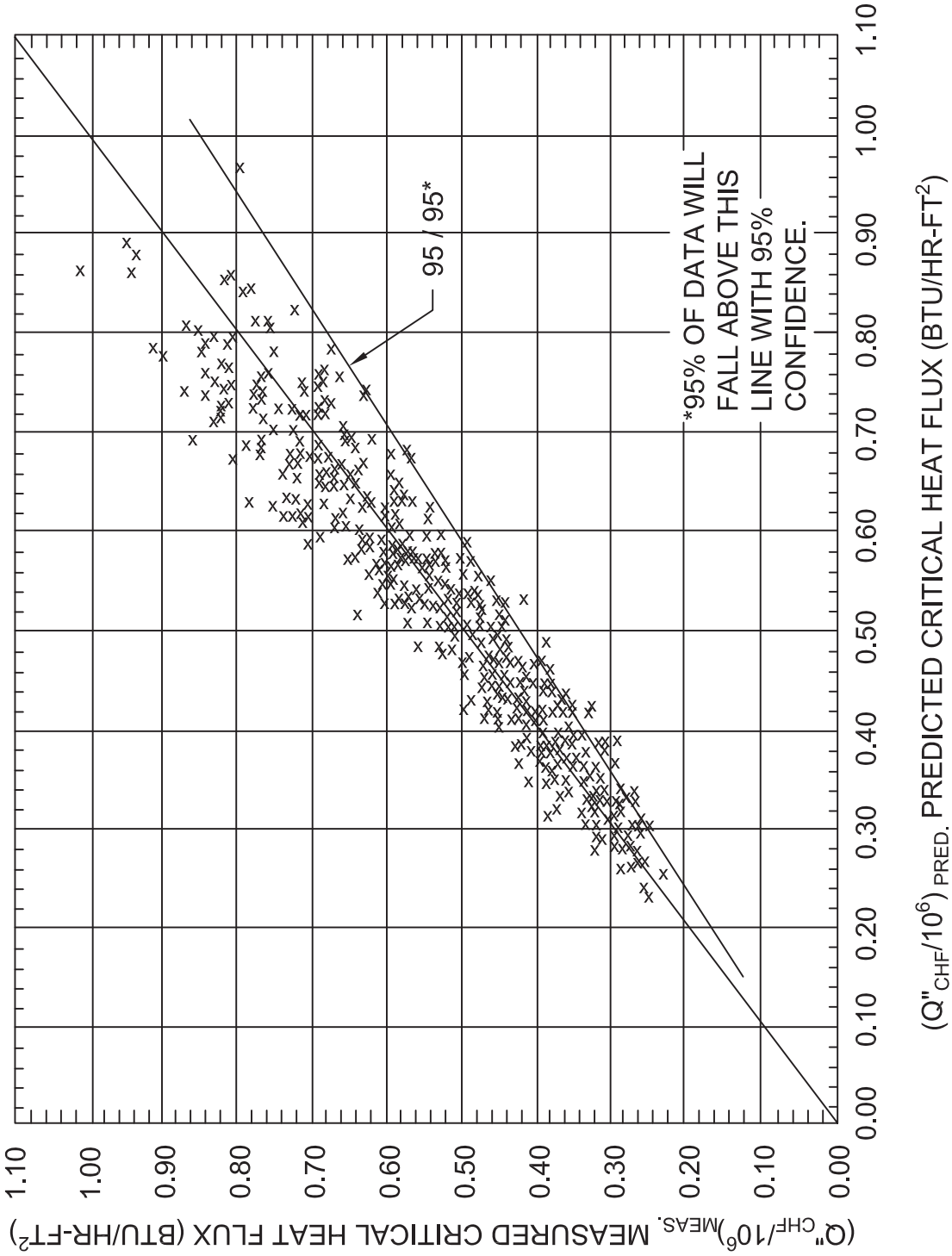
Revision 11 November 1996



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.4-18 IMPROVED THERMAL DESIGN PROCEDURE ILLUSTRATION



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 4.4-19 MEASURED VERSUS PREDICTED CRITICAL HEAT FLUX - WRB-1 CORRELATION



FSAR UPDATE
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NOTE:

[a] This figure corresponds to a controlled engineering drawing that is incorporated by reference into the FSAR Update. See Table 1.6-1 for the correlation between the FSAR Update figure number and the corresponding controlled engineering drawing number.

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Chapter 5

REACTOR COOLANT SYSTEM

5.1 SUMMARY DESCRIPTION

The reactor coolant system (RCS) consists of four similar heat transfer loops connected in parallel to the reactor pressure vessel (RPV), which are located inside the containment. Each loop contains a reactor coolant pump (RCP), steam generator (SG), and associated piping and valves. The system also includes a pressurizer, a pressurizer relief tank (PRT), interconnecting piping, and instrumentation necessary for operation.

During operation, the RCS, using coolant flow provided by the RCPs, transfers heat generated in the core to the SGs where the steam that drives the turbine-generator is produced. Borated pressurized water circulates in the RCS at a flowrate and temperature consistent with the reactor core thermal-hydraulic performance requirements. The water also acts as a neutron moderator and reflector, and as a solvent for the boric acid neutron absorber used as chemical shim control.

The reactor coolant pressure boundary (RCPB) provides a barrier against the release of radioactivity generated within the reactor, and is designed to ensure a high degree of integrity throughout plant life.

RCS pressure is controlled by the pressurizer in which water and steam are maintained in equilibrium by electrical heaters or water sprays. Steam can be formed (by the heaters) or condensed (by the pressurizer spray) to minimize reactor coolant pressure variations. Spring-loaded pressurizer safety valves (PSVs) and power-operated relief valves (PORVs) are mounted on the pressurizer, and discharge to the PRT where the steam is condensed and cooled by mixing with water. Noncondensable gases (primarily) or steam can be removed from the reactor vessel closure head (RVCH) by the reactor vessel head vent system (RVHVS).

The chemical and volume control system (CVCS) is designed to avoid uncontrolled reductions in boric acid concentration or reactor coolant temperature. The reactor coolant is the core moderator, reflector, and solvent for the chemical shim. As a result, changes in coolant temperature or boric acid concentration affect the reactivity level in the core.

Whenever the RCS boron concentration is varied, good mixing is provided to ensure uniform boron concentration throughout the RCS. Coolant flow is provided by either an RCP or a residual heat removal (RHR) pump to ensure uniform mixing whenever the boron concentration is varied. Although pressurizer mixing is not achieved to the same degree, the fraction of the total RCS volume, which is in the pressurizer is small. Pressurizer spray provides homogenization of boron concentration.

Also, the distribution of flow around the system is not subject to the degree of variation that would be required to produce non-homogeneities in coolant temperature or boron concentration as a result of areas of low coolant flowrate.

The RCS design arrangement eliminates dead-ended sections and other areas of low coolant flow in which non-homogeneities in coolant temperature or boron concentration could develop.

The RCS is designed to operate within the coolant temperature change limitations.

Refer to Tables 5.5-1, 5.5-3, 5.5-6, 5.5-12, and 5.5-14 through 5.5-17 for system design pressures and temperatures.
The design basis and safety evaluation of the RCS and its associated structures, systems, and components (SSCs), with the exception of the RCPB are discussed in this section. The RCPB is discussed in Section 5.2. The following are interfacing functions and SSCs that are discussed in the identified section:

(1) Reactor and reactor core design, nuclear design, and thermal-hydraulic design are discussed in Chapter 4;

(2) The RHR system is discussed in Section 5.5.6.

(3) Emergency core cooling is discussed in Section 6.3;

(4) RCS instrumentation associated with the reactor trip system (RTS) are discussed in this section, in conjunction with Section 7.2, and other RCS instrumentation, including the reactor vessel level instrumentation system (RVLIS), are discussed in this section, in conjunction with Sections 7.3, 7.4 and 7.5;

(5) RCP seal cooling is provided by the component cooling water (CCW) system and seal injection is provided by the CVCS (refer to Sections 9.2.2 and 9.3.4, respectively);

(6) RCS inventory and volume control, in conjunction with the CVCS, is discussed in this section and, with respect to CVCS, in Section 9.3.4;

(7) RCS coolant as a solvent, in conjunction with CVCS, functions as a neutron moderator and reflector and is discussed in this section. Refer to Section 9.3.4.2.8.2.4 for discussion on chemical shim and reactor coolant makeup;

(8) Sampling of the RCS using the nuclear steam supply system (NSSS) sampling system is described in Section 9.3.2.1.

(9) Main steam flow restriction, in conjunction with the main steam system, is discussed in this section with respect to the integral flow restrictor in the SGs (refer to Sections 5.5, 10.3, and 15.4 for further discussion of the main steam flow restrictors);

(10) Main steam isolation is discussed in Section 10.3;

(11) Decay heat removal, in conjunction with Sections 10.3 and 10.4.8, is discussed in this section;

(12) The main feedwater system is discussed in Section 10.4.7, with exception of the main feedwater ring in the SGs, which is covered in this section.

5.1.1 DESIGN BASES

5.1.1.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portion of the RCS is designed to withstand the effects of, or is protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

5.1.1.2 General Design Criterion 3, 1971 - Fire Protection

The RCS is designed and located to minimize, consistent with other safety requirements, the probability and effects of fires and explosions.

5.1.1.3 General Design Criterion 4, 1967 – Sharing of Systems

The RCS and components are not shared by the Diablo Canyon Power Plant (DCPP) units unless it is shown safety is not impaired by the sharing.

5.1.1.4 General Design Criterion 4, 1987 – Environmental and Dynamic Effects Design Bases

Consideration of the dynamic effects associated with main reactor coolant loop (RCL) piping postulated pipe ruptures are excluded from the DCPP design basis with the approval of leak-before-break (LBB) methodology by demonstrating that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

5.1.1.5 General Design Criterion 6, 1967 – Reactor Core Design

The RCS is designed to provide decay heat removal so that fuel damage limits are not exceeded under all expected conditions of normal operation with appropriate margins for uncertainties and for transient situations which can be anticipated, including the

effects of the loss of power to recirculation pumps, tripping out of a turbine generator set, isolation of the reactor from its primary heat sink, and loss of all offsite power.

5.1.1.6 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The RCS design includes provisions for the control of RCS chemistry such that the materials of construction of the pressure-retaining boundary of the RCS are protected from corrosion that might otherwise reduce the system structural integrity during its service lifetime.

5.1.1.7 General Design Criterion 11, 1967 - Control Room

The RCS is designed to or contains instrumentation and controls that support actions to maintain and control the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

5.1.1.8 General Design Criterion 12, 1967 - Instrumentation and Controls

Instrumentation and controls are provided, as required, to monitor and maintain RCS variables within prescribed operating ranges.

5.1.1.9 General Design Criterion 13, 1967 – Fission Process Monitors and Controls

The RCS design includes means for monitoring and maintaining control over the fission process throughout core life and for all conditions that can reasonably be anticipated to cause variations in reactivity of the core, such as indication of position of control rods and concentration of soluble reactivity control poisons.

5.1.1.10 General Design Criterion 15, 1967 – Engineered Safety Features Protection Systems

The RCS is provided with instrumentation for sensing accident situations and initiating the operation of necessary engineered safety features (ESFs).

5.1.1.11 General Design Criterion 21, 1967 – Single Failure Definition

Portions of the RCS are designed to perform their function after sustaining a single failure. Multiple failures resulting from a single event are treated as a single failure.

5.1.1.12 General Design Criterion 40, 1967 – Missile Protection

The RCS is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

5.1.1.13 General Design Criterion 49, 1967 – Containment Design Basis

The RCS is designed so that the containment structure can accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a loss-of-coolant accident (LOCA), including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of emergency core cooling systems (ECCSs).

5.1.1.14 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The RCS piping that penetrates containment is provided with leak detection, isolation, redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The piping is designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

5.1.1.15 General Design Criterion 55, 1971 – Reactor Coolant Pressure Boundary Penetrating Containment

Each RCS line that penetrates the containment is provided with containment isolation valves (CIVs).

5.1.1.16 General Design Criterion 56, 1971 – Primary Containment Isolation

The RCS contains piping that penetrates containment and that is connected directly to the containment atmosphere. Normally closed isolation valves are provided outside containment and automatic (check) valves are provided inside containment to ensure containment integrity is maintained.

5.1.1.17 Reactor Coolant System Safety Function Requirements

(1) <u>Protection from Missiles and Dynamic Effects</u>

PG&E Design Class I RCS SSCs are designed to be protected against the effects of missiles and dynamic effects which may result from plant equipment failure.

(2) <u>Reactor Heat Removal</u>

The RCS provides sufficient heat transfer capability to transfer the heat produced during power operation, plant cooldown, cold shutdown, operational transients, and accidents.

(3) <u>RCS Thermal-Hydraulic Requirements</u>

The RCS thermal-hydraulic design provides appropriate limits on RCS pressure and ensures adequate RCP net positive suction head (NPSH).

(4) RCS Coolant Functional Properties

The RCS contains the water used as a core neutron moderator and reflector and as a solvent for chemical shim control.

(5) RCS Pressure and Volume Control

The pressurizer maintains system pressure and volume and limits pressure transients using the surge line, pressurizer (via free volume), heaters, spray, and the PORVs.

(6) Steam Flow Restriction

The RCS is designed with flow restrictors that limit the steam flow in the event of a main steam line break (MSLB) at any location on the main steam line.

(7) RCP Coastdown

The RCP is designed to mitigate a loss of RCS flow by coasting down upon a loss of motive power.

(8) Pressurizer Relief Tank

The PRT is designed to prevent collapse under a full vacuum.

5.1.1.18 10 CFR 50.49 – Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

PG&E Design Class I RCS components that require environmental qualification (EQ) are qualified to the requirements of 10 CFR 50.49.

5.1.1.19 10 CFR 50.55a(f) – Inservice Testing Requirements

RCS American Society of Mechanical Engineers (ASME) Code components are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

5.1.1.20 10 CFR 50.55a(g) – Inservice Inspection Requirements

RCS ASME Code components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

5.1.1.21 10 CFR 50.63 – Loss of All Alternating Current Power

The RCS is designed to provide: (1) cooling of the core by natural circulation of reactor coolant through the core and SGs; (2) RCS pressure control; and (3) system monitoring

in the event of a station blackout (SBO), including RCS temperature, pressurizer pressure, pressurizer level, and source range monitors.

The RCPs are capable of withstanding an SBO event without a loss of seal integrity.

5.1.1.22 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The RCS is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

5.1.1.23 Regulatory Guide 1.89, November 1974 – Environmental Qualification of Class 1E Equipment for Nuclear Power Plants

The subcooled margin monitors (SCMMs) are designed to be environmentally qualified in accordance with the requirements of Regulatory Guide 1.89, November 1974 (refer to Section 3.11).

5.1.1.24 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The RCS provides instrumentation to monitor system variables during and following an accident.

5.1.1.25 Regulatory Guide 1.121, August 1976 – Bases for Plugging Degraded PWR Steam Generator Tubes

DCPP has established criteria defining the limiting safe conditions of tube degradation of SG tubing beyond which defective tubes, as established by inservice inspection (ISI), are removed from service by installing a tube plug at each end of the tube.

5.1.1.26 NUREG-0737 (Items II.B.1, II.D.1, II.E.3.1, II.F.2, II.G.1, II.K.3.5, and II.K.3.25), November 1980 – Clarification of TMI Action Plan Requirements

Item II.B.1 - Reactor Coolant System Vents: RVCH high point vents are capable of being remotely operated from the control room.

Item II.D.1 - Performance Testing of Boiling-Water Reactors and Pressurized-Water Reactor Relief and Safety Valves (originally Recommendation 2.1.2 of NUREG-0578, July 1979): The pressurizer PORVs and PSVs are capable of operating under expected operating conditions for design-basis transients and accidents.

Item II.E.3.1 - Emergency Power Supply for Pressurizer Heaters: All four pressurizer heater groups can be supplied with power from the offsite power system when offsite

power is available. In addition, power can be provided to two of the four heater groups from the standby power system through the Class 1E buses when offsite power is not available. This arrangement is adequate for establishing and maintaining natural circulation during hot standby conditions. Redundancy is provided by supplying each of the two groups of heaters from a different Class 1E bus.

Item II.F.2 - Instrumentation for Detection of Inadequate Core Cooling: Instrumentation is provided to unambiguously detect inadequate core cooling. The instrumentation includes reactor water level indication and provides an advance warning of the approach to inadequate core cooling. The instrumentation covers the full range from normal operation to the complete uncovering of the core.

Item II.G.1 - Emergency Power for Pressurizer Equipment: PORVs, PORV block valves, and pressurizer level instruments are capable of being supplied from either the offsite power system or the onsite distribution system, when offsite power is unavailable, through PG&E Design Class I motive and control components.

Item II.K.3.5 - Automatic Trip of Reactor Coolant Pumps During Loss-Of-Coolant Accident: DCPP provides alternative means to automatically trip the RCPs in response to small-break LOCAs (SBLOCAs).

Item II.K.3.25 - Effect of Loss of Alternating-Current Power on Pump Seals: RCP pump seals are designed to withstand a complete loss of alternating-current power for at least two hours.

5.1.1.27 Generic Letter 83-37, November 1983 - NUREG-0737 Technical Specifications

Item II.B.1 - Reactor Coolant System Vents: The RVHVS is designed with testing and surveillance provisions to ensure operability.

5.1.1.28 Generic Letter 88-05, March 1988 - Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants

A comprehensive boric acid corrosion control program (BACCP) is established to address boric acid corrosion concerns associated with RCS leakage at less than Technical Specification limits.

5.1.1.29 Generic Letter 90-06, June 1990 – Resolution of Generic Issue 70, "Power-Operated Relief Valve and Block Valve Reliability" and Generic Issue 94, "Additional Low-Temperature Over Pressure Protection for Light-Water Reactors" Pursuant to 10 CFR 50.54(f)

The RCS PORVs and PORV block valves are included in the inservice testing (IST) program.

5.1.1.30 Generic Letter 95-07, August 1995 – Pressure Locking and Thermal Binding of Safety-Related Power-Operated Valves

RCS PG&E Design Class I, power-operated gate valves meet the requirements of Generic Letter 95-07, August 1995.

5.1.1.31 NRC Bulletin 88-09, July 1988 - Thimble Tube Thinning in Westinghouse Reactors

An inspection program is established to perform periodic, non-destructive examination of the incore neutron monitoring thimble tubes for the purposes of measuring and monitoring thimble tube wear.

5.1.1.32 NRC Bulletin 88-11, December 1988 - Pressurizer Surge Line Thermal Stratification

DCPP implemented a program to confirm pressurizer surge line integrity with respect to thermal stratification and striping concerns.

5.1.1.33 Branch Technical Position ASB 10-2, March 1978 - Design Guidelines for Avoiding Water Hammers in Steam Generators

The SGs are designed and demonstrated to reduce the possibility and/or consequences of feedwater hammer. The DCPP design prevents or delays water draining from the feedring following a drop in SG level and minimizes the volume of feedwater piping external to the SG which could pocket steam.

5.1.2 SCHEMATIC FLOW DIAGRAMS

Figure 3.2-7 is a schematic flow diagram of the RCS. Principal pressures, temperatures, flowrates, and coolant volume under normal full power operating conditions are listed in Table 5.1-1.

The RCPB (refer to Section 5.2) is defined as:

(1) The RPV, including the RVCH and control rod drive mechanism (CRDM) housings

(2) The reactor coolant side of the SGs

(3) RCP casings

(4) A pressurizer attached to one of the RCLs

(5) Pressurizer PSVs and PORVs

(6) The interconnecting piping, valves, and fittings between the principal components listed above

(7) The piping, fittings, and valves leading to connecting auxiliary or support systems up to and including the second isolation valve (from the high-pressure side) on each line

Piping and components designated as part of the RCS but that do not contain reactor coolant at design temperature and pressure (such as the PRT and associated piping) are outside the bounds of the RCPB.

5.1.3 PIPING AND INSTRUMENTATION DIAGRAMS

RCS piping and instrumentation are shown schematically in Figure 3.2-7.

5.1.4 ELEVATION DRAWINGS

Physical layout of the RCS is shown in the following figures:

Figures 1.2-4, 1.2-5, and 1.2-6 (plan views inside containment)
Figures 1.2-22, 1.2-24, and 1.2-28 (section views inside containment)
Figure 5.5-10 (SG and RCP supports)
Figure 5.5-11 (component supports)
Figure 5.5-12 (pressurizer support)

5.1.5 REACTOR COOLANT SYSTEM COMPONENTS

The principal RCS components are described in Sections 5.2 and 5.5. Refer to Section 5.2.2.1.15.4 for a description of the RPV, Section 5.5.1 for a description of the RCPs, Section 5.5.2 for a description of the SGs, Section 5.5.3 for a description of the RCS piping, Section 5.5.9 for a description of the pressurizer, Section 5.5.10 for a description of the PRT, and Section 5.5.12 for a description of the RCS PSVs and PORVs.

5.1.6 REACTOR COOLANT SYSTEM PERFORMANCE AND SAFETY FUNCTIONS

The RCS transfers heat from the reactor to the SGs under conditions of both forced and natural circulation flow. The heat transfer capability of the SGs is sufficient to transfer to the steam and power conversion system (SPCS) the heat generated during normal operation and the initial phase of plant cooldown under natural circulation conditions.

The RCS, in conjunction with the reactor control and protection systems, maintains the reactor coolant at conditions of temperature, pressure, and flow adequate to protect the core from damage. The safety design requirements are to prevent conditions of high power, high reactor coolant temperature, or low reactor coolant pressure, or buildup of noncondensable gases which could interfere with core cooling, or combinations of these

which could result in a departure from nucleate boiling ratio (DNBR) smaller than the applicable limit value (refer to Sections 4.4.3.3 and 4.4.4.1).

Design and performance characteristics of the RCS are provided in Table 5.1-1 and Figures 5.1-2 and 5.1-2A.

5.1.6.1 Reactor Coolant System Flow Determination and Safety Analyses

Reactor coolant flow is an important parameter in most of the non-LOCA safety analyses. Figure 5.1-2 provides a representation of how the Thermal Design Flow (TDF) and Mechanical Design Flow (MDF) were established for the DCPP original design. These values were generated based on the best estimate flow expected after start-up. The TDF, a conservatively low flow, and the MDF, a conservatively high flow, are used in various safety analyses, depending on whether low flow or high flow is conservative for each particular analysis. Figure 5.1-2A provides a representation of the relationship between the best estimate flow, the MDF, the minimum measured flow (MMF), and the TDF. The values of these parameters are presented in Table 5.1-1.

The total RCS flow assumed in the safety analyses depends on the methodology for each specific analysis. For departure from nucleate boiling (DNB) analyses that employ the Improved Thermal Design Procedure (ITDP), the MMF value is assumed directly in the analysis. In the ITDP, a random flow uncertainty of 2.4 percent of flow is accounted for in a statistical square root of the sum of the squares (SRSS) combination with other appropriate plant input parameter uncertainties to set the DNBR limit. For non-DNB related events or DNB events for which the ITDP is not employed, the TDF value is used.

RCS flow is measured in accordance with the surveillance frequency control program, and is compared directly to the Unit 1 and Unit 2 Technical Specification flow limits in Limiting Condition of Operation (LCO) 3.4.1c and Surveillance Requirements 3.4.1.3 and 3.4.1.4. The RCS minimum flow limits provided by the LCO and surveillance requirements include both the TDF values for each unit explicitly approved by the U.S. Nuclear Regulatory Commission (NRC) and the MMF values provided in the Unit 1 and Unit 2 cycle specific Core Operating Limits Report to ensure continued plant operation consistent with the safety analyses.

5.1.6.2 Reactor Coolant Flow

The reactor coolant flow, a major parameter in the design of the system and its components, is established using a detailed design procedure supported by operating plant performance data, by pump model tests and analysis, and by pressure drop tests and analyses of the RPV and fuel assemblies.

Evaluation of the RCS flow involves a number of parameters. RCS best estimate flow, TDF, MDF, MMF, and Minimum Required Total RCS Flow Rate are parameters established during original design and are evaluated in the safety analyses of record.

Figures 5.1-2 and 5.1-2A provide a representation of these RCS flow parameters relative to original design considerations and the current safety analyses of record.

RCS flow is measured using the cold leg elbow differential pressure taps. The cold leg elbow tap flow methodology was established using Reference 2 and Reference 3.

5.1.6.3 Best Estimate Flow

The best estimate flow is the most likely value for the actual plant operating condition. The best estimate flow is used in developing the TDF and MDF. This flow is calculated based on the best estimate of the RPV, SG and piping flow hydraulic resistance, and on the best estimate of the RCP head-flow performance, with no uncertainties assigned to either the RCS component flow resistance or the pump head. The best estimate flow is calculated based on hydraulic analyses.

The best estimate flow is also used to confirm the cold leg elbow tap flow measurement while limiting the elbow flow tap measurement to a maximum value corresponding to the best estimate flow plus an allowance for the elbow tap flow repeatability uncertainty. The hydraulic analysis uncertainty is 2 percent, while the instrument analysis repeatability allowance is 0.4 percent, for a total uncertainty of 2.4 percent. Application of this acceptance criterion results in definition of a conservative current cycle flow, confirmed by both the elbow tap flow measurements and the best estimate hydraulic analysis.

In the event that changes are made to the plant primary side hydraulic resistance or RCP characteristics, the best estimate flow must be recalculated.

Although the best estimate flow is the most likely value to be expected in operation, more conservative flowrates are applied in the thermal and mechanical designs, as discussed in Sections 5.1.6.4 and 5.1.6.5, below. The relationship between these parameters is reflected in Figures 5.1-2 and 5.1-2A.

5.1.6.4 Thermal Design Flow

TDF is the basis for the reactor core thermal performance, the SG thermal performance, and the design plant parameters used throughout the design. To provide the required margin in the safety analyses, the TDF accounts for the uncertainties in the RPV, SG, and piping flow resistances, RCP head, and the methods used to measure flowrate. The combination of these uncertainties, which includes a conservative estimate of the pump discharge weir flow resistance, is equivalent to increasing the initial plant design best estimate RCS flow resistance by approximately 19 percent. The intersection of this conservative flow resistance with the initial plant design best estimate pump curve established the TDF. Figures 5.1-2 and 5.1-2A illustrate the relationship of TDF to other design and operating parameters. This procedure provides a flow margin for TDF of approximately 4 percent from the best estimate flow. The TDF is the initial flow assumed for non-DNB related accident and transient analyses and DNB analyses for

which the ITDP is not used. The TDF for each unit is maintained during plant operation by satisfying the minimum RCS flow requirements of Technical Specification LCO 3.4.1c. Refer to Section 4.4.4.1 for a discussion of ITDP.

Data from all operating plants have indicated that the actual flow has been well above the flow specified for the thermal design of the plant. Tabulations of important design and performance characteristics of the RCS, as provided in Table 5.1-1, are based on the TDF, as indicated.

5.1.6.5 Mechanical Design Flow

MDF is the flow used in the mechanical design of the RPV internals and fuel assemblies. To ensure that a conservatively high flow is specified, the MDF was based on a reduced system resistance (90 percent of initial plant design best estimate) and on increased pump head capability (107 percent of initial plant design best estimate). The intersection of this flow resistance with the higher pump curve established the MDF. Figures 5.1-2 and 5.1-2A illustrate the relationship of MDF to other design and operating parameters.

5.1.6.6 Minimum Measured Flow

The plant MMF, the RCS minimum measured flow, is the flow used in reactor core DNB analyses for the ITDP. The MMF is defined as the TDF plus at least one flow measurement uncertainty. The MMF value included in the Unit 1 and Unit 2 cycle specific Core Operating Limits Report allows for a measurement uncertainty error of 2.4 percent. The MMF for each unit is also provided in Tables 4.1-1 and 5.1-1. The MMF for each unit is maintained during plant operation by satisfying the minimum RCS flow requirements of Technical Specification LCO 3.4.1c.

5.1.6.7 Minimum Required Reactor Coolant System Flow Rate

The minimum required RCS flow rate is the RCS total flow rate limit provided for each unit in the Technical Specifications Limiting Condition of Operation (LCO) 3.4.1c and verified under Surveillance Requirements 3.4.1.3 and 3.4.1.4. These RCS total flow rate limits incorporate a measurement error of no more than 2.4 percent. The RCS flow rate allowable values and nominal trip setpoints reflected in Technical Specification 3.3.1, Function 10, are based on a percentage of the loop flow measured every 24 months under Technical Specification Surveillance Requirement 3.4.1.4. This is determined using the cold leg elbow taps.

The RCS cold leg taps indicated total flow is continuously compared to the Reactor Coolant Flow-Low nominal trip setpoint (refer to Section 7.2.2.1.4). The best estimate flow (refer to Section 5.1.6.2) may not be used as a substitute for the Technical Specification 3.4.1.4 Surveillance Requirement for flow measurement.

5.1.7 SYSTEM OPERATION

Brief descriptions of normal plant operations covering plant startup, power generation and hot standby, plant shutdown, refueling, and mid-loop operation are provided below.

5.1.7.1 Plant Startup

Plant startup encompasses the operations which bring the reactor plant from cold shutdown to no-load power operating temperature and pressure.

Before plant startup, the RCLs and pressurizer are filled completely with reactor coolant to eliminate noncondensable gases. If the vacuum refill method of filling the RCS is performed, the vacuum process will remove noncondensable gases and the pressurizer will not need to be filled completely. The water contains the correct concentration of boron to maintain shutdown margin (SDM). The secondary side of the SG is filled with water to normal startup level.

Coolant temperature variation during normal operation is limited and the associated reactivity change is well within the capability of the rod control group movement. For design evaluation, the RCS heatup and cooldown transients are analyzed using a rate of temperature change equal to 100°F per hour. Over certain temperature ranges, fracture prevention criteria will impose a lower limit to heatup and cooldown rates.

The RCS is then pressurized using the low-pressure control valve and either the centrifugal charging pump (CCP3) (preferentially) or the centrifugal charging pumps (CCP1 and CCP2) to obtain the required pressure drop across the No. 1 seal of the RCPs. The pumps may then be operated intermittently in venting operations. As an alternative, a vacuum process can be used in filling the RCS. If this method is used, operating the RCPs intermittently to aid venting noncondensable gases may not be required.

During RCP operation, a charging pump and the low-pressure letdown path from the RHR system to the CVCS maintain the necessary RCS pressure. RCP operation is initiated after the required pressure differential across the No. 1 seal is achieved. The brittle fracture prevention temperature limitations of the RPV impose an upper pressure limit during low temperature operation. The charging pump supplies seal injection water for the RCP shaft seals. A nitrogen atmosphere and normal operating temperature, pressure, and water level are established in the PRT.

After venting, the RCS is pressurized, all RCPs are started, and the pressurizer heaters are energized to begin heating the reactor coolant in the pressurizer, which leads to formation of the steam bubble. If the vacuum refill method of filling the RCS is performed, a pressurizer steam bubble may be formed prior to starting the RCPs. The pressurizer liquid level is reduced until the no-load power level volume is established. During the initial heatup phase, hydrazine is added to the reactor coolant to scavenge

the oxygen in the system; the heatup is not taken beyond 250°F until the oxygen level has been reduced to the specified level.

As the reactor coolant temperature increases, the pressurizer heaters are manually controlled to maintain adequate suction pressure for the RCPs.

5.1.7.2 Power Generation and Hot Standby

Power generation includes steady state operation, ramp changes not exceeding the rate of 5 percent of full power per minute, step changes of 10 percent of full power (not exceeding full power), and step load decreases with steam dump not exceeding 50 percent of full power.

During power generation, RCS pressure is maintained by the pressurizer controller at or near 2235 psig, while the pressurizer liquid level is controlled by the charging-letdown flow control of the CVCS.

When the reactor power level is less than 15 percent, the reactor power is controlled manually. At powers above 15 percent, the operator may select the automatic mode of operation. The rod motion is then controlled by the reactor control system that automatically maintains an average coolant temperature, which follows a program based on turbine load.

During hot standby operations, when the reactor is subcritical, the RCS temperature is normally maintained by steam dump to the main condenser. This is accomplished by valves in the steam line, operating in the pressure control mode, which is set to maintain the SG steam pressure, or manually. Residual heat from the core and/or operation of an RCP provides heat to overcome RCS heat losses.

5.1.7.3 Plant Shutdown

Before plant cooldown is initiated, the boron concentration in the RCS is increased to the value required for the corresponding target temperature. Subsequent reactor coolant samples are taken to verify that the RCS boron concentration is correct.

During plant cooldown, minimum SDM is maintained in accordance with requirements of the Technical Specifications. The temperature changes imposed on the RCS during its normal modes of operation do not cause any unacceptable reactivity changes.

Plant shutdown is the operation that brings the reactor plant from no-load power operating temperature and pressure to cold shutdown. During plant cooldown from hot standby to hot shutdown conditions, concentrated boric acid solution from the CVCS is added to the RCS to increase the reactor coolant boron concentration to that required for cold shutdown. If the RCS is to be opened during the shutdown, the hydrogen and fission gas in the reactor coolant is reduced by degassing the coolant in the volume control tank (VCT).

Plant shutdown is attained in two phases: first, by the combined use of the RCS and steam systems, and, second, by the RHR system. During the first phase of shutdown, residual core and reactor coolant heat are transferred to the main steam system via the SG. Steam from the SG is dumped to the main condenser or to the atmosphere. At least one RCP is kept running to ensure uniform RCS cooldown. Pressurizer heaters and spray flow are manually controlled to cool the pressurizer while maintaining the required RCP suction pressure. The plant does not permit the pressurizer to go water-solid without the RHR system and low temperature overpressure protection (LTOP) systems in service. As the pressurizer cools, the low-pressure control valve, pressurizer spray, pressurizer heaters, and the charging pumps maintain the required RCS pressure.

When the reactor coolant temperature is below approximately 350°F and the nominal pressure is less than or equal to 390 psig, the second phase of shutdown commences with the operation of the RHR system.

During the second phase of plant cooldown and during cold shutdown and refueling, the heat exchangers of the RHR system are employed. Their capability is discussed in Section 5.5.

At least one RCP (either of those in a loop containing a pressurizer spray line) is kept running until the coolant temperature is reduced in accordance with plant procedures. Pressurizer cooldown continues by initiating auxiliary spray flow from the CVCS if the RCPs are not available. Plant shutdown continues until the reactor coolant temperature is 140°F or less.

5.1.7.4 Refueling

Before removing the RVCH for refueling, the system temperature is reduced to 160°F or less, and hydrogen and fission product levels are reduced. Water level is monitored to indicate when the water level is below the top of the RVCH. Draining continues until the water level is below the RPV flange. The RVCH is then removed and the refueling cavity is flooded. Upon completion of refueling, the system is refilled for plant startup.

5.1.7.5 Mid-Loop Operation

During refueling conditions, SG nozzle dams may be used in accordance with approved plant procedures to isolate the SG U-tubes and channel heads from the RCS for inspection and maintenance. The SGs are discussed further in Section 5.5.2.

Use of SG nozzle dams requires lowering the water level in the RCS to a level below that necessary to remove the RVCH (i.e., partial drain or mid-loop operation). Mid-loop operation, when performed in accordance with approved plant procedures, is acceptable when core decay heat is less than or equal to 15.3 MWt (Reference 1).

During mid-loop operation, water level is closely monitored to ensure adequate RHR pump suction and decay heat removal by the RHR system.

5.1.8 SAFETY EVALUATION

5.1.8.1 General Design Criterion 2, 1967 – Performance Standards

All RCS components are located within the PG&E Design Class I auxiliary and containment buildings. These buildings, or applicable portions thereof, are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other natural phenomena, to protect RCS SSCs, ensuring their design functions will be performed.

PG&E Design Class I RCS SSCs are designed to perform their function of providing shutdown capability under Double Design Earthquake (DDE) and Hosgri Earthquake (HE) loading. The seismic requirements are defined in Sections 3.7 and 3.10, and the provisions to protect the system from seismic damage are discussed in Sections 3.7, 3.9, and 3.10.

5.1.8.2 General Design Criterion 3, 1971 - Fire Protection

The RCS is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

5.1.8.3 General Design Criterion 4, 1967 – Sharing of Systems

RCP vibration monitoring is provided by field equipment mounted in instrument racks in each containment building. Vibration data from the instrument racks is collected and stored on a shared server in the Administration Building and can be viewed on a workstation in the common control room. The RCP vibration monitoring system does not perform a safety function, or provide a direct control function; it only provides indication and alarms in the control room. Refer to Section 5.5.1.2 for additional information on RCP vibration monitoring.

5.1.8.4 General Design Criterion 4, 1987 – Environmental and Dynamic Effects Design Bases

Detailed analysis has shown that the primary loops are highly resistant to stress corrosion cracking and high and low cycle fatigue. Based on this analysis, dynamic effects of RCS primary loop pipe breaks need not be considered in the structural design basis. Protection from the dynamic effects of the most limiting breaks of auxiliary branch lines needs to be considered. This includes RCS branch line breaks and other high energy line breaks as described in Sections 5.2.2.1.9, 5.2.2.1.10, 5.2.2.1.11, 5.2.2.1.14, 5.2.2.1.15, and 5.2.2.1.16. Refer to Section 3.6.2.1.1.1 for discussion of the LBB methodology and application to the primary loops of DCPP Unit 1 and Unit 2.

5.1.8.5 General Design Criterion 6, 1967 – Reactor Core Design

Each reactor core is designed to function throughout its design lifetime without exceeding acceptable fuel damage limits. The RCS is a reliable process and decay heat removal system that provides for this capability under all expected conditions of normal operation, with appropriate margins for uncertainties and anticipated transient situations.

5.1.8.6 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The provisions for the control of water chemistry to protect the RCS from corrosion are discussed in Sections 5.2.2.3.4 and 5.5.2.3.5, and therefore ensure the RCPB is maintained.

CVCS provides RCP seal injection to ensure RCP seal integrity, and therefore maintaining the RCPB (refer to Section 9.3.4.3.21). Refer to Section 5.2.2.3 for a discussion of the RCPB materials of construction. Refer to Section 5.2.3.23.2 for leakage limits for the RCS pressure isolation valves (PIVs).

5.1.8.7 General Design Criterion 11, 1967 - Control Room

Instrumentation and controls are provided in the control room for operators to maintain the RCS within design parameters. RCS instrumentation and controls in the control room include:

(1) RCS temperature, pressure, and flow indication

(2) RCS subcooling margin and RPV level indication

(3) Pressurizer pressure, level, and temperature indication, and heater group controls and power indication

(4) PRT pressure, level, and temperature indication

(5) RCP controls and motor amps indication

(6) RCP seal flow, differential pressure, and temperature indication

(7) PORVs/PSVs discharge temperature indication

(8) PSV acoustic monitor flow indication

(9) PORV and PORV block valve, PRT valve, and RVHVS valve controls and position indication

In the event control room access is lost, instrumentation and controls required for safe shutdown, are provided outside the control room (refer to Section 7.4.2.1) at the HSP and the dedicated shutdown panel. Pressurizer heater on-off control is provided on the HSP for two backup heater groups; however, these controls are not required for safe

shutdown (refer to Section 7.4.2.1.2.4). Instrumentation requirements for the RCS are discussed in Section 5.6.1.

5.1.8.8 General Design Criterion 12, 1967 - Instrumentation and Controls

RCS Instrumentation and controls are provided, as required, to monitor and maintain the RCS variables within prescribed operating ranges, and to provide post-accident monitoring (refer to Section 5.6.1 for additional information).

Monitored RCS variables include:

(1) RCS temperature

(2) RCS pressure

(3) Pressurizer pressure and level

(4) RCS flow

(5) RCP motor amps

(6) Subcooling Margin

(7) RPV level

(8) PORV and PSV position

5.1.8.9 General Design Criterion 13, 1967 – Fission Process Monitors and Controls

The RCS instrumentation monitors and provides continuous indication of RCS temperature for additional fission process information. Refer to Sections 7.7.3.3 and 9.3.4.3.7 for additional information.

5.1.8.10 General Design Criterion 15, 1967 – Engineered Safety Features Protection System

The pressurizer pressure circuit initiates safety injection (SI) when 2-out-of-4 pressurizer pressure channels read below the specified setpoint (refer to Sections 7.3.2.1 and 7.3.3.3).

5.1.8.11 General Design Criterion 21, 1967 – Single Failure Definition

The PG&E Design Class I RCS SSCs described below are designed so that a single failure will not prevent the RCS from performing its design function. Redundant Class 1E power is provided, as necessary, for PG&E Design Class I SSCs.

Redundant pressurizer PORVs function in the event of an accident (refer to Sections 5.2.2, 15.2.15, and 15.4.3).

RVHVS vent valves provide redundant capability to vent noncondensible gases from the RCS which might inhibit core cooling during natural circulation assuming a single failure (refer to Section 5.5.14.2).

The RVLIS supplements RCS pressure and temperature sensors and the SCMM in detection of inadequate core cooling (refer to Sections 5.6.1 and 7.5.2.2).

Refer to Sections 5.1.8.15, 5.1.8.16, and 6.2.4 for a discussion of the configuration of the containment isolation system (CIS).

Refer to Section 5.1.8.10 for a discussion of the pressurizer pressure circuit for initiation of SI.

Refer to Section 5.1.8.26, Items II.E.3.1 and II.G.1 for a discussion of the emergency power supplies for pressurizer equipment.

Refer to Sections 3.9 and 5.2 for a discussion of active valves.

5.1.8.12 General Design Criterion 40, 1967 – Missile Protection

There are no credible missiles generated by the failure of the RCS components that would prevent the ESFs SSCs inside containment from performing their design functions.

Precautionary measures, taken to preclude missile formation from RCP components, ensure that the pumps will not produce missiles under any anticipated accident condition (refer to Sections 5.2.3.20 and 5.5.1.3.7).

A failure of a CRDM housing sufficient to allow a control rod to be rapidly ejected from the core is not considered credible based on the precautionary measures; however, a missile shield structure is provided over the CRDMs which will block missiles which might be generated in the event of a fracture of the pressure housing of any mechanism (refer to Sections 3.5.2.1.1, 3.5.2.2.1, 3.5.2.3.1, 3.5.2.4 and 3.5.2.5).

Missiles generated by smaller components such as valves, temperature and pressure element assemblies, and pressurizer heaters are either not credible or have been shown to not impact safety functions (refer to Sections 3.5.2.1.1, 3.5.2.2.1, 3.5.2.3.1, 3.5.2.4 and 3.5.2.5).

5.1.8.13 General Design Criterion 49, 1967 – Containment Design Basis

The RCS piping routed through containment penetrations is designed and analyzed to withstand the pressures and temperatures that could result from a LOCA without exceeding the design leakage rates. Refer to Sections 3.8.2.1.3 and 6.2.4, and Table 6.2-39 for additional details.

5.1.8.14 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The RCS CIVs required for containment closure are periodically tested for operability and leakage. Test connections are provided in the penetration and in the piping to verify valve leakage and penetration leakage are within prescribed limits. Testing of the components required for the CIS is discussed in Section 6.2.4.

5.1.8.15 General Design Criterion 55, 1971 – Reactor Coolant Pressure Boundary Penetrating Containment

The RCS penetrations that are part of the CIS include the PRT makeup and gas analyzer lines, and the RVLIS lines, which comply with the requirements of GDC 55, 1971, as described in Section 6.2.4 and Table 6.2-39. Refer to Section 9.3.6 for the nitrogen line to the PRT.

5.1.8.16 General Design Criterion 56, 1971 – Primary Containment Isolation

The RCS penetrations that are part of the CIS include the common inlet line to the PRT that accepts discharge from the various ECCS relief valves, which complies with the requirements of GDC 56, 1971, as described in Section 6.2.4 and Table 6.2-39.

5.1.8.17 Reactor Coolant System Safety Function Requirements

(1) Protection from Missiles and Dynamic Effects

The PG&E Design Class I RCS SSCs are protected from the effects of missiles and dynamic effects as discussed in Sections 3.5.3.1 and 3.6, respectively, and Section 5.2.

(2) Reactor Heat Removal

The RCS provides sufficient heat transfer capability, using coolant flow from the RCPs, to transfer the heat produced during power operation and the initial phase of plant cooldown, when the reactor is subcritical, to the steam system via the SGs.

The system provides sufficient heat transfer capability to transfer the heat produced during the subsequent phase of plant cooldown and cold shutdown to the RHR system.

The system heat removal capability under power operation and normal operational transients, including the transition from forced to natural circulation, ensures that no fuel damage occurs within the operating bounds permitted by the reactor control and protection systems.

(3) RCS Thermal-Hydraulic Requirements

The RCS thermal-hydraulic design provides appropriate limits on RCS pressure (refer to Section 5.3.1) and ensures adequate RCP NPSH (refer to Sections 5.3.2 and 5.5.1). Refer to Section 7.7.2 for discussion of T_{avg} control.

(4) RCS Coolant Functional Properties

The RCS contains the water used as the core neutron moderator and reflector and as a solvent for chemical shim control. The system, together with the CVCS, maintains the homogeneity of soluble neutron poison concentration and controls the rate of change of coolant temperature, preventing uncontrolled reactivity changes.

(5) RCS Pressure and Volume Control

The pressurizer maintains RCS pressure and volume through the surge line during operation and limits pressure changes during transients. During plant load reduction or increase, reactor coolant volume changes are accommodated in the pressurizer via the surge line, pressurizer sprays and/or heaters, and the PORVs. Refer to Sections 5.5.9 and 5.5.12 for additional information. For RCS pressure control during a steam generator tube rupture (SGTR), refer to Section 15.4.3.

(6) Steam Flow Restriction

Each SG has an integral flow restrictor located in the steam outlet nozzle to limit the steam blowdown from the SGs in the event of a main steam line rupture. The flow restrictor consists of seven 6.03-inch ID venturi nozzles. These flow restrictors are separate from the in-line 16-inch diameter flow restrictors in the MSS described in Section 10.3.3.13 (5). The flow restrictors are discussed in detail in Sections 5.5.4 and 15.4.2.

(7) RCP Coastdown

Sufficient pump rotation inertia is provided by a flywheel, in conjunction with the impeller and motor assembly, to provide adequate RCS flow during coastdown. The flywheel inertia of the four RCPs sustains reactor coolant flow for a period of time sufficient to assure the minimum heat removal needed to prevent immediate damage to the core.

The assumption of RCP coastdown in relation to the safety analyses is discussed further in Sections 5.5.1.3.2, 15.2.5, 15.2.9, 15.3.1, 15.3.4, 15.4.1, and 15.4.2.

(8) Pressurizer Relief Tank

The PRT and rupture disks are designed for a vacuum to prevent tank collapse if the contents cool following a discharge without nitrogen being added.

5.1.8.18 10 CFR 50.49 – Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

RCS instrumentation and control equipment required to function in a harsh environment under accident conditions is qualified to the applicable environmental conditions to ensure that they will continue to perform their PG&E Design Class I functions. Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment. The affected equipment is listed in the EQ Master List and includes junction boxes, switches, solenoid valves, valve motors, acoustic monitors, resistance temperature detectors (RTDs), differential pressure indicating switches, and pressure transmitters.

5.1.8.19 10 CFR 50.55a(f) – Inservice Testing Requirements

The PG&E Design Class I RCS components comply with the ASME Code for Operation and Maintenance of Nuclear Power Plants and are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

5.1.8.20 10 CFR 50.55a(g) – Inservice Inspection Requirements

The PG&E Design Class I portion of the RCS ASME BPVC Section XI components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical. Refer to Section 5.2.3.15 for ISI of the RPV and RVCH. Refer to Section 5.2.3.21 for ISI of the RCP flywheel.

5.1.8.21 10 CFR 50.63 – Loss of All Alternating Current Power

For DCPP, safe shutdown for SBO is assumed to be Mode 3. Core cooling in this mode is to be provided by natural circulation of the reactor coolant through the core and SGs, with heat removal from the SGs provided by the atmospheric steam dump valves.

The SBO event will result in RCP trip with the simultaneous loss of seal injection flow and CCW flow to the RCP, which allows hot RCS water to enter the pump bearing and seal areas. The thermal barrier heat exchanger is designed to cool the RCS water upon restoration of CCW flow using the ac standby power supply to prevent seal damage for the duration of the SBO event.

5.1.8.22 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The RCS is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

5.1.8.23 Regulatory Guide 1.89, November 1974 – Environmental Qualification of Class 1E Equipment for Nuclear Power Plants

The SCMM is qualified in accordance with the requirements of Regulatory Guide 1.89, November 1974 (refer to Section 3.11).

5.1.8.24 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

RCS post-accident variables required to be monitored for meeting Regulatory Guide 1.97, Revision 3, requirements consist of: RCS soluble boron concentration; RCS cold leg water temperature; RCS hot leg water temperature; RCS pressure; core exit temperature; coolant level in the reactor; subcooling margin indication; pressurizer level; SG pressure; RCP status; PSV position; pressurizer heater status; PRT level, temperature and pressure; and CIV position (refer to Table 7.5-6).

5.1.8.25 Regulatory Guide 1.121, August 1976 – Bases for Plugging Degraded PWR Steam Generator Tubes

Regulatory Guide 1.121, August 1976 provides guidelines for establishing criteria for SG tube defects, minimum wall thickness and analytical and loading criteria for tubes exhibiting partial or complete thru-wall cracks and wastage. DCPP uses the guidance of Regulatory Guide 1.121, August 1976 to assess the limits of tube degradation criteria. DCPP procedures ensure that SG tube inspections and tube integrity assessments are conducted on the appropriate frequency as specified in the technical specifications, and that all SG tubes satisfying the tube repair criteria are plugged. Refer to Section 5.5.2.5 for a discussion of the SG tube inspection program.

5.1.8.26 NUREG-0737 (Items II.B.1, II.D.1, II.E.3.1, II.F.2, II.G.1, II.K.3.5, and II.K.3.25), November 1980 – Clarification of TMI Action Plan Requirements

Item II.B.1 - Reactor Coolant System Vents: The RVHVS can be used to remove non-condensable gases or steam from the RVCH to support natural circulation cooling by remote-manual operation from the control room (refer to Section 5.5.14).

Item II.D.1 - Performance Testing of Boiling-Water Reactors and Pressurized-Water Reactor Relief and Safety Valves (NUREG-0578, July 1979, Section 2.1.2): Refer to Sections 3.9.2.1.7, 5.2.3.26, and 5.5.12.4 for a discussion of testing of RCS PSVs and PORVs.

Item II.E.3.1 - Emergency Power Supply for Pressurizer Heaters: All of the four pressurizer heater groups can be supplied with power from off-site power sources when they are available. In addition, power can be provided to two of the four heater groups from the Class 1E power source through the Class 1E buses when off-site power is not available. This arrangement is adequate for establishing and maintaining natural

circulation during hot standby conditions. Redundancy is provided by supplying each of the two groups of heaters from a different Class 1E bus.

Plant procedures direct the operators to connect the required pressurizer heaters to the emergency buses. Loading of each Class 1E bus can be accomplished from the main control board. Procedures identify under what conditions selected loads can be shed from the Class 1E bus to prevent overloading when the pressurizer heaters are connected. The procedures also include provisions to reset the safety injection actuation signal to permit the operation of the heaters. Transfer to the power supplies can be accomplished within 1 hour after a loss of offsite power.

Devices which supply the pressurizer heaters with motive and control power from the Class 1E buses are PG&E Design Class I.

Item II.F.2 - Instrumentation for Detection of Inadequate Core Cooling: To meet the requirements for supplementing existing instrumentation, the instrumentation for detection of inadequate core cooling includes the SCMM, core exit thermocouple system, and RVLIS, which covers the range from normal operation to complete uncovering of the core. Refer to Sections 5.6.1.1 and 7.5.2.2 for further discussion.

Item II.G.1 - Emergency Power for Pressurizer Equipment: The PORVs are air-to-open, fail-closed valves. They are normally supplied by the plant air compressors. Two of the three valves have a backup supply from the nitrogen system to function on loss of air, including PG&E Design Class I high pressure accumulators which have sufficient capability to operate each valve more than 100 times after the loss of both air and nitrogen. The third PORV is not supplied with a backup motive power supply.

Each PORV is opened by a solenoid valve which is energized-to-open, spring-to-close. The circuits to the solenoid valves are supplied with redundant interlocks which prevent energization below normal operating pressures. These control circuits are powered from the redundant Class 1E station batteries.

The backup PORV air supply is PG&E Design Class I. The piping, accumulators, control power connections, and the solenoid valves are PG&E Design Class I.

The PORV block valves, including the control power connections, are powered from Class 1E buses which are served by either offsite power or the standby power supply. Each of the three valves is powered from a separate Class 1E 480-V bus.

The pressurizer level indication circuits are PG&E Design Class I. AC power for all Class 1A instrument channels is supplied from inverters which are supplied from the Class 1E buses with automatic backup from the Class 1E 125-Vdc batteries.

Item II.K.3.5 - Auto Trip of RCPs During Loss-of-Coolant Accident: The RCPs do not automatically trip on a SBLOCA as sufficient time is available for manual trip (Reference 4). Plant procedures direct the operators to manually trip the RCPs if necessary. The

implementation of this item utilized the required Westinghouse Owner's Group RCP trip criteria that had been submitted by the Westinghouse Owner's Group in response to Generic Letter 83-10c, February 1983. Generic Letter 85-12, June 1985, also provided guidance concerning implementation of the approved RCP trip criteria.

Item II.K.3.25 - Effect of Loss of Alternating-Current Power on Pump Seals: The CCW system that provides cooling water to the RCP thermal barriers can be supplied from the standby power supply and its operability will not be lost with a loss of ac power.

5.1.8.27 Generic Letter 83-37, November 1983 - NUREG-0737 Technical Specifications

Item II.B.1 - Reactor Coolant System Vents: One of the two separate vent paths, consisting of at least two valves in series which are powered from Class 1E buses, is required to be operable by plant procedures. Refer to Section 5.5.14 for a description of the RVHVS.

5.1.8.28 Generic Letter 88-05, March 1988 - Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants

The DCPP BACCP monitors and maintains the integrity of the RVCH, the RCS and its supports, and all other borated systems pressure boundary components in accordance with Generic Letter 88-05, March 1988.

The BACCP is established to minimize boric acid induced corrosion by providing for:

(1) Early detection of boric acid leaks.

(2) Thorough inspection of the surrounding areas.

(3) Proper evaluation of areas where leakage has occurred. Of special concern is any impact to ASME Code Class 1 equipment.

(4) Prompt action to mitigate the leak, perform repairs, and avoid future damage.

5.1.8.29 Generic Letter 90-06, June 1990 – Resolution of Generic Issue 70, "Power-Operated Relief Valve and Block Valve Reliability" and Generic Issue 94, "Additional Low-Temperature Over Pressure Protection for Light-Water Reactors" Pursuant to 10 CFR 50.54(f)

The pressurizer PORVs and PORV block valves are included in the scope of the IST program. The block valves are also included in the DCPP Generic Letter 89-10, June 1989, motor-operated valves (MOV) program (refer to Section 5.2.3.27). Technical Specifications ensure valves required for LTOP protection will be able to perform their design function.

5.1.8.30 Generic Letter 95-07, August 1995 – Pressure Locking and Thermal Binding of Safety-Related Power-Operated Valves

PG&E Design Class I power-operated gate valves in the RCS that were determined to be susceptible to pressure locking have been modified by drilling a hole in the high pressure side of the disk to prevent pressure locking. No power operated gate valves in the RCS were found susceptible to thermal binding.

5.1.8.31 NRC Bulletin 88-09, July 1988 - Thimble Tube Thinning in Westinghouse Reactors

The incore neutron monitoring system is inspected in accordance with plant procedures. The inspection confirms the integrity of the incore neutron monitoring system thimble tube.

5.1.8.32 NRC Bulletin 88-11, December 1988 - Pressurizer Surge Line Thermal Stratification

Analyses were performed to evaluate the stress and fatigue effects due to thermal stratification and thermal striping of the pressurizer surge lines. The fatigue evaluation determined the pressurizer surge lines meet the acceptance criteria of ASME BPVC Section III-1986.

5.1.8.33 Branch Technical Position ASB 10-2, March 1978 - Design Guidelines for Avoiding Water Hammers in Steam Generators

The SGs include top-discharge spray nozzles in the feedwater ring which reduce the possibility of steam pockets being trapped in the feedwater ring (refer to Section 5.5.2). The main feedwater piping has been designed minimizing the length of horizontal feedwater piping which could be emptied when the SG water level drops below the level of the feedwater ring (refer to Section 10.4.7.3.20).

5.1.9 REFERENCES

1. RCS Pressurization Analysis for Diablo Canyon Shutdown Scenarios, Westinghouse Technical Report, April 1997.

2. RCS Flow Measurement Using Elbow Tap Methodology at Diablo Canyon Units 1 and 2, WCAP-15113, Revision 1, Westinghouse Electric Company LLC, April 2002.

3. RCS Flow Verification Using Elbow Taps at Westinghouse 3-Loop PWRs, WCAP-14750, Revision 1, Westinghouse Electric Company, September 1999.

4. Analysis of Delayed Reactor Coolant Pump Trip during Small Loss of Coolant Accidents for Westinghouse Nuclear Steam Supply Systems, WCAP-9584, Westinghouse Electric Company LLC, August 1979.

5.1.10 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

5.2 INTEGRITY OF THE REACTOR COOLANT PRESSURE BOUNDARY

The RCPB is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation, including all anticipated transients, and to maintain the resulting stresses within allowable values. The system is protected from overpressure by means of pressure relieving devices as required by applicable codes and a special system for low temperature operation. Materials of construction are specified to minimize corrosion and erosion and to provide a structure and system pressure boundary that will maintain its integrity throughout the life of the plant. Inspections in accordance with Reference 8, and provisions for surveillance of critical areas to enable periodic assessment of the boundary integrity, are made.

5.2.1 DESIGN BASES

5.2.1.1 General Design Criterion 2, 1967 - Performance Standards

The RCPB is designed to withstand the effects of, or is protected against, natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

5.2.1.2 General Design Criterion 4, 1987 – Environmental and Dynamic Effects Design Bases

Consideration of the dynamic effects associated with main RCL piping postulated pipe ruptures are excluded from the DCPP design basis with the approval of LBB methodology by demonstrating that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping systems.

5.2.1.3 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The RCPB is designed and constructed so as to have an exceedingly low probability of gross rupture or significant leakage throughout its lifetime.

5.2.1.4 General Design Criterion 11, 1967 - Control Room

The RCPB is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

5.2.1.5 General Design Criterion 12, 1967 - Instrumentation and Controls

Instrumentation and controls are provided as required to monitor and maintain the RCPB variables within prescribed operating ranges.

5.2.1.6 General Design Criterion 16, 1967 - Monitoring Reactor Coolant Pressure Boundary

Means are provided for monitoring the RCPB to detect leakage.

5.2.1.7 General Design Criterion 33, 1967 – Reactor Coolant Pressure Boundary Capability

The RCPB is capable of accommodating without rupture, and with only limited allowance for energy absorption through plastic deformation, the static and dynamic loads imposed on any boundary components as a result of any inadvertent and sudden release of energy to the coolant.

5.2.1.8 General Design Criterion 34, 1967 – Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention

The RCPB is designed to minimize the probability of rapidly propagating type failures. Consideration is given (a) to notch-toughness properties of materials extending to the upper shelf of the Charpy transition curve, (b) to the state of the stress of materials under static and transient loadings, (c) to the quality control specified for materials and component fabrication to limit flaw sizes, and (d) to the provisions for control over service temperature and irradiation effects which may require operational restrictions.

5.2.1.9 General Design Criterion 35, 1967 – Reactor Coolant Pressure Boundary Brittle Fracture Prevention

Under conditions where RCPB system components constructed of ferritic materials may be subjected to potential loadings, such as a reactivity induced loading, service temperatures are at least 120°F above the nil ductility transition (NDT) temperature of the component material if the resulting energy release is expected to be absorbed by plastic deformation or 60°F above the NDT temperature of the component material if the resulting energy release is expected to be absorbed within the elastic strain energy range.

5.2.1.10 General Design Criterion 36, 1967 – Reactor Coolant Pressure Boundary Surveillance

RCPB components have provisions for inspection, testing, and surveillance by appropriate means to access the structural and leaktight integrity of the boundary components during their service lifetime. For the reactor vessel, a material surveillance program conforming to ASTM-E-185-66 is provided.

5.2.1.11 General Design Criterion 51, 1967 - Reactor Coolant Pressure Boundary Outside Containment

For the portion of the RCPB outside containment, appropriate features as necessary are provided to protect the health and safety of the public in case of accidental rupture in that part. Determination of the appropriateness of features such as isolation valves and additional containment include consideration of the environmental and population conditions surrounding the site.

5.2.1.12 Reactor Coolant Pressure Boundary Safety Function Requirement

(1) Protection from Missiles and Dynamic Effects

The RCPB is designed to be protected against missile and dynamic effects which may result from equipment failures.

5.2.1.13 10 CFR 50.55a- Codes and Standards

The RCPB is designed in accordance with the requirements of 10 CFR 50.55a to the extent practical.

5.2.1.14 10 CFR 50.55a(f) – Inservice Testing Requirements

RCPB ASME Code components are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

5.2.1.15 10 CFR 50.55a(g) - Inservice Inspection Requirements

The RCPB ASME Code components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

5.2.1.16 10 CFR 50.60 - Acceptance Criteria for Fracture Prevention Measures for Lightwater Nuclear Power Reactors for Normal Operation

The fracture toughness and material surveillance program requirements are implemented for the RCPB set forth in Appendices G and H to 10 CFR Part 50.

5.2.1.17 10 CFR 50.61- Fracture Toughness Requirements for Protection against Thermal Shock Events

10 CFR 50.61 specifies the calculation of projected values of the reference temperature for reactor vessel material evaluated for the highest neutron fluence expected throughout expiration of the operating license.

5.2.1.18 10 CFR Part 50 Appendix G- Fracture Toughness Requirements

The fracture toughness requirements for ferritic materials of pressure-retaining components of the RCPB are implemented to provide adequate margins of safety during any condition of normal operation, including anticipated operational occurrences and system hydrostatic tests, to which the pressure boundary may be subjected over its service lifetime.

5.2.1.19 10 CFR Part 50 Appendix H- Reactor Vessel Material Surveillance Program Requirements

A surveillance program is implemented to monitor changes in the fracture toughness properties of ferritic materials in the reactor vessel beltline region which result from exposure of these materials to neutron irradiation and the thermal environment. Under the program, fracture toughness test data are obtained from material specimens exposed in surveillance capsules, which are withdrawn periodically from the reactor vessel.

5.2.1.20 Safety Guide 14, October 1971 - Reactor Coolant Pump Flywheel Integrity

For the original reactor coolant pump (RCP) motors, missile protection, with regards to the flywheels of the RCP motors, is provided in accordance with Safety Guide 14, October 1971, with exception to the ISI requirement C.4. The ISI requirements are in accordance with Regulatory Position C.4.b of Regulatory Guide 1.14, Revision 1.

5.2.1.21 Regulatory Guide 1.14, Revision 1, August 1975 – Reactor Coolant Pump Flywheel Integrity

For replacement motor coolant pump (RCP) motors, missile protection, with regards to the flywheels, is provided in accordance with Regulatory Guide 1.14, Revision 1.

For all reactor coolant pump (RCP) motors, a program provides for the inspection of each RCP flywheel per the recommendations of Regulatory Position C.4.b of Regulatory Guide 1.14, Revision 1, with exception to the examination requirements given by Regulatory Guide 1.14, Revision 1, Positions C.4.b(1) and C.4.b(2).

5.2.1.22 Regulatory Guide 1.44, May 1973 – Control of the Use of Sensitized Stainless Steel

Regulatory Guide 1.44, May 1973, describes methods for control of the application and processing of stainless steel to avoid severe sensitization to diminish occurrences of stress corrosion cracking.

5.2.1.23 Regulatory Guide 1.45, May 1973 - Reactor Coolant Pressure Boundary Leakage Detection Systems

Leakage detection systems are designed with acceptable methods to detect and identify the location of the source of RCPB leakage.

5.2.1.24 Regulatory Guide 1.97, Revision 3, May 1983 - Criteria for Accident Monitoring Instrumentation for Nuclear Power Plants

Instrumentation is provided to monitor RCPB integrity following an accident.

5.2.1.25 Regulatory Guide 1.99, Revision 2, May 1988 - Radiation Embrittlement of Reactor Vessel Materials

Predicted change in reference temperature at nil ductility transition (ΔRT_{NDT}) values are derived for 1/4T and 3/4T (thickness) in the limiting material by using the method described in Regulatory Guide 1.99, Revision 2 (Reference 27), and the maximum fluence for the applicable service period. Methods acceptable to the U.S. Nuclear Regulatory Commission (NRC) for estimating the embrittlement of reactor vessel beltline materials is provided in Regulatory Guide 1.99, Revision 2, which was endorsed in Generic Letter 88-11, July 1988.

5.2.1.26 NUREG-0737 (Items II.B.1, II.D.1, II.D.3, II.K.2.13, and III.D.1.1), November 1980 - Clarification of TMI Action Plan Requirements

Item II.B.1 – Reactor Vessel Head Vent System: A RVHVS is provided to exhaust non-condensable gases and/or steam from the RCS that could inhibit natural circulation core cooling. The configuration of the RCS vent paths serves to minimize the probability of inadvertent or irreversible actuation while ensuring that a single failure of a vent valve power supply or control system does not prevent isolation of the vent path.

Item II.D.1 – Performance Testing of Pressurized-Water Reactor Relief and Safety Valves: PSVs and PORVs and block valves: a program has been implemented for testing to qualify RCS relief and safety valves under expected design transients.

Item II.D.3 – Valve Position Indication for PSVs and PORVs: Positive PSV and PORV position indication is provided in the control room.

Item II.K.2.13 – Thermal Mechanical Report: An analysis has been performed to evaluate the effects of high pressure injection on vessel integrity.

Item III.D.1.1 – Integrity of Systems Outside Containment Likely to Contain Radioactive Material for Pressurized-Water Reactors and Boiling Water Reactors: A program has been implemented for preventative maintenance for leakage testing and reduction of

leakage for primary systems that could contain highly radioactive fluids during a serious accident or transient.

5.2.1.27 Generic Letter 1989-10, June 1989 - Safety-Related Motor-Operated Valve Testing and Surveillance

The RCPB PG&E Design Class I and position changeable MOVs are included in the MOV Program for Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996.

5.2.1.28 Generic Letter 1990-06, June 1990 – "Enclosure B, Resolution of Generic Issue 94 – 'Additional Low-Temperature Overpressure Protection For Light-Water Reactors' "

The RCPB is designed such that brittle fracture of the RPV while at low temperature, if combined with a critical crack in the reactor coolant pressure vessel welds or plate material, will not occur.

5.2.2 SYSTEM DESCRIPTION

5.2.2.1 Design of Reactor Coolant Pressure Boundary Components

The RCPB is defined as those piping systems and components that contain reactor coolant at design pressure and temperature. RCPB piping systems and components are defined as PG&E Quality/Code Class I, with the exception of those RCPB components excluded from PG&E Quality/Code Class I requirements by 10 CFR 50.55a as described in Section 3.2.2.3. With the exception of the reactor coolant sampling lines, the entire RCPB, as defined above, is located entirely within the containment structure.

The RCS boundaries are designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation, including all anticipated transients, and to maintain the stresses within applicable stress limits.

5.2.2.1.1 Performance Objectives

The performance objectives of the RCS are described in Section 5.1. Equipment codes and classification of the components within the RCS boundary are listed in Table 5.2-2. Procurement information for major RCS components is provided in Table 5.2-3.

The following five operating conditions are considered in the design of the RCS:

(1) Normal Conditions

Any condition in the course of startup, operation in the design power range, hot standby and system shutdown, other than upset, emergency, faulted, or testing conditions.

(2) Upset Conditions

Any deviations from normal conditions anticipated to occur often enough that the design should include a capability to withstand the conditions without operational impairment. The upset conditions include those transients that result from any single operator error control malfunction, transients caused by a fault in a system component requiring its isolation from the system, and transients due to loss of load or power.

Upset conditions include any abnormal incidents not resulting in a forced outage and also forced outages for which the corrective action does not include any repair of mechanical damage. The estimated duration of an upset condition was included in the design specifications.

(3) Emergency Conditions

Emergency conditions are those deviations from normal conditions that require shutdown for correction of the conditions or repair of damage in the system. These conditions have a low probability of occurrence but are included to ensure that no gross loss of structural integrity results as a concomitant effect of any damage developed in the system. The total number of postulated occurrences for such events will not cause more than 25 stress cycles having an Sa value greater than that for 106 cycles from the applicable ASME BPVC Section III, fatigue design curves.

(4) Faulted Conditions

Faulted conditions are those combinations of conditions associated with extremely low probability postulated events whose consequences are such that the integrity and operability of the nuclear energy system may be impaired to the extent that considerations of public health and safety are involved. Such conditions require compliance with safety criteria as may be specified by jurisdictional authorities.

(5) Testing Conditions

Testing conditions are those tests, in addition to the hydrostatic or pneumatic tests, permitted by the ASME BPVC Section III, including leak tests or subsequent hydrostatic tests.

5.2.2.1.2 Design Parameters

The design parameters of the RCS are described in Section 5.1 and Table 5.1-1.

5.2.2.1.3 Compliance with 10 CFR 50.55a

Codes and standards applicable to RCPB components are specified in 10 CFR 50.55a. They depend on when the plant was designed and constructed. Construction permits for DCPP Unit 1 and Unit 2 were issued on April 23, 1968, and December 9, 1970, respectively. Therefore, codes and standards specified in 10 CFR 50.55a for construction permits issued before January 1, 1971, are applicable to the DCPP.

The codes, standards, and component classifications used in the design and construction of the DCPP RCPB components are shown in Table 5.2-2 and are in accordance with the applicable provisions of 10 CFR 50.55a. Where text refers to codes in general, the applicable code edition and addenda are as specified in Table 5.2-2. These design codes specify applicable surveillance requirements including allowances for normal degradation.

Although use of the normal, upset, emergency, and faulted condition terminology was introduced in codes (ASME BPVC, Section III, Summer 1968 Addenda) and standards after the code applicability date for the DCPP, analyses of RCS components in accordance with the ASME BPVC conditions (normal, upset, and faulted) have been performed for the load combinations and associated stress limits identified in Tables 5.2-5through 5.2-7.

For the RCL piping, the 1967 or 1973 versions of the B31.1 Code do not contain explicit description for the load combinations or allowable stress limits for the faulted loading conditions. As a result, the load combinations and allowable stress limits for the faulted loading conditions are provided in Table 5.2-5. The stresses due to the above conditions are combined using the equations described in two editions of the B31.1 Code (both the 1967 Code with 1971 Addendum, and the 1973 Code with Summer 1973 Addendum). The combined stresses are compared with the allowable stress limits as shown in Table 5.2-5. Valves have been designed in accordance with USAS B16.5, in general, and ASME BPVC Section VIII, for flange connections.

5.2.2.1.4 Applicable Code Cases

Application, by Westinghouse or other vendors, of the code cases in Table 5.2-1 is in accordance with ASME Code guidelines. Specific application of any of these code cases to both DCPP units has not been identified since, at the time of their fabrication, there was neither code, nor NRC requirements to maintain and update a centralized list of these code cases.

5.2.2.1.5 Design Transients

The design transients in this section and in Table 5.2-4, in general, apply to the RCPB ASME III Components. Additional, specific transient analysis which applies to individual components may be found in Section 5.2.2.1.5.6, Component Transients, and Section 5.5, Component and Subsystem Design.

To ensure the high degree of integrity of RCS equipment over the design life of the plant, fatigue evaluation is based on conservative estimates of the magnitude and frequency of temperature and pressure transients resulting from various operating conditions in the plant. To a large extent, the specific transient operating conditions to be considered for equipment fatigue analyses were determined by Westinghouse. The transients selected represent operating conditions that should be prudently anticipated during plant operation and are sufficiently severe or frequent to be of possible significance to component cyclic behavior.

The design cycles discussed herein are conservative estimates for equipment design purposes only and are not intended to be an accurate representation of actual transients or to reflect operating experience. As such, the number of occurrences specified in Table 5.2-4 is not an absolute limit, but reflect design bases assumptions. The design limit requires that the cumulative fatigue usage factor (as calculated per ASME code guidance) for the equipment or component is less than 1.0. Therefore, a higher number of occurrences may be allowable based upon evaluation of actual stresses.

A program has been established and will be maintained which includes tracking the number of cyclic or transient occurrences of Table 5.2-4 to ensure that components are maintained within their design limit unless the program demonstrates by other means that the design limit will not be exceeded.

DCPP Unit 1 and Unit 2 are licensed for LBB for the main RCL piping. LBB allows the elimination of the dynamic effects of pipe rupture from the design basis. Dynamic effects of pipe rupture are defined as missile generation, pipe whip, pipe break reaction forces, jet impingement, decompression waves within the ruptured pipe, and local pressurizations. Although the dynamic effects of pipe rupture have been eliminated from the design basis, LBB cannot be applied to: containment design, ECCS performance, and EQ of electrical and mechanical equipment. For these applications, the main RCL pipe breaks must be used. The LOCA transient included in Section 5.2.2.1.5, Design Transients, for the plant and for each component provides limiting pressure and temperature blowdown curves which were originally generated for the main loop pipe breaks. Since PG&E has applied LBB to the Reactor Coolant (main loop) piping, the LOCA transient presented herein bounds the transients which would be generated by the large branch line breaks, i.e., the Pressurizer Surge Line, the RHR Suction Line, and the Accumulator Lines.

5.2.2.1.5.1 Normal Conditions

The following five transients are considered normal conditions:

(1) Heatup and Cooldown

For design evaluation, the heatup and cooldown cases are conservatively represented by continuous heatup or cooldown at a rate of 100°F per hour, which corresponds conceivably to a heatup or cooldown rate that could only occur under upset or emergency conditions. Heatup brings the RCS from ambient to the no-load temperature and pressure conditions. Cooldown represents the reverse situation.

The limitations on heatup reflect:

(a) Criteria for prevention of nonductile failures that establish maximum permissible temperature change rates, as a function of plant pressure and temperature.

(b) Slower initial heatup rates when using pumping energy only.

(c) Interruptions in the heatup and cooldown cycles due to such factors as drawing a pressurizer steam bubble, rod withdrawal, sampling, water chemistry, and gas adjustments.

(2) Unit Loading and Unloading

The unit loading and unloading cases under automatic reactor control are conservatively represented by a continuous and uniform ramp power change of 5 percent per minute between 15 percent load and full load. This load swing is the maximum possible consistent with operation under automatic reactor control. The reactor temperature varies with load as prescribed by the temperature control system.

(3) Step Load Increase and Decrease of 10 percent of Full Power

The ±10 percent step change in load demand is a control transient that is assumed to be a change in turbine control valve opening that might be caused by disturbances in the outside electrical network. The reactor control system is designed to restore plant equilibrium without reactor trip following a ±10 percent step change in turbine load demand initiated from nuclear plant equilibrium conditions in the range between 15 and 100 percent of full load, the power range for automatic reactor control. During load change conditions, the reactor control system attempts to match turbine and reactor outputs in such a manner that peak reactor coolant temperature is minimized and reactor coolant temperature is restored to its programmed setpoint at a sufficiently slow rate to prevent an excessive change in pressurizer pressure.

Following a step load decrease in turbine load, the secondary side steam pressure and temperature initially increase since the decrease in nuclear power lags behind the step decrease in turbine load. During the same

time increment, the RCS average temperature and pressurizer pressure also increase initially. Because of the power mismatch between the turbine and reactor and the increase in reactor coolant temperature, the control system automatically inserts the control rods to reduce core power. The reactor coolant temperature is ultimately reduced from its peak value to a value below its initial equilibrium value at the beginning of the transient.

The reactor coolant average temperature setpoint changes as a function of turbine-generator load, as determined by first-stage turbine pressure measurement. Pressurizer spray causes the pressurizer pressure to decrease from its peak pressure value. At some point during the decreasing-pressure transient, the saturated water in the pressurizer begins to flash, reducing the rate of pressure decrease. Subsequently, the pressurizer heaters come on to restore the plant pressure to its normal value.

Following a step load increase in turbine load, the reverse situation occurs; i.e., the secondary side steam pressure and temperature initially decrease and the reactor coolant average temperature and pressure initially decrease. The control system automatically withdraws the control rods to increase core power. The decreasing pressure transient is reversed by actuation of the pressurizer heaters, and eventually the system pressure is restored to its normal value. The reactor coolant average temperature is raised to a value above its initial equilibrium value at the beginning of the transient.

(4) Large Step Decrease in Load

This transient applies to a step decrease in turbine load from full power of such magnitude that the resultant rapid increase in reactor coolant average temperature and secondary side steam pressure and temperature automatically initiates a secondary side steam dump system response that prevents a reactor shutdown or lifting of SG safety valves.

DCPP was originally designed to accept step load reductions from 0 to 95 percent without a reactor trip. Industry experience and operational analysis have shown a 95 percent step load decrease to be very difficult to recover from without the occurrence of a reactor trip. Therefore, the design basis load reduction transient for DCPP has been revised to a 50 percent step load reduction. However, for equipment fatigue and design purposes, the large step decrease in load transient continues to be based on a 95 percent step decrease since it results in more severe pressure and temperature changes.

(5) Steady State Fluctuations

The reactor coolant average temperature, for purposes of design, is assumed to increase or decrease at a maximum rate of 6°F in 1 minute. The temperature changes are assumed to be around the programmed value of Tavg (Tavg ±3°F). The corresponding reactor coolant pressure is assumed to vary accordingly, and thus be within 2250 ± 50 psia. It is assumed that an infinite number of these fluctuations occur during the design life of the plant.

5.2.2.1.5.2 Upset Conditions

The following seven transients are considered upset conditions:

(1) Loss of Load Without Immediate Turbine or Reactor Trip

This transient applies to a step decrease in turbine load from full power occasioned by the loss of turbine load without immediately initiating a reactor trip and represents the most severe transient on the RCS. The reactor and turbine eventually trip as a consequence of a high pressurizer level trip initiated by the reactor protection system (RPS). Since redundant means of tripping the reactor are provided as a part of the RPS, transients of this nature are not expected but are included to ensure a conservative design.

(2) Loss of Power

This transient involves the loss of outside electrical power to the station with a reactor and turbine trip. Under these circumstances, the RCPs are de-energized and, following their coastdown, natural circulation is established in the system to some equilibrium value. This condition permits removal of core residual heat through the SGs that are being fed by the auxiliary feedwater system (AFWS) powered either by a diesel generator or main steam. Steam is initially removed for reactor cooldown through atmospheric dump valves provided for this purpose.

(3) Partial Loss of Flow

This transient applies to a partial loss of flow accident from full power in which a RCP is tripped as a result of a loss of power to the pump. The consequences of such an accident are a reactor and turbine trip on low reactor coolant flow followed by automatic opening of the steam dump system and flow reversal in the affected loop. The flow reversal results in a reactor coolant at cold leg temperature, being passed through the SG and cooled still further. This cooler water then passes through the hot leg piping and enters the reactor vessel outlet nozzles. The net result of the

flow reversal is a sizable reduction in the hot leg coolant temperature of the affected loop.

(4) Reactor Trip from Full Power

A reactor trip from full power may occur for a variety of causes resulting in RCS and SG secondary side temperature and pressure transients. It results from continued heat transfer from the reactor coolant to the SG. The transient continues until the reactor coolant and SG secondary side temperatures are in equilibrium at zero power conditions. A continued supply of feedwater and controlled dumping of secondary steam remove the core residual heat and prevent the SG safety valves from lifting. The reactor coolant temperatures and pressures undergo a rapid decrease from full power values as the RPS causes the control rods to move into the core.

(5) Inadvertent Auxiliary Spray

The inadvertent pressurizer auxiliary spray transient will occur if the auxiliary spray valve is opened inadvertently during normal operation. This will introduce cold water into the pressurizer causing a very sharp pressure decrease.

Auxiliary spray water temperature depends on regenerative heat exchanger performance. The most conservative case occurs when the letdown stream is shut off and unheated charging fluid enters the pressurizer.

The design assumes a spray water temperature of 100°F and a flowrate of 200 gpm. It is also assumed that, if activated, the auxiliary spray will continue for 5 minutes until shut off.

The pressure decreases rapidly to the low-pressure reactor trip point and the pressurizer low-pressure reactor trip is assumed to be actuated. This accentuates the pressure decrease until the pressure is finally limited to the hot leg saturation pressure. After 5 minutes the spray is stopped and the pressurizer heaters return the pressure to 2250 psia.

For design purposes, it is assumed that RCS temperature changes do not occur as a result of auxiliary spray initiation except in the pressurizer.

(6) Design Earthquake (DE)

The DE loads are a part of the mechanical loading conditions specified in equipment specifications. The origin of their determination is separate and distinct from those transient loads resulting from fluid pressure and

temperature. Their magnitude is considered in the fatigue design analysis for comparison with appropriate stress limits.

(7) RCS Cold Overpressurization

RCS cold overpressurization may occur during startup and shutdown conditions at low temperature, with or without the existence of a steam bubble in the pressurizer. The event is inadvertent, and can potentially occur by any one of a variety of malfunctions or operator errors. The function of the cold overpressure mitigation system (COMS), also known as the LTOP system, is twofold:

1. To provide RCS pressure relief capability to maintain RCS pressure below the limit based on the more limiting of; the fracture toughness requirements of Appendix G of 10 CFR Part 50 for the reactor vessel at low RCS temperatures, or the maximum RCS pressure requirements as dictated by the PORV discharge piping limits.
2. To comply with the minimum RCS pressure constraint consistent with RCP No. 1 seal integrity. This limit is of concern after COMS is actuated (i.e., a PORV opens) and the transient pressure decreases to its minimum value.

All LTOP events can be categorized as belonging to either of the two following transient mechanisms:

1. Events resulting in the addition of mass (mass input transient), or
2. Events resulting in the input of heat (heat input transient).

Umbrella cases of the temperature and pressure transients that can occur from each mechanism are provided for use in the component design.

5.2.2.1.5.3 Emergency Conditions

No transient is classified as an emergency condition.

5.2.2.1.5.4 Faulted Conditions

The following transients are considered faulted conditions:

(1) RCPB Pipe Break

This accident involves the postulated rupture of a pipe within the RCPB. It is conservatively assumed that system pressure is reduced rapidly and the ECCS is initiated to introduce water into the RCS. The SI signal will also initiate a turbine and reactor trip.

(2) Steam Line Break

For RCS component evaluation, the following conservative conditions are considered:

(a) The reactor is initially in hot, zero power subcritical condition assuming all rods in, except the most reactive rod, which is assumed to be stuck in its fully withdrawn position.

(b) A steam line break occurs inside the containment.

(c) Subsequent to the break, there is no return to power and the reactor coolant temperature cools down to 212°F.

(d) The ECCS pumps restore the reactor coolant pressure.

The above conditions result in the most severe temperature and pressure variations that the component will encounter during a steam line break accident.

(3) Double Design Earthquake

The mechanical stress resulting from the DDE is considered for each component. The seismic analysis is described in Section 3.7.

(4) Hosgri Earthquake

The mechanical stress resulting from the HE is considered for each component. The seismic analysis is described in Section 3.7.

The design transients and the number of occurrences of each are shown in Table 5.2-4.

5.2.2.1.5.5 Preoperational Tests and Condition Transients

The following hydrostatic tests and leak test conditions were considered in RCS component fatigue evaluations. In some instances, these tests were conducted prior to plant startup.

(1) Turbine Roll Test

This test was imposed upon the plant during the hot functional test period for turbine cycle checkout. RCP power heats the reactor coolant to operating temperature and the steam generated is used to perform a turbine roll test. Plant cooldown during the test exceeds, however, the 100°F per hour maximum rate.

(2) Hydrostatic and Leak Test Conditions

Each of the major NSSS components (SG, RCPs, reactor vessel, CRDMs, loop piping and pressurizer) may be subjected to a maximum of 10 hydrostatic tests without exceeding ASME BPVC criteria.

The pressure tests are:

(a) Primary Side Hydrostatic Test Before Initial Startup

Pressure tests include both shop and field hydrostatic tests that occur as a result of component or system testing. This hydrostatic test was performed prior to initial fuel loading at a water temperature of at least 168°F (calculated using the methods presented in Paragraph NB2300 of ASME BPVC Section III-1971, Summer 1972 Addenda), which is compatible with reactor vessel fracture prevention criteria requirements, and a maximum test pressure. In this test, the primary side of the SG is pressurized to 1.25 times design pressure (3107 psig) coincident with no pressurization of the secondary side.

(b) Secondary Side Hydrostatic Test Before Initial Startup

The secondary side of the SG is pressurized to 1357 psig (1.25 times the design pressure of the secondary side) coincident with the primary side at zero psig.

(c) Primary Side Leak Test

Each time the primary system is opened, a leak test will be performed. During this test the primary system pressure is assumed, for design purposes, to be raised to 2500 psia, with the system temperature above design transition temperature, while the system is checked for leaks.

In actual practice, the primary system is pressurized to less than 2500 psia to prevent the PSVs from lifting during the leak test. The secondary side of the SG is pressurized by closing off the steam lines, so that the pressure differential across the tubesheet does not exceed 1600 psi.

(d) Secondary Side Leak Test

During the life of the plant it may be necessary to check the SG secondary side, particularly the manway closure, for leakage. For design purposes, the secondary side is assumed to be pressurized

just below 1085 psig (the design pressure of the secondary side of the SG) to prevent the main steam safety valves from lifting. The primary side will also be pressurized so as to not exceed a differential pressure of 670 psi.

(e) Tube Leakage Test

During the life of the plant it may be necessary to check the SG for tube leakage and tube-to-tube sheet leakage. This is done by visual inspection of the underside (channel head side) of the tube sheet for water leakage, with the secondary side pressurized. Tube leakage tests are performed during plant cold shutdown.

For these tests, the secondary side of the SGs is pressurized with water, initially at a very low pressure, and the primary system remains depressurized (i.e., 0 psig). The underside of the tube sheet is examined visually for leaks. If any leaks are observed, the secondary side is depressurized and repairs made by tube plugging. The secondary side is then repressurized (to a higher pressure) and the underside of the tube sheet is again checked for leaks. The process is repeated until all the leaks are repaired. The maximum (final) secondary-side test pressure reached is 840 psig.

The total number of tube leakage tests considered as part of the SG design is 800 during the life of the component. The following is a breakdown of the anticipated number of occurrences at each secondary side pressure.

Case	Test Pressure, psig	No. of Occurrences
Case 1	200	400
Case 2	400	200
Case 3	600	120
Case 4	840	80

Both the primary and secondary sides of the SGs will be at ambient temperature during these tests.

Since the tests outlined under items (a) and (b) occur prior to plant startup, the number of cycles is independent of other operating plant conditions.

5.2.2.1.5.6 Component Transients

The following transients apply to the components listed, and are provided to clarify the specific transient applicable to the component.

(1) Steam Generator Evaluation

Hot standby operation / feedwater cycling is a normal transient which occurs when the plant is being maintained at hot standby or no load conditions. It is assumed that the low steam generation rate is made up by intermittent slug feeding of 32°F feedwater into the SG. Feedwater additions required during plant heatup and cooldown are also assumed to be covered by the feedwater cycling transient, but with no increase in the total number of cycles.

The fatigue analysis for the SG design also considers a one-time upset event where 32° F feedwater is introduced to a hot, dried-out secondary side of the SG.

(2) Pressurizer Evaluation

Normal heatup cases, as mentioned in Section 5.2.2.1.5.1, are conservatively represented by continuous operation at a uniform temperature rate of 100ºF per hour. In actual practice, the rate of temperature change is lower because of other limitations such as material considerations, use of RCP for heatup, or interruptions during normal startup operations to draw a steam bubble, etc. For the pressurizer, the design cooldown rate is 200ºF per hour.

Following any large change in boron concentration in the RCS, the pressurizer spray is operated to equalize concentration between the loops and the pressurizer. This can be done by manually operating the pressurizer backup heaters, thus causing a pressure increase and initiation of spray flow. The pressurizer pressure increases initially before being returned to nominal pressure by the proportional spray. The pressure is then maintained at nominal pressure by spray operation, matching the heat input from the backup heaters until the concentration is equalized. The only effects of these operations on the primary system are as follows:

1. The reactor coolant pressure varies in step with the pressurizer pressure.
2. The pressurizer surge line nozzle at the hot leg will experience the thermal shocks associated with outflow from the pressurizer

5.2.2.1.6 Identification of Active Pumps and Valves

Pumps and valves are classified as either active or inactive components for faulted conditions. Active components are those whose operability is relied upon to perform a PG&E Design Class I function as described in Section 3.2.2.1. Inactive components are those whose operability (e.g., valve opening or closure, pump operation or trip) is not relied upon to perform a PG&E Design Class I function. The RCPs are the only pumps in the RCS boundary and are classified as "inactive" in the event of a RCL pipe rupture.

Valves in sample lines are not considered to be part of the RCS boundary because the nozzles where these lines connect to the RCS are orificed to a 3/8-inch hole. This hole restricts the flow such that loss through a severance of one of these lines is sufficiently

small to allow operators to execute an orderly plant shutdown (refer to Section 9.3.2 for description of the portion of the sample lines that are part of the RCPB).

Table 5.2-9 lists the active and inactive valves between major components in the main process lines of the RCPB, along with the actuation type, valve types, and location. The listed valves are those that are within the RCPB. Check valves are also included in Table 5.2-9. Check valves are a credited means of pressure boundary isolation for the original design. Vents, drains, test and instrument root valves are excluded from the table as they meet the isolation requirements and are not between major components of the RCPB. Manual valves are passive components and are not considered either active or inactive, therefore they are not included on Table 5.2-9.

5.2.2.1.7 Design of Active Pumps and Valves

The design criteria for active PG&E Design Class I pumps outside the RCS boundary are discussed in Section 3.9.2. All these PG&E Design Class I pumps are designated either PG&E Quality/Code Class II or III.

The valves were designed to function at normal operating conditions, maximum design conditions, and DDE/Hosgri conditions. Active valves that are used for accident mitigation only, and do not serve to support safe shutdown following a HE, were qualified for active function for a HE to provide increased conservatism in accordance with Reference 30. The design meets the requirements of the ANSI B31.1, ANSI B16.5, and MSS-SP-66 codes (refer to Table 5.2-2).

The stress limits for the valves in the RCS pressure boundary are indicated in Table 5.2-5.

In addition, all valves 1 inch and larger within the RCPB were checked for wall thickness to ANSI B16.5, MSS-SP-66, or ASME BPVC Section III-1968 (some 1974) requirements, as applicable, and subjected to nondestructive tests in accordance with ASME and American Society for Testing and Materials (ASTM) codes.

The valves were designed to the requirements of ANSI B16.5 or MSS-SP-66 pertaining to minimum wall thickness for pressure containing components. Analyses were performed to qualify active valves.

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These valves were subjected to a series of stringent tests prior to service and during the plant life. Prior to installation, the following tests were performed: shell hydrostatic tests to MSS-SP-61 requirements, backseat and main seat leakage tests. Cold hydrostatic tests, hot functional qualification tests, periodic ISIs and operability tests have been and are performed to verify and assure the functional ability of the valves. These tests assure reliability of the valves for the design life of the plant.

On all active valves, an analysis of the extended structure was performed for static equivalent seismic loads applied at the center of gravity (CG) of the extended structure. The minimum stress limits allowed in these analyses will assure that no significant permanent damage occurs in the extended structures during the earthquake.

Motor operators and other electrical appurtenances necessary for operation were qualified.

The natural frequencies of all active valves were determined by test or by analysis. If the natural frequencies of the valves were shown to be less than 33 Hz, one of the following options was employed:

(1) The valve was qualified by dynamic testing.

(2) The valve was modified to increase the minimum frequency to greater than 33 Hz.

(3) The valve was qualified conservatively using static accelerations that are sufficiently in excess of accelerations it might experience in the plant to take into account any effect due to both multifrequency excitation and multi-mode response (a factor of 1.5 times peak acceleration is generally accepted, although lower coefficients can be used when shown to yield conservative results).

(4) A dynamic analysis of the valve was performed to determine the equivalent acceleration to be applied during the static analysis. The analysis provided the amplification of the input acceleration considering the natural frequency of the valve and the frequency content of the applicable plant floor response spectra. The adjusted accelerations were then used in the static analysis and the valve operability was assured by the methods outlined above, using the modified acceleration input.

Swing check valves are characteristically simple in design and their operation is not affected by seismic accelerations or applied nozzle loads. The check valve design is compact and there are no extended structures or masses whose motion could cause distortions which could restrict operation of the valve. The nozzle loads due to seismic excitation do not affect the functional ability of the valve since the valve disc is typically designed to be isolated from the casing wall. The clearance available around the disc prevents the disc from becoming bound or restricted due to any casing distortions caused by nozzle loads. Therefore, the design of these valves is such that once the structural integrity of the valve is assured using standard design or analysis methods, the ability of the valve to operate is assured by the design features. For the faulted condition evaluations, since piping stresses are shown to be acceptable, the check valves are qualified.

The valves have undergone the following tests: (a) in-shop hydrostatic test, (b) in-shop seat leakage test, and (c) periodic in-plant exercising and inspection to assure functional ability.

By the above methods, all active valves are qualified for operability for the faulted condition seismic loads. These methods simulate the seismic event and assure that the active valves will perform their PG&E Design Class I functions when necessary.

5.2.2.1.8 Inadvertent Operation of Valves

The inactive valves within the RCPB listed in Table 5.2-9 are not relied upon to function after an accident. They meet redundancy requirements and will not increase the severity of any of the transients discussed in Section 5.2.2.1.5, if operated inadvertently during any such transient.

5.2.2.1.9 Stress and Pressure Limits

System hydraulic and thermal design parameters are the basis for the analysis of equipment, coolant piping, and equipment support structures for normal and upset loading conditions. The analysis uses a static model to predict deformation and stresses in the system. The analysis gives six components, three moments, and three forces. These moments and forces are resolved into pipe stresses in accordance with applicable codes. Stresses in the structural supports are determined by the material and section properties based on linear elastic small deformation theory.

In addition to the loads imposed on the system under normal and upset conditions, the design of mechanical equipment and equipment supports requires that consideration also be given to faulted loading conditions such as those experienced during seismic and pipe rupture events.

Analysis of the RCLs and support systems for seismic loads is based on a three dimensional, multi-mass elastic dynamic model. The floor response spectra are used as input to the detailed dynamic model, which includes the effects of the supports and the supported equipment. The loads developed from the dynamic model are incorporated into a detailed support model to determine the support member stresses.

The dynamic analysis employs the displacement method, lumped parameter, stiffness matrix formulations, and assumptions that all components behave in a linearly elastic manner. Seismic analyses are covered in detail in Section 3.7.

5.2.2.1.10 Stress Analysis for Structural Adequacy

Methods and models used to determine the structural adequacy of components under the normal and upset conditions are described herewith.

5.2.2.1.10.1 Analysis Method for Reactor Coolant System

Loading combinations and allowable stresses for RCS components are provided in Tables 5.2-5through 5.2-7.

The load combinations considered in the design of structural steel members of component supports are summarized in Tables 5.2-8 and 5.2-8a. The RCS design is described in Section 5.5. The following paragraphs define the loads applied in the analysis:

(1) Deadweight

The deadweight loading imposed by the RCL piping and primary equipment components on the supports consists of the dry weight of the coolant piping and weight of the water contained in the piping during normal operation. In addition, the total weight of the primary equipment components, including water, forms a deadweight loading on the individual component supports.

The deadweight loading imposed on the RCL piping consists of the dry weight of the coolant piping and weight of the water contained in the piping, SG, and the RCP during normal operation. The weight of the water in the SG and the RCP is applied as an external force in the deadweight analysis to account for equipment nozzle displacement as an external movement. The deadweight loading imposed on the RCL piping does not include the dry weight of the primary equipment since the components are set onto the primary equipment supports prior to the welding of the RCL piping.

(2) Thermal Expansion

The free vertical thermal growth of the reactor vessel nozzle centerlines is considered to be an external anchor movement transmitted to the RCL. The primary equipment supports are designed to allow the RCL piping and primary equipment components to expand thermally up to the normal operating temperature conditions. The thermal expansion analyses of the RCL piping include the thermal expansion effects of the RCL piping and primary equipment.

(3) Earthquake Loads (DE, DDE and Hosgri)

The earthquake (DE, DDE and Hosgri) acceleration, which produces transient vibration of the equipment mounted within the containment building, is specified in terms of the floor response spectrum curves at various elevations within the containment building.

These floor response spectrum curves for earthquake motions are described in detail in Section 3.7.

(4) Pressure

The steady state hydraulic forces based on the system's initial pressure are applied as internal loads to the RCL model for determination of the RCL support system deflections and support forces.

(5) LOCA

The RCL piping was analyzed for dynamic effects of pipe rupture events. Since the dynamic effects of pipe rupture events in the main RCL piping no longer have to be considered in the design basis analyses (refer to Section 3.6.2.1.1.1), pipe rupture loads for the analysis are defined for RCL branch line breaks. The pipe rupture load analysis considered double-ended circumferential breaks in the RHR, SI (accumulator line), and pressurizer surge line connections to the RCL piping. These are the bounding RCL branch line breaks.

(6) Other Pipe Rupture Loads

The analysis also considered the effects of main steamline and feedline breaks on the RCL piping and the RCS equipment supports.

5.2.2.1.10.2 Analytical Models

The static and dynamic structural analyses assume linear elastic behavior and employ the displacement (stiffness) matrix method and the normal mode theory for lumped-parameter, multimass structural representation to formulate the solution.

(1) Reactor Coolant Loop Model

The RCL model is constructed for the WESTDYN (Reference 18) computer program. This is a special purpose program designed for the static and dynamic analysis of redundant piping systems with arbitrary loads and boundary conditions.

The RCL and support model used for static and LOCA analysis is a one-loop model that describes the spatial geometry, lumped-mass locations, and the node points as shown in Figure 5.2-2. Stiffness characteristics of the equipment support structures are incorporated as linear elastic restraints in the RCL model. The WESTDYN program computes internal member forces, support structure reactions, nodal point deflections, and stresses and also determines system natural frequencies.

The RCL seismic model for DE, DDE and Hosgri is a four-loop model that describes the spatial geometry, lumped-mass locations, and other node points as shown in Figure 5.2-2A. Stiffness characteristics of the equipment support structures are incorporated as linear elastic restraints in the RCL model. Two lumped masses represent the vessel shell. One is located at the vessel flange and the other is located at the lower radial restraints. Four lumped masses represent the core barrel and internals. One mass is located at each of the upper and lower core plates and another mass is located at the middle of the core plates. The fourth mass is lumped at the lower radial restraints. Fuel assemblies are also represented by three lumped masses. Each is located at a quarter point along the length of the assembly. The SG is represented by a three-mass, lumped model. The lower mass position is located at the intersection of the inlet and outlet nozzles of the SG. The middle mass position is located at the SG upper support elevation. The upper mass position is located at the top of the SG.

In the seismic DE, DDE and Hosgri analyses, the RCP is represented by a five-mass lumped model. For the RCP five-mass, lumped model, the lowest mass position is located at the intersection of the pump suction and discharge nozzles. The remaining four lumped-masses were used to represent the various components of the reactor coolant pump, such as the main flange, rotor, stator, motor stand, and flywheel.

(2) Support Structure Models

The equipment support structure models have dual purposes since they are required:

(a) To quantitatively represent, in terms of 6 x 6 or 3 x 3 stiffness matrices, or stiffness values, the elastic restraints which the supports impose upon the loop

(b) To evaluate the individual support member stresses due to the forces imposed upon the support by the loop.

The loadings on the component supports are obtained from the analysis of an integrated RCL support system's dynamic structural model, as shown in Figures 5.2-2 and 5.2-2A.

Figures 5.2-2 and 5.2-2A show the RCL model and component supports included in the RCL piping analysis. The analysis considered the pipe rupture restraints on the main RCL piping to be inactive. The pipe rupture restraints on the main RCL piping were made inactive by either removing shims or by removing the support.

The primary equipment supports were evaluated using ANSYS, GTSTRUDL and WESPLAT finite element analysis computer programs.

(3) Hydraulic Models

The hydraulic model is constructed to quantitatively represent the behavior of the coolant fluid within the RCLs in terms of the concentrated time-dependent loads imposed upon the loops.

In the original analysis, in evaluating the hydraulic forcing functions during a LOCA, the pressure and the momentum flux terms are dominant. Inertia and gravitational terms were neglected although they were taken into account when evaluating the local fluid conditions.

Thrust forces resulting from a LOCA were calculated in a two-step process. First, the MULTIFLEX 3.0 (Reference 6) code calculated transient pressure, flowrates, and other coolant properties as a function of time. Second, the THRUST (Reference 18) code used the results obtained from MULTIFLEX 3.0 and calculated time-history of forces at locations where there is a change in either direction or area of flow within the RCL. These locations for the broken loop are shown in Figure 5.2-3.

For the RCL piping analysis, thrust forces and blowdown loads were determined for RCS branch line, main steamline, and feedline breaks identified in Section 5.2.2.1.10.1.

5.2.2.1.10.3 Analysis and Solutions

(1) Static Load Solutions

The static solutions for deadweight, thermal expansion, and pressure load conditions are obtained by using the WESTDYN computer program.

(2) Normal Mode Response Spectral Seismic Load Solution

The stiffness matrices representing various supports for dynamic behavior are incorporated into the RCL model. The response spectra for the DE, DDE and HE are applied along the horizontal and vertical axes simultaneously. From the input data, the overall stiffness matrix of the three-dimensional RCL is generated and the natural frequencies and normal modes are obtained by the modified Jacobi method.

The forces, moments, deflections, rotations, support structure reactions and stresses are then calculated for each significant mode. The total

seismic response is computed by combining the contributions of the significant modes by the SRSS method.

5.2.2.1.10.4 Reactor Coolant Loop Stress Analysis Results

The stress for the normal and upset conditions shows that the stresses in the piping are below the code-allowable values.

(1) Normal Conditions

Stresses due to primary loading of pressure and deadweight are combined and compared with the stress value for the applicable material property. Refer to Section 5.2.2.1.3. for the applicable code edition. The thermal expansion stress is a secondary stress. The magnitude of the thermal stress is compared with the B31.1 Piping Code allowable expansion stress limit.

The stress evaluation for the normal condition shows that the stresses in all RCL members are within the allowable stress values.

(2) Upset Conditions

The DE stresses are added to the stresses due to primary loadings of pressure and deadweight. The stress evaluation for the upset condition shows that stresses in all RCL members are within the allowable stress values.

5.2.2.1.10.5 Component Supports Stress Analysis Results

(1) Normal Conditions

Thermal, weight, and pressure forces (obtained from the RCL analysis) acting on the support structures are combined algebraically.

(2) Upset Conditions

DE support forces are added algebraically to normal condition forces. The interaction and stress equations are compared to the allowable limits specified by AISC-1969, which includes a 1/3 allowable stress increase for seismic.

The stress evaluation for the normal and upset conditions shows that the stresses in all members are within the allowable values.

5.2.2.1.11 Analysis Method for Faulted Condition

The analysis of the RCLs and support systems for blowdown loads resulting from a LOCA is based on the time-history response of simultaneously applied blowdown forcing functions on a dynamic model of the RCL and support system. The forcing functions are defined at points in the system loop where changes in cross-section or direction of flow occur such that differential loads are generated during the blowdown transient. Stresses and loads are checked and compared to the corresponding allowable stress.

The stresses the RCL piping, components, and component supports resulting from normal sustained loads and the worst case blowdown analysis (LOCA or other pipe breaks) are combined with the results of seismic faulted condition analyses, using absolute sum or SRSS methodology to determine the maximum stress for the combined loading case. Combining LOCA or other pipe break and seismic loads is considered very conservative since it is highly improbable that both maxima will occur at the same instant. These stresses are combined to ensure that the main reactor coolant piping loops and connected primary equipment support system will not lose their intended functions under this highly improbable situation.

Combining seismic faulted condition and LOCA dynamic loads using SRSS methodology is subject to the conditions and limitations of NUREG-0484, May 1980, Methodology for Combining Dynamic Responses:

- The SRSS technique is acceptable contingent upon performance of a linear, elastic, dynamic analysis to meet the appropriate ASME BPVC Section III, Service Limit for faulted load condition.

For components not designed to ASME Section III, a code reconciliation to ASME BPVC Section III is required to apply the above.

For faulted conditions, the limits are provided in Tables 5.2-5 and 5.2-7.

Further details of the stress analysis for faulted conditions are presented in Sections 5.2.2.1.14 and 5.2.2.1.15.

Protection criteria against dynamic effects associated with pipe breaks are covered in Section 3.6. For the RCL analysis, thrust forces and blowdown loads were determined for RCS branch line breaks identified in Section 5.2.2.1.10.1.

5.2.2.1.12 Protection Against Environmental Factors

Protection provided for the RCS against environmental factors is discussed in Sections 3.3, 3.4, 3.5 and 3.6. Fire protection is discussed in Section 9.5.1.

5.2.2.1.13 Compliance with Code Requirements

In the PG&E classification of DCPP fluid systems and fluid system components, the vessels, piping, valves, pumps and their supports of the RCS pressure boundary are designated PG&E Design Class I, PG&E Quality/Code Class I. The comparison of DCPP system Design/Quality/Code classifications to non-licensing basis regulations and codes is discussed in Section 3.2 and delineated in Table 3.2-4.

For conservative fatigue evaluations of the reactor vessel, SG, RCP, and pressurizer in accordance with the ASME BPVC per Table 5.2-2, maximum stress intensity ranges are derived from combining the normal and upset condition transients discussed in Section 5.2.2.1.5. The stress ranges and number of occurrences are then used in conjunction with the fatigue curves in the ASME BPVC per Table 5.2-2 to get the associated cumulative usage factors.

The criterion presented in the ASME BPVC per Table 5.2-2 is used for fatigue analysis. The cumulative usage factor is less than 1, hence, the fatigue design is adequate.

The reactor vessel stress reports include a summary of the critical stress locations analyzed in the vessel, a discussion of the results including a comparison with the corresponding code limits, descriptions of the methods of analysis and computer programs used, a presentation of some of the actual hand calculations performed, and a tabulation of the references cited in the report. The content of the stress report is in accordance with the requirements of the ASME BPVC per Table 5.2-2.

For the RVCH, the content of the stress report is in accordance with the requirements of the ASME BPVC per Table 5.2-2.

5.2.2.1.14 Stress Analysis for Faulted Condition Loadings (Double Design Earthquake, Hosgri, Loss-of-Coolant Accident and Pipe Rupture)

Stress analyses of the RCS for faulted conditions employ the displacement (stiffness) matrix method and lumped-parameter, multimass representation of the system. The analyses are based on adequate and accurate representation of the system using an idealized, mathematical model. This section discusses the RCL and support structures analysis. Refer to Section 5.2.2.1.15 for component analysis.

5.2.2.1.14.1 Analysis Method

(1) Reactor Coolant Loop

The procedure for evaluation of the piping stresses due to combined loadings of weight, pressure, DDE or Hosgri, LOCA, and other pipe breaks is as follows:

(a) The LOCA and other pipe break stress analysis yields the time-history of stresses at various crosssections in the RCL piping.

(b) The DDE and Hosgri analysis of the RCL piping was performed using the response spectra method. The RCL seismic model was constructed for the WESTDYN computer program.

(c) Containment internal concrete structure horizontal response spectra at elevations corresponding to the SG upper supports, SG lower supports, RCP supports, and the reactor vessel supports were used in the analysis. For the Hosgri seismic analysis, a vertical response spectra envelope from 114 foot elevation to the base slab 87 foot elevation was used in the analysis. For the DDE seismic analysis, the vertical response spectrum is two-thirds of the ground horizontal response spectrum.

(d) For each mode, the results due to the vertical shock were combined by direct addition with the results of the horizontal shock directions. The modal contributions were then added by the SRSS method.

(e) For the Hosgri seismic analyses, eight horizontal shock directions were performed and the eight directions were made up of four pairs of perpendicular shock directions. The shock directions correspond to the following: 1) parallel with the north-south axis, 2) parallel with the east-west axis, 3) 22 degrees counterclockwise off the north-south axis, 4) 22 degrees counterclockwise off the east-west axis, 5) 22 degrees clockwise off the north-south axis, 6) 22 degrees clockwise off the east-west axis, 7) 45 degrees clockwise off the north-south axis, and 8) 45 degrees clockwise off the east-west axis.

(f) For the DDE seismic analyses, eight horizontal shock directions were performed and the eight directions were made up of four pairs of perpendicular shock directions. The shock directions correspond to the following: 1) parallel with the north-south axis, 2) parallel with the east-west axis, 3) 22 degrees counterclockwise off the north-south axis, 4) 22 degrees counterclockwise off the east-west axis, 5) 22 degrees clockwise off the north-south axis, 6) 22 degrees clockwise off the east-west axis, and 7) 45 degrees clockwise off the north-south axis, and 8) 45 degrees clockwise off the east-west axis.

(g) The results of the analysis are as follows: The results of the seismic evaluation were combined with the pressure and

deadweight stresses. The revised RCL piping stresses were all under the allowable stress limits in Table 5.2-5.

(h) Since the DDE results are obtained by the response spectra method, the six components of a state vector for deflection at a point or for internal member force cannot be assigned absolute and/or relative algebraic signs. Consequently, the maximum values of the DDE axial and shear stresses at a pipe cross-section are calculated from the internal force state vector at that cross-section by considering all possible permutations of signs of the six components of the state vector. The DDE axial and shear stresses are combined with the time-history of LOCA, or other pipe breaks, axial and shear stresses.

(i) Dynamic LOCA loads resulting from pipe rupture events in the RCL branch lines were considered in the design basis stress analyses and were included in the loading combinations. Dynamic pipe break loads at the main steamline and feedline were also considered in the design basis stress analyses and were included in the loading combinations.

(j) The stresses in the RCL piping are calculated using the equations specified in the B31.1 Code. The code equation piping stresses are compared to the applicable material code allowable stress limits to demonstrate conformance to the B31.1 Code requirements.

(k) The previous steps are performed for various cross-sections in the RCL piping. It should be emphasized that, for a given location of the pipe cross-section, the stress intensity calculation is performed with either the maximum stress for all given time steps, or for every step computed from the time-history analysis.

(l) Maximum resultant deadweight, DDE or Hosgri, and LOCA or other pipe break moments were determined at locations located along the RCL piping, elbows, and connections to equipment. At each location, the maximum resultant moment for DDE or Hosgri is the largest resultant moment from the various shock cases that were performed for the seismic analysis. The largest resultant moment for LOCA or other pipe break is the largest moment from the pipe rupture analyses for RCL branch line breaks (LOCA) and other pipe breaks (main steamline or feedline breaks).

(m) As explained in Section 5.2.2.1.3, B31.1 Code pipe stress equations were used with the resultant moments to determine deadweight, DDE or Hosgri, and LOCA or other pipe break pipe

stresses at locations along the RCL corresponding to the maximum resultant moment locations. At each location, the stresses were combined by absolute sum and were added to the pressure stress to determine the maximum stress at that location. This maximum stress was then verified to be within the stress limit provided in Table 5.2-5. It should be emphasized that the above analysis method is very conservative since the peak DDE or Hosgri, and LOCA or other pipe break pipe stresses are considered to occur at the exact same instant in time and that the resultant moments for each load type are considered to be aligned such that the maximum pipe stress occurs at the same location around the pipe circumference for each load type.

(2) Evaluation of Support Structures

The support loads are computed by multiplying the support stiffness values by the displacement values at the support point. The support loads are used for support member evaluation.

For the support qualification, the following inputs were entered into a GTSTRUDL or ANSYS finite element analysis computer program:

(a) Loads acting on the supports obtained from the RCL analysis (including time-history LOCA forces)
(b) Support seismic self-weight excitation loads.
(c) Attached platform loads.
(d) Attached pipe support loads.
(e) Asymmetric compartment pressurization loads.
(f) Jet impingement loads.
(g) Support structure member properties.
(h) Support Geometry.
(i) Material properties and code parameters.

The resulting member and component stresses were compared to the acceptance criteria allowable stresses as specified in Table 5.2-8.

RCS component supports were shown adequate by evaluating the supports for the loads determined in the integrated RCLs seismic analysis.

Stress analyses for structural qualification of the primary equipment supports were performed using the load combinations described in Table 5.2-8. ANSYS, GTSTRUDL and WESPLAT finite element analysis computer programs were used to perform the analysis. The independent loadings included deadweight (DW), thermal expansion (TH), system pressure (P), design earthquake (DE), double design earthquake (DDE), Hosgri earthquake (HE), loss-of-coolant accident (LOCA), other pipe ruptures (OPR), jet impingement (JI) and asymmetric compartment pressurization loads.

Input loads applied to the primary equipment supports were taken from the results of an integrated reactor coolant loop/support model. Loads from pipe supports and platforms attached to the primary equipment supports were also applied. For seismic self-weight excitation (SWE) of the support structure, the containment internal building structure seismic data (peak accelerations, zero period accelerations (ZPAs) and response spectra) for the DE, DDE and HE earthquakes were applied. The use of ZPAs in lieu of peak accelerations was supported by modal analysis to show that supports behave as rigid structures.

ANSYS and GTSTRUDL finite element analysis computer programs were also used to obtain support stiffness values for the equipment supports.

In summary, stresses in all RCS component support members are within the acceptance criteria limits specified in Table 5.2-8 for the DE, DDE and Hosgri seismic events combined as specified in Table 5.2-8.

(3) Integrated Head Assembly (IHA)

The ANSYS general purpose finite element program was used to perform structural analysis of the IHA. The IHA was evaluated for stresses due to combined loadings of weight (dead load), pressure, thermal, maintenance, missile impact, seismic (DDE or Hosgri) and LOCA. The seismic loading associated with the DDE and Hosgri was developed as described in Section 3.7.3.15.4. LOCA loads were applied where the IHA is attached to the reactor head. Seismic, LOCA, and other loads were combined as shown in Table 5.2-8a. The resulting loads and stresses for the various components of the IHA were evaluated using the requirements of ASME Section III, Division I, 2001 Edition through 2003 Addenda, Subsection NF and Appendix F as shown in Table 5.2-8a.

5.2.2.1.14.2 Time-history Dynamic Solution for Loss-of-Coolant Accident Loading

The initial displacement configuration of the mass points is defined by applying the initial steady state hydraulic forces to the RCL model. These initial displacement conditions, natural frequencies, normal modes, the time-history hydraulic forcing functions and reactor vessel nozzle displacements are used by the WESTDYN program to calculate the time-history dynamic response for the RCL model. The time-history response is used to determine pipe moments, support forces, and pipe deflections.

5.2.2.1.14.3 Analysis Results

All support system elements were evaluated to verify that the supported equipment and piping remain within their respective faulted condition stress limits. Stresses in the support system elements for faulted conditions are below the limits provided in Table 5.2-8. Stresses in the RCL piping for faulted conditions are below code-allowable

values. Stresses in the PG&E Design Class I members and connections of the IHA for the specified load conditions meet the acceptance criteria provided in Table 5.2-8a.

5.2.2.1.15 Component Stress Analysis for Faulted Condition Loadings (Double Design Earthquake, Hosgri, Loss-of-Coolant Accident and Pipe Rupture)

5.2.2.1.15.1 Integrated Reactor Coolant Loop Analysis

Stress analysis for faulted condition loadings (DDE, Hosgri, LOCA, and other pipe breaks) is discussed in Section 5.2.2.1.14.1 for the RCL.

5.2.2.1.15.2 Steam Generator Evaluation

The SGs are designed and analyzed in accordance with the ASME Boiler and Pressure Vessel Code of the 1998 Edition through the 2000 Addenda of the ASME Code, Section III. The SG primary side is classified as ASME Code Class 1 (PG&E Quality/Code Class I); the SG secondary side is classified as ASME Code Class 2 (PG&E Quality/Code Class II). The evaluation of the LOCA and seismic (Faulted) conditions are based on meeting the acceptance criteria of ASME III, Appendix F. The design load combinations are identified in Table 5.2-6 and the stress criteria are identified in Table 5.2-7.

Loss-of-coolant primary pipe break hydraulic forcing functions time history were obtained from the LOCA hydraulic forces analysis for the SG. Seismic response spectra, pipe rupture loadings, and pipe nozzle loadings were obtained from applicable design specifications and the RCL analysis for the SG. The Design Limits for Level D (Faulted) Conditions were obtained from Subsection NB and Appendix F, respectively, of the ASME Code. Service Limits were also obtained from the ASME Code.

A finite element based model of the DCPP SGs is used for the dynamic analysis. The model consists of a system of pipe and beam elements, lumped mass elements, and general matrix elements (with both mass and stiffness options). The primary piping stiffness, secondary piping stiffness, external supports stiffness, and some internals stiffness are represented using general matrix elements. The SG dynamic model is coded for use with the ANSYS computer program. ANSYS is a general purpose finite element program with a wide variety of capabilities and an extensive library of finite elements.

A seismic faulted analysis has been performed to predict the response of the SG and its internals to DDE and HE loadings. A linear response spectrum dynamic analysis is used to predict the seismic response of the SG. The seismic analysis of the SGs has been performed using the plant response spectra and external support and piping stiffness for the DCPP Unit 1 and Unit 2 site configuration.

5.2.2.1.15.3 Reactor Coolant Pump Evaluation

The RCPs are designed and analyzed in accordance with the ASME Boiler and Pressure Vessel Code Section III per Table 5.2-2. The evaluation of the LOCA and seismic (Faulted) conditions are based on meeting the stress limits in Table 5.2-7. The design load combinations are identified in Table 5.2-6.

The seismic analyses of the RCP were performed using dynamic modal methods with a finite element computer program. The seismic response spectra corresponding to the elevation of the RCP support structure were used.

The RCP and motor were modeled as a system of nodes and elements (pipes, beams, mass with rotary inertia, springs, fluid elements and stiffness matrices). A modal analysis was performed to determine mode frequencies, mode shapes, and mode participation factors of the pump and motor. The seismic response spectra analyses were performed using the EMDAC_FEA finite element computer program. Seismic response spectra loadings and pipe rupture loadings were determined and the RCP evaluated for the faulted conditions.

The LOCA analysis was performed by a nonlinear transient dynamic method using the EMDAC_FEA computer program. Time histories of the external forces and moments acting on the RCP and the severed cross-over leg were applied to the finite element model of the RCP.

The nozzles and support feet of the RCP were analyzed by static stress analysis methods with externally applied design loads.

5.2.2.1.15.4 Reactor Vessel Evaluation

The reactor vessel is designed and analyzed in accordance with the ASME BPVC 1965 (Unit 1) through Winter 1966 Addenda and 1968 (Unit 2) Editions of the ASME BPVC Section III. The reactor vessel is classified as ASME Code Class A. The evaluation of the LOCA and seismic (Faulted) conditions are based on meeting the stress limits in Table 5.2-7. The design load combinations are identified in Table 5.2-6.

Loss-of-coolant primary pipe break hydraulic forcing functions were obtained from the LOCA hydraulic forces analysis for the reactor vessel. Seismic response spectra, pipe rupture loadings, and pipe nozzle loadings were determined and evaluated for the faulted condition.

A seismic faulted analysis has been performed to predict the response of the reactor vessel and its internals to DDE and HE loadings. A linear response spectrum dynamic analysis is used to predict the seismic response of the reactor vessel. The seismic analysis of the reactor vessel has been performed using the plant response spectra and external support and piping stiffness for the DCPP Unit 1 and Unit 2 site configuration.

Several portions of the reactor vessel were evaluated using static stress analysis methods with externally applied design loads. The CRDM and core exit thermocouple head adapter, closure head flange, vessel flange, closure studs, inlet nozzle, outlet nozzle, vessel support, vessel wall transition, core barrel support pads, bottom head shell juncture and bottom head instrumentation penetrations were analyzed by this method. The design loads for all areas evaluated are based on the actual plant loads. All stresses and fatigue usage factors were found to be acceptable.

5.2.2.1.15.5 Reactor Vessel Internals Evaluation

The reactor vessel internals evaluation is presented in Sections 3.7.3.15 and 3.9.2.3.

5.2.2.1.15.6 Fuel Assembly Evaluation

The fuel assembly evaluation is presented in Sections 3.7.3.15 and 3.9.2.

5.2.2.1.15.7 Control Rod Drive Mechanism

The SYSTUS finite element computer code was used to perform structural analysis of the replacement CRDM pressure housings. The CRDM pressure housings were evaluated for stresses due to combined loadings of deadweight, pressure, thermal, seismic, LOCA, and other pipe ruptures as shown in Table 5.2-6a. The seismic loadings were developed as described in Section 3.7.3.15.3. The combined stresses were determined at each critical location along the length of the CRDM assembly including locations along the rod travel housing, latch housing, and CRDM penetration into the RVCH. The resulting loads and stresses for the CRDM pressure housings were evaluated using the requirements of ASME Section III, Division I, 2001 Edition through 2003 Addenda, Subsection NB and Appendix F as shown in Table 5.2-6a. The results demonstrated the ASME code limits are met for the CRDM pressure housings.

5.2.2.1.15.8 Primary Equipment Support Evaluation

The evaluation of primary equipment supports is presented in Section 5.2.2.1.14.1(2).

5.2.2.1.15.9 Pressurizer Evaluation

The pressurizer is designed and analyzed in accordance with the ASME Boiler and Pressure Vessel Code of the 1965 Edition through Summer 1966 Addenda of the ASME Code, Section III. The evaluation of the LOCA and seismic (Faulted) conditions are based on meeting the stress limits in Table 5.2-7. The design load combinations are identified in Table 5.2-6.

A dynamic modal analysis was performed to evaluate the response of the pressurizer and its internals to DDE and Hosgri loadings. The seismic dynamic analysis modeled the heater rods, pressurizer vessel, and vessel support with beam elements and lumped

mass elements. Seismic response spectra, pipe rupture loadings, and pipe nozzle loadings were determined and the pressurizer evaluated for the faulted conditions. Refer to Section 3.7.1.4 for the applicable DDE and Hosgri percent of critical damping values.

The Hosgri response spectra for 4 percent damping at the 140 feet elevation has a peak of 5.1 g horizontally, well below the value used to qualify the pressurizer.

A dynamic RCL analysis, which included a surge line model and was performed with the DDE and Hosgri response spectra, produced loads (forces and moments) on the support skirt, surge nozzle, and upper seismic lugs which were evaluated and shown to be acceptable.

5.2.2.1.15.10 Reactor Vessel Closure Head

The RVCH was designed and analyzed in accordance with the ASME Boiler and Pressure Vessel Code Section III, Division I, 2001 Edition through 2003 Addenda, Subsection NB and Appendix F. The RVCH is classified as ASME Code Class 1.

A finite element model of the reactor vessel closure region was used to perform the dynamic analysis of the RVCH. To adequately analyze the effects of the important structural items, a 46.67 degree circumferential segment of the reactor vessel closure region was modeled. The ANSYS general purpose finite element program was used to perform the dynamic analysis of the RVCH model. The RVCH model was evaluated for stresses due to combined loadings of dead weight, pressure, thermal, seismic (DE, DDE or Hosgri), LOCA, and other pipe ruptures as shown in Table 5.2-6a. The seismic and LOCA loadings were developed as described in Section 3.9.2.1.3. The resulting loads and stresses for the RVCH were evaluated using the requirements of ASME Section III, Division I, 2001 Edition through 2003 Addenda, Subsection NB and Appendix F as shown in Table 5.2-6a. The results demonstrated the ASME code limits are met for the replacement RVCH.

5.2.2.1.15.11 Core Exit Thermocouple Nozzle Assembly

The ANSYS finite element computer code was used to perform structural analyses of the core exit thermocouple nozzle assembly (CETNA) pressure boundary components. The CETNA pressure-retaining components were evaluated for stresses due to combined loadings of deadweight, pressure, thermal, seismic, and LOCA, as shown in Table 5.2-6a.

The seismic and LOCA loadings were developed using the response spectrum modal superposition method described in Section 3.7.3.15.3. Horizontal and vertical response spectra at the RVCH CG elevation were input to the model. The two orthogonal horizontal direction response spectra were combined using the SRSS method. Horizontal and vertical seismic responses were combined using SRSS method. Seismic (DDE and HE) and LOCA stresses were combined using the SRSS method. Response

spectra critical damping values were analyzed according to welded steel structures in Regulatory Guide 1.61, October 1973.

The combined stresses were determined at each critical location and were evaluated using the requirements of ASME BPVC Section III, Division I, 1989 Edition, Subsection NB. A code reconciliation is performed for the requirements of ASME BPVC Section III, Division I, 2001 Edition through 2003 Addenda. The results demonstrated that the ASME code limits are met for the CETNA pressure-retaining components.

5.2.2.1.16 Stress Levels in Reactor Coolant Pressure Boundary Components

Sections 5.2.2.1.10.4, 5.2.2.1.14 and 5.2.2.1.15 discuss RCS PG&E Quality/Code Class I components and the resulting stress levels under normal, upset and faulted conditions.

5.2.2.1.17 Analytical Methods for Stresses in Pumps and Valves

The design and analysis to ensure structural integrity and operability of the RCPs and valves used the load combinations and stress limits as defined in Table 5.2-5 for stress limits for Class A loop piping and valves, and Tables 5.2-6 and 5.2-7 for the RCPs. As a result, the design and analyses of these components are based on the requirements of various codes and procedures that were in effect when the equipment was purchased.

These codes and procedures have been widely used by the nuclear industry and were, to a large extent, incorporated or referenced in ASME BPVC Section III-1971 (refer to Section 3.9.2). Every valve and pump is hydrostatically tested to the applicable ASME BPVC requirements, as listed in Table 5.2-2, ensures the integrity of the pressure boundary parts.

5.2.2.1.18 Analytical Methods for Evaluation of Pump Speed and Bearing Integrity

RCP overspeed evaluation is covered in Section 5.5.1.

5.2.2.1.19 Operation of Active Valves Under Transient Loadings

Operation of active valves under transient loadings is discussed in Sections 3.9.2 and 3.10. Refer to Table 5.2-9 for a listing of active and inactive valves within the RCPB.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

During plant startup testing, the preoperational piping dynamics effects test program described in Section 3.9.1 will note and correct excessive piping deflections and vibrations. Since all valves are supported as part of adjoining piping, this testing and any required corrective action, will ensure that the deflections by the pipe (and valve) supports will not impair the operability of active PG&E Design Class I valves, including those in the RCS pressure boundary.

5.2.2.2 Overpressurization Protection

The pressurizer is designed to accommodate pressure increases (as well as decreases) caused by load transients. The spray system condenses steam to prevent the pressurizer pressure from reaching the setpoint of the PORVs during a step reduction in power level of 10 percent of load. Flashing of water to steam and generation of steam by automatic actuation of the heaters keeps the pressure above the low-pressure reactor trip setpoint.

The spray nozzles are located on the top of the pressurizer. Spray is initiated when the pressure controlled spray demand signal is above a given setpoint. The spray flow increases proportionally with increasing pressure and pressure error until it reaches a maximum value.

Overpressure protection is discussed in the Sections 5.2.2.2.1 through 5.2.2.2.3. Protection against overpressurization during low temperature operation is provided by the LTOP system, which is described in Section 5.2.3.28.

5.2.2.2.1 Location of Pressure-Relief Devices

The pressurizer is equipped with three PORVs that limit system pressure for a large power mismatch and thus prevent actuation of the fixed high-pressure reactor trip. The relief valves are operated automatically or by remote-manual control. The operation of these valves also limits the undesirable opening of the spring-loaded safety valves. Remotely operated block valves are provided to isolate the PORVs if excessive leakage occurs. The relief valves are designed to limit the pressurizer pressure to a value below the high-pressure trip setpoint for all design transients, up to and including, the design percentage step load decrease with steam dump but without reactor trip.

Isolated output signals from the pressurizer pressure protection channels are used for pressure control. These are used to control pressurizer spray and heaters, and PORVs.

In the event of a complete loss of heat sink, protection of the RCS against overpressure (Reference 1) is afforded by pressurizer and SG safety valves along with any of the following reactor trip functions:

(1) Reactor trip on turbine trip

(2) Pressurizer high-pressure reactor trip

(3) Overtemperature ΔT reactor trip

(4) SG low-low water level reactor trip

A detailed functional description of the process equipment associated with the high-pressure trip is provided in Reference 2.

The overpressure protection upper limit is based on the positive surge of the reactor coolant produced as a result of turbine trip under full load, assuming the core continues to produce full power and normal feedwater is maintained. The self-actuated safety valves are sized on the basis of steam flow from the pressurizer to accommodate this surge at a setpoint of 2500 psia and a total accumulation of 3 percent. Each of the safety valves is rated to carry 420,000 lb/hr, which is greater than one-third of the total rated capacity of the system. Note that no credit is taken for the relief capability provided by the PORVs during this surge.

The RCS design and operating pressures, together with the safety, power-relief, and pressurizer spray valve setpoints, and the protection system setpoint pressures are listed in Table 5.2-10. A schematic representation of the RCS showing the location of pressure-relieving devices is shown in Figure 3.2-7.

System components whose design pressure and temperature are less than the RCS design limits are provided with overpressure protection devices and redundant isolation means. System discharge from overpressure protection devices is collected in the PRT in the RCS. Isolation valves are provided at all connections to the RCS. Figures 3.2-8 through 3.2-10 show those systems that communicate directly with the RCS, and all pressure-relieving devices to prevent reactor coolant pressure from causing overpressure in auxiliary emergency systems in the event of leakage into those systems.

All pressurizer relief piping was manufactured, installed, and tested in accordance with ANSI B31.7-1969 with 1970 Addenda. The piping from the pressurizer to the relief valves is designed to ANSI B31.1-1967. The valve discharge piping to the PRT is designed to ANSI B31.7-1967 with 1970 Addenda - Class III piping. Refer to Section 3.9.2.1.7 for piping analysis.

5.2.2.2.2 Mounting of Pressure-Relief Devices

The pressurizer safety and relief valve piping system has undergone extensive analysis considering combined loads due to internal pressure, pipe and valve deadweight, thermal growth of the pressurizer, seismic accelerations due to earthquakes, and hydraulic hammer forces due to operation of the valve and the volume of water in the water seal at the inlet to the valve.

A vertical loop in the pipe between the pressurizer and the safety valve is provided to allow for differential thermal growth between the safety valves and the pressurizer. Previously, the loop provided a water seal against the valve seat to prevent gas and steam leakage through the valve from damaging the seat. The safety valves have been modified from a water-seated to a steam-seated design and water in the loop is continuously drained. The hydraulic hammer analysis was a dynamic time-history type

of analysis taking into account the water seal volume, the valve opening time, the location and number of bends in the downstream piping, and the lengths of each piece of straight pipe on the discharge of the valves. Analyses consider combinations of all three valves open or shut to determine the most highly stressed condition. The analyses have not been revised to reflect the absence of the water seal volume, resulting in a conservative design since the loads are less severe without the water seal volume.

5.2.2.2.3 Report on Overpressurization Protection

The design bases for overpressurization protection of the RCS are discussed in Section 5.5.9. Additional information is also provided in Section 5.2.3.28.

5.2.2.3 General Material Considerations

This section discusses the materials used in the RCS.

5.2.2.3.1 Material Specifications

The reactor vessels for Unit 1 and Unit 2 were fabricated to the 1965 Edition through Winter 1966 Addenda for Unit 1 and the 1968 Edition for Unit 2, of the ASME BPVC, Section III.

Materials of construction for the RVCHs meet the requirements of the ASME BPVC, Section III, 2001 Edition with Addenda through 2003.

Materials of construction for the SGs meet the requirements of the 1998 Edition of the ASME BPVC, Section III, with addenda through the 2000 Addenda. SG pressure boundary ferritic material is procured with reference temperature at nil ductility transition (RT_{NDT}) of 0°F.

Materials of construction for the pressurizers for Unit 1 and Unit 2 meet the requirements of the 1965 Edition of the ASME BPVC, Section III, and addenda through the 1966 Addenda. Charpy tests in the major working or rolling direction were performed at 10°F to ensure that the required toughness levels were obtained. The fracture toughness of these materials is considered sufficient to ensure a margin of safe operation.

Pipe is seamless forged stainless steel conforming to ASTM A376, Type 316 with weld repair limited to 3 percent of nominal wall thickness. Fittings in the main RCLs for both Unit 1 and Unit 2 are cast stainless steel conforming to ASTM A351, Gr. CF8M. The 90-degree elbows are cast in sections and joined by electroslag welds. The cobalt content is limited to 0.20 percent.

The minimum wall thickness of the pipe and fittings is not less than that calculated using ASA B31.1, Section 1, formula of paragraph 122 with an appropriate allowable stress value provided in Nuclear ASA Code Cases N-7 (for piping) and N-10 (for fittings).

The pressurizer surge line pipe conforms to ASTM A-376, Type 316, with supplementary requirements S2 (transverse tension tests) and S6 (ultrasonic test). The S2 requirements apply to each length of pipe. The S6 requirements apply to 100 percent of the piping wall volume. The pipe wall thickness for the pressurizer surge line is Schedule 140 for Unit 1 and Schedule 160 for Unit 2. There are two elbow fittings in the pressurizer surge line for both Unit 1 and Unit 2. The Unit 1 and Unit 2 surge line 14-inch elbows are wrought stainless steel conforming to ASTM A-403, WP316. The Unit 1 and Unit 2 surge line socket weld half coupling fittings are forged stainless steel conforming to ASTM A-182, F316.

Branch nozzles conform to SA-182, Grade F316. Thermal sleeves for Unit 1 and Unit 2 conform to SA-312 or SA-240, Type 316 or 304. The sample scoop conforms to SA-182, Type 304 or 316. The pressurizer spray scoop conforms to SA-403, Grade WP 304 or 316.

Stainless steel pipe conforms to ANSI B36.19 for sizes 1/2 through 12 inches and wall thickness schedules 40S through 80S. Stainless steel pipe outside of the scope of ANSI B36.19 conforms to ANSI B36.10, exclusive of the RCL piping of special sizes 27-1/2, 29, and 31 inches I.D. Flanges conform to ANSI B16.5. Socket weld fittings and socket joints conform to ANSI B16.11.

Radiographic or ultrasonic examination was performed throughout 100 percent of the wall volume of each pipe and fitting. Acceptance standards for ultrasonic testing are in accordance with ASME BPVC Section III, except that the defect standard for acceptance is a Charpy-V notch not exceeding 1 inch in length and 3 percent of wall thickness in depth. Acceptance standards for radiographic examination are in accordance with ASTM E-186 Severity Level 2, except that defect Categories D and E are not acceptable.

A liquid penetrant examination was performed on both the entire outside and inside surfaces of each finished hot, cold, and crossover loop fitting and pipe in accordance with the procedure of ASME BPVC Section VIII, Appendix VIII, and the acceptance standards of ASA B31.1, Code Cases N-9 or N-10.

All unacceptable defects were eliminated in accordance with the requirements of ASME BPVC Section III. All butt welds and nozzle welds are of a full penetration design; welds 2 inches and smaller are socket-welded joints. The mechanical properties of representative material heats in the final heat treat condition were no less than 1.20 times the allowable stress tabulated in ASA Code Case N-7 corresponding to 650°F.

Type 308 weld filler material was used for all welding applications to avoid microfissuring. As an option, Type 308L weld filler metal analysis was substituted for consumable inserts when this technique was used for the weld root closure. All welding was performed in accordance with the ASME BPVC Section IX. In all welding, except for the RVCH cladding operations, the interpass temperature was limited to 350°F maximum. The methodology used for the RVCH cladding was qualified using the guidance in Regulatory Guide 1.43, May 1973.

5.2.2.3.2 Compatibility with Reactor Coolant

The materials of construction of the RCPB were specified to minimize corrosion and erosion. To avoid the possibility of accelerated erosion, the internal coolant velocity is limited to about 50 fps.

The reactor vessel is constructed of carbon steel with a 0.125 inch minimum of stainless steel or Inconel cladding on all internal surfaces that are in contact with the reactor coolant. The pressurizer is also constructed of carbon steel with austenitic stainless steel or Inconel (Unit 2 only) cladding on all surfaces exposed to the reactor coolant. All parts of the RCP in contact with the reactor coolant are austenitic stainless steel except for seals, bearings, and secondary seals (O-rings made of elastomer material).

The portions of the SG in contact with the reactor coolant water are clad with austenitic stainless steel. The SG tubesheet is weld clad with Inconel and the heat transfer tubes are made of Inconel. Tables 5.2-11 through 5.2-14 summarize the materials of construction of these RCS components.

The reactor coolant piping and fittings that make up the loops are austenitic stainless steel. All smaller piping that comprises part of the RCS boundary, such as the pressurizer surge line, spray and relief line, loop drains, and connecting lines to other systems, is also made of austenitic stainless steel. All valves in the RCS that are in contact with the coolant are constructed primarily of stainless steel. Other materials in contact with the coolant, such as materials for hard surfacing and packing, are special materials.

5.2.2.3.3 Compatibility with External Insulation and Environmental Atmosphere

The materials of construction of the RCPB were specified to ensure compatibility with the containment-operating environment. All insulation used on the RCPB, as defined by the ASME BPVC Section XI, is of the reflective stainless steel type or as described in Section 6.3.3.35. Additional information on the compatibility of RCPB materials with the containment environment to which they are exposed is provided in Section 3.11.

5.2.2.3.4 Chemistry of Reactor Coolant

The RCS water chemistry is selected to minimize corrosion. A periodic analysis of the coolant chemical composition is performed to verify that the reactor coolant quality meets the specifications for coolant chemistry, activity level, and boron concentration.

The CVCS provides a means for adding chemicals to the RCS that control the pH of the coolant during initial startup and subsequent operation, scavenge oxygen from the coolant during startup, and control the oxygen level of the coolant due to radiolysis during all power operations subsequent to startup. To ensure thorough mixing, at least one RCP or RHR pump is always in service when chemicals are being added to the system or when changing the boron concentration.

The chemical used for pH control is lithium hydroxide. This chemical is chosen for its compatibility with the materials and water chemistry of the borated water/stainless steel/zirconium/Inconel system. In addition, lithium is present in solution from the neutron irradiation of dissolved boron in the coolant. The lithium hydroxide is introduced into the RCS via the charging flow. The solution is prepared in the plant and poured into the chemical mixing tank. Reactor makeup water is then used to flush the solution to the suction manifold of the charging pumps.

The concentration of lithium hydroxide in the RCS is maintained in the range specified for pH control. If the concentration exceeds this range, a demineralizer is valved in to remove the excess lithium. Since the amount of lithium to be removed is small and its buildup can be readily calculated and determined by analysis, the flow through the cation bed demineralizer is not required to be full letdown flow.

During reactor startup from the cold condition, hydrazine is employed as an oxygen scavenging agent. The hydrazine solution is introduced into the RCS using the same injection flow path as the pH control agent, as described above.

Dissolved hydrogen is employed to control and scavenge oxygen produced due to radiolysis of water in the core region. Sufficient partial pressure of hydrogen is maintained in the VCT such that the specified equilibrium concentration of hydrogen is maintained in the reactor coolant. A self-contained pressure control valve maintains a minimum pressure in the vapor space of the VCT. This can be adjusted to provide the correct equilibrium hydrogen concentration. The RCS water chemistry specifications are provided in Table 5.2-15.

5.2.2.4 Fracture Toughness

This section addresses fracture toughness in the RCPB. The RCS component upon which operating limitations are based is the reactor vessel.

5.2.2.4.1 Compliance with Code Requirements

Assurance of adequate fracture toughness of the RPV is established using methods to estimate the RT_{NDT} (Reference 5). The fracture toughness properties of the reactor vessel wall material surrounding the irradiated core region are the limiting properties. The stringent fracture toughness requirements were determined based on the ASME BPVC Section III-1971 Edition, and the 1972 Summer Addenda. The estimated RT_{NDT} uses as a guide the fracture toughness requirements of NB2300 of the Summer 1972 Addenda, which meet the intent of 10 CFR Part 50, Appendix G. For materials not in the beltline region, RT_{NDT} was estimated using methods identified in Section 5.3.2 of the NRC Standard Review Plan. The upper-shelf energy level of the material is established using methods (Reference 5), which are responsive to 10 CFR Part 50, Appendix G.

The DCPP Unit 1 and Unit 2 reactor vessels were fabricated to the 1965 Edition through the Winter 1966 Addenda for Unit 1, and the 1968 Edition for Unit 2, of the ASME BPVC Section III. Thus, Charpy impact test orientation was parallel to the working or rolling direction of the base materials. Additional impact tests were performed, however, on the intermediate and lower shell course plates of both vessels. These plates surround the effective height of the fuel assemblies. Full Charpy test curves were obtained on these plates from specimens oriented normal to the principal rolling direction. Full Charpy curves for all the base material in the vessels have been obtained by the fabricator on impact specimens oriented parallel to the principal working or rolling direction. Reactor vessel fracture toughness data are provided in Tables 5.2-17A and 5.2-18A, and Tables 5.2-17B and 5.2-18B for Unit 1 and Unit 2, respectively.

The RVCH was manufactured to the requirements of the ASME BPVC Section III, 2001 Edition with Addenda through 2003. Fracture toughness data is provided in Table 5.2-17B.

Reactor vessel beltline region weld test specimens were taken from weldments prepared from excess production plate, weld wire, and flux materials. After completion of welding, the weldments were subjected to heat treatment to obtain the metallurgical effects equivalent to those produced during fabrication of the reactor vessel. The significant properties (e.g., weld wire chemical composition and weld flux type) of the weld materials in the beltline region were representative of the actual beltline materials and their fracture toughness. The use of test specimens prepared from excess production plate, weld wire, and flux materials and subjected to heat treatment satisfies the intent of the specific requirement of 10 CFR Part 50, Appendix G, Section III.C.2 and ensures an adequate margin of safety.

Two hundred forty bolting material specimens were impact tested at 10°F. The average of all the impact energy values was 50.5 ft-lb. The lateral expansion was measured on 24 specimens, and an average value of 35 mils was recorded. Fracture energy values obtained on 90 percent of the 240 specimens tested at 10°F either met or exceeded the fracture toughness requirements of 10 CFR Part 50, Appendix G. The lowest value of 40 ft-lb. exceeded the special mechanical property requirements of paragraph N-330 of

the 1965 Edition of the ASME BPVC, which states that an average of 35 ft-lb. fracture energy is considered adequate for pressure vessel materials to be pressurized at ambient temperature (70°F).

5.2.2.4.2 Acceptable Fracture Energy Levels

The identification and location of reactor vessel beltline region materials for Unit 1 and Unit 2 are shown in Figures 5.2-1 and 5.2-4, respectively. Chemical composition, fracture toughness properties, estimates of maximum anticipated ΔRT_{NDT}, and upper-shelf energy at the end-of-license fluence at the vessel wall 1/4 thickness location for materials in the beltline region are provided in Tables 5.2-18A through 5.2-21B for Unit 1 and Unit 2.

The stresses due to gamma heating in the vessel walls were also calculated and combined with the other design stresses. They were compared with the code-allowable limit for mechanical plus thermal stress intensities to verify that they are acceptable. The gamma stresses are low and thus have a negligible effect on the stress intensity in the vessel.

5.2.2.4.3 Operating Limitations During Startup and Shutdown

Allowable pressures as a function of the rate of temperature change and the actual temperature relative to the reactor vessel RT_{NDT} are established according to the methods in the 1972 NDT Summer Addenda of the ASME BPVC Section III, Appendix G. Heatup and cooldown curves are provided in the DCPP Pressure Temperature Limits Report. The heatup and cooldown curves are based on the estimated RT_{NDT} fracture toughness properties of the reactor vessel materials. Toughness data for the reactor vessel base materials are provided in Tables 5.2-17A and 5.2-17B for Unit 1 and Unit 2, respectively.

Predicted reference temperature at pressurized thermal shock (RT_{PTS}) values and upper shelf energy (USE) are derived in the limiting materials by using the method described in Reference 27, 10 CFR 50.61, 10 CFR Part 50, Appendix G, and the maximum fluence for the applicable service period.

For a Unit 1 operating period of 54 effective full-power years (EFPY), which supports up to a 60-year end of operating license (EOL) on 11/2/2044, the limiting RT_{PTS} values calculated and their respective 10 CFR 50.61 screening limits are:

- RT_{PTS} (weld 3-442C) = 245.5 °F, which is <270 °F plate or axial weld limit
- RT_{PTS} (weld 9-442) = 216.3 °F, which is <300 °F circumferential weld limit

For a Unit 2 operating period of approximately 54 EFPY, which supports up to a 60-year EOL on 08/26/2045, the limiting RT_{PTS} values calculated and their respective 10 CFR 50.61 screening limits are:

- RT_{PTS} (plate B5454-2) = 224.6 °F, which is <270 °F plate or axial weld limit
- RT_{PTS} (weld 8-201) = 54.4 °F, which is <300 °F circumferential weld limit

10 CFR Part 50, Appendix G requires that the USE remain ≥ 50 foot pounds (ft-lbs) throughout the life of the vessel at 1/4T. For Unit 1, the limiting (minimum) 1/4T USE at EOL is 58.2 ft-lbs. This is predicted to occur for axial weld 3-442C. Similarly, for Unit 2, the limiting (minimum) 1/4T USE at EOL is 51.9 ft-lbs. This is predicted to occur for axial weld 3-201C.

5.2.2.4.4 Compliance with Reactor Vessel Material Surveillance Program Requirements

The toughness properties of the reactor vessel beltline material will be monitored throughout the service life with a material surveillance program that meets the requirements of 10 CFR Part 50, Appendix H. The original surveillance test program (Reference 11) for DCPP Unit 1 complies with ASTM E 185-70, the standard in effect when the vessel was manufactured. With three exceptions, the program also complies with ASTM E 185-73. The exceptions are the number of capsules in the program containing the limiting material, the number of Charpy specimens in each capsule, and the orientation of the base metal specimens.

A supplemental surveillance program was implemented at the Unit 1 fifth refueling outage to improve the existing program by bringing the overall surveillance program in better compliance with ASTM E 185-82, provide data for the period beyond which the original surveillance program was designed, and to provide the necessary data to demonstrate the effectiveness of reactor vessel thermal annealing. Capsule D from Unit 1, which was meant to be annealed and reinserted into the reactor vessel, was removed during 1R12 and is stored in the spent fuel pool. There are currently no industry plans to anneal reactor vessels. The Unit 1 supplemental surveillance program is described in References 28 and 29. For Unit 2, the specimen orientation, number, selection procedure, and removal schedule conform to ASTM E 185-73. The surveillance capsule program for Unit 2 is described in Reference 26.

5.2.2.4.4.1 Program Description

The evaluation of radiation damage is based on pre-irradiation testing of Charpy V-notch and tensile specimens, and post-irradiation testing of Charpy V-notch, and tensile specimens; plus wedge opening loading (WOL) fracture mechanics test specimens for Unit 1 and compact tension and bend bar fracture mechanics test specimens for Unit 2. These programs are based on transition temperature and fracture mechanics approaches, and conform with ASTM E-185, Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels and 10 CFR Part 50, Appendix H. Thermal control specimens are not required since the surveillance specimens will be exposed to the combined neutron irradiation and temperature effects, and the test results will provide the maximum transition temperature shift. The surveillance program for Unit 2 does not include correlation monitors, but the program for Unit 1 does.

Neutron dosimeters included in the capsules can be used to measure exposure throughout the life of the reactor vessel.

5.2.2.4.4.2 Surveillance Capsules

The Unit 1 original reactor vessel surveillance program included eight specimen capsules and the supplemental surveillance program consists of four additional specimen capsules. The Unit 2 surveillance program consists of six specimen capsules. The Type II capsules in Unit 1 and all of the Unit 2 capsules utilize fissionable materials (uranium-238 and neptunium-237) as neutron dosimeters. The fissionable materials, in the form of U_30_8 and $Np0_2$ powder, are encapsulated in metal (brass or stainless steel) capsules, which are sealed in steel blocks. The capsules are located in guide baskets welded to the outside of the thermal shield and neutron shield pads for Unit 1 and Unit 2, respectively, and are positioned directly opposite the center portion of the core. Sketches showing the location and spacing of the capsules for Unit 1 relative to the core, thermal shield, vessel, and weld seams are shown in Figures 5.2-16 and 5.2-17. Sketches showing the location and spacings of the capsules for Unit 2 are shown in Figures 5.2-18 and 5.2-19. The capsules can be removed when the vessel head and upper internals are removed and can be replaced when the lower internals are removed.

The eight capsules in the Unit 1 original surveillance program contain reactor vessel steel specimens from the intermediate shell plate or plates located in the core region of the reactor. The three Type II capsules also contain weld metal and heat affected zone specimens. All of the base material specimens are oriented parallel to the principal rolling direction. In addition, correlation monitors made from fully documented specimens of SA-533, Grade B, Class 1 material obtained through Subcommittee II of ASTM Committee E10, Radioisotopes and Radiation Effects, are inserted in the capsules of Unit 1 only. The eight capsules contain 27 tensile specimens, 256 Charpy V-notch specimens (which include weld metal and heat affected zone material), and 42 WOL specimens.

The four supplemental surveillance capsules for Unit 1 contain Charpy impact and tensile specimens machined from intermediate shell plate 4107-1, and oriented such that the specimen longitudinal axis is normal (transverse) to the plate principal rolling direction. Shell plate 4107 is the limiting base metal at 48 EFPY. These four capsules also contain surrogate weld metal specimens obtained from ABB Combustion Engineering. These surrogate weld specimens were made with the same weld wire heat (27204) and flux type (Linde 1092) as the Unit 1 reactor vessel limiting weld metal, and are representative of the Unit 1 limiting weld. The four capsules will also contain various Charpy specimens supplied by Electric Power Research Institute (EPRI) which will be used to obtain data on the effects of a reactor vessel thermal anneal. Two of the capsules will also contain previously irradiated test material from surveillance capsule S. This material consists of heat-affected zone and limiting weld metal broken Charpy specimens (which can be reconstituted into testable specimens), and weld metal WOL specimens. The 4 capsules contain 266 Charpy specimens, 24 tensile specimens, 17

reconstitution blanks from surveillance capsule S tested Charpy specimens, and 2 WOL specimens.

The six capsules for Unit 2 contain reactor vessel steel specimens oriented both parallel and normal (longitudinal and transverse) to the principal rolling direction of the limiting shell plate located in the core region of the reactor and associated weld metal and heat affected zone metal. The six capsules contain 54 tensile specimens, 360 Charpy V-notch specimens (which include weld metal and heat affected zone material), 72 compact tension specimens, and six bend bar specimens.

Dosimeters including Ni, Co, Fe (Unit 2 only), Co-Al, Cd shielded Co-Al, Cd shielded Np-237, and Cd shielded U-238 are placed in filler blocks drilled to contain the dosimeters. The dosimeters permit evaluation of the flux seen by the specimens and the vessel walls. In addition, thermal monitors made of low melting alloys are included to monitor the temperature of the specimens. The specimens are enclosed in a tight fitting stainless steel sheath to prevent corrosion and ensure good thermal conductivity. The complete capsule is helium leak tested. Vessel base material sufficient for at least two capsules will be kept in storage should the need arise for additional replacement test capsules in the program. Sufficient weld metal and heat affected zone material from Unit 2 for two additional capsules will also be stored. No additional weld metal or heat affected zone material is available for Unit 1.

As part of the surveillance program, a report of the residual elements in weight percent to the nearest 0.01 percent will be made for surveillance material and as deposited weld metal. Each of five Type I (base metal only) capsules (T, U, W, X and Z) for Unit 1 contains the following specimens:

Material	No. of Charpys	No. of Tensiles	No. of WOL
Plate No. B4106-1	8	1	2
Plate No. B4106-2	8	1	2
Plate No. B4106-3	8	1	2
ASTM Reference	8	-	-

The following dosimeters and thermal monitors are included in each of the five capsules:

Dosimeters

Copper
Nickel
Cobalt-aluminum (0.15% Co.)
Cobalt-aluminum (cadmium shielded)
U-238 (cadmium shielded)
Np-237 (cadmium shielded)

Thermal Monitors

97.5% Pb, 2.5% Ag (579°F melting point)
97.5% Pb, 1.75% Ag, 0.75% Sn (590°F melting point)

The four supplemental capsules for Unit 1 contain the following specimens, dosimeters, and thermal monitors:

	CAPSULE A(Note i)		CAPSULE B(Note i)			CAPSULE C(Note i)		CAPSULE D(Note ii)	
	Charpy	Tension	Charpy	Tension	WOL	Charpy	Tension	Charpy	Tension
Weld Metal (Surrogate 27204)	15	3	15	3	—	30	3	15	3
Base Metal (Plate 4107-1)	15	3	15	3	—	15	3	15	3
Correlation Monitor (HSST-02 Plate)	12	—	8	—	—	—	—	—	—
Capsule S Weld Metal (Original 27204)	—	—	9 (Note iii)	—	2	—	—	8 (Note iii)	—
EPRI Specimens	—	—	30	—	—	35	—	46	—

Notes:

(i) Dosimeter wires: copper, iron, nickel and aluminum-0.15% cobalt (cadmium shielded and unshielded)
Fission dosimeters: neptunium-237 (cadmium oxide shielded), and uranium 238 (cadmium oxide shielded)
Thermal monitors: 97.5% Pb, 2.5% Ag (579°F melt point), 97.5% Pb, 1.75% Ag, 0.75% Sn (590°F melt point)

(ii) Capsule D will contain the following dosimeters:
Dosimeter wires: copper, iron, nickel and aluminum-0.15% cobalt (gadolinium shielded and unshielded)
Fission dosimeters: neptunium-237 (gadolinium shielded) and uranium 238 (gadolinium shielded)
Thermal monitors: will not be provided because annealing temperature will exceed the melting point of thermal monitors

(iii) Broken weld metal and heat-affected zone Charpy specimens from capsule S, suitable for reconstitution

Each of the six capsules for Unit 2 will contain the following specimens:

Material	No. of Charpys	No. of Tensiles	No. of Cts	No. of Bend Bars
Plate B5454-1[a]	15	3	4	
Plate B5454-1[b]	15	3	4	1
Weld Metal[c]	15	3	4	
Heat Affected Zone Metal (Plate B5454-1)	15			

(a) Specimens oriented parallel to the principal rolling direction (longitudinal).
(b) Specimens oriented normal to the principal rolling direction (transverse).
(c) Weld fabricated from weld wire heat numbers 21935 and 12008 using Linde 1092 Flux Lot No. 3869.

The following dosimeters and thermal monitors are included in each of the six capsules:

Dosimeters
Iron
Copper
Nickel
Cobalt-aluminum (0.15% Co)
Cobalt-aluminum (cadmium shielded)
U-238 (cadmium shielded)
NP-237 (cadmium shielded)

Thermal Monitors
97.5% Pb, 2.5% Ag (579°F melting point)
97.5% Pb, 1.75% Ag, 0.75% Sn (590°F melting point)

The fast neutron exposure of the specimens occurs at a faster rate than that experienced by the vessel wall with the specimens being located between the core and the vessel. Since these specimens experience accelerated exposure and are actual samples from the materials used in the vessel, the changes in material properties are representative of the vessel at a later time in life. Data from the fracture toughness specimens (WOL, compact tension, and bend bar) are expected to provide additional information for use in determining fracture toughness for irradiated material.

The reactor vessel surveillance capsules for Unit 1 are shown in Figure 5.2-16 and in Figure 5.2-18 for Unit 2.

Correlation between calculations and measurements on the irradiated samples in the capsules, assuming the same neutron spectrum at the samples and the vessel inner wall, is described in Section 5.2.2.4.4.5 and has indicated good agreement. The degree to which the specimens perturb the fast neutron flux and energy distribution is considered in the evaluation of the surveillance specimen data. The integrated flux calculations at the vessel wall are adjusted using the surveillance data to provide best estimate fluence values. For an initial 40-year operating period, the calculated maximum EOL fast neutron exposure at the vessel wall is 1.43×10^{19} n/cm^2 and 1.68×10^{19} n/cm^2 (E > 1 MeV) for Unit 1 and Unit 2, respectively. For an analyzed 60-year operating period, the calculated maximum EOL fast neutron exposure at the vessel wall is 2.15×10^{19} n/cm^2 and 2.45×10^{19} n/cm^2 (E > 1 MeV) for Unit 1 and Unit 2, respectively.

5.2.2.4.4.3 Capsule Removal

For Unit 1 and Unit 2, the removal schedule conforms to 10 CFR Part 50, Appendix H. The schedule for removal of the Unit 1 and Unit 2 capsules is provided in Table 5.2-22.

5.2.2.4.4.4 Measurement of Integrated Fast Neutron (E > 1.0 MeV) Flux at the Irradiation Samples

The use of passive neutron sensors such as those included in the internal surveillance capsule dosimetry sets does not yield a direct measure of the energy-dependent neutron flux level at the measurement location. Rather, the activation or fission process is a measure of the integrated effect that the time-and energy-dependent neutron flux has on the target material over the course of the irradiation period. An accurate assessment of the average flux level and, hence, time integrated exposure (fluence) experienced by the sensors may be developed from the measurements only if the sensor characteristics and the parameters of the irradiation are well known.

In particular, the following variables are of interest:

(1) the measured specific activity of each sensor

(2) the physical characteristics of each sensor

(3) the operating history of the reactor

(4) the energy response of each sensor

(5) the neutron energy spectrum at the sensor location

In this section, the procedures used to determine sensor-specific activities, to develop reaction rates for individual sensors from the measured specific activities and the operating history of the reactor, and to derive key fast neutron exposure parameters from the measured reaction rates are described.

5.2.2.4.4.4.1 Determination of Sensor Reaction Rates

The specific activity of each of the radiometric sensors is determined using established ASTM procedures. Following sample preparation and weighing, the specific activity of each sensor is determined by means of a lithium-drifted germanium, Ge(Li), gamma spectrometer. In the case of the surveillance capsule multiple foil sensor sets, these analyses are performed by direct counting of each of the individual wires or, as in the case of U-238 and Np-237 fission monitors, by direct counting preceded by dissolution and chemical separation of cesium from the sensor.

The irradiation history of the reactor over its operating lifetime is obtained from NUREG-0020, "Licensed Operating Reactors Status Summary Report," or from other plant records. In particular, operating data are extracted on a monthly basis from reactor startup to the end of the capsule irradiation period. For the sensor sets utilized in the surveillance capsule irradiations, the half-lives of the product isotopes are long enough that a monthly histogram describing reactor operation has proven to be an adequate representation for use in radioactive decay corrections for the reactions of interest in the exposure evaluations.

Having the measured specific activities, the operating history of the reactor, and the physical characteristics of the sensors, reaction rates referenced to full power operation are determined from the following equation:

$$R = \frac{A}{N_o \, F \, Y \sum_j \frac{P_j}{P_{ref}} C_j \left[1 - e^{-\lambda t_j} \right] e^{-\lambda t_d}} \qquad (5.2\text{-}1)$$

where:

- A = measured specific activity (dps/gm)
- R = reaction rate averaged over the irradiation period and referenced to operation at a core power level of P_{ref} (rps/nucleus)
- N_o = number of target element atoms per gram of sensor
- F = weight fraction of the target isotope in the sensor material
- Y = number of product atoms produced per reaction
- P_j = average core power level during irradiation period j (MW)
- P_{ref} = maximum or reference core power level of the reactor (MW)
- C_j = calculated ratio of ϕ (E > 1.0 MeV) during irradiation period j to the time weighted averaged ϕ (E > 1.0 MeV) over the entire irradiation period
- λ = decay constant of the product isotope (sec^{-1})
- t_j = length of irradiation period j (sec)
- t_d = decay time following irradiation period j (sec)

and the summation is carried out over the total number of monthly intervals comprising the total irradiation period.

In the above equation, the ratio P_j/P_{ref} accounts for month-by-month variation of power level within a given fuel cycle. The ratio C_j is calculated for each fuel cycle and accounts for the change in sensor reaction rates caused by variations in flux level due to changes in core power spatial distributions from fuel cycle to fuel cycle. For a single cycle irradiation C_j = 1.0. However, for multiple cycle irradiations, particularly those employing low leakage fuel management, the additional C_j correction must be utilized.

5.2.2.4.4.4.2 Corrections to Reaction Rate Data

Prior to using the measured reaction rates in the least squares adjustment procedure discussed in Section 5.2.2.4.4.4.3, additional corrections are made to the U-238 measurements to account for the presence of U-235 impurities in the sensors as well as to adjust for the build-in of plutonium isotopes over the course of the irradiation.

In addition to the corrections made for the presence of U-235 in the U-238 fission sensors, corrections are also made to both the U-238 and Np-237 sensor reaction rates to account for gamma ray induced fission reactions occurring over the course of the irradiation.

5.2.2.4.4.4.3 Least Squares Adjustment Procedure

Values of key fast neutron exposure parameters are derived from the measured reaction rates using the FERRET least squares adjustment code (Reference 12). The FERRET approach uses the measured reaction rate data, sensor reaction cross-sections, and a calculated trial spectrum as input and proceeds to adjust the group fluxes from the trial spectrum to produce a best fit (in a least squares sense) to the measured reaction rate data. The "measured" exposure parameters along with the associated uncertainties are then obtained from the adjusted spectrum.

In the FERRET evaluations, a log-normal least squares algorithm weights both the trial values and the measured data in accordance with the assigned uncertainties and correlations. In general, the measured values f are linearly related to the flux ϕ by some response matrix A:

$$f_i^{(s,\alpha)} = \sum_g A_{ig}^{(s)} \phi_g^{(\alpha)} \qquad (5.2\text{-}2)$$

where i indexes the measured values belonging to a single data set s, g designates the energy group, and α delineates spectra that may be simultaneously adjusted. For example,

$$R_i = \sum_s \sigma_{ig} \phi_g \qquad (5.2\text{-}3)$$

relates a set of measured reaction rates R_i to a single spectrum ϕ_g by the multigroup reaction cross-section σ_{ig}. The log-normal approach automatically accounts for the physical constraint of positive fluxes, even with large assigned uncertainties.

In the least squares adjustment, the continuous quantities (i.e., neutron spectra and cross-sections) are approximated in a multigroup format consisting of 53 energy groups. The trial input spectrum is converted to the FERRET 53 group structure using the SAND-II code (Reference 13). This procedure is carried out by first expanding the 47 group calculated spectrum into the SAND-II 620 group structure using a SPLINE

interpolation procedure in regions where group boundaries do not coincide. The 620-point spectrum is then re-collapsed into the group structure used in FERRET.

The sensor set reaction cross-sections, obtained from the ENDF/B-VI dosimetry file (Reference 14), are also collapsed into the 53 energy group structure using the SAND-II code. In this instance, the trial spectrum, as expanded to 620 groups, is employed as a weighting function in the cross-section collapsing procedure. Reaction cross-section uncertainties in the form of a 53 x 53 covariance matrix for each sensor reaction are also constructed from the information contained on the ENDF/B-VI data files. These matrices include energy group-to-energy group uncertainty correlations for each of the individual reactions.

Due to the importance of providing a trial spectrum that exhibits a relative energy distribution close to the actual spectrum at the sensor set locations, the neutron spectrum input to the FERRET evaluation is obtained from plant-specific calculations for each dosimetry location. While the 53 x 53 group covariance matrices applicable to the sensor reaction cross-sections are developed from the cross-section data files, the covariance matrix for the input trial spectrum is constructed from the following relation:

$$M_{gg'} = R_n^2 + R_g R_{g'} P_{gg'} \qquad (5.2\text{-}4)$$

where R_n specifies an overall fractional normalization uncertainty (i.e., complete correlation) for the set of values. The fractional uncertainties, R_g, specify additional random uncertainties for group g that are correlated with a correlation matrix given by:

$$P_{gg'} = [1-\theta]\ \delta_{gg'} + \theta\, e^{-H} \qquad (5.2\text{-}5)$$

where:

$$H = \frac{(g-g')^2}{2\gamma^2}$$

The first term in the correlation matrix equation specifies purely random uncertainties, while the second term describes short-range correlations over a group range γ (θ specifies the strength of the latter term). The value of δ is 1 when g = g' and 0 otherwise.

5.2.2.4.4.5 Calculation of Integrated Fast Neutron (E > 1.0 MeV) Flux at the Irradiation Samples

Discrete ordinates transport calculations are performed on a plant- and fuel-cycle-specific basis to determine the neutron and gamma ray environment within the reactor. The specific methods applied are consistent with those described in WCAP-18124-NP-A and WCAP-18124-NP-A Revision 0 Supplement 1 (References 44 and 45, respectively). The methodology described in References 44 and 45 is generically

approved for calculating exposures to the RPV beltline and extended beltline materials. The plant-specific forward transport calculations are used to directly solve for the space- and energy-dependent scalar flux.

The transport calculations are carried out using the BUGLE-96 cross-section library (Reference 16), which provides a coupled 47-neutron-, 20-gamma-ray-group cross-section data set produced specifically for light water reactor applications. Plant-specific energy- and space-dependent core power distributions and operating temperatures are treated on a fuel-cycle-specific basis. The plant-specific, cycle-specific core power distributions are processed to produce spatial- and energy-dependent source distributions for use in the discrete ordinates transport calculations. The transport calculations treat anisotropic scattering with a P_3 Legendre expansion and model the angular discretization with an S_{16} order of angular quadrature.

5.2.2.4.4.5.1 DELETED

5.2.2.4.4.5.2 DELETED

5.2.2.4.5 Reactor Vessel Annealing

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

There are no special design features that would prohibit the onsite annealing of the vessel. In the event that an annealing operation should be required to restore the properties of the vessel material opposite the reactor core because of neutron irradiation damage, a metal temperature of approximately 850°F maximum for a period of 168 hours maximum would be applied.

A plan for conducting the thermal annealing must be submitted in accordance with 10 CFR 50.4 at least three years prior to the date at which the limiting fracture toughness criteria in 10 CFR 50.61 or 10 CFR Part 50, Appendix G would be exceeded.

5.2.2.4.6 Loss-of-Coolant Accident Thermal Transient

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

In the event of a large LOCA, the RCS rapidly depressurizes and the loss of coolant may empty the reactor vessel. If the reactor is at normal operating conditions before the accident, the reactor vessel temperature is approximately 550°F, and, if the plant has been in operation for some time, part of the reactor vessel is irradiated. At an early stage in the depressurization transient, the ECCS rapidly injects cold coolant into the reactor vessel. This produces a thermal stress in the vessel wall. To evaluate the effect of the stress, three possible modes of failure are considered; ductile yielding, brittle fracture, and fatigue.

(1) Ductile Mode

The failure criterion used for this evaluation is that there shall be no gross yielding across the vessel wall using the material yield stress specified in the ASME BPVC Section III. The combined pressure and thermal stresses during injection through the vessel thickness as a function of time have been compared to the material yield stress during the SI transient.

The results of the analyses showed that local yielding may occur only in approximately the inner 18 percent of the base metal and in the vessel cladding, complying with the above criterion.

(2) Brittle Mode

The possibility of brittle fracture of the irradiated reactor vessel core region has been considered utilizing fracture mechanics concepts. This analysis takes into account the effects of water temperature, heat transfer coefficients, and fracture toughness as a function of time, temperature, and irradiation. Both a local crack effect and a continuous crack effect have been considered, with the latter requiring the use of a rigorous finite element axisymmetric code. On the weight of this evidence, the thermal shock resulting from the LOCA will not produce instability in the vessel wall even at the end of plant life.

(3) Fatigue Mode

The failure criterion used for fatigue analysis was based on the ASME BPVC Section III. In this method the piece is assumed to fail once the combined usage factor at the most critical location for all transients applied to the vessel exceeds the code-allowable usage factor of 1.

The location in the vessel below the nozzle level, which will see the emergency core cooling water and have the highest usage factor will be the incore instrumentation tube attachment welds to the vessel bottom head. As a worst case assumption, the incore instrumentation tubes and attachment penetration welds are considered to be quenched to the cooling water temperature while the vessel wall maintains its initial temperature before the start of the transient.

The maximum possible pressure stress during the transient is also taken into account. This method of analysis is quite conservative and yields calculated stresses greater than would actually be experienced. The resulting usage factor for the instrument tube welds considering all operating transients and including the SI transient occurring at the end of the plant life is below 0.2, which compares favorably with the code-allowable usage factor of 1.

It is concluded from the results of these analyses that the delivery of cold emergency core cooling water to the reactor vessel following a LOCA does not cause any loss of integrity of the vessel.

5.2.2.5 Austenitic Stainless Steel

The unstabilized austenitic stainless steel materials used in the RCPB, in systems required for reactor shutdown, and for emergency core cooling, are processed and fabricated using established methods and techniques to avoid partial or local sensitization. The measures taken to avoid sensitization are in general conformance with the recommendations of Regulatory Guide 1.44, May 1973 (Reference 22).

5.2.2.5.1 Cleaning and Contamination Protection Procedures

All materials are cleansed and protected by procedures that guard against contaminants capable of causing stress corrosion cracking during storage, fabrication, shipment, erection, testing and operation. Contaminant concentration limits are implemented per plant approved procedures.

5.2.2.5.2 Solution Heat Treatment Requirements

Whenever applicable, solution heat treatment of materials prior to fabrication or assembly into components or systems is discussed in Section 5.2.2.5.5 below. In such cases, solution heat treatment conformed to the requirements of Regulatory Guide 1.44, May 1973.

5.2.2.5.3 Material Inspection Program

Austenitic stainless steel materials are procured from raw material produced in the final heat-treated condition as required by the respective ASTM or ASME material specification for the particular type or grade of alloy.

Westinghouse-furnished wrought austenitic stainless steel alloy materials are corrosion tested in the final heat-treated condition. These tests are performed in accordance with ASTM A262.

5.2.2.5.4 Unstabilized Austenitic Stainless Steel

Unstabilized austenitic stainless steel used in components of the RCPB are as follows:

(1) Reactor Vessel

(a) (Unit 1) Primary nozzle safe-ends - Type 316 stainless steel forgings.

(Unit 2) Primary nozzle safe-ends - Type 316 stainless steel forgings overlaid with weld metal after final post-weld heat treatment.

(2) Steam Generators

Primary nozzle safe-ends - Grade F316LN forging.

(3) Pressurizers

		Unit 1	Unit 2
(a)	Surge nozzle safe-end	Type 316 forging	Type 316L forging
(b)	Spray nozzle safe-end	Type 316 forging	Type 316L forging
(c)	Relief nozzle safe-end	Type 316 forging	Type 316L forging
(d)	Safety valve (3) nozzle safe-end	Type 316 forging	Type 316L forging

5.2.2.5.5 Avoidance of Sensitization

Methods and material techniques used to avoid partial or local severe sensitization are as follows:

(1) Core Structural Components

In all cases where austenitic stainless steel must be given a stress-relieving treatment above 800°F, a high-temperature stabilizing procedure was used. This is performed in the temperature range of 1600-1900°F, with holding time sufficient to achieve chromium diffusion to the grain boundary regions. Proof that such stabilization is achieved is based on ASTM A393.

(2) Stainless Welding

(a) Nozzle safe-ends

1. Weld deposit with Ni-Cr-Fe Weld Metal F-Number 43 and attach austenitic stainless steel safe-end after final post-weld heat treatment.

2. Use of a stainless steel weld metal analysis A-7 containing less than 0.02 percent carbon or more than 5 percent ferrite, or both.

(b) All welding is conducted using procedures that are in accordance with the ASME BPVC Section IX.

(c) All welding procedures and welders have been qualified to the ASME BPVC rules of Section IX.

When these welding procedure tests are performed on test welds made from base metal and weld metal materials that are from the same lot(s) of materials used in the fabrication of components, additional testing is frequently required to determine the metallurgical, chemical, physical, corrosion, etc., characteristics of the weldment. The additional tests conducted on a technical case basis are as follows: light and electron microscopy, elevated temperature mechanical properties, chemical check analysis, fatigue tests, intergranular corrosion tests or static and dynamic corrosion tests within reactor water chemistry limitations.

(d) The interpass temperature of all welding methods is limited to 350°F maximum, with the exception of the RVCH cladding operations. The methodology used for the RVCH cladding weld operations was qualified using the guidance in Regulatory Guide 1.43, May 1973.

(e) Travel speed, voltage, amperage, as well as thickness of weld metal layers, and degree of weaving (two electrode diameters or ID of gas cup maximum) are carefully controlled on all welding processes to minimize sensitization in the completed welds.

(f) All welds are nondestructively examined in accordance with code requirements.

(g) Code-authorized inspectors are required to review and sign off on all welding done both in the shop and field.

(h) For the SGs, ferrite level is 5-18 percent, calculated by WRC sketch.

(3) Hard Facing

All hard facing procedures on austenitic stainless steel use low (less than 800°F) preheat temperatures to preclude sensitization of the base metal. Processes approved are limited to those proven by tests not to cause sensitization.

(4) Bent Pipe Sections

Bent pipe sections are solution heat-treated to produce nonsensitized conditions in the material after bending; this is done by controlling

handling temperatures and water quenching time to ensure that all carbides are in solution.

5.2.2.5.6 Retesting Unstabilized Austenitic Stainless Steel Exposed to Sensitizing Temperatures

It is not normal Westinghouse practice to expose unstabilized austenitic stainless steels to the sensitization range of 800 to 1500°F during fabrication into components except as described in Section 5.2.2.5.5. If, during the course of fabrication, the steel is inadvertently exposed to the sensitization temperature range, 800 to 1500°F, the material may be tested in accordance with A262 to verify that it is not susceptible to intergranular attack. Testing is not required for:

(1) Cast metal or weld metal with a ferrite content of 5 percent or more.

(2) Material with a carbon content of 0.03 percent or less that is subjected to temperatures in the range of 800 to 1500°F for less than 1 hour.

(3) Material exposed to special processing provided the processing is properly controlled to develop a uniform product and provided that adequate documentation exists of service experience and/or test data to demonstrate that the processing will not result in increased susceptibility to intergranular stress corrosion.

If it was verified that such material was susceptible to intergranular attack, the material would have been solution annealed again and water quenched or rejected.

5.2.2.5.7 Control of Delta Ferrite

Welding of austenitic stainless steel was controlled to mitigate the occurrence of microfissuring or hot cracking in the weld. Although published data and experience have not confirmed that fissuring is detrimental to the quality of the weld, it is recognized that such fissuring is undesirable in a general sense. Also, the presence of delta ferrite is one of the mechanisms for reducing the susceptibility of stainless steel welds to hot cracking.

The scope of these controls encompassed welding processes used to join stainless steel parts in components designed, fabricated, or stamped in accordance with the ASME BPVC Section III, Classes 1, 2, and core support components. Delta ferrite control was appropriate for the above welding requirements except where no filler metal was used if for other reasons such control was not applicable. These exceptions included electron beam welding, autogenous gas shielded tungsten arc welding, explosive welding, and welding using fully austenitic welding materials.

In accordance with Section III, fabrication and installation specifications required welding procedure and welder qualification and included delta ferrite determinations for

the austenitic stainless steel welding materials used for welding qualification testing and for production processing. Specifically, the undiluted weld deposits of the "starting" welding materials were required to contain a minimum of 5 percent delta ferrite as determined by chemical analysis and calculation using the appropriate weld metal constitution diagrams in Section III. New welding procedure qualification tests were evaluated for these applications in accordance with the requirements of Sections III and IX.

The results of all the destructive and nondestructive tests were reported in the procedure qualification record in addition to the information required by Section III.

The "starting" welding materials used for fabrication and installation welds of austenitic stainless steel materials and components meet the requirements of Section III. Welding materials were tested using the welding energy inputs to be employed in production welding.

Combinations of approved heats and lots of starting welding materials were used for all welding processes. The welding quality assurance program included identification and control of welding material by lots and heats as appropriate. All of the weld processing was monitored according to approved inspection programs, including review of starting materials, qualification records, and welding parameters. Welding systems are also subject to quality assurance audit including calibration of gauges and instruments; identification of starting and completed materials; welder and procedure qualifications; availability and use of approved welding and heat treating procedures; and documentary evidence of compliance with materials, welding parameters, and inspection requirements. Fabrication and installation welds were inspected using nondestructive examination methods according to Section III rules.

5.2.3 SAFETY EVALUATION

5.2.3.1 General Design Criterion 2, 1967 - Performance Standards

Protection provided for the RCS against environmental factors is discussed in Sections 3.3, 3.4, 3.5 and 3.6. In the PG&E quality group classification of DCPP fluid systems and fluid system components, the vessels, piping, valves, pumps and their supports of the RCPB are designated as PG&E Design Class I, PG&E Quality/Code Class I. The RCPB is designed to the requirements of DE, DDE and Hosgri as described in Sections 5.2.2.1.10, 5.2.2.1.14 and 5.2.2.1.15.

As discussed in Sections 3.9.2.1, 3.9.2.2, and 3.9.2.3, the PG&E Design Class I mechanical systems and components are designed to withstand the effects of earthquakes. PG&E Design Class I mechanical systems and components are protected from the effect of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), and external missiles (refer to Section 3.5), ensuring their design function can be performed.

5.2.3.2 General Design Criterion 4, 1987 – Environmental and Dynamic Effects Design Bases

The LBB methodology was applied to the primary loops of DCPP Unit 1 and Unit 2. The following postulated breaks were eliminated: the six terminal ends in the cold, hot, and crossover legs; a split in the SG inlet elbow; and the loop closure weld in the crossover leg. Protection from the dynamic effects of the most limiting breaks of auxiliary branch lines needs to be considered. This includes RCS branch line breaks and other high energy line breaks as described in Sections 5.2.2.1.9, 5.2.2.1.10, 5.2.2.1.11, 5.2.2.1.14, 5.2.2.1.15, and 5.2.2.1.16.

RCS leakage detection and monitoring is discussed in Section 5.2.3.6 for General Design Criterion 16, 1967 and Section 5.2.3.23 for Regulatory Guide 1.45, May 1973.

5.2.3.3 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The RCPB is designed and constructed so as to have an exceedingly low probability of gross rupture or significant leakage throughout its lifetime. The RCPB is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation, including all anticipated transients, and to maintain the stresses within applicable stress limits. Refer to Section 5.2.2.1, Design of Reactor Coolant Pressure Boundary Components.

The RCPB is protected from overpressure by means of pressure-relieving devices as required by applicable codes. Refer to Section 5.2.2.2, Overpressurization Protection.

The materials of construction of the pressure-retaining boundary of the RCS are protected by control of coolant chemistry from corrosion that might otherwise reduce the system structural integrity during its service lifetime. Refer to Section 5.2.2.3, General Material Considerations.

Generic Letter 87-06, March 1987, applies to the RCPB. PIVs are defined for each interface as any two valves in series within the RCPB which separate the high pressure RCS from an attached low pressure system. These valves are normally closed during power operation. The PIVs are tested for leak tight integrity per Technical Specification 3.4.14.

Based on NRC Bulletin 88-11, December 1998, thermal stratification phenomenon could occur in the surge line and may invalidate the analyses supporting the integrity of the surge line with respect to unexpected bending and thermal striping (rapid oscillation of the thermal boundary interface along the piping inside surface) as they affect the overall integrity of the surge line for its design life (e.g., the increase of fatigue). Consistent with assumptions used and results obtained in the analysis, operating restrictions limit the pressurizer/hot leg differential temperature to 300°F.

5.2.3.4 General Design Criterion 11, 1967 - Control Room

Instrumentation and controls necessary to ensure the integrity of the RCPB are provided in the control room. This instrumentation and controls consist of RCPB leakage detection, pressure boundary valve position indication, and post-accident RCS pressure indication.

Refer to Section 5.2.3.23 for further discussion on operational conditions which may indicate changes in RCPB leakage rates. The RCPB leakage detection instrumentation provided in the control room is listed on Table 5.2-16.

The PORV and PSV position indication and controls are provided in the control room. The PSV position indication system provides the necessary information in the control room to determine the position (open/close) of each of the three PSVs. Refer to Section 7.5.2.8 for details. Also the PORV block valves can be controlled from the control room to isolate the PORV if leaking. Temperature indication in the discharge piping of the PSV and PORVs is provided to identify leakage. RHR isolation valve control, valve position indication, and annunciation are provided in the control room as described in Section 7.6.2.1.

The instrumentation required for post-accident monitoring of the RCPB is discussed in Section 5.2.3.24.

Emergency close controls for the PORVs are provided on the HSP in addition to control from the control room (refer to Figure 7.3-21). Indication of RCS pressure is provided by the pressurizer pressure indication located at the HSP.

5.2.3.5 General Design Criterion 12, 1967 - Instrumentation and Controls

Instrumentation and controls are provided to monitor and maintain the RCPB.

Valve position indication is provided for RCPB remotely operated valves listed on Table 5.2-9. RHR isolation valve control, valve position indication, and annunciation are provided. PSV and PORV control and indication are provided as discussed in Section 5.2.3.4.

As described in Section 5.2.3.28, the LTOP function is completely automatic after being manually enabled. Whenever the system is enabled and reactor coolant temperature is below the low temperature setpoint (i.e., PORV arming temperature), a high-pressure signal will trip it automatically and open the PORV until the pressure drops below the reset value.

Regulatory Guide 1.45, May 1973, describes requirements for instruments available for implementing leakage detection systems for the RCPB. Refer to the discussion of reactor coolant leakage requirements in Section 5.2.3.23 and Table 5.2-16.

Instrumentation is provided to monitor RCS integrity following an accident. Instrumentation related to the RCPB which is required to meet Regulatory Guide 1.97, Revision 3, Criteria for Accident Monitoring Instrumentation for Nuclear Power Plants, is discussed in Section 5.2.3.24.

5.2.3.6 General Design Criterion 16, 1967 - Monitoring Reactor Coolant Pressure Boundary

RCPB components are designed, fabricated, inspected, and tested to the ASME codes and conditions as summarized in Tables 5.2-2 through 5.2-8. Leakage is detected by an increase in the amount of makeup water required to maintain a normal level in the pressurizer. The reactor vessel closure joint is provided with a temperature monitored leakoff between double gaskets. Leakage into the reactor containment is drained to the reactor building sump where the level is monitored. Leakage is also detected by measuring the airborne activity and quantity of the condensate drained from each reactor containment fan cooler unit (CFCU). Allowable total leakage rates for the DCPP units are presented in the Technical Specifications.

RCS identified leakage is limited to 10 gpm by Technical Specification 3.4.13. As prescribed by the Technical Specifications, a RCS water inventory balance shall be performed at least once every 72 hours, with exceptions as noted in the Technical Specifications. Tracking the RCS inventory in a consistent manner provides an effective means of quantifying overall system leakages.

Regulatory Guide 1.45, May 1973, describes acceptable methods of implementing this requirement with regard to the selection of leakage detection systems for the RCPB. Data on leak detection capabilities are provided in Section 5.2.3.23 and in Table 5.2-16.

5.2.3.7 General Design Criterion 33, 1967 - Reactor Coolant Pressure Boundary Capability

The RCPB is designed to withstand the static and dynamic loads imposed on boundary components as a result of an inadvertent and sudden release of energy to the coolant. Design transients are discussed in Section 5.2.2.1.5. Stress and pressure limits are discussed in Section 5.2.2.1.9. The stress analysis for structural integrity is discussed in Section 5.2.2.1.10. The static and dynamic load analyses are described in Sections 5.2.2.1.11, 5.2.2.1.14, 5.2.2.1.15, and 5.2.2.1.16.

5.2.3.8 General Design Criterion 34, 1967 – Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention

The RCPB is designed to minimize the probability of rapidly propagating type failures. RCS materials exposed to the coolant are corrosion-resistant stainless steel or Inconel. The NDT temperature of the reactor vessel material samples are established by Charpy

V-notch and drop weight tests. The materials testing is consistent with 10 CFR Part 50, Appendices G and H. These tests also ensure that only materials with adequate toughness properties are used.

As part of the reactor vessel specification, certain additional tests are performed:

(1) Ultrasonic Testing

In addition to code requirements, the performance of a 100 percent volumetric ultrasonic test of reactor vessel plate for shear wave and a post-hydrotest ultrasonic map of all welds in the pressure vessel are required. Cladding bond ultrasonic inspection to more restrictive requirements than code is also required to preclude interpretation problems during ISI.

(2) Radiation Surveillance Program

In the surveillance programs, the evaluation of the radiation damage is based on pre-irradiation and post-irradiation testing of Charpy V-notch and tensile specimens. These programs are directed toward evaluation of the effect of radiation on the fracture toughness of reactor vessel steels based on the transition temperature approach and the fracture mechanics approach, and are in accord with ASTM-E-185, Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels.

The inspections of reactor vessel, pressurizer, piping, pumps, and SGs are governed by ASME code requirements.

The allowable heatup and cooldown rates as well as the static loading stresses during plant life are predicted, using conservative values for the change in ductility transition temperature due to irradiation.

Refer to Sections 5.2.2.4.1 through 5.2.2.4.3 for discussion of tests that ensure only materials with adequate toughness properties are used per 10 CFR Part 50, Appendix G. Refer to Section 5.2.2.4.4 for discussion of 10 CFR Part 50, Appendix H requirements.

5.2.3.9 General Design Criterion 35, 1967 – Reactor Coolant Pressure Boundary Brittle Fracture Prevention

Testing and analysis of materials employed in RCS components is performed to ensure that the required NDT temperature limits specified in the criterion are met. Removable test capsules are installed in the reactor vessel and removed and tested at various times in the plant lifetime to determine the effects of operation on system materials. Details of the testing and analysis programs are discussed in Section 5.2.2.4, Fracture Toughness.

Close control is maintained over material selection and fabrication for the RCS. Materials exposed to the coolant are corrosion-resistant stainless steel or Inconel. Materials testing

consistent with 10 CFR Part 50 assures that only materials with adequate toughness properties are used.

The fabrication and quality control techniques used in the fabrication of the RCS are equivalent to those used for the reactor vessel. The inspections of reactor vessel, SGs, pressurizer, pumps, and piping are governed by ASME code requirements.

5.2.3.10 General Design Criterion 36, 1967 – Reactor Coolant Pressure Boundary Surveillance

The design of the RCPB provides for accessibility during service life to the entire internal surface of the reactor vessel and certain external zones of the vessel, including the nozzle to reactor coolant piping welds and the top and bottom heads, except where control rod drive or instrument penetrations prevent access. The reactor arrangement within each containment provides sufficient space for inspection of the external surfaces of the reactor coolant piping, except for the area of pipe within the primary shielding concrete. The inspection capability complements the leakage detection systems in assessing the pressure boundary components' integrity.

Monitoring of the NDT temperature properties of each core region plate, forging, weldment, and associated heat-treated zones are performed in accordance with ASTM-E-185, Recommended Practice for Surveillance Tests on Structural Materials in Nuclear Reactors. Samples of reactor vessel plate materials are retained and cataloged in case future engineering development shows the need for further testing.

The material properties surveillance program includes not only the conventional tensile and impact tests, but also fracture mechanics specimens. The observed shifts in NDT temperature of the core region materials with irradiation are used to confirm the calculated limits to startup and shutdown transients.

To define permissible operating conditions below NDT temperature, a pressure range is established that is bounded by a lower limit for pump operation and an upper limit that satisfies reactor vessel stress criteria. To allow for thermal stresses during heatup or cooldown of the reactor vessel, an equivalent pressure limit is defined to compensate for thermal stress as a function of rate of change of coolant temperature. Since the normal operating temperature of the reactor vessel is well above the maximum expected NDT temperature brittle fracture during normal operation, it is not considered to be a credible mode of failure.

5.2.3.11 General Design Criterion 51, 1967 – Reactor Coolant Pressure Boundary Outside Containment

The RCPB is defined as those piping systems and components that contain reactor coolant at design pressure and temperature. With the exception of the reactor coolant sampling lines, the entire RCPB, as defined above, is located entirely within the containment structure. All sampling lines are provided with remotely operated valves for

isolation in the event of a failure. These valves also close automatically on a containment isolation signal. Sampling lines are only used during infrequent sampling and can readily be isolated.

All other piping and components that may contain reactor coolant are low-pressure, low temperature systems which would yield minimal environmental doses in the event of failure.

The sampling system and low-pressure systems are described in Chapter 9. An analysis of malfunctions in these systems is included in Chapter 15.

5.2.3.12 Reactor Coolant Pressure Boundary Safety Function Requirement

(1) Protection from Missiles and Dynamic Effects

The RCPB is protected against postulated missiles sources generated within containment as described in Section 3.5. The design and fabrication of the RCPs ensure that a missile will not be generated under any anticipated accident as described in Section 5.2.3.20, Safety Guide 14, October 1971 and is, therefore, not a credible missile source as described in Section 3.5.

The RCPB is PG&E Design Class I equipment and therefore is designed to be protected against dynamic effects which may result from equipment failures as described in Section 3.6.

5.2.3.13 10 CFR 50.55a- Codes and Standards

For codes and standards applicability to the RCPB, refer to Section 5.2.2.1.3, Compliance with 10 CFR 50.55a; and Section 5.2.2.3, General Material Considerations. For description of the RCPB PG&E Quality/Code Class requirements refer to Section 5.2.2.1, Design of Reactor Coolant Pressure Boundary Components.

5.2.3.14 10 CFR 50.55a(f) – Inservice Testing Requirements

The IST requirements for the RCPB are contained in the DCPP IST Program Plan.

5.2.3.15 10 CFR 50.55a(g) - Inservice Inspection Requirements

The ISI program complies, except where relief is granted by the NRC, with the requirements of 10 CFR 50.55a(b)(2), in effect on May 7, 2014, and uses the ASME BPVC Section XI, 2007 Edition with 2008 Addenda, as the basis for the inservice examinations and tests conducted during the fourth 120-month inspection interval which commenced May 7, 2015 for Unit 1 and March 13, 2016 for Unit 2. Components that are designated ASME BPVC Class 1, 2, and 3 for ISIs are included in the ISI Program Plan (Reference 8). The ISI Program Plan also describes the pressure test program for

pressure-retaining Code Class 1, 2, and 3 components; examination techniques; Code Cases; and compliance with ASME BPVC Section XI.

The third interval Containment Inservice Inspection Program Plan implements the ASME Code Section XI, Subsections IWE and IWL, 2007 Edition with 2008 Addenda within the limits and modifications of 10 CFR 50.55a. IWE exams o the metallic liner are performed on a 40-month frequency within the 10 year interval starting September 9th, 2018. Concrete shell exams occur on a 5-year frequency as specified by IWL 2410(a) with the initial examinations performed on November 2000 and August 2001 for Unit 1 and Unit 2 respectively.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

The second interval Containment Inservice Inspection Program Plan implemented the ASME Code Section XI, Subsections IWE and IWL, 2001 Edition with 2003 Addenda, within the limits and modifications of 10CFR50.55a. IWE exams of the metallic liner are performed on a 40-month frequency within the 10 year interval starting September 9th, 2008. Concrete shell exams were performed on a 5-year frequency as specified by IWL 2410(a) with the initial examinations performed on November 2000 and August 2001, for Unit 1 and Unit 2 respectively.

As part of the inspection effort for Unit 1, a preservice inspection (PSI) program for Class 1, 2, and 3 systems was conducted in compliance with the requirements of ASME BPVC Section XI, 1974 Edition including the Summer 1975 Addenda, except where relief was granted by the NRC. For PSI piping examinations in Unit 1, the examination technique of Appendix III and the acceptance criteria of IWB-3514, both from the Winter 1975 Addenda of the ASME BPVC Section XI, were used. For Unit 2, a PSI program for Class 1, 2, and 3 systems was conducted in compliance with the requirements of ASME BPVC Section XI, 1977 Edition including the Summer 1978 Addenda, except where relief was granted by the NRC.

The ISI program for the first inspection interval for Unit 1 and Unit 2 met the requirements of the ASME BPVC Section XI, 1977 Edition including the Summer 1978 Addenda, except where relief was granted by the NRC. The ISI program for the second inspection interval for Unit 1 and Unit 2 met the requirements of the ASME BPVC Section XI, 1989 Edition without addenda, except where relief was granted by the NRC. The ISI program for the third inspection interval for Unit 1 and Unit 2 met the requirements of the ASME BPVC Section XI, 2001 Edition through 2003 Addenda, except where relief was granted by the NRC. Where examination techniques differed due to Code changes between the PSI and the ISI examinations, or between subsequent ISI examinations, the latest inservice examination data is used as the new baseline.

Design provisions for access to the reactor vessel are described in Section 5.4.1.5. Remote access and data acquisition methods have been developed to facilitate inspection of reactor vessel areas that are not readily accessible for direct examination.

Areas that are inaccessible for the remote examination equipment are detailed in PG&E requests for relief that have been submitted to the NRC.

5.2.3.16 10 CFR 50.60 - Acceptance Criteria for Fracture Prevention Measures for Lightwater Nuclear Power Reactors for Normal Operation

Refer to Section 5.2.2.4, Fracture Toughness, for discussion of 10 CFR Part 50, Appendices G and H requirements.

5.2.3.17 10 CFR 50.61 - Fracture Toughness Requirements for Protection against Pressurized Thermal Shock Events

10 CFR 50.61 provides requirements for protection against pressurized thermal shock events involving rapid cooldown and high reactor vessel pressure.

10 CFR 50.61 requires projected values of RT_{PTS} for each reactor vessel beltline material using a fluence value, f, which is the EOL fluence for the material. DCPP Unit 1 and Unit 2 are currently licensed for 40 years of operation. The current RT_{PTS} evaluation is analyzed for 54 EFPY for both Units, which supports up to 60 years of operation. The projected EOL vessel fluence at the clad/base metal interface (OT) has been shown not to exceed the PTS screening criteria, i.e., an ART of 270°F for plates and axial welds, and an ART of 300 °F for circumferential welds, as required by 10 CFR 50.61. Refer to Section 5.2.2.4, Fracture Toughness, for discussion of Appendix G requirements.

5.2.3.18 10 CFR Part 50 Appendix G - Fracture Toughness Requirements

10 CFR Part 50, Appendix G specifies fracture toughness requirements for ferritic materials of pressure-retaining components of the RCPB of light water nuclear power reactors to provide adequate margins of safety during any condition of normal operation, including anticipated operational occurrences and system hydrostatic tests, to which the pressure boundary may be subjected over its service lifetime. Refer to Section 5.2.2.4, Fracture Toughness, for discussion of Appendix G requirements.

5.2.3.19 10 CFR Part 50 Appendix H - Reactor Vessel Material Surveillance Program Requirements

10 CFR Part 50, Appendix H implements a surveillance program to monitor changes in the fracture toughness properties of ferritic materials in the reactor vessel beltline region of light water nuclear power reactors which result from exposure of these materials to neutron irradiation and the thermal environment. Under the program, fracture toughness test data are obtained from material specimens exposed in surveillance capsules, which are withdrawn periodically from the reactor vessel. Refer to Section 5.2.2.4.4, Materials Surveillance, for discussion of 10 CFR Part 50, Appendix H requirements.

5.2.3.20 Safety Guide 14, October 1971 - Reactor Coolant Pump Flywheel Integrity

For the original reactor coolant pump (RCP) motors:

The flywheel consists of two thick plates bolted together. The flywheel material is produced by a process that minimizes flaws in the material and improves its fracture toughness properties; i.e., an electric furnace with vacuum degassing. Each plate is fabricated from SA-533, Grade B, Class 1 steel. Supplier certification reports are available for all plates and demonstrate the acceptability of the flywheel material on the basis of the requirements of Safety Guide 14, October 1971 (Reference 23).

Flywheel blanks are flame cut from SA-533, Grade B, Class 1 plates with at least ½ inch of stock left on the outer and bore surfaces for machining to final dimensions. The finished machined flywheels, including bores, keyways, and drilled holes, are subjected to magnetic particle or liquid penetrant examinations in accordance with the requirements of ASME BPVC Section III. The finished flywheels, as well as the flywheel material (rolled plate), are subjected to 100 percent volumetric ultrasonic inspection using procedures and acceptance standards specified in ASME BPVC Section III.

The RCP motors are designed such that, by removing the cover to provide access, the flywheel is available to allow an ISI program in accordance with the Technical Specifications.

Determining acceptability of the flywheel material involves two steps as follows:

(1) Establish a reference curve describing the lower bound fracture toughness behavior for the material in question.

(2) Use Charpy (CV) impact energy values obtained in certification tests at 10°F to fix position of the heat in question on the reference curve.

A lower bound K_{Id} reference curve (refer to Figure 5.2-7) has been constructed from dynamic fracture toughness data generated by Westinghouse (Reference 3) on A-533, Grade B, Class 1 steel. All data points are plotted on the temperature scale relative to the RT_{NDT}. The construction of the lower-bound curve below which no single test point falls, combined with the use of dynamic data when flywheel loading is essentially static, together represent a large degree of conservatism.

The applicability of a 30 ft-lb Charpy energy reference value has been derived from sections on Special Mechanical Property Requirements and Tests in Article 3, Section III, of the ASME BPVC. The implication is that the low test temperature of +10°F, and the 30 ft-lb. requirement at that temperature provide assurance that RT_{NDT} is less than +10°F. Flywheel plates exhibit an average value of 30 ft-lb or greater in the weak direction and, therefore, meet the specific Safety Guide 14, October 1971 requirement that RT_{NDT} must be no higher than 10°F. Making the conservative

assumption that all materials in compliance with the code requirements are characterized by an RT_{NDT} of 10°F, it is possible to reassign the reference temperature position RT_{NDT} in Figure 5.2-7 to a value of 10°F.

Flywheel operating temperature at the surface is 120°F. The lower bound toughness curve indicates a value of 116 ksi-in$^{1/2}$ at the (NDT + 110) position corresponding to operating temperature. Thus, the Safety Guide 14, October 1971 requirement that the operating temperature be at least 100°F above RT_{NDT} is fulfilled.

At the time the flywheels were ordered, Charpy V-notch tests were required only at 10°F. However, by assuming a minimum toughness at operating temperature in excess of 100 ksi-in$^{1/2}$, it can be seen by examination of the correlation in Figure 5.2-8 that the C_V upper-shelf energy must be in excess of 50 ft-lb. Therefore, the requirement "b", that the upper-shelf energy must be at least 50 ft-lb, is satisfied.

It is concluded that flywheel plate materials are suitable for use and meet the Safety Guide 14, October 1971 acceptance criteria on the bases of suppliers' certification data.

The calculated stresses at operating speed are based on stresses due to centrifugal forces. The stress resulting from the interference fit of the flywheel on the shaft is less than 2000 psi at zero speed and becomes zero at approximately 600 rpm because of radial hub expansion.

The RCPs run at approximately 1190 rpm and may operate briefly at overspeeds of up to 109 percent (at 1295 rpm). For conservatism, however, 125 percent of operating speed was selected as the design speed for the RCPs. The flywheels are given a preoperational test prior to shipment at 125 percent of the operating speed.

Precautionary measures, taken to preclude missile formation from primary coolant pump components, ensure that the pumps will not produce missiles under any anticipated accident condition. Each component of the primary pump motors has been analyzed for missile generation. Any fragments of the motor rotor would be contained by the heavy stator. The same conclusion applies to the pump impeller because the small fragments that might be ejected would be contained by the heavy casing.

5.2.3.21 Regulatory Guide 1.14, Revision 1, August 1975 – Reactor Coolant Pump Flywheel Integrity

For replacement reactor coolant pump (RCP) motors:

The flywheel consists of two thick plates bolted together. The flywheel material is produced by a process that minimizes flaws in the material and improves its fracture toughness properties; i.e., an electric furnace with vacuum degassing. Each plate is fabricated from SA-533, Grade B, Class 1 steel. Supplier certification reports are available for all plates and demonstrate the acceptability of the flywheel material on the basis of the requirements of Regulatory Guide 1.14, Revision 1, August 1975 (Reference 39).

Flywheel blanks are flame cut from SA-533, Grade B, Class 1 plates with at least ½ inch of stock left on the outer and bore surfaces for machining to final dimensions. The finished machined flywheels, including bores, keyways, and drilled holes, are examined for surface defects by a penetrant examination in accordance with the requirements of Section III of the ASME BPVC. The finished flywheels, as well as the flywheel material (rolled plate), are subjected to 100 percent volumetric ultrasonic inspection using procedures and acceptance standards specified in Section III of the ASME BPVC.

The RCP motors are designed such that, by removing the cover to provide access, the flywheel is available to allow and ISI program in accordance with the Technical Specifications.

Fracture toughness and tensile properties of each plate of flywheel material have been checked by tests that yield results suitable to confirm the applicability to that flywheel of the properties used in the fracture analyses called for in Regulatory Guide 1.14, Revision 1, on the bases of suppliers' certification data.

The calculated stresses at operating speed are based on stresses due to centrifugal forces. The stress resulting from the interference fit of the flywheel on the shaft is less than 2000 psi at zero speed and becomes zero at approximately 600 rpm because of radial hub expansion.

The RCPs run at approximately 1190 rpm and may operate briefly at overspeeds of up to 109 percent (at 1295 rpm). For conservatism, however, 125 percent of operating speed was selected as the design speed for the RCPs. The flywheels are given a preoperational test prior to shipment at 125 percent of the operating speed.

Precautionary measures, taken to preclude missile formation from primary coolant pump components, ensure that the pumps will not produce missiles under any anticipated accident condition. Each component of the primary pump motors has been analyzed for missile generation. Any fragments of the motor rotor would be contained by the heavy stator. The same conclusion applies to the pump impeller because the small fragments that might be ejected would be contained by the heavy casing.

For both original and replacement reactor coolant pump (RCP) motors:

The RCP Flywheel Inspection Program provides the ISI requirements for the RCP flywheel, which is in accordance with Regulatory Guide 1.14, Revision 1, Position C.4.b. Reference 39 demonstrates compliance with the RCP motor flywheel design requirements given by Regulatory Guide 1.14, Revision 1, in Position C.2.

An exception to the examination requirements given by Regulatory Guide 1.14, Revision 1, Positions C.4.b(1) and C.4.b(2) was granted based on Reference 32 allowing either an ultrasonic volumetric or surface examination at ten year intervals. Subsequently, the

examination frequency was extended to an interval not to exceed 20 years based on Reference 39.

In lieu of Position C.4.b(1) and C.4.b(2), a qualified in-place ultrasonic testing examination over the volume from the inner-bore of the flywheel to the circle one-half of the outer radius or a surface examination (MT and/or PT) of exposed surfaces of the removed flywheels may be conducted at an interval not to exceed 20 years.

5.2.3.22 Regulatory Guide 1.44, May 1973 – Control of the Use of Sensitized Stainless Steel

Regulatory Guide 1.44, May 1973, describes methods for control of the application and processing of stainless steel to avoid severe sensitization to diminish occurrences of stress corrosion cracking. The measures taken to avoid sensitization are in general conformance with the recommendations of Regulatory Guide 1.44, May 1973 (Reference 22) (refer to Section 5.2.2.5).

5.2.3.23 Regulatory Guide 1.45, May 1973 - Reactor Coolant Pressure Boundary Leakage Detection Systems

Means are provided to detect and, to the extent practical, identify the location of reactor coolant leakage sources. Detection systems with diverse modes of operation are used to ensure adequate surveillance with sufficient sensitivity so that increases in leakage rate can be detected before the integrated leakage rate reaches a value that could interfere with the safe operation of the plant. Section 5.2.3.23 discusses sources of reactor coolant leakage outside containment.

Regulatory Guide 1.45, May 1973 (Reference 25), described acceptable methods for selection of leakage detection systems for the RCPB. The construction permits for DCPP Unit 1 and Unit 2 were issued prior to the guidance of Regulatory Guide 1.45, May 1973. The RCPB leakage detection system meets the intent of Regulatory Guide 1.45, May 1973, to detect and monitor RCS leakage such that operators have sufficient time to take corrective actions (References 31 and 37).

5.2.3.23.1 Leakage Detection Methods

Systems using diverse methods and modes of operation are provided to continuously monitor environmental conditions within the containment, and to detect the presence of radioactive and nonradioactive leakage to the containment. Once operation begins, background levels are established, thereby providing a baseline for leakage detection. Deviations from normal conditions indicate possible changes in leakage rates and are monitored in the control room and the auxiliary building. Indications of leakage include changes in containment particulate and gaseous activity, containment sump level, containment condensation, and other volumetric measurement such as increased

coolant makeup demand. A list of systems available to detect these changes is provided in Table 5.2-16.

5.2.3.23.1.1 Containment Radioactivity Monitors

Containment radioactivity monitors continuously monitor the air particulate and gaseous activity levels in the containment during normal plant operation. Leakage to the containment from the RCPB will result in changes in airborne radioactivity levels that can be detected by this equipment. Detector sensitivity, in terms of leakage rates, depends on the radioactivity level in the reactor coolant itself.

The containment radioactivity monitors measure beta and/or gamma activity in the containment by taking continuous air samples from the containment atmosphere. This sample flow first passes through the air particulate monitor and then through the gas monitor assembly. The sample is then returned to the containment. A complete description of the containment activity monitors, including sensitivity and control, indication, and alarm, is presented in Section 11.4.

5.2.3.23.1.2 Containment Sump Levels and Pump Operation

Leakage from the primary system would result in reactor coolant flowing into one of the containment sumps. Sump level and sump pump integrated flow is monitored to provide a measure of the overall leakage that remains in liquid state.

5.2.3.23.1.3 Containment Condensation Measurements

The containment condensation measuring system provides a measure of the amount of leakage vaporized (refer to Section 5.2.3.23.3). This system collects and measures moisture condensed from the containment atmosphere by the cooling coils of the fan cooler air circulation units. Moisture from leaks up to sizes permissible for continued plant operation will partially evaporate into the containment atmosphere and will be condensed on the fan cooling coils. This system dependably and accurately measures total vaporized leakage, including leakage from the cooling coils themselves. It measures the liquid runoff flowrate from the drain pans under each CFCU. The condensate measuring system consists of a vertical standpipe, valves, and instrumentation installed in the drain piping of the reactor CFCU.

Depending on the number of reactor CFCUs in operation, the drainage flowrate from each unit due to normal condensation can be determined. Additional or abnormal leaks will result in containment humidity and condensation runoff rate increases, and the additional leakage can then be measured.

5.2.3.23.1.4 Other Methods of Detection

(1) Charging Pump Operation

During normal operation only one charging pump is operating. If a gross loss of reactor coolant should occur which was not detected by the methods previously described, the flowrate mismatch of the charging and letdown flows would indicate RCS leakage.

(2) Liquid Inventory

Gross leakage can also be detected by an increase in the makeup rate to the RCS. This is inherently a low-precision indication, because makeup to the RCS is also required due to other process variables. A quantitative measurement of leakage requires a test over a reasonable period of time to establish changes in the physical inventory.

(3) Coolant Radiation Monitors

The component cooling liquid monitor continuously monitors the CCW system for activity indicative of a leak of reactor coolant from either the RCS or the RHR system loop in the CCW system. In addition, condenser offgas monitors and SG blowdown radiation detectors are available to detect SG tube leakage.

(4) Containment Atmosphere Temperature and Pressure Measurement

Various air temperature and pressure sensors would supplement indications of RCS leakage. Containment temperature and pressure fluctuate slightly during plant operation, but a rise above the normally indicated range of values may indicate RCS leakage into the containment. The accuracy and relevance of temperature and pressure measurements is a function of containment free volume and detector location. Alarm signals from these instruments would be valuable in recognizing rapid and sizable energy releases to the containment.

Thermoswitches are installed in the leakoff piping from RCS valves with restricted access during plant operation as a means of identifying the source of leakage (i.e., the specific valve) from a packing or bellows failure. Identified indicating lights, located in a routinely inspected area, are actuated by the thermoswitches. A control room alarm is provided for valve stem leakoff.

5.2.3.23.1.5 Visual and Ultrasonic Inspections

Visual and ultrasonic inspections of the RCPB will be made periodically during plant shutdown periods. Limited access to the containment is possible for this purpose during

normal plant operation. The design of the reactor vessel and its arrangement in the system provides accessibility during service life to the entire internal surface of the vessel (except where access is limited by control rod drive or instrument penetrations). Access is also provided to the entire primary piping system, except for the area of pipe within the concrete biological shielding.

5.2.3.23.1.6 Reactor Coolant System Water Inventory Balance

As prescribed by the Technical Specifications, a RCS water inventory balance shall be performed at least once every 72 hours, with exceptions as noted in the Technical Specifications. Tracking the RCS inventory in a consistent manner provides an effective means of quantifying overall system leakages.

Data on other secondary methods of leak detection, such as pressurizer liquid level, VCT liquid level, charging pump flowrate, and PRT liquid level are provided in Table 5.2-16.

5.2.3.23.1.7 Indication in Control Room

Positive indications in the control room of coolant leakage from the RCS to the containment are provided by equipment that permits continuous monitoring of containment air activity, containment sump level changes, and of runoff from the condensate collecting pans under the cooling coils of the CFCUs. This equipment provides indication of normal background, which is indicative of a basic level of leakage from the RCS and components. An increase in observed parameters is an indication of leakage within the containment, and the equipment provided is capable of monitoring this change.

As indicated in Table 5.2-16, numerous other forms of RCS leakage indication are provided in the control room or auxiliary building control area. Leakage detection systems are provided and located in a manner such that for minor leakages the operator can identify the subsystem that is leaking and effectively isolate that leakage with no more than short-term interruption of the operation of the complete system. Figures 5.2-14 and 5.2-15 are examples of the correlative relationships between radioactivity leak detector indications and the corresponding volumetric leak flowrate. This information is provided to the operator for a quick and easy interpretation of leakage conditions, and forms the basis for determining operator action.

5.2.3.23.2 Limits for Reactor Coolant Leakage

Operational leakage limiting conditions for RCS operation are presented in the Technical Specifications.

The Technical Specifications also present leakage limitations for the RCS PIVs listed in Table 5.2-23.

RCS PIVs protect low pressure ECCS systems such as the RHR system and the SI system from overpressurization and rupture of their low pressure piping which could result in a LOCA that bypasses the containment. Testing of these valves at least once per refueling interval during startup ensures a low probability of gross failure. Each PIV is required to be tested prior to returning the valve to service following maintenance, repair, or replacement work.

5.2.3.23.3 Unidentified Leakage

The sensitivity and response time of RCPB leakage detection systems vary for different methods of detection. However, the diverse systems available are required to have the capability to detect continuous leakage rates as low as 1 gpm within 1 hour for unidentified leaks at the design conditions and assumptions, as recommended by Regulatory Guide 1.45, May 1973 (Reference 25). The LBB analysis (Reference 42) demonstrates that this leak detection capability is sufficient to provide the margin of 10 on the leak rate in support of LBB (refer to Section 5.2.3.2, GDC 4, 1987).

The containment particulate monitor is the most sensitive instrument of those available for detection of reactor coolant leakage into the containment. This instrument is capable of detecting particulate radioactivity concentrations as low as 10^{-11} μCi/cc. The sensitivity of the air particulate monitor to an increase in reactor coolant leakage rate is dependent on the magnitude of the normal leakage into the containment. The sensitivity is greatest where normal leakage is low, as has been demonstrated by the experience of Indian Point Unit No. 1, Yankee Rowe, and Dresden Unit 1. Based on data from these operating plants, it is expected that this unit will detect (at the 95 percent confidence level) an increase in containment air particulate activity resulting in a gross count rate equivalent to 1×10^{-9} μCi/cc during normal full power operation. As shown in Figure 5.2-9, this system has adequate response to detect a 1 gpm leak within 1 hour assuming a reactor coolant particulate activity corresponding to as low as 0.1 percent fuel defects. The assumption of 0.1 percent fuel defects used in the design calculation is less than the percentage of failed fuel assumed in the Environmental Report (Reference 36) and follows the guidance of Regulatory Guide 1.45, May 1973 (References 25 and 37).

The containment radioactive gas monitor is inherently less sensitive (threshold at 10^{-7} μCi/cc) than the containment air particulate monitor, and would function in the event that significant reactor coolant gaseous activity results from fuel cladding defects. The sensitivity and range are such that gross count rates equivalent to from 10^{-6} to 10^{-3} μCi/cc will be detected. This system is also adequate to detect a 1 gpm leak within 1 hour assuming a reactor coolant gaseous activity corresponding to as low as 0.1 percent fuel defects as shown in Figure 5.2-9. The assumption of 0.1 percent fuel defects used in the design calculation is less than the percentage of failed fuel assumed in the Environmental Report and follows the guidance of Regulatory Guide 1.45, May 1973 (References 25 and 37).

The containment gaseous activity will result from any fission product gases (Kr-85, Xe-135) leaking from the RCS as well as from the argon-41 produced in the air around the reactor vessel. Assuming a constant background radioactivity in the containment atmosphere due predominantly to argon-41, and reactor coolant gaseous activity of 0.03 μCi/cc (corresponding to about 0.05 percent fuel defects), a 1-gpm coolant leak would double the fission product gas background in about 2 hours. The occurrence of a leak of 2 to 4 gpm would double the background in less than 1 hour. In these circumstances, this instrument is a useful backup to the air particulate monitor.

The adequacy of the containment particulate and radioactive gas monitors to detect a change in leakage during the initial period of plant operation will be limited by low coolant activity levels. The gas detector will not be as sensitive as the other leakage detection systems during this period because the argon-41 background will mask the low level of gaseous activity from coolant leakage.

Within the containment, the average air temperature is held at 120°F or below in accordance with the Technical Specifications. The hot dry air promotes evaporation of water leakage from hot systems, and the cooling coils of the fan cooler units provide a significant surface area at or below the dewpoint temperature. Therefore, under equilibrium conditions, the quantity of condensate collected by the cooling coils of the fan cooler units should be equal to the evaporated water leakage and steam leakage from systems within the containment.

To determine abnormal leakage rate inside the containment based on condensation measurements, it will first be necessary to determine the condensation rate from the fan coolers during normal operation. With the initiation of an additional or abnormal leak, the containment atmosphere humidity will begin to increase but such an increase in humidity is reduced by additional condensation on the fan cooler tubes. (assuming that there is no large heat addition to the containment that could cause the cooling water temperature to increase.)

With the increasing specific and relative humidity, the heat removal capacity needed to cool the air-vapor mixture to its dewpoint decreases. Therefore, increases in available heat removal capacity (i.e., increases in the number of fans in operation) will result in added condensate flow. Through accurate measurement of condensate flow from the fan coolers, a reliable estimate of evaporated leakage inside the containment can be made.

A preliminary estimate of the evaporated leakage can be obtained from the condensate flow increase rate during the transient; a better estimate can be determined from the steady state condensate flow when equilibrium has been reached. After equilibrium is attained, condensate flow from approximately 0.1 to 30 gpm per detector can be measured by this system.

Except for the condensate measuring system, the sensitivities of the RCPB leakage detection systems are not significantly affected during plant operation with concurrent

leaks from other sources. Condensation of moisture on the containment air cooler coils will produce a scrubbing effect for particulate activity, but is not expected to appreciably reduce particulate detector sensitivity.

When the plant is shut down, personnel can enter the containment to check visually for leaks. The lack of escaping steam or water during hydrostatic tests has been widely used as a criterion for leaktightness of pressurized systems. Detection of the location of significant leaks would be aided by the presence of boric acid crystals near a leak. The boric acid crystals are transported outside the RCS in the leaking fluid and then deposited by the evaporation process. Sensitivities and response times of other methods of leak detection are provided in Table 5.2-16 and in Figures 5.2-10 through 5.2-13.

5.2.3.23.4 Maximum Allowable Total Leakage

As discussed above, the reactor coolant leakage detection systems provide the capability for detecting extremely small leakage rates from the RCPB during normal operation. Signals from the various leak detectors are displayed in the control room and are used by the operators to determine if corrective action is required.

A limited amount of leakage is expected from the RCPB and from auxiliary systems within the containment. Although it is desirable to maintain leakage at a minimum, a maximum allowable total leakage rate is established and used as a basis for action by the reactor operator to initiate corrective measures. Allowable total leakage rates for the DCPP units are presented in the Technical Specifications. RCS identified leakage is limited to 10 gpm by Technical Specification 3.4.13.

5.2.3.23.5 Differentiation Between Identified and Unidentified Leaks

Generally, leakage into closed systems, or leakage into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of the unidentified leakage monitoring systems or not to be from a flaw in the RCPB, are called identified leakages. Uncontained leakage to the containment atmosphere may be the result of a variety of possible leakages that are generally classified as unidentified leakages. Unidentified leakage is eventually collected in tanks or sumps where the flowrate can be established and monitored during operation.

5.2.3.23.5.1 Leakage Location Capability

Leakage detection systems have been designed to aid operating personnel, to the extent possible, in differentiating between possible sources of detected leakage within the containment and in identifying the physical location of the leak. Containment entry for visual inspection will, however, remain the only method of positively identifying the source and magnitude of leakage detected by remote sensing systems.

The containment monitoring system provides the primary means of remotely identifying the source and location of leakage within the containment. Increases in containment airborne activity levels detected by any of the monitor channels will indicate the RCPB as the source of leakage. Additionally, the capability of drawing monitored samples from several containment locations will allow localization of the general area of leakage since activity levels will be somewhat higher in the vicinity of the leakage source. Conversely, if the condensate measuring system detects increased containment moisture without a corresponding increase in airborne activity level, the indicated source of leakage would be judged to be a nonradioactive system, except when the reactor coolant activity may be low.

Less sensitive methods of leakage detection, such as unexplained increases in reactor plant makeup requirements to maintain pressurizer level, will also provide positive indication of the RCPB as the leakage source. Increases in the frequency of a particular containment sump pump operation will facilitate localization of the source to components whose leakage would drain to that sump. Leakage rates of the magnitude necessary to be detectable by these latter methods are expected to be noted first by the more sensitive radiation detection equipment.

5.2.3.23.5.2 Adequacy of Leakage Detection System

The component cooling liquid monitor continuously monitors the component cooling loop of auxiliary coolant for activity indicative of a leak of reactor coolant from either the RCS or the RHR system.

If an accident involving gross leakage from the RCS occurred, it would be detected by the following methods:

(1) Pump Operation

During normal operation, only one charging pump is operating. If a gross loss of reactor coolant occurred which was not detected by previously described methods, the difference between charging and letdown flowrate would indicate the leakage.

(2) Liquid Inventory

Gross leaks might be detected by unscheduled increases in the amount of reactor coolant makeup water, which is required to maintain the normal level in the pressurizer. Gross leakage would also be detected by a rise in the normal containment sump level.

(3) RHR Loop

The RHR loop removes residual and sensible heat from the core and reduces the temperature of the RCS during the second phase of plant

shutdown. Tube leaks from the RHR heat exchangers during normal operation would be detected outside the containment by the component cooling loop radiation monitors.

Leakage detection systems are provided and located in a manner such that the operator can identify the subsystem, which is leaking and effectively isolate that leakage with no more than short-term interruption of the operation of the complete system.

5.2.3.23.6 Sensitivity and Operability Tests

Periodic testing of leakage detection systems will be conducted to verify the operability and sensitivity of detector equipment. These tests include installation calibrations and alignments, periodic channel calibrations, functional tests, and channel checks.
The containment monitoring system is calibrated on installation using typical isotopes of interest. Subsequent periodic calibrations using detector check sources will consist of single-point calibration to confirm detector sensitivity based on the known correlation between the detector response and the check source standard. This procedure will adequately measure instrument sensitivity since the geometry of the sampler cannot be significantly altered after the initial calibration. Channel checks to verify acceptable channel operability during normal operation and functional testing to verify proper channel response to simulated signals will also be conducted on a regular basis. A complete description of calibration and maintenance procedures and frequencies for the containment radiation monitor system is presented in Section 11.4. The condensate measuring system will also be periodically tested to ensure proper operation and verify sensitivity.

The equipment used, procedures involved, and frequency of testing, inspection surveillance and examination of the structural and leaktight integrity of RCPB components are described in detail in Section 5.2.3.14.

5.2.3.24 Regulatory Guide 1.97, Revision 3, May 1983 - Criteria for Accident Monitoring Instrumentation for Nuclear Power Plants

Instrumentation is provided to monitor RCS integrity following an accident. Instrumentation related to RCPB is required to meet Regulatory Guide 1.97, Revision 3. The requirements consist of continuous indication and recording of RCS level, RCS pressure, containment sump water level (wide and narrow ranges), containment pressure (normal range and wide range), high range containment area radiation monitor, condenser noble gas effluent radiation monitor. Refer to Table 7.5-6 for details.

Primary system relief valve continuous position indication and recording are provided for the PSVs (i.e., acoustic monitors). Refer to Section 7.5.2.8 for details. Position indication for the PORVs (i.e., valve position switches) is also provided.

5.2.3.25 Regulatory Guide 1.99, Revision 2, May 1988 - Radiation Embrittlement of Reactor Vessel Materials

Regulatory Guide 1.99, Revision 2, provides general procedures for calculating the effects of neutron radiation embrittlement of the low-alloy steels currently used in the DCPP Unit 1 and Unit 2 reactor vessels. Refer to Section 5.2.2.4 for information regarding predicted ΔRT_{NDT} values.

Generic Letter 88-11, July 1988, recommends the use of Regulatory Guide 1.99, Revision 2. For the DCPP reactor vessels, PG&E has committed to use the methodology in Regulatory Guide 1.99, Revision 2.

5.2.3.26 NUREG-0737 (Items II.B.1, II.D.1, II.D.3, II.K.2.13, and III.D.1.1), November 1980 - Clarification of TMI Action Plan Requirements

Item II.B.1 – Reactor Vessel Head Vent System: A RVHVS is provided to exhaust non-condensable gases and/or steam from the RCS that could inhibit natural circulation core cooling. The configuration of the RCS vent paths serves to minimize the probability of inadvertent or irreversible actuation while ensuring that a single failure of a vent valve power supply or control system does not prevent isolation of the vent path.

Item II.D.1 – Performance Testing of Pressurized-Water Reactor Relief and Safety Valves: A program has been implemented for testing of the PSVs, PORVs and block valves to qualify these components under expected design transients.

Item II.D.3 – Valve Position Indication for PSVs and PORVs: Positive PSV and PORV position indication is provided in the in the control room. Refer to Section 7.5.2.8 for details.

Item II.K.2.13 – Thermal Mechanical Report: An analysis has been performed to evaluate the effects of high pressure injection on vessel integrity for a SBLOCA. A generic report (Reference 40) provides a conservative bases for demonstrating that reactor vessel integrity is maintained for such an event. The conclusions of the generic report coupled with the requirements for protection of pressurized thermal shock demonstrate no loss of vessel integrity at EOL. Refer to Section 5.2.3.17 for discussion of protection against pressurized thermal shock events.

Item III.D.1.1 – Integrity of Systems Outside Containment Likely to Contain Radioactive Material for Pressurized-Water Reactors: DCPP implements a program to reduce leakage from systems outside the containment that would or could contain highly radioactive fluids during a severe transient or accident. The systems, or portions of systems, that are included in the leakage reduction program required by NUREG-0737, November 1980, and the reason for their inclusion, are as follows:

(1) The RHR and SI system that would circulate radioactive water from the RCS

(2) The containment spray system (CSS) that would circulate radioactive water from the containment sump

(3) The NSSS sampling system because of the highly radioactive fluids to be sampled

(4) The gaseous radwaste system (GRS) because it could be used to collect highly radioactive gases from the RCS

At intervals of approximately 24 months, operating pressure leak tests will be performed on appropriate portions of the SI system, the RHR system, the NSSS sampling system, and the CSS. Systems that normally contain liquids will be pressurized to normal operating pressure using systems pumps or hydro pumps. Each liquid system will be visually inspected during its pressure test so that leakage from the system can be measured and corrected. Systems that normally contain gases will be pressurized with a gas, and leakage will be determined using a calibrated leakrate monitor. If gaseous systems have excessive leakage, then leaks will be located using appropriate leak detection methods such as the soap bubble. After initial criticality, leakage from the GRS will be evaluated by monitoring the auxiliary building ventilation exhaust with radiation detectors.

5.2.3.27 Generic Letter 1989-10, June 1989 - Safety-Related Motor-Operated Valve Testing and Surveillance

The RCPB PG&E Design Class I and position changeable MOVs are subject to the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996, and meet the requirements of the DCPP MOV Program Plan. The PORV block valves are included in the MOV testing program.

5.2.3.28 Generic Letter 1990-06, June 1990 – "Enclosure B, Resolution of Generic Issue 94 – 'Additional Low-Temperature Overpressure Protection For Light-Water Reactors'"

Pressure/temperature limit curves are generated in accordance with WCAP-14040-A (Reference 41) and are documented in the Pressure and Temperature Limits Report (PTLR) per Technical Specification 5.6.6. Per NRC Regulatory Issue Summary 2004-04 (Reference 46), the provisions in 10 CFR 50.55a and Regulatory Guide 1.147 allow the application of ASME Code Case N-641, "Alternative Pressure-Temperature Relationship and Low Temperature Overpressure Protection System Requirements," in determining the acceptable LTOP system setpoints without need for exemption from the requirements of 10 CFR 50 Appendix G.

RCS overpressure protection during startup and shutdown is provided by the LTOP system, which consists of two mutually redundant and independent systems. Each system receives reactor coolant pressure and temperature signals. When a

low-temperature, high-pressure transient occurs, it opens a pressurizer PORV until the pressure returns to within acceptable limits. During normal operation, the system is off. If the reactor coolant temperature is below the low temperature setpoint and the enable switch on the main control board is not in the enable position, an alarm will sound on the main annunciator. The operator can then enable the circuit before a water-solid condition is reached, and the system is then ready to operate without further operator action.

During startup, at the temperature at which the steam bubble is formed, the trip circuit is automatically defeated and the operator can disable the system later in the startup sequence.

The system is completely automatic after being manually enabled. Whenever the system is enabled and reactor coolant temperature is below the low temperature setpoint, a high-pressure signal will trip it automatically and open the PORV until the pressure drops below the reset value.

Features of the LTOP control system include: indicating lights and annunciator alarm when the system trips, indicating lights when the system is enabled, and annunciator alarm when the isolation valve for the PORV is closed and the system is enabled.

The LTOP system relieves the RCS pressure transient given a single failure. Since the two LTOP systems are mutually redundant and independent, failure of either one would not affect the remaining system.

The system is testable at all times. The pressurizer PORVs are in series with motor-operated block valves, which may be closed during testing. Test signals may be injected into the appropriate control circuits and the position of the valve monitored and timed.

All LTOP components meet PG&E Design Class I. Refer to Chapter 7 for IEEE-279-1971 (Reference 21) criteria. The electrical portions of the system are powered from Class 1E 125-Vdc power sources. The air to the valves is backed by bottled nitrogen.

5.2.4 REFERENCES

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5.2.5 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

5.3 THERMAL HYDRAULIC SYSTEM DESIGN

The overall objective of the reactor core thermal and hydraulic design is to provide adequate heat transfer, compatible with the heat generation distribution in the core, such that the performance and safety criteria requirements of Chapter 4 are met under all plant operating conditions.

5.3.1 ANALYTICAL METHODS AND DATA

The thermal and hydraulic design bases of the RCS are described in Sections 4.3 and 4.4 in terms of core heat generation rates, DNBR, analytical models, peaking factors, and other relevant aspects of the reactor.

5.3.2 OPERATING RESTRICTIONS ON REACTOR COOLANT PUMPS

The No. 1 seal is a controlled-leakage, film-riding face seal. To establish face plate separation and equilibrium for startup of the RCPs, the operating procedures ensure that the pressure differential across the No. 1 seal will be at least 200 psid before starting the RCP. To ensure sufficient NPSH, the RCS pressure must be maintained at a minimum of 325 psig (with RCS temperature compatible with the pressure), with the VCT pressure high enough to provide an effective back pressure on the No. 1 seal of at least 15 psig.

5.3.3 TEMPERATURE-POWER OPERATING MAP

The programmed relationship between RCS temperature and power for Unit 1 is shown in Figure 5.3-1. A similar relationship has been programmed for Unit 2 and the corresponding temperatures are also shown in Figure 5.3-1.

The effects of reduced core flow due to inoperative pumps are discussed in Sections 5.5.1, 15.2, and 15.3.

Natural circulation capability of the system is shown in Section 4.4.3.

5.3.4 LOAD-FOLLOWING CHARACTERISTICS

The RCS is designed on the basis of steady state operation at full power heat load. The RCPs utilize constant-speed drives as described in Section 5.5 and the average coolant temperature is controlled to have a value that is a linear function of load, as described in Section 7.7.

5.3.5 TRANSIENT EFFECTS

Evaluation of transient effects is presented as follows:

Event	FSAR Section
Complete loss of forced reactor coolant flow	15.3.4
Partial loss of forced reactor coolant flow	15.2.5
Loss of external electrical load and/or turbine trip	15.2.7
Loss of normal feedwater	15.2.8
Loss of offsite power	15.2.9
Accidental depressurization of the RCS	15.2.13

Component cyclic and transient design occurrences are contained in Table 5.2-4.

5.3.6 THERMAL AND HYDRAULIC CHARACTERISTICS SUMMARY TABLE

The thermal and hydraulic characteristics are provided in Tables 4.1-1 and 5.1-1.

5.4 REACTOR PRESSURE VESSEL AND APPURTENANCES

Section 5.4 discusses the design, material, fabrication, inspection, and quality provisions that apply to the RPV and its appurtenances.

5.4.1 REACTOR PRESSURE VESSEL DESCRIPTION

5.4.1.1 Design Bases

The RPV is an integral part of the RCPB and is designed to maintain its integrity under all anticipated modes of plant operation, including exposure to all foreseeable pressure and temperature transients and neutron flux during the life of the plant, by ensuring that all resulting stresses remain within allowable values. The RPV supports the reactor core and CRDMs.

5.4.1.2 Design Transients

Cyclic loads are introduced by normal power changes, reactor trip, startup, and shutdown operations. These design bases cycles are selected for fatigue evaluation and constitute a conservative design envelope for the projected plant life. RPV analysis results in a usage factor that is less than 1.

Regarding the thermal and pressure transients involved in the LOCA, the RPV is analyzed to confirm that the delivery of cold emergency core cooling water to the vessel following a LOCA does not cause a loss of RPV integrity.

The design specifications require analysis to prove that the RPV is in compliance with the fatigue limits of ASME BPVC Section III-1965 through Winter 1966 Addenda (Unit 1) and Section III-1968 (Unit 2). The loadings and transients specified for the analysis are based on the most severe conditions expected during service. The typical normal heatup and cooldown rates are less than the 100°F per hour upset or faulted condition rate used for design evaluation purposes. These rates are reflected in the vessel design specifications (refer to Section 5.2).

5.4.1.3 Codes and Standards

The manufacturer of the reactor vessels for Diablo Canyon Unit 1 and Unit 2 is Combustion Engineering, Inc., Chattanooga, Tennessee. Refer to Table 5.2-3 for procurement information on RCS components. Pursuant to 10 CFR 50.55a(c), the applicable ASME requirements for RPV design, fabrication, and material specifications are ASME BPVC Section III-1965 through Winter 1966 Addenda for Unit 1 and Section III-1968 for Unit 2.

The RVCH was manufactured by AREVA. Pursuant to 10 CFR 50.55a(c), the applicable ASME BPVC requirements for design, fabrication, and material specifications are the requirements of ASME BPVC Section III-2001 through 2003 Addenda.

5.4.1.4 Reactor Pressure Vessel Description

The RPV is cylindrical with a welded hemispherical bottom head and removable, bolted, flanged, and gasketed hemispherical RVCH. The RPV flange and head are each sealed by two hollow metallic O-rings. Seal leakage is detected by means of two leakoff channels: one between the inner and outer ring and one outside the outer O-ring. The RPV contains the core, core support structures, control rods, and other parts directly associated with the core.

The RVCH contains fifty-eight head adapters (nozzles). These head adapters are tubular members, attached by partial penetration welds to the underside of the closure head. The upper end of the head adapters are welded to a CRDM latch housing or instrument adapter. The upper end of these items contains threads for the assembly of a CRDM rod drive travel housing or CET column. The RVCH also contains dedicated nozzles for the head vent and RVLIS.

Inlet and outlet nozzles are spaced evenly around the RPVs. Outlet nozzles are located on opposite sides of the RPV to facilitate optimum layout of the RCS equipment. The inlet nozzles are tapered from the coolant loop RPV interfaces to the RPV inside wall to reduce loop pressure drop.

The IHA is a multi-function structure located on top of the RVCH. The IHA includes the RVCH lift rig, the CRDM ventilation system (including fans, shrouds, and plenum), the CRDM missile shield, radiation shielding, the RPV stud tensioner hoist monorail, cable bridges, personnel access platforms, and ladders. The IHA also includes a seismic support structure, which is an integral part of the IHA that provides lateral structural support for the IHA and CRDMs. The seismic support structure assembly includes eight seismic tie-rod restraints to transfer load from the IHA and the CRDMs to the reactor cavity walls. Figure 5.4-3 shows the major components included in the seismic support structure (some items attached to the support structure are excluded for clarity).

The bottom head of the RPV contains penetration nozzles for connection and entry of the nuclear incore instrumentation. Each nozzle consists of a tubular member made of an Inconel stainless steel composite tube. Each tube is attached to the inside of the bottom head by a partial penetration weld.

Internal surfaces of the RPV that are in contact with primary coolant are weld overlaid with 5/32-inch minimum of stainless steel. The exterior of the RPV is insulated with canned stainless steel reflective sheets. The insulation is 3 inches thick and contoured to enclose the top, sides, and bottom of the RPV.

A schematic of the RPV is shown in Figure 5.4-1 for Unit 1 and Figure 5.4-2 for Unit 2. RPV principal design parameters for both Unit 1 and Unit 2 are provided in Table 5.4-1.

5.4.1.5 Inspection Provisions

The internal surface of the RPV can be inspected using visual nondestructive techniques over the accessible areas. If necessary, the core barrel can be removed, making the entire inside surface of the RPV accessible.

The RVCH is examined visually during each refueling. Periodic visual inspections of accessible outer CRDM penetration tubes and the gasket seating surface are performed. The transition area between the dome and head flange, which is the area of highest stress of the RVCH, is accessible on the outer surface for visual inspection, surface examination, and ultrasonic testing. The closure studs, nuts, and washers can be inspected periodically using visual, magnetic particle, and/or ultrasonic techniques.

Full-penetration welds in the following irradiated areas of the installed RPV are available for visual and/or nondestructive inspection:

(1) RPV shell

(2) Primary coolant nozzles

(3) Bottom head

(4) Field welds between the RPV, nozzles, and the main coolant piping

The design considerations that have been incorporated into the system to permit the above inspections are as follows:

(1) All reactor internals are completely removable. Appropriate tools, and the storage space required to permit these inspections, are provided.

(2) The RVCH is stored dry on the reactor operating deck during refueling to facilitate direct visual inspection.

(3) All RPV studs, nuts, and washers are removed to dry storage during refueling.

(4) Removable plugs are provided in the primary shield. The insulation covering the nozzle welds may be removed.

(5) A removable plug is provided in the lower core support plate to allow remote access for inspection of the bottom head without removal of the lower internals.

The RPV presents access problems because of the radiation levels and remote underwater accessibility to this component. Because of these limitations, several steps have been incorporated into the design and manufacturing procedures in preparation for

the periodic nondestructive tests that are required by the ISI program, and in accordance with ASME BPVC Section XI-2001 through 2003 Addenda. These are:

(1) Shop ultrasonic examinations were performed on all internally clad surfaces to acceptance and repair standards that ensure an adequate cladding bond to allow later ultrasonic testing of the base metal from the inside surface. The size of cladding bonding defect allowed is 3/4-inch by 3/4-inch.

(2) The design of the RPV shell in the core area is a clean, uncluttered, cylindrical surface to permit positioning of the ISI test equipment without obstruction.

(3) After the shop hydrostatic testing, selected areas of the RPV were ultrasonically tested and mapped to facilitate the ISI program.

5.4.2 FEATURES FOR IMPROVED RELIABILITY

RPV performance reliability is based on a conservative design, adequate protection measures, proper selection of materials, appropriate fabrication processes, quality assurance program implementation, conservative operating procedures, and an adequate ISI and material surveillance program. Section 5.2 addresses RPV design, overpressure protection, material selection, pressure and temperature operating limitations, and surveillance programs. Fabrication and quality assurance measures are discussed below.

5.4.3 PROTECTION OF CLOSURE STUDS

Refueling procedures require the studs, nuts, and washers be removed from the RVCH and placed in storage racks during preparation for refueling. The storage racks are then removed from the refueling cavity for maintenance and inspection prior to reactor closure and refueling cavity flooding. Therefore, the RVCH studs are never exposed to the borated refueling cavity water.

The stud holes in the reactor flange are sealed with special plugs before removing the RVCH, thus preventing leakage of the borated refueling water into the stud holes.

5.4.4 MATERIALS AND INSPECTIONS

RPV materials are listed in Table 5.2-11. Construction, inspections and tests for the RPV and appurtenances are presented in Table 5.4-2. ISIs meet the requirements of ASME BPVC Section XI-2001 through 2003 Addenda, as referenced in 10 CFR 50.55a.

5.4.5 SPECIAL PROCESSES FOR FABRICATION AND INSPECTION

5.4.5.1 Fabrication Processes

(1) Minimum preheat requirements were established for pressure boundary welds using low alloy weld material. Special preheat requirements were added for stainless steel cladding of low-stressed areas. Preheat was maintained until post-weld heat treatment, except for overlay cladding. Limitations on preheat requirements (a) decrease the probabilities of weld cracking by decreasing temperature gradients, (b) lower susceptibility to brittle transformation, (c) prevent hydrogen embrittlement, and (d) reduce peak hardness.

(2) On Unit 2, the use of severely sensitized stainless steel as a pressure boundary material was prohibited and eliminated either by choice of material or by programming the assembly method. This restriction on the use of sensitized stainless steel provides the primary system with preferential materials suitable for:

(a) Improved resistance to contaminants during shop fabrication, shipment, construction, and operation

(b) Application of critical areas.

Refer to Sections 5.2.2.5 and 5.2.3.22 for discussion of sensitization of RCS components.

(3) Galling prevention is accomplished by chrome plating of the surfaces of the guide studs in the RPV flange.

(4) Cracking prevention is accomplished by ensuring that the final joining beads are Inconel weld metal at all locations in the RPV where stainless steel and Inconel are joined.

(5) Core region shells fabricated of plate material have longitudinal welds and are angularly located away from the peak neutron exposure experienced in the RPV.

5.4.5.2 Tests and Inspections

Tests and inspections for the RPV and appurtenances are listed in Table 5.4-2. They are discussed below.

5.4.5.2.1 Ultrasonic Examinations

The following ultrasonic examinations were performed:

(1) During fabrication, angle beam inspection of 100 percent of plate material is performed to detect discontinuities that may be undetected by longitudinal wave examination, in addition to the design code straight beam ultrasonic test.

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(2) The RPV is examined after hydrotesting to provide a baseline map for use as a reference document in relation to later ISIs.

5.4.5.2.2 Penetrant Examinations

The partial penetration welds for the CRDM and instrument head adapters and RVHVS and RVLIS head penetration nozzles are inspected by dye penetrant after the first layer of weld material, after each 1/4-inch of weld metal, and the final surface. Bottom instrumentation tubes are inspected by dye penetrant after each layer of weld metal. Core support block attachment welds are inspected by dye penetrant after the first layer of weld metal and after each 1/2-inch of weld metal. This is required to detect cracks or other defects, to lower the weld surface temperatures for cleanliness, and to prevent microfissures. All austenitic steel surfaces are 100 percent dye penetrant tested after the hydrostatic test.

5.4.5.2.3 Magnetic Particle Examination

(1) All surfaces of quenched and tempered materials are inspected on the inside diameter prior to cladding and the outside diameter is 100 percent inspected after hydrotesting. This serves to detect possible defects resulting from the forming and heat treatment operations.

(2) The attachment welds for the RPV supports, lifting lugs, and refueling seal ledge are inspected after the first layer of weld metal and after each 1/2-inch of weld thickness. Where welds are back chipped, the areas are inspected prior to welding.

(3) All carbon steel surfaces are magnetic particle tested after the hydrostatic test.

5.4.6 QUALITY ASSURANCE SURVEILLANCE

The surveillance program that calls for RPV quality assurance provisions to verify proper fabrication and to ensure that integrity is maintained throughout the plant's lifetime, is listed in Table 5.4-2.

5.4.7 REACTOR PRESSURE VESSEL DESIGN DATA

The RPV design parameters are presented in Table 5.4-1.

5.4.8 REACTOR PRESSURE VESSEL EVAULATION

Section 5.2 presents an assessment of the stresses induced in the RPV during normal, upset, and faulted conditions, showing that in all cases they are below the respective allowable stresses (refer to Tables 5.2-5, 5.2-6, and 5.2-7).

5.5 COMPONENT AND SUBSYSTEM DESIGN

This section discusses performance requirements and design features of the various components of the RCS and associated subsystems.

5.5.1 REACTOR COOLANT PUMPS

Each unit has four identical RCPs, one in each loop.

5.5.1.1 Design Bases

The RCP ensures adequate core cooling by forced circulation flow, and hence sufficient heat transfer, to maintain a DNBR greater than the applicable limit value (refer to Sections 4.4.2.1 and 4.4.3.3) for all normal modes of operation. The required NPSH is, by conservative pump design, always less than that available by system design and operation.

Sufficient pump rotation inertia is provided by a flywheel, in conjunction with the impeller and motor assembly, to provide adequate flow during coastdown. This flow provides the core with adequate cooling, following an assumed loss of pump power.

The RCP motor has been tested without mechanical damage, at overspeeds up to and including 125 percent of normal speed (refer to Section 5.2.3.20).

The RCP is shown in Figure 5.5-1; its design parameters are provided in Table 5.5-1.

Code applicability and material requirements are provided in Tables 5.2-2 and 5.2-13, respectively.

5.5.1.2 Design Description

The RCP is a vertical, single-stage, centrifugal, shaft seal pump designed to pump large volumes of main coolant at high temperatures and pressures.

The pump consists of, from bottom to top, the hydraulic section, the shaft seal, and the motor. Each section is described as follows:

(1) The hydraulic section consists of an impeller, diffuser, casing, thermal barrier, heat exchanger, lower radial bearing, bolting ring, motor stand, and pump shaft.

(2) The shaft seal section consists of the No. 1 controlled leakage, film riding face seal, a shutdown seal (SDS) assembly, and the No. 2 and No. 3 rubbing face seals. The seals are contained within the main flange and seal housing.

(3) The motor section consists of a vertical solid-shaft, squirrel cage induction-type motor, and oil-lubricated double Kingsbury-type thrust bearing, two oil-lubricated radial bearings, and a flywheel.

Attached to the bottom of the pump shaft is the impeller. The reactor coolant is drawn up through the impeller, discharged through passages in the diffuser, and out through the discharge nozzle in the side of the casing. A thermal barrier heat exchanger above the impeller limits heat transfer between hot system water and pump internals. A weir plate, installed in the pump discharge nozzle, prevents excessive flow of ECCS injection water into the casing in the event of an SBLOCA.

High-pressure seal injection water is introduced through the thermal barrier wall. A portion of this water flows through the seals; the remainder flows downward into the RCS, where it acts as a buffer to prevent system water from entering the radial bearing and seal section of the unit. The heat exchanger provides a means of cooling system water entering the pump radial bearing and seal section to an acceptable level in the event that seal injection flow is lost. The water-lubricated journal-type pump bearing, mounted above the thermal barrier heat exchanger, has a self-aligning spherical seat.

The RCP motor bearings are of conventional design. The radial bearings are the segmented- pad-type and the thrust bearings are tilting pad Kingsbury bearings. All are oil-lubricated. The lower radial bearing and the thrust bearings are submerged in oil and the upper radial bearing is fed oil from the oil flow off the outer surface of the thrust runner.

The motor is an air-cooled squirrel cage induction motor. The insulation class of the motor is listed in Table 5.5-1. The rotor and stator are of standard construction and are cooled by air. A minimum of six RTDs are located throughout the stator to sense the winding temperature. The top of the motor consists of a flywheel and an anti-reverse rotation device.

Each RCP is equipped with a system to monitor shaft vibration. The system monitors pump shaft radial vibration, motor shaft radial vibration, and motor frame velocity. The two pump shaft radial vibration probes are mounted in a horizontal plane above the seal housing with one probe parallel to the pump discharge and the other perpendicular to the pump discharge. The two motor shaft vibration probes are mounted in a horizontal plane below the lower motor bearing with one probe parallel to the pump discharge and the other perpendicular to the pump discharge. The two velocity probes are mounted in a horizontal plane on the motor stand with one probe parallel to the pump discharge and the other perpendicular to the pump discharge. A keyphasor probe is mounted below the lower motor bearing and is used for spectral analysis and to measure pump speed. In the event that the signal from a probe becomes invalid and becomes a nuisance alarm the signal may be defeated, since the probes and cables are not accessible during power operation.

The instrumentation monitors are mounted in a common rack located on the operating deck in containment. Alarms in the control room are provided by the rack in containment. Vibration data from the instrument rack is collected and stored on a server in the administration building, and analyzed at a workstation in the common control room. The server and computer are shared by both units. The server or computer may be turned off to support maintenance or power switching, as the vibration equipment will still provide alarms and indication. If the server is off, indication requires connection of test equipment to the local rack. The RCP vibration monitoring system does not perform a PG&E Design Class I function.

As shown in Table 5.2-13, all parts of the pump in contact with the reactor coolant are austenitic stainless steel except for seals, bearings, and special parts. CCW is supplied to the two oil coolers on the pump motor and to the pump thermal barrier heat exchanger.

The pump shaft, seal housing, thermal barrier, bolting ring, and motor stand can be removed from the casing as a unit without disturbing the reactor coolant piping. The flywheel is available for inspection by removing the cover.

The performance characteristic, shown in Figure 5.5-2, is common to all of the fixed-speed mixed-flow pumps, and the "knee" at about 45 percent design flow introduces no operational restrictions since the pumps operate at full speed.

5.5.1.3 Design Evaluation

This section discusses RCP design features incorporated to ensure safe and reliable operation while maintaining RCS integrity.

5.5.1.3.1 Pump Performance

The RCPs are sized to equal or exceed the required flowrates (refer to Section 5.1.6). Initial RCS tests confirm the total delivery capability. Thus, assurance of adequate forced circulation coolant flow is provided prior to initial plant operation.

The RTS ensures that pump operation is within the assumptions used for loss-of-coolant flow analyses, which also ensures that adequate core cooling is provided to permit an orderly reduction in power if flow from an RCP is lost during operation.

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An extensive test program was conducted for several years to develop the controlled leakage shaft seal for pressurized water reactor applications. Long-term tests were conducted on less than full-scale prototype seals as well as on full-size seals. Operating plants continue to demonstrate the satisfactory performance of the controlled leakage shaft seal pump design.

The support of the stationary member of the No. 1 seal (seal ring) is such as to allow large deflections, both axial and tilting, while still maintaining its controlled gap relative to the seal runner. Even if all the graphite were removed from the pump bearing, the shaft could not deflect far enough to cause opening of the controlled leakage gap. The "spring-rate" of the hydraulic forces associated with the maintenance of the gap is high enough to ensure that the ring follows the runner under very rapid shaft deflections.

Testing of pumps with the No. 1 seal entirely bypassed (full reactor pressure on the No. 2 seal) shows that relatively small leakage rates would be maintained for long periods of time. The plant operator is warned of this condition by the increase in No. 1 seal leakoff, and has time to close this line and to conduct a safe plant shutdown without significant leakage of reactor coolant to the containment. Thus, it may be concluded that gross leakage from the pump does not occur, even if seals were to suffer physical damage.

The effect of loss of offsite power on the pump itself is to cause an RCS pump trip, and temporary stoppage in the supply of injection water to the pump seals and CCW to the thermal barrier for seal and bearing cooling if a generator trip results. The emergency diesel generators are started automatically due to loss of offsite power, so that CCW flow is automatically restored to ensure cooling of the pump seals and bearings when the reactor coolant temperature is above 150°F. Seal water injection flow is subsequently restored by automatically restarting a charging pump on diesel generator electrical power.

The SDS is housed within the No. 1 seal area and is a passive device actuated by high temperature resulting from a loss of seal injection and CCW cooling to the thermal barrier heat exchanger. The SDS is designed to function only when exposed to an elevated fluid temperature downstream of the RCP No. 1 seal, resulting from a loss of seal injection and CCW flow to the thermal barrier heat exchanger. SDS deployment limits leakage from the RCS through the RCP seal package. Leakage is limited when the SDS thermal actuator retracts due to intrusion of hot reactor coolant water into the seal area, which causes the SDS seal ring to constrict around the No. 1 seal sleeve.

5.5.1.3.2 Coastdown Capability

It is important to reactor operation that the reactor coolant continues to flow for a short time after reactor trip. To provide this flow after a reactor trip, each RCP is provided with a flywheel. Thus, the rotating inertia of the pump, motor, and flywheel is employed during the coastdown period to continue the reactor coolant flow.
An inadvertent actuation of the SDS on a rotating assembly will not have any measurable impact on RCP coastdown or on the pump’s capability to provide sufficient cooling flow to the reactor core.

The pump is designed for the design earthquake (DE), double-design earthquake (DDE), and Hosgri earthquake (HE) at the site. Bearing integrity is maintained as discussed below. It is, therefore, concluded that the coastdown capability of the pumps

is maintained even under the most adverse case of a pump trip coincident with the DE, DDE, or HE.

5.5.1.3.3 Flywheel Integrity

Integrity of the RCP flywheel is discussed in Sections 5.2.3.20 and 5.2.3.21.

5.5.1.3.4 Bearing Integrity

The design requirements for the RCP bearings are primarily aimed at ensuring a long life with negligible wear, so as to give accurate alignment and smooth operation over long periods of time. To this end, the surface-bearing stresses are held at a very low value, and, even under the most severe seismic transients, do not begin to approach loads which cannot be adequately carried for short periods of time.

Because there are no established criteria for short-term, stress-related failures in such bearings, it is not possible to make a meaningful quantification of such parameters as margins to failure, safety factors, etc. A qualitative analysis of the bearing design, embodying such considerations, gives assurance of the adequacy of the bearing to operate without failure.

High/low oil level in the motor bearings signals an alarm in the control room. Each motor bearing contains embedded temperature detectors, and so initiation of failure, separate from loss of oil, is indicated and alarmed in the control room as a high bearing temperature. Even if these indications are ignored and the bearing proceeds to fail, the low melting point of Babbitt metal on the pad surfaces ensures that no sudden seizure of the bearing occurs. In this event, the motor continues to drive since it has sufficient reserve capacity to operate until it can be shut down.

The RCP shaft is designed so that its critical speed is well above the operating speed.

5.5.1.3.5 Locked Rotor

The postulated case in which the pump impeller severely rubs on a stationary member and then seizes, was evaluated (refer to Section 15.4.4 for the evaluation of this event on the RCS as a whole). The analysis showed that under such conditions, assuming instantaneous seizure of the impeller, the pump shaft fails in torsion just below the coupling to the motor, disengaging the flywheel and motor from the shaft. This constitutes a loss of coolant flow in the loop. Following such a postulated seizure, the motor continues to run without any overspeed, and the flywheel maintains its integrity since it is still supported on a shaft with two bearings.

There are no credible sources of shaft seizure other than impeller rubs. Any seizure of the pump bearing is precluded by the graphite in the bearing. Any seizure in the seals results in a shearing of the anti-rotation pin in the seal ring. The motor has adequate power to continue pump operation even after the above occurrences. Indications of

pump malfunction in these conditions are first, by high-temperature signals from the bearing water temperature detector, and second, by excessive No. 1 seal leakoff indications. Along with these signals, pump vibration levels are checked. When there are indications of a serious malfunction, the pump is shut down for investigation.

5.5.1.3.6 Critical Speed

The RCPs are designed to operate below first critical speed. This results in a shaft design that, even under the most severe postulated transient, gives very low stress values.

Both the damped and lateral natural frequencies are determined by establishing a number of shaft sections and applying weights and moments of inertia for each section bearing spring and damping data. The torsional natural frequencies are similarly determined. The lateral and torsional natural frequencies are greater than 120 and 110 percent of the running speed, respectively.

5.5.1.3.7 Missile Generation

Each pump component is analyzed for missile generation. Any fragments of the motor rotor would be contained by the heavy stator. The same conclusion applies to the pump impeller because the small fragments that might be ejected would be contained by the heavy casing (refer to Sections 5.2.3.20 and 5.2.3.21).

5.5.1.3.8 Pump Cavitation

The minimum NPSH required by the RCP at running speed is approximately 170 feet (approximately 74 psi). For the controlled leakage seal to operate correctly, a differential pressure of approximately 200 psi across the seal is necessary. This results in a requirement for a minimum of 325 psi pressure in the primary loop before the RCP may be operated. This 325 psi requirement is for initial fill and vent only. In normal operation, a Δp greater than 200 psi at the Number 1 seal is required for RCP operation. This requirement is reflected in the operating instructions. At this pressure, the NPSH requirement is exceeded and no limitation on pump operation occurs from this source.

5.5.1.3.9 Pump Overspeed Considerations

The generator and the RCP remain electrically connected for 30 seconds following turbine trip actuated by either the RTS or the turbine protection systems, except for certain trips caused by electrical or mechanical faults which require immediate tripping of the generator. A complete load disconnect with turbine overspeed would result in an overspeed potential for the RCP. The turbine control system and the turbine intercept valves limit the overspeed to less than 120 percent, which is less than the design overspeed of the RCP. As additional backup, the main turbine has a mechanical overspeed protection trip usually set at about 110 percent.

The details of the turbine trip interface logic are shown in Figures 5.5-13 and 5.5-17. The sequence of events following a generator trip, which transfers the ESFs onto the standby power supply, is discussed in Section 8.3.

5.5.1.3.10 Anti-reverse Rotation Device

Each RCP is provided with an anti-reverse rotation device in the motor. This anti-reverse mechanism consists of five pawls mounted on the outside diameter of the flywheel, a serrated ratchet plate mounted on the motor frame, a spring return for the ratchet plate, and three shock absorbers.

After the motor comes to a stop, a minimum of one pawl engages the ratchet plate and, as the motor tends to rotate in the opposite direction, the ratchet plate also rotates until stopped by the shock absorbers. The rotor remains in this position until the motor is energized again. After the motor comes up to speed, the ratchet plate is returned to its original position by the spring return.

When the motor is started, the pawls initially drag over the ratchet plate. Once the motor reaches sufficient speed, centrifugal forces acting on the pawls produce enough friction to prevent the pawls from rotating, and thus hold the pawls in the elevated position until the motor is stopped.

5.5.1.3.11 Shaft Seal Leakage

During normal operation, leakage along the RCP shaft is controlled by three shaft seals arranged in series so that reactor coolant leakage to the containment is essentially zero. Charging flow is directed to each RCP via a 5-micron seal (maximum) water injection filter. It enters the pumps through the thermal barrier and is directed down to a point between the pump shaft bearing and the thermal barrier cooling coils. Here the flow splits and a portion flows down past the thermal barrier cooling cavity and labyrinth seals. The remainder flows up the pump shaft, cooling the lower bearing, and leaves the pump via the No. 1 seal bypass line or the No. 1 seal leakoff line. There is also a minor flow through the No. 2 seal.

Leakoff flow through the No. 1 seal from each pump is piped to a common manifold, and then, via a seal water return filter, through a seal water heat exchanger, to the VCT. The VCT provides a back pressure of at least 15 psig on the No. 1 seal.

A small amount of No. 1 seal leakoff passes through the No. 2 seal. No. 2 seal leakoff flows to the reactor coolant drain tank (RCDT).

The No. 3 seal is a double dam seal that divides seal flow into two paths. Part of the flow is directed radially outward to join the No. 2 seal leakoff line and the second part flows radially inward to the No. 3 seal leakoff line to the containment structure sump. A

standpipe is provided to ensure a back pressure of at least 7 feet of water on the No. 3 seal.

In the event of a loss of seal injection and CCW flow to the thermal barrier heat exchanger, reactor coolant begins to travel along the RCP shaft and displaces the cooler seal injection water. The SDS, designed to actuate only when exposed to an elevated fluid temperature downstream of the RCP No. 1 seal, deploys via retraction of a thermal actuator, which causes the SDS seal ring to constrict around the No. 1 seal sleeve. SDS deployment controls shaft seal leakage and limits the loss of reactor coolant via the RCP seal package to 1 gpm or less.

5.5.1.3.12 Spacer Couplers

The installation of a removable spool piece, shown in Figure 5.5-3, in the RCP shaft facilitates the inspection and maintenance of the pump seal system without breaking any of the fluid, electrical, or instrumentation connections to the motor, without removal of the motor.

5.5.1.4 Tests and Inspections

Support feet are cast integral with the casing to eliminate a weld region. The design enables disassembly and removal of the pump internals for normal access to the internal surface of the pump casing.

The RCP quality assurance program is given in Table 5.5-2. Refer to Sections 5.1.8.19, 5.1.8.20, 5.2.3.14, and 5.2.3.15 for further discussion of testing and inspection of the RCS.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

5.5.1.4.1 Electroslag Welding

RCP casings fabricated by electroslag welding were qualified as follows:

(1) The electroslag welding procedure employing 2- and 3-wire technique was qualified in accordance with the requirements of the ASME BPVC, Section IX, and Code Case 1355 (refer to Table 5.2-1) plus supplementary evaluations specified by Westinghouse.

(2) A separate weld test was made using the 2-wire electroslag technique to evaluate the effects of a stop and restart of welding by this process. This evaluation was performed to establish proper procedures and techniques as such an occurrence was anticipated during production applications due to equipment malfunction, power outages, etc.

(3) All of the weld test blocks in (1) and (2) above were radiographed using a 24 MeV betatron. The radiographic quality level obtained was between 0.5 and 1 percent, as defined by ASTM E-94. There were no discontinuities evident in any of the electroslag welds.

The casting segments were surface conditioned for 100 percent radiographic and penetrant inspections. The radiographic acceptance standards were ASTM E-186 Severity Level 2 except no Category D or E defectives were permitted for section thicknesses up to 4-1/2 inches and ASTM E-280, Severity Level 2, for section thicknesses greater than 4-1/2 inches. The edges of the electroslag weld preparations were machined. These surfaces were also penetrant inspected prior to welding. The penetrant acceptance standards were those of the ASME BPVC, Section III, Paragraph N-627.

The completed electroslag weld surfaces were ground flush with the casting surface. The electroslag weld and adjacent base material were then 100 percent radiographed in accordance with ASME BPVC Case 1355. Also, the electroslag weld surfaces and adjacent base material were penetrant inspected in accordance with ASME BPVC, Section III, Paragraph N-627. Weld metal and base metal chemical and physical properties were determined and certified. Heat treatment furnace charts were recorded and certified, and are available at the NSSS vendor's facilities.

5.5.1.4.2 In-process Control of Variables

Many variables must be controlled to maintain desired quality welds. These variables and their relative importance are as follows:

(1) Heat Input vs. Output

The heat input is determined by the product of volts and current and measured by voltmeters and ammeters, which are considered accurate and are calibrated every 30 days. During any specific weld these meters are constantly monitored by the operators.

(2) Weld Gap Configuration

The weld gap configuration is controlled by 1-1/4-inch spacer blocks. As these blocks are removed, there is the possibility of gap variation. It has been found that a variation from 1 to 1-3/4 inches is not detrimental to weld quality as long as the current is adjusted accordingly.

(3) Flux Chemistry

The flux used for welding is Arcos BV-I Vertomax. This is a neutral flux, the chemistry of which is specified by Arcos Corporation. The molten slag is kept at a nominal depth of 1-3/4 inches and may vary in depth by plus or

minus 3/8 inch without affecting the weld. This is measured with a stainless steel dipstick.

(4) Weld Cross-Section Configuration

The higher the current or heat input and the lower the heat output, the greater the dilution of weld metal with base metal. This causes a rounder barrel-shaped configuration compared to welding with lower heat input and higher heat output, which reduces the amount of dilution and provides a more narrow barrel-shaped configuration. Configuration is also a function of section thickness; the thinner the section, the rounder the pattern produced.

5.5.1.4.3 Welder Qualification

Welder qualification is in accordance with ASME BPVC, Section IX rules.

5.5.2 STEAM GENERATORS

Each RCS loop contains a vertical U-tube SG. The SGs provide high quality steam to the turbine. The tube and tubesheet boundary are designed to prevent the transfer of radioactivity generated within the core to the secondary system.

5.5.2.1 Design Bases

SG design data are provided in Table 5.5-3. The design can sustain the transient conditions identified in Table 5.2-4. Estimates of radioactivity levels anticipated in the secondary side of the SGs during normal operation and their bases for the estimates are discussed in Section 11.1. The transient analysis of a SGTR is discussed in Section 15.4.

When operating at 100 percent power, integral moisture separating equipment reduces moisture content of the steam at the exit of the SGs to ≤0.05 percent. Under the following transient conditions, the moisture content at the exit of the SGs is <0.25 percent:

- loading or unloading at a rate of 5 percent of full power steam flow per minute in the range from 15 to 100 percent of full load steam flow
- a step load change of 10 percent of full power in the range from 15 to 100 percent of full load steam flow

The SG tubesheet complex meets the stress limitations and fatigue criteria specified in ASME BPVC Section III-1998 through 2000 Addenda. Per Section 5.2.2.1.5.3, emergency conditions do not apply. Codes and materials requirements of the SG are

listed in Tables 5.2-2 and 5.2-14, respectively. The SG design maximizes integrity against hydrodynamic excitation and vibration failure of the tubes for plant life.

The water chemistry in the reactor side is selected to provide the necessary boron content for reactivity control and to minimize corrosion of RCS surfaces. Water chemistry for the primary coolant side is presented in Table 5.2-15.

5.5.2.1.1 Design Basis for the Steam Outlet Nozzle Flow Restrictor

The design criterion for the steam nozzle flow restrictors is to limit steam flow in the event of an MSLB during normal operating conditions, in order to reduce pressure drop loadings on the SG internal components, as well as to limit the mass and energy release rate into the containment.

5.5.2.2 Design Description

The SG, shown in Figure 5.5-4, is a vertical shell and U-tube design with evaporators having integral moisture separating equipment. The reactor coolant flows through the inverted U-tubes, entering and leaving through the nozzles located in the hemispherical bottom head of the SG. Steam is generated on the shell side and flows upward through the moisture separators to the outlet nozzle at the top of the vessel. The head is divided into inlet and outlet chambers by a vertical partition plate extending from the head to the tubesheet. Manways are provided for access to both sides of the divided head.

The SG unit is primarily carbon steel. The heat transfer tubes and the divider plate are Inconel and the interior surfaces of the reactor coolant channel heads and nozzles are clad with austenitic stainless steel. The primary side of the tubesheet is weld clad with Inconel.

Feedwater is introduced into the SGs through a feedwater nozzle located in the upper shell. The nozzle does not require a flow-limiting device because the feedring itself provides this function. The nozzle contains a welded thermal liner that minimizes the impact of rapid feedwater temperature transients on the nozzle. The feedwater distribution ring is welded to the feedwater nozzle to minimize the potential for draining the ring. The feedring is located above the elevation of the feed nozzle to minimize the time required to fill the feed nozzle during a cold water addition transient. The feedwater is discharged through spray nozzles installed on the top of the ring. These features reduce the thermal fatigue loading on the feedwater nozzle, eliminate steady-state thermal stratification in the feedwater nozzle and feedwater piping elbow at the feedwater nozzle entrance, and minimize the potential for bubble- collapse water hammer in the feedwater distribution ring. The feedwater piping elbow at the feedwater nozzle entrance also contains an elbow thermal liner that minimizes the effects of thermal stratification on the elbow-to-nozzle weld and the weld of the feedwater inlet thermal sleeve to feedwater nozzle.

The SG feedring is fabricated from alloy steel with a significant chromium content to provide enhanced erosion/corrosion resistance characteristics. The feedring has spray nozzles that are spaced around the feedring circumference to distribute the feedwater into the upper shell recirculating water pool. The spray nozzle perforations also act to prevent loose parts ingress from the feedwater system.

Subsequently, the water-steam mixture flows upward through the tube bundle and into the steam drum section. A set of centrifugal moisture separators, located above the tube bundle, removes most of the entrained water from the steam. The moisture separators recirculate flow that mixes with feedwater as it enters the downcomer formed by the shell and tube bundle wrapper. Steam dryers are employed to increase the steam quality to a minimum of 99.95 percent, which corresponds to a steam outlet moisture content of 0.05 percent. The dryers can be inspected, or disassembled and removed, through one of two bolted and gasketed secondary manway access openings.

5.5.2.2.1 Design Description of the Steam Outlet Nozzle Flow Restrictor

An integral flow restrictor is provided in each steam nozzle to limit flow in the event of an MSLB accident downstream of the steam nozzle. The flow restrictor consists of seven holes in the steam outlet nozzle forging, with Venturi type flow limiting inserts installed in each of these holes. The total minimum flow area is 1.4 ft^2 for the seven inserts. The Alloy 690 flow limiting inserts are welded to the Alloy 690 cladding at the steam nozzle bottom. Materials and inspection requirements applied in fabrication of the steam nozzle flow restrictor assemblies conform to ASME BPVC Section III-1998 through 2000 Addenda requirements.

The steam outlet nozzle flow restrictor assembly is shown in Figure 5.5-18.

5.5.2.3 Design Evaluation

5.5.2.3.1 Forced Convection

The limiting case for heat transfer capability is the nominal 100 percent design thermal duty. To ensure that this thermal duty will be met, the SGs are designed to operate with an effective fouling factor, or heat transfer resistance, that is greater than that experienced for comparable units in service. Adequate tubing area is selected to ensure that the full design heat removal rate is achieved for these conditions.

The historical best estimate fouling factor applied to Alloy 690-TT tubing is 0.00006 hr-ft^2-°F/Btu. The design fouling factor for the Diablo Canyon SGs is 0.00018 hr-ft^2-°F/Btu. When added to the conduction resistance of the tubing, this additional resistance accounts for approximately 17 percent margin for heat transfer, i.e., a 17 percent higher heat transfer coefficient is expected compared to the design value. This margin ensures that the SGs will provide sufficient heat transfer capability through the design life.

5.5.2.3.2 Natural Circulation Flow

The driving head created by the change in coolant density as it is heated in the core and rises to the outlet nozzle initiates convection circulation. This circulation is enhanced by the fact that the SGs, which provide a heat sink, are at a higher elevation than the reactor core, which is the heat source. Thus, natural circulation is ensured for the removal of decay heat during hot shutdown in the unlikely event of loss of forced circulation. This was confirmed by DCPP Unit 1 testing.

5.5.2.3.3 Secondary System Fluid Flow Instability Prevention

Undesirable perturbations in secondary side flow are postulated to result from events such as water hammer and circulation loop instability. Such events can compromise the functional capability and mechanical integrity of the secondary system. The SGs include design features intended to preclude these occurrences.

The potential for water hammer is mitigated by the inclusion of an upward-sloping section of the feedwater ring header. This reduces the volume within the feedwater ring assembly that could potentially be filled with steam, and also reduces the possibility of thermal stratification in the feed flow. The SGs include top-discharge spray nozzles, which further reduce the possibility of steam pockets being trapped in the feedwater ring, and also serve as a means to prevent loose parts from entering the SG through the feedwater system.

Instability in the circulation loop for the secondary fluid can result from a distribution of pressure drops that favors two-phase flow, which is de-stabilizing and is found in the upper tube bundle and moisture separators, as opposed to single-phase flow, which is stabilizing and is found in the downcomer and lower tube bundle areas. A stability damping factor is determined in which a negative value indicates damped, stable circulation flow. The SGs are designed to provide damped, stable circulation over the full range of operating conditions, with sufficient margin to prevent increased two-phase pressure drop, caused by conditions such as a partially blocked, broached tube support plate flow area, from causing instability.

5.5.2.3.4 Tube and Tubesheet Stress Analyses

Tube and tubesheet stress analyses for the SGs confirm that the SG tubesheet will withstand the loading (quasi-static rather than shock loading) caused by LOCA. With the acceptance of the DCPP LBB analysis by the NRC (Reference 10), dynamic loading conditions resulting from pipe rupture events in the main RCL piping no longer have to be considered in the design basis analyses; only the much smaller dynamic loads resulting from RCS branch line breaks have to be considered (refer to Section 3.6.2.1.1.1).

5.5.2.3.5 Corrosion

All volatile chemistry is used in the main steam, feedwater, and condensate systems to provide improved corrosion protection and control.

The control measures exercised over the secondary water chemistry for the purpose of inhibiting SG tube degradation consist of a program encompassing: (a) scheduled sampling and analyses of fluid systems for the critical control parameters, (b) recording, reviewing, and management of data, (c) identification of process sampling points, (d) guidance for corrective actions for off-point chemistry, (e) identification of the authority responsible for the interpretation of data, and (f) the sequence and timing of administrative events required to initiate corrective action.

Additional control measures for secondary water chemistry come from the turbine manufacturer. The program includes the monitoring of main steam purity. The SGs include a number of key design features that enhance operation, performance, and maintenance. The design features and materials have been developed and selected to minimize the potential for tube degradation. The design features enhance steam and water flow by the tubes, which minimizes the potential for concentration of chemical species that can be detrimental to tubing material.

The U-tubes are fabricated of nickel-chromium-iron (Ni-Cr-Fe) Alloy 690. The tubes undergo thermal treatment following tube-forming and annealing operations. The thermal treatment subjects the tubes to elevated temperatures for a prescribed period of time to improve the microstructure of the material. Thermally treated Alloy 690 has been shown in laboratory tests and operating nuclear power plants to be very resistant to primary water stress corrosion cracking and outside diameter initiated stress corrosion cracking.

5.5.2.3.6 Design Evaluation for the Steam Outlet Nozzle Flow Restrictor

In the event of an MSLB, steam flow rate from the SGs is restricted by the outlet nozzle Venturi inserts, which limit the steam blowdown rate from the SGs.

5.5.2.3.7 Flow-induced Vibration

In the design of the SGs, the possibility of degradation of tubes due to either mechanical- or flow-induced excitation is thoroughly evaluated. This evaluation includes detailed analysis of the tube support systems as well as an extensive research program with tube vibration model tests.

In evaluating degradation due to vibration, consideration is given to sources of excitation such as those generated by primary fluid flowing within the tubes, mechanically induced vibration, and secondary fluid flow on the outside of the tubes. During normal operation, the effects of primary fluid flow within the tubes and mechanically induced vibration are considered to be negligible and should cause little

concern. Thus, the primary source of tube vibrations is the hydrodynamic excitation by the secondary fluid on the outside of the tubes. In general, three vibration mechanisms have been identified:

(1) Vortex shedding

(2) Fluidelastic excitation

(3) Turbulence

Vortex shedding does not provide detectable tube bundle vibration for the following reasons:

(1) Flow turbulence in the downcomer and tube bundle inlet region inhibits the formation of Von Karman's vortex train.

(2) The spatial variations of cross flow velocities along the tube preclude vortex shedding at a single frequency.

(3) Both axial and cross flow velocity components exist on the tubes. The axial flow component disrupts the Von Karman vortices.

The SG design is qualified by analyses (relying on theoretical calculations based on laboratory test data and operating SG experience), which demonstrate that no tubes will experience unacceptable degradation or wear due to vibration over the SG design life.

5.5.2.4 Tests and Inspections

The SG quality assurance program is given in Table 5.5-5. Radiographic inspection and acceptance standards are in accordance with the requirements of ASME BPVC Section III-1998 through 2000 Addenda.

Liquid penetrant inspection was performed on weld deposited tubesheet cladding, channel head cladding, tube-to-tubesheet weldments, and weld deposit cladding. Liquid penetrant inspection and acceptance standards are in accordance with the requirements of ASME BPVC Section III-1998 through 2000 Addenda.

Magnetic particle inspection was performed on all pressure boundary forgings (tubesheet, shell barrels, channel head, transition cone, elliptical head, and secondary-side nozzles), and the following weldments:

- Nozzle to shell
- Upper lateral support lugs
- Instrument connections
- Temporary attachments after removal
- All accessible pressure-retaining welds after hydrostatic testing.

Magnetic particle inspection and acceptance standards were in accordance with the requirements of ASME BPVC Section III-1998 through 2000 Addenda.

Ultrasonic examination was performed on all pressure boundary forgings (tubesheet, shell barrels, channel head, transition cone, elliptical head, primary nozzle safe ends, and secondary-side nozzles).

Manways provide access to both the primary and secondary sides of the SGs. Primary side inspection and maintenance is described in Section 5.5.2.5 and is typically performed with nozzle dams in place to isolate the SG bowl from the RCS.

5.5.2.4.1 Tests and Inspections for the Steam Outlet Nozzle Flow Restrictor

The flow restrictor Venturi inserts at the steam outlet are located inside the steam outlet nozzle and welded to the cladding. Therefore, the flow restrictor inserts are not a pressure boundary component. However, component integrity is ensured by compliance with ASME BPVC Section III-1998 through 2000 Addenda requirements.

5.5.2.5 Steam Generator Tube Surveillance Program

5.5.2.5.1 Inservice Inspection

SG tube inspection is performed in accordance with the Technical Specifications (Reference 6) and the DCPP surveillance test procedure. Eddy current non-destructive testing is used to perform tube inspections. The SG tube surveillance program ensures that the structural and leakage integrity of this portion of the RCS will be maintained. The program for ISI of SG tubes is based on NEI 97-06 (Reference 5). ISI of SG tubing is essential in order to maintain surveillance of the conditions of the tubes in the event there is evidence of mechanical damage or progressive degradation due to design, manufacturing errors, or inservice conditions that lead to corrosion. ISI of SG tubing also provides a means of characterizing the nature and cause of any tube degradation so that corrective measures can be taken.

Tube degradation will be detected during scheduled inservice SG tube examinations. SG tube inspections of operating plants have demonstrated the capability to reliably detect degradation that has penetrated 20 percent of the original tube wall thickness. Plugging is required for all tubes with imperfections exceeding the plugging limit defined in the Technical Specifications. Degraded tubes may be left in service if non-destructive examination sizing techniques verify that the imperfection is less than the plugging limit (References 5 and 6).

5.5.2.5.2 Primary-to-Secondary Leakage

The plant is expected to be operated in a manner such that the secondary coolant will be maintained within those chemistry limits found to result in negligible corrosion of the

SG tubes. DCPP Technical Specifications limit primary to secondary leakage through an SG to 150 gallons per day. This limit is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or an MSLB. DCPP has demonstrated that primary-to-secondary leakage of 150 gallons per day per SG can readily be detected during power operation. Leakage in excess of this limit will require plant shutdown and an unscheduled inspection, during which the leaking tubes will be located and plugged.

The dose consequence analyses in Section 15.5 address accident-induced leakage up to 0.75 gpm (total for all 4 SGs) at standard temperature and pressure.

5.5.3 REACTOR COOLANT PIPING

Reactor coolant piping provides a flowpath connecting the major components of each RCS loop. The RCS piping constitutes a boundary to contain the coolant under operating temperature and pressure conditions and limit leakage (and radioactivity release) to the containment atmosphere. It contains pressurized water that is circulated at a flowrate and temperature consistent with reactor core thermal and hydraulic performance requirements.

5.5.3.1 Design Bases

The RCS piping was designed and fabricated to accommodate the stresses due to the pressures and temperatures attained under all expected modes of plant operation or system interactions. Code and material requirements are provided in Table 5.2-2 and Section 5.2.2.3.

Materials of construction are specified to minimize corrosion/erosion and ensure compatibility with the operating environment.

Refer to Section 5.2.2.1.3 for the codes and standards applicable to the RCL and pressurizer surge line piping for both Unit 1 and Unit 2.

5.5.3.2 Design Description

Principal design data for the RCS piping for both Unit 1 and Unit 2 are provided in Table 5.5-6. The RCS piping was specified in the smallest sizes consistent with system requirements. In general, high fluid velocities are used to reduce piping sizes. This design philosophy results in the reactor inlet and outlet piping diameters listed in Table 5.5-6. The line between the SG and the pump suction is larger to reduce pressure drop and improve flow conditions to the pump suction. To further improve pump suction conditions, a flow splitter is provided in the pipe bend upstream of the pump suction.

The reactor coolant piping is seamless forged, and fittings are cast. Cast sections of large 90° elbows are joined by electroslag welds. All materials are austenitic stainless steel. All smaller piping that is part of the RCPB, such as the pressurizer surge line,

spray and relief line, loop drains, and connecting lines to other systems are also austenitic stainless steel. The nitrogen supply line for the PRT is carbon steel. All joints and connections are welded, except for the PORVs and PSVs, where flanged joints are used. Thermal sleeves are installed at points in the system where high thermal stresses could develop due to rapid changes in fluid temperature during normal operational transients. These points include:

(1) Charging connections at the primary loop from the CVCS

(2) Both ends of the pressurizer surge line

(3) Pressurizer spray line connection at the pressurizer

Thermal sleeves were not provided for the remaining injection connections of the ECCS since these connections are not in normal use.

All piping connections from auxiliary systems were made above the horizontal centerline of the reactor coolant piping, with the exception of:

(1) RHR pump suction, which is 45° down from the horizontal centerline. This enables the water level in the RCS to be lowered in the reactor coolant pipe while continuing to operate the RHR system, should this be required for maintenance.

(2) Loop drain lines and the connection for temporary level measurement of water in the RCS during refueling and maintenance operation.

(3) The differential pressure taps for flow measurement are downstream of the SGs on the first 90° elbow. There are three flow transmitters at each elbow. The transmitters at each elbow are arranged so that they use a common high-pressure tap (on the outside of the elbow) and separate low pressure taps (on the inside of the elbow). Additional discussion is included in Section 7.2.2.1.4.

Penetrations into the coolant flowpath were limited to the following:

(1) The spray line inlet connections extend into the cold leg piping in the form of a scoop so that the velocity head of the RCL flow adds to the spray driving force.

(2) The reactor coolant sample system taps protrude into the main stream to obtain a representative sample of the reactor coolant.

(3) The narrow range RCS temperature sensors (RTDs) are mounted in thermowells that extend into the hot and cold legs. The RTD bypass scoops and nozzles have been capped.

(4) The wide range RCS temperature sensors (RTDs) are mounted in thermowells that protrude into the hot legs and cold legs.

Signals from these instruments are used to compute the reactor coolant ΔT (temperature of the hot leg, T_{hot}, minus the temperature of the cold leg, T_{cold}) and an average reactor coolant temperature (T_{avg}). The T_{avg} and ΔT for each loop are indicated on the main control board. Chapter 7 further describes the temperature sensor arrangement.

The RCPB piping includes those sections of piping interconnecting the RPV, SG, and RCP. It also includes the following:

(1) Charging line and alternate charging line from the isolation valve up to the branch connections on the RCL

(2) Letdown line and excess letdown line from the branch connections on the RCL to the isolation valve

(3) Pressurizer spray lines from the reactor coolant cold legs to the spray nozzle on the pressurizer vessel

(4) RHR lines to or from the RCLs up to the designated isolation or check valve

(5) SI lines from the designated isolation or check valve to the RCLs

(6) Accumulator lines from the designated isolation or check valve to the RCLs

(7) Loop fill, loop drain, sample, and instrument lines to or from the designated isolation valve to or from the RCLs

(8) Pressurizer surge line from one RCL hot leg to the pressurizer vessel inlet nozzle

(9) Abandoned RTD scoop element, pressurizer spray scoop, sample connection with scoop, reactor coolant temperature element installation boss, and the temperature element thermowell itself

(10) All branch connection nozzles attached to RCLs

(11) Pressure relief lines from nozzles on top of the pressurizer vessel up to and through the PORVs and PSVs

(12) Seal injection water and labyrinth differential pressure lines to or from the RCP inside reactor containment

(13) Auxiliary spray line from the isolation valve to the pressurizer spray line header

(14) Sample lines from pressurizer to the isolation valve

(15) Pressurizer loop seal drain lines to the pressurizer.

Details of the materials of construction and codes used in the fabrication of reactor coolant piping and fittings are discussed in Section 5.2.

5.5.3.3 Design Evaluation

5.5.3.3.1 Piping Load and Stress Evaluation

Piping loads and stress evaluation methodology for normal, upset, and faulted conditions are described in Section 5.2.2.1.

5.5.3.3.2 Material Corrosion/Erosion Evaluation

The water chemistry is selected to minimize corrosion. A periodic analysis of the coolant chemical composition is performed to verify that the reactor coolant quality meets the specifications. The RCS water chemistry is presented in Section 5.2.2.3.4 and Table 5.2-15.

An upper limit of about 50 feet per second is specified for internal coolant velocity to avoid the possibility of accelerated erosion. All pressure-containing welds within the RCPB are available for examination and have removable insulation.

5.5.3.4 Tests and Inspections

5.5.3.4.1 Inservice Testing and Inspection

Refer to Sections 5.1.8.19, 5.1.8.20, 5.2.3.14, and 5.2.3.15 for further discussion of testing and inspection of the RCS.

5.5.3.4.2 Piping Quality Assurance

The RCS piping quality assurance program is given in Table 5.5-7.

5.5.3.4.3 Electroslag Weld Quality Assurance

The 90° elbows used in the RCL piping were electroslag welded. A description of this procedure is contained in Section 5.5.1.

The following quality assurance actions for RCS piping were undertaken:

(1) The electroslag welding procedure employing 1-wire technique was qualified in accordance with the requirements of ASME BPVC Section IX, and Code Case 1355 plus supplementary evaluation.

(2) The casting segments were surface conditioned for 100 percent radiographic and penetrant inspections. The acceptance standards were USAS Code Case N-10, and ASTM E-186, Severity Level 2, except no Category D or E defectives were permitted.

5.5.4 MAIN STEAM LINE FLOW RESTRICTORS

As described in Section 5.5.2.2.1, each SG has a flow restrictor located in the steam outlet nozzle to limit the steam blowdown from the SGs in the event of an MSLB. The flow restrictor consists of seven 6.03-inch ID venturi nozzles. In addition, a 16-inch flow restrictor is installed in each main steam line outlet to measure steam flow.

The main steam line flow restrictors are welded into the inside of a length of main steam pipe. Therefore, the 16-inch flow restrictors are not a pressure boundary component. However, component integrity is ensured by compliance with ASME Code requirements.

5.5.5 MAIN STEAM LINE ISOLATION SYSTEM

Each main steam line has one isolation valve and one check valve, both of the swing check type, located outside the containment. The isolation valves are held open by a pneumatic actuator until a trip signal is received, as discussed in Section 6.2.4. For analysis of the ability of these valves to close under pipe break conditions (refer to Section 10.3.2.1).

5.5.6 RESIDUAL HEAT REMOVAL SYSTEM

The RHR system is a dual function system that is aligned to immediately serve as the low-head portion of the ECCS in Modes 1 through 3 and is also aligned to provide normal plant cooldown function in Modes 4 through 6. This section discusses the design, functions, and requirements of the RHR system while performing the plant cooldown function.

The RHR system functions in conjunction with the high-head and intermediate-head portions of the ECCS to provide injection of borated water from the refueling water storage tank (RWST) into the RCS cold legs during the injection phase following a LOCA. During normal operation, the RHR system is lined up to perform this emergency function.

In its capacity as the low-head portion of the ECCS, the RHR system provides long-term recirculation capability for core cooling following the injection phase of the LOCA. This function is accomplished by aligning the RHR system to take suction from the containment recirculation sump.

For a more complete discussion of the use of the RHR system as part of the ECCS, refer to Section 6.3.

The RHR system transfers heat from the RCS to the CCW system to reduce reactor coolant temperature to the cold shutdown temperature at a controlled rate during the latter part of normal plant cooldown, and maintains this temperature until the plant is started up again.

The RHR system can also be used to transfer refueling water between the RWST and the refueling cavity before and after the refueling operations.

During the recirculation phase of a LOCA, if both RHR pumps are in operation, one RHR pump may be used to provide flow from the containment recirculation sump to two containment spray rings for continued post-accident spray operation (refer to Section 6.2.2.2).

5.5.6.1 Design Bases

5.5.6.1.1 General Design Criterion 2, 1967 - Performance Standards

The RHR system is designed to withstand the effects of, or be protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

5.5.6.1.2 General Design Criterion 3, 1971 - Fire Protection

The RHR system is designed and located to minimize, consistent with other safety requirements, the probability and effects of fires and explosions.

5.5.6.1.3 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The portion of the RHR system that is part of the RCPB is designed and constructed so as to have an exceedingly low probability of gross rupture or significant leakage throughout its lifetime.

5.5.6.1.4 General Design Criterion 11, 1967 - Control Room

The RHR system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

5.5.6.1.5 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Instrumentation and controls are provided, as required, to monitor and maintain RHR system variables within prescribed operating ranges.

5.5.6.1.6 General Design Criterion 40, 1967 – Missile Protection

The ESF (containment isolation) portion of the RHR system is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

5.5.6.1.7 General Design Criterion 49, 1967 - Containment Design Basis

The RHR system supply line from RCS hot leg loop 4 is designed so that the containment structure can accommodate, without exceeding the design leakage rate, pressures and temperatures resulting from the largest credible energy release following a LOCA, including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of ECCSs.

5.5.6.1.8 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The RHR system supply line from RCS hot leg loop 4 piping that penetrates containment is provided with leak detection, isolation, redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The piping is designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

5.5.6.1.9 General Design Criterion 55, 1971 - Reactor Coolant Pressure Boundary Penetrating Containment

Each RHR system line that penetrates containment is provided with CIVs.

5.5.6.1.10 Residual Heat Removal System Safety Function Requirements

(1) <u>Overpressurization Protection</u>

Overpressure protection is provided for the RHR system when it is in operation (not isolated from the RCS), to prevent accidental overpressurization.

(2) Protection from Missiles

The non-ESF PG&E Design Class I portion of the RHR system is designed to be protected against the effects of missiles which may result from plant equipment failure and from events and conditions outside the plant.

(3) Shared Function

The normal plant cooldown function of the RHR system does not compromise its ESF safety function.

(4) Protection Against High Energy Pipe Rupture Effects

The non-ESF PG&E Design Class I portion of the RHR system is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(5) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The PG&E Design Class I portion of the RHR system located outside containment is designed to be protected against the effects of moderate energy pipe failure.

(6) Protection from Jet Impingement – Inside Containment

The PG&E Design Class I portion of the RHR system located inside containment is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

(7) Protection from Flooding Effects – Outside Containment

The PG&E Design Class I portion of the RHR system located outside containment is designed to be protected from the effects of internal flooding.

5.5.6.1.11 10 CFR 50.49 - Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

RHR system components that require EQ are qualified to the requirements of 10 CFR 50.49.

5.5.6.1.12 10 CFR 50.55a(f) - Inservice Testing Requirements

RHR system ASME Code components are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

5.5.6.1.13 10 CFR 50.55a(g) - Inservice Inspection Requirements

RHR system ASME Code components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

5.5.6.1.14 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The RHR system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

5.5.6.1.15 Generic Letter 87-12, July 1987 - Loss of Residual Heat Removal While the Reactor Coolant System is Partially Filled

RHR system operation when the RCS water level is below the top of the RPV was evaluated to identify and enhance configurational, operational, procedural, and training requirements to ensure that the RHR system continues to meet the licensing basis of the plant, and that no unanalyzed event, or threat to safety, exists in this condition.

5.5.6.1.16 Generic Letter 88-17, October 1988 - Loss of Decay Heat Removal 10 CFR 50.54(f)

DCPP implements the expeditious action and programmed enhancement recommendations of Generic Letter 88-17, October 1988, with respect to operation following placement of the NSSS on RHR system cooling, or following the attainment of NSSS conditions under which RHR system operation would be normally initiated, to ensure loss of decay heat removal does not occur.

5.5.6.1.17 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

The RHR system MOVs meet the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996.

5.5.6.1.18 Generic Letter 95-07, August 1995 - Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves

The RHR system PG&E Design Class I, power-operated gate valves meet the requirements of Generic Letter 95-07, August 1995.

5.5.6.1.19 Generic Letter 98-02, May 1998 - Loss of Reactor Coolant Inventory and Associated Potential for Loss of Emergency Mitigation Functions While in a Shutdown Condition

The RHR system is administratively controlled, configurationally managed, and procedurally operated to preclude an inadvertent draindown event as described in Generic Letter 98-02, May 1998.

5.5.6.1.20 NRC Bulletin 88-04, May 1988 - Potential Safety-Related Pump Loss

The RHR system is designed such that the PG&E Design Class I pumps that share a common minimum flow recirculation line are not susceptible to the pump-to-pump interaction or dead-heading as described in NRC Bulletin 88-04, May 1988. In addition, the installed minimum flow capacity for RHR system PG&E Design Class I pumps is adequate for even a single pump in operation.

5.5.6.1.21 Branch Technical Position RSB 5-1, 1980 – Design Requirements of the Residual Heat Removal System

The DCPP reactor design is such that it can be taken from normal operating conditions to cold shutdown using only systems qualified for the Hosgri earthquake (refer to Section 3.7.6), with either only onsite or only offsite power, and with the most limiting single failure.

5.5.6.2 System Description

The RHR system is designed to remove heat from the core and reduce the temperature of the RCS during the second phase of plant cooldown. During the first phase of cooldown, the temperature of the RCS is reduced by transferring heat from the RCS to the SPCS via the SGs.

The RHR system is placed in operation when the nominal temperature and pressure of the RCS are ≤ 350°F and ≤ 390 psig, respectively. The cooldown calculation of Reference 12 assumes the RHR is placed in service no sooner than 4 hours after reactor shutdown. Assuming that two RHR heat exchangers and two RHR pumps are in service and that each heat exchanger is supplied with CCW at design flow and temperature, the analysis shows that the RHR system design is capable of reducing the temperature of the reactor coolant to 140°F in less than 20 hours after reactor shutdown. The heat load handled by the RHR system during the cooldown transient includes sensible and decay heat from the core and RCP heat.

RHR system design parameters are listed in Table 5.5-8. A schematic diagram of the RHR system is shown in Figure 3.2-10.

The RHR system consists of two RHR heat exchangers, two RHR pumps, and the associated piping, valves, and instrumentation necessary for operational control. The

inlet line to the RHR system is connected to the hot leg of RCL 4, while the return lines are connected to the cold legs of each of the RCLs. These normal return lines are also the ECCS low-head injection lines (refer to Figure 6.3-4).

The RHR system suction line is isolated from the RCS by two MOVs in series while the discharge lines are isolated by two check valves in each line. These check valves are not a part of the RHR system; they are shown as part of the ECCS. The isolation valves inlet line pressure-relief valve and associated piping are located inside the containment. The remainder of the system is located outside the containment.

During system operation, reactor coolant flows from the RCS to the RHR pumps, through the tube side of the RHR heat exchangers, and back to the RCS. The heat is transferred in the RHR heat exchangers to the CCW circulating through the shell side of the heat exchangers.

Coincident with RHR operations, a portion of the reactor coolant flow may be diverted from downstream of the RHR heat exchangers to the CVCS low-pressure letdown line for cleanup and/or pressure control. By regulating the diverted flowrate and the charging flow, the RCS pressure can be controlled. Pressure regulation is necessary to maintain the pressure range dictated by the fracture prevention criteria requirements of the RPV and by the No. 1 seal differential pressure and NPSH requirements of the RCPs.

The RCS cooldown rate is manually controlled by regulating the reactor coolant flow through the tube side of the RHR heat exchangers. A line containing a flow control valve bypasses the RHR heat exchangers and is used to maintain a constant return flow to the RCS. Instrumentation is provided to monitor system pressure, temperature, and total flow, and to activate an alarm on system low flow.

The RHR system is also used for filling the refueling cavity before refueling. After refueling operations, water is pumped back to the RWST until the RPV water level is brought down to the desired level below the RPV flange. The remainder is removed via a drain connection at the bottom of the refueling canal.

When the RHR system is in operation, the water chemistry is the same as that of the reactor coolant. Provision is made for the sampling system to extract samples from the flow of reactor coolant downstream of the RHR heat exchangers. A local sampling point is also provided on each RHR train between the pump and heat exchanger.

5.5.6.2.1 Component Description

The materials used to fabricate RHR system components are in accordance with applicable code requirements. All parts of components in contact with borated water are fabricated or clad with austenitic stainless steel or equivalent corrosion resistant material.

RHR component applicable codes and classification are provided in Table 5.5-9. Component parameters are listed in Table 5.5-10.

5.5.6.2.1.1 Residual Heat Removal Pumps

Two pumps are installed in the RHR system. The two pumps are vertical, centrifugal units with mechanical shaft seals. The pumps are sized to deliver sufficient reactor coolant flow through the RHR heat exchangers to meet the plant cooldown requirements. The use of two pumps ensures that cooling capacity is only partially lost should one pump become inoperative.

The RHR pumps are protected from overheating and loss of suction flow by miniflow bypass lines that provide flow to the pump suction at all times. A control valve located in each miniflow line is regulated by a signal from the flow transmitters located in each pump discharge header. The control valves open on low RHR pump discharge flow and close when RHR flow has been established. To prevent pump to pump interaction as a result of differences between pump flow characteristics, check valves were installed downstream of the RHR heat exchangers. During minimum flow operation the check valve will prevent the stronger pump from dead heading or reversing flow into the weaker pump, thereby maintaining minimum required recirculation flow.

A pressure sensor in each pump discharge header provides a signal for an indicator in the control room. A high pressure alarm is also actuated by the pressure sensor.

5.5.6.2.1.2 Residual Heat Removal Heat Exchangers

Two RHR heat exchangers are installed in the system. The heat exchanger design is based on heat load and temperature differences between reactor coolant and CCW existing 20 hours after reactor shutdown when the temperature difference between the two systems is small. The decay heat removal used in the cooldown analysis is given in Table 5.5-8.

The RHR heat exchangers are part of the ECCS, supporting the recirculation mode in which long-term core cooling is provided during the accident recovery period. During the emergency core cooling recirculation phase, water from the containment recirculation sump flows through the tube side of the RHR heat exchangers, transferring heat from containment to the CCW system. Further discussion of the RHR heat exchangers in this mode is found in Section 6.3.2.4.4.

The most limiting RHR system heat exchanger design requirement is to remove decay heat, sensible heat and RCP heat at the design flow rates starting four hours following reactor shutdown. Less limiting, the initial heat removal provided by the RHR heat exchangers after a design basis LOCA occurs after the RWST inventory has been injected into the reactor. Under these conditions, the RHR heat exchangers are in service with a containment recirculation sump temperature well below the limiting

condition. In addition to RHR heat exchangers, heat removal from containment following a LOCA is shared with the CFCUs.

The installation of two heat exchangers ensures that the heat removal capacity of the system is only partially lost if one heat exchanger becomes inoperative.

The RHR heat exchangers are of the shell and U-tube type. Reactor coolant circulates through the tubes, while CCW circulates through the shell. The tubes and other surfaces in contact with reactor coolant are austenitic stainless steel or equivalent corrosion resistant material. The shell is carbon steel. The tubes are welded to the tubesheet to prevent leakage of reactor coolant.

5.5.6.2.1.3 Residual Heat Removal System Valves

Valves that perform a modulating function are equipped with two sets of packing and an intermediate leakoff connection that discharges to the drain header.

Some manual valves and MOVs have backseats to facilitate repacking and to limit stem leakage when the valves are open. Leakoff connections are provided where required by valve size and fluid conditions.

5.5.6.2.2 System Operation

A discussion of RHR system operation during various reactor operating modes follows.

5.5.6.2.2.1 Reactor Startup

Generally, during cold shutdown, residual heat from the reactor core is being removed by the RHR system. The number of pumps and heat exchangers in service depends on the RHR load at the time.

At initiation of plant startup, the RCS is completely filled, and the pressurizer heaters are energized. The RHR pumps are operating, but a portion of the discharge is directed to the CVCS via a line that is connected to the common header downstream of the RHR heat exchanger. After the RCPs are running and the pressurizer steam bubble has formed, the RHR pumps are stopped. Indication of steam bubble formation is provided in the control room by the damping out of the RCS pressure fluctuations and by pressurizer level indication. The RHR system is then isolated from the RCS and the system pressure is controlled by normal letdown and the pressurizer spray and pressurizer heaters.

An alternative to this startup process is a vacuum refill method of filling the RCS, described in Section 5.1.7.1. This may result in starting the RCPs after the pressurizer steam bubble is formed.

5.5.6.2.2.2 Power Generation and Hot Standby Operation

During power generation and hot standby operation, the RHR system is not in service but is aligned for operation as part of the ECCS.

5.5.6.2.2.3 Reactor Shutdown

The initial phase of reactor cooldown is accomplished by transferring heat from the RCS to the SPCS through the use of the SGs.

When the reactor coolant nominal temperature and pressure are reduced to ≤ 350°F and ≤ 390 psig, respectively, the second phase of cooldown starts with the RHR system being placed in operation. Data and procedure reviews indicate it will require more than 4 hours after reactor shutdown to initiate RHR cooldown (Reference 12).

Startup of the RHR system includes a warm-up period during which time reactor coolant flow through the heat exchangers is limited to minimize thermal shock. The rate of heat removal from the reactor coolant is manually controlled by regulating the coolant flow through the RHR heat exchangers. By adjusting the control valves downstream of the RHR heat exchangers, the mixed mean temperature of the return flows is controlled. Coincident with the manual adjustment, the heat exchanger bypass valve contained in the common bypass line is regulated to give the required total flow.

The reactor cooldown rate is limited by RCS equipment cooling rates based on allowable stress limits, as well as the operating temperature limits of the CCW system. As the reactor coolant temperature decreases, the reactor coolant flow through the RHR heat exchangers is increased.

As cooldown continues, the pressurizer is filled with water and the RCS is operated in the water-solid condition.

At this stage, pressure is controlled by regulating the charging flow rate and the alternate letdown rate to the CVCS from the RHR system.

After the reactor coolant pressure is reduced and the temperature is 160°F or lower, the RCS may be opened for refueling or maintenance.

5.5.6.2.2.4 Refueling

Several systems may be used during refueling to provide borated water from the RWST to the refueling cavity. These include the RHR system, CSS, SI system, refueling water purification system, and the CVCS (which includes the liquid holdup tanks [LHUTs]). During this operation, the isolation valves to the RWST are opened.

The RVCH is removed. The refueling water is then pumped into the RPV and into the refueling cavity through the open RPV.

After the water level reaches the desired level, the RWST supply valves are closed, and RHR operation continues.

During refueling, the RHR system is maintained in service with the number of pumps and heat exchangers in operation as required by the heat load.

Following refueling, the RHR pumps are used to drain the refueling cavity to the top of the RPV flange, and reduce the level in the RPV to the desired level below the top of the RPV flange by pumping water from the RCS to the RWST.

5.5.6.3 Design Evaluation

Design features of the RHR system ensure safe and reliable system performance as discussed below.

5.5.6.3.1 System Availability and Reliability

The system is provided with two RHR pumps and two RHR heat exchangers arranged in separate flowpaths. If one of the two pumps or one of the two heat exchangers is not operable, safe cooldown of the plant is not compromised, although the time required for cooldown is extended.

To ensure reliability, the two RHR pumps are connected to two separate electrical buses so that each pump receives power from a different source. If a total loss of offsite power occurs while the system is in service, each bus is automatically transferred to a separate emergency diesel power supply.

5.5.6.3.2 Radiological Considerations

The highest radiation levels experienced by the RHR system are those that would result from a LOCA. Following a LOCA, the RHR system is used as part of the ECCS. During the recirculation phase of emergency core cooling, the RHR system is designed to operate for up to a year pumping water from the containment recirculation sump, cooling it, and returning it to the containment to cool the core.

Since the RHR system is located outside the containment, except for some valves and piping, most of the system is not subjected to the high levels of radioactivity in the containment post-accident environment. To ensure continued operation of the RHR system components, the valve motor operators, the RHR pump motors, and the RHR pump seals have been evaluated for operation in post-accident environments (refer to Section 5.5.6.4.11). Refer to Section 3.11 for details of the evaluation.

The operation of the RHR system does not involve a radiation hazard for the operators since the system is controlled remotely from the control room. If maintenance of the system is necessary, the portion of the system requiring maintenance is isolated by

remotely operated valves and/or manual valves with stem extensions, which allow operation of the valves from a shielded location. The isolated piping is drained and flushed before maintenance is performed.

5.5.6.4 Safety Evaluation

5.5.6.4.1 General Design Criterion 2, 1967 - Performance Standards

All RHR components are located within the PG&E Design Class I auxiliary and containment buildings. These buildings, or applicable portions thereof, are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other natural phenomena, to protect the RHR SSCs, ensuring their design functions will be performed.

PG&E Design Class I SSCs of the RHR system are seismically qualified to ensure their design functions can be performed following an earthquake, as described in Section 3.7.

5.5.6.4.2 General Design Criterion 3, 1971 - Fire Protection

The RHR system is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

Power is removed from the RHR suction line isolation valve motors when the RHR system is isolated (refer to Section 5.5.6.4.10).

5.5.6.4.3 General Design Criterion 9, 1967 - Reactor Coolant Pressure Boundary

The portion of the RHR system that is part of the RCPB is designed and constructed so as to have an exceedingly low probability of gross rupture or significant leakage throughout its lifetime. The RCPB is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation, including all anticipated transients, and to maintain the stresses within applicable stress limits (refer to Section 5.2.3.3).

5.5.6.4.4 General Design Criterion 11, 1967 - Control Room

Instrumentation, alarms, and controls are provided in the control room for operators to monitor and maintain RHR system parameters. Instrumentation and controls for the RHR system are further discussed in Sections 5.5.6.4.5 and 6.3.3.4. Cold shutdown from outside the control room is accomplished with the use of RHR system indicators and controls which are located outside the control room. Interlocks with MOVs are discussed in Section 7.6.2.

5.5.6.4.5 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Instrumentation and controls are provided, as required, to monitor and maintain RHR variables within prescribed operating ranges. Specifically, the RHR system variables that are monitored are: RHR heat exchanger outlet temperature; RHR pump-motor temperature and discharge pressure; and RHR system flow to the RCS hot and cold legs. An RHR pump discharge header flow meter controls the RHR pump minimum flow. Further discussion of these instruments and controls is provided by Section 6.3.3.4.

5.5.6.4.6 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the ESF (containment isolation) portion of the RHR system from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures are discussed in Sections 3.5, 3.6, and 6.2.4.

5.5.6.4.7 General Design Criterion 49, 1967 - Containment Design Basis

The RHR system supply line from the RCS hot leg loop 4 containment penetration, including the system piping and valves required for containment isolation, is designed to withstand the pressures and temperatures that could result from a LOCA without exceeding containment design leakage rates. Refer to Sections 3.8.2.1.3 and 6.3.3.17 for additional justification. Refer to Section 6.3 and Table 6.2-39 for penetrations that are part of ECCS.

5.5.6.4.8 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The RHR system supply line from the RCS hot leg loop 4 isolation valves required for containment closure are periodically tested as part of the IST Program Plan for operability in accordance with GDC 54, 1971. Test connections are provided in the piping of applicable penetrations to verify valve leakages are within prescribed limits. Testing of the components required for the CIS is discussed in Section 6.2.4. Refer to Section 6.3 and Table 6.2-39 for penetrations that are part of ECCS.

5.5.6.4.9 General Design Criterion 55, 1971 - Reactor Coolant Pressure Boundary Penetrating Containment

The RHR system is designed such that each RHR line that is part of the RCPB that penetrates containment is provided with CIVs in compliance with GDC 55, 1971. Refer to Section 6.2.4.2.1 and Table 6.2-39 for penetration and configuration details with regards to GDC 55, 1971.

5.5.6.4.10 Residual Heat Removal System Safety Function Requirements

(1) Overpressurization Protection

The inlet line to the RHR system is equipped with a pressure relief valve sized to relieve the combined flow of both charging pumps into the RCS and thus prevents exceeding the RHR system design pressure.

Each discharge line to the RCS is equipped with a pressure relief valve located in the ECCS (refer to Figure 3.2-9, Sheets 5 and 6 and Figure 3.2-10, Sheets 1 and 2). They relieve the maximum possible back-leakage through the valves separating the RHR system from the RCS.

The design of the RHR system includes the following features for valves on the inlet line between the high-pressure RCS and the lower pressure RHR system:

(1) To prevent both RHR suction line isolation valves from opening as a result of fire damage to electrical cables, ac power is removed from the operators of the indicated MOVs for plant conditions during which the RHR system is isolated.

(2) The isolation valve adjoining the RCS is interlocked with a pressure signal to prevent it from being opened whenever the RCS pressure is greater than a set value.

(3) The second isolation valve, the one adjoining the RHR system, is similarly interlocked with a pressure signal to prevent opening if RCS pressure is above a set value, and a pressurizer temperature signal to prevent opening if it exceeds a set value.

(4) The RHR suction valves interlock relays are powered from the solid state protection system (SSPS) output cabinets. To maintain the ability to open the RHR suction valve(s) when the SSPS output cabinet(s) are de-energized in Mode 6 or defueled, a jumper(s) is used to lock-in the RHR suction valve(s) open permissive. This defeats the applicable RHR system overpressurization/temperature protection. Jumper installation is limited to Mode 6 and defueled only.

Refer to Section 7.6 for a more complete discussion of the permissive interlocks on these isolation valves.

(2) Protection from Missiles

The provisions taken to protect the non-ESF PG&E Design Class I portion of the RHR system from missiles are discussed in Section 3.5. The RHR system design is such that

physical protection is adequately provided against physical hazards in areas through which the system is routed.

(3) Shared Function

The safety function performed by the RHR system is not compromised by its normal function during plant cooldown. The valves associated with the RHR system are normally aligned to allow immediate use of this system in its ESF mode of operation. The system has been designed in such a manner that two redundant flow circuits are available, ensuring the availability of at least one train for safety purposes.

The normal plant cooldown function of the RHR system is accomplished through a suction line arrangement that is independent of any safety function. The normal cooldown return lines are arranged in parallel redundant circuits and are utilized also as the low-head SI lines to the RCS. Utilization of the same return circuits for the safety function as well as for normal cooldown, lends assurance to the proper functioning of these lines for safety purposes.

(4) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the non-ESF PG&E Design Class I portion of the RHR system from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Section 3.6. The RHR system design is such that physical protection is adequately provided against physical hazards in areas through which the system is routed.

(5) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection of the PG&E Design Class I portion of the RHR system located outside containment from the effects of moderate energy pipe failure are discussed in Section 3.6.

(6) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the PG&E Design Class I portion of the RHR system located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

(7) Protection from Flooding Effects

The provisions taken to provide protection of the PG&E Design Class I portion of the RHR system from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

If a pipe rupture or equipment failure occurs in a RHR pump compartment, overflow from one pump compartment would drain through a 14-inch line to the pipe trench

rather than flood the adjacent compartment. Additionally, the maximum calculated flood level within each compartment is below the elevation of the RHR pump motors.

5.5.6.4.11 10 CFR 50.49 - Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

The RHR SSCs required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Refer to Section 6.3 for RHR SSCs that are also a part of ECCS. Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment. The affected equipment includes flow and pressure transmitters, valve motors and operators, and switches, and is listed on the EQ Master List. Refer to Section 5.5.6.3.2 for additional information.

5.5.6.4.12 10 CFR 50.55a(f) - Inservice Testing Requirements

The IST requirements for the RHR system are contained in the DCPP IST Program Plan.

5.5.6.4.13 10 CFR 50.55a(g) - Inservice Inspection Requirements

The RHR system is inspected in accordance with ASME BPVC Section XI-2001 through 2003 Addenda, as stated in the DCPP ISI Program Plan.

5.5.6.4.14 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The RHR system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

5.5.6.4.15 Generic Letter 87-12, July 1987 - Loss of Residual Heat Removal While the Reactor Coolant System is Partially Filled

The RHR system design and operating procedures ensure that decay heat removal is provided and that the integrity of the RCPB is ensured during operation with a partially filled RCS. Training is provided to operators to ensure RCS inventory and RHR flow are maintained during operation in this condition.

5.5.6.4.16 Generic Letter 88-17, October 1988 - Loss of Decay Heat Removal 10 CFR 50.54(f)

There are limited periods during plant operation when the RCS may be operated with reduced inventory while irradiated fuel is in the RPV. Examples include refueling outages or maintenance evolutions. A reduced inventory condition, including mid-loop conditions, exists whenever the RCS level is lower than 111 feet elevation, which is

three feet below the RPV flange. This section describes the administrative controls and instrumentation relied upon during reduced inventory operations.

Procedures and administrative controls have been implemented to assure that containment closure will be achieved prior to the time at which core uncovery could result from a loss of decay heat removal coupled with the inability to initiate alternate core cooling or addition of water to the RCS inventory. Procedures have been implemented to avoid operations that deliberately or knowingly lead to perturbations to the RCS and/or to systems that are necessary to maintain the RCS in a stable and controlled condition while the RCS is in a reduced inventory condition.

At least two independent, continuous temperature indications that are representative of the core exit conditions are available whenever the RCS is in a mid-loop condition and the RVCH is located on top of the RPV.

At least two independent, continuous RCS water level indications are provided whenever the RCS is in a reduced inventory condition. Water level indications are periodically checked and recorded by an operator or automatically and continuously monitored and alarmed.

At least two available or operable means of adding additional inventory to the RCS are available that are in addition to pumps that are a part of the normal decay heat removal systems. Specifically, prior to draining to mid-loop, one charging pump, gravity fill makeup from the RWST, and an SI pump with associated hot leg flow path to the RCS are available.

Analyses have been performed to supplement existing information and to develop a basis for other actions.

A pressurization analysis for shutdown conditions was performed to evaluate, for low-to-high decay heat shutdown conditions, the thermal hydraulic response, particularly the maximum RCS pressure limits, if no operator recovery actions were taken to limit or prevent boiling in the RCS (References 13 and 14). The results of these analyses are used to determine acceptable RCS vent path configurations used during outage conditions as a contingency to mitigate RCS pressurization upon a postulated loss of RHR. Typical RCS vent path openings capable of use include the RPV flange, one or more PSVs or PORVs, SG primary hot leg manways, or combinations of these openings depending on the decay heat load.

Other analyses performed include the pressurization and integrity of containment after a loss of RHR while at mid-loop, and a level instrumentation analysis in order to understand its behavior during reduced inventory.

5.5.6.4.17 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

RHR system MOVs 8701 and 8702 are subject to the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996, and meet the requirements of the DCPP MOV Program Plan.

5.5.6.4.18 Generic Letter 95-07, August 1995 - Pressure Locking and Thermal Binding of Safety- Related Power-Operated Gate Valves

RHR system power operated gate valves 8701 and 8702, which were determined to be susceptible to pressure locking, were modified by installing bonnet cavity leakoffs with block valves to the high pressure inlet lines to prevent pressure locking. No power-operated gate valves in the RHR system were found susceptible to thermal binding.

5.5.6.4.19 Generic Letter 98-02, May 1998 - Loss of Reactor Coolant Inventory and Associated Potential for Loss of Emergency Mitigation Functions While in a Shutdown Condition

DCPP Unit 1 and Unit 2 are vulnerable to the potential draindown of the RCS to the RWST, and render the RHR system inoperable, if valve 8741 were inadvertently opened with RHR in service in Mode 4. Procedural controls are in place to prevent this from occurring.

5.5.6.4.20 NRC Bulletin 88-04, May 1988 - Potential Safety-Related Pump Loss

The RHR system is designed to ensure the installed miniflow capacity is adequate for even a single pump in operation and to prevent dead-heading of either RHR pump due to pump-to-pump interaction during miniflow operation.

5.5.6.4.21 Branch Technical Position RSB 5-1, 1980 – Design Requirements of the Residual Heat Removal System

The DCPP reactor design is such that it can be taken from normal operating conditions to cold shutdown using only PG&E Design Class I systems, with either only onsite or only offsite power, and with the most limiting single failure.

DCPP conducted tests with supporting analysis to: (a) confirm that adequate mixing of borated water was achieved under natural circulation conditions with an estimation of the times required to achieve such mixing; (b) confirm that the cooldown under natural circulation was achieved within the limits specified in the emergency operating procedures; and (c) confirm no credible single failure would preclude achieving cold shutdown conditions.

5.5.6.5 Tests and Inspections

Periodic visual inspections and preventive maintenance are conducted during plant operation according to normal industrial practice.

The instrumentation channels for the RHR pump flow instrumentation devices are calibrated on a nominal 24-month frequency.

The RHR pumps are tested by starting them periodically.

5.5.6.6 Instrumentation Applications

Refer to Section 5.5.6.4.5 for the instrumentation applications related to the RHR system.

5.5.7 REACTOR COOLANT CLEANUP SYSTEM

The CVCS provides reactor coolant cleanup and is discussed in Section 9.3. The radiological considerations are discussed in Chapter 11.

5.5.8 MAIN STEAM LINE AND FEEDWATER PIPING

Main steam line piping is covered in Section 10.3. Feedwater piping is covered in Section 10.4.

5.5.9 PRESSURIZER

The pressurizer provides a point in the RCS where liquid and vapor are maintained at equilibrium temperature and pressure under saturated conditions for pressure control purposes.

During an insurge, the spray system, fed from two cold legs, condenses steam in the vessel to prevent the pressurizer pressure from reaching the setpoint of the PORVs. During an outsurge, flashing of water to steam and generation of steam by automatic actuation of the heaters helps keep the pressure above the low-pressure reactor trip setpoint. Heaters are also energized, on high water level during insurges, to heat the subcooled surge water entering the pressurizer from the RCL.

5.5.9.1 Design Bases

The general configuration of the pressurizer is shown in Figure 5.5-8. The design data of the pressurizer are provided in Table 5.5-12. Codes and material requirements are provided in Section 5.2.

5.5.9.1.1 Pressurizer Surge Line

The surge line is sized to limit the pressure drop between the RCS and the PSVs with maximum allowable discharge flow from the PSVs. Overpressure of the RCS does not exceed 110 percent of the design pressure. The surge line and the thermal sleeves at each end are designed to withstand the thermal stresses resulting from volume surges, which occur during operation.

5.5.9.1.2 Pressurizer

The pressurizer volume (refer to Table 5.5-12) satisfies the following requirements:

(1) The combined saturated water volume and steam expansion volume is sufficient to provide the desired pressure response to system volume changes.

(2) The water volume is sufficient to prevent the heaters from being uncovered during a step load increase of 10 percent of full power.

(3) The steam volume is large enough to accommodate the surge resulting from the design step load reduction from full load with reactor control and steam dump without the water level reaching the high level reactor trip point.

(4) The steam volume is large enough to prevent water relief through the PSVs following a loss of load with the high water level initiating a reactor trip.

(5) The pressurizer does not empty following reactor and turbine trip.

(6) The emergency core cooling signal is not activated during reactor trip and turbine trip.

5.5.9.2 Design Description

The pressurizer is designed to accommodate positive and negative reactor coolant surges caused by RCS transients.

5.5.9.2.1 Pressurizer Surge Line

The pressurizer surge line connects the pressurizer to one reactor hot leg. The line enables continuous coolant volume/pressure adjustments between the RCS and the pressurizer.

5.5.9.2.2 Pressurizer

The pressurizer is a vertical, cylindrical vessel with essentially hemispherical top and bottom heads constructed of carbon steel, with austenitic stainless steel cladding on all surfaces exposed to the reactor coolant.

The surge line nozzle and removable electric heaters are installed in the bottom head. The heaters are removable for maintenance or replacement. A thermal sleeve is provided to minimize stresses in the surge line nozzle. A screen at the surge line nozzle and baffles in the lower section of the pressurizer prevent a cold insurge of water from flowing directly to the steam/water interface and assist mixing.

Spray line nozzles and PORV/PSV connections are located in the top head of the vessel. Spray flow is modulated by automatically controlled air-operated valves. The spray valves can also be operated manually by a switch in the control room.

A small continuous spray flow is provided through a manual bypass valve around the power-operated spray valves to ensure that the pressurizer liquid is homogeneous with the coolant and to prevent excessive cooling of the spray piping. During an outsurge from the pressurizer, flashing of water to steam and generating of steam by automatic actuation of the heaters keep the pressure above the minimum allowable limit. During an insurge from the RCS, the spray system, which is fed from two cold legs, condenses steam in the vessel to prevent the pressurizer pressure from reaching the setpoint of the PORVs for normal design transients. Heaters are energized on high water level during insurge to heat the subcooled surge water that enters the pressurizer from the RCL. The heaters are further discussed in Section 8.3.

5.5.9.2.2.1 Pressurizer Support

The skirt-type support, shown in Figure 5.5-12, is attached to the lower head and extends for a full 360° around the vessel. The lower part of the skirt terminates in a bolting flange with bolt holes to secure the vessel to its structural steel framework. The skirt-type support is provided with ventilation holes around its upper perimeter to ensure free convection of ambient air past the heater plus connector ends for cooling.

5.5.9.2.2.2 Pressurizer Instrumentation

Refer to Chapter 7 for details of the instrumentation associated with pressurizer pressure, level, and temperature.

5.5.9.2.2.3 Spray Line Temperatures

Temperatures in the spray lines from two loops are measured and indicated. Alarms from these signals are actuated by low spray water temperature. Low temperature conditions indicate insufficient flow in the spray lines.

5.5.9.2.2.4 Safety and Relief Valve Discharge Temperatures

Temperatures in the PSV and PORV discharge lines are measured and indicated. An increase in a discharge line temperature is an indication of leakage through the associated valve.

5.5.9.3 Design Evaluation

The pressurizer is designed to provide safe and reliable RCS pressure control.

5.5.9.3.1 System Pressure

RCS pressure is maintained by the steam bubble in the pressurizer. During normal operation, the pressurizer maintains RCS pressure by automatic operation of pressurizer heaters and spray. When the pressurizer is filled with water (i.e., near the end of the second phase of plant cooldown and during initial system heatup, if the vacuum refill method of filling the RCS is not used as described in Section 5.1.7.1), RCS pressure is maintained by the RHR, CVCS, and LTOP systems. Safety limits are established to control the rate of temperature change in the pressurizer. These safety limits are administratively controlled to ensure that RCS pressure and temperature do not exceed the maximum transient value allowed under ASME BPVC Section III, and thereby ensure continued integrity of the RCPB.

5.5.9.3.2 Pressurizer Performance

The pressurizer has a minimum free internal volume. The normal operating water volume at full load conditions is 60 percent of the minimum free internal vessel volume. Under part load conditions, the water volume in the vessel is reduced for proportional reductions in plant load to 22 percent of free vessel volume at zero power level. During a shutdown to Mode 3 and when power is ≤20%, the pressurizer water volume is controlled between 22 percent and 35 percent of the indicated level. During shutdown modes 3, 4, and 5, the pressurizer water volume is controlled between ≥22 percent and ≤90 percent of the indicated level. Whenever the LTOP system is enabled as described in Section 5.2.3.28, the administrative controls and requirements of the PTLR take precedence. Pressurizer performance has been analyzed for the various plant operating transients discussed in Section 5.2.2.1. The design pressure was not exceeded with the pressurizer design parameters listed in Table 5.5-12.

5.5.9.3.3 Pressure Setpoints

The RCS design and operating pressure together with the safety, PORV, and pressurizer spray valves setpoints, and the protection system setpoint pressures are listed in Section 5.2.2.2. The design pressure allows for operating transient pressure changes. The selected design margin considers core thermal lag, coolant transport times and pressure drops, instrumentation and control response characteristics, and system relief valve characteristics.

5.5.9.3.4 Pressurizer Spray

Two separate, automatically controlled spray valves with remote-manual overrides are used to initiate pressurizer spray. In parallel with each spray valve is a manual throttle valve that permits a small, continuous flow through both spray lines to reduce thermal stresses and thermal shock when the spray valves open, and to help maintain uniform water chemistry and temperature in the pressurizer. Spray flow is not normally initiated if the temperature difference between the pressurizer and spray fluid exceeds 320°F. Temperature sensors with low alarms are provided in each spray line to alert the operator to insufficient bypass flow. The layout of the common spray line piping to the pressurizer forms a water seal that prevents the steam buildup back to the control valves. The spray rate is selected to prevent the pressurizer pressure from reaching the operating setpoint of the PORVs during a step reduction in power level of 10 percent of full load.

The pressurizer spray lines and valves are large enough to provide adequate spray using as the driving force the differential pressure between the surge line connection in the hot leg and the spray line connection in the cold leg. The spray line inlet connections extend into the cold leg piping in the form of a scoop so that the velocity head of the RCL flow adds to the spray driving force. The spray valves and spray line connections are arranged so that the spray will operate when one RCP is not operating. The line may also be used to assist in equalizing the boron concentration between the RCLs and the pressurizer.

A flowpath from the CVCS to the pressurizer spray line is also provided. This additional facility provides auxiliary spray to the vapor space of the pressurizer during cooldown if the RCPs are not operating. The thermal sleeves on the pressurizer spray connection and the spray piping are designed to withstand the thermal stresses resulting from the introduction of cold spray water.

5.5.9.3.5 Pressurizer Design Analysis

The occurrences for pressurizer design cycle analysis are defined as follows:

(1) For design purposes, the temperature in the pressurizer vessel is always assumed to equal saturation temperature for the existing RCS pressure, except in the pressurizer steam space subsequent to a pressure increase.

In this case, the temperature of the steam space will exceed the saturation temperature since an isentropic compression of the steam is assumed.

(2) The temperature shock on the spray nozzle is assumed to equal the temperature of the nozzle minus the cold leg temperature, and the temperature shock on the surge nozzle is assumed to equal the pressurizer water space temperature minus the hot leg temperature.

(3) Pressurizer spray is assumed to be initiated instantaneously reaching its design value as soon as the RCS pressure increases 40 psi above the nominal operating pressure. Spray is assumed to be terminated as soon as the RCS pressure falls below the normal operating pressure-plus 40 psi-level.

(4) Unless otherwise noted, pressurizer spray is assumed to be initiated once during each transient condition. The pressurizer surge nozzle is also assumed to be subject to one temperature transient per transient condition, unless otherwise noted.

(5) At the end of each transient, except the faulted conditions, the RCS is assumed to return to a load condition consistent with the plant heatup transient.

(6) Temperature changes occurring as a result of pressurizer spray are assumed to be instantaneous. Temperature changes occurring on the surge nozzle are also assumed to be instantaneous.

(7) Whenever spray is initiated in the pressurizer, the pressurizer water level is assumed to be at the no-load level.

5.5.9.4 Tests and Inspections

The pressurizer is designed and constructed in accordance with ASME BPVC Section III-1965 through Summer 1966 Addenda. Peripheral support rings are furnished for the insulation modules. The pressurizer quality assurance program is given in Table 5.5-13. Refer to Sections 5.1.8.19, 5.1.8.20, 5.2.3.14, and 5.2.3.15 for further discussion of testing and inspection of the RCS.

5.5.10 PRESSURIZER RELIEF TANK

The PRT accommodates the pressurizer and other relief valve discharges.

5.5.10.1 Design Bases

Design data for the PRT are provided in Table 5.5-14. Codes and materials applicable to the tank are discussed in Section 5.2.

The tank design is based on the requirement to condense and cool a discharge of pressurizer steam equal to 110 percent of the volume above the full power pressurizer water level setpoint. The tank is not designed to accept a continuous discharge from the pressurizer. The volume of water in the tank (refer to Table 5.1-1) is capable of absorbing the heat from the assumed discharge, with an initial temperature of 120°F and increasing to a final temperature of 200°F. The tank is cooled, when necessary, by manual spraying of cool water into the tank and draining the warm mixture to the RCDT.

5.5.10.2 Design Description

The PRT is a horizontal, cylindrical vessel with elliptical ends, which condenses and cools the discharge from the PSVs and PORVs. Discharge from smaller relief valves located inside and outside the containment is also piped to the PRT. The PRT normally contains water and a predominantly nitrogen atmosphere. The atmosphere inside the tank is controlled to avoid a combustible mixture. Provision is made to permit the gas in the tank to be periodically monitored for hydrogen and/or oxygen concentrations. Through its connection to the GRW system, the PRT provides a means for removing any noncondensable gases from the RCS that might collect in the pressurizer vessel.

Steam is discharged through a sparger pipe under the water level. This condenses and cools the steam by mixing it with water that is near ambient temperature. The PRT is equipped with an internal spray and a drain that are used to cool the PRT following a discharge. A flanged nozzle is provided on the PRT for the pressurizer discharge line connection. The PRT is protected against a discharge exceeding its design pressure by two rupture disks that discharge into the reactor containment.

5.5.10.2.1 Pressurizer Relief Tank Pressure

The PRT pressure transmitter supplies a signal for an indicator with a high-pressure alarm. Also, the PRT pressure transmitter provides a signal to close the air-operated valve to the GRW system vent header on high pressure.

5.5.10.2.2 Pressurizer Relief Tank Level

The PRT level transmitter supplies a signal for an indicator with high and low level alarms.

5.5.10.2.3 Pressurizer Relief Tank Water Temperature

The temperature of the water in the PRT is indicated in the control room. An alarm actuated by high temperature informs the operator that cooling of the tank contents is required.

5.5.10.3 Design Evaluation

The volume of water in the PRT is capable of absorbing heat from the pressurizer discharge during a step load decrease of 10 percent. Water temperature in the PRT is maintained at the nominal containment temperature.

The rupture disks on the PRT have a relief capacity equal to the combined capacity of the PSVs. The PRT design pressure is twice the calculated pressure resulting from the maximum design PSV discharge described above. The PRT and rupture disks holders are also designed for full vacuum to prevent tank collapse if the contents cool following a discharge without nitrogen being added. The discharge piping from the PSVs and PORVs to the PRT is sufficiently large to prevent back pressure at the PSVs from exceeding 20 percent of the setpoint pressure at full flow.

5.5.11 VALVES

The PG&E Design Class I function of the valves within the RCPB listed in Table 5.2-9 is to act as pressure-retaining components and leaktight barriers during normal plant operation and accidents.

5.5.11.1 Design Bases

As noted in Section 5.2, all RCS valves including those in connected systems, out to and including the second isolation valve, are normally closed or capable of automatic or remote manual closure. Valve closure time must be such that for any postulated component failure outside the system boundary, the loss of reactor coolant event would not prevent orderly reactor shutdown and cooldown assuming makeup is provided by normal makeup systems. Normal makeup systems are those systems normally used to maintain reactor coolant inventory under startup, hot standby, operation, or cooldown conditions. If the second of two normally open check valves is considered as the pressure boundary, means are provided to periodically assess back-flow leakage of the first valve when closed. For a check valve to qualify as the system pressure boundary, it must be located inside the containment.

RCPB valves are listed in Table 5.2-9. Materials of construction are specified to minimize corrosion/erosion and to ensure compatibility with the environment. Design parameters are provided in Table 5.5-15.

Valves are designed and fabricated in accordance with either USAS B16.5, MSS-SP-66, or ASME BPVC Section III-1968 or 1974. To the extent practicable, valve leakage is minimized by design.

5.5.11.2 Design Description

Gate valves are either wedge design or parallel disk and are essentially straight through. The wedge may be either split or solid. All gate valves have a backseat,

outside screw and yoke. Globe valves, "T" and "Y" style, are full-ported with outside screw and yoke construction. Ball valves are V-notch design for equal percentage flow characteristics. Check valves are spring-loaded lift piston types for sizes 2 inches and smaller, and swing type for sizes 2-1/2 inches and larger. All check valves containing radioactive fluid are stainless steel and do not have body penetrations other than the inlet, outlet, and bonnet. The check hinge is serviced through the bonnet. The RHR heat exchanger outlet check valves have hinge pin covers.

All valves in the RCS that are in contact with the coolant are constructed primarily of stainless steel. Other materials in contact with the coolant, such as for hard surfacing and packing, are special materials.

All RCPB manual and MOVs that are 3 inches and larger are provided with double-packed stuffing boxes and stem intermediate lantern gland leakoff connections. Some of the throttling control valves, regardless of size, are provided with double-packed stuffing boxes and with stem leakoff connections. All leakoff connections are piped to a closed collection system. Leakage to the atmosphere is essentially zero for these valves.

Each accumulator check valve is designed with a low-pressure drop configuration with all operating parts contained within the body. The disk has unlimited rotation to provide a change of seating surface and alignment after each valve opening.

Valves at the RHR system interface are provided with interlocks that meet the intent of Reference 1. These interlocks are discussed in detail in Sections 5.5.6 and 7.6.

5.5.11.3 Design Evaluation

Stress analysis of the RCL/support system, discussed in Sections 3.9 and 5.2, ensure acceptable stresses for all valves in the RCPB. Reactor coolant chemistry parameters are specified to minimize corrosion. Periodic analyses of coolant chemical composition, discussed in the DCPP Equipment Control Guidelines, ensure that the reactor coolant meets these specifications. The upper-limit coolant velocity of about 50 feet per second minimizes erosion. Valve leakage is minimized by design features as discussed above.

5.5.11.4 Tests and Inspections

Hydrostatic, seat leakage, and operation tests are performed on RCPB valves in accordance with ASME BPVC Section XI, Subsection IWV, (hydrostatic) and the IST Program Plan (all other testing), as required by the Technical Specifications and 10 CFR 50.55a. Refer to Sections 5.1.8.19, 5.1.8.20, 5.2.3.14, and 5.2.3.15 for further discussion of testing and inspection of the RCS.

There are no full-penetration welds within valve body walls. Valves are accessible for disassembly and internal visual inspection.

5.5.12 SAFETY AND RELIEF VALVES

The pressurizer is equipped with PSVs and PORVs for overpressure protection and control. Their use is described in Section 5.2.2.2.

5.5.12.1 Design Bases

The combined capacity of the PSVs is designed to accommodate the maximum surge resulting from complete loss of load. This objective is met without reactor trip or any operator action, provided the main steam safety valves open as designed when steam pressure reaches the main steam safety valve setting. The PORVs are designed to limit pressurizer pressure to a value below the fixed high-pressure reactor trip setpoint. The PORVs are also credited to prevent pressurizer overfill in a spurious SI event (refer to Section 15.2.15.3).

5.5.12.2 Design Description

The PSVs are totally enclosed pop type. The valves are spring loaded, self-actuated, and have back pressure compensation features.

The pressurizer is equipped with three PORVs, each with a corresponding PORV block valve. The PORVs are air-operated and actuated by Class 1E 125-Vdc solenoid valves that are energized-to-open, spring-to-close. The circuits to the solenoid valves are supplied with redundant interlocks that prevent energization below normal operating pressure. Control power is Class 1E 125-Vdc from the station batteries (refer to Section 8.3.2). Indication is powered from the Class 1E 120-Vac instrument power supply system. The PORV block valves are shown schematically in Figure 3.2-7. Each of the three valves is powered from a separate Class 1E 480-V bus.

Positive indication of PORV position is obtained by a direct, stem-mounted indicator, which mechanically actuates limit switches at the full-open and full-closed valve stem positions. Acoustic monitors located in the downstream piping provide indication of PSV positions. The acoustic position indication is seismically qualified to the DDE and HE and environmentally qualified. Sections 3.10 and 3.11 discuss equipment qualification. An alarm is provided in the control room to signal if a PORV is not fully closed.

The 6-inch pipes connecting the pressurizer nozzles to their respective PSVs are shaped in the form of a loop seal. This arrangement is necessary to accommodate thermal movement and the collection of condensate for the water loop seal. However, the PSVs have been converted from water-seated to steam-seated, and the water loop seal was eliminated by continuously draining the condensate back to the pressurizer liquid space. With the elimination of the water loop seal, hydraulic loading due to the presence of water in the loop seal is no longer a concern.

The PORVs are quick-opening, operated automatically or by remote control. Remotely operated stop valves are provided to isolate the PORVs if excessive leakage develops.

Temperatures in the PSV and PORV discharge lines are measured and indicated. An increase in a discharge line temperature is an indication of leakage through the associated valve. Design parameters for the pressurizer spray control, PSV, and PORVs are provided in Table 5.5-16.

5.5.12.3 Design Evaluation

The PSVs prevent RCS pressure from exceeding 110 percent of design pressure. The pressurizer PORVs prevent actuation of the fixed high-pressure trip for all design transients up to and including the design step load decrease, with steam dump but without reactor trip. The PORVs also limit undesirable opening of the spring-loaded PSVs.

The mounting of these valves is designed to accommodate the magnitude and direction of thrust of the PSV discharges. In addition, the physical layout is such as to limit the piping reaction loads on these valves.

5.5.12.4 Tests and Inspections

PSVs and PORVs, as well as the corresponding PORV block valves, were tested on a prototypical basis to demonstrate their ability to open and close under expected operating conditions for design basis transients and accidents. Qualification criteria include provisions for the associated circuitry, piping, and supports as well as the valves themselves.

Each pressurizer PORV will be demonstrated operable at least once per 24 months by performing a channel calibration of the actuation instrumentation. This frequency interval is subject to Surveillance Requirement 3.0.2 of the Technical Specifications.

The only other testing performed on PSVs and PORVs, other than operational tests and inspections, is the required hydrostatic, seat leakage, and operation tests. These tests ensure that the valves will operate as designed. Refer to Sections 5.1.8.19, 5.1.8.20, 5.2.3.14, and 5.2.3.15 for further discussion of testing and inspection of the RCS.

There are no full-penetration welds within the valve body walls. Valves are accessible for disassembly and internal visual inspection.

5.5.13 COMPONENT SUPPORTS

RCS component supports are designed to maintain safe and reliable component and system operation.

5.5.13.1 Design Bases

Component supports allow virtually unrestrained lateral thermal movement of the loop during plant operation and provide restraint to the loops and components during accident conditions. The loading combinations and stress limits are discussed in Section 5.2. The design maintains the integrity of the RCPB for normal and accident conditions and satisfies the requirements of the piping code. Results of piping and supports stress evaluation are presented in Section 5.2.2.1.10.4 and Table 5.2-5 and Section 5.2.2.1.10.5 and Table 5.2-8, respectively.

5.5.13.2 Design Description

The support structures for the SG lower supports and the RCP supports are primarily welded structural steel sections. The SG upper supports consist of a steel ring with lateral bumpers and four snubbers per SG. The primary equipment supports consist of both linear-type components (tension and compression struts, columns, and beams) and plate and shell components. The RPV supports incorporate a closed, grout-filled steel box ring-type structure.

Attachments to the supported equipment are the nonintegral type that are bolted to or bear against the components. The supports-to-concrete attachments are either embedded anchor bolts or fabricated assemblies. The supports permit virtually unrestrained thermal growth of the supported systems but restrain vertical, lateral, and rotational movement resulting from seismic and pipe break loadings. This is accomplished using spherical bushings in the SG columns for vertical support and structural frames, hydraulic snubbers, and struts for lateral support.

The principal support material is welded and bolted structural steel that is subjected to Charpy V-notch impact tests in accordance with ASTM Standard Method A370. Material properties are discussed in Section 5.2.2.3. The supports for the various components are described in the following paragraphs.

5.5.13.2.1 Reactor Support

The reactor is supported on a massive concrete structure that also serves as a biological shield. Forces are transmitted from the reactor to the concrete support structure by an octagonal closed steel box that provides support at four of the eight reactor nozzles as shown in Figure 5.5-9. The bearing plates below the reactor nozzle support shoes contain cooling water passages to control the temperature of the supporting concrete. The reactor support resists seismic loads and coolant loop (hot and cold leg) piping reactions. The reactor support system allows the reactor to expand radially over the supports but resists translational and torsional movement by the combined tangential restraining action of each nozzle support.

5.5.13.2.2 Steam Generator Supports

The SGs are supported by two independent upper and lower structural systems as shown in Figures 5.5-10 and 5.5-11 and described below:

(1) Vertical Supports

Four vertical pipe columns for each SG provide full vertical restraint while allowing free movement radially with respect to the reactor. These are bolted at the top to the SG and at the bottom to the concrete structure. Spherical ball bushings at the top and bottom of each of column allow unrestrained lateral movement of the SG during heatup and cooldown.

(2) Horizontal Supports

Horizontal supports restrain the SGs at two levels:

(a) At elevation 140 feet, where the reinforced concrete slab acts as a rigid diaphragm supporting horizontal forces (predominantly seismic) generated at this level.

(b) At elevation 111 feet (the channel head), where support pads are provided on the SG.

The horizontal supports permit slow radial movement due to thermal expansion while maintaining a positive restraint against sudden loads such as an earthquake or pipe rupture. This is accomplished through the use of four hydraulic snubbers that have a normal/upset allowable load rating of 1450 kips each at elevation 140 feet attached to a ring shimmed to the SG at 20 locations around the circumference. The faulted allowable snubber load is 2050 kips.

The support pads at elevation 111 feet are keyed and shimmed to a sliding frame that is sandwiched between two rigid stationary frames anchored to massive concrete walls. The sliding frame is provided with a bumper system to transfer load to the stationary frames. The frame system for each of two sets of SGs is interconnected so that pipe rupture loads in one loop are distributed between two frame systems.

5.5.13.2.3 Reactor Coolant Pump Supports

The RCPs are supported on structural steel frames restrained horizontally at elevation 106 feet 5-1/2 inches by a system of steel struts anchored to rigid concrete walls as shown in Figures 5.5-10 and 5.5-11. Thermal expansion is permitted by low friction support pads and oversized mounting holes. The support pads are keyed and shimmed to the frame. This support system resists vertical and lateral loads due to all plant operating conditions.

5.5.13.2.4 Pressurizer Support

The pressurizer is bolted to a structural steel frame, providing vertical and lateral support at its base at elevation 113 feet 2 inches as shown in Figure 5.5-12. Additional lateral support is provided by rigid guides embedded in the concrete slab near the CG of the vessel at elevation 139 feet, in conjunction with lugs projecting from the vessel shell. The upper support allows the pressurizer to expand radially and vertically, but resists torsional and translational horizontal movements.

5.5.13.2.5 Crossover Pipe Restraint

The crossover leg is restrained at elevation 96 feet by a system of two sets of steel bumpers located at the elbows of the pipe as shown in Figure 5.5-10. Each set consists of a bumper strapped to the pipe, which bears on a rigid bumper anchored to a concrete pad at elevation 94 feet. The restraint resists blowdown loads from a rupture of the crossover pipe. The crossover pipe restraints were deactivated by removing shims. The bumpers strapped to the pipe and the rigid bumpers were left intact and are abandoned in place.

5.5.13.3 Design Evaluation

Detailed evaluation ensures the design adequacy and structural integrity of the RCL and the primary equipment supports system. The detailed evaluation is made by comparing the analytical results with established criteria for acceptability. Structural analyses are performed to demonstrate design adequacy for safety and reliability of the plant in case of a large or small seismic disturbance and/or LOCA conditions. Loads (thermal, weight and pressure) that the system is expected to encounter often during its lifetime are applied and stresses are compared to allowable values, as described in Section 5.2.2.1. The stress limits for component supports are provided in Tables 5.2-8 and 5.2-8a.

5.5.14 REACTOR VESSEL HEAD VENT SYSTEM

5.5.14.1 Design Bases

The basic function of the RVHVS is to remove noncondensable gases from the RVCH. This system is designed to mitigate a possible condition of inadequate core cooling or impaired natural circulation resulting from the accumulation of noncondensable gases in the RCS. The design of the RVHVS is in accordance with the requirements of NUREG-0578, July 1979 (Reference 7) and the subsequent definitions and clarifications in NUREG-0737, November 1980 (Reference 8) (refer to Section 5.1.8.26, Item II.B.1).

5.5.14.2 Design Description

The RVHVS removes noncondensable gases or steam from the RCS via remote-manual operations from the control room. The system discharges at the RVCH, into a well-ventilated area of the containment, to ensure optimum dilution of combustible

gases. The RVHVS is designed to vent a volume of hydrogen at system design pressure and temperature approximately equivalent to one-half of the RCS volume in 1 hour.

The flow diagram of the RVHVS is shown in Figure 5.5-14. The RVHVS consists of two parallel flowpaths with redundant isolation valves in each flowpath. The venting operation uses only one of these flowpaths at any time. Equipment design parameters are listed in Table 5.5-17. Isolation valve limit switch position indication is provided in the control room.

The active portion of the system consists of four 1 inch open/close solenoid operated isolation valves connected to a dedicated RVCH penetration, located near the center of the RVCH. The use of two valves in series in each flowpath minimizes the possibility of RCPB leakage. The isolation valves in one flowpath are powered by one Class 1E power supply, and the valves in the second flowpath are powered by a second Class 1E power supply. The isolation valves are fail closed, normally closed, active valves. Device qualification is described in Sections 3.10 and 3.11.

If one single active failure prevents a venting operation through one flowpath, the redundant path is available for venting. Similarly, the two isolation valves in each flowpath provide a single failure method of isolating the venting system. With two valves in series, the failure of any one valve or power supply will not inadvertently open a vent path. These valves are energized-to-open, spring-to-close. Thus, the combination of PG&E Design Class I train assignments and valve failure modes will not prevent vessel head venting or venting isolation with any single active failure.

The RVHVS has two normally deenergized valves in series in each flowpath. This arrangement eliminates the possibility of a spuriously opened flowpath due to the spurious movement of one valve. As such, power lockout to any valve is not considered necessary.

The RVHVS is connected to a RVCH vent nozzle penetration. The reactor vent piping utilizes a 3/8-inch orifice prior to branching into two redundant flowpaths. The system is designed to limit the blowdown from a break downstream of the orifices such that loss through a severance of one of these lines is sufficiently small to allow operators to execute an orderly plant shutdown.

A break of the RVHVS line upstream of the orifices would result in an SBLOCA of not greater than 1 inch diameter. Such a break is similar to those analyzed in Reference 2. Since a break in the head vent line would behave similarly to the hot leg break case presented in Reference 2, the results presented therein are applicable to a RVHVS line break. This postulated vent line break results, therefore, in no calculated core uncovery.

All piping and equipment from the RVHVS nozzle to the second isolation valve are designed and fabricated in accordance with ASME BPVC Section III-2001 through 2003 Addenda, Class 1 requirements. The remainder of the piping is PG&E Design Class II.

5.5.14.3 Supports

The RVHVS piping is supported to ensure that the resulting loads and stresses on the piping and on the vent connection to the housing are acceptable. All supports and support structures comply with the requirements of the ASME BPVC Section III-2001 through 2003 Addenda, Subsection NF.

5.5.15 REFERENCES

1. IEEE-Std-279, Criteria for Protection Systems for Nuclear Power Generating Station, 1971.

2. Report on Small Break Accidents for Westinghouse NSSS System, WCAP-9600, June 1979.

3. Deleted in Revision 18.

4. Deleted in Revision 19.

5. NEI 97-06, Steam Generator Program Guidelines, latest revision.

6. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

7. Nuclear Regulatory Commission, TMI Short-Term Lessons Learned Requirements, NUREG-0578, July 1979.

8. Nuclear Regulatory Commission, Clarification of TMI Plan Requirements, NUREG-0737, November 1980.

9. Deleted in Revision 19.

10. Letter from Sheri R. Peterson (NRC) to Gregory M. Rueger (PG&E), “Leak-Before-Break Evaluation of Reactor Coolant System Piping for DCPP Units 1 and 2,” March 2, 1993,

11. Deleted in Revision 19.

12. Westinghouse Calculation SE/FSE-C-PGE-0013, “RHRS Cooldown Performance at Uprated Conditions,” June 5, 1996.

13. Toby Burnett, et al., Systems Evaluation for Reactor Flange Venting for the Diablo Canyon Power Plant, Westinghouse Technical Report, August 1992.

14. E. R. Frantz, et al., RCS Pressurization Analysis for Diablo Canyon Shutdown Scenarios, Westinghouse Technical Report, April 3, 1997.

5.5.16 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

5.6 INSTRUMENTATION REQUIREMENTS

5.6.1 REACTOR COOLANT SYSTEM

The RPV, pressurizer, and each of the RCLs are monitored by process control instrumentation. This instrumentation provides the input signals to the following control, display, and protection functions that are described in Chapter 7:

(1) Reactor trip (Section 7.2)

- (a) RCS temperatures (overtemperature ΔT, overpower ΔT)
- (b) Pressurizer pressure (low and high pressure trips)
- (c) Pressurizer level
- (d) RCS flow
- (e) RCP breaker position

(2) Engineered safety features actuation (Section 7.3)

- (a) Pressurizer pressure

(3) PG&E Design Class I functions for safe shutdown (Section 7.4)

- (a) Decay heat removal (RCS loop temperatures)
- (b) RCS pressure control (pressurizer level and pressure)

(4) PG&E Design Class I display information (Section 7.5)

- (a) RCS temperatures
- (b) Pressurizer level
- (c) Pressurizer pressure
- (d) RCS pressure
- (e) RCS flow
- (f) RCP motor amps
- (g) PSV position
- (h) PORV position
- (i) RPV level
- (j) Subcooling margin
- (k) Incore temperatures

(5) Other safety features (Section 7.6)

- (a) RCS pressure (RHR valve interlock)
- (b) Pressurizer temperature (RHR valve interlock)

(6) Control systems not required for safety (Section 7.7)

(a) Reactor control system (T_{avg} control)
(b) Plant control system interlocks (overtemperature turbine runback)
(c) Pressurizer pressure control
(d) Pressurizer level control
(e) Steam dump control (T_{avg} based)
(f) Incore temperatures

Refer to Section 5.5.1.2 for a discussion of RCP vibration monitoring.

The RCS design and operating pressure together with the PSV, PORV, and pressurizer spray valves nominal setpoints, and the protection system nominal setpoint pressures are listed in Table 5.2-10. The design pressure allows for operating transient pressure changes. The selected design margin considers core thermal lag, coolant transport times and pressure drops, instrumentation and control response characteristics, and system relief valve characteristics.

5.6.1.1 Inadequate Core Cooling Instrumentation

To meet the requirements for supplementing existing instrumentation to unambiguously indicate inadequate core cooling (refer to Sections 5.1.1.26 and 5.1.8.26, Item II.F.2), a subcooling meter and a reactor vessel water level measurement are provided. Inadequate core cooling detection instrumentation is discussed in more detail in Section 7.5.2.2. The subcooling meters are a subset of RVLIS and provide the operator with on-line indication of the core coolant temperature and pressure margins to saturation conditions. The reactor vessel water level is determined by the reactor vessel head level system by measuring the pressure drop between the upper and lower plena in the vessel.

Each subcooling meter (train A or B) has wide range temperature inputs from two each of the RCS hot legs and the hottest incore thermocouple associated with that train. Two pressure measurements (one per train) are input from the hot legs. The subcooling meter displays consist of a digital meter on the main control board (train B), a recorder to provide a redundant display (train A/PAM1), and the indication on each RVLIS display (PAM3 and PAM4). All the indications provide the temperature margin to saturation of the RCS. In addition to temperature margin, the RVLIS displays also provide the pressure margin.

The reactor vessel level measurement is used in combination with the existing core exit thermocouples and the subcooling meter. Differential pressure between the top of the reactor vessel and the bottom of the reactor vessel on two narrow-range and two wide-range instruments is measured. The system functions as follows: with the RCPs off, the pressure drop between the top and the bottom of the vessel indicates the collapsed liquid level (the equivalent liquid level without voids in the two-phase region) in the vessel. This is read on the narrow-range instrument in terms of feet of liquid. With the RCPs running, the pressure drop (in feet of liquid) from the top to the bottom of

the vessel when compared to the measurement with the same combination of running pumps during normal, single phase RCS condition, provides an approximate indication of the void fraction in the vessel. This is read on the wide-range instrument as percent of full flow differential pressure with the vessel filled with water.

5.6.2 RESIDUAL HEAT REMOVAL SYSTEM

Process control instrumentation for the RHR system is provided for the following purposes:

(1) Furnish input signals for monitoring and/or alarming purposes for:

- (a) Temperature indications
- (b) Pressure indications
- (c) Flow indications

(2) Furnish input signals for control purposes of such processes as follows:

- (a) Control valve in the RHR pump bypass line so that it opens at flows below a preset limit and closes at flows above a preset limit
- (b) RHR isolation valves control circuitry (refer to Section 7.6 for the description of the interlocks)
- (c) Control valve in the RHR heat exchanger bypass line to control temperature of reactor coolant returning to reactor loops during plant cooldown
- (d) RHR pump circuitry for starting RHR pumps on "S" signal
- (e) RHR pump trip on low RWST level

5.6.3 REFERENCES

1. Deleted in Revision 22.

TABLE 5.0-1

APPLICABLE DESIGN BASIS CRITERIA

CRITERIA	TITLE	APPLICABILITY	
Reactor Coolant System		Reactor Coolant System	Reactor Coolant Pressure Boundary
Section		5.1	5.2
1. General Design Criteria			
Criterion 2, 1967	Performance Standards	X	X
Criterion 3, 1971	Fire Protection	X	
Criterion 4, 1967	Sharing of Systems	X	
Criterion 4, 1987	Environmental and Dynamic Effects Design Bases	X	X
Criterion 6, 1967	Reactor Core Design	X	
Criterion 9, 1967	Reactor Coolant Pressure Boundary	X	X
Criterion 11, 1967	Control Room	X	X
Criterion 12, 1967	Instrumentation and Controls	X	X
Criterion 13, 1967	Fission Process Monitors and Controls	X	
Criterion 15, 1967	Engineered Safety Features Protection Systems	X	
Criterion 16, 1967	Monitoring Reactor Coolant Pressure Boundary		X
Criterion 21, 1967	Single Failure Definition	X	
Criterion 33, 1967	Reactor Coolant Pressure Boundary Capability		X
Criterion 34, 1967	Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention		X
Criterion 35, 1967	Reactor Coolant Pressure Boundary Brittle Fracture Prevention		X
Criterion 36, 1967	Reactor Coolant Pressure Boundary Surveillance		X
Criterion 40, 1967	Missile Protection	X	
Criterion 49, 1967	Containment Design Basis	X	
Criterion 51, 1967	Reactor Coolant Pressure Boundary Outside Containment		X
Criterion 54, 1971	Piping Systems Penetrating Containment	X	
Criterion 55, 1971	Reactor Coolant Pressure Boundary Penetrating Containment	X	
Criterion 56, 1971	Primary Containment Isolation	X	

TABLE 5.0-1

APPLICABLE DESIGN BASIS CRITERIA

CRITERIA	TITLE	APPLICABILITY	
Reactor Coolant System		Reactor Coolant System	Reactor Coolant Pressure Boundary
Section		5.1	5.2
2. System Safety Functional Requirements			
Protection from Missiles and Dynamic Effects		X	X
Reactor Heat Removal		X	
RCS Thermal-Hydraulic Requirements		X	
RCS Coolant Functional Properties		X	
RCS Pressure and Volume Control		X	
Steam Flow Restriction		X	
RCP Coastdown		X	
Pressurizer Relief Tank		X	
3. 10 CFR Part 50			
50.48(c)	National Fire Protection Association Standard NFPS 805	X	
50.49	Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants	X	
50.55a	Codes and Standards		X
50.55a(f)	Inservice Testing Requirements	X	X
50.55a(g)	Inservice Inspection Requirements	X	X
50.60	Acceptance Criteria for Fracture Prevention Measures for Lightwater Nuclear Power Reactors for Normal Operation		X
50.61	Fracture Toughness Requirements for Protection against Pressurized Thermal Shock Events		X
50.63	Loss of All Alternating Current Power	X	
Appendix G	Fracture Toughness Requirements		X
Appendix H	Reactor Vessel Material Surveillance Program Requirements		X

TABLE 5.0-1

APPLICABLE DESIGN BASIS CRITERIA

CRITERIA	TITLE	APPLICABILITY	
Reactor Coolant System		Reactor Coolant System	Reactor Coolant Pressure Boundary
Section		5.1	5.2
4. Regulatory Guides			
Safety Guide 14, October 1971	Reactor Coolant Pump Flywheel Integrity		X
Regulatory Guide 1.14, Revision 1, August 1975	Reactor Coolant Pump Flywheel Integrity		X
Regulatory Guide 1.44, May 1973	Control of the Use of Sensitized Stainless Steel		X
Regulatory Guide 1.45, May 1973	Reactor Coolant Pressure Boundary Leakage Detection Systems		X
Regulatory Guide 1.89, November 1974	Environmental Qualification of Class 1E Equipment for Nuclear Power Plants	X	
Regulatory Guide 1.97, Revision 3, May 1983	Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident	X	X
Regulatory Guide 1.99, Revision 2, May 1988	Radiation Embrittlement of Reactor Vessel Materials		X
Regulatory Guide 1.121, August 1976	Bases for Plugging Degraded PWR Steam Generator Tubes	X	
5. NRC NUREG			
NUREG-0737, November 1980	Clarification of TMI Action Plan Requirements	X	X
6. NRC Generic Letters			
Generic Letter 83-37, November 1983	NUREG-0737 Technical Specifications	X	
Generic Letter 88-05, March 1988	Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants	X	
Generic Letter 89-10, June 1989	Safety-Related Motor-Operated Valve Testing and Surveillance		X

TABLE 5.0-1

APPLICABLE DESIGN BASIS CRITERIA

CRITERIA	TITLE	APPLICABILITY	
Reactor Coolant System		Reactor Coolant System	Reactor Coolant Pressure Boundary
Section		5.1	5.2
Generic Letter 90-06, June 1990	Resolution of Generic Issue 70, "Power-Operated Relief Valve and Block Valve Reliability" and Generic Issue 94, "Additional Low-Temperature Over Pressure Protection for Light-Water Reactors" Pursuant to 10 CFR 50.54(f)	X	X
Generic Letter 95-07, August 1995	Pressure Locking and Thermal Binding of Safety-Related Power-Operated Valves	X	
7. NRC Bulletins			
NRC Bulletin 88-09, July 1988	Thimble Tube Thinning in Westinghouse Reactors	X	
NRC Bulletin 88-11, December 1988	Pressurizer Surge Line Thermal Stratification	X	
8. Branch Technical Position			
Branch Technical Position ASB 10-2, March 1978	Design Guidelines for Avoiding Water Hammers in Steam Generators	X	

TABLE 5.1-1

SYSTEM DESIGN AND OPERATING PARAMETERS[c]

	Unit 1	Unit 2
Plant design life, years[a]	50	50
Nominal operating pressure, psig	2,235	2,235
Total system volume, including pressurizer and surge line, ft^3	12,064 +/- 100	12,169 +/- 100
System liquid volume, including pressurizer water, ft^3 (nominal)	11,082 - 11,337[f]	11,187 - 11,448[d]
Total heat output , Btu/hr	11,687 $x10^6$	11,687x 10^6
System thermal and hydraulic data [f]		
Minimum Measured Flow (RCS total flow), gpm	359,200	362,500
Core Bypass Flow, %	7.5	9.0
Mechanical Design Flow (MDF), gpm/loop	99,600	102,000
Thermal Design Flow, lb/hr	132.9 x 10^6 – 135.1 x 10^6 [f]	134.0 x 10^6 – 136.3 x 10^6 [d]
Reactor vessel		
Inlet temp, °F	531.7 - 544.5[f]	531.9 - 545.1[d]
Outlet temp, °F	598.3 - 610.1[f]	598.1 - 610.1[d]
Steam generator		
Inlet temp, °F	598.3 - 610.1[f]	598.1 - 610.1[d]
Outlet temp, °F	531.4 - 544.2[f]	531.6 - 544.8[d]
Design Fouling Factor, hr-ft^2-°F/BTU	0.00018	0.00018
Reactor coolant pump		
Inlet temp, °F	531.4 - 544.2[f]	531.6 - 544.8[d]
Outlet temp, °F	531.7 - 544.5[f]	531.9 - 545.1[d]
Steam pressure, psia	730 - 821[f] [g]	731 - 825[d] [h]

TABLE 5.1-1

Steam flow, lb/hr (total)	14.64×10^6 – 14.89×10^6 (f)(g)	14.64×10^6 - 14.90×10^6 (d) (h)
Feedwater inlet temp, °F	425.0 - 435.0	425.0 - 435.0
Pressurizer spray rate, maximum, gpm	800	800
Pressurizer heater capacity, kW(b)	1800	1800
Pressurizer relief tank volume, ft^3	1800	1800
Best Estimate Operating Data(c)		
NSSS Power, MWt	3425	3425
(a) Primary System Flows and ΔP(e):		
Reactor Vessel Avg. Temp., °F	565.0	565.0
RCS Flow, gpm/loop	94,900	95,500
Reactor Coolant Pump developed head, ft	282.3	266.6
Component ΔP, psia		
Reactor Vessel ΔP, psi	48.2	42.46
Steam Generator ΔP, psi	38.5	38.9
RCS Piping ΔP, psi	7.2	7.3
(b) Secondary Side Performance Parameters:		
Reactor Vessel Avg. Temp., °F	577.3	577.6
RCS Flow, gpm/loop	94,900	95,500
Steam Generators		
Steam pressure, psia	874	878
Steam flow, lb/hr x 10^6	14.920	14.924
Best Estimate Fouling Factor, hr-ft^2-°F/BTU	0.00006	0.00006

(a) Although DCPP useful life is expected to be 40 years, the RCS design conservatively assumes that integrity must be maintained during 50 years.
(b) See Table 5.5-12.
(c) 0% SGTP, NSSS rated power
(d) Design value corresponding to full power, 565.0 - 577.6°F vessel average temperature.
(e) Best Estimate calculations were performed to maximize Best Estimate Flow and system/component pressure drops.
(f) Design value corresponding to full power, 565.0 - 577.3°F vessel average coolant temperature.
(g) If a high steam pressure is more limiting for analysis purposes, a greater steam pressure of 881 psia, steam temperature of 529.4°F, and steam flow of 14.93×10^6 lb/hr total should be assumed for Unit 1. This is to envelop the possibility that the plant could operate with better than expected steam generator performance.
(h) If a high steam pressure is more limiting for analysis purposes, a greater steam pressure of 885 psia, steam temperature of 530.0°F, and steam flow of 14.93×10^6 lb/hr total should be assumed for Unit 2. This is to envelop the possibility that the plant could operate with better than expected steam generator performance.

TABLE 5.2-1

ASME CODE CASES
FOR WESTINGHOUSE PWR CLASS A COMPONENTS

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Code Case[b]	*Title*
1141	*Foreign Produced Steel*
1332	*Requirements for Steel Forgings*
1334	*Requirements for Corrosion Resistant Steel Bars*
1335	*Requirements for Bolting Material*
1337	*Requirements for Special Type 403 Modified Forgings or Bars (Section III)*
1344	*Requirements for Nickel-Chromium Age-Hardenable Alloys*
1345	*Requirements for Nickel-Molybdenum-Chromium-Iron Alloys*
1355	*Electroslag Welding*
1358[a]	*High Yield Strength Steel for Section III Construction*
1360[a]	*Explosive Welding*
1361	*Socket Welds*
1364	*Ultrasonic Transducers SA-435 (Section II)*
1384	*Requirements for Precipitation Hardening Alloy Bars & Forgings*
1388	*Requirements for Stainless Steel – Precipitation Hardening*
1390	*Requirements for Nickel-Chromium Age-Hardenable Alloys for Bolting*
1395	*SA-508, Class 2 Forgings – Modified Manganese Content*
1401	*Welding Repair to Cladding*
1407	*Time of Examination*
1412[a]	*Modified High Yield Strength Steel*
1414[a]	*High Yield Strength Cr-Mo*
1423	*Plate: Wrought Type 304 with Nitrogen Added*
1433	*Forgings: SA-387*
1434	*Class BN Steel Casting (Postweld Heat Treatment for SA-487)*
1448	*Use of Case Interpretations of ANSI B31 Code for Pressure Piping*
1456	*Substitution of Ultrasonic Examination*
1459	*Welding Repairs to Base Metal*
1461	*Electron Beam Welding*
1470	*External Pressure Charts for Low Alloy Steel*
1471	*Vacuum Electron Beam Welding of Tube Sheet Joints*
1474	*Integrally Finned Tubes (Section III)*
1477	*B-31.7, ANSI 1970 Addenda*
N-20-4	*SB-163 Nickel-Chromium-Iron Tubing at a Specified Minimum Yield Strength of 40,000 psi*
1487	*Evaluation of Nuclear Piping for Faulted Conditions*
1492	*Postweld Heat Treatment*
1493	*Postweld Heat Treatment*
1494	*Weld Procedure Qualification Test*
1498	*SA-508, Class 2, Minimum Tempering Temperature*
1501	*Use of SA-453 Bolts in Service Below 800 degrees F without Stress Rupture Tests*
1504	*Electrical and Mechanical Penetration Assemblies*
1505[a]	*Use of 26 Cr, 1 Mo Steel*
1508	*Allowable Stresses, Design Stress Intensity and/or Yield Strength Values*
1514	*Fracture Toughness Requirements*
1515	*Ultrasonic Examination of Ring Forgings for Shell Section of Section III – Class I Vessels*
1516	*Welding of Non-Integral Seats in Valves for Section III Application*
1517	*Material Used in Pipe Fittings*
1519	*Use of A-105-71 in lieu of SA-105*
1521	*Use of H. Grades SA-240, SA-479, SA-336, and SA-358*

TABLE 5.2-1

Code Case[b]	*Title*
1522	*ASTM Material Specifications*
1523	*Plate Steel Refined by Electroslag Remelting*
1524	*Piping 2" NPS and Smaller*
1525	*Pipe Descaled by Other Than Pickling*
1526	*Elimination of Surface Defects*
1527	*Integrally Finned Tubes*
1528	*High Strength SA-508 Class 2 and SA-541 Class 2 Forgings for Section III Construction of Class I Components*
1529	*Material for Instrument Line Fittings*
1531	*Electrical Penetrations, Special Alloys for Electrical Penetrations Seals*
1534	*Overpressurization of Valves*
1535	*Hydrostatic Test of Class I Nuclear Valves*
1539	*Metal Bellows and Metal Diaphragm Steam Sealed Valves, Class 1, 2, and 3*
1542	*Requirements for Type 403 Modified Forgings of Bars for Bolting Material*
1544	*Radiographic Acceptance Standards for Repair Welds*
1545	*Test Specimens from Separate Forgings for Class 1, 2, 3, and MC.*
1546	*Fracture Toughness Test for Weld Metal Section*
1547	*Weld Procedure Qualification Tests; Impact Testing Requirements, Class I*
1522	*Design by Analysis of Section III Class I Valves*
1556[a]	*Penetrameters for Film Side Radiographs in Table T-320 of Section V*
1567	*Test Lots for Low Alloy Steel Electrodes*
1568	*Test Lots for Low Alloy Steel Electrodes*
1571	*Materials for Instrument Line Fittings; For SA-234 Carbon Steel Fittings*
1573	*Vacuum Relief Valves*
1574	*Hydrostatic Test Pressure for Safety Relief Valves*

(a) Westinghouse has performed a review of these specific code cases and knows of no specific application made to components for Diablo Canyon Units 1 and 2.

(b) Code cases adopted for use at DCPP are specified in the introduction to the Inservice Inspection Program Plan.

TABLE 5.2-2

EQUIPMENT CODE AND CLASSIFICATION LIST

Component	Code Class[d]	Unit 1 Code	Unit 1 Addenda	Unit 2 Code	Unit 2 Addenda
Reactor Coolant System					
Reactor vessel	A	ASME III 1965	thru Winter 1966	ASME III 1968	none
Reactor vessel closure head	A	ASME III 2001	thru 2003	ASME III 2001	thru 2003
Control rod drive mechanism housing	A	ASME III 2001	thru 2003	ASME III 2001	thru 2003
Steam generator (primary side pressure boundary)	A	ASME III 1998	thru 2000	ASME III 1998	thru 2000
(secondary side pressure boundary)	B[a]	ASME III 1998	thru 2000	ASME III 1998	thru 2000
Pressurizer	A	ASME III 1965	thru Summer 1966	ASME III 1965	thru Summer 1966
Reactor coolant piping[b][c], fittings	N/A	ASA B31.1 1955	none	USAS B31.1.0 1967	none
Surge pipe, fittings	N/A	ASA B31.1 1955	none	USAS B31.1.0 1967	none
Reactor coolant thermowells	N/A	ASA B31.1	none	ASA B31.1	none
Safety valves	N/A	ASME III 1968	Article 9	ASME III 1968	Article 9
Relief valves	N/A	USAS B16.5	none	USAS B16.5	none
Valves to reactor coolant system boundary	N/A	USAS B16.5 or MSS-SP-66 or ASME III 1968 or 1974[e]	None	USAS B16.5 or MSS-SP-66 or ASME III 1968 or 1974[e]	None
Piping to reactor coolant system boundary	A	ANSI B31.7 1969	1970	ANSI B31.7 1969	1970
Pressurizer relief tank	C	ASME III 1968	thru Summer 1968	ASME III 1968	thru Summer 1968
Reactor coolant pump standpipe orifice	N/A	No Code		No Code	
Reactor coolant pump standpipe	N/A	ASME VIII 1968	None	ASME VIII 1968	None

TABLE 5.2-2

Component	Code Class[d]	Unit 1 Code	Unit 1 Addenda	Unit 2 Code	Unit 2 Addenda
Reactor coolant pump[f][g]					
Casing	A	ASME III 1965	thru Summer 1966	ASME III 1968	thru Winter 1970
Main flange	A	ASME III 1965	thru Summer 1966	ASME III 1968	thru Winter 1970
Thermal barrier	A	ASME III 1965	thru Summer 1966	ASME III 1968	thru Winter 1970
#1 seal housing	A	ASME III 1965	thru Summer 1966	ASME III 1968	thru Winter 1970
#2 seal housing	A	ASME III 1965	thru Summer 1966	ASME III 1968	thru Winter 1970
Pressure retaining bolting	A	ASME III 1965	thru Summer 1966	ASME III 1968	thru Winter 1970
Remaining parts	N/A	ASME III 1965	thru Summer 1966	ASME III 1968	thru Winter 1970
Reactor coolant pump motor oil coolers	N/A	No Code			

(a) Code design requirements are in excess of the requirement dictated by the applicable safety class.

(b) Reactor coolant system piping subassemblies inspected to ASME I as required by California law.

(c) Classification for other piping and associated valves in the reactor coolant system boundary shall be as defined by the systems engineering flow diagrams for the appropriate safety class.

(d) ASME Code Classes A, B, and C were re-designated 1, 2 and 3 in Editions starting in 1971. Refer to Chapter 3.

(e) A small number of valves was purchased to ASME Section III, 1974 requirements.

(f) Originally supplied Unit 1 RCP stress limits and analysis based on ASME III 1968 Edition thru Winter 1970 Addenda.

(g) Originally supplied Unit 1 RCPs are not ASME Code N-Symbol stamped.

TABLE 5.2-3

PROCUREMENT INFORMATION
COMPONENTS WITHIN REACTOR COOLANT SYSTEM BOUNDARY

Component	Purchase Order Dates	
	Unit 1	Unit 2
Reactor vessel	3/27/67	12/27/68
Replacement RVCH	7/28/06	7/28/06
CRDM housing	7/28/06	7/28/06
Original steam generator	11/22/66	4/6/67
Replacement steam generator	8/12/04	8/12/04
Pressurizer	4/24/67	4/24/67
Reactor coolant pump	3/29/67	3/29/67
Reactor coolant pipe, fittings, and fabrication	5/2/67[a] 1/16/68[b]	10/7/68[a] 11/20/69[b]
Surge pipe, fittings, and fabrication	5/2/67[a]	10/7/68[a]
Piping to reactor coolant system boundary fabrication and installation	5/25/70	5/25/70

(a) Purchase of pipe.
(b) Fabrication of pipe.

TABLE 5.2-4

SUMMARY OF REACTOR COOLANT SYSTEM DESIGN TRANSIENTS

Normal Conditions	Occurrences
1. RCS heatup and cooldown at ≤ 100°F/hr	250 (each)[e]
2. Unit loading and unloading at 5% of full power/min	18,300 (each)
3. Step load increase and decrease of 10% of full power	2,500 (each)
4. Large step load decrease	250
5. Steady state fluctuations	infinite
Upset Conditions	
1. Loss of load (above 15% full power), without immediate turbine or reactor trip	100[e]
2. Loss of all offsite power	50[e]
3. Partial loss of flow	100[e]
4. Reactor trip from full power	500[e]
5. Inadvertent auxiliary spray (differential temperature > 320°F	12[e]
6. Design earthquake	20
7. Cold Overpressurization (LTOP)	10
Faulted Conditions[a]	
1. RCPB pipe break[d]	1
2. Steam line break	1
3. Double design earthquake[b]	1
4. 7.5M Hosgri earthquake[b]	1
Test Conditions	
1. Turbine roll test	10[e]
2. Hydrostatic test conditions	
a. Primary side	10[e]
b. Secondary side	10[e]
3. Leak tests (for closures)	
a. Primary side	60[e]
b. Secondary side	10
4. Tube leak tests (secondary side pressurized as follows)	
200 psig	400
400 psig	200
600 psig	120
840 psig	80

Component Specific Analysis[g]

Normal Conditions	Occurrences
1. Pressurizer heatup at ≤ 100°F/hr and cooldown at ≤ 200°F/hr	250
2. Steam Generator hot standby operation/feedwater cycling (f)	18,300
3. Pressurizer boron concentration equalization	32,000

TABLE 5.2-4

(a) In accordance with the ASME Boiler and Pressure Vessel Code, faulted conditions are not included in fatigue evaluations.
(b) See Section 3.7.
(c) Deleted in Revision 22.
(d) With the acceptance of the DCPP leak-before-break analysis by the NRC, dynamic loading conditions resulting from pipe rupture events in the main reactor coolant loop piping no longer have to be considered in the design basis analyses; only the loads resulting from RCS branch line breaks have to be considered.
(e) These limits were contained in Technical Specifications (Table 5.7-1) prior to License Amendment 135 (Improved Technical Specifications)
(f) Applies to steam generator only.
(g) These transients apply to the specific component listed, and are provided to clarify the applicable transient. The number of occurrences represents the applicable number of cycles for the component, consistent with the occurrences identified at the system level. These are not in addition to the number of occurrences identified at the system level.

TABLE 5.2-5

STRESS LIMITS FOR PG&E QUALITY/CODE CLASS I LOOP PIPING AND VALVES

Condition / Loading Combinations	Loop Piping[a] [f]	Valves
1. Normal		
(Deadweight + Pressure)	$\sigma \leq S_h$	See Section 3.9.2
(Thermal)	$\sigma \leq S_a$	See Section 3.9.2
2. Upset (Normal ± DE loads)	$\sigma \leq 1.2\ S_h$	See Section 3.9.2
3. Faulted – 1 (Deadweight +Pressure ± DDE)	$\sigma \leq 1.8\ S_h$[b]	See Section 3.9.2
4. Faulted – 2 (Deadweight + Pressure ± DDE/Hosgri[c] + LOCA[d])	$\sigma \leq 3.6\ S_h$[b]	See Section 3.9.2
5. Faulted – 3 (Deadweight + Pressure ± Hosgri)	$\sigma \leq 2.4\ S_h$[b]	See Section 3.9.2
6. Faulted – 4 (Deadweight + Pressure ± DDE/Hosgri[c] + Other Pipe Rupture[e])	$\sigma \leq 3.6\ S_h$[b]	See Section 3.9.2

(a) S_h = allowable stress from B31.1 Code for power piping
$S_a = 1.25\ S_c + 0.25\ S_h$

TABLE 5.2-5

STRESS LIMITS FOR PG&E QUALITY/CODE CLASS I LOOP PIPING AND VALVES

S_c = allowable stress at cold (ambient) temperature
σ = piping stress calculated per B31.1 Code requirements.

(b) See Table 5.2-7 for additional faulted condition stress limits for loop piping.

(c) The more limiting between the DDE loads and the Hosgri loads.

(d) Loss of Coolant Accident (LOCA) Loads – The original stress analysis considered main coolant pipe ruptures. With the acceptance of DCPP leak-before-break analysis by the NRC, only the loads resulting from branch line breaks are considered.

(e) Main steam line or feedwater line rupture.

(f) Loop piping and branch lines ≥ 6 inch diameter.

TABLE 5.2-6

LOAD COMBINATIONS AND STRESS CRITERIA FOR PRIMARY EQUIPMENT [a]

CONDITION	LOAD COMBINATION	STRESS CRITERIA[e][j]
Design	Deadweight + Pressure ± DE	$P_m \leq S_m$ $P_L + P_b \leq 1.5\ S_m$
Normal	Deadweight + Pressure + Thermal	$P_L + P_b + P_e + Q \leq 3\ S_m$[b]
Upset - 1	Deadweight + Pressure + Thermal ± DE	$U_T \leq 1.0$[b] $P_L + P_b + P_e + Q \leq 3\ S_m$[b]
Upset - 2	Deadweight + Pressure + Thermal	$U_T \leq 1.0$[b] $P_L + P_b + P_e + Q \leq 3\ S_m$[b]
Faulted - 1	Deadweight + Pressure ± DDE	Table 5.2-7[k]
Faulted - 2	Deadweight + Pressure ± (DDE or Hosgri[d,h])+LOCA[d, g]	Table 5.2-7
Faulted - 3	Deadweight + Pressure ± Hosgri	Table 5.2-7
Faulted - 4	Deadweight + Pressure ± DDE or Hosgri[h] + Other Pipe Rupture[f, i]	Table 5.2-7

(a) Reactor coolant pressure boundary components of the steam generators, reactor vessel, reactor coolant pumps, pressurizer.
(b) Based on elastic analysis. For simplified elastic-plastic analysis, the stress limits of the 1971 ASME Code Section III, NB-3228.3 apply.
(c) Deleted
(d) Seismic faulted conditions (DDE or Hosgri) and LOCA combined by ABSUM or SRSS method (SRSS subject to the conditions and limitations of NUREG-0484).
(e) For definition of stress criteria terms, see Additional Notes.
(f) Main steam line or feedwater line rupture as applicable.
(g) Loss of Coolant Accident (LOCA) Loads - The original stress analysis considered main coolant pipe ruptures. With the acceptance of the DCPP leak-before-break analysis by the NRC, only the loads resulting from RCS branch line breaks are considered.
(h) The more limiting between the DDE loads and the Hosgri loads.
(i) DDE or Hosgri and Other Pipe Rupture combined by ABSUM, unless otherwise noted.
(j) For steam generators, stress limits are taken from Appendix F of ASME III.
(k) For the reactor vessel, the Faulted-1stress limit is:
P_m (or P_L) $\leq 1.2S_m$ or S_y*P_m (or P_L) + $P_b \leq 1.8S_m$ or 1.5 S_y*
(*For elastic analysis, use the greater of the values specified).

P_m = General membrane; average primary stress across solid section. Excludes discontinuities and concentrations. Produced only by mechanical loads.
P_L = Local membrane; average stress across any solid section. Considers discontinuities, but not concentrations. Produced only by mechanical loads.
P_b = Bending; component of primary stress proportional to distance from centroid of solid section. Excludes discontinuities and concentrations. Produced only by mechanical loads.

TABLE 5.2-6

LOAD COMBINATIONS AND STRESS CRITERIA FOR PRIMARY EQUIPMENT

P_e = Expansions; stresses which result from the constraint of "free end displacement" and the effect of anchor point motions resulting from earthquakes. Considers effects of discontinuities, but not local stress concentration. (Not applicable to vessels and pumps).

Q = Membrane Plus Bending; self-equilibrating stress necessary to satisfy continuity of structure. Occurs at structural discontinuities. Can be caused by mechanical loads or by differential thermal expansion. Excludes local stress concentrations.

U_T = Cumulative usage factor.

S_m = Stress intensity from ASME Section III at temperature

S_y = Yield stress at temperature

TABLE 5.2-6a

LOAD COMBINATIONS AND ACCEPTANCE CRITERIA FOR REPLACEMENT PRIMARY EQUIPMENT(Note 1)

LOAD CONDITION	LOAD COMBINATION(Note 2 & 6)	ACCEPTANCE CRITERIA
Design	DL + P ± DE	ASME Boiler and Pressure Vessel (B&PV) Code, Section III, Division 1, 2001 Edition through 2003 Addenda – Subsections NCA and NB
Normal (ASME Service Level A)	DL + P ± I(Note 3) + T	
Upset (ASME Service Level B)	DL + P + T ± DE DL + P + T	
Faulted (ASME Service Level D)	DL + P ± (HE or DDE) DL + P ± DDE + LOCA(Note 4 & 5) DL + P ± HE + LOCA(Note 4, 5)	ASME B&PV Code, Section III, Division 1, 2001 Edition through 2003 Addenda - Appendix F

NOTES:

1. RVCH, CRDM pressure housings (pressure retaining components), CETNA, and Vent/RVLIS nozzle
2. Load Case Description
   - DL Dead Load (or Dead Weight)
   - I Impulse
   - P Pressure
   - T Thermal Expansion (considered if applicable)
   - DE Design Earthquake
   - DDE Double Design Earthquake
   - HE Hosgri Earthquake
   - LOCA Loss of Coolant Accident Load(Note 4)
3. Impulse loads apply only to CRDMs
4. For CRDMs, LOCA loads are applied where the CRDM attaches to the RVCH.
5. Seismic faulted conditions (DDE or HE) and LOCA combined by ABSUM or SRSS method (SRSS subject to the conditions and limitations of NUREG-0484).
6. Other pipe ruptures; i.e., main steam line break and feedwater line break, do not impact these components and, therefore, are not included in the load combinations.

TABLE 5.2-7

FAULTED CONDITION STRESS LIMITS FOR PG&E QUALITY/CODE CLASS I COMPONENTS

System (or Subsystem) Analysis	Component Analysis	Stress Limits for Vessels and Pumps [f]		Stress Limits for Loop Piping[h]	Test
		P_m	$P_m + P_b$	P	
Elastic	Elastic	Smaller of 2.4 S_m and 0.70 S_u	Smaller of 3.6 Sm and 1.05 S_u[b]	$3.6S_h$[g]	0.8 L_T[c][d]
	Plastic	Larger of 0.70 S_u or $S_y + 1/3\ (S_u - S_y)$[c]	Larger of 0.70 S_{ut} or $S_y + 1/3\ (S_{ut} - S_y)$[c]	Larger of 0.70 S_{ut} or $S_y + 1/3\ (S_{ut} - S_y)$[c]	0.8 L_T[c][d]
	Limit Analysis	$0.9L_1$[a][c]	$0.9L_1$[a][c]	$0.9L_1$[a][c]	0.8 L_T[c][d]
Plastic	Plastic	Larger of 0.70 S_u or	Larger of 0.70 S_{ut} or	Larger of 0.70 S_{ut} or	0.8 L_T[c][d]
	Elastic	$S_y + 1/3\ (S_u - S_y)$	$S_y + 1/3\ (S_{ut} - S_y)$	$S_y + 1/3\ (S_{ut} - S_y)$	

S_y = Yield stress at temperature
S_u = Ultimate stress from engineering stress strain curve at temperature
S_h = Allowable stress from B31.1 Code
S_{ut} = ultimate stress from true stress-strain curve at temperature
S_m = stress intensity from ASME Section III at temperature

(a) L_1 = Lower bound limit load with an assumed yield point equal to 2.3 S_m or 1.5 S_y, as applicable.
(b) These limits are based on a bending shape factor of 1.5 for simple bending cases with different shape factors; the limits will be changed proportionally.
(c) When elastic system analysis is performed, the effect of component deformation on the dynamic system response should be checked.
(d) L_T = The limits established for the analysis need not be satisfied if it can be shown from the test of a prototype or model that the specified loads (dynamic or static equivalent) do not exceed 80% of L_T, where L_T is the ultimate load or load combination used in the test. In using this method, account shall be taken of the size effect and dimensional tolerances (similitude relationships) that may exist between the actual component and the tested models to ensure that the loads obtained from the test are a conservative representation of the load carrying capability of the actual component under postulated loading for faulted conditions.
(e) Deleted
(f) For steam generators, stress limits are taken from Appendix F of ASME Section III.
(g) 3.6 S_h limit applies to DDE or Hosgri + pipe break (LOCA, main steam line, or feedwater line rupture) faulted conditions only.
(h) Loop piping and branch lines ≥ 6 inch diameter.

TABLE 5.2-8

LOADING COMBINATIONS AND ACCEPTANCE CRITERIA FOR PRIMARY EQUIPMENT[a] SUPPORTS

CONDITION	LOADING COMBINATIONS	LINEAR-TYPE COMPONENT SUPPORT STRESS LIMITS[i][j]
Normal	Deadweight + Temperature + Pressure	1969 AISC Specification, Part 1
Upset	Deadweight + Temperature + Pressure ± DE	1969 AISC Specification, Part 1
Faulted - 1	Deadweight + Pressure ± DDE	1969 AISC Specification, Part 2[c] or S_y after load redistribution, whichever is higher
Faulted - 2	Deadweight + Pressure ± DDE or Hosgri[b,g] + LOCA[b,f]	1969 AISC Specification, Part 2[c] or S_y after load redistribution, whichever is higher
Faulted - 3	Deadweight + Pressure ± Hosgri	1969 AISC Specification, Part 2[c] or S_y after load redistribution, whichever is higher
Faulted - 4	Deadweight + Pressure ± DDE or Hosgri[g] + Other Pipe Rupture[d,h]	1969 AISC Specification, Part 2[c] or S_y after load redistribution, whichever is higher

(a) Steam generators, reactor vessel, reactor coolant pumps, pressurizer.
(b) Seismic faulted conditions (DDE or Hosgri) and LOCA combined by ABSUM or SRSS method (SRSS subject to the conditions and limitations of NUREG-0484).
(c) For supports qualified by load test, allowable loads = 0.8 times L_t per UFSAR Table 5.2-7.

TABLE 5.2-8

LOADING COMBINATIONS AND ACCEPTANCE CRITERIA FOR
PRIMARY EQUIPMENT SUPPORTS

(d) Main steam line or feedwater line rupture whichever is more limiting.
(e) Deleted
(f) LOCA – Loss of Coolant Accident Loads - The original stress analysis considered main coolant pipe ruptures. With the acceptance of the DCPP leak-before-break analysis by the NRC, only the loads resulting from RCS branch line breaks are considered.
(g) The more limiting between the DDE loads and the Hosgri loads.
(h) DDE or Hosgri and Other Pipe Rupture combined by ABSUM, unless otherwise noted.
(i) Stress Limits are also applicable to bolts and anchor bolts. When using S_y, connection strength shall exceed the strength of the weakest connected member, shear yield shall be taken as $Sy/3^{0.5}$, and combined tension/shear shall meet the elliptical interaction relationship.
(j) For plate and shell-type component supports, allowable stress limits shall be per ASME BPVC Section III, Sub-Section NF, 1980 Edition including Winter 82 Addenda.

TABLE 5.2-8a

LOAD COMBINATIONS AND ACCEPTANCE CRITERIA
FOR INTEGRATED HEAD ASSEMBLY (IHA)

[PG&E Design Class I Support Structure Components]

LOAD CONDITION	LOAD COMBINATION(Notes 1 &,2)	ACCEPTANCE CRITERIA
Design	DL + P	ASME Boiler and Pressure Vessel (B&PV) Code, Section III, Division 1, 2001 Edition through 2003 Addenda - Subsection NF
Normal (ASME Service Level A)	DL + ML DL + P + T	
Upset (ASME Service Level B)	DL + P ± DE DL + P + T ± DE	
Faulted (ASME Service Level D)	DL + P + T ± (HE or DDE) DL + P + T ± $(DDE^2+LOCA^2)^{1/2}$ DL + P + T ± $(HE^2+LOCA^2)^{1/2}$	ASME B&PV Code, Section III, Division 1, 2001 Edition through 2003 Addenda - Appendix F
Faulted (Missile Shield and Support)	DL + P + T ± $(DDE^2+MI^2)^{1/2}$ DL + P + T ± $(HE^2+ MI^2)^{1/2}$	

NOTES:

1. Load Case Description

DL	Dead Load
P	Pressure
T	Thermal(Note 2)
ML	Maintenance Load (live loads on walkways during maintenance activities)
MI	Missile impact load (missile shield and support only)
DE	Design Earthquake
DDE	Double Design Earthquake
HE	Hosgri Earthquake
LOCA	Loss of Coolant Accident Load(Note 3)

2. The IHA offers no resistance to reactor vessel thermal growth and, therefore, sustains no stress due to such growth. The temperature load symbol is included in the above table since this load was considered as part of the IHA design criteria. Applicable service and accident temperatures are considered when determining material properties and material allowable stress values.

3. The response spectra input used for the IHA LOCA analysis is the envelope of the Unit 1 and 2 LOCA response spectra associated with a pressurizer surge line break, residual heat removal (RHR) line break, and accumulator line break. LOCA motions are at the reactor head and were therefore applied where the IHA is attached to the reactor head.

TABLE 5.2-9

ACTIVE AND INACTIVE VALVES IN THE REACTOR COOLANT PRESSURE BOUNDARY[a]

System	Valves I.D. Number	Location and Figure Number	Type	Valve Size, in.	Valve Actuation	Type A-Active I-Inactive
RCS	8000 A, B, C	Pressurizer Figure 3.2-7, Sheets 3 & 4	Gate	3	Motor	A
RCS	8010 A, B, C	Pressurizer Figure 3.2-7, Sheets 3 & 4	Relief	6	ΔP	A
RCS	8078 A,B,C,D	Reactor vessel head vent Figure 5.5-14	Globe	1	Solenoid	A
RCS	PCV-455 A,B	Pressurizer spray Figure 3.2-7, Sheets 3 & 4	Ball	4	Air	I
RCS	PCV-455 C PCV-456	Pressurizer Figure 3.2-7, Sheets 3 & 4	Globe	2	Air	A
RCS	PCV-474	Pressurizer Figure 3.2-7, Sheets 3 & 4	Globe	2	Air	I
CVCS	LCV-459	RCS cold leg loop 2 Figure 3.2-8, Sheets 5 & 6	Globe	2	Air	A
CVCS	LCV-460	RCS cold leg loop 2 Figure 3.2-8, Sheets 5 & 6	Globe	2	Air	A
CVCS	8145 8148	CVCS pressurizer auxiliary spray Figure 3.2-8, Sheets 5 & 6	Globe	2	Air	A
CVCS	8166 8167	RCS excess letdown Figure 3.2-8, Sheets 1B & 2	Globe	1	Air	I

TABLE 5.2-9

System	Valves I.D. Number	Location and Figure Number	Type	Valve Size, in.	Valve Actuation	Type A-Active I-Inactive
CVCS	8367 A, B, C, D	CVCS seal water injection Figure 3.2-8, Sheets 1, 1A, 1B, 1C & 2	Check	2	ΔP	I
CVCS	8372 A, B, C, D	CVCS seal water injection Figure 3.2-8, Sheets 1, 1A, 1B, 1C & 2	Check	2	ΔP	I
CVCS	8377	CVCS pressurizer auxiliary spray Figure 3.2-8, Sheets 5 & 6	Check	2	ΔP	I
CVCS	8378 A 8379 A	CVCS charging line to loop 3 Figure 3.2-8, Sheets 5 & 6	Check	3	ΔP	I
CVCS	8378 B 8379 B	CVCS charging line to loop 4 Figure 3.2-8, Sheet 5 & 6	Check	3	ΔP	I
RHR	8701	RHR isol. hot leg loop 4 Figure 3.2-10, Sheets 1 & 2	Gate	14	Motor	I[(b)]
RHR	8702	RHR isol. hot leg loop 4 Figure 3.2-10, Sheets 1 & 2	Gate	14	Motor	I[(b)]
RHR	8740 A, B	RCS hot leg Figure 3.2-10, Sheets 1 & 2	Check	8	ΔP	I
SIS	8818 A, B, C, D	SIS cold leg Figure 3.2-9, Sheets 5 & 6	Check	6	ΔP	I
SIS	8819 A, B, C, D	SIS cold legs Figure 3.2-9, Sheets 5 & 6	Check	2	ΔP	I

TABLE 5.2-9

System	Valves I.D. Number	Location and Figure Number	Type	Valve Size, in.	Valve Actuation	Type A-Active I-Inactive
SIS	8820	SIS boron injection containment isolation, Figure 3.2-9, Sheets 3 & 4	Check	3	ΔP	I
SIS	8900 A, B, C, D	SIS cold leg Figure 3.2-9, Sheets 3 & 4	Check	1 1/2	ΔP	I
SIS	8905 A, B, C, D	RCS hot legs Figure 3.2-9, Sheets 5 & 6	Check	2	ΔP	I
SIS	8948 A, B, C, D	RCS cold leg Figure 3.2-9, Sheets 1 & 2	Check	10	ΔP	I
SIS	8949 A, B, C, D	RCS hot legs Figure 3.2-9, Sheets 5 & 6	Check	6	ΔP	I
SIS	8956 A, B, C, D	RCS cold leg Figure 3.2-9, Sheets 1 & 2	Check	10	ΔP	I

(a) As defined in 10 CFR 50.2, valves are listed first by system (RCS, CVCS, RHR, and SIS) and then by valve I.D. number.

(b) For the postulated Hosgri earthquake this valve is considered active.

TABLE 5.2-10

REACTOR COOLANT SYSTEM NOMINAL PRESSURE SETPOINTS (PSIG)

Design pressure	2485
Operating pressure	2235
Safety valves	2485
Power relief valves	2335
Pressurizer spray valves (begin to open)	2260
Pressurizer spray valves (full open)	2310
High-pressure reactor trip	2385
High-pressure alarm	2310
Low-pressure reactor trip (typical, but variable)	1950
Low-pressure alarm	2210
Hydrostatic test pressure	3107
Backup heaters on (pressurizer)	2210
Proportional heaters (begin to operate)	2250
Proportional heaters (full operation) pressurizer	2220
Pressurizer power relief valve interlock	2185

TABLE 5.2-11

REACTOR VESSEL MATERIALS

Section	Materials
Pressure plate	Unit 1: A-533 Grade B Class 1 Unit 2: SA-533 Grade B Class 1
Pressure forgings	Unit 1: A-508 Class 2 Unit 2: SA-508 Class 2
RVCH Forging	SA-508 Grade 3 Class 1
Primary nozzle safe ends	Stainless steel Type 316 Forging
Cladding, stainless	Type 304 or equivalent (Combination of Types 308, 308L, 309, 309L, and 312)
Stainless weld rod	Types 308L, 308, and 309
O-ring head seals	Inconel 718
CRDM housings	Inconel 690 and stainless Type 304
Lower tube	SB-167
Studs	SA-540 Grade B-23 and B-24
Instrumentation nozzles	Inconel 600
Thermal insulation	Stainless steel

TABLE 5.2-12

PRESSURIZER, PRESSURIZER RELIEF TANKS, AND SURGE LINE MATERIALS

Pressurizer	Unit 1	Unit 2
Shell	SA-533, Grade A (Class 1)	SA-533, Grade A (Class 2)
Heads	SA-216, Grade WCC	SA-533, Grade A (Class 2)
Support skirt	SA-516, Grade 70	SA-516, Grade 70
Nozzle weld ends	SA-182, F316	SA-182, F316L
Inst. tube coupling	SA-182, F316	SA-182, F316
Cladding, stainless	Type 304 or equivalent	Type 304 or equivalent
Nozzle forgings		SA-508, Class 2 Mn-Mo
Nozzle Weld Overlay	N/A	
First pass		309L, ERNiCr-3 over dissimilar metal weld
Remainder of overlay		ERNiCrFe-7 (Automatic GTAW) ERNiCrFe-7A (Manual GTAW)
Internal plate	SA-240, Type 304	SA-240, Type 304
Inst. tubing	SA-213, Type 304 316	SA-213, Type 304 316
Heater well tubing	SA-213, Type 316 seamless	SA-213, Type 316 seamless
Heater well adaptor	SA-182, F316	SA-182, F316
Pressurizer Relief Tank		
Shell	ASTM A-285, Grade C	ASTM A-285, Grade C
Heads	ASTM A-285, Grade C	ASTM A-285, Grade C
Internal coating	Amercoat 55	Amercoat 55
Surge Line		
Pipes	ASTM A-376, Type 316	ASTM A-376, Type 316
Fittings (14 inch elbows)	ASTM A-403, WP316	ASTM A-403, WP316
Nozzles	ASTM A-182, Grade F316	ASTM A-182, Grade F316

TABLE 5.2-12

Valves	Unit 1	Unit 2
Pressure-containing parts	ASTM A-351, Grade CF8M ASTM A-182, Grade F and ASME SA-351, Grade CF3M (for RCS-8029)	ASTM A-351, Grade CF8M ASTM A-182, Grade F and ASME SA-351, Grade CF3M (for RCS-8029)

TABLE 5.2-13

REACTOR COOLANT PUMP MATERIALS

Shaft	ASTM A-182, Grade F347
Impeller	ASTM A-351, Grade CF8
Casing	ASTM A-351, Grade CF8
Flywheel	ASTM A-533, Grade B, Class I

TABLE 5.2-14

STEAM GENERATOR MATERIALS

Pressure forgings	ASME SA 508, Grade 3, Class 2
Cladding	Stainless steel Types 309L, 308L
Tubesheet cladding	Alloy 690 weld material
Tubes	Alloy 690 TT

TABLE 5.2-15

REACTOR COOLANT WATER CHEMISTRY SPECIFICATION

Parameter	Steady State	Transient Limit
Conductivity, μMho/cm @ 25°C	(a)(c)	----
pH @ 25°C	(a)(c)	----
Oxygen, ppm[b]	≤ 0.10	≤ 1.0
Chloride, ppm	≤ 0.15	≤ 1.5
Fluoride, ppm	≤ 0.15	≤ 1.5
Hydrogen, cc(STP)/kg		
power > 1 MWt	(c)	----
normal target band	(c)	----
Total suspended solids, ppm	(c)	----
Li-7, ppm as Li	(c)	----
Boric acid, ppm as B	(c)	----
Silica, ppm	(c)	----
Aluminum, ppm	(c)	----
Calcium, ppm	(c)	----
Magnesium, ppm	(c)	----
Sulfur compounds, ppm	(c)	----

(a) Varies with boric acid and lithium hydroxide concentration.

(b) Limit is not applicable with Tavg ≤ 250°F. During startup, hydrazine may be used to achieve RCS concentrations of up to 10 ppm when the coolant temperature is between 150 and 180°F and the oxygen exceeds 0.1 ppm.

(c) Chemical Control Limits and Actions Guidelines for the Primary Systems are listed in plant procedures.

TABLE 5.2-16

REACTOR COOLANT BOUNDARY LEAKAGE DETECTION SYSTEMS

Radioactivity Detection Systems

Detector Location or Process	Medium	Type	Range	Approximate Time to Detect 1-gpm Leak	Identified Leak Detection[c]	Instrument Class[a]	Indicator in Control Room
Containment	Air	G-M	10^{-1} to 10^{4} mR/hr	Less responsive than other detection systems	No	II	Yes
Incore inst area	Air	G-M	10^{-1} to 10^{4} mR/hr	Less responsive than other detection systems	No	II	Yes
Containment air particulate	Air	NaI Scintillator	10 to 10^{6} cpm	See Fig. 5.2-9	No	II[b]	Yes
Containment radiogas	Air	G-M	10 to 10^{6} cpm	See Fig. 5.2-9	No	II[b]	Yes
Plant vent radiogas	Air	Beta Scintillator	10 to 5E6 cpm	Less responsive than other detection systems	No	IB	Yes
Condenser air ejector	Air	Beta Scintillator	10 to 5E6 cpm	See Fig. 5.2-10	Yes	II	Yes
Component cooling liquid	Liquid	NaI Scintillator	10 to 10^{6} cpm	See Fig. 5.2-12	No	IC	Yes
Steam generator blowdown	Liquid	NaI Scintillator	10 to 10^{6} cpm	See Fig. 5.2-11	Yes	II	Yes

Other Detection Systems

Detector Location or Process	Medium	Type	Range and Repeatability[e]	Approximate Time to Detect 1-gpm Leak [q]	Identified[c] Leak Detection	Instrument Class[a]	Indicator in Control Room
Containment[d] condensation	Liquid	Change in time required to accumulate fixed volume	see note (m)	1 hr [g][h][l]	No	II	Yes
Containment sumps	Liquid	Liquid level and quantity of liquid	1 to 48 in. W.C. [n] 1 to 35 in. W.C. [p] ±1 in.	<1 hr [h]	No	II	Yes
Reactor vessel flange leakoff	Liquid	Temperature	50 to 300 °F ±5 °F	<30 sec [f]	Yes	II	Yes
Reactor coolant drain tank	Liquid	Liquid level and quantity of liquid	0-100% ±2%	<20 min [h]	Yes	II	No
Pressurizer relief valve discharge	Liquid	Temperature	50 to 400 °F ±7 °F	<30 sec [f]	Yes	II	Yes
Pressurizer relief tank	Liquid				Yes	II	Yes
		Liquid level	0 to 100 % ±2%	<12 hrs [h]			

Systems Used to Quantify Leakage [i]

Detector System	Medium	Type	Range/Sensitivity	Instrument Class	Indicated in Control Room
Pressurizer level	Liquid	Liquid level	0 to 100% [g][j] ~125 gal/% level	IA	Yes
Volume control tank level	Liquid	Liquid level	0 to 100% [g][j] ~19 gal/% level	II	Yes
Charging pump flow	Liquid	Flow	0 to 200 gpm [k] ± 10% span when flow >60 gpm (channel uncertainty value)	IB	Yes
Pressurizer relief tank level	Liquid	Liquid level	0 to 100% [h] ~128 gal/% level	II	Yes

(a) The PG&E Design Class I instrumentation (i.e., Instrument Class IA and Instrument Class IB Category 1) is capable of performing its nuclear safety function during and after a Double Design Earthquake (DDE) and/or Hosgri Earthquake (HE). Class IC instrument systems refer to maintenance of pressure boundary integrity of Category I fluid systems. Also refer to UFSAR Sections 3.2 and 3.10.2.

(b) These units were not constructed to withstand DDE accelerations; however, they will be housed in a PG&E Design Class I structure and protected from external damage associated with a seismic event. Therefore, it is considered that these units can be returned to operational status within 36 hours of a DDE.

(c) Leakage is defined as identified or unidentified in accordance with Regulatory Guide 1.45.

(d) Containment condensation measures moisture condensed by the fan cooler drip collection system.

(e) Repeatability, including the operators ability to read the same value at another time, is included in this column; this is a true measure of ability to detect a change in system conditions over a period of time.

(f) Automatically alarmed.

(g) Requires operator action - (i.e., close valve, start-stop pump, etc., and operator monitoring and logging).

(h) Requires operator monitoring and logging to note changes in rate, level, flow, etc.

(i) Systems listed here would be used to quantify true leakage rate in the event systems listed on Sheets 1 & 2 above detected an unidentified leak. These systems also provide additional capability for detecting leak rates of 1-gpm within short periods of time.

(j) Normal variations in process variable or automatic control systems will mask this change. Operator must take action as in (g) above to detect leakage.

(k) Insufficient accuracy/repeatability to ever detect a 1-gpm change in flowrate.

(l) Dependent on initial conditions. May take longer for fan cooler drip level if humidity is initially low.

(m) Level switches (HI and HI-HI) are provided in each CFCU drain line. The level switches have a fixed location in each drain line providing a repeatable alarm. The time intervals between the receipt of the HI level and HI-HI level alarms are monitored and logged by the operator. Alarm intervals less than a conservative pre-defined value directs the operator to perform an RCS water inventory balance to quantify the RCS leakage rate.

(n) This range refers to the containment structure sumps.

(o) Not used.

(p) This range refers to the reactor cavity sump.

(q) This column refers to the capability of the detection system to sense a leak.

TABLE 5.2-17A

DCPP UNIT 1 REACTOR VESSEL TOUGHNESS DATA

Component	Plate No.	Material Type	Cu (Wt%)	Ni (Wt%)	P (Wt%)	NDTT °F	Minimum 50 Ft-lb/35 Mil Tempt °F Long	Minimum 50 Ft-lb/35 Mil Tempt °F Trans	RT_{NDT} °F	Average Upper Shelf Ft-lb Long	Average Upper Shelf Ft-lb Trans
Repl. Cl. Hd.	07W89-1-1	SA508,CL1	0.05	0.82	0.005	-50[b]	-	20	-50[b]	-	211
Ves. Sh. Flg.	B4101	A508,CL2	--	0.75	0.010	35[a]	-5	15[a]	35		99[a]
Inlet Noz.	B4103-1	A508,CL2	--	0.66	0.013	60[a]	17	37[a]	60		77[a]
Inlet Noz.	B4103-2	A508,CL2	--	0.67	0.013	60[a]	27	47[a]	60		75[a]
Inlet Noz.	B4103-3	A508,CL2	--	0.68	0.010	43[a]	10	30[a]	43		108[a]
Inlet Noz.	B4103-4	A508,CL2	--	0.66	0.010	48[a]	2	22[a]	48		106[a]
Outlet Noz.	B4104-1	A508,CL2	--	0.74	0.011	60[a]	-13	7[a]	60		77[a]
Outlet Noz.	B4104-2	A508,CL2	--	0.76	0.006	43[a]	-3	17[a]	43		74[a]
Outlet Noz.	B4104-3	A508,CL2	--	0.71	0.012	54[a]	-12	8[a]	54		86[a]
Outlet Noz.	B4104-4	A508,CL2	--	0.68	0.008	60[a]	30	50[a]	60		84[a]
Upper Shl.	B4105-1	SA533B,CL1	0.12	0.56	0.010	10	68	88[a]	28		80[a]
Upper Shl.	B4105-2	SA533B,CL1	0.12	0.57	0.008	0	49	69[a]	9		74[a]
Upper Shl.	B4105-3	SA533B,CL1	0.14	0.56	0.010	0	54	74[a]	14		81[a]
Inter. Shl.	B4106-1	SA533B,CL1	0.125	0.53	0.013	-10	57	40	-10	134	116
Inter. Shl.	B4106-2	SA533B,CL1	0.120	0.50	0.013	-10	36	57	-3	132	114
Inter.Shl.	B4106-3	SA533B,CL1	0.086	0.476	0.011	10	70	90[a]	30	119	77[a]
Lower Shl.	B4107-1	SA533B,CL1	0.13	0.56	0.011	-10	59	75	15	127	110
Lower Shl.	B4107-2	SA533B,CL1	0.12	0.56	0.010	-10	64	80	20	127	103
Lower Shl.	B4107-3	SA533B,CL1	0.12	0.52	0.010	-50	52	38	-22	135	116
Bot. Hd. Seg.	B4111-1	SA533B,CL1	0.15	0.51	0.014	-20	33	53[a]	-7		82[a]
Bot. Hd. Seg.	B4111-2	SA533B,CL1	0.12	0.53	0.009	-40	16	36[a]	-24		90[a]
Bot. Hd. Seg.	B4111-3	SA533B,CL1	0.13	0.50	0.009	-40	21	41[a]	-19		85[a]
Bot. Hd. Seg.	B4110	SA553B,CL1	0.06	0.44	0.010	-10	60	80[a]	20		75[a]

(a) Estimated per NRC Standard Review Plan Section 5.3.2.
(b) An NDTT value of -40F was used in the vendor analysis.

TABLE 5.2-17B

DCPP UNIT 2 REACTOR VESSEL TOUGHNESS DATA

Component	Plate No.	Material Type	Cu (Wt%)	Ni (Wt%)	P (Wt%)	NDTT °F	Minimum 50 Ft-lb/35 Mil Tempt °F Long	Minimum 50 Ft-lb/35 Mil Tempt °F Trans	RT_{NDT} °F	Average Upper Shelf Ft-lb Long	Average Upper Shelf Ft-lb Trans
Repl. Cl. Hd.	06W255-1-1	SA508,CL1	0.05	0.82	0.005	-40	--	20	-40	--	211
Inlet Noz.	B5461-1	A508,CL2	0.09	0.70	0.012	-20	23	43[a]	-17	116	75
Inlet Noz.	B5461-2	A508,CL2	0.09	0.70	0.012	-20	-2	18[a]	-20	119	77[a]
Inlet Noz.	B5461-3	A508,CL2	0.10	0.82	0.013	-40	-45	-25[a]	-40	127	83[a]
Inlet Noz.	B5461-4	A508,CL2	0.10	0.81	0.013	-40	-48	-28[a]	-40	129	84[a]
Outlet Noz.	B5462-1	SA508,CL2	0.11	0.67	0.010	-50	-4	16[a]	-44	145	94
Outlet Noz.	B5462-4	SA508,CL2	0.11	0.67	0.009	-40	-10	10[a]	-40	137.5	89[a]
Outlet Noz.	B5462-2	SA508,CL2	0.11	0.67	0.009	-40	14	34[a]	-26	135.5	88[a]
Outlet Noz.	B5462-3	SA508,CL2	0.11	0.67	0.009	-50	17	37[a]	-23	131.5	85[a]
Upper Shl.	B5453-1	SA533B,CL1	0.11	0.60	0.014	0	85	88	28	92	82
Upper Shl.	B5453-3	SA533B,CL1	0.11	0.60	0.012	-10	45	65[a]	5	136.5	86.5[ab]
Upper Shl.	B5011-1R	SA533B,CL1	0.11	0.65	0.015	10	40	60[a]	0	110	72[a]
Inter. Shl.	B5454-1	SA533B,CL1	0.14	0.65	0.010	-40	14	112	52	128	91
Inter. Shl.	B5454-2	SA533B,CL1	0.14	0.59	0.012	0	60	127	67	113	99
Inter. Shl.	B5454-3	SA533B,CL1	0.15	0.62	0.013	-40	30	93	33	129	90
Lower Shl.	B5455-1	SA533B,CL1	0.14	0.56	0.010	-20	42	45	-15	134	112
Lower Shl.	B5455-2	SA533B,CL1	0.14	0.56	0.011	0	25	45	0	137	122
Lower Shl.	B5455-3	SA533B,CL1	0.10	0.62	0.010	0	55	75	15	128	100
Bot. Hd. Seg.	B5009-2	SA533B,CL1	0.13	0.57	0.011	-10	110	130[a]	70	85	55[a]
Bot. Hd. Seg.	B5009-3	SA533B,CL1	0.13	0.60	0.009	-20	-12	8[a]	-20	131	84
Bot. Hd. Seg.	B5009-1	SA533B,CL1	0.13	0.58	0.010	0	88	108[a]	48	95	62[a]
Bot. Hd. Seg.	B5010	SA533B,CL1	0.14	0.63	0.011	-30	20	40[a]	-20	114	74

(a) Estimated per NRC Standard Review Plan Section 5.3.2.
(b) Westinghouse Letter LTR-PCAM-09-26, Revision 1, "Diablo Canyon Units 1 and 2 Reactor Vessel Extended Beltline Material Properties Search," June 3, 2009

TABLE 5.2-18A

IDENTIFICATION OF UNIT 1 REACTOR VESSEL BELTLINE REGION BASE MATERIAL

Component	Plate No.	Heat No.	Material Spec. No.	Composition, Wt.%							
				C	Mn	P	S	Si	Ni	Mo	Cu
Inter shell	B4106-1	C2884-1	SA533B,CL1	0.25	1.34	0.013	0.015	0.21	0.53	0.45	0.125
Inter shell	B4106-2	C2854-2	SA533B,CL1	0.18	1.32	0.013	0.015	0.23	0.50	0.46	0.120
Inter shell	B4106-3	C2793-1	SA533B,CL1	0.20	1.33	0.011	0.012	0.25	0.476	0.46	0.086
Lower shell	B4107-1	C3121-1	SA533B,CL1	0.25	1.36	0.011	0.014	0.24	0.56	0.48	0.13
Lower shell	B4107-2	C3131-2	SA533B,CL1	0.24	1.32	0.010	0.013	0.23	0.56	0.46	0.12
Lower shell	B4107-3	C3131-1	SA533B,CL1	0.19	1.38	0.010	0.013	0.26	0.52	0.46	0.12

TABLE 5.2-18B

IDENTIFICATION OF UNIT 2 REACTOR VESSEL BELTLINE REGION BASE MATERIAL

Component	Plate No.	Heat No.	Material Spec. No.	Composition, Wt.%							
				C	Mn	P	S	Si	Ni	Mo	Cu
Inter shell	B5454-1	C5161-1	SA533B,CL1	0.21	1.30	0.010	0.015	0.19	0.65	0.46	0.14
Inter shell	B5454-2	C5168-2	SA533B,CL1	0.25	1.38	0.012	0.016	0.21	0.59	0.55	0.14
Inter shell	B5454-3	C5161-2	SA533B,CL1	0.23	1.32	0.013	0.015	0.20	0.62	0.45	0.15
Lower shell	B5455-1	C5175-1	SA533B,CL1	0.21	1.38	0.010	0.018	0.19	0.56	0.56	0.14
Lower shell	B5455-2	C5175-2	SA533B,CL1	0.22	1.40	0.011	0.018	0.19	0.56	0.56	0.14
Lower shell	B5455-3	C5176-1	SA533B,CL1	0.23	1.34	0.010	0.014	0.20	0.62	0.56	0.10

TABLE 5.2-19A

FRACTURE TOUGHNESS PROPERTIES OF UNIT 1 REACTOR VESSEL BELTLINE REGION BASE MATERIAL

Material	T_{NDT} (°F)	Initial RT_{NDT} (°F)	Initial USE[b] (ft-lb)	EOL[a] Fluence[c] (N/cm^2)	EOL[a] RT_{NDT}[d] (°F)	EOL[a] USE[d] (ft-lb)
Upper Shell Plate						
B4105-1	10	28[e]	80[e]	1.43E+17	75.3	74
B4105-2	0	9[e]	74[e]	1.43E+17	56.3	68
B4105-3	0	14[e]	81[e]	1.43E+17	64.3	74
Inter Shell Plate						
B4106-1	-10	-10	116	1.28E+19	115.2	90
B4106-2	-10	-3	114	1.28E+19	117.6	88
B4106-3	10	30[e]	77[e]	1.28E+19	137.1	63
Lower Shell Plate						
B4107-1	-10	15	110	1.27E+19	144.8	84
B4107-2	-10	20	103	1.27E+19	141.7	80
B4107-3	-50	-22	116	1.27E+19	98.8	90

(a) Data shown above is analyzed to 54 EFPY (60 operating years), November 2044.
(b) Upper shelf energy.
(c) Fluence at vessel wall 1/4 thickness location.
(d) Per Regulatory Guide 1.99, Revision 2.
(e) Estimated from data in the longitudinal direction per NRC Standard Review Plan Section 5.3.2.

TABLE 5.2-19B

FRACTURE TOUGHNESS PROPERTIES OF UNIT 2 REACTOR VESSEL BELTLINE REGION BASE MATERIAL

Material	T_{NDT} (°F)	Initial RT_{NDT} (°F)	Initial USE[b] (ft-lb)	EOL[a] Fluence[c] (N/cm^2)	EOL[a] RT_{NDT}[d] (°F)	EOL[a] USE[d] (ft-lb)
Upper Shell Plate						
B5453-1	0	28	82	2.57E+17	57.7	75
B5453-3	-10	5[e]	86.5[f]	2.57E+17	56.9	79
B5011-1R	10	0[e]	72[e]	2.57E+17	52.1	66
Inter Shell Plate						
B5454-1	-40	52	91	1.46E+19	182.5	71
B5454-2	0	67	99	1.46E+19	211.1	74
B5454-3	-40	33	90	1.46E+19	189.1	66
Lower Shell Plate						
B5455-1	-20	-15	112	1.45E+19	127.4	83
B5455-2	0	0	122	1.45E+19	142.4	91
B5455-3	0	15	100	1.45E+19	121.0	79

(a) Data shown above is analyzed to 54 EFPY (60 operating years), August 2045.
(b) Upper shelf energy.
(c) Fluence at vessel wall 1/4 thickness location.
(d) Per Regulatory Guide 1.99, Revision 2.
(e) Estimated from data in the longitudinal direction per NRC Standard Review Plan Section 5.3.2.
(f) Westinghouse Letter LTR-PCAM-09-26, Revision 1, "Diablo Canyon Units 1 and 2 Reactor Vessel Extended Beltline Material Properties Search," June 3, 2009

TABLE 5.2-20A

IDENTIFICATION OF UNIT 1 REACTOR VESSEL BELTLINE REGION WELD METAL

Weld Location	Weld Process	Weld Wire		Flux		Average Deposit Composition, Wt.%								
		Type	Heat No.	Type	Lot No.	C	Mn	P	S	Si	Mo	Ni	CR	Cu
Upper shell to inter shell circle seam 8-442	Sub-Arc	B-4 Mod.	13253	Linde 1092	3774	0.18	1.30	0.020	0.013	0.24	0.45	0.73	0.19	0.25
Inter shell long seams 2-442 A, B, & C	Sub-Arc	B-4 Mod.	27204	Linde 1092	3724	0.14	1.36	0.016	0.025	0.45	0.48	1.018	0.06	0.203
Inter shell to lower shell circle seam 9-442	Sub-Arc	B-4 Mod.	21935	Linde1092	3869	0.14	1.38	0.015	0.010	0.15	0.54	0.704	--	0.183
Lower shell long seams 3-442 A, B, & C	Sub-Arc	B-4 Mod.	27204	Linde 1092	3774	0.14	1.36	0.016	0.025	0.45	0.48	1.018	0.06	0.203

TABLE 5.2-20B

IDENTIFICATION OF UNIT 2 REACTOR VESSEL BELTLINE REGION WELD METAL

Weld Location	Weld Process	Weld Wire Type	Weld Wire Heat No.	Flux Type	Flux Lot No.	Average Deposit Composition, Wt.% C	Mn	P	S	Si	Mo	Ni	CR	Cu
Nozzle shell to inter shell circle seam 8-201	Sub-Arc	B-4 Mod.	21935	Linde 1092	3889	0.14	1.38	0.015	0.010	0.15	0.54	0.704	—	0.183
Inter shell long seams 2-201 A, B, & C	Sub-Arc (Tandem)	B-4 Mod. B-4 Mod.	21935 12008	Linde 1092	3869	0.13	1.41	0.018	0.010	0.16	0.55	0.87	0.03	0.22
Inter shell to lower shell circle seam 9-201	Sub-Arc	B-4	10120	Linde 0091	3458	0.14	1.12	0.011	0.008	0.18	0.48	0.082	—	0.046
Lower shell long seams 3-201 A, B, & C	Sub-Arc	B-4	33A277	Linde 124	3878	0.11	1.17	0.015	0.011	0.26	0.50	0.165	0.06	0.258

TABLE 5.2-21A

FRACTURE TOUGHNESS PROPERTIES OF UNIT 1 REACTOR VESSEL BELTLINE REGION WELD METAL

Material	Initial		EOL[a]		
	RT_{NDT} (°F)	USE[b] (ft-lb)	Fluence[c] (N/cm^2)	RT_{NDT}[d] (°F)	USE[d] (ft-lb)
Upper Shell Long. Welds 1-442 A,B,C	-20	86[f]	1.30E+17	36.4	75
Upper Shell to Inter. Shell Weld 8-442	-56[e]	111[g]	1.63E+17	19.1	94
Inter. Shell Long. Welds 2-442 A,B,C	-56[e]	91[h]	9.36E+18	197.7	61
Inter. Shell to Lower Shell Weld 9-442	-56[e]	109[i]	1.25E+19	192.3	72
Lower Shell Long. Welds 3-442 A,B,C	-56[e]	91[h]	1.27E+19	215.8	59

(a) Data shown above is analyzed to 54 EFPY (60 operating years), November 2044.
(b) Upper shelf energy.
(c) Fluence at vessel wall 1/4 thickness location.
(d) Per Regulatory Guide 1.99, Revision 2.
(e) Generic value per 10 CFR 50.61.
(f) CE Vessel Weld Test Report, April 9, 1968.
(g) WCAP 10492, Analysis of Capsule T, Salem 2 Surveillance Program, March 1984.
(h) WCAP 15958, Rev. 0, "Analysis of Capsule V from PG&E Diablo Canyon Unit 1 Reactor Vessel Radiation Surveillance Program," January 2003.
(i) PG&E Letter DCL-95-176, August 16, 1995, and PG&E Letter DCL-98-094, July 6, 1998.

TABLE 5.2-21B

FRACTURE TOUGHNESS PROPERTIES OF UNIT 2 REACTOR VESSEL BELTLINE REGION WELD METAL

Material	Initial		EOL[a]		
	RT_{NDT} (°F)	USE[b] (ft-lb)	Fluence[c] (N/cm^2)	RT_{NDT}[d] (°F)	USE[d] (ft-lb)
Upper Shell Long. Welds 1-201 A,B,C	-50	118[f]	2.82E+17	20.8	100
Upper Shell to Inter. Shell Weld 8-201	-56[e]	109[g]	2.93E+17	31.8	94
Inter. Shell Long. Welds 2-201 A,B,C	-50	118[f]	1.03E+19	181.7	75
Inter. Shell to Lower Shell Weld 9-201	-56[e]	125[h]	1.42E+19	31.8	99
Lower Shell Long. Welds 3-201 A,B,C	-56[e]	88[h]	1.03E+19	106.7	52

(a) Data shown above is analyzed to 54 EFPY (60 operating years), August 2045.
(b) Upper shelf energy.
(c) Fluence at vessel wall 1/4 thickness location.
(d) Per Regulatory Guide 1.99, Revision 2.
(e) Generic value per 10 CFR 50.61.
(f) WCAP 15423, "Analysis of Capsule V from PG&E Diablo Canyon Unit 2 Reactor Vessel Radiation Surveillance Program," September 2000.
(g) PG&E Letter DCL-95-176, August 16, 1995.
(h) Average of three Charpy tests at +10°F, CD weld wire/flux qualification test.

TABLE 5.2-22

REACTOR VESSEL MATERIAL SURVEILLANCE PROGRAM
WITHDRAWAL SCHEDULE

UNIT 1

Capsule[f][g]	Location	Lead Factor[d]	Fluence at Capsule Center (n/cm^2)[d]	Removal Time (Plant EFPY)[a]
S	320°	3.48	2.83E+18	1.25 (Tested,1R1)
Y	40°	3.45	1.05E+19	5.86 (Tested, 1R5)
T	140°	3.45	1.05E+19	5.86 (Removed, 1R5)
Z	220°	3.45	1.05E+19	5.86 (Removed, 1R5)
V	320°	2.26	1.36E+19	14.3 (Tested 1R11)
C[b]	140°	3.47	1.22E+19	15.9 (Removed 1R12)
D[b]	220°	3.47	1.22E+19	15.9 (Removed 1R12)
B[b]	40°	3.47	(3.56E+19 projected)	34.97 (Removed 1R25)
A[b]	184°	1.32	Standby	Standby
U	356°	1.24	Standby	Standby
X	176°	1.24	Standby	Standby
W	4°	1.24	Standby	Standby

UNIT 2

Capsule	Location	Lead Factor[d]	Fluence at Capsule Center (n/cm^2)[d]	Removal Time (EFPY)[a]
U	56°	5.20	3.30E+18	1.02 (Tested, 2R1)
X	236°	5.39	9.06E+18	3.16 (Tested, 2R3)
Y	238.5°	4.56	1.53E+19	7.08 (Tested, 2R6)
W[e]	124°	5.35	2.78E+19	11.49 (Removed, 2R9)
V[e]	58.5°	4.57	2.38E+19	11.49 (Tested, 2R9)
Z[e]	304°	5.35	2.78E+19	11.49 (Removed, 2R9)

(a) Approximate full power years from plant startup.
(b) Four supplemental capsules installed at 5.86 EFPY (EOC5).
(c) Deleted in Revision 16.
(d) Approximate values taken from WCAP-17299-NP (Rev. 0) or WCAP-18655-NP (Rev. 0) for Units 1 and 2.
(e) Capsule EFPY for Unit 2 capsules removed in 2R9; W = 61.5, V = 52.5, and Z = 61.5
(f) Unit 1 capsules T, U, W, X, and Z are Type 1 (base metal only)
(g) Unit 1 capsules S, V, and Y are Type 2 (base metal and weld)

TABLE 5.2-23

REACTOR COOLANT SYSTEM PRESSURE BOUNDARY ISOLATION VALVES

	VALVE NUMBER	FUNCTION
1.	8948 A, B, C, and D	Accumulator, RHR, and SIS first off check valves from RCS cold legs
2.	8819 A, B, C, and D	SIS second off check valves from RCS cold legs
3.	8818 A, B, C, and D	RHR second off check valves from RCS cold legs
4.	8956 A, B, C, and D	Accumulator second off check valves from RCS cold legs
5.	8701 and 8702	RHR suction isolation valves
6.	8949 A, B, C, and D	RHR and SIS first off check valves from RCS hot legs
7.	8905 A, B, C, and D	SIS second off check valves from RCS hot legs
8.	8740[(a)] A and B	RHR second off check valves from RCS hot legs

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[(a)] 8703 may be used to satisfy Technical Specification 3.4.14 Required Actions A.1 or A.2.1 when in Condition A for valves 8740A and 8740B.

TABLE 5.4-1

REACTOR VESSEL DESIGN PARAMETERS (BOTH UNITS)

Design/operating pressure, psig	2485/2235
Design temperature, °F	650
Overall height of vessel and closure head, ft-in. (bottom head OD to the control rod mechanism latch housing mating surface)	47-9
Thickness of insulation, min, in.	3
Number of reactor closure head studs	54
Diameter of reactor closure head/studs, in.	7
ID of flange, in.	167
OD of flange, in.	205
ID at shell, in.	173
Inlet nozzle ID, in.	27-1/2
Outlet nozzle ID, in.	29
Cladding thickness, min, in.	5/32
Lower head thickness, min, in.	5-1/4
Vessel beltline thickness, min, in.	8-1/2
Closure head thickness, in.	7

TABLE 5.4-2

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

REACTOR VESSEL CONSTRUCTION QUALITY ASSURANCE PROGRAM

Forgings	*RT*[a]	*UT*[a]	*PT*[a]	*MT*[a]
1. Flanges	-	*Yes*	-	*Yes*
2. Studs	-	*Yes*	-	*Yes*
3. Instrumentation tubes	-	*Yes*	*Yes*	-
4. Main nozzles	-	*Yes*	-	*Yes*
5. Nozzles safe ends	-	*Yes*	*Yes*	-
6. CRDM and Thermocouple Nozzles	-	*Yes*	*Yes*	-
7. RVHVS and RVLIS Nozzles	*Yes*	-	*Yes*	-
Plates	-	*Yes*	-	*Yes*
Weldments				
1. Main seam	*Yes*	*Yes*[c]	-	*Yes*
2. Instrumentation tube connection	-	-	*Yes*	-
3. Main nozzles	*Yes*	*Yes*[c]	-	*Yes*
4. Cladding	-	*Yes*[b]	*Yes*	-
5. Nozzle to safe ends weld	*Yes*	-	-	*Yes*
6. Nozzle to safe ends weld overlay (Unit 2)	*Yes*	*Yes*[c]	*Yes*	-
7. All ferritic welds accessible after hydrotest	-	-	-	*Yes*
8. All nonferritic welds accessible after hydrotest	-	-	*Yes*	-
9. Seal ledge	-	-	-	*Yes*
10. Head lift lugs	-	-	-	*Yes*
11. Core pads welds	-	*Yes*	*Yes*	*Yes*
12. CRDM and Thermocouple Nozzle Connections	-	-	*Yes*	-
13. RVHVS and RVLIS Nozzle Connections	-	-	*Yes*	-
14. CRDM Nozzle to Integrated Latch Housing Weld	*Yes*	-	*Yes*	-

(a) RT - Radiographic; UT - Ultrasonic; PT - Dye penetrant; MT - Magnetic particle
(b) UT of cladding bond-to-base metal
(c) UT after hydrotest

TABLE 5.5-1

REACTOR COOLANT PUMP DESIGN PARAMETERS (BOTH UNITS)

Design pressure, psig	2,485
Design temperature, °F	650
Capacity per pump, gpm	88,500
Developed head, ft	277
NPSH required, ft	170
Suction temperature, °F	545
RPM nameplate rating	1,180
Discharge nozzle, ID, in.	27-1/2
Suction nozzle, ID, in.	31
Overall unit height, ft-in.	28-6.7
Water volume, ft^3	56
Moment of inertia, ft-lb	82,000
Weight, dry, lb	198,000
Motor	
Type	AC induction single-speed, air-cooled
Power, HP	6,000
Voltage, volts	11,500
Insulation class	B, F or H Thermalastic Epoxy F Megaseal Epoxy
Phase	3
Starting	
Current, amps	1,700
Input (hot reactor coolant), kW	4,371
Input (cold reactor coolant), kW	5,790
Seal water injection, gpm	8
Seal water return, gpm	3

TABLE 5.5-2

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

REACTOR COOLANT PUMP QUALITY ASSURANCE PROGRAM

	RT[a]	*UT*[a]	*PT*[a]	*MT*[a]
Castings	*Yes*	-	*Yes*	-
Forgings				
1. Main shaft	-	*Yes*	*Yes*	-
2. Main studs	-	*Yes*	*Yes*	-
3. Flywheel (rolled plate)	-	*Yes*	*Yes (for the bore)*	
Weldments				
1. Circumferential	*Yes*	-	*Yes*	-
2. Instrument connections	-	-	*Yes*	-

(a) RT - Radiographic
UT - Ultrasonic
PT - Dye penetrant
MT - Magnetic particle

TABLE 5.5-3

STEAM GENERATOR DESIGN DATA[a]

	Unit 1	Unit 2
Number of steam generators	4	4
Design pressure, reactor coolant/steam, psig	2,485/1085	2,485/1085
Reactor coolant hydrostatic test pressure (tube side-cold), psig	3,107	3,107
Design temperature, reactor coolant/steam, °F	650/600	650/600
Reactor coolant flow, (per SG) lb/hr	33.2×10^6	33.5×10^6
Total heat transfer surface area, ft^2	54,240	54,240
Heat transferred, Btu/hr	$2,922 \times 10^6$	$2,922 \times 10^6$
Steam conditions at full load		
Outlet nozzle:		
Steam flow, lb/hr	3.7×10^6	3.7×10^6
Steam temperature, °F	504.3/521.2	504.5/521.7
Steam pressure, psia	708/821	709/825
Maximum moisture carryover, wt %	0.05	0.05
Feedwater, temperature, °F	425/435	425/435
Overall height, ft-in.	68-2	68-2
Shell OD, upper/lower, in.	175-3/8 /135-3/8	175-3/8/135-3/8
Number of U-tubes[b]	4,444	4,444
U-tube outer diameter, in.	0.75	0.75
Tube wall thickness, (minimum), in.	0.043	0.043
Number of manways/ID, in.	4/18	4/18
Number of handholes/ID, in.	4/6	4/6
Number of inspection ports/ID, in.	8/2.5	8/2.5
Number of tube upper bundle inspection ports/ID, in.	2/4	2/4

TABLE 5.5-3

	Rated Load	
	Unit 1	Unit 2
Reactor coolant water volume, ft^3	1022.3	1022.3
Primary side fluid heat content, Btu	2.634×10^7	2.635×10^7
Secondary side water volume, ft^3	2122	2125
Secondary side steam volume, ft^3	3679	3677
Secondary side fluid heat content, Btu	5.97×10^7	5.98×10^7

(a) Quantities are for each steam generator.

(b) The actual number of “active” tubes (i.e., those contributing to the heat transfer surface area) may be less than the number given due to the plugging and/or removal of some tubes.

TABLE 5.5-5

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

STEAM GENERATOR QUALITY ASSURANCE PROGRAM
(BOTH UNITS)

	RT[a]	*UT*[a]	*PT*[a]	*MT*[a]	*ET*[a]
Tubesheet					
1. Forging	-	*Yes*	-	*Yes*	-
2. Cladding	-	*Yes*[b]	*Yes*	-	-
Channel Head					
1. Forging		*Yes*	-	*Yes*	-
2. Cladding	-	*Yes*	*Yes*	-	-
Secondary Shell and Head					
1. Forgings	-	*Yes*	-	*Yes*	-
Tubes	-	*Yes*	-	-	*Yes*
Nozzles (Forging)	-	*Yes*	-	*Yes*	-
Weldments					
1. Shell, circumferential	*Yes*	*Yes* [d]	-	*Yes*	-
2. Cladding, (channel head-tubesheet joint cladding restoration)	-	*Yes*	*Yes*	-	-
3. Feedwater nozzle to shell	*Yes*	-	-	*Yes*	-
4. Support brackets	-	-	-	*Yes*	-
5. Tube to tubesheet	-	-	*Yes*	-	-
6. Instrument connections (primary and secondary)	-	-	-	*Yes*	-
7. Temporary attachments	-	-	-	*Yes*	-

TABLE 5.5-5

	RT[a]	UT[a]	PT[a]	MT[a]	ET[a]
after removal					
Weldments (Cont'd)					
8. After hydrostatic test (all welds where accessible)	-	-	-	Yes	-
9. Primary nozzle safe ends	Yes	Yes	Yes	-	-
10. Steam nozzle safe ends	Yes	-	-		-
11. Feedwater nozzle safe ends	Yes	Yes	Yes	-	-

(a) RT - Radiographic
UT - Ultrasonic
PT - Dyepenetrant
MT - Magnetic particle
ET - Eddy current

(b) Flat surfaces only

(c) Weld deposit areas only

(d) Welds subject to ASME Section XI ISI

TABLE 5.5-6

REACTOR COOLANT PIPING DESIGN PARAMETERS (BOTH UNITS)

Reactor inlet piping, ID, in.	27.5
Reactor inlet piping, nominal/min wall thickness, in.	2.38/2.22
Reactor outlet piping, ID, in.	29
Reactor outlet piping, nominal/min wall thickness, in.	2.50/2.33
Coolant pump suction piping, ID, in.	31
Coolant pump suction piping, nominal/min wall thickness, in.	2.63/2.50
Pressurizer surge line piping, Unit 1/Unit 2 ID, in.	11.50/11.19
Pressurizer surge line piping, Unit 1/Unit 2 nominal wall thickness, in.	1.25/1.41
Water volume, all loops and surge line, ft^3	1500
Design/operating pressure, psig	2485/2235
Design temperature, °F	650
Design temperature (pressurizer surge line) °F	680
Design pressure, pressurizer relief line	From pressurizer to safety valve, 2485 psig, 680° F
Design temperature, pressurizer relief lines	From safety valve to pressurizer relief tank, 600 psig, 450°F

TABLE 5.5-7

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

REACTOR COOLANT PIPING QUALITY ASSURANCE PROGRAM (BOTH UNITS)

	RT[a]	*UT*[a]	*PT*[a]
Fittings and Pipe (Castings)	*Yes*	*-*	*Yes*
Fittings and Pipe (Forgings)	*-*	*Yes*	*Yes*
Weldments			
1. Circumferential	*Yes*	*-*	*Yes*
2. Nozzle to piperun (except no RT for nozzles less than 4 inches)	*Yes*	*-*	*Yes*
3. Instrument connections	*-*	*-*	*Yes*

(a) RT - Radiographic
UT - Ultrasonic
PT - Dye penetrant

TABLE 5.5-8

DESIGN BASES FOR RESIDUAL HEAT REMOVAL SYSTEM OPERATION
(BOTH UNITS)

Residual heat removal system startup	No sooner than 4 hours after reactor shutdown
Number of Trains in Operation	2
Reactor coolant system initial pressure, psig	390
Reactor coolant system initial temperature, °F	350
Component cooling water design temperature, °F	95
Cooldown time, hours after reactor shutdown	<20
Reactor coolant system temperature at end of cooldown, °F	140
Decay heat generation used in cooldown analysis, Btu/hr	75.5×10^6

TABLE 5.5-9

RESIDUAL HEAT REMOVAL SYSTEM CODES AND CLASSIFICATIONS
(BOTH UNIT 1 and UNIT 2)

Components		Code
Residual heat removal pump		Draft ASME Code for Pumps and Valves for Nuclear Power-1968, Class II
Residual heat exchanger	(tube side)	ASME BPVC Section III-1968, Class C
	(shell side)	ASME BPVC Section VIII-1968
Piping		ANSI B31.7-1969 with 1970 Addendum, Class II for PG&E Design Class I portions
		ANSI B31.1-1967 with 1970 Addendum for non-PG&E Design Class I portions
Valves		ANSI B16.5-1968

TABLE 5.5-10

RESIDUAL HEAT REMOVAL SYSTEM COMPONENT DATA
(BOTH UNITS)

Residual Heat Removal Pump	
Number	2 (per unit)
Design pressure, psig	700
Design temperature, °F	400
Design flow, gpm	3000
Design head, ft	350
Net positive suction head, ft	
Available	36.3
Required	11.0
Residual Heat Exchanger	
Number	2 (per unit)
Design heat removal capacity, Btu/hr	34.15×10^6

	Tube-side	Shell-side
Design pressure, psig	630	150
Design temperature, °F	400	250
Design flow, lb/hr	1.48×10^6	2.48×10^6
Inlet temperature, °F	137	95
Outlet temperature, °F	114	108.8
Material	Austenitic stainless steel	Carbon steel
Fluid	Reactor coolant	Component cooling water

TABLE 5.5-10

Piping and Valves	
Design pressure, psig	2485[(a)]
Design temperature, °F	650[(a)]
Design pressure, psig	700
Design temperature, °F	400
Suction side relief valve	
Relief pressure, psig	450
Relief capacity, gpm	900
Discharge side relief valve	
Relief pressure, psig	600
Relief capacity, gpm	20
Material	Austenitic stainless steel

(a) Valves and piping that are part of the reactor coolant pressure boundary.

TABLE 5.5-11

RECIRCULATION LOOP LEAKAGE

Items	No. of Units	Type of Leakage Control and Unit Leakage Rate Used in the Analysis	Leakage to Atmosphere, cc/hr	Leakage to Drain Tank, cc/hr
Residual heat removal pumps (low-head safety injection)	2	Mechanical seal with leakoff of one drop/min	20	0
Centrifugal charging pump (CCP1 and CCP2)	2	Same as residual heat removal pump	40	0
Safety injection	2	Same as residual heat removal pump	40	0
Flanges:				
a. Pump	12	Gasket-adjusted to zero leakage following any test	0	0
b. Valves bonnet body (larger than 2 in.)	40	10 drops/min/flange used in analysis (30 cc/hr)	1200	0
c. Control valves	6		180	0
d. Heat exchangers	2		240	0
Valves - stem leakoffs	40	Backseated, double packing with leak-off of 1 cc/hr/in. stem diameter	0	40
Miscellaneous small valves	50	Flanged body packed stems - 1 drop/min used	150	0
Miscellaneous large valves (larger than 2 in.)		Double-packing 1 cc/hr/in. stem diameter	40	0
		TOTALS	1910	40

TABLE 5.5-12

PRESSURIZER DESIGN DATA

Design/operating pressure, psig	2485/2235
Hydrostatic test pressure (cold), psig	3107
Design/operating temperature, °F	680/653
Water volume, full power, ft^3	1080
Steam volume, full power, ft^3	720
Surge line nozzle diameter, in.	14
Shell ID, in.	84
Electric heaters capacity, kW[(a)]	1800
Heatup rate of pressurizer using heaters only, °F/hr	55
Maximum spray rate, gpm	800

(a) Initial heater capacity limit; 150 kW is the minimum required capacity for each backup group that can be supplied by emergency vital power (2 groups).

TABLE 5.5-13

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PRESSURIZER QUALITY ASSURANCE PROGRAM (BOTH UNITS)

Heads	*RT*[a]	*UT*[a]	*PT*[a]	*MT*[a]	*ET*[a]
1. Plates	*Yes*	-	-	*Yes*	-
2. Cladding	-	-	*Yes*	-	-
Shell					
1. Plates	-	*Yes*	-	*Yes*	-
2. Cladding	-	-	*Yes*	-	-
Heaters					
1. Tubing[b]	-	*Yes*	*Yes*	-	-
2. Center of element	-	-	-	-	*Yes*
Nozzle	-	*Yes*	*Yes*	-	-
Weldments					
1. Shell, longitudinal	*Yes*	-	-	*Yes*	-
2. Shell, circumferential	*Yes*	-	-	*Yes*	-
3. Cladding	-	-	*Yes*	-	-
4. Nozzle safe end (forging)	*Yes*	-	*Yes*	-	-
5. Instrument connections	-	-	*Yes*	-	-
6. Support skirt	-	-	-	*Yes*	-
7. Temporary attachments after removal	-	-	-	*Yes*	-
8. All welds and plate heads after hydrostatic test	-	-	-	*Yes*	-
Final Assembly					
1. All accessible exterior surfaces after hydrostatic test	-	-	-	*Yes*	-

(a) RT - Radiographic; UT - Ultrasonic; PT - Dye penetrant; MT - Magnetic particle; ET - Eddy current
(b) Or a UT and ET

TABLE 5.5-14

PRESSURIZER RELIEF TANK DESIGN DATA

Design pressure, psig	100
Rupture disk release pressure, psig	100 ± 5%
Design temperature, °F	340
Total rupture disk relief capacity lb/hr at 100 psig	1.6×10^6

TABLE 5.5-15

REACTOR COOLANT SYSTEM BOUNDARY VALVE DESIGN PARAMETERS

Design pressure, psig	2485
Nominal operating pressure, psig	2235
Preoperational plant hydrotest, psig	3107
Design temperature, °F	650

TABLE 5.5-16

PRESSURIZER VALVES DESIGN PARAMETERS

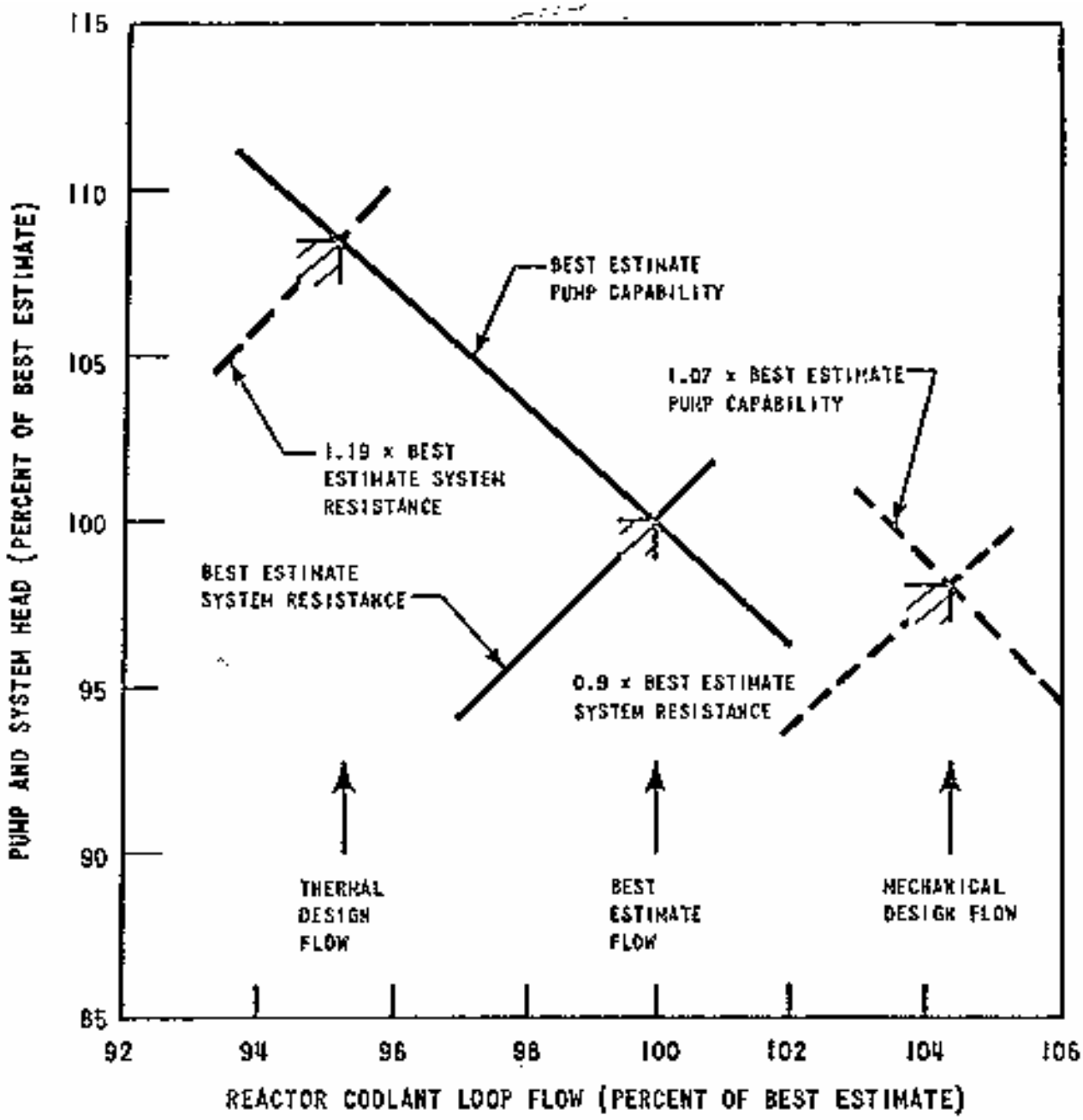
Pressurizer Spray Control Valves	
Number	2
Design pressure	2485
Design temperature, °F	650
Design flow for valves full open, each, gpm	400
Pressurizer Safety Valves	
Number	3
Maximum relieving capacity, ASME rated flow, lb/hr (per valve)	420,000
Set pressure, psig	2485
Fluid	Saturated steam
Backpressure:	
Normal, psig	3 to 5
Expected during discharge, psig	350
Pressurizer Operated Power Relief Valves[(a)]	
Number	3
Design pressure, psig	2485
Design temperature, °F	650
Relieving capacity at 2,350 psig, lb/hr (per valve)	210,000
Fluid	Saturated steam

(a) PORVs are credited with liquid discharge for spurious operation of the safety injection system at power events (refer to Section 15.2.15).

TABLE 5.5-17

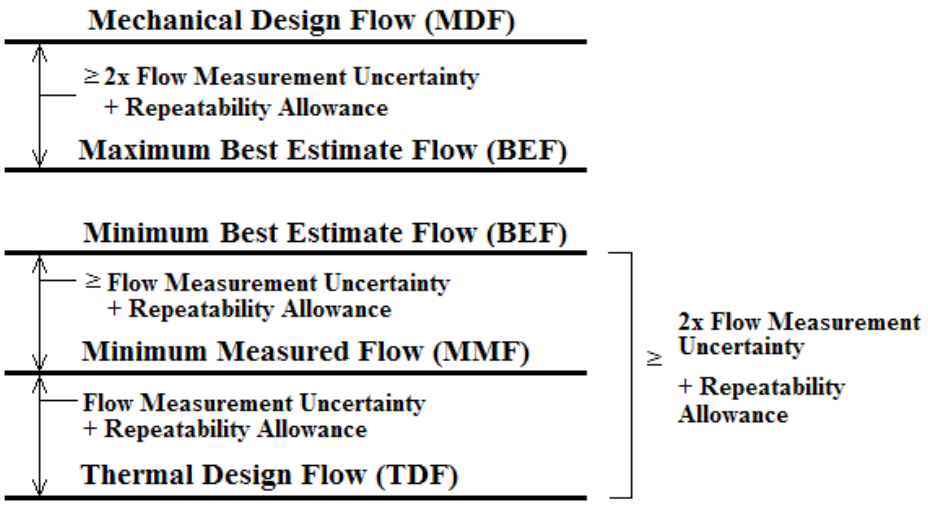
REACTOR VESSEL HEAD VENT SYSTEM EQUIPMENT DESIGN PARAMETERS

Valves	
Number (includes six manual valves)	10
Design pressure, psig	2485
Design temperature, °F	650
Piping	
Vent line, nominal diameter, in.	1
Design pressure, psig	2485
Design temperature, °F	650



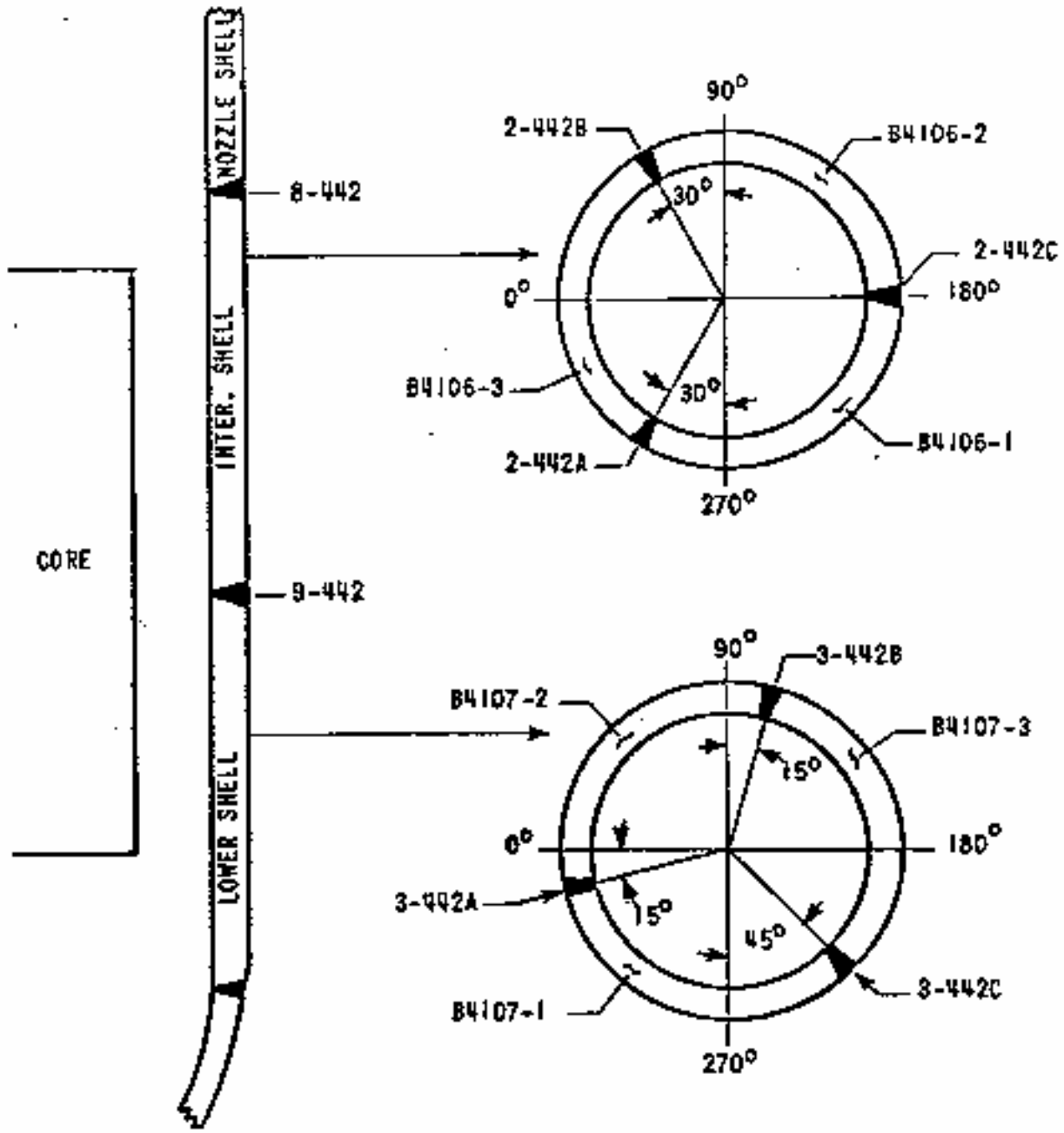
This figure depicts information utilized in the original plant design and is not intended to be updated. For current plant information, refer to Figure 5.1-2A.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.1-2 PUMP HEAD - FLOW CHARACTERISTICS



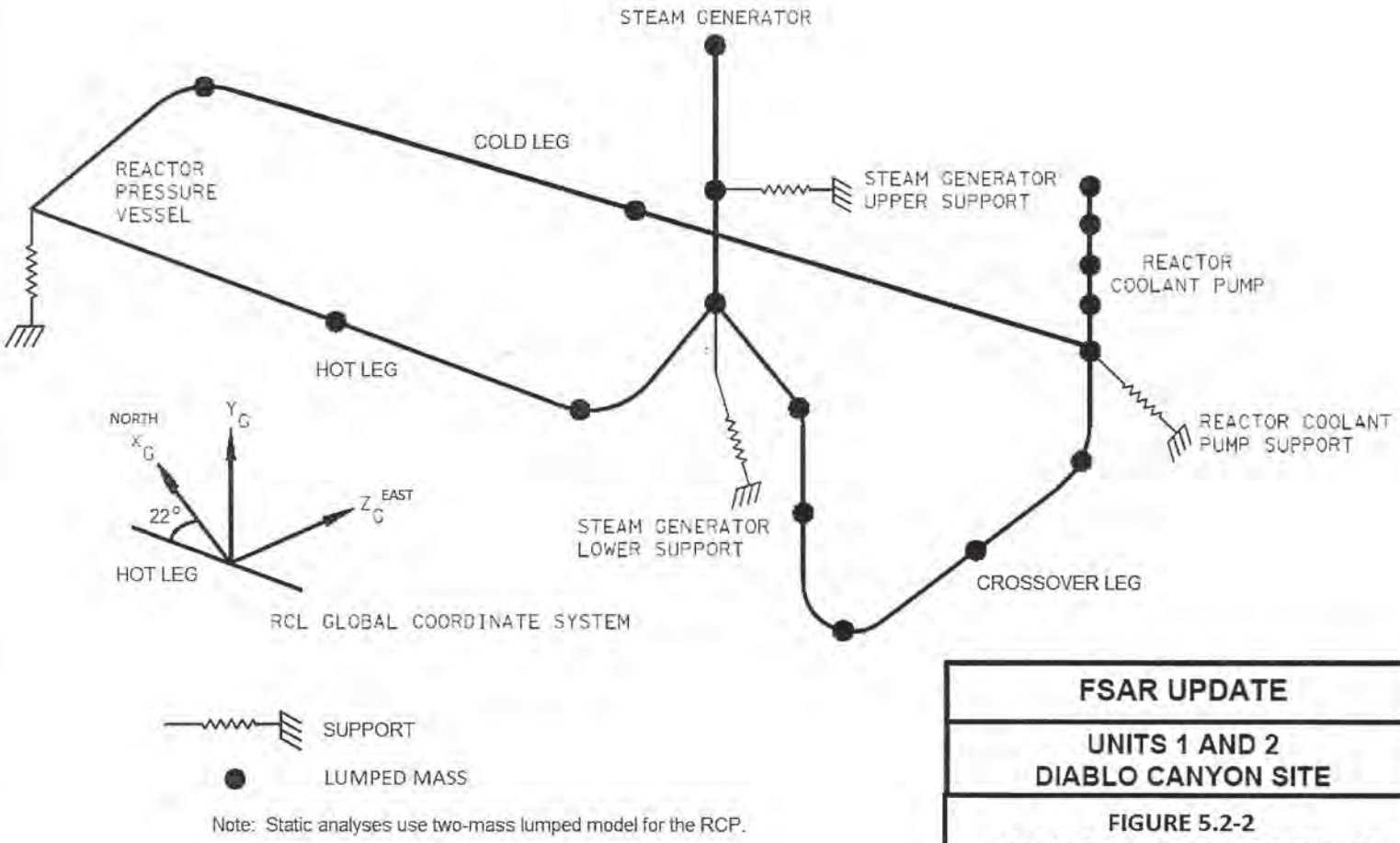
FSAR UPDATE
UNITS 1 and 2 DIABLO CANYON SITE
FIGURE 5.1-2A SAFETY ANALYSIS- RCS FLOW PARAMETERS

Revision 22 May 2015



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 5.2-1 IDENTIFICATION AND LOCATION OF BELTLINE REGION MATERIALS FOR THE REACTOR VESSEL

Revision 11 November 1996



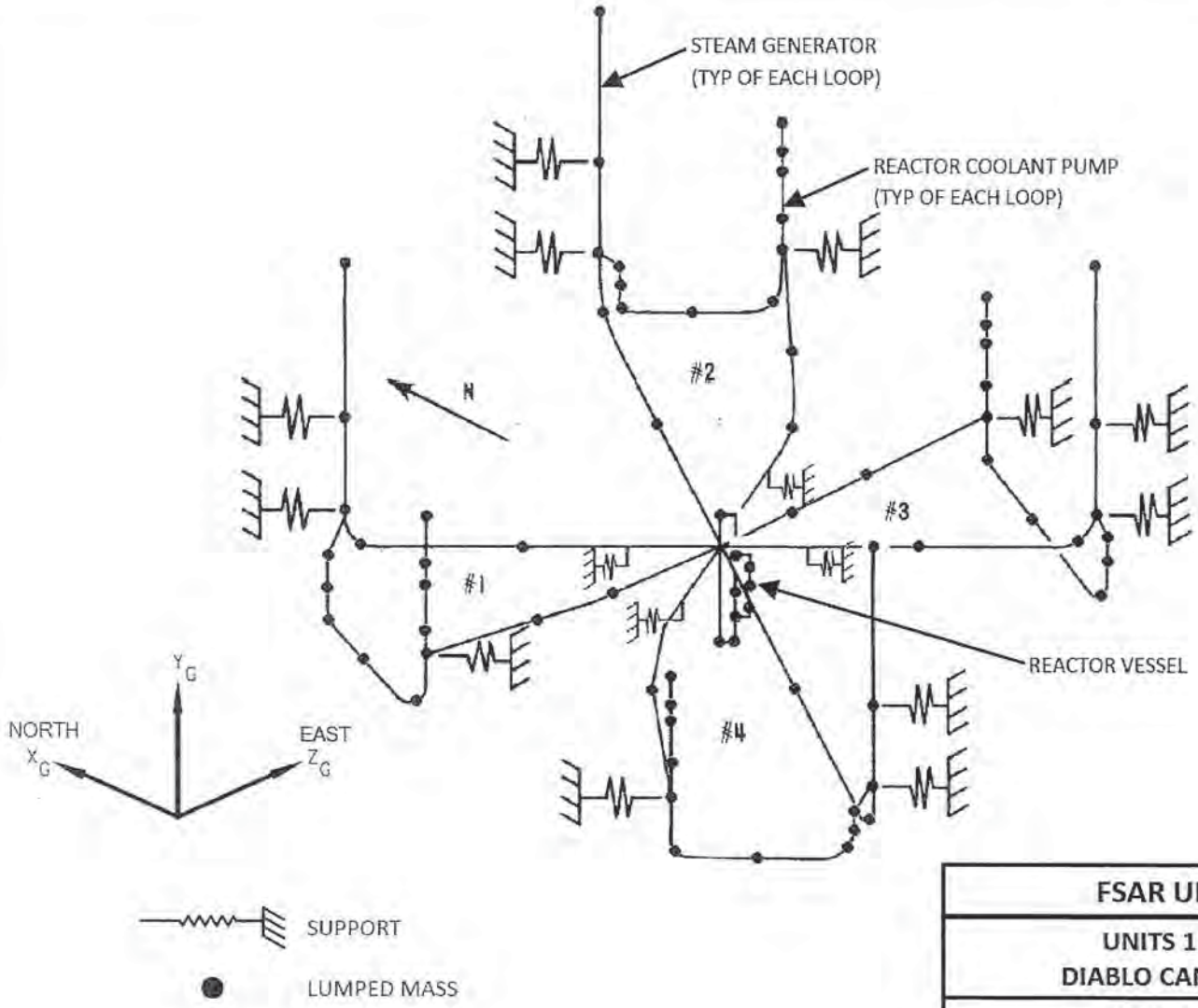
Note: Static analyses use two-mass lumped model for the RCP.

FSAR UPDATE

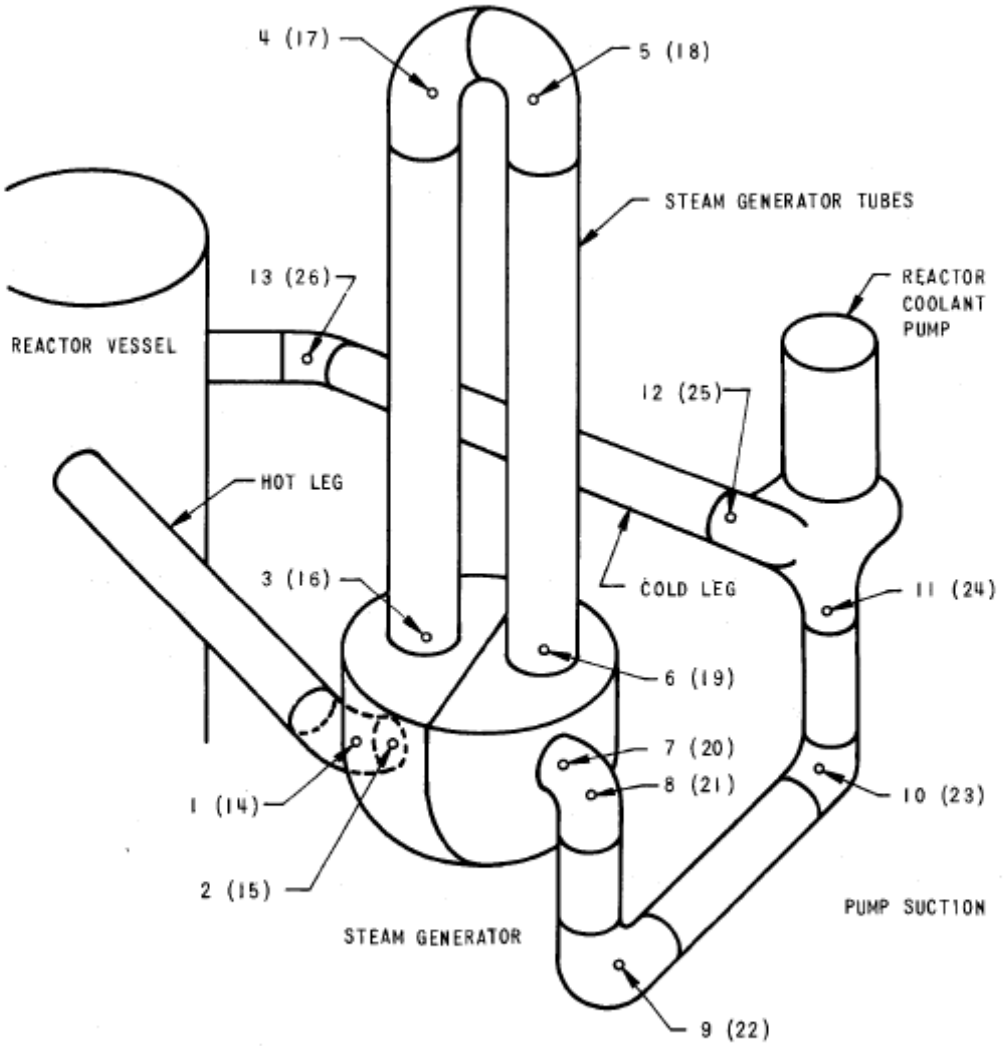
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 5.2-2
REACTOR COOLANT LOOP MODEL FOR STATIC AND LOCA

Revision 24 September 2018



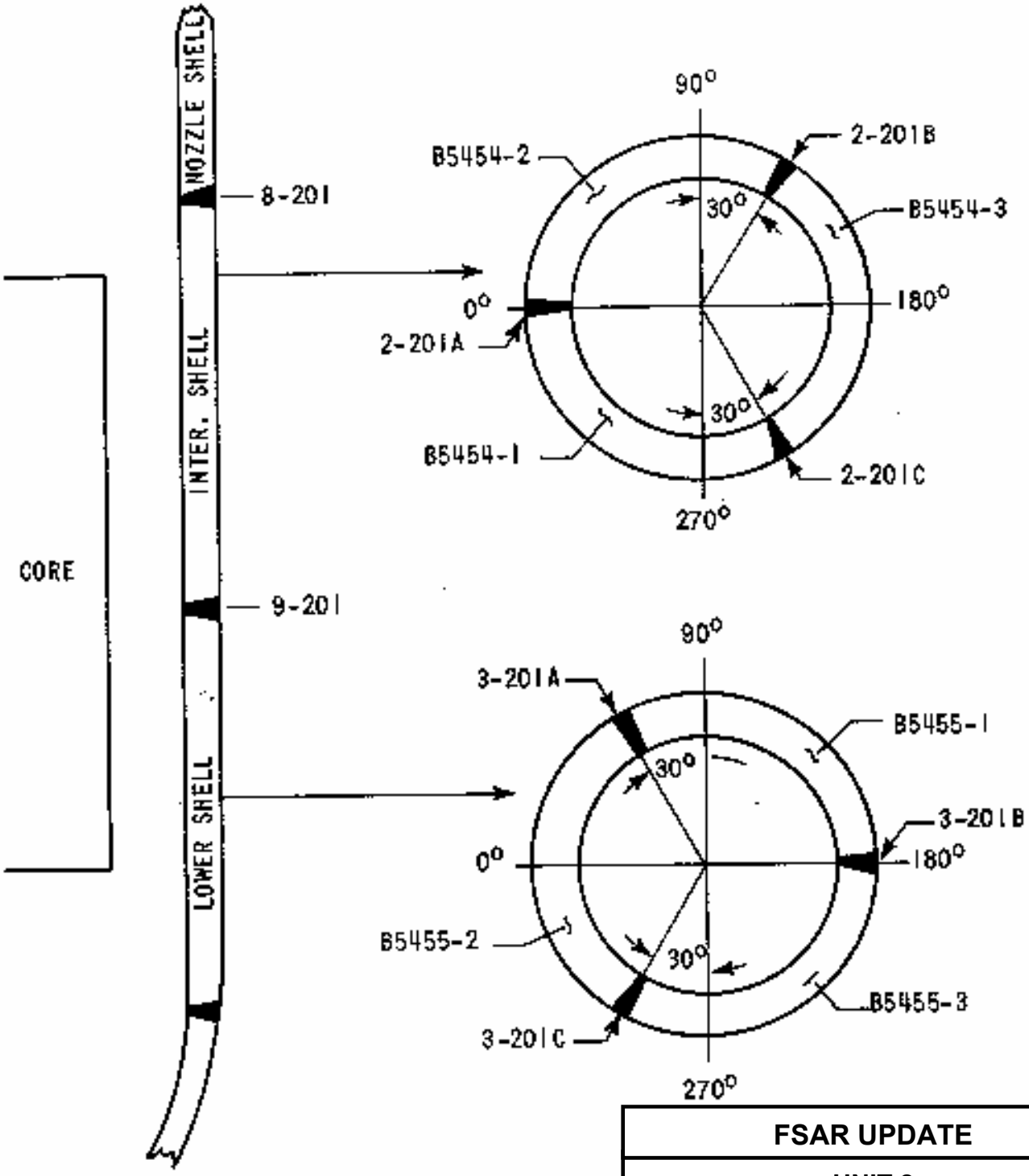
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.2-2A REACTOR COOLANT 4-LOOP MODEL



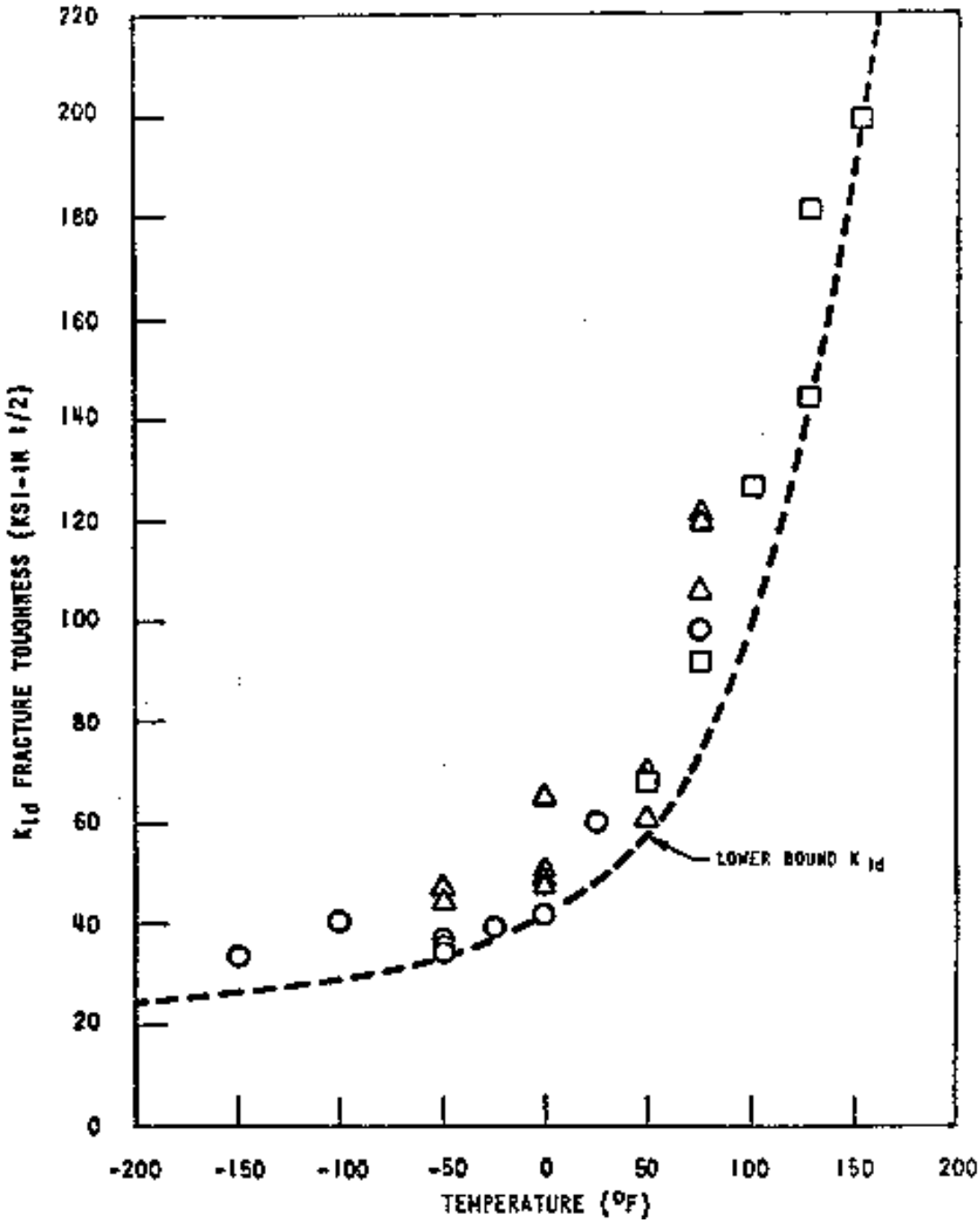
X - BROKEN LOOP FORCE NODES

(X) - UNBROKEN LOOP FORCE NODES

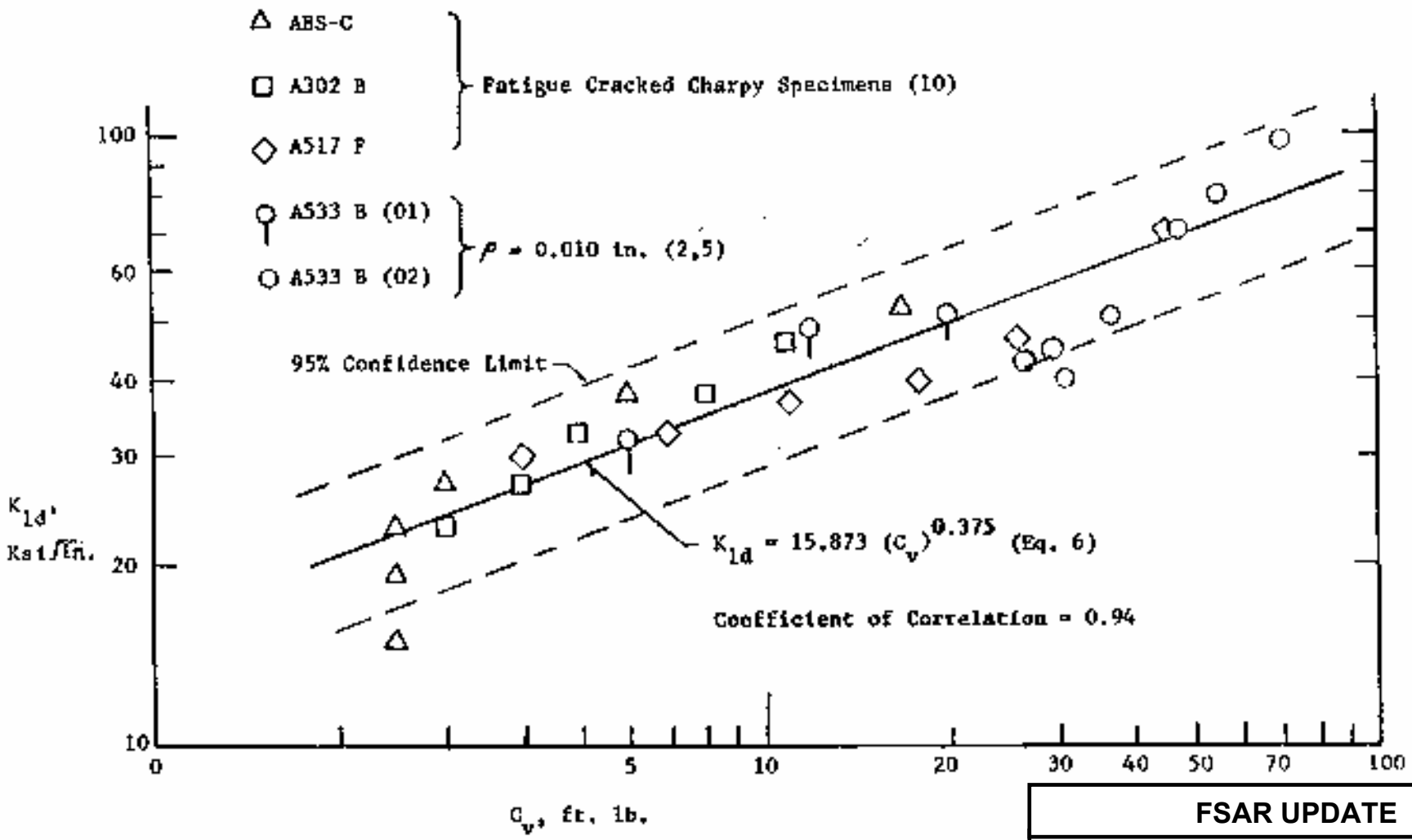
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.2-3 THRUST RCL MODEL SHOWING HYDRAULIC FORCE LOCATIONS



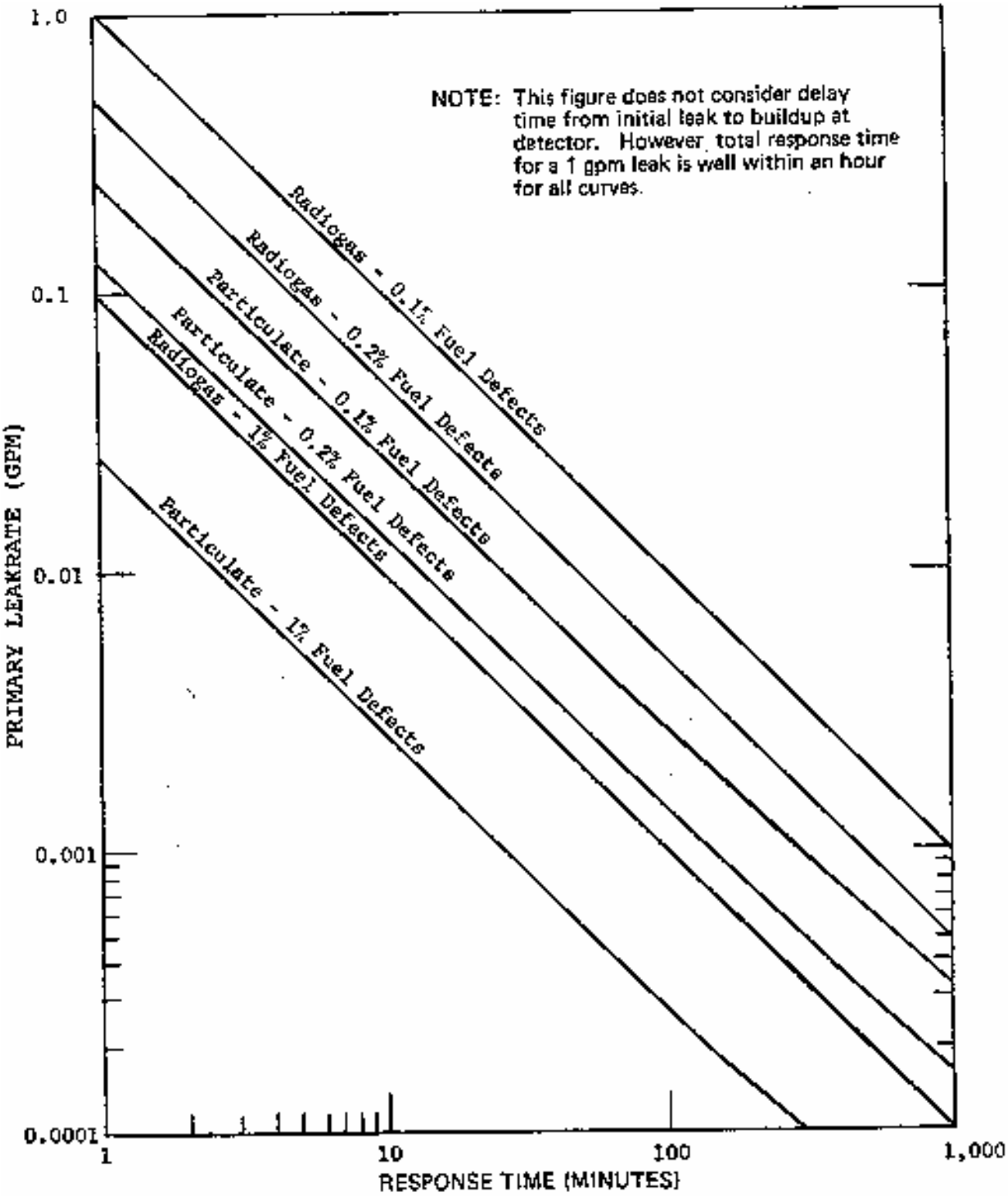
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 5.2-4 IDENTIFICATION AND LOCATION OF BELTLINE REGION MATERIAL FOR THE REACTOR VESSEL



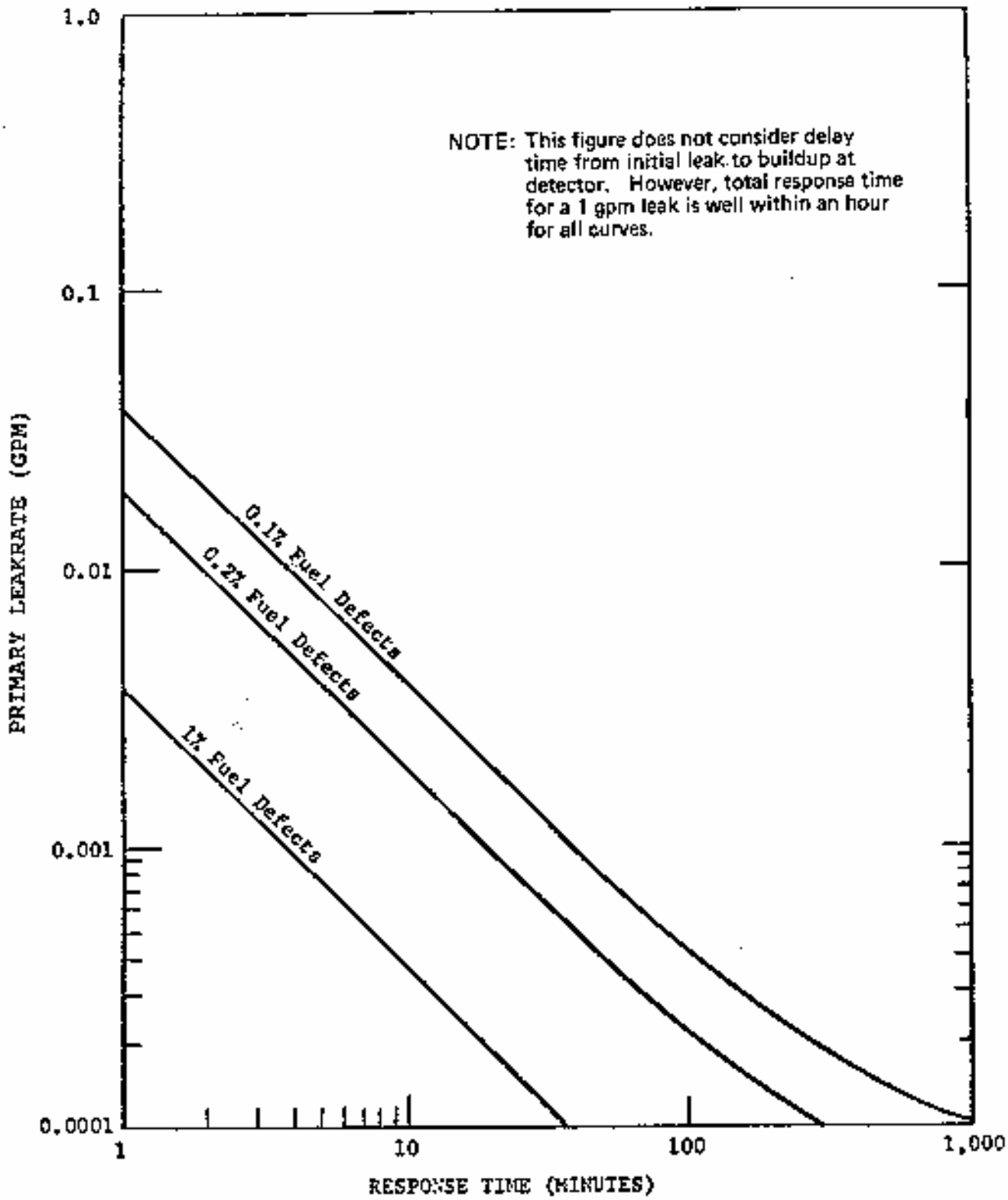
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 5.2-7 LOWER BOUND FRACTURE TOUGHNESS A533 GRADE B CLASS 1 (REF WCAP-7623)



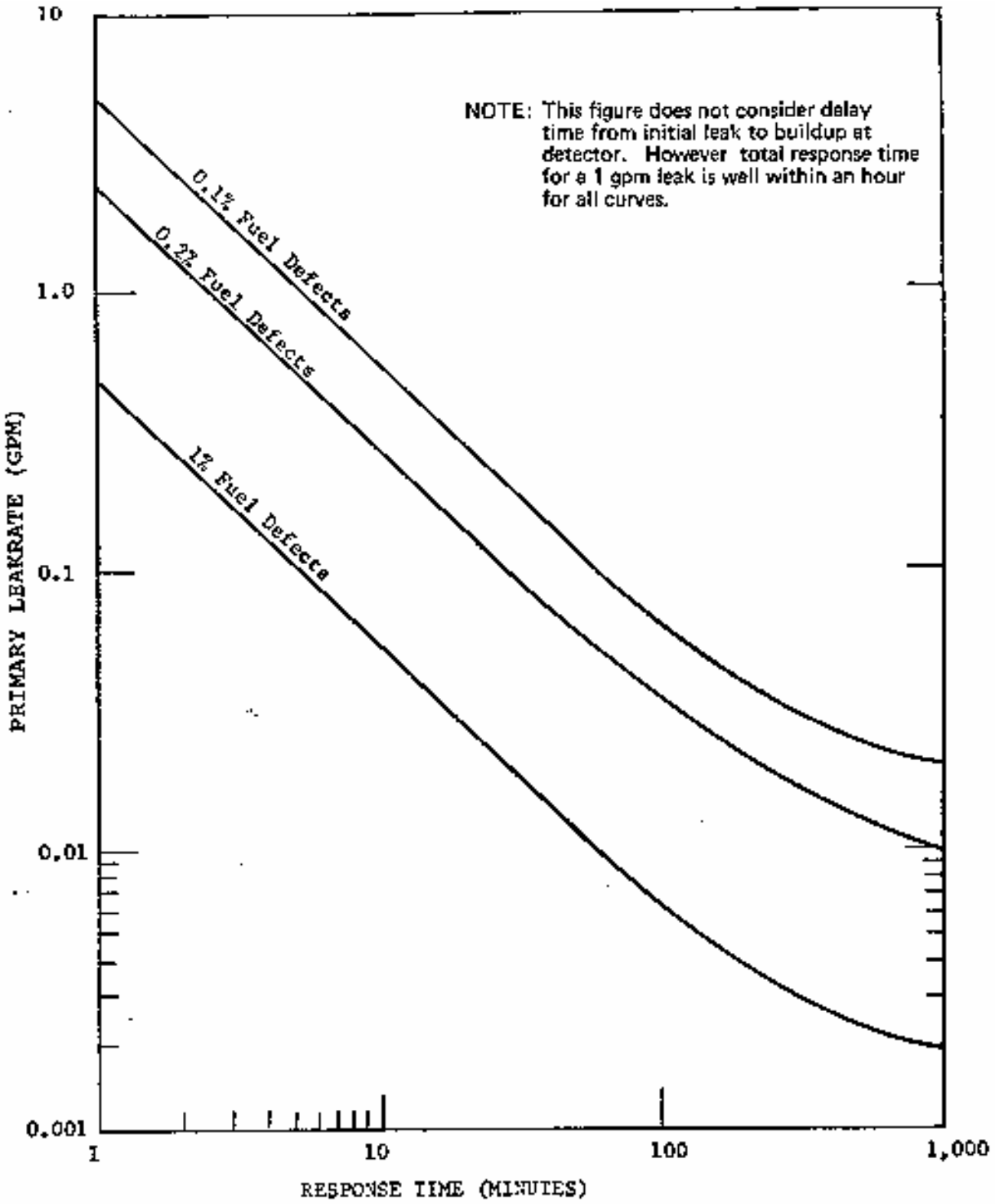
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.2-8 TRANSITION TEMPERATURE CORRELATION BETWEEN K_{Id} (DYNAMIC) AND C_v FOR A SERIES OF UNIRRADIAYED STEELS



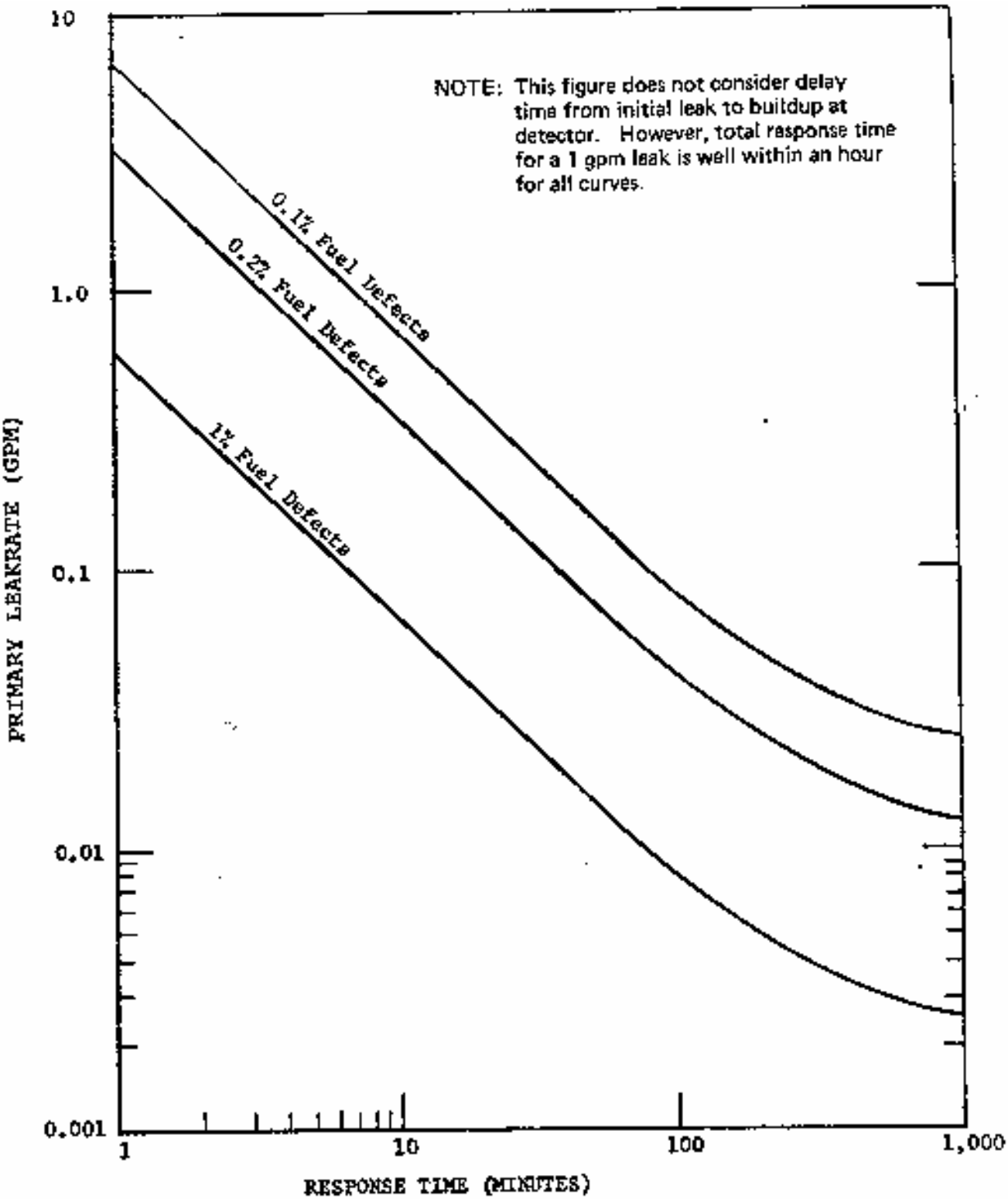
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.2-9 CONTAINMENT MONITOR RESPONSE TIME VERSUS PRIMARY LEAKRATE



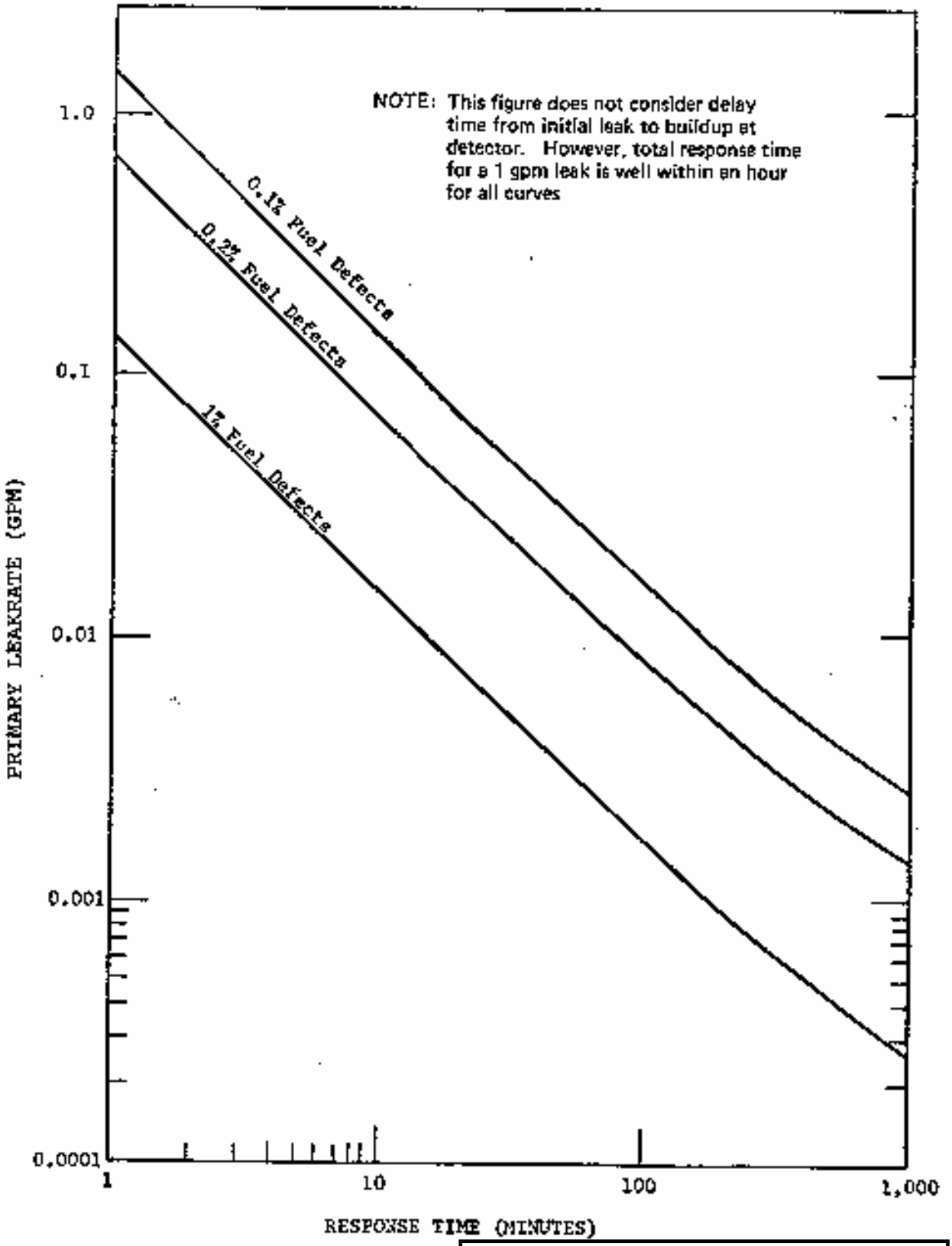
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.2-10 AIR EJECTOR RADIOGAS MONITOR RESPONSE TIME VERSUS PRIMARY LEAKRATE



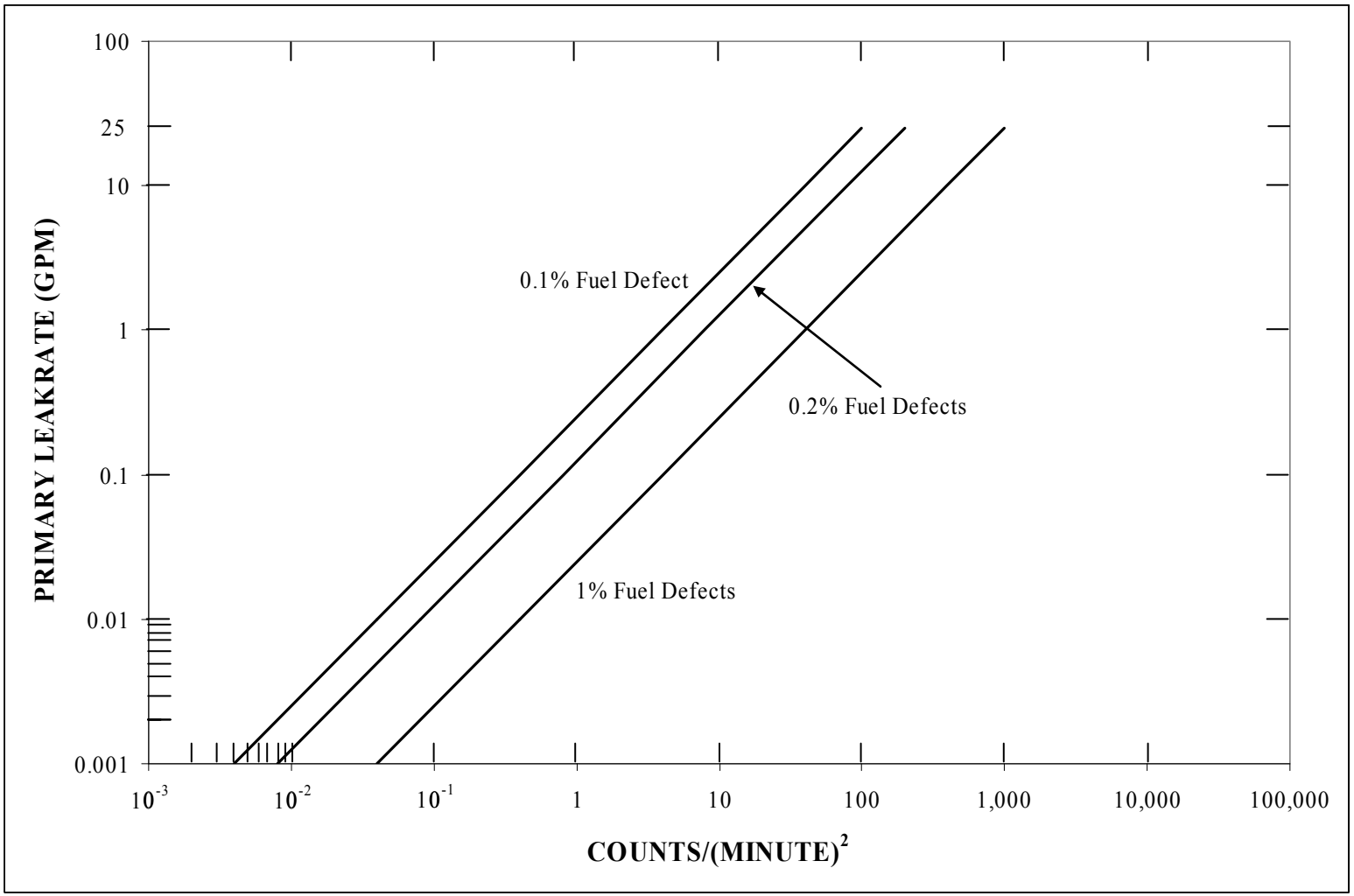
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.2-11 BLOWDOWN LIQUID MONITOR RESPONSE TIME VERSUS PRIMARY LEAKRATE



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.2-12 CONTAINMENT COOLING WATER LIQUID MONITOR RESPONSE TIME VERSUS PRIMARY LEAKRATE



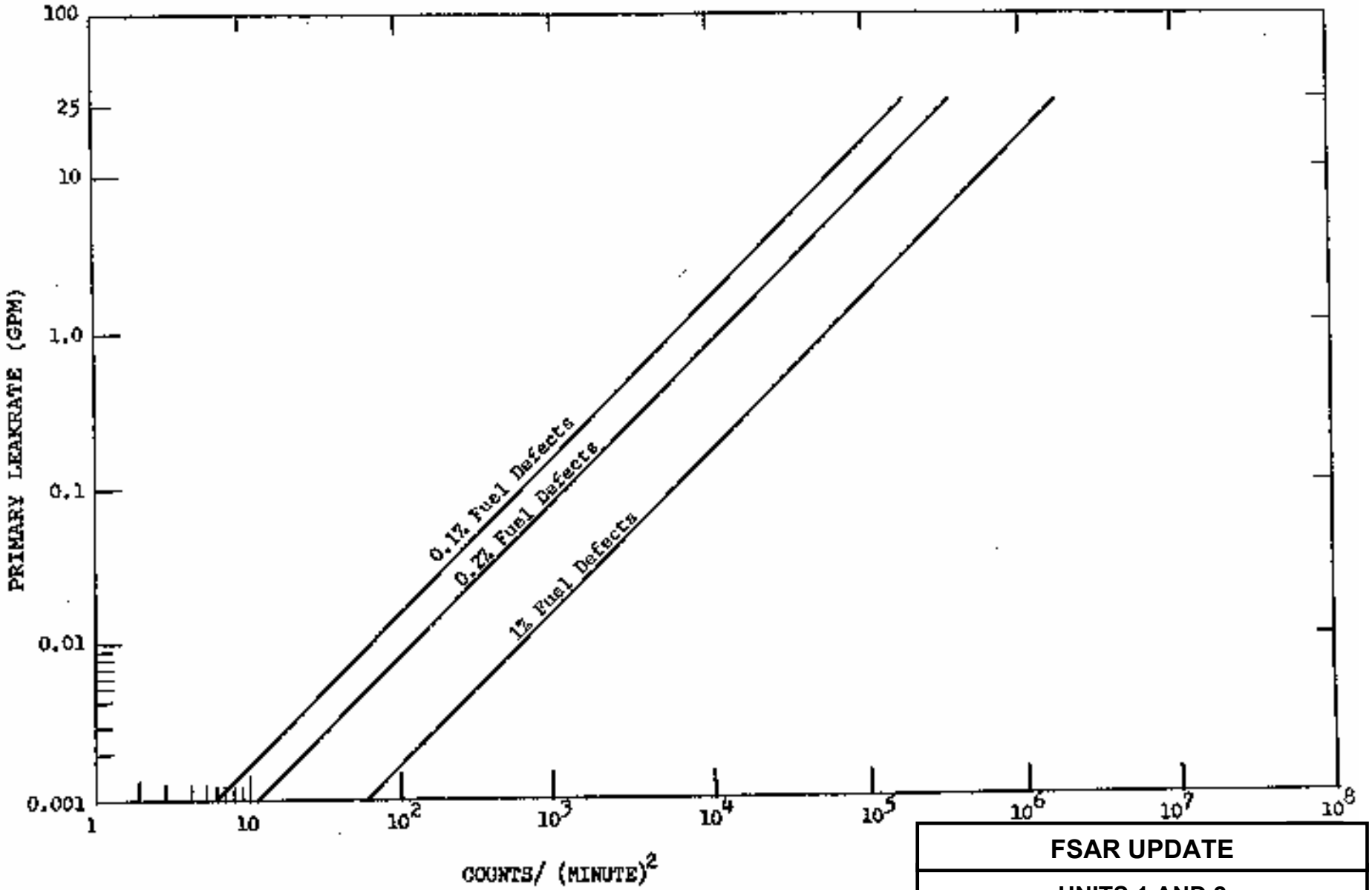
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.2-13 CONTAINMENT AREA MONITOR RESPONSE TIME VERSUS PRIMARY LEAKRATE



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 5.2-14
CONTAINMENT RADIOGAS MONITOR COUNT RATE VERSES PRIMARY LEAKRATE AFTER EQUILIBRIUM

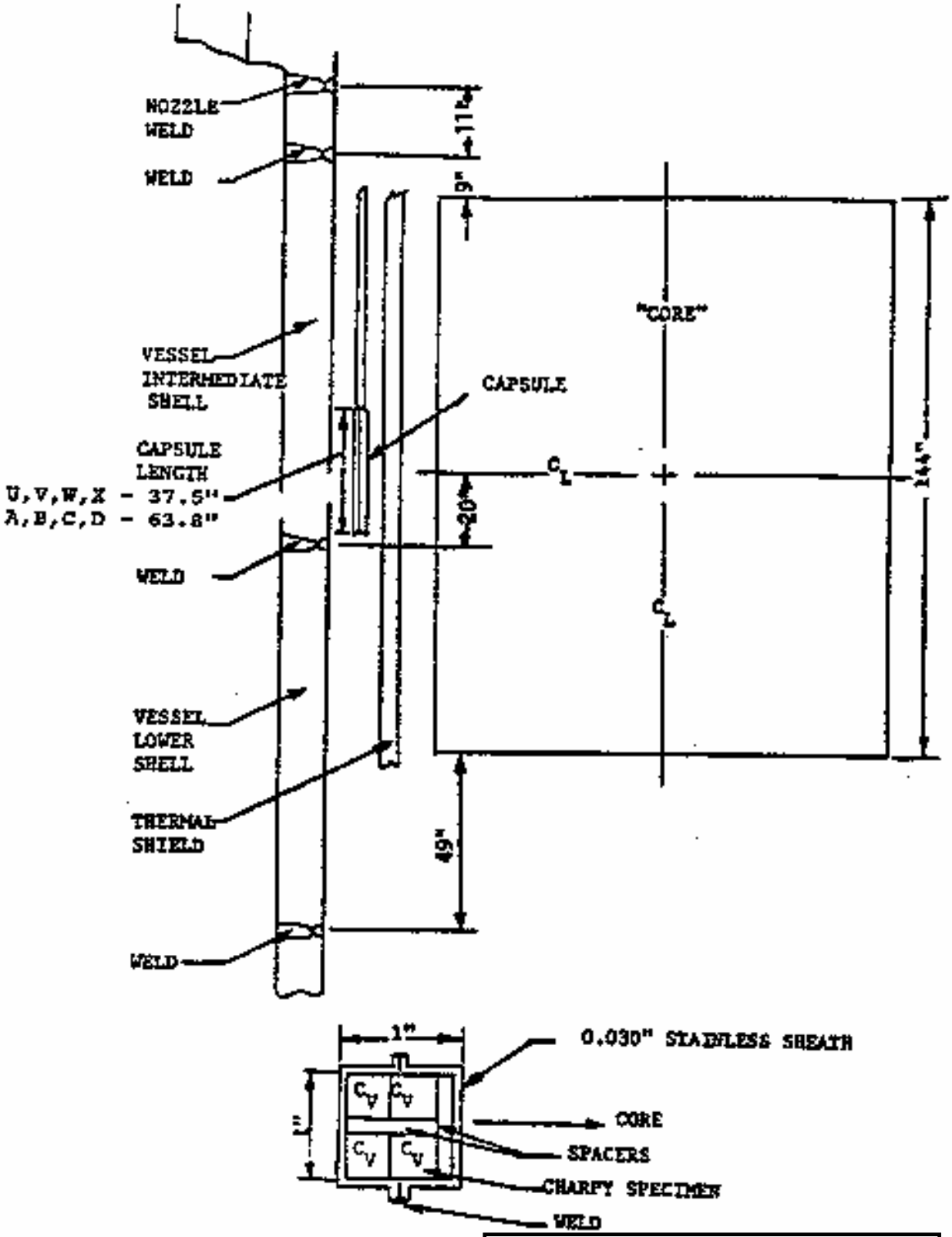


FSAR UPDATE

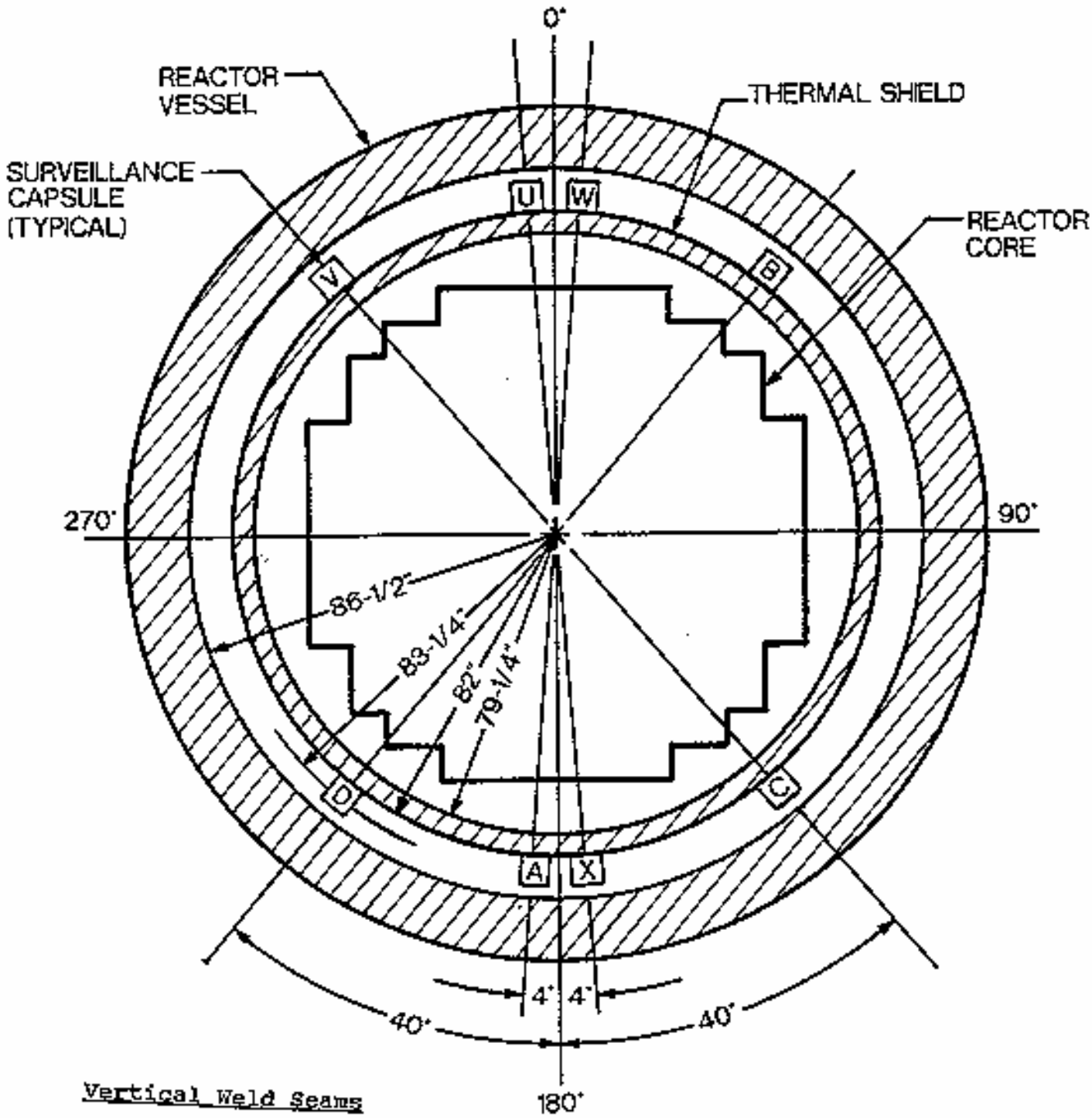
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 5.2-15

CONTAINMENT PARTICULATE MONITOR COUNT RATE VERSUS PRIMARY LEAKRATE AFTER EQUILIBRIUM



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 5.2-16 SURVEILLANCE CAPSULE ELEVATION VIEW

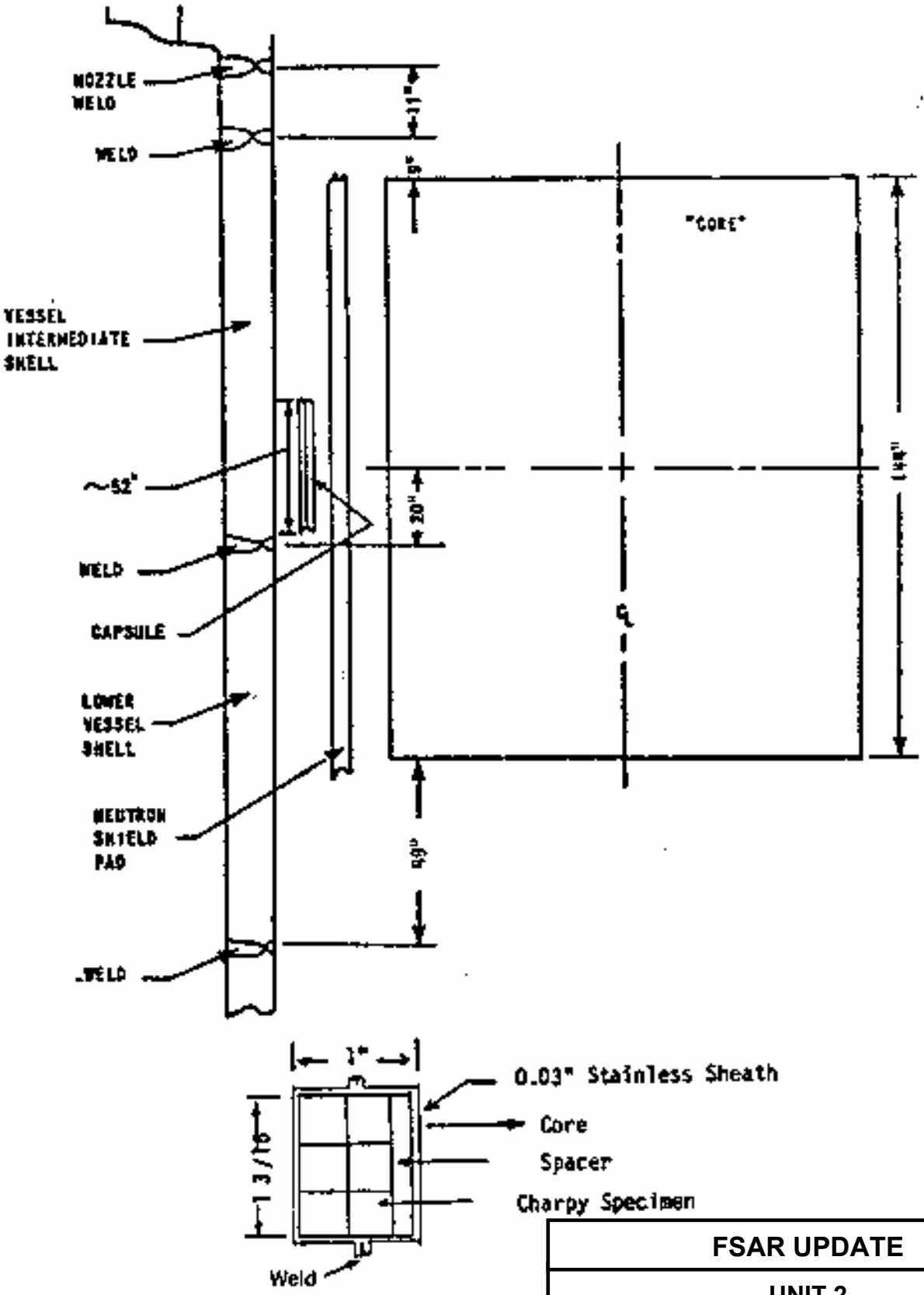


Vertical Weld Seams

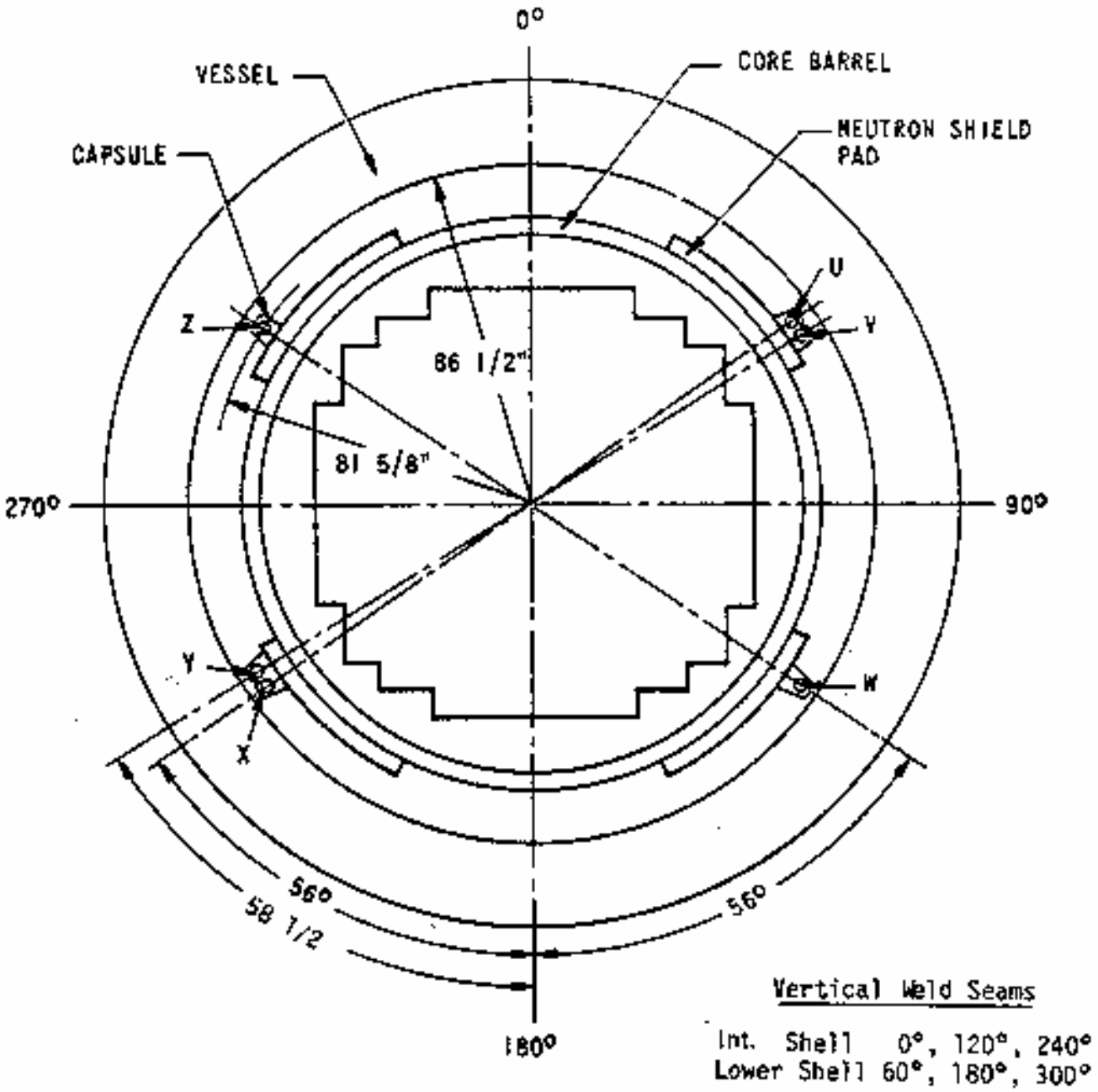
Int. Shell 0°, 120°, 240°

Lower Shell 60°, 180°, 300°

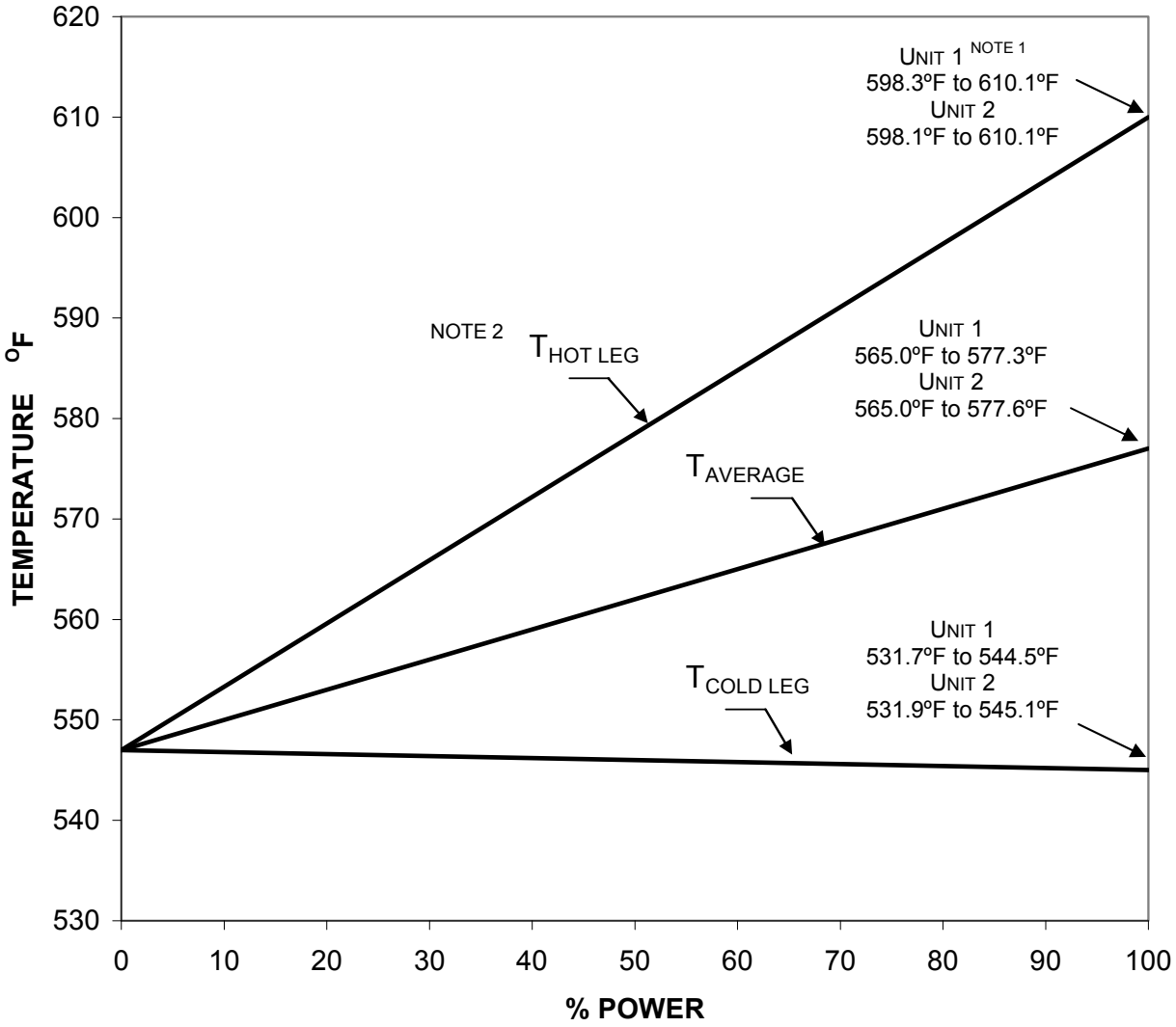
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 5.2-17 SURVEILLANCE CAPSULE PLAN VIEW



FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 5.2-18 SURVEILLANCE CAPSULE ELEVATION VIEW



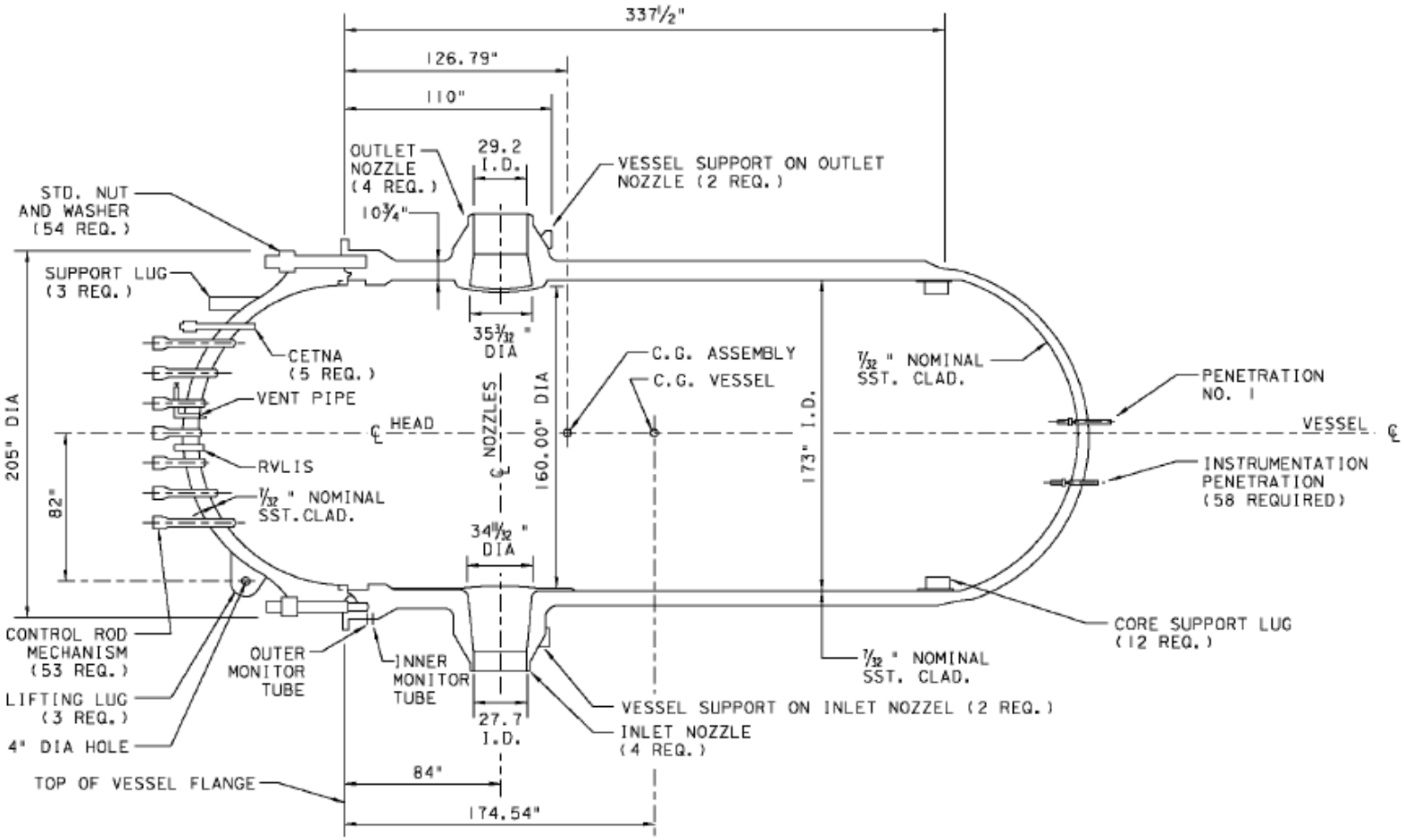
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 5.2-19 SURVEILLANCE CAPSULE PLAN VIEW



NOTE 1: UNIT 1 AND UNIT 2 DESIGN VALUE RANGES FOR FULL POWER.

NOTE 2: THE PLOTS SHOWN ARE FOR THE MAXIMUM $T_{HOT\ LEG}$, $T_{AVERAGE}$, AND $T_{COLD\ LEG}$ TEMPERATURES AT FULL POWER.

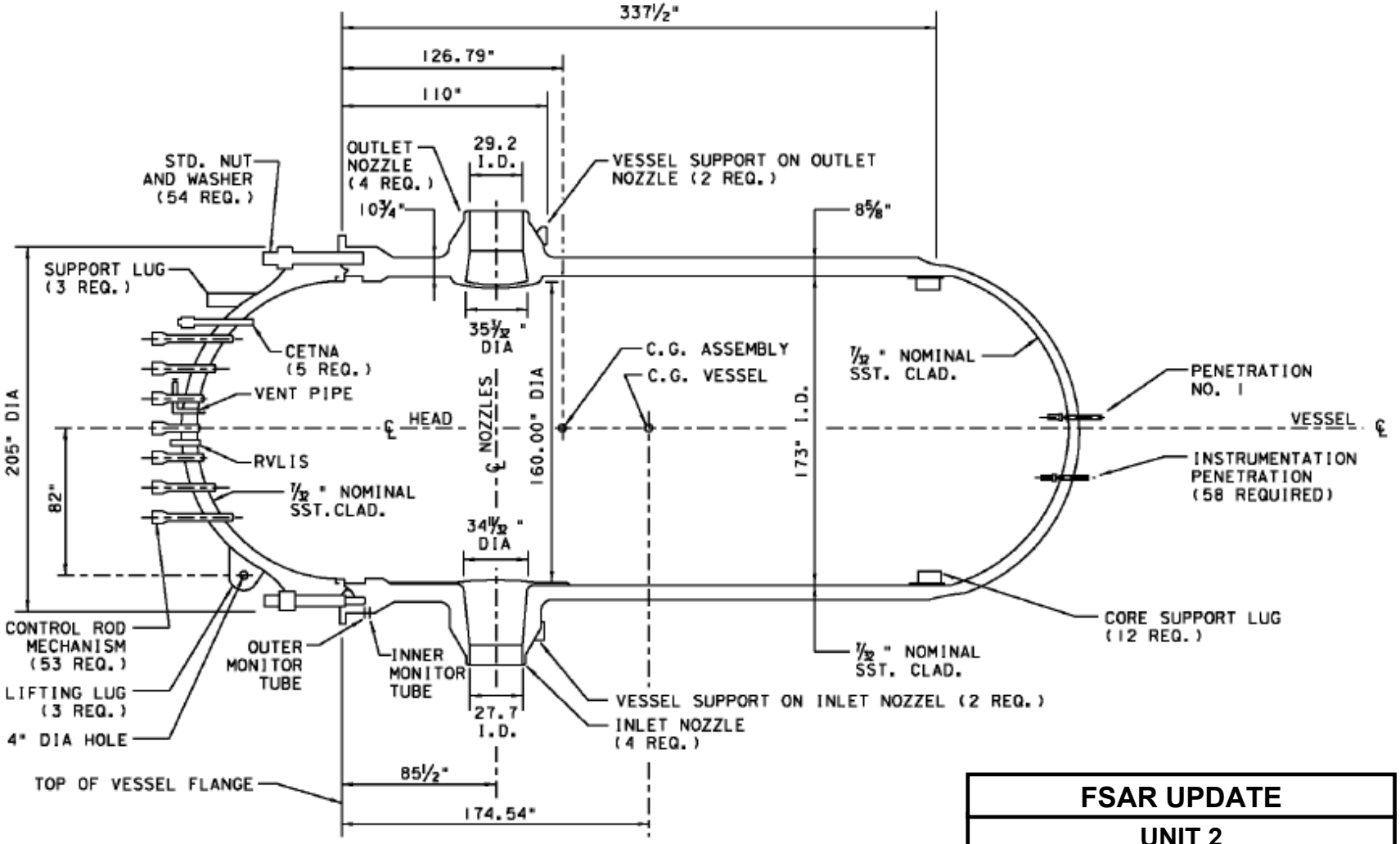
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.3-1 HOT LEG, COLD LEG, AND AVERAGE REACTOR COOLANT LOOP TEMPERATURE AS A FUNCTION OF PERCENT FULL POWER



SECTIONAL ELEVATION

FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 5.4-1 REACTOR VESSEL

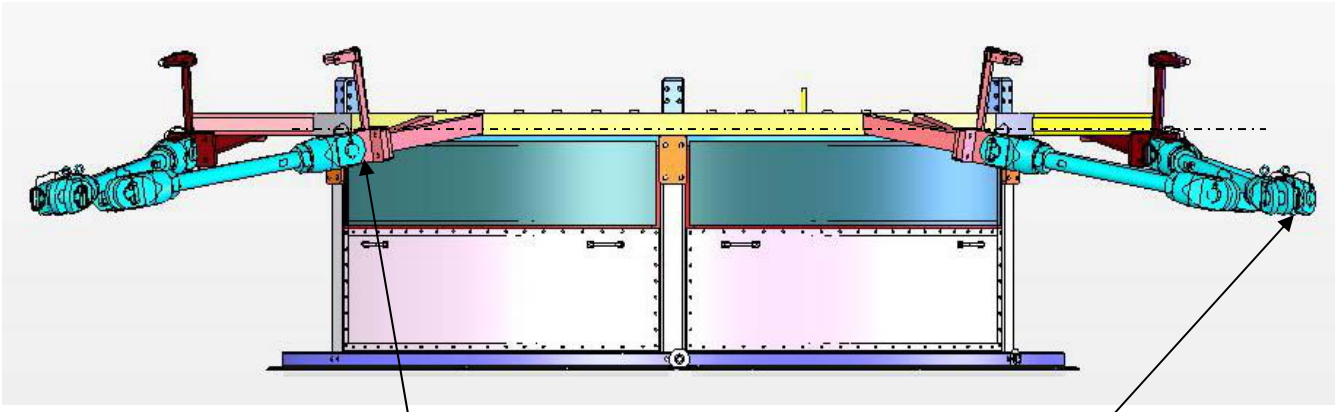
Revision 20 November 2011



SECTIONAL ELEVATION

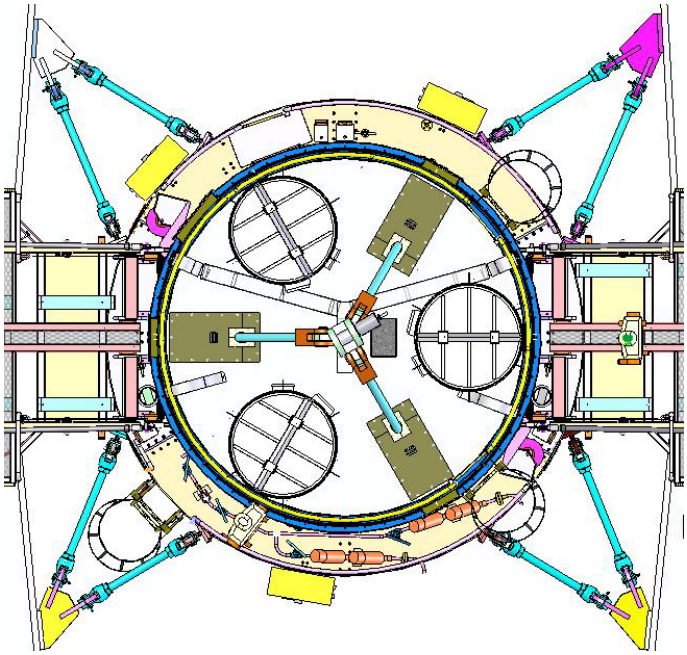
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 5.4-2 REACTOR VESSEL

Revision 20 November 2011

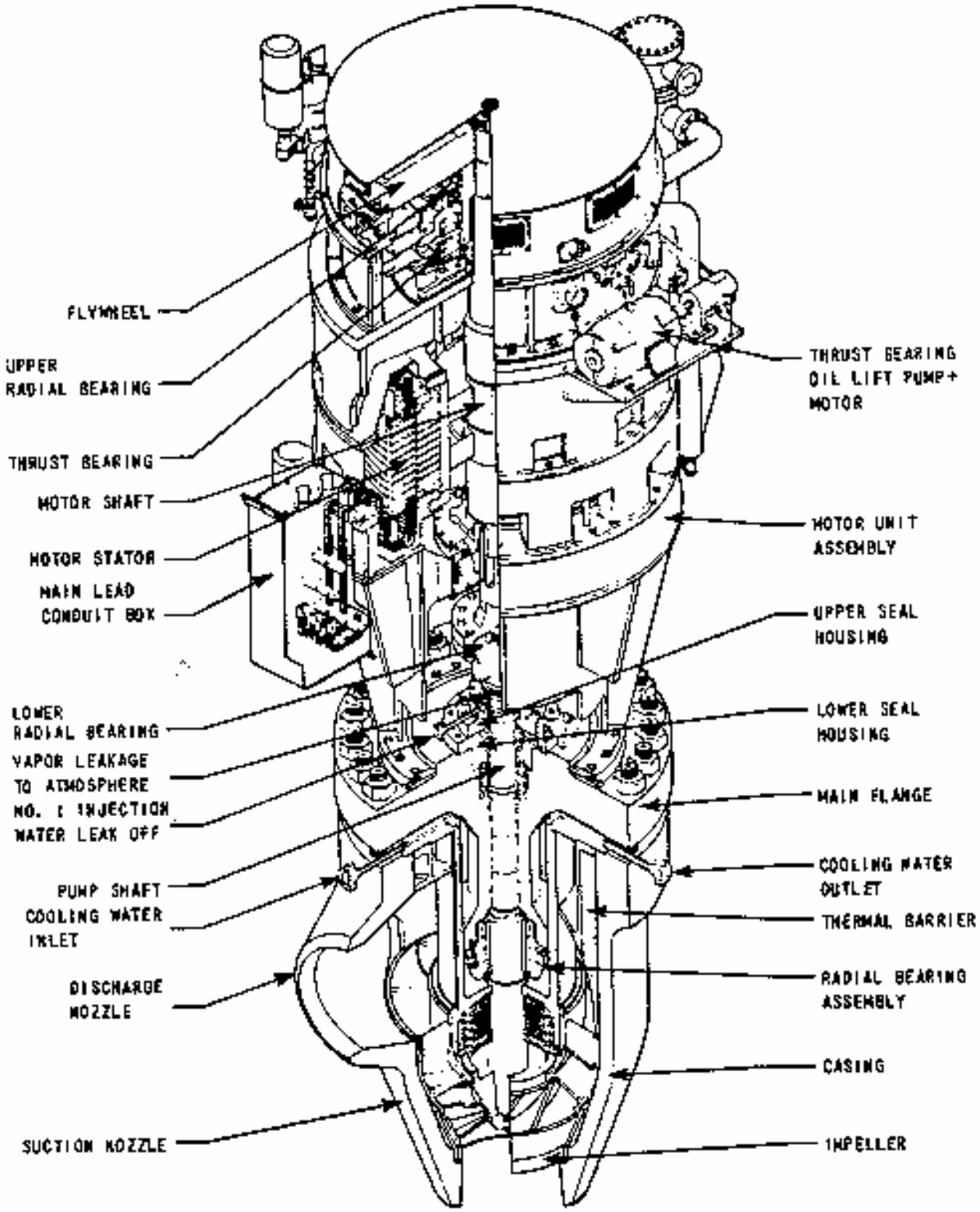


Pin connection
Between seismic tie-rods and
IHA seismic support brackets

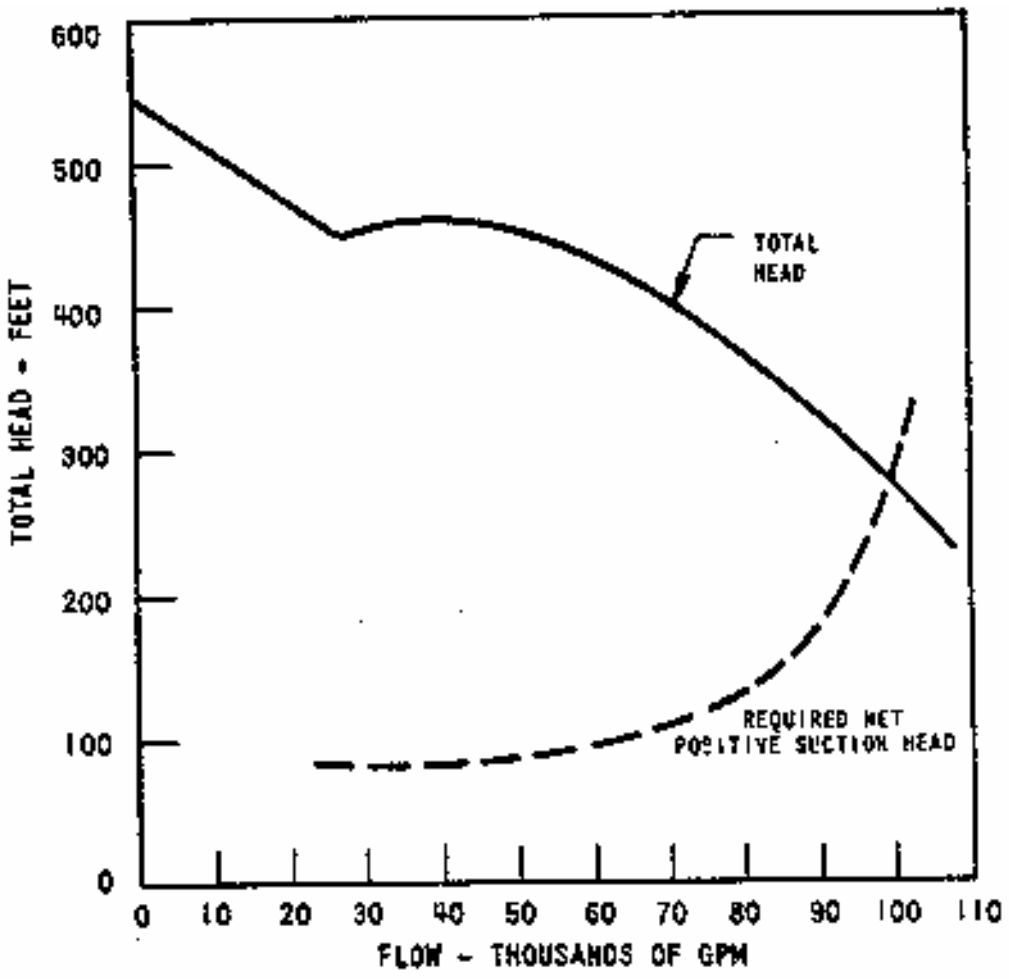
Pin connection
Between seismic tie-rods and
seismic wall support brackets



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.4-3 INTEGRATED HEAD ASSEMBLY SEISMIC SUPPORT STRUCTURE ASSEMBLY

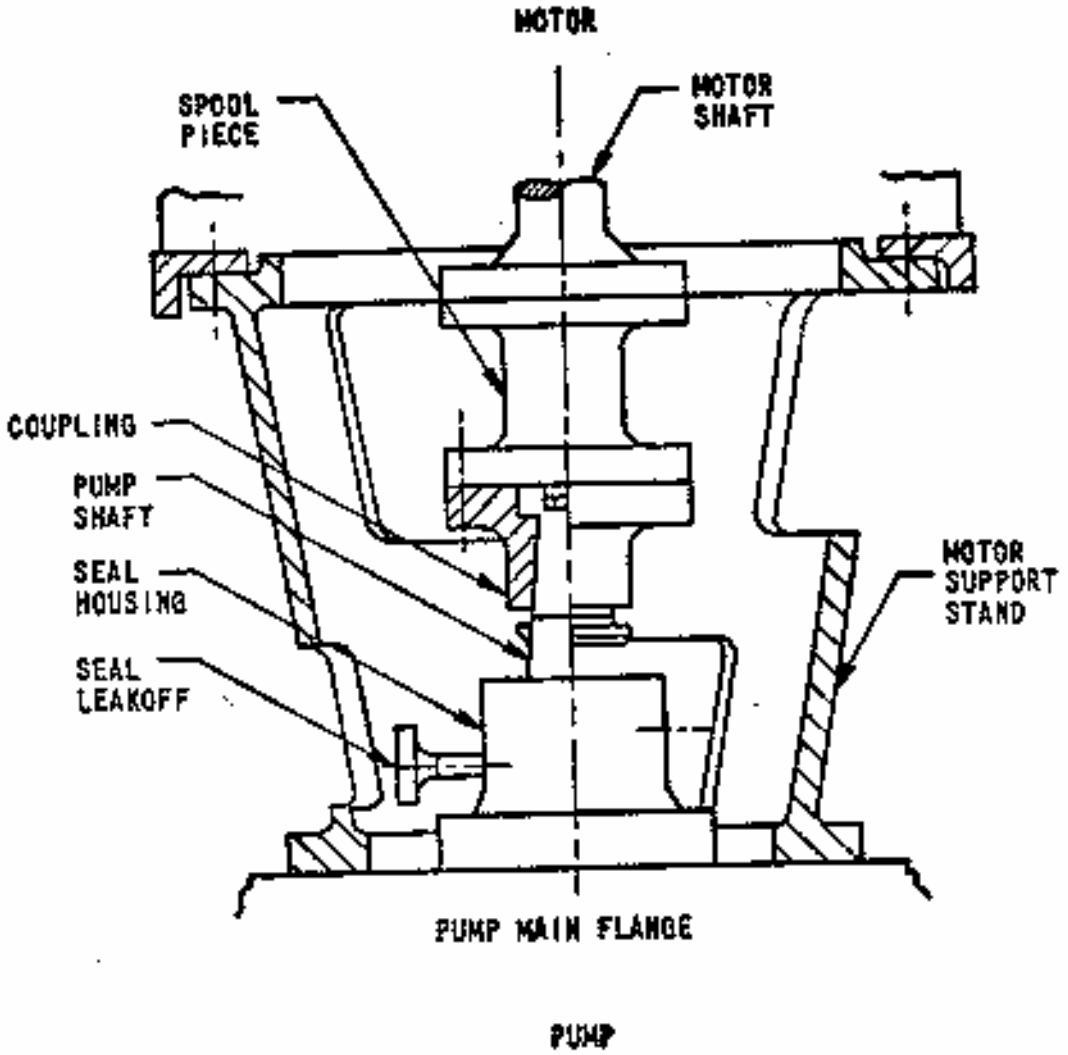


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.5-1 REACTOR COOLANT CONTROLLED LEAKAGE PUMP



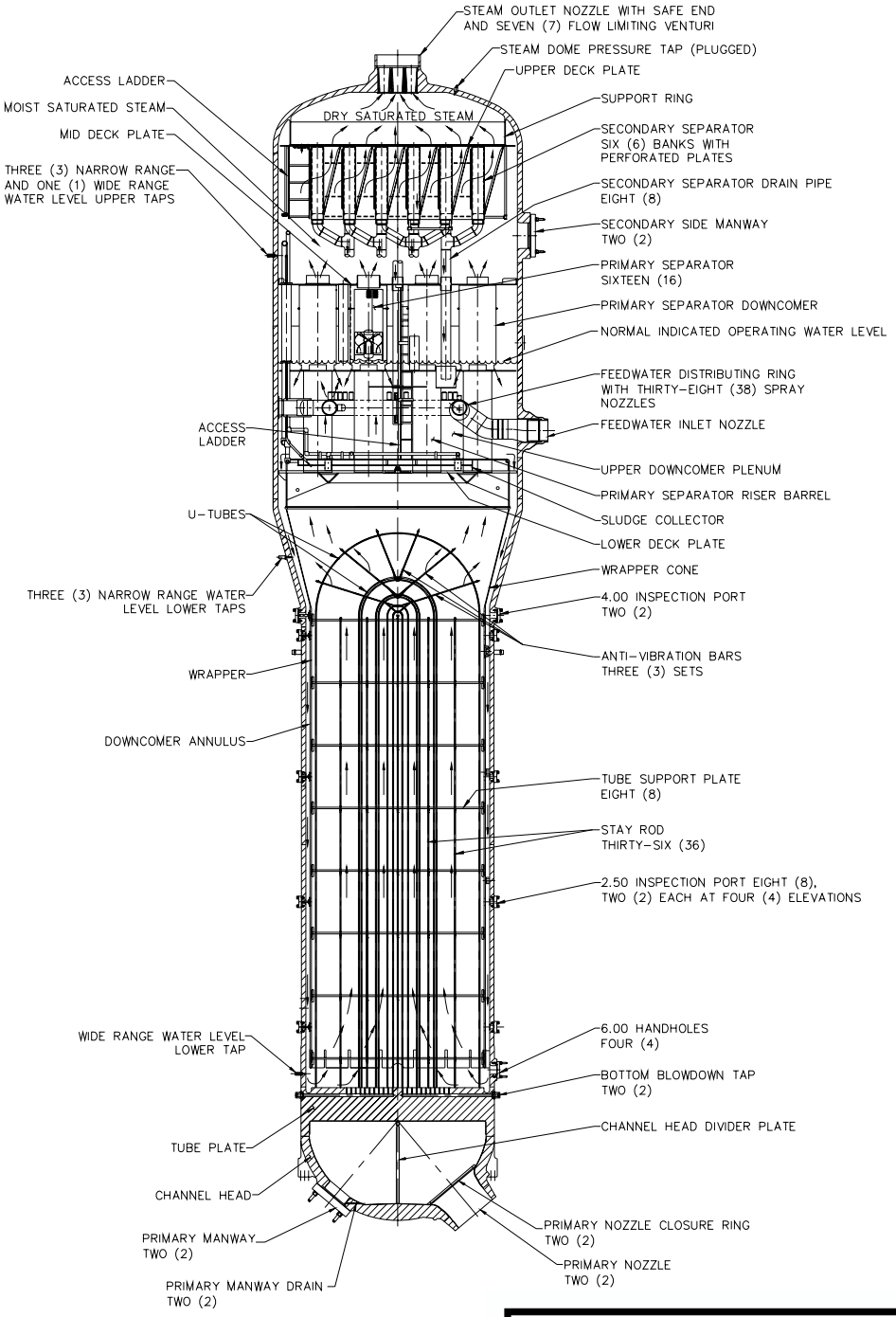
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.5-2 REACTOR COOLANT PUMP ESTIMATED PERFORMANCE CHARACTERISTICS

Revision 11 November 1996



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.5-3 REACTOR COOLANT PUMP SPOOL PIECE AND MOTOR SUPPORT STAND

Revision 11 November 1996

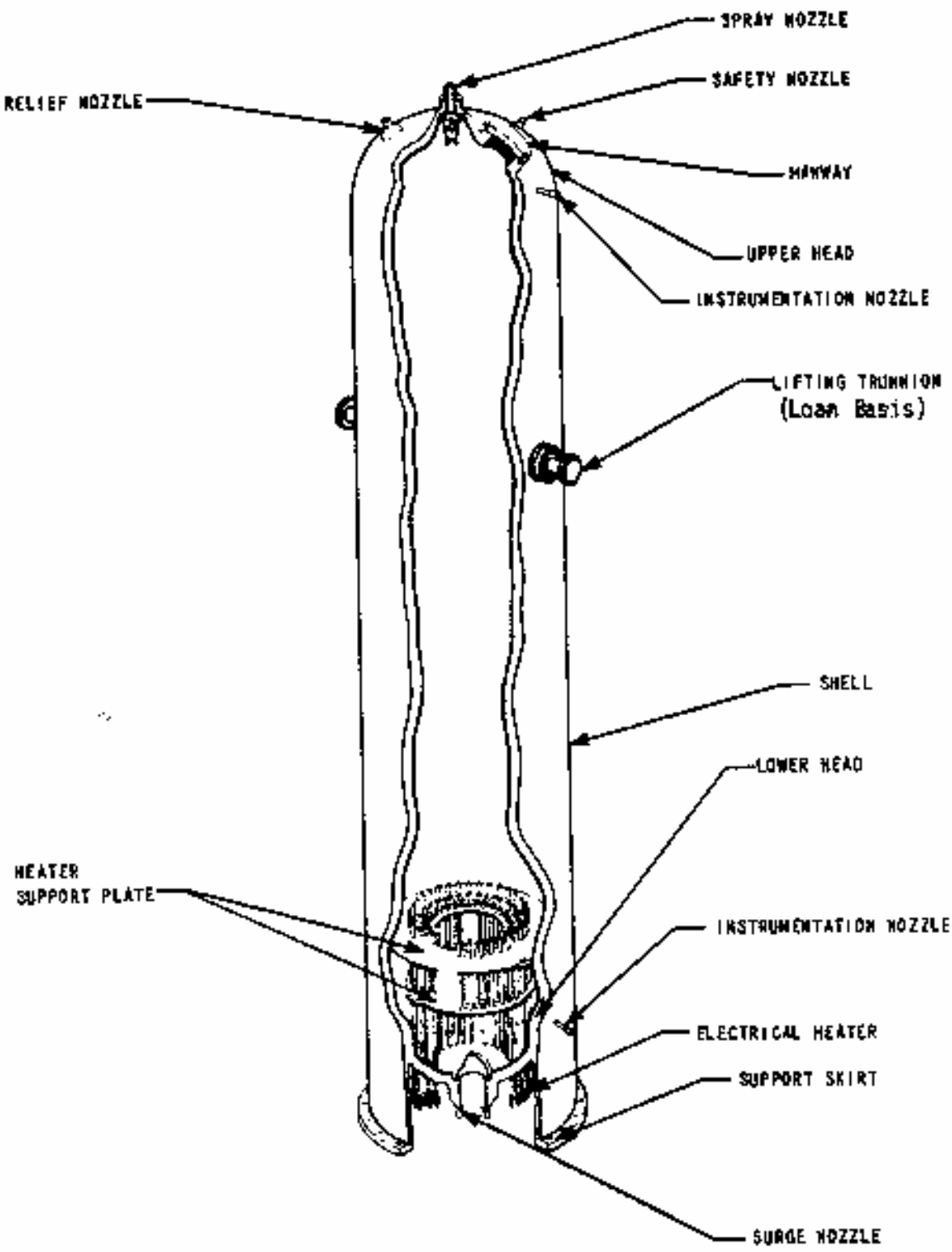


FSAR UPDATE

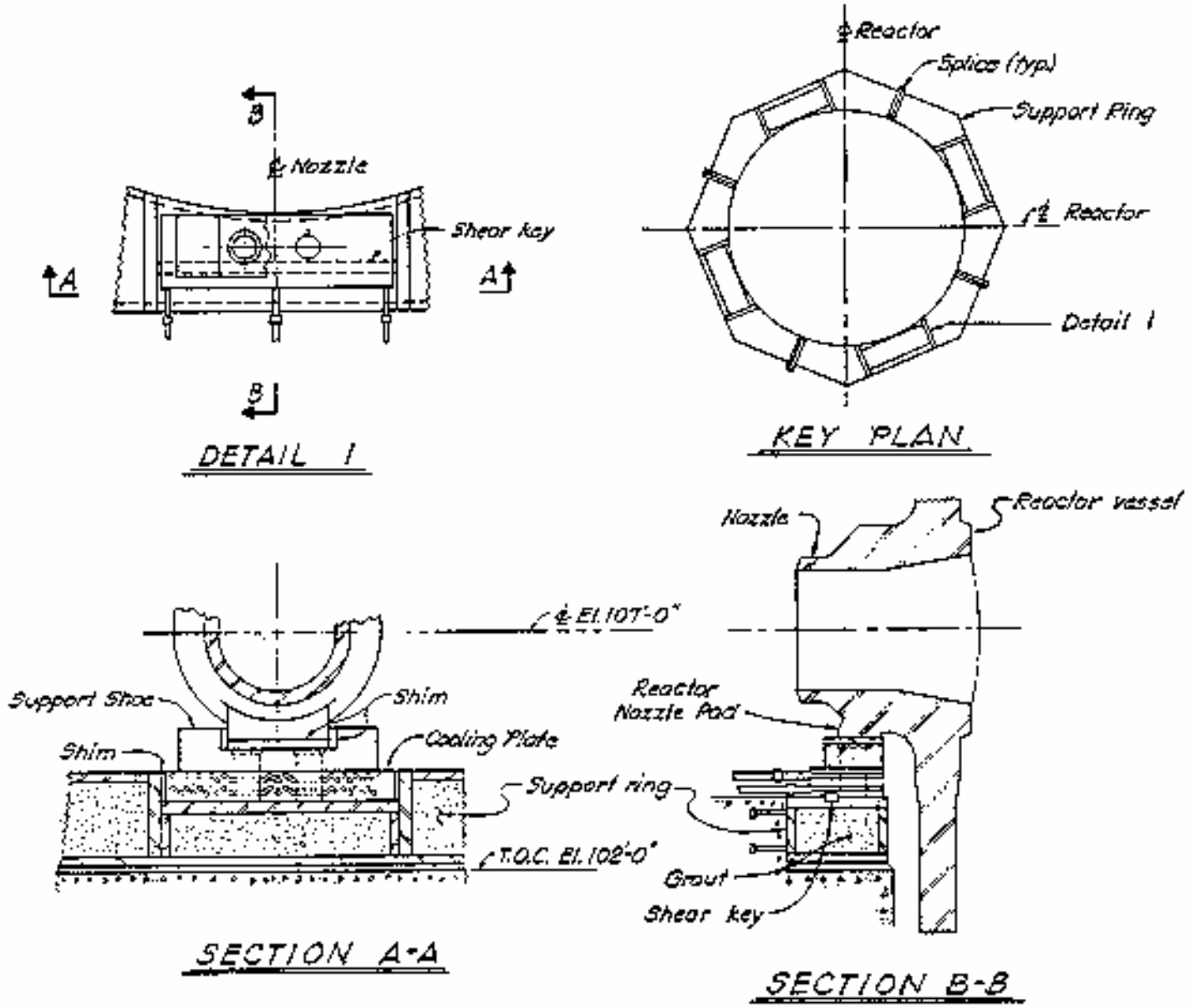
UNITS 1 AND 2
DIABLO CANYON

FIGURE 5.5-4
WESTINGHOUSE DELTA 54
STEAM GENERATOR

Revision 19 May 2010

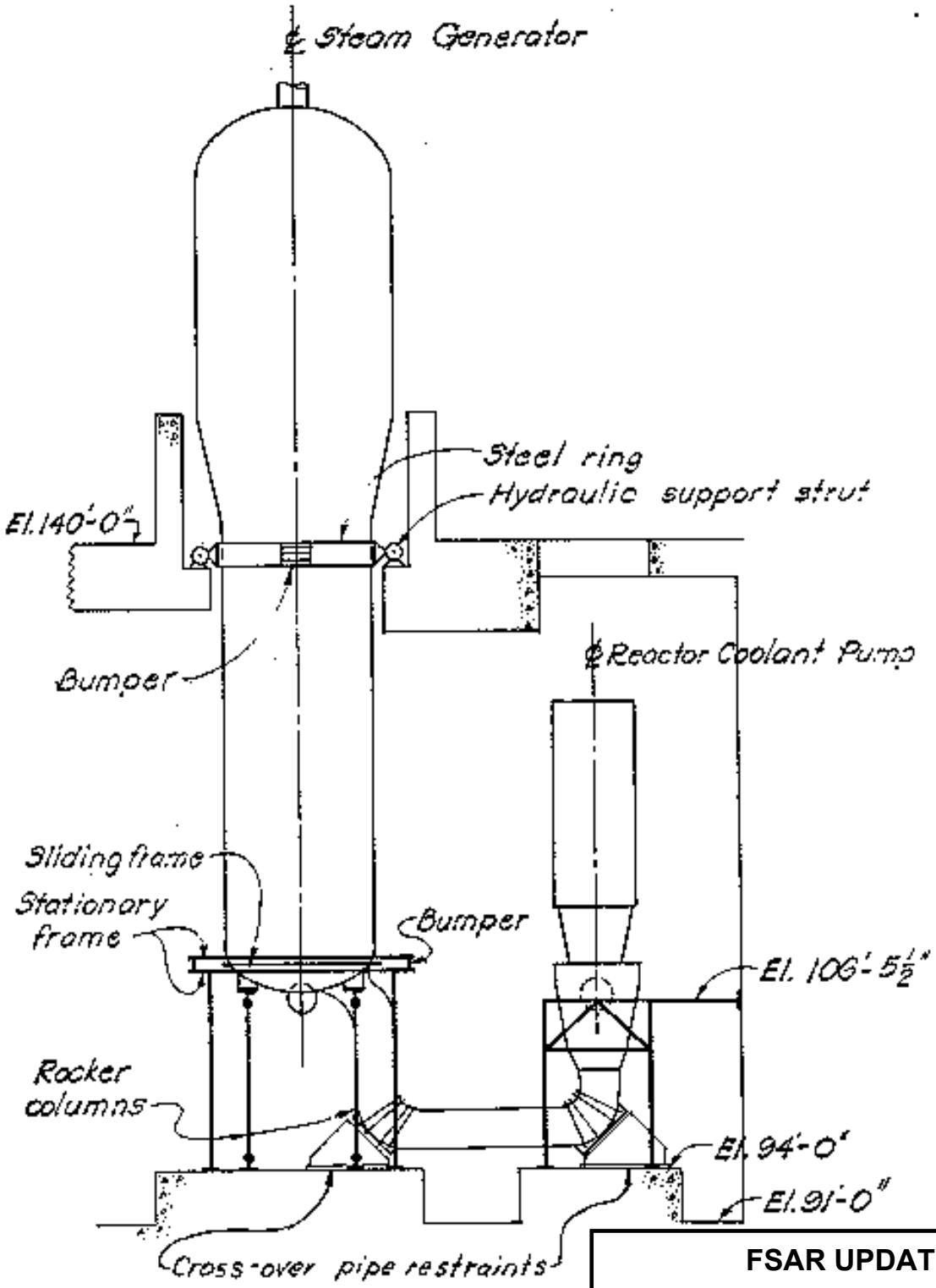


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.5-8 PRESSURIZER



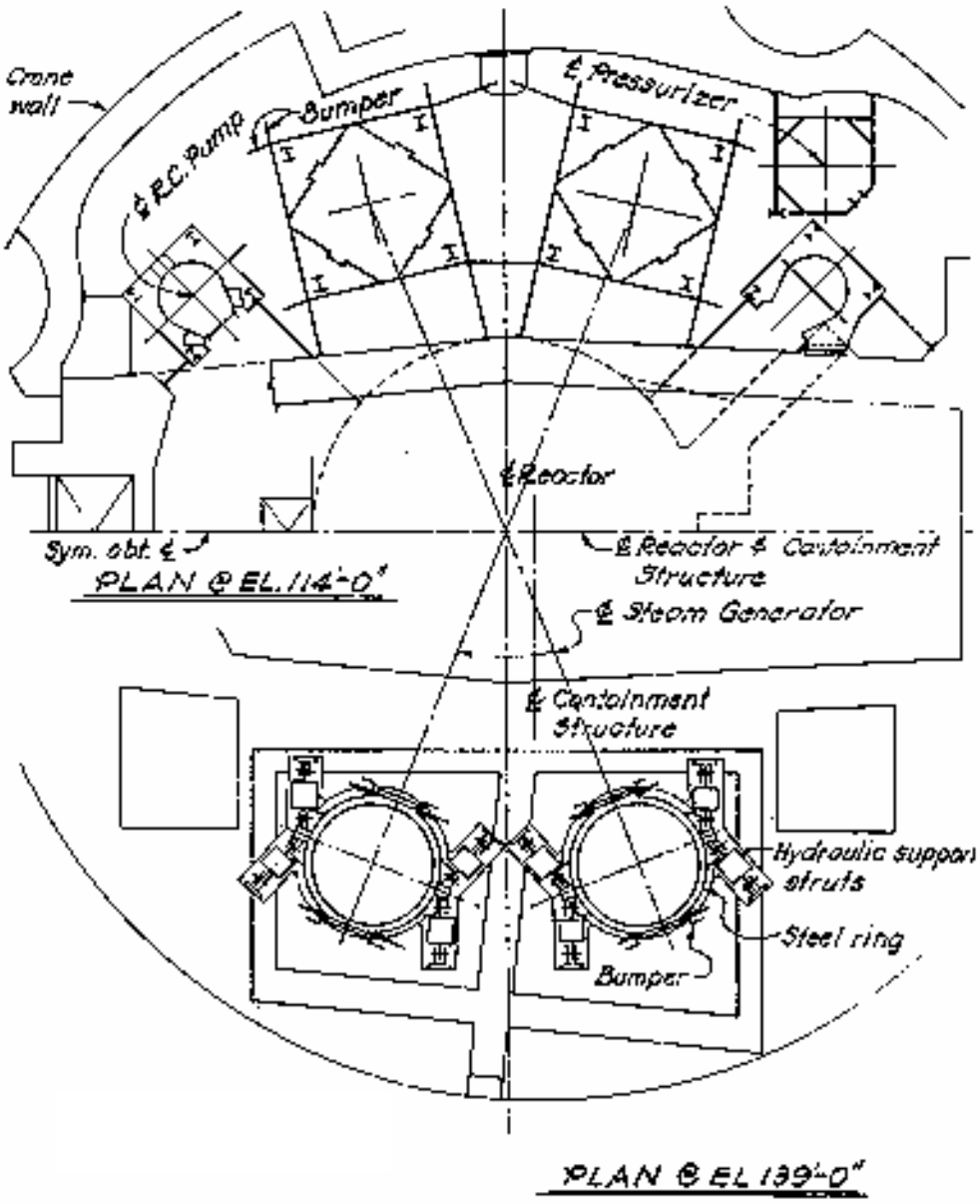
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.5-9 REACTOR SUPPORT

Revision 11 November 1996

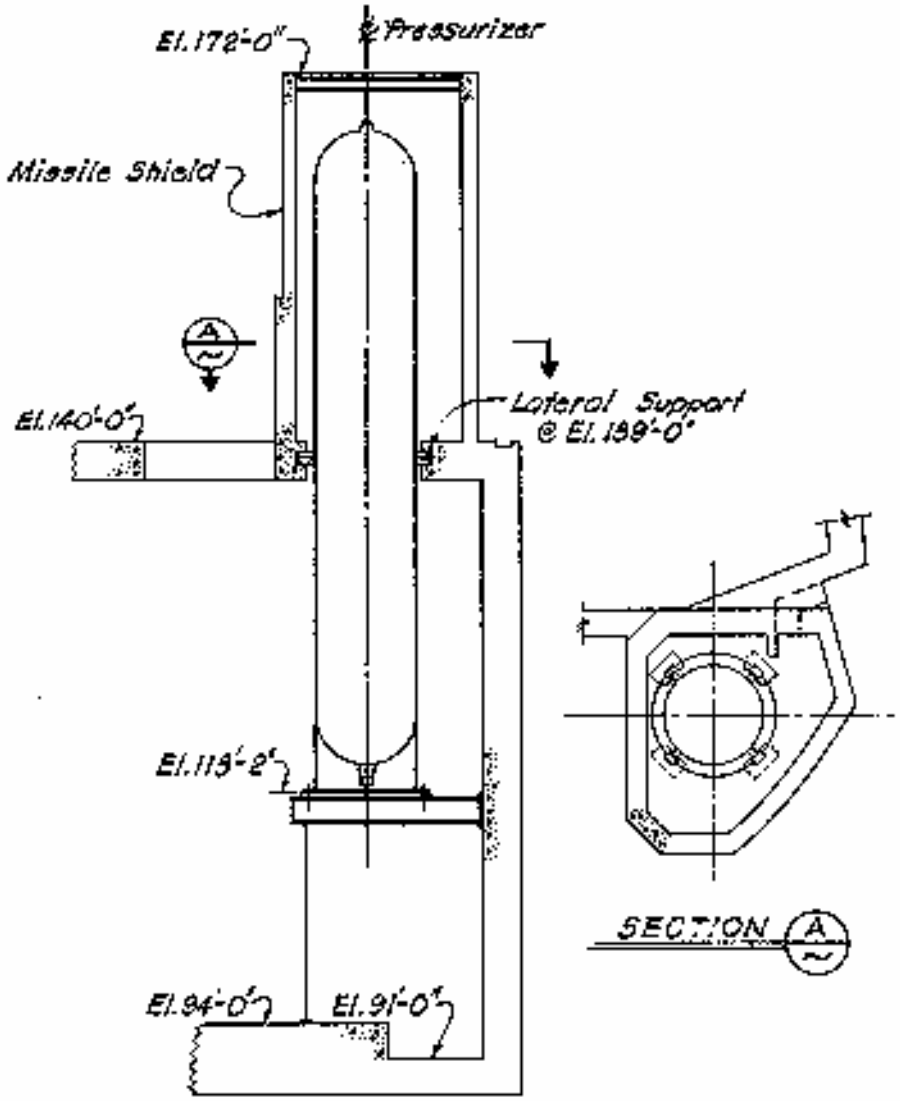


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.5-10 STEAM GENERATOR AND REACTOR COOLANT PUMP SUPPORTS

* Crossover pipe restraints Inactive.

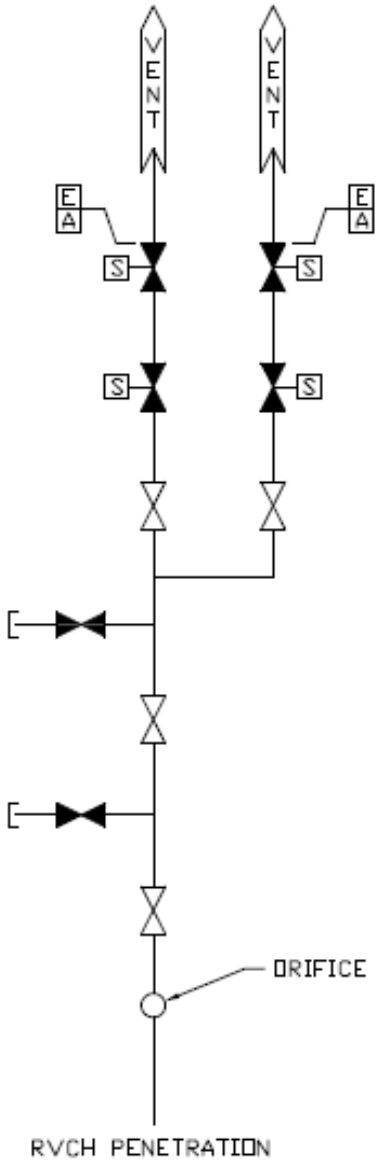


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.5-11 COMPONENT SUPPORTS



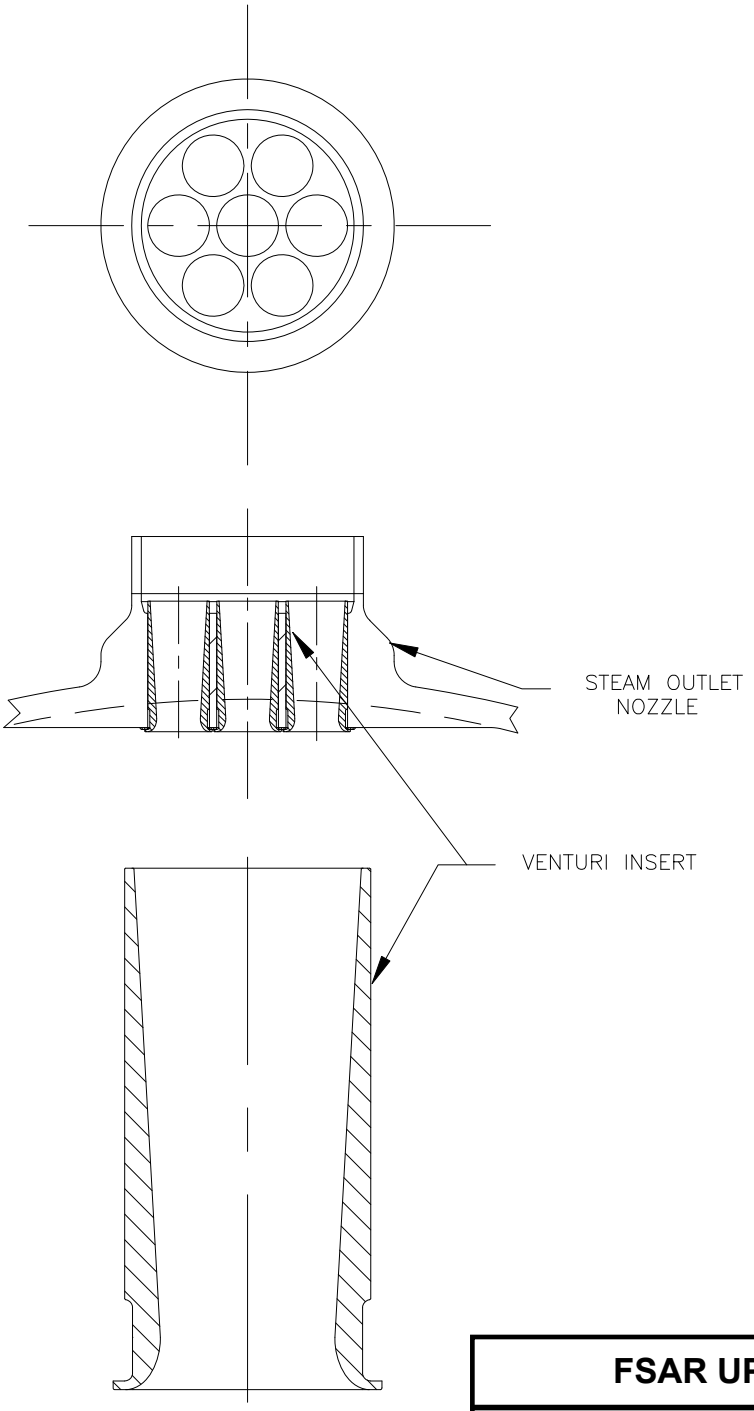
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.5-12 PRESSURIZER SUPPORT

Revision 11 November 1996



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 5.5-14 SCHEMATIC FLOW DIAGRAM OF THE REACTOR VESSEL HEAD VENT SYSTEM

Revision 20 November 2011



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 5.5-18
SEVEN NOZZLE RSG OUTLET FLOW RESTRICTOR

Chapter 6

ENGINEERED SAFETY FEATURES

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NOTE:

FIGURES (Continued)

Figure	Title

[a] This figure corresponds to a controlled engineering drawing that is incorporated by reference into the FSAR Update. See Table 1.6-1 for the correlation between the FSAR Update figure number and the corresponding controlled engineering drawing number.

Chapter 6

APPENDICES

Appendix	Title
6.2A	Deleted in Revision 18.
6.2B	Deleted in Revision 11.
6.2C	Deleted in Revision 19.
6.2D	REANALYSIS OF LONG-TERM LOSS-OF-COOLANT ACCIDENTS AND MAIN STEAMLINE BREAK EVENTS
6.3A	Deleted in Revision 22.

Chapter 6

ENGINEERED SAFETY FEATURES

6.1 GENERAL

6.1.1 INTRODUCTION

Engineered safety feature (ESF) systems are provided to reduce the safety and radiological consequences of possible Diablo Canyon Power Plant (DCPP) accidents. These systems cool the reactor core during a loss-of-coolant accident (LOCA) or main steam line break (MSLB), absorb energy released during accidents, contain solids, liquids, or gases released during accidents, and/or absorb radioactive materials that could otherwise be released from the plant buildings. These systems are standby systems, in that they are called upon to perform their ESF functions only in the event of unexpected severe plant accidents. They provide protection beyond the systems and plant design features that are primarily intended for the prevention of accidents.

The principles and guidelines used in the design, construction, and operation of the ESF systems described in Chapter 6 are specified in the individual sections of Chapter 6 and Table 6.1-1. Refer to Section 3.2 and Table 3.2-4 for a comparison of the Pacific Gas and Electric Company (PG&E) Quality/Code classes to the recommendations of ANSI Standard N18.2 1970, Draft.

The methods used to evaluate ESF performance are primarily contained in this chapter and Chapter 15.

The DCPP Technical Specifications (Reference 1) establish limiting conditions for maintenance of ESF components. Maintenance of a particular component is permitted if the remaining components meet the minimum requirements for operation and the following conditions are also met:

(1) The remaining equipment has been demonstrated to be in operable condition.

(2) A suitable limit is placed on the total time required to complete maintenance to return the component to an operable condition.

ESF systems meet redundancy requirements, thus maintenance of active components is possible during operation without impairment of the safety function. Routine servicing and maintenance of equipment of this type that is not required more frequently than on an outage basis would generally be scheduled for periods of refueling and maintenance outages. Any continued reactor operation during outages of individual ESF components will conform to reasonable, experienced judgment and industry practices, thus ensuring safe operation.

This chapter provides detailed descriptions of the DCPP ESFs and evaluates their performance under postulated accident conditions. Specifically, information is provided which shows that:

(1) The concept upon which the operation of each system is predicted has been proven sufficiently by experience, and/or by tests under simulated accident conditions, and/or by conservative extrapolations from present knowledge.

(2) The system will function during the period required and will accomplish its intended purpose.

(3) The system has been designed with adequate consideration of component and system reliability, component and system redundancy, and separation of components and portions of systems.

(4) Provisions have been made for periodic tests, inspections, and surveillance to ensure that the systems will be dependable and effective when called upon to function.

6.1.2 SUMMARY DESCRIPTION

The ESFs provided at DCPP are the following:

(1) *Containment Systems*

The steel-lined, reinforced concrete containment structure, including the concrete cylindrical wall, base, and dome, is designed to prevent significant release to the environs of radioactive materials that could be released into the containment as a result of accidents inside the containment (refer to Sections 6.2.1 and 6.2.4).

(2) *The Emergency Core Cooling System (ECCS)*

The ECCS provides water to cool the core in the event of an accidental loss of primary reactor coolant water. The ECCS also supplies dissolved boron into the cooling water to provide shutdown margin (refer to Section 6.3).

(3) *The Containment Spray System (CSS)*

The primary function of the CSS is to help limit the peak temperature and pressure in the containment in the event of a LOCA or MSLB (refer to Section 6.2.2). The CSS, in conjunction with the spray additive system (SAS), also helps to limit the offsite radiation levels following the postulated LOCA by removing airborne radioactive iodine and particulates

from the containment atmosphere during the injection and recirculation phases. The CSS function of mixing the containment atmosphere for hydrogen control is discussed below.

(4) *The Containment Fan Cooler System (CFCS)*

The CFCS functions in conjunction with the CSS to limit the temperature and pressure in the containment structure in the event of a LOCA or MSLB (refer to Section 6.2.2). The CFCS also provides mixing of the sprayed and unsprayed regions of the containment atmosphere to improve airborne fission product removal (refer to Section 6.2.3). The CFCS function of mixing the containment atmosphere for hydrogen control is discussed below.

(5) *The Spray Additive System*

The SAS functions by adding sodium hydroxide, an effective iodine scrubbing solution, to the CSS water to reduce the content of iodine and other fission products in the containment atmosphere and prevent the re-evolution of the iodine in the recirculated containment spray and core cooling solution following a LOCA (refer to Section 6.2.3).

(6) *Containment Combustible Gas Control*

The long-term buildup of gaseous hydrogen in the containment following a LOCA is primarily controlled by ensuring a mixed containment atmosphere and providing equipment for monitoring hydrogen concentrations. The CFCS and the CSS are the primary means credited for containment atmosphere mixing (refer to Section 6.2.5).

(7) *The Fuel Handling Building Ventilation System (FHBVS)*

The FHBVS provides the capability for significant reduction in the amounts of volatile radioactive materials that could be released to the atmosphere in the event of a major fuel handling accident (refer to Section 9.4.4).

(8) *The Auxiliary Building Ventilation System(ABVS)*

The ABVS provides the capability for significant reductions in the amounts of volatile radioactive materials that could be released to the atmosphere in the event of leakage from the residual heat removal (RHR) system recirculation loop following a LOCA (refer to Section 9.4.2).

(9) *The Control Room Ventilation System(CRVS)*

The CRVS permits continuous occupancy of the control room and technical support center (TSC) under design basis accidents (DBA) by

providing the capability to control infiltration of volatile radioactive material (refer to Sections 9.4.1 and 6.4.1).

(10) *The Auxiliary Feedwater (AFW) System*

The AFW system supplies water to the secondary side of the steam generators (SGs) for reactor decay heat removal, when the main feedwater system is unavailable (refer to Section 6.5).

Instrument air is used in most of the ESF systems. In some cases nitrogen is used. Bottled air or nitrogen is provided, as required, via the backup air/nitrogen supply system. ESF devices are designed to maintain a safe position or move to a safe position on loss of air or nitrogen pressure. Thus, the air and nitrogen systems are not needed to ensure device initial positioning or safe operation and are PG&E Design Class II. Detailed analyses of the compressed air and backup air/nitrogen supply systems, and their relation to PG&E Design Class I devices, are found in Section 9.3.1 (refer to Tables 3.9-9 and 6.2-39 for a listing of such devices).

All ESF remotely operated valves have position indication on the control board in two places. Red and green indicator lights are located next to the manual control station, showing open and closed valve positions. The ESF positions of these valves are displayed on the monitor light panels (four panels), which consist of an array of white lights.

Three of the light panels are de-energized during normal operation; applicable portions of these are energized concurrent with a Phase A containment isolation, a Phase B containment isolation, a safety injection signal (“S” signal), a containment ventilation isolation, a SG high-high level, a main steam isolation, or a feedwater isolation. The remaining panel is always energized. The design of these arrays is such that the white lights will be dark when the valves are in their normal or required positions for power operation, or their correct position after automatic actuation. These light panels can be tested during normal operation with switches on the control panel. These monitor lights thus enable the operator to quickly assess the status of the ESF systems. These indications are derived from contacts integral to the valve operators. In the case of the accumulator isolation valves, redundancy of position indication is provided by valve stem-mounted limit switches (the stem-mounted switches are independent of the limit switches in the motor operators), which actuate an annunciator on the control board when the valves are not correctly positioned. Refer to Section 7.6 for additional information.

Pump motor power feed breakers indicate that they have closed by energizing indicating lights on the control board in order to enable additional monitoring of in-containment conditions in the post-LOCA recovery period.

6.1.3 REFERENCES

1. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

6.2 CONTAINMENT SYSTEMS

Containment systems enclose the reactor and most plant systems and equipment that operate at high temperatures and pressures and may contain radioactive materials. This section describes and evaluates the design of the containment systems and confirms their capability to fulfill their intended objectives.

6.2.1 CONTAINMENT FUNCTIONAL DESIGN

The containment structure and subcompartments are designed to sustain the resulting pressures and temperatures from gross failure up to and including a LOCA. Long-term mass and energy (M&E) releases and containment integrity from a LOCA or MSLB are analyzed in Appendix 6.2D for the evaluation of the resulting peak containment pressure. Short-term M&E releases and subcompartment integrity analyses are addressed in the following sections.

6.2.1.1 Design Bases

6.2.1.1.1 General Design Criterion 4, 1987 – Environmental and Dynamic Effects Design Bases

Consideration of the dynamic effects associated with postulated reactor coolant system (RCS) primary loop pipe ruptures are excluded from the DCPP design basis with the approval of leak before break (LBB) methodology by demonstrating that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

6.2.1.1.2 General Design Criterion 10, 1967 – Containment

The containment is designed to sustain the initial effects of gross equipment failures, such as a LOCA, without loss of required integrity. The containment together with other ESFs, is designed to retain for as long as the situation requires the functional capability to protect the public.

6.2.1.1.3 General Design Criterion 40, 1967 – Missile Protection

The containment structure is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

6.2.1.1.4 General Design Criterion 49, 1967 – Containment Design Basis

The containment is designed to accommodate, without exceeding the design leakage rate, pressures and temperatures resulting from the largest credible energy release following a LOCA.

6.2.1.1.5 General Design Criterion 54, 1967 – Containment Leakage Rate Testing

The containment is designed with the capability for integrated leakage rate testing to be conducted at design pressure after installation of all penetrations and the leakage rate measured over a sufficient period of time to verify its conformance with required performance.

6.2.1.1.6 General Design Criterion 55, 1967 – Containment Periodic Leakage Rate Testing

The containment is designed so that integrated leakage rate testing can be done at the design pressure periodically during the plant's lifetime.

6.2.1.1.7 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The containment is designed as a barrier to maintain control over plant radioactive effluents, whether gaseous, liquid, or solid meeting the radiological limits of 10 CFR Part 50.67. Appropriate holdup capacity is provided for retention of gaseous effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment.

6.2.1.1.8 10 CFR Part 50 Appendix J, Option B – Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors

The containment is designed to allow for conductance of a performance-based containment leakage rate testing program for Type A containment integrated leak rate tests (ILRT) and Type B testing for the air lock door seals.

6.2.1.1.9 10 CFR Part 50 Appendix K, Part I.A – Emergency Core Cooling System Evaluation Models, Sources of Heat during the Loss-of-Coolant Accident

The containment is designed to accommodate the largest credible energy release following a postulated pipe break taking into account the heat sources listed in Paragraph I.A of 10 CFR Part 50, Appendix K.

6.2.1.1.10 Regulatory Guide 1.163, September 1995 – Performance-Based Containment Leak-Test Program

The containment is designed to allow the use of a performance-based leak-test program, including the leakage-rate test methods, procedures, and analyses as required by Regulatory Guide 1.163, September 1995.

6.2.1.2 Containment Subcompartment Analysis

Short-term M&E release calculations from primary (LOCAs) and secondary side (non-LOCAs) piping are performed to support pressurization analyses for subcompartments inside the containment including the reactor cavity region, the loop compartments, the pressurizer enclosure and the SG enclosure. These analyses are performed to ensure that the structural elements in the immediate proximity of the break location can maintain their structural integrity during the short pressure pulse (generally less than 3 seconds) that accompanies a high-energy pipe break within the region.

There are two reasons for the specified duration. The first is that the initial pulse that occurs upon the opening of the break is typically the most limiting for a subcompartment. The second is that the global containment pressure will approach an individual subcompartment pressure rather quickly and the goal of the subcompartment analysis is to determine the peak differential pressure across walls, supports, components, and structures. When components are being considered, the peak differential pressure is commonly used to determine an asymmetric load. The peak differential pressure can often occur within milliseconds of the break opening time.

The double-ended guillotine and split breaks that have been postulated in primary coolant loop piping in the loop compartments, the reactor cavity region, the reactor vessel annulus, the pipe annulus, and for the SG analysis and that are currently presented in Reference 75 are no longer necessary for Diablo Canyon Unit 1 and Unit 2 due to the approval (Reference 74) and subsequent application of LBB analysis and monitoring. The only break that remains from the original design basis subcompartment analyses is the double-ended spray line break inside the pressurizer enclosure. Therefore, the short-term M&E scope only includes generating LOCA M&E releases for large branch line breaks (refer to Section 6.2.1.2.1) and non-LOCA M&E releases for double-ended breaks of the secondary side (refer to Section 6.2.1.2.3).

6.2.1.2.1 Short-Term Loss-of-Coolant Accident Mass and Energy Releases

A RCS model that bounds both Diablo Canyon Unit 1 and Unit 2 was developed. All M&E releases were generated with the SATAN-V code (Reference 59) that has been approved for use in generating short-term LOCA M&E releases.

The piping analysis for the large branch lines was used to determine the break locations that required analysis as part of the subcompartment response. All breaks were conservatively analyzed as full double-ended guillotine breaks. The short-term LOCA M&E releases are calculated with the SATAN-V computer program documented in Reference 59.

6.2.1.2.1.1 Input Parameters and Assumptions

The release of M&E created by a postulated break in the RCS piping are principally a function of the calculated break area, system pressure, and RCS fluid density, which is

a function of the operating conditions of temperature and pressure. The LOCA short-term M&E are relatively insensitive to initial RCS conditions of flow and power except as they relate to coolant density, where higher coolant density and system pressure lead to increased LOCA M&E releases. Lower flow rates and higher power lead to lower cold leg temperatures (and higher coolant density) for the same average coolant temperature. Therefore, the limiting LOCA M&E are calculated for conditions consistent with a minimum thermal design flow at normal operating conditions at full power. RCS temperatures are nominal values reduced by the known instrument uncertainty in order to assure the lowest operating temperatures.

To conservatively calculate LOCA short-term M&E for Diablo Canyon Unit 1 and Unit 2, the following operating conditions were considered in establishing the limiting temperature and pressures:

<u>Unit 1 and Unit 2 Bounding Conditions</u>

1. Initial RCS conditions associated with a minimum thermal design flow of 87,700 gpm per loop.
2. Reactor core power of 3411 MWt.
3. A nominal RCS hot full power vessel T_{AVG} of 565.0°F. This provides lowest possible RCS T_{COLD} of 531.7°F and T_{HOT} of 598.1°F minus a temperature uncertainty of 4.3°F.
4. A nominal RCS pressure of 2250 psia plus a pressure uncertainty of 42 psia.

Thus, the LOCA M&E releases were generated with a minimum T_{COLD} of 527.4°F, a minimum T_{HOT} of 593.8°F, and a pressurizer pressure of 2292 psia, including uncertainties, in order to bound the operation of both Unit 1 and Unit 2.

6.2.1.2.1.2 Description of Analyses and Evaluations

The M&E releases from the postulated break must be determined prior to evaluating the containment subcompartment responses. The SATAN-V computer code is used to calculate short-term blowdown transients. This code uses a control volume approach to model the behavior of the piping system, includes critical flow calculation and applies an implicit representation of the depressurization. Due to the short-term length of the transient, the break flow remains subcooled throughout the 3 second transient and thus only the Zaloudek correlation is relied upon in the calculation. The LOCA short-term M&E for Diablo Canyon's Unit 1 and Unit 2 used the code and methodology described in Reference 59 and the operating parameters described above. The large branch lines that are considered are:

a. Pressurizer Surge Line
b. Pressurizer Spray Line
c. RHR Suction Line
d. Accumulator Lines

Furthermore, some of these pipes can be postulated to break in more than one location. Therefore, the locations that are considered are:

1. Pressurizer Surge Line Break at the Hot Leg Connection
2. Pressurizer Surge Line Break at the Pressurizer Nozzle
3. Pressurizer Spray Line Break at the Top of the Pressurizer
4. Pressurizer Spray Line Break at the RCS Cold Leg Connection
5. RHR Suction Line Break at the Hot Leg Nozzle
6. Accumulator Line Break at the RCS Cold Leg Connection
7. Accumulator Line Break at the Tank

Tables 6.2-57 through 6.2-60 document the time histories of the limiting LOCA short-term M&E releases.

Discussion of Breaks Analyzed

Pressurizer Surge Line Break at the Hot Leg Connection

The Unit 1 pressurizer surge line is 14 inch outside diameter (OD), Schedule 140, and the Unit 2 surge line is 14 inch OD, Schedule 160. The pipe schedule for the Unit 1 surge line produces a larger break area for the same nominal pipe size and thus a larger M&E release for Unit 1. Therefore, the Unit 1 configuration is bounding and is used in the analysis. The pressurizer surge line break is the largest break to be analyzed among the breaks that could occur when LBB analysis and monitoring is applied to the primary loop piping and thus is expected to generate the largest differential pressures in the loop compartment, across the primary shield wall, and across the crane wall. The pressurization resulting from this break could be used to determine asymmetric loads on components within this region. This break is modeled as a hole in the RCS hot leg on one side and the surge line piping on the opposite side that is connected to the pressurizer tank. The volume and hydraulic resistance of the surge line are modeled. Table 6.2-57 provides the LOCA M&E used in the subcompartment pressurization analysis.

Pressurizer Surge Line Break at the Pressurizer Nozzle

This break is at the bottom of the pressurizer tank at an approximate elevation of 113 feet. This elevation puts this break in the lower region of the containment very near the elevation for the surge line connection at the RCS hot leg and thus would affect the same structures and components. This break differs from surge line break at the RCS hot leg in the placement of the surge line volume and in piping hydraulic resistance. In the pressurizer surge line break at the pressurizer tank, the surge line remains attached to the RCS hot leg and provides an increased resistance to break flow from the RCS. Thus, the M&E release is reduced compared to a surge line break at the RCS hot leg connection and, therefore, is not limiting.

Pressurizer Spray Line Break at the Top of the Pressurizer

The pressurizer spray line is inside the pressurizer enclosure and a break in the pressurizer spray line will result in pressurizing the enclosure. Thus, this case is analyzed to assure that the enclosure design limit is not exceeded. These results may also be incorporated in the determination of the asymmetric loads on the pressurizer. The spray lines in both Diablo Canyon Unit 1 and Unit 2 are made of 4 inch Schedule 120 piping. The spray line break at the top of the pressurizer has less M&E release than a spray line break at the RCS cold leg. This is due to having steam at the top of the pressurizer and the flow resistance of the portion of piping still attached to the cold leg that limits the M&E release rate. However, due to the small volume at the top of the pressurizer enclosure, to accommodate the spray line break release, this analysis is deemed necessary to assure the design criteria are met. Table 6.2-58 provides the LOCA M&E used in the pressurizer enclosure subcompartment analysis.

Pressurizer Spray Line Break at the RCS Cold Leg Connection

This break is located below the pressurizer enclosure at the RCS cold leg elevation and thus has a negligible effect in pressurization of the pressurizer enclosure. The spray line piping at this elevation is 4 inch Schedule 120 and the break is modeled as having occurred at the cold leg connection. Thus, one side of the break is modeled as a hole with a diameter equal to 4 inch Schedule 120 pipe at the RCS cold leg and the other side is the pressurizer spray line attached to the pressurizer. This break occurs in the same compartment as the much larger surge line break, and is therefore bounded by the surge line M&E release.

RHR Suction Line Break at the RCS Hot Leg Connection

This is the line used to cool the RCS continually starting from mode 4 (T < 350°F) until the RCS temperature is again returned to above 350°F, usually during a shut down or refueling. The RHR suction piping is 14 inch Schedule 160 pipe which is valved-out during power operation. Thus, the break is modeled as a single-ended break at the RCS hot leg. The M&E release from the isolated RHR high pressure piping up to the isolation valve is calculated as a steady release rate based on the break flow correlation using the initial pressure and temperature as the input condition. The volume of piping between the RCS hot leg connection and the RHR suction isolation valve is less than 10 ft^3. The blowdown of this portion of the piping section would occur in less than 0.05 seconds. Table 6.2-59 provides the LOCA M&E used in the subcompartment pressurization analysis.

Accumulator Line Break at the RCS Cold Leg Connection

This break is located between the accumulator injection line check valve (CV) closest to the RCS and the RCS cold leg connection. Thus, both the accumulator tank and the RCS blow down through the double-ended break. The accumulator lines at the cold leg connection are 10 inch Schedule 140 piping and thus the break size is based on this

piping diameter and schedule. The choice of accumulator injection lines among the four accumulators does not affect the results. The transient is limited to 3 seconds in duration and the injection line and the RCS cold leg do not experience flashing and thus the break flow remains subcooled liquid. Flashing does not occur internal to the piping since the pressure remains above the saturation pressure for the 3 second period. Since the flow is always critically limited, the small differences in accumulator injection line piping lengths and hydraulic resistances do not affect the results. Table 6.2-60 presents the LOCA M&E used in the subcompartment pressurization analysis.

Accumulator Nozzle Break at the Tank

Separate LOCA M&E releases were not generated for a break at the accumulator tank nozzle since this would result in a blowdown of only the accumulator tank. The RCS side of the accumulator line at this connection is protected from blowing down by two CVs in series. However, for the purposes of subcompartment pressurization response, the LOCA M&E at these locations were conservatively analyzed with the same LOCA M&E at the RCS cold leg connection. Subcompartment pressures were computed for these break cases.

6.2.1.2.1.3 Loss-of-Coolant Accident Mass and Energy Releases Conclusion

LBB analysis and monitoring as applied to the primary loop piping at Diablo Canyon Unit 1 and Unit 2 has been used to eliminate primary loop piping, leaving select primary side branch line breaks as limiting pipe break events. Branch lines analyzed were the pressurizer surge line at two locations, pressurizer spray line at two locations, RHR suction line and the most limiting of the four accumulator injection lines. The location of the break within any analyzed piping run was chosen to maximize the release of M&E. Consideration was given to the location of CVs, isolation valves, hydraulic resistance, or other restrictions to the release of M&E in selecting the most conservative break locations. The limiting M&E releases resulting from these analyses are provided in Tables 6.2-57 through 6.2-60 and are used in the analysis of the post-LOCA pressurization of the containment subcompartments.

6.2.1.2.2 Loss-of-Coolant Accident Subcompartment Pressurization

A conservative representation of the Diablo Canyon Unit 1 and Unit 2 containment was nodalized in order to determine the pressurization in certain regions that would result from a localized pipe rupture. A plant specific model with 38 nodes was created that bounds both units. Table 6.2-61 summarizes the nodalization based on subcompartment boundaries within the containment. Structural elements (walls, ceilings, and floors) and components were used to define the boundaries for the subcompartments. Table 6.2-62 provides conservative minimum volumes for each of the 38 nodes in the network. Table 6.2-63 provides individual flow path characteristics for the nodal network that conservatively minimizes the flow from the upstream node to the downstream node. The minimum volume of each node, combined with the flow path characteristics that minimize communication between the nodes, create a

subcompartment network that will conservatively maximize the differential pressure between the nodes. The spatial presentation of the 38 nodes by elevation is provided in Figures 6.2-53 through Figure 6.2-62. The Transient Mass Distribution (TMD) (Reference 60) nodal flow path connections are shown schematically in Figures 6.2-63 through 6.2-65.

The LOCA subcompartment analysis described below and in Sections 6.2.1.2.2.1 through 6.2.1.2.2.3 was performed to determine subcompartment pressures and resulting differential pressures on various structural elements within containment.

During the early stages of a LOCA, pressure differentials may be briefly established in the containment. While the geometry of the containment, except for the net free volume, has no direct effect upon the containment peak pressure, indirect considerations such as the design of structural supports of ESF equipment and the prevention of missile generation make it desirable to calculate the differential pressure transients caused by different breaks.

Application of LBB has determined that breaks in the RCS branch lines must still be considered for the design of containment structural elements. RCS branch lines that are postulated to break resulting in a LOCA are 1) the pressurizer surge line, 2) the pressurizer spray line, 3) the RHR suction line, and 4) the accumulator injection lines. There are other smaller branch lines connected to the RCS that could result in a LOCA but these smaller branch lines are bounded by consideration of the four branch lines identified above. There are various locations within containment that need to be considered for these breaks. For instance, the pressurizer surge line can break at the connection to the RCS hot leg or at the bottom of the pressurizer tank. Therefore, both locations are considered. In addition, due to the application of LBB, the double-ended ruptures of secondary side piping could become limiting and also need to be considered.

The compartment responses with the 38 node model to the M&E releases from the four branch lines above were analyzed using the TMD (Reference 60) computer code with an unaugmented homogeneous critical mass flowrate correlation. The analyses using the TMD code (Reference 60), with the compressibility factor and non-augmented critical flow correlation, were performed to determine the response of the postulated ruptures. The nodalization sensitivity study indicates that the model selected is adequate to determine the asymmetrical pressurization forces that may act upon a vessel. The U.S. Nuclear Regulatory Commission (NRC) evaluated the TMD code (Reference 60) and found the methods acceptable provided that non-augmented critical flow relationships are used rather than augmented.

The TMD mathematical model used to calculate the flows and pressures throughout the containment is based upon time-dependent equations of conservation of mass, conservation of energy, conservation of momentum, and state. Flow inertia effects between the volumes are also calculated. The model calculates critical flow conditions for application under high-pressure differentials. A 100 percent entrainment of the water

emerging from the break is assumed. Subcompartment vent discharge flows are considered as unrecoverable pressure losses and, consequently, vent discharge coefficients are not used. A vent discharge coefficient of unity is conservatively assumed when vent flow is critical.

Calculated values of peak differential pressure and the absolute pressure at the time of peak differential pressure are tabulated in Table 6.2-64 for compartments within the containment.

6.2.1.2.2.1 Loop Compartment Analysis

The loop compartment is the region outside the reactor cavity wall but inside the crane wall from elevation 91 feet up to elevation 140 feet. This region is defined by 6 nodes with boundaries that bisect each of the four SGs as seen in Figures 6.2-53 through 6.2-55.

If a postulated LOCA occurs in the loop compartment region, the steam mass that enters this space must be vented to the rest of the containment. The flowpaths potentially available for such venting are through the operating deck at elevation 140 feet, through the crane wall, and into the reactor vessel annulus, as well as to the adjacent loop compartments. The first of these routes permits steam, air, and water to directly enter the upper dome of containment, the second grants access to the annular spaces between the crane wall and the containment shell, and the third allows entry to the space surrounding the reactor vessel. The M&E release rates used in the analysis are given, as a function of time after the postulated break (refer to Section 6.2.1.2.1.2).

The limiting break in the loop compartments is a break of the pressurizer surge line at the hot leg connection (refer to Figures 6.2-72, 6.2-66 and 6.2-74). Additional breaks analyzed, but not limiting for the loop compartments, are a break in the accumulator injection line (refer to Figure 6.2-69) at the RCS cold leg connection and a break in the RHR suction line at the RCS hot leg (refer to Figure 6.2-67).

The limiting pressure differential acting across the crane wall occurred for a break in the pressurizer surge line located in TMD node 3. The limiting pressure differential acting across the 140-foot elevation operating deck and the loop compartment floor above the lower reactor cavity also occurred due to a break in the pressurizer surge line in TMD node 3. The peak differential pressures, with the absolute pressures at the time of peak differential pressure, are included in Table 6.2-64.

As shown in Table 6.2-64, the peak differential pressure calculated for each structural element (defining the bounds of the subcompartments) in the loop compartment region is less than the design value.

6.2.1.2.2.2 Pressurizer Enclosure Analysis

The pressurizer enclosure is shown in Figures 6.2-56 through 6.2-59. The enclosure begins at the 140-foot elevation and extends upward to elevation 176 feet.

The analysis assumed a double-ended rupture of the pressurizer spray line, since this would result in the maximum differential pressure across the pressurizer enclosure walls. In the event of such a rupture, fluid from the break would be vented to both the containment dome and the loop compartment regions. The M&E release rates used in the analysis are given, as a function of time after the postulated break (refer to Section 6.2.1.2.1.2).

The limiting break for the pressurizer enclosure is a break in the pressurizer spray line at the top of the pressurizer in TMD node 38 (refer to Figure 6.2-68). The peak differential pressure, with the absolute pressure at the time of peak differential pressure, is included in Table 6.2-64.

As shown in Table 6.2-64, the peak differential pressure calculated with the TMD code for the pressurizer enclosure is less than the design value.

6.2.1.2.2.3 Reactor Cavity Analysis

The reactor cavity region is represented by three nodes in the subcompartment model (refer to Figures 6.2-53 and 6.2-54), with two nodes surrounding the cylindrical portion of the reactor vessel and one node in the lower reactor cavity below the reactor vessel. The reactor cavity region is defined from elevation 61.5 feet up to approximately elevation 114 feet.

The bounding break for the reactor cavity analysis assumes a break of the pressurizer surge line at the hot leg connection (refer to Figure 6.2-73). This break will pressurize the loop compartment region of containment and steam will flow into the reactor cavity through the area around the hot leg and cold leg nozzles where the loop piping penetrates the primary shield wall. The M&E release rates used in the analysis are given as a function of time after the postulated break (refer to Section 6.2.1.2.1.2).

The peak differential pressure across the primary shield wall occurred for the above break in TMD node 3. The peak differential pressures, with the absolute pressures at the time of peak differential pressure, are included in Table 6.2-64.
As shown in Table 6.2-64, the peak differential pressure calculated with the TMD code for the primary shield wall is less than the design value.

6.2.1.2.2.4 Loss-of-Coolant Accident Subcompartment Pressurization Conclusions

The LOCA breaks were reviewed and selections were made to analyze the most limiting break locations. The most limiting break location for the LOCA analysis is a break in the

pressurizer surge line at the RCS hot leg connection, which yielded a result of 5.90 psi pressure differential between a loop compartment and the annulus region between nodes 3 and 12. Table 6.2-64 provides a summary of the peak differential pressure results for the LOCA transients.

6.2.1.2.3 Short-Term Non-Loss-of-Coolant Accident Mass and Energy Releases

High-energy lines inside containment include not only primary-side piping but also secondary-side main steam lines and main feedwater lines. Postulated breaks in these secondary-side lines are commonly referred to as non-LOCA breaks. The short-term M&E releases from these non-LOCA breaks are included in the containment subcompartment pressurization analyses, which are performed to ensure that the structural elements can maintain their structural integrity (refer to Section 6.2.1.2).

6.2.1.2.3.1 Input Parameters

To conservatively calculate the non-LOCA short-term M&E release rates for Diablo Canyon Unit 1 and Unit 2, the following data was considered in establishing the limiting M&E releases.

<u>Unit 1 and Unit 2 Bounding Conditions</u>

- Initial RCS temperature of 547°F (no-load)
- Steam pressure of 1020 psia at no-load saturated temperature conditions
- Maximum main feedwater temperature of 435.0°F

6.2.1.2.3.2 Description of Analyses and Evaluations

The non-LOCA short-term M&E releases from the postulated secondary-side breaks must be determined prior to evaluating the containment subcompartment response. The Moody critical flow correlation is used to determine short-term blowdown M&E releases using the calculation technique documented in Appendix E of ANSI/ANS 58.2-1980 (Reference 76). With no consideration for steam line and feedwater line isolation due to the short duration of the M&E releases, the break flowrates from the forward and reverse directions are determined. The break flows are held constant with a step change in flow when a segment of piping is determined to have been emptied.

Calculations of the non-LOCA short-term M&E releases do not credit protection system actuations or details such as system depressurization. All non-LOCA short-term M&E releases are generated using the Moody critical mass flux correlation (Reference 77). Therefore, the M&E releases represent a conservative upper-bound value for use in short-term pressurization calculations.

Breaks analyzed were full double-ended guillotine breaks of the main steam line at the outlet nozzle of the SG, the main steam line at the containment penetration, the main

feedwater line connection at the inlet to the SG, and the main feedwater line at the containment penetration. Breaks postulated in these pipes bound other secondary-side breaks because of the break area and the system pressure.

Discussion of Breaks Analyzed

MSLB Inside the SG Enclosure

This break is modeled at the outlet nozzle of the SG assuming no-load power conditions to maximize the pressure in the main steam system. The total break area for a double-ended steam line break is not equal to a double-ended severance of the main steam line because one end of the break is limited via the integral flow restrictor in the discharge nozzle of the faulted SG.

This break releases directly into the upper dome of containment, which causes negligible differential pressures, and is bounded by other break cases.

Main Feedwater Line Break Inside the SG Enclosure

This break is modeled at the inlet to the SG assuming no-load power conditions in the SG to maximize the pressure in the SG; and assuming full-power conditions in the main feedwater system to maximize the enthalpy of the feedwater fluid. The main feedwater temperature is assumed at the high end of the full-power feedwater temperature window to maximize the saturation pressure in the main feedwater system. The break area for a double-ended main feedwater line break is equal to a double-ended severance of the main feedwater line.

The main feedwater line break short-term M&E release data is presented in Table 6.2-66 and was used in the subcompartment pressurization analysis.

MSLB Outside the Crane Wall

This break is modeled at the containment penetration assuming no-load power conditions to maximize the pressure in the main steam system. The initial break area for a double-ended MSLB is equal to a double-ended severance of the main steam line since the break location is downstream of the discharge nozzle of the SG. Following the initial blowdown of the piping between the break location and the SG, the break is limited via the integral flow restrictor at the discharge nozzle of the faulted SG. Since this break location is a significant distance from the faulted SG, the timing of the release rates considers the length of main steam line piping between the break and the SG.

The MSLB short-term M&E release data is presented in Table 6.2-65 and was used in the subcompartment pressurization analysis.

Main Feedwater Line Break Outside the Crane Wall

This break is modeled at the containment penetration assuming no-load power conditions in the SG to maximize the pressure in the SG; and assuming full-power conditions in the main feedwater system to maximize the enthalpy of the feedwater fluid. The main feedwater temperature is assumed at the high end of the full-power feedwater temperature window to maximize the saturation pressure in the main feedwater system. The break area for a double-ended main feedwater line break is equal to a double-ended severance of the main feedwater line. Since the break location is a significant distance from the faulted SG, the timing of the release rates considers the length of feedwater line piping between the break and the SG.

This postulated break is situated next to the MSLB outside the crane wall. The MSLB produces a larger M&E release. Therefore, the main feedwater line break is bounded by the MSLB at this location.

6.2.1.2.3.3 Non-Loss-of-Coolant Accident Mass and Energy Releases Conclusion

The secondary-side breaks analyzed are the double-ended guillotine break of the main steam line and the double-ended guillotine break of the main feedwater line at the SG inside the SG enclosure and at the containment penetration outside the crane wall. Consideration was given to the location of check valves in the main feedwater system to determine the piping volume that would be involved with a particular break location. The M&E releases that are generated for these break locations are provided in Tables 6.2-65 and 6.2-66 and are used in the analysis of the subcompartment pressurization.

6.2.1.2.4 Non-Loss-of-Coolant Accident Subcompartment Pressurization

The following containment subcompartments were analyzed for the non-LOCA breaks. The non-LOCA breaks were analyzed using the TMD (Reference 60) computer code. The noding displayed in Figures 6.2-53 through 6.2-62 provide the noding of the containment subcompartments and are referenced for identification of the break location.

MSLB Inside the SG Enclosure

This break is at the top of the SG (steam outlet nozzle, refer to Figure 6.2-53). The M&E releases enter the upper part of the containment dome (node 7) and would not be expected to result in a very significant pressurization or differential pressure that would provide a load on a wall, component, or support. The maximum differential pressure for a double-ended MSLB in node 7 is 0.52 psi occurring at 0.302 second (3/10th of a second). This break is bounded by the main feedwater line break inside the SG enclosure.

Main Feedwater Line Break Inside the SG Enclosure

This break at the side of the SG (node 36) is at the main feedwater nozzle (refer to Figures 6.2-53, 6.2-60, 6.2-62, and 6.2-65). The M&E releases enter this small volume and result in a pressurization or differential pressure that would provide a load on the SG shield wall, and the SG enclosure walls. The M&E release rates used in the analysis are given as a function of time after the postulated break (refer to Section 6.2.1.2.3).

The peak differential pressure for a double-ended main feedwater line break occurs in node 36 (refer to Figure 6.2-70). The peak differential pressure with the absolute pressure at the time of peak differential pressure is included in Table 6.2-67.

As shown in Table 6.2-67, the peak differential pressure calculated with the TMD code for the SG shield wall is less than the design value.

MSLB Outside the Crane Wall

This break in the main steam line is at the containment penetration (refer to Figures 6.2-53 and 6.2-55). The M&E releases enter the annulus region between the containment shell and the crane wall. The resulting pressurization would produce an inward localized load on the crane wall or an outward localized load on the containment shell. The M&E release rates used in the analysis are given as a function of time after the postulated break (refer to Section 6.2.1.2.3).

The peak differential pressure for a double-ended MSLB occurs in node10 (refer to Figure 6.2-71). The peak differential pressure with the absolute pressure at the time of peak differential pressure is included in Table 6.2-67.

As shown in Table 6.2-67, the peak differential pressure calculated with the TMD code for the crane wall is less than the design value.

Main Feedwater Line Break Outside the Crane Wall

This break in the main feedwater line is at the containment penetration (refer to Figures 6.2-53 and 6.2-55). The M&E releases enter the annulus region between the containment shell and the crane wall. The resulting pressurization would produce an inward localized load on the crane wall or an outward localized load on the containment shell. The maximum differential pressure for a double-ended main feedwater line break in node 10 is 2.33 psi occurring at 0.033 second (1/30th of a second). This break is bounded by the MSLB outside the crane wall.

6.2.1.2.4.1 Non-Loss-of-Coolant Accident Subcompartment Pressurization Conclusions

The non-LOCA breaks were reviewed and selections were made to analyze the limiting MSLB and main feedwater line break locations. The most limiting non-LOCA break is a main feedwater line break at the inlet connection to the side of the SG in a localized space defined as node 36. The maximum differential pressure between the break node and the surrounding nodes in the containment model is 19.54 psi occurring instantaneously with the initiation of the break. Table 6.2-67 provides a summary of the peak differential pressure results for the non-LOCA transients.

6.2.1.2.5 Asymmetric Subcompartment Pressurization Loads

Asymmetric subcompartment pressurization loads, were developed for the RCL piping system analysis. LOCA and non-LOCA postulated breaks were reviewed and selections were made to analyze the most limiting break locations as described in Sections 6.2.1.2, 6.2.1.2.2, and 6.2.1.2.4.

LOCA and non-LOCA postulated pipe breaks include breaks in the pressurizer surge, pressurizer spray, RHR suction, accumulator injection, main steam and main feedwater lines. For each line, breaks were postulated at various locations resulting in multiple break cases.

From these localized pipe breaks, time-history pressures were developed and maximum differential pressures were established for the different subcompartments within containment. These pressure differentials will potentially cause asymmetric pressure loads across the components or structures contained in between the compartments.

The force acting on a component from the asymmetric pressure can be calculated as the pressure differential multiplied by the equivalent area of the component.

Numerous break cases were evaluated to determine the various pressure differentials across compartments. In order to develop a limiting time-history pressure differential function; typically, time-history pressure differentials were enveloped creating a composite time-history pressure differential function for the different breaks. These composite functions were used in the dynamic asymmetric pressurization analyses.

<u>RCL Piping System</u>

The RCL piping, reactor coolant pump, and lower portions of the SG and pressurizer components are all contained within the lower containment compartments, nodes 1 through 6 (refer to Figures 6.2-53 and 6.2-54).

For the most limiting breaks in the lower containment compartments, the maximum pressure differentials were enveloped for the pressurizer surge, RHR suction, and accumulator injection break cases.

Reactor Pressure Vessel (RPV)

The RPV is contained within nodes 31, 32, and 33 (refer to Figure 6.2-53).

For the most limiting breaks outside the reactor cavity region, the maximum pressure differentials in the horizontal (nodes 31-32) direction and in the vertical direction (nodes 33-7) were enveloped for the pressurizer surge, RHR suction, and accumulator injection break cases.

SG

The lower portions of the SG are contained within the lower containment compartment nodes 1 through 6 (refer to Figures 6.2-53 and 6.2-54) The upper portions of the SG are contained within nodes 34, 35, 36, 37, and 7 (refer to Figures 6.2-53, 6.2-56, and 6.2-60 through 6.2-62).

The feedwater nozzle break at the SG results in larger horizontal asymmetric pressurization loads than the other postulated breaks. The development of time-history forcing functions, including the locations and directions of those forcing functions were developed to represent the asymmetric pressurization load and applied in the feedwater line pipe break analysis.

To evaluate the vertical asymmetric pressurization effect on the SG, the maximum differential pressures between the lower containment compartment nodes (nodes 1 through 6) were compared with the upper containment compartment node (node 7) for the pressurizer surge, RHR suction, and the accumulator injection break cases.

The most limiting break cases for the pressurizer surge, RHR suction, and accumulator injection breaks occurring in the lower containment region were used to determine the asymmetric pressurization effects on the upper portion of the SG, with the exception for the feedwater break case, which was evaluated in a separate analysis for evaluating the feedwater break as described above.

Pressurizer

The pressurizer is contained within the lower containment compartment, node 3 (refer to Figures 6.2-53 and 6.2-54), and the pressurizer compartment, nodes 19 through 30 and node 38 (refer to Figures 6.2-56 through 6.2-59).

To evaluate the vertical asymmetric pressurization effect on the pressurizer, the maximum differential pressure between the lower containment compartment, node 3, was compared with the pressurizer upper compartment, node 38. The vertical upward asymmetric force on the pressurizer was determined from the maximum pressure

differential from a surge line break. The vertical downward asymmetric force on the pressurizer was determined from the maximum pressure differential from a spray line break.

To evaluate the horizontal asymmetric pressurization effect on the pressurizer, horizontal forces were developed for breaks in the pressurizer surge and spray lines.

The horizontal and vertical forces are applied to the pressurizer analysis to represent the asymmetric pressurization effects.

Dynamic Asymmetric Pressurization Analyses

A RCL piping system analysis was performed to evaluate the dynamic time-history asymmetric subcompartment pressurization effects from breaks in the pressurizer surge, RHR suction, and accumulator injection lines in the lower containment region. A dynamic time-history analysis was selected to evaluate the asymmetric pressure effects as opposed to a static analysis so that the results from the asymmetric pressure analysis could be combined on a time-history basis with the results from the LOCA time-history analysis. The dynamic time-history asymmetric pressurization analysis was performed using the WESTDYN piping analysis software.

The time-history asymmetric pressure forcing functions were developed by taking the time-history pressure differential functions adjusted for direction of the force and multiplying them by the equivalent areas of the various components. The forcing functions are applied to the RPV, steam generator and the RCP in the WESTDYN model. The WESTDYN input model represents a four-loop model of the RCL piping system which includes the RPV. The WESTDYN four loop seismic model was used, however, the asymmetric pressure forces are only applied to a single loop in the model since postulated breaks only occur in one loop at a time. The results represent an enveloped maximum of the time-history data points that can be conservatively added to the results of the LOCA analysis to obtain the combined LOCA plus asymmetric pressurization effects. The maximum enveloped primary equipment support loads and primary equipment nozzle loads are calculated.

The asymmetric pressure forces are then used in the RCL and the nuclear steam supply system (NSSS) component (RPV, SG, Pressurizer, and RCP) and supports evaluations (refer to Section 5.2).

6.2.1.3 Safety Evaluation

6.2.1.3.1 General Design Criterion 4, 1987 – Environmental and Dynamic Effects Design Bases

The LBB criterion is not applicable to the long-term M&E release containment integrity analysis in Appendix 6.2D.

LBB is approved as a part of the DCPP license basis for the RCS primary loop piping (refer to Section 3.6.2.1.1.1). The containment subcompartments are designed to sustain the short-term effects of postulated branch line failures as demonstrated in Section 6.2.1.2.2 and Table 6.2-64.

6.2.1.3.2 General Design Criterion 10, 1967 – Containment

The containment is designed to sustain the effects of LOCA and MSLB events as demonstrated by the containment integrity analysis in Appendix 6.2D. This demonstrates that the containment, supported by the containment heat removal system (CHRS), will retain its functional capability. Refer to Section 6.2.2 for the discussion of the CHRS.

6.2.1.3.3 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the containment structure and subcompartments from damage that might result from missiles and dynamic effects associated equipment and high-energy pipe failures are discussed in Sections 3.5 and 3.6

6.2.1.3.4 General Design Criterion 49, 1967 – Containment Design Basis

The results of the containment integrity analysis demonstrate that the containment pressure and temperature are maintained below the design conditions following limiting LOCA events (refer to Appendix 6.2D). This demonstrates that the containment, supported by the CHRS, will retain its functional capability to not exceed the design leakage rate in order to protect the public. Refer to Section 6.2.2 for a discussion of the CHRS.

6.2.1.3.5 General Design Criterion 54, 1967 – Containment Leakage Rate Testing

Containment leakage rate testing was conducted after completion of construction and installation of all penetrations to verify its conformance with required performance (refer to Section 6.2.1.4.1).

6.2.1.3.6 General Design Criterion 55, 1967 – Containment Periodic Leakage Rate Testing

Periodic ILRT of the containment is performed as part of the DCPP Containment Periodic Leakage Rate Testing Program (refer to Sections 6.2.1.3.8 and 6.2.1.3.10).

6.2.1.3.7 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The containment, in conjunction with the containment isolation system (CIS) (refer to Section 6.2.4.4.14), is designed to be a barrier to maintain control over plant radioactive effluents, whether gaseous, liquid, or solid. The containment is designed to withstand

the effects of a LOCA (refer to Section 6.2.1.3.4), ensuring that the offsite radiological exposures resulting from a LOCA are within the limits of 10 CFR 50.67 (refer to Section 15.5).

6.2.1.3.8 10 CFR Part 50 Appendix J, Option B – Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors

10 CFR Part 50, Appendix J, Option B, Type A and B testing, as modified by approved exemptions, are performed in accordance with Technical Specification 5.5.16, Containment Leakage Rate Testing Program. The ILRT is performed at a P_a, calculated peak containment internal pressure, of 43.5 psig. The maximum allowable leakage rate is not greater than 0.10% of the containment air weight per day. For the discussion of Type C testing (testing of containment penetrations) refer to Section 6.2.4.4.14.

6.2.1.3.9 10 CFR Part 50 Appendix K, Part I.A – Emergency Core Cooling System Evaluation Models, Sources of Heat during the Loss-of-Coolant Accident

The initial conditions for the LOCA and MSLB events of the containment integrity analyses are established at the maximum calculated power for the reactor with additional margins for instrument error for the sources of heat listed in accordance with 10 CFR Part 50, Appendix K, Part I.A (refer to Section 6.2D.3.1.4).

6.2.1.3.10 Regulatory Guide 1.163, September 1995 – Performance-Based Containment Leak-Test Program

The DCPP Containment Leakage Rate Testing Program utilizes a performance-based approach, consistent with Regulatory Guide 1.163, September 1995, to comply with the requirements of 10 CFR Part 50, Appendix J, Option B (refer to Section 6.2.1.3.8).

6.2.1.4 Tests and Inspections

6.2.1.4.1 Preoperational Testing

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Following completion of each containment structure, a structural integrity test was performed by pressurizing the containment with air to 115 percent of design pressure, or 54 psig. These tests were performed as described in Section 3.8.2.1.7.

During the depressurization phase of the structural integrity tests, overall integrated leakage rate tests were performed in accordance with the requirements of Appendix J to 10 CFR Part 50 (refer to Section 3.8.2.1.7).

6.2.1.4.2 Inservice Surveillance

Periodic leakage rate testing will be performed over the life of the units in accordance with the requirements of Appendix J to 10 CFR Part 50, Option B, as modified by approved exemptions (refer to Section 6.2.1.3.8). Applicable surveillance requirements for such testing are included in the Technical Specifications. A leakage detection system has been installed to measure leakrate for the personnel air lock door seals to ensure compliance with the Technical Specifications (Reference 46). Periodic testing of the containment isolation valves is discussed in Sections 6.2.4.4.12 and 6.2.4.5.

6.2.1.5 Instrumentation Applications

Pressure inside the containment is continuously monitored by independent pressure transmitters located at widely separated points outside the containment. Instruments with range of -5 to 55 psig and 0 to 200 psig are available. Section 7.3.2 describes containment pressure as an input to the engineered safety features actuation system (ESFAS) and Section 7.5.2 describes containment pressure display instrumentation. Other instrumentation available for monitoring conditions within the containment include:

(1) Containment water level monitors (described in Sections 6.3.3.4.4 and 7.5.2.1.3)

(2) Containment hydrogen monitors (described in Section 6.2.5.5)

(3) Temperature detectors positioned at various locations within the containment air volume (described in Section 9.4.5.3.3)

(4) Containment radiation and plant vent monitors (described in Sections 9.4.2 and 11.4.2.1.2)

6.2.1.6 Materials

Containment structural heat sink materials used for containment integrity analyses following a LOCA or MSLB are listed in Table 6.2D-19; corresponding material properties are listed in Table 6.2D-20 (refer to Section 6.2D.3.2.4). A current record of paint used on containment heat sink structures and equipment is maintained in engineering files.

6.2.2 CONTAINMENT HEAT REMOVAL SYSTEMS

The CHRSs are the CFCS and the CSS. The functional performance objectives of the CHRS are:

(1) The CFCS limits the containment ambient temperature during normal plant operating conditions (refer to Section 9.4.5);

(2) The CFCS and CSS reduce the containment ambient temperature and pressure following a LOCA or MSLB inside containment. While performing this cooling function, the CHRS also helps limit offsite radiation levels by reducing the pressure differential between containment and outside atmosphere, thus reducing the driving force for leakage of fission products from the containment atmosphere;

(3) The CFCS provides mixing of the sprayed and unsprayed regions of the containment to improve airborne fission product removal (refer to Section 6.2.3);

(4) The CSS removes airborne fission products from the containment atmosphere following a LOCA (refer to Section 6.2.3);

(5) The CSS, in conjunction with the SAS, prevents the re-evolution of the iodine in the recirculated containment spray core cooling solution (i.e., sump water) following a LOCA (refer to Section 6.2.3);

(6) The CFCS and CSS provide a mixed atmosphere for hydrogen control (refer to Section 6.2.5).

Used in conjunction with one another during the injection phase, one containment spray pump and two containment fan cooler units (CFCUs) will provide the heat removal capability to maintain the post-accident containment atmospheric pressure and temperature below the design values of 47 psig and 271°F, respectively. The CFCS is credited for long-term containment pressure and temperature control throughout the injection and recirculation phases following a LOCA or MSLB. The operation of CSS in the injection phase is credited for heat removal following a LOCA or MSLB. To address the delayed radioactivity release associated with the core damage sequence of Alternative Source Terms (AST), credit is taken for CSS operation in both the injection and recirculation phases to support fission product removal following a LOCA (refer to Section 15.5). The physical SSC design bases, testing, and inspection requirements of the CFCS and CSS are discussed in this section.

6.2.2.1 Design Bases

6.2.2.1.1 General Design Criterion 2, 1967 - Performance Standards

The CFCS and CSS are designed to withstand the effects of, or are protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

6.2.2.1.2 General Design Criterion 10, 1967 - Containment

The CFCS and CSS are designed, together with other ESFs to retain for as long as the situation requires the functional capability of the containment to protect the public in the event of gross equipment failures, such as a LOCA.

6.2.2.1.3 General Design Criterion 11, 1967 - Control Room

The CFCS and CSS are designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room.

6.2.2.1.4 General Design Criterion 12, 1967 - Instrumentation and Control Systems

The CFCS and CSS are provided with instrumentation and controls as required to monitor and maintain the CHRS variables within prescribed operating ranges.

6.2.2.1.5 General Design Criterion 15, 1967 - Engineered Safety Features Protection Systems

The CFCS and CSS are provided with instrumentation for sensing accident conditions and initiating the operation of necessary engineered safety features.

6.2.2.1.6 General Design Criterion 19, 1999 - Control Room

The CFCS and CSS, in conjunction with the SAS, are designed to limit radiation exposure to personnel to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE, for the duration of the accident.

6.2.2.1.7 General Design Criterion 21, 1967 - Single Failure Definition

The CFCS and CSS are designed to tolerate a single failure during the period of recovery following an accident without loss of their protective functions, including multiple failures resulting from a single event, which is treated as a single failure.

6.2.2.1.8 General Design Criterion 37, 1967 - Engineered Safety Features Basis for Design

The CFCS and CSS are designed to provide back-up to the safety functions provided by the core design, the reactor coolant pressure boundary (RCPB), and their protection systems.

6.2.2.1.9 General Design Criterion 38, 1967 - Reliability and Testability of Engineered Safety Features

The CFCS and CSS are designed to provide high functional reliability and ready testability.

6.2.2.1.10 General Design Criterion 40, 1967 - Missile Protection

The CFCS and CSS are designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

6.2.2.1.11 General Design Criterion 41, 1967 - Engineered Safety Features Performance Capability

The CFCS and CSS are designed to provide sufficient performance capabilities to accommodate a partial loss of installed capacity, including a single failure of an active component, and still perform their required safety functions.

6.2.2.1.12 General Design Criterion 42, 1967 - Engineered Safety Features Components Capability

The CFCS and CSS are designed so that the capability of each component and system to perform its required function is not impaired by the effects of a LOCA.

6.2.2.1.13 General Design Criterion 49, 1967 - Containment Design Basis

The CFCS and CSS are designed so that the containment structure can accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible mass and energy releases following a LOCA, including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of emergency core cooling systems.

6.2.2.1.14 General Design Criterion 52, 1967 - Containment Heat Removal Systems

The CFCS and CSS are designed as two systems of different principles, each with full capacity, for active heat removal from the containment under accident conditions to prevent exceeding containment design pressure.

6.2.2.1.15 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The CSS piping that penetrates containment is provided with leak detection, isolation, redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The piping is designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

6.2.2.1.16 General Design Criterion 56, 1971 - Primary Containment Isolation

The CSS contains valving in piping that penetrates containment and that is connected directly to the containment atmosphere. Remote manual isolation valves are provided outside containment and automatic (check) valves are provided inside containment to ensure containment integrity is maintained.

6.2.2.1.17 General Design Criterion 58, 1967 - Inspection of Containment Pressure-Reducing Systems

The CFCS and CSS are designed to facilitate the periodic physical inspection of all important components, such as fans, pumps, valves, dampers, and spray nozzles.

6.2.2.1.18 General Design Criterion 59, 1967 - Testing of Containment Pressure-Reducing Systems

The CFCS and CSS are designed so that active components, such as fans, pumps, valves, and dampers can be tested periodically for operability and required functional performance.

6.2.2.1.19 General Design Criterion 60, 1967 - Testing of Containment Spray Systems

The CSS is designed to allow periodic testing of the delivery capability of the system at a position as close to the spray nozzles as is practical.

6.2.2.1.20 General Design Criterion 61, 1967 - Testing of Operational Sequence of Containment Pressure-Reducing Systems Components

The CFCS and CSS are designed to provide the capabilities to test under certain conditions as close to the design as practical, the full operational sequence that would bring the CHRS into action, including the transfer to alternate power sources.

6.2.2.1.21 General Design Criterion 62, 1967 - Inspection of Air Cleanup Systems

The CFCS and CSS are designed to facilitate physical inspection of all critical parts, such as ducts, fans, pumps, valves, dampers, and spray nozzles.

6.2.2.1.22 General Design Criterion 63, 1967 - Testing of Air Cleanup Systems Components

The CFCS and CSS are designed so that active components, such as fans, pump, valves, and dampers, can be tested periodically for operability and required functional performance.

6.2.2.1.23 General Design Criterion 64, 1967 - Testing of Air Cleanup Systems

The CFCS is designed to provide for in situ periodic testing and surveillance to ensure trapping materials have not deteriorated beyond acceptable limits.

6.2.2.1.24 General Design Criterion 65, 1967 - Testing of Operational Sequence of Air Cleanup Systems

The CFCS and CSS are designed with the capability to test, under conditions as close to design as practical, the full operational sequence that would bring the CHRS into action, including the transfer to alternate power sources and design air flow delivery capability.

6.2.2.1.25 General Design Criterion 70, 1967 - Control of Releases of Radioactivity to the Environment

The CFCS and CSS, in conjunction with the SAS, are designed with provisions for maintaining control of the plant's radioactive gaseous effluents to meet the radiological limits of 10 CFR 50.67.

6.2.2.1.26 Containment Heat Removal System Safety Function Requirements

(1) Protection from Jet Impingement – Inside Containment

The CFCS system and the CSS system portion located inside containment is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

6.2.2.1.27 10 CFR 50.49 - Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

CFCS and CSS components that require environmental qualification (EQ) are qualified to the requirements of 10 CFR 50.49.

6.2.2.1.28 10 CFR 50.55a(f) - Inservice Testing Requirements

CFCS and CSS ASME code components are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

6.2.2.1.29 10 CFR 50.55a(g) - Inservice Inspection Requirements

CFCS and CSS ASME code components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

6.2.2.1.30 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The CFCS and CSS provide instrumentation to monitor containment isolation valve position, containment spray flow, containment pressure, containment temperature during and following an accident, and a two-step process for monitoring heat removal by the CFCS.

6.2.2.1.31 NUREG-0737 (Items II.F.1, III.D.1.1), November 1980 - Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident Monitoring Instrumentation: Position (4) – The CSS provides instrumentation to continuously monitor and record containment pressure in the control room.

Item III.D.1.1 - Integrity of Systems Outside Containment Likely to Contain Radioactive Material for Pressurized-Water Reactors and Boiling-Water Reactors: The CSS is designed to allow for the performance of leak rate tests as part of the containment isolation valve surveillance test program.

6.2.2.1.32 Generic Letter 89-10, June 1989 - Safety-Related Motor-Operated Valve Testing and Surveillance

The CSS PG&E Design Class I and position changeable motor-operated valves (MOVs) meet the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996.

6.2.2.1.33 Generic Letter 97-04, October 1997 – Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps

The CSS is evaluated to assure adequate net positive suction head (NPSH) is available to the containment spray pumps under all DBA scenarios.

6.2.2.1.34 Generic Letter 2008-01, January 2008 – Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems

The CSS is designed, periodically inspected, and procedurally managed to assure that gas accumulation in CSS piping will not impact the CSS safety-related functions, as required by Generic Letter 2008-01, January 2008.

6.2.2.1.35 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The CFCS and CSS is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

6.2.2.2 System Description

The CHRS is designed to provide sufficient heat removal capability to maintain the post-accident containment atmospheric pressure and temperature below the design values of 47 psig and 271°F, respectively (refer to Section 3.8.2.1.1). The containment atmospheric temperature after a MSLB does briefly increase greater than the containment design temperature, but, as discussed in Section 6.2D.4.2.1, there is no explicit design temperature limit for a MSLB. Heat energy sources considered are described in Section 6.2D.3.1.4.

The CFCS also functions during normal operating conditions to limit the containment ambient temperature to 120°F and is described in Section 9.4.5.

The CFCS, shown schematically in Figure 9.4-4, consists of five fan coolers, each including cooling coils (refer to Section 6.2.2.2.1.2.1), fan and drive motor, locked-open air flow dampers and pressure relief dampers, duct distribution system, instrumentation, and control. During operation of the units, air is drawn into the cooling coils, cooled, and discharged back through the ductwork to the containment atmosphere.

The design parameters for the CHRS components and materials are listed in Table 6.2-26. Codes and standards used as a basis for the design of the components are given in Table 6.2-25.

Ductwork distributes the cooled air to the various containment compartments and areas. During normal and post-accident operations, the flow sequence through each air fan cooler is as follows: locked-open normal and accident air flow dampers, cooling coils, fan, and distribution ductwork.

Airflow through the exhaust ducting, towards the fan, can occur when the fan is idle. Incorporated into the fan/motor coupling is an anti-reverse rotation device (ARRD) that precludes the fan motor from rotating backwards. This device replaces backdraft dampers previously installed in the fan discharge duct.

The CSS, shown schematically in Figure 3.2-12, consists of two pumps, spray ring headers and nozzles, valves, and connecting piping. Following a LOCA, water from the refueling water storage tank (RWST) is initially used for containment spray. Later, water recirculated from the containment sump is supplied by the RHR pumps for recirculation spray. Single failures that result in the loss of one RHR train are taken into consideration in system alignment to ensure appropriate division of the recirculation flow between spray and core injection to ensure fission product removal from the containment atmosphere and core cooling.

6.2.2.2.1 Component Descriptions

6.2.2.2.1.1 Containment Spray System

6.2.2.2.1.1.1 Refueling Water Storage Tank

The RWST serves as a source of emergency borated cooling water for the injection phase. The RWST will normally be aligned to the suction of the emergency core cooling pumps and the containment spray pumps. During a MSLB inside containment or LOCA the containment spray pumps will continue to take suction from the RWST until the RWST low-low level signal is provided. Refer to Section 6.3 for additional details on the RWST.

6.2.2.2.1.1.2 Containment Spray Pumps

The containment spray pumps are of the horizontal centrifugal type and are driven by electric motors. The motors are powered from separate Class 1E, 4.16-kV buses.

6.2.2.2.1.1.3 Spray Nozzles

The spray nozzles are of the hollow cone design having an open throat and 3/8 inch spray orifice and are not subject to clogging by particles less than 1/4 inch in size. Refer to discussion in Section 6.2.2.3.8.1.2.

6.2.2.2.1.1.4 Containment Spray System Piping and Valves

The piping and valves for the CSS have design pressures and temperatures of 240 psig and 200°F, respectively.

6.2.2.2.1.2 Containment Fan Cooler System

The design data of the CFCS are presented in Table 6.2-26. During normal operation, the number of units running will depend on the amount of cooling required in the containment. The operator uses the containment temperature and pressure readings to determine how many fan cooler units should be operating. At full power operation, four or fewer units are usually required, while at cold shutdown only one unit may be needed (refer to Section 9.4.5). Limiting conditions for operation are included in the Technical Specifications.

6.2.2.2.1.2.1 Cooling Coils

All cooling coils are Westinghouse coils, except for the Unit 1 coil for CFCU 1-5 and Unit 2 coil for CFCU 2-5, which are Super Radiator Coils (SRC).

Westinghouse Coils

The coils are fabricated with copper plate fins on copper tubes. Each fan cooler consists of 12 individual coils mounted in two banks, 6 coils high. These banks are located one behind the other for horizontal series air flow, and the tubes of the coil are horizontal with vertical fins.

The cooling coil assembly consists of one bank of WC-36114-4H (1/2 water velocity circuiting) coils four rows deep and one bank of WC-36114-6T (1/3 water velocity circuiting) coils six rows deep. Each coil is provided with a drain pan and drain piping to prevent flooding of the coil face area during accident conditions. This condensate is drained to the containment sump. The monitoring of this condensate for the leakage detection system of the RCS pressure boundary is discussed in Section 5.2.3.23.

The component cooling water (CCW) system supplies cooling water to the containment fan coolers and is discussed in Section 9.2.2.

SRC Coils

The coils are fabricated with copper plate fins on copper tubes. Each fan cooler consists of 6 individual coils mounted in one bank. The tubes of the coil are horizontal with vertical fins.

Each coil is provided with a drain pan and drain piping to prevent flooding of the coil face area during accident conditions. This condensate is drained to the containment

sump. The monitoring of this condensate for the leakage detection system of the RCS pressure boundary is discussed in Section 5.2.3.23.

The CCW system supplies cooling water to the containment fan coolers and is discussed in Section 9.2.2.

6.2.2.2.1.2.2 Fans

The five containment cooling fans are of the centrifugal, nonoverloading direct-drive type. The fan bearings have a specially designed seal, are heavy duty, and are selected for the proper thrust and axial loads. Special lubricant is used to ensure protection during accident operation (refer to Section 6.2.2.3.27).

6.2.2.2.1.2.3 Enclosure

Each of the five fan cooler enclosure assemblies consists of four prefabricated modular units. Modules 1, 2, and 3 are located on the inlet side of the cooling coils. Module 4 is located on the outlet side of the cooling coils and serves as a plenum for the fan inlet.

The CFCS was modified to remove the moisture separators and high-efficiency particulate air (HEPA) filters.

6.2.2.2.1.2.4 Anti-Reverse Rotation Device

An ARRD is incorporated into the fan/motor coupling that prevents the fan motor from rotating backwards. This device protects the fan motor from airflow that could cause an over-current trip condition when the idle fan starts.

6.2.2.2.1.2.5 Pressure Relief Damper

Each fan cooler unit is equipped with a pressure relief damper. These dampers are normally closed counterweighted devices that open progressively as the pressure differential across them exceeds 0.25 psi.

6.2.2.2.1.2.6 Ductwork

Vacuum relief dampers and pressure relief dampers are provided along the ductwork to limit the differential pressure acting on the duct to 0.2 psi during accident conditions. The debris screen, flexible connection, duct branch, and vacuum relief dampers are required to function from the beginning of an accident to full closure of the containment purge isolation valves (assuming the valve is open for containment purge when the accident occurs). This is to ensure that debris generated during an accident will not lodge in the seat of the containment isolation valve to prevent its full closure.

Ducts are constructed of galvanized sheet steel. Bolted flanges are provided with gaskets suitable for 300°F service for the PG&E Design Class I portion of the ducts and

suitable for 250°F for the PG&E Design Class II portion of the ducts. All longitudinal seams are tack welded or riveted and sealed.

6.2.2.2.1.2.7 Air Flow Dampers

Dampers are locked in their normal operating position. The air flow dampers are an integral part of the fan coolers. Each damper is constructed of steel painted with corrosion-inhibiting paint, with multiple blades and edge seals to minimize leakage.

6.2.2.2.1.2.8 Motors for Fan Coolers

A two-speed, single-winding motor is used to drive each fan cooler. The motor operates at the high speed during normal operation and at the low speed during post-accident operation.

The motor unit is provided with an integral air-to-water heat exchanger.

The motor heat exchanger consists of the cooling coil, the housing, and two pressure equalization dampers (relief valves to vent containment pressure into the heat exchanger).

The motor heat exchanger circulates CCW. The joints of the motor heat exchanger cooling coil are brazed with a high-temperature alloy.

The motor heat exchanger cooling coil is mounted within the motor heat exchanger housing and is generally of the same type construction as the main coils. The plenum after the coil has a condensate drain connection.

The fan cooler motor heat exchanger housing is equipped with two pressure equalization dampers to relieve pressure differentials resulting from a post-accident pressure transient. The valves begin to open at 5 inches water gauge. The valves are designed for a maximum pressure differential of 30 inches of water. Each valve has a maximum flow area of 7.07 square inches. The valves and body flapper plates are electrolytically nickel-coated carbon steel. The valve brackets, links, shafts, springs, and fasteners are Type 316 stainless steel. The seat seals are a silicone rubber O-ring. Each valve is subjected to a certification test before shipment to ensure proper opening pressure and leaktightness.

The motor, motor heat exchanger, and fan are mounted on a common base for extra rigidity.

6.2.2.2.1.3 Electrical Supply

The CFCS fan motors and CSS valves are powered from separate Class 1E 480-V buses and the containment spray pumps are powered from separate Class 1E 4.16-kV buses (refer to Section 8.3.1.1.3).

6.2.2.3 Safety Evaluation

6.2.2.3.1 General Design Criterion 2, 1967 - Performance Standards

With the exception of the RWST and connected piping, the CFCS and CSS components are located within the PG&E Design Class I auxiliary and containment buildings. The applicable portions of these buildings are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7). The design of the auxiliary and containment buildings will protect the CFCS and CSS components against natural phenomena and local site effects, ensuring their design functions will be performed.

The evaluation of the performance standards for the RWST is provided in Section 6.3.3.1.

The CFCS fan coolers are designed to PG&E Design Class I criteria.

The fan cooler discharge ductwork and supports, up to and including the backdraft dampers' frame, are PG&E Design Class I to maintain the integrity and the design heat removal capability of the operating fan coolers. Except for the short section of branch duct between the containment purge exhaust isolation valve and its debris screen, the ducting is PG&E Design Class II and is seismically designed. This duct section must maintain its integrity during an accident up to the time full closure of the containment purge isolation valve has been attained to ensure that debris generated during an accident will not lodge in the seat of the containment isolation valve to prevent its full closure. The duct branch bounded by the containment purge isolation valve and its debris screen, including the flexible connection, is classified as PG&E Design Class I. The vacuum relief dampers are classified as PG&E Design Class I and the pressure relief dampers are classified as PG&E Design Class II. This greatly minimizes the collapsing/damage to the distribution ductwork from pressure transients during an accident condition.

The Hosgri Earthquake (HE) and Double Design Earthquake (DDE) piping analyses for the piping located inside containment downstream of sealed-open isolation valves 9006 A and B take credit for the empty piping configuration that exists during normal plant operation.

6.2.2.3.2 General Design Criterion 10, 1967 – Containment

The CFCS and CSS are designed to support containment integrity to sustain the effects of a LOCA or MSLB. The CHRS maintains the containment within its maximum design conditions therefore retaining its functional capability. The containment atmospheric temperature after a MSLB does briefly increase greater than the containment design temperature, but, as discussed in Section 6.2D.4.2.14, there is no explicit design

temperature limit for a MSLB. The containment integrity analyses are demonstrated in Appendix 6.2D.

6.2.2.3.3 General Design Criterion 11, 1967 - Control Room

The CFCS and CSS are designed with remote-manual operation for each train of CSS and CFCUs in the control room.

The CFCS and CSS are designed with control room indication including containment pressure, containment isolation valve position, containment spray pump discharge flow, heat removal by containment fan heat removal system through: CFCU motor speed indicating lights, CCW flow indication, containment pressure indication, and containment atmosphere temperature indication (refer to Section 7.5.2).

Therefore, indication and controls are provided in the main control room to maintain safe operational status of the CFCS and CSS.

6.2.2.3.4 General Design Criterion 12, 1967 - Instrumentation and Control Systems

The CFCS and CSS are provided with instrumentation and controls to monitor and maintain CHRS variables within prescribed operating ranges. In addition to actuating based on signals generated by the ESFAS, which receives input from containment pressure-related instrumentation (refer to Section 7.3.2), CHRS instrumentation requirements include the capabilities for measurement and local indication of suction pressure which can be used to evaluate NPSH and discharge pressure in the containment spray pumps and containment spray pump flow to containment. To ensure that water flows to the SI system after a LOCA and determine when to shift from the injection to the recirculation mode, RWST level indication and alarm are provided. High-high containment pressure (“P” signal) coincident with a “S” signal will automatically initiate the CSS as discussed in Section 6.2.2.3.5.

The containment fan cooler bearings are monitored for vibration. Similarly, the containment fan cooler motor assembly bearings and windings are monitored to ensure that vibration and temperature limits are not exceeded.

The following instrumentation associated with the containment fan coolers enables additional monitoring of in-containment conditions in the post-LOCA recovery period:

(1) The CCW discharge flow for the containment fan coolers is indicated in the control room and alarmed if the flow is low.

(2) The CCW exit temperatures are indicated locally outside the containment building.

(3) Bearing temperatures are indicated and alarmed on the plant process computer.

6.2.2.3.5 General Design Criterion 15, 1967 - Engineered Safety Features Protection Systems

The CHRS is designed with instrumentation that measures containment pressure. The CSS will be actuated through ESFAS by a "P" signal (high-high containment pressure actuation setpoint) on coincidence of two-out-of-four ”P” signals. Coincidence of "S" (safety injection) and "P" signals starts the containment spray pumps and opens the discharge valves to the spray headers. Refer to Section 7.3 for a description of the ESFAS.

6.2.2.3.6 General Design Criterion 19, 1999 - Control Room

The CSS is designed to deliver borated water from the RWST to the containment atmosphere during the injection phase following a LOCA. The CSS, in conjunction with the CFCS, reduces the containment ambient temperature and pressure following a LOCA or MSLB, thus reducing the driving force for leakage of fission products from the containment atmosphere. The CFCS provides mixing of the sprayed and unsprayed regions of the containment to improve airborne fission product removal. The SAS, as discussed in Section 6.2.3, injects sodium hydroxide to the suction of the CSS for delivery to the containment atmosphere to prevent the re-evolution of the iodine in the recirculated core cooling solution. The CSS removes radioactive iodines and particulates from the containment atmosphere during the injection and recirculation phases following a LOCA to ensure that radiological exposures for control room personnel are within 5 rem TEDE, for the duration of the accident. Refer to Section 15.5 for radiological consequences of plant accidents. Therefore, the CSS, in conjunction with the CFCS and SAS, limits the control room doses to 5 rem TEDE.

6.2.2.3.7 General Design Criterion 21, 1967 - Single Failure Definition

The CFCS and CSS are designed such that no single failure in either train will prevent the CHRS from performing its design function. The CSS is comprised of two completely independent trains of containment spray. Each CSS train of pumps and valves are powered by separate Class 1E 4.16-kV and 480-V power supplies, respectively. The CFCS is comprised of five independent fan coolers; two are powered from Class 1E 480-V Bus F, two are powered from Class 1E 480-V Bus G, and one is powered from Class 1E 480-V Bus H.

Any single failure will still leave sufficient CSS and CFCS capability to together mitigate DBAs. Used in conjunction with one another during the injection phase, one containment spray pump and two CFCUs will provide the heat removal capability to maintain the post-accident containment pressure below the design value of 47 psig. CHRS design parameters are listed in Table 6.2-26.

A single failure analysis on all active components of the CHRS was performed to show that the failure of any single component will not prevent performance of the design function. This analysis is summarized in Table 6.2-27.

6.2.2.3.8 General Design Criterion 37, 1967 - Engineered Safety Features Basis for Design

Operation of the CSS during the injection phase following a LOCA and MSLB is credited for heat removal. As stated in Section 6.2.2, credit is taken for CSS operation during the injection and recirculation phases to support fission product removal following a LOCA. The CFCS is credited for containment pressure and temperature control and mixing of the sprayed and unsprayed regions of the containment to improve airborne fission product removal throughout the injection and recirculation phases following a LOCA or MSLB.

The CSS and CFCS limit the effects of post blowdown energy additions to the containment during the injection phase following a LOCA. For a detailed description of the analytical methods and models used to assess the performance capability of the CHRS, refer to the containment integrity analysis presented in Appendix 6.2D.

The CHRS provides a backup to the safety provided by the core design, the RCPB, and their protection systems. As discussed in this section, the CHRS is designed to withstand any size reactor or secondary coolant pressure boundary break, including a LOCA or MSLB.

6.2.2.3.8.1 Containment Spray System

The CSS, in conjunction with the CFCS, reduces the containment ambient temperature and pressure following a LOCA or MSLB, thus reducing the driving force for leakage of fission products from the containment atmosphere. The CSS removes radioactive - airborne iodine and particulates from the containment atmosphere following a LOCA (refer to Section 6.2.3). The CSS, in conjunction with the SAS, prevents the re-evolution of the iodine in the recirculated spray and core cooling solution (also known as sump water) following a LOCA (refer to Section 6.2.3).

6.2.2.3.8.1.1 Containment Spray Pumps

The containment spray pumps are designed to perform at rated capacity against a total head composed of containment design pressure, nozzle elevation head, and the line and nozzle pressure losses. Adequate NPSH is available for operation of the containment spray pumps throughout the entire spray injection phase considering the low-low level
in the RWST. A performance curve for the containment spray pumps is shown in Figure 6.2-10.

6.2.2.3.8.1.2 Containment Spray Nozzles

The CSS nozzles produce a mean drop diameter of 700 microns at rated system conditions (40 psi Δp and 15.2 gpm per nozzle). The minimum fall path for CSS water droplets is conservatively assumed to be the distance from the lowest spray ring to the operating deck. The heat transfer calculations presented in Section 6.2.1 and Appendix 6.2D show that essentially all spray droplets reach thermal equilibrium at containment design temperature and pressure in a distance considerably less than the minimum fall path. The spray solution is stable and soluble at all temperatures of interest in the containment and will not precipitate or otherwise interfere with nozzle performance. If containment spray is used in the recirculation phase, the containment recirculation sump screens (refer to Figures 6.3-6 and 6.3-7) limit particle size to preclude the possibility of clogging (refer to Section 6.3). Nozzle design and performance characteristics are listed in Table 6.2-26 and in Figure 6.2-12. A plan view of the containment spray headers showing the location of the spray nozzles is given in Figure 6.2-13. An evaluation of
the containment spray pattern, including droplet size and distribution, is discussed in Section 6.2.3.

6.2.2.3.8.1.3 Containment Spray System Phases of Operation

The CSS may operate over an extended period and under the environmental conditions existing following a LOCA or an MSLB. The system operation can be divided into the following two distinct phases.

6.2.2.3.8.1.3.1 Injection Phase

The CSS will be actuated by a "P" signal, either manually from the control room, or on coincidence of two-out-of-four ”P” signals. Coincidence of "S" and "P" signals starts the containment spray pumps and opens the discharge valves to the spray headers. The "P" signal alone will open the valves associated with the spray additive tank. During the spray injection phase, the pumps are drawing borated water from the RWST and mixing it with NaOH solution from the spray additive tank (refer to Section 6.2.3). Spray injection will continue until the RWST low-low level is reached, at which time the containment spray pumps are manually tripped and isolated.

6.2.2.3.8.1.3.2 Recirculation Phase

CSS operation in the spray recirculation mode is manually initiated within 12 minutes of termination of injection spray. Recirculation spray is provided by the RHR pumps, which draw suction from the containment sump. During the spray recirculation phase, a single RHR pump delivers a minimum flow rate of 1211 gpm to a single spray header. The minimum ECCS core flow available when containment spray is operating in the recirculation mode exceeds the required core flow acceptance criteria taking into consideration the worst case single active failure to minimize the number of pumps

available for core cooling. Spray recirculation phase operation of the RHR pumps is discussed in Sections 6.3.2.4.3.1 and 5.5.6.

6.2.2.3.8.2 Containment Fan Cooler System

6.2.2.3.8.2.1 Containment Fan Coolers

In addition to limiting maximum containment pressure and temperature, the containment fan coolers provide mixing of the containment atmosphere for radioactive iodine and particulate removal and control of hydrogen buildup as discussed in Sections 6.2.3 and 6.2.5, respectively.

Westinghouse Coils

The heat removal capability of the containment fan cooler cooling coils is 81 x 10^6 Btu/hr per fan cooler unit at saturation conditions (271°F, 47 psig), with 2000 gpm cooling water supply at 125°F and air flow of 47,000 CFM (refer to Table 6.2-26).

The design internal pressure of each coil is 200 psig and the coils can withstand an external pressure of 47 psig at a temperature of 271°F without damage.

Each cooling coil assembly has a top and bottom horizontal coil casing made of galvanized steel. The safety function of the cooling coil casings is to fill the air gap between each stacked cooling coil assembly and direct airflow through the cooling fins to ensure that adequate heat transfer occurs within the CFCUs.

SRC Coils

The minimum heat removal capability of the cooling coils is 75.489 x 10^6 Btu/hr per fan cooler unit at saturation conditions (271°F, 47 psig), with 2000 gpm cooling water supply at 125°F and air flow at 37,000 CFM.

The design internal pressure of each coil is 200 psig and the coils can withstand an external pressure of 47 psig at a temperature of 271°F without damage.

The cooling coil assembly has a top and bottom horizontal coil casing made of stainless steel. The safety function of the cooling coil casings is to fill the air gap between each stacked cooling coil assembly and direct airflow through the cooling fins to ensure that adequate heat transfer occurs within the containment fan cooler units.

Fans

Each fan can provide a minimum flowrate of 47,000 cfm (in low speed) when operating against the system resistance of approximately 3-3/4 inches of water existing during the accident condition. Minimum flowrate assumptions used to establish containment mixing or fission product removal are discussed in Section 6.2.3 and 15.5.17.

As discussed in Section 6.2.2.2.1.2.3, each CFCS unit is comprised of four, pre-fabricated modular units. As a result of the modifications made to the fan cooler enclosure assemblies, only Module 3 serves to direct the airflow into the coils for normal and post-LOCA operations. Modules 1 and 2 are no longer required for service.

Module 1 contains the locked-open accident flow inlet dampers. Locking the accident inlet damper open prevents module overpressurization during a LOCA. Module 2 contains the locked-closed accident flow outlet dampers. Modules 1 and 2 are open to one another (i.e., Module 1 and Module 2 do not have a division or dampers separating the two). Module 3 contains the locked-open normal flow inlet dampers and the pressure-relief damper.

The ARRD is designed to withstand the dynamic loads associated with *a* 7 psi pressure differential.

The pressure relief dampers limit the pressure differential across the fan cooler enclosure walls in the event of a LOCA or MSLB, and thus maintain the structural integrity of the fan cooler units during the pressure transient.

The fan cooler motor heat exchanger has sufficient capacity to remove all motor assembly heat losses and external heat loads under all operating conditions, while limiting the maximum thermal environment consistent with motor design.

In the event of a LOCA or MSLB, two of the five fan coolers are required to operate. The units are placed in post-accident mode of operation either by a ”S” signal or manually from the control room.

As shown in Table 6.2-26, during a LOCA or MSLB, each fan cooler motor will automatically trip. The motors will then restart at low speed (600 rpm) and provide a heat removal capacity of 81 x 10^6 Btu/hr (CFCUs with Westinghouse coils) and 75.489 x 10^6 Btu/hr (CFCU with SRC coils) at containment design conditions. The cooler heat removal capacity is based on 125°F cooling water and other parameters as specified in Table 6.2-26.

A high degree of mechanical reliability is incorporated in the containment ventilation system. The fan cooler system regularly demonstrates its availability because it is used during normal plant operation to control temperature inside the containment (refer to Section 9.4.5). In the event of a failure of offsite electric power concurrent with a LOCA or MSLB, the fan cooler units and the CCW pumps supplying cooling water to these coolers are started automatically and supplied with power from the standby power source.

Immediately following a LOCA, the peak steam-air mixture entering the cooling coils is at approximately 271°F with a density of 0.175 pounds per cubic foot. Part of the water vapor condenses on the cooling coils. The air-side pressure drop is not appreciably

affected by the condensate on the cooling coils. The air leaving the coils is saturated at a temperature somewhat below 271°F.

The steam-air mixture remains in this condition as it flows into the fan. At this point it picks up some sensible heat from the fan and fan motor before entering the distribution header and the dry-bulb temperature rises slightly above 271°F and the relative humidity drops to slightly below 100 percent.

6.2.2.3.8.2.2 Flow Distribution and Flow Characteristics

The location of the distribution ductwork outlets, together with the location of the fan cooler unit inlets, ensures that the air will be directed to all areas requiring ventilation before returning to the units.

In addition to ventilating areas inside the periphery of the polar crane wall, the distribution system also includes branch ducts for ventilating the upper portion of the containment. These ducts extend upward along the containment wall to the dome area, although the volume control dampers have been closed and no longer supply air flow. Refer to Section 6.2.2.3.1 for a discussion on the PG&E design classification of the ductwork.

The air discharged inside the periphery of the polar crane wall will circulate and rise above the operating floor though openings around the SGs where it will mix with air displaced from the dome area. This mixture will return to the fan cooler inlets located on the operating floor. The temperature of this air will essentially be the design ambient for the containment (refer to Section 9.4.5).

In the accident mode of operation, the recirculation rate with five coolers operating is approximately 5.4 containment volumes per hour.

6.2.2.3.8.2.3 Cooling Water for the Fan Cooler Units

The cooling water requirements for the fan cooler units during a LOCA or MSLB and the recovery are supplied by the CCW system, which is described in Section 9.2.2 and in Table 6.2-26.

The CFCS removes sufficient heat from the containment, following the initial LOCA or MLSB containment pressure transients, to keep the containment pressure from exceeding the design pressure. The fans and cooling coils continue to remove heat after the LOCA or MSLB and reduce the containment pressure close to atmospheric within the first 24 hours.

In addition, the following objectives are met to provide the ESF functions:

(1) Each of the five fan cooler units is capable of transferring heat from the containment atmosphere, at the design basis rate for post-accident design conditions (refer to Table 6.2-26).

(2) In removing heat at the design basis rate, the coils are capable of discharging the resulting condensate without impairing their flow capacities and without raising the cooling water exit temperature to the boiling point. Since condensation of water from the air-steam mixture is the principal mechanism for removal of heat from the post-accident containment atmosphere by the cooling coils, the coil fins will operate as wetted surfaces under these conditions. Entrained water droplets added to the air-steam mixture will therefore have essentially no effect on the heat removal capability of the coils.

The post-accident heat removal capability of the Westinghouse fan coolers (refer to Section 6.2.2.2.1.2.1) is demonstrated by the Westinghouse computer program HECO (Reference 36).

The post-accident heat removal capability of the fan cooler with SRC cooling coils (refer to Section 6.2.2.2.1.2.1) is supported by an in-house computer model developed by SRC. The heat performance of the coils is documented in a heat removal report supplied by the vendor. The accuracy of the computer model was benchmarked against a performance test on a scaled down coil performed at an independent test laboratory.

6.2.2.3.9 General Design Criterion 38, 1967 - Reliability and Testability of Engineered Safety Features

The CFCS and CSS are designed with high reliability and testability. This is demonstrated through testing included in the surveillance test procedures for the plant delineated in the Technical Specifications as discussed in Sections 6.2.2.3.8.2, 6.2.2.3.15, 6.2.2.3.17 through 6.2.2.3.23, and 6.2.2.3.27 through 6.2.2.3.29.

6.2.2.3.10 General Design Criterion 40, 1967 - Missile Protection

The provisions taken to protect the CFCS and CSS from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures are discussed in Sections 3.5, 3.6, and 6.2.4.

All of the fan coolers, the distribution ductwork to the annulus ring (inclusive), and cooling water piping are located outside the missile shield wall. This arrangement provides protection from missiles for all system components. Portions of the branch

ductwork from the annulus penetrate and extend past the missile shield wall. However, as described in Section 6.2.2.3.12, they are not required for accident mitigation.

The CSS is protected from missiles, pipe whip, or jet impingement from the rupture of any nearby high-energy lines (refer to Sections 3.5 and 3.6). A vulnerability of the system to this is with the portion of the CSS piping located outside of containment in the containment penetration area (GE/GW area) which could potentially result in missiles as a result of a MSLB; however, a MSLB outside of containment does not require operation of the CSS.

6.2.2.3.11 General Design Criterion 41, 1967 - Engineered Safety Features Performance Capability

The CFCS and CSS, including required auxiliary systems, are both designed to tolerate a single active failure during the spray injection phase following a LOCA or MSLB without loss of protective function. Therefore, the CFCS and CSS provide sufficient performance capability to accommodate partial loss of installed capacity and still fulfill the required functions for containment heat removal, airborne fission product removal, and CFCS mixing for hydrogen control.

6.2.2.3.12 General Design Criterion 42, 1967 - Engineered Safety Features Components Capability

The CFCS and CSS component design pressure and temperature conditions in Table 6.2-26 are specified as the most severe conditions to which each component is exposed during either normal or post-LOCA operation.

During a LOCA, the primary objective of the CFCS is heat removal for containment pressure reduction. The exact distribution of the recirculation flow through the ductwork is not critical. In the event of breakage/damage to PG&E Design Class II ductwork branches, no significant reduction in CFCS performance is anticipated because ductwork damage will not reduce the total heat removal capability of the operating fan coolers.

Therefore, the CFCS and CSS are designed so that the capabilities to perform the required functions are not impaired by the effects of a LOCA.

6.2.2.3.13 General Design Criterion 49, 1967 - Containment Design Basis

The CFCS and CSS ensure that the containment design pressure and temperature are maintained below the design conditions following limiting LOCA events. Refer to Appendix 6.2D for the containment integrity analysis.

The CSS penetrations are designed to withstand the pressures and temperatures that could result from a LOCA without exceeding the design leakage rates. Refer to Section 3.8.2.1.1.3 for additional details.

6.2.2.3.14 General Design Criterion 52, 1967 - Containment Heat Removal Systems

Adequate heat removal capability for the containment atmosphere is provided by two diverse and separate ESFs, the CSS and the CFCS, capable of maintaining the containment below the maximum design pressure and temperature following a LOCA or MSLB. During the recirculation phase, the CFCS alone is capable of maintaining the containment below its maximum design pressure and temperature. These two systems are designed to work in conjunction with one another to meet the single failure criteria as discussed in Section 6.2.2.3.7.

6.2.2.3.15 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The CSS containment isolation valves are periodically tested for operability and leakage. Testing of the components required for the CIS is discussed in Section 6.2.4. Test connections (TCs) are provided in the penetration and in the piping to verify valve leakage and penetration leakage are within prescribed limits.

6.2.2.3.16 General Design Criterion 56, 1971 - Primary Containment Isolation Valves

The CSS containment penetrations that are part of the CIS include the containment spray pump discharge lines which comply with the requirements of GDC 56, 1971, as described in Section 6.2.4 and Table 6.2-39.

6.2.2.3.17 General Design Criterion 58, 1967 - Inspection of Containment Pressure-Reducing Systems

Access is available for visual inspection of the fan cooler components, including fans, cooling coils, enclosure dampers, and ductwork. Since these units are in use during power operation, continuous checks of their status are available.

The containment fan cooler cooling coils are designed to be easily removed for inspection and maintenance.

Refer to Section 6.2.2.3.19 and 6.2.2.3.28 for a discussion on testing and inspection of the CSS.

Therefore, provisions are available to facilitate periodic inspection of all important components of the CFCS and CSS.

6.2.2.3.18 General Design Criterion 59, 1967 - Testing of Containment Pressure-Reducing Systems

Provisions are available for periodic testing of active CSS components to ensure operability and required functional performance is maintained (refer to Section 6.2.2.3.19).

The fan cooling units are used during normal operation (refer to Section 9.4.5). The fans not in use can be started from the control room to verify readiness. A test signal is used to demonstrate proper fan starting.

6.2.2.3.18.1 Anti-Reverse Rotation Device Tests

The air is discharged through the ducting to the annular ring where the air is distributed to various compartments and areas. The return air to the fan coolers is taken at elevation 140 feet where the containment fan coolers are located. After a LOCA, the pressure rise at the upper elevation is relatively slow and, as a result, the pressure difference that is expected between the inlet and outlet of the CFCU is extremely small. A value of 7 psi pressure difference was chosen as a conservative design limit.

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To demonstrate the adequacy of the ARRD design, dynamic tests were performed to demonstrate that the device will withstand the dynamic loads associated with a 7 psi pressure differential. Static tests were performed to show that the subsequent transient differential pressure can react on the ARRD without failure. The results of these tests and subsequent stress analyses are summarized below:

(1) The ARRD was statically loaded to 3828 ft-lb driven torque and 2400 ft-lb reverse rotation torque with no failure. Spin testing was performed to validate retraction of the pawls. The ARRD showed no permanent deformation.

(2) The ARRD was tested to validate its ability to react to reverse rotation of the fan shaft under dynamic loading conditions. The dynamic load test conditions include the following: 317 ft-lb of torque, 3 degrees total rotation, 0.391 radians/second angular velocity at end of rotation.

From these results, it was concluded that the ARRD will withstand the load imposed by a 7 psi pressure differential and the design of the ARRD is adequate for the intended use.

6.2.2.3.18.2 Containment Fan Cooler Cooling Coil Test Summary

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Applicable for CFCUs with Westinghouse Coils

Plate-finned cooling coils are an integral part of the CFCS. These heat exchangers remove sensible heat during normal operation, but become condensers in the post-accident environment. Because of limited experimental information concerning the performance of plate-finned cooling coils operating in a condensing environment in the presence of a noncondensible (air), a demonstration test was undertaken.

The test method was to subject a scaled coil to a parametric test. These parameters were (a) containment pressure (with corresponding steam density and temperature), (b) air flowrate, (c) cooling water flowrate, (d) cooling water temperature, and (e) entrained water content. Each parametric test condition was then used as input to the HECO computer program used in coil selections. The results of the test and the computer program predictions were compared.

In all cases, the measured heat transfer rate was greater than that predicted by the HECO code. The range of parameter variations was selected to be consistent with the design points of the containment fan cooling coils contained in actual plants. It is apparent that for this specific type of heat exchanger, functioning in the range of environments tested, no moisture separator is needed to protect the coils from excessive waterlogging due to entrained spray droplets.

The extension of the test to full-size units is merely an increase in component size and total flow quantities, but not a change in controlling parameters. It is concluded that the test demonstrates that the computer code used to select cooling coil design is valid in defining the heat removal rates of plate-finned tube cooling coil assemblies of the CFCS. Therefore, these tests demonstrate that fan cooler designs, which are selected by this computer program, will perform as required in the post-accident containment environment.

Applicable for CFCU with SRC Coils

The heat performance of the coils under normal and accident conditions was documented in a report by SRC.

6.2.2.3.19 General Design Criterion 60, 1967 - Testing of Containment Spray Systems

The CSS is designed so that component surveillance can be performed periodically to demonstrate system readiness. Containment spray valve alignment is periodically verified.

The containment spray pumps are tested individually by manually shutting the spray header isolation valves, manually opening the RWST test return line isolation valves, and manually starting the pumps. Pump differential pressure can be used to verify pump performance.

Periodic testing of the containment spray nozzles, as required by Technical Specifications, will ensure that nozzles are unobstructed. Each containment spray header can be tested individually by connecting an air source to the normally capped flange connection on the spray pump discharge header, shutting the manual spray header isolation valve, and opening the air test line isolation valve and the motor-operated spray header isolation valve. Individual nozzles can then be checked for proper performance by streamers, which indicate unobstructed air flow.

6.2.2.3.20 General Design Criterion 61, 1967 - Testing of Operation Sequence of Containment Pressure Reducing Systems

The CFCS is periodically tested to verify the CFCUs actuate properly upon receipt of an actual or simulated actuation signal and transfer to the standby power supply in the required timeframe.

The aim of the periodic CSS testing is to:

(1) Verify the proper sequencing of valves and pumps on initiation of the containment spray signal and demonstrate the proper operation of remotely operated valves. A spray test interlock prevents accidental actuation of containment spray during testing.

(2) Verify the operation of the spray pumps; each pump will be run at minimum flow and the flow directed through the normal path back to the RWST.

Testing of the “S” and “P” actuation signals is addressed in Section 7.3.4.1.5.2. Component actuation logic, transfer to the standby power supply, and component capability are governed and tested in accordance with the Technical Specifications.

6.2.2.3.21 General Design Criterion 62, 1967 - Inspection of Air Cleanup Systems

During periodic tests, the CFCS and CSS equipment are inspected visually. Leaking seals, packing, or flanges are corrected to eliminate the leak. Valves and pumps are operated and inspected after every maintenance activity to ensure proper operation. Visual inspection of major components of the CFCS is regularly performed. The major components inspected include access doors to the fan cooler units, the fan cooler housings, the CFCS duct work, cooling coils, and dampers. Therefore, the CFCS and CSS are designed with provisions to allow for physical inspection of all critical components.

6.2.2.3.22 General Design Criterion 63, 1967 - Testing of Air Cleanup Systems Components

Periodic testing of the CFCS is performed in accordance with the Technical Specifications. The testing performed on the CFCS includes operation of the fans and ensuring that equipment in the CFCS actuates upon receipt of actual or simulated actuation signals.

Provisions are available for periodic testing of active CSS components to ensure operability and required functional performance is maintained (refer to Section 6.2.2.3.19).

Therefore, provisions are provided for testing of the active components of the CFCS and CSS.

6.2.2.3.23 General Design Criterion 64, 1967 - Testing of Air Cleanup Systems

The CSS, in conjunction with the SAS, serves as the air cleanup system. System water flow can be tested through the test lines permitting the test of the system up to the containment isolation valves. Periodically, a sample of the sodium hydroxide solution is tested to assure proper concentration. Testing of the sodium hydroxide additive solution is discussed in Section 6.2.3.3.14. The fan coolers are normally in use and, therefore, the readiness of the system is verified.

6.2.2.3.24 General Design Criterion 65, 1967 - Testing of Operational Sequence of Air Cleanup Systems

The testing of the operational sequences of the CFCS and CSS are performed in accordance with the Technical Specifications. The surveillance tests include verifying that the containment spray pumps, automatic valves, and fan cooler units actuate properly upon receipt of an actual or simulated actuation signal and transfer to the standby power supply in the required timeframe; therefore, provisions for testing of the operational sequence of the CFCS and CSS is provided.

6.2.2.3.25 General Design Criterion 70, 1967 - Control of Releases of Radioactivity to the Environment

As discussed in Section 6.2.3, the functional performance requirements of the CFCS and CSS, in conjunction with the SAS, are to ensure that the offsite radiological exposures resulting from a LOCA are within the limits of 10 CFR 50.67. Refer to Section 15.5 for a discussion of offsite radiological exposures resulting from a LOCA.

6.2.2.3.26 Containment Heat Removal System Safety Function Requirements

(1) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the CFCS and the CSS portion located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

6.2.2.3.27 10 CFR 50.49 - Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

The CFCS and CSS meet the requirements of 10 CFR 50.49 as described in the DCPP EQ Program. CFCS and CSS SSCs required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment. The affected equipment includes CFCU motors, valves, pressure sensors, and flow transmitters and are listed on the EQ Master List. The containment spray pump motors are not located within a harsh environment area and are therefore not environmentally qualified.

6.2.2.3.27.1 Containment Fan Cooler System

The containment fan cooler motor insulation is Class F (National Electrical Manufacturers Association rated hot spot temperature of 155°C). At DBA conditions, the motor insulation hot spot temperature is not expected to exceed 122°C. The motors have 2300-V insulation for 460-V service that provides additional insulation margin. The insulation is impregnated and coated to give a homogeneous insulation system that is highly moisture resistant. Internal leads and terminal box-motor interconnections are given special design consideration to ensure that the level of insulation exceeds that of the service voltage for the motor. The motor ball bearings are lubricated with high-temperature grease.

The motor heat exchanger housings enclose the major functional element of the motor and limit exposure to the environment that would exist in the containment under post-accident conditions.

The containment fan cooler motor heat exchanger is designed to maintain the environment of the fan cooler motor within an acceptable range during normal and post-accident operation.

The design of the motor and heat exchanger housing seals out the post-accident environment to minimize the amount of moisture entering the motor windings. In addition, any moisture entering the motor housing will condense on the motor heat exchanger. The chief attribute of this design approach is that it ensures that the internal

motor parts are maintained in a "usual service condition" despite the hostile environment outside the motor.

The motors are designed for Class F temperature in normal operation, which is consistent with the 40-year plant life requirement. During post-accident operation, the motor heat exchanger keeps winding temperatures below the 155°C insulation hot spot temperature rating.

Qualification of the fan cooler motors is described in PG&E EQ File IH-05 (Reference 39). The bases for motor temperature rise calculations are complete engineering tests of typical motors, which provide winding temperature rises and heat losses. These data are used to validate equations that predict temperature rises and heat losses for various design parameters and service conditions. A number of machines are tested to permit computer interpolation of each loss curve.

The qualification (i.e., tested) hot spot winding temperatures are 105°C (Normal), 122°C (DBA), and 97°C (Post DBA). The calculated total (i.e., Maximum) winding temperature values are 102°C (Normal), 111°C (DBA), and 92°C (Post DBA). These results confirm the ability of the motor heat exchanger to maintain winding hot-spot temperatures below the qualification level temperatures established in WCAP-7829 (Reference 4 of EQ File IH-05).

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Tests indicate that the insulation system will survive direct exposure to the postulated post-accident environment. Hence, the heat exchanger system used to cool the windings provides an additional margin of safety. In addition, it should be noted that at the time of the postulated incident, the fan motor would be started if not already running, and its internal temperature, being higher than the ambient, would tend to drive any moisture present out of the windings.

The heat exchanger was designed using a very conservative fouling factor. However, if surface fouling reduces the capability of the heat exchanger by one-half, the motor would still have a normal life expectancy, even under postulated accident conditions.

To prove the effectiveness of the heat exchanger in inhibiting large quantities of the steam-air mixture from impinging on the winding and bearings, several full-scale motor tests were performed at representative accident conditions. The tests exposed the motors to a steam-air mixture as well as boric acid and alkaline spray at 80 psig and saturated temperature conditions. Insulation resistance, winding and bearing temperatures, relative humidity, voltage and current, as well as heat exchanger water temperature and flow, were recorded periodically during the test. Following the test, the motors were disassembled and inspected and tested to further ensure that the units had performed as designed. In all tests, the motor unit performed satisfactorily.

The bearings are designed to perform in the ambient temperature conditions resulting from the postulated incident. It should be noted, however, that the interior bearing housing details are cooled by the heat exchanger, thus providing an extra margin of

assurance. In addition, separate tests were performed on bearings mounted within a test rig. These bearings were directly exposed to the immediate accident environment including temperature, pressure, steam-air mixture, and chemical sprays. The bearing ran continuously for 22 months without failure. In all tests, bearings were lubricated with fully irradiated grease prior to testing.

To further ensure motor insulation effectiveness (thermalastic epoxy), a separate motor test was conducted by Westinghouse in accordance with IEEE 334-1971 (Reference 47) without the heat exchanger attached to the motor. The test was completed satisfactorily.

6.2.2.3.27.2 Motor Unit Testing

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Tests were conducted (Reference 39) to demonstrate the effectiveness of a heat exchanger assembly in isolating motor windings from the steam and chemistry of the post-LOCA environment. Additional tests were conducted in 1971 to comply with provisions of IEEE 334-1971. These tests also qualified design features not included in the original motor. Steam exposure tests per IEEE 334-1971 were performed on the same motor with and without the heat exchanger to qualify it for both types of application.

Objectives given particular attention in the current tests to meet proposals of IEEE 334-1971 included:

(1) Aging of all samples to full service life prior to exposure to simulated DBA conditions

(2) Vibration of thermally aged models prior to steam exposure

(3) Change of facilities to provide fast pressure transients to simulate accident conditions during the initial transient

(4) Performance of five pressure transients and exposure to a saturated steam environment for 7 days on the prototype in accordance with the DBA simulation model

(5) Comparisons between insulation samples subjected to combined environment and irradiation and those exposed sequentially to thermal aging, irradiation, moisture, and voltage

(6) Irradiation of all lubricants to 2×10^8 rads before use

(7) Destructive tests of statistically selected insulation samples to measure degradation caused by environments including irradiation, with various combinations and durations

The tests in this series qualified all motor materials and design features for the conditions and duration of the test.

6.2.2.3.27.3 Containment Fan Cooler Motor Insulation Irradiation Testing

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

The testing program on the effects of radiation on the WF-SAC "Thermalastic" Epoxy insulation system used in the fan cooler motors has been completed. In these tests, irradiation of form-wound motor coil sections was accomplished up to exposure levels exceeding that calculated for the design basis LOCA. Three coil samples received the following treatment sequence: irradiation, vibration test, high-potential test, and vibration test. Six of the nine coil samples received high-potential and breakdown voltage tests. All coil samples passed the high-potential tests. The breakdown voltage levels of all coils were well in excess of those required by the design and clearly indicate that the fan cooler motor insulation system will perform satisfactorily following exposure to the radiation levels calculated for the DBA.

6.2.2.3.27.4 Containment Fan Cooler Motor Lubricant Irradiation Testing

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

This section summarizes the results of tests performed on samples of unirradiated and irradiated Westinghouse Style No. 773A773G05 (Chevron SRI) lubricant, which is used in the fan cooler fan bearing as well as in the motor bearing. The results of these tests indicate that the shear stability or consistency of the grease is increased by irradiation levels anticipated in the containment following a DBA. The consistency of the grease following irradiation remained within the most commonly recommended consistency for ball bearing application (NLGI No. 2).

The purpose of this test program was to establish the effect of irradiation on the bearing lubrication used on both the fan cooler motor and fan bearings. The maximum calculated 1-year integrated dose for the bearing lubricant, using the DBA with no credit for fission product removal from the containment atmosphere other than by natural decay, is 1.5×10^8 rads. The fan and motor bearings would receive a lesser exposure due to self-shielding effects of the motor housing bearing seals and bearing pillow blocks.

Samples of the lubricant were placed in a vented 1.5- x 12 inch aluminum tube. The tube was then placed adjacent to a 34 kilo-curie Cobalt 60 source and irradiated for 79 hours. Dosimetry measurements were made at various locations in the tube using Dupont light blue calibration paper 300 MS-C, No. CB-91639.

Following exposures to average levels of 1.2×10^8, 1.5×10^8, and 1.8×10^8 rads, the irradiated grease along with unirradiated grease taken from the same supply were

subjected to the Micro-Cone Penetration Test using standard apparatus conforming to ASTM D1403-56T.

The results of the penetration test indicate that as exposure increased, the grease underwent a change in thickness function to the point that, at 1.8 x 10^8 rads, sufficient change had taken place to cause the grease to increase in consistency to an NLGI No. 2 rating, as the grease was "worked" or sheared rather than decreased as in the unirradiated grease. The most commonly used greases, for ball bearing applications such as those in the fan cooler, have consistencies ranging between NLGI No. 1 and No. 3.

Based on the tests results from irradiation and ASTM Micro-Cone penetration measurements, the containment fan cooler bearing lubricant, Westinghouse Style No. 773A773G05 (Chevron SRI) undergoes no significant change in properties, as measured in terms of consistency.

6.2.2.3.28 10 CFR 50.55a(f) - Inservice Testing Requirements

The CFCS and CSS meet the inservice testing (IST) requirements as described in the DCPP IST Program Plan.

6.2.2.3.29 10 CFR 50.55a(g) - Inservice Inspection Requirements

Design provisions have been made, to the extent practicable, to facilitate access for periodic visual inspection of all important components of the CFCS. Testing of any components, after maintenance or as a part of a periodic inspection program, may be performed at any time, since the CFCS units are in operation on an essentially continuous schedule during normal plant operation. The inservice inspection (ISI) requirements for the CFCS and CSS are contained in the DCPP ISI Program Plan.

6.2.2.3.30 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

CFCS and CSS post-accident instrumentation for meeting Regulatory Guide 1.97, Revision 3, requirements consist of containment isolation valve position indication, containment spray flow indication, containment pressure indication, heat removal by containment fan heat removal system through: CFCU motor speed indication, CCW flow indication, containment pressure indication, and containment atmosphere temperature indication (refer to Table 7.5-6). The instrumentation described above is directly monitored in the control room.

Based on the above discussion, the CFCS and CSS instrumentation satisfy the requirements of Regulatory Guide 1.97, Revision 3, as described in Table 7.5-6.

6.2.2.3.31 NUREG-0737 (Items II.F.1, III.D.1.1), November 1980 - Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident Monitoring Instrumentation: Position (4) – Instrumentation to continuously monitor and record the containment pressure is provided in the control room (refer to Sections 6.2.2.3.3 and 7.5.2.1.2). The wide-range containment pressure indicators satisfy the measurement and indication capability requirements of NUREG-0737, November 1980, Item II.F.1, Position (4). Instrument ranges and accuracies are provided in Table 7.5-4.

Item III.D.1.1 - Integrity of Systems Outside Containment Likely to Contain Radioactive Material for Pressurized-Water Reactors and Boiling-Water Reactors: The pressure-containing portions of the CSS are tested periodically to check for leakage. This testing includes the portions of the system that would circulate radioactive water from the containment sump, if recirculation spray is required.

6.2.2.3.32 Generic Letter 89-10, June 1989 - Safety-Related Motor-Operated Valve Testing and Surveillance

The CSS PG&E Design Class I MOVs are subject to the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996, and meet the requirements of the DCPP MOV Program Plan.

6.2.2.3.33 Generic Letter 97-04, October 1997 – Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps

The containment spray pumps have been evaluated in accordance with Generic Letter 97-04, October 1997 and adequate NPSH is shown to be available. Refer to Section 6.3 for the evaluation of the ECCS pumps.

6.2.2.3.34 Generic Letter 2008-01, January 2008 – Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems

The DCPP Gas Intrusion Program prevents and manages gas accumulation to within design and licensing requirements. DCPP Technical Specifications (Reference 46) require verification that CSS locations susceptible to gas intrusion are sufficiently filled with water.

6.2.2.3.35 10 CFR 50-48(c) – National fire Protection Association Standard NFPA 805

The CFCS is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

6.2.2.4 Tests and Inspections

Refer to Sections 6.2.2.3.15, 6.2.2.3.17 through 6.2.2.3.23, and 6.2.2.3.27 through 6.2.2.3.29 for details regarding tests and inspections of the CHRS.

6.2.2.4.1 Preoperational Testing

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

The aim of preoperational CSS testing was to:

(1) Demonstrate that the system is adequate to meet the design pressure conditions. Outside containment piping welds were subjected to radiographic inspection and/or partial hydrotesting; inside the containment the spray header welds were subjected to 100 percent radiographic inspection.

(2) Demonstrate that the spray nozzles in the containment spray header are clear of obstructions by passing air through the TCs.

(3) Verify that the proper sequencing of valves and pumps occurs on initiation of the containment spray signal and demonstrate the proper operation of remotely operated valves.

(4) Verify the operation of the spray pumps; each pump is run at minimum flow and the flow directed through the normal path back to the RWST. During this time, the minimum flow is adjusted to that required for routine testing.

Each fan cooler unit was tested after installation for proper flow and distribution through the duct distribution system.

6.2.2.4.2 Periodic Testing

Periodic testing of the CHRS is discussed in Sections 6.2.2.3.15, 6.2.2.3.18 through 6.2.2.3.20, 6.2.2.3.22, 6.2.2.3.23, and 6.2.2.3.27.

6.2.2.5 Instrumentation Applications

Refer to Section 6.2.2.3.4 for the instrumentation requirements related to the CHRS.

6.2.2.6 Materials

Design parameters and materials used in the construction of CHRS components are listed in Table 6.2-26. Those parts of the system that may come in contact with borated

water or sodium hydroxide solution are made of stainless steel or a similarly corrosion-resistant material.

6.2.3 Containment Air Purification and Cleanup Systems

The containment air purification and cleanup systems are made up of the SAS, the CSS, and the CFCS. The functional performance objectives of the containment air purification and cleanup systems are:

(1) The SAS provides a chemical additive to the CSS to prevent the re-evolution of the iodine in the recirculated spray and core cooling solution (also known as sump water) following a LOCA;

(2) The CSS removes airborne radioactive iodine and particulates from the containment atmosphere following a LOCA;

(3) The CFCS provides mixing of the sprayed and unsprayed regions of the containment to improve airborne iodine removal. Mixing the containment atmosphere maximizes the gas volume treated by the containment spray;

(4) The CFCS and CSS reduce the containment ambient temperature and pressure following a LOCA or a MSLB. While performing this cooling function, the CHRS also helps limit offsite radiation levels by reducing the pressure differential between containment and outside atmospheres, thus reducing the driving force for leakage of fission products from the containment atmosphere (refer to Section 6.2.2);

(5) The CFCS and CSS provide a mixed containment atmosphere for hydrogen control (refer to Section 6.2.5);

(6) The CFCS limits the containment ambient temperature during normal plant operating conditions (refer to Section 9.4.5).

The SAS boundary consists of all piping and valves between, and including, the isolation valve from the RWST, the spray additive tank and the spray eductors. The safety function of iodine removal occurs during operation of the CSS and while core coolant is retained in the containment sump. The physical SSC design bases, testing and inspection requirements of the CSS and CFCS are discussed in Section 6.2.2, therefore the following section addresses the SAS SSCs only.

The two small charcoal filter units in the containment air purification system are not classified as ESFs and are described in Section 9.4.5. These units are not necessary for cleanup during accident conditions.

6.2.3.1 Design Bases

6.2.3.1.1 General Design Criterion 2, 1967 – Performance Standards

The SAS is designed to withstand the effects of, or is protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds tsunamis, and other local site effects.

6.2.3.1.2 General Design Criterion 3, 1971 – Fire Protection

The SAS is designed and located to minimize, consistent with other safety requirements, the probability and effects of fires and explosions.

6.2.3.1.3 General Design Criterion 11, 1967 – Control Room

The SAS is designed to or contains instrumentation and controls that support actions to maintain and control the safe operational status of the plant from the control room.

6.2.3.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain SAS variables within prescribed operating ranges.

6.2.3.1.5 General Design Criterion 19, 1999 – Control Room

The SAS, in conjunction with the iodine removal function of the CSS and CFCS, is designed to support radiation protection to permit access and occupancy of the control room under accident conditions without personnel receiving radiation in excess of 5 rem TEDE, for the duration of the accident.

6.2.3.1.6 General Design Criterion 21, 1967 – Single Failure Definition

The SAS is designed to tolerate a single failure during the period of recovery following an accident without loss of its protective function, including multiple failures resulting from a single event, which is treated as a single failure.

6.2.3.1.7 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

The SAS, in conjunction with the iodine removal function of the CSS, is designed to prevent the re-evolution of iodine in the containment spray and core cooling solution and provide back-up to the safety function provided by the core design, the RCPB, and their protection systems.

The CFCS is designed to ensure mixing of the sprayed and unsprayed regions of the containment atmosphere, to improve airborne fission product removal following any size RCPB break.

6.2.3.1.8 General Design Criterion 38, 1967 – Reliability and Testability of Engineered Safety Features

The SAS is designed to provide high functional reliability and ready testability.

6.2.3.1.9 General Design Criterion 40, 1967 – Missile Protection

The SAS is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

6.2.3.1.10 General Design Criterion 41, 1967 – Engineered Safety Features Performance Capability

The SAS is designed to provide sufficient performance capability to accommodate a partial loss of installed capacity, such as a single failure of an active component, and still perform its required safety function.

6.2.3.1.11 General Design Criterion 42, 1967 – Engineered Safety Features Components Capability

In support of the iodine removal function, the CSS and CFCS are designed so that the capability of each component and system to perform its required function is not impaired by the effects of a LOCA.

6.2.3.1.12 General Design Criterion 62, 1967 – Inspection of Air Cleanup Systems

The SAS is designed to facilitate physical inspection of critical parts required for operation.

6.2.3.1.13 General Design Criterion 63, 1967 – Testing of Air Cleanup Systems Components

The SAS is designed so that active components can be tested periodically for operability and required functional performance.

6.2.3.1.14 General Design Criterion 64, 1967 – Testing of Air Cleanup Systems

The SAS is designed for in-situ periodic testing and surveillance.

6.2.3.1.15 General Design Criterion 65, 1967 – Testing of Operational Sequence of Air Cleanup Systems

The SAS is designed with the capability to test, under conditions as close to design as practical, the full operational sequence that would bring the SAS into action.

6.2.3.1.16 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The SAS, in conjunction with the iodine removal function of the CSS and CFCS, is designed with provisions for maintaining control over the plant's radioactive gaseous effluents.

6.2.3.1.17 10 CFR 50.55a(f) – Inservice Testing Requirements

ASME code components within the SAS are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

6.2.3.1.18 10 CFR 50.55a(g) – Inservice Inspection Requirements

ASME code components within the SAS are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

6.2.3.1.19 Regulatory Guide 1.183, July 2000, Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors

The steady state elemental iodine removal coefficients, and the time dependent particulate aerosol removal coefficients, are developed in accordance with Regulatory Guide 1.183, July 2000, Appendix A, Section 3.3.

6.2.3.1.20 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

The SAS PG&E Design Class I MOVs meet the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996.

6.2.3.2 System Description

6.2.3.2.1 General Description

The SAS is designed to add sodium hydroxide to the containment spray water to enhance the absorption of elemental iodine from the containment atmosphere and to retain the iodine in the containment sump water in nonvolatile forms.

According to the known behavior of elemental iodine in highly dilute solutions, the hydrolysis reaction, described by the relationships:

$$I_2 + OH^- \rightleftarrows HIO + I^- \qquad (6.2\text{-}8)$$

proceeds nearly to completion (Reference 4) at pH values between 8 and 9.5. The iodine form is highly soluble, and HIO readily undergoes additional reactions to form iodate.

The overall iodate reaction is:

$$3I_2 + 3H_2O \rightleftarrows 5HI + HIO_3 \qquad (6.2\text{-}9)$$

Values of the spray removal half-life of the molecular iodine in a typical containment are on the order of minutes, or less. This makes the spray system a very efficient fission product removal system in comparison to such alternatives as charcoal filtration systems.

The SAS, as shown schematically in Figure 3.2-12, consists of the spray additive tank, eductors, valves, and connecting piping. The design parameters are presented in Table 6.2-29. Applicable codes and standard are given in Table 6.2-30.

The CFCS ensures appropriate mixing of the containment atmosphere following a DBA to maximize the containment gas volume treated by the containment spray.

On actuation, approximately 4 percent of each spray pump discharge flow will be diverted through each spray additive eductor to draw sodium hydroxide from the tank. This sodium hydroxide solution will then mix with the liquid entering the suction line of the pumps to give a solution suitable for removal of iodine from the containment atmosphere.

During the injection phase, the emergency core cooling pumps will inject borated water drawn from the RWST into the reactor and containment. Since these flowpaths will not inject sodium hydroxide, the ratio of the total volume injected by all pumps to the volume injected by the spray pumps will determine the change in sodium hydroxide concentration during the injection phase. The total volume of water in the sump includes the total amount contained in the primary coolant and accumulators that could be released to the containment recirculation sump at the start of the LOCA.

6.2.3.2.2 Component Descriptions

6.2.3.2.2.1 Spray Additive Tank

The stainless steel tank will contain sufficient 30 to 32 weight percent sodium hydroxide solution to bring the containment sump fluid to a minimum pH of 8.0 on mixing with the

borated water from the RWST, the accumulators, and reactor coolant following a large break LOCA (LBLOCA). This will ensure continued iodine removal and retention effectiveness of the containment sump water during the recirculation phase.

6.2.3.2.2.2 Spray Additive Eductors

Sodium hydroxide will be added to the spray liquid by a liquid jet eductor, a device which uses kinetic energy of a pressurized liquid to entrain another liquid. The pressurized liquid in this case is the spray pump discharge used to entrain the sodium hydroxide solution, which is then discharged back into the suction of the spray pumps. On actuation, approximately 4 percent of each spray pump discharge flow is diverted through each spray additive eductor to draw sodium hydroxide solution from the spray additive tank. An eductor motive flowrate of 104 gpm and an eductor suction flowrate of 35 gpm results in a spray solution pH of greater than or equal to 9.5 (refer to design case in Table 6.2-36).

6.2.3.2.2.3 Spray Nozzles

A description of the containment spray nozzles is provided in Section 6.2.2.

6.2.3.2.2.4 Piping and Valves

The piping and valves for the SAS are designed for 240 psig at 200 degrees F.

6.2.3.2.2.5 Electrical Supply

Details of the Class 1E power sources are discussed in Chapter 8.

6.2.3.3 Safety Evaluation

6.2.3.3.1 General Design Criterion 2, 1967 – Performance Standards

The SAS is located within the auxiliary building, which is a PG&E Design Class I structure (refer to Section 3.8). The auxiliary building is designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7) therefore protecting the SAS, ensuring its design functions will be performed.

The SAS is designed to accommodate the Design Earthquake (DE) within applicable code stress limits and to withstand the DDE or HE without rupture or loss of function.

6.2.3.3.2 General Design Criterion 3, 1971 – Fire Protection

The SAS is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

6.2.3.3.3 General Design Criterion 11, 1967 – Control Room

Each of the system's MOVs can be operated individually by switches in the control room. Valve position indication on the same control room panel is used to verify valve operability.

The spray additive tank level instruments provide two alarms to announce when the solution in the tank has dropped below a level approaching the Technical Specification minimum requirements.

6.2.3.3.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Analog and logic channels employed for initiation of SAS operation are discussed in Section 7.3. All alarms will be annunciated in the control room.

The SAS will be actuated by a "P" signal initiated either manually from the control room or on coincidence of two sets of two-out-of-four ”P” signals. Coincidence of "S" and "P" signals will start the containment spray pumps and open the discharge valves to the spray headers. The "P" signal alone will open the valves associated with the spray additive tank.

A locally mounted indicator on the nitrogen line monitors the spray additive tank pressure while adding nitrogen and during periodic inspections.

A flow element is located in the discharge line from the spray additive tank. Flow indication is provided in the control room.

For the spray additive tank, two separate instruments are provided: one to supply readout in the control room and the other to provide local indication.

6.2.3.3.5 General Design Criterion 19, 1999 – Control Room

The CSS provides iodine removal from the containment atmosphere. The CFCS provides mixing of the containment atmosphere to maximize iodine removal. The SAS increases pH in the containment recirculation sump water. The SAS, CSS and CFCS work in conjunction to ensure that radiological exposures for control room personnel are within 5 rem TEDE for the duration of the accident. Refer to Section 15.5 for radiological consequences of plant accidents.

6.2.3.3.6 General Design Criterion 21, 1967 – Single Failure Definition

A failure analysis was conducted on the active components, MOVs 8994A/B, of the SAS to show that failure of any single active component will not prevent the design function from being fulfilled. This analysis is summarized in Table 6.2-38.

MOV 8992 in the spray additive line, which is required only in the short term, is not included in the single failure analysis of Table 6.2-38 because it is not an active component. It performs no active function, is normally open, receives a "P" signal to ensure positive opening, and is designed to fail as is, i.e., in the open position.

In addition, during power operation, power is removed from the single inline SAS outlet MOV 8992 at the circuit breaker at the motor control center with the valve in the open position to prevent a single active failure.

The single failure analysis for the CSS is given in Section 6.2.2.

6.2.3.3.7 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

The design basis of the SAS is two-fold:

(1) Sufficient sodium hydroxide must be added to the containment spray water to ensure rapid absorption by the spray of elemental iodine present in the containment atmosphere following a LOCA.

(2) During the injection phase operation of the spray pumps, a sufficient amount of sodium hydroxide must be carried to the containment sump water via the containment spray to ensure retention of the iodine in the sump solution.

The CSS, by virtue of the large contact surface area provided between the droplets and the containment atmosphere, affords an excellent means of absorbing radioactive iodine released as a consequence of a LOCA. Sodium hydroxide is added to the spray fluid to increase the absorption of iodine in the spray to the point where the rate of absorption is largely limited by the transfer rate through the gas film surrounding the drops. Reference 5 describes in detail the analytical and experimental basis for the above containment atmosphere iodine removal mechanism.
However, the SAS does not have a significant effect on aerosol particle removal as this removal process is largely mechanical.
The SAS is dependent upon the CSS for operation. The CSS can function with one spray train operating (abnormal operating mode) or with both spray trains operating (normal operating mode). In addition, the operation of one or both ECCS trains affects the rate of withdrawal of water from the RWST, the duration of the spray injection phase, and thus the amount of sodium hydroxide added to the containment.

The SAS has been evaluated for the design case, a double-ended LOCA, assuming that:

(1) Only one-out-of-two spray pumps operate (one spray train operating)

(2) The ECCS operates at its maximum capacity (two ECCS trains operating)

(3) Borated water is retained in the RWST for the exclusive use of the spray during the first part of the ECCS recirculation phase

The second assumption maximizes ECCS flow from the RWST. Overall, the first two assumptions give the most conservative prediction of sodium hydroxide introduction into the containment (minimum containment recirculation sump pH). The third assumption ensures that sufficient sodium hydroxide solution is added to provide for a sump pH of 8.0 or greater when spray injection terminates. Figure 6.2-15 presents various resulting sump pH versus time curves.

During the spray injection phase, a single containment spray pump delivers approximately 2466 gpm to the spray header, at containment design pressure (47 psig). If both of the two spray pumps are available in this phase, approximately 4932 gpm is delivered to the containment spray headers from the RWST. This flowrate is not ECCS dependent.

The variation of sump pH with time after the accident is shown for various cases in Figure 6.2-15 (Reference 51). At the time spray injection terminates, the sump water has reached an equilibrium pH of at least 8.0.

Any revolution of dissolved iodine from the sump to the containment atmosphere depends upon the concentration gradient between the liquid and vapor phases. The equilibrium between these iodine concentrations is given by the partition coefficient, H, and is a function of concentration, pH, and temperature. The partition coefficient at pH 8.0 exceeds the value of approximately 4×10^3 required to maintain a decontamination factor of 100 in the containment atmosphere for sump temperature above 120° F, and thus a containment atmosphere decontamination factor of 100 or greater can be expected. Figure 6.2-16 presents equilibrium elemental iodine partition coefficients in the containment at various temperatures for the minimum sump pH case. The equations given by Eagleton (Reference 8) were used to determine the partition coefficients. Although the iodate reaction is expected to contribute significantly to the iodine partition at high sump pH values, it has been neglected in these calculations in the interest of conservatism.

SRP Section 6.1.1, Revision 2, Section II, SRP Acceptance Criteria 2A (Reference 72) and SRP Section 6.5.2, Revision 4, Acceptance Criteria 1G (Reference 61) require that the pH of the sump water be controlled to maintain a minimum value of 7.0 following a LOCA. This is required to prevent re-evolution of the iodine that has been removed from the containment atmosphere by the containment spray and washed into the sump water. A neutral pH also limits material degradation, in particular, stress corrosion cracking of austenitic stainless-steel components in the post LOCA environment.

Long-term retention of iodine in the sump fluid is strongly dependent on the pH. In determining whether the plant chemical addition system is adequate for long-term pH control, long-term production of acids (hydrochloric acid (HCl) and nitric acid (HNO_3)) by irradiation was addressed. A conservative analysis was performed to confirm that the sump water pH at thirty (30) days following a LOCA remains greater than 7.5. The analysis assumed the minimum volume / concentration values for NaOH, in combination with the maximum volume / boration values for the water sources contributing to the sump water volume.

SRP Section 6.5.2, Revision 4, Acceptance Criteria II.1.g, states that long term iodine retention may be assumed when the equilibrium sump water pH, after mixing and dilution with the primary coolant, is above 7.0.

NUREG/CR-5732, April 1992 (Reference 73), states that iodine re-evolution is not a factor if the ultimate sump water pH of ≥ 7 is achieved prior to the time when iodine re-evolution could potentially occur. Section 3.1 of NUREG /CR-5732, April 1992 notes that the following phenomena occur during the first-time interval between t = 0 to t = 1000 min, a) events “leading” to the formation of I_2 by radiolysis, and b) all HI effects except for those related to pH. Re-evolution (i.e. vapor phase elemental iodine produced by radiolysis and partitioned between the aqueous and gas) can occur in the second-time interval which is from t=1000 min to t~2 to 3 weeks. Thus, for Light Water Reactors, a pH of 7 must be achieved within 1000 min of the initial post-LOCA release.

At DCPP, RWST drain-down and chemical addition is essentially complete within an hour post-LOCA; thus, it is expected that as a result of recirculation, the sump water will be well mixed by t=1000 minutes or ~ 16 hours.

Based on the above assessment it was concluded that the DCPP sump water pH will remain greater than 7.0, and the post-LOCA dose consequence analyses need not consider iodine re-evolution from the sump fluid.

6.2.3.3.7.1 Mixing between Sprayed and Unsprayed Regions of Containment

As stated in Section 6.2.3.1.7, the CFCS is designed to ensure mixing of the sprayed and unsprayed regions of the containment atmosphere, to improve airborne fission product removal following any size reactor coolant pressure boundary break.

The containment sprayed volume for the spray injection mode is calculated based on the assumption that the unoccupied containment volume above the operating floor is 100 percent covered by sprays. It includes the sprayed volume below the grating in the operating floor deck, and the refueling cavity volume. Approximately 17.5 percent of the containment free air volume is not reached by the spray. The values listed below were used to estimate the total unsprayed volume in the containment.

(1)	Containment radius	70 ft
	Height between operating deck and spring line	91 ft

Approximate deck area covered only by grating	2,990 ft^2
Height between elevation 91 feet and deck	49 ft
Average fall height below deck through grating	12 ft

(2) These data result in the following volumes:

Volume in dome	717,000 ft^3
Volume in cylinder above deck	1,400,000 ft^3
Occupied volume above deck	-95,000 ft^3
Sprayed volume below deck	36,000 ft^3
Sprayed refueling cavity volume	45,000 ft^3
Total sprayed volume	2,103,000 ft^3
Total free volume	2,550,000 ft^3
Total unsprayed volume	447,000 ft^3
Percent unsprayed volume	~17.5 %

To justify the assumption that the unoccupied containment volume above the operating floor is 100 percent covered by sprays, the analysis of the containment spray coverage during the spray injection mode with only one CSS train operating estimated the projected unsprayed area percentage of the containment deck area of 42 percent for Unit 1 and 44 percent for Unit 2, using actual spray flow patterns. The spray reduction factor of 0.5 used to address the spray compression effect due to elevated containment pressure was conservatively based on the containment design pressure. It was concluded that the whole volume above the operating floor can be considered well mixed and totally subjected to the sprays given the estimated spray coverage calculated above based on actual spray patterns, and the high levels of turbulence due to spray action, entrainment of the air from the volume outside the spray patterns, and induced upflow of air to balance the downflow experienced in the sprayed volume.

The effect of the reduction in spray flow rate between the spray injection phase (i.e., 2456 gpm) and the spray recirculation phase (i.e., 1211 gpm) on the containment spray coverage was evaluated. The minimum volumetric flow rate of water through the spray nozzles, the associated nozzle water pressure drop, and Figure 1 of NUREG/CR-5966, June 1993 (Reference 63), were used to establish the effect of the reduction in spray flow rate on the spray pattern. The analysis determined that with the continued use of a spray reduction factor of 0.5 for spray compression, there was a 3 percent increase in the unsprayed area percentage of the containment deck for both units. It was concluded that the continued use of a spray pattern reduction factor of 0.5 is extremely conservative when applied to the recirculation mode (the containment pressure is substantially lower than the design pressure), and that there is no significant increase in the unsprayed area percentage of the containment deck for both Unit 1 and Unit 2. Thus, a sprayed volume of 82.5 percent of the containment free volume is also applicable for the containment spray recirculation mode.

The CFCUs support post-LOCA mixing of the sprayed and unsprayed volume of the containment at a rate higher than that justified by natural convection. The containment mixing rate between the sprayed and unsprayed regions following a

LOCA is determined to be 9.13 turnovers of the unsprayed regions per hour. This mixing rate is based on the operation of two CFCUs, with an assumed total volumetric flow rate of 68,000 cfm between the unsprayed regions and sprayed regions.

Review of the locations of the intake and exhaust registers of the operating fan coolers, the major openings in the containment structure, and various active and passive mixing mechanisms, results in the conclusion that following a LOCA, credit can be taken for a) the entire flowrate provided by each operating CFCU to support mixing between the sprayed and unsprayed regions, and b) homogeneous mixing within the sprayed and unsprayed regions, of the volume of air transferred from one region to the other due to CFCU operation.

6.2.3.3.7.2 Fission Product Removal

Regulatory Guide 1.183, July 2000, Appendix A, Section 3.3 (Reference 62), invokes the guidance of SRP 6.5.2, Revision 4 and NUREG/ CR-5966, June 1993 (Reference 63) as acceptable models for removal of iodines and particulates.

In accordance with the above guidance, the fission product removal coefficients developed for the LOCA are based on the following:

1) Elemental iodine removal coefficients are calculated using guidance provided in SRP 6.5.2 which is invoked by Regulatory Guide 1.183, July 2000, Appendix A, Section 3.3.

2) Time dependent particulate aerosol removal coefficients are estimated using guidance provided in Regulatory Guide 1.183, July 2000, Appendix A, Section 3.3, for alternative source terms, and use of computer program SWNAUA. Refer to Section 15.5.8.12 for a description of computer program SWNAUA.

The total elemental iodine and particulate removal coefficients in the sprayed and unsprayed region of the containment as a function of time are summarized in Table 6.2-32. The methodology utilized to develop these values is summarized below.

6.2.3.3.7.2.1 Elemental Iodine Removal

The methodology presented in Section III, 4.C.i, of SRP 6.5.2, Revision 4 is used to estimate the elemental iodine removal coefficients. The removal of elemental iodine from the containment atmosphere can be attributed due to wall deposition ($\lambda_{E,\ Wall}$) and due to the action of containment spray ($\lambda_{E,\ Spray}$).

<u>Elemental Iodine Removal Coefficients Due to Wall Deposition ($\lambda_{E,Wall}$)</u>

The elemental iodine removal coefficients due to wall deposition can be estimated using the equation provided in SRP 6.5.2, Revision 4.

$$\lambda_{E,\ Wall} = K_w \cdot A / V \qquad (6.2\text{-}10)$$

Where: K_w = mass transfer coefficient (ft/hr) A = wetted surface area (ft^2)
V = volume of the containment (ft^3)

Note: K_w value of 4.9 m/hr (or 16.08 ft/hr.) conservatively envelopes all available experimental data (SRP 6.5.2, Revision 4).

The total containment surface area (435,256 ft^2) is initially available for wall deposition due to condensation on heat sink surfaces prior to spray actuation after accident. Subsequently, due to heat-up, certain portions of the heat sink surfaces become non-condensing and can no longer be considered as "wetted" surfaces. However, after spray actuation, since the heat sink surfaces in the sprayed region are continuously wetted by sprays, elemental iodine removal due to wall deposition in the sprayed region is valid over the entire period of containment spray operation. The wetted surface area within the sprayed volume is conservatively assumed to be limited to the carbon steel lined containment shell surface area (90,560 ft^2) multiplied by the spray coverage fraction of containment volume. Therefore, wall deposition elemental iodine removal coefficients are calculated during the period 1) prior to containment spray actuation, applicable to the entire containment, and 2) post containment spray actuation, applicable in the sprayed region for the duration of spray operation.

Elemental Iodine Removal Coefficients Due to Sprays in the Sprayed Region ($\lambda_{E,Spray}$)

The elemental iodine removal coefficients due to spray actuation can be estimated using the equation provided in Section III, 4.C.i, of SRP 6.5.2.

$$\lambda_{E,\,Spray} = (6\,K_g \cdot t \cdot F) / (V_s \cdot d) \qquad (6.2\text{-}11)$$

Note: This equation is valid for 10 hr^{-1} $\leq \lambda_{E,\,Spray} \leq$ 20 hr^{-1} to prevent extrapolation beyond the existing data for boric acid solution with a pH of 5.

Where: K_g = gas phase mass transfer coefficient (ft/hr)
t = time of fall of the spray droplets (= h/U_T) (hr)
F = volumetric spray flow rate (ft^3/hr)
V_s = effectively sprayed containment free volume (ft^3)
d = mass-mean diameter of the spray droplets (ft)
h = mean fall height of the spray droplet (ft)
U_T = terminal velocity of the spray droplet (ft/hr)

The gas phase mass transfer coefficient is determined by using the equation provided in Reference 64.

$$K_g = (D_g/d) \times 2.0 \times (1 + 0.276 \cdot Re^{1/2}\, Sc^{1/3}) \qquad (6.2\text{-}12)$$

Where: D_g = diffusivity of iodine in the gas film surrounding the drop (ft^2/hr)
Re = dimensionless Reynolds number
Sc = dimensionless Schmidt number

6.2.3.3.7.2.2 Particulate Removal

There are several aerosol mechanics phenomena that promote the depletion of aerosols from the containment atmosphere. These include the natural phenomena of particle growth due to agglomeration, gravitational settling of particles (also called gravitational sedimentation), diffusiophoresis (particulate removal due to steam condensation), and removal by fluid mechanical interaction with the falling droplets that enter the containment atmosphere through the spray system nozzles (i.e., containment spray).

All of the above phenomena are credited for DCPP. Agglomeration of the aerosol is considered in both sprayed and unsprayed regions. In the sprayed region, the particulate removal calculation takes credit for the removal effectiveness of diffusiophoresis and sprays. Gravitational settling is considered only in the unsprayed region**.**

<u>Removal of Particulates by Sprays</u>

The particulate removal rate is calculated using computer code SWNAUA. The model correlations implemented into SWNAUA conservatively underestimates the spray removal coefficient. The spray model incorporated in the SWNAUA code was originally described in Reference 66. When performing DBA calculations to determine particulate removal in the effectively sprayed region of the containment, only the conservatively developed spray removal models and conservative steam condensation rates for the diffusiophoresis calculation are utilized. While agglomeration is considered in the calculation, its impact on the resulting particulate removal rates is negligible. In summary, the aerosol removal rates calculated by SWNAUA are conservative lower bound estimates.

The spray model in SWNAUA evaluates the particulate removal efficiency for each particle size in the aerosol by the following mechanisms: inertial impaction, interception, and Brownian diffusion. The aerosol removal constant due to spray is presented in NUREG-0772, June 1981 (Reference 67) as:

$$\lambda_{spray} = \frac{3F_m h\varepsilon}{4R_{sp}\rho_W V} \text{ x } \frac{v_{spray} - v_{sed}}{v_{spray}} \qquad (6.2\text{-}13)$$

Where

λ_{spray}	=	Particulate removal constant for spray,
F_m	=	Spray mass flow rate,
h	=	Spray fall height,
ε	=	Collision efficiency,
R_{sp}	=	Spray droplet radius,
ρ_w	=	Density of the spray droplet,
V	=	Effectively sprayed volume of containment,
v_{spray}	=	Velocity of the spray droplets, and
v_{sed}	=	Aerosol sedimentation velocity.

The collision efficiency is divided into three contributing mechanisms as described in BMI-2104 (Reference 68):

$$\varepsilon = \varepsilon_i + \varepsilon_r + \varepsilon_d \tag{6.2-14}$$

Where

ε_i	=	Efficiency due to inertial impaction,
ε_r	=	Efficiency due interception and
ε_d	=	Efficiency due to Brownian diffusion.

For viscous flow around the spray droplet, the inertial impaction efficiency is given in Reference 67:

$$\varepsilon_i = \frac{1}{\left[1 + \frac{0.75\ln(2\,\mathrm{Stk})}{\mathrm{Stk} - 1.214}\right]^2} \tag{6.2-15}$$

The critical Stokes number, Stk, for viscous flow is 1.214; for Stk below this value, the model assumes the efficiency of inertial impaction is 0.0. The Stk is calculated from Reference 68:

$$\mathrm{Stk} = \frac{2\rho_p r^2 C_c (v_{spray} - v_{sed})}{9\mu R_{sp}} \tag{6.2-16}$$

Where

r	=	Aerosol particle radius,
ρ_p	=	Aerosol density,
C_c	=	Cunningham slip correction factor,
μ	=	Gas viscosity.

For droplet sizes typical of nuclear plant spray systems, the data of Walton and Woolcock (Reference 70) show that collision efficiency will be closer to that predicted for potential flow around the droplet. Calvert (Reference 71) fitted this data to the expression:

$$\varepsilon_i = \left(\frac{Stk}{Stk + 0.7}\right)^2 \qquad (6.2\text{-}17)$$

The collision efficiency predicted by this equation is always higher than that predicted by the viscous flow expression given above. The Calvert's fit is employed in this calculation.

As for the remaining constituents of the collision efficiency, the spray model employs an interception efficiency of the form:

$$\varepsilon_r \cong \frac{3}{2}\left(\frac{r}{R_{sp}}\right)^2 x\left(1 - \frac{1}{3}\frac{r}{R_{sp}}\right) \qquad (6.2\text{-}18)$$

which is a conservative approximation of the expression given by Reference 68. The efficiency due to Brownian motion is also taken from this report:

$$\varepsilon_d = 3.5 Pe^{-2/3} \qquad (6.2\text{-}19)$$

Where

Pe	=	Peclet number
	=	$2v_{spray} R_{sp}/D_B$,
D_B	=	Aerosol diffusion coefficient
	=	k_{Boltz} TB (Fuchs: Reference 69),
k_{Boltz}	=	Boltzmann constant
	=	1.3804×10^{-16} erg/K.
T	=	Temperature, K

Reference 69 gives the aerosol mobility, B:

$$B = \frac{C_c}{6\pi\mu r} \qquad (6.2\text{-}20)$$

In most cases, the overall collision efficiency is dominated by inertial impaction, but for small aerosols, Brownian diffusion may become dominant. The collision efficiency due to inertial impaction increases as the aerosol size is increased, whereas that due to Brownian diffusion increases as the aerosol size decreases.

Removal of Particulates by Diffusiophoresis

Particulate matter is entrained in the steam as it flows to the condensation surfaces. This phenomenon is called diffusiophoresis. Steam is assumed to condense on spray droplets, on the containment fan cooler units, and on heat sinks.

Particulate matter is entrained in the steam as it flows to the condensation surfaces. This phenomenon is called diffusiophoresis. Steam is assumed to condense on spray droplets, on the containment fan cooler units, and on heat sinks.

The key input parameters used for the particulate removal coefficients are presented in Tables 6.2-33, 6.2-34, 6.2-35, and 6.2-37.

6.2.3.3.8 General Design Criterion 38, 1967 – Reliability and Testability of Engineered Safety Features

The SAS testing and inspections are enveloped by the ISI and IST programs. Pressure containing portions of the CSS and SAS are inspected in accordance with ASME BPVC, Section XI, as required by the Technical Specifications and the ISI Program Plan (Reference 38) (refer to Section 6.2.3.3.17 for IST and Section 6.2.3.3.18 for ISI).

6.2.3.3.9 General Design Criterion 40, 1967 – Missile Protection

The SAS is protected from internal missiles, pipe whip, and jet impingement effects resulting from equipment failure and the rupture of any nearby high-energy line (refer to Sections 3.5.3.2 and 3.6.6.2.).

6.2.3.3.10 General Design Criterion 41, 1967 – Engineered Safety Features Performance Capability

The SAS is designed to tolerate a single active failure without loss of protective function and as such is designed with the redundancy to accommodate a partial loss of installed capacity. The SAS is in use only during the injection period following a LOCA (refer to Section 6.2.2.3.6).

6.2.3.3.11 General Design Criterion 42, 1967 – Engineered Safety Features Components Capability

The CSS and CFCS component design pressure and temperature conditions in Table 6.2-26 are specified as the most severe conditions to which each component is exposed during either normal or post-LOCA operation while maintaining the capability of the system to provide its required design function in post-LOCA conditions (refer to Section 6.2.2).

6.2.3.3.12 General Design Criterion 62, 1967 – Inspection of Air Cleanup Systems

During periodic tests, the equipment is inspected visually for leaks. Leaking seals, packing, or flanges are corrected to eliminate the leak. Valves and pumps are operated and inspected after every maintenance to ensure proper operation.

All critical parts of the SAS are inspected in accordance with the plant ISI Program and in compliance with 10 CFR 50.55a(g). Refer to Section 6.2.3.3.18 for further discussion.

6.2.3.3.13 General Design Criterion 63, 1967 – Testing of Air Cleanup Systems Components

Routine periodic testing of the SAS components and all necessary support systems at power, under the conditions defined in the Technical Specifications, is performed.

Each of the SAS MOVs are tested while the pumps are shut down. During eductor suction valve operation, the normally open spray additive tank valve is closed. Relief valves and vacuum breakers on the sodium hydroxide tank are set and tested prior to installation and periodically thereafter.

The purpose of the motor-operated double-disk gate valve in the spray additive line, shown in Figure 3.2-12, is to permit periodic testing of the two parallel MOVs downstream from that valve.

6.2.3.3.14 General Design Criterion 64, 1967 – Testing of Air Cleanup Systems

The concentration of the sodium hydroxide additive solution is established at the time of initial tank fill, and then periodically checked by titration of tank samples taken from the local sample connection.

The testing of the CSS and CFCS is discussed in Section 6.2.2.

6.2.3.3.15 General Design Criterion 65, 1967 – Testing of Operational Sequence of Air Cleanup Systems

Provisions are made in the circuitry of the various system alarms to test the proper operations of the alarm circuitry with a test signal input. These circuits include the sodium hydroxide tank low-level alarms, the RWST low-level alarms, and the containment high-pressure alarms.

The SAS is tested to verify operational sequence under conditions as close to design as practical. For testing of the operational sequence required to actuate the SAS, refer to Section 7.3.4.1.5.2.

6.2.3.3.16 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The functional performance requirement for the SAS, in conjunction with the iodine removal functions of the CSS and CFCS, is to ensure that offsite radiological exposures resulting from a LOCA are within the limits of 10 CFR 50.67, refer to Section 15.5.

The use of the spray removal coefficients in the radiological release calculations for the LOCA is described in Section 15.5.

6.2.3.3.17 10 CFR 50.55a(f) – Inservice Testing Requirements

The IST requirements for SAS ASME code class valves are contained within the IST Program Plan.

6.2.3.3.18 10 CFR 50.55a(g) – Inservice Inspection Requirements

Pressure containing portions of the CSS and SAS are inspected in accordance with ASME BPVC Section XI, as required by the Technical Specifications and the ISI Program Plan (Reference 38).

6.2.3.3.19 Regulatory Guide 1.183, July 2000, Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors

The steady state elemental iodine removal coefficients, and the time dependent particulate aerosol removal coefficients, are developed in accordance with Regulatory Guide 1.183, July 2000, Appendix A, Section 3.3, and discussed in detail in Section 6.2.3.3.7.2.

6.2.3.3.20 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

The SAS MOVs are subject to the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996, and meet the requirements of the DCPP MOV Program Plan.

6.2.3.4 Tests and Inspections

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

The CSS was tested functionally in accordance with written procedures, as outlined in Chapter 14.

Spray pump delivered flow and head data were recorded to verify that the containment spray pumps meet design criteria.

Spray additive eductor performance data were provided by the manufacturer based on actual tests of a similar eductor. These tests were conducted using a 1.3 specific gravity solution to verify eductor design performance. Additional manufacturer's tests were run using water so that comparative performance data were available for the two different additive solutions at eductor design conditions. Eductor performance was checked subsequent to installation into the system. Spray additive flowrates were measured, with resulting rates in the range 31.5 to 38.5 gpm (35 gpm ± 10 percent) considered acceptable.

Each containment spray header was tested individually by connecting a source of air to the normally capped flange connection on the spray pump discharge header, shutting the manual spray header isolation valve and opening the air test line isolation valve and the motor-operated spray header isolation valve. Individual nozzles were checked for proper performance by streamers, which indicated unobstructed air flow.

The containment sump recirculation mode was tested initially as part of a preoperational flow test under ambient conditions of the SI system. The purpose of the test was to demonstrate the capability of appropriate subsystems to deliver fluid from the containment sump into the RCS in the required time.

6.2.3.5 Instrumentation Applications

Refer to Section 6.2.3.3.4 for instrumentation important to the operation of the SAS.

6.2.3.6 Materials

The SAS design parameters and materials of construction are listed in Table 6.2-29. Code compliance is shown in Table 6.2-30.

Parts of the system in contact with borated water, the sodium hydroxide spray additive, or mixture of the two are stainless steel or an equivalent corrosion-resistant material.

6.2.4 CONTAINMENT ISOLATION SYSTEM

The CIS prevents excessive radioactivity from passing through the containment to the atmosphere in the event of a LOCA. This is accomplished by automatically sealing the various lines through the containment walls.

6.2.4.1 Design Bases

The CIS is designed to meet the containment isolation requirements of the 1971 GDC except where specifically indicated. When deviations are noted, these cases do not

meet the 1971 GDC because of commitment to design and construction prior to issuance of these criteria. Such cases do comply with the 1967 GDC, however.

6.2.4.1.1 General Design Criterion 2, 1967 – Performance Standards

The components that make up the CIS are designed to withstand the effects of, or are protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

6.2.4.1.2 General Design Criterion 10, 1967 – Containment

The CIS is designed, together with other engineered safety features, to retain for as long as the situation requires the functional capability of the containment to protect the public in the event of gross equipment failures, such as a LOCA.

6.2.4.1.3 General Design Criterion 11, 1967 – Control Room

The CIS is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room.

6.2.4.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The CIS is designed with instrumentation and controls as required to monitor and maintain variables within prescribed operating ranges.

6.2.4.1.5 General Design Criterion 21, 1967 - Single Failure Criterion

The CIS is designed to tolerate a single failure during the period of recovery following an accident without loss of its protective function, including multiple failures resulting from a single event, which is treated as a single failure.

6.2.4.1.6 General Design Criterion 40, 1967 – Missile Protection

The CIS is designed with protection against dynamic effects and missiles that might result from plant equipment failures.

6.2.4.1.7 General Design Criterion 53, 1967 – Containment Isolation Valves

The CIS is designed such that the CCW penetration to the excess letdown heat exchanger is provided with redundant valving and associated apparatus. The CCW penetration to the excess letdown heat exchanger does not meet GDC 57, 1971 because of commitments to design and construction made prior to the issuance of the 1971 GDC. This penetration does comply with GDC 53, 1967.

6.2.4.1.8 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The CIS is designed such that the piping systems that penetrate containment are provided with leak detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. These piping systems are designed with a capability to test periodically that operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

6.2.4.1.9 General Design Criterion 55, 1971 - Reactor Coolant Pressure Boundary Penetrating Containment

The CIS is designed such that each line that is part of the RCPB that penetrates containment is provided with containment isolation valves as follows, unless otherwise demonstrated that the containment isolation provisions for a specific class of lines are acceptable on another defined basis:

(1) One locked closed isolation valve inside and one locked closed isolation valve outside containment; or

(2) One automatic isolation valve inside and one locked closed isolation valve outside containment; or

(3) One locked closed isolation valve inside and one automatic isolation valve outside containment. A simple CV is not used as the automatic isolation valve outside containment; or

(4) One automatic isolation valve inside and one automatic isolation valve outside containment. A simple CV is not used as the automatic isolation valve outside containment.

Isolation valves outside containment are located as close to the containment as practical and upon loss of actuating power, automatic isolation valves are designed to take the position that provides greater safety.

6.2.4.1.10 General Design Criterion 56, 1971 - Primary Containment Isolation

The CIS is designed such that each line that connects directly to the containment atmosphere and penetrates containment is provided with containment isolation valves as follows, unless it is demonstrated that the containment isolation provisions for a specific class of lines are acceptable on another defined basis:

(1) One locked closed isolation valve inside and one locked closed isolation valve outside containment; or

(2) One automatic isolation valve inside and one locked closed isolation valve outside containment; or

(3) One locked closed isolation valve inside and one automatic isolation valve outside containment. A simple CV is not used as the automatic isolation valve outside containment; or

(4) One automatic isolation valve inside and one automatic isolation valve outside containment. A simple CV is not used as the automatic isolation valve outside containment.

Isolation valves outside containment are located as close to the containment as practical and upon loss of actuating power, automatic isolation valves are designed to take the position that provides greater safety.

6.2.4.1.11 General Design Criterion 57, 1971 - Closed System Isolation Valves

The CIS is designed such that each line that penetrates containment and is neither part of the RCPB nor connected directly to the containment atmosphere has at least one containment isolation valve which is either automatic or locked closed or capable of remote-manual operation. This valve is outside containment and located as close to the containment as practical. A simple CV is not used as the automatic isolation valve.

Refer to Table 6.2-39 for exceptions to GDC 57, 1971.

6.2.4.1.12 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The containment is designed as a barrier to maintain control over plant radioactive effluents, whether gaseous, liquid, or solid to meeting the radiological limits of 10 CFR 50.67. Appropriate holdup capacity is provided for retention of gaseous effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment.

6.2.4.1.13 Containment Isolation System Safety Function Requirements

(1) <u>Protection from Jet Impingement – Inside Containment</u>

The portion of the CIS located inside containment is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

6.2.4.1.14 10 CFR Part 50 Appendix J, Option B - Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors

The CIS is designed to enable implementation of a performance-based containment leakage rate testing program for Type C local leak rate tests with approved exemptions.

6.2.4.1.15 Regulatory Guide 1.163, September 1995 - Performance-Based Containment Leak-Test Program

The CIS is designed to allow the use of a performance-based leak-test program, including the leakage-rate test methods, procedures, and analyses as required by Regulatory Guide 1.163, September 1995.

6.2.4.1.16 NUREG-0737 (Item II.E.4.2), November 1980 - Clarification of TMI Action Plan Requirements

Item II.E.4.2 - Dependability of Containment Isolation:

Position (1) - The CIS is designed with diverse parameters sensed for the initiation of containment isolation.
Position (2) - The CIS process penetrations are classified as nonessential, essential, and safety system process lines for the determination of those penetrations isolated by a containment isolation signal.

Position (3) - The CIS nonessential systems use either manually sealed closed valves or are automatically isolated on a Phase A containment isolation signal. Additionally, essential systems are automatically isolated on a Phase B isolation signal.

Position (4) - The CIS is designed so that re-setting of a containment isolation signal will not result in the automatic re-opening of any containment isolation valves. Ganged re-opening cannot result from a single operator action after the containment isolation signal has been reset.

Position (5) - The CIS is designed so that the containment setpoint pressure that initiates containment isolation for nonessential penetrations is set to the minimum compatible with normal operating conditions with additional margin to allow for a small pressure transient.

Position (6) – The vacuum/overpressure relief valves satisfy Branch Technical Position CSB 6-4, September 1975.

The containment purge system valves are sealed closed in accordance with SRP 6.2.4, Item II.6 and II.14.

Position (7) - The containment vent and purge isolation valves close on a high radiation signal.

6.2.4.1.17 Generic Letter 89-10, June 1989 - Safety-Related Motor-Operated Valve Testing and Surveillance

In the CIS, PG&E Design Class I position-changeable MOVs meet the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996.

6.2.4.1.18 Generic Letter 96-06, September 1996 - Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions

6.2.4.1.19 10 CFR 50.48(c) – National fire Protection Association Standard NFPA 805

The CIS is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

The CIS is designed to prevent thermally induced overpressurization of isolated water-filled piping sections in containment during design-basis accidents.

6.2.4.2 System Description

The CIS includes the mechanical and instrumentation fluid penetrations and associated valves and isolation devices. These penetrations are identified in Figure 6.2-19 and Table 6.2-39. The CIS design uses the following premises:

(1) An automatic containment isolation barrier is provided by a closed system, a trip valve, or a CV.

(2) A closed system meets the following requirements:

a) Inside the containment:

1. No mass transfer with either the RCS or the reactor containment interior
2. Has the same safety classification as ESFs (PG&E Design Class I, PG&E Quality/Code Class II)
3. Must withstand an external pressure and temperature that is greater than containment design pressure and temperature
4. Must withstand accident transient and environmental parameters
5. Must be protected against missiles and high-energy jets

b) Outside the containment:

1. Does not communicate with the atmosphere outside the containment

2. Has the same safety classification as ESFs (PG&E Design Class I, PG&E Quality/Code Class II)

3. Internal design pressure and temperature must be greater than containment design pressure and temperature

4. Must be protected against missiles and high-energy jets

(3) A trip valve is a motor-, air-operated, or solenoid valve that moves to a preferred position upon a containment isolation signal. It can additionally be opened or closed manually from a remote location.

(4) Lines that must remain in service subsequent to certain accidents have, as a minimum, one manual isolation valve.

(5) Lines 1 inch nominal pipe size and larger that penetrate the containment and are connected to the RCS have at least two valves inside the containment. The valves are normally closed or have automatic closure. For incoming lines, CVs are permitted and are considered as an automatic barrier inside containment.

(6) All isolation valves (automatic and manual) and associated equipment are PG&E Design Class I. The isolation section piping is PG&E Design Class I, PG&E Quality/Code Class II.

6.2.4.2.1 Containment Penetration Piping Isolation Grouping

The definitions used in the design bases and the physical configuration of various systems that penetrate the containment divide themselves naturally into five groups. These groups were used to determine the necessary valves on lines penetrating the containment. The lines and valves are shown graphically in Figure 6.2-17. PG&E has named and defined each group as shown below. The groupings, A through E, do not correspond to the piping code classes described in Section 3.2.2.3.

6.2.4.2.1.1 Group A Piping

Group A piping complies with the requirements of either GDC 55, 1971 or GDC 56, 1971. Outside the containment this piping either connects directly to the atmosphere or is considered open, even though it may be physically closed. Inside the containment, it is either part of the RCPB, opens directly to the containment atmosphere, or is

considered open, even though it may be physically closed. In this group, the following minimum requirements apply:

(1) Incoming Lines: One trip valve inside the containment and one trip valve outside the containment, or one CV inside the containment and one trip valve outside the containment

(2) Outgoing Lines: One trip valve inside the containment and one trip valve outside the containment

6.2.4.2.1.2 Group B Piping

Group B piping complies with the requirements of either GDC 55, 1971 or GDC 56, 1971. Outside the containment, this piping operates in a closed system (physically closed and PG&E Design Class I), and inside the containment it is either part of the RCPB or connects directly to the containment atmosphere. For this group the following minimum requirements apply:

(1) Incoming Lines: One CV inside the containment and a closed system outside the containment

(2) Outgoing Lines: One trip valve inside the containment and a closed system outside the containment

6.2.4.2.1.3 Group C Piping

Group C piping complies with the requirements of GDC 57, 1971 which states that isolation valves in closed systems must be outside the containment and no simple CV may be used. Outside the containment, this piping connects with systems that are either opened or closed. Inside the containment, both types of systems are separated from the RCPB and from the containment atmosphere by a membrane barrier. For this group, the following minimum requirements apply:

(1) Incoming Lines: One trip valve outside containment

(2) Outgoing Lines: One trip valve outside containment

6.2.4.2.1.4 Group D Piping

Group D piping complies with the requirements of the applicable GDC 55, 1971; GDC 56, 1971; or GDC 57, 1971 to the extent that valves are provided in the proper locations. These lines must, however, remain in service following an accident and, therefore, the valves do not isolate automatically, but trip to the required position. Piping for the ESFs and supporting systems are included in this class. For this group, the following minimum requirements apply:

(1) Incoming Lines: One local or remote-manual valve outside the containment

(2) Outgoing Lines: One local or remote-manual valve outside the containment

6.2.4.2.1.5 Group E Piping

Group E piping complies with the requirements of either GDC 55, 1971; GDC 56, 1971; or GDC 57, 1971. This piping is characterized by sealed closed valves and is used for intermittent service not related to system functions. For this group, the following minimum requirements apply:

(1) Incoming Lines: Sealed closed manual valve outside the containment and a sealed closed manual valve or a CV inside the containment

(2) Outgoing Lines: Sealed closed manual valve outside the containment and a sealed closed manual valve inside the containment

(3) No-flow Lines: Diaphragm or sealed closed valve outside containment and diaphragm inside containment

6.2.4.2.2 Piping Systems

With some exceptions, such as those noted in Table 6.2-39, piping systems penetrating the containment conform to GDC 54, 1971; GDC 55, 1971; GDC 56, 1971; and GDC 57, 1971. The number and location of isolation valves are shown graphically in Figure 6.2-19; the legend for the diagrams is given in Figure 6.2-18. The criteria to which each penetration complies and a description of the isolation valves are given in Table 6.2-39. To the extent indicated in Table 6.2-39 and Figure 6.2-19, piping penetrations are designed with the capability of leak detection and periodic testing of the isolation valve operability.

6.2.4.3 System Design

All piping, valves, and connected equipment necessary to maintain the containment isolation boundary are designed to withstand post-accident conditions with respect to pressure, temperature, and atmospheric conditions at which they are required to maintain that boundary.

Analyses were made to ensure the integrity of the isolation valve system and connecting lines due to the forces resulting from inadvertent closure of isolation valves under operating conditions. Potential maximum forces and moments have been calculated, and valves, piping systems, and piping configurations have been designed to withstand these forces. Flued heads have also been designed to withstand these

forces. Where required, snubbers and pipe restraints have been installed to absorb forces and prevent pipe ruptures caused by the inadvertent closure of an isolation valve.

6.2.4.3.1 Valve Positioning

Valves that operate as part of the SI system are designated by the letter "S" in the penetration diagrams in Figure 6.2-19.

Specific administrative procedures govern the positioning of all of the containment isolation valves (except CVs) during normal operation, shutdown, and accident conditions. The positioning of all of the valves required to maintain the penetration pressure boundary and containment integrity, as well as any flanged closures, is governed by the administrative procedures.

The main steam lines each have a CV in series with the isolation valve to prevent reverse flow of steam in the event of the rupture of a steam line inside the containment. Instrumentation and logic circuits are provided to detect a ruptured steam line and to close the automatic trip isolation valves on the steam lines.

6.2.4.3.2 Systems Data

Table 6.2-39 lists the CIS penetrations and the valves and closed systems employed for containment isolation. This table lists the number and types of isolation valves, valve positions during normal operation, shutdown, accident conditions, and primary and secondary modes of actuation, as well as their functional classification in accordance with the definitions in Section 6.2.4.2.1 above. The containment isolation valves that are normally closed to maintain the containment isolation and do not perform an active function following an accident are administratively sealed closed. Associated isolation devices required to maintain containment leakage integrity of penetrations and closed systems such as vent, drain, test, instrumentation and branch line valves, blind flanges, caps or other passive devices are not shown in Table 6.2-39, but are administratively controlled to be in their proper isolation configuration by plant procedures. Supplementary information regarding the listing in the table is discussed in the following paragraphs:

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

(1) *Leakage Characteristics at Accident Pressures*

All valves for containment isolation were specified, constructed, and tested to the maximum allowable leakage rates as shown in the following (Type C leakage limits are administratively assigned in the Containment Leakage Rate Testing Program):

Valve Type	*Seat Leakage[a]*
Ball	*<0.3*
Globe and gate	*3*
Check[b]	*3*
Diaphragm (Saunders Patent)	*Negligible*
Butterfly (rubber-seated)	*Negligible*

Notes:

(a) Leakage is expressed in units of cubic centimeters of water per hour per inch of nominal pipe size at valve design conditions

(b) The main steam isolation valve is a Schutte-Koerting reverse check which does not meet this seat leakage criterion.

Maximum allowable stem leakage for open backseated valves was specified as one cubic centimeter of water per hour per inch of stem diameter at design conditions.

(2) Control System Type

Containment isolation valves are provided with actuation and control features appropriate to the valve type. For example, air-operated globe and diaphragm valves are generally equipped with air diaphragm operators, spring loaded to fail-closed on loss of air or electrical signal. Motor-operated gate valves can be supplied from Class 1E Standby Power Supply as well as their normal power source. Manual and CVs do not require actuation or control systems. Valve and operator types are listed in Table 6.2-39.

(3) Signal to Operate the Valve

All remote-manual containment isolation valves are opened and closed normally from the control room or from local control panels (e.g., sampling system valves are operated from a panel in the post-accident sample room).

(4) Power Source Required to Actuate or Operate the Valve

Remote-manual containment isolation valves are actuated by compressed gas or electrical power (refer to Table 6.2-39).

(5) Time Necessary to Close the Valve

Standard closing times normally available are adequate for the sizes of containment isolation valves used. Valves equipped with air diaphragm operators generally close in approximately 2 seconds; 10 seconds is typical of the closing time available in large motor-operated gate valves.

(6) Normal and Failed Positions of the Valves

Normal and failed positions of the valves are indicated in Table 6.2-39. Diagrams for each penetration, showing all valves, barriers, missile shielding, and leakage TCs are shown in Figure 6.2-19. The parts of the piping systems that are PG&E Design Class I are also indicated in this figure. The conditions requiring containment isolation are listed in Table 6.2-40.

6.2.4.4 Safety Evaluation

6.2.4.4.1 General Design Criterion 2, 1967 – Performance Standards

The CIS is designed such that many of the CIS components are contained in the auxiliary building and containment structure. These structures are PG&E Design Class I (refer to Section 3.8). These buildings or applicable portions thereof are designed to withstand the effects of winds and tornadoes (refer to Section 3.3) , floods and tsunamis (refer to Section 3.4) , external missiles (refer to Section 3.5) , earthquakes (refer to Section 3.7), and other natural phenomena, and to protect CIS components, ensuring their design function will be performed.

Portions of the CIS are not contained within a building and are exposed directly to potential wind and tornado loads and have been evaluated. Loss or failure of this equipment does not compromise the capability of maintaining containment integrity (refer to Section 3.3.2).

All valves, piping, and equipment that are considered to be isolation barriers are designed to PG&E Design Class I requirements and are protected against potential missiles and water jets.

6.2.4.4.2 General Design Criterion 10, 1967 – Containment

6.2.4.4.2.1 Piping Penetrations

The CIS limits radioactivity passing from the containment to the atmosphere in the event of a DBA. This is accomplished as described in Section 6.2.4.2 and Table 6.2-39.

The CIS provides a minimum of two barriers to prevent leakage of radioactivity to the outside environment. Either barrier is sufficient to keep leakage within the allowable limits.

6.2.4.4.2.2 Instrument Lines

Instrument lines penetrating containment meet the intent of Safety Guide 11, March 1971 (Reference 48), by providing a double barrier (one inside and one outside) between containment and the outside atmosphere. It provides double barrier isolation without operator action and without sacrificing any reliability with regard to its engineered safety functions (refer to Figure 6.2-19 and Table 6.2-39 for the penetration configurations).

The containment pressure instrumentation penetration lines (refer to Sheet 15 of Figure 6.2-19 and Table 6.2-39) consist of a sealed, fluid-filled system with a sealed bellows sensor connected to the diaphragm of the pressure transmitter by a sealed fluid-filled tube. The bellows and tubing inside containment and transmitter diaphragm and tubing outside containment are protected from postulated missile and high energy line break (HELB) pipe whip/jet impingement effects by their location, which provides separation and shielding from these hazards. Isolation valving is not essential to meet the intent of Safety Guide 11, March 1971.

The abandoned-in-place deadweight pressure calibrator penetration line (refer to Sheet 22 of Figure 6.2-19 and Table 6.2-39) meets the intent of Safety Guide 11, March 1971, by the use of a diaphragm on both Units plus one sealed-closed valve on Unit 1 and an instrument cap on Unit 2. 1-PT-458A and 2-PT-458A have been abandoned-in-place, resulting in the isolation valves being closed. Therefore, the inboard barrier is a closed valve with the PT-458A diaphragm as a back-up. The calibrator and tube are filled with distilled water that is separated from the reactor coolant by the diaphragm in the pressure sensor. This diaphragm is designed to withstand full RCS pressure from either side.

The spare instrument test line penetrations used to measure containment pressure during the integrated leakrate test meet the intent of Safety Guide 11, March 1971 by providing a double barrier, one inside and one outside containment (refer to Sheet 11 of Figure 6.2-19 and Table 6.2-39).

Reactor vessel level instrumentation penetration lines (refer to Sheet 25 of Figure 6.2-19 and Table 6.2-39) consist of a sealed fluid-filled system, with a sealed bellows sensor inside containment connected to one side of a differential pressure unit (DPU) outside of containment by a sealed fluid-filled system. The sensor and the DPU are capable of withstanding full RCS pressure. Isolation valving is not essential to meet the intent of Safety Guide 11, March 1971.

6.2.4.4.3 General Design Criterion 11, 1967 – Control Room

The CIS is designed with indication and controls located in the control room as necessary to shut down and maintain safe control of the facility.

Each automatic isolation valve is provided with a manual switch for operation. The position of each automatic isolation valve and remote-manual valve is displayed in the control room. All automatic isolation valves are operable from the control room. All remote-manual containment isolation valves are opened and closed normally from the control room or from local control panels (e.g., sampling system valves are operated from a panel in the sampling room). Position indicators are provided for each valve near its manual control switch. Control room indication, valve actuators, trip signals, and valve positions are listed in Table 6.2-39.

6.2.4.4.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The CIS is designed with automatic and remote-manual containment isolation valves that are provided with instrumentation and controls as required to monitor and maintain variables within prescribed operating ranges. Governing conditions regarding closure of isolation valves and the instrumentation and controls for the system are described in Sections 6.2.4.4.3 and in 7.3.2.4.3, and in Table 6.2-39.

6.2.4.4.5 General Design Criterion 21, 1967 – Single Failure Criterion

The CIS is designed with penetration configurations to ensure that a single failure will not prevent the CIS from performing its design function. Refer to Section 6.2.4.2.1 for a description of the PG&E containment penetration piping isolation grouping.

No manual operation is required for Phase A and Phase B containment isolation although isolation can be accomplished manually. Each remote-manual and automatic isolation valve is designed to close or go to a preferred position on a loss of power or air or nitrogen supply, except for MOVs, which fail as-is.

Also, a single failure in the instrumentation and control circuits will not prevent isolation. The instrumentation and control circuits are redundant in the sense that a single failure cannot prevent containment isolation.

Control circuits are designed to close the air and solenoid operated isolation valves on a de-energized state. No power is therefore required to isolate the containment. The exception to this is steam line isolation, which requires the energization of one of two mutually redundant circuits.

6.2.4.4.6 General Design Criterion 40, 1967 – Missile Protection

The CIS is designed with adequate protection for containment isolation, including piping, valves, and vessels, against dynamic effects and missiles that might result from plant equipment failures, including a LOCA (refer to Sections 3.5 and 3.6).

No valve is considered to be an isolation valve if it is not missile-protected. Isolation valves, actuators, and control devices required inside the containment are located between the crane wall or some other missile shield and the outside containment wall. Isolation valves, actuators, and control devices outside the containment are located outside the path of potential missiles or are provided with missile protection. Piping or vessels that provide one of the isolation barriers outside the containment are similarly protected. The missile barrier for each isolation valve is shown schematically on the penetration diagrams (refer to Figure 6.2-19). Refer to Section 3.5 for additional information on missile protection. Refer to the individual system sections for a discussion regarding missile protection.

6.2.4.4.7 General Design Criterion 53, 1967 – Containment Isolation Valves

The CIS is designed such that penetrations that require closure for containment function are provided with at least two barriers. The CIS is designed to meet either GDC 55, 1971; GDC 56, 1971; or GDC 57, 1971 requirements with exceptions. The CCW penetration to the excess letdown heat exchanger is an exception that does not meet the 1971 GDC because of commitments to design and construction made prior to the issuance of the 1971 GDC. The CCW penetration to the excess letdown heat exchanger does comply with GDC 53, 1967. Refer to Table 6.2-39 for penetration and configuration details with regards to GDC 53, 1967.

6.2.4.4.8 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The CIS design provides for a double barrier at the containment penetration in those fluid systems that are not required to function following a design basis event. The capability for periodic leakage testing is discussed in Section 6.2.4.4.13. Those automatic isolation valves that do not restrict normal plant operation are periodically tested to ensure operability. Refer to Section 6.2.4.2.2 and Table 6.2-39 for penetration and configuration details with regards to GDC 54, 1971.

Automatic Phase A and Phase B valves and sealed closed containment isolation valves are periodically tested for leak-tightness as described in Table 6.2-39.

6.2.4.4.9 General Design Criterion 55, 1971 – Reactor Coolant Pressure Boundary Penetrating Containment

The CIS is designed such that for each line that is part of the RCPB that penetrates containment is provided with containment isolation valves in compliance with GDC 55, 1971. Refer to Section 6.2.4.2.1 and Table 6.2-39 for penetration and configuration details with regards to GDC 55, 1971.

6.2.4.4.10 General Design Criterion 56, 1971 – Primary Containment Isolation

The CIS is designed such that each line that connects directly to the containment atmosphere and penetrates containment is provided with containment isolation valves in compliance with GDC 56, 1971. Refer to Section 6.2.4.2.1 and Table 6.2-39 for penetration and configuration details with regards to GDC 56, 1971.

6.2.4.4.11 General Design Criterion 57, 1971 – Closed System Isolation Valves

The CIS is designed such that each line that penetrates containment and is neither part of the RCPB nor connected directly to the containment atmosphere is provided with at least one containment isolation valve in compliance with GDC 57, 1971. Refer to Section 6.2.4.2.1 and Table 6.2-39 for penetration and configuration details with regards to GDC 57, 1971.

6.2.4.4.12 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The CIS, in conjunction with the containment (refer to Section 6.2.1.3.7), is designed to be a barrier to maintain control over plant radioactive effluents, whether gaseous, liquid, or solid. The CIS is designed to withstand the effects of a LOCA (refer to Section 6.2.4.4.2), ensuring that the offsite radiological exposures resulting from a LOCA are within the limits of 10 CFR 50.67 (refer to Section 15.5).

6.2.4.4.13 Containment Isolation System Safety Function Requirements

(1) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the CIS located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.6.3.

6.2.4.4.14 10 CFR Part 50 Appendix J, Option B – Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors

Testing of containment penetrations (Type C testing) is performed in accordance with the Technical Specifications 5.5.16, Containment Leakage Rate Testing Program, as

required by 10 CFR 50.54(o), and 10 CFR Part 50, Appendix J, Option B, as modified by approved exemptions. As a general requirement, all containment isolation valves will be tested periodically with a gas to determine leaktightness. Refer to Section 6.2.1 for information regarding Type A (ILRT) and Type B (air locks, electrical penetrations, hatches, etc.) testing.

Exceptions to this requirement are those valves not required to be testable by Appendix J to 10 CFR Part 50, and certain valves that cannot be isolated for air testing. These include the first of double CVs to the RCS and valves for which such testing would require draining significant portions of the RHR system or the SI system. Even if these systems were drained, the presence of other valves associated with the systems would make it impractical to determine the source of any measured leakage. Where a quantitative leakage test is necessary, provisions are made for each valve to measure the inflow of the pressurizing medium, collect and measure leakage, or calculate the leakage from the rate of pressure drop. The test pressure on the valve will be at a differential pressure of not less than the peak calculated containment internal pressure related to the design basis LOCA (P_a). The P_a value specified in Technical Specification 5.5.16 bounds the calculated LOCA containment integrity results in Section 6.2D.3.2.6.

CVs and single-disk gate valves will have the test pressure applied to the inboard side of the valve. Exceptions are the three RHR injection lines. The valves in these lines will be tested from the outboard side, as there is no practical method to test from the inboard side. Diaphragm valves may be tested on either side since their leakage characteristics are the same in either direction. Double-disk gate valves may be tested by applying the test pressure between the disks. Globe valves may be tested by pressurizing either the inboard side or under the seat.

Piping systems are provided with test vents (TVs) and TCs or have other provisions to allow periodic leakage testing of the containment isolation valves, as required. Locations of TCs and TVs are shown on the penetration diagram (refer to Figure 6.2-19). In most cases, equipment vents or drains can be used as TCs or TVs.

6.2.4.4.15 Regulatory Guide 1.163, September 1995 – Performance-Based Containment Leak-Test Program

The DCPP Containment Leakage Rate Testing Program is performed in accordance with the Technical Specifications. The DCPP Containment Leakage Rate Testing Program utilizes a performance-based approach, consistent with Regulatory Guide 1.163, September 1995, to comply with the requirements of 10 CFR Part 50, Appendix J, Option B (refer to Section 6.2.4.4.13).

6.2.4.4.16 NUREG-0737 (Item II.E.4.2), November 1980 – Clarification of TMI Action Plan Requirements

Item II.E.4.2 - Containment Isolation Dependability:

Position (1) – The automatically tripped isolation valves are actuated to the closed position by one of two separate containment isolation signals.

Immediate isolation of the containment is accomplished automatically. There are two automatic phases of containment isolation at DCPP. Phase A isolates all nonessential process lines but does not affect SI, containment spray, CCW supplied to the reactor coolant pumps and containment fan coolers, and steam and AFW lines. Phase B isolates all process lines except SI, containment spray, AFW, and the containment fan coolers CCW system. Valves which close automatically upon receipt of a Phase A isolation signal are designated by the letter "T" in the penetration diagrams (refer to Figure 6.2-19). The letter "P" is used to designate those valves that close automatically upon receipt of a Phase B isolation signal.

Phase A isolation is initiated by high containment pressure, low pressurizer pressure, low steamline pressure, or manual initiation. Phase B isolation is initiated by high-high containment pressure or manual initiation.

Section II.6 of Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition (SRP) 6.2.4 establishes the DCPP licensing basis, but the design basis preceded the issuance of NUREG-0578, July 1979, and subsequently NUREG-0737, May 1980. The DCPP Phase A and Phase B containment isolation signals comply with Section II.6 of SRP 6.2.4, 1975, for diversity of parameters that initiate containment isolation. Section II.6 of SRP 6.2.4 does not constitute the DCPP design basis because the definitions of “essential,” “nonessential,” and “safety system process lines,” as well as those parameters that initiate a Phase A or Phase B containment isolation signal, were established prior to the issuance of NUREG-0578, July 1979, and subsequently NUREG-0737, May 1980.

Position (2) – Three levels of containment process penetrations have been defined for the DCPP:

(1) "Nonessential" process lines are defined as those that do not increase the potential for damage for in-containment equipment when isolated. These are isolated on Phase A isolation.

(2) "Essential" process lines are those providing cooling water and seal water flow through the reactor coolant pumps. These services should not be interrupted while the reactor coolant pumps are operating unless absolutely necessary. These are isolated on Phase B isolation.

(3) Safety system process lines are those required to perform the function of the ESF system.

Table 6.2-39 identifies nonessential, essential, and safety systems penetrating containment.

Position (3) – All nonessential systems use either manually sealed closed valves or else the valves are automatically isolated on a Phase A containment isolation signal. Additionally, all essential systems (defined in Position (2) above) are automatically isolated on a Phase B containment isolation signal.

Position (4) – Resetting the isolation signals will not result in the automatic reopening of containment isolation valves. Reopening of containment isolation valves requires deliberate action and ganged reopening will not result from a single operator action after the signal has been reset.

Position (5) – Table 6.2-40 shows operating conditions that make containment isolation mandatory. Setpoints are specified in the Technical Specifications.

Position (6) – The vacuum/overpressure relief valves satisfy the operability criteria set forth in BTP CSB 6-4, 1975. The opening of the 12-inch vacuum/overpressure relief valves is restricted to no more than 50 degrees.

The containment purge system valves are sealed closed in accordance with SRP Section 6.2.4, Revision 3, Item II.6 and II.14 during Mode 1 through 4 in accordance with the Technical Specifications, therefore satisfying NUREG-0737, November 1980 Item II.E.4.2, Position (6):

Position (7) - The vent isolation valves are closed automatically by any one of the following:

(1) Phase A containment isolation signal

(2) High gaseous or air particulate radioactivity in containment

(3) High radiation at the plant vent

The containment purge valves are isolated during Modes 1 through 4 in accordance with the Technical Specifications, and are closed automatically by High gaseous or air particulate radioactivity in containment. The phase A containment isolation signal is no longer credited for automatic isolation of the containment purge valves.

6.2.4.4.17 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

The CIS MOVs are subject to the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996, and meet the requirements of the DCPP MOV program.

6.2.4.4.18 Generic Letter 96-06, September 1996 – Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions

6.2.4.4.19 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The CIS is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

Containment isolation valves LWS-FCV-253 and LWS-FCV-500 (Penetrations 50 and 49, respectively) have both been modified through the addition of a pressure relief hole to prevent overpressurization of the associated isolated section of piping during design-basis accidents to ensure containment integrity is maintained. All other piping penetrations that are susceptible to overpressurization either have valves whose design prevents overpressurization (air-operated diaphragm valves, solenoid valves, or air-operated globe valves) or have been drained to prevent overpressurization and thereafter maintained drained as appropriate.

6.2.4.5 Tests and Inspections

The CIS design provides such functional reliability and ready testing facilities as are necessary to avoid undue risk to the health and safety of the public. CIS periodic tests and inspections are provided to ensure a continuous state of readiness to perform its safety function.

Containment isolation signal actuation channels are designed with sufficient redundancy to provide the capability for channel testing and calibration during power operation without tripping the system (refer to Section 7.3.3.4 for more details).

The pneumatic-operated isolation valves close on loss of control power or compressed gas. Isolation valves will be periodically tested for operability.

For additional details regarding periodic testing and inspection of valves, refer to the Technical Specifications.

6.2.4.6 Materials

Materials selection for the penetration lines and isolation valves of the CIS depends on the particular application and function of the systems involved. Further information is provided in the sections describing the individual systems of interest, and in Section 3.8 where details of penetration designs are presented.

6.2.5 COMBUSTIBLE GAS CONTROL IN CONTAINMENT

Following a LOCA, hydrogen may be produced inside the reactor containment by radiolysis of the core and sump solutions, by corrosion of aluminum and zinc, by reaction of the zirconium in fuel cladding with water, and by release of the hydrogen contained in the RCS.

The original design of the containment structure utilized the containment hydrogen purge system (CHPS) which includes dedicated containment penetrations for the purposes of purging hydrogen.

Following the TMI-2 incident and issuance of NUREG-0737, November 1980, PG&E committed to provide an electrical hydrogen recombiner system (EHRS) inside the containment structure as the primary means of hydrogen buildup mitigation. In addition, PG&E committed to providing the installed capability to connect external hydrogen recombiners outside the containment structure, cross tying the CHPS supply and exhaust piping into a closed loop.

In 2003, revisions to 10 CFR 50.44 removed the definition of a design basis LOCA hydrogen release, and eliminated the requirements for hydrogen control systems to mitigate such a release. The requirements remaining include the need to maintain a mixed atmosphere to prevent coalescence of high concentration local hydrogen collections that may provide a flammability risk and the need to provide equipment for monitoring hydrogen concentrations in the containment atmosphere.

To fulfill the requirements of 10 CFR 50.44, PG&E credits the use of the CFCS and CSS as the means of containment atmosphere mixing. Refer to Section 6.2.2 for discussion of CFCS and CSS design bases.
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

The research and development work discussed in more detail in Section 6.2.5.3 substantially reduced the uncertainties in both the expected rates of hydrogen accumulation and the potential exposures that would result from hydrogen control by venting as follows:

(1) Research on the corrosion of aluminum and associated hydrogen production rates by Westinghouse (References 12 through 15 and 42) has reduced uncertainties on corrosion rates in the expected post-accident environment and allowed a reduction in the expected corrosion rate from the 42 mg/dm^2/hr used in the Unit 2 Preliminary Safety Analysis Report (PSAR) to the value shown in Figure 6.2-24.

(2) The amounts of aluminum used in the as-built plant have been minimized through materials design specifications. Zinc is another significant

contributor. The uncertainties in the amounts of hydrogen produced from both have been reduced by itemized accounting (refer to Table 6.2-42).

(3) The amounts of hydrogen expected to be produced by the zirconium-water reaction have been reduced by the more stringent limits established on ECCS performance.

(4) Research by the Atomic Energy Commission (AEC) and its contractors (a partial compilation is included in Reference 16) in the context of ECCS studies has substantially reduced uncertainties in the extent of zirconium-water reactions following a LOCA.

(5) Reevaluation of energy generation rates has allowed reduction of hydrogen generation rate from sump radiolysis.

(6) Research on hydrogen yield in the core and sumps by Westinghouse (References 13 through 15) has reduced uncertainties in these constants.

(7) Refined analysis of the distribution of fission product decay energy (Reference 17) has resulted in more precise values for the fractions of beta and gamma energies absorbed by water.

(8) Additional meteorological data and analysis (References 18 through 20) conducted by PG&E as a part of the 2-year site program has established high probabilities of conditions favorable for controlled venting.

(9) *Development of the general-purpose EMERALD (Reference 21) computer program for the calculation of doses following accidents has resulted in more accurate estimates of potential exposures, and permitted additional sensitivity studies of the influence of various parameters on potential exposures.*

6.2.5.1 Design Bases

6.2.5.1.1 General Design Criterion 2, 1967 – Performance Standards

The CHPS, the EHRS and the hydrogen monitoring system (containment penetrations and containment isolation valves only) are designed to withstand the effects of, or are protected against, natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

6.2.5.1.2 General Design Criterion 3, 1971 – Fire Protection

The CHPS, the EHRS and the hydrogen monitoring system SSCs are designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

6.2.5.1.3 General Design Criterion 11, 1967 – Control Room

The CHPS and hydrogen monitoring system are designed to or contain instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room.

6.2.5.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain hydrogen concentrations within prescribed operating ranges.

6.2.5.1.5 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The CHPS is designed to provide means for monitoring the facility effluent discharge paths and the facility environs for radioactivity that could be released.

6.2.5.1.6 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

Means are provided in the containment to back up the safety function provided by the core design, the RCPB, and their protection systems. The CFCS and CSS are designed to ensure containment atmosphere mixing as a result of any size RCPB break to prevent the coalescence of local hydrogen concentrations within containment.

6.2.5.1.7 General Design Criterion 40, 1967 – Missile Protection

The CFCS and the containment isolation portion of the CHPS and hydrogen monitoring system are designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

6.2.5.1.8 General Design Criterion 41, 1967 – Engineered Safety Features Performance Capability

The CFCS and CSS are designed to provide sufficient performance capability to accommodate partial loss of installed capacity and still fulfill containment atmosphere mixing.

6.2.5.1.9 General Design Criterion 42, 1967 – Engineered Safety Features Components Capability

The CFCS and CSS are designed so that the capability of each component and system to perform its required function is not impaired by the effects of a LOCA.

6.2.5.1.10 General Design Criterion 49, 1967 – Containment Design Basis

The containment combustible gas control systems are designed so that the containment structure can accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a LOCA, including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of ECCSs.

6.2.5.1.11 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The piping that is part of the CHPS and hydrogen monitoring system that penetrate containment is provided with leak detection, isolation, redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The piping is designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

6.2.5.1.12 General Design Criterion 56, 1971 – Primary Containment Isolation Valves

The CHPS and hydrogen monitoring system contain valves in piping that penetrate containment and connect directly to the containment atmosphere. Remote manual isolation valves are provided outside containment and automatic (check) valves are provided inside containment to ensure containment integrity is maintained.

6.2.5.1.13 Combustible Gas Control System Safety Function Requirements

(1) Protection from Missiles

The EHRS and the PG&E Design Class I non-ESF portions of the CHPS and containment hydrogen monitoring system are designed to be protected against the effects of missiles which may result from plant equipment failure.

(2) Protection Against High Energy Pipe Rupture Effects

The EHRS and the PG&E Design Class I non-ESF portions of CHPS and containment hydrogen monitoring system are designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection from Jet Impingement – Inside Containment

The CFCS, EHRS, and the inside containment portion of CHPS and containment hydrogen monitoring system are designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

6.2.5.1.14 10 CFR 50.44 – Combustible Gas Control for Nuclear Power Reactors

The CFCS and CSS ensure a mixed atmosphere is maintained within containment to prevent high localized concentrations of hydrogen gas accumulation.

The hydrogen monitoring system is designed to be functional, reliable, and capable of continuously measuring the concentration of hydrogen in the containment atmosphere.

6.2.5.1.15 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

CHPS, EHRS and the hydrogen monitoring system components that require EQ are qualified to the requirements of 10 CFR 50.49.

6.2.5.1.16 10 CFR 50.55a(f) – Inservice Testing Requirements

ASME code components of the CHPS and hydrogen monitoring system are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

6.2.5.1.17 1 0 CFR 50.55a(g) – Inservice Inspection Requirements

ASME code components of the CHPS and hydrogen monitoring system are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

6.2.5.1.18 Regulatory Guide 1.7, Revision 2, November 1978 – Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident

The CFCS and CSS are designed to provide a mixed atmosphere in containment and thus control combustible gas concentrations without relying on purging of the containment atmosphere following a LOCA. The CFCS and CSS meet the design, quality assurance, redundancy, energy source, and instrumentation requirements for an ESF. The hydrogen monitoring system provides a means to measure the hydrogen concentration in the containment.

6.2.5.1.19 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The hydrogen monitoring system is designed to provide continuous indication in the control room of hydrogen concentration in the containment atmosphere following a beyond DBA and meets the design provisions of Regulatory Guide 1.97, Revision 3, including qualification, redundancy and testability.

6.2.5.1.20 NUREG-0737 (Items II.E.4.1, II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.E.4.1 – Dedicated Hydrogen Penetrations: The CHPS for post-accident combustible gas control of the containment atmosphere is provided with dedicated containment penetrations separate from other containment venting systems.

Item II.F.1 – Additional Accident Monitoring Instrumentation: Position (6) - The display instrumentation is designed to include the containment hydrogen monitors. Indication of hydrogen concentration in the containment atmosphere is provided in the control room.

6.2.5.1.21 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

The CHPS MOVs meet the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996.

6.2.5.2 System Description

6.2.5.2.1 Containment Fan Cooler and Containment Spray Systems

The CFCS and CSS provide mixing of the containment atmosphere following a DBA to ensure that hydrogen concentrations are within prescribed limits. Refer to Sections 6.2.2 and 9.4.5 for further details on the CFCS. Refer to Section 6.2.2 for further details on the CSS.

6.2.5.2.2 Electric Hydrogen Recombiner System

Internal EHRSs are installed in both units of the DCPP as a means of controlling containment atmosphere hydrogen concentration following a LOCA.

The EHRSs are natural convection, flameless, thermal reactor-type hydrogen-oxygen recombiners. In their basic operation, they heat a continuous stream of air-hydrogen mixture to a temperature sufficient for spontaneous recombination of the hydrogen with the oxygen in the air to form water vapor.

The system for each unit consists of two independent recombiners, each of which contains the electric heater banks, a power supply panel that contains the equipment for powering the heaters, and a power control panel to the heaters. The recombiners are located inside the containment building; the power supply and control panels are located outside this building. The EHRS units are completely enclosed and the internals are protected against impingement from containment spray.

Each recombiner consists of an inlet preheater section, a heater-recombination section, and a mixing chamber (refer to Figure 6.2-23). Air and the hydrogen are drawn into the unit by natural convection via the inlet louvers and pass through the preheater section, which consists of a shroud placed around the central heaters to take advantage of heat conduction through the walls. In this area, the temperature of the inlet air is raised. This rise in temperature accomplishes the dual function of increasing system efficiency and evaporating any moisture droplets that may be entrained in the air. The warmed air then passes through the flow orifice that has been specifically sized to regulate air flow through the unit. After passing through the orifice plate, the air flows vertically upward through the heater section, where its temperature is raised to the range of 1150°F to 1400°F, causing the recombination of H_2 and O_2 to occur. The recombination temperature is approximately 1135°F.

Next, the air rises from the top of the heater section and flows into the mixing chamber, which is at the top of the unit. Here, the hot air is mixed with the cooler containment air and then discharged back into the containment at a lower temperature. The cooler containment air enters the mixing chamber through the lower part of the upper louvers located on three sides of the unit.

The major structural components are manufactured from stainless steel and Incoloy-800. The heater sheathing is also Incoloy-800. Each bank is constructed of Incoloy-800 sheathed tubular elements mounted in a heavy-gauge steel flange with holes for mounting into the recombiner heater frame.

There are four banks of heaters in each recombiner. Each bank contains 60 individual, U-type heating elements connected in series-parallel arrangements as required to obtain the power rating for each bank. The internal connections are wired to special terminal blocks located outside the heater flange. Each bank is sized for a specific power rating.

The power supply panel contains all the necessary electrical equipment to provide the power required by the heaters in the recombiner.

The panel consists of an isolation transformer, silicon-controlled rectifier module, an auxiliary control power transformer, and a main line contactor. The control panel contains all the control and monitoring equipment required for operating the recombiner and is easily accessible to the plant operators.

Thermocouples are provided for convenience in testing and periodic checkout; they are not considered necessary, however, to ensure proper operation of the recombiner.

The EHRS design characteristics conservatively bound the design conditions following a LOCA and are as follows:

	Normal Operating Conditions	Post-LOCA Operating Conditions
Temperature, °F	120	288 (max)
Pressure, psia	15	77 (max)
Pressure transient, psia	N/A	77 (max in 10 sec)
Relative humidity, %	0-100	100
Radiation, rads/hr	5	3.3×10^5
Radiation-total dose, rads	NA	2×10^8 (max)
Spray solution, ppm B/pH	NA/NA	2550/9-10.5
Recombiner capacity, scfm of containment gas at 1 atm	NA	100 (min)

From the results shown in Figures 6.2-26 through 6.2-29, a 100 scfm hydrogen recombiner, started when the bulk containment hydrogen concentration reaches 3.5 percent by volume (after 3 days), or earlier, will ensure that the bulk containment hydrogen concentration will not reach the lower flammability limit of 4 percent by volume. The licensing limit of 4.0 percent by volume is assured by operating procedures that direct operators to initiate recombiner operation at hydrogen concentrations as low as 0.5 percent by volume. Thus, neither hydrogen burning nor detonation will occur.

6.2.5.2.3 Containment Hydrogen Purge System

The CHPS is designed for either intermittent or continuous flow operation. While the hydrogen recombiner system is the primary system for post-LOCA containment hydrogen control, in the event that hydrogen concentration were to reach the control limit of 3.5 percent, the hydrogen purge system may be placed into operation under strict administrative controls.
The CHPS is a PG&E Design Class I system consisting of two diverse purge routes and two redundant supply routes. The system is available for control of hydrogen and includes provisions for post-accident installation of portable recombiners. The basic features of the CHPS are shown in Figures 6.2-20 through 6.2-22.

Each purge stream leaves the containment through a motor-operated isolation valve, which opens remotely during venting. One purge stream is routed through a manual valve, roughing filter, HEPA filter, charcoal, HEPA after-filter, a blower, a hand control valve, a flow measuring device, plant vent radiation monitor, and the associated plant vent radiation monitoring systems. The second purge stream is routed through a flow measuring device, a hand-controlled valve, and the containment excess pressure relief line to the ABVS carbon filter plenum. This purge stream then follows the auxiliary

building ventilation exhaust flowpath through the roughing filter, HEPA filter, carbon absorber, exhaust fan, plant vent and the associated plant vent radiation monitoring system. The purge stream can be operated independently of the supply stream.

The supply stream is drawn through a roughing filter and a blower and routed through a hand control valve, a flow measuring device, a gate valve, and isolation CVs. The supply stream can be operated independently of the purge stream.

The supply stream entrance and the purge stream exit are widely separated to prevent short circuiting. The CFCUs ensure complete mixing of the post-accident containment atmosphere.

All CHPS MOVs inside containment are supplied with Class 1E power.

Prior to initiation of hydrogen purge, the containment radiation monitoring system is used to monitor, either continuously or intermittently, the radioactivity in containment. The plant vent radiation monitors measure the radioactivity in the purge stream. Refer to Section 9.4.2 for information on the plant vent.

The supply stream isolation valves and blower are operated manually.

The supply stream provides for immediate dilution, and the hydrogen concentration decreases. The purge stream is initiated after the supply stream begins diluting hydrogen.

The CHPS is provided with charcoal filters to minimize the release of radioactive iodine. The filters are sized in accordance with activity loading specifications associated with ESFs.

The operators are provided with current data on containment hydrogen concentration, containment activity levels, wind direction, and wind speed to determine optimum purge schedules.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

In the PSAR (Reference 9) for DCPP Unit 2, an analysis of the expected hydrogen production concluded that any hydrogen accumulation could be controlled by containment venting, with radiological exposures below the annual limits specified in 10 CFR Part 20. Using more conservative parameters, the AEC regulatory staff calculated that the lower flammability limit would be attained in less than 40 days (Reference 10). The staff concluded that the purging operation could result in offsite activity concentration levels that exceed 10 CFR Part 20 limits. Additional capability for filtering of containment effluent, including charcoal beds, would, however, reduce the I-131 concentration level. Assuming 90 percent filter efficiency for iodine removal, the staff estimated (Reference 11) that doses at the site boundary would be about 0.8 rem whole body and about 8.5 rem to the thyroid if the entire contents of the containment

were vented over a 30-day period. Estimated exposures were, therefore, less than 10 percent of the guideline levels established in 10 CFR Part 100.

6.2.5.2.4 Hydrogen Monitoring System

The hydrogen monitors are located outside containment in the containment hydrogen monitor panels. The sample flows pass from the containment through inner and outer solenoid containment isolation valves to the monitors. The sample flows return to the containment through outer solenoid containment isolation valves and inner containment isolation CVs. Refer to Figure 6.2-22 for schematic configuration of the system.

Refer to Section 6.2.5.5.1 for additional information on the hydrogen monitors.

6.2.5.3 Safety Evaluation

6.2.5.3.1 General Design Criterion 2, 1967 – Performance Standards

The auxiliary building and containment structure, which contain the EHRS, CHPS and hydrogen monitoring system SSCs are PG&E Design Class I (refer to Section 3.8). These buildings or applicable portions thereof are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other natural phenomena, and to protect EHRS, CHPS and hydrogen monitoring system SSCs ensuring their design functions will be performed.

The EHRS and CHPS are PG&E Design Class I and are maintained as such to withstand additional forces that might be imposed by natural phenomena such as winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5) and earthquakes (refer to Section 3.7).

6.2.5.3.2 General Design Criterion 3, 1971 – Fire Protection

The CHPS, EHRS and hydrogen monitoring system are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

6.2.5.3.3 General Design Criterion 11, 1967 – Control Room

Two redundant hydrogen monitors are installed in each unit to provide continuous indication and recording in the control room of containment hydrogen concentration.

Containment isolation valve status is shown on the main control board as indicated in Table 6.2-39. For the CHPS, annunciation is provided to alarm on high radioactivity, high flowrate, and fan failure.

Refer to Section 6.2.5.5 for additional discussion of instrumentation and controls.

6.2.5.3.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The EHRS does not require any instrumentation inside the containment for proper operation after a LOCA. Proper recombiner operation after an accident is ensured by measuring the amount of electric power to the recombiner from the control panel located outside containment accessible to operators following an accident. The temperature readout device is a monitoring unit, not a control unit. For additional information refer to Section 6.2.5.2.2.

For the CHPS, the supply and the purge streams may be adjusted to regulate the flowrates to values required to maintain hydrogen level in the containment at or below the 4.0 percent limit. Instrumentation is provided to monitor flowrate and hydrogen concentration. The containment radiation monitoring system and the plant vent radiation monitors are used to monitor the radioactivity in containment and the hydrogen purge line.

Refer to Section 6.2.5.5 for additional discussion of instrumentation and controls.

6.2.5.3.5 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The CHPS is vented through the plant vent which is equipped with a radiation monitoring system. Refer to Sections 9.4.5.3.5 and 11.4 for further details on the plant vent and radiation monitoring system.

6.2.5.3.6 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

The basis for design is centralized upon the requirements set forth in 10 CFR 50.44 in which the containment structure must have the capability for ensuring a mixed atmosphere. A mixed atmosphere is obtained through use of the CFCS and CSS in which post-accident hydrogen produced is circulated throughout the containment structure in conjunction with other gases to prevent local hydrogen concentrations from reaching a lower flammability limit of 4 percent hydrogen by volume. The method of analysis used to determine the post-accident production rate of hydrogen used in the basis of the system design is given below.

6.2.5.3.6.1 Analysis of Hydrogen Generation and Accumulation

The quantity of zirconium, which reacts with the core cooling solution, depends on the performance of the ECCS.

The criteria for ECCS evaluation (10 CFR 50.46) requires that the zirconium-water reaction be limited to 1 percent by weight of the total quantity of zirconium in the core. ECCS calculations have shown the zirconium-water reaction to be less than 1 percent.

Aluminum inside the containment is not used in PG&E Design Class I components that are in contact with the recirculating core cooling fluid. It is more reactive with the containment spray alkaline borate solution than other plant materials such as galvanized steel, copper, and copper nickel alloys.

The zirconium-water reaction and aluminum and zinc corrosion with containment spray are chemical reactions, which are essentially independent of the radiation field inside the containment following a LOCA. Radiolytic decomposition of water is dependent on the radiation field intensity. The radiation field inside the containment is calculated for the maximum credible accident for which the fission product activities are given in TID-14844 (Reference 24).

The hydrogen generation is calculated using the NRC model discussed in Regulatory Guide 1.7, Revision 2 (Reference 22), Standard Review Plan 6.2.5 (Reference 40) and Branch Technical Position CSB 6-2 (Reference 41).

6.2.5.3.6.1.1 Hydrogen Generation from the Zirconium-Water Reaction

The zirconium-water reaction is described by the chemical equation:

$$Zr + 2H_2O \rightarrow Zr\,O_2 + 2H_2 + \text{Heat}$$

Hydrogen generation due to this reaction will be completed during the first day following the LOCA. The NRC model assumes a 5 percent (5 times the maximum allowable value defined by 10 CFR Part 50, Appendix K [ECCS]) zirconium-water reaction. The hydrogen generated is assumed to be released immediately to the containment atmosphere.

6.2.5.3.6.1.2 Hydrogen Available from the Reactor Coolant System

The quantity of hydrogen in the RCS during normal operation includes hydrogen from the pressurizer gas space and hydrogen dissolved in the reactor coolant. The pressurizer gas space hydrogen is based on:

(1) A maximum allowable coolant hydrogen concentration of 60 cc(stp)/kg of coolant (stp denotes standard temperature and pressure)

(2) Control banks of pressurizer heaters will modulate to control pressurizer heat losses to maintain constant pressurizer temperature and pressure

(3) Minimum bypass spray rate of 2.0 gpm

(4) Normal liquid level of the pressurizer (60 percent)

(5) Pressurizer power-operated relief valves closed

The hydrogen from the reactor coolant and the pressurizer vapor space is available for release to the containment immediately following a LOCA.

6.2.5.3.6.1.3 Hydrogen Generation from the Corrosion of Plant Materials

Oxidation of metals in aqueous solution generates hydrogen gas as one of the corrosion products. Extensive corrosion testing has been conducted to determine the behavior of the various metals used within the containment. Metals tested include zirconium alloys, Inconel, aluminum alloys, cupronickel alloys, carbon steel, galvanized carbon steel, and copper.

Tests conducted at ORNL (References 25 and 26) and Westinghouse (Reference 42) have verified the compatibility of the various materials with alkaline borate solution and have shown that aluminum and zinc will corrode at a rate that will significantly add to the hydrogen accumulation in the containment atmosphere.

The corrosion of aluminum may be described by the overall reaction:

$$2\ Al + 3\ H_2O \rightarrow Al_2O_3 + 3\ H_2$$

Three moles of hydrogen are produced for every two moles of aluminum oxidized.

The corrosion of zinc may be described in the overall reaction:

$$Zn + 2H_2O \rightarrow Zn(OH)_2 + H_2$$

One mole of hydrogen is produced for each mole of zinc oxidized.

The time-temperature cycle (refer to Table 6.2-41) considered in the calculation of aluminum and zinc corrosion is a step-wise representation of the postulated post-accident containment temperature transient. The corrosion rates at the various steps were determined from the aluminum and zinc corrosion rate design curves (References 42 and 55) shown in Figure 6.2-24, which include the effects of temperature and spray solution conditions. For conservative estimation, no credit was taken for protective shielding effects of insulation or enclosures from the spray, and complete and continuous immersion was assumed.

The calculations were performed by Westinghouse using the methodology of Regulatory Guide 1.7, Revision 2, but using the corrosion rates given in Figure 6.2-24 and the containment time-temperature values given in Table 6.2-41.

For this hydrogen generation reanalysis the aluminum and zinc inventories inside containment are as shown in Table 6.2-42.

6.2.5.3.6.1.4 Hydrogen Generation from the Radiolysis of Core and Sump Water

Water radiolysis is a complex process involving reactions of numerous intermediates. However, the overall radiolytic process may be described by the reaction:

$$H_2O \rightleftarrows H_2 + 1/2\ O_2$$

Table 6.2-43 presents the total decay energy (β + γ) of a reactor core. It assumes full power operation with extended fuel cycles prior to the accident. For the maximum credible accident case, the contained decay energy in the core accounts for the assumed TID-14844 release of 50 percent halogens and 1 percent other fission products. In the TID-14844 model, the noble gases are assumed to escape to the containment vapor space.

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The yield of hydrogen from radiolytically decomposed solution has been studied extensively by Westinghouse and ORNL. The results of static capsule tests conducted by Westinghouse indicate hydrogen yields much lower than 0.44 molecules per 100 eV for core radiolysis.

There are, however, differences between the static capsule tests and the dynamic condition in core, where the cooling fluid is continuously flowing. The flow is assumed to disturb the steady state conditions that are observed in static capsule tests, and while the occurrence of back reactions is still significant, the overall net yield of hydrogen is somewhat higher in the flowing system.

Westinghouse studies of radiolysis in dynamic systems (Reference 15) show 0.44 molecules per 100 eV to be a maximum yield for high solution flowrates through a gamma radiation field. Work by ORNL (References 25 and 26), Zittel (Reference 28), and Allen (Reference 29) confirm this value.

Analysis, based on Regulatory Guide 1.7, Revision 2, is conservative because it assumes a hydrogen yield value of 0.5 molecules per 100 eV. It also assumes that 10 percent of the gamma energy, produced from fission products in the fuel rods, is absorbed by the solution in the region of the core, and the noble gases escape to the containment vapor space.

Another potential source of hydrogen assumed for the post-accident period arises from water in the reactor containment sump being subjected to radiolytic decomposition by fission products. An assessment must therefore be made of the decay energy deposited in the solution and the radiolytic hydrogen yield, much in the same manner as for core radiolysis.

The energy deposited in solution is computed using the following basis:

(1) For the maximum credible accident, a TID-14844 release model (Reference 24) is assumed where 50 percent of the total core halogens and 1 percent of all other fission products, excluding noble gases, are released from the core to the sump solution.

(2) The quantity of fission product release considers a reactor operating with extended fuel cycles prior to the accident.

(3) The total decay energy from the released fission products, both beta and gamma, is assumed to be fully absorbed in the solution.

The calculation of the fission product decay energy deposited in the sump solution considers the decay of halogens and the decay of the remaining 1 percent of fission products. The energy release rates and integrated energy release for various times after a LOCA are listed in Table 6.2-44.

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The yield of hydrogen from sump solution radiolysis is most nearly represented by the static capsule tests performed by Westinghouse and ORNL with an alkaline sodium borate solution. The differences between these tests and the actual conditions for the sump solution, however, are important and render the capsule tests conservative in their predictions of radiolytic hydrogen yields.

In this assessment, the sump solution will have considerable depth, which inhibits the ready diffusion of hydrogen from solution, as compared to the case with shallow-depth capsule tests. This retention of hydrogen in solution will have a significant effect in reducing the hydrogen yields to the containment atmosphere. The buildup of hydrogen in solution will enhance the back reaction to form water and lower the net hydrogen yields, in the same manner as a reduction in the gas to liquid volume ratio will reduce the yield. This is illustrated by the data presented in Figure 6.2-25 for capsule tests with various gas to liquid volume ratios. The data show a significant reduction in the net hydrogen yield from the primary maximum yield of 0.44 molecules per 100 eV. Even at the very highest ratios, where capsule solution depths are very low, the yield is less than 0.30, with the highest scatter data point at 0.39 molecules per 100 eV.

Taking these data into account, a reduced hydrogen yield is a reasonable assumption for the case of sump radiolysis. The expected yield is on the order of 0.1 molecules per 100 eV or less. Regulatory Guide 1.7, Revision 2, does not, however, allow credit for the reduced hydrogen yields and a yield value of 0.5 molecules per 100 eV is used in the analyses.

All containment volumes are connected by large vent areas to promote good air circulation. Hydrogen will diffuse very rapidly giving an even distribution under the

conditions existing in the containment structure. In addition, thermal mixing effects, heating of air above the hot sump water, and possible steam released from the RCS will move the hydrogen-laden air from the points of generation toward the cool external walls. Although hydrogen is lighter than air, it will not concentrate significantly in high areas because of the high diffusion rate, the open design of the containment, and the fan cooler air mixing.

The ability of hydrogen to diffuse rapidly into all volumes is inferred from a CSE experiment (Reference 23). These tests showed very good mixing in the main chamber and a rapid interchange by diffusion and mixing with the atmosphere of other chambers that had limited communication. The diffusivity of hydrogen is approximately 10 times that of iodine, so a more uniform mixture is expected for hydrogen. Also, higher concentration provides greater concentration gradients for better diffusion than indicated by the CSE tests.

Table 6.2-45 summarizes the calculated hydrogen production and accumulation data.

6.2.5.3.6.1.5 Results of the Hydrogen Generation and Accumulation Analyses

The results of the hydrogen generation and accumulation analyses are presented in Figures 6.2-26 through 6.2-29.

6.2.5.3.7 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the CFCS and the containment isolation portion of the CHPS and hydrogen monitoring system from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures are discussed in Sections 3.5, 3.6, and 6.2.4.

6.2.5.3.8 General Design Criterion 41, 1967 – Engineered Safety Features Performance Capability

The CFCS, including required auxiliary systems, is designed to tolerate a single active failure following a LOCA without loss of protective function. Refer to Section 6.2.2.3.2 for further discussion.

6.2.5.3.9 General Design Criterion 42, 1967 – Engineered Safety Features Components Capability

The component design pressure and temperature conditions in Table 6.2-26 are specified as the most severe conditions to which each CFCS and CSS component is exposed during either normal or post-LOCA operation allowing the system to provide a mixed atmosphere in post-LOCA conditions. Refer to Section 6.2.2.3.1 for further discussion.

6.2.5.3.10 General Design Criterion 49, 1967 – Containment Design Basis

The CFCS and CSS ensure a mixed atmosphere within the containment structure to prevent the ignition of high concentration hydrogen collections that may produce quick and large pressure and temperature rises.

The containment penetrations, including the CHPS and hydrogen monitoring system piping and valves required for containment isolation, are designed and analyzed to withstand the pressures and temperatures that could result from a LOCA without exceeding design leakage rates. Refer to Section 3.8.2.1.1.3 for additional details.

6.2.5.3.11 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The CHPS and hydrogen monitoring system valves required for containment isolation are periodically tested. Testing of the components required for the CIS is discussed in Section 6.2.4.

6.2.5.3.12 General Design Criterion 56, 1971 – Primary Containment Isolation Valves

The CHPS and containment hydrogen monitoring system containment penetrations comply with the requirements of GDC 56, 1971, as described in Section 6.2.4 and Table 6.2-39.

6.2.5.3.13 Combustible Gas Control System Safety Function Requirements

(1) Protection from Missiles – Inside Containment

The provisions taken to protect the EHRS and the PG&E Design Class I non-ESF portions of the CHPS and containment hydrogen monitoring system from missiles resulting from plant equipment failures assure that their design functions are not impaired following a LOCA. Refer to Section 3.5 for additional information.

(2) Protection Against High Energy Pipe Rupture Effects – Inside Containment

The provisions taken to protect the EHRS and the PG&E Design Class I non-ESF portions of the CHPS and containment hydrogen monitoring system from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping assure that their design functions are not impaired following a LOCA. Refer to Section 3.6 for additional information.

(3) Protection from Jet Impingement – Inside Containment

The provisions taken to protect the CFCS, EHRS, the inside containment portion of CHPS, and the hydrogen monitoring system from the effects of jet impingement which may result from high energy pipe rupture assure that their design functions are not impaired following a LOCA. Refer to Section 3.6.6.3 for additional information.

6.2.5.3.14 10 CFR 50.44 – Combustible Gas Control for Nuclear Power Reactors

The CFCS and CSS are credited as the means for providing a mixed atmosphere in the containment structure in accordance with 10 CFR 50.44. Refer to Section 6.2.2 for discussion of the CFCS and CSS.

The hydrogen monitoring system is provided to continuously measure hydrogen concentrations in the containment structure following a significant beyond DBA for accident management, including emergency planning. Refer to Section 6.2.5.5 for further details on the hydrogen monitoring instrumentation.

6.2.5.3.15 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

CHPS, EHRS and hydrogen monitoring system components required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment. The affected equipment, including the CFCS and CSS equipment (refer to Section 6.2.2.3.26), containment isolation solenoid valves, containment isolation valve motor actuators, and the recombiners, are listed on the EQ master equipment list.

6.2.5.3.16 10 CFR 50.55a(f) – Inservice Testing Requirements

Periodic IST of all containment isolation valves, in the system is performed. The IST requirements are contained within the IST Program Plan and comply with the ASME code for Operation and Maintenance of Nuclear Power Plants. Refer to Section 6.2.2.4 for a discussion of testing of the CFCS.

6.2.5.3.17 10 CFR 50.55a(g) – Inservice Inspection Requirements

The ISI requirements for the CHPS and containment hydrogen monitoring penetrations are contained within the ISI Program Plan and comply with the ASME BPVC Section XI. Refer to Section 6.2.2.4 for a discussion of inspection of the CFCS and CSS.

6.2.5.3.18 Regulatory Guide 1.7, Revision 2, November 1978 – Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident

The CFCS and CSS, serve as the credited means for containment atmosphere mixing in accordance with 10 CFR 50.44, are designed and constructed to PG&E Design Class I standards.

The hydrogen monitoring system includes two hydrogen monitors to measure the hydrogen concentration in the containment.

The hydrogen monitoring system was originally designed and constructed as Category 1, as defined by Regulatory Guide 1.97, Revision 2 however has been reclassified as Category 3, as defined by Regulatory Guide 1.97, Revision 3 as a result of the rulemaking revision to 10 CFR 50.44 (refer to Section 6.2.5.3.19).

The EHRS is available to control containment hydrogen concentration following a LOCA to at or below 4.0 percent by volume without relying on the CHPS. Each of the two redundant recombiners is capable of providing the required removal capacity. The CHPS is also available.

To ensure that the lower flammability limit (4 percent) will not be exceeded, the internal electric hydrogen recombiners will be started at or below 3.5 percent by volume.

The EHRS and CHPS systems meet PG&E Design Class I design and construction standards.

The EHRS provides 100 percent redundancy since each recombiner and its associated power supply and control panel are capable of providing the required hydrogen removal capacity. The second unit, including its associated power supply and control panels, is normally on standby following a postulated LOCA.

The CHPS is provided as a means to carry out controlled purging of the containment atmosphere. While it is intended to serve only as an additional option for containment hydrogen control, and may not be acceptable for operation following a LOCA, the CHPS otherwise satisfies the design requirements for an ESF system. Two redundant systems complete with separate lines, blowers, and filters have been provided. These lines, valves, instrumentation, and blowers are PG&E Design Class I. Each blower and its associated controls are powered by independent electrical power supplies.

The basic data and analytical models and assumptions used for determining hydrogen production and accumulation shall be based on Regulatory Guide 1.7, Revision 2 (Reference 22). The parameter values listed in Table 1 of Regulatory Guide 1.7, Revision 2 were used in calculating the hydrogen gas concentration in containment. Refer to Section 6.2.5.3.6 for further discussion of the analysis.

The use of corrodible materials that yield hydrogen due to corrosion from the emergency cooling or containment spray solutions has been controlled in the containment to minimize hydrogen production.

6.2.5.3.19 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Two Category 3 hydrogen monitors per unit monitor post-accident hydrogen concentration (refer to Figure 6.2-22) and indication is provided in the control room for Regulatory Guide 1.97, Revision 3 monitoring. Although designed to Category 1, the monitors have been reclassified to meet the requirements of Category 3 as described in Section 6.2.5.3.18. Their characteristics are described in Section 6.2.5.5 and Table 7.5-6.

6.2.5.3.20 NUREG-0737 (Items II.E.4.1, II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.E.4.1 – Dedicated Hydrogen Penetrations: Dedicated penetrations are used for the purge system. Refer to Section 6.2.5.2.3 for a description of the CHPS and Sections 6.2.5.3.11 and 6.2.5.3.12 for discussions of GDC 54, 1971 and GDC 56, 1971, respectively.

Item II.F.1 – Additional Accident Monitoring Instrumentation: Position (6) - The display instrumentation for containment hydrogen monitoring is described in Section 6.2.5.5.1.

6.2.5.3.21 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

The CHPS MOVs are subject to the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996, and meet the requirements of the DCPP MOV Program Plan.

6.2.5.4 Tests and Inspections

Tests and inspections for the containment hydrogen control equipment are discussed in Sections 6.2.2, 6.2.5.3.16, and 6.2.5.3.17. The valves associated with containment isolation will be tested as described in Sections 6.2.4.4.13 and 6.2.4.5. Tests and inspections of filters and fans are described in Section 9.4.

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All PG&E Design Class I components of the combustible gas control systems were designed, fabricated, installed, and tested under quality assurance requirements in accordance with 10 CFR Part 50, Appendix B, as described in Chapter 17.

Nondestructive examination has been performed on the components of the systems in accordance with the requirements of the applicable codes as described in Section 3.2. The systems have been tested in accordance with the procedures outlined in Chapter 14.

During preoperational startup testing of the plant, a functional test using predetermined sample hydrogen gas mixtures was performed to verify hydrogen analyzer operation.

6.2.5.5 Instrumentation Applications

Because of the possibility of hydrogen release to the containment atmosphere following a LOCA, means to monitor and control the post-accident concentration of hydrogen in the containment are necessary.

6.2.5.5.1 Hydrogen Monitoring System

Two redundant hydrogen monitors are installed in each unit to provide continuous indication and recording in the control room of containment hydrogen concentration. The monitors are PG&E Instrument Class II, Type C, Regulatory Guide 1.97 Category 3 and each has its own dedicated containment penetration and isolation valves to meet single failure criteria (refer to Figure 6.2-22 for system layout). The monitoring system is capable of sampling and measuring the hydrogen concentration inside the containment to diagnose the course of beyond-design-basis accidents. The system has a range of 0-10 percent by volume. The normal system configuration is with the hydrogen monitors off-line and their respective containment isolation valves closed.

Refer to Sections 6.2.5.3.3, 6.2.5.3.18, and 6.2.5.3.19 for additional discussion on the hydrogen monitors.

6.2.5.5.2 Containment Hydrogen Purge System

Instrumentation is provided to monitor the flowrate and the amount of radioactivity released by the purging operation.

The containment radiation monitoring system and the plant vent radiation monitors are used to monitor the radioactivity in containment and the hydrogen purge line. Refer to Sections 9.4.2 and 11.4 for information regarding the plant vent.

A manual sample point is provided on each exhaust line to obtain a grab sample for laboratory analysis.
Flow indicators are provided for each CHPS exhaust line. The indicators are PG&E Design Class I. The range is 500 to 4000 feet per minute (corresponding to flowrates of approximately 45 to 350 cfm).

Containment isolation valves status is shown on the main control board as indicated in Table 6.2-39. Annunciation is provided to alarm on high radioactivity, high flowrate, and fan failure.

Refer to Sections 6.2.5.3.3 and 6.2.5.3.4 for additional discussion on the CHPS instrumentation.

6.2.5.6 Materials

Materials of construction of components are indicated in Section 6.2.2.6.

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77. F.J. Moody, Maximum Flow Rate of a Single Component, Two Phase Mixture, Journal of Heat Transfer, Transactions of the ASME, Series C, vol. 87, February 1965.

6.2.7 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

6.3 EMERGENCY CORE COOLING SYSTEM

The ECCS is comprised of the RWST and piping and components of the RHR system, SI system, and chemical and volume control system.

The primary function of the ECCS is to deliver borated cooling water to the reactor core in the event of a LOCA. This limits the fuel cladding temperature and thereby ensures that the core will remain intact and in place, with its essential heat transfer geometry preserved. This protection is afforded for:

- All pipe break sizes up to and including the hypothetical circumferential rupture of a RCL
- A loss of coolant associated with a rod ejection accident

The following normal operation functions are not covered in this section:

- The RHR system pumps, heat exchangers, valves, and associated piping are normally used during the latter stages of normal reactor cooldown and during refueling operations (refer to Section 5.5.6).
- The CCPs are normally aligned for charging and letdown service; along with providing seal water to the reactor coolant pumps (refer to Section 9.3.4).
- The RWST is used to fill the refueling canal for refueling operations (refer to Section 9.1.4).

The CCPs, SI pumps, and RHR pumps are commonly referred to as "high-head pumps," “intermediate-head pumps,” and "low-head pumps,” respectively. The term "high-head injection" is used to denote CCP and SI pump injection; while the term "low-head injection" refers to RHR pump injection.

6.3.1 DESIGN BASES

6.3.1.1 General Design Criterion 2, 1967 – Performance Standards

The ECCS is designed to withstand the effects of, or are protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

6.3.1.2 General Design Criterion 3, 1971 – Fire Protection

The ECCS is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

6.3.1.3 General Design Criterion 11, 1967 – Control Room

The ECCS is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room.

6.3.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided, as required, to monitor and maintain ECCS variables within prescribed operating ranges.

6.3.1.5 General Design Criterion 21, 1967 – Single Failure Definition

The ECCS is designed to tolerate a single failure during the period of recovery following an accident without loss of its protective function, including multiple failures resulting from a single event, which is treated as a single failure.

6.3.1.6 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

The ECCS is designed to provide back-up to the safety provided by the core design, the RCPB, and their protection systems. The ECCS is designed to cope with any size RCPB break, up to and including the circumferential rupture of any pipe in that boundary, assuming unobstructed discharge from both ends.

6.3.1.7 General Design Criterion 38, 1967 – Reliability and Testability of Engineered Safety Features

The ECCS is designed to provide high functional reliability and ready testability.

6.3.1.8 General Design Criterion 40, 1967 – Missile Protection

The ECCS is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

6.3.1.9 General Design Criterion 41, 1967 – Engineered Safety Features Performance Capability

The ECCS is designed to provide sufficient performance capability to accommodate a partial loss of installed capacity, such as a single failure of an active component, and still perform its required safety function.

6.3.1.10 General Design Criterion 42, 1967 – Engineered Safety Features Components Capability

The ECCS is designed so that the capability of each component and system to perform its required function is not impaired by the effects of a LOCA.

6.3.1.11 General Design Criterion 43, 1967 – Accident Aggravation Prevention

The ECCS is designed so that any action of the ESFs which might accentuate the adverse after effects of the loss of normal cooling is avoided.

6.3.1.12 General Design Criterion 44, 1967 – Emergency Core Cooling Systems Capability

The ECCS is designed to provide the capability of accomplishing abundant emergency core cooling with two systems of different design principles. Each ECCS and the core are designed to prevent fuel and clad damage that would interfere with the emergency core cooling function and to limit the clad metal-water reaction to negligible amounts for all sizes of breaks in the RCPB, including the double-ended rupture of the largest pipe. The performance of each ECCS is evaluated conservatively in each area of uncertainty. The systems do not share active components and do not share other features or components unless it is demonstrated that (a) the capability of the shared feature or component to perform its required function is readily ascertained during reactor operation, (b) failure of the shared feature or component does not initiate a LOCA, and (c) capability of the shared feature or component to perform its required function is not impaired by the effects of a LOCA and is not lost during the entire period this function is required following the accident.

6.3.1.13 General Design Criterion 45, 1967 – Inspection of Emergency Core Cooling Systems

The ECCS is designed to facilitate physical inspection of all critical parts, including reactor vessel internals and water injection nozzles.

6.3.1.14 General Design Criterion 46, 1967 – Testing of Emergency Core Cooling Systems Components

The ECCS is designed so that active components, such as pumps and valves, can be tested periodically for operability and required functional performance.

6.3.1.15 General Design Criterion 47, 1967 – Testing of Emergency Core Cooling Systems

The ECCS is designed to provide the capability to periodically test the delivery capability at a location as close to the core as is practical.

6.3.1.16 General Design Criterion 48, 1967 – Testing of Operational Sequence of Emergency Core Cooling Systems

The ECCS is designed to provide the capability to test, under conditions as close to design as practical, the full operational sequence that would bring the ECCS into action, including the transfer to alternate power sources.

6.3.1.17 General Design Criterion 49, 1967 – Containment Design Basis

The ECCS is designed so that the containment structure can accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a LOCA, including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of emergency core cooling systems.

6.3.1.18 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The piping that is part of the ECCS that penetrates containment is provided with leak detection, isolation, redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The piping is designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

6.3.1.19 General Design Criterion 55, 1971 – Reactor Coolant Pressure Boundary Penetrating Containment

Each ECCS line that penetrates the containment is provided with containment isolation valves.

6.3.1.20 General Design Criterion 56, 1971 – Primary Containment Isolation

The ECSS contains valving in piping that penetrates containment and that is connected directly to the containment atmosphere. Remote manual isolation valves are provided outside containment and either automatic (check) valves are provided inside containment, or the system outside containment is considered a closed system, to ensure containment integrity is maintained.

6.3.1.21 Emergency Core Cooling System Safety Function Requirements

(1) <u>Leakage Provisions and Flooding Protection</u>

The ECCS includes provisions to detect and accommodate leakage during post-LOCA operation and mitigate any consequential flooding.

(2) Protection from Jet Impingement – Inside Containment

The portion of the ECCS located inside containment is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

6.3.1.22 10 CFR 50.46 – Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Plants

The ECCS is designed so that its calculated cooling performance following postulated LOCAs conforms to the criteria set forth in 10 CFR 50.46. ECCS cooling performance is calculated in accordance with an acceptable evaluation model for a number of postulated LOCAs of different sizes, locations, and other properties sufficient to provide assurance that the most severe postulated LOCAs are calculated.

6.3.1.23 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

ECCS components that require EQ are qualified to the requirements of 10 CFR 50.49.

6.3.1.24 10 CFR 50.55a(f) – Inservice Testing Requirements

ECCS ASME Code components are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

6.3.1.25 10 CFR 50.55a(g) – Inservice Inspection Requirements

ECCS ASME Code components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

6.3.1.26 Safety Guide 1, November 1970 – Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps

The ECCS is designed such that adequate NPSH is provided to system pumps assuming maximum expected temperatures of pumped fluids and no increase in containment pressure from that present prior to postulated LOCAs.

6.3.1.27 Regulatory Guide 1.79, June 1974 – Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors

A series of comprehensive preoperational tests were performed on the ECCS in accordance with Regulatory Guide 1.79, June 1974, with noted exceptions, to assure the ECCS will accomplish its intended function when required.

6.3.1.28 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The ECCS provides instrumentation to monitor RHR system flow, SI pump discharge flow, CCP 1 and 2 injection header flow, RHR heat exchanger outlet temperature, containment recirculation sump water level and temperature, accumulator tank level and pressure, accumulator isolation valve position, RWST level, containment isolation valve position, and subcooling margin indication during and following an accident.

6.3.1.29 NUREG-0737 (Items I.C.1, I.D.2, II.B.2, II.F.1, II.F.2, II.K.3.30, II.K.3.31, III.D.1.1), November 1980 – Clarification of TMI Action Plan Requirements

Item I.C.1 – Guidance for the Evaluation and Development of Procedures for Transients and Accidents: NUREG-0737, Supplement 1, January 1983 provides the requirements for I.C.1 as follows:

Section 7.1(b) – Transients and accidents were reanalyzed for the purposes of preparing technical guidelines and upgrading emergency operating procedures.

Item I.D.2 – Plant Safety Parameter Display Console: NUREG-0737, Supplement 1, January 1983 provides the requirements for I.D.2 as follows:

Section 4.1(f)(v), Containment Conditions: The ECCS provides instrumentation for control room personnel to monitor containment recirculation sump water level during and following an accident. Additional monitors are provided in the TSC and emergency operations facility (EOF).

Item II.B.2 – Design Review of Plant Shielding and Environmental Qualification of Equipment for Space/Systems Which May Be Used in Post-accident Operations: Plant shielding provides adequate access to, and occupancy of, the switchgear rooms for the purpose of restoring power to normally de-energized ECCS valves.

Item II.F.1 – Additional Accident Monitoring Instrumentation:

Position (5) – The ECCS provides continuous instrumentation to monitor containment recirculation sump water level in the control room.

Item II.F.2 – Instrumentation for Detection of Inadequate Core Cooling: ECCS instrumentation provides an unambiguous indication of inadequate core cooling by indicating the existence of inadequate core cooling caused by various phenomena and does not erroneously indicate inadequate core cooling due to the presence of an unrelated phenomenon. The instrumentation includes reactor water level indication and provides an advance warning of the approach to inadequate core cooling. The instrumentation covers the full range from normal operation to complete core uncovery.

Item II.K.3.30 – Revised Small-Break Loss-Of-Coolant-Accident Methods to Show Compliance with 10 CFR Part 50, Appendix K: The analysis method for small-break loss-of-coolant accidents (SBLOCAs) is a realistic evaluation model (EM) in compliance with 10 CFR Part 50.46(a)(1)(i). An Appendix K method is no longer used for the SBLOCA analysis, but the use of a realistic method has been approved for use in SBLOCA analysis. The revision accounts for comparisons with experimental data, including data from the loss of fluid test, rig-of-safety assessment, and semiscale test facilities.

Item II.K.3.31 – Plant-Specific Calculations to Show Compliance with 10 CFR 50.46: Plant-specific calculations for SBLOCA, using a NRC approved model, show compliance with 10 CFR 50.46.

Item III.D.1.1 – Integrity of Systems Outside Containment Likely to Contain Radioactive Material for Pressurized-Water Reactors and Boiling-Water Reactors: Appropriate portions of the ECCS are periodically pressure leak tested and visually inspected for leakage into the building environment.

6.3.1.30 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

ECCS PG&E Design Class I and position changeable MOVs meet the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996, “Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves.”

6.3.1.31 Generic Letter 95-07, August 1995 – Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves

ECCS PG&E Design Class I, power-operated gate valves meet the requirements of Generic Letter 95-07, August 1995.

6.3.1.32 Generic Letter 96-06, September 1996 – Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions

ECCS piping has been evaluated for the issue of thermal overpressurization of isolated piping sections that could affect containment integrity during accident conditions, as described in Generic Letter 96-06, September 1996.

6.3.1.33 Generic Letter 97-04, October 1997 – Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps

The ECCS has been evaluated to assure adequate NPSH is available to ECCS pumps

under all DBA scenarios.

6.3.1.34 Generic Letter 98-04, July 1998 – Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment

The ECCS and containment recirculation sump have been evaluated to assure construction and protective coating deficiencies or foreign material in containment will not cause degradation of the ECCS, as required by Generic Letter 98-04, July 1998 and discussed in associated NRC Bulletin 93-02, May 1993, “Debris Plugging of Emergency Core Cooling Suction Strainers.”

6.3.1.35 Generic Letter 2004-02, September 2004 – Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-Water Reactors

The ECCS and containment recirculation sump have been evaluated to assure that potential debris blockage due to a DBA will not impact the ECCS safety-related functions, as required by Generic Letter 2004-02, September 2004.

6.3.1.36 Generic Letter 2008-01, January 2008 – Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems

The ECCS is designed, periodically inspected, and procedurally managed to assure that gas accumulation in ECCS piping will not impact the ECCS safety-related functions, as required by Generic Letter 2008-01, January 2008.

6.3.1.37 IE Bulletin 79-06A (Position 8), April 1979 – Review of Operational Errors and System Misalignments Identified During the Three Mile Island Incident

Position (8) (subsequently NUREG-0737, November 1980, Item II.K.1.5, Safety Related Valve Position):

ECCS PG&E Design Class I valve positions, positioning requirements, and positive controls have been assured such that the valves remain positioned (open or closed) in a manner to ensure the proper operation of the ESF to satisfy Position (8) of IE Bulletin 79-06A, April 1979.

6.3.1.38 IE Bulletin 80-18, July 1980 – Maintenance of Adequate Minimum Flow Thru Centrifugal Charging Pumps Following Secondary Side High Energy Line Rupture

The availability of adequate ECCS CCP minimum flow has been ensured under all conditions in order to protect the pumps during the possible deadheading conditions described in IE Bulletin 80-18, July 1980.

6.3.1.39 NRC Bulletin 88-04, May 1988 – Potential Safety-Related Pump Loss

The ECCS is designed such that PG&E Design Class I pumps that share a common minimum flow recirculation line will not be susceptible to the pump-to-pump interaction described in NRC Bulletin 88-04, May 1988.

6.3.1.40 NRC Bulletin 88-08, June 1988 – Thermal Stresses in Piping Connected to Reactor Coolant Systems

Unisolable ECCS piping sections connected to the RCS, which have the potential to be subjected to unacceptable thermal stresses due to temperature stratifications induced by leaking valves, have been identified. Means have been provided to ensure that the pressure upstream from block valves, which might leak, is monitored and controlled.

6.3.1.41 NRC Bulletin 2003-01, June 2003 – Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized-Water Reactors

Modifications have been implemented to prevent potential blockage of drainage paths to the containment recirculation sump due to post-accident debris.

6.3.1.42 Branch Technical Position EICSB 18, November 1975 – Application of the Single Failure Criterion to Manually-Controlled Electrically-Operated Valves

Certain ECCS manually-controlled, electrically-operated valves have their electric power removed during normal operation to satisfy the single failure criterion, as discussed in Branch Technical Position EICSB 18, November 1975. Continuous, redundant position indication for these valves is provided in the control room.

6.3.1.43 10 CFR 50.48(c) – National Fire Protection association Standard NFPA 805

The ECCS is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

6.3.2 SYSTEM DESCRIPTION

The ECCS is designed to cool the reactor core as well as to provide additional shutdown capability following initiation of the following accident conditions:

(1) A pipe break or spurious valve lifting in the RCS that causes a discharge larger than that which can be made up by the normal makeup system, up to and including the circumferential rupture of the largest pipe in the RCS (refer to Sections 15.3.1 and 15.4.1 for a discussion of these accidents)

(2) Rupture of a control rod drive mechanism causing a rod cluster control assembly (RCCA) ejection accident (refer to Section 15.4.6)

(3) A pipe break or spurious valve lifting in the steam system, up to and including the instantaneous circumferential rupture of the largest pipe in the steam system (refer to Sections 15.2.14, 15.3.2, and 15.4.2)

(4) A SG tube rupture (refer to Section 15.4.3)

6.3.2.1 Range of Coolant Ruptures and Leaks

Sections 15.3.1 and 15.4.1 provide discussion on the ranges of coolant ruptures and leaks evaluated for ECCS performance.

6.3.2.2 Fission Product Decay Heat

The primary function of the ECCS following a LOCA is to remove the stored and fission product decay heat from the reactor core to prevent fuel rod damage to the extent that such damage may impair effective core cooling. The acceptance criteria for the accidents, as well as their analyses, are provided in Sections 15.3.1 and 15.4.1.

6.3.2.3 Reactivity Required for Cold Shutdown

The ECCS provides shutdown capability for the accidents listed in Section 6.3.2 by means of shutdown chemical (boron) injection. The most critical accident for shutdown capability is the MSLB and for this accident the ECCS meets the criteria defined in Sections 15.3.2 and 15.4.2.

6.3.2.4 Equipment and Component Descriptions

The major components of the ECCS are described in the following sections. Pertinent design and operating parameters for ECCS components are given in Table 6.3-1.

6.3.2.4.1 Accumulators

The accumulators are pressure vessels partially filled with borated water and pressurized with nitrogen gas. During normal operation each accumulator is isolated from the RCS by two check valves in series. Should the RCS pressure fall below the accumulator pressure (refer to Table 6.3-1), the check valves open and borated water is forced into the RCS. One accumulator is attached to each of the cold legs of the RCS. Mechanical operation of the swing-disk check valves is the only action required to open the injection path from the accumulators to the core via the cold leg. Sections 6.3.3.4.5.1 and 6.3.3.5.5 describe the accumulator MOVs and their position indicators.

Connections are provided to remotely adjust the level and boron concentration of the borated water in each accumulator during normal plant operation, as required. Accumulator water level may be adjusted either by draining to the reactor coolant drain tank and then to the liquid holdup tank, or by pumping borated water from the RWST to the accumulator. Samples of the solution in the accumulators are taken periodically to check boron concentration.

Accumulator pressure is provided by a supply of nitrogen gas and can be adjusted as required during normal plant operation. The accumulators are, however, normally isolated from this nitrogen supply. Gas relief valves on the accumulators protect them from pressures in excess of design pressure.

The accumulators are located within the containment but outside of the secondary shield wall, which protects them from missiles. Since the accumulators are located within the containment, a release of the nitrogen gas from the accumulators would cause an increase in normal containment pressure. Containment pressure increase following release of the gas from all accumulators has been calculated and is well below the containment pressure setpoint for ECCS actuation.

Release of accumulator gas is detected by the accumulator pressure indicators and alarms. Thus, the operator can take action promptly as required to maintain plant operation within the requirements of the Technical Specification (Reference 10) covering accumulator operability.

6.3.2.4.2 Refueling Water Storage Tank

The content of the RWST is normally used to supply borated water to the refueling canal for refueling operations. In addition to its usual service, this tank provides borated water to the ECCS pumps and the CSS pumps following a LOCA or MSLB. For RWST volume requirements, refer to Section 6.3.2.11 and Table 6.3-1. For ECCS operation requirements following a LOCA or MSLB, refer to Section 6.3.3.6.1.1.

During normal operation, the RWST is aligned to the suction of the SI pumps, RHR pumps, and CSS pumps. The suction of CCP1 and CCP2 is automatically aligned to the tank by the safety injection signal ("S" signal).

The water in this tank is borated to a minimum concentration of 2300 ppm boron that ensures reactor shutdown by at least 5 percent $\Delta k/k$ when all RCCAs are inserted with the most reactive RCCA completely removed from its fuel assembly, and when the reactor is cooled down for refueling.

The RWST is vented directly to the atmosphere.

6.3.2.4.3 Pumps

6.3.2.4.3.1 Residual Heat Removal Pumps

The RHR pumps are provided to deliver water from the RWST to the RCS should the RCS pressure fall below their shutoff head during the injection phase. The pumps are automatically started upon receipt of the "S" signal. Each RHR pump is a single-stage, vertical, centrifugal pump. It has an integral motor-pump shaft, driven by an induction motor, and is powered by the Class 1E 4.16-kV system. The unit has a self-contained mechanical seal, which is cooled by CCW.

During the injection mode of ECCS operation, the RHR pumps draw water from the RWST; during the recirculation mode, they draw water from the containment recirculation sump. The changeover from the injection mode to recirculation mode (refer to Section 6.3.3.6.1.1.2 and Table 6.3-5) is initiated by low level in the RWST, which results in an automatic trip of the RHR pumps. The operator then manually changes system alignment to the recirculation mode after water is available in the containment recirculation sump and before water is exhausted from the RWST. Adequate NPSH is always available to the RHR pumps in both the injection phase and the recirculation phase. Table 6.3-11 lists available and required NPSH. Phase I of the preoperational system test (refer to Section 6.3.3.27.1.1) verified that the RHR pump performance was satisfactory for all required alignments.

A minimum flow recirculation line is provided for the pumps to recirculate fluid through the RHR heat exchangers and return the cooled fluid to the pump suction should these pumps be started with their normal flowpaths blocked. Once flow to the RCS is established, the recirculation line is automatically closed. This line prevents deadheading the pumps and permits pump testing during normal operation. The RHR pumps are also discussed in Section 5.5.6.

6.3.2.4.3.2 Centrifugal Charging Pumps (CCP1 and CCP2)

When aligned for SI operation, CCP1 and CCP2 deliver water from the RWST to the RCS at the prevailing RCS pressure. The pumps are automatically started upon receipt of the "S" signal. CCP1 and CCP2 are multistage, diffuser design, barrel-type casing pumps with vertical suction and discharge nozzles.

The pump is driven by an induction motor, powered by the Class 1E 4.16-kV system. The unit has a self-contained lubrication system cooled by CCW and a mechanical seal system that requires no external cooling.

A minimum flow bypass line is provided on each pump discharge to recirculate flow to the pump suction after cooling in the seal water heat exchanger during normal operation. Valves in minimum flow bypass lines are closed by the operator when the ECCS is transferred to the recirculation mode of operation following a LOCA. During normal plant operation, CCP1 or CCP2 may be in use. CCP1 and CCP2 may be tested during normal operation through the use of the minimum flow bypass line.

6.3.2.4.3.3 Safety Injection Pumps

SI pumps deliver water from the RWST to the RCS after the RCS pressure is reduced below the shutoff head of the pumps. The pumps are automatically started upon receipt of the "S" signal. Each SI pump is a multistage, centrifugal pump. The pump is driven directly by an induction motor, powered by the Class 1E 4.16-kV system. The unit has a self-contained lubrication system and a mechanical seal system that are cooled by CCW.

A minimum flow bypass line is provided on each pump discharge to recirculate flow to the RWST in the event the pumps are started with the normal flowpaths blocked. This line also permits pump testing during normal operation. Two MOVs in series are provided in this line. These valves are closed by operator action during the switchover to the ECCS recirculation mode.

6.3.2.4.4 Residual Heat Removal Heat Exchangers

The RHR heat exchangers are conventional shell- and U-tube-type units. During normal cooldown of the primary system, reactor coolant flows through the tube side while CCW flows through the shell side. During the emergency core cooling recirculation phase, water, from the containment recirculation sump, flows through the tube side. Further discussion of the RHR heat exchangers is found in Section 5.5.6. Design characteristics are included in Table 5.5-10.

6.3.2.4.5 Valves

Stroke times for MOVs used in the ECCS are given in Table 6.3-1. This table also lists the leakage specification for the various types of valves used in the ECCS. Setpoints and capacities for relief valves are given in Table 6.3-10.

Design features employed to minimize valve leakage include the following:

(1) Globe valves, which during post-accident recirculation are normally closed, are installed with the recirculated fluid pressure under the seat to prevent stem leakage of recirculated (radioactive) water.

(2) Relief valves are enclosed; i.e., they are provided with a closed bonnet and discharge to a closed system.

(3) Control valves and MOVs (2-1/2 inches and above) in the RHR portion of the ECCS recirculation loop outside containment have double-packed stuffing boxes and stem leakoff connections to the equipment drain system. Valves in the other portions of the ECCS recirculation loop outside containment have their leakoff connections capped.

6.3.2.4.5.1 Motor-Operated Gate Valves

The seating design of all motor-operated gate valves is of either the parallel-disk design or the flexible wedge design. The seating surfaces are hard-faced to prevent galling and reduce wear.

Where a gasket is employed for the body-to-bonnet joint, it is either a fully trapped, controlled compression, spiral-wound gasket with provisions for seal welding, or of the pressure-seal design. The valve stuffing boxes are designed with a lantern ring leakoff connection with a minimum of a full set of packing below the lantern ring and a minimum of one-half of a set of packing above the lantern ring for valves that have leakoff connections piped to an equipment drain system.

The motor operator incorporates a "hammer blow" feature that allows the motor to attain its full speed prior to being placed under load. MOVs are further discussed in Sections 6.3.3.30 and 6.3.3.31.

6.3.2.4.5.2 Accumulator Check Valves (Swing-Disk)

The accumulator check valves are designed with a low pressure drop configuration with all operating parts contained within the body.

Design considerations and analyses that ensure that leakage across the check valves located in each accumulator injection line will not impair accumulator availability are as follows:

(1) During normal operation the check valves are in the closed position with a nominal differential pressure across the disk of approximately 1650 psi. Since the valves remain in this position except for testing or when called upon to function, and are therefore not subject to abuse of flowing operation or impact loads caused by sudden flow reversal and seating, they do not experience significant wear of the moving parts and are expected to function with minimal leakage.

(2) When the RCS is being pressurized during the normal plant heatup operation, the check valves are tested for leakage as soon as there is a

stable differential pressure of about 100 psi or more across the valve. This test confirms the seating of the disk and whether or not there has been an increase in the leakage since the last test. When this test is completed, the discharge line motor-operated isolation valves are opened and the RCS pressure increase is continued. There should be no increase in leakage from this point on since increasing reactor coolant pressure increases the seating force and decreases the probability of leakage.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

(3) The experience derived from the check valves employed in the emergency injection systems indicates that the system is reliable and workable. This is substantiated by the satisfactory experience obtained from operation of the Ginna and subsequent plants where the usage of check valves is identical to this application.

(4) The accumulators can accept some inleakage from the RCS without affecting availability. Inleakage would require, however, that the accumulator water volume be adjusted in accordance with Technical Specification (Reference 10) requirements.

6.3.2.4.5.3 Relief Valves

Relief valves are installed in various sections of the ECCS to protect the system from overpressure. Valves that normally see liquid service have their stem and spring adjustment assemblies isolated from the system fluid by a bellows seal between the valve disk and spindle. The closed bonnet provides an additional barrier for enclosure of the relief valves. Table 6.3-10 lists the system relief valves with their capacities and setpoints. The accumulator relief valves are sized to pass nitrogen gas at a rate in excess of the accumulator gas fill line delivery rate. The relief valves will also pass water in excess of the maximum water fill rate, but this is not considered important, because the time required to fill the gas space gives the operator ample opportunity to correct the situation.

6.3.2.4.5.4 Ball Valves

Each main RHR line has an air-operated ball valve, which is normally open and is designed to fail in the open position, thus maximizing flow from this system to the RCS during ECCS operation. These ball valves at the discharge of each RHR system heat exchanger along with the ball valve in the RHR system heat exchanger bypass line are adjusted during RHR system operation to meet the design plant cooldown requirements.

6.3.2.4.6 Piping

All piping joints are either welded, flanged, or threaded connections.

Weld connections for pipes sized 2-1/2 inches and larger are butt-welded.
Minimum piping and fitting wall thickness, as determined by ANSI B31.7-1969 with 1970 Addenda Code formula, are increased to account for the material specifications permissible tolerance on the nominal wall and an appropriate allowance for wall thinning on the external radius during any pipe bending operations in the shop fabrication of the subassemblies.

6.3.2.4.7 Heat Tracing

With the lowering of the normal boric acid solution from 12 to 4 percent, for Cycle 5 and later, the heat tracing on piping, valves, flanges, and instrumentation lines carrying boric acid solution were downgraded to PG&E Design Class II. Refer to Section 9.3.4.2.9.30 for further discussion.

6.3.2.4.8 Containment Recirculation Sump and Strainer

The containment recirculation sump and strainer is a large collecting reservoir designed to provide an adequate supply of water with a minimum amount of particulate matter to the SI system, CCP1 and CCP2, the RHR system, and the CSS during the recirculation mode of ECCS operation following a postulated LOCA.

The sump is located in the annulus area of the containment between the crane wall and the containment liner at the 91 foot elevation. It is approximately 50 feet from RCS piping and components that could become sources of debris. The two 14-inch suction pipes are located on opposite sides of the sump for ECCS train separation. In the sump, there is a strainer assembly, which includes a trash rack with integral debris curb and two strainers (front and rear). Each strainer is designed with 3/32-inch nominal diameter openings, which are sized for the smallest credible restriction in the ECCS flowpath. Each strainer has a plenum. These plenums come together above the two 14-inch RHR pump suction lines and both plenums feed both RHR lines. The lower or rear plenum assembly is water tight to allow collection of any potential back leakage from the RHR system.

The strainer assemblies are designed to minimize blockage. The design provides enough screen area to ensure, with maximum accident debris loads and RHR flowrates, the RHR system has sufficient NPSH margin. Since both plenums feed both RHR trains, without complete blockage of both strainer assemblies, there is no condition that would cause both RHR trains to fail.

The physical arrangement of the strainer for DCPP Unit 1 is shown in Figure 6.3-6 and the DCPP Unit 2 arrangement is shown in Figure 6.3-7.

Any debris or other matter that passes into the sump through the 3/32-inch maximum hole size allowed for the strainers will pass through the SI system, CCP1 and CCP2, the RHR system, and the CSS without restriction and eventually will be pumped back into the containment. This is based on the maximum nominal-sized debris (i.e., the evaluation is based on a 1/8 inch diameter, therefore conservative using a 3/32 inch diameter) that could potentially pass through the sump strainers and pass through the ECCS throttle valves.

Safety Injection System Flow Path

Fluid from the containment recirculation strainer passes into the 14 inch RHR pump suction piping. The flow passes through the RHR pumps and heat exchangers. The flowpath continues from the exit of the RHR heat exchanger to the suction of the SI pumps. The SI pumps discharge to either the cold or hot legs of the RCS loops. The flowpath continues through the RCS cold or hot legs into the core, through the reactor vessel, into the ruptured RCS loop, through the rupture into the containment and, finally, ends in the containment recirculation sump.

Centrifugal Charging Pump System (CCP1 and CCP2) Flow Path

Fluid from the containment recirculation strainer passes into the 14 inch RHR pump suction piping. The flow passes through the RHR pumps and heat exchangers. The flowpath continues from the exit of the RHR heat exchangers to the suction of CCP1 and CCP2. From these CCPs, it goes through the charging injection to the cold legs of the RCS loops. The flowpath continues through the 27-1/2 inch piping of the RCS cold legs, into the core, through the reactor vessel, into the ruptured RCS loop, through the rupture into the containment and, finally, into the containment recirculation sump. CCP3, which replaced the positive displacement pump, is not credited as part of the CCP system (CCP1 and CCP2) described within this section and Chapter 15.

Residual Heat Removal System Flow Path

Fluid from the containment recirculation strainer passes into the 14 inch RHR pump suction piping. The flow passes through the RHR pumps and heat exchangers. The flowpath continues from the exit of the RHR heat exchangers to either the cold or hot legs of the RCS loops. The flowpath continues through the cold legs or hot legs of the RCS loop piping, into the core, through the reactor vessel, into the ruptured RCS loop, through the rupture into the containment and, finally, into the containment recirculation sump. During normal plant operation, when the RCS is hot and pressurized, there is no direct connection between the RWST and the RCS. Also during normal plant shutdown, when the RCS is being cooled down and the RHR system begins to operate, the RHR system is isolated from the RWST by an MOV in addition to a check valve.

Containment Spray System Flow Path

Fluid from the containment recirculation strainer passes into the 14 inch RHR pump suction piping. The flow passes through the RHR pumps and heat exchangers. The flowpath continues from the exit of the RHR heat exchangers to the spray headers and out of the 3/8 inch spray nozzles into the containment. Finally, fluid in the containment drains into the containment recirculation sump. The CSS is discussed in Section 6.2.2.

6.3.2.4.8.1 Sump Strainer Submergence During a Small Break Loss-of-Coolant Accident

Since SBLOCA scenarios may result in a partially-submerged strainer, a set of flow straighteners were added to the strainer system to reduce the tendency to vortex and to eliminate air entrainment as a concern. The performance of the DCPP strainers at water levels representative of a SBLOCA will not result in conditions which would entrain excessive amounts of air into the suctions of the RHR pumps.

6.3.2.5 Motor-Operated Valves and Controls

Each containment recirculation sump isolation valve is interlocked with its respective pump suction/RWST isolation valve to the RHR system. This interlock prevents opening the sump isolation valve when the RWST isolation valves are open and thus prevents dumping the RWST contents into the containment recirculation sump.

To preclude spurious movement of specific MOVs that could result in a loss of ECCS function, electric power is removed from certain valves during normal operation. These valves are listed in Table 6.3-12 and further discussion is provided in Section 6.3.3.42.

6.3.2.6 Schematic Piping and Instrumentation Diagrams

Piping schematic diagrams of the ECCS are shown in Figures 3.2-8 through 3.2-10.

6.3.2.7 Emergency Core Cooling System Flow Diagrams

Alignment of the major ECCS components during the injection and recirculation phases is shown in Figures 6.3-4 and 6.3-5, respectively. Tables 15.4.1.3-2A, 15.4.1.3-2B, 15.4.1.3-3A, 15.4.1.3-3B, and 15.3-3 summarize the calculated times at which the major components perform their safety-related functions for various accident conditions (tabulated in Table 15.1-2) that require ECCS operations.

6.3.2.8 Applicable Codes and Classifications

The codes and standards to which the individual ECCS components are designed are listed in Table 6.3-2.

6.3.2.9 Materials

Table 6.3-3 lists the materials used in ECCS components.

6.3.2.9.1 Material Specifications and Compatibility

Materials employed for ECCS components are given in Table 6.3-3. Materials are selected to meet the applicable material code requirements of Table 6.3-2 and the following additional requirements:

(1) All parts of components in contact with borated water are fabricated of or clad with austenitic stainless steel or similar corrosion-resistant material.

(2) All parts of components in contact (internal) with sump solution during recirculation are fabricated of austenitic stainless steel or similar corrosion resistant material.

(3) Valve seating surfaces are hard-faced with Stellite No. 6 or similar to prevent galling and to reduce wear.

(4) Valve stem materials were selected for their corrosion resistance, high tensile properties, and resistance to surface scoring by the packing.

The elevated temperature of the sump solution during recirculation is well within the design temperature of all ECCS components. In addition, consideration has been given to the potential for corrosion of various types of metals exposed to the fluid conditions prevalent immediately after the accident or during long-term recirculation operations.

Environmental testing of ECCS equipment inside the containment, which is required to operate following a LOCA, is discussed in Section 3.11. The results of the test program indicate that the equipment will operate satisfactorily during and following exposure to the combined containment post-accident environmental temperature, pressure, chemistry, and radiation.

6.3.2.10 Design Pressures and Temperatures

The component design pressure and temperature conditions as given in Table 6.3-1 are specified as the most severe conditions to which each component is exposed to during either normal plant operation or during ECCS operation.

6.3.2.11 Coolant Quantity

The quantities and minimum boron concentration of coolant available to the ECCS are summarized in Table 6.3-1.

The minimum volume that will be maintained in the RWST is 455,300 gallons (this includes the usable and unusable volume). In the event of a LOCA, this volume also provides a sufficient amount of borated water to meet the following requirements:

(1) Provide adequate coolant during the injection phase to meet ECCS design objectives (refer to Sections 15.3 and 15.4).

(2) Increase the boron concentration of reactor coolant and recirculation water to a point that ensures no return to criticality with the reactor at cold shutdown and all control rods, except the most reactive RCCA, inserted into the core (refer to Sections 15.3.1 and 15.4.1).

(3) Fill the containment recirculation sump to support continued operation of the ECCS pumps at the time of transfer from the injection mode to the recirculation mode of cooling. The sump strainer assemblies are required to be fully submerged to prevent vortexing and air ingestion, during changeover from the injection mode to the recirculation mode, for a LBLOCA (Reference 16). Refer to Section 6.3.2.4.8.1 for discussion on partial submergence of the strainer assemblies during an SBLOCA.

(4) Fulfill spray requirements (refer to Section 6.2.2).

6.3.2.12 Accumulator Availability

Accumulator availability requirements during power operation, hot standby, and startup conditions are detailed in the Technical Specifications (Reference 10).

6.3.2.13 Dependence on Other Systems

Other systems that operate in conjunction with the ECCS are as follows:

(1) The CCW system (refer to Section 9.2.2) cools the RHR heat exchangers during the recirculation mode of operation. It also supplies cooling water to CCP1 and CCP2, the SI pumps, and the RHR pumps during the injection and recirculation modes of operation.

(2) The ASW system (refer to Section 9.2.1) provides cooling water to the CCW heat exchangers.

(3) The Preferred Power Supply (230-kV and 500-kV), Onsite Distribution System (120-Vac, 480-V, and 4.16-kV), and Standby Power Supply provide normal and emergency power sources for the ECCS (refer to Sections 8.2, and 8.3.1.1.3 through 8.3.1.1.6).

(4) The ESFAS (refer to Section 7.3) generates the initiation signal for emergency core cooling.

(5) The AFW system (refer to Section 6.5) supplies feedwater to the SGs.

(6) The ABVS (refer to Section 9.4.2) removes heat from the pump compartments and provides for radioactivity contamination control should some leakage occur in a compartment.

6.3.2.14 Lag Times

The sequence and time-delays for actuation of ECCS components for the injection and recirculation phases of emergency core cooling are given in Table 6.3-7. Alignment of the major ECCS components during the injection and recirculation phases is shown in Figures 6.3-4 and 6.3-5, respectively. Tables 15.4.1.3-2A, 15.4.1.3-2B, 15.4.1.3-3A, and 15.4.1.3-3B, 15.4.1-1A, and 15.4.1-B summarize the calculated times at which the major components perform the safety-related functions for those various accident conditions that require the ECCS.

The minimum active components will be capable of delivering full rated flow within a specified time interval after process parameters reach the setpoints for the "S" signal. Response of the system is automatic with appropriate allowances for delays in actuation of circuitry and active components. The active portions of the system are actuated by the "S" signal. In analyses of system performance, delays in reaching the programmed trip points and in actuation of components are established on the basis that only Standby Power Supply is available. The starting sequence following a loss of offsite power is discussed in detail in Chapter 8.

For events like a LOCA which assume a loss of offsite power, the ECCS provides cold leg injection flow after an elapsed time not greater than 25 seconds after the “S” signal, including the diesel generator start time and the time to bring all ECCS pumps up to full speed.

For major secondary system pipe rupture events like the Main Steam Line Break (MSLB) which credit boron injection to mitigate the core reactivity increase, there is an additional assumed delay time associated with the CCP valve re-alignments necessary to open the RWST suction valves and then isolate the Volume Control Tank. For these events, the ECCS provides borated cold leg injection flow from the RWST within 25 seconds after the “S” signal when offsite power is available, and 35 seconds when offsite power is not available.

The starting times for components of the ECCS are consistent with the delay times used in the LOCA analyses for large and small breaks.

In the LOCA analysis presented in Sections 15.3 and 15.4, no credit is assumed for partial flow prior to the establishment of full flow and no credit is assumed for the availability of the Preferred Power Supply.

For smaller LOCAs, there is some additional delay before the process variables reach their respective programmed trip setpoints since this is a function of the severity of the transient imposed by the accident. This is allowed for in the analyses of the range of LOCAs (refer to Tables 15.4.1.2-1A and 15.4.1.2-1B).

Accumulator injection occurs immediately when RCS pressure has decreased below the operating pressure of the accumulator.

6.3.3 SAFETY EVALUATION

6.3.3.1 General Design Criterion 2, 1967 – Performance Standards

With the exception of the RWST, all ECCS components are housed within the PG&E Design Class I auxiliary and containment buildings. These buildings, or applicable portions thereof, are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other natural phenomena, to protect ECCS SSCs, ensuring their safety-related design functions will be performed.

The RWST, as discussed in Section 3.8, is a PG&E Design Class I outdoor water storage tank which is designed to withstand the effects of floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other natural phenomena. The ability of the RWST to withstand the effects of winds and tornadoes is addressed in Section 3.3. The loss of the RWST, which is not contained within a building and is exposed directly to potential wind and tornado loads, has been evaluated. Loss of this equipment does not compromise the capability of shutting down the plant safely (refer to Section 3.3.2). Leakage from the RWSTs due to tornado or missile-induced damage will not result in the flooding of PG&E Design Class I equipment in the auxiliary building since essentially watertight cover plates are installed over the pipe entranceway from each tank into the auxiliary building. The water will drain away from the building via the plant yard drainage system.

The ECCS is designed to perform its function of ensuring core cooling and providing shutdown capability following an accident under simultaneous DDE or HE loading. The seismic requirements are defined in Sections 3.7 and 3.10, and the provisions to protect the system from seismic damage are discussed in Sections 3.7, 3.9, and 3.10. ECCS components are designed to withstand the appropriate seismic loadings in accordance with PG&E Design Class I criteria.

6.3.3.2 General Design Criterion 3, 1971 – Fire Protection

The ECCS is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

6.3.3.3 General Design Criterion 11, 1967 – Control Room

No manual actions are required from the operator during the injection phase of ECCS operation. Those manual actions from the control room required for changeover from the injection phase to the recirculation phase are described in Section 6.3.3.6.1.1.2 and in Table 6.3-5.

Instrumentation, alarms, and controls are provided in the control room for operators to monitor and maintain ECCS parameters. Instrumentation and alarms for the ECCS is further discussed in Section 6.3.3.4.

6.3.3.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Varied instrumentation is available to assist the operator in assessing post-accident conditions. This instrumentation is listed below.

Instrumentation and associated analog and logic channels used to initiate ECCS operation are discussed in Section 7.3. This section describes the instrumentation employed to monitor ECCS components during normal plant operation and ECCS post-accident operation. All alarms are annunciated in the control room.

6.3.3.4.1 Temperature Indication

6.3.3.4.1.1 Residual Heat Exchanger Outlet Temperature

The fluid temperature at the outlet of each RHR heat exchanger is recorded in the control room.

6.3.3.4.1.2 Emergency Core Cooling System Pump-motor Temperatures

Temperature indicators are provided to monitor RHR pump, CCP1 and CCP2, and SI pump motor/motor bearing temperatures. High temperatures activate alarms in the control room.

6.3.3.4.1.3 Containment Recirculation Sump Water Temperature

The fluid temperature of the containment recirculation sump water is provided on the post-accident monitoring panel PAM1.

6.3.3.4.2 Pressure Indication

6.3.3.4.2.1 Charging Injection Line Pressure

The charging injection line pressure (PT-947 between valves 8801A & 8801B and 8803A & 8803B) shows that the CCPs are operating. The transmitters are outside the containment, with indicators on the control board.

6.3.3.4.2.2 Safety Injection Header Pressure

SI pump discharge pressure for each pump shows that the SI pumps are operating. The transmitters are outside the containment, with indicators on the control board.

6.3.3.4.2.3 Accumulator Pressure

Duplicate pressure channels are installed on each accumulator. Pressure indication in the control room and high- and low-pressure alarms are provided by each channel.

6.3.3.4.2.4 Residual Heat Removal Pump Discharge Pressure

RHR pump discharge pressure for each pump is indicated in the control room. A high-pressure alarm is actuated by each channel.

6.3.3.4.3 Flow Indication

6.3.3.4.3.1 CCP1 and CCP2 Injection Flow

Injection flow through the common header to the reactor cold legs is indicated in the control room.

6.3.3.4.3.2 Safety Injection Pump Header Flow

Flow through the SI pump headers is indicated in the control room.

6.3.3.4.3.3 Residual Heat Removal Pump Injection Flow

Flow through each RHR injection and recirculation header leading to the reactor cold or hot legs is indicated in the control room.

6.3.3.4.3.4 Test Line Flow

Local indication of the leakage test line flow is provided to check for proper seating of the accumulator CVs between the injection lines and the RCS.

6.3.3.4.3.5 Safety Injection Pump Minimum Flow

A local flow indicator is installed in the SI pump minimum flow line.

6.3.3.4.3.6 Residual Heat Removal Pump Minimum Flow

A flowmeter installed in each RHR pump discharge header provides control for the valve located in the pump minimum flow line.

6.3.3.4.4 Level Indication

6.3.3.4.4.1 Refueling Water Storage Tank Level

Three water level instrumentation channels are provided for the RWST. Each channel provides independent indication on the main control board, thus satisfying the requirements of paragraph 4.20 of IEEE 279-1971 (Reference 12). Two-out-of-three logic is provided for RHR pump trip and low-level alarm initiation. One channel provides low-low water level alarm initiation. One channel also provides a high water level alarm.

6.3.3.4.4.2 Accumulator Water Level

Duplicate water level channels are provided for each accumulator. Both channels provide indication in the control room and actuate high- and low-water level alarms.

6.3.3.4.4.3 Containment Recirculation Sump Water Level

Two redundant containment wide-range water level channels are provided to measure level from the bottom of the reactor cavity. Wide-range recorders are located on the post-accident monitoring (PAM) panel.

Two redundant narrow-range instruments measure level from the bottom of the containment recirculation sump. The containment recirculation sump level instrumentation consists of two level sensor elements, junction boxes, and connection sleeves designed to operate in a post-accident environment inside containment. The junction boxes and connection sleeves are located above any possible flooding level. Level transmitters are located outside of containment and are not required to be environmentally qualified as they are not required for a postulated line break outside of containment. Narrow-range indicators are located on the main control board. The containment recirculation sump level instrumentation is described in more detail in Section 7.5.

6.3.3.4.5 Valve Position Indication

Valve positions that are indicated on the control board are done so by a "normal off" system; i.e., should the valve not be in its proper position, a bright white light will give a

highly visible indication to the operator. This indication is only active upon receipt of an "S" signal for those ECCS-related valves that are required to automatically change position to align CCP1 and CCP2 for injection, as described in Section 6.3.3.6.1.1.1.

6.3.3.4.5.1 Accumulator Isolation Valve Position Indication

The accumulator MOVs are provided with red (open) and green (closed) position indicating lights located at the control switch for each valve. These lights are energized from the Class 1E 120-Vac Instrument Power Supply System and actuated by the associated valve motor operator limit switches.

A monitor light that is on when the valve is not fully open is provided in an array of monitor lights that are all off when their respective valves are in proper position enabling safety features operation. This light is energized from a separate Class 1E 120-Vac circuit and actuated by a valve motor-operated limit switch.

An alarm annunciator point is activated by a valve motor operator limit switch or a stem travel limit switch whenever an accumulator valve is not fully open with the system at pressure (the pressure at which the SI block is unblocked). The alarm is reinstated once an hour. A separate annunciator point is used for each accumulator valve.

6.3.3.4.6 Subcooling Meter

Each subcooling meter provides continuous digital-type display of either the temperature or pressure subcooling margin. The displays are a subset of the reactor vessel level instrumentation system (RVLIS) and are located on PAM panels, PAM3 and PAM4, with low and low-low alarms being provided. A digital display of the temperature margin is fed from train B and is available on the main control board. A recorder fed from train A is located on PAM1. The subcooling meter displays, calculators, and inputs are described in Sections 5.6 and 7.5.

6.3.3.5 General Design Criterion 21, 1967 – Single Failure Definition

To ensure that the ECCS will perform its intended function if any of the accidents listed in Section 6.3.2 occurs, it is designed to tolerate a single active failure during the short-term immediately following an accident, or to tolerate a single active or passive failure during the long-term following an accident. This subject is detailed in Section 3.1 and the following subsections.

6.3.3.5.1 Definition of Terms

Definitions of terms used in this section are located in Section 3.1.1.1.

6.3.3.5.2 Active Failure Criteria

The ECCS is designed to accept a single failure following the incident without loss of its protective function. The system design will tolerate the failure of any single active component in the ECCS itself or in the necessary associated service systems at any time during the period of required system operations following the incident.

A single active failure analysis is presented in Table 6.3-13, and demonstrates that the ECCS can sustain the failure of any single active component in either the short- or long-term and still meet the level of performance for core cooling.

Since the operation of the active components of the ECCS following an MSLB is identical to that following a LOCA, the same analysis is applicable and the ECCS can sustain the failure of any single active component and still meet the level of performance for the addition of shutdown reactivity.

6.3.3.5.3 Passive Failure Criteria

The following philosophy provides for necessary redundancy in component and system arrangement to meet the single failure criterion, as it specifically applies to failure of passive components in the ECCS. Thus, for the long-term, the system design is based on accepting either a passive or an active failure.

6.3.3.5.3.1 Redundancy of Flow Paths and Components for Long-Term Emergency Core Cooling

In the design of the ECCS, Westinghouse utilizes the following criteria:

(1) During the long-term cooling period following a loss of coolant, the emergency core cooling flow paths are separable into two subsystems, either of which can provide minimum core cooling functions and return spilled water from the floor of the containment back to the RCS.

(2) Either of the two subsystems can be isolated and removed for service in the event of a leak outside the containment.

(3) Adequate redundancy of check valves is provided to tolerate failure of a check valve during the long-term as a passive component.

(4) Should one of these two subsystems be isolated in this long-term period, the other subsystem remains operable.

(5) Provisions are also made in the design to detect leakage from components outside the containment and collect this leakage.

The two separate heat exchanger and pump flowpaths provide redundant capability of meeting the engineered safety function of the RHR system. The loss of one of these RHR system flowpaths would not negate the capability of the ECCS since the two flowpaths provide full redundancy for engineered safety requirements. The injection flow paths to loops one and two and to loops three and four are not redundant. Both of these flowpaths must be available with the heat exchanger discharge cross tie open to meet the engineered safety function of the RHR system.

Thus, for the long-term emergency core cooling function, adequate core cooling capacity exists with one flow path removed from service whether isolated due to a leak, because of blocking of one flow path, or because failure in the containment results in a spill of the delivery of one subsystem.

6.3.3.5.3.2 Subsequent Leakage from Components in Engineered Safety Systems

With respect to piping and mechanical equipment outside the containment, considering the provisions for visual inspection and leak detection, leaks will be detected before they propagate to major proportions. A review of the equipment in the system indicates that the largest sudden leak potential would be the sudden failure of a pump shaft seal. Evaluation of leak rate assuming only the presence of a seal retention ring around the pump shaft showed flows less than 50 gpm would result. Piping leaks, valve packing leaks, or flange gasket leaks have been of a nature to build up slowly with time and are considered less severe than the pump seal failure.

Larger leaks in the ECCS are prevented by the following:

(1) The system piping is located within a controlled area on the plant site.

(2) The piping system receives periodic pressure tests and is accessible for periodic visual inspection (refer to Sections 6.3.3.24 and 6.3.3.25).

(3) The piping is austenitic stainless steel that, due to its ductility, can withstand severe distortion without failure.

Based on this review, the design of the auxiliary building and related equipment is based on handling of leaks up to a maximum of 50 gpm. Means are also provided to detect and isolate such leaks in the emergency core cooling flow path within 30 minutes.

With these design ground rules, continued function of the ECCS will meet minimum core cooling requirements, and offsite doses resulting from the leak will be within 10 CFR 50.67 limits. Refer to Section 15.5 for discussion of radiological consequences of plant accidents.

A single passive failure analysis is presented in Table 6.3-14. It demonstrates that the ECCS can sustain a single passive failure during the long-term phase and still retain an

intact flow path to the core to supply sufficient flow to maintain the core covered and effect the removal of decay heat. The procedure followed to establish the alternate flow path also isolates the component that failed.

6.3.3.5.4 Single Failures in Electrical and Control Circuitry

ESF systems, including the ECCS, are designed to tolerate single failures in the electrical and control circuitry as defined below. Each ECCS train is supplied from separate Class 1E power sources. In addition, provisions are made in construction, layout, and installation that minimize the occurrence of electrical faults.

Single failures of switching components that are considered in the design include (a) a single instance of contact failure, (b) a loss of control power, or (c) mechanical failure resulting in the sticking of a component in any position. Faults that require a particular time sequence of abnormal connections or that involve selective combinations of multiple contact closures are considered to involve more than one failure, and hence to be incredible. Examples of a single wiring failure considered in design include the single short and open circuit faults. Single short circuits considered are (a) a single conductor shorted to ground or to a structure such as a cable tray, or (b) two conductors in the same cable shorted together. Faults that require several particular wires to be connected, or which require sustained application of power through a short circuit, are not considered to be credible. Open circuit faults considered include (a) a single conductor breaking, (b) a single connector being disconnected, or (c) a single field-run cable severed.

The random shorting to the manual closing switch contacts or a hot short in the cable run to the closing coil have been identified as control system failure modes that could lead to spurious movement of a passive MOV.

During the safety review of the operating license application for the DCPP, the AEC (now the NRC) regulatory staff adopted the position that failures of the type discussed above that could lead to spurious movement of passive MOVs must be considered in relation to satisfying the single failure criterion. The regulatory staff's position, as stated in Branch Technical Position EICSB 18, November 1975, considers removal of electric power an acceptable means, under certain conditions, of satisfying the single failure criterion. Refer to Section 6.3.3.42 for further discussion.

6.3.3.5.5 Control of Accumulator Motor-Operated Isolation Valves

During power operation, electrical power is removed from the valves by opening the 480-V breaker, thereby preventing inadvertent closure due to an electrical short. As the valve is provided with an automatic opening signal whenever RCS pressure exceeds the unblocking pressure, P11, a manual override permits closing of the valves at pressures exceeding P11 (refer to Figure 7.3-33 for controls). Additionally, it will open automatically upon receipt of the "S" signal should the valve be closed and the breaker

is racked in. This "S" signal overrides any bypass feature. Position indicators for these valves are discussed in Section 6.3.3.4.5.1.

The accumulator MOVs are considered to be “operating bypasses” in the context of IEEE 279-1971 (Reference 12), which requires that bypasses of a protective function be removed automatically whenever permissive conditions are not met. In addition, as these accumulator isolation valves fail to meet single failure criteria, removal of power to the valves is required.

6.3.3.6 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

6.3.3.6.1 Systems Operation

The operation of the ECCS following a LOCA or MSLB is discussed below.

6.3.3.6.1.1 Operation After Loss of Primary Coolant

The operation of the ECCS following a LOCA can be divided into two distinct modes:

(1) The injection mode in which any reactivity increase following the postulated accident is terminated, initial cooling of the core is accomplished, and coolant lost from the primary system is replenished

(2) The recirculation mode in which long-term core cooling is provided during the accident recovery period

A discussion of these modes follows:

6.3.3.6.1.1.1 Injection Mode After Loss of Primary Coolant

As shown in Figure 6.3-4, the principal mechanical components of the ECCS that provide core cooling immediately following a LOCA are the accumulators (one for each loop), the SI pumps, the CCPs (CCP1 and CCP2), the RHR pumps, and the associated valves, tanks, and piping.

For large pipe ruptures, (0.5 square feet equivalent and larger), the RCS would be depressurized and voided of coolant rapidly. A high flowrate of emergency coolant is required to quickly cover the exposed fuel rods and limit possible core damage. This high flow is provided by the passive accumulators, followed by CCP1 and CCP2, SI pumps, and the RHR pumps discharging into the cold legs of the RCS.

During the injection mode, the RHR and SI pumps deliver into the accumulator injection lines between the two check valves. CCP1 and CCP2 deliver through the charging injection line directly into the cold legs.

Emergency cooling is provided for small ruptures primarily by high-head injection. Small ruptures are those, with an equivalent diameter of 6 inches or less, that do not immediately depressurize the RCS below the accumulator discharge pressure. CCP1 and CCP2 deliver borated water at the prevailing RCS pressure to the cold legs of the RCS, from the RWST during the injection mode.

The SI pumps also take suction from the RWST and deliver borated water to the cold legs of the RCS. The SI pumps begin to deliver water to the RCS after the pressure has fallen below the pump shutoff head.

The RHR pumps take suction from the RWST and deliver borated water to the RCS. These pumps begin to deliver water to the RCS only after the pressure has fallen below the pump shutoff head.

The injection mode of emergency core cooling is initiated by the "S" signal. This signal is actuated by any of the following:

(1) Pressurizer low pressure

(2) Containment high pressure

(3) Low steamline pressure

(4) Manual actuation

Operation of the ECCS during the injection mode is completely automatic. The "S" signal automatically initiates the following actions:

(1) Starts the diesel generators and, if all other sources of power are lost, aligns them to the Class 1E buses (refer to Section 8.3.1.1.6)

(2) Starts CCP1 and CCP2, the SI pumps, and the RHR pumps

(3) Aligns CCP1 and CCP2 for injection by:

    (a) Closing the valves in the charging pump discharge line to the normal charging line

    (b) Opening the valves in the charging pumps suction line from the RWST

    (c) Closing the valves in the charging pump normal suction line from the volume control tank

    (d) Opening the charging injection inlet and outlet line isolation valves

(4) Provides an open signal to the accumulator isolation valves; and if they are energized and closed, they will open (refer to Section 6.3.3.5.5).

The injection mode continues until the low level is reached in the RWST, at which time the RHR pumps are automatically tripped. The operator then manually changes system alignment to the recirculation mode. The remaining water in the RWST provides a reserve to be used by the CSS pumps to ensure that enough sodium hydroxide has been added to the containment, utilizing the SAS, to maintain the pH of the recirculation fluid greater than 8.0. Three channels of RWST instrumentation are used, providing three independent and redundant RWST level indications that are displayed in the control room, to inform the operator of the water level in the tank at all times. Any two of these three channels will actuate the low-level alarm and will automatically trip the RHR pumps on low RWST level. After the changeover begins, the rate of possible demand on the tank is reduced, providing increasing periods of operation for the pumps still drawing water from the tank, and giving further assurance that water will remain in the tank after the completion of the changeover.

6.3.3.6.1.1.2 Changeover from Injection Mode to Recirculation After Loss of Primary Coolant

Water level indication and alarms on the RWST and level indication in the containment recirculation sump provide ample warning to terminate the injection mode while the operating pumps still have adequate NPSH. Since the injection mode of operation following a LOCA is terminated before the RWST is completely emptied, all pipes are kept filled with water before recirculation is initiated. For some SBLOCAs, the RCS pressure may remain above the shut off head of the RHR pumps that would be providing only recirculation flow. For these scenarios, the operators will trip the RHR pumps or initiate CCW flow to an RHR heat exchanger within 30 minutes. This ensures that pump recirculation does not result in heating and pressurizing the RHR suction piping.

Following receipt of the RWST low-level alarm and automatic tripping of the RHR pumps, the remainder of the changeover sequence from injection mode to recirculation mode is accomplished manually by the operator from the control room (except for restoring power to the RWST supply valves to the RHR and the SI pumps). The same sequence (as delineated in Table 6.3-5) is followed regardless of which power supply is available (Offsite Power System or Standby Power Supply). Controls for ECCS components are grouped together on the main control board. The component position lights verify when the function of a given switch has been completed. The total required switchover time for the changeover from injection to recirculation is approximately 10 minutes, as shown in Table 6.3-5. The postulated single failure during the changeover sequence is the failure of an RHR pump to trip on low RWST level. The operator action requires approximately 5 minutes to locally open the breaker for an RHR pump motor. The operator action is performed concurrently with the changeover sequence and there is no increase in the total time for the changeover. The

changeover sequence can be completed, with the single failure, and the remaining useable RWST volume exceeds the licensing basis of 32,500 gallons.

6.3.3.6.1.1.3 Recirculation Mode After Loss of Primary Coolant

After the injection operation, water collected in the containment recirculation sump is cooled and returned to the RCS by the low-head/high-head recirculation flowpath. The RCS can be supplied simultaneously from the RHR pumps and from a portion of the discharge from the RHR heat exchanger that is directed to CCP1 and CCP2 and SI pumps that return the water to the RCS. The latter mode of operation ensures flow in the event of a small rupture where the depressurization proceeds more slowly, so that the RCS pressure is still in excess of the shutoff head of the RHR pumps at the onset of recirculation. Hot leg recirculation is implemented to ensure termination of boiling and prevent boric acid crystallization. Approximately 7.0 hours after LOCA inception, the operators will manually initiate hot leg recirculation and are expected to complete the switchover process within approximately 15 minutes. Some cold leg recirculation would be maintained with the CCPs (CCP1 and CCP2) after hot leg recirculation is initiated.

As discussed in Section 6.2.2, the CSS is operated during the injection and recirculation mode (up to 6.25 hours) to support fission product removal following a LOCA. During the recirculation mode, the CS pumps are isolated (refer to Table 6.3-5) and water, recirculated from the containment sump, is supplied by the RHR pumps for recirculation spray to the headers. Single failures that result in the loss of one RHR train are taken into consideration in system alignment to ensure appropriate division of the recirculation flow between containment spray and core injection to ensure fission product removal from the containment atmosphere and adequate core cooling.

The RWST is protected from back flow of reactor coolant from the RCS. All connections to the RWST except those that are designed to return flow to the RWST are provided with check valves to prevent back flow.

Redundancy in the external recirculation loop is provided by duplicate CCPs (CCP1 and CCP2), SI pumps, and RHR pumps and heat exchangers. Inside the containment, the high-pressure injection system is divided into two separate flow trains. For cold leg recirculation, CCP1 and CCP2 deliver to all four cold legs and the SI and RHR pumps deliver also to all four cold legs by separate flowpaths. For hot leg recirculation, each SI pump delivers through separate paths to two hot legs, while the RHR pumps deliver to two of the four hot legs.

The sump isolation valves are located in steel-lined pressure-tight compartments. This arrangement contains any leakage from an isolation valve stem or bonnet.

6.3.3.6.1.2 Operation After Main Steam Line Break

Following an MSLB, the ECCS is automatically actuated to deliver borated water from the RWST to the RCS. The response of the ECCS following an MSLB is identical to its response during the injection mode of operation following a LOCA. The ”S” signal initiates identical actions as described for the injection mode of the LOCA, even though not all of these actions are required following an MSLB; e.g., the RHR pumps are not required since the RCS pressure will remain above the pump shutoff head.

The delivery of the concentrated boric acid from the RWST provides negative reactivity to counteract the increase in reactivity caused by the system cooldown. CCP1 and CCP2 continue to deliver borated water from the RWST until enough water has been added to the RCS to make up for the shrinkage due to cooldown. The SI pumps also deliver borated water from the RWST for the interval when the RCS pressure is less than the shutoff head of the SI pumps. After pressurizer water level has been restored, the injection is manually terminated.

The sequence of events following a postulated MSLB is described in Section 15.4.2.

6.3.3.6.2 Emergency Core Cooling System Performance

The following events were analyzed to ensure that the limits on core behavior following an RCS pipe rupture are not exceeded when the ECCS operates with minimum design equipment:

(1) Large pipe break analysis

(2) Small line break analysis

(3) ECCS recirculation mode cooling

The adequacy of flow delivered to the RCS by the ECCS with the operation of minimum design equipment is demonstrated in Sections 15.3.1 and 15.4.1.

The design basis performance characteristic is derived from the specified performance characteristic for each pump with a conservative estimate of system piping resistance, based on the final piping layout. The performance characteristic utilized in the accident analyses includes a decrease in the design head for margin. When the initiating incident is assumed to be the severance of an injection line, the injection curve utilized in the analyses accounts for the loss of injection water through the broken line.

6.3.3.6.2.1 Large Pipe Break Analysis

The large pipe break analysis is used to evaluate the initial core thermal transient for a spectrum of pipe ruptures from a break size greater than 1.0 square foot up to the double-ended rupture of the largest pipe in the RCS.

The injection flow from active components is required to control the cladding temperature subsequent to accumulator injection, complete reactor vessel refill, and eventually return the core to a subcooled state. The results indicate that the maximum cladding temperature attained at any point in the core is such that the limits on core behavior as specified in Section 15.4.1 are met.

6.3.3.6.2.2 Small Pipe Break Analysis

The small pipe break analysis is used to evaluate the initial core thermal transient for a spectrum of pipe ruptures to ensure that the small breaks with a likelihood of the most severe core uncover are captured within the analysis.

The results of the small pipe break analysis indicate that the limits on core behavior are adequately met, as shown in Section 15.3.1 and Section 15.4.1.

6.3.3.6.2.3 Recirculation Cooling

Core cooling during recirculation can be maintained by the flow from one RHR pump if RCS pressure is low. If RCS pressure remains high, either CCP1 or CCP2 and one SI pump operating in series with one RHR pump provide the added head and flow needed to maintain adequate cooling.

Heat removal from the recirculated sump water is accomplished via operation of one or both of the RHR heat exchangers.

6.3.3.6.2.4 Required Operating Status of Emergency Core Cooling System Components

Normal operating status of ECCS components is given in Table 6.3-6.

ECCS components are available whenever the coolant energy is high and the reactor is critical. During low temperature physics tests, there is a negligible amount of stored energy and low decay heat in the coolant; therefore, an accident comparable in severity to accidents occurring at operating conditions is not possible in low temperature physics tests, and ECCS components are not required.

6.3.3.6.2.5 Loss of Offsite Power

The ECCS is designed to meet its minimum required level of functional performance with onsite electrical power system operation (assuming offsite power is not available)

or with offsite electrical power system operation for any of the above abnormal occurrences assuming a single failure as discussed in Sections 3.1 and 6.3.3.5.

Diesel generators supply power to ECCS components in the event that all sources of offsite power become unavailable.

The supply of emergency power to the ECCS components is arranged so that, as a minimum, CCP1 or CCP2, one SI pump, and one RHR pump together with the associated valves will automatically receive adequate power in the event that a loss of offsite power occurs simultaneously with any of the DBAs described in Section 6.3.2. Adequate power is provided even if the single failure is the failure of an EDG to start.

6.3.3.6.2.6 Range of Core Protection

Core protection is afforded with the minimum ESF equipment, defined by consideration of the single failure criteria as discussed in Sections 3.1 and 6.3.3.5. The minimum design case will ensure that the entire break spectrum is accounted for and the core cooling design bases of Section 6.3.2 are met. The analyses for this case are presented in Sections 15.3 and 15.4.

For large RCS ruptures, the accumulators and the active high-head (CCP), intermediate-head (SI), and low-head (RHR) pumping components serve to complete the core refill. One RHR pump is required for long-term recirculation.

If the break is small (1.0 square foot or less), the accumulators, CCP1 or CCP2, and one SI pump ensure adequate cooling during the injection mode. Long-term recirculation requires operation of one RHR pump in conjunction with CCP1 or CCP2 and one SI pump and components of the auxiliary heat removal systems that are required to transfer heat from the ECCS (e.g., CCW system and ASW system). The LOCA analyses, presented in Sections 15.3 and 15.4, indicate that certain modifications (i.e., reduced component availability) to the normal operating status of the ECCS, as given in Table 6.3-6, are permissible without impairing the ability of the ECCS, to provide adequate core cooling capacity.

6.3.3.6.2.7 Emergency Core Cooling System Piping Failures

The rupture of the portion of an injection line from the last check valve to the connection of the line to the RCS can cause not only a loss of coolant but impair the injection as well. To reduce the probability of an emergency core cooling line rupture causing a LOCA, the check valves that isolate the ECCS from the RCS are installed adjacent to the reactor coolant piping.

For a small break, the reactor pressure maintains a relatively uniform back pressure in all injection lines so that a significant flow imbalance does not occur. Also, system resistances are balanced by adjustment of throttling valves in the injection lines prior to plant operation. A rupture in an accumulator injection line is accounted for in the

analyses by assuming that for cold leg breaks the entire contents of the associated accumulator are discharged through the break.

6.3.3.6.2.8 External Recirculation Loop

Major ECCS components are shielded, as required, from their associated redundant train to facilitate maintenance. During recirculation, following a LOCA, access to these components is not credited.

Pressure relieving devices with setpoints below the shutoff head of the high-head ECCS pumps (CCP1 and CCP2), from portions of the ECCS located outside of containment that might contain radioactivity, discharge to the pressurizer relief tank.

An analysis has been performed to evaluate the radiological effects of recirculation loop leakage (refer to Sections 6.3.3.5.3.2 15.5). A loop is assumed to include CCP1 or CCP2, an SI pump, an RHR pump, an RHR heat exchanger, and the associated piping. Thus two loops are provided, each of which is adequate for core cooling. In the analysis, maximum leakage was assumed as discussed in Section 6.3.3.5. Analyses indicate that the offsite dose resulting from such leakage is much less than the requirements of 10 CFR 50.67.

Since redundant flowpaths are provided during recirculation, a leaking component in one of the flowpaths may be isolated. This action curtails any further leakage. Maximum potential leakage from components during normal operation is given in Table 6.3-9.

Each pump compartment and heat exchanger compartment are provided with sufficient drains to the RHR room sump to prevent compartment overflow due to the design leakage rate. Containment isolation valves can be remote manually closed before the pump compartment can overflow.

This layout permits the detection of a leaking recirculation loop component by means of a radiation monitor that samples the air exiting the heat exchanger compartment. Alarms in the control room will alert the operator when the activity exceeds a preset level. Sump level alarms and operation of sump pumps will be indicated in the control room as a backup for detection of water leaks.

Should a tube-to-shell leak develop in a RHR heat exchanger, the operator will be warned by a CCW high radiation alarm. For large leaks, the operator will also be warned by a CCW surge tank high-level alarm. In the event that the leak cannot be isolated before the CCW surge tank fills, the tank relief valve will lift and direct the excess water to the auxiliary building sump.

6.3.3.6.2.9 Evaluation of Shutdown Reactivity Capability Following an Abnormal Release of Steam from the Main Steam System

Analyses are performed to ensure that the core limitations defined in Sections 15.2, 15.3, and 15.4 are met following a steam line rupture or a single active failure in the main steam system.

6.3.3.6.2.9.1 Main Steam System Single Active Failure

Analyses of reactor behavior following any single active failure in the main steam system that results in an uncontrolled release of steam are included in Section 15.2. The analyses assume that a single valve (largest of the safety, relief, or bypass valves) opens and fails to close, resulting in an uncontrolled cooldown of the RCS.

Results indicate that if the incident is initiated at the hot shutdown condition, which results in the worst reactivity transient, the limiting departure from nucleate boiling ratio values will be met. Thus, the ECCS provides adequate protection for this incident.

6.3.3.6.2.9.2 Main Steam Line Break

This accident is discussed in detail in Section 15.4. The limiting MSLB is a complete line severance.

The results of the analysis indicate that the design basis criteria are met. Thus, the ECCS adequately fulfills its shutdown reactivity addition function.

Following a secondary side high-energy (steam or feedwater) line break, CCW is supplied to the seal-water heat exchanger to provide cooling for CCP1 and CCP2 under miniflow conditions. This action prevents damage to the CCPs before SI termination criteria are reached and CCP operation is terminated.

6.3.3.6.2.10 Alternate Analysis Methods

The method of break analysis and the spectrum of breaks analyzed are described in Sections 15.3.1 and 15.4.1.

6.3.3.6.2.11 Fuel Rod Perforations

Results of the small pipe break and large pipe break analyses are presented in Sections 15.3.1 and 15.4.1, respectively.

6.3.3.7 General Design Criterion 38, 1967 – Reliability and Testability of Engineered Safety Features

ECCS reliability was considered in all aspects of system evolution, from initial design to periodic testing of the components during plant operation.

The preoperational testing program ensures that the systems, as designed and constructed, meet functional requirements.

The ECCS is designed with the ability for on-line testing of most components so that availability and operational status can be readily confirmed. The integrity of the ECCS is ensured through examination of critical components during routine ISI.

6.3.3.7.1 Provisions for Performance Testing

Design features have been incorporated to ensure that the following testing can be performed:

(1) Active components may be tested periodically for operability (e.g., pumps on miniflow, certain valves, etc.).

(2) An integrated system actuation test can be performed when the plant is cooled down and the RHR system is in operation. The ECCS will be arranged so that no flow will be introduced into the RCS for this test.

(3) An initial flow test of the full operational sequence can be performed.

Specific design features that ensure this test capability are the following:

(1) Power sources are provided to permit actuation of individual ECCS active components.

(2) The SI pumps can be tested periodically during plant operation using the minimum flow recirculation lines provided.

(3) The RHR pumps are used every time the RHR system is put into operation. They can also be tested periodically when the plant is at power using the miniflow recirculation lines.

(4) CCP1 and CCP2 are either normally in use for charging service or can be tested periodically on miniflow.

(5) Remotely operated valves can be exercised during routine plant maintenance.

(6) For each accumulator tank, level and pressure instrumentation is provided for continuous monitoring during plant operation.

(7) Pressure instrumentation and a flow indicator are provided in the SI pump header and in the RHR pump headers.

(8) An integrated system test can be performed when the plant is cooled down and the RHR system is in operation. This test does not introduce flow into the RCS but does demonstrate the operation of the valves, pump circuit breakers, and automatic circuitry including diesel starting and the automatic loading of ECCS components off the diesels (by simultaneously simulating a loss of offsite power to the Class 1E electrical buses).

6.3.3.8 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the ECCS from damage that might result from dynamic effects associated with a postulated rupture of piping are discussed in Section 3.6. The provisions taken to protect the system from missiles are discussed in Section 3.5. The ECCS design is such that physical protection is adequately provided against physical hazards in areas through which the system is routed.

6.3.3.8.1 Safety Injection System Pump Missile Proneness

The capability of SI pump-motor combination to generate an external missile has been evaluated in Section 3.5. The results of this evaluation showed that neither the SI pump nor the motor are capable of generating external missiles.

However, the flexible coupling between the pump and motor could conceivably become a missile in the unlikely event that it should fail to maintain its mechanical integrity, due to a maximum overspeed condition caused by a large pressure head driving the pump in reverse. Such failure would require the failure of two check valves in the open position in conjunction with a rupture of the pipe on the suction side of the pump.

Despite the low probability of such a combination of failures, a shroud has been installed around the flexible coupling to eliminate all possibility of missiles being generated in the unlikely event of gross coupling failure.

6.3.3.9 General Design Criterion 41, 1967 – Engineered Safety Features Performance Capability

The ECCS is a two-train, fully redundant, standby ESF. The system was designed to withstand any single credible active failure during injection or active or passive failure during recirculation and maintain the performance objectives outlined in Section 6.3.2. Two trains of pumps, heat exchangers, and flowpaths are provided for redundancy; only one train is required to satisfy performance requirements. Initiating signals for the ECCS are derived from independent sources as measured from process (e.g., low

pressurizer pressure) or environmental variables (e.g., containment pressure).

Each train is physically separated and protected so that a single event cannot initiate a common mode failure. Each ECCS train is supplied from separate Class 1E power sources. The Class 1E power sources are discussed in Chapter 8.

6.3.3.9.1 Pump Characteristics

Typical performance curves for RHR pumps, CCP1 and CCP2, and SI pumps are shown in Figures 6.3-1, 6.3-2, and 6.3-3, respectively. The upper curves represent the typical performance characteristics of the pump. The lower curves illustrate that margins for the potential pump degradation have been considered in the analyses described in Chapter 15.

6.3.3.9.2 Limits on System Parameters

The specification of individual parameters as indicated in Table 6.3-1 includes due consideration of allowances for margin over and above the required performance value (e.g., pump flow and NPSH), and the most severe conditions to which the component could be subjected (e.g., pressure, temperature, and flow).

This consideration ensures that the ECCS is capable of meeting its minimum required level of functional performance.

6.3.3.9.2.1 Coolant Storage Reserves

A minimum RWST volume is provided to ensure that, after an RCS break, sufficient water is injected and available within containment to permit recirculation cooling flow to the core, to meet the NPSH requirement of the RHR pumps. This volume is less than that required to fill the refueling canal (to permit normal refueling operation). Thus, adequate emergency coolant storage volume for ECCS operation is provided. For RWST operational volumes, refer to Section 6.3.2.11 and Table 6.3-1.

6.3.3.9.2.2 Limiting Conditions for Maintenance During Operation

Maintenance on an active component will be permitted if the remaining components meet the minimum conditions for operation as well as the following conditions:

(1) The remaining equipment has been verified to be in operable condition, ready to function just before the initiation of the maintenance.

(2) A suitable time limit is placed on the total time span of successful maintenance that returns the components to an operable condition, ready to function.

The design philosophy with respect to active components in the high-head/low-head injection system is to provide backup equipment so that maintenance is possible during operation without impairment of the system safety function (refer to Section 6.3.3). Routine servicing and maintenance of equipment of this type that is not required more frequently than on an outage basis would generally be scheduled for periods of refueling and maintenance outages. The Technical Specifications (Reference 10) discuss in detail the applicable limiting conditions for maintenance during operations.

6.3.3.10 General Design Criterion 42, 1967 – Engineered Safety Features Components Capability

Instrumentation, motors, and penetrations located inside the containment are selected to meet the most adverse accident conditions to which they may be subjected. These items are either protected from containment accident conditions or are designed to withstand, without failure, exposure to the worst combination of temperature, pressure, and humidity expected during the required operational period.

The ECCS pipes serving each loop are anchored at the missile barrier (i.e., the crane wall) in each loop area to restrict potential accident damage to the portion of piping beyond this point. The anchorage is designed to withstand, without failure, the thrust force exerted by any branch line severed from the reactor coolant pipe and discharging fluid to the atmosphere, and to withstand a bending moment equivalent to that producing failure of the piping under the action of a free-end discharge to atmosphere or motion of the broken reactor coolant pipe to which the ECCS pipes are connected. This prevents possible failure at any point upstream from the support point including the branch line connection into the piping header.

6.3.3.11 General Design Criterion 43, 1967 – Accident Aggravation Prevention

As discussed in Section 15.4.1.3.2, the introduction of ECCS supplied borated cooling water into the core does not result in a net positive reactivity addition.

When water in the RWST at its minimum boron concentration is mixed with the contents of the RCS, the resulting boron concentration ensures that the reactor will remain subcritical in the cold condition with all control rods, except the most reactive RCCA, inserted into the core.

The boron concentration of the accumulator and the RWST is below the solubility limit of boric acid at the respective temperatures.

Thermal stresses on the RCS are discussed in Section 5.2.

6.3.3.12 General Design Criterion 44, 1967 – Emergency Core Cooling Systems Capability

By combining the use of passive accumulators with two CCPs (CCP1 and CCP2), two SI

pumps, and two RHR pumps, emergency core cooling is provided even if there should be a failure of any single component in any system. The ECCS employs a passive system of accumulators that do not require any external signals or source of power for their operation to cope with the short-term cooling requirements of large reactor coolant pipe breaks. Two independent and redundant high-pressure flow and pumping systems, each capable of the required emergency cooling, are provided for small break protection and to keep the core submerged after the accumulators have discharged following a large break. These systems are arranged so that the single failure of any active component does not interfere with meeting the short-term cooling requirements.

Borated water is injected into the RCS by accumulators, SI pumps, RHR pumps, and CCPs. Pump design includes consideration of fluid temperature and containment pressure in accordance with Safety Guide 1, November 1970 (refer to Section 6.3.3.26). The failure of any single active component or the development of excessive leakage during the long-term cooling period does not interfere with the ability to meet necessary long-term cooling objectives with one of the systems.

The primary function of the ECCS is to deliver borated cooling water to the reactor core in the event of a LOCA. This limits the fuel cladding temperature and thereby ensures that the core will remain intact and in place, with its essential heat transfer geometry preserved. This protection is afforded for:

(1) All pipe break sizes up to and including the hypothetical circumferential rupture of a RCL

(2) A loss of coolant associated with a rod ejection accident

The basic criteria for LOCA evaluations are (a) no cladding melting will occur, (b) zirconium-water reactions will be limited to an insignificant amount, and (c) the core geometry will remain essentially in place and intact so that effective cooling of the core will not be impaired. The zirconium-water reactions will be limited to an insignificant amount so that the accident:

(1) Does not interfere with the emergency core cooling function to limit cladding temperatures

(2) Does not produce hydrogen in an amount that, when burned, would cause the containment pressure to exceed the design value

For any rupture of a steam pipe and the associated uncontrolled heat removal from the core, the ECCS adds shutdown reactivity so that with a stuck rod, no offsite power, and minimum ESF, there is no consequential damage to the primary system and the core remains in place and intact. With no stuck rod, offsite power, and all equipment operating at design capacity, there is insignificant cladding rupture.

6.3.3.12.1 Use of Dual Function Components

The ECCS contains components that have no other operating function as well as components that are shared with other systems. Components in each category are as follows:

(1) Components of the ECCS that perform no other function are:

(a) One accumulator for each RCL that discharges borated water into its respective cold leg of the RCL piping

(b) Associated piping, valves, and instrumentation

(2) Components of the ECCS that also have a normal operating function are as follows:

(a) The RHR pumps and heat exchangers: These components are normally used during the latter stages of normal reactor cooldown and when the reactor is held at cold shutdown for core decay heat removal. However, during all other plant operating periods, they are aligned to perform the low-head injection function.

(b) Two SI pumps that supply borated water for core cooling to the RCS (note that the SI pumps are also used for SI accumulator fill and makeup, but this is not a significant function.) During refueling, the pumps may be used for the boration flow path with all reactor head bolts fully detensioned.

(c) CCP1 and CCP2: These pumps are normally aligned for charging service. The normal operation of the pumps as part of the chemical and volume control system is discussed in Section 9.3.4.

(d) The RWST: This tank is used to fill the refueling canal for refueling operations (refer to Section 9.1). During all other plant operating periods, it is aligned to the suction of the SI pumps and the RHR pumps. CCP1 and CCP2 are automatically aligned to the suction of the RWST upon receipt of the "S" signal.

An evaluation of all components required for operation of the ECCS demonstrates that either:

(1) The component is not shared with other systems.

(2) If the component is shared with other systems, it is aligned during normal plant operation to perform its accident function, or, if not aligned to its accident function, two valves in parallel are provided to align the system

for injection, and two valves in series are provided to isolate portions of the system not utilized for injection. These valves are automatically actuated by the "S" signal.

Table 6.3-8 indicates the alignment of components during normal operation, and the realignment required to perform the accident function.

6.3.3.13 General Design Criterion 45, 1967 – Inspection of Emergency Core Cooling Systems

The components outside containment are accessible for leak tightness inspection during operation of the reactor. Periodic visual inspection of portions of the ECCS for leakage is specified in the Technical Specifications (Reference 10). ECCS systems are inspected in accordance with ASME BPVC Section XI-2001 through 2003 Addenda, as stated in the DCPP ISI Program Plan (Reference 9). Details of the inspection program for the reactor vessel internals are included in Section 5.4.

6.3.3.14 General Design Criterion 46, 1967 – Testing of Emergency Core Cooling Systems Components

Routine periodic testing of the ECCS components and all necessary support systems is specified in the Technical Specifications (Reference 10). If such testing indicates a need for corrective maintenance, the redundancy of equipment in these systems permits such maintenance without shutting down or reducing load under the conditions established in the Technical Specifications (Reference 10).

Test connections are provided for periodic checks of the leakage of reactor coolant back through the accumulator discharge line check valves and to ascertain that these valves seat properly whenever the RCS pressure is raised. This test will be performed following valve actuation due to automatic or manual action, or flow through the valve in accordance with Technical Specifications (Reference 10). The SI test lines (and associated RCPB test valves) that are used for ECCS check valve surveillance testing are designed for testing in Modes 4 and 5 only. Per Section 6.3.3.6.2.2, maximum flow rate through each RCPB test valve is limited such that, in the event of a downstream pipe break during testing in Modes 4 or 5, the makeup flow rate from either CCP1 or CCP2 is adequate to allow time for an orderly plant shutdown/cooldown without ECCS actuation.

6.3.3.15 General Design Criterion 47, 1967 – Testing of Emergency Core Cooling Systems

In addition to the Technical Specification (Reference 10) requirements, an ECCS subsystem is demonstrated operable during shutdown, following completion of modifications to the ECCS subsystem that alter the subsystem flow characteristics by performing a flow balance test to verify:

For CCP1 and CCP2, with a single pump running that:

(1) The sum of injection line flow rates, excluding the highest flow rate, is greater than or equal to 299 gpm, and

(2) The total flow rate through all four injection lines is less than or equal to 461 gpm, and

(3) The difference between the maximum and minimum injection line flow rates is less than or equal to 15.5 gpm, and

(4) The total pump flow rate is less than or equal to 560 gpm.

For SI pumps, with a single pump running that:

(1) The sum of injection line flow rates, excluding the highest flow rate, is greater than or equal to 427 gpm, and

(2) The total flow rate through all four injection lines is less than or equal to 650 gpm, and

(3) The difference between the maximum and minimum injection line flow rates is less than or equal to 20.0 gpm, and

(4) The total pump flow rate is less than or equal to 675 gpm.

The RHR subsystem is demonstrated operable during shutdown, following completion of modifications to the RHR subsystem that alter the subsystem flow characteristics, by performing a flow test and verifying a total flow rate greater than or equal to 3976 gpm with a single RHR pump running and delivering flow to all four cold legs.

6.3.3.16 General Design Criterion 48, 1967 – Testing of Operational Sequence of Emergency Core Cooling Systems

As discussed in Section 6.3.3.7, a system actuation test can be performed when the plant is cooled down and the RHR system is in operation. Details of the testing of the sensors and logic circuits associated with the generation of an "S" signal, together with the application of this signal to the operation of each active component, are given in Section 7.3.

6.3.3.17 General Design Criterion 49, 1967 – Containment Design Basis

The ECCS containment penetrations, including the system piping and valves required for containment isolation, are designed and analyzed to withstand the pressures and temperatures that could result from a LOCA without exceeding design leakage rates. Refer to Section 3.8.2.1.1.3 for additional details.

6.3.3.18 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The ECCS isolation valves required for containment closure are periodically tested as part of the IST Program Plan for operability in accordance with GDC 54, 1971. Refer to Section 6.3.3.14 for additional discussion on periodic testing. Test connections are provided in the piping of applicable penetrations to verify valve leakages are within prescribed limits. Testing of the components required for the CIS is discussed in Section 6.2.4.

6.3.3.19 General Design Criterion 55, 1971 – Reactor Coolant Pressure Boundary Penetrating Containment

The ECCS is designed such that for each line that is part of the RCPB that penetrates containment is provided with containment isolation valves in compliance with GDC 55, 1971. Refer to Section 6.2.4.2.1 and Table 6.2-39 for penetration and configuration details with regards to GDC 55, 1971.

6.3.3.20 General Design Criterion 56, 1971 – Primary Containment Isolation

The ECCS is designed such that each line that connects directly to the containment atmosphere and penetrates containment is provided with containment isolation valves in compliance with GDC 56, 1971. Refer to Section 6.2.4.2.1 and Table 6.2-39 for penetration and configuration details with regards to GDC 56, 1971.

6.3.3.21 Emergency Core Cooling System Safety Function Requirements

(1) Leakage Provisions and Flooding Protection

In the event of a LOCA, fission products may be recirculated via the RHR system exterior to the containment. If an RHR pump seal should fail, water would spill onto the floor of the pump compartment. Each RHR pump is in a separate, shielded compartment that drains to a sump containing two pumps that can pump the spillage to the liquid radwaste system. Each sump pump is capable of removing the spillage that would result from the failure of one RHR pump seal.

If flooding occurred, overflow from one pump compartment would drain through a 14 inch line to the pipe trench rather than flood the adjacent compartment. Added sump pump reliability is achieved by elevating the drive motors above the compartment overflow drain so that the pump motors would not be flooded. Gross leakage from the RHR system can be accommodated in the pump compartments, each of which has a capacity of 9450 gallons.

The RHR heat exchangers and pumps can also be isolated, in the event of gross leakage, through appropriate isolation valves. The isolation valves are operated manually by means of remote valve reach-rod operators located in a shielded valve

gallery. Radiation levels in the vicinity of the recirculation loop are discussed in Chapter 12.

Recirculation loop component leakage is detected by means of a radiation monitor that samples the air in the ventilation exhaust ducts from each compartment. Supplemental radiation monitoring is provided in the plant vent (refer to Section 9.4.2.3.6). Alarms in the control room alert the operator when the activity exceeds a preset level, and the capability exists to detect small leaks within a short period of time. Operation of the sump pumps is a less sensitive indication of leakage. Recirculation loop components that are potential sources of leaks are described in Table 5.5-11. The table lists conservative estimates of the maximum leakage expected from each leak source during normal operation. However, the design basis for sizing auxiliary building sump pumps that will be required to dispose of this leakage employs a conservative value of 35 gpm, as described above.

The consequences of a leak through an RHR heat exchanger to the CCW system are discussed in Section 9.2.

(2) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the ECCS located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.6.3.

6.3.3.22 10 CFR 50.46 – Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Plants

The ECCS calculated cooling performance is capable of demonstrating a high level of probability that the limits set forth in 10 CFR 50.46 are met. Sections 15.3.1 and 15.4.1 provide discussion of SBLOCA and LBLOCA analyses, respectively, including the approved evaluation methodology, range of coolant rupture and leak sizes evaluated, other properties sufficient to provide assurance that the most severe postulated LOCAs are calculated, and demonstration that the limits set forth in 10 CFR 50.46 are met.

6.3.3.23 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

The ECCS SSCs required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment. The affected equipment includes flow and pressure transmitters, valves, and switches, and are listed on the EQ Master List.

6.3.3.23.1 Evaluation of the Capability to Withstand Post-Accident Environment

A comprehensive testing program was undertaken to demonstrate that ECCS components and associated instrumentation and electrical equipment that are located inside the containment will operate for the required time period, under the combined post-LOCA conditions of temperature, pressure, humidity, radiation, chemistry, and seismic phenomena (Reference 6).

6.3.3.24 10 CFR 50.55a(f) – Inservice Testing Requirements

The IST requirements for the ECCS are contained in the DCPP IST Program Plan.

6.3.3.25 10 CFR 50.55a(g) – Inservice Inspection Requirements

ECCS systems are inspected in accordance with ASME BPVC Section XI-2001 through 2003 Addenda, as stated in the DCPP ISI Program Plan (Reference 9).

6.3.3.26 Safety Guide 1, November 1970 – Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps

The ECCS is designed so that adequate NPSH is provided to system pumps. In addition to considering the static head and suction line pressure drop, the calculation of available NPSH in the recirculation mode for the RHR pumps assumes that the vapor pressure of the liquid in the sump equals containment pressure. This assumption ensures that the actual available NPSH is always greater than the calculated NPSH. The calculation of available NPSH during recirculation is as follows:

$$NPSH_{actual} = (h)_{containment\ pressure} - (h)_{water\ vapor,\ partial\ pressure} + (h)_{static\ head} - (h)_{loss}$$

$$NPSH_{calculated} = (h)_{static\ head} - (h)_{loss}$$

NPSH for ECCS pumps is further discussed in Section 6.3.3.33.

6.3.3.27 Regulatory Guide 1.79, June 1974 – Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors

The integrated system test for the ECCS was formulated using Regulatory Guide 1.79, June 1974 as a basis. The integrated system test was divided into three phases and was performed after the five component tests, discussed in Section 6.3.4.2.1, had been completed.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

6.3.3.27.1 Integrated System Tests

6.3.3.27.1.1 System Test - Phase I

The Phase I test was conducted prior to hot functional tests and involved testing the ECCS at ambient conditions with the reactor vessel open.

A loss of offsite power was simulated prior to test initiation. The EDGs supplied power to the ESF equipment through Phase I of the test.

The ECCS was tested functionally by manually initiating SI and monitoring components for correct system alignment, autostarts, and pump delivery rates. Response time data were obtained for components being tested to demonstrate that they meet or exceed acceptance criteria as established in the test.

At the conclusion of the test, the RHR, SI pump, and CCP1/CCP2 were realigned to the recirculation mode to demonstrate the capability of the RHR pumps to deliver water from the containment recirculation sump to the SI pump and CCP1/CCP2 suctions, and to the CSS headers. The time required for changeover to recirculation was evaluated to demonstrate that it can be completed during the time allowed.

6.3.3.27.1.2 System Test - Phase II

The Phase II test was conducted during hot functional testing with the RCS at hot operating conditions.

High-pressure safety injection (CCP1 and CCP2) was tested by manually initiating safety injection and monitoring components for correct alignment, autostarts of pumps, and delivery of water from the RWST to the reactor vessel through the high-pressure safety injection branch lines.

Response time data were obtained for components being tested to demonstrate that they met or exceeded acceptance criteria.

6.3.3.27.1.3 System Test - Phase III

During Phase III tests, the SI pumps and accumulator check valves were tested. The test was conducted during the cooldown phase of hot functional testing as the required RCS pressures were reached.

SI pumps were tested by manually initiating safety injection with the RCS pressure at a value below the shutoff head of the pumps. SI pump autostart and delivery of water from the RWST to the reactor vessel via SI pump injection flowpaths were checked.

Response time data were obtained for components being tested to demonstrate that they meet or exceed acceptance criteria.

Accumulator check valve operation was verified as RCS pressure decreased to a value below the accumulator pressure setpoint. The accumulator discharge isolation valves were closed as soon as flow through the check valves had been verified to minimize the thermal transient to the RCS.

6.3.3.27.2 Preoperational Testing Conformance with Regulatory Guide 1.79, June 1974

The ECCS tests described above meet the requirements of Regulatory Guide 1.79, June 1974, except in the following instances:

During the hot flow test (refer to Section 6.3.3.27.1.3/Paragraph C.3.a(2) of Regulatory Guide 1.79, June 1974), feedwater flow from the AFW pumps is blocked in order to avoid a temperature and pressure transient from this cause in the RCS. The pumps are started on the "S" signal but will be run on recirculation. Flow from the AFW pumps to the SGs is verified as part of the feedwater system tests. The quantity of water injected into the RCS by CCP1 and CCP2 during this test is limited by pressurizer water level, rather than limiting the quantity to avoid reducing the number of design stress cycles. Calculations indicate that the injection nozzles are subjected to essentially the full thermal shock by the time any meaningful data can be obtained from this test.

During the recirculation phase of the SI pumps low-pressure test at ambient conditions with the reactor vessel open (refer to Section 6.3.3.27.1.1/Paragraph C.3.b(2) of Regulatory Guide 1.79, June 1974), temporary piping is installed from the refueling canal into the containment recirculation sump. This temporary piping bypasses the coarse but not the fine sump screen. The pressure drop across the coarse and fine screens is less than one thousandth of a foot of water head, which is impractical to measure and which will not compromise the pump NPSH.

During the testing of the accumulators under ambient conditions to verify flowrates (refer to Section 6.3.4.2.1/Paragraph C.3.c(1) of Regulatory Guide 1.79, June 1974), the accumulator discharge is initiated by opening the accumulator isolation valves, not by rapidly reducing RCS pressure. The discharge flowrate is calculated from the change of accumulator pressure with time, not from the change of accumulator level with time. Accumulator discharge tests are not repeated for normal and emergency power supplies; operation of the accumulator isolation valves with both normal and emergency power supplies is demonstrated as a part of other tests.

6.3.3.28 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

ECCS post-accident instrumentation for meeting Regulatory Guide 1.97, Revision 3, requirements consist of RHR system flow indication, SI pump discharge flow indication, CCP1 and CCP2 injection header flow indication, RHR heat exchanger outlet temperature indication, containment recirculation sump water level and temperature indication, accumulator tank level and pressure indication, accumulator isolation valve position indication, RWST level indication, containment isolation valve position indication, and subcooling margin indication (refer to Table 7.5-6).

DCPP uses the RVLIS processors to calculate RCS subcooling. Refer to Section 7.5.2.2.1 for details of the display, calculator, and inputs.

6.3.3.29 NUREG-0737 (Items I.C.1, I.D.2, II.B.2, II.F.1, II.F.2, II.K.3.30, II.K.3.31, III.D.1.1), November 1980 – Clarification of TMI Action Plan Requirements

Item I.C.1 – Guidance for the Evaluation and Development of Procedures for Transients and Accidents: NUREG-0737, Supplement 1, January 1983 provides the ECCS requirements for I.C.1:

Section 7.1(b) – Upgraded emergency operating procedures have been implemented in accordance with the Westinghouse Owners Group (WOG) developed generic emergency response guidelines. The WOG is now known as the Pressurized Water Reactor Owners' Group (PWROG).

Item I.D.2 – Plant Safety Parameter Display Console: NUREG-0737, Supplement 1, January 1983 provides the ECCS requirements for I.D.2:

Section 4.1(f)(v) – Containment Conditions: Containment recirculation sump water level indication is provided on secondary displays of the safety parameter display system (SPDS). The SPDS displays are available in the control room, TSC, and EOF (refer to Section 7.5.2.10).

Item II.B.2 – Design Review of Plant Shielding and Environmental Qualification of Equipment for Space/Systems Which May Be Used in Post-accident Operations: The switchgear rooms are sufficiently shielded from external sources of radiation such that personnel access and occupancy would not be unduly limited by the radiation environment caused by a degraded core accident.

Item II.F.1 – Additional Accident Monitoring Instrumentation:

Position (5) – Continuous instrumentation to monitor containment recirculation sump water level is provided in the control room (refer to Sections 6.3.3.4.4.3 and 7.5.2.1.3;

and Figures 7.5-1, and 7.5-1B). Instrument ranges and accuracies are provided in Tables 7.5-2 and 7.5-4.

Item II.F.2 – Instrumentation for Detection of Inadequate Core Cooling: The instrumentation for detection of inadequate core cooling includes the subcooled margin monitors, core exit thermocouple system, and RVLIS. Refer to Section 7.5.2.2 for further discussion.

Item II.K.3.30 – Revised Small-Break Loss-Of-Coolant-Accident Methods to Show Compliance with 10 CFR Part 50, Appendix K: The methodology for calculating SBLOCAs (i.e., the FSLOCA evaluation model (EM)) was generically approved by the NRC Staff for use on Westinghouse designed 3-loop and 4-loop plants with cold leg injection systems. Refer to Section 15.3.1 and Section 15.4.1 for further discussion.

Item II.K.3.31 – Plant-Specific Calculations to Show Compliance with 10 CFR 50.46: Plant specific calculations were performed for DCPP using an NRC approved model (FSLOCA) for evaluating SBLOCAs. These calculations determined the acceptance criteria of 10 CFR 50.46 are met for DCPP. Refer to Section 15.3.1 and Section 15.4.1 for further discussion.

Item III.D.1.1 – Integrity of Systems Outside Containment Likely to Contain Radioactive Material for Pressurized-Water Reactors and Boiling-Water Reactors: Pressure containing portions of the ECCS are tested periodically to check for leakage. This testing includes the portions of the system that would circulate radioactive water from the containment recirculation sump. The requirements for a leakage reduction program from reactor coolant sources outside containment are included in the Technical Specifications (Reference 10). Inservice valve leakage requirements are specified in the IST Program. Refer to Section 6.2.4 for additional information on the CIS and Section 6.3.3.14 for additional discussion on ECCS leakage testing.

6.3.3.30 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

PG&E Design Class I MOVs are designed to function with a pressure differential across the valve disk determined in accordance with Generic Letter 89-10, June 1989. ECCS MOVs, except the accumulator isolation valves, are subject to the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996, “Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves,” and meet the requirements of the DCPP MOV Program Plan. The accumulator isolation valves have no active or credited safety function; therefore, they are not included in DCPP’s formal MOV Program Plan.

6.3.3.31 Generic Letter 95-07, August 1995 – Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves

PG&E Design Class I power-operated gate valves in the ECCS that were determined to

be susceptible to pressure locking were modified by installing bonnet cavity leakoffs with block valves to the high pressure inlet lines to prevent pressure locking. No power-operated gate valves in the ECCS were found susceptible to thermal binding.

6.3.3.32 Generic Letter 96-06, September 1996 – Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions

Generic Letter 96-06, September 1996 identified the potential of thermally induced overpressurization of isolated water-filled piping sections in containment that could jeopardize the ability of accident mitigating systems to perform their safety functions and could also lead to a breach of containment integrity via bypass leakage.

In the evaluation to determine potentially affected piping sections, DCPP identified two ECCS piping sections. The evaluation concluded that no corrective actions were necessary on ECCS piping as one section was deemed to meet ANSI B31.1-1967 allowable pressure values and the other section was deemed to have an isolation valve (air-operated globe valve) whose design prevents overpressurization.

For the section of piping that was deemed to have an isolation valve whose design prevents overpressurization, PG&E performed a bench test on a representative globe valve from their warehouse. The prototype test demonstrated that all 3/8-, 3/4- and 1-inch installed globe valves could be credited to relieve pressure prior to their piping section pressure stresses exceeding ANSI B31.1-1973 Summer Addenda allowable design values and, therefore, this section did not need physical modification.

6.3.3.33 Generic Letter 97-04, October 1997 – Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps

The general methodology for calculating NPSH is discussed in Section 6.3.3.26. Evaluation of head loss associated with the ECCS suction strainers is discussed in Section 6.3.3.35. Adequate NPSH is shown to be available for all ECCS pumps as follows:

(1) RHR Pumps

The NPSH of the RHR pumps was evaluated for normal plant shutdown operation, and for both the injection and recirculation modes of operation for the DBA. Recirculation operation gives the limiting NPSH requirement. The NPSH evaluation was based on all pumps (i.e., both RHR, CCP1 and CCP2, both SI, and both CSS pumps) operating at the maximum design (runout) flowrates. The minimum available and required NPSH values for this pump are given in Table 6.3-11.

(2) Safety Injection and Centrifugal Charging Pumps 1 and 2

The NPSH for the SI pumps and CCP1/CCP2 was evaluated for both the injection and recirculation modes of operation for the DBA. The end of the injection mode of operation gives the limiting NPSH available. The limiting NPSH was determined from the elevation head and vapor pressure of the water in the RWST, which is at atmospheric pressure, and the pressure drop in the suction piping from the tank to the pumps. The NPSH evaluation is based on all pumps operating at the maximum design flowrates. Following switchover to the recirculation mode, adequate NPSH is supplied from the containment recirculation sump by the booster action of the RHR pumps. The minimum available and required NPSH for these pumps are given in Table 6.3-11.

6.3.3.34 Generic Letter 98-04, July 1998 – Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment

PG&E has implemented controls for procurement, application, and maintenance of Service Level 1 protective coatings used inside containment. The requirements of 10 CFR Part 50, Appendix B, are implemented through specification of appropriate technical and quality requirements for the Service Level 1 coatings program which includes ongoing maintenance activities.

PG&E has implemented a Coating Quality Monitoring Program that includes a thorough visual inspection of selected portions of the coatings inside the containment. As localized areas of degraded coatings are identified, those areas are evaluated and scheduled for repair or replacement, as necessary. The periodic condition assessments, and the resulting repair/replacement activities, assure that the amount of Service Level 1 coatings which may be susceptible to detachment from the substrate during a LOCA event is minimized. PG&E conducts condition assessments of Service Level 1 coatings inside containment every refueling outage.

DCPP Technical Specifications (Reference 10) require periodic verification by visual inspection that the containment recirculation sump suction inlet trash racks and screens are not restricted by debris and show no evidence of structural distress or abnormal corrosion. DCPP plant procedures require internal inspection of sump plenums and RHR suction piping under specific circumstances. DCPP plant procedures ensure no loose debris (rags, trash, clothing, insulation, plastics, etc.) exists inside containment that could be transported to the containment recirculation sump in the event of a LOCA.

6.3.3.35 Generic Letter 2004-02, September 2004 – Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-Water Reactors

The evaluation of insulation, coatings and other debris affecting containment recirculation sump availability during the post-LOCA sump recirculation phase was completed to address the requirements of Generic Letter 2004-02. Various testing and analyses have been performed by DCPP in accordance with the methodology and acceptance criteria specified in NEI 04-07 and its associated Safety Evaluation, and NRC review guidance.

The analysis confirmed that the ECCS and CSS recirculation functions supported by the sump strainer under debris loading conditions comply with 10 CFR 50.46; 10 CFR 50.67; 10 CFR 100; and 10 CFR 50, Appendix A, GDC 35, 38, and 41. This confirmation provides assurance of long-term core cooling capability during recirculation following a LOCA, thereby ensuring that the design basis containment heat removal capabilities are maintained and that the containment atmosphere cleanup capability is preserved.

The analysis is performed by first quantifying the debris that is generated from pipe break locations throughout containment. The break size, location, and orientation determine the type, size distribution, and quantity of generated debris. The fractions of generated debris that could transport to the sump strainer were determined and used to quantify the debris at the sump strainer. Products of chemical reactions inside the sump pool could precipitate out of solution as the sump temperature drops and could then transport to the sump strainer. The debris bed that forms on the sump strainer, consisting of fibrous, particulate, and chemical debris, increases the head loss across the sump strainer, thereby affecting the NPSH margin of the RHR pumps. The debris could also challenge the structural integrity of the sump strainer; therefore, testing was performed to determine the debris bed head loss.

A portion of the debris passes through the perforations of the sump strainer and could impact the ECCS and CSS piping and components downstream of the sump strainer by wear and clogging. The pumps, valves and other ECCS and CSS components were evaluated for potential plugging or excessive wear during the post LOCA sump recirculation phase using the methodology in WCAP-16406-P Revision 1.

Some debris could also reach the reactor and impact the long-term core cooling by accumulating at the core inlet, or accumulating inside the heater region, or depositing on the fuel rods. The evaluation of peak cladding temperature and deposition thickness due to deposition of debris on fuel rods was performed using the methodology in WCAP-16793-NP-A Revision 2. The evaluation of the amount of fiber accumulation at reactor core inlet and inside reactor vessel was performed using the methodology in WCAP-17788 Revision 1 and the NRC review guidance on in-vessel effects.

The evaluation of the debris effects stated above provides assurance of long-term cooling capability during recirculation.

6.3.3.36 Generic Letter 2008-01, January 2008 – Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems

Comprehensive piping isometric drawing reviews were performed to evaluate ECCS piping for the potential for gas accumulation and transport to the suction of the ECCS pumps. Plant modifications (e.g., the replacement of air operated valves with manual valves, and the installation of high point vents, void headers, etc.) were implemented to prevent gas intrusion/accumulation in the ECCS.

The DCPP Gas Intrusion Program prevents and manages gas accumulation to within design and licensing requirements. System venting procedures ensure appropriate accumulated gas removal following system breaches and during normal operation. DCPP plant procedures include instructions and controls for performing ultrasonic testing of ECCS piping to detect gas accumulation. The ECCS is periodically inspected per DCPP Technical Specifications (Reference 10) to verify that ECCS piping is sufficiently full of water.

Design drawing details support fill and vent activities and periodic venting of gas accumulation during normal plant operations. Drawings and procedures provide guidance for evaluating on-line maintenance including details of flushing capability to preclude gas intrusion into system piping that cannot be vented during refill operations.

6.3.3.37 IE Bulletin 79-06A (Position 8), April 1979 – Review of Operational Errors and System Misalignments Identified During the Three Mile Island Incident

Position (8) (subsequently NUREG-0737, November 1980, Item II.K.1.5, Safety Related Valve Position):

Critical manual valves in the ECCS are sealed in position and a check list is maintained for inspection on a typical audit basis. When the ESF system operates, the misalignment of any remotely-operated critical valve in the ECCS will be shown by a monitor light on the main control board.

All ECCS PG&E Design Class I valves, which are operated remotely and whose purpose is to open or close (rather than throttle flow), have position indicating lights on the main control board. Valves with power removed from their motor operators during normal operation have continuously energized position indicating lights on the main control board which are redundant to the monitor lights that indicate misalignment of any remotely-operated critical valve discussed above.

6.3.3.38 IE Bulletin 80-18, July 1980 – Maintenance of Adequate Minimum Flow Thru Centrifugal Charging Pumps Following Secondary Side High Energy Line Rupture

In order to ensure adequate minimum flow is available to the ECCS CCPs, DCPP maintains the CCP recirculation line isolation MOVs in the open position under all pumping conditions, except for post-LOCA recirculation mode when they are closed. The “S” signal no longer provides automatic closure of these valves, as that signal was removed from the valves in response to IE Bulletin 80-18, July, 1980.

6.3.3.39 NRC Bulletin 88-04, May 1988 – Potential Safety-Related Pump Loss

To prevent pump to pump interaction as a result of differences between pump flow characteristics, check valves were installed downstream of the RHR heat exchangers. During minimum flow operation the check valve will prevent the stronger pump from deadheading/reversing flow into the weaker pump, thereby maintaining minimum required recirculation flow.

An evaluation concluded that the existing pump minimum flow rates are adequate for all the pumps evaluated and no changes to hardware or operating procedures would be required, with the exception of the RHR pumps during an inadvertent safety injection. When the RHR pumps are operating in this mode, they could potentially experience unusual wear and aging due to the flow hydraulic effects. This wear and aging is long term in nature and is expected to result in gradual wear to the pumps. Wear and aging of the pumps can be detected through monitoring and trending pump performance parameters, vibration levels, and bearing temperatures. Increased maintenance and part replacement may occur due to the described wear and aging effects.

6.3.3.40 NRC Bulletin 88-08, June 1988 – Thermal Stresses in Piping Connected to Reactor Coolant Systems

The charging injection header, for both DCPP Unit 1 and Unit 2, has been modified to include a recirculation line back to the charging pump suction. This passive recirculation line continuously vents valve seepage and accompanying pressure build-up in the charging injection header during normal operations. During accident conditions, the small size and large resistance of the recirculation line limits the recirculation flow to an acceptable negligible value. The charging injection header is also periodically verified to be less than RCS pressure, and is procedurally directed to be depressurized via venting if RCS pressure is approached. The periodic verification of the charging injection header pressure serves as a redundant means to prevent unacceptable thermal stresses due to temperature stratifications induced by leaking valves in the event of blockage or maintenance to the recirculation line.

In a similar manner, the charging injection bypass line is periodically verified to be less than RCS pressure; thereby eliminating the possibility of undetected leakage from this line. If RCS pressure is approached, the charging injection bypass line is procedurally

directed to be vented.

6.3.3.41 NRC Bulletin 2003-01, June 2003 – Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized-Water Reactors

DCPP Unit 1 and Unit 2 had two configurations where the flow paths to the containment recirculation sump were possibly susceptible to the issue of blockage due to the accumulation of debris, as discussed in NRC Bulletin 2003-01, June 2003. These were the refueling cavity drain (at elevation 99 feet 6 inches) and the three doors installed in the crane wall (at elevation 91 feet 0 inches).

To prevent potential blockage due to the accumulation of debris, the refueling cavity drain was modified with a raised drain screen and the three crane wall doors were modified with replacement bars that are less restrictive to flow. This configuration allows the passage of most of the floating debris without causing a blockage of the flow path. The doorframes function as debris curbs.

A licensee controlled program provides administrative control for the crane wall doors to ensure they perform their intended safety function. DCPP plant procedures ensure no loose debris (rags, trash, clothing, insulation, plastics, etc.) exists inside containment and provide instructions to personnel not to use fibrous insulation inside containment as a replacement for reflective metal or calcium silicate insulation without prior authorization.

6.3.3.42 Branch Technical Position EICSB 18, November 1975 – Application of the Single Failure Criterion to Manually-Controlled Electrically-Operated Valves

During the safety review of the operating license application for the DCPP, the AEC (now NRC) regulatory staff adopted the position that failures of the type discussed in Section 6.3.3.5.4, that could lead to spurious movement of passive MOVs, must be considered in relation to satisfying the single failure criterion. The regulatory staff's position, as stated in Branch Technical Position EICSB 18, November 1975, considers removal of electric power an acceptable means, under certain conditions, of satisfying the single failure criterion. As a consequence of the regulatory staff's requirements, electric power will be removed from certain ECCS and RHR valves during normal operation. These valves are listed in Table 6.3-12. When electric power is removed from the valve operators, power is still supplied to position indication circuitry so that there is continuous, redundant position indication on the control board. Redundant position indication is provided by two sets of lights: (a) red and green position lights that indicate open or closed, and (b) white monitor lights that illuminate when the valves are not in their proper locked-out position.

6.3.3.43 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The ECCS is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1)

6.3.4 TESTS AND INSPECTIONS

To demonstrate the readiness and operability of the ECCS, all of the components are subjected to periodic tests and inspections. Preoperational performance tests of ECCS components were conducted in the manufacturer's shop. An initial system flow test was performed to demonstrate proper components functioning.

Refer to Sections 6.3.3.7, 6.3.3.13 through 6.3.3.16, 6.3.3.18, 6.3.3.24, and 6.3.3.25 for details regarding tests and inspections of the ECCS.

6.3.4.1 Quality Control

Tests and inspections were carried out during fabrication of each of the ECCS components. These tests were conducted and documented in accordance with the Diablo Canyon Quality Assurance Program Description.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

6.3.4.2 Preoperational System Tests

These tests evaluated the hydraulic and mechanical performance of the passive and active components involved in the injection mode by demonstrating that they have been installed and adjusted so they will operate in accordance with the intent of the design. The tests were divided into two categories: component tests and integrated system test. The components tests were divided into the following five sub-categories: (a) valve and pump actuation, (b) accumulator injection, (c) RHR pump, (d) SI pump, and (e) CCP1/CCP2 performance tests. The integrated systems tests are described in Section 6.3.3.27.1.

6.3.4.2.1 Component Tests

The actuation tests verified: the operability of all ECCS valves initiated by the "S" signal, the phase A containment isolation signal ("T"), and the Phase B containment isolation signal ("P"), the operability of all safety feature pump circuitry down through the pump breaker control circuits, and the proper operation of all valve interlocks. Sequencing and timing tests were conducted to verify that the ECCS components will be aligned properly to perform their intended functions.

The objective of the accumulator injection test was to verify that the injection lines were free from obstruction and that the accumulator check valves operate correctly. The test objectives were met by a low-pressure blowdown of each accumulator. The test was performed with the reactor head and internals removed. The acceptance criteria for the accumulator blowdown test were based on equaling or exceeding a calculated curve; the curve simulated the system line resistances (L/D). The primary intent of the accumulator blowdown tests was to verify these calculated discharge line resistances.

The purpose of the three pump performances tests (RHR pumps, SI pumps, and CCP1/CCP2) was to evaluate the hydraulic and mechanical performance of the pumps delivering through the flowpath required for emergency core cooling. These tests were divided into two parts: pump operation under miniflow conditions and pump operation at full flow conditions.

The predicted system resistances were verified by measuring the flow in each piping branch, as each pump delivered from the RWST to the open reactor vessel, and adjustments were made where necessary to ensure that flow was distributed properly among branches.

During flow tests, each system was checked to ensure that there is sufficient minimum total line resistance to preclude runout from overloading the motor of any pump. At the completion of the flow tests, the total pump flow and relative flow between the branch lines were compared with the system acceptable flows.

Each system was accepted only after demonstration of proper actuation of all components and after demonstration of flow delivery of all components within design requirements.

6.3.4.3 Containment Recirculation Sump and Screen Inspection

No periodic testing is performed for the containment recirculation sump. However, the sump and screens are inspected during each regularly scheduled refueling outage, and after any maintenance that could result in sufficient debris to block the sump screens. Work area inspections are performed at the conclusion of maintenance activities anywhere in the containment to ensure that debris that could block the sump screens is removed.

6.3.5 INSTRUMENT APPLICATIONS

Refer to Section 6.3.3.4 for the instrument applications related to ECCS.

6.3.6 REFERENCES

1. Deleted in Revision 22.

2. Deleted in Revision 22.

3. Deleted in Revision 22.

4. Deleted in Revision 22.

5. Deleted in Revision 22.

6. Environmental Testing of Engineered Safety Features Related Equipment (NSSS-Standard Scope), WCAP-7744, Volume I, August 1971.

7. Deleted in Revision 22.

8. DELETED

9. Diablo Canyon Power Plant - Inservice Inspection Program Plan - The Third 10 Year Inspection Interval.

10. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

11. Deleted in Revision 22.

12. IEEE-Std-279, Criteria for Protection Systems for Nuclear Power Generating Stations, 1971.

13. Deleted in Revision 22.

14. Deleted in Revision 22.

15. Deleted in Revision 22.

16. License Amendment Nos. 199 (DPR-80) and 200 (DPR-82), "Technical Specification 3.5.4, Refueling Water Storage Tank (RWST)," USNRC, March 26, 2008.

17. Rinkacs, W.J., et al., Evaluation of Downstream Sump Debris Effects in Support of GSI-191, WCAP-16406-P, Revision 1 (Proprietary), August 2007.

18. WCAP-16793-NP-A, Evaluation of Long-Term Cooling Considering Particulate, Fibrous and Chemical Debris in the Recirculating Fluid, Revision 2 (Non-Proprietary), July 2013.

19. WCAP-17788-P, Comprehensive Analysis and Test Program for GSI-191 Closure (PA-SEE-1090), Revision 1 (Proprietary), December 2019.

20. U.S. Nuclear Regulatory Commission Staff Review Guidance for In-Vessel

Downstream Effects Supporting Review of Generic 2004092 Responses, September 4, 2019 (ADAMS Accession No. ML19228A011).

21. ML21203A314 Dated 7/29/2021, Diablo Canyon Nuclear Power Plant, Units 1 And 2 – Closeout of Generic Letter 2004-02, “Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-Water Reactors” (EPID L-2017-LRC-0000).

6.3.7 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

6.4 HABITABILITY SYSTEMS

The DCPP habitability systems are associated with the control room and the onsite TSC.

Both facilities are designed to be habitable throughout the course of a DBA and the resulting radiological conditions, except that the TSC system is manually activated. In addition, the control room is designed to be habitable throughout the course of a hazardous chemical release.

6.4.1 CONTROL ROOM

The DCPP control room, located at elevation 140 feet of the auxiliary building, is common to Unit 1 and Unit 2. The associated habitability systems provide for access and occupancy of the control room during normal operating conditions, radiological emergencies, hazardous chemical emergencies, and fire emergencies. Control room habitability is supported by administrative procedures, shielding, the ventilation and air conditioning system, the fire protection system, kitchen facilities, and sanitary facilities Normal operating and post-accident control room operating, emergency, and administrative procedures are contained in the DCPP Plant Manual. The several volumes of the Plant Manual are listed in Section 13.5.

6.4.1.1 Design Bases

6.4.1.1.1 General Design Criterion 2, 1967 - Performance Standards

The control room habitability systems are designed to withstand the effects of or are protected against natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

6.4.1.1.2 General Design Criterion 3, 1971 - Fire Protection

The control room habitability systems are designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

6.4.1.1.3 General Design Criterion 4, 1967 - Sharing of Systems

The control room habitability systems and components are not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

6.4.1.1.4 General Design Criterion 11, 1967 - Control Room

A control room is provided from which actions to maintain safe operational status of the plant can be controlled. The control room is designed to support safe shutdown and to maintain safe shutdown from the control room or from an alternate location if control room access is lost due to fire or other causes. The control room provides adequate

radiation protection to permit access without radiation exposures to personnel in excess of 10 CFR Part 20 limits under normal conditions.

6.4.1.1.5 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Instrumentation and controls related to control room habitability are provided to monitor and maintain applicable variables within prescribed operating ranges.

6.4.1.1.6 General Design Criterion 17, 1967 - Monitoring Radioactivity Releases

Radiation monitoring instrumentation is provided to monitor radioactive releases entering each control room normal air intake and pressurization system intake. Area radiation monitoring is provided in the control room.

6.4.1.1.7 General Design Criterion 19, 1999 - Control Room

The control room is designed to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE for the duration of a DBA.

6.4.1.1.8 General Design Criterion 37, 1967 - Engineered Safety Features Basis for Design

The Control Room Habitability Systems are designed to provide backup to the safety provided by the core design, the RCPB, and their protection systems.

6.4.1.1.9 General Design Criterion 40, 1967 – Missile Protection

The CRVS is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

6.4.1.1.10 Control Room Heating and Ventilation System Safety Function Requirements

(1) <u>Protection from Moderate Energy Pipe Rupture Effects – Outside Containment</u>

The PG&E Design Class I portion of the CRVS located outside containment is designed to be protected against the effects of moderate energy pipe failure.

(2) <u>Protection from Flooding Effects – Outside Containment</u>

The PG&E Design Class I portion of the CRVS located outside containment is to be protected from the effects of internal flooding.

6.4.1.1.11 10 CFR Part 50.48(c) – National Fire Protection Association Standard NFPA 805

The control room is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

6.4.1.1.12 Regulatory Guide 1.52, June 1973 - Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants

The CRVS design, testing, and maintenance comply with applicable Regulatory Guide 1.52, June 1973, requirements with exceptions as noted in Table 9.4-2.

6.4.1.1.13 Regulatory Guide 1.78, June 1974 – Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release

The control room is appropriately protected from hazardous chemicals that may be discharged as a result of equipment failures, operator errors, or events and conditions outside the control of the plant.

6.4.1.1.14 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Instrumentation is provided to monitor control room emergency ventilation damper position failure on ESFs actuation.

6.4.1.1.15 Regulatory Guide 1.197, May 2003 - Demonstrating Control Room Envelope Integrity At Nuclear Power Reactors

Control room envelope (CRE) integrity testing is conducted such that:

(1) An integrated in-leakage test (i.e., the ASTM Standard E741-2000 method) is conducted in concert with the component test.

(2) The results of the two methods correlate; and

(3) The components tested account for no less than 95 percent of the CRE in-leakage as determined by the integrated in-leakage test.

6.4.1.1.16 NUREG-0737 (Items II.B.2 and III.D.3.4), November 1980 - Clarification of TMI Action Plan Requirements

Item II.B.2 – Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems Which May Be Used in Post-accident Operations:

Adequate access to the control room is provided by design changes, increased permanent or temporary shielding, or post-accident procedural controls.

Item III.D.3.4 – Control-Room Habitability Requirements: The control room is designed to ensure operators are adequately protected against the effects of accidental release of toxic and radioactive gases such that the nuclear power plant can be safely operated or shut down under DBA conditions.

6.4.1.1.17 Generic Letter 2003-01, June 2003 - Control Room Habitability

The control room meets the applicable habitability regulatory requirements and the habitability systems are designed, constructed, configured, operated, and maintained in accordance with the facility's design and licensing bases, with emphasis on ensuring:

(1) The most limiting unfiltered in-leakage (and the filtered in-leakage if applicable) into the CRE is no more than the value assumed in the design basis radiological analyses for control room habitability.

(2) The most limiting unfiltered in-leakage into the CRE is incorporated into the hazardous chemical assessments. This in-leakage may differ from the value assumed in the design basis radiological analyses. The reactor control capability is maintained from either the control room or alternate shutdown location in the event of smoke.

(3) Technical specifications verify the integrity of the CRE, and the assumed in-leakage rates of potentially contaminated air.

6.4.1.2 System Description

The design bases for the functional design of control room habitability systems for both normal and emergency radiological hazards were:

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

(1) *10 CFR 20.1 through 20.601, Standards for Protection Against Radiation (pre-1994; compliance with current requirements of Part 20 is addressed in Chapter 12):*

"...no licensee shall possess, use, or transfer licensed material in such a manner as to cause any individual in a restricted area to receive in any period of one calendar quarter from radioactive material and other sources of radiation in the licensee's possession a dose in excess of the standards specified in the following table:

Rems per calendar quarter

Whole body; head and trunk, active blood-forming organs; lens of eyes, or gonads	*1-1/4*
Hands and forearms; feet and ankles	*18-3/4*
Skin of whole body	*7-1/2"*

(2) GDC 19, 1999 - Refer to Sections 6.4.1.1.7 and 6.4.1.3.7 for discussion

(3) The National Council on Radiation Protection and Measurements Report No. 39 (1971), Basic Radiation Protection Criteria:

"It is compatible with the risk concept to accept exposures leading to doses considerably in excess of those appropriate for lifetime use when recovery from an accident or major operational difficulty is necessary. Saving of life, measures to circumvent substantial exposures to population groups or even preservation of valuable installations may all be sufficient cause for accepting above-normal exposures. Dose limits cannot be specified. They should be commensurate with the significance of the objective, and held to the lowest practicable level that the emergency permits."

As described in Section 12.1.2, control room shielding consists of concrete walls, floor, and roof. Control room shielding design radiation exposure limits are consistent with GDC 19, 1999.

The CRVS is a redundant, PG&E Design Class I system. The PG&E Design Class I systems included in the CRVS are the control room heating, ventilation, and air conditioning (CRHVAC) system and the control room pressurization system (CRPS). The third system included in the CRVS, the plant process computer room air conditioning system, is PG&E Design Class II. Sections 9.4 and 12.2 describe the CRVS.

Control room communications are described in Section 9.5.2.

Kitchen and sanitary facilities are shared by Unit 1 and Unit 2 and are designed to support operating personnel during normal operating conditions and for the duration of an accident.

6.4.1.3 Safety Evaluation

6.4.1.3.1 General Design Criterion 2, 1967 - Performance Standards

The structures (auxiliary and turbine buildings) that form the CRE are PG&E Design Class I or QA Class S (refer to Section 3.8). These buildings or applicable portions

thereof are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunami (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other applicable natural phenomena, and to protect the CRE and its safety functions from damage due to these events.

Refer to Section 9.4.1 for evaluation of CRVS components.

6.4.1.3.2 General Design Criterion 3, 1971 - Fire Protection

The control room habitability systems are designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition. The adequacy of the control room fire protection system is evaluated in Sections 7.7.1 and 9.5.1.

6.4.1.3.3 General Design Criterion 4, 1967 - Sharing of Systems

The control room is common to DCPP Unit 1 and Unit 2 and therefore requires sharing of SSCs between units. The CRVS is shared between Unit 1 and Unit 2. In addition, CRPS pressurization is shared by the control room and the TSC. The sharing of these systems is addressed in Section 9.4.1.3.3.

6.4.1.3.4 General Design Criterion 11, 1967 - Control Room

Control room habitability is provided by shielding, the CRVS, and the fire protection system. The adequacy of control room shielding is evaluated for normal operating conditions in Chapter 11 and Section 12.1. The adequacy of the CRVS is evaluated for normal operating conditions in Chapter 11 and Sections 9.4.1 and 12.1; for hazardous chemical emergencies in Section 6.4.1.3.13; and for fire emergencies in Sections 9.4.1 and 9.5.1.

6.4.1.3.5 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Controls for control room habitability components are provided for system operation. Instrumentation is provided for monitoring habitability system parameters during normal operations and accident conditions (refer to Sections 6.4.1.3.6 and 6.4.1.5).

6.4.1.3.6 General Design Criterion 17, 1967 - Monitoring Radioactivity Releases

Main control room normal air intake radiation monitors and CRPS intake radiation monitors are provided to detect radioactivity in the air flow into the control room ventilation and pressurization systems. A control room area radiation monitor is provided to monitor radiation in the control room environs.

6.4.1.3.7 General Design Criterion 19, 1999 - Control Room

The control room habitability systems permit access and occupancy for operating the plant without personnel receiving radiation exposures in excess of GDC 19, 1999, limits for the duration of a DBA. The adequacy of control room shielding is evaluated for post-accident conditions in Sections 12.1 and 15.5. The adequacy of the CRVS is evaluated for radiological emergencies in Section 15.5.

6.4.1.3.8 General Design Criterion 37, 1967 - Engineered Safety Features Basis for Design

By providing for operator access and occupancy so that the plant can be maintained in a safe condition under accident conditions, the control room habitability system ESF function performed by the CRVS provides the capability to control the airborne radioactive material that could enter the control room atmosphere in the event of a postulated LOCA to acceptable levels (refer to Section 6.1.2).

6.4.1.3.9 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the CRVS from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures are discussed in Sections 3.5 and 3.6.

6.4.1.3.10 Control Room Heating and Ventilation System Safety Function Requirements

(1) <u>Protection from Moderate Energy Pipe Rupture Effects – Outside Containment</u>

The provisions taken to provide protection of the PG&E Design Class I portion of the CRVS from the effects of moderate energy pipe failure are discussed in Section 3.6.

(2) <u>Protection from Flooding Effects – Outside Containment</u>

The provisions taken to provide protection of the PG&E Design Class I portion of the CRVS located outside containment from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

6.4.1.3.11 10 CFR Part 50.48(c) – National Fire Protection Association Standard NFPA 805

The control room habitability systems are designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

6.4.1.3.12 Regulatory Guide 1.52, June 1973 - Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants

The CRVS is the ESF system that provides the capability to control the airborne radioactive material that could enter the control room atmosphere during design basis events to acceptable levels. The extent of compliance and noted exceptions to Regulatory Guide 1.52, June 1973, design, testing, and maintenance criteria are discussed in Table 9.4-2. Requirements for the performance of ventilation filter testing are stated in the DCPP Technical Specifications.

6.4.1.3.13 Regulatory Guide 1.78, June 1974 – Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release

The control room is adequately protected from hazardous chemicals that may be released on site. A chemical analysis demonstrates that the inadvertent release of any single hazardous chemical stored or used on site does not adversely impact control room habitability.

The control room is adequately protected from hazardous chemicals that may be released as a result of events or conditions outside the control of the plant as described in Section 2.2.3.3.

6.4.1.3.14 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for I Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Damper failure indication in the control room provides status of the Unit 1 and Unit 2 CRPS fan suction and discharge motorized dampers in response to an ESF actuation (refer to Table 7.5-6, Item 63).

6.4.1.3.15 Regulatory Guide 1.197, May 2003 - Demonstrating Control Room Envelope Integrity At Nuclear Power Reactors

Required testing for CRE integrity includes:

(1) An integrated test for total CRE in-leakage per ASTM E741-2000,

(2) The integrated test is conducted in concert with and correlated with component testing, and

(3) The components tested should account for no less than 95 percent of the CRE in-leakage as determined by the integrated in-leakage test.

Testing includes peer reviews to identify in-leakage vulnerabilities, quantitative testing methods, and verification, prior to testing, of the consistency of air sources and ventilation system flow rates with the licensing basis. The requirements for compliance with Regulatory Guide 1.197, May 2003, are described in the DCPP Technical Specifications.

6.4.1.3.16 NUREG-0737 (Items II.B.2 and III.D.3.4), November 1980 - Clarification of TMI Action Plan Requirements

Plant shielding and the CRVS are designed to maintain control room habitability under accident conditions as discussed in the following sections:

Item II.B.2 - Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems Which May Be Used in Post-accident Operations: The adequacy of control room shielding is evaluated for post-accident conditions in Sections 12.1 and 15.5.

Item III.D.3.4 – Control-Room Habitability Requirements: The adequacy of the CRVS is evaluated for radiological emergencies in Section 15.5, for hazardous chemical emergencies in Section 6.4.1.3.13, and for fire emergencies in Sections 9.4.1 and 9.5.1. A minimum of ten SCBA units (five for each unit) are provided in the control room.

6.4.1.3.17 Generic Letter 2003-01, June 2003 - Control Room Habitability

Testing is performed to demonstrate compliance with guidance provided by Regulatory Guide 1.197, May 2003, using the alignment that would result in the greatest consequence to the control room operator. The purpose of operating the CRVS in mode 4 (the pressurization mode) is to limit radiation exposure to control room personnel in the event of a radiation release. An outside air supply damper and an exhaust damper powered by a common power supply are intentionally failed opened as the single active failure condition for each test configuration. The test alignment involves operating one train in mode 4. The opposite train is placed in mode 3, recirculation, but all fans are shut off.

The DCPP CRE is designed to minimize unfiltered in-leakage. Consistent with Regulatory Guide 1.197, May 2003, Section 1.4, “Test Results and Uncertainty,” the test uncertainty value is not included in results showing in-leakage to be less than 100 standard cubic feet per minute. DCPP Technical Specifications verify the integrity of the CRE with respect to the in-leakage rates of potentially contaminated air assumed in the accident analysis.

There are no offsite or onsite hazardous chemicals that would pose a credible threat to DCPP control room habitability. Therefore, engineered controls for the control room are not required to ensure habitability against a hazardous chemical threat and no amount of assumed unfiltered in-leakage is incorporated into PG&E’s hazardous chemical assessment.

The DCPP assessment of alternate shutdown capability in the event of fire and related smoke effects is discussed in Section 9.5 and associated appendices. SCBA units are provided within the CRE for operator use and portable fans for use with temporary power are appropriately staged to allow operators to provide ventilation in the event that a loss-of-power event has occurred.

6.4.1.4 Tests and Inspections

Testing of the control room habitability systems is discussed in the following sections:

(1)	CRVS	Section 9.4.1
(2)	Fire protection system	Section 9.5.1
(3)	Communication system	Section 9.5.2

Surveillance requirements for inspection and testing of plant equipment are contained in the Technical Specifications (Reference 3) and the Plant Manual. These requirements ensure that performance capability is maintained throughout the lifetime of the plant.

6.4.1.5 Instrumentation Applications

Smoke detector and radiation detector instrumentation employed for monitoring and actuation of the control room habitability systems are discussed in the following sections:

(1)	CRVS	Section 9.4.1
(2)	Fire protection system	Section 9.5.1
(3)	Communication systems	Section 9.5.2

Design details and logic of the instrumentation are discussed in Chapter 7.

6.4.2 Technical Support Center

The onsite TSC, located on the upper levels of the buttresses on the west side of the Unit 2 turbine building, is common to Unit 1 and Unit 2. The associated habitability systems provide for access and occupancy of the TSC during normal plant operating conditions, fire emergencies, and, with manual activation, throughout the course of a DBA. To this end, administrative procedures and shielding, as well as the ventilation and air conditioning, and the fire protection systems, are used.

The TSC is sized to accommodate a minimum of 20 PG&E and 5 NRC personnel as well as necessary data and information displays. It serves as the onsite NRC emergency headquarters. Access to the control room is via the east door of the TSC, across the Unit 2 turbine building at elevation 104 feet, and then to the control room at elevation 140 feet via the elevator or stairway on the east side of the turbine building.

Instrumentation in the TSC is capable of providing displays of vital plant parameters throughout the course of a DBA and personnel have the capability for transmitting technical information between the control room and the TSC by telephone and process computer printout.

6.4.2.1 Design Bases

6.4.2.1.1 General Design Criterion 4, 1967 - Sharing of Systems

The TSC habitability systems are not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

6.4.2.1.2 10 CFR Part 20 - Standards for Protection Against Radiation

During normal operation TSC personnel are protected from radiation sources such that concentration limits are maintained below those prescribed in 10 CFR Part 20.

6.4.2.1.3 10 CFR 50.47 - Emergency Plans

Adequate emergency facilities and equipment to support the emergency response are provided and maintained.

6.4.2.1.4 NUREG-0737 (Items II.B.2 and III.A.1.2), November 1980 - Clarification of TMI Action Plan Requirements

Item II.B.2 - Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems Which May Be Used in Post-accident Operations: Adequate access to the TSC is provided by increased permanent or temporary shielding.

Item III.A.1.2 - Upgrade Emergency Support Facilities: NUREG-0737, Supplement 1, January 1983 provides the requirements for III.A.1.2 as follows:

Section 8.2.1(e) - The TSC is environmentally controlled to provide room air temperature, humidity, and cleanliness appropriate for personnel and equipment.

Section 8.2.1(f) - The TSC is provided with radiological protection and monitoring equipment necessary to assure that radiation exposure to any person working in the TSC would not exceed 5 rem TEDE for the duration of the accident.

6.4.2.2 System Description

The TSC is designated to be habitable throughout the course of a DBA The outside walls, with steel bulkhead doors, form an airtight perimeter boundary. The TSC structure is designed to PG&E Design Class III. For seismic qualification, refer to Table 3.2-3.
During normal operation the outside air intake flow into the TSC is filtered through a pre-filter and HEPA filter. The TSC has the manual capability to isolate the area from the outside and to recirculate air by the air conditioning system (refer to Section 9.4.11). The hazardous chemical release warning will have to be received from the control room to enable those in the TSC to manually isolate the area from the outside.

The TSC is provided with its own PG&E Design Class II heating, ventilation and air conditioning (HVAC) system. The ducting, duct supports, and equipment supports have been evaluated to Seismic Category I criteria. The system is fed from a non-Class 1E power source, although the air cleanup portion of the system has the capability to be supplied power from a Class 1E bus. The PG&E Design Class I CRPS system provides a redundant supply of pressurization air to the TSC ventilation system. The CRPS connecting ductwork is designed to PG&E Design Class I and the TSC ventilation fans, pre-filter and HEPA filter units are designed to PG&E Design Class II. For seismic qualification, refer to Table 3.2-3. Sections 12.2 and 9.4.11 describe the TSC HVAC system.

TSC fire protection features are designed considering the standards of the National Fire Protection Association, as described in Section 9.5.1. A minimum of ten SCBAs (five for each unit) are provided in the TSC.

The TSC includes provisions to monitor important plant parameters. The TSC computers provide all necessary plant and health physics data to offsite facilities.

The TSC is tied to the radiological monitoring network such that a laboratory, located adjacent to the TSC, is set aside for analytical work. The principal purpose of this facility is to provide minimum onsite analytical capability in the event that the normal facilities are unavailable.

Normal operating and post-accident TSC administrative procedures are discussed and evaluated in the DCPP Manual, in Chapters 12 and 13, and in the Emergency Plan.

The TSC communications are described in Section 9.5.2.

6.4.2.3 Safety Evaluation

6.4.2.3.1 General Design Criterion 4, 1967 - Sharing of Systems

The TSC habitability systems are common to Unit 1 and Unit 2 and therefore require sharing of SSCs between units. Because the TSC habitability systems serve no safety functions, sharing between units does not impair safety functions. The CRPS is shared by the control room and the TSC. Sharing of the CRPS by the control room and the TSC is addressed in Section 9.4.1.3.3.

6.4.2.3.2 10 CFR Part 20 - Standards for Protection Against Radiation

During normal operation TSC personnel are protected from radiation sources such that concentration limits are maintained below those prescribed in 10 CFR Part 20. Compliance with 10 CFR Part 20 for TSC personnel is discussed in Sections 12.1 (shielding) and 12.2 (ventilation).

6.4.2.3.3 10 CFR 50.47 - Emergency Plans

A TSC that meets applicable requirements is provided and maintained in support of emergency response (refer to Sections 6.4.2, 6.4.2.2, and 6.4.2.3.4). Accessibility to the records of the as-built plant conditions and layout of SSCs is provided.

6.4.2.3.4 NUREG-0737 (Items II.B.2 and III.A.1.2), November 1980 - Clarification of TMI Action Plan Requirements

Item II.B.2 - Design Review Of Plant Shielding And Environmental Qualification Of Equipment For Space/Systems Which May Be Used In Post-accident Operations (originally Recommendation 2.1.6.b of NUREG-0578 [Reference 1]): The TSC is designed to meet the criteria for shielding provided in NUREG-0737, Item II.B.2. Adequate shielding is provided to permit access to vital areas, including the control room and TSC. The acceptance criteria for the TSC dose is based on 10 CFR 50.67, in which dose to an operator in the TSC should not exceed 5 rem TEDE for the duration of the accident. The adequacy of TSC shielding is evaluated for post-LOCA conditions in Sections 12.1.2.7 and 15.5.

Item III.A.1.2 - Upgrade Emergency Support Facilities: NUREG-0737, Supplement 1, January 1983 provides the requirements for III.A.1.2.

The TSC is designed to meet the criteria for habitability provided in NUREG-0737, Supplement 1, items 8.2.1(e) and 8.2.1(f) (Reference 4). The guidance of NUREG-0696, 1981 (Reference 2), cited by NUREG-0737, Supplement 1, is followed regarding ventilation, filtration, radiation monitoring, and radiation protection. The TSC HVAC system is designed to PG&E Design Class II (refer to Section 9.4.11.3).

Section 8.2.1(e) - The adequacy of the TSC ventilation system has been evaluated for normal and post-accident operating conditions as described in Sections 9.4.11 and 12.2 and for fire emergencies as described in Sections 9.4.1 and 9.5.1.

The adequacy of TSC fire protection features is evaluated in Section 9.5.1.

Section 8.2.1(f) – The acceptance criteria for the TSC dose is based on Section 8.2.1(f) of NUREG-0737, Supplement 1, Regulatory Guide 1.183, July 2000, Section 1.2.1, and 10 CFR 50.67. The dose to an operator in the TSC should not exceed 5 rem TEDE for the duration of the accident. TSC shielding and the ventilation system prevent post-accident doses inside the TSC from exceeding 5 rem TEDE for the duration of the accident. Refer to Section 6.4.2.2 for a description of the TSC ventilation system. The adequacy of TSC shielding and ventilation is evaluated for post-LOCA conditions in Section 15.5.

The TSC is provided the capability for monitoring direct radiation and airborne radioactive contaminants. The monitors will provide warning if the radiation levels in the TSC reach potentially dangerous levels.

6.4.2.4 Tests and Inspections

Preoperational testing of TSC habitability systems is discussed in the following sections:

(1)	Ventilation and air conditioning system	Section 9.4.11
(2)	Fire protection system	Section 9.5.1
(3)	Communication systems	Section 9.5.2

6.4.2.5 Instrumentation Applications

Instrumentation and habitability support equipment associated with the TSC are addressed in the Emergency Plan.

6.4.3 REFERENCES

1. NUREG-0578, TMI Short-term Lessons Learned Requirements, U. S. Nuclear Regulatory Commission, 1979.

2. NUREG-0696, Functional Criteria for Emergency Response Facilities, U. S. Nuclear Regulatory Commission, 1981.

3. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

4. NUREG-0737 Supplement 1, Clarification of TMI Action Plan Requirements - Requirements for Emergency Response Capability, U. S. Nuclear Regulatory Commission, 1983.

6.5 AUXILIARY FEEDWATER SYSTEM

The AFW system serves as a backup supply of feedwater to the secondary side of the SGs when the main feedwater system is not available, thereby maintaining the heat sink capabilities of the SGs. As an ESFs system, the AFW system is directly relied upon to prevent core damage and RCS overpressurization in the event of transients such as a loss of feedwater or a secondary system pipe rupture, and to provide a means for plant cooldown following any plant transient.

6.5.1 DESIGN BASES

6.5.1.1 General Design Criterion 2, 1967 - Performance Standards

The AFW system is designed to withstand the effects of, or is protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

6.5.1.2 General Design Criterion 3, 1971 - Fire Protection

The AFW system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

6.5.1.3 General Design Criterion 4, 1967 - Sharing of Systems

The AFW system and components are not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

6.5.1.4 General Design Criterion 11, 1967 - Control Room

The AFW system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

6.5.1.5 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain AFW system variables within prescribed operating ranges.

6.5.1.6 General Design Criterion 21, 1967 - Single Failure Definition

The AFW system is designed to tolerate a single failure during the period of recovery following an accident without loss of its protective function, including multiple failures resulting from a single event, which is treated as a single failure.

6.5.1.7 General Design Criterion 37, 1967 - Engineered Safety Features Basis for Design

The AFW system is designed to provide back-up to the safety provided by the core design, the RCPB, and their protection systems in the event of a DBA.

The AFW system is designed to ensure sufficient supplies of condensate-grade AFW are available to support natural circulation cooldown (Generic Letter 81-21, May 1981).

The AFW system is designed to prevent steam binding of the AFW pumps (Generic Letter 88-03, February 1988).

6.5.1.8 General Design Criterion 38, 1967 - Reliability and Testability of Engineered Safety Features

The AFW system is designed to provide high functional reliability and ready testability.

6.5.1.9 General Design Criterion 40, 1967 - Missile Protection (Dynamic Effects)

The AFW system is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

6.5.1.10 General Design Criterion 41, 1967 - Engineered Safety Features Performance Capability

The AFW system is designed to provide sufficient performance capability to accommodate a partial loss of installed capacity, such as a failure of a single active component, and still perform its required safety function.

6.5.1.11 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The AFW system piping that penetrates containment is provided with leakage detection, isolation, redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The AFW system is provided with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

6.5.1.12 General Design Criterion 57, 1971 - Closed System Isolation Valves

The AFW system contains piping connected to containment penetrations that are neither part of the RCPB nor connected directly to the containment atmosphere. These penetrations are Group D containment isolation and are provided with one local or remote-manual valve outside the containment.

6.5.1.13 Auxiliary Feedwater System Safety Function Requirements

(1) Decay Heat Removal

The AFW system supplies sufficient water to the SGs to remove decay heat and maintain adequate SG inventory.

(2) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The portion of the AFW system located outside containment is designed to be protected against the effects of moderate energy pipe failure.

(3) Protection from Flooding Effects – Outside Containment

The portion of the AFW system located outside containment is to be protected from the effects of internal flooding.

6.5.1.14 10 CFR 50.49 - Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

AFW system components that require EQ are qualified to the requirements of 10 CFR 50.49.

6.5.1.15 10 CFR 50.55a(f) - Inservice Testing Requirements

AFW system ASME Code components are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

6.5.1.16 10 CFR 50.55a(g) - Inservice Inspection Requirements

AFW system ASME Code components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

6.5.1.17 10 CFR 50.62 - Requirements for Reduction of Risk from Anticipated Transients Without Scram Events for Light-Water-Cooled Nuclear Power Plants

The AFW system is designed to initiate upon receipt of a signal from the Anticipated Transients Without Scram (ATWS) Mitigation System Actuation Circuitry (AMSAC).

6.5.1.18 10 CFR 50.63 - Loss of All Alternating Current Power

The AFW system is required to perform its function of decay heat removal in the event of a Station Blackout (SBO).

6.5.1.19 10 CFR Part 50.48(c) – National Fire Protection Association Standard NFPA 805

The AFW system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

6.5.1.20 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The AFW system provides instrumentation to monitor AFW flow and Condensate Storage Tank (CST) level indication during and following an accident.

6.5.1.21 NUREG-0737 (Items II.E.1.1 and II.E.1.2), November 1980 - Clarification of TMI Action Plan Requirements

Item II.E.1.1 - Auxiliary Feedwater System Evaluation: The AFW system is designed such that AFW suction flow will not be interrupted by the failure of a common valve. Additionally, the AFW system is designed to provide a train of AFW independent of on-site and off-site ac power and with sufficient redundancy to ensure that only one (1) train of AFW is required to achieve and maintain safe shutdown.

Item II.E.1.2 - Auxiliary Feedwater System Initiation and Flows: The AFW system is designed to automatically initiate and is designed to the requirements of IEEE 279-1971.

6.5.1.22 Generic Letter 89-10, June 1989 - Safety-Related Motor-Operated Valve Testing and Surveillance

The AFW system's PG&E Design Class I and position changeable MOVs meet the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996.

6.5.2 SYSTEM DESCRIPTION

Following a reactor trip, decay heat is dissipated by evaporating water in the SGs and venting the generated steam either to the condensers through the 40 percent steam dump valves or to the atmosphere through the SG safety valves or the 10 percent atmospheric dump valves. SG water inventory must be sufficient to ensure adequate heat transfer and decay heat removal. The AFW system must be capable of functioning for extended periods, allowing time either to restore main feedwater flow or to proceed with an orderly cooldown of the reactor coolant to 350°F where the RHR system can assume the burden of decay heat removal (refer to Section 5.5.6).

AFW system flow and emergency water supply capacity must be sufficient to remove core decay heat, reactor coolant pump heat, and sensible heat during the plant

cooldown. The AFW system can also be used to maintain the SG water level above the tubes following a LOCA. The water head in the SGs prevents leakage of fission products from the RCS into the secondary side once the RCS is depressurized.

The AFW system is comprised of three independent pump trains. Two trains consist of motor-driven AFW pumps backed by Class 1E power supplies, and one train consists of a turbine-driven AFW pump with a Class 1E 125-Vdc steam inlet admission valve.

The motor-driven AFW pumps are each aligned to two SGs. Flow to the SGs is modulated by PG&E Design Class I, electro-hydraulic level control valves (LCVs) powered from Class 1E power supplies. These valves also provide for pump runout protection.

The turbine-driven AFW pump is aligned to all four SGs and contains motor-operated LCVs; however, these valves do not automatically modulate. AFW is provided to the pumps from the PG&E Design Class I CST, which is backed by the PG&E Design Class I fire water storage tank (FWST), and by the PG&E Design Class II raw water storage reservoirs. The branch connection on two main steam lines for the auxiliary feed pump turbine is provided with isolation valves and CVs.

In the unlikely event of a complete loss of the preferred power supply and main generator electrical power to the station, decay heat removal would continue to be ensured by the availability of one turbine-driven, and two motor-driven AFW pumps (powered by the standby power source), and steam discharged to atmosphere through the SG power operated relief valves and/or the spring-loaded safety valves. The system is shown in simplified form in Figure 6.5-1. For the detailed piping schematic, refer to Figure 3.2-3, Sheets 3 and 4.

6.5.2.1 Equipment and Component Descriptions

6.5.2.1.1 Water Sources

The minimum CST volume alone is sufficient to perform the plant cooldown described in Section 6.5.3.7 and to address Generic Letter 81-21, May 1981, postulated worst-case natural circulation cooldown.

In the event the CST becomes exhausted, additional cooling water supplies are available to maintain hot standby conditions or to bring the plant to cold shutdown. These additional long-term cooling water sources use both existing piping systems and pumps, along with temporary portable pump driver units and hoses. Two million gallons of water will be available from the raw water reservoir for both units following exhaustion of preferential water sources (Reference 4). The FWST is the PG&E Design Class I backup water source for AFW. The design basis of the AFW system is to cooldown the RCS utilizing the PG&E Design Class I AFW sources to the point where the RHR system may be relied upon to complete the cooldown of the unit.

The additional sources, listed in order of preference according to water quality, are as follows:

(1) Unit 1 and Unit 2 CST (supply from un-affected unit if water inventory is not required for that unit)

(2) Main condenser hotwells (using condensate pumps)

(3) Fire water transfer tank

(4) FWST

(5) Main condenser hotwells (using portable fire pumps)

(6) Raw water storage reservoirs (5 million gallons)

(7) Pacific Ocean (via ASW system)

The above order of preference, although desirable relative to control of SG secondary side water chemistry, is not necessarily the preferred order in response to a plant transient requiring rapid operator response. The operating procedures identify an order of preference that is based on ensuring rapid alignment of the long-term cooling water supply.

The various long-term cooling water sources and their connections to the AFW system are shown schematically in Figure 6.5-2. Water systems are discussed in Section 9.2.

Connections and valving arrangements are provided to interconnect permanent plant systems by means of special-use hoses as follows:

(1) ASW system at the inlet water box of the CCW heat exchanger to the turbine building fire water system and then into the FWST

(2) Raw water storage reservoir to the plant raw water supply line

(3) Condenser hotwells to the turbine building fire water system and then into the FWST

(4) Fire water system crosstie (through PG&E Design Class I piping) to the AFW system.

The available hoses and portable pumps (not permanently connected to existing systems) are stored in structures that have been verified to survive the Hosgri seismic event.

6.5.2.1.2 Auxiliary Feedwater Pumps and Controls

Each of the two steam supply lines to the turbine-driven AFW pump is provided with a separate, normally open, PG&E Design Class I motor-operated isolation valve with PG&E Instrument Class IA control circuitry and a non-return valve. The non-return valves provide protection against potential cross-connection between the steam lines. A normally closed, motor-operated stop valve is located in the steam supply line to the turbine inlet. During normal operation, the steam supply line is pressurized up to this stop valve, with steam available to operate the turbine-driven AFW pump when a control signal is received to open the stop valve. The turbine-driven AFW pump can deliver a net flow of 780 gpm to all four SGs.

The four motor-driven AFW pumps (two per unit) are powered from the Class 1E 4.16-kV buses. They are available for standby service when there is insufficient steam to operate the turbine-driven AFW pump, or when the turbine-driven AFW pump is unavailable. Each motor-driven AFW pump can deliver a net flow of 390 gpm to two SGs. Note that the flow rates of 780 and 390 gpm represent the minimum required flow rates of the turbine- and motor-driven AFW pumps at a SG back-pressure corresponding to the lowest SG safety valve set pressure, plus 3 percent for setpoint tolerance and 5 psi for accumulation.

Controls for the AFW system are described in Sections 7.1 through 7.7. In addition to the manual actuation of the AFW pumps, the following signals provide for automatic actuation of the motor-driven AFW pumps:

(1) Two-out-of-three low-low level signals in any one SG

(2) Trip of both main feedwater pumps

(3) ”S” signal

(4) Transfer to diesel without ”S” signal

(5) AMSAC

The turbine-driven AFW pump automatic actuation signals are:

(1) Two-out-of-three low-low level signals in any two SGs

(2) Undervoltage on one-out-of-two relays on both RCP buses (loss of offsite power)

(3) AMSAC

The SG blowdown isolation valves and the blowdown sample isolation valves are tripped shut whenever an AFW pump is started automatically.

6.5.2.2 Design Conditions

The reactor plant conditions that impose PG&E Design Class I performance requirements on the AFW system are as follows:

(1) LONF transient

(a) LONF with offsite power available

(b) Loss of offsite power to the station auxiliaries

(2) Major secondary system pipe ruptures

(c) Feedline rupture

(d) Steam line rupture (inside containment)

(3) Loss of all ac power

(4) SBLOCA

(5) Cooldown

Each of these conditions is discussed in more detail in the following sections.

6.5.2.2.1 Loss of Normal Feedwater Transients

Design basis LONF transients are caused by:

(1) Interruptions of the main feedwater system flow due to a malfunction in the feedwater or condensate system

(2) Loss of offsite power with the consequential shutdown of the system pumps, auxiliaries, and controls

Loss of Normal Feedwater (With Offsite Power Available)

LONF transients are characterized by a reduction in SG water level that results in a reactor trip, a turbine trip, and AFW actuation by the protection system logic. Following reactor trip from a high initial power level, the power quickly falls to decay heat levels. The SG water levels continue to decrease, progressively uncovering the SG tubes as decay heat is transferred and discharged in the form of steam either through the 40 percent dump valves to the condenser or to the atmosphere through the SG safety

valves or the 10 percent atmospheric dump valves. The reactor coolant temperature increases since the residual heat exceeds that dissipated through the SGs. With increased temperature, reactor coolant volume expands and begins to fill the pressurizer. Without the addition of sufficient AFW, further expansion will result in liquid being discharged through the pressurizer safety and/or relief valves.

If the temperature rise and the resulting volumetric expansion of the primary coolant are permitted to continue, then the following may occur: (a) pressurizer safety valve capacities may be exceeded causing overpressurization of the RCS, and/or (b) the continuing loss of fluid from the primary coolant system may result in bulk boiling in the RCS system and eventually in core uncovering, loss of natural circulation, and core damage. If such a situation were to occur, the ECCS would not be effective because the primary coolant system pressure exceeds the shutoff head of the SI pumps, the nitrogen overpressure in the accumulator tanks, and the design pressure of the RHR loop.

Loss of Offsite Power to the Station Auxiliaries

The loss of offsite power transient differs from a simple LONF in that emergency power sources must be relied upon to operate vital equipment. The loss of power to the motor-driven circulating water pumps results in a loss of condenser vacuum and, therefore, of use of the 40 percent condenser dump valves. Hence, steam generated by decay heat is relieved through the SG safety valves or the power-operated relief valves. The LONF and loss of offsite power transient analyses are similar with the exception that reactor coolant pump heat input is not a consideration in the loss of offsite power transient following loss of power to the reactor coolant pump bus.

The LONF transient was the original basis for the minimum flow required for the smallest capacity single AFW system pump. Each pump was originally sized so that any single pump will provide sufficient flow against a conservative SG safety valve set pressure with 3 percent tolerance and 5 psi accumulation to prevent liquid relief from the pressurizer. The LONF analysis requires that at least two motor-driven AFW pumps provide at least 600 gpm of AFW (assuming a single failure of the turbine-driven AFW pump) to four SGs to prevent pressurizer overfilling. Refer to Sections 6.5.3.7 and 15.2.8.2 for further discussion on LONF.

6.5.2.2.2 Major Secondary System Pipe Ruptures

Feedwater Line Rupture

A feedwater line rupture results in the loss of feedwater flow to the SGs and the complete blowdown of one SG within a short time if the rupture occurs downstream of the last non-return valve in the main or AFW system piping to an individual SG. A feedwater line rupture may also cause spilling of AFW through the break due to the fact that the AFW system branch line may be connected to the main feedwater line in the region of the postulated break. Such situations can result in the injection of a

disproportionately large fraction of the total AFW system flow (the system preferentially pumps water to the lowest pressure region) to the faulted loop rather than to the effective SGs, which are at relatively high pressure. System design provides for terminating, limiting, or minimizing that fraction of AFW flow, which is delivered to a faulted loop or spilled through a break to ensure that sufficient flow is delivered to the remaining effective SG(s).

Main Steam Line Rupture Inside Containment

Main steam line rupture accident conditions are characterized initially by a plant cooldown and, for breaks inside containment, by increasing containment pressure and temperature. AFW is not required during the early phase of the transient. However, modeling AFW flow to the faulted loop contributes to an excessive release of M&E to containment, maximizing the peak containment pressure. In this way, these steam line rupture conditions establish the upper limit on AFW flow delivered to a faulted loop and the time required to isolate the faulted SG. Eventually, however, the RCS heats up again and AFW flow is required for the non-faulted loops, but at a lower rate than the loss of feedwater transients described previously. Provisions in the design of the AFW system limit, control, or terminate AFW flow to the faulted loop as necessary to prevent containment overpressurization following a steam line break inside containment, or, for steam leads 3 and 4, to maintain the temperature profile in the GE/GW area within analyzed limits, and to ensure minimum flow to the remaining intact loops.

6.5.2.2.3 Loss of All AC Power

The loss of all ac power is postulated as resulting from accident conditions wherein not only onsite and offsite ac power is lost, but also emergency ac (EAC) power is lost as an assumed common mode failure. Battery power for operation of protection circuits is assumed available. The impact on the AFW system is the necessity for providing both AFW pump power and a control source that are not dependent on ac power (refer to Section 6.5.3.21) and which are capable of maintaining the plant at hot shutdown until ac power is restored. In the event of a Loss of All AC Power, decay heat removal would continue to be ensured through the availability of one turbine-driven AFW pump.

6.5.2.2.4 Small-Break Loss-of-Coolant Accident

The LOCAs do not impose any flow requirements on the AFW system that are in excess of those required by the other accidents addressed in this section.

SBLOCAs cause relatively slow rates of decrease in RCS pressure and liquid volume. The principal contribution from the AFW system following a SBLOCA is essentially the same as the system's function during hot shutdown or following a spurious ”S” signal which trips the reactor. Maintaining a water level inventory in the secondary side of the SGs provides a heat sink for removing decay heat and establishes the capability for providing a buoyancy head for natural circulation. The primary contributor to heat removal during a SBLOCA, however, is through the break. The AFW system may be

used to assist in system cooldown and depressurization following a SBLOCA while bringing the reactor to a cold shutdown condition.

6.5.2.2.5 Cooldown

The AFW system is required to cool down the RCS from normal zero load temperature to a hot leg temperature of approximately 350°F. This is the maximum temperature recommended for placing the RHR system into service. The RHR system completes the cooldown to cold shutdown conditions. Cooldown may be required following expected transients, following an accident such as a main feedline break, or prior to refueling or plant maintenance. If the reactor trips following extended operation at rated power level, the AFW system delivers sufficient feedwater to remove decay heat and reactor coolant pump heat following reactor trip while maintaining SG water level. Following transients or accidents, the recommended cooldown rate is consistent with expected needs and at the same time does not impose additional requirements on the capacities of the AFW pumps, considering a single failure.

6.5.2.3 Applicable Codes and Classifications

All AFW pumps and their appropriate piping and valves are PG&E Design Class I. The AFW system fittings and piping are designed to ANSI Code for Pressure Piping B31.1 and B31.7, as appropriate. The system valves were originally designed to the requirements of the ASME Pump and Valve Code, 1968 Draft. Later additions were designed to ASME BPVC Section III.

6.5.3 SAFETY EVALUATION

6.5.3.1 General Design Criterion 2, 1967 - Performance Standards

The AFW system components are located at the 100 foot elevation of the auxiliary building, a PG&E Design Class I structure (refer to Figure 1.2-6). The auxiliary building is designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7). This design protects the AFW SSCs, ensuring their design functions will be performed.

Portions of the AFW system are not contained within a building and are exposed directly to potential wind and tornado loads and have been evaluated. Loss of this equipment does not compromise the capability of shutting down the plant safely due to the availability of a train of AFW completely located within qualified structures (refer to Section 3.3.2.5).

The AFW system SSCs are designed to perform their safety functions under the effects of earthquakes. The PG&E Design Class I portion of the AFW system is seismically qualified.

Flooding of PG&E Design Class I equipment due to an AFW line rupture would not occur because of the relatively low flowrates and the location of the system. The consequences of postulated pipe rupture outside the containment, including the postulated rupture of AFW system lines, are discussed in Section 3.6.

6.5.3.2 General Design Criterion 3, 1971 - Fire Protection

The AFW system is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

6.5.3.3 General Design Criterion 4, 1967 - Sharing of Systems

The CSTs for Unit 1 and Unit 2 are cross-tied through a 4-inch line. The effective elevation of the nozzles have been raised above the Technical Specification volume requirement for AFW due to the addition of internal plenums, thereby ensuring that failure of the crosstie line cannot reduce the condensate storage capacity below the minimum required volume to ensure SG makeup from the AFW pumps. Refer to Section 9.2.6.3 for a discussion on the Condensate Storage Facilities.

There is no direct connection between the raw water supply header in the plant and the CST such that any single failure of a component could cause the loss of both CST inventory and reservoir water. Refer to Section 9.2.3.2.2 for a discussion on the raw water reservoir. The FWST provides a PG&E Design Class I source of backup water to Unit 1 and Unit 2 for the AFW system. This source of water (the FWST) is connected to the common supply header from both the Raw Water Reservoir and the FWST to both units' AFW pumps. A normally closed PG&E Design Class I valve separates the PG&E Design Class II Raw Water Reservoir supply and the PG&E Design Class I FWST supply. This ensures that a failure of the PG&E Design Class II Raw Water Reservoir's piping will not result in drain down of the FWST or the prevention of the FWST from supplying backup PG&E Design Class I AFW. The piping from the FWST is provided with isolation valves such that a failure in this line will not prevent sufficient backup supplies of AFW from being provided by other backup AFW sources. As discussed in Section 6.5.3.7, there is a sufficient volume of water available and maintained in the CSTs for the AFW system to perform the worst-case natural circulation cooldown.

The turbine-driven AFW pump leakoffs and bearing cooling water return lines are piped to the PG&E Design Class II common auxiliary steam drain receiver tank. Isolation valves and CVs in these drain lines ensure that a failure of the tank or PG&E Design Class II piping will not impair the operation of either units' AFW system.

There is no sharing between units that would prevent either Unit 1 or Unit 2 AFW system from performing its design function.

6.5.3.4 General Design Criterion 11, 1967 - Control Room

Manual initiation for each train exists in the control room. The manual initiation system is installed in the same manner as the automatic initiation system.

One PG&E Design Class I AFW flow indicator is provided for each of four SGs. Indication is provided at the main control board and the HSP (refer to Section 7.5.1.6). Instrument Class II AFW backup flow indicators are provided at the HSP for loops 3 and 4.

These flow indicators monitor the flow from the turbine-driven AFW pump and the motor-driven AFW pumps.

Additional indication of AFW flow is provided by PG&E Design Class I SG wide-range level indication (refer to Section 7.5.2.6). This provides recording on the main control board and indication on the HSP.

The AFW system primary water supply source, the CST, contains redundant, PG&E Design Class I level recording with indication in the main control board (refer to Table 7.5-6). PG&E Design Class II CST level indication is provided at the HSP.

Additional controls for components of the AFW system are available in the control room and at the HSP. Controls for the AFW LCVs, start/stop switches for the motor-driven AFW pump, control of the steam admission valve for the turbine-driven AFW pump, and AFW pump discharge pressure indication are all provided in the control room and at the HSP. In addition to cooling the RCS down to RHR entry conditions (Mode 4), the AFW system allows the plant to remain in hot standby (Mode 3) for an extended period of time if desired by operation and/or required for safe shutdown (refer to Section 7.4.2.1).

Annunciation is provided in the main control room for AFW pump discharge piping temperature to prevent steam binding of the AFW pumps (refer to Section 6.5.3.7).

Controls for the AFW system are provided in the control room such that the AFW system may be operated to perform its design function.

6.5.3.5 General Design Criterion 12, 1967 - Instrumentation and Control Systems

All automatic initiating signals and circuits are installed in accordance with IEEE 279-1971 (Reference 1) and are PG&E Design Class I and redundant (refer to Section 7.3).

As discussed in Section 7.3 and shown in Figures 7.3-8 and 7.3-17 the motor-driven AFW pumps are started by closure of the SSPS output relay and one of the timers. The relay is actuated by SI initiation or low-low level in any SG. The timers provide automatic starting sequences after bus transfer either with or without SI. Each pump is started by a separate relay or timer from redundant SSPS trains A or B. The motor-

driven pumps are also automatically started by trip of both main feedwater pumps, or an AMSAC signal.

The turbine-driven AFW system pump is started by opening steam supply valve FCV-95. As shown in Figure 7.3-18, this valve is opened by one of the SSPS output relays. One of these relays starts on loss of offsite power and the other on low-low level in any two SGs. The turbine-driven pump is also started by an AMSAC signal.

The initiating sensors are powered from separate and redundant nuclear instrumentation and control panels, each of which is supplied by either the Class 1E 120-Vac power supply or Class 1E 125-Vdc batteries. Each of the two redundant SSPS trains is supplied by a separate Class 1E power source.

Instrumentation is provided in the motor-driven AFW pump discharge line to sense low pump discharge pressure indicative of a depressurized SG. In a low pump discharge pressure situation, control valves are automatically throttled to prevent pump runout. This automatic action limits flow to any depressurized SG.

No such instrumentation is provided for the turbine-driven AFW pump. Manual action by the plant operator is required to terminate flow to a depressurized SG.

6.5.3.6 General Design Criterion 21, 1967 - Single Failure Definition

No single failure in the manual initiation portion of the circuit can result in the loss of the AFW system function (refer to Section 7.3.4.1.1 and Figures 7.3-17 and 7.3-18 for the circuitry).

No single failure in the automatic portion of the circuit will result in loss of the capability to manually initiate the AFW system from the control room.

All automatic initiating signals and circuits are installed in accordance with IEEE 279-1971 (Reference 1) and are PG&E Design Class I and redundant (refer to Section 7.3).

A single failure that results in the failure of multiple components, such as the failure of an EDG, will not result in a failure of the AFW system to perform its design function. The AFW system is designed with a train that is completely independent of the preferred power supply or standby power supply (refer to Section 6.5.3.21). Isolation valves are provided in the water supply lines to the AFW pumps such that a single failure of a valve in the suction line of the AFW pumps will not result in the failure of the remaining pumps.

6.5.3.7 General Design Criterion 37, 1967 - Engineered Safety Features Basis for Design

Analyses have been performed for the limiting transients that define the AFW system performance requirements. Specifically, they include:

(1) LONF

(2) Loss of Offsite Power to the Station Auxiliaries

(3) Rupture of a Main Feedwater Pipe

(4) Rupture of a Main Steam Pipe Inside Containment

(5) SBLOCA

In addition, specific calculations for DCPP Unit 1 and Unit 2 were performed to determine plant cooldown flow (storage capacity) requirements.

The loss of all ac power was evaluated by comparison with the transient results of a loss of offsite power, assuming an available AFW pump having a diverse (non-ac) power supply. The SBLOCA analysis incorporates system flow requirements defined by other transients and is, therefore, not performed to determine AFW system flow requirements. Each of the above analyses is explained further below.

Loss of Normal Feedwater

A LONF was analyzed in Section 15.2.8 to show that two motor-driven AFW system pumps delivering at least 600 gpm of AFW flow to four SGs does not result in pressurizer over-filling. Furthermore, the peak RCS pressure remains below the criterion for Condition II transients and no fuel failures occur.

Table 6.5-2 summarizes the assumptions used in the Chapter 15 analysis. All main feedwater flow to the SGs is terminated at event initiation. Reactor trip is assumed to occur when the water level in any SG reaches the low-low level trip setpoint. AFW flow from both motor-driven pumps initiates within 60 seconds after receiving a low-low level signal in any SG. The analysis assumes that the plant is initially operating at 102 percent (calorimetric error) of the NSSS design rating shown in Table 6.5-2, and includes a conservative assumption in defining decay heat and stored energy in the RCS.

Both the LONF and loss of offsite power analyses demonstrate that there is considerable margin with respect to pressurizer over-filling (refer to Sections 15.2.8 and 15.2.9).

A better-estimate analysis is performed to address the reliability of the AFW system. This analysis is similar to that described above for the Chapter 15 analysis, but assuming that only a single motor-driven AFW system pump supplies a minimum of 390 gpm to two of the four SGs. The cases considered in this additional analysis assume better-estimate conditions for several key parameters, including initial power level, decay heat, RCS temperature, pressurizer pressure, and the low-low SG water level reactor trip setpoint. The results of this better-estimate analysis demonstrate that there is margin to pressurizer over-filling. While this analysis demonstrates that the AFW system remains highly reliable, the DCPP licensing basis requires that at least two AFW pumps delivering at least 600 gpm to four SGs is required for this event.

Loss of Offsite Power to the Station Auxiliaries

The AFW system is initiated for a loss of offsite power to the station auxiliaries' transient as discussed in Section 15.2.9. The same assumptions discussed above for the LONF transient apply to this analysis, except that power is assumed to be lost to the reactor coolant pumps following reactor trip.

As with all ESF equipment, the ac motor-driven AFW pumps and all valves in the system are automatically and sequentially loaded on the emergency buses on loss of offsite power.

Rupture of Main Feedwater Pipe

The double-ended rupture of a main feedwater pipe downstream of the main feedwater line CV was analyzed (refer to Sections 15.4.2.2 and 15.4.2.4). Table 6.5-2 summarizes the assumptions used in these analyses. A reactor trip is assumed to occur when the faulted SG reaches the low-low level trip setpoint (adjusted for errors). The initial power rating assumed in the feedline break analysis is 102 percent of the NSSS design rating.

For the analysis in Section 15.4.2.2, although the AFW system at DCPP Unit 1 and Unit 2 would allow delivery of AFW to two intact loops automatically in 1 minute, no AFW flow is assumed until 10 minutes after the break. At this time it is assumed that the operator has isolated the AFW system from the break and flow from one motor-driven AFW pump of 390 gpm (total) to two SGs commences. As discussed in Section 15.4.2.2, the analysis assumes a single failure of the most limiting component, the turbine-driven AFW pump, and assumes that all flow from the motor-driven AFW pump aligned to the faulted SG is lost through the break. The AFW flow is asymmetrically split between two of the three unaffected SGs. The analysis demonstrates that the reactor coolant remains subcooled, assuring that the core remains covered with water and no bulk boiling occurs in the hot leg.

For the analysis in Section 15.4.2.4, the limiting single failure is the failure of a PG&E Design Class I pressurizer power-operated relief valve. It is assumed the motor-driven AFW pump that is initially aligned to two intact SGs delivers 390 gpm total AFW flow to

two of the three intact SGs at 1 minute after the trip. It is also assumed that operator actions are taken within 10 minutes to isolate the faulted SG. For this reason, the other motor-driven AFW pump, which is initially aligned to both the third intact SG and the faulted SG, is assumed to deliver an additional 195 gpm of AFW flow to the third intact SG at 10 minutes after the trip. Similarly, the turbine-driven AFW pump, which is initially aligned to all four SGs, is assumed to deliver an additional total 585 gpm of AFW flow to all three intact SGs at 10 minutes after the trip. The analysis demonstrates that water relief through the pressurizer safety valves is precluded.

Rupture of a Main Steam Pipe Inside Containment

Because the result of the steam line break transient is an initial RCS cooldown, the AFW system does not have a requirement to remove heat in the short term. However, addition of AFW to the faulted SG will increase the secondary mass available for release to the containment thus maximizing the peak containment pressure following a steam line break inside containment. This transient is performed at four power levels for several break sizes. AFW is assumed to be initiated at the time the SI setpoint is reached. The AFW flowrate to the faulted SG is maximized based on flow from both motor-driven AFW pumps and the turbine-driven AFW pump where runout protection is not credited. Table 6.5-2 summarizes the assumptions used in this analysis. At 10 minutes after the break, it is assumed that the operator has isolated the AFW system from the faulted SG, which subsequently blows down to ambient pressure. This assumption for operator action is also used for temperature profile development for MSLBs outside containment. Refer to Section 6.2D.3 for further discussion on a MSLB inside containment.

Small Break Loss of Coolant Accident

A SBLOCA is described in Section 15.3.1. The AFW system plays a minor role in response to an SBLOCA. This is due to the primary means of RCS heat removal occurring through the break. However, once the SG secondary sides' are isolated, the boiling process essentially ceases unless the safety valves are lifting. This means, excluding the safety valves, the only heat removal mechanism through the SGs will be through sensible heat gain of the AFW mass addition. Therefore, the significance of AFW flow with respect to the SBLOCA transient is considered small. For this transient, only 390 gpm of AFW flow is assumed to be provided by one motor-driven AFW pump divided equally to four SGs (97.5 gpm per SG). Refer to Section 15.3.1 for a discussion on the SBLOCA event.

Natural Circulation Cooldown

Maximum and minimum flow requirements from the previously discussed transients meet the flow requirements of plant cooldown. This operation, however, defines the basis for tank size, based on the required cooldown duration, maximum decay heat input, and maximum stored heat in the system. The AFW system partially cools the RCS to the point where the RHR system may complete the cooldown . Table 6.5-2

shows the assumptions used to determine the cooldown heat capacity of the AFW system.

The minimum CST volume alone is sufficient to perform the plant cooldown described in Section 6.5.2.2.5 and to address Generic Letter 81-21, May 1981, postulated worst-case natural circulation cooldown.

Due to Unit 2 being converted to a T_{cold} reactor vessel head design, the natural circulation cooldown rates, and subsequent water volume requirement, between the two units is different. With the Unit 2 T_{cold} upper head design, a cooldown rate of up to 50°F per hour can be used. With Unit 1 being a T_{hot} upper head design, a reduced cooldown rate of 25°F per hour is required to maintain sub-cooling in the reactor vessel upper head region. The natural circulation cooldown analysis has shown that with the two reactor vessel head designs, the worst case conditions for each unit occurred when Unit 2 was held in hot standby for two hours followed by a four hour cooldown at a rate of 50°F per hour. The worst-case natural circulation cooldown for Unit 1 was determined to be when Unit 1 was held in hot standby for one hour followed by an eight hour cooldown at 25 °F per hour.

For a worst-case natural circulation cooldown, 196,881 gallons for Unit 1 and 163,058 gallons for Unit 2 are required to cooldown the RCS to 350°F (Mode 4, RHR entry temperature conditions). An additional volume of 3,119 gallons for Unit 1 and 2,942 gallons for Unit 2 are reserved for allowed leakage through internal plenums at CST connections and for margin. The inventory of the CST at the minimum Technical Specification usable volumes of 200,000 gallons for Unit 1 and 166,000 gallons for Unit 2 envelops this total required amount. The usable reserved inventory in both CSTs was increased from 164,678 gallons to 224,860 gallons (Reference 3). In addition to cooling the RCS down to RHR entry conditions, the AFW system allows the plant to remain in hot standby (Mode 3) for an extended period of time if desired by operation and/or required for safe shutdown. Holding Unit 1 in hot standby for 8 hours requires 140,584 gallons. Holding Unit 2 in hot standby for 8 hours requires 140,703 gallons.

The Technical Specifications do not permit the RCS to be heated above 350°F without at least 200,000 gallons for Unit 1 and 166,000 gallons for Unit 2 of usable water in the CST.

Therefore, the volume of water maintained in the CST, as ensured by the Technical Specifications, is sufficient for all DBAs for which the AFW system is required to perform its design function.

In case of an incident, such as a small break in the RCL concurrent with a loss of offsite and main generator power, the plant can remain at the hot standby condition for a period of time that depends on the amount of water available in the CST. Cooldown delay guidance is found in the plant operating procedures, which, under certain conditions (e.g., control room inaccessibility), allow a delay in beginning cooldown. Backup sources of AFW are available as described in Section 6.5.2.1.1.

Table 6.5-1 summarizes the criteria used for the AFW system general design bases for various plant conditions.

Steam Binding of the AFW Pumps

In accordance with GL 1988-03, February 1988, the AFW system is equipped with permanently installed temperature sensors on the AFW discharge lines to each SG main feedwater line. The temperature sensors detect high temperatures caused by main feedwater system back-leakage through the AFW discharge CVs. This hot water back-leakage could result in steam binding of the AFW pumps. Annunciation is provided in the main control room if the AFW pipe fluid temperatures reach 200 °F. Operations responds to this annunciation by venting the AFW pump casings until the temperatures are reduced. Also, the AFW pumps may be run to feed forward to displace the hot water in the pipes with cold CST water and attempt to reduce CV leakage by cycling the valve.

6.5.3.8 General Design Criterion 38, 1967 - Reliability and Testability of Engineered Safety Features

The AFW system initiation signals and circuitry are testable. Such testability is included in the surveillance test procedures for the plant as delineated in the Technical Specifications.

The AFW system piping also has a periodic ISI program in accordance with the ASME BPVC Section XI (refer to Section 5.2.3.15).

6.5.3.9 General Design Criterion 40, 1967 - Missile Protection (Dynamic Effects)

The provisions taken to protect the AFW system from damage that might result from missiles and dynamic effects associated with equipment and high energy pipe failures (pipe whip, jet impingement, environmental) are discussed in Sections 3.5 and 3.6.

The AFW system is protected by barriers and restraints from the dynamic effects of a ruptured pipe outside the containment.

An analysis, using the methodology presented in Reference 1 and Section 3.6.4.2, shows that cooldown using the AFW system will not be prevented by any postulated auxiliary steam line break within an AFW system compartment.

Rupture of a Steam Supply Line to the Turbine-Driven AFW Pump

The double-ended rupture of a turbine-driven AFW pump steam supply line in the GE/GW area (downstream of the non-return valves associated with steam supply isolation valves, FCV-37/38, and upstream of steam supply stop valve, FCV-95) will not result in loss of all AFW flow.

The postulated break would render the turbine driven AFW pump No. 1 inoperable due to loss of steam supply. FCV-37 and FCV-38 are capable of remote manual closure. FCV-37 is located outside of the GE/GW area and would not be subjected to a harsh environment. FCV-38 is located within the GE/GW area and is qualified for operation in a harsh environment. Therefore, the break can be isolated from the main steamline.

The resulting increased temperature in the GE/GW area would cause the E/H actuated LCVs associated with motor driven AFW pump No. 3 to fail due to a harsh environment. However, due to the small rupture, motor-driven AFW pump No. 3 will not trip due to pump runout and subsequent overcurrent.

The E/H actuated LCVs associated with motor-driven AFW pump No. 2 are located outside of the GE/GW area and would not be subjected to a harsh environment.

If either of the steam supply valves (FCV-37/38) fails to close, isolation of feedwater to the respective SG will effectively isolate the AFW steam supply line break, thus ensuring at least one motor-driven AFW pump is available to provide sufficient AFW flow to two intact loops.

Isolation of the faulted SG within 10 minutes ensures the GE/GW area does not exceed its analyzed temperature profile.

6.5.3.10 General Design Criterion 41, 1967 - Engineered Safety Features Performance Capability

The single failure of any active component in the AFW system will not prevent the system from performing its design function (refer to Sections 6.5.3.6 and 6.5.3.7).

6.5.3.11 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The AFW system isolation valves required for containment closure are periodically tested as part of the MOV program for operability in accordance with GDC 54, 1971 (refer to Section 6.5.3.2.2); however, since the AFW piping must remain in service following an accident, these valves are not tested for leakage (refer to Section 6.2.4 for leakage testing of the CIS). Leakage detection is provided in the AFW discharge lines that sense back leakage of main feedwater as discussed in Sections 6.5.3.4 and 6.5.3.7.

6.5.3.12 General Design Criterion 57, 1971 - Closed System Isolation Valves

The AFW system containment penetrations include the AFW pump discharge lines to the main feedwater lines (Penetrations 1, 2, 3, and 4) and the steam supply lines to the turbine-driven AFW pump (Penetrations 6 and 7).

These penetrations are classified as Group D containment isolation because they are lines that must remain in service following an accident and, therefore, do not isolate automatically.

Refer to Section 6.2.4.1 and Table 6.2-39 for additional information on these penetrations and their containment isolation capabilities.

6.5.3.13 Auxiliary Feedwater System Safety Function Requirements

(1) Decay Heat Removal

Auxiliary feed pumps are provided and designed to ensure complete reactor decay heat removal under plant transient and accident conditions, including loss of power and loss of the normal heat sink (the condenser circulating water), while maintaining minimum water levels within the SG. The AFW system may be used for plant startup and for a controlled shutdown.

(2) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection of the portion of the AFW system located outside containment from the effects of moderate energy pipe failure are discussed in Section 3.6.

(3) Protection from Flooding Effects – Outside Containment

The provisions taken to provide protection of the portion of the AFW system located outside containment from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

6.5.3.14 10 CFR 50.49 - Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

AFW system SSCs required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment. The affected equipment includes valves, switches, and flow transmitters and are listed on the EQ Master List.

6.5.3.15 10 CFR 50.55a(f) - Inservice Testing Requirements

All AFW pumps and their appropriate piping and valves are PG&E Design Class I (refer to Section 3.2) and PG&E Quality Class II or III. The IST requirements for these components are contained in the IST Program Plan.

6.5.3.16 10 CFR 50.55a(g) - Inservice Inspection Requirements

The AFW system piping also has a periodic ISI program in accordance with the ASME BPVC Section XI.

6.5.3.17 10 CFR 50.62 - Requirements for Reduction of Risk from Anticipated Transients Without Scram Events for Light-Water-Cooled Nuclear Power Plants

The AFW system is automatically initiated as part of the AMSAC (refer to Section 7.6.2.3).

6.5.3.18 10 CFR 50.63 - Loss of All Alternating Current Power

As addressed in Section 8.3.1.6, SBO at DCPP is defined as loss of power from the preferred power source concurrent with turbine trip and failure of two of the three EAC sources (EDGs) in the unit experiencing the SBO. Since at least one EDG remains operational during an SBO event, it differs from the “Loss of All AC Power” event described in Section 6.5.2.2.3, in which offsite power, onsite ac power, and all onsite EAC sources are lost.

In the event of an SBO, makeup feedwater from the condensate storage tank (CST) to two SGs is provided by the motor-driven AFW pump on 4.16-kV Class 1E Bus F, which is the bus supplied by the alternate AC (AAC) power source.

The AFW system is sufficiently sized to maintain the plant in hot standby conditions (Mode 3) for the 4 hour SBO coping period.

Refer to Section 8.3.1.6 for further discussion of station blackout.

6.5.3.19 10 CFR Part 50.48(c) – National Fire Protection Association Standard NFPA 805

The AFW system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (Refer to Section 9.5.1).

6.5.3.20 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

AFW system post-accident instrumentation for meeting Regulatory Guide 1.97, Revision 3, requirements consist of flow indication to all four SGs and CST level indication.

One AFW flow indicator is provided for each of four SGs. The indicators are PG&E Design Class I (refer to Section 7.5.2.6 and Table 7.5-6). Indication is provided at the main control board and the HSP.

Two separate critical instrument power buses are used for the four flow indicators, with two flow indicators on each bus. The flow from the turbine-driven AFW pump is monitored by the same indicators that monitor the motor-driven AFW pump flow.

6.5.3.21 NUREG-0737 (Items II.E.1.1 and II.E.1.2), November 1980 - Clarification of TMI Action Plan Requirements

Item II.E.1.1 - Auxiliary Feedwater System Evaluation: The AFW pumps takes water from the CST, which is the preferred source of AFW. The CST provides redundant level indication and low level alarms in the control room. The purpose of the low-low level alarm is to notify the operator that the AFW supply is running low and must be aligned to an alternate water supply. The alarm provides the operator with at least a 20 minute supply of water for the auxiliary feed pumps at a net flowrate of 880 gpm. The turbine-driven AFW pump has a net flow of 780 gpm available to supply the SGs. One normally open, manual valve in the common suction piping of the AFW pumps is secured in the open position to prevent interruption of AFW flow. The train of AFW provided by the turbine-driven AFW pump is designed to be completely independent from a standby and preferred ac power source. This train consists of a steam supply stop valve powered from a Class 1E 125-Vdc bus, automatic AFW system actuation instrumentation powered from a Class 1E instrument ac bus (powered by station batteries through an inverter), and SG level and AFW flow indication instrumentation powered from station batteries. Driving steam for the turbine-driven AFW pump is taken from two of the four main steam lines upstream of the main steam isolation valves and is exhausted to the atmosphere. Only one steam supply is required for turbine operation. However, steam must always be available from both steam lines during plant operation to preclude a loss of all steam supplies due to any single failure incident. Therefore, in accordance with Item II.E.1.1, the AFW system is designed with one train of AFW that contains a pump power and control source not dependent on ac power and that can provide sufficient AFW flow to the SGs to bring the plant to hot shutdown conditions.

The motor-driven AFW pumps are powered from the Class 1E buses. They are available for standby service when there is insufficient steam to operate the turbine-driven AFW pump, or when the turbine-driven AFW pump is unavailable (refer to Section 8.3.1.1.3). Each motor-driven AFW pump can deliver a net flow of 390 gpm to two SGs.

Note that the flow rates of 780 and 390 gpm represent the minimum required flow rates of the turbine- and motor-driven AFW pumps at a SG back-pressure corresponding to the lowest SG safety valve set pressure, plus 3 percent for setpoint tolerance and 5 psi for accumulation.

Item II.E.1.2 - Auxiliary Feedwater System Initiation and Flows: The AFW system LCVs are normally open and require no actions for system operation. The AFW initiation circuitry is part of the ESF, and as such, is installed in accordance with IEEE 279-1971 (refer to Section 7.3) and meets the requirements of Item II.E.1.2.

6.5.3.22 Generic Letter 89-10, June 1989 - Safety Related Motor-Operated Valve Testing and Surveillance

The AFW system MOVs are subject to the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996, and meet the requirements of the DCPP MOV Program Plan.

6.5.4 TESTS AND INSPECTIONS

Refer to Sections 6.5.3.8 and 6.5.3.16

6.5.5 INSTRUMENTATION REQUIREMENTS

Refer to Sections 6.5.2.1.2, 6.5.3.4, 6.5.3.5, and 6.5.3.20.

6.5.6 REFERENCES

1. IEEE 279-1971, Criteria for Protection Systems for Nuclear Power Generating Stations.

2. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

3. DCPs C-50829 and C-049829, Condensate Storage Tank Modification to Add Plenums

4. PG&E Letter to the NRC, “Review of Systems and Equipment Necessary to Accomplish a Safe Shutdown Following a Major Earthquake,” dated January 26, 1978.

6.5.7 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

TABLE 6.1-1

APPLICABLE DESIGN BASIS CRITERIA

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
1. General Design Criteria										
Criterion 2, 1967	Performance Standards		X	X	X	X	X	X		X
Criterion 3, 1971	Fire Protection			X		X	X	X		X
Criterion 4, 1967	Sharing of Systems							X	X	X
Criterion 4, 1987	Environmental and Dynamic Effects Design Bases	X								
Criterion 10, 1967	Containment	X	X		X					
Criterion 11, 1967	Control Room		X	X	X	X	X	X		X
Criterion 12, 1967	Instrumentation and Control System		X	X	X	X	X	X		X
Criterion 15, 1967	Engineered Safety Features Protection Systems		X							
Criterion 17, 1967	Monitoring Radioactivity Releases					X		X		
Criterion 19, 1971	Control Room		X	X				X		
Criterion 21, 1967	Single Failure Definition		X	X	X		X			X
Criterion 37, 1967	Engineered Safety Features Basis for Design		X	X		X	X	X		X
Criterion 38, 1967	Reliability and Testability of Engineered Safety Features		X	X			X			X

TABLE 6.1-1

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
Criterion 40, 1967	Missile Protection		X	X	X		X			X
1. General Design Criteria (contd.)										
Criterion 41, 1967	Engineered Safety Features Performance Capability		X	X		X	X			X
Criterion 42, 1967	Engineered Safety Features Components Capability		X	X		X	X			
Criterion 43, 1967	Accident Aggravation Prevention						X			
Criterion 44, 1967	Emergency Core Cooling Systems Capability						X			
Criterion 45,1967	Inspection of Emergency Core Cooling Systems						X			
Criterion 46, 1967	Testing of Emergency Core Cooling Systems Components						X			
Criterion 47, 1967	Testing of Emergency Core Cooling Systems						X			
Criterion 48, 1967	Testing of Operational Sequence of Emergency Core Cooling Systems						X			
Criterion 49, 1967	Containment Design Basis	X	X			X	X			

TABLE 6.1-1

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
Criterion 52, 1967	Containment Heat Removal Systems		X							
1. General Design Criteria (contd.)										
Criterion 53, 1967	Containment Isolation Valves				X					
Criterion 54, 1967	Containment Leakage Rate Testing	X								
Criterion 54, 1971	Piping Systems Penetrating Containment		X		X	X	X			X
Criterion 55, 1967	Containment Periodic Leakage Rate Testing	X								
Criterion 55, 1971	Reactor Coolant Pressure Boundary Penetrating Containment				X		X			
Criterion 56, 1971	Primary Containment Isolation		X		X	X	X			
Criterion 57, 1971	Closed System Isolation Valves				X					X
Criterion 58, 1967	Inspection of Containment Pressure-Reducing Systems		X							

TABLE 6.1-1

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
Criterion 59, 1967	Testing of Containment Pressure-Reducing Systems		X							
1. General Design Criteria (contd.)										
Criterion 60, 1967	Testing of Containment Spray Systems		X							
Criterion 61, 1967	Testing of Operational Sequence of Containment Pressure-Reducing Systems Components		X							
Criterion 62, 1967	Inspection of Air Cleanup Systems		X	X						
Criterion 63, 1967	Testing of Air Cleanup Systems Components		X	X						
Criterion 64, 1967	Testing of Air Cleanup Systems		X	X						
Criterion 65, 1967	Testing of Operational Sequence of Air Cleanup Systems		X	X						
Criterion 70, 1967	Control of Releases of Radioactivity to the Environment		X	X						

TABLE 6.1-1

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
2. 10 CFR Part 20										
Part 20	Standards for Protection Against Radiation								X	
3. 10 CFR Part 50										
50.44	Combustible Gas Control for Nuclear Power Reactors					X				
50.46	Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Plants						X			
50.47	Emergency Plans								X	
50.48(c)	National Fire Protection Association Standard NFPA 805		X		X		X	X		X
50.49	Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants		X			X	X			X
50.55a(f)	Inservice Testing Requirements		X	X		X	X			X
50.55a(g)	Inservice Inspection Requirements		X	X		X	X			X

TABLE 6.1-1

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
50.62	Requirements of Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants									X
50.63	Loss of All Alternating Current Power									X
3. 10 CFR Part 50 (contd.)										
Appendix J, Option B	Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors	X			X					
Appendix K, Part I.A	ECCS Evaluation Models, Sources of Heat during the LOCA	X								
4. Atomic Energy Commission (AEC) Safety Guides										
Safety Guide 1, November 1970	Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps						X			

TABLE 6.1-1

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
5. Regulatory Guides										
Regulatory Guide 1.7, Revision 2, November 1978	Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident					X				
Regulatory Guide 1.52, Revision 0, June 1973	Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants							X		
Regulatory Guide 1.78, June 1974	Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release							X		

TABLE 6.1-1

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
Regulatory Guide 1.79, June 1974	Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors						X			
Regulatory Guide 1.97, Revision 3, May 1983	Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident		X			X	X	X		X
5. Regulatory Guides (contd.)										
Regulatory Guide 1.163, September 1995	Performance-Based Containment Leak-Test Program	X			X					
Regulatory Guide 1.183, July 2000	Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors			X						
Regulatory Guide 1.197, Revision 0, May 2003	Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors							X		
6. NRC NUREG										

TABLE 6.1-1

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
NUREG-0737, November 1980	Clarification of TMI Action Plan Requirements		X		X	X	X	X	X	X
7. NRC Generic Letters										
Generic Letter 89-10, June 1989	Safety-Related Motor-Operated Valve Testing and Surveillance		X	X	X	X	X			X
Generic Letter 95-07, August 1995	Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves						X			
7. NRC Generic Letters (contd.)										
Generic Letter 96-06, September 1996	Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions				X		X			

TABLE 6.1-1

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
Generic Letter 97-04, October 1997	Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps		X				X			
Generic Letter 98-04, July 1998	Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System after a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment						X			
7. NRC Generic Letters (contd.)										
Generic Letter 2003-01, June 2003	Control Room Habitability							X		

TABLE 6.1-1

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
Generic Letter 2004-02, September 2004	Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-Water Reactors						X			
Generic Letter 2008-01, January 2008	Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems						X			

8. Bulletins

TABLE 6.1-1

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
IE Bulletin 79-06A, April 1979	Review of Operational Errors and System Misalignments Identified During the Three Mile Island Incident						X			
IE Bulletin 80-18, July, 1980	Maintenance of Adequate Minimum Flow Thru Centrifugal Charging Pumps Following Secondary Side High Energy Line Rupture						X			
NRC Bulletin 88-04, May 1988	Potential Safety-Related Pump Loss						X			
NRC Bulletin 88-08, June 1988	Thermal Stresses in Piping Connected to Reactor Coolant Systems						X			
NRC Bulletin 2003-01, June 2003	Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized-Water Reactors						X			
9. Branch Technical Position										

TABLE 6.1-1

CRITERIA	TITLE	APPLICABILITY								
Engineered Safety Features		Containment Functional Design	Containment Heat Removal Systems	Containment Air Purification and Cleanup Systems	Containment Isolation System	Combustible Gas Control in Containment	Emergency Core Cooling System	Control Room Habitability System	Technical Support Center Habitability System	Auxiliary Feedwater System
Section		6.2.1	6.2.2	6.2.3	6.2.4	6.2.5	6.3	6.4.1	6.4.2	6.5
Branch Technical Position EICSB 18, November 1975	Application of the Single Failure Criterion to Manually-Controlled Electrically-Operatred Valves						X			

TABLE 6.2-25

CONTAINMENT HEAT REMOVAL SYSTEMS DESIGN CODE REQUIREMENTS

Component	Code
Valves	ANSI B16.5-1968
Piping (including headers and spray nozzles)	
- PG&E Design Class I portions	ANSI B31.7-1969 with 1970 Addenda
- PG&E Design Class II portions	ANSI B31.1-1967
Containment Spray Pump	ASME P&V III-1968[a]
Refueling Water Storage Tank	AWWA D100-1967[b]

(a) Draft ASME Code for Pumps and Valves for Nuclear Power, November 1968.

(b) ASME BPVC Section VIII-1974, Allowable Stresses Used for Design

TABLE 6.2-26

CONTAINMENT HEAT REMOVAL SYSTEMS DESIGN PARAMETERS

Containment Spray Pump	
Type	Horizontal Centrifugal
Number (per unit)	2
Design pressure, psig	275[c]
Design temperature, °F	275[c]
Design flowrate, gpm	2600
Design head, ft	450
Material	Type 316 stainless steel
Containment Spray Nozzle	
Number (per unit)	343 (Unit 1)/ 342 (Unit 2)
Type	Spraco 1713A
Flow per nozzle at 40 psi Δp, gpm	15.2
Material	Type 304 stainless steel
Refueling Water Storage Tank	
Number (per unit)	1
Total available tank volume (includes only usable volume)[a], gal	450,000
Minimum Technical Specifications required volume (includes usable and unusable volume), gal	455,300
Accident analysis volume (assumed), gal	350,000
Boron concentration, ppm	2300-2500
Design temperature, °F	100
Design pressure, psig	Atmospheric
Operating pressure, psig	Atmospheric
Material	Austenitic stainless steel with reinforced concrete shroud
Containment Fan Coolers	
Number (per unit)	5
Fan type	Centrifugal
Bearing monitors	Vibration

TABLE 6.2-26

Containment Fan Coolers (Continued)	Normal Mode Operation[b]	Accident Mode Operation[b]
Speed, rpm	1,200	600
Capacity, cfm	110,000	47,000
Static pressure at 0.075 lb/ft^3, in. water	7.3	3.75
Containment atmosphere pressure, psig	0	47
Containment atmosphere temperature, °F	120	271
Containment atmosphere density, lb/ft^3	0.0685	0.175
Brake horsepower	275	103
Name plate horsepower	300	100
Component cooling water flow to motor heat exchanger, gpm	50	30 (min)
Motor Assembly		
Number (per unit)	5	
Type	460 V, 3 phase, 60 Hz, two speed, single winding	
Bearing monitor	Vibration and temperature	
Winding monitor	RTDs	
Service factor	1	
Heat exchange cooling media	Component cooling water	
Cooling Coil Assembly		
Number (per unit)	5	
Type	Plate-finned	
Tube material		
Westinghouse coils	Copper	
SRC coils	Copper-Nickel	
Fin material	Copper	
Fins per inch		
Westinghouse coils	8.5	
SRC coils	6.5	
Tube thickness, in.	0.035	
Fin thickness, in.		
Westinghouse coils	0.008	
SRC coils	0.0075	
Tube normal OD, in.	0.625	
Tube length, in.	114	
Vertical drain pan spacing, ft	3.25	
Pan drain diameter, in.	2	
Assembly drain diameter, in.	8	
Drain pipe, Sch	10	

TABLE 6.2-26

Assembly frame material	
Westinghouse coils	Steel
SRC coils	Stainless Steel (304L)
Drain pan material	
Westinghouse coils	Steel
SRC coils	Stainless Steel (304L)

TABLE 6.2-26

Containment Fan Coolers (Continued)[d]

	Normal Operation[b]	Accident Mode Operation[b]
Heat removal minimum, Btu/hr		
Westinghouse coils[d]	3.14×10^6 (at 110,000cfm)	81×10^6 (at 47,000cfm)
SRC coils[e]	2.501×10^6 (98,000cfm)	75.489×10^6 (37,000cfm)
Steam-air flow, cfm		
Westinghouse coils[d]	110,000	47,000
SRC coils[e]	98,000	37,000
Steam-air inlet temperature, °F	120	271
Steam-air outlet temperature, °F		
Westinghouse coils[d]	92.5	269
SRC coils[e]	95.2	261
Total pressure, psig	0	47
Air density, lb/ft^3	0.0685	0.0677
Steam density, lb/ft^3	-	0.1073
Condensation rate, gpm		
Westinghouse coils[d]	0	180.7
SRC coils[e]	0	168.4
Air face velocity, fpm		
Westinghouse coils[d]	645	275
SRC coils[e]	625	236
Static pressure drop (0.075 lb/ft^3), in. water		
Westinghouse coils[d]	2.0	0.3 clean, 0.74 dirty
SRC coils[e]	0.87	0.46
Cooling water flow, gpm	2000	2000
Cooling water inlet temperature, °F	90	125
Cooling water outlet temperature, °F		
Westinghouse coils[d]	94	212
SRC coils[e]	92.5	201.4
Pressure drop, ft water		
Westinghouse coils[d]	8.8	8.8
SRC coils[e]	3.5	3.5
Coil tube side foul factor	0.0005	0.0005
Water velocity, fps		
Westinghouse coils[d]	3.43	3.43
SRC coils[e]	4.5	4.5

The moisture separator and HEPA filter were deleted in Revision 9.

(a) Usable volume includes the water above the outlet pipe. Unusable water includes the water below the outlet.

(b) CFCU data are shown for an illustration of performance at typical operating points. Design minimum CCW flow to the CFCU cooling coils is nominally 1600 gpm for both normal and limiting accident modes. Design maximum CCW flow to the CFCU cooling coils is 2500 gpm for accident modes. Temperatures, heat removal rates, and other parameters will vary dynamically according to the accident conditions.

(c) Specified values for containment spray pump design pressure and temperature are maximum values and do not designate concurrent design conditions for the pump.

(d) Values for CFCUs with Westinghouse Sturtevant coils are historical and for normal mode operation are based off a maximum flow of 110,000 CFM. Values for accident mode operation are based off a flow rate of 47,000 CFM. The operating values depend on the operating point in the acceptable range of airflow rates for both modes. Under normal conditions the range is 68,000-110,000 CFM, under accident conditions the range of airflow rates is 34,000-57,000 CFM. At airflow rates less than 47,000 CFM, the heat removal performance is still acceptable (See Westinghouse Calc. Note CN-CRA-12-5).

(e) Values for the SRC cooling coils CFCU are based on a maximum flow of 98,000 cfm for normal mode operation and a minimum flow of 37,000 cfm for accident mode operation. The operating values depend on the operating point in the acceptable range of airflow for both modes. Under normal conditions the range is 74,000 – 98,000 cfm, under accident conditions the range of airflow is 37,000 cfm – 49,000 cfm.

TABLE 6.2-27

SINGLE FAILURE ANALYSIS - CONTAINMENT HEAT REMOVAL SYSTEMS

Component	Malfunction	Comments and Consequences
A. Spray Nozzles	Clogged	Large number of nozzles precludes clogging of a significant number.
B. Pumps		
Containment spray pump	Fails to start	Two pumps provided. Operation of one required.
C. Automatically Operated Valves: (9001A/B): (Open on coincidence of two out of four high-high containment pressure signals)		
Containment spray pump discharge isolation valve	Fails to open	Two complete systems provided. Operation of one required.
D. Valves Operated From Control Room for Spray Recirculation, if Used (9003A/B):		
Containment spray header isolation valve from residual heat exchanger discharge	Fails to open	Two complete systems provided. Operation of spray recirculation not required.
E. Containment Fan Coolers	Fails to start	Five fan coolers provided. Two required for minimum safety feature operation.

TABLE 6.2-29

SPRAY ADDITIVE SYSTEM DESIGN PARAMETERS

Eductors	
Quantity	2
Eductor Inlet (motive)	
Operating fluid	Borated Water
Operating temperature	Ambient
Eductor Suction fluid	
NaOH concentration, wt%	30
Specific gravity	~ 1.3
Viscosity (design), cp	~ 10
Operating temperature	Ambient
Spray Additive Tank	
Number	1
Total Volume (nominal), gal.	4000
NaOH Concentration, wt%	30
Design Temperature, °F	300
Internal Design Pressure, psig	14
Operating Temperature, °F	100
Operating Pressure, psig	5[(a)]
Material	Stainless Steel

(a) During normal operating and test conditions, the tank is pressurized with nitrogen at 5 psig. During preoperational testing or following a postulated accident, the nitrogen supply system will supply sufficient nitrogen to maintain this pressure as the tank empties. In the postulated event that the nitrogen supply system is inoperative, the tank pressure would fall below atmospheric pressure as the tank empties. Vacuum breakers are provided for this occurrence.

TABLE 6.2-30

SPRAY ADDITIVE SYSTEM - CODES USED IN SYSTEM DESIGN

Spray Additive Tank	ASME B&PV, Section VIII Code Class 3
Valves	ANSI B16.5
Piping (including headers and spray nozzles)	
Design Class I portions	ANSI B31.7
Design Class II portions	ANSI B31.1
Eductors	ASME B&PV, Section III

TABLE 6.2-32

LOSS-OF-COOLANT ACCIDENT
TOTAL ELEMENTAL IODINE & PARTICULATE REMOVAL COEFFICIENTS

<table>
<tr><th rowspan="2">From Time (sec)</th><th rowspan="2">To Time (sec)</th><th colspan="2">Elemental Iodine Removal Coefficient (hr^{-1}) – Note 1</th><th colspan="2">Particulate Removal Coefficient (hr^{-1})</th></tr>
<tr><th>Sprayed Region</th><th>Unsprayed Region</th><th>Sprayed Region</th><th>Unsprayed Region</th></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>0</td><td>30</td><td rowspan="2">2.74</td><td rowspan="2">2.74</td><td>N/A</td><td>N/A</td></tr>
<tr><td>30</td><td>111</td><td>5.89</td><td>0.0062</td></tr>
<tr><td>111</td><td>1,800</td><td rowspan="2">20.57 (Note 2)</td><td rowspan="10">0.00</td><td>2.24</td><td>0.0071</td></tr>
<tr><td>1,800</td><td>3,798</td><td>9.35</td><td>0.1144</td></tr>
<tr><td>3,798</td><td>4,518</td><td>0.00 (Note 3)</td><td>1.02</td><td>0.1229</td></tr>
<tr><td>4,518</td><td>5,030</td><td rowspan="7">19.91 (Note 2)</td><td>7.50</td><td>0.1239</td></tr>
<tr><td>5,030</td><td>6,480</td><td>6.40</td><td>0.1237</td></tr>
<tr><td>6,480</td><td>7,200</td><td>4.74</td><td>0.1236</td></tr>
<tr><td>7,200</td><td>8,004</td><td>3.39</td><td>0.1222</td></tr>
<tr><td>8,004</td><td>22,152</td><td rowspan="2">1.53</td><td>0.1040</td></tr>
<tr><td>22,152</td><td>22,518</td><td rowspan="2">0.00</td></tr>
<tr><td>22,518</td><td>720 hrs</td><td>0.00</td><td>0.00 (Note 4)</td></tr>
</table>

Notes:

1. Per Regulatory Guide 1.183, July 2000, and SRP 6.5.2, Revision 4, removal credit for elemental iodine by sprays is eliminated after a DF=200 is reached in the containment atmosphere.
2. Wall deposition removal coefficient (0.57 hr^{-1}) is included.
3. Time period without spray.
4. For purposes of conservatism, no credit is taken for particulate removal in the sprayed region after termination of recirculation spray.

TABLE 6.2-33

LOSS-OF-COOLANT ACCIDENT
CONTAINMENT PRESSURE, TEMPERATURE & RELATIVE HUMIDITY DATA

Post-LOCA Time	Containment Pressure	Containment Temperature	Containment - RH
Seconds	psia	°F	%
0.00	16.00	120	18
0.52	18.81	145.9	72.3
1.04	21.45	163.8	88.2
1.54	23.76	176.78	93.5
2.04	25.88	186.8	96
2.54	27.80	194.83	97.4
3.04	29.44	201.03	98.1
3.54	30.86	205.97	98.5
4.04	32.10	210.01	98.9
4.54	33.21	213.43	99.1
5.04	34.24	216.47	99.2
7.04	38.04	226.75	99.5
7.54	38.96	229.03	99.5
8.54	40.68	233.06	99.6
10.04	43.06	238.34	99.7
10.54	43.81	239.9	99.7
11.54	45.21	242.76	99.8
13.04	47.12	246.47	99.8
14.54	48.82	249.65	99.8
16.04	50.36	252.4	99.9
17.54	51.70	254.7	99.9
19.04	52.87	256.67	99.9
20.54	53.88	258.34	99.9
21.54	54.24	258.9	99.9
22.04	54.36	259.08	100
23.54	54.48	259.25	100
25.04	54.40	259.12	100
29.54	53.87	258.24	100
32.54	53.62	257.85	100
48.54	53.14	257.02	100
54.54	53.37	257.03	100
68.04	53.70	256.79	100
86.54	53.18	255.93	100
144.18	50.88	251.95	100
158.18	50.44	251.15	100

TABLE 6.2-33

LOSS-OF-COOLANT ACCIDENT
CONTAINMENT PRESSURE, TEMPERATURE & RELATIVE HUMIDITY DATA

Post-LOCA Time	Containment Pressure	Containment Temperature	Containment - RH
Seconds	psia	°F	%
188.18	49.70	249.82	100
200.18	49.48	249.41	100
212.18	49.33	249.15	100
266.18	49.21	248.92	100
333.18	49.37	249.2	100
400.18	49.70	249.82	99.9
534.18	50.56	251.76	99.1
668.18	51.49	254.34	97.4
803.18	52.60	256.32	97.3
816.18	52.43	255.22	98.7
857.18	52.08	254.17	99.5
912.18	51.73	253.6	99.4
1021.19	51.21	252.76	99.3
1131.19	50.83	252.11	99.2
1240.19	50.55	251.61	99.1
1458.19	50.16	250.91	99
1677.19	49.94	250.49	98.9
1730.19	50.43	251.61	98.5
1746.19	50.26	250.56	99.9
1859.19	49.41	248.91	100
1988.19	48.57	247.32	100
2247.19	47.07	244.4	100
2505.19	45.75	241.75	100
2764.19	44.56	239.29	100
3022.19	43.47	236.96	99.9
3281.19	42.45	234.71	99.8
3604.24	41.26	231.94	99.9
3798.24	40.10	229.1	100
3888.29	40.52	230.99	98.2
3978.29	40.92	233.84	94.6
4068.29	41.24	235.73	92.5
4158.29	41.48	237.00	91.3
4338.29	41.86	238.43	90.3
4518.29	42.13	239.07	90.3
4536.29	42.05	237.81	92.2
4555.29	41.94	235.91	95.2

TABLE 6.2-33

LOSS-OF-COOLANT ACCIDENT
CONTAINMENT PRESSURE, TEMPERATURE & RELATIVE HUMIDITY DATA

Post-LOCA Time	Containment Pressure	Containment Temperature	Containment - RH
Seconds	psia	°F	%
4573.29	41.87	234.69	97.2
4592.29	41.82	233.97	98.4
4666.29	41.74	233.23	99.5
5110.73	41.37	232.3	99.6
5700.73	40.79	230.94	99.6
6890.73	39.55	227.94	99.6
8080.73	38.36	224.96	99.5
10000.80	36.64	220.36	99.4
11001.50	35.82	218.08	99.4
12001.50	35.08	215.93	99.4
13001.50	34.39	213.85	99.4
14001.50	33.74	211.85	99.4
15001.50	33.13	209.91	99.4
16001.50	32.57	208.07	99.3
18001.50	31.59	204.69	99.3
20001.50	30.71	201.53	99.3
21001.50	30.31	200.06	99.3
22518.00	29.78	198.01	99.4

TABLE 6.2-34

LOSS-OF-COOLANT ACCIDENT
CONTAINMENT STEAM CONDENSTION DATA

Post-LOCA Time	Steam Condensation Rate					
	Thermal Conductor	Containment Fan Coolers	Injection Spray	Recirculation Spray	Total Steam Condensation Rate	
Seconds	lbm/sec	lbm/sec	lbm/sec	lbm/sec	lbm/sec	g/sec
0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.52	8.37	0.00	0.00	0.00	8.37	3796.57
1.04	49.71	0.00	0.00	0.00	49.71	22548.08
2.54	204.71	0.00	0.00	0.00	204.71	92854.90
3.04	250.47	0.00	0.00	0.00	250.47	113611.29
3.54	290.16	0.00	0.00	0.00	290.16	131614.37
4.04	325.28	0.00	0.00	0.00	325.28	147544.54
5.04	384.15	0.00	0.00	0.00	384.15	174247.52
7.54	509.97	0.00	0.00	0.00	509.97	231318.52
10.04	611.01	0.00	0.00	0.00	611.01	277149.49
12.54	684.86	0.00	0.00	0.00	684.86	310647.29
15.04	734.83	0.00	0.00	0.00	734.83	333313.30
17.54	766.16	0.00	0.00	0.00	766.16	347524.35
20.54	783.18	0.00	0.00	0.00	783.18	355244.50
24.54	742.58	0.00	0.00	0.00	742.58	336828.64
28.54	684.40	0.00	0.00	0.00	684.40	310438.64
32.54	644.28	0.00	0.00	0.00	644.28	292240.51
37.04	623.09	0.00	0.00	0.00	623.09	282628.89
53.54	538.96	0.00	0.00	0.00	538.96	244468.16
70.04	469.30	0.00	0.00	0.00	469.30	212870.91
87.04	412.48	0.00	0.00	0.00	412.48	187097.79
87.57	410.75	44.28	0.00	0.00	455.03	206398.15
88.07	409.15	45.29	0.00	0.00	454.44	206130.53
107.14	354.70	44.87	13.61	0.00	413.18	187415.31
124.18	312.19	44.28	72.76	0.00	429.23	194695.47
146.18	267.97	43.51	70.37	0.00	381.85	173204.26
169.18	231.50	42.78	68.46	0.00	342.74	155464.26
197.18	197.26	41.97	66.66	0.00	305.89	138749.38
234.18	166.95	41.32	49.25	0.00	257.52	116809.11
262.18	149.95	41.00	48.48	0.00	239.43	108603.63
327.18	121.98	40.50	47.28	0.00	209.76	95145.54
403.18	100.43	40.23	46.58	0.00	187.24	84930.64
449.18	91.02	40.17	46.66	0.00	177.85	80671.41
502.18	82.32	40.11	47.29	0.00	169.72	76983.70

TABLE 6.2-34

LOSS-OF-COOLANT ACCIDENT
CONTAINMENT STEAM CONDENSTION DATA

Post-LOCA Time	Steam Condensation Rate					
	Thermal Conductor	Containment Fan Coolers	Injection Spray	Recirculation Spray	Total Steam Condensation Rate	
Seconds	lbm/sec	lbm/sec	lbm/sec	lbm/sec	lbm/sec	g/sec
558.18	74.79	40.09	48.64	0.00	163.52	74171.43
560.18	74.55	40.08	48.66	0.00	163.29	74067.10
629.18	67.45	40.12	47.87	0.00	155.44	70506.40
683.18	63.43	40.22	47.23	0.00	150.88	68438.02
754.18	59.41	40.45	47.01	0.00	146.87	66619.12
802.18	57.28	40.64	46.99	0.00	144.91	65730.07
832.18	49.92	40.37	57.62	0.00	147.91	67090.85
876.18	43.40	40.00	58.41	0.00	141.81	64323.94
937.18	37.29	39.57	57.66	0.00	134.52	61017.25
1013.19	32.26	39.16	56.94	0.00	128.36	58223.12
1094.19	28.58	38.82	56.39	0.00	123.79	56150.20
1148.19	26.76	38.64	56.09	0.00	121.49	55106.94
1243.19	24.16	38.39	55.68	0.00	118.23	53628.23
1341.19	22.03	38.19	55.34	0.00	115.56	52417.14
1423.19	20.55	38.07	55.11	0.00	113.73	51587.06
1492.19	19.48	37.98	54.94	0.00	112.40	50983.79
1564.19	18.50	37.90	54.79	0.00	111.19	50434.94
1607.19	17.97	37.86	54.72	0.00	110.55	50144.64
1644.19	17.54	37.83	54.66	0.00	110.03	49908.77
1672.19	17.23	37.81	54.61	0.00	109.65	49736.41
1678.19	17.19	37.71	54.73	0.00	109.63	49727.33
1730.19	19.93	36.37	52.72	0.00	109.02	49450.64
1794.19	16.03	35.05	60.34	0.00	111.42	50539.27
1859.19	14.01	33.89	60.13	0.00	108.03	49001.59
1985.19	11.88	32.19	59.74	0.00	103.81	47087.43
2052.19	11.05	31.50	59.53	0.00	102.08	46302.71
2116.19	10.33	30.96	59.34	0.00	100.63	45645.00
2244.19	9.09	30.09	58.96	0.00	98.14	44515.56
2311.19	8.50	29.72	58.76	0.00	96.98	43989.39
2439.19	7.47	29.12	58.40	0.00	94.99	43086.74
2567.19	6.53	28.62	57.93	0.00	93.08	42220.38
2695.19	5.66	28.19	57.37	0.00	91.22	41376.70
2763.19	5.23	27.94	57.08	0.00	90.25	40936.71
2890.19	4.47	27.51	56.53	0.00	88.51	40147.46
3018.19	3.76	27.11	56.00	0.00	86.87	39403.57

TABLE 6.2-34 Sheet 3 of 3

LOSS-OF-COOLANT ACCIDENT
CONTAINMENT STEAM CONDENSTION DATA

Post-LOCA Time	Steam Condensation Rate					
	Thermal Conductor	Containment Fan Coolers	Injection Spray	Recirculation Spray	Total Steam Condensation Rate	
Seconds	lbm/sec	lbm/sec	lbm/sec	lbm/sec	lbm/sec	g/sec
3082.19	3.43	26.92	55.74	0.00	86.09	39049.77
3210.19	2.80	26.56	55.23	0.00	84.59	38369.38
3338.19	2.21	26.22	54.74	0.00	83.17	37725.28
3466.19	1.64	25.89	54.25	0.00	81.78	37094.79
3594.19	1.12	25.58	53.78	0.00	80.48	36505.12
3722.24	0.24	25.02	54.13	0.00	79.39	36010.70
3796.24	0.02	24.72	53.61	0.00	78.35	35538.96
3843.29	2.24	24.91	0.00	0.00	27.15	12315.03
3901.29	4.39	25.13	0.00	0.00	29.52	13390.05
3995.29	6.72	25.42	0.00	0.00	32.14	14578.46
4105.29	8.33	25.70	0.00	0.00	34.03	15435.75
4189.29	9.21	25.87	0.00	0.00	35.08	15912.02
4291.29	10.03	26.06	0.00	0.00	36.09	16370.15
4383.29	10.63	26.21	0.00	0.00	36.84	16710.34
4463.29	11.06	26.33	0.00	0.00	37.39	16959.82
4515.29	11.25	26.41	0.00	0.00	37.66	17082.29
4518.29	11.26	26.41	0.00	0.92	38.59	17504.13
4584.29	10.17	26.48	0.00	8.26	44.91	20370.83
4592.29	10.15	26.49	0.00	9.02	45.66	20711.03
4654.29	10.18	26.55	0.00	11.12	47.85	21704.40
4698.29	10.19	26.59	0.00	11.33	48.11	21822.33
4734.29	10.21	26.60	0.00	11.39	48.20	21863.15
4785.29	10.19	26.62	0.00	11.43	48.24	21881.30
4807.29	10.17	26.63	0.00	11.44	48.24	21881.30
4843.29	10.14	26.63	0.00	11.46	48.23	21876.76
4851.29	10.13	26.64	0.00	11.46	48.23	21876.76
4895.29	10.09	26.64	0.00	11.48	48.21	21867.69
4926.29	10.05	26.64	0.00	11.49	48.18	21854.08
4932.29	10.06	26.63	0.00	11.49	48.18	21854.08
4988.29	9.99	26.63	0.00	11.51	48.13	21831.40
6120.73	8.70	25.98	0.00	11.43	46.11	20915.15
7400.73	7.52	25.02	0.00	11.13	43.67	19808.38
8680.73	6.51	24.04	0.00	10.86	41.41	18783.26
9510.73	6.06	23.47	0.00	10.70	40.23	18248.02
14001.50	4.42	20.91	0.00	9.98	35.31	16016.35
18001.50	3.69	18.95	0.00	9.59	32.23	14619.28
22518.00	3.23	17.41	0.00	9.27	29.91	13566.95

TABLE 6.2-35

PARAMETERS FOR FISSION PRODUCT REMOVAL ANALYSIS

Parameter	Value
Total Containment Volume, ft^3	2.55×10^6
Containment Spray Coverage Fraction	0.825
Average Spray Fall Height, ft	116 (Note 1)
Spray Flow Rate, gpm	2,456 for 111 sec ≤ t ≤ 3,798 sec 0 for 3,798 sec < t ≤ 4,518 sec 1,211 for 4,518 sec < t ≤ 22,518 sec
Spray Droplet Radius, cm	500×10^{-4}

Note 1: The average fall height is conservatively approximated as the distance from the lowest spray header to the operating deck as follows:

Elevation of Header #1 = 256'-0"
Elevation of Deck = 140'-0"
Fall Height to the Deck = 116'-0"

Note that this fall height is more conservative than the area-weighted average drop fall height of 128 ft shown in Table 6.2-37.

TABLE 6.2-37

SPRAY FALL HEIGHTS IN THE CONTAINMENT

Area[a], ft^2	Drop Fall Height[b], ft
1,075	58
1,400	93
100	105
225	122
9,900	128
150	145
2,550	177

(a) Area represents portion of operating deck covered by spray nozzles located at a particular elevation above the operating deck.

(b) Measured from 268 ft minimum average nozzle elevation. Average spray fall height: 128 ft.

TABLE 6.2-38

SPRAY ADDITIVE SYSTEM SINGLE FAILURE ANALYSIS

Component	Malfunction	Comments and Consequences
Automatically Operated Valves: (Open on coincidence of two-out-four high-high signals)		
Spray additive tank outlet isolation valve	Fails to open	Two parallel provided (8994A/B). Operation of one required.

TABLE 6.2-39

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
1	Feedwater	57	Yes	1 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	(NE/SA)				A	FW-FCV-438	Gte	Mtr	O	C	Yes	O	As is	F	N	C	W	Hot	1,26
					B	FW-140	Gte	Man	O	D	No	O	As is	-	Y	O	W	Hot	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Hot	2
2	Feedwater	57	Yes	1 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	(NE/SA)				A	FW-FCV-439	Gte	Mtr	O	C	Yes	O	As is	F	N	C	W	Hot	1,26
					B	FW-147	Gte	Man	O	D	No	O	As is	-	Y	O	W	Hot	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Hot	2
3	Feedwater	57	Yes	1 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	(NE/SA)				A	FW-FCV-440	Gte	Mtr	O	C	Yes	O	As is	F	N	C	W	Hot	1,26
					B	FW-153	Gte	Man	O	D	No	O	As is	-	Y	O	W	Hot	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Hot	2
4	Feedwater	57	Yes	1 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	(NE/SA)				A	FW-FCV-441	Gte	Mtr	O	C	Yes	O	As is	F	N	C	W	Hot	1,26
					B	FW-157	Gte	Man	O	D	No	O	As is	-	Y	O	W	Hot	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Hot	2
5	Main steam	57	Yes	1 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	(NE/SA)				E	MS-FCV-41	-	Air	O	C	Yes	O	As is	M	N	C	G	Hot	3,4,26
					F	MS-FCV-25	Glb	Air	O	C	Yes	C	Closed	M	N	C	G	Hot	4,26
					G	MS-PCV-19	Glb	Air	O	D	Yes	C	Closed	-	N	C	G	Hot	5,26
					H	MS-RV-3, 4, 5, 6, 222	Rlf	Spr	O	D	No	C	-	-	N	C	G	Hot	6,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	G	Hot	2
6	Main steam	57	Yes	2 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	(NE/SA)				A	MS-FCV-42	-	Air	O	C	Yes	O	As is	M	N	C	G	Hot	3,4,26
					B	MS-FCV-24	Glb	Air	O	C	Yes	C	Closed	M	N	C	G	Hot	4,26
					C	MS-PCV-20	Glb	Air	O	D	Yes	C	Closed	-	N	C	G	Hot	5,26
					D	MS-RV-7, 8, 9, 10, 223	Rlf	Spr	O	D	No	C	-	-	N	C	G	Hot	6,26
					E	MS-FCV-37	Gte	Mtr	O	D	Yes	O	As is	R-M	Y	O	G	Hot	26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	G	Hot	2
7	Main steam	57	Yes	2 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	(NE/SA)				A	MS-FCV-43	-	Air	O	C	Yes	O	As is	M	N	C	G	Hot	3,4,26
					B	MS-FCV-23	Glb	Air	O	C	Yes	C	Closed	M	N	C	G	Hot	4,26
					C	MS-PCV-21	Glb	Air	O	D	Yes	C	Closed	-	N	C	G	Hot	5,26
					D	MS-RV-11,12,13,14,224	Rlf	Spr	O	D	No	C	-	-	N	C	G	Hot	6,26

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
					E	MS-FCV-38	Gte	Mtr	O	D	Yes	O	As is	R-M	Y	O	G	Hot	26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	G	Hot	2
8	Main steam (NE/SA)	57	Yes	1 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					E	MS-FCV-44	-	Air	O	C	Yes	O	As is	M	N	C	G	Hot	3,4,26
					F	MS-FCV-22	Glb	Air	O	C	Yes	C	Closed	M	N	C	G	Hot	4,26
					G	MS-PCV-22	Glb	Air	O	D	Yes	C	Closed	-	N	C	G	Hot	5,26
					H	MS-RV-58,59,60,61,225	Rlf	Spr	O	D	No	C	-	-	N	C	G	Hot	6,26
					-	Closed System	Cls	-	I	D	-	-	-	-	N	-	G	Hot	2
9	Component Cooling Water to Fan Coolers (SA)	57	Yes	3 (V)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
					H	CCW-169	But	Man	O	D	No	O	As is	-	Y	O	W	Cold	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Cold	47
10	Component Cooling Water to Fan Coolers (SA)	57	Yes	3 (V)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
					H	CCW-177	But	Man	O	D	No	O	As is	-	Y	O	W	Cold	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Cold	47
11	Component Cooling Water to Fan Coolers (SA)	57	Yes	3 (V)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
					H	CCW-469	But	Man	O	D	No	O	As is	-	Y	O	W	Cold	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Cold	47
12	Component Cooling Water to Fan Coolers (SA)	57	Yes	3 (V)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
					H	CCW-477	But	Man	O	D	No	O	As is	-	Y	O	W	Cold	7,26

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Cold	47
13	Component Cooling Water to Fan Coolers (SA)	57	Yes	3 (V)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
					H	CCW-185	But	Man	O	D	No	O	As is	-	Y	O	W	Cold	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Cold	47
14	Component Cooling Water from Fan Coolers (SA)	57	Yes	3 (VI)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
					I	CCW-176	But	Man	O	D	No	O	As is	-	Y	O	W	Cold	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Cold	47
15	Component Cooling Water from Fan Coolers (SA)	57	Yes	3 (VI)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
					I	CCW-184	But	Man	O	D	No	O	As is	-	Y	O	W	Cold	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Cold	47
16	Component Cooling Water from Fan Coolers (SA)	57	Yes	3 (VI)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
					I	CCW-476	But	Man	O	D	No	O	As is	-	Y	O	W	Cold	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Cold	47
17	Component Cooling Water from Fan Coolers	57	Yes	3 (VI)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
					I	CCW-484	But	Man	O	D	No	O	As is	-	Y	O	W	Cold	7,26

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
	(SA)																		
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Cold	47
18	Component Cooling Water from Fan Coolers (SA)	57	Yes	3 (VI)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
					I	CCW-192	But	Man	O	D	No	O	As is	-	Y	O	W	Cold	7,26
					-	Closed System	Cls	-	I	D	-	-	-	-	Y	-	W	Cold	47
19	Component Cooling Water to Reactor Coolant Pumps (ES)	55	Yes	4 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	CCW-FCV-356	But	Mtr	O	A	Yes	O	As is	P	N	C	W	Cold	-
					B	CCW-585	Chk	-	I	A	No	O	-	-	N	C	W	Cold	-
20	Component Cooling Water from Reactor Coolant Pumps (ES)	55	Yes	4 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					F	CCW-FCV-363	But	Mtr	O	A	Yes	O	As is	P	N	C	W	Cold	-
					E	CCW-FCV-749	But	Mtr	I	A	Yes	O	As is	P	N	C	W	Cold	-
					H	CCW-581	Chk	-	I	A	No	O	-	-	N	C	W	Cold	-
21	Component Cooling Water from Reactor Coolant Pumps (ES)	55	Yes	4 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					C	CCW-FCV-750	Glb	Mtr	I	A	Yes	O	As is	P	N	C	W	Hot	-
					D	CCW-FCV-357	Glb	Mtr	O	A	Yes	O	As is	P	N	C	W	Hot	-
					G	CCW-670	Chk	-	I	A	No	O	-	-	N	C	W	Hot	-
22	CCW to Excess Letdown	57	No	4 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8
					I	CCW-695	Chk	-	O	C	No	C	-	-	N	C	W	Cold	8

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
	Heat Exchanger (NE)				-	Closed System	Cls	-	I	C	-	-	-	-	N	-	W	Cold	-
23	CCW from Excess Letdown	57	Yes	4 (V)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					J	CCW-FCV-361	But	Air	O	C	Yes	C	Closed	T	N	C	W	Cold	-
	Heat Exchanger (NE)				-	Closed System	Cls	-	I	C	-	-	-	-	N	-	W	Cold	-
24	Residual Heat Removal No. 1 Cold Leg Injection (SA)	55	Yes	5 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	SI-8818A	Chk	-	I	B	No	C	-	-	Y	C	W	Hot	26
					B	SI-8818B	Chk	-	I	B	No	C	-	-	Y	C	W	Hot	26
					C	SI-8809A	Gte	Mtr	O	B	Yes	O	As is	R-M	Y	C	W	Hot	7,9,26,40
					M	SI-8885A (U1)	Glb	Air	I	E	-	C	Closed	-	N	C	W	Hot	22,26, 41
						Closed System	Cls	-	O	B	-	-	-	-	Y	-	W	Hot	10
25	Residual Heat Removal No. 2 Cold Leg Injection (SA)	55	Yes	5 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					I	SI-8818C	Chk	-	I	B	No	C	-	-	Y	C	W	Hot	26
					J	SI-8818D	Chk	-	I	B	No	C	-	-	Y	C	W	Hot	26
					K	SI-8885B (U1)	Glb	Air	I	E	-	C	Closed	-	N	C	W	Hot	22,26, 41
					L	SI-8809B	Gte	Mtr	O	B	Yes	O	As is	R-M	Y	C	W	Hot	7,9,26,40
					-	Closed System	Cls	-	O	B	-	-	-	-	Y	-	W	Hot	10
26	Residual Heat Removal Hot Leg Injection (SA)	55	Yes	5 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					D	RHR-8716A	Gte	Mtr	O	B	Yes	O	As is	R-M	Y	C	W	Hot	7,9,26,40
					G	RHR-8716B	Gte	Mtr	O	B	Yes	O	As is	R-M	Y	O	W	Hot	7,9,26,40
					H	RHR-8703	Gte	Mtr	I	B	Yes	C	As is	R-M	Y	O	W	Hot	7,11, 26
					-	Closed System	Cls	-	O	B	-	-	-	-	Y	-	W	Hot	10
27	Reactor	55	Yes	6 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
	Coolant System Loop 4 Recirculation (SA)				A	RHR-8701	Gte	Mtr	I	D	Yes	C	As is	R-M	N	C	W	Hot	7,11, 26
					H	RHR-1012	Glb	Man	O	D	No	C	-	-	N	C	W	Hot	11,26,45
					I	RHR-1014	Glb	Man	O	D	No	C	-	-	N	C	W	Hot	11,26,45
					B	SI-8980	Gte	Mtr	O	D	Yes	O	As is	R-M	Y	C	W	Hot	11,7, 26
					C	RHR-8700A	Gte	Mtr	O	D	Yes	O	As is	R-M	Y	C	W	Hot	11,7, 26
					D	RHR-8700B	Gte	Mtr	O	D	Yes	O	As is	R-M	Y	C	W	Hot	11,7, 26
28	Containment Sump Recirculation (SA)	56	Yes	6 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					E	SI-8982A	Gte	Mtr	O	D	Yes	C	As is	-	Y	O	W	Hot	12,26
					-	Closed System	Cls	-	O	D	-	-	-	-	Y	-	W	Hot	10
29	Containment Sump Recirculation (SA)	56	Yes	6 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					F	SI-8982B	Gte	Mtr	O	D	Yes	C	As is	-	Y	O	W	Hot	12,26
					-	Closed System	Cls	-	O	D	-	-	-	-	Y	-	W	Hot	10
30	Containment Spray System (SA)	56	Yes	7 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	CS-9011B	Chk	-	I	D	No	C	-	-	Y	C	W	Cold	-
					B	CS-9001B	Gte	Mtr	O	D	Yes	C	As is	R-M	Y	C	W	Cold	11,13
					C	CS-32	Glb	Man	O	E	No	C	-	-	N	C	W	Cold	
					D	CS-9003B	Gte	Mtr	O	D	Yes	C	As is	R-M	Y	C	W	Cold	7,11, 26,48
31	Containment Spray System (SA)	56	Yes	7 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					E	CS-9011A	Chk	-	I	D	No	C	-	-	Y	C	W	Cold	-
					F	CS-9003A	Gte	Mtr	O	D	Yes	C	As is	R-M	Y	C	W	Cold	7,11, 26,48
					G	CS-9001A	Gte	Mtr	O	D	Yes	C	As is	R-M	Y	C	W	Cold	11,13
					H	CS-31	Glb	Man	O	E	No	C	-	-	N	C	W	Cold	
32	Spare	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26
33	Safety	55	Yes	8 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
	Injection System (SA)				B	SI-8835	Gte	Mtr	O	D	Yes	O	As is	R-M	Y	C	W	Cold	7,11, 26
					G	SI-8823 (U1)	Glb	Air	I	E	-	C	Closed	-	N	C	W	Cold	22,26,41
34	Safety Injection System (SA)	55	Yes	8 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					D	SI-8801A, 8801B	Gte	Mtr	O	D	Yes	C	As is	S	Y	O	W	Cold	11,14,26
					I	SI-8969	Glb	Man	O	E	No	C	-	-	N	C	W	Cold	26,48
35	Regenerative Heat Exchanger to Letdown Heat Exchanger (NE)	55	Yes	9 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	CVCS-8149A	Glb	Air	I	A	Yes	O	Closed	T	N	C	W	Hot	-
					B	CVCS-8149B	Glb	Air	I	A	Yes	O	Closed	T	N	C	W	Hot	-
					C	CVCS-8149C	Glb	Air	I	A	Yes	O	Closed	T	N	C	W	Hot	-
					D	CVCS-8152	Glb	Air	O	A	Yes	O	Closed	T	N	C	W	Hot	-
36	Normal Charging to Regenerative Heat Exchanger (SA)	55	Yes	9 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34
					E	CVCS-8378C	Chk	-	I	A	No	O	-	-	N	C	W	Cold	26
					F	CVCS-8107	Gte	Mtr	O	A	Yes	O	As is	S	N	C	W	Cold	26
37	Steam Generator Blowdown (NE)	57	Yes	1 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					J	MS-FCV-151	Glb	Air	O	C	Yes	O	Closed	T	N	C	W	Hot	26,55
					I	MS-FCV-760	Glb	Air	I	C	Yes	O	Closed	M	N	C	W	Hot	2,4, 26,48
					-	Closed System	Cls	-	I	C	-	-	-	-	-	-	W	Hot	2
38	Steam Generator Blowdown (NE)	57	Yes	1 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					J	MS-FCV-154	Glb	Air	O	C	Yes	O	Closed	T	N	C	W	Hot	26,55
					I	MS-FCV-761	Glb	Air	I	C	Yes	O	Closed	M	N	C	W	Hot	2,4,

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
					-	Closed System	Cls	-	I	C	-	-	-	-	-	-	W	Hot	26,48 2
39	Steam Generator Blowdow n (NE)	57	Yes	1 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					J	MS-FCV-157	Glb	Air	O	C	Yes	O	Closed	T	N	C	W	Hot	26,55
					I	MS-FCV-762	Glb	Air	I	C	Yes	O	Closed	M	N	C	W	Hot	2,4, 26,48 2
					-	Closed System	Cls	-	I	C	-	-	-	-	-	-	W	Hot	
40	Steam Generator Blowdow n (NE)	57	Yes	1 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					J	MS-FCV-160	Glb	Air	O	C	Yes	O	Closed	T	N	C	W	Hot	26,55
					I	MS-FCV-763	Glb	Air	I	C	Yes	O	Closed	M	N	C	W	Hot	2,4, 26,48 2
					-	Closed System	Cls	-	I	C	-	-	-	-	-	-	W	Hot	
41	Reactor Coolant Pump Seal Water Supply (ES)	55	Yes	10 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	CVCS-8368A	Chk	-	I	B	No	O	-	-	Y	O	W	Cold	-
					-	Closed System	Cls	-	O	B	-	-	-	-	Y	-	W	Cold	10
42	Reactor Coolant Pump Seal Water Supply (ES)	55	Yes	10 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	CVCS-8368B	Chk	-	I	B	No	O	-	-	Y	O	W	Cold	-
					-	Closed System	Cls	-	O	B	-	-	-	-	Y	-	W	Cold	10
43	Reactor Coolant Pump Seal Water Supply (ES)	55	Yes	10 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	CVCS-8368C	Chk	-	I	B	No	O	-	-	Y	O	W	Cold	-
					-	Closed System	Cls	-	O	B	-	-	-	-	Y	-	W	Cold	10
44	Reactor Coolant	55	Yes	10 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
	Pump Seal Water Supply (ES)				A	CVCS-8368D	Chk	-	I	B	No	O	-	-	Y	O	W	Cold	-
					-	Closed System	Cls	-	O	B	-	-	-	-	Y	-	W	Cold	10
45	Reactor Coolant Pump Seal Water Return (NE)	55	Yes	10 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					B	CVCS-8112	Gte	Mtr	I	A	Yes	O	As is	T	N	C	W	Cold	-
					C	CVCS-8109	Chk	-	I	A	No	O	-	-	Y	O	W	Cold	-
					D	CVCS-8100	Gte	Mtr	O	A	Yes	O	As is	T	N	C	W	Cold	-
46	Refueling Canal Recirculation (NE)	56	Yes	3 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					C	LWS-8796	Dia	Man	I	E	No	C	-	-	N	C	W	Cold	-
					D	LWS-8787	Dia	Man	O	E	No	C	-	-	N	C	W	Cold	-
47	Refueling Canal Return (NE)	56	Yes	3 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					F	LWS-8795	Dia	Man	I	E	No	C	-	-	N	C	W	Cold	-
					G	LWS-8767	Dia	Man	O	E	No	C	-	-	N	C	W	Cold	-
48	Spare	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26
49	Containment Sump Discharge (NE)	56	Yes	3 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	LWS-FCV-500	Bal	Air	I	A	Yes	O	Closed	T	N	C	W	Cold	56
					B	LWS-FCV-501	Bal	Air	O	A	Yes	O	Closed	T	N	C	W	Cold	-
50	Reactor Coolant Drain Tank Discharge (NE)	56	Yes	12 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					G	LWS-FCV-254	Bal	Air	O	A	Yes	O	Closed	T	N	C	W	Hot	-
					H	LWS-FCV-253	Bal	Air	I	A	Yes	O	Closed	T	N	C	W	Hot	56
51A	Nitrogen Supply Header to	56	Yes	8 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					E	SI-8880	Glb	Air	O	A	Yes	O	Closed	T	N	C	G	Cold	-

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Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
	Accumulators (NE)				F	SI-8916	Chk	-	I	A	No	O	-	-	N	C	G	Cold	-
51B	Safety Injection	55	Yes	13 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	SI-8871	Glb	Air	I	A	Yes	C	Closed	T	N	C	W	Cold	-
	System				B	SI-8883	Glb	Air	O	A	Yes	C	Closed	T	N	C	W	Cold	-
	Test Line (NE)				C	SI-8961	Glb	Air	O	A	Yes	C	Closed	T	N	C	W	Cold	-
					D	SI-161	Glb	Man	O	E	No	C	-	-	N	C	W	Cold	48
51C	Reactor Coolant	56	Yes	12 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Drain Tank				C	LWS-FCV-256	Bal	Air	O	A	Yes	O	Closed	T	N	C	G	Cold	-
	Vent (NE)				D	LWS-FCV-255	Bal	Air	I	A	Yes	O	Closed	T	N	C	G	Cold	-
51D	Reactor Coolant	56	Yes	12 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Drain Tank to Gas				E	LWS-FCV-257	Bal	Air	O	A	Yes	C	Closed	T	N	C	W	Cold	-
	Analyzer (NE)				F	LWS-FCV-258	Bal	Air	I	A	Yes	O	Closed	T	N	C	W	Cold	-
52A	Pressurizer Relief	55	Yes	14 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Tank Makeup				E	RCS-8029	Bal	Air	O	A	Yes	O	Closed	T	N	C	W	Cold	-
	(NE)				F	RCS-8046	Chk	-	I	A	No	O	-	-	N	C	W	Cold	-
52B	Pressurizer Relief	55	Yes	14 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Tank Nitrogen				C	RCS-8047	Chk	-	I	A	No	O	-	-	N	C	G	Cold	-
	Supply (NE)				D	RCS-8045	Dia	Air	O	A	Yes	O	Closed	T	N	C	G	Cold	-
52C	Steam Generator	56	Yes	2 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Nitrogen Supply				F	MS-902	Gte	Man	O	E	No	C	-	-	N	C	G	Cold	26
	(NE)				G	MS-5200	Chk	-	I	E	No	C	-	-	N	C	G	Cold	26

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Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
52D	Reactor Coolant Drain Tank Nitrogen Supply (NE)	56	Yes	12 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	LWS-FCV-260	Bal	Air	O	A	Yes	O	Closed	T	N	C	G	Cold	-
					B	LWS-60	Chk	-	I	A	No	O	-	-	N	C	G	Cold	-
52E	Containment H_2 Monitor Supply (NE)	56	Yes	24 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	VAC-FCV-235	Glb	Sol	I	E	Yes	C	Closed	-	Y	O	G	Cold	28,29
					B	VAC-FCV-236	Glb	Sol	O	E	Yes	C	Closed	-	Y	O	G	Cold	28,29
52F	Containment H_2 Monitor Return (NE)	56	Yes	24 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					C	VAC-FCV-237	Glb	Sol	O	E	Yes	C	Closed	-	Y	O	G	Cold	28,29
					D	VAC-252	Chk	-	I	E	No	C	-	-	Y	O	G	Cold	29
52G	Containment Pressure PT-937 (SA)	56	Yes	15 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	G	Cold	16
					B	Sealed Instrument	Sin	-	O	-	-	-	-	-	-	-	G	Cold	16
52H	Containment Pressure PT-932 (SA)(abandon in place)	56	Yes	15 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Sealed Instrument	Sin	-	O	-	-	-	-	-	-	-	W	Cold	16
53A	Steam Generator 1 Blowdown Sample (NE)	57	Yes	1 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					K	MS-FCV-250	Glb	Air	O	C	Yes	O	Closed	T	N	C	W	Hot	26,55
					I	MS-FCV-760	Glb	Air	I	C	Yes	O	Closed	M	N	C	W	Hot	2,4, 26,48
					-	Closed System	Cls	-	I	C	-	-	-	-	-	-	W	Hot	2
53B	Steam Generator 2 Blowdown	57	Yes	1 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					K	MS-FCV-248	Glb	Air	O	C	Yes	O	Closed	T	N	C	W	Hot	26,55

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
	Sample (NE)				I	MS-FCV-761	Glb	Air	I	C	Yes	O	Closed	M	N	C	W	Hot	2,4, 26,48
					-	Closed System	Cls	-	I	C	-	-	-	-	-	-	W	Hot	2
53C	Steam Generator 3	57	Yes	1 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Blowdown				K	MS-FCV-246	Glb	Air	O	C	Yes	O	Closed	T	N	C	W	Hot	26,55
	Sample (NE)				I	MS-FCV-762	Glb	Air	I	C	Yes	O	Closed	M	N	C	W	Hot	2,4, 26,48
					-	Closed System	Cls	-	I	C	-	-	-	-	-	-	W	Hot	2
53D	Steam Generator 4	57	Yes	1 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Blowdown				K	MS-FCV-244	Glb	Air	O	C	Yes	O	Closed	T	N	C	W	Hot	26,55
	Sample (NE)				I	MS-FCV-763	Glb	Air	I	C	Yes	O	Closed	M	N	C	W	Hot	2,4, 26,48
					-	Closed System	Cls	-	I	C	-	-	-	-	-	-	W	Hot	2
54	Instrument Air Header (NE)	56	Yes	16 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	AIR-I-587	Chk	-	I	A	No	O	-	-	N	C	G	Cold	-
					B	FCV-584	Bal	Air	O	A	Yes	O	Closed	T	N	C	G	Cold	-
					E	AIR-I-585	Dia	Man	O	E	No	C	-	-	N	C	G	Cold	48
55	Spare		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26
56	Service Air Header (NE)	56	Yes	16 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					C	AIR-S-114	Chk	-	I	E	No	C	-	-	N	C	G	Cold	-
		-			D	AIR-S-200	Bal	Man	O	E	No	C	-	-	N	C	G	Cold	-
57	Containment External H_2 Recombiners (SA)	56	Yes	24 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					E	VAC-FCV-669	Gte	Mtr	O	E	Yes	C	As is	-	Y	C	G	Cold	28,38
					F	VAC-FCV-659	Gte	Mtr	I	E	Yes	C	As is	-	Y	C	G	Cold	28,38
58	Mini-Equipment Hatch	-	-	-	-	Not a piping penetration	-	-	-	-	-	-	-	-	-	-	-	-	-

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
	(NE)																		
59A	Pressurizer Liquid Sample (NE)	55	Yes	17 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					C	NSS-9355A	Glb	Air	I	A	Yes	O	Closed	T	N	C	W	Hot	-
					D	NSS-9355B	Glb	Air	O	A	Yes	O	Closed	T	N	C	W	Hot	-
59B	Hot Leg Sample (NE)	55	Yes	17 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					E	NSS-9356A	Glb	N_2	I	A	Yes	O	Closed	T	Y	C	W	Hot	-
			-		F	NSS-9356B	Glb	N_2	O	A	Yes	O	Closed	T	Y	C	W	Hot	-
59C	Accumulator Sample (NE)	55	Yes	17 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					G	NSS-9357A	Glb	Air	I	A	Yes	C	Closed	T	N	C	W	Cold	-
					H	NSS-9357B	Glb	Air	O	A	Yes	C	Closed	T	N	C	W	Cold	-
59D	Containment Pressure Transmitter PT-938 (SA)	56	Yes	15 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Instrument	Sin	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Sealed Bellows	Sbl	-	O	-	-	-	-	-	-	-	W	Cold	16
59E	RV Level Instrumentation Transmitter LIS-1310 (SA)	55	Yes	25 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Hydraulic Isolators	Hys	-	O	-	-	-	-	-	-	-	W	Cold	16
59F	RV Level Instrumentation Transmitter LIS-1311 (SA)	55	Yes	25 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Hydraulic Isolators	Hys	-	O	-	-	-	-	-	-	-	W	Cold	16
59G	RV Level Instrumentation Transmitt	55	Yes	25 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Hydraulic Isolators	Hys	-	O	-	-	-	-	-	-	-	W	Cold	16

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
	er LIS-1312 (SA)																		
59H	Containment Pressure Transmitters PT-933 & PT-935 (SA)	56	Yes	15 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Instrument	Sin	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Sealed Bellows	Sbl	-	O	-	-	-	-	-	-	-	W	Cold	16
60	Mini-Equipment Hatch (NE)	-	-	-	-	Not a piping penetration	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Containment Purge Supply (NE)	56	Yes	18 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					D	VAC-FCV-660	But	Air	I	AE	Yes	C	Closed	T	N	C	G	Cold	57
					E	VAC-FCV-661	But	Air	O	AE	Yes	C	Closed	T	N	C	G	Cold	57
62	Containment Purge Exhaust (NE)	56	Yes	18 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					F	VAC-RCV-11	But	Air	I	AE	Yes	C	Closed	T	N	C	G	Cold	57
					G	VAC-RCV-12	But	Air	O	AE	Yes	C	Closed	T	N	C	G	Cold	57
63	Containment Pressure and Vacuum Relief (NE)	56	Yes	18 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	VAC-FCV-662	But	Air	I	A	Yes	C	Closed	T	N	C	G	Cold	18
					B	VAC-FCV-663	But	Air	O	A	Yes	C	Closed	T	N	C	G	Cold	18
					C	VAC-FCV-664	But	Air	O	A	Yes	C	Closed	T	N	C	G	Cold	18
					J	Spectacle Flange	Spf	-	O	A	-	N/A	-	-	N/A	N/A	G	Cold	26
64	Fuel Transfer Tube (NE)	-	-	3 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26
						Not a piping penetration	-	-	-	-	-	-	-	-	-	-	-	-	-

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
65	Personnel Hatch (NE)	-	-		-	Not a piping penetration	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Emergenc y Personnel Hatch (NE)	-	-		-	Not a piping penetration	-	-	-	-	-	-	-	-	-	-	-	-	-
67	Equipmen t Hatch (NE)	-	-		-	Not a piping penetration	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-		-		-	-	-	-	-	-	-	-	-	-	-	-	-
68	Containm ent Air Sample (NE)	56	Yes	19 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					C	VAC-FCV-679	Bal	Air	O	A	Yes	O	Closed	T	N	C	G	Cold	18
					D	VAC-FCV-678	Bal	Air	I	A	Yes	O	Closed	T	N	C	G	Cold	18
69	Containm ent Air Sample (NE)	56	Yes	19 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	VAC-FCV-681	Bal	Air	O	A	Yes	O	Closed	T	Y	C	G	Cold	18
					B	VAC-21	Chk	-	I	A	No	O	-	-	Y	C	G	Cold	-
70	Auxiliary Steam Supply (NE)	56	Yes	20 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	AXS-26	Gte	Man	O	E	No	C	-	-	N	C	G	Hot	-
					B	AXS-208	Chk	-	I	E	No	C	-	-	N	C	G	Hot	-
71	Relief Valve (NE) Header	56	Yes	14 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					G	RCS-8028	Chk	-	I	E	No	C	-	-	N	C	G	Hot	-
					H	CVCS-RV-8125,	Rlf	-	O	E	No	C	-	-	N	C	G	Hot	20,26
					H	SI-RV-8851,8853A,8853B,	Rlf	-	O	E	No	C	-	-	N	C	G	Hot	20,26
					H	8856A,8856B,8858	Rlf	-	O	E	No	C	-	-	N	C	G	Hot	20,26
					H	CS-RV-9007A,9007B	Rlf	-	O	E	No	C	-	-	N	C	G	Hot	20,26
					I	RCS-512	Glb	Man	O	E	No	C	-	-	N	C	G	Hot	-
72	Spare	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
73	Spare	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26
74	Spare	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26
75	Safety Injection	55	Yes	21 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Pump 2 Discharge (SA)				A	SI-8802B	Gte	Mtr	O	D	Yes	C	As is	R-M	Y	O	W	Cold	7,11, 26
76A	Pressurizer	55	Yes	17 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Steam				A	NSS-9354A	Glb	Air	I	A	Yes	C	Closed	T	Y	C	G	Hot	-
	Sample				B	NSS-9354B	Glb	Air	O	A	Yes	C	Closed	T	Y	C	G	Hot	-
76B	Pressurizer Relief	55	Yes	14 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Tank Gas				A	RCS-8034B	Glb	Air	O	A	Yes	C	Closed	T	N	C	G	Cold	-
	Analyzer (NE)				B	RCS-8034A	Glb	Air	I	A	Yes	C	Closed	T	N	C	G	Cold	-
76C	Deadweight Tester	55	Yes	22 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	(Abandoned in				A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	W	Cold	16
	place.				B	U1: 1-07P-8085B	Glb	Man	O	E	No	C	-	-	N	C	W	Cold	26
	Tester removed.) (NE)				-	U2: 1/4" Instrument cap	-	-	O	-	-	-	-	-	-	-	-	-	16
76D	Containment	56	Yes	15 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Pressure Transmitter				A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	Y	-	W	Cold	16
	PT-934 (SA)				B	Sealed Instrument	Sin	-	O	-	-	-	-	-	Y	-	W	Cold	16
76E	Spare Connection	56	Yes	11 (III)	-	U1: 3/8” Inst Cap	-	-	I	-	-	-	-	-	-	-	-	-	26
					-	U1: 3/8” Inst Cap	-	-	O	-	-	-	-	-	-	-	-	-	26
		-	-		-	U2: 1” Welded Pipe Cap	-	-	-	-	-	-	-	-	-	-	-	-	26

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
77	Safety Injection Pump 1 Discharge (SA)	55	Yes	21 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					E	SI-8802A	Gte	Mtr	O	D	Yes	C	As is	R-M	Y	O	W	Cold	7,11, 26
78A	Containment H_2 Monitor Supply (SA)	56	Yes	24 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	VAC-FCV-238	Glb	Sol	I	E	Yes	C	Closed	-	Y	O	G	Cold	28,29
					B	VAC-FCV-239	Glb	Sol	O	E	Yes	C	Closed	-	Y	O	G	Cold	28,29
78B	Containment H_2 Monitor Return (SA)	56	Yes	24 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					C	VAC-FCV-240	Glb	Sol	O	E	Yes	C	Closed	-	Y	O	G	Cold	28,29
					D	VAC-253	Chk	-	I	E	No	C	-	-	Y	O	G	Cold	29
78C	Containment Pressure Transmitter PT-936 (SA)	56	Yes	15 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Sealed Instrument	Sin	-	O	-	-	-	-	-	-	-	W	Cold	16
78D	Spare Connection	56	Yes	11 (III)															
					-	U1: 3/8" Inst Plug	-	-	I	-	-	-	-	-	-	-	-	-	26
					-	U1: 3/8" Inst Plug	-	-	O	-	-	-	-	-	-	-	-	-	26
		-	-		-	U2: 1" Welded Pipe Cap	-	-	-	-	-	-	-	-	-	-	-	-	26
78E	Spare Connection	-	-		-	1" Welded Pipe Cap	-	-	-	-	-	-	-	-	-	-	-	-	26
78F	Spare Connection	-	-		-	1" Welded Pipe Cap	-	-	-	-	-	-	-	-	-	-	-	-	26
78G	Spare Connection	-	-	-	-	1" Welded Pipe Cap	-	-	-	-	-	-	-	-	-	-	-	-	26

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
78H	Spare Connectio n	-	-		-	1” Welded Pipe Cap	-	-	-	-	-	-	-	-	-	-	-	-	26
79	Fire Water (NE)	56	Yes	23 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	FP-FCV-633	Glb	Air	O	A	Yes	O	Closed	T	N	C	W	Cold	-
					B	FP-180(U1),FP-867(U2)	Chk	-	I	A	No	O	-	-	N	C	W	Cold	-
80A	Spare Instrumen t	56	Yes	11 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(U1)	Test Line (Unit-1)				-	Instrument Plug	-	-	I	E	No	-	-	-	N	-	G	Cold	26
					-	VAC-301	Glb	Man	O	E	No	C	-	-	N	C	G	Cold	26
80A	Spare Instrumen t	56	Yes	11 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(U2)	Test Line (Unit-2)				-	VAC-303	Glb	Man	I	E	No	C	-	-	N	C	G	Cold	26
					-	VAC-301	Glb	Man	O	E	No	C	-	-	N	C	G	Cold	26
80B	Spare Instrumen t	56	Yes	11 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(U1)	Test Line (Unit-1)				-	Instrument Plug	-	-	I	E	No	-	-	-	N	-	G	Cold	26
					-	VAC-302	Glb	Man	O	E	No	C	-	-	N	C	G	Cold	26
80B	Spare Instrumen t	56	Yes	11 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(U2)	Test Line (Unit-2)				-	VAC-304	Glb	Man	I	E	No	C	-	-	N	-	G	Cold	26
					-	VAC-302	Glb	Man	O	E	No	C	-	-	N	C	G	Cold	26
80C	Spare Instrumen t	56	Yes	11 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Test Line				-	Instrument Plug	-	-	I	E	No	-	-	-	N	C	G	-	26
					-	Instrument Plug	-	-	O	E	No	-	-	-	N	C	G	-	26
80D	Containm	56	Yes	15 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
	ent Pressure Transmitter PT-939 (SA)				A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Sealed Instrument	Sin	-	O	-	-	-	-	-	-	-	W	Cold	16
80E	RV Level Instrumentation Transmitter LIS-1320 (SA)	55	Yes	25 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Hydraulic Isolators	Hys	-	O	-	-	-	-	-	-	-	W	Cold	16
80F	RV Level Instrumentation Transmitter LIS-1321 (SA)	55	Yes	25 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Hydraulic Isolators	Hys	-	O	-	-	-	-	-	-	-	W	Cold	16
80G	RV Level Instrumentation Transmitter LIS-1322 (SA)	55	Yes	25 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	Sealed Bellows	Sbl	-	I	-	-	-	-	-	-	-	W	Cold	16
					B	Hydraulic Isolators	Hys	-	O	-	-	-	-	-	-	-	W	Cold	16
81	Containment External H_2 Recombiners (SA)	56	Yes	24 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					E	VAC-FCV-668	Gte	Mtr	O	E	Yes	C	As is	-	Y	C	G	Cold	28,38
					F	VAC-FCV-658	Gte	Mtr	I	E	Yes	C	As is	-	Y	C	G	Cold	28,38
82A	Post-Accident Sampling System Reactor Cavity	56	Yes	25 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					G	LWS-FCV-697	Glb	Sol	O	A	Yes	C	Closed	-	Y	C	W	Cold	28,29
					H	LWS-FCV-696	Glb	Sol	I	A	Yes	C	Closed	-	Y	C	W	Cold	28

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
	Sump (NE)																		
82B	Post-Accident Sampling System Containment Air Supply (NE)	56	Yes	25 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					C	VAC-FCV-698	Glb	Sol	I	A	Yes	C	Closed	-	Y	C	G	Cold	28,29
					D	VAC-FCV-699	Glb	Sol	O	A	Yes	C	Closed	-	Y	C	G	Cold	28,29
82C	Post-Accident Sampling System Containment Air Return (NE)	56	Yes	25 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					E	VAC-FCV-700	Glb	Sol	O	A	Yes	C	Closed	-	Y	C	G	Cold	28,29
					F	VAC-116	Chk	-	I	A	No	C	-	-	Y	C	G	Cold	29
82D (U1)	Spare Piping Connection	56	Yes	11 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					-	Blind Flange	-	-	I	E	No	C	-	-	N	C	G	Cold	26
					-	VAC-1-680	Gte	Man	O	E	No	C	-	-	N	C	G	Cold	26
82D (U2)	Chilled Water Supply (NE) (abandon in place)	-	-	7 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	52
82E	Spare Instrument Test Line	56	Yes	11 (III)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					-	Instrument Plug	-	-	I	E	No	-	-	-	-	-	G	Cold	26
					-	Instrument Plug	-	-	O	E	No	-	-	-	-	-	G	Cold	26
83A (U1)	Spare Piping Connection	56	Yes	11 (II)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					-	Blind Flange	-	-	I	E	No	C	-	-	N	C	G	Cold	26

CONTAINMENT PIPING PENETRATIONS AND VALVING

Pentr. Nos.	System (Safety Priority) (Note 33)	Appli-cable GDC	GDC Confor-mance	Figure 6.2-19 Sheet No.	Vlv Ltr	Valve ID Number (Note 51)	Valve Type (Note 30)	Operator Type (Note 31)	Cntmt Locat. (Note 32)	PG&E Piping Group	Control Room Indication	Normal Position (Note 35)	Power Fail. Position	Trip On (Note 25)	Used After LOCA (Note 36)	Long Term Post-LOCA Position (Note 37)	Fluid (Note 23)	Temp (Note 24)	Notes
					-	VAC-1-681	Gte	Man	O	E	No	C	-	-	N	C	G	Cold	26
83A (U2)	Chilled Water Return (NE) (abandon in place)	-	-	7 (IV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	52
83B	Hydrogen Purge Supply (NE)	56	Yes	11 (I)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
					A	VAC-200,201	Chk	-	I	E	No	C	-	-	Y	O	G	Cold	38
					B	VAC-1,2	Gte	Man	O	E	No	C	-	-	Y	C	G	Cold	38
84	Spare	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26

Notes:

1. Trip on feedwater isolation. (refer to Table 6.2-40, Item 4.)
2. Steam generator secondary side is missile-protected closed system. The closed loop system includes all pressure boundary test, vent, drain, and instrument valves; instruments; blanked flange connections; and steam generator tubes.
3. Reverse check (main steam isolation).
4. Trip on steam line isolation. (refer to Table 6.2-40, Item 3.)
5. Safety-related function. Valve trip is related to systems safety function.
6. PG&E considers the five main steam relief valves to be containment isolation valves.
7. Safety-related function demands that this valve not automatically isolate.
8. Penetration does not meet 1971 GDC but does meet the GDC 53, 1967 which was applicable at time of construction commitment.
9. This valve is not considered as the automatic isolation barrier. The barrier is provided by the closed system. The valve does have provision for remote manual isolation should the situation require it.
10. PG&E considers the closed system outside containment as an automatic isolation barrier.
11. Provision for remote manual isolation exists should the situation require it. Safety-related function demands that this valve not isolate. It conforms with the intent of the GDC as it affects maintenance of the containment boundary.
12. The protective chamber is considered outside containment. The motor-operated valves are the isolation valves outside containment.
13. Valve opens on containment spray signal.

14. Valve opens on SIS signal.

15. Deleted in Revision 17

16. Containment isolation effected by completely sealed instrument system. This penetration is not leak tested.

17. Deleted in Revision 22

18. Containment vent isolation trip. (refer to Table 6.2-40, Item 5)

19. The fuel transfer tube is not considered to be a piping penetration, but rather a Type B test penetration. The quick-opening hatch is double gasketed with a test connection allowing pressurization between the gaskets for Type B testing. The portion of the transfer tube inside the containment is considered to be part of the containment liner; the portion of the transfer tube outside the containment is not considered to be part of the containment boundary.

20. The relief valves are considered as normally closed containment isolation valves.

21. Deleted.

22. Administratively controlled valve which is treated in the same manner as a sealed closed valve. Control room indication is only active when the valve is not administratively cleared.

23. W = Water; G = Gas

24. Hot - over 200°F; Cold - 200°F or less

25. R-M = Remote Manual; S = Safety Injection; T = Containment Isolation Signal, Phase A; P = Containment Isolation Signal, Phase B; F = Feedwater Isolation Signal; M = Main Steam Isolation Signal.

26. Testability not required under Option B of Appendix J to 10 CFR Part 50.

27. Deleted in Revision 17.

28. This device is used for post-accident monitoring or control and must not be isolated by a containment isolation signal.

29. Multiple penetration number usage results from multiple tubes running though the guard pipe of a single penetration.

30. The following abbreviations are used:

Gte = Gate	Cls = Closed system	Sbl = Sealed bellows	Spf = Spectacle flange
Glb = Globe	Chk = Check	Blf = Blind flange	
Rlf = Relief	Dia = Diaphragm	Sin = Sealed instruments	
But = Butterfly	Bal = Ball	Hys = Hydraulic isolators	

31. The following abbreviations are used:

Man	=	Manual	Mtr	=	Motor
Air	=	Air	E/H	=	Electrohydraulic
Spr	=	Spring	Sol	=	Solenoid
N_2	=	Nitrogen			

32. "I" is used for inside and "O" for outside.

33. Safety-related priority designation for each penetration per Section 6.2.4.4.15 is as follows:
ES = Essential SA = Safety
NE = Nonessential

34. Penetration 36 is not used by a safety system for accident mitigation. However, flow through this Penetration may be required to achieve safe shutdown following a Hosgri earthquake or a fire.

35. “Normal Position” column:

(A) C = Closed, O = Open
(B) For check valves, position is stated open if flow passes through the check valve during normal operation, otherwise the valve is stated closed.
(C) "Normal" configuration applies to the following plant conditions:
(a) Modes 1-4, applicable T.S. 3.6.1 and 3.6.3.
(b) Mode 6, applicable ECG 42.1.
(D) If valve is normally open it is designated "Open" or if only periodically opened for fulfillment of its function during the "Normal" plant configurations, then a "Closed" designator is used.
(E) If valve is normally closed and opened only in support of testing, under administrative control per T.S. 3.6.3, or for stroke testing of the valve itself, then a "Closed" designator is used.
(F) Relief valves are assigned a "Closed" designator.

36. "Used After LOCA" column:
(A) N = No, Y = Yes
(B) For check valves, if valve passes flow at any point following the accident, then a "Yes" designator is used.
(C) For valves that change position on a safeguards signal, this change is not considered a use, that is, the time the safeguards signal is received is not considered after the accident.
(D) Use is principally an indicator of a valve passing flow at any point after the accident.

37. "Long Term Post-LOCA Position" column:
(A) C = Closed, O = Open
(B) The column pertains to a post accident condition, long term core cooling.
(C) The assumed accident is a primary system LOCA with Containment isolation Phase A and B signals generated, system depressurization below 150 PSIG, corresponding to a RHR pump injection flow of greater than 200 GPM. The accident is assumed to progress through injection, cold leg recirculation, and to hot leg recirculation for the long term.
(D) The hot leg injection flowpath is injection to RHR hot legs 1 & 2, SI pump hot legs 1,2,3, & 4, and Charging cold legs 1,2,3, & 4; the condition established by EOP E-1.4, (no RNOs entered).
(E) Containment temperature has been reduced to near ambient conditions.
(F) Containment pressure has been reduced to near atmospheric conditions.
(G) Primary system/containment recirculation sump temperature has been reduced to below 200°F.
(H) Although used periodically, PASS valves are considered to be normally closed.

38. Valve may be used following a LOCA only in the event of a failure of both internal hydrogen recombiners.

39. Deleted in Revision 22

40. Valve is not subject to Type C leakage tests because it is required to be in service post accident and the line pressure upstream of the CIV is greater than the post-accident pressure inside containment.

41. Deleted in Revision 22

42. Deleted in Revision 22

43. Deleted in Revision 22

44. Deleted in Revision 22.

45. This penetration does not require testing per Appendix J section II.H because the penetration does not provide a direct connection to the atmosphere during normal operation, is not required to close automatically, and is not required to operate intermittently. This penetration is filled with water from the submerged sump preventing gas escape to the outside and meets the test exception per Appendix J section II.c.3.

46. Deleted in Revision 22

47. The Containment Fan Coolers are a closed system inside containment. CCW does not communicate directly with the containment atmosphere. The closed loop system includes all pressure boundary test, vent, drain and instrument valves; instruments; blanked flange connections; and CFCU tubing.

48. Valve is included as a credited CIV because it was included on the original Tech Specs for the plant license.

49. Deleted in Revision 22

50. Deleted in Revision 22

51. This column lists the credited containment isolation valve or barrier that is used to demonstrate conformance to the PG&E Piping Group and the applicable GDC. Associated isolation devices required to maintain containment leakage integrity of penetrations and closed systems such as vent, drain test, instrumentation and branch line valves, blind flanges, caps or other passive devices are not shown They are administratively controlled to be in their proper isolation configuration by plant procedures and per TS 3.6.3.

52. This penetration is abandoned in place through the installation of welded plugs in the penetration.

53. Deleted in Revision 22

54. Deleted in Revision 22

55. The Steam Generator Blowdown System does not communicate directly with the containment atmosphere or reactor coolant pressure boundary. This valve is required to close when the auxiliary feedwater pumps are started in order to maintain steam generator inventory.

56. Valve is installed with a hole drilled through the ball allowing unidirectional pressure relief to meet the requirements of Generic Letter 96-06, September 1996 (refer to Section 6.2.4.4.17).

57. Administratively controlled valve per Technical Specifications. Valve is sealed closed in accordance with SRP Section 6.2.4, Revision 3 Criteria II.6 and II.14.

TABLE 6.2-40

OPERATING CONDITIONS FOR CONTAINMENT ISOLATION

Item No.	Functional Unit	Operating Conditions
1	Containment isolation Phase A	a. High containment pressure
		b. Pressurizer low pressure
		c. Low steamline pressure
		d. Manual
2	Containment isolation Phase B	a. High-high containment pressure
		b. Manual
3	Steam line isolation	a. Low steamline pressure
		b. High steamline pressure rate
		c. High-high containment pressure
		d. Manual
4	Feedwater line isolation	a. High containment pressure
		b. Low steamline pressure
		c. Pressurizer low pressure
		d. Steam generator high-high level
		e. Manual SIS

TABLE 6.2-40

Item No.	Functional Unit	Operating Conditions
5	Containment ventilation isolation	a. Containment exhaust detectors b. Safety injection activation c. Manual Phase A or Manual Phase B or Manual Spray Actuation

TABLE 6.2-41

POST-LOCA TEMPERATURE TRANSIENT
USED FOR ALUMINUM AND ZINC CORROSION

Time Interval, sec	Temperature, °F
0 - 10	240
10 - 30	265
30 - 750	258
750 - 2000	253
2000 - 10,000	250
10,000 - 20,000	245
20,000 - 50,000	240
50,000 - 75,000	230
75,000 - 100,000	220
100,000 - 200,000	210
200,000 - 400,000	198
400,000 - 600,000	185
600,000 - 800,000	175
800,000 - 1,200,000	160
1,200,000 - 2,000,000	153
2,000,000 - 3,000,000	145
3,000,000 - 5,000,000	138
5,000,000 - 8,640,000	129

TABLE 6.2-42

PARAMETERS USED TO DETERMINE HYDROGEN GENERATION

Plant Thermal Power Rating	3,425 MWt
Containment Temperature Prior to Accident	120°F
Containment Free Volume	2,550,000 ft^3
Weight Zirconium Cladding	43,300 lb
Hydrogen Recombiner Flowrate	100 scfm
Corrodible Metals	Aluminum and zinc
Core Cooling Solution Radiolysis Sources	
Percent of total halogens retained in the core	50.00
Percent of total noble gases retained in the core	0.00
Percent of other fission products retained in the core	99.00
Energy Distribution	
Percent of total decay energy - gamma	50.00
Percent of total decay energy - beta	50.00
Energy Absorption by Core Cooling Solution	
Percent of gamma energy absorbed by solution	10.00
Percent of beta energy absorbed by solution	0.00
Hydrogen Production	
Molecules H_2 produced per 100 eV energy absorbed by solution	0.50
Sump Solution Radiolysis Sources	
Percent of total halogens released to sump solution	50.00
Percent of noble gases released to sump solution	0.00
Percent of other fission products released to sump solution	1.00

TABLE 6.2-42

Energy Absorption by Sump Solution	
Percent of total energy (beta and gamma) which is absorbed by the sump solution	100.00
Hydrogen Production	
Molecules of hydrogen produced per 1000 eV of energy absorbed by the sump solution	0.50
Long-term Aluminum Corrosion Rate	200 mils/year
Aluminum Inventory in Containment (amount used in analyses)	3585 lb 15,988 ft^2
Zinc Inventory in Containment (amount used in analysis)	58,449 lb 397,000 ft^2

TABLE 6.2-43

CORE FISSION PRODUCT ENERGY AFTER
OPERATION WITH EXTENDED FUEL CYCLES

Time After Reactor Trip, days	Core Fission Product Energy[a] Energy Release Rate, watts/MWt x 10^3	Core Fission Product Energy[a] Integrated Energy Release, watts days/MWt x 10^4
1	5.11	0.696
5	3.41	2.28
10	2.72	3.80
20	2.00	6.11
30	1.66	7.92
40	1.47	9.48
50	1.33	10.9
60	1.21	12.2
70	1.12	13.3
80	1.02	14.4
90	0.943	15.4
100	0.868	16.2

(a) TID-14844 methodology: Assumes 50% core halogens +99% other fission products and no noble gases. Values are for total (β and γ) energy.

TABLE 6.2-44

FISSION PRODUCT DECAY DEPOSITION IN SUMP SOLUTION

Time After Reactor Trip, days	Sump Fission Product Energy[a]	
	Energy Release Rate, watts/MWt x 10	Integrated Energy Release, watt-days/MWt x 10^3
1	25.6	0.535
5	8.17	1.02
10	5.35	1.35
15	3.80	1.57
20	2.91	1.75
30	2.06	1.99
40	1.69	2.18
60	1.30	2.47
80	1.04	2.70
100	0.837	2.88

(a) TID-14844 methodology: Considers release of 50 percent of core halogens, no noble gases, and 1 percent of other fission products to the sump solution.

TABLE 6.2-45

SUMMARY OF HYDROGEN ACCUMULATION DATA

(with no recombination)

Volume Percent Hydrogen	Time of Occurrence, days	Total Production Rate, scfm
2.09	1	10.9
2.65	2	8.18
3.09	3	6.45
3.48	4	6.23
3.83	5	5.03
4.13	6	4.90
5.10	10	3.19
5.96	15	2.62
6.68	20	2.42
9.77	50	1.66
11.54	75	1.22
12.95	100	1.11

TABLE 6.2-47

CONTAINMENT REFLECTIVE INSULATION[a]

Line No.	Size, in.	Length, ft.	Line Designation
1	29	19	Reactor Coolant Out Loop 1
2	29	19	Reactor Coolant Out Loop 2
3	29	19	Reactor Coolant Out Loop 3
4	29	19	Reactor Coolant Out Loop 4
5	31	22	Reactor Coolant PP Suction Loop 1
6	31	22	Reactor Coolant PP Suction Loop 2
7	31	13	Reactor Coolant PP Suction Loop 3
8	1	3	Reactor Coolant PP Suction Loop 4
9	27-1/2	21	Reactor Coolant PP Discharge Loop 1
10	27-1/2	4	Reactor Coolant PP Discharge Loop 2
11	27-1/2	23	Reactor Coolant PP Discharge Loop 3
12	27-1/2	23	Reactor Coolant PP Discharge Loop 4
13	4	111	Loop 1 spray line
14	4	84	Loop 2 spray line
15	4	96	Pressurizer spray line
16	14	65	Pressurizer surge line
24	3	38	Letdown Line Loop 2
50	3	9	Charging Line Loop 3
109	14	45	Hot Leg Recirc. Before V-8702
235	6	13	Safety Injection Loop 1 Hot Leg
236	6	10	Safety Injection Loop 2 Hot Leg
237	6	8	Safety Injection Loop 3 Hot Leg
238	6	11	Safety Injection Loop 4 Hot Leg
246	3	6	Charging Line Loop 4
253	10	41	Accumulator Injection Loop 1
254	10	35	Accumulator Injection Loop 2
255	10	14	Accumulator Injection Loop 3
256	10	30	Accumulator Injection Loop 4
958	2	4	Loop 1 cold leg drain RCDT
959	2	6	Loop 2 cold leg drain RCDT
960	2	2	Loop 3 cold leg drain RCDT
961	2	3	Loop 4 cold leg drain RCDT
1665	14	21	Loop 4 hot leg before V 8701
1992	1-1/2	3	Boron Inj Tk. Out Loop 2 cold
1993	1-1/2	3	Boron Inj Tk. Out Loop 3 cold

TABLE 6.2-47

Line No.	Size, in.	Length, ft.	Line Designation
3844	6	35	RHR PP 1-1 Inj Cold Leg 1
3845	6	48	RHR PP 1-1 Inj Cold Leg 2
3846	6	48	RHR PP 1-1 Inj Cold Leg 3
3847	6	48	RHR PP 1-1 Inj Cold Leg 4
3855	2	4	SI PPS Cold Leg Loop 1 recirc.

(a) The information contained in this table is "representative" of Units 1 and 2. Data reflecting actual conditions for any individual line may be somewhat different than that presented, or may change with plant modifications. This table will not be revised to reflect these individual conditions or changes.

TABLE 6.2-48

CONTAINMENT CONVENTIONAL INSULATION

Line No.	Insul.	Size, in.	Length, ft.	Line Designation
23	IV	12	45	Pressurizer relief header
50	IV	3	64	Charging Line Loop 3
51	IV	2	77	Charging line auxiliary spray
63	V	1	218	Excess Letdown Loop 2
214	V	3/4	3	Loop 1 hot leg sample
215	V	3/4	1	Loop 4 hot leg sample
225	V	28	94	Steam Gen. 1-4 steam outlet
226	V	28	96	Steam Gen. 1-3 steam outlet
227	V	28	96	Steam Gen. 1-2 steam outlet
228	V	28	94	Steam Gen. 1-1 steam outlet
246	IV	3	115	Charging Line Loop 4
508	III	8	226	RHR PP 1-1 Inj Cold Leg 1 + 2
509	III	8	77	RHR PP 1-1 Inj Cold Leg 3 + 4
528	III	2-1/2	123	Reactor coolant drain tk. PP disch.
554	IV	16	54	Steam Gen. 1 feedwater supply
555	IV	16	57	Steam Gen. 2 feedwater supply
556	IV	16	53	Steam Gen. 4 feedwater supply
557	IV	16	54	Steam Gen. 3 feedwater supply
692	III	3/4	4	Cold Leg Loop 3 + 4 test line
927	III	14	33	Loop 4 hot leg to RHR PPS
1012	V	2	3	Steam Gen. 1 blowdown out N/S
1017		2	3	Steam Gen. 2 blowdown out N/S
1020	V	2	14	Steam Gen. 3 blowdown out N/S
1038	V	2	8	Steam Gen. 4 blowdown out N/S
1040	V	2-1/2	235	Steam Gen. 1-1 blowdown tank hdr.
1041	V	2-1/2	189	Steam Gen. 1-2 blowdown tank hdr.
1042	V	2-1/2	85	Steam Gen. 1-3 blowdown tank hdr.
1043	V	2-1/2	116	Steam Gen. 1-4 blowdown tank hdr.
1059	V	2	32	Steam Gen. 1 blowdown out S/N
1060	V	2	17	Steam Gen. 2 blowdown out S/N
1061	IV	2	3	Steam Gen. 3 blowdown out S/N
1062	V	2	15	Steam Gen. 4 blowdown out S/N
1167	III	4	51	RHR hot leg RV outlet
1169	V	3/4	7	Loop 1 spray line bypass
1170	V	3/4	7	Loop 2 spray line bypass
1675	V	3/8	51	Loop 1 hot leg sample
1676	V	3/8	6	Loop 4 hot leg sample

TABLE 6.2-48

Line No.	Insul.	Size, in.	Length, ft.	Line Designation
1901	III	1	8	Loop 2 V8076 + V8074B Lkoff. H
1999	III	3/4	10	SIS Accum. 1 test
2000	III	3/4	13	SIS Accum. 2 test
2001	III	3/4	60	SIS Accum. 3 test
2002	III	3/4	28	SIS Accum. 4 test
2158	IV	3/4	12	Regen. hx. channel temp. relief
2176	III	1	35	Leakoff header line to PRT
2385	III	4	202	SIS RV outlet header to PRT
2523	III	1/2	4	RHR Suction Vlv. 2 Loop 4 leakoff
2524	III	1/2	18	RHR Suction Vlv. 1 Loop 4 leakoff
2638	III	1	57	Cont. aux. steam supply to el. 91
2766	III	1/2	2	PCV-455 A leakoff line
2773	III	1/2	4	PCV-455 B leakoff line
2998	III	4	4	SIS RV outlet header to PRT
2999	III	4	5	SIS RV outlet header to PRT
3094	V	3/4	5	RHR Loop 4 V-8702 8702 therm
3095	III	3/4	5	RHR Loop 4 V-8701 8702 therm
3214	I	2	73	Incore chiller chill wtr. sup.
3215	I	2	73	Incore chiller chill wtr. ret.
3407	III	1/2	6	Loop 2 Letdown V-8076 leakoff
3729	III	2-1/2	14	REAC Clnt. Dr. PPS Disch. Header
3844	II	6	70	RHR PP 1-1 inj cold leg 1
3845	II	6	59	RHR PP 1-1 inj cold leg 2
3900	III	1	174	Reactor head aux. steam
3936	I	2	2	Incore chiller chill wtr. ret.
4399	III	1/2	1	
4400	III	1/2	7	
4402	III	1/2	5	
4406	III	1	4	
4407	III	1	2	

(a) This line is contained completely within the hot leg insulation.

(b) The information contained in this table is "representative" of Units 1 and 2. Data reflecting actual conditions for any individual line may be somewhat different than that presented, or may change with plant modifications. This table will not be revised to reflect these individual conditions or changes.

TABLE 6.2-57

CONTAINMENT SUBCOMPARTMENT ANALYSES
DOUBLE-ENDED PRESSURIZER SURGE LINE BREAK
AT THE HOT LEG CONNECTION
MASS AND ENERGY RELEASES

Time Seconds	Mass Flow Lbm/Sec	Energy Release Btu/Sec
.0000E+00	.0000E+00	.0000E+00
.1010E-02	.4634E+04	.2822E+07
.2020E-02	.8154E+04	.4968E+07
.4020E-02	.1135E+05	.6943E+07
.6030E-02	.1267E+05	.7788E+07
.1104E-01	.1857E+05	.1148E+08
.1201E-01	.1926E+05	.1191E+08
.1404E-01	.1970E+05	.1221E+08
.1804E-01	.1816E+05	.1134E+08
.2305E-01	.2121E+05	.1327E+08
.3503E-01	.2317E+05	.1459E+08
.4007E-01	.2250E+05	.1421E+08
.5809E-01	.2386E+05	.1515E+08
.6803E-01	.2351E+05	.1496E+08
.7805E-01	.2276E+05	.1453E+08
.8503E-01	.2313E+05	.1478E+08
.1010E+00	.2489E+05	.1587E+08
.1051E+00	.2497E+05	.1593E+08
.1720E+00	.2140E+05	.1376E+08
.1870E+00	.2019E+05	.1304E+08
.2370E+00	.2020E+05	.1305E+08
.2731E+00	.1905E+05	.1235E+08
.3070E+00	.1707E+05	.1115E+08
.3530E+00	.1593E+05	.1047E+08
.7550E+00	.1565E+05	.1027E+08
.8100E+00	.1583E+05	.1037E+08
.8300E+00	.1568E+05	.1027E+08
.8400E+00	.1586E+05	.1038E+08
.8550E+00	.1555E+05	.1019E+08
.9000E+00	.1564E+05	.1024E+08
.9350E+00	.1614E+05	.1053E+08
.9500E+00	.1590E+05	.1039E+08
.9751E+00	.1619E+05	.1056E+08
.9850E+00	.1657E+05	.1079E+08
.1000E+01	.1785E+05	.1155E+08
.1020E+01	.1711E+05	.1110E+08
.1060E+01	.1679E+05	.1091E+08

TABLE 6.2-57

CONTAINMENT SUBCOMPARTMENT ANALYSES
DOUBLE-ENDED PRESSURIZER SURGE LINE BREAK
AT THE HOT LEG CONNECTION
MASS AND ENERGY RELEASES

Time Seconds	Mass Flow Lbm/Sec	Energy Release Btu/Sec
.1080E+01	.1631E+05	.1062E+08
.1150E+01	.1629E+05	.1060E+08
.1180E+01	.1702E+05	.1102E+08
.1200E+01	.1691E+05	.1096E+08
.1220E+01	.1734E+05	.1121E+08
.1260E+01	.1635E+05	.1062E+08
.1300E+01	.1659E+05	.1077E+08
.1340E+01	.1712E+05	.1108E+08
.1420E+01	.1670E+05	.1083E+08
.1470E+01	.1698E+05	.1100E+08
.1900E+01	.1652E+05	.1075E+08
.2400E+01	.1528E+05	.1002E+08
.3000E+01	.1483E+05	.9772E+07

* - The LOCA M&E in this table was increased by 10% for use in the subcompartment pressurization calculations. WCAP-8264-P-A contains the basis for the 10% increase.

TABLE 6.2-58

CONTAINMENT SUBCOMPARTMENT ANALYSES
DOUBLE ENDED PRESSURIZER SPRAY LINE BREAK
AT THE TOP OF THE PRESSURIZER
MASS AND ENERGY RELEASES

Time Seconds	Mass Flow Lbm/Sec	Energy Release Btu/Sec
.0000E+00	.0000E+00	.0000E+00
.1040E-02	.3410E+02	.1772E+05
.2010E-02	.7114E+02	.3695E+05
.3010E-02	.1087E+03	.5644E+05
.4020E-02	.1449E+03	.7520E+05
.5080E-02	.1811E+03	.9395E+05
.6030E-02	.2113E+03	.1096E+06
.7060E-02	.2415E+03	.1251E+06
.8070E-02	.2681E+03	.1387E+06
.9000E-02	.2895E+03	.1497E+06
.1003E-01	.3110E+03	.1607E+06
.1104E-01	.3285E+03	.1696E+06
.1209E-01	.3433E+03	.1771E+06
.1304E-01	.3537E+03	.1824E+06
.1502E-01	.3676E+03	.1894E+06
.1809E-01	.3957E+03	.2041E+06
.2305E-01	.4347E+03	.2248E+06
.2713E-01	.4730E+03	.2456E+06
.3212E-01	.5367E+03	.2803E+06
.4204E-01	.6965E+03	.3686E+06
.4702E-01	.7684E+03	.4090E+06
.5203E-01	.8232E+03	.4408E+06
.6102E-01	.8809E+03	.4769E+06
.7504E-01	.9400E+03	.5199E+06
.7805E-01	.9637E+03	.5358E+06
.8005E-01	.9869E+03	.5502E+06
.8901E-01	.1125E+04	.6326E+06
.9410E-01	.1190E+04	.6707E+06
.9908E-01	.1223E+04	.6911E+06
.1230E+00	.1308E+04	.7701E+06
.1271E+00	.1340E+04	.7929E+06
.1420E+00	.1489E+04	.8905E+06
.1460E+00	.1513E+04	.9067E+06
.1510E+00	.1524E+04	.9183E+06
.1580E+00	.1509E+04	.9195E+06
.1670E+00	.1529E+04	.9408E+06
.1840E+00	.1599E+04	.9943E+06

TABLE 6.2-58

CONTAINMENT SUBCOMPARTMENT ANALYSES
DOUBLE ENDED PRESSURIZER SPRAY LINE BREAK
AT THE TOP OF THE PRESSURIZER
MASS AND ENERGY RELEASES

Time Seconds	Mass Flow Lbm/Sec	Energy Release Btu/Sec
.6102E-01	.8809E+03	.4769E+06
.7504E-01	.9400E+03	.5199E+06
.7805E-01	.9637E+03	.5358E+06
.8005E-01	.9869E+03	.5502E+06
.8901E-01	.1125E+04	.6326E+06
.9410E-01	.1190E+04	.6707E+06
.9908E-01	.1223E+04	.6911E+06
.1230E+00	.1308E+04	.7701E+06
.1271E+00	.1340E+04	.7929E+06
.1420E+00	.1489E+04	.8905E+06
.1460E+00	.1513E+04	.9067E+06
.1510E+00	.1524E+04	.9183E+06
.1580E+00	.1509E+04	.9195E+06
.1880E+00	.1603E+04	.9991E+06
.2050E+00	.1576E+04	.9980E+06
.2281E+00	.1563E+04	.1003E+07
.2390E+00	.1529E+04	.9878E+06
.2800E+00	.1365E+04	.8975E+06
.3011E+00	.1272E+04	.8374E+06
.3220E+00	.1213E+04	.7950E+06
.3431E+00	.1176E+04	.7690E+06
.3841E+00	.1157E+04	.7567E+06
.4960E+00	.1152E+04	.7525E+06
.1470E+01	.1147E+04	.7487E+06
.3000E+01	.1128E+04	.7373E+06

* - The LOCA M&E in this table was increased by 10% for use in the subcompartment pressurization calculations. WCAP-8264-P-A contains the basis for the 10% increase.

Table 6.2-59

CONTAINMENT SUBCOMPARTMENT ANALYSES
DOUBLE-ENDED RESIDUAL HEAT REMOVAL SUCTION LINE BREAK
AT THE RCS HOT LEG CONNECTION
MASS AND ENERGY RELEASES

Time Seconds	Mass Flow Lbm/Sec	Energy Release Btu/Sec
.0000E+00	.0000E+00	.0000E+00
.1000E-05	.1548E+05	.9356E+07
.1010E-02	.1588E+05	.9604E+07
.2040E-02	.1635E+05	.9882E+07
.4010E-02	.1720E+05	.1040E+08
.6050E-02	.1804E+05	.1090E+08
.1404E-01	.2111E+05	.1275E+08
.1603E-01	.2181E+05	.1318E+08
.2003E-01	.2300E+05	.1389E+08
.2805E-01	.2518E+05	.1521E+08
.3029E-01	.2570E+05	.1552E+08
.3030E-01	.1022E+05	.6172E+07
.3301E-01	.1076E+05	.6500E+07
.3702E-01	.1150E+05	.6943E+07
.4109E-01	.1214E+05	.7332E+07
.4901E-01	.1295E+05	.7816E+07
.5703E-01	.1361E+05	.8215E+07
.6509E-01	.1412E+05	.8529E+07
.7305E-01	.1444E+05	.8721E+07
.1140E+00	.1529E+05	.9230E+07
.1300E+00	.1548E+05	.9342E+07
.1430E+00	.1532E+05	.9243E+07
.1930E+00	.1323E+05	.7967E+07
.2060E+00	.1277E+05	.7695E+07
.2191E+00	.1243E+05	.7484E+07
.2320E+00	.1229E+05	.7405E+07
.2471E+00	.1233E+05	.7433E+07
.2631E+00	.1227E+05	.7387E+07
.2791E+00	.1201E+05	.7233E+07
.3270E+00	.1074E+05	.6463E+07
.3430E+00	.1042E+05	.6270E+07
.3590E+00	.1032E+05	.6210E+07
.3890E+00	.1042E+05	.6273E+07
.4250E+00	.1029E+05	.6190E+07
.4650E+00	.1005E+05	.6045E+07
.4780E+00	.1011E+05	.6086E+07

Table 6.2-59

CONTAINMENT SUBCOMPARTMENT ANALYSES
DOUBLE-ENDED RESIDUAL HEAT REMOVAL SUCTION LINE BREAK
AT THE RCS HOT LEG CONNECTION
MASS AND ENERGY RELEASES

Time Seconds	Mass Flow Lbm/Sec	Energy Release Btu/Sec
.5401E+00	.1099E+05	.6613E+07
.5601E+00	.1110E+05	.6680E+07
.6100E+00	.1111E+05	.6683E+07
.6750E+00	.1162E+05	.6983E+07
.7500E+00	.1159E+05	.6960E+07
.8450E+00	.1207E+05	.7235E+07
.9851E+00	.1225E+05	.7334E+07
.1150E+01	.1234E+05	.7378E+07
.1320E+01	.1218E+05	.7289E+07
.1600E+01	.1147E+05	.6892E+07
.1680E+01	.1120E+05	.6742E+07
.2300E+01	.1037E+05	.6354E+07
.2500E+01	.1003E+05	.6184E+07
.3000E+01	.9022E+04	.5649E+07

* - The LOCA M&E in this table was increased by 10% for use in the subcompartment pressurization calculations. WCAP-8264-P-A contains the basis for the 10% increase.

Table 6.2-60

CONTAINMENT SUBCOMPARTMENT ANALYSES
DOUBLE-ENDED ACCUMULATOR LINE BREAK
AT THE RCS COLD LEG CONNECTION
MASS AND ENERGY RELEASES

Time Seconds	Mass Flow Lbm/Sec	Energy Release Btu/Sec
.0000E+00	.0000E+00	.0000E+00
.1020E-02	.3693E+04	.1900E+07
.2020E-02	.6600E+04	.3386E+07
.3020E-02	.8247E+04	.4219E+07
.4030E-02	.9129E+04	.4656E+07
.6030E-02	.9893E+04	.5020E+07
.1003E-01	.1047E+05	.5276E+07
.1400E-01	.1228E+05	.6194E+07
.1601E-01	.1274E+05	.6419E+07
.1900E-01	.1289E+05	.6479E+07
.2302E-01	.1277E+05	.6379E+07
.2504E-01	.1300E+05	.6481E+07
.3109E-01	.1411E+05	.6981E+07
.4210E-01	.1449E+05	.7014E+07
.5501E-01	.1383E+05	.6560E+07
.7304E-01	.1482E+05	.6848E+07
.9313E-01	.1451E+05	.6516E+07
.1080E+00	.1579E+05	.7031E+07
.1121E+00	.1591E+05	.7066E+07
.1180E+00	.1576E+05	.6959E+07
.1301E+00	.1527E+05	.6587E+07
.1591E+00	.1563E+05	.6591E+07
.1800E+00	.1565E+05	.6483E+07
.2011E+00	.1546E+05	.6269E+07
.2240E+00	.1588E+05	.6413E+07
.2690E+00	.1584E+05	.6263E+07
.2930E+00	.1594E+05	.6270E+07
.3170E+00	.1560E+05	.6059E+07
.4111E+00	.1582E+05	.6105E+07
.4310E+00	.1571E+05	.6041E+07
.4900E+00	.1608E+05	.6227E+07
.7400E+00	.1634E+05	.6395E+07
.1210E+01	.1570E+05	.6145E+07
.1700E+01	.1609E+05	.6446E+07
.1720E+01	.1649E+05	.6654E+07
.1730E+01	.1609E+05	.6450E+07

Table 6.2-60

CONTAINMENT SUBCOMPARTMENT ANALYSES
DOUBLE-ENDED ACCUMULATOR LINE BREAK
AT THE RCS COLD LEG CONNECTION
MASS AND ENERGY RELEASES

Time Seconds	Mass Flow Lbm/Sec	Energy Release Btu/Sec
.1740E+01	.1590E+05	.6347E+07
.1810E+01	.1630E+05	.6571E+07
.1860E+01	.1607E+05	.6456E+07
.1870E+01	.1620E+05	.6527E+07
.1880E+01	.1654E+05	.6714E+07
.1890E+01	.1650E+05	.6692E+07
.1900E+01	.1625E+05	.6559E+07
.1930E+01	.1614E+05	.6508E+07
.1950E+01	.1629E+05	.6591E+07
.1980E+01	.1607E+05	.6481E+07
.2000E+01	.1632E+05	.6618E+07
.2100E+01	.1618E+05	.6558E+07
.2500E+01	.1619E+05	.6625E+07
.3000E+01	.1579E+05	.6481E+07

* - The LOCA M&E in this table was increased by 10% for use in the subcompartment pressurization calculations. WCAP-8264-P-A contains the basis for the 10% increase.

TABLE 6.2-61

CONTAINMENT SUBCOMPARTMENT ANALYSES NODE DESCRIPTIONS FOR SUBCOMPARTMENT MODEL

Node	Lower Elev. (ft.)	Upper Elev. (ft.)	Azimuth 1 (deg.)	Azimuth 2 (deg.)	Inner Boundary	Outer Boundary	Description
1	91	138	270	338	Primary Shield Wall	Crane Wall	RV E-W CL to CL SG 1-1
2	91	138	338	22	Primary Shield Wall	Crane Wall	CL SG 1-1 to CL SG 1-2
3	91	138	22	90	Primary Shield Wall	Crane Wall	CL SG 1-2 to RV E-W CL
4	91	138	90	158	Primary Shield Wall	Crane Wall	RV E-W CL to CL SG 1-3
5	91	138	158	202	Primary Shield Wall	Crane Wall	CL SG 1-3 to CL SG 1-4
6	91	138	202	270	Primary Shield Wall	Crane Wall	CL SG 1-4 to RV E-W CL
7	140	301	0	360	N/A	Containment Liner	Dome & Upper RV Cavity
8	117	138	103	208	Crane Wall	Containment Liner	CFCU 1-4 to 1-5 Headers
9	117	138	208	326	Crane Wall	Containment Liner	CFCU 1-5 to 1-1 Headers
10	117	138	326	10	Crane Wall	Containment Liner	CFCU 1-1 to 1-2 Headers
11	117	138	10	54	Crane Wall	Containment Liner	CFCU 1-2 to 1-3 Headers
12	117	138	54	103	Crane Wall	Containment Liner	CFCU 1-3 to 1-4 Headers
13	91	117	90	154	Crane Wall	Containment Liner	Fuel Xfr. Canal to Acc. 1-3
14	91	117	154	248	Crane Wall	Containment Liner	Acc. 1-3 to Acc. 1-4
15	91	117	248	292	Crane Wall	Containment Liner	Acc. 1-4 to Acc. 1-1
16	91	117	292	0	Crane Wall	Containment Liner	Acc. 1-1 to PZR Relief Tank
17	91	117	0	26	Crane Wall	Containment Liner	PZR Relief Tank to Acc. 1-2
18	91	117	26	90	Crane Wall	Containment Liner	Acc. 1-2 to Fuel Xfr. Canal
19	161.5	166	N/A	N/A	Pressurizer Vessel	Pressurizer Enclosure	Upper Pressurizer Head
20	161.5	166	N/A	N/A	Pressurizer Vessel	Pressurizer Enclosure	Upper Pressurizer Head
21	161.5	166	N/A	N/A	Pressurizer Vessel	Pressurizer Enclosure	Upper Pressurizer Head
22	161.5	166	N/A	N/A	Pressurizer Vessel	Pressurizer Enclosure	Upper Pressurizer Head
23	147.75	161.5	N/A	N/A	Pressurizer Vessel	Pressurizer Enclosure	Mid Pressurizer Enclosure
24	147.75	161.5	N/A	N/A	Pressurizer Vessel	Pressurizer Enclosure	Mid Pressurizer Enclosure
25	147.75	161.5	N/A	N/A	Pressurizer Vessel	Pressurizer Enclosure	Mid Pressurizer Enclosure
26	147.75	161.5	N/A	N/A	Pressurizer Vessel	Pressurizer Enclosure	Mid Pressurizer Enclosure
27	140	147.75	N/A	N/A	Pressurizer Vessel	Pressurizer Enclosure	Bot Pressurizer Enclosure
28	140	147.75	N/A	N/A	Pressurizer Vessel	Pressurizer Enclosure	Bot Pressurizer Enclosure
29	140	147.75	N/A	N/A	Pressurizer Vessel	Pressurizer Enclosure	Bot Pressurizer Enclosure
30	140	147.75	N/A	N/A	Pressurizer Vessel	Pressurizer Enclosure	Bot Pressurizer Enclosure

Note: The compartment locations and angles refer to the Unit 1 layout. The Unit 2 layout is a mirror image across column line 18. Azimuth angles are measured from plant North relative to Containment CL, in the clockwise direction.

TABLE 6.2-61

CONTAINMENT SUBCOMPARTMENT ANALYSES
NODE DESCRIPTIONS FOR
SUBCOMPARTMENT MODEL

Node	Lower Elev. (ft.)	Upper Elev. (ft.)	Azimuth 1 (deg.)	Azimuth 2 (deg.)	Inner Boundary	Outer Boundary	Description
31	87	114.13	270	90	Reactor Vessel	Primary Shield Wall	North half of RV Annulus
32	87	114.13	90	270	Reactor Vessel	Primary Shield Wall	South half of RV Annulus
33	61.5	87	N/A	N/A	N/A	Cavity Walls	Lower Reactor Cavity
34	140	152	N/A	N/A	Steam Generator 1-1	SG Enclosure	North half of SG Enclosure
35	140	152	N/A	N/A	Steam Generator 1-1	SG Enclosure	South half of SG Enclosure
36	152	157	N/A	N/A	Steam Generator 1-1	SG Shield Walls	Upper SG Enclosure
37	157	171	N/A	N/A	Steam Generator 1-1	SG Shield Walls	Upper SG Enclosure
38	166	174	N/A	N/A	N/A	Pressurizer Enclosure	Top Pressurizer Enclosure

Note: The compartment locations and angles refer to the Unit 1 layout. The Unit 2 layout is a mirror image across column line 18. Azimuth angles are measured from plant North relative to Containment CL, in the clockwise direction.

TABLE 6.2-62

CONTAINMENT SUBCOMPARTMENT ANALYSES
VOLUMES FOR
SUBCOMPARTMENT MODE
L

Node	Volume (ft^3)	Node	Volume (ft^3)	Node	Volume (ft^3)	Node	Volume (ft^3)
1	2.827×10^4	**11**	1.394×10^4	**21**	1.57×10^2	**31**	4.11×10^2
2	2.560×10^4	**12**	1.620×10^4	**22**	2.09×10^2	**32**	4.11×10^2
3	2.347×10^4	**13**	2.551×10^4	**23**	6.57×10^2	**33**	1.185×10^4
4	2.393×10^4	**14**	3.693×10^4	**24**	2.39×10^2	**34**	1.228×10^3
5	2.560×10^4	**15**	1.722×10^4	**25**	4.80×10^2	**35**	8.94×10^2
6	2.774×10^4	**16**	2.710×10^4	**26**	6.39×10^2	**36**	3.24×10^2
7	1.974×10^6	**17**	9.103×10^3	**27**	3.70×10^2	**37**	9.07×10^2
8	3.403×10^4	**18**	2.142×10^4	**28**	1.35×10^2	**38**	1.68×10^3
9	3.953×10^4	**19**	2.15×10^2	**29**	2.71×10^2		
10	1.456×10^4	**20**	7.82×10^1	**30**	3.60×10^2		

TABLE 6.2-63

CONTAINMENT SUBCOMPARTMENT ANALYSES
SUBCOMPARTMENT MODEL FLOW PATH CHARACTERISTICS

Flow path Between Elements		Minimum Flow Area	*Maximum Flow Area	Hydraulic Diameter of Smaller Element	Inertial Length	Equivalent Length	$K_{forward}$	$K_{reverse}$
From	**To**	ft^2	ft^2	ft	ft	ft	-	-
1	**2**	660	1,030	11.18	26.46	22.38	0.97	1.47
1	**6**	249.5	1,214	15.06	34.36	30.36	1.50	1.50
1	**7**	79.10	500	0.507	12.08	5.84	1.94	1.94
1	**15**	17.78	100	0.256	5.98	3.40	2.08	2.08
1	**31**	2.69	50	0.251	4.92	4.59	1.50	1.50
1	**34**	4.61	29.05	1.322	6.06	5.12	1.50	1.50
1	**35**	8.56	38.39	1.322	6.58	5.25	1.50	1.50
2	**3**	660	1,030	11.77	32.74	32.74	0.47	0.47
2	**7**	13.16	500	1.322	6.18	5.02	1.50	1.50
2	**16**	10.53	100	0.585	4.76	3.14	2.08	2.08
2	**31**	1.799	50	0.251	4.92	4.59	1.50	1.50
2	**34**	8.56	81.86	1.322	5.94	5.06	1.50	1.50
2	**35**	4.61	46.24	1.322	5.74	5.05	1.50	1.50
3	**4**	55.52	1,200	7.028	32.97	31.95	1.50	1.50
3	**7**	92.26	500	0.556	13.26	6.14	1.94	1.94
3	**12**	11.03	100	0.277	4.85	3.15	2.08	2.08
3	**27**	0.94	46.80	0.280	5.49	5.01	1.50	1.50
3	**28**	0.94	12.33	0.280	5.71	5.03	1.50	1.50
3	**29**	0.94	22.05	0.280	5.58	5.01	1.50	1.50
3	**30**	0.94	45.18	0.280	5.49	5.01	1.50	1.50
3	**31**	2.69	50	0.251	4.92	4.59	1.50	1.50
4	**5**	660	1,030	11.77	32.74	32.74	0.47	0.47
4	**7**	92.26	500	0.556	13.26	6.14	1.94	1.94
4	**8**	8.71	100	0.277	4.46	3.10	2.08	2.08
4	**32**	2.69	50	0.251	4.92	4.59	1.50	1.50
5	**6**	660	1,030	11.18	26.46	22.38	1.47	0.97
5	**7**	26.33	500	1.322	7.36	5.09	1.50	1.50
5	**14**	10.23	100	0.956	4.71	3.13	2.08	2.08
5	**32**	1.80	50	0.251	4.92	4.59	1.50	1.50
6	**7**	92.26	500	0.556	13.26	6.14	1.94	1.94

TABLE 6.2-63

CONTAINMENT SUBCOMPARTMENT ANALYSES
SUBCOMPARTMENT MODEL FLOW PATH CHARACTERISTICS

Flow path Between Elements		Minimum Flow Area	*Maximum Flow Area	Hydraulic Diameter of Smaller Element	Inertial Length	Equivalent Length	$K_{forward}$	$K_{reverse}$
From	To	ft^2	ft^2	ft	ft	ft	-	-
6	9	6.84	100	0.277	4.15	3.06	2.08	2.08
6	32	2.69	50	0.251	4.92	4.59	1.50	1.50
7	8	773	1,724	0.554	18.43	7.64	1.08	1.58
7	9	356	1,373	0.554	15.61	5.85	1.08	1.58
7	12	109	820.8	0.792	15.04	5.67	1.08	1.58
7	29	13.31	22.05	3.645	4.71	3.15	1.99	1.88
7	30	13.50	45.18	3.086	6.66	5.29	2.45	2.45
7	31	4.32	11.66	0.300	8.56	5.80	1.50	1.50
7	32	4.32	11.66	0.300	8.56	5.80	1.50	1.50
7	34	17.46	1,000	3.352	6.69	6.01	0.50	1.00
7	35	52.55	1,000	3.553	8.08	6.11	0.50	1.00
7	36	24.19	1,000	4.838	5.83	4.81	0.50	1.00
7	37	129.1	1,000	5.538	10.34	5.50	0.50	1.00
7	38	48.24	198.8	6.761	4.20	2.25	1.50	1.50
8	9	212	303.5	8.835	119.18	119.18	0.14	0.14
8	12	212	303.5	8.835	83.17	83.17	0.14	0.14
8	13	651	837.4	0.554	17.13	12.14	0.58	0.58
8	14	690	887.0	0.554	17.13	12.14	0.58	0.58
9	10	212	303.5	8.835	86.94	86.94	0.14	0.14
9	14	501	644.0	0.554	17.13	12.14	0.58	0.58
9	15	570	732.8	0.554	17.12	12.14	0.58	0.58
9	16	425	545.9	0.554	17.12	12.14	0.58	0.58
10	11	212	303.5	8.835	47.21	47.21	0.14	0.14
10	16	440	565.8	0.554	17.13	12.14	0.58	0.58
10	17	134	172.1	0.554	17.13	12.14	0.58	0.58
11	12	212	303.5	8.835	49.91	49.91	0.14	0.14
11	17	192	247.3	0.554	17.13	12.14	0.58	0.58
11	18	357	459.3	0.554	17.13	12.14	0.58	0.58
12	13	139	179.3	0.554	17.13	12.14	0.58	0.58
12	18	311	399.7	0.554	17.12	12.14	0.58	0.58
13	14	230	397.8	6.724	83.26	83.26	0.28	0.28
13	18	94.01	397.8	9.601	45.79	35.52	1.50	1.50
14	15	230	397.8	6.724	73.98	73.98	0.28	0.28
15	16	230	397.8	6.724	60.28	60.28	0.28	0.28
16	17	314	397.8	10.82	50.03	50.03	0.43	0.43
17	18	230	397.8	6.724	41.78	41.78	0.28	0.28

TABLE 6.2-63

CONTAINMENT SUBCOMPARTMENT ANALYSES
SUBCOMPARTMENT MODEL FLOW PATH CHARACTERISTICS

Flow path Between Elements		Minimum Flow Area	*Maximum Flow Area	Hydraulic Diameter of Smaller Element	Inertial Length	Equivalent Length	$K_{forward}$	$K_{reverse}$
From	**To**	ft^2	ft^2	ft	ft	ft	-	-
19	**20**	6.16	22.44	2.045	8.30	8.30	0.19	0.78
19	**22**	13.41	22.44	3.433	11.38	11.38	0.21	0.49
19	**23**	37.17	47.79	0.266	6.56	4.56	0.58	0.58
19	**38**	53.10	60.16	9.390	5.43	4.77	0.10	0.04
20	**21**	6.16	13.01	2.045	8.62	8.62	0.61	0.23
20	**24**	13.51	17.37	0.253	6.23	4.25	0.58	0.58
20	**38**	19.30	29.74	4.209	4.59	3.62	0.20	0.12
21	**22**	13.00	13.41	3.372	8.01	8.01	0.30	0.30
21	**25**	27.16	34.92	0.263	6.48	4.47	0.58	0.58
21	**38**	38.80	47.29	7.487	5.20	4.43	0.13	0.06
22	**26**	36.12	46.44	0.266	6.56	4.56	0.58	0.58
22	**38**	51.60	58.81	9.365	5.41	4.74	0.10	0.05
23	**24**	18.81	68.55	2.464	8.30	8.30	0.17	0.76
23	**26**	40.96	68.55	4.802	11.38	11.38	0.19	0.47
23	**27**	36.40	46.80	0.266	7.93	5.63	0.58	0.58
24	**25**	18.81	39.73	2.464	8.62	8.62	0.60	0.21
24	**28**	9.59	12.33	0.246	6.63	4.10	0.58	0.58
25	**26**	39.72	40.96	4.684	8.01	8.01	0.29	0.29
25	**29**	17.15	22.05	0.255	6.25	3.74	0.58	0.58
26	**30**	35.14	45.18	0.265	7.89	5.59	0.58	0.58
27	**28**	7.11	38.65	1.622	8.08	8.08	0.20	0.89
27	**30**	23.09	38.65	4.175	11.05	11.05	0.20	0.47
28	**29**	7.11	15.42	1.622	7.83	7.83	0.65	0.25
29	**30**	15.41	23.09	3.095	8.31	8.31	0.45	0.23
31	**32**	14.46	14.46	1.044	26.95	26.95	0.21	0.21
31	**33**	6.91	204.3	0.526	14.25	13.58	0.88	0.51
32	**33**	6.91	204.3	0.526	14.25	13.58	0.88	0.51
34	**35**	54.09	54.09	4.508	24.00	24.00	0.37	0.85
34	**36**	61.38	61.38	6.591	8.50	8.50	0.26	0.21
36	**37**	61.38	61.38	6.591	9.50	9.50	0.00	0.00

TABLE 6.2-64

CONTAINMENT SUBCOMPARTMENT ANALYSES
LOCA PEAK DIFFERENTIAL PRESSURES

Break	Differential Pressure Across (Node Numbers)	Design Differential Pressure, psi	Calculated Peak Differential Pressure, psi	Calculated Absolute Pressure At Time of Peak Differential, psia	Figure
Pressurizer Surge Line at the RCS Hot Leg Connection	Loop Compartment Crane Wall (Node 3 to 12)	15.0	5.90	21.87	6.2-66
Pressurizer Surge Line at the RCS Hot Leg Connection	Loop Compartment Operating Deck Elev. 140', inside Crane Wall (Node 3 to 7)	15.0	5.86	21.87	6.2-72
Pressurizer Surge Line at the RCS Hot Leg Connection	Loop Compartment Floor / Lower reactor cavity (Node 3 to 33)	6.0	5.80	21.87	6.2-74
Pressurizer Surge Line at the RCS Hot Leg Connection	Reactor Cavity Primary Shield Wall (Node 3 to 31)	6.0	4.93	21.87	6.2-73
Pressurizer Spray Line at the Top of the Pressurizer	Pressurizer Enclosure Pressurizer Enclosure Wall (Node 38 to 7)	4.0	0.96	16.95	6.2-68

TABLE 6.2-65

CONTAINMENT SUBCOMPARTMENT ANALYSES
MAIN STEAM LINE BREAK OUTSIDE THE CRANE WALL
AT THE CONTAINMENT PENETRATION
MASS AND ENERGY RELEASES

Time (sec)	Forward Flow (lbm/sec)	Enthalpy (Btu/lbm)	Energy Rate (Btu/sec)	Time (sec)	Reverse Flow (lbm/sec)	Enthalpy (Btu/lbm)	Energy Rate (Btu/sec)	Time (sec)	Total Flow (lbm/sec)	Total Energy Rate (Btu/sec)
0.0	6203.4	1192.2	7.396×10^6	0.0	7740.4	1192.2	9.228×10^6	0.0	13943.8	16.624×10^6
0.096	6203.4	1192.2	7.396×10^6		7740.4	1192.2	9.228×10^6	0.096	13943.8	16.624×10^6
0.097	2914.8	1192.2	3.475×10^6		7740.4	1192.2	9.228×10^6	0.097	10655.2	12.703×10^6
0.964	2914.8	1192.2	3.475×10^6		7740.4	1192.2	9.228×10^6	0.964	10655.2	12.703×10^6
0.965	10271.2	571.5	5.870×10^6		7740.4	1192.2	9.228×10^6	0.965	18011.6	15.098×10^6
	10271.2	571.5	5.870×10^6	1.391	7740.4	1192.2	9.228×10^6	1.391	18011.6	15.098×10^6
	10271.2	571.5	5.870×10^6	1.392	27275.7	571.5	15.588×10^6	1.392	37546.9	21.458×10^6

TABLE 6.2-66

CONTAINMENT SUBCOMPARTMENT ANALYSES
MAIN FEEDWATER LINE BREAK INSIDE THE STEAM GENERATOR ENCLOSURE
AT THE INLET TO THE STEAM GENERATOR
MASS AND ENERGY RELEASED

Time (sec)	Reverse Flow (lbm/sec)	Enthalpy (Btu/lbm)	Energy Rate (Btu/sec)	Time (sec)	Forward Flow (lbm/sec)	Enthalpy (Btu/lbm)	Energy Rate (Btu/sec)	Time (sec)	Total Flow (lbm/sec)	Total Energy Rate (Btu/sec)
0.0	8920.1	545.6	4.867×10^6	0.0	5315.5	413.9	2.200×10^6	0.0	14235.6	7.067×10^6
	8920.1	545.6	4.867×10^6	0.268	5315.5	413.9	2.200×10^6	0.268	14235.6	7.067×10^6
	8920.1	545.6	4.867×10^6	0.269	5315.5	413.9	2.200×10^6	0.269	14235.6	7.067×10^6
18.60	8920.1	545.6	4.867×10^6		5315.5	413.9	2.200×10^6	18.60	14235.6	7.067×10^6
18.61	0.0	NA	0.0		5315.5	413.9	2.200×10^6	18.61	5315.5	2.200×10^6

TABLE 6.2-67

CONTAINMENT SUBCOMPARTMENT ANALYSES
Non-LOCA PEAK DIFFERENTIAL PRESSURES

Break	Differential Pressure Across (Node Numbers)	Design Differential Pressure, psi	Calculated Peak Differential Pressure, psi	Calculated Absolute Pressure At Time of Peak Differential, psia	Figure
Main Feedwater Line Break Inside the Steam Generator Enclosure	Steam Generator Enclosure Steam Generator Shield Wall (Elev. 152' to 157') (Node 36 to 7)	20.0	19.54	33.24	6.2-70
Main Steam Line Break Outside the Crane Wall	Crane Wall (Node 10 to 1)	15.0	8.43	24.43	6.2-71

TABLE 6.3-1

EMERGENCY CORE COOLING SYSTEM
COMPONENT PARAMETERS

Accumulators	Number (per unit)	4
	Design Pressure, psig	700
	Design Temperature, °F	300
	Operating Temperature, °F	50-150
	Normal Operating Pressure, psig	621.5
	Minimum Operating Pressure, psig [c]	579
	Total Volume, ft^3	1,350 each
	Nominal Water Volume, ft	850
	Boric Acid Concentration Nominal, ppm Minimum, ppm	 2,350 2,200
	Relief Valve Setpoint, psig	700
Centrifugal Charging Pumps (CCP1 and 2)	(Design parameters for these pumps are given in Table 9.3-5.)	
Safety Injection Pumps	Number (per unit)	2
	Design Pressure, psig	1,700
	Design Temperature, °F	300
	Design Flowrate, gpm	425
	Design Head, ft	2,500
	Max Flowrate, gpm	675
	Head at Max Flowrate, ft	1,500
	Discharge Pressure at Shutoff Head, psig	1,520
	Motor Rating, hp[a]	400
Residual Heat Removal Pumps	(Design parameters for these pumps are given in Table 5.5-10)	

Residual Heat Exchangers	(Design parameters for these heat exchangers are given in Table 5.5-10)	
Refueling Water Storage Tank	Number (per unit)	1
	Total available tank volume (includes only usable volume)[b], gal	450,000
	Minimum Technical Specifications required volume (includes usable and unusable volume), gal	455,300
	Accident analysis minimum volume (to low level, gal)	250,000
	Boron Concentration, ppm	2300-2500
	Design Pressure, psig	Atmospheric
	Operating Pressure, psig	Atmospheric
	Design Temperature, °F	100
	Material	Austenitic stainless steel with reinforced concrete shroud
Valves		
(1) All Motor-Operated Valves That Must Function on Safety Injection ("S") Signal		
(a) Up to and including 8 inches (excluding SI-8805 A&B, CVCS-8107 and CVCS-8108)	Maximum opening or closing time, sec	10
(b) CVCS-8107 and CVCS 8108	Maximum opening and closing time, sec	14

(c) SI-8805 A&B	Maximum opening or closing time, sec	11
(d) Over 8 inches	Minimum opening or closing rate, in./min	60
(2) All Other Motor-Operated Gate Valves Up to and Including 8 Inches	Minimum opening or closing rate, in./min	12

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

(3) Original purchase specification leakage criteria. Inservice leakage requirements are specified in the valve Inservice Testing Program.

(a) Conventional globe valves	*Disk leakage, cc/hr/in. of nominal pipe size*	*3*
	Backseat leakage (when open), cc/hr/in. of stem diameter	*1*
(b) Gate valves	*Disk leakage, cc/hr/in. of nominal pipe size*	*3*
	Backseat leakage (when open), cc/hr/in. of stem diameter	*1*
(c) Check valves	*Disk leakage, cc/hr/in. of nominal pipe size*	*3*
(d) Diaphragm valves	*Disk leakage*	*None*
(e) Pressure relief	*Disk leakage, cc/hr/in. of nominal pipe size*	*3*
(f) Accumulator check valves	*Disk leakage, cc/hr/in. of nominal pipe size*	*3*

(a) 1.15 service factor not included.

(b) Usable volume includes the water above the outlet pipe. Unusable water includes the water below the outlet.

(c) This minimum SI accumulator pressure is the value that is used in the accident analysis in Chapter 15. (Note that more conservative values may appear in other documents such as Technical Specifications, operating procedures, etc.)

TABLE 6.3-2

EMERGENCY CORE COOLING SYSTEM
DESIGN CODE REQUIREMENTS

Component	Code
Accumulators	ASME B&PV, Section III[a] Class C
Refueling Water Storage Tank Valves	AWWA D100[c] USAS B16.5, MSS-SP-66 and ASME B&PV, Section III[a]
Piping[b]	
- Design Class I portions (excluding Code Class A and @)	ANSI B31.7
- Design Class I, Code Classes A and @ portions and Design Class II portions	ANSI B31.1
Pumps	
Charging	ASME B&PV, Section III[a]
Residual heat removal	ASME B&PV, Section III[a]
Safety injection	ASME B&PV, Section III[a]

(a) Draft Code November 1968 Edition.

(b) See Q-List (Reference 8 of Section 3.2) for piping classification.

(c) ASME B&PV Code, Section VIII, allowable stresses used for design.

TABLE 6.3-3

MATERIALS OF CONSTRUCTION
EMERGENCY CORE COOLING SYSTEM COMPONENTS

COMPONENT	MATERIAL
Accumulators	Carbon steel, clad with austenitic stainless steel
Refueling Water Storage Tank	Austenitic stainless steel with reinforced concrete shroud
Pumps (parts in contact with coolants)	
Centrifugal charging	Austenitic stainless steel
Safety injection	Martensitic stainless steel
Residual heat removal	Austenitic stainless steel or equivalent corrosion-resistant material
Residual Heat Exchangers	
Shell	Carbon steel
Shell end cap	Carbon steel
Tubes	Austenitic stainless steel
Channel	Austenitic stainless steel
Channel cover	Austenitic stainless steel
Tube sheet	Forged carbon steel with austenitic stainless steel weld overlay
Valves	
Motor-operated valves containing radioactive fluids and pressure-containing parts	Austenitic stainless steel or equivalent
Body-to-bonnet bolting and nuts	Low-alloy steel, austenitic stainless steel, or 17-4PH stainless
Seating surfaces	Stellite No. 6 or equivalent
Stems	Austenitic stainless steel or 17-4PH stainless

TABLE 6.3-3

COMPONENT	MATERIAL
Motor-operated Valves Containing Non-radioactive, Boron-free Fluids	
Body, bonnet, and flange	Carbon steel
Stems	Corrosion resistant steel
Diaphragm	Austenitic stainless steel
Accumulator Check Valves	
Parts contacting borated water	Austenitic stainless steel
Clapper arm shaft	Corrosion resistant steel
Relief Valves	
Stainless steel bodies	Stainless steel
Carbon steel bodies	Carbon steel
All nozzles, disks, spindles, and guides	Austenitic stainless steel
Bonnets for stainless steel valves without a balancing bellows	Stainless steel
All other bonnets	Carbon steel
Piping	
All piping in contact with borated water	Austenitic stainless steel

TABLE 6.3-5

SAFETY INJECTION TO RECIRCULATION MODE; SEQUENCE AND TIMING OF MANUAL CHANGEOVER

Action	Status	Item	Actuation Time sec	Time for Operation sec	Total Elapsed Time min
	LOCA				0:00
	Safety injection signal-all RHR, SI and charging pumps (CCP1 and CCP2) in operation				0:20
	Spray initiation				0:40
	RWST low level alarm and RHR pumps trip; initiate recirculation changeover				17:56
IMPLEMENT - Appendix EE			0	10	18:06
CUT IN - Series Contactors **		8974A, 8809A, 8982A, 8982B, 8974B, 8809B	0	10	18:16
VERIFY - Safety injection signal reset **			5	10	18:26
VERIFY - Containment isolation Phase A and Phase B reset **			5	10	18:36
CHECK - Both ASW pumps running			0	5	18:41
VERIFY - CCW heat exchanger saltwater inlet valves open **		FCV-602(603) (Note 3)	5	10	18:51
VERIFY - CCW heat exchanger CCW outlet valves open **		FCV-430(431) (Note 3)	5	10	19:01

TABLE 6.3-5

OPEN - Component cooling water to RHR heat exchanger 2 **	FCV-364	10	15	19:16
OPEN - Component cooling water to RHR heat exchanger 1 **	FCV-365	10	15	19:31
STOP - Centrifugal charging pump CCP3 **		5	10	19:41
PA Announcement **		0	10	19:51
Dispatch Operators to locally close breakers for 8976 and 8980 **	52-1H/2H-20 52-1F/2F-31	0	20	20:11
VERIFY - RHR Pump 2 stopped		0	5	18:11
CLOSE - RHR pump suction valve from RWST	8700B	120	125	20:16
VERIFY - RHR Pump 1 stopped		0	5	20:21
CLOSE - RHR pump suction valve from RWST	8700A	120	125	22:26
CLOSE - RHR crosstie isolation valves	8716A 8716B	20 20	30	22:56
CHECK – RCS Pressure less than 1500 PSIG		0	5	23:01
CLOSE - SI pump miniflow block valves	8974A 8974B	10 10	20	23:21
CLOSE - CCP recirculation valves	8105 8106	10 10	20	23:41
CHECK - recirculation sump level > 92.0’	LI-940 LI-941	5 5	10	23:51
CHECK - RHR pump 2 stopped		0	5	23:56

TABLE 6.3-5

CHECK - RHR P2 suction from RWST closed		8700B	0	5	24:01
OPEN – RHR P2 suction from sump		8982B	30	35	24:36
VERIFY - RHR HX 1-2 in Service per App. EE			5	5	24:41
START - RHR-P2		RHR-P2	1	15	24:56
OPEN - SI pumps suction from RHR HX2		8804B	20	25	25:21
CHECK - RCS Pressure less than 1500 PSIG			0	5	25:26
VERIFY - SI pumps running			0	5	25:31
CHECK - RHR Pump 2 motor current less than 57 amps AND stable			0	5	25:36
OPEN - Cross-connect line from SI pump 1 to charging pumps (CCP1 and CCP2)		8807A 8807B	20 20	30	26:06
VERIFY - CCP1 and CCP2 running	Changeover of a single train complete at 26:11		0	5	26:11
CHECK - RHR pump 1 stopped			0	5	26:16
CHECK - RHR P1 suction from RWST closed		8700A	0	5	26:21
OPEN - RHR P1 suction from sump		8982A	30	35	26:56
VERIFY - RHR HX 1 in Service per App. EE			5	5	27:01
START - RHR P1		RHR-P1	1	15	27:16
OPEN - SI pump suction from RHR HX1	Changeover of both trains complete at 27:41	8804A	20	25	27:41

TABLE 6.3-5

CHECK- RCS Pressure less than 1500 PSIG			0	5	27:46
VERIFY - SI pumps running			0	5	27:51
CHECK - RHR Pump 1 motor current less than 57 amps AND stable			0	5	27:56
CHECK - at least one RHR pump running		RHR Pump	0	5	28:01
CLOSE - Charging pump suction RWST isolation		8805A 8805B	11 11	21	28:22
CLOSE - SI pump suction RWST isolation		8976	20	25	28:47
CLOSE - RHR pump suction from RWST		8980	25	30	29:17
	Receive RWST low-low level alarm				33:25
CHECK - both RHR pumps running			0	5	33:30
CHECK - PK01-18, Containment Spray Actuated On OR Cont. Pressure greater than 22 PSIG			0	10	33:40
CHECK - RWST level less than 4%		LI-920 LI-921 LI-922	5 5 5	15	33:55
RESET - Containment spray			5	10	34:05
STOP - Containment Spray (CS) pumps1 & 2		CS-P1 CS-P2	1 1	5	34:10
CLOSE - CS pump discharge to spray header valves	System in recirculation mode	9001A 9001B	10 10	20	34:30

TABLE 6.3-5

VERIFY - Both RHR trains in service			0	5
CLOSE - RCS from RHR-P1 (Note 4)	Cold leg injection terminated	8809A	20	25
OPEN - RHR-P1 to spray header (Note 4)	Recirculation sump to spray header	9003A	15	20

Notes to Table 6.3-5

1. Actuation Time: The estimated actuation time for a component to complete its function. For valves, this is the maximum expected stroke time. In some cases, where the component is already expected to be in the desired position, no actuation time is added.

2. Time for Operation: The actuation time plus the estimated operator action, if applicable.

3. If the valves are not already in the desired position the analysis assumes they are stroked concurrently while the crew continues in the procedure, since subsequent checks of ASW/CCW alignment are made at decision points further on in the procedure.

4. If only 1 train of RHR is in service, the in-service train is used.

** All these steps from Appendix EE of Procedure EOP E-1.3 can be performed in parallel with the steps that follow since they add up to 125 seconds, which is less than the 295 seconds (from 18:06 to 23:01) needed before we close 8974A/B (this is the first step that depends on a step from Appendix EE).

The following assumptions are used for Table 6.3-5:

1. Double-ended reactor coolant pump suction LOCA.

2. Maximum safety features implemented:

   a. Pumps at flow limited by pipe friction
      2 RHR pumps: 7300 gpm total during injection
      1 RHR pump: 4600 gpm for 5 minutes during changeover, when assuming a single failure of one RHR pump to trip on low RWST level
      2 SI pumps: 900 gpm total
      2 Charging pumps (CCP1 and CCP2): 900 gpm total

b. 2 Containment spray pumps: 6550 gpm total during injection, assuming 20 psig in containment
6800 gpm total during changeover, assuming 0 psig in containment

c. Allowable 100 gpm leakage penalty from RWST

3. Refueling water storage tank.

a. Maximum outflow: 15,750 gpm based on 2a and 2b during injection
8,700 gpm based on 2a and 2b during changeover, no single failure

b. Volume available: 404,511 gal.

c. Low-level alarm volume: 116,812 gal.

d. Low-low level alarm volume: 0 gal.

TABLE 6.3-6

NORMAL OPERATING STATUS OF EMERGENCY CORE COOLING SYSTEM COMPONENTS FOR CORE COOLING

Number of Safety Injection Pumps Operable	2
Number of Charging Pumps Operable	2
Number of Residual Heat Removal Pumps Operable	2
Number of Residual Heat Exchangers Operable	2
Refueling Water Storage Tank Available Volume, gal	350,000
Boron Concentration in Refueling Water Storage Tank,	
Maximum, ppm	2,500
Minimum, ppm	2,300
Boron Concentration in Accumulators,	
Maximum, ppm	2,500
Minimum, ppm	2,200
Number of Accumulators	4
Minimum Accumulator Pressure, psig [(a)]	579
Nominal Accumulator Water Volume, ft^3	850
System Valves, Interlocks, and Piping Required for the Above Components which are Operable	All

(a) This minimum SI accumulator pressure is the value that is used in the accident analysis in Chapter 15. (Note that more conservative values may appear in other documents such as Technical Specifications, operating procedures, etc.)

TABLE 6.3-7

SEQUENCE AND DELAY TIMES FOR STARTUP OF ECCS
CHANGES ON THIS TABLE APPLY TO BOTH UNIT 1 and UNIT 2

Accident	Actuation Signal(s)	Action Sequence (Subsystem or Component)	Delay, sec (h)	Delay, sec (i)	Delay, sec (j)	Design Performance	Minimum ECCS Performance Assumed in Analysis	References Section FSAR	References Figures	References Tables
1. Major Reactor Coolant System Rupture (LOCA)								15.4.1		
a. Injection phase	(g)	Accumulator tank	(g)	(g)	(g)	4 tanks, each with 850 ft^3 of borated water @ 600 psig	Three tanks injecting into RCS; one injecting into broken loop	6.3		
	(a)	Containment isolation valves	4	10	10	Double barrier; fast automatic valve closure upon receipt of CIS (m)	A single active failure is allowable	6.2.4	6.2-17, 6.2-18 & 6.2-19	8.3-4
	(b) (d)	ECCS required valves	(k)	(k)	See Table 6.3-1	Rapid reliable system alignment or isolation	A single active failure is allowable	6.3.2	7.3-22, 7.3-33	8.3-4
	(b) (d)	Centrifugal charging pumps	6	12	4-1/2	Two centrifugal charging pumps supply borated water into a single injection flowpath splitting into 4 cold leg injection lines	One pump required at assumed flow	6.3.2, 9.3.4	7.3-4	8.3-4
	(b) (d)	Safety injection pumps	6/10	12/16	2.5	Two pumps inject via a single path splitting into 4 cold leg injection lines	One pump delivering at assumed flow	6.3.2	3.2-9	
	(b) (d)	Residual heat removal pumps	10	16	1.5	Two pumps inject into 4 cold legs, via 2 lines that each split into 2 cold leg injection lines	One pump delivering at assumed flow	6.3.2, 5.5.6	3.2-9	
	(b) (d)	Component cooling water pumps	14/14 /18	20/20/ 24	4-1/2	Two flowpaths; each 10,500 gpm @ 120 ft	One flowpath required at assumed flow	9.2.2	7.3-7	8.3-4
	(e)	Auxiliary feed-water pumps	22/30	28/36	6.9	Two flowpaths; each 800 gpm @ 2350 ft	Not modeled for LBLOCA	6.5.2	7.3-8	8.3-4
	(b) (d)	Auxiliary salt-water pumps	18/18	24/24	5	Two flowpaths; each 11,000 gpm @ 115 ft	One flowpath required at assumed flow	9.2.7	7.3-5	8.3-4

TABLE 6.3-7

CHANGES ON THIS TABLE APPLY TO BOTH UNIT 1 and UNIT 2

Accident	Actuation Signal(s)	Action Sequence (Subsystem or Component)	Delay, sec (h)	Delay, sec (i)	Delay, sec (j)	Design Performance	Minimum ECCS Performance Assumed in Analysis	References Section FSAR	References Figures	References Tables
	(c) (l)	Containment spray pumps				Two flowpaths; each 2600 gpm @ 450 ft	One flowpath required at assumed flow	6.2.2	7.3-11	8.3-4
		Pump 1	30	36	1.7					
		Pump 2	30	36	1.7					
b. Recirculation phase	(f)	Operating personnel shift system alignment from injection phase	(Total switchover time is approximately 10 min. See 6.3.2)			(Design performance for ECCS and related equipment as described in 1a above)	A single failure is allowable	6.3.3		6.3-5
2. Major Seccondary System Rupture	(b)	Action sequence similar to 1a above. Operation of ESF required. Valves isolate feedwater & steam	Same as 1a above			Same as 1a above	Same as 1a above with these further notes: Accumulator and low head injection required only in the severe cases. Since no RCS rupture has occurred, all four accumulators are functional	15.4.2		

TABLE 6.3-7

CHANGES ON THIS TABLE APPLY TO BOTH UNIT 1 and UNIT 2

Accident	Actuation Signal(s)	Action Sequence (Subsystem or Component)	(h)	(i)	(j)	Design Performance	Minimum ECCS Performance Assumed in Analysis	Section FSAR	Figures	Tables
3. Steam Generator Tube Rupture	Low pressurizer pressure	Same as 1a above although no containment spray. Additionally, automatic isolation of individual steam generator blowdown valve occurs due to SGBD liquid radiation monitor. Injection and charging flow regulated to maintain visible pressurizer water level. Auxiliary feedwater to affected SG manually isolated. Pressurizer reliefs operated to reduce RCS pressure to less than the ruptured SG pressure.	Same as 1a above with additional isolation done within 30 minutes			Same as 1a above	Same as 1a above (but all four accumulators assumed functional, AFW available).	15.4.3		
4. Minor RCS Rupture which Actuates ECCS	Low pressurizer pressure or high containmen t pressure							15.3.1		
a. Injection phase	Same as 1a above	Same as 1a above	Same as 1a above			Same as 1a above	Same as 1a above			
b. Recirculation	Same as 1a above	Same as 1a above	Same as 1a above			Same as 1a above	Same as 1a above			

TABLE 6.3-7

CHANGES ON THIS TABLE APPLY TO BOTH UNTIS 1 & 2

(a) Initiated by means of containment isolation signal, which occurs on containment high pressure (2 of 3, Phase A), containment high-high pressure (2 of 4, Phase B), low pressurizer pressure (Phase A) or on manual actuation (Phase A and/or B).

(b) Safety injection signal (SIS) actuates on any of the following: Low pressurizer pressure, high containment pressure, low steamline pressure, or manual actuation.

(c) Containment spray signal, which occurs on containment high-high pressure (2 of 4), or manual actuation.

(d) Emergency diesel loading sequencer loads the diesel in accordance with the sequence shown in Tables 8.3-2 and 8.3-4. Also see Figures 8.3-9, 8.3-10, 8.3-11, and 8.3-16.

(e) Auxiliary feedwater autostart signal, which occurs with an SIS, SG low-low level, or tripping of both main feedwater pumps.

(f) Water level indication and alarms on the refueling water storage tank and in the containment sump provide ample warning to terminate the injection mode and begin the recirculation mode while the operating pumps still have adequate net positive suction head. Manual switchover by operating personnel changes the ECCS from injection to recirculation mode.

(g) All valves between the accumulators and the RCS are required to be open in Modes 1, 2, and 3; consequently, the accumulators inject as soon as the RCS pressure drops below the pressure (600 psia) of the accumulators.

(h) Electrical and instrumentation delay time after "S" signal with main generator power or offsite power available and a 4 second bus auto transfer.

(i) Electrical and instrumentation delay time after "S" signal using diesel generator.

(j) Equipment startup time after receipt of signal.

(k) These delay times vary.

(l) DIT 68029121-1-0 and Westinghouse containment integrity analysis CN-CRA-14-6 and CN-CRA-14-7 established the limiting containment spray delay time to be based on the “S” signal rather than the “P” signal.

(m) Containment purge supply and exhaust valves are sealed closed in Modes 1-4.

TABLE 6.3-8

EMERGENCY CORE COOLING SYSTEM SHARED FUNCTIONS EVALUATION

Component	Normal Operating Arrangement	Accident Arrangement
Refueling water storage tank	Lined up to suction of safety injection and residual heat removal pumps	Lined up to suction of centrifugal charging, safety injection, and residual heat removal pumps. Valves for realignment meet single failure criteria.
Centrifugal charging pumps	Lined up for charging service	Lined up to charging injection header. Valves for realignment meet single failure criteria.
Residual heat removal pumps	Lined up to cold legs of reactor coolant piping	Lined up to cold legs of reactor coolant piping.
Residual heat exchangers	Lined up for residual heat removal pump operation	Lined up for residual heat removal pump operation.

TABLE 6.3-9

MAXIMUM POTENTIAL RECIRCULATION LOOP LEAKAGE EXTERNAL TO CONTAINMENT

Items	Type of Leakage Control and Unit Leakage Rate Used in the Analysis	Leakage to Atmosphere, cc/hr	Leakage to Drain Tank, cc/hr
1. Residual Heat Removal Pumps	Mechanical seal with leakoff - 10 cc/hr seal[(a)]	20	0
2. Safety Injection Pumps	Same as residual heat removal pump	40	0
3. Charging Pumps	Same as residual heat removal pump	40	0
4. Flanges:			
a. Pumps	Gasket - adjusted to zero leakage following any test; 10 drops/min/flange used(30 cc/hr). Due to leak tight flanges on pumps, no leakage to atmosphere is assumed	0	0
b. Valves bonnet to body (larger than 2 in.)		1200	0
c. Control valves		180	0
d. Heat exchangers		240	0
5. Valves - Stem Leakoffs	Backseated double-packing with leakoff - 1 cc/hr in. stem diameter used (see Table 6.3-1)	0	40
6. Misc. Small Valves	Flanged body-packed stems -1 drop/min used (3 cc/hr).	150	0
7. Misc. Large Valves (larger than 2 in.)	Double-packing 1 cc/hr/in. stem diameter used	40	0
	TOTALS	1910	40

(a) Seals are acceptance tested to essentially zero leakage.

TABLE 6.3-10

ECCS RELIEF VALVE DATA

Description	Fluid Discharged	Fluid Inlet Temp Normal, °F	Set Pressure, psig	Back Pressure Constant	Psig Build-up	Capacity
N_2 supply to accumulators	N_2	120	700	0	0	1500 scfm
SIS pump discharge	Water	100	1750	3	50	20 gpm
RHR pumps SI line	Water	120	600	3	50	400 gpm
SI pumps suction header	Water	120	220	3	50	20 gpm
Accumulator to containment	Water or N_2 gas	120	700	0	0	1500 scfm

TABLE 6.3-11

NET POSITIVE SUCTION HEADS FOR
POST-DBA OPERATIONAL PUMP[(a)]

Pump	Flow and Condition	Suction Source	Minimum Available NPSH, ft	Required NPSH, ft	Water Temp, °F
Safety injection	675 gpm runout flow	Refueling water storage tank	31	29	100 max
Centrifugal charging	560 gpm runout flow	Refueling water storage tank	44	24	100 max
Residual heat removal	4500 gpm	Refueling water storage tank	27	20	100 max
Residual heat removal	4900 gpm runout flow	Containment sump	25	24	Saturated liquid
Containment spray	3500 gpm runout flow	Refueling water storage tank	40	19	100 max

(a) NPSH conservatively calculated without considering additional static suction head of water in the RWST.

TABLE 6.3-12

ECCS MOTOR-OPERATED VALVES WITH
ELECTRIC POWER REMOVED DURING NORMAL POWER PLANT OPERATION

Valve Identification	Service Description	Position: Normal Operation	Position: Injection Phase	Position: Cold Leg Recirc Phase	Position: Hot Leg Recirc Phase	Power Restorable From Control Room
8703	RHR pump discharge to RCS hot leg loops	Closed	Closed	Closed	Open	No
8802 A, B	SIS pump discharge to RCS hot leg loops	Closed	Closed	Closed	Open	No
8808 A, B, C, D	Accumulator isolation	Open	Open	Open	Open	No
8809 A	RHR pump discharge to RCS cold leg loops	Open	Open	Closed[b]	Closed	Yes
8809 B		Open	Open	Open	Closed	Yes
8835	SIS pump discharge to RCS cold leg loops	Open	Open	Open	Closed	No
8974 A, B	SIS pump miniflow	Open	Open	Closed	Closed	Yes
8976	RWST supply to SIS pumps	Open	Open	Closed	Closed	No
8980	RWST supply to RHR pumps	Open	Open	Closed	Closed	No
8982 A, B	Containment recirc. sump supply to RHR pumps	Closed	Closed	Open	Open	Yes

TABLE 6.3-12

Valve Identification	Service Description	Position: Normal Operation	Position: Injection Phase	Position: Cold Leg Recirc Phase	Position: Hot Leg Recirc Phase	Power Restorable From Control Room
8992	NaOH spray additive supply	Open	Open	Open	Open	No
8701[(a)]	Loop 4 hot leg RHR suction valve 2	Closed	Closed	Closed	Closed	No
8702[(a)]	Loop 4 hot leg RHR suction valve 1	Closed	Closed	Closed	Closed	No

(a) Valve required to function for a normal RHR cooldown not for ECCS.
(b) Closed if containment spray is required.

Table 6.3-13

SINGLE ACTIVE FAILURE ANALYSIS FOR EMERGENCY CORE COOLING SYSTEM COMPONENTS

SHORT-TERM PHASE

Component	Malfunction	Comments
A. Accumulator	Deliver to broken loop	Totally passive system with one accumulator per loop. Evaluation based on one spilling accumulator.
B. Pump		
1. Centrifugal charging	Fails to start	Two provided; evaluation based on operation of one.
2. Safety injection	Fails to start	Two provided; evaluation based on operation of one.
3. Residual heat removal	Fails to start	Two provided; evaluation based on operation of one.
4. Residual heat removal	Fails to trip on RWST Low Level	Operator trips pump locally at the breaker.
C. Automatically Operated Valves		
1. Charging injection isolation		
a. Inlet	Fails to open	Two parallel lines; one valve in either line required to open
b. Outlet	Fails to open	Two parallel lines; one valve in either line required to open.
2. Centrifugal Charging Pumps		
a. Suction line from refueling water storage tank	Fails to open	Two parallel lines; only one valve in either line is required to open.

SHORT-TERM PHASE (Continued)

Component	Malfunction	Comments
b. Discharge line to the normal charging path	Fails to close	Two valves in series; only one valve required to close.
c. Minimum flow line	Fails to close	Two valves in series; only one valve required to close.
d. Suction line from volume control tank	Fails to close	Two valves in series; only one valve required to close.

LONG-TERM PHASE

A. Valves Operated from Control Room for Recirculation		
1. Containment sump recirculation isolation	Fails to open	Two parallel lines; only one valve in either line is required to open.
2. Residual heat removal pump suction line from refueling water storage tank	Fails to close	Check valve in series with gate valve, operation of only one valve required.
3. Safety injection pump suction line from refueling water storage tank	Fails to close	Check valve in series with gate valve, operation of only one valve required.
4. Centrifugal charging pump (CCP1 and 2) suction line from refueling water storage tank	Fails to close	Check valve in series with two parallel gate valves. Operation of either the check valve or the gate valve required.

Table 6.3-13

LONG-TERM PHASE (Continued)

Component	Malfunction	Comments
5. Safety injection pump suction line at discharge of residual heat exchanger No. 2	Fails to open	Separate and independent high head injection path taking suction from discharge of residual heat exchanger No. 1. A crossover line allows flow from one heat exchanger to reach both safety injection and charging pumps, if necessary.
6. Centrifugal charging pump (CCP1 and CCP2) suction line at discharge of residual heat exchanger No. 1	Fails to open	Separate and independent high head injection path taking suction from discharge of residual heat exchanger No. 2. A crossover line allows flow from one heat exchanger to reach both safety injection and charging pumps, if necessary.
7. Centrifugal charging pump (CCP1 And CCP2) crossover line to safety injection pump suction	Fails to open	Two parallel lines; only one valve in either line is required to open.
B. Pumps		
1. Residual heat removal pump	Fails to start	Two provided. Evaluation based on operation of one.
2. Charging pump	Fails to operate	Same as short-term phase
3. Safety injection pumps	Fails to operate	Same as short-term phase

Table 6.3-14

EMERGENCY CORE COOLING SYSTEM RECIRCULATION PIPING PASSIVE FAILURE ANALYSIS

LONG-TERM PHASE

Flow Path	Indication of Loss of Flow Path	Alternate Flow Path
Low Head Recirculation		
From containment sump to low head injection header via the residual heat removal pumps and the residual heat exchangers	Reduced flow in the discharge line from one of the residual heat exchangers (one flow monitor in each discharge line). Accumulation of water in a residual heat removal pump compartment or auxiliary building sump.	Via the independent identical low head flow path utilizing the second residual heat exchanger.
High Head Recirculation		
From containment sump to the high head injection header via residual heat removal pump residual heat exchanger, and the high head injection pumps	1) Increasing activity of the air exhausted from the RHR heat exchanger rooms or in the plant vent. 2) Accumulation of water in a residual heat removal pump compartment or the auxiliary building sump 3) Increasing ESF pump room temperature 4) Reduced ECCS flow rates	From containment sump to the high head injection headers via alternate residual heat removal pump, residual heat exchanger, and the alternate high head charging pump

TABLE 6.5-1

CRITERIA FOR AUXILIARY FEEDWATER SYSTEM DESIGN BASIS CONDITIONS

Condition or Transient	Classification[a]	Criteria[a]	Additional Design Criteria
Loss of Normal Feedwater (Refer to Section 15.2.8)	Condition II	AFW capable of removing stored and residual heat to prevent pressurizer liquid relief.[b]	AFW automatically initiated on low-low SG level.
Loss of Offsite Power to the Station Auxiliaries (Refer to Section 15.2.9)	Condition II	AFW capable of removing stored and residual heat to prevent pressurizer liquid relief.	AFW automatically initiated on low-low SG level.
Steamline Rupture (Mass & Energy Release – Refer to Section 6.2D.3)	Condition IV	N/A – not an AFW system design requirement.	AFW flow maximized for mass and energy release.
Major Rupture of a Main Feedwater Pipe (Refer to Section 15.4.2.2)	Condition IV	AFW to provide assured source of feedwater to SGs for decay heat removal.	AFW flow to SGs assumed in 10 minutes after reactor trip.
Major Rupture of a Main Feedwater Pipe for Pressurizer Filling (Refer to Section 15.4.2.4)	Condition IV	AFW to provide assured source of feedwater to SGs for decay heat removal.	AFW flow to SGs assumed within 1 minute after reactor trip
Loss of all ac power	N/A	AFW to provide assured source of feedwater to SGs for decay heat removal independent of ac power.	AFW system turbine-driven pump train independent of ac power.
Small-Break Loss of Coolant (Refer to Section 15.3.1)	Condition III	AFW provide 390 gpm.[d]	N/A
Natural Circulation Cooldown	Same as LONF	AFW system provides an assured source of feedwater to SGs to prevent reactor vessel head voiding	Unit 1 – Hot Standby 1 hour, 8 hour cooldown @ 25 °F per hour. Unit 2 – Hot Standby 2 hours, 4 hour cooldown @ 50 °F per hour.

TABLE 6.5-1

CRITERIA FOR AUXILIARY FEEDWATER SYSTEM DESIGN BASIS CONDITIONS

(a) Ref: ANS N18.2 (This information provided for those transients analyzed in Chapter 15.)
(b) A better-estimate analysis has also been performed to demonstrate that the pressurizer does not fill with a single motor-driven auxiliary feedwater pump feeding 2 SGs a total of 390 gpm.
(c) Refer to Section 15.5 for 10 CFR 100.11 (for tank rupture accidents) or 10 CFR 50.67 (for accidents analyzed using AST methodology) acceptance criteria for accident analysis dose consequences.
(d) An AFW flowrate of 97.5 gpm per SG is assumed in the FSLOCA evaluation model (EM) based on 390 gpm divided evenly among 4 SGs.

TABLE 6.5-2

SUMMARY OF ASSUMPTIONS
AFW SYSTEM DESIGN VERIFICATION

Transient	Loss of Normal Feedwater (Loss of Offsite Power)	Natural Circulation Cooldown	Major Rupture of a Main Feedwater Pipe	Major Steam Line Break[b] (Containment)	Small Break Loss of Coolant Accident
a. Max NSSS power	102% of 3425 MW_t	102% of 3411MW_t	102% of 3425 MW_t	102% of 3425 MW_t	102% of 3411 MW_t
b. Time delay from event to Rx trip	(Refer to Table 15.2-1)	2 sec	(Refer to Table 15.4-8)	Variable	variable
c. AFW system actuation signal/time delay for AFW system flow	Low-low SG level 1 minute	Low-low SG Level 1 minute	Low-low SG level (Refer to Table 15.4-8)	Assumed immediately 0 sec (no delay)	Low pressurizer pressure SI signal / 60 sec
d. SG water level at time of reactor trip.	Low-low SG level 8 % narrow range span (NRS)	Same as LOOP	Low-low SG level 0% NRS	N/A	N/A
e. Decay heat	Figure 15.1-7	Figure 15.1-7	Figure 15.1-7	Figure 15.1-7	Section 15.1.10.1
f. AFW pump design pressure	1102 psig	1112 psia	1102 psig	N/A	N/A
g. Min. No. of SGs that must receive AFW flow	4 of 4	Same as LONF/LOOP	2 of 4 (Section 15.4.2.2) 3 of 4 (Section 15.4.2.4)	N/A	4 of 4[c]
h. Maximum AFW	100 °F	100 °F	100 °F	100 °F	100 °F

TABLE 6.5-2

	Transient	Loss of Normal Feedwater (Loss of Offsite Power)	Natural Circulation Cooldown	Major Rupture of a Main Feedwater Pipe	Major Steam Line Break[b] (Containment)	Small Break Loss of Coolant Accident
	temperature					
i.	Operator action	None	N/A	10 minutes to isolate the faulted SG	10 minutes to isolate the faulted SG	None
j.	AFW purge volume/ temperature	113 ft^3per loop/435° F	113 ft^3 per loop/435 °F	113 ft^3per loop/435° F (Section 15.4.2.2), 425°F (Section 15.4.2.4)	0.0ft^3/ based on power	N/A
k.	Normal blowdown	None assumed	None assumed	None assumed	None assumed	None assumed
l.	Sensible heat	Table 6.5-3	Table 6.5-3	Refer to cooldown	N/A	N/A
m.	Time at standby/time to cooldown to RHR	2 hr/4 hr with offsite power available (without offsite power available refer to Natural Circulation Cooldown)	Unit 1 – 1 hr/8 hr @ 25 °F Unit 2 – 2 hr/4 hr @ 50 °F	N/A	N/A	N/A
n.	AFW flowrate	600 gpm (total) constant (minimum requirement	Variable based on maintaining SG level at lower NR level tap at SG backpressure	For Section 15.4.2.2, 390 gpm (total) constant (after 10 minutes)[a] (minimum requirement) For Section 15.4.2.4, refer to Table 15.4-8	569 gpm to 1588 gpm varying due to faulted SG pressure changes	390 gpm to 4 SGs[c]

(a) Minimum flow of 175.5 / 214.5 gpm to each of the two steam generators receiving AFW flow.
(b) A rupture of a main steam pipe inside containment does not impose any performance related requirements on the AFW system. For the accident analysis, AFW flowrates were maximized to increase the mass and energy contributions from the AFW system (Refer to Section 6.2D.3).
(c) 390 gpm to four SGs was assumed to be provided by one motor-driven AFW pump. The 390 gpm is assumed to be distributed equally among the four SGs

TABLE 6.5-3

SUMMARY OF SENSIBLE HEAT SOURCES
(For Plant Cooldown by AFW system)

Primary Water Sources (initially at emergency safeguards design (ESD) power temperature and inventory)

- RCS fluid
- Pressurizer fluid (liquid and vapor)

Primary Metal Sources (initially at ESD power temperature)

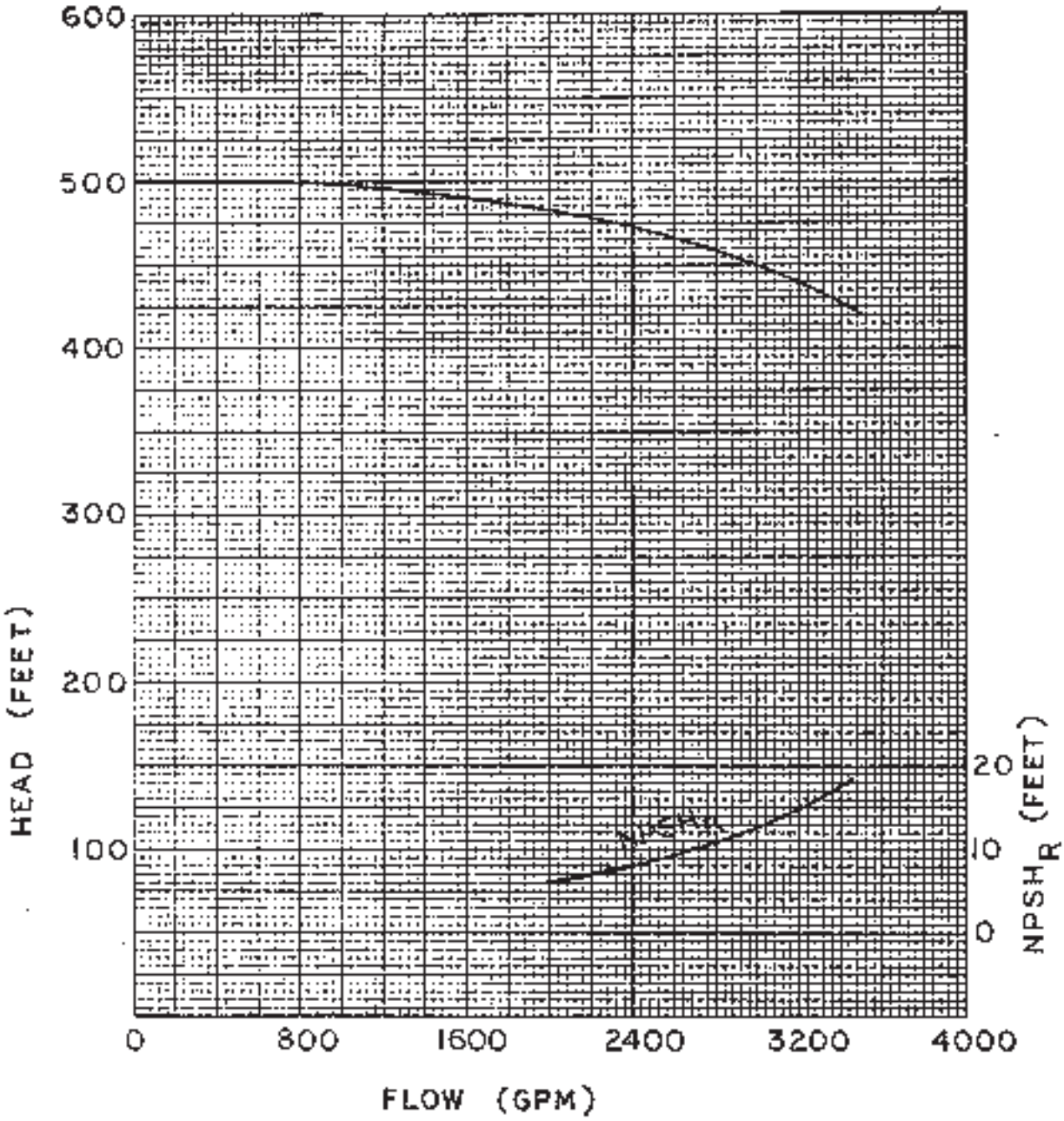
- Reactor coolant piping, pumps and reactor vessel
- Pressurizer
- Steam generator tube metal and tubesheet
- Reactor vessel internals

Secondary Water Sources (initially at ESD power temperature and inventory)

- Steam generator fluid (liquid and vapor)
- Main feedwater purge fluid between steam generator and AFW system piping

Secondary Metal Sources (initially at ESD power temperature)

- All steam generator metal above tubesheet, excluding tubes

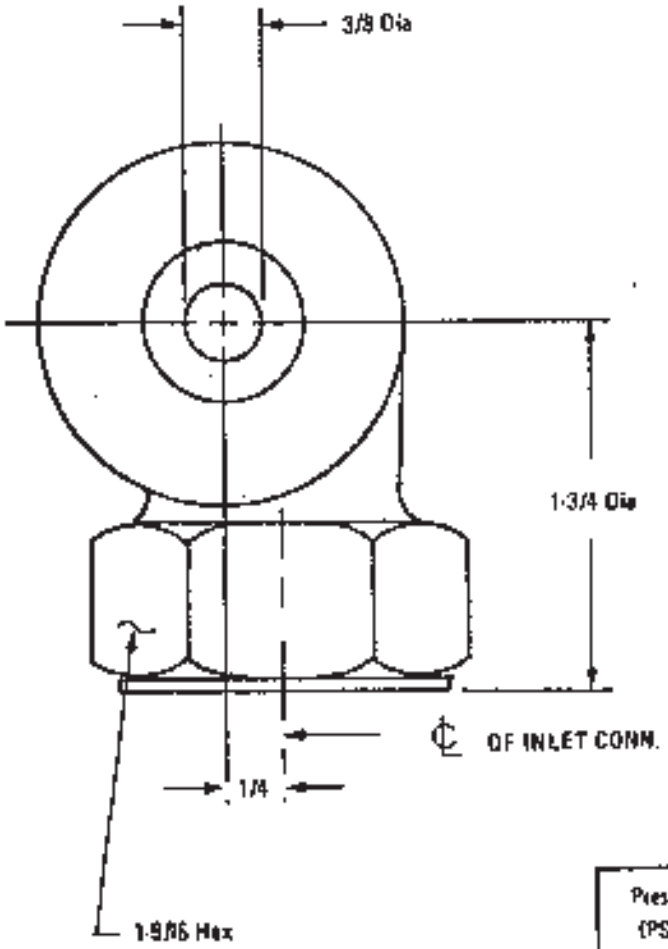


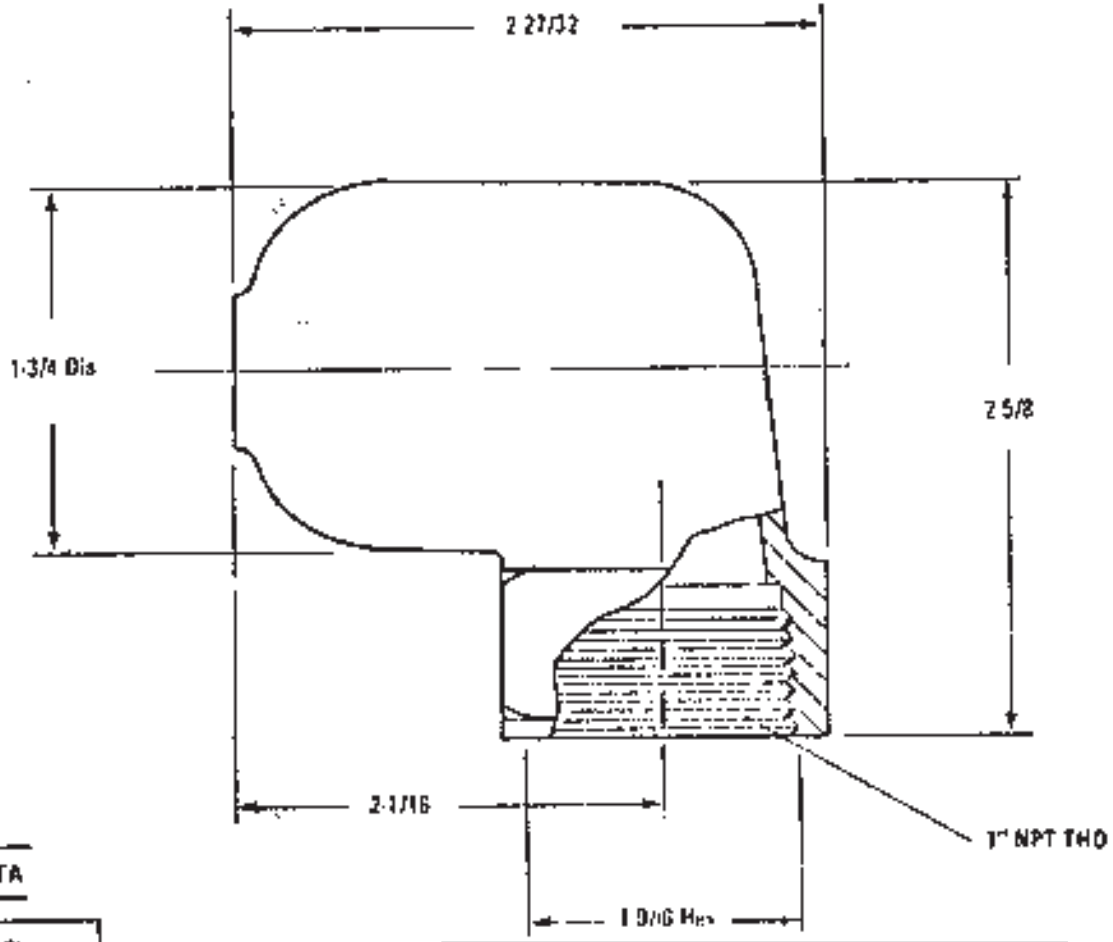
NPSH$_{AVAILABLE}$

FLOW	NPSH$_A$*
2,600 GPM	46.1 FT.
3,400 GPM	26.8 FT.

* PUMPS TAKING SUCTION FROM REFUELING WATER STORAGE TANK.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-10 CONTAINMENT SPRAY PUMP PERFORMANCE CURVE





FLOW DATA

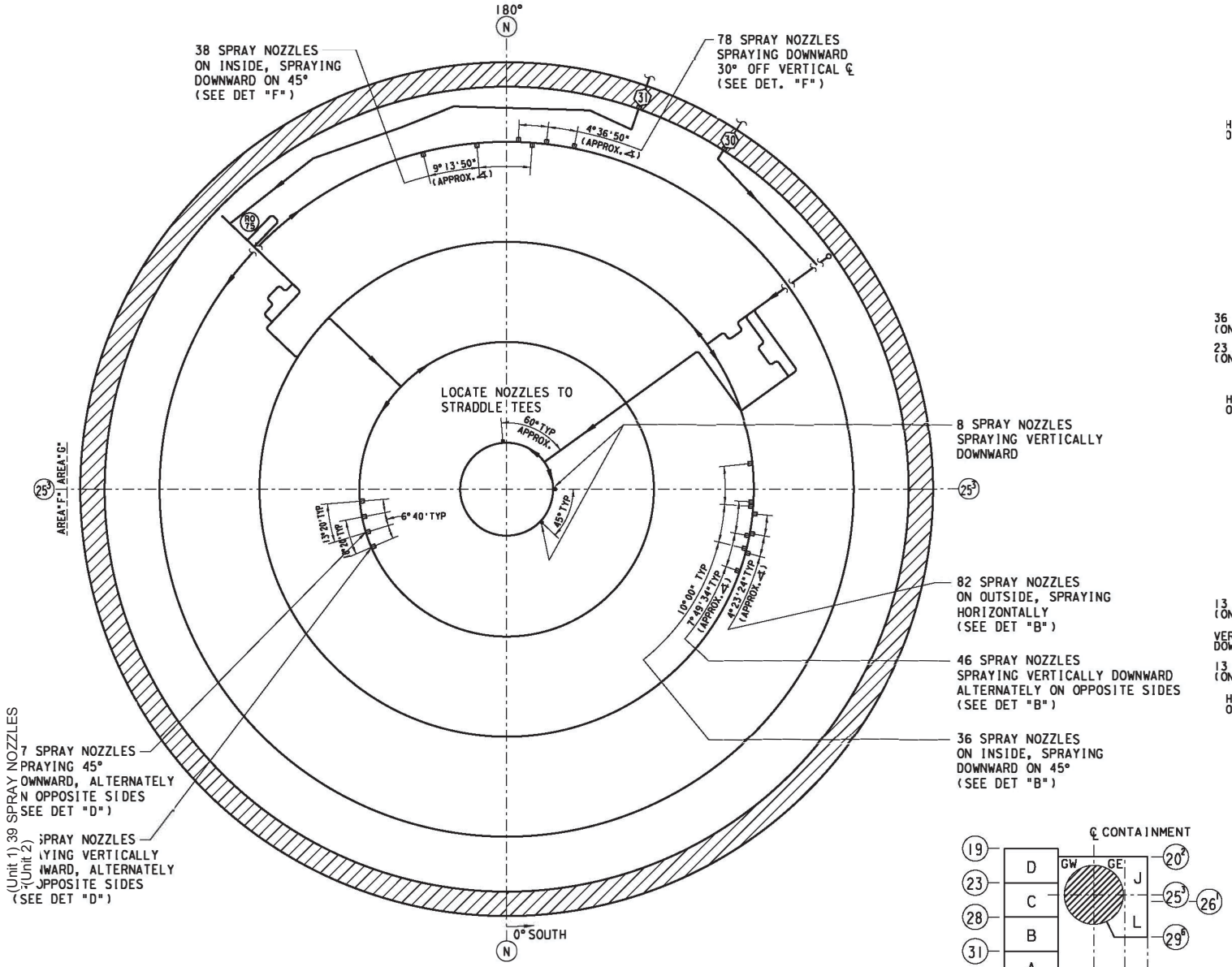
Pressure (PSIG)	Flow (GPM)
10	7.6
20	10.7
30	13.3
40	15.2
50	17.0

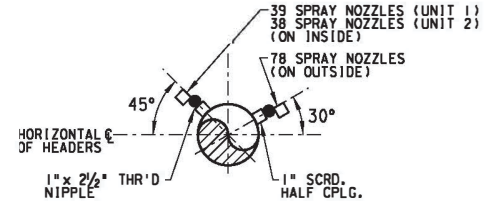
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-12

CONTAINMENT SPRAY NOZZLE CUTAWAY





(SEE TYPICAL NOTES SHOWN ON DET. "D")

DETAIL "F"
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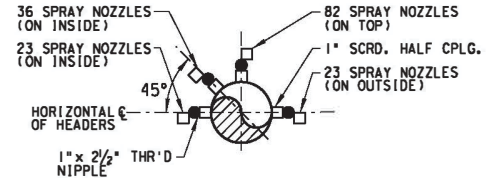

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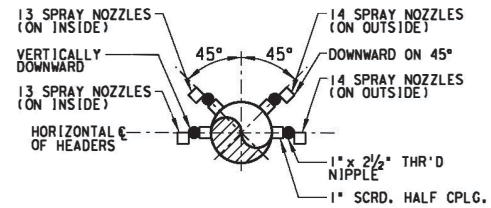

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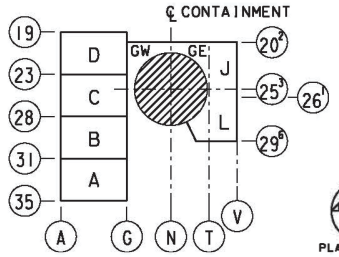
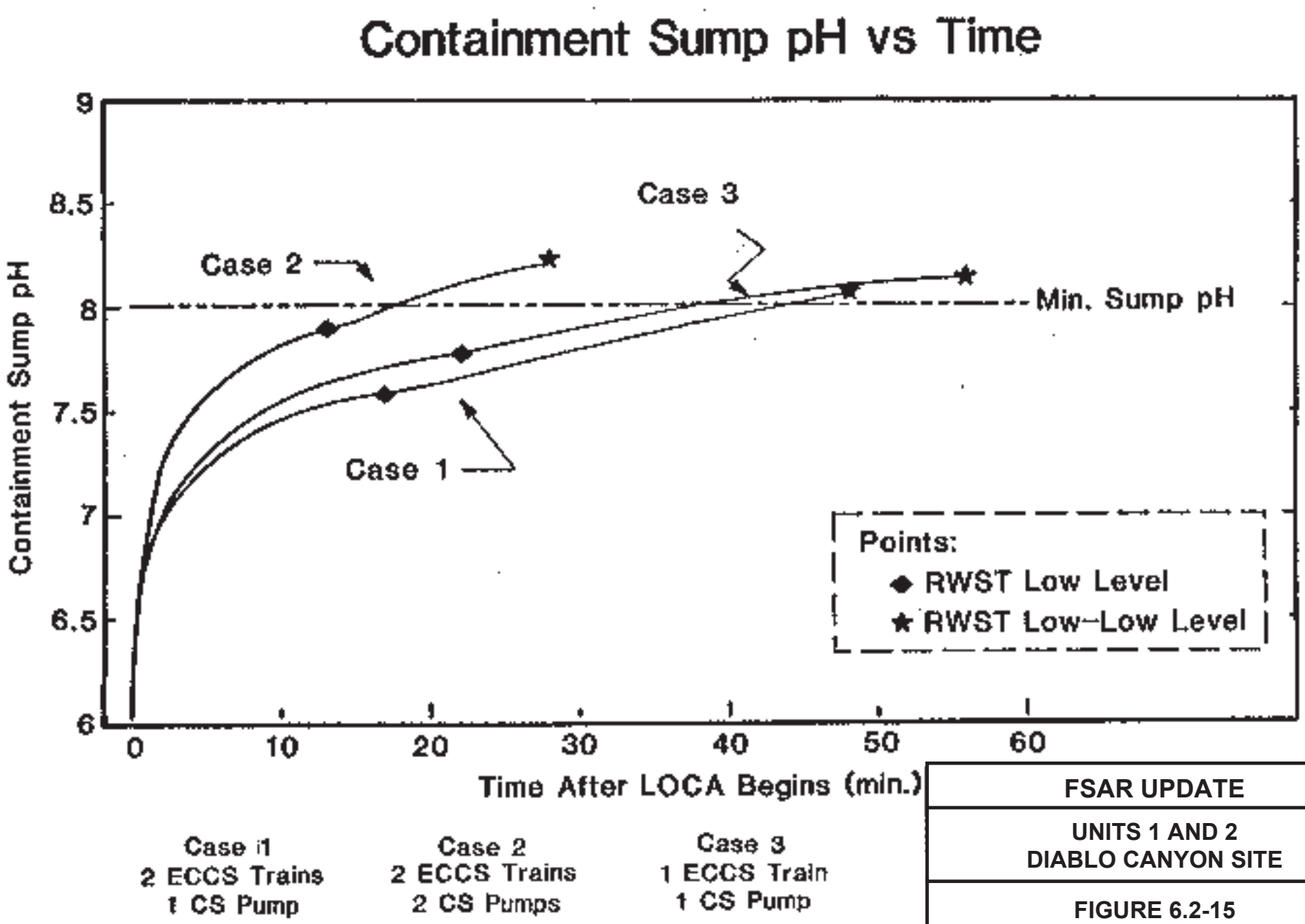
NOT TO SCALE
HEADER No. 3



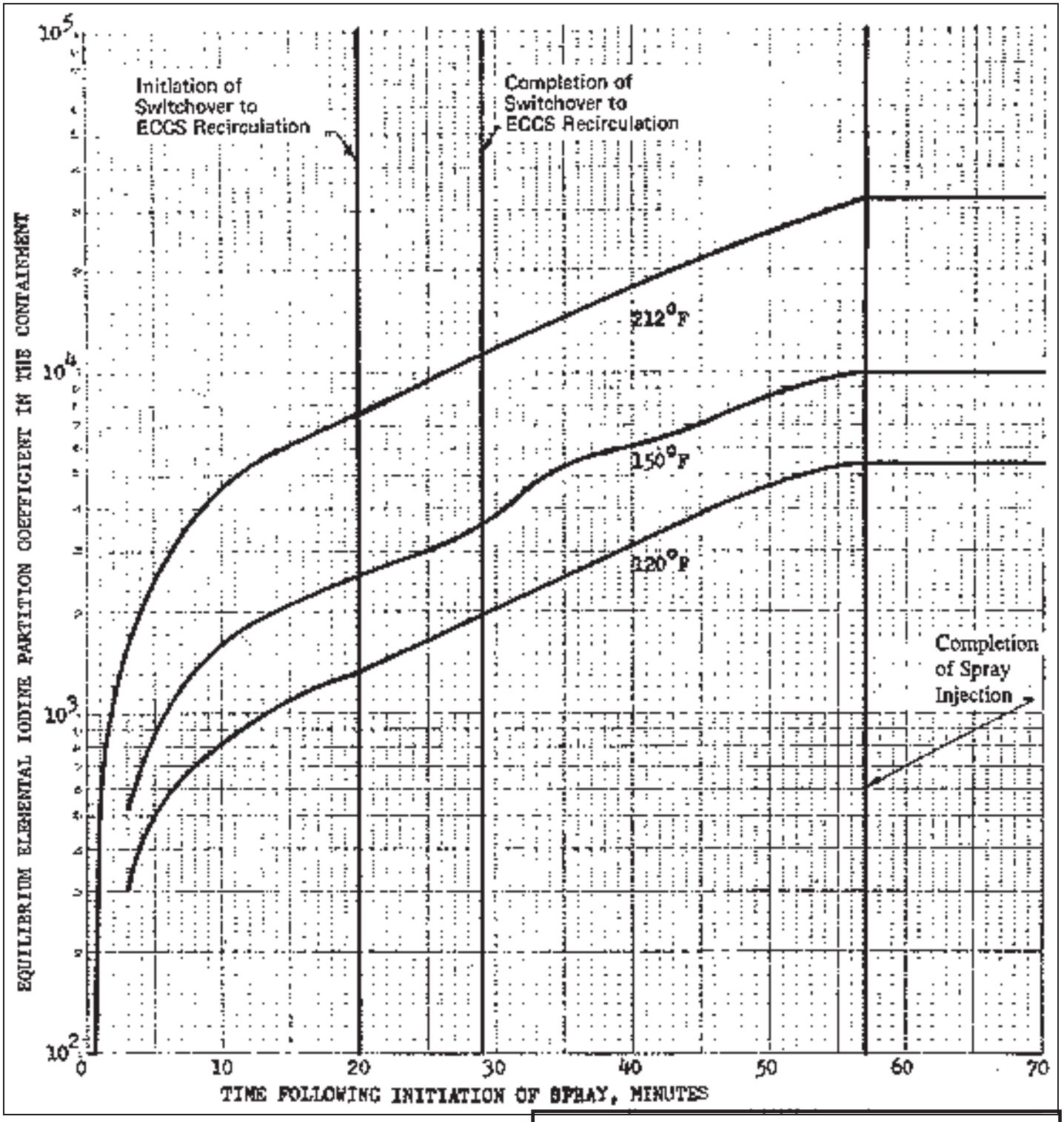
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-13
CONTAINMENT SPRAY HEADERS
PLAN VIEW



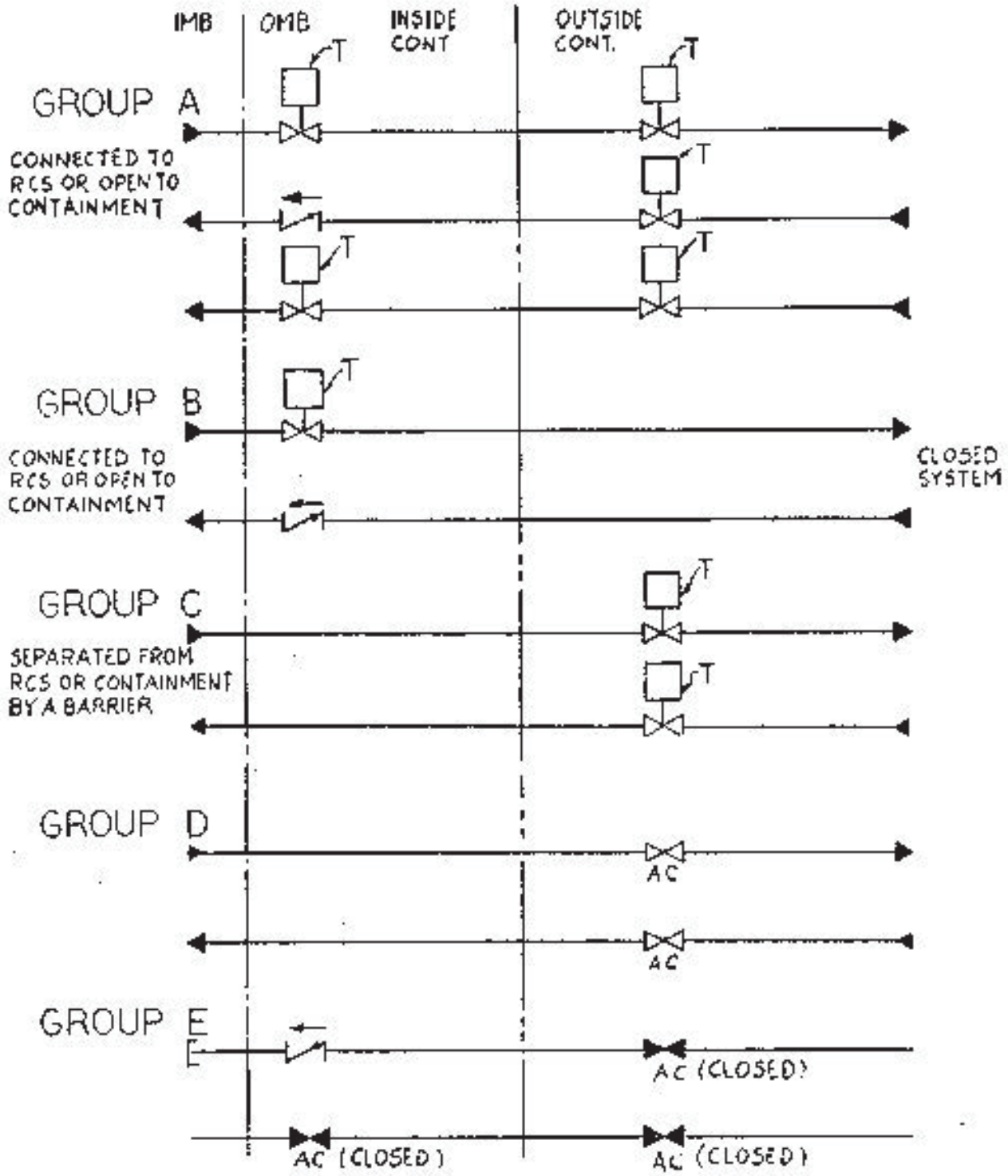
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-15 CONTAINMENT RECIRCULATION SUMP pH VERSUS TIME AFTER LOCA BEGINS



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-16
CONTAINMENT EQUILIBRIUM ELEMENTAL IODINE PARTITION COEFFICIENT VERSUS TIME FOR MINIMUM SUMP pH CASE (2 ECCS TRAINS AND 1 SPRAY TRAIN) FOR THREE TEMPERATURES



1. AC - MANUAL VALVE POSITION MAINTAINED BY ADMINISTRATIVE CONTROL
2. □T - TRIP VALVE EITHER MOTOR OR AIR OPERATED
3. ALL PENETRATION VALVES AND PIPING ARE CLASS I

CONTAINMENT ISOLATION SYSTEM

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-17 CONTAINMENT ISOLATION SYSTEM

LEGEND
FOR SYMBOL USED ON:

VALVES

NEEDLE

HAND CONTROL

GLOBE

GATE

DOUBLE DISC GATE

CHECK

CONTROL

BUTTERFLY

THREE WAY

SAFETY OR RELIEF

DIAPHRAGM

SELF-CONTAINED PRESSURE REGULATOR

BALL VALVE

DARKENED SYMBOL INDICATES NORMALLY CLOSED VALVE

OPERATORS

AIR DIAPHRAGM

AIR CYLINDER

EH ELECTROHYDRAULIC

M MOTOR

MISCELLANEOUS

SPECTACLE FLANGE

FLOW ELEMENT OR RESTRICTING ORIFICE

BLIND FLANGE

VALVE STEM LEAK-OFF

CAPPED VALVE LEAK-OFF

PENETRATION

TEST CONNECTION OR VENT LOCATION.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-18 (Sheet 1 of 2) PENETRATION DIAGRAM LEGEND

NOTATION

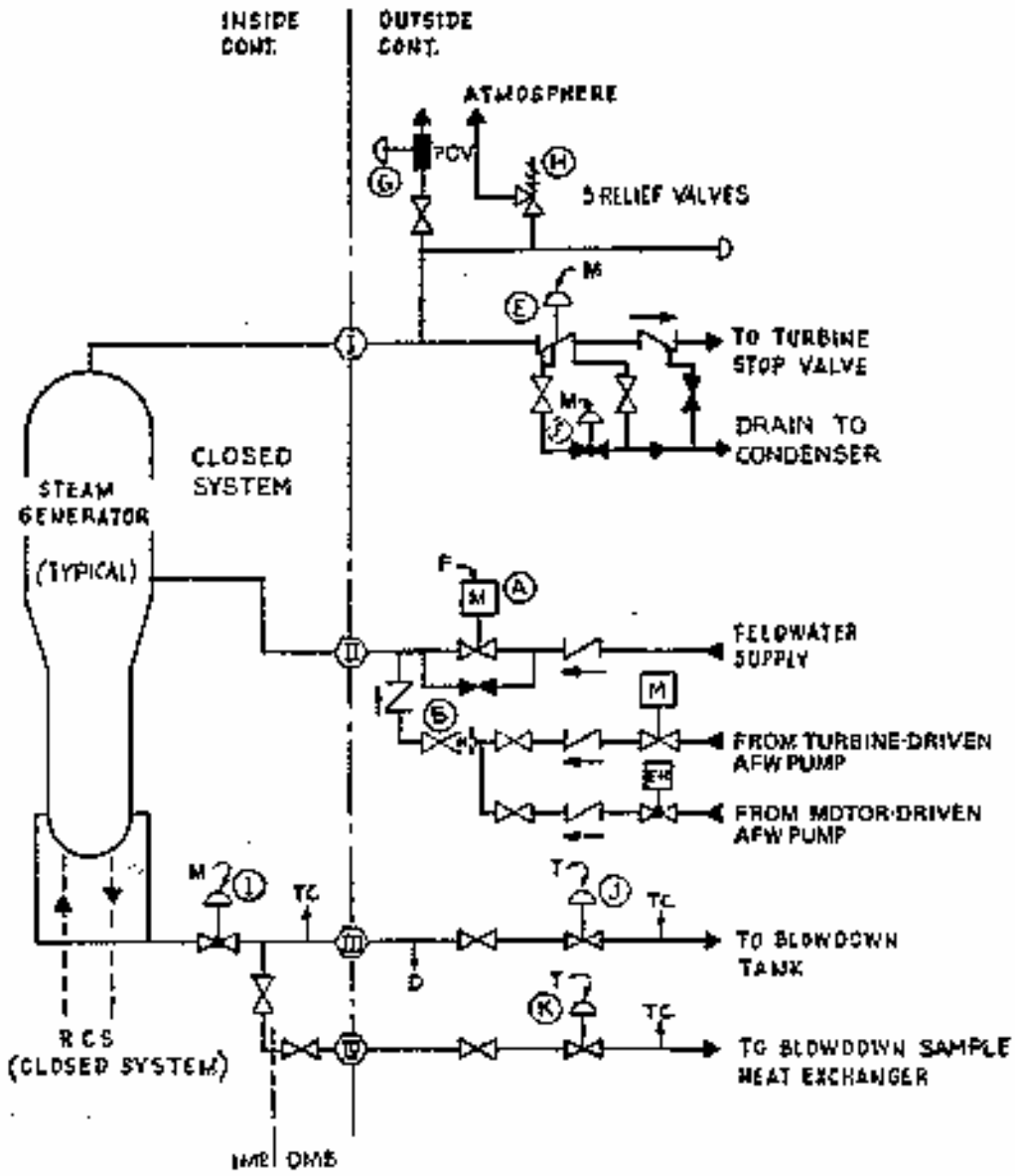
Encircled Letter

○	- VALVE DESIGNATION - SEE TABLE 6.2-39 FOR DESCRIPTION
RWST	- REFUELING WATER STORAGE TANK
DT	- REACTOR COOLANT DRAIN TANK
M	- TRIPPED BY MAIN STEAM ISOLATION SIGNAL
T	- TRIPPED BY CONTAINMENT ISOLATION SIGNAL, PHASE A
P	- TRIPPED BY CONTAINMENT ISOLATION SIGNAL, PHASE B
F	- TRIPPED BY FEEDWATER ISOLATION SIGNAL
RCS	- REACTOR COOLANT SYSTEM
CVCS	- CHEMICAL AND VOLUME CONTROL SYSTEM
CONT	- CONTAINMENT
IMB	- INSIDE MISSILE BARRIER
OMB	- OUTSIDE MISSILE BARRIER
SO	- SEALED OPEN
SC	- SEALED CLOSED
PRT	- PRESSURIZER RELIEF TANK
D	- DRAIN
V	- VENT
PCV	- PRESSURE CONTROL VALVE
TC	- TEST CONNECTION
TV	- TEST VENT
S	- SAFETY INJECTION SIGNAL
S-I	- DESIGN CLASS I

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-18 (Sheet 2 of 2)
PENETRATION DIAGRAM LEGEND



SHOWN CONFIGURATION AT PENETRATION(S) 1,2,3,4,5,8 IS GENERAL ONLY. FOR DETAILED SYSTEM CONFIGURATION, REFER TO FSAR FIGURE # AND SHEET # AS SHOWN ON CHART AT RIGHT.

PEN #	UNIT 1		UNIT 2	
	FIG #	SHT #	FIG #	SHT #
1	3.2-03	3 of 8	3.2-03	4 of 8
2	3.2-03	3 of 8	3.2-03	4 of 8
3	3.2-03	3 of 8	3.2-03	4 of 8
4	3.2-03	3 of 8	3.2-03	4 of 8
5	3.2-04	5 of 14	3.2-04	6 of 14
8	3.2-04	1 of 14	3.2-04	2 of 14

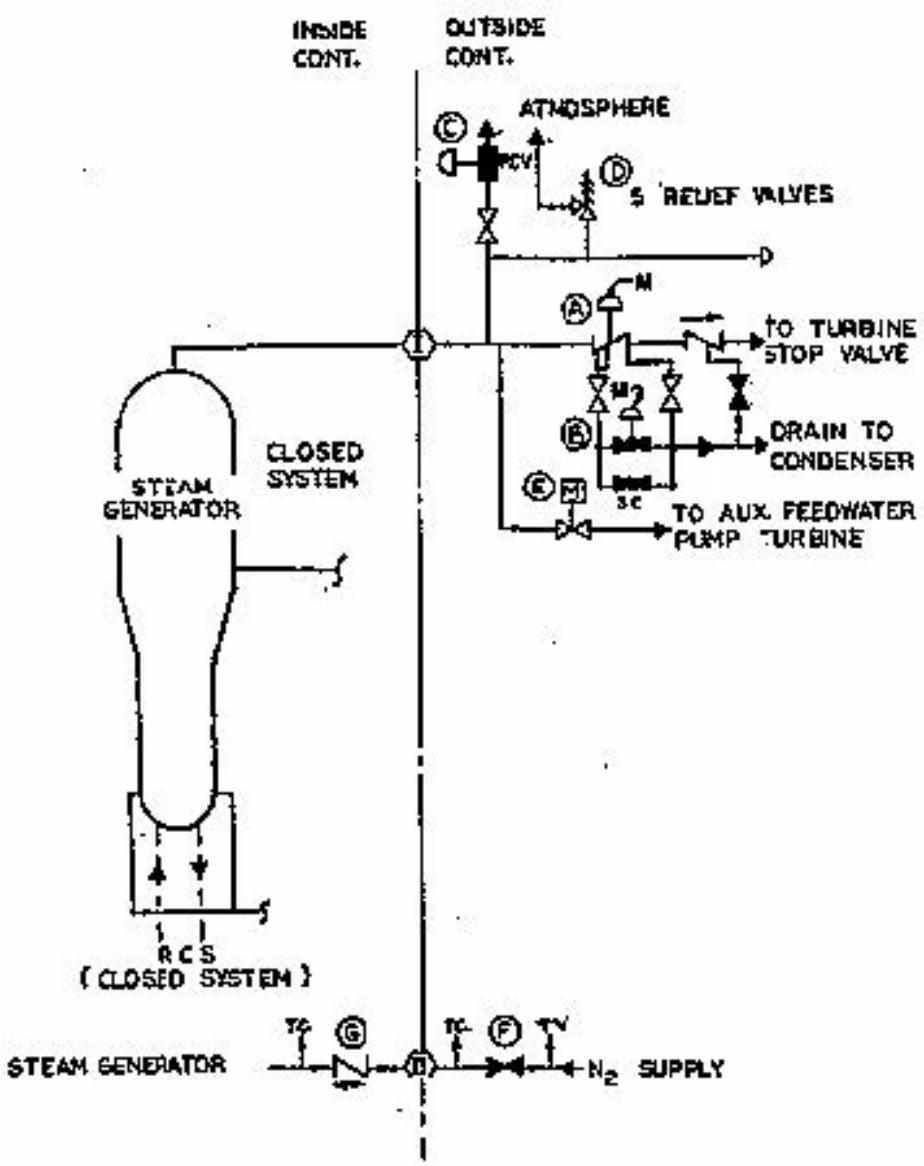
ALL SYSTEMS ARE DESIGN CLASS 1
(I) MAIN STEAM (5,8)
(II) FEEDWATER (1,2,3,4)
(III) STEAM GENERATOR BLOWDOWN (37,38, 39,40)
(IV) STEAM GENERATOR BLOWDOWN SAMPLE (53) 4 LINES

*Valves area sealed closed in Modes 1-4

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 1 OF 25)



SHOWN CONFIGURATION AT PENETRATION(S) 6,7 IS GENERAL ONLY. FOR DETAILED SYSTEM CONFIGURATION, REFER TO FSAR FIGURE # AND SHEET # AS SHOWN ON CHART AT RIGHT.

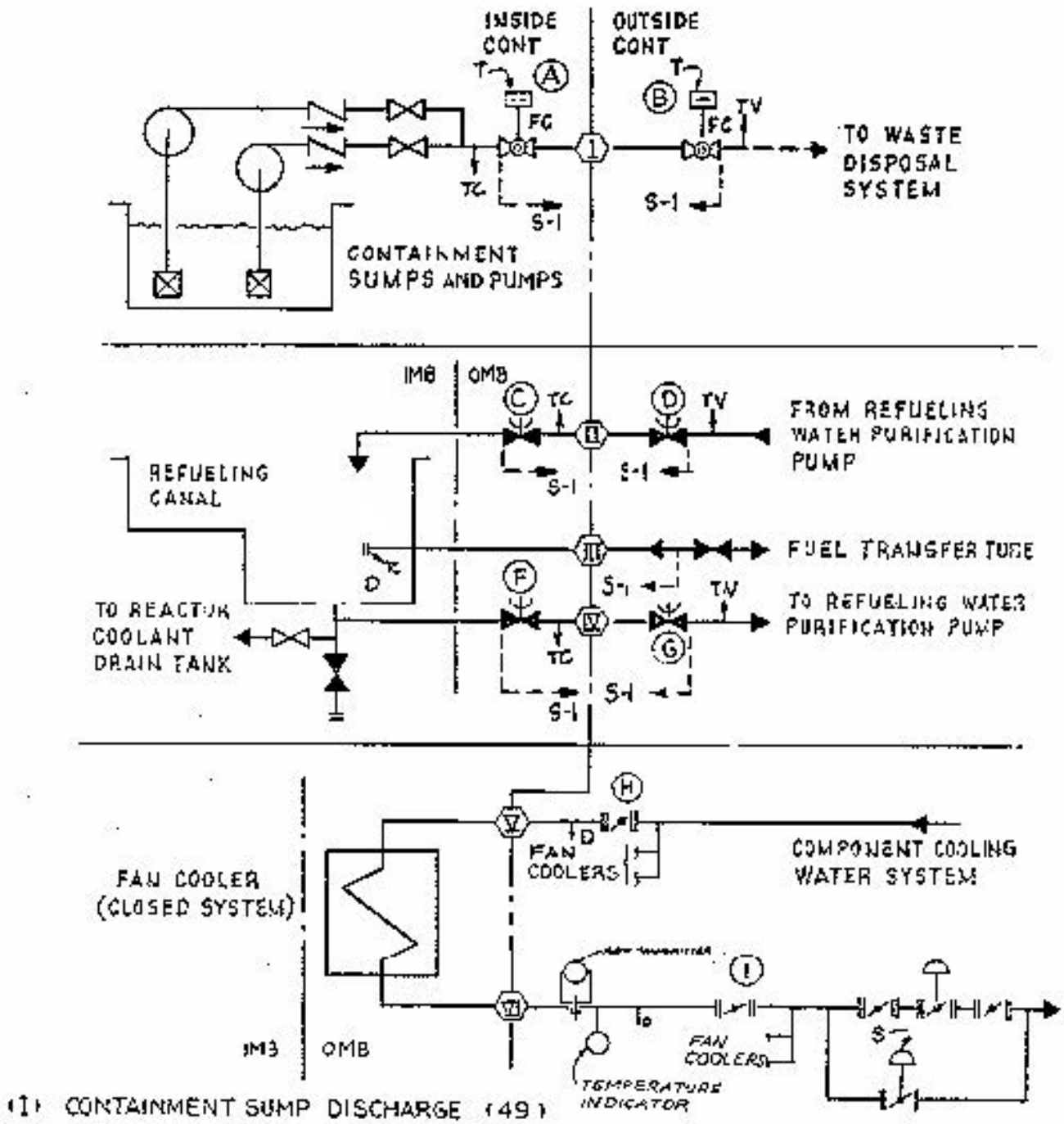
PEN #	UNIT 1 FIG #	UNIT 1 SHT #	UNIT 2 FIG #	UNIT 2 SHT #
6	6.2-04	5 of 14	3.2-04	6 of 14
7	6.2-04	1 of 14	3.2-04	2 of 14

SYSTEMS ARE DESIGN CLASS 1
(I) MAIN STEAM (6,7)
(II) STEAM GENERATOR N_2 (52)

FSAR UPDATE

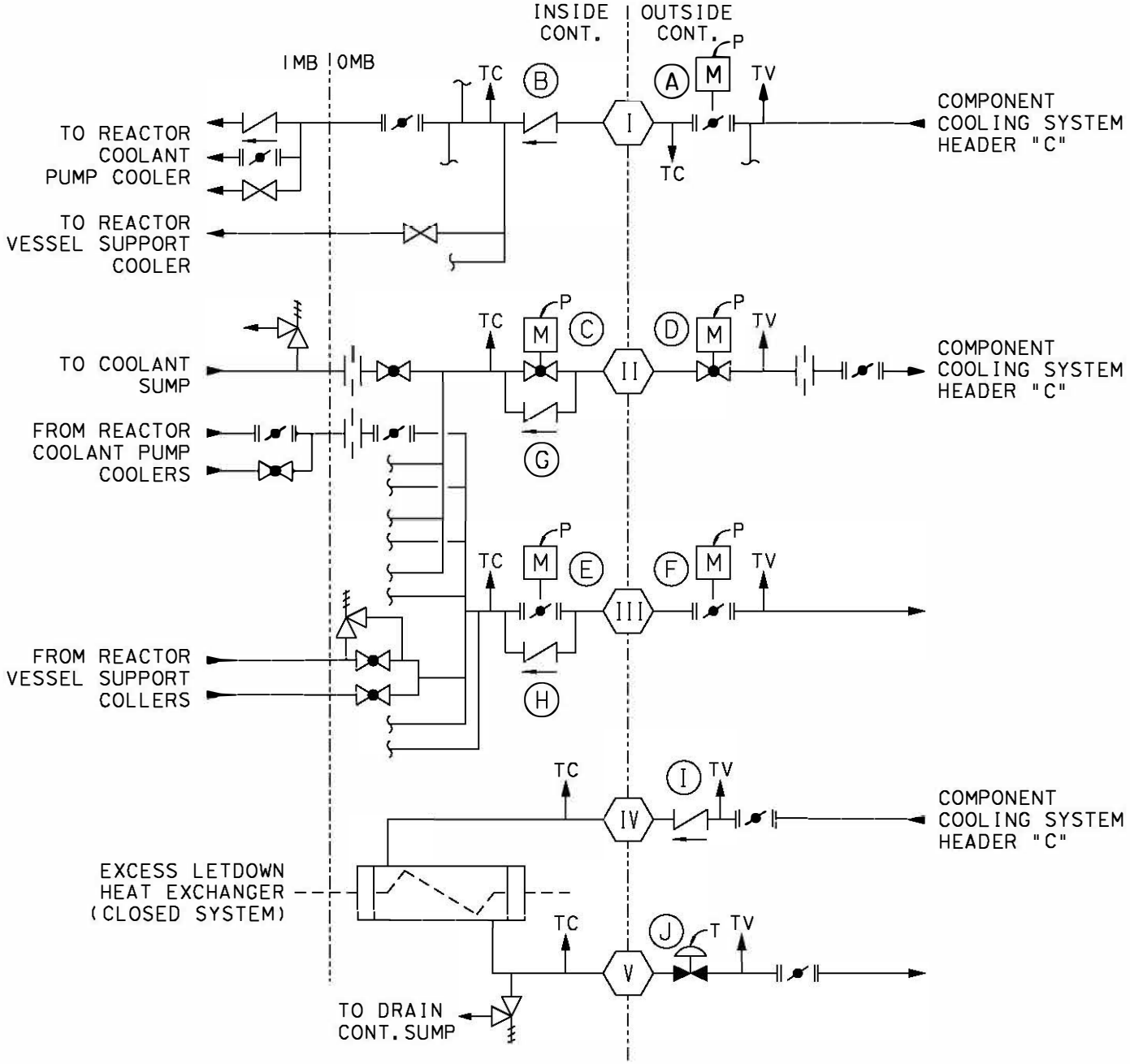
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 2 OF 25)



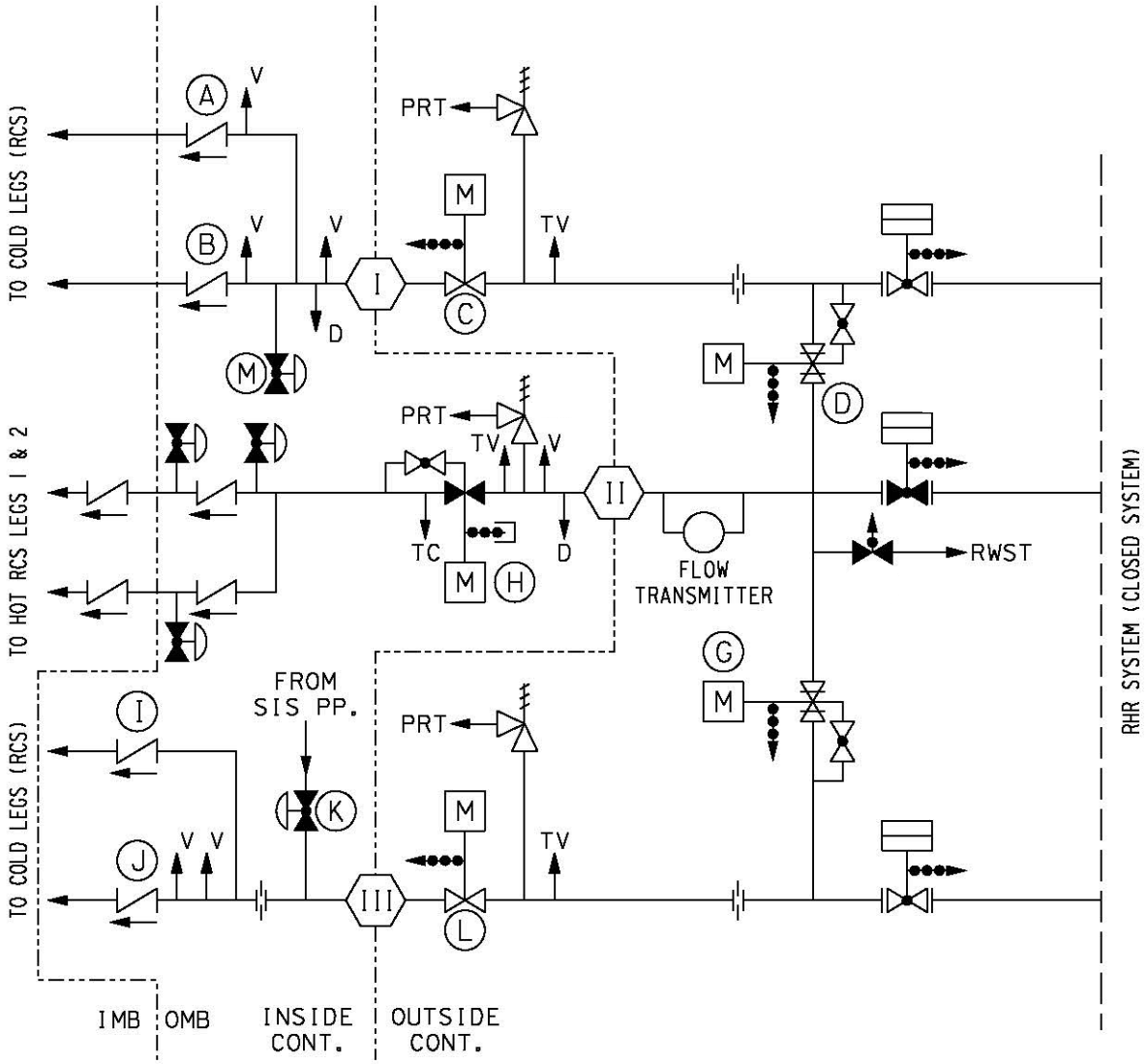
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 3 OF 25)

Revision 26 September 2021



(I) CCW TO RCP (19)
(II) CCW FROM RCP (21)
(III) CCW FROM RCP (20)
(IV) CCW TO ELD HX (22)
(V) CCW FROM ELD HX (23)

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 4 OF 25)



(I) RHR 1 INJECTION (24)
(II) RHR HOT LEG INJECTION (26)
(III) RHR 2 INJECTION (25)

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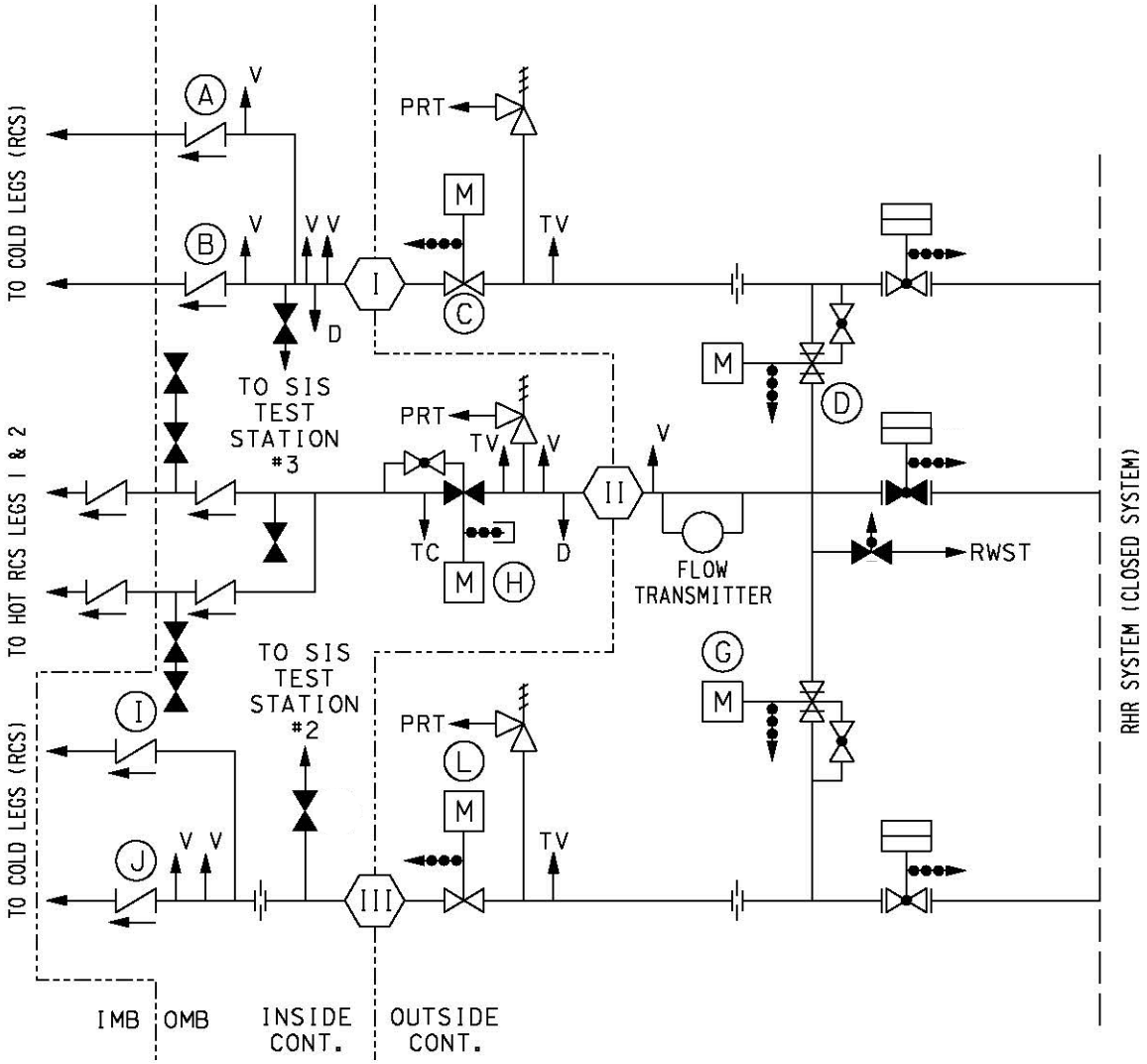
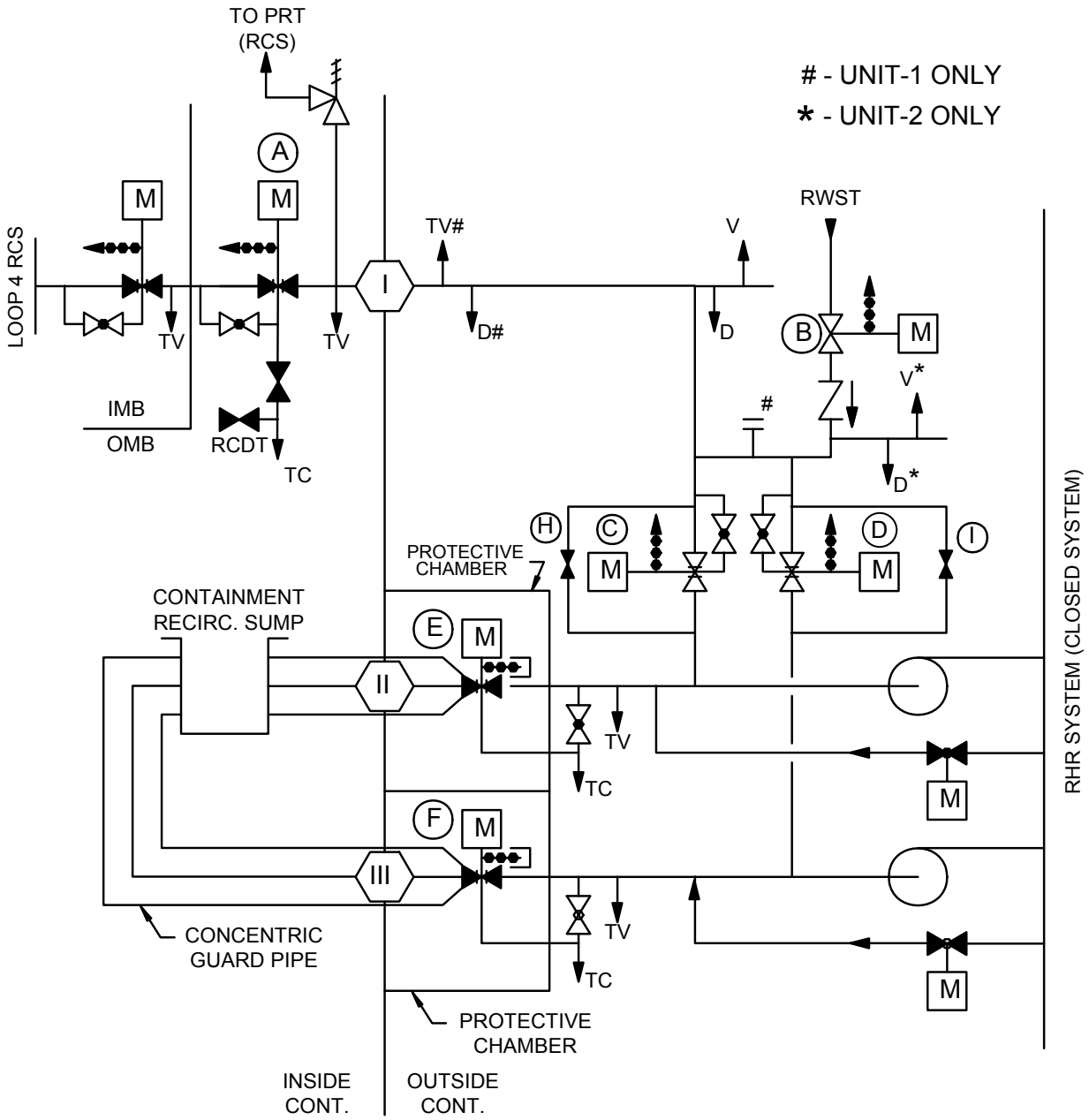
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 5 OF 25)



(I) RHR 1 INJECTION (24)
(II) RHR HOT LEG INJECTION (26)
(III) RHR 2 INJECTION (25)

FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 5A OF 25)

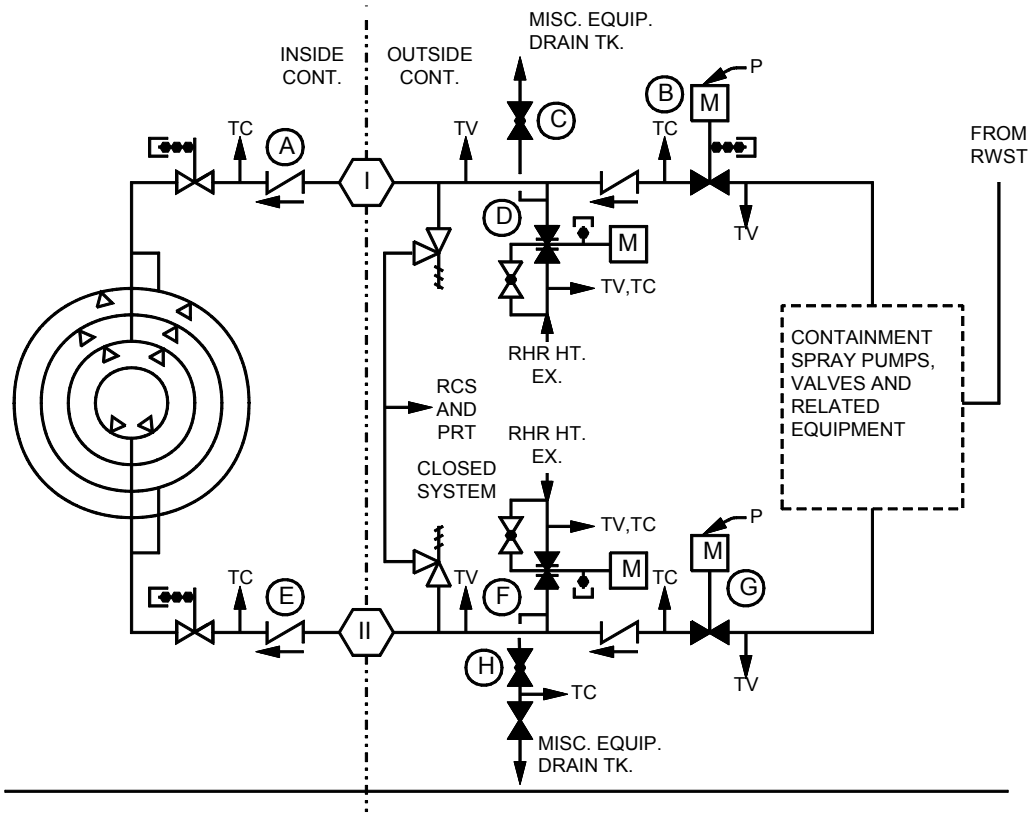


(I) RCS LOOP 4 RECIRC. (27)
(II) CONT. SUMP RECIRC. (28)
(III) CONT. SUMP RECIRC. (29)

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 6 OF 25)

Revision 26 September 2021

THIS SYSTEM IS DESIGN CLASS I

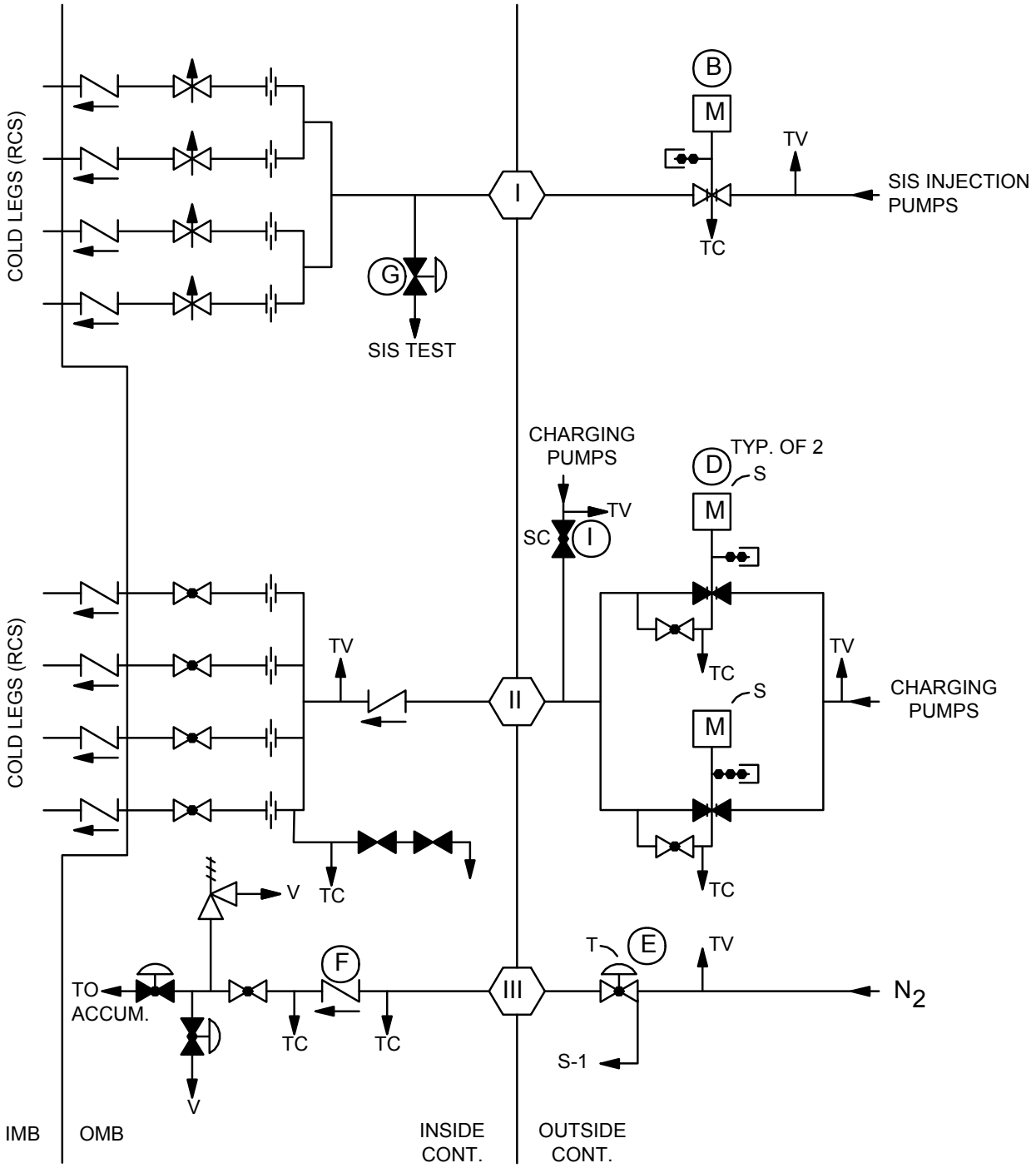


* -UNIT-2 ONLY

(I) CONTAINMENT SPRAY (30)
(II) CONTAINMENT SPRAY (31)

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 7 OF 25)

Revision 24 September 2018

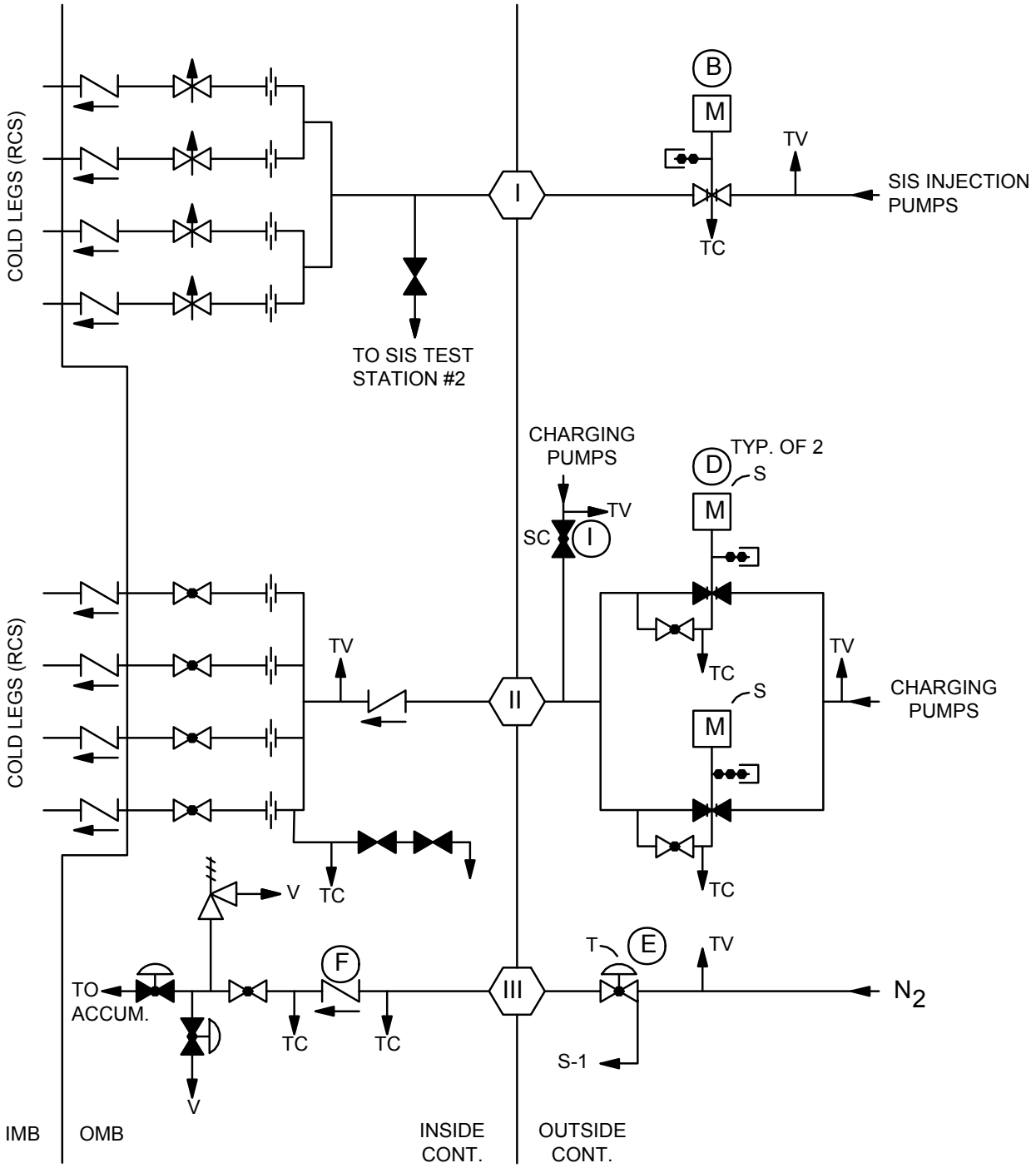


(I) SIS COLD INJECTION (33)
(II) SIS COLD INJECTION (34)
(III) N_2 SUPPLY TO ACCUM. (51A)

FSAR UPDATE

UNIT 1
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 8 OF 25)

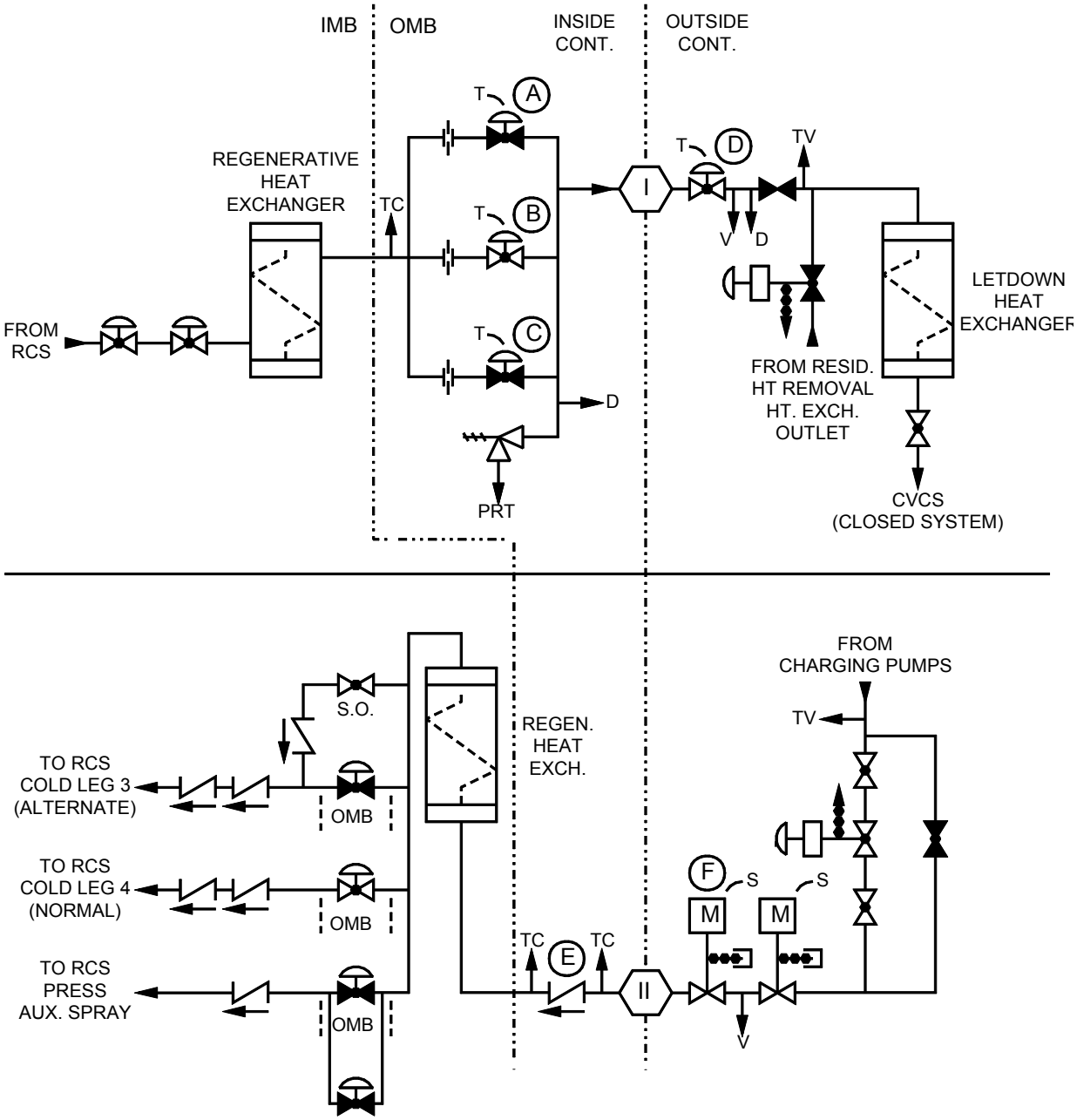


(I) SIS COLD INJECTION (33)
(II) SIS COLD INJECTION (34)
(III) N_2 SUPPLY TO ACCUM. (51A)

FSAR UPDATE

UNIT 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 8A OF 25)



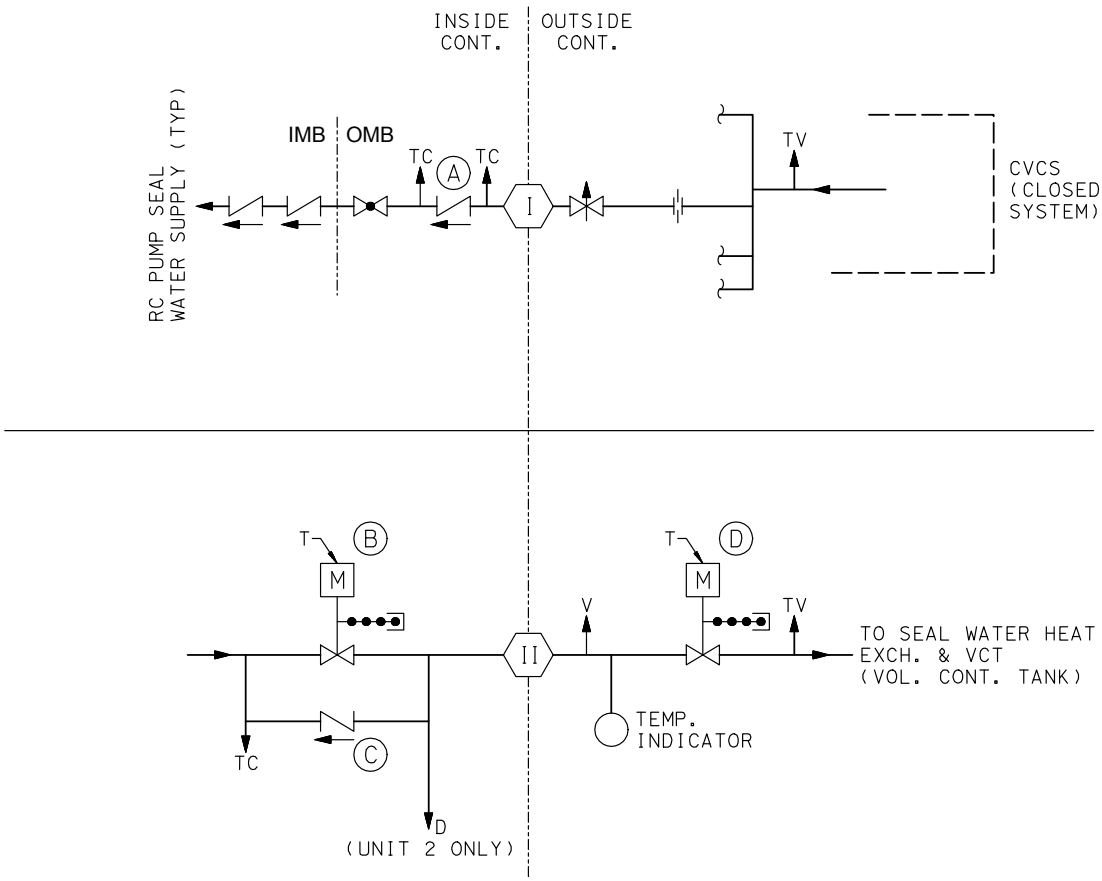
(I) LETDOWN LINE REGEN. HEAT EXCHR. TO LETDOWN HEAT EXCHR. (35)

(II) REGEN. HEAT EXCHR. CHARGING/AUX. SPRAY (36)

FSAR UPDATE

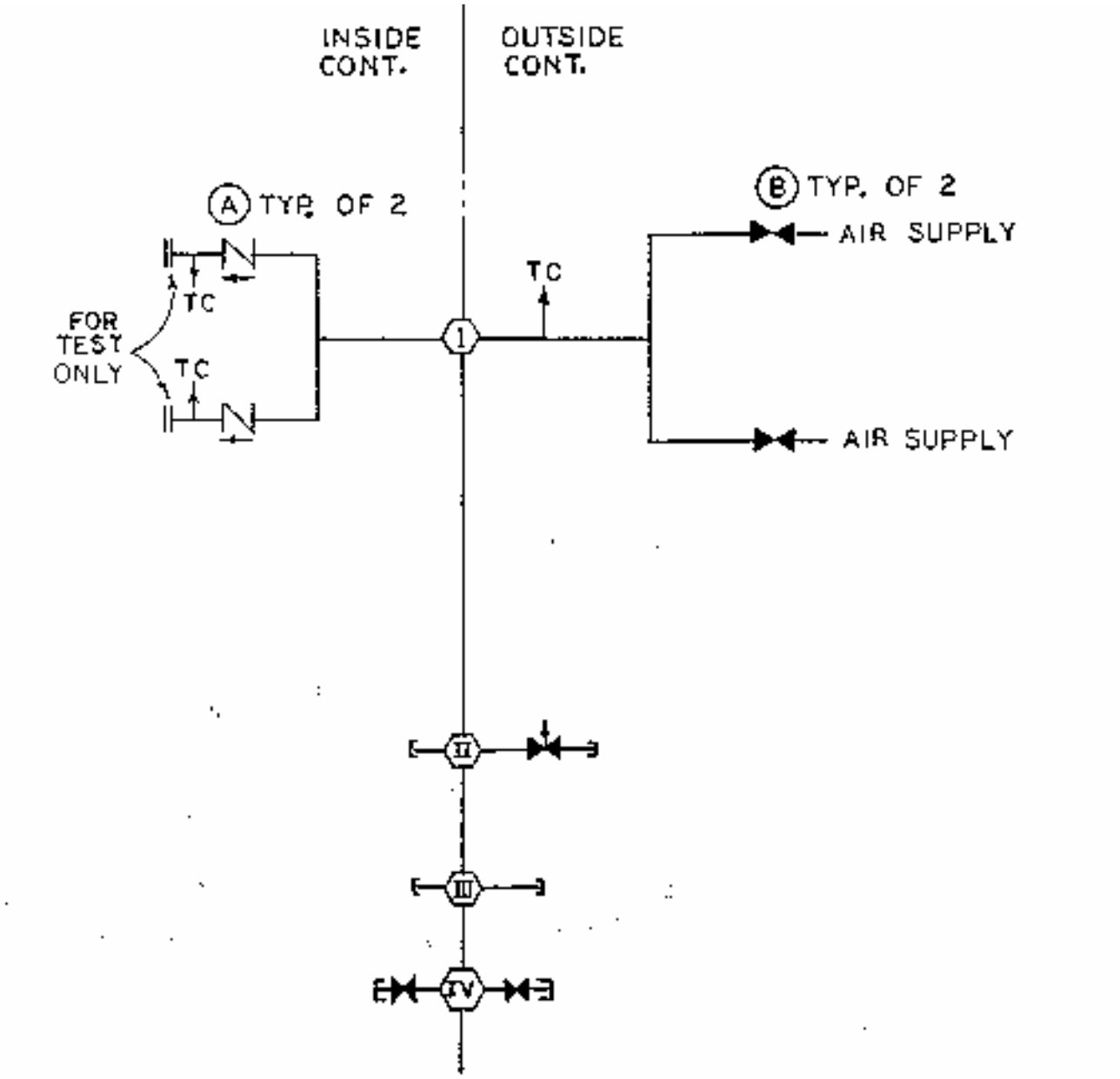
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-19
PENETRATION DIAGRAM
(SHEET 9 OF 25)



(I) SEAL WATER SUPPLY (41,42,43,44)
(II) SEAL WATER RETURN AND LETDOWN (45)

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 10 OF 25)



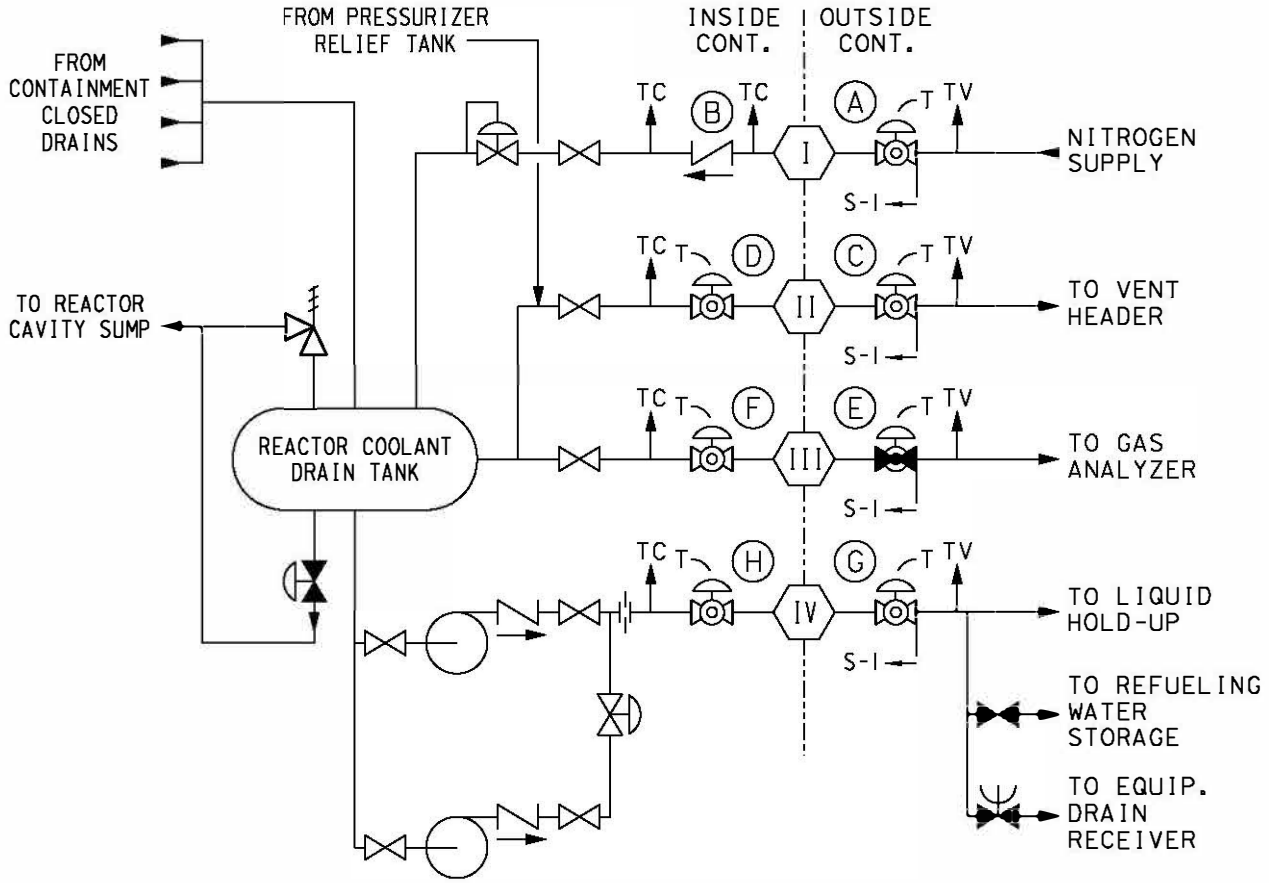
(I) H_2 PURGE SUPPLY (83)

(II) SPARE INSTRUMENT TEST LINE (80--2 LINES) UNIT 1 ONLY

(III) SPARE INSTRUMENT TEST LINE (80,82,76,78) UNIT 1 ,LINE (80 ,82) UNIT 2

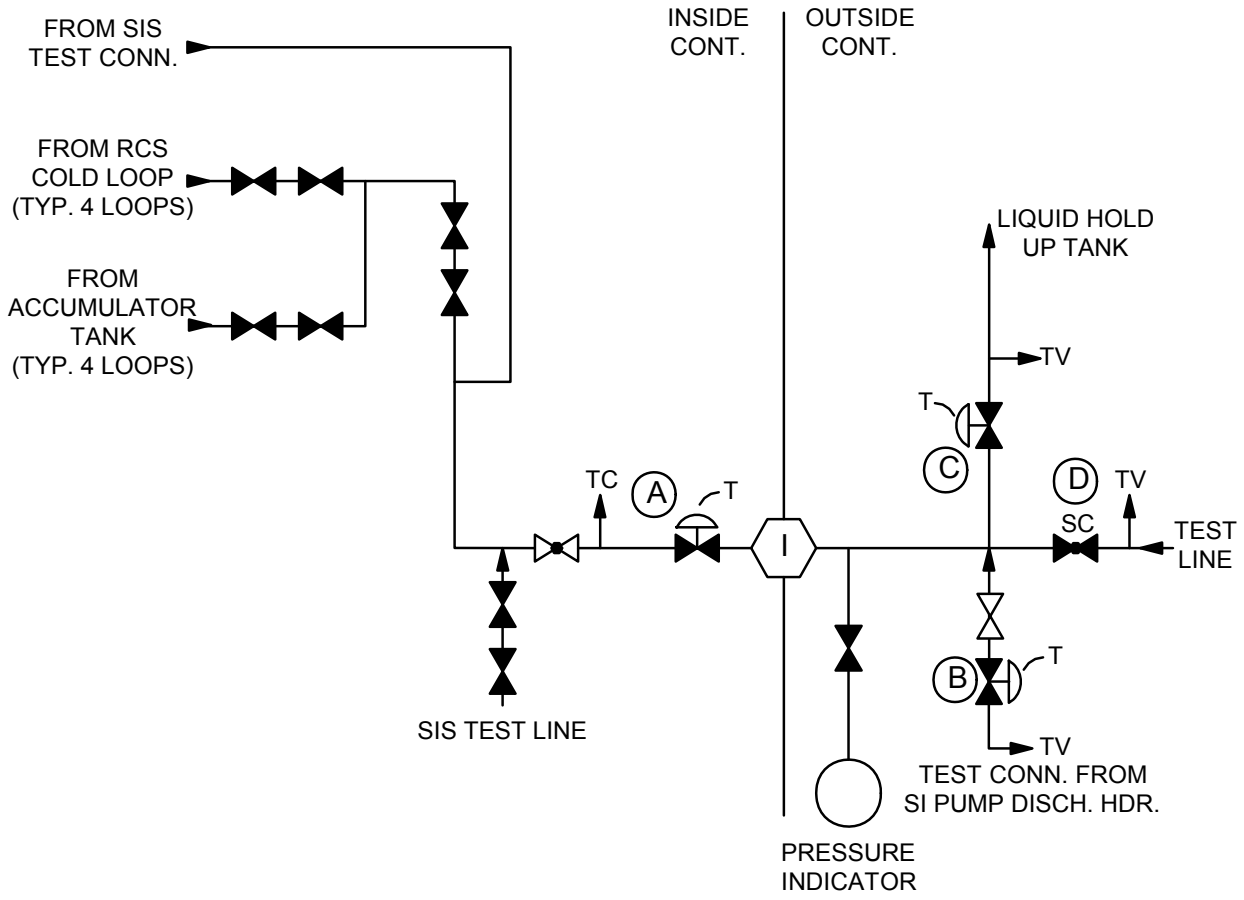
(IV) SPARE INSTRUMENT TEST LINE (80--2 LINES) UNIT 2 ONLY

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 11 OF 25)



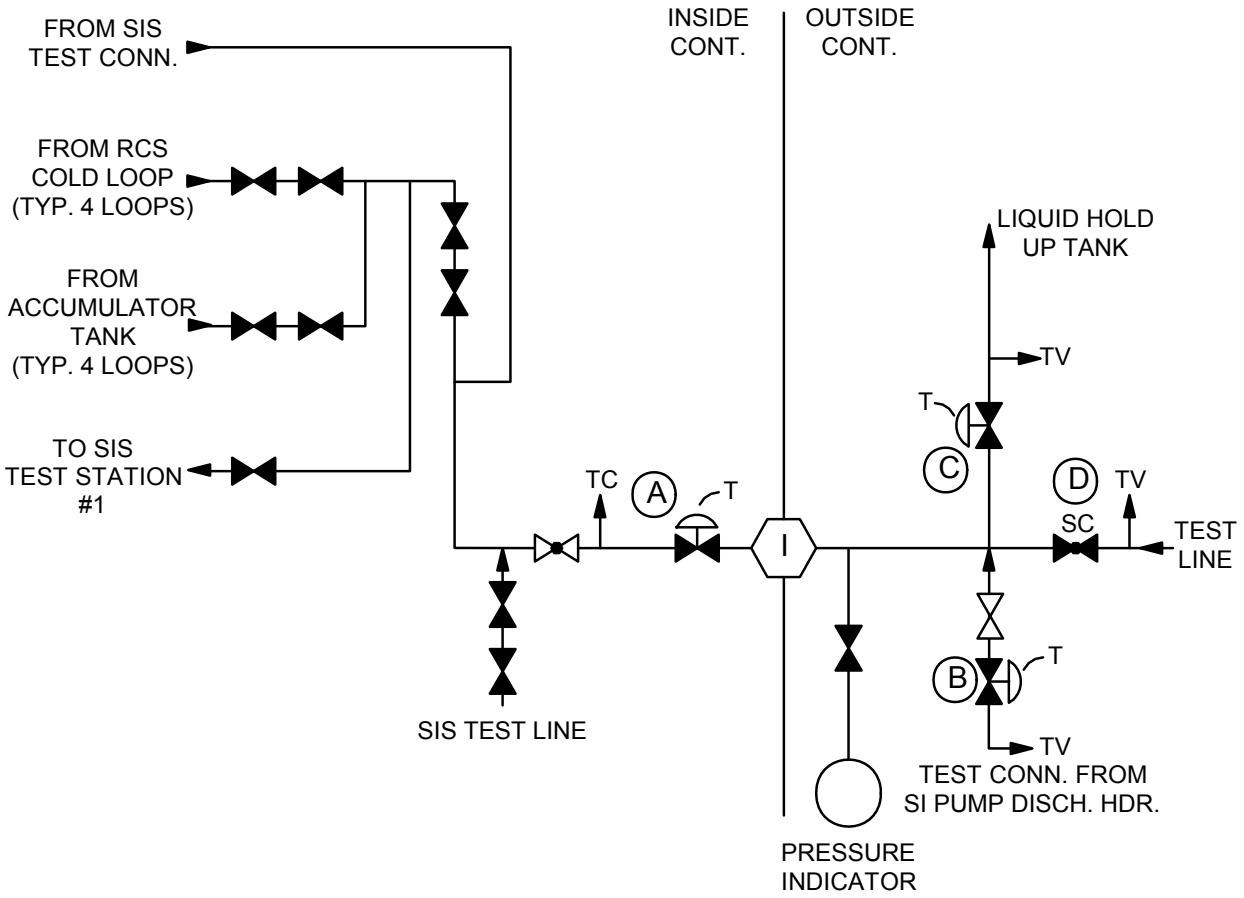
(I) REACTOR COOLANT DRAIN TANK N_2 SUPPLY (52D)
(II) REACTOR COOLANT DRAIN TANK VENT HEADER (51C)
(III) REACTOR COOLANT DRAIN TANK GAS ANALYZER (51D)
(IV) REACTOR COOLANT DRAIN TANK DISCHARGE (50)

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 12 OF 25)



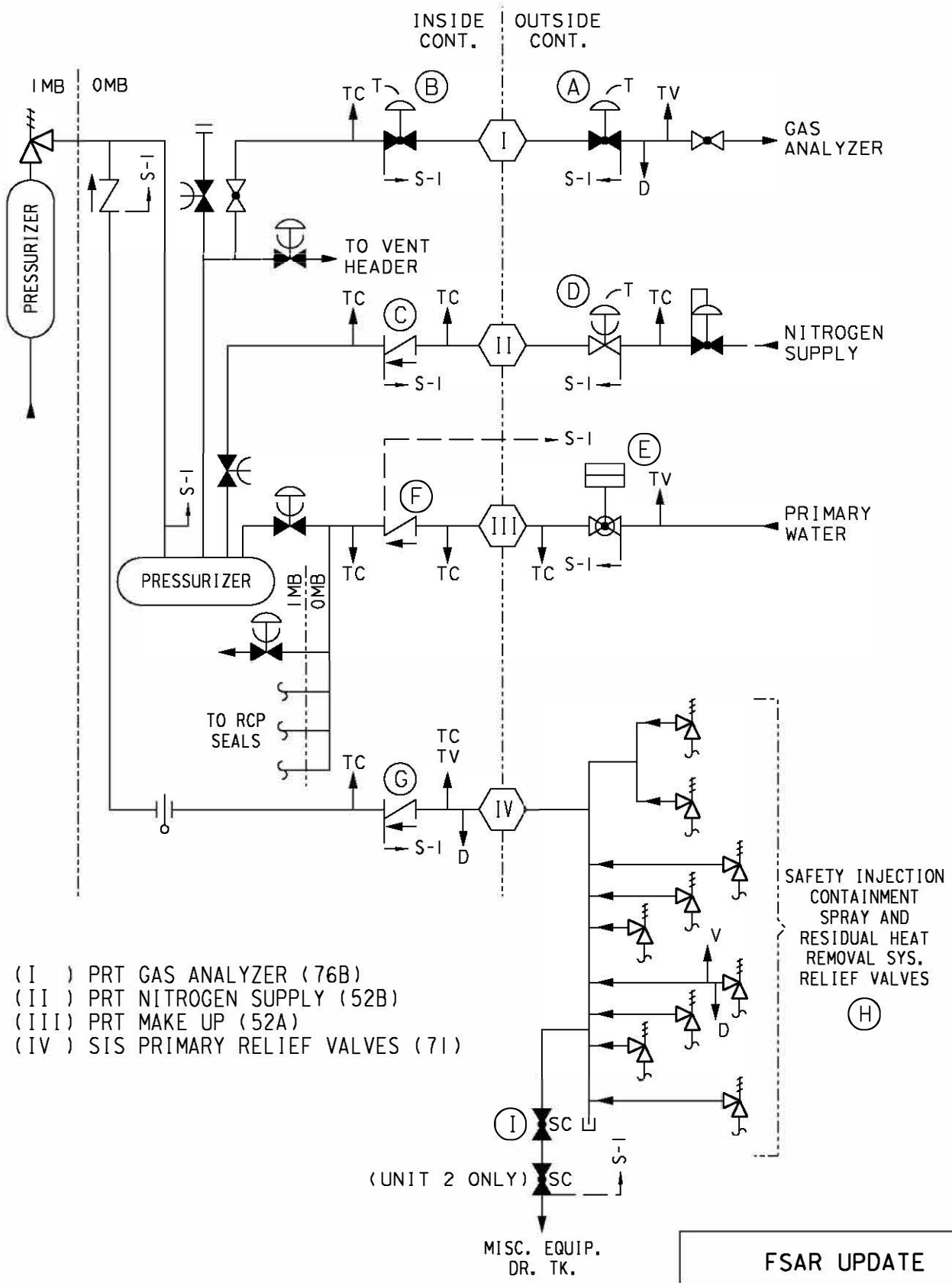
(I) TEST LINE FROM SAFETY INJECTION SYSTEM (51B)

FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 13 OF 25)

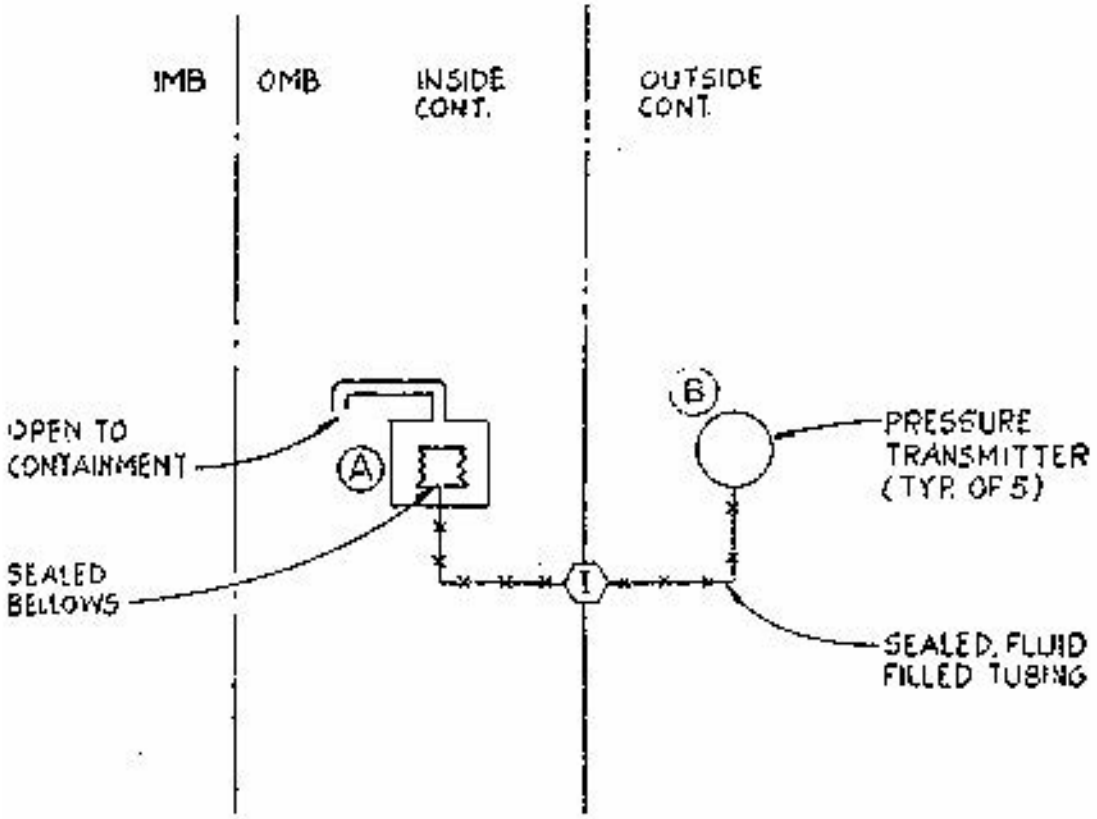


(I) TEST LINE FROM SAFETY INJECTION SYSTEM (51B)

FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 13A OF 25)

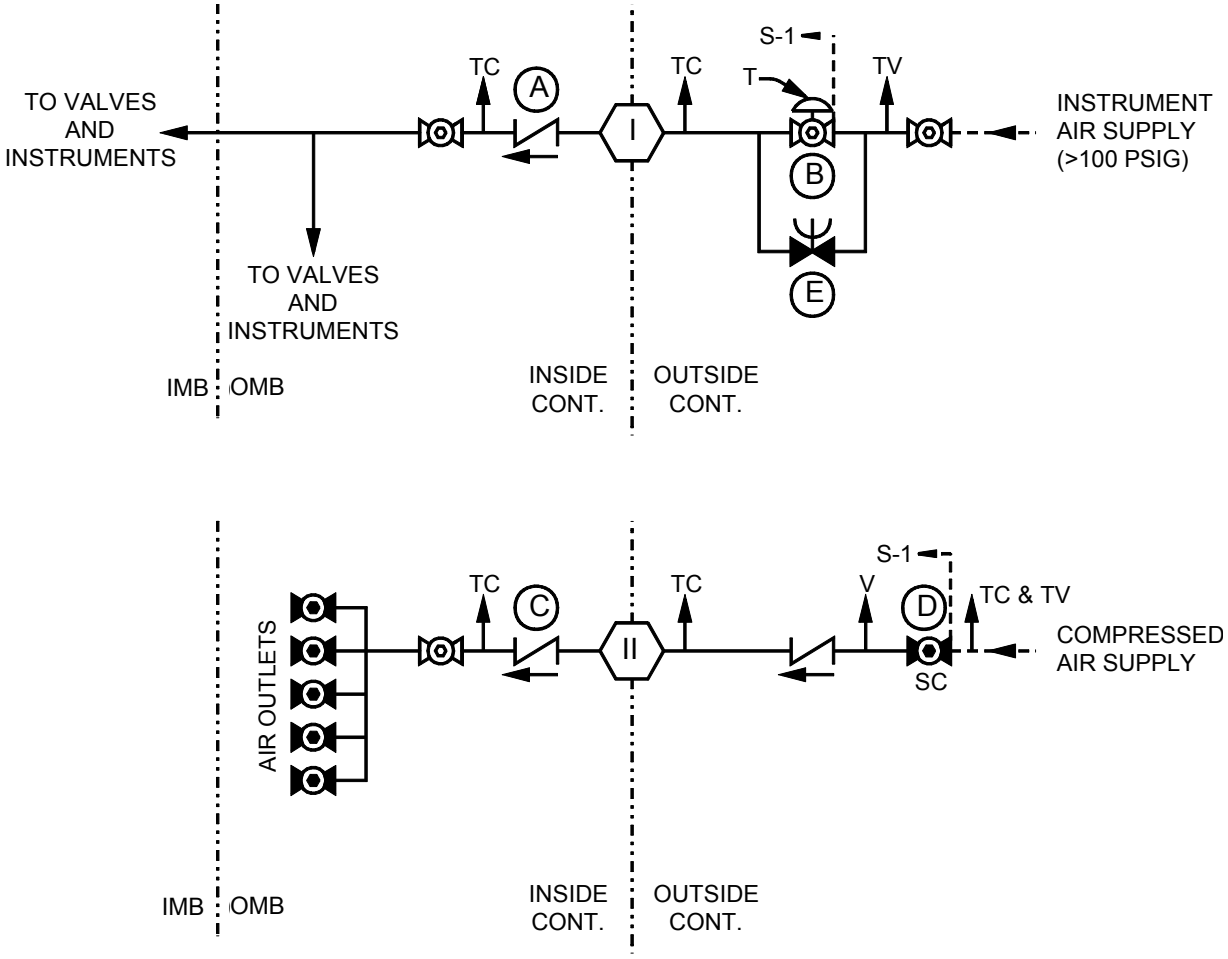


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 14 OF 25)



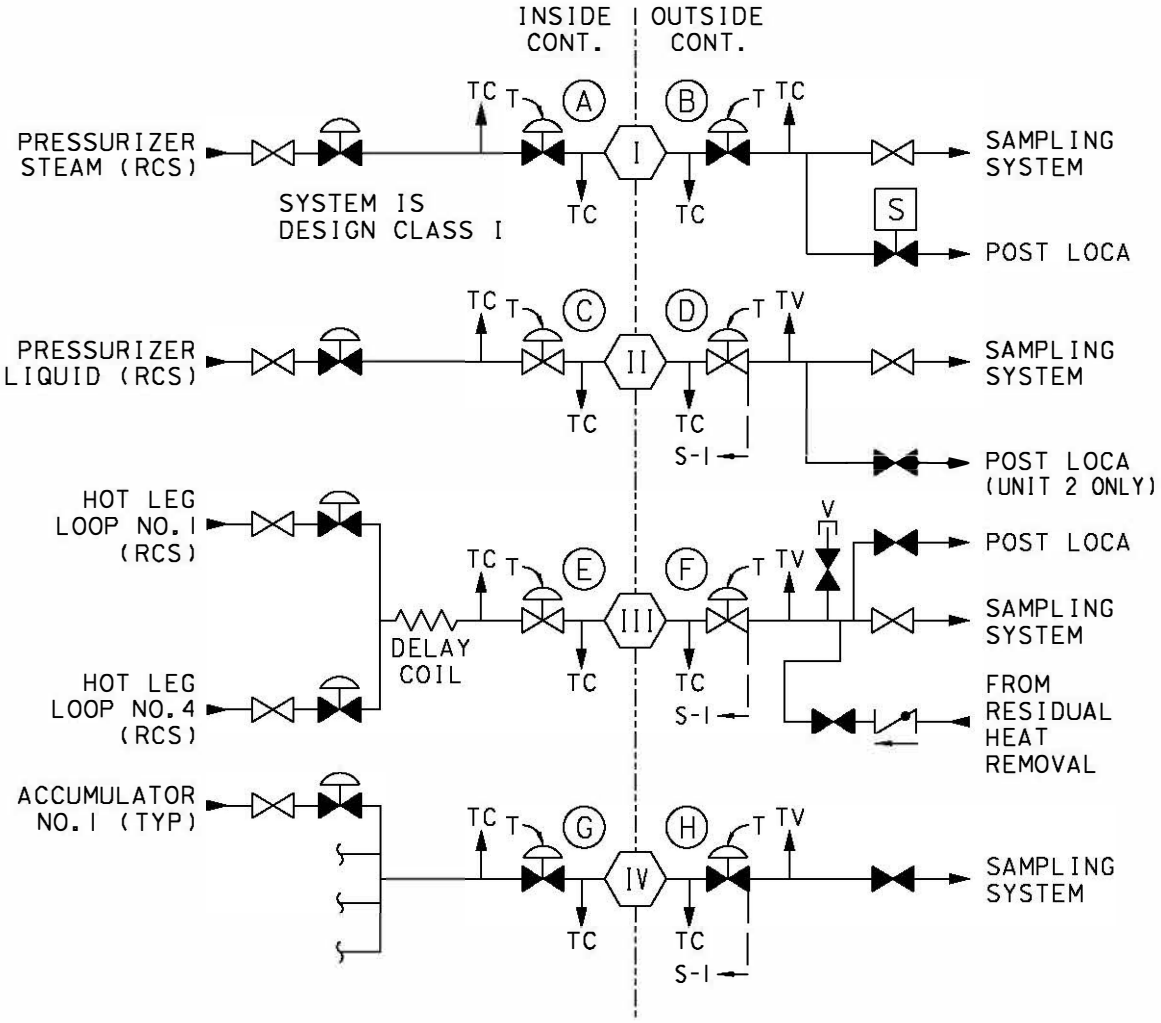
SYSTEM IS DESIGN CLASS I
(I) CONTAINMENT PRESSURE (52&59-2 LINES; 76, 78&80-1 LINE)

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 15 OF 25)



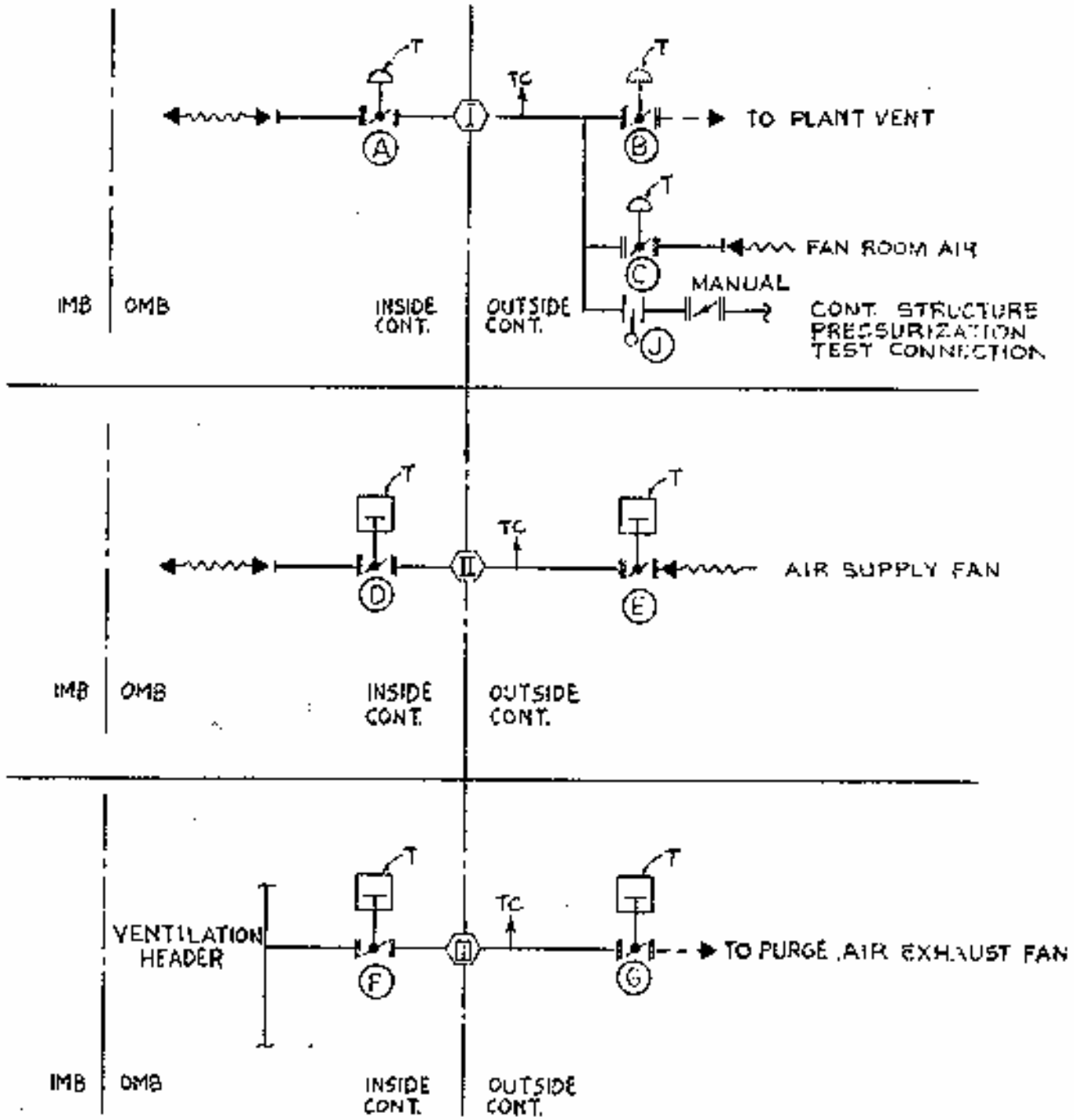
(I) INSTRUMENT AIR HEADER (54)
(II) SERVICE AIR HEADER (56)

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 16 OF 25)



(I) PRESSURIZER STEAM SAMPLE (76A)
(II) PRESSURIZER LIQUID SAMPLE (59A)
(III) HOT LEG SAMPLE (59B)
(IV) ACCUMULATOR SAMPLE (59C)

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 17 OF 25)



ALL SYSTEMS ARE DESIGN CLASS I

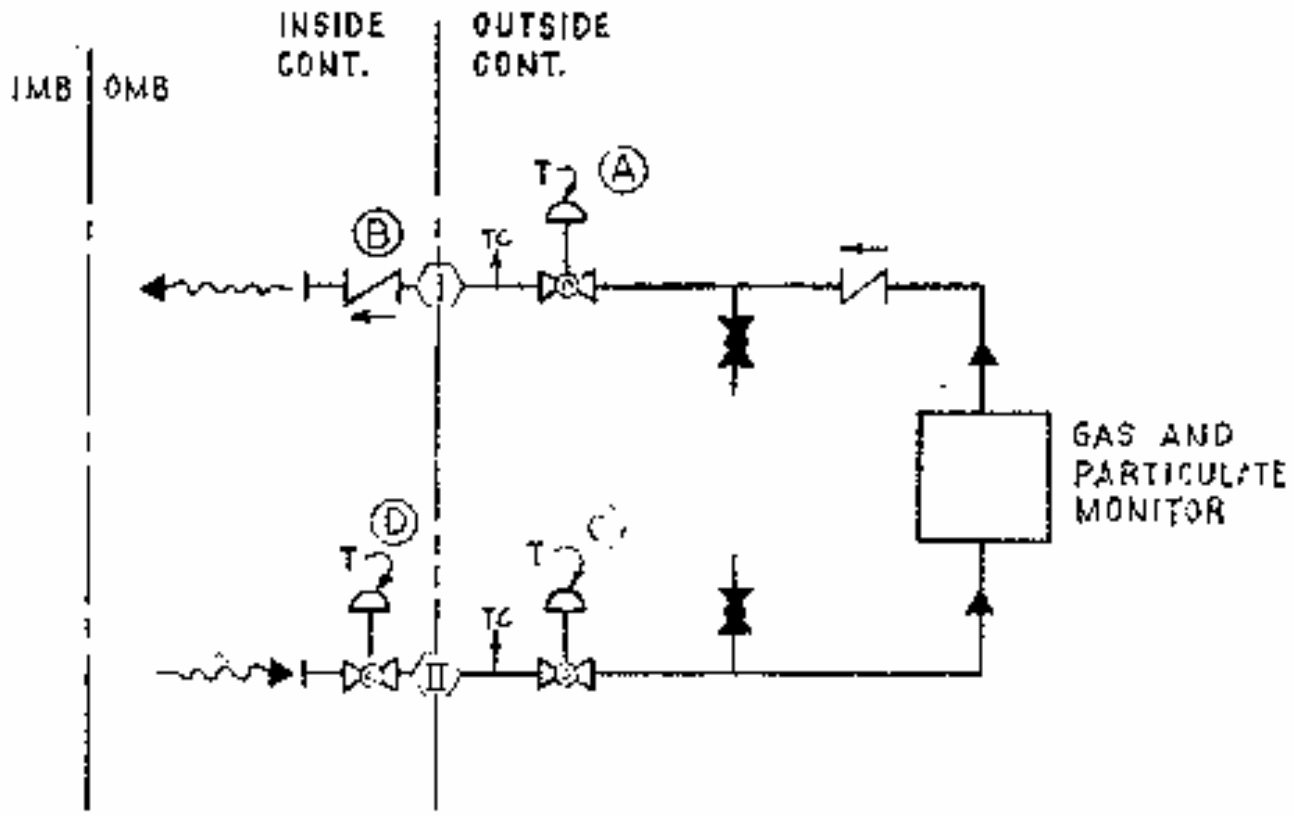
(I) CONTAINMENT PRESSURE AND VACUUM RELIEF (63)

(II) CONTAINMENT PURGE SUPPLY DUCT (61)*

(III) CONTAINMENT PURGE EXHAUST DUCT (62)*

*Valves are sealed closed in Modes 1-4

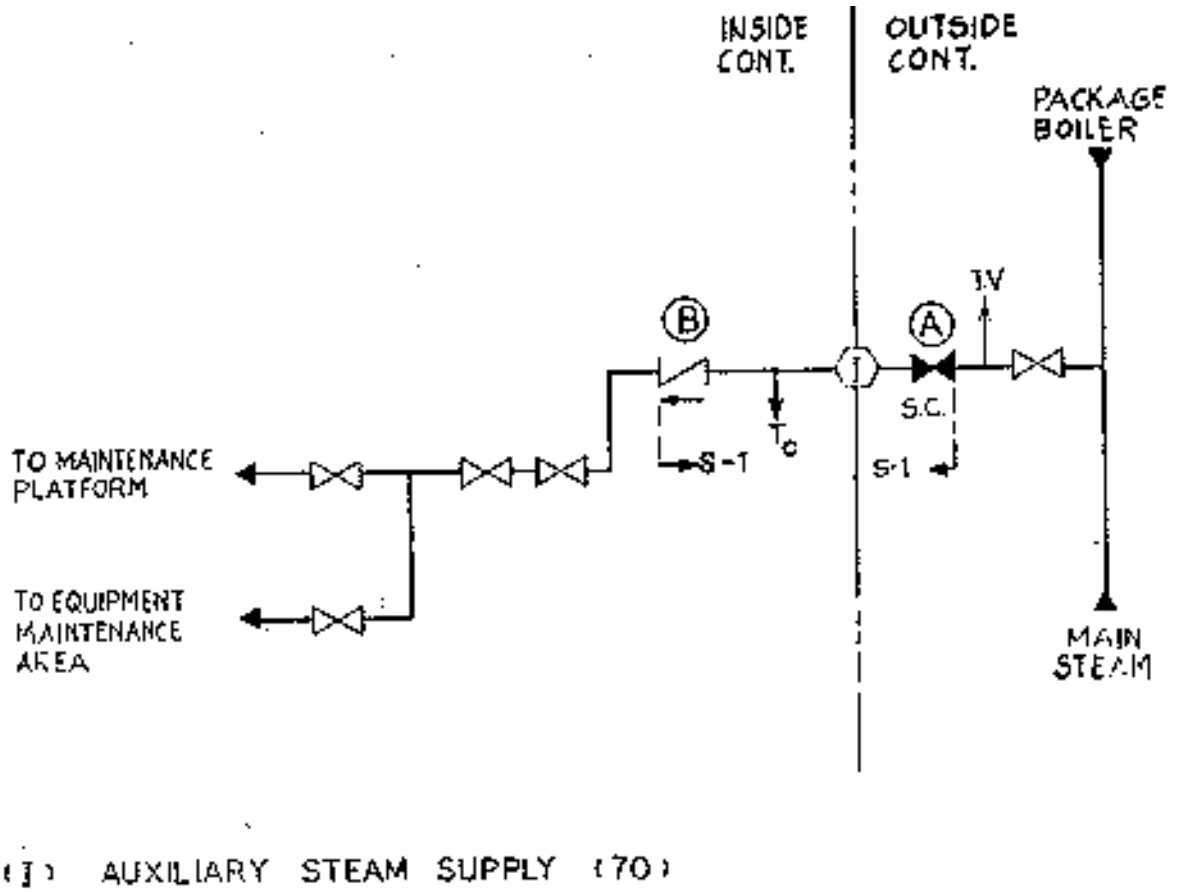
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 18 OF 25)



VALVES AND PIPING ARE DESIGN CLASS I

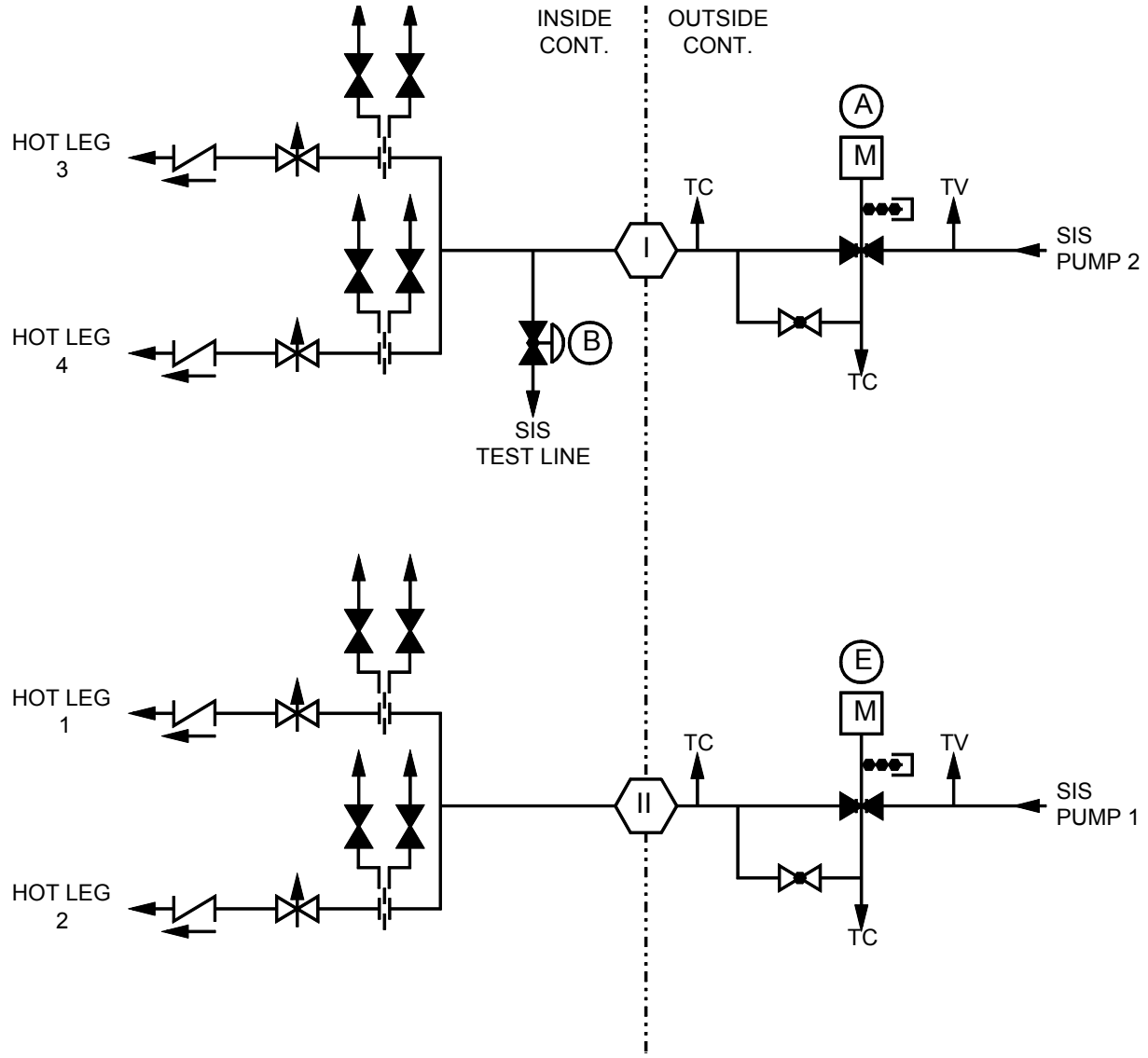
(I) CONTAINMENT AIR SAMPLE (69)
(II) CONTAINMENT AIR SAMPLE (68)

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 19 OF 25)



(J) AUXILIARY STEAM SUPPLY (70)

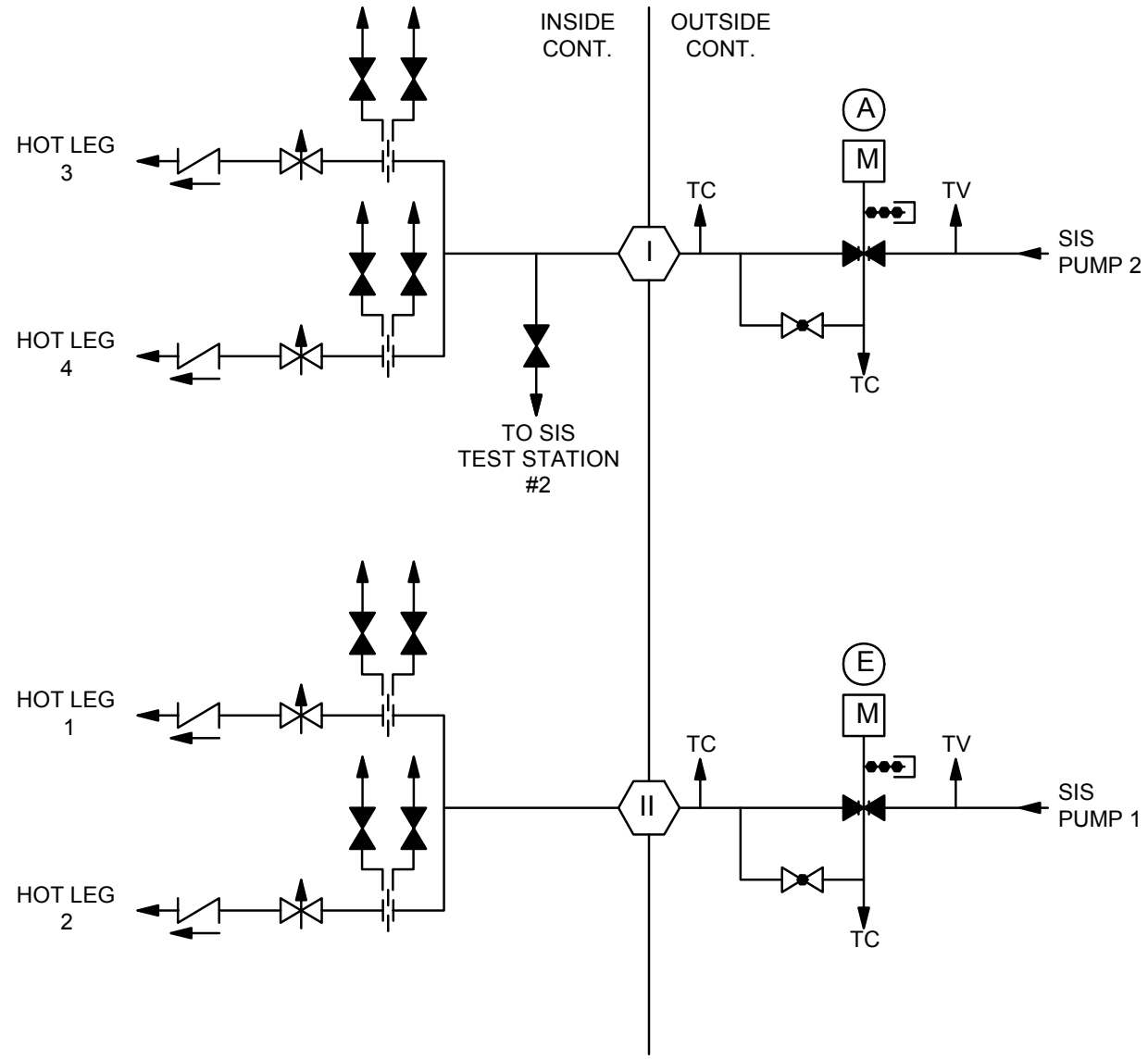
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 20 OF 25)



(I) SIS PUMP 2 DISCHARGE (75)
(II) SIS PUMP 1 DISCHARGE (77)

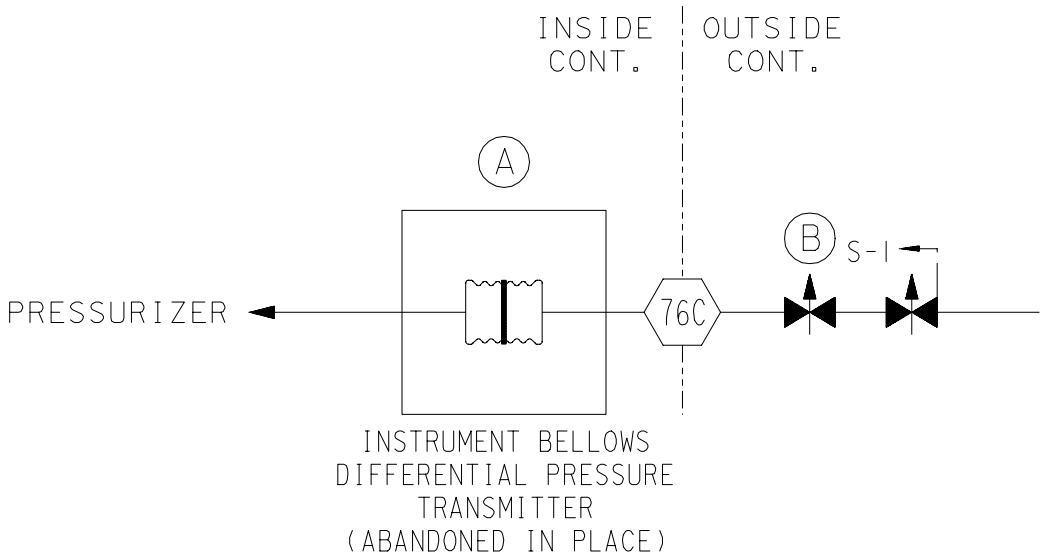
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 21 OF 25)

Revision 26 September 2021



(I) SIS PUMP 2 DISCHARGE (75)
(II) SIS PUMP 1 DISCHARGE (77)

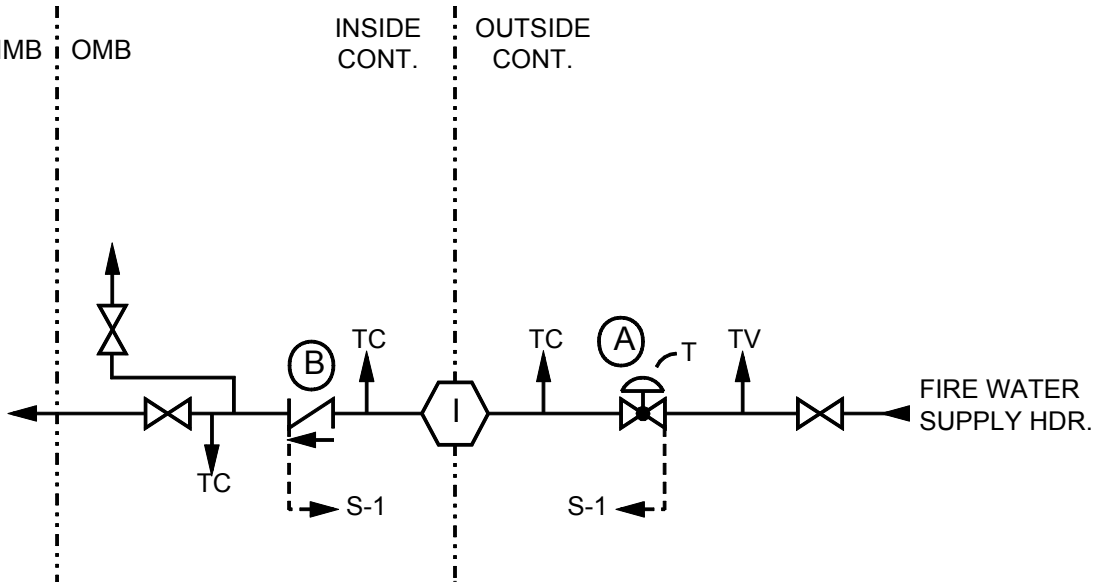
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 21A OF 25)



NOTES:

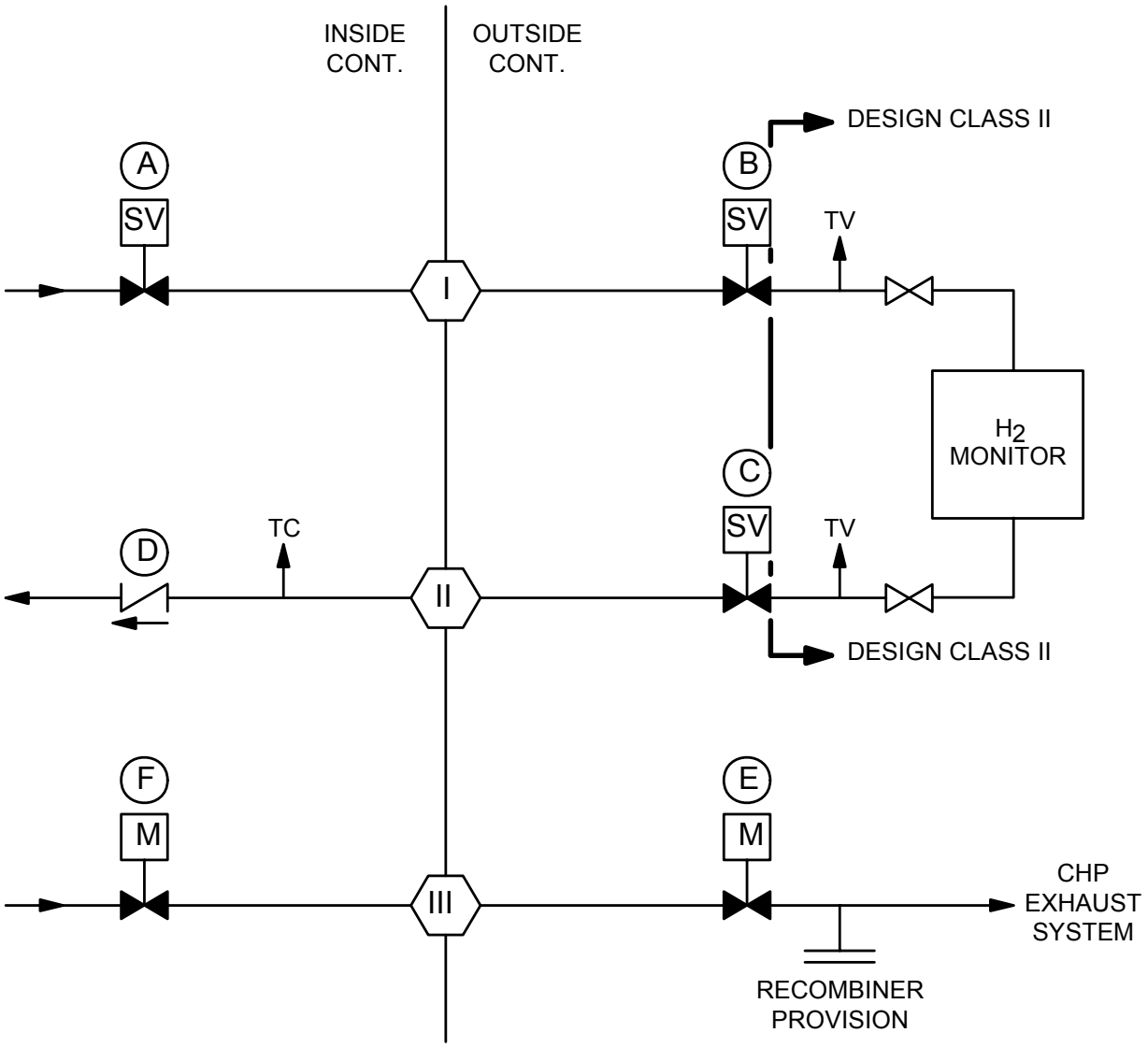
1. FOR UNIT 1, THE TUBING BETWEEN VALVES OUTSIDE CONTAINMENT IS REMOVED AND A CAP INSTALLED ON THE INBOARD VALVE.
2. FOR UNIT 2, THE TUBING OUTSIDE CONTAINMENT HAS BEEN REMOVED AND A CAP INSTALLED AT THE PENETRATION.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 22 OF 25)



(I) FIRE WATER SUPPLY (79)

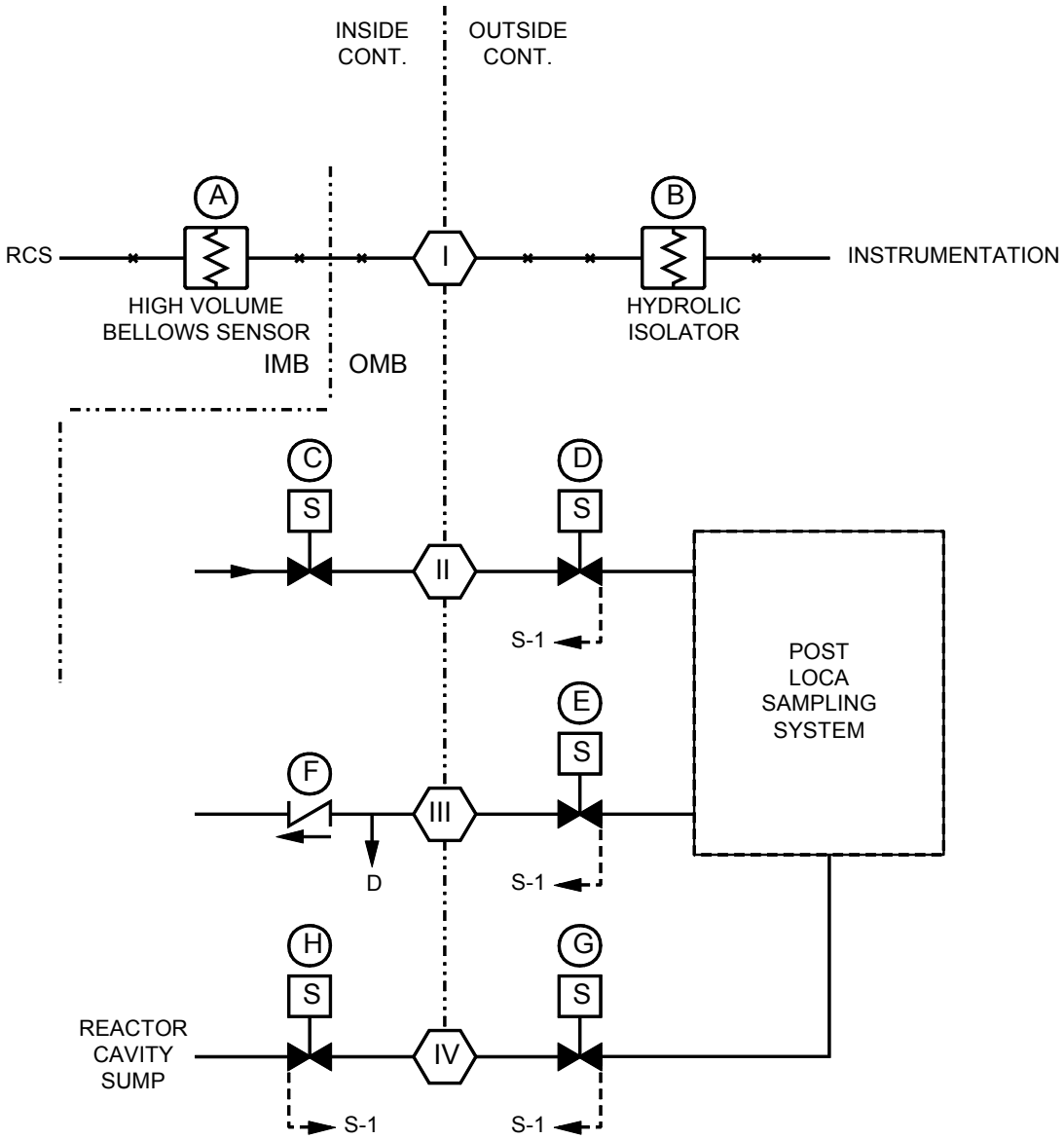
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 23 OF 25)



ALL SYSTEMS ARE DESIGN CLASS I, EXCEPT AS NOTED.

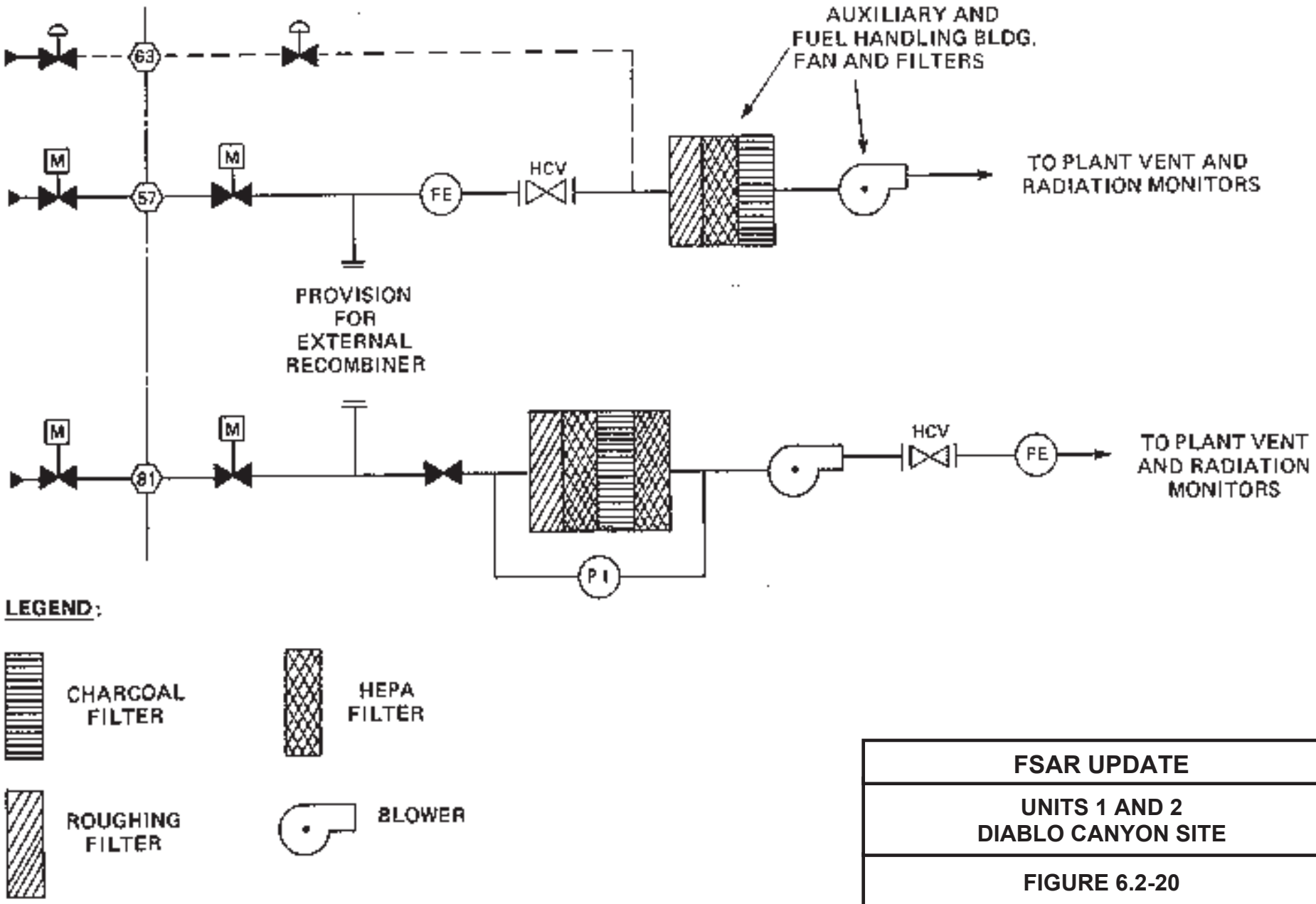
(I) CONTAINMENT H_2 MONITOR SUPPLY (52E, 78A)
(II) CONTAINMENT H_2 MONITOR RETURN (52C, 78B)
(III) CONTAINMENT H_2 EXTERNAL RECOMBINER (57, 81)

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 24 OF 25)

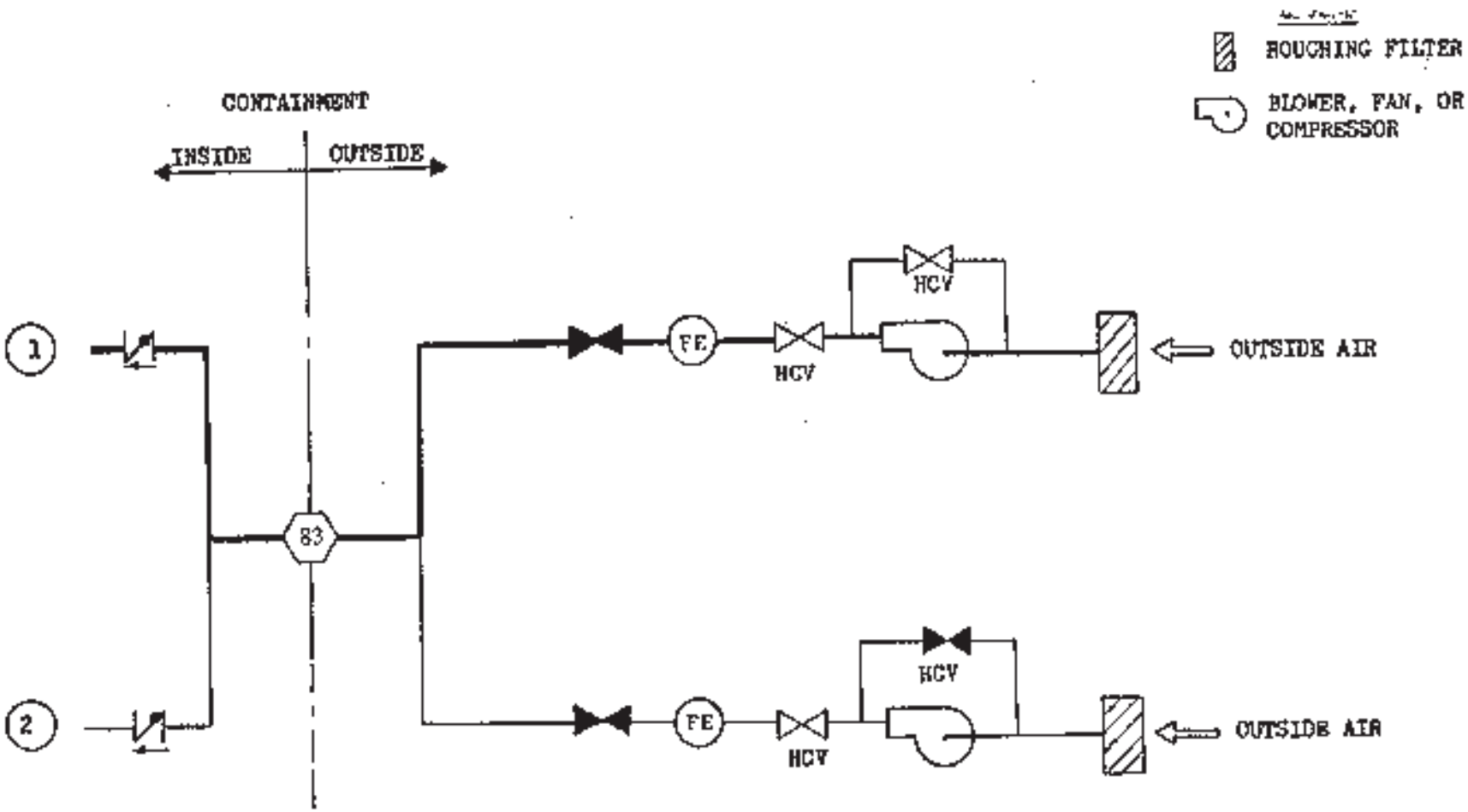


(I) REACTOR VESSEL LEVEL INSTRUMENTATION (59E,59F,59G,80E,80F,80G)
(II) POST-LOCA SAMPLING SYSTEM CONT. AIR SUPPLY (82B)
(III) POST-LOCA SAMPLING SYSTEM CONT. AIR RETURN (82C)
(IV) POST-LOCA SAMPLING SYSTEM REACTOR CAVITY SUMP (82A)

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-19 PENETRATION DIAGRAM (SHEET 25 OF 25)



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-20 CONTAINMENT HYDROGEN PURGE SYSTEM PURGE STREAM

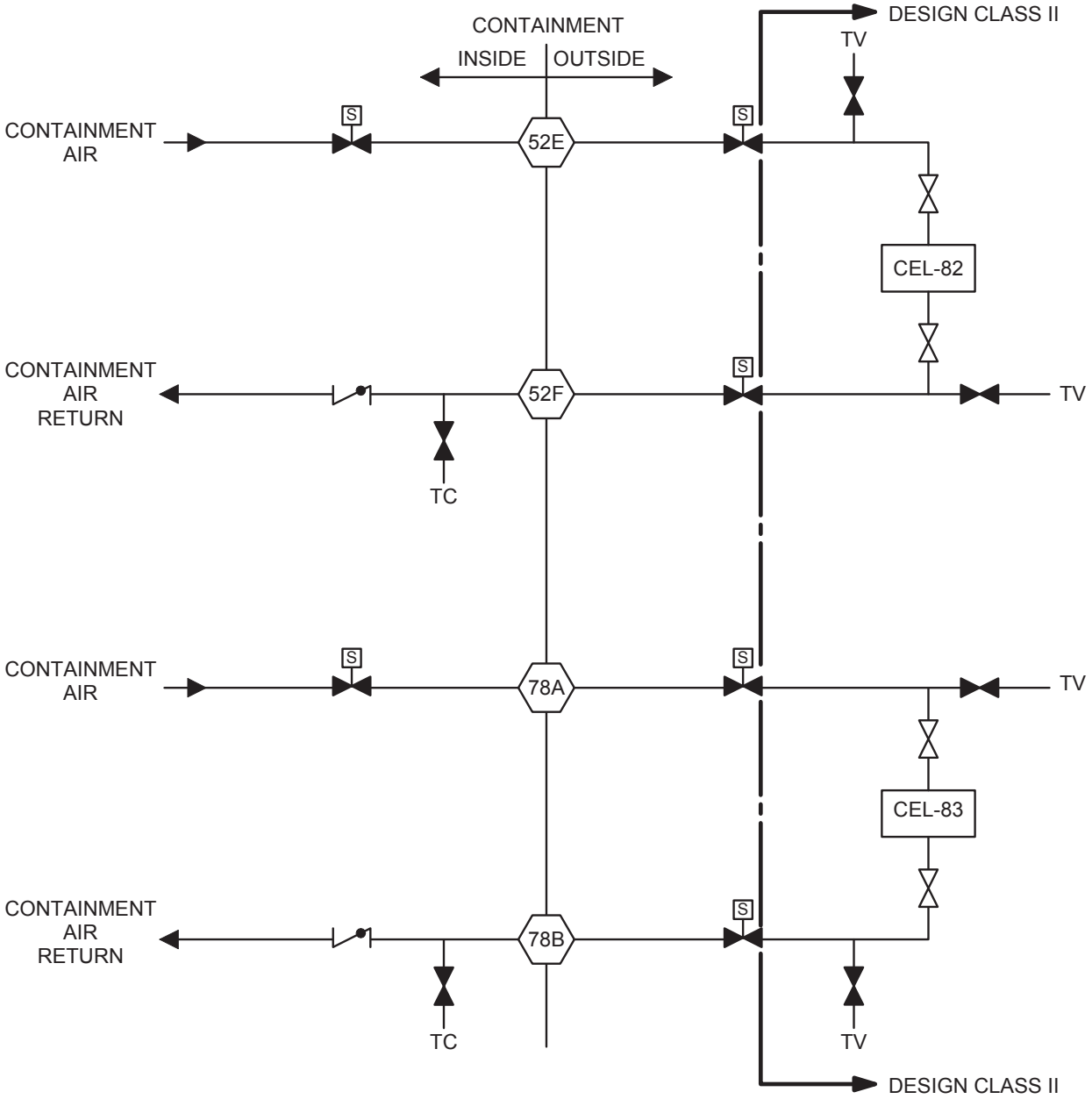


NOTE

1. VALVES SHOWN IN POSITION FOR HYDROGEN DILUTION ON LINE (1)

2. ALL PIPING, VALVES, FILTERS, BLOWERS, AND FLOW INSTRUMENTS ARE DESIGN CLASS I.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-21 CONTAINMENT HYDROGEN PURGE SYSTEM SUPPLY STREAM



NOTES:

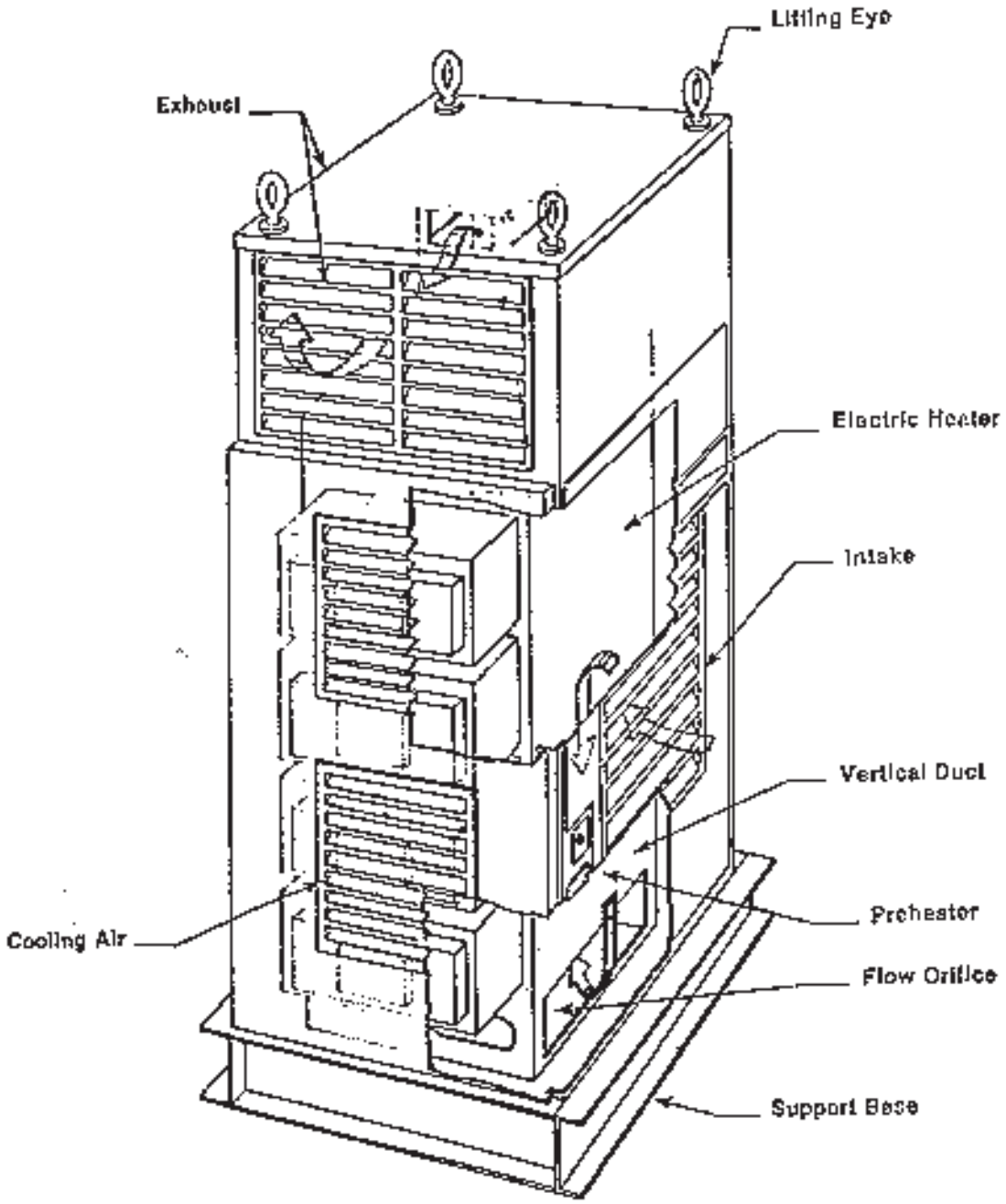
1. VALVES SHOWN FOR NORMAL PLANT OPERATION.
2. ALL PIPING AND VALVES ARE DESIGN CLASS I, EXCEPT AS NOTED.
3. HYDROGEN MONITORS ARE CLASS II.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

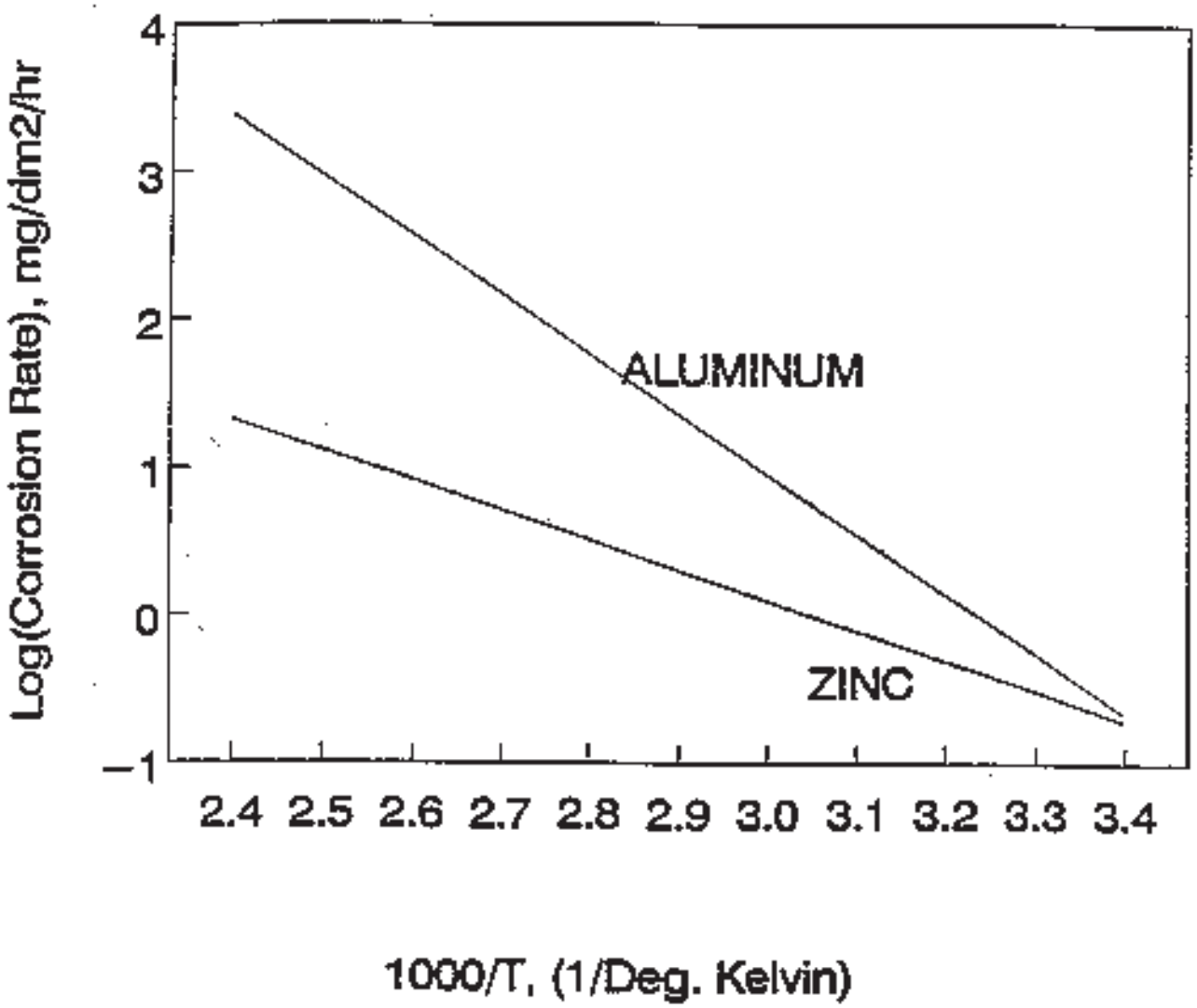
FIGURE 6.2-22
CONTAINMENT HYDROGEN PURGE SYSTEM
HYDROGEN ANALYZER STREAM

Revision 16 June 2005

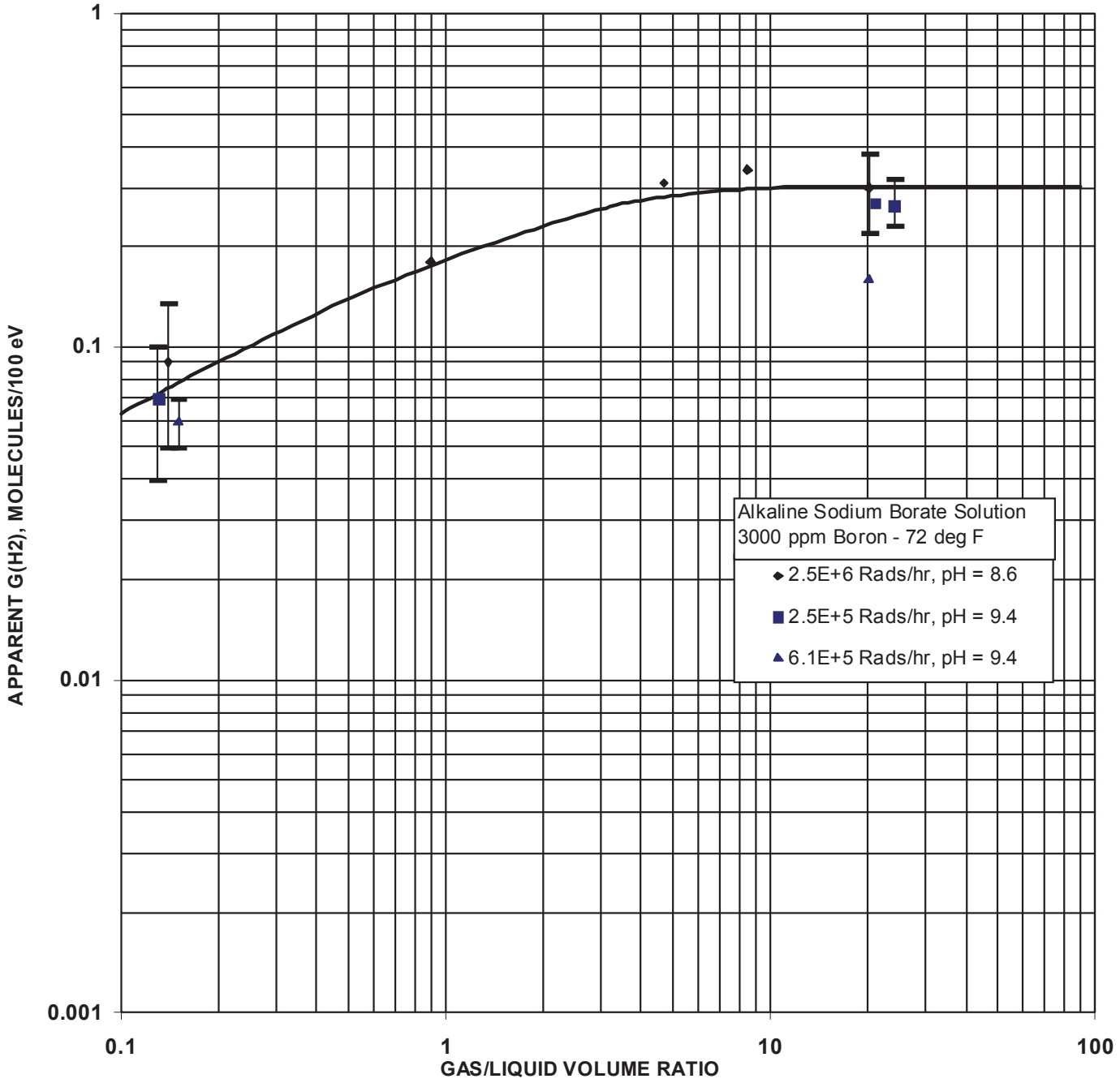


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-23 MODEL B ELECTRIC HYDROGEN RECOMBINER CUTAWAY

ALUMINUM AND ZINC CORROSION RATE
DESIGN CURVES



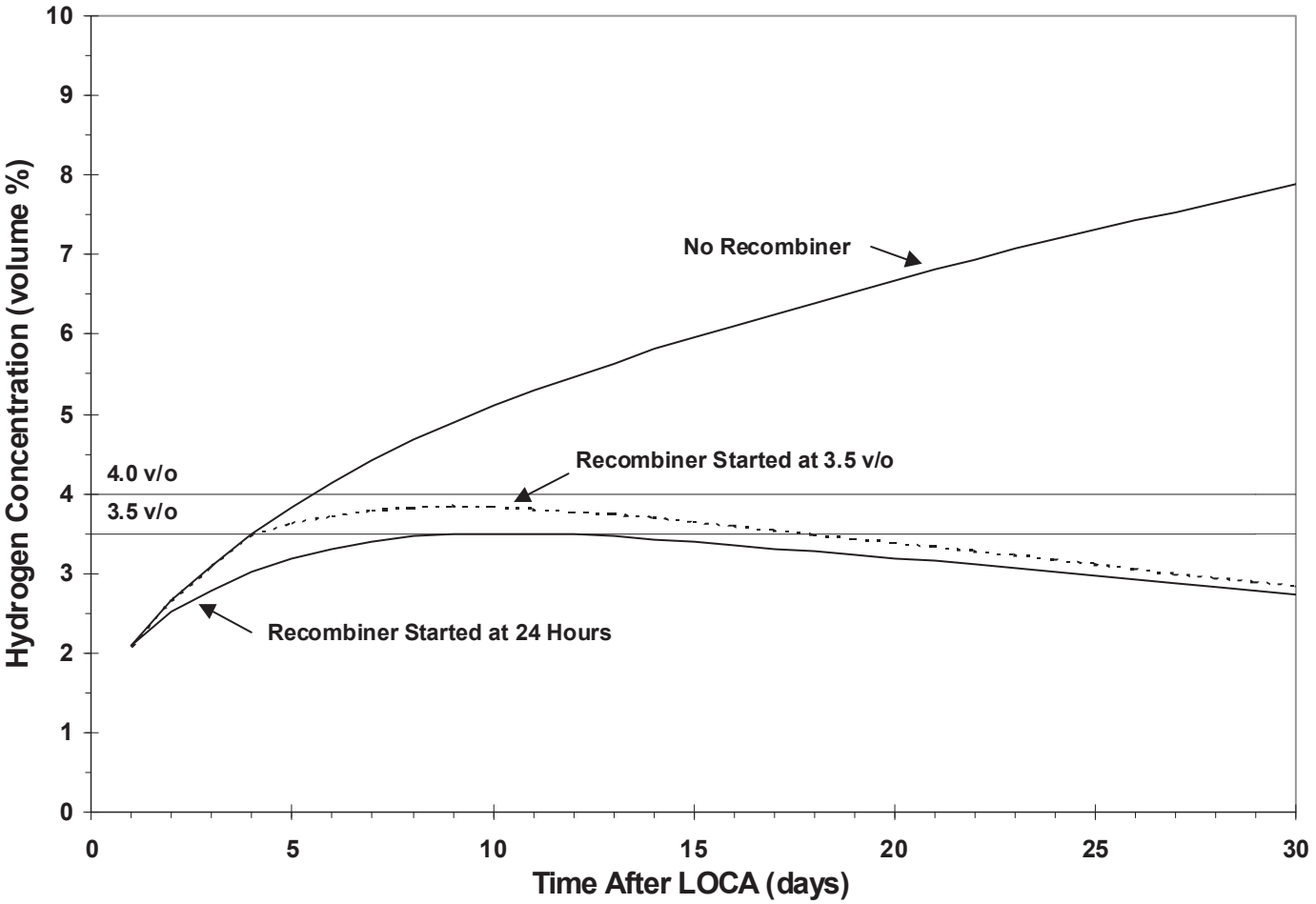
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-24 ALUMINUM AND ZINC CORROSION RATE DESIGN CURVE



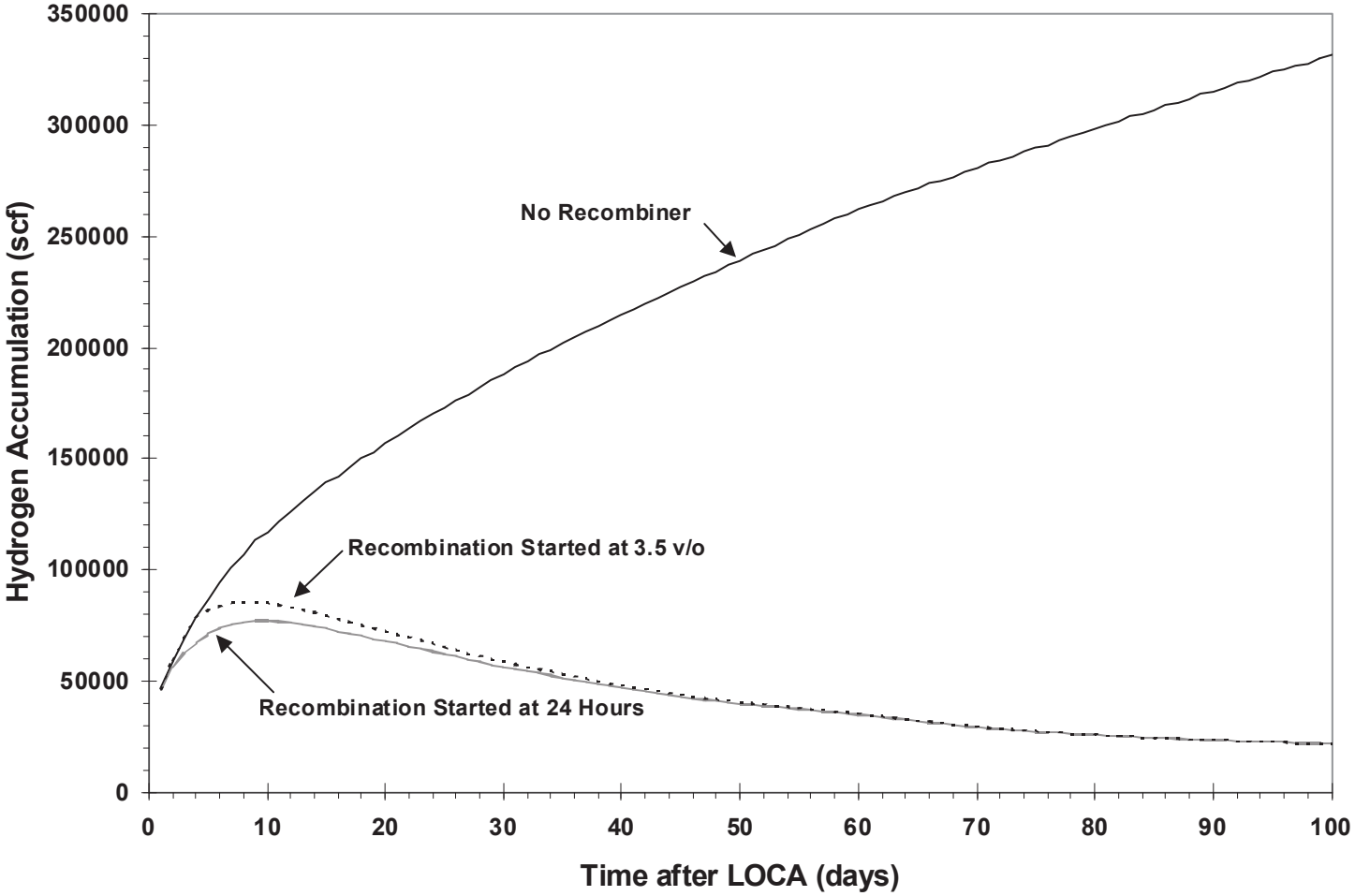
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

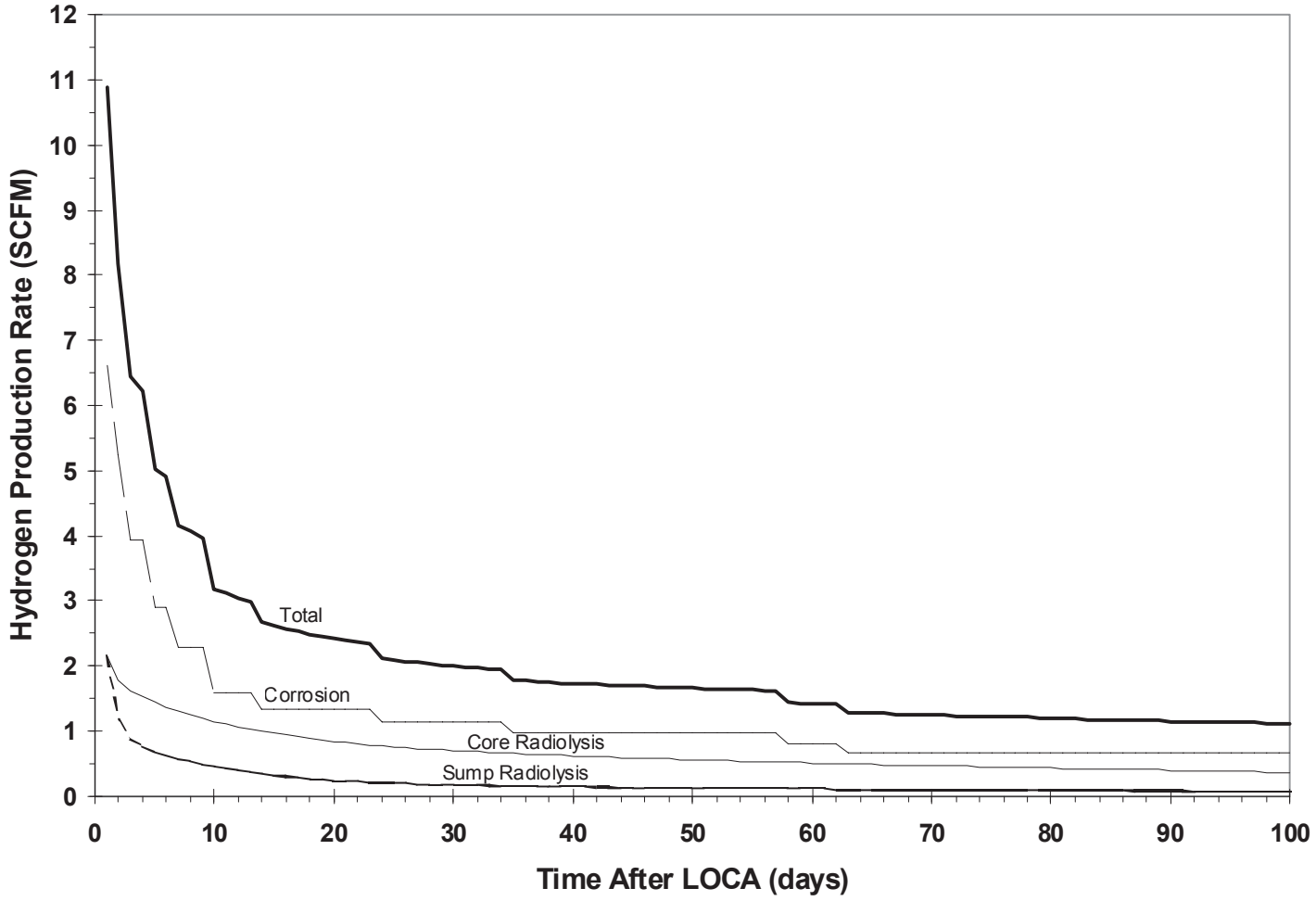
FIGURE 6.2-25
RESULTS OF WESTINGHOUSE CAPSULE IRRADIATION TESTS



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-26 POST-LOCA CONTAINMENT HYDROGEN CONCENTRATION

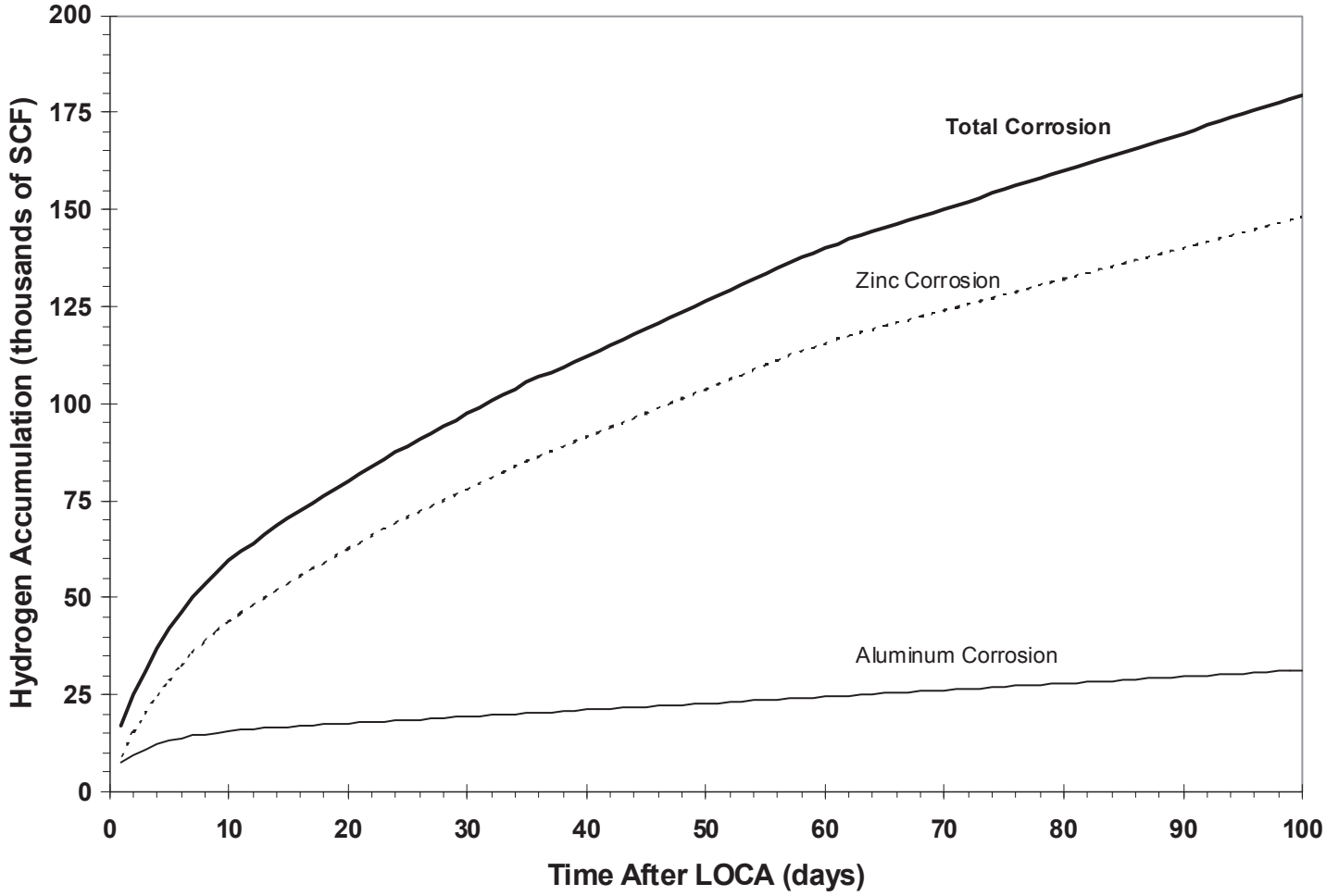


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-27 POST-LOCA HYDROGEN ACCUMULATION



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-28 POST-LOCA HYDROGEN PRODUCTION

Revision 14 November 2001

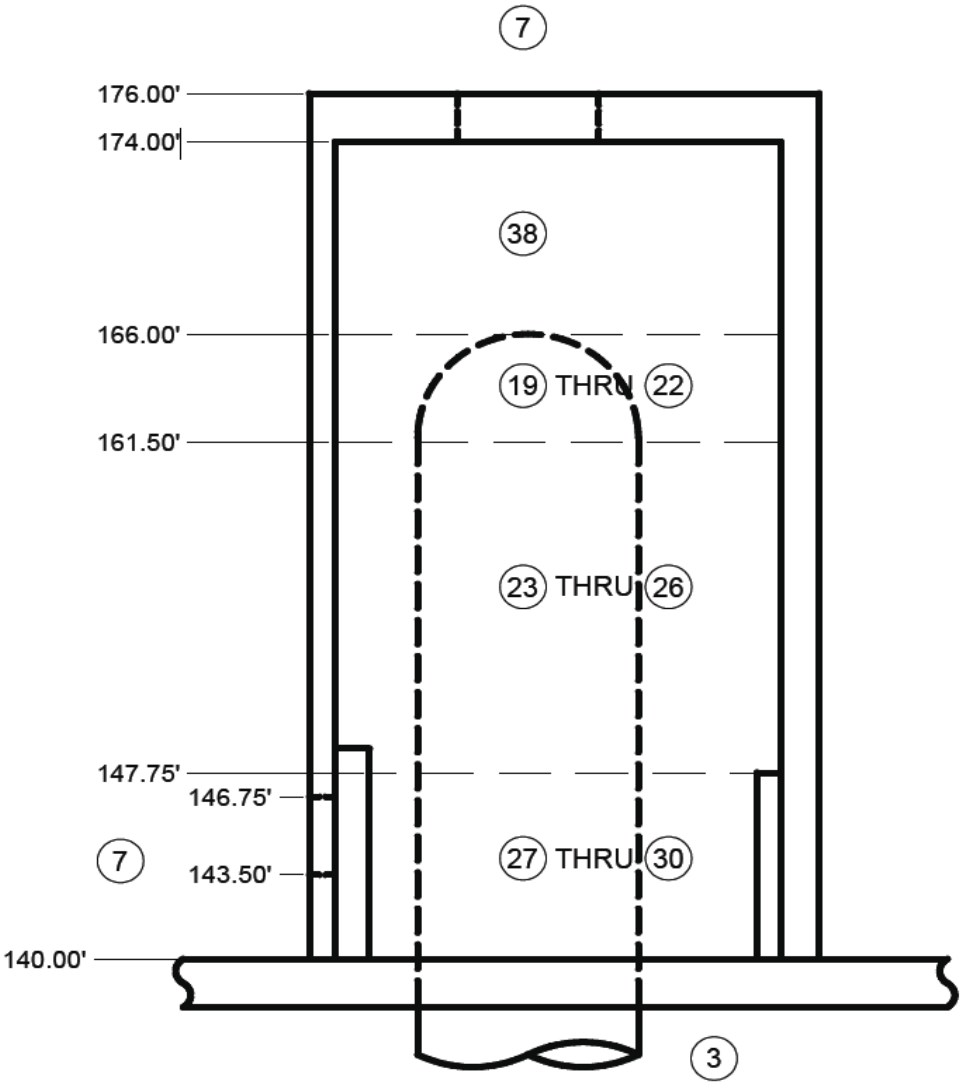


FSAR UPDATE

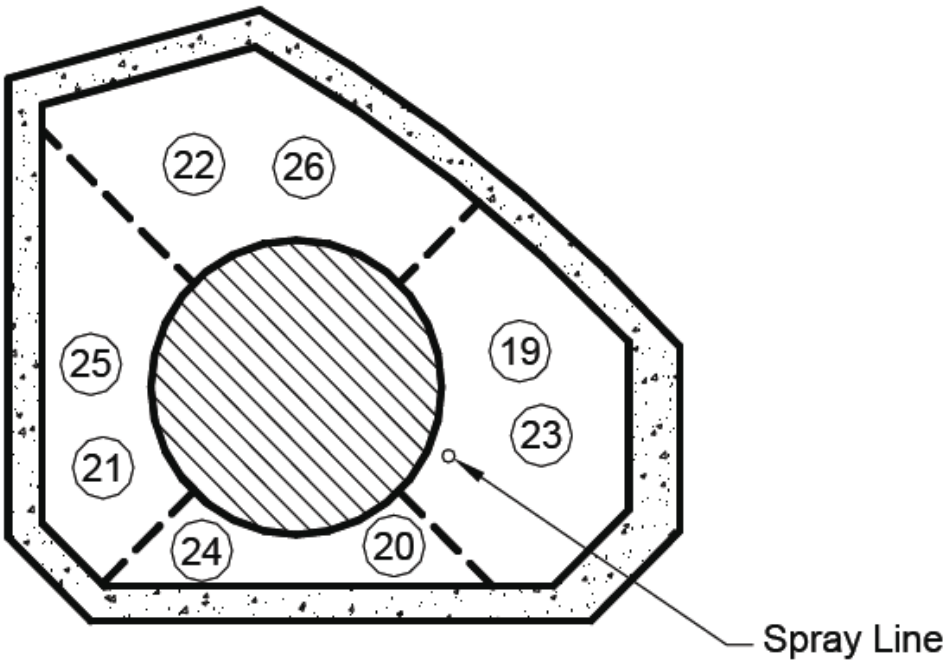
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.2-29
POST-LOCA HYDROGEN ACCUMULATION FROM CORROSION OF MATERIAL INSIDE CONTAINMENT WITH NO RECOMBINER

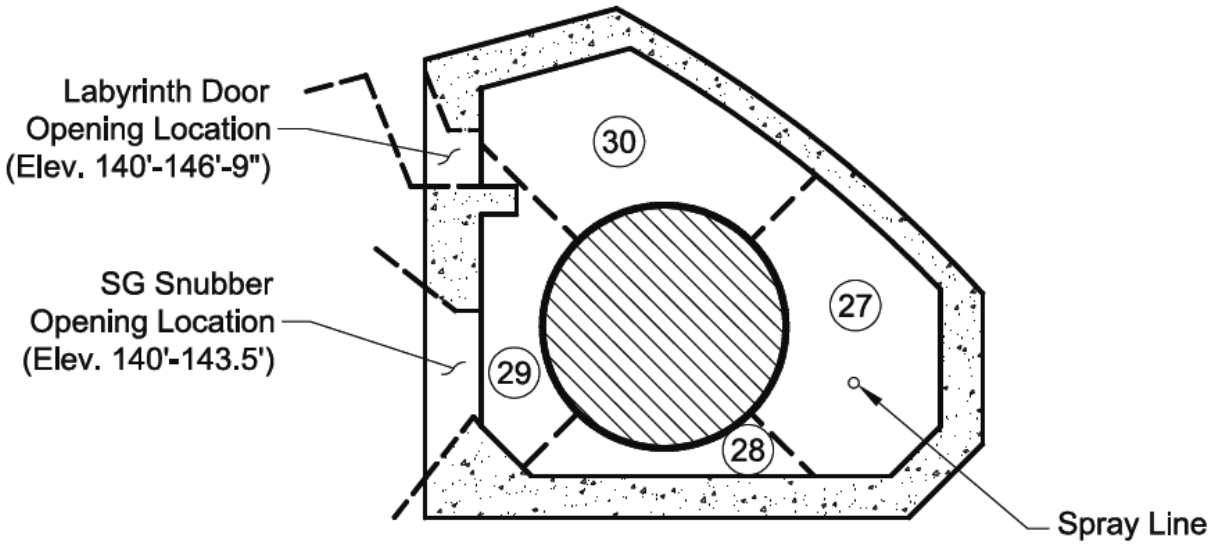
Figures 6.2-53 Through 6.2-56
Withheld From Public Disclosure
In Accordance With 10 CFR 2.390



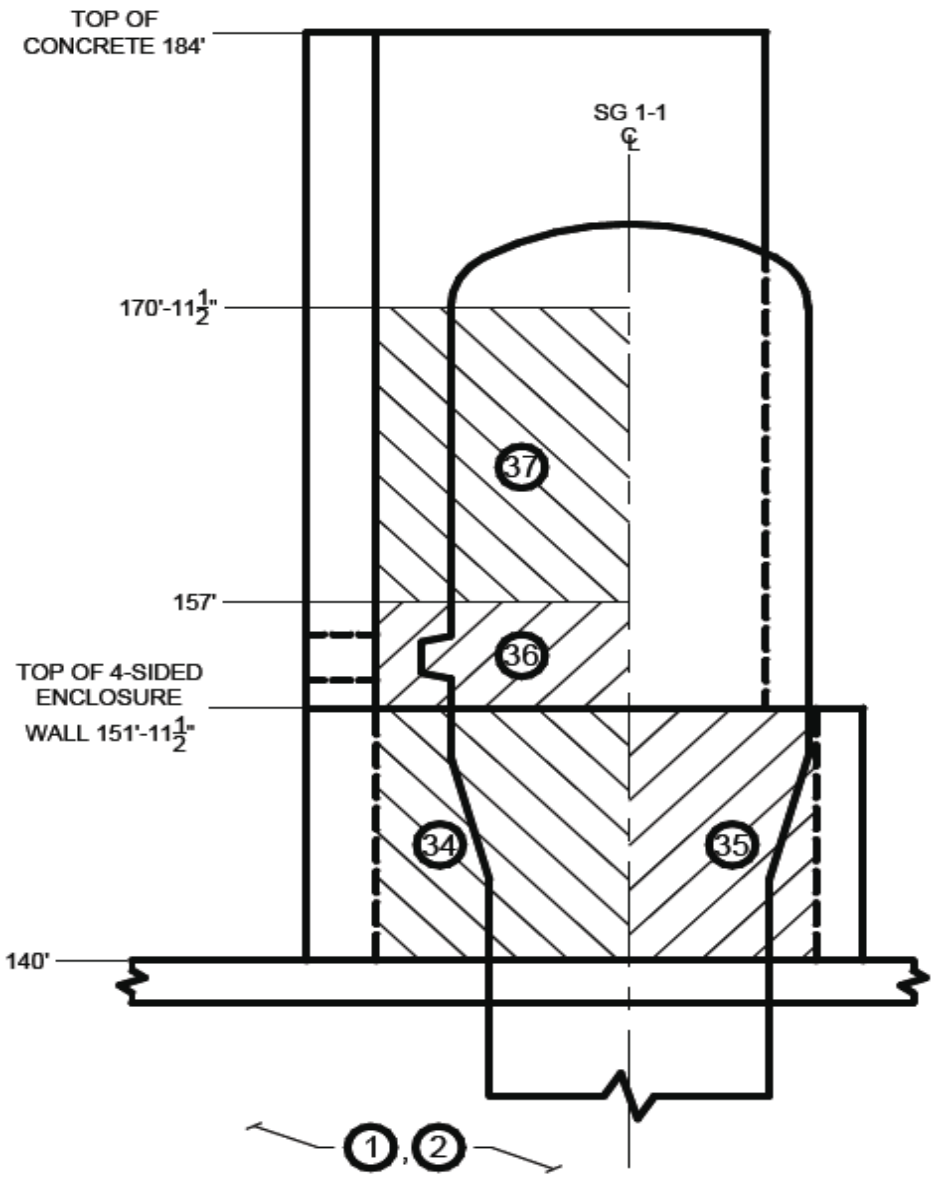
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-57 CONTAINMENT SUBCOMPARTMENT ANALYSES PRESSURIZER ENCLOSURE MODEL FROM ELEVATION 140 FEET TO 176 FEET



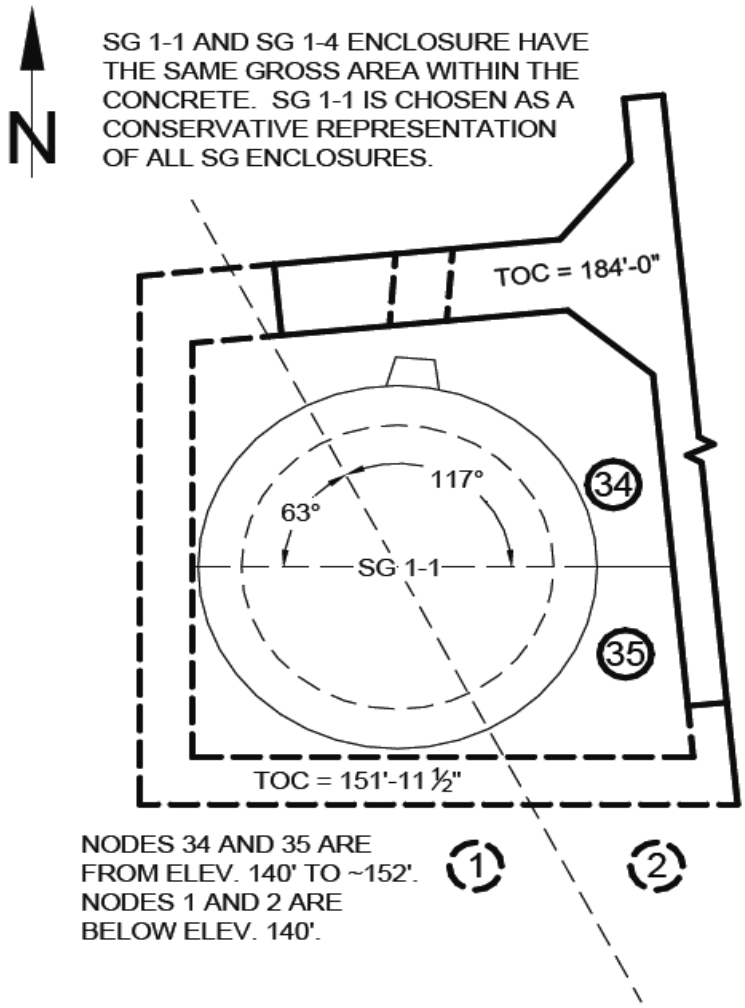
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-58 CONTAINMENT SUBCOMPARTMENT ANALYSES PRESSURIZER ENCLOSURE MODEL FROM ELEVATION 147 FEET 9 INCHES TO 166 FEET



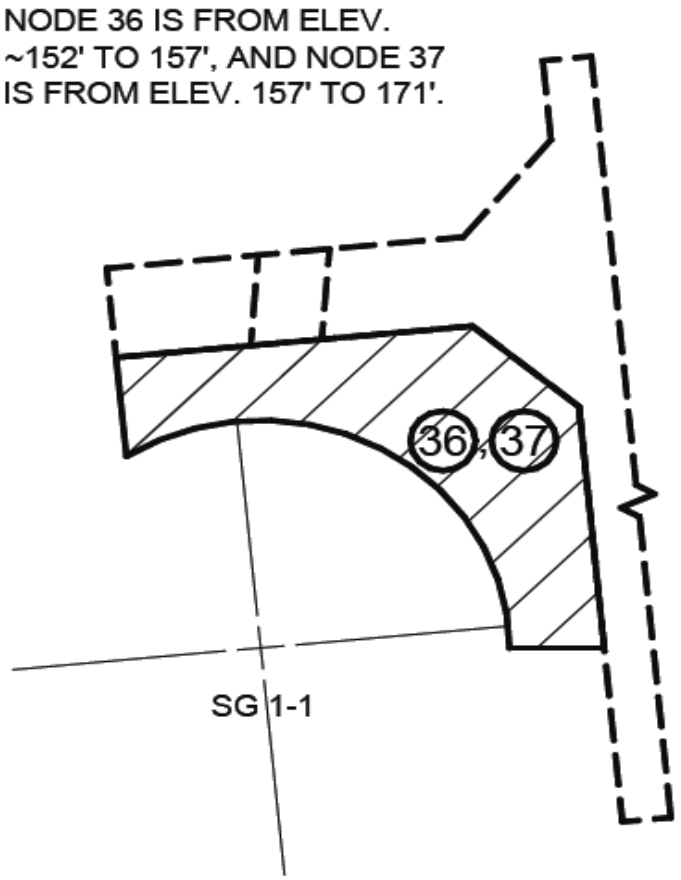
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-59 CONTAINMENT SUBCOMPARTMENT ANALYSES PRESSURIZER ENCLOSURE MODEL FROM ELEVATION 140 FEET TO 147 FEET 9 INCHES



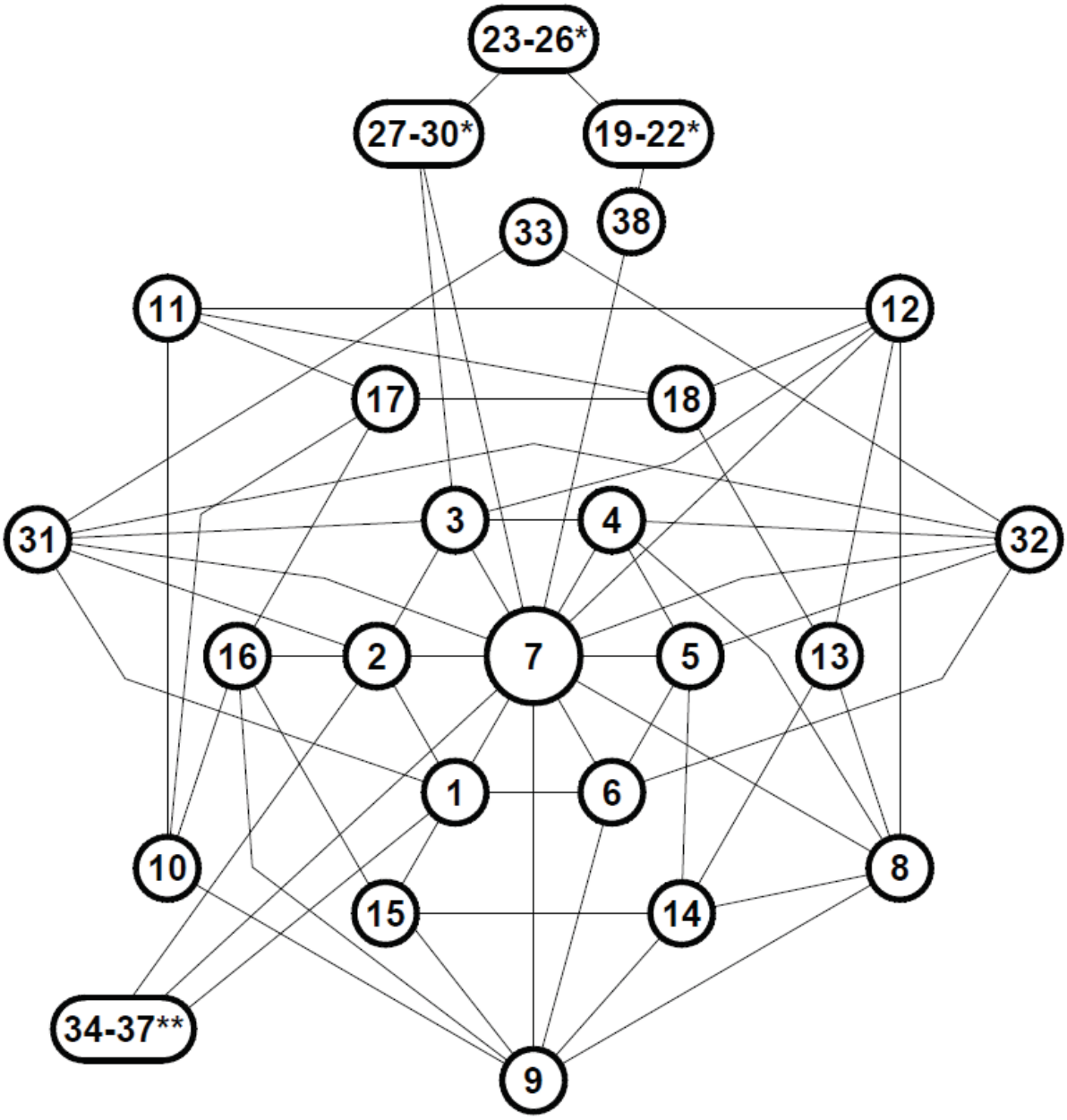
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-60 CONTAINMENT SUBCOMPARTMENT ANALYSES STEAM GENERATOR ENCLOSURE MODEL FROM ELEVATION 140 FEET TO 184 FEET



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-61 CONTAINMENT SUBCOMPARTMENT ANALYSES STEAM GENERATOR ENCLOSURE MODEL FROM ELEVATION 140 FEET TO 151 FEET 11-1/2 INCHES



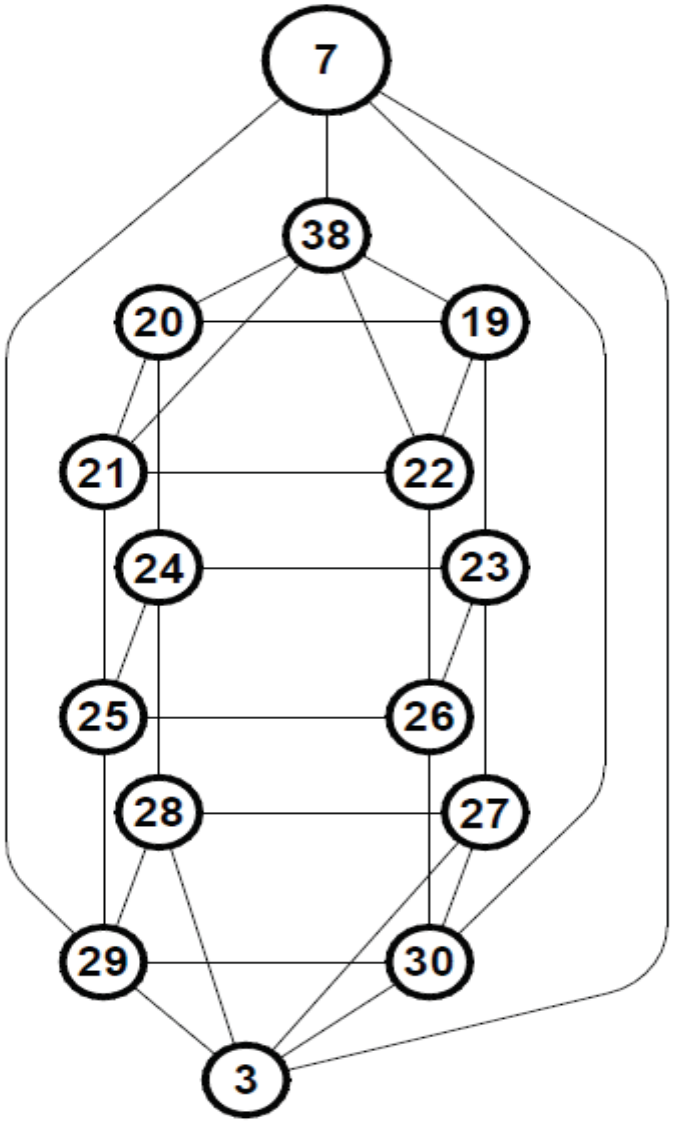
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-62 CONTAINMENT SUBCOMPARTMENT ANALYSES STEAM GENERATOR ENCLOSURE MODEL FROM ELEVATION 151 FEET 11-1/2 INCHES TO 171 FEET



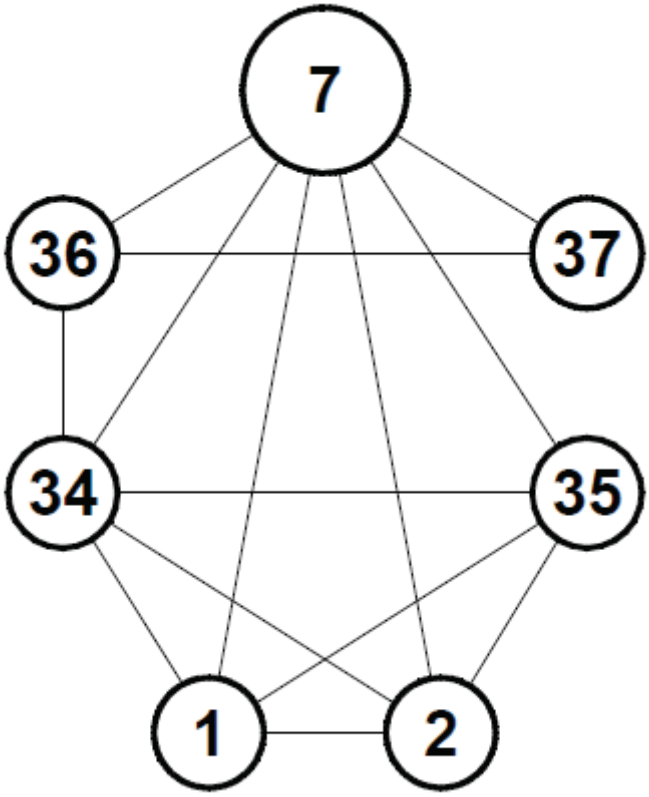
*For a detailed schematic of Nodes 19 through 30 & 38, see Figures 6.2-64 and 6.2-57 through 6.2-59

**For a detailed schematic of Nodes 34 through 37, see Figures 6.2-65 and 6.2-60 through 6.2-62

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-63 CONTAINMENT SUBCOMPARTMENT ANALYSES NODES AND FLOW PATHS FOR SUBCOMPARTMENT MODEL

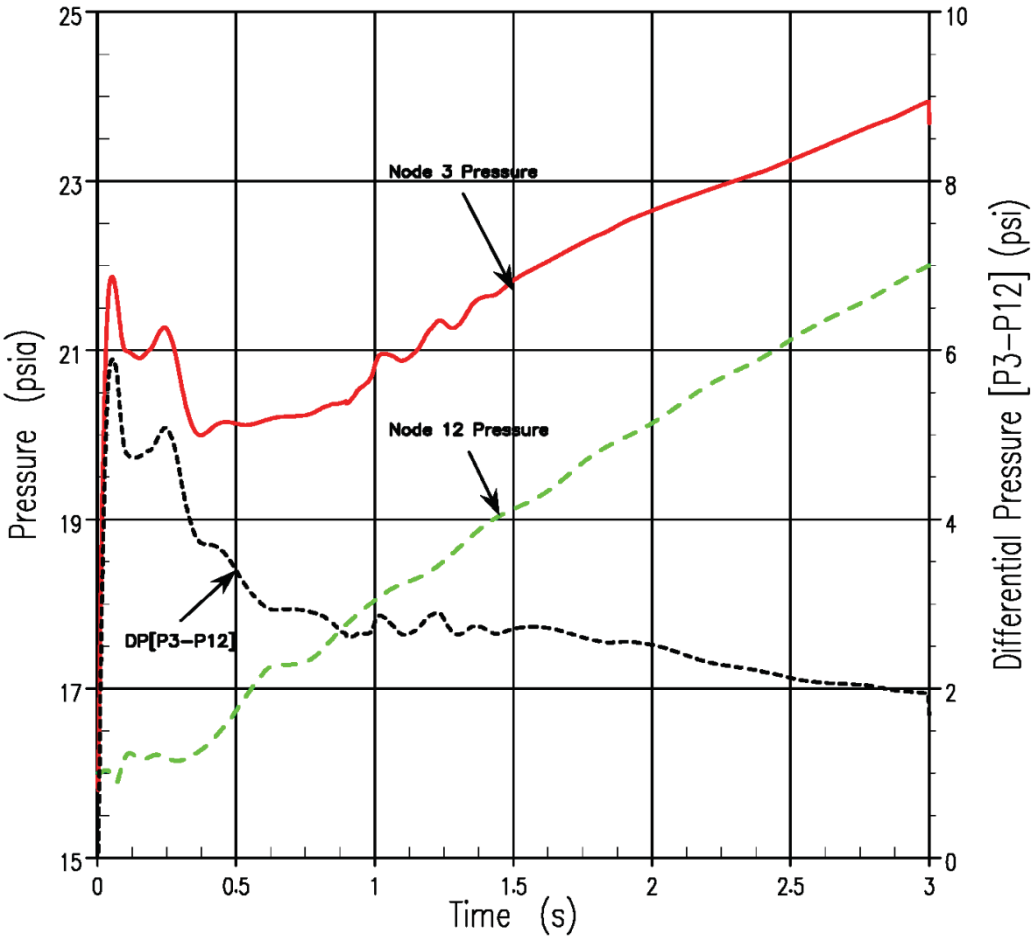


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-64 CONTAINMENT SUBCOMPARTMENT ANALYSES NODES AND FLOW PATHS FOR SUBCOMPARTMENT MODEL

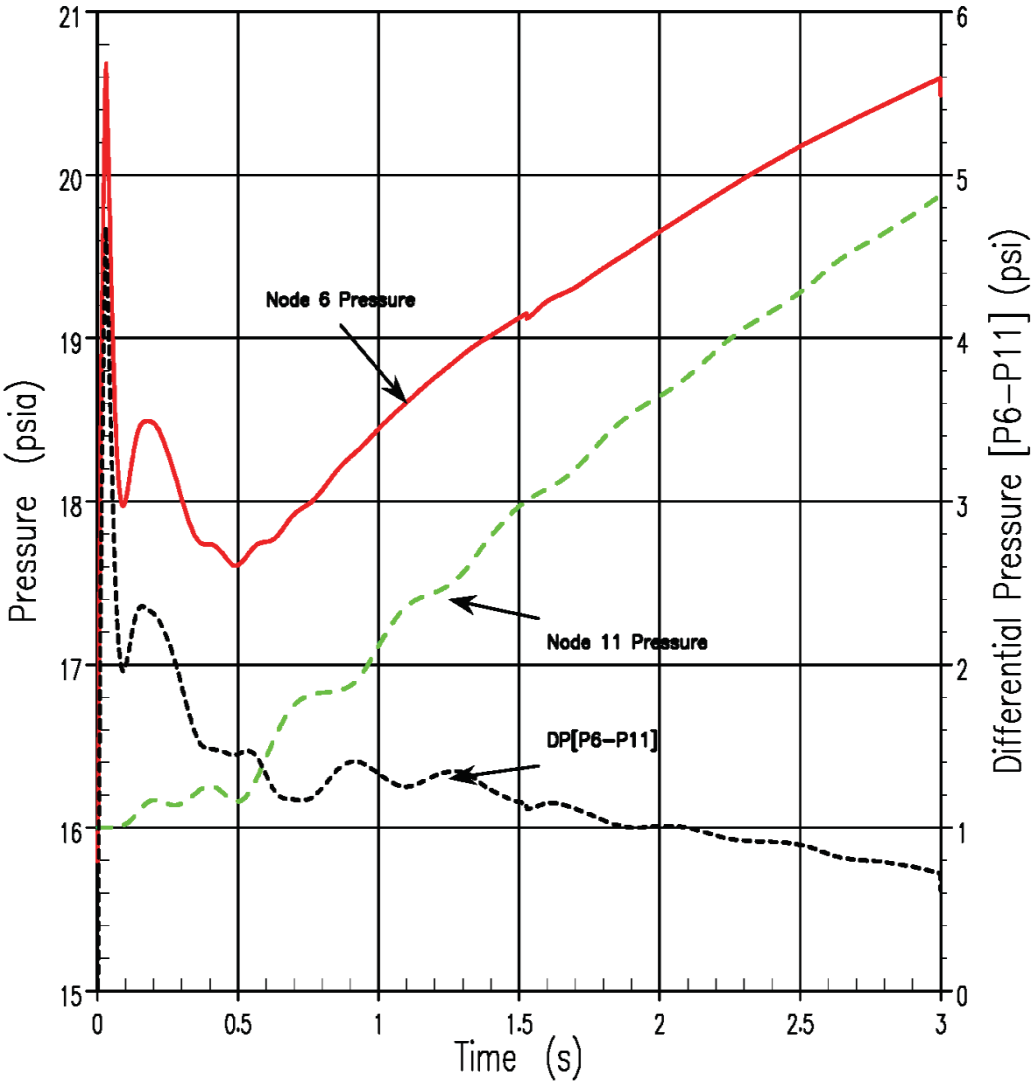


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-65 CONTAINMENT SUBCOMPARTMENT ANALYSES NODES AND FLOW PATHS FOR SUBCOMPARTMENT MODEL

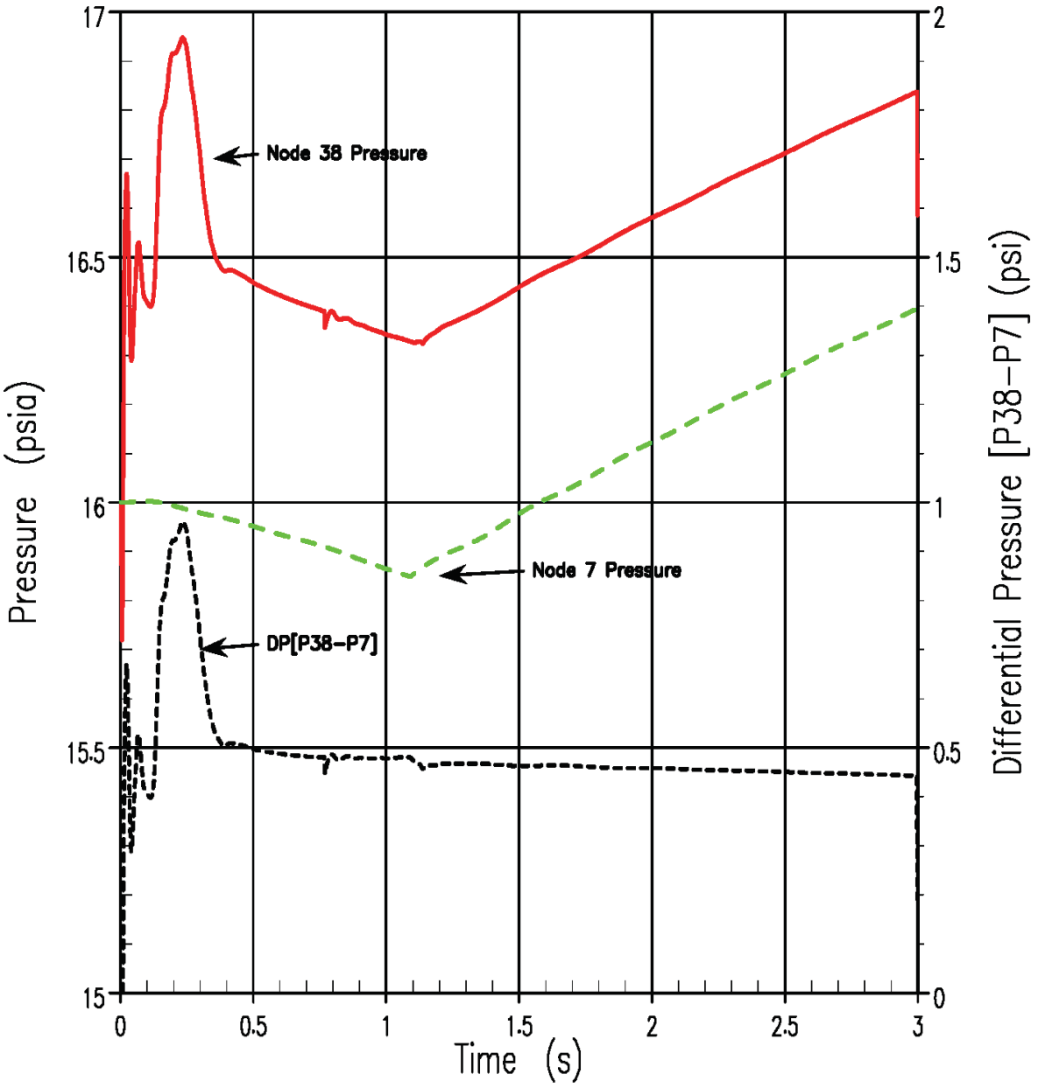
Revision 23 December 2016



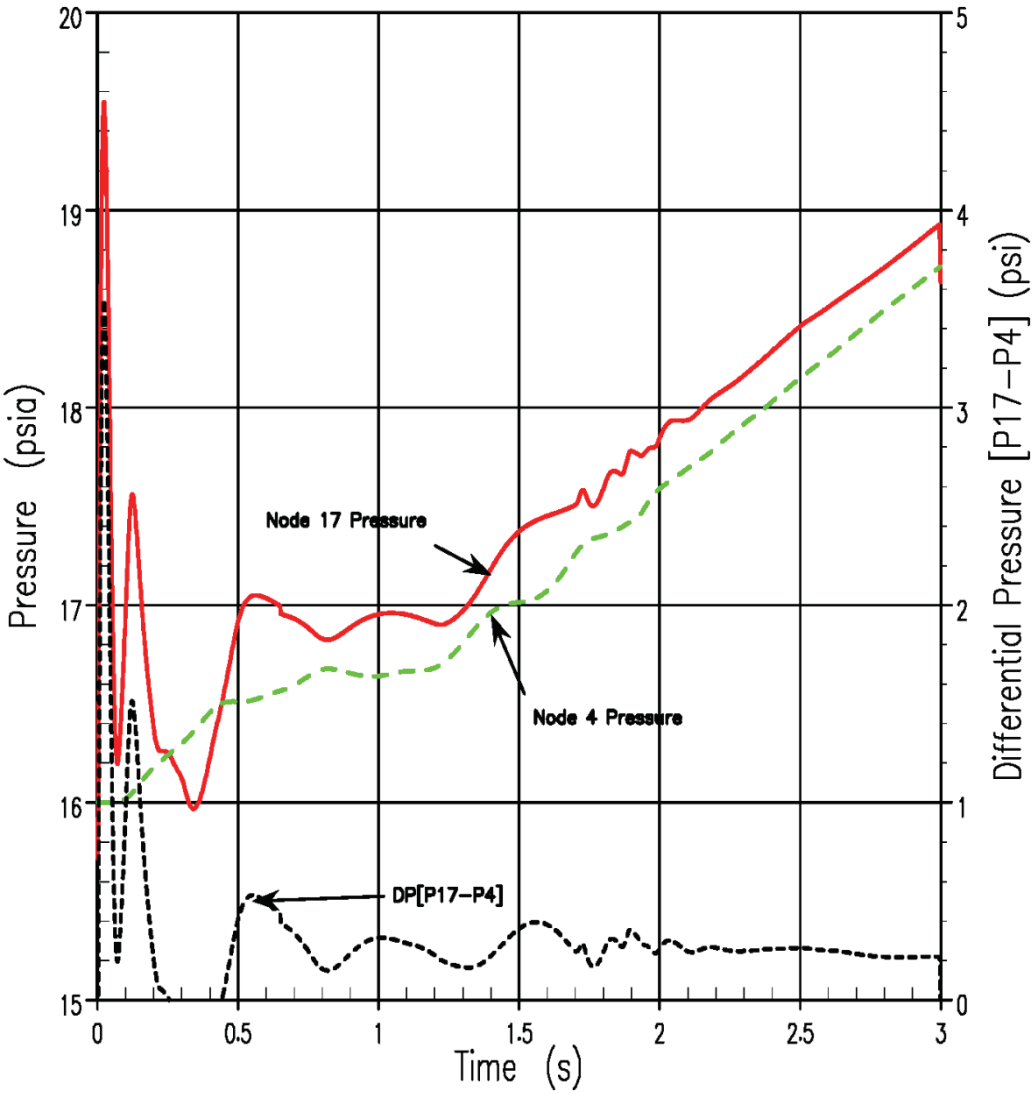
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-66 CONTAINMENT SUBCOMPARTMENT ANALYSES MAXIMUM DIFFERENTIAL PRESSURE FOR PRESSURIZER SURGE LINE BREAK AT HOT LEG CONNECTION IN NODE 3



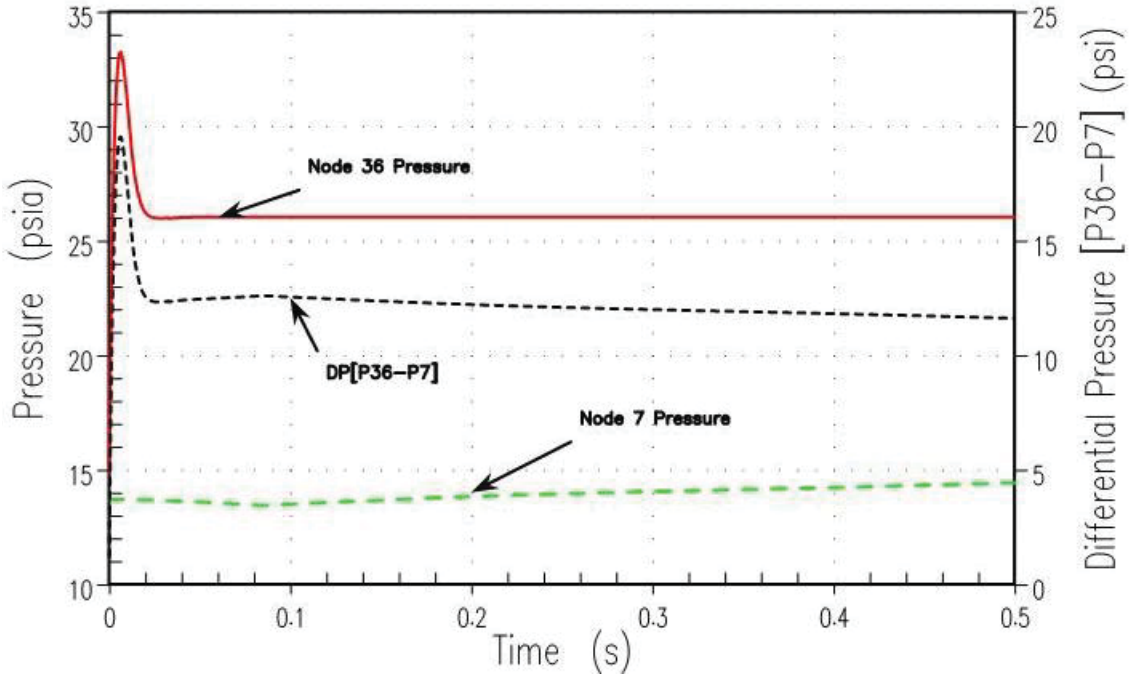
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-67 CONTAINMENT SUBCOMPARTMENT ANALYSES MAXIMUM DIFFERENTIAL PRESSURE FOR RHR SUCTION LINE BREAK AT HOT LEG CONNECTION IN NODE 6



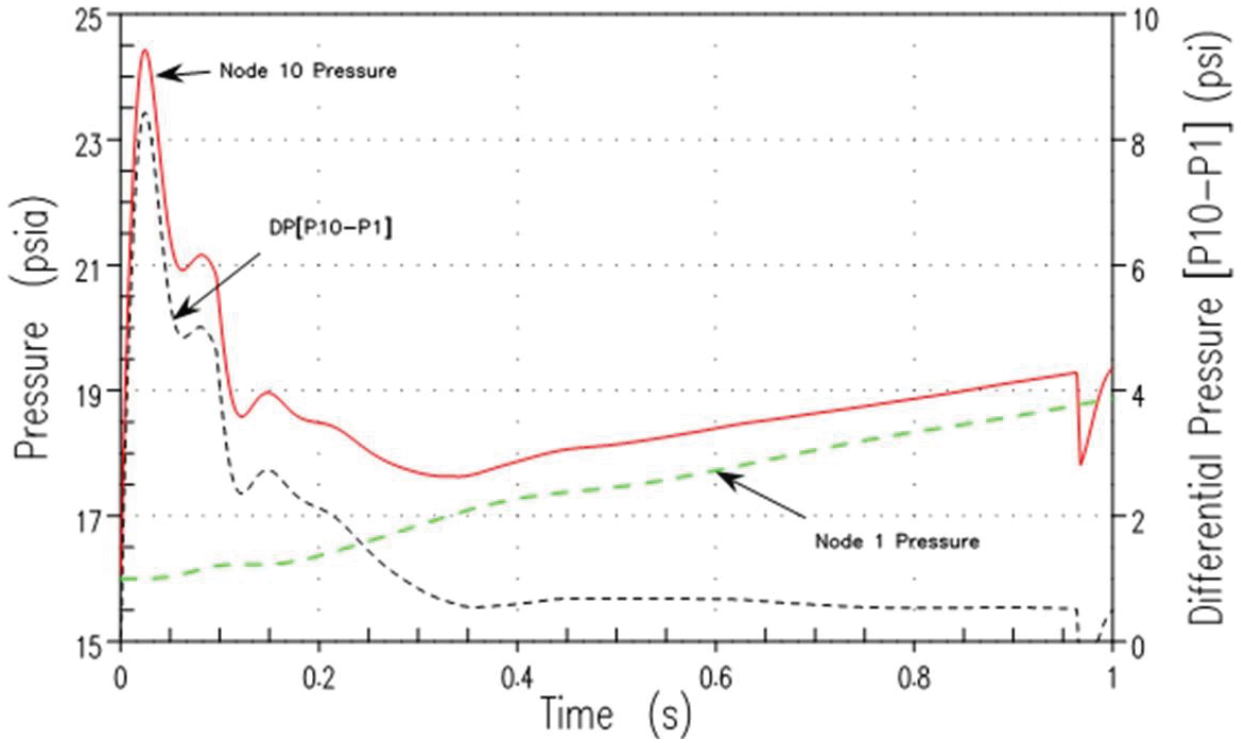
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-68 CONTAINMENT SUBCOMPARTMENT ANALYSES MAXIMUM DIFFERENTIAL PRESSURE FOR PRESSURIZER SPRAY LINE BREAK AT THE TOP OF THE PRESSURIZER IN NODE 38



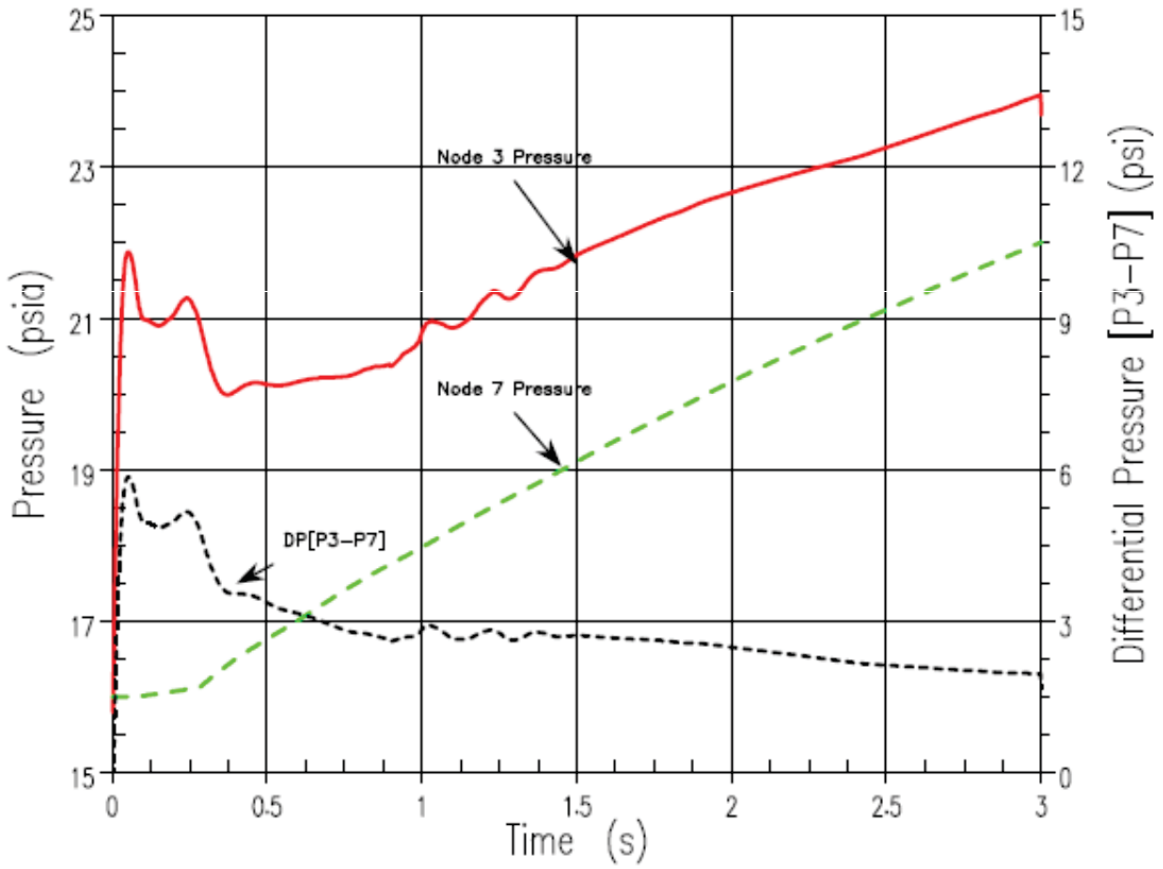
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-69 CONTAINMENT SUBCOMPARTMENT ANALYSES MAXIMUM DIFFERENTIAL PRESSURE FOR AN ACCUMULATOR LINE BREAK AT THE TANK NOZZLE IN NODE 17



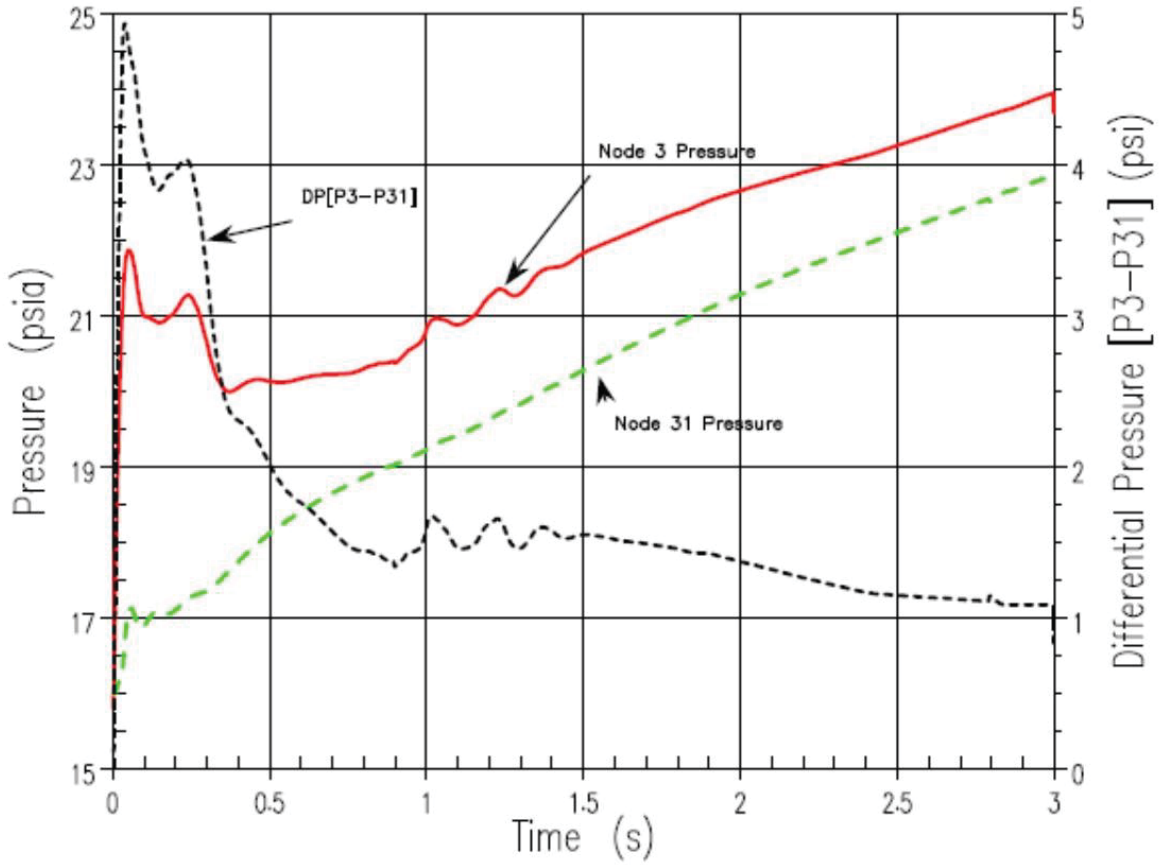
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-70 CONTAINMENT SUBCOMPARTMENT ANALYSES MAXIMUM DIFFERENTIAL PRESSURE FOR MAIN FEEDWATER LINE BREAK AT THE STEAM GENERATOR INLET NOZZLE NODE 36



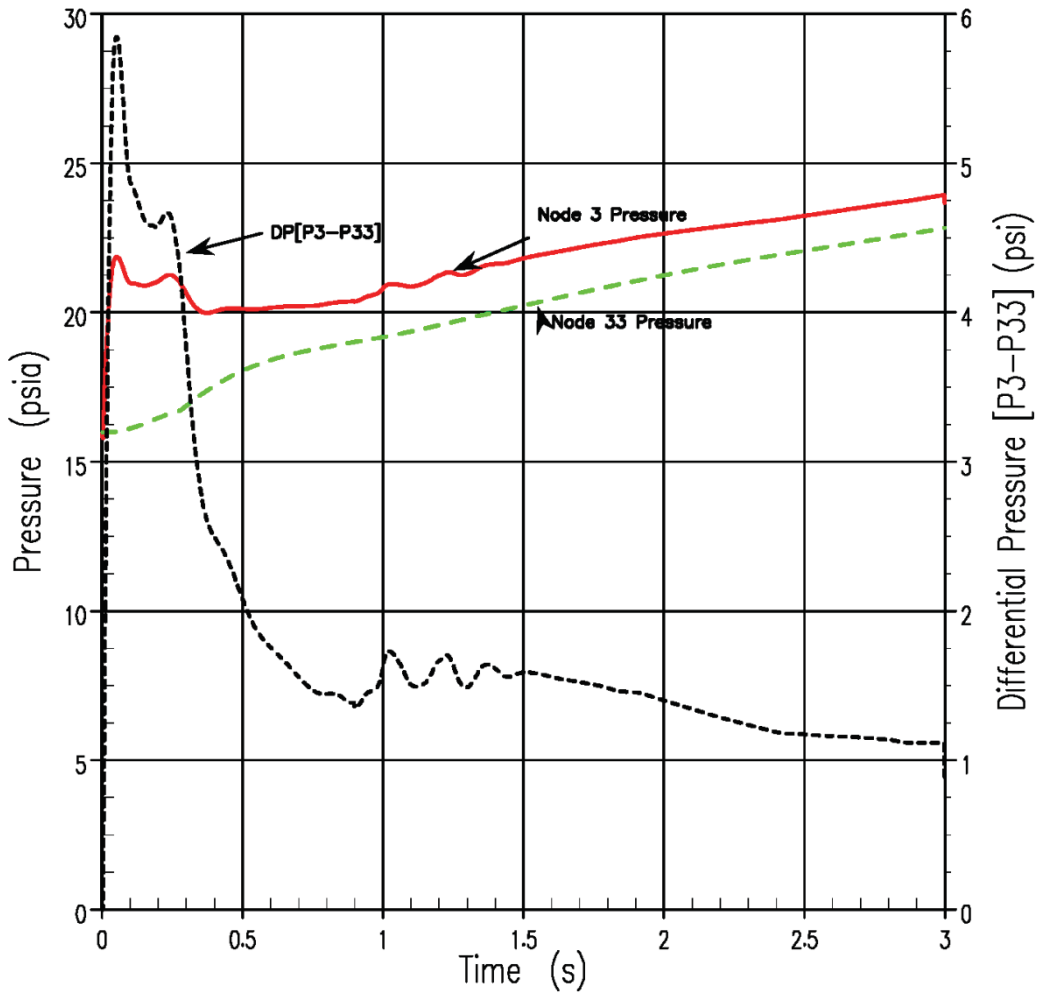
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-71 CONTAINMENT SUBCOMPARTMENT ANALYSES MAXIMUM DIFFERENTIAL PRESSURE MAIN STEAM LINE BREAK AT THE CONTAINMENT PENETRATION NODE 10



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-72 CONTAINMENT SUBCOMPARTMENT ANALYSES MAXIMUM DIFFERENTIAL PRESSURE FOR PRESSURIZER SURGE LINE BREAK AT HOT LEG CONNECTION IN NODE 3

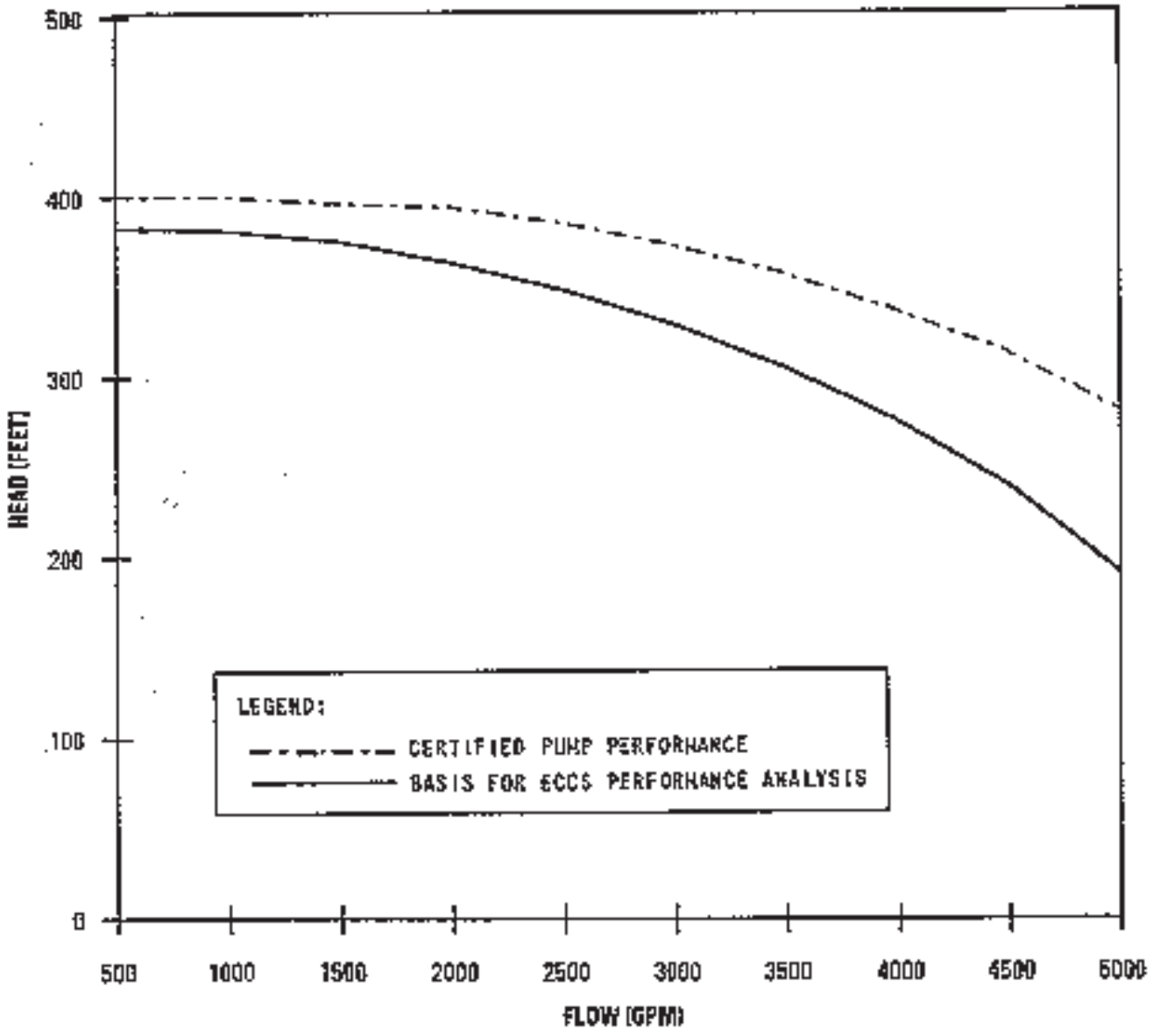


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-73 CONTAINMENT SUBCOMPARTMENT ANALYSES MAXIMUM DIFFERENTIAL PRESSURE FOR PRESSURIZER SURGE LINE BREAK AT HOT LEG CONNECTION IN NODE 3

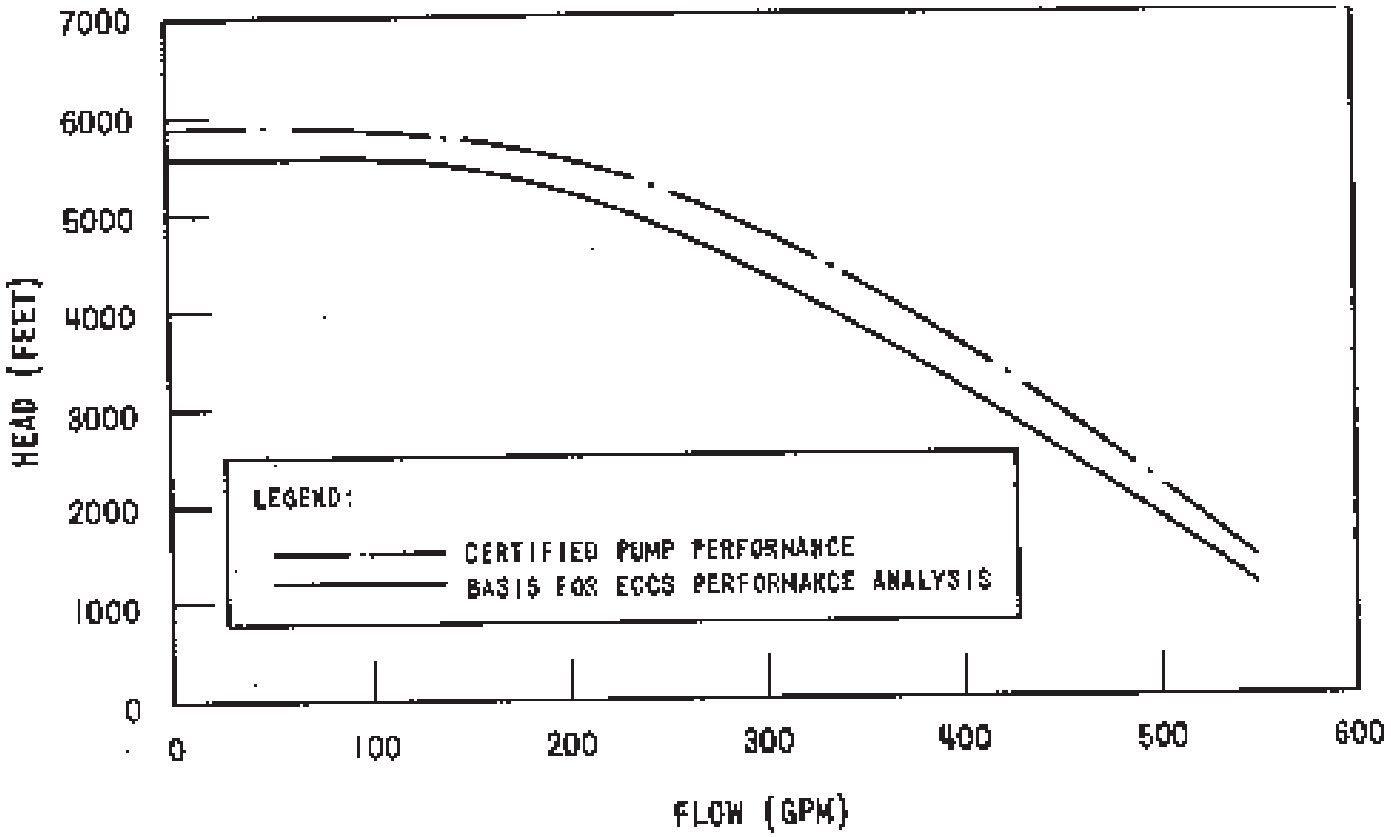


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2-74 CONTAINMENT SUBCOMPARTMENT ANALYSES MAXIMUM DIFFERENTIAL PRESSURE FOR PRESSURIZER SURGE LINE BREAK AT HOT LEG CONNECTION IN NODE 3

Revision 23 December 2016

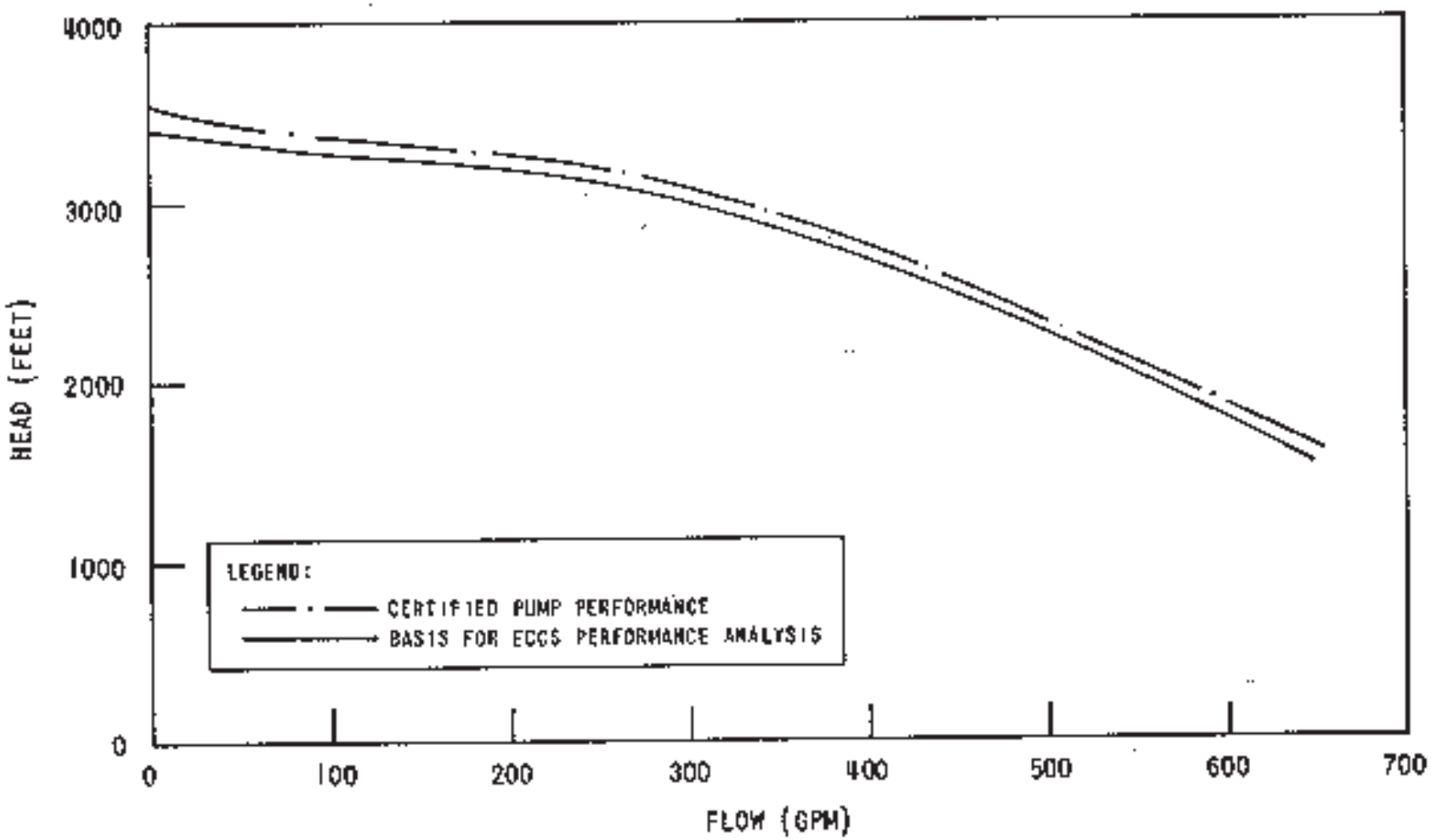


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.3-1 RESIDUAL HEAT REMOVAL PUMP PERFORMANCE CURVES (TYPICAL)

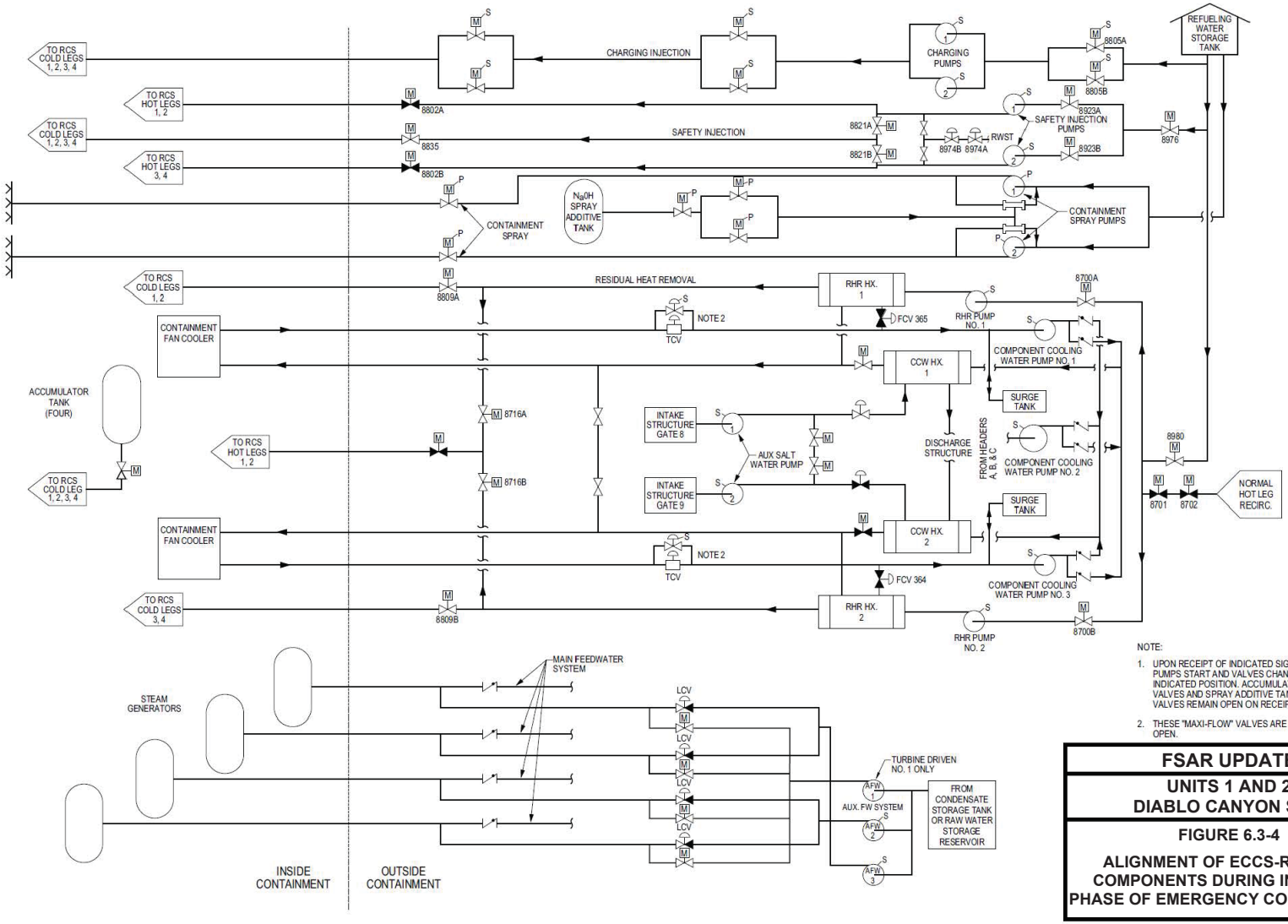


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.3-2 CENTRIFUGAL CHARGING PUMPS 1 & 2 PERFORMANCE CURVES (TYPICAL)

Revision 18 October 2008



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.3-3 SAFETY INJECTION PUMP PERFORMANCE CURVES (TYPICAL)



NOTE:

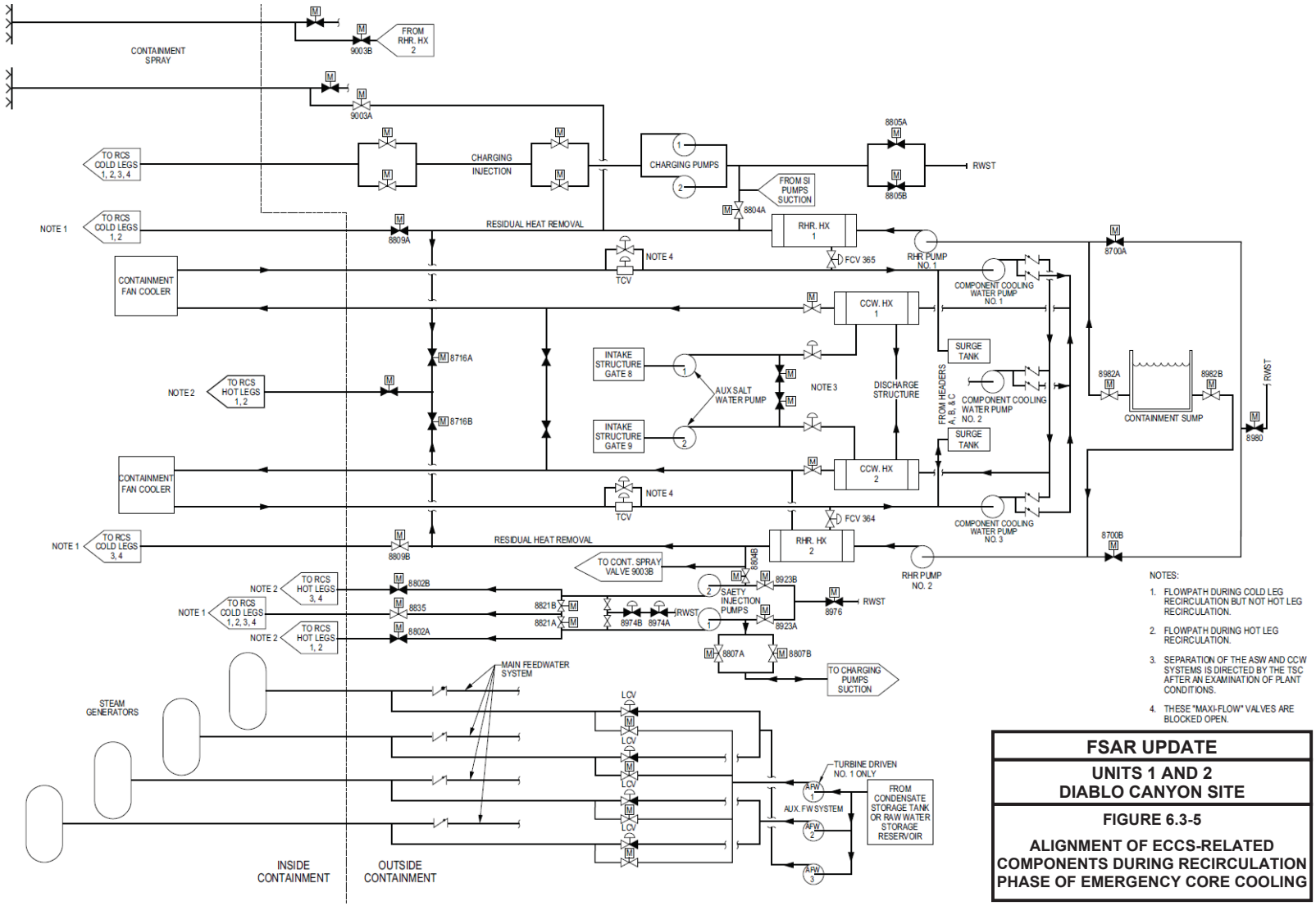
1. UPON RECEIPT OF INDICATED SIGNALS S OR P PUMPS START AND VALVES CHANGE TO INDICATED POSITION. ACCUMULATOR DISCHARGE VALVES AND SPRAY ADDITIVE TANK DISCHARGE VALVES REMAIN OPEN ON RECEIPT OF S SIGNAL.
2. THESE "MAXI-FLOW" VALVES ARE BLOCKED OPEN.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 6.3-4

ALIGNMENT OF ECCS-RELATED COMPONENTS DURING INJECTION PHASE OF EMERGENCY CORE COOLING



NOTES:

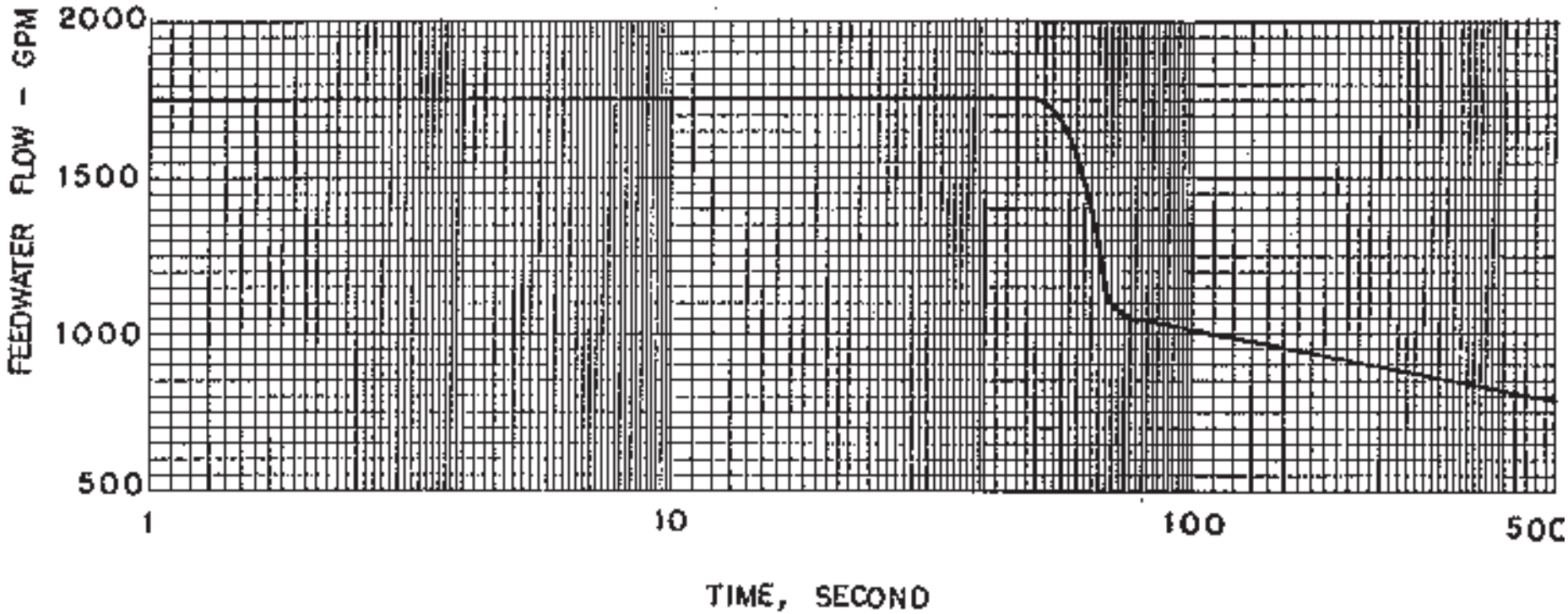
1. FLOWPATH DURING COLD LEG RECIRCULATION BUT NOT HOT LEG RECIRCULATION.
2. FLOWPATH DURING HOT LEG RECIRCULATION.
3. SEPARATION OF THE ASW AND CCW SYSTEMS IS DIRECTED BY THE TSC AFTER AN EXAMINATION OF PLANT CONDITIONS.
4. THESE "MAXI-FLOW" VALVES ARE BLOCKED OPEN.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

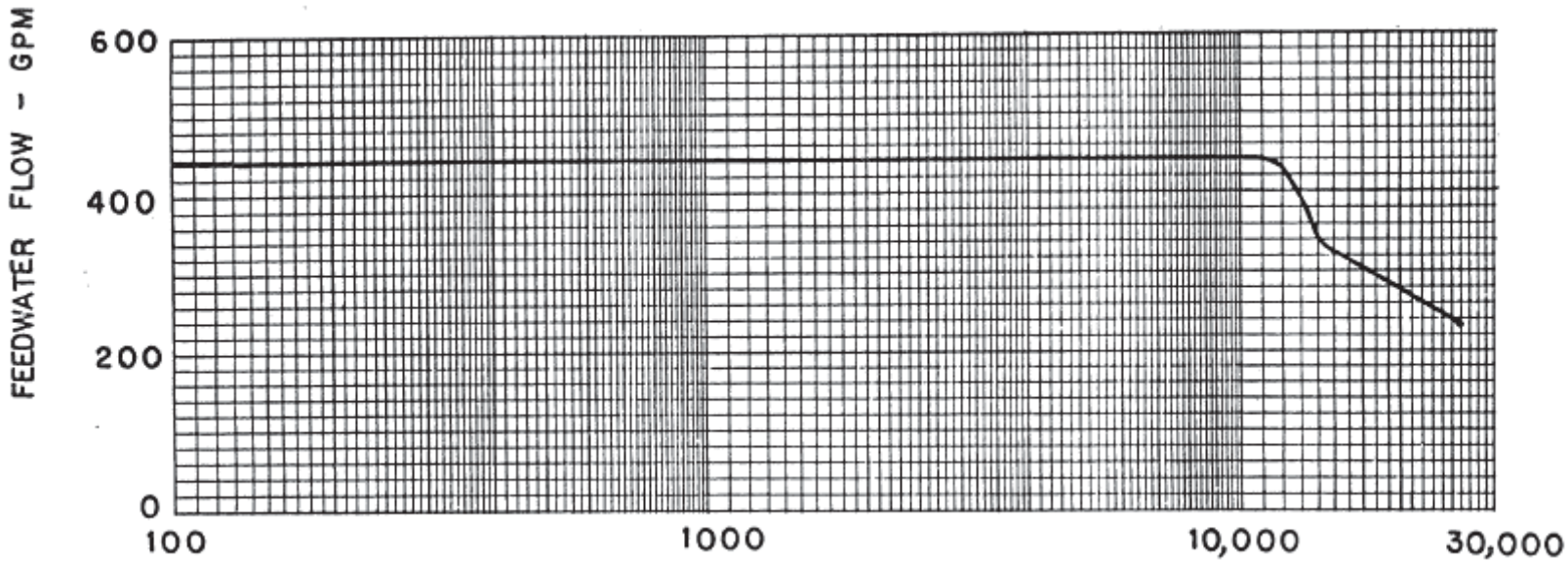
FIGURE 6.3-5

ALIGNMENT OF ECCS-RELATED COMPONENTS DURING RECIRCULATION PHASE OF EMERGENCY CORE COOLING



AUXILIARY FEEDWATER FLOW FOR PLANT SHUTDOWN FROM 3568 MWT WITH ALL THREE AFW PUMPS IN OPERATION (FOR INFORMATION ONLY

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.5-3 (Sheet 1) AUXILIARY FEEDWATER FLOW FOR PLANT SHUTDOWN



AUXILIARY FEEDWATER FLOW FOR PLANT SHUTDOWN FROM 3568 MWT WITH ONLY ONE 440 GPM MOTOR-DRIVEN AFW PUMP IN OPERATION (FOR INFORMATION ONLY)

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.5-3 (Sheet 2) AUXILIARY FEEDWATER FLOW FOR PLANT SHUTDOWN

APPENDIX 6.2D

ANALYSIS OF LONG-TERM LOSS-OF-COOLANT ACCIDENTS AND MAIN STEAMLINE BREAK EVENTS

6.2D.1 INTRODUCTION

This appendix details the methodology for calculating the long-term M&E releases and the resulting containment response subsequent to a hypothetical LOCA or a MSLB in DCPP Unit 1 and Unit 2. Short-term LOCA-related M&E releases are used as input to the subcompartment analyses and are discussed in Section 6.2.1.

The containment system is designed such that for all break sizes, up to and including the double-ended severance of a reactor coolant pipe or secondary system pipe, the containment peak calculated pressure is less than the containment design pressure.

The M&E releases from the LOCA and MSLB analyses are used as input to the containment response analyses. The containment integrity analysis conclusions are discussed in Sections 6.2D.3.2.7 (LOCA) and 6.2D.4.2.6 (MSLB). Section 6.2.1 includes an evaluation demonstrating that the containment satisfies the applicable design requirements.

6.2D.2 COMPUTER CODES WHICH SUPPORT CURRENT ANALYSES

Computer Codes which Support Current Analyses	LOCA	MSLB
SATAN-VI	X	N/A
WREFLOOD	X	N/A
FROTH	X	N/A
EPITOME	X	N/A
RETRAN-02W (used with NRC limitations, refer to WCAP-14882-P-A)	N/A	X
GOTHIC Version 7.2a	X	X

The WCAP-10325-P-A (Reference 1) M&E release evaluation model is comprised of M&E release versions of the following codes: SATAN-VI, WREFLOOD, FROTH, and EPITOME. These codes were used to calculate the long-term LOCA M&E releases for DCPP Unit 1 and Unit 2.

SATAN-VI calculates blowdown, the first portion of the thermal-hydraulic transient following break initiation, including pressure, enthalpy, density, M&E flow rates, and energy transfer between primary and secondary systems as a function of time.

The WREFLOOD code addresses the portion of the LOCA transient where the core reflooding phase occurs after the primary coolant system has depressurized (blowdown) due to the loss of water through the break and when water supplied by the ECCS refills the reactor vessel and provides cooling to the core. The most important feature of WREFLOOD is the steam/water mixing model (refer to Section 6.2D.3.1.4).

FROTH models the post-reflood portion of the transient. The FROTH code is used for the SG heat addition calculation from the broken and intact loop SGs.

EPITOME continues the FROTH post-reflood portion of the transient from the time at which the secondary equilibrates to containment design pressure to the end of the transient. It also compiles a summary of data on the entire transient, including formal instantaneous M&E release tables and M&E balance tables with data at critical times.

The Westinghouse steamline break M&E release methodology was approved by the NRC (Reference 8) and is documented in WCAP-8822, “Mass and Energy Releases Following a Steam Line Rupture” (Reference 9) and WCAP-8822-S2-P-A, “Mass and Energy Releases Following a Steam Line Rupture, Supplement 2 – Impact of Steam Superheat in Mass/Energy Releases Following a Steamline Rupture of Dry and Subatmospheric Containment Designs” (Reference 11). WCAP-8822 forms the basis for the assumptions used in the calculation of the M&E releases resulting from a steamline rupture. The analysis documented herein uses the RETRAN-02W code, which is documented in WCAP-14882-P-A, “RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses” (Reference 12).

GOTHIC Version 7.2a is used to perform the containment response analyses for the LOCA and MSLB events.

6.2D.3 LONG-TERM LOSS-OF-COOLANT ACCIDENTS

6.2D.3.1 Long-Term Loss-of-Coolant Accident Mass and Energy Release Analysis

6.2D.3.1.1 Acceptance Criteria

There are no direct acceptance criteria for LOCA M&E releases. The analysis methods follow the guidelines provided by the NRC with respect to the sources of M&E during the various phases of a LBLOCA transient (refer to Section 6.2D.3.1.4).

The specific acceptance criteria for the containment response to a LOCA are discussed in Section 6.2D.3.2.1.

6.2D.3.1.2 Introduction and Background

Discussion of the short-term LOCA-related M&E releases which are used as input to the subcompartment analyses can be found in Section 6.2.1.2.

The uncontrolled release of pressurized high-temperature reactor coolant, termed a LOCA, would result in release of steam and water into the containment. This, in turn, would result in increases in the local subcompartment pressures, and an increase in the global containment pressure and temperature. Therefore, there are both long- and short-term issues relative to a postulated LOCA that must be considered at the conditions for DCPP Unit 1 and Unit 2 at the licensed core power of 3411 MWt.

The long-term LOCA M&E releases are analyzed to approximately 10^7 seconds and are utilized as input to the containment integrity analysis. The containment integrity

analysis demonstrates the acceptability of the containment safeguards systems to mitigate the consequences of a hypothetical LBLOCA. The containment safeguards systems must be capable of limiting the peak containment pressure to less than the design pressure and to limit the temperature excursion to less than the acceptance limits. Westinghouse generated the M&E releases using the March 1979 model, described in WCAP-10325-P-A (Reference 1). The NRC review and approval letter is included with WCAP-10325-P-A (Reference 1). Section 6.2D.3.1 discusses the long-term LOCA M&E releases generated. The results of this analysis were provided for use in the containment integrity analysis (refer to Section 6.2D.3.2).

The M&E release rates described in this section form the basis of further computations to evaluate the containment following the postulated accident. Discussed in this section are the long-term LOCA M&E releases for the hypothetical double-ended pump suction (DEPS) rupture with minimum safeguards and maximum safeguards and double-ended hot-leg (DEHL) rupture break cases. These LOCA cases are used for the long-term containment integrity analyses in Section 6.2D.3.2.

6.2D.3.1.3 Input Parameters and Assumptions

The M&E release analysis is sensitive to the assumed characteristics of various plant systems, in addition to other key modeling assumptions. Where appropriate, bounding inputs are utilized and instrumentation uncertainties are included. For example, the RCS operating temperatures are chosen to bound the highest average coolant temperature range of all operating cases and a temperature uncertainty allowance of +5.0°F is then added. Nominal parameters are used in certain instances. For example, the RCS pressure in this analysis is based on a nominal value of 2,250 psia plus an uncertainty allowance +42.0 psi. All input parameters are chosen consistent with accepted analysis methodology.

Some of the most critical items are the RCS initial conditions, core decay heat, SI flow, and primary and secondary metal mass and SG heat release modeling. Specific assumptions concerning each of these items are discussed in the following paragraphs. Tables 6.2D-1 and 6.2D-2 present key data assumed in the analysis.

The core thermal power of 3479 MWt adjusted for calorimetric error (that is, 102 percent of 3411 MWt) was used in the analysis. As previously noted, RCS operating temperatures to bound the highest average coolant temperature range were used as bounding analysis conditions. The use of higher temperatures is conservative because the initial fluid energy is based on coolant temperatures that are at the maximum levels attained in steady-state operation. Additionally, an allowance to account for instrument error and dead-band is reflected in the initial RCS temperatures. The selection of 2,250 psia plus uncertainty as the limiting pressure is considered to affect the blowdown phase results only, since this represents the initial pressure of the RCS. The RCS rapidly depressurizes from this value until the point at which it equilibrates with containment pressure.

The rate at which the RCS blows down is initially more severe at the higher RCS pressure. Additionally, the RCS has a higher fluid density at the higher pressure (assuming a constant temperature) and subsequently has a higher RCS mass available for releases. Thus, 2,250 psia plus uncertainty was selected for the initial pressure as the limiting case for the long-term M&E release calculations.

The selection of the fuel design features for the long-term M&E release calculation is based on the need to conservatively maximize the energy stored in the fuel at the beginning of the postulated accident (that is, to maximize the core stored energy). The core stored energy, selected to bound the 17x17 fuel product used at DCPP Unit 1 and Unit 2, was 3.50 full-power seconds. The margins in the core stored energy include a statistical uncertainty in order to address the thermal fuel model and associated manufacturing uncertainties and the time in the fuel cycle for maximum fuel densification. Thus, the analysis very conservatively accounts for the stored energy in the core.

A margin in the RCS volume of 3 percent (which is composed of a 1.6-percent allowance for thermal expansion and a 1.4-percent allowance for uncertainty) was modeled.

A uniform SG tube plugging level of 0 percent was modeled. This assumption maximizes the reactor coolant volume and fluid release by virtue of consideration of the RCS fluid in all SG tubes. During the post-blowdown period, the SGs are active heat sources since significant energy remains in the secondary metal and secondary mass that has the potential to be transferred to the primary side. The 0 percent tube plugging assumption maximizes the heat transfer area and, therefore, the transfer of secondary heat across the SG tubes. Additionally, this assumption reduces the RCL resistance, which reduces the ΔP upstream of the break for the pump suction breaks and increases break flow. Thus, the analysis conservatively accounts for the level of SG tube plugging.

The secondary-to-primary heat transfer is maximized by assuming conservative heat transfer coefficients. This conservative energy transfer is ensured by maximizing the initial internal energy of the inventory in the SG secondary side. This internal energy is based on full-power operation plus uncertainties.

Regarding SI flow, the M&E release calculation considered configurations/failures to conservatively bound respective alignments. The limiting case is the failure of a train of the solid state protection system (SSPS). This configuration/failure would credit minimum flow from one centrifugal charging pump (CCP1 or CCP2), one SI pump, and one RHR pump (refer to Table 6.2D-2). In addition, the containment backpressure is assumed to be equal to the containment design pressure. This assumption was shown in WCAP-10325-P-A (Reference 1) to be conservative for the generation of M&E releases.

In summary, the following assumptions were employed to ensure that the M&E releases are conservatively calculated, thereby maximizing energy release to containment:

- Maximum expected operating temperature of the RCS (100-percent full-power conditions)
- Allowance for RCS temperature uncertainty (+5.0°F)
- Margin in RCS volume of 3 percent (which is composed of 1.6-percent allowance for thermal expansion and 1.4-percent allowance for uncertainty)
- Core rated power of 3411 MWt
- Allowance for calorimetric error (+2.0 percent of power)
- Conservative heat transfer coefficients (that is, SG primary/secondary heat transfer, and RCS metal heat transfer)
- Allowance in core stored energy for effect of fuel densification
- A margin in core stored energy (statistical uncertainty to account for manufacturing tolerances)
- An allowance for RCS initial pressure uncertainty (+42.0 psi)
- A maximum containment backpressure equal to design pressure (47.0 psig)
- SG tube plugging level (0-percent uniform)
    - Maximizes reactor coolant volume and fluid release
    - Maximizes heat transfer area across the SG tubes
    - Reduces coolant loop resistance, which reduces the ΔP upstream of the break for the pump suction breaks and increases break flow

Thus, based on the previously discussed conditions and assumptions, an analysis of DCPP Unit 1 and Unit 2 was made for the release of M&E from the RCS in the event of a LOCA at 3479 MWt.

6.2D.3.1.4 Description of Analyses and Evaluations

The evaluation model used for the long-term LOCA M&E release calculations is described in WCAP-10325-P-A (Reference 1).

This section presents the long-term LOCA M&E releases generated in support of DCPP Unit 1 and Unit 2.

The guidance of NRC Standard Review Plan Section 6.2.1.3 was used to determine what should be addressed in the M&E release analysis for postulated LOCAs as documented in WCAP-16638-P. Criteria applicable to DCPP are contained in 10 CFR Part 50, Appendix K, Part I.A.

To meet those requirements, the following were addressed by the LOCA M&E release analysis:

- Calculation of each phase of the accident
- Break size and location
- M&E release data
- Sources of energy

These M&E releases are then subsequently used in the containment integrity analysis.

Loss-of-Coolant Accident Mass and Energy Release Phases

The containment system receives M&E releases following a postulated rupture in the RCS. These releases continue over a time period, which, for the LOCA M&E analysis, is typically divided into four phases.

Blowdown – the period of time from accident initiation (when the reactor is at steady-state operation) to the time that the RCS and containment reach an equilibrium state.

Refill – the period of time when the lower plenum is being filled by accumulator and ECCS water. At the end of blowdown, a large amount of water remains in the cold legs, downcomer, and lower plenum. To conservatively consider the refill period for the purpose of containment M&E releases, it is assumed that this water is instantaneously transferred to the lower plenum along with sufficient accumulator water to completely fill the lower plenum. This allows an uninterrupted release of M&E to containment. Thus, the refill period is conservatively neglected in the M&E release calculation.

Reflood – begins when the water from the lower plenum enters the core and ends when the core is completely quenched.

Post-reflood – describes the period following the reflood phase. For the pump suction break, a two-phase mixture exits the core, passes through the hot legs, and is superheated in the SGs prior to exiting the break as steam. After the broken loop SG cools, the break flow becomes two phase.

Break Size and Location

Generic studies have been performed with respect to the effect of postulated break size on the LOCA M&E releases. The double-ended guillotine break has been found to be limiting due to larger mass flow rates during the blowdown phase of the transient. During the reflood and post-reflood phases, the break size has little effect on the releases.

Three distinct locations in the RCS loop can be postulated for a pipe rupture for M&E release purposes:

- Hot leg (between vessel and SG)
- Cold leg (between pump and vessel)
- Pump suction (between SG and pump)

The break locations analyzed for this program are the DEPS rupture with a total break area of (10.46 ft^2) and the DEHL rupture with a total break area of (9.17 ft^2). Break M&E releases have been calculated for the blowdown, reflood, and post-reflood phases of the LOCA for the DEPS cases. For the DEHL case, the releases were calculated only for the blowdown. The following information provides a discussion on each break location.

The DEHL rupture has been shown in previous studies to result in the highest blowdown M&E release rates. Although the core flooding rate would be the highest for this break location, the amount of energy released from the SG secondary is minimal because the majority of the fluid that exits the core vents directly to containment bypassing the SGs. As a result, the reflood M&E releases are reduced significantly as compared to either the pump suction or cold-leg break locations where the core exit mixture must pass through the SGs before venting through the break. For the hot-leg break, generic studies have confirmed that there is no reflood peak (that is, from the end of the blowdown period the containment pressure would continually decrease). Therefore, only the M&E releases for the hot-leg break blowdown phase are calculated and presented.

The cold-leg break location has also been found in previous studies to be much less limiting in terms of the overall containment energy releases. The cold-leg blowdown is faster than that of the pump suction break, and more mass is released into the containment. However, the core heat transfer is greatly reduced, and this results in a considerably lower energy release into containment. Studies have determined that the blowdown transient for the cold leg is, in general, less limiting than that for the pump suction break. During reflood, the flooding rate is greatly reduced and the energy release rate into the containment is reduced. Therefore, the cold-leg break is bounded by other breaks and no further evaluation is necessary.

The pump suction break combines the effects of the relatively high-core flooding rate, as in the hot-leg break, and the addition of the stored energy in the SGs. As a result,

the pump suction break yields the highest energy flow rates during the post-blowdown period by including all of the available energy of the RCS in calculating the releases to containment. Thus, only the DEHL and DEPS cases are used to analyze long-term LOCA containment integrity.

Application of Single-Failure Criterion

An analysis of the effects of the single-failure criterion has been performed on the M&E release rates for each break analyzed. An inherent assumption in the generation of the M&E release is that offsite power is lost. This results in the actuation of the emergency diesel generators (EDGs), required to power the SI system. This is not an issue for the blowdown period, which is limited by the DEHL break.

Two cases have been analyzed to assess the effects of a single failure. The first case assumes minimum safeguards SI flow based on the postulated single failure of a train of the SSPS. This results in the loss of one train of safeguards equipment. The other case assumes maximum safeguards SI flow based on no postulated failures that would impact the amount of ECCS flow. The analysis of the cases described provides confidence that the effect of credible single failures is bounded.

The M&E releases for the DCPP Unit 2 cases are shown in Tables 6.2D-3 through 6.2D-9. The Unit 2 results bound the Unit 1 results.

Blowdown M&E Release Data

The SATAN-VI code is used for computing the blowdown transient. The SATAN-VI code utilizes the control volume (element) approach with the capability for modeling a large variety of thermal fluid system configurations. The fluid properties are considered uniform and thermo-dynamic equilibrium is assumed in each element. A point kinetics model is used with weighted feedback effects. The major feedback effects include moderator density, moderator temperature, and Doppler broadening. A critical flow calculation for subcooled (modified Zaloudek), two-phase (Moody), or superheated break flow is incorporated into the analysis. The methodology for the use of this model is described in WCAP-10325-P-A (Reference 1).

Table 6.2D-3 presents the calculated M&E release for the blowdown phase of the DEHL break without any pumped SI for DCPP Unit 2. For the hot leg break M&E release tables, break path 1 refers to the M&E exiting from the reactor-vessel side of the break; break path 2 refers to the M&E exiting from the steam-generator side of the break. Tables 6.2D-4 and 6.2D-5 present the M&E balance data for the Unit 2 DEHL case.

Table 6.2D-6 presents the calculated M&E releases for the blowdown phase of the DEPS break. For the pump suction breaks, break path 1 in the M&E release tables refers to the M&E exiting from the steam-generator side of the break. Break path 2 refers to the M&E exiting from the pump-side of the break.

Refill M&E Release Data

As noted earlier in the discussion of LOCA M&E release phases, the refill period is conservatively neglected in the M&E release calculation.

Reflood M&E Release Data

The WREFLOOD code is used for computing the reflood transient. The WREFLOOD code consists of two basic hydraulic models: one for the contents of the reactor vessel and one for the coolant loops. The two models are coupled through the interchange of the boundary conditions applied at the vessel outlet nozzles and at the top of the downcomer. Additional transient phenomena such as pumped SI and accumulators, reactor coolant pump performance, and SG release are included as auxiliary equations that interact with the basic models as required. The WREFLOOD code permits the capability to calculate variations during the core reflooding transient of basic parameters such as core flooding rate, core and downcomer water levels, fluid thermo-dynamic conditions (pressure, enthalpy, density) throughout the primary system, and mass flow rates through the primary system. The code permits hydraulic modeling of the two flow paths available for discharging steam and entrained water from the core to the break, that is, the path through the broken loop and the path through the unbroken loops.

A complete thermal equilibrium mixing condition for the steam and ECCS injection water during the reflood phase has been assumed for each loop receiving ECCS water. This is consistent with the usage and application of the WCAP-10325-P-A (Reference 1) M&E release evaluation model in contemporary analyses, for example, D. C. Cook Docket 50-315 (Reference 3). Even though the WCAP-10325-P-A (Reference 1) model credits steam/water mixing only in the intact loop and not in the broken loop, the justification, applicability, and NRC approval for using the mixing model in the broken loop has been documented (Reference 3). Moreover, this assumption is supported by test data and is further discussed below.

The model assumes a complete mixing condition (that is, thermal equilibrium) for the steam/water interaction. The complete mixing process, however, is made up of two distinct physical processes. The first is a two-phase interaction with condensation of steam by cold ECCS water. The second is a single-phase mixing of condensate and ECCS water. Since the steam release is the most important influence to the containment pressure transient, the steam condensation part of the mixing process is the only part that need be considered. (Any spillage directly heats only the sump.)

The most applicable steam/water mixing test data have been reviewed for validation of the containment integrity reflood steam/water mixing model. This data was generated in 1/3-scale tests (Reference 4), which were the largest scale data available in 1975 and thus most clearly simulated the flow regimes and gravitational effects that would occur in a pressurized water reactor (PWR). These tests were designed specifically to study the steam/water interaction for PWR reflood conditions.

A group of 1/3-scale tests corresponds directly to containment integrity reflood conditions. The injection flow rates for this group cover all phases and mixing conditions calculated during the reflood transient. The data from these tests were reviewed and discussed in detail in WCAP-10325-P-A (Reference 1). For all of these tests, the data clearly indicate the occurrence of very effective mixing with rapid steam condensation. The mixing model used in the containment integrity reflood calculation is, therefore, wholly supported by the 1/3-scale steam/water mixing data.

Additionally, the following justification is also noted. The post-blowdown limiting break for the containment integrity peak pressure analysis is the pump suction double-ended rupture break. For this break, there are two flow paths available in the RCS by which M&E may be released to containment. One is through the outlet of the SG, the other via reverse flow through the reactor coolant pump. Steam that is not condensed by ECCS injection in the intact RCS loops passes around the downcomer and through the broken loop cold leg and pump in venting to containment. This steam also encounters ECCS injection water as it passes through the broken loop cold leg, complete mixing occurs and a portion of it is condensed. It is this portion of steam that is condensed that is taken credit for in this analysis. This assumption is justified based upon the postulated break location, and the actual physical presence of the ECCS injection nozzle. A description of the test and test results are contained in WCAP-10325-P-A (Reference 1) and operating license Amendment No. 126 for D.C. Cook (Reference 3).

Table 6.2D-7 presents the calculated M&E releases for the reflood phase of the pump suction double-ended rupture with a single failure of a train of the SSPS for DCPP Unit 2. The principal parameters during reflood are given in Table 6.2D-8 for the bounding DEPS case.

Post-Reflood M&E Release Data

The FROTH code (Reference 5) is used for computing the post-reflood transient. The FROTH code calculates the heat release rates resulting from a two-phase mixture present in the SG tubes. The M&E releases that occur during this phase are typically superheated due to the depressurization and equilibration of the broken loop and intact loop SGs. During this phase of the transient, the RCS has equilibrated with the containment pressure. However, the SGs contain a secondary inventory at an enthalpy that is much higher than the primary side. Therefore, there is a significant amount of reverse heat transfer that occurs. Steam is produced in the core due to core decay heat. For a pump suction break, a two-phase fluid exits the core, flows through the hot legs, and becomes superheated as it passes through the SG (Reference 6). Once the broken loop cools, the break flow becomes two phase. During the FROTH calculation, ECCS injection is addressed for both the injection phase and the recirculation phase. The FROTH code calculation stops when the secondary side equilibrates to the saturation temperature (T_{sat}) at the containment design pressure; after this point the EPITOME code completes the SG depressurization (refer to Sections 6.2D.3.1.4, Reflood Mass and Energy Release Data and 6.2D.3.1.4, Decay Heat Model for additional information).

The methodology for the use of this model is described in WCAP-10325-P-A (Reference 1). The M&E release rates are calculated by FROTH and EPITOME until the time of containment depressurization. After containment depressurization (14.7 psia), the M&E release available to containment is generated directly from core boil-off/decay heat.

Table 6.2D-9 presents the two-phase post-reflood M&E release data for the pump suction double-ended break case with a single failure of a train of the SSPS.

Decay Heat Model

ANS Standard 5.1 (Reference 7) was used in the LOCA M&E release model for DCPP Unit 1 and Unit 2 for the determination of decay heat energy. This standard was balloted by the Nuclear Power Plant Standards Committee in October 1978 and subsequently approved. The official standard (Reference 7) was issued in August 1979. Table 6.2D-10 lists the decay heat generation rate used in the DCPP M&E release analysis.

Based upon NRC staff review, (Safety Evaluation Report [SER] of the March 1979 evaluation model [Reference 1]), use of the ANS Standard-5.1, November 1979 decay heat model was approved for the calculation of M&E releases to the containment following a LOCA.

Significant assumptions in the decay heat generation rate for use in the LOCA M&E releases analysis include the following:

- The decay heat sources considered are fission product decay and heavy element decay of U-239 and Np-239.
- The decay heat power from fissioning isotopes other than U-235 is assumed to be identical to that of U-235.
- The fission rate is constant over the operating history of maximum power level.
- The factor accounting for neutron capture in fission products has been taken from Equation 11 of Reference 7 up to 10,000 seconds and from Table 10 of Reference 7 beyond 10,000 seconds.
- The fuel has been assumed to be at full power for 10^8 seconds.
- The number of atoms of U-239 produced per second has been assumed to be equal to 70 percent of the fission rate.

- The total recoverable energy associated with one fission has been assumed to be 200 MeV/fission.

- An uncertainty of two sigma (two times the standard deviation) has been applied to the fission product decay.

Steam Generator Equilibration and Depressurization

SG equilibration and depressurization is the process by which secondary-side energy is removed from the SGs in stages. The FROTH computer code calculates the heat removal from the secondary mass until the secondary temperature is the T_{sat} at the containment design pressure. After the FROTH calculations, the EPITOME code continues the FROTH calculation for SG cooldown removing SG secondary energy at different rates (that is, first- and second-stage rates). The first-stage rate is applied until the SG reaches T_{sat} at the user-specified intermediate equilibration pressure, when the secondary pressure is assumed to reach the actual containment pressure. Then the second-stage rate is used until the final depressurization, when the secondary reaches the reference temperature of T_{sat} at 14.7 psia, or 212°F. The heat removal of the broken loop and intact loop SGs are calculated separately.

During the FROTH calculations, SG heat removal rates are calculated using the secondary side temperature, primary side temperature, and a secondary side heat transfer coefficient determined using a modified McAdam's correlation. SG energy is removed during the FROTH transient until the secondary side temperature reaches T_{sat} at the containment design pressure. The constant heat removal rate used during the first heat removal stage is based on the final heat removal rate calculated by FROTH. The SG energy available to be released during the first stage interval is determined by calculating the difference in secondary energy available at the containment design pressure and that at the (lower) user-specified intermediate equilibration pressure, assuming saturated conditions. This energy is then divided by the first-stage energy removal rate, resulting in an intermediate equilibration time. At this time, the rate of energy release drops substantially to the second-stage rate. The second-stage rate is determined as the fraction of the difference in secondary energy available between the intermediate equilibration and final depressurization at 212°F, and the time difference from the time of the intermediate equilibration to the user-specified time of the final depressurization at 212°F. With current methodology, all of the secondary energy remaining after the intermediate equilibration is conservatively assumed to be released by imposing a mandatory cooldown and subsequent depressurization down to atmospheric pressure at 3,600 seconds, that is, 14.7 psia and 212°F (the M&E balance tables have this point labeled as "Available Energy").

Sources of M&E

The sources of mass considered in the LOCA M&E release analysis are given in Table 6.2D-4 for the DEHL breaks for DCPP Unit 2. The sources of mass for the DEPS

break case with the SSPS failure for DCPP Unit 2 are given in Table 6.2D-11. These sources are the RCS, accumulators, and pumped SI.

The energy inventory considered in the DEHL breaks for DCPP Unit 2 is given in Table 6.2D-5. The energy inventory for the DEPS break M&E release analysis for DCPP Unit 2 is given in Table 6.2D-12. The energy sources are as follows:

- RCS water
- Accumulator water (all inject)
- Pumped SI water
- Decay heat
- Core-stored energy
- RCS metal (includes SG tubes)
- SG metal (includes transition cone, shell, wrapper, and other internals)
- SG secondary energy (includes fluid mass and steam mass)
- Secondary transfer of energy (feedwater into and steam out of the SG secondary)

The analysis used the following energy reference points:

Available energy:	212°F; 14.7 psia (energy available that could be released)
Total energy content:	32°F; 14.7 psia (total internal energy of the RCS)

The M&E inventories are presented at the following times, as appropriate:

- Time zero (initial conditions)
- End of blowdown time
- End of refill time
- End of reflood time
- Time of broken loop SG equilibration to pressure setpoint
- Time of intact loop SG equilibration to pressure setpoint
- Time of full depressurization (3,600 seconds)

The energy release from the metal-water reaction rate is considered as part of the WCAP-10325-P-A (Reference 1) methodology. Based on the way that the energy in the fuel is conservatively released to the vessel fluid, the fuel cladding temperature does not increase to the point where the metal-water reaction is significant. This is in contrast to the 10 CFR 50.46 analyses, which are biased to calculate high fuel rod cladding temperatures and, therefore, a significant metal-water reaction. For the LOCA M&E release calculation, the energy created by the metal-water reaction value is small and is not explicitly provided in the energy balance tables. The energy that is determined is part of the M&E releases and is therefore already included in the overall M&E releases for DCPP.

The sequence of events for the LOCA transients is shown in Tables 6.2D-13 through 6.2D-15.

6.2D.3.1.5 Results

The consideration of the various energy sources in the long-term M&E release analysis provides assurance that all available sources of energy have been included in this analysis. The results of this analysis were provided for use in the LOCA containment integrity analysis in Section 6.2D.3.2.

6.2D.3.2 Long-Term Loss-of-Coolant Accident Containment Integrity Analysis

6.2D.3.2.1 Acceptance Criteria

The containment response for design basis LOCA containment integrity is an ANS Condition IV event, an infrequent fault. The relevant requirements to satisfy NRC acceptance criteria are as follows:

- The peak calculated containment pressure should be less than the containment design pressure of 47 psig.
- The peak calculated containment average air temperature should be less than the containment design temperature of 271 °F
- The calculated pressure at 24 hours should be less than 50 percent of the peak calculated value. (This is related to the criteria for containment leakage assumptions as affecting doses at 24 hours.)

Section 6.2.1 includes an evaluation demonstrating that the containment satisfies the applicable design requirements.

6.2D.3.2.2 Introduction and Background

The purpose of the LOCA containment integrity analysis is to evaluate the bounding peak pressure and temperature of a design basis LOCA event inside containment and to demonstrate the ability of the CHRSs to mitigate the accident. The impact of LOCA M&E releases on the containment pressure and temperature are assessed to ensure that the containment pressure and temperature remain below their respective design limits. The CHRSs must also be capable of maintaining the EQ parameters to within acceptable limits.

The DCPP LOCA containment response analysis considers a spectrum of cases that address differences between the individual DCPP units, LOCA break locations, and postulated single failures (minimum and maximum safeguards). The limiting cases that address the containment peak pressure case and limiting long-term EQ temperature are presented in this section.

Calculation of the containment response following a postulated LOCA was analyzed by use of the digital computer code GOTHIC version 7.2a. The GOTHIC Technical Manual

(Reference 13) provides a description of the governing equations, constitutive models, and solution methods in the solver. The GOTHIC Qualifications Report (Reference 14) provides a comparison of the solver results with both analytical solutions and experimental data.

The GOTHIC containment modeling for DCPP is consistent with the NRC approved Kewaunee evaluation model (Reference 15). Kewaunee and DCPP both have large dry containment designs with similar active heat removal capabilities. The latest code version is used to take advantage of the diffusion layer model heat transfer option. This heat transfer option was approved by the NRC (Reference 15) for use in Kewaunee containment analyses with the condition that the effect of mist be excluded from what was earlier termed as the mist diffusion layer model. The GOTHIC containment modeling for DCPP has followed the conditions of acceptance placed on Kewaunee. The differences in GOTHIC code versions are documented in Appendix A of the GOTHIC User Manual Release Notes (Reference 16). Version 7.2a is used consistently with the restrictions identified in Reference 15; none of the user-controlled enhancements added to version 7.2a were implemented in the DCPP containment model. A description of the DCPP GOTHIC model is provided later in this section.

6.2D.3.2.3 Input Parameters and Assumptions

The major modeling input parameters and assumptions used in the DCPP LOCA containment evaluation model are identified in this section. The assumed initial conditions and input assumptions associated with the fan coolers and containment sprays are listed in Table 6.2D-17. The containment spray flow data used in the analysis are presented in Table 6.2D-18. The function of the RHR system during a LOCA is to remove heat from the core by way of the ECCS. The ECCS recirculation and CCW system parameters are outlined in Table 6.2D-17. The containment structural heat sink input is provided in Table 6.2D-19, and the corresponding material properties are listed in Table 6.2D-20.

As stated in Section 6.2.2, and further discussed in Section 15.5, to address the delayed radioactivity release associated with the core damage sequence of Alternative Source Term (AST), credit is taken for fission product removal due to CSS operation in the injection and recirculation mode following a LOCA. The effect of CSS during the recirculation mode is not considered in this analysis as there is a negligible effect due to AST changes to CSS.

The LOCA containment analysis described here uses revised input and assumptions in support of the current design, while addressing analytical conservatisms. The assumptions used in the M&E release input model and the containment pressure input model are discussed in WCAP-10325-P-A (Reference 1) and WCAP-8264-P-A Revision 1 (Reference 5). Significant assumptions contained in the LOCA containment integrity analysis include:

(1) For all the long term cases and the base hot leg cases, there is a loss of offsite power coincident with the LOCA. For the hot leg break case with SI, off site power is available to allow the SI to begin during the blowdown.

(2) In all cases, two CFCUs, each from separate trains, are assumed to be unavailable due to maintenance

(3) The long term decay heat steaming M&E release calculation assumes that:

(a) All the decay heat is released to the containment as steam to maximize the pressure and temperature of the containment vapor region,

(b) 102% reactor power and ANS 1979 +2 sigma decay heat,

(4) The bounding auxiliary saltwater (ASW) temperature is 64 °F

(a) It should be noted that a separate set of analyses assuming a 70 °F ocean water temperature addresses operation with an elevated ultimate heat sink temperature (refer to Section 9.2.2.3.10).

The following are notable features of the current containment integrity analysis.

Decay heat steaming M&E release rates, after the end of the sensible heat release from the RCS and SGs, are calculated each time step by GOTHIC using the transient containment pressure and recirculation SI water temperature.

Non-condensable accumulator gas release is modeled in the GOTHIC model (refer to Section 6.2D.3.2.5); no accumulator nitrogen gas addition due to refill is considered in the analysis.

A recirculation system model that couples the RHR, CCW, CFCUs and ASW systems was developed. Detailed accounting of CCW flow rates through the CHRSs was used for the CFCUs, RHR heat exchangers, and miscellaneous CCW heat loads.

The DCPP LOCA containment response analysis considered a spectrum of cases. The cases address break locations, and postulated single failures (minimum and maximum safeguards) for each DCPP unit. Only the limiting cases, which address the containment peak pressure and limiting long-term EQ temperature, are presented. The LOCA pressure and temperature response analyses were performed assuming a loss of offsite power and a worst single failure (loss of one SSPS train, i.e., loss of one containment cooling train). The active heat removal available in the long term cooling case is:

- One containment spray pump during injection-phase only
- Two CFCUs

- One RHR pump and one RHR heat exchanger
- Two CCW pumps and one CCW heat exchanger
- One ASW pump.

The Unit 2 DEHL break produces the overall bounding peak pressure at the end of the blowdown. The calculation for the DEPS case was performed for a 116 day ($1x10^7$ second) transient in support of long term EQ temperatures. The sequence of events for the DEHL containment peak pressure case is shown in Table 6.2D-13 and the DEPS long term EQ temperature case for Unit 1 and Unit 2 are shown in Tables 6.2D-14 and 6.2D-15, respectively.

6.2D.3.2.4 Description of Analyses and Evaluations

Plant input assumptions (identified in Section 6.2D.3.2.3) are the same as, or slightly more restrictive, than in the original analyses performed with the COCO code (Reference 18). Benchmarking between the DCPP COCO and GOTHIC models was performed to confirm consistency in the implementation of the plant input values.

Noding Structure

The DCPP GOTHIC containment model is comprised of one control volume with separate vapor and liquid regions. M&E releases, containment spray injection, and sump water recirculation are modeled using boundary conditions. A cooler component is used to model CFCUs heat removal. Injection of accumulator nitrogen during the event is modeled with a boundary condition.

The CCW system model is comprised of three control volumes (CFCU cooling water, the hot side of the CCW system, and the cold side of the CCW system) and uses GOTHIC component models for the RHR and CCW heat exchangers. A heater component models the CFCU heat transfer to the CCW water. Boundary conditions model the CCW flow through the CFCUs, RHR heat exchangers, and miscellaneous CCW heat loads.

Volume Input

Values for the volume, height, hydraulic diameter, and elevation are input for each node. The containment is modeled as a single control volume. The lower bound free volume is 2,550,000 ft^3. The hydraulic diameter, height, and floor elevation input values are 24.1 feet, 166 feet, and 91 feet, respectively.

A conservatively calculated pool surface area is used to model interfacial heat and mass transfer to liquid pools on the various floor surfaces in the containment volume. The conductor representing the floor is essentially insulated from the vapor region after

the sump pool develops; however, there can still be condensation or evaporation from the surface of the liquid pools. Using this method to model the interfacial heat and mass transfer between the pools and the atmosphere was previously approved by the NRC for the Kewaunee containment DBA and equipment qualification analyses (Reference 15).

Initial Conditions

The containment initial conditions for containment integrity cases are:

- Pressure: 16.0 psia
- Relative Humidity: 18 percent
- Temperature: 120°F

The LOCA containment response model contains volumes representing the CCW system. The system volumes are water solid and assumed to be initially at 50 psia and 90°F.

Flow Paths

Flow boundary conditions linked to functions that define the M&E release model the LOCA break flow to the containment. The boundary conditions are connected to the containment control volume via flow paths. The containment spray is modeled as a boundary condition connected to the containment control volume via a flow path.

The flow rates through the flow paths are specified by the boundary conditions, so the purpose of the flow path is to direct the flow to the proper control volume. The flow path input is mostly arbitrary. Standard values are used for the area, hydraulic diameter, friction length, and inertia length of the flow path. Since this is a single volume lumped parameter model, the elevation of the break flow paths is arbitrarily set to 100 feet and the elevation of the spray flow paths is arbitrarily set to 70 feet above the containment floor.

Heat Sinks

The structural heat sinks in the containment are modeled as GOTHIC thermal conductors. The heat sink geometry data is based on conservatively low surface areas and is summarized in Table 6.2D-19. A thin air gap is assumed to exist between the steel and concrete for steel-jacketed heat sinks. A gap conductance of 10 Btu/hr-ft^2-°F is conservatively assumed between steel and concrete. The volumetric heat capacity and thermal conductivity for the heat sink materials are summarized in Table 6.2D-20.

Heat and Mass Transfer Correlation

GOTHIC has several heat transfer coefficient options that can be used for containment analyses. For the DCPP GOTHIC model, the direct heat transfer coefficient set is used

with the diffusion layer model mass transfer correlation for the heat sinks inside containment. This heat transfer methodology was reviewed by the NRC and approved for use in containment DBA analyses in the Kewaunee analysis (Reference 15). The diffusion layer model correlation does not require the user to specify a revaporization input value, as was done in previous analyses using the Uchida correlation.

Split heat transfer coefficients are used for the heat sinks representing walls and floors. The split coefficient allows one thermal conductor to model heat transfer to both the water and vapor regions. The submerged portions of conductors are essentially insulated from the vapor after the pool develops. The fraction of the wall that is not submerged uses the vapor heat transfer coefficient as described above. GOTHIC calculates the fraction of the walls that are submerged in the sump water. The floors are submerged quickly.

Sump Recirculation

The calculated containment peak pressure and temperature occur before the transfer to cold leg recirculation. However, a sump recirculation model comprised of simplified RHR and CCW system models was added to the DCPP containment model for the long-term LOCA containment pressure and temperature response calculation.

ECCS recirculation is actuated after a low RWST level signal and the ECCS takes suction from the containment sump. The RHR heat exchanger cools the water before it is injected back into the reactor vessel. The RHR heat exchanger is cooled by CCW and ASW provides the ultimate heat sink, cooling the CCW heat exchangers.

Switchover to hot leg recirculation is assumed to occur at 7 hours.

6.2D.3.2.5 Boundary Conditions

M&E Release

Section 6.2D.3.1 describes the long-term LOCA M&E release. The LOCA M&E release rates are generated using the Westinghouse methodology (Reference 1). M&E releases are calculated for both sides of the double-ended break in the coolant loop: the vessel side of the break and the SG side of the break. The M&E releases are input to the GOTHIC containment model as mass flow rates and enthalpies via boundary conditions connected to the containment volume with flow paths.

During blowdown, the liquid portion of the break flow is released as drops with an assumed diameter of 100 microns (0.00394 inches). This is consistent with the methodology approved for Kewaunee (Reference 15) and is based on data presented in Reference 17. After blowdown, the liquid release is assumed to be a continuous pour into the sump.

GOTHIC uses the M&E release tables from the time of accident initiation to 3,600 seconds, the time at which all energy in the primary heat structures and SG secondary system is assumed to be released/depressurized to atmospheric pressure, (i.e., 14.7 psia and 212°F). After primary system and secondary system energy have been released, the M&E releases to the containment are due to long-term steaming of decay heat. GOTHIC calculates the decay heat steaming M&E releases within user defined control variables. The steaming calculations incorporate the transient containment pressure and RHR recirculated ECCS enthalpy to calculate the M&E release. The calculations are essentially the same as the Westinghouse methodology previously approved by the NRC, except the calculations are performed within the GOTHIC code.

The ANS Standard 5.1 decay heat model (+2 sigma uncertainty) (Reference 7) is used to calculate the long-term boil-off from the core. All the decay heat is assumed to produce steam from the recirculated ECCS water. The remainder of the ECCS water is returned to the sump region of the containment control volume. These assumptions are consistent with the long-term M&E release methodology documented in Reference 1.

Containment Fan Coolers

The CFCUs are modeled with a GOTHIC cooler component. There are a total of five CFCUs in three trains. In all cases, two CFCUs are assumed to be out of service for maintenance. An inherent assumption in the LOCA containment analysis is that offsite power is lost with the pipe rupture. This results in the actuation of three EDGs, powering the two trains of safeguards equipment. Startup of the EDGs delays the operation of the safeguards equipment that is required to mitigate the transient. There are two trains of the SSPS that actuate the two trains of emergency safeguards. The failure of one train of SSPS will fail one train of safeguards. A minimum of two CFCUs are available and a maximum of three CFCUs are assumed to be available based on the single failure assumptions. In order to incorporate a fan cooler flow of 34,000 cfm (37,000 cfm for fan coolers with Super Radiator Coils), a conservative multiplier of 0.9600 was used on the fan cooler heat rate input calculated at 47,000 cfm.

Three long term cases are analyzed to assess the effects of single failures. The first case assumes minimum safeguards based on the postulated single failure of an SSPS train. This assumption results in the loss-of-one train of safeguards equipment. The operating equipment is conservatively modeled as: two CFCUs, one containment spray pump, one train of RHR, and one CCW heat exchanger. The other two cases assume maximum safeguards, in which both trains of SSPS are available. With the maximum safeguards cases, the single failure assumptions are the failure of one containment spray pump or the failure of one CFCU. The analysis of these three cases provides confidence that the effect of credible single failures is bounded.

For LOCA cases, the fan coolers in the containment evaluation model are modeled to actuate on the SI actuation, and begin removing heat from containment after a 64-second delay.

The CFCUs are cooled by CCW. The heat removal rate per containment fan cooler is calculated as a function of containment steam saturation temperature, the CCW inlet temperature and flow rate, and input to the GOTHIC cooler model. The heat removal rate is multiplied by the number of CFCUs available. The heat removed from the containment control volume is transferred to the CCW control volume receiving the flow through the CFCUs using a coupled heater model.

Containment Spray System

The containment spray is modeled with a boundary condition. DCPP has two trains of containment safeguards available, with one spray pump per train. An inherent assumption in the LOCA containment analysis is that offsite power is lost with the pipe rupture. This results in the actuation of the three EDGs powering the two trains of safeguards equipment. Startup of the EDGs delays the operation of the safeguards equipment that is required to mitigate the transient.

Relative to the single failure criterion with respect to a LOCA event, one spray pump is considered inoperable due to the SSPS failure (minimum safeguards case) or as a single failure in a maximum safeguards case. In the maximum safeguards case, in which the single failure is assumed to be one CFCU, two spray pumps are available.

The containment spray actuation is modeled on the SI actuation, conservatively assumed to be 7.0 seconds. The sprays begin injecting 90°F water after a specified 100 second delay. The spray flow rate is a function of containment pressure and is presented in Table 6.2D-18. The containment spray is credited only during the injection phase of the transient and is terminated on a RWST empty alarm after switchover to cold leg recirculation at a time based on the number of SI and spray pumps operating. The timing of recirculation and spray termination assumed in the LOCA containment analysis are presented in Table 6.2D-17.

Accumulator Nitrogen Gas Modeling

The accumulator nitrogen gas release is modeled with a flow boundary condition in the LOCA containment model. The nitrogen release rate was conservatively calculated by maximizing the mass available to be injected. The nitrogen gas release rate was used as input for the GOTHIC function, as a specified rate over a fixed time period. Nitrogen gas was released to the containment at a rate of 327.4 lbm/s. The release begins at 51.9 seconds, the minimum accumulator tank water depletion time.

6.2D.3.2.6 Loss-of-Coolant Accident Containment Integrity Analysis Results

The containment pressure, steam temperature, and water (sump) temperature profiles of the DEHL peak pressure case are shown in Figures 6.2D-3 through 6.2D-5. Table 6.2D-13 provides the transient sequence of events for the DEHL transient.

The containment pressure, steam temperature, and water (sump) temperature profiles of the DEPS long-term EQ temperature transient are shown in Figures 6.2D-6 through 6.2D-8 (the peak DEPS values are from Unit 2). The sequence of events for the Unit 1 and Unit 2 DEPS transients are presented in Tables 6.2D-14 and 6.2D-15, respectively. The peak pressure (refer to Figure 6.2D-6) for the DEPS case occurs at 23.5 seconds after the end of the blowdown. The fans begin to cool the containment at 71.0 seconds. Containment sprays begin injecting at 107.0 seconds. The pressure comes down as the SGs reach equilibrium with the containment environment, but spikes up again at recirculation when the CCW temperature increases and the CCW flow rate to the CFCUs decreases. The sensible heat release from the SG secondary system and RCS metal is completed at 3600 seconds, but at 3798 seconds, the RWST reaches a low level alarm and spray flow is terminated. The containment pressure increases for a time and then begins to decrease over the long term as the RHR heat exchangers and CFCUs remove the heat from the containment.

Table 6.2D-21 summarizes the containment peak pressure and temperature results and pressure and temperature at 24 hours for EQ support and the acceptance limits for these parameters.

A review of the results presented in Table 6.2D-21 shows that the analysis margin (analysis margin is the difference between the calculated peak pressure and temperature and the acceptance limits) is maintained for DCPP. From the GOTHIC analysis the containment peak pressure is 41.4 psig. At 24 hours, the maximum containment pressure is 8.5 psig and the maximum temperature is 164.97°F.

An assessment was performed to evaluate the effect of operation of containment spray in the recirculation mode following a LOCA on the sump water temperature transient. As shown in Figure 6.2D-8A, the sump water temperature transient is effected only in the long-term (i.e., after initiation of recirculation spray) at which time it becomes more limiting due to increased heat addiction from the containment atmosphere to the sump fluid by the containment recirculation sprays which is credited to operator for approximately 6.25 hours. The effect of this increase in temperature on the performance of the CCW system is discussed in Section 9.2.2.3.13.

6.2D.3.2.7 Conclusion

The DCPP containment can adequately account for the M&E releases that would result from a LOCA. The DCPP containment systems will provide sufficient pressure and temperature mitigation capability to ensure that containment integrity is maintained.

- The peak calculated pressure is less than the containment design pressure of 47 psig

- The peak calculated containment average air temperature is less than the containment design temperature of 271 °F

- The calculated pressure at 24 hours is less than 50 percent of the peak calculated value

6.2D.4 LONG-TERM MAIN STEAM LINE BREAK INSIDE CONTAINMENT

6.2D.4.1 Main Steam Line Break Mass and Energy Release Analysis

6.2D.4.1.1 Acceptance Criteria

There are no direct acceptance criteria for MSLB M&E releases. The analysis methods follow the guidelines provided by the NRC with respect to the sources of M&E during the various phases of a MSLB transient (refer to Section 6.2D.4.1.4).

The specific acceptance criteria for the containment response to a MSLB are discussed in Section 6.2D.4.2.1.

6.2D.4.1.2 Introduction and Background

The MSLB is classified as an ANS Condition IV event, an infrequent fault. A MSLB occurring inside a reactor containment structure may result in significant releases of high-energy fluid to the containment environment that could produce high pressure conditions for extended periods of time. The magnitude of the releases following a MSLB is dependent upon the plant initial operating conditions and the size of the rupture as well as the configuration of the plant steam system and the containment design. There are competing effects and credible single failures in the postulated accident scenario used to determine the worst cases for containment pressure and the associated containment temperature following a MSLB.

The DCPP MSLB and containment response analysis considers a spectrum of cases that vary the initial power condition, break size, and the postulated single failure.

6.2D.4.1.3 Input Parameters and Assumptions

Major assumptions affecting the M&E releases to containment are summarized below:

<u>Initial Steam Generator Inventory</u>

A high initial SG mass is assumed. The initial level corresponds to 75 percent narrow range span (NRS) at all power levels. This consists of a nominal level of 65 percent NRS plus a SG water level control uncertainty of 10 percent NRS.

<u>Main Feedwater System</u>

The rapid depressurization that occurs following a MSLB typically results in large amounts of water being added to the SGs through the main feedwater system. A rapid-closing main feedwater regulating valve (MFRV) near each SG limits this effect. The

feedwater addition to the faulted SG is maximized to be conservative since it increases the water mass inventory that will be converted to steam and released from the break.

Following the initiation of the MSLB, main feedwater flow is conservatively modeled by assuming that sufficient feedwater flow is provided to match or exceed the steam flow prior to reactor trip. The initial increase in feedwater flow is in response to the MFRV opening in response to the steam flow/feedwater flow mismatch and the lower backpressure on the feedwater pump as a result of the depressurizing SG. This maximizes the total mass addition prior to feedwater isolation. The feedwater isolation response time, following the “S” signal, is assumed to be a total of 9 seconds, accounting for delays associated with signal processing plus the valve stroke time.

The feedwater in the unisolable feedline between the MFRV and faulted SG is also considered in the analysis. The hot main feedwater reaches saturated conditions as the SG and feedline depressurize. The decrease in density as flashing occurs causes most of the unisolable feedwater to enter the faulted SG. This unisolable feedwater line volume of 208 ft^3 is an additional source of fluid that can increase the mass discharged out of the break.

Some cases postulate the MFRV on the faulted loop failing open. Refer to Section 6.2D.3.1.4 for information on the effects of this single failure.

Auxiliary Feedwater

Within the first minute following a MSLB, an ”S” signal is generated. Immediately upon receipt of the “S” signal, AFW is initiated. Addition of AFW to the faulted SG will increase the secondary mass available for release to the containment. The AFW flowrate to the faulted SG is maximized based on flow from both motor-driven AFW pumps and the turbine-driven AFW pump. The AFW flowrate is modeled as a function of SG pressure, varying from 569 gpm to 1588 gpm to the faulted SG.

Operator action is credited to terminate the AFW flow to the faulted SG after 10 minutes.

Unisolable Steamline

The initial steam in the main steamline between the break and the main steamline isolation valve (MSIV) and CV is included in the M&E released from the break. The MSIV/CV is considered a single plant component and is credited to prevent reverse flow from the main steamline header and intact SGs for most cases. Cases that postulate the failure of the MSIV/CV are discussed in Section 6.2D.3.1.4.

Quality of the Break Effluent

The quality of the break effluent is assumed to be 1.0, corresponding to saturated steam that is all vapor with no liquid. Although it is expected that there would be a significant

quantity of liquid in the break effluent for a full double-ended rupture, the all-vapor assumption conservatively maximizes the energy addition to the containment atmosphere.

Reactor Coolant System Assumptions

While the M&E released from the break is determined from assumptions that have been discussed above, the rate at which the release occurs is largely controlled by the conditions in the RCS. The major features of the primary side analysis model are summarized below:

- Continued operation of the reactor coolant pumps maintains a high heat transfer rate to the SGs.
- The model includes consideration of the heat that is stored in the RCS metal.
- Reverse heat transfer from the intact SGs to the RCS is modeled as the temperature in the RCS falls below the intact SG fluid temperature.
- Minimum flowrates are modeled from ECCS injection to conservatively minimize the amount of boron that provides negative reactivity feedback. Both the high-head and intermediate-head SI systems are considered available, with unborated purge volumes of 75.9 ft^3 and 19.4 ft^3, respectively. A failure of one train of ECCS is included for cases that also model a failure on a containment safeguards train (refer to Section 6.2D.3.1.4).
- The initial NSSS thermal power output assumed is 3,425 MWt, which includes the thermal power generated by the reactor coolant pumps minus heat losses to the containment and the letdown system.
- RCS average temperature is the full-power nominal value of 577.3°F (DCPP Unit 1) or 577.6°F (DCPP Unit 2) plus an uncertainty of +5.0°F.
- Core residual heat generation is assumed based on the 1979 ANS decay heat plus 2 sigma model (Reference 7).
- Conservative core reactivity coefficients (e.g., moderator temperature) corresponding to end-of-cycle conditions with the most reactive rod stuck out of the core are assumed. This maximizes the reactivity feedback effects as the RCS cools down as a result of the MSLB.
- All cases have credited a minimum shutdown margin of 1.6 percent Δk.

6.2D.4.1.4 Description of Analyses and Evaluations

The following limitations in the NRC Safety Evaluation Report for WCAP-14882-P-A have been adhered to in the use of RETRAN-02W to analyze this event.

- The break flow model is the Moody model.
- Only steam (dry vapor) will exit the break, since perfect steam separation in the SGs is assumed.
- The superheat in the steam released to the containment is not evaluated. Any superheated conditions will be reset to be equal to the saturation temperature.

Case Definitions and Single Failures

There are many factors that influence the quantity and rate of the M&E release from the main steamline. To encompass these factors, a spectrum of cases varies the initial power level, break size and the single failure. This section summarizes the basis of the cases that have been defined for DCPP.

The power level at which the plant is operating when the MSLB is postulated can cause different competing effects that make it difficult to pre-determine a single limiting case. For example, at higher power levels there is less initial water/steam in the SG, which is a benefit. However, at a higher power level there is a higher initial feedwater flowrate, higher feedwater temperature, higher decay heat, and there is a higher rate of heat transfer from the primary side, which are all penalties. Therefore, cases consider initial power levels varying from full power to zero power. The specific initial power levels that are analyzed are 100, 70, 30 and 0 percent, as presented in WCAP-8822. A calorimetric uncertainty of 2 percent is applied to the initial condition for the full power case.

Most cases consider the largest possible break, a double-ended rupture immediately downstream of the flow restrictor at the outlet of the SG. This break conservatively bounds the plant response to a smaller break size. The effective forward break area is limited by the 1.4 ft^2 cross-sectional area of the flow restrictor that is integral to the SG. The actual break area is the cross-sectional area of the pipe, which is 3.67 ft^2.

A few cases also consider the effects of a smaller, split break which allows contributing steam from the main steamline header and the intact SGs until the intact loop MSIVs close. This break size is defined to be the largest break that does not generate a low main steamline pressure signal. Instead, split breaks have to rely on high containment pressure signals to actuate SI (and reactor trip, feedline isolation, etc.) and main steamline isolation. The split break is only considered when the faulted loop MSIV/CV is postulated as the single failure. The split breaks have the penalty of a higher

integrated M&E released to the containment, but the smaller break size provides a beneficial reduction in the rate that the M&E is released.

Several single failures can be postulated that would impair the performance of various MSLB protection systems. The single failures either reduce the heat removal capacity of the containment safeguards systems or increase the energy release from the MSLB. The single failures that have been postulated for DCPP are summarized below. The analysis cases separately consider each single failure at each initial power level.

(1) Containment Safeguards Failure

This is a failure of one safeguards train. The main impact is on the containment response analysis, where the active heat removal is reduced by the loss of one train of fan coolers and one containment spray pump. This failure also causes the loss of one train of ECCS in the MSLB M&E release analysis.

(2) MFRV Failure

The MFRV is a fast-closing (7 second stroke time) valve in the feedwater system that is the preferred (fastest) method for terminating feedwater addition to the faulted SG during a MSLB. If the MFRV on the faulted loop fails open, the back-up main feedwater isolation valve (MFIV) is credited to close 64 seconds after an SI setpoint is reached. The slower closure time creates the possibility of additional pumped feedwater entering the faulted SG. Although the main feedwater pumps trip on an “S” signal, the condensate pumps do not trip and can continue to provide pumped flow when the faulted SG depressurizes below approximately 625 psia.

(3) MSIV/CV Failure

The MSIV/CV is considered a single plant component that is credited to function when another single failure is postulated. When the MSIV/CV is postulated as the single failure, this means the failure of both the forward flow isolating function (MSIV) and the reverse flow isolation function (CV) on the faulted loop. Therefore the main steamline blowdown initially includes steam mass from the main steamline header and intact SGs. Isolation of the break occurs due to the closure of the MSIVs on the intact SGs.

<u>Protection Logic and Setpoints</u>

The pertinent signals and setpoints that are actuated in these analyses are summarized below.

The first “S” signal is generated by a low steamline pressure signal in all double-ended rupture cases. The assumed setpoint is 458.7 psia (DCPP low steamline pressure setpoint is 600 psig), with a lead/lag of 50/5 seconds. For split rupture cases, the first

"S" signal that is credited in the analysis comes from the high containment pressure setpoint (5.0 psig) (DCPP high containment pressure setpoint is 3 psig). The "S" signal is credited to cause:

- Start of charging, RHR and SI pumps
- Reactor trip
- Start of AFW pumps
- Closure of MFRVs and MFIVs
- Trip of main feedwater pumps (only credited for MFRV failure cases).

Most cases isolate the MSLB to blowdown of a single SG by fast closure of the passive CV, which prevents reverse flow from the intact main steamline. For cases that model the MSIV/CV failure on the faulted loop, the closure of the intact MSIVs are credited due to the low steamline pressure signal (for double-ended ruptures) or the "P" signal (for split breaks)(DCPP "P" signal setpoint is 22 psig which initiates Phase B containment isolation).

6.2D.4.1.5 Main Steam Line Break Inside Containment Mass and Energy Release Results

Sixteen MSLB cases were analyzed varying the initial power level, break size and the assumed single failure.

The limiting containment pressure case is double-ended rupture MSLB initiated from 70 percent power with the faulted loop MFRV failed open. The break flowrate is shown in Figure 6.2D-1 and the break enthalpy is shown in Figure 6.2D-2 (refer to Section 6.2D.4.2 for the basis of this case being the limiting transient). Section 6.2D.4.2 also contains the sequence of events for this case, including primary, secondary, and containment system actuations.

A sensitivity analysis was performed to consider the effects of the plant response for Unit 1 versus Unit 2. It was determined that the plant response to this event is essentially the same for either unit. The MSLB analysis results bound the plant response for either Unit 1 or Unit 2.

The MSLB inside containment event has been analyzed with conservative assumptions to maximize the M&E release from the break. The M&E releases from this analysis are used as input to the containment integrity analysis documented in Section 6.2D.4.2.

6.2D.4.2 Long-Term Main Steam Line Break Containment Integrity Analysis

6.2D.4.2.1 Acceptance Criteria

The containment response to a MSLB is analyzed to ensure that the containment pressure remains below the containment design pressure of 47.0 psig. There is no explicit design temperature limit to be met for the MSLB containment response.

6.2D.4.2.2 Introduction and Background

Containment integrity analyses are performed to ensure that pressure inside containment will remain below the containment building design pressure for a postulated secondary system pipe rupture. The M&E release analysis discussed in Section 6.2D.4.1 is input to this analysis.

6.2D.4.2.3 Input Parameters and Assumptions

This section identifies the major input values that are used in the MSLB containment response analysis. The assumed initial conditions and the input assumptions associated with the fan coolers and containment sprays are listed in Table 6.2D-22, which lists that the MSLB conservatively assumes offsite power remains available since this maximizes the primary to secondary heat transfer. The assumed delay times bound the auto-bus transfer when offsite power is available. The containment thermal conductor input is provided in Table 6.2D-19, and the corresponding material properties are listed in Table 6.2D-20.

6.2D.4.2.4 Description of Analyses and Evaluations

The containment response analysis uses the GOTHIC computer code. The GOTHIC Technical Manual (Reference 13) provides a description of the governing equations, constitutive models, and solution methods in the solver. The GOTHIC Qualifications Report (Reference 14) provides a comparison of the solver results with both analytical solutions and experimental data.

The DCPP GOTHIC containment evaluation model consists of a single lumped-parameter node; the diffusion layer model is used for heat transfer to all structures in the containment. Plant input assumptions (identified in Section 6.2D.3.2.3) are the same as, or slightly more restrictive, than in the original analyses performed with the COCO code (Reference 18). Benchmarking between the DCPP COCO and GOTHIC models was performed to confirm consistency in the implementation of the plant input values. The benchmarking results show that the GOTHIC model predicted similar transient results.

This MSLB containment response analysis uses GOTHIC version 7.2a. This code version is used to take advantage of the diffusion layer model heat transfer option. This

heat transfer option was approved by the NRC (Reference 19) for use in Kewaunee containment analyses with the condition that mist be excluded from what was earlier termed as the mist diffusion layer model. The GOTHIC containment modeling for DCPP has followed the conditions of acceptance placed on Kewaunee. Kewaunee and DCPP both have large, dry containments. Changes in the GOTHIC code versions are detailed in Appendix A of the GOTHIC User Manual Release Notes (Reference 16). Version 7.2a is used consistent with the restrictions identified in Reference 19; none of the user-controlled enhancements added to version 7.2a were implemented in the DCPP containment model.

6.2D.4.2.5 Results

Sixteen MSLB cases were analyzed varying the initial power level and the assumed single failure. The M&E release from the break was calculated using the RETRAN-02W code (refer to Section 6.2D.4.1.4), while the containment pressure response was determined with the GOTHIC code. The MSLB results are based on Unit 2 configuration, which was determined to be bounding for Unit 1.

The peak pressures and peak temperatures from the spectrum of cases are listed in Table 6.2D-23. The limiting peak pressure case is a MFRV failure at 70 percent power assuming a full double-ended rupture. The sequence of events for this limiting case is listed in Table 6.2D-24. The containment pressure and temperature transient for the limiting case is shown in Figures 6.2D-9 and 6.2D-10, respectively.

6.2D.4.2.6 Conclusions

The peak containment pressure is 42.4 psig, which is below the containment design pressure of 47.0 psig. The analysis demonstrates that the containment pressure remains below the containment design pressure throughout the transient for a postulated secondary system pipe rupture. Thus the containment integrity has been demonstrated and the applicable acceptance criteria are therefore met.

6.2D.5 REFERENCES

1. Westinghouse LOCA Mass and Energy Release Model for Containment Design - March 1979 Version, WCAP-10325-P-A (Proprietary), WCAP-10326-A (Non-Proprietary), May 1983.

2. Deleted in Revision 22.

3. License Amendment No.126 for D. C. Cook Nuclear Plant Unit 1, Operating License No. DPR-58 (TAC No. 71062), June 9, 1989.

4. Mixing of Emergency Core Cooling Water with Steam; 1/3-Scale Test and Summary, WCAP-8423, EPRI 294-2, Final Report, June 1975.

5. Westinghouse Mass and Energy Release Data for Containment Design, WCAP-8264-P-A, Revision 1 (Proprietary), WCAP-8312-A, Revision 2 (Non-Proprietary), August 1975.

6. Letter from Herbert N. Berkow, Director (NRC) to James A. Gresham (Westinghouse), "Acceptance of Clarifications of Topical Report WCAP-10325-P-A, 'Westinghouse LOCA Mass and Energy Release Model for Containment Design - March 1979 Version', (TAC No. MC7980)".

7. ANSI/ANS-5.1 1979, "American National Standard for Decay Heat Power in Light Water Reactors", August 29, 1979.

8. Letter from Cecil O. Thomas (NRC), "Acceptance for Referencing of Licensing Topical Report WCAP-8821(P)/8859(NP), TRANFLO Steam Generator Code Description", and "WCAP-8822(P)/8860(NP), "Mass and Energy Release Following a Steam Line Rupture," August 1983.

9. R. E. Land, Mass and Energy Releases Following a Steam Line Rupture, WCAP-8822 (Proprietary), WCAP-8860 (Non-Proprietary), September 1976.

10. Deleted in Revision 22

11. J. C. Butler and P. A. Lin, Mass and Energy Releases Following a Steam Line Rupture, Supplement 2 – Impact of Steam Superheat in Mass/Energy Releases Following a Steamline Rupture for Dry and Subatmospheric Containment Designs, WCAP-8822-S2-P-A (Proprietary), September 1986

12. D. S. Huegel, et al. RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, [RETRAN-02W] WCAP-14882-P-A (Proprietary), April 1999, WCAP-15234-A (Non-Proprietary), May 1999.

13. GOTHIC Containment Analysis Package Technical Manual, Version 7.2a, NAI-8907-06, Revision 16, January 2006.

14. GOTHIC Containment Analysis Package Qualification Report, Version 7.2a, NAI-8907-09, Revision 9, January 2006.

15. License Amendment No. 169 for Kewaunee Nuclear Power Plant, Operating License No. DPR-43 (TAC No. MB6408), September 29, 2003.

16. GOTHIC Containment Analysis Package User Manual, Version 7.2a, NAI-8907-02, Revision 17, January 2006.

17. Brown and York, "Sprays formed by Flashing Liquid Jets", AICHE Journal, Volume 8, #2, May 1962.

18. F. M. Bordelon and E. T. Murphy, Containment Pressure Analysis Code (COCO), WCAP-8327 (Proprietary), WCAP-8326 (Non-Proprietary), July 1974.

19. Letter from Anthony C. McMurtray (NRC) to Thomas Coutu (NMC), “Enclosure 2, Safety Evaluation,” September 29, 2003.

20. CN-CRA-12-5, Rev 0, Diablo Canyon Containment Integrity Reanalysis to Address CFCU Fan Flow and NSAL-11-5 Issues

21. CN-CRA-14-6, Rev 0, Diablo Canyon Units 1 & 2, Delay in CFCU Start and a Decrease in Containment Heat Removal Capability

22. CN-CRA-14-7, Rev 0, Diablo Canyon Units 1 & 2, Steamline Break Containment Response for Revised CFCU and CS

TABLE 6.2D-1

SYSTEM PARAMETERS INITIAL CONDITIONS

Parameters		Value
Core Thermal Power (MWt)[1]		3479.0
RCS Total Flow Rate (lbm/sec)		37222.22
Vessel Outlet Temperature (°F)		615.1
Core Inlet Temperature (°F)		550.1
Vessel Barrel-Baffle Configuration[2]		Upflow
Initial Steam Generator Steam Pressure (psia)		903.0
Steam Generator Design		Δ54
Steam Generator Tube Plugging (%)		0
Initial Steam Generator Secondary Side Mass (lbm)		132,953.7
Assumed Maximum Containment Backpressure (psia)		61.7
Accumulator		
Water volume (ft^3) per accumulator		850.0
N_2 cover gas pressure (psia)		695.2
Temperature (°F)		120.0
SI Start Time, (sec) [total time from beginning of event which includes the maximum delay from reaching the setpoint]		42.0

Notes:

1. Core thermal power, RCS total flow rate, RCS coolant temperatures, and SG secondary-side mass include appropriate uncertainty and/or allowance.
2. The upflow configuration of Unit 2 bounds the downflow configuration of Unit 1.

TABLE 6.2D-2

SI FLOW MINIMUM SAFEGUARDS – BOTH UNITS

RCS Pressure (psig)	Total Flow (gpm)
Injection Mode (reflood phase)	
0	4805.0
20	4558.8
40	4298.6
60	4017.4
80	3710.2
100	3363.0
120	2950.4
140	2403.8
160	1386.2
180	780.6
200	775.0
Cold-Leg Recirculation Flow	3252.3
Hot-Leg Recirculation Flow	3071.7

TABLE 6.2D-3

DEHL BREAK
NO SAFETY INJECTION
MASS AND ENERGY RELEASES DURING BLOWDOWN

	Break Path No. 1 Flow[1]		Break Path No. 2 Flow[2]	
Time(s)	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
1.062358E-03	4.421330E+04	2.795865E+04	4.421073E+04	2.795568E+04
2.116870E-03	4.513561E+04	2.854166E+04	4.484486E+04	2.835063E+04
1.011610E-01	4.558368E+04	2.916997E+04	2.631157E+04	1.660517E+04
2.012629E-01	3.325809E+04	2.154267E+04	2.336337E+04	1.466358E+04
3.015284E-01	3.328901E+04	2.151881E+04	2.074400E+04	1.287011E+04
4.018289E-01	3.233691E+04	2.087650E+04	1.940834E+04	1.185700E+04
5.016486E-01	3.179156E+04	2.051087E+04	1.860073E+04	1.118752E+04
6.010187E-01	3.175035E+04	2.047324E+04	1.806742E+04	1.071491E+04
7.010036E-01	3.170974E+04	2.045320E+04	1.764590E+04	1.033815E+04
8.020547E-01	3.143076E+04	2.030445E+04	1.731057E+04	1.003537E+04
9.019648E-01	3.098787E+04	2.006708E+04	1.705860E+04	9.802414E+03
1.001210E+00	3.054152E+04	1.983958E+04	1.686041E+04	9.616324E+03
1.101514E+00	3.017290E+04	1.967163E+04	1.671930E+04	9.473734E+03
1.201277E+00	2.999474E+04	1.963587E+04	1.659974E+04	9.353070E+03
1.301412E+00	2.976682E+04	1.957221E+04	1.656717E+04	9.287328E+03
1.401996E+00	2.943739E+04	1.943873E+04	1.658615E+04	9.255053E+03
1.501864E+00	2.901809E+04	1.924138E+04	1.662590E+04	9.239039E+03
1.602090E+00	2.857801E+04	1.902255E+04	1.668783E+04	9.239026E+03
1.701623E+00	2.821512E+04	1.884598E+04	1.676359E+04	9.250566E+03
1.802174E+00	2.792087E+04	1.871164E+04	1.684624E+04	9.269260E+03
1.901835E+00	2.758637E+04	1.854544E+04	1.692639E+04	9.290490E+03
2.001085E+00	2.715653E+04	1.830796E+04	1.699545E+04	9.309264E+03
2.101509E+00	2.666613E+04	1.802233E+04	1.705422E+04	9.325545E+03
2.201561E+00	2.621646E+04	1.776084E+04	1.710275E+04	9.339314E+03
2.301787E+00	2.583163E+04	1.754326E+04	1.714244E+04	9.350919E+03
2.401518E+00	2.545424E+04	1.732786E+04	1.717032E+04	9.358416E+03
2.501914E+00	2.503389E+04	1.707628E+04	1.718287E+04	9.359553E+03
2.602138E+00	2.459066E+04	1.680199E+04	1.718151E+04	9.354817E+03
2.702086E+00	2.415870E+04	1.653089E+04	1.716793E+04	9.344832E+03
2.801309E+00	2.376343E+04	1.628281E+04	1.714481E+04	9.330784E+03
2.901624E+00	2.339761E+04	1.605365E+04	1.711252E+04	9.312652E+03
3.001978E+00	2.304258E+04	1.582842E+04	1.707259E+04	9.291107E+03
3.101309E+00	2.267665E+04	1.558865E+04	1.702505E+04	9.266022E+03
3.201600E+00	2.232172E+04	1.535143E+04	1.696861E+04	9.236593E+03
3.301245E+00	2.200559E+04	1.513983E+04	1.690832E+04	9.205429E+03

TABLE 6.2D-3

DEHL BREAK
NO SAFETY INJECTION
MASS AND ENERGY RELEASES DURING BLOWDOWN

	Break Path No. 1 Flow[1]		Break Path No. 2 Flow[2]	
Time(s)	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
3.401754E+00	2.170027E+04	1.493186E+04	1.684303E+04	9.171848E+03
3.501091E+00	2.141111E+04	1.473030E+04	1.677380E+04	9.136342E+03
3.601199E+00	2.115167E+04	1.454707E+04	1.670002E+04	9.098566E+03
3.701428E+00	2.090290E+04	1.436717E+04	1.662281E+04	9.059060E+03
3.801487E+00	2.066214E+04	1.418769E+04	1.654094E+04	9.017175E+03
3.901424E+00	2.045532E+04	1.402983E+04	1.645629E+04	8.973907E+03
4.001087E+00	2.026789E+04	1.388271E+04	1.636891E+04	8.929290E+03
4.200070E+00	1.993782E+04	1.360944E+04	1.618343E+04	8.834705E+03
4.401104E+00	1.967616E+04	1.337388E+04	1.597713E+04	8.729512E+03
4.600449E+00	1.948249E+04	1.317866E+04	1.575242E+04	8.614931E+03
4.800778E+00	1.936158E+04	1.302737E+04	1.550211E+04	8.487160E+03
5.000381E+00	1.933507E+04	1.293779E+04	1.518745E+04	8.324583E+03
5.200546E+00	1.933505E+04	1.286676E+04	1.473428E+04	8.086715E+03
5.401286E+00	1.938190E+04	1.283109E+04	1.438802E+04	7.910627E+03
5.600623E+00	1.945952E+04	1.281432E+04	1.417807E+04	7.809886E+03
5.800968E+00	1.960274E+04	1.281936E+04	1.375662E+04	7.589370E+03
6.000423E+00	1.978556E+04	1.284097E+04	1.333628E+04	7.369933E+03
6.200714E+00	2.005063E+04	1.290744E+04	1.299385E+04	7.194837E+03
6.401191E+00	2.046116E+04	1.303434E+04	1.262515E+04	7.004489E+03
6.600091E+00	1.547757E+04	1.086055E+04	1.229050E+04	6.832616E+03
6.800170E+00	1.530222E+04	1.067566E+04	1.195706E+04	6.660028E+03
7.000022E+00	1.549690E+04	1.069490E+04	1.160642E+04	6.476845E+03
7.200609E+00	1.563658E+04	1.071619E+04	1.130097E+04	6.318775E+03
7.400177E+00	1.578609E+04	1.072046E+04	1.100946E+04	6.167301E+03
7.600533E+00	1.593356E+04	1.070815E+04	1.072214E+04	6.017282E+03
7.801034E+00	1.615061E+04	1.077797E+04	1.043611E+04	5.867256E+03
8.000298E+00	1.632238E+04	1.079936E+04	1.016568E+04	5.725268E+03
8.200516E+00	1.639457E+04	1.077841E+04	9.913078E+03	5.592690E+03
8.400596E+00	1.650113E+04	1.079726E+04	9.671393E+03	5.465471E+03
8.601646E+00	1.636407E+04	1.063906E+04	9.437511E+03	5.342136E+03
8.801463E+00	1.656999E+04	1.068611E+04	9.214691E+03	5.224589E+03
9.000441E+00	1.676613E+04	1.073297E+04	9.001371E+03	5.112124E+03
9.201846E+00	1.696588E+04	1.078521E+04	8.793862E+03	5.002893E+03
9.401161E+00	1.717369E+04	1.084538E+04	8.592599E+03	4.896921E+03
9.601131E+00	1.741410E+04	1.092530E+04	8.393214E+03	4.792029E+03
9.801950E+00	1.776281E+04	1.106534E+04	8.196650E+03	4.688971E+03
1.000068E+01	1.839142E+04	1.135395E+04	8.003922E+03	4.588161E+03

TABLE 6.2D-3

DEHL BREAK
NO SAFETY INJECTION
MASS AND ENERGY RELEASES DURING BLOWDOWN

Time(s)	Break Path No. 1 Flow[1]		Break Path No. 2 Flow[2]	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
1.020140E+01	1.851964E+04	1.140232E+04	7.810060E+03	4.487047E+03
1.020362E+01	1.851891E+04	1.140156E+04	7.808551E+03	4.486299E+03
1.040086E+01	1.833975E+04	1.126025E+04	7.618512E+03	4.387523E+03
1.060050E+01	1.804366E+04	1.104730E+04	7.425827E+03	4.287746E+03
1.080127E+01	1.635122E+04	1.012610E+04	7.230032E+03	4.186827E+03
1.100122E+01	1.495018E+04	9.366321E+03	7.043013E+03	4.091326E+03
1.120105E+01	1.495589E+04	9.329105E+03	6.857841E+03	3.997307E+03
1.140234E+01	1.505645E+04	9.349147E+03	6.683749E+03	3.910070E+03
1.160104E+01	1.518993E+04	9.395547E+03	6.524124E+03	3.830459E+03
1.180020E+01	1.534510E+04	9.458602E+03	6.372764E+03	3.754714E+03
1.200164E+01	1.543409E+04	9.486852E+03	6.226401E+03	3.681190E+03
1.220032E+01	1.547409E+04	9.492495E+03	6.086830E+03	3.610949E+03
1.240054E+01	1.542898E+04	9.455210E+03	5.949447E+03	3.541731E+03
1.260148E+01	1.504712E+04	9.243750E+03	5.813945E+03	3.473712E+03
1.280136E+01	1.404974E+04	8.712991E+03	5.678712E+03	3.406016E+03
1.300163E+01	1.341850E+04	8.370817E+03	5.547233E+03	3.340880E+03
1.320039E+01	1.321660E+04	8.247448E+03	5.418112E+03	3.277430E+03
1.340088E+01	1.309170E+04	8.167251E+03	5.292336E+03	3.216163E+03
1.360132E+01	1.292232E+04	8.068071E+03	5.169267E+03	3.156194E+03
1.380186E+01	1.266645E+04	7.927508E+03	5.041325E+03	3.093249E+03
1.400069E+01	1.232011E+04	7.743278E+03	4.905249E+03	3.026344E+03
1.420193E+01	1.189811E+04	7.521688E+03	4.753275E+03	2.952577E+03
1.440144E+01	1.146758E+04	7.298080E+03	4.588016E+03	2.874162E+03
1.460128E+01	1.106268E+04	7.091303E+03	4.409904E+03	2.791234E+03
1.480068E+01	1.068885E+04	6.905159E+03	4.224909E+03	2.705894E+03
1.500023E+01	1.033246E+04	6.733536E+03	4.040939E+03	2.620500E+03
1.520003E+01	9.984955E+03	6.576100E+03	3.864887E+03	2.536414E+03
1.540118E+01	9.317167E+03	6.407015E+03	3.709484E+03	2.459092E+03
1.560109E+01	8.714224E+03	6.305064E+03	3.572296E+03	2.385381E+03
1.580010E+01	8.266204E+03	6.250359E+03	3.461553E+03	2.320330E+03
1.600106E+01	7.696312E+03	6.075593E+03	3.370571E+03	2.260741E+03
1.620100E+01	7.124064E+03	5.829973E+03	3.295617E+03	2.207467E+03
1.640032E+01	6.541715E+03	5.540556E+03	3.231165E+03	2.160269E+03
1.660015E+01	5.772028E+03	5.130904E+03	3.171035E+03	2.117409E+03
1.680034E+01	5.318274E+03	4.796410E+03	3.109013E+03	2.077173E+03
1.700009E+01	5.008771E+03	4.554054E+03	3.047012E+03	2.040953E+03

TABLE 6.2D-3

DEHL BREAK
NO SAFETY INJECTION
MASS AND ENERGY RELEASES DURING BLOWDOWN

	Break Path No. 1 Flow[1]		Break Path No. 2 Flow[2]	
Time(s)	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
1.720029E+01	4.694776E+03	4.337421E+03	2.981612E+03	2.004773E+03
1.740054E+01	4.381731E+03	4.131616E+03	2.903048E+03	1.963422E+03
1.760086E+01	4.072314E+03	3.927940E+03	2.813318E+03	1.922735E+03
1.780037E+01	3.798619E+03	3.740319E+03	2.712476E+03	1.883886E+03
1.800024E+01	3.577700E+03	3.585851E+03	2.599361E+03	1.844563E+03
1.820044E+01	3.434225E+03	3.452000E+03	2.475408E+03	1.802445E+03
1.840049E+01	3.302377E+03	3.322555E+03	2.348470E+03	1.759088E+03
1.860098E+01	3.169430E+03	3.190353E+03	2.224475E+03	1.715486E+03
1.880010E+01	3.027789E+03	3.048826E+03	2.107528E+03	1.672662E+03
1.900057E+01	2.868351E+03	2.906054E+03	1.998177E+03	1.631855E+03
1.920019E+01	2.709716E+03	2.766480E+03	1.896698E+03	1.594088E+03
1.940071E+01	2.575033E+03	2.627882E+03	1.800793E+03	1.559035E+03
1.960032E+01	2.452574E+03	2.501322E+03	1.706999E+03	1.524038E+03
1.980017E+01	2.292345E+03	2.388876E+03	1.616612E+03	1.492169E+03
2.000005E+01	2.129252E+03	2.281103E+03	1.521493E+03	1.465201E+03
2.020031E+01	1.963596E+03	2.170189E+03	1.420540E+03	1.438942E+03
2.040059E+01	1.821726E+03	2.070901E+03	1.307619E+03	1.410822E+03
2.060048E+01	1.686111E+03	1.969454E+03	1.207293E+03	1.373882E+03
2.080012E+01	1.567739E+03	1.881512E+03	1.144899E+03	1.329894E+03
2.100034E+01	1.455380E+03	1.774918E+03	1.122059E+03	1.301265E+03
2.120069E+01	1.367142E+03	1.681319E+03	1.122412E+03	1.285166E+03
2.140071E+01	1.268643E+03	1.567466E+03	1.120282E+03	1.271598E+03
2.160041E+01	1.184332E+03	1.468961E+03	1.086405E+03	1.251029E+03
2.180002E+01	1.099172E+03	1.358462E+03	1.007622E+03	1.208777E+03
2.200024E+01	8.315474E+02	1.041161E+03	8.745183E+02	1.068759E+03
2.220025E+01	5.277383E+02	6.618167E+02	7.617935E+02	9.355157E+02
2.240053E+01	3.415200E+02	4.291319E+02	5.945007E+02	7.313068E+02
2.260050E+01	2.190858E+02	2.748483E+02	4.904691E+02	6.069666E+02
2.280063E+01	0.000000E+00	0.000000E+00	3.511805E+02	4.352937E+02
2.300058E+01	0.000000E+00	0.000000E+00	1.792344E+02	2.229219E+02
2.320074E+01	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00

Notes:
1. Mass and energy exiting from the reactor-vessel side of the break.
2. Mass and energy exiting from the steam-generator side of the break.

TABLE 6.2D-4

DEHL BREAK
NO SAFETY INJECTION
MASS BALANCE

Time(s)		**0.00**	**23.20**	**23.20**
		Mass (thousand lbm)		
Initial	In RCS and Accumulator	746.11	746.11	746.11
Added Mass	Pumped Injection	0.0	0.0	0.0
	Total Added	0.0	0.0	0.0
*****Total Available*****		**746.11**	**746.11**	**746.11**
Distribution	Reactor Coolant	527.79	81.96	92.03
	Accumulator	218.32	158.86	148.79
	Total Contents	746.11	240.82	240.82
Effluent	Break Flow	0.00	505.27	505.27
	ECCS Spill	0.00	0.00	0.00
	Total Effluent	0.00	505.27	505.27
*****Total Accountable*****		**746.11**	**746.09**	**746.09**

*See Section 6.2D.3.1.4 for a description of the mass and energy balance tables. Some round-off and truncation exists.

TABLE 6.2D-5

DEHL BREAK
NO SAFETY INJECTION
ENERGY BALANCE

Time(s)		.00	23.20	23.20
		Energy (Million Btu)		
Initial Energy	In RCS, Accumulator, SG	909.96	909.96	909.96
Added Energy	Pumped Injection	0.00	0.00	0.00
	Decay Heat	0.00	8.22	8.22
	Heat from Secondary	0.00	-5.00	-5.00
	Total Added	0.00	3.22	3.22
***** Total Available *****		**909.96**	**913.18**	**913.18**
Distribution	Reactor Coolant	307.96	21.10	22.00
	Accumulator	19.59	14.26	13.35
	Core Stored	21.81	8.19	8.19
	Primary Metal	155.40	146.48	146.48
	Secondary Metal	111.31	109.70	109.70
	SG	293.89	288.66	288.66
	Total Contents	909.96	588.38	588.38
Effluent	Break Flow	0.00	324.20	324.20
	ECCS Spill	0.00	0.00	0.00
	Total Effluent	0.00	324.20	324.20
***** Total Accountable *****		**909.96**	**912.58**	**912.58**

*See Section 6.2D.3.1.4 for a description of the mass and energy balance tables. Some round-off and truncation exists.

TABLE 6.2D-6
DEPS BREAK MASS AND ENERGY RELEASES DURING BLOWDOWN

Time(s)	Break Path No. 1 Flow(1)		Break Path No. 2 Flow(2)	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
1.012155E-03	9.252190E+04	5.030486E+04	3.880431E+04	2.103613E+04
2.079687E-03	4.081721E+04	2.212773E+04	4.048589E+04	2.194649E+04
1.010149E-01	4.039251E+04	2.195494E+04	2.110978E+04	1.143701E+04
2.012392E-01	4.096699E+04	2.239887E+04	2.305680E+04	1.249944E+04
3.016804E-01	4.168919E+04	2.297532E+04	2.322227E+04	1.259865E+04
4.012768E-01	4.245918E+04	2.362371E+04	2.279445E+04	1.237826E+04
5.014424E-01	4.319495E+04	2.429389E+04	2.194319E+04	1.192387E+04
6.013018E-01	4.359878E+04	2.478882E+04	2.112506E+04	1.148468E+04
7.022743E-01	4.349955E+04	2.498848E+04	2.047199E+04	1.113286E+04
8.018839E-01	4.271585E+04	2.476116E+04	1.991531E+04	1.083234E+04
9.014520E-01	4.162552E+04	2.433228E+04	1.947506E+04	1.059479E+04
1.001292E+00	4.055578E+04	2.390234E+04	1.917617E+04	1.043403E+04
1.101543E+00	3.951127E+04	2.348347E+04	1.901385E+04	1.034785E+04
1.201758E+00	3.841998E+04	2.303971E+04	1.894217E+04	1.031017E+04
1.301335E+00	3.728278E+04	2.256854E+04	1.892713E+04	1.030310E+04
1.401155E+00	3.614663E+04	2.208747E+04	1.894157E+04	1.031162E+04
1.501798E+00	3.509478E+04	2.163480E+04	1.897107E+04	1.032800E+04
1.601713E+00	3.421789E+04	2.126281E+04	1.899927E+04	1.034346E+04
1.701023E+00	3.346560E+04	2.095155E+04	1.903190E+04	1.036135E+04
1.801546E+00	3.276563E+04	2.066905E+04	1.906613E+04	1.038022E+04
1.901489E+00	3.207894E+04	2.039198E+04	1.909244E+04	1.039482E+04
2.001166E+00	3.137079E+04	2.009829E+04	1.908695E+04	1.039204E+04
2.101973E+00	3.056791E+04	1.974044E+04	1.904905E+04	1.037167E+04
2.201918E+00	2.983342E+04	1.941747E+04	1.898670E+04	1.033809E+04
2.301623E+00	2.906627E+04	1.906466E+04	1.889729E+04	1.028983E+04
2.401150E+00	2.827822E+04	1.868987E+04	1.858292E+04	1.011806E+04
2.501416E+00	2.744303E+04	1.827727E+04	1.835090E+04	9.992681E+03
2.601523E+00	2.637734E+04	1.769804E+04	1.819343E+04	9.908046E+03
2.701054E+00	2.503526E+04	1.691292E+04	1.803376E+04	9.822080E+03
2.801538E+00	2.301249E+04	1.563913E+04	1.784718E+04	9.721403E+03
2.901077E+00	2.071230E+04	1.415471E+04	1.763414E+04	9.606299E+03
3.001147E+00	2.006955E+04	1.381607E+04	1.742081E+04	9.491216E+03
3.101327E+00	2.019607E+04	1.396411E+04	1.721577E+04	9.380798E+03
3.201589E+00	1.937606E+04	1.341843E+04	1.701253E+04	9.271432E+03
3.301334E+00	1.874670E+04	1.301718E+04	1.679817E+04	9.155889E+03

TABLE 6.2D-6
DEPS BREAK MASS AND ENERGY RELEASES DURING BLOWDOWN

Time(s)	Break Path No. 1 Flow[1]		Break Path No. 2 Flow[2]	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
3.401203E+00	1.828567E+04	1.272827E+04	1.658303E+04	9.039954E+03
3.501188E+00	1.763436E+04	1.229725E+04	1.638264E+04	8.932213E+03
3.601297E+00	1.699057E+04	1.187174E+04	1.619298E+04	8.830374E+03
3.701527E+00	1.634982E+04	1.144691E+04	1.601211E+04	8.733377E+03
3.801280E+00	1.570858E+04	1.101978E+04	1.584464E+04	8.643747E+03
3.901184E+00	1.510531E+04	1.061852E+04	1.568558E+04	8.558731E+03
4.001285E+00	1.454678E+04	1.024840E+04	1.553119E+04	8.476258E+03
4.200344E+00	1.364992E+04	9.658193E+03	1.526236E+04	8.333218E+03
4.400461E+00	1.298935E+04	9.220547E+03	1.500957E+04	8.198719E+03
4.600081E+00	1.246184E+04	8.865649E+03	1.478485E+04	8.079567E+03
4.800520E+00	1.205610E+04	8.585036E+03	1.457353E+04	7.967578E+03
5.000148E+00	1.172034E+04	8.344687E+03	1.437991E+04	7.865314E+03
5.200246E+00	1.146733E+04	8.152774E+03	1.418011E+04	7.759525E+03
5.400347E+00	1.126195E+04	7.986499E+03	1.398521E+04	7.656539E+03
5.600211E+00	1.110929E+04	7.850742E+03	1.381060E+04	7.564359E+03
5.800925E+00	1.100068E+04	7.739160E+03	1.411973E+04	7.744306E+03
6.000424E+00	1.096464E+04	7.671271E+03	1.530308E+04	8.392624E+03
6.200824E+00	1.099064E+04	7.641513E+03	1.504573E+04	8.253777E+03
6.400746E+00	1.107517E+04	7.647963E+03	1.476541E+04	8.103967E+03
6.600282E+00	1.118138E+04	7.667223E+03	1.466591E+04	8.052643E+03
6.800970E+00	1.133501E+04	7.717190E+03	1.447111E+04	7.949621E+03
7.000510E+00	1.193072E+04	8.058007E+03	1.432975E+04	7.876542E+03
7.200167E+00	1.169015E+04	7.886052E+03	1.434763E+04	7.891389E+03
7.400278E+00	1.077083E+04	7.618760E+03	1.416369E+04	7.792666E+03
7.600314E+00	9.425007E+03	7.126252E+03	1.394847E+04	7.675799E+03
7.800761E+00	8.905678E+03	6.881320E+03	1.375589E+04	7.571474E+03
8.000278E+00	8.884489E+03	6.834976E+03	1.363074E+04	7.505109E+03
8.200306E+00	8.933121E+03	6.811539E+03	1.355253E+04	7.463369E+03
8.400263E+00	8.969356E+03	6.782147E+03	1.341046E+04	7.383984E+03
8.600921E+00	9.026595E+03	6.765638E+03	1.323944E+04	7.288037E+03
8.800923E+00	9.113672E+03	6.758857E+03	1.310265E+04	7.211740E+03
9.000819E+00	9.221286E+03	6.757776E+03	1.296445E+04	7.134939E+03
9.200841E+00	9.351532E+03	6.768901E+03	1.281140E+04	7.049831E+03
9.400370E+00	9.500649E+03	6.789450E+03	1.265876E+04	6.964813E+03
9.600385E+00	9.634203E+03	6.798282E+03	1.250945E+04	6.881762E+03
9.800733E+00	9.739468E+03	6.793960E+03	1.236770E+04	6.802965E+03

TABLE 6.2D-6
DEPS BREAK MASS AND ENERGY RELEASES DURING BLOWDOWN

Time(s)	Break Path No. 1 Flow(1)		Break Path No. 2 Flow(2)	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
1.000034E+01	9.783865E+03	6.757637E+03	1.222972E+04	6.726037E+03
1.020022E+01	9.729238E+03	6.667920E+03	1.209631E+04	6.651525E+03
1.040008E+01	9.615334E+03	6.555336E+03	1.197774E+04	6.585208E+03
1.060056E+01	9.482281E+03	6.442565E+03	1.186170E+04	6.520128E+03
1.080006E+01	9.329076E+03	6.326956E+03	1.174497E+04	6.454605E+03
1.100096E+01	9.172094E+03	6.217775E+03	1.163586E+04	6.393530E+03
1.100218E+01	9.171177E+03	6.217152E+03	1.163521E+04	6.393166E+03
1.100341E+01	9.170260E+03	6.216529E+03	1.163456E+04	6.392801E+03
1.100463E+01	9.169345E+03	6.215914E+03	1.163390E+04	6.392436E+03
1.100585E+01	9.168431E+03	6.215294E+03	1.163325E+04	6.392070E+03
1.100707E+01	9.167519E+03	6.214681E+03	1.163259E+04	6.391700E+03
1.120110E+01	9.023630E+03	6.118759E+03	1.152602E+04	6.332097E+03
1.140019E+01	8.865687E+03	6.015470E+03	1.141487E+04	6.269979E+03
1.160050E+01	8.702383E+03	5.911213E+03	1.131075E+04	6.211891E+03
1.180084E+01	8.541833E+03	5.811101E+03	1.120434E+04	6.152488E+03
1.200019E+01	8.375662E+03	5.709694E+03	1.109930E+04	6.093814E+03
1.220043E+01	8.209419E+03	5.611355E+03	1.099869E+04	6.037670E+03
1.240006E+01	8.046150E+03	5.517244E+03	1.089649E+04	5.980579E+03
1.260108E+01	7.881466E+03	5.424035E+03	1.079598E+04	5.924426E+03
1.280039E+01	7.718821E+03	5.333581E+03	1.069874E+04	5.870198E+03
1.300054E+01	7.562658E+03	5.249283E+03	1.060003E+04	5.815084E+03
1.320034E+01	7.416179E+03	5.171624E+03	1.049863E+04	5.758525E+03
1.340101E+01	7.271644E+03	5.093622E+03	1.040210E+04	5.704791E+03
1.360006E+01	7.134836E+03	5.018972E+03	1.030282E+04	5.649594E+03
1.380005E+01	7.002797E+03	4.946589E+03	1.020627E+04	5.595929E+03
1.400101E+01	6.874522E+03	4.876558E+03	1.010893E+04	5.541868E+03
1.420035E+01	6.750774E+03	4.809434E+03	1.001363E+04	5.489012E+03
1.440070E+01	6.629884E+03	4.744007E+03	9.917720E+03	5.435941E+03
1.460076E+01	6.512911E+03	4.680452E+03	9.823523E+03	5.383951E+03
1.480022E+01	6.400260E+03	4.618759E+03	9.729319E+03	5.332120E+03
1.500103E+01	6.291234E+03	4.558519E+03	9.636747E+03	5.281414E+03
1.520031E+01	6.184864E+03	4.498873E+03	9.539283E+03	5.228168E+03
1.540081E+01	6.077813E+03	4.438157E+03	9.432446E+03	5.170221E+03
1.560049E+01	5.960578E+03	4.368594E+03	9.311637E+03	5.104554E+03
1.580117E+01	5.836925E+03	4.293759E+03	9.218488E+03	5.044265E+03
1.600086E+01	5.709824E+03	4.214848E+03	9.122408E+03	4.965471E+03

TABLE 6.2D-6
DEPS BREAK MASS AND ENERGY RELEASES DURING BLOWDOWN

Time(s)	Break Path No. 1 Flow(1)		Break Path No. 2 Flow(2)	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
1.620058E+01	5.587617E+03	4.135735E+03	9.106010E+03	4.913600E+03
1.640125E+01	5.477640E+03	4.059340E+03	9.079253E+03	4.843633E+03
1.660063E+01	5.381762E+03	3.989510E+03	9.116459E+03	4.803105E+03
1.680111E+01	5.293340E+03	3.924600E+03	9.141485E+03	4.758903E+03
1.700146E+01	5.207144E+03	3.863129E+03	9.158340E+03	4.718763E+03
1.720114E+01	5.123663E+03	3.806274E+03	9.161252E+03	4.682141E+03
1.740038E+01	5.039230E+03	3.752181E+03	9.055504E+03	4.598112E+03
1.760033E+01	4.953065E+03	3.700900E+03	8.982615E+03	4.533026E+03
1.780120E+01	4.872939E+03	3.657670E+03	8.943335E+03	4.490926E+03
1.800104E+01	4.797113E+03	3.620798E+03	8.652300E+03	4.325661E+03
1.820150E+01	4.744428E+03	3.599257E+03	8.610273E+03	4.285440E+03
1.840098E+01	4.713919E+03	3.606751E+03	8.374818E+03	4.156671E+03
1.860029E+01	4.666316E+03	3.645949E+03	8.229559E+03	4.070613E+03
1.880018E+01	4.548645E+03	3.688666E+03	8.093555E+03	3.991217E+03
1.900086E+01	4.366806E+03	3.713797E+03	8.179343E+03	4.024514E+03
1.920041E+01	4.157564E+03	3.733778E+03	7.416306E+03	3.620298E+03
1.940109E+01	3.853495E+03	3.678385E+03	8.063020E+03	3.883554E+03
1.960014E+01	3.533753E+03	3.593126E+03	6.570183E+03	3.134617E+03
1.980101E+01	3.228186E+03	3.477395E+03	7.339075E+03	3.403570E+03
2.000052E+01	2.887077E+03	3.288436E+03	1.209313E+04	5.647652E+03
2.020091E+01	2.609423E+03	3.121453E+03	6.727976E+03	3.180710E+03
2.040094E+01	2.439007E+03	2.977250E+03	3.790347E+03	1.784955E+03
2.060005E+01	2.221885E+03	2.733147E+03	8.895489E+03	3.725262E+03
2.080075E+01	1.978307E+03	2.447160E+03	7.998499E+03	3.369649E+03
2.100027E+01	1.818310E+03	2.257756E+03	5.286446E+03	2.246938E+03
2.120034E+01	1.709551E+03	2.127575E+03	3.776545E+03	1.613664E+03
2.140036E+01	1.586928E+03	1.978608E+03	2.943544E+03	1.207452E+03
2.160000E+01	1.456885E+03	1.819756E+03	5.023900E+03	1.858291E+03
2.180062E+01	1.330542E+03	1.665168E+03	6.286374E+03	2.276864E+03
2.200064E+01	1.219142E+03	1.528474E+03	5.131978E+03	1.845515E+03
2.220020E+01	1.115549E+03	1.400790E+03	4.406142E+03	1.571743E+03
2.240054E+01	1.028179E+03	1.292863E+03	4.212132E+03	1.480872E+03
2.260055E+01	9.252404E+02	1.165147E+03	4.033567E+03	1.385548E+03
2.280061E+01	8.358047E+02	1.054029E+03	3.696047E+03	1.237628E+03
2.300001E+01	7.627867E+02	9.629636E+02	3.266675E+03	1.063116E+03
2.320024E+01	7.007720E+02	8.852832E+02	2.819002E+03	8.892898E+02

TABLE 6.2D-6
DEPS BREAK MASS AND ENERGY RELEASES DURING BLOWDOWN

Time(s)	Break Path No. 1 Flow[1]		Break Path No. 2 Flow[2]	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
2.340068E+01	6.692970E+02	8.463311E+02	2.448506E+03	7.485734E+02
2.360008E+01	6.403119E+02	8.101765E+02	2.067099E+03	6.134657E+02
2.380041E+01	5.949544E+02	7.531772E+02	1.637313E+03	4.733364E+02
2.400079E+01	5.463386E+02	6.920027E+02	1.149306E+03	3.254831E+02
2.420033E+01	4.963731E+02	6.290783E+02	6.261196E+02	1.749727E+02
2.440036E+01	4.442113E+02	5.632914E+02	1.863815E+02	5.183787E+01
2.460038E+01	3.890625E+02	4.936335E+02	0.000000E+00	0.000000E+00
2.480069E+01	3.305772E+02	4.196723E+02	0.000000E+00	0.000000E+00
2.500051E+01	2.760499E+02	3.506891E+02	1.366954E+02	3.836163E+01
2.520014E+01	2.116667E+02	2.691038E+02	1.698429E+02	4.740880E+01
2.540063E+01	1.775000E+02	2.258605E+02	1.075425E+02	2.978558E+01
2.560069E+01	1.241001E+02	1.580873E+02	4.893733E+01	1.346882E+01
2.580059E+01	9.152902E+01	1.167691E+02	2.915437E+01	7.982361E+00
2.600015E+01	4.796144E+01	6.133642E+01	0.000000E+00	0.000000E+00
2.620025E+01	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00

Notes:

1. Mass and energy exiting from the steam-generator side of the break (path 1).
2. Mass and energy exiting from the pump-side of the break (path 2).

TABLE 6.2D-7

DEPS BREAK
MASS AND ENERGY RELEASES DURING REFLOOD
MINIMUM SAFEGUARDS (SSPS FAILURE)

Time(s)	Break Path No. 1 Flow(1)		Break Path No. 2 Flow(2)	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
2.620025E+01	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
2.670025E+01	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
2.690025E+01	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
2.700025E+01	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
2.710025E+01	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
2.715025E+01	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
2.722525E+01	2.165524E+01	2.550970E+01	0.000000E+00	0.000000E+00
2.733775E+01	5.814556E+01	6.851338E+01	0.000000E+00	0.000000E+00
2.743775E+01	3.050782E+01	3.594081E+01	0.000000E+00	0.000000E+00
2.756275E+01	3.119871E+01	3.675424E+01	0.000000E+00	0.000000E+00
2.766275E+01	3.767301E+01	4.438228E+01	0.000000E+00	0.000000E+00
2.776275E+01	4.459477E+01	5.253904E+01	0.000000E+00	0.000000E+00
2.786275E+01	4.965626E+01	5.850383E+01	0.000000E+00	0.000000E+00
2.796275E+01	5.440227E+01	6.409731E+01	0.000000E+00	0.000000E+00
2.806275E+01	5.886939E+01	6.936254E+01	0.000000E+00	0.000000E+00
2.816275E+01	6.310501E+01	7.435530E+01	0.000000E+00	0.000000E+00
2.826275E+01	6.714333E+01	7.911587E+01	0.000000E+00	0.000000E+00
2.836275E+01	7.101016E+01	8.367465E+01	0.000000E+00	0.000000E+00
2.838775E+01	7.195254E+01	8.478573E+01	0.000000E+00	0.000000E+00
2.846275E+01	7.472578E+01	8.805553E+01	0.000000E+00	0.000000E+00
2.856275E+01	7.830655E+01	9.227776E+01	0.000000E+00	0.000000E+00
2.866275E+01	8.176593E+01	9.635718E+01	0.000000E+00	0.000000E+00
2.876275E+01	8.511521E+01	1.003071E+02	0.000000E+00	0.000000E+00
2.886275E+01	8.836394E+01	1.041387E+02	0.000000E+00	0.000000E+00
2.896275E+01	9.152037E+01	1.078618E+02	0.000000E+00	0.000000E+00
2.906275E+01	9.459160E+01	1.114846E+02	0.000000E+00	0.000000E+00
2.916275E+01	9.758387E+01	1.150146E+02	0.000000E+00	0.000000E+00
2.926275E+01	1.005027E+02	1.184582E+02	0.000000E+00	0.000000E+00
3.026275E+01	1.265132E+02	1.491583E+02	0.000000E+00	0.000000E+00
3.126275E+01	1.484303E+02	1.750465E+02	0.000000E+00	0.000000E+00
3.226275E+01	4.795427E+02	5.687037E+02	4.801765E+03	6.722576E+02
3.256275E+01	5.011402E+02	5.947591E+02	4.970418E+03	7.211898E+02
3.326275E+01	5.041333E+02	5.983989E+02	4.989726E+03	7.327193E+02
3.426275E+01	4.966638E+02	5.894510E+02	4.923798E+03	7.262894E+02

TABLE 6.2D-7

Time(s)	Break Path No. 1 Flow[1]		Break Path No. 2 Flow[2]	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
3.526275E+01	4.880143E+02	5.790889E+02	4.845609E+03	7.175836E+02
3.626275E+01	4.791370E+02	5.684565E+02	4.764119E+03	7.081898E+02
3.666275E+01	4.755969E+02	5.642175E+02	4.731347E+03	7.043605E+02
3.726275E+01	4.703337E+02	5.579160E+02	4.682363E+03	6.985993E+02
3.826275E+01	4.617388E+02	5.476282E+02	4.601740E+03	6.890457E+02
3.926275E+01	4.534123E+02	5.376647E+02	4.522925E+03	6.796472E+02
4.026275E+01	4.453781E+02	5.280540E+02	4.446239E+03	6.704639E+02
4.126275E+01	4.376392E+02	5.187993E+02	4.371815E+03	6.615220E+02
4.206275E+01	4.316596E+02	5.116503E+02	4.313924E+03	6.545524E+02
4.226275E+01	4.301935E+02	5.098977E+02	4.299680E+03	6.528358E+02
4.326275E+01	4.230315E+02	5.013378E+02	4.229806E+03	6.444074E+02
4.426275E+01	4.161413E+02	4.931050E+02	4.162131E+03	6.362330E+02
4.526275E+01	4.095097E+02	4.851833E+02	4.096579E+03	6.283057E+02
4.626275E+01	4.031233E+02	4.775566E+02	4.033063E+03	6.206165E+02
4.726275E+01	4.308891E+02	5.107277E+02	4.331879E+03	6.374699E+02
4.821275E+01	3.503389E+02	4.146454E+02	3.458540E+03	5.452824E+02
4.831275E+01	3.482873E+02	4.121656E+02	3.466671E+03	5.396508E+02
4.931275E+01	4.173104E+02	4.943417E+02	3.175222E+02	2.256082E+02
5.031275E+01	4.451279E+02	5.277542E+02	3.295084E+02	2.428155E+02
5.131275E+01	4.331521E+02	5.134402E+02	3.241187E+02	2.356100E+02
5.231275E+01	4.202809E+02	4.980568E+02	3.183594E+02	2.278838E+02
5.331275E+01	4.076300E+02	4.829435E+02	3.127126E+02	2.203218E+02
5.431275E+01	3.964120E+02	4.695485E+02	3.077136E+02	2.136435E+02
5.481275E+01	3.910326E+02	4.631274E+02	3.053198E+02	2.104518E+02
5.531275E+01	3.857790E+02	4.568579E+02	3.029845E+02	2.073416E+02
5.631275E+01	3.756297E+02	4.447497E+02	2.984807E+02	2.013526E+02
5.731275E+01	3.659328E+02	4.331859E+02	2.941875E+02	1.956553E+02
5.831275E+01	3.566617E+02	4.221344E+02	2.900927E+02	1.902321E+02
5.931275E+01	3.477929E+02	4.115664E+02	2.861852E+02	1.850667E+02
6.031275E+01	3.393043E+02	4.014551E+02	2.824547E+02	1.801444E+02
6.131275E+01	3.311674E+02	3.917663E+02	2.788886E+02	1.754475E+02
6.231275E+01	3.233722E+02	3.824873E+02	2.754814E+02	1.709675E+02
6.331275E+01	3.159035E+02	3.735999E+02	2.722258E+02	1.666939E+02
6.431275E+01	3.087464E+02	3.650860E+02	2.691146E+02	1.626164E+02
6.531275E+01	3.018869E+02	3.569286E+02	2.661411E+02	1.587256E+02
6.631275E+01	2.953122E+02	3.491120E+02	2.632979E+02	1.550124E+02
6.731275E+01	2.890055E+02	3.416163E+02	2.605531E+02	1.514666E+02

TABLE 6.2D-7

Time(s)	Break Path No. 1 Flow[1]		Break Path No. 2 Flow[2]	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
6.831275E+01	2.829973E+02	3.344771E+02	2.579486E+02	1.481060E+02
6.931275E+01	2.772468E+02	3.276458E+02	2.554630E+02	1.449030E+02
7.031275E+01	2.717317E+02	3.210958E+02	2.530862E+02	1.418439E+02
7.111275E+01	2.674830E+02	3.160510E+02	2.512601E+02	1.394959E+02
7.131275E+01	2.664430E+02	3.148161E+02	2.508138E+02	1.389223E+02
7.231275E+01	2.613721E+02	3.087964E+02	2.486414E+02	1.361323E+02
7.331275E+01	2.565109E+02	3.030269E+02	2.465651E+02	1.334685E+02
7.431275E+01	2.518518E+02	2.974984E+02	2.445810E+02	1.309256E+02
7.531275E+01	2.473875E+02	2.922019E+02	2.426855E+02	1.284985E+02
7.631275E+01	2.431109E+02	2.871292E+02	2.408751E+02	1.261825E+02
7.731275E+01	2.390144E+02	2.822709E+02	2.391461E+02	1.239726E+02
7.831275E+01	2.350922E+02	2.776201E+02	2.374954E+02	1.218646E+02
7.931275E+01	2.313383E+02	2.731696E+02	2.359201E+02	1.198544E+02
8.031275E+01	2.277460E+02	2.689114E+02	2.344171E+02	1.179380E+02
8.131275E+01	2.243029E+02	2.648306E+02	2.329809E+02	1.161082E+02
8.231275E+01	2.210094E+02	2.609276E+02	2.316109E+02	1.143641E+02
8.331275E+01	2.178609E+02	2.571970E+02	2.303049E+02	1.127024E+02
8.431275E+01	2.148522E+02	2.536325E+02	2.290602E+02	1.111198E+02
8.531275E+01	2.119783E+02	2.502280E+02	2.278744E+02	1.096130E+02
8.631275E+01	2.092343E+02	2.469779E+02	2.267450E+02	1.081788E+02
8.731275E+01	2.066155E+02	2.438763E+02	2.256699E+02	1.068142E+02
8.931275E+01	2.017352E+02	2.380974E+02	2.236733E+02	1.042822E+02
9.131275E+01	1.973026E+02	2.328495E+02	2.218678E+02	1.019948E+02
9.271275E+01	1.944485E+02	2.294709E+02	2.207093E+02	1.005281E+02
9.331275E+01	1.932848E+02	2.280935E+02	2.202378E+02	9.993153E+01
9.531275E+01	1.896509E+02	2.237926E+02	2.187688E+02	9.807358E+01
9.731275E+01	1.863718E+02	2.199121E+02	2.174474E+02	9.640343E+01
9.931275E+01	1.834203E+02	2.164198E+02	2.162609E+02	9.490492E+01
1.013128E+02	1.807619E+02	2.132745E+02	2.151950E+02	9.355949E+01
1.033128E+02	1.783711E+02	2.104462E+02	2.142383E+02	9.235254E+01
1.053128E+02	1.762355E+02	2.079200E+02	2.133846E+02	9.127593E+01
1.073128E+02	1.743340E+02	2.056709E+02	2.126246E+02	9.031799E+01
1.093128E+02	1.726478E+02	2.036766E+02	2.119502E+02	8.946830E+01
1.113128E+02	1.711585E+02	2.019152E+02	2.113538E+02	8.871700E+01
1.133128E+02	1.698493E+02	2.003670E+02	2.108281E+02	8.805514E+01
1.153128E+02	1.687048E+02	1.990136E+02	2.103669E+02	8.747454E+01
1.173128E+02	1.677105E+02	1.978379E+02	2.099643E+02	8.696770E+01

TABLE 6.2D-7

Time(s)	Break Path No. 1 Flow[1]		Break Path No. 2 Flow[2]	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
1.188128E+02	1.670554E+02	1.970633E+02	2.096974E+02	8.663185E+01
1.193128E+02	1.668533E+02	1.968242E+02	2.096147E+02	8.652780E+01
1.213128E+02	1.661208E+02	1.959581E+02	2.093133E+02	8.614860E+01
1.233128E+02	1.655019E+02	1.952263E+02	2.090556E+02	8.582439E+01
1.253128E+02	1.649861E+02	1.946164E+02	2.088375E+02	8.555000E+01
1.273128E+02	1.645632E+02	1.941164E+02	2.086546E+02	8.532002E+01
1.293128E+02	1.641954E+02	1.936815E+02	2.084907E+02	8.511387E+01
1.313128E+02	1.639049E+02	1.933381E+02	2.083562E+02	8.494477E+01
1.333128E+02	1.636866E+02	1.930800E+02	2.082492E+02	8.481017E+01
1.353128E+02	1.635336E+02	1.928991E+02	2.081670E+02	8.470675E+01
1.373128E+02	1.634397E+02	1.927880E+02	2.081072E+02	8.463147E+01
1.393128E+02	1.633990E+02	1.927400E+02	2.080675E+02	8.458158E+01
1.413128E+02	1.634064E+02	1.927487E+02	2.080461E+02	8.455458E+01
1.433128E+02	1.634571E+02	1.928086E+02	2.080410E+02	8.454818E+01
1.453128E+02	1.635466E+02	1.929144E+02	2.080507E+02	8.456030E+01
1.473128E+02	1.636711E+02	1.930616E+02	2.080737E+02	8.458908E+01
1.474128E+02	1.636782E+02	1.930700E+02	2.080751E+02	8.459092E+01
1.493128E+02	1.638268E+02	1.932457E+02	2.081085E+02	8.463279E+01
1.513128E+02	1.640012E+02	1.934519E+02	2.081509E+02	8.468611E+01
1.533128E+02	1.641896E+02	1.936746E+02	2.081992E+02	8.474668E+01
1.553128E+02	1.644007E+02	1.939242E+02	2.082561E+02	8.481826E+01
1.573128E+02	1.646323E+02	1.941980E+02	2.083210E+02	8.489975E+01
1.593128E+02	1.648821E+02	1.944933E+02	2.083929E+02	8.499012E+01
1.613128E+02	1.651481E+02	1.948079E+02	2.084712E+02	8.508846E+01
1.633128E+02	1.654286E+02	1.951395E+02	2.085551E+02	8.519393E+01
1.653128E+02	1.657219E+02	1.954863E+02	2.086441E+02	8.530578E+01
1.673128E+02	1.660266E+02	1.958466E+02	2.087376E+02	8.542333E+01
1.693128E+02	1.663414E+02	1.962188E+02	2.088352E+02	8.554599E+01
1.713128E+02	1.666651E+02	1.966016E+02	2.089364E+02	8.567321E+01
1.733128E+02	1.669967E+02	1.969937E+02	2.090408E+02	8.580449E+01
1.753128E+02	1.673353E+02	1.973939E+02	2.091482E+02	8.593943E+01
1.773128E+02	1.676799E+02	1.978015E+02	2.092581E+02	8.607762E+01
1.793128E+02	1.680299E+02	1.982154E+02	2.093703E+02	8.621875E+01
1.813128E+02	1.683847E+02	1.986349E+02	2.094846E+02	8.636252E+01
1.833128E+02	1.687437E+02	1.990594E+02	2.096009E+02	8.650867E+01
1.853128E+02	1.691065E+02	1.994884E+02	2.097188E+02	8.665699E+01
1.873128E+02	1.694727E+02	1.999214E+02	2.098383E+02	8.680729E+01

TABLE 6.2D-7

Time(s)	Break Path No. 1 Flow[1]		Break Path No. 2 Flow[2]	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
1.893128E+02	1.698418E+02	2.003579E+02	2.099593E+02	8.695944E+01
1.913128E+02	1.702138E+02	2.007978E+02	2.100816E+02	8.711329E+01
1.933128E+02	1.705884E+02	2.012408E+02	2.102051E+02	8.726877E+01
1.953128E+02	1.710176E+02	2.017482E+02	2.103509E+02	8.745078E+01
1.973128E+02	1.722048E+02	2.031523E+02	2.111980E+02	8.805146E+01
1.993128E+02	1.732382E+02	2.043744E+02	2.126468E+02	8.865913E+01
2.013128E+02	1.743215E+02	2.056557E+02	2.146654E+02	8.935882E+01
2.033128E+02	1.754164E+02	2.069508E+02	2.171236E+02	9.011824E+01
2.053128E+02	1.764819E+02	2.082110E+02	2.198982E+02	9.090494E+01
2.073128E+02	1.774732E+02	2.093836E+02	2.228862E+02	9.168800E+01
2.085128E+02	1.780188E+02	2.100290E+02	2.247492E+02	9.214683E+01

Notes:

1. Mass and energy exiting from the steam-generator side of the break (path 1).
2. Mass and energy exiting from the pump-side of the break (path 2).

TABLE 6.2D-8

DEPS SSPS CASE
PRINCIPAL PARAMETERS DURING REFLOOD

Time(s)	Flooding		Carryover Fraction	Core Height (ft)	Downcomer Height (ft)	Flow Fraction	Total	Injection Accumulator	Spill	Enthalpy (Btu/lbm)
	Temp (°F)	Rate (in/s)					(lbm/s)			
26.2	184.8	0	0	0	0	0.25	0	0	0	0
26.9	182.6	21.428	0	0.54	1.64	0	8131.3	8131.3	0	89.74
27.2	180.8	25.482	0	1.03	1.58	0	8052.1	8052.1	0	89.74
28.4	180	2.629	0.302	1.5	5.16	0.334	7723.7	7723.7	0	89.74
29.3	180.1	2.543	0.414	1.62	8.05	0.352	7527.7	7527.7	0	89.74
32.6	180.5	4.899	0.627	2.01	16.12	0.602	6240.1	6240.1	0	89.74
34.3	180.8	4.513	0.675	2.24	16.12	0.6	5961.3	5961.3	0	89.74
36.7	181.4	4.18	0.704	2.5	16.12	0.596	5663	5663	0	89.74
42.1	183.7	3.75	0.727	3	16.12	0.584	5122.1	5122.1	0	89.74
46.3	185.9	3.525	0.733	3.35	16.12	0.575	4780.8	4780.8	0	89.74
47.3	186.5	3.681	0.735	3.43	16.12	0.588	5121.9	4595.2	0	86.48
48.2	187	3.188	0.734	3.5	16.12	0.544	4122.2	3575.3	0	85.54
48.3	187.1	3.183	0.734	3.51	16.12	0.55	4124.3	3576.9	0	85.53
49.3	187.7	3.606	0.737	3.58	16.02	0.593	532.7	0	0	58.05
50.3	188.3	3.725	0.738	3.66	15.74	0.597	522.1	0	0	58.05
54.8	191.8	3.313	0.738	4.01	14.63	0.589	534.9	0	0	58.05
62.3	198.8	2.81	0.738	4.5	13.32	0.575	549.4	0	0	58.05
71.1	207.9	2.401	0.736	5	12.39	0.558	559.5	0	0	58.05
81.3	218.5	2.086	0.735	5.51	11.86	0.54	565.8	0	0	58.05
92.7	228.3	1.87	0.735	6	11.7	0.523	569.7	0	0	58.05
105.3	237.1	1.735	0.736	6.5	11.85	0.51	571.9	0	0	58.05
118.8	245.1	1.663	0.739	7	12.22	0.502	572.9	0	0	58.05
133.3	252.4	1.629	0.743	7.52	12.72	0.5	573.3	0	0	58.05
147.4	258.5	1.618	0.747	8	13.26	0.5	573.4	0	0	58.05
157.3	262.4	1.617	0.751	8.34	13.65	0.501	573.3	0	0	58.05

TABLE 6.2D-8

Time(s)	Flooding		Carryover Fraction	Core Height (ft)	Downcomer Height (ft)	Flow Fraction	Total	Injection Accumulator	Spill	Enthalpy (Btu/lbm)
	Temp (°F)	Rate (in/s)					(lbm/s)			
163.3	264.6	1.618	0.753	8.54	13.88	0.502	573.2	0	0	58.05
177.3	269.2	1.621	0.758	9	14.43	0.504	573	0	0	58.05
193.3	273.9	1.628	0.764	9.52	15.05	0.507	572.8	0	0	58.05
208.5	277.7	1.656	0.77	10	15.57	0.516	571.9	0	0	58.05

TABLE 6.2D-9

DEPS BREAK
MASS AND ENERGY RELEASES DURING POST-REFLOOD
SSPS FAILURE

Time(s)	Break Path No. 1 Flow(1)		Break Path No. 2 Flow(2)	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
2.086000E+02	2.099452E+02	2.622469E+02	3.708333E+02	1.285948E+02
2.136000E+02	2.091126E+02	2.612068E+02	3.716659E+02	1.286068E+02
2.186000E+02	2.091996E+02	2.613155E+02	3.715789E+02	1.283755E+02
2.236000E+02	2.083520E+02	2.602567E+02	3.724265E+02	1.283907E+02
2.286000E+02	2.084145E+02	2.603348E+02	3.723640E+02	1.281651E+02
2.336000E+02	2.075510E+02	2.592562E+02	3.732275E+02	1.281837E+02
2.386000E+02	2.075883E+02	2.593028E+02	3.731902E+02	1.279640E+02
2.436000E+02	2.067086E+02	2.582039E+02	3.740699E+02	1.279861E+02
2.486000E+02	2.067197E+02	2.582178E+02	3.740588E+02	1.277725E+02
2.536000E+02	2.058232E+02	2.570980E+02	3.749553E+02	1.277982E+02
2.586000E+02	2.058074E+02	2.570782E+02	3.749711E+02	1.275909E+02
2.636000E+02	2.048932E+02	2.559363E+02	3.758853E+02	1.276204E+02
2.686000E+02	2.048499E+02	2.558822E+02	3.759286E+02	1.274196E+02
2.736000E+02	2.039173E+02	2.547173E+02	3.768611E+02	1.274532E+02
2.786000E+02	2.038453E+02	2.546274E+02	3.769331E+02	1.272592E+02
2.836000E+02	2.028939E+02	2.534389E+02	3.778846E+02	1.272969E+02
2.886000E+02	2.027921E+02	2.533118E+02	3.779864E+02	1.271099E+02
2.936000E+02	2.026699E+02	2.531591E+02	3.781086E+02	1.269278E+02
2.986000E+02	2.016834E+02	2.519269E+02	3.790951E+02	1.269737E+02
3.036000E+02	2.015299E+02	2.517351E+02	3.792486E+02	1.267991E+02
3.086000E+02	2.013545E+02	2.515160E+02	3.794240E+02	1.266298E+02
3.136000E+02	2.003307E+02	2.502372E+02	3.804477E+02	1.266842E+02
3.186000E+02	2.001219E+02	2.499763E+02	3.806566E+02	1.265230E+02
3.236000E+02	1.998907E+02	2.496875E+02	3.808878E+02	1.263673E+02
3.286000E+02	1.988290E+02	2.483614E+02	3.819494E+02	1.264304E+02
3.336000E+02	1.985659E+02	2.480328E+02	3.822125E+02	1.262822E+02
3.386000E+02	1.982758E+02	2.476703E+02	3.825027E+02	1.261408E+02
3.436000E+02	1.971681E+02	2.462867E+02	3.836104E+02	1.262148E+02
3.486000E+02	1.968385E+02	2.458751E+02	3.839399E+02	1.260829E+02
3.536000E+02	1.964831E+02	2.454311E+02	3.842954E+02	1.259575E+02
3.586000E+02	1.961017E+02	2.449547E+02	3.846768E+02	1.258384E+02
3.636000E+02	1.956925E+02	2.444435E+02	3.850860E+02	1.257263E+02
3.686000E+02	1.952563E+02	2.438986E+02	3.855222E+02	1.256208E+02
3.736000E+02	1.947907E+02	2.433170E+02	3.859878E+02	1.255227E+02
3.786000E+02	1.942961E+02	2.426993E+02	3.864823E+02	1.254318E+02
3.836000E+02	1.937716E+02	2.420441E+02	3.870069E+02	1.253483E+02

TABLE 6.2D-9

Time(s)	Break Path No. 1 Flow[1]		Break Path No. 2 Flow[2]	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
3.886000E+02	1.932153E+02	2.413492E+02	3.875632E+02	1.252729E+02
3.936000E+02	1.926279E+02	2.406155E+02	3.881506E+02	1.252052E+02
3.986000E+02	1.920068E+02	2.398396E+02	3.887717E+02	1.251460E+02
4.036000E+02	1.914574E+02	2.391534E+02	3.893210E+02	1.250730E+02
4.086000E+02	1.909151E+02	2.384760E+02	3.898634E+02	1.250000E+02
4.136000E+02	1.903349E+02	2.377512E+02	3.904436E+02	1.249365E+02
4.186000E+02	1.897178E+02	2.369804E+02	3.910607E+02	1.248823E+02
4.236000E+02	1.890630E+02	2.361625E+02	3.917155E+02	1.248377E+02
4.286000E+02	1.890361E+02	2.361289E+02	3.917423E+02	1.246267E+02
4.336000E+02	1.882818E+02	2.351866E+02	3.924967E+02	1.246075E+02
4.386000E+02	1.874848E+02	2.341911E+02	3.932937E+02	1.245989E+02
4.436000E+02	1.872848E+02	2.339412E+02	3.934937E+02	1.244324E+02
4.486000E+02	1.870107E+02	2.335989E+02	3.937678E+02	1.242849E+02
4.536000E+02	1.860347E+02	2.323797E+02	3.947438E+02	1.243223E+02
4.586000E+02	1.856217E+02	2.318639E+02	3.951568E+02	1.242106E+02
4.636000E+02	1.851226E+02	2.312405E+02	3.956559E+02	1.241211E+02
4.686000E+02	1.845362E+02	2.305079E+02	3.962423E+02	1.240542E+02
4.736000E+02	1.838579E+02	2.296606E+02	3.969206E+02	1.240112E+02
4.786000E+02	1.836536E+02	2.294055E+02	3.971249E+02	1.238424E+02
4.836000E+02	1.827479E+02	2.282742E+02	3.980306E+02	1.238586E+02
4.886000E+02	1.822836E+02	2.276942E+02	3.984949E+02	1.237575E+02
4.936000E+02	1.816661E+02	2.269229E+02	3.991123E+02	1.236965E+02
4.986000E+02	1.814072E+02	2.265994E+02	3.993713E+02	1.235404E+02
5.036000E+02	1.804155E+02	2.253607E+02	4.003630E+02	1.235772E+02
5.086000E+02	1.802293E+02	2.251281E+02	4.005492E+02	1.234009E+02
5.136000E+02	1.792619E+02	2.239197E+02	4.015166E+02	1.234304E+02
5.186000E+02	1.789515E+02	2.235319E+02	4.018270E+02	1.232858E+02
5.236000E+02	1.782211E+02	2.226197E+02	4.025573E+02	1.232517E+02
5.286000E+02	1.774647E+02	2.216748E+02	4.033138E+02	1.232240E+02
5.336000E+02	1.769559E+02	2.210393E+02	4.038225E+02	1.231304E+02
5.386000E+02	1.764325E+02	2.203855E+02	4.043459E+02	1.230402E+02
5.436000E+02	1.755528E+02	2.192866E+02	4.052257E+02	1.230436E+02
5.486000E+02	1.748402E+02	2.183965E+02	4.059382E+02	1.230023E+02
5.536000E+02	1.744347E+02	2.178900E+02	4.063438E+02	1.228795E+02
5.586000E+02	1.736270E+02	2.168810E+02	4.071515E+02	1.228623E+02
5.636000E+02	1.729183E+02	2.159958E+02	4.078602E+02	1.228185E+02
8.055732E+02	1.729183E+02	2.159958E+02	4.078602E+02	1.228185E+02
8.056732E+02	8.997459E+01	1.114205E+02	4.908039E+02	1.415338E+02

TABLE 6.2D-9

Time(s)	Break Path No. 1 Flow[1]		Break Path No. 2 Flow[2]	
	(lbm/s)	Thousand (Btu/s)	(lbm/s)	Thousand (Btu/s)
8.086000E+02	8.991267E+01	1.113432E+02	4.908658E+02	1.413797E+02
1.677900E+03	8.991267E+01	1.113432E+02	4.908658E+02	1.413797E+02
1.678000E+03	7.760926E+01	9.597472E+01	3.388307E+02	1.647982E+02
1.714013E+03	7.760926E+01	9.597472E+01	3.388307E+02	1.647982E+02
1.714113E+03	7.522245E+01	8.655221E+01	3.412175E+02	7.583629E+01
2.000000E+03	7.210053E+01	8.296007E+01	3.443395E+02	7.639954E+01
2.000100E+03	7.209993E+01	8.295938E+01	3.443401E+02	7.598320E+01
2.500000E+03	6.909680E+01	7.950393E+01	3.473432E+02	7.652502E+01
2.500100E+03	6.909620E+01	7.950324E+01	3.473438E+02	7.610868E+01
3.000000E+03	6.609308E+01	7.604779E+01	3.503469E+02	7.665050E+01
3.000100E+03	6.609248E+01	7.604710E+01	3.503475E+02	7.577608E+01
3.500000E+03	6.308935E+01	7.259166E+01	3.533506E+02	7.631789E+01
3.500100E+03	6.308875E+01	7.259097E+01	3.533512E+02	7.523526E+01
3.600000E+03	6.248861E+01	7.190043E+01	3.539514E+02	7.534353E+01

Notes:

1. Mass and energy exiting from the steam-generator side of the break (path 1).
2. Mass and energy exiting from the pump-side of the break (path 2).

TABLE 6.2D-10

LOCA MASS AND ENERGY RELEASE ANALYSIS CORE DECAY HEAT RATE

Time (sec)	Decay Heat Generation Rate (Btu/Btu)
10	0.053876
15	0.050401
20	0.048018
40	0.042401
60	0.039244
80	0.037065
100	0.035466
150	0.032724
200	0.030936
400	0.027078
600	0.024931
800	0.023389
1000	0.022156
1500	0.019921
2000	0.018315
4000	0.014781
6000	0.013040
8000	0.012000
10000	0.011262
15000	0.010097
20000	0.009350
40000	0.007778
60000	0.006958
80000	0.006424
100000	0.006021
150000	0.005323
200000	0.004847
400000	0.003770
600000	0.003201
800000	0.002834
1000000	0.002580

TABLE 6.2D-11

DEPS SSPS CASE – MASS BALANCE

Time(s)		**0**	**26.2**	**26.2**	**208.51**	**805.67**	**1714.01**	**3600**
Mass (thousand lbm)								
Initial	In RCS and ACC	746.11	746.11	746.11	746.11	746.11	746.11	746.11
Added Mass	Pumped Injection	0	0	0	91.98	438.75	939.84	1745.78
	Total Added	0	0	0	91.98	438.75	939.84	1745.78
***** Total Available *****		**746.11**	**746.11**	**746.11**	**838.09**	**1184.86**	**1685.95**	**2491.88**
Distribution	Reactor Coolant	527.79	58.46	81.87	143.19	143.19	143.19	143.19
	Accumulator	218.32	154.59	131.19	0	0	0	0
	Total Contents	746.11	213.05	213.05	143.19	143.19	143.19	143.19
Effluent	Break Flow	0	533.04	533.04	684.35	1031.12	1552.74	2338.14
	ECCS Spill	0	0	0	0	0	0	0
	Total Effluent	0	533.04	533.04	684.35	1031.12	1552.74	2338.14
***** Total Accountable *****		**746.11**	**746.09**	**746.09**	**827.54**	**1174.31**	**1695.93**	**2481.33**

*See Section 6.2D.3.1.4 for a description of the mass and energy balance tables. Some round-off and truncation exists.

TABLE 6.2D-12

DEPS SSPS FAILURE ENERGY BALANCE

Time(s)		0	26.2	26.2	208.51	805.67	1714.01	3600
Energy (million Btu)								
Initial Energy	In RCS, ACC, SG	909.96	909.96	909.96	909.96	909.96	909.96	909.96
Added Energy	Pumped Injection	0	0	0	5.34	25.47	61.39	181.19
	Decay Heat	0	8.48	8.48	29.84	81.75	144.93	250.98
	Heat from Secondary	0	15.88	15.88	15.88	15.88	15.88	15.88
	Total Added	0	24.36	24.36	51.06	123.1	222.2	448.05
***** Total Available *****		**909.96**	**934.32**	**934.32**	**961.02**	**1033.06**	**1132.16**	**1358.01**
Distribution	Reactor Coolant	307.96	12.69	14.8	37.63	37.63	37.63	37.63
	Accumulator	19.59	13.87	11.77	0	0	0	0
	Core Stored	21.81	10.67	10.67	4.85	4.64	4.21	3.33
	Primary Metal	155.4	147.92	147.92	123.1	85.17	63.66	49.31
	Secondary Metal	111.31	110.43	110.43	101.44	76.77	52.33	40.09
	Steam Generator	293.89	315.65	315.65	286.48	210.21	138.99	105.51
	Total Contents	909.96	611.24	611.24	553.51	414.43	296.82	235.87
Effluent	Break Flow	0	322.5	322.5	398.11	609.23	839.99	1131.76
	ECCS Spill	0	0	0	0	0	0	0
	Total Effluent	0	322.5	322.5	398.11	609.23	839.99	1131.76
***** Total Accountable *****		**909.96**	**933.73**	**933.73**	**951.62**	**1023.66**	**1136.82**	**1367.64**

*See Section 6.2D.3.1.4 for a description of the mass and energy balance tables. Some round-off and truncation exists.

TABLE 6.2D-13

DOUBLE-ENDED HOT-LEG BREAK SEQUENCE OF EVENTS

Time(s)	Event Description
0.0	Break Occurs and Loss of Offsite Power is Assumed
1.1	Compensated Pressurizer Pressure for Reactor Trip (1859.7 psia) Reached and Turbine Trip Occurs
4.0	Low-Pressurizer Pressure SI Setpoint (1694.7 psia) Reached
12.9	Broken Loop Accumulator Begins Injecting Water
13.1	Intact Loop Accumulator Begins Injecting Water
23.2	End of Blowdown Phase
23.2	Transient Modeling Terminated

TABLE 6.2D-15

DOUBLE-ENDED PUMP SUCTION BREAK
SEQUENCE OF EVENTS
(MINIMUM SAFEGUARDS)

Time(s)	Event Description
0.0	Break Occurs and Loss of Offsite Power is Assumed
0.7	Containment Hi-1 Reached
1.2	Reactor Trip Occurs on Compensated Pressurizer Pressure Setpoint of 1,859.7 psia and SG Throttle Valves Closed
4.3	Low Pressurizer Pressure SI Setpoint = 1,694.7 psia Reached (SI begins after a 27-second delay and feedwater control valve starts to close)
7.9	Containment Hi-2 Reached
13.3	Main Feedwater Control Valve Closed
15.4	Broken-Loop Accumulator Begins Injecting Water
15.6	Intact-Loop Accumulator Begins Injecting Water
26.2	End of Blowdown Phase
46.3	Pumped Safety Injection Begins
48.0	Broken-Loop Accumulator Water Injection Ends
48.6	Intact-Loop Accumulator Water Injection Ends
71.0	CFCUs On
107.0	Containment Sprays Begin Injecting
208.5	End of Reflood for Minimum Safeguards Case
568.6	Mass and Energy Release Assumption: Broken-Loop SG Equilibration to 61.7 psia
805.7	Mass and Energy Release Assumption: Broken-Loop SG Equilibration to 51.7 psia
1553.1	Mass and Energy Release Assumption: Intact-Loop SG Equilibration to 61.7 psia
1,678.2	Cold Leg Recirculation Begins
1,714.0	Mass and Energy Release Assumption: Intact-Loop SG Equilibration to 41.7 psia
3,600.0	End of Sensible Heat Release from RCS and SGs
3,798.0	Containment Sprays Terminated (no credit for recirculation spray; Injection Mode terminated)
25,200.0	Switchover to Hot Leg Recirculation
10,400.000	Transient Terminated

TABLE 6.2D-17

DIABLO CANYON CONTAINMENT LOCA INTEGRITY ANALYSIS PARAMETERS

Parameter	Value
Auxiliary Saltwater Temperature (°F)	64
RWST Water Temperature (°F)	90
Initial Containment Temperature (°F)	120
Initial Containment Pressure (psia)	16.0
Initial Relative Humidity (%)	18
Net Free Volume (ft^3)	2,550,000
Reactor Containment Fan Coolers	
Total CFCUs	5
Analysis Maximum	3
Analysis Minimum	2
Safety Injection Time (sec)	7.0
Delay Time (sec) Without Offsite Power	 64.0
CCW Flow to the CFCUs (gpm) During Injection During Recirculation	 8,000 7,450
Containment Spray Pumps	
Total CSPs	2
Analysis Maximum	2
Analysis Minimum	1
Flowrate (gpm) During Injection During Recirculation	 Table 6.2.D-18 0
Safety Injection Time (sec)	7.0
Spray Delay Time (sec) Without Offsite Power	 100.0
Containment Spray (Injection Mode) Termination Time, (sec) Minimum Safeguards Maximum Safeguards (1 CSP) Maximum Safeguards (2 CSPs)	 3,798 3,018 1,824

TABLE 6.2D-17

Parameter	Value
ECCS Recirculation	
ECCS Cold-Leg Recirculation Switchover, sec Minimum Safeguards Maximum Safeguards (1 CSP) Maximum Safeguards (2 CSPs)	 1,678 1,033 829
Containment ECCS Cold-Leg Recirculation Flow, (gpm) Minimum Safeguards (1 RHR train) Maximum Safeguards (2 RHR trains)	 3,252.3 8,082.4
ECCS Hot-Leg Recirculation Switchover, sec	25,200
Containment ECCS Hot-Leg Recirculation Flow, (gpm) Minimum Safeguards (1 RHR train) Maximum Safeguards (2 RHR trains)	 3,071.7 4,576.8
Component Cooling Water System	
Total CCW Heat Exchangers	2
Analysis Maximum	2
Analysis Minimum	1
CCW Flow Rate to RHR Heat Exchanger (gpm per available HX)	4,800
ASW Flow Rate to CCW Heat Exchanger (gpm per available HX)	10,300
CCW Misc. Heat Loads (MBTU/hr) During Injection During Recirculation	 1.0 2.0
CCW Flow Rate to Misc. Heat Loads (gpm) During Injection During Recirculation	 2,500 500

TABLE 6.2D-18

CONTAINMENT SPRAY FLOW RATES
AS A FUNCTION OF CONTAINMENT PRESSURE

Containment Pressure (psig)	**1 CSP Spray Flow Rate (gpm)**	**2 CSPs Spray Flow Rate (gpm)**
0	3036	6142
10	2926	5922
20	2806	5692
30	2686	5442
40	2546	5182
47	2456	4992

TABLE 6.2D-19

GOTHIC THERMAL CONDUCTOR MODELING

No.	Description	Materials	Surface Area (ft^2)	Thickness (in)	Initial Temp (°F)
1	Concrete Interior Walls	Paint Concrete	79965	0.0075 12	120
2	Concrete Floor	Paint Concrete	13012	0.0075 24	120
3	SS Fuel Transfer Tube	Stainless Steel	8852	0.144	120
4	SS Structures	Stainless Steel	857	0.654	120
5	CS Structures	Paint Carbon Steel	48024	0.0075 0.0815	120
6	CS Structures	Paint Carbon Steel	60941	0.0075 0.133	120
7	CS Lined Containment Concrete Shell	Paint Carbon Steel HGap = 10 Concrete	90560	0.0075 0.375 0.0168 35.6007	120
8	CS Structures	Paint Carbon Steel	42517	0.0075 0.567	120
9	CS Structures	Paint Carbon Steel	56494	0.0075 0.738	120
10	CS Structures	Paint Carbon Steel	31902	0.0075 1.355	120
11	CS SG Snubbers	Paint Carbon Steel	522	0.0075 3.0	120
12	CS RCP Motors	Paint Carbon Steel	1610	0.0075 6.99	200

TABLE 6.2D-20

MATERIAL PROPERTIES FROM THE GOTHIC MODEL (REFERENCE 15)

Material	**Thermal Conductivity (BTU/hr-ft-°F)**	**Vol. Heat Capacity (BTU/ft^3-°F)**
Paint	0.2083	35.91
Carbon Steel	28	58.8
Air Gap	0.0148	0.018
Concrete	1.04	23.4
Stainless Steel	8.6	58.8

TABLE 6.2D-21

SUMMARY OF LOCA PEAK CONTAINMENT PRESSURE AND TEMPERATURES

Break Location	**Peak Pressure (psig)**	**Time (sec)**	**Peak Air Temp (°F)**	**Time (sec)**	**Press @ 24 hours (psig)**	**Temp @ 24 hours (°F)**
DEHL	41.4	22.5	261.8	22.4	-	-
DEPS min SI	39.8	23.5	259.3	23.5	8.5	165.0
Acceptance Criteria	<47 (Containment Design Pressure)	-	<271 (Containment Design Temperature)	-	<50% of peak pressure	-

TABLE 6.2D-22
INITIAL CONTAINMENT CONDITIONS, FAN COOLER AND CONTAINMENT SPRAY PUMP ASSUMPTIONS

Parameter	**Value**		
Containment net free volume (ft^3)	2,550,000		
Initial containment temperature (°F)	120.0		
Initial containment pressure (psia)	16.0		
Initial relative humidity (%)	18		
Number of fan coolers - All - Analysis maximum - Containment safeguards failure	 5 3 2		
High containment pressure setpoint (psig)	5.0		
Fan Cooler Actuation LOCA – without offsite power MSLB – with offsite power	LOCA – 7.0 sec + 64 sec delay MSLB – 5.0 psig + 44 sec delay		
Containment fan cooler heat removal (MBTU/hr) vs. Component Cooling Water (CCW) Flow rate (gpm) assuming T_{sat} = 271°F and T_{CCW} = 125°F(1)	Flow	Heat Removal	
	1000	59.12	
	1500	73.18	
	2000	82.47	
	2500	89.03	
	3000	93.93	
	3250	95.90	
	3500	97.73	
Containment fan cooler air flowrate (ft^3/min per fan cooler)	34,000(2)		
Number of spray pumps - All - Containment safeguards failure	 2 1		
High-high containment pressure setpoint (psig)	24.7		
Containment Spray Actuation LOCA – without offsite power MSLB – with offsite power	LOCA – 7.0 sec + 100 sec delay MSLB – 24.7 psig + 76 sec delay		
Containment spray flowrate (gpm) vs. containment pressure (psig)	Press	Flow 1 Pump	Flow 2 Pumps
	0	3036	6142
	10	2926	5922
	20	2806	5692
	30	2686	5442
	40	2546	5182
	47	2456	4992
RWST/containment spray water temperature (°F)	90.0		

Notes:
1. To conservatively model CFCU heat rate at 34,000 cfm, the heat rate data from 47,000 cfm was multiplied by 0.9600.
2. For CFCUs with SRC cooling coils the required flow to provide an equivalent heat rate is 37,000 cfm.

TABLE 6.2D-23
PEAK PRESSURES AND TEMPERATURES FOR
CONTAINMENT RESPONSE TO MAIN STEAMLINE BREAKS

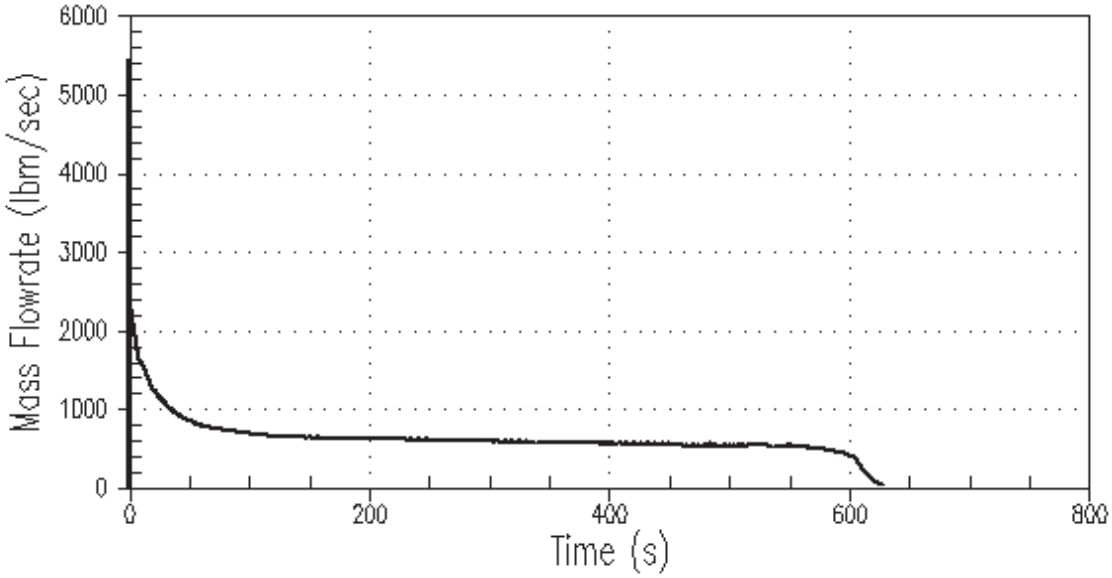
Case	Description			Peak Pressure (psig @ sec)	Peak Temperature (°F @ sec)
	Break	Initial Power	Failure		
1a	1.4 ft^2 DER	102%	containment safeguards	29.55 @ 229.2	282.3 @ 223.5
2a	1.4 ft^2 DER	70%	containment safeguards	30.04 @ 613.7	282.0 @ 235.3
3a	1.4 ft^2 DER	30%	containment safeguards	32.21 @ 612.6	278.9 @ 248.0
4a	1.4 ft^2 DER	0%	containment safeguards	32.60 @ 368.5	278.0 @ 256.7
1b	1.4 ft^2 DER	102%	FRV	37.01 @ 464.1	281.3 @ 222.9
2b*	1.4 ft^2 DER	70%	FRV	42.41 @ 607.1	281.2 @ 237.1
3b	1.4 ft^2 DER	30%	FRV	39.99 @ 692.8	277.4 @ 263
4b	1.4 ft^2 DER	0%	FRV	31.63 @ 413.4	276.0 @ 261.9
1c	1.4 ft^2 DER	102%	MSIV/CV	31.29 @ 251.5	310.2 @ 26.5
2c	1.4 ft^2 DER	70%	MSIV/CV	32.68 @ 294.7	310.7 @ 25.8
3c	1.4 ft^2 DER	30%	MSIV/CV	33.17 @ 347.6	311.4 @ 24.9
4c	1.4 ft^2 DER	0%	MSIV/CV	34.22 @ 417.3	312.4 @ 24.4
5c	0.73 ft^2 Split Break	102%	MSIV/CV	33.52 @ 629.8	296.6 @ 118.7
6c	0.87 ft^2 Split Break	70%	MSIV/CV	33.84 @ 665.9	302.4 @ 104.0
7c*	0.94 ft^2 Split Break	30%	MSIV/CV	32.88 @ 719.6	303.6 @ 98.1
8c	0.90 ft^2 Split Break	0%	MSIV/CV	30.82 @ 712.6	297.9 @ 108.8

*These cases were analyzed with a CFCU actuation delay of 44 seconds and a CS actuation delay of 76 seconds. The remainder of the cases documented in this table assumed a CFCU actuation delay of 38 seconds and a CS actuation delay of 74.5 seconds.

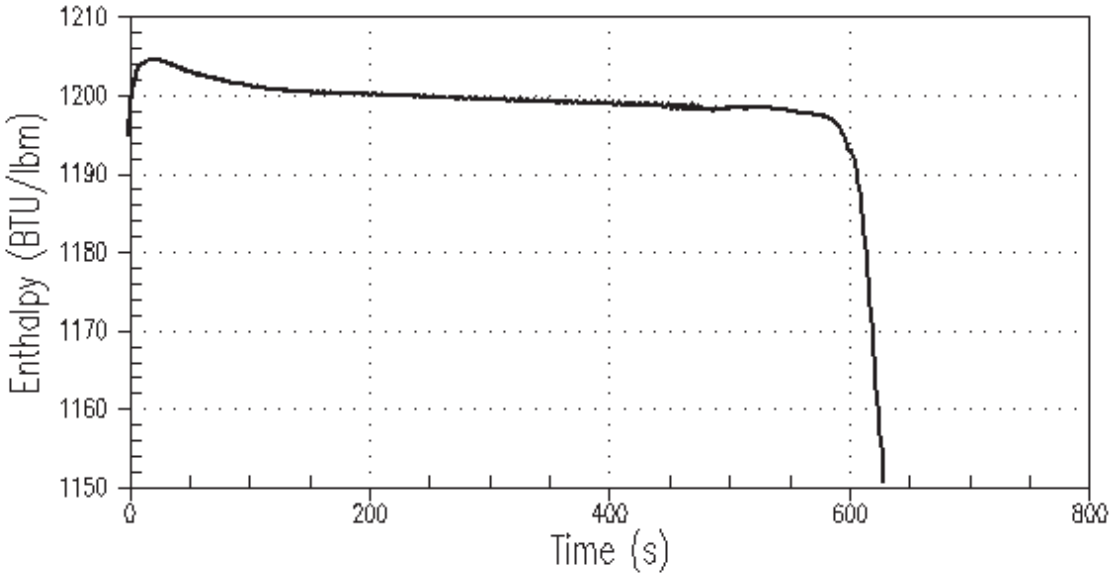
TABLE 6.2D-24

SEQUENCE OF EVENTS
MAIN STEAMLINE BREAK, MFRV FAILURE, 70% POWER

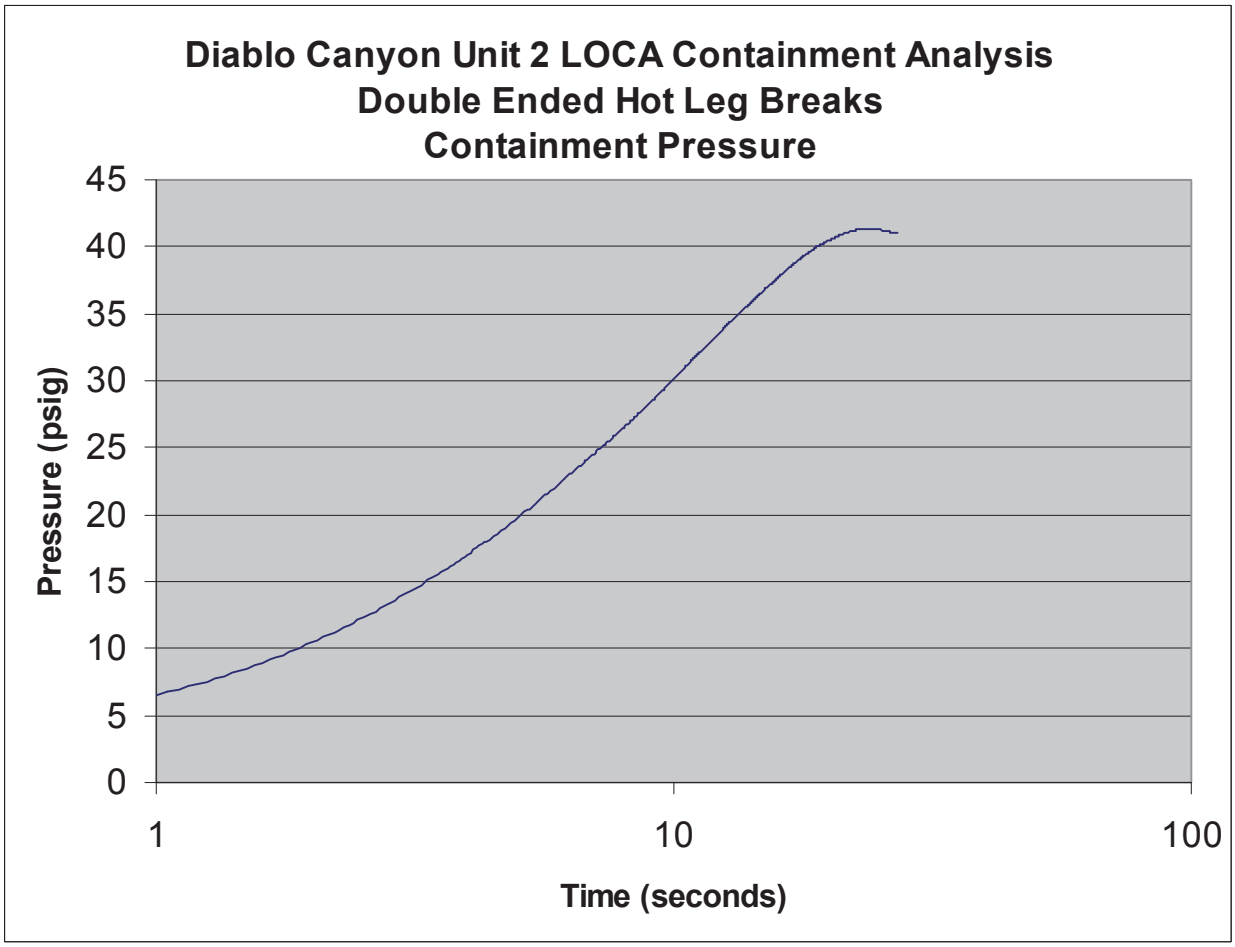
Event	Time (sec)
SI Low Steamline Pressure Setpoint Reached	0.051
AFW Initiation	0.051
Closure of Steamline CV on Faulted Loop	0.1
Reactor Trip – Start of Rod Motion	2.1
Faulted Loop MFRV Fully Closed	Failed Open
High Containment Pressure Setpoint Reached	5.7
SI Flow Starts	27.1
Fan Coolers Start	49.7
Faulted Loop Backup MFIV Fully Closed	64.1
SI Boron Reaches Core	148
High-High Containment Pressure Setpoint Reached	161.1
Containment Sprays Start	237.1
Accumulator Injection	n/a
AFW Re-aligned from Faulted SG	600
Peak Containment Pressure Occurs	607
Mass Release Terminated	630



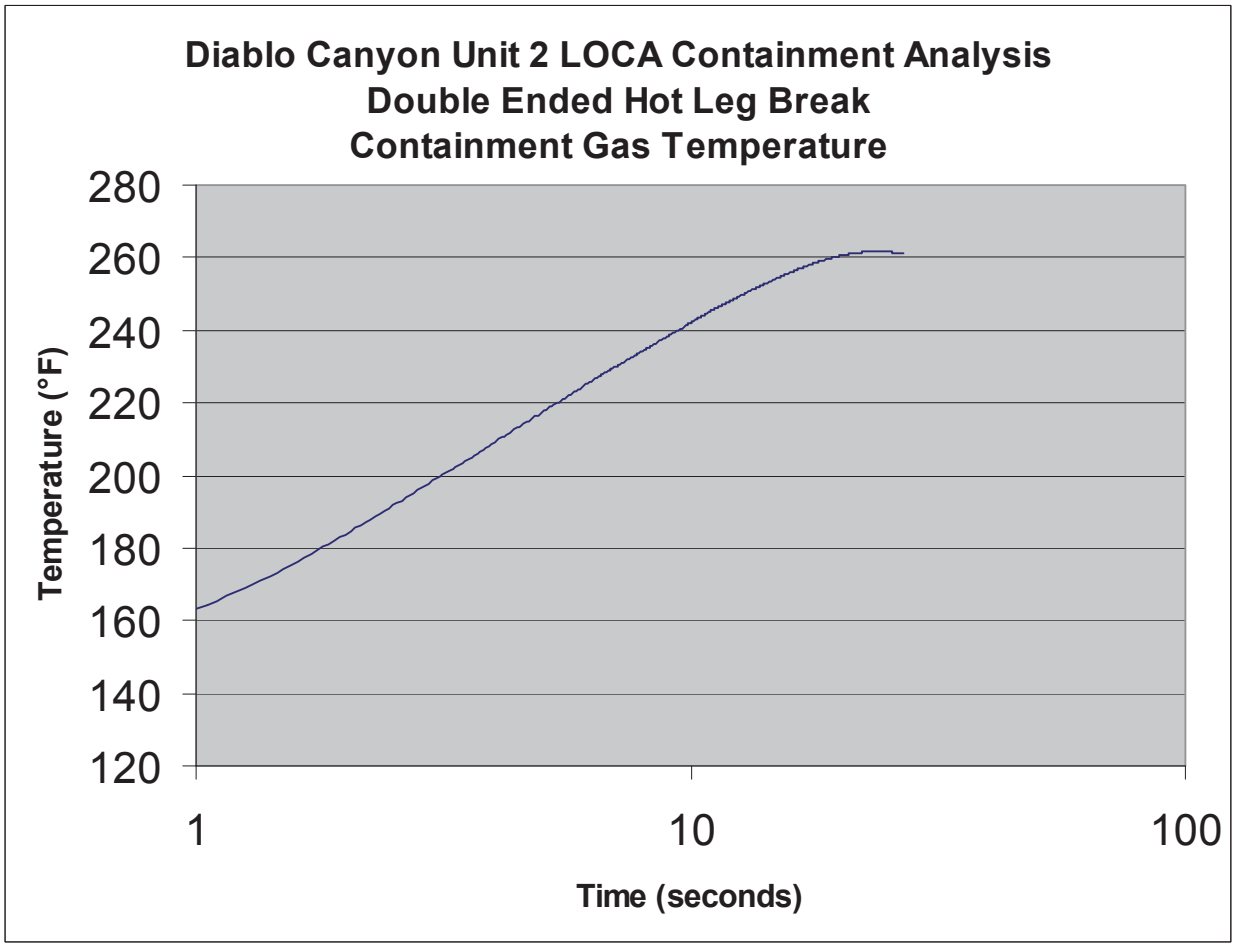
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2D-1 STEAMLINE BREAK MASS RELEASE TO CONTAINMENT 1.4 ft^2 DER. 70% POWER, MFRV FAILURE



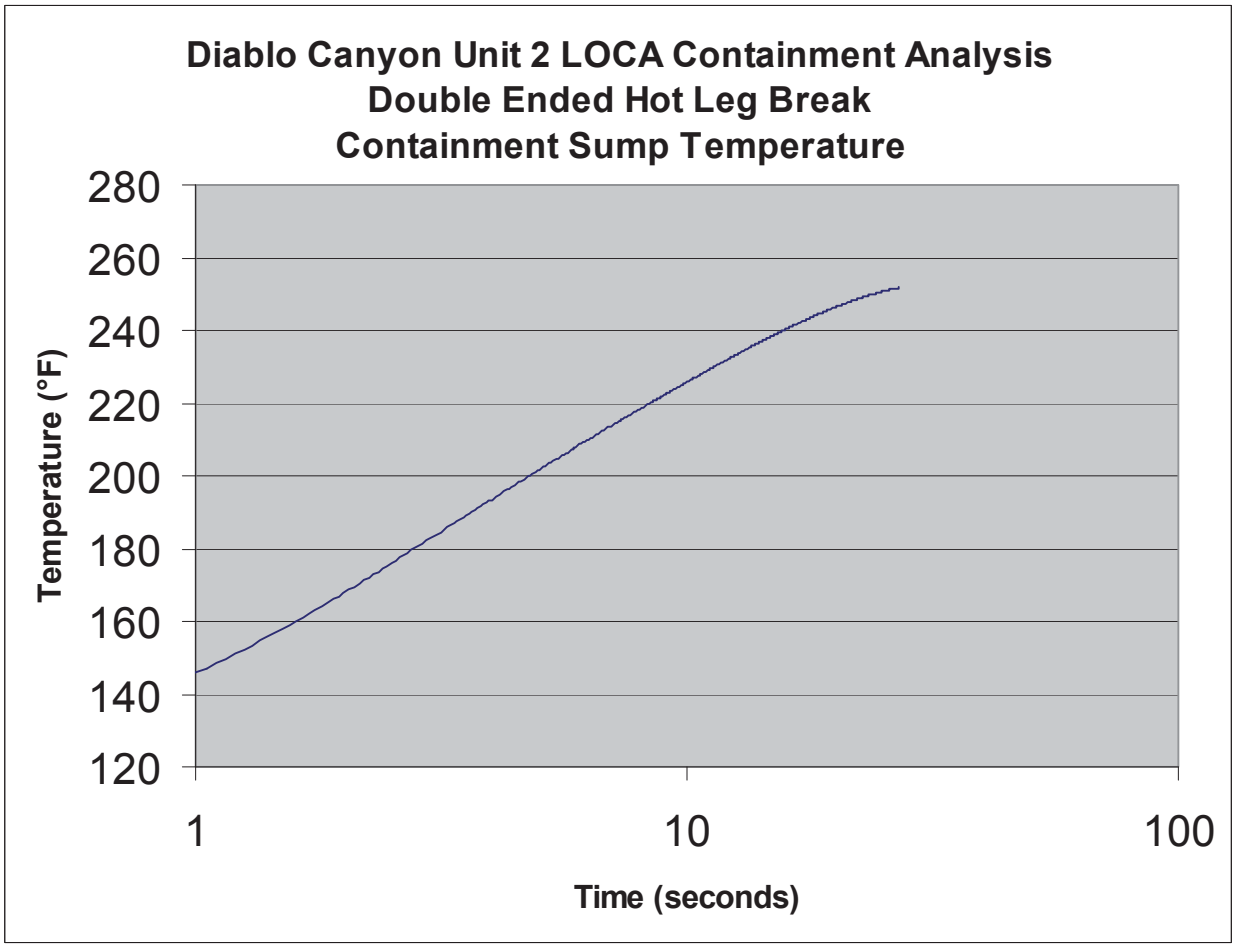
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2D-2 STEAMLINE BREAK ENTHALPY OF BREAK EFFLUENT 1.4 ft^2 DER. 70% POWER, MFRV FAILURE



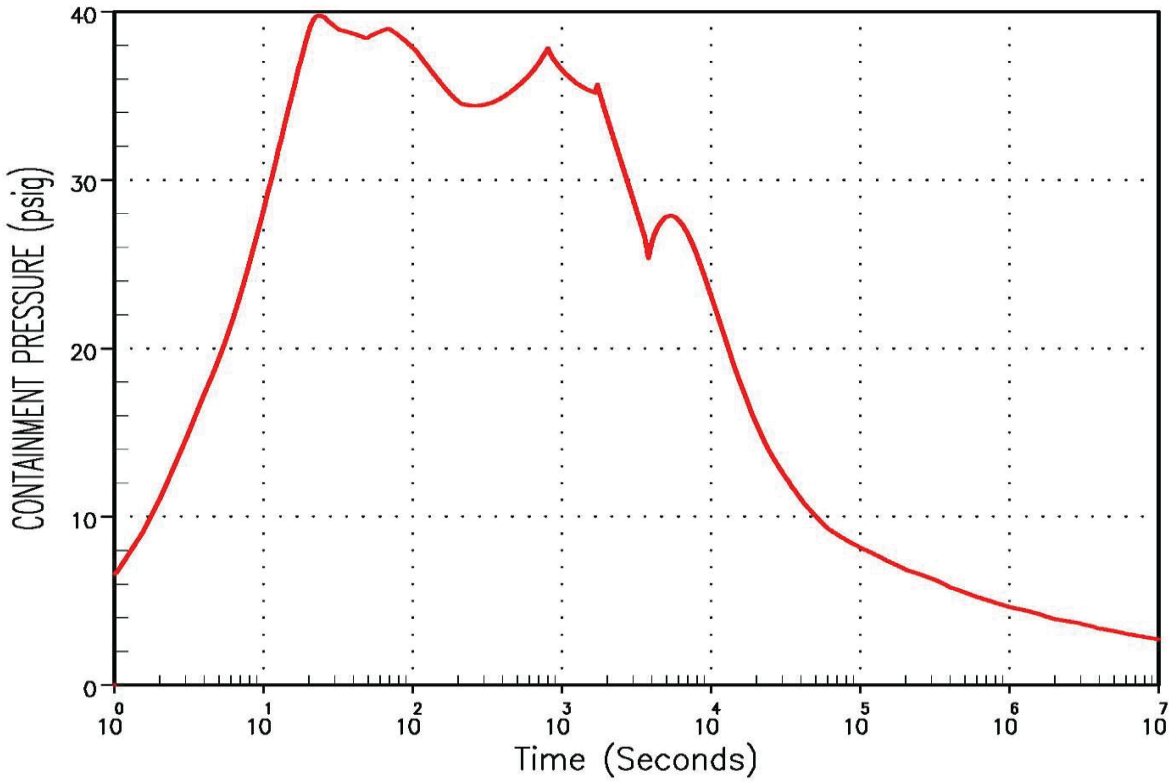
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 6.2D-3 CONTAINMENT PRESSURE DOUBLE-ENDED HOT LEG BREAK



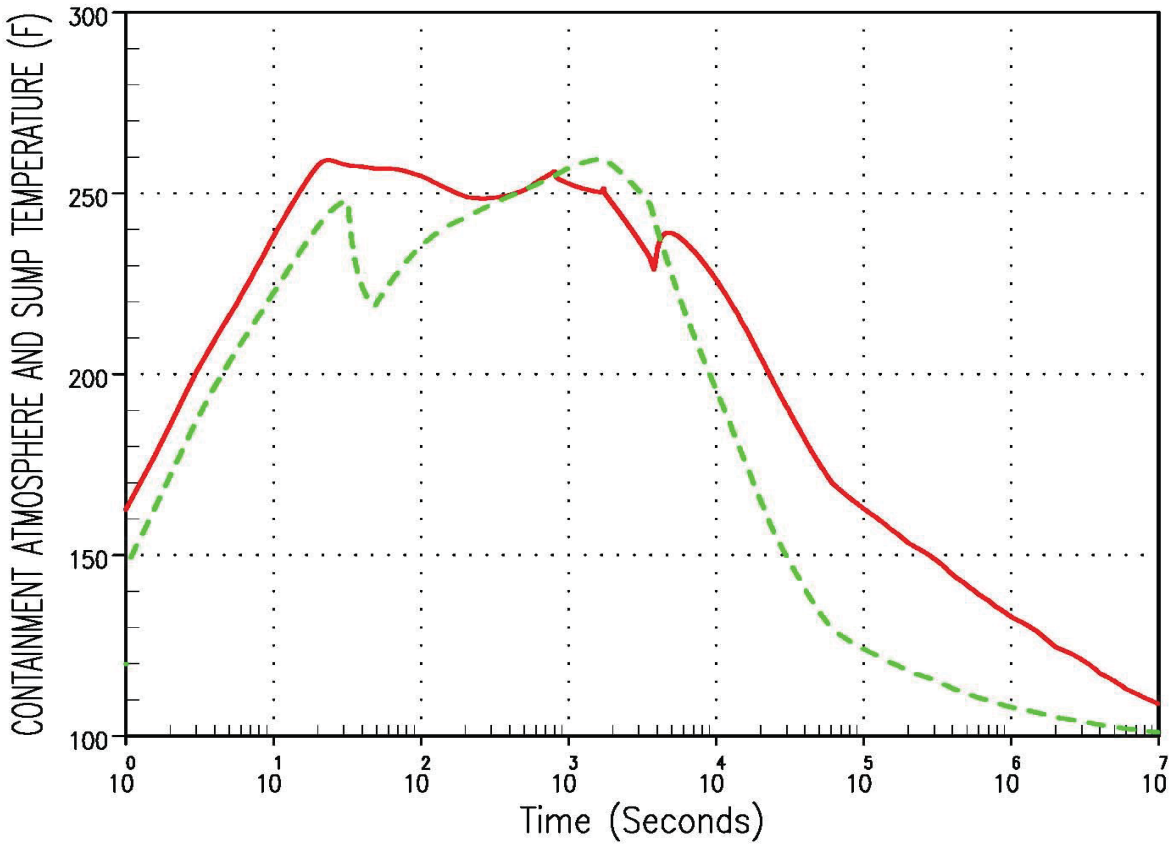
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 6.2D-4 CONTAINMENT TEMPERATURE DOUBLE-ENDED HOT LEG BREAK



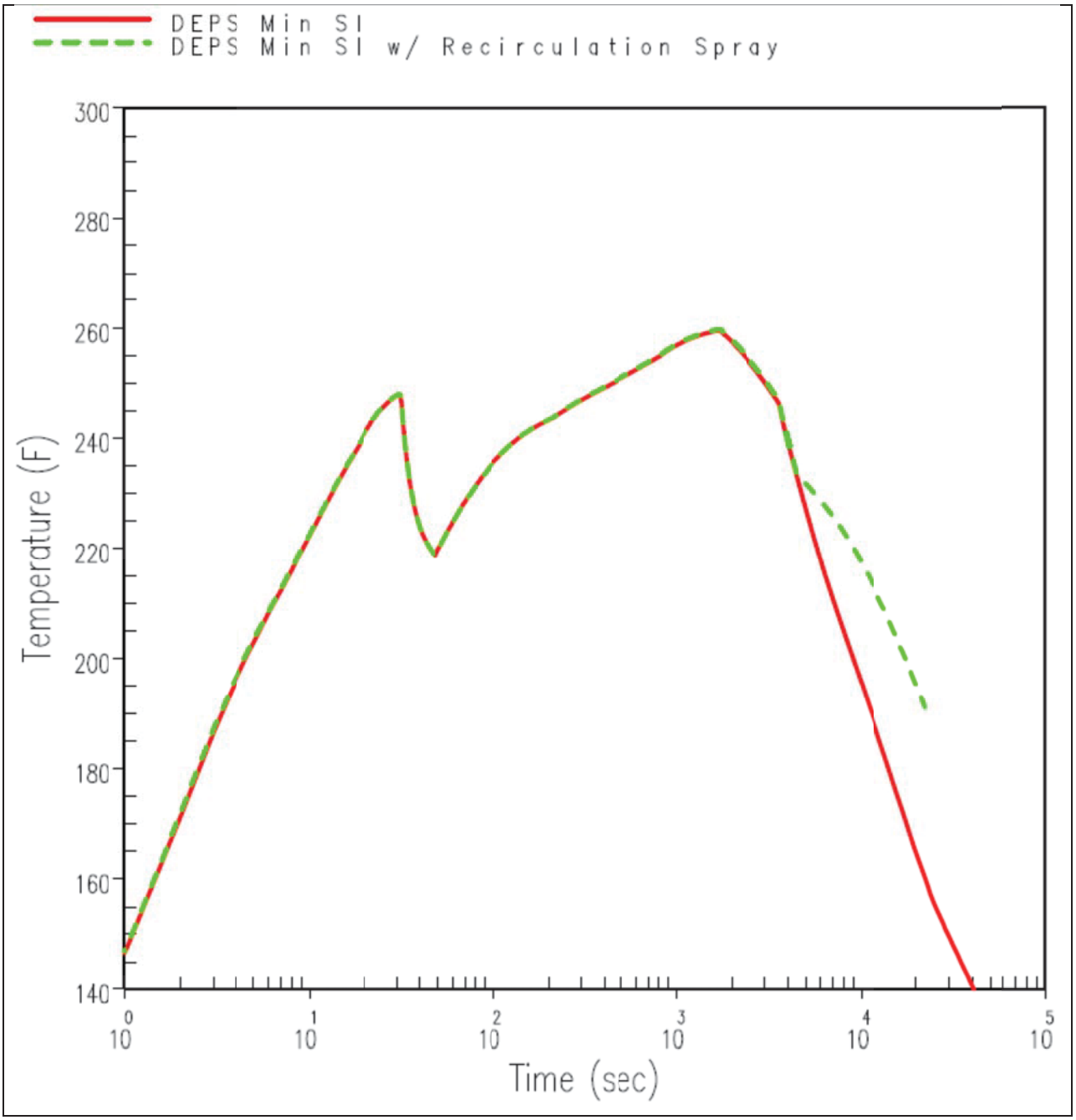
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 6.2D-5 CONTAINMENT SUMP TEMPERATURE DOUBLE-ENDED HOT LEG BREAK



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2D-6 **LOCA CONTAINMENT INTEGRITY DOUBLE ENDED PUMP SUCTION BREAK WITH EDG/SSPS SINGLE FAILURE 64 SECOND DELAY IN STARTING THE CFCUs**

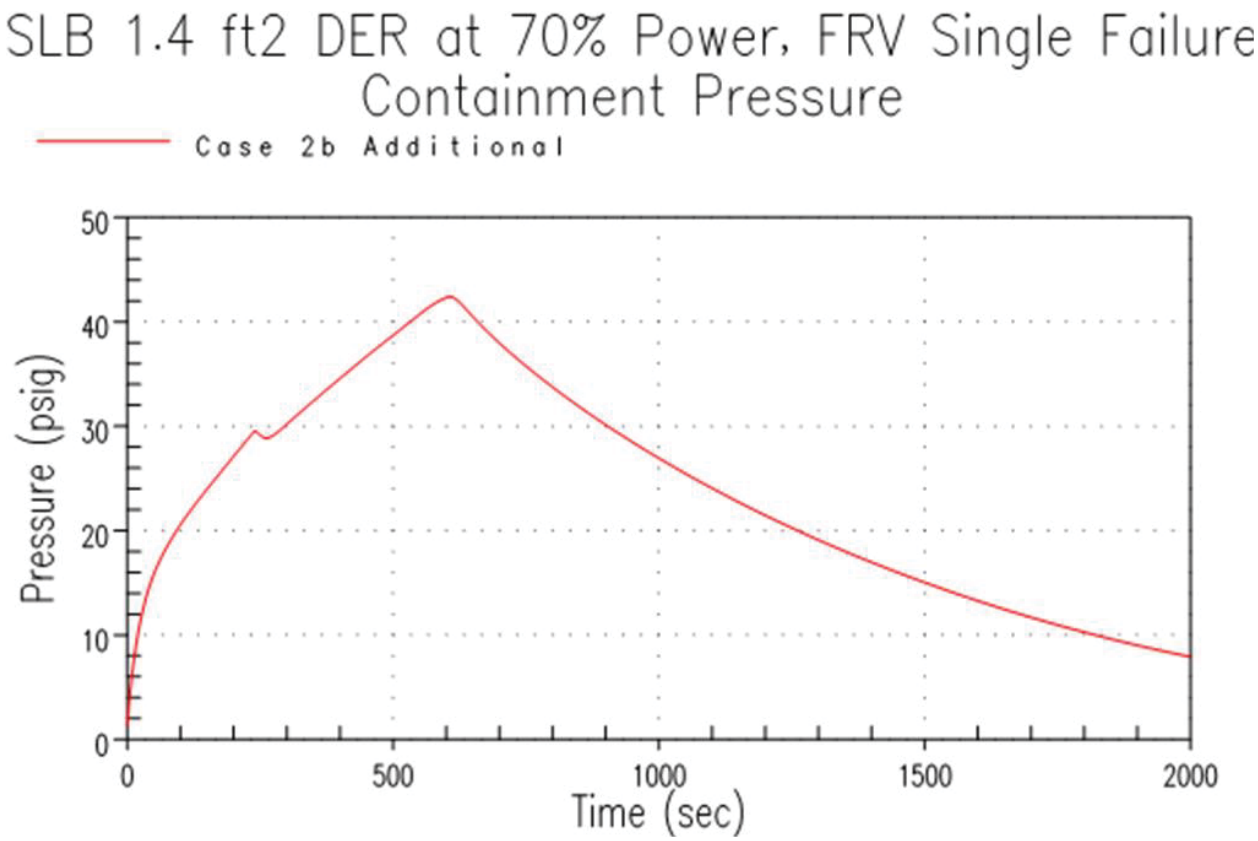


FSAR UPDATE
UNITS 1 AND 2 **Diablo Canyon Site**
FIGURE 6.2D-7 **LOCA CONTAINMENT INTEGRITY DOUBLE ENDED PUMP SUCTION BREAK WITH EDG/SSPS SINGLE FAILURE 64 SECOND DELAY IN STARTING THE CFCUs**



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 6.2D-8A DEPS Minimum SI Sump Temperature Comparison

Revision 24 September 2018



FSAR UPDATE
UNITS 1 and 2 Diablo Canyon Site
FIGURE 6.2D-9 SLB 1.4 FT 2 DER at 70% POWER, FRV SINGLE FAILURE CONTAINMENT PRESSURE

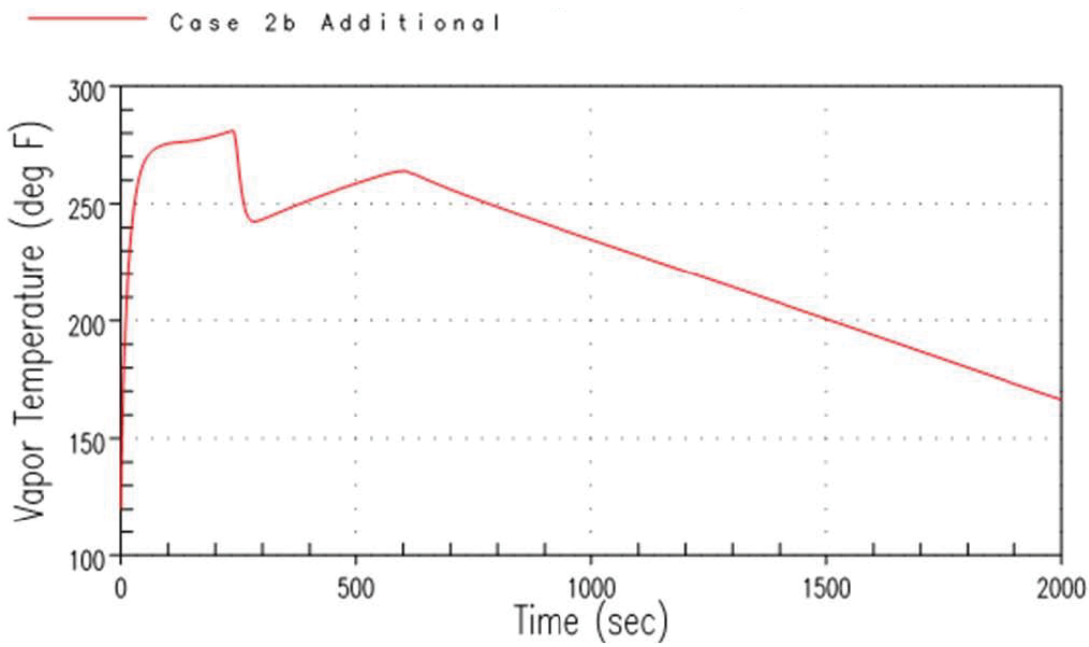


FIGURE 6.2D-10

FSAR UPDATE
Units 1 and 2 Diablo Canyon Site
FIGURE 6.2D-10 SLB 1.4 FT. 2 DER at 70% POWER, FRV SINGLE FAILURE CONTAINMENT VAPOR TEMPERATURE

Chapter 7

Instrumentation and Control

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NOTE:

[a] This figure corresponds to a controlled engineering drawing that is incorporated by reference into the FSAR Update. See Table 1.6-1 for the correlation between the FSAR Update figure number and the corresponding controlled engineering drawing number.

Chapter 7

INSTRUMENTATION AND CONTROLS

7.1 INTRODUCTION

This chapter presents the various plant instrumentation and control systems by relating the functional performance requirements, design bases, system descriptions, design evaluations, and tests and inspections for each. The information provided in this chapter emphasizes those instruments and associated equipment that constitute the protection system as defined in IEEE 279-1971(Reference 1).

The primary purpose of the instrumentation and control systems is to provide automatic protection against unsafe and improper reactor operation during steady state and transient power operations (Conditions I, II, and III) and to provide initiating signals to mitigate the consequences of faulted conditions (Condition IV). For a discussion of the four conditions, refer to Chapter 15. The information presented in this chapter emphasizes those instrumentation and control systems necessary to ensure that the reactor can be operated to produce power in a manner that ensures no undue risk to the health and safety of the public.

It is shown that the applicable criteria and codes, such as the U.S. Atomic Energy Commission's (AECs) General Design Criteria (GDC) and IEEE standards, concerned with the safe generation of nuclear power are met by these systems. Table 7.1-1 provides a summary of the applicable design basis criteria for each section within Chapter 7.

The classification of instrumentation is described in Section 3.2.2.5.

7.1.1 DEFINITIONS

The definitions below establish the meaning of certain terms in the context of their use in Chapter 7.

(1) Actuation Accuracy - Synonymous with trip accuracy, but used where the word "trip" may cause ambiguity.

(2) Channel - An arrangement of components, modules and software as required to generate a single protective action signal when required by a generating station condition. A channel loses its identity where single action signals are combined.

(3) Channel Accuracy (an element of trip accuracy) - Includes accuracy of the primary element, transmitter, and rack-mounted electronics, but does not include indication accuracy.

(4) Cold Shutdown Condition - When the reactor is subcritical by an amount greater than the margin specified in the applicable Technical Specification and Tavg is less than or equal to the temperature specified in the applicable Technical Specification. Section 15.1 defines this as MODE 5.

(5) Components - Items from which the system is assembled (such as resistors, capacitors, wires, connectors, transistors, tubes, switches, and springs).

(6) Degree of Redundancy - The difference between the number of channels monitoring a variable and the number of channels that, when tripped, will cause an automatic system trip.

(7) Hot Shutdown Condition - When the reactor is subcritical by an amount greater than the margin specified in the applicable Technical Specification and Tavg is within the temperature range specified in the applicable Technical Specification. Section 15.1 defines this as MODE 4.

(8) Hot Shutdown Panel – The hot shutdown panel, which is the alternate control location in the event that the main control room is rendered uninhabitable, is provided with a mode switch, control switch and status for each of the pumps required to bring the plant to a safe shutdown condition.

(9) Hot Standby Condition - When the reactor is subcritical by an amount greater than the margin specified in the Technical Specification and the Tavg is greater than or equal to the temperature specified in the applicable Technical Specification. Section 15.1 defines this as MODE 3.

(10) Indication Accuracy - The tolerance band containing the highest expected value of the difference between: (a) the value of a process variable read on an indicator or recorder, and (b) the actual value of that process variable. An indication must fall within this tolerance band. It includes channel accuracy, accuracy of readout devices, and rack environmental effects but not process effects such as fluid stratification.

(11) Minimum Degree of Redundancy - The degree of redundancy below which operation is prohibited or otherwise restricted by the Technical Specifications.

(12) Module - Any assembly of interconnected components that constitutes an identifiable device, instrument, or piece of equipment. A module can be disconnected, removed as a unit, and replaced with a spare. It has definable performance characteristics that permit it to be tested as a unit. A module can be a card or other subassembly of a larger device, provided it meets the requirements of this definition.

(13) Phase A Containment Isolation - Closure of all nonessential process lines that penetrate containment. Initiated by high containment pressure, pressurizer low pressure (LP), low steamline pressure, or manual actuation.

(14) Phase B Containment Isolation - Closure of remaining process lines. Initiated by containment high-high pressure signal (process lines do not include engineered safety features [ESFs] lines) or manual actuation.

(15) Protective Action - A protective action can be at the channel or the system level. A protective action at the channel level is the initiation of a signal by a single channel when the variable sensed exceeds a limit. A protective action at the system level is the initiation of the operation of a sufficient number of actuators to effect a protective function.

(16) Protective Function - A protective function is the sensing of one or more variables associated with a particular generating station condition, signal processing, and the initiation and completion of the protective action at values of the variable established in the design bases.

(17) Reproducibility - This term may be substituted for "accuracy" in the above definitions for those cases where a trip value or indicated value need not be referenced to an actual process variable value, but rather to a previously established trip or indication value; this value is determined by test.

(18) Safe Shutdown - This term is defined as hot standby (MODE 3). Refer to Table 3.9-9, Note (a) for additional Diablo Canyon Power Plant (DCPP) safe shutdown definitions.

(19) Single Failure - Any single event that results in a loss of function of a component or components of a system. Multiple failures resulting from a single event shall be treated as a single failure.

(20) Trip Accuracy - The tolerance band containing the highest expected value of the difference between (a) the desired trip point value of a process variable, and (b) the actual value at which a comparator trips (and thus actuates some desired result). This is the tolerance band within which a comparator must trip. It includes comparator accuracy, channel accuracy for each input, and environmental effects on the rack-mounted electronics. It comprises all instrumentation errors; however, it does not include any process effects such as fluid stratification.

(21) Type Tests - Tests made on one or more units to verify adequacy of design of that type of unit.

7.1.2 IDENTIFICATION OF SAFETY-RELATED SYSTEMS

The instrumentation and control systems and supporting systems discussed in Chapter 7 that are required to function to achieve the system responses assumed in the safety evaluations, and those needed to shut down the plant safely are:

(1) Reactor trip system (RTS)

(2) Engineered safety features actuation system (ESFAS)

(3) Instrumentation and control power supply system (refer to Section 8.3.1.1.5)

(4) Remote shutdown panel controls and instrumentation

The RTS and the ESFAS are functionally defined systems. The functional descriptions of these systems are provided in Sections 7.2 and 7.3. The trip functions identified in Section 7.2, Reactor Trip System, are provided by the following:

(1) Process instrumentation and control system (References 3 and 10)

(2) Nuclear instrumentation system (NIS) (Reference 4)

(3) Solid-state logic protection system (Reference 5)

(4) Reactor trip switchgear (Reference 5)

(5) Manual actuation circuitry

The actuation functions identified in Section 7.3 are provided by the following:

(1) Process instrumentation and control system (References 3 and 10)

(2) Solid-state logic protection system (Reference 5)

(3) ESF test cabinet (Reference 6)

(4) Manual actuation circuitry

WCAP-7671 (Reference 3) describes the instrumentation and instruments systems that are safety-related as defined in the scope of IEEE 279-1971 (Reference 1).

The original Hagan/Westinghouse process control system (PCS) was replaced with a programmable logic controller (PLC) based system (DDP 1000000237 and 1000000501).

The PCS converts physical plant parameters such as temperature, pressure, level, and flow into electrical signals during normal operation. These signals are used for plant control, remote process indication, and computer monitoring. The PCS also provides signals to components located in the Hot Shutdown Panel. The PCS comprises Control Racks 17-32, panels PIA, PIB, PIC, and the Instrument Rack (RI Rack).

The sixteen Control Racks are divided into four Control Sets. Control Set I comprises Racks 17-20. Control Set II comprises Racks 21-24. Control Set III comprises Racks 25-27. Control Set IV comprises Racks 28-32. The Control Sets and the associated Class 1E 120-Vac power sources are physically separated. Each Control Set contains two sub-systems based on a PLC platform. One PLC sub-system contains PG&E Design Class I components and functions. The other PLC sub-system contains PG&E Design Class II components and functions. The two PLC sub-systems are separated within the Control Racks. The PG&E Design Class I sub-system in each Control Set receives Class 1E 120-Vac power from an independent Class 1E 120-Vac power source. The PG&E Design Class II sub-system in each Control Set receives non-Class 1E 120-Vac power from two separate sources; one of which is inverter backed. Circuit separation and isolation is maintained for Class 1E power sources to the Control Racks.

Instrument Panels PIA, PIB, and PIC are physically separated from each other and contain Class 1E power sources. These instrument panels receive 120-Vac power from Class 1E 120-Vac power supplies.

The RI Rack contains PG&E Design Class II related components and functions that are processed by a PLC. The RI Rack receives 120-Vac power from two non-Class 1E sources.

7.1.3 IDENTIFICATION OF SAFETY CRITERIA

7.1.3.1 Design Bases

The design bases and functional performance for the PG&E Design Class I systems described in this chapter are provided in Sections 7.2 (RTS), 7.3 (ESFAS), and 8.3.1.1.5 (Instrumentation and Control Power Supply System). Table 7.1-1 provides a summary of the applicable design basis criteria for each section within Chapter 7.

The design bases for the ESF are discussed in Chapter 6; specifically, Section 6.2 for containment systems and Section 6.3 for emergency core cooling system (ECCS).

7.1.3.2 Independence of Redundant Safety-Related Systems

Separation and independence for individual channels of the RTS and ESFAS are discussed in Sections 7.2 and 7.3, respectively. Separation of protection and control

systems is discussed in Section 7.7. Refer to Section 8.3 for a discussion of separation and independence of Class 1E electrical systems.

For separation requirements for control board wiring, refer to Section 7.7.

Separation criteria for circuits entering the containment structure are met by providing separate electrical penetrations as follows:

(1) *Reactor Protection Instrumentation* - Each of the Eagle 21 protection sets (I, II, III, and IV) utilizes one or more penetrations dedicated to that protection set.

(2) *Isolation Valves (solenoid-operated)* - Each isolation valve inside the containment structure is connected to its respective ESF dc bus, and circuits are run through associated 480-V bus penetrations. All isolation valves inside the containment structure receive train A signals. Redundant isolation valves outside the containment receive train B signals.

(3) *Isolation Valves (motor-operated)* - Each isolation valve utilizes a penetration dedicated to the 480-V ESF bus that provides power to the valve.

(4) *Fan Coolers* - One penetration for each fan cooler motor.

(5) *Nuclear Instrumentation (out-of-core)* - Four separate penetrations are provided for out-of-core nuclear instrumentation.

The installation of other cable complies with the criteria presented in Chapter 8.

7.1.3.3 Physical Identification of Safety-Related Equipment

There are four separate process protection system rack sets. Separation of redundant process channels begins at the process sensors and is maintained in the field wiring, containment penetrations, and process protection racks to the redundant trains in the protection logic racks. Redundant process channels are separated by locating the electronics in different rack sets. A color-coded nameplate on each rack is used to differentiate between different protective sets. The color coding of the nameplates is:

Protection Set	Color Coding
I	Red with white lettering
II	White with black lettering
III	Blue with white lettering
IV	Yellow with black lettering

Each field wire termination point is tagged to assist identification. However, these tags are not color-coded.

All nonrack-mounted protective equipment and components are provided with an identification tag or nameplate. Small electrical components such as relays have nameplates on the enclosure that houses them.

Post-accident monitoring instruments and controls are identified "PAMS" as required by Regulatory Guide 1.97, Revision 3.

For further details of the process protection system, refer to Sections 7.2, 7.3, and 7.7.

There are identification nameplates on the input panels of the logic system. For details of the logic system, refer to Sections 7.2 and 7.3.

7.1.3.4 Conformance with IEEE Standards

The PG&E Design Class I control and instrumentation systems comply with the following IEEE standards, only as discussed in the appropriate sections. However, because the IEEE standards were issued after much of the design and testing had been completed, the equipment documentation may not meet the format requirements of the standards.

(1) IEEE 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations."

(2) IEEE 308-1971, "Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations."

(3) IEEE 317-1971, "IEEE Standard for Electrical Penetration Assemblies in Containment Structures for Nuclear Fueled Power Generating Stations."

(4) IEEE 323-1971, "IEEE Trial-Use Standard: General Guide for Qualifying Class I Electric Equipment for Nuclear Power Generating Stations."

(5) IEEE 323-1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations."

(6) IEEE 334-1971, "Trial-Use Guide for Type Tests of Continuous-Duty Class I Motors Installed Inside the Containment of Nuclear Power Generating Stations."

(7) IEEE 336-1971, "Installation, Inspection, and Testing Requirements for Instrumentation and Electrical Equipment During the Construction of Nuclear Power Generating Stations."

DCPP is in conformance with IEEE 336-1971, with the following exceptions:

Paragraph 2.4 - "Data sheets shall contain an evaluation of acceptability." The evaluation of acceptability is indicated on the results and data sheets by the approval signature.

Paragraph 3(4) - "Visual examination of contact corrosion." No visual examination for contact corrosion is made on breaker and starter contacts unless there is evidence of water damage or condensation. Contact resistance tests are made on breakers rated at 4 kV and above. No contact resistance test is made of lower voltage breakers or starters.

Paragraph 6.2.2 - "Demonstrate freedom from unwanted noise." No system test incorporates a noise measurement. If the system under test meets the test criteria, then noise is not a problem.

(8) IEEE 338-1971, "IEEE Trial-Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems."

(9) IEEE 344-1971, "Trial-Use Guide for Seismic Qualification of Class I Electric Equipment for Nuclear Power Generating Stations."

(10) IEEE 344-1975, "Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations."

(11) IEEE 384-1974, "Criteria for Independence of Class 1E Equipment and Circuits"

(12) IEEE 603-1980, “IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations.”

(13) ANSI/IEEE-ANS-7-4.3.2-1982, “Application Criteria for Programmable Digital Computer Systems in Safety Systems of Nuclear Power Generating Stations,” 1982 (ANSI/IEEE-ANS-7-4.3.2-1982, expands and amplifies the requirements of IEEE 603-1980).

7.1.4 REFERENCES

1. IEEE Standard, 279-1971, Criteria for Protection Systems for Nuclear Power Generating Stations, The Institute of Electrical and Electronics Engineers, Inc.

2. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

3. J. A. Nay, Process Instrumentation for Westinghouse Nuclear Steam Supply Systems, WCAP-7671, April 1971.

4. J. B. Lipchak and R. A. Stokes, Nuclear Instrumentation System, WCAP-7669, April 1971.

5. D. N. Katz, Solid State Logic Protection System Description, WCAP-7672, June 1971.

6. J. T. Haller, Engineered Safeguards Final Device or Activator Testing, WCAP-7705, February 1973.

7. Deleted

8. Deleted

9. Deleted

10. Summary Report EAGLE 21 Process Protection System Upgrade for Diablo Canyon Power Plant Units 1 and 2, WCAP-12813, Revision 3, June 1993.

7.2 REACTOR TRIP SYSTEM

This section provides a system description and the design bases for the reactor trip system (RTS).

The RTS automatically keeps the reactor operating within a safe region by tripping the reactor whenever the limits of the region are approached. The safe operating region is defined by several considerations such as mechanical and hydraulic limitations on equipment, and heat transfer phenomena. Therefore, the RTS keeps surveillance on process variables that are directly related to equipment mechanical limitations such as pressure, pressurizer water level (to prevent water discharge through safety valves and uncovering heaters), and also on variables that directly affect the heat transfer capability of the reactor (e.g., flow and reactor coolant temperatures). Other parameters utilized in the RTS are calculated from various process variables. In any event, whenever a direct process or a calculated variable exceeds a setpoint, the reactor will be shut down to protect against either gross damage to fuel cladding or loss of system integrity that could lead to release of radioactive fission products into the containment.

7.2.1 Design Bases

7.2.1.1 General Design Criterion 2, 1967 – Performance Standards

The reactor trip system (RTS) is designed to withstand the effects of or is protected against natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

7.2.1.2 General Design Criterion 11, 1967 – Control Room

The RTS is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

7.2.1.3 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the RTS variables within prescribed operating ranges. The RTS is provided to receive plant instrumentation signals and automatically trip the reactor as prescribed limits are approached or reached.

7.2.1.4 General Design Criterion 14, 1967 – Core Protection Systems

The RTS is designed to act automatically to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits.

7.2.1.5 General Design Criterion 19, 1967 – Protection Systems Reliability

The RTS is designed for high functional reliability and in-service testability commensurate with the safety functions to be performed.

7.2.1.6 General Design Criterion 20, 1967 – Protection Systems Redundancy and Independence

Redundancy and independence are designed into the RTS sufficient to assure that no single failure or removal from service of any component or channel of a system will result in loss of the protection function. The redundancy provided shall include, as a minimum, two channels of protection for each protection function to be served. Different principles are used where necessary to achieve true independence of redundant instrumentation components.

7.2.1.7 General Design Criterion 21, 1967 – Single Failure Definition

The RTS is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event are treated as a single failure.

7.2.1.8 General Design Criterion 22, 1967 – Separation of Protection and Control Instrumentation Systems

The RTS is designed such that protection systems are separated from control instrumentation systems to the extent that failure or removal from service of any control instrumentation system component or channel, or of those common to control instrumentation and protection circuitry, leaves intact a system satisfying all requirements for the protection channels.

7.2.1.9 General Design Criterion 23, 1967 – Protection Against Multiple Disability for Protection Systems

The RTS is designed such that the effects of adverse conditions to which redundant channels or RTS might be exposed in common, either under normal conditions or those of an accident will not result in loss of the reactor trip function.

7.2.1.10 General Design Criterion 24, 1967 – Emergency Power for Protection Systems

The RTS is designed such that in the event of loss of all offsite power, sufficient alternate sources of power are provided to permit the required functioning of the RTS.

7.2.1.11 General Design Criterion 25, 1967 – Demonstration of Functional Operability of Protection Systems

The RTS includes the means for testing the RTS while the reactor is in operation to demonstrate that no failure or loss of redundancy has occurred.

7.2.1.12 General Design Criterion 26, 1967 – Protection Systems Fail-Safe Design

The RTS is designed, with noted exceptions, to fail into a safe state or into a state established as tolerable on a defined basis if conditions such as disconnection of the system, loss of energy (e.g., electric power, instrument air), or adverse environments (e.g., extreme heat or cold, fire, steam, or water) are experienced.

7.2.1.13 General Design Criterion 31, 1967 – Reactivity Control Systems Malfunction

The RTS is designed to prevent exceeding acceptable fuel damage limits by limiting reactivity transients resulting from any single malfunction in the reactivity control systems, such as, unplanned continuous withdrawal (not ejection) of a control rod.

7.2.1.14 General Design Criterion 49, 1967 – Containment Design Basis

The RTS instrumentation circuits routed through containment electrical penetrations are designed so that the containment structure can accommodate, without exceeding the design leakage rate, pressures and temperatures resulting from the largest credible energy release following a loss-of-coolant accident (LOCA).

7.2.1.15 Reactor Trip System Safety Function Requirements

(1) <u>Protection from Missiles</u>

The RTS is designed to be protected against the effects of missiles which may result from plant equipment failure and from events and conditions outside the plant.

(2) <u>Protection Against High Energy Pipe Rupture Effects</u>

The RTS is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) <u>Protection from Moderate Energy Pipe Rupture Effects – Outside Containment</u>

The RTS system portion located outside containment is designed to be protected against the effects of moderate energy pipe failure

(4) Protection from Jet Impingement – Inside Containment

The RTS system portion located inside containment is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

(5) Protection from Flooding Effects – Outside Containment

The RTS system portion located outside containment is to be protected from the effects of internal flooding.

7.2.1.16 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

The RTS electric components that require environmental qualification are qualified to the requirements of 10 CFR 50.49.

7.2.1.17 Safety Guide 22, February 1972 – Periodic Testing of Protection System Actuation Functions

The RTS is periodically tested to provide assurance that the system will operate as designed and will be available to function properly. The testing program conforms to Safety Guide 22, February 1972.

7.2.1.18 NUREG-0737 (Items II.K.3.10 and II.K.3.12), November 1980 – Clarification of TMI Action Plan Requirements

Item II.K.3.10 – Proposed Anticipatory Trip Modification: The setpoint for the anticipatory reactor trip on turbine trip bypass (P-9) cannot be raised above 10% reactor power until it has been shown that the probability of a small-break loss-of-coolant accident (LOCA) resulting from a stuck-open power-operated relief valve (PORV) is substantially unaffected by the modification.

Item II.K.3.12 – Anticipatory Reactor Trip upon Turbine Trip: The RTS includes an anticipatory reactor trip upon turbine trip.

7.2.1.19 Generic Letter 83-28 (Actions 4.3 and 4.5), July 1983 – Required Actions Based on Generic Implications of Salem ATWS Events

Action 4.3 – RTS Reliability (Automatic Actuation of Shunt Trip Attachment for Westinghouse and B&W Plants): The RTS provides actuation of the breaker shunt trip attachments. The shunt trip attachment is considered Class 1E.

Action 4.5 – RTS Reliability (System Functional Testing): On-line functional testing of the RTS, including independent testing of the diverse trip features, is performed.

7.2.2 System Description

The RTS uses sensors that feed the process circuitry consisting of two to four redundant channels, which monitor various plant parameters. The RTS also contains the logic circuitry necessary to automatically open the reactor trip breakers. The logic circuitry consists of two redundant logic trains that receive input from the protection channels.

Each of the two logic trains, A and B, is capable of opening a separate and independent reactor trip breaker (52/RTA and 52/RTB). Logic train A opens reactor trip breaker 52/RTA and bypass breaker 52/BYB. Logic train B opens reactor trip breaker 52/RTB and bypass breaker 52/BYA. The two trip breakers in series connect three-phase ac power from the rod drive motor generator sets to the rod drive power bus, as shown in Figure 7.2-1, Sheets 3 and 4. For reactor trip, a loss of dc voltage to the undervoltage coil releases the trip plunger and trips open the breaker. Additionally, an undervoltage trip auxiliary relay provides a trip signal to the shunt trip coil that trips open the breaker in the unlikely event of an undervoltage coil malfunction. When either of the trip breakers opens, power is interrupted to the rod drive power supply, and the control rods fall by gravity into the core. The rods cannot be withdrawn until an operator resets the trip breakers. The trip breakers cannot be reset until the bistable, which initiated the trip, reenergizes. Bypass breakers BYA and BYB are provided to permit testing of the trip breakers, as discussed below.

The RTS design was evaluated in detail with respect to common mode failure and is presented in References 1 and 11. Preoperational testing was performed on RTS components and systems to determine equipment readiness for startup. This testing served as a further evaluation of the system design.

Analyses of the results of Conditions I, II, III, and IV events, including considerations of instrumentation installed to mitigate their consequences, are presented in Chapter 15. The instrumentation installed to mitigate the consequences of load reduction and turbine trip is identified in Section 7.4.2 and Section 10.2.2.

7.2.2.1 Reactor Trips

The various reactor trip circuits automatically open the reactor trip breakers whenever a condition monitored by the RTS reaches a preset level. In addition to redundant channels and trains, the design approach provides an RTS that monitors numerous system variables, thereby providing RTS functional diversity. The extent of this diversity has been evaluated for a wide variety of postulated accidents and is detailed in Reference 1.

Table 7.2-1 provides a list of reactor trips that are described below.

7.2.2.1.1 Nuclear Overpower Trips

The specific trip functions generated are:

(1) *Power Range High Nuclear Power Trip* - The power range high nuclear power trip circuit trips the reactor when two of the four power range channels exceed the trip setpoint. There are two independent bistables each with its own trip setting (a high and a low setting). The high trip setting provides protection during normal power operation and is always active. The low trip setting, which provides protection during startup, can be manually blocked when two of the four power range channels read above approximately 10 percent power (P-10). This trip function is automatically reinstated when three of the four power range channels decrease below 10 percent power. Refer to Table 7.2-2 for a listing of all protection system interlocks.

(2) *Intermediate Range High Neutron Flux Trip* - The intermediate range high neutron flux trip circuit trips the reactor when one of the two intermediate range channels exceeds the trip setpoint. This trip, which provides protection during reactor startup, can be manually blocked if two of the four power range channels are above approximately 10 percent power (P-10). This trip function is automatically reinstated when three of the four power range channels decrease below 10 percent power. The intermediate range channels (including detectors) are separate from the power range channels. The intermediate range channels can be individually bypassed at the nuclear instrumentation racks to permit channel testing during plant shutdown or prior to startup. This bypass action is annunciated on the control board.

(3) *Source Range High Neutron Flux Trip* - The source range high neutron flux trip circuit trips the reactor when one of the two source range channels exceeds the trip setpoint. This trip, which provides protection during reactor startup and plant shutdown, can be manually blocked when one of the two intermediate range channels reads above the P-6 setpoint value and is automatically reinstated when both intermediate range channels decrease below the P-6 value. This trip is also automatically bypassed by two-out-of-four logic from the power range interlock (P-10). This trip function can also be reinstated below P-10 by an administrative action requiring manual actuation of two control board-mounted switches. Each switch will reinstate the trip function in one of the two protection logic trains. The source range trip point is set between the P-6 setpoint (source range cutoff flux level) and the maximum source range flux level. The channels can be individually bypassed at the nuclear instrumentation racks to permit channel testing during plant shutdown or prior to startup. This bypass action is annunciated on the control board.

Administrative controls are in place to manually disable high voltage to the SR detectors during reactor startup above P-6 and power operation

(Modes 2 and 1) by pulling the instrument power fuses or some other means to prevent inadvertent operation at power. This manual action prevents damage to the source range detectors. The high voltage is reenabled following a reactor trip or during a controlled shutdown.

(4) *Power Range High Positive Nuclear Power Rate Trip* - This circuit trips the reactor when an abnormal rate of increase in nuclear power occurs in two of the four power range channels. This trip provides protection against rod ejection and rod withdrawal accidents of low worth from middle to low power conditions and is always active.

Figure 7.2-1, Sheets 5 and 6, shows the logic for all of the nuclear overpower and rate trips. A detailed functional description of the equipment associated with this function is provided in Reference 2.

7.2.2.1.2 Core Thermal Overpower Trips

The specific trip functions generated are:

(1) *Overtemperature ΔT Trip* - This trip protects the core against DNB and trips the reactor on coincidence, as listed in Table 7.2-1, with one set of temperature measurements per loop. The setpoint for this trip is continuously calculated by process protection circuitry for each loop by solving the following equation:

$$\Delta Ti\frac{(1+\tau_4 s)}{(1+\tau_5 s)} \le \Delta Ti^{\circ}\left\{K_1 - K_2\frac{(1+\tau_1 s)}{(1+\tau_2 s)}\left[Tavg_i - Tavg_i^{\circ}\right] + K_3(P - P^{\circ}) - f_1(\Delta I)\right\} \qquad (7.2\text{-}1)$$

where:

ΔTi° = indicated ΔT at rated thermal power from loop i, °F

$Tavg_i^{\circ}$ = Indicated Tavg at rated thermal power from loop i, °F

P° = 2235 psig (indicated RCS nominal operating pressure)

Th_{ij} = jth narrow range Thot input signal from loop i

$T^f h_{ij}$ = $Th_{ij}\ (1/(1+\tau_6 s))$

$\frac{1}{1+\tau_6 s}$ = Lag compensator on measured Thot

$Thave_i$ = $\sum(T^f h_{ij})/3$ for j = 1 - 3 for each loop, i = 1 - 4

Note: A 3-input redundant sensor algorithm (RSA) eliminates $T^f h_{ij}$ values that result from known bad inputs or that fail a consistency check. The RSA also determines a quality code for $Thave_i$, depending on the quality and consistency of the individual $T^f h_{ij}$ values. (Refer to Section 7.2.2.3)

Tc_{ij} = jth narrow-range Tcold input signal from loop i

$T^f c_{ij}$ = $Tc_{ij}\ (1/(1+\tau_7 s))$

$\frac{1}{1+\tau_7 s}$ = Lag compensator on measured Tcold

$\tau_6; \tau_7$ = Time constants utilized in the lag compensator for Thot and Tcold: τ_6 = 0 secs; τ_7 = 0 secs

$Tcave_i$ = $\sum (T^f c_{ij})/2$ for j = 1 - 2 for each loop, i = 1 - 4

Note: A 2-input RSA determines a quality code and a value for $Tcave_i$, depending on the quality and consistency of the individual $T^f c_{ij}$ values. (Refer to Section 7.2.2.3)

ΔTi = $(Thave_i - Tcave_i)$ for each loop, i = 1 - 4, °F

$\overline{Tavg}_i$ = $(Thave_i + Tcave_i)/2$ for each loop, i = 1 - 4, °F

$\frac{1+\tau_4 s}{1+\tau_5 s}$ = The function generated by the lead-lag controller for ΔT dynamic compensation

$\tau_4; \tau_5$ = Time constants utilized in the lead-lag controller for ΔT: τ_4 = 0 sec; τ_5 = 0 sec

P = pressurizer pressure signal, psig

$\frac{1+\tau_1 s}{1+\tau_2 s}$ = the function generated by the lead-lag controller for $Tavg_i$ dynamic compensation

τ_1 ; τ_2 = time constants utilized in the lead-lag controller for Tavg:
τ_1 = 30 sec;
τ_2 = 4 sec

s = Laplace transform operator, sec^{-1}

K_1 = (*)

K_2 = (*)

K_3 = (*)

f_1 (ΔI) = a function of the indicated difference between top and bottom detectors of the power range nuclear ion chambers, with grains to be selected based on measured instrument response during plant startup tests such that:

(a) for $q_t - q_b$ between (*) and (*), f_1 (ΔI) = 0
(where q_t and q_b are percent rated thermal power in the top and bottom halves of the core respectively, and $q_t + q_b$ is total thermal power in percent of rated thermal power)

(b) for each percent that the magnitude of ($q_t - q_b$) exceeds (*), the ΔT trip setpoint shall be automatically reduced by (*) of its value at rated thermal power

(c) for each percent that the magnitude of ($q_t - q_b$) exceeds (*), the ΔT trip setpoint shall be automatically reduced by (*) of its value at rated thermal power

Note: The channel's maximum trip point shall not exceed its computed trip point by more than (*).

(*) Refer to Technical Specifications for current values to be used.

One power range channel separately feeds each overtemperature ΔT trip channel.

Changes in f_1 (ΔI) can only lead to a decrease in the trip setpoint; refer to Figure 7.2-2.

The single pressurizer pressure parameter required per loop is obtained from separate sensors that are connected to three pressure taps at the top of the pressurizer. The four pressurizer pressure signals are obtained from the three taps by connecting one of the taps to two pressure transmitters. Refer to Section 7.2.2.1.3 for analysis of this arrangement. Figure 7.2-1, Sheets 9 and 10, shows the logic for the overtemperature ΔT trip function.

(2) *Overpower ΔT Trip* - This trip protects against excessive power (fuel rod rating protection) and trips the reactor on coincidence as listed in Table 7.2-1, with one set of temperature measurements per loop. The setpoint for each channel is continuously calculated using the following equation:

$$\Delta Ti\frac{(1+\tau_4 s)}{(1+\tau_5 s)} \le \Delta Ti^{\circ}\left\{K_4 - K_5\frac{\tau_3 s}{1+\tau_3 s}Tavg_i - K_6\left[Tavg_i - Tavg_i^{\circ}\right] - f_2(\Delta I)\right\} \qquad (7.2\text{-}2)$$

where:

$Tavg_i$	=	As defined for overtemperature ΔT trip
ΔT_i	=	As defined for overtemperature ΔT trip
$Tavg_i^o$	=	As defined for overtemperature ΔT trip
ΔT_i^o	=	As defined for overtemperature ΔT trip
$\frac{1+\tau_4 s}{1+\tau_5 s}$	=	The function generated by the lead-lag controller for measured ΔT
τ_4; τ_5	=	Time constants used in the lead-lag controller for measured ΔT: τ_4 = 0 sec; τ_5 = 0 sec
K_4	=	(*)
K_5	=	(*)/°F for increasing average temperature; 0 for decreasing average temperature
K_6	=	(*) for $Tavg_i > Tavg_i^o$; K6 = 0 for $Tavg_i \le Tavg_i^o$
$\frac{\tau_3 s}{1+\tau_3 s}$	=	the function generated by the rate-lag controller for $Tavg_i$ dynamic compensation
τ_3	=	time constants utilized in the rate-lag controller for Tavg τ_3 = 10 sec
s	=	Laplace transform operator, sec^{-1}
f_2 (ΔI)	=	0 for all ΔI

Note: The channel's maximum trip point shall not exceed its computed trip point by more than (*).

(*) Refer to Technical Specifications for current values.

The source of temperature and flux information is identical to that of the overtemperature ΔT trip and the resultant ΔT setpoint is compared to the same ΔT. Figure 7.2-1, Sheets 9 and 10, shows the logic for this trip function.

7.2.2.1.3 Reactor Coolant System Pressurizer Pressure and Water Level Trips

The specific trip functions generated are:

(1) *Pressurizer Low-Pressure Trip* - The purpose of this trip is to protect against low pressure that could lead to departure from nucleate boiling (DNB), and to limit the necessary range of protection afforded by the overtemperature ΔT trip. The parameter being sensed is reactor coolant pressure as measured in the pressurizer. Above P-7, the reactor is tripped when the dynamically compensated pressurizer pressure measurements fall below preset limits. This trip is blocked below P-7 to permit startup. The trip logic and interlocks are provided in Table 7.2-1.

The trip logic is shown in Figure 7.2-1, Sheets 11 and 12.

(2) *Pressurizer High-Pressure Trip* - The purpose of this trip is to protect the reactor coolant system (RCS) against system overpressure.

The same sensors and transmitters used for the pressurizer low-pressure trip are used for the high-pressure trip except that separate comparators are used for the trip. These comparators trip when nondynamically compensated pressurizer pressure signals exceed preset limits on coincidence, as listed in Table 7.2-1. There are no interlocks or permissives associated with this trip function.

The logic for this trip is shown in Figure 7.2-1, Sheets 11 and 12.

(3) *Pressurizer High Water Level Trip* - This trip is provided as a backup to the pressurizer high-pressure trip and prevents the pressurizer from becoming water solid during low worth and low power rod withdrawal accidents. This trip is blocked below P-7 to permit startup. The coincidence logic and interlocks of the pressurizer high water level signals are provided in Table 7.2-1.

The trip logic for this function is shown in Figure 7.2-1, Sheets 11 and 12.

7.2.2.1.4 Reactor Coolant System Low-Flow Trips

These trips protect the core from DNB in the event of a loss of coolant flow situation. The means of sensing the loss of coolant are:

(1) *Reactor Coolant Low-Flow Trip* - The parameter sensed is reactor coolant flow. Three elbow taps in each coolant loop are used as flow devices that indicate the status of reactor coolant flow. The basic function of these devices is to provide information as to whether or not a reduction in flow has occurred. An output signal from two out of the three comparators in a loop would indicate a low flow in that loop. The trip logic for this function is shown in Figure 7.2-1, Sheets 9 and 10. The coincidence logic and interlocks are shown in Table 7.2-1.

(2) *Reactor Coolant Pump Breakers Open Trip* - Opening of two reactor coolant pump breakers or redundant overcurrent protection breakers above the P-7 interlock setpoint, which is indicative of an imminent loss of coolant flow, also causes a reactor trip.

One set of auxiliary contacts on each pump breaker serves as the input signal to the trip logic. The trip logic for this function is shown in Figure 7.2-1, Sheets 9 and 10. The coincident logic and interlocks are shown in Table 7.2-1.

(3) *Reactor Coolant Pump Bus Undervoltage Trip* - This trip is required to protect against low flow that can result from loss of voltage to the reactor coolant pumps. Time delays are incorporated in the undervoltage trip relays to prevent spurious reactor trip from momentary electrical power transients. The maximum external time delay is determined to be 0.6 seconds. This allows the total time delay for reactor UV trip to stay within the limits specified in Equipment Control Guidelines and also within the limit established in the accident analysis, Section 15.1.5. (The nominal time delay will be 0.5 seconds, with a tolerance of +/- 0.05 seconds.) There are two undervoltage sensors on each of the two buses. A one-out-of-two undervoltage signal on both buses trips the reactor if above the P-7 setpoint and starts the turbine-driven auxiliary feedwater pump at any reactor power level. The trip logic for this function is shown in Figure 7.2-1, Sheets 9 and 10.

(4) *Reactor Coolant Pump Bus Underfrequency Trip* - This trip is required to protect against low flow resulting from bus underfrequency, which might result from a major power grid frequency disturbance.

There are three underfrequency sensors on each of two buses. A two-out-of-three underfrequency signal on either bus trips the reactor if above the P-7 setpoint. The logic scheme is arranged so that a two-out-of-three underfrequency signal on bus 1 trips the breakers to reactor coolant pumps 1 and 2 only, and a two-out-of-three underfrequency signal on bus 2 will trip the breakers to reactor coolant pumps 3 and 4 only. The trip logic for this function is shown in Figure 7.2-1, Sheets 9 and 10.

7.2.2.1.5 Low-Low Steam Generator Water Level Trip (Including Trip Time Delay)

This trip protects the reactor from loss of heat sink in the event of a loss of feedwater to one or more steam generators or a major feedwater line rupture. This trip is actuated on two out of three low-low water level signals occurring in any steam generator. If a low-low water level condition is detected in one steam generator, signals shall be generated to trip the reactor and start the motor-driven auxiliary feedwater pumps. If a low-low water level condition is detected in two or more steam generators, a signal is generated to start the turbine-driven auxiliary feedwater pump as well.

The signals to actuate reactor trip and start auxiliary feedwater pumps are delayed through the use of a Trip Time Delay (TTD) system for reactor power levels below 50 percent of RTP. Low-low water level in any protection set in any steam generator will generate a signal that starts an elapsed time trip delay timer. The allowable trip time delay is based upon the prevailing power level at the time the low-low level trip setpoint is reached. If power level rises after the trip time delay setpoints have been determined, the trip time delay is redetermined (i.e., decreased) according to the increase in power level. However, the trip time delay is not changed if the power level decreases after the delay has been determined. The use of this delay allows added time for natural steam generator level stabilization or operator intervention to avoid an inadvertent protection system actuation.

The logic is shown in Figure 7.2-1, Sheets 13 and 14.

Steam generator water level low-low trip time delay:

$$TD = B1(P)^3 + B2(P)^2 + B3(P) + B4 \qquad (7.2\text{-}3)$$

where:

P = RCS loop ΔT equivalent to power (% rated thermal power (RTP)); $P \leq 50\%$ RTP

TD = time delay for steam generator water level low-low reactor trip (in seconds)

B1, B2, B3, and B4 are constants:

B1 = -0.007128
B2 = +0.8099
B3 = -31.40
B4 = +464.1

7.2.2.1.6 Turbine Trip-Reactor Trip

The turbine trip-reactor trip is actuated by two-out-of-three logic from low autostop oil pressure signals or by all closed signals from the turbine steam stop valves. A turbine trip causes a direct reactor trip above P-9.

Other turbine trips are discussed in Chapter 10.

The logic for this trip is shown in Figure 7.2-1, Sheets 3, 7, 19, 31 and Sheets 4, 8, 20, 32.

The analog portion of the trip shown in Figure 7.2-1, Sheets 31 and 32, is represented by dashed lines. When the turbine is tripped, turbine autostop oil pressure drops, and the pressure is sensed by three pressure sensors. A logic output is provided from each sensor when the oil pressure drops below a preset value. These three outputs are transmitted to two redundant two-out-of-three logic matrices, either of which trips the reactor if above P-9.

The autostop oil pressure signal also dumps the emergency trip fluid, closing all of the turbine steam stop valves. When all stop valves are closed, a reactor trip signal is initiated if the reactor is above P-9. This trip signal is generated by redundant contacts in each stop valve limit switch.

7.2.2.1.7 Safety Injection Signal Actuation Trip

A reactor trip occurs when the safety injection system (SIS) is actuated. The means of actuating the SIS are described in Section 7.3.2. Figure 7.2-1, Sheets 15 and16, shows the logic for this trip.

7.2.2.1.8 Manual Trip

The manual trip consists of two switches with four outputs on each switch. Each switch provides a trip signal for both trip breakers and both bypass breakers. (Operating a manual trip switch also removes the voltage from the undervoltage trip coil.)
There are no interlocks that can block this trip. Figure 7.2-1, Sheets 5 and 6, shows the manual trip logic.

7.2.2.1.9 Seismic Trip

The seismic trip system operates to shut down reactor operations should ground accelerations exceed a preset level in any two of the three orthogonal directions monitored (one vertical, two horizontal). The preset level is indicated in the Technical Specifications (Reference 4). No credit was taken for operation of the seismic trip in the safety analysis; however, its functional capability at the specified trip settings is required to enhance the overall reliability of the reactor protection system.

Three triaxial sensors (accelerometers) are anchored to the containment base in three separate locations 120 degrees apart (Figure 7.2-6). Each senses acceleration in three mutually orthogonal directions. Output signals are generated when ground accelerations exceed the preset level. These signals, lasting from 6 to 20 seconds (adjustable), are wired directly to the Trains A and B solid state protection system (SSPS). Refer to Figure 7.2-1, Sheets 35 and 36. If two of the three sensors in any direction produce simultaneous outputs, the logic produces trains A and B reactor trip signals.

The seismic reactor trip system was designed in compliance with IEEE 279-1971 (Reference 7) and IEEE 344-1975 (Reference 21), but will not be required to function during or following a LOCA or fire. Cables and raceways are separated in accordance with Section 8.3.1.4.1

7.2.2.1.10 Automatic Trip Logic

The general alarm system, described in Reference 5, maintains a check on each train of the solid-state logic protection system for the existence of certain undesirable conditions. Both trains are tripped if an abnormal condition occurs simultaneously in both trains. Reference 5 states that SSPS printed circuit boards (PCBs) use Motorola High Threshold Logic (MHTL). MHTL based PCBs are obsolete and have been replaced with PCBs which are not based on MHTL (Reference 33). The replacement universal logic, safeguards driver, or under voltage driver PCBs have diagnostic features that can activate a general warning alarm when there is a critical board problem.

7.2.2.2 Reactor Trip System Interlocks

7.2.2.2.1 Power Escalation Permissives

The overpower protection provided by the out-of-core nuclear instrumentation consists of three discrete, but overlapping, levels. Continuation of startup operation or power increase requires a permissive signal from the higher range instrumentation channels before the lower range level trips can be manually blocked by the operator.

A one-out-of-two intermediate range permissive signal (P-6) is required prior to source range level trip blocking and detector high voltage cutoff. Source range level trips are automatically reactivated and high voltage restored when both intermediate range channels are below the permissive (P-6) levels. There is a manual reset switch for administratively reactivating the source range level trip and detector high voltage when between the permissive P-6 and P-10 level, if required. Source range level trip block and high voltage cutoff are always maintained when above the permissive P-10 level.

The intermediate range level trip and power range (low setpoint) trip can be blocked only after satisfactory operation and permissive information are obtained from two-out-of-four power range channels. Individual blocking switches are provided so that the low range power range trip and intermediate range trip can be independently

blocked. These trips are automatically reactivated when any three of the four power range channels are below the permissive (P-10) level, thus ensuring automatic activation to more restrictive trip protection.

The development of permissives P-6 and P-10 is shown in Figure 7.2-1, Sheets 7 and 8. All of the permissives are digital; they are derived from analog signals in the nuclear power range and intermediate range channels.

Refer to Table 7.2-2 for the list of protection system interlocks.

7.2.2.2.2 Blocks of Reactor Trips at Low Power

Interlock P-7 blocks a reactor trip at low power (below approximately 10 percent of full power) on a low reactor coolant flow or reactor coolant pump open breaker signal in more than one loop, reactor coolant pump undervoltage, reactor coolant pump underfrequency, pressurizer low pressure, and pressurizer high water level on both units. Refer to Figure 7.2-1, Sheets 9, 10 and Sheets 11, 12 for permissive applications. The low power signal is derived from three-out-of-four power range neutron flux signals below the setpoint in coincidence with one-out-of-two turbine impulse chamber pressure signals below the setpoint (low plant load).

The P-8 interlock blocks a reactor trip when the plant is below a preset level specified in the Technical Specifications on a low reactor coolant flow in any one loop. The block action (absence of the P-8 interlock signal) occurs when three-out-of-four neutron flux power range signals are below the setpoint. Thus, below the P-8 setpoint, the reactor is allowed to operate with one inactive loop, and trip will not occur until two loops are indicating low flow. Refer to Figure 7.2-1, Sheets 7 and 8, for derivation of P-8, and Sheet 5 for the applicable logic.

The P-9 interlock blocks a reactor trip below the maximum value of 50 percent of full power on a turbine trip signal. Refer to Figure 7.2-1, Sheets 2, 7, 31 and Sheets 4, 8, 32 for the application logic. The reactor trip on turbine trip is actuated by two-out-of-three logic from emergency trip fluid pressure signals or by all closed signals from the turbine steam stop valves.

Refer to Table 7.2-2 for the list of protection system blocks.

7.2.2.3 Coolant Temperature Sensor Arrangement and Calculational Methodology

The individual narrow range cold and hot leg temperature signals required for input to the reactor trip circuits and interlocks are obtained using resistance temperature detectors (RTDs) installed in each reactor coolant loop.

The cold leg temperature measurement on each loop is accomplished with a dual element narrow-range RTD mounted in a thermowell. The cold leg sensors are inherently redundant in that either sensor can adequately represent the cold leg

temperature measurement. Temperature streaming in the cold leg is not a concern due to the mixing action of the reactor coolant pump.

The hot leg temperature measurement on each loop is accomplished with three dual element narrow-range RTDs mounted in thermowells spaced 120 degrees apart around the circumference of the reactor coolant pipe for spatial variations. One of the elements in each thermowell is an installed spare.

These cold and hot leg narrow-range RTD signals are input to the protection system digital electronics and processed as follows:

The two filtered cold leg temperature input signals $T^f c_j$ for each loop i are processed to determine a group average value $T^f cave_i$. The 2-input redundant sensor algorithm (RSA) calculates the group average value based on the number of good input signals.

If both input signals are BAD, the group value is set equal to the average of the two bad sensor values. If one signal is BAD and the other is DISABLED, the group value is set equal to the value of the bad sensor. The group quality is set to BAD in either case.

If one of the input signals is BAD and the other is GOOD, the group value is set equal to the GOOD value. A consistency check is not performed. The group quality is set to POOR.

If neither of the input signals is BAD, a consistency check is performed. If the deviation of these two signals is within an acceptance tolerance (±DELTAC), the group quality is set to GOOD and the group value is set equal to the average of the two inputs. If the difference exceeds ±DELTAC, the group quality is set to BAD, and the individual signal qualities are set to POOR. The group value is set equal to the average of the two inputs.

DELTAC is a fixed input parameter based on operating experience. One DELTAC value is required for each protection set.

Estimates of hot leg temperature are derived from each T_{hot} input signal as follows:

$$\overline{T}_{hestij} = T^f_{hij} - P_{B_i S^o_{ij}} \qquad (7.2\text{-}4)$$

where:

T^f_{hij} is the filtered T_{hot} signal for the jth RTD (j = 1 to 3) in the ith loop (i = 1 to 4)

P_{B_i} = power fraction being used to correct the bias value being used for any power level

$$P_{B_i} = \left(T^f_{have_i} - T^f_{cave_i}\right) / \Delta T^\circ_i \qquad (7.2\text{-}5)$$

where:

ΔT^o_i is the full power ΔT in the ith loop

S^o_{ij} = manually input bias that corrects the individual T_{hot} RTD value to the loop average.

The three hot leg temperature estimates T_{hestj} for each loop i are processed to determine a group average value T^f_{havei}. The 3-input RSA calculates the group value T^f_{havei} based on the available number of good input values.

If all three inputs are BAD, the group value is set to the average of the three input sensor values. The group value quality is set to BAD. If only one input is GOOD, the group value is set equal to the value of the good sensor. The group quality is set to BAD.

If two inputs are good, the difference between the two sensors is compared to DELTAH. If the inputs do not agree within ±DELTAH, the group quality is set to BAD and the quality of both inputs is set to POOR. If the inputs agree, the group quality is set to GOOD. The group value is set equal to the average of the two inputs in either case.

If all three inputs are good, an average of the three estimated hot leg temperatures is computed and the individual signals are checked to determine if they agree within ± DELTAH of the average value. If all of the signals agree within ± DELTAH of the average value, the group quality is set to GOOD. The group value (T^f_{havei}) is set to the average of the three estimated average hot leg temperatures.

If the signal values do not all agree within ± DELTAH of the average, the RSA will delete the signal value that is furthest from the average. The quality of this signal will be set to POOR and a consistency check will then be performed on the remaining GOOD signals. If these signals pass the consistency check, the group value will be taken as the average of these GOOD signals and the group quality will be set to POOR. However, if these signals again fail the consistency check (within ± DELTAH), then the group value will be set to the average of these two signals; but the group quality will be set to BAD. All of the individual signals will have their quality set to POOR.

DELTAH is a fixed input parameter based upon temperature fluctuation within the hot leg. One DELTAH value is required for each protection set.

Delta T and T Average are calculated as follows:

$$\Delta T_i = T^f_{have_i} - T^f_{cave_i} \qquad (7.2\text{-}6)$$

$$T_{avg_i} = (T^f_{have_i} + T^f_{cave_i}) / 2.0 \qquad (7.2\text{-}7)$$

The calculated values for Delta T and T_{avg} are then utilized for both the remainder of the Overtemperature and Overpower Delta T protection channel and channel outputs for control purposes.

A similar calculation of Delta T is performed for and used by the steam generator low-low level trip time delay (TTD) function.

Alarms are generated from a group status that is based on the quality of $T^f_{have_i}$ and $T^f_{cave_i}$ out of the RSA. If the quality of either group is BAD and all of the inputs for that group are not off scale low, then the group status is set to TROUBLE and RTD FAILURE. If either quality is POOR and all of its inputs are not off scale low, then the group status is set to TROUBLE. Otherwise, the group status is set to GOOD.

7.2.2.4 Pressurizer Water Level Reference Leg Arrangement

The design of the pressurizer water level instrumentation includes a slight modification of the usual tank level arrangement using differential pressure between an upper and a lower tap. The modification shown in Figure 7.2-4 consists of the use of a sealed reference leg instead of the conventional open column of water. Refer to Section 7.2.2.11.4 for an analysis of this arrangement.

7.2.2.5 Process Protection System

The process protection system is described in Reference 3.

With the installation of the RTD bypass elimination functional upgrade as part of the Eagle 21 process protection system upgrade, the following plant operating concerns are addressed:

(1) The possibility of loss of flow or reduced flow through the common return line of the hot and cold RTD bypass manifold, as a result of transport time of the temperature measurements for the RTD loop, affecting the design basis for the overtemperature, overpower and control channels monitoring associated with the affected RTD bypass loop is eliminated.

(2) Operator indication of the loop Tavg, Tavg, and Delta-T deviation alarms is maintained, providing the operator the same detecting signals as with the bypass loops.

(3) The potential for a failed Thot RTD affecting the loop Tavg, Tavg, and ΔT measurements is reduced due to the algorithms provided in the Eagle 21 process protection system software that automatically detect a failed RTD

and eliminate the failed RTDs measurement from affecting these plant parameters

7.2.2.6 Solid State (Digital) Logic Protection

The solid-state logic protection system takes binary inputs, (voltage/no voltage) from the process and nuclear instrument channels and direct inputs corresponding to conditions (normal/abnormal) of plant parameters. The system combines these signals in the required logic combination and generates a trip signal (no voltage) to the undervoltage coils of the reactor trip circuit breakers and an undervoltage auxiliary relay when the necessary combination of signals occurs. The undervoltage auxiliary relay sends a trip signal (125-Vdc) to the shunt trip coils of the reactor trip breakers. The system also sends actuation signals to engineered safety features (ESF) components (as discussed in Section 7.3), provides annunciator, status light, and computer input signals that indicate the condition of bistable input signals, partial- and full-trip functions, and the status of the various blocking, permissive, and actuation functions. In addition, the system includes means for semiautomatic testing of the logic circuits. A detailed description of this system is provided in Reference 6. Reference 6 is based on SSPS printed circuit boards (PCBs) that use Motorola High Threshold Logic (MHTL). MHTL based PCBs are obsolete and have been replaced with PCBs which are not based on MHTL (Reference 33).

7.2.2.7 Reactor Trip Breakers

The reactor trip breakers are equipped for automatic actuation of both the undervoltage trip device and the shunt trip device. The reactor trip breakers are also equipped to permit manual trip of the breakers at the switchgear cabinet.

7.2.2.8 Isolation Devices

In certain applications, it is advantageous to employ control signals derived from individual protection channels through isolation devices contained in the protection channel, as permitted by IEEE-279-1971 (Reference 7).

In all of these cases, signals derived from protection channels for nonprotective functions are obtained through isolation devices located in the process protection racks. By definition, nonprotective functions include those signals used for control, remote process indication, and computer monitoring.

Isolation devices qualification type tests are described in References 8, 9, and 32.

7.2.2.9 Energy Supply and Environmental Qualification Requirements

The energy supply for the RTS, including the voltage and frequency variations, is described in Section 8.3.1.1.5.2.1, Class 1E 120-Vac Instrument Power Supply System.

Refer to Section 8.3.1.1.5.2.1 and Section 8.3.1.1.5.3.8 for a discussion on the power supply for the RTS and compliance with IEEE 308-1971 (Reference 13).

There are no Class I motors in the RTS; therefore, IEEE 334-1971 (Reference 15) does not apply.

The environmental qualification requirements are identified in Section 3.11.

7.2.2.10 Reactor Trip System Instrumentation Trip Setpoints

While most setpoints used in the RTS are fixed, there are variable setpoints, most notably the overtemperature ΔT and overpower ΔT setpoints. All setpoints in the RTS have been selected either on the basis of applicable engineering code requirements or engineering design studies. Methodologies for determining RTS setpoint and allowable values are presented in WCAP-11082, Technical Specification 3.3.1, or in plant procedures. The capability of the RTS to prevent loss of integrity of the fuel cladding and/or RCS pressure boundary during Condition II transients is demonstrated in Section 15.2. A reactor trip is also credited for certain Condition III and IV events as described in Sections 15.3 and 15.4. These accident analyses are carried out using those setpoints determined from results of the engineering design studies. Functions that require a reactor trip and associated setpoint limits are presented in the Technical Specifications. A discussion of the intent for each of the various reactor trips and the accident analysis (where appropriate) that utilize the trip is presented in Section 7.2.2.1. It should be noted that the selected trip setpoints all provide for margin before protection action is actually required to allow for uncertainties and instrument errors.

The setpoints for the various functions in the RTS have been analytically determined such that the operational limits so prescribed prevent fuel rod cladding damage and loss of integrity of the RCS as a result of any Condition II incident (anticipated malfunction). As such, the RTS limits the following parameters to:

(1) Minimum DNBR = The applicable limit value (Refer to Sections 4.4.4.1 and 4.4.3.3)

(2) Maximum system pressure = 2,750 psia

(3) Total core power less than or equal to 118 percent of nominal (limits the fuel rod maximum linear power to a kW/ft., less than the value that could cause fuel centerline melt)

The accident analyses described in Section 15.2 demonstrate that the functional requirements as specified for the RTS are adequate to meet the above considerations, even assuming, for conservatism, adverse combinations of instrument errors (Refer to Table 15.1-2). A discussion of the safety limits associated with the reactor core and RCS, plus the limiting safety system setpoints, is presented in the Technical Specifications.

7.2.2.11 Specific Control and Protection Interactions

7.2.2.11.1 Nuclear Power

Four power range nuclear power channels are provided for overpower protection. An additional control input signal is derived by auctioneering of the four channels for automatic rod control. If any channel fails producing a low output, that channel is incapable of proper overpower protection but does not cause control rod movement because of the auctioneer. Two-out-of-four overpower trip logic ensures an overpower trip, if needed, even with an independent failure in another channel.

In addition, a deviation signal gives an alarm if any nuclear power channel deviates significantly from any of the other channels. Also, the control system responds only to rapid changes in nuclear power; slow changes or drifts are compensated by the temperature control signals. Finally, an overpower signal from any nuclear power range channel will block manual and automatic rod withdrawal. The setpoint for this rod stop is below the reactor trip setpoint.

7.2.2.11.2 Coolant Temperature

The accuracy of the RTD temperature measurements is demonstrated during plant startup tests by comparing temperature measurements from all RTDs with one another. The comparisons are done with the RCS in an isothermal condition. The linearity of the ΔT measurements obtained from the hot leg and cold leg RTDs as a function of plant power is also checked during plant startup tests.

The absolute value of ΔT versus plant power is not important as far as reactor protection is concerned. RTS setpoints are based on percentages of the indicated ΔT at nominal full power, rather than on absolute values of ΔT. For this reason, the linearity of the ΔT signals as a function of power is of importance rather than the absolute values of the ΔT. As part of the plant startup tests, the loop RTDs signals are compared with the core exit thermocouple signals. Note also that reactor control is based on signals derived from protection system channels after isolation by isolation devices so that no feedback effect can perturb the protection channels.

Because control is based on the average temperature of the loop having the highest average temperature, the control rods are always moved based on the most conservative temperature measurement with respect to margins to DNB. A spurious low average temperature measurement from any loop temperature control channel causes no control action. A spurious high average temperature measurement causes rod insertion (safe direction).

In addition, channel deviation signals in the control system give an alarm if any temperature channel deviates significantly from the auctioneered (highest) value.

Automatic rod withdrawal blocks also occur if any two of the temperature channels indicate an overtemperature or overpower condition.

7.2.2.11.3 Pressurizer Pressure

The pressurizer pressure protection channel signals are used for high- and low-pressure protection and as inputs to the overtemperature ΔT trip protection function. Isolated output signals from these channels are used for pressure control. These are used to control pressurizer spray and heaters, and power-operated relief valves. Pressurizer pressure is sensed by fast-response pressure transmitters.

A spurious high-pressure signal from one channel can cause decreasing pressure by actuation of either spray or relief valves. Additional redundancy is provided in the low pressurizer pressure reactor trip logic and in the logic for safety injection to ensure low-pressure protection.

The pressurizer heaters are incapable of over pressurizing the RCS. Overpressure protection is based on the positive volume surge of the reactor coolant produced as a result of turbine trip under full load, assuming the core continues to produce full power. The self-actuated safety valves are sized on the basis of steam flow from the pressurizer to accommodate this surge at a setpoint of 2500 psia and an accumulation of 3 percent. Note that no credit is taken for the relief capability provided by the power-operated relief valves during this surge.

In addition, operation of any one of the power-operated relief valves can maintain pressure below the high-pressure trip point for most transients. The rate of pressure rise achievable with heaters is slow, and ample time and pressure alarms are available to alert the operator to the need for appropriate action.

Two of the pressure sensors share a common tap. The other two sensors use separate taps. Redundancy is not impaired by having a shared tap because the logic for this trip is two-out-of-four. If the shared tap is plugged, the reading of the affected channels will remain static. If the impulse line bursts, the indicated pressure will drop to zero. In either case, the fault is easily detectable, and the protective function remains operable.

7.2.2.11.4 Pressurizer Water Level

Three pressurizer water level channels are used for reactor trip (two-out-of-three high level). Isolated signals from these channels are used for pressurizer water level control. A failure in the water level control system could fill or empty the pressurizer at a slow rate (on the order of 1/2 hour or more).

Experience has shown that hydrogen gas can accumulate in the upper part of the condensate pot on conventional open reference leg systems in pressurizer water level service. At RCS operating pressures, high concentrations of dissolved hydrogen in the reference leg water are possible. On sudden depressurization accidents, it has been hypothesized that rapid effervescence of the dissolved hydrogen could blow water out of

the reference leg and cause a large level error, measuring higher than actual level. Accurate calculations of this effect have been difficult to obtain. To eliminate the possibility of such effects in this application, a bellows is used in a pot at the top of the reference leg to provide an interface seal and prevent dissolving the hydrogen gas into the reference leg water. Supplier tests confirmed a time response of less than 1 second for the channel.

The reference leg is uninsulated and remains at local ambient temperature. This temperature varies somewhat over the length of the reference leg piping under normal operating conditions, but does not exceed 140°F. During the extreme temperature conditions caused by a blowdown accident, any reference leg water flashing to steam is confined to the condensate steam interface in the weir at the top of the temperature barrier leg and has only a small (about 12 inches between the top of weir and bellows) effect on the measured level. Some additional error may be expected due to effervescence of hydrogen in the temperature barrier water. However, even if complete loss of this water is assumed, the error will be less than 1 foot and will not violate a safety limit.

The sealed reference leg design has been installed in various plants since early 1970, and operational accuracy was verified by use of the sealed reference leg system in parallel with an open reference leg channel. No effects of operating pressure variations on either the accuracy or integrity of the channel have been observed.

Calibration of the sealed reference leg system is done in place, after installation, by application of known pressure to the high pressure side of the transmitter with the pressure of the height of the reference column, corrected for density, applied to the transmitter low side. The effects of static pressure variations are predictable. The largest effect is due to the density change in the saturated fluid in the pressurizer itself. The effect is typical of level measurements in all tanks with two-phase fluid and is not peculiar to the sealed reference leg technique.

In the sealed reference leg, there is a slight compression of the fill water with increasing pressure, but this is taken up by the flexible bellows. A leak of the fill water in the sealed reference leg is detectable by comparison of redundant channel readings while the plant is on-line, and by physical inspection of the reference leg while the plant is off-line. Leaks of the reference leg to atmosphere are immediately detectable by off-scale indications and alarms on the control board. A closed pressurizer level instrument shutoff valve would be detected by comparing the level indications from the redundant level channels (three channels). In addition, there are alarms on one of the three channels to indicate an error between the measured pressurizer water level and the programmed pressurizer water level. The instrument sensing lines for these level sensing instruments are designed so that no single instrument valve can affect more than one of the three level channels.

The high water level trip setpoint provides sufficient margin so that the undesirable condition of discharging liquid coolant through the safety valves is avoided. Even at full power conditions, which would produce the worst thermal expansion rates, a failure of

the water level control would not lead to any liquid discharge through the safety valves. This is due to the automatic high pressurizer pressure reactor trip actuating at a pressure sufficiently below the safety valve setpoint.

For control failures that tend to empty the pressurizer, two-out-of-four logic for safety injection action low pressurizer pressure ensures that the protection system can withstand an independent failure in another channel. In addition, ample time and alarms exist to alert the operator of the need for appropriate action.

7.2.2.11.5 Signal Validation Functions

The basic function of the reactor protection circuits associated with low steam generator water level is to preserve the steam generator heat sink for removal of long-term residual heat.

Should a complete loss of feedwater occur, the reactor would be tripped on low-low steam generator water level. In addition, redundant auxiliary feedwater pumps are provided to supply feedwater in order to maintain residual heat removal after trip, preventing eventual thermal expansion and discharge of the reactor coolant through the pressurizer relief valves into the relief tank even when main feedwater pumps are incapacitated. This reactor trip acts before the steam generators are dry to reduce the required capacity and starting time requirements of these auxiliary feedwater pumps, and to minimize the thermal transient on the RCS and steam generators. Therefore, a low-low steam generator water level reactor trip is provided for each steam generator to ensure that sufficient initial thermal capacity is available in the steam generator at the start of the transient. It is desirable to minimize thermal transients on a steam generator for a credible loss of feedwater accident. Hence, it should be noted that a protection system failure causing control system reaction is eliminated by implementation of control system signal validation; that is, steam generator water level (SGWL) median signal selector (MSS) and steam flow arbitrator (SFA) functions in the PG&E Design Class II digital feedwater control system.

The prime objective of the signal validation functions is to prevent a single failed protection system instrument channel from causing a disturbance in the feedwater control system requiring subsequent protective action, as required by IEEE 279-1971. All three isolated narrow range water level channels for each steam generator are input to the SGWL MSS. The device selects the median value of its inputs for use by the feedwater control system, and control system action is then based on this validated signal. By rejecting the high and low signals, the control system is prevented from acting on any single, failed protection system instrument channel.

The SFA function is provided to validate the steam flow inputs. The SFA uses logic to determine an appropriate control signal output based on the two steam flow channels for each steam generator. If the two input signals agree within a specified limit, the arbitrator output is the average of the inputs. If the deviation between the input signals exceeds the specified limit, the input signal closest to the arbitration signal is selected as

the output. If neither of the inputs is within a specified limit, the arbitration signal itself is selected as the output of the arbitrator. The arbitration signal is based on turbine first stage pressure.

These algorithms prevent a single input channel failure from causing a control system transient requiring protective action. This includes failure of the instrument tap that is shared between one narrow-range level channel and one steam flow channel on each steam generator. The MSS function for steam generator narrow range level and the SFA function for steam flow satisfy the control and protection interaction requirement of IEEE 279-1971.

Since no adverse control system action may result from a single, failed protection instrument channel, a second random protection system failure (as would otherwise be required by IEEE 279-1971) need not be considered. A more detailed discussion of the SFA and MSS and their compliance with control and protection system interaction criteria is provided in Reference 27.

7.2.2.12 TESTS AND INSPECTIONS

The periodic testing of the RTS conforms to the requirements of IEEE 338-1971 (Reference 16), with the following comment:

(1) The periodic test frequency specified in the Technical Specifications was conservatively selected, using the considerations discussed in paragraph 4.3 of Reference 16, to ensure that equipment associated with protection functions has not drifted beyond its minimum performance requirements.

The testability of the system is discussed in Section 7.2.4.1.10.

The minimum frequencies for checks, calibration, and testing at each of the plant's operating modes are defined in the Technical Specifications. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

7.2.2.12.1 In-Service Tests and Inspections

Periodic surveillance of the RTS is performed to ensure proper protective action. This surveillance consists of checks, calibrations, and functional testing that are summarized in the following sections.

7.2.2.12.1.1 Channel Checks

A channel check consists of a qualitative assessment of channel behavior during operation by observation. This determination shall include, where possible, comparison of the channel indication and/or status with other indications and/or status derived from independent instrument channels measuring the same parameters.

7.2.2.12.1.2 Channel Calibration

A channel calibration shall be the adjustment, as necessary, of the channel such that it responds within the required range and accuracy to known values of input. The channel calibration shall encompass the entire channel including the sensors and alarm, interlock and/or trip functions, and may be performed by any series of sequential, overlapping, or total channel steps such that the entire channel is calibrated.

7.2.2.12.1.3 Actuation Logic Test

An actuation logic test shall be the application of various simulated input combinations in conjunction with each possible interlock logic state and verification of the required logic output. The actuation logic test shall include a continuity check, as a minimum, of output devices.

7.2.2.12.1.4 Process Protection Channel Operational Test

A channel operational test shall be the injection of a simulated signal into the channel as close to the sensor as practicable to verify operability of alarm, interlock, and/or trip functions. The channel operational test shall include adjustments, as necessary, of the alarm, interlock, and/or trip setpoints such that the setpoints are within the required range and accuracy.

7.2.2.12.1.5 Trip Actuating Device Operational Test

A trip actuating device operational test shall consist of operating the trip actuating device and verifying operability of alarm, interlock, and/or trip functions. The trip actuating device operational test shall include adjustment, as necessary, of the trip actuating device such that it actuates at the required setpoint within the required accuracy.

7.2.2.12.1.6 Reactor Trip System Response Time

The RTS response time shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until loss of stationary gripper coil voltage.

7.2.2.13 Current System Drawings

The current system drawings for the RTS and supporting systems are presented in Figures 7.2-1 through 7.2-6, and 7.3-1 through 7.3-52.

7.2.3 SAFETY EVALUATION

7.2.3.1 General Design Criterion 2, 1967 – Performance Standards

The RTS is located in the auxiliary building, which is a PG&E Design Class I structure. The auxiliary building is designed to withstand the effects of winds and tornadoes (refer

to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7) to protect the RTS and ensure its design function will be performed. Externally exposed equipment is evaluated in Section 3.3.2.3.2.6.

The seismic design considerations for the RTS are discussed in Section 3.10. A discussion of the seismic testing of the RTS equipment is presented in Section 3.10.3.

The monitoring circuitry, sensors and signal electronics, for several variables that provide inputs to the RTS are not seismically qualified, and in some cases, are not seismically mounted or classified as PG&E Design Class I. Those circuits are:

(1) Source range (SR) nuclear instrumentation - sensors and electronics (PG&E Design Class I)

(2) Intermediate range (IR) nuclear instrumentation - sensors and electronics (PG&E Design Class I)

(3) Main turbine stop valve closed limit switches (PG&E Design Class II)

(4) Main turbine auto-stop oil pressure switches (PG&E Design Class II)

(5) 12-kV bus underfrequency relays, potential transformers and test switches (PG&E Design Class II)

(6) 12-kV bus undervoltage relays, potential transformers and test switches (PG&E Design Class II)

(7) 12-kV reactor coolant pump circuit breaker open position switches (PG&E Design Class II)

Analyses have been performed to assure that the lack of seismic qualification and seismic installation of these inputs will not degrade the function of the RTS. The electrical circuits that provide the inputs to the RTS from these monitoring channels all are classified as PG&E Design Class I, Class 1E circuits. These analyses are based upon the following:

(1) *SR and IR Nuclear Instrumentation* - The DCPP safety analysis does not take credit for the SR or IR nuclear instrumentation as a primary reactor trip function. The safety analysis is bounded by credit taken for the seismically qualified power range nuclear instrumentation. Although the SR and IR nuclear instrumentation sensors and electronics are not seismically qualified, the SR and IR electronics drawers that provide the inputs to the RTS are seismically mounted in a seismically qualified cabinet. Therefore, no seismically induced common mode failures of the

SR or IR nuclear instrumentation drawers exist that could degrade the RTS safety function.

(2) *Main Turbine Stop Valve Closed Limit Switches* - The main turbine stop valve closed limit switches provide inputs to the RTS to signal a turbine tripped (loss of heat sink) condition. These inputs are secondary (backup) reactor trip signals. The stop valve limit switches and field termination cabinets have been seismically analyzed to confirm that the structural integrity of the limit switches and field termination cabinets are such that no seismically induced common mode failures of the main turbine stop valve closed limit switches or field termination cabinets exist that could degrade a primary RTS safety function.

(3) *Main Turbine Auto-Stop Oil Pressure Switches* - The main turbine auto-stop oil pressure switches provide inputs to the RTS to signal a turbine tripped (loss of heat sink) condition. These inputs are secondary (backup) reactor trip signals. The auto-stop oil pressure switches and the cabinet have been seismically analyzed to confirm that the structural integrity of the pressure switches and cabinet to which they are mounted is such that no seismically induced common mode failures of the pressure switches or cabinet exist that could degrade a primary RTS safety function.

(4) *12-kV System RTS Input Signals* - The 12-kV undervoltage (UV) circuits, underfrequency (UF) circuits and breaker open position switches provide inputs from the 12-kV system to the RTS to signal a loss of reactor coolant flow condition. The UV and UF inputs are backup reactor trip signals. The breaker open position inputs are also backup reactor trip signals. These circuits individually do not meet the RTS seismic qualification or mounting requirements. The UF circuits do not meet the fail-safe criterion. However, when analyzed as a "system," the 12-kV inputs to the RTS fail in such a manner as to assure a reactor trip should the equipment be subjected to an RTS design basis seismic event. In addition, the UV, UF and breaker position switch monitoring circuits and the equipment in which they are mounted have been seismically analyzed to confirm that their structural integrity is such that no seismically induced common mode failures of the monitoring circuits or the equipment in which they are mounted exist that could degrade an RTS safety function.

7.2.3.2 General Design Criterion 11, 1967 – Control Room

Controls and instrumentation related to RTS include control room status lights, annunciator displays and RTB switches on the control board with indicating lights to display breakers' position. Additionally, the reactor trip and bypass breakers can be operated locally.

7.2.3.3 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The RTS keeps surveillance on process variables that are directly related to equipment mechanical limitations such as pressure, pressurizer water level (to prevent water discharge through safety valves and uncovering heaters), and also on variables that directly affect the heat transfer capability of the reactor (e.g., flow and reactor coolant temperatures). Other parameters utilized in the RTS are calculated from various process variables. In any event, whenever a direct process or a calculated variable exceeds a setpoint, the reactor will be shut down to protect against either gross damage to fuel cladding or loss of system integrity that could lead to release of radioactive fission products into the containment.

While most setpoints used in the RTS are fixed, there are variable setpoints, most notably the overtemperature ΔT and overpower ΔT setpoints. All setpoints in the RTS have been selected either on the basis of applicable engineering code requirements or engineering design studies. Methodologies for determining RTS setpoint and allowable values are presented in WCAP-11082, Technical Specification 3.3.1, or in plant procedures. It should be noted that the selected trip setpoints all provide for margin before protection action is actually required to allow for uncertainties and instrument errors.

7.2.3.4 General Design Criterion 14, 1967 – Core Protection Systems

The RTS, together with associated equipment, is designed to act automatically to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits.

Operation below the applicable DNBR limit could result in excessive cladding temperature because of the onset of DNB and the resultant sharp reduction in heat transfer coefficient. Fuel centerline melting occurs when the local LHR, or power peaking, in a region of the fuel is high enough to cause the fuel centerline temperature to reach the melting point of the fuel. The core safety limits are established to prevent overheating of the fuel and cladding as well as possible cladding perforation. Figure 15.1-1 presents the allowable reactor coolant loop average temperature and ΔT for the design flow and the NSSS Design Thermal Power distribution as a function of primary coolant pressure. Refer to Section 15.1 for additional information.

DNBR is not a directly measurable quantity; however, the process variables that are statistically related to DNBR are sensed and evaluated. Small isolated changes in various process variables may not individually result in violation of a core safety limit, whereas the combined variation over sufficient time may cause the overpower or overtemperature safety limit to be exceeded. The design concept of the RTS takes cognizance of this situation by providing reactor trips associated with individual process variables in addition to the overpower and overtemperature safety limit trips. The process variable trips prevent reactor operation whenever a change in the monitored value is such that a core or system safety limit is in danger of being exceeded should

operation continue. Basically, the high-pressure, low-pressure, and overpower and overtemperature ΔT trips provide sufficient protection for slow transients, as opposed to such trips as low flow or high flux, which trip the reactor for rapid changes in flow or flux, respectively, that could result in fuel damage before actuation of the slower responding ΔT channels.

Therefore, the RTS has been designed to provide protection for fuel cladding and RCS pressure boundary integrity where: (a) a rapid change in a single variable or factor that will quickly result in exceeding a core or a system safety limit, and (b) a slow change in one or more variables has an integrated effect that causes safety limits to be exceeded. Overall, the RTS offers diverse and comprehensive protection against fuel cladding failure and/or loss of RCS integrity. Technical Specification Table 3.3.1-1 lists information related to the reactor trip system instrumentation safety limits and safety system settings. The limiting safety system settings are defined in Technical Specification Table 3.3.1-1 as the Allowable Values. The capability of the RTS to prevent loss of integrity of the fuel cladding and/or RCS pressure boundary during Condition II transients is demonstrated in Section 15.2. A reactor trip is credited for certain Condition III and IV events as described in Sections 15.3. and 15.4.

7.2.3.5 General Design Criterion 19, 1967 – Protection Systems Reliability

The protection systems are designed for high functional reliability and inservice testability. Each design employs redundant logic trains and measurement and equipment diversity. Sufficient redundancy is provided to enable individual end-to-end channel tests with each reactor at power without compromise of the protective function. Built-in semiautomatic testers provide means to test the majority of system components very rapidly.

The RTS uses sensors that feed the process circuitry consisting of two to four redundant channels, which monitor various plant parameters. The RTS also contains the logic circuitry necessary to automatically open the reactor trip breakers. The logic circuitry consists of two redundant logic trains that receive input from the protection channels.

Each of the two logic trains, A and B, is capable of opening a separate and independent reactor trip breaker (52/RTA and 52/RTB).

7.2.3.6 General Design Criterion 20, 1967 – Protection Systems Redundancy and Independence

Sufficient redundancy and independence is designed into the protection systems to ensure that neither single failure nor removal from service of any component or channel of a system will result in loss of the protection function.

Each individual channel is assigned to one of four channel designations, e.g., Channel I, II, III, or IV, refer to Figure 7.2-5. Channel independence is carried throughout

the system, extending from the sensor through to the devices actuating the protective function. Physical separation is used to achieve separation of redundant transmitters. Separation of wiring is achieved using separate wireways, cable trays, conduit runs, and containment penetrations for each redundant channel. Redundant process equipment is separated by locating electronics in different protection rack sets. Each redundant channel is energized from a separate ac power feed.

Position Regarding Separation of Isolated Signal Outputs within Process Protection Racks

It is PG&E's position that specific physical separation is not required within the process protection racks between the protection circuits and isolated nonprotection circuits, and that the degree of electrical separation plus the physical separation associated with the insulation on the wires is sufficient to meet the requirements of IEEE 279-1971.

The justification for this position is that IEEE 279-1971 covers this situation in three paragraphs quoted below:

4.2 Single Failure Criterion. Any single failure within the protection system shall not prevent proper protective action at the system level when required.

4.6 Channel Independence. Channels that provide signals for the same protective function shall be independent and physically separated to accomplish decoupling of the effects of unsafe environmental factors, electric transients, and physical accident consequences documented in the design basis, and to reduce the likelihood of interactions between channels during maintenance operations or in the event of channel malfunction.

4.7.2 Isolated Devices. The transmission of signals from protection system equipment for control system use shall be through isolation devices, which shall be classified as part of the protection system and shall meet all the requirements of this document. No credible failure at the output of an isolation device shall prevent the associated protection system channel from meeting the minimum performance requirements specified in the design base.

Examples of credible failures include short circuits, open circuits, grounds, and the application of the maximum credible ac and dc potential. A failure in an isolation device is evaluated in the same manner as a failure of other equipment in the protection system.

The intent of 4.2 and 4.6 with regard to protection signals is handled through a combination of electrical and physical separation. The electrical separation is handled by supplying each protection rack set with separate independent sources of power. Physical separation is provided by locating redundant channels in separate racks sets.

Thus separation, both electrical and physical, outside the rack is ensured. The intent of 4.7.2 is met within the process protection racks by the provision of qualified isolators that have been tested and verified to perform properly under the credible failures listed in 4.7.2. The isolator is designed to be an electrical barrier between protection and nonprotection and, as such, the degree of physical separation provided within the modules is that which is consistent with the voltages involved.

The question of whether or not specific physical separation is required is best addressed by reviewing the potential hazards involved. There are three general categories of hazards that must be protected against. These are missiles, electrical faults, and fire. Missiles external to the rack can be ruled out on the basis that the racks are located in general plant areas where it is not credible to assume missiles capable of penetrating the steel rack. (Refer to Section 3.5) Missiles within the rack can be ruled out on the basis that there is no mechanism within the racks for the generation of missiles with sufficient energy to cause damage to the hardware or wiring.

Electrical faults within a rack constitute a single failure. Since there is no internal mechanism capable of simultaneously causing such a failure in more than one protection set, the result is acceptable. The plant remains safe with three out of the four protection sets remaining in operation. A few very specific electrical faults, external to the protection racks, on the signals derived from protection channels may have access to the outputs of all protection sets simultaneously. However, the isolators have been shown to prevent these disturbances from entering the protection circuits; thus the results are acceptable.

Fire external to the racks is a potential hazard; however, fire retardant paint and wiring, fire barriers at the rack entrances, and adequate separation external to the racks provide a satisfactory defense against the hazard. For further discussions on fire protection, refer to Sections 8.3.1.2 and 9.5.1. A potential cause of fire within more than one protection set is an electrical fault involving the nonprotection outputs from these sets; however, it has been verified during the isolator tests that the fault current is terminated by the failure of certain components with no damage occurring in the wiring leading to the module. Thus, a fire within a rack set due to high current igniting or otherwise damaging the wiring is not possible.

The remaining source of fire within the racks - a short circuit within the protection wiring-effects only one protection set and thus is acceptable since three of the four protection sets remain.

It is thus established that no credible failure associated with the isolator output wiring violates the single failure criterion; therefore, the present method of rack wiring is entirely adequate.

7.2.3.7 General Design Criterion 21, 1967 – Single Failure Definition

The protection system is designed to provide two, three, or four instrumentation channels for each protective function and redundant (two) logic trains. These redundant channels and trains are electrically isolated and physically separated. Thus, any single failure within a channel or train will not prevent protective action at the system level when required.

To prevent the occurrence of common mode failures, such additional measures as functional diversity, testing, as well as administrative control during design, production, installation, and operation are employed, as discussed in Reference 11, for protection logic. Standard reliability engineering techniques were used to assess the likelihood of trip failure due to random component failures. Common mode failures were also qualitatively investigated. It was concluded from the evaluation that the likelihood of no trip following initiation of Condition II events is extremely small (2×10^{-7} derived for random component failures). The solid-state protection system design has been evaluated by the same methods as used for the relay system and the same order of magnitude of reliability is provided.

7.2.3.8 General Design Criterion 22, 1967 – Separation of Protection and Control Instrumentation Systems

The protection system is designed to be independent of the control system. In certain applications, the control signals and other nonprotective functions are derived from individual protective channels through isolation devices. The isolation devices are classified as part of the protection system and are located in the process protection racks. Nonprotective functions include those signals used for control, remote process indication, and computer monitoring. The isolation devices are designed so that a short circuit, open circuit, or the application of 118-Vac or 140-Vdc on the isolated output portion of the circuit (i.e., the nonprotective side of the circuit) will not affect the input (protective) side of the circuit. The signals obtained through the isolation devices are never returned to the protective racks.

A detailed discussion of the design and testing of the isolation devices is provided in References 8, 9, and 32. These reports include the results of applying various malfunction conditions on the output portion of the isolation devices. The results show that no significant disturbance to the isolation devices input signal occurred.

To provide additional assurance that the electrical wiring to and from the isolators, as installed, would not permit control-side faults to enter the protection system through input-output electrical coupling, tests were conducted at DCPP using voltages of 118-Vac, 250-Vdc, 460-Vac, 580-Vac and electrical noise. A description of these tests is provided in References 8, 12, and 32.

Where failure of a protection system component can cause a process excursion that requires protective action, the protection system can withstand another independent

failure without loss of protective action. The steam generator low-low water level protective function relies upon two-out-of-three (2/3) trip logic. The digital feedwater control system (DFWCS) uses the same steam generator level sensors as the steam generator low-low water level protective function. The DFWCS includes the median signal selector (MSS) and the Steam Flow Arbitrator (SFA). The installation of the MSS and SFA eliminates the possibility that failure of the instrument tap shared between one narrow-range level channel and one steam flow channel on each steam generator will cause a transient that would require protective action by any of the level channels. The MSS prevents the resulting failed high narrow range level signal from causing a level transient via the level portion of the DFWCS. The SFA prevents the resulting failed low steam flow signal from causing a level transient via the feed forward mass balance portion of the DFWCS. (Refer to Section 7.2.2.11.5) For details refer to Reference 27.

7.2.3.9 General Design Criterion 23, 1967 – Protection Against Multiple Disability for Protection Systems

Physical separation and electrical isolation of redundant channels and subsystems are employed in the RTS as defenses against functional failure through exposure to common causative factors.

Information from both logic trains is transmitted to the plant control boards and computer using a multiplex system. To ensure separation of the signals from each train, each signal is passed through an optically-coupled isolator. Verification tests on these isolators using voltages of 118-Vac and 250-Vdc are described in Reference 12.

To provide physical separation between input and output circuits in the solid-state protection system racks, physical barriers have been provided to separate input and output wire bundles.

Independence of the logic trains is discussed in Reference 6. Two reactor trip breakers are actuated by two separate logic matrices that interrupt power to the control rod drive mechanisms. The breaker main contacts are connected in series with the power supply so that opening either breaker interrupts power to all control rod drive mechanisms, permitting the rods to free-fall into the core. The design philosophy is to make maximum use of a wide variety of measurements. The protection system continuously monitors numerous diverse system variables. The extent of this diversity has been evaluated for a wide variety of postulated accidents and is discussed in Reference 1. Generally, two or more diverse protection functions would terminate the accident conditions before intolerable consequences could occur.

For a discussion of the tests made to verify the performance requirements, refer to Section 3.11.

7.2.3.10 General Design Criterion 24, 1967 – Emergency Power for Protection Systems

The instrumentation and controls portions of the protection systems are supplied initially from the station batteries and subsequently from the emergency diesel generators. A single failure of any one component will not prevent the required functioning of the RTS.

7.2.3.11 General Design Criterion 25, 1967 – Demonstration of Functional Operability of Protection Systems

The RTS is capable of being tested during power operation. Where only parts of the system are tested at any one time, the testing sequence provides the necessary overlap between the parts to ensure complete system operation. The process protection equipment is designed to permit any channel to be maintained in a bypassed condition and, when required, tested during power operation without initiating a protective action at the system level. This is accomplished without lifting electrical leads or installing temporary jumpers.

If a protection channel has been bypassed for any purpose, a signal is provided to allow this condition to be continuously indicated in the control room.

The operability of the process sensors is ascertained by comparison with redundant channels monitoring the same process variables or those with a fixed known relationship to the parameter being checked. The in-containment process sensors can be calibrated during plant shutdown, if required.

Surveillance testing of the process protection system is performed with the use of a Man Machine Interface (MMI) test system. The MMI is used to enter instructions to the installed test processor in the process protection rack being tested which then generates the appropriate test signals to verify proper channel operation. The capability is provided to test in either partial trip mode or bypass mode where the channel comparators are maintained in the not-tripped state during the testing. Testing in bypass is allowed by the plant Technical Specifications. The bypass condition is continuously indicated in the control room via an annunciator.

The power range channels of the nuclear instrumentation system are tested by superimposing a test signal on the actual detector signal being received by the channel at the time of testing. The output of the bistable is not placed in a tripped condition prior to testing. Also, because the power range channel logic is two-out-of-four, bypass of this reactor trip function is not required. Note, however, that the source and intermediate-range high neutron flux trips must be bypassed during testing.

To test a power range channel, a TEST-OPERATE switch is provided to require deliberate operator action. Operation of the switch initiates the CHANNEL TEST annunciator in the control room. Bistable operation is tested by increasing the test signal

level up to its trip setpoint and verifying bistable relay operation by control board annunciator and trip status lights.

It should be noted that a valid trip signal would cause the channel under test to trip at a lower actual reactor power level. A reactor trip would occur when a second bistable trips. No provision has been made in the channel test circuit for reducing the channel signal level below that signal being received from the nuclear instrumentation system detector. A nuclear instrumentation system channel that causes a reactor trip through one-out-of-two protection logic (source or intermediate range) is provided with a bypass function, which prevents the initiation of a reactor trip from that particular channel during the short period that it is undergoing testing. These bypasses initiate an alarm in the control room.

For a detailed description of the nuclear instrumentation system, refer to Reference 2.

The logic trains of the RTS are designed to be capable of complete testing at power, except for those trips listed in Section 7.2.3.17. Annunciation is provided in the control room to indicate when a train is in test, when a reactor trip is bypassed, and when a reactor trip breaker is bypassed. Details of the logic system testing are provided in Reference 6.

The reactor coolant pump breakers cannot be tripped at power without causing a plant upset by loss of power to a coolant pump. However, the reactor coolant pump breaker trip logic and continuity through the shunt trip coil can be tested at power. Manual trip cannot be tested at power without causing a reactor trip, because operation of either manual trip switch actuates both trains A and B. Note, however, that manual trip could also be initiated from outside the control room by manually tripping one of the reactor trip breakers. Initiating safety injection cannot be done at power without upsetting normal plant operation. However, the logic for these trips is testable at power.

7.2.3.12 General Design Criterion 26, 1967 – Protection Systems Fail-Safe Design

The PPS channels are designed so that upon loss of electrical power to any channel, the output of that channel is a trip signal. The following exceptions to GDC 26, 1967 are applicable to DCPP:

1. The RCP bus underfrequency trip channels are an exception to the fail-safe design requirement. The RCP bus underfrequency trip function, in conjunction with the RCP bus undervoltage function, provides a fail-safe protective function.

2. The seismic trip channels are an exception to the fail-safe design. Since no credit is taken in accident analyses for the seismic trip, the seismic trip channels are designed energize-to-actuate to eliminate the possibility of spurious trips.

7.2.3.13 General Design Criterion 31, 1967 – Reactivity Control Systems Malfunction

The RTS and its function, reactor shutdown by RCCA insertion, is completely independent of the normal control function, since the trip breakers interrupt power to the drive mechanisms regardless of existing control signals. The protection system is designed to limit reactivity transients so that DNBR will exceed the applicable limit value (refer to Sections 4.4.4.1 and 4.4.3.3) for any single malfunction in either reactor control system.

The analysis presented in Chapter 15 shows that for postulated dilution during refueling, startup, or manual or automatic operation at power, the operator has ample time to determine the cause of dilution, terminate the source of dilution, and initiate reboration before the shutdown margin is lost. The facility reactivity control systems are discussed further in Chapter 7, and analyses of the effects of the other possible malfunctions are discussed in Chapter 15. The analyses show that acceptable fuel damage limits are not exceeded in the event of a single malfunction of either system.

7.2.3.14 General Design Criterion 49, 1967 – Containment Design Basis

The RTS instrumentation circuits routed through containment electrical penetrations are designed to support the containment design basis as described in Section 7.2.4.2.

7.2.3.15 Reactor Trip System Safety Function Requirements

(1) Protection from Missiles

The provisions taken to protect the RTS from missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Section 3.5.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the RTS from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Section 3.6.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection of the RTS system portion located outside containment from the effects of moderate energy pipe failure are discussed in Section 3.6.

(4) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the RTS system portion located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

(5) Protection from Flooding Effects – Outside Containment

The provisions taken to provide protection of the RTS system portion located outside containment from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

7.2.3.16 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

The Class 1E RTS instrument cables required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ program and the requirements for the environmental design of the electrical and related mechanical equipment. The affected components are listed on the EQ Master List.

7.2.3.17 Safety Guide 22, February 1972 – Periodic Testing of Protection System Actuation Functions

Periodic testing of the RTS actuation functions, as described, complies with AEC Safety Guide 22, February 1972 (Reference 22). Under the present design, there are protection functions that are not tested at power. These are:

(1) Generation of a reactor trip by tripping the reactor coolant pump breakers

(2) Generation of a reactor trip by tripping the turbine

(3) Generation of a reactor trip by use of the manual trip switch

(4) Generation of a reactor trip by actuating the safety injection system

(5) Generation of a reactor trip by general warning circuitry (both redundant trains)

(6) Generation of a reactor trip by closing both reactor trip bypass breakers

The actuation logic for the functions listed is tested as described in Section 7.2.2.12. As required by Safety Guide 22, February 1972, where equipment is not tested during reactor operation, it has been determined that:

(1) There is no practicable system design that would permit operation of the equipment without adversely affecting the safety or operability of the plant.

(2) The probability that the protection system will fail to initiate the operation of the equipment is, and can be maintained, acceptably low without testing the equipment during reactor operation.

(3) The equipment can be routinely tested when the reactor is shut down.

Where the ability of a system to respond to a bona fide accident signal is intentionally bypassed for the purpose of performing a test during reactor operation, each bypass condition is automatically indicated to the reactor operator in the main control room by a separate annunciator for the train in test. Test circuitry does not allow two trains to be tested at the same time so that extension of the bypass condition to redundant systems is prevented.

7.2.3.18 NUREG-0737 (Items II.K.3.10 and II.K.3.12), November 1980 – Clarification of TMI Action Plan Requirements

Item II.K.3.10 – Proposed Anticipatory Trip Modification: The setpoint for the anticipatory reactor trip on turbine trip bypass (P-9) cannot be raised above 10% reactor power until it has been shown that the probability of a small-break loss-of-coolant accident (LOCA) resulting from a stuck-open power-operated relief valve (PORV) is substantially unaffected by the modification. DCPP raised P-9 to 50% with prior approval of the NRC after meeting this requirement. Refer also to Section 7.2.2.2.2.

Item II.K.3.12 – Anticipatory Reactor Trip upon Turbine Trip: The RTS includes an anticipatory reactor trip upon turbine trip for DCPP Unit 1 and Unit 2.

7.2.3.19 Generic Letter 83-28 (Actions 4.3 and 4.5), July 1983 – Required Actions Based on Generic Implications of Salem ATWS Events

Action 4.3 -- RTS Reliability (Automatic Actuation of Shunt Trip Attachment for Westinghouse and B&W Plants). The shunt trip was added to the reactor trip and bypass breakers.

Action 4.5 – RTS Reliability (System Functional Testing). The RTS is designed to allow on-line functional testing of the reactor trip system and this on-line testing includes independent testing of the undervoltage and shunt trip attachments of the reactor trip breakers. The intervals for on-line testing of the RTS are consistent with achieving high RTS availability.

7.2.4 COMPLIANCE WITH IEEE STANDARDS

7.2.4.1 Compliance with IEEE 279-1971

The RTS meets the requirements of IEEE 279-1971 as indicated below. SSPS was designed prior to IEEE 279-1971; however, its design has been approved by the NRC.

7.2.4.1.1 General Functional Requirement

The following are the generating station conditions requiring reactor trip:

(1) DNBR approaching the applicable limit value (Refer to Sections 4.4.4.1 and 4.4.3.3)

(2) Power density (kilowatts per foot) approaching rated value for Condition II faults (Refer to Sections 4.2.1, 4.3.2 and 4.4.2 for fuel design limits)

(3) RCS overpressure creating stressing approaching the limits specified in Sections 5.2 and 5.5

For a discussion of energy supply and environmental variations, refer to Sections 8.3.1.1.5 and 3.11.

The following is a list of the malfunctions, accidents, or other unusual events that could physically damage RTS components or cause environmental changes. The UFSAR sections noted with each item present discussions on the provisions made to retain the necessary protective action.

(1) Loss-of-coolant accident (Refer to Sections 15.3.1, 15.3.4, and 15.4.1)

(2) Steam breaks (Refer to Sections 15.3.2 and 15.4.2)

(3) Earthquake (Refer to Sections 2.5, 3.2, 3.7, and 3.8)

(4) Fire (Refer to Section 9.5)

(5) Explosion (hydrogen buildup inside containment; refer to Sections 6.2 and 15.4)

(6) Missiles (Refer to Section 3.5)

(7) Flood (Refer to Sections 2.4 and 3.4)

(8) Wind (Refer to Section 3.3)

The performance requirements are:

(1) System Response Times

The RTS response time shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until loss of stationary gripper coil voltage. The RTS response times shall be demonstrated as required by the Technical Specifications.

Maximum allowable time delays in generating the reactor trip signal are identified in the Equipment Control Guidelines.

(2) Reactor trip setpoint allowable values are provided in the Technical Specifications.

(3) RTS ranges:

RTS range is the output range for a device that provides input to the RTS. It is defined as the range for which the device is calibrated and verified to be operable. As described in Sections 7.2.2.10 and 7.2.3.3, methodologies for determining RTS setpoint and allowable values are presented in WCAP-11082, Technical Specification 3.3.1 or in plant procedures. Specific device ranges are presented in plant procedures.

RTS	Range
(a) Power range nuclear power	1 to 120% rated thermal power (RTP)
(b) Neutron flux rates	+5 to +30% of full power
(c) Overtemperature ΔT	
$T_{hot\ leg}$	530 to 650°F
$T_{cold\ leg}$	510 to 630°F
T_{avg}	530 to 630°F
Pressurizer pressure	1250 to 2500 psig
ΔI	-60 to +60%
f_1 (ΔI)	1 to 3%/%ΔI
ΔT setpoint	0 to 150% power
(d) Overpower ΔT	
$T_{hot\ leg}$	530 to 650°F
$T_{cold\ leg}$	510 to 630°F
T_{avg}	510 to 630°F

RTS	Range
ΔI	-60 to +60%
f_2 (ΔI)	1 to 3%/%ΔI
ΔT setpoint	0 to 150 % power
(e) Pressurizer pressure	1250 to 2500 psig
(f) Pressurizer water level	Entire cylindrical portion of pressurizer (0 - 100 %)
(g) Reactor coolant flow	0 to 120% of rated flow
(h) Reactor coolant pump bus	50 to 70 Hz underfrequency
(i) Reactor coolant pump	0 to 150 Vac bus voltage
(j) Low-low steam generator water level	0 to 45% of narrow-range span

7.2.4.1.2 Single Failure Criterion

Refer to Section 7.2.3.7 for a discussion regarding the single failure criterion for RTS.

7.2.4.1.3 Quality of Components and Modules

For a discussion on the quality assurance program for the components and modules used in the RTS, refer to Section 3.1.2.1 and the Diablo Canyon Quality Assurance Program Description.

7.2.4.1.4 Equipment Qualification

Portions of the RTS are designated PG&E Design Class I. Refer to Sections 7.2.3.15 and 3.11 for a discussion on Class 1E electrical equipment environmental qualification and compliance to IEEE 323-1971 (Reference 14). Documentation of the Environmental and Seismic qualification of the process protection system is provided in References 23, 24, 25, 26 and 34.

7.2.4.1.5 Channel Integrity

The RTS channels are designed to maintain necessary functional capability under extremes of conditions related to environment, (refer to Section 7.2.3.1), energy supply (refer to Section 7.2.3.10), malfunctions (refer to Section 7.2.3.7), and accidents (refer to Section 7.2.4.1.1).

7.2.4.1.6 Channel Independence

Refer to Section 7.2.3.6 for a discussion regarding RTS channel independence.

7.2.4.1.7 Control and Protection System Interaction

Refer to Section 7.2.2.11 for a discussion regarding RTS control and protection interaction.

7.2.4.1.8 Derivation of System Inputs

The following are the variables required to be monitored in order to provide reactor trips (refer to Figure 7.2-1 and Table 7.2-1):

(1) Neutron flux

(2) Reactor coolant temperature

(3) RCS pressure (pressurizer pressure)

(4) Pressurizer water level

(5) Reactor coolant flow

(6) Reactor coolant pump operational status (bus voltage and frequency, and breaker position)

(7) Steam generator water level

(8) Turbine operational status (autostop oil pressure and stop valve position)

Reactor coolant temperature is a spatially dependent variable. The effect on the measurement is negated by taking multiple samples from the reactor coolant hot leg and electronically averaging these samples in the process protection system.

7.2.4.1.9 Capability for Sensor Checks

The RTS provides a means for checking, with a high degree of confidence, the operational availability of each system input sensor during reactor operation. This is accomplished by channel checks as described in Section 7.2.2.12.1.1, Channel Checks.

7.2.4.1.10 Capability for Test and Calibration

The reactor protection system is capable of testing and calibrating channels and the devices used to derive the final system output signal from the various channel signals.

Testing of the logic trains of the reactor protection system includes a check of the input relays and a logic matrix check. The following sequence is used to test the system:

(1) Check of Input Relays - During testing of the process instrumentation system and nuclear instrumentation system comparators, each channel comparator is placed in a trip mode causing one input relay in train A and one in train B to de-energize. A contact of each relay is connected to a universal logic printed circuit card. This card performs both the reactor trip and monitoring functions. The contact that creates the reactor trip also causes a status lamp and an annunciator on the control board to operate. Either train A or B input relay operation lights the status lamp and sounds the annunciator.

Each train contains a multiplexing test switch. This switch is normally configured such that train A is in the A+B position, while train B is in the Normal position. Administrative controls are used to control this configuration and may be changed to other configurations as necessary to meet plant conditions. The A+B position alternately allows information to be transmitted from the two trains to the control board. A steady-status lamp and annunciator indicates that input relays in both trains have been deenergized. A flashing lamp means that both input relays in the two trains did not deenergize. Contact inputs to the logic protection system, such as reactor coolant pump bus underfrequency relays, operate input relays that are tested by operating the remote contacts as previously described and using the same indications as those provided for bistable input relays.

Actuation of the input relays provides the overlap between the testing of the logic protection system and the testing of those systems supplying the inputs to the logic protection system. Test indications are status lamps and annunciators on the control board. Inputs to the logic protection system are checked one channel at a time, leaving the other channels in service. For example, a function that trips the reactor when two-out-of-four channels trip becomes a one-out-of-three trip when one channel is placed in the trip mode. Both trains of the logic protection system remain in service during this portion of the test.

(2) Check of Logic Matrices - Logic matrices are checked one train at a time. Input relays are not operated during this portion of the test. Reactor trips from the train being tested are inhibited with the use of the input error inhibit switch on the semiautomatic test panel in the train. Details of semiautomatic tester operation are provided in Reference 6. At the completion of the logic matrix tests, one bistable in each channel of process instrumentation or nuclear instrumentation is tripped or is verified in the tripped state to check closure of the input error inhibit switch contacts.

With the exception of the P-8 blocking function, the logic test scheme uses pulse techniques to check the coincidence logic. All possible trip and nontrip combinations are checked. Pulses from the tester are applied to the inputs of the universal logic card at the same points electrically that connect to the input relay contacts. Thus, there is an overlap between the input relay check and the logic matrix check. Pulses are fed back from the reactor trip breaker undervoltage coil to the tester. The pulses are of such short duration that the reactor trip breaker undervoltage coil armature should not respond mechanically.

Because the P-8 block of the one of four RCS low flow trip is not connected to the semiautomatic tester, it is tested using the manual input function pushbuttons. The P-8 block function is verified in accordance with the Surveillance Frequency Control Program.

Test indications that are provided are an annunciator in the control room indicating that reactor trips from the train have been blocked and that the train is being tested, and green and red lamps on the semiautomatic tester to indicate a good or bad logic matrix test. Protection capability provided during this portion of the test is from the train not being tested.

The general design features and details of the testability of the logic system are described in Reference 6.

(3) Testing of Reactor Trip Breaker*s* - Normally, reactor trip breakers 52/RTA and 52/RTB are in service, and bypass breakers 52/BYA and 52/BYB are withdrawn (out of service). In testing the protection logic, pulse techniques are used to avoid tripping the reactor trip breakers, thereby eliminating the need to bypass them during the testing, although the associated bypass breaker is closed to preclude an inadvertent reactor trip and to allow reactor trip breaker testing. The following procedure describes the method used for testing the trip breakers:

(a) Bypass breaker 52/BYB is racked to test position and closed

(b) With bypass breaker 52/BYA racked out (test position), manually close and trip it to verify its operation

(c) Rack in and close 52/BYA (bypasses 52/RTA)

(d) While blocking 52/RTA shunt trip, manually trip 52/RTA and 52/BYB through a protection system logic matrix

(e) Reset 52/RTA

(f) Manually trip 52/RTA using the shunt trip coil only with the shunt trip test push button

(g) Reset 52/RTA

(h) Rack out 52/BYB

(i) Trip and rack out 52/BYA

(j) Repeat above steps to test trip breaker 52/RTB and bypass breaker 52/BYA using bypass breaker 52/BYB to bypass 52/RTB

Auxiliary contacts of the bypass breakers are connected so that if either train is placed in test while the bypass breaker of the other train is fully racked in and closed, both reactor trip breakers and the bypass breaker automatically trip.

Auxiliary contacts of the bypass breakers are also connected in such a way that if an attempt is made to fully rack in and close the bypass breaker in one train while the bypass breaker of the other train is already fully racked in and closed, both bypass breakers automatically trip. Additionally, trip signals will be sent to both reactor trip and bypass breakers through the protection system logic.

The train A and train B alarm systems operate an annunciator in the control room. The two bypass breakers also operate an annunciator in the control room. Bypassing of a protection train with either the bypass or the test switches results in audible and visual indications.

The complete RTS is normally required to be in service. However, to permit on-line testing of the various protection channels or to permit continued operation in the event of a subsystem instrumentation channel failure, a Technical Specification defining the minimum number of operable channels and the minimum degree of channel redundancy has been formulated. This Technical Specification also defines the required restriction to operation in the event that the channel operability and degree of redundancy requirements cannot be met.

The RTS is designed in such a way that some components' response time tests can only be performed during shutdown. However, the safety analyses utilize conservative numbers for trip channel response times. The measured channel response times are compared with those used in the safety evaluations.

Refer to Sections 7.2.2.12, 7.2.2.12.1.2, and 7.3.4.1.5 for additional discussion.

7.2.4.1.11 Channel Bypass or Removal from Operation

The Eagle 21 process protection system is designed to permit an inoperable channel to be placed in a bypass condition for the purpose of troubleshooting or periodic test of a redundant channel. Use of the bypass mode disables the individual channel comparator trip circuitry that forces the associated logic input relays to remain in the non-tripped state until the "bypass" is removed. If the process protection channel has been bypassed for any purpose, a signal is provided to allow this condition to be continuously indicated in the control room. During such operation, the process protection system continues to satisfy the single failure criterion. This is acceptable since there are 4 channels and the two-out-of-four trip logic reduces to two-out-of-three during the test. For functions that use two-out-of-three logic, it is implicitly accepted that the single failure criterion is met because of the results of the system reliability study. From the results of this it was concluded that the Eagle 21 digital system availability is equivalent to the respective analog process protection system availability even without the incorporation of the redundancy, automatic surveillance testing, self-calibration and self diagnostic features of the Eagle 21 process protection system.

The following exception to IEEE 279-1971 is applicable to DCPP:

> Technical Specifications allow a temporary relaxation, up to 4 hours, of the single failure criterion for the “one-out-of-two” function, reactor trip on SI signal, during channel bypass for surveillance testing provided the other train is operable.

7.2.4.1.12 Operating Bypasses

A listing of the operating bypasses is included in Table 7.2-2. These bypasses meet the requirement of Paragraph 4.12 of IEEE 279-1971 that the bypass will be removed automatically whenever permissive conditions are not met. The SSPS is used to achieve automatic removal of the bypass of a protective function.

> Note: The term "bypass" is defined as the meeting of the coincident permissive (interlock) logic to permit the protective logic to become enabled/disabled as required. The term "bypass," in this section is not intended to be defined as the disabling of the individual channel comparator trip circuitry during routine test or surveillance that forces the associated logic input relays to remain in the non-tripped state until the "bypass" is removed.

7.2.4.1.13 Indication of Bypasses

Indication is provided in the control room if some part of the system has been administratively bypassed or taken out of service.

7.2.4.1.14 Access to Means for Bypassing

The design provides for administrative control of access to the means for manually bypassing channels or protective functions. For details refer to References 23 and 24.

7.2.4.1.15 Multiple Set Points

For monitoring neutron flux, multiple setpoints are used. When a more restrictive trip setting becomes necessary to provide adequate protection for a particular mode of operation or set of operating conditions, the protective system circuits are designed to provide positive means or administrative control to ensure that the more restrictive trip setpoint is used. The SSPS logic is used to prevent improper use of less restrictive trip settings.

7.2.4.1.16 Completion of Protective Action Once It Is Initiated

The RTS is so designed that, once initiated, a protective action goes to completion. Return to normal operation requires action by the operator.

7.2.4.1.17 Manual Initiation

Switches are provided on the control board for manual initiation of protective action. Failure in the automatic system does not prevent the manual actuation of the protective functions. Manual actuation relies on the operation of a minimum of equipment. Additionally, the reactor trip and bypass breakers can be operated locally.

7.2.4.1.18 Access to Set Point Adjustments, Calibration, and Test Points

The design provides for administrative control of access to all setpoint adjustments, module calibration adjustments, and test points. For details refer to References 23 and 34.

7.2.4.1.19 Identification of Protective Actions

The system provides annunciator, status light, and computer input signals that indicate the condition of bistable input signals, partial- and full-trip functions, and the status of the various blocking, permissive, and actuation functions.

7.2.4.1.20 Information Read-out

The RTS provides the operator with complete information pertinent to system status and safety. All transmitted signals (flow, pressure, temperature, etc.) that cause a reactor trip are either indicated or recorded for every channel including all neutron flux power range currents (top detector, bottom detector, algebraic difference, and average of bottom and top detector currents).

Any reactor trip actuates an annunciator.

Annunciators are also used to alert the operator of deviations from normal operating conditions so that he may take appropriate corrective action to avoid a reactor trip. Actuation of any rod stop or trip of any reactor trip channel actuates an annunciator.

7.2.4.1.21 System Repair

The RTS design features allow for recognition, location, replacement, and repair or adjustment of malfunctioning components or modules as discussed in References 3, 23 and 34.

7.2.4.1.22 Identification

The identification described in Section 7.1.3.3 provides immediate and unambiguous identification of the protection equipment.

7.2.4.2 Compliance with IEEE 317-1971

RTS instrumentation cables which are routed through containment penetrations are designed to meet IEEE 317-1971. Circuits without direct in-line redundant protection have been analyzed, which determined the available fault current is not of sufficient magnitude to damage the penetration conductor or penetration. These circuits will not adversely heat the penetrations as presently designed. (Refer to Section 8.3.1.4.8).

7.2.4.3 Evaluation of Compliance with IEEE 344-1971

The seismic testing, as discussed in Section 3.10.2, conforms to IEEE 344-1971 (Reference 17) except the format of the documentation may not meet the requirements because testing was completed prior to issuance of the standard. Documentation of the Environmental and Seismic qualification of the process protection system is provided in References 23, 24, 25, 26 and 34.

7.2.4.4 Evaluation of Compliance with IEEE 603-1980

IEEE 603-1980 (Reference 28), which is endorsed by Regulatory Guide 1.153, December 1985 (Reference 30), is applicable to the Eagle 21 Design, Verification, and Validation Plan.

7.2.4.5 Evaluation of Compliance with ANSI/IEEE-ANS-7-4.3.2-1982

ANSI/IEEE-ANS-7-4.3.2-1982 (Reference 31), which is endorsed by Regulatory Guide 1.152, November 1985 (Reference 29), is applicable to the Eagle 21 Design, Verification, and Validation Plan.

7.2.5 REFERENCES

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15. IEEE Standard 334-1971, Trial-Use Guide for Type Tests of Continuous-Duty Class I Motors Installed Inside the Containment of Nuclear Power Generating Stations, The Institute of Electrical and Electronics Engineers, Inc.

16. IEEE Standard 338-1971, Trial-Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems, The Institute of Electrical and Electronics Engineers Inc.

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19. Deleted

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29. Regulatory Guide 1.152, Criteria for Programmable Digital Computer System Software in Safety-Related Systems in Nuclear Plants, November 1985.

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31. ANSI/IEEE-ANS 7-4.3.2, Application Criteria for Programmable Digital Computer Systems in Safety Systems of Nuclear Power Generating Stations, 1982.

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7.2.6 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

7.3 ENGINEERED SAFETY FEATURES ACTUATION SYSTEM

The ESFAS senses selected plant parameters and initiates necessary safety systems to protect against violating core design limits and the RCS pressure boundary and to mitigate accidents. If the measured value of a sensed parameter exceeds a predetermined setpoint, a signal is sent into logic matrices sensitive to combinations indicative of faults described in Chapter 15. Once the required logic combination is completed, the system sends actuation signals to those ESFs components whose aggregate function best serves the requirements of the accident. Included in this section are the electrical schematic diagrams for all ESF systems circuits and supporting systems. Figure 7.3-52 shows containment electrical penetrations, cable trays, and supports.

7.3.1 DESIGN BASES

7.3.1.1 General Design Criterion 2, 1967 – Performance Standards

ESFAS is designed to withstand the effects of or is protected against natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

7.3.1.2 General Design Criterion 11, 1967 – Control Room

ESFAS is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room.

7.3.1.3 General Design Criterion 15, 1967 – Engineered Safety Features Protection Systems

ESFAS provides instrumentation for sensing accident situations and initiating the operation of necessary ESFs.

7.3.1.4 General Design Criterion 19, 1967 – Protection Systems Reliability

ESFAS is designed for high functional reliability and in-service testability commensurate with the safety functions to be performed.

7.3.1.5 General Design Criterion 20, 1967 – Protection Systems Redundancy and Independence

Redundancy and independence are designed into the ESFAS sufficient to assure that no single failure or removal from service of any component or channel of a system will result in loss of the protection function. The redundancy provided includes, as a minimum, two channels of protection for each protection function served.

7.3.1.6 General Design Criterion 21, 1967 – Single Failure Definition

ESFAS is designed to perform its function after sustaining a single failure. Multiple failures resulting from a single event shall be treated as a single failure.

7.3.1.7 General Design Criterion 22, 1967 – Separation of Protection and Control Instrumentation Systems

ESFAS is designed such that protection functions are separated from control instrumentation functions to the extent that failure or removal from service of any control instrumentation system component or channel, or of those common to control instrumentation and protection circuitry, leaves intact a system satisfying all requirements for the protection channels.

7.3.1.8 General Design Criterion 23, 1967 – Protection Against Multiple Disability for Protection Systems

ESFAS is designed such that the effects of adverse conditions to which redundant channels or protection systems might be exposed in common, either under normal conditions or those of an accident, does not result in loss of the protection function.

7.3.1.9 General Design Criterion 24, 1967 – Emergency Power for Protection Systems

ESFAS is designed such that in the event of loss of all offsite power, sufficient alternate sources of power are provided to permit the required functioning of the protection systems.

7.3.1.10 General Design Criterion 25, 1967 – Demonstration of Functional Operability of Protection Systems

ESFAS includes means for testing protection systems while the reactor is in operation to demonstrate that no failure or loss of redundancy has occurred.

7.3.1.11 General Design Criterion 26, 1967 – Protection Systems Fail-Safe Design

The ESFAS is designed to fail into a safe state or into a state defined as tolerable on a defined basis if conditions such as disconnection of the system, loss of electric power, or adverse environments are experienced.

7.3.1.12 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

ESFAS is designed to actuate the ESFs provided to back up the safety provided by the core design, the reactor coolant pressure boundary, and their protection systems.

7.3.1.13 General Design Criterion 38, 1967 – Reliability and Testability of Engineered Safety Features

ESFAS is designed to provide high functional reliability and ready testability.

7.3.1.14 General Design Criterion 40, 1967 – Missile Protection

ESFAS is protected against dynamic effects and missiles that might result from plant equipment failures.

7.3.1.15 General Design Criterion 48, 1967 – Testing of Operational Sequence of Emergency Core Cooling Systems

ESFAS is designed with the capability to test under conditions as close to design as practical the full operational sequence that brings the ECCS into action, including the transfer to alternate power sources.

7.3.1.16 General Design Criterion 49, 1967 – Containment Design Basis

The ESFAS circuits routed through containment electrical penetrations are designed so that the containment structure can accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a LOCA.

7.3.1.17 Engineered Safety Features Actuation System Safety Function Requirements

(1) Protection from Jet Impingement – Inside Containment

The ESFAS system portion located inside containment is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

7.3.1.18 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

The ESFAS electric components that require EQ are qualified to the requirements of 10 CFR 50.49.

7.3.1.19 Safety Guide 22, February 1972 – Periodic Testing of Protection System Actuation Functions

The ESFAS are periodically tested to provide assurance that the systems will operate as designed and will be available to function properly in the unlikely event of an accident. The testing program conforms to Safety Guide 22, February 1972.

7.3.2 SYSTEM DESCRIPTION

7.3.2.1 Functional Design

The following summarizes those generating station conditions requiring protective action:

(1) Primary system

(a) Rupture in small pipes or crack in large pipes (refer to Section 15.3.1)

(b) Rupture of a reactor coolant pipe - LOCA (refer to Section 15.4.1)

(c) SG tube rupture (refer to Section 15.4.3)

(2) Secondary system

(a) Minor secondary system pipe break resulting in steam release rates equivalent to the actuation of a single dump, relief, or safety valve (refer to Section 15.2.14)

(b) Rupture of a major secondary system pipe (refer to Section 15.4.2)

The following summarizes the generating station variables required to be monitored for the initiation of the ESF for each accident in the preceding list:

(1) Rupture in small pipes or crack in large primary system pipes

(a) Pressurizer pressure

(b) Containment pressure

(2) Rupture of a reactor coolant pipe LOCA

(a) Pressurizer pressure

(b) Containment pressure

(3) SG tube rupture

(a) Pressurizer pressure

(4) Minor or major secondary system pipe rupture

(a) Pressurizer pressure

(b) Steam line pressures

(c) Steam line pressure rate

(d) Containment pressure

7.3.2.2 Signal Computation

The ESFAS consists of two discrete portions of circuitry: (a) a process protection portion consisting of three to four redundant channels that monitor various plant parameters and containment pressures, and (b) a logic portion consisting of two redundant logic trains that receive inputs from the process protection channels and perform the needed logic to actuate the ESF. Each logic train is capable of actuating the ESF equipment required. The intent is that any single failure within the ESFAS shall not prevent system action when required.

The redundancy concept is applied to the process protection and logic portions of the system. Separation of redundant process protection channels begins at the process sensors and is maintained in the field wiring, containment penetrations, and process protection racks, terminating at the redundant groups of ESF logic racks as shown in Figure 7.3-50. This conforms to GDC 20, 1967 (refer to Section 7.3.3.5).

Section 7.2 provides further details on protection instrumentation. The same design philosophy applies to both systems and conforms to GDC 19, 1967; GDC 20, 1967; GDC 22, 1967; and GDC 23, 1967 (refer to Sections 7.3.3.4, 7.3.3.5, 7.3.3.7, and 7.3.3.8).

The variables are sensed by the process protection circuitry, as discussed in Reference 2 and in Section 7.2. The outputs from the process protection channels are combined into actuation logic as shown on Sheets 9 and 10, 11 and 12, 13 and 14, 15 and 16 of Figure 7.2-1. Tables 7.3-1 and 7.3-2 provide additional information pertaining to logic and function.

The interlocks associated with the ESFAS are outlined in Table 7.3-3. These interlocks satisfy the functional requirements discussed in Section 7.3.2.1

7.3.2.3 Devices Requiring Actuation

The following are the actions that the ESFAS initiates when performing its function:

(1) Safety injection (SI pumps, RHR pumps, charging pumps)

(2) Reactor trip

(3) Feedwater line isolation by closing all main feedwater regulating valves (MFRVs), feedwater bypass valves, main feedwater isolation valves (MFIVs) and tripping the feedwater pumps.

(4) AFW system actuation

(5) Auxiliary saltwater (ASW) pump start

(6) Automatic containment spray (spray pumps, sodium hydroxide tank)

(7) Containment isolation

(8) Containment fan coolers start

(9) EDG startup

(10) Main steam line isolation

(11) Turbine and generator trips

(12) Control room isolation

(13) Component cooling water (CCW) pump start

(14) Trip RHR pumps on low refueling water storage tank (RWST) level

Refer to Figure 7.3-50 for a complete list of actuated components.

7.3.2.4 Implementation of Functional Design

7.3.2.4.1 Process Protection Circuitry

The process protection sensors and racks for the ESFAS are covered in References 2, 17, 72 and 73. Discussed in these reports are the parameters to be measured including pressures, tank and vessel water levels, as well as the measurement and signal transmission considerations. These latter considerations include the basic current signal transmission system, transmitters, RTDs, and pneumatics. Other considerations covered are automatic calculations, signal conditioning, and location and mounting of the devices.

The sensors monitoring the primary system are located as shown on the piping schematic diagram, Figure 3.2-7, Reactor Coolant System. The secondary system sensor locations are shown on the piping schematic diagram, Figure 3.2-4, Turbine Steam Supply System.

Containment pressure is sensed by four physically separated DP transmitters mounted outside of the containment structure. The transmitters are connected to containment atmosphere by filled and sealed hydraulic transmission systems similar to the sealed

pressurizer water level reference leg described in Section 7.2.2.11.4. Refer to Section 6.2.4.4.2.2 for additional information on instrument lines penetrating containment.

Three water level instrumentation channels are provided for the RWST. Each channel provides independent indication on the main control board, thus meeting the requirements of Paragraph 4.20 of IEEE 279-1971 (Reference 4). Two-out-of-three logic is provided for RHR pump trip and low-level alarm initiation. One channel provides low-low-level alarm initiation; another channel provides a high-level alarm to alert the operator of overfill and potential spillage of radioactive material. Refer to Sections 3.10.3.5 and 6.3.3.4.4.1 for additional information on the RWST level circuits and logic relays.

7.3.2.4.2 Logic Circuitry

The ESF logic racks are discussed in detail in Reference 5. The description includes the considerations and provisions for physical and electrical separation as well as details of the circuitry. Reference 5 also covers certain aspects of on-line test provisions, provisions for test points, considerations for the instrument power source, considerations for accomplishing physical separation, and provisions for ensuring instrument qualification. The outputs from the process protection channels are combined into ESF actuation logic, as shown on Sheets 9 and 10 (RCP bus UV), 11 and 12 (pressurizer pressure), 13 and 14 (steam pressure rate, steamline pressure, and SG level), and 15 and 16 (ESF actuation and containment pressure) of Figure 7.2-1.

To facilitate ESF actuation testing, two cabinets (one per train) are provided that enable operation, to the maximum practical extent, of safety features loads on a group-by-group basis until actuation of all devices has been checked. Final actuation testing is discussed in detail in Section 7.3.4.1.5.8.

7.3.2.4.3 Final Actuation Circuitry

The outputs of the solid-state logic protection system (the slave relays) are energized to actuate, as are most final actuators and actuated devices. These devices are:

(1) SI System Pumps and Valve Actuators - Refer to Section 6.3 for flow diagrams and additional information.

(2) Containment Isolation - Phase A - T signal isolates all nonessential (to reactor operation) process lines on receipt of SI signal; Phase B - P signal isolates remaining process lines (which do not include SI lines) on receipt of a two-out-of-four high-high containment pressure signal. For further information, refer to Section 6.2.4.

(3) Containment Fan Coolers - Refer to Section 6.2.2.3.

(4) Component Cooling Pumps and Valves - Refer to Section 9.2.2.

(5) ASW Pumps - Refer to Section 9.2.7.

(6) AFW Pumps Start - Refer to Section 6.5.5.

(7) Diesel Generators Start - Refer to Section 8.3.1.1.3.3.5.2.

(8) Feedwater Isolation - Refer to Section 10.4.7.

(9) Ventilation Isolation Valve and Damper Actuators - Refer to Section 6.2.4.

(10) Steam Line Isolation Valve Actuators - Refer to Section 10.3.2.

(11) Containment Spray Pumps and Valve Actuators - Refer to Section 6.2.2.3.

When the ESF loads are to be powered by diesel generators, they must be sequenced to prevent overloading. This sequencing is discussed in Section 8.3.1.1.3.3.5.2.

The following systems are required for support of the ESFs:

(1) ASW System - Heat removal, refer to Section 9.2.7.

(2) CCW System - Heat removal, refer to Section 9.2.2.

(3) Electrical Power Distribution Systems - Refer to Chapter 8.

7.3.2.4.4 Safety System Status Display

The following provisions have been made to automatically display the status of safety systems.

(1) Monitor light display panels are provided to verify correct system alignment for:

(a) Safety feature valves

(b) Phase A isolation system equipment

(c) SI, charging (CCP1 and CCP2), CCW, AFW, ASW, and RHR pumps

(d) Phase B isolation system equipment and containment spray pumps

(e) Containment fan coolers

(2) A partial list of annunciator displays is included in Section 7.7.2.10.1.1.1:

In addition to the status lights and annunciator displays described, system control switches on the control board are provided with indicating lights to display valve position and motor status with power potential indicating lights provided where equipment power is 480-V or higher.

The features described above, supplemented with administrative procedures, provide the operator with safety system status information, by means of which the status of bypassed or inoperable systems is available to the operator, in accordance with the intent of Regulatory Guide 1.47 (Reference 6).

7.3.2.5 Additional Design Information

The generating station conditions that require protective action are discussed in Section 7.3.2.1. The generating station variables that are required to be monitored in order to provide protective actions are also summarized in Section 7.3.2.1.

The ESFAS functional units and trip setpoints are provided in the Technical Specifications (Reference 7). The methodology for determining ESFAS setpoints and allowable values is presented in WCAP 11082 or in plant procedures.

The following is a list of the malfunctions, accidents, or other unusual events that could physically damage protection system components or could cause environmental changes. The sections noted with each item present discussions on the provisions made to retain the necessary protective action.

(1) LOCA (refer to Sections 15.3.1 and 15.4.1)

(2) Secondary System breaks (refer to Sections 15.3.2 and 15.4.2)

(3) Earthquakes (refer to Sections 2.5, 3.2, 3.7, and 3.8)

(4) Fire (refer to Section 9.5.1)

(5) Explosion (hydrogen buildup inside containment; refer to Sections 6.2 and 15.4)

(6) Missiles (refer to Section 3.5)

(7) Flood (refer to Sections 2.4 and 3.4)

(8) Wind (refer to Section 3.3)

Minimum performance requirements are:

(1) System response times

The actuation system response time is included in the overall ESF response time.

The Technical Specifications define ESF response time. Acceptance criteria for ESF response time testing is located in ECG 38.2, “Engineered Safety Features (ESF) Response Times.”

(2) System accuracies

The system actuation setpoints together with their allowable values are provided in the Technical Specifications.

(3) Ranges of sensed variables to be accommodated until conclusion of protective action is ensured

Information readouts and the ranges required in generating the required actuation signals for loss-of-coolant and secondary system pipe break protection are discussed in Section 7.5.1 and presented in Tables 7.5-1 and 7.5-2.

7.3.2.6 Current System Drawings

The schematic diagrams and logic diagrams for ESF circuits and supporting systems are presented at the end of Chapter 7 (refer to Figures 7.3-1 through 7.3-49).

7.3.3 SAFETY EVALUATION

7.3.3.1 General Design Criterion 2, 1967 – Performance Standards

The ESFAS structures, systems and components (SSCs) are contained in the auxiliary buildings that are PG&E Design Class I (refer to Section 3.8). These buildings are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other natural phenomena to protect ESFAS SSCs to ensure their safety-related functions and designs will perform.

Refer to Section 7.3.2.5 for additional information.

7.3.3.2 General Design Criterion 11, 1967 – Control Room

Controls and instrumentation related to ESFAS include control room status lights, annunciator displays and system control switches on the control board with indicating lights to display valve position and motor status with power potential indicating lights provided where equipment power is 480-V or higher.

Refer to Section 7.3.2.4.4 for additional information.

7.3.3.3 General Design Criterion 15, 1967 – Engineered Safety Features Protection Systems

The ESFAS is designed to monitor plant variables and respond to the accident conditions identified in Section 7.3.2.1. If necessary, ESFAS will initiate the operation of the ESFs as described in Section 7.3.2.3.

The effectiveness of the ESFAS is evaluated in Chapter 15 based on the ability of the system to contain the effects of Conditions III and IV faults including loss of coolant and secondary system pipe rupture accidents. The ESFAS parameters are based on the component performance specifications that are provided by the manufacturer, or verified by test for each component. Appropriate factors to account for uncertainties in the data are factored into the constants characterizing the system.

The ESFAS must detect Conditions III and IV faults and generate signals that actuate the ESF. The system must sense the accident condition and generate the signal actuating the protection function reliably, and within a time determined by, and consistent with, the accident analyses in Sections 15.3 and 15.4. The ESFAS will mitigate other faults as discussed in Section 15.2.

The time required for the generation of the actuation signal of ESFAS is relatively short. The remainder of the time is associated with the actuation of the mechanical and fluid system equipment associated with ESF. This includes the time required for switching, bringing pumps and other equipment to speed, and the time required for them to take load.

7.3.3.3.1 Loss-of-Coolant Protection

By analysis of LOCA and in-system tests, it has been verified that except for very small coolant system breaks, which can be protected against by the charging pumps (CCP1 and CCP2) followed by an orderly shutdown, the effects of various LOCAs are reliably detected by the low pressurizer pressure. The ECCS is actuated in time to prevent or limit core damage.

For large coolant system breaks, the passive accumulators inject first because of the rapid pressure drop. This protects the reactor during the unavoidable delay associated with actuating the active ECCS phase.

High containment pressure also actuates the ECCS, providing additional protection as a backup to actuation on low pressurizer pressure. Emergency core cooling actuation can be brought about upon sensing this other direct consequence of a primary system break; that is, the protection system detects the leakage of the coolant into the containment.

Containment spray provides containment pressure reduction and also limits fission product release, upon sensing elevated containment pressure (high-high), to mitigate the effects of a LOCA.

The delay time between detection of the accident condition and the generation of the actuation signal for these systems is well within the capability of the protection system equipment. However, this time is short compared to that required for startup of the fluid systems.

The analyses in Chapter 15 show that the diverse methods of detecting the accident condition and the time for generation of the signals by the protection systems are adequate to provide reliable and timely protection against the effects of loss of coolant.

7.3.3.3.2 Secondary System Pipe Rupture Protection

The ECCS is also actuated to protect against a secondary system line break. Analysis of secondary system pipe rupture accidents shows that the ECCS is actuated for a secondary system pipe rupture in time to limit or prevent further damage.

There is a reactor trip, but the core reactivity is further reduced by the highly borated water injected by the ECCS.

Additional protection against the effects of secondary system pipe rupture is provided by feedwater isolation that occurs upon actuation of the ECCS. Feedwater line isolation is initiated to prevent excessive cooldown of the reactor.

Additional protection against a secondary system pipe rupture accident is provided by closure of all steam line isolation valves to prevent uncontrolled blowdown of all SGs. Generation of the protection system signal is again short compared to the time to trip the fast acting steam line isolation valves that are designed to close in less than 5 seconds.

The analyses in Chapter 15 of the secondary system pipe rupture accidents and an evaluation of the protection system instrumentation and channel design show that the EFSAS are effective in preventing or mitigating the effects of a secondary system pipe rupture accident.

7.3.3.4 General Design Criterion 19, 1967 – Protection Systems Reliability

The ESFAS is designed for high functional reliability and in-service testability. The design employs redundant logic trains and measurement and equipment diversity. Sufficient redundancy is provided to enable individual end-to-end channel tests with each reactor at power without compromise of the protective function. Built-in semiautomatic testers provide means to test the majority of system components very rapidly.

Refer to Sections 7.3.4.1.5.1 and 7.2.3.11 for additional information.

7.3.3.5 General Design Criterion 20, 1967 – Protection Systems Redundancy and Independence

Sufficient redundancy and independence is designed into the protection systems to ensure that no single failure, or removal from service of any component or channel of a system will result in loss of the protection function. The minimum redundancy is exceeded in each protection function that is active with the reactor at power. Functional diversity and consequential location diversity are designed into the systems.

The ESF outputs from the solid-state logic protection cabinets are redundant, and the actuations associated with each train are energized to actuate, up to and including the final actuators, by the separate ac power supplies that power the respective logic trains. Mutually redundant ESF circuits utilize separate relays in separate racks.

The protection system is designed to provide two, three, or four instrumentation channels for each protective function and redundant (two) logic trains. These redundant channels and trains are electrically isolated and physically separated. Thus, any single failure within a channel or train will not prevent protective action at the system level when required.

Each individual channel is assigned to one of four channel designations, e.g., Channel I, II, III, or IV. Channel independence is carried throughout the system, extending from the sensor through to the devices actuating the protective function. Physical separation is used to achieve separation of redundant transmitters. Separation of wiring is achieved using separate wireways, cable trays, conduit runs, and containment penetrations for each redundant channel. Redundant process equipment is separated by locating electronics in different protection rack sets. Each redundant channel is energized from a separate ac power feed.

Refer to Sections 7.3.4.1.1 and 7.3.4.1.3 for additional information.

7.3.3.6 General Design Criterion 21, 1967 – Single Failure Definition

The protection system is designed to provide two, three, or four instrumentation channels for each protective function and redundant (two) logic trains. These redundant channels and trains are electrically isolated and physically separated. Thus, any single failure within a channel or train will not prevent protective action at the system level when required.

Refer to Section 7.3.4.1.1 for additional information.

7.3.3.7 General Design Criterion 22, 1967 – Separation of Protection and Control Instrumentation Systems

The protection systems comply with the requirements of IEEE 279-1971, Criteria for Protection Systems for Nuclear Power Generating Stations (Reference 4), although construction permits for the DCPP units were issued prior to issuance of the 1971 version of the standard (refer to Section 7.3.4.1). Each protection system is separate and distinct from the respective control systems. The control system is dependent on the protection system in that control signals are derived from protection system measurements, where applicable. These signals are transferred to the control system by isolation amplifiers that are classified as protection system components. The adequacy of system isolation has been verified by testing or analysis under conditions of all postulated credible faults. Isolation devices that serve to protect PG&E Instrument Class IA instrument loops have all been tested. For certain applications where the isolator is protecting a PG&E Instrument Class IB instrument loop, and the isolation device is a simple linear device with no complex failure modes, the analysis was used to verify the adequacy of the isolation device. The failure or removal of any single control instrumentation system component or channel, or of those common to the control instrumentation system component or channel and protection circuitry, leaves intact a system that satisfies the requirements of the protection system.

To provide physical separation between input and output circuits in the solid-state protection system racks, physical barriers have been provided to separate input and output wire bundles.

The protection system is designed to be independent of the control system. In certain applications, the control signals and other non-protective functions are derived from individual protective channels through isolation devices. The isolation devices are classified as part of the protection system and are located in the process protection racks. Non-protective functions include those signals used for control, remote process indication, and computer monitoring. The isolation devices are designed so that a short circuit, open circuit, or the application of 118-Vac or 140-Vdc on the isolated output portion of the circuit (i.e., the non-protective side of the circuit) will not affect the input (protective) side of the circuit. The signals obtained through the isolation devices are never returned to the protective racks.

7.3.3.8 General Design Criterion 23, 1967 – Protection Against Multiple Disability for Protection Systems

Physical separation and electrical isolation of redundant channels and subsystems, functional diversity of subsystems, and safe failure modes are employed in the design of the reactor's defenses against functional failure through exposure to common causative factors. The redundant logic trains, reactor trip breakers, and ESF actuation devices are physically separated and electrically isolated. Physically separate channel trays, conduits, and penetrations are maintained upstream from the logic elements of each train.

The protection system components have been qualified by testing under extremes of the normal environment. In addition, components are tested and qualified according to individual requirements for the adverse environment specific to their location that might result from postulated accident conditions.

Refer to Sections 7.3.4.1.2 and 7.3.4.3 for additional information.

7.3.3.9 General Design Criterion 24, 1967 – Emergency Power for Protection Systems

Emergency power for the instrumentation and control portions of the protection systems is provided initially from the station batteries, supplying dedicated 120-Vac inverters for each protection channel, and subsequently from the EDGs. A single failure of any one component will not prevent the required functioning of protection systems.

Refer to Section 8.3 for additional information.

7.3.3.10 General Design Criterion 25, 1967 – Demonstration of Functional Operability of Protection Systems

The ESFAS includes means for testing protection systems while the reactor is in operation to demonstrate that no failure or loss of redundancy has occurred.

Operating procedures normally require that the complete ESF actuation system be operable. However, redundancy of system components is such that the system operability assumed for the safety analyses can still be met with certain instrumentation channels out of service. Channels that are out of service are to be placed in the bypass/tripped mode.

Refer to Section 7.3.4.1.5.1 for additional information.

7.3.3.11 General Design Criterion 26, 1967 – Protection Systems Fail-Safe Design

In the ESF, a loss of instrument power to a specific channel/rack/or protection set will call for actuation of ESF equipment controlled by the specific channel that lost power (exceptions to the fail-safe design requirement are the containment spray and the radiation monitoring channels that initiate containment ventilation isolation). The actuated equipment in some cases must have power to comply. The power supply for the protection systems is discussed in Chapter 8. The containment spray function is energized to trip in order to avoid spurious actuation. In addition, manual containment spray requires simultaneous actuation of both manual controls. This is considered acceptable because spray actuation on high-high containment pressure signal provides automatic initiation of the system via protection channels, meeting the criteria in Reference 4. When the construction permits for the Diablo Canyon units were issued in April 1968 and December 1970, manual initiation at the system level was in compliance with paragraph 4.17 of IEEE 279-1968 (Reference 8). No single random failure in the

manual initiation circuits can prevent automatic initiation. Failure of manual initiation at the system level is not considered a significant safety problem because the operator can initiate operation manually at the component level.

Refer to Section 7.3.4.1.1 for additional information.

7.3.3.12 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

ESFAS actuates the ESFs required to cope with any size reactor coolant pipe break up to and including the circumferential rupture of any pipe in that boundary assuming unobstructed discharge from both ends, and to cope with any steam or feedwater line break up to and including the main steam or feedwater headers. Limiting the release of fission products from the reactor fuel is accomplished by the ECCS, which, by cooling the core, keeps the fuel in place and substantially intact and limits the metal-water reaction to an acceptable amount.

7.3.3.13 General Design Criterion 38, 1967 – Reliability and Testability of Engineered Safety Features

A comprehensive program of testing has been formulated for all equipment and instrumentation vital to the functioning of the ESF. The program consists of startup tests of system components and integrated tests of the system. Periodic tests of the activation circuitry and system components, throughout the station lifetime, with maintenance performed as necessary, ensure that high reliability will be maintained and that the system will perform on demand. Details of the test program are provided in the Technical Specifications.

Refer to Section 7.3.4.1.5.1 for additional information.

7.3.3.14 General Design Criterion 40, 1967 – Missile Protection

The various sources of missiles that might affect the ESF have been identified, and protective measures have been implemented to minimize these effects (refer to Sections 3.5 and 8.3). Electrical raceways containing circuits for the ESF have not been installed in zones where provision against dynamic effects must be made, with a few exceptions. When routing through such zones was necessary, metallic conduits only were used, and conduits containing redundant circuits were separated physically as far as practical.

7.3.3.15 General Design Criterion 48, 1967 – Testing of Operational Sequence of Emergency Core Cooling Systems

The design provides for capability to test, to the extent practical, the full operational sequence up to design conditions, including transfer to alternative power sources for the ECCS, to demonstrate the state of readiness and capability of the system. This

functional test is performed with the RCS initially cold and at LP. The ECCS valve alignment is set to initially simulate the system alignment for plant power operation. Details of the ECCS are found in Section 6.3. Refer to Section 7.3.4.1.5.5 for a description of the initiation circuitry.

Refer to Section 7.3.4.1.5.1 for additional information.

7.3.3.16 General Design Criterion 49, 1967 – Containment Design Basis

ESFAS circuits routed through containment are analyzed for redundant overcurrent protection and available fault energy. ESFAS circuits routed through containment penetrations are installed without direct in-line protection. The available fault current is not of sufficient magnitude to damage the penetration conductor. These circuits will not adversely heat the penetrations as presently designed.

Refer to Section 8.3 for additional information.

7.3.3.17 Engineered Safety Features Actuation System Safety Function Requirements

(1) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the ESFAS system portion located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

7.3.3.18 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

The Class 1E ESFAS SSCs required to function in harsh environments under accidents conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ program and the requirements for the environmental design of the electrical and related mechanical equipment. The affected components are listed on the EQ Master List.

7.3.3.19 Safety Guide 22, February 1972 – Periodic Testing of Protection System Actuation Functions

Periodic testing of the ESF actuation functions, as described, complies with Safety Guide 22, February 1972 (Reference 9). Under the present design, those protection functions that are not tested at power are discussed in Section 7.3.4.1.5.9.

As described by Safety Guide 22, February 1972, where actuated equipment is not tested during reactor operation, it has been determined that:

(1) There is no practicable system design that would permit operation of the actuated equipment without adversely affecting the safety or operability of the plant.

(2) The probability that the protection system will fail to initiate the operation of the actuated equipment is, and can be maintained, acceptably low without testing the actuated equipment during reactor operation.

(3) The actuated equipment can be routinely tested when the reactor is shut down.

Where the ability of a system to respond to a bona fide accident signal is intentionally bypassed, for the purpose of performing a test during reactor operation, each bypass condition is automatically indicated to the reactor operator in the control room by a common "ESF testing" annunciator for the train in test. Test circuitry does not allow two ESF trains to be tested at the same time so that extension of the bypass condition to redundant systems is prevented.

The discussion on "bypass" in Section 7.2.4.1.11 is applicable.

Refer to Section 7.3.4.1.5.1 for additional information.

7.3.4 COMPLIANCE WITH IEEE STANDARDS

7.3.4.1 Evaluation of Compliance with IEEE 279-1971 – Criteria for Protection Systems for Nuclear Power Generating Stations

The ESFAS meets the criteria as set forth in IEEE 279-1971 (Reference 4), as follows:

7.3.4.1.1 Single Failure Criterion

The discussion presented in Section 7.2.3.7 is applicable to the ESFAS, with the following exception:

In the ESF, a loss of instrument power to a specific channel/rack/or protection set will call for actuation of ESF equipment controlled by the specific channel that lost power (exceptions to the fail-safe design requirement are the containment spray and the radiation monitoring channels that initiate containment ventilation isolation). The actuated equipment in some cases must have power to comply. The power supply for the protection systems is discussed in Chapter 8. The containment spray function is energized to trip in order to avoid spurious actuation. In addition, manual containment spray requires simultaneous actuation of both manual controls. This is considered acceptable because spray actuation on high-high containment pressure signal provides automatic initiation of the system via protection channels, meeting the criteria in Reference 4. When the construction permits for the Diablo Canyon units were issued in April 1968 and December 1970, manual initiation at the system level was in compliance

with paragraph 4.17 of IEEE 279-1968 (Reference 8). No single random failure in the manual initiation circuits can prevent automatic initiation. Failure of manual initiation at the system level is not considered a significant safety problem because the operator can initiate operation manually at the component level.

The design conforms to GDC 21, 1967 and GDC 26, 1967.

7.3.4.1.2 Equipment Qualification

The ability of the equipment inside the containment required to function for post-LOCA operation in the adverse environment associated with the LOCA or in-containment steam break, has been evaluated in Section 3.11.

Sensors for measurement of pressurizer pressure, are located inside the containment and will be exposed to the post-LOCA environment.

7.3.4.1.3 Channel Independence

The discussion presented in Section 7.2.3.6 is applicable. The ESFAS outputs from the solid-state logic protection cabinets are redundant, and the actuations associated with each train are energized to actuate, up to and including the final actuators, by the separate ac power supplies that power the respective logic trains. Mutually redundant ESFAS circuits utilize separate relays in separate racks.

7.3.4.1.4 Control and Protection System Interaction

The discussions presented in Section 7.3.3.7 are applicable.

7.3.4.1.5 Capability for Sensor Checks and Equipment Test and Calibration

The discussions of system testability in Section 7.2.4.1.10 are applicable to the sensors, analog circuitry and logic trains of the ESFAS.

The following sections cover those areas in which the testing provisions differ from those for the RTS.

7.3.4.1.5.1 Testing of Engineered Safety Features Actuation System

The ESFAS is tested to ensure that the systems operate as designed and function properly in the unlikely event of an accident. The testing program, which conforms with GDC 19, 1967; Criteria GDC 25 1967; GDC 38 1967; GDC 48 1967; and GDC 57 1967, and to Safety Guide 22, February 1972 (Reference 9), is as follows:

(1) Prior to initial plant operations, ESFAS tests will be conducted.

(2) Subsequent to initial startup, ESFAS tests will be conducted as required in the Technical Specifications.

(3) During on-line operation of the reactor, the ESFAS process and logic circuitry are fully tested. In addition, essentially all of the ESF final actuators can be fully tested. The few final actuators whose operation is not compatible with continued on-line plant operation are checked during refueling outages. Slave relays are tested on an interval defined in the Technical Specifications.

(4) During normal operation, the operability of testable final actuation devices of the ESFAS are tested by manual initiation from the test control panel.

The discussions on capability for testing, as presented in Section 7.2.2.12, are applicable.

7.3.4.1.5.2 Performance Test Acceptability Standard for the "S" (Safety Injection Signal) and the "P" (Automatic Demand Signal for Containment Spray Actuation) Actuation Signals Generation

During reactor operation, the acceptability of the ESFAS is based on the successful completion of the overlapping tests performed on the initiating system and the ESFAS. Checks of process indications verify operability of the sensors. Process checks and tests verify the operability of the process circuitry from the input of these circuits through the logic input relays and the inputs to the logic matrices. Solid-state logic testing checks the signal path through the logic matrices and master relays and performs continuity tests on the coils of the output slave relays. Final actuator testing can be performed by operating the output slave relays and verifying the required ESF actuation. Actuators whose testing is not compatible with on-line operation are tested during refueling outages, except those actuators normally in their required positions, which will not be tested. Operation of the final devices is confirmed by control board indication and visual observation that the appropriate pump breakers close and automatic valves have completed their travel.

The basis for acceptability for the ESFAS interlocks is receipt of proper indication upon introducing a trip.

Maintenance checks (performed during regularly scheduled refueling outages), such as resistance to ground of signal cables in radiation environments, are based on qualification test data that identify what constitutes acceptable degradation, e.g., radiation and thermal.

7.3.4.1.5.3 Frequency of Performance of Engineered Safety Features Actuation Tests

During reactor operation, complete system testing (excluding sensors or those devices whose operation would cause plant upset) is performed as required by the Technical

Specifications. Testing, including the sensors, is also performed during scheduled plant shutdown for refueling.

7.3.4.1.5.4 Engineered Safety Features Actuation Test Description

The following sections describe the testing circuitry and procedures for the on-line portion of the testing program. The guidelines used in developing the circuitry and procedures are:

(1) The test procedures must not involve the potential for damage to any plant equipment.

(2) The test procedures must minimize the potential for accidental tripping.

(3) The provisions for on-line testing must minimize complication of ESF actuation circuits so that their reliability is not degraded.

7.3.4.1.5.5 Description of Initiation Circuitry

Several systems comprise the total ESFAS, the majority of which may be initiated by different process conditions and reset independently of each other.

The remaining functions (listed in Section 7.3.2) are initiated by a common signal (SI), which in turn may be generated by different process conditions.

In addition, operation of all other vital auxiliary support systems, such as AFW, CCW, and ASW, is initiated via the ESF starting sequence actuated by the SI signal.

Each function is actuated by a logic circuit that is duplicated for each of the two redundant trains of ESF initiation circuits.

The output of each of the initiation circuits consists of a master relay, which drives slave relays for contact multiplication as required. The logic, master, and slave relays are mounted in the solid-state logic protection cabinets designated trains A and B, respectively, for the redundant counterparts. The master and slave relay circuits operate various pump and fan circuit breakers or starters, motor-operated valve contactors, solenoid-operated valves, start the EDG, etc.

7.3.4.1.5.6 Process Protection Testing

Process protection testing is identical to that used for reactor trip circuitry and is described in Section 7.2.4.1.10. Briefly, in the process protection racks, a man machine interface unit is used together with a rack mounted test panel to facilitate testing.

Section 7.2.3.11 discusses testing in bypass which is the normal method. Alternatively, administrative controls allow, during channel testing, that the channel output be put in a trip condition that de-energizes (operates) the input relays in train A and train B cabinets. Of necessity this is done on one channel at a time. Status lights and single

channel trip alarms in the main control room verify that the logic input relays have been deenergized and the channel outputs are in the trip mode. An exception to this is containment spray, which is energized to actuate two-out-of-four logic and reverts to two-out-of-three logic when one channel is in test.

7.3.4.1.5.7 Solid-State Logic Testing

After the individual process channel testing is complete, the logic matrices are tested from the trains A and B logic rack test panels. This step provides overlap between the process protection and logic portions of the test program. During this test, each of the logic inputs is actuated automatically in all combinations of trip and nontrip logic. Trip logic is not maintained long enough to permit master relay actuation - master relays are "pulsed" to check continuity. Following the logic testing, the individual master relays are actuated electrically to test their mechanical operation. Actuation of the master relays during this test applies low voltage to the slave relay coil circuits to allow continuity checking, but not slave relay actuation. During logic testing of one train, the other train can initiate the required ESF function. For additional details, refer to Reference 5.

7.3.4.1.5.8 Actuator Testing

At this point, testing of the initiation circuits through operation of the master relay and its contacts to the coils of the slave relays has been accomplished. Slave relays do not operate because of reduced voltage.

In the next step, operation of the slave relays and the devices controlled by their contacts are checked. For this procedure, control switches mounted in the safeguards test cabinet near the logic rack area are provided for most slave relays. These controls require two deliberate actions on the part of the operator to actuate a slave relay. By operation of these relays one at a time through the control switches, all devices that can be operated on-line without risk to the plant are tested.

Devices are assigned to the slave relays to minimize undesired effects on plant operation. This procedure minimizes the possibility of upset to the plant and again ensures that overlap in the testing is continuous, since the normal power supply for the slave relays is utilized.

During this last procedure, close communication between the main control room operator and the person at the test panel is required. Before energizing a slave relay, the operator in the control room ensures that plant conditions will permit operation of the equipment that will be actuated by the relay. After the tester has energized the slave relay, the control room operator observes that all equipment has operated as indicated by appropriate indicating lamps, monitor lamps, and annunciators on the control board. The test director, using a prepared check list, records all operations. The operator then resets all devices and prepares for operation of the next slave relay-actuated equipment.

By means of the procedure outlined above, all devices actuated by ESFAS initiation circuits can be operated by the test circuitry during on-line operation, with the following exceptions:

(1) Main steam isolation - During cold shutdowns, these valves are full stroke tested.

(2) Feedwater isolation - Air-operated, spring-closed regulating control valves and feedwater bypass valves are provided for each main feedwater line. Operation of these valves is continually monitored by normal operation. During cold shutdown, these valves are tested for closure times. MFIVs are also provided for each feedwater isolation line.

(3) RCP essential service isolation

(a) CCW supply and return. These valves cannot be fully tested during normal operation.

(b) Seal water return header. These valves cannot be fully testing during normal operation.

(4) Normal charging and normal letdown isolation. These valves cannot be fully tested during normal operation due to thermal and hydraulic transients induced on the lines.

(5) Sequential transfer of centrifugal charging pump (CCP1 and CCP2) suction from the volume control tank to the RWST for charging injection. These valves cannot be fully tested during normal operation due to reactivity transients associated with the swap. Additionally, restoration of normal charging and letdown following testing causes thermal and hydraulic transients.

(6) Autotransfer Class 1E buses to startup power or EDG.

(7) Containment spray additive tank outlet valves. These valves cannot be tested during normal operation without isolating the spray additive tank.

(8) Accumulator outlet valves. These valves are required by Technical Specifications to be open with power removed from their operators during normal operation to prevent their inadvertent closure by a spurious signal, and therefore are not tested (refer to Section 7.3.4.1.5.2).

(9) Main turbine trip.

(10) Main feedwater pump trip.

(11) Blocking of the non-ESF starts of ESF pumps during an SI signal to assure bus loading will be controlled by the ESF load sequencing timers. This circuitry cannot be fully tested during normal operation since slave relay contact position cannot be verified.

(12) Containment spray initiation circuit interlock from an SI signal. This circuit cannot be fully tested during normal operation since slave relay contact position cannot be verified.

(13) Other circuitry not associated with the ESF; for example, main generator trip, RCP trip, and SR block.

7.3.4.1.5.9 Actuator Blocking and Continuity Test Circuits

The limited number of components that cannot be operated on-line are assigned to slave relays separate from those assigned to components that can be operated on-line. For some of these components, additional blocking relays are provided that allow operation of the slave relays without actuation of the associated ESF devices. Interlocking prevents blocking the output of more than one slave relay at a time. The circuits provide for monitoring of the slave relay contacts, the devices control circuit cabling, control voltage, and the devices actuating solenoids. These slave relays and actuators may be tested using the blocking and continuity test circuits while the unit is on line; however, use of these circuits can increase the risk associated with testing, since failure of the blocking circuits may result in a reactor trip.

7.3.4.1.5.10 Time Required for Testing

The system design includes provisions for timely testing of both the process protection and logic sections of the system. Testing of actuated components (including those that can only be partially tested) is a function of control room operator availability. It is expected to require several shifts to accomplish these tests. During this procedure, automatic actuation circuitry will override testing, except for those few devices associated with a single slave relay whose outputs must be blocked and then only while blocked. It is anticipated that continuity testing associated with a blocked slave relay could take several minutes. During this time, the redundant devices in the other trains would be functional.

7.3.4.1.5.11 Summary

The testing program and procedures described provide capability for checking completely from the process signal to the logic cabinets and from these to the individual pump and fan circuit breakers or starters, valve contactors, pilot solenoid valves, etc., including all field cabling actually used in the circuitry called upon to operate for an accident condition. For those devices whose operation could affect plant or equipment operation, the same procedure provides for checking from the process signal to the logic rack. To check the final actuation device, the device itself is tested during

shutdown conditions. All testing is performed as required by the Technical Specifications.

The procedures require testing at various locations:

(1) Process channel testing and verification of setpoints are accomplished at the process protection racks. Verification of logic input relay operation is done at the control room status lights.

(2) Logic testing through operation of the master relays and low voltage application to slave relays is done at the logic rack test panel.

(3) Testing of pumps, fans, and valves is done at a test panel located in the vicinity of the logic racks, in combination with the control room operator.

(4) Continuity testing for the circuits that cannot be operated is done at the same test panel mentioned in (3) above.

7.3.4.1.6 Testing During Shutdown

ECCS components and the system, including emergency power supplies, will be tested in accordance with the Technical Specifications.

Containment spray system tests are performed at each major fuel reloading. The tests are performed with the isolation valves in the spray supply lines at the containment and spray additive tank blocked closed, and are initiated manually or by using an actual or simulated actuation signal.

All final actuators can be tested during a refueling outage. The final actuators that cannot be tested during on-line operation are tested during each major fuel reloading. All testing is performed as required by the Technical Specifications.

7.3.4.1.7 Periodic Maintenance Inspections

Periodic maintenance on the system equipment is accomplished and documented according to the maintenance procedures contained in the Plant Manual. Refer to Section 13.5.1.

The balance of the requirements listed in Reference 4 (Paragraphs 4.11 through 4.22) is discussed in Section 7.2.4.1. Paragraph 4.20 receives special attention in Section 7.5.

7.3.4.2 Evaluation of Compliance with IEEE 308-1971, Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations

The power supplies for the ESF equipment conform to IEEE 308-1971 (Reference 10).

Refer to Section 7.6 and Chapter 8, which discuss the power supply for the protection systems, for additional discussions on compliance with this criteria.

7.3.4.3 Evaluation of Compliance with IEEE 323-1971, Trial-Use Standard: General Guide for Qualifying Class I Electric Equipment for Nuclear Power Generating Stations

Refer to Section 3.11 for a discussion on ESF electrical equipment EQ and compliance to IEEE 323-1971 (Reference 11). Documentation of the environmental and seismic qualification of the process protection system is provided in References 18, 19, 20, and 21.

7.3.4.4 Evaluation of Compliance with IEEE 338-1971, Trial-Use Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

The periodic testing of the ESF actuation system conforms to the requirements of IEEE 338-1971 (Reference 13), with the following comments:

(1) The periodic test frequency specified in the Technical Specifications was conservatively selected, using considerations in paragraph 4.3 of Reference 13, to ensure that equipment associated with protection functions has not drifted beyond its minimum performance requirements.

(2) The test interval discussed in Paragraph 5.2 of Reference 13 is primarily developed on past operating experience, and modified, as necessary, to ensure that system and subsystem protection is reliably provided. Analytic methods for determining reliability are not used to determine test interval.

7.3.4.5 Evaluation of Compliance with IEEE 344-1971, Trial-Use Guide for Seismic Qualifications of Class I Electric Equipment for Nuclear Power Generating Stations

The seismic testing, as set forth in Section 3.10, conforms to the testing requirements of IEEE 344-1971 (Reference 14); however, because the IEEE standards were issued after much of the design and testing had been completed the equipment documentation may not meet the format requirements of the standards. Documentation of the environmental and seismic qualification of the process protection system is provided in References 18, 19, 20, and 21.

7.3.4.6 Evaluation of Compliance with IEEE 317-1971, Electric Penetration Assemblies in Containment Structures for Nuclear Fueled Power Generating Stations

Refer to Section 7.2.4.2 for a discussion of conformance with IEEE 317-1971 (Reference 15). The same applies to penetrations for systems described in Section 7.3.

7.3.4.7 Evaluation of Compliance with IEEE 336-1971, Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

Refer to Section 7.1.3.4 for a discussion of conformance with IEEE 336-1971 (Reference 16).

7.3.4.8 Eagle 21 and Process Control System Design, Verification, and Validation

The standards that are applicable to the Eagle 21 Design, Verification and Validation Plan (Reference 17) are IEEE-Standard 603-1980 (Reference 21), which was endorsed by Regulatory Guide 1.153, December 1985 (Reference 23), and ANSI/IEEE-ANS-7-4.3.2-1982 (Reference 24) which was endorsed by Regulatory Guide 1.152, November 1985 (Reference 22).

The following ESFAS related instrument signals are processed by the PCS:

(1) RHR Pump Trip on Low RWST Level (refer to Sections 6.3.3.4.4.1 and 7.3.2.4.1).

References 4, 10, 13, 16, and 27 through 71 were used for design, verification, validation, and qualification of all or portions of the safety related PCS hardware and software (encompassing Triconex components, manual/auto hand stations, signal converters/isolators and loop power supplies).

7.3.5 REFERENCES

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7.3.6 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

7.4 SYSTEMS REQUIRED FOR SAFE SHUTDOWN

The functions necessary for safe shutdown, defined as hot standby (MODE 3), are available from instrumentation channels that are associated with the major systems in both the primary and secondary sides of the plant. These channels are normally aligned to serve a variety of operational functions, including startup and shutdown, as well as protective functions. Prescribed procedures for securing and maintaining the plant in a safe shutdown condition can be instituted by appropriate alignment of selected systems. The discussion of these systems, together with the applicable codes, criteria, and guidelines, is included in other sections. In addition, the alignment of shutdown functions associated with the ESFs that are invoked under postulated limiting fault situations is discussed in Chapter 6 and Section 7.3.

The instrumentation and control functions that are required to be aligned for maintaining safe shutdown (MODE 3) of the reactor, which are discussed in this section, are the minimum number under nonaccident conditions. These functions permit the necessary operations to:

(1) Prevent the reactor from achieving criticality in violation of the Technical Specifications (Reference 2)

(2) Provide an adequate heat sink so that design and safety limits are not exceeded

Refer to Section 9.5.1 to determine instrumentation and controls required for safe shutdown in the event of fire.

7.4.1 DESIGN BASES

7.4.1.1 General Design Criterion 3, 1971 – Fire Protection

The instrumentation and control systems required for safe shutdown are designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

7.4.1.2 General Design Criterion 11, 1967 – Control Room

The instrumentation and control systems required for safe shutdown are designed to support actions to maintain and control the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

7.4.1.3 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The instrumentation and control systems required for safe shutdown are designed to monitor and maintain variables within prescribed operating ranges.

7.4.1.4 Safe Shutdown Systems Safety Function Requirements

(1) Protection from Missiles

The instrumentation and control systems required for safe shutdown are designed and located to be protected against the effects of missiles which may result from plant equipment failure and from events and conditions outside the plant.

(2) Protection Against High Energy Pipe Rupture Effects

The instrumentation and control systems required for safe shutdown are designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The outside containment instrumentation and control systems required for safe shutdown are designed to be protected against the effects of moderate energy pipe failure.

(4) Protection from Jet Impingement – Inside Containment

The inside containment instrumentation and control systems required for safe shutdown are designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

(5) Protection from Flooding Effects – Outside Containment

The outside containment instrumentation and control systems required for safe shutdown are to be protected from the effects of internal flooding.

7.4.2 DESCRIPTION

The designation of systems used for safe shutdown depends on identifying those systems that provide the following capabilities for maintaining a safe shutdown (MODE 3):

(1) Boration

(2) Adequate supply of AFW

(3) Decay heat removal

These systems are identified in the following sections, together with the associated instrumentation and controls provisions. The design basis information for these

systems, as required by IEEE 279-1971 (Reference 3), is provided in other sections herein. For convenience, cross-referencing to these other sections is provided.

In the event that safe shutdown from outside of the control room is required, remote instrumentation, controls, and transfer switches are required for the following functions to maintain safe shutdown (MODE 3):

(1) Reactor trip indication

(2) RCS pressure control

(3) Decay heat removal via the AFW system and the SG safety valves

(4) RCS inventory control via charging flow

(5) Safety support systems for the above functions, including ASW, CCW, and EDGs

Instrumentation and controls required to fulfill these functions are described in the following sections. Other instrumentation and controls provided for cold shutdown (MODE 5) and operator convenience are also identified but are not required for safe shutdown (MODE 3).

7.4.2.1 Safe Shutdown Equipment

7.4.2.1.1 Monitoring Indicators

The characteristics of the monitoring indicators that are provided inside and outside, the control room are described in Section 7.5. The necessary safe shutdown (MODE 3) indications are:

(1) Water level indications for each SG

(2) Pressure indication for each SG

(3) Pressurizer water level indication

(4) Pressurizer pressure indication

(5) Condensate storage tank level indication

(6) RCS temperature indication for loop 1 or, loop 4 hot leg and cold leg

(7) AFW flow indication

(8) Charging flow indication

(9) Reactor trip breaker indication

All indications external to the control room are provided at the hot shutdown panel except for the RCS temperature indication (which is provided at the dedicated shutdown panel) and the reactor trip breaker indication (which is provided at the trip breaker switchgear). The dedicated shutdown panel is described in Section 7.5.2.7.

In addition, other remote shutdown indications are provided for operator convenience at the hot shutdown panel (refer to Figure 7.7-30) but not required for safe shutdown (MODE 3).

7.4.2.1.2 Controls

Controls utilized for obtaining and maintaining safe shutdown (MODE 3) are addressed below.

7.4.2.1.2.1 General Considerations

(1) The turbine is tripped from the control room (note that this can also be accomplished at the turbine).

(2) The reactor is tripped from the control room (note that this can also be accomplished at the reactor trip switchgear).

(3) All automatic systems continue functioning (refer to Sections 7.2 and 7.7).

Safe shutdown (MODE 3) is a stable plant condition automatically reached following a plant shutdown. The safe shutdown condition can be safely maintained for an extended time.

In addition, the SI signal trip circuit must be defeated and the accumulator isolation valves closed.

(4) For motor-driven equipment that must be operated from outside the control room due to control room evacuation, controls are provided at the hot shutdown panel. A control transfer switch is provided at the 4.16-kV or 480-V switchgear to directly transfer control to the hot shutdown panel for some equipment. For other equipment, a control transfer switch is provided at the hot shutdown panel to transfer control to that panel. Transfer of control is interlocked with a permissive switch that is located at the motor control center. This interlock is provided to permit isolation of the hot shutdown panel to prevent spurious actions in the event of a fire in or at the hot shutdown panel.

Three methods of transfer control are employed:

(a) For one set of redundant equipment, the permissive switch is normally closed, permitting transfer of control to the hot shutdown panel when the control transfer switch is operated. Abnormal permissive switch alignment or transfer of control is annunciated in the control room.

(b) For the second set of redundant equipment, the permissive switch is normally open, permitting transfer of control by operating the transfer switch only after closing the permissive switch. Abnormal permissive switch alignment is annunciated in the control room.

(c) For the third set of redundant equipment, the transfer switch on the 4.16-kV or 480 V switchgear permits the transfer of control to the hot shutdown panel. Transfer of control is annunciated in the control room.

7.4.2.1.2.2 Pumps, Fan Coolers, and Ventilation Systems

To maintain safe shutdown (MODE 3) conditions from inside or outside of the control room, controls and transfer switches are required for the AFW pumps, centrifugal charging pumps (CCP1 and CCP2), ASW pumps and the CCW pumps. Other controls are available for "operational convenience" but are not required for safe shutdown. The controls for the required pumps and other equipment are described below.

(1) AFW Pumps - In the event of a main feedwater pump stoppage due to a loss of electric power, the motor-driven and turbine-driven AFW pumps start automatically (these pumps can also be started manually). Motor-driven AFW pump start and stop motor controls are located on the hot shutdown panel, in the 4.16-kV switchgear rooms, and in the control room (refer to Figures 7.3-8 and 7.3-17). Controls for the steam supply valve to the turbine-driven AFW pump are located on the hot shutdown panel and in the control room (refer to Figure 7.3-18).

(2) Centrifugal Charging and Boric Acid Transfer Pumps - Start and stop motor controls are provided for these pumps. The controls for the centrifugal charging pumps (CCP1 and CCP2) and the boric acid transfer pumps are located on the hot shutdown panel, as well as in the control room. Additionally, the charging pumps can be started and stopped in the 4.16-kV switchgear rooms. (For charging pumps, refer to Figures 7.3-3, 7.3-4, and 7.3-29. For boric acid transfer pumps, refer to Figures 7.3-13 and 7.3-30, Sheet 2.)

(3) ASW Pumps - These pumps restart automatically following a loss of normal electric power. Start and stop motor controls are located on the

hot shutdown panel, in the 4.16-kV switchgear rooms, as well as in the control room (refer to Figures 7.3-5 and 7.3-28).

(4) CCW Pumps - These pumps restart automatically following a loss of normal electric power. Start and stop motor controls are located on the hot shutdown panel, in the 4.16-kV switchgear rooms, as well as in the control room (refer to Figures 7.3-7 and 7.3-27).

(5) Reactor Containment Fan Cooler Units - These units restart automatically following a loss of normal electric power. Start and stop motor controls with a selector switch are provided for the fan motors. The controls are located on the hot shutdown panel, as well as in the control room (refer to Figures 7.3-6 and 7.3-31).

(6) Control Room Heating, Ventilation and Air-Conditioning System (includes fans and dampers) - A start and stop switch is located in the control room for the fan(s). Also, a control to open or close the inlet air damper(s) is located near the dampers. When placed in automatic control, the inlet air dampers are designed to position automatically to meet the requirements of the mode of operation of the system.

(7) Auxiliary Building Ventilation System - Operation of the system can be initiated from the ventilation control board in the control room. The system is designed to automatically shift to meet the requirements of the mode of operation of the system.

(8) Fuel Handling Building Ventilation System (Provides ventilation for the AFW pumps) - Operation of the system can be initiated from the control room. Normally, the system operates with one set of supply and exhaust fans. In the event of failure of an operating fan, the redundant fan is designed to start automatically.

(9) 4.16-kV Switchgear Room Ventilation System - Operation of the system can be initiated from the locally mounted control switches.

(10) 125-Vdc and 480-V Switchgear Room Ventilation System - Operation of the system can be initiated from the locally mounted control switches.

7.4.2.1.2.3 Valves

To maintain safe shutdown (MODE 3) conditions from inside or outside of the control room, control of AFW system level control valves is required. Other controls are available for "operational convenience" but are not required for safe shutdown. The controls for the AFW valves and other remotely operated valves with controls external to the control room are described below.

(1) Letdown Orifice Isolation Valves - Open and close controls for these valves are located on the hot shutdown panel . These controls duplicate functions that are inside the control room (refer to Figure 7.3-45, Sheet 1).

(2) AFW Control Valves - Manual control is provided on the hot shutdown panel that duplicates functions inside the control room (refer to Figure 7.3-14).

(3) Condenser Steam Dump and Atmospheric Steam Relief Valves - The condenser steam dump and atmospheric relief valves are automatically controlled. In addition to local and control room control, the 10 percent atmospheric dump valves can be manually controlled at the hot shutdown panel. Manual control is provided locally as well as inside the control room for the atmospheric relief valves. Steam dump to the condenser is blocked on high condenser pressure. Cut-out switches allow de-energizing steam generator 3 and 4, 10 percent atmospheric steam dump valve solenoids if they spuriously energize in a fire.

(4) Charging Flow Control Valves - Controls for the emergency borate valve (refer to Figure 7.3-34) and charging pump discharge header flow control valves are located on the hot shutdown panel in addition to the control room. Controls for a pressurizer auxiliary spray valve are located at the dedicated shutdown panel in addition to the control room (refer to Figure 7.3-45, Sheet 1).

(5) Pressurizer Power Operated Relief Valves - Emergency close controls for these valves are provided on the hot shutdown panel in addition to control from the control room (refer to Figure 7.3-21).

(6) Chemical and Volume Control System Valves – Controls for charging line isolation valves and charging to loop 4 isolation valve are located at the hot shutdown panel in addition to the control room (refer to Figures 7.3-34 and 7.3-45).

(7) Safety Injection System Valves – Controls for RWST to charging pump suction header valve are located at the hot shutdown panel in addition to the control room (refer to Figure 7.3-33).

7.4.2.1.2.4 Pressurizer Heater Control

The pressurizer heaters are normally controlled from the control room. On-off control is provided on the hot shutdown panel for two backup heater groups. The control is grouped with the charging flow controls and duplicates functions available in the control room. These controls are for "operational convenience" but are not required for safe shutdown (MODE 3).

7.4.2.1.2.5 Diesel Generators

These units are started automatically on a SI, loss of voltage on either the offsite source or the Class 1E buses, or on degraded bus voltage on the Class 1E buses. Manual controls for diesel starting and control are provided at the main control room and also locally at the diesel generators. Additional description is provided in Section 8.3.

7.4.2.1.3 Maintenance of Safe Shutdown (MODE 3) Conditions Using Remote Shutdown Instrumentation and Controls

The normal and preferred location to operate the plant from is the control room. However, in the event that the control room becomes inaccessible, the operators can establish remote control and place the unit in safe shutdown (MODE 3). Remote Shutdown System Technical Specifications (Reference 2) have been established to ensure the operability of the remote shutdown instrumentation and controls.

To establish and maintain safe shutdown (MODE 3) conditions from outside of the control room, the reactor must be tripped, decay heat must be removed, and the RCS temperature, pressure, and inventory must be controlled. Additionally, systems required to support equipment performing these functions must be operable. The following provides a discussion of the minimum functions required to establish and maintain safe shutdown (MODE 3) conditions from outside of the control room until a cooldown is initiated or control is transferred back to the control room.

(1) Reactor Trip - Core subcriticality is achieved by tripping the reactor. The reactor can be tripped from outside the control room by opening the reactor trip breakers at the reactor trip switchgear. Reactor trip indication is provided from outside the control room by the reactor trip breaker position. The insertion of the control rods during a reactor trip provides the negative reactivity needed to establish and maintain safe shutdown (MODE 3) conditions until such time that either control is returned to the control room or a cooldown is initiated.

(2) Decay Heat Removal via the AFW System and the SG Safety Valves - Heat removal from the RCS is accomplished by transferring heat to the secondary plant through the SGs. The decay heat is then removed from the SGs via boiling and steam release through the SG code safety valves. Indication of secondary heat sink is provided by SG pressure indication, SG wide range level indication, and AFW flow indication at the hot shutdown panel. Indication is also provided at the hot shutdown panel for steam generator 3 and 4 cold calibrated narrow range levels. The hot shutdown panel also provides indication of condensate storage tank level to allow monitoring of water available to supply the suction of the AFW pumps for extended operation at safe shutdown (MODE 3).

To ensure that SG level remains within its expected range, the AFW pump and level control valves are controllable from the hot shutdown panel. Upon initiation of a reactor trip, SG level will decrease due to shrink and the trip of the main feedwater pumps. The AFW pumps supply feedwater to the SGs to compensate for the loss of main feedwater. After the level in the SGs recovers, the feedwater supply to the SGs must be controlled to prevent the SGs from overfilling and overcooling the RCS, which could result in a SI. The feedwater flow can be controlled from the hot shutdown panel by using the AFW level control valves or by starting and stopping the AFW pumps. AFW flow indication is provided to aid in flow control.

To monitor the rate of heat removal from the core during all plant conditions, including a loss of offsite power, indications of RCS hot and cold leg temperature indication are required. Loop 1 RCS hot and cold leg temperature indication is available at the dedicated shutdown panel. Loop 4 RCS wide range hot and cold leg temperature indications are available at the hot shutdown panel.

(3) RCS Pressure Control - Indication of RCS pressure is provided by the pressurizer pressure indication located at the hot shutdown panel. An indication of RCS loop 4 hot leg pressure is also provided at the hot shutdown panel. RCS overpressure protection is provided by the pressurizer code safety valves. Although pressurizer heaters would assist in controlling RCS pressure, they are not required to maintain RCS pressure control.

(4) RCS Inventory Control via Charging Flow - Indication of RCS inventory is provided by the pressurizer level indication located at the hot shutdown panel. Level control is necessary to prevent the loss of level in the pressurizer and the subsequent loss of RCS pressure control, to prevent the RCS from achieving a solid water condition where pressure would no longer be readily controllable, and to prevent the core from being uncovered due to low level.

The hot shutdown panel contains controls to start and stop each centrifugal charging pump (CCP1 and CCP2). The charging pumps not only supply water to the RCS for pressurizer level control, but also provide water to the RCP seals. By starting and stopping the charging pumps, pressurizer level can be controlled. During any time when the charging pumps are shut off, RCP seal degradation would be prevented by reactor coolant flowing past the thermal barrier heat exchanger (HX), which is cooled by CCW flow, and out of the RCP seals. This would also remove water injected into the RCS that may have caused an increase in pressurizer level.

(5) Safety Support Systems - In order for the above equipment to perform its intended safety function, it must have power and be cooled. Heat removal can be accomplished via the CCW and ASW systems. The CCW system removes heat from the lube oil and seals of the ESF pumps. The ASW removes heat from the CCW system and rejects it to the ultimate heat sink. Both the CCW pumps and the ASW pumps can be started from the hot shutdown panel. Although the CCW and ASW pumps are normally in operation and are designed to auto-start, pump controls at the hot shutdown panel ensure that the pumps are available in the event that they do not start automatically.

To ensure that power is available to ESF equipment, EDGs are available to supply power in the event that offsite power is unavailable. Although the EDGs should auto-start during a loss of offsite power, local manual controls for diesel starting and control provide additional assurance that power will be available to the ESF equipment required to establish and maintain hot safe shutdown
(MODE 3) conditions.

(6) Additional Controls Provided for Operational Convenience - Controls are also provided at the hot shutdown panel to manipulate charging flow, the 10 percent atmospheric dump valves, the containment fan cooler units, the pressurizer heaters, the pressurizer PORVs, and the letdown orifice isolation valves. Controls are provided at the dedicated shutdown panel for pressurizer auxiliary spray. These controls are provided as an operational convenience.

The above evaluation demonstrates that the reactor can be maintained in a safe condition.

7.4.2.1.4 Process Control System

The PCS performs the same design functions as the original PCS. Some of the instrumentation and control functions described in this chapter are processed by the PCS. References 3 through 52 were used for design, verification, validation, and qualification of all or portions of the PG&E Design Class I PCS hardware and software (encompassing Triconex components, manual/auto hand stations, signal converters/isolators and loop power supplies).

7.4.2.2 Equipment, Services, and Approximate Time Required After Incident that Requires Hot Shutdown (MODE 4)

(1) AFW pumps - required if main feedwater pumps are not operating. For loss of plant ac power, the turbine-driven AFW pump starts automatically within 1 minute (refer to Section 6.5).

(2) Reactor containment fan cooler units - within 15 minutes (refer to Chapter 6)

(3) EDGs - loaded within 1 minute (refer to Section 8.3).

(4) Lighting in the areas of plant required during this condition - immediately (refer to Section 8.3).

(5) Pressurizer heaters - within 8 hours (refer to Section 5.5.9).

(6) Communication network - to be available for prompt use between the hot shutdown panel area and the following areas:

(a) Outside telephone exchange

(b) Boric acid transfer pump

(c) EDGs

(d) Switchgear room

(e) Steam relief valves

(f) Dedicated shutdown panel

7.4.2.3 Equipment and Systems Available for Cold Shutdown (MODE 5)

(1) Reactor coolant pump (not available after loss of offsite power; refer to Section 5.5.1)

(2) Auxiliary feedwater pumps (refer to Section 6.5.3.5)

(3) Boric acid transfer pump (refer to Section 9.3.4)

(4) Charging pumps (refer to Section 9.3.4)

(5) Containment fan coolers (refer to Section 9.4.5)

(6) Control room ventilation (refer to Section 9.4.1)

(7) Component cooling pumps (refer to Section 9.2.2)

(8) Residual heat removal pumps (refer to Section 5.5.6)[(a)]

(9) Vital MCC and switchgear sections (refer to Section 8.3)

(10) Controlled steam release and feedwater supply (refer to Sections 7.7 and 10.4)

(11) Boration capability (refer to Section 9.3.4)

(12) Nuclear instrumentation system (source range and intermediate range; refer to Sections 7.2 and 7.7)[a]

(13) Reactor coolant inventory (charging and letdown; refer to Section 9.3.4)

(14) Pressurizer pressure control including control for pressurizer power-operated relief valves, heaters, and spray (refer to Sections 5.5.9 and 5.5.12)[a]

(15) 10 percent atmospheric dump valves (refer to Section 10.4.4)

7.4.3 SAFETY EVALUATION

7.4.3.1 General Design Criterion 3, 1971 – Fire Protection

The instrumentation and control systems required for safe shutdown (MODE 3) are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

7.4.3.2 General Design Criterion 11, 1967 – Control Room

The instrumentation and control functions required for safe shutdown (MODE 3) are located in the control room. Redundant instrumentation and controls are located on the hot shutdown panel, switchgear, and on the dedicated shutdown panel for the purpose of achieving and maintaining a safe shutdown in the event an evacuation of the control room is required.

These controls and the instrumentation channels, together with the equipment and services that are available for both hot and cold shutdown, identify the potential capability for cold shutdown of the reactor, subsequent to a control room evacuation, through the use of suitable procedures.

In the unlikely event that access to the control room is restricted, the plant can be safely maintained at safe shutdown (MODE 3), and until the control room can be reentered, by the use of the monitoring indicators and the controls listed in Section 7.4.2. These

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[a] Instrumentation and controls for these systems would require some modifications so that their functions may be performed from outside the control room. Note that the reactor plant design does not preclude attaining the cold shutdown condition from outside the control room. An assessment of plant conditions could be made on a long-term basis (a week or more) to establish procedures for making the necessary physical modifications to instrumentation and control equipment in order to attain cold shutdown. During such time, the plant could be safely maintained in the hot shutdown condition.

indicators and controls are provided on the hot shutdown panel, the dedicated shutdown panel, or local area panel as well as inside the control room.

7.4.3.3 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The safety evaluation of the maintenance of a shutdown with the systems described in Section 7.4.2 and associated instrumentation and controls has included consideration of the accident consequences that might jeopardize safe shutdown (MODE 3) conditions. The germane accident consequences are those that would tend to degrade the capabilities for boration, adequate supply of AFW, and decay heat removal.

The results of the accident analyses are presented in Chapter 15. Of these, the following produce the most severe consequences that are pertinent:

(1) Uncontrolled boron dilution

(2) Loss of normal feedwater

(3) Loss of external electrical load and/or turbine trip

(4) Loss of all ac power to the station auxiliaries

It is shown by these analyses that safety is not adversely affected by the incidents with the associated assumptions being that the instrumentation and controls indicated in Section 7.4.2 are available to control and/or monitor shutdown. These available systems allow the maintenance of safe shutdown (MODE 3) even under the accident conditions listed above that would tend toward a return to criticality or a loss of heat sink.

A plant design evaluation was performed by PG&E to identify the safe shutdown equipment that could be susceptible to loss of function due to the environmental conditions resulting from moderate-energy line breaks. Equipment modification such as spray barriers, terminal box cover gasket, and piping enclosures were designed and installed as required to preclude any loss of function in the event of a moderate-energy line break.

Additional information concerning protection of equipment from the effects of postulated piping ruptures is presented in Section 3.6.

7.4.3.4 Safe Shutdown Systems Safety Function Requirements

(1) <u>Protection from Missiles</u>

The provisions taken to protect the instrumentation and control systems required for safe shutdown from missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Section 3.5.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the instrumentation and control systems required for safe shutdown from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Section 3.6.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection of the instrumentation and control systems required for safe shutdown located outside containment from the effects of moderate energy pipe failure are discussed in Section 3.6.

(4) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the instrumentation and control systems required for safe shutdown located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

(5) Protection from Flooding Effects – Outside Containment

The provisions taken to provide protection of the instrumentation and control systems required for safe shutdown located outside containment from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

7.4.4 REFERENCES

1. Deleted in Revision 21.

2. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

3. IEEE Standard 279-1971, Criteria for Protection Systems for Nuclear Power Generating Stations, Institute of Electrical and Electronics Engineers, Inc.

4. IEEE Standard 308-1971, Criteria for Class 1E Power Systems for Nuclear Power Generating Stations, Institute of Electrical and Electronics Engineers, Inc.

5. IEEE Standard 323-2003, Qualifying Class 1E Equipment for Nuclear Power Generating Stations, Institute of Electrical and Electronics Engineers, Inc.

6. IEEE Standard 336-1971, Installation, Inspection, and Testing Requirements for Power, Instrumentation, and Control Equipment at Nuclear Facilities, Institute of Electrical and Electronics Engineers, Inc.

7. IEEE Standard 338-1971, Criteria for the Periodic Surveillance Testing of Nuclear Power Generating Station Safety Systems, Institute of Electrical and Electronics Engineers, Inc.

8. IEEE Standard 344-1987, Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations, Institute of Electrical and Electronics Engineers, Inc.

9. IEEE Standard 384-1974, Criteria for Independence of Class 1E Equipment and Circuits, Institute of Electrical and Electronics Engineers, Inc.

10. IEEE Standard 730-1998, Software Quality Assurance Plans, Institute of Electrical and Electronics Engineers, Inc.

11. IEEE Standard 828-1990, Software Configuration Management Plans, Institute of Electrical and Electronics Engineers, Inc.

12. IEEE Standard 829-1983, Software Test Documentation, Institute of Electrical and Electronics Engineers, Inc.

13. IEEE Standard 830-1993, Recommended Practice for Software Requirements Specifications, Institute of Electrical and Electronics Engineers, Inc.

14. IEEE Standard 1008-1987, Software Unit Testing, Institute of Electrical and Electronics Engineers, Inc.

15. IEEE Standard 1012-1998, Software Verification and Validation, Institute of Electrical and Electronics Engineers, Inc.

16. IEEE Standard 1016-1987, Recommended Practice for Software Design Descriptions, Institute of Electrical and Electronics Engineers, Inc.

17. IEEE Standard 1016.1-1993, Guide to Software Design Descriptions, Institute of Electrical and Electronics Engineers, Inc.

18. IEEE Standard 1059-1993, Guide for Software Verification and Validation Plans, Institute of Electrical and Electronics Engineers, Inc.

19. IEEE Standard 1074-1995, Developing Software Life Cycle Processes, Institute of Electrical and Electronics Engineers, Inc.

20. IEEE Standard 1233-1998, Guide for Developing System Requirements Specifications, Institute of Electrical and Electronics Engineers, Inc.

21. IEEE Standard C62.41-1991, Recommended Practice for Surge Voltages in Low Voltage AC Power Circuits, Institute of Electrical and Electronics Engineers, Inc.

22. IEEE Standard C62.45-1992, Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and less) AC Power Circuits, Institute of Electrical and Electronics Engineers, Inc.

23. IEEE Standard 7-4.3.2-2003, Digital Computers in Safety Systems of Nuclear Power Generating Stations, Institute of Electrical and Electronics Engineers, Inc.

24. EPRI TR-106439, Guideline on Evaluation and Acceptance of Commercial-Grade Digital Equipment for Nuclear Safety Applications, Electric Power Research Institute, October, 1996.

25. EPRI TR-102323 Revision 3, Guidelines for Electromagnetic Interference Testing in Power Plants, Electric Power Research Institute, November 2004.

26. EPRI TR-107330, Generic Requirements Specification for Qualifying a Commercially Available PLC for Safety-Related Applications in Nuclear Power Plants, Electric Power Research Institute, December 1996.

27. EPRI TR-102348 Revision 1, Guideline on Licensing Digital Upgrades, Electric Power Research Institute, March 2002.

28. Regulatory Guide 1.100 Revision 2, Seismic Qualification of Electrical and Mechanical Equipment for Nuclear Power Plants, USNRC, June 1988.

29. Regulatory Guide 1.105, Revision 3, Setpoints for Safety-Related Instrumentation, USNRC, December 1999.

30. Regulatory Guide 1.152, Revision 1, Criteria for Digital Computers in Safety Systems of Nuclear Power Plants, USNRC, January 1996.

31. Regulatory Guide 1.168, Verification, Validation, Reviews and Audits for Digital Computer Software Used in Safety Systems of Nuclear Power Plants, USNRC, February 2004.

32. Regulatory Guide 1.169, Configuration Management Plans for Digital Computer Software Used in Safety Systems of Nuclear Power Plants, USNRC, September 1997.

33. Regulatory Guide 1.170, Software Test Documentation for Digital Computer Software Used in Safety Systems of Nuclear Power Plants, USNRC, September 1997.

34. Regulatory Guide 1.171, Software Unit Testing for Digital Computer Software

Used in Safety Systems of Nuclear Power Plants, USNRC, September 1997.

35. Regulatory Guide 1.172, Software Requirements Specifications for Digital Computer Software Used in Safety Systems of Nuclear Power Plants, USNRC, September 1997.

36. Regulatory Guide 1.173, Developing Software Life Cycle Processes For Digital Computer Software Used in Safety Systems of Nuclear Power Plants, USNRC, September 1997

37. Regulatory Guide 1.180, Revision 1, Guidelines for Evaluating Electromagnetic and Radio-Frequency Interference in Safety-Related Instrumentation and Control Systems, USNRC, October 2003.

38. Regulatory Guide 1.22, Periodic Testing of Protection System Actuation Functions, USNRC, February 1972.

39. Regulatory Guide 1.29, Revision 3, Seismic Design Classification, USNRC, September 1978.

40. Regulatory Guide 1.30, Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment, USNRC, August 1972.

41. Regulatory Guide 1.47, Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems, USNRC, May 1973.

42. Regulatory Guide 1.89, Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants, USNRC, November 1974.

43. Regulatory Guide 1.97, Revision 3, Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident, USNRC, May 1983.

44. NUREG-0800, Appendix 7.0-A, Revision 5, Review Process for Digital Instrumentation and Control Systems, USNRC, March 2007.

45. BTP 7-14 Revision 5 Guidance on Software Reviews for Digital Computer-Based Instrumentation and Control Systems, USNRC, March 2007.

46. BTP 7-18 Revision 5, Guidance on the use of Programmable Logic Controllers in Digital Computer-Based Instrumentation and Control Systems, USNRC, March 2007.

47. MIL-STD-461E Requirements for the Control of Electromagnetic Interference Characteristics of Subsystems and Equipment, USDOD, August 1999

48. ANSI/ANS-4.5-1980, Criteria for Accident Monitoring Functions in Light-Water-Cooled Reactors, American Nuclear Society, January 1980

49. NEMA ICS 1-2000, Industrial Control and Systems: General Requirements, National Electrical Manufacturers Association, December 2008

50. NFPA 70 (NEC) 2002 National Electric Code, National Fire Protection Association, January 2002

51. IEC 61131-3 1993, Programming Industrial Automations Systems, International Electrotechnical Commission, December 1993

52. ISA-S67.04-1994, Setpoints for Nuclear Safety-Related Instrumentation, International Society of Automation, January 1994

53. NFPA-805, Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants, 2001 Edition

7.4.5 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

7.5 SAFETY-RELATED DISPLAY INSTRUMENTATION

This section provides a description of the instrumentation display systems that provide information to enable the operator to perform required safety functions and post-accident monitoring.

7.5.1 DESIGN BASES

7.5.1.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I display instrumentation is designed to withstand the effects of or is protected against natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

7.5.1.2 General Design Criterion 11, 1967 – Control Room

The PG&E Design Class I display instrumentation is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

7.5.1.3 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The PG&E Design Class I display instrumentation is designed to monitor and maintain variables within prescribed operating ranges.

7.5.1.4 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The PG&E Design Class I display instrumentation is designed to provide means for monitoring the containment atmosphere, the facility effluent discharge paths, and the facility environs for radioactivity that could be released from normal operations, from anticipated transients and from accident conditions.

7.5.1.5 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

The PG&E Design Class I display instrumentation that requires environmental qualification are qualified to the requirements of 10 CFR 50.49.

7.5.1.6 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The PG&E Design Class I display instrumentation is designed to provide instrumentation to monitor plant variables and systems during and following an accident.

7.5.1.7 NUREG-0737 (Items I.D.2, II.D.3, II.E.1.2, II.F.1, II.F.2, and III.A.1.2), November 1980 – Clarification of TMI Action Plan Requirements

Item I.D.2 – Plant Safety Parameter Display Console: The safety parameter display system (SPDS) is designed to display to operating personnel a minimum set of parameters which define the safety status of the plant in accordance with the guidance of NUREG-0737, Supplement 1.

Item II.D.3 – Direct indication of relief and safety valve position: The pressurizer safety valve (PSV) position indication system provides positive indication in the control room to determine valve position using acoustic monitoring in the discharge pipe.

The pressurizer PORV position indication provides positive indication in the control room to determine valve position using valve mounted limit switches.

Item II.E.1.2 – Auxiliary Feedwater System Automatic Initiation and Flow Indication: The Auxiliary Feedwater (AFW) System is designed to automatically initiate and is designed to the requirements of IEEE 279-1971. The AFW System is designed to provide a reliable indication of auxiliary feedwater system performance.

Item II.F.1 – Additional Accident Monitoring Instrumentation: The safety-related display instrumentation is designed to include the following subparts:

- Noble gas effluent radiological monitor;
- Provisions for continuous sampling of plant effluents for post-accident releases of radioactive iodines and particulates and onsite laboratory capabilities;
- Containment high-range radiation monitor;
- Containment pressure monitor;
- Containment water level monitor; and
- Containment hydrogen concentration monitor

Item II.F.2 – Instrumentation for Detection of Inadequate Core Cooling: The safety-related display instrumentation is designed to provide an unambiguous, easy-to-interpret indication of inadequate core cooling.

Item III.A.1.2 – Upgrade Emergency Support Facilities: The safety-related display instrumentation is designed to support the Technical Support Center (TSC), the Operations Support Center (OSC) and the Emergency Operations Facility (EOF) in accordance with the guidance of NUREG-0737, Supplement 1.

7.5.2 DESCRIPTION

Tables 7.5-1 and 7.5-2 list the information readouts provided to enable the operator to perform required manual safety functions and to determine the effect of manual actions taken following a reactor trip due to a Condition II, III, or IV event, as defined in Sections 15.2, 15.3, and 15.4, respectively. The tables list the information readouts required to

maintain the plant in a hot standby condition or to proceed to cold shutdown within the limits of the Technical Specifications (Reference 1). Adequate shutdown margin following Condition II and III events is verified by sampling of the reactor coolant for boron to ensure that the concentration is sufficient to maintain the reactor subcritical, as directed by emergency procedures.

Table 7.5-3 lists the information available to the operator for monitoring conditions in the reactor, the reactor coolant system (RCS), and in the containment and process systems throughout all normal operating conditions of the plant, including anticipated operational occurrences.

Table 7.5-4 lists the information available to the operator on the post-accident monitoring panels located in the control room. This information is designed to complement the information available on the control boards during post-accident conditions.

The following sections describe the monitoring systems available to the operator for assessing post-accident conditions in the RCS and the containment. Variables monitored include containment water level, hydrogen concentration and ambient pressure in the containment; RCS pressure; subcooling margin; and water level in the reactor vessel.

7.5.2.1 Post-Accident Reactor Coolant Pressure and Containment Monitors

The systems described in this section meet the following requirements:

(1) All devices must be environmentally qualified in accordance with IEEE-323-1974 (Reference 2).

(2) All devices must be seismically qualified in accordance with IEEE-344-1975 (Reference 3).

(3) Cables and raceways shall be separated in accordance with Section 8.3.1.4.1.

7.5.2.1.1 Reactor Coolant Pressure Monitors

The RCS pressure monitors consist of two mutually redundant monitors. The transmitters are mounted outside of containment and are tied to the RCS by means of sealed systems. Each sealed system consists of a bellows seal inside containment to separate the transmitter from the RCS, tubing through the penetration with a special fill fluid, and the transmitters outside of containment. The indicators for both monitors and the recorder for one of the monitors are provided in the control room.

7.5.2.1.2 Containment Pressure Monitors

The DCPP containment is a steel-lined, reinforced concrete structure designed for pressure loads and load combinations described in Section 3.8.2.1.3.2. Containment pressure transmitters with a range of -5 to 200 psig are connected to control room recorders. This instrumentation complements the reactor protection system containment pressure indicators that have a range of -5 to 55 psig.

7.5.2.1.3 Containment Water Level Monitors

The containment water level indication system consists of wide- and narrow-range monitors. Each monitor consists of two mutually redundant and separated channels that are post-accident qualified in accordance with Class 1E requirements and Regulatory Guide 1.97, Revision 3 as noted in Table 7.5-6. In addition, because of their locations, each of the wide-range monitor differential pressure transmitters has been qualified for submerged post-accident operation.

Each of the wide-range monitors is provided with a recorder that is mounted on the post-accident monitor panel in the control room.

The residual heat removal (RHR) recirculation sump water level instrumentation (the narrow-range monitor) has a level indicator mounted on the main control board. These indicators are located above the respective recirculation control switches as these indicators are used by the operator when operating pumps for recirculation.

Figure 7.5-1 represents the level indication system described above.

Figure 7.5-1B shows the Unit 2 wide-range level monitors with an installed spare transmitter in service.

7.5.2.1.4 Containment Hydrogen Monitors

The hydrogen monitoring system is described in Section 6.2.5.5.

7.5.2.1.5 High-Range Containment Radiation Monitor

Two mutually redundant high-range area radiation monitors are provided for containment monitoring. Both indication and recording of the readouts for these monitors are provided in the control room.

A detailed discussion of these monitors is presented in Section 11.4.2.1.3.1.

7.5.2.2 Instrumentation for Detection of Inadequate Core Cooling

The function of core cooling monitoring in a redundant and diverse manner is provided by the subcooling margin monitors described in Section 7.5.2.2.1 and the core exit

thermocouples described in Section 7.5.2.2.2. A supplemental source of information for use in the detection of inadequate core cooling is provided by the reactor vessel level instrumentation system described in Section 7.5.2.2.3.

7.5.2.2.1 Subcooling Meter

DCPP uses the reactor vessel level instrumentation system (RVLIS) processors to calculate RCS subcooling. Information required on the subcooled margin monitors (SCMMs) is provided in Table 7.5-5. Details of the display, calculator, and inputs are as follows:

7.5.2.2.1.1 Display

Each display (one in post-accident monitoring panel PAM3 (train A) and one in PAM4 (train B)) indicates either the temperature or pressure margin to saturation continuously on each RVLIS monitor. A one-hour trend of the temperature margin is also displayed. Train A of the SCMM provides a temperature margin output to an analog recorder. A remote digital display of the temperature margin from SCMM B is located on the main control board in the control room. The recorder is on the post-accident monitoring panel (PAM1) with other recorders to assess core cooling conditions. Each train of the SCMM provides a temperature margin analog signal to emergency response facility display system (ERFDS) for logging purposes. Refer to Section 3.10 for a discussion of the seismic qualification of the displays.

7.5.2.2.1.2 Calculator

The redundant RVLIS processors calculate the subcooled margin. The SCMM subset of RVLIS is a software program that uses RCS pressure and temperature inputs in addition to look-up steam tables to determine subcooling. The selection logic uses the highest temperature and the input pressure. Refer to Section 3.10 for a discussion of the seismic qualification of the RVLIS processor.

7.5.2.2.1.3 Inputs

(1) Temperature – Each SCMM has three temperature inputs. Four temperature signals come from each of the four hot leg wide-range resistance temperature detectors (RTDs). Hot legs 1 and 2 input to SCMM train B, and hot legs 3 and 4 input to SCMM train A. The other temperature signal into each SCMM is the hottest temperature taken from each train of core exit thermocouples. The hottest core exit thermocouple as monitored by train A inputs to SCMM A and the hottest core exit thermocouple as monitored by train B inputs to SCMM B. The temperature inputs meet Class 1E requirements and Regulatory Guide 1.97, Revision 3 as noted in Table 7.5-6.

(2) Pressure - Pressure is sensed by the wide-range reactor coolant loop pressure transmitters as described in Section 7.5.2.1.1. Each SCMM receives a pressure input from a different wide range pressure transmitter.

7.5.2.2.2 Incore Thermocouple System

Chromel-Alumel thermocouples are inserted into guide tubes that penetrate the reactor vessel head through seal assemblies and terminate at the exit flow end of the fuel assemblies. The thermocouples are provided with two primary seals, a conoseal, and a compression-type seal from conduit to head. The thermocouples are supported in guide tubes in the upper core assembly. The incore thermocouple system incorporates the installed incore thermocouples so that a complete temperature distribution can be provided.

The system consists of two redundant trains. The thermocouples are chosen so that all areas of the core are covered by each display. The number of operable thermocouples required per core quadrant is governed by the requirements provided in the Technical Specifications.

The display unit for each of the redundant trains can read out all thermocouple temperatures assigned to the train or can indicate selective incore thermocouple temperatures continuously on demand. The highest thermocouple reading in each train is recorded on the post-accident panel. The range and accuracy of these thermocouple readings are provided in Table 7.5-4.

The incore thermocouple signals are also provided as inputs to the plant computer as described in Section 7.7.2.9.1.

The incore thermocouple system is seismically and environmentally qualified. Each of the display units is powered from an independent Class 1E power source.

7.5.2.2.3 Reactor Vessel Level Instrumentation System

The reactor vessel level instrumentation system (RVLIS) uses differential pressure (DP) measuring devices to measure vessel level or relative void content of the circulating primary coolant system fluid. The system is redundant and includes automatic compensation for potential temperature variations of the impulse lines. Essential information is displayed in the main control room on the post-accident monitoring panel in a form directly usable by the operator.

The RVLIS is a microprocessor-based system. The system inputs to the microprocessor include the DP cell inputs, compensating inputs from the temperature measurements of the DP cell impulse lines, compensating temperature and pressure measurements from the RCS, and status inputs from the reactor coolant pumps. The system consists of two independent channels. Each channel utilizes three DP cells.

This DP measuring system utilizes cells of differing ranges to cover different flow behaviors with and without pump operation, as discussed below.

(1) *Reactor Vessel - Upper-Range* -- This DP cell provides a measurement of reactor vessel level above the hot leg pipe when the reactor coolant pump in the loop with the hot leg connection is not operating.

(2) *Reactor Vessel - Narrow-Range* -- This DP measurement provides a measurement of reactor vessel level from the bottom of the reactor vessel to the top of the reactor core during natural circulation conditions.

(3) *Reactor Vessel - Wide-Range* -- This DP cell provides an indication of reactor core and internals pressure drop for any combination of operating reactor coolant pumps. The comparison of the measured pressure drop with the normal single-phase pressure drop will provide an approximate indication of the relative void content or density of the circulating fluid. This instrument will monitor coolant conditions on a continuing basis during forced flow conditions.

To provide the required accuracy for the level measurement, the temperature measurements of the impulse lines to the DP cells, together with the temperature measurement of the reactor coolant and the reactor coolant system pressure, are employed to compensate the DP cell outputs for differences in system density and reference leg density. This process occurs particularly during the change in the environment inside the containment structure following an accident.

The DP cells are located outside of the containment to eliminate the potential reduction of accuracy that may result from various accident conditions. The location of the cells outside of containment makes the system operation, including calibration and maintenance, easier (Refer to Figure 7.5-2).

7.5.2.3 Plant Vent Post-Accident Radiation Monitors

The plant vent post-accident monitoring is provided by dual-path iodine and particulate grab samplers and an extended range noble gas monitoring channel. The grab sample paths can be changed remotely. The extended range noble gas detector is a beta scintillation detector operated in the current mode.

Potential release paths not using the plant vent are the atmospheric steam dumps/reliefs, the steam generator blowdown tank vent and the main condenser vacuum pump. The steam generator blowdown sample header and the steam generator blowdown tank overflow line to the discharge tunnel are continuously monitored using in-line radiation detectors. The blowdown tank is automatically isolated on a high-radiation signal from either of these monitors, and the discharge is rerouted to the equipment drain tank receiver for further processing so that the vent of the blowdown tank is not a discharge path under these conditions.

The steam lines, which provide the potential source for radiological release from the condenser vacuum pump exhaust and/or atmospheric steam dumps/reliefs during an accident, are monitored using Geiger-Mueller (GM) detectors shielded from background activity. The control room readout has direct indication, recorder output, high alarm, failure alarm, and is powered from Class 1E power supplies.

These monitors meet the requirements of Regulatory Guide 1.97, Revision 3 (Reference 6). A detailed discussion of these monitors is provided in Section 11.4.2.1.2.1.

7.5.2.4 ALARA Monitors for Post-Accident Monitor Access

The as low as is reasonably achievable (ALARA) monitors for post-accident monitors access are provided to monitor the area where the plant vent radiation monitoring post-accident systems are located. Remote indication in a low dose area is provided. Indication in the control room for RE-34 is provided by RR-34.

7.5.2.5 Radioactive Gas Decay Tank Pressure

Post-accident monitoring of the pressures in the three radioactive gas decay tanks is provided in the control room. Each pressure measurement circuit consists of a field-mounted transmitter and an indicator located on the post-accident monitoring panel. The range and accuracy of these measurements are provided in Table 7.5-4.

7.5.2.6 Auxiliary Feedwater Flow Indication

The auxiliary feedwater (AFW) flow indication is provided by a single flow indication channel for the individual AFW feed lines to each of the four steam generators. These flow channels are Class 1Eand powered from the instrument and control power supply system.

An alternative means of AFW flow indication is provided by a Class 1E steam generator water level indication for each steam generator.

7.5.2.7 Dedicated Shutdown Panel

The instrumentation on the dedicated shutdown panel provides the indication required to bring the reactor to cold shutdown from hot standby (MODE 3) in the event that all equipment in the cable spreading room, including all protection racks, are destroyed by fire. In addition to indication, control of the pressurizer auxiliary spray valve (control remote from the control room) is located in this panel. Control of vital equipment is maintained at electrical switchgear and the hot shutdown panel. Equipment is powered from the Class 1E ac instrumentation panels.

None of the instrumentation and control or electrical components in this panel are required to complete any active functions for any seismic events, or events that produce harsh environmental conditions; however, the panel and certain components within the panel are seismically and environmentally qualified for integrity of Class 1E circuits.

The following parameters are provided on the panel:

Reactor coolant system pressure
Pressurizer level
Reactor coolant system temperature
Steam generator level

Steam generator pressure is available from local indicators adjacent to the dedicated shutdown panel.

Alarms and recorders are not required for this system.

Additional information concerning the use of the dedicated shutdown panel to support remote operations is provided in Section 7.4.

7.5.2.8 Pressurizer Safety Valve Position Indication System and Power Operated Relief Valve Position Indication

The PSV position indication system provides the necessary information in the control room to determine the position (open/close) of each of the three PSVs. One acoustic monitor (piezoelectric accelerometer) per PSV is mounted inside containment on the discharge pipe in close proximity to its associated PSV. In the event of a PSV opening, the discharge from the pressurizer will induce pipe vibrations that will be sensed by the acoustic monitor associated with the opened PSV. The electric signal originating from the acoustic monitors is first amplified by charge-mode amplifiers (located inside containment) and then electronically processed (on a per channel basis) in the control room to show, in the form of a bar graph (LED lights on panel RCRM) and a digital readout (on VB2), the percent flow (0 to 100 percent) of each of the three PSVs. Additionally, a ganged annunciator will light in the event that one or more PSVs have opened.

Positive indication of PORV position is obtained by a direct, stem-mounted actuator which mechanically activates limit switches at the full-open and full-closed valve stem positions. These switches are seismically (DE, DDE, and HE) and environmentally qualified and provide an annunciator alarm in the control room if a PORV is not fully closed. These circuits are powered from a Class 1E bus for each PORV.

7.5.2.9 Emergency Response Facility Data System

The emergency response facility data system (ERFDS) is used to monitor and display plant parameters used for post-accident monitoring. The safety parameter display system (SPDS) is part of this system and is described in Section 7.5.2.10. The total ERFDS is not Class 1E nor does it meet the single failure criterion; however, it is designed to be a highly reliable system. The ERFDS is server-based with distributed desktop PCs for data displays. The ERFDS meets the criteria set forth in NUREG-0737, Supplement 1 (Reference 8). NUREG-0696, 1981 (Reference 9) is used for guidance as identified in NUREG-0737, Supplement 1.

The data storage and data retrieval functions associated with post-accident monitoring are performed by the Main Plant Historian. The Main Plant Historian is hosted on Plant Information Network (PIN) Servers in the TSC.

Each power plant unit has its own system to acquire and process data. However, Unit 1 and Unit 2 will share Technical Support Center (TSC) data display equipment. Similarly, the Alternate Technical Support Center/Operational Support Center (Alternate TSC/OSC), and Emergency Operations Facility (EOF) equipment will be shared by Unit 1 and Unit 2.

The system is divided into three subsystems as discussed in the following subsections.

7.5.2.9.1 High-Speed Data Acquisition Subsystem

The data acquisition subsystem is a high-speed, remote multiplexing system that interfaces with the plant instrumentation, converts the data to a digital form, and then transmits the data to other parts of the ERFDS.

The data acquisition subsystem provides Class 1E isolation in the remote multiplexers between the different Class 1E instrument loops, and also between the Class 1E instrument loops and the rest of the system. Remote multiplexers are located so as to minimize additional wire runs. Each remote multiplexer has a 12-bit analog to digital (A/D) converter for high accuracy. The remote multiplexers can also interface with bilevel signals. The digital information from the remote multiplexers for Unit 1 and Unit 2 is transmitted to both the Unit 1 and Unit 2 Transient Recording System (TRS) servers which host the SPDS application.

7.5.2.9.2 SPDS TRS Server Subsystem

The TRS Server Subsystem for each unit is a dedicated server that controls data transfer between the data acquisition subsystem and the different desktop PCs making up the data display subsystem. Display data is updated at 1-second intervals.

The TRS serverhosts the SPDS application. Each unit's TRS acquires ERFDS data for both units. The TRS servers transmit the data via the Plant Data Network (PDN) to the

PPC, display PCs in the control room, and the Plant Information Network (PIN) servers in the TSC. TSC, Alternate TSC/OSC and EOF displays receive data from the PIN servers via the PIN and the DCPP LAN using remote applications (Remote Desktop Services). ERDS data to the NRC is sent via a secure internet connection on the PG&E LAN.

7.5.2.9.3 Display System

The display subsystem provides the system interface for the operators and emergency personnel. The ERFDS has two categories of display devices: the ERFDS displays and the SPDS displays. The subsystem has independent functional stations in the TSC, Alternate TSC/OSC, EOF, and control room, as described below.

The TSC, Alternate TSC/OSC, and EOF display equipment includes two ERFDS Human System Interfaces (HSIs) and two SPDS-HSIs. The HSIs are connected to the DCPP LAN. A color printer connected to the DCPP LAN may be used for printouts of ERFDS, SPDS, EARS, radiation data processor, and PPC displays. The control room display equipment includes two SPDS HSIs. Additionally, SPDS screens may be displayed on a TV monitor. The displays are human-engineered with functional groupings of variables.

With the exception of an additional display monitor, the EOF portion of the display subsystem is identical to the TSC display subsystem.

7.5.2.9.4 Equipment Location

7.5.2.9.4.1 Control Room

(1) Ten remote multiplexers for each unit are located in the control room. The multiplexer location and instrument channel are specified as follows:

Multiplexer Number	Instrument Channel	Location
1	I	Main Control Board, VB1
2	II	Main Control Board, VB1
3	III	Main Control Board, VB1
4	Nonvital	Main Control Board, VB1
5	I	Main Control Board, VB4 Unit 1, (VB5, Unit 2)
6	II	Main Control Board, VB4 Unit 1, (VB5, Unit 2)
7	III	Main Control Board, VB4 Unit 1, (VB5, Unit 2)
8	IV	Main Control Board, VB4 Unit 1, (VB5, Unit 2)
9	II	Post-accident monitoring

Multiplexer Number	Instrument Channel	Location
		panel, PAM3
10	III	Post-accident monitoring panel, PAM4
11	Nonvital	Rack remote multiplexer, RM (Reference 1)

(2) Two submultiplexers are located in the main control board, VB1 of each unit.

(3) The SPDS desks are located in the control room. Each unit has an SPDS desk. The desks each house two SPDS monitors and personal computer, a TV monitor that is available to display SPDS screens and the Main Annunciator System (MAS) secondary display monitor facing the Shift Foreman's desk.

7.5.2.9.4.2 Technical Support Center

The following equipment is located in the TSC:

(1) A color printer connected to the DCPP LAN may be used to print ERFDS, SPDS, PPC, EARS, and radiation data processor displays

(2) Two SPDS HSIs

(3) Two ERFDS HSIs

(4) PDN and PIN network infrastructure, domain servers, and data/application servers.

7.5.2.9.4.3 Emergency Operations Facility

The following equipment is located in the EOF:

(1) Two SPDS HSIs

(2) Two ERFDS HSIs

(3) Network infrastructure

(4) A color printer connected to the DCPP LAN may be used to print ERFDS, SPDS, PPC, EARS, and radiation data processor displays.

7.5.2.9.4.4 Alternate TSC/OSC

The following equipment is located in the Alternate TSC/OSC:

(1) Two SPDS HSIs

(2) Two ERFDS HSIs

(3) Network infrastructure

(4) Acolor printer connected to the DCPP LAN may be used to print ERFDS, SPDS, PPC, EARS, and radiation data processor displays.

7.5.2.10 Safety Parameter Display System

The SPDS is the display subsystem of the ERFDS. The ERFDS is described in Section 7.5.2.9. The SPDS provides a display of plant parameters from which the safety status of operation may be assessed in the control room. The primary function of the SPDS is to help operating personnel in the control room make quick assessments of plant safety status.

The SPDS equipment includes HSIs with color displays.

HSIs with color displays are located in the control room, TSC, Alternate TSC/OSC, and EOF. Each control room HSI receives data from the Unit 1 or Unit 2 TRS via the PDN. TSC, Alternate TSC/OSC, and EOF HSIs receive Unit 1 and Unit 2 data from the DCPP LAN.

The SPDS has one primary display and a number of secondary displays. The primary display addresses the following important plant functions:

(1) Reactivity control

(2) Reactor core cooling and heat removal from primary system

(3) Reactor coolant system integrity

(4) Radioactivity control

(5) Containment integrity

All displays are redundant (available to both SPDS display monitors in each location). All the displays are integrated with the plant operating procedures. Magnitudes and trends can be displayed.

The SPDS displays are available in the control room, TSC, Alternate TSC/OSC, and EOF.

7.5.3 SAFETY EVALUATION

7.5.3.1 General Design Criterion 2, 1967 – Performance Standards

Seismic qualification of safety-related display instrumentation is identified in Table 7.5-6.

The post-accident reactor coolant pressure and containment monitors described in Section 7.5.2.1 are seismically qualified in accordance with IEEE-344-1975 (Reference 3).

The seismic qualification of instrumentation used for detection of inadequate core cooling is described in Sections 3.10.3.21, 3.10.3.22, and 3.10.3.31.

None of the instrumentation and control or electrical components in the dedicated shutdown panel are required to complete any active functions for any seismic events, or events that produce harsh environmental conditions; however, the panel and certain components within the panel are seismically and environmentally qualified for integrity of Class 1E circuits.

The post-accident reactor coolant pressure and containment monitors, the instrumentation used for detection of inadequate core cooling and the dedicated shutdown panel are housed in seismically qualified buildings (containment structure and auxiliary building). These buildings are PG&E Design Class I (refer to Section 3.8) and designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other natural phenomena to protect the safety-related display instrumentation that perform PG&E Design Class I functions.

7.5.3.2 General Design Criterion 11, 1967 – Control Room

Tables 7.5-1 and 7.5-2 list the information readouts provided to enable the operator to perform required manual safety functions and to determine the effect of manual actions taken following a reactor trip due to a Condition II, III, or IV event, as defined in Sections 15.2, 15.3, and 15.4, respectively. The tables list the information readouts required to maintain the plant in a hot standby condition or to proceed to cold shutdown within the limits of the Technical Specifications (Reference 1). Adequate shutdown margin following Condition II and III events is verified by sampling of the reactor coolant for boron to ensure that the concentration is sufficient to maintain the reactor subcritical, as directed by emergency procedures.

Table 7.5-3 lists the information available to the operator for monitoring conditions in the reactor, the reactor coolant system (RCS), and in the containment and process systems

throughout all normal operating conditions of the plant, including anticipated operational occurrences.

Table 7.5-4 lists the information available to the operator on the post-accident monitoring panels located in the control room. This information is designed to complement the information available on the control boards during post-accident conditions.

For Conditions II, III, and IV events (Refer to Tables 7.5-1 and 7.5-2), sufficient duplication of information is provided to ensure that the minimum information required will be available. The information is part of the operational monitoring of the plant that is under surveillance by the operator during normal plant operation. This is functionally arranged on the control board to provide the operator with ready understanding and interpretation of plant conditions. Comparisons between duplicate information channels or between functionally related channels enable the operator to readily identify a malfunction in a particular channel.

Refueling water storage tank level is indicated and alarmed by three independent single channel systems. Similarly, two channels of the RCS pressure (wide-range) are available for maintaining proper pressure-temperature relationships following a postulated Condition II or III event. One channel of steam generator water level (wide-range) is provided for each steam generator; this duplicates level information from steam generator water level (narrow-range) and ensures availability of level information to the operator.

The remaining safety-related display instrumentation necessary for Conditions II, III, or IV events is obtained through isolation devices from the protection system. These protection channels are described in Section 7.2.2.8.

The readouts identified in the tables were selected on the basis of sufficiency and availability during, and subsequent to, an accident for which they are necessary. Thus, the occurrence of an accident does not render this information unavailable, and the status and reliability of the necessary information is known to the operator before, during, and after an accident. No special separation is required to ensure availability of necessary and sufficient information. In fact, such separation could reduce the operator's ease of interpretation of data.

The design criteria used in the display system are listed below:

(1) Range and accuracies listed in Tables 7.5-1 and 7.5-2 are validated through the analysis of operator actions during Condition II, III, or IV events as described in Chapter 15. The display system meets the following requirements:

(a) The range of the readouts extends over the maximum expected range of the variable being measured, as listed in column 4 of Tables 7.5-1 and 7.5-2.

(b) The combined indicated accuracies are shown in column 5 of Tables 7.5-1 and 7.5-2.

(2) Power for the display instruments is obtained from the Class 1E 120-Vac Instrument Power Supply System as described in Section 8.3.1.1.5.2.1 and the non-Class 1E 120-Vac Instrument Power Supply System as described in Section 8.3.1.1.5.2.2.

(3) Those channels determined to provide useful information in charting the course of events are recorded as shown in column 6 of Tables 7.5-1 and 7.5-2.

The dedicated shutdown panel described in Section 7.5.2.7 provides information concerning indications to support remote operations if control room access is lost due to fire or other causes.

7.5.3.3 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Section 7.5.2 provides a description of the instrumentation display systems that provide information to enable the operator to perform required safety functions and post-accident monitoring. They are designed to monitor and maintain variables within prescribed operating ranges.

7.5.3.4 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The monitors for the plant vent and containment radiation are described in Section 11.4.2.1.2.1.

The post-accident monitors used for monitoring radioactivity releases are described in Section 7.5.2.3.

7.5.3.5 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

Environmental qualification of safety-related display instrumentation is identified in Table 7.5-6. The post-accident reactor coolant pressure and containment monitors described in Section 7.5.2.1 are environmentally qualified in accordance with IEEE-323-1974 (Reference 2).

7.5.3.6 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Table 7.5-6 summarizes the compliance of Diablo Canyon Power Plant with Regulatory Guide 1.97, Rev. 3. The format and content of the table are consistent with both the recommendations in Table 3 of the Regulatory Guide and the guidance provided at the March 1, 1983, NRC Regional meeting.

Post-Accident Monitoring Instruments and Controls

Post-accident monitoring instruments and controls are divided into variable Types A through E and Categories 1 through 3 as outlined in Regulatory Guide 1.97, Rev. 3. The variable types indicate whether the variable is considered to be a key variable needed for: (a) plant operation, (b) system status indication, or (c) backup or diagnosis. The three categories provide a graded approach to design, qualification, and quality requirements depending on the importance to safety of the measurement of a specific variable. The variable types and categories are as follows:

Variable Types

Type A - This variable is for components that provide primary information required to permit the control room (operating personnel) to take the specific manually controlled actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for design basis accident events. Type A variables must meet the Category 1 qualification requirements.

Type B - This variable is for components that provide information to indicate whether plant safety functions are being accomplished. Plant safety functions are (a) reactivity control, (b) core cooling, (c) maintaining reactor core coolant system integrity, and (d) maintaining containment integrity.

Type C - This variable is for components that provide information to indicate the potential for being breached or the actual breach of the barriers to fission product release. The barriers are (a) fuel cladding, (b) primary coolant pressure boundary, and (c) containment.

Type D - This variable is for components that provide information to indicate the operation of individual safety systems and other systems important to safety.

Type E - This variable is for components that are monitored as required for use in determining the magnitude of the release of radioactive materials and for continually assessing such releases.

Categories 1 through 3:

Category 1 - Provides the most stringent design and qualification criteria and is intended for key variables.

Category 2 - Provides less stringent design, qualification, and quality criteria and generally applies to instruments and controls designated for indicating system operating status.

Category 3 - Provides design and qualification criteria that will ensure that high-quality, off-the-shelf instrumentation is obtained. Category 3 applies to backup and diagnostic instrumentation and is also used when the design requires state-of-the-art equipment, but equipment qualified to a higher category is not available.

Category 3 instrumentation is non-Class 1E.

Process Control System

The PCS processes the following post-accident monitoring channels:

(1) Auxiliary Feedwater Flow (Type A, Cat. 1)

(2) Charging Injection Header Flow (Type D, Cat. 2)

(3) Letdown Outlet Flow (Type D, Cat. 2)

(4) Makeup Flow-in (Type D, Cat. 2)

(5) RHR Flow to RCS Cold Legs Temperature (Type D, Cat. 2)

(6) RHR HX Outlet Flow (Type D, cat. 2)

(7) RHR HX Outlet to Hot Legs 1 & 2 Flow (Type D, Cat. 2)

(8) Safety Injection Pump Discharge Flow (Type D, Cat. 2)

(9) Steam Generator Wide Range Level (Type A, Cat. 1)

(10) Volume Control Tank Level Control (Type D, Cat. 2)
(11) CCW Heat Exchanger Outlet Temperature (Type D, Cat. 2)

(12) CCW Supply Headers A and B Flow (Type D, Cat. 2)

(13) Condensate Storage Tank Level (Type A, Cat. 1)

(14) Refueling Water Storage Tank Level (Type A, Cat. 1)

(15) Accumulator Tank Pressure (Type D, Cat. 3)

(16) Quench Tank (PRT) Level (Type D, Cat. 3)

(17) Quench Tank (PRT) Temperature (Type D, Cat. 3)

(18) Quench Tank (PRT) Pressure (Type D, Cat. 3)

References 6 and 10 through 58 were used for design, verification, validation, and qualification of all or portions of the PG&E Design Class I PCS hardware and software (encompassing Triconex components, manual/auto hand stations, signal converters/isolators and loop power supplies).

7.5.3.7 NUREG-0737 (Items I.D.2, II.D.3, II.E.1.2, II.F.1, II.F.2, and III.A.1.2), November 1980 – Clarification of TMI Action Plan Requirements

7.5.3.7.1 Item I.D.2 – Plant Safety Parameter Display Console

SPDS Display

The primary SPDS display was designed to provide the control room operators with a concise format of critical plant variables to aid in determining the safety status of the plant. Parameter selection was made to address the five functions as listed in Section 7.5.2.10. The major types of possible accidents were evaluated to develop the minimum number of plant variables necessary to alert the operator of an abnormal condition. The parameters selected for each function were:

(1) *Reactivity Control*

(a) Three ranges of flux indication from 120 percent full power to 1 count/second using all three ranges of nuclear instrumentation: monitors neutron flux during all modes of operation.

(b) Startup rate indication.

(c) "Control Rods In" alert, which warns the operator of a reactor trip without insertion of all control rods.

(2) *Reactor Core Cooling and Heat Removal*

(a) Subcooled margin, which is a derived variable based on RCS pressure and temperature inputs, indicates the degree of subcooling or superheat present.

(b) Highest core exit thermocouple temperature monitors core exit temperature conditions.

(c) Reactor vessel level, wide- or narrow-range depending on reactor coolant pump status, indicates lack of adequate core cooling.

(d) Narrow-range steam generator level can be used to determine heat removal capability of the secondary system.

(3) *RCS Integrity*

(a) Reactor coolant system pressure can be used to monitor high-pressure conditions against design limits and can be used with cold leg temperature to monitor plant conditions against system nil ductility transition (NDT) limits.

(b) Pressurizer level is actually used as an indication of inventory if RCS has been, or is, subcooled. However, it is an important parameter with RCS pressure for rapid determination of normal or expected plant status.

(c) Cold leg temperature can be used with RCS pressure to monitor plant status with respect to system NDT limits.

(4) *Radioactivity Control*

(a) Containment radiation monitor indicates the release of radiation from the primary system to containment.

(b) Vent gas and vent iodine monitors monitor radioactivity releases from the plant vent to the environment.

(c) Main steam monitors indicate radioactivity released to the secondary system and/or atmosphere via steam generator tube leaks or tube failures.

(5) *Containment Integrity*

(a) Containment pressure monitors monitor actual pressure against design limit.

(b) Containment Isolation Phase A and/or B alert informs the operator that a Phase A and/or B isolation signal has occurred and whether alignment of the isolation valves is complete.

SPDS Display Groupings

The parameters for the SPDS display were grouped in each of the five areas. Alarm setpoints were selected to duplicate the trip and alarm settings of the plant instrumentation, plant Technical Specification requirements, or limits specified in the plant manuals. Distinctive color coding is used on the display to alert control room personnel to an abnormal condition. If a parameter is within its normal range, the bar for that parameter on the display is green; it is displayed red if outside the specified limits.

SPDS Operation

The basis for the location of the SPDS monitors in the control room was to ensure adequate visibility by the senior control room operator and not to impede movement in the control room. Console location is indicated in Figure 7.7-16. The color coding of the SPDS display readily enables the user to determine if a parameter on the display is within normal limits. In the case of an abnormal condition, the Emergency Evaluation Coordinator will typically be the prime user of the SPDS.

SPDS Monitors

There are two (2) SPDS displays in the control room, EOF, and TSC. Each screen has the critical safety function status shown at the top.

7.5.3.7.2 Item II.D.3 – Direct indication of relief and safety valve position

The PORV position indication and PSV position indication system provide the necessary information in the control room to determine the position (open/close) of each of the three PORVs and three PSVs as described in Section 7.5.2.8.

7.5.3.7.3 Item II.E.1.2 – Auxiliary Feedwater System Automatic Initiation and Flow Indication

AFW flow indication is provided in the control room as described in Section 7.5.2.6. AFW automatic initiation is provided as described in Section 6.5.

7.5.3.7.4 Item II.F.1 – Additional Accident Monitoring Instrumentation

The safety-related display instrumentation includes the following subparts:

- Noble gas effluent radiological monitor – refer to Section 7.5.2.3;
- Provisions for continuous sampling of plant effluents for post-accident releases of radioactive iodines and particulates – refer to Section 7.5.2.3
- Onsite laboratory capabilities – refer to Sections 12.3.2 and 6.4.2.3;
- Containment high-range radiation monitor – refer to Section 7.5.2.1.5;
- Containment pressure monitor – refer to Section 7.5.2.1.2;

- Containment water level monitor – refer to Section 7.5.2.1.3; and
- Containment hydrogen concentration monitor – refer to Section 7.5.2.1.4

A discussion of each subpart is described in the indicated section.

7.5.3.7.5 Item II.F.2 – Instrumentation for Detection of Inadequate Core Cooling

The instrumentation used for detection of inadequate core cooling is described in Section 7.5.2.2.

7.5.3.7.6 Item III.A.1.2 – Upgrade Emergency Support Facilities

ERFDS is described in Section 7.5.2.9. All input parameters are routed from the Validyne data acquisition system to the Transient Recording System (TRS), which provides the data recall and storage for ERFDS. Each Unit's TRS acquires ERFDS data for both Units. The TRS servers provide data to PDN connected HSIs and PIN servers. PIN servers provide ERFDS data to DCPP LAN connected HSIs. PDN-connected HSIs with recall capability can display ERFDS data for either Unit. There are two dedicated ERFDS HSIs connected to the DCPP LAN in both the TSC and EOF. In addition, other selected DCPP LAN connected HSIs in the TSC and EOF may also view ERFDS and SPDS data. All data available on the ERFDS HSIs in the TSC and EOF is also available on the Plant Process Computer (PPC). The PPC HSIs in the TSC and EOF receive data from PIN servers via PIN and the DCPP LAN. Additional parameters available for display by the PPC are specified in Table 7.5-6. Other parameters are also available to allow post-accident monitoring and analysis via the PPC.

7.5.4 REFERENCES

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51. BTP 7-14 Rev. 5, Guidance on Software Reviews for Digital Computer-Based Instrumentation and Control Systems, USNRC, March 2007.

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53. MIL-STD-461E, Requirements for the Control of Electromagnetic Interference Emissions and Susceptibility, USDOD, August 1999

54. ANSI/ANS-4.5-1980, Criteria for Accident Monitoring Functions in Light-Water-Cooled Reactors, American Nuclear Society, January 1980

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56. NFPA 70 (NEC) 2002 National Electric Code, National Fire Protection Association, January 2002

57. IEC 61131-3 1993, Programming Industrial Automations Systems, International Electrotechnical Commission, December 1993

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7.5.5 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

7.6 ALL OTHER INSTRUMENTATION SYSTEMS REQUIRED FOR SAFETY

This section provides a description and an analysis of: (a) residual heat removal (RHR) isolation valves, (b) the pipe break isolation system (PBIS), and (c) the anticipated transients without scram (ATWS) mitigation system actuation circuitry (AMSAC). The instrumentation and control power supply system is described and analyzed in Section 8.3.1.1.5. A discussion of the refueling interlocks is provided in Section 9.1. The fire detection and protection system is described in Section 9.5.1.

7.6.1 DESIGN BASES

7.6.1.1 General Design Criterion 2, 1967 – Performance Standards

The RHR isolation valves and the PBIS are designed to withstand the effects of or are protected against natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

7.6.1.2 General Design Criterion 11, 1967 – Control Room

The RHR isolation valves, the PBIS, and the AMSAC system are designed to or contain instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room.

7.6.1.3 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The RHR isolation valves and the PBIS have instrumentation and controls to monitor and maintain system variables within prescribed operating ranges.

7.6.1.4 Other Instrumentation Systems Safety Function Requirements

(1) Protection from Missiles

The RHR isolation valves instrumentation and the PBIS are designed and located to be protected against the effects of missiles which may result from plant equipment failure and from events and conditions outside the plant.

(2) Protection Against High Energy Pipe Rupture Effects

The RHR isolation valves instrumentation and the PBIS are designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The outside containment RHR isolation valves instrumentation and the PBIS are designed to be protected against the effects of moderate energy pipe failure.

(4) Protection from Jet Impingement – Inside Containment

The inside containment RHR isolation valves instrumentation and the PBIS are designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

(5) Protection from Flooding Effects – Outside Containment

The outside containment RHR isolation valves instrumentation and the PBIS are to be protected from the effects of internal flooding.

7.6.1.5 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

The RHR isolation valves and associated components and PBIS components that require environmental qualification are qualified to the requirements of 10 CFR 50.49.

7.6.1.6 10 CFR 50.62 – Requirements for Reduction of Risk from Anticipated Transients Without Scrams (ATWS) Events for Light-Water-Cooled Nuclear Power Plants

AMSAC meets the requirement of providing a system independent of the reactor trip system to initiate auxiliary feedwater flow and turbine trip under ATWS conditions.

7.6.2 DESCRIPTION

7.6.2.1 Residual Heat Removal Isolation Valves

There are two motor-operated gate valves in series in the inlet line from the reactor coolant system (RCS) to the RHR system. They are normally closed and can only be opened for RHR after RCS pressure is reduced below approximately 390 psig. In addition, one valve cannot open until the pressurizer vapor space temperature has been reduced to approximately 475°F (refer to Sections 5.6.2 and 5.5.6 for details of the RHR system.) RHR isolation valve control and indications are as follows:

(1) One isolation valve, that nearest the RCS, is interlocked with a pressure signal to prevent its being opened whenever the RCS pressure is greater than the setpoint pressure (approximately 390 psig). This interlock is derived from one process control channel.

(2) The other valve is similarly interlocked. Control signals are derived from a second process control channel. In order to both comply with IEEE 279-1971 (Reference 1) and to provide diversity, the permissive interlock to open this valve is satisfied when the pressurizer vapor space temperature is reduced to approximately 475°F and the RCS pressure is reduced below approximately 390 psig. This temperature control signal is derived from one process instrumentation protection channel.

(3) Each isolation valve is provided with an independent alarm circuit from independent process protection channels that will actuate a common annunciator in the control room whenever the isolation valve is not 100 percent closed and RCS pressure is greater than approximately 435 psig. Procedures instruct the operators to stop RCS pressurization and close the isolation valves should this alarm condition occur during RCS pressurization with the RHR system removed from service.

(4) The RHR suction valves interlock relays are powered from the solid state protection system (SSPS) output cabinets. To maintain the ability to open the RHR suction valves when the SSPS output cabinets are de-energized in Mode 6 or defueled, jumpers are used to lock-in the RHR suction valves open permissive. This defeats the applicable RHR system overpressurization/temperature protection. Jumper installation is limited to Mode 6 and defueled only.

In the fire protection review, it was postulated that fire damage to electrical cables could cause both RHR suction line isolation valves to open. To prevent this, the power will be removed from each valve's motor operator by opening manual circuit breakers after the valves have been correctly positioned whenever RCS pressure is greater than 390 psig. Continuous indication that the RHR suction line isolation valves are in the correct position is provided for each valve. The control room valve position indicators are not disabled by opening the circuit breakers and removing power from the valves' motor operators.

RHR isolation valve control, valve position indication, and annunciation are provided in the control room.

7.6.2.2 Pipe Break Isolation System

The PBIS provides a means to detect and isolate breaks in high-energy lines in the auxiliary building. This system limits the postulated mass/energy release in affected compartments. This reduces the environmental effect on a number of PG&E Design Class I and Class 1E components in the area.

There are two postulated pipe breaks that could affect Area K of the auxiliary building: (a) chemical and volume control system (CVCS) letdown line, and (b) auxiliary steam line. The PBIS provides an alarm and automatic isolation (redundant) of a break in the

letdown line after the letdown isolation valves. An alarm and a switch for manual isolation are provided for the auxiliary steam line.

A break in a high-energy line is detected by redundant temperature sensors monitoring ambient air temperature. Alarms are provided at predetermined setpoints, based on an analysis of the postulated breaks. Annunciation is provided in the control room.

The Process Control System (PCS) processes the CVCS letdown line break temperature detector inputs and provides an output to the pipe break isolation logic. The PCS also processes the Auxiliary steam line area temperature detector inputs and provides control room indication and alarm. References 1, 2, 3 and 9 through 55 were used for design, verification, validation, and qualification of all or portions of the PG&E Design Class I PCS hardware and software (encompassing Triconex components, manual/auto hand stations, signal converters/isolators and loop power supplies).

7.6.2.3 ATWS Mitigation System Actuation Circuitry (AMSAC)

DCPP has installed an AMSAC system in both Units.

The system uses the standard Westinghouse design with the steam generator water level option. References 5 and 6 describe the generic AMSAC design. A functional logic diagram is shown in Figure 7.2-1, Sheets 33 and 34.

The AMSAC system trips the turbine, starts auxiliary feedwater, and isolates steam generator blowdown on coincidence of an AMSAC low steam generator water level signal from three out of four steam generators.

The AMSAC system performs an important safety function if the plant's primary reactor protection system fails. Accordingly, to ensure the reliability of the system, all activities that could affect the quality of non-Class 1E AMSAC equipment shall be controlled as if the equipment were Class 1E.

ATWS Mitigation System Actuation Circuitry indication is provided in the control room with annunciation windows.

7.6.3 SAFETY EVALUATION

7.6.3.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portion of the RHR isolation valves and pipe break isolation system are seismically designed and housed in seismically qualified buildings (containment structure and auxiliary building). These buildings are Design Class I (refer to Section 3.8) and designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other natural phenomena to protect

the PG&E Design Class I portion of the RHR isolation valves and pipe break isolation system to ensure their safety-related functions and designs will be performed.

7.6.3.2 General Design Criterion 11, 1967 – Control Room

Controls and instrumentation related to (a) RHR Isolation Valves, (b) PBIS and (c) anticipated transients without scram (ATWS) mitigation system actuation circuitry (AMSAC) which are designed to support actions to maintain and control the safe operational status of the plant from the control room are as follows:

RHR Isolation Valves

Each RHR isolation valve is provided with an independent alarm circuit from independent process protection channels that will actuate a common annunciator in the control room whenever the isolation valve is not 100 percent closed and RCS pressure is greater than approximately 435 psig.

Continuous indication that the RHR suction line isolation valves are in the correct position is provided for each valve by control room valve position indicators that are not disabled by opening the circuit breakers and removing power from the valves' motor operators.

Pipe Break Isolation System

The PBIS provides an alarm and automatic isolation (redundant) of a break in the letdown line after the letdown isolation valves. An alarm and a switch for manual isolation are provided for the auxiliary steam line.

A break in a high-energy line is detected by redundant temperature sensors monitoring ambient air temperature. Alarms are provided at predetermined setpoints, based on an analysis of the postulated breaks.

The auxiliary steam line break isolation system provides an alarm based on any one of several high-temperature detectors. A switch is provided on the main control board to close the valves on lines that supply auxiliary steam to the auxiliary building. Since the auxiliary steam line is tied to both the Unit 1 and Unit 2 main steam lines, the crosstie through the auxiliary building to both main steam lines can be closed from either board on detection of high area temperature. Indication of area temperature is provided on the main control board to verify that isolation has occurred. Temperature indication is the only PG&E Design Class I function of the auxiliary steam line isolation system.

ATWS Mitigation System Actuation Circuitry

ATWS Mitigation System Actuation Circuitry indication is provided in the control room with annunciation windows.

7.6.3.3 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The RHR isolation valves and the PBIS have instrumentation and controls to monitor and maintain system variables within prescribed operating ranges as follows:

Residual Heat Removal Isolation Valves

Based on the scope definitions presented in IEEE-279-1971 (Reference 1) and IEEE 338-1971 (Reference 3), these criteria do not apply to the RHR isolation valve interlocks; however, in order to meet NRC requirements, and because of the possible severity of the consequences of loss of function, the requirements of IEEE-279-1971 are applied with the following comments.

(1) For the purpose of applying IEEE-279-71 (Reference 1) to this circuit, the following definitions are used:

(a) Protection System - The two valves in series in each line and all components of their interlocking and closure circuits.

(b) Protective Action - The automatic interlock of the RHR system isolation from the RCS pressure above RHR design pressure.

(2) IEEE-279-71, Paragraph 4.10: The requirement for on-line test and calibration capability is applicable only to the actuation signal and not to the isolation valves, which are required to remain closed during power operation.

(3) IEEE-279-71, Paragraph 4.15: This requirement does not apply as the setpoints are independent of mode of operation and are not changed.

Pipe Break Isolation System

The CVCS letdown line break isolation system fully complies with IEEE-279-71 (Reference 1). Three high temperature detectors are provided. Each is powered from a separate Class 1E power source. A two-out-of-three logic is used with redundant logic trains so that a single failure will not prevent system operation, while at the same time the chance of spurious operation is limited. Redundancy is carried through to the final actuation devices.

The auxiliary steam line break isolation system provides an alarm based on any one of several high-temperature detectors. A switch is provided on the main control board to close the valves on lines that supply auxiliary steam to the auxiliary building. Since the auxiliary steam line is tied to both the Unit 1 and Unit 2 main steam lines, the crosstie through the auxiliary building to both main steam lines can be closed from either board on detection of high area temperature. Indication of area temperature is provided on the main control board to verify that isolation has occurred. Temperature indication is the

only PG&E Design Class I function of the auxiliary steam line isolation system. A PG&E Design Class I backup is provided by use of the main steam line isolation system. Manual action is acceptable because of the relatively slow temperature transient that occurs due to this accident. There is sufficient time for the operator to verify that the break has been isolated before backup action is required.

7.6.3.4 Other Instrumentation Systems Safety Function Requirements

(1) Protection from Missiles

The provisions taken to protect RHR isolation valves instrumentation and the PBIS from missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Section 3.5.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the RHR isolation valves instrumentation and the PBIS from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Section 3.6.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection of the RHR isolation valves instrumentation and the PBIS located outside containment from the effects of moderate energy pipe failure are discussed in Section 3.6.

(4) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the RHR isolation valves instrumentation and the PBIS located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

(5) Protection from Flooding Effects – Outside Containment

The provisions taken to provide protection of the RHR isolation valves instrumentation and the PBIS located outside containment from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

7.6.3.5 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

The RHR isolation valves and associated components and PBIS components listed in the DCPP EQ Master List are qualified to the requirements of 10 CFR 50.49.

Environmental qualification of the valves and wiring is discussed in Section 3.11.

7.6.3.6 10 CFR 50.62 – Requirements for Reduction of Risk from Anticipated Transients Without Scrams (ATWS) Events for Light-Water-Cooled Nuclear Power Plants

The AMSAC system is independent and diverse from the reactor protection system. (Refer to Section 7.2 for a description of the reactor protection system). The AMSAC system trips the turbine, starts auxiliary feedwater, and isolates steam generator blowdown on coincidence of an AMSAC low steam generator water level signal from three out of four steam generators. This meets the requirements of 10 CFR 50.62.

The Westinghouse AMSAC System has been analyzed by the Westinghouse owners group, and has been shown to maintain the reactor coolant system pressure boundary within the ASME Boiler and Pressure Vessel Code (Reference 7). Level C stress limits in the event of a Condition II event as described in Section 4.2. This is documented in Westinghouse Report NS-TMA-2182 (Reference 8).

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50. MIL-STD-461E, Requirements for the Control of Electromagnetic Interference Characteristics of Sub-systems and Equipment, USDOD, August 1999

51. ANSI/ANS-4.5-1980, Criteria for Accident Monitoring Functions in Light-Water-Cooled Reactors, American Nuclear Society, January 1980

52. NEMA ICS 1-2000, Industrial Control and Systems: General Requirements, National Electrical Manufacturers Association, December 2008

53. NFPA 70 (NEC) 2002 National Electric Code, National Fire Protection Association, January 2002

54. IEC 61131-3 1993, Programming Industrial Automations Systems, International Electrotechnical Commission, December 1993

55. ISA-S67.04-1994, Setpoints for Nuclear Safety-Related Instrumentation, International Society of Automation, January 1994

7.6.5 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

7.7 CONTROL SYSTEMS NOT REQUIRED FOR SAFETY

The general design objectives of the plant control systems are:

(1) To establish and maintain power equilibrium between primary and secondary systems during steady state unit operation

(2) To constrain operational transients so as to preclude unit trip and reestablish steady state unit operation

(3) To provide the reactor operator with monitoring instrumentation that indicates required input and output control parameters of the systems, and provides the operator with the capability of assuming manual control of the system

7.7.1 DESIGN BASES

7.7.1.1 General Design Criterion 11, 1967 – Control Room

The plant control systems are designed to or contain instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

7.7.1.2 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The plant control systems have instrumentation and controls to monitor and maintain variables within prescribed operating ranges.

7.7.1.3 General Design Criterion 13, 1967 – Fission Process Monitors and Controls

The plant control systems are designed to monitor and maintain control over the fission process throughout core life and for all conditions that can reasonably be anticipated to cause variations in reactivity of the core, such as indication of position of control rods and concentration of soluble reactivity control poisons.

7.7.1.4 General Design Criterion 22, 1967 – Separation of Protection and Control Instrumentation Systems

The plant control systems are designed such that protection functions are separated from control instrumentation functions to the extent that failure or removal from service of any control instrumentation system component or channel, or of those common to control instrumentation and protection circuitry, leaves intact a system satisfying all requirements for the protection channels.

7.7.1.5 General Design Criterion 26, 1971 – Reactivity Control System Redundancy and Capability

Two independent reactivity control systems of different design principles are provided, each having the capability to control the rate of reactivity changes resulting from planned, normal power changes. One of the systems is capable of reliably controlling anticipated operational occurrences. In addition, one of the systems is capable of holding the reactor core subcritical under cold conditions.

7.7.1.6 General Design Criterion 31, 1967 – Reactivity Control Systems Malfunction

The rod control system is designed such that it is capable of sustaining any single malfunction, such as, unplanned continuous withdrawal (not ejection) of a control rod, without causing a reactivity transient which could result in exceeding acceptable fuel damage limits.

7.7.2 SYSTEM DESCRIPTION

The plant control systems described in Sections 7.7.2.1 through 7.7.2.10 perform the following functions:

(1) *Reactor Control System*

(a) Enables the nuclear plant to accept a step load increase or decrease of 10 percent, and a ramp increase or decrease of 5 percent per minute, within the load range of 15 to 100 percent without reactor trip, steam dump, or pressurizer relief actuation, subject to possible xenon limitations.

(b) Maintains reactor coolant average temperature Tavg within prescribed limits by creating the bank demand signals for moving groups of rod cluster control assemblies (RCCAs) during normal operation and operational transients. The Tavg auctioneer unit supplies signals to pressurizer water level control and steam dump control.

(2) *Rod Control System*

(a) Provides for reactor power modulation by manual or automatic control of control rod banks in a preselected sequence, and for manual operation of individual banks

(b) Provides manual control of control banks to control the power balance between the top and bottom halves of the core

(c) Provides systems for monitoring and indicating:

1. Provide alarms to alert the operator if the required core reactivity shutdown margin is not available due to excessive control rod insertion

2. Display control rod position

3. Provide alarms to alert the operator in the event of control rod deviation exceeding a preset limit

(3) *Plant Control Signals for Monitoring and Indicating*

(a) Provide for measurement of reactor power level, axial power imbalance, and radial power imbalance

(b) Sense and display control rod position

(c) Provide warning to the operator of excessive rod insertion

(d) Provide an alarm whenever an individual rod position signal deviates from the other rods in the bank by a preset limit

(e) Provide rod bottom alarm for individual dropped rods

(4) *Plant Control System Interlocks* (refer to Table 7.7-1)

(a) Prevent further withdrawal of the control banks when signal limits are approached that predict the approach of a departure from nucleate boiling ratio (DNBR) limit or kW/ft limit

(b) Initiate automatic turbine load runback on overpower or overtemperature

(5) *Pressurizer Pressure Control* - Maintains or restores the pressurizer pressure to the nominal operating pressure ±60 psi (which is well within reactor trip and relief and safety valve action setpoint limits) following normal operation transients that induce pressure changes by control (manual or automatic) of heaters and spray in the pressurizer. It also provides steam relief by controlling the power-operated relief valves

(6) *Pressurizer Water Level Control* - Establishes, maintains, and restores pressurizer water level within specified limits as a function of the average coolant temperature. Changes in level are caused by coolant density changes induced by loading, operational, and unloading transients. Level changes required to maintain the level within prescribed limits are produced by charging flow control (manual or automatic), as well as by manual selection of letdown orifices

(7) *Steam Generator Water Level Control*

(a) Establishes and maintains the steam generator water level to within predetermined physical limits during normal operating transients

(b) Restores the steam generator water level to within predetermined limits at unit trip conditions. Regulates the feedwater flow under operational transients to maintain the proper heat sink for the reactor coolant system (RCS). Steam generator water inventory control is manual or automatic through use of the digital feedwater control system (Reference 7).

(8) *Steam Dump Control*

(a) Permits the nuclear plant to accept a sudden loss of load without incurring reactor trip. Steam is dumped to the condenser and/or the atmosphere as necessary to accommodate excess power generation in the reactor during turbine load reduction transients

(b) Ensures that stored energy and residual heat are removed following a reactor trip to bring the plant to equilibrium no-load conditions without actuation of the steam generator safety valves

(c) Maintains the plant at no-load conditions and permits a manually controlled cooldown of the plant

(9) *Incore Instrumentation* - Provides information on the neutron flux distribution and on the core outlet temperatures at selected core locations

(10) *Control Locations* - Provide central control and monitoring locations to perform plant operations both inside and outside the control room

7.7.2.1 Reactor Control System

The reactor control system enables the nuclear plant to follow load changes automatically, including the acceptance of step load increases or decreases of 10 percent, and ramp increases or decreases of 5 percent per minute within the load range of 15 to 100 percent without reactor trip, steam dump, or pressure relief, subject to possible xenon limitations. The system is also capable of restoring coolant average temperature to within the programmed temperature deadband following a change in load. Manual control rod operation may be performed at any time.

The reactor control system controls the reactor coolant average temperature by regulation of control rod bank position. The reactor coolant loop average temperatures are determined from hot leg and cold leg measurements in each reactor coolant loop. There is an average coolant temperature (T_{avg}) computed for each loop, where:

$$T_{avg_i} = \frac{T_{have_i} + T_{cave_i}}{2} \qquad (7.7\text{-}1)$$

$$i = \text{loop numbers } 1 \rightarrow 4$$

The error between the programmed reference temperature (based on turbine impulse chamber pressure), and the highest of the average loop measured temperatures (which is then processed through a lead-lag compensation unit) from each of the reactor coolant loops, constitutes the primary control signal as shown in general in Figure 7.7-1, and in more detail on the functional diagrams shown in Figure 7.2-1, Sheets 17 and 18. The system is capable of restoring coolant average temperature to the programmed value following a change in load. The programmed coolant temperature increases linearly with turbine load from zero power to the full power condition. The T_{avg} auctioneer unit also supplies a signal to pressurizer level control and steam dump control, and rod insertion limit monitoring.

An additional control input signal is derived from the reactor power versus turbine load mismatch signal. This additional control input signal improves system performance by enhancing response. The T_{avg} and T_{ref} signals are also supplied to the plant computer for a T_{avg} vs T_{ref} deviation alarm.

7.7.2.2 Rod Control System

7.7.2.2.1 Control Rod System

The control rod system receives rod speed and direction signals from the reactor control system. The rod speed demand signal varies over the corresponding range from 5 to 45 inches per minute (8 to 72 steps/minute), depending on the magnitude of the error signal. The rod direction demand signal is determined by the positive or negative value of the error signal. Manual control is provided to move a control bank in or out at a prescribed fixed speed.

When the turbine load reaches approximately 15 percent of rated load, the operator may select the AUTOMATIC mode, and rod motion is then controlled by the reactor control system. A permissive interlock C-5 (refer to Table 7.7-1), derived from measurements of turbine impulse chamber pressure, prevents automatic withdrawal when the turbine load is below 15 percent. In the AUTOMATIC mode, the rods are again withdrawn (or inserted) in a predetermined programmed sequence by the automatic programming equipment. The manual and automatic controls are further interlocked with the control interlocks (refer to Table 7.7-1).

The shutdown banks are always in the fully withdrawn position during normal operation (except as required by surveillance testing) and are moved to this position prior to criticality. A reactor trip signal causes them to fall by gravity into the core. There are four shutdown banks.

The control banks are the only rods that can be manipulated under automatic control. Each control bank is divided into two groups to obtain smaller incremental reactivity changes per step. All rod cluster control assemblies (RCCAs) in a group are electrically paralleled to move simultaneously. There is individual position indication for each RCCA.

Power to rod drive mechanisms is supplied by two motor generator sets operating from two separate 480-V, three-phase buses. Each generator is the synchronous type and is driven by a 150 hp induction motor. The ac power is distributed to the rod control power cabinets through the two series-connected reactor trip breakers.

The variable speed rod control system rod drive programmer affords the ability to insert small amounts of reactivity at low speed to accomplish fine control of reactor coolant average temperature about a small temperature deadband, as well as furnishing control at high speed.

A summary of the RCCA sequencing characteristics is provided below:

(1) Two groups within the same bank are stepped so that the relative position of the groups will not differ by more than one step.

(2) The control banks are programmed so that withdrawal of the banks is sequenced in the following order: control bank A, control bank B, control bank C, and control bank D. The programmed insertion sequence is the opposite of the withdrawal sequence; i.e., the last control bank withdrawn (bank D) is the first control bank inserted.

(3) The control bank withdrawals are programmed so that when the first bank reaches a preset position, the second bank begins to move out simultaneously with the first bank. When the first bank reaches the top of the core, it stops, while the second bank continues to move toward its fully withdrawn position. When the second bank reaches a preset position, the third bank begins to move out, and so on. This withdrawal sequence continues until the unit reaches the desired power. The control bank insertion sequence is the opposite.

(4) Overlap between successive control banks is adjustable between 0 to 50 percent (zero and 115 steps), with an accuracy of ±1 step.

(5) Rod speeds for either shutdown banks or control banks are capable of being controlled between a minimum of 8 steps per minute and a maximum of 72 steps per minute.

7.7.2.3 Plant Control Signals for Monitoring and Indicating

The following sections describe the monitoring and/or indicating functions provided by:

(1) Nuclear instrumentation system (7.7.2.3.1)

(2) Rod position (7.7.2.3.2)

(3) Control bank rod insertion monitoring (7.7.2.3.3)

(4) Rod deviation alarm (7.7.2.3.4)

(5) Rod bottom alarm (7.7.2.3.5)

7.7.2.3.1 Monitoring Functions Provided by the Nuclear Instrumentation System

The nuclear instrumentation system (NIS) is described below and in detail in Reference 1. However, the Reference 1, Section 3.7 Item e, Ion-Chamber-Current Recorders (NR-41 through NR-44) description does not apply.

The power range channels are important because of their use in monitoring power distribution in the core within specified safe limits. They are used to measure reactor power level, axial power imbalance, and radial power imbalance. These channels are capable of recording power excursions up to 200 percent of full power. Suitable alarms are derived from these signals as described below.

Basic power range signals are:

(1) Total current from a power range detector (four such signals from separate detectors). These detectors are vertical and have a neutron sensitive length of 10 feet

(2) Current from the upper half of each power range detector (four such signals)

(3) Current from the lower half of each power range detector (four such signals)

Derived from these basic signals are the following (including standard signal processing for calibration):

(1) Indicated nuclear power (four such)

(2) Indicated axial flux imbalance, derived from upper half flux minus lower half flux (four such)

Alarm functions derived are as follows:

(1) Deviation (maximum minus minimum of four) in indicated nuclear power

(2) Upper radial tilt (maximum to average of four) on upper half currents

(3) Lower radial tilt (maximum to average of four) on lower half currents

Axial Flux Difference (AFD) limits are found in the cycle specific COLR (Core Operating Limits Report) for each unit. Technical Specifications provide the limiting values for the QPTR (Quadrant Power Tilt Ratio) limit.

Nuclear power and axial flux imbalance are selectable for recording. Indicators are provided on the control board for nuclear power and for axial flux imbalance.

7.7.2.3.2 Rod Position Monitoring

Two separate systems are provided to sense and display control rod position as described below:

(1) *Digital Rod Position Indication System (DRPI)* - The digital rod position indication system measures the actual position of each rod using a detector that consists of 42 discrete coils mounted concentric with the rod drive pressure housing. The coils are located axially along the pressure housing on 3.75 inch spacing. They magnetically sense the entry and presence of the rod drive shaft through its centerline. The coils are interlaced into two data channels and are connected to the containment electronics (Data A and B) by separate multiconductor cables. Multiplexing is used to transmit the digital position signals from the containment electronics to two main control board DRPI electronic displays. The rod positions are displayed both in numerical as well as top down bar-graph format reflecting the inserted position for each rod. By employing two separate channels of information and two displays, the digital rod position indication system can continue to function (at reduced accuracy) when one channel fails. If both channels indicate the same position for all rods in a bank, but a single rod indicates a different position on one train, DRPI system automatically recognizes the nonconforming rod and causes the display to go into half accuracy for that rod only.

Included in the system is a rod-at-bottom signal that operates a local alarm and a control room annunciator.

(2) *Demand Position Indication System* - The demand position indication system counts pulses generated in the rod drive control system to provide a digital readout of the demanded bank position.

The demand position indication and digital rod position indication systems are separate systems; each serves as a backup for the other. Operating procedures require the reactor operator to compare the demand and digital (actual) readings upon recognition of any apparent malfunction. Therefore, a single failure in rod position indication does not in itself lead the operator to take erroneous action in the operation of the reactor.

The demand position indication system is described in detail in Reference 2.

7.7.2.3.3 Control Bank Rod Insertion Monitoring

When the reactor is critical, the normal indication of reactivity status in the core is the position of the control bank in relation to reactor power (as indicated by RCS loop ΔT) and coolant average temperature. These parameters are used to calculate insertion limits for the control banks. Two alarms are provided for each control bank:

(1) The low alarm alerts the operator of an approach to the rod insertion limits requiring boron addition by following normal procedures with the chemical and volume control system (CVCS).

(2) The low-low alarm alerts the operator to take immediate action to add boron to the RCS by any one of several alternate methods.

The purpose of the control bank rod insertion monitor is to give warning to the operator of excessive rod insertion. The insertion limit maintains sufficient core reactivity shutdown margin following reactor trip, provides a limit on the maximum inserted rod worth in the unlikely event of a hypothetical rod ejection, and limits rod insertion so that acceptable nuclear peaking factors are maintained. Since the amount of shutdown reactivity required for the design shutdown margin following a reactor trip increases with increasing power, the allowable rod insertion limits must be decreased (the rods must be withdrawn further) with increasing power. Two parameters that are proportional to power are used as inputs to the insertion monitor. These are the ΔT between the hot leg and the cold leg, which is a direct function of reactor power, and T_{avg}, which is programmed as a function of power.

The rod insertion monitor uses parameters for each control rod bank as follows:

$$Z_{LLi} = K_{1i}\,\Delta T_{auct} + K_{2i}\,(T_{avg\ auct} - T_{no\text{-}load}) + K_{3i} \qquad (7.7\text{-}2)$$

where:

Z_{LLi} = maximum permissible insertion limit for affected control bank

i = A, B, C, and D respectively

$(\Delta T)_{auct}$ = highest ΔT of all loops

$(T_{avg})_{auct}$ = highest T_{avg} of all loops

K_{1i}, K_{2i}, K_{3i} = constants chosen to maintain $Z_{LLi} \geq$ actual limit based on physics calculations

The control rod bank demand position Z is compared to Z_{LLi} as follows:

If $Z - Z_{LLi} \leq D$, a low alarm is actuated
If $Z - Z_{LLi} \leq E$, a low-low alarm is actuated

where:

D, E = constants as described below

Since the highest values of T_{avg} and ΔT are chosen by auctioneering, a conservatively high representation of power is used in the insertion limit calculation.

Actuation of the low alarm alerts the operator of an approach to a reduced shutdown reactivity situation. Plant procedures require the operator to add boron through the CVCS. Actuation of the low-low alarm requires the operator to initiate emergency boration procedures. The value for E is chosen so that the low-low alarm would normally be actuated before the insertion limit is reached. The value for D is chosen to allow the operator to follow normal boration procedures. Figure 7.7-2 shows a block diagram of the control rod bank insertion monitor. The monitor is shown in more detail in the functional diagrams in Figure 7.2-1, Sheets 17 and 18. In addition to the rod insertion monitor for the control banks, an alarm system is provided to warn the operator if any shutdown RCCA leaves the fully withdrawn position. Rod insertion limits are found in the cycle specific COLR for each unit and are established by:

(1) Establishing the allowed rod reactivity insertion at full power, consistent with the purposes discussed above

(2) Establishing the differential reactivity worth of the control rods when moved in normal sequence

(3) Establishing the change in reactivity with power level by relating power level to rod position

(4) Linearizing the resultant limit curve. All key nuclear parameters in this procedure are measured as part of the initial and periodic physics testing program.

Any unexpected change in the position of the control bank under automatic control, or a change in coolant temperature under manual control, provides a direct and immediate indication of a change in the reactivity status of the reactor. In addition, samples are taken periodically of coolant boron concentration. Variations in concentration during core life provide an additional check on the reactivity status of the reactor including core depletion.

7.7.2.3.4 Rod Deviation Alarm

The demanded and measured rod position signals are displayed on the control board. They are also monitored by the plant computer that provides an indication and an alarm whenever an individual rod position signal deviates from the other rods in the bank by a preset limit. The alarm can be set with appropriate allowance for instrument error and within sufficiently narrow limits to preclude exceeding core design hot channel factors. Rod alignment requirements are provided in the Technical Specifications.

Figure 7.7-3 is a block diagram of the rod deviation comparator and alarm system.

7.7.2.3.5 Rod Bottom Alarm

A rod bottom signal for each rod in the digital rod position system is used to operate a control relay, which generates the ROD BOTTOM alarm.

7.7.2.4 Plant Control System Interlocks

The listing of the plant control system interlocks, along with the description of their derivations and functions, is presented in Table 7.7-1. It is noted that the designation numbers for these interlocks are preceded by C. The development of these logic functions is shown in the functional diagrams (Figure 7.2-1, Sheets 17 to 32).

7.7.2.4.1 Rod Stops

Rod stops are provided to prevent abnormal power conditions that could result from excessive control rod withdrawal initiated by either a control system malfunction or operator violation of administrative procedures.

Rod stops are the C_1, C_2, C_3, C_4, and C_5 control interlocks identified in Table 7.7-1. The C_3 rod stop derived from overtemperature ΔT, and the C_4 rod stop derived from overpower ΔT, are also used for turbine runback, which is discussed below.

7.7.2.4.2 Automatic Turbine Load Runback

Automatic turbine load runback is initiated by an approach to an overpower or overtemperature condition. This prevents high power operation that might lead to an undesirable condition, which, if reached, would be protected by reactor trip.

Turbine load reference reduction is initiated by either an overtemperature or overpower ΔT signal. Two-out-of-four coincidence logic is used.

A rod stop and turbine runback are initiated when:

$$\Delta T > \Delta T_{rod\ stop}$$

For the overtemperature condition, an overtemperature ΔT ($OT\Delta T$) turbine runback (TR) occurs when:

$$\Delta T_i \left(\frac{1+\tau_4 s}{1+\tau_5 s} \right) - OT\Delta T_{setpoint_i} > OTTR_{setpoint_i}$$

$\Delta T_i = T_{havei} - T^f c_i$

T_{havei}, $T^f c_i$, τ_4, and τ_5 are defined in Section 7.2.2.1.2

$OT\Delta T_{setpoint_i}$ = -20 to +20% (usually zero)[(a)]

$OTTR_{setpoint_i}$ = -20 to +20% (usually negative)[(a)]

For the overpower condition, an overpower ΔT ($OP\Delta T$), turbine runback occurs when:

$$\Delta T_i \left(\frac{1+\tau_4 s}{1+\tau_5 s} \right) - OP\Delta T_{setpoint_i} > OPTR_{setpoint_i}$$

$\Delta T_i = T_{havei} - T^f c_i$

T_{havei}, $T^f c_i$, τ_4, and τ_5 are defined in Section 7.2.2.1.2

$OP\Delta T_{setpoint_i}$ = -20 to +20% (usually zero)[(a)]

$OPTR_{setpoint_i}$ = -20 to +20% (usually negative)[(a)]

(a) The measured ΔT and ΔT setpoints should be in percent of full power ΔT. During initial plant operation, the ΔT channels were calibrated to indicate 100 percent at 100 percent power such that the channels do not reflect minor flow variations between loops or minor variations from design flow. Provisions to allow this calibration must be available in each channel before the ΔT signal is used for any alarm or protection function.

ΔT setpoint refers to the overtemperature ΔT reactor trip value and the overpower ΔT reactor trip value for the two conditions. The turbine runback is continued until ΔT is equal to or less than $\Delta T_{rod\ stop}$.

This function serves to maintain an essentially constant margin to trip.

7.7.2.5 Pressurizer Pressure Control

The RCS pressure is controlled by using either the heaters (in the water region) or the spray (in the steam region) of the pressurizer plus steam relief for large transients. The electrical immersion heaters are located near the bottom of the pressurizer. A portion of the heater group is proportional plus integral controlled to correct small pressure variations. These variations are due to heat losses, including heat losses due to a small continuous spray. The remaining (backup) heaters are turned on when the pressurizer pressure-controlled signal demands approximately 100 percent proportional plus integral heater power.

The spray nozzles are located on the top of the pressurizer. Spray is initiated when the pressure controller spray demand signal is above a given setpoint. The spray rate increases proportionally with increasing spray demand signal until it reaches a maximum value.

Steam condensed by the spray reduces the pressurizer pressure. A small continuous spray is normally maintained to reduce thermal stresses and thermal shock and to help maintain uniform water chemistry and temperature in the pressurizer.

Three power operated relief valves limit system pressure for large positive pressure transients. In the event of a large load reduction, not exceeding the design plant load reduction capability, the pressurizer power-operated relief valves might be actuated for the most adverse conditions; e.g., the most negative Doppler coefficient and the minimum incremental rod worth. The relief capacity of the power-operated relief valves is sized large enough to limit the system pressure to prevent actuation of high-pressure reactor trip for the above condition.

A block diagram of the pressurizer pressure control system is shown in Figure 7.7-4.

7.7.2.6 Pressurizer Water Level Control

The pressurizer operates by maintaining a steam cushion over the reactor coolant. As the density of the reactor coolant adjusts to the various temperatures, the steam-water interface moves to absorb the variations with relatively small pressure disturbances.

The water inventory in the RCS is maintained by the CVCS. During normal plant operation, charging flow varies to produce the flow demanded by the pressurizer water level controller. The pressurizer water level is programmed as a function of coolant average temperature, with the highest average temperature (auctioneered) being used.

The pressurizer water level decreases as the load is reduced from full load. This is a result of coolant contraction following programmed coolant temperature reduction from full power to low power. The programmed level is designed to match as nearly as possible the level changes resulting from the coolant temperature changes. To control pressurizer water level during startup and shutdown operations, the charging flow is either automatically regulated with the controller setpoint adjusted to the desired level or manually regulated from the main control room. The pressurizer water level is programmed so that the water level is above the setpoint for heater cutout (refer to Section 7.7.3.2.2).

A block diagram of the pressurizer water level control system is shown in Figure 7.7-5.

7.7.2.7 Steam Generator Water Level Control

Each steam generator is equipped with a digital feedwater flow control system that maintains a constant steam generator (SG) water level over all power ranges. The feedwater controller regulates the MFRV and the bypass feedwater valve by continuously comparing the feedwater flow signal, the water level signal, the programmed level, and the pressure-compensated steam flow signal. The digital feedwater control system has high and low power modes, determined by the feedwater flow measurement. The mode switch will automatically occur for a given loop when the feedwater flow in the subject loop reaches a predetermined valid value. In the low power mode, wide-range steam generator level provides a feedforward index to a single element feedwater control algorithm to anticipate nuclear steam supply system (NSSS) load changes. High power mode control is three element.

In both modes, feedwater temperature adjusts the level controller gain to account for variations in steam generator level dynamics with feedwater temperature. Narrow-range level is validated in both modes as the median value of the three isolated protection system level channels on each steam generator. As explained in WCAP-12221, this median signal selection (MSS) validation scheme meets the requirements of IEEE Std 279-1971 regarding separation of control and protection functions and control/protection interaction. The MSS was implemented to reduce the frequency of unscheduled trips resulting from equipment failure or human error during surveillance testing.

The feedwater pump speed is varied to maintain a programmed pressure differential between the average of the four steam generator steam line pressures and the feed pump discharge header. The speed demand controller continuously compares the actual differential pressure (DP) with a programmed DP_{ref} that is a linear function of steam flow. The speed demand controller then provides the feedpump speed demand to the feedpump speed control system. This system opens or closes the high pressure (HP) and low pressure (LP) governor valves for each pump to match the actual pump speed to the speed demand. The system also has a feature to back down or limit pump speed if pump discharge pressure is going high, to avoid feedpump trips on high discharge pressure due to feedwater system transients.

Continued delivery of feedwater to the steam generators is required as a sink for the heat stored and generated in the reactor following a reactor trip and turbine trip. An override signal closes the feedwater valves when the average coolant temperature is below a given temperature and the reactor has tripped. Manual override of the feedwater control system is available at all times in the absence of a main feedwater isolation signal. Refer to Reference 7 for additional details.

A block diagram of the steam generator water level control system is shown in Figures 7.7-6 and 7.7-7.

7.7.2.8 Steam Dump Control

The steam dump system was originally designed to accept a 100 percent net load loss exclusive of the station auxiliaries without reactor or turbine trip. However, as described in Section 5.2.2.1.5.1, the design basis load reduction transient has been revised to a 50 percent step load reduction.

The automatic steam dump system is able to accommodate this abnormal load reduction and to reduce the effects of the transient imposed upon the RCS. By bypassing main steam directly to the condenser, an artificial load is thereby maintained on the primary system. The rod control system can then reduce the reactor temperature to a new equilibrium value without causing overtemperature and/or overpressure conditions.

If the difference between the T_{ref} based on turbine impulse chamber pressure and the lead/lag compensated auctioneered T_{avg} exceeds a predetermined amount, and the interlock mentioned below is satisfied, a demand signal will actuate the steam dump to maintain the RCS temperature within control range until a new equilibrium condition is reached.

To prevent actuation of steam dump on small load perturbations, an independent load reduction sensing circuit is provided. This circuit senses the rate of decrease in the turbine load as detected by the turbine impulse chamber pressure. The circuit is provided to unblock the dump valves when the rate of load reduction exceeds a preset value corresponding to a 10 percent step load decrease or a sustained ramp load decrease of 5 percent per minute.

A block diagram of the steam dump control system is shown in Figure 7.7-8.

7.7.2.8.1 Load Rejection Steam Dump Controller

This circuit prevents a large increase in reactor coolant temperature following a large, sudden load decrease. The error signal is a difference between the lead-lag compensated auctioneered T_{avg} and the T_{ref}, which is based on turbine impulse chamber pressure.

The T_{avg} signal is the same as that used in the reactor control system. The lead-lag compensation for the T_{avg} signal is to compensate for lags in the plant thermal response and in valve positioning. Following a sudden load decrease, T_{ref} is immediately decreased and T_{avg} tends to increase, thus generating an immediate demand signal for steam dump. Since control rods are available in this situation, steam dump terminates as the error comes within the maneuvering capability of the control rods.

7.7.2.8.2 Reactor Trip Steam Dump Controller

Following a reactor trip above 15 percent power, the load rejection steam dump controller is defeated and the reactor trip steam dump controller becomes active. Since control rods are not available in this situation, the demand signal is the error signal between the lead-lag compensated auctioneered T_{avg} and the no-load reference T_{avg}. When the error signal exceeds a predetermined setpoint, the dump valves are tripped open in a prescribed sequence. As the error signal reduces in magnitude, indicating that the RCS T_{avg} is being reduced toward the reference no-load value, the dump valves are modulated by the reactor trip controller to regulate the rate of removal of decay heat and thus gradually establish the equilibrium hot shutdown condition.

The error signal determines whether a group of valves is to be tripped open or modulated open. In either case, they are modulated when the error is below the trip-open setpoints.

Some documentation may refer to the “reactor trip steam dump controller” as the “plant trip steam dump controller.”

7.7.2.8.3 Steam Header Pressure Controller

The removal of residual heat from the system is maintained by the steam header pressure controller (manually selected) that controls the amount of steam flow to the condensers. This controller operates a portion of the same steam dump valves to the condensers that are used during the initial transient following turbine/reactor trip or load reduction. This mode of operation is used during startup and cooldown (turbine not paralleled), and when operating the turbine below approximately 15 percent load.

7.7.2.9 Incore Instrumentation

The incore instrumentation system consists of Chromel-Alumel thermocouples at fixed core outlet positions, and movable miniature neutron detectors that can be positioned at the center of selected fuel assemblies anywhere along the length of the fuel assembly vertical axis. The basic system for inserting these detectors is shown in Figure 7.7-9. Sections 1 and 2 of Reference 3 outline the incore instrumentation system in more detail.

7.7.2.9.1 Thermocouples

The incore thermocouple system has been upgraded to safety-grade to qualify the system for postaccident monitoring. The upgraded system is discussed in Section 7.5.2.2.2.

The plant computer is also used to monitor and display the incore thermocouple temperatures through Class 1E isolation devices provided in the upgraded thermocouple system.

7.7.2.9.2 Movable Neutron Flux Detector Drive System

Miniature fission chamber detectors can be remotely positioned in retractable guide thimbles to provide flux mapping of the core. Flux mapping is described in Section 7.7.2.9.3 and the use of the data is described in Section 4.3.3.2. Refer to Reference 3 for neutron flux detector parameters. The stainless steel detector shell is welded to the leading end of helical wrap drive cable and to stainless steel sheathed coaxial cable. The retractable thimbles, into which the miniature detectors are driven, are pushed into the reactor core through conduits that extend from the bottom of the reactor vessel, down through the concrete shield area, and then up to a thimble seal table.

The thimbles are closed at the leading ends, are dry inside, and serve as the pressure barrier between the reactor water pressure and the atmosphere.

Mechanical seals between the retractable thimbles and the conduits are provided at the seal line. During reactor operation, the retractable thimbles are stationary. They are extracted downward from the core during refueling to avoid interference within the core. A space above the seal line is provided for the retraction operation.

The drive system for inserting the miniature detectors consists basically of drive assemblies, five-path rotary transfer operation selector assemblies, ten-path rotary transfer selector assemblies, and stop valves, as shown in Figure 7.7-9. These assemblies are described in Reference 3. The drive system pushes hollow helical wrap drive cables into the core with the miniature detectors attached to the leading ends of the cables and small-diameter sheathed coaxial cables threaded through the hollow centers back to the ends of the drive cables. Each drive assembly consists of a gear motor that pushes a helical, wrap-drive cable and a detector through a selective thimble path by means of a special drive box and includes a storage device that accommodates the total drive cable length.

The leakage detection and gas purge provisions are discussed in Reference 3.

Manual isolation valves (one for each thimble) are provided for closing the thimbles. When closed, the valve forms a 2500 psig barrier. The manual isolation valves are not designed to isolate a thimble while a detector/drive cable is inserted into the thimble.

The detector/drive cable must be retracted to a position above the isolation valve prior to closing the valve.

A small leak would probably not prevent access to the isolation valves and, thus, a leaking thimble could be isolated during a hot shutdown. A large leak might require cold shutdown for access to the isolation valve. Access to the lower reactor cavity is provided through a small access room located below the incore instrumentation seal area. During normal operations and hot or cold shutdown, the access room will be pressurized as cooling air from the containment heating, ventilating, and air conditioning (HVAC) system is forced through the lower reactor cavity. A normally closed PG&E Design Class I pressure relief shutter damper in the access room may be opened manually to relieve the pressure through the damper opening into the larger containment volume, thus reducing the pressure against the entry door and facilitating personnel access to the room. This damper contains counterweight devices that permit it to be automatically forced open if the pressure in the access room rises above the maximum normal operating pressure. In the event of a loss-of-coolant accident (LOCA), this damper will open and act as one of several reactor cavity subcompartment pressure-relief flowpaths.

7.7.2.9.2.1 Flux Thimble Tube Acceptance Criteria

The acceptance criteria to address nonlinear wear include capping or replacing flux thimble tubes that:

(1) showed greater than 25 percent wear per year; or

(2) had to be repositioned more than once; or

(3) had multiple wear scars with any two that measured greater than 40 percent; or

(4) had to be repositioned more than a total of 6 inches; or

(5) can not be inspected.

For wear above 40 percent, an additional predictability allowance of 5.1 percent is adequate to ensure that actual nonlinear wear does not exceed projected wear.

Based on Reference 11, 80 percent acceptance criterion, including 5.1 percent predictability uncertainty and 10 percent for eddy current testing instrument and wear scar uncertainty, PG&E will use a net acceptance criterion of 64.9 percent (References 9 and 10).

7.7.2.9.3 Control and Readout Description

The control and readout system provides means for inserting the miniature neutron detectors into the reactor core and withdrawing the detectors while plotting neutron flux versus detector position. The thimbles are distributed nearly uniformly over the core with about the same number of thimbles in each quadrant. The control system consists of two sections, one physically mounted with the drive units, and the other contained in the control room. Limit switches in each transfer device provide feedback of path selection operation. Each gear box drives an encoder for position feedback. One five-path operation selector is provided for each drive unit to insert the detector in one of five functional modes of operation. A ten-path rotary transfer assembly is a transfer device that is used to route a detector into any one of up to ten selectable paths. A common path is provided to permit cross-calibration of the detectors.

The control room contains the necessary equipment for control, position indication, and flux recording for each detector. Panels are provided to indicate the position of the detectors and to plot the flux level. Additional panels are provided for such features as drive motor controls, core path selector switches, plotting, and gain controls.

A flux mapping consists, briefly, of selecting (by panel switches) flux thimbles in given fuel assemblies at various core locations. The detectors are driven to the top of the core and stopped automatically. An x-y plot (position versus flux level) is initiated with the slow withdrawal of the detectors through the core from the top to a point below the bottom. Other core locations are selected and plotted in a similar manner. Each detector provides axial flux distribution data along the center of a fuel assembly. Various radial positions of detectors may then be compared to obtain a flux map for a region of the core.

Operating plant experience has demonstrated the adequacy of the incore instrumentation system in meeting the design bases stated.

7.7.2.10 Control Locations

7.7.2.10.1 Control Room

A common control room for Unit 1 and Unit 2 contains the controls and instrumentation necessary for operating each unit's reactor and turbine-generator during normal and accident conditions. The control boards for Unit 2 are physically separated from the Unit 1 control boards. The control room is continuously occupied by licensed operating personnel during all operating conditions. It is also expected to be continuously occupied during all accident conditions. In the remote case where it is not possible to occupy the control room, alternative control locations are provided. The control room for each unit is designed to normally accommodate three to five people.

Sufficient shielding, distance, and containment integrity are provided to ensure that control room personnel are not subjected to doses under postulated accident conditions

that would exceed 5 rem TEDE. The doses received by the operator during both entry and exit is expected to be minimal (refer to Section 15.5 and Table 15.5-33 for detail). Control room ventilation is provided by a system capable of having a large percentage of recirculated air. The fresh air intake can be closed to limit the intake of airborne activity if monitors indicate that such action is appropriate. (A complete discussion of control room ventilation and air conditioning is presented in Chapter 9.)

Provisions are made so that plant operators can readily shut down and maintain the plant at hot standby by means of controls located outside the control room at central alternative locations, one for each unit, in the auxiliary building.
Control room arrangement is shown in Figure 7.7-16.

7.7.2.10.1.1 Main Control Boards

The control board design and layout presents all the controls, indicators, recorders, and alarms required for the safe startup, operation, and shutdown of the plant.

The control board layout is based on operator ease in relating the control board devices to the physical plant and determining, at a glance, the status of related equipment. This is referred to as providing a functional layout. Within the boundaries of a functional layout, modules are arranged in columns of control functions associated with separation trains defined for the reactor protection and Engineered Safety Features (ESF) systems. Teflon-coated wire is used within the module and between the module and the first termination point.

Modular train column wiring is formed into wire bundles and carried to metal wireways (gutters). Gutters are run into metal vertical wireways (risers). The risers are the interface between field wiring and control board wiring. Risers are arranged to maintain the separated routing of the field wire trays.

Alarms and annunciators on the control board provide warning of abnormal plant conditions that might lead to possible unsafe conditions. An annunciator terminal display and logger printer are also available in the main control room. Indicators and recorders are provided for observation of instantaneous and trend values of plant operating conditions. The charts are also used for record-keeping purposes.

The bench-vertical control boards and control console are arranged to afford the operator instant access to the continuing controllers, recorders, and indicators, while allowing easy access to all the other controls. Refer to Figure 7.7-17.

The control console houses the reactor controls, plant process computer terminals, turbine controls, and generator controls. These are arranged from left to right of an operator sitting at the console. Various trip switches and safety system indicators are also located on the console. Refer to Figures 7.7-18 and 7.7-19.

The bench-vertical board houses the indicators, recorders, and controllers for ESF, primary plant, steam generator, turbine-generator, ventilation, diesel generator, and station electrical systems. These instruments, however, do not require the immediate attention of the operator as do those located on the control console. Refer to Figures 7.7-20 through 7.7-29.

Indication provided in the control room is discussed under the description of each individual system.

A process computer is used to provide supplementary information to the operator and to effectively assist in the operation of the NSSS. However, the analog indication provides the operator with ample information for safe operation without the computer system.

The plant operator's computer panel is located on the control console for easy access to information. A plant process computer terminal display is also at this location.

7.7.2.10.1.1.1 Main Annunciator System

The function of the main annunciator system is to monitor the status of selected plant equipment, systems and components, and to alert the Plant Operations Staff when an abnormal (alarm) condition is detected. The design of the main annunciator system is described in Section 3.10.3.9.

A partial list of annunciator displays includes:

(1) Loss of power supplies

(2) SSPS trouble

(3) SSPS in test

(4) NIS detector loss

(5) NIS channel test

(6) NIS trip bypass

(7) Hot shutdown panel open

(8) Hot shutdown panel in control

(9) Heat tracing fault (boric acid systems)

(10) Radiation monitoring system failure

(11) Radiation monitoring system in test

(12) Diesel generator system

(13) NIS reactor trip bypass

(14) NIS rod stop bypass

(15) Containment high-high pressure in test

(16) Process protection system (PPS) channel in bypass

(17) PPS channel set failure

(18) PPS trouble

(19) PPS RTD failure

(20) Steam generator trip time delay timer actuated

7.7.2.10.1.2 Occupancy Requirements

The control room area that is located in the auxiliary building at elevation 140 feet is designed for safe occupancy during abnormal conditions. Adequate shielding is used to maintain acceptable radiation levels in these areas under all normal operating and accident conditions. Radiation detectors and smoke detectors are provided to monitor the air intake and to initiate appropriate alarms and modes of operation. Air conditioning is included with provisions for the air to be recirculated through charcoal filters. Emergency lighting is provided in the control room area.

Fire hazards in the control room area are limited by the following:

(1) Noncombustible materials are used in construction where possible. Structural and finish materials (including furniture) for the control room and interconnecting areas have been selected on the basis of fire-retardant characteristics. Structural floors and exterior and interior walls are of reinforced concrete. Interior partitions within the control room areas incorporate concrete blocks, metal, and gypsum drywalls on metal studs. The control room door frames and doors are metallic. Personnel doors are tight fitting and gasketed. Wood trim is not used.

(2) Control cables are provided with an individual flame-retardant insulation over each single conductor and overall flame-retardant jacket over multiconductor cables. Cables throughout the installation have an exterior jacket that meets the Insulated Power Cable Engineers Association (IPCEA) requirements. Shielded instrumentation cables are provided with fire-resistant insulation and covered with a jacket of the same material.

For a more detailed discussion on insulated cable construction, refer to Appendix 8.3B and Sections 8.3.1.2 and 8.3.1.4.3.

(3) All pressure information is transmitted to the control room by electrical signals. No high-pressure fluids are piped into the control room.

(4) Combustible materials are administratively controlled in the control room area.

(5) Combustible supplies, such as logs, records, procedures, and manuals, are limited to the amounts required for current operation.

(6) Detectors, sensitive to smoke and combustibles, are located in the vicinity of equipment cabinets and in the air conditioning system ducts. Fire detection alarms are provided in the control room with indication of which detector has been actuated.

(7) All areas of the control room are readily accessible for fire extinguishing.

(8) Adequate fire extinguishers and breathing apparatus that are easily accessible are provided and are to be used in accordance with National Fire Code (NFC) and National Fire Protection Association (NFPA) requirements. This equipment is provided to control any fire that could occur.

(9) The control room is occupied at all times by an operator who has been trained in fire extinguishing techniques.

Therefore, as a result of these provisions, any fires in the control room area are expected to be of such small magnitude that they could be extinguished by the operator using a hand fire extinguisher. The resulting smoke and vapors would be removed by the air conditioning system.

The control room area is protected from infiltration of fire, smoke, or airborne radioactivity from outdoors and other areas of the auxiliary building by minimum leakage penetrations, weather-stripped doors, absence of outside windows, and the positive air pressure maintained in the area during normal and accident operation.

A smoke detection device provides warning so that the operator can take steps to minimize any hazard (refer to Section 9.4).

An area radiation detector monitors the control room for radiation content and will alert the operator to a high radioactivity level.

There are additional area radiation monitors in the auxiliary building and containment structures that provide the plant operator with a warning of unexpected high levels of radioactivity. Process monitors located in the residual heat removal exhaust ducts,

component cooling water system, and liquid and gaseous radwaste systems also warn the operator of higher than expected concentrations of radioactivity. A plant vent gas process monitor is backed up by an air particulate monitor that can also sample the containment air and detect primary plant piping leaks within containment. For a complete discussion of the radiation monitoring system, refer to Section 11.4.

Should the operator be forced to leave the control room, operating procedures require that the operator first trip the reactor and turbine-generator through manual trip switches located on the console. The operator would then verify the reactor trip and the turbine trip using approved plant procedures. After the reactor and turbine have tripped, plant controls automatically bring the plant to no-load condition after which it is necessary only to control the removal of decay heat and to maintain the water level in the pressurizer to maintain the plant in a safe condition. The operator would monitor and control these operations from the hot shutdown panel.

7.7.2.10.2 Hot Shutdown Panel

The hot shutdown panel, which is located in the auxiliary building at elevation 100 feet (refer to Figure 7.7-30), contains control stations, switches, and indicators to:

(1) Enable the operator to control water level in the steam generators with the auxiliary feedwater system (pumps and valves)

(2) Display auxiliary feedwater pump discharge pressure, auxiliary feedwater flow, auxiliary feedwater source levels, steam generator pressure and level, pressurizer pressure and level, emergency borate flow, charging flow, source range neutron flux, and Class 1E 4.16-kV bus voltages. Display RCS loop 4 wide range hot leg and cold leg temperatures.

(3) Enable the operator to manipulate the 10 percent atmospheric dump valves

(4) Start and stop:

(a) Component cooling water pumps (3)

(b) Auxiliary saltwater pumps (2)

(c) Charging pumps CCP1 and CCP2 (2)

(d) Boric acid transfer pumps (2)

(e) Containment fan coolers (5)

(5) Control:

(a) Emergency boric acid valve (1)

(b) Charging flow control valves (2)

(c) Power-operated relief valves (PORVs) for the pressurizer (close only) (3)

(d) RCP seal injection back-pressure

(e) RCP seal injection pressure

(f) RWST to charging pump suction header isolation valve (1)

(g) Charging line isolation valves (2)

(h) Charging to loop 4 isolation valve (1)

Boric acid concentration can be verified by reading the boron analyzer local indication or by sampling and analysis.

Transfer switches are located on this panel to allow the operator to activate these controls individually. Transfer switches for items (f) and (g) are in the associated vital 480V motor control center and the transfer switch for item (h) is in the associated 125 VDC inverter room. Except for motor-driven equipment, any transfer switch operation will cause annunciation in the control room. For motor-driven equipment, refer to Section 7.4.1.2.1(4).

The hot shutdown panel for plant shutdown and decay heat removal would be used only under abnormal conditions when access to the control room has been lost, and not during normal plant operation. The controls and indicators are located behind doors of the main panel and under the lids of the sub-panels to reduce the possibility of misoperation during normal operation. An alarm is initiated when a main panel door or the switch sub-panel lid or maintenance hatch is opened.

The indications and controls listed above are required for remote shutdown and/or Title 10, U.S. Code of Federal Regulations, Part 50.48(c), NFPA 805 purposes. Other indications and controls located on the hot shutdown panel are for operator convenience (additional indications and controls required for remote shutdown and NFPA 805 are located elsewhere throughout the plant.

7.7.2.10.3 Auxiliary Building Control Board

The auxiliary building control board, which is located in the auxiliary building at elevation 85 feet (refer to Figure 7.7-31), contains the controls, indicators, and alarm functions for:

(1) CVCS (Unit 1)

(2) Common panel for radioactive waste handling

(3) CVCS (Unit 2)

The control system provides a mimic for the radioactive waste handling system to aid the operator in setting up these systems.

7.7.2.10.4 Auxiliary Control Stations

Local control panels are provided for systems and components that do not require full-time operator attendance or are not used on a continuous basis. Examples of such systems are the waste disposal system and the turbine-generator hydrogen cooling system. In these cases, however, appropriate alarms are activated in the control room to alert the operator to an equipment malfunction or approach to unsafe conditions.

7.7.3 SAFETY EVALUATION

7.7.3.1 General Design Criterion 11, 1967 – Control Room

The plant is provided with a centralized control room common to both Unit 1 and Unit 2 that contains the controls and instrumentation necessary for operation of both units under normal and accident conditions. Should the operator be forced to leave the control room, operating procedures require that the operator first trip the reactor and turbine-generator through manual trip switches located on the console. Provisions are made so that plant operators can readily shut down and maintain the plant at hot standby by means of controls located outside of the control room. Refer to Section 7.7.2.10.

Proper positioning of the control rods is monitored in the control room by bank arrangements of the individual column meters for each RCCA. A rod deviation alarm alerts the operator of a deviation of one RCCA from the other rack in that bank position. There are also insertion limit monitors with visual and audible annunciation. A rod bottom alarm signal is provided to the control room for each RCCA. Four out-of-core long ion chambers also detect asymmetrical flux distribution indicative of rod misalignment.

7.7.3.2 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The plant control systems are designed to ensure high reliability in any anticipated operational occurrences. Equipment used in these systems is designed and constructed to maintain a high level of reliability.

7.7.3.2.1 Step Load Changes without Steam Dump

The plant control systems restore equilibrium conditions, without a trip, following a ± 10 percent step change in load demand, over the 15 to 100 percent power range for automatic control. Steam dump is blocked for load decrease less than or equal to 10 percent. A load demand greater than full power is prohibited by the turbine control load limit devices.

The plant control systems minimize the reactor coolant average temperature deviation during the transient within a given value, and restore average temperature to the programmed setpoint. Excessive pressurizer pressure variations are prevented by using spray and heaters and power operated relief valves in the pressurizer.

The control systems limit nuclear power overshoot to acceptable values following a 10 percent increase in load to 100 percent.

7.7.3.2.2 Loading and Unloading

Ramp loading and unloading of 5 percent per minute can be accepted over the 15 to 100 percent power range under automatic control without tripping the plant. The function of the control systems is to maintain the coolant average temperature as a function of turbine-generator load.

The coolant average temperature increases during loading and causes a continuous insurge to the pressurizer as a result of coolant expansion. The sprays limit the resulting pressure increase. Conversely, as the coolant average temperature is decreasing during unloading, there is a continuous outsurge from the pressurizer resulting from coolant contraction. The pressurizer heaters limit the resulting system pressure decrease. The pressurizer water level is programmed so that the water level is above the setpoint for heater cutout during the loading and unloading transients. The primary concern during loading is to limit the overshoot in nuclear power and to provide sufficient margin in the overtemperature ΔT setpoint.

7.7.3.2.3 Load Reduction Furnished by Steam Dump System

When a load reduction occurs, if the difference between the required temperature setpoint of the RCS and the actual average temperature exceeds a predetermined amount, a signal will actuate the steam dump to maintain the RCS temperature within control range until a new equilibrium condition is reached.

The reactor power is reduced at a rate consistent with the capability of the rod control system. Reduction of the reactor power is automatic. The steam dump flow reduction is as fast as RCCAs are capable of inserting negative reactivity.

The rod control system can then reduce the reactor temperature to a new equilibrium value without causing overtemperature and/or overpressure conditions. The steam

dump steam flow capacity is nominally 40 percent of full load steam flow at full load steam pressure.

The steam dump flow reduces proportionally as the control rods act to reduce the average coolant temperature. The artificial load is therefore removed as the coolant average temperature is restored to its programmed equilibrium value.

The dump valves are modulated by the reactor coolant average temperature signal. The required number of steam dump valves can be tripped quickly to stroke full open or modulate, depending on the magnitude of the temperature error signal resulting from loss of load.

7.7.3.2.4 Turbine-Generator Trip with Reactor Trip

Whenever the turbine-generator unit trips at an operating power level above the protection system interlock P-9 setting, the reactor also trips. The unit is operated with a programmed average temperature as a function of load, with the full load average temperature significantly greater than the equivalent saturation pressure of the safety valve setpoint. The thermal capacity of the RCS is greater than that of the secondary system, and because the full load average temperature is greater than the no-load temperature, a heat sink is required to remove heat stored in the reactor coolant to prevent actuation of steam generator safety valves for a trip from full power. This heat sink is provided by the combination of controlled release of steam to the condenser and by makeup of cold feedwater to the steam generators.

The steam dump system is controlled from the reactor coolant average temperature signal whose setpoint values are programmed as a function of turbine load. Actuation of the steam dump is rapid to prevent actuation of the steam generator safety valves. With the 10 percent atmospheric dump valves open, the average coolant temperature starts to reduce quickly to the no-load setpoint. A direct feedback of temperature acts to close the valves proportionally to minimize the total amount of steam that is bypassed.

Following the turbine trip, the feedwater flow is cut off when the average coolant temperature decreases below a given temperature, or when the steam generator water level reaches a given high level.

Additional feedwater makeup is then controlled manually to restore and maintain steam generator water level, while ensuring that the reactor coolant temperature is at the desired value. Residual heat removal is maintained by the steam header pressure controller (manually selected) that controls the amount of steam flow to the condensers. This controller operates a portion of the same 40 percent condenser dump valves to the condensers that are used during the initial transient following turbine and reactor trip.

The pressurizer pressure and water level fall rapidly during the transient because of coolant contraction. Following the turbine and reactor trip, the pressurizer level control follows RCS T_{avg} to its no load value. If heaters become uncovered following the trip,

they are deenergized and the CVCS will provide full charging flow to restore water level in the pressurizer. Heaters are then turned on to restore pressure to normal.

The steam dump feedwater control systems are designed to prevent the average coolant temperature from falling below the programmed no-load temperature following the trip to ensure adequate reactivity shutdown margin.

7.7.3.2.5 General Considerations

The plant control systems prevent an undesirable condition in the operation of the plant that, if reached, would be protected by reactor trip. The description and analysis of this protection is covered in Section 7.2. Worst-case failure modes of the plant control systems are postulated in the analysis of off-design operational transients and accidents covered in Chapter 15, such as the following:

(1) Uncontrolled RCCA withdrawal from a subcritical condition

(2) Uncontrolled RCCA withdrawal at power

(3) RCCA misalignment

(4) Loss of external electric load and/or turbine trip

(5) Loss of all ac power to the station auxiliaries

(6) Excessive heat removal due to feedwater system malfunctions

(7) Excessive load increase

(8) Accidental depressurization of the RCS

These analyses show that a reactor trip setpoint is reached in time to protect the health and safety of the public under these postulated incidents, and that the resulting coolant temperatures produce a DNBR well above the applicable limit value (refer to Sections 4.4.4.1 and 4.4.3.3). Thus, there will be no cladding damage and no release of fission products to the RCS under the assumption of these postulated worst case failure modes of the plant control systems.

7.7.3.3 General Design Criterion 13, 1967 – Fission Process Monitors and Controls

Overall reactivity control is achieved by the combination of soluble boron and RCCAs. Long-term regulation of core reactivity is accomplished by adjusting the concentration of boric acid in the reactor coolant. Short-term reactivity control for power changes is accomplished by the plant control systems that automatically move RCCAs. This system uses input signals including neutron flux, coolant temperature, and turbine load.

7.7.3.4 General Design Criterion 22, 1967 – Separation of Protection and Control Instrumentation Systems

In some cases, it is advantageous to employ control signals derived from individual protection channels through isolation devices contained in the protection channel. As such, a failure in the control circuitry does not adversely affect the protection channel. Accordingly, this postulated failure mode meets the requirements of GDC 22, 1967. Test results have proved that failure of any single control system component or channel did not perceptibly disturb the protection side (input) of the devices.

Where a single random failure can cause a control system action that results in a generating station condition requiring protective action, and can also prevent proper action of a protection system channel designed to protect against the condition, the remaining redundant protection channels are capable of providing the protective action even when degraded by a second random failure. This meets the applicable requirements of Paragraph 4.7 of IEEE-279-1971 (Reference 5).

Channels of the nuclear instrumentation that are used in the protective system are combined to provide nonprotective functions, such as signals, to indicating or recording devices; the required signals are derived through isolation devices.

These isolation devices are designed so that open or short circuit conditions, as well as the application of 120-Vac or 140-Vdc to the isolation side of the circuit, will have no effect on the input, or protection, side of the circuit. As such, failures on the nonprotective side of the system will not affect the individual protection channels.

7.7.3.5 General Design Criterion 26, 1971 – Reactivity Control System Redundancy and Capability

Two independent reactivity control systems are provided for each reactor. These are RCCAs and chemical shim (boration).

Overall reactivity control is achieved by the combination of soluble boron and RCCAs. Long-term regulation of core reactivity is accomplished by adjusting the concentration of boric acid in the reactor coolant. Short-term reactivity control for power changes is accomplished by the plant control systems that automatically move RCCAs. This system uses input signals including neutron flux, coolant temperature, and turbine load.

No single electrical or mechanical failure in the rod control system could cause the accidental withdrawal of a single RCCA from the partially inserted bank at full power operation. The operator could deliberately withdraw a single RCCA in the control bank; this feature is necessary in order to retrieve a rod, should one be accidentally dropped. In the extremely unlikely event of simultaneous electrical failures that could result in single withdrawal, rod deviation would be displayed on the plant annunciator, and the rod position indicators would indicate the relative positions of the rods in the bank.

Withdrawal of a single RCCA by operator action, whether deliberate or by a combination of errors, would result in activation of the same alarm and the same visual indications.

The control and shutdown rods are arranged as follows:

Control	Shutdown
Bank A Group 1	Bank A Group 1
Bank A Group 2	Bank A Group 2
Bank B Group 1	Bank B Group 1
Bank B Group 2	Bank B Group 2
Bank C Group 1	Bank C One Group
Bank C Group 2	Bank D One Group
Bank D Group 1	
Bank D Group 2	

The rods in a group operate in parallel through multiplexing thyristors. The two groups in a bank move sequentially so that the first group is always within one step of the second group in the bank. A definite schedule of actuation or deactuation of the stationary gripper, movable gripper, and lift coils of a mechanism is required to withdraw the RCCA attached to the mechanism. Since the four stationary grippers, movable grippers, and lift coils associated with the RCCAs of a rod group are driven in parallel, any single failure that could cause rod withdrawal would affect a minimum of one group of RCCAs. Mechanical failures are in the direction of insertion, or immobility.

The identified multiple failure involving the least number of components consists of open circuit failure of the proper two out of sixteen wires connected to the gate of the lift coil thyristors. The probability of open wire (or terminal) failure is 0.016 x 10-6 per hour by MIL HDBK-217A (Reference 6). These wire failures would have to be accompanied by failure, or disregard, of the indications mentioned above. The probability of this occurrence is therefore too low to have any significance.

Concerning the human element, to erroneously withdraw a single RCCA, the operator would have to improperly set the bank selector switch, the lift coil disconnect switches, and the in-hold-out switch. In addition, the three indications would have to be disregarded or ineffective. Such a series of errors would require a complete lack of understanding and administrative control. A probability number cannot be assigned to a series of errors such as these. Such a number would be highly subjective.

The rod position indication provides direct visual displays of each control rod assembly position. The plant computer alarms for deviation of rods from their banks. In addition, a rod insertion limit monitor provides an audible and visual alarm to warn the operator of an approach to an abnormal condition due to dilution. The low-low insertion limit alarm alerts the operator to follow emergency boration procedures. The facility reactivity control systems are such that acceptable fuel damage limits will not be exceeded in the event of a single malfunction of either system.

An important feature of the control rod system is that insertion is provided by gravity fall of the rods.

In all analyses involving reactor trip, the single, highest worth RCCA is postulated to remain untripped in its full out position.

One means of detecting a stuck control rod assembly is available from the actual rod position information displayed on the control board. The control board position readouts for each rod give the plant operator the actual position of the rod in steps. The indications are grouped by banks (e.g., control bank A, control bank B, etc.) to indicate to the operator the deviation of one rod with respect to other rods in a bank. This serves as a means to identify rod deviation.

The plant computer monitors the actual position of all rods. Should a rod be misaligned from the other rods in that bank by more than 12 steps, the rod deviation alarm is actuated.

Misaligned RCCAs are also detected and alarmed in the control room via the flux tilt (QPTR) monitoring system that is independent of the plant computer.

Isolated signals derived from the NIS are compared with one another to determine if a preset amount of deviation of average power has occurred. Should such a deviation occur, the comparator output will operate a bistable unit to actuate a control board annunciator. This alarm will alert the operator to a power imbalance caused by a misaligned rod. By use of individual rod position readouts, the operator can determine the deviating control rod and take corrective action. Thus, the design of the plant control systems meets the applicable requirements of GDC 12, 1967 and GDC 31, 1967.

The boron system can compensate for all xenon burnout reactivity transients without exception.

The rod system can compensate for xenon burnout reactivity transients over the allowed range of rod travel. Xenon burnout transients of larger magnitude must be accommodated by boration or by reactor trip (which eliminates the burnout).

The boron system is not used to compensate for the reactivity effects of fuel/water temperature changes accompanying power level changes.

The rod system can compensate for the reactivity effects of fuel/water temperature changes accompanying power level changes over the full range from full-load to no-load at the design maximum load uprate.

Automatic control of the rods is, however, limited to the range of approximately 15 to 100 percent of rating for reasons unrelated to reactivity or reactor safety.

The boron system (by the use of administrative measures) will maintain the reactor in the cold shutdown state, irrespective of the disposition of the control rods.

The overall reactivity control achieved by the combination of soluble boron and RCCAs meets the applicable requirements of GDC 27, 1967.

7.7.3.6 General Design Criterion 31, 1967 – Reactivity Control Systems Malfunction

Reactor shutdown with control rods is completely independent of the control functions since the trip breakers interrupt power to the rod drive mechanisms regardless of existing control signals. The design is such that the system can withstand accidental withdrawal of control groups or unplanned dilution of soluble boron without exceeding acceptable fuel design limits. Thus, the design meets the applicable requirements of GDC 31, 1967.

7.7.4 REFERENCES

1. J. B. Lipchak and R. A. Stokes, Nuclear Instrumentation System, WCAP-7669, April 1971.

2. A. E. Blanchard, Rod Position Monitoring, WCAP-7571, March 1971.

3. J. J. Loving, In-Core Instrumentation (Flux-Mapping System and Thermocouples), WCAP-7607, July 1971.

4. Deleted in Revision 21.

5. IEEE Standard 279-1971, Criteria for Protection Systems for Nuclear Power Generating Stations, Institute of Electrical and Electronics Engineers, Inc.

6. MIL-HDBK-217A, Reliability Prediction of Electronic Equipment, December 1965.

7. Advanced Digital Feedwater Control System Input Signal Validation for Pacific Gas and Electric Co., Diablo Canyon Units 1 and 2, WCAP - 12221, April 1997 (W Proprietary Class 3) (PGE-97-540) and WCAP - 12222, March 1989 (W Proprietary Class 3).

8. Westinghouse Protection System Noise Tests, WCAP - 12358, Revision 2, October 1975 (W Proprietary Class 3).

9. PG&E Letter DCL-24-092, Supplement and Annual Update: Diablo Canyon Power Plant License Renewal Application, Amendment 1, dated October 14, 2024.

10. NRC Letter to PG&E, Diablo Canyon Nuclear Power Plant, Units 1 and 2 – Safety Evaluation For The License Renewal Application (EPID No. L-2023-RNW-0021), dated June 4, 2025 (Section 3.0.3.1.12).

11. Westinghouse Commercial Atomic Power (WCAP) - 12866, Bottom Mounted Instrumentation Flux Thimble Wear, January 1991

7.7.5 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

TABLE 7.1-1

APPLICABLE DESIGN BASIS CRITERIA

CRITERIA	TITLE	APPLICABILITY					
Instrumentation and Controls		Reactor Trip System (RTS)	Engineered Safety Features Actuation System (ESFAS)	Systems Required for Safe Shutdown	Safety-Related Display Instrumentation	All Other Instrumentation Systems Required for Safety	Control Systems Not Required for Safety
Section		7.2	7.3	7.4	7.5	7.6	7.7
1. General Design Criteria							
Criterion 2, 1967	Performance Standards	X	X		X	X	
Criterion 3, 1971	Fire Protection			X			
Criterion 11, 1967	Control Room	X	X	X	X	X	X
Criterion 12, 1967	Instrumentation and Control System	X		X	X	X	X
Criterion 13, 1967	Fission Process Monitors and Controls						X
Criterion 14, 1967	Core Protection Systems	X					
Criterion 15, 1967	Engineered Safety Features Protection Systems		X				
Criterion 17, 1967	Monitoring Radioactivity Releases				X		
Criterion 19, 1967	Protection Systems Reliability	X	X				
Criterion 20, 1967	Protection Systems Redundancy and Independence	X	X				
Criterion 21, 1967	Single Failure Definition	X	X				
Criterion 22, 1967	Separation of Protection Control Instrumentation Systems	X	X				X
Criterion 23, 1967	Protection Against Multiple Disability for Protection Systems	X	X				
Criterion 24, 1967	Emergency Power for Protection Systems	X	X				
Criterion 25, 1967	Demonstration of Functional Operability of Protection Systems	X	X				
Criterion 26, 1967	Protection Systems Fail-Safe Design	X	X				

TABLE 7.1-1

APPLICABLE DESIGN BASIS CRITERIA

CRITERIA	TITLE	APPLICABILITY					
Instrumentation and Controls		Reactor Trip System (RTS)	Engineered Safety Features Actuation System (ESFAS)	Systems Required for Safe Shutdown	Safety-Related Display Instrumentation	All Other Instrumentation Systems Required for Safety	Control Systems Not Required for Safety
Section		7.2	7.3	7.4	7.5	7.6	7.7
Criterion 27, 1967	Redundancy of Reactivity Control						X
Criterion 31, 1967	Reactivity Control Systems Malfunction	X					X
Criterion 37, 1967	Engineered Safety Features Basis for Design		X				
Criterion 38, 1967	Reliability and Testability of Engineered Safety Features		X				
Criterion 40, 1967	Missile Protection		X				
Criterion 48, 1967	Testing of Operational Sequence of Emergency Core Cooling Systems		X				
Criterion 49, 1967	Containment Design Basis	X	X				
2. 10 CFR Part 50							
50.49	Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants	X	X		X	X	
50.62	Requirements for Reduction of Risk from Anticipated Transients without Scrams (ATWS) Events for Light-Water-Cooled Nuclear Power Plants					X	
3. Atomic Energy Commission (AEC) Safety Guides							
Safety Guide 22, February 1972	Periodic Testing of Protection System Actuation Functions	X	X				
4. Regulatory Guides							
Regulatory Guide 1.97, Revision 3, May 1983	Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and				X		

TABLE 7.1-1

APPLICABLE DESIGN BASIS CRITERIA

CRITERIA	TITLE	APPLICABILITY					
Instrumentation and Controls		Reactor Trip System (RTS)	Engineered Safety Features Actuation System (ESFAS)	Systems Required for Safe Shutdown	Safety-Related Display Instrumentation	All Other Instrumentation Systems Required for Safety	Control Systems Not Required for Safety
Section		7.2	7.3	7.4	7.5	7.6	7.7
	Following an Accident						
5. NRC NUREG							
NUREG-0737 (Item I.D.2), November 1980	Clarification of TMI Action Plan Requirements				X		
NUREG-0737 (Item II.D.3), November 1980	Clarification of TMI Action Plan Requirements				X		
NUREG-0737 (Item II.E.1.2), November 1980	Clarification of TMI Action Plan Requirements				X		
NUREG-0737 (Item II.F.1), November 1980	Clarification of TMI Action Plan Requirements				X		
NUREG-0737 (Item II.F.2), November 1980	Clarification of TMI Action Plan Requirements				X		
NUREG-0737 (Item II.K.3.10), November 1980	Clarification of TMI Action Plan Requirements	X					
NUREG-0737 (Item II.K.3.12), November 1980	Clarification of TMI Action Plan Requirements	X					
NUREG-0737 (Item II.A.1.2), November 1980	Clarification of TMI Action Plan Requirements				X		
6. NRC Generic Letters							
Generic Letter 83-28, July 1983	Required Actions Based on Generic Implications of Salem ATWS Events	X					

TABLE 7.2-1

LIST OF REACTOR TRIPS

Reactor Trip	Coincidence Logic	Interlocks	Comments
1. Power range high nuclear power	2/4	Manual block of low setting permitted by P-10	High and low settings; manual and automatic reset of low setting by P-10
2. Intermediate range high neutron flux	1/2	Manual block permitted by P-10	Manual block and automatic reset
3. Source range high neutron flux	1/2	Manual block permitted by P-6, interlocked with P-10	Manual block and automatic reset. Automatic block above P-10
4. Power range high positive nuclear power rate	2/4	No interlocks	-
5. Deleted in Revision 20.		-	-
6. Overtemperature ΔT	2/4	No interlocks	-
7. Overpower ΔT	2/4	No interlocks	-
8. Pressurizer low pressure	2/4	Interlocked with P-7	Blocked below P-7
9. Pressurizer high pressure	2/4	No interlocks	-

TABLE 7.2-1

Reactor Trip	Coincidence Logic	Interlocks	Comments
10. Pressurizer high water level	2/3	Interlocked with P-7	Blocked below P-7
11. Reactor coolant low flow	2/3 per loop	Interlocked with P-7 and P-8	Low flow in one loop will cause a reactor trip when above P-8 and a low flow in two loops will cause a reactor trip with permissive P-7 enabled. Blocked below P-7
12. Reactor coolant pump breakers open or redundant breaker open	2/4	Interlocked with P-7	Blocked below P-7
13. Reactor coolant pump bus under-voltage	1/2 on both buses	Interlocked with P-7	Low voltage on all buses permitted below P-7
14. Reactor coolant pump bus under-frequency	2/3 on either bus	Interlocked with P-7	Underfrequency on 2/3 sensors on either bus will trip reactor if above P-7 setpoint
15. Steam generator low- low level	2/3 per loop	No interlocks	-

TABLE 7.2-1

Reactor Trip	Coincidence Logic	Interlocks	Comments
16. Safety injection signal	Coincidence with actuation of safety injection	No interlocks	(See Section 7.3 for engineered safety features actuation conditions)
17. Turbine trip-Reactor trip			
a. Low autostop oil pressure	2/3	Interlocked with P-9	Blocked below P-9
b. Turbine stop valve close	4/4	Interlocked with P-9	Blocked below P-9
18. Manual	1/2	No interlocks	Reactor trip or Safety Injection Signal Actuation
19. Seismic	2/3 per axis	No interlocks	-
20. Reactor trip/bypass breakers	2/2	No interlocks	Both trains
21. Automatic trip logic	1/2	No interlocks	Both trains
22. General warning	2/2	No interlocks	Both trains

TABLE 7.2-2

PROTECTION SYSTEM INTERLOCKS

Designation	Derivation	Function
	Power Escalation Permissives	
P-6	1/2 Neutron flux (intermediate range) above setpoint	Allows manual block of source range reactor trip
	2/2 Neutron flux (intermediate range) below setpoint	Defeats the block of source range reactor trip
P-10	2/4 Nuclear power (power range) above setpoint	Allows manual block of power range (low setpoint) reactor trip
		Allows manual block of intermediate range reactor trip and intermediate range rod stops (C-1)
		Blocks source range reactor trip (backup for P-6)
		Blocks subcooled margin monitor lo-margin alarm
	3/4 Nuclear power (power range) below setpoint	Defeats the block of power range (low set- point) reactor trip
		Defeats the block of intermediate range reactor trip and intermediate range rod stops (C-1)
		Input to P-7
		Enables subcooled margin monitor lo-margin alarm

TABLE 7.2-2

Designation	Derivation	Function
	Blocks of Reactor Trips	
P-7	3/4 Nuclear power (power range) below setpoint (from P-10), and 2/2 turbine impulse chamber pressure below setpoint (from P-13)	Blocks reactor trip on: low flow or reactor coolant pump breakers open in more than one loop, undervoltage, underfrequency, pressurizer low pressure, and pressurizer high level
P-8	3/4 Nuclear power (power range) below setpoint	Blocks reactor trip on low flow in a single loop
P-9	3/4 Neutron Flux (power range) below setpoint	Blocks reactor trip on turbine trip
P-13	2/2 Turbine impulse chamber pressure below setpoint	Input to P-7

TABLE 7.3-1

INSTRUMENTATION OPERATING CONDITION
FOR ENGINEERED SAFETY FEATURES

No.	Functional Unit	No. of Channels	No. of Channels To Trip
1.	Safety Injection		
	a. Manual	2	1
	b. High containment pressure	3	2
	c. Pressurizer low pressure	4	2
	d. Low steam line pressure (lead/lag compensated)	12 (3/steam line)	2/3 in any steam line
2.	Containment Spray		
	a. Manual	2	2 coincident
	b. Containment pressure high-high	4	2

TABLE 7.3-2

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM
INSTRUMENTATION OPERATING CONDITIONS FOR ISOLATION FUNCTIONS

No.	Functional Unit	No. of Channels	No. of Channels To Trip
1.	Containment Isolation		
	a. Safety injection (Phase A)	(See Item No. 1 of Table 7.3-1)	
	b. Containment pressure (Phase B)	(See Item No. 2b of Table 7.3-1)	
	c. Manual		
	Phase A	2	1
	Phase B	(See Item No. 2a of Table 7.3-1)	
2.	Steam Line Isolation		
	a. Low steam line pressure (lead/lag compensated)	(See Item No. 1d of Table 7.3-1)	
	b. High steam pressure rate (rate lag compensated)	12 (3/steam line)	2/3 in any steam line
	c. Containment pressure high- high 2/4	(See Item No. 2b of Table 7.3-1)	
	d. Manual	1/loop	1/loop
3.	Feedwater Line Isolation		
	a. Safety injection	(See Item No. 1 of Table 7.3-1)	
	b. Steam generator high-high level	12 (3/steam generator)	2/3 in any steam generator

TABLE 7.3-2

No.	Functional Unit	No. of Channels	No. of Channels To Trip
4.	Containment Ventilation Isolation		
	a. Safety injection	(See Item No. 1 of Table 7.3-1)	
	b. Containment exhaust detectors	2	1
	c. Containment isolation		
	1) Phase A (manual)	2	1
	2) Phase B (manual)	2	2
	3) Spray actuation (manual)	2	2
5.	Control Room Air Intake Duct Isolation		
	a. Safety injection	(See Item No. 1 of Table 7.3-1)	
	b. Control room air intake radiation monitor[a,b,c]	2	1
	c. Manual	1	1

(a) Circuitry is not part of the safeguards system.

(b) Monitors on either unit control room air intake duct will initiate the isolation of both Units' control room ventilation systems.

(c) Circuitry is not redundant.

TABLE 7.3-3

INTERLOCKS FOR ENGINEERED SAFETY FEATURES ACTUATION SYSTEM

Designation	Input	Function Performed
P-4	Reactor trip	Actuates turbine trip
		Closes all MFRVs and all main feedwater bypass valves on T_{avg} below setpoint
		Prevents opening of all MFRVs, all main feedwater bypass valves, and all MFIVs which were closed by safety injection or high steam generator water level
		Allows manual block of safety injection
	Reactor not tripped	Defeats the block of the automatic reactuation of safety injection
P-11	2/3 Pressurizer pressure below setpoint	Allows manual block of safety injection actuation on low pressurizer pressure signal
		Allows manual block of safety injection and steam line isolation on low steamline pressure. Steam line isolation on high negative rate steam line pressures is permitted when this manual block is accomplished
	2/3 Pressurizer pressure above setpoint	Defeats manual block of safety injection actuation
		Defeats manual block of safety injection and steam line isolation on low steam line pressure and defeats steam line isolation on high negative rate steam line pressure

TABLE 7.3-3

Designation	Input	Function Performed
P-12[a]	2/4 T_{avg} below setpoint	Blocks steam dump condenser valves
		Allows manual bypass of steam dump block for the cooldown condenser valves only[b]
		Blocks trip open atmospheric dump
		Blocks modulation of the dump valves according to sequence described in Sheets 19 and 20 of Figure 7.2-1
	3/4 T_{avg} above setpoint	Defeats the manual bypass of steam dump block
		Enables steam dump (all condenser dump valves except the cooldown dump valves)
		Enables steam dump (atmospheric dump valves)
P-14	2/3 Steam generator water level above setpoint in any steam generator	Closes all MFRVs, all main feedwater bypass valves, and all MFIVs
		Trips all main feedwater pumps
		Actuates turbine trip

(a) Circuitry is not part of safeguards system

(b) Operations procedures allow bypassing the P-12 interlock once the reactor is in Mode 3 and borated to cold shutdown conditions.

TABLE 7.5-1

MAIN CONTROL BOARD INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR (CONDITIONS II AND III EVENTS)

Parameter	No. of Channels Avail.	No. of Channels Req.	Range	Available Indicated Accuracy[a]	Indicator/ Recorder	Purpose
1. T_{cold} &/or T_{hot} (measured, wide-range)	1 T_{hot} or 1 T_{cold} per loop	1 T_{hot} & 1 T_{cold} any 2 operating loops	0 to 700°F	±4% of full range	All channels are recorded	Ensure maintenance of proper cooldown rate and maintenance of proper relationship between system pressure and temperature for NDT considerations
2. Pressurizer Water Level	3	2	0 to 100%	±6% span at 2250 psia	All three channels indicated; one channel is selected for recording	Ensure maintenance of proper reactor coolant inventory
3. RCS Pressure (wide-range)	2	2	0 to 3000 psig	±4% of full range	One channel indicated and one recorded	Ensure maintenance of proper relationship between system pressure and temperature for NDT considerations
4. Containment Pressure (normal-range)	4	2	-5 to +55 psig	±3.5% of full span	All 4 are indicated	Monitor containment conditions to indicate need for potential engineered safety features

TABLE 7.5-1

Parameter	No. of Channels Avail.	No. of Channels Req.	Range	Available Indicated Accuracy[a]	Indicator/ Recorder	Purpose
5. Steam Line Pressure	3/Loop	2/Loop	0 to 1,200 psig	±4.0% of full span	All channels are indicated	Monitor steam generator pressure conditions during hot shutdown and cooldown, and for use in recovery from steam generator tube ruptures
6. Steam Generator Water Level (wide-range)	1/Steam generator	N/A	0 to 100%	±3% span[b]	All channels recorded	Ensure maintenance of reactor heat sink
7. Steam Generator Water level (narrow-range)	3/Steam generator	2/Steam generator	0 to 100%	±3% span[b]	All channels indicated; the channels used for control are recorded	Ensure maintenance of reactor heat sink
8. Intermediate Range Flux Level	2	N/A	8 decades logarithmic 10^{-11} to 10^{-3} amps overlapping the source range by 2 decades	Indicator: -16.8% to +20.2% of input; Recorder: -24% to +30% of input[c]	Both channels indicated. All channels are recorded.	

TABLE 7.5-1

Parameter	No. of Channels Avail.	No. of Channels Req.	Range	Available Indicated Accuracy[a]	Indicator/ Recorder	Purpose
9. Power Range						
a. Uncompensated ion chamber current (top and bottom uncompensated ion chambers)	4	N/A	0 to 120% of full power current	±1% of full span	All 8 current signals indicated	
b. Average flux of the top and bottom ion chambers	4	N/A	0 to 120% of full power	±3% of full power for indication, ±2% for recording	All 4 channels indicated. All channels are recorded.	
c. Average flux of the top and bottom ion chambers	4	N/A	0 to 200% of full power	±2% of full power to 120% ±6% of full power to 200%	All 4 channels recorded	
d. Flux difference of the top and bottom ion chambers	4	N/A	-30 to +30%	±4%	All 4 channels indicated. All channels are recorded.	

(a) Includes channel accuracy and environmental effects during normal plant operation, but does not include post-accident environmental effects.

Changes which are within the stated accuracy band or within the reading accuracy of the indicator are not reflected in this table. Actual values are found in design documents.

The instrumentation accuracies listed are typical indicator values and are not directly comparable to the channel accuracies utilized in the Chapter 15 analysis.

(b) Instrument accuracy only. The accuracy statement does not include the effect of density changes in the vessel.

(c) Does not include instrument drift allowance.

TABLE 7.5-2

MAIN CONTROL BOARD INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR
(CONDITION IV EVENTS)

Parameter	No. of Channels Avail.	No. of Channels Req.	Range	Available Indicated Accuracy[a]	Indicator/ Recorder	Purpose
1. Containment Pressure (normal range)	4	2	-5 to +55 psig	±3.5% of full span	All 4 are indicated	Monitor post-LOCA containment conditions
2. Containment Sump Level (NR)	2	1	88.5 to 96.6 ft El.	±6.5% of full span[e]	Indicator	Assess recirculation mode and general conditions
3. Refueling Water Storage Tank Water Level	3	2	0 to 100% of span	±4.5% of level span	All 3 are indicated and alarmed	Ensure that water is flowing to the safety injection system after a LOCA, and determine when to shift from injection to recirculation mode
4. Steam Generator Water Level (narrow-range)	3/Steam generator	2/Steam generator	0 to 100%	±3% of level span[b][c]	All channels indicated; the channels used for control are recorded	Detect steam generator tube rupture; monitor steam generator water level following a feedwater line break

TABLE 7.5-2

Parameter	No. of Channels Avail.	No. of Channels Req.	Range	Available Indicated Accuracy[a]	Indicator/ Recorder	Purpose
5. Steam Generator Water Level (wide range)	1/Steam generator	N/A	0 to 100%	±3% of level span[b][c]	All channels are recorded	Detect steam generator tube rupture; monitor steam generator water level following a feedwater line break
6. Steam Line Pressure	3/Steam line	2/Steam line	0 to 1,200 psig	±4% of full scale	All channels are indicated	Monitor steam line pressures following steam generator tube rupture or steam line break
7. Steam Line Flow	2/Steam line	N/A	0 to 4.5 million pounds/hour	Within ±10% span when flow >25%	All channels are indicated; the channels used for control are recorded	Indication purposes only
8. Pressurizer Water Level	3	2	0 to 100%	Indicate that level is somewhere between 0 and 100% of span	All three channels are indicated, and one channel is selected for recording	Indicate that water has returned to the pressurizer following cooldown after steam generator tube rupture or steam line break
9. Pressurizer Pressure	4	3	1250 to 2500 psig	±3.5% of full span	All channels indicated, one channel recorded	Detect steam generator tube breaks

TABLE 7.5-2

Parameter	No. of Channels Avail.	No. of Channels Req.	Range	Available Indicated Accuracy[a]	Indicator/ Recorder	Purpose
10. Intermediate Range Flux Level	2	N/A	Logarithmic 10^{-11} to 10^{-3} amps	Indicator: -16.8% to +20.2% of input; Recorder: -24% to +30% of input[d]	Both channels indicated. All channels are recorded.	Assess rod cluster control assembly ejection
11. Power Range						
a. Un-compensated ion chamber current (top and bottom un-compensated ion chambers)	4	N/A	0 to 120% of full power current	±1% of full span	All 8 current signals indicated	Assess rod cluster control assembly ejection
b. Average flux of the top and bottom ion chambers	4	N/A	0 to 120% of full power	±3% of full power for indication, ±2% for recording	All four channels indicated. All channels are recorded.	Assess rod cluster control assembly ejection

(a) Includes channel accuracy and environmental effects for normal operation. Does not include post-accident environmental effects. The instrumentation accuracies listed are typical indicator values and are not directly comparable to the channel accuracies utilized in the Chapter 15 analysis.

Changes which are within the stated accuracy band or within the reading accuracy of the indicator are not reflected in this table. Actual values are found in design documents.

(b) For the steam break, when the water level channel is exposed to a hostile environment, the accuracy required can be relaxed. The indication need only convey to the operator that water level in the steam generator is somewhere between the narrow-range steam generator water level taps.

TABLE 7.5-2

(c) Instrument accuracy only. The accuracy statement does not include the effect of density changes in the vessel, mid-deck plate delta-P, and other process measurement or environmental uncertainties.

(d) Does not include instrument drift allowance.

(e) Stated uncertainty applied to channel safety function as it is used in accordance with the EOPs. Channel uncertainty at 100% span is within ±10% span.

TABLE 7.5-3

CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR TO MONITOR SIGNIFICANT PLANT PARAMETERS DURING NORMAL OPERATION

Parameter	No. of Channels Available	Indicated Range	Indicator/ Accuracy[a]	Indicator/Recorder	Location	Notes
Nuclear Instrumentation						
1. Source Range						
a. Count rate	2	1 to 10^6 counts/sec	±7% of the linear full scale analog voltage	Both channels indicated. All channels are recorded.	Control console	Deenergize above P-6
b. Startup rate	2	-0.5 to 5.0 decades/min	±7% of the linear full scale analog voltage	Both channels indicated	Control console	Deenergize above P-6
2. Intermediate Range						
a. Flux level	2	8 decades logarithmic 10^{-11} to 10-3 amps overlapping the source by 2 decades	Indicator: -16.8% to +20.2% of input; Recorder: -24% to +30% of input	Both channels indicated. All channels are recorded.	Control console	
b. Startup rate	2	-0.5 to 5.0 decades/min	±7% of the linear full scale analog voltage	Both channels indicated	Control console	

TABLE 7.5-3

Parameter	No. of Channels Available	Indicated Range	Indicator/ Accuracy[a]	Indicator/Recorder	Location	Notes
3. Power Range						
a. Uncompensated ion chamber current (top and bottom uncompensated ion chambers)	4	0 to 5 mA	±1% of full span	All 8 current signals indicated	NIS racks in control room	
b. Average flux of the top and bottom ion chambers	4	0 to 120% of full power	±3% of full power for indication, ±2% for recording	All 4 channels indicated. All channels are recorded.	Control console	
c. Average flux of the top and bottom ion chambers	4	0 to 200% of full power	±2% of full power to 120% ±6% of full power to 200%	All 4 channels recorded	Control board	
d. Flux difference of the top and bottom ion chambers	4	-30 to +30%	±4%	All 4 channels indicated. All channels are recorded.	Control console	
Reactor Coolant System						
1. $T_{average}$ (measured)	1/Loop	530 to 630°F	±4°F	All channels indicated; auctioneered high is recorded	Control console	

TABLE 7.5-3

Parameter	No. of Channels Available	Indicated Range	Indicator/ Accuracy[a]	Indicator/Recorder	Location	Notes
2. ΔT (measured)	1/Loop	0 to 150% of full power ΔT	±4% of full power ΔT	All channels indicated. One channel is selected for recording	Control console	
T_{cold} or T_{hot} (measured, wide-range)	1-T_{hot} and 1-T_{cold} per loop	0 to 700°F	±4%	Both channels recorded	Control board	
3. Overpower ΔT Setpoint	1/Loop	0 to 150% of full power ΔT	±4% of full power ΔT	All channels indicated. One channel is selected for recording	Control board & control console	
4. Overtemperature ΔT Setpoint	1/Loop	0 to 150% of full power ΔT	±4% of full power ΔT	All channels indicated. One channel is selected for recording	Control board & control console	
5. Pressurizer Pressure	4	1250 to 2500 psig	±3.5% of span	All channels indicated, controlling channel recorded	Control board & control console	
6. Pressurizer Level	3	0 to 100%	±6.1% span at 2250 psia[b]	All channels indicated. One channel is selected for recording	Control board & control console	Two-pen recorder used, second pen records reference level signal

TABLE 7.5-3

Parameter	No. of Channels Available	Indicated Range	Indicator/ Accuracy[a]	Indicator/Recorder	Location	Notes
7. Primary Coolant Flow	3/Loop	0 to 120% of rated flow	Repeatability of ±4% of full flow	All channels indicated	Control board	
8. Reactor Coolant Pump Motor Amperes	1/Loop	0 to 400 amp	±2%	All channels indicated	Control board	One channel for each motor
9. RCS Pressure Wide-range	2	0 to 3000 psig	±4%	One channel indicated and one recorded	Control board	
10. Pressurizer Safety Relief Valve Position	3	Open/closed	NA	All channels indicated	Vertical board	
Reactor Control System						
1. Demanded Rod Speed	1	8 to 72 steps/min	±2 steps/min	The one channel is indicated	Control console	
2. Auctioneered $T_{average}$	1	530 to 630°F	±4°F	The one channel is recorded	Control console	The highest of the four T_{avg} channels into the auctioneer will be passed to the recorder
3. $T_{reference}$	1	530 to 630°F	±4°F	The one channel is recorded	Control console	
4. Control Rod Position						If system not available, borate and sample accordingly

TABLE 7.5-3

Parameter	No. of Channels Available	Indicated Range	Indicator/ Accuracy[a]	Indicator/Recorder	Location	Notes
a. Number of steps of demanded rod withdrawal	1/group	0 to 231 steps	±1 step	Each group is indicated.	Control console	These signals are used in conjunction with the measured position signals (4b) to detect deviation of any individual rod from the demanded position. A deviation will actuate an annunciator. An alarm annunciator is actuated when the last rod control bank to be withdrawn reaches the withdrawal limit, when any rod control bank reaches the low insertion limit, and when any rod control bank reaches the low-low insertion limit
b. Full-length rod measured position	1 for each rod	0 to 228 steps	±3 steps at full accuracy, ±6 steps at 1/2 accuracy	Each rod position is indicated	Control board	
Containment System						
1. Containment Pressure (normal range)	4	-5 to +55 psig	±3.5% of full span	All 4 channels indicated	Control board	

TABLE 7.5-3

Parameter	No. of Channels Available	Indicated Range	Indicator/ Accuracy[a]	Indicator/Recorder	Location	Notes
2. Containment Pressure (narrow range)	1	-1 to +1.5 psig	±0.1 psi	Recorded	Control board	
Feedwater and Steam Systems						
1. Auxiliary Feedwater Flow	1/Steam generator	0 to 300 gpm	±10% of full span	All channels indicated	Control board	One channel to measure the flow to each steam generator
2. Steam Generator Level (narrow-range)	3/Steam generator	0 to 100%	±3% of ΔP span (hot) [b]	All channels indicated. The channels used for control are trended indications.	Control board & control console	
3. Steam Generator Level (wide-range)	1/Steam generator full load level	0 to 100%	±3% of ΔP span (hot) [b]	All channels recorded	Control board	
4. Programmed Steam Generator Signal	1 for 4 Steam generators	0 to 100%	±4%	One channel indicated	Control board	
5. Main Feedwater Flow	2/Steam generator	0 to 4.5 million pounds per hour	Within ±10% span when flow >25%	All channels indicated. The channels used for control are trended indications.	Control board	

TABLE 7.5-3

Parameter	No. of Channels Available	Indicated Range	Indicator/ Accuracy[a]	Indicator/Recorder	Location	Notes
6. Magnitude of Signal Controlling Main and Bypass Feedwater Control Valve	1/main 1/bypass	0 to 100% of valve opening	±2%	All channels indicated	Control board & control console	One channel for each main and bypass valve. OPEN/SHUT indication is provided in the control room for each main and bypass feedwater control valve
7. Steam Flow	2/Steam generator	Unit 1: 0 to 4.5 million pounds per hour Unit 2: 0 to 4.5 million pounds per hour	±10% span when flow >20%	All channels indicated. The channels used for control are trended indications.	Control board	Accuracy is equipment capability; however, absolute accuracy depends on calibration against feedwater flow
8. Steam Line Pressure	3/Loop	0 to 1,200 psig	±4.0% of full span	All channels indicated	Control board	
9. Steam Dump Demand Signal	1	0 to 100% equivalent to 0 to 85% max calculated steam flow	±2% span[c]	The one channel is indicated	Control board	OPEN/SHUT indication is provided in the control room for each steam dump valve

TABLE 7.5-3

Parameter	No. of Channels Available	Indicated Range	Indicator/ Accuracy[a]	Indicator/Recorder	Location	Notes
10. Turbine Impulse Chamber Pressure	2	0 to 110% of max calculated turbine load	±3.5% of full span	Both channels indicated	Control board	OPEN/SHUT indication is provided in the control room for each turbine stop valve
11. Condensate Storage Tank Level	1	0 to 100%	±3.5% of full span	Indicator and Recorded	Control board	
Charging and Volume Control						
1. Boric Acid Tank Level	1/Tank	0 to 100%	±3.5% of full span	Indicator	Control board	
2. Emergency Borate Flow	1	0 to 50 gpm	±4% of full span	Indicator	Control board	
3. Charging Pump Flow	1	0 to 200 gpm	±10% span when flow >60 gpm	Indicator	Control console	

(a) Includes channel accuracy and environmental effects.
Changes which are within the stated accuracy band or within the reading accuracy of the indicator are not reflected in this table. Actual values are found in design documents.

(b) Instrument accuracy only. The accuracy statement does not include the effect of density changes in the vessel.

(c) Indicator calibration tolerance.

TABLE 7.5-4

POSTACCIDENT MONITORING PANEL INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR

Parameter	No. of Channels	Indicated Range	Available Indicated Accuracy[j]	Indicator/ Recorder	Comments
1. Reactor vessel level (bottom of vessel to top)	2	0 to 120% (vessel span)	±10% of calibrated span [h]	Recorder/indicator	
2. Reactor plenum level (hot leg pipe to top of vessel)	2	60 to 120% (vessel span)	25.4% of calibrated span total error band [i]	Recorder	
3. Containment pressure (wide-range)	2	-5 to 200 psig	±4% of full span	Recorder	
4. Containment water level (wide-range)	2	64 ft to 98 ft	-8 to +5.5 ft[e]	Recorder	
5. Containment radiation (high-range)	2	1 to 10^7 R/hr	-50% to +60% reading[d]	Recorder/indicator	
6. Plant vent noble gas – normal and extended range	1	10^{-6} to 10^5 µCi/cc	±15% reading based on min. expected sample pressure[f]	Recorder[c]/indicator	
7. Containment hydrogen	2	0 to 10%	±10% of full span	Recorder	
8. Degree of subcooling	2	-40 to +200°F	< 20°F when RCS pressure >900 psig[e] and temperature ≤ 700°F	Recorder (Train A)/ Indicator (Train B)	
9. Plant vent monitor (ALARA)	1	0.1 to 10^7 mR/hr	-40% to +55% reading	Recorder	
10. Gas decay tank pressure	1 per tank	0 to 200 psig	±3.5% of full span[b]	Indicator	

TABLE 7.5-4

Parameter	No. of Channels	Indicated Range	Available Indicated Accuracy[j]	Indicator/ Recorder	Comments
11. Incore temperature	65	0 to 2300°F	±5% of full span[g]	Recorder/indicator	
12. Liquid hold-up tank level	1 per tank	0 to 100%	±5% of full span	Indicator	
13. Containment spray pump discharge flow	1 per pump	0 to 3000 gpm	±5% of full span from 550 to 3000 gpm	Indicator	

(a) Deleted.

(b) Does not include sensor accuracy.

(c) Indicator on RMS panels - Recorder available on EARS until the Central Radiation Processor is available.

(d) Includes detector efficiency.

(e) Accident scenario: HELB inside containment.

(f) Indication accuracy is computed based on the expected detector efficiency. In calculating the offsite dose, however, the actual detector efficiency is taken into account for expected distribution of radioisotopes based on the accident condition.

(g) The stated accuracy is met in the instrument range needed for operator action.

(h) Levels ≤69.3% vessel span (top of hot leg) and coolant temperature ≤650°F.

(i) Top of vessel and coolant temperature 600°F.

(j) Changes which are within the stated accuracy band or within the reading accuracy of the indicator are not reflected in this table. Actual values are found in design documents.

TABLE 7.5-5

INFORMATION REQUIRED ON THE SUBCOOLEDMARGIN MONITORS (SCMMs)

Display	
Information displayed	TSAT - T, P - PSAT
Display type	Digital and analog
Continuous or on demand	Continuous
Single or redundant display	Redundant
Location of displays	Control board, (indicator from SCMM B) PAM 1 (recorder from SCMM A) PAM 3 and 4 (indicator and trend)
Alarms	30°F, 20°F Subcooling from SCMM A or B
Overall uncertainty	<+20°F when RCS pressure >900 psig, temperature ≤ 700°F
Range of display	-40 to +200°F
Qualifications	Seismic
Calculator (Processors)	
Type	Digital (shared with RVLIS)
If process computer is used, specify availability	N/A
Single or redundant calculators	Redundant
Selection logic	High T
Qualifications	Seismic
Calculational technique	Steam tables 0.1 to 3000 psi 150 to 750°F

	TABLE 7.5-5	Sheet 2 of 2

Input

Temperature	4 RTDs, hottest T/C
Temperature	Hottest core exit T/C (per train) and 2 Reactor Hot Leg (per train)
Range of temperature sensors	0 to 700°F (RTDs) (useful 150°F to 700°F) 100 to 2300°F (T/Cs) (useful 150°F to 750°F)
Uncertainty[(a)] of temperature signal	< +12°F (up to 700°F), < +23°F (up to 1200°F)
Qualifications	Seismic, environmental
Pressure	Barton Model 763 or Rosemount Model 1153
Pressure	1 on loop 3 hot leg (train A input) 1 on loop 4 hot leg (train B input)
Range of pressure sensors	0 to 3000 psi
Uncertainty[(a)] of pressure signal	≤±35 psi
Qualifications	Seismic, environmental

(a) Uncertainties must address conditions of forced flow and natural circulation

TABLE 7.5-6

SUMMARY OF COMPLIANCE WITH REGULATORY GUIDE 1.97 REV. 3

TYPE A VARIABLES

RCS cold leg water temperature (see Item 4)

RCS hot leg water temperature (see Item 5)

RCS pressure (see Item 7)

Core exit temperature (see Item 8)

Containment sump water level - wide range (see Item 12)

Containment sump water level - narrow range (see Item 13)

Containment pressure - normal range (see Item 14)

Refueling water storage tank level (see Item 38)

Pressurizer level (see Item 41)

Steam generator level - narrow range (see Item 46)

Steam generator level - wide range (see Item 46)

Steam generator pressure (see Item 47)

Auxiliary feedwater flow (see Item 50)

Condensate storage tank level (see Item 51)

TABLE 7.5-6

Reg Guide 1.97 Variable	RG 1.97 Category		Instrument Range[a]	Envr. Qual[b]	Seismic Qual[c]	QA[d]	Redundant	Power Supply	Control Room	Display at TSC[e]	Display at EOF	Comments
TYPE B VARIABLES												
Reactivity Control												
1. Neutron flux	NRC	1	10^{-6}-100% Full power	Yes	Yes	Yes	Yes	1E	Continuous recording			
	DCPP	1	10^{-8}-100% Full power	Yes	Yes	Yes	Yes	1E	Continuous indication& recording	No	No	Note 27 Note 57
2. Control rod position	NRC	3	Full in or not full in	No	No	Yes	No	--	Continuous indication			
	DCPP	3	Full range indication	No	No	Yes	No	Non-1E	Continuous indication	Yes	Yes	
3. RCS soluble boron concentration												Note 1
4. RCS cold leg water temp.	NRC	1	50-700°F	Yes	Yes	Yes	Yes	1E	Continuous recording			
	DCPP	1	50-700°F	Yes	Yes	Yes	Yes	1E	Continuous recording	Yes	Yes	Note 47 Note 48 Note 58
Core Cooling												
5. RCS hot leg water temp	NRC	1	50-700°F	Yes	Yes	Yes	Yes	1E	Continuous recording			
	DCPP	1	0-700°F	Yes	Yes	Yes	Yes	1E	Continuous recording	Yes	Yes	Note 47 Note 48 Note 58
6. RCS cold leg water temp (see Item 4)												
7. RCS pressure	NRC	1	0-3000 psig	Yes	Yes	Yes	Yes	1E	Continuous recording			
	DCPP	1	0-3000 psig	Yes	Yes	Yes	Yes	1E	Continuous indication & recording	Yes	Yes	Note 27 Note 48
8. Core exit temperature	NRC	1	200-2300°F	Yes	Yes	Yes	Yes	1E	Continuous recording			
	DCPP	1	0-2300°F	Yes	Yes	Yes	Yes	1E	Continuous indication & recording	Yes	Yes	Note 48

TABLE 7.5-6

Reg Guide 1.97 Variable	RG 1.97 Category	Instrument Range[a]	Envr. Qual[b]	Seismic Qual[c]	QA[d]	Redundant	Power Supply	Control Room	Display at TSC[e]	Display at EOF	Comments
9. Coolant level in reactor	NRC 1	Bottom of hot leg to top of vessel	Yes	Yes	Yes	Yes	1E	Continuous recording			
	DCPP 1	Bottom to top of vessel	Yes	Yes	Yes	Yes	1E	Continuous indication & recording	Yes	Yes	
10. Degrees of subcooling	NRC 2	200°F subcooling to 35°F superheat	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP 2	200°F subcooling to 40°F superheat	Yes	Yes	Yes	Yes	1E	Continuous indication & recording	Yes	Yes	Note 46
Maintaining Reactor Coolant System Integrity											
11. RCS pressure (see Item 7)											
12. Containment sump water level (WR)	NRC 1	Plant specific	Yes	Yes	Yes	Yes	1E	Continuous recording			
	DCPP 1	64 ft (CNT bottom) to 98 ft	Yes	Yes	Yes	Yes	1E	Continuous recording	Yes	Yes	Note 48
13. Containment sump water level (NR)		Sump depth	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP 1	88.5-96.6 ft	Yes	Yes	Yes	Yes	1E	Continuous indication	No	No	Note 48
14. Containment pressure	NRC 1	-5 psig to 3 times design pressure	Yes	Yes	Yes	Yes	1E	Continuous recording			
Normal range	DCPP 1	-5 to +55 psig	Yes	Yes	Yes	Yes	1E	Continuous indication	Yes	Yes	Note 48
Wide range	DCPP 1	-5 to 200 psig	Yes	Yes	Yes	Yes	1E	Continuous recording	Yes	Yes	N0te 39
Maintaining Containment Integrity											
15. Containment isolation valve position	NRC 1	Closed-not closed	Yes	Yes	Yes	Yes	1E	Continuous recording			
	DCPP 1	Closed-not closed	Yes	Yes	Yes	Yes	1E	Indication	Yes	Yes	Note 28 Note 36 Note 49 Note 59
16. Containment pressure (see Item 14)											

TABLE 7.5-6

Reg Guide 1.97 Variable	RG 1.97 Category	Instrument Range[a]	Envr. Qual[b]	Seismic Qual[c]	QA[d]	Redundant	Power Supply	Control Room	Display at TSC[e]	Display at EOF	Comments
TYPE C VARIABLES											
Fuel Cladding											
17. Core exit temperature (see Item 8)											
18. Radioactivity concentration in circulating primary coolant (see Note 18)											
19. Analysis of primary coolant - gamma spectrum (seeNote 55)											
Reactor Coolant Pressure Boundary											
20. RCS pressure (see Item 7)											
21. Containment pressure (see Item 14)											
22. Containment sump water level (see Items 12 and 13)											
23. Containment area radiation (see Item 65)											
24. Effl. radio-activity-noble gas effl. from condenser air removal sys. exhaust	NRC	3	10^{-6} to 10^{-2} μCi/cc	No	No	Yes	No	-	Recording		
	DCPP	3	10^{-4} to 3 μCi/cc	No	No	Yes	No	non-1E	Continuous indication, recording	Yes	Yes	Note 3 Note 34
Containment											
25. RCS pressure (see Item 7)											
26. Containment hydrogen concentration	NRC	3	0-10%	No	No	Yes	No	Highly Reliable	Continuous recording		
	DCPP	3	0-10%	No	No	Yes	Yes	Highly Reliable	Continuous recording	Yes	Yes	
27. Containment pressure (see Item 14)											
28. Containment effluent radioactivity - noble gases from identified release points (see Item 67)											
29. Effluent radioactivity - noble gases from buildings or areas where penetrations and hatches are located (see Item 67)											

TABLE 7.5-6

Reg Guide 1.97 Variable	RG 1.97 Category	Instrument Range[a]	Envr. Qual[b]	Seismic Qual[c]	QA[d]	Redundant	Power Supply	Control Room	Display at TSC[e]	Display at EOF	Comments
TYPE D VARIABLES											
Residual Heat Removal System											
30. RHR system flow	NRC 2	0-110% design flow	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP 2	0-1500 gpm (Lo) 0-5000 gpm (Hi) 0-7000gpm (HL)	Yes	No	Yes	No	1E	Continuous indication	Yes	Yes	Note 50
31. RHR heat exchanger outlet temp.	NRC 2	40-350°F	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP 2	50-400°F	Yes	No	Yes	No	1E	Continuous recording	Yes	Yes	Note 6
32. Accumulator tank level	NRC 2	10%-90% volume	No	No	Yes	No	Highly reliable	Continuous indication			Note 51
	DCPP 3	10%-90% volume	No	No	Yes	No	Highly reliable, non-1E	Continuous indication	No	No	
33. Accumulator tank pressure	NRC 2	0-750 psig	No	No	Yes	No	Highly reliable	Continuous indication			Note 51
	DCPP 3	0-700 psig	No	No	Yes	Yes	Highly reliable, non-1E	Continuous indication	Yes	Yes	Note 7
34. Accumulator isolation valve position	NRC 2	Closed or open	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP 3	Closed or open	No	No	Yes	No	1E	Continuous indication	No	No	Note 32
35. Boric acid charging flow (charging inj header flow)	NRC 2	0-110% design	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP 2	0-1000 gpm	Yes	No	Yes	No	1E	Continuous indication	Yes	Yes	
36. Flow in HPI system (SI pump disch.)	NRC 2	0-110% design	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP 2	0-750 gpm	Yes	No	Yes	No	1E	Continuous indication	Yes	Yes	
37. Flow in LPI system - RHR system (see Item 30)											

TABLE 7.5-6

Reg Guide 1.97 Variable	RG 1.97 Category		Instrument Range[a]	Envr. Qual[b]	Seismic Qual[c]	QA[d]	Redundant	Power Supply	Control Room	Display at TSC[e]	Display at EOF	Comments
38. Refueling water storage tank level	NRC	2	Top to bottom	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP	1	0-100%	Yes	Yes	Yes	Yes	1E	Continuous indication	Yes	Yes	Note 8 Note 28 Note 41 Note 48
Primary Coolant System												
39. Reactor coolant pump status	NRC	3	Motor current	No	No	Yes	No	--	Continuous indication			
	DCPP	3	Motor current 0-400 amp	No	No	Yes	No	non-1E	Continuous indication	Yes	Yes	Note 21
40. Primary system safety relief valve position	NRC	2	Closed-not closed	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP	2	Closed-not closed	Yes	Yes	Yes	No	1E	Continuous indication	Yes	Yes	Note 9 Note 46
41. Pressurizer level	NRC	1	Bottom to top	Yes	Yes	Yes	Yes	1E	Continuous recording			
	DCPP	1	0-100%	Yes	Yes	Yes	Yes	1E	Continuous indication	Yes	Yes	Note 8 Note 28 Note 33 Note 48
42. Pressurizer heater status	NRC	2	Electric current	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP	2	Electric power 0-600 kW	Yes	No	Yes	No	1E	Continuous indication	Yes	Yes	Note 45
43. Quench tank (PRT) level	NRC	3	Top to bottom	No	No	Yes	No	--	Continuous indication			
	DCPP	3	0-100%	No	No	Yes	No	Highly reliable, non-1E	Continuous indication	Yes	Yes	Note 8
44. Quench tank (PRT) temperature	NRC	3	50-750°F	No	No	Yes	No	--	Continuous indication			
	DCPP	3	50-350°F	No	No	Yes	No	Highly reliable, non-1E	Continuous indication	Yes	Yes	Note 10

TABLE 7.5-6

Reg Guide 1.97 Variable	RG 1.97 Category		Instrument Range[a]	Envr. Qual[b]	Seismic Qual[c]	QA[d]	Redundant	Power Supply	Control Room	Display at TSC[e]	Display at EOF	Comments
45. Quench tank (PRT) pressure	NRC	3	0 design	No	No	Yes	No	--	Continuous indication			
	DCPP	3	0-100 psig	No	No	Yes	No	Highly reliable, non-1E	Continuous indication	Yes	Yes	
Secondary System (Steam Generator)												
46. Steam generator level	NRC	1	From tube sheet to separators	Yes	Yes	Yes	Yes	1E	Continuous recording			
Narrow range	DCPP	1	From within the transition cone to separators.	Yes	Yes	Yes	Yes	1E	Continuous indication	Yes	Yes	Note 26 Note 28 Note 48
Wide range	DCPP	1	From 12 inches above tube sheet to separators	Yes	Yes	Yes	Yes	1E	Continuous recording	Yes	Yes	Note 26 Note 36 Note 47 Note 48
47. Steam generator pressure	NRC	2	From atm. press. to 20% above the lowest safety valve setting	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP	1	0-1200 psig	Yes	Yes	Yes	Yes	1E	Continuous indication	Yes	Yes	Note 11 Note 28 Note 41 Note 48
48. Main steam flow	NRC	2	--	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP	2	0-4.5 x 10^6 lb/hr	Yes	No	Yes	No	1E	Continuous indication	Yes	Yes	
49. Main feedwater flow	NRC	3	0-110% design	No	No	Yes	No	--	Continuous indication			
	DCPP	3	0-4.5 x 10^6 lb/hr	No	No	Yes	No	1E	Continuous indication	Yes	Yes	
Auxiliary Feedwater or Emergency Feedwater System												
50. Auxiliary or emergency feedwater flow	NRC	2	0-110% design	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP	1	0-300 gpm	Yes	Yes	Yes	Yes	1E	Continuous indication	Yes	Yes	Note 26 Note 28 Note 47 Note 48 Note 52

TABLE 7.5-6

Reg Guide 1.97 Variable	RG 1.97 Category		Instrument Range[a]	Envr. Qual[b]	Seismic Qual[c]	QA[d]	Redundant	Power Supply	Control Room	Display at TSC[e]	Display at EOF	Comments
51. Condensate storage tank	NRC	1	Plant specific	Yes	Yes	Yes	Yes	1E	Continuous recording			
	DCPP	1	0-100%	Yes	Yes	Yes	Yes	1E	Continuous recording	Yes	Yes	Note 37 Note 48
Containment Cooling Systems												
52. Containment spray flow	NRC	2	0-110% design	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP	2	0-3000 gpm	Yes	No	Yes	No	1E	Continuous indication	No	No	
53. Heat removal by containment fan heat removal system	NRC	2	Plant specific	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP	2	See Note 12	Yes	No	Yes	No	1E	Continuous indication	Yes	Yes	Note 12
54. Containment atmosphere temperature	NRC	2	40-400°F	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP	2	0-400°F	Yes	No	Yes	Yes	1E	Continuous indication	No	No	
55. Containment sump water temperature	NRC	2	50-250°F	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP	2	0-300°F	Yes	No	Yes	Yes	1E	Continuous indication	No	No	
Chemical and Volume Control System												
56. Makeup flow-in	NRC	2	0-110% design	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP	2	0-50 gpm 0-200 gpm	Yes	No	Yes	No	1E	Continuous indication	Yes	Yes	Note 53
57. Letdown flow-out	NRC	2	0-110% design	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP	2	0-200 gpm	Yes	No	Yes	No	1E	Continuous indication	Yes	Yes	
58. Volume control tank level	NRC	2	Top to bottom	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP	2	0-100%	Yes	No	Yes	No	1E	Continuous indication	Yes	Yes	Note 8

TABLE 7.5-6

Reg Guide 1.97 Variable	RG 1.97 Category		Instrument Range[a]	Envr. Qual[b]	Seismic Qual[c]	QA[d]	Redundant	Power Supply	Control Room	Display at TSC[e]	Display at EOF	Comments
Cooling Water System												
59. CCW temp. to ESF system	NRC	2	40-200°F	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP	2	0-200°F	Yes	No	Yes	No	1E	Continuous indication	Yes	Yes	
60. CCW flow to EFS system	NRC	2	0-110% design	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP	2	0-12,000 gpm	Yes	No	Yes	No	1E	Continuous indication	Yes	Yes	
Radwaste Systems												
61. High level radioactive liquid tank level	NRC	3	Top to bottom	No	No	Yes	No	--	Continuous indication			
	DCPP	3	0-100%	No	No	Yes	No	1E	Continuous indication	No	No	Yes Yes
62. Radioactive gas holdup tank pressure	NRC	3	0-150% design	No	No	Yes	No	--	Continuous indication			
	DCPP	3	0-200 psig	No	No	Yes	No	1E	Continuous indication	Yes	Yes	Note 54
Ventilation Systems												
63. Emergency ventilation damper position	NRC	2	Open-closed	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP	2	Open-closed	Yes	No	Yes	No	1E	Continuous indication	No	No	Note 24
Power Supplies												
64. Status of standby power and other emergency sources	NRC	2	Voltages, currents	Yes	No	Yes	No	Highly reliable	Continuous indication			
	DCPP	2	Voltages, currents	Yes	No	Yes	No	1E	Continuous indication	Yes	Yes	Note 13 Note 43
TYPE E VARIABLES												
Containment Radiation												
65. Containment area radiation - high range	NRC	1	1 to 10^7 R/hr	Yes	Yes	Yes	Yes	1E	Continuous recording			
	DCPP	1	1 to 10^7 R/hr	Yes	Yes	Yes	Yes	1E	Continuous recording	Yes	Yes	

TABLE 7.5-6

Reg Guide 1.97 Variable	RG 1.97 Category		Instrument Range[a]	Envr. Qual[b]	Seismic Qual[c]	QA[d]	Redundant	Power Supply	Control Room	Display at TSC[e]	Display at EOF	Comments
Area Radiation												
66. Radiation exposure rate (inside bldgs or areas)	NRC	3	10^{-1} to 10^{4} mR/hr	No	No	Yes	No	--	Recording			
	DCPP	3	10^{-1} to 10^{4} mR/hr	No	No	Yes	No	Non-1E	Local indication and alarm	No	No	Note 5 Note 34
Airborne Radioactive Materials Released From Plant												
67. Noble gases and vent flow rate: Containment or purge effluent (see Note 14) Reactor shield building annulus (see Note 14) Auxiliary building (see Note 14) Condenser air removal system exhaust (see Item 24)												
Noble gases from common-plant vent + discharging any of above releases (including cont. purge)	NRC	2	10^{-6} to 10^{4} μCi/cc	Yes	No	Yes	No	Highly reliable	Continuous recording			
	DCPP	2	10^{-6} to 10^{4} μCi/cc	Yes	No	Yes	No	Highly reliable	Continuous indication, recording	Yes	Yes	Note 34
Plant vent flow	NRC	2	0-110% design	Yes	No	Yes	No	Highly reliable	Continuous recording			
	DCPP	2	0-30x10^{4} cfm	Yes	No	Yes	No	Highly reliable	Continuous recording			
Vent from steam generator safety relief valves or atmospheric dump valves	NRC	2	10^{-1} to 10^{3} μCi/cc	Yes	No	Yes	No	Highly reliable	Continuous recording			
	DCPP	2	10^{-1} to 10^{3} μCi/cc	Yes	No	Yes	No	1E	Continuous recording			
All other identified release points (see Note 56)												
68. Particulates and halogens	NRC	3	10^{-3} to 10^{2} μCi/cc	No	No	Yes	No	--	Recording			
	DCPP	2	Note 15	Yes	No	Yes	No	Highly reliable	Continuous indication, recording	Yes	Yes	Note 15 Note 34

TABLE 7.5-6

Reg Guide 1.97 Variable	RG 1.97 Category	Instrument Range[a]	Envr. Qual[b]	Seismic Qual[c]	QA[d]	Redundant	Power Supply	Control Room	Display at TSC[e]	Display at EOF	Comments
Environs Radiation and Radioactivity											
69. Airborne radiohalogens & particulates (portable with on-site analysis)	NRC 3	10^{-9} to 10^{-3} µCi/cc	No	No	Yes	No	--	--			
	DCPP 3	10^{-9} to 10^{-3} µCi/cc	No	No	Yes	No	--	--	--	--	
70. Plant and environs radiation (portable instrumentation)	NRC -	As specified in RG 1.97, Rev. 3	No	No	Yes	No	--	--			
	DCPP -	As specified in RG 1.97, Rev. 3	No	No	Yes	No	--	--	--	--	
71. Plant and environs radioactivity (portable instrumentation)	NRC 3	Isotopic analysis	No	No	Yes	No	--	--			
	DCPP 3	Multichannel gamma-ray spectrometer	No	No	Yes	No	--	--	--	--	Note 16
Meteorology											
72.	NRC	As specified in RG 1.97, Rev. 3	No	No		No	--	Recording			
	DCPP	As specified in RG 1.97, Rev. 3	No	No		No	non-1E	Indication, recording	Yes	Yes	Note 38 Note 40
Accident Sampling Capability											
73.											Note 55

(a) Instrument Range - Where the NRC and Diablo Canyon instrument ranges are not directly comparable, the Diablo Canyon ranges meet or exceed the NRC ranges, unless otherwise noted

(b) EQ (Environmental Qualification) - A "Yes" entry means that the instrumentation complies with 10 CFR 50.49. A "No" entry means there is no specific provision for environmental qualification of this instrumentation

(c) Seismic Qualification - A "Yes" entry means that the instrumentation complies with Regulatory Guide (RG) 1.100. A "No" entry means there are no specific provisions for seismic qualification of this instrument.

(d) QA (Quality Assurance) - A "Yes" entry means that the instrumentation complies with the applicable quality assurance provisions contained in RG 1.97 for the category of the instrument.

(e) This column represents the TSC and the Alternate TSC/OSC.

1. Elimination of the boron concentration monitoring system (BCMS) and utilization of the post-accident monitoring system (PASS) was approved by NRC letter dated December 4, 2000. Elimination of the PASS was approved by License Amendments 149 (Unit 1) and 149 (Unit 2), dated July 13, 2001

2. Deleted in Revision 4.

3. Installed range is adequate since air ejector exhaust is routed to the plant vent.

4. Deleted in Revision 11.

5. The Reg Guide 1.97 instrument range is erroneously stated as 10-1 to 104 R/hr for this variable.

6. Installed range is adequate for the Diablo Canyon site as the RHR outlet temperature is not expected to be less than 50°F.

7. Installed range is adequate. Tank pressure limited to 700 psig by relief valve.

8. Zero to 100% indicates usable volume of tank.

9. Position indication for safety valves is provided by acoustic monitors and by position switches for the power operated relief valves.

10. Quench tank pressure is limited to 100 psig by a rupture disk, so water temperature cannot exceed the saturation temperature at 100 psig, or 338°F. Therefore, the range of 50-350°F is adequate.

11. Installed ranged is adequate. Redundant instrumentation is installed and all safety valves lift before 1200 psig. The relieving capability of the safety valves is greater than rated steam flow. Hence, pressure cannot physically reach 1200 psig.

12. Containment fan cooler unit (CFCU) operation is verified by white monitor lights (that confirm proper CFCU response to ESF actuation), CFCU ammeters, and CFCU motor speed indicating lights. Category 1 containment pressure (Variable 14) and Category 2 containment temperature (Variable 54) provide an overall indication of CFCU system performance. CFCU operation is an indirect measurement of these containment parameters that are of primary importance to plant operators.

13. Category 2 indications for vital 4 KV voltage, EDG wattage and amperage, 4 KV/480 V transformer primary side amperage, 480 V voltage, and battery voltage and amperage are provided. All indications are Class 1E except for battery voltage and amperage.

14. Not needed if effluent discharges through common plant vent.

15. The particulate monitor has a range of 10^{-12} to 10^{-7} μCi.cc. Additional range is achieved through use of particulate filters installed on postaccident grab sampling equipment. The iodine monitor has a range of 10^{-7} to 10^{-2} μCi/cc. Additional range is provided by postaccident grab sampling equipment up to 102 μCi/cc.

16. An offsite laboratory with gamma spectroscopy equipment is available for environmental analysis.

17. Deleted in Revision 4.

18. Category 1 instrumentation to monitor radiation level in circulating primary coolant is not provided. Routine reactor coolant sampling verifies fuel cladding integrity during normal operation. During an accident, rapid assessment of cladding failures can be obtained from the Category 1 containment high range area radiation monitors in conjunction with a DCPP emergency procedure titled, “Core Damage Assessment Procedure”.

19. Deleted in Revision 4.

20. Deleted in Revision 7.

21. Display at TSC, Alternate TSC/OSC, and EOF is circuit breaker status.

22. Deleted in Revision 4.

23. Deleted in Revision 4.

24. Most of the critical damper positions are indicated at the TSC, Alternate TSC/OSC, and EOF, enough to assure that the system is working as expected.

25. Deleted in Revision 11.

26. The narrow range steam generator level is the key variable for monitoring secondary heat sink if the water level is within the narrow range span. If the water level is below the narrow range span, auxiliary feedwater flow in conjunction with steam generator wide range level meet the Category 1 requirements for monitoring steam generator status.

27. Category 1 recording is provided for one channel.

28. This post-accident monitoring data is recorded/stored in the Transient Recording System (TRS). The TRS provides the data storage and recall functions associated with ERFDS. The TRS is a Class II, highly reliable computer system with uninterruptible battery backed power.

29. Deleted in Revision 11.

30. Deleted in Revision 7.

31. Deleted in Revision 7.

32. Accumulator isolation valve position indication is Category 3. Power is removed from the valve actuator during normal operation; hence, following an accident the valve is known to be in its correct (open) position. Power to these valves may be manually restored following a LOCA, but operation of the valves, and thus the position indication, is not critical for post-LOCA accident mitigation or plant shutdown. Power is also restored to these valves during certain (non-LOCA) emergency conditions when operation of the valves is required. However, the position switches will not be exposed to a harsh environment under these conditions, so the position switches will remain operable.

33. Pressurizer water level indication meets Category 1 requirements; the recorder for this variable is Instrument Class II and is common for all the channels. This combination of Category 1 indication and Class II recording is sufficient to meet the Regulatory Guide requirements.

34. Recording as necessary on EARS, ERFDS and/or TRS.

35. Deleted.

36. Redundant channels are powered from different Class 1E power supplies; however, electrical cabling does not meet separation criteria.

37. Zero to 100% indicates contained volume of tank.

38. The plant process computer is used as the indicating device to display meteorological instrument signals. In addition, a Type E, Category 3 multi-point recorder is located at each meteorological tower building.

39. Normal range containment pressure channels provide indication from -5 to +55 psig. Wide range channels provide recording from -5 to 200 psig, but only the positive pressure range is credited as Category 1. Recording negative pressures is not required as negative pressures would not be the range of interest during an accident when containment pressures can be expected to increase.

40. Control room indication is processed for display upon demand.

41. Recording of this Category 2 variable which PG&E classifies as Category 1 is not provided because variable trending does not provide essential information.

42. DCPP instrument ranges are in terms of CPM or mR/hr., with conversion factors and graphs that allow easy conversion.

43. 480V and 4160V bus voltages are indicated on an indicator scale of 0 to 150; actual voltage is determined by applying a scaling factor (4 for the 480V bus, and 35 for the 4160V bus).

44. The recording capability associated with this variable is provided by a Category 3 multi-channel recorder.

45. Pressurizer heater power consumption is indicated, for groups 2 and 3 only, at CC-1 and (via ERFDS) the TSC and EOF. Although not credited for RG 1.97, circuit breaker status is also available at the TSC and EOF for groups 1 and 4.

46. Seismic qualification in accordance with NUREG-0737 requirements.

47. Redundancy is provided on a system basis as opposed to a per loop basis. Loop 1 and 2 channels are redundant to loop 3 and 4 channels.

48. Instrument channels are designated as Type A variables as they provide information required for operator action.

49. CIV position indication redundancy is provided on a per penetration basis as opposed to a per valve basis.

50. Each RHR train is monitored by 0-1500 gpm and 0-5000 gpm flow indicators in all modes of RHR operation except hot leg recirculation. The 0-7000 gpm flow indication monitors RHR system flow in the hot leg recirculation mode of operation.

51. In accordance with NRC guidance subsequent to issuance of Reg Guide 1.97, environmental qualification is not required for the accumulator tank pressure and level channels.

52. If flow exceeds instrument range, steam generator level instruments provide the necessary information to monitor steam generator status.

53. Emergency borate flowpath to charging pump suction monitored by 0-50 gpm flow indication. Charging pump discharge flow monitored by 0-200 gpm flow indication.

54. Gas decay tank pressure indication spans 0-200 psig. Control system maintains normal tank pressure in the range of 0-100 psig and relief valves limit tank pressure to 150 psig.

55. Post-accident sampling system requirements were deleted by License Amendments (LAs) 149 (Unit 1) and 149 (Unit 2), dated July 13, 2001. Three commitments were established to meet the conditions of LAs 149/149 to (1) maintain contingency plans for obtaining and analyzing highly radioactive samples of reactor coolant, containment sump, and containment atmosphere (T36279), (2) maintain a capability for classifying fuel damage events at the Alert level threshold (T36280), and (3) maintain the capability to monitor radioactive iodines that have been released to offsite environs (T36281).

56. The steam generator blowdown tank vent is a potential noble gas release point that is not discharged through the plant vent. However, the blowdown tank is only used intermittently and is automatically isolated on high radiation in the liquid blowdown effluent. This is not a credible noble gas release path. Grab sample capability is provided for the blowdown tank vent effluent.

57. Source, intermediate and power range nuclear instrumentation provide displays at TSC and EOF.

58. RCS loop 1 hot leg and cold leg temperature channels are not environmentally qualified for outside-containment line break accidents.

59. Containment isolation valves credited for RG 1.97 Category 1 position indication are defined as only those containment isolation valves that receive a Phase A, Phase B or containment ventilation isolation signal.

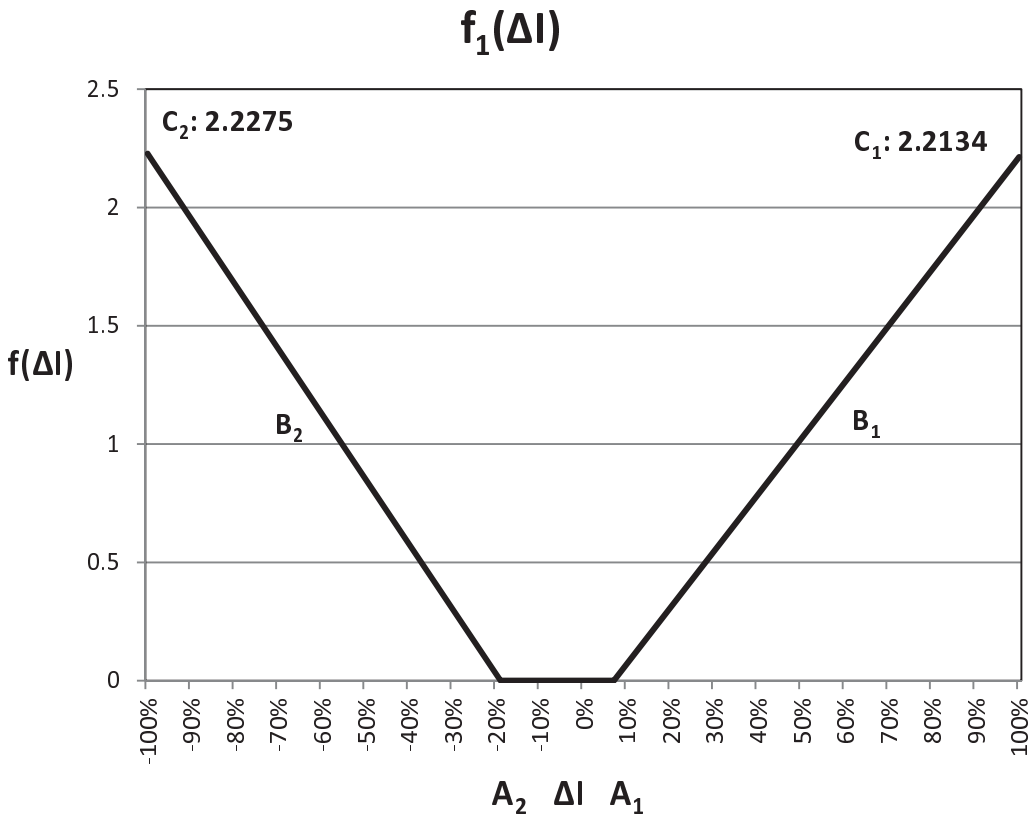
TABLE 7.7-1

PLANT CONTROL SYSTEM INTERLOCKS

Designation	Derivation	Function
C-1	1/2 Neutron flux (intermediate range) above setpoint	Blocks automatic and manual control rod withdrawal
C-2	1/4 Nuclear power (power range) above setpoint	Blocks automatic and manual control rod withdrawal
C-3	2/4 Overtemperature ΔT above setpoint	Blocks automatic and manual control rod withdrawal Actuates turbine runback via load reference Defeats remote load dispatching
C-4	2/4 Overpower ΔT above setpoint	Blocks automatic and manual control rod withdrawal Actuates turbine runback via load reference Defeats remote load dispatching
C-5	1/1 Turbine impulse chamber pressure below setpoint	Defeats remote load dispatching Blocks automatic control rod withdrawal
C-7A	1/1 Time derivative (absolute value) of turbine impulse chamber pressure (decreases only) above setpoint	Makes 40 percent condenser dump valves available for either tripping or modulation

TABLE 7.7-1

Designation	Derivation	Function
C-7B	1/1 Time derivative (absolute value) of turbine impulse chamber pressure (decreases only) above setpoint	Makes 10 percent atmospheric dump valves available for either tripping or modulation
P-4	Reactor trip	Blocks steam dump control via load rejection T_{avg} controller Makes 40 percent condenser dump valves available for either tripping or modulation Blocks 10 percent atmospheric dump valves Unblocks steam dump control via reactor trip T_{avg} controller
C-9	Any condenser pressure above setpoint or All circulating water pump breakers open	Blocks steam dump to condenser
C-11	1/1 Bank D control rod position above setpoint	Blocks automatic rod withdrawal



ΔI	–	NEUTRON FLUX DIFFERENCE BETWEEN UPPER AND LOWER LONG ION CHAMBERS
A_1 to A_2	–	LIMIT OF F(ΔI) DEADBAND (+7 TO -19)
B_1 and B_2	–	SLOPE OF RAMP; DETERMINES RATE AT WHICH FUNCTION REACHES ITS MAXIMUM VALUE ONCE DEADBAND IS EXCEEDED
C_1 and C_2	–	MAGNITUDE OF MAXIMUM VALUE THE FUNCTION MAY ATTAIN

NOTE:
- NOTE 1 IN TABLE 3.3.1-1 OF THE TECHNICAL SPECIFICATIONS GIVES THE REDUCTION FUNCTIONS FOR THE OTΔT AND OPΔT SETPOINTS.
- $F_2(\Delta I) = 0$ FOR ALL VALUES OF ΔI

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UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 7.2-2 SETPOINT REDUCTION FUNCTION FOR OVERPOWER AND OVERPRESSURE ΔT TRIPS

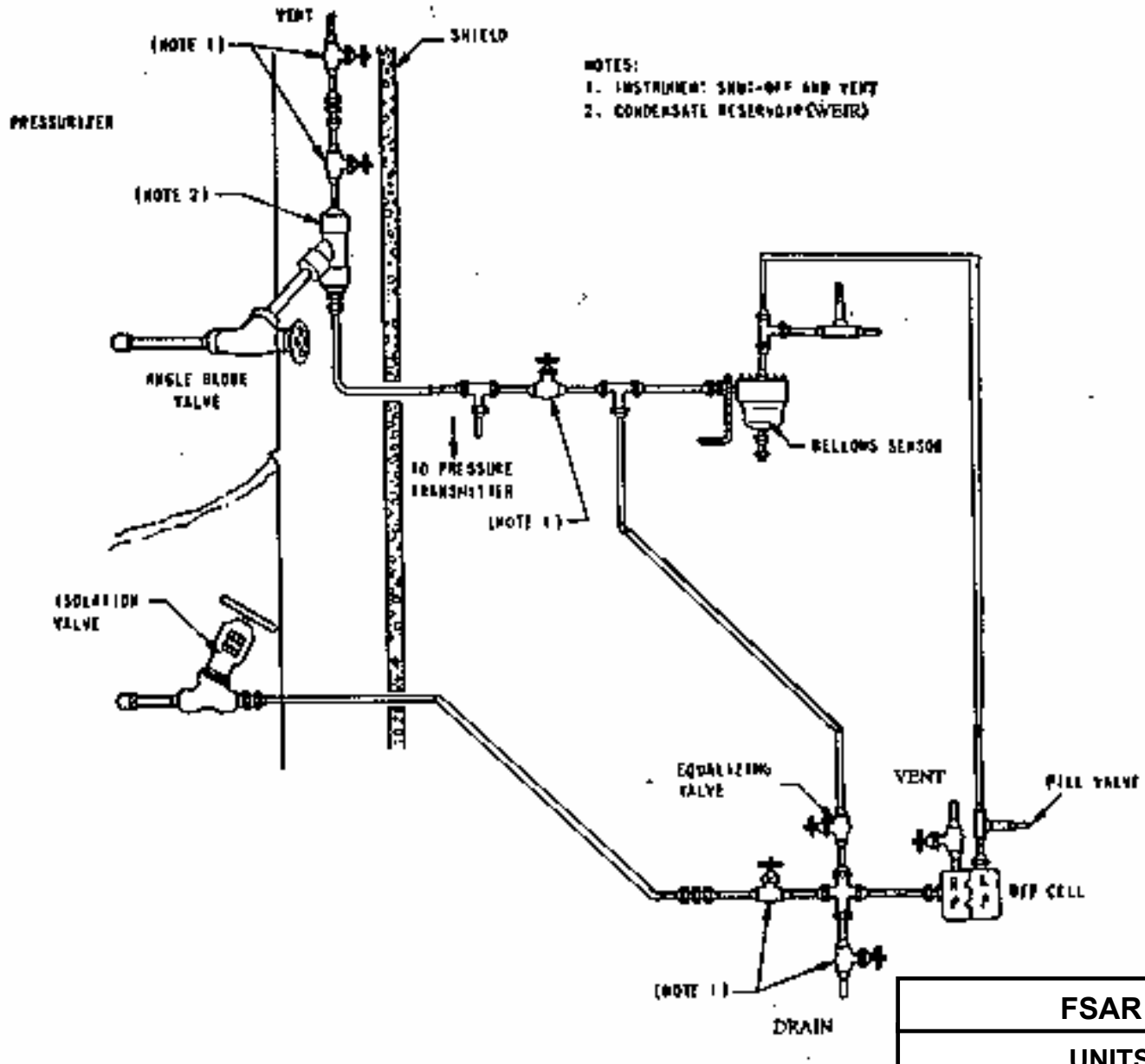

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FIGURE 7.2-4 PRESSURIZER SEALED REFERENCE LEG LEVEL SYSTEM

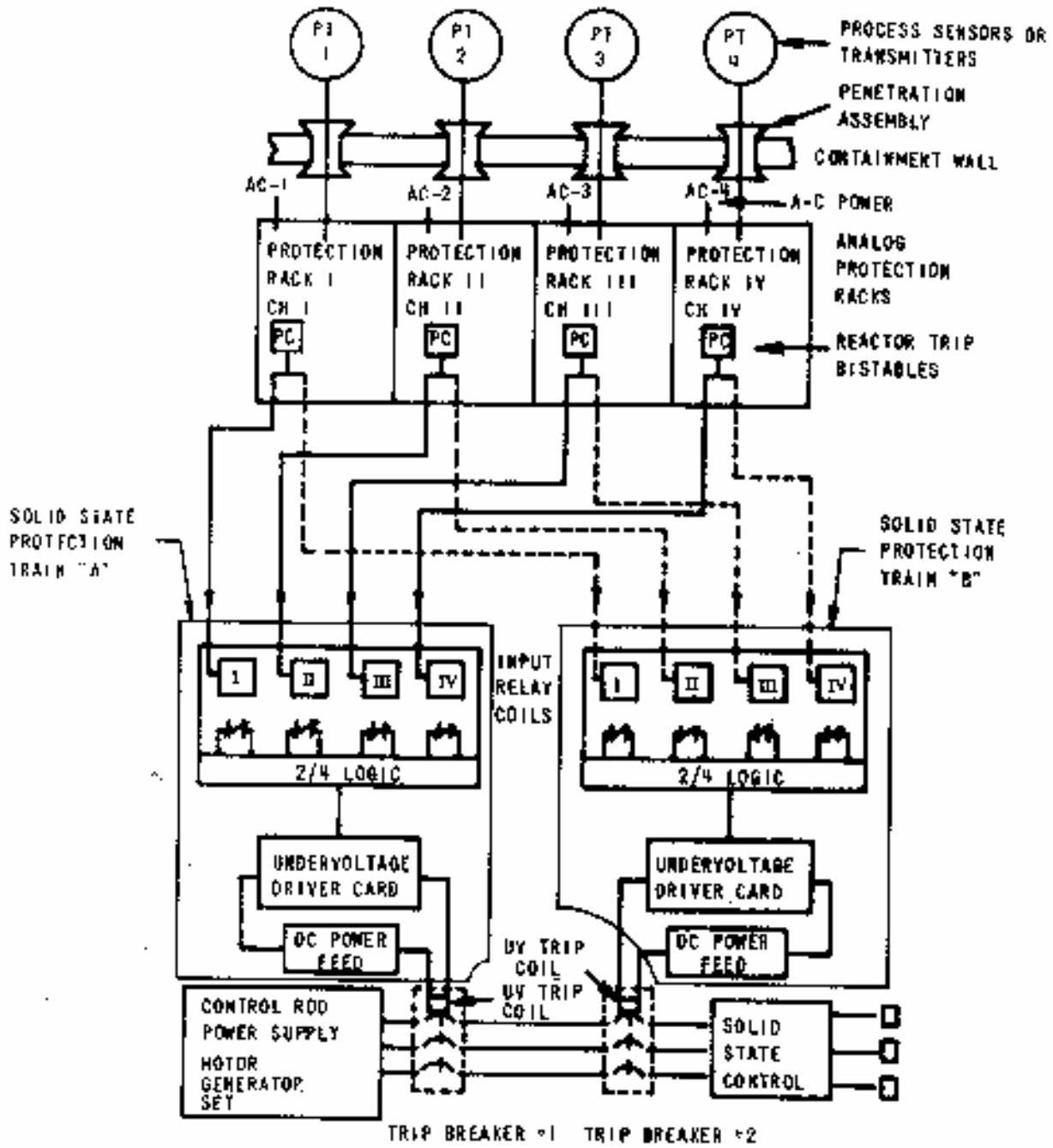

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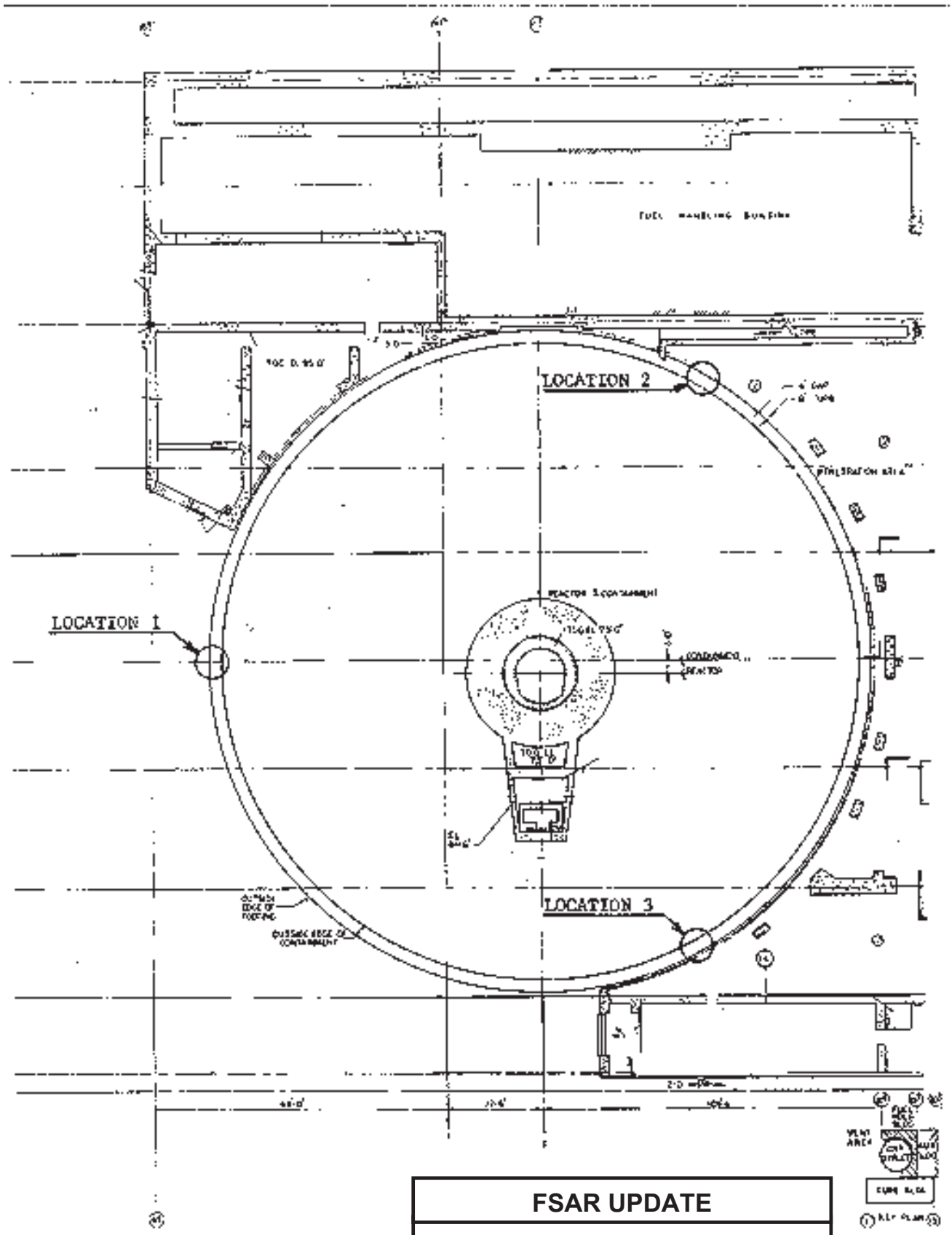
FIGURE 7.2-5 DESIGN TO ACHIEVE ISOLATION BETWEEN CHANNELS



NOTE: THIS FIGURE IS FOR UNIT 1, UNIT 2 IS OPPOSITE HAND

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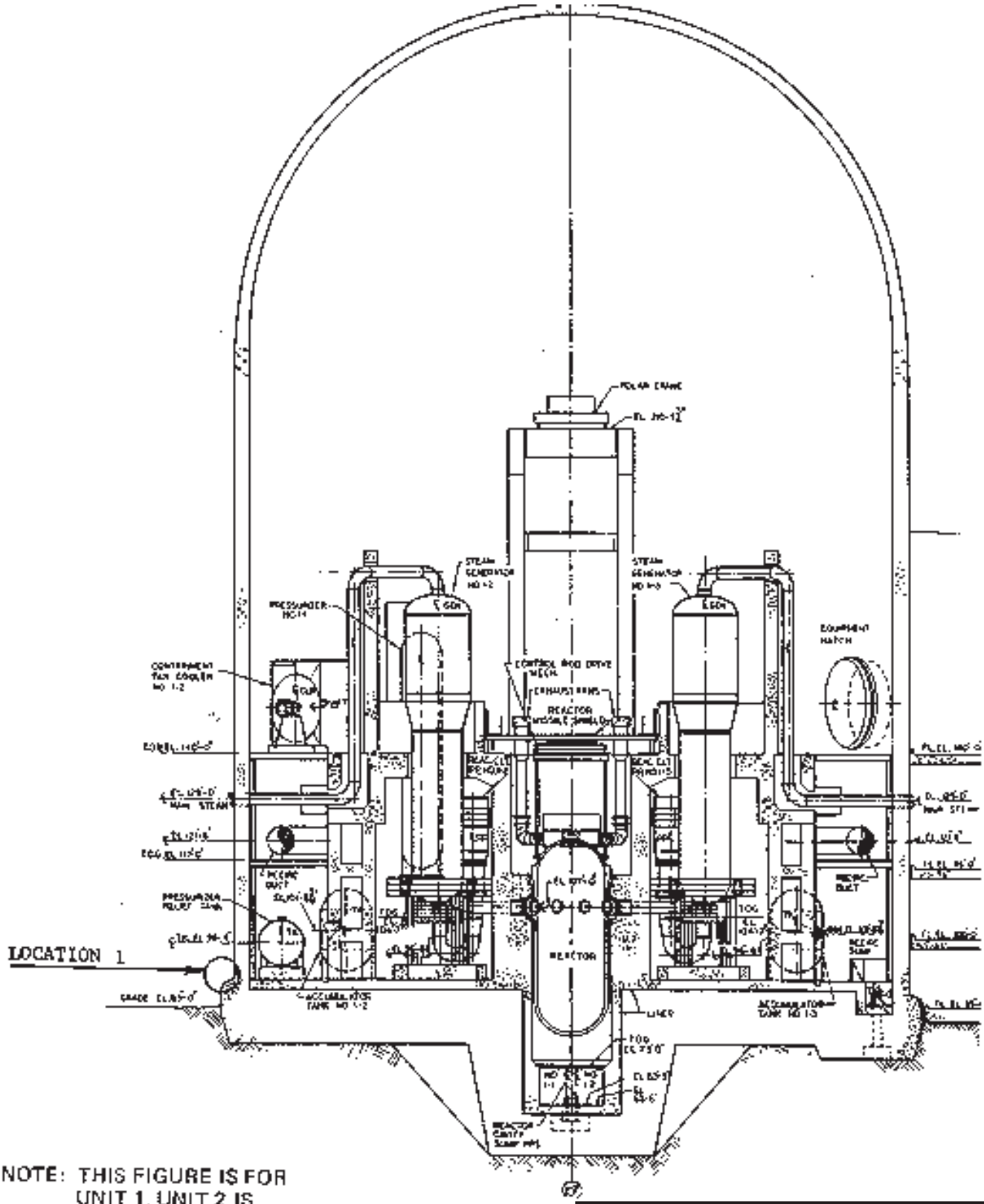
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 7.2-6 (Sheet 1 of 2) SEISMIC SENSOR LOCATIONS



NOTE: THIS FIGURE IS FOR UNIT 1, UNIT 2 IS OPPOSITE HAND

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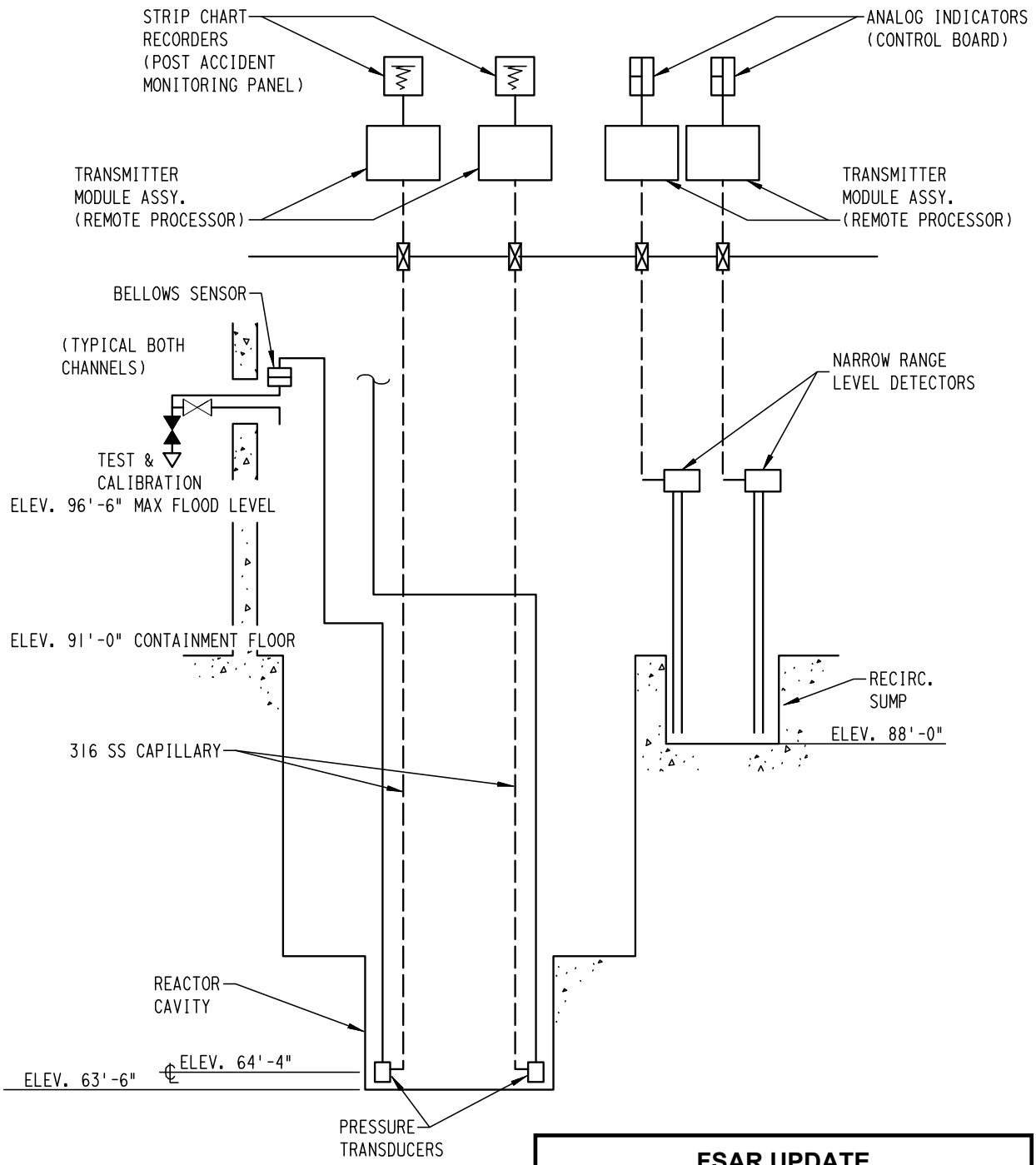
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 7.2-6 (Sheet 2 of 2)
SEISMIC SENSOR LOCATIONS



NOTE:
Refer to Figure 7.5-1B for
Unit 2 Wide-Range Diagram

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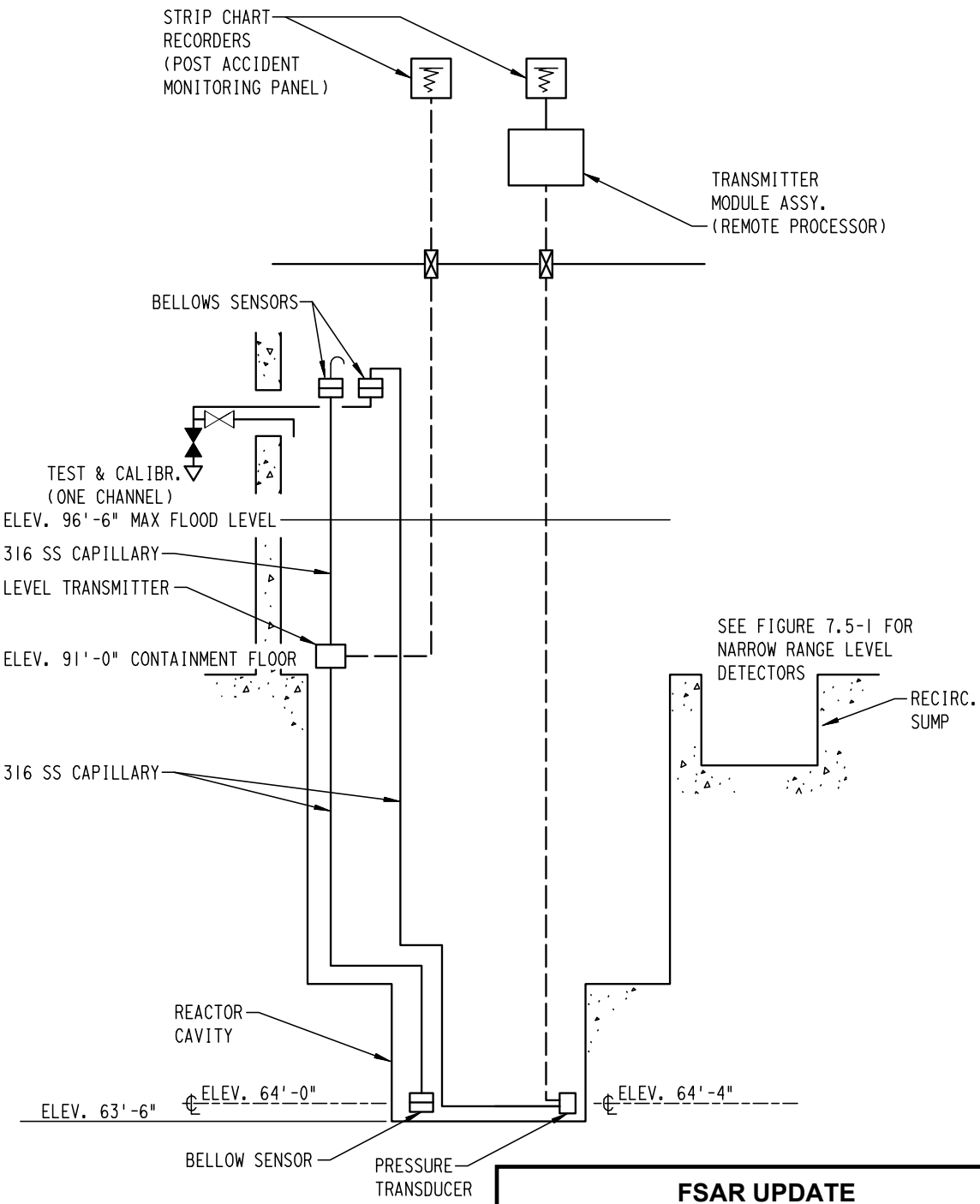
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 7.5-1
CONTAINMENT WATER LEVEL INDICATION
(NOT AN ACTUAL LAYOUT)



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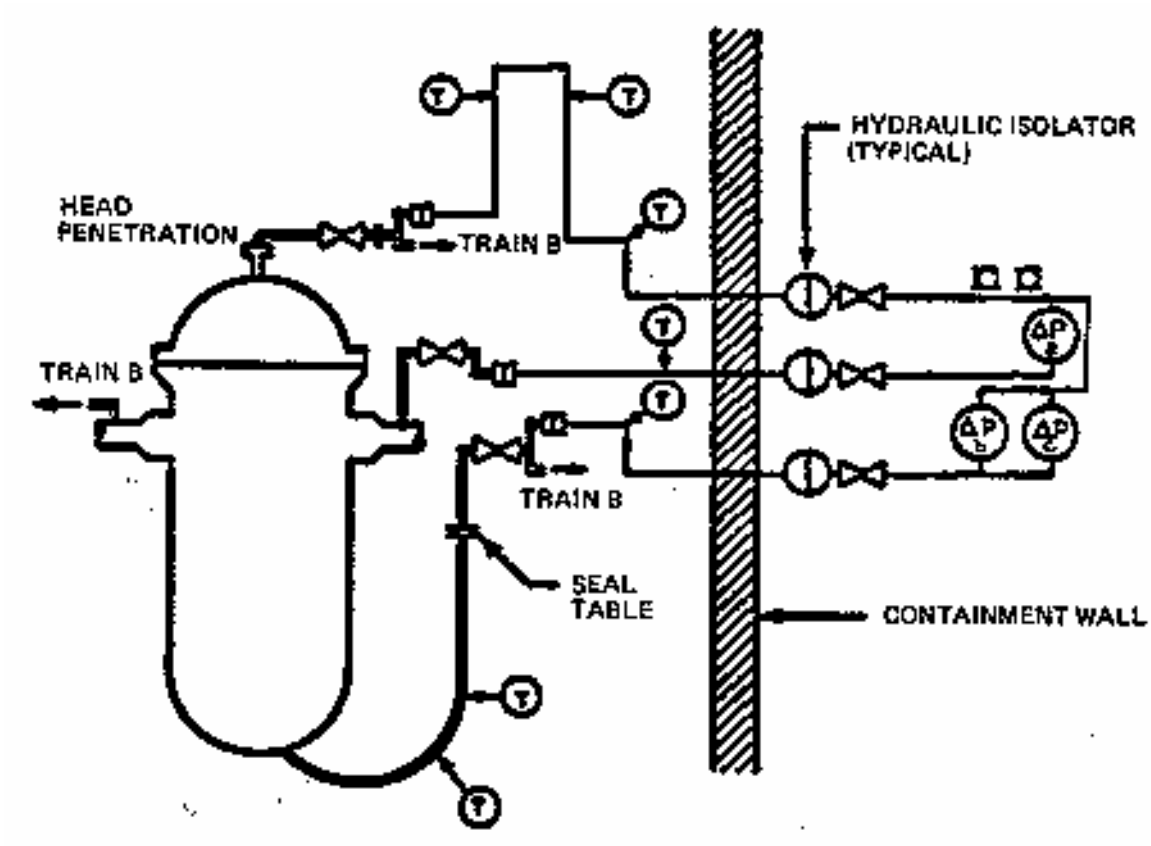
UNIT 2
DIABLO CANYON SITE

FIGURE 7.5-1B

CONTAINMENT WATER LEVEL WIDE-RANGE INDICATION WITH INSTALLED SPARE WIDE-RANGE LEVEL TRANSMITTER IN SERVICE (NOT AN ACTUAL LAYOUT)



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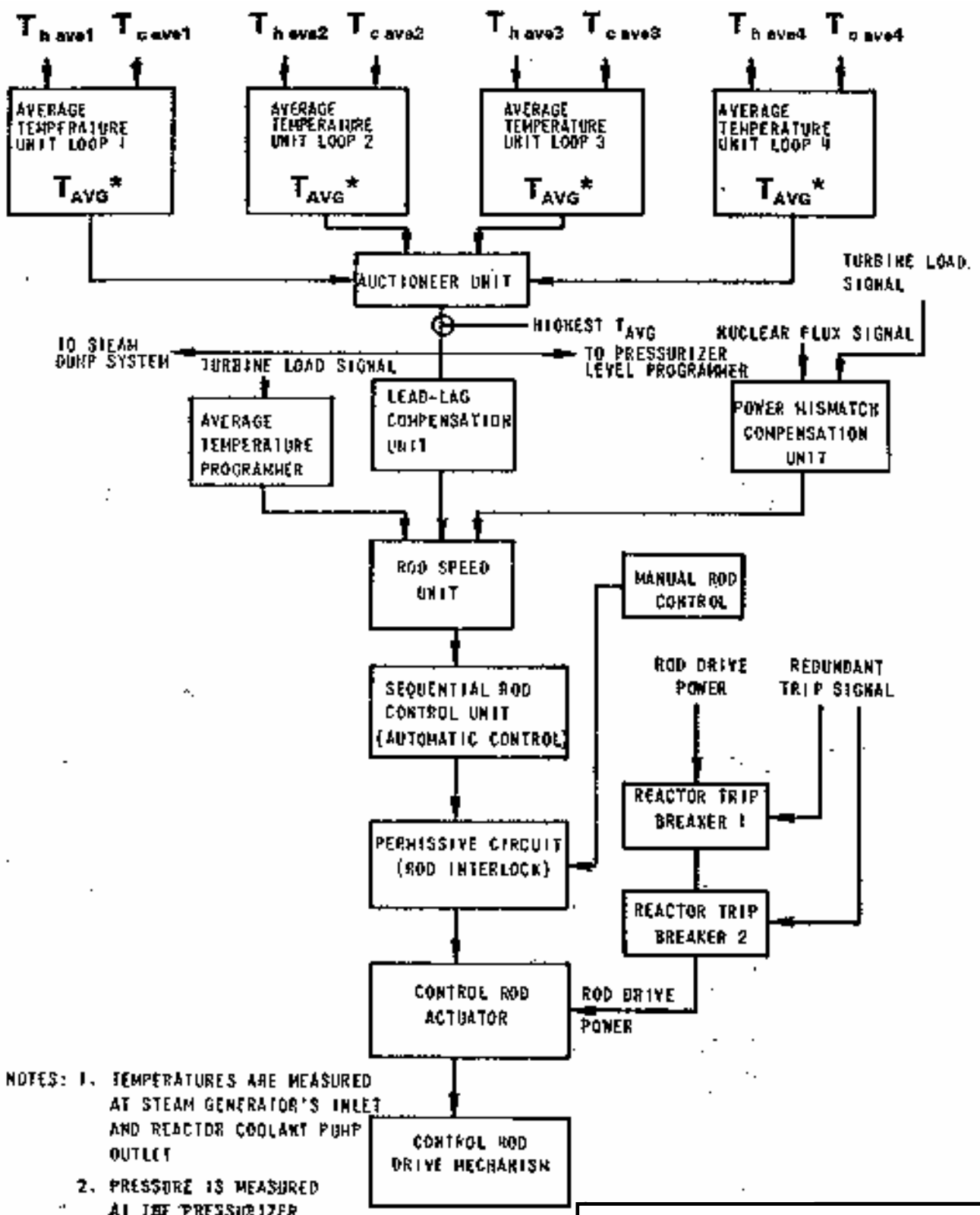
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 7.5-2 REACTOR VESSEL LEVEL INSTRUMENTATION PROCESS CONNECTION SCHEMATIC (TRAIN A)



NOTES: 1. TEMPERATURES ARE MEASURED AT STEAM GENERATOR'S INLET AND REACTOR COOLANT PUMP OUTLET

2. PRESSURE IS MEASURED AT THE PRESSURIZER

$$* \quad T_{AVG} = \frac{T_{h\,ave\,i} + T_{c\,ave\,i}}{2}$$

i = Loop numbers 1 → 4

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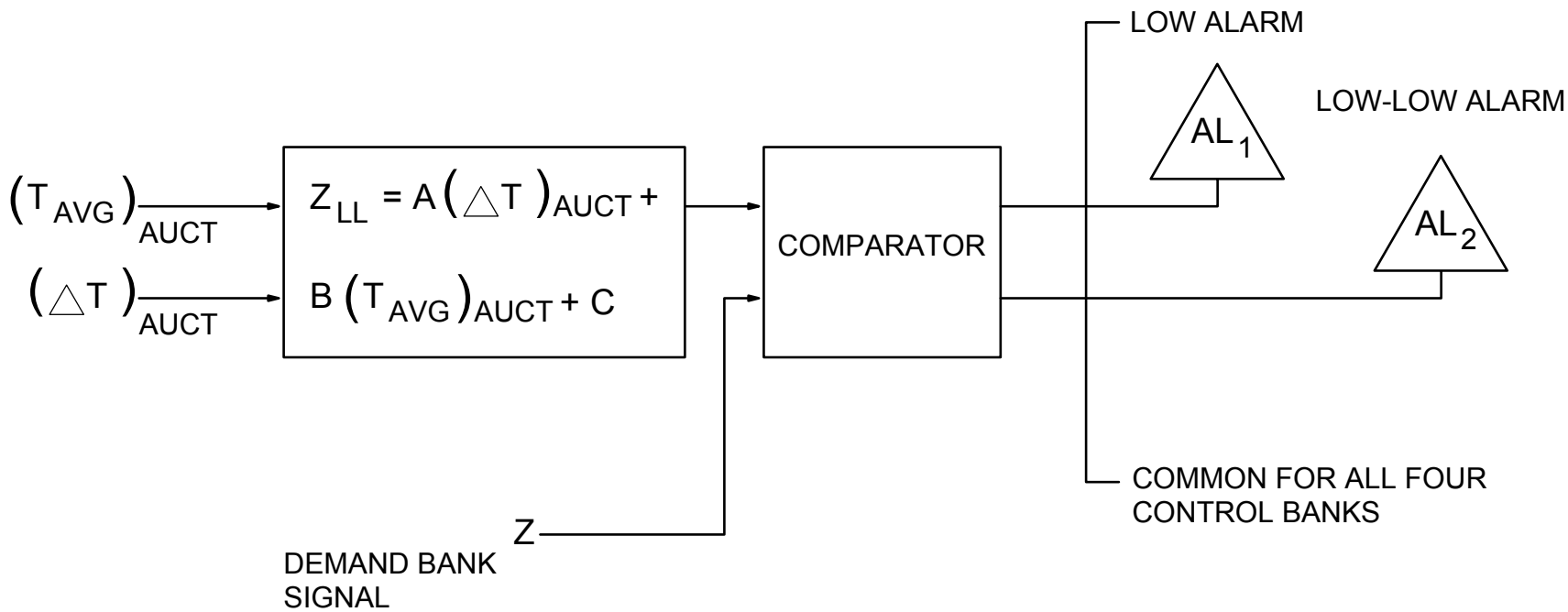
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 7.7-1
SIMPLIFIED BLOCK DIAGRAM OF REACTOR CONTROL SYSTEM



TYPICAL OF ONE CONTROL BANK

NOTES:
1. The PPC is used for the comparator network.
2. Comparison is done for all control banks.

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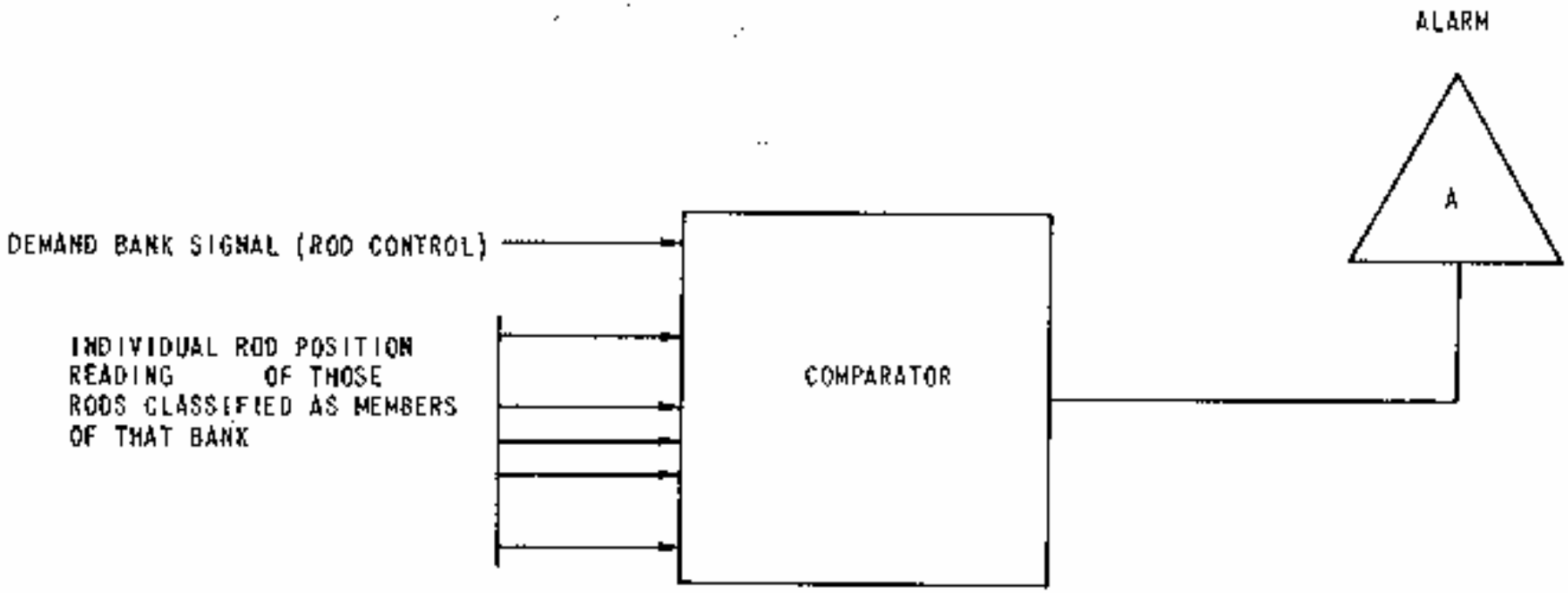
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 7.7-2 CONTROL BANK ROD INSERTION MONIOTOR

Revision 16 June 2005



NOTE:
1. DIGITAL OR ANALOG SIGNALS MAY BE USED FOR THE COMPARATOR COMPUTER INPUTS.
2. THE COMPARATOR WILL ENERGIZE THE ALARM IF THERE EXISTS A POSITION DIFFERENCE GREATER THAN A PRESENT LIMIT BETWEEN ANY INDIVIDUAL ROD AND THE DEMAND BANK SIGNAL.
3. COMPARISON IS INDIVIDUALLY DONE FOR ALL CONTROL BANKS.

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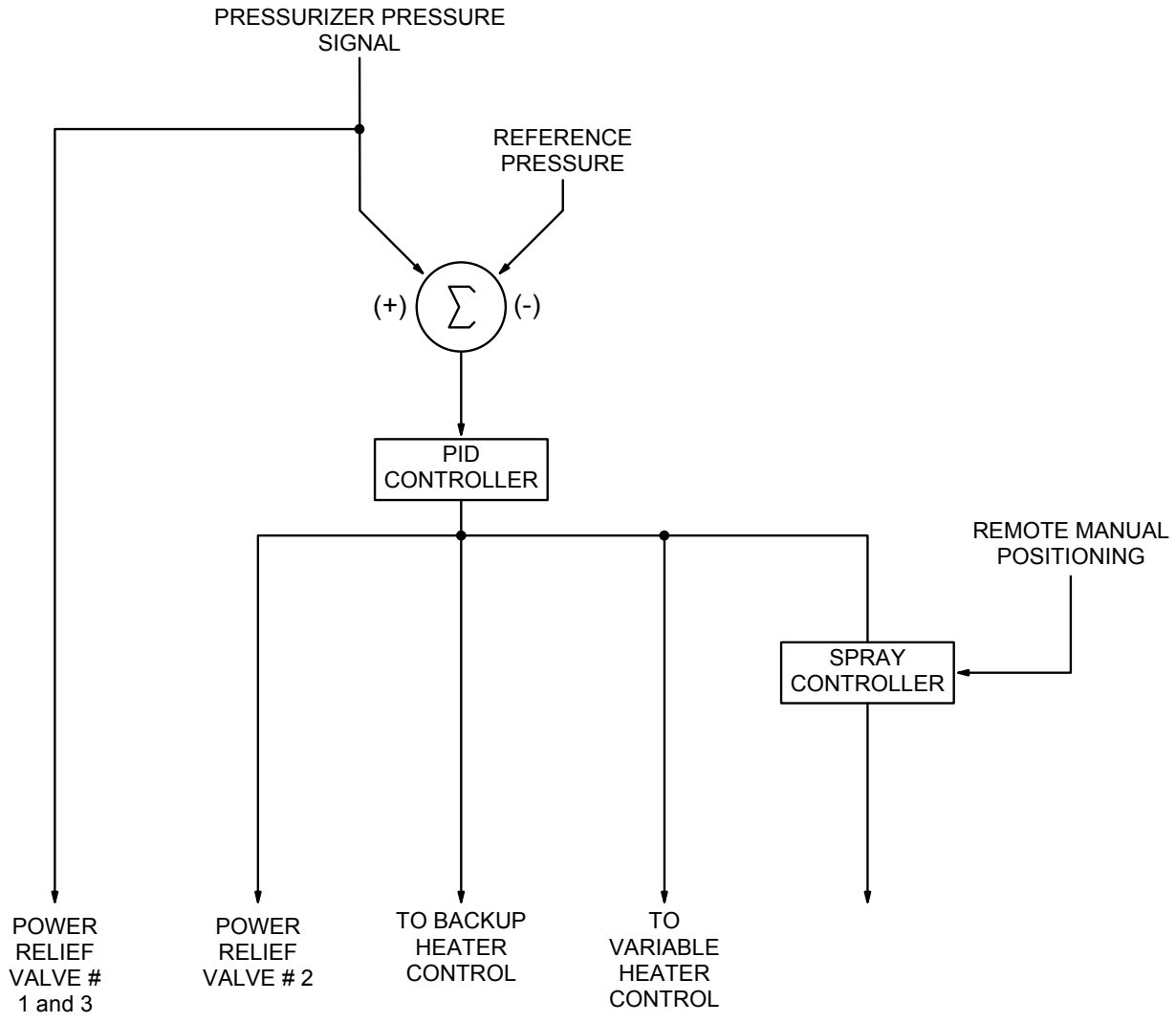
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 7.7-3

ROD DEVIATION COMPARATOR



Note:
Valve 1 = PCV 456
Valve 2 = PCV 474
Valve 3 = PCV 455C

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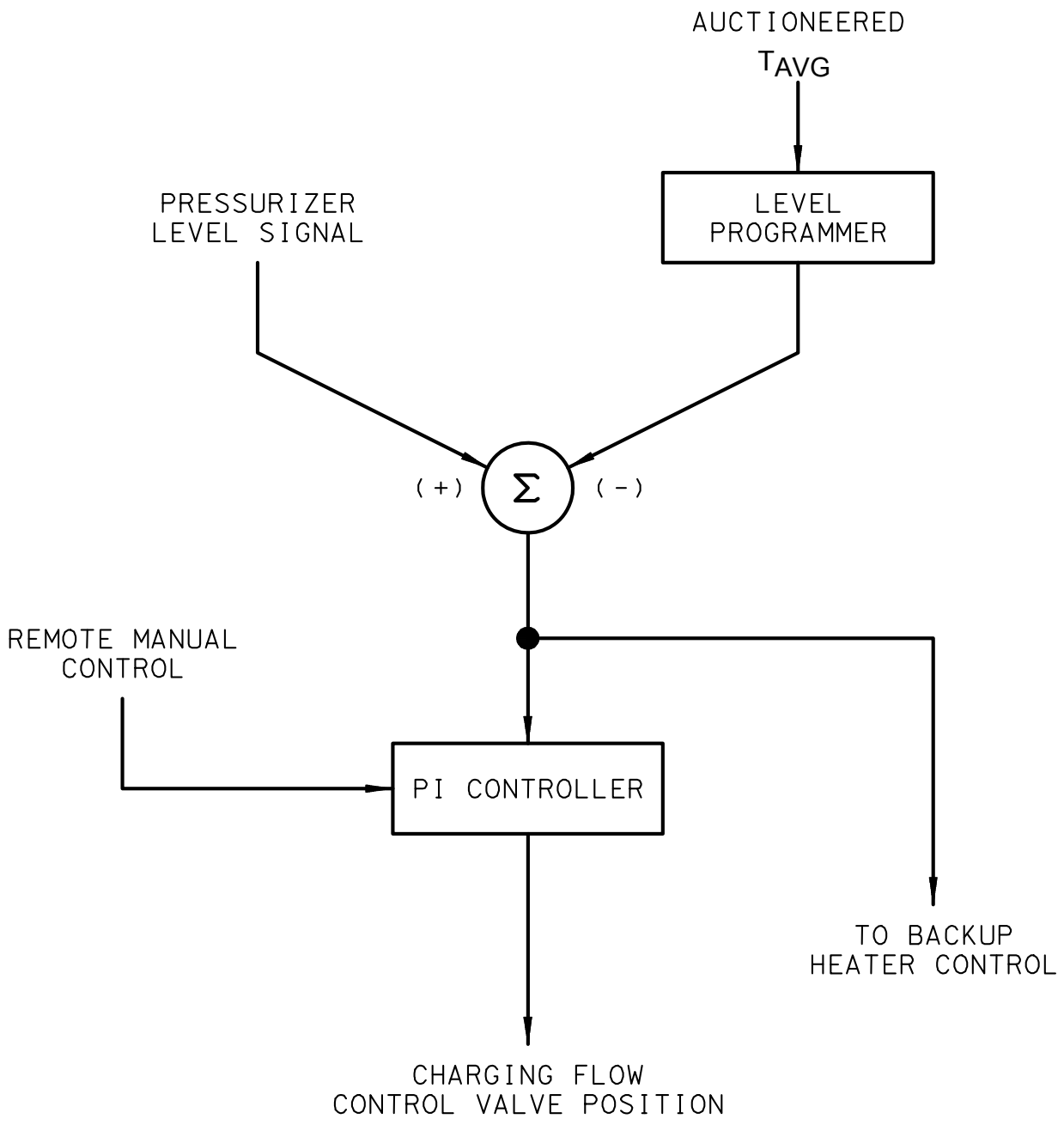
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 7.7-4
BLOCK DIAGRAM OF PRESSURIZER PRESSURE CONTROL SYSTEM

Revision 16 June 2005



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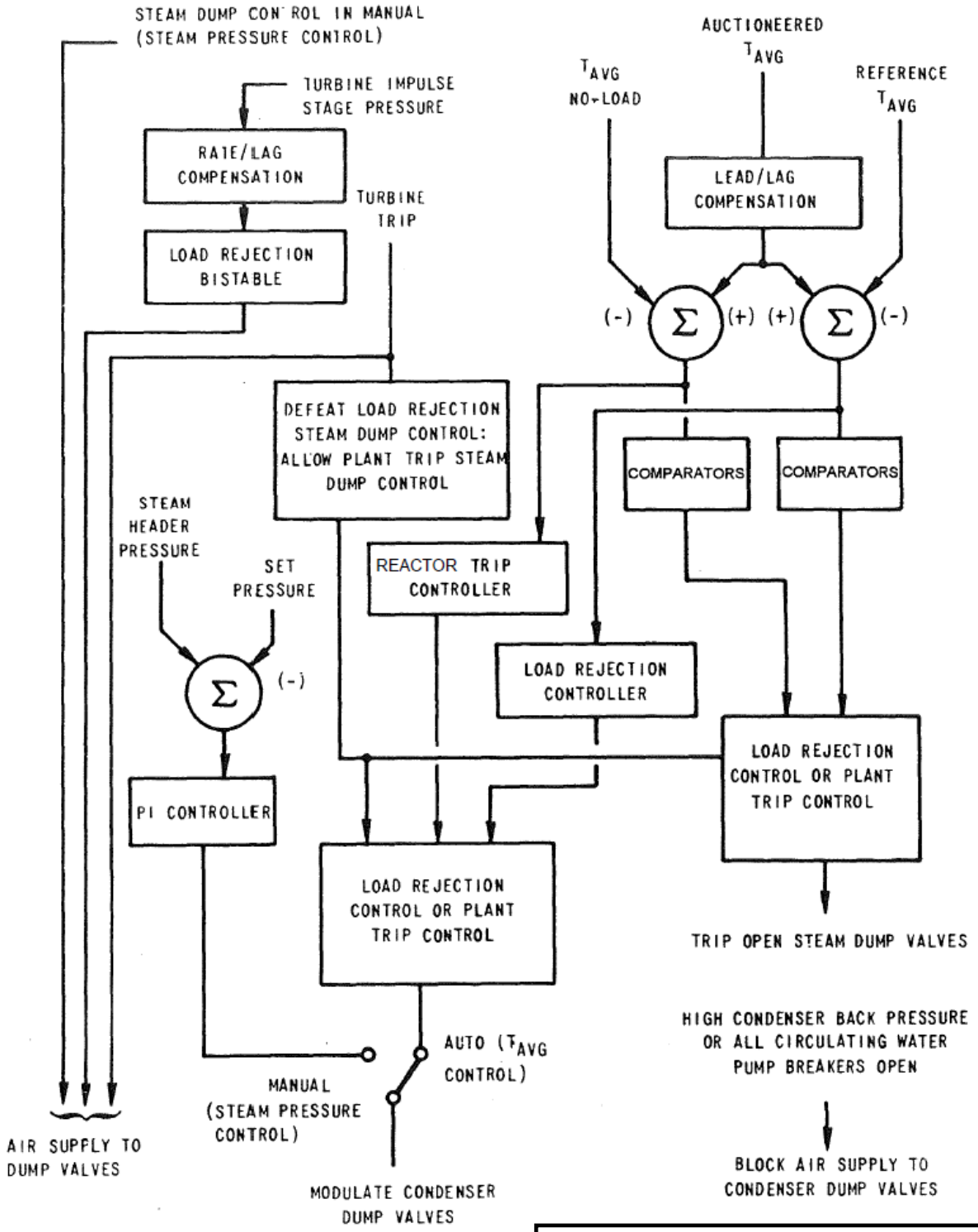
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 7.7-5
BLOCK DIAGRAM OF PRESSURIZER LEVEL CONTROL SYSTEM

Revision 21 September 2013



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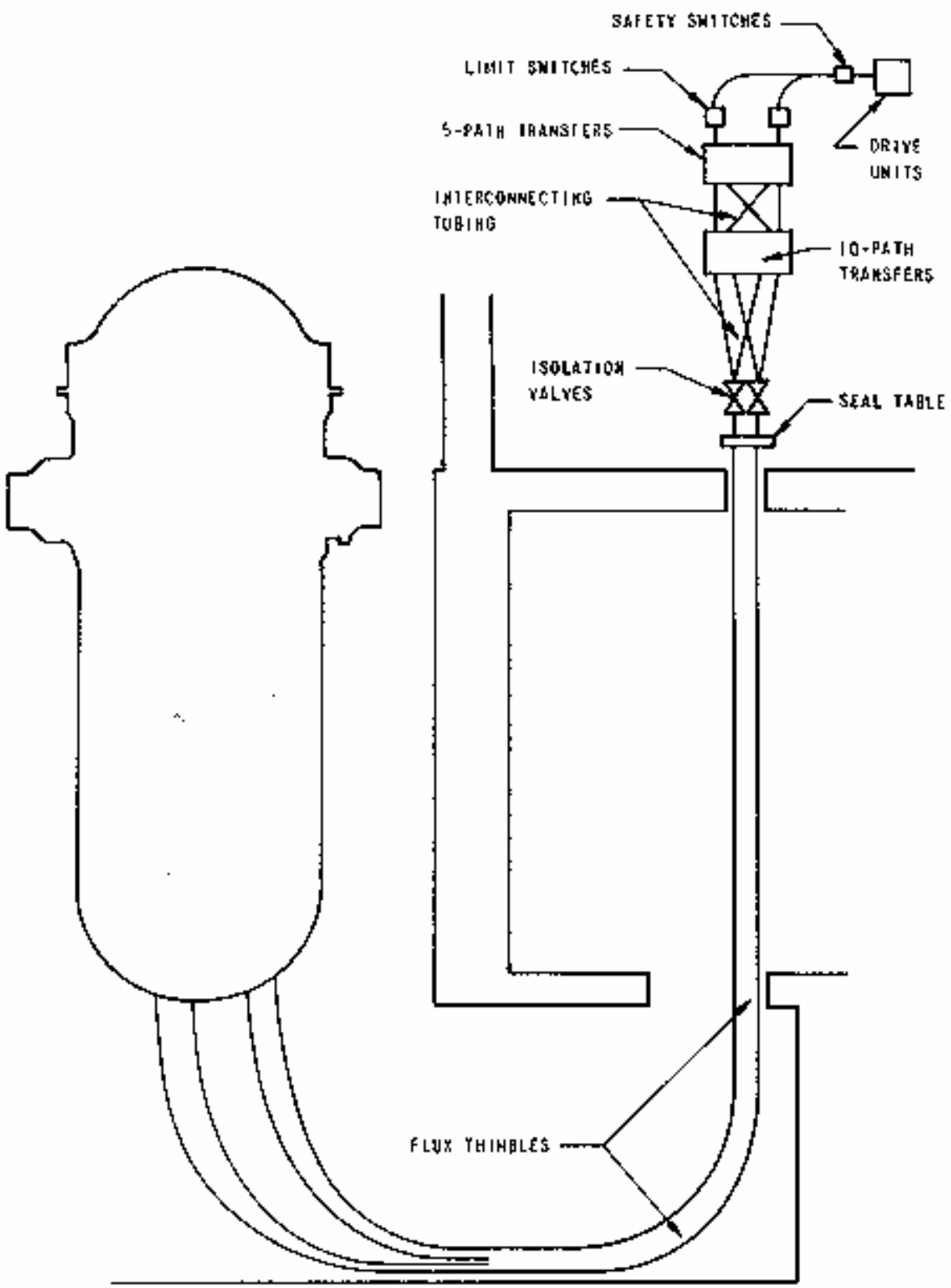
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 7.7-8 BLOCK DIAGRAM OF STEAM DUMP CONTROL SYSTEM



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 7.7-9 BASIC FLUX MAPPING SYSTEM

Chapter 8

ELECTRIC POWER

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NOTE:

[a] This figure corresponds to a controlled engineering drawing that is incorporated by reference into the FSAR Update. See Table 1.6-1 for the correlation between the

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Chapter 8

ELECTRIC POWER

8.1 INTRODUCTION

The electrical auxiliary power system at the Diablo Canyon Power Plant (DCPP) is designed to provide electric power to the necessary plant electrical equipment under all foreseeable combinations of plant operation and electric power source availability. The various subsystems provide adequate protection for electrical equipment during fault conditions, while maintaining maximum system flexibility and reliability.

8.1.1 DEFINITIONS

The following definitions apply to the electrical auxiliary power system.

Offsite Power System:	The system that delivers electric power from the transmission network to the onsite distribution system
Preferred Power Supply:	The preferred power supply is the offsite power system. The preferred power supply is comprised of two physically independent offsite power circuits. The startup offsite power circuit (230-kV) and the auxiliary offsite power circuit (500-kV).
Normal Onsite Power Source:	The normal onsite power source is the electric source which is generated by DCPP via the main generator and distributed by the 25-kV system to the 4.16-kV system.
Startup Offsite Power Circuit:	The startup offsite power circuit (230-kV system) provides an immediate source of offsite power from either of the two 230-Kv transmission lines connecting to the 230-kV switchyard. Refer to Section 8.2 and Figure 8.1-2 for description of the boundary of the startup offsite power circuit.
Auxiliary Offsite Power Circuit:	The auxiliary offsite power circuit (500-kV system) provides the delayed source of offsite power from any one of the three 500-kV transmission lines connecting to the 500-kV switchyard. Refer to Section 8.2 and Figure 8.1-2 for description of the boundary of the auxiliary offsite power circuit. The main generator also feeds the auxiliary offsite

power circuit during normal plant operation.

Onsite Distribution System: The Class 1E distribution system (both ac and dc voltages) permits the functioning of structures, systems, and components (SSCs) important to safety. Refer to Sections 8.3.1.1.1 through 8.3.1.1.5 and 8.3.2 for detailed descriptions of the onsite distribution systems.

There is also a non-Class 1E electrical distribution system (i.e., balance of plant). Those balance of plant portions comprising part of an offsite power circuit are subject to offsite power requirements. Those portions supplied from a Class 1E bus are subject to Class 1E isolation requirements. The remainder of the non-Class 1E balance of plant electrical distribution system is outside the scope of GDC 17, 1971 and IEEE 308-1971.

Standby Power Supply: The onsite emergency power supply. The emergency diesel generators (EDGs) are the ac standby power supply when the preferred power supply is not available. The dc standby power supply is comprised of the station batteries and the 125-Vdc system. Refer to Section 8.3.1.1.6 and 8.3.2 for detailed descriptions of the standby power supplies.

Class 1E: Refer to 3.2.2.6

Non-Class 1E: Refer to 3.2.2.6

Source: In the context of GDC 17, 1971 and IEEE 308-1971, the Class 1E ac electrical distribution system has three sources:

1) the preferred power supply

2) the standby power supply

3) the normal onsite power supply

Grid: The grid is the source of electrical power to the offsite power system. The grid is comprised of the electrical generation resources, transmission lines,

	interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100-kV or higher.
Transmission Network:	The grid elements operating at a given voltage level. DCPP connects with the grid at both the 230-kV and 500-kV transmission network level.

8.1.2 GENERAL DESCRIPTION

The electrical systems generate and transmit power to the high-voltage system, distribute power to the auxiliary loads, and provide control, protection, instrumentation, and annunciation power supplies for the units. Power is generated at 25-kV. Auxiliary loads are served at 12-kV, 4.16-kV, 480-V, 120-Vac, 250-Vdc, and 125-Vdc. The engineered safety feature (ESF) auxiliary loads are served directly by the 4.16-kV, 480-V, 120-Vac, and 125-Vdc Class 1E systems.

Offsite ac power for plant auxiliaries is available from two 230-kV transmission circuits and three 500-kV transmission circuits (refer to Figures 8.1-1 and 8.1-2).

Onsite ac auxiliary power is supplied by each unit's main generator and is also available for Class 1E loads from six diesel engine-driven generators. Three diesel generators are dedicated to each unit.

Onsite dc power is supplied from six 125-Vdc station batteries in each unit. Three batteries serve 125-Vdc Class 1E loads plus some non-Class 1E loads, and three batteries serve 125-Vdc non-Class 1E loads. Two of the three batteries supplying the non-Class 1E loads are also used together (i.e., in series) to supply 250-Vdc non-Class 1E loads (refer to Figure 8.3-18).

8.1.3 POWER TRANSMISSION SYSTEM

The Pacific Gas and Electric Company (PG&E) 500-kV ac transmission system overlays an extensive 230-kV ac transmission network. The 500-kV system is further connected through the 500-kV Pacific Intertie to the Western Systems Coordinating Council network covering the eleven western states plus British Columbia. Since March 31, 1998, the California Independent System Operator (CAISO) has been responsible for operating the transmission system within California. PG&E, as well as the other transmission system operators (owners) in the state, continues to own and operate their transmission facilities.

8.1.4 SAFETY LOADS

A representative listing of each unit's systems and loads requiring electric power to perform their safety functions are listed below.

(1) Emergency core cooling system, including two each of centrifugal charging pumps (CCP1 and CCP2), residual heat removal pumps, safety injection (SI) pumps, motor-driven auxiliary feedwater pumps (AFW), and their associated valves and lube oil pumps

(2) Containment spray system, including two pumps and associated valves

(3) Containment ventilation system, including five fan cooler units

(4) Auxiliary saltwater (ASW) system, including two pumps and associated valves

(5) Component cooling water (CCW) system, including three pumps and associated motor-operated valves

(6) Diesel fuel oil (DFO) system, including two pumps and valves

(7) Auxiliary building ventilation system, including fans, dampers, and control cabinets

(8) Fuel handling building ventilation system, including fans, dampers, and control cabinets

(9) Chemical and volume control system, including boric acid transfer pumps, valves, and tank heaters

Each of these and the other safety systems are discussed in detail in the appropriate section of this FSAR Update. The safety loads, plus additional important loads that are listed in Table 8.3-5 are served from Class 1E buses at 4.16-kV or 480-V. These buses are designated buses F, G, and H; Unit 1 is shown, with its bus loads, in Figures 8.3-4 and 8.3-6 through 8.3-8. The Unit 1 Class 1E 125-Vdc and 120-Vac instrumentation systems, with their loads, are shown in Table 8.3-11 and Figures 8.3-17 and 7.6-1. The Class 1E 480-V buses are supplied through transformers fed from the Class 1E 4.16-kV buses. These, in turn, are supplied power from both the normal and the emergency power sources described in Sections 8.2 and 8.3. Unit 2 loads and configuration are similar to Unit 1.

8.1.5 DESIGN BASES, CRITERIA, SAFETY GUIDES, AND STANDARDS

The electric power system is designed to provide reliable power for all necessary equipment during startup, normal operation, shutdown, and all emergency situations. Design criteria, as well as guides, codes, and applicable standards, are discussed in this section.

8.1.5.1 Design Bases

The electrical systems are designed to ensure an adequate supply of electrical power to all essential auxiliary equipment during normal operation and under accident conditions. PG&E Design Class I loads receive power from Class 1E buses that meet the requirements for IEEE Class 1E systems as defined in IEEE 308-1971. Those electrical systems and components which are not classified Class 1E are designated non-Class 1E.

Non-Class 1E 4.16-kV auxiliary buses are provided with two power sources: offsite power and power from the main generator. Class 1E buses have an additional source: onsite diesel generators. The Class 1E electrical systems are designed so that failure of any one electrical device will not prevent operation of the minimum required ESF equipment.

The overall plant single line diagram is shown in Figure 8.1-1. The loads on the Class 1E buses and the capabilities of the diesel generators are listed in Section 8.3.

8.1.5.2 Applicable Design Basis Criteria

The documents listed in Table 8.1-1 were utilized in the design, construction, testing, and inspection of the electrical systems. Table 8.1-1 designates the electrical systems which have relevance to the indicated design basis criteria. The design basis criteria for each system are addressed in the relevant system sections of Chapter 8.

Compliance of electrical systems with the general design criteria, including seismic and environmental qualifications (EQs), is also discussed in Chapter 3.

8.1.5.3 Codes and Standards

The following codes and standards have been implemented where applicable:

IEEE Standard No. 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations"

IEEE Standard No. 308-1971, "Criteria for Class 1E Electric Systems for Nuclear Power Stations"

IEEE Standard No. 317-1971, "Electrical Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations"

IEEE Standard No. 323-1971, "IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations," except for formal organization of the documentation

IEEE Standard No. 334-1971, "IEEE Trial Use Guide for Type Tests of Continuous Duty Class 1 Motors Installed Inside the Containment of Nuclear Power Generating Stations"

IEEE Standard No. 336-1971, "Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations-Installation, Inspection, and Testing"

IEEE Standard No. 344-1971, "Trial Use Guide for Seismic Qualification of Class I Electric Equipment for Nuclear Power Generating Stations"

(NOTE: Original Westinghouse-supplied equipment was qualified to IEEE 344-1971. Specific cases have been supplemented by seismic qualification criteria per IEEE 344-1975, "IEEE Recommended Practices for Seismic Qualification of Class I Electric Equipment for Nuclear Power Generating Stations")

IEEE Standard No. 485-1983, “Recommended Practice for Sizing Large Lead Storage Batteries for Generating Stations and Substations.”

ANSI Standard C37, 1972 Edition

ANSI Standard C57, 1971 Edition

AIEE Publication S-135-1, (1962), "Power Cable Ampacities"

IPCEA Standard S-66-524, (1971)

NEMA Standards MG-1, SG-5, SG-6, IC-1, VE-1, TR-1, (1971 Editions)

National Electric Code, 1968 Edition

8.1.6 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

8.2 OFFSITE POWER SYSTEM

The PG&E grid, which operates at several voltage levels, provides power to the DCPP preferred power supply as defined in Section 8.1. DCPP is interconnected to PG&E's electric grid system via two 230-kV and three 500-kV transmission lines emanating from their respective switchyards. These switchyards are physically and electrically separated and independent of each other. The 500-kV transmission lines out from the 500-kV switchyard provide for transmission of the plant's electric power output to the PG&E grid. The numbers of 230-kV and 500-kV transmission lines provide capability beyond that required to meet minimum U.S. Nuclear Regulatory Commission (NRC) regulatory requirements to ensure reliability of the offsite power systems.

The preferred power supply consists of the two independent circuits (230-kV and 500-kV) from the PG&E transmission networks. The preferred power supply consists of the offsite circuits from the switchyards' DCPP circuit breakers (including associated disconnect switches) 212 (230-kV) and 532, 542, 632 and 642 (500-kV) to the onsite distribution systems. The startup offsite power circuit consists of the 230-kV switchyard breaker (212) and lines to the standby startup transformers and the 12-kV onsite distribution which provides power to the onsite Class 1E 4.16-kV distribution system. The auxiliary offsite power circuit consists of the 500-kV switchyard breakers 532, 542, 632 and 642 and lines to the main transformers and the 25-kV onsite distribution system which also provide power to the onsite Class 1E 4.16-kV distribution system. The 12-kV system, the 25-kV system and the onsite Class 1E 4.16-kV system are addressed in Section 8.3.

The startup offsite power circuit provides startup and standby power, and is immediately available following a loss-of-coolant accident (LOCA) to assure that core cooling, containment integrity, and other vital safety functions are maintained. The auxiliary offsite power circuit provides a delayed access source of preferred power supply after the main generator is disconnected following anticipated operational occurrences. A combination of the startup offsite power circuit and the auxiliary offsite power circuit provides the preferred power supply, as required by GDC 17, 1971.

8.2.1 DESIGN BASES

8.2.1.1 General Design Criterion 4, 1967 – Sharing of Systems

The startup offsite power circuit is designed with a single line and breaker (212) which is shared with both units startup offsite circuits. The startup offsite power circuit is designed such that the shared components do not impair plant safety. The startup offsite power circuit is designed with sufficient capacity and capability to operate the ESFs for a design basis accident (or unit trip) on one unit, and those systems required for a concurrent safe shutdown of the second unit consistent with the requirements of Section 8 of IEEE 308-1971. Additionally, the startup offsite power circuit has sufficient capacity and capability to operate the ESF for a dual unit trip as a result of a seismic event or abnormal operational occurrences.

8.2.1.2 General Design Criterion 17, 1971 – Electric Power Systems

The DCPP preferred power supply is designed with two physically independent circuits. The preferred power supply has sufficient capacity and capability to assure that:
(1) specified fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences, and
(2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

Each of the offsite power circuits are designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded.

The startup offsite power circuit provides startup and standby power, and is immediately available following a design basis accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.

The auxiliary offsite power circuit provides a delayed access source of preferred power supply after the main generator is disconnected to assure specified fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operation occurrences. The auxiliary offsite power circuit is available in sufficient time to safely shutdown the plant following a loss of the normal onsite power source and the startup offsite power circuit.

The combination of the startup offsite power circuit and the auxiliary offsite power circuit provide physical independent sources of preferred power supply, as required by GDC 17, 1971. The preferred power supply is designed to minimize the probability of losing electric power from the transmission network coincident with the loss of onsite power generated by the main generator or the loss of onsite electric power sources (standby power supply as defined in IEEE 308-1971).

DCPP maintains protocols with the grid operator to help ensure grid reliability, to ensure that impacts on plant risk are understood, and to ensure the operability of the preferred power supply is maintained.

8.2.1.3 General Design Criterion 18, 1971 – Inspection and Testing of Electric Power Systems

The preferred power supply and its components have provisions for periodic inspection and testing. The preferred power supply components have been provided with convenient and safe features for inspecting, and testing.

8.2.1.4 Offsite Power System Safety Function Requirements

(1) Transmission Capacity

Each of the 230-kV transmission lines feeding the DCPP 230-kV switchyard is independently able to support the loads for a design basis accident on one unit and loads required for concurrent safe shutdown on the other unit.

(2) Single Failure

The preferred power supply has sufficient independence, capacity and testability to permit the operation of the ESF systems assuming a failure of a single active component.

8.2.1.5 10 CFR 50.63 – Loss of All Alternating Current Power

The preferred power supply is used for restoration of offsite power following a station blackout (SBO) event.

8.2.1.6 Safety Guide 32, August 1972 – Use of IEEE Standard 308-1971 Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations

Safety Guide 32, August 1972 identifies a conflict between IEEE 308-1971 and GDC 17, 1971 specifically with respect to the time at which the delayed access offsite power circuit is required. Safety Guide 32, August 1972 supports a delayed access offsite power circuit provided that the availability of the delayed access offsite power circuit conforms to the requirements of GDC 17, 1971.

The startup offsite power circuit is the immediate source of the preferred power supply following a design basis accident or unit trip. The auxiliary offsite power circuit provides a delayed access source of preferred power supply within sufficient time as required by GDC 17, 1971.

8.2.1.7 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The 230-kV system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

8.2.2 DESCRIPTION

8.2.2.1 230-kV System

Offsite electrical power for startup and standby service is provided from the 230-kV system. The two incoming 230-kV transmission lines, one from the Morro Bay switchyard (about 10 miles away) and the other from the Mesa Substation, feed the 230-kV switchyard (refer to Figures 8.1-1 and 8.1-2). Shunt capacitors at DCPP and

Mesa Substations are utilized to provide voltage support when required by the 230-kV grid conditions.

Each of the two 230-kV transmission lines feeding the 230-kV switchyard is provided with relay protection consisting of a carrier distance relaying terminal, including carrier distance and directional ground relays, with backup directional ground and fault detector relays, and automatic reclosing.

A single tie-line from the 230-kV switchyard supplies the 230-kV/12-kV standby startup transformer for each unit through breaker 212. The 230-kV standby startup service power line from the 230-kV switchyard to the plant is provided with relay protection consisting of a differential pilot wire relay system with overcurrent and fault detector relays for backup.

The single line diagram of the grid and the preferred offsite power supply to Unit 1 and Unit 2 is shown on Figures 8.1-1 and 8.1-2. Figure 8.2-3 shows the general location of the 230-kV (and 500-kV) switchyards. Reference 4 shows the arrangement of the 230-kV switch, bus, and circuit breaker structures. Figure 8.2-6 shows the arrangement of the 230-kV/12-kV standby startup transformers.

The tap position on each 230-kV/12-kV standby startup transformer load tap changer (LTC) is monitored in the DCPP main control room. Malfunction of the LTC is monitored in the control room through indication and annunciator action which could include taking manual control of the LTC or removing the transformer from service. Both units are designed to be supplied from a dedicated startup transformer, with the startup bus Unit 1-Unit 2 cross-tie breaker open. However, a single 230-kV/12-kV standby startup transformer can be aligned to both units via the cross-tie breaker. Operation in this configuration is restricted by Technical Specification. The DCPP surveillance program confirms the availability of the preferred power supply by verifying the correct breaker alignments, voltage levels, capacitor bank status, and any configuration control measures.

The automatic LTCs on the 230-kV/12-kV standby startup transformers, in addition to the grid shunt capacitors, assure the voltage on the plant 12-kV and 4-kV buses is maintained within acceptable limits and has adequate VAR support (References 1 and 2).

The 230-kV switchyard dc control power is provided by a lead-acid battery and two battery chargers. Each charger is capable of supplying the normal dc load of the 230-kV switchyard and maintaining the battery in a fully charged condition. Normally, one charger is operating with the second charger available on standby. Both chargers may be operated in parallel if desired. Each charger is equipped with an ac failure alarm that operates on loss of ac to the charger. The battery and chargers feed a 125-Vdc distribution panel that is equipped with a dc undervoltage (UV) relay that initiates an alarm if the dc voltage drops below a preset value. Separate dc control

circuits are provided from the dc distribution panel for each 230-kV power circuit breaker.

8.2.2.2 500-kV System

The 500-kV system provides for transmission of the plant's power output to the grid. The three 500-kV transmission lines, one from the Gates Substation (about 79 miles away) and two other from the Midway Substation (about 84 miles away), feed the DCPP 500-kV switchyard.

Each 500-kV transmission line is provided with relay protection terminal equipment consisting of two line relay sets (directional comparison), each operating over physically separate channels, microwave and power line carrier, and each provided with a separate dc power circuit. Single-pole tripping is not enabled for any of the lines. High-speed automatic reclosing is not enabled for the circuit breakers at the DCPP end of the lines. Backup protection (provided by a distance relaying terminal, including distance and directional ground relays) is normally cut-out, and cut-in when either primary relay set is not operable.

The 500-kV system provides power for station auxiliaries via the main transformer and the unit auxiliary transformers. Offsite electrical power is also provided from the 500-kV system. A single circuit to each unit from the 500-kV switchyard provides auxiliary offsite power through the 500-kV/25-kV main transformers and through breakers 532 and 632 (Unit 1) and breakers 542 and 642 (Unit 2). The dc motor operated main generator disconnecting switch is opened to provide auxiliary offsite power (backfeed). This telescoping disconnect switch is an integral part of the generator isolated phase bus. This switch is operated under manual control from the control room and is interlocked to prevent opening under load. Upon actuation, the motor-operated disconnect (MOD) switch takes approximately 30 seconds to isolate the main generator from the main and the unit auxiliary transformers. In the event of a loss of main generator output and the 230-kV system, the auxiliary offsite power circuit would be placed in service within 2 hours. The position of the MOD switch is verified prior to backfeeding from the 500-kV switchyard.

Figures 8.1-1 and 8.1-2 (plant single line diagram) shows the three 500-kV transmission lines from the transmission network to the interconnections to the plant auxiliaries. Figure 8.2-3 shows the general location of the 230-kV and 500-kV switchyards. Reference 5 shows the arrangement of the 500-kV switches, buses, and circuit breaker structures.

Each 500-kV line between the 500-kV switchyard and a generator step-up transformer bank is provided with redundant current differential protection channels. Directional over-current protection is available as backup. A Special Protection Scheme (SPS) supplements the existing DCPP 500-kV switchyard/line protection (refer to Section 8.2.3.2.2).

The 500-kV switchyard dc control power is provided by a lead-acid battery and two battery chargers. Each charger is capable of supplying the normal dc load of the 500-kV switchyard and maintaining the battery in a fully charged condition. Normally, one charger is operating with the second charger available on standby. Both chargers may be operated in parallel, if desired. Each charger is equipped with an ac failure alarm that operates on loss of ac to the charger. The battery and chargers feed two 125-Vdc distribution panels, one of which is equipped with a dc UV relay that initiates an alarm if the dc voltage should drop below a preset value. Separate dc control circuits are provided for each 500-kV power circuit breaker.

8.2.3 SAFETY EVALUATION

8.2.3.1 General Design Criterion 4, 1967 – Sharing of Systems

The startup offsite power circuit is designed such that the single 230-kV line from the 230-kV switchyard, including breaker 212, is shared by both Unit 1 and Unit 2 startup offsite power circuits. The shared components have sufficient capacity to operate the ESF for a design basis accident (or unit trip) on one unit, and those systems required for a concurrent safe shutdown of the second unit consistent with the requirements of Section 8 of IEEE 308-1971. Additionally, the startup offsite power circuit has sufficient capability to operate the ESF for a dual unit trip as a result of a seismic event or abnormal operational occurrences (Reference 8). The capacity of the shared startup offsite power circuit components is evaluated to ensure that a spurious ESF actuation on the non-accident unit, concurrent with a design basis accident on the other unit, would not result in the loss of the preferred power supply.

Both units are designed to be supplied from a dedicated startup transformer, with the startup bus Unit 1-Unit 2 cross-tie breaker open. However, a single 230-kV/12-kV standby startup transformer can be aligned to both units via the cross-tie breaker. Operation in this configuration is restricted by Technical Specification.

8.2.3.2 General Design Criterion 17, 1971 – Electric Power Systems

8.2.3.2.1 Preferred Power Supply

The preferred power supply is designed to provide two physically independent offsite power circuits (from the 230-kV and the 500-kV systems) for the Class 1E buses. The startup offsite power circuit is the 230-kV power supply which includes the first inter-tie breaker (212) at the 230-kV switchyard, 230-kV/12-kV standby startup transformers and includes all equipment downstream such as transformers, switches, interrupting devices, cabling, and controls up to the Class 1E buses. The startup offsite power circuit is designed to provide the immediate access preferred power supply from the 230-kV switchyard to the Class 1E buses within a few seconds after a LOCA.

The auxiliary offsite power circuit is the 500-kV power supply which includes inter-tie breakers (generator output breakers 532 and 632 for Unit 1, breakers 542 and 642 for

Unit 2) at the 500-kV switchyard, 500-kV/25-kV main transformers and all equipment downstream such as isophase bus, breakers, transformers, switches, interrupting devices, cabling, and controls up to the Class 1E buses. The auxiliary offsite power circuit is designed to provide the delayed access source of preferred power supply from the 500-kV switchyard to the Class 1E buses after the main generator MOD switch is opened. The auxiliary offsite power circuit is available in sufficient time to safely shutdown the plant following a loss of the auxiliary onsite power source and the startup offsite power circuit (refer to Section 8.2.3.6).

The combination of the startup offsite power circuit and the auxiliary offsite power circuit provide physical independent sources of preferred power supply, as required by GDC 17, 1971. The preferred power supply is designed to minimize the probability of losing electric power from the transmission network coincident with the loss of onsite power generated by the main generator or the loss of onsite electric power sources (standby power supply as defined in IEEE-308 1971).

8.2.3.2.2 Analysis

8.2.3.2.2.1 Grid Load Flow Analysis

Load flow analyses are performed for anticipated configurations of the grid (e.g., generating units out of service, transmission line(s) out of service, or voltage control devices out of service).

For postulated design-basis events, the transmission system is assumed to be in steady state. Any external condition affecting the transmission network is assumed to occur in sufficient time prior to the transfer to the 230-kV system such that the voltage on the 230-kV/12-kV LTC has adjusted to the transient.

PG&E’s Grid Control Center controls the DCPP 230-kV switchyard voltage to meet or exceed the minimum allowed pre-trip voltage. The minimum voltage from the transmission network at the DCPP 230-kV switchyard is maintained at or above 218-kV for normal operation with all transmission lines in service. The minimum voltage from the transmission network at the DCPP 500-kV switchyard is maintained at or above 512-kV. With both DCPP units off-line, the preferred power supply is capable of providing 104-MW and 78-MVAR to DCPP for normal operation, safe shutdown and design basis accident mitigation.

Depending upon system load and available voltage support, a degraded grid voltage condition could occur and result in DCPP configuration control measures (refer to Section 8.2.3.2.2.2). PG&E operating procedures are used by the CAISO, Grid Control Center, the Diablo Canyon Control Center, and DCPP.

Configuration control measures and the voltages required to maintain operability are reviewed annually. The purpose of the review is to examine major changes in system load projections, generating capacity, and transmission grid connections. PG&E's

Energy Delivery engineering staff performs the load flow studies using the current analytical model of the entire Western Electricity Coordinating Council (WECC). The maximum permissible transmission network loading is determined for various 230 kV network operating configurations, given a complete loss of DCPP generation. The 230-kV configurations modeled include all local transmission elements in service; one line out of service; two parallel lines out of service; split buses at nearby 230-kV substations; and capacitor banks unavailable. The results of the studies are calculated system equivalents and voltages with and without DCPP loading for each configuration. The results of the system load flow studies ensure transmission voltages are adequate to support a postulated DCPP post trip load transfer.

8.2.3.2.2.2 DCPP Load Flow and Dynamic Loading Analysis

The startup offsite power circuit is the immediate source of preferred power supply following a design basis accident or unit trip. The DCPP design and licensing basis requires that the startup offsite power circuit have sufficient capacity and capability to: (1) operate the ESFs for a design-basis accident on one unit and concurrent safe shutdown on the other unit, and (2) operate the ESFs for dual unit trips as a result of a seismic event or abnormal operational occurrences.

Existing DCPP calculations demonstrate the capacity of the preferred power supply for anticipated operational occurrences and postulated post-accident conditions. The calculations demonstrate that the preferred power supply has sufficient capacity and capability to start and operate the required loads.

Depending upon system load and available voltage support, a degraded grid voltage condition can result. DCPP configuration control measures, including blocking the transfer of non-essential loads, may be necessary for certain transmission network configurations to ensure adequate voltage to the Class 1E buses and return to the startup offsite power circuit to operable status.

PG&E operating procedures identify when configuration control measures are necessary based on surrounding area load, voltage, and the availability of critical transmission elements. When notified of adverse grid conditions, DCPP operating procedures identify what configuration control measures to invoke. Continued operation of the DCPP units under these conditions is procedurally controlled to ensure the preferred power supply meets DCPP operability requirements.

Configuration control measures and the voltages required to maintain operability are reviewed annually. DCPP dynamic loading analyses are then performed, using the results of the transmission load flow studies as input. The DCPP analyses determine if the calculated voltages are adequate for starting of required plant loads and for the bus transfer to the startup offsite power circuit following a design basis accident on one unit and concurrent safe shutdown of the second unit, or a dual unit trip following a seismic event or other abnormal operational occurrences. If the voltages and existing configuration control measures are not adequate, the analysis is rerun with additional

configuration control measures. Analyses are also performed to examine the effect of one 230-kV/12-kV standby startup transformer being unavailable, and for manual 230-kV/12-kV standby startup transformer LTC operation. DCPP procedures (which provide configuration control measures for the preferred power supply operability) are then modified to reflect the results of the analyses.

8.2.3.2.2.3 Grid Stability Analysis

The licensing basis requires the grid to remain stable (no complete loss of power from the preferred power source) following the loss of a generator, the loss of a large load block, or a fault on the most critical transmission line. Grid stability analyses are performed periodically whenever there is a significant change in generation, load, or transmission capability to ensure that this criterion is met. These analyses, and the load flow and dynamic loading analyses discussed above, are done to demonstrate compliance with GDC 17, 1971.

The fundamental purpose of the grid is to move electric power from the areas of generation to the areas of customer demand. The transmission network should be capable of performing this function under a wide variety of expected conditions. In addition to the more probable forced and planned outage contingencies, the planned ability to withstand less probable contingencies measure the robustness of a system.

The California transmission network (control area under CAISO) is designed and operated to comply with WECC reliability criteria (Reference 6). These criteria establish performance requirements for numerous grid contingencies, including the DCPP license basis contingencies which consist of the loss of any generator, the loss of a large load block, or a fault on the most critical transmission line.

The WECC criteria define four levels of transmission events, as follows:

Category A: No contingency, all facilities in service
Category B: Events resulting in the loss of a single grid element
Category C: Events resulting in the loss of two or more elements
Category D: Extreme events resulting in two or more (multiple elements removed or cascading out of service)

The DCPP licensing basis contingencies identified earlier in this section are consistent with the above WECC Category B events. CAISO compliance with WECC Category B ensures the availability of offsite power to DCPP because the loss of multiple elements and cascading are not involved.

The Category C and D events are beyond the licensing basis to satisfy GDC 17, 1971 criteria. CAISO compliance with WECC Category C and select Category D contingencies provides additional margin to ensure an adequate offsite power to Diablo Canyon units by protecting against dual unit trips.

Grid stability analyses are performed periodically by PG&E Electrical Operations whenever there is a significant change in generation, load, or transmission capability (based on an annual review of configuration control measures and voltages required to maintain operability) to ensure that the Category B criterion is met.

The model used in these studies represents PG&E grid and the interconnected western states in sufficient detail so that they properly address the electromechanical reaction of the combined systems to the cases studied. Scenarios modeled by PG&E include both a single-unit trip and a dual-unit trip of DCPP. Both worst case summer and winter loadings are simulated because the total area load and available generation varies with the season.

Assuming one DCPP unit already shutdown, the grid stability study concluded that the loss of the remaining generating unit at the Diablo Canyon site has little effect on the preferred power supply feeding the DCPP switchyard 230-kV buses and will not result in the complete loss of the preferred power supply. Both voltage and frequency will stabilize within several seconds. For a single-unit trip, the availability of the preferred power supply to the ESFs at Diablo Canyon will not be affected.

For a dual-unit trip (WECC Category C event), the 230-kV switchyard will remain energized (i.e., non-cascading event).

8.2.3.2.2.4 Operation During Severe Grid Disturbances Analysis

The CAISO exercises centralized control over generation and transmission facilities within California. CAISO schedules electric generation and operates the transmission network to minimize cascading during severe transmission network disturbances.

The CAISO also coordinates the scheduled outage of the electric generation and transmission facilities for preventive maintenance and repair, thereby ensuring a nearly constant level of system reliability.

It is the CAISO's responsibility to carry, at all times, operating reserve to satisfy the WECC Reliability Criteria and meet the requirements of the North American Electric Reliability Council.

To preserve the integrity of generating units during extreme grid disturbances, nuclear power plants (including DCPP) will be given the highest priority for restoration of power to their switchyards. PG&E and the CAISO have emergency restoration plans in place to utilize combustion turbine units, hydroelectric units, and the transmission grid to provide startup power to its major thermal electric generating plants. PG&E has several megawatts of its own hydro-generation within its control area that assists the grid through disturbances.

System disturbances can be initiated by trouble either within the CAISO control area or external to it. The 500-kV ac Pacific Intertie, running the length of PG&E's grid,

provides an internal transmission network with ties to neighboring utilities. If the grid is subjected to a severe disturbance caused by upset conditions external to the PG&E grid, underfrequency (UF) protective relaying has been provided that will activate at the interface. This relaying automatically separates the PG&E grid from its neighbors should frequency drop below relay settings in accordance with Exhibit A of PG&E Utility Standard S1426 for Tie Lines.

The WECC has prepared a coordinated response to UF events. A coordinated response by all utilities and generation owners under WECC jurisdiction maximizes the integrity of the grid. PG&E has implemented a multi-step load shed scheme within WECC guidelines to maintain a balance between load and generation.

These guidelines include the separation of generation based on UF setpoints that have been coordinated within the WECC areas of control. All setpoints for load shedding and generation tripping have been selected to minimize equipment damage and provide long term grid reliability. To minimize the possibility of a cascading failure and the possibility of severe overloading of generating units, UF load shedding is used to automatically relieve load during an extreme emergency. This load is removed automatically in increments based on declining frequency. Should these measures fail to arrest system frequency decay, provisions have been made to automatically separate thermal power plants from the transmission network should abnormal low frequency conditions develop. DCPP has implemented setpoints and durations for conditions corresponding to those specified in Exhibit A of PG&E Utility Operations Standard S1426 for Thermal Power Plants. Additional manual load shedding may be required to stabilize the grid. Hydroelectric units connected to the transmission network have a broad capability to operate during UF conditions. The hydroelectric units' UF setpoints are lower than the thermal power plants, although most hydroelectric units do not have UF control and would remain connected and continue to provide power to the transmission system.

A SPS has been added to supplement the existing DCPP 500-kV switchyard/line protection. This SPS was designed and installed by PG&E's transmission organization. An SPS is designed to detect abnormal grid conditions and take pre-planned, corrective action (other than the isolation of faulted elements) to provide acceptable grid performance. SPS actions may include, among others, changes in demand (e.g., load shedding), generation, or system configuration to maintain grid stability, acceptable voltages, or acceptable facility loadings. The use of an SPS is an acceptable transmission practice to meet the grid performance requirements as defined under WECC Categories A, B, or C.

The Diablo Canyon switchyard SPS was installed to mitigate the potential loss of two Diablo Canyon units after the occurrence of certain 500-kV Category C events. These events, if left unmitigated, would result in the loss of both Diablo Canyon units. The SPS will prevent voltage dips that are in violation of the WECC standards. The SPS system will selectively open the generator output breakers of one generating unit (i.e., load rejection) when the pre-defined conditions exist regarding the DCPP outlet lines.

The purpose of this corrective action is to prevent intensive swings that would otherwise result in the trip of both units by either reactor coolant pump (RCP) UV or generator out-of-step protection.

The impact of open phase conditions (OPCs) on the capability of the 500/25-kV Auxiliary and 230/12-kV Startup transformers was evaluated. The conditions analyzed consisted of single (i.e., one of three) and double (two of three) open phase conductors on the high voltage side of the Auxiliary and Startup transformers. The analysis considered open phase conditions with and without a ground. Open phase detection (OPD) systems for the transformers were installed in response to NRC Bulletin 2012-01, “Design Vulnerability in Electric Power System,” and in accordance with the NEI OPC Initiative. OPCs are alarmed in the control room.

A risk-informed assessment utilizing the DCPP specific electrical design configuration was performed in accordance with the guidance in NEI 19-02, “Guidance for Assessing Open Phase Condition Implementation Using Risk Insights.” The assessment demonstrated that in the event of an OPC, the risk associated with an OPD system that is reliant on manual operator action versus the automatic actuation of an open phase isolation system was insignificantly increased. Based on the results of the risk-informed assessment, DCPP has opted to utilize the OPD system and operator manual actions to address OPCs.

The measures outlined above, together with others, provide the basis for PG&E's confidence that the offsite power sources to the Diablo Canyon site are extremely reliable. The interconnection of Diablo Canyon to the 500-kV transmission network by way of Midway and Gates switchyards, and to the 230-kV transmission network by way of Morro Bay switchyard and Mesa substation, ensures access to PG&E's electrical grid systems.

8.2.3.3 General Design Criterion 18, 1971 - Inspection and Testing of Electric Power Systems

Periodic testing and surveillance of the standby startup transformers, unit auxiliary transformers, and the main transformer are part of the normal DCPP program for oil-filled transformers.

The DCPP surveillance program confirms the availability of the preferred power supply by verifying the correct breaker alignments, voltage levels, capacitor bank status, and any configuration control measures.

8.2.3.4 Offsite Power System Safety Function Requirements

(1) Transmission Capacity

Each of the two 230-kV transmission lines feeding the DCPP 230-kV switchyard is independently able to support the loads for a design basis accident on one unit and loads required for concurrent safe shutdown on the other unit.

The startup preferred power supply from the transmission network including the 230-kV/12-kV standby startup offsite power circuit is designed in a manner intended to obtain a high degree of service reliability and to minimize the time and extent of outage if failures do occur. Other than the failure mechanisms identified in Section 8.2.3.4(2), the startup offsite power circuit is designed for the following normal grid conditions:

(1) Each transmission line (as described in Section 8.2.2) in service with full capacity.

(2) Voltage support devices such as the automatic LTCs and capacitor banks at DCPP and Mesa in service

(3) Operating at full load under maximum expected transmission system load

The startup offsite power circuit is capable of mitigating a design basis event without reliance on manual operator actions to restore capability. This startup offsite power circuit capability includes automatic operation of voltage support devices and transmission switching systems to re-stabilize the system following a loss of a single generator in the transmission network, transmission line, or voltage support device. For off normal conditions (e.g., following a loss of a single generator in the transmission network, transmission line, or voltage support device) such that transmission from one of the two 230-kV transmission lines is degraded, configuration control measures, that include the blocking of selective large loads (e.g., 12-kV buses D and E auto transfer, condensate/condensate booster pumps auto start), are required to maintain operability (capability to mitigate an accident in one unit and a concurrent trip of the other unit) from the other 230-kV transmission line. These configuration control measures are procedurally controlled based on grid conditions.

(2) Single Failure

The preferred power supply is designed such that both the offsite and the onsite power systems have sufficient independence, capacity and testability to permit the operation of the ESF systems assuming a failure of a single active component in each system. The combination of either two 230-kV line plus the 500-kV system provides a high degree of assurance that offsite power will be available when required.

Occurrences that could result in the loss of the startup offsite power circuit are described below. Note that these occurrences do not result in a loss of the auxiliary

offsite power circuit and therefore ensure the preferred power supply is available in the event of a loss of the startup offsite power circuit.

(1) Loss of Morro Bay Switchyard or loss of both circuits of the 230-kV transmission line in the sections between the Morro Bay switchyard and Diablo Canyon site. It is noted that an outage of any one of the three 230-kV circuits (Morro Bay-Diablo Canyon, Diablo Canyon-Mesa, or Morro Bay-Mesa) would not result in interruption of the transmission supply to Diablo Canyon.

(2) Loss of the 230-kV bus structure at the Diablo Canyon site. This 230-kV structure has a double bus arranged so that either bus can supply the feed to the 230-kV/12-kV standby startup transformers. A permanently faulted bus section can be isolated from the remaining unfaulted bus section by means of manual switching operations. These structures are suitably spaced from one another. Only an event of great physical extent would cause the loss of both buses.

(3) Loss of the 230-kV line from the Diablo Canyon switchyard to the 230-kV/12-kV standby startup transformers, or loss of its associated 230-kV oil circuit breaker. If the power loss is due to mechanical or electrical failure of the oil circuit breaker, the circuit breaker can be isolated and bypassed by means of manual switching operations. A physical disruption of the short section of 230-kV line from the switchyard to the plant is considered highly unlikely.

(4) Loss of either 230-kV/12-kV standby startup transformer 11 or 21 or the associated 12-kV breakers or buses. Standby startup transformers 11 and 21 are normally separated on the 12-kV side, with transformer 11 feeding Unit 1 and transformer 21 feeding Unit 2. In case of a failure of either transformer, the faulted transformer can be manually switched out of service, its bus can then be transferred to the other transformer by closing the 12-kV bus tie vacuum circuit breaker. This circuit breaker is common to the 12-kV standby startup buses of Unit 1 and Unit 2, and is normally kept open (i.e., procedurally controlled).

(5) Failure of 12-kV/4.16-kV standby startup transformer 12 (22). By means of manual switching after a failure, the buses served from this transformer can be supplied from the 230-kV system by unit auxiliary transformer 12 (22) through unit auxiliary transformer 11 (21), fed from the 12-kV standby startup bus. This requires removal of links in the generator bus at the main transformer as well as opening of the disconnecting switch to the generator. This is an unusual configuration and is used only when better methods are not available.

8.2.3.5 10 CFR 50.63 - Loss of All Alternating Current Power

The 230-kV system or the 500-kV system is used for restoration of offsite power following a SBO. The plant procedures for SBO use several different flow paths to restore ac power and place the plant in a safe, controlled condition. Refer to Section 8.3.1.6 for additional discussion.

8.2.3.6 Safety Guide 32, August 1972 - Use of IEEE Standard 308-1971 Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations

Safety Guide 32, August 1972 identifies a conflict between IEEE 308-1971 and GDC 17, 1971 specifically with respect to the time at which the delayed access circuit is required. Safety Guide 32, August 1972 allows a delayed access circuit provided that the availability of the delayed access circuit conforms to requirements of GDC 17, 1971.

The startup offsite power circuit provides standby startup power, and is immediately available following a LOCA to assure that core cooling, containment integrity, and other vital safety functions are maintained. The auxiliary offsite power circuit provides a delayed access source of preferred power supply to the plant auxiliary systems and Class 1E buses when the main generator is not in operation. The auxiliary offsite power circuit is available in sufficient time to safely shutdown the plant following anticipated operational occurrences. In the event of a loss of main generator output and the 230-kV system, the auxiliary offsite power circuit would be placed in service within 2 hours to ensure that specified acceptable fuel design limits and design conditions of the reactor coolant boundary are not exceeded.

The position of the MOD switch is verified prior to backfeeding from the 500-kV switchyard.

After the two 500-kV breakers are opened, operations personnel coordinate with PG&E's Grid Control Center to realign plant protective relaying; open the generator disconnect; and re-close the generator output breakers.

8.2.3.7 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The 230-kV system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

8.2.4 TESTS AND INSPECTIONS

Refer to Section 8.2.3.3 for inspection and testing of electric power systems.

8.2.5 INSTRUMENTATION APPLICATIONS

The tap position on each 230-kV/12-kV startup/standby transformer LTC is monitored in the DCPP main control room. Malfunctioning of the LTC is alarmed in the main control room.

8.2.6 REFERENCES

1. License Amendment Request 98-01 submitted to the NRC by PG&E Letters DCL-98-008, dated January 14, 1998; DCL-98-076, dated May 19, 1998; DCL-99-013, dated February 5, 1999; and DCL-99-018, dated February 5, 1999. Also PG&E Letter DCL-99-014, dated February 5.

2. NRC Letter to PG&E, dated April 29, 1999, granting License Amendments No. 132 to Unit 1 and No. 130 to Unit 2.

3. Deleted in Revision 21.

4. PG&E Substation and Transmission Drawing 435895, “Arrangement of 230-kV Switch, Bus, and Circuit Breaker Structures (DCPP)”

5. PG&E Substation and Transmission Drawing 57486, “Arrangement of 500-kV Switch, Bus, and Circuit Breaker Structures (DCPP)”

6. WECC “Reliability Criteria”, Part 1, “NERC/WECC Planning Standards”

7. IEEE Standard 308-1971, Criteria for Class 1E Electric Systems for Nuclear Power Generation

8. NRC Letter to PG&E, dated December 14, 2009, Safety Evaluation, Diablo Canyon Power Plant, Unit Nos. 1 and 2 - Request for Technical Specification Interpretation of 230 Kilovolt System Operability (TAC Nos. ME0711 and ME0712).

8.2.7 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

8.3 ONSITE POWER SYSTEMS

The onsite power systems consist of all sources of electric power and their associated distribution systems within the DCPP. Included are the main generators, EDGs, and the Class 1E and non-Class 1E station batteries.

8.3.1 AC POWER SYSTEMS

As described in the introduction (refer to Section 8.1), the onsite ac systems consist of the 25-kV, 12-kV, 4.16-kV, and 480-V power systems, the 208Y/120-Vac lighting system, and the 120-Vac instrument supply systems.

8.3.1.1 Description

Auxiliary power for normal plant operation is supplied by each unit's main generators through the unit auxiliary transformers (refer to Figure 8.1-1), except during startups and shutdowns. Auxiliary power for startups and shutdowns is supplied by offsite power sources. If offsite power is unavailable, auxiliary shutdown power is furnished by the EDGs.

8.3.1.1.1 25-kV System

As described in Section 8.2.2.2, the auxiliary offsite power circuit consists of the 500-kV switchyard breakers 532, 542, 632 and 642 and lines to the main transformers and the portion of the 25-kV onsite distribution system which provide power to the onsite Class 1E 4.16-kV distribution system.

8.3.1.1.1.1 Design Bases

8.3.1.1.1.1.1 General Design Criterion 17, 1971 – Electric Power Systems

The auxiliary offsite power circuit provides a delayed access source of preferred power supply after the main generator is disconnected to assure specified fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operation occurrences. The auxiliary offsite power circuit is available in sufficient time to safely shut down the plant following a loss of the normal onsite power source and the startup offsite power circuit.

8.3.1.1.1.1.2 General Design Criterion 18, 1971 – Inspection and Testing of Electric Power Systems

The 25-kV system design permits appropriate periodic inspection and testing of functional and operational performance of the system as a whole and under conditions as close to design as practical.

8.3.1.1.1.1.3 Single Failure Requirements

The preferred power supply has sufficient independence, capacity and testability to permit the operation of the ESF systems assuming a failure of a single active component.

8.3.1.1.1.1.4 10 CFR 50.63 - Loss of All Alternating Current Power

The 25-kV system is used for restoration of the preferred power supply following a SBO.

8.3.1.1.1.1.5 Safety Guide 32, August 1972 – Use of IEEE Standard 308-1971, Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

Safety Guide 32, August 1972 identifies a conflict between IEEE 308-1971 and GDC 17, 1971 with respect to the time at which the delayed access offsite power circuit is required. Safety Guide 32, August 1972 supports a delayed access offsite power circuit provided that the availability of the delayed access offsite power circuit conforms to the requirements of GDC 17, 1971.

The auxiliary offsite power circuit provides a delayed access source of preferred power supply within sufficient time as required by GDC 17, 1971, after the main generator is disconnected.

8.3.1.1.1.2 System Description

The main electrical generator output voltage is 25-kV. Approximately 96 percent of the generated power is transformed to 500-kV at the main transformers, and the remainder is transformed to 12-kV and 4.16-kV at the unit auxiliary transformers. The portion of the 25-kV system which is part of the auxiliary offsite power circuit provides access to the 500-kV preferred power supply after the main generator is disconnected by operating the isophase bus motor operated generator disconnect switch.

8.3.1.1.1.3 Safety Evaluation

8.3.1.1.1.3.1 General Design Criterion 17, 1971 – Electric Power Systems

The portion of the 25-kV system which is part of the auxiliary offsite power circuit is designed to assure specified fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded in the event of the loss of the standby power source or the startup offsite power circuit. The capability and capacity of the auxiliary offsite power circuit is adequate to power both ESF and non-ESF functions (refer to Section 8.2.3.2).

8.3.1.1.1.3.2 General Design Criterion 18, 1971 – Inspection and Testing of Electric Power Systems

Periodic testing and surveillance of the 500-kV/25-kV main transformers and the 25-kV/4.16-kV transformers are part of the normal DCPP program for oil-filled transformers.

The DCPP surveillance program confirms the availability of the auxiliary offsite power circuit by verifying the correct 25-kV isolated phase bus MOD switch alignment and voltage levels.

8.3.1.1.1.3.3 Single Failure Requirements

A failure of a single active component in the 25-kV portion of the auxiliary offsite power circuit does not result in a complete loss of the preferred power supply (refer to Section 8.2.3.4(2)).

8.3.1.1.1.3.4 10 CFR 50.63 – Loss of All Alternating Current Power

The 25-kV system is a part of the auxiliary offsite power circuit used for restoration of the preferred power supply following a SBO. Refer to Section 8.3.1.6 for further discussion of SBO.

8.3.1.1.1.3.5 Safety Guide 32, August 1972 – Use of IEEE Standard 308-1971, Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

The portion of the 25-kV system which is part of the auxiliary offsite power circuit provides access to the auxiliary offsite power circuit after the main generator is disconnected (refer to Section 8.2.3.6).

8.3.1.1.1.4 Tests and Inspections

Refer to 8.3.1.1.1.3.2 for test and inspection details.

8.3.1.1.1.5 Instrumentation Applications

Equipment monitoring instrumentation is provided for the 25-kV isophase bus and main transformer banks.

8.3.1.1.2 12-kV System

As described in Section 8.2.2.1, the startup offsite power circuit consists of the 230-kV switchyard breaker (212) and lines to the standby startup transformers and a portion of the 12-kV onsite distribution which provides power to the onsite Class 1E 4.16-kV distribution system.

8.3.1.1.2.1 Design Bases

8.3.1.1.2.1.1 General Design Criterion 2, 1967 – Performance Standards

The portion of the 12-kV system which provides input to the reactor trip system (RTS), UV relays and UF relays, is designed to withstand the effects of, or is protected against, natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

8.3.1.1.2.1.2 General Design Criterion 4, 1967 – Sharing of Systems

The 12-kV system and components are not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

8.3.1.1.2.1.3 General Design Criterion 11, 1967 – Control Room

The 12-kV system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room.

8.3.1.1.2.1.4 General Design Criterion 12, 1967 – Instrumentation and Control System

Instrumentation and controls are provided as required to monitor and maintain 12-kV system variables within prescribed operating ranges.

8.3.1.1.2.1.5 General Design Criterion 15, 1967 – Engineered Safety Features Protection Systems

The 12-kV system design provides input to the solid state protection system (SSPS) through bus monitoring UV and UF relays for the RCPs. The UV and UF relays monitor the 12-kV bus for accident situations through potential transformer (PT) sensing circuits.

8.3.1.1.2.1.6 General Design Criterion 17, 1971 – Electric Power Systems

The startup offsite power circuit is designed to provide an immediate access source of preferred power supply from the 230-kV switchyard to the ESF buses within a few seconds after a LOCA. A portion of the 12-kV system (from the standby startup transformer 11[21] through the standby startup transformer 12[22] to the 4.16-kV Class 1E buses) is designed with sufficient capacity and capability, and is immediately available to operate the ESFs following a design basis accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.

8.3.1.1.2.1.7 General Design Criterion 18, 1971 – Inspection and Testing of Electric Power Systems

The 12-kV system design permits appropriate periodic inspection and testing of functional and operational performance of the system as a whole and under conditions as close to design as practical.

8.3.1.1.2.1.8 General Design Criterion 49, 1967 – Containment Design Basis

The 12-kV system circuits routed through containment electrical penetrations are designed to support the containment design basis such that the containment structure can accommodate, without exceeding the design leakage rate, pressure and temperatures following a LOCA.

8.3.1.1.2.1.9 Single Failure Requirements

The preferred power supply has sufficient independence, capacity and testability to permit the operation of the ESF systems assuming a failure of a single active component in the 12-kV system.

8.3.1.1.2.1.10 10 CFR 50.63 – Loss of All Alternating Current Power

The 12-kV system is a part of the auxiliary offsite power circuit used for restoration of the preferred power supply following a SBO.

8.3.1.1.2.1.11 Safety Guide 32, August 1972 – Use of IEEE Standard 308-1971 Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations

Safety Guide 32, August 1972 identifies a conflict between IEEE 308-1971 and GDC 17, 1971 specifically with respect to the time at which the delayed access offsite power circuit is required. Safety Guide 32, August 1972 supports a delayed access offsite power circuit provided that the availability of the delayed access offsite power circuit conforms to the requirements of GDC 17, 1971.

The startup offsite power circuit is the immediate source of the preferred power supply following a design basis accident or unit trip.

8.3.1.1.2.1.12 Regulatory Guide 1.63, Revision 1, May 1977 – Electrical Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Plants

The 12-kV circuits routed through containment electrical penetrations are designed to the requirements of Regulatory Guide 1.63, Revision 1, regarding installation of redundant or backup fault current protection devices to limit fault current to less than

that which the penetration can withstand, assuming a single random failure of the circuit overload protective device.

8.3.1.1.2.2 System Description

The 12-kV system for each unit is a three-phase, three-wire, high-resistance-grounded non-Class 1E system that serves two circulating water pumps and the four RCPs. The loads are divided into two groups, each served by a separate bus having two sources: one from the main generator through the unit auxiliary transformer 11(21) and one from the 230-kV transmission system through standby startup transformer 11(21), as shown in Figures 8.1-1, 8.3-1, 8.3-2, and 8.3-5.

Auxiliary buildings and other loads not associated with power generation are normally fed from two 12-kV circuit breakers on the startup bus of each unit.

The 12-kV system is provided with metalclad switchgear located indoors. Refer to Figures 8.1-1, 8.3-2, and 8.3-5 for detailed component ratings and vendor information. Each bus section is separated from the other by an aisle space, and each circuit breaker cubicle is separated from adjacent units by metal barriers. The 230-kV/12-kV standby startup transformer 11(21) LTCs are described in Section 8.2.2. A grounding transformer is provided on each 12-kV source. No ESF loads are served at 12-kV; however, the startup bus is part of the startup offsite power circuit between the 230-kV switchyard and the 4.16-kV Class 1E buses for each respective unit (refer to Figure 8.1-1).

8.3.1.1.2.3 Safety Evaluation

8.3.1.1.2.3.1 General Design Criterion 2, 1967 – Performance Standards

The 12-kV UV and UF circuits are contained within the PG&E Design Class II turbine building. This building or applicable portions have been designed not to impact PG&E Design Class I components and associated safety functions. Refer to Sections 3.2.1, 3.3.2.5.2.8, 3.4.2.1.1, 3.5.1.2, and 3.7.2.2.2.1 for additional information. Analyses have been performed to assure that the lack of seismic qualification and seismic installation of these inputs will not degrade the function of the RTS from these monitoring channels. Refer to Section 7.2.3.1 for additional discussion.

8.3.1.1.2.3.2 General Design Criterion 4, 1967 – Sharing of Systems

The 12-kV system is designed with cross-tie capability to align a single 230-kV/12-kV standby startup transformer (11 or 21) to provide power to both units via the cross-tie breaker. Operation in this configuration is restricted by Technical Specification. The shared portion of the 12-kV system is designed with sufficient capacity and capability to operate the ESFs for a design basis accident (or unit trip) on one unit, and those systems required for a concurrent safe shutdown of the second unit consistent with the requirements of IEEE 308-1971, Section 8 (Reference 3).

8.3.1.1.2.3.3 General Design Criterion 11, 1967 – Control Room

Each 12-kV bus feeder (i.e., unit auxiliary transformer and standby startup transformer) is provided with a voltmeter and ammeter mounted on the control room main control board for remote indication to facilitate actions that maintain the safe operational status of the plant.

8.3.1.1.2.3.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The startup switchgear has internally mounted PTs and current transformers for maintaining and operating the 12-kV system within prescribed operating ranges through use of the 230-kV/12-kV standby startup transformer 11(21) LTC. Refer to Section 8.2.2.1 for additional discussion.

8.3.1.1.2.3.5 General Design Criterion 15, 1967 – Engineered Safety Features Protection Systems

The 12-kV system provides input to the SSPS for reactor protection through UV and UF sensors. Refer to Section 7.2.3.1 for additional discussion.

8.3.1.1.2.3.6 General Design Criterion 17, 1971 – Electric Power System

The DCPP offsite power system is designed to supply offsite electrical power by two physically independent circuits. The portion of the 12-kV system from the 230-kV/12-kV standby startup transformer 11(21) through the 12-kV/4.16-kV standby startup transformer 12(22) to the 4.16-kV Class 1E buses provide startup and standby power, and is immediately available following a design basis accident to assure that core cooling, containment integrity, and other vital safety functions are maintained. The portion of the 12-kV system which is part of the immediately available offsite power circuit is designed with sufficient capacity and capability to operate the ESFs following a design basis accident. The startup bus portion of the 12-kV system is included in the startup offsite power circuit and provides input to the startup transformer 11(21) LTC controller for voltage control. The capability of the 12-kV startup bus is adequate to power both ESF and non-ESF functions. Refer to Section 8.2.3.2.1 for additional discussion of capacity and capability of the startup offsite power circuit.

8.3.1.1.2.3.7 General Design Criterion 18, 1971 – Inspection and Testing of Electric Power Systems

Periodic testing and surveillance of the standby startup transformers and the 12-kV/4.16-kV transformers are part of the normal DCPP program for oil-filled transformers.

The DCPP surveillance program confirms the availability of the startup offsite power circuit by verifying the correct breaker alignments, voltage levels, and compensatory measures.

8.3.1.1.2.3.8 General Design Criterion 49, 1967 – Containment Design Basis

The 12-kV circuits routed through containment electrical penetrations are each provided with electrical protection devices. This arrangement is such that with the failure of one device, the penetration remains protected from high current temperature by the other in-series device to ensure the containment penetration remains functional (refer to Sections 3.8.2.1.1.3 and 8.3.1.4.8 for additional details).

8.3.1.1.2.3.9 Single Failure Requirements

A failure of a single active component in the 12-kV portion of the startup offsite power circuit does not result in a complete loss of the preferred power supply. Refer to Section 8.2.3.4(2).

8.3.1.1.2.3.10 10 CFR 50.63 – Loss of All Alternating Current Power

A portion of the 12-kV system is used as an attendant distribution system of the 230-kV offsite power circuits used for restoration of offsite power following a SBO event. The plant procedures for SBO and loss of offsite power (LOOP) use several different flow paths to restore ac power and place the plant in a safe, controlled cooldown. Refer to Section 8.3.1.6 for further discussion of SBO.

8.3.1.1.2.3.11 Safety Guide 32, August 1972 – Use of IEEE Standard 308-1971 Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations

The portion of the 12-kV system from the standby startup transformer 11(21) through the standby startup transformer 12(22) to the 4.16-kV Class 1E buses provides startup and standby power, and is immediately available following a design basis accident or unit trip to assure that core cooling, containment integrity, and other vital safety functions are maintained. The immediately available 12-kV startup bus is continuously energized to support the immediate availability of the startup offsite power circuit (refer to Section 8.2.3.6.

8.3.1.1.2.3.12 Regulatory Guide 1.63, Revision 1, May 1977 – Electrical Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Plants

12-kV circuits routed through containment electrical penetrations are designed with redundant overcurrent protection. Refer to Section 8.3.1.4.8 for additional details.

8.3.1.1.2.4 Tests and Inspections

Refer to Section 8.3.1.1.2.3.7 for test and inspection details.

8.3.1.1.2.5 Instrumentation Applications

Refer to Section 8.3.1.1.2.3.4 for instrumentation applications.

8.3.1.1.3 4.16-kV System

8.3.1.1.3.1 Design Bases

8.3.1.1.3.1.1 General Design Criterion 2, 1967 – Performance Standards

The Class 1E portion of the 4.16-kV system is designed to withstand the effects of, or is protected against, natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

8.3.1.1.3.1.2 General Design Criterion 3, 1971 – Fire Protection

The Class 1E portion of the 4.16-kV system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

8.3.1.1.3.1.3 General Design Criterion 11, 1967 – Control Room

The Class 1E portion of the 4.16-kV system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

8.3.1.1.3.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain 4.16-kV system variables within prescribed operating ranges.

8.3.1.1.3.1.5 General Design Criterion 17, 1971 – Electric Power Systems

The Class 1E portion of the 4.16-kV system is designed with sufficient capacity, capability, independence, redundancy, and testability to perform its safety function assuming a single failure.

8.3.1.1.3.1.6 General Design Criterion 18, 1971 – Inspection and Testing of Electric Power Systems

The Class 1E portion of the 4.16-kV system design permits appropriate periodic inspection and testing of functional and operational performance of the system as a whole and under conditions as close to design as practical.

8.3.1.1.3.1.7 General Design Criterion 21, 1967 – Single Failure Definition

The Class 1E portion of the 4.16-kV system is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event shall be treated as a single failure.

8.3.1.1.3.1.8 General Design Criterion 40, 1967 – Missile Protection

The portions of the Class 1E 4.16-kV system, that support ESF loads, are designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

8.3.1.1.3.1.9 4.16-kV System Safety Function Requirements

(1) Protection from Missiles

The Class 1E portion of the 4.16-kV system is designed and located to be protected against the effects of missiles which may result from plant equipment failure and from events and conditions outside the plant.

(2) Protection Against High Energy Pipe Rupture Effects

The Class 1E portion of the 4.16-kV system is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The outside containment Class 1E portion of the 4.16-kV system required to bring the plant to cold shutdown is designed to be protected against the effects of moderate energy pipe failure.

(4) Protection from Jet Impingement – Inside Containment

The inside containment Class 1E portion of the 4.16-kV system is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

(5) Protection from Flooding Effects – Outside Containment

The outside containment Class 1E portion of the 4.16-kV system required to bring the plant to cold shutdown is to be protected from the effects of internal flooding.

8.3.1.1.3.1.10 10 CFR 50.49 – Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

The Class 1E 4.16-kV system electrical components that require EQ are qualified to the requirements of 10 CFR 50.49.

8.3.1.1.3.1.11 10 CFR 50.63 – Loss of All Alternating Current Power

The Class 1E 4.16-kV system provides power to the loads required to support systems that assure core cooling and containment integrity is maintained following a SBO event.

8.3.1.1.3.1.12 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The Class 1E portion of the 4.16 kV System is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

8.3.1.1.3.1.13 Safety Guide 6, March 1971 – Independence Between Redundant Standby (Onsite) Power Sources and Between their Distribution Systems

The Class 1E portion of the 4.16-kV system is designed so that electrically powered loads are separated into redundant load groups such that loss of any one group will not prevent the minimum safety functions from being performed.

8.3.1.1.3.1.14 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The 4.16-kV system provides instrumentation in the control room to monitor 4.16-kV system electrical status for post-accident instrumentation.

8.3.1.1.3.2 System Description

The 4.16-kV system is a three-phase, three-wire, high-resistance-grounded neutral system that serves motors from 200 to 3000 hp, and transformers for the smaller loads at the lower voltages. The Class 1E 4.16-kV distribution system provides power to ESF loads to safely shut down the unit. The 4.16-kV loads are divided into five groups; two of these groups are not vital to the ESFs and are connected to non-Class 1E 4.16-kV Buses D and E. Each of the non-Class 1E buses has two sources of preferred power supply: one from the main generator (or the 500-kV system through the main

transformer) through the 25-kV/4.16-kV unit auxiliary transformer 12(22), and one from the 230-kV transmission system through the 230-kV/12-kV standby startup transformers 11(21) and 12-kV/4.16-kV standby startup transformers 12(22) (refer to Figures 8.1-1, 8.3-3, and 8.3-5). Utility power for the 230-kV and 500-kV switchyards is provided from the Unit 1, non-Class 1E, 4.16-kV switchgear Buses D and E, respectively. Refer to Sections 8.2.2.1 (230-kV system) and 8.2.2.2 (500-kV system) for further discussion.

The other three load groups are important to safety and are connected to 4.16-kV Class 1E Buses F, G, and H. Each of these buses has three sources: two being the immediate and delayed preferred power supply, and the standby power supply from the diesel-driven generators (refer to Figures 8.3-3 and 8.3-4).

As noted in Section 8.2.3.2, compensatory action will be taken as necessary to ensure that the ESF motor terminal voltages are within their acceptable voltage tolerance (typically ±10 percent) when fed from the preferred power supply. Once started, the motors will operate with applied voltages as low as 70 percent of rated voltage without breakdown, but the time is limited because of motor heating.

The 4.16-kV system is provided with metal clad switchgear and breakers rated at 350-MVA interrupting capacity, and 78,000 amperes of closing and latching capability. The circuit breakers are in individual cubicles, each separated from the adjacent circuit breakers by metal barriers. All 4.16-kV switchgear is located in the turbine building. The non-Class 1E 4.16-kV switchgear is located in the same room as the 12-kV switchgear and have the two bus sections separated by a common aisle. The Class 1E 4.16-kV switchgear is located in rooms separated from each other and from non-Class 1E equipment (refer to Figures 1.2-14 through 1.2-16 and 1.2-18 through 1.2-20).

The unit auxiliary and standby startup transformers are equipped with an automatic water spray deluge system that can be manually actuated locally at the system valves or remotely from the control room (refer to Section 9.5.1.2.4).

8.3.1.1.3.3 Safety Evaluation

8.3.1.1.3.3.1 General Design Criterion 2, 1967 – Performance Standards

The Class 1E 4.16-kV switchgear and associated 4.16-kV/120-Vac PTs and safeguard relay boards are located in the PG&E Design Class II turbine building. This building, or applicable portions thereof, has been designed not to impact PG&E Design Class I components and associated safety functions (refer to Section 3.7.2.2.2). The turbine building is designed to withstand the effects of winds and tornadoes (refer to Section 3.3.1.2 and 3.3.2.5.2.8), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7.2.2.2) to protect the Class 1E 4.16-kV switchgear and associated 4.16-kV/120-Vac PTs and safeguard relay boards, ensuring their design function will be performed.

The 4.16-kV switchgear and associated 4.16-kV/120-Vac PTs and safeguard relay boards are seismically designed to perform their safety functions under the effects of earthquakes (refer to Section 3.10.3.7).

8.3.1.1.3.3.2 General Design Criterion 3, 1971 – Fire Protection

The Class 1E 4.16-kV switchgear and cable spreading room are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

Refer to Section 8.3.1.4.9 for further discussion on fire barriers and separation.

8.3.1.1.3.3.3 General Design Criterion 11, 1967 – Control Room

The Class 1E 4.16-kV supply and load breakers are controlled remotely from the main control room and locally at their respective switchgear cubicles. The supply breaker for each Class 1E load center transformer is equipped with an isolation switch, located at the switchgear that disconnects breaker control from the control room in the event that the main control room is rendered uninhabitable. The HSP, which is the alternate control location in the event that the main control room is rendered uninhabitable, is provided with a mode switch, control switch and status indication for each of the pumps required to bring the plant to a safe shutdown condition. It is also provided with a voltage indication of each Class 1E 4.16-kV bus. Transfer switches are located in the Class 1E 4.16-kV switchgear cubicles to isolate 4.16-kV circuit breaker control cables between the main control room and the switchgear and transfer control of the breaker locally to the HSP or the switchgear. Alarms are provided in the control room to monitor the status of the 4.16-kV system and alert the plant when an abnormal condition is detected. Refer to Section 8.3.1.1.3.3.4 for additional instrumentation and control information.

8.3.1.1.3.3.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Control switches, status indication and ammeters are provided in the main control room and at the respective switchgear cubicle for all the motor load and load center transformer feeder breakers. Additionally, watt and var meters are provided for each load center transformer feeder in the main control room as well as voltage indication for each 4.16-kV bus.

The unit auxiliary and standby startup transformers feeding the 4.16-kV buses are provided with an ammeter, voltmeter, wattmeter, varmeter, watt-hour meter and an indicating light in the main control room.

8.3.1.1.3.3.5 General Design Criterion 17, 1971 – Electric Power Systems

Each unit’s Class 1E 4.16-kV distribution system is comprised of three electrically independent and redundant load groups. Each Class 1E switchgear, including its

associated relay board, is located in separate rooms and meets the single failure criteria. If a single failure occurs in any of the three load groups, the remaining load groups have sufficient capability and capacity to provide power to ESF loads required to safely shut the unit down.

Each load group is normally supplied power from the main generator via the unit auxiliary transformer. In the event of a unit trip or accident condition, the power source to each Class 1E, 4.16-kV switchgear is automatically transferred to the immediate preferred power source via the standby startup transformers 11 and 12 (21 and 22) in series. If the transfer to the standby startup transformer is unsuccessful or if there is a loss of voltage or degraded voltage from the standby startup transformer, UV protection for each Class 1E 4.16-kV bus is provided by the first level UV relays (FLUR) and second level UV relays (SLUR). These sets of relays and associated timers start the EDG, perform a load shed on its respective bus and transfer loading to the EDG in the event the preferred power supply is unavailable or in a degraded condition (refer to Figure 8.3-16).

8.3.1.1.3.3.5.1 Class 1E Bus Undervoltage Protection Design Criteria

The emergency electric power system including each Class 1E bus and its control, protection, and instrumentation is designed in accordance with IEEE 308-1971 (Reference 3), IEEE 279-1971 (Reference 4), and the following supplemental NRC positions regarding the susceptibility to sustained degraded voltage conditions and the interaction of the preferred power supply and standby power supply (Reference 26).

(1) Second Level UV Protection with Time Delay:

A second level of voltage protection for the onsite power system is provided (i.e., in addition to loss of voltage protection). The preferred power supply is the common source that normally supplies power to the redundant Class 1E buses. Any transient or sustained degradation of this common source will be reflected onto the onsite Class 1E electrical distribution system. A sustained degradation of the preferred power supply voltage could result in the loss of capability of the redundant safety loads, their control circuitry, and the associated electrical components required for performing safety functions. The following requirements ensure adequate protection from this common mode failure mechanism:

(a) The selection of voltage and time set points are based on an analysis of the voltage requirements of the safety related loads at all onsite system distribution levels;

(b) The voltage protection includes coincidence logic to preclude spurious trips of the preferred power supply;

(c) The time delay selection is based on the following conditions:

i) The allowable time delay, including margin, does not exceed the maximum time delay that is assumed in the accident analyses;

ii) The time delay minimizes the effect of short duration disturbances from reducing the availability of the preferred power supply;

iii) The allowable time duration of a degraded voltage condition at all distribution system levels does not result in failure of safety systems or components;

(d) The voltage sensors automatically initiate the disconnection of the preferred power supply whenever the voltage set point and time delay limits have been exceeded; and

(e) The voltage sensors are designed to satisfy the applicable requirements of IEEE 279-1971 (Reference 4).

(2) Interaction of Onsite Power Supplies with Load Shed Feature:

The second level UV logic (i.e., degraded grid) input to the load shed feature for each Class 1E 4.16-kV bus is inhibited when the EDG output breaker is closed and the auxiliary preferred power supply feeder breaker is open (i.e., bus is solely energized by the standby power supply). The second level UV logic input to the load shed feature is also inhibited when EDG is paralleled to the startup preferred power supply. The second level UV logic input to the load shed feature is automatically reinstated when the EDG output breaker opens.

8.3.1.1.3.3.5.2 Operation of 4.16-kV Distribution System

The ESF loads and their onsite sources are grouped so the functions required during a major accident are provided regardless of any single failure in the electrical system. Any two of the three diesel generators and their buses are adequate to serve at least the minimum required ESF loads of a unit after a major accident.

During normal operation, the main generator supplies the auxiliary load for each unit. The circuit breakers on 4.16-kV Class 1E Buses F, G, and H, which feed the ESFs, are aligned as follows:

(1) 4.16-kV circuit breakers that are open:

(a) Diesel-driven generators

(b) Standby startup Transformer 12 (22)

(c) SI pumps

(d) Containment spray pumps

(e) AFW pumps

(f) Residual heat removal pumps

(2) 4.16-kV circuit breakers that are closed:

(a) Unit auxiliary transformer 12 (22)

(b) 4.16-kV/480-V Class 1E load centers that provide power for pumps, fans, valves, and other low-voltage devices

(3) 4.16-kV circuit breakers that may be either open or closed, depending on the operating conditions of the following pumps:

(a) Charging pumps

(b) ASW pumps

(c) CCW pumps

To achieve the objective of an adequate source of electrical power for the Class 1E 4.16-kV Buses F, G, and H, the electrical systems are designed to operate as follows:

In the event of a loss of satisfactory electrical power from the main generating unit, due to a unit trip, a safeguard signal, or a loss of voltage on the bus, the Class 1E 4.16-kV buses are automatically disconnected immediately from the main unit as a source.

If power is available from the startup offsite power circuit, the Class 1E 4.16-kV buses are transferred to this source automatically after a short delay to allow for voltage decay on the motors that were running.

The delayed method of transfer is used to protect the ESF motors from overvoltage transients. The advantage of motor protection is greater than any disadvantage of reduced operating capacity during the short delay period, especially in view of the fact that when there is also a loss of startup offsite power circuit, the delay in transferring to emergency power is on the order of 10 seconds (the time for the diesel generators to reach minimum bus voltage) plus load sequencing. Schematic diagrams of the automatic transfer circuits for the ESF buses are presented in Figures 8.3-9 through 8.3-11; logic diagrams are shown in Figure 8.3-16.

Because the individual loads are not tripped under these circumstances, they remain in the same operating state as before the transfer, except for the low-voltage loads operated by magnetic controllers having no maintained contact control circuits, such as the containment fan coolers. Without an SIS signal, individual timers start the

containment fan coolers and the ASW pump. The containment fan coolers would operate at the low speed after the transfer of the Class 1E power supply. With an SIS signal, the Class 1E loads are started in sequence in the same manner as with the diesel generators. As noted in Table 8.3-4, an SIS signal only allows the containment fan coolers to start on low speed.

Also, if bus voltage is not restored, the associated diesel generator is started automatically and brought to a condition suitable for loading.

Each of the following initiates the starting of the diesel generators:

(1) A SI actuation signal from either Train A or B of the ESF actuation system.

(2) UV on the startup offsite power circuit to each of the Class 1E 4.16-kV buses start its respective diesel.

(3) Sustained UV or loss of voltage on any of the Class 1E 4.16-kV buses starts its respective diesel.

In each case, an independent set of signals or relays is applied to start the diesel for its bus. The first level UV relay (initiating load shedding signal) for the startup offsite power circuit of each Class 1E 4.16-kV bus has inverse time characteristics and a slight delay upon complete voltage failure. The first level UV relay has three select voltages and time delay settings, with the lowest being set at approximately
818-V.

The second level of UV protection for each Class 1E 4.16-kV bus is set at approximately 3800-V. The protection consists of two relays for each bus having a two-out-of-two logic arrangement. Start of the respective diesel is delayed by 10 seconds. Bus loads are shed in 20 seconds, and bus transfer to the diesel generator takes place in 22 seconds. These timing features will prevent needless diesel starts during transient voltage dips, and provide adequate time delay for the startup offsite power circuit voltage to recover before transferring the bus to the diesel generator.

Should there be a loss of the startup offsite power circuit concurrent with the loss of onsite power (i.e., the main generating unit), the following events occur automatically, initiated by the first level of UV protection:

(1) The 4.16-kV circuit breaker feeding the Class 1E 4.16-kV Buses F, G, and H from the main generating unit is opened immediately.

(2) All three diesel generators for the unit are started and accelerated to minimum required frequency and bus voltage in a period of less than 10 seconds.

(3) Should the startup offsite power circuit be restored before the diesel auto-transfer interlock relay actuates, the circuit breakers feeding the Class 1E 4.16-kV Buses F, G, and H from the startup offsite power circuit are closed to restore power to the loads. First-level UV relays have already shed loads. Loads, including certain ESF loads that may not have been operating, are started in the same manner and sequence as when fed from the diesel generator. The preferred power supply may be restored by reclosing the circuit breakers for the 230-kV transmission lines automatically and/or manually at Morro Bay switchyard under the control of the CAISO (refer to Section 8.2.3.2).

Should the startup offsite power circuit still be unavailable when the diesel generators have reached breaker close-in voltage, all circuit breakers from the standby power supply and startup offsite power circuit to these Class 1E 4.16-kV buses are given a trip signal independently to make sure they are open (the expected condition at this point). The startup offsite power circuit is automatically blocked from reclosing. The circuit breakers for all loads, except the 4.16-kV/480-V load center transformers, have already been opened by the first level UV relays. Each of the Class 1E 4.16-kV buses has a separate pair of these relays. The relays have a two-out-of-two logic arrangement for each bus to prevent inadvertent tripping of operating loads during a loss of voltage either from a single failure in the potential circuits or from human error. Also, one of the relays has an inverse time characteristic and a slight delay of about 4 seconds at no voltage to prevent loss of operating loads during transient voltage dips, and to permit the startup offsite power circuit to pick up the load.

The Class 1E buses are then isolated from the rest of the plant, and from each other, and therefore operate independently. Any required or desired bus interconnecting is done manually by the operator.

The 4.16-kV circuit breaker for each diesel generator then closes automatically to restore power to the Class 1E 4.16-kV bus, and, consequently, the 480-V and 120-Vac buses also. All 4.16-kV circuit breakers have stored-energy closing mechanisms and close in less than 0.1 seconds.

The loads that remain connected to the 480-V buses become energized at the same time as the buses (refer to Section 8.3.1.1.4). These loads are within the initial load pickup capability of the diesel generators and are composed of the Class 1E lighting, the battery chargers, etc.

Other 480-V and 120-Vac equipment that can also operate immediately are those that are under automatic process control, and those under control of the protection system for the ESFs.

When the bus voltage is restored by the diesel generators, the UV relays that previously had tripped the loads will reset automatically. The individual loads are put into operation in a staggered sequence to reduce the effects of momentary loads and motor

starting on the diesel generators (refer to Technical Specifications [Reference 5]). The timing sequences have been given a nominal 4-second interval between steps during an SI signal, and a nominal 2 to 6 seconds between steps without an SI signal. The overall time to complete starting of all Class 1E loads is limited to less than 1 minute. The remaining loads can then be put into operation as desired.

The timing sequence for each Class 1E bus is initiated only when voltage is restored to the bus. When the startup offsite power circuit is available, power to the buses is restored in a few seconds when the residual voltage on the motors drops to 25 percent of normal. Otherwise, the delay is the time required for the diesel generators to transfer to the bus (shed loads and reach the minimum bus voltage, approximately 10 seconds or less).

To improve independence of control and to provide flexibility in setting the delays, individual adjustable timing relays are used for each motor. In addition, separate sets of these timing relays are used, depending on the presence or absence of the SI signal, so that response can be optimized for each condition. Should there be a second-level degraded grid condition, where the voltage of the Class 1E 4.16-kV buses remains at approximately 3,800-V or below, but above the setpoints of the first-level UV relays, the following events occur automatically within the time periods stated in the Technical Specifications:

(1) After the specified time delay, the respective diesel generators will be started.

(2) After the next specified time delay, if the UV condition persists, the circuit breakers for all loads to the respective Class 1E 4.16-kV buses, except the 4.16-kV/480-V load center transformer, are opened.

(3) Then the 4.16-kV circuit breakers from the normal onsite power source is given a trip signal to open the breaker feeding the bus and the standby power source breaker is already open, and then the circuit breaker for each respective diesel generator is closed.

(4) Restoration of normal voltage to the Class 1E 4.16-kV buses, supplied by the individual diesel generators, actuates timers that put loads back into operation in a staggered sequence.

Each Class 1E 4.16-kV bus has its own set of second level UV relays and associated timers causing the above sequences. Again, the Class 1E buses are now isolated from each other and from the rest of the plant and operate independently. Any required or desired bus interconnection has to be done manually by the operator. The transfer and subsequent operation of the Class 1E buses, because of degraded grid UV protection, is the same as described above for loss of the startup offsite power circuit concurrent with a loss of onsite power. However, no attempt will be made to transfer to the startup

offsite power circuit. Switching directly to the diesel generators ensures fast restoration of reliable power to the Class 1E 4.16-kV buses.

The logic used in starting and loading the EDGs is shown in Figure 8.3-16. Schematic diagrams of these functions are shown in Figures 8.3-12 through 8.3-14. A schematic diagram of the potential and synchronizing circuitry for the Class 1E buses is shown in Figure 8.3-20.

The starting inrush and momentary loads that occur during the initial phases of each interval will be handled by the short-time overload capability of the diesel generators. The diesel generators can maintain the electric power frequency and voltage at satisfactory levels during the cumulative loading of the successive steps.

The engine has an adequate short-time overload capability along with a fast response governor to hold the frequency. The generator has a low subtransient reactance and a voltage regulator with a fast response and a high excitation ceiling that will hold the voltage to a minimum of 75 percent of nominal during motor starting.

The Class 1E 4.16-kV/480-V load centers are left connected to their buses and are, therefore, energized first. Their initial load will consist of the momentary loads of the equipment that was left on, in addition to those initiated during the interruption. The net initial load on the load center consists of those loads that operate for a short time, such as motor operated valves, auxiliary lube oil pumps, etc., and the normal steady-state values for the remainder.

The starting loads of the larger motors that are started subsequently have also been included in the capabilities of the diesel generators.

8.3.1.1.3.3.5.3 4.16-kV Emergency Loads

In the event of an emergency shutdown of the main generating unit in the absence of the preferred power supply, the loads supplied by the diesel generator are applied in the following manner:

(1) In the absence of a SI signal, the first set of timing relays will operate and start the loads listed:

(a) The timing sequence and intervals are listed in Table 8.3-2. Notes for Table 8.3-2 and others in Section 8.3 are listed in Table 8.3-1.

(b) The loading on the Class 1E 4.16-kV buses, immediately following a unit shutdown without a LOCA, is as listed in Table 8.3-3.

(2) In the presence of a SI signal, the second set of timing relays operate and start the loads for the injection phase as listed in Table 8.3-4.

(3) The loading on the Class 1E 4.16-kV buses immediately following a unit shutdown, concurrent with a LOCA, is as listed in Table 8.3-5.

(4) The loading of the Class 1E 4.16-kV/480-V load centers, following a unit shutdown, with or without a LOCA, is as detailed on Figures 8.3-6 through 8.3-8.

8.3.1.1.3.3.6 General Design Criterion 18, 1971 – Inspection and Testing of Electric Power Systems

Surveillance tests and inspections are performed periodically to demonstrate the 4.16-kV system's design basis requirements are met. The controls for the 4.16-kV system are designed to be capable of periodic testing to assure operational and functional performance of the Class 1E components and operability of the system as a whole.

8.3.1.1.3.3.7 General Design Criterion 21, 1967 – Single Failure Definition

Each unit's Class 1E 4.16-kV distribution system is comprised of three electrically independent and redundant (refer to Section 8.3.1.4) Class 1E buses enclosed in separate rooms. If a single failure occurs in any of the three buses, the remaining buses have sufficient capability to provide power to ESF loads required to safely shut down the unit.

8.3.1.1.3.3.8 General Design Criterion 40, 1967 – Missile Protection

The portions of the Class 1E 4.16-kV system that support ESF loads and are located in zones where provision against dynamic effects must be made, are protected from missiles, pipe whip, or jet impingement from the rupture of any nearby high-energy line (refer to Sections 3.5, 3.6, 8.3.1.4.10.2, and 8.3.1.4.10.3).

8.3.1.1.3.3.9 4.16-kV System Safety Function Requirements

(1) Protection from Missiles

The provisions taken to protect the Class 1E portion of the 4.16-kV system from missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Sections 3.5 and 8.3.1.4.10.2.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the Class 1E portion of the 4.16-kV system from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Sections 3.6 and 8.3.1.4.10.3.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection of the Class 1E portion of the 4.16-kV system located outside containment from the effects of moderate energy pipe failure are discussed in Section 3.6.

(4) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the Class 1E portion of the 4.16-kV system located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6 and 8.3.1.4.10.3.

(5) Protection from Flooding Effects – Outside Containment

The provisions taken to provide protection of the Class 1E portion of the 4.16-kV system located outside containment from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

8.3.1.1.3.3.10 10 CFR 50.49 – Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

The Class 1E 4.16-kV system SSCs required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ program and the requirements for the environmental design of the electrical and related mechanical equipment. The affected components are listed in the EQ Master List.

8.3.1.1.3.3.11 10 CFR 50.63 – Loss of All Alternating Current Power

The Class 1E portion of the 4.16-kV system serves to distribute power to loads required to bring the plant to a safe shutdown condition (Mode 3) following a SBO. Refer to Section 8.3.1.6 for further discussion on SBO.

8.3.1.1.3.3.12 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The Class 1E 4.16-kV system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

Refer to Section 8.3.1.4.10.1 for additional discussion.

8.3.1.1.3.3.13 Safety Guide 6, March 1971 – Independence Between Redundant Standby (Onsite) Power Sources and Between their Distribution Systems

The three Class 1E 4.16-kV buses are physically enclosed in separate rooms and are electrically independent from each other when powered from their respective EDGs. Refer to Section 8.3.1.4 for further discussion on independence of redundant systems.

8.3.1.1.3.3.14 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Class 1E, Category 2 indication for each of the Class 1E 4.16-kV bus voltage and load center transformer primary amperage is provided in the control room for Regulatory Guide 1.97, Revision 3, monitoring (refer to Table 7.5-6).

8.3.1.1.3.4 Tests and Inspections

Refer to Section 8.3.1.1.3.3.6 for test and inspections details.

8.3.1.1.3.5 Instrumentation Applications

Refer to Section 8.3.1.1.3.3.4 for instrumentation details.

8.3.1.1.4 480-V System

8.3.1.1.4.1 Design Bases

8.3.1.1.4.1.1 General Design Criterion 2, 1967 – Performance Standards

The Class 1E portion of the 480-V system is designed to withstand the effects of, or is protected against, natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

8.3.1.1.4.1.2 General Design Criterion 3, 1971 – Fire Protection

The Class 1E portion of the 480-V system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

8.3.1.1.4.1.3 General Design Criterion 4, 1967 – Sharing of Systems

The 480-V system or components are not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

8.3.1.1.4.1.4 General Design Criterion 11, 1967 – Control Room

The Class 1E portion of the 480-V system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

8.3.1.1.4.1.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain 480-V system variables within prescribed operating ranges.

8.3.1.1.4.1.6 General Design Criterion 17, 1971 – Electric Power Systems

The Class 1E portion of the 480-V system is designed to have sufficient capacity, capability, independence, redundancy, and testability to perform its safety function assuming a single failure.

8.3.1.1.4.1.7 General Design Criterion 18, 1971 – Inspection and Testing of Electric Power Systems

The Class 1E portion of the 480-V system design permits appropriate periodic inspection and testing of functional and operational performance of the system as a whole and under conditions as close to design as practical.

8.3.1.1.4.1.8 General Design Criterion 21, 1967 – Single Failure Definition

The Class 1E portion of the 480-V system is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event shall be treated as a single failure.

8.3.1.1.4.1.9 General Design Criterion 40, 1967 – Missile Protection

The portions of the Class 1E 480-V system that support ESF loads are designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

8.3.1.1.4.1.10 General Design Criterion 49, 1967 – Containment Design Basis

The Class 1E and non-Class1E 480-V circuits routed through containment electrical penetrations are designed to support the containment design basis such that the containment structure can accommodate, without exceeding the design leakage rate, pressures and temperatures following a LOCA.

8.3.1.1.4.1.11 480-V System Safety Function Requirements

(1) Protection from Missiles

The Class 1E portion of the 480-V system is designed and located to be protected against the effects of missiles which may result from plant equipment failure and from events and conditions outside the plant.

(2) Protection Against High Energy Pipe Rupture Effects

The Class 1E portion of the 480-V system is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The outside containment Class 1E portion of the 480-V system required to bring the plant to cold shutdown is designed to be protected against the effects of moderate energy pipe failure.

(4) Protection from Jet Impingement – Inside Containment

The inside containment Class 1E portion of the 480-V system is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

(5) Protection from Flooding Effects – Outside Containment

The outside containment Class 1E portion of the 480-V system required to bring the plant to cold shutdown is to be protected from the effects of internal flooding.

8.3.1.1.4.1.12 10 CFR 50.49 – Environmental Qualification of Electrical Equipment

The 480-V system electrical components that require EQ are qualified to the requirements of 10 CFR 50.49.

8.3.1.1.4.1.13 10 CFR 50.63 – Loss of All Alternating Current Power

The Class 1E 480-V system provides power to the loads required to support systems that ensure core cooling and containment integrity is maintained following a SBO event.

8.3.1.1.4.1.14 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The Class 1E portion of the 480-V system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

8.3.1.1.4.1.15 Safety Guide 6, March 1971 – Independence Between Redundant Standby (Onsite) Power Sources and Between their Distribution Systems

The Class 1E portion of the 480-V system is designed such that electrically powered loads are separated into redundant load groups such that loss of any one group will not prevent the minimum safety functions from being performed.

8.3.1.1.4.1.16 Regulatory Guide 1.63, Revision 1, May 1977 – Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Plants

The Class 1E and non-Class1E 480-V circuits routed through containment electrical penetrations are designed to meet the requirements of Regulatory Guide 1.63, Revision 1, for the installation of redundant or backup fault current protection devices. The protection devices are designed to limit fault current to less than which the penetration can withstand assuming a single random failure of the circuit overload protective device.

8.3.1.1.4.1.17 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The 480-V system provides instrumentation in the control room to monitor 480-V system electrical status for post-accident instrumentation.

8.3.1.1.4.1.18 NUREG-0737 (Items II.E.3.1 (1) and II.G.I (2)), November 1980 – Clarification of TMI Action Plan Requirements

Item II.E.3.1 (1) – Emergency Power for Pressurizer Heaters: The non-Class 1E pressurizer heater power supply design provides the capability to supply, from either the preferred offsite power source or the standby power source (when offsite power is not available), to a predetermined number of pressurizer heaters and associated controls necessary to establish and maintain natural circulation at hot standby conditions. The required heaters and their controls are connected to the Class 1E emergency buses in a manner that will provide redundant power supply capability.

Item II.G.1 (2) – Emergency Power for Pressurizer Equipment: Motive and control components associated with the power operated relief valve (PORV) block valves are

capable of being supplied from either the preferred offsite power source or the standby power source when the offsite power is not available.

8.3.1.1.4.2 System Description

The 480-V system is a three-phase, three-wire, ungrounded system that provides power to motors not greater than 350 hp, lighting and electric heating systems, battery chargers, and instrument and control systems.

The 480-V loads are served from the 4.16-kV buses through 4.16-kV/480-V transformers closely coupled to either metal-enclosed low voltage switchgear or to motor control centers (MCCs). Five transformers in a duplex arrangement are provided for the non-Class 1E 480-V loads; two in the turbine building, two in the auxiliary building, and one at the intake structure. Three additional transformers, connected radially, are provided for the Class 1E 480-V loads, and the units are isolated from each other to maintain separation for the redundant Class 1E loads (refer to Figures 1.2-6, 1.2-8, 1.2-14, 1.2-16, 1.2-18, 1.2-20, and 8.3-6 through 8.3-8).

8.3.1.1.4.2.1 Maximum Demand

The loading on the Class 1E 480-V load centers immediately following a unit shutdown is as detailed on Figures 8.3-6 through 8.3-8. About 40 minutes after a major accident, the manual change-over of certain Class 1E bus loads to support the recirculation phase would be completed.

8.3.1.1.4.2.2 Pressurizer Equipment Power Supplies

Pressurizer equipment power supplies are designed to meet the requirements of GDC 17, 1971 and NUREG-0737 (Reference 2) in the event of LOOP. For further discussion of pressurizer equipment, refer to Section 5.5.9.

8.3.1.1.4.2.2.1 Pressurizer Heaters

The four pressurizer heater groups are normally connected to non-Class 1E 480-V power sources. All of the four pressurizer heater groups can be supplied with power from the offsite power sources when they are available.

When offsite power is not available, power can be provided to two out of four heater groups from the emergency power system (refer to Section 8.3.1.1.6) through Class 1E Buses G and H (refer to Figure 8.3-19). Sufficient power (150 kW) is available from the Class 1E buses to energize enough heaters to maintain natural circulation at hot standby conditions. Redundancy is provided by supplying the two groups of heaters from the different Class 1E buses. The ability to supply emergency power to the heaters minimizes a potential loss of subcooling in the reactor coolant system after a LOOP.

Transfer of pressurizer heater power supplies can be performed manually (in accordance with operating procedures) in less than 60 minutes using manual transfer switches located at the 100-foot elevation in the auxiliary building. Since the pressurizer heaters are non-Class 1E loads, they are automatically tripped off of the Class 1E buses upon occurrence of a SI actuation signal. Breaker and switchgear equipment interfacing the pressurizer heaters with the Class 1E buses is Class 1E and seismically qualified.

8.3.1.1.4.2.3 Lighting

Normal lighting is operated at 208Y/120-Vac, three-phase, on a four-wire solidly grounded system supplied from the 480-V system through dry-type, delta-wye connected, 3-phase transformers.

The ac emergency lighting is supplied from two of the three Class 1E 480-V buses. Emergency lighting is located throughout the plant to provide minimum general lighting during a failure of normal lighting. Direct current emergency lighting is operated at 125-Vdc from the non-Class 1E station batteries.

ESF equipment areas and various access routes thereto are provided with individual BOLs capable of providing 8 hours of illumination when ac power to the BOL is lost. The batteries are continuously charged with a built-in charger. Rack area uninterruptible power supply (UPS) lighting is provided for the same purpose.

Refer to Section 9.5.3 for requirements for battery operated lights.

8.3.1.1.4.3 Safety Evaluation

8.3.1.1.4.3.1 General Design Criterion 2, 1967 – Performance Standards

The Class 1E 480-V load center transformers and switchgear are located at 100 foot elevation of the auxiliary building, a PG&E Design Class I structure (refer to Figure 1.2-6). The auxiliary building is designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7). This design protects the Class 1E 480-V load center transformers and switchgear, ensuring their design function will be performed.

The Class 1E 480-V load center transformers and switchgear are seismically designed to perform their safety functions under the effects of earthquakes (refer to Section 3.10.3.7.4).

8.3.1.1.4.3.2 General Design Criterion 3, 1971 – Fire Protection

The Class 1E 480-V switchgear and cable spreading room are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

Refer to Section 8.3.1.4.9 for further discussion on fire barriers and separation.

8.3.1.1.4.3.3 General Design Criterion 4, 1967 – Sharing of Systems

Portions of the control room ventilation system (CRVS) and control room pressurization system equipment required to maintain control room habitability are shared between Unit 1 and Unit 2, 480-V, Class 1E switchgear buses via mechanically interlocked transfer switches.

Power to the technical support center, which is normally fed by a Unit 2, non-Class 1E, 480-V MCC, may be manually transferred via a transfer switch to a Unit 2, Class 1E 480-V switchgear. If this power supply is not available, power can be transferred to the Unit 1 Class 1E 480-V switchgear via another transfer switch.

The DFO transfer pumps are powered from either Unit 1 or Unit 2 Class 1E 480-V bus via a manual transfer switch.

The Unit 1 and Unit 2 communication room power distribution panels are normally fed from their corresponding Class 1E 480-V bus. Each is provided with a manual transfer switch, which allows transfer of power source to the other unit's Class 1E 480-V bus.

Operation of these transfer switches is administratively controlled to ensure that a fault in one unit is isolated from the other units power source.

8.3.1.1.4.3.4 General Design Criterion 11, 1967 – Control Room

The Class 1E 480-V switchgear and MCCs fed by a load transformer have a single phase voltmeter and an indicating potential light to monitor bus availability within the control room.

The HSP, which is the alternate control location in the event that the control room is rendered uninhabitable, is provided with transfer switches, control switches and status indication for the 480-V components that are controllable at the HSP. Additionally, a cut-in/cut-out switch and relay located at the 480-V MCC is provided to isolate the HSP from the switchgear control circuits in the event of fire at the HSP.

8.3.1.1.4.3.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The Class 1E and non-Class 1E 480-V switchgear and MCCs that are directly fed from a load transformer are equipped with a ground detection circuit and ground indicating lights that provide annunciation in the main control room. The 480-V switchgears and MCCs are also provided with local bus monitoring devices. The load center transformers are equipped with winding temperature sensors with alarm contacts and provide automatic and manual control of the cooling fans.

8.3.1.1.4.3.6 General Design Criterion 17, 1971 – Electric Power Systems

The Class 1E 480-V distribution system is comprised of three (3) electrically independent and redundant load groups (refer to Section 8.3.1.4). Each of the Class 1E MCCs are located in separate rooms for independence to meet the single failure criterion. If a single failure occurs in any of the three MCC groups, the remaining two MCC groups have sufficient capacity and capability (refer to Section 8.3.1.1.4.3.8) to provide power to ESF loads required to safely shut down the unit.

8.3.1.1.4.3.7 General Design Criterion 18, 1971 – Inspection and Testing of Electric Power Systems

The Class 1E 480-V system is designed to be capable of periodic testing to assure operational and functional performance of the Class 1E components and operability of the system. Refer to Section 8.3.1.4.3.2 for further discussion on test and inspection for electrical cables.

Each MCC is independently supplied power (refer to Section 8.3.1.4) from a load center transformer that derives power from a 4.16-kV switchgear and allows for testability of the 480-V distribution system.

8.3.1.1.4.3.8 General Design Criterion 21, 1967 – Single Failure Definition

The Class 1E 480-V distribution system is comprised of three (3) electrically independent and physically separated redundant (refer to Section 8.3.1.4) Class 1E buses enclosed in separate rooms. If a single failure occurs in any of the Class 1E buses, the remaining two buses have sufficient capacity and capability to provide power to ESF loads required to safely shut down the unit.

8.3.1.1.4.3.9 General Design Criterion 40, 1967 – Missile Protection

The portions of the Class 1E 480-V system that support ESF loads and are located in zones where provision against dynamic effects must be made, are protected from missiles, pipe whip, or jet impingement from the rupture of any nearby high-energy line (refer to Sections 3.5, 3.6, and 8.3.1.4.10.2).

8.3.1.1.4.3.10 General Design Criterion 49, 1967 – Containment Design Basis

The Class 1E and non-Class1E 480-V circuits routed through containment electrical penetrations are each provided with electrical protection devices. This arrangement is such that with the failure of one device, the penetration remains protected from high current temperature by the other in-series device to ensure the containment penetration remains functional. Refer to Sections 3.8.2.1.1.3.1 and 8.3.1.4.8 for additional details.

8.3.1.1.4.3.11 480-V System Safety Function Requirements

(1) Protection from Missiles

The provisions taken to protect the Class 1E portion of the 480-V system from missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Sections 3.5 and 8.3.1.4.10.2.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the Class 1E portion of the 480-V system from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Sections 3.6 and 8.3.1.4.10.3.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection of the Class 1E portion of the 480-V system located outside containment from the effects of moderate energy pipe failure are discussed in Section 3.6.

(4) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the Class 1E portion of the 480-V system located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6 and 8.3.1.4.10.3.

(5) Protection from Flooding Effects – Outside Containment

The provisions taken to provide protection of the Class 1E portion of the 480-V system located outside containment from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

8.3.1.1.4.3.12 10 CFR 50.49 – Environmental Qualification of Electrical Equipment

Except for the cables and splices, all the Class 1E 480-V system SSCs are located in a mild environment unaffected by the harsh condition created by a design basis accident (DBA). Therefore, only cable and splices located in a harsh environment are environmentally qualified. Section 3.11 describes the DCPP EQ program and the requirements for the environmental design of the electrical and related mechanical equipment. The environmental qualification of the cables and splices is controlled by the DCPP EQ program.

8.3.1.1.4.3.13 10 CFR 50.63 – Loss of All Alternating Current Power

The Class 1E portion of the 480-V system serves to distribute power to loads required to bring the plant to a safe shutdown condition (Mode 3) following a SBO. Refer to Section 8.3.1.6 for further discussion on SBO.

8.3.1.1.4.3.14 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The Class 1E 480-V system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

8.3.1.1.4.3.15 Safety Guide 6, March 1971 – Independence Between Redundant Standby (Onsite) Power Sources and Between their Distribution Systems

The three Class 1E 480-V buses are physically enclosed in separate rooms and are electrically independent from each other when powered from their respective EDGs. Refer to Section 8.3.1.4 for further discussion on independence of redundant systems.

8.3.1.1.4.3.16 Regulatory Guide 1.63, Revision 1, May 1977 – Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Plants

Class 1E and non-Class 1E 480-V circuits routed through containment electrical penetrations are designed with redundant overcurrent protection. Refer to Section 8.3.1.4.8 for further discussion.

8.3.1.1.4.3.17 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Class 1E, Category 2 indications for each Class 1E 480-V bus voltage is provided in the control room for Regulatory Guide 1.97, Revision 3, monitoring (refer to Table 7.5-6).

8.3.1.1.4.3.18 NUREG-0737 (Items II.E.3.1 (1) and II.G.1 (2)), November 1980 – Clarification of TMI Action Plan Requirements

II.E.3.1 (1) – Emergency Power Supply for Pressurizer Heaters: Section 8.3.1.1.4.2.2.1 provides a discussion of the power supply design configuration for the pressurizer heaters in conformance with NUREG-0737, II.E.3.1 (1).

II.G.1 (2) – Emergency Power for Pressurizer Equipment: The three Class 1E 480-V motor operated PORV block valves are each powered independently from the Class 1E 480-V ESF buses which are capable of being supplied from either the offsite source or

the emergency power source when the offsite power source is not available. This conforms to the requirement of NUREG-0737, II.G.1 (2).

8.3.1.1.4.4 Tests and Inspections

Refer to Section 8.3.1.1.4.3.7 for tests and inspections.

8.3.1.1.4.5 Instrumentation Applications

Refer to Section 8.3.1.1.4.3.5 for instrumentation applications.

8.3.1.1.5 120-Vac Instrument Supply Systems

8.3.1.1.5.1 Design Bases

8.3.1.1.5.1.1 General Design Criterion 2, 1967 – Performance Standards

The Class 1E 120-Vac system is designed to withstand the effects of, or is protected against, natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

8.3.1.1.5.1.2 General Design Criterion 3, 1971 – Fire Protection

The Class 1E 120-Vac system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

8.3.1.1.5.1.3 General Design Criterion 4, 1967 – Sharing of Systems

The 120-Vac system or components are not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

8.3.1.1.5.1.4 General Design Criterion 11, 1967 – Control Room

The Class 1E portion of the 120-Vac system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

8.3.1.1.5.1.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the 120-Vac system variables within prescribed operating ranges.

8.3.1.1.5.1.6 General Design Criterion 17, 1971 – Electric Power Systems

The Class 1E 120-Vac system is required to have sufficient capacity, capability, independence, redundancy, and testability to perform its safety function assuming a single failure.

8.3.1.1.5.1.7 General Design Criterion 18, 1971 – Inspection and Testing of Electric Power Systems

The Class 1E portion of the 120-Vac system design permits appropriate periodic inspection and testing of functional and operational performance of the system as a whole and under conditions as close to design as practical.

8.3.1.1.5.1.8 General Design Criterion 21, 1967 – Single Failure Definition

The Class 1E portion of the 120-Vac system is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event shall be treated as a single failure.

8.3.1.1.5.1.9 General Design Criterion 24, 1967 – Emergency Power for Protection Systems

The Class 1E portion of the 120-Vac system is designed to remain operable after a loss of all offsite power.

8.3.1.1.5.1.10 General Design Criterion 40, 1967 – Missile Protection

The portions of the Class 1E 120-Vac system that support ESF loads are designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

8.3.1.1.5.1.11 General Design Criterion 49, 1967 – Containment Design Basis

The Class 1E and non-Class 1E 120-Vac circuits routed through containment electrical penetrations are designed to support the containment design basis such that the containment structure can accommodate, without exceeding the design leakage rate, the pressures and temperatures following a LOCA.

8.3.1.1.5.1.12 120-Vac System Safety Function Requirements

(1) <u>Protection from Missiles</u>

The Class 1E 120-Vac system is designed and located to be protected against the effects of missiles which may result from plant equipment failure and from events and conditions outside the plant.

(2) Protection Against High Energy Pipe Rupture Effects

The Class 1E 120-Vac system is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The outside containment portion of the Class 1E 120-Vac system required to bring the plant to cold shutdown is designed to be protected against the effects of moderate energy pipe failure.

(4) Protection from Jet Impingement – Inside Containment

The inside containment portion of the Class 1E 120-Vac system is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

(5) Protection from Flooding Effects – Outside Containment

The outside containment portion of the Class 1E 120-Vac system required to bring the plant to cold shutdown is to be protected from the effects of internal flooding.

8.3.1.1.5.1.13 10 CFR 50.49 – Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

The Class 1E 120-Vac system electrical components that require EQ are qualified to the requirements of 10 CFR 50.49.

8.3.1.1.5.1.14 10 CFR 50.62 – Requirements for Reduction of Risk from Anticipated Transients without Scram Events for Light-Water-Cooled Nuclear Power Plants

The non-Class 1E 120-Vac power source meets the electrical power requirements to provide a source to the anticipated transients without scram (ATWS) mitigation actuation circuitry (AMSAC) that is independent from the protection system power supplies.

8.3.1.1.5.1.15 10 CFR 50.63 – Loss of All Alternating Current Power

The Class 1E 120-Vac system provides power to the loads required to support systems that assure core cooling and containment integrity is maintained following a SBO event.

8.3.1.1.5.1.16 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The Class 1E portion of the 120-Vac system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

8.3.1.1.5.1.17 Safety Guide 6, March 1971 – Independence Between Redundant Standby (Onsite) Power Sources and Between their Distribution Systems

The Class 1E portion of the 120-Vac system is designed such that electrically powered loads are separated into redundant load groups such that loss of any one group will not prevent the minimum safety functions from being performed.

8.3.1.1.5.1.18 Regulatory Guide 1.63, Revision 1, May 1977 – Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants

The Class 1E and non-Class 1E 120-Vac circuits routed through containment electrical penetrations are designed to meet the requirements of Regulatory Guide 1.63, Revision 1, regarding installation of redundant or backup fault current protection devices to limit fault current to less than the penetration can withstand assuming a single random failure of the circuit overload protective device.

8.3.1.1.5.1.19 NUREG-0737 (Item II.G.1 (4)), November 1980 – Clarification of TMI Action Plan Requirements

Item II.G.1 (4) – Emergency Power for Pressurizer Equipment (Pressurizer Level Indication): The pressurizer level indication instrument channels shall be powered from the Class 1E instrument buses. The buses shall have the capability of being supplied from either the preferred power supply or the standby power supply when the preferred power supply is not available.

8.3.1.1.5.2 System Description

8.3.1.1.5.2.1 Class 1E 120-Vac Instrument Power Supply System

The 120-Vac Class 1E instrument bus system shown in Figure 7.6-1 supplies electric power for instrumentation, control, protection, and annunciation for the nuclear steam supply system and other Class 1E loads. The nuclear steam supply system loads are divided into four redundant groups each with its own distribution panel(s) for each unit. The six panels are served by four dedicated UPSs supplied either from their associated Class 1E 480-V bus or from their associated Class 1E batteries. The UPSs are sized to continuously carry the maximum connected load without exceeding their nameplate rating. In addition, each UPS has a backup regulating transformer with manual transfer switch that can be fed from either of two 480-V Class 1E buses. This backup power is

provided through the UPS static transfer switch or the UPS manual bypass switch, and supplies backup 120-Vac power to the instrument bus when its UPS is out of service. This four UPS design provides redundant, uninterrupted 120-Vac, 60-Hz, single-phase power to the Class 1E instrument buses.

The dc power flow control of the inverter unit ensures that while the ac power input to the rectifier is available, the power to the distribution panels will be supplied through the rectifier and the inverter. When the ac power input to the rectifier is not available, the power to the distribution panel(s) will be supplied from the dc bus through the inverter.

8.3.1.1.5.2.2 Non-Class 1E 120-Vac Instrument Power Supply System

Other UPSs and inverters are supplied from the 480-V or 208Y/120-Vac systems and backed up by either station batteries or a dedicated UPS battery. UPSs and inverters are used to supply the plant's digital computers and other non-Class 1E plant instrumentation and control systems needing uninterrupted ac power.

8.3.1.1.5.3 Safety Evaluation

8.3.1.1.5.3.1 General Design Criterion 2, 1967 – Performance Standards

The Class 1E 120-Vac UPSs, inverter, voltage regulating transformer and distribution panel equipment are located in the auxiliary building, which is a PG&E Design Class I structure, contained within the Class 1E 125-Vdc switchgear rooms (refer to Figure 1.2-5). The Class 1E 125-Vdc switchgear rooms are adjacent to the Class 1E 125-Vdc battery rooms. The auxiliary building is designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7) to protect the Class 1E 120-Vac UPSs, inverters, voltage regulating transformers and distribution panel equipment, ensuring their design function will be performed. Loss of dc switchgear/inverter room ventilation and Class 1E raceways located outdoors, associated with 120-Vac system that are exposed to effects of tornadoes, have been evaluated and they do not compromise the capability of shutting down the plant safely (refer to Section 3.3.2.3).

The Class 1E 120-Vac UPSs, inverters, and voltage regulating transformers are seismically designed to perform their safety functions under the effects of earthquakes (refer to Section 3.10.3.1.4).

8.3.1.1.5.3.2 General Design Criterion 3, 1971 – Fire Protection

The Class 1E inverters are located in the Class 1E 125-Vdc switchgear rooms. The 125-Vdc switchgear rooms are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

Refer to Section 8.3.1.4.9 for further discussion on fire barriers and separation.

8.3.1.1.5.3.3 General Design Criterion 4, 1967 – Sharing of Systems

The Class 1E 120-Vac system is shared between the CRVS for both units through the use of manually operated mechanical transfer switches.

Power to Unit 1 CRVS panels, which is normally fed from a Unit 1, Class 1E 120-Vac instrument supply system, may be manually transferred to a Unit 2 Class 1E 120-Vac instrument supply system, in the event the Unit 1 supply is not available, through the mechanical transfer switch. Similar operation can be accomplished for the Unit 2 CRVS panels.

Safety is not impaired by the sharing since the transfer of power supply between the units is not done automatically but through the use of manually operated mechanical transfer switches. These transfer switches ensure that a fault in one unit is isolated from the other unit's power source. In addition, operation of these transfer switches is administratively controlled.

8.3.1.1.5.3.4 General Design Criterion 11, 1967 – Control Room

The dc power flow is monitored internally in the UPS, and dc input power to the inverter is supplied from the rectifier or from the dc bus as appropriate.

The loss of ac power to the distribution panels is alarmed in the control room. There are no UPS breaker controls on the control board, as transfers between Class 1E ac and dc sources will occur automatically without interruption due to loss of the 480-V power source.

8.3.1.1.5.3.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The loss of ac power to the distribution panels is alarmed in the control room.

The Class 1E UPSs have locally mounted meters for dc input, bypass input, and ac output indications. They also have power available indication lights for ac input, dc input and bypass input power sources. An alarm mimic panel mounted on the face of the UPS panel is provided with alarm indication lights to indicate normal and abnormal conditions.

8.3.1.1.5.3.6 General Design Criterion 17, 1971 – Electric Power Systems

The Class 1E UPSs are sized to continuously carry the maximum connected loads without exceeding their nameplate rating.

The inverters are designed to maintain their outputs within the limits of 60 Hz ± 0.5 percent and 120-Vac ± 2 percent from zero to full load.

There are three independent Class 1E 480-V power sources, Buses F, G, and H, in each unit. Bus F serves UPS 11, Bus G serves UPS 12, and Bus H serves UPSs 13 and 14. Three Class 1E 125-Vdc sources serve the four UPSs: UPS 11 is supplied power from battery 11, UPSs 12 and 14 are supplied power from battery 12, and UPS 13 is supplied power from battery 13. The UPSs operate normally on both the ac and dc systems. If either system is interrupted, the UPS will be supplied from the remaining source without interruption (refer to Figure 7.6-1).

Each of the four UPSs is independently connected to its respective channel instrument distribution panels so that the loss of a UPS cannot affect more than one channel of the system.

8.3.1.1.5.3.7 General Design Criterion 18, 1971 – Inspection and Testing of Electric Power Systems

The Class 1E UPS inverters are routinely checked on a weekly basis and are inspected and tested on a refueling outage frequency. Periodic component replacements per manufacturer's specifications are performed to maintain the Class 1E qualification.

Additional discussion on inspection and testing is found in Section 8.3.1.4.3.2

8.3.1.1.5.3.8 General Design Criterion 21, 1967 – Single Failure Definition

The onsite Class 1E electrical power distribution system is designed with three independent 4.16-kV and 480-V Class 1E buses (F, G, and H) and three 125-Vdc Class 1E buses in each unit (refer to Section 8.3.1.1.5.3.6 and Figure 7.6-1).

Each of the four UPSs is independently connected to its respective channel instrument distribution panels so that the loss of a UPS cannot affect more than one channel of the system.

In addition, each of the four UPSs may be automatically transferred to a regulated 120-Vac backup power source by its static transfer switch. Each distribution panel can also receive power from the regulated 120-Vac backup source by its manual bypass switch. Each regulating transformer has its normal and alternate power source through a manual transfer switch. Each UPS has its rectifier connected to the inverter and the dc power source through a blocking diode that prevents the rectifier from backfeeding the dc system.

The UPSs operate normally on both the ac and dc systems. If the ac system is interrupted, the inverter will be supplied from the Class 1E dc source without interruption (refer to Figure 7.6-1).

The plant protection system is designed with four input channels (I, II, III, and IV) powered from four 120-Vac Class 1E buses (1, 2, 3, and 4). The four channels provide input to the SSPS Trains A and B. Class 1E 120-Vac Bus 1 and 4 provide power to the

SSPS train A and train B output relays, respectively. The SSPS input relays are fail safe (with the exception of the input circuits that initiate containment spray, the radiation monitoring channels that initiate containment ventilation isolation, and the RCP UF low flow trip channels [refer to Sections 7.2.3.12 and 7.3.4.1.1]), whereas the SSPS output relays require power to actuate.

Each SSPS train actuates ESF equipment in the three Class 1E ac and dc buses and certain Non-Class 1E equipment in the Non-Class 1E ac and dc buses. As allowed per IEEE 308-1971, Class 1E dc Bus 12 feeds Class 1E 120-Vac Buses 12 and 14 in Unit 1 and Class 1E dc Bus 22 feeds Class 1E 120-Vac Buses 22 and 24 in Unit 2. For design basis accident scenarios concurrent with a LOOP, a single failure of the Unit 1 Class 1E dc Bus 12 will cause the loss of Class 1E 120-Vac Buses 12 and 14 in Unit 1. Similarly a single failure of the Unit 2 Class 1E dc Bus 22 will cause the loss of Class 1E 120-Vac Buses 22 and 24 in Unit 2. This is acceptable because the loss of Class 1E dc Bus 12 in Unit 1 or Class 1E dc Bus 22 in Unit 2 does not prevent the minimum safety functions from being performed. Loss of both IY/PY 12(22) and IY/PY 14(24) is acceptable because the remaining two 120-Vac inverters and buses can supply at least one full ESF train.

Therefore, a single failure in the instrumentation and control power supply system or its associated power supplies does not prevent the minimum safety functions from being performed.

8.3.1.1.5.3.9 General Design Criterion 24, 1967 – Emergency Power for Protection Systems

In the event of a loss of all offsite power, the Class 1E 120-Vac system is automatically powered from the Class 1E 125-Vdc system and will automatically be re-powered from the Class 1E 4.16-kV/480-V bus when the EDG loads onto its Class 1E 4.16-kV bus.

8.3.1.1.5.3.10 General Design Criterion 40, 1967 – Missile Protection

Class 1E 120-Vac instrument supply system equipment and cables that support ESF loads are protected from internally generated missiles, pipe-whip and jet impingement. Detailed discussions of these protections are delineated in Sections 8.3.1.4.10.2 and 8.3.1.4.10.3 respectively.

8.3.1.1.5.3.11 General Design Criterion 49, 1967 – Containment Design Basis

Class 1E and non-Class 1E 120-Vac circuits routed through containment are analyzed for redundant overcurrent protection and available fault energy. Circuits without direct in-line redundant protection have been analyzed to determine the available fault current is not of sufficient magnitude to damage the penetration conductor, penetration, or containment integrity.

Refer to Sections 3.8.2.1.1.3, 8.3.1.1.5.3.15, and 8.3.1.4.8 for additional details.

8.3.1.1.5.3.12 120-Vac System Safety Function Requirements

(1) Protection from Missiles

The provisions taken to protect the Class 1E 120-Vac system from missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Sections 3.5 and 8.3.1.4.10.2.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the Class 1E 120-Vac system from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Sections 3.6 and 8.3.1.4.10.3.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection of the Class 1E portion of the 120-Vac system located outside containment from the effects of moderate energy pipe failure are discussed in Section 3.6.

(4) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the Class 1E portion of the 120-Vac system located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6 and 8.3.1.4.10.3.

(5) Protection from Flooding Effects – Outside Containment

The provisions taken to provide protection of the Class 1E portion of the 120-Vac system located outside containment from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

8.3.1.1.5.3.13 10 CFR 50.49 – Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

The Class 1E 120-Vac system SSCs required to function in harsh environments under accidents conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ program and the requirements for the environmental design of the electrical and related mechanical equipment. The affected components are listed on the EQ Master List.

8.3.1.1.5.3.14 10 CFR 50.62 – Requirements for Reduction of Risk from Anticipated Transients without Scram Events for Light-Water-Cooled Nuclear Power Plants

The AMSAC in both units is powered from the Non-Class 1E chemistry lab and counting room inverter. This inverter is powered from non-reactor protection system (RPS) power supplies in either Unit 1 or Unit 2.

8.3.1.1.5.3.15 10 CFR 50.63 – Loss of All Alternating Current Power

The Class 1E UPSs are sized to continuously carry the maximum connected loads without exceeding their nameplate rating during a SBO event.

To prevent receiving an spurious SI signal during a SBO condition, operator action is taken within 2 hours to provide at least two input channels of instrumentation to monitor system functions and actuate one train of safeguards equipment.

The Class 1E portion of the 120-Vac system serves to distribute power to loads required to bring the plant to a safe shutdown condition (Mode 3) following a SBO event. Refer to Section 8.3.1.6 for further discussion on SBO.

8.3.1.1.5.3.16 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The Class 1E 120-Vac system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

8.3.1.1.5.3.17 Safety Guide 6, March 1971 – Independence Between Redundant Standby (Onsite) Power Sources and Between their Distribution Systems

Each of the redundant onsite Class 1E 120-Vac power sources and its distribution system is independent from each other. The electrically powered loads are separated into redundant load groups such that loss of any one group will not prevent the minimum safety functions from being performed.

For discussion related to independence of redundant systems, separation criteria for Class 1E systems and Class 1E separation and protection criteria (refer to Sections 8.3.1.4, 8.3.1.4.1, and 8.3.1.4.10, respectively).

Further discussions on separation and isolations are found in Sections 8.3.1.4.2, 8.3.1.4.4, and 8.3.1.4.6.

8.3.1.1.5.3.18 Regulatory Guide 1.63, Revision 1, May 1977 – Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants

Class 1E and non-Class 1E 120-Vac circuits routed through containment electrical penetrations are designed with redundant overcurrent protection. Circuits without direct in-line redundant protection have been analyzed to determine the available fault current is not of sufficient magnitude to damage the penetration conductor or penetration.

Refer to Sections 8.3.1.1.5.3.11 and 8.3.1.4.8 for additional details.

8.3.1.1.5.3.19 NUREG-0737 (Item II.G.1 (4)), November 1980 – Clarification of TMI Action Plan Requirements

Item II.G.1 (4) – Emergency Power for Pressurizer Equipment (Pressurizer Level Indication): The pressurizer level indication circuits are Class 1E and qualified for post-accident. The Class 1E instrument channels are supplied from inverters which are supplied from the ESF buses with automatic backup from the Class 1E emergency batteries.

8.3.1.1.5.4 Tests and Inspections

Refer to Section 8.3.1.1.5.3.7 for tests and inspections details.

8.3.1.1.5.5 Instrumentation Applications

Refer to Section 8.3.1.1.5.3.5 for instrumentation applications.

8.3.1.1.6 Diesel Generator Units

The physical arrangement of the engine generator units is shown in Figures 9.5-10 and 9.5-11 for Unit 1; the arrangement is similar for Unit 2. Figure 9.5-12 shows the outline of the Unit 1 engine generators. The arrangement is similar for the Unit 2 generators with the exception of EDG 2-3, which is slightly different.

The six diesel generators for Unit 1 and Unit 2 are essentially identical, self-contained units housed in individual compartments at elevation 85 feet in the turbine building. Three are located in the northwest or Unit 1 portion, and three are located in the southwest or Unit 2 portion of the structure. The compartments separate each diesel generator and its accessories from the adjacent units and conform to PG&E Design Class I requirements.

8.3.1.1.6.1 Design Bases

8.3.1.1.6.1.1 General Design Criterion 2, 1967 – Performance Standards

The EDG system is designed to withstand the effects of, or is protected against natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

8.3.1.1.6.1.2 General Design Criterion 3, 1971 – Fire Protection

The EDG system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

8.3.1.1.6.1.3 General Design Criterion 4, 1967 – Sharing of Systems

The EDG system or components are not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

8.3.1.1.6.1.4 General Design Criterion 11, 1967 – Control Room

The EDG system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

8.3.1.1.6.1.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain EDG system variables within prescribed operating ranges.

8.3.1.1.6.1.6 General Design Criterion 17, 1971 – Electric Power Systems

The EDG system is designed to have sufficient capacity, capability, independence, redundancy, and testability to perform its safety function assuming a single failure.

8.3.1.1.6.1.7 General Design Criterion 18, 1971 – Inspection and Testing of Electric Power Systems

The EDG system design permits appropriate periodic inspection and testing of functional and operational performance of the system as a whole and under conditions as close to design as practical.

8.3.1.1.6.1.8 General Design Criterion 21, 1967 – Single Failure Definition

The EDG system is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event shall be treated as a single failure.

8.3.1.1.6.1.9 Emergency Diesel Generator System Safety Function Requirements

(1) Protection from Missiles

The EDG system is designed and located to be protected against the effects of missiles which may result from plant equipment failure and from events and conditions outside the plant to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(2) Protection Against High Energy Pipe Rupture Effects

The EDG system is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The EDG system is designed to be protected against the effects of moderate energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(4) Protection from Flooding Effects – Outside Containment

The EDG system is to be protected from the effects of internal flooding to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

8.3.1.1.6.1.10 10 CFR 50.55a(g) – Inservice Inspection Requirements

Applicable EDG system components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

8.3.1.1.6.1.11 10 CFR 50.63 – Loss of All Alternating Current Power

The EDG system meets the criterion of providing an alternate ac (AAC) source within ten minutes of SBO.

8.3.1.1.6.1.12 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The EDG system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

8.3.1.1.6.1.13 Safety Guide 9, March 1971 – Selection of Diesel Generator Set Capacity for Standby Power Supplies

The EDG system meets the applicable requirements of Safety Guide 9, March 1971 for steady state loading capability with one regulatory approved exception for DCPP:

(1) Exception to loading sequence frequency requirements of Safety Guide 9, March 1971, Position C.4 for motor-driven AFW pump loading on EDGs 1-1, 1-3, 2-2, and 2-3 (Reference 30).

8.3.1.1.6.1.14 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The EDG instrumentation systems provide instrumentation in the control room to monitor EDG electrical status for post-accident instrumentation.

8.3.1.1.6.1.15 Regulatory Guide 1.108, Revision 1, August 1977 – Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants

As required by Regulatory Guide 1.108, Revision 1 (Reference 25), EDG testing simulates, where practical, the parameters of operation that would be expected if actual demand were to be placed on the system, as delineated in Technical Specification Bases 3.8.1.

There are four regulatory approved exceptions to Regulatory Guide 1.108, Revision 1 for DCPP:

(1) Exception to testing frequency guidelines of Regulatory Position C.2.a based on compliance with the TS 5.5.18 Surveillance Frequency Control Program (Reference 27).

(2) Exception to EDG hot restart testing guidelines of Regulatory Position C.2.a (5) based on use of a modified hot restart test (Reference 28).

(3) Exceptions to Regulatory Positions C.2.a (9), C.2.d, C.2.e and C.3 based on compliance with NUMARC 93-01, Revision 2, “Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants” (Reference 29).

(4) Exception to Regulatory Position C.2.a(3) to demonstrate full-load-carrying capability for an interval of 2 hours at a load equivalent to the 2-hour rating of the diesel generator (Reference 33).

8.3.1.1.6.2 System Description

8.3.1.1.6.2.1 Diesel Generator Unit Description

Each diesel generator unit consists of a self-contained diesel engine directly connected to an alternating current generator, and the separate accessories needed for proper operation, all mounted on a common structural steel skid-type base. Mechanical power is provided by an 18 cylinder, vee configuration, four-cycle, 9-inch bore x 10-1/2 inch stroke, 12,024 cubic inch displacement, 3630 horsepower at 900 rpm, turbocharged and aftercooled, heavy-duty, stationary-type diesel engine.

The generator is rated at 3250 kVA, 0.8 PF, 4.16kV, 60 Hz, three-phase, Y-connected, ungrounded, 80°C temperature rise, Class B insulation, with a drip-proof enclosure. The transient reactance is 14.1 percent, and the subtransient reactance is 8.1 percent. The exciter is a static series, boost-type exciter controlled by a static solid-state voltage regulator.

Five diesel engine generator units have been supplied by the ALCO Engine Division of White Industrial Power, Inc. The sixth diesel engine generator, EDG 2-3, was manufactured by G. E. Locomotives, the current owner and manufacturer of ALCO engines and locomotives at the time. In most respects, this EDG is similar to the other five EDGs; the differences and commercial grade dedication are documented in RPE M-6602. ALCO has supplied engine generator units to serve as emergency onsite standby power at several nuclear power plants. Among these are two ALCO units for the Palisades Nuclear Plant, which have the same engine as the first five DCPP engine generator units and a slightly smaller generator (2500kW continuous rating), and the two ALCO units for the Pilgrim I Nuclear Station, which has engines and generators that are identical to the first 5 at DCPP. Both of these nuclear power plants are in operation. In addition, the Salem 1 and 2 nuclear power plant has engine generator units with the same engines and generators as the first five DCPP engine generator units.

The EDG auxiliary systems; starting air system, ventilation system, cooling water system, lubrication system, fuel oil storage and transfer system, and compartment ventilation system are described in Sections 9.4.7 and 9.5.4 through 9.5.7.

8.3.1.1.6.2.2 Combustion Air Intake System

The combustion air is taken into the engine through woven, dry-type, particulate filter media, encased in a cylindrical steel retaining structure. This air intake filter structure is supported from the ceiling in the radiator fan portion of the engine generator compartment. After passing through the filter, the combustion air is drawn into the engine through a 22-inch carbon steel pipe. The physical arrangement of the air intake filter and piping for Unit 1 is shown in Figures 9.5-10 and 9.5.11, and is similar for Unit 2. The diagram of the combustion air intake system is shown in Figure 3.2-21 (Sheets 7, 8, 8A, and 8B).

As shown in Figures 9.5-10 and 9.5-11 for Unit 1, the combustion air for the diesel engines is taken from the west side of the building, and the exhaust from the engines is directed upward through the roof on the north side of the turbine building for Unit 1. Unit 2 diesels are similar, except the exhaust is through the south wall of the turbine building. The exhaust is at a higher elevation than the combustion air intake. This arrangement ensures that the engine exhaust will be dispersed without the possibility of diluting the combustion air. There is no equipment or structure on the west side of the turbine building within the proximity of the combustion air intake that would create the potential for noncombustible or explosive gases being drawn into the engine.

Approximately 30 percent of the outside air drawn by the radiator fan is routed through ductwork providing ventilation for the diesel generator compartment. Refer to Section 9.4.7 for a complete description of the ventilation system.

8.3.1.1.6.3 Safety Evaluation

8.3.1.1.6.3.1 General Design Criterion 2, 1967 – Performance Standards

The EDGs are located at elevation 85 foot of the turbine building, which is a PG&E Design Class II structure (refer to Figures 1.2-16 and 1.2-20). This building or applicable portions have been designed not to impact PG&E Design Class I components and associated safety functions (refer to Section 3.7.2.2.2.1). The turbine building is designed to withstand the effects of winds and tornadoes (refer to Sections 3.3.1.2 and 3.3.2.5.2.8), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7.2.2.2.1) to protect the EDGs.

The diesel generator excitation cubicle and control cabinet are seismically qualified to perform their safety functions under the effects of the Design Earthquake (DE), Double Design Earthquake (DDE), and Hosgri Earthquake (HE) (refer to Section 3.10.3.6).

The engine generator units and their associated auxiliary systems, as shown for Unit 1 in Figures 9.5-8 through 9.5-10, and similarly for Unit 2, are installed in separate compartments that are protected from fires, flooding, and external missiles.

Any postulated external missile would not penetrate into more than one compartment. Section 3.3.2 provides more discussion on hypothetical external missiles generated by a postulated tornado. No common failure mode exists where one single event would disable more than one diesel generator.

It is not credible for the HE to restrict the flow of exhaust gases from the diesel engine and thereby create excessive back pressure on the engine. The design of the exhaust system, shown schematically in Figure 3.2-21 (Sheet 7), precludes any major failures, such as a major failure of the silencer and/or the connecting piping, which would have to develop to produce any significant flow restriction. The internal baffles and chambers of the silencer are designed so that even if an internal baffle breaks completely loose, it will not block exhaust flow. The silencer supports, as well as the connecting piping

supports, are designed in accordance with the same criteria as for PG&E Design Class I equipment supports; i.e., to withstand the HE with no loss of function. Exhaust and combustion air inlet piping is qualified for the HE.

The exhaust silencers and piping are located in separate compartments with no other piping or equipment that could adversely affect the silencers or piping during a HE. The exhaust lines of the Unit 1 diesels pass through the turbine building roof, and the exhaust lines of the Unit 2 diesels pass through the south wall of the turbine building, but are not considered a risk in the seismically induced system interaction (SISI) program. The compartments are located immediately above the engine generators in the turbine building. An engineering review of the turbine building has shown that during a seismic event the building will not collapse. This analysis is discussed in Section 3.7.2.

Other equipment associated with the diesel generators that is seismically qualified includes:

(1) Fuel oil day tanks

(2) Closed cooling water system, including fan and radiator

(3) Fuel oil storage tanks and fuel oil piping

(4) Lube oil system

(5) Ventilation system

8.3.1.1.6.3.2 General Design Criterion 3, 1971 – Fire Protection

The EDG areas are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

Refer to Section 8.3.1.4.9 for further discussion on fire barriers and separation. The portion of each compartment that houses the diesel generator is provided with a thermally actuated total flooding CO_2 gas system, in accordance with NFPA Standard No. 12, 1973 (Reference 6). Temperature-actuated, automatic closing, roll-down fire-rated doors close ventilation air openings to prevent CO_2 leakage. The CO_2 flooding is restricted to the engine generator compartment by closing fire doors that isolate and seal the compartment. Refer to Section 9.5.1 for a complete description of the CO_2 system. Additionally, two hose stations are provided adjacent to the compartment locations in each unit. The diesel generator installation is in accordance with NFPA 37-1970 (Reference 7).

Each engine generator compartment is provided with a CO_2 flooding system for fire suppression. CO_2 flooding will extinguish a fire in one compartment while the other engine generator units continue normal operation. In addition, 3-hour fire walls are

provided between the individual compartments. A normally closed, 3-hour fire door separates the corridor connecting the diesel generator rooms from the main condenser area. This door is also designed to prevent a postulated condenser leak from flooding the diesel generator rooms (refer to Section 10.4.5). Section 9.5.1 provides more information on the fire protection system.

There is no combustible gas line or storage facility within or near the engine generator compartments. The only flammable liquids contained within the engine generator compartments are those necessary for the operation of the engines, i.e.; engine lube oil and DFO.

The startup transformers, located immediately north of the Unit 1 and south of the Unit 2 engine generator compartments, contain insulating oil, which is a potential fire hazard. However, the transformers are equipped with fire detection and fire suppression systems to quench potential fires. The engine generator compartment nearest the startup transformer is separated from the transformer by a 3-hour fire wall. The engine generator combustion air intakes are not affected by a transformer fire since combustion air is drawn from the west side of the building.

The main turbine seal oil systems are the closest source of flammable liquids within the turbine building. The seal oil units are located about 65 feet from the common corridor for each unit's diesel generators. Each seal oil unit is supplied with a fire detection and fire suppression system.

A failure of the number 10 turbine bearing (between the exciter and generator) is the next closest potential fire hazard, since an open bay connects the turbine deck elevation (140 feet) with the diesel generator elevation (85 feet). The bay opening is located about 35 feet horizontally from the diesel generator common corridor. The Number 10 bearing is equipped with a fire detection and fire suppression system. The turbine building fire suppression systems would contain any turbine lube oil fire and prevent any hazard to the diesel engine generators. Refer to Section 9.5.1 for additional fire protection system information.

8.3.1.1.6.3.3 General Design Criterion 4, 1967 – Sharing of Systems

The fuel oil storage and transfer subsystem of the EDG system are shared between Unit 1 and Unit 2 (refer to Section 9.5.4.3.3).

8.3.1.1.6.3.4 General Design Criterion 11, 1967 – Control Room

Controls for engine generator functions are both local at the engine generator compartment and remote in the main control room. Each of the units may be manually started or stopped from either location to facilitate periodic testing. The generators may be synchronized from the control room so that they can be paralleled with the other power systems for testing. In addition, there is an emergency manual stop for each unit located outside each engine generator compartment. Automatic starting of the units

occurs in the event of the conditions listed in Section 8.3.1.1.3.3.5.1. Each of the six units is provided with two starting control circuits.

Engine generator units are normally controlled from the control room. A two-position local-remote switch located at each engine generator unit allows control of each unit to be switched from the control room (remote) to the engine generator compartment (local). Whenever control of any of the units is switched to the compartment (local), the operator is informed by a control room annunciator alarm. The alarm identifies the engine generator unit on local control.

8.3.1.1.6.3.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The units are fully instrumented to monitor important parameters and alarm abnormal conditions, both locally at the engine generator compartment and remotely in the main control room.

Each diesel generator is designed with two starting control circuits, one field flashing circuit, and one sensing circuit. These circuits receive Class 1E dc control power through a manual transfer switch. Class 1E dc power is from the same train as the diesel generator. In the event of failure of dc power to these control circuits, an alarm appears on the main annunciator. The manual transfer switch, located near the control panel at the diesel generator can be used to transfer to backup Class 1E dc power.

Loading of the diesel generators during the recirculation phase is under the control of the operator. To aid in loading these units, instruments are provided to indicate their load at all times.

For additional information on instrumentation application, refer to Section 8.3.1.1.6.5

8.3.1.1.6.3.6 General Design Criterion 17, 1971 – Electric Power System

The EDG system is required to have sufficient capacity, capability, independence, redundancy, and testability to perform its safety function assuming a single failure.

The emergency power system includes onsite, independent, automatic starting diesel generators that supply power to essential auxiliaries if normal power sources are not available.

Three dedicated 4.16-kV, three-phase, 60-Hz, 2600-kW, 0.8 PF continuous rating diesel generators are provided for each unit as shown in Figure 8.1-1. The individual diesel generator units are physically isolated from each other and from other equipment. Each diesel generator supplies power to its associated 4.16-kV Class 1E bus (refer to Figures 8.3-4, 1.2-16, and 1.2-20).

The ESF loads and their onsite sources are grouped so the functions required during a major accident are provided regardless of any single failure in the electrical system. Any two of the three diesel generators and their buses are adequate to serve at least the minimum required ESF loads of a unit after a major accident.

Refer to Section 8.3.1.1.3.3.5.2 for additional discussion of ESF load grouping.

Section 8.3.1.1.6.3.13 discusses EDG capacity and Section 8.3.1.1.6.4 demonstrates EDG system testability.

8.3.1.1.6.3.7 General Design Criterion 18, 1971 – Inspection and Testing of Electric Power Systems

Descriptions of the inspections and tests are provided in Section 8.3.1.1.6.4.

8.3.1.1.6.3.8 General Design Criterion 21, 1967 – Single Failure Definition

The ESF loads and their onsite standby sources (EDGs) are grouped so the functions required during a major accident or transient coincident with a complete loss of the preferred power source are provided regardless of a single failure of an EDG. Any two of the three diesel generators and their buses are adequate to serve the required ESF loads of a unit after a major accident or transient.

The single failure criterion applies to the DFO system. Refer to Section 9.5.4.3.7 for discussion related to the DFO system.

8.3.1.1.6.3.9 Emergency Diesel Generator Systems Safety Function Requirements

(1) <u>Protection from Missiles</u>

The engine generator units and their associated auxiliary systems, as shown for Unit 1 in Figures 9.5-8 through 9.5-10, and similarly for Unit 2, are installed in separate compartments that provide protection from internal missiles.

Because the engine generator units are separated from each other by the concrete walls of the compartments, the units are protected from postulated internal missiles. Any missile created by an explosion within a compartment would remain in that compartment.

The provisions taken to protect the EDG system from missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Sections 3.5 and 8.3.1.4.10.2.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the EDG system from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Sections 3.6 and 8.3.1.4.10.3.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection of the EDG system portion located outside containment from the effects of moderate energy pipe failure are discussed in Section 3.6.

(4) Protection from Flooding Effects – Outside Containment

The provisions taken to provide protection of the EDG system portion located outside containment from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

The possibility of flooding in the turbine building is discussed in Sections 9.2.1, 9.2.2, 9.2.7, 10.4.5, and 10.4.7 under the service cooling water, CCW, ASW, circulating water and condensate and feedwater systems, respectively. Flooding in these areas of the turbine building were assessed for impact on the diesel generator compartments.

High-energy line breaks outside the containment that could affect the turbine building are discussed in Section 3.6. There is no significant source of water within any of the engine generator compartments, and the design of the engine generator compartments (refer to Figures 1.2-16 and 1.2-20) prevents flooding within the generator compartments because the cross-sectional area for water to enter the compartments is less than the cross-sectional area for water to exit the compartments.

8.3.1.1.6.3.10 10 CFR 50.55a(g) – Inservice Inspection Requirements

Only the EDG jacket water cooling system components are included in the DCPP Inservice Inspection Program per 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5).

8.3.1.1.6.3.11 10 CFR 50.63 – Loss of All Alternating Current Power

The SBO analysis demonstrates that the plant can be safely shutdown following a SBO event utilizing Bus F and its normally connected EDG (AAC source). The AAC source is a Class 1E EDG and meets the criteria for an AAC stated in NUMARC-8700 (Reference 23). The AAC source will be available within 10 minutes of the onset of SBO with a target reliability of 0.95. The SBO Analysis demonstrates that the AAC source has sufficient capacity and capability to operate systems necessary for coping with a SBO for the required duration of 4 hours to maintain the unit in a safe shutdown condition (Mode 3). Refer to Section 8.3.1.6 for a complete discussion of SBO.

8.3.1.1.6.3.12 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The EDG system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

8.3.1.1.6.3.13 Safety Guide 9, March 1971 – Selection of Diesel Generator Set Capacity for Standby Power Supplies

The diesel generators have a net continuous electrical output rating of 2600 kW at 0.8 PF, and 2750 kW at 0.8 PF, for 2000 hours per year. Short-term ratings of the diesel generators are 2860 kW at 0.8 PF for 2 hours per 24-hour period, and 3056 kW at 0.8 PF for 30 minutes per 24-hour period. During the starting sequence for the safeguard loads, these machines can also carry short-time overloads. EDG loading meets the applicable criteria of Safety Guide 9, March 1971 (Reference 8).

Momentary loads consisting principally of transient inrush currents, relay and solenoid short-time currents, starting currents to motors, and starting and operating currents for motor-operated valves are within the short-time capability of the electric power systems and the engine generators.

During a design basis-loading scenario with nominal timer interval, these machines maintain the electric power frequency within 5 percent, hold voltages to a minimum of 75 percent, and recover successfully by complying with Safety Guide 9, March 1971 (Reference 8) with the exception of Regulatory Position C.4. Safety Guide 9, March 1971, Regulatory Position C.4 specifies that during the EDG loading sequence the frequency should be restored to within 2 percent of nominal in less than 40 percent of each load sequence time interval. For AFW pump loading for EDGs 1-1, 1-3, 2-2, and 2-3, the frequency is restored to within 2 percent of nominal in less than 60 percent of the load sequence time interval. Based on test data, EDGs 1-1, 1-3, 2-2, and 2-3 have adequate margin to prevent overlapping of loads and meet the objectives of Safety Guide 9, March 1971, Regulatory Position C.4. This exception to Safety Guide 9, March 1971, was approved in License Amendments 211/213 dated March 29, 2012.

Refer to Section 8.3.1.1.3.3.5.2 for additional discussion of EDG ESF loading and functions.

8.3.1.1.6.3.14 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Class 1E, Category 2 indications for each EDG wattage and amperage is provided in the control room for Regulatory Guide 1.97, Revision 3, monitoring (refer to Table 7.5-6).

8.3.1.1.6.3.15 Regulatory Guide 1.108, Revision 1, August 1977 – Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants

The EDGs are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with GDC 18, 1971. This periodic testing ensures that the EDGs will meet their availability requirements. Periodic component tests are supplemented by extensive functional tests during refueling outages.

Additionally, Generic Letter 84-15 was issued to improve EDG reliability by reducing the number of cold fast starts and by eliminating excessive testing. Cold fast starting of EDGs is not applicable to DCPP as the EDGs are equipped with lube oil and water jacket heating devices to maintain the oil and water temperatures at levels which permit immediate assumption of load. Also, engine bearings are lubricated by motor-driven lube oil circulating pumps which run continuously prior to engine start.

8.3.1.1.6.4 Tests and Inspections

The electrical systems have been designed to permit inservice inspection and periodic functional testing. The tests and scheduling are specified in the Technical Specifications. These tests are made to demonstrate that all Class 1E electrical systems are capable of performing their safety functions.

All six Diablo Canyon diesel engine generator units have undergone extensive shop testing to qualify the units as emergency standby power sources. A large part of the shop testing at ALCO Engine Division of White Industrial Power, Inc. was in addition to the normal manufacturer performance tests for units of this type. Special shop tests were conducted to verify the unit design capabilities, their reliability, and their conformance to specification requirements.

A summary of the ALCO shop testing is shown in Table 8.3-8. In addition, extensive preoperational qualification testing was performed for the engine generator units during DCPP startup. A summary of preoperational testing for the engine generators at Diablo Canyon is shown in Table 8.3-9.

Automatic starting of the diesel generators is tested by removal of available power from its offsite source or its bus, simulating a bus UV condition, or by initiating a test from the RPS. The bus should transfer to the offsite source automatically, and the diesel generators should start and reach normal operating conditions if bus voltage is not restored within one second.

The absence of offsite power is simulated by opening the bus feeder breaker, simulating a bus UV condition, or removal of its potential to the transfer control circuits. The test is repeated, with the diesel generator as the source and the loading sequence for the

absence of safety injection. In the presence of a test safety injection signal (SIS), the test is repeated with the loading sequence for this condition.

Should there be an actual SIS while the diesel generator is paralleled with the unit auxiliary transformer during a test, the SIS signal would trip the unit auxiliary transformer (preventing a potential overload of the diesel generators), and diesel generator breaker closed prevents transfer of this bus to the startup source. Loads already running on this bus will continue to run, other loads will be started by their SIS timers, and any containment fan coolers running on high will automatically be restarted on low speed.

8.3.1.1.6.5 Instrumentation Applications

All operating conditions that could normally be expected to render the diesel generators incapable of responding to an automatic emergency start signal are alarmed in the control room. A "diesel generator trouble" annunciator is alarmed in the main control room whenever any of the following conditions occur:

(1) Diesel is in manual or test condition

(2) Loss of dc control power

(3) Low fuel level in day tank

(4) Low starting air pressure

(5) Shutdown relay tripped

(6) Lube oil system trouble

(7) Primary filter high differential pressure (Unit 2 only)

In addition to the diesel generator trouble annunciator window, there are alarm annunciator windows and data logger printouts for each of the above seven conditions.

The following abnormal conditions are annunciated in the main control room for each unit:

(1) Engine generator on local control, manual control, or test

(2) Generator circuit breaker on local control

(3) DC control UV

(a) Engine generator control

(b) Circuit breaker control

(4) Engine starting air pressure - low

(5) Engine fails to start (overcrank)

(6) Engine lube oil system trouble

(a) Low lube oil pressure

(b) Low lube oil level

(c) High lube oil filter differential pressure

(d) High lube oil temperature

(e) Low lube oil temperature

(f) Precirculating lube oil pump failure

(7) Engine cooling system trouble

(a) High jacket water temperature

(b) Low jacket water level

(c) High compartment air temperature

(d) High radiator discharge air temperature

(8) Engine fuel oil system trouble

(a) High/low engine fuel oil day tank level

(b) High/low storage fuel oil storage tank level

(c) Fuel oil transfer pump overcurrent

(d) Low engine fuel oil priming tank level

(e) Fuel oil transfer pump running

(9) Engine crankcase vacuum trouble

(10) Generator stator temperature - high

(11) Ground overcurrent

(12) Generator negative sequence

(13) Engine trip (shutdown relay tripped)

(14) Engine generator circuit breaker trip

(a) Reverse power

(b) Loss of field

(c) Generator differential overcurrent

(15) Auxiliaries UV or overcurrent

(16) Engine generator on backup dc supply

(17) High fuel oil transfer filter differential pressure (Plant common alarm annunciated in Unit 1 control room only)

(18) High diesel room temperature (temperature monitoring system)

If the engine generator unit is started automatically on loss of standby power, or safety injection, or both, the engine trip or shutdown functions are limited to the following:

(1) Engine overspeed

(2) Engine low lube oil pressure

(3) Generator current differential

(4) Emergency stop switch

The engine overspeed trip is a mechanical device relying on centrifugal force to release a spring that, by mechanical action alone, stops the flow of fuel and shuts down the engine. Although a mechanical failure of the device could occur and cause a spurious shutdown of the engine, the manufacturer has many years of satisfactory operational experience with this device in all types of service. Also, the engine overspeed trip is a single-purpose device, designed specifically as a secondary or backup device in the event the normal speed control system malfunctions. Normal engine speed control is provided by the governor. The governor and the overspeed trip are considered independent, redundant devices.

The low lubricating oil pressure shutdown is actuated by two pressure switches in the engine lubricating oil system. Both devices must be actuated by low pressure to shut

down the engine. A malfunction by one can be postulated but, by itself, could not generate an engine trip. Also, the low lubricating oil pressure trip is actually a low-low lubricating oil pressure condition. The setpoint for shutdown is 20 psig below the low lubricating oil pressure alarm point at which the operator is informed of the low-pressure condition.

The generator current differential relay has successfully undergone seismic testing as part of the relay boards, as reported in Section 3.10, so false operation due to an earthquake should not occur. False operation under conditions other than an earthquake would occur only due to failure of a particular internal component of the relay.

If the engine generator unit is started manually in the test mode, greater engine protection is provided and the following abnormal conditions, in addition to the four for automatic mode, will also trip the engine:

(1) Engine overcrank (after 10 seconds of engine cranking and failure to start)

(2) Engine high jacket water temperature

Protection of the electrical equipment associated with the engine generator units is provided by opening the generator circuit breaker in the event of any of the trips listed above, and any of the following abnormal electrical conditions:

(1) Generator loss of field excitation

(2) Generator reverse power (antimotoring)

(3) Generator overcurrent

(4) 4.16-kV bus current differential

(5) Generator current differential

(6) Generator field shorting contactor de-energized (loss of jacket water pressure and nominal speed less than 100 rpm)

A trip cutout switch disables the loss of field, reverse power, and overcurrent protection for each diesel generator during normal operation; that is, when the diesel is not in test mode. The switch is located in each bus's respective safeguard relay board and activates an alarm whenever protection is cut in.

Generator loss of field relay, reverse power relay, overcurrent relays, and bus differential relays have been successfully tested for seismic loads, as detailed in Section 3.10, so false operation due to an earthquake will not occur.

8.3.1.2 Analysis

As previously described in this chapter, standby and preferred power supplies are provided, each adequately sized to permit functioning of systems, equipment, and components important to safety. An analysis of the preferred power supply is contained in Section 8.2.2. Section 8.3.1.1 contains an analysis and description of the design and operation of the preferred power supply, including a tabulation of diesel generator capabilities and loading.

The design bases established for the design of the Class 1E electrical circuits, their conductors, and raceways ensure that the nuclear reactor and safeguards system and equipment can operate properly at all times. These bases comply with GDC 17, 1971; GDC 18, 1971; Safety Guide 6, March 1971 (Reference 9); and IEEE 308-1971. In developing these design bases, careful consideration was given to the following factors:

(1) Separation and isolation of redundant electrical circuits

(2) Construction, capacity, and loading of electrical conductors and cables

(3) Construction, arrangement, and conductor fill of electrical raceways

(4) Environmental conditions and protection from physical hazards

(5) Electrical fault protection

The power and control cable insulation used has been specified and tested to meet requirements that exceed IEEE, National Electric Code, or Insulated Power Cable Engineers Association (IPCEA) standards for flame retardance and self-extinguishing capabilities.

8.3.1.3 Conformance with Appropriate Quality Assurance Standards

The Class 1E electrical systems, equipment, and components were designed, fabricated, installed, inspected, and tested under the formal quality assurance program developed during design and construction of the plant. The current quality assurance program is described in the Diablo Canyon Quality Assurance Program Description. Reactor protection system testing is described in Chapter 7.

8.3.1.4 Independence of Redundant Systems

This section presents the criteria and bases for the installation of Class 1E electrical systems. These criteria establish the minimum requirements for preserving the independence of redundant Class 1E electrical systems to ensure that they remain operational during any design basis event.

Each of the redundant, onsite, ac power sources and its distribution system is independent from the others. The Class 1E Buses F, G, and H are each independently supplied by one diesel generator. No swing bus is utilized. There is no provision for automatically paralleling the standby power source of one load with the standby source of another load. There is no provision for automatically connecting one Class 1E load group with another load group or for the automatic transfer of load groups between redundant standby power sources.

8.3.1.4.1 Separation Criteria for Class 1E Systems

Mutually redundant Class 1E electrical power equipment, devices, and circuits are physically separated from each other to meet single failure criteria of the standards. Diablo Canyon is not committed to Regulatory Guide 1.75 separation and isolation requirements.

Major Class 1E electric power distribution equipment is located in individual rooms isolated from non-Class 1E equipment, and also from other mutually redundant Class 1E equipment. In this case, separation of internal wiring is inherently achieved by the amount of spacing of the equipment, isolation by fire-rated concrete walls and floors, and use of fire-rated doors. Where Class 1E circuits of more than one mutually redundant system are in proximity in the same enclosure, panel, board, or unit of equipment, these circuits are run in separate metallic wireways or conduits and are typically connected to different terminal blocks. Separate wireways are not provided for certain low-energy steam generator wide-range water level instrument loops resulting from original plant construction. Exposed wiring at end connections to control devices (such as control switches) is separated by at least 5 inches for mutually redundant circuits. Less than 5 inches of separation is allowed for (a) low-energy signal (instrument loop) connections to indicating devices (such as recorders) that must be functionally grouped to enhance operator comprehension, and (b) certain existing Class 1E ammeters with ≥ 3 inches separation resulting from original plant construction. Mutually redundant circuits in boards and panels are separated by one of the following methods:

(1) Five-inch minimum separation in air

(2) Metallic barrier

(3) Metallic conduit

(4) Glastic barrier

(5) Sealtite Flex

(6) "Scotch Brand" 7700 or equivalent electric arc and fireproofing tape with "Pluton" fabric exposed, and a minimum of a 1/4-inch overlap between wraps. This tape is held in place after application with AMP-TY stainless

steel cable ties, or two complete wraps of Varglass silicone tying cord, Type 46. Maximum length between steel or cord ties does not exceed 18 inches

(7) Varflex Type HA (heat-treated glassbraid)

(8) Varflex silifex sleeving

(9) Silicone RTV fire sealant material

Methods (1) through (5) are used wherever possible. Methods (6) through (9) are used only where methods (1) through (5) are not feasible. In the main control board and console, mutually redundant Class 1E devices are placed in individual modules, 5 inches apart, which provide two thicknesses of metallic or electrical insulating material between them, or the devices are separated by one of the above methods. For low-energy devices (indicators and recorders) unit cases are relied upon for adequate separation. External connections for mutually redundant circuits are brought through separate floor openings and risers. In addition, design for routing of interconnecting wiring is based on a requirement that there be no direct line of sight exposure between mutually redundant circuit conductors.

Electrical conductors that interconnect separate units of equipment or devices throughout the plant are separated for redundant systems in these ways:

(1) Where a separate room is provided exclusively for a group of redundant equipment requiring circuits, the cables may be placed in trays or troughs within the room. With the exception of underfloor wiring beneath the protection racks, these are the only areas where cable trays are used.

(2) In all other areas of the plant, Class 1E circuits are placed in metallic conduit for exposed conduit, and ABS plastic or rigid iron for embedded conduit.

(3) Nuclear protection instrumentation channels are placed in separate raceways. Cable trays under the protection racks are enclosed beneath a subfloor and barriered from each other by solid structural floor support beams. Each protection channel output from the same channel to the same logic train shares the same raceway. Separate raceways are used for the direct inputs to logic Trains A or B.

(4) In the cable spreading areas of each unit, electrical cables for redundant functions are placed in separate conduits. Circuit segregation can be on either a protection channel, train, Class 1E bus, or dc bus basis. All conductors in the cable spreading area associated with safety-related functions are enclosed in metallic conduits. Only non-Class 1E wiring is

run in trays, with the exception of underfloor wiring beneath the protection racks.

For more details on separation of protective circuits, refer to Figure 7.3-50 (Sheets 1 and 2).

8.3.1.4.2 Separations and Isolations

Electrical circuits are separated from each other according to class of service and to redundancy group. Separation criteria for mutually redundant circuits are given in the preceding section. Separate raceway systems are used for each of the following service categories:

(1) High-Voltage Power - This category contains all of the power circuits above 600-V; in this case, the 4.16-kV and 12,000-V conductors.

(2) Low Voltage Power and Control - This category includes power circuits below 600-V; in this case, 480-V and 120-Vac/208-V, and also the 120-Vac and 125-Vdc control circuits.

(3) Instrumentation - This category contains the circuits transmitting low-level sensitive signals for instrumentation and process control. It includes the conductors for thermocouples, resistance temperature detectors, and the transducers and transmitters used in the fluid process and electric power instrumentation systems.

(4) Nuclear Instrumentation - This category contains the circuits for the nuclear instrumentation and control system.

8.3.1.4.3 Insulated Electrical Conductors

Electrical conductors are copper, except for some thermocouple wire, and are stranded except for thermocouple, communications, and lighting branch circuits. Conductor sizes are based on the current and temperature ratings given in the National Electric Code (Reference 10), the "Power Cable Ampacities," Publication S-135-1 (Reference 11) of the American Institute of Electrical Engineers (AIEE), or by the cable manufacturer, as appropriate. Cables have been derated for ambient temperature and cable grouping in a common raceway. Low-voltage small power cables have been derated as specified in the National Electric Code, 1968 Edition, Table 3.10-12, and Notes 8 and 15. High-voltage and large power cables have been derated as specified in AIEE Publication S-135-1, Tables VII, VIII, and IX for grouping, and by using a conductor temperature that is less than the rating of the insulation by the same amount that the ambient is above the standard used in the table. Cables located in cable trays may be derated in accordance with Insulated Cable Engineers Association (ICEA) P-54-440 (Reference 19).

8.3.1.4.3.1 Construction and Voltage Ratings

The insulation and jacket materials are selected for their superior electrical and physical characteristics and will perform their function under the most severe conditions expected for the application. The compounds are thermally stable and do not melt. All power and control cable jacket materials are flame retardant. Power and control cable insulations are also flame retardant.

Wire and cables run between equipment located in the conventional environment are insulated with ethylene-propylene rubber or cross-linked polyethylene (XLPE). Jacket materials are either neoprene, hypalon (chlorosulfonated polyethylene [CSPE]), thermoset chlorinated polyethylene (TS-CPE), XLPE or linear low density polyethylene. Silicon rubber, polyarlene, polyimide film, Tefzel, XLPE, or equivalent insulation material, with a silicone rubber, polyarlene, Tefzel, hypalon (CSPE), XLPE, or equivalent jacket material are used for circuits located where high ambient temperatures may be encountered.

Within equipment, boards, panels, and devices, insulation is either fluorinated ethylene-propylene, XLPE, polyvinyl chloride (PVC) with an asbestos jacket (NEC Type TA), or PVC alone. The use of PVC has been kept to a minimum and is used only where a manufacturer has standardized production with this material. No PG&E Design Class I or Class 1E panel, board, or equipment has PVC insulated wires, except that devices such as relays, transmitters, and instruments may have some PVC. The small amount of PVC present does not present any problems with respect to toxic effects or corrosive products in the event of fire.

The insulated electrical conductors that externally interconnect separate units of equipment throughout the plant are described in Appendix 8.3B

8.3.1.4.3.2 Test and Inspection

The construction and material composition of each type of cable has been selected based on careful investigation and analysis, including the results of tests performed in accordance with Underwriters' Laboratories (UL), IPCEA-NEMA, AEIC, and PG&E requirements.

All cables for circuits that externally interconnect separate units of equipment were given the production electrical and physical tests described in the standards. Flame tests for low-voltage power, control, and instrumentation cable were made according to UL and IPCEA standard procedures and to special PG&E methods using large groups of wires bundled in a cable tray and a large burner. The cable supplier was also required to make this test. Only cables that were self-extinguishing upon removal of the burner flame were selected. Refer to the previous section for those types of cables requiring flame retardant insulation. Conductors for equipment, boards, panels, and devices were selected and specified on the basis of UL approval for this service and special PG&E or manufacturer's tests.

Conductors required to operate in containment atmosphere during a LOCA were tested in a steam chamber, either by the manufacturer or PG&E, before approval for quotations. Refer to Section 3.11 for additional information on equipment required to operate during a LOCA.

A particular effort was made to ensure that manufacturing standards of the highest quality were maintained in the production of all cables for use in Class 1E circuits. To ensure that the cable, as manufactured, is of the highest quality, PG&E inspectors performed visual inspections and witnessed factory tests on sample reels from each production run of cable.

8.3.1.4.4 Electrical Raceways

The total cross-sectional area of conductors in trays is limited generally to 30 percent of the tray cross-sectional area, with a maximum limit of 32 percent unless otherwise approved by an engineering evaluation. Electrical conduits are designed to the limits given in the NEC. The limit of 40 percent conduit fill is generally required, with a maximum of 42 percent fill unless otherwise approved by an engineering evaluation.

Electrical raceways that interconnect individual sets or units of equipment throughout the plant are arranged to provide separate raceways for each class of service and redundancy group. Also, separate raceways are provided for Class 1E electrical systems. Exposed raceways are either cable tray or metallic electrical conduit. Embedded raceways are ABS plastic of standard iron pipe size, except that some very short lengths are rigid iron.

8.3.1.4.5 Cable Trays

Cable trays are generally of the ventilated uncovered type. Solid bottom or covered trays are placed in locations where protection is needed and ventilation may be reduced. Trays are made of formed steel, hot-dip galvanized, with sides 3 inches high and widths up to 24 inches. The trays comply with NEMA Standard VE-1-1965 for Class 2 construction. Aluminum trays are used in a few cases where severe corrosion of steel is a problem, such as at the intake structure. Aluminum is not used in the containment. Cable trays for Class 1E systems are only installed where a separate room is provided exclusively for each mutually redundant group of Class 1E circuits.

8.3.1.4.6 Conduit

Metallic conduits are generally hot-dipped galvanized steel, either rigid iron or electrical metallic tubing. Aluminum conduit is used where magnetic induction may be a problem. Aluminum, Stainless Steel or PVC-coated rigid iron conduit may be used where corrosion is present, such as at the intake structure. Aluminum conduit is not used in the containment. Stainless steel conduit is used, as needed, for example where electrical circuits enter stainless steel liners. Flexible liquid-tight conduit is used in short

sections where vibration or differential expansion may occur. An exception to this is the reactor head assembly where long flexible liquid-tight conduits exist for the convenience of the reactor head removal process upon refueling. Long flexible conduits in cable trays are also utilized in the cable spreading room for the white light circuits due to space limitations. Plastic (ABS) conduit is installed completely encased in concrete or in earth beneath a protective concrete slab. Metallic conduit is installed for mutually redundant Class 1E electrical circuits where they are close to, and exposed to, each other.

8.3.1.4.7 Supports

Cable trays are supported on spans of 8 feet or less, and also at each end of the fittings. Unless otherwise approved by an engineering evaluation, exposed conduits are supported at intervals of 8-1/2 feet or less, and also within 4 feet of any termination. Supports for Class 1E electrical raceways are designed to withstand the seismic forces established for the location. Refer to Section 3.10 for more information on seismic design. PG&E Design Class I supports are not normally shared by mutually redundant Class 1E circuits. Exceptions to this are areas such as in the cable spreading room under the control room and in the fuel handling building at elevation 100 feet. However, as stated earlier, all PG&E Design Class I supports are seismically qualified.

8.3.1.4.8 Penetrations

Cable penetrations through walls are (a) in jumboduct embedded in concrete (refer to Figures 8.3-21 and 8.3-22), (b) in conduit embedded in concrete (refer to Figure 8.3-23), or (c) in conduit passing through a wall opening with the space between the conduit and the concrete sealed as described below. Containment penetrations by high- and low-voltage and signal cables are either a canister-type design or feed through penetration modules that provide a single seal as part of the pressure barrier. Containment penetrations are also provided as part of the personnel and emergency airlocks. Additional information on the containment penetration design is provided in Section 3.8.2.1.1.3.1. These containment penetrations are LOCA qualified as described in Section 3.11.

Overcurrent protection of the containment electrical penetrations meets the requirements of Regulatory Guide 1.63, Revision 1 (Reference 12). In addition, non-Class 1E penetration overcurrent protection has procurement documentation or an engineering evaluation verifying the capability to protect the penetration during and after a DE.

The electrical penetrations are designed and built in accordance with IEEE 317-1971 (Reference 32) with the following exceptions:

(1) Prototype tests were not made with all of the physical conditions of the accident environment applied simultaneously with the electrical tests, although they were successfully made separately. For example, the

momentary current tests on power penetrations are not run under simulated accident conditions. It is felt that such tests need not be made simultaneously because the construction of the penetration assemblies is such that the outer seal is located about 4-1/2 feet away from the inner seal and the containment liner and, therefore, will not be exposed to accident environmental conditions. The integrity of the containment is, therefore, maintained at the penetration assemblies during a LOCA.

(2) Dielectric strength tests were conducted in accordance with the NEMA standard that permits testing of this type of equipment at 20 percent higher than twice-rated voltage plus 1000-V for 1 second.

Wire and cable splice samples used at the containment penetrations were tested under conditions simulating a LOCA environment. Refer to Section 3.11 for a discussion on Class I electrical equipment EQ.

8.3.1.4.9 Fire Barriers and Separation

Adequacy of design with regard to fire hazards in areas of concentration of electrical cables is analyzed in Section 8.3.1.4.10.1. Section 9.5.1 covers the fire protection program and system.

Penetration fire stops and seals between rooms, fire seals inside conduits, fire stops on vertical and horizontal trays, and fire seals under equipment all serve to control and prevent propagation of fire from one redundant system to another, and from one room to another. All jumbo ducts for cable trays are provided with fire stops where they penetrate walls, floors, ceilings, and electrical equipment. In addition, fire stops are installed at intervals of 5 feet on vertical trays and 12 feet on horizontal trays, and within 5 feet of tray crossings, either above or below. Reference drawing 050029, DCP A-47854, DCP M-049476, and FPEEs 101 and 103. Typical fire stops are shown in Figures 8.3-24 through 8.3-28. Conduits are provided with fire stops at the penetration of a fire barrier or at the nearest accessible point to that penetration. All cable entrances to the cable spreading room, control room areas, and interconnecting cable entrances between these two rooms are sealed to ensure the integrity of each area. Materials used for fire stops and seals are described in Appendix 8.3C.

8.3.1.4.10 Class 1E Separation and Protection Criteria

Separation and protection of mutually redundant Class 1E systems prevent the loss of safeguard functions. Thus, a function is available even if the use of one redundant system is lost.

The criteria discussed in this section ensure protection for safeguard functions in case of fire, missiles, pipe whip, and jet impingement. (Protection from natural hazards such as earthquake, flood, and tornado is discussed in Sections 3.10, 3.4, and 3.3, respectively.)

8.3.1.4.10.1 Fire

Specifications require that Class 1E cables be insulated with materials that do not support fire and are self-extinguishing. This prevents the spread or support of combustion from the original location of any fire along Class 1E cable. Outside of Class 1E equipment rooms, all mutually redundant Class 1E cables are required to be run in separate metallic conduit. This conduit prevents direct flame contact with Class 1E cable. Thus, it provides a second barrier to fire propagation along Class 1E cable.

Specifications require that electrical conductors have adequate ratings and overcurrent protection to prevent breakdown of insulation or excessive heating. Thus, fires will not be started in cable inside conduits due to overcurrent.

IEEE 308-1971 requires that Class 1E equipment be located in individual rooms. This isolates Class 1E equipment from non-Class 1E equipment and from mutually redundant Class 1E equipment. Isolation from fire is accomplished through the use of concrete walls with fire dampers and penetration seals, as necessary. It is not credible for fire to spread between rooms. Therefore, mutually redundant Class 1E equipment will not be disabled by a single fire.

10 CFR 50.48(c), National Fire Protection Association Standard NFPA 805 (Reference 13), provides criteria for protection of equipment and circuits required for safe shutdown. These criteria ensure that redundant safe shutdown trains will not be damaged as a result of a single fire. Protection of redundant trains is provided by a combination of physical separation, fire-rated barriers, and/or automatic suppression and detection. Exceptions to these criteria are documented based on the fire hazard in the area and/or other compensatory fire protection features provided.

The diesel generator and Class 1E cable spreading rooms are protected by an automatic CO_2 fire extinguishing system. Any fire starting in the cable spreading room will be extinguished in time to prevent the loss of safe shutdown capability. Class 1E cables are also run in rooms containing equipment that is not Class 1E. The possibility of fires starting in these rooms has been analyzed. It is not credible that any fire that may start in these rooms could destroy a protection function and impair plant safety.

As discussed above, fire will not cause a loss of any protection function for the following reasons:

(1) Class 1E equipment will not support fire or is protected by fire extinguishing equipment.

(2) Class 1E systems are physically separated.

(3) Redundant safe shutdown trains are separated and protected in accordance with NFPA 805, Section 4.2.3, with exceptions.

For further information on fire protection, refer to Section 9.5.1.

8.3.1.4.10.2 Missiles

The basic approach for protection of Class 1E equipment and cables from missiles is to ensure design adequacy against generation of missiles. Where missiles cannot be contained within parent equipment, missile protection is attained by routing or placing Class 1E cables and equipment in nonmissile-prone areas or by shielding the equipment.

Section 3.5 discusses postulated high-energy missiles. Class 1E cables and equipment are routed and placed so that they are protected from these missiles.

Outside of areas affected by high-energy missiles there is a very low probability of missile generation. Class 1E cables are protected from any possible low-energy missiles by the conduit in which they run.

Class 1E equipment, located in individual rooms, is protected from missiles generated outside the rooms by concrete walls and floors. After redundant Class 1E cables have passed into rooms where they make connections, they may be run in cable trays. However, mutually redundant wiring is not run in the same room. Therefore, missiles generated in the room will not cause a loss of any protection function.

8.3.1.4.10.3 Pipe Whip and Jet Impingement

The protection of Class 1E equipment and cables from pipe whip and jet impingement has been studied (refer to Section 3.6). All Class 1E cables and equipment required for this accident are protected from damage caused by these hazards.

8.3.1.5 Physical Identification of Safety-Related Equipment

Class 1E electrical power equipment is located in individual rooms isolated from non-Class 1E equipment and also from each other for mutually redundant sets of equipment. Nameplates on the sets of equipment and on the entrances to the rooms identify the equipment.

8.3.1.5.1 Color Coding

Some electrical systems are color-coded:

(1) The Class 1E electrical power systems and equipment for each mutually redundant system

(2) The RPSs

(3) The 120-Vac power circuits from the instrument inverters to the reactor protection channels

(4) Control, indication, and annunciation circuits that are not required for safe shutdown that are in Class 1E raceways

These colors are listed in Table 8.3-10 and have been applied to the Class 1E electrical circuits and their raceways that externally interconnect individual sets or units of equipment.

Internal wiring within units of equipment are not necessarily color-coded. Where a set of equipment is only one redundancy class that is clearly identified by other means, the circuits may have some or all of the conductors without any color coding. Standard Type TA switchboard wire, for example, is available in either black or gray colors only.

Where circuits of more than one mutually redundant system appear in the proximity or the same enclosure, the circuits have either the conductors, their bundling bands, or wireways identified by the assigned color code.

Conductors of control, indication, and annunciation circuits that are not required for safe shutdown may, to improve reliability, be purchased and installed as Class 1E and color-coded. These circuits are designed with sufficient isolation to ensure that a single failure does not propagate to the mutually redundant device. Circuits that do not serve safety-related functions, but are affiliated with safety-related devices, are colored consistent with the safety-related device, train, or circuit. Consequently, the coloring of these nonsafety-related circuits may not necessarily reflect the color code of their electric power sources.

Generally, non-Class 1E electric systems are assigned the color black. Because of certain industry standard practices, some non-Class 1E conductors are color-coded. These conductors are in circuits that are in no way related to those for operating the plant and are kept entirely separate. The functions of these systems are so obvious that there should be no confusion with the colors. These circuits are:

(1) Communication - these circuits are generally multiconductor with color-coded individual conductors.

(2) Thermocouple - these circuits are always multiconductor and have individual conductors colored according to the ISA standard to denote the type of metal. However, the jacket is generally color-coded to match the assigned redundancy group. Special applications and systems may have other color-coding.

(3) Lighting - these circuits have conductors color-coded according to the NEC.

Electrical conductors that interconnect separate units of equipment are identified by the color assigned to the system. On multiconductor cables, the color code is generally applied to the outer jacket and also to the individual conductors, except that thermocouple extension conductors have the ISA standard color designated for the type of metal. Each electrical raceway has its identification number stenciled in paint at readily visible places on its surface in the following colors:

(1) Black - all circuits 600-V and below

(2) Red - all circuits above 600-V

Cable tray designations are 1-inch high and spaced not more than 15 feet apart. Conduit designations are 1-inch high, except that designations for conduits smaller than 1 inch are 1/2-inch high, and placed at each end of the conduit, at pull boxes, and at intermediate points to effectively identify the run.

In addition, each Class 1E raceway, either conduit or tray, is distinctly marked at termination points and at intermediate points with a vertical stripe, 2-inches wide, and colored to match the circuits within. The color code is given under the description of electrical conductors.

8.3.1.5.2 Design and Installation

The design of electrical circuits is developed from the system requirements in conjunction with the manufacturer's circuits selected to perform the required functions. Past practices that have been successfully used by PG&E and the industry are also included in the design where possible. Functional analyses are made on the circuits by the designers and engineers during the completion of the schemes. Further review and coordination is made with persons whose interests are affected by the operation of the circuit. Final approval is made in the manner described in the Diablo Canyon Quality Assurance Program Description.

Electrical circuits are shown on the type of diagram appropriate to the information desired. Diagrams generally consist of these types: single line meter and relay, schematic, logic, block or functional, and connection. Conductor and main circuit numbers, as well as the equipment identification, are given in the schematic diagrams. Power conductor sizes are given in the single line meter and relay diagrams and checked by the responsible engineer.

Electrical circuits that interconnect separate units of equipment and devices throughout the plant are compiled, tabulated, and checked by electronic data processing equipment. Each termination point is given a unique designation, referred to as the location code, for convenience and to prevent ambiguity.

Each type of electrical conductor is given a unique code (known as the wire code) that identifies its class of service and redundancy group. Also, each individual electrical conductor has a unique identity given by its wire ID and circuit number.

Each circuit is listed, giving the size and number of conductors, the raceway routing and termination points, and the identification symbol, coded to denote the circuit class of service and redundancy group and the conductor type, rating, and color. These listings are then checked manually against approved electrical diagrams. Also, the connection diagrams and a computer listing of circuits and conductors arranged by termination location are cross-checked manually. In addition, the computer checks that the circuits and raceways selected are of the same class of service and redundancy group.

Each raceway, tray, or conduit is assigned a unique code, referred to as the tray or conduit number. The raceway is then listed, giving its type, size, terminating or junction points, and the arrangement drawings showing its physical layout.

Separate circuit schedules are made for each class of service except for lighting branch circuits and telephone cables that are shown only on diagrams. Circuit schedules are typically not utilized for loads fed from the 12-kV underground distribution system.

The circuit information is stored by computer using a software program in the form of electronic drawings distributed by downloading from the network to individual computers. The electronic drawings can then be printed for use in the field.
The circuit information software checks that the raceway contains only the allowable grouping of circuits according to the class of service and redundancy. The software also calculates the percentage fill. Any overfills are corrected manually.

Individual circuit installation records for the installation and termination of the electrical circuits are derived from circuit data stored by computer using a software program. Each circuit installation record consists of installation and termination data. All predetermined data is entered in these forms.

The installation data may include the circuit schedule, termination locations, raceway routing, cable data, and purchase order or stock code.

Termination data may provide the diagram of connection for each termination point and the type and size of connectors and tools used.

Circuit and raceway installation data is retained for quality assurance purposes.

The methods and procedures for the design and installation of Class 1E electrical equipment and material are described in Chapter 17, Quality Assurance.

8.3.1.6 Station Blackout

SBO at DCPP is defined as loss of power from the preferred power source concurrent with turbine trip and the failure of two emergency AC (EAC) sources (EDGs) in the unit experiencing the SBO (References 20 through 23). The other unit is assumed to experience only a LOOP.

To comply with the requirements of 10 CFR 50.63, a sixth EDG was added to Unit 2 and the existing (swing) fifth EDG was made Unit 1 specific. There are now three dedicated EDGs per unit.

The DCPP units are assigned an allowed EDG target reliability of 0.950 and a SBO duration of 4 hours. The Bus F EDGs 1-3 and 2-3, the designated AAC power sources, are available within ten minutes from the onset of the SBO event. These EDGs have sufficient capacity and connectability to operate systems necessary for mitigating a SBO event for the required duration of 4 hours to maintain the reactor in a safe shutdown condition (Mode 3).

The DCPP SBO analysis was performed using the guidance provided in NUMARC-8700, Rev. 0 (Reference 23) and Regulatory Guide 1.155, August 1988 (Reference 31), which contains guidance that is not provided in NUMARC-8700. Using this guidance, the postulated maximum SBO duration for DCPP was determined to be 4 hours. This SBO duration time was determined using the methodology in Reference 23 based on the following factors:

(1) The site susceptibility to grid-related LOOP events of greater than 5 minutes duration is less frequent than once per 20 years. Grid-related LOOP events are defined as losses of offsite power associated with the loss of the transmission and distribution system due to insufficient generating capacity, excessive loads, or dynamic instability. Although grid failure may also be caused by other factors, such as severe weather conditions or brush fires, these events are not considered grid-related since they are caused by external events.

(2) The probability of LOOP due to the occurrence of extremely severe weather at the plant site based on site specific wind speed data is low. The probability of loss of offsite power due to the occurrence of severe weather at the plant site is low based on historical weather data.

(3) The plant is served by two offsite power circuits connected to the plant's Class 1E buses through two electrically independent switchyards.

(4) Each unit has two redundant and independent EAC power sources not credited as an AAC power source; only one EAC power source per unit is necessary to operate safe shutdown equipment following a loss of offsite power (EAC Power Supply System Configuration Group C).

(5) The target reliability of the EDGs is equal to 0.95.

8.3.1.6.1 Emergency AC Analysis

As discussed in Section 8.3.1.6 above, the EAC classification for DCPP is Group C. For DCPP, the EAC criteria require that the unit under consideration be capable of attaining Mode 5 in the event of a loss of offsite power (LOOP) and single failure (within each unit), without use of the designated AAC source. The DCPP EAC analysis demonstrates that the plant can be safely shutdown to Mode 5 utilizing either Bus G or H and its normally connected EDG (EAC source) independent of the third EDG (considered the AAC source) and its Bus F.

When Bus G is the available bus, the turbine-driven AFW pump is credited for operation. When Bus H is the available bus, the motor-driven AFW pump powered by Bus H, supplemented by the turbine driven AFW pump, is credited for operation. The EAC analysis determined that the only required shutdown system not provided on Bus H is the ASW system. However, ASW can be made available (even given an active failure or bus failure on the other unit) through the ASW hydraulic interconnection between units. To accomplish the unit-to-unit ASW interconnection, the analysis assumes the common unit valve FCV-601 would be manually opened. One ASW pump is capable of supplying sufficient flow to both a Unit 1 and a Unit 2 CCW heat exchanger, thus handling the shutdown heat loads from both units.

For purposes of the EAC analysis, to determine the adequacy of the Unit 1 or Unit 2 EDGs as EAC sources, no credit is taken for the plant procedure which allows for interconnecting 4.16-kV electrical buses. However, during an actual SBO event, appropriate use of electrically interconnected buses within existing procedural guidance will be made.

During a SBO event, operator action is necessary to energize the battery charger(s), within the 2-hour battery duty cycle, to provide at least two input channels of instrumentation to monitor system functions and actuate one train of safeguards equipment. This action involves closing an input and output breaker to battery charger 121(221) if Bus G is not available.

Sufficient input channels may be deenergized such that a SI signal may be initiated. However, it was determined that generation of an inadvertent SI signal is acceptable and does not interfere with maintaining the safe shutdown of the unit.

8.3.1.6.2 Alternate AC Analysis

The SBO AAC analysis demonstrates that the Bus F EDGs satisfy the criteria specified in Appendix B to NUMARC-8700, and will be available within ten minutes of the onset of the SBO event, and has sufficient capacity and capability to operate systems necessary for the required duration of 4 hours to maintain the unit in a safe shutdown condition

(Mode 3). Although AAC analysis is focused on the Bus F EDGs as the AAC source, any EDG and Class 1E bus could act as the AAC source. Plant procedures, in recognition that multiple buses are likely to be available, take advantage of the ability to electrically cross-connect buses to most effectively provide the required functions to maintain safe shutdown. Because the AAC source will be available within 10 minutes, no coping analysis is required to be performed.

The SBO AAC analysis is not required to assume a concurrent single failure or design basis accident. In addition, Regulatory Guide 1.155 (Reference 31) permits the use of non-safety-related systems and equipment to respond to a SBO event. Based on the SBO AAC analysis, operation of required systems and components were evaluated for the required duration of 4 hours to maintain the unit in a safe shutdown condition. The only equipment not available from the AAC Bus F is the DFO transfer pumps which can be supplied from either Bus G or Bus H of the other unit, and one subtrain of control room cooling, which is available from the other unit.

During an SBO event, operator action is necessary to energize the battery charger(s) within the 2 hour battery duty cycle, to provide at least two input channels of instrumentation to monitor system functions and actuate one train of safeguards equipment. This action involves closing an input and an output breaker to Battery Charger 131 (231).

Sufficient input channels may be deenergized such that a SI signal may be initiated. The additional loading on Bus F of the SI pump can be accommodated; such an inadvertent SI is acceptable.

Plant-specific procedures were reviewed and updated to incorporate the requirements associated with the recovery from an SBO event. Recovery plans that include coordination with other power stations to re-route power to DCPP were also developed and implemented (Reference 21).

8.3.2 DC POWER SYSTEMS

There are two dc power systems in each unit at Diablo Canyon. One is a non-Class 1E system serving 125-Vdc and 250-Vdc non-Class 1E loads. The other is a Class 1E system serving Class 1E 125-Vdc loads that include ESF loads and some non-Class 1E loads (refer to Figures 8.3-17 and 8.3-18).

8.3.2.1 Design Bases

8.3.2.1.1 General Design Criterion 2, 1967 – Performance Standards

The Class 1E 125-Vdc system is designed to withstand the effects of or be protected against natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

8.3.2.1.2 General Design Criterion 3, 1971 – Fire Protection

The Class 1E 125-Vdc system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

8.3.2.1.3 General Design Criterion 4, 1967 – Sharing of Systems

The 125-Vdc system or components are not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

8.3.2.1.4 General Design Criterion 11, 1967 – Control Room

The Class 1E 125-Vdc system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other cause.

8.3.2.1.5 General Design Criterion 12, 1967 – Instrumentation and Control

The Class 1E 125-Vdc system design has instrumentation and controls to monitor and maintain system variables within prescribed operating ranges.

8.3.2.1.6 General Design Criterion 17, 1971 – Electric Power Systems

The Class 1E 125-Vdc system design has sufficient capacity, capability, independence, redundancy, and testability to perform its safety function assuming a single failure.

8.3.2.1.7 General Design Criterion 18, 1971 – Inspection and Testing of Electric Power Systems

The Class 1E 125-Vdc system design permits appropriate periodic inspection and testing of functional and operational performance of the system as a whole and under conditions as close to design as practical.

8.3.2.1.8 General Design Criterion 21, 1967 – Single Failure Definition

The Class 1E 125-Vdc system is designed to remain functional after sustaining a single failure. Multiple failures resulting from a single event shall be treated as a single failure.

8.3.2.1.9 General Design Criterion 24, 1967 – Emergency Power for Protection Systems

The Class 1E 125-Vdc system provides an alternate source of power to permit the required functioning of the protection systems in the event of loss of all offsite power.

8.3.2.1.10 General Design Criterion 40, 1967 – Missile Protection

The ESF portion of the Class 1E 125-Vdc system is designed to be protected against dynamic effects and missiles that result from plant equipment failures.

8.3.2.1.11 General Design Criterion 49, 1967 – Containment Design Basis

The Class 1E 125-Vdc and non-Class 1E 125-Vdc circuits routed through containment electrical penetrations are designed to support the containment design basis so that the containment structure can accommodate, without exceeding the design leakage rate, the pressure and temperatures following a LOCA.

8.3.2.1.12 Class 1E 125-Vdc System Safety Function Requirements

(1) Protection from Missiles

The Class 1E 125-Vdc system is designed and located to be protected against the effects of missiles which may result from plant equipment failure and from events and conditions outside the plant.

(2) Protection Against High Energy Pipe Rupture Effects

The Class 1E 125-Vdc system is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The outside containment portion of the Class 1E 125-Vdc system required to bring the plant to cold shutdown is designed to be protected against the effects of moderate energy pipe failure.

(4) Protection from Jet Impingement – Inside Containment

The inside containment portion of the Class 1E 125-Vdc system is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

(5) Protection from Flooding Effects – Outside Containment

The outside containment portion of the Class 1E 125-Vdc system required to bring the plant to cold shutdown is to be protected from the effects of internal flooding.

8.3.2.1.13 10 CFR 50.49 – Environmental Qualification of Electric Equipment

The Class 1E 125-Vdc system electric components that require EQ are qualified to the requirements of 10 CFR 50.49.

8.3.2.1.14 10 CFR 50.62 – Requirements for Reduction of Risk from Anticipated Transients Without Scram Events for Light-Water-Cooled Nuclear Power Plants

The non-Class 1E 125-Vdc power source, as required for ATWS, provides a source that is independent form the protection system power supplies.

8.3.2.1.15 10 CFR 50.63 – Loss of All Alternating Current Power

The Class 1E 125-Vdc system provides power to the loads required to support systems that ensure core cooling and containment integrity is maintained from the AAC source following a SBO.

8.3.2.1.16 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The Class 1E 125-Vdc system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

8.3.2.1.17 Safety Guide 6, March 1971 – Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems

The Class 1E 125-Vdc system is designed so dc electrically powered safety loads are separated into redundant load groups so that loss of any one group will not prevent the minimum safety functions from being performed. Each dc load group should be energized by a battery and battery charger. The battery-charger combination should have no automatic connection to any other redundant dc load group. If means exist for manually connecting redundant load groups together, at least one interlock should be provided to prevent an operator error that would parallel the standby power sources.

8.3.2.1.18 Safety Guide 32, August 1972 – Use of IEEE Standard 308-1971 Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations

Safety Guide 32, August 1972 identifies a conflict between IEEE 308-1971 and GDC 17, 1971, specifically with respect to battery charger supply. IEEE 308-1971 requires that each battery charger supply shall furnish electric energy for the steady-state operation of connected loads required during normal operation while maintaining its battery in a fully charged state, and have sufficient capacity to restore the battery from the design minimum charge to its fully charged state while supplying normal steady-state loads. In contrast, the equivalent provision of GDC 17, 1971 requires that

the onsite electric power supplies shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure. This safety guide imposes GDC 17, 1971, which does not restrict the battery charger supply load to that of the steady-state condition during normal operation.

8.3.2.1.19 Regulatory Guide 1.63, Revision 1, May 1977 – Electrical Penetration Assemblies in Containment Structures for Light-Water-cooled Nuclear Plants

The Class 1E 125-Vdc and non-Class 1E 125-Vdc circuits routed through containment electrical penetrations are designed to the requirements of Regulatory Guide 1.63, Revision 1, for installation of redundant or backup fault current protection devices to limit fault current to less than that which the penetration can withstand, assuming a single random failure of the circuit overload protective device.

8.3.2.1.20 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The Class 1E 125-Vdc battery voltmeters and ammeters located in the control room are credited Regulatory Guide 1.97, Revision 3, indications for power supply status.

8.3.2.2 System Description

8.3.2.2.1 Non-Class 1E 125-Vdc / 250-Vdc Power System

The non-Class 1E system consists of three 60-cell, 125-Vdc nominally rated batteries. Two of these batteries are connected in series to provide 250-Vdc power to a 250-Vdc MCC. The MCC serves the non-Class 1E 250-Vdc loads, as shown in Figure 8.3-18, Sheet 1 of 2. The 125-Vdc distribution panels associated with these batteries supply power non-Class 1E 125-Vdc loads, as shown in Figure 8.3-18. The third battery provides non-Class 1E 125-Vdc power to the plant process computer UPS. Each of the three batteries is continuously charged by a battery charger. The battery chargers are powered from separate 480-V non-Class 1E buses.

8.3.2.2.2 Class 1E 125-Vdc Power System

The Class 1E dc system consists of, or has, the following features (refer to Figure 8.3-17):

(1) Three 60-cell (refer to Section 8.3.2.3.6.3 for 59-cell configuration), 125-Vdc batteries.

(2) Three separate 125-Vdc power distribution switchgear assemblies, each including a 125-Vdc bus, circuit breakers, fuses, metering, and two distribution panels.

(3) Five battery chargers. Each of the three 125-Vdc switchgear buses has a battery charger. Batteries 11(21)[a] and 12(22) have an additional swing backup battery charger that can be connected to either bus by manually closing one of the two interlocked breakers. The fifth battery charger is a backup charger for battery 13(23). Manual operation of a circuit breaker is required to place this battery charger in service on the bus. No interlock is provided between the two battery chargers on this bus.

(4) The system and equipment is designed Class 1E from, and including, the batteries to, and including, the molded case distribution panel circuit breakers.

8.3.2.2.2.1 Class 1E Power Distribution System Equipment

The dc power distribution system for each unit consists of three completely metal-enclosed switchgear assemblies, as follows:

(1) Three separate 125-Vdc copper Buses 11(21), 12(22), and 13(23) are completely enclosed in their own metalclad switchgear. Each bus is rated at 1200 amperes continuous. There is one 125-Vdc, 60-cell (refer to Section 8.3.2.3.6.3 for 59-cell configuration) battery supplying each 125-Vdc bus. Source protection is provided by fuses rated at 3000 amperes.

(2) Two 125-Vdc circuit breaker distribution panels are connected to each of the 125-Vdc Buses 11(21), 12(22), and 13(23). The connection to Buses 11(21) and 12(22) is made through drawout, manually operated air circuit breakers[b], and Bus 13(23) connects directly to the panels. The air circuit breakers are rated 600 amperes with long- and short-time overcurrent elements. One panel per bus is generally utilized for Class 1E loads and the other typically used for non-Class 1E loads. The panels are an integral part of the respective switchgear and, therefore, they are all designed, engineered, and constructed as Class 1E panels. Each panel is ungrounded and has one main bus, rated 600 amperes continuous. Panel branch circuit breakers are molded case, thermal magnetic, quick-make and quick-break, rated 250-Vdc, ≥ 20,000-amperes interrupting capacity.

The two panels on each bus have the same designation (e.g., on Buses 11, both panels are called 125-Vdc distribution Panel 11) because they are electrically connected as one panel. However, typically they are physically separated on the left and right side of the switchgear to generally supply Class 1E and non-Class 1E loads, respectively.

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[a] Each unit's dc power system is identical; therefore, unit identification is as follows: e.g., 11, 12, and 13 = Unit 1, and (21), (22), and (23) = Unit 2.

[b] These circuit breakers were required for the original design when buses 11(21) and 12(22) were connected in series to provide 250-Vdc non-Class 1E power.

The left side panels typically provide power to the following loads:

(a) Class 1E dc power and control

(b) Class 1E dc diesel generator field flashing

(c) Class 1E dc instrumentation.

(d) Main annunciator

(e) UPSs for nuclear instrumentation

The right side panels typically provide power to the following loads:

(a) Non-Class 1E dc power and control

(b) Non-Class 1E dc instrumentation

(c) Auxiliary annunciators

An additional 125-Vdc distribution panel 14(24) is a subpanel of distribution panel 13(23) for non-Class 1E loads.

8.3.2.2.2.2 Class 1E 125-Vdc Battery Chargers

The 125-Vdc battery chargers are Class 1E power supplies. A total of ten battery chargers are supplied, five for Unit 1 and five for Unit 2. Three chargers serve two of the 125-Vdc buses (Buses 11[21] and 12[22]) and two chargers serve 125-Vdc Bus 13(23). Each of the chargers is connected to a bus through a molded case, manually operated thermal-magnetic 600 ampere breaker located in dc switchgear 11(21), 12(22), and 13(23). Normally, Buses 11(21), 12(22), and 13(23) are supplied by one battery charger each. Buses 11(21) and 12(22) share a swing backup battery charger for closing in on Bus 11(21) or 12(22) if either primary battery charger on 11(21) or 12(22) is not able to provide service. A second battery charger is a backup charger for Bus 13(23). Each charger is constructed of high quality, reliable, solid-state components conservatively rated for long life. The chargers provide rated direct current output continuously at a voltage smoothly adjustable from 118-Vdc to 144-Vdc, and regulated to ±0.5 percent through the entire range of input and local variations. The maximum output current is 110 percent of rated output under any loads or short circuit conditions. The charger is self-protected against transient voltages that may occur on the dc system.

An alarm cutout switch is provided on the outside of each battery charger cabinet. Each cutout switch disables the following battery charger alarms:

(1) ac fuse failure

(2) dc UV and overvoltage

(3) ac breaker trip

(4) dc breaker trip

The cutout switch is used to avoid unnecessary alarms and operator distractions when a battery charger is out of service or receiving maintenance. Proper use of the cutout switches is administratively controlled by operating procedures.

8.3.2.2.2.3 Class 1E 125-Vdc Batteries

The 125-Vdc batteries are Class 1E power supplies. Mean life of the batteries is 20 years (refer to Section 3.10.3.8.1 for battery qualification). Each cell is contained in a sealed, heat resistant, shock absorbing, clear polycarbonate case. Similar cells were tested and met seismic and vibration requirements. A total of six batteries, 11(21), 12(22), and 13(23) are supplied for Unit 1 and Unit 2.

Battery racks are provided with an analytically calculated, earthquake-proof, engineered rigid rack design to meet the seismic requirements of the battery room. The battery racks are of Unistrut construction and mounted to the floor and wall for rigid seismic mounting.

Diffusion vents on battery filling openings provide continuous and uniform dispersion of hydrogen produced by the batteries. These vents are designed to prevent localized hazardous concentrations of hydrogen.

8.3.2.2.2.4 Safety-Related Loads

Normally, the battery chargers will supply the total load requirements of the dc system as well as maintain a constant floating charge on the batteries. The batteries are paralleled with the chargers and supply dc power to the system if the ac power fails. The nuclear instrumentation UPSs and the main annunciator are automatically supplied from either the 125-Vdc system or the 480-V system depending on their availability. The voltage level of the rectifier in the UPS unit is set such that the inverter preferentially feeds from the 480-V system via the rectifier. Considering normal starting times for the diesel generators and the battery charger dc output time delay circuit that prevents full charger output for 20 to 30 seconds, the first 40-second loads on each bus are supplied by its respective battery.

The dc loads on the bus after 40 seconds will be carried by the battery charger. The charger has sufficient capacity to carry loads up to 110 percent of its 400-ampere rating. When the chargers are not loaded to maximum rating, then excess capacity charges the battery (refer to Section 8.3.2.3.6).

8.3.2.3 Safety Evaluation

8.3.2.3.1 General Design Criterion 2, 1967 – Performance Standards

The Class 1E 125-Vdc system is located in the auxiliary building which is a PG&E Design Class I structure (refer to Figure 1.2-5). The auxiliary building is designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7), to protect Class 1E 125-Vdc SSCs from damage due to these events to ensure they will continue to perform their safety function.

Loss of the 125-Vdc inverter room ventilation system and Class 1E 125-Vdc raceways located outdoors, and exposed to the effects of tornadoes, has been evaluated and the consequences of a tornado do not compromise the capability to safely shut down the plant (refer to Section 3.3.2.3).

Equipment included in the dc system was proved to be acceptable to seismic requirements by testing, analytical calculations, or testing on similar equipment. The manufacturers were required to conform to approved quality assurance procedures. Refer to Section 3.10.3.8 for a description of the seismic qualification for batteries, battery racks, battery chargers and dc switchgear.

Although the ventilating system for the battery rooms is PG&E Design Class II, the supply and exhaust ductwork serving the battery rooms are designed and installed to meet Seismic Category I criteria.

8.3.2.3.2 General Design Criterion 3, 1971 – Fire Protection

The Class 1E 125-Vdc system is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

Ventilation for the Class 1E dc equipment is provided as follows:

(1) Battery rooms are ventilated to prevent accumulation of hydrogen gas and to maintain ambient temperature. For each unit, the three battery rooms are constructed of reinforced concrete and cement block grout walls. Ventilation air is supplied by a common duct and supply fan, and is exhausted through an exhaust fan to a common duct that exhausts directly to the atmosphere. The ventilation system is PG&E Design Class II

(2) The dc switchgear rooms have PG&E Design Class I ventilation supply and exhaust systems and are described in Section 9.4.9. These three separate rooms, housing separate buses, panelboards, and battery chargers, have a common ventilation system.

In case of loss of forced ventilation, the calculated natural ventilation rate due to the thermal stack effect will maintain hydrogen gas below 1 percent by volume. This accumulation is below the allowable limit of 2 percent by volume as recommended by Regulatory Guide 1.128, Revision 1 (Reference 17).

8.3.2.3.3 General Design Criterion 4, 1967 – Sharing of Systems

The Class 1E 125-Vdc system for each unit is not shared with the other unit. The Class 1E 125-Vdc system is a support system for common unit systems and components listed in Section 1.2.2.10.

8.3.2.3.4 General Design Criterion 11, 1967 – Control Room

Each Class 1E bus is provided with a voltmeter and ammeter mounted on the control room main control board for remote indication.

The chargers have voltmeters and ammeters remotely located on the main control board to indicate operational status of battery chargers.

8.3.2.3.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Each Class 1E bus is provided with a voltmeter mounted on the switchgear for local indication. Each charger has a locally mounted voltmeter, ammeter, and instrumentation for alarming dc UV, dc overvoltage, ac fuse failure, dc breaker trip, and ac breaker trip (refer to Section 8.3.2.2.2.2), adjustable controls for both normal and equalizing charge settings, and a manually adjustable equalizing timer.

Each of the Class 1E battery rooms is provided with an air temperature monitoring system. Refer to Section 3.11.3.1 for details.

8.3.2.3.6 General Design Criterion 17, 1971 – Electric Power Systems

Sufficient physical separation, electrical isolation, system coordination, and redundancy are provided to ensure availability of required dc power and to prevent the occurrence of common mode failure of each unit's Class 1E dc systems.

The codes and standards that have been implemented, where applicable, in the design of the dc systems are listed in Section 8.1.4.

8.3.2.3.6.1 Class 1E 125-Vdc Distribution

The Class 1E dc power circuits from the separate battery rooms 11(21), 12(22), and 13(23) are run in separate conduits to dc equipment rooms 11, 12, and 13. The battery chargers are in these rooms and are connected to the buses in the dc switchgear. The

dc buses are connected to the molded case breaker panel board with load circuits channeled throughout the plant in Class 1E circuit systems with power (600-V and under) and control systems. The non-Class 1E dc power feeders are channeled with non-Class 1E (600-V and under) ac power and control systems. DC feeder instrumentation circuits are channeled with low-level instrumentation circuits.

The dc system redundancy follows the redundant lines delineated by the 4.16-kV and 480-V Class 1E systems:

(1) Battery 11(21), battery charger 11(21), switchgear Bus 11(21), and distribution panel 11(21) are associated with 4.16-kV Bus 1F(2F) and 480-V Bus 1F(2F), and diesel 13(23).

(2) Battery 12(22), battery charger 12(22), switchgear Bus 12(22), and distribution panel 12(22) are associated with 4.16-kV Bus 1G(2G) and 480-V Bus 1G(2G), and diesel 12(21).

(3) Battery 13(23), battery charger 132(232), switchgear Bus 13(23), distribution panel 13(23), and distribution Panel 14(24) are associated with 4.16-kV Bus 1H(2H) and 480-V Bus 1H(2H) and diesel 11(22).

(4) Instrumentation dc circuits are also separated similarly to Items 1, 2, and 3 above.

(5) Breakers on the distribution Panels 11(21), 12(22), and 13(23) can be used to disconnect all non-Class 1E loads from the batteries.

8.3.2.3.6.2 Class 1E 125-Vdc Battery Charger

The input to the chargers is 480-V, 3-phase, 60 Hz. The 480-V Buses F, G, and H supply chargers 11(21), 12(22), and 132(232), respectively. Backup battery chargers 121(221) and 131(231) receive their inputs from 480-V Buses H and F, respectively. The chargers provide rated output voltage and current with an input voltage range from 432-V to 528-V. Each input is provided with a manual circuit breaker mounted on the front and an UV alarm relay on the ac side of the rectifiers.

During normal operation, power is furnished by these 480-V battery chargers at approximately 135-Vdc, with the electric storage batteries floating on the dc buses. Sufficient battery charger capacity, 400 amperes per charger, is provided to carry the normal continuous load and to recharge the batteries in a reasonable time with any one charger out of service.

Battery chargers have sufficient capacity to carry the normal continuous load and to recharge the battery within 12 hours. The battery charger sizing is within the guidelines of IEEE-946, IEEE Recommended Practice for the Design of Safety Related DC Auxiliary Power Systems for Nuclear Power Generating Stations and Safety Guide 32, August 1972, B-2 and C-b (Reference 16) (refer also to Section 8.3.2.3.18).

8.3.2.3.6.3 Class 1E 125-Vdc Batteries

The batteries are sized to provide sufficient power to operate the dc loads for the time necessary to safely shut down the unit, should a 480-V source to one or more battery chargers be unavailable. Although each battery consists of 60 cells, the battery sizing calculations are in place to support a 59-cell configuration. The 59-cell configuration may be necessary in case a defective cell needs to be bypassed. The battery cells are lead-acid type with lead-calcium grids. Each battery is rated at 2320 ampere-hours (8-hour rate, discharged to 1.75-V per cell) and has current ratings as follows:

1 minute	1 hour	8 hours
2080 amperes	1120 amperes	290 amperes

Sufficient capacity is provided for all simultaneous loads to be superimposed for the following durations:

(1) Two hours for continuous loads, such as instrumentation and annunciation

(2) One minute for all momentary loads such as dc control power for switchgear devices, inrush to continuous loads, and diesel generator field flashing

The method used to determine battery sizing and recommendation for replacement of batteries is based on IEEE 485-1983 (Reference 15).

If a diesel generator associated with a particular bus fails to start and a redundant charger supplied from another Class 1E 480-V bus is not available, the battery has sufficient capacity to continue to carry dc loads for 2 hours on the associated bus.

8.3.2.3.7 General Design Criterion 18, 1971 – Inspection and Testing of Electric Power Systems

Battery capacity is verified by performing a battery performance test in accordance with IEEE 450-1995 (Reference 18) with the exception that if the battery shows signs of degradation, or if the battery has reached 85 percent of its expected service life and capacity is less than 100 percent of the manufacturer's rated capacity, the performance test is required on a 24-month frequency to coincide with a refueling outage instead of on an annual frequency as required by IEEE 450-1995. Battery monitoring and maintenance is controlled by a battery monitoring and maintenance program based on the recommendations of IEEE 450-1995.

8.3.2.3.8 General Design Criterion 21, 1967 – Single Failure Definition

DC loads for control of ESFs are divided into three groups, each served from a 125-Vdc battery. The grouping corresponds to the grouping of the ac loads and provides redundant service to ESFs (refer to Figure 8.3-17).

Should a failure occur on any 125-Vdc distribution circuit on panel 11(21) the associated molded case circuit breaker would trip to isolate this failure while the unaffected circuits in panel 11(21) would remain energized. If the distribution panel molded case circuit breaker failed to trip, the 600 ampere drawout breaker would trip to isolate distribution panel 11(21) from 125-Vdc Bus 11(21). This latter event would be a single failure in the ESF panel 11(21). Similar analysis was applied to the 125-Vdc distribution circuits on panel 12(22).

This would result in the loss of 125-Vdc power and control to 4.16-kV Bus F and other related Bus F power and control circuits. The ESFs would then be performed by 4.16-kV and 480-V Buses G and H, and 125-Vdc Buses 12(22) and 13(23), respectively.

8.3.2.3.9 General Design Criterion 24, 1967 – Emergency Power for Protection Systems

The safety-related loads on individual dc buses are as listed in Table 8.3-11.

The dc power and control systems are specified, designed, engineered, and manufactured to perform the required ESF functions.

The dc systems for control of ESFs are divided into three groups, each served from a 125-Vdc battery bus. The grouping corresponds to the grouping of the ac loads and provides redundant service to ESFs (refer to Table 8.3-11). A descriptive analysis of the dc system is provided in Section 8.3.2.2.2.

8.3.2.3.10 General Design Criterion 40, 1967 – Missile Protection

The ESF portions of the Class 1E 125-Vdc system that are located in zones where provision against dynamic effects must be made, are protected from missiles, pipe whip, or jet impingement from the rupture of any nearby high-energy line (refer to Sections 3.5, 3.6, and 8.3.1.4.10.2).

8.3.2.3.11 General Design Criterion 49, 1967 – Containment Design Basis

The Class 1E 125-Vdc and non-Class 1E 125-Vdc circuits routed through containment electrical penetrations are each provided with electrical protection devices. This arrangement is such that with the failure of one device, the penetration remains protected from high current temperature by the other in-series device to ensure the containment penetration remains functional. Refer to Section 3.8.2.1.1.3 and 8.3.1.4.8 for additional details.

8.3.2.3.12 Class 1E 125-Vdc System Safety Function Requirement

(1) Protection from Missiles

The provisions taken to protect the Class 1E portion of the 125-Vdc system from missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Sections 3.5 and 8.3.1.4.10.2.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the Class 1E portion of the 125-Vdc system from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Sections 3.6 and 8.3.1.4.10.3.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection of the Class 1E portion of the 125-Vdc system portion located outside containment from the effects of moderate energy pipe failure are discussed in Section 3.6.

(4) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the Class 1E portion of the 125-Vdc system portion located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6 and 8.3.1.4.10.3.

(5) Protection from Flooding Effects – Outside Containment

The provisions taken to provide protection of the Class 1E portion of the 125-Vdc system portion located outside containment from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

8.3.2.3.13 10 CFR 50.49 – Environmental Qualification of Electric Equipment

Except for the cables and splices, the Class 1E 125-Vdc system SSCs are located in a mild environment unaffected by the harsh condition created by a design basis accident (DBA). Therefore, only cables and slices located in a harsh environment are environmentally qualified. Section 3.11 describes the DCPP EQ program and the requirements for the environmental design of electrical and related mechanical equipment. The environmental qualification of the cables and splices is controlled by the DCPP EQ program.

8.3.2.3.14 10 CFR 50.62 – Requirements for Reduction of Risk from Anticipated Transients Without Scram Events for Light-Water-Cooled Nuclear Power Plants

The AMSAC is designed to comply with 10 CFR 50.62. The AMSAC is required to be powered from a non-Class 1E 125-Vdc electrical power source that is independent from the protection system power supplies. Refer to Section 7.6.2.3 and 7.6.3.6 for additional details.

8.3.2.3.15 10 CFR 50.63 – Loss of All Alternating Current Power

With respect to battery adequacy, for an actual SBO response, procedures would provide battery charging and operation for all Class 1E instrument channels and RPS output trains.

The Class 1E 125-Vdc system serves to distribute power to the 125-Vdc loads required to bring the plant to a safe shutdown condition (Mode 3) following a SBO event.

For purposes of the SBO analysis, it is assumed that operator action is taken within 2 hours to provide at least two input channels of instrumentation to monitor system functions and actuate one train of safeguards equipment. Refer to Section 8.3.1.6 for additional details.

8.3.2.3.16 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The Class 1E 125-Vdc system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

8.3.2.3.17 Safety Guide 6, March 1971 – Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems

Each of the three 125-Vdc switchgear buses has a battery charger. Batteries 11(21) and 12(22) have an additional swing backup battery charger that can be connected to either bus by manually closing one of the two interlocked breakers. The fifth battery charger is a backup charger for battery 13(23). Manual operation of a circuit breaker is required to place this battery charger in service on the bus. No interlock is provided between the two battery chargers on this bus. Refer to Section 8.3.2.2.2 for additional detail.

8.3.2.3.18 Safety Guide 32, August 1972 – Use of IEEE Standard 308-1971 Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations

The supply to battery chargers is designed using the criteria of Safety Guide 32, August 1972 (Reference 16), paragraphs B-2 and C-b, so that abnormal long-term loads (e.g., hot or cold shutdown and post-accident shutdown) are not greater than the steady state loads during normal operation. The design requirements of the battery charger supply are as covered within GDC 17, 1971. Accordantly the capacity of the battery charger supply is based on the largest combined demands of the various steady-state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the plant during which these demands occur.

8.3.2.3.19 Regulatory Guide 1.63, Revision 1, May 1977 – Electrical Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Plants

The Class 1E and non-Class 1E 125-Vdc circuits routed through containment electrical penetrations are designed to provide overcurrent protection. Refer to Section 8.3.1.4.8 for additional details.

8.3.2.3.20 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Each 125-Vdc Class 1E bus is provided with a voltmeter and ammeter mounted on the control room main control board for remote indication. Refer to Table 7.5-6 for additional detail.

8.3.2.4 Tests and Inspections

Refer to Section 8.3.2.3.7 for test and inspection details.

8.3.2.5 Instrumentation Applications

Refer to Sections 8.3.2.3.4 and 8.3.2.3.5 for instrumentation applications

8.3.3 REFERENCES

1. Deleted in Revision 21.

2. NUREG 0737, Clarification of TMI Action Plan Requirements, November 1980.

3. IEEE 308-1971, Criteria for Class IE Electric Systems for Nuclear Power Generating Stations.

4. IEEE 279-1971, Criteria for Protection Systems for Nuclear Power Generating Stations.

5. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

6. NFPA 12, Carbon Dioxide Extinguishing Systems, 1973.

7. NFPA 37, Installation and Use of Stationary Combustion Engines and Gas Turbines, 1970.

8. Safety Guide 9, Selection of Diesel Generator Set Capacity for Standby Power Supplies, March 1971.

9. Safety Guide 6, Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems, March 1971.

10. National Electric Code (NFPA 70-1968).

11. AIEE S-135-1, Power Cable Ampacities, 1962.

12. Regulatory Guide 1.63, Electric Penetration Assemblies in Containment Structures for Light-Water- Cooled Nuclear Power Plants, USNRC, Revision 1, May 1977.

13. 10 CFR 50.48(c), National Fire Protection Association Standard NFPA 805, Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants, 2001 Edition.

14. Diablo Canyon Power Plant, Unit Nos. 1 and 2 – Amendments 225 to Facility Operating License No. DPR-80 and Amendment No. 227 to Facility Operating License No. DPR-82 regarding Transition to a Risk-Informed Performance-Based Fire Protection Program in Accordance with 10 CFR 50.48(c).

15. IEEE 485-1983, Recommended Practice for Sizing Large Lead Storage Batteries for Generating Stations and Substations.

16. Safety Guide 32, Use of IEEE Standard 308-1971 Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations, August 1972.

17. Regulatory Guide 1.128, Revision 1, Installation Design and Installation of Large Lead Storage Batteries for Nuclear Power Plants, USNRC, October 1978.

18. IEEE 450-1995, Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations.

19. ICEA P-54-440, Cables in Open-Top Cable Trays, 1975.

20. 10 CFR 50.63, Station Blackout (SBO) Rule, Loss of All Alternating Current Power.

21. PG&E Letter DCL-92-084 to USNRC, Revised Response to Station Blackout, April 13, 1992.

22. Supplemental Safety Evaluation of PG&E Response to Station Blackout Rule (10 CFR 50.63) for Diablo Canyon, USNRC, (TAC Nos. M68537 and M68538), May 29, 1992.

23. NUMARC-8700, Rev. 0, Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors, November 1987.

24. Deleted in Revision 21.

25. Regulatory Guide 1.108, Revision 1, August 1977 – Periodic Testing of Diesel Generating Units Used as Onsite Electric Power Systems at Nuclear Power Plants,

26. NRC (Mr. John Stolz) Letter to PG&E (Mr. John Morrissey), dated November 22, 1977, Request for Additional Information – Diablo Canyon Nuclear Power Plant, Units 1 & 2.

27. License Amendments 200/201, Technical Specifications Change to Relocate Surveillance Test Intervals to a Licensee-Controlled Program, issued by the NRC, October 30, 2008.

28. License Amendments 105/104, Revision of Technical Specification for Diesel Generator Surveillance Testing, issued by the NRC, June 26, 1995.

29. License Amendments 135/135, Conversion to Improved Technical Specifications, issued by the NRC, May 28, 1999.

30. License Amendments 211/213, Revision to Technical Specification 3.8.1, "AC Sources – Operating," to Incorporate TSTF-163, Revision 2, issued by the NRC, March 29, 2012.

31. Regulatory Guide 1.155, Station Blackout, August 1988.

32. IEEE Standard 317-1971, Electric Penetration Assemblies in Containment Structures for Nuclear Fueled Power Generating Stations, The Institute of Electrical and Electronics Engineers, Inc.

33. License Amendments 218/220, Revision to Technical Specification 3.8.1, “AC Sources – Operating,” issued by the NRC, July 1, 2015.

8.3.4 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

TABLE 8.1-1

APPLICABLE DESIGN BASIS CRITERIA

CRITERIA	TITLE	APPLICABILITY									
Electrical Power System		230-kV	500-kV	25-kV	12-kV	4.16-kV	480-V	120-Vac	EDG	SBO	125-Vdc
Section		8.2.1	8.2.2	8.3.1.1.1	8.3.1.1.2	8.3.1.1.3	8.3.1.1.4	8.3.1.1.5	8.3.1.1.6	8.3.1.6	8.3.2
1. 10 CFR 50 - Domestic Licensing of Production and Utilization Facilities											
50.48(c)	National Fire Protection Association Standard NFPA 805	X				X	X	X	X		X
50.49	Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants					X	X	X			X
50.55a(g)	Inservice Inspection Requirements								X		
50.62	Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants							X			X
50.63	Loss of All Alternating Current Power	X	X	X	X	X	X	X	X	X	X
2. General Design Criteria											
Criterion 2, 1967	Performance Standards				X	X	X	X	X		X
Criterion 3, 1971	Fire Protection					X	X	X	X		X
Criterion 4, 1967	Sharing of Systems	X			X		X	X	X		X
Criterion 11, 1967	Control Room				X	X	X	X	X		X
Criterion 12, 1967	Instrumentation and Control				X	X	X	X	X		X

TABLE 8.1-1

Systems

CRITERIA	TITLE	APPLICABILITY									
Electrical Power System		230-kV	500-kV	25-kV	12-kV	4.16-kV	480-V	120-Vac	EDG	SBO	125-Vdc
Section		8.2.1	8.2.2	8.3.1.1.1	8.3.1.1.2	8.3.1.1.3	8.3.1.1.4	8.3.1.1.5	8.3.1.1.6	8.3.1.6	8.3.2
2. General Design Criteria (continued)											
Criterion 15, 1967	Engineered Safety Features Protection Systems				X						
Criterion 17, 1971	Electric Power Systems	X	X	X	X	X	X	X	X		X
Criterion 18, 1971	Inspection and Testing of Electric Power Systems	X	X	X	X	X	X	X	X		X
Criterion 21, 1967	Single Failure Definition					X	X	X	X		X
Criterion 24, 1967	Emergency Power For Protection Systems							X			X
Criterion 40, 1967	Missile Protection					X	X	X			X
Criterion 49, 1967	Containment Design Basis				X		X	X			X
3. Design Basis Functional Criteria											
Transmission Capacity Requirements		X	X								
Single Failure Requirements (Preferred Power Supply)		X	X	X	X						
Protection from High and Moderate Energy Systems and Internal Missiles									X		
4. Atomic Energy Commission (AEC) Safety Guides											
Safety Guide 6, March 1971	Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems					X	X	X			X

TABLE 8.1-1

CRITERIA	TITLE	APPLICABILITY									
Electrical Power System		230-kV	500-kV	25-kV	12-kV	4.16-kV	480-V	120-Vac	EDG	SBO	125-Vdc
Section		8.2.1	8.2.2	8.3.1.1.1	8.3.1.1.2	8.3.1.1.3	8.3.1.1.4	8.3.1.1.5	8.3.1.1.6	8.3.1.6	8.3.2
4. Atomic Energy Commission (AEC) Safety Guides (continued)											
Safety Guide 9, March 1971	Selection of Diesel Generator Set Capacity for Standby Power Supplies								X		
Safety Guide 32, August 1972	Use of IEEE Std 308-1971 "Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations"	X	X	X	X						X
5. Regulatory Guides											
Regulatory Guide 1.63, May 1977	Electric Penetration Assemblies in Containment Structures for Light Water Cooled Nuclear Power Plants				X		X	X			X
Regulatory Guide 1.97, Revision 3, May 1983	Instrumentation For Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident					X	X		X		X
Regulatory Guide 1.108, Revision 1, August 1977	Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants								X		

TABLE 8.1-1

CRITERIA	TITLE	APPLICABILITY									
Electrical Power System		230-kV	500-kV	25-kV	12-kV	4.16-kV	480-V	120-Vac	EDG	SBO	125-Vdc
Section		8.2.1	8.2.2	8.3.1.1.1	8.3.1.1.2	8.3.1.1.3	8.3.1.1.4	8.3.1.1.5	8.3.1.1.6	8.3.1.6	8.3.2
6. NRC NUREGs											
NUREG-0737	Clarification of TMI Action Plan Requirements						X	X			
7. NRC Generic Letters											
1984-15	Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability								X		

TABLE 8.3-1

NOTES FOR TABLES

(a) When supplied from the diesel generators, these motors are started automatically in the absence of a safety injection signal.

(b) The containment fan cooler unit (CFCU) motors are two-speed, rated 300 and 100 horsepower, and are fed from the vital 480-V load centers. The low speed is used under loss-of-coolant accident (LOCA) and auto-bus transfer conditions. There are five motors: two on bus F, two on bus G, and one on bus H.

(c) 1. The EDG net power factor is expected to be not less than the EDG rated power factor of 80 percent.

2. The power factor of the containment fan cooler units (CFCUs) at slow speed, however, is 49.0 percent.

(d) Deleted

(e) Deleted

(f) For total time, add approximately 4 seconds for offsite power auto-bus transfer, and 10 seconds for the diesel generators to start.

(g) These loads are not required for nuclear safety but will probably operate at the same time to perform other important plant functions.

(h) These items are shared between Units 1 and 2.

(i) Two of the battery chargers are spares. Only one battery charger can be connected to a bus except during an abnormal operating condition which is time limited.

(j) The Technical Support Center, pressurizer heaters, containment hydrogen purge system fans, spent fuel pit pump, internal hydrogen recombiners, and charcoal filter preheater are manually controlled loads that can be added to the vital buses, providing the load demand has diminished and the diesel generators will not be overloaded.

(k) Containment spray is initiated after the time shown, provided "S" and "P" signals are present. All other components are started on the occurrence of an "S" signal.

(l) Deleted in Revision 7.

(m) Does not include loads that are cut off prior to diesel generator connection to bus.

(n) Only one group of control room air conditioning and vent equipment can be connected to a bus at one time.

(o) All tests conducted on all six diesel engine generator units, except as noted.

(p) The following Design Basis Accidents (DBAs) are considered in the EDG Load Study Analyses:

1. Event 1: Large Break Loss of Coolant Accident (LBLOCA)

2. Event 2: Small Break Loss of Coolant Accident (SBLOCA)
3. Event 3: Steam Generator Tube Rupture (SGTR)

4. Event 4: Steamline Rupture Inside Containment at Power

5. Event 5: Steamline Rupture Inside Containment at Hot Zero Power

6. Event 6: Feedwater Line Break (FWLB)

7. Event 7: Loss of Normal Feedwater (LONF)

8. Event 8: Loss of Offsite Power (LOOP)

9. Event 9: Station Blackout (SBO)

(q) The following Class 1 E 4160 V ESF bus loading cases are considered for each of the postulated DBAs evaluated in the EDG Load Study Analyses. (Refer to Table 8.3-12 for maximum steady loads at 4340 V and 60.8 Hz).

1. Case 1: All EDGs operating energizing Class 1 E 4160 V ESF buses (F, G, & H) and supplying all associated accident loads with single component failure Considerations.

2. Case 2: The EDG associated with Class 1 E 4160 V ESF bus F failed resulting in Class 1 E 4160 V ESF bus F being deenergized with accident loads supplied by Class 1 E 4160 V buses G and H and associated EDGs.

3. Case 3: The EDG associated with Class 1 E 4160 V ESF bus G failed resulting in Class 1 E 4160 V ESF bus G being deenergized with accident loads supplied by Class 1 E 4160 V buses F and H and associated EDGs.

4. Case 4: The EDG associated with Class 1 E 4160 V ESF bus H failed resulting in Class 1 E 4160 V ESF bus H being deenergized with accident loads supplied by Class 1 E 4160 V ESF buses F and G and associated EDGs.

5. Case 5: Failure of SSPS Train A will result in the EDG associated with Class 1 E 4160 V Bus F to fail and to fail one train of safeguards equipment which will render certain pump/fan mechanical load demands to not load on a Class 1 E 4160 V Bus.

6. Case 6: Failure of SSPS Train B will result in the EDG associated with Class 1 E 4160 V Bus G to fail and to fail one train of safeguards equipment which will render certain pump/fan mechanical load demands to not load on a Class 1 E 4160 V Bus.

TABLE 8.3-2

TIMING SEQUENCE AND INTERVALS - NO SAFETY INJECTION SIGNAL

Loads	Starting Delay in Seconds After Power is Restored to the Vital Buses[f]			Minimum Number Required
	Bus F	Bus G	Bus H	
Small loads (480 and 120 V) on vital 480-V load centers	0	0	0	2
Component cooling water pumps	5	5	5	2
Auxiliary saltwater pumps	10	10	-	1
Auxiliary feedwater pumps[a]	14	-	14	1
Centrifugal charging pumps (CCP1 and CCP2)	20	20	-	1
Containment fan coolers[b]	25	25	25	3

TABLE 8.3-3

IDENTIFICATION OF MAJOR LOADS - NO SAFETY INJECTION SIGNAL

Load	Rating (each)	EDG 1-3 U1 Bus F	EDG 1-2 U1 Bus G	EDG 1-1 U1 Bus H	EDG 2-3 U2 Bus F	EDG 2-1 U2 Bus G	EDG 2-2 U2 Bus H
480-V load Center Transformer	1000 kVA	1F	1G	1H	2F	2G	2H
Centrifugal Charging Pump	600 hp	1-1	1-2	---	2-1	2-2	---
Auxiliary Saltwater Pump	400 hp	1-1	1-2	---	2-1	2-2	---
Motor Driven Auxiliary Feedwater Pump[(a)]	600 hp	1-3	---	1-2	2-3	---	2-2
Component Cooling Water Pump	400 hp	1-1	1-2	1-3	2-1	2-2	2-3
Containment Fan Cooler Unit[(b)]	100 hp	1-1 & 1-2	1-3 & 1-5	1-4	2-1 & 2-2	2-3 & 2-5	2-4

Diesel Generator Rating[1]:

Continuous = 2600 kW
2 Hours per 24 hour period = 2860 kW
2000 Hours per one year period = 2750 kW
30 minute = 3056 kW

[1] In accordance with the manufacturer's engine description and data sheet, the DGs are required to be derated if the inlet combustion air at the engine air intake filter is greater than 90°F and/or the jacket water temperature to the aftercooler inlet exceeds 160°F.

TABLE 8.3-4

DIESEL GENERATOR LOADING
TIMING SEQUENCE AND INTERVALS - WITH SAFETY INJECTION SIGNAL
CHANGES ON THIS PAGE APPLY TO BOTH UNTIS 1 & 2

Loads	Starting Delay in Seconds After Power is Restored to the Vital Buses[f]			Minimum Number Required
	Bus F	Bus G	Bus H	
Small loads (480 and 120 V) on vital 480-V load centers	0	0	0	2
Centrifugal charging pumps (CCP1 and CCP2)	2	2	-	1
Safety injection pumps	6	-	2	1
Residual heat removal pumps	-	6	6	1
Containment fan coolers[b]	18,22	18,22	22	2
Component cooling water pumps	10	10	14	2
Auxiliary saltwater pumps	14	14	-	1
Auxiliary feedwater pumps	26	-	18	1
Containment spray pumps[k]	-	26	26	1

TABLE 8.3-5

DIESEL GENERATOR LOADING FOLLOWING A LOSS-OF-COOLANT ACCIDENT

Load	Rating (each)	EDG 1-3 U1 Bus F	EDG 1-2 U1 Bus G	EDG 1-1 U1 Bus H	EDG 2-3 U2 Bus F	EDG 2-1 U2 Bus G	EDG 2-2 U2 Bus H
480-V load Center Transformer	1000 kVA	1F	1G	1H	2F	2G	2H
Centrifugal Charging Pump	600 hp	1-1	1-2	---	2-1	2-2	---
Safety Injection Pump	400 hp	1-1	---	1-2	2-1	---	2-2
Residual Heat Removal Pump	400 hp	---	1-1	1-2	---	2-1	2-2
Auxiliary Saltwater Pump	400 hp	1-1	1-2	---	2-1	2-2	---
Motor Driven Auxiliary Feedwater Pump	600 hp	1-3	---	1-2	2-3	---	2-2
Containment Spray Pump	400 hp	---	1-1	1-2	---	2-1	2-2
Component Cooling Water Pump	400 hp	1-1	1-2	1-3	2-1	2-2	2-3
Containment Fan Cooler Unit[(b)]	100 hp	1-1 & 1-2	1-3 & 1-5	1-4	2-1 & 2-2	2-3 & 2-5	2-4

Diesel Generator Rating[1]:

Continuous = 2600 kW
2 Hours per 24 hour period = 2860 kW
2000 Hours per one year period = 2750 kW
30 minute = 3056 kW

[1] In accordance with the manufacturer's engine description and data sheet, the DGs are required to be derated if the inlet combustion air at the engine air intake filter is greater than 90°F and/or the jacket water temperature to the aftercooler inlet exceeds 160°F.

TABLE 8.3-8

SUMMARY OF SHOP TESTING OF DIABLO CANYON DIESEL ENGINE GENERATOR UNITS BY ALCO ENGINE DIVISION (Note 1)

Test and Purpose[o]	Conduct of Tests	Results of Test
1. Standard Shop Tests To check out manufacturing and assembly	A. Calibration testing of all meters, switches, and gauges. B. Engine "break in" running and check out pressures. C. Electrical wire-by-wire functional testing. D. Matching tests for engine with governor and generator with regulator.	Engine generator units satisfactorily met all test requirements.
2. Performance Run To prove performance and rating	Unit performance run at 50, 75, 100, and 115% of full load, while recording pressures, temperatures, fuel consumption, etc.	Engine generator units satisfactorily met all test requirements.

TABLE 8.3-8

Test and Purpose[o]	Conduct of Tests	Results of Test
3. Starting Capability To show capacity of starting air systems (conducted on one engine generator unit).	A. Demonstrate 45 seconds of engine cranking for starting, with each of two redundant starting air systems, and without recharging air receivers. B. Demonstrate the number of successful engine starts, with each of two redundant starting air systems, and without recharging air receivers.	A. Forty-five seconds of continuous cranking with each starting air system.
4. Starting Reliability To show reliability of starting (conducted on one engine generator unit).	Demonstrate 100 consecutive engine generator unit starts, 50 with each redundant starting air system.	Fifty consecutive successful unit starts with each start ing air system.
5. Acceleration To show capability of fast starting.	Recorded time to accelerate units from standby condition (zero rpm) to rated speed (frequency) and voltage, with both redundant starting systems and with single failures in redundant start ing systems.	All engine generator units accelerated to rated speed (frequency) and voltage in less than 8.5 seconds with both starting systems, and in less than 12.3 seconds with simulated failure in a redundant starting system.

TABLE 8.3-8

Test and Purpose[o]	Conduct of Tests	Results of Test
6. Motor Start To show capability of starting and accelerating a large induction motor (conducted on one engine generator unit).	Recorded speed (frequency) and voltage decrease and time to recover to nominal when starting and accelerating an 800 hp induction motor, which is larger than any Diablo Canyon LOCA loads.	Maximum voltage decrease did not exceed 75% of nominal, and maximum speed decrease (frequency) did not exceed 95% of nominal. Voltage was restored to within 10% of nominal, speed (frequency) was restored to within 2% of nominal, in less than 2 seconds. Engine generator unit is capable of starting and accelerating an induction motor larger than any for Diablo Canyon.
7. Dead Load Pick Up To show capability of picking up large resistive loads and, by evaluation, to show capability of starting and accelerating large induction motors.	Recorded speed (frequency)and volt age decrease and the time to recover to nominal when picking up large resistive loads, starting with 500 kW and picking up successive loads in 100 kW increments up to at least 1300 kW. Performance of all units evaluated against the performance of the unit tested for motor start capability. (Test No. 6.)	All engine generator units picked up resistive loads with speed (frequency) and voltage decrease and time to recover evaluated to satisfactorily show capability for starting and accelerating the large induction motors of the Diablo Canyon LOCA loads.

TABLE 8.3-8

Test and Purpose[o]	Conduct of Tests	Results of Test
8. Motor Starting - LOCA Sequence To show capability of starting and accelerating large induction motors in rapid succession. (Conducted on one engine generator unit.)	Recorded speed (frequency) and voltage decrease and time to recover to nominal when starting and accelerating large induction motors, 400, 600, and 800 hp, in rapid succession and in the Diablo Canyon LOCA sequence. Load sequence time interval was 5 seconds.	Maximum voltage decrease did not exceed 75% of nominal, and maximum speed decrease (frequency) did not exceed 95% of nominal. Voltage was restored to within 10% of of nominal, and speed (frequency) was restored to within 2% of nominal, in less than 2 seconds (40% of load sequence time interval). Engine generator units are capable of starting and accelerating large induction motors in rapid succession.
9. Simulated Motor Starting - LOCA Sequence To show capability of picking up resistive loads (simulating induction motors) in rapid succession and, by evaluation, to show capability of starting and accelerating large induction motors in rapid succession.	Recorded speed (frequency) and voltage decrease and time to recover to nominal when picking up resistive loads in rapid succession and in Diablo Canyon LOCA sequence. Load sequence time interval was 5 seconds. Resistive loading schedule simulated the LOCA load demand by the large induction motors. Performance of all units evaluated against the performance of the unit tested for Motor Starting LOCA sequence capability (Test No. 8.)	All engine generator units picked up resistive loads with speed (frequency) and voltage decrease and time to recover evaluated to satisfactorily show capability for starting and accelerating in rapid succession the large induction motors of the Diablo Canyon LOCA sequence.

TABLE 8.3-8

Test and Purpose[o]	Conduct of Tests	Results of Test
10. Full Load Drop To show capability of large load step decrease (2,600 kW).	Recorded speed (frequency) and voltage increase and time to recover to nominal following a full load drop (2,600 kW).	Speed of the diesel generator units did not exceed 75% of the difference between the nominal speed, and either the overspeed trip setpoint or 115% of nominal. Engine generator units are capable of recovery from the largest load reduction, a full load drop.

Note 1: Original testing was done using a nominal 5-second load sequence time interval with the KWS relay installed. Since a nominal 4-second load sequence time interval is used in the design basis loading scenario and the EDG loading capability is demonstrated through computer simulation without KWS relays, the test results of Table 8.3-8 are of historical value.

TABLE 8.3-9

SUMMARY OF PREOPERATIONAL TESTING OF DIABLO CANYON DIESEL ENGINE GENERATOR UNITS BY PG&E DURING STARTUP

Test and Purpose	Conduct of Tests
1. Standard Startup Tests To check out installation and onsite performance.	Startup, cleaning, flushing, performance checks, load capability, acceleration tests, etc., were performed on all engine generator units.
2. Integrated Safety Injection To verify capability to accept loads in rapid succession following the LOCA.	Safety injection was initiated manually with offsite power not available. The sequential loading of all engine generator units was monitored by recording voltage and current decrease.
3. Onsite Power Redundancy To prove auxiliary devices of one unit are not affected by failures in other units.	Test procedures used AEC Regulatory Guide 1.41 as an outline. Test was conducted in the same time period and in sequence with the Integrated Safety Injection tests described above.

TABLE 8.3-10

IDENTIFICATION OF ELECTRICAL SYSTEMS

Class 1E Equipment and Associated Buses[a]

	AC Systems		DC Systems	
	Unit 1	Unit 2	Unit 1	Unit 2
Orange	Bus 1F	Bus 2F	Bus 11	Bus 21
Gray	Bus 1G	Bus 2G	Bus 12	Bus 22
Purple	Bus 1H	Bus 2H	Bus 13	Bus 23

Reactor Protection Systems

Red	Channel 1	Reactor protection system instrumentation
White	Channel 2	Reactor protection system instrumentation
Blue	Channel 3	Reactor protection system instrumentation
Yellow	Channel 4	Reactor protection system instrumentation
Brown	Train A	Direct logic inputs
Green	Train B	Direct logic inputs

Power Circuits from Instrument Inverters

Orange	Reactor Protection Channel I
Gray	Reactor Protection Channel II
Purple	Reactor Protection Channel III
Black/Yellow	Reactor Protection Channel IV

(a) Circuits that do not serve a required Class 1E function may also be color-coded. (For instance, the main annunciator circuits are color-coded although the main annunciator system is not mutually redundant or required for safe shutdown.) In such cases, the color coding will normally follow the above conventions. There may, however, be infrequent instances where this is not practical; color coding in these instances will primarily indicate that these circuits were purchased and installed as Class 1E conductors.

TABLE 8.3-11

UNIT 1 - 125-VDC DISTRIBUTION PANEL
SAFETY-RELATED LOADS[a]

DESCRIPTION	Battery 11	Battery 12	Battery 13
Nuclear instrumentation UPS[b]	11	12 & 14	13
4-kV switchgear	Bus F	Bus G	Bus H
DG Gauge Panel Normal Source	DG 13	DG 12	DG 11
DG Gauge Panel Emergency Source	DG 12	DG 11	DG 13
NU safeguards control board solenoid valves	F	G	H
Safeguards relay board	F	G	H
Reactor control board solenoid valves	X	X	X
480-V MCC relay board	F	G	H
Auxiliary safeguards cabinet	Train A	Train B	-
Reactor trip breakers	X	X	-
FWP turbine local control board	12	11	-
Auxiliary relay rack	-	X	-
Dedicated shutdown panel	-	-	X

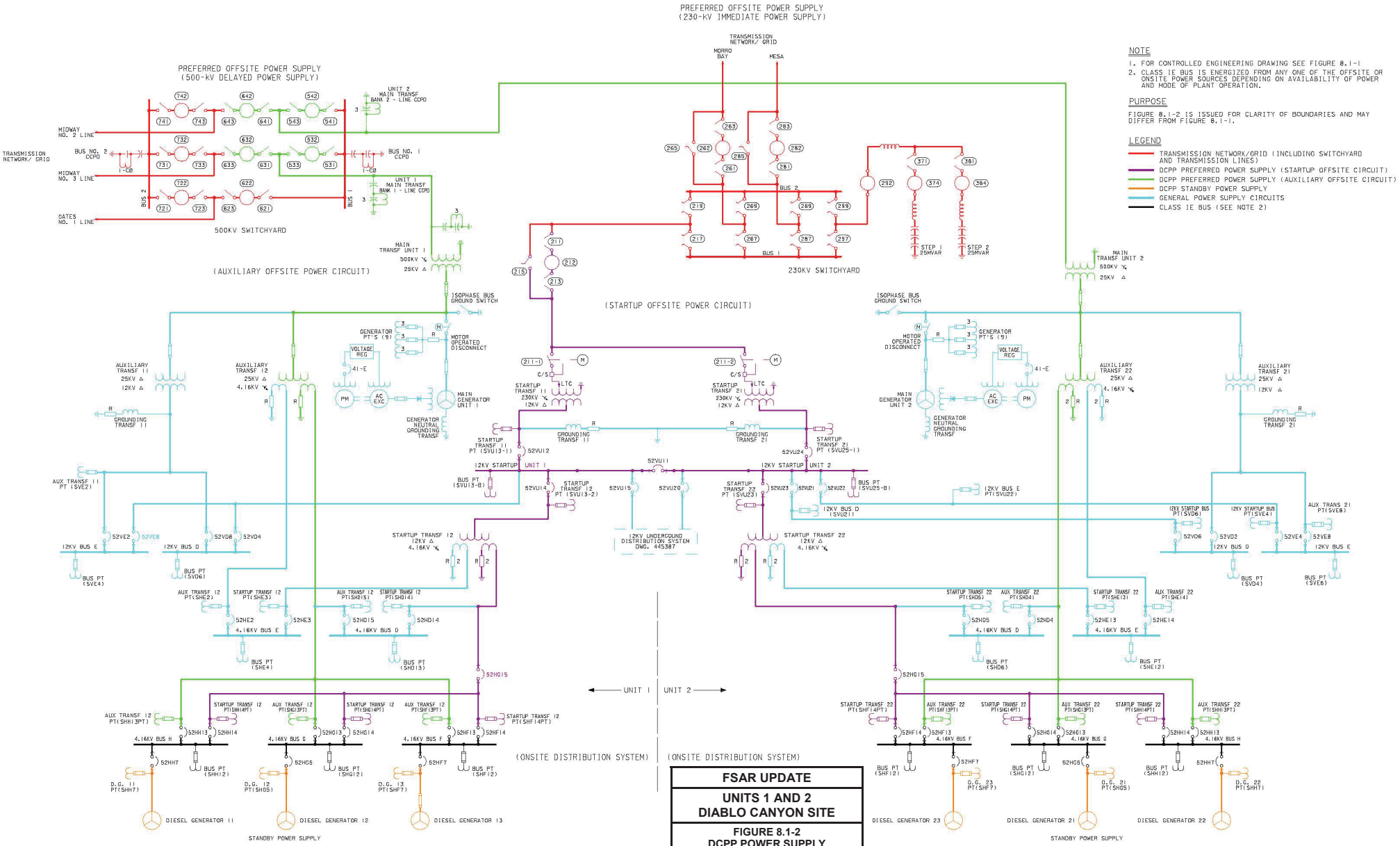
(a) Unit 2 loads are similar.

(b) UPS fed via 480 V when bus is transferred to the diesel generator.

TABLE 8.3-12

MAXIMUM STEADY STATE DG LOADING AT 4340 V AND 60.8 HZ [p][q]

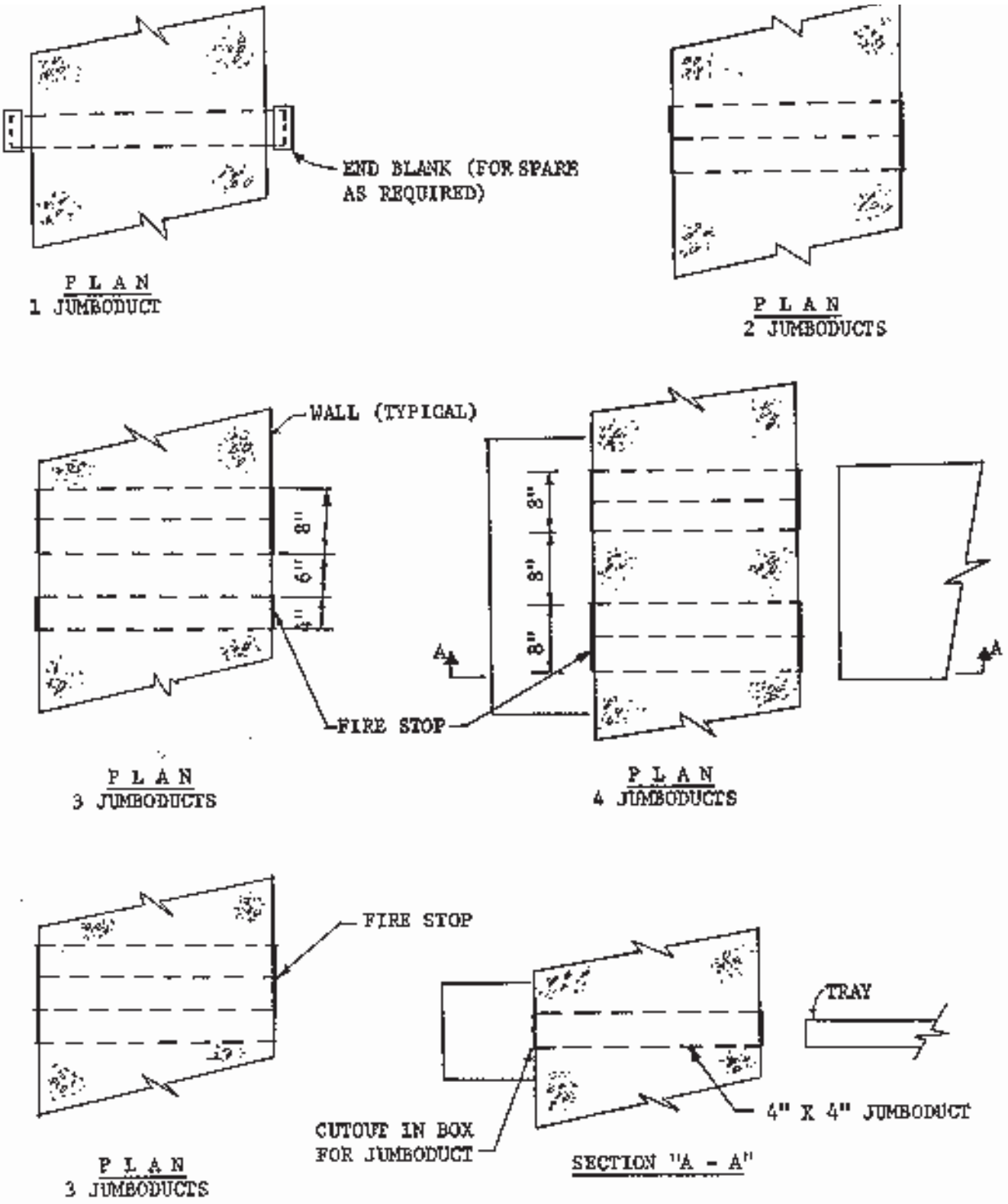
Unit	DG	Bus	Description	Loading (kw)	Power Factor
1	1-3	F	Event 1, Case 4; LBLOCA, Bus H is De-Energized	2654	84.6%
	1-2	G	Event 1, Case 4; LBLOCA, Bus H is De-Energized	2648	85.4%
	1-1	H	Event 1, Case 3; LBLOCA, Bus G is De-Energized	2614	86.6%
2	2-3	F	Event 1, Case 4; LBLOCA, Bus H is De-Energized	2663	84.6%
	2-1	G	Event 1, Case 4; LBLOCA, Bus H is De-Energized	2641	85.1%
	2-2	H	Event 1, Case 3; LBLOCA, Bus G is De-Energized	2592	86.6%



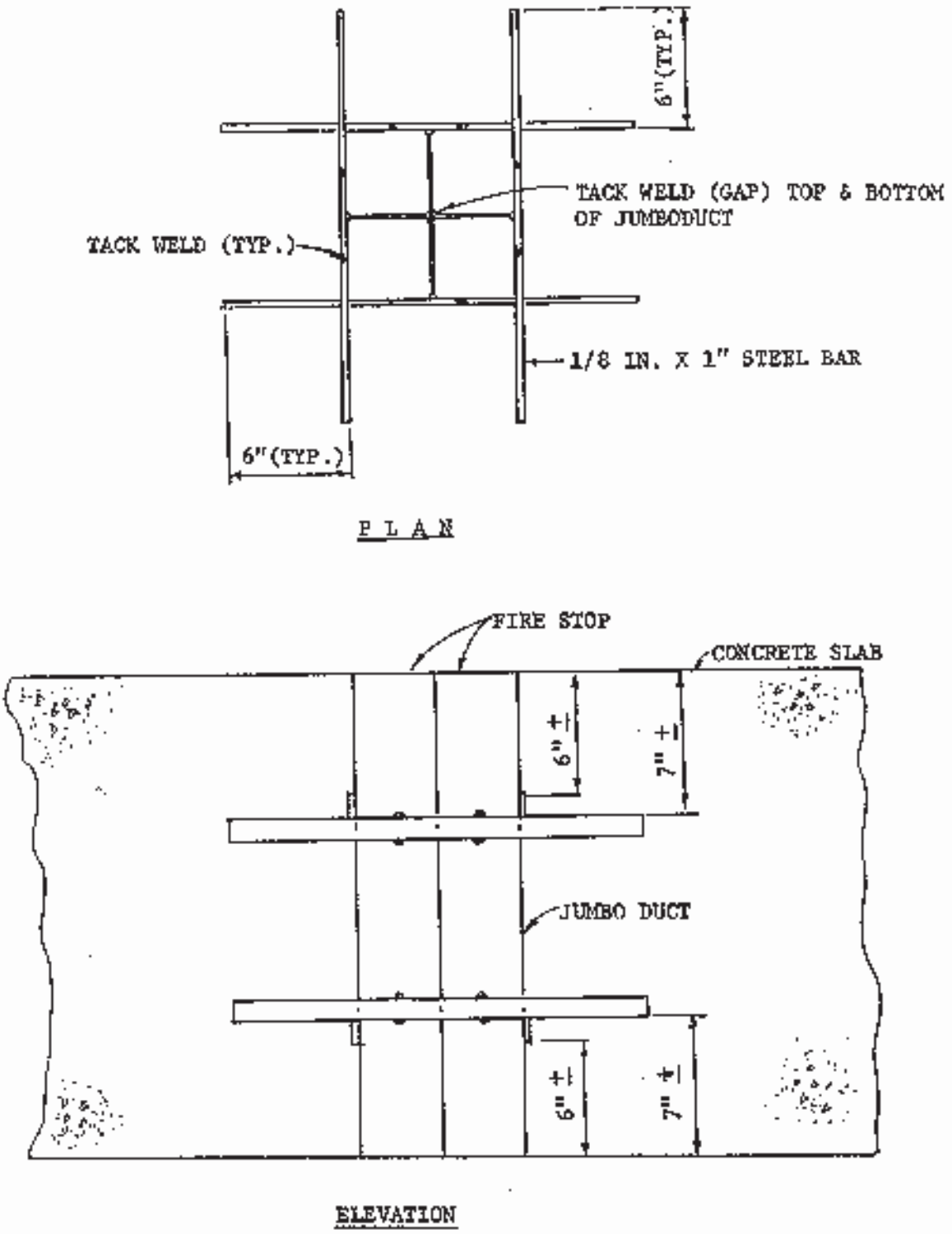
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

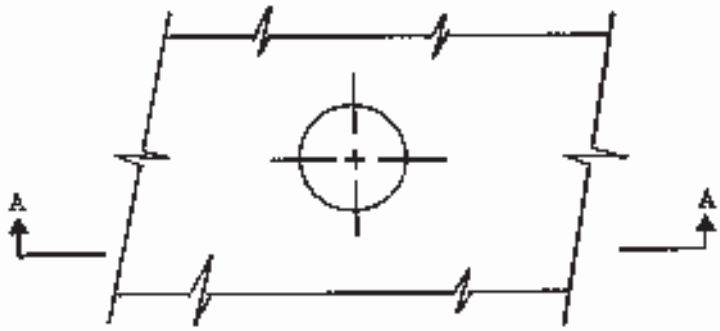
FIGURE 8.1-2
DCPP POWER SUPPLY
BOUNDARY DIAGRAM



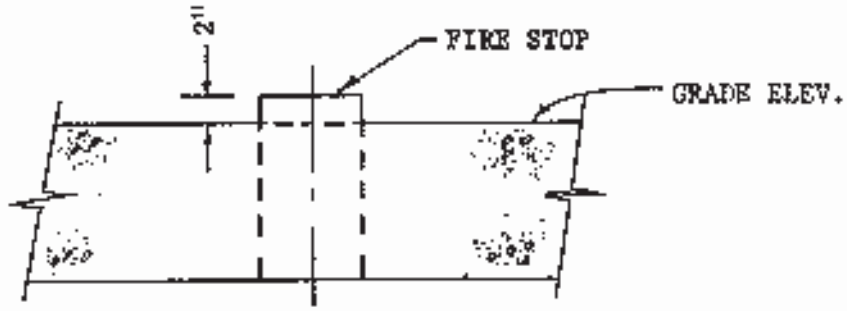
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 8.3-21 TYPICAL ARRANGEMENT OF JUMBODUCT SLEEVE THROUGH CONCRETE



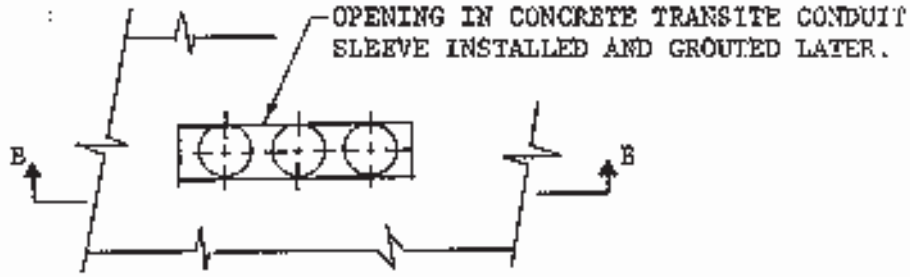
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 8.3-22 TYPICAL DETAIL OF FOUR OR MORE JUMBODUCTS IN CONCRETE SLAB



PLAN



SECTION "A -A"



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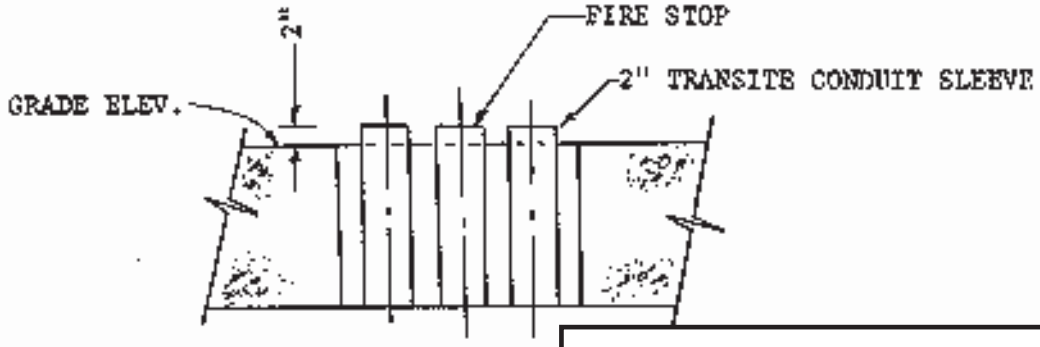
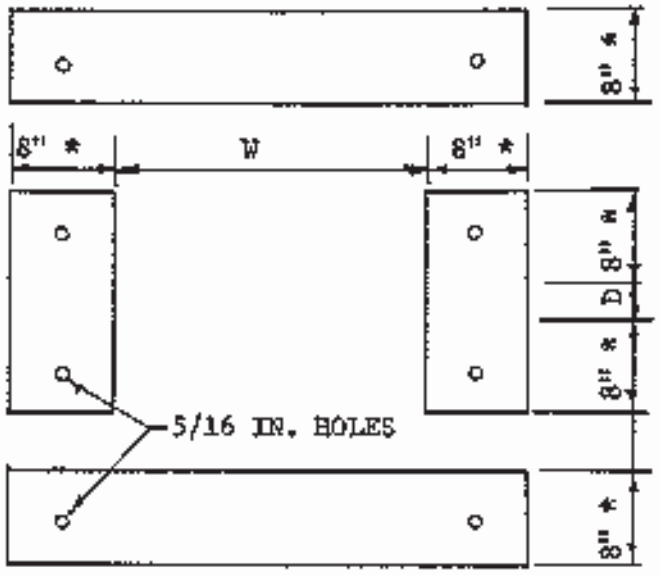
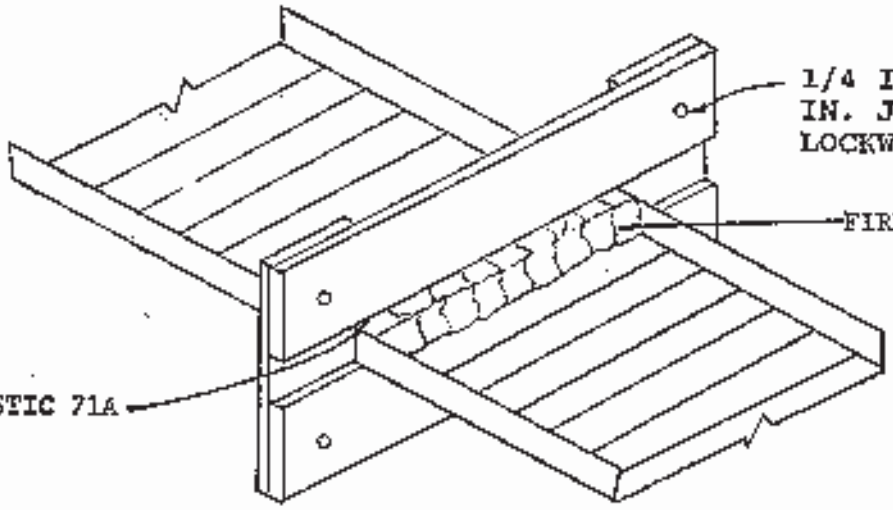


SECTION "B - B"

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 8.3-23 TYPICAL ARRANGEMENT OF TRANSITE CONDUIT SLEEVE FOR ELECTRICAL CABLES THROUGH CONCRETE



D = TRAY DEPTH, OUTER DIMENSION
W = TRAY WIDTH, OUTER DIMENSION
* - NOMINAL - VARY AS NECESSARY TO SUIT



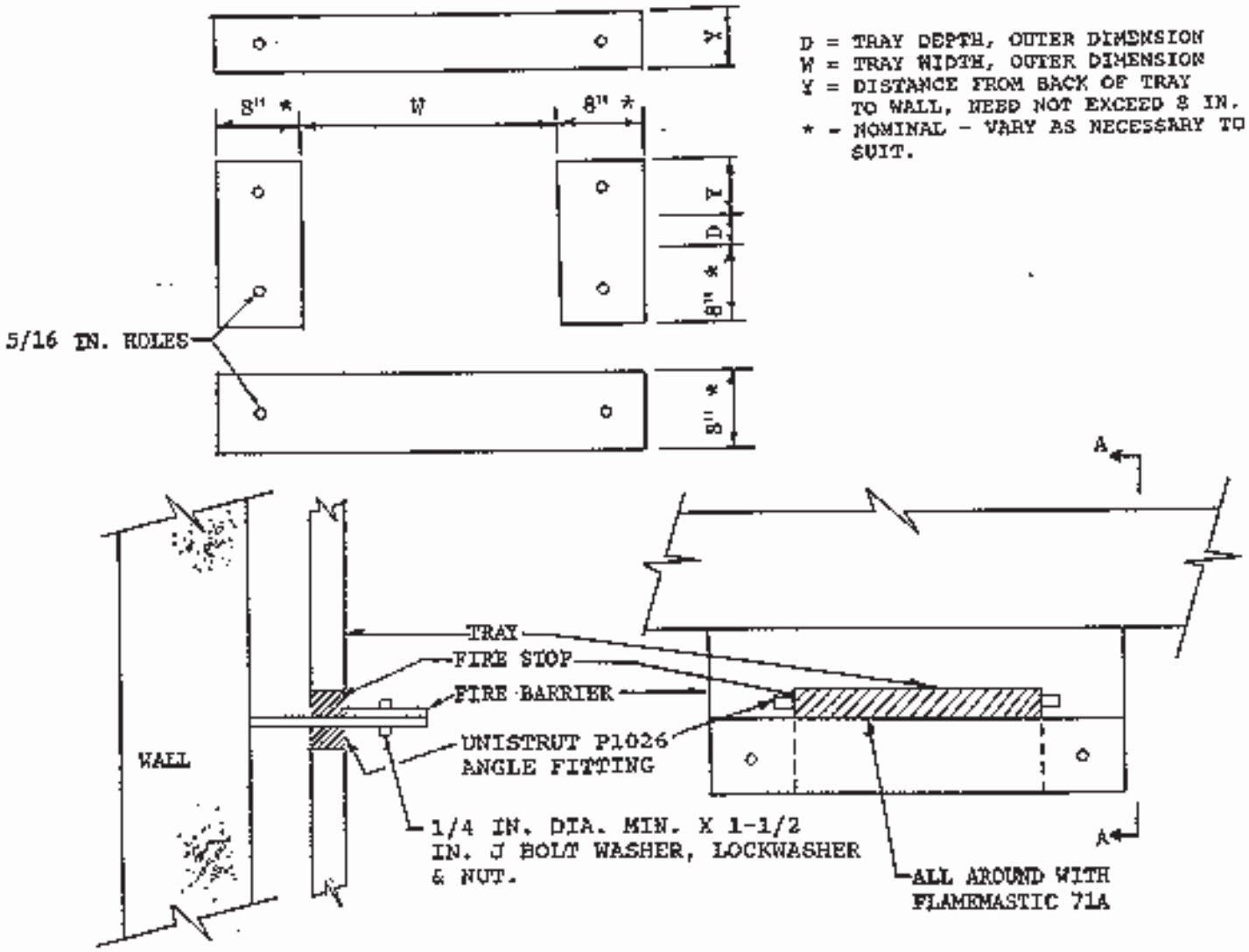
NOTES:

1. FIRE BARRIER BOARD MATERIAL MIN.- 1/2 IN. MARINITE XL PANEL. ALTERNATE MATERIAL - MIN. 1/2 IN. M BOARD OF CERAMIC FIBER.

2. FIRE STOP MATERIAL SHALL BE 4 IN. OF LDSE OR 10 IN. RTV 3-6548.

3. FOR ALTERNATE HORIZONTAL TRAY FIRESTOP DESIGN - SEE FIGURE 8.3-28.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 8.3-24 TYPICAL FIRE STOP FOR HORIZONTAL CABLE TRAYS



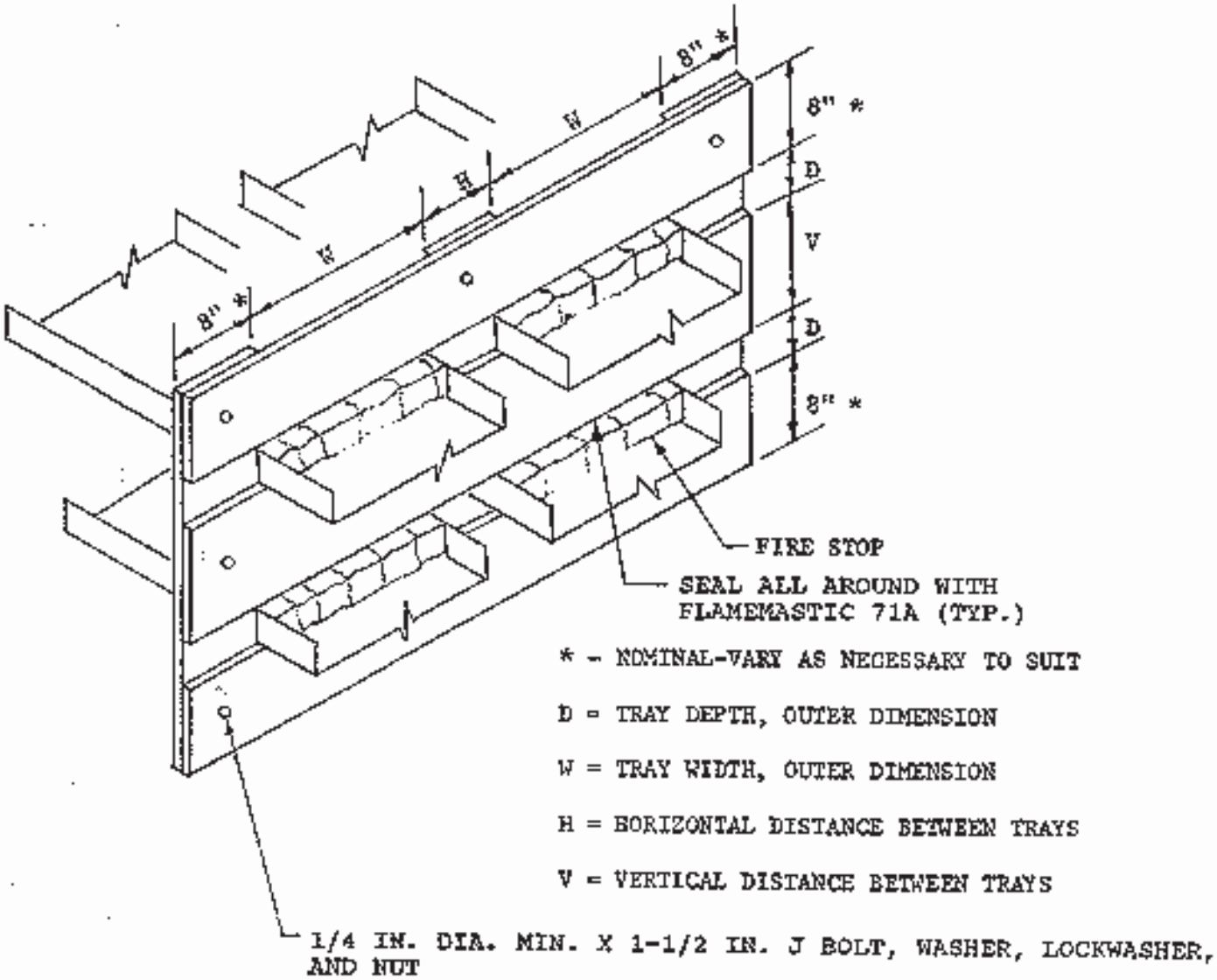
SECTION "A - A"

NOTES:

1. FIRE BARRIER BOARD MATERIAL - MIN. 1/2 IN. MARINITE XL PANEL. ALTERNATE MATERIAL - MIN. 1/2 IN. KAOWOOL M BOARD OF CERAMIC FIBER.

2. FIRE STOP MATERIAL SHALL BE 4 IN. OF LDSF OR 10 IN. RTV 3-6548.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 8.3-25 TYPICAL FIRE STOP FOR VERTICAL TRAYS

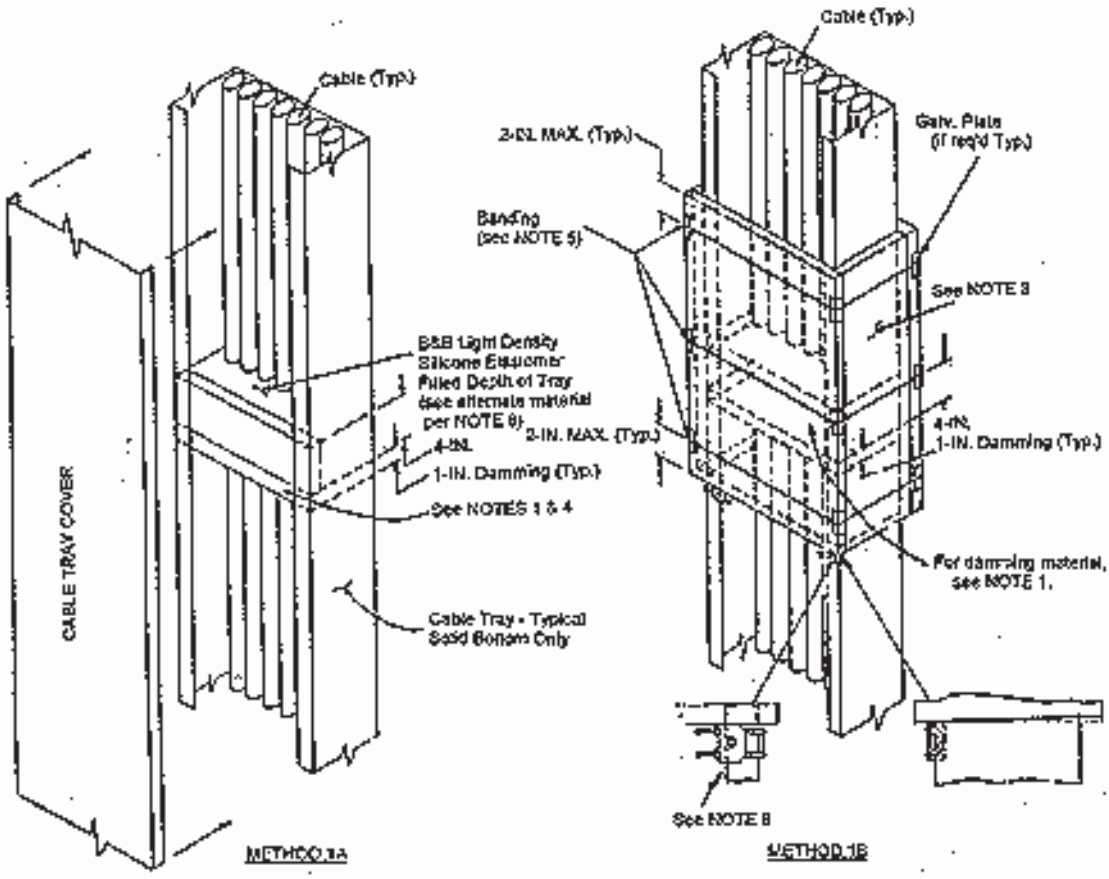


NOTES:

1. FIRE BARRIER BOARD MATERIAL - MIN. 1/2 IN. MARINITE XL PANEL. ALTERNATE MATERIAL - MIN. 1/2 IN. KAOWOOL M BOARD OF CERAMIC FIBER.

2. FIRE STOP MATERIAL SHALL BE 4 IN. OF LDSE OR 10 IN. RTV 3-6548.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 8.3-26 TYPICAL FIRE STOP FOR PARALLEL TRAYS



NOTE 1 Damming (typ.)
Damming is to be left in place and fire rated materials such as J-M Cera Products or B & W Kaowool Products, shall be utilized. Such products shall be board form only.

NOTE 2 Cable separation
J-M or B & W bulk fiber shall be used at point of damming for cable separation, where possible, to facilitate flow of seal material.

NOTE 3 For open and ladder type trays, enclose tray with 3'-0" of fire rated board, as referred in NOTE 1 above, and locate board material to suit field installation, but maintain cover of entire firebreak face.

NOTE 4 For open solid back trays, install firebreak per Method 1A (excluding Cover), and install fire board over open area, using banding material as noted in Method 1B.

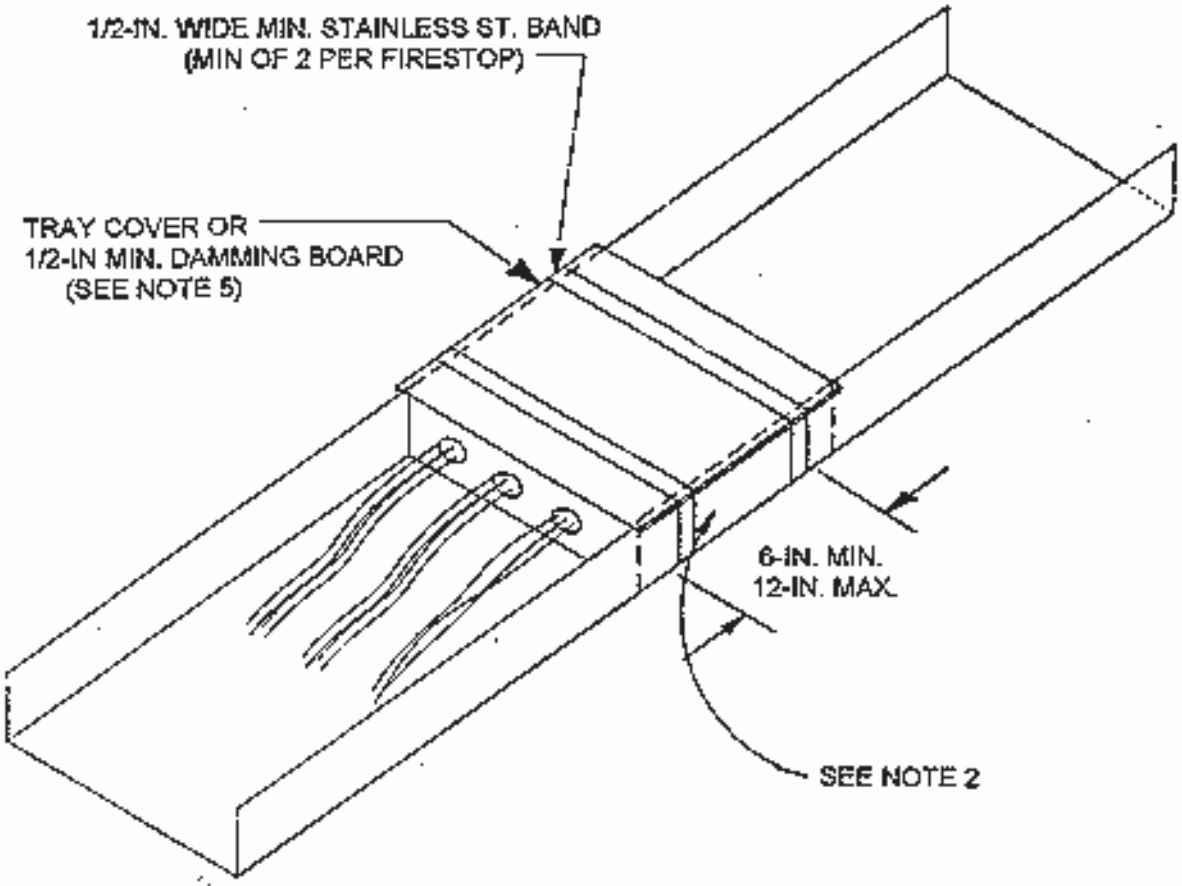
NOTE 5 Banding material shall be 3/4" X 0.020" stainless steel band with stainless steel wing seals. Banding shall be installed at three (3) approx. equally spaced locations.

NOTE 6 Alternate to the 4" of B & B Light Density Silicone Elastomer (LDSE) is 10" of Dow Corning 3-6548 Silicone RTV Foam. All other requirement per the above notes and details, to be incorporated.

NOTE 7 If necessary, add galvanized angle plate (approx. 1" X 2") under banding at corners.

NOTE 8 B-line clamp 0400-101 and/or 97-1155 to be installed in the front side of cable tray on the bottom of the firebreak (for vertical tray only).

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 8.3-27 TYPICAL VERTICAL TRAY FIRE STOP



NOTES:

1. 12 FEET FOR HORIZONTAL RUNS AND WITHIN 5 FEET OF TRAY CROSSINGS.

2. FILL WITH DOW CORNING RTV 3-6548 SILICONE RTV FOAM. ALL CABLES IN TRAY SHOULD BE COVERED WITH FOAM. COVER TRAY VENTILATION OPENING WITH TAPE WHILE FOAM IS CURING. THEN REMOVE TAPE.

3. FOR OTHER "FIRE BARRIER FOR VENTILATED TRAY" DESIGN, SEE FIGURE 8.3-24.

4. IN CASES WHERE DAMMING BOARD CANNOT BE INSTALLED DUE TO AMOUNT OF CABLES, A MINIMUM OF 8 INCHES OF RTV FOAM SHALL BE USED.

5. DAMMING BOARD MATERIAL TO BE 1-INCH KAOWOOL M BOARD OF CERAMIC FIBERS OR EQUIV.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 8.3-28 TYPICAL FIRE BARRIER FOR HORIZONTAL TRAYS

APPENDIX 8.3B

INSULATED CABLE
CONSTRUCTION AND VOLTAGE RATINGS

Appendix 8.3B

INSULATED CABLE CONSTRUCTION AND VOLTAGE RATINGS

The insulated cables that externally interconnect separate units of equipment throughout the plant are described below:

(1) High-voltage power cables for 4160- and 12,000-V service are rated 5000 and 15,000 V, respectively, for ungrounded or high-resistance grounded operation. All of these cables are rated 90°C because they are expected to operate only in an environment having a normal maximum temperature of 40 to 50°C. These cables are all single conductor, with ethylene-propylene insulation and a neoprene, hypalon (chlorosulfonated polyethylene (CSPE)), thermoset chlorinated polyethylene (TS-CPE), or linear low density polyethylene (LLDPE) jacket. These cables are provided with an extruded semiconducting shield surrounding the conductor and another over the insulation, all covered by a tinned or bare copper tape. A polyester-polypropylene tape and a nylon-neoprene tape are used as a heat shield between the copper tape and the jacket. A stress cone is provided at each terminal, with one of them grounded.

(2) Low-voltage power cables are all of the single conductor type, rated 600 V. Generally, those expected to operate in a maximum ambient temperature of 40 to 50°C are rated 90°C and have ethylene-propylene insulation and a hypalon (CSPE) jacket for sizes 8 AWG and larger. Smaller cables are insulated with flame-retardant cross-linked polyethyelene (XLPE). Those cables located very near or connected to hot equipment and devices, or those required to operate in the atmosphere of the containment during a loss-of-coolant-accident (LOCA), are insulated with silicon rubber, XLPE, Tefzel, or equivalent insulation material and covered by a hypalon (CSPE), XLPE, Tefzel, or equivalent jacket material (except for power cables to the containment fan cooler motors and pressurizer heaters). Cables for the containment fan cooler motors are insulated with a combination of silicone resin-impregnated glass braid, polyimide (Kapton) tapes, an asbestos mat, and a jacket of hypalon. Heat-shrinkable tubing is provided at terminations and splices to seal the cable. Cables for the pressurizer heaters are rated 600 V, 1000°F, and are insulated with a combination of mica and glass tapes with a glass braid jacket.

(3) Cables for control circuits are single and multiple conductor, rated 600 V. Generally, single conductor cables are not less than 12 AWG, and multiple conductor cables are not less than 14 AWG. Cables operating in normal maximum ambient temperature are rated 90°C and are insulated with cross-linked polyethylene with multiple conductor cables having an overall jacket of

the same material. Cables that are located very near or connected to hot equipment and devices, or required to operate in the atmosphere of the containment during a LOCA, are insulated with silicone rubber, XLPE, Tefzel, or equivalent insulation material and covered by a hypalon (CSPE), XLPE, Tefzel, Stilan, or equivalent jacket material.

(4) Instrument cables composed of adjacent conductors have the conductors twisted and shielded with an aluminized mylar tape in continuous contact with a copper drain wire, grounded only at one point. Signal circuits are generally 16 AWG copper, and thermocouple circuits are also 16 AWG. Those cables operating in a normal environment are insulated with cross-linked polyethylene (XLPE) and covered by a jacket of the same material. Cables that are located very near or connected to hot equipment and devices, or required to operate in the atmosphere of the containment during a LOCA, are insulated with silicone rubber and covered by a silicone rubber, Tefzel, Stilan, XLPE, or equivalent jacket material.

(5) Instrument cables of the coaxial and triaxial types have insulations of alkane-imide polymer and cross-linked polyolefin, and jackets of cross-linked polyethylene. Incore thermocouple extension wire is 20 AWG Chromel-Alumel for use in ambient up to 400°F. Primary insulation is a heavy polyimide enamel, and silicone-impregnated fiberglass braid covers the insulation.

APPENDIX 8.3C

MATERIALS FOR FIRE STOPS AND SEALS

Appendix 8.3C

MATERIALS FOR FIRE STOPS AND SEALS

Materials used for fire stops and penetration seals are as follows:

(1) **Refractory Ceramic Damming Materials -** Approved damming material, when required as part of a PG&E Approved penetration seal design, is installed on the bottom of the penetration seal in floors/ceilings and on both sides of the penetration seal in walls. Variations are not allowed without Fire Protection Engineering Approval. Kaowool M board, or engineering approved equivalent, is also used as cable tray fire stop damming. Damming materials consist of the following:

Board:
- Thermal Ceramics Kaowool M Board
- Johns-Manville (JM) Ceraform Board Type 103
- Johns-Manville (JM) Ceraboard Type 126/103
- Fire Protection Design Engineer, or designee, approved equivalent

Blanket:
- Thermal Ceramics Kaowool blanket
- Chemtrol CT-23B alumina silica blanket
- Johns-Manville (JM) Cerablanket
- Fire Protection Design Engineer, or designee, approved equivalent

Bulk Fiber:
- Thermal Ceramics Kaowool bulk fiber
- Chemtrol CT-23F alumina silica bulk fiber
- Johns-Manville (JM) Cerafiber Bulk
- Fire Protection Design Engineer, or designee, approved equivalent

(2) **Marinite Panels -** These panels are composed of calcium silicate and inorganic binders. Can be used as tray fire stop damming or shielding. Can only be used as part of a penetration seal with engineering evaluation. ASTM Specification C5676.

(3) **Flamemastic 77 -** This material, as manufactured by Flamemaster Corporation, is used in conjunction with Kaowool M board or Marinite Panels for tray fire stop construction. This material can only be used as part of a penetration seal design with engineering evaluation.

(4) **Dow Corning 3-6548 Silicone RTV Foam -** This material, as manufactured by Down Corning Corporation, is used in PG&E Engineering approved penetration seal and cable tray fire stop designs.

(5) **Dow Corning Sylgard 170 Silicone Elastomer -** This material, as manufactured by Dow Corning Corporation, is used in PG&E Engineering approved penetration seal designs.

(6) **LDSE (Light Density Silicone Elastomer) -** This material, as manufactured by PROMATEC, Inc., is used in PG&E Engineering approved penetration seal designs.

(7) **TS-MS-45B (Medium Density Silicone Elastomer) -** This material, as manufactured by PROMATEC, Inc., is used in PG&E Engineering approved penetration seal designs and for internal bus duct sealing.

(8) **HDSE (High Density Silicone Elastomer) -** This material, as manufactured by PROMATEC, Inc., is used in PG&E Engineering approved penetration seal designs, typically where gamma radiation shielding is a concern.

(9) **RADFLEX -** This material, as manufactured by PROMATEC, Inc., is used in PG&E Engineering approved penetration seal designs, typically where gamma radiation shielding and mechanical pipe movement is a concern.

(10) **PROMAFLEX -** This material, as manufactured by PROMATEC, Inc., is used in PG&E Engineering approved penetration seal designs, typically where mechanical pipe movement is a concern.

(11) **Approved Boot Fabric Material -** This material is used in conjunction with PG&E Engineering approved penetration seal designs, typically where mechanical pipe movement is a concern.

- Connecticut Hard Rubber (CHR) 1032
- Keene Grade 56493F031
- Fire Protection Design engineer, or designee, approved equivalent

(12) **Silicone Adhesive Sealant -** Approved material is used in conjunction with PG&E Engineering approved penetration seal designs, or as an engineering approved sealant in other specific design applications.

- Dow Corning 732 silicone adhesive sealant
- Dow Corning 96-081 silicone adhesive sealant
- Fire Protection design Engineer, or designee, approved equivalent

(13) **Grout -** This material is used in PG&E Engineering approved penetration seal designs, and as a barrier restoration material for poured n place concrete and concrete block barriers. Typically, the only approved grout material is a cement based grout. With limitation in certain design applications, Ceilcote 658N Epoxy resin grout is approved.

(14) **Pyrocrete -** This material, as manufactured by Carboline, Inc., is used as a PG&E Engineering approved penetration seal design as a barrier restoration material around penetrants through Pyrocrete construction barriers. The specific type, grade, and thickness of Pyrocrete is dependent on the barrier contraction, or engineering evaluated equivalent.

(15) **Plaster -** This material is used as a PG&E Engineering approved penetration seal design as a barrier restoration material around penetrants through Plaster construction barriers. The specific type, grade, and thickness of Plaster is dependent of the barrier construction or engineering evaluated equivalent.

(16) **Epoxy XR5126 -** This material is used where electrical and pressure isolation is required.

Fire barrier penetration seals and credited cable tray fire stops are visually inspected periodically.

Chapter 9

AUXILIARY SYSTEMS

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NOTE:

[a] This figure corresponds to a controlled engineering drawing that is incorporated by reference into the FSAR Update. See Table 1.6-1 for the correlation between the FSAR Update figure number and the corresponding controlled engineering drawing number.

Chapter 9

AUXILIARY SYSTEMS

This chapter discusses auxiliary systems installed in Unit 1 and Unit 2 at the Diablo Canyon Power Plant (DCPP) site. Fuel storage and handling systems; water systems; process auxiliaries; and air conditioning, heating, cooling, and ventilation systems are described as well as other auxiliary systems. The design classifications for these various systems and their associated structures and components are discussed in Section 3.2.

9.1 FUEL STORAGE AND HANDLING

The fuel storage and handling systems provide safe and effective means of storing, transporting, and handling new and irradiated nuclear fuel. These systems are located mainly in the fuel handling building (FHB), adjacent to the east walls of the containment structures. Separate facilities are provided for each unit.

The fuel storage and handling systems comply with the criticality accident requirements of 10 CFR 50.68(b), “Criticality Accident Requirements,” in lieu of maintaining a monitoring system capable of detecting a criticality as described in 10 CFR 70.24, “Criticality Accident Requirements.” In accordance with 10 CFR 50.68(b)(6), radiation monitors are provided in storage and associated handling areas when fuel is present to detect excessive radiation levels and to initiate appropriate safety actions.

9.1.1 NEW FUEL STORAGE

New fuel is stored in new fuel storage racks (NFSRs), which are in storage vaults in the FHB, or in the spent fuel pool (SFP) storage racks, as discussed in Section 9.1.2. The NFSRs are designed to store, protect, and prevent criticality of new fuel assemblies until used within the reactor.

9.1.1.1 Design Bases

Refer to Section 9.1.1.3.6 for a discussion of k_{eff} limits including allowance for uncertainties.

9.1.1.1.1 General Design Criterion 2, 1967 – Performance Standards

New fuel storage is located in the FHB, which is designed to withstand the effects of, or is protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds, and tsunamis, and other local site effects.

9.1.1.1.2 General Design Criterion 3, 1971 – Fire Protection

The NFSRs are designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.1.1.1.3 General Design Criterion 11, 1967 – Control Room

The NFSRs are designed to or contain instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room.

9.1.1.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the NFSR variables within prescribed operating ranges. NFSR area radiation monitoring equipment is provided in the control room.

9.1.1.1.5 General Design Criterion 18, 1967 – Monitoring Fuel and Waste Storage

The NFSRs are provided with monitoring and alarm instrumentation for conditions that might contribute to radiation exposure.

9.1.1.1.6 General Design Criterion 66, 1967 – Prevention of Fuel Storage Criticality

The NFSRs are designed to prevent new fuel criticality through physical systems or processes such as geometrically safe configurations.

9.1.1.1.7 New Fuel Storage System Safety Function Requirements

(1) Protection from Missiles

The NFSRs are designed to be protected against the effects of missiles that might result from plant equipment failures and from events and conditions outside the plant.

(2) Protection Against High Energy Pipe Rupture Effects

The NFSRs are designed to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to prevent a criticality accident.

9.1.1.1.8 10 CFR 50.68(b) – Criticality Accident Requirements

The NFSRs are designed to support compliance with the applicable requirements of 10 CFR 50.68(b) to prevent inadvertent criticality.

9.1.1.2 System Description

There are two NFSRs for each unit. Each NFSR is approximately 9 feet 6 inches wide, 13 feet long, and 13 feet 6 inches high (excluding centering cones). It is built from Type 304 stainless steel.

The storage cells in the NFSRs are in seven rows, five deep, and are spaced to have a nominal center-to-center distance of 22 inches. They are of Type 304 stainless steel and have a cone shaped top entrance to facilitate loading of fuel elements. They are shaped in a 9-inch square (cross-section) hollow beam configuration, standing upright.

The NFSRs are designed in accordance with the American Institute of Steel Construction (AISC) Standard AISC 360-1969, Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, published on February 12, 1969. The ASME BPVC Section III-1983 is used to determine allowable limits for materials not addressed by the AISC specification.

The NFSRs are designed to withstand a vertical (uplift) force of 4000 pounds in the unlikely event that an assembly would bind in the NFSR while being lifted by the SFP bridge crane.

The NFSRs are located in the FHB at elevation 125 feet. Assembly access is from elevation 140 feet.

For each unit, new fuel assemblies with possible inserts (e.g., rod cluster control assemblies [RCCAs]) are stored to facilitate the unloading of new fuel assemblies from trucks. The storage vaults are designed to hold new fuel assemblies in NFSRs and are utilized primarily for the temporary storage of the replacement fuel every cycle. The storage vault for each unit consists of two NFSRs with 35 storage cells per NFSR (70 cells per unit). The cells are arranged in a 5x7 array for each NFSR.

9.1.1.3 Safety Evaluation

9.1.1.3.1 General Design Criterion 2, 1967 – Performance Standards

The NFSRs are located in the FHB which is a PG&E Design Class I structure. This building is designed to withstand the effects of winds (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), and earthquakes (refer to Section 3.7), and to protect PG&E Design Class I structures, systems and components (SSCs) to ensure their safety functions are maintained.

The NFSRs and the anchorage of the NFSRs to the floor are designed for the Design Earthquake (DE) and Double Design Earthquake (DDE) loading conditions and evaluated for a Hosgri seismic event. In addition, the NFSRs must be capable of maintaining the horizontal center-to-center spacing of the fuel assemblies, and of supporting assemblies vertically under postulated seismic events.

Each NFSR is seismically qualified to store only six assemblies; one at each corner, in addition to one assembly in the central cell at the East and West ends. Each fuel assembly is assumed to also contain an insert component (e.g. RCCA). The assumed combined weight of each fuel assembly and insert is 1570 pounds. Also, together with these six assemblies and their potential inserts, a maximum of two additional insert components may be stored in each NFSR in cells face-adjacent to the corner cells in diagonally opposite corners. The seismic qualification is based on an assumed weight of each of the two additional inserts of 170 pounds.

9.1.1.3.2 General Design Criterion 3, 1971 – Fire Protection

The NFSRs are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.1.1.3.3 General Design Criterion 11, 1967 – Control Room

The area radiation monitoring equipment for the new fuel storage area is annunciated in the control room.

9.1.1.3.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided to monitor area radiation variables within specified operating ranges.

Radiation levels are monitored locally in the FHB. Signal input is provided to local alarms and main control room annunciators, and to the fuel handling building ventilation system (FHBVS) to automatically initiate iodine removal mode operation (refer to Section 9.4.4.2).

9.1.1.3.5 General Design Criterion 18, 1967 – Monitoring Fuel and Waste Storage

Radiation monitors are provided in storage areas and associated handling areas when fuel is present to detect excessive radiation levels and to initiate appropriate safety actions. New fuel storage is provided with monitoring and alarm instrumentation for conditions that might contribute to radiation exposure (refer to Section 11.4.2.1.3 and Table 11.4-1).

9.1.1.3.6 General Design Criterion 66, 1967 – Prevention of Fuel Storage Criticality

The fuel storage criticality analysis assumes the NFSRs are completely filled with 5.0 weight percent U-235 fuel with no credit taken for any burnable absorber that may be present in the fuel assemblies (e.g., integral fuel burnable absorber [IFBA]). Although the storage vault containing the NFSRs is normally dry, two accident

scenarios were considered as part of the NFSRs' design bases: (1) when fully flooded with unborated water, a $k_{eff} \leq 0.95$ must be maintained after allowing for calculational uncertainties, and (2) when flooded with aqueous foam, a $k_{eff} \leq 0.98$ must be maintained after allowing for calculational uncertainties.

For each case, calculations were made for both the Westinghouse standard and optimized fuel assembly (OFA) designs, which have different fuel rod diameters. The standard fuel gave the higher reactivity for the aqueous foam case whereas the OFA fuel gave the higher reactivity under the fully flooded accident condition. For the fully flooded case, the calculated k_{eff} was 0.9380 ± 0.0069 (95 percent probability, 95 percent confidence level). For the aqueous foam case, the calculated k_{eff} was 0.8949 ± 0.0053 (95 percent probability, 95 percent confidence level). Thus, allowing for all uncertainties, the maximum k_{eff} was 0.9449 for the flooded case, and 0.9002 for the aqueous foam case. These maximum values are within their respective 0.95 and 0.98
10 CFR 50.68(b)(2) and
10 CFR 50.68(b)(3) limits.

Center-to-center assembly spacing is held to a tolerance of ±1/16 inch to ensure a K_{eff} of less than 0.95, even when the storage vault is flooded with unborated water. After the NFSRs were installed, a dummy fuel element was inserted in each location and critical measurements taken to ensure proper arrangement and support. A metal cap covers the top of the NFSR. If a fuel assembly is accidentally dropped, it will only be able to drop into a holder and could not drop into the space between fuel assemblies. Refer to Section 15.4.5 for a discussion of fuel handling accidents (FHAs).

9.1.1.3.7 New Fuel Storage System Safety Function Requirements

(1) Protection from Missiles

There are no credible missiles outside of containment resulting from plant equipment failure that would prevent the PG&E Design Class I NFSRs from performing their design functions (refer to Section 3.5.3.3). Protection of the NFSRs from the effects of missiles and protection of PG&E Design Class I SSCs from damage that may result from these events is discussed in Section 3.5.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the PG&E Design Class I NFSRs from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Section 3.6.

9.1.1.3.8 10 CFR 50.68(b) – Criticality Accident Requirements

The new fuel storage and handling systems comply with the criticality accident requirements of 10 CFR 50.68(b), “Criticality Accident Requirements,” in lieu of

maintaining a monitoring system capable of detecting a criticality as described in 10 CFR 70.24, “Criticality Accident Requirements.”

In accordance with 10 CFR 50.68(b)(1), plant procedures prohibit handling and storage at any one time of more fuel assemblies than have been determined to be safely subcritical.

Refer to Section 9.1.1.3.6 for a discussion of implementation of 10 CFR 50.68(b)(2) and 10 CFR 50.68(b)(3), with regard to k_{eff} limits for new fuel storage in the NFSRs assuming other-than-dry conditions.

The requirements in 10 CFR 50.68(b)(4) and 10 CFR 50.68(b)(5) regard spent fuel and special nuclear material other than nuclear fuel, respectively, and are therefore not applicable to the NFSRs.

In accordance with 10 CFR 50.68(b)(6), radiation monitors are provided in storage and associated handling areas when new fuel is present to detect excessive radiation levels and to initiate appropriate safety actions (refer to Sections 9.1.1.3.4 and 9.1.1.3.5).

Refer to Section 9.1.1.3.6 for information on implementation of 10 CFR 50.68(b)(7) regarding maximum nominal U-235 enrichment of new fuel assemblies.

Implementation of 10 CFR 50.68(b)(8) was completed with the submittal of Revision 15 of the UFSAR.

9.1.1.4 Tests and Inspections

New fuel is stored in the NFSRs prior to removal for receipt inspection and placement in the SFP. Tests and inspections are conducted in accordance with plant procedures.

9.1.1.5 Instrumentation Applications

The NFSR radiation monitor provides a signal to the ventilation control logic to realign the FHBVS exhaust flow through the charcoal filter banks (Iodine Removal Mode) upon sensing a high radiation condition (refer to Section 9.1.1.3.4).

9.1.2 SPENT FUEL POOL STORAGE SYSTEM

The SFP, shown in Figure 9.1-2, is the storage space in the DCPP 10 CFR Part 50 facilities for irradiated spent fuel from the reactor. New fuel may also be stored in the SFP. The figure shows the arrangement of the SFP storage racks. The SFP is not required for any plant operating mode safety-related function. As described in Section 3.2, the SFP concrete structure is PG&E Design Class I. Two pools are provided, one for each unit. The Unit 2 SFP is a mirror image of the Unit 1 SFP, reflected around column line 12[9].

The SFP for each unit comprises high density fuel storage racks, the SFP liner, the SFP liner leakage detection system, and key instruments to monitor SFP level, temperature and rate of temperature change, and local radiation levels. The SFP interfaces with the SFP cooling and cleanup system (refer to Section 9.1.3) and the fuel handling system (FHS) (refer to Section 9.1.4).

Refer to Section 9.1.4.2.6 for information on the Diablo Canyon independent spent fuel storage installation (ISFSI).

9.1.2.1 Design Bases

9.1.2.1.1 General Design Criterion 2, 1967 – Performance Standards

The SFP is designed to withstand the effects of, or is protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

9.1.2.1.2 General Design Criterion 3, 1971 – Fire Protection

The SFP is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.1.2.1.3 General Design Criterion 11, 1967 – Control Room

The SFP is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room.

9.1.2.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the SFP variables within prescribed operating ranges.

9.1.2.1.5 General Design Criterion 18, 1967 – Monitoring Fuel and Waste Storage

The SFP is provided with monitoring and alarm instrumentation for conditions that might contribute to loss of continuity in decay heat removal and to radiation exposures.

9.1.2.1.6 General Design Criterion 66, 1967 – Prevention of Fuel Storage Criticality

The SFP is designed to prevent criticality in SFP-stored new and spent fuel through physical systems or processes such as geometrically safe configurations.

9.1.2.1.7 General Design Criterion 68, 1967 – Fuel and Waste Storage Radiation Shielding

The SFP is designed to provide shielding for radiation protection to meet the requirements of 10 CFR Part 20.

9.1.2.1.8 General Design Criterion 69, 1967 – Protection Against Radioactivity Release from Spent Fuel and Waste Storage

The SFP is designed to provide containment of radioactive releases to the public environs as a result of an accident.

9.1.2.1.9 Spent Fuel Pool Storage System Safety Function Requirements

(1) Protection from Missiles

The SFP is designed to be protected against the effects of missiles that might result from plant equipment failures and from events and conditions outside the plant.

(2) Protection Against High Energy Pipe Rupture Effects

The SFP is designed to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary for the PG&E Design Class I SFP to perform its design functions.

9.1.2.1.10 10 CFR 50.68(b) – Criticality Accident Requirements

The SFP is designed to support compliance with the applicable requirements of 10 CFR 50.68(b) to prevent inadvertent criticality, with a noted exemption.

9.1.2.1.11 Safety Guide 13, March 1971 – Fuel Storage Facility Design Basis

Regulatory Position 1:

The SFP is designed to Category I seismic requirements.

Regulatory Position 2:

The PG&E Design Class I FHB that houses the SFP is designed to prevent tornadoes and tornado-borne missiles from causing significant loss of watertight integrity of the SFP and to prevent tornado-borne missiles from contacting fuel within the SFP.

Regulatory Position 5.b:

The SFP is designed to withstand, without leakage which could uncover the fuel, the impact of the heaviest load to be carried by the crane from the maximum height to which it can be lifted.

Regulatory Position 7:

The SFP design provides for reliable monitoring equipment that will alarm both locally and in the control room if the SFP water level falls below a predetermined level or if high local radiation levels are experienced.

9.1.2.2 System Description

The SFP for each unit is a reinforced concrete structure with seam-welded stainless steel plate liner. The floor elevation of the SFP is nominally at elevation 99 feet, and the normal water surface is at elevation 137 feet 8 inches. The SFP storage racks rest on bridge plates supported on the floor and have a total height of 14 feet 11 inches. Thus, normal water depth over the SFP storage racks is 23 feet 9 inches. DCPP Technical Specifications require that the SFP level be greater than or equal to 23 feet over the top of irradiated fuel assemblies seated in the storage racks during movement of irradiated fuel.

The pool is filled with borated water at a concentration greater than or equal to 2000 ppm boron as discussed in the Technical Specifications (Reference 2). Additional borated water to maintain this concentration is supplied from the refueling water storage tank (RWST) via the refueling water purification (RWP) system, or from other sources within the chemical and volume control system (CVCS).

Each SFP is designed to hold 1324 assemblies in the SFP storage racks, allowing for the concurrent storage of a full core of irradiated fuel assemblies and a managed quantity of spent fuel assemblies from reactor refueling operations. RCCAs and burnable poison rods requiring removal from the reactor are normally stored in the spent fuel assemblies.

The high density SFP storage racks for each fuel pool consist of a total of 16 stainless steel racks of various sizes, with a total of 1324 fuel assembly storage cells plus 10 miscellaneous storage locations. Individual storage cells have an 8.85-inch (nominal) square cross-section, and each is sized to contain and protect a single Westinghouse-type pressurized water reactor (PWR) 17x17 fuel assembly. The cells are arranged with a nominal 11-inch center-to-center spacing in the 16 rack modules.

The SFP storage racks are freestanding, with no connection to the SFP floor, walls, or adjacent SFP storage rack modules. The SFP storage rack support feet rest on bridge plates on the SFP floor. Each module is equipped with a girdle bar on the outside of each of the modules' four sides, near the top. Each girdle bar serves as a designated

impact location, and each is designed to accommodate impact loads, which may occur during a seismic event. They also maintain a specified minimum gap between the cell walls of adjacent SFP storage rack modules for all loading conditions.

Adjacent to the SFP is the stainless-steel-lined fuel transfer canal, which is connected to the refueling cavity (inside the containment). The transfer canal is separated from the SFP by a gate. An inflatable gate seal provides leak protection.

Almost all components in contact with the SFP water (handling tools, new fuel elevator, etc.) are constructed of stainless steel, which has very good corrosion resistance. There are a few components made of bronze, which also has good corrosion resistance in aqueous environments. The compatibility of bronze and stainless steel maintains the integrity of the stainless steel components in the SFP.

A cooling and cleanup system for the SFP water is described in Section 9.1.3.

9.1.2.3 Safety Evaluation

Refer to Section 9.1.2.3.10 for a discussion of k_{eff} limits including allowance for uncertainties.

9.1.2.3.1 General Design Criterion 2, 1967 – Performance Standards

The FHB is PG&E Design Class I (refer to Section 3.8) and contains the PG&E Design Class I SFP and SFP storage racks. These components are designed to withstand the effects of winds and tornadoes (refer to Section 3.3); floods and tsunamis (refer to Section 3.4); external missiles (refer to Section 3.5); and earthquakes (refer to Section 3.7). Note that some metal siding on the FHB may detach during the postulated tornado.

In General Electric Topical Report APED - 5696, Tornado Protection for the Spent Fuel Storage Pool (refer to Reference 5, Section 3.3.3), a highly conservative model demonstrates that removal of more than 5 feet of water by a tornado mechanism is highly improbable. The 20 feet of water cover remaining over the fuel racks is shown to provide adequate protection against both fuel damage and liner penetration from a wide spectrum of tornado-generated missiles ranging up to a 3-inch diameter steel cylinder (7 feet long) or a 14 inch diameter wood pole (12 feet long). A potential for damage can only be shown by arbitrarily assuming long cylindrical objects hurled into the pool by winds acting on their maximum cross-sectional area and then impacting the pool with their minimum cross-sectional area. The probability of such an event is calculated to be about once per 1.4 billion reactor lifetimes. It is therefore concluded that adequate protection against tornado forces and tornado-generated missiles has been provided for the SFP (refer to Section 3.3).

The SFP storage racks are designed for the DE, DDE, and Hosgri Earthquake (HE) with the racks filled with fuel assemblies and as shown in Table 3.2-3. The SFP storage

racks are designed to withstand a vertical (uplift) force of 4400 pounds in the unlikely event that an assembly would bind in the rack while being lifted by the spent fuel bridge crane. The design classification of the SFP storage racks, as well as the SFP structure, is discussed in Section 3.2.2.1.1, and the design requirements and acceptance criteria are discussed in Section 3.8.4.2.

Refer to Section 3.8.4.2.6 for a discussion of the evaluation of the SFP structure for postulated interactions of the SFP storage racks with the structure as a result of a seismic event.

9.1.2.3.2 General Design Criterion 3, 1971 – Fire Protection

The SFP storage system area is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.1.2.3.3 General Design Criterion 11, 1967 – Control Room

SFP level monitoring equipment and area radiation monitoring equipment are provided in the control room to support actions to maintain and control the safe operational status of the plant (refer to Sections 9.1.3.3.5 and 11.4.2.1.4.1, respectively).

9.1.2.3.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation is provided to give an alarm in the control room when the water level in the SFP reaches either the high- or low-level alarm setpoint (refer to Section 9.1.3.3.5).

Local instrumentation is provided to measure the temperature of the water in the SFP and provide local indication as well as annunciation in the control room when normal temperatures or rates of temperature change are exceeded (refer to Section 9.1.3.3.5).

Radiation levels are monitored locally in the SFP area (refer to Section 9.1.2.3.5). Signal input is provided to local alarms and control room annunciators, and to the FHBVS to initiate automatic iodine removal mode operation (refer to Section 9.4.4.2).

9.1.2.3.5 General Design Criterion 18, 1967 – Monitoring Fuel and Waste Storage

A controlled and monitored ventilation system removes any gaseous radioactivity from the atmosphere above the SFP and discharges it through the plant vent. This system is described in Section 9.4.4.

Radiation monitors RM-14 and RM-14R continuously monitor the gases discharging through the plant vent—including the gases exhausted from the SFP areas—and alarm when the activity level of the gases reaches a preset limit. The alarm alerts the operators to take appropriate action. Refer to Section 9.4.4.2 for a discussion of FHBVS operation, including operation following detection of high activity levels. The

radiation monitors for the fuel storage areas, RM-58 or RM-59, change the FHBVS exhaust mode from normal to automatic iodine removal mode (roughing, high-efficiency particulate air [HEPA], and charcoal filters) if measured area radiation levels increase to preset alarm levels.

An SFP area radiation monitoring system is provided for personnel protection and general surveillance of the SFP area. This system is described in Section 11.4.2.1.4.1. Continuous monitoring and recording readouts and high radiation level alarms in the control room, plus local audible and visual indicators, are provided for use during the movement of irradiated fuel assemblies in the FHB. Refer to Section 9.4.4.2 for discussion concerning FHBVS modes of operation and Section 15.4 for a discussion of radiation monitoring and ventilation during a FHA. SFP radiation, temperature, and level instrumentation are discussed in Section 9.1.2.3.4.

9.1.2.3.6 General Design Criterion 66, 1967 – Prevention of Fuel Storage Criticality

Constraints for storing fuel in the high density SFP racks are identified in the DCPP Technical Specifications. Fresh and burned fuel assembly storage in the SFP is maintained such that any four cells are in one of three configurations allowable by the DCPP Technical Specifications. The three allowable storage configurations specified by the DCPP Technical Specifications are: (a) the all cell, (b) the 2x2 array, and (c) the checkerboard configuration. Spent fuel assemblies satisfying the discharge burnup requirements of Figure 9.1-2A can be stored in the all cell configuration in the SFP. One fuel assembly, with an initial enrichment less than or equal to 4.9 weight percent U-235 or with an initial enrichment less than or equal to 5.0 weight percent U-235 and an IFBA loading equivalent to 16 rods each with 1.5 milligrams B-10 per inch over 120 inches, and three fuel assemblies satisfying the discharge burnup requirements of Figure 9.1-2B can be stored in the 2x2 array configuration. Fresh and spent fuel assemblies not satisfying the initial enrichment, discharge burnup, and IFBA loading requirements for the all cell and 2x2 array configurations must be stored in the checkerboard configuration with water cells or non-fissile material. Figure 9.1-2 shows the arrangement of the rack modules for Unit 1. The Unit 2 SFP is a mirror image of the Unit 1 SFP, reflected around column line 12[9] (south end of Unit 1 SFP).

Potential SFP fuel-mishandling accidents and fuel-drop accidents, which result in a reactivity insertion, were evaluated in the SFP criticality analysis. Examples of such accidents include the misplacement of a fresh fuel assembly in place of a burned fuel assembly within a rack module, the misplacement of a fresh fuel assembly outside the rack module, accidental drop of a fresh fuel assembly outside the rack module, and the T-Bone drop of a fresh assembly. The most limiting SFP accident was determined to be the misplacement of a fresh fuel assembly with 4.9 weight percent U-235 outside the rack module such that it is adjacent to a fresh fuel assembly with 4.9 weight percent U-235 within the rack module, resulting in two fresh assemblies adjacent to each other in the SFP. For the most limiting SFP accident, an SFP soluble boron concentration of 806 ppm is required to maintain K_{eff} less than or equal to 0.95 at a 95 percent

probability, 95 percent confidence level. The DCPP Technical Specifications establish that the minimum SFP boron concentration is 2000 ppm. This boron concentration is more than sufficient concentration to maintain 5 percent subcriticality margin in the SFP during the most limiting SFP accident. Administrative procedures to ensure the presence of soluble boron in the SFP during fuel handling operations preclude the possibility of the simultaneous occurrence of two independent accident conditions such as a fuel assembly misplacement and loss of soluble boron.

9.1.2.3.7 General Design Criterion 68, 1967 – Fuel and Waste Storage Radiation Shielding

During transfer of spent fuel assemblies, the borated water level in the SFP is maintained to provide at least 9 feet of water above the top of the active portion of the spent fuel assemblies. Normally, the borated water level in the SFP is maintained to provide at least 23 feet of water over the top of the irradiated fuel assemblies seated in the storage racks, as discussed in the Technical Specifications. This ensures sufficient water depth to remove 99.5 percent of all the iodine activity that could be released from a rupture of an irradiated fuel assembly. Gaseous radioactivity above the SFP is thus maintained below 10 CFR Part 20 limits. This water barrier also serves as a radiation shield, limiting the gamma dose rate at the pool surface.

SFP concrete walls have been evaluated for effectiveness of shielding in the SFP area including adjacent corridors and stairways (refer to Section 12.1).

9.1.2.3.8 General Design Criterion 69, 1967 – Protection Against Radioactivity Release from Spent Fuel and Waste Storage

The SFP containment is provided by maintaining at least 23 feet of water over the top of the irradiated fuel assemblies (refer to Section 9.1.2.3.7). The SFP area is enclosed, and is maintained under negative pressure during normal operation. The plant Technical Specifications prescribe operability requirements for FHBVS equipment that are applicable during movement of recently irradiated fuel assemblies, and a surveillance requirement that periodically tests the ability of the FHBVS, while in the post-accident, iodine removal mode of operation, to maintain a negative pressure in the FHB. All ventilation air is passed through HEPA filters prior to being released to the plant vent. In the event of an accident, high activity would be detected by the radiation monitor and the exhaust air would be diverted through charcoal filters (refer to Sections 9.4.4.2 and 11.4.3.15).

Refer to Section 9.1.2.3.7 for a discussion of iodine release attenuation attributable to SFP water depth over the top of the irradiated fuel assemblies.

9.1.2.3.9 Spent Fuel Pool Storage System Safety Function Requirements

(1) Protection from Missiles

There are no credible missiles outside of containment resulting from plant equipment failure that would prevent the PG&E Design Class I SFP from performing its design functions (refer to Section 3.5.3.3). Protection of the SFP from the effects of missiles and protection of PG&E Design Class I SSCs from damage that may result from these events is discussed in Section 3.5.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the PG&E Design Class I SFP from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Section 3.6.

9.1.2.3.10 10 CFR 50.68(b) – Criticality Accident Requirements

In accordance with 10 CFR 50.68(b)(1), plant procedures prohibit handling and storage at any one time of more fuel assemblies than have been determined to be safely subcritical under the most adverse moderation conditions feasible by unborated water, with the exception that the U.S. Nuclear Regulatory Commission (NRC) granted an exemption request related to the need to take credit for borated water for the loading, unloading, and handling of the components of the HI-STORM 100 dual-purpose dry cask storage system (refer to Section 9.1.4.3.8).

The requirements in 10 CFR 50.68(b)(2) and 10 CFR 50.68(b)(3) regard storage of fresh fuel in the NFSRs and are therefore not applicable to the SFP.

In accordance with 10 CFR 50.68(b)(4), the high-density SFP storage racks are designed to ensure that, with credit for soluble boron (References 8 and 9) and with fuel of the maximum fuel assembly reactivity, a K_{eff} of less than or equal to 0.95 is maintained, at a 95 percent probability, 95 percent confidence level, if the racks are flooded with borated water, and a K_{eff} of less than 1.0 is maintained, at a 95 percent probability, 95 percent confidence level, if the racks are flooded with unborated water.

The associated spent fuel criticality analysis (Reference 24) modeled a full-pool representation of the storage racks and infinite arrays of fuel using the SCALE-PC computer code, which includes the CSAS25 control module and functional modules BONAMI, NITAWL-II and KENO-Va, and employs the 44-Group Evaluated Nuclear Data File Version 5 (ENDF/B-V) neutron cross-section library. SCALE-PC has been validated against 30 critical experiments and the calculations adequately reproduced the data. The DIT computer code was used to generate a set of isotopic concentrations based on ENDF/B-VI. DIT has been benchmarked against Combustion Engineering PWR cores and against other PWR lattice codes, such as CASMO, with very good agreement.

Reference 24 considers the 2x2 array and checkerboard spent fuel configurations and associated fuel type and burnup characteristics specified in the DCPP Technical Specifications. The analysis assumed a fresh fuel assembly, which was a conservative representation of the Westinghouse OFA 17x17 fuel assembly with a nominal enrichment of 4.9 weight percent U-235 and no IFBAs. This fresh assembly conservatively envelopes the characteristics of possible fresh fuel types that may be used. The analysis assumed a burned fuel assembly, which was a conservative representation of a Westinghouse Standard 17x17 fuel assembly. This burned assembly conservatively envelopes the characteristics of burned fuel assemblies stored in the SFP. The analysis evaluated the region of the SFP that does not contain Boraflex panels since the storage requirements for this region are more restrictive and yield more conservative reactivity results than the region containing Boraflex panels. Therefore, the analysis does not credit the negative reactivity associated with the Boraflex panels.

Reference 24 considered biases and uncertainties such that the K_{eff} value was determined at a 95 percent probability, 95 percent confidence level. The biases considered included a KENO-Va computer code methodology bias and a reactivity bias to account for a range of SFP water temperature. The uncertainties considered included those due to fuel assembly manufacturing tolerances, rack fabrication tolerances, KENO-Va computer code methodology, fuel assembly reactivity, and absolute fuel assembly burnup.

Reference 24 assumed a core moderator average temperature of 579.95°F. Higher moderator temperature affects analysis results for discharged spent fuel in a non-conservative direction (i.e., reduces margin). Since moderator temperature in the core can potentially reach 582.3°F, an evaluation was performed to assess the impact of this higher temperature on the analysis (Reference 25). The evaluation concluded that adequate margin exists such that the potentially higher moderator temperature is acceptable and can be accommodated in the existing SFP criticality analysis.

Reference 24 does not consider the "all cell" storage configuration in the SFP (i.e., all cells filled and all fuel assemblies with discharge burnup in the acceptable area of Technical Specification Figure 3.7.17-2). A Holtec analysis (Reference 26) is the analysis of record (AOR) for that configuration. The core moderator average temperature value assumed for the Holtec AOR is 591.5°F. This value bounds the maximum potential core average temperature of 582.3°F. Therefore, the AOR for the "all cell" storage configuration is bounding for the maximum expected core moderator temperature.

For normal conditions (no SFP fuel mishandling or fuel drop accident), the SFP criticality analysis determined that a K_{eff} of less than 1.0 is maintained, at a 95 percent probability, 95 percent confidence level, if the SFP storage racks are flooded with unborated water.

An SFP boron dilution analysis was performed to evaluate the time and water volumes required to dilute the SFP from the DCPP Technical Specification required minimum boron concentration of 2000 ppm to approximately 800 ppm. The 800 ppm endpoint was utilized to ensure that the K_{eff} of the SFP storage racks would remain less than or equal to 0.95.

A large volume of pure water (approximately 339,000 gallons) is necessary to dilute the SFP from 2000 ppm to 800 ppm. Dilution sources available which exceed 339,000 gallons (primary water makeup system, makeup water system [MWS], and fire protection system) were evaluated against the calculated dilution volumes to determine the potential of an SFP-dilution event. The dilution from seismic events or random pipe breaks is bounded by the primary water makeup system flow. Dilution due to the drain system was not evaluated since backflow through the system is not considered credible. Also, the SFP demineralizer was not evaluated since it cannot provide sufficient dilution.

The boron dilution analysis demonstrates that adequate time is available to identify and mitigate the dilution event before the K_{eff} of the SFP storage racks would exceed 0.95. A dilution event large enough to result in a significant reduction in the SFP boron concentration would involve the transfer of a large quantity of water from a dilution source and a significant increase in SFP level, which would ultimately overflow the pool. Such a large water volume turnover, and overflow of the SFP, would be readily detected and terminated by plant personnel. In addition, because of the large quantities of water required and the low dilution flow rates available, any significant dilution of the SFP boron concentration would only occur over a long period of time (hours to days). Detection of an SFP boron dilution via SFP level alarms, visual inspection during normal operator rounds, significant changes in SFP boron concentration, or significant changes in the unborated water source volume, would be expected before a dilution event sufficient to increase K_{eff} above 0.95 could occur.

The results of the boron dilution analysis concluded that an unplanned or inadvertent event that would result in the dilution of the SFP boron concentration from 2000 ppm to 800 ppm is not a credible event. However, even if the SFP were diluted to zero ppm boron, which would take significantly more water than evaluated in the dilution analysis, the SFP would remain subcritical, and the health and safety of the public would be protected. Sampling of the SFP boron concentration is required by the DCPP Technical Specifications on a 7-day frequency, which provides adequate assurance that smaller and less readily identifiable boron concentration reductions are not taking place.

Controls over special nuclear material are maintained to prevent a criticality accident. In addition to the controls for both new (fresh) and spent (burned) fuel, as required by 10 CFR 50.68(b)(5) the quantity and forms of special nuclear material other than nuclear fuel that is stored onsite in any given area are less than the quantities necessary for a critical mass. Special nuclear materials are required to be stored in inventory control areas except when in transit.

In accordance with 10 CFR 50.68(b)(6), radiation monitors are provided in storage and associated handling areas when fuel is present to detect excessive radiation levels and to initiate appropriate safety actions (refer to Sections 9.1.2.3.4 and 9.1.2.3.5).

Refer to Section 9.1.1.3.6 for information on implementation of 10 CFR 50.68(b)(7) regarding maximum nominal U-235 enrichment of new fuel assemblies that may be stored in the SFP.

As discussed in Section 9.1.1.3.8, implementation of 10 CFR 50.68(b)(8) was completed with the submittal of Revision 15 of the UFSAR.

9.1.2.3.11 Safety Guide 13, March 1971 – Fuel Storage Facility Design Basis

Regulatory Position 1:

The SFP is designed to accommodate both new and spent fuel assemblies in a subcritical array such that a $k_{eff} < 1.0$ is maintained if flooded with unborated water. It is constructed of reinforced concrete as part of the auxiliary building structure. The design is described in Section 3.8.2.3. The entire structure and the SFP storage racks have been designed in accordance with PG&E Design Class I seismic requirements. Criteria set by Safety Guide 13, March 1971 (Reference 3), have been followed.

The SFP storage racks are designed in accordance with Safety Guide 13, March 1971, and the ASME BPVC Section III-1983 (Subsection NF).

Regulatory Position 2:

Refer to Section 9.1.2.3.1 for a discussion of the DCPP environmental protections, such as protection from cyclonic winds and external missiles, for the PG&E Design Class I SFP. Refer to Section 3.3 for a broad discussion of wind and tornado loadings on PG&E Design Class I structures.

Regulatory Position 5.b:

PG&E has evaluated the drop of a loaded transfer cask from highest point in the lift to the bottom of the cask recess area in the SFP. The postulated drop consists of 4.67 feet in air followed by 42.83 feet in water. Analysis demonstrates the adequacy of the affected structures during the postulated drop, demonstrating that the drop will not cause (1) loss of building structural function; (2) damage to the SFP resulting in loss of SFP water; or (3) unacceptable damage to other systems or equipment. The SFP stainless steel liner may be damaged in this drop; however, the structural integrity of the concrete forming the SFP is maintained, preventing any uncontrolled leakage.

Refer to Section 9.1.4.3.9 for a discussion of fuel handling area crane design provisions that prevent the movement of heavy loads over the area of the pool that can contain spent fuel.

In addition, protection of nuclear fuel assemblies from overhead load handling is a key element of the Control of Heavy Loads Program described in Section 9.1.4.3.10.

Regulatory Position 7:

Refer to Section 9.1.2.3.4 for a discussion of the alarms provided both locally and in the control room if the water level in the SFP falls below a predetermined level (control room alarm) or if high local radiation levels are experienced (local and control room alarm).

9.1.2.4 Tests and Inspections

After erection of the SFP storage racks, tests were conducted with a dummy fuel assembly by passing it into and out of each storage position to ensure that binding would not occur.

9.1.2.5 Instrumentation Applications

Instrumentation applications are described in Section 9.1.2.3.4.

9.1.3 SPENT FUEL POOL COOLING AND CLEANUP SYSTEM

The piping, valves, pumps, and heat exchanger used to cool the SFP are PG&E Design Class I. Additionally, the piping and components used to transfer water to and from the RWST are PG&E Design Class I. Portions of the SFP cleanup system are PG&E Design Class I including the RWP filter, SFP resin trap filter, SFP demineralizer, and RWP pump. The piping and components used to transport water to the SFP filter (including the filter itself) are PG&E Design Class II. Refer to Table 3.2-3 for a listing of PG&E Design Class II equipment that is included in the SFP cooling and cleanup system.

The SFP skimmer system, including piping, valves, pumps, strainers, and filters, is PG&E Design Class III.

Section 9.1.3.3.9 provides discussion on PG&E Design Class I systems that are available to provide makeup water to the SFP.

Each unit has a completely independent SFP cooling and cleanup system.

The SFP cooling and cleanup system design parameters are given in Table 9.1-1.

9.1.3.1 Design Bases

9.1.3.1.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portions of the SFP cooling and cleanup system are designed to withstand the effects of, or are protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

Tornado-induced FHB structural damage does not impair the ability of the plant to achieve safe shutdown.

9.1.3.1.2 General Design Criterion 3, 1971 – Fire Protection

The PG&E Design Class I portions of the SFP cooling and cleanup system are designed and located to minimize, consistent with other requirements, the probability and effect of fires and explosions.

9.1.3.1.3 General Design Criterion 11, 1967 – Control Room

The PG&E Design Class I portions of the SFP cooling and cleanup system are designed to or contain instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room.

9.1.3.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the PG&E Design Class I portions of the SFP cooling and cleanup system variables within prescribed operating ranges.

9.1.3.1.5 General Design Criterion 18, 1967 – Monitoring Fuel and Waste Storage

The PG&E Design Class I portions of the SFP cooling and cleanup system are equipped with adequate instrumentation to identify conditions that contribute to a loss of continuity in decay heat removal and to radiation exposures.

9.1.3.1.6 General Design Criterion 67, 1967 – Fuel and Waste Storage Decay Heat

The PG&E Design Class I portions of the SFP cooling and cleanup system provide a reliable and adequate decay heat removal system to prevent damage to the fuel in the SFP that could result in radioactivity release to plant operating areas or the public environs.

9.1.3.1.7 Spent Fuel Pool Cooling and Cleanup System Safety Function Requirements

(1) Missile Protection

The PG&E Design Class I SFP cooling and cleanup system components are designed to be protected against internal missiles generated outside containment and dynamic effects that might result from plant equipment failure.

(2) Water Purification

The SFP cooling and cleanup system purifies and demineralizes SFP water to maintain SFP water quality to ensure access to the SFP storage racks for fuel handling and maintain optical clarity of the SFP water.

9.1.3.1.8 10 CFR 50.55a(g) – Inservice Inspection Requirements

The SFP cooling and cleanup system ASME Code components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

9.1.3.1.9 Safety Guide 13, March 1971 –Fuel Storage Facility Design Basis

The SFP cooling and cleanup system is designed and constructed in accordance with Safety Guide 13, March 1971.

9.1.3.1.10 Generic Letter 96-04, June 1996 – Boraflex Degradation in Spent Fuel Pool Storage

Silica levels in the SFP are monitored using DCPP procedures for trending purposes due to the possible interaction between SFP water and reactor coolant system (RCS) water during refueling outages.

9.1.3.2 System Description

The PG&E Design Class I portions of the SFP cooling and cleanup system maintain a water inventory in the SFP sufficient to keep spent fuel immersed at all times and provide a highly reliable pumped-fluid system to transfer decay heat from the SFP to the component cooling water (CCW) system via the SFP heat exchanger.

The SFP cooling and cleanup system, shown in Figure 3.2-13, removes decay heat from fuel stored in the SFP. Spent fuel is placed in the SFP during the refueling sequence and stored there until it is shipped offsite or loaded into a fuel transfer cask and transported to the Diablo Canyon ISFSI. Refer to Reference 12 for information regarding the Diablo Canyon ISFSI. Heat is transferred through the SFP heat exchanger to the CCW system.

When the SFP cooling and cleanup system is in operation, water flows from the SFP to the SFP pump suction, is pumped through the tube side of the heat exchanger, and is returned to the SFP. The suction line, which is protected by a strainer, is located at an elevation 4 feet below the normal SFP water level, while the return line contains an antisiphon hole near the surface of the water to prevent gravity drainage of the SFP.

While the heat removal operation is in process, a portion of the SFP water may be diverted away from the heat exchanger through the RWP filter, spent fuel pit demineralizer, spent fuel pit resin trap filter, and the spent fuel pit filter to maintain water clarity and purity. A resin trap and check valve, located upstream of the demineralizer, prevent backflushing demineralizer resins to the SFP. Transfer canal water may also be circulated through the same demineralizer and filter by opening the gate between the canal and the SFP. This purification loop removes fission products and other contaminants, which could be introduced if a fuel assembly with defective cladding is transferred to the SFP.

The RWP system can be aligned to recirculate the contents of the RWST. The RWP system is placed into service by manual operation of isolation valves and manual RWP pump start. This alignment enables tank mixing and cleanup of the RWST contents via the RWP filter, demineralizer, and resin trap filter. Processing the RWST contents through the RWP system enables the removal of radiological impurities to ensure RWST activities (refer to Table 12.1-13) and radiation exposure rates (refer to Table 12.1-14) are within 10 CFR Part 20 limits and are as low as is reasonably achievable (ALARA).

The RWP system filters and demineralizes the RWST water in order to maintain water quality and clarity for fuel transfer and inspection purposes. Refueling water clarity is both a personnel and equipment safety and radiation ALARA consideration. Also, the RWP system may be used to filter the contents of the RWST prior to employing a reverse osmosis system (ROS). The ROS is a temporary system, connected directly to the RWST, which may be used to reduce silica concentrations in the RWST. Design and administrative controls ensure minimum required RWST volume and boron concentrations are maintained throughout ROS operation.

During refueling outages, connections are provided such that the refueling water may be pumped from either the RWST or the refueling cavity, through the filter, demineralizer, and resin trap and discharged to either the refueling cavity or the RWST. In addition to this flowpath, it is possible to manually align the SFP cleanup system with the RWP system to clean the refueling canal water during fuel movement. The RWP pump may also be utilized to pump down the refueling canal by pumping water to the liquid hold-up tanks (LHUTs) through the RWP filter. To further assist in maintaining SFP water clarity, the water surface is cleaned by a skimmer loop. Water is removed from the surface by the skimmers, pumped through a strainer and filter, and returned to the SFP surface at three locations remote from the skimmers.

Refer to Section 9.1.2.3.6 for discussion on the required boron concentration in the SFP. Additional borated water is supplied from the RWST via the RWP system, or from other sources within the CVCS, to maintain the required boron concentration in the SFP.

A gate is installed between the SFP and the transfer canal so that the transfer canal may be drained to allow maintenance of the fuel transfer equipment. The water in the transfer canal is first pumped, using a portable pump, into the SFP and then is transferred to a holdup tank in the CVCS by the SFP pump. When needed for refueling operations, water is returned directly to the transfer canal by the holdup tank recirculation pump.

In the event of high level in the SFP, water can be removed via the SFP pump and pumped to the LHUTs. Water can also be removed by the RWP pump delivering to the RWST. In the event of low water level, makeup water can be transferred to the SFP from either PG&E Design Class I or PG&E Design Class II sources as described in Section 9.1.3.3.9.

9.1.3.2.1 Component Description

SFP cooling and cleanup system codes and classifications are given in Table 3.2-3. System design and operating parameters are given in Table 9.1-2.

9.1.3.2.1.1 Spent Fuel Pool Pump

The SFP pumps are horizontal, centrifugal units, with all wetted surfaces being stainless steel or an equivalent corrosion-resistant material. The pumps are controlled manually from a local station. There are no Class 1E electrical loads in the SFP system; however, the SFP cooling pumps are powered from a Class 1E source. For Modes 5, 6, and no mode operation during electrical bus outages and maintenance periods, the standby/redundant pump may be temporarily aligned to an alternate Class 1E source, using installed transfer switches, until its primary Class 1E power supply is returned to service. If connection to the alternate Class 1E bus via the transfer switch is necessary in Modes 1 through 4, Engineering will be required to evaluate the acceptability of this configuration on a case by case basis prior to use of the transfer switch.

9.1.3.2.1.2 Spent Fuel Pool Skimmer Pump

The SFP skimmer pump is a horizontal centrifugal unit, with all wetted surfaces being stainless steel or an equivalent corrosion-resistant material. The pump is controlled manually from a local station.

9.1.3.2.1.3 Refueling Water Purification Pump

The RWP pump is a horizontal centrifugal unit, with all wetted surfaces being stainless steel or an equivalent corrosion-resistant material. The pump is operated manually from a local station.

9.1.3.2.1.4 Spent Fuel Pool Heat Exchanger

The spent fuel heat exchanger is of the shell and U-tube type with the tubes welded to the tubesheet. CCW circulates through the shell, and SFP water circulates through the tubes. Construction is carbon steel on the shell-side and stainless steel on the tube side.

9.1.3.2.1.5 Spent Fuel Pool Demineralizer

The SFP demineralizer is a flushable, mixed bed demineralizer. The demineralizer is designed to provide adequate SFP water purity and limit the dose rate at the surface of the SFP. Submersible demineralizer vessels may be used in the SFP or reactor cavity to perform or augment water purification.

9.1.3.2.1.6 Spent Fuel Pool Resin Trap Filter

The SFP resin trap filter is designed to prevent resin beads from entering the SFP and connected systems. It is designed to remove particles 5 microns or greater.

9.1.3.2.1.7 Spent Fuel Pool Filter

The SFP filter is designed to improve the SFP water clarity by removing particles 5 microns or greater. Underwater vacuum and/or underwater vacuums equipped with surface skimmer filter units may be used to augment SFP or reactor cavity water treatment.

9.1.3.2.1.8 Spent Fuel Pool Skimmer Filter

The SFP skimmer filter is used to remove particles that are not removed by the strainer. It is designed to remove particles 5 microns or greater.

9.1.3.2.1.9 Refueling Water Purification Filter

The RWP filter is designed to improve the clarity of the refueling water in the refueling canal or in the RWST by removing particles 5 microns or greater. The RWP filter also filters the SFP contents and functions as a prefilter to the SFP demineralizer.

9.1.3.2.1.10 Spent Fuel Pool Strainer

A strainer is located within the SFP on the pump suction enclosure for removal of relatively large particles, which might otherwise clog the SFP demineralizer or damage the SFP pump. It is a slotted screen design with stainless steel construction.

9.1.3.2.1.11 Spent Fuel Pool Skimmer Strainer

The SFP skimmer strainer is designed to remove debris from the skimmer process flow. It is an in-line basket strainer of stainless steel construction.

9.1.3.2.1.12 Spent Fuel Pool Skimmers

Two SFP skimmers are provided to remove water from the surface of the SFP. The skimmer heads are manually positioned to take water from near the SFP surface. The skimmer, pipe, and supports are of stainless steel construction.

9.1.3.2.2 Valves

Manual stop valves are used to isolate equipment, and manual throttle valves provide flow control. Valves in contact with SFP water are austenitic stainless steel or equivalent corrosion-resistant material.

9.1.3.2.3 Piping

All piping in contact with SFP water is austenitic stainless steel. The piping is welded except where flanged connections are used to facilitate maintenance.

9.1.3.3 Safety Evaluation

9.1.3.3.1 General Design Criterion 2, 1967 – Performance Standards

The FHB and auxiliary building, which contain the spent fuel cooling and cleanup systems are PG&E Design Class I structures (refer to Section 3.8). The auxiliary building is designed to withstand the effects of winds and tornadoes (refer to Section 3.3) and external missiles (refer to Section 3.5). The basic structure of the FHB is tornado resistant, with damage to non-structural building components. Damage to these components does not adversely impact the plant's ability to achieve safe shutdown (refer to Section 3.3). The auxiliary and FHBs are designed to withstand the effect of floods (refer to Section 3.4), earthquakes (refer to Section 3.7), and to protect the spent fuel cooling and cleanup system, ensuring its design function will be performed.

Protection of fuel assemblies from tornadoes and external missiles is discussed in Section 9.1.2.3.1.

A piping design analysis, including DE, DDE, and HE seismic loads, was performed to ensure that the cooling loop conforms to PG&E Design Class I piping criteria as indicated in Table 3.2-3. The failure or malfunction of any of the spent fuel cooling and cleanup system components, including failures resulting from the DE, DDE, or a HE will not cause the fuel to be uncovered.

9.1.3.3.2 General Design Criterion 3, 1971 – Fire Protection

The SFP area is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.1.3.3.3 General Design Criterion 11, 1967 – Control Room

Annunciation in the control room is provided when normal SFP temperatures are exceeded. Additionally, instrumentation is provided to give an alarm in the control room when the water level in the SFP reaches either the high or low level setpoint. These instruments support actions to observe the safe operational status of the SFP cooling and cleanup system from the control room.

9.1.3.3.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation is provided for the SFP cooling and cleanup system as follows:

- Local instrumentation is provided to give indication of the temperature of the SFP water as it leaves the SFP heat exchanger. Refer to Section 9.1.3.3.5 for temperature instrumentation provided for the water in the SFP.

- Local instrumentation is provided to measure and give indication of pressures across the SFP and RWP pumps. Instrumentation is also provided to measure pressure differential on the SFP demineralizer, SFP resin trap filter and RWP filter.

- Local instrumentation is provided to measure and give indication of flows in the outlet line of the SFP filter and the inlet line to the SFP demineralizer.

9.1.3.3.5 General Design Criterion 18, 1967 – Monitoring Fuel and Waste Storage

Local instrumentation is provided to measure the temperature of the water in the SFP and give local indication as well as annunciation in the control room when normal temperatures are exceeded.

As indicated in Section 9.1.3.3.3, instrumentation is provided to give an alarm in the control room when the water level in the SFP reaches either the high or low level setpoint.

The exposure rate at the SFP surface is routinely monitored with radiation surveys and monitoring equipment (refer to Section 12.3). The major contributor to the surface dose is the radioactivity within the SFP water and not the spent fuel assemblies stored in the SFP. The SFP demineralizer will be used as necessary to maintain radiation exposures ALARA.

9.1.3.3.6 General Design Criterion 67, 1967 – Fuel and Waste Storage Decay Heat

The SFP cooling system is designed to remove that amount of decay heat that is produced by spent fuel assemblies that are stored in the SFP following a refueling. A cask pit rack was installed in the SFP of each unit during Cycle 14, prior to the 14th refueling outage. During Cycle 15, the cask pit rack was removed from Unit 1. The cask pit rack in Unit 2 was removed during Cycle 16.

PG&E has updated its SFP thermal-hydraulic analyses as part of the cask pit rack project (Reference 15). These updated analyses were performed using more recent analytical methods that have been previously accepted by the NRC. These analytical methods and the associated full core and emergency offload scenarios discussed below will bound both the installation of the cask pit rack and future DCPP SFP fuel storage requirements once the cask pit rack has been removed. These new analyses will serve as the new licensing basis of record for future spent fuel storage requirements, including the temporary supplemental spent fuel storage capacity provided by the cask pit rack.

The cask pit thermal-hydraulic analyses are based on the evaluation of three offload scenarios that bound the past and future operating practices at DCPP. For each scenario, the transient and steady state decay heat loads were combined to provide a total decay heat load on the SFP cooling system (Reference 15).

The partial core offload scenario assumes a discharge of 96 fuel assemblies during the 15th refueling outage. All of the 96 fuel assemblies offloaded are conservatively assumed to have a burnup of 52,000 MWD/MTU.

The full core offload scenario assumes a discharge of 193 fuel assemblies during the 15th refueling outage. The 193 offloaded assemblies are separated into two distinct groups; 101 assemblies with 52,000 MWD/MTU burnup and 92 assemblies with 25,000 MWD/MTU burnup.

The emergency full core offload scenario assumes that the 15th refueling outage is completed in 30 days, leaving 104 assemblies in the SFP at restart. After 36 days of operation at 100 percent power in Cycle 16, an emergency full core offload is performed, completely filling all available storage locations. The 193 assemblies are separated into two distinct groups: 113 assemblies with 40,000 MWD/MTU burnup and 80 assemblies with 3,000 MWD/MTU burnup.

All of these scenarios have been evaluated with a base decay heat load contribution from previously discharged fuel assemblies using actual operational data for operating

Cycles 1 through 11. The contribution to the base decay heat load from fuel that will be discharged in Cycles 12 through 14 is based on an assumed discharge of 104 assemblies each Cycle using bounding assumptions on fuel assembly burnup and operating power. Cycle lengths assumed for Cycles 12 through 14 are assumed to be 18 months, which conservatively minimizes the decay time and maximizes the base decay heat load. All three of these scenarios assume a core offload rate of four assemblies per hour, starting 100 hours after reactor shutdown, and other appropriately conservative fuel assembly discharge and burnup assumptions.

Conservative values for pump flow and heat exchanger performance were selected to provide bounding calculations for the peak SFP bulk temperature. The thermal performance of the heat exchangers was determined with all heat transfer surfaces assumed to be fouled to their design basis maximum levels and also included an allowance for five percent tube plugging. CCW supplied to the heat exchanger was assumed to be 75°F at a flow rate of 3400 gpm which is bounded by SFP cooling system design parameters. Plant procedures are currently in place to limit the peak SFP temperature to within 140°F. The procedural controls currently suspend offload activities at a SFP temperature of 125°F to maintain peak SFP bulk temperatures less than 140°F. Past operating experience at DCPP has shown that peak SFP temperatures are less than 115°F during a typical full core offload.

Due to the many variables that can have an impact on peak SFP temperature, DCPP may elect to use a cycle specific offload analysis, following the requirements of Section 3.1 of Attachment 2 to Matrix 5 of Section 2.1 of RS-001, December 2003, in lieu of the operating restrictions of the bounding thermal analyses described above. Consideration will be given to the actual core power history, scheduled offload start time, offload rates, actual CCW temperature, and actual CCW and SFP cooling water flow rates to the SFP heat exchanger in the establishment of the specific control values. If DCPP elects to use a cycle specific analysis, plant procedures will require that core offload be suspended at a temperature, which would ensure that the 140°F limit is not exceeded.

Results of the thermal-hydraulic analyses are described below.

The partial core offload analysis resulted in a maximum SFP bulk temperature of 127°F. The full core offload analysis resulted in a maximum SFP bulk temperature of 157°F. The emergency core offload analysis resulted in a peak bulk temperature of less than 162°F.

The time-to-boil evaluation assumed that forced cooling was lost the moment the peak SFP bulk temperature for each case was reached. The SFP time to boil and corresponding maximum boil-off rates were then determined.

For the worst-case scenario, the emergency core offload, the calculated time-to-boil was determined to be 3.76 hours after a loss of forced cooling at the peak SFP bulk temperature. The corresponding maximum boil-off rate for this condition was approximately 87 gpm.

Given the conservatisms incorporated into the calculations, actual times-to-boil will be higher than these calculated values and actual boil-off rates will be lower than calculated. Based on the time-to-boil, plant personnel will have sufficient time to identify elevated SFP temperatures and adequate time to provide makeup to the SFP, if needed.

Local temperature analyses were also performed to determine maximum local water and fuel cladding temperatures. The worst case peak local water temperature is 188 °F and below the local saturation temperature (240 °F) at the depth of the cask pit. The results also demonstrate that the peak fuel cladding temperature of 213 °F for the hottest fuel assembly is below the local saturation temperature, and the critical heat flux for departure from nucleate boiling is not exceeded. Therefore, no bulk boiling will occur in the SFP, and the local water and fuel temperatures are acceptable.

The SFP cooling and cleanup system has no emergency function during an accident. This manually controlled system may be shut down for limited periods of time for maintenance or replacement of components. Redundancy of the SFP cooling and cleanup system components is not required because of the large heat capacity of the SFP and the slow heatup rate. In the unlikely event that the SFP pump should fail, the backup pump can provide circulation of the SFP water through the SFP heat exchanger. If a failure should occur that would prevent the use of the SFP heat exchanger for cooling the SFP water (e.g., severance of the piping which constitutes the cooling recirculation path), natural surface cooling would maintain the water temperature at or below the boiling point. A PG&E Design Class I backup makeup water source is provided to ensure that the water level in the SFP can be maintained.

9.1.3.3.7 Spent Fuel Pool Cooling and Cleanup System Safety Function Requirements

(1) Missile Protection

There are no credible missiles outside of containment resulting from plant equipment failure that would prevent the PG&E Design Class I portions of the SFP cooling and cleanup system from performing their design functions (refer to Section 3.5.1.2). Dynamic effects as a result of plant equipment failure will not prevent the PG&E Design Class I portions of the SFP cooling and cleanup system from performing their design functions.

(2) Water Purification

The system's demineralizer and filters are designed to provide adequate purification of the SFP contents to permit access to the SFP storage area and maintain optical clarity of the SFP water. The optical clarity of the SFP water surface is maintained by use of the system's skimmers, strainer, and skimmer filter. Refer to Section 9.1.3.2 for a description of water purification equipment used to maintain optical clarity of the SFP

water. The purification loop is capable of removing fission products and other contaminants from the SFP water, including small quantities of fission products from leaking spent fuel assemblies.

The SFP demineralizer and filter flowpath bypasses the SFP heat exchanger. The demineralizer and filter may be brought into or out of service by manual operation of isolation valves. No other operator action is required. The bypass flowpath can be through the filter only, or through the filter and demineralizer in series, as shown in Figure 3.2-13. The piping configuration allows an alternate flowpath that utilizes the RWP filter upstream of the SFP demineralizer to allow optimization of filter and demineralizer operation. The demineralizer may also be used in conjunction with the RWP pump, filter, and resin trap to clean and purify the refueling water while SFP heat removal operations proceed.

A significant reduction of radioactive effluents is achieved through filtration and ion exchange, and by recycling refueling water as opposed to disposing of and making new refueling water. In addition, by concentrating impurities and radioactive particles on filter medium and demineralizer resin, which are more easily shielded, radiation levels are maintained ALARA.

Only a very small amount of water is interchanged between the refueling canal and the SFP while fuel assemblies are transferred in the refueling process. Whenever a leaking fuel assembly is transferred from the fuel transfer canal to the SFP, a small quantity of fission products may enter the spent fuel cooling water. The purification loop removes fission products and other contaminants from the water, thereby maintaining radioactivity concentration in the SFP water ALARA.

The SFP water meets the following water quality requirements:

Boric acid, ppm as boron, minimum	2000
pH at 77°F, minimum	4.1
Chloride, ppm maximum	0.15
Fluoride, ppm maximum	0.15

Boron concentrations in the SFP water are maintained as discussed in the Technical Specifications, and the pH of SFP water is controlled to prevent separation of top nozzles from a fuel assembly as a result of intergranular stress corrosion cracking.

The inservice inspection (ISI) requirements for the SFP cooling and cleanup system are contained in the ISI Program Plan.

9.1.3.3.8 10 CFR 50.55a(g) – Inservice Inspection Requirements

The ISI requirements for the SFP cooling and cleanup system are contained in the ISI Program Plan.

9.1.3.3.9 Safety Guide 13, March 1971 – Fuel Storage Facility Design Basis

Regulatory Position 1:

The spent fuel storage facilities, including structures and equipment are PG&E Design Class I. Refer to Section 3.2 for a discussion of this issue.

As discussed in Section 9.1.3.3.1, the FHB and auxiliary building, which contain the spent fuel cooling and cleanup systems are PG&E Design Class I (refer to Section 3.8). A piping design analysis, including seismic loads, was performed to ensure that the SFP cooling loop conforms to PG&E Design Class I piping criteria and the SFP cooling pumps are powered from a Class 1E source.

Regulatory Position 2:

Analysis of potential water loss from the SFP shows that the water cover remaining over the fuel provides adequate protection against both fuel damage and pool liner penetration from tornado missiles (refer to Section 3.3.2.5.2.3).

Section 9.1.3.3.1 provides a discussion of the DCPP environmental protections for the SFP cooling and cleanup system.

Regulatory Position 6:

The most serious failure of this system would be complete loss of water in the SFP. To protect against this possibility, the SFP cooling suction connection enters near the normal water level so that the SFP cannot be gravity-drained. The cooling water return line contains an antisiphon hole to prevent the possibility of gravity draining the SFP.

System piping is arranged so that failure of any pipeline cannot inadvertently drain the SFP below the water level required for radiation shielding. This level is maintained by:

(1) SFP suction piping located 20 feet above the top of the fuel assemblies, and

(2) a siphon breaker on the cooling pipe's return line into the SFP.

This design ensures greater than ten feet of water exists over the top of the fuel assemblies should inadvertent drainage occur.

Normal SFP water levels are maintained a minimum of 23 feet over the top of irradiated fuel assemblies seated in the storage racks as discussed in Section 9.1.2.2.

Regulatory Position 7:

Section 9.1.3.3.3 provides a discussion of DCPP capabilities for monitoring water level in the SFP.

Radiation monitoring of the SFP area is discussed in 9.1.1.1.5 and 9.1.2.3.5.

Regulatory Position 8:

Demineralized makeup water can be added directly to the SFP by a PG&E Design Class I source. Water from the condensate storage tank (CST) is pumped to the SFP using the makeup water transfer pumps (refer to Section 9.2.6 and Table 9.2-9) and appropriate interconnecting piping and valves. This source has the capability of providing up to 200 gpm of demineralized water, if required. The above tank, pumps, piping, and valves are designed in accordance with Safety Guide 13, March 1971. The transfer tank is another PG&E Design Class I source of SFP makeup, and water can be pumped to the SFP by the makeup water transfer pumps. However, the flowpath from the transfer tank is not completely PG&E Design Class I. In addition to the above source of makeup water, the PG&E Design Class I fire water tank could provide makeup from local hose reels.

9.1.3.3.10 Generic Letter 96-04, June 1996 – Boraflex Degradation in Spent Fuel Pool Storage

Samples are taken from the SFP monthly and are tested for silica in accordance with the response to Generic Letter 96-04, June 1996 and as modified in Reference 27. This testing was originally established to trend Boraflex degradation in the SFP. The current method of crediting soluble boron to control reactivity in the SFP precludes the need to monitor Boraflex degradation. However, due to the fact that it is desirable to minimize silica content in water that could interact with RCS water, the silica levels in the RWST and SFP water continue to be monitored. As discussed in Section 9.1.3.2, a ROS may be used to reduce the silica concentration in the RWST to levels that are compatible for the RCS.

9.1.3.4 Inspection and Testing Requirements

Active components of the SFP cooling and cleanup system are either in continuous or intermittent use during normal system operation. Periodic visual inspection and preventive maintenance are conducted using normal industry practice. Refer to Section 9.1.3.3.8 for SFP cooling and cleanup system ISI requirements.

9.1.3.5 Instrumentation Applications

The instrumentation provided for the SFP cooling and cleanup system is discussed in Sections 9.1.3.3.4 and 9.1.3.3.5. Alarms and indications are provided as noted.

Local instrumentation is provided to measure and give indication of pressures across the skimmer pumps. Instrumentation is also provided to measure pressure differential on the SFP filter and SFP skimmer filter and strainer.

9.1.4 FUEL HANDLING SYSTEM

The FHS consists of equipment and structures utilized for handling new and spent fuel assemblies in a safe manner during refueling and fuel transfer and cask loading operations.

The FHS makes use of components and structures that fall within PG&E Design Class I, PG&E Design Class II, and PG&E Design Class III classifications. The FHS components are PG&E Design Class I with the following exceptions:

(1) The fuel transfer system used to move fuel assemblies between containment and the FHB uses PG&E Design Class III components, with the exception of the fuel transfer tube and quick opening hatch, which are PG&E Design Class I.

(2) The tools used for fuel handling activities are PG&E Design Class II and PG&E Design Class III.

(3) The fuel handling area movable partition walls are PG&E Design Class II.

(4) The seal ring and assembly between the reactor vessel (RV) and the refueling cavity are PG&E Design Class II.

(5) The components used to store damaged fuel rods, debris captured from the fuel nozzles, and spent fuel storage rack poison specimens are PG&E Design Class II.

(6) The containment structure polar crane and portions of the fuel handling area crane are PG&E Design Class I. Note that the cables and hooks for the containment structure polar crane are PG&E Design Class II.

(7) All other cranes and hoists used in the FHS are PG&E Design Class II and PG&E Design Class III.

9.1.4.1 Design Bases

9.1.4.1.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portion of the FHS is designed to withstand the effects of, or is protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

9.1.4.1.2 General Design Criterion 4, 1967 – Sharing of Systems

The FHS and components are not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

9.1.4.1.3 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided to monitor and maintain FHS variables within prescribed operating ranges.

9.1.4.1.4 General Design Criterion 49, 1967 – Containment Design Basis

The FHS is designed so that the containment structure can accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a loss-of-coolant accident (LOCA), including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of emergency core cooling systems (ECCSs).

9.1.4.1.5 General Design Criterion 66, 1967 – Prevention of Fuel Storage Criticality

Equipment used to store spent fuel assemblies is designed to maintain the spent fuel assemblies in a subcritical state, even under postulated seismic conditions.

9.1.4.1.6 General Design Criterion 68, 1967 – Fuel and Waste Storage Radiation Shielding

Shielding for radiation protection is provided in the design of the spent fuel facilities as required to meet the requirements of 10 CFR Part 20.

9.1.4.1.7 10 CFR 50.55a(g) – Inservice Inspection Requirements

ASME code components within the PG&E Design Class I portion of the FHS are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

9.1.4.1.8 10 CFR 50.68(b) – Criticality Accident Requirements

FHS components that store and transport fuel assemblies are designed in accordance with 10 CFR 50.68, with a noted exemption.

9.1.4.1.9 Safety Guide 13, March 1971 – Fuel Storage Facility Design Basis

Regulatory Position 1:

The FHS is designed to Category I seismic requirements.

Regulatory Position 2:

The PG&E Design Class I portion of the FHS is designed to prevent tornadoes and tornado-borne missiles from causing significant loss of watertight integrity of the SFP and to prevent tornado-borne missiles from contacting fuel within the SFP.

Regulatory Position 3:

Interlocks are provided to prevent cranes from passing over the SFP when fuel handling is not in progress.

Regulatory Position 5(b):

The SFP is designed to withstand, without leakage which could uncover the fuel, the impact of the heaviest load to be carried by the crane from the maximum height to which it can be lifted.

9.1.4.1.10 NUREG-0612, July 1980 – Control of Heavy Loads at Nuclear Power Plants

The FHS is designed and constructed to meet the requirements of NUREG-0612, July 1980, minimizing the probability of dropping a heavy load on spent fuel or equipment necessary for safe shutdown of the plant.

9.1.4.2 System Description

The FHS equipment needed for the refueling of the reactor core consists of cranes, lifting and handling devices including tools, and a fuel transfer system.

The reactor is refueled with fuel handling equipment designed to handle the spent fuel under water from the time it leaves the RV until it is placed in the SFP racks. Underwater transfer of spent fuel provides an effective, economic, and transparent radiation shield as well as a reliable cooling medium for removal of decay heat. Boric acid is added to the water to ensure subcritical conditions.

The associated fuel handling structures may be generally divided into three areas: (a) the refueling cavity and refueling canal which are flooded only during plant shutdown for refueling, (b) the SFP which is kept full of water and is always accessible to operating personnel, and (c) the new fuel storage area which is separate and protected for dry storage. The refueling canal and the SFP are connected by the fuel transfer

tube. This tube is fitted with a quick opening hatch on the canal end and a gate valve on the SFP end. The quick opening hatch is in place, except during refueling, to ensure containment integrity.

The new fuel containers are unloaded from the shipping vehicle and placed on the 115-foot elevation using the fuel handling area crane. New fuel assemblies are removed one at a time from the shipping containers using the new fuel handling tool and the spent fuel bridge hoist such that only one fuel assembly is moved or suspended at a time in a specific area. Plant administrative controls do not permit more than one fuel assembly to be out of storage or in transit between its associated shipping cask and dry storage rack at one time. The assemblies are stored either in the NFSRs in the fuel storage area or in the SFP. Each assembly is inspected for possible shipping damage prior to insertion into the reactor core.

New fuel is delivered to the reactor by first transferring the fuel with the spent fuel bridge hoist to the new fuel elevator. The fuel is lowered into the SFP where the spent fuel handling tool is interchanged with the new fuel tool. The assembly is then stored in the SFP or transferred to the upender for movement to the reactor.

The upender at either end of the fuel transfer tube is used to pivot a fuel assembly to the horizontal position for passage through the transfer tube. Fuel is carried through the tube on a transfer car. After the transfer car transports the fuel assembly through the transfer tube, the upender at that end of the tube pivots the assembly to a vertical position so that it can be lifted out of the fuel container. Fuel is moved between locations in the RV and the transfer mechanism by the manipulator crane.

In the SFP, fuel assemblies are moved about by the SFP bridge hoist. A long-handled tool is used with the bridge hoist to prevent the lifting of fuel assemblies any closer than 8 feet from the SFP surface; this ensures that sufficient radiation shielding is maintained. A shorter tool is used to handle new fuel, but the new fuel elevator must be used to lower the assembly to a depth at which the hoist and the long-handled tool can be used to place the new assembly into the upender or into a SFP cell.

When fuel repair or post-irradiation examinations are necessary, the fuel assemblies may be reconstituted in the new fuel elevator. The new fuel elevator is modified temporarily by the insertion of hard stops and resetting the upper electrical limit switch to prevent raising the irradiated fuel assemblies to within eight feet of the SFP surface. The SFP bridge hoist is utilized to transfer fuel rods within the SFP. The tooling on the hoist is configured to maintain nine feet of water shielding over the active fuel.

Decay heat, generated by the spent fuel assemblies in the SFP, is removed by the SFP cooling and cleanup system. Refer to Section 9.1.3.3.6 for discussion on decay heat removal.

The decontamination area has a stainless-steel-lined base, and a curb is provided around it to prevent the water and solvents used during decontamination from spreading

over the building floor. Drains in the floor of the area remove the decontaminants to the waste disposal system for processing.

9.1.4.2.1 Component Description

The following sections describe major components of the FHS as they relate to refueling and fuel transfer operations.

In the event of a power failure, no hazardous condition would exist during refueling or spent fuel handling. Electric motors associated with the manipulator crane, SFP bridge crane and hoist, fuel handling area crane, fuel transfer system, and new fuel elevator have solenoid-actuated brakes capable of holding the rated loads during a power failure. The SFP bridge crane trolley has an electromagnetic brake. When current is interrupted to the motor, the electromagnetic brake is spring set. During a power failure, a fuel assembly being handled would remain in the position held at the time of failure.

9.1.4.2.1.1 Manipulator Crane

The manipulator crane shown in Figure 9.1-8 is a rectilinear bridge and trolley crane with a vertical mast extending down into the refueling water. The bridge spans the refueling cavity and runs on rails set into the edge of the refueling cavity. The bridge and trolley motions are used to position the vertical mast over a fuel assembly. A long tube with a pneumatic gripper on the end is lowered down out of the mast to grip the fuel assembly. The gripper tube is long enough so that the upper end is still contained in the mast when the gripper end contacts the fuel. A winch mounted on the trolley raises the gripper tube and fuel assembly up into the mast tube. While inside the mast tube, the fuel is transported to its new position.

All controls for the manipulator crane are mounted on a console on the trolley. The bridge is positioned on a coordinate system laid out on one rail. A video indexing system with a camera mounted to the bridge, over an indicating scale, and a monitor on the console indicates the position of the bridge. The trolley is positioned with the aid of a scale on the bridge structure. The scale is read directly by the operator at the console. The drives for the bridge, trolley, and winch are variable speed and include a separate inching control on the winch. Electrical interlocks and limit switches on the bridge and trolley drives prevent damage to the fuel assemblies. The winch is provided with a limit switch and a backup programmable limit switch to prevent a fuel assembly from being raised above a safe shielding depth. In an emergency, the bridge, trolley, and winch can be operated manually by means of handwheels on the motor shafts.

The main and auxiliary hoists are equipped with two independent braking systems. A solenoid release-spring set electric brake is mounted on the motor shaft. This brake operates in the normal manner to release upon application of current to the motor and set when current is interrupted. The second brake is a mechanically actuated load brake internal to the hoist gear box that sets if the load starts to overhaul the hoist. It is necessary to apply torque from the motor to raise or lower the load.

In raising, the motor cams release the brake open; in lowering, the motor slips the brake allowing the load to lower. This brake actuates upon loss of torque from the motor for any reason and is not dependent on any electrical circuits. On the main hoist, the motor brake is rated at 350 percent of operating load and the mechanical brake at 300 percent.

The manipulator crane structure is designed for Class C, Moderate Service, as defined by the Overhead Electric Crane Institute Specification No. 61. The electrical interlocks that ensure safe operation are designed to meet the single failure criteria of IEEE 279-1971 (Reference 4). The electrical wiring meets the applicable requirements of the National Fire Code, Electrical, Volume 5, Article 610. The design of the crane meets the applicable requirements of Section 1910.179 of subpart N of the OSHA Code. The bridge, trolley, and hoist drive motors are NEMA Class D induction motors with Class H insulation. The hoist rope is stainless steel, and the load rating is sufficient to support five times the design load. The crane design class is provided in Table 3.2-3.

The manipulator crane design load is the dead weight plus 4500 lb (three times the fuel assembly weight). The crane was erected in the shop and given a complete functional test including a load test at 110 percent of the design load. The maximum operating load of fuel assembly plus gripper is approximately 2500 lb. The gripper itself has four fingers gripping the fuel, any two of which will support the fuel assembly weight. Test loads during the life of the facility are in accordance with requirements established by the State of California Division of Occupational Safety and Health as part of its responsibilities for implementing OSHA in the state.

9.1.4.2.1.2 Spent Fuel Pool Bridge

The spent fuel pool (SFP) bridge, shown in Figure 9.1-9, is a wheel-mounted walkway spanning the SFP and carrying two monorail hoists on an overhead structure. Both hoists have a maximum lift capability of 43 feet. One hoist is used for maintenance of the fuel transfer system and for removing new fuel assemblies from their shipping containers.

Fuel assemblies are moved within the SFP by means of a long-handled tool suspended from either hoist. The bridge, trolley, and hoists are all electrically driven. The maximum lift of either hoist, combined with the long-handled tool length, is designed to maintain a safe shielding depth above a spent fuel assembly within the pool.

For fuel repairs and post-irradiation examinations, the fuel rod handling tool configuration on the hoist is required to be physically verified to maintain nine feet of water shielding in the SFP prior to handling irradiated fuel rods. The fuel rod handling tool configuration on the hoist is controlled by an approved administrative control.

The design class of the bridge is given in Table 3.2-3.

9.1.4.2.1.3 Fuel Handling Area Crane

The fuel handling area crane is an overhead bridge crane located in the fuel handling area at elevation 170 feet. This crane, shown in Figure 3.8-59, has a 125-ton capacity main hook for handling spent fuel casks and a 15-ton capacity auxiliary hook for handling new fuel shipping containers. The crane structures and components responsible for lifting of the maximum critical load (MCL) and distribution of the load to the FHB superstructure have been upgraded to meet single-failure-proof criteria through the replacement of the original trolley and reanalysis of existing structures retained in the new design.

The crane was originally designed and fabricated to the Specification for Electrical Overhead Traveling Cranes for Steel Mill Service, Association of Iron and Steel Engineers Standard No. 6 (tentative) dated May 1, 1969. All members not covered by that standard are designed and fabricated in accordance with the Specification for the Design, Fabrication and Erection of Structural Steel for Buildings by the AISC, dated February 12, 1969.

The electrical installation and all electrical equipment is in accordance with the National Electrical Code dated 1968, and the National Electrical Manufacturers Association.

Design, fabrication, and erection of the crane rail and crane support structure is in accordance with the AISC specifications. The fuel handling area crane complies with the requirements of OSHA Subpart N, Materials Handling and Storage, of 29 CFR Part 1910, Section 1910.179.

The integrity of the crane load transfer path is ensured by the following measures:

(1) The main hoist sister hook is designed such that the loads imposed by the MCL at both the pin location and the hooks result in factors of safety of 3.45 against yield strength of the hook material. The application of the MCL is considered to be fully carried by each of the attachment points. Stresses in the shank and nut are designed to remain below levels resulting in a factor of safety of 10 against the ultimate strength of the hook and nut material.

(2) The main hook and nut is shop tested at 2 times the MCL.

(3) Following the shop test, the main hook receives a volumetric and liquid penetrant inspection.

(4) The main hoist hooks and auxiliary hoist hook are field tested for 10 minutes at 1-1/4 times their rated loads.

(5) The main hoist ropes are designed with greater than 10:1 safety factor against breaking strength. They are part of a four part double reeving

system that is designed to withstand the loss of any one of the four ropes without the loss of function and without significant vertical motion of the MCL.

(6) All components in the load transference path that must retain their structural integrity are considered to be Critical Items as defined by ASME NOG-1-2004. These Critical Items have material traceability and are subject to appropriate non-destructive examination to provide assurance against material failure.

(7) The crane is equipped with redundant main hoist drive trains, brakes and reeving. The failure of any one component in the reeving or drive train will not result in a load drop or excessive vertical motion of the load.

(8) The electrical power supply to the crane contains a means for automatic disconnection should a seismic event occur. The loss of power results in the brakes setting to retain any load that may be currently lifted and assures that un-commanded motion due to relay chatter or other interaction will not occur. An emergency lowering procedure is available should this be necessary.

(9) The crane is equipped with redundant protections against overload. A trip signal is provided from the weight monitoring system, which provide direct indication, as well as the main hoist variable frequency drive control system, which provides load sensing by monitoring the motor torque.

(10) The crane is equipped with redundant protections against two-blocking. The first line of protection is provided by a limit switch that provides a trip signal if the bottom block approaches a two-block condition. The second level of protection is provided by the weight monitoring system, which will provide a trip signal if sensed load exceeds a preset value. A third level of protection is provided by the upper block hydraulic support system, which is designed to mitigate the loadings created during an actual two-block event. The upper block pivot arm limit switch functions to assure hoist motion is stopped prior to the end of hydraulic cylinder travel. The two-block protection system is fully shop tested at each protection level to verify the effectiveness of the system.

(11) The crane has been subjected to a Cold Proof Test as allowed in NUREG-0554, May 1979, since verification of the Nil Ductility Transition characteristics of the existing bridge components is not available. The Cold Proof Test provides assurance that the crane will not fail due to brittle fracture. The operation of the crane is administratively controlled such that crane operations are not allowed when the structure temperature is below the temperature at which the Cold Proof Test has been performed.

Conservative fleet angles, drum diameter and sheave diameter are utilized in the design in accordance with ASME NOG-1-2004 and NUREG-0554, May 1979. These conservative design parameters assure wear and fatigue of the ropes is minimized.

The hoisting ropes are 1-1/2-inch Python Power 9 V EEIPS with a 172.8 ton breaking strength. The hoisting rope for the main hook is stainless steel. The hoisting rope for the auxiliary hook (which is configured in four-part double reeving) is 3/8-inch Python stainless steel with a breaking strength of 11.2 tons.

Each hoist drive has two brakes, one with time delay application. These brakes are automatically, mechanically applied in the absence of motion command or crane power. A regenerative type brake is also supplied to provide controlled lowering of a load should the main hoist motor fail to operate. Should the regenerative brake fail, emergency lowering procedures utilizing controlled manual release of the redundant mechanical brakes are available. All hoist brakes are rated at 150 percent of maximum torque that can be developed by its respective system. Trolley and bridge brakes are rated at 100 percent of motor full load torque. The bridge and trolley braking systems are manually adjusted to allow motion in the N-S and E-W directions during a seismic event. The brake adjustment is administratively controlled and is required to ensure the qualification of the FHB superstructure. A vertical stop is provided along the entire length of the runway to prevent bridge uplift and derailing. Vertical restraints are also provided on the trolley to prevent uplift and derailing.

The fuel handling area crane is equipped with a skeleton cab containing a control console chair. The crane may also be controlled by a radio remote control, which may be harness mounted and worn by the operator. Transfer of operation of the crane to the remote control is provided by a control chair mounted transfer switch.

The fuel handling area crane is also used to relocate the movable partition walls, which function to segregate the Unit 1 and Unit 2 SFP areas from the hot shop as described in Section 9.1.4.2.1.4. The crane control chair and radio remote control are equipped with switches to latch and unlatch the mechanism connecting the partition walls to the crane bridge structure. Indication of a latched condition is provided in two locations on the underside of the bridge girders.

Following erection, the hooks, lifting mechanisms, cables, brakes, trolleys, and structural members of the fuel handling area crane are tested at 1/2, 3/4, 1, and 1-1/4 times the rated load. The test loads are maintained for a minimum of 10 minutes prior to changing to a different load.

During fabrication of the upgraded trolley assembly, each hoist was functionally load tested at 1 times the rated load and proof load tested at 1-1/4 times the rated load. The emergency manual load lowering function of the main hoist was tested at 1 times the rated load. Following installation atop the existing bridge crane girders, each hoist was proof load tested at 1-1/4 times the rated load. During the site proof load test of each

hoist, the trolley and bridge motions were also tested to the maximum extent practicable.

The State of California assumed responsibility for the implementation of OSHA on January 1, 1974. The crane test loads to be used throughout the life of the facility will meet specific regulations for such loads, as established by the California Division of Industrial Safety.

The conservative design stress limits and redundant design features afforded by the single-failure-proof trolley and reanalyzed crane structures provide the added reliability to justify considering the crane as single-failure-proof. Nonetheless, the travel of both hooks over the SFP is restricted as described in Section 9.1.2.

9.1.4.2.1.4 Fuel Handling Area Movable Partition Walls

Movable partition walls allow the fuel handling area crane access to the fuel handling areas for both units and to the hot shop area, while maintaining proper operation of the FHBVS. The FHBVS is described in Section 9.4.4. Additionally, the movable partition wall panel in Unit 1 and the movable partition wall panel in Unit 2 (panel 1 and panel 4 as shown in Figure 9.1-19) are equipped with a monorail.

The fuel handling area crane may be used in the fuel handling area for Unit 1, the fuel handling area for Unit 2, or the hot shop area. Two movable partition walls are provided for the plant. These movable partition walls are repositioned when it is necessary to move the fuel handling area crane from one area to another. This repositioning is accomplished prior to the start of any fuel handling operations. The location of the movable partition walls is shown in Figure 9.1-19. Figure 9.1-20 shows a movable partition wall in place along either column line $15^{\underline{7}}$ or column line $20^{\underline{3}}$ where the wall serves to isolate the FHBVS from the hot shop area.

A monorail is attached to the side of the movable partition wall panels, each with a capacity of 4000 pounds. Travel is limited to the eastern end of these monorails to prevent the lifting of heavy loads over spent fuel. Any lifting of items in the western portions are administratively controlled by the Control of Heavy Loads Program (refer to Section 9.1.4.3.10).

The movable partition walls travel on wheels on the same rail track used by the fuel handling area crane. A movable partition wall is moved by securely attaching it to the fuel handling area crane and moving both the crane and the movable partition wall along the track as an integrated unit.

All members are designed as described in Section 3.8.2.3. The applicable code used in the design and fabrication is the Specification for the Design Fabrication and Erection of Structural Steel for Buildings, AISC, February 12, 1969. The movable partition wall panels and monorails have been evaluated for a HE concurrent with a maximum lifted load attached.

Wheels for the movable partition walls are double flanged. Additional assurance that derailing cannot take place is provided by a vertical stop running the entire length of each track. Details showing the movable partition wall, track, and vertical stop are shown in Figure 9.1-21.

9.1.4.2.1.5 Containment Structure Polar Crane

The containment structure polar crane (one for each unit) is an overhead gantry crane located on top of the circular crane wall at elevation 140 feet. This polar crane has a main hook capacity of 200 tons and an auxiliary hook capacity of 35 tons. In addition to the main and auxiliary hooks, the polar crane is equipped with a dome service crane.

The dome service crane has a manbasket rated at 750 pounds to lift tools and personnel for inspection and maintenance of the spray ring headers and upper containment structure. It also has an auxiliary hoist rated at 1950 pounds. The arrangement for the polar crane is shown in Figure 3.8-23.

Structural design is in accordance with the Specification for Electrical Overhead Traveling Cranes for Steel Mill Service, Association of Iron and Steel Engineers Standard No. 6 (tentative) dated May 1, 1969. All members not covered by that standard are designed according to the Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, AISC, dated February 12, 1969.

The electrical installation and all electrical equipment are in accordance with the National Electrical Code, dated 1968, and the National Electrical Manufacturers Association. The containment structure polar crane complies with the requirement of OSHA Subpart N, Materials and Handling Storage, of 29 CFR Part 1910, Section 1910.179. Fabrication and erection of the crane support rail is in accordance with the AISC specifications. Design, fabrication, and erection of the concrete supporting structure are described in Section 3.8.2.1.

The integrity of the crane hooks is ensured by the following measures:

(1) Stresses in the hooks and all other mechanical parts are limited to 80 percent of yield strength for the effect of maximum torque of the motors, braking, or collision of the trolley against the rail stops.

(2) Each hook is shop tested at 1-1/2 times its rated load.

(3) Following the shop test, each hook is magnetic particle inspected.

(4) Both hooks are field tested for 10 minutes at 1/2, 3/4, and 1-1/4 times the rated loads.

The pitch diameter of running sheaves is required to be not less than 24 times the nominal rope diameter. Likewise, the drum diameter is required to be not less than 24 times the nominal rope diameter.

The hoisting ropes are 6 x 37, uncoated, extra flexible, preformed, improved plow steel rope with hemp core or independent wire rope core. The maximum calculated stress in the ropes considering the efficiency of the reeving and weight of the blocks in addition to the crane rated load, is limited to 1/6 of the manufacturer's specified breaking strength.

The entire reeving system is designed so that minimum and commonly accepted fleet angles are maintained, and the rope is guarded against leaving the drum grooves or sheaves.

Each hoist drive on the Unit 1 and Unit 2 polar crane has two sets of brakes. The primary set is an alternating current, quick acting brake and the secondary set is a direct current, inherently slower acting brake. All these brakes are automatic and mechanically applied when the current to the motors is cut off. All hoist brakes are rated at 150 percent of maximum torque that can be developed by its respective system. Trolley and gantry brakes are rated at 100 percent of motor full load torque.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

After installation, the gantry legs and beam were tested as a structure (without running gear) with a load of 414 tons for 1 hour. With a 250-ton load, two 10-minute lifts plus gantry and trolley travel tests of the assembled crane were conducted. The maximum operating load for the containment polar crane is 185 tons.

The conservative design stress limits, the dual braking system, the preoperational tests and the test loads used throughout the life of the facility all combine to provide assurance against the modes of failure that otherwise might be assigned to a gantry crane. Nonetheless, the travel of both hooks over the opened RV is restricted and controlled by administrative controls.

During plant operation, the polar crane is parked unlocked and provided with guides to prevent derailment due to a seismic event. The guides resist horizontal shear normal to the crane rails. The crane rail is anchored continuously to the concrete by special clamps, capable of resisting forces due to an earthquake.

9.1.4.2.1.6 New Fuel Elevator

The new fuel elevator shown in Figure 9.1-10 consists of a box-shaped elevator assembly with its top end open and sized to house one fuel assembly. Depth of the structure is slightly less than the overall length of the fuel assembly, which rests on the bottom plate. The design class of the new fuel elevator is listed in Table 3.2-3. The new fuel elevator has been evaluated for the DDE and the HE concurrent with a maximum lifted load attached.

The new fuel elevator is used to lower a new fuel assembly to the bottom of the SFP where it is transported to the fuel transfer system by the SFP bridge hoist. It is also used to raise the dummy fuel assembly out of the SFP for transfer between units and occasionally for raising a newly received assembly to the surface for additional inspection.

The new fuel elevator can also be used for handling a spent fuel assembly, for example, during fuel assembly repair or post-irradiation examinations. The restriction imposed by the minimum water shielding requires that:

(1) Administrative controls are imposed to maintain an adequate submergence.

(2) The upper limit switch is adjusted to trip the hoist at a lower elevation to ensure adequate submergence.

(3) Mechanical stops are installed prior to insertion of a spent fuel assembly in the new fuel elevator to physically limit the raising of the elevator to ensure minimum submergence.

(4) No other fuel assembly movement is allowed in the SFP while an assembly is in the new fuel elevator.

9.1.4.2.1.7 Fuel Transfer System

The fuel transfer system (refer to Figure 9.1-11) includes a transfer car that runs on tracks extending from the refueling canal through the transfer tube into the SFP and an upender lifting frame at each end of the transfer tube. The upender in the refueling canal receives a fuel assembly in the vertical position from the manipulator crane. The fuel assembly is then pivoted to a horizontal position for passage through the transfer tube and pivoted to a vertical position by the upender in the SFP. The SFP bridge hoist takes the fuel assembly to a position in the spent fuel storage racks.

A quick opening hatch is used to close the refueling canal end of the transfer tube to seal the reactor containment. The terminus of the tube outside the containment is closed by a gate valve. The design class of the fuel transfer system is given in Table 3.2-3.

9.1.4.2.1.8 Rod Cluster Control Changing

RCCAs in the SFP are transferred from one fuel assembly to another by the RCC changing tool shown in Figure 9.1-12a. The RCC changing tool is portable and functions in a manner similar to the RCC changing fixture described above. This tool is suspended from the SFP bridge crane hoist and is operated from the bridge crane walkway. The tool is lowered by the bridge hoist until it rests upon the nozzle of the

desired fuel assembly seated in the spent fuel storage rack. The gripper actuator is then lowered and latched onto the RCC spider which allows the entire RCC to be drawn up inside the guide tube of the tool. Once this operation is completed, the tool may be repositioned over another fuel assembly. The above process is then reversed for reinsertion of the RCC. The RCC changing tool is PG&E Design Class II and is stored on the wall of the fuel transfer canal or SFP as needed. The tool consists of three basic assemblies: the guide tube, the support tube, and the drive mechanism.

The guide tube is the square cross-sectioned tube at the bottom of the tool. Guide plates are provided over the entire length of the tube to prevent damaging the rod clusters and to properly align the gripper. The gripper actuator is also contained within the guide tube. The electro-mechanical RCC changing tool uses a pneumatic gripper, and is operated using controls on the top of the tool. Two limit switches provide upper and lower limits for the motion of the unit. The bottom of the RCC changing tool is equipped with guide pins to insure alignment of the tool with the fuel assembly.

Above the guide tube is the support tube, which gives the proper length to the tool, provides support for the gripper actuator, and supplies protection for the lift cable. Also enclosed within the support tube are the air hose for the gripper and the electrical cable for the limit switches. To prevent tangling of the hose and cable, the cable has been placed inside the coiled air hose with seals at each end to allow separation of the two.

The drive mechanism, at the top of the tool, consists of a winch powered by an ac electric motor, the operator's panel, and four limit switches. One of the limit switches provides overload protection in the event of an RCC hang-up. The other three are geared limit switches; two providing upper and lower limits and the third controls the pneumatic system.

9.1.4.2.1.9 Spent Fuel Handling Tool

The manually actuated spent fuel handling tool, shown in Figure 9.1-13, is used to handle new and spent fuel in the SFP. It is mounted on the end of a long pole suspended from the SFP bridge hoist. An operator on the SFP bridge guides and operates the tool. The tool is stored on the wall of the SFP.

9.1.4.2.1.10 New Fuel Assembly Handling Fixture

The short-handled new fuel assembly handling fixture, shown in Figure 9.1-14, is used to handle new fuel on the operating deck of the fuel storage area, to remove the new fuel from the shipping container, and to facilitate inspection and storage of the new fuel and loading of fuel into the new fuel elevator.

9.1.4.2.1.11 Reactor Vessel Head Lifting Device

The RV head lifting device, shown in Figure 9.1-15, consists of a welded and bolted structural steel frame with suitable rigging to enable the crane operator to lift the head

and store it during refueling operations. The lifting lugs are permanently attached to the RV head. The RV head lifting device is a part of the integrated head assembly (IHA), as described in Section 5.4.1.4. During evolutions that require the removal of the reactor pressure vessel head, the entire IHA is lifted at once. The design class of this device is given in Table 3.2-3.

9.1.4.2.1.12 Reactor Internals Lifting Device

The reactor internals lifting device, shown in Figure 9.1-16, is a structural frame suspended from the overhead crane. The frame is lowered onto the guide tube support plate of the internals, and is manually bolted to the support plate by three bolts. Bushings on the frame engage guide studs in the vessel flange to provide guidance during removal and replacement of the internals package. The device is stored on a PG&E Design Class II stand in the containment refueling canal.

9.1.4.2.1.13 Reactor Vessel Stud Tensioner

Stud tensioners, shown in Figure 9.1-17, are employed to secure the head closure joint at every refueling. The stud tensioner is a hydraulically operated device that permits preloading and unloading of the RV closure studs at cold shutdown conditions. A hydraulic pumping unit operates the tensioners, which are hydraulically connected in series.

9.1.4.2.2 Tool Storage Locations and Supports

The storage locations of miscellaneous fuel handling tools are shown in Figure 9.1-18. The design classifications for these locations (containment structure, FHB, and support racks) are given in Table 3.2-3. Many of the major and miscellaneous tool supports are designed to meet PG&E Design Class I requirements. If not, the tools are stored in an area such that their failure or failure of their supports would not endanger plant operation or prevent safe plant shutdown during a seismic event.

9.1.4.2.3 Refueling Procedure

The refueling operation follows a detailed procedure that provides a safe, efficient refueling operation. The following significant points are ensured by the refueling procedure:

(1) The refueling water and the reactor coolant contain a minimum of approximately 2000 ppm boron (refer to Section 9.1.3.3.7).

(2) The water level in the refueling cavity is high enough to keep the radiation levels within acceptable limits when the fuel assemblies are being removed from the core. This water also provides adequate cooling for the fuel assemblies during transfer operations. Refer to Section 9.1.4.3.6 for

discussion regarding methods for maintaining adequate radiation shielding during the fuel handling process.

(3) The potential for grid strap damage during refueling operations is minimized by exercising care during the handling operations. Such care includes proper training of operators, ensuring adequate water clarity and lighting, confirmation of proper functioning and alignment of the fuel handling and transfer equipment, and implementation of appropriate fuel handling precautions.

The refueling operation is divided into four major phases: (a) preparation, (b) reactor disassembly, (c) fuel handling, and (d) reactor assembly. A general description of a typical refueling operation through the four phases is given below:

(1) Phase I - Preparation

The reactor is shut down and cooled to cold shutdown conditions with a minimum boron concentration of 2000 ppm in the reactor coolant and a Keff $\leq$ 0.95. Radiological assessments are performed in accordance with the Radiation protection program prior to general entry into containment. The coolant level in the RV is lowered to a point slightly below the vessel flange. The fuel transfer equipment and manipulator crane are checked for proper operation.

(2) Phase II - Reactor Disassembly

All cables are disconnected at the 140-foot elevation, seismic braces are unpinned, RV level instrumentation system tubing is disconnected, reactor head flange insulation is removed, head studs are detensioned, and the head studs and nuts are removed. The refueling cavity is then prepared for flooding by sealing off the reactor cavity; checking the underwater lights, tools, and fuel transfer system; closing the refueling canal drain holes; and removing the quick opening hatch from the fuel transfer tube. With the refueling cavity prepared for flooding, the vessel head is unseated, raised, and placed on the head storage stand. Water from the RWST is pumped into the RCS causing the water to overflow into the refueling cavity. The control rod drive shafts are disconnected and, with the upper internals, removed from the vessel. The fuel assemblies and RCCAs are now free from obstructions, and the core is ready for refueling.

Prior to moving the upper internals over fuel, each containment penetration will be in the following status:

(a) Equipment hatch capable of being closed and held in place by a minimum of four bolts

(b) One door in each air lock capable of being closed

(c) Each penetration providing direct access from the containment atmosphere to the outside atmosphere is capable of being closed by manual or automatic isolation valve, blind flange, or equivalent; or be capable of being closed by an operable automatic containment purge and exhaust valve.

Otherwise, all operations involving movement of the upper internals over fuel are suspended.

(3) Phase III - Fuel Handling

The refueling sequence consists of either a full core off-load or a partial core off-load and incore shuffle.

The full core off-load consists of removing all of the fuel assemblies from the core, storing them in the SFP, and then returning the partially spent assemblies, as well as the new assemblies that replace the fully spent assemblies, to the core according to the final reload configuration.

An incore shuffle consists of removing the fully spent fuel assemblies from the core to the SFP, rearranging the remaining partially spent assemblies in the core, and adding new assemblies to replace the removed fully spent assemblies.

The general fuel handling sequence is:

(a) The manipulator crane is positioned over a fuel assembly in the core.

(b) The fuel assembly is lifted by the manipulator crane to a predetermined height to clear the RV and still leave sufficient water coverage to eliminate any radiation hazard to the operating personnel.

(c) The fuel transfer car is moved into the upender inside containment.

(d) The fuel assembly container is pivoted to the vertical position by the upender.

(e) The manipulator crane is moved to line up the fuel assembly with the fuel transfer system.

(f) The manipulator crane loads a fuel assembly into the fuel assembly container of the fuel transfer car.

(g) The container is pivoted to the horizontal position by the upender.

(h) The fuel container is moved through the fuel transfer tube to the SFP by the transfer car.

(i) The fuel assembly container is pivoted to the vertical position. The fuel assembly is unloaded by the spent fuel handling tool attached to the SFP bridge hoist.

Crane operations with loads over the SFP are suspended with less than 23 feet of water over the top of irradiated fuel assemblies seated in the storage racks. The water level is specified in the Technical Specifications.

Crane operations with loads containing recently irradiated fuel over the SFP are suspended with no FHBVS trains operable. Recently irradiated fuel is defined as fuel that has been part of a critical reactor within the last 100 hours.

Crane operations with loads containing recently irradiated fuel over the SFP may proceed with one FHBVS train inoperable provided the operable train is capable of being powered from an operable emergency power source and is in operation and discharging through at least one train of HEPA filters and charcoal absorbers.

(j) The fuel assembly is placed in the spent fuel storage rack.

(k) The procedure for off-load is continued until all assemblies identified by the off-load procedure are removed. The core may be either partially or fully off-loaded.

(l) On core reload, assemblies are moved from the SFP storage location (or the new fuel storage vault via the new fuel elevator) to the fuel assembly container according to the reload procedure, and the fuel assembly container is pivoted to the horizontal position and the transfer car is moved back into the refueling canal.

(m) For an incore shuffle, partially spent fuel assemblies are relocated in the reactor core, and new fuel assemblies are added to the core.

(n) Any new assembly or transferred fuel assembly that is placed in a control position will receive an RCCA in the SFP using the RCC change tool.

(o) This procedure is continued until refueling is completed.

(4) Phase IV - Reactor Assembly

Reactor assembly, following refueling, is essentially achieved by reversing the operations given in Phase II - Reactor Disassembly.

9.1.4.2.4 Reactor Vessel Closure Head Lifting Administrative Controls

DCPP administrative controls are used to control the lift and replacement of the reactor vessel closure head (RVCH). They establish limits on load height, load weight, and medium present under the load. The administrative controls: (1) use the guidance and acceptance criteria in NEI 08-05, Industry Initiative on Control of Heavy Loads (Reference 21), particularly in regards to Section 2 of the initiative, which addresses criteria for RVCH load drop and consequences analysis; and (2) provide additional assurance that the core will remain covered and cooled in the event of a postulated RVCH drop.

9.1.4.2.5 Reactor Vessel Closure Head Load Drop Analyses

RVCH drop analyses have been performed for DCPP Unit 1 and Unit 2 in accordance with NEI 08-05, which was endorsed by the NRC, with exceptions, in the NRC safety evaluation of NEI 08-05 (Reference 22). The DCPP analyses were performed in accordance with the NRC exceptions, as follows:

(1) “The staff considers the ASME Code, Section III, Appendix F acceptance criteria for limiting events (i.e., Service Level D) acceptable for the analytical methods proposed in the guidance.” Therefore, the NEI 08-05 stress based criteria using ASME Section III, Appendix F, were used in the DCPP head drop analysis evaluation for coolant retaining components.

(2) “For energy balance evaluations using the large-displacement finite element methods described in the guidance, the staff finds the criteria applied to pipe whip restraint evaluations (i.e., one-half of ultimate strain) acceptable for the analytical methods proposed in the draft guidance.” The Standard Review Plan 3.6.2, Revision 1, criteria applicable to pipe whip restraint evaluations is 0.5 of the ultimate uniform strain limit for pure tension members. Therefore, the uniform tensile strain in tensile plus bending support members was limited to 0.5 of the ultimate strain.

The purpose of the analyses was to evaluate the consequences of a postulated heavy load drop of the RVCH in the reactor cavity, while raising or lowering the RVCH during outages at DCPP. The heads weigh 366 Kip, however for analysis purposes, a conservative head weight of 380 Kip dropping a distance of 38 feet in air was assumed. The RVCH centerline is considered concentric with the RV centerline. The 38-foot height limit is removed once the RVCH centerline is outside the RV flange outside diameter. The dynamic head drop analysis methodology used for DCPP is an acceptable methodology per NEI 08-05, Section 2.3, and the NRC safety evaluation of

NEI 08-05 (Reference 22). Details of the analysis and results are provided in Reference 23.

The dynamic impact model includes a system of non-linear springs and masses of the falling head with the upper service structures, and impact on an integrated spring mass model of the RV target structures. The target structures consist of the RV shell, nozzles, the RCS loop piping, reactor coolant pumps (RCPs), and the steam generators (SGs). An impact damping ratio of 5 percent was applied in the analysis to address the plastic deformation of the contact surfaces of the head and the vessel flanges. The load-deflection curve of the non-linear spring elements are developed from a non-linear finite element analysis model of the components.

The dynamic impact analysis results indicate, for all drop cases, stresses in the RV shell, RV nozzles, RCS loop piping, bottom mounted instrumentation piping and all RCS attached piping meet the allowable stresses per ASME BPVC Section III, Appendix F, for faulted conditions per the NEI 08-05 Guideline as endorsed by the NRC. Stresses in the reactor coolant pressure retaining components are below the ASME Section III, Appendix F, stress limits for faulted conditions.

Concrete under the RV support base steel plate exceeds the local bearing stress limit; thus, the RV supports were considered to be ineffective after the concrete crushing. Local concrete under the pipe whip saddle inside the wall penetration also partially crushed, however, the strain in pipe whip support plates remains below the allowable strain. Thus, the RVCH, RV, and RCS piping remain supported after the impact.

The SG and RCP nozzle loads and support loads due to head drop load impact are less than or approximately the same as the component faulted design loads (based on combined LOCA, seismic, pressure, and deadweight loads). Thus, the RCP and SG support structures would remain functional to support the weight of the RCS components after the head drop accident.

9.1.4.2.6 Cask Loading Operations

A summary description of the FHS equipment for cask loading operations is provided in this section. Additional details are included in References 10, 11, and 12. Refer to Section 4.4.1.3 of Reference 12 for the division of safety considerations inside and outside the 10 CFR Part 50 facility.

The FHS equipment needed to load spent fuel into a cask for transfer to the Diablo Canyon ISFSI consists of cranes, lifting and handling devices including tools, a low profile transporter (LPT), and an SFP transfer cask restraint cup. The primary structures associated with this equipment are the SFP, the cask loading area of the SFP, and the Unit 2 cask washdown area (CWA).

Decay heat, generated by the spent fuel assemblies in the SFP, is removed by the SFP cooling and cleanup system. When fuel is to be moved to the Diablo Canyon ISFSI,

selected assemblies are removed from the racks and loaded into a multi-purpose canister (MPC) that is located inside a transfer cask (the HI-TRAC 125D cask shown in Figure 9.1-4). The cask handling route within the FHB is shown in Figure 9.1-7. The minimum cooling time for fuel to be loaded into the transfer cask is 5 years.

The cranes, lifting and handling devices, and tools used for cask loading operations are essentially the same as those used for refueling and fuel transfer operations (described in Section 9.1.4.2). They are, however, configured differently for cask loading operations, as further described below in Section 9.1.4.2.6.1. The LPT is used to move the empty transfer cask into the FHB. The transfer cask is detached from the LPT and moved into the Unit 2 CWA seismic restraint using the fuel handling area crane. While located in the CWA, the empty transfer cask/MPC is restrained as shown in Figure 9.1-24. When the transfer cask is moved to the cask loading area, it is lowered into the SFP transfer cask restraint cup (refer to Figure 9.1-6), which provides lateral support of the cask while it is lowered, loaded with fuel, and lifted from the SFP. Once the loaded cask is raised out of the SFP, it is moved to the Unit 2 CWA for decontamination, MPC processing, and preparation for transport to the cask transfer facility (CTF). When ready, the loaded cask is lifted out of the Unit 2 CWA, fastened onto the LPT, and moved out of the FHB for subsequent transport to the CTF using the cask transporter.

9.1.4.2.6.1 Component Descriptions

The following sections describe major components of the FHS as they relate to cask loading operations in the FHB. The cranes, lifting and handling devices, and tools described in Section 9.1.4.2.1 for refueling and fuel transfer operations are essentially the same as those used for cask loading operations. There are, however, some configuration differences. The component descriptions in this section focus on the configuration differences for the cranes, lifting and handling devices, and tools, as well as describing those components unique to cask loading and handling in the FHB. Other FHS components not addressed in this section remain the same as described in Sections 9.1.4.2.1 and 9.1.4.2.2.

9.1.4.2.6.1.1 HI-STORM 100 Interchangeable Multi-Purpose Canisters

The HI-STORM MPC provides for confinement of radioactive materials, criticality control, and the means to dissipate decay heat from the stored fuel. It is a welded cylindrical canister with a honeycombed fuel basket, which contains a Boral or Metamic neutron absorber for criticality control. Although MPC-24s and MPC-32s are certified for use at DCPP, only the MPC-32 is used. The MPC-32 is designed for intact spent fuel. All MPCs certified for use at DCPP have the same outside dimensions and use the same transfer cask.

9.1.4.2.6.1.2 HI-TRAC 125D Transfer Cask

The HI-TRAC 125D transfer cask (refer to Figure 9.1-4) contains the MPC during loading, unloading, and transfer operations. The physical characteristics of the 125D

cask are shown in Table 4.2-3 of the Diablo Canyon ISFSI UFSAR . It provides shielding and structural protection of the MPC in the FHB and from the SFP to the CTF. The transfer cask is a multi-walled (carbon steel/lead/carbon steel) cylindrical vessel with a built-in exterior water jacket. The maximum weight including the lifting yoke during any loading, unloading, or transfer operation does not exceed 125 tons.

9.1.4.2.6.2 Transfer Cask/Multi-Purpose Canister Loading Process

The transfer cask/MPC loading process is briefly summarized in this section. Additional detail is provided in Section 3.2 of Reference 10 and in Section 5.1 of Reference 12.

An empty MPC is loaded into the transfer cask in the FHB using the fuel handling area crane. Borated water is added to the MPC and the transfer cask is lifted above the SFP wall using the fuel handling area crane. The cask is then traversed into position over the cask loading area of the SFP and SFP transfer cask restraint cup. The cask is lowered into the SFP transfer cask restraint cup, which rests on a platform near the bottom of the cask loading area. The restraint precludes tipping or damage to adjacent fuel racks.

After fuel loading is complete, a lid is placed on the MPC, the transfer cask is lifted out of the SFP, traversed and lowered into the Unit 2 CWA seismic restraint, and decontaminated. The MPC lid is welded to the MPC shell, hydro leak tested, water is drained from the MPC, and the MPC is dehydrated, filled with Helium, isolated, Helium leak tested, and seal welded to closure. The top lid is then installed on the transfer cask.

The fuel handling area crane is then used to lift the loaded transfer cask out of the CWA restraint and to place the loaded transfer cask onto the LPT. The cask is fastened to the LPT and the LPT is moved out of the FHB on removable tracks to a position where it is rigged to the cask transporter for movement to the CTF.

9.1.4.2.6.3 Unloading Operations

While unlikely, certain conditions described in Reference 12 may require unloading of the fuel assemblies from the transfer cask/MPC. The unloading process is generally the reverse order of the loading process.

9.1.4.3 Safety Evaluation

9.1.4.3.1 General Design Criterion 2, 1967 – Performance Standards

The FHB, auxiliary building, and containment structure, which contain the FHS are PG&E Design Class I (refer to Section 3.8). These buildings or applicable portions thereof are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7). These designs protect the FHS, ensuring its safety functions are performed.

The cranes and movable partition walls of the FHS have been seismically qualified to either DEs, DDEs, or HEs, as discussed in Section 9.1.4.2.1.4.

The LPT, with a loaded transfer cask attached, is qualified for DE, DDE, and HE events.

Refer to Section 9.1.4.3.9 for further discussion of the seismic qualifications of the FHS equipment.

Tornado Winds and Tornado Generated Missiles

The overall tornado resistance of the FHB is addressed in Section 9.1.2.3.1. The effects of tornado wind loads acting on the cask suspended from the FHB crane are enveloped by the seismic analysis for this configuration. However, cask handling introduces new tornado missile targets. Analysis results demonstrate that the 125-ton transfer cask satisfies all functional requirements under postulated impact scenarios and the system will not be subject to a loss of load due to a missile impact. For discussions of wind and tornado loading and associated tornado generated missiles, refer to Sections 3.3 and 3.5, respectively.

9.1.4.3.2 General Design Criterion 4, 1967 – Sharing of Systems

The FHB is a steel framed building anchored to the concrete auxiliary building structure (refer to Section 3.8.2.3.4.1). The FHB encloses the fuel handling areas of Unit 1 and Unit 2 (refer to Figures 1.2-4 and 1.2-10). Therefore, the FHB is a shared structure.

One fuel handling area crane services both units (refer to Section 9.1.4.2.1.3). DCPP administrative controls are used to restrict the path of loads, such as the handling of spent fuel casks, which could damage fuel assemblies. The restrictions on fuel handling prevent a failure of the fuel handling area crane from negatively impacting the safety of both units (refer to Section 9.1.4.3.10).

Two movable partition walls are used in the FHB to allow the fuel handling area crane to transition from one unit to the other unit. The movable partition walls serve to separate the Unit 1 and Unit 2 areas of the FHB during fuel handling operations (refer to Section 9.1.4.2.1.4).

The function of the FHBVS is not impacted by the shared use of the movable partition walls, due to the fact that these walls are moved into their required positions before fuel handling begins. This allows the FHBVS to maintain the required negative atmospheric pressure for the fuel handling process (refer to Section 9.1.4.2.1.4).

Movement of fuel assemblies is controlled by DCPP administrative controls, ensuring the safe handling of fuel in the shared FHB. When the fuel handling area crane is not needed in the Unit 1 or Unit 2 fuel handling areas, the movable partition walls are

positioned such that they provide a ventilation boundary between the hot shop and the fuel handling area of each unit (refer to Section 9.1.4.2.1.4).

9.1.4.3.3 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Electrical interlocks (i.e., limit switches) are provided for minimizing the possibility of damage to the fuel during fuel handling operations. The electrical interlocks for the manipulator crane are not specifically designed to the requirements of Reference 4 because of the primary dependence on mechanical stops.

The manipulator crane design includes the following provisions to ensure safe handling of fuel assemblies:

(1) Bridge, trolley, and winch drives are mutually interlocked, using redundant interlocks, to prevent simultaneous operation of any two drives.

(2) Bridge and trolley drive operation is prevented except when both gripper tubeup position switches are actuated.

(3) An interlock is supplied that prevents the operation of either the engaging or disengaging solenoid valves unless the load and elevation requirements are satisfied. As backup protection for this interlock, the mechanical weight-actuated lock in the gripper prevents operation of the gripper under load even if air pressure is applied to the operating cylinder.

(4) An excessive suspended weight switch opens the hoist drive circuit in the up direction when the loading is in excess of 110 percent of a fuel assembly weight.

(5) An interlock of the hoist drive circuit in the up direction permits the hoist to be operated only when either the open or closed indicating switch on the gripper is actuated.

(6) An interlock of the bridge and trolley drives prevents the bridge drive from traveling beyond the edge of the core unless the trolley is aligned with the refueling canal centerline. The trolley drive is locked out when the bridge is beyond the edge of the core.

The following safety features are provided for in the fuel transfer system control circuit:

(1) Transfer car operation is possible only when both upenders are in the down position as indicated by the limit switches.

(2) The remote control panels have a permissive switch in the transfer car control circuit that prevents operation of the transfer car in either direction

when either switch is open; i.e., with two remote control panels, one in the refueling canal and one in the SFP, the transfer car cannot be moved until both "go" switches on the panels are closed.

(3) An interlock allows upender operation only when the transfer car is at either end of its travel.

(4) Transfer car operation is possible only when the transfer tube gate valve position switch indicates the valve is fully open.

(5) The refueling canal upender is interlocked with the manipulator crane. The upender cannot be operated unless the manipulator crane gripper tube is in the fully retracted position or the crane is over the core.

Fuel handling devices have provisions to avoid dropping or jamming of fuel assemblies during transfer operations.

9.1.4.3.4 General Design Criterion 49, 1967 – Containment Design Basis

The fuel transfer system, where it penetrates the containment, has provisions to preserve the integrity of the containment pressure boundary. The fuel transfer tube that connects the refueling canal (inside the containment) and the SFP (outside the containment) is closed on the refueling canal side by a quick opening hatch at all times except during refueling operations. Two seals are located around the periphery of the quick opening hatch with leak-check provisions between them. The terminus of the tube outside the containment is closed by a gate valve.

The portion of the fuel transfer tube inside the containment is considered to be part of the containment liner and is a Type B containment test penetration (refer to Table 6.2-39). In accordance with Technical Specifications, the fuel transfer tube penetration is tested up to expected LOCA pressure to ensure that the design leakage rate is not exceeded. Other than during refueling operations, the transfer tube remains empty therefore there are no means for affecting the functional design of the penetration.

9.1.4.3.5 General Design Criterion 66, 1967 – Prevention of Fuel Storage Criticality

As discussed in Section 9.1.4.2.6.1.1, the design of the Holtec HI-STORM MPC provides criticality control for spent fuel stored in the MPC.

The boron concentration of the water that communicates with the reactor pressure vessel during the refueling process is controlled by Technical Specifications and DCPP administrative controls to ensure that the fuel assemblies located inside the reactor pressure vessel remain subcritical.

During refueling operations when the SFP water mixes through the fuel transfer tube with the reactor refueling cavity water, SFP chemistry is controlled to ensure compatibility with the RCS and residual heat removal (RHR) system chemistry requirements to preclude a boron dilution accident.

For the period of time that an MPC is located in the MPC cavity of one of the SFPs, the water is free to communicate between the MPC and the SFP. During cask loading operations in the SFP, boron concentrations in the SFP (and thus, the MPC cavity) are maintained in accordance with the ISFSI Technical Specifications. For an MPC-32, a boron concentration range between 2000 ppm and 2600 ppm is required depending on the initial enrichment (wt%) of the loaded fuel assemblies. Boration levels up to 3,000 ppm in the MPC and SFP have been evaluated and determined to have no adverse effects on materials or thermal performance.

Protection from boron dilution events is discussed in Section 9.1.4.3.8.1.

9.1.4.3.5.1 Fuel Assembly Drop into Loaded Transfer Cask

While very unlikely, analysis of this event shows that a fuel assembly drop into the MPC could result in physical deformation that would challenge criticality margins. However, the results of the analysis show that the criticality margins would continue to meet the licensing basis (k_{eff} <0.95) and that the radiological consequences are enveloped by the existing fuel assembly drop accident described in Section 15.5.22.1.

9.1.4.3.6 General Design Criterion 68, 1967 – Fuel and Waste Storage Radiation Shielding

Cranes and hoists used to lift spent fuel assemblies have a limited maximum lift height so that the minimum required depth of water shielding is maintained. During all phases of spent fuel transfer, the gamma dose rate at the surface of the water is limited by maintaining a minimum of 8 feet of water above the top of the fuel assembly during all handling operations. This corresponds to about 9 feet of water shielding over the active fuel.

The two cranes used to lift spent fuel assemblies are the manipulator crane and the SFP bridge hoist. The manipulator crane contains positive stops, which prevent the top of a fuel assembly from being raised to within 8 feet of the water level in the refueling cavity. The hoist on the SFP bridge moves spent fuel assemblies with a long-handled tool. Hoist travel and tool length likewise limit the maximum lift of a fuel assembly to assure 8 feet of water shielding in the SFP.

When handling irradiated fuel rods, during fuel repairs and post-irradiation examinations, nine feet of water is maintained above the active fuel.

9.1.4.3.7 10 CFR 50.55a(g) – Inservice Inspection Requirements

The FHS has a periodic ISI program in accordance with the ASME BPVC Section XI.

9.1.4.3.8 10 CFR 50.68(b) – Criticality Accident Requirements

Based on the alarms, procedures, administrative controls, assumption of zero burnup fuel, and availability of trained operators described in Reference 13, the NRC has granted an exemption from the criticality requirements of 10 CFR 50.68(b)(1) during loading, unloading, and handling of the MPC in the DCPP SFP (Reference 14).

In accordance with 10 CFR 50.68(b)(1), plant administrative controls prohibit handling and storage at any one time of more fuel assemblies than have been determined to be safely subcritical.

Refer to Section 9.1.4.3.5 for a discussion on measures used during fuel handling activities to ensure the K_{eff} of the fuel assemblies remains below the limits established in 10 CFR 50.68(b)(4).

Implementation of 10 CFR 50.68(b)(8) was completed with the submittal of Revision 15 of the UFSAR.

9.1.4.3.8.1 Mulit-Purpose Canister Boron Dilution

The original boron dilution analysis was performed and submitted to the NRC (Reference 13) to determine the time available for operator action to ensure criticality does not occur in an MPC-32 during fuel loading and unloading operations. The results of the analysis of record show that operators have 4.7 hours available to identify and terminate the source of unborated water flow from the limiting boron dilution event to ensure criticality in the MPC-32 does not occur. To minimize the possibility of a dilution event, a temporary administrative control is implemented while the MPC is in the SFP that will require, with the exception of the 1-inch line used to rinse the cask as it is removed from the SFP, at least one valve in each potential flow path of unborated water to the SFP to be closed and tagged out. During the cask rinsing process, the MPC will have a lid in place that will minimize entry of any unborated water into the MPC. The flow path with the highest potential flow rate of 494 gpm is doubly isolated by having two valves closed and tagged out while the MPC is in the SFP.

9.1.4.3.9 Safety Guide 13, March 1971 – Fuel Storage Facility Design Basis

<u>Regulatory Position 1:</u>

The FHB, auxiliary building, and containment structure, which contain the FHS, are designed to withstand the effects earthquakes (refer to Section 9.1.4.3.1).

Fuel lifting and handling devices are capable of supporting maximum loads under seismic conditions. The fuel handling equipment will not fail so as to cause damage to

any fuel elements should the seismic event occur during a refueling operation. The earthquake loading of the fuel handling equipment is evaluated in accordance with the seismic considerations addressed in Section 9.1.4.3.1. However, several components used in the fuel transfer system are not seismically qualified. This includes the upenders (one inside containment and one inside the FHB), the fuel transfer car, and the rails that the fuel transfer car rides on. Refer to Table 3.2-3 for further details on the classification of the fuel transfer system.

The maximum design stress for the fuel handling area crane structures and for all parts involved in gripping, supporting, or hoisting the fuel assemblies is 1/5 ultimate strength of the material. This requirement applies to normal working load and emergency pullout loads, when specified, but not to earthquake loading. To resist earthquake forces, the fuel handling area crane structures are designed to limit the stress in the load bearing parts to either 0.96 times the yield stress for a combination of normal working load plus DDE forces, or 1 times the yield strength for a combination of normal working load plus HE forces, whichever is greater. To ensure the ability of the lifting and handling devices to support maximum loads under seismic conditions, the design safety factor of the lifting and handling devices has been evaluated against the actual calculated HE loads. The evaluation indicates the inherent design safety factor is sufficient to envelope the combined normal working load plus DDE or HE loads.

For the manipulator crane, restraints are provided between the bridge and trolley structures and their respective rails to prevent derailing due to the DDE and HE. The manipulator crane is designed to prevent disengagement of a fuel assembly from the gripper under the DDE and HE. The SFP bridge crane is seismically qualified for the DDE and HE.

While in the Unit 2 CWA, the HI-TRAC is seismically restrained by the CWA seismic restraint system. This system includes a wall mounted restraint and service platform and a floor restraint plate.

The potential impact of seismic events on cask loading, handling, closure, and transport activities has been considered in the evaluation of the cask system components and in the design and evaluation of the interfaces with 10 CFR Part 50 facilities. Two structures, the SFP transfer cask restraint cup and the Unit 2 CWA seismic restraint structure, are designed to preclude unacceptable movement of the cask system components, assuring all involved SSCs remain within their design bases.

Seismic analyses have been performed that demonstrate the adequacy of the SFP transfer cask restraint cup and Unit 2 CWA restraint to preclude unacceptable movement or impact on the 10 CFR Part 50 facilities.

Regulatory Position 2:

Section 9.1.4.3.1 provides a discussion of the DCPP environmental protections, such as protection from cyclonic winds and external missiles, for the PG&E Design Class I portions of the FHS.

Regulatory Position 3:

Electrical interlocks (i.e., limit switches) are provided for minimizing the possibility of damage to the fuel during fuel handling operations. Mechanical stops are provided as the primary means of preventing FHAs. For example, safety aspects of the manipulator crane depend on the use of electrical interlocks and mechanical stops. The electrical interlocks for the manipulator are not specifically designed to the requirements of Reference 4 because of the primary dependence on mechanical stops.

Section 9.1.4.3.3 provides a more detailed overview of the interlocks used to ensure that fuel assemblies are safely handled.

Regulatory Position 5(b):

Crane operation in the fuel handling area is such that the heavy loads cannot traverse over the spent fuel storage racks in the SFP. Redundant electrical interlocks are installed on the fuel handling area crane to prevent movement of heavy loads over the area of the SFP which can contain spent fuel. The backup interlock is connected to a different circuit than the primary interlock to preclude heavy loads movement over stored fuel resulting from a single failure.

These limitations on fuel handling area crane travel preclude the possibility of dropping heavy objects from above the spent fuel storage racks. The spent fuel bridge hoist and the movable partition wall monorail are the only cranes capable of moving objects over the spent fuel storage racks.

The rated capacity of the spent fuel bridge hoist is 2500 pounds. The Equipment Control Guideline (ECG 42.4) prohibits movement of any load greater than 2500 pounds over fuel assemblies in the spent fuel pool. As stated in the ECG, the 2500 pounds is the approximate weight of a fuel assembly, control assembly, and associated handling tool. This is the assumed load in the fuel handling accident. The restriction on loads in excess of 2500 pounds over the other fuel assemblies in the spent fuel pool (SFP) ensures in the event this load is dropped that: (1) the activity release will be limited to that contained in a single fuel assembly, and (2) any possible distortion of the fuel in the storage racks will not result in a critical array.
The rated capacity of the movable partition wall monorail is 4000 pounds, however, physical restrictions (trolley stops) are provided to prevent movement of loads over the SFP. Lighting fixtures or other components of the building above the racks are not sufficiently massive to cause damage to the racks if they are assumed to fall into the

pool. Protection of nuclear fuel assemblies from overhead load handling is a key element of the Control of Heavy Loads Program described in Section 9.1.4.3.10.

9.1.4.3.10 NUREG-0612, July 1980 – Control of Heavy Loads at Nuclear Power Plants

The objective of the Control of Heavy Loads Program is to ensure that all load handling systems are designed, operated, and maintained such that their probability of failure is uniformly small and appropriate for the critical tasks in which they are employed. The program is based on all seven general guideline areas of NUREG-0612, July 1980 Section 5.1.1, also known as Phase I (Safe Load Paths; Load Handling Procedures; Crane Operator Training; Special Lifting Devices; General Lifting Devices; Crane Inspection, Testing and Maintenance, and Crane Design).

The Control of Heavy Loads Program for refueling and fuel transfer operations is described in Section 9.1.4.3.10.3. The Control of Heavy Loads Program for cask loading operations, which includes revisions for loading the HI-STORM System components within the 10 CFR Part 50 facility, complies with the guidelines of NUREG-0612, July 1980. Details specific to cask loading and handling in the FHB are provided in References 10 and 11.

Generic Letter 80-113, December 1980 (Reference 18) required PG&E to review their provisions for handling and control of heavy loads at DCPP to determine the extent to which the guidelines of NUREG-0612, July 1980 Phase I and II were satisfied and to commit to mutually agreeable changes and modifications that would be required to fully satisfy these guidelines. An overview of the DCPP heavy loads program is presented in this section.

PG&E has developed and is maintaining a robust heavy loads control program at DCPP to minimize the potential for adverse interaction between overhead load handling operations and: 1) nuclear fuel assemblies to ensure a subcritical configuration and preclude radiological consequences and; 2) SSCs selected to ensure safe, cold shutdown of the plant following a postulated heavy load drop event. The bases of the NRC-accepted program are summarized in Reference 7.

Implementation of Sections 5.1.2 through 5.1.6 of NUREG-0612, July 1980, also known as Phase II, was determined by the NRC in Generic Letter 85-11, June 1985 to not require NRC review. While not a requirement, the NRC encouraged the implementation of any licensee actions identified in Phase II that are considered appropriate.

To accomplish the program, PG&E defined as heavy load targets nuclear fuel assemblies and selected SSCs necessary to safely shut down the plant and maintain the plant in a safe, cold shutdown condition. Initial plant operating modes of normal operation, shutdown, and refueling were considered in the selection of the target equipment. Overhead load handling operations and heavy load target SSCs were then evaluated for potential interaction. Mitigation measures for minimizing adverse

interactions include as applicable: (1) to the extent possible, changing methods, routes or scheduling of the overhead load handling operation to avoid the interaction; (2) analyzing the intervening floor structural capacity for protection of target SSCs against postulated damage due to a load drop, and restricting overhead loads in the plant area by weight and handling height above the intervening floor (i.e., restricted area); and (3) excluding the plant area from non-essential overhead load handling operations (i.e., exclusion area). PG&E plans and capabilities to handle heavy loads at DCPP are described in PG&E correspondence to the NRC in response to NUREG-0612, July 1980 and are summarized in Reference 7. Sections 2.2.4, 2.3.4, and 2.4.2 of PG&E's NUREG-0612, July 1980 submittals (References 19 and 20) provide the results of various load drop analyses.

The results of these evaluations are used to create administrative controls for overhead load handling operations in plant areas where heavy load targets exist. The Plant Staff Review Committee is responsible for reviewing administrative controls for overhead load handling operation in exclusion areas (refer to the Diablo Canyon Quality Assurance Program Description). Additional controls for the training of crane operators, design, operation, maintenance and inspection of rigging, lifting devices, and overhead load handling systems are administered through plant administrative controls.

The movable wall partitions, which have monorail lifting devices attached, are designed and configured as described in Section 9.1.4.2.1.4.

9.1.4.3.10.1 Reactor Vessel Closure Head Load Drop

Controls implemented by NUREG-0612, July 1980 Phase I elements make the risk of a load drop very unlikely, and, in the event of a postulated RVCH drop, the load drop analysis demonstrates that the consequences are acceptable (refer to Section 9.1.4.2.5). Restrictions on load height, load weight, and medium under the load consistent with analysis assumptions are reflected in plant administrative controls.

9.1.4.3.10.2 RCP Motor Load Drop

While the likelihood of a load drop is very unlikely under DCPP's Control of Heavy Loads Program, in the event of a postulated drop of an RCP motor heavy load component, a load drop analysis demonstrates that the consequences are acceptable. Restrictions on load height, load weight, intervening structures, and plant conditions consistent with analysis are reflected in plant administrative controls. These administrative controls provide additional assurance that the core will remain covered and cooled in the event of a postulated drop of an RCP motor heavy load component. The consequences of dropping a fully assembled motor have not been analyzed.

RCP motor load drop analysis have been performed for DCPP Unit 1 and Unit 2 in accordance with NEI 08-05, which was endorsed by the NRC, with exceptions, in the NRC safety evaluation of NEI 08-05 (Reference 22). This is the same non-linear dynamic impact analysis methodology used for the RPVH drop analysis. The results of

the analysis determined that the consequences satisfy the acceptance criteria of NUREG-0612 Section 5.1.3 part (3), using the guidelines of NUREG-0612 Appendix A. In the analysis, the RCS integrity is evaluated with three postulated drop locations, which are considered to be the worst consequences to the RCS pressure boundary components and their support components during a RCP motor load handling activity. The results of the analysis apply only in plant Modes 5 or 6 while the RCS is depressurized with the RPVH on or off the vessel.

The purpose of the analyses was to evaluate the consequences of a postulated heavy load drop of the heaviest RCP motor component, the upper end bracket (UEB), while raising or lowering the load over the RCP hatch area during plant Modes 5 and 6. The maximum analyzed below-the-hook load is 52,000 lbs lifted up to 5 feet above the 140-foot containment elevation, which conservatively bounds lifting the UEB and all lighter RCP motor components in any sequence. A design analysis of a Rotor Impact Absorber (RIA) is also performed to protect the RCP casing from excessive stresses if the rotor is lifted separately from the UEB and is concentrically dropped through the stator and the lower end bracket. Procedures and design documents control the use and configuration of the RIA.

9.1.4.3.10.3 Cask Loading Operations

Potential spent fuel cask accidents and off-normal events related to handling and loading (or unloading) of the MPC in the HI-TRAC 125D transfer cask, including safe handling as related to use of cranes and lifts; potential drops and tipovers; operational errors and mishandling events; support system malfunctions; and fires, are addressed in this section. Additional details of the methodology, acceptance criteria, and results are provided in Section 4.3 of Reference 10.

9.1.4.3.10.3.1 Defense-in-Depth Measures

9.1.4.3.10.3.1.1 Safe Handling

The safe handling discussion in Section 9.1.4.3.3 for the FHB cranes and lifts applies to cask loading operations. In addition, the FHB crane is configured and operated as described in Section 9.1.4.2.1.3 when performing cask loading and handling operations.

Structural, mechanical, and electrical design of the fuel handling area crane is in accordance with ASME NOG-1-2004, as conformed to the requirements of NUREG-0554, May 1979 per the guidance of NUREG-0612, July 1980, Appendix C. Furthermore, the crane structural design has been demonstrated to envelope the structural requirements of the original design codes as enumerated below. The main hoist, trolley, and bridge members meet ASME NOG-1-2004, Type I, design standards. Original bridge members and components retained for the current single-failure-proof design has been reanalyzed and inspected in accordance with the guidance provided by NUREG-0612, July 1980, Appendix C. The 15-ton auxiliary hoist meets ASME NOG-1-2004, Type II standards and therefore is not considered as single-failure-proof.

9.1.4.3.10.3.1.2 Drops and Tipovers

Upgraded cranes and hoists used during cask handling and loading minimize the potential for load drops. In particular, the FHB crane bridge and main hoist have been upgraded to meet single-failure-proof criteria, as described in Section 9.1.4.2.1.3.

The transfer cask, MPC and its internals, MPC lids, and spent fuel assemblies must be handled in and around the SFP and spent fuel (in the SFP and MPC). With the exception of the spent fuel assemblies, all of these items represent heavy loads.

The potential for drops or tipovers of any of these heavy loads is extremely small due to DCPP's Control of Heavy Loads Program and fuel-handling operations administrative controls. The Control of Heavy Loads Program provides procedures, training, and designs to minimize the potential for load drops, meets PG&E's commitments to NUREG-0612, July 1980, and has been accepted by the NRC (Reference 28). The single-failure-proof upgrade to the FHB crane further reduces the potential for a crane-related failure or mishandling event that could result in the drop of a cask.

Nonetheless, the following potential heavy-load drops have been postulated and evaluated, where credible, in accordance with the guidance of NUREG-0612, July 1980, Section 5.1, demonstrating defense in depth.

9.1.4.3.10.3.2 Cask Loading Accident Analyses

9.1.4.3.10.3.2.1 Loaded Transfer Cask Drops

PG&E has provided defense in depth through crane enhancements (described in Section 9.1.4.2.6) in those locations where a drop could have unacceptable consequences. Use of a single-failure-proof FHB crane ensures that an uncontrolled drop onto the edge of the SFP wall, which could allow the cask to tip or tumble horizontally into the SFP or into the CWA, is not credible. The single-failure-proof FHB crane also precludes drops during the placement of the transfer cask/MPC onto the LPT.

Further, movement of heavy loads over fuel in the SFP, or over any other safe shutdown systems or equipment identified in PG&E's NUREG-0612, July 1980 submittals, is controlled by administrative controls and considers the design of the single-failure-proof crane system and/or travel limit devices.

To ensure the cask does not adversely affect the stored spent fuel in the adjacent racks, the cask is inserted and seated in the transfer cask restraint cup during fuel loading or unloading operations. Structurally separating the transfer cask restraint cup from the fuel storage racks is the spent fuel cask restraint. The restraint is made of 12-inch Schedule 80S Type 304 stainless steel pipe, as shown in Figure 9.1-5.

The evaluations for postulated cask drops do not consider orientations for a tipped cask. This exception to NUREG-0612, July 1980, Appendix A, Consideration (1) is acceptable, due to cask restraints in the SFP and CWA.

9.1.4.3.10.3.2.2 Multi-Purpose Canister or Transfer Cask Lids, AWS Baseplate Shield, or Lifting Yoke Drops into Loaded Cask

While these components are classified as heavy loads and handling them over the MPC is required for dry fuel operations, drops are not considered credible because they are handled with a single-failure-proof overhead load handling system and rigged in accordance with the Control of Heavy Loads Program.

9.1.4.3.10.3.2.3 Operational Errors and Mishandling Events

The design of the dry cask handling system and associated administrative controls provide assurance that operational errors and mishandling events will not result in an increase in the probability or consequences of an accident previously analyzed. The following operational errors and mishandling events were evaluated and found to either have consequences within the design or licensing basis of DCPP, be precluded by compliance with the Control of Heavy Loads Program and/or operations procedures, or to not be credible.

- SFP Liner Breach Due to Cask Drop
- Crane Mishandling Operation with Transfer Cask/MPC Resulting in Horizontal Impact or Drops Outside of the Analyzed Lift Points
- Loss of the Transfer Cask Water Jacket Water During MPC and Cask Handling Operations
- Boron Dilution of the SFP and Associated Criticality Concerns
- Loading of an Unauthorized Fuel Assembly

9.1.4.3.10.3.2.4 Support System Malfunctions

The following support system malfunctions have been evaluated and found to not adversely affect plant safety:

- Loss of Electrical Power or Component Failures During Handling Operations
- Rupture of MPC Dewatering, Vacuum, FHD, or Related Closure System Lines or Equipment
- Failure of the LPT or Crane Handling Systems

9.1.4.3.10.3.3 Fires

The DCPP fire protection program is described in Section 9.5.1. The program incorporates the requirements of the ISFSI fire analyses, such that the required controls are provided to ensure the plant and the ISFSI components remain within their licensing bases.

Inside the FHB

The transporter and its associated fuel tank remain outside of the buildings. However, transient materials brought into the FHB associated with dry cask storage activities could provide additional fire loading. These activities and materials are under the control of DCPP's fire protection program. The current program ensures that ignition sources are monitored and that combustible loading requirements for the FHB areas are followed. To the extent practical, combustibles are kept away from the transfer cask to minimize the effects of any potential fire.

Outside the FHB

The fire protection program ensures potential fires during the transport and storage are handled consistently with the plant program requirements and meet the assumptions described in the Diablo Canyon ISFSI UFSAR. Prior to any cask transport, a walkdown is performed to ensure local combustible materials, including transient combustibles, are controlled in accordance with ISFSI fire protection requirements.

9.1.4.4 Tests and Inspections

As part of normal plant operations, the fuel handling equipment is inspected for operating conditions prior to each refueling operation. During the operational testing of this equipment, administrative controls are followed that will affirm the correct performance of the FHS interlocks.

Prior to each cask loading operation, the fuel and cask handling equipment is inspected for operating conditions During operational testing of the equipment, procedures are followed to affirm the correct performance of interlocks and controls.

9.1.4.5 Instrumentation Applications

For instrumentation and control systems for the FHS, refer to Section 9.1.4.3.3.

9.1.5 REFERENCES

1. Deleted in Revision 24.

2. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

3. U.S. Atomic Energy Commission, "Fuel Storage Facility Design Basis," Safety Guide 13, March 1971.

4. IEEE Standard, 279-1971, Criteria for Protection Systems for Nuclear Power Generating Stations, The Institute of Electrical and Electronics Engineers, Inc.

5. NRC Letter to PG&E, dated May 30, 1986, granting License Amendments No. 8 to Unit 1 and No. 6 to Unit 2.

6. License Amendment Request 95-01, submitted to the NRC by PG&E Letters DCL-95-28, dated February 6, 1995; DCL-95-063, dated March 23, 1995; DCL-95-112, dated May 22, 1995; and DCL-95-178, dated August 22, 1995.

7. PG&E Letter (DCL-96-111) to the NRC, “Response to NRC Bulletin 96-02, ‘Movement of Heavy Loads Over Spent Fuel, Over Fuel in the Reactor Core, or Over Safety-Related Equipment,’” dated May 13, 1996.

8. License Amendment Request 01-02, Credit for Soluble Boron in the Spent Fuel Pool Criticality Analysis, PG&E Letter DCL-01-096, dated September 13, 2001, supplemented by PG&E Letter DCL-02-022, dated February 27, 2002.

9. License Amendments 154/154, Credit for Soluble Boron in the Spent Fuel Pool Criticality Analysis, issued by the NRC, September 23, 2003.

10. License Amendment Request 02-03, Spent Fuel Cask Handling, PG&E Letter DCL-02-044, dated April 15, 2002.

11. License Amendments 162 and 163, Spent Fuel Cask Handling, issued by the NRC, September 26, 2003.

12. Diablo Canyon ISFSI Final Safety Analysis Report Update.

13. PG&E Letter (DCL-03-126) to the NRC, “Request for Exemption from 10 CFR 50.68, Criticality Accident Requirements, for Spent Fuel Cask Handling,” dated October 8, 2003, supplemented by PG&E Letters (DCL-03-150 and DIL-03-014), “Response to NRC Request for Additional Information Regarding Potential Boron Dilution Events with a Loaded MPC in the DCPP SFP,” dated November 25, 2003.

14. NRC Letter to PG&E, dated January 30, 2004, “Exemption from the Requirements of 10 CFR 50.68(b)(1).”

15. License Amendment Request 04-07, Revision to Technical Specifications 3.7.17 and 4.3 for Cycles 14-16 for a Cask Pit Spent Fuel Storage Rack, PG&E Letter DCL-04-149 dated November 3, 2004.

16. Deleted in Revision 20.

17. Deleted in Revision 20.

18. NRC Generic Letter GL 80-113, “Control of Heavy Loads,” December 22, 1980.

19. PG&E Letter to NRC, “Control of Heavy Loads (NUREG-0612),” September 30, 1982.

20. PG&E Letter to NRC, “Control of Heavy Loads (NUREG-0612),” May 9, 1983.

21. NEI 08-05, “Industry Initiative on Control of Heavy Loads,” July 2008.

22. NRC Safety Evaluation, “NEI 08-05, Revision 0, Industry Initiative on Control of Heavy Loads,” September 5, 2008.

23. PG&E Calculation SAP DIR No. 9000040722, Legacy HID-12, Binder No. MR-11 (S&L Calculation 2008-13003, “Analysis of Postulated Reactor Vessel Head Drop for DCPP,” Proprietary and Confidential, Sargent & Lundy, LLC).

24. Westinghouse Calculation No. A-DP1 -FE-0001, "DCPP Units 1 &2 Spent Fuel Criticality Analysis," September 2001.

25. PG&E Vendor Document 6021773-88, "WCAP-16985-P Revision 2, DCPP Tavg & Tfeed Ranges Program NSSS Engineering Report," April 2009.

26. Holtec Report HI-931 077 Revision 3, "Criticality Safety Evaluation of Region 2 of the Diablo Canyon Spent Fuel Storage Racks w/ 5% Enrichment," June 1995.

27. PG&E Letter (DCL-12-117) to NRC, “Summary of Regulatory Commitment Changes January 1, 2011, Through December 31, 2011,” Dated November 20, 2012.

28. NRC Supplemental Safety Evaluation Report (SSER) 31 for Diablo Canyon Power Plant, April 1985.

29. PG&E Calculation SAP Dir No. 9000041782, Legacy / S&L No. 2015-05116, “Analysis of Postulated Reactor Coolant Pump Motor Drop For DCPP,” Proprietary and Confidential, Sargent & Lundy, LLC.

9.1.6 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

9.2 WATER SYSTEMS

This section describes all of the auxiliary water supply and cooling water systems in the plant except for the fire protection system, which is discussed in Section 9.5.1 and the seawater supply to the service cooling water (SCW) heat exchangers, which is described in Section 10.4.5. Water used in the plant is a combination of processed seawater and well water.

9.2.1 SERVICE COOLING WATER SYSTEM

The SCW system, shown in Figure 3.2-15, is a closed system used to cool equipment in the secondary or steam and power conversion portion of the plant, as well as miscellaneous air conditioning systems. The SCW system is classified as PG&E Design Class II (refer to Section 3.2). Since no PG&E Design Class I components are cooled by the SCW system, complete shutdown of the system does not affect safe operation or shutdown of the reactor. The design requirements for flow are based on the heat load demands of the various components cooled by the SCW system.

9.2.1.1 Design Bases

9.2.1.1.1 General Design Criterion 4, 1967 – Sharing of Systems

The SCW system is not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

9.2.1.1.2 Service Cooling Water System Function Requirements

(1) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

SCW system failures are evaluated for the effects of moderate energy pipe failure on PG&E Design Class I equipment to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(2) Protection from Flooding Effects

SCW system header failure is evaluated for the effects of flooding on PG&E Design Class I equipment.

9.2.1.2 System Description

The SCW system is a closed system that supplies buffered cooling water for the following plant equipment:

(1) Post-accident sample room air conditioning

(2) Onsite technical support center (TSC) air conditioning condenser

(3) Personnel access control area air conditioning

(4) Plant air compressors and aftercoolers

(5) Plant air dryer cooler

(6) Main Steam lead, SG blowdown, and feedwater heater 1 outlet header sample coolers

(7) Main turbine lube oil reservoir coolers

(8) Condenser vacuum pump seal water cooler

(9) Electrohydraulic control coolers

(10) Feedwater sample coolers

(11) Heater 2 drain tank pump discharge sample coolers

(12) Heater No. 2 drain pump

(13) Secondary process control room isothermal bath water chiller

(14) Main feedwater pumps 1 and 2 lube oil coolers

(15) Condensate pump motor upper bearing coolers

(16) Condensate booster pump lube oil coolers

(17) Air conditioning for operation ready room (Unit 2 only)

(18) Generator exciter coolers

(19) Fuse wheel cooler

(20) Stator coil cooling water corrosion sampler and sample cooler (Unit 1 only)

(21) Generator seal oil coolers

(22) Isophase bus coolers

The SCW heat exchangers are normally cooled by the circulating water system (CWS) described in Section 10.4.5; however, alternative cooling supplies are available. Makeup water to the system is from the PG&E Design Class II portion of the MWS

described in Section 9.2.3. This is controlled automatically by the level in the service water head tank.

9.2.1.3 Safety Evaluation

9.2.1.3.1 General Design Criterion 4, 1967 – Sharing of Systems

The DCPP Unit 1 and Unit 2 SCW systems have the ability to cross-connect through the SCW system headers. The SCW system is PG&E Design Class II and not designed to remain functional when subjected to DE, DDE, or HE seismic loads. No PG&E Design Class I components are cooled by the SCW system. Therefore, safety is not impaired by sharing because the SCW system is not necessary to assure: the integrity of the reactor coolant pressure boundary (RCPB); the capability to shut down the reactor and maintain it in a safe shutdown condition; or the capability to prevent or mitigate the consequences of accidents which could result in the release of substantial amounts of radioactivity.

9.2.1.3.2 Service Cooling Water System Function Requirements

(1) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The PG&E Design Class I systems are designed to be protected against the effects of SCW system moderate energy pipe failures to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(2) Protection from Flooding Effects

The low operating pressure and temperature of the SCW system minimizes the probability of line failures. The physical location of the lines and components cooled by the SCW system is such that the failure of a SCW system header would not create an adverse environment for any PG&E Design Class I components.

9.2.1.4 Tests and Inspections

The operating components are in either continuous or intermittent use during normal plant operation, and no additional periodic tests are required. Periodic visual inspections and preventive maintenance are conducted in accordance with normal plant operating practices.

9.2.1.5 Instrumentation Applications

The operation of the system is monitored with the following instrumentation:

(1) High and low level alarms in the service water head tank

(2) Automatic pump start pressure switches on the common pump discharge

(3) Temperature sensing devices at:

(a) Main turbine reservoir lube oil coolers outlet

(b) SCW supply header

(c) Isophase bus cooler fans hot air inlet

(d) Generator exciter and fuse wheel cooler water return

(e) Post-accident sample room air conditioning system inlet and outlet

(f) Onsite TSC air conditioning cooling water inlets and outlets

(g) Personnel access control area air conditioning inlets and outlets

(4) Pressure sensing devices at:

(a) SCW pumps outlet

(b) CCW chemical addition system

(c) SCW heat exchanger inlets and outlets

(d) Main turbine lube oil coolers water supply

(e) Post-accident sample room air conditioning system inlet and outlet

(f) SCW filter inlets and outlets

(g) Onsite TSC air conditioning cooling water inlets and outlets

(h) SCW booster pumps inlet and outlet

9.2.2 COMPONENT COOLING WATER SYSTEM

The CCW system, shown in Figure 3.2-14, is a closed-cycle cooling system that transfers heat from nuclear (primary) plant equipment and other systems/components (refer to Table 9.2-4) during normal plant operation, plant cooldown, and following a LOCA or main steam line break (MSLB) to the auxiliary saltwater (ASW) system. Except for normally closed makeup lines and seal water make-up to the waste gas compressor, there is no direct connection between the CCW system and other systems. The CCW system provides a monitored intermediate barrier between equipment and components handling radioactive fluids and the ASW system.

9.2.2.1 Design Bases

9.2.2.1.1 General Design Criterion 2, 1967 - Performance Standards

The CCW system is designed to withstand the effects of or is protected against natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

9.2.2.1.2 General Design Criterion 3, 1971 - Fire Protection

The CCW system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.2.2.1.3 General Design Criterion 4, 1967 - Sharing of Systems

The CCW systems or components are not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

9.2.2.1.4 General Design Criterion 11, 1967 - Control Room

The CCW system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

9.2.2.1.5 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain CCW system variables within prescribed operating ranges.

9.2.2.1.6 General Design Criterion 17, 1967 - Monitoring Radioactivity Releases

The CCW system is designed to provide means for monitoring the facility effluent discharge paths, and the facility environs for radioactivity that could be released from normal operations, from anticipated transients and from accident conditions.

9.2.2.1.7 General Design Criterion 40, 1967 – Missile Protection

The containment isolation portion of the CCW system is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

9.2.2.1.8 General Design Criterion 53, 1967 - Containment Isolation Valves

CCW system containment penetrations that require closure for the containment isolation function are protected by redundant valving and associated apparatus.

9.2.2.1.9 General Design Criterion 57, 1967 - Provisions for Testing Isolation Valves

The CCW system provides capability for testing functional operability of valves and associated apparatus essential to the containment function for establishing that no failure has occurred and for determining that valve leakage does not exceed acceptable limits.

9.2.2.1.10 Component Cooling Water System Safety Function Requirements

(1) Waste Heat Removal

The CCW system is designed to remove waste heat from the nuclear (primary) plant equipment and components during normal plant operation, plant cooldown, and design basis accidents.

(2) Single Failure

The CCW system and ASW system are essentially considered a single heat removal system for the purpose of assessing the ability to sustain either a single active or passive failure and still perform design basis heat removal.

(3) Redundancy

The CCW system components considered vital are redundant.

(4) Isolation

The CCW system includes provision for isolation of system components and may be split into separate trains during long term post-LOCA conditions.

(5) Protection from Missiles

Vital portions of the CCW system are designed, located, or protected against the effects of missiles which may result from plant equipment failure and from events and conditions outside the plant to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(6) Protection Against High Energy Pipe Rupture Effects

Vital portions of the CCW system are designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(7) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The outside containment portion of the vital CCW system is designed to be protected against the effects of moderate energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(8) Protection from Jet Impingement – Inside Containment

The inside containment portion of the vital CCW system is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(9) Protection from Flooding Effects – Outside Containment

The outside containment portion of the vital CCW system is designed to be protected from the effects of internal flooding to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(10) Leak Detection

The CCW system serves as an intermediate system between normally or potentially radioactive systems and the ASW system.

9.2.2.1.11 10 CFR 50.49 - Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

CCW system electric components that require environmental qualification (EQ) are qualified to the requirements of 10 CFR 50.49.

9.2.2.1.12 10 CFR 50.55a(f) - Inservice Testing Requirements

CCW system ASME Code components are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

9.2.2.1.13 10 CFR 50.55a(g) - Inservice Inspection Requirements

CCW system ASME Code components (including supports) are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

9.2.2.1.14 10 CFR 50.63 - Loss of All Alternating Current Power

The CCW system is required to provide cooling water to the reactor coolant pump (RCP) thermal barriers, the operating CCW pump cooler, the operating centrifugal charging pump coolers, and the seal water heat exchanger in the event of a Station Blackout (SBO).

9.2.2.1.15 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The CCW system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

9.2.2.1.16 Regulatory Guide 1.97 Revision 3, May 1983 - Instrumentation for Light-Water Cooled Nuclear Power Plants to Assess Plant and Environs Condition During and Following an Accident

The CCW system provides instrumentation to monitor CCW flow and temperature and containment isolation valve (CIV) position indication on the monitor light box (for applicable CCW valves) during and following an accident.

9.2.2.1.17 NUREG-0737 (Item II.K.3.25), November 1980 – Clarification of TMI Action Plan Requirements

Item II.K.3.25 – Effect of Loss of Offsite AC Power on RCP Seals: The CCW system is designed such that the RCP seals can withstand a complete loss of offsite alternating current power for at least two hours.

9.2.2.1.18 Generic Letter 89-10, June 1989 - Safety Related Motor-Operated Valve Testing and Surveillance

The CCW system safety related and position changeable motor-operated valves (MOVs) meet the requirements of Generic Letter 89-10, June 1989 and associated Generic Letter 96-05, September 1996.

9.2.2.1.19 Generic Letter 89-13, July 1989 - Service Water System Problems Affecting Safety Related Equipment

The CCW system heat exchangers are subject to monitoring and maintenance programs to ensure capability to perform their safety function as an alternative to a testing program. Maintenance practices, operating and emergency procedures, and training ensure effectiveness of these programs.

9.2.2.1.20 Generic Letter 96-06, September 1996 - Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions

The CCW system is designed so that it is not subject to the hydrodynamic effects of water hammer, reduced cooling effectiveness due to two phase flow conditions, or thermal overpressurization of isolated piping sections that could affect containment integrity during design basis accident conditions, as described in Generic Letter 96-06, September 1996.

9.2.2.2 System Description

The CCW system is designed to provide cooling water to vital and nonvital components and to operate in all plant operating modes, including normal power operation, plant cooldown, and emergencies, including a LOCA or MSLB.

The CCW system includes three CCW pumps, two CCW heat exchangers, and an internally baffled CCW surge tank as described in Table 9.2-3. The piping system consists of three parallel headers. Two are separable redundant vital service headers A and B, which serve only the unit's engineered safety feature (ESF) equipment and the post-LOCA sample cooler (header A only). A miscellaneous service loop C serves nonvital equipment. Except for normally closed makeup lines and seal water make-up to the waste gas compressor, there is no direct connection between the CCW system and other systems. The equipment cooled is tabulated in Table 9.2-4. Nominal flows for major CCW system operating modes are tabulated in Table 9.2-5.

Cooling water for the CCW heat exchangers is supplied from the ASW system. Together, CCW/ASW support heat transfer to the ultimate heat sink (UHS). The CCW system serves as an intermediate system between the RCS and ASW system, ensuring that any leakage of radioactive fluid from the components being cooled is contained within the plant.

Operation under normal and accident conditions will be as follows:

(1) Normal Operation

During normal operation, all loops are in operation. Two CCW pumps and one or two CCW heat exchangers are in use and are capable of serving all operating components. The third pump and the second heat exchanger generally provide backup during normal operation.

(2) Plant Cooldown

During the cooldown phase of a unit shutdown, all loops are operated with two or three pumps and two heat exchangers used for the removal of residual and sensible heat from the RCS through the RHR system (refer

to Figure 3.2-10). If one of the pumps or one of the heat exchangers is inoperative, orderly shutdown is not affected, but the time for cooldown is extended.

(3) Accident Conditions

In the event of a LOCA or MSLB, three CCW pumps are placed in service to provide protection against an active failure. The safety injection (SI) signal initiates an automatic start signal for the standby CCW pump. When containment pressure reaches the high containment pressure setpoint, a Phase A isolation signal is generated and CCW flow to the excess letdown heat exchanger is isolated. When the containment pressure reaches the high-high containment pressure setpoint (containment Phase B isolation), a signal to close the C (non-vital) header isolation valve is generated because components on the C header are not required for post-accident cooling. The portion of the non-vital header that serves the RCPs and vessel support coolers located within the reactor primary shield wall is independently isolated (Phase B), due to its vulnerability during a LOCA, to assure isolation

The CCW system is required to provide cooling water to the ESF pump coolers and the containment fan cooler units (CFCUs) during the injection and recirculation phase of a LOCA and during an MSLB. The CCW system is flow balanced to ensure that adequate flow is maintained to each component. Following the post-LOCA injection phase, the CCW system is realigned for the recirculation phase by valving in the RHR heat exchangers to cool the water collected in the containment sump. Additionally, if a containment Phase B isolation signal has occurred but the C header does not automatically isolate during the injection phase, it is manually isolated prior to realignment for recirculation.

The additional heat load on the CCW system is controlled by plant operators by limiting the heat input equipment (operating CFCUs and RHR heat exchangers) based on the available heat removal equipment (operating CCW heat exchangers and ASW pumps) to prevent the CCW system supply temperature from exceeding its design basis limit.

During long-term post-accident recirculation operation, the CCW system may be manually realigned into two separate redundant loops. Each loop has a pump and a heat exchanger and is capable of fulfilling the minimum long-term cooling requirements. This provides protection against a passive failure in one loop. Should one loop fail, the other loop is unaffected, and the ESF components that it serves remain operative.

Due to its vulnerability to a loss of inventory, the CCW system should be split into separate trains as soon as possible after aligning for long-term post

LOCA recirculation if plant conditions are acceptable. The decision to split CCW trains will be made by the TSC based on the physical integrity of the trains, the availability of active components, and the reliability of power systems. This long-term post-accident alignment provides further assurance of the capability to withstand a passive failure (Reference 8).

Design data for some major CCW system equipment are listed in Table 9.2-3. The CCW system consists of the following major pieces of equipment.

9.2.2.2.1 Component Cooling Water Pumps

The three CCW pumps that circulate CCW through the CCW system are horizontal, double suction, centrifugal units. The pumps operate on electric power from the Class 1E 4.16-kV buses that can be supplied from either normal or emergency sources.

9.2.2.2.2 Component Cooling Water Heat Exchangers

The two CCW heat exchangers are shell and tube type. Seawater circulates through the tube side. The shell is carbon steel, and the tubes are 90-10 Cu-Ni.

9.2.2.2.3 Component Cooling Water Surge Tank

The CCW surge tank, which is connected by two surge lines to the vital headers on the pump suction piping, is constructed of carbon steel. The tank is internally divided into two compartments by a partial height partition to hold two separate volumes of water. This arrangement provides redundancy to accommodate a passive failure when the CCW system is manually realigned into two trains.

The surge tank accommodates thermal expansion and contraction, and in- or out-leakage of water from the system. The tank is normally pressurized with nitrogen to a minimum of 17 psig to provide sufficient static head to prevent boiling and two-phase flow conditions in the CCW to the CFCUs during a postulated large break LOCA coincident with a loss of offsite power. The primary source of nitrogen is the Class II nitrogen system (Reference 7).

A back-pressure regulator is provided downstream of the surge tank vent valve to prevent the pressure in the surge tank from exceeding the desired pressure range. This back-pressure control valve maintains surge tank pressure at all times at its setpoint by relieving excess nitrogen to the atmosphere. The surge tank vent valve closes when a high radiation level is detected by radiation monitors provided in the CCW pump discharge headers. The monitor also actuates an alarm in the control room.

In the event of a low level in the surge tank, makeup water is automatically added to the system through control valves from the MWS (refer to Section 9.2.3).

9.2.2.2.4 Chemical Addition System

The closed chemical addition system supplies various treatment chemical solutions to the CCW. The system contains chemical addition tanks, an injection pump, pressure and flow indication, and a fume hood for personnel protection. The system is common to Unit 1 and Unit 2 CCW and also supplies chemicals to the SCW.

9.2.2.2.5 Component Cooling Water Corrosion Monitor

A corrosion test loop is provided to monitor the effectiveness of the corrosion inhibitor used in the CCW system. The test loop consists of four coupon locations and two spare connections for future use. Test coupons of representative materials are exposed to CCW system conditions for a period of time and then analyzed to determine the overall corrosion rates.

9.2.2.2.6 Residual Heat Removal Heat Exchangers

Control room operated air-actuated valves control the CCW flow to the RHR heat exchangers (refer to Chapter 5) in order to place these components in service during plant cooldown or after a LOCA. The valves, which open on loss of air, are provided with a PG&E Design Class I backup air supply to allow positive operator control after loss of the plant compressed air system.

9.2.2.2.7 Containment Fan Coolers

CCW is supplied to the containment fan coolers (refer to Chapter 6) by the two vital headers. Two fan coolers are on loop A and three on header B. Drain and isolation valves are provided on each side of the fan coolers allowing each cooler to be isolated individually for leakage testing. The flow of CCW through the fan coolers is throttled (position fixed) by a manual valve downstream of each fan cooler to ensure adequate flow to support design basis accident analyses as discussed below. The air-actuated temperature control valves, provided originally to limit the flow to the CFCUs, are not required. Therefore, instrument air to these valves has been isolated and the valves remain in the fully open position.

The above valve alignment assures minimum required flow through each fan cooler under accident conditions without any immediate automatic or operator action. The only required manual action would be header C isolation when transferring to post-LOCA recirculation.

The ability of the CCW system to adequately remove heat from containment without overheating the CCW fluid is demonstrated by several transient analyses. For determining adequate containment heat removal, the minimum CCW flow rate to CFCUs is 1600 gpm to the cooling coils. For determining maximum CCW temperature, the maximum CCW flow rate to CFCU cooling coils is 2500 gpm. Data presented in Tables 9.2-5 and 6.2-26 are nominal data that are enveloped by these extremes. CCW

is also supplied to a separate cooling coil located in the CFCU motor enclosure. This cooling flow path is in parallel to the CFCU cooling coil flow path.

Specific conditions, such as inlet and outlet temperatures to the CFCUs, are dynamically calculated and vary over the course of the transient according to the scenario assumptions.

9.2.2.2.8 Reactor Vessel Supports

Cooling water is provided to the RV supports (refer to Chapter 3) to prevent overheating and dehydration of the concrete for the RV support shoes. This is accomplished by the use of water-cooled steel blocks between each of the four vessel support pads and its support shoe. CCW flows in labyrinth flow passages in the blocks providing heat removal sufficient to prevent the concrete from dehydrating.

9.2.2.2.9 Valves

The valves in the CCW system are standard commercial valves constructed of carbon steel with carbon steel, bronze, or stainless steel trim. Since the CCW is normally not radioactive, special features to prevent leakage to the atmosphere are not provided. Self-actuated spring-loaded relief valves are provided for lines and components that may be pressurized to above their design pressure by improper operation or malfunction. The valves associated with CCW pumps, the CCW heat exchangers, large piping and associated instrumentation are located outside the containment and are therefore available for maintenance and inspection during power operation.

CCW valves associated with containment isolation are discussed as a part of the containment isolation system (CIS) (refer to Section 6.2.4).

The equipment vent and drain lines have manual valves that are normally closed (the surge tank vent line has an automatic back-pressure regulator that is also normally closed) unless the equipment is being vented or drained for maintenance or repair operations.

The relief valves on the CCW lines downstream of the sample, letdown, seal water, SFP, and RHR heat exchangers are sized to relieve the volumetric expansion occurring if the exchanger shell-side is isolated and high-temperature coolant flows through the tube side. The relief pressures do not exceed 150 psig.

Relief valves for volumetric expansion are provided on the downstream side of the waste gas compressor heat exchanger and the abandoned in place boric acid and waste evaporator condenser. Relief pressures do not exceed 150 psig. Waste gas compressor relief and evaporator packages relief is back to the return line downstream of the respective shutoff valve.

The relief valve on the CCW surge tank is sized to relieve the maximum flow-rate of water that could enter the surge tank following an RHR heat exchanger tube rupture. The discharge from this valve is directed to the skirted area under the surge tank and then enters a floor drain routed to the auxiliary building sump.

9.2.2.2.10 Piping

All piping components of the CCW system are designed to the applicable codes and standards listed in Table 3.2-3. CCW system piping is carbon steel, with welded joints and flanged connections at components, and designed to USAS B31.7 for Class II and Class III pipe. A molybdate blend solution is added to the CCW as a corrosion inhibitor.

9.2.2.2.11 Component Cooling Water Filter Housing

The CCW side-stream filter is provided in order to remove particulates in the CCW system. The filter housing is designed for 150 psig at 200°F.

9.2.2.2.12 Radiation Monitoring

Leaks in components being cooled are detected by radiation monitors located in the two CCW pump discharge headers. Because the discharge of all three CCW pumps is into these two headers, the flow from any combination of pumps placed in operation is monitored continuously. During normal plant operations, the inservice CCW pump discharge header is determined by which of the two CCW heat exchangers is operating (refer to Figure 3.2-14). A single failure in the radiation monitoring system on the discharge header in operation alarms in the control room. The operator can take action to correct the problem or to put into operation the redundant heat exchanger and header. This action places the redundant radiation monitoring system into operation. During operation with both heat exchangers in service, both radiation monitors are in service continuously. Because of the discharge piping configuration, only the radiation monitor associated with the in-service CCW heat exchanger is sampling flow representative of the bulk system.

The CCW may become contaminated with radioactive water from any of the following sources:

(1) Leakage in any heat exchanger tube or tubesheet in the CVCS, the nuclear steam supply system (NSSS) sampling system, the RHR system, the SFP cooling system, or the gaseous radwaste system

(2) Leakage in a cooling coil for the thermal barrier cooler on a RCP

(3) Leakage in a containment fan cooler coil following an accident

9.2.2.3 Safety Evaluation

Refer to Section 3.1 for a more comprehensive discussion of General Design Criteria applicable to DCPP. In addition to Section 3.1, other sections are referenced, where appropriate, for individual design basis requirements discussed under 9.2.2.3.

9.2.2.3.1 General Design Criterion 2, 1967 - Performance Standards

The buildings that contain the majority of the CCW system SSCs (containment, auxiliary and FHB, and the turbine building) are PG&E Design Class I or QA Class S (refer to Section 3.8). These buildings or applicable portions thereof are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunami (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other appropriate natural phenomena and to protect CCW SSCs, and their safety functions, from damage due to these events. The loss of CCW components that are not contained within these buildings, and are directly exposed to potential wind and tornado loads, has been evaluated. Loss of this equipment does not compromise the capability to safely shut down the plant (refer to Section 3.3.2.3).

The CCW system SSCs important to safety are designed to perform their safety functions under the effects of earthquakes. The PG&E Design Class II portions of CCW (except the chemical addition system) as well as components from other systems served by the non-vital CCW header (header C) have been analyzed to the same seismic requirements as for the CCW PG&E Design Class I components to ensure pressure boundary integrity is maintained. The chemical addition system is not required for the system to perform its safety function and is normally isolated at the PG&E Design Class I to Class II code break boundary.

The makeup water for the CCW surge tank is provided by the MWS. This source is backed up by several alternative sources, including the CST. Seismic design capability of makeup sources is discussed in Section 9.2.3.

The primary source of nitrogen pressurization for the CCW surge tank is the nonseismically-qualified PG&E Design Class II nitrogen system. If this supply is lost, PG&E Design Class I nitrogen is automatically supplied from dedicated bottles. The Class II plant instrument air supply (with a normally closed valve) is also available to provide the required pressurization of the tank.

9.2.2.3.2 General Design Criterion 3, 1971 - Fire Protection

The CCW system is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.2.2.3.3 General Design Criterion 4, 1967 - Sharing of Systems

The design basis of the CCW system does not require sharing of SSCs between Unit 1 and Unit 2 because each unit has its own CCW system. A means to cross-tie the Unit 1 and Unit 2 CCW systems (valving associated with the spare waste gas compressor piping) is available in the event of a loss of surge tank for supplying CCW from a unit with an operating CCW system to a unit with an inoperable system (e.g., to permit shutdown). However, the associated valves to Unit 2 CCW are normally closed and cross-connection is procedurally controlled. Therefore, safety is not impaired by the sharing.

9.2.2.3.4 General Design Criterion 11, 1967 - Control Room

Appropriate CCW system instruments and controls are provided to permit system operation from the control room (refer to Section 9.2.2.5). The CCW pumps are designed to be remotely operated from the hot shutdown panel (HSP) in the event that the main control room is uninhabitable (refer to Section 7.4.2.1.2.2).

9.2.2.3.5 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Required controls for CCW components are provided for system operation. Instrumentation is provided for monitoring CCW system parameters during normal operations and accident conditions (refer to Section 9.2.2.5).

9.2.2.3.6 General Design Criterion 17, 1967 - Monitoring Radioactivity Releases

A radiation monitor associated with each of the two CCW pump discharge headers monitors the CCW system for radioactive in-leakage. Because the discharge of all three CCW pumps is into these two headers, the flow from any combination of pumps placed in operation is monitored continuously.

9.2.2.3.7 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the containment isolation portion of the CCW system from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures are discussed in Sections 3.5, 3.6, and 6.2.4.

9.2.2.3.8 General Design Criterion 53, 1967 - Containment Isolation Valves

The CCW system containment penetrations that are credited as part of the CIS include CCW supply/return for containment fan cooler (Group D), RCP (Group A), and excess letdown heat exchangers (Group C). These lines can be isolated remotely from the control room. The configuration / requirements for each Group are described in Section 6.2.4.2 and a description of the isolation valves / piping configuration for each penetration is provided in Table 6.2-39.

9.2.2.3.9 General Design Criterion 57, 1967 - Provisions for Testing Isolation Valves

CCW system piping that penetrates containment is provided with the capability for leak detection and operability testing. Most of the piping, valves, and instrumentation inside the containment, including the vital components, are located outside the crane wall at an elevation above the water level in containment following an accident. Exceptions are the cooling lines for the RCPs and the RV support which are on miscellaneous nonvital header "C." This location affords radiation shielding which permits maintenance and inspection during power operation if required.

9.2.2.3.10 Component Cooling Water System Safety Function Requirements

A malfunction analysis of pumps, heat exchangers, and valves is presented in Table 9.2-7.

(1) <u>Waste Heat Removal</u>

The CCW system is designed to remove waste heat from nuclear (primary) plant equipment and components during normal plant operation, plant cooldown, and accident conditions. Analytical results show that the CCW system performs adequately during design basis accidents while providing cooling to all safety-related components cooled by CCW. In the event of a LOCA or MSLB, non-vital / unnecessary heat loads are isolated and analyses demonstrate that the CCW system does not exceed its design basis temperature limit under maximum mechanistically calculated heat loads. At least two CCW pumps must be in operation to ensure that the minimum CCW flow rates are achieved.

Safety analyses for containment peak pressure demonstrate that only one ASW pump and one CCW heat exchanger is required to provide sufficient heat removal from containment to mitigate a MSLB or LOCA (refer to Section 6.2). The analyses were performed assuming minimum CCW flow rate to the CFCUs. Other critical assumptions incorporated into those analyses include the CCW flow rate to the CCW heat exchanger, and CCW heat exchanger UA (heat transfer index and area of the heat exchanger, refer to Section 6.2).

Analyses that demonstrate the CCW system does not exceed its design basis temperature limit following a LOCA or MSLB credit one or two ASW pumps, depending on the assumed single failure. A single CCW heat exchanger was assumed to be in service throughout the transient (except as noted in Section 9.2.2.2). These analyses assume single failures that maximize heat input to the CCW system and maximum flow rates consistent with the system flow balance. The limiting post-LOCA injection phase CCW temperature transient is a solid state protection system Train A failure scenario. The limiting post-LOCA recirculation phase CCW temperature transient results from a solid state protection system Train A failure scenario that conservatively assumes that only three CFCUs are in operation during the injection phase. The highest peak CCW temperature following an MSLB results from a double ended rupture at 70 percent power with the failure of a feedwater regulation valve. All of the limiting CCW temperature analyses assume 64°F ocean water and a single CCW heat exchanger in service. A separate set of analyses assuming a 70°F ocean water temperature credit two CCW heat exchangers in service to address operation with an elevated UHS temperature (Reference 3). Technical Specifications require that the second CCW heat exchanger be placed in service when the UHS temperature is greater than 64°F.

The CCW system is qualified for a maximum post-accident supply temperature of 140°F for a period of up to 6 hours, and a long-term continuous supply temperature of 120°F. Therefore, predicted CCW temperatures during both normal and accident conditions are within the limits of the CCW system temperature qualification.

(2) Single Failure

The CCW system is designed to continue to perform its safety function following an accident assuming a single active failure during the short-term recovery period and either a single active or passive failure during the long-term recovery period. Refer to Section 3.1.1 for a description of DCPP single failure criteria and definition of terms. During normal operation and up to 24 hours after an accident (the short-term recovery period), the CCW headers are crosstied. This configuration will withstand a single active failure without the loss of safety function. For a passive failure (up to a 200 gpm leak for 20 minutes), operator mitigation action (consisting of valve manipulations) is credited to stop leaks (refer to Table 9.2-7). The CCW headers are evaluated for separation, per procedure, during long term post LOCA recirculation. When separated during the remainder of the recovery period, this configuration will withstand either an active failure or a passive failure without the loss of safety function.

(3) Redundancy

The CCW system components that are considered vital are redundant. The redundant vital CCW headers served by headers A and B supply cooling water to the containment fan coolers, the RHR heat exchangers, each redundant set of ESF pumps (SI, centrifugal charging, and RHR), and the CCW pumps. The automatic flow cutoff (closure of inlet valve) of the non-vital header (served by header C) on containment Phase B isolation is not redundant and operator action is credited prior to realignment

for recirculation if automatic isolation fails. However, analyses that assume a failure to isolate during the LOCA injection phase, or during an MSLB, demonstrate that CCW heat removal capability continues to support post-accident cooling requirements without exceeding design temperature limitations (140°F peak and 120°F for six hours).

The three CCW pump motors are on separate Class 1E 4.16-kV buses that have diesel generator standby power sources. The CCW surge tank, which is connected by two surge lines to the vital headers near the pump suction, is internally divided into two compartments by a partial height partition to hold two separate volumes of water. This arrangement provides redundancy to accommodate a passive failure when the CCW system is manually realigned into two trains. In the event of loss of the PG&E Design Class II nitrogen supply, PG&E Design Class I nitrogen is supplied from dedicated bottles, or the plant instrument air system will be available to provide the required pressurization of the tank.

Makeup water is supplied to the CCW system through two redundant makeup valves feeding into the two redundant CCW surge lines, described in Section 9.2.3 and schematically shown in Figure 3.2-14. These air-actuated level control valves (LCVs) open automatically when surge tank level decreases below the associated setpoint, and normal operating conditions for the MWS allow immediate makeup to the CCW system through the makeup valves whenever they open.

Redundant radiation monitors are provided in the system for detection of radioactivity entering the CCW system from the RCS and its associated auxiliary systems.

(4) Isolation

The CCW piping design includes valving for isolating cooling water flow associated with individual components and for complete isolation of a header. In addition to facilitating maintenance and testing, valving is used to: 1) stop leaks from / into the CCW system, 2) prevent an unmonitored release in the event of a radiation monitor alarm, 3) isolate non-vital header C to accommodate higher heat load under accident conditions, 4) separate CCW into two trains to enhance protection against passive failure for long term accident recovery.

Leaks from the CCW system arise from open drain valves or severed piping, ruptured heat exchanger tube, or other malfunction. The location of a leak can be determined by sequential isolation or visual inspection of equipment and hence stopped by closing the appropriate valve(s). Refer to Table 9.2-7 for an evaluation of leakage from the system.

Leaks into the CCW system can result from heat exchanger tube failures. For the RCP thermal barrier, the system design is to contain the in-leakage to the CCW system within the containment structure. This is accomplished by closure of the outboard CIV associated with return of CCW from all RCP thermal barriers on a high flow signal. All piping and valves required to contain this in-leakage are designed for an RCS design pressure of 2485 psig. Should a coolant leak develop from the postulated failure mode

that does not result in automatic flow isolation, the corresponding increase in CCW volume is accommodated by the relief valve on the CCW surge tank. The four relief valves on the CCW returns from thermal barriers are sized to relieve volumetric expansion and are set to relieve at RCS design pressure.

Table 9.2-6 shows components in the CCW system with a single barrier between CCW and reactor coolant water.

As shown in Table 9.2-6, the pressure and temperature design requirements of the barriers in the RHR heat exchangers, the letdown heat exchanger, and the seal water heat exchanger are less than the RCS pressure and temperature during full power operation. For the letdown heat exchanger and the seal water heat exchanger, this condition results because the pressure and temperature of the reactor coolant water are reduced to the values shown in the table before the flow reaches the components.

In the case of the RHR heat exchangers and RHR pumps (seal coolers), the RCS pressure and temperature are reduced to less than or equal to 390 psig and 350°F before the RHR system is brought into service to complete the cooldown of the reactor. The RHR system is protected from overpressurization as discussed in Section 5.5.6.4.10. The controls and interlocks provided for the isolation valves between the RCS and the RHR system are described in Section 7.6.2.1.

Tube failure in components with design pressures and temperatures less than RCS design condition may initiate a leak into the CCW system. The radioactivity associated with the reactor coolant would actuate the CCW system radiation monitor. The monitor in turn would annunciate in the control room and close the vent valve located just upstream of the CCW surge tank back-pressure regulator to prevent the regulator from venting after sensing high radiation. The operator would then take the appropriate action to isolate the failed component. In addition to the radiation monitoring system, the operator would also receive high level and high-pressure alarms from the surge tank as it filled. If the in-leakage continued after the vent valve closed, the surge tank pressure would increase until the high surge tank pressure alarm was received and then the relief valve setpoint was reached. The relief valve on the surge tank will protect the system from overpressurization. The maximum postulated in-leakage into the CCW system is based on an RHR heat exchanger tube rupture. The relief valve will accommodate this flow. Relief valve discharge from the CCW system surge tank is routed to the skirted area under the surge tank, which then enters a floor drain routed to the auxiliary building sump. Refer to Table 9.2-7 for an evaluation of leakage into the CCW system.

Under accident conditions, automatic isolation is initiated for CCW flow to the excess letdown heat exchanger on a containment Phase A isolation signal and for the C (non-vital) header on a containment Phase B isolation signal. Independently, the portion of the C header serving the RCPs and vessel support coolers is also isolated.

(5) Protection from Missiles

The provisions taken to protect the vital CCW system from missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Sections 3.5.

(6) Protection Against High Energy Pipe Rupture Effects

The plant is designed so that a postulated piping failure will not cause the loss of needed functions of safety related systems and structures that would prevent safe shutdown. The measures taken in design and construction of the plant for protection of the vital CCW system against dynamic effects associated with a postulated rupture of high-energy piping both inside and outside containment are discussed in Section 3.6.

CCW SSCs important to safety are designed, located, or protected against dynamic effects. With respect to post-accident conditions in containment, most of the piping, valves, and instrumentation are located outside the crane wall at an elevation above the water level in containment following an accident. Exceptions are the cooling lines for the RCPs and the RV support which are on portions of header C inside the crane wall. The vital portions of the CCW system within the containment are protected during accidents from dynamic effects associated with accidents by routing piping away from high energy lines and from credible internal missiles by separation / barriers (refer to Section 6.2.4.4.6).

(7) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection of the vital portion of the CCW system located outside containment from the effects of moderate energy pipe failure are discussed in Section 3.6.

(8) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the vital portion of the CCW system located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

(9) Protection from Flooding Effects – Outside Containment

The provisions taken to provide protection of the vital portion of the CCW system from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

The CCW pumps, heat exchangers and associated valves, and all of the large piping and instrumentation are located outside containment. Each CCW pump is protected against flooding due to rupture of another because they are located in separate compartments with a raised curb in the doorway to prevent water in the rest of the

auxiliary building from entering the compartment. Check valves are provided on each pump discharge to prevent back leakage into a compartment from an operating pump.

Flooding of the CCW heat exchangers is highly improbable because of their location on the turbine building ground level where there are large door openings to allow water to run out, several floor drains, sumps, and a large condenser pit below the elevation of the heat exchangers. Based on this, operation of the heat exchangers would not be impaired by flooding.

(10) Leak Detection

Leakage from the CCW system can be detected by a decreasing level in the CCW surge tank. Using the tank geometry, an estimate of leakage rate can be determined by timing the change in indicated level. A maximum 200 gpm leak or rupture is postulated. Refer to Table 9.2-7 for a discussion of leakage from the system.

A radiation monitor associated with each of the two CCW pump discharge headers is provided for the CCW system to detect radioactivity entering the CCW system from the RCS and its associated auxiliary systems. In-leakage from components being cooled is detected by a radiation monitor associated with each of the two CCW pump discharge headers. Because the discharge of all three CCW pumps is into these two headers, the flow from any combination of pumps placed in operation is monitored continuously. Leaks can also be detected by surge tank level instrumentation and alarms.

9.2.2.3.11 10 CFR 50.49 - Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

CCW system SSCs required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment. The affected components include valves, switches and flow transmitters and are listed on the EQ Master List.

9.2.2.3.12 10 CFR 50.55a(f) - Inservice Testing Requirements

The inservice testing (IST) requirements for CCW system components are contained in the IST Program Plan and comply with the ASME Code for Operation and Maintenance of Nuclear Power Plants.

9.2.2.3.13 10 CFR 50.55a(g) - Inservice Inspection Requirements

The ISI requirements for CCW system components are contained in the ISI Program Plan and comply with the ASME BPVC Section XI.

9.2.2.3.14 10 CFR 50.63 - Loss of All Alternating Current Power

The CCW system provides for safe shutdown and cooldown of the reactor by removing heat from safety-related system components after a SBO. The CCW system is used to cool the RCP provides cooling water in support of safe shutdown of the plant (Mode 3) following a SBO. Using a single CCW pump and heat exchanger, the system provides cooling water to the RCP thermal barriers to prevent overheating and degradation of the RCP seals following an SBO cooling water to the operating CCW pump and centrifugal charging pump coolers to support proper pump operation, and cooling water to the seal water heat exchanger in the RCP seal leakoff flowpath.

The CCW pumps can be provided with alternate ac (AAC) power within 10 minutes of an SBO event. Refer to Section 8.3.1.6 for further discussion of station blackout.

9.2.2.3.15 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The CCW System is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

9.2.2.3.16 Regulatory Guide 1.97 Revision 3, May 1983 - Instrumentation for Light-Water Cooled Nuclear Power Plants to Assess Plant and Environs Condition During and Following an Accident

CCW post-accident instrumentation for meeting Regulatory Guide 1.97, May 1983 guidelines consist of flow indication for CCW supply headers A & B, temperature indication for each CCW heat exchanger outlet, and CIV position indication on the monitor light box for applicable CCW valves (refer to Section 7.5.3.6).

9.2.2.3.17 NUREG-0737 (Item II.K.3.25), November 1980 – Clarification of TMI Action Plan Requirements

Item II.K.3.25 - Effect of Loss of Alternating Current Power on Reactor Coolant Pump Seals: Required confirmation that RCP thermal barriers can withstand a loss of CCW cooling water to the RCP seal coolers due to a loss of ac power for at least two hours. This requirement is accommodated because the CCW pumps are supplied from Class 1E buses that have emergency on-site backup power (refer to Section 9.2.2.2.1). The associated CIVs are also supplied with emergency on-site backup power or are check valves (refer to Section 6.2.4.2).

9.2.2.3.18 Generic Letter 89-10, June 1989 - Safety Related Motor-Operated Valve Testing and Surveillance

CCW system MOVs are addressed by the DCPP MOV Program Plan, and the plan applies the recommendations of Generic Letter 89-10, June 1989 and associated Generic Letter 96-05, September 1996.

9.2.2.3.19 Generic Letter 89-13, July 1989 - Service Water System Problems Affecting Safety Related Equipment

The applicable recommendations of Generic Letter 89-13, July 1989 for ongoing surveillance and control have been applied to the CCW system, including a monitoring program combining flow testing, trending, inspection, and frequent preventive maintenance. Corrosion inhibitors and additives to prevent biofouling are included as part of preventive maintenance. The CCW heat exchangers provide pressure differential indication in the control room to alert operators to the need for cleaning and sample coupons are used to assess conditions and effectiveness of the program.

9.2.2.3.20 Generic Letter 96-06, September 1996 - Assurance of Equipment Operability and Containment Integrity during Design-Basis Accident Conditions

Generic Letter 96-06, September 1996 identified the potential for waterhammer or two-phase flow in the portion of the CCW system serving the CFCUs and for overpressurization of piping in systems that penetrate containment during accident conditions. The CCW nitrogen pressurization system was installed in response to the waterhammer concern to mitigate the possibility of flashing and subsequent waterhammer.

Subsequent review concluded that a limited amount of cavitation was possible during normal operation in the CCW flow downstream of the exit from the CFCUs, but that post-accident conditions would not result in a significant increase in the condition. Because CCW flow balance, and thus operability, is not affected, there is no impact on the ability of the CCW system to perform its design basis function.

A comprehensive review identified all containment mechanical piping and tubing penetrations and isolated piping segments inside containment. For CCW, other than the nitrogen pressurization system, no other actions were required to be taken.

9.2.2.4 Tests and Inspections

The active components of the CCW system are in either continuous or intermittent use during normal plant operation, and no additional periodic tests are required. Periodic visual inspections and preventive maintenance are conducted in accordance with normal plant operating practice.

9.2.2.5 Instrumentation Applications

The operation of the system is monitored with the following major or vital instrumentation:

(1) Temperature detectors at the inlet and at the outlet of each CCW heat exchanger, with control room temperature indication and alarm for heat exchanger outlet high/low temperatures

(2) A control room flow indicator and low flow alarm for each header

(3) Low-pressure switches with alarms and auto pump start near the inlet to each vital supply header

(4) Radiation monitor and alarm in the two pump discharge headers

(5) Control room level indicator and high/low level alarm for each half of the CCW surge tank

(6) Flow indication, temperature indication, or pressure indication on the equipment return lines

(7) Surge tank low and high pressure alarms in the control room

(8) Valve position indications in the control room

Design flowrates for normal, loss of coolant, and cooldown conditions are listed in Table 9.2-5.

9.2.3 COMMON MAKEUP WATER SYSTEM

The MWS, shown in Figure 3.2-16, supplies demineralized makeup water of the quality and quantity necessary for normal reactor coolant services, secondary system makeup, firewater, and miscellaneous plant uses. The system has the capacity necessary to meet the water requirements of a cold plant shutdown and subsequent startup from cold conditions at a time late in core life. The MWS provides makeup to the CCW surge tank. The MWS also supplies water to the CST, which provides a supply of water for the auxiliary feedwater (AFW) system.

For discussion specific to the condensate storage facilities (including the Unit 1 and Unit 2 CSTs and the common transfer tank), refer to Section 9.2.6. Refer to Section 6.5 for discussion regarding the AFW system. Refer to Section 9.2.2 for discussion regarding the CCW system.

9.2.3.1 Design Bases

9.2.3.1.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portion of the MWS is designed to withstand the effects of, or is protected against, natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

9.2.3.1.2 General Design Criterion 3, 1971 – Fire Protection

The PG&E Design Class I portion of the MWS is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.2.3.1.3 General Design Criterion 4, 1967 – Sharing of Systems

The MWS is not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

9.2.3.1.4 General Design Criterion 11, 1967 – Control Room

The PG&E Design Class I portion of the MWS is designed to or contains instrumentation and controls that support actions to maintain and control the safe operational status of the plant from the control room or from a remote location if control room access is lost due to fire or other cause.

9.2.3.1.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain MWS variables within prescribed operating ranges.

9.2.3.1.6 General Design Criterion 67, 1967 – Fuel and Waste Storage Decay Heat

The PG&E Design Class I portion of the MWS from the CST to the SFP provides a reliable and adequate method to deliver makeup water for decay heat removal to prevent damage to the fuel in the SFP that could result in radioactivity release to plant operating areas or the public environs.

9.2.3.1.7 Makeup Water System Safety Function Requirements

(1) <u>Protection from Missiles</u>

The PG&E Design Class I portion of the MWS is designed to be protected against the effects of missiles that may result from equipment failures and from events and conditions outside the plant.

(2) <u>Internal Flooding Protection</u>

Rupture of the PG&E Design Class II portion of the MWS will not impact PG&E Design Class I SSCs required for safe (cold) shutdown.

(3) Makeup Capabilities

The MWS is designed to provide a PG&E Design Class I flow path for makeup water from the CST to the CCW surge tank.

(4) Water Purification

The MWS is designed to filter and demineralize water to provide water that meets the quality requirements of the primary system.

9.2.3.1.8 10 CFR 50.55a(f) – Inservice Testing Requirements

The PG&E Design Class I MWS ASME Code pumps and valves are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

9.2.3.1.9 10 CFR 50.55a(g) – Inservice Inspection Requirements

The PG&E Design Class I MWS ASME Code components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

9.2.3.1.10 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The MWS is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

9.2.3.1.11 Safety Guide 13, March 1971 – Fuel Storage Facility Design Basis

The MWS is designed to provide a PG&E Design Class I flow path for makeup water from the CST to the SFP in accordance with Regulatory Position 8 of Safety Guide 13, March 1971.

9.2.3.1.12 IE Bulletin 80-10, May 1980 – Contamination of Nonradioactive System and Resulting Potential for Unmonitored, Uncontrolled Release of Radioactivity to Environment

The MWS is designed to maintain control over boundaries between potentially radioactive and nonradioactive portions of the system to prevent the spread of contaminated water into the nonradioactive portions of the system.

9.2.3.2 System Description

The MWS provides the following levels of water quality:

(1) Raw reservoir water

(2) Demineralized water

The MWS makes use of well water and seawater as sources of raw water. The well water is filtered and then discharged to the raw water storage reservoirs by a rental pretreatment system. The seawater is treated in the rental seawater reverse osmosis system and then pumped to the raw water storage reservoirs.

The seawater evaporators are abandoned in place. The water quality produced by the rental makeup water treatment system (MWTS) meets the specification of various plant operating services, which fall under the following categories:

(1) Makeup water for the primary system

(2) Makeup water for the secondary system

(3) Makeup water for the CCW system and SCW system

(4) Water in adequate quantity for fire fighting

(5) Water supply to the AFW system

(6) Provide an adequate reserve of water for startup and upset conditions for the secondary systems

(7) Supply water for dilution, flushing, and cleanup

Seawater is filtered, sterilized, and desalinated by the seawater reverse osmosis system. The desalinated product water is pumped to a 5.0-million gallon open reservoir system with plastic lined concrete walls.

The well water is pumped to a 100,000-gallon raw water storage tank. From the raw water storage tank, the water is processed through the pretreatment system and then discharged to the open raw water storage reservoirs. The reservoir water is treated with sodium hypochlorite to retard algae growth.

The reservoir water is treated by the MWTS. The system is capable of producing up to 600 gpm of deoxygenated/demineralized water for makeup to the CST or primary water storage tank (PWST). The MWTS consists of reverse osmosis, vacuum deaerator, and mixed-bed demineralizers.

The water produced by the MWTS is distributed to the CST, PWST or transfer tank for storage. The CST is used to supply the secondary system makeup, the AFW system, the auxiliary boiler, and the CCW system.

9.2.3.2.1 Raw Water Storage Reservoirs

The raw water storage reservoirs have a combined capacity of 5.0 million gallons. They have concrete-lined walls and are primarily intended to serve as fresh water storage for fire protection. The raw water storage reservoirs also serve as a source to the MWS and the AFW pumps, providing a large water storage reserve when the raw water supply is lower than the MWS demand.

9.2.3.2.2 Transfer, Distribution, and Storage

Most of the piping in the MWS, except the MWTS piping, is constructed in accordance with ANSI B31.1-1967, except the lines supplying water to the firewater pumps header, AFW pumps, and CCW system. The design classifications for these various SSCs are discussed in Table 3.2-3.

The water for decay heat removal by the AFW pumps is reserved in the CSTs (one for each unit) and supplied to the pump suction through PG&E Design Class I piping. Refer to Section 9.2.6.2 for the capacity of the CST and to Section 6.5.3.7 for additional information on usable inventory. The raw water storage reservoir is also used as a backup source for the AFW pumps.

There is no direct connection between the raw water supply header in the plant and the CST such that any single failure of a component could cause the loss of both CST AFW and reservoir water. A failure of the normal supply header from the CST to the AFW pumps would require opening the manually-operated valves to use the raw water storage reservoirs as a source of AFW. Check valves prevent back-flow of raw water through the failed header. Back-flow of CST water from the AFW pumps suctions through the connections to a postulated break in the raw water supply header is prevented by check valves and normally closed manually-operated stop valves.

The 200,000 gallon PWST is diaphragm-sealed to maintain the low oxygen content required for the reactor makeup water. For a description of reactor coolant water chemistry refer to Section 5.2.2.3.4. Design and operating parameters of the PWST are given in Table 9.2-9.

The PWSTs have been designed and erected to PG&E Design Class II standards and should contain only highly purified water.

9.2.3.2.2.1 Component Cooling Water System Makeup Capabilities

The available sources of makeup water to the CCW system are listed below with their respective makeup capacities. The design classification for each of the tanks and pumps is identified in Table 3.2-3.

	Source	Pumps

The following makeup water source and pumps provide a PG&E Design Class I flow path for MWS supply to the CCW surge tank:

(1)	CST	Makeup water transfer pumps, two 250 gpm pumps

The following makeup water sources and pumps provide alternative methods for MWS supply to the CCW surge tank:

(2)	Transfer tank	Makeup water transfer pumps, two 250 gpm pumps
(3)	PWST (Unit 1)	Primary water makeup pumps (Unit 1), two 150 gpm pumps
(4)	PWST (Unit 2)	Primary water makeup pumps (Unit 2), two 150 gpm pumps
(5)	Firewater tank, 300,000 gallons	Makeup water transfer pumps, two 250 gpm pumps
(6)	MWTS can supply water to CCW system directly or via other storage tanks (CSTs, PWSTs, transfer tank and firewater tank)	Makeup water transfer pumps, two 250 gpm pumps Primary water makeup pumps (Unit 1 and Unit 2), four 150 gpm pumps

Flowpaths associated with the source and pump combinations 2, 3, 4, 5, and 6 are not completely PG&E Design Class I, but the number of methods does provide considerable redundancy in backup provisions for makeup water to the CCW system.

9.2.3.3 Safety Evaluation

9.2.3.3.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portions of the MWS which are located within the PG&E Design Class I auxiliary building are protected from the effects of natural phenomena ensuring their safety functions will be performed. The auxiliary building, or applicable portions thereof, is designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7).

The PG&E Design Class I portions of the MWS are designed to remain functional when subjected to DE, DDE, and HE seismic loads (refer to Section 3.2.2.4.1). The seismic requirements are defined in Sections 3.7 and 3.10, and the provisions to protect the system from seismic damage are discussed in Sections 3.7, 3.9, and 3.10.

Certain PG&E Design Class I portions of the MWS are located outside and are vulnerable to tornadoes. However, they are not required for plant safe shutdown (refer to Sections 3.3.2.5.2.2 and 3.3.2.5.2.9).

Leakage from the PWSTs due to a tornado or missile-induced damage will not result in the flooding of PG&E Design Class I equipment in the auxiliary building since essentially watertight cover plates are installed over the pipe entranceway from each tank into the auxiliary building. Gross leakage from the tanks can be detected by level indication or visual inspection. The tank level is continuously monitored by the plant computer, and a high or low water level will initiate a control room alarm.

9.2.3.3.2 General Design Criterion 3, 1971 – Fire Protection

The MWS is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.2.3.3.3 General Design Criterion 4, 1967 – Sharing of Systems

The CSTs for Unit 1 and Unit 2 are cross-connected so that additional makeup is available from the other unit if required. Manual isolation valves and administrative controls are used to prevent unwanted flow between the Unit 1 and Unit 2 CSTs.

The two PG&E Design Class I makeup water transfer pumps are shared between Unit 1 and Unit 2. Each pump can draw water from the shared fire water storage tank, the shared transfer tank, or the Unit 1 or Unit 2 CSTs. The discharge from the makeup water transfer pumps can be directed to Unit 1 or Unit 2.

A portion of the suction piping to each of the three AFW pumps for each unit is common to the two feedwater sources, the raw water storage reservoirs, and the CST. A failure in this portion of the suction piping to the AFW pumps could draw from both sources. However, the manual stop valve to the raw water supply header is normally closed so the supply of raw reservoir water to the other unit would be unaffected by such a failure. In the affected unit, only one type of AFW pump, either turbine-driven or motor-driven, would be made inoperable by such a failure.

The MWTS is common for both units. No PG&E Design Class I systems are dependent on the output of the MWTS for their operation.

Water can be transferred between the Unit 1 and Unit 2 PWSTs and the tanks can be cross-tied to allow the two tanks to act as one source. The PWSTs are PG&E Design Class II and are not the seismically qualified sources for providing makeup water to the

CCW surge tank or SFP. Manual isolation valves and administrative controls are provided to ensure that the sharing of the Unit 1 and Unit 2 PWSTs does not impair the safety of either unit.

In the event that the makeup water transfer pumps are not operable, the MWTS equipment can provide demineralized water to the SFP. Makeup water to the CCW surge tank can be provided using water from the PWST using the primary water makeup pumps. Through the use of administrative controls, the use of shared makeup water components does not impair the safety of either unit.

9.2.3.3.4 General Design Criterion 11, 1967 – Control Room

The PG&E Design Class I portion of the MWS is designed to support actions to maintain and control the safe operational status of the plant from the control room.

The operation of the makeup water transfer pumps is controlled from the control room.

No PG&E Design Class I MWS components are required to be operated from the control room or remotely for safe shutdown.

Refer to Section 9.2.3.3.7 for a description of the instrumentation used to monitor the CCW surge tank makeup valves.

9.2.3.3.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation is provided as required to monitor and maintain the MWS variables within prescribed operating ranges. Instrumentation is installed to measure the water level inside the PG&E Design Class II PWST. The water levels in the two raw water storage reservoirs are monitored through the use of instrumentation that indicates the water levels on the main control board and the HSP. Local instrumentation, in the form of pressure indicators and flow indicators, is provided to monitor the operational status of the MWS. Controls to start and stop the MWS transfer pumps are located on the main control board. Controls to start and stop the primary water makeup pumps are provided at a local control board.

Refer to Section 9.2.3.3.8 for discussion regarding instrumentation used to meet IST requirements.

9.2.3.3.6 General Design Criterion 67, 1967 – Fuel and Waste Storage Decay Heat

The MWS provides a PG&E Design Class I flow path for makeup water from the CST to the SFP to ensure adequate decay heat removal in the event of a failure of the SFP cooling and cleanup system. Makeup water to the SFP is supplied by the MWS as described in Section 9.1.3.3.9.

9.2.3.3.7 Makeup Water System Safety Function Requirements

(1) Protection from Missiles

The design function of the PG&E Design Class I portion of the MWS will not be prevented by internal missiles and/or missiles resulting from external events. Provisions taken to protect the PG&E Design Class I portion of the MWS from the effects of missiles are discussed in Section 3.5.

(2) Internal Flooding Protection

Although the raw water storage reservoirs are not PG&E Design Class I items, their location, on a bench excavated into the ridge above the power plant at elevation 310 feet, as shown in Figure 1.2-1, poses a small potential flood risk to the site. Since a portion of the reservoir bench drains toward the power plant, the raw water storage reservoirs were lowered by excavating the basin entirely in rock, eliminating the risk of flooding due to dike failure. The discussion of slope stability in Section 2.5.6 provides assurances that the slope between the power plant yard and the reservoir bench will not fail. Slope failure in any other direction, which results in a reservoir rupture will release the water into the Diablo Canyon.

The discussion of flooding in Section 2.4.4.5 provides assurance that the drainage capacity of the Diablo Canyon is sufficient to pass the entire volume of the raw water storage reservoirs safely by the plant in approximately 1 minute. The raw water reservoirs have a plastic lining on reinforced concrete to prevent leakage. The water levels in the raw water reservoirs are indicated in the control room and at the HSP and low levels are annunciated in the control room.

The two pipelines (12 and 6 inches) between the raw water storage reservoirs and the plant have been examined for their potential for flooding. The maximum combined flow from these lines if ruptured would be 7000 to 8000 gallons per minute. This flow-rate would be intercepted by the site storm drainage systems and diverted from PG&E Design Class I equipment.

The 8 inch raw water supply header in the auxiliary building presents the potential flooding source with the largest volume of water (the raw water storage reservoirs). Flooding of the auxiliary building from this header would be recognized by the annunciation of the auxiliary building sump high-level alarm. The flow would be terminated by an operator using the appropriate manual isolation valve. A volume of 345,000 gallons in the auxiliary building pipe tunnel for sump overflow storage is available to receive water flooding from this source. This storage capacity allows the operator sufficient time to close the stop valve in the yard to prevent overflooding.

The flow rate of water flooding from the raw water supply header in the auxiliary building is defined by moderate energy line break (MELB) analysis criteria, and is bounded by that from other high energy line break (HELB)/MELB sources.

(3) Makeup Capabilities

Refer to Section 9.1.3.3.9 for discussion regarding the use of the MWS to provide makeup water to the SFP.

Normal operating conditions for the MWS allow immediate makeup to the CCW system through the makeup valves whenever they open (shown in the CCW system piping schematic, refer to Figure 3.2-14). These air-actuated LCVs open automatically in the event of low level in the CCW surge tank. They close automatically when the normal operating level in the surge tank is restored or on loss of air. Opening these valves is annunciated in the control room, indicating that CCW system makeup is required. Makeup water to the CCW system is normally supplied from the transfer tank through the makeup water transfer pumps. The MWS supplies water to the 150,000 gallon transfer tank.

The most demanding transient on the water inventory of the condensate system and the CST is a natural circulation cooldown. After such a transient, as much as 225,000 gallons available remain in the CST for makeup to the CCW system. This inventory provides for more than one complete refill of the CCW system. One refill is considered adequate makeup reserve capacity. The nozzle for MWS on the CST draws water from a level above the CST water volume dedicated as a source of AFW supply water. Nozzles for non-seismically qualified PG&E Design Class II systems are attached to the CST at the same elevation as the MWS. The use of CST water for AFW purposes or the failure of non-MWS piping attached to the CST could lower the water inside the CST to a level below the MWS nozzle. In such cases, an alternative water source would need to be used. The firewater tank, which is also seismically qualified, can be aligned as an additional makeup water supply for the CCW system.

The makeup water from the CSTs, both Unit 1 and Unit 2, is pumped from the tank to the CCW system by the PG&E Design Class I makeup water transfer pumps. All piping and valves in the makeup path from the CSTs (including their cross-connections) through the makeup water transfer pumps up to and including the makeup valves on the CCW system lines, are PG&E Design Class I. Two redundant, full capacity, makeup water transfer pumps are each capable of delivering approximately 250 gpm makeup to the CCW system. Each pump is powered from the Class 1E 480-V electrical buses, which are energized by either normal sources or the emergency diesel engine-generator units. A 250 gpm makeup rate is considered to be greater than any credible leakage from the CCW system during normal operation or post-accident injection. This conclusion is based on the low operating pressures and the protection afforded large piping and equipment and the flow rate of the largest postulated leak.

Makeup water for the CCW system can be provided from various water sources and through various pumps and flowpaths in the MWS. Refer to Section 9.2.3.2.2.1 for a list of available alternative PG&E Design Class I and PG&E Design Class II sources and pumps that the MWS can utilize to deliver water to the CCW surge tank.

Refer to Section 9.2.6.2 for the capacity of the CST and to Section 6.5.3.7 for additional information on usable inventory.

(4) Water Purification

The system supplies makeup water of the quality and quantity necessary for normal reactor coolant services, secondary system makeup, and miscellaneous plant uses.

The PWST, which has a diaphragm seal to minimize O_2 contact, supplies water for the primary system.

9.2.3.3.8 10 CFR 50.55a(f) – Inservice Testing Requirements

The PG&E Design Class I MWS pumps and valves comply with the ASME code for Operation and Maintenance of Nuclear Power Plants and are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

Instrumentation is installed to measure the flow rate of the PG&E Design Class I makeup water transfer pumps for IST purposes.

9.2.3.3.9 10 CFR 50.55a(g) – Inservice Inspection Requirements

The PG&E Design Class I MWS ASME BPVC Section XI components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

9.2.3.3.10 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The MWS System is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

9.2.3.3.11 Safety Guide 13, March 1971 – Fuel Storage Facility Design Basis

Regulatory Position 8:

The MWS provides a PG&E Design Class I flow path for makeup water from the CST to the SFP, in accordance with Regulatory Position 8 of Safety Guide 13, March 1971. Refer to Section 9.1.3.3.9 for discussion regarding the use of the MWS to provide makeup water to the SFP.

9.2.3.3.12 IE Bulletin 80-10, May 1980 – Contamination of Nonradioactive System and Resulting Potential for Unmonitored, Uncontrolled Release of Radioactivity to Environment

Isolation valves and administrative controls are used to prevent contamination of the CCW. Water from the PWSTs is not used for normal makeup to the CCW system as a result of IE Bulletin 80-10, May 1980. The PWST makeup to CCW system isolation valve is normally locked closed. The lock was installed to preclude opening the valve and contaminating the CCW system with tritiated water. If the valve is to be opened, the plant operator must obtain concurrence from the chemistry and radiation protection group.

9.2.3.4 Tests and Inspections

The operating components of the MWTS are in either continuous or intermittent use during normal plant operation and no additional periodic tests are required. Periodic visual inspections and preventive maintenance are conducted in accordance with plant procedures for plant controlled distribution system components, or in accordance with vendor procedures for the vendor-owned water treatment facilities.

9.2.3.5 Instrumentation Applications

Refer to Section 9.2.3.3.5 for discussion on the instrumentation used to monitor the function of the MWS.

The vendor-owned makeup water treatment facility is equipped with dissolved oxygen, conductivity, silica, and organic carbon monitoring instrumentation. In the event the product from the makeup water plant exceeds the values established in plant procedures, the product is automatically diverted to the raw water storage reservoirs until corrected.

9.2.4 POTABLE WATER SYSTEM

There is no separate potable water system. Potable water is supplied by the domestic water system (DWS) as discussed in Section 9.2.8.

9.2.5 ULTIMATE HEAT SINK

The UHS dissipates residual heat after normal and emergency shutdown conditions. The following sections provide information on (a) design bases, (b) system description, (c) safety evaluation, (d) tests and inspections, and (e) instrumentation applications.

9.2.5.1 Design Bases

9.2.5.1.1 General Design Criterion 2, 1967 - Performance Standards

The UHS is designed to withstand the effects of natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

9.2.5.1.2 General Design Criterion 4, 1967 - Sharing of Systems

The UHS (Pacific Ocean) is not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

9.2.5.1.3 General Design Criterion 11, 1967 - Control Room

The UHS is available to support safe shutdown from the control room or an alternate location if control room access is lost due to fire or other causes.

9.2.5.1.4 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Instrumentation is provided as required to monitor UHS system variables.

9.2.5.1.5 Safety Guide 27, March 1972 - Ultimate Heat Sink for Nuclear Power Plants

The UHS will provide in excess of 30-day supply of cooling water to be available for shutdown and cooldown after normal and emergency conditions.

9.2.5.2 System Description

The Pacific Ocean is the UHS. The Pacific Ocean is the source of cooling water to the safety-related ASW system, along with other non-safety related cooling water systems discussed in Sections 9.2.3 and 10.4.5. The seawater from the Pacific Ocean passes through screening equipment located in the intake upstream of the pumps for which it supplies cooling water.

The ocean water supply to the ASW system provides the cooling and heat absorption capability required to remove waste heat under normal and emergency conditions from the NSSS. The waste heat from containment and other plant equipment is transferred to the CCW system. The heat picked up by the CCW system is transferred to the ASW system by the CCW heat exchangers. The ASW flows into the main condenser circulating water discharge structure and then into the ocean.

9.2.5.3 Safety Evaluation

9.2.5.3.1 General Design Criterion 2, 1967 - Performance Standards

The availability of the heat sink to provide cooling when required under severe conditions is discussed in detail in Section 2.4.12.6. The most severe oceanographic phenomenon to consider is a tsunami as discussed in Section 2.4.7. Estimates of wave runup on the plant facility are referenced in Section 2.4.6.6.

The expected downsurge during short periods of time would be to 9 feet below mean lower low water (MLLW). The arrangement of the intake channel and the design of the ASW pumps allow operation down to 17.4 feet below MLLW in the normal one-pump one-heat exchanger alignment. For reference, MLLW equals mean sea level (MSL) minus 2.6 feet. MSL is ground elevation zero.

The ASW portion of the intake structure and piping systems associated with the UHS are designed to the seismic conditions and requirements described in Section 2.5 and Sections 3.7 through 3.10, respectively. These components are constructed of materials compatible with the saltwater environment, or provided with protective features, to ensure the functionality of the components required for delivering the required cooling water supply to the ASW system and CCW heat exchangers.

9.2.5.3.2 General Design Criterion 4, 1967 - Sharing of Systems

The Pacific Ocean is the UHS. The Pacific Ocean is the source of cooling water to the safety-related ASW system. Because of the location of the plant on the ocean and the separation of intake and discharge structures, insignificant recirculation occurs.

9.2.5.3.3 General Design Criterion 11, 1967 - Control Room

Temperature of the UHS is measured at the circulating water pumps discharge and monitored in the control room.

9.2.5.3.4 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Temperature of the UHS is measured at the circulating water pumps discharge and monitored in the control room. Also, the temperature is measured outside the bar racks and recorded near the HSP.

9.2.5.3.5 Safety Guide 27, March 1972, - Ultimate Heat Sink for Nuclear Power Plants

Maximum temperature limits exist on the UHS to ensure the heat removal capability of the ASW/CCW system in normal and accident conditions. When the UHS exceeds 64°F, both CCW heat exchangers must be placed in service. Operation with elevated

UHS temperatures as high as 70°F is acceptable with two CCW heat exchangers in service. It has also been confirmed that the CCW heat exchangers will operate in a one pump two heat exchanger configuration. The limiting condition for operation and surveillance requirements of the UHS is discussed in the Technical Specifications (refer to Section 3.7.9 of Reference 1).

The ocean as a single water source for the UHS will provide in excess of 30 days of cooling water during normal and emergency shutdown conditions as required by Safety Guide 27, March 1972.

9.2.5.4 Tests and Inspections

Tests and inspections of piping systems between the reactor heat source and the UHS are discussed in their respective sections.

9.2.5.5 Instrumentation Applications

Temperature of the UHS is measured at the circulating water pumps discharge and monitored in the control room. Also, the temperature is measured outside the bar racks and recorded near the HSP.

9.2.6 CONDENSATE STORAGE FACILITIES

The ESF function of the CST in support of the AFW system is discussed in Section 6.5. The safety function of the CST is to provide condensate storage for RCS cooldown.

The condensate storage facilities, shown in Figure 3.2-16, provide for the storage and transfer of demineralized water from the MWS to the AFW system and to supply the normal makeup and rejection requirements of the steam plant.

The CST provides, as available, makeup water for CCW and SFP makeup (refer to Section 9.2.3).

The boundary of the condensate storage facilities consists of one CST per unit, a single makeup water transfer tank, the hydrazine mixing pumps, and interconnected valves and piping.

9.2.6.1 Design Bases

9.2.6.1.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portion of the condensate storage facilities are designed to withstand the effects of, or are protected against, natural phenomena such as earthquakes, flooding, tornadoes, winds, tsunamis and other local site effects.

9.2.6.1.2 General Design Criterion 3, 1971 – Fire Protection

The condensate storage facilities are designed and located to minimize, consistent with other safety requirements, the probability of fires and explosions.

9.2.6.1.3 General Design Criterion 4, 1967 – Sharing of Systems

The condensate storage facilities are not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

9.2.6.1.4 General Design Criterion 11, 1967 – Control Room

The PG&E Design Class I portion of the condensate storage facilities are designed to or contain instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

9.2.6.1.5 General Design Criterion 12, 1967 – Instrumentation and Controls

Instrumentation is provided as required to monitor the condensate storage facilities variables within prescribed operating ranges.

9.2.6.1.6 Condensate Storage Facilities System Safety Function Requirements

(1) Condensate Storage

The CST is designed to provide condensate storage to support RCS decay heat removal and cooldown and as a backup for makeup water to CCW and the SFP.

(2) Protection from Missiles

The PG&E Design Class I portion of the condensate storage facilities are designed to be protected from missiles.

9.2.6.1.7 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The condensate storage facilities are designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

9.2.6.1.8 10 CFR 50.55a(f) – Inservice Testing Requirements

The condensate storage facilities ASME Code components are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

9.2.6.1.9 10 CFR 50.55a(g) – Inservice Inspection Requirements

The condensate storage facilities ASME Code components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

9.2.6.1.10 10 CFR 50.63 – Loss of All Alternating Current Power

The CST provides a sufficient inventory of water to support RCS cooldown during a SBO event.

9.2.6.1.11 NUREG-0737 (Item II.E.1.1), November 1980 –Clarification of TMI Action Plan Requirements

Item II.E.1.1 – Auxiliary Feedwater Reliability System Evaluation: The CST is designed to provide redundant level indication and low level alarms in the control room to allow the operator 20 minutes to anticipate the need for makeup water or transfer to an alternate water supply to support AFW pump operation.

9.2.6.2 System Description

Design and operating parameters for the condensate storage facilities are given in Table 9.2-9. The condensate storage facilities consist of a CST for each unit and a common transfer tank located outside the east end of the auxiliary building. The CST has a floating roof to minimize oxygen absorption by the stored water. The capacity of each CST is 425,000 gallons, which includes a minimum reserve of approximately 225,000 usable gallons for AFW pump operation and a drainable but not usable volume of approximately 13,000 gallons. Refer to Section 6.5.3.7 for additional information on usable inventory (refer to Section 6.5 for a description of the AFW system). The capacity of the transfer tank is 150,000 gallons. The CST is used for condensate makeup and rejection. The DCPP Unit 1 CST serves as a source of water to the auxiliary boiler. Makeup water to other plant systems can be supplied from the CSTs by use of the makeup water transfer pump (refer to Section 9.2.3). The transfer tank provides a holding storage capacity while transferring water. The condensate storage facilities are shown in Figure 3.2-16.

The CST capacity is based on supplying the normal makeup and rejection requirements of the steam plant, and providing a source of feedwater for the AFW system. The seismic evaluation of these tanks is discussed in Sections 3.7.2.2.1.5, 3.8.2.4 and 3.9.2.2.3. All outdoor tanks are designed for atmospheric pressure and for 32 to 200°F design temperature.

The PG&E design classifications of the CST and the transfer tank are given in Table 3.2-3.

A gravity flow line is also provided to allow water to flow between the transfer tank and CST when required.

In an emergency, water can be supplied from other sources through a connection to the CST hydrazine recirculation line.

The makeup water transfer pumps can be used to pump water to the CSTs of DCPP Unit 1 and Unit 2 and the transfer tank (refer to Section 9.2.3).

The suction lines from the CSTs to the makeup water transfer pumps, which can supply makeup water to the CCW system are crosstied between DCPP Unit 1 and Unit 2 but are isolated by two manual valves. If necessary, the DCPP Unit 1 and Unit 2 CSTs can provide an additional source of makeup water to the DCPP Unit 1 and DCPP Unit 2 CCW systems. The DCPP Unit 1 and Unit 2 crosstie provides an operating flexibility that minimizes the possibility of system failure. The CST also provides a source of makeup water to the SFP (refer to Section 9.1.3.2).

9.2.6.3 Safety Evaluation

9.2.6.3.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portions of the condensate storage facilities are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Sections 3.7 and 3.8.2.4).

The tornado wind and associated missiles capability of the CST is given in Table 3.3-2. As discussed in Section 3.3.2.5.2.9, a tornado-induced tank failure causing an instantaneously large leak and flood is extremely unlikely. Loss of this tank does not significantly compromise safe shutdown capability, since the PG&E Design Class II raw water reservoir provides a backup supply of water for the AFW pumps. Leakage from the CSTs and transfer storage tank due to tornado or missile-induced damage will not result in the flooding of PG&E Design Class I equipment in the auxiliary building since essentially watertight cover plates are installed over the pipe entranceway from each tank into the auxiliary building. The water will drain away from the building via the plant yard drainage system.

The storage tanks are located outside the auxiliary building and, therefore, will not be subject to any unusual post-accident environment. The codes to which the tanks were built consider normal atmospheric conditions such as wind and rain in the design guides. Protective coats of paint are applied to the outside of each tank.

9.2.6.3.2 General Design Criterion 3, 1971 – Fire Protection

The condensate storage facilities are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.2.6.3.3 General Design Criterion 4, 1967 – Sharing of Systems

The DCPP Unit 1 and Unit 2 CSTs are crosstied through a 4- inch line. The crosstie lines nozzles on each tank are located above the Technical Specification (Reference 1) volume requirement for AFW, thereby ensuring that failure of the crosstie line cannot reduce the condensate storage capacity for SG makeup from the AFW pumps. Additional sources of water for the AFW pumps are described in Section 6.5.2.

9.2.6.3.4 General Design Criterion 11, 1967 – Control Room

The PG&E Design Class I portion of the condensate storage facilities is designed to support actions to maintain and control the safe operational status of the plant from the control room.

The water level in each CST is displayed on a PG&E Design Class I local indicator and redundant PG&E Design Class I recorders in the control room. High, low, and low-low water levels are alarmed in the control room. The low level alarm on both DCPP Unit 1 and Unit 2 annunciates when the tank level is approaching the top of the internal plenums of the PG&E Design Class II nozzles. Refer to Section 6.5.3.7 for additional information on usable inventory. CST water level indication is provided locally at the tank, at the HSP, and in the control room.

9.2.6.3.5 General Design Criterion 12, 1967 – Instrumentation and Controls

Instrumentation is provided as required to monitor the condensate storage facilities variables within prescribed operating ranges as discussed in Section 9.2.6.3.4.

Refer to Section 6.5.3.20 for Regulatory Guide 1.97, Revision 3 CST level indication compliance.

9.2.6.3.6 Condensate Storage Facilities System Safety Function Requirements

(1) Condensate Storage

The CST provides storage of condensate to support RCS decay heat removal and cooldown as discussed in Section 6.5. The usable minimum reserve in the CST of approximately 225,000 usable gallons is discussed in Section 6.5.3.7. The usable volume CST reserve is ensured by internal plenums at the connections of all consumers of CST inventory in the usable volume region.

(2) Protection from Missiles

The condensate storage facilities design is such that physical protection is adequately provided against physical hazards in areas through which the system is routed. The CSTs and transfer tank are cylindrical steel tanks protected by reinforced concrete

encasements (refer to Section 3.5). The location of the tanks also provides protection from physical hazards.

9.2.6.3.7 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The CST is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

9.2.6.3.8 10 CFR 50.55a(f) – Inservice Testing Requirements

The IST requirements for the applicable condensate storage facilities components are contained in the DCPP IST Program Plan.

9.2.6.3.9 10 CFR 50.55a(g) – Inservice Inspection Requirements

The ISI requirements for the applicable condensate storage facilities components are contained in the DCPP ISI Program Plan.

9.2.6.3.10 10 CFR 50.63 – Loss of All Alternating Current Power

During an SBO event, decay heat is removed from the core by natural circulation of the reactor coolant. This heat is then transferred to the secondary side of the SGs and discharged to the atmosphere through the 10 percent atmospheric dump valves. The CST provides storage of makeup water to the AFW pumps to support decay heat removal (refer to Section 6.5.3.18).

9.2.6.3.11 NUREG-0737 (Item II.E.1.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.E.1.1 – Auxiliary Feedwater Reliability System Evaluation: The AFW pumps take water from the CST, which is the preferred source of water for AFW. The CST provides redundant level indication and low level alarms in the control room. Additional sources of water for the AFW pumps are described in Section 6.5.2.1.1.

9.2.6.4 Tests and Inspections

The water in the CSTs will be sampled periodically to determine chemical quality. In addition, the activity level of the water will be checked, and if SG leakage is suspected, the frequency of the activity samples of water will be increased.

9.2.6.5 Instrumentation Applications

Instrumentation for the condensate storage facilities is discussed in Sections 9.2.6.3.4 and 9.2.6.3.5.

9.2.7 AUXILIARY SALTWATER SYSTEM

The ASW system, shown in Figure 3.2-17, is an open-cycle system that supplies cooling water to the CCW heat exchangers from the UHS, the Pacific Ocean, during normal operation, plant cooldown, and following a LOCA or MSLB. It transfers waste heat from the CCW system, via each CCW heat exchanger to the UHS.

9.2.7.1 Design Bases

9.2.7.1.1 General Design Criterion 2, 1967 - Performance Standards

The ASW system is designed to withstand the effects of or is protected against natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

9.2.7.1.2 General Design Criterion 3, 1971 - Fire Protection

The ASW system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.2.7.1.3 General Design Criterion 4, 1967 - Sharing of Systems

The ASW systems or components are not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

9.2.7.1.4 General Design Criterion 11, 1967 - Control Room

The ASW system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

9.2.7.1.5 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain ASW system variables within prescribed operating ranges.

9.2.7.1.6 Auxiliary Saltwater System Safety Function Requirements

(1) <u>Waste Heat Removal</u>

The ASW/CCW systems are designed to remove waste heat from the nuclear (primary) plant equipment and components during normal plant operation, plant cooldown, and design basis accidents.

(2) Single Failure

The ASW system and CCW system are essentially considered a single heat removal system for the purpose of assessing the ability to sustain either a single active or passive failure and still perform design basis heat removal.

(3) Redundancy

PG&E Design Class I ASW system components are redundant.

(4) Isolation

The ASW system includes provision for isolation of system components and may be split into separate trains during long term post-LOCA conditions.

(5) Protection from Missiles

PG&E Design Class I portions of the ASW system are designed, located, or protected against effects of missiles which may result from plant equipment failure and from events and conditions outside the plant to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(6) Protection Against High Energy Pipe Rupture Effects

PG&E Design Class I portions of the ASW system are designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(7) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The outside containment PG&E Design Class I portion of the ASW system is designed to be protected against the effects of moderate energy pipe failure.

(8) Protection from Flooding Effects – Outside Containment

The outside containment PG&E Design Class I portion of the ASW system is designed to be protected from the effects of internal flooding.

(9) Leak Detection

The CCW system serves as an intermediate system between normally or potentially radioactive systems and the ASW system, which is an open-cycle system that discharges to the UHS (Pacific Ocean).

9.2.7.1.7 10 CFR 50.55a(f) - Inservice Testing Requirements

ASW system ASME Code components are tested to the requirements of 10 CFR 50.55 a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical

9.2.7.1.8 10 CFR 50.55a(g) - Inservice Inspection Requirements

ASW system ASME Code components (including supports) are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

9.2.7.1.9 10 CFR 50.63 - Loss of All Alternating Current Power

The ASW system is required to provide cooling water to the CCW System following a SBO.

9.2.7.1.10 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The ASW system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

9.2.7.1.11 Generic Letter 89-10, June 1989 - Safety Related Motor-Operated Valve Testing and Surveillance

The ASW system safety-related and position-changeable MOVs meet the requirements of Generic Letter 89-10, June 1989 and associated Generic Letter 96-05, September 1996.

9.2.7.1.12 Generic Letter 89-13, July 1989 - Service Water System Problems Affecting Safety-Related Equipment

The CCW heat exchangers cooled by the ASW system are subject to monitoring and maintenance programs to ensure capability to perform their safety function as an alternative to a testing program. Maintenance practices, operating and emergency procedures, and training ensure effectiveness of these programs.

9.2.7.1.13 Generic Letter 91-13, September 1991 - Essential Service Water System Failures at Multi-Unit Sites

The DCPP procedures establish periodic flow testing, surveillance, and operability of the ASW cross-tie valve FCV-601.

9.2.7.2 System Description

There is a separate ASW system for Unit 1 and Unit 2. Each unit is provided with two ASW trains with crosstie capability. Each train consists of a full capacity electric motor-driven pump, the tubeside of the CCW heat exchanger and associated supply

and discharge piping for the CCW heat exchanger. Upstream of the pumps, there is a unit ASW traveling water screen and a suction bay gate for each pump. There is a vacuum relief system on each ASW supply header piping to prevent water hammer. In addition, the Unit 1 and Unit 2 ASW piping system is arranged with interunit crosstie capability.

Each train is designed with the capability of providing adequate cooling to the CCW system during normal operation, plant safe shutdowns following normal operation, and refueling modes. Equipment design margins and system redundancy allow either an active or a passive failure of any component without degrading the system's cooling function under all modes of operation, including a design basis accident.

All system boundary components are located within the turbine building, the vacuum breaker vault, and the intake structure. These locations provide access for inspections and maintenance during either normal or post-accident operation.

The components are connected via buried, plastic-lined, carbon steel pipes between these structures. The buried piping is accessible for inspections and maintenance during train outages of sufficient duration (typically refueling).

9.2.7.2.1 Auxiliary Saltwater Pumps

The ASW pumps are powered from separate Class 1E 4.16-kV buses, which can be energized by either the normal source or the emergency diesel generators (EDGs). All train components satisfy PG&E Design Class I criteria. The pumps are single stage, vertical, wet pit type driven by 4.16-kV motors. The design data for the ASW pumps are tabulated in Table 9.2-1. The piping and other essential lines (power, sensing, and control) that pass from the pumps to the main portion of the plant are shown in Figure 9.2-3.

9.2.7.2.2 Electrical Conduits

The route of circuits F, G, and H carrying these Class 1E power and instrument signals to the ASW pumps parallels the piping between the turbine building and the intake structure, as shown in Figure 9.2-3. Embedded plastic (ABS) conduits are used. These conduits are encased in a sand envelope with a reinforced concrete slab cover throughout the entire run except at structure crossings and the portion from bluff penetration to the intake structure where they are encased in reinforced concrete envelopes. All connections to pull boxes or structures are flexible. The electrical aspects of these safety-related circuits are described in Section 8.3.

9.2.7.2.3 Intake Structure and Equipment

The ASW pumps are installed at the intake structure, as shown in Figure 9.2-2. This arrangement provides a separate bay and intake bay gate for each pump. The design classification of the intake structure is given in Table 3.2-3 and the seismic analysis is

presented in Section 3.7.2. The PG&E Design Class I equipment located in the intake structure are the ASW pumps, ASW MOVs, ASW piping, including valves in the piping, ASW pump compartment heating, ventilation and air-conditioning (HVAC), and some ASW instrumentation.

Each unit's pair of ASW pump trains share a common traveling screen to remove floating debris from the incoming seawater. If the common screen for a unit becomes clogged with debris, seawater may be supplied to the ASW pump bays from the unit's circulating water pump bays via the demusseling valves. Level transmitters are provided on both the inlet and outlet of the ASW common traveling screen in each unit for the purpose of indication and annunciation of water level differential across the common screen and for automatic screen start. The level transmitters are shown in Figure 3.2-17.

Provisions exist to control marine fouling buildup in the ASW system pump forebays, piping and the CCW heat exchanger to minimize flow blockage, and slime buildup in tubes. Flow testing is routinely performed and heat exchanger differential pressure is monitored to ensure adequate flow for heat removal capabilities. Biofouling is controlled by continuous chlorination.

The ASW pumps, traveling screens, gates, and guides are cathodically protected to protect the equipment from corrosion.

9.2.7.2.4 Piping

The design classification for ASW piping is given in Table 3.2-3. The ASW piping is designed to perform its function and maintain its integrity considering the effects of the environment and load combinations due to varying pressures, temperatures, and seismic conditions. The arrangement of the ASW system buried supply piping between the intake structure and turbine building is shown in Figure 9.2-3. The supply lines exit the east wall of the intake structure and are supported by thrust blocks and surrounding soil in the filled area. The supply lines are typically anchored to the circulating water conduits and are buried in the same trenches except for the new bypass piping just outside of the intake structure that is buried in soil and supported by large reinforced concrete thrust blocks. Refer to Section 2.5.5.8 for discussion of potential liquefaction of soil beneath a portion of buried ASW piping. The supply lines are anchored in concrete to the circulating water conduits at 40-foot intervals. The pipe trench is backfilled with compacted granular fill between the anchors. Within the turbine building, the pipes are embedded in concrete.

A separate ASW line from each CCW heat exchanger discharges to the ocean at the discharge structure.

The pipe used in the ASW system is standard weight ASTM A53 and A106 seamless steel with a 1/8 inch thick layer of polyvinyl chloride thermally bonded to the pipe's interior surface and over the full face of the flanged ends. A polyurea liner has been

qualified to replace or repair the original liner. The exterior surface of the pipe is coated with epoxy for corrosion resistance.

Portions of the buried ASW supply and discharge pipes are cathodically protected by an impressed current system or embedded in concrete.

Due to the vulnerability of the buried portions of the ASW system supply piping to potential corrosion damage, corrosion protection for the piping is provided by an internal lining and external coating applied directly to the piping and cathodic protection systems installed at selected locations.

9.2.7.2.5 Discharge Structure

The discharge structure is a massive energy dissipating device located in the coastal bluff. The arrangement of the structure and the ASW pipe discharge is illustrated in Figure 11.2-9. The structure is divided into two chambers (one for each unit) that are open to the ocean under all conditions. The two ASW return lines for each unit discharge into the chamber of that unit. The base slab of the discharge structure is keyed into and poured on sound rock. Where possible, the walls were formed directly against sound rock.

9.2.7.2.6 Heat Exchangers

The design details of the CCW heat exchangers are given in Table 9.2-3. Performance of the CCW heat exchanger is based on performance curves provided by the manufacturer.

9.2.7.3 Safety Evaluation

9.2.7.3.1 General Design Criterion 2, 1967 - Performance Standards

The design classifications for PG&E Class I ASW SSCs are identified in Table 3.2-3. The PG&E Design Class I equipment located in the intake structure are the ASW pumps, ASW MOVs, ASW piping, including valves in the piping, ASW pump compartment HVAC, and some ASW instrumentation. In order to provide assurance that the function of PG&E Design Class I equipment will not be adversely affected even in the unlikely event of a seismic event, the intake structure (QA Class S) was reviewed to ensure that it would not collapse. The failure analysis was based on the HE discussed in Section 3.7.1. The capability of the intake structure to withstand winds, tornadoes, and associated missiles is discussed in Section 3.3, and to withstand design flood events is discussed in Sections 2.4 and 3.4.

The invert depth in the ASW channel is 31.5 feet below MSL. The ASW pump's intake bells are at 23 feet below MSL, and the pumps are designed to operate with a water level at 20 feet below MSL, which envelopes the postulated tsunami drawdown conditions (refer to Sections 2.4.6 and 2.4.12). The pump's mounting plates are located at the pump deck 2.1 feet below MSL with the motor drivers at 4 feet above MSL.

Pumps and motors are situated in watertight compartments that are ventilated by forced air through a roof ventilation shaft with vent extensions (snorkels) having a high point of 49.4 feet above MSL and a low point of 45.57 feet above MSL. The ASW pump room vents are extended with steel snorkels to prevent seawater ingestion due to splash-up during the design flood event as described in Section 3.4. PG&E Design Class I equipment is thus ensured of operation during extreme tsunami drawdown and combined tsunami and storm wave runup conditions.

During tsunami drawdown, each ASW pump will deliver about 85 percent of design flow due to increased static head losses. This is a temporary condition and would not result in excessive temperatures in components to be cooled. If a second ASW pump is available, the temporary condition can be avoided by running two pumps in parallel. For operation with two CCW heat exchangers with no second pump available, operator action is required to isolate one of the heat exchangers during the tsunami drawdown as described in Sections 2.4.12.5 and 2.4.12.6.

Design flow can readily be maintained during high water conditions. MSL is ground elevation zero; MSL (in feet) equals MLLW (in feet) plus 2.6 feet.

The ASW system is the only safety-related system that has components within the projected sea wave zone. The ASW pumps are housed in watertight compartments in the intake structure. These compartments are ventilated by forced air through a roof ventilator as described in Section 2.4.6.7.

ASW pump vents are extended with steel snorkels that face eastward to prevent seawater ingestion due to splash-up during the design flood event and are described in Section 2.4.6.7. The pump and piping are designed to handle the increased pressure in the system due to the combination of normal system operating and temporary-high wave conditions. The expected downsurge during short periods of time would be to 9 feet below MLLW. The arrangement of the intake channel and the design of the ASW pumps allow operation down to 17.4 feet below MLLW in the normal one-pump one-heat exchanger alignment. For operation with two CCW heat exchangers in service, operator action would be required to isolate one of the heat exchangers during the tsunami drawdown as described in Sections 2.4.12.5 and 2.4.11.6. PG&E Design Class I equipment is therefore assured of operation during extreme tsunami drawdown and combined tsunami and storm wave runup conditions. For reference, MLLW equals MSL minus 2.6 feet. MSL is ground elevation zero.

The piping and Class 1E electrical circuits associated with the ASW system are buried except for short exposed portions at the intake structure vacuum breaker vault and at the turbine building, and therefore not subject to damage due to missiles from rotating equipment or tornadoes, or due to collapse of nonseismic structures. Seismic design for the PG&E Design Class I piping (including buried and embedded portions) is provided in the applicable ASW piping stress analysis and discussed in Section 3.7. Since no surface fault movement is postulated for the site (as discussed in Section 2.5) and since consideration has been given to the ductility of the material (as discussed in

Section 3.8.2.3.5) and the method of construction for the conduit runs, they can be assured to remain in service during and following seismic events.

Wave protection measures at ground level and below to protect the ASW system buried piping and electrical conduits from tsunami/storm conditions include concrete covers, revetments, roadway slabs, pavement and gabion mattresses.

The ASW pumps are housed in watertight compartments preventing flooding from occurring from sources external to the compartments.

Differential rock movement would be required to overload the discharge structure. Differential rock movement or faulting is not a design criterion (refer to Section 2.5.4). However, if a collapse of the structure were postulated, it is not likely that the ASW flow would be obstructed. There is insufficient rubble from such a postulated collapse to block the flow from both ASW pipes.

9.2.7.3.2 General Design Criterion 3, 1971 - Fire Protection

The ASW system is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.2.7.3.3 General Design Criterion 4, 1967 - Sharing of Systems

A normally closed MOV provides separation between the Unit 1 and Unit 2 ASW supply headers and is shown in Figure 3.2-17. Since the valve is normally closed, the crosstie does not expose either unit to an additional active failure. The unit crosstie provides operating flexibility in that it is possible to have the Unit 2 standby pump provide water to Unit 1 in the event the Unit 1 standby pump is inoperable and vice versa. The operating condition of Unit 2 will be considered before crosstying to prevent jeopardizing the safety of Unit 2. If Unit 2 is already in a shutdown condition during a postulated accident on Unit 1, then the Unit 2 standby saltwater pump can provide backup to Unit 1.

9.2.7.3.4 General Design Criterion 11, 1967 - Control Room

Appropriate ASW system instruments and controls are provided to permit system operation from the control room (refer to Section 9.2.7.5). The ASW pumps are designed to be remotely operated from the HSP in the event that the main control room is uninhabitable (refer to Section 7.4.2.1.2.2).

9.2.7.3.5 General Design Criterion 12, 1967 - Instrumentation and Control Systems

The ASW system is monitored by the instrumentation listed in Section 9.2.7.5.

9.2.7.3.6 Auxiliary Saltwater System Safety Function Requirements

(1) Waste Heat Removal

The ASW system is designed to provide sufficient heat removal to maintain the CCW system within its design basis temperature limits for normal operation, plant cooldown and design basis accident conditions.

The CCW system transfers heat from both vital and non-vital systems to the UHS via the ASW system during normal operations and reactor shutdown. During normal operation, both ASW pumps and one supply header are aligned with the operating CCW heat exchanger. Only one pump is required to run; the second pump, being on standby, provides backup against an active failure. By means of unit and redundant supply header crosstie MOVs, the standby pump for one plant unit may act as a second standby for the other unit.

The ASW system capability to perform its design basis function assumes the ASW pumps are capable of providing the minimum required flow under conditions of low tide, high CCW heat exchanger tube side differential pressure and supply temperatures up to 64°F. As discussed in Section 9.2.5, the Technical Specifications require a second CCW heat exchanger be placed in service when UHS temperature exceeds 64°F. The ASW flow rate and minimum acceptable flow are a function of the number of ASW pumps and CCW heat exchangers in service based on operating conditions and assumed single failure.

The ASW system is designed to provide sufficient heat removal to maintain the CCW system within its design basis temperature limits for normal CCW system conditions.

During plant cooldown the ASW and CCW systems operate together to remove heat from vital equipment as follows:

- Reactor decay heat (RHR)
- Equipment and cooling

During the cooldown phase of a routine plant shutdown, both ASW pumps and CCW heat exchangers are in operation. If one pump or supply header is inoperative during cooldown, cooling would be accomplished safely, but the cooldown time would be extended.

Following design basis accidents with a postulated single active or passive failure, the ASW and CCW systems operate together to remove heat from vital equipment including heat loads as follows:

- Reactor Decay Heat

- Containment Accident Heat Loads
- Vital Loads

The ASW/CCW system must be able to remove the minimum required heat in order to ensure that the containment design pressure and temperature is not exceeded. Additionally, the ASW system must be able to remove sufficient heat from the CCW system so as to not exceed the CCW system design basis temperature limits when the containment heat removal equipment is operating at maximum predicted heat removal rates. The adequacy of the heat sink provided by the ASW/CCW systems has been evaluated to ensure that the minimum heat removal function is satisfied following a LOCA or MSLB (References 5 and 6). The ability of the ASW/CCW system to support the maximum containment heat removal without exceeding the CCW system design basis temperature limits following LOCA or MSLB has also been demonstrated (Reference 3).

During the SI phase or upon loss of the offsite power supply, both ASW pumps receive a start signal. On a bus transfer with no SI signal or loss of the offsite power supply, the previously operating ASW pump will immediately be restarted and the standby pump will receive a start signal. This design ensures both pumps in operation following the event of accident or upset condition, excluding the condition of a Class 1E F or G bus failure.

In the injection and post-LOCA recirculation phases of the accident, no operator action is required for operation or reconfiguration of the ASW system and its components. A decision to split the ASW system into separate trains to mitigate a passive failure would be made by the TSC if it became required. (Reference 8)

The capacity of the ASW system is based on post-design basis accident heat rejection requirements. The ASW and CCW systems operate together to remove heat from containment and safety-related loads following a design basis accident. Together the ASW and CCW systems must be able to remove the minimum required heat loads to ensure that the containment design pressure and temperature limits are not exceeded. The ASW system is designed to provide sufficient heat removal to maintain the CCW system within its design basis temperature limits for post-accident CCW system conditions.

The ASW system and CCW system are essentially considered a single heat removal system for the purpose of assessing the ability to sustain either a single active or passive failure and still perform design basis heat removal. The heat removal capability of the ASW/CCW system has been evaluated to ensure that the minimum containment heat removal function is satisfied following a LOCA or MSLB (References 5 and 6). A single train of ASW (one ASW pump and one CCW heat exchanger) provides sufficient heat removal from containment to mitigate an MSLB or LOCA. The ability of the ASW and CCW systems to support the maximum containment heat removal without exceeding the CCW maximum supply temperature design basis limit following a LOCA

or MSLB has also been demonstrated (Reference 3). The mechanistic analyses credited one or two ASW pumps, depending on the assumed single failure. A single CCW heat exchanger was assumed to be in service throughout the transient (except when the UHS temperature exceeds 64°F, two CCW heat exchangers are assumed in service). No credit was taken for operator action to align the second CCW heat exchanger or an ASW pump from the opposite unit.

The design basis for ASW system performance to support analysis for peak containment pressure is described in Section 6.2. The design basis for ASW system performance to support the analysis for peak CCW temperature transients is described in Section 9.2.2. Critical ASW system assumptions include maximum ASW temperature, minimum ASW flow rate to the CCW heat exchanger, and single pump/heat exchanger operation (refer to References 3, 5, and 6).

(2) Single Failure

A malfunction analysis is presented in Table 9.2-2.

The ASW system and CCW system are essentially considered a single heat removal system for the purpose of assessing the ability to sustain either a single active or passive failure and still perform design basis heat removal. Refer to Section 3.1.1 for a description of DCPP single failure criteria and definition of terms.

During post-LOCA long term recirculation, the ASW trains should remain cross-tied to assure that any active failure in the ASW or CCW system would not result in the loss of CCW system cooling. While vulnerable to a passive failure in this configuration, the ASW system capacity is such that the ASW system function would not be affected. A decision to split the ASW system into separate trains to mitigate a passive failure would be made by the TSC if it became required. (Reference 8)

The ASW system is comprised of active components for which design classifications are given in Table 3.2-3. The ASW system can sustain either an active or a passive failure and still perform its function.

(3) Redundancy

Redundancy is provided by having two ASW pumps, one running and one on standby, and two CCW heat exchangers, with one normally in service and one in standby. The ASW system can be cross-connected within trains and between units so that various pump-heat exchanger combinations can be used for cooling. Redundant vacuum breakers are installed at the vertical bend of each line to eliminate water hammer.

Each unit's pair of ASW pump trains shares a common traveling screen to remove floating debris from the incoming seawater. If the common screen for a unit becomes clogged with debris, seawater may be supplied to the ASW pump bays from the unit's circulating water pump bays via the demusseling valves. Level transmitters are

provided on both the inlet and outlet of the ASW common traveling water screen in each unit for the purpose of indication and annunciation of water level differential across the common screen and for automatic screen start. The level transmitters are shown in Figure 3.2-17.

(4) Isolation

The design classification of the CCW heat exchangers is listed in Table 3.2-3. Rupture of the heat exchanger tubes or channel is considered highly unlikely because of low operating pressures and the use of corrosion-resistant materials. However, a leaking heat exchanger can be identified by sequential isolation or visual inspection. If the leak should be in the operating heat exchanger, the standby heat exchanger will be placed in operation and the leaking heat exchanger isolated and repaired.

(5) Protection from Missiles

The provisions taken to protect the vital CCW system from missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Sections 3.5.

(6) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the PG&E Design Class I portion of the ASW system from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Section 3.6.

(7) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection of the PG&E Design Class I portion of the ASW system located outside containment from the effects of moderate energy pipe failure are discussed in Section 3.6.

(8) Protection from Flooding Effects – Outside Containment

The provisions taken to provide protection of the vital portion of the CCW system from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

No systems that are required for safe shutdown are rendered inoperable due to flooding caused by a postulated break in the ASW piping. The low operating pressure and temperature of the saltwater system minimizes the possibility of a line severance. However, a severance would be detected and alarmed to the control room as low differential pressure across the heat exchanger and a high temperature rise across the CCW system, and possibly a pump motor failure. Sufficient valving is provided to isolate the units and their redundant trains from the failed section of piping.

Most of the ASW piping is buried except for short sections in the intake structure, the vacuum breaker vaults and the turbine building. A pipe break inside an ASW pump room or outside the boundary of both unit rooms in the Intake would not jeopardize the other pump motors. Each pump is housed in its own watertight compartment; therefore a pipe break would only flood one compartment. No components required to be operated for safe shutdown are located in the vacuum breaker vault. Failure of the ASW supply inside the turbine building would result in draining to the turbine building sumps (TBSs); a break in the ASW system discharge piping to the ocean would not result in flooding of the turbine building unless flow blockage in the line occurs, since the line pressure is negative.

In the event that the entire contents of the hotwell and heater drain tanks are discharged to the turbine building, the operability of PG&E Design Class I equipment (CCW heat exchangers) in the building is not endangered. The volume of water that would be discharged is within the capacity of the turbine building drain system. This system includes one 18-inch drain line from the TBS of each unit to the CWS discharge structure (refer to Figure 3.2-27 and Table 1.6-1). If this drain were clogged, the water flow would begin to fill the TBSs and equipment pits below 85 feet (refer to Figures 1.2-16 and 1.2-20). However, the capacity (58,000 cubic feet) below this elevation is more than the potential flooding volume. Refer to Section 10.4.7 for further discussion of flooding in the turbine building.

The ASW system is physically separated from all piping carrying high-energy fluid. The ASW system is a moderate-energy system as described in Section 3.6.

(9) Leak Detection

Provisions exist to isolate the CCW heat exchanger on both the ASW (tube-side) and CCW (shell-side). Large leakage could be detected by differential pressure across the tube side of the heat exchanger, by a decrease in CCW flow out of the heat exchanger, or by makeup to the CCW system.

The ASW discharges directly to the UHS. The ASW system provides cooling to the CCW heat exchanger. The CCW system is normally non-radioactive; however, the radiation level of the CCW system is monitored and an alarm is provided with a predetermined radiation level setpoint (refer to Section 11.4). In the event of an alarm for radiation on the CCW system, immediate efforts would be made to isolate the in-leakage. If the in-service CCW heat exchanger developed a leak at the same time, the heat exchanger would be isolated and the standby heat exchanger placed in service. Potential radioactive leakage into the CCW system is monitored to prevent/minimize release to the environment, via the ASW system, in the event of a concurrent leak in the heat exchanger.

Molybdate concentration in the CCW system is maintained by procedure for corrosion prevention. In the event of a leak, small or large, the chemical concentration in plant

effluent would be greatly reduced by dilution with the ASW system and then by the main CWS.

9.2.7.3.7 10 CFR 50.55a(f) - Inservice Testing Requirements

The ASW system contains pumps and valves classified as PG&E Design Class I. The IST requirements for these components are contained in the IST Program Plan and comply with the ASME Code.

9.2.7.3.8 10 CFR 50.55a(g) - Inservice Inspection Requirements

The ISI requirements for CCW system components are contained in the ISI Program Plan and comply with the ASME Code.

9.2.7.3.9 10 CFR 50.63 – Loss of All Alternating Current Power

The ASW system provides cooling water in support of safe shutdown of the plant (Mode 3) following a SBO. Using a single ASW pump and heat exchanger, the system provides cooling water to the CCW system. Refer to Section 9.2.2.3.19 for description of components cooled by the CCW system.
Refer to Section 8.3.1.6 for further discussion of station blackout.

9.2.7.3.10 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The ASW system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

9.2.7.3.11 Generic Letter 89-10, June 1989 - Safety-Related Motor-Operated Valve Testing and Surveillance

The ASW system MOVs subject to the requirements of Generic Letter 89-10, June 1989 and associated Generic Letter 96-05, September 1996 meet the requirements of the DCPP MOV Program Plan.

9.2.7.3.12 Generic Letter 89-13, July 1989 - Service Water System Problems Affecting Safety-Related Equipment

Design fouling is considered in accident analyses. Fouling is a combination of tube microfouling and tube flow blockage resulting from marine life. Mechanical tube plugging is limited to two percent of the tubes before the performance of the heat exchanger, as defined by the curves, is impacted. As noted in Section 9.2.7.2.3, provisions exist to control marine fouling on the tube side (ASW) of the CCW heat exchanger. Cathodic protection is provided on the tube side of the heat exchanger in the waterboxes.

9.2.7.3.13 Generic Letter 91-13, September 1991 - Essential Service Water System Failures at Multi-Unit Sites

A normally closed MOV provides separation between the Unit 1 and Unit 2 ASW supply headers and is shown in Figure 3.2-17. Since the valve is normally closed, the crosstie does not expose either unit to an additional active failure. The unit crosstie provides operating flexibility in that it is possible to have the Unit 2 standby pump provide water to Unit 1 in the event the Unit 1 standby pump is inoperable and vice versa. The operating condition of Unit 2 will be considered before crosstying to prevent jeopardizing the safety of Unit 2. If Unit 2 is already in a shutdown condition during a postulated accident on Unit 1, then the Unit 2 standby saltwater pump can provide backup to Unit 1. Equipment Control Guideline 17.1, ”Auxiliary Saltwater Cross-Tie Valve FCV-601,” provides requirements for the valve operability.

The ASW system provides cooling water in support of safe shutdown of the plant (Mode 3) following a SBO. Using a single ASW pump and heat exchanger, the system provides cooling water to the CCW system. Refer to Section 9.2.2.3.19 for description of components cooled by the CCW system.
Refer to Section 8.3.1.6 for further discussion of station blackout.

9.2.7.4 Tests and Inspections

The operating components are in either continuous or intermittent use during normal plant operation. Periodic testing of the standby feature of the ASW pump, testing of alarm setpoints, and visual inspections and preventive maintenance will be conducted in accordance with normal plant operating practices.

9.2.7.5 Instrumentation Applications

The ASW system is monitored by the following instrumentation:

(1) Differential pressure transmitters for both CCW heat exchangers

(2) ASW header pressure indicators

(3) Automatic start feature of the standby pump on loss of header pressure with pump status indicator in the control room

(4) Temperature indicators on the CCW heat exchanger, ASW (tube side) inlet and outlet

(5) Valve position indicators in the control room

(6) Differential level across the traveling water screens

(7) ASW pump room high water level alarm

(8) ASW pump room watertight door alarm

(9) High-temperature alarm for the ASW pump room

(10) ASW pump motor temperature indicators: upper/lower bearings and motor stator winding

(11) Inlet gate position indicator

(12) CCW heat exchanger, CCW (shell side) outlet temperature indicators

(13) ASW pump bay level indication

(14) ASW pump bay level alarm

9.2.8 DOMESTIC WATER SYSTEM

The DWS processes raw water from the raw water storage reservoirs to provide water suitable for human consumption.

9.2.8.1 Design Bases

The DWS is designed to provide drinking water at the plant. It is a PG&E Design Class III system.

9.2.8.2 System Description

The DWS receives its water from the domestic water treatment system. The domestic water treatment system takes water from the raw water storage reservoirs and processes it through a multi-media filter, a reverse osmosis module, a neutralizing-media filter, an activated carbon filter, and finally through a 10-micron cartridge filter. Prior to transferring the water to the domestic water storage and distribution piping system, it is disinfected using chlorine. The water is then supplied to the plant for drinking.

The radioactively uncontaminated utilities that receive domestic water include:

(1) Lavatories

(2) Water heaters

(3) Showers

(4) Maintenance connections

(5) Emergency eye wash

(6) Hose bibs

(7) Kitchen sinks

(8) Chemical laboratory sink in the chlorination building

(9) Drinking fountains

(10) Chemical laboratory sinks in maintenance shop buildings

(11) Landscape irrigation

After use, the domestic water passes into the plant sewage system where it is treated in a sewage treatment plant before being discharged to the ocean.

The potentially radioactively contaminated utilities that use domestic water are:

(1) Hot showers

(2) Laundry facilities

(3) Laboratory sinks

(4) Washdown area in hot machine shop

(5) Utility water connections in the radiologically controlled area

This water, after being used, drains to the liquid radwaste system (LRS) (refer to Section 11.2) for treatment.

9.2.8.3 Safety Evaluation

Failure of the DWS will not affect nuclear safety. Back-flow preventers are provided to prevent contamination of the domestic water by back-siphonage from potentially radioactively contaminated areas.

9.2.8.4 Tests and Inspections

Water quality tests and system integrity inspections will be performed periodically in accordance with normal plant operating procedures.

9.2.8.5 Instrumentation Applications

Local flow, pressure, and temperature indicators are used to monitor the system condition.

9.2.9 REFERENCES

1. Technical Specifications, Diablo Canyon Power Plant Unit 1 and Unit 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

2. Deleted in Revision 8

3. Evaluation of Peak CCW Temperature Scenarios for Diablo Canyon Units 1 and 2, WCAP-14282, Revision 1.

4. Deleted in Revision 12.

5. Analysis for Containment Response Following Loss-of-Coolant Accidents for Diablo Canyon Units 1 and 2, December 1993, WCAP-13907.

6. Analysis for Containment Response Following Main Steam Line Break for Diablo Canyon Units 1 and 2, December 1993, WCAP-13908.

7. NRC Letter, dated May 13, 1999, “Issuance of Amendments for Diablo Canyon Nuclear Power Plant, Unit No. 1 (TAC No. M98829) and Unit No. 2 (TAC No. M98830) and Close-out of Generic Letter 96-06 (TAC Nos. M96804 and M96805) (License Amendments 134/132)

8. NRC Letter, dated January 13, 2000, “Issuance of Amendments for Diablo Canyon Nuclear Power Plant Unit Nos. 1 and 2 (TAC Nos. MA 1406 and MA 1407) (License Amendments 138/138)

9.2.10 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

9.3 PROCESS AUXILIARIES

The process auxiliaries consist of those auxiliary systems associated with the reactor process systems. These systems include:

(1) the compressed air systems, including the backup air/nitrogen supply system (refer to Section 9.3.1);

(2) the sampling system (refer to Section 9.3.2);

(3) equipment and floor drainage systems (refer to Section 9.3.3);

(4) the CVCS (refer to Section 9.3.4);

(5) failed fuel detection (performed using the sampling system) (refer to Section 9.3.5);

(6) nitrogen and hydrogen systems (refer to Section 9.3.6);

(7) miscellaneous process auxiliaries (i.e., the auxiliary steam system, and the oily water separator [OWS] and TBS system) (refer to Section 9.3.7).

9.3.1 COMPRESSED AIR SYSTEM

The compressed air system (refer to Figure 3.2-25) provides compressed air for process control systems and for station service throughout Unit 1 and Unit 2 under normal operating conditions. The compressed air system consists of instrument air, service air, and the backup air/nitrogen systems. The backup air/nitrogen supply system is described in Section 9.3.1.2.2. The compressed air system is shared by Unit 1 and Unit 2. Table 3.2-3 lists its design classification.

The PG&E Design Class I portions of the instrument air and service air systems include the piping penetrating containment between the CIVs. The backup air/nitrogen supply system supplies compressed gas to the PG&E Design Class I pneumatic-operated components that are required to perform an active PG&E Design Class I function after the loss of the compressed air system. The backup air/nitrogen supply system also supplies air/nitrogen to selected components, pursuant to PG&E's commitments to the NRC to provide a seismically qualified backup air/nitrogen supply; hence these components are classified as PG&E Design Class I even though operability of the valves is not strictly a PG&E Design Class I function.

9.3.1.1 Design Bases

9.3.1.1.1 General Design Criterion 2, 1967 – Performance Standards

Portions of the compressed air system are designed to withstand the effects of, or are protected against, natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

9.3.1.1.2 General Design Criterion 3, 1971 – Fire Protection

The compressed air system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.3.1.1.3 General Design Criterion 4, 1967 – Sharing of Systems

The compressed air system is not shared by the DCPP units unless it is shown that safety is not impaired by the sharing.

9.3.1.1.4 General Design Criterion 11, 1967 – Control Room

The compressed air system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room.

9.3.1.1.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the compressed air system variables within prescribed operating ranges.

9.3.1.1.6 General Design Criterion 40, 1967 – Missile Protection

The containment isolation portion of the compressed air piping system that penetrates containment is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

9.3.1.1.7 General Design Criterion 49, 1967 - Containment Design Basis

The compressed air system piping penetrating containment is designed so that the containment structure can accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a LOCA including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of ECCSs.

9.3.1.1.8 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The portions of the instrument air and service air piping systems that penetrate containment are provided with leak detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. These piping systems are designed with a capability to test periodically that operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

9.3.1.1.9 General Design Criterion 56, 1971 - Primary Containment Isolation

The instrument air system contains valves in piping that penetrates containment and is connected directly to the containment atmosphere. One automatic isolation valve is provided outside containment and one check valve inside containment to ensure containment integrity is maintained.

The service air system contains valves in piping that penetrates containment and is connected directly to the containment atmosphere. One normally sealed closed manual valve is provided outside containment and one check valve inside containment to ensure containment integrity is maintained.

9.3.1.1.10 Compressed Air System Safety Function Requirements

(1) Protection from Missiles

The PG&E Design Class I backup-air/nitrogen supply portion of the compressed air system is designed to be protected against the effects of missiles and dynamic effects which may result from equipment failures and postulated rupture of piping. In addition, PG&E Design Class I components are protected against the effects of missiles resulting from the postulated failure of compressed air cylinders and associated piping.

(2) Protection Against High Energy Pipe Rupture Effects

The PG&E Design Class I backup-air/nitrogen supply portion of the compressed air system are designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The outside containment portion of the PG&E Design Class I backup-air/nitrogen system is designed to be protected against the effects of moderate energy pipe failure.

(4) Protection from Jet Impingement – Inside Containment

The inside containment portion of the PG&E Design Class I backup-air/nitrogen system is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

(5) Protection from Flooding Effects – Outside Containment

The outside containment portion of the PG&E Design Class I backup-air/nitrogen system is to be protected from the effects of internal flooding.

(6) Backup Air/Nitrogen Capacity

The backup air/nitrogen system is designed to have sufficient capacity to allow pneumatically operated devices to perform their design functions.

9.3.1.1.11 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

Instrument air components that require EQ are qualified to the requirements of 10 CFR 50.49.

9.3.1.1.12 10 CFR 50.55a(f) – Inservice Testing Requirements

The PG&E Design Class I compressed air system ASME pump and valves are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

9.3.1.1.13 10 CFR 50.55a(g) – Inservice Inspection Requirements

The PG&E Design Class I compressed air system ASME BPVC Section XI components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

9.3.1.1.14 10 CFR 50.63 – Loss of All Alternating Current Power

The backup air bottles supplying the 10 percent atmospheric dump valves contain sufficient pressure to support decay heat removal to maintain hot standby during a SBO event.

9.3.1.1.15 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The compressed air system provides instrumentation in the control room to monitor instrument air CIV status post-accident.

9.3.1.1.16 Generic Letter 88-14, August 1988 – Instrument Air Supply Problems Affecting Safety-Related Equipment

The PG&E Design Class I portions of the instrument air system address the air quality requirements of Generic Letter 88-14, August 1988.

9.3.1.2 System Description

9.3.1.2.1 Compressed Air System

Compressed air is provided to each unit via two subsystems, instrument air and service air.

The compressed air system arrangement for Unit 1 and Unit 2 is shown in Figure 3.2-25. Table 9.3-1 lists design data for the components. Portions of the compressed air system are utilized by both the instrument air system and the service air system.

During normal operation the service air system is isolated from the instrument air system. A cross-tie line between the service air and the instrument air system can be used to supply instrument air if needed. To maintain instrument air purity, the backfeed air enters the instrument air system upstream of the instrument air after filters.

The compressed air system is required for startup and normal operation of the plant. Except for the portion of the backup air/nitrogen supply system described in Section 9.3.1.2.2, and the portion of the air distribution piping penetrating the containment, the compressed air system is PG&E Design Class II.

The plant can be taken to and maintained at hot shutdown without the use of air-operated valves. However, some air-operated valves are required for going from hot shutdown to cold shutdown.

Multiple air compressors supply instrument air to Unit 1 and Unit 2.

Two 650 scfm (minimum) water-cooled compressors and one 650 scfm air-cooled compressor provide instrument air. Typically, one compressor operates as a base-loaded machine with other compressors in automatic standby-start control

Four additional 300 scfm water-cooled compressors are available as needed to support instrument air system pressure under conditions where one or more compressors are out of service or the instrument air system is supplying the service air system.

Each 650 scfm compressor has its own control panel and remote loading/unloading sensor that senses pressure of the plant air receiver's outlet header via a pressure sensing line. Start and stop operation of each 300 scfm compressor is manual from their local control panels. Once started, these compressors load and unload

automatically to maintain system pressure based on the signal from the load/unload sensor to the compressors' respective PLC.

Since the compressed air system is not required for proper operation of pneumatically operated devices which have PG&E Design Class I functions, the system is not automatically switched to EDG power in the event of a loss of power. However, if diesel generator loading conditions permit, the air compressors can be manually restarted on EDG power.

All of the compressors in the DCPP compressed air systems are oil-free. This contributes to meeting the air quality requirements referenced in section 9.3.1.1.16.

The system has two air dryers. Both air dryers are designed to produce -40°F pressure dewpoint with a dryer inlet air temperature of 100°F and a pressure of 100 psig. However, the system components served by instrument air do not require that the system pressure dewpoint be maintained at -40°F. The air system pressure dewpoint is maintained at least 18°F below the minimum temperature at any point in the instrument air system to preclude water blockage of instrument air lines and to prevent a buildup of rust that can break free and block instrument air lines. The system pressure dewpoint is monitored by a direct reading dewpoint indicator, with a "high moisture content" local alarm and "common trouble alarm" in the main control room.

Dry air leaving the air receiver is filtered through a 1 micron positive seal type after-filter before passing to the instrument air distribution system. The after-filter is provided with differential pressure indication, with a "high differential pressure" local alarm and a "common trouble alarm" in the control room.

The two air receivers provide storage capacity to meet occasional high demands for compressed air.

Service Air System

The service air system, located outdoors east of Unit 2 transformer yard, has two compressors. Power supply to these compressors is from the 12-kV underground distribution system. Normally, one of the service air compressors operates as a base-loaded machine and the other service air compressor is on automatic standby – start control. The compressors automatically match the downstream Service Air demand at the target pressure setpoint by utilizing the internal discharge pressure transmitters and variable frequency drives to vary the motor speed. Start and stop operation of the compressors is manual from its local control panels. Once started, these compressors operate automatically.

The service air system has two air dryers. Like the instrument air system air dryers, these dryers are also designed to produce -40°F pressure dewpoint. The service air system pressure dewpoint is also maintained within the limits stated above for the

instrument air system. Dry air leaving the air dryers is filtered through a 1-micron positive seal type after-filter before passing to the service air distribution system.

Additional temporary compressors may be used, as appropriate, to supply supplemental service air.

9.3.1.2.2 Backup Air/Nitrogen Supply System

The backup air/nitrogen supply system supplies the motive force to operate certain pneumatic components in the event of a loss of the compressed gas system. In some cases the backup air/nitrogen supply system supplements the compressed gas system rather than serving as a backup air/nitrogen supply. The backup air/nitrogen supply system utilizes as its source instrument air supplied from the compressed air system, and high pressure nitrogen supplied from the nitrogen system, which is then stored for use in accumulators. In addition, high pressure bottled air, high pressure bottled nitrogen and low pressure nitrogen from the nitrogen system are utilized. Compressed gas from these sources is supplied to pneumatic components that normally use instrument air from the compressed air system or high-pressure nitrogen from the nitrogen supply system.

Pneumatically operated devices are identified in the piping schematics of the various systems in Section 3.2. Loss of the normal air supply from the compressed air system will result in a safe shutdown of the unit. Most pneumatically operated devices in the plant that have PG&E Design Class I functions are designed to maintain a safe position or to assume a safe position upon loss of air pressure. Movement to this safe position (or maintaining this safe position) is accomplished by means of spring-return actuators and compressed gas from the backup air/nitrogen supply system. All such pneumatically operated devices are designed to achieve this safe position in the required time under the most limiting conditions, including gradual loss of the normal air supply from the compressed air system. Tables 3.9-9 and 6.2-39 show how valves will fail on loss of air or electrical power and the desired condition for safe shutdown. The tabulations show that most air-operated valves fail in the safe shutdown position upon loss of power or air. The tabulations also show the air operated valves that are required to operate or be maintained in a certain position for safe shutdown after an assumed loss of the compressed air system and that they are supplied with compressed gas from the backup air/nitrogen supply system (refer to Section 9.3.1.2.2). Therefore, safe shutdown will not be compromised upon loss of power or the compressed air system.

The backup air/nitrogen supply system supplies compressed gas to the PG&E Design Class I pneumatic-operated components that are required to perform an active PG&E Design Class I function after the loss of the compressed air system. The backup air/nitrogen supply system also supplies air/nitrogen to selected components, pursuant to PG&E's commitments to the NRC to provide a seismically qualified backup air/nitrogen supply; hence these components are classified as PG&E Design Class I even though operability of the valves is not strictly a PG&E Design Class I function. There are a number of PG&E Design Class II components that have a backup supply of

air/nitrogen in the event of loss of the compressed air system to prevent undesirable transients and/or to facilitate normal operation and shutdown. In addition, there are some components, or group of components, that when actuated require more air than can readily be supplied through the air/nitrogen supply connection. In these cases, local accumulators or receivers are provided that contain enough stored gas to allow these components to respond in the desired time. Design classifications are included in Table 3.2-3. This equipment is not part of a PG&E Design Class I pressure boundary, so it is not subject to ASME BPVC Section III or ANSI B31.7.

In general, accumulators and bottles are wall-mounted or column-mounted as close to the application as possible.

The main steam isolation valves (MSIVs) receive a close signal on indication of a main steam line rupture (low steam line pressure, above P-11 setpoint, or high steam line pressure rate, below P-11 setpoint, in any steam line), or high-high containment pressure. Locally mounted air reservoirs, protected against system failure by check valves, can hold open the MSIVs for a short duration of time to allow for recovery of the air system. However, if the air system cannot be recovered, the plant can still be safely shutdown with the MSIVs closed.

9.3.1.3 Safety Evaluation

9.3.1.3.1 General Design Criterion 2, 1967 – Performance Standards

Portions of the compressed air system are housed within the PG&E Design Class I auxiliary and containment buildings. These buildings, or applicable portions thereof, are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), external floods and tsunamis (refer to Section 3.4), earthquakes (refer to Sections 3.7 and 3.8.3), and other natural phenomena.

The PG&E Design Class I compressed air components have been seismically qualified.

PG&E Design Class I portions of the compressed air system that are located outside are resistant to tornadoes. The capability of the system served by compressed air to support plant safe shutdown is maintained if compressed air service to the supported components is lost (refer to Section 3.3.2).

The compressed air system components required to perform their PG&E Design Class I functions are located at higher elevations such that they are not affected by external floods and tsunamis.

The PG&E Design Class I portion of the backup air/nitrogen supply system is installed in accordance with the quality assurance requirements for PG&E Instrument Class IA and PG&E Instrument Class ID equipment. The accumulators are fabricated in accordance with the quality assurance requirements for PG&E Design Class I.

The PG&E Design Class I tubing is installed and protected in accordance with the PG&E Design Class I air piping requirements. The equipment is seismically qualified for its location in the plant to the applicable seismic spectra as described in Section 3.7.

9.3.1.3.2 General Design Criterion 3, 1971 – Fire Protection

The compressed air system is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.3.1.3.3 General Design Criterion 4, 1967 – Sharing of Systems

Since the instrument air and service air systems are not required for proper operation of pneumatically operated devices, which have PG&E Design Class I functions, sharing one air system for both units does not affect plant safety. A major failure of the distribution system for one unit could result in a loss of air pressure for the second unit but would not affect the safety of either unit. Manual isolation valves between units and on all major distribution headers allow isolation of sections of the system without affecting the normal operation of the remainder of the system. Automatic containment isolation will prevent accident conditions from propagating through the air system. The PG&E Design Class I portions of the backup air/nitrogen system are not shared between Unit 1 and Unit 2.

9.3.1.3.4 General Design Criterion 11, 1967 – Control Room

The compressed air system is designed to support actions to maintain and control the safe operational status of the plant from the control room.

Alarms in the control room indicate:

(1) "Common trouble" instrument air

(2) "Common trouble" service air

The "Common Trouble" Instrument Air alarms are comprised of various system and component abnormal operations, and are flashed at the local annunciator "PK-80" located near the compressors at the 85 feet elevation in the turbine building.

The "common trouble" service air alarms are comprised of:

(1) Service air high moisture

(2) Service air low pressure

Instruments are provided to indicate operational status of the major components of the compressed air system.

Backup air for the 10 percent atmospheric dump valves is alarmed in the control room.

9.3.1.3.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the compressed air system variables within prescribed operating ranges.

Local indications for the service air system moisture and pressure are provided near Unit 2 containment access controls at elevation 140 feet of the turbine building.

9.3.1.3.6 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the containment isolation portion of the compressed air system from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures are discussed in Sections 3.5, 3.6, and 6.2.4.

9.3.1.3.7 General Design Criterion 49, 1967 - Containment Design Basis

The compressed air piping routed through containment penetrations is designed to withstand the pressures and temperatures that could result from a LOCA without exceeding the design leakage rates. Refer to Sections 3.8.2.1.1.3 and 6.2.4, and Table 6.2-39 for additional details.

9.3.1.3.8 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The compressed air system CIVs are periodically tested for operability and leakage. Testing of components required for the CIS is discussed in Section 6.2.4. Test connections are provided in the penetration and in the piping to verify valve and penetration leakage within prescribed limits.

9.3.1.3.9 General Design Criterion 56, 1971 - Primary Containment Isolation

The compressed air penetrations that are part of the CIS include the instrument and service air penetrations, which comply with the requirements of GDC 56, 1971, as described in Section 6.2.4 and Table 6.2-39.

9.3.1.3.10 Compressed Air System Safety Function Requirements

(1) Protection from Missiles

The provisions taken to protect the PG&E Design Class I backup-air/nitrogen portion of the compressed air system are discussed in Section 3.5.

Equipment essential for a safe and maintained reactor shutdown is located near major components of the compressed air system. This equipment is separated from these components by a PG&E Design Class I structure. As discussed in Section 3.5.2, the air receiver tanks (refer to Table 3.9-11) are capable of withstanding the thrust developed by failure of the largest pipe connected to them. The stresses in the tank holddown structure relating from this thrust do not exceed yield strength. Thus there is no danger to safe shutdown from postulated missiles created by the compressed air system.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the PG&E Design Class I backup-air/nitrogen portion of the compressed air system from damage that might result from dynamic effects associated with a postulated rupture of piping are discussed in Section 3.6.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection of the PG&E Design Class I backup-air/nitrogen portion of the compressed air system located outside containment from the effects of moderate energy pipe failure are discussed in Section 3.6.

(4) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the PG&E Design Class I backup-air/nitrogen portion of the compressed air system located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

(5) Protection from Flooding Effects – Outside Containment

The provisions taken to provide protection of the PG&E Design Class I backup-air/nitrogen portion of the compressed air system from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

(6) Backup Air/Nitrogen Capacity

The backup air/nitrogen system is designed to have sufficient capacity to allow pneumatically operated devices to perform their safety functions.

The backup air/nitrogen supply system provides a backup supply of compressed gas to the air-operated valves that are required to take the plant to cold shutdown and for those pneumatic operated valves that require a backup supply of compressed gas for other functions.

To take the plant to cold shutdown from hot shutdown, compressed gas from the backup air/nitrogen supply system is provided to valves for charging/spray capability, steam dump capability, and RCS boration sample capability. In addition, the operator also will have available the pressurizer power-operated relief valves (PORVs) required for overpressure protection, the capacity of letdown by line isolation valves, and containment fire water isolation valves. Backup air is also supplied to CCW control valves on the outlet of the RHR heat exchanger and the ASW control valves on the inlet of the CCW heat exchanger to ensure that these valves may be operated or maintained in the required position for safe shutdown.

Backup air/nitrogen for shutdown is provided in four ways:

(1) RCS boration sample valves are equipped with air accumulators that are protected from back flow into the main system by check valves. These can be used because the number of cycles for each valve is small, the air required for each valve is small, and the valves do not consume air in the quiescent state. The containment fire water isolation valve, the RHR heat exchanger CCW outlet valves and CCW heat exchanger ASW inlet valves are also equipped with accumulators to ensure that the valves can be operated or maintained in the required position for safe shutdown in the event of a loss of offsite power that causes the loss of the compressed air system. The containment fire water isolation valve is equipped with a seismically qualified accumulator to help ensure the valve can remain open in the event of a fire after an earthquake so that manual fire fighting capabilities are available inside containment to the PG&E Design Class I equipment.

(2) Throttling valves (the SG 10 percent atmospheric dump valves) and charging pump valve (the discharge to regenerative heat exchanger) consume air in the quiescent state. These valves are supplied with backup nitrogen supplies. The nitrogen system is capable of supplying motive gas as long as required since the requirements are small compared to the system capacity. The nitrogen system is not seismically qualified, so a second backup system is provided. It is composed of compressed air bottles for the 10 percent atmospheric dump valves which can supply varying amounts of air via solenoid valves controlled from the control room and a nitrogen accumulator for the charging pump valve. Should the compressed air system and the nitrogen backup systems both fail, the compressed air bottles will be enabled by the operator to allow the operator to position the 10 percent atmospheric dump valves at any position desired. The charging pump valve (the discharge to regenerative

heat exchanger) needs only to be placed in the open or closed position, so its backup consists of a control-room-operated solenoid valve that can supply motive gas from the nitrogen accumulator bypassing the normal control system.

(3) Letdown line isolation valves are supplied with backup nitrogen from the nitrogen system.

(4) The pressurizer PORVs, charging pump valves (to loop 3 and loop 4 of the cold leg), and the pressurizer auxiliary spray valve are special cases of on-off valves. Due to the number of cycles and the size of the valves, normal air receivers would be huge. Therefore, a high pressure nitrogen accumulator for each valve is provided which is supplied by the nitrogen system at approximately 850 psig. These high-pressure accumulators are capable of providing sufficient motive gas to meet all the requirements on loss of both the compressed air and nitrogen systems. (It should be noted that the cycling requirements for the PORVs comes from overpressure protection for mitigation of a spurious SI event, not shutdown requirements [refer to Section 15.2.15.3]).

9.3.1.3.11 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

The instrument air components required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. The affected equipment are instrument air control isolation valve FCV-584 components consisting of a solenoid valve and position indication require EQ that are listed on the EQ Master List.

9.3.1.3.12 10 CFR 50.55a(f) – Inservice Testing Requirements

The IST requirements for compressed air pumps and valves are contained in the IST Program Plan and comply with the ASME Code for Operation and Maintenance of Nuclear Power Plants.

9.3.1.3.13 10 CFR 50.55a(g) – Inservice Inspection Requirements

Compressed air system components are included in the ISI program in accordance with ASME BPVC, Section XI.

9.3.1.3.14 10 CFR 50.63 – Loss of All Alternating Current Power

The backup air bottles supplying the 10 percent atmospheric dump valves contain sufficient pressure to support decay heat removal to maintain hot standby during a SBO event.

9.3.1.3.15 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The compressed air system provides instrumentation in the control room to monitor the instrument air system CIV post-accident position indication.

9.3.1.3.16 Generic Letter 88-14, August 1988 – Instrument Air Supply Problems Affecting Safety-Related Equipment

In the response to Generic Letter 88-14, August 1988, PG&E committed to verify by test that actual instrument air quality supplied to PG&E Design Class I equipment was consistent with the manufacturer's recommendations and that PG&E Design Class I equipment would function as intended on loss of instrument air.

In order to ensure that oil, water, or other impurities will not result in the failure of instrumentation or other equipment, the compressed air system is provided with oil-free compressors, prefilters, moisture separators, air dryers, and 1-micron after-filters.

9.3.1.4 Tests and Inspections

The compressed air system was tested and inspected prior to initial plant operation. Provisions are made for functional tests of the low air pressure alarm and containment isolation. Filters, air dryers, and air receivers are periodically inspected.

9.3.1.5 Instrumentation Applications

Instrumentation for the compressed air system is discussed in Sections 9.3.1.3.4 and 9.3.1.3.5.

9.3.2 SAMPLING SYSTEMS

The plant sampling systems provide a means for obtaining liquid and gas samples for laboratory analyses of chemical and radiochemical conditions of the designated reactor and secondary plant systems. The systems are designed to permit sampling during all modes of plant operation. The sampling systems provide the means for manual, grab type, sample collection, and where applicable, on-line monitoring of key chemistry parameters. Assurance of a representative sample will be by administrative procedures based on experience and good sampling techniques. These will include purging of sample lines prior to taking a sample and utilizing appropriate pre-cleaned sampling containers.

The DCPP Unit 1 and Unit 2 sampling systems are composed of the following subsystems:

1) NSSS sampling system (refer to Section 9.3.2.2.1)

2) Post-accident sampling system (PASS) (refer to Section 9.3.2.2.2)

3) Secondary sampling system (refer to Section 9.3.2.2.3)

4) Turbine steam analyzer system (refer to Section 9.3.2.2.4)

9.3.2.1 Design Bases

9.3.2.1.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portion of the NSSS sampling system, containment atmosphere monitoring system, and secondary sampling system are designed to withstand the effects of, or are protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

9.3.2.1.2 General Design Criterion 3, 1971 – Fire Protection

The PG&E Design Class I portion of the NSSS sampling system, containment atmosphere monitoring system, and secondary sampling system are designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.3.2.1.3 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The portion of the NSSS sampling system within the RCPB is designed and constructed to have an exceedingly low probability of gross rupture or significant leakage throughout its design lifetime.

9.3.2.1.4 General Design Criterion 11, 1967 – Control Room

The NSSS sampling system, containment atmosphere monitoring system, and secondary sampling system are designed to or contain instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room.

9.3.2.1.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the NSSS sampling system, secondary sampling system, and PASS variables within prescribed operating ranges.

9.3.2.1.6 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The sampling systems are designed to provide means for monitoring the containment atmosphere, the facility effluent discharge paths of the NSSS sampling system and containment atmosphere monitoring system, and the facility environs for radioactivity that could be released from normal operations, from anticipated transients, and from accident conditions (refer to Section 12.2).

9.3.2.1.7 General Design Criterion 40, 1967 – Missile Protection

The containment isolation portion of the NSSS sampling, secondary sampling, and containment atmosphere monitoring systems that penetrate containment is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

9.3.2.1.8 General Design Criterion 49, 1967 – Containment Design Basis

The PG&E Design Class I portion of the NSSS sampling system, containment atmosphere monitoring system, and secondary sampling system are designed so that the containment structure can accommodate without exceeding the design leakage rate the pressures and temperatures resulting from the largest credible energy release following a LOCA, including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of ECCSs.

9.3.2.1.9 General Design Criterion 54, 1971 – Piping Penetrating Containment

NSSS sampling system piping, containment atmosphere monitoring system piping, and secondary sampling system piping that penetrate containment are provided with leak detection, isolation, redundancy, reliability and performance capabilities that reflect the importance to safety of isolating the system. The piping is designed with the capability to periodically test the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

9.3.2.1.10 General Design Criterion 55, 1971 – Reactor Coolant Pressure Boundary Penetrating Containment

Each NSSS sampling system line piping that penetrates containment is provided with CIVs.

9.3.2.1.11 General Design Criterion 56, 1971 – Primary Containment Isolation

The containment atmosphere monitoring system contains valves in piping that penetrates containment and is connected directly to the containment atmosphere. One automatic isolation valve is provided inside containment and one automatic isolation valve outside containment to ensure containment integrity is maintained.

9.3.2.1.12 General Design Criterion 57, 1971 – Closed System Isolation Valves

The secondary sampling system is designed such that each line that penetrates primary reactor containment and is not part of the RCPB or connected directly to the containment atmosphere has at least one CIV which is automatic.

9.3.2.1.13 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The NSSS sampling system is designed for maintaining control over the plants radioactive gaseous effluents. Appropriate holdup capacity is provided for retention of gaseous effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment.

9.3.2.1.14 Sampling System Safety Function Requirement

(1) Post-accident Sampling

Contingency plans are required for obtaining and analyzing highly radioactive samples of reactor coolant, containment sump, and containment atmosphere.

(2) Protection from Jet Impingement – Inside Containment

The PG&E Design Class I portion of the NSSS, post-accident, and secondary sampling systems located inside containment is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

9.3.2.1.15 10 CFR Part 20 – Standards for Protection Against Radiation

The NSSS sampling system supports the protection of personnel from radiation sources such that doses are maintained below the limits prescribed in 10 CFR Part 20.

9.3.2.1.16 10 CFR 50.49 – Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

NSSS sampling system, containment atmosphere monitoring system, and secondary sampling system that require EQ are qualified to the requirements of 10 CFR 50.49.

9.3.2.1.17 10 CFR 50.55a(f) – Inservice Testing Requirements

The PG&E Design Class I sampling system valves comply with the ASME code for Operation and Maintenance of Nuclear Power Plants and are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

9.3.2.1.18 10 CFR 50.55a(g) – Inservice Inspection Requirements

The PG&E Design Class I sampling system components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

9.3.2.1.19 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water- Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The NSSS sampling system provides instrumentation to monitor system variables during and following an accident.

9.3.2.1.20 NUREG-0737 (Item III.D.1.1), November 1980 – Clarification of TMI Action Plan Requirements

Item III.D.1.1 – Primary Coolant Outside Containment: A program to reduce leakage from the NSSS sampling system and PASS outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as-low-as-practical levels.

9.3.2.1.21 Generic Letter 96-06, September 1996 – Assurance of Equipment Operability and Containment Integrity during Design-Basis Accident Conditions

NSSS sampling system piping and secondary sampling system piping have been evaluated for the issue of thermal over-pressurization of isolated piping sections that could affect containment integrity during accident conditions, as described in Generic Letter 96-06, September 1996.

9.3.2.2 System Description

9.3.2.2.1 Nuclear Steam Supply System Sampling System

The NSSS sampling system is designed for manual operation on an intermittent basis, under conditions ranging from full power operation to cold shutdown. Pipe internal diameters are sized such that solids do not clog the lines.

Sampling system discharge flows are limited under normal and anticipated fault conditions (malfunctions or failure) to preclude any radioactivity release beyond the site

boundary in excess of plant release limitations. Adequate safety features are provided to protect laboratory personnel and prevent the spread of contamination from the sampling room. The reactor coolant hot leg samples are routed through a sufficiently long length of tubing inside containment, and flow rates are controlled to permit decay of the short-lived N^{16} isotope to a level that permits normal access to the sampling room. Equipment required for sampling capability to confirm RCS boron concentration is seismically qualified to allow the plant to be taken to cold shutdown conditions following a design basis seismic event. Backup air or nitrogen is provided to the required pneumatic-operated valves as described in Section 9.3.1.2.2.

The sampling system(refer to Figure 3.2-11) provides the representative samples for laboratory analyses. The analyses show both chemical and radiochemical conditions and provide guidance in the operation of the RCS, RHR, CVCS. Typical information obtained includes reactor coolant boron and chloride concentrations, fission product radioactivity level, hydrogen, oxygen, and fission gas content, conductivity, pH, corrosion product concentration, chemical additive concentration, etc. The information is used in regulating boron concentration adjustments, evaluating fuel element integrity and CVCS mixed bed demineralizer performance, and regulating additions of corrosion-inhibiting chemicals to the systems.

Samples are drawn from the following locations:

(1) Inside Containment

(a) The pressurizer steam space (RCS)

(b) The pressurizer liquid space (RCS)

(c) Hot legs of reactor coolant loops (2 points in the RCS)

(d) Each accumulator (SI system)

(2) Outside Containment

(a) The letdown line (2 points, upstream and downstream of the demineralizers) (CVCS)

(b) Each RHR heat exchanger outlet (RHR system)

(c) The volume control tank (VCT) gas and liquid space (CVCS)

Local sample connections are provided at various locations throughout the plant. These connections are not considered part of the sampling system. Samples originating from locations within the containment flow through lines to the sampling room in the auxiliary building. Each line is equipped with a manual isolation valve close to the sample

source, a remote air-operated valve immediately downstream of the isolation valve, and containment boundary isolation valves located inside and outside the containment.

Manual valves are located inside the sampling room for component isolation, sample flow control, and routing. High-temperature sample lines also contain a sample heat exchanger.

The reactor coolant hot leg samples are routed through a sufficiently long length of tubing inside containment, and flow rates are controlled to permit decay of the short-lived N^{16} isotope to a level that permits normal access to the sampling room. This room has controlled ventilation and drainage to control radioactivity release.

All sample lines originating from locations outside the containment are provided with manual isolation valves. The RHR system sample lines and the VCT liquid sample lines have, in addition, a remote air-operated sampling valve. Manual valves are located in the sampling room for flow control and routing.

The sample sink, which is located in the sampling room, contains a drain line to the LRS. Local instrumentation is provided to permit manual control of sampling operations and to ensure that the samples are at suitable temperatures and pressures before diverting flow to the sample sink. All sample lines are provided with a sample valve located at the sample sink, except for the VCT gas sample. The sample sink has a hood that is connected to the building ventilation exhaust system.

9.3.2.2.1.1 Component Description

Component codes and classifications are given in Table 3.2-3 and component design parameters are listed in Table 9.3-2.

9.3.2.2.1.1.1 Sample Heat Exchangers

The sample heat exchangers are of the shell and coil tube type. Sample flow circulates through the tube side, while CCW circulates through the shell-side. The tube side connections have socket-welded joints for connections to the high-pressure sample lines.

9.3.2.2.1.1.2 Sample Pressure Vessels

The sample vessels are sized to provide sufficient gas volume to perform a radiochemical analysis on the VCT gas space constituents, or sufficient reactor coolant volume for dissolved hydrogen and fission gas analyses.

Integral isolation valves are furnished with the vessel. Quick disconnect couplings containing poppet-type check valves are connected to nipples extending from the valves on each end.

9.3.2.2.1.1.3 Sample Sink

The sample sink is located in a hooded enclosure connected to the auxiliary building ventilation exhaust system. The work area around the sink and the enclosure is large enough for sample collection and storage, as well as for the radiation monitoring equipment.

The enclosure is penetrated by the various sample lines from the reactor systems and by a demineralized water line, all of which discharge into the sink which drains to the LRS. The sink and work area material is stainless steel.

9.3.2.2.1.1.4 Delay Line

The high-pressure reactor coolant loop sample line has sufficient length to provide at least a 40-second sample transit time within the containment. Additional transit time from the reactor containment to the sampling hood is provided by the sampling line. This allows for decay of the short-lived isotope, N^{16}, to a level that permits normal access to the sampling room.

9.3.2.2.1.1.5 Piping

All liquid and gas sample lines are austenitic stainless steel tubing and are designed for high-pressure service. Lines are so located as to protect them from accidental damage during routine operation and maintenance.

9.3.2.2.1.1.6 Valves

Stop valves within the containment are remotely operated from the sampling room. They are used to isolate all sample points and to route sample flow. A remotely operated isolation valve is provided for samples originating from the RHR system so that the operator need not enter a possibly high radiation area following a LOCA. Two isolation valves are provided, one inside and one outside the containment, on all sample lines leaving the containment. The valves trip closed upon actuation of the containment isolation signal. All valves in the system are constructed of austenitic stainless steel or equivalent corrosion-resistant material.

9.3.2.2.1.1.7 Hot Sample Sub-System (Unit 1 only)

The RCS Hot Sample Sub-system provides the capability to collect samples filtered from a side stream of the hot-leg sample flow. Filters to collect solids from the flow are located both upstream and downstream of a heat exchanger. The sub-system includes temperature, flow, and pressure instruments as well as valves and tubing.

9.3.2.2.1.2 System Operation

9.3.2.2.1.2.1 Reactor Coolant Loop and Pressurizer Liquid Samples

Reactor coolant loop and pressurizer liquid samples are obtained by opening the remotely operated isolation valve of the selected sample point. The sample heat exchangers cool the liquid samples.

A valve downstream of each heat exchanger is manually throttled to obtain the correct liquid sample flow rate. The sample stream flows through the sampling system to either sample sink 1-1 and 2-1 or the VCT in the CVCS until sufficient volume is purged to ensure that a representative sample will be obtained. When purging is completed, flow is diverted, if necessary, into the sample sink, and a sample is collected in a suitable container.

To obtain a reactor coolant loop liquid or pressurizer liquid sample for dissolved gas content, flow is diverted by opening and closing the appropriate valves into the appropriate sample pressure vessel. A valve is adjusted to the required downstream pressure for obtaining the correct sample flow rate. After the sample pressure vessel is purged and the sample collected by closing the isolation valves, the sample vessel is removed by opening the quick disconnect couplings. Note that pressurized samples of reactor coolant for gas analysis are normally obtained from the CVCS demineralizer inlet sample lines as described below.

9.3.2.2.1.2.2 Pressurizer Steam Space Samples

Pressurizer steam space samples are obtained by opening the remotely operated isolation valves. The sample heat exchanger condenses and cools the steam and the pressure is reduced by a manual valve. The condensate flows through a sample pressure vessel and into either sample sink 1-1 and 2-1 or the VCT in the CVCS until sufficient purge flow has been passed. The sample pressure vessel is then isolated and removed.

9.3.2.2.1.2.3 Residual Heat Removal Samples

During plant shutdown operations, samples are withdrawn from the outlet line of the RHR heat exchangers at a maximum temperature of 350°F. The correct sample flow rate is obtained by adjusting the valve downstream of the hot leg sample heat exchanger.

The fluid temperature is reduced in the sample heat exchanger by manual regulation of the sample flow to the heat exchanger. After sufficient volume has been purged to either sample sink 1-1 and 2-1 or the VCT in the CVCS to ensure that a representative sample will be obtained, flow is diverted, if necessary, to the sample sink for collection. If the pressure and temperature is low in the RHR system, local samples off the pump discharge can be taken.

9.3.2.2.1.2.4 Letdown Line Samples

Samples are obtained from the letdown line at a point upstream of the mixed bed demineralizers and at a point upstream of the VCT. After throttling, the fluid is initially purged to either sample sink 1-1 and 2-1 or the VCT in the CVCS and then routed into the sample sink for collection.

9.3.2.2.1.2.5 Volume Control Tank Gas Samples

After the VCT gas sample line has been drained of condensate, the gas is sampled by collection with a pressurized sample vessel or laboratory apparatus.

9.3.2.2.1.2.6 Volume Control Tank Liquid Samples

VCT liquid samples are obtained by opening the remotely operated isolation valve and purging the line to the sample sink. Following sufficient purging, a sample may be taken at the sample sink.

9.3.2.2.1.2.7 Accumulator Samples

Accumulator samples are obtained by opening the remotely operated isolation valve of the selected accumulator and purging the line to sample sink 1-1 and 2-1. Following sufficient purging, a sample is drawn at the sample sink.

9.3.2.2.1.2.8 Reactor Coolant Solids Samples (Unit 1 only)

Samples of solids from the RCS are obtained by opening manual valves on the hot sample panel to direct a small flow through the sampling filters. The filter effluent is directed to the inlet of the CVCS demineralizers. After the sub-system is isolated, collected solids can be dried and examined in onsite or offsite laboratories.

9.3.2.2.1.2.9 Availability and Reliability

The sampling system is not required to function during an emergency but is utilized to classify an emergency condition and is PG&E Design Class II. In the event of a LOCA, the system is isolated at the containment boundary. RCS sampling capability is available following a design basis seismic event.

9.3.2.2.1.2.10 Leakage Provisions

Samples are collected under a hood provided with a vent to the building exhaust ventilation system. Liquid leakage in the sample sink is collected in the sink and drained to the LRS. If there is any leakage from the system inside the containment (e.g., valve stem leakage), it is collected in the containment sump.

9.3.2.2.1.2.11 Exposure Control

The sampling room is equipped with a ventilated sample hood to reduce the potential for airborne radioactivity exposure of operating personnel. Sufficient length and flow control is provided in the reactor coolant sample line to reduce personnel exposure from short-lived radionuclides. Shielding is provided, as necessary, to reduce personnel exposures. The operating procedures specify the precautions to be observed when purging and drawing samples. All sampling operations are conducted with strict adherence to plant health physics safety regulations.

9.3.2.2.1.2.12 Incident Control

The system is designed to be operated on an intermittent basis under administrative control. The system is normally closed with no flow, except for the pressurizer steam space sample, which may be left open to provide a continuous purge. The reactor coolant hot leg sample may be open for extended periods of time for operation of the hot sample panel sub-system (Unit 1 only).

Sample lines penetrating the containment are equipped with remotely operated isolation valves that close on receipt of a containment isolation signal. In addition, the isolation valve in the CVCS letdown line outside the containment will close on containment isolation signal, isolating the letdown line sample lines from the containment.

9.3.2.2.2 Post-Accident Sampling System

The PASS (refer to Figure 3.2-11) is composed of the reactor coolant and containment sump (RHR pumps discharge) liquid sampling system and the containment atmosphere monitoring system. The equipment location for this system is also shown in Figure 3.2-11.

License Amendment 149 (Unit 1) and 149 (Unit 2) removed PASS administrative controls from the Technical Specifications and removed PASS-specific requirements from the DCPP licensing bases. License Amendment 168 (Unit 1) and 169 (Unit 2) eliminated Technical Specification requirements associated with hydrogen recombiners and hydrogen monitors. However, contingency plans to obtain samples from the RCS, containment sump, and containment atmosphere are required.

Elimination of PASS requirements does not affect previous approval of elimination of the boron concentration monitoring system (BCMS). Although approval of the elimination of the BCMS was based, in part, on the availability of PASS, the use of contingency plans is an acceptable alternative to PASS to obtain post-accident RCS chemistry information.

The PASS, also referred to as the Post-LOCA Sampling System in other plant documentation, provides facilities for sampling and analysis of reactor coolant, containment sump (RHR pumps discharge), and containment atmosphere following an

accident. This system may be used to obtain further information on accident conditions in the RCS and containment.

The system is designed and located such that plant personnel are able to obtain the necessary samples and analyses under accident conditions while limiting personnel radiation exposure.

The PASS system (excluding the portions involved with containment penetrations), the sample room enclosure, the electrical supply, and the HVAC system are all designated as PG&E Design Class II.

9.3.2.2.2.1 Personnel Protection

The shielding panels provided in the sampling system cabinets and the 2 foot thick concrete walls that enclose the post-accident sampling room and its access ways, provide the necessary shielding to allow occupancy of the sample room and operation of the sampling system following a LOCA.

The ventilation system for the sample room is designed to aid in the protection of plant personnel from radiological contamination. This system is discussed in Section 9.4.10.

An area radiation monitor with local annunciation is installed in the post-accident sampling room to warn personnel occupying the sampling room of high or increasing radiation. High radiation in the sampling room is also alarmed at the main control room annunciator.

An eyewash station is provided in the post-accident sampling room.

9.3.2.2.2.2 Post-Accident Sampling System Liquid Sampling System

The PASS liquid sampling system consists of the liquid sample panel and the sample coolers.

The following liquid samples are received at the liquid sample panel:

(1) Reactor coolant hot legs 1 and 4

(2) RHR pump discharge

All samples received at the liquid sample panel are taken from existing lines outside of containment.

The liquid samples flow from their sources through the sample cooler to the liquid sample panel.

The liquid sample panel provides the means to purge each sample through its sample line and the sample panels to ensure representative samples are obtained for analysis.

All sample lines can be flushed with makeup water following each sampling operation, thereby reducing the radiation level in the sampling system.

The sample coolers for the liquid sampling system are installed in a sample cooler rack. One sample cooler is provided for each liquid sample line.

The cooling water sides of the sample coolers are arranged into two cooling banks. Each bank consists of five sample coolers connected in series and is provided with the following:

(1) Cooling water over-temperature switch

(2) Cooling water under-pressure switch

(3) Cooling water low flow switch

(4) Cooling water relief valve sized to relieve a full bore flow from a broken sample coil

(5) Cooling water isolation valves for the inlet and discharge for each bank

Each sample line is provided with an inlet isolation valve for maintenance purposes.

9.3.2.2.2.3 Containment Atmosphere Monitoring System

The containment atmosphere monitoring system is designed to sample the containment atmosphere for isotopic analysis.

The containment atmosphere samples are collected in the containment and routed through a containment penetration, then through the sample panel, and returned to the containment atmosphere. A containment atmosphere dilution system provides the capability to obtain grab samples of diluted containment atmosphere. For particulate and iodine isotopic analysis, removable particulate and silver zeolite filters are provided in the sampling panel.

The sample flow to the containment atmosphere sample panel is established with a nitrogen gas flow through an eductor.

Special features are employed to prevent particulate and iodine plateout in the inlet line to the first air sample flask. These features include electrical heat tracing on the sample line, minimum radius bends in the sample lines, and the use of plug valves that avoid changes in the sample conditions.

The sampling panel design provides the means to purge or flush the sample system.

9.3.2.2.2.4 Control Provisions

Controls are provided on the control panel in the PASS room that allows the operator to route these selected samples to the PASS room. Controls are also provided on the control panel to position the electrically operated CIVs on the containment air monitoring system.

Under accident conditions, post-accident sampling waste is returned to the containment via a local valve and a remote valve with controls at the control panel in the post-accident sample room.

9.3.2.2.3 Secondary Sampling System

Samples from the secondary side of the SGs originate at several points in the turbine cycle. These samples are taken from the discharge of condensate pumps, condensate booster pumps, condensate demineralizers, condensate drain pump, feedwater heaters, main steam leads and SG blowdown lines. Samples may be obtained at various local panels or at the secondary process control room for analysis. The analysis may be used to determine action level, condenser leak detection, corrosion product transport, and/or annunciator alarm signals. The main condensers are equipped with tube sheet and condensate tray salt water leak detection systems. These systems identify sea water ingress to the condenser. The leak detection system consists of eight in-line tube sheet monitors and seven in-line condensate tray monitors. Each sample point is monitored separately to identify condenser in-leakage.

9.3.2.2.4 Turbine Steam Analyzer System

A turbine steam analyzer system, which was originally installed to provide continuous direct sampling and analysis of both the low and high pressure turbine steam on Unit 1 and only high pressure steam on Unit 2, is no longer being used at DCPP. Other chemistry methods for evaluating steam chemistry are used.

9.3.2.3 Safety Evaluation

9.3.2.3.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portion of the NSSS sampling system, containment atmosphere monitoring system, and secondary sampling system are located in the containment and the auxiliary buildings that are PG&E Design Class I (refer to Section 3.8). These buildings or applicable portions thereof are designed to withstand the effects of, or are protected against, natural phenomena, such as earthquakes (refer to Section 3.7), flooding (refer to Section 3.4) and tsunamis (refer to Section 2.4), tornadoes and winds (refer to Section 3.3), and other local site effects.

Equipment required for sampling capability to confirm RCS boron concentration is PG&E Design Class II and seismically qualified to allow the plant to be taken to cold shutdown conditions following a design basis seismic event.

9.3.2.3.2 General Design Criterion 3, 1971 – Fire Protection

The sampling systems are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.3.2.3.3 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The portions of the NSSS sampling system within the RCPB are designed and constructed to have an exceedingly low probability of gross rupture or significant leakage throughout its design lifetime. Piping upstream of and including the RCS hot leg sampling CIV outside containment is designed to accommodate the system pressures and temperatures attained under all expected modes of plant operation including all anticipated transients and to maintain the stress levels within applicable stress limits (refer to Section 5.2.3 for a discussion of the RCPB materials of construction).

9.3.2.3.4 General Design Criterion 11, 1967 – Control Room

The plant is provided with a centralized control room common to both units that contain the controls and instrumentation necessary for operation of both units under normal and accident conditions.

The RCS hot legs sampling, pressurizer liquid and steam space sampling, and accumulator sampling CIVs can be operated from the control room.

The sampling system may be operated from the post-accident sampling room. An area radiation monitor with local annunciation is installed in the post-accident sampling room to warn personnel occupying the sampling room of high or increasing radiation. High radiation in the sampling room is also alarmed at the main control room annunciator (refer to Section 9.3.2.2.2.1).

9.3.2.3.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Process control instrumentation within the NSSS sampling system, secondary sampling system, and PASS are provided to acquire data concerning key sampling system parameters (refer to Section 9.3.2.5).

9.3.2.3.6 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The containment atmosphere monitoring, the plant vents, and the liquid and gaseous waste systems effluent discharge paths are monitored for radioactivity concentrations during all modes of operations. Sampling of effluents is described in Section 11.4.2.2. The offsite radiological monitoring program is described in Section 11.6. GDC 17, 1967 is discussed in Section 12.2 (refer to Section 9.3.2.2.3).

9.3.2.3.7 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the containment isolation portion of the NSSS sampling, secondary sampling, and containment atmosphere monitoring systems from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures are discussed in Sections 3.5, 3.6, and 6.2.4.

9.3.2.3.8 General Design Criterion 49, 1967 – Containment Design Basis

The NSSS sampling system, containment atmosphere monitoring system, and secondary sampling system penetrations are designed to withstand the pressures and temperatures that could result from a LOCA without exceeding the design leakage rates (refer to Section 3.8.2.1.1.3).

9.3.2.3.9 General Design Criterion 54, 1971 – Piping Penetrating Containment

The NSSS sampling system, containment atmosphere monitoring system, and secondary sampling system CIVs are periodically tested for operability and leakage. Testing of components required for the CIS is discussed in Section 6.2.4. Test connections are provided in the penetration and in the piping to verify valve and penetration leakage within prescribed limits.

9.3.2.3.10 General Design Criterion 55, 1971 – Reactor Coolant Pressure Boundary Penetrating Containment

The NSSS sampling system is designed such that each line that is part of the RCPB that penetrates containment is provided with CIVs that comply with GDC 55, 1971 (refer to Section 6.2.4 and Table 6.2-39 for penetration configuration details).

9.3.2.3.11 General Design Criterion 56, 1971 – Primary Containment Isolation

The containment atmosphere monitoring portion of the sampling system is designed such that each line that connects directly to the containment atmosphere and penetrates primary reactor containment is provided with CIVs in compliance with GDC 56, 1971 (refer to Section 6.2.4 and Table 6.2-39 for penetration configuration details).

9.3.2.3.12 General Design Criterion 57, 1971 – Closed System Isolation Valves

The secondary sampling system is designed such that each line that is not part of the RCPB that penetrates containment or connected directly to the containment atmosphere is provided with CIVs that comply with GDC 57, 1971 (refer to Section 6.2.4 and Table 6.2-39 for penetration configuration details).

9.3.2.3.13 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The sample sink, part of the NSSS sample system, located in the sample room, which is located in the auxiliary building, has a hood that is connected to the building ventilation and exhausts through the plant vent. Liquid leakage in the sample sink is collected in the sink and drained to the LRS (refer to Sections 9.4.10, 9.3.2.2.1 and 11.2).

9.3.2.3.14 Sampling System Safety Function Requirement

(1) Post-Accident Sampling

Contingency plans have been developed to obtain and analyze highly radioactive samples of reactor coolant, containment sump, and containment atmosphere. Plant procedures provide instructions for operating PASS during post-accident conditions for obtaining reactor coolant, containment sump, and containment air hydrogen concentration and containment particulate, iodine, and noble gas samples during post-accident recovery (refer to Section 9.3.2.2.2).

(2) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the PG&E Design Class I portion of the NSSS, post-accident, and secondary sampling system located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

9.3.2.3.15 10 CFR Part 20 – Standards for Protection Against Radiation

The reactor coolant hot leg sample line is designed to provide a sufficient transit time in containment to allow decay of the short lived isotope N^{16}. This reduces doses to allow normal access to the sample panel (refer to Section 9.3.2.2.1.1.4).

9.3.2.3.16 10 CFR 50.49 – Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

The PG&E Design Class I NSSS sampling system, containment atmosphere monitoring system, and secondary sampling system SSCs required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. The

affected equipment is CIV solenoid valves and position switches that are listed on the EQ Master List.

9.3.2.3.17 10 CFR 50.55a(f) – Inservice Testing Requirements

The NSSS sampling system, containment atmosphere monitoring system, and secondary sampling system valves are contained within the IST program. The IST requirements for these components are contained in the IST Program Plan and comply with the ASME code for Operations and Maintenance of Nuclear Power Plants.

9.3.2.3.18 10 CFR 50.55a(g) – Inservice Inspection Requirements

The NSSS sampling system piping and secondary sampling system piping have a periodic ISI program in accordance with the ASME BPVC, Section XI.

9.3.2.3.19 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

CIV position indication meets the requirements of Regulatory Guide 1.97, Revision 3 (refer to Section 7.5 and Table 7.5-6).

The elimination of the BCMS and the use of the PASS to meet the guidance in Regulatory Guide 1.97, Revision 3, is acceptable.

9.3.2.3.20 NUREG-0737 (Item III.D.1.1), November 1980 – Clarification of TMI Action Plan Requirements

Item III.D.1.1 – Primary Coolant Outside Containment: Plant procedures have been developed to reduce leakage by monitoring surveillance requirements of radioactive systems outside containment.

9.3.2.3.21 Generic Letter 96-06, September 1996 – Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions

Generic Letter 96-06, September 1996, identified the potential of thermally induced overpressurization of isolated water-filled piping sections in containment that could jeopardize the ability of accident mitigating systems to perform their safety functions and could also lead to a breach of containment integrity via bypass leakage.

In the evaluation to determine potential effects of piping sections, DCPP identified potentially affected sampling system piping sections. The evaluations concluded that all potentially overpressurized penetrations were operable. The sections included isolation valves (air operated globe valve) whose design prevents overpressurization.

9.3.2.4 Tests and Inspections

The sampling system is in use daily. Periodic visual inspection and preventive maintenance are conducted using normal industry practice.

9.3.2.5 Instrumentation Applications

The instrumentation provided for the sampling system is discussed below. All of the instrumentation gives local indication.

9.3.2.5.1 Temperature

Instrumentation is provided to measure the temperature of the sample flow in the outlet line of each sample heat exchanger.

9.3.2.5.2 Pressure

Instrumentation is provided to measure the pressure in the sample lines downstream of each of the three sample vessels: (a) pressurizer steam sample vessel, (b) pressurizer liquid sample vessel, and (c) hot leg sample vessel.

9.3.2.5.3 Flow

Instrumentation is provided to measure the sample purge flow of all liquid samples to the VCT in the CVCS and also the VCT gas sample purge to the vent header in the gaseous waste system.

9.3.2.5.4 Chemical

Instrumentation is provided to measure dissolved hydrogen and oxygen in the letdown line sample. These in-line instruments provide an alternate to manual collection.

9.3.3 EQUIPMENT AND FLOOR DRAINAGE SYSTEMS

The equipment and floor drainage systems collect and channel waste liquids to be either reprocessed or discharged from the plant, except for those originating in the turbine building. The equipment drainage system originates at tanks, heat exchangers, pumps, flanges, filters, and valves in the containment (refer to Section 9.3.3.2.1.1) and auxiliary building, including the fuel handling area (refer to Section 9.3.3.2.1.2), that may contain radioactive liquids, and terminates at the inlet to the reactor coolant drain tank (RCDT) or the miscellaneous equipment drain tank (MEDT). The containment building floor drainage system terminates at the inlet to either the reactor cavity sump or one of the two containment structure sumps. The auxiliary building floor drains for both Unit 1 and Unit 2 terminate at the entry to the auxiliary building sump.

The equipment and floor drainage systems discharge to the LRS, which is described in detail in Section 11.2. The LRS accepts the liquid wastes from the equipment and floor drainage systems for processing or discharge from the plant. Figure 3.2-19 shows detailed piping schematics of these systems.

9.3.3.1 Design Bases

9.3.3.1.1 General Design Criterion 3, 1971 – Fire Protection

The equipment and floor drainage systems are designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.3.3.1.2 General Design Criterion 4, 1967 – Sharing of Systems

Portions of the equipment and floor drainage systems are shared by the DCPP units only where it is shown that safety is not impaired by the sharing.

9.3.3.1.3 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The equipment and floor drainage systems are designed to maintain control of radioactive liquids.

9.3.3.2 System Description

The equipment and floor drainage systems are designed to provide adequate drainage during normal operation and inadvertent actuation of a single fire water sprinkler head. Provisions are made for (a) multiple drainage of certain areas; (b) prevention of backflooding; and (c) visual inspection of flow in drain lines wherever space permits; i.e., most lines above elevation 70 feet. The floor drainage systems also provide a detection method in the event of flooding.

However, the water accumulation that would result from any postulated failure of the drain system would not preclude safe shutdown of the plant.

9.3.3.2.1 Equipment Drain or Closed Drain System

The closed drain system is so called because drains from equipment are connected directly to the drainage system. The system provides drainage for equipment located both inside and outside containment. Liquid waste is not exposed to the atmosphere once it leaves the equipment until it reaches its destination, which is either the RCDT in containment or the MEDT in the auxiliary building.

9.3.3.2.1.1 Containment Building Equipment Drain or Closed Drain System

Containment building closed drain wastes are collected in the RCDT. Sources include the following:

(1) Reactor coolant loop drains

(2) Pressurizer relief tank

(3) RCPs No. 2 seal leakoff

(4) Excess letdown line

(5) Accumulators

(6) Refueling canal

(7) RCPs seal water inlet line drain

(8) Reactor flange leakoff

(9) Excess letdown heat exchanger

(10) Regenerative heat exchanger outlet line drain

9.3.3.2.1.2 Auxiliary Building Equipment Drain or Closed Drain System

Auxiliary building closed drain wastes are collected in the MEDT. Sources include the following:

(1) CVCS

(a) Deborating demineralizer drain

(b) Mixed bed demineralizer drain

(c) Cation bed demineralizer drain

(d) Evaporator feed ion exchanger drains

(e) Reactor coolant letdown filter

(f) Seal water heat exchanger (tube side) and filter

(g) VCT drain and sample line drain

(h) Charging pumps, header, bypass, and seal injection filter

(i) Letdown heat exchanger (tube side)

(j) Gas stripper feed pumps drain

(k) LHUTs recirculation pumps, line, and relief valve discharge

(2) SI system

(a) Containment recirculation water chamber

(b) SI pumps seal and drip pocket drain

(c) Various valve steam leakoffs

(3) RHR system

(a) RHR heat exchanger tube side drains

(b) RHR pump and line drain

(c) Various valve steam leakoffs

(4) NSSS sampling system

(a) NSSS sampling sink drain

(b) NSSS sample line drain

(c) VCT sample line drain

(5) Containment spray system

(a) Containment spray line drain

(b) Containment spray pumps

(6) SFP cooling system

(a) SFP resin trap filter

(b) SFP filter

(c) SFP pumps

(d) RWP filter

(e) SFP skimmer filter, pump, strainer, and drain

(f) SFP heat exchanger

(g) SFP demineralizer drain

(7) CCW system

(a) Waste gas compressor seal water coolers

(8) LRS

(a) Equipment drain receivers overflow and pumps

(b) Processed waste receivers overflow and pumps

(c) Spent resin motive water pumps

(d) Spent resin storage tanks

(9) Gaseous radwaste system

(a) Gas decay tanks drain

(b) Waste gas compressor moisture separator

(c) Gaseous radwaste vent header drain

(d) Waste gas compressor surge tank

(10) Turbine steam supply system

(a) SG blowdown tank

(11) Gland steam sealing system

Note: Normally the following drains go to the miscellaneous condensate return tank and TBS. They can be routed to the MEDT if elevated levels of radioactivity are present.

(a) Gland steam condenser drains

(b) Steam jet air ejector

9.3.3.2.2 Floor Drain or Open Drain System

The open drain system, also known as the floor drainage system, drains potentially contaminated areas in the containment and auxiliary building, and collects liquids from equipment that is located in those areas and that normally does not handle reactor coolant. The piping systems or trenches used in this system permit exposure of contents to the atmosphere.

The auxiliary building has been divided into a number of drainage zones. Each equipment compartment or area within a zone is drained by several grated floor drains (refer to Figure 9.3-5). The piping connected to the individual floor drains is 2 inches in diameter and feed 4-inch diameter headers, which eventually drain to a common collection header leading to the auxiliary building sump. Each header is provided with a check valve and loop seal as it enters the sump to prevent backup of water.

9.3.3.2.2.1 Containment Building Floor Drain or Open Drain System

Inside containment floor drain wastes are collected in the containment sumps and the reactor cavity sump. Sources include the following:

(1) RCP seal No. 3 leakoff

(2) Excess letdown heat exchanger shell relief and drain

(3) RCP thermal barrier relief

(4) RCP upper bearing cooling relief

(5) Containment fan cooler drip pans and coils

(6) RV support cooler relief

(7) RCP lube oil spill collection tanks

9.3.3.2.2.2 Auxiliary Building Floor Drain or Open Drain System

Potentially contaminated auxiliary building floor drain wastes are collected in the auxiliary building sump.

Sources for the auxiliary building sump include the following:

(1) CVCS

(a) Charging pump base drains

(b) Boric acid tanks, filters, and transfer pump drains

(c) Boric acid reserve tanks and transfer pumps' drain

(d) Chemical mixing tank

(e) Batching tank

(2) NSSS sampling system

(a) Sample sinks (1-2 and 2-2)

(3) Containment spray system

(a) Spray additive tank

(4) SFP cooling system

(a) SFP sump

(5) CCW system

(a) CCW surge tank relief

(b) RHR heat exchanger shell side drains

(6) LRS

(a) Floor drain receivers and pumps

(b) Chemical drain tank overflow

(c) Laundry and hot shower tanks overflow

(d) Spent resin loadout area

(e) Spent resin transfer filters

(f) Laundry/distillate tanks and pumps drain and tank overflow

(7) Ventilation system

(a) Plant vent drains

(8) Auxiliary steam system

(a) Package boiler blowdown tempering tank

(b) Auxiliary steam drain receiver and pumps

(9) Elevation 140-foot roof drains discharge to LRS only if contamination is detected

9.3.3.3 Safety Evaluation

9.3.3.3.1 General Design Criterion 3, 1971 – Fire Protection

The equipment and floor drainage systems are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.3.3.3.2 General Design Criterion 4, 1967 – Sharing of Systems

Sharing of drain system components by the two units does not adversely affect plant safety. The use of shared components provides additional operating flexibility and provides increased capacity to accommodate occurrences which result in large drain system flows.

9.3.3.3.3 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The equipment and floor drainage systems design includes piping, sumps, and trenches that control radioactive liquids (refer to Section 9.3.3.2).

An analysis of the consequences of leakage from the LRS, including normal operation and postulated accidental releases, is presented in Chapters 11 and 15.

9.3.3.4 Tests and Inspections

The drainage systems were tested and inspected prior to plant operation and are periodically monitored during plant operation.

9.3.3.5 Instrumentation Applications

Flow and level instruments are provided for control, indication, and alarm in the drainage systems piping, collection tanks, and sumps. These instruments are described in Section 11.2.

9.3.4 CHEMICAL AND VOLUME CONTROL SYSTEM

The CVCS(refer to Figure 3.2-8) provides the following services to the RCS:

(1) Control of water chemistry conditions, activity level, soluble chemical neutron absorber concentration, and makeup water

(2) Maintenance of required water inventory in the RCS

(3) Filling, draining, and pressure testing

(4) Maintenance of seal water injection flow to the RCPs

(5) Processing of effluent reactor coolant to effect recovery and reuse of soluble chemical neutron absorber and makeup water

(6) High-head SI for the ECCS (refer to Section 6.3)

The CVCS is required for safe shutdown of the plant (refer to Sections 7.4, 9.3.4.1.5, and 9.3.4.1.26).

Centrifugal charging pumps (CCPs) CCP1 and CCP2 in the CVCS serve as the high-head SI pumps in the ECCS. Other than CCP1 and CCP2 and associated piping and valves, the CVCS is not required to function during a LOCA. During a LOCA, the CVCS is isolated except for CCP1 and CCP2 and the piping in the SI and seal injection paths. Operation of CVCS components performing ECCS functions to mitigate the effects of accidents is addressed in Section 6.3. CVCS components required to maintain the RCPB are discussed in Section 5.2. The remaining functions of the CVCS are discussed within this section.

9.3.4.1 Design Bases

9.3.4.1.1 General Design Criterion 2, 1967 – Performance Standards

The CVCS is designed to withstand the effects of, or be protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

9.3.4.1.2 General Design Criterion 3, 1971 – Fire Protection

The CVCS is designed and located to minimize, consistent with other safety requirements, the probability and effects of fires and explosions.

9.3.4.1.3 General Design Criterion 4, 1967 – Sharing of Systems

The CVCS is not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

9.3.4.1.4 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The CVCS design includes provisions for the control of RCS chemistry such that the materials of construction of the pressure-retaining boundary of the RCS are protected

from corrosion that might otherwise reduce the system structural integrity during its service lifetime.

9.3.4.1.5 General Design Criterion 11, 1967 – Control Room

The CVCS is designed to support actions for safe shutdown and to maintain and control the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

9.3.4.1.6 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided, as required, to monitor and maintain the CVCS variables within prescribed operating ranges.

9.3.4.1.7 General Design Criterion 13, 1967 – Fission Process Monitors and Controls

The CVCS design includes means for monitoring and maintaining control over the fission process throughout core life and for all conditions that can reasonably be anticipated to cause variations in reactivity of the core, such as concentration of soluble reactivity control poisons.

9.3.4.1.8 General Design Criterion 21, 1967 – Single Failure Definition

The CVCS is designed to perform its function after sustaining a single failure. Multiple failures resulting from a single event are treated as a single failure.

9.3.4.1.9 General Design Criterion 26, 1971 – Reactivity Control System Redundancy and Capability

The CVCS design includes one of the two independent reactivity control systems which are based on different design principles. The CVCS reactivity control system is capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure acceptable fuel design limits are not exceeded. The CVCS is capable of holding the reactor core subcritical under cold conditions.

9.3.4.1.10 General Design Criterion 28, 1967 – Reactivity Hot Shutdown Capability

The CVCS design includes one of the two independent reactivity control systems which are capable of independently making and holding the core subcritical from any hot standby or hot operating condition.

9.3.4.1.11 General Design Criterion 30, 1967 – Reactivity Holddown Capability

The CVCS design includes a reactivity control system capable of making and holding the core subcritical under any conditions with appropriate margins for contingencies.

9.3.4.1.12 General Design Criterion 31, 1967 – Reactivity Control Systems Malfunction

The CVCS design includes reactivity control systems capable of sustaining any single malfunction without causing a reactivity transient which could result in exceeding acceptable fuel damage limits.

9.3.4.1.13 General Design Criterion 32, 1967 – Maximum Reactivity Worth of Control Rods

Limits, which include considerable margin, are placed on the maximum rates at which reactivity can be increased by the CVCS to ensure that the potential effects of a sudden or large change of reactivity cannot: (a) rupture the RCPB, or (b) disrupt the core, its support structures, or other vessel internals sufficiently to impair the effectiveness of emergency core cooling.

9.3.4.1.14 General Design Criterion 40, 1967 – Missile Protection

The containment isolation portion of the CVCS is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

9.3.4.1.15 General Design Criterion 49, 1967 – Containment Design Basis

The CVCS is designed so that the containment structure can accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a LOCA, including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of ECCSs.

9.3.4.1.16 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The piping that is part of the CVCS that penetrates containment is provided with leak detection, isolation, redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The piping is designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

9.3.4.1.17 General Design Criterion 55, 1971 – Reactor Coolant Pressure Boundary Penetrating Containment

Each CVCS line that penetrates the containment is provided with CIVs.

9.3.4.1.18 General Design Criterion 56, 1971 – Primary Containment Isolation

The CVCS contains valving in piping that penetrates containment and that is connected directly to the containment atmosphere. Normally closed isolation valves are provided outside containment and automatic (check) valves are provided inside containment to ensure containment integrity is maintained.

9.3.4.1.19 General Design Criterion 68, 1967 – Fuel and Waste Storage Radiation Shielding

Radiation shielding is provided in the design of CVCS waste storage tanks, as required, to meet the requirements of 10 CFR Part 20.

9.3.4.1.20 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The CVCS design includes those means necessary to maintain control over the plant radioactive effluents, whether gaseous, liquid, or solid. Appropriate holdup capacity is provided for retention of gaseous, liquid, or solid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. The design for radioactivity control is justified on the basis of 10 CFR Part 20 requirements for normal operations and for any transient situation that might reasonably be anticipated to occur.

9.3.4.1.21 Chemical and Volume Control System Safety Function Requirements

(1) Reactor Coolant System Inventory and Pressure Control

The CVCS is designed to maintain proper coolant inventory in the RCS for all normal modes of operation, including startup from cold shutdown, full power operation, and plant cooldown.

The CVCS is also designed to provide a flowpath to the pressurizer auxiliary spray system for means of cooling the pressurizer vapor volume during plant cooldown conditions.

(2) Protection from Missiles

The PG&E Design Class I portions of the CVCS are designed to be protected against the effects of missiles which may result from plant equipment failure and from events and conditions outside the plant.

(3) Protection Against High Energy Pipe Rupture Effects

The PG&E Design Class I portions of the CVCS are designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(4) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The PG&E Design Class I portions of the CVCS located outside containment are designed to be protected against the effects of moderate energy pipe failure.

(5) Protection from Jet Impingement – Inside Containment

The PG&E Design Class I portions of the CVCS located inside containment are designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

(6) Protection from Flooding Effects – Outside Containment

The PG&E Design Class I portions of the CVCS located outside containment are designed to be protected from the effects of internal flooding.

(7) Reactor Coolant Pump Seal Water Injection

The CVCS is designed to provide filtered seal water flow to each RCP seal to provide cooling of the RCP seals and bearings.

9.3.4.1.22 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

CVCS components that require EQ are qualified to the requirements of 10 CFR 50.49.

9.3.4.1.23 10 CFR 50.55a(f) – Inservice Testing Requirements

CVCS ASME Code components are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

9.3.4.1.24 10 CFR 50.55a(g) – Inservice Inspection Requirements

CVCS ASME Code components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

9.3.4.1.25 10 CFR 50.63 – Loss of All Alternating Current Power

The CVCS seal water system (supplied by CCP1, powered from the Class 1E bus associated with the credited AAC power source) is required to provide RCP seal injection in the event of a SBO.

9.3.4.1.26 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

Fire Protection of the CVCS is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

9.3.4.1.27 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The CVCS provides instrumentation to monitor system variables during and following an accident.

9.3.4.1.28 NUREG-0737 (Items I.C.1, II.B.2, II.K.1.5, III.D.1.1), November 1980 – Clarification of TMI Action Plan Requirements

Item I.C.1 – Guidance for the Evaluation and Development of Procedures for Transients and Accidents: NUREG-0737, Supplement 1, January 1983 provides the requirements for I.C.1 as follows:

Section 7.1(b) – Transients and accidents were reanalyzed for the purposes of preparing technical guidelines and upgrading emergency operating procedures.

Item II.B.2 – Design Review of Plant Shielding and Environmental Qualification of Equipment for Space/Systems Which May Be Used in Post-accident Operations: Plant shielding provides adequate access to, and occupancy of, the switchgear rooms for the purpose of manually operating CVCS in its normal charging and letdown mode from the HSP, if required, following an MSLB.

Item II.K.1.5 – Safety Related Valve Position: Refer to Section 9.3.4.1.33.

Item III.D.1.1 – Integrity of Systems Outside Containment Likely to Contain Radioactive Material for PWRs and Boiling-Water Reactors: Appropriate portions of the CVCS are

periodically pressure leak tested and visually inspected for leakage into the building environment.

9.3.4.1.29 Generic Letter 80-21, March 1980 – Vacuum Condition Resulting in Damage to Chemical Volume Control System Holdup Tanks

CVCS low pressure tanks, that can be valved to contain RCS water, are protected against vacuum conditions that could result in tank damage.

9.3.4.1.30 Generic Letter 88-17, October 1988 – Loss of Decay Heat Removal

To meet the requirements of Generic Letter 88-17, October 1988, and associated Generic Letter 87-12, July 1987, the CVCS PG&E Design Class I CCPs serve as the high pressure injection pumps to provide one of the two available or operable means of adding inventory to the RCS, that are in addition to the normal decay heat removal systems, to serve as backup sources to control RCS inventory upon loss of decay heat removal during non-power operation.

9.3.4.1.31 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

CVCS PG&E Design Class I and position changeable MOVs meet the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996.

9.3.4.1.32 Generic Letter 95-07, August 1995 – Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves

The CVCS PG&E Design Class I, power-operated gate valves are designed such that they are not susceptible to pressure locking or thermal binding.

9.3.4.1.33 IE Bulletin 79-06A (Positions 8 and 12), April 1979 – Review of Operational Errors and System Misalignments Identified During the Three Mile Island Incident

Position (8) (subsequently NUREG-0737, November 1980, Item II.K.1.5, Safety Related Valve Position): CVCS PG&E Design Class I valve positions, positioning requirements, and positive controls have been assured such that the valves remain positioned (open or closed) in a manner to ensure the proper operation of ESF to satisfy Position (8) of IE Bulletin 79-06A, April 1979.

Position (12): CVCS design features are provided and procedures are in place during operating modes to deal with hydrogen gas that may be generated during a transient or other accident that would either remain inside the primary system or be released to the containment.

9.3.4.1.34 NRC Bulletin 88-04, May 1988 – Potential Safety-Related Pump Loss

The CVCS is designed such that PG&E Design Class I pumps that share a common minimum flow recirculation line will not be susceptible to the pump-to-pump interaction described in NRC Bulletin 88-04, May 1988.

9.3.4.1.35 NRC Bulletin 88-08, June 1988 – Thermal Stresses in Piping Connected to Reactor Coolant Systems

Unisolable CVCS piping sections connected to the RCS, which have the potential to be subjected to unacceptable thermal stresses due to temperature stratifications induced by leaking valves, have been identified. Means have been provided to ensure that the pressure upstream from block valves, which might leak, is monitored and controlled.

9.3.4.2 System Description

9.3.4.2.1 Reactivity Control

The CVCS regulates the concentration of chemical neutron absorber in the reactor coolant to control reactivity changes resulting from the change in reactor coolant temperature between cold shutdown and hot full power operation, burnup of fuel and burnable poisons, and xenon transients.

9.3.4.2.1.1 Reactor Makeup Control

(1) The CVCS is capable of borating the RCS through either one of two flowpaths and from either one of two boric acid sources.

(2) The amount of boric acid stored in the CVCS always exceeds that amount required to borate the RCS to cold shutdown concentration assuming that the RCCA with the highest reactivity worth is stuck in its fully withdrawn position. This amount of boric acid also exceeds the amount required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay.

(3) The CVCS is capable of counteracting inadvertent positive reactivity insertion caused by the maximum boron dilution accident.

9.3.4.2.2 Regulation of Reactor Coolant Inventory

The CVCS maintains the proper coolant inventory in the RCS for all normal modes of operation including startup from cold shutdown, full power operation, and plant cooldown. This system also has sufficient makeup capacity to maintain the minimum required inventory in the event of minor RCS leaks.

The CVCS flow rate is based on the requirement that it permits the RCS to be either heated to or cooled from hot standby condition at the design rate and maintain proper coolant level.

9.3.4.2.3 Reactor Coolant Purification

The CVCS removes fission products and corrosion products from the reactor coolant during operation of the reactor and maintains these within acceptable levels. The CVCS can also remove excess lithium from the reactor coolant, keeping the lithium ion concentration within the desired limits for pH control.

The CVCS is capable of removing fission and activation products, in ionic form or as particulates, from the reactor coolant to provide access to those process lines carrying reactor coolant during operation and to minimize activity released due to leakage.

9.3.4.2.4 Chemical Additions

The CVCS provides a means for adding chemicals to the RCS to control the pH of the coolant during initial startup and subsequent operation, scavenge oxygen from the coolant during startup, and control the oxygen level of the reactor coolant due to radiolysis during all operations subsequent to startup. The CVCS is capable of maintaining the oxygen content and pH of the reactor coolant within limits specified in Table 5.2-15. There is also a capability to add zinc acetate to inhibit primary water stress corrosion cracking in Alloy 600 RCS components.

9.3.4.2.5 Seal Water Injection

The CVCS is able to continuously supply filtered water to each RCP seal, as required by the RCP design.

9.3.4.2.6 Hydrostatic Testing of the Reactor Coolant System

The CVCS can pressurize the RCS to its maximum specified hydrostatic test pressure to verify the integrity and leaktightness of the RCS through the use of a temporary hydrostatic test pump. The pump is capable of producing a hydrostatic test pressure greater than that required. The hydrostatic test is performed prior to initial operation and as part of the periodic RCS ISI program.

9.3.4.2.7 Emergency Core Cooling

The CVCS components providing ECCS functions are discussed in Section 6.3.

9.3.4.2.8 Subsystems Description

The CVCS is shown in Figure 3.2-8 with system design parameters listed in Table 9.3-5.

The CVCS consists of several subsystems: the charging, letdown, and seal water system; the chemical control, purification and makeup system; and the boron recycle system.

9.3.4.2.8.1 Charging, Letdown, and Seal Water System

The charging and letdown functions of the CVCS are employed to maintain a programmed water level in the RCS pressurizer, thus maintaining proper reactor coolant inventory during all phases of normal plant operation. This is achieved by means of a continuous feed and bleed process during which the feed rate is automatically controlled based on pressurizer water level. The bleed rate can be chosen to suit various plant operational requirements by selecting the proper combination of letdown orifices in the letdown flowpath.

Reactor coolant is discharged to the CVCS from the reactor coolant loop piping between the RCP and the SG; it then flows through the shell-side of the regenerative heat exchanger where its temperature is reduced by heat transfer to the charging flow passing through the tubes. The coolant then experiences a large pressure reduction as it passes through a letdown orifice and flows through the tube side of the letdown heat exchanger where its temperature is further reduced to the operating temperature of the mixed bed demineralizers. Downstream of the letdown heat exchanger a second pressure reduction occurs. This second pressure reduction is performed by the low-pressure letdown valve, the function of which is to maintain upstream pressure, which prevents flashing downstream of the letdown orifices.

The coolant then flows through one of the two mixed bed demineralizers. The flow may then pass through the cation bed demineralizer, which is used intermittently when additional purification of the reactor coolant is required.

The coolant then flows through the reactor coolant letdown filter and into the VCT through a spray nozzle in the top of the tank. The gas space in the VCT is filled with hydrogen. The partial pressure of hydrogen in the VCT determines the concentration of hydrogen dissolved in the reactor coolant.

The CCPs normally take suction from the VCT and return the cooled, purified reactor coolant to the RCS through the charging line. The VCT is located above the CCPs to provide sufficient net positive suction head. Normal charging flow is handled by one of the three CCPs. The bulk of the charging flow is pumped back to the RCS through the tube side of the regenerative heat exchanger. The letdown flow in the shell-side of the regenerative heat exchanger raises the charging flow to a temperature approaching the reactor coolant temperature. The flow is then injected into a cold leg of the RCS. Two charging paths are provided from a point downstream of the regenerative heat exchanger. A flowpath is also provided from the regenerative heat exchanger outlet to the pressurizer spray line. An air-operated valve in the spray line is employed to provide auxiliary spray from the CCPs to the vapor space of the pressurizer during plant

cooldown. This provides a means of cooling the pressurizer near the end of plant cooldown, when the RCPs are not operating.

A portion of the charging flow is directed to the RCPs through a seal water injection filter. It enters the pumps at a point between the labyrinth seals and the No. 1 seal. Here the flow splits and a portion enters the RCS through the labyrinth seals and thermal barrier. The remainder of the flow is directed up the pump shaft, cooling the lower bearing, and leaves the pump via the No. 1 seal. Most of the No. 1 seal flow discharges to a common manifold, exits the containment, and then passes through the seal water return filter and the seal water heat exchanger to the suction side of the CCPs, or by alternate path to the VCT. A very small portion of the seal flow leaks through to the No. 2 seal. Seal No. 3 is a double-dam seal, providing a final barrier to leakage to containment atmosphere.

An excess letdown path from the RCS is provided in the event that the normal letdown path is inoperable. Reactor coolant can be discharged from a cold leg and flows through the tube side of the excess letdown heat exchanger. Downstream of the heat exchanger a remote-manual control valve controls the excess letdown flow. The flow normally joins the No. 1 seal discharge manifold and passes through the seal water return filter and heat exchanger to the VCT. The excess letdown flow can also be directed to the RCDT. When the normal letdown line is not available, the normal purification path is also not in operation. Therefore, this alternative condition would allow continued power operation for limited periods of time dependent on RCS chemistry and activity. The excess letdown flowpath may also be used to provide additional letdown capability when needed. This capability may be needed during RCS heatup, as a result of coolant expansion. This path removes some of the excess reactor coolant due to expansion of the system as a result of the RCS temperature increase. In this case, the excess letdown is diverted to the RCDT.

urges in RCS inventory due to load changes are accommodated for the most part in the pressurizer. The VCT provides surge capacity for reactor coolant expansion not accommodated by the pressurizer. If water level in the VCT exceeds the normal operating range, a proportional controller modulates a three-way valve downstream of the reactor coolant letdown filter to divert a portion of the letdown to the LHUTs in the boron recovery system. If the high-level limit in the VCT is reached, an alarm is actuated in the control room and the letdown is completely diverted to the LHUTs.

Liquid effluent in the LHUTs is processed as a batch operation. This liquid is pumped by the gas stripper feed pumps through the evaporator feed ion exchangers. It then flows through the ion exchanger filter, and then the liquid is drained to the LRS for processing.

Low level in the VCT initiates makeup from the reactor makeup control system (RMCS). If the RMCS does not supply sufficient makeup to keep the VCT level from falling to a lower level, an emergency low-level signal causes the suction of the CCPs to be transferred to the RWST.

All parts of the charging and letdown system are shielded as necessary to limit dose rates during operation with 1 percent fuel defects assumed. The regenerative heat exchanger, excess letdown heat exchanger, letdown orifices, and seal bypass orifices are located within the reactor containment. All other system equipment is located inside the auxiliary building.

9.3.4.2.8.2 Chemical Control, Purification, and Makeup System

9.3.4.2.8.2.1 pH Control

The pH control chemical employed is lithium hydroxide. This chemical is chosen for its compatibility with the materials and water chemistry of borated water/stainless steel/zirconium alloy/Inconel systems. In addition, lithium is produced in the core region due to irradiation of the dissolved boron in the coolant.

The lithium hydroxide is introduced into the RCS via the charging flow. The solution is prepared in the laboratory and poured into the chemical mixing tank. Primary makeup water is then used to flush the solution to the suction manifold of the CCPs. The concentration of lithium hydroxide in the RCS is maintained in the range specified for pH control (refer to Table 5.2-15). If the concentration exceeds this range, as it may during the early stages of core life, the cation bed demineralizer is employed in the letdown line in series operation with a mixed bed demineralizer. Since the amount of lithium to be removed is small and its buildup can be readily calculated, the flow through the cation bed demineralizer is not required to be full letdown flow.

9.3.4.2.8.2.2 Oxygen Control

During reactor startup from the cold condition, hydrazine is employed as an oxygen-scavenging agent. The hydrazine solution is introduced into the RCS in the same manner as described above for the pH control agent. Hydrazine is not employed at any time other than startup from the cold shutdown state.

Dissolved hydrogen is employed to control and scavenge oxygen produced due to radiolysis of water in the core region. Sufficient partial pressure of hydrogen is maintained in the VCT such that the specified equilibrium concentration of hydrogen is maintained in the reactor coolant. A pressure control valve maintains a minimum pressure in the vapor space of the VCT. This valve can be adjusted to provide the correct equilibrium hydrogen concentration.

9.3.4.2.8.2.3 Reactor Coolant Purification

Mixed bed demineralizers are provided in the letdown line to provide cleanup of the letdown flow. The demineralizers remove ionic corrosion products and certain fission products. One demineralizer is usually in continuous service for normal letdown flow and can be supplemented intermittently by the cation bed demineralizer, if necessary,

for additional purification. The cation resin removes principally cesium and lithium isotopes from the purification flow.

The maximum temperature that will be allowed for the mixed bed and cation bed demineralizers is approximately 140°F. If the temperature of the letdown stream approaches this level, the flow will be diverted automatically so as to bypass the demineralizers. If the letdown is not diverted and temperature increases, there would be a decrease in overall ion removal capacity; however, the resins do not lose their exchange capability immediately.

There would be no safety problem associated with overheating of the demineralizer resins. The only effect on reactor operating conditions would be the possibility of a slight increase in the reactor coolant activity level and RCS chemical contaminants.

The deborating demineralizers are located downstream of the mixed bed and cation bed demineralizers and can be used intermittently to remove boron from the reactor coolant near the end of the core life when boron concentration is low. When the deborating demineralizers are in operation, the letdown stream passes through the mixed bed demineralizers and then through the deborating demineralizers and into the VCT after passing through the reactor coolant letdown filter.

A further cleanup feature is provided for use during cold shutdown and RHR. A remotely operated valve admits a bypass flow from the RHR system into the letdown line upstream of the letdown heat exchanger. The flow passes through the heat exchanger, through a mixed bed demineralizer and the reactor coolant letdown filter to the VCT. The fluid is then returned to the RCS via the normal charging route.

Filters are provided at various locations to ensure filtration of particulate and resin fines and to protect the seals on the RCPs.

Fission gases are removed from the system by venting the VCT to the waste disposal system.

9.3.4.2.8.2.4 Chemical Shim and Reactor Coolant Makeup

The soluble neutron absorber (boric acid) concentration and the reactor coolant inventory are controlled by the RMCS. In addition, for emergency boration and makeup, the capability exists to provide refueling water or 4 weight percent boric acid (7,000 ppm boron) to the suction of the CCPs. All CCPs are capable of providing emergency boration flow; however, only CCP1 and CCP2 are credited with this function during power operation, startup, and hot standby. However, CCP3 can serve as a backup to CCP1 and CCP2 in the event they are lost due to a fire (refer to Section 9.5.1).

The boric acid is stored in two boric acid tanks (also known as boric acid storage tanks). Two boric acid transfer pumps are provided with one pump normally aligned with one boric acid tank running continuously at low speed to provide recirculation of the boric

acid system. The second pump is aligned with the second boric acid tank and is considered as a standby pump, with service being transferred as operation requires. This second pump also circulates fluid, as needed, through the second boric acid tank. Manual or automatic initiation of the RMCS will activate the running pump to the higher speed to provide normal makeup of boric acid solution as required.

The primary makeup water pumps, taking suction from the primary makeup water storage tank, are employed for various makeup and flushing operations throughout the systems. One of these pumps also starts on demand from the RMCS and provides flow to the boric acid blender. The flow from the boric acid blender is directed to either the suction manifold of the CCPs or the VCT through the letdown line and spray nozzle.

During reactor operation, changes are made in the reactor coolant boron concentration for the following conditions:

(1) Reactor startup - boron concentration must be decreased from shutdown concentration to achieve criticality.

(2) Load follow - boron concentration must be either increased or decreased to compensate for the xenon transient following a change in load.

(3) Fuel burnup - boron concentration must be decreased to compensate for fuel burnup.

(4) Cold shutdown - boron concentration must be increased to the cold shutdown concentration.

The RMCS instruments provide a manually preselected makeup composition to the CCP suction header or the VCT. The makeup control functions are those of maintaining desired operating fluid inventory in the VCT and adjusting reactor coolant boron concentration for reactivity control.

Automatic Makeup of Reactor Makeup Control System

The automatic makeup mode of operation of the RMCS provides boric acid solution preset to match the boron concentration in the RCS. The automatic makeup compensates for minor leakage of reactor coolant without causing significant changes in the coolant boron concentration.

Under normal plant operating conditions, the RMCS mode and makeup stop valves are set in the "automatic makeup" position. A preset low-level signal from the VCT level controller causes the automatic makeup control action to start a primary makeup water pump, switch a boric acid transfer pump to high-speed operation, open the makeup stop valve to the CCP suction, and throttle the concentrated boric acid control valve and the primary makeup water control valve. The flow controllers then blend the makeup stream according to the preset concentration. Makeup addition to the CCP suction

header causes the water level in the VCT to rise. At a preset high-level point, the makeup is stopped, the primary makeup water pump stops, the primary makeup water control valve closes, the boric acid transfer pump returns to low-speed operation, the concentrated boric acid control valve closes, and the makeup stop valve to CCP suction closes.

If the automatic makeup fails or is not aligned for operation and the tank level continues to decrease, a low-level alarm is actuated. Manual action may correct the situation or, if the level continues to decrease, an emergency low-level signal from both channels opens the stop valves in the refueling water supply line and closes the stop valves in the VCT outlet line.

Dilute

The dilute mode of operation permits the addition of a preselected quantity of primary makeup water at a preselected flow rate to the RCS. The operator sets the RMCS mode to "dilute," the primary makeup water flow setpoint to the desired flow rate, the primary makeup water batch to the desired quantity, and initiates system start. This opens the primary makeup water control valve to the VCT and starts a primary water makeup pump that will deliver water to the VCT. From here the water goes to the CCP suction header. Excessive rise of the VCT water level is prevented by automatic actuation (by the tank level controller) of a three-way diversion valve which routes the reactor coolant letdown flow to the LHUTs in the boron recovery system. When the preset quantity of water has been added, the RMCS causes the pump to stop and the control valve to close.

Alternate Dilute

The alternate dilute mode of operation is similar to the dilute mode except a portion of the dilution water flows directly to the CCP suction and a portion flows into the VCT via the spray nozzle and then flows to the CCP suction.

Borate

The borate mode of operation permits the addition of a preselected quantity of concentrated boric acid solution at a preselected flow rate to the RCS. The operator sets the RMCS mode to "borate," the concentrated boric acid flow setpoint to the desired flow rate, the concentrated boric acid batch to the desired quantity, and initiates system start. This opens the makeup stop valve to the CCPs' suction and switches the boric acid transfer pump to high-speed operation, which delivers a 4 weight percent boric acid solution (7,000 ppm boron) to the CCP suction header. The total quantity added in most cases is so small that it has only a minor effect on the VCT level. When the preset quantity of concentrated boric acid solution is added, the RMCS returns the boric acid transfer pump to low-speed operation and closes the makeup stop valve to the suction of the CCPs.

Manual

The manual mode of operation may be used to provide a blend of boric acid solution, to borate, or to dilute to the RCS, to the RWST, or to the LHUTs in the boron recovery system. While in the manual mode of operation, automatic makeup to the RCS is precluded. The discharge flowpath may be manually configured.

The operator then sets the RMCS mode to "manual," the concentration of boric acid is set and the required batch gallons are set to the desired flow rates, the boric acid and primary makeup water batch to the desired quantities, and initiates system start. The system start actuates the boric acid flow control valve and the primary makeup water flow control valve to the boric acid blender, starts the preselected primary makeup water pump, and switches the boric acid transfer pump to high-speed operation.

When the preset quantities of boric acid and primary makeup water have been added, the primary makeup water pump stops, the boric acid transfer pump returns to low-speed operation, and the boric acid control valve and the primary makeup water flow control valve close. This operation may be stopped manually by initiating system stop.

If either batch setpoint is satisfied before the other has recorded its required total, the pump and valve associated with the setpoint which has been satisfied will terminate flow. The flow controlled by the other setpoint will continue until that setpoint is satisfied.

Alarm Functions

The RMCS is provided with alarm functions to call the operator's attention to the following conditions:

(1) Deviation of primary makeup water flow rate from the control setpoint.

(2) Deviation of concentrated boric acid flow rate from control setpoint.

(3) High level in the VCT. This alarm indicates that the level in the tank is approaching high level and a resulting 100 percent diversion of the letdown stream to the LHUTs in the boron recovery system.

(4) Low level in the VCT. This alarm indicates that the level in the tank is approaching emergency low level and resulting realignment of CCP suction to the RWST.

9.3.4.2.8.3 Boron Recovery System

The boron recovery system collects borated water that results from the following plant operations. In each of these operations, the excess reactor coolant is diverted from the letdown line to the LHUTs as a result of high VCT level.

(1) Dilution of reactor coolant to compensate for core burnup

(2) Load follow

(3) Hot shutdowns and startups

(4) Cold shutdowns and startups

(5) Refueling shutdowns and startups

Excess liquid effluents containing boric acid and flow from the RCS through the letdown line are collected in the LHUTs. As liquid enters the LHUTs, the nitrogen cover gas is displaced to the gas decay tanks in the waste disposal system through the waste vent header. The concentration of boric acid in the LHUTs varies through core life from the refueling concentration to near zero at the end of the core cycle. An LHUT recirculation pump is provided to transfer liquid from one LHUT to another.

Liquid effluent in the LHUTs is processed as a batch operation. This liquid is pumped by the gas stripper feed pumps through the evaporator feed ion exchangers. It then flows through the ion exchanger filter, and then the liquid is drained to the LRS for processing.

9.3.4.2.9 Component Description

A summary of principal CVCS component design parameters is given in Table 9.3-6. CVCS safety classifications and design codes are given in Table 3.2-3. All CVCS piping that handles radioactive liquid is austenitic stainless steel. All piping joints and connections are welded, except where flanged connections are required to facilitate equipment removal for maintenance and hydrostatic testing.

9.3.4.2.9.1 Centrifugal Charging Pumps

Three CCPs inject coolant into the RCS and are of the single-speed, horizontal, centrifugal type. All parts in contact with the reactor coolant are fabricated of austenitic stainless steel or other material of adequate corrosion-resistance. There is a minimum flow recirculation line on each CCP discharge header to protect them against a closed discharge valve condition.

Charging flow rate is determined from a pressurizer level signal. Charging flow control is accomplished by a modulating valve on the discharge side of the CCPs. CCP1 and

CCP2 also serve as the high-head SI pumps in the ECCS with induction motors that are powered by the Class 1E 4.16-kV system.

9.3.4.2.9.2 Boric Acid Transfer Pumps

Two horizontal, centrifugal, two-speed pumps with mechanical seals are supplied. The pumps' motors are powered by the Class 1E 480-V system. Normally, one pump is aligned with one boric acid tank and runs continuously at low speed to provide recirculation of the boric acid system. The second pump is aligned with the second boric acid tank, then considered as a standby pump, with service being transferred as operation requires. This second pump also intermittently circulates fluid through the second tank. Manual or automatic initiation of the RMCS will activate the running pump to the higher speed to provide normal makeup of boric acid solution, as required. For emergency boration, supplying of boric acid solution to the suction of the CCPs can be accomplished by manually actuating either or both pumps. The transfer pumps also function to transfer boric acid solution from the batching tank to the boric acid tanks. In addition to the automatic actuation by the RMCS, and manual actuation from the main control board, these pumps may also be controlled locally at the HSP.

The pumps are heat-traced to prevent crystallization of the boric acid solution. All parts in contact with the solution are of austenitic stainless steel.

9.3.4.2.9.3 Gas Stripper Feed Pumps

The two gas stripper feed pumps supply feed through the evaporator feed ion exchangers from the LHUTs and route it to the LRS. The non-operating pump is a standby and is available for operation in the event the operating pump malfunctions. These centrifugal pumps are constructed of austenitic stainless steel.

9.3.4.2.9.4 Liquid Holdup Tank Recirculation Pump

The recirculation pump is used to mix the contents of an LHUT for sampling or to transfer the contents of an LHUT to another LHUT. The wetted surface of this pump is constructed of austenitic stainless steel.

9.3.4.2.9.5 Boric Acid Reserve Tank Pumps

The two boric acid reserve tank pumps discharge water from the boric acid reserve tanks to other portions of the CVCS. The pumps are constructed of austenitic stainless steel.

9.3.4.2.9.6 Boric Acid Reserve Tank Recirculation Pumps

Two boric acid reserve tank recirculation pumps are provided for each tank. Only one pump per tank is running at a time with the other on standby. These pumps are used to recirculate boric acid through installed piping, equipment, and an inline heater to

maintain a fluid temperature above 80°F. These pumps are seal-less and the wetted surface is constructed of austenitic stainless steel.

9.3.4.2.9.7 Regenerative Heat Exchanger

The regenerative heat exchanger is designed to recover heat from the letdown flow by reheating the charging flow, which reduces thermal shock on the charging penetrations into the reactor coolant loop piping.

The letdown stream flows through the shell of the regenerative heat exchanger, and the charging stream flows through the tubes. The unit is made of austenitic stainless steel and is of an all-welded construction.

9.3.4.2.9.8 Letdown Heat Exchanger

The letdown heat exchanger cools the letdown stream to the operating temperature of the mixed bed demineralizers. Reactor coolant flows through the tube side of the exchanger while CCW flows through the shell-side. All surfaces in contact with the reactor coolant are austenitic stainless steel, and the shell is carbon steel.

9.3.4.2.9.9 Excess Letdown Heat Exchanger

The excess letdown heat exchanger cools reactor coolant letdown flow, which is equivalent to the nominal seal injection flow which flows downward through the RCP labyrinth seals.

The excess letdown heat exchanger can be employed either when normal letdown is temporarily out of service to maintain the reactor in operation or it can be used to supplement maximum letdown during the final stages of heatup. The letdown flows through the tube side of the unit and CCW is circulated through the shell side. All surfaces in contact with reactor coolant are austenitic stainless steel, and the shell is carbon steel. All tube joints are welded.

9.3.4.2.9.10 Seal Water Heat Exchanger

The seal water heat exchanger is designed to cool fluid from three sources: RCP seal water returning to the CVCS, reactor coolant discharged from the excess letdown heat exchanger, and CCP bypass flow. Reactor coolant flows through the tube side of the heat exchanger, and CCW is circulated through the shell side. The design flow rate is equal to the sum of the excess letdown flow, maximum design RCP seal leakage, and bypass flow from the CCPs. The unit is designed to cool the above flow to the temperature normally maintained in the VCT. All surfaces in contact with reactor coolant are austenitic stainless steel, and the shell is carbon steel.

9.3.4.2.9.11 Volume Control Tank

The VCT provides surge capacity for part of the reactor coolant expansion volume not accommodated by the pressurizer. When the level in the tank reaches the high-level setpoint, the remainder of the expansion volume is accommodated by diversion of the letdown stream to the LHUTs. It also provides a means for introducing hydrogen into the coolant to maintain the required equilibrium concentration, is used for degassing the reactor coolant, and serves as a head tank for the suction of the CCPs.

A spray nozzle located inside the tank on the letdown line nozzle provides liquid-to-gas contact between the incoming fluid and the hydrogen atmosphere in the tank.

For degassing, the tank is provided with a remotely operated solenoid valve backed up by a pressure control valve, which ensures that the tank pressure does not fall below minimum operating pressure during degassing to the waste disposal system. Relief protection, gas space sampling, and nitrogen purge connections are also provided. The tank can also accept the seal water return flow from the RCPs, although this flow normally goes directly to the suction of the CCPs.

9.3.4.2.9.12 Boric Acid Tanks

The combined boric acid tank capacity is sized to store sufficient boric acid solution for a cold shutdown from full power operation immediately following refueling with the most reactive RCCA not inserted, plus operating margins.

The concentration of boric acid solution in storage is maintained between 4.0 and 4.4 percent by weight (7,000 to 7,700 ppm boron). Periodic manual sampling and corrective action, if necessary, ensure that these limits are maintained. As a consequence, measured amounts of boric acid solution can be delivered to the reactor coolant to control the concentration.

Each of two electric heaters in each boric acid tank is designed to maintain the temperature of the boric acid solution at 165°F with ambient air temperature of 40°F, thus ensuring a temperature in excess of the solubility limit. Heater controls maintain the temperature of the boric acid solution at nominally between 110°F and 120°F.

The boric acid tanks can be filled from the batch tank.

9.3.4.2.9.13 Batching Tank

The batching tank is used for mixing a makeup supply of boric acid solution for transfer to the boric acid tanks or the boric acid reserve tanks. The tank may also be used for solution storage.

A local sampling point is provided for verifying the solution concentration prior to transferring it out of the tank. The tank is provided with an agitator to improve mixing during batching operations and a means for heating the boric acid solution.

9.3.4.2.9.14 Chemical Mixing Tank

The primary use of the chemical mixing tank is in the preparation of lithium hydroxide solutions for pH control and hydrazine for oxygen scavenging.

9.3.4.2.9.15 Liquid Holdup Tanks

A total of five LHUTs are provided for DCPP Unit 1 and Unit 2. Two of these tanks serve Unit 1, and two serve Unit 2. The fifth tank can be used with either Unit 1 or Unit 2. The LHUTs hold radioactive liquid, which enters from the letdown line. The liquid is released from the RCS during startup, shutdowns, load changes, and from boron dilution to compensate for burnup. The contents of one tank are normally being processed by the ion exchangers while the other tank is being filled. The tank shared by Unit 1 and Unit 2 is typically kept empty to provide additional storage capacity, when needed, and can be used to store supplemental refueling water.

The total liquid storage capacity of three LHUTs is approximately equal to two RCS volumes. The tanks are constructed of austenitic stainless steel.

9.3.4.2.9.16 Boric Acid Reserve Tanks

Two boric acid reserve tanks are provided for storage of boric acid to meet operational needs for a ready supply of boric acid solution. One tank is maintained on a short recirculation through an inline circulation heater to maintain the tank contents and the associated piping and equipment above 80°F. The other tank is maintained on long recirculation, which also includes the transfer piping in the recirculation loop. Recirculation is normally accomplished by using either one of the two installed recirculation pumps. A transfer pump is provided to send boric acid to the boric acid tank or to the batch tank.

Flush water can be provided from the MWS to flush the boric acid from the piping, through the flush bypass line, to the LHUTs. In addition, water from the boric acid reserve tank can also be pumped to the processed waste receiver or to the LHUTs via installed connections.

The tanks are provided with a Hypalon coated floating cover that will prevent absorption of oxygen by the boric acid solution. In addition, the annular space around the side of the cover between the fluid surface and the bladder attachment point is continuously purged with nitrogen to further reduce the absorption of oxygen by the boric acid. The nitrogen purge vents out vent holes in the bladder attachment bar inside the tank and then vents to the room atmosphere through the tank vent.

9.3.4.2.9.17 Mixed Bed Demineralizers

Two flushable mixed bed demineralizers assist in maintaining reactor coolant purity. A lithium-form cation resin and hydroxyl-form anion resin are charged into the demineralizers. Both forms of resin remove fission and corrosion products. The resin bed is designed to reduce the concentration of ionic isotopes in the purification stream, except for cesium, yttrium, and molybdenum, by a minimum factor of 10.

Each demineralizer nominally has sufficient capacity for approximately one core cycle with 1 percent defective fuel rods. One demineralizer serves as a standby unit for use if the operating demineralizer becomes exhausted during operation.

The normal resin volume is 30 cubic feet per demineralizer. The maximum resin volume is 39 cubic feet per demineralizer. Resin volumes greater than 30 cubic feet cannot be regenerated in the vessel and must be flushed when no longer needed. Resin volumes less than 30 cubic feet may be used for special resins or to meet various requirements.

9.3.4.2.9.18 Cation Bed Demineralizer

The flushable cation resin bed in the hydrogen form is located downstream of the mixed bed demineralizers and is used intermittently to control the concentration of Li^7 which builds up in the coolant from the B^{10} (n, α) Li^7. The demineralizer also has sufficient capacity to maintain the cesium-137 concentration in the coolant below 1 μCi/cc with 1 percent defective fuel. The resin bed is designed to reduce the concentration of ionic isotopes, particularly cesium, yttrium, and molybdenum, by a minimum factor of 10.

The cation bed demineralizer has sufficient capacity for approximately one core cycle with 1 percent defective fuel rods.

9.3.4.2.9.19 Deborating Demineralizers

When required, two anion demineralizers remove boric acid from the RCS fluid. The demineralizers are provided for use near the end of a core cycle, but can be used at any time when boron concentration is low. As an alternative, one of these demineralizers may be filled with a mixed bed and used for removal of radionuclides during forced oxygenation.

The normal resin volume is 30 cubic feet per demineralizer. The maximum resin volume is 39 cubic feet per demineralizer. Resin volumes greater than 30 cubic feet cannot be regenerated in the vessel and must be flushed when no longer needed.

Hydroxyl-based ion exchange resin is used to reduce RCS boron concentration by releasing a hydroxyl ion when a borate is absorbed. Facilities are provided for regeneration. When regeneration is no longer feasible, the resin is flushed to the spent resin storage tank.

The demineralizers are sized to remove approximately 100 ppm of boric acid from the RCS to maintain full power operation near the end of core life should the LHUTs be full.

9.3.4.2.9.20 Evaporator Feed Ion Exchangers

Two trains of ion exchangers purify the feed and routes it to the LRS. Each train consists of two demineralizer vessels in series. The resin beds in these demineralizers remove cationic impurities including cesium and molybdenum, and anionic impurities including chlorides, fluorides, and sulfur species. One train is in service during evaporator operation and the other is on standby.

9.3.4.2.9.21 Reactor Coolant Letdown Filter

The reactor coolant letdown filter is located on the letdown line upstream of the VCT. The filter collects resin fines and particulates from the letdown stream. The nominal flow capacity of the filter is equal to the maximum purification flow rate. A redundant reactor coolant letdown filter has been installed as a standby.

9.3.4.2.9.22 Seal Water Injection Filters

Two seal water injection filters are located in parallel in a common line to the RCP seals; they collect particulate matter that could be harmful to the seal faces. Each filter is sized to accept flow in excess of the normal seal water requirements. One filter is normally in operation and the other is in standby.

9.3.4.2.9.23 Seal Water Return Filter

The seal water return filter collects particulates from the RCP seal water return and from the excess letdown flow. The filter is designed to pass flow in excess of the sum of the excess letdown flow and the maximum design leakage from the RCP seals.

9.3.4.2.9.24 Boric Acid Filter

The boric acid filter collects particulates from the boric acid solution being pumped to the CCP suction line or boric acid blender. The filter is designed to pass the design flow of two boric acid transfer pumps operating simultaneously.

9.3.4.2.9.25 Ion Exchange Filter

This filter collects resin fines and particulates from the gas stripper feed pumps and routes the effluent to the LHUTs or the LRS.

9.3.4.2.9.26 Boric Acid Reserve Tank Recirculation Heaters

Two, 12-kW heaters are provided in the boric acid reserve tank recirculation paths (one heater per path) to heat the boric acid. This will in turn maintain the tank contents and the associated recirculation piping above 80°F. The heaters are controlled by a temperature controller that senses tank temperature and regulates the power supplied to the heaters accordingly. An over temperature controller is provided which senses heater temperature and cuts power to the heater when a high temperature is sensed at the heating element.

9.3.4.2.9.27 Boric Acid Blender

The boric acid blender promotes thorough mixing of boric acid solution and reactor makeup water for the reactor coolant makeup circuit. The blender consists of a conventional pipe tee fitted with a perforated tube insert. The blender decreases the pipe length required to homogenize the mixture for taking a representative local sample. A sample point is provided in the piping just downstream of the blender.

9.3.4.2.9.28 Letdown Orifices

The three letdown orifices are arranged in parallel and serve to reduce the pressure of the letdown stream to a value compatible with the letdown heat exchanger design. Two of the three are sized such that either can pass normal letdown flow; the third can pass less than the normal letdown flow. One or both standby orifices may be used with the normally operating orifice in order to increase letdown flow such as during reactor heatup operations. This arrangement also provides a full standby capacity for control of letdown flow.

9.3.4.2.9.29 Gas Stripper-Boric Acid Evaporator Package

Liquid effluent in the LHUTs is processed as a batch operation. This liquid is pumped by the gas stripper feed pumps through the evaporator feed ion exchangers. It then flows through the ion exchanger filter, and then the liquid is drained to the LRS for processing. The boric acid evaporator system is abandoned in place and no longer in use.

9.3.4.2.9.30 Electric Heat Tracing

Electric heat tracing is installed under the insulation on piping, valves, line-mounted instrumentation, and components normally containing concentrated boric acid solution. The heat tracing is designed to prevent boric acid precipitation due to cooling, by compensating for heat loss. Even though the heat tracing is not required to maintain the 4 percent boric acid solution above the 65°F precipitation temperature, it does provide added assurance against falling below this limit. The existing boric acid heat tracing provides two parallel PG&E Design Class II heater circuits in a bifilar arrangement. One circuit is used for normal operations and the second serves as a backup. The parallel circuits are supplied from different power sources to provide

power supply redundancy. The size of the section heated by each pair of circuits is determined by the capacity of the heaters and their feeders, as well as the temperatures required.

There are no heat tracings on:

(1) Lines that may transport concentrated boric acid but are subsequently flushed with reactor coolant or other liquid of low boric acid concentration during normal operation

(2) The boric acid tanks, which are provided with immersion heaters

(3) The boric acid reserve tanks, which are provided with inline recirculation heaters

(4) The batching tank, which is provided with a steam jacket

Each circuit is controlled independently by a thermostat at a location having the most representative temperature of the circuit. The backup circuits are set to operate at a slightly lower temperature than the normal circuits. A thermocouple to detect metal temperature is installed under the thermal insulation near the thermostats. The thermocouple monitor has local indication and stored data memory that may be downloaded to commercial spreadsheet software and printed. The thermocouples are monitored, and both low and high temperatures are alarmed. The low-temperature alarm setpoint is within the operating range of the backup heater.

The boric acid tank sample lines to the sample sink are provided with a single circuit of self-regulating heat trace. Because the precipitation temperature of 4 percent boric acid solution is below normal room temperature, the boric acid line heat tracing functions as a precautionary measure, and is PG&E Design Class II. The circuit is monitored by an indicating light.

9.3.4.2.9.31 Valves

Valves, other than diaphragm valves, that perform a modulating function are equipped with two sets of packing and an intermediate leakoff connection. Valves are normally installed such that, when closed, pressure is not on the packing. Basic material of construction is stainless steel for all valves. Isolation valves are provided for all lines entering the reactor containment. These valves are discussed in detail in Section 6.2.4.

Relief valves are provided for lines and components that might be pressurized above design pressure by improper operation or component malfunction. Relief valves with potentially contaminated effluent are collected and routed to tanks in order to minimize radioactive releases inside the auxiliary building.

Charging Line Downstream of Regenerative Heat Exchanger

If the charging side of the regenerative heat exchanger is isolated while the hot letdown flow continues at its maximum rate, the volumetric expansion of coolant on the charging side of the heat exchanger is relieved to the RCS through a spring-loaded check valve. The spring in the valve is designed to permit the check valve to open in the event that the differential pressure exceeds the design pressure differential of approximately 75 psi.

Letdown Line Downstream of Letdown Orifices

The pressure-relief valve downstream of the letdown orifices protects the low-pressure piping and the letdown heat exchanger from overpressure when the low-pressure piping is isolated. The capacity of the relief valve exceeds the maximum flow rate through all letdown orifices. The valve set pressure is equal to the design pressure of the letdown heat exchanger tube side.

Letdown Line Downstream of Low-pressure Letdown Valve

The pressure-relief valve downstream of the low-pressure letdown valve protects the low-pressure piping, demineralizers, and filter from overpressure when this section of the system is isolated. The overpressure may result from leakage through the low-pressure letdown valve. The capacity of the relief valve exceeds the maximum flow rate through all letdown orifices. The valve set pressure is equal to the design pressure of the demineralizers.

Volume Control Tank

The relief valve on the VCT permits the tank to be designed for a lower pressure than the upstream equipment. This valve has a capacity greater than the summation of the following items: maximum letdown, maximum seal water return, excess letdown, and nominal flow from one reactor makeup water pump. The valve set pressure equals the design pressure of the VCT.

Charging Pump Suction

A relief valve on the CCP suction header relieves pressure that may build up if the suction line isolation valves are closed or if the system is overpressurized. The valve set pressure is equal to the design pressure of the associated piping and equipment.

Seal Water Return Line (Inside Containment)

This relief valve is designed to relieve overpressurization in the seal water return piping inside the containment if the motor-operated isolation valve is closed. The valve is designed to relieve the total leakoff flow from the No. 1 seals of the RCPs plus the

design excess letdown flow. The valve is set to relieve at the design pressure of the piping.

Seal Water Return Line (Charging Pumps Bypass Flow)

This relief valve protects the seal water heat exchanger and its associated piping from overpressurization. If either of the isolation valves for the heat exchanger is closed and if the bypass line is closed, the piping may be overpressurized by the bypass flow from the CCPs. It is assumed that all CCPs are running with full bypass flow. The valve is set to relieve at the design pressure of the heat exchanger.

9.3.4.2.9.32 Piping

All CVCS piping handling radioactive liquid is austenitic stainless steel. All piping joints and connections are welded, except where flanged connections are required to facilitate equipment removal for maintenance and hydrostatic testing.

9.3.4.2.9.33 Zinc Injection Sub-systems

The CVCS includes a skid-mounted zinc injection sub-system that provides the capability to inject a zinc acetate solution to a line leading to the VCT. The chemical solution is injected into the PG&E Design Class II portion of the CVCS.

This sub-system includes a storage and mixing tank, three chemical feed pumps with electrical controls, and the associated piping, tubing, valves, controls, and instrumentation. The tank has a divider that separates the chemical supply for Unit 1 and Unit 2. There is one chemical feed pump dedicated to each unit and a common pump that can serve either Unit 1 or Unit 2. The valves and pumps associated with this sub-system are all manually controlled from the skid. A nitrogen blanket is provided in the tank to exclude oxygen. Make-up water to prepare the zinc acetate solution is provided from the PWST. Power is provided from a non-Class 1E power source.

9.3.4.2.9.34 Argon Injection Sub-systems

The CVCS includes a wall mounted argon injection sub-system that provides the capability to inject high purity argon into the zinc acetate supply line. The zinc acetate injection sub-system is described in 9.3.4.2.9.33. The argon injection sub-system is PG&E Design Class II and connects to a PG&E Design Class II portion of the CVCS.

Argon injection aids in the identification of small primary to secondary SG tube leaks. Trace amounts of argon is injected to generate a short half-life isotope (Ar-41) that can easily be detected by the condenser off gas steam jet air ejector radiation monitor in the event of an SG tube leak.

This sub-system includes an argon bottle, regulator, valves and controls connected via tubing. A flow indicating controller and relief valve is installed downstream from the

regulator to control the injection rate and provide over pressure protection. A check valve is located upstream of the zinc injection system tie-in. Other valves associated with this sub-system are all manually controlled from the skid. Power for the flow controller is provided from a non-Class 1E power source.

9.3.4.2.10 System Operation

9.3.4.2.10.1 Chemical and Volume Control System Operation During Reactor Startup

Reactor startup is defined as the operations which bring the reactor from cold shutdown to normal operating temperature and pressure. Reactor pressure vessel heatup and cooldown and compliance with ASME BPVC Section III–1972 Summer Addenda, Appendix G, is discussed in Section 5.2.

It is assumed that:

(1) Normal RHR is in progress.

(2) RCS boron concentration is at or above the cold shutdown concentration.

(3) RMCS is set to provide makeup at or above the cold shutdown concentration.

(4) RCS is either water-solid or drained to minimum level for the purpose of refueling or maintenance. If the RCS is water-solid, system pressure is controlled by letdown through the RHR system and through the letdown pressure control valve.

(5) The charging and letdown lines of the CVCS are filled with coolant at the cold shutdown boron concentration. The letdown orifice isolation valves are closed.

If the RCS requires filling and venting, the general process is as follows (depending on plant conditions, the startup process may vary):

(1) One CCP is started, which provides blended flow from the RMCS (or RWST) at the cold shutdown boron concentration.

(2) The vents on the head of the RV and pressurizer are vented.

(3) The various portions of the RCS are filled and the vents closed.

The CCP and the low-pressure letdown valve continue to pressurize the system. When the system pressure is adequate for operation of the RCPs, seal water flow to the

pumps is established (if not already in service) and the pumps are sequentially operated and the RCS is vented until all gases are cleared from the system.

After the filling and venting operations are completed, pressurizer heaters are energized and the RCPs are operated to heat up the system. After the RCPs are started, the RHR pumps are stopped, but pressure control via the RHR system and the low-pressure letdown line is continued. At this point, steam formation in the pressurizer is accomplished by adjusting charging flow and the pressurizer pressure controller. When the pressurizer level reaches the no-load programmed setpoint, the pressurizer level is controlled to maintain the programmed level. The RHR system is then configured in its ECCS alignment.

The reactor coolant boron concentration is now reduced by operating the RMCS in the "dilute" mode. The reactor coolant boron concentration is adjusted to the point where the RCCAs may be withdrawn and criticality achieved. Power operation may then proceed with corresponding manual adjustment of the reactor coolant boron concentration to balance the temperature coefficient effects and maintain the RCCAs within their operating range. During operation, the appropriate combination of letdown orifices is used to provide necessary letdown flow.

Prior to and during the heatup process, the CVCS is employed to obtain the correct chemical properties in the RCS. The RMCS is operated on a continuing basis to ensure correct RCCA position. Chemicals are added through the chemical mixing tank, as required, to control reactor coolant chemistry such as pH and dissolved oxygen content. Hydrogen overpressure is established in the VCT to ensure the appropriate hydrogen concentration in the reactor coolant.

9.3.4.2.10.2 Power Generation and Hot Standby Operation

Base Load

At a constant power level, the rates of charging and letdown are dictated by the requirements for seal water to the RCPs and the normal purification of the RCS. Typically, one CCP is employed and charging flow is controlled automatically from pressurizer level. The only adjustments in boron concentration necessary are those to compensate for core burnup. Rapid variations in power demand are accommodated automatically by RCCA movement. If variations in power level occur, and the new power level is sustained for long periods, some adjustment in boron concentration may be necessary to maintain the RCCAs at their desired position.

During typical operation, normal letdown flow is maintained and one mixed bed demineralizer is in service. Reactor coolant samples are taken periodically to check boron concentration, water quality, pH, and activity level. The CCP flow to the RCS is controlled by the pressurizer level control signal through the discharge header flow control valve.

Load Follow (not normally performed)

A power reduction will initially cause a xenon buildup followed by xenon decay to a new, lower equilibrium value. The reverse occurs if the power level increases; initially, the xenon level decreases and then it increases to a new and higher equilibrium value associated with the amount of the power level change.

The RMCS is used to vary the reactor coolant boron concentration to compensate for xenon transients occurring when reactor power level is changed.

One indication available to the plant operator (enabling him to determine whether dilution or boration of the RCS is necessary) is the position of the RCCAs within the desired band. If, for example, the RCCAs are moving down into the core and are approaching the bottom of the desired band, the operator must borate the reactor coolant to bring the RCCAs outward. If not, the RCCAs may move into the core beyond the insertion limit. If, on the other hand, the RCCAs are moving out of the core, the operator dilutes the reactor coolant to keep the RCCAs from moving above the top of the desired band.

During periods of plant loading, the reactor coolant expands as its temperature rises. The pressurizer absorbs most of this expansion as the level controller raises the level setpoint to the increased level associated with the new power level. The remainder of the excess coolant is let down and may be accommodated in the VCT or LHUTs. During this period, the flow through the letdown orifice remains constant and the charging flow is reduced by the pressurizer level control signal, resulting in an increased temperature at the regenerative heat exchanger outlet. The temperature controller downstream from the letdown heat exchanger increases the CCW flow to maintain the desired letdown temperature.

During periods of plant unloading, the charging flow is increased to make up for the coolant contraction not accommodated by the programmed reduction in pressurizer level.

Hot Standby

If required for periods of maintenance or following reactor trips, the reactor can be held subcritical, but with the capability to return to full power within the period of time it takes to withdraw RCCAs. During this hot standby period, temperature is maintained at no-load T_{avg} by dumping steam to remove core residual heat.

Following shutdown, xenon buildup and decay results in a variation in the degree of shutdown. During this time, boration and dilution of the system are performed to counteract these xenon variations.

9.3.4.2.10.3 Reactor Shutdown

Reactor shutdown is defined as the operations that bring the reactor to cold shutdown for maintenance or refueling.

Before initiating a cold shutdown, the RCS hydrogen concentration is reduced by reduction of the VCT overpressure and venting the gases to the waste gas vent header.

Before cooldown and depressurization of the reactor plant is initiated, the reactor coolant boron concentration is increased to the value required for the corresponding target temperature. The operator uses the RMCS to add the volume of concentrated boric acid solution necessary to perform the boration. After the boration is completed, the operator uses the RMCS to maintain the desired reactor coolant boron concentration. Subsequent reactor coolant samples are taken to verify that the RCS boron concentration is correct.

Contraction of the coolant during cooldown of the RCS results in actuation of the pressurizer level control to maintain normal pressurizer water level. The charging flow is increased, relative to letdown flow, and results in a decreasing VCT level. The RMCS initiates makeup to maintain the inventory.

Coincident with plant cooldown, a portion of the reactor coolant flow may be diverted from the RHR system to the CVCS for cleanup. Demineralization of ionic radioactive impurities and stripping of fission gases reduce the reactor coolant activity level sufficiently to permit personnel access for refueling or maintenance operations.

9.3.4.3 Safety Evaluation

9.3.4.3.1 General Design Criterion 2, 1967 – Performance Standards

All CVCS components are located within the PG&E Design Class I auxiliary and containment buildings. These buildings, or applicable portions thereof, are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other natural phenomena, to protect CVCS SSCs, ensuring their safety functions will be performed.

The CVCS is designed to perform its function of providing shutdown capability under DDE and HE loading. The seismic requirements are defined in Sections 3.7 and 3.10, and the provisions to protect the system from seismic damage are discussed in Sections 3.7, 3.9, and 3.10. CVCS components are designed to withstand the appropriate seismic loadings in accordance with their design class. CVCS components required for safe shutdown are PG&E Design Class I.

9.3.4.3.2 General Design Criterion 3, 1971 – Fire Protection

The CVCS is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.3.4.3.3 General Design Criterion 4, 1967 – Sharing of Systems

The CVCS components which are shared by both Unit 1 and Unit 2 are the boric acid batching tank, the boric acid reserve tanks, the boric acid reserve tank pumps, the boric acid reserve tank recirculation pumps, and the zinc injection tank. Other components which can be aligned to either Unit 1 or Unit 2 include the LHUTs (refer to Section 9.3.4.2.9.15), LHUT recirculation pumps, and the zinc injection pumps. Administrative controls are in place to ensure that PG&E Design Class I components are not aligned to both Unit 1 and Unit 2 at the same time through the use of closed isolation valves. These administrative controls ensure that CVCS safety functions are not affected by the sharing.

9.3.4.3.4 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The CVCS provides a means for controlling the RCS water chemistry to minimize corrosion and protect the RCS pressure boundary (refer to Section 5.2.2.3.4). The CVCS is designed with provisions for pH control, oxygen control, and purification of the RCS. The CVCS provides a means for adding chemicals to the RCS to control the pH of the coolant during initial startup and subsequent operation (refer to Section 9.3.4.2.8.2.1), scavenge oxygen from the coolant during startup, and control the oxygen level of the reactor coolant due to radiolysis during all operations subsequent to startup (refer to Sections 9.3.4.2.4 and 9.3.4.2.8.2.2). The CVCS removes fission products and corrosion products from the reactor coolant during operation of the reactor and maintains these within acceptable levels (refer to Sections 9.3.4.2.3 and 9.3.4.2.8.2.3).

9.3.4.3.5 General Design Criterion 11, 1967 – Control Room

Instrumentation, alarms, and controls are provided in the control room for operators to monitor and maintain CVCS parameters. In the event that control room access is lost, CVCS components required for safe shutdown which can be manually controlled from the HSP are: CCP1 and CCP2, boric acid transfer pumps, emergency borate valve 8104, charging flow control valves FCV-128 and HCV-142, and the letdown isolation valves. Refer to Section 7.4.2.1 for additional discussion.

The HSP also provides indication for the following CVCS parameters: RCP seal No. 1 differential pressure, emergency boration flow, VCT level, letdown flow, and charging header pressure and flow.

Instrumentation and alarms for the CVCS is further discussed in Section 9.3.4.3.6.

9.3.4.3.6 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Process control instrumentation is provided to acquire data concerning key parameters about the CVCS. The location of the instrumentation is shown in Figure 3.2-8.

The instrumentation furnishes input signals for monitoring and/or alarming purposes. Indications and/or alarms are provided for the following parameters:

(1) Temperature

(2) Pressure

(3) Flow

(4) Water level

The instrumentation also supplies input signals for control purposes. Some specific control functions are:

(1) Letdown flow is diverted to the VCT upon high-temperature indication upstream of the mixed bed demineralizers

(2) Pressure downstream of the letdown heat exchangers is controlled to prevent flashing of the letdown liquid

(3) Charging flow rate is controlled during CCP operation(refer to Section 9.3.4.2.9.1)

(4) Water level is controlled in the VCT

(5) Temperature of the boric acid solution in the batching tank is maintained

(6) Reactor makeup is controlled

Refer to Section 9.3.4.2.8.2.4 for a discussion of alarm functions.

Reactor coolant samples are taken to verify that the RCS boron concentration is within administrative limits. RCS boron concentration is maintained using the RMCS.

9.3.4.3.6.1 Regenerative Heat Exchanger

The temperatures of both outlet streams from the heat exchanger are monitored with indication given in the control room. High alarm is given on the main control board if the temperature of the letdown stream exceeds desired limits.

Excessive pressure in the letdown line at the regenerative heat exchanger would be indicated in the control room by signals from:

(1) Pressure sensors located on Loop 4 of the RCS

(2) Pressure sensors located on the pressurizer

9.3.4.3.6.2 Letdown Heat Exchanger

The letdown temperature control indicates and controls the temperature of the letdown flow exiting from the letdown heat exchanger. The temperature sensor, which is part of the CVCS, provides input to the controller in the CCW system. The exit temperature is controlled by regulating the CCW flow through the letdown heat exchanger by using the control valve located in the CCW discharge line. Temperature indication is provided on the main control board. Abnormally high temperature on the letdown line downstream of the regenerative heat exchanger or the letdown heat exchanger is indicated by a high-temperature alarm.

Pressure in the letdown line at the letdown heat exchanger is indicated in the control room by signals from the pressure sensor in the letdown line downstream of the letdown heat exchanger. Excessive pressure could lift the relief valve located downstream of the letdown orifices. This would be indicated on the main control board by a temperature sensor located in the relief valve of the relief discharge line.

9.3.4.3.6.3 Excess Letdown Heat Exchanger

A temperature detector measures temperature of excess letdown downstream of the excess letdown heat exchanger. High-temperature alarm and indication are provided on the main control board.

A pressure sensor indicates the pressure of the excess letdown flow downstream of the excess letdown heat exchanger and excess letdown control valve. Pressure indication is provided on the main control board.

9.3.4.3.6.4 Volume Control Tank

VCT pressure and temperature are monitored with indication given in the control room. Alarm is given in the control room for high- and low-pressure conditions and for high temperature. Two level channels govern the water inventory in the VCT. These channels provide local and remote level indication, level alarms, level control, makeup control, and emergency makeup control.

If the VCT level rises above the normal operating range, one channel provides an analog signal to a proportional controller, which modulates the three-way valve downstream of the reactor coolant letdown filter to maintain the VCT level within the normal operating band. The three-way valve can split letdown flow so that a portion

goes to the LHUTs and a portion to the VCT. The controller would operate in this fashion during a dilution operation when primary makeup water is being fed to the VCT from the RMCS.

If the modulating function of the channel fails and the VCT level continues to rise, then the high-level alarm will alert the operator to the malfunction and the letdown flow can be manually diverted to the LHUTs. If no action is taken by the operator and the tank level continues to rise, the letdown flow will be automatically diverted to protect the tank from an overpressure condition.

During normal power operation, a low level in the VCT initiates automatic makeup, which injects a preselected blend of boron and water into the CCP suction header. When the VCT is restored to normal, automatic makeup stops.

If the automatic makeup fails or is not aligned for operation and the tank level continues to decrease, a low-level alarm is actuated. Manual action may correct the situation or, if the level continues to decrease, an emergency low-level signal from both channels opens the stop valves in the refueling water supply line and closes the stop valves in the VCT outlet line.

9.3.4.3.6.5 Boric Acid Tanks

A temperature sensor provides temperature measurement of each tank's contents. Local temperature indication is provided as well as high- and low-temperature alarms which are indicated on the main control board. For boric acid heater controls, refer to Section 9.3.4.2.9.12.

A level detector indicates the level in each boric acid tank. Level indication with high, low, and low-low level alarms is provided on the main control board. The low alarm is set to indicate the minimum level of boric acid in the tank to ensure sufficient boric acid to provide for a cold shutdown with one stuck RCCA.

9.3.4.3.6.6 Boric Acid Reserve Tanks

Recirculating flow indication and a low flow alarm are provided for each tank. Also provided are a tank low temperature alarm and a high-low tank level alarm. For controls associated with the boric acid reserve tank recirculation heaters, refer to Section 9.3.4.2.9.26.

9.3.4.3.6.7 Mixed Bed Demineralizers

A temperature sensor measures temperature of the letdown flow downstream of the letdown heat exchanger and controls the letdown flow to the mixed bed demineralizers by means of a three-way valve. If the letdown temperature exceeds the allowable resin operating temperature, the flow is automatically bypassed around the demineralizers.

Temperature indication and high alarm are provided on the main control board. The air-operated three-way valve failure mode directs flow to the VCT.

9.3.4.3.6.8 Reactor Coolant Letdown Filter

Two local pressure indicators are provided to show the pressures upstream and downstream of the reactor coolant letdown filter and thus provide filter differential pressure.

9.3.4.3.6.9 Seal Water Injection Filters

A differential pressure indicator monitors the pressure drop across each seal water injection filter and gives local indication with high differential pressure alarm on the main control board.

9.3.4.3.6.10 Seal Water Return Filter

Two local pressure indicators are provided to show the pressures upstream and downstream of the filter and thus provide the differential pressure across the filter.

9.3.4.3.6.11 Boric Acid Filter

The condition of the filter can be ascertained using a local differential pressure indicator.

9.3.4.3.6.12 Ion Exchange Filter

Local pressure indicators indicate the pressure upstream and downstream of the filter and thus provide filter differential pressure.

9.3.4.3.6.13 Letdown Orifices

Letdown flow rate is controlled by orifices, which are placed in and taken out of service by remote-manual operation of their respective isolation valves. A flow monitor provides indication in the control room of the letdown flow rate and high alarm to indicate unusually high flow.

A low-pressure letdown controller controls the pressure downstream of the letdown heat exchanger to prevent flashing of the letdown liquid. Pressure indication and high-pressure alarm are provided on the main control board.

9.3.4.3.6.14 Electric Heat Tracing

For details of the electric heat tracing instrumentation and controls, refer to Section 9.3.4.2.9.30.

9.3.4.3.6.15 Zinc Injection and Argon Injection Sub-systems

For details of the instrumentation and controls associated with the Zinc Injection and Argon Injection Sub-systems, refer to Sections 9.3.4.2.9.33 and 9.3.4.2.9.34, respectively.

9.3.4.3.7 General Design Criterion 13, 1967 – Fission Process Monitors and Controls

Control over the fission process for each reactor will be maintained throughout the core life by the combination of RCCAs (refer to Chapter 4) and chemical shim (boration). Long-term regulation of core reactivity is accomplished by adjusting the concentration of boric acid in the reactor coolant. Periodic samples of boron concentration provide fission process information. Refer to Section 7.7.3.3 for additional discussion.

The boron system maintains the reactor in the cold shutdown state independent of the position of the RCCAs and can compensate for all xenon burnout transients, as discussed in Section 9.3.4.3.9.

9.3.4.3.8 General Design Criterion 21, 1967 – Single Failure Definition

Two separate and independent flowpaths are available for reactor coolant boration; i.e., the charging line and the RCP seal injection. A single failure does not result in the inability to borate the RCS. An alternate flowpath is always available for emergency boration of the reactor coolant. Refer to Section 9.3.4.3.26 for discussion of flowpaths required for safe shutdown.

As backup to the normal boric acid supply, the operator can align the RWST outlet to the suction of the CCPs or SI pumps when all the RV head bolts are fully detensioned. If an SI pump is used for boration, it is aligned to take suction from the RWST and discharge to the cold legs of the RCS, and the boundary valves from the CVCS to the SI system are closed. At least one flowpath is available for boron injection whenever fuel is in the reactor, and the capability of such injection is adequate to ensure that cold shutdown can be maintained. Redundant Class 1E power supplies are provided for CCP1 and CCP2, the SI pumps, and the valves in the charging injection flowpath from the RWST to the RCS cold legs. Refer to Section 9.3.4.3.11 for additional information.

Since inoperability of a single component does not impair ability to meet boron injection requirements, plant operating procedures allow components to be temporarily out of service for repairs. However, with an inoperable component, the ability to tolerate additional component failure is limited. Therefore, operating procedures require immediate action to effect repairs of an inoperable component, restrict permissible repair time, and require verification of the operability of the redundant component. Boron injection system operability requirements are administratively controlled.

The reactor will not be made critical unless redundant boration capability is available in quantity sufficient to ensure shutdown to cold conditions.

Flow to the RCPs' seals is ensured by the fact that there are three CCPs, any one of which is capable of supplying the normal charging line flow plus the nominal seal water flow.

9.3.4.3.9 General Design Criterion 26, 1971 – Reactivity Control System Redundancy and Capability

Two independent reactivity control systems are provided for each reactor. These are RCCAs (refer to Chapter 4) and chemical shim (boration) provided by CVCS. The CVCS boron system maintains the reactor in the cold shutdown state independent of the position of the RCCAs and can compensate for all xenon burnout transients.

The CVCS reactivity control system is capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout). During normal power operation, routine boration and dilution of the RCS are administratively controlled to assure acceptable fuel design limits are not exceeded.

Any time that the plant is at power, the quantity of boric acid retained in the boric acid tanks and ready for injection always exceeds that quantity required for the normal cold shutdown, assuming that the RCCA of greatest worth is in its fully withdrawn position. This quantity always exceeds the quantity of boric acid required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay. An adequate quantity of boric acid is also available in the RWST to achieve cold shutdown. Refer to Section 9.3.4.2 for additional detail on xenon transients, CCP net positive suction head, and boric acid solution concentration and temperatures.

9.3.4.3.10 General Design Criterion 28, 1967 – Reactivity Hot Shutdown Capability

The chemical shim control provided by CVCS is one of two independent systems capable of making and holding the core subcritical, but at a slower rate than the other system (RCCAs), and is not employed as a means of compensating for rapid reactivity transients. Refer to Chapter 4 for the details of the RCCA system which is used in protecting the core from fast transients. For additional discussion, refer to Sections 9.3.4.2.1.1 and 9.3.4.2.8.2.4.

An upper limit to the boric acid tank boron concentration and a lower limit to the temperature for the tank and for flowpaths from the tank are specified in order to ensure that solution solubility is maintained. Refer to Section 9.3.4.2.9.12 for additional detail on boric acid tank concentration and temperature.

9.3.4.3.11 General Design Criterion 30, 1967 – Reactivity Holddown Capability

The CVCS boron reactivity (chemical shim) control system is the reactivity control system capable of making and holding the core subcritical under any anticipated condition and with appropriate margin for contingencies. Normal reactivity shutdown capability is provided by rapid RCCA insertion (refer to Chapter 4). The chemical shim control system permits the necessary shutdown margin to be maintained during long-term xenon decay and plant cooldown. For additional discussion, refer to Section 9.3.4.3.9.

When the reactor is subcritical; i.e., during cold or hot shutdown, refueling, and approach to criticality, the neutron source multiplication is continuously monitored and indicated. Any appreciable increase in the neutron source multiplication, including that caused by the maximum physical boron dilution rate, is slow enough to give ample time to start a corrective action (boron dilution stop and boration) to prevent the core from becoming critical. The rate of boration, with a single boric acid transfer pump operating, is sufficient to take the reactor from full power operation to 1 percent shutdown in the hot condition, with no RCCAs inserted, in 150 minutes. In an additional 3 hours, enough boric acid can be injected to compensate for xenon decay, although xenon decay below the full power equilibrium level will not begin until approximately 25 hours after shutdown. Additional boric acid is employed if it is desired to bring the reactor to cold shutdown conditions. Boric acid can also be added by injection through the RCP seals at approximately 5 gpm per pump (20 gpm total). At this rate, enough boric acid solution to compensate for xenon decay is added in less than 5 hours. Refer to Sections 9.3.4.2.1.1 and 9.3.4.2.8.2.4 for additional detail on xenon transients.

In the event of loss of offsite power, the safety (boration) function of the CVCS would be maintained. Power to CCP1 and CCP2 or SI pumps and associated valves would be available from the diesel generators. CCP1 or CCP2 or an SI pump is sufficient to meet boron injection requirements for shutdown. Since each CCP (CCP1 and CCP2) or SI pump is loaded on a separate diesel generator, a single failure of any one diesel generator will not impair the safety function of the pumps. A natural circulation test program was conducted during startup testing to demonstrate that the boron mixing and cooldown functions associated with taking the plant to cold shutdown can be accomplished under natural circulation.

9.3.4.3.12 General Design Criterion 31, 1967 – Reactivity Control Systems Malfunction

For postulated boron dilution during refueling, startup, or with the reactor in manual or automatic operation at power, the operator has ample time to determine the cause of dilution, terminate the source of dilution, and initiate boration before the shutdown margin is lost. The facility reactivity control systems are discussed further in Chapter 7, and analyses of the effects of the other possible malfunctions are discussed in Chapter 15. For additional discussion on boron dilution, refer to Sections 9.3.4.2.1.1 and 9.3.4.2.8.2.4.

9.3.4.3.13 General Design Criterion 32, 1967 – Maximum Reactivity Worth of Control Rods

The maximum rates of reactivity insertion employing boron removal are limited to values that could not cause rupture of the RCS boundary or disruptions of the core or vessel internals to a degree that could impair the effectiveness of emergency core cooling.

The appropriate reactivity insertion rate for the dilution of the boric acid in the RCS is determined by safety analyses for the facility. The data on reactivity insertion rates and dilution, together with RCCA withdrawal limits, are discussed in Section 4.3. The CVCS has the capability to avoid an inadvertent excessive rate of boron dilution. The core and RCS are not adversely affected by the maximum rate of reactivity increase due to boron dilution, which is less than that assumed for RCCA withdrawal analyses (refer to Section 15.2). For additional discussion on boron dilution, refer to Sections 9.3.4.2.1.1 and 9.3.4.2.8.2.4. The reactivity insertion rates due to uncontrolled boron dilution and the evaluation of plant safety is discussed in Section 15.2.4.

9.3.4.3.14 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the containment isolation portion of the CVCS from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures are discussed in Sections 3.5, 3.6, and 6.2.4.

9.3.4.3.15 General Design Criterion 49, 1967 – Containment Design Basis

The CVCS penetrations are designed to withstand the pressures and temperatures that could result from a LOCA without exceeding the design leakage rates. Refer to Section 3.8.2.1.1.3 for additional details.

9.3.4.3.16 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The CVCS CIVs are periodically tested for operability and leakage. Testing of the components required for the CIS is discussed in Section 6.2.4. Test connections are provided in the penetration and in the piping to verify valve leakage and penetration leakage are within prescribed limits.

9.3.4.3.17 General Design Criterion 55, 1971 – Reactor Coolant Pressure Boundary Penetrating Containment

The CVCS penetrations that are part of the CIS include the regenerative heat exchanger to the letdown heat exchanger, normal charging to the regenerative heat exchanger, and the RCP seal water supply and return lines, which comply with the requirements of GDC 55, 1971, as described in Section 6.2.4 and Table 6.2-39.

9.3.4.3.18 General Design Criterion 56, 1971 – Primary Containment Isolation

The CVCS penetrations that are part of the CIS include the relief valve header lines, which comply with the requirements of GDC 56, 1971, as described in Section 6.2.4 and Table 6.2-39.

9.3.4.3.19 General Design Criterion 68, 1967 – Fuel and Waste Storage Radiation Shielding

Radiation shielding is provided, as required to meet the requirements of 10 CFR Part 20, for the LHUTs which store radioactive liquid until the batch processing for each tank begins. The radiation shielding is provided by the concrete walls, ceiling, and ground in the auxiliary building. Refer to Section 12.1.2.5 and Table 12.1-2 for details of radiation shielding for CVCS components, including the LHUTs.

9.3.4.3.20 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The CVCS is designed with provisions for maintaining control over radioactive liquid and gaseous effluents. Relief valves with potentially contaminated effluent are collected and routed to tanks in order to minimize radioactive releases inside the auxiliary building. The CVCS is designed with tanks (VCT and LHUTs) that allow for processing and/or appropriate confinement of radioactivity associated with the liquid and gaseous effluents from normal operation. Fission gases are removed from the system by venting the VCT to the waste disposal system. When the level in the VCT reaches the high-level setpoint, the remainder of the expansion volume is accommodated by diversion of the letdown stream to the LHUTs. As liquid enters the LHUTs, the nitrogen cover gas is displaced to the gas decay tanks in the waste disposal system through the waste vent header. Liquid effluent in the LHUTs is processed as a batch operation in the CVCS and then the liquid is drained to the LRS for processing.

The CVCS is capable of reducing the concentration of ionic isotopes in the purification stream, as required in the design basis, to minimize activity released due to leakage. This is accomplished by passing the letdown flow through the mixed bed demineralizers that remove ionic isotopes, except those of cesium, molybdenum, and yttrium, with a minimum decontamination factor of 10. Through occasional use of the cation bed demineralizer, the concentration of cesium can be maintained below 1 μCi/cc, assuming 1 percent of the power is being produced by defective fuel. The cation bed demineralizer is capable of passing the normal letdown flow, though only a portion of this capacity is normally utilized. Each mixed bed demineralizer is capable of processing the maximum letdown flow rate. If the normally operating mixed bed demineralizer's resin has become exhausted, the second demineralizer can be placed in service. Each demineralizer is designed, however, to operate for one core cycle with 1 percent defective fuel.

Administrative and engineering controls are in place for the control of radioactive effluents, as required to meet the requirements of 10 CFR Part 20 (refer to Sections 9.3.4.3.19, 9.4.2.3.13, and 12.2). The LHUTs and VCT are located in containment vaults in the auxiliary building that are sized to contain the full volume of liquid effluents for its respective tank. The VCT is designed with a spray nozzle inside the tank to strip part of the noble gases from the incoming liquid and retain these gases in the VCT vapor space. Gaseous effluents from an LHUT or VCT rupture will be released through the plant vent via the auxiliary building ventilation system (ABVS) (refer to Section 9.4.2.3.13). The radiological consequences of LHUT and VCT ruptures are analyzed in Sections 15.5.25 and 15.5.26, respectively. For additional discussion on CVCS leakage, refer to Section 9.3.4.3.28 (Item III.D.1.1).

9.3.4.3.21 Chemical and Volume Control System Safety Function Requirements

(1) Reactor Coolant System Inventory and Pressure Control

The CVCS maintains the proper coolant inventory in the RCS for all normal modes of operation including startup from cold shutdown, full power operation, and plant cooldown. The VCT provides surge capacity for reactor coolant expansion not accommodated by the pressurizer. For additional discussion, refer to Sections 9.3.4.2.2, 9.3.4.2.8.1, and 9.3.4.2.8.2.4. Pressurizer level control is discussed in Section 9.3.4.2.10.2.

The CVCS, coincident with RHR system operation during plant startup and shutdown, controls the RCS pressure. The CVCS regulates the flow rate to the low-pressure letdown line and the charging flow to control RCS pressure during these modes of operation. Refer to Section 5.5.6.2 for additional details.

The CVCS design includes a flowpath from the regenerative heat exchanger outlet to the pressurizer spray line. An air-operated valve in the spray line is employed to provide auxiliary spray from the CCPs to the vapor space of the pressurizer during plant cooldown. This provides a means of cooling the pressurizer near the end of plant cooldown, when the RCPs are not operating. Refer to Section 5.5.9.3.4 for additional details.

(2) Protection from Missiles

The provisions taken to protect the system from missiles are discussed in Section 3.5. Missile protection for portions of the CVCS which also serve ECCS functions are addressed in Section 6.3.3.8.

(3) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the PG&E Design Class I portion of the CVCS system from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Section 3.6.

(4) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection of the PG&E Design Class I portion of the CVCS system located outside containment from the effects of moderate energy pipe failure are discussed in Section 3.6.

(5) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the PG&E Design Class I portion of the CVCS system located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

(6) Protection from Flooding Effects

The provisions taken to provide protection of the PG&E Design Class I portion of the CVCS system from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

(7) Reactor Coolant Pump Seal Water Injection

The CVCS is able to continuously supply filtered water to each RCP seal, as required by the RCP design. Flow to the RCPs' seals is ensured by the fact that there are three CCPs, any one of which is capable of supplying the normal charging line flow plus the nominal seal water flow. Refer to Section 9.3.4.2.8.1 for a detailed discussion on the seal water system.

9.3.4.3.22 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

The CVCS SSCs required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment. The affected equipment list includes: pump motors, valve motors, valve operators, solenoid valves, heaters, switches, transmitters, local starters, and indicators and are listed in the EQ Master List.

9.3.4.3.23 10 CFR 50.55a(f) – Inservice Testing Requirements

The IST requirements for the CVCS are contained in the DCPP IST Program Plan.

9.3.4.3.24 10 CFR 50.55a(g) – Inservice Inspection Requirements

The ISI requirements for the CVCS are contained in the DCPP ISI Program Plan and comply with ASME BPVC Section XI-2001 through 2003 Addenda.

9.3.4.3.25 10 CFR 50.63 – Loss of All Alternating Current Power

The CVCS provides RCP seal injection in support of safe shutdown of the plant (Mode 3) following a SBO. With seal injection flow, there is no loss of reactor coolant from the RCP seals. Also, in conjunction with RCP seal cooling provided by the CCW system (refer to Section 9.2.2.3.14). RCP seal cooling provided by seal injection protects the RCP seals from overheating in the event of an SBO event. CCP1 is available on the Class 1E Bus F associated with the credited AAC power source during the SBO event.

Refer to Section 8.3.1.6 for further discussion of station blackout.

9.3.4.3.26 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

Fire Protection of the CVCS is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

9.3.4.3.27 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

CVCS post-accident instrumentation for meeting Regulatory Guide 1.97, Revision 3, requirements consist of CCP1 and CCP2 injection header flow indication, RCS makeup flow indication, RCS letdown flow indication, VCT level indication, and CIV position indication (refer to Table 7.5-6).

9.3.4.3.28 NUREG-0737 (Items I.C.1, II.B.2, II.K.1.5, III.D.1.1), November 1980 – Clarification of TMI Action Plan Requirements

Item I.C.1 – Guidance for the Evaluation and Development of Procedures for Transients and Accidents: NUREG-0737, Supplement 1, January 1983 provides the requirements for I.C.1 as follows:

Section 7.1(b) – Upgraded emergency operating procedures, which include guidance for initiating normal charging and emergency boration, have been implemented in accordance with the Westinghouse Owners Group developed generic emergency response guidelines.

Item II.B.2 – Design Review of Plant Shielding and Environmental Qualification of Equipment for Space/Systems Which May Be Used in Post-accident Operations: The switchgear rooms are sufficiently shielded from external sources of radiation such that personnel access and occupancy would not be unduly limited by the radiation environment caused by a degraded core accident.

Item II.K.1.5 – Safety Related Valve Position: Refer to Section 9.3.4.3.33.

Item III.D.1.1 – Integrity of Systems Outside Containment Likely to Contain Radioactive Material for PWRs and Boiling-Water Reactors: CVCS components, valves, and piping that see radioactive service are designed to permit essentially zero leakage to the atmosphere. The components are provided with welded connections except where flanged connections are provided to permit removal for maintenance.

The VCT in the CVCS provides an inferential measurement of leakage from the CVCS as well as the RCS. Low level in the VCT actuates makeup at the prevailing reactor coolant boron concentration. The amount of leakage can be inferred from the amount of makeup added by the RMCS.

Pressure containing portions of the CVCS are tested periodically to check for leakage. This testing includes the portions of the system flowpath that would circulate radioactive water from the RCS.

The requirements for a leakage reduction program from reactor coolant sources outside containment are included in the Technical Specifications (Reference 1). Inservice valve leak testing requirements are specified in the DCPP IST Program Plan. Refer to Section 6.2.4 for additional information on the CIS.

9.3.4.3.29 Generic Letter 80-21, March 1980 – Vacuum Condition Resulting in Damage to Chemical Volume Control System Holdup Tanks

The CVCS low pressure tanks that can be valved to contain RCS water are the VCT and the LHUTs. Both tanks are protected against failure under vacuum conditions. The VCT is structurally designed to withstand 15 psig external pressure. The LHUTs rely on at least one of several design features functioning to protect the tanks from vacuum conditions. These features include an LHUT discharge pump trip on negative tank pressure, control valves on the independent cover-gas supplies, and a vacuum relief valve on each tank set to open prior to reaching the LHUT allowable external pressure. This meets the requirements of Generic Letter 80-21, March 1980, which was issued as IE Bulletin 80-05, March 1980.

9.3.4.3.30 Generic Letter 88-17, October 1988 – Loss of Decay Heat Removal

The CVCS PG&E Design Class I CCPs are one of the two required available or operable means of adding inventory to the RCS, that are in addition to the normal decay heat removal systems, to meet the requirements of Generic Letter 88-17, October 1988. Makeup to the RCS is provided by a CCP, gravity feed from the RWST, and an SI pump which can quickly be put in service should RHR be lost. Each of these backup sources can provide enough water for decay heat removal in addition to continued core coverage. PG&E updated procedures to ensure these pumps are available prior to entering RHR mid-loop operation.

9.3.4.3.31 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

CVCS MOVs are subject to the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996, and meet the requirements of the DCPP MOV Program Plan.

9.3.4.3.32 Generic Letter 95-07, August 1995 – Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves

PG&E Design Class I power-operated gate valves in the CVCS were evaluated and determined to not be susceptible to pressure locking or thermal binding.

9.3.4.3.33 IE Bulletin 79-06A (Positions 8 and 12), April 1979 – Review of Operational Errors and System Misalignments Identified During the Three Mile Island Incident

Position (8) (subsequently NUREG-0737, November 1980, Item II.K.1.5, Safety Related Valve Position): Critical manual valves in the CVCS are sealed in position and a check list is maintained for inspection on a typical audit basis. All CVCS PG&E Design Class I valves which are operated remotely and whose purpose is to open or close (rather than throttle flow) have position indicating lights on the main control board.

Position (12): During normal operating modes, hydrogen can be removed from the RCS by the letdown line and stripped in the VCT where it enters the waste gas system.

9.3.4.3.34 NRC Bulletin 88-04, May 1988 – Potential Safety-Related Pump Loss

The CVCS is designed such that PG&E Design Class I pumps that share a common minimum flow recirculation line are not susceptible to the pump-to-pump interaction described in NRC Bulletin 88-04, May 1988, and the existing minimum flow rates for CVCS PG&E Design Class I pumps are adequate.

9.3.4.3.35 NRC Bulletin 88-08, June 1988 – Thermal Stresses in Piping Connected to Reactor Coolant Systems

The unisolable CVCS lines connected to the RCS which are subject to thermal stresses are the charging injection headers, for both DCPP Unit 1 and Unit 2. A recirculation line was added to the charging injection header that provides continuous vent capability of the charging injection header back to the CCP suction. The charging injection header recirculation line is sized such that 1) during normal operation (charging injection header not in service), this passive recirculation line continuously vents valve seepage and accompanying pressure build-up in the charging injection header, and 2) during ECCS operation, charging injection header recirculation line flow is low enough such that ECCS flows are maintained within their required ranges. For additional discussion, refer to Section 6.3.3.40.

9.3.4.4 Tests and Inspections

As part of plant operation, periodic tests, surveillance inspections, and instrument calibrations are made to monitor equipment condition and performance.

Most components are in use regularly; therefore, assurance of the availability and performance of the systems and equipment is provided by control room and/or local indication. Refer to Sections 9.3.4.3.5 and 9.3.4.3.6 for details regarding local and remote indication.

Technical specifications have been established concerning calibration, checking, and sampling of the CVCS.

Refer to Sections 9.3.4.3.16, 9.3.4.3.23, 9.3.4.3.24, and 9.3.4.3.28 (Item III.D.1.1) for details regarding tests and inspections of the CVCS.

Refer to Section 9.3.4.2.6 for details of hydrostatic testing of the RCS.

9.3.4.5 Instrumentation Applications

Refer to Section 9.3.4.3.6 for the instrumentation applications related to CVCS.

9.3.5 FAILED FUEL DETECTION

Failed fuel detection is provided by analyzing reactor coolant grab samples via the nuclear steam supply sampling system.

9.3.6 NITROGEN AND HYDROGEN SYSTEMS

The nitrogen and hydrogen systems supply gases required for cover gases, accumulator fill, certain instrumentation operations, degasification purging, layup of SGs and feedwater heaters, and generator cooling. The nitrogen and hydrogen systems are not required for reactor protection, containment isolation, or ESFs. The design classifications for these systems are given in Table 3.2-3. The only PG&E Design Class I portions of the nitrogen and hydrogen systems are the containment penetrations for the nitrogen system. The supply sources of nitrogen and hydrogen are shared by both units but delivered by separate supply headers. The backup air/nitrogen supply system is described in Section 9.3.1.2.2.

9.3.6.1 Design Bases

9.3.6.1.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portion of the nitrogen system is designed to withstand the effects of, or is protected against, natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

9.3.6.1.2 General Design Criterion 3, 1971 – Fire Protection

The nitrogen and hydrogen systems are designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.3.6.1.3 General Design Criterion 4, 1967 – Sharing of Systems

The nitrogen and hydrogen systems are not shared by the DCPP units unless it is shown that safety is not impaired by the sharing.

9.3.6.1.4 General Design Criterion 11, 1967 – Control Room

The nitrogen system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

9.3.6.1.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the nitrogen and hydrogen system variables within prescribed operating ranges.

9.3.6.1.6 General Design Criterion 40, 1967 – Missile Protection

The ESF containment isolation portion of the nitrogen system is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

9.3.6.1.7 General Design Criterion 49, 1967 - Containment Design Basis

The PG&E Design Class I portion of the nitrogen system is designed so that the containment structure can accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a LOCA including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of ECCSs.

9.3.6.1.8 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The PG&E Design Class I portion of the nitrogen system piping penetrating containment is provided with leak detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. This piping system is designed with a capability to test periodically that operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

9.3.6.1.9 General Design Criterion 55, 1971 – Reactor Coolant Pressure Boundary Penetrating Containment

The PG&E Design Class I portion of the nitrogen system that penetrates the containment is provided with CIVs.

9.3.6.1.10 General Design Criterion 56, 1971 - Primary Containment Isolation

The PG&E Design Class I portion of the nitrogen system contains valves in piping that penetrate containment. One automatic isolation valve is provided outside containment and one check valve inside containment to ensure containment integrity is maintained.

9.3.6.1.11 Nitrogen System Safety Function Requirements

(1) Protection from Jet Impingement – Inside Containment

The PG&E Design Class I containment isolation portion of the nitrogen system located inside containment is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

9.3.6.1.12 10 CFR 50.55a(f) – Inservice Testing Requirements

The PG&E Design Class I nitrogen system ASME Code pumps and valves are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

9.3.6.1.13 10 CFR 50.55a(g) – Inservice Inspection Requirements

The PG&E Design Class I nitrogen system ASME BPVC Section XI components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

9.3.6.2 System Description

9.3.6.2.1 Nitrogen System

The nitrogen system consists of a liquid nitrogen storage facility, which is the nitrogen source for both the low pressure gaseous nitrogen header and a series of high pressure gaseous nitrogen storage bottles. Nitrogen from the liquid supply tank is (a) gasified and supplied directly to the low pressure header or (b) compressed, then gasified, and supplied to the high pressure storage bottles.

The nitrogen system is capable of delivering nitrogen gas for various purposes. Pressure regulators are capable of reducing the pressure down to 1 psig. This is accomplished through a series of regulators from the supply source to the required equipment. Relief valves are set appropriately to prevent overpressure on the equipment. Refer to Table 9.3-7 for the list of equipment requiring nitrogen and their supply pressures and flows. The pressure and flow data envelope the actual operating conditions.

All nitrogen system piping penetrating the containment not isolated with sealed closed valves is isolated automatically by a containment isolation signal.

9.3.6.2.2 Hydrogen System

The hydrogen system is capable of delivering hydrogen gas for various purposes at a supply pressure of 2200 psig and reduced by pressure regulators in series to the required pressures. Relief valves are set at 2400 psig on the supply header. Other relief valves downstream of pressure regulators are set appropriately to prevent overpressure on the equipment. An excess flow check valve, FCV-39/40, is provided in the hydrogen supply header at each unit. The excess flow check valve (flow fuse) is a flow control device that limits the flow of hydrogen to the plant loads. Refer to Table 9.3-8 for the list of equipment requiring hydrogen and their supply pressures and flows.

9.3.6.3 Safety Evaluation

9.3.6.3.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portions of the nitrogen system are housed within the PG&E Design Class I auxiliary and containment buildings. These buildings, or applicable portions thereof, are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), earthquakes (refer to Section 3.7), and other natural phenomena.

The PG&E Design Class I nitrogen system components have been seismically qualified.

Portions of the nitrogen system are located outside and are partially resistant to tornadoes. However, the capability of the system to support plant safe shutdown is maintained (refer to Section 3.3.2).

The nitrogen system components required to perform their PG&E Design Class I functions are located at higher elevations such that they are not affected by floods and tsunamis.

9.3.6.3.2 General Design Criterion 3, 1971 – Fire Protection

The nitrogen and hydrogen systems are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

In fire zones containing equipment required for safe shutdown, the hydrogen system is enclosed in guard pipes and enclosures such that if leaks occur, the leakage is vented to areas that do not contain equipment required for safe shutdown. Enclosures containing valves and instrumentation have flanges or doors that make the instrumentation and valves accessible for operation and maintenance.

9.3.6.3.3 General Design Criterion 4, 1967 – Sharing of Systems

The nitrogen and hydrogen systems are shared by the DCPP units. The PG&E Design Class I portion of the nitrogen system consists of containment penetration piping and isolation valves in Unit 1 and Unit 2 that are not shared between the DCPP units. Only the PG&E Design Class II nitrogen and hydrogen storage facilities and PG&E Design Class II piping are shared between the DCPP units, and this sharing does not affect plant safety.

9.3.6.3.4 General Design Criterion 11, 1967 – Control Room

The nitrogen system is designed to support actions to maintain and control the safe operational status of the plant from the control room and from a remote location.

Low nitrogen header pressure is alarmed in the control room of each unit.

9.3.6.3.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the nitrogen and hydrogen system variables within prescribed operating ranges.

Local temperature indicators measure the temperature of the nitrogen and hydrogen supply.

Local pressure indicators measure the pressures in the various lines of the nitrogen and hydrogen systems.

Pressure transmitters located on the nitrogen and hydrogen supply headers are used to transmit the pressure to indicators on the auxiliary building control board. Pressure switches also located on the headers give a low-pressure alarm on the auxiliary building control board.

9.3.6.3.6 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the PG&E Design Class I containment isolation portion of the nitrogen system from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures are discussed in Sections 3.5, 3.6, and 6.2.4.

9.3.6.3.7 General Design Criterion 49, 1967 - Containment Design Basis

The nitrogen piping routed through containment penetrations is designed to withstand the pressures and temperatures that could result from a LOCA without exceeding the design leakage rates. Refer to Sections 3.8.2.1.1.3 and 6.2.4, and Table 6.2-39 for additional details.

9.3.6.3.8 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The nitrogen system CIVs are periodically tested for operability and leakage. Testing of components required for the CIS is discussed in Section 6.2.4. Test connections are provided in the penetration and in the piping to verify valve and penetration leakage within prescribed limits.

CIVs associated with penetration 52C (nitrogen supply to the SGs) are exempted from IST.

No piping associated with the hydrogen system penetrates the containment.

9.3.6.3.9 General Design Criterion 55, 1971 – Reactor Coolant Pressure Boundary Penetrating Containment

The nitrogen system penetrations that are part of the CIS include the nitrogen supply lines for the pressurizer relief tanks, which comply with the requirements of GDC 55, 1971, as described in Section 6.2.4 and Table 6.2-39.

9.3.6.3.10 General Design Criterion 56, 1971 - Primary Containment Isolation

The nitrogen system penetrations that are part of the CIS include the nitrogen supply lines for the SI accumulators, the SGs, and the RCDT, which comply with the requirements of GDC 56, 1971, as described in Section 6.2.4 and Table 6.2-39. That portion of the nitrogen system piping penetrating the containment is PG&E Design

Class I and meets the single failure criterion required for containment isolation as described in Section 6.2.4 and Table 6.2-39. The remainder of the hydrogen and nitrogen systems is PG&E Design Class II.

9.3.6.3.11 Nitrogen System Safety Function Requirements

(1) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the PG&E Design Class I containment isolation portion of the nitrogen system located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

9.3.6.3.12 10 CFR 50.55a(f) – Inservice Testing Requirements

The IST requirements for nitrogen system components are contained in the IST Program Plan and comply with the ASME Code for Operation and Maintenance of Nuclear Power Plants.

9.3.6.3.13 10 CFR 50.55a(g) – Inservice Inspection Requirements

Nitrogen system components are included in the ISI program in accordance with ASME BPVC, Section XI.

9.3.6.4 Tests and Inspections

Periodic inspections are made on the nitrogen and hydrogen systems. Periodic visual inspection and preventive maintenance are made using normal industry practice. Functional and leakage tests are performed on the CIVs.

9.3.6.5 Instrumentation Applications

The instrumentation for the nitrogen and hydrogen systems is discussed in Sections 9.3.6.3.4 and 9.3.6.3.5.

9.3.7 MISCELLANEOUS PROCESS AUXILIARIES

The process auxiliary systems not associated with the reactor process system but necessary for plant operation are:

(1) Auxiliary steam system

(2) OWS and TBS system

The PG&E Design Class I portion of the auxiliary steam system extends from the upstream side of the outboard CIV to the downstream side of the inboard CIV. The

remainder of the auxiliary steam system is classified as PG&E Design Class II. The OWS and TBS system is classified as PG&E Design Class II (refer to Section 3.2).

The requirements for the temperature sensors, alarm, and switch associated with the pipe break isolation system (PBIS), used for manual isolation of an auxiliary steam system pipe break, are discussed in Section 7.6.

9.3.7.1 Auxiliary Steam System

Main steam is supplied to the auxiliary steam system through a branch line off of the 35 percent atmospheric dump header through a pressure reducing valve. Each unit can supply steam to the auxiliary steam system either separately or simultaneously.

9.3.7.1.1 Design Bases

9.3.7.1.1.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portion of the auxiliary steam system is designed to withstand the effects of, or be protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

9.3.7.1.1.2 General Design Criterion 3, 1971 - Fire Protection

The PG&E Design Class I portion of the auxiliary steam system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.3.7.1.1.3 General Design Criterion 4, 1967 – Sharing of Systems

The auxiliary steam system is not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

9.3.7.1.1.4 General Design Criterion 40, 1967 – Missile Protection

The PG&E Design Class I containment isolation portion of the auxiliary steam system is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

9.3.7.1.1.5 General Design Criterion 49, 1967 - Containment Design Basis

The PG&E Design Class I portion of the auxiliary steam system is designed so that the containment structure can accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a LOCA, including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of ECCSs.

9.3.7.1.1.6 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The PG&E Design Class I portion of the auxiliary steam system that penetrates containment is provided with leak detection, isolation, redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The piping is designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

9.3.7.1.1.7 General Design Criterion 56, 1971 - Primary Containment Isolation

The PG&E Design Class I portion of the auxiliary steam system contains valving in piping that penetrates containment and that is connected directly to the containment atmosphere. A sealed closed manual isolation valve is provided outside containment and an automatic (check) valve is provided inside containment to ensure containment integrity is maintained.

9.3.7.1.1.8 Auxiliary Steam System Safety Function Requirement

(1) Protection Against High-Energy Pipe Rupture Effects

The dynamic effects from a rupture of the PG&E Design Class II portion of the auxiliary steam system will not impact PG&E Design Class I essential SSCs required for safe (cold) shutdown of the plant.

(2) Protection from Jet Impingement – Inside Containment

The PG&E Design Class I containment isolation portion of the auxiliary steam system located inside containment is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

9.3.7.1.1.9 10 CFR 50.55a(f) - Inservice Testing Requirements

PG&E Design Class I auxiliary steam system ASME Code components are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

9.3.7.1.1.10 10 CFR 50.55a(g) - Inservice Inspection Requirements

PG&E Design Class I auxiliary steam system ASME Code components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

9.3.7.1.1.11 Generic Letter 89-08, May 1989 - Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP has implemented formalized procedures and administrative controls to assure long-term implementation of its erosion/corrosion monitoring program for the auxiliary steam system.

9.3.7.1.2 System Description

This system is required to supply steam to certain pieces of equipment and plant locations. Steam is required for the following:

(1) Cask decontamination area

(2) Caustic storage tank

(3) Boric acid batching tank and water preheater

(4) Gland steam supply for the main turbine and main feedwater pump drive turbines

(5) Steam jet air ejector (main condenser)

(6) Containment atmosphere

(7) Steam for service cleaning and equipment maintenance inside containment

(8) Building heating reboiler:

  (a) Containment purge air

  (b) Fuel handling area

  (c) Machine shop

(9) Main condenser deaeration steam

(10) Caustic regeneration system

(11) Carbon dioxide (CO_2) vaporizer

During shutdown, it will be necessary to supply steam to the boric acid batch tank. All pressure parts and accessories are designed, constructed, inspected, and stamped in accordance with ASME BPVC Section I–1980 through 1980 Summer Addenda.

9.3.7.1.3 Safety Evaluation

9.3.7.1.3.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portion of the auxiliary steam system is contained within the auxiliary building and containment building. These structures are PG&E Design Class I (refer to Section 3.8). These buildings or applicable portions thereof are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other natural phenomena. This design protects auxiliary steam system components, ensuring their design function will be performed.

All valves, piping, and equipment that are considered to be isolation barriers are designed to PG&E Design Class I requirements ensuring their design function will be performed.

9.3.7.1.3.2 General Design Criterion 3, 1971 - Fire Protection

The PG&E Design Class I portion of the auxiliary steam system is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.3.7.1.3.3 General Design Criterion 4, 1967 – Sharing of Systems

The auxiliary steam system is designed such that either unit can supply the other unit with auxiliary steam. The interface between the auxiliary steam system and the main steam system is downstream of the MSIVs in the PG&E Design Class II portion of the system. Check valves in the supply lines prevent reverse flow from auxiliary steam to the main steam system. DCPP Unit 1 and Unit 2 also share auxiliary boiler 0-2, which is classified as PG&E Design Class II. Therefore, safety is not impaired by sharing the auxiliary steam system.

9.3.7.1.3.4 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the PG&E Design Class I containment isolation portion of the auxiliary steam system from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures are discussed in Sections 3.5, 3.6, and 6.2.4.

9.3.7.1.3.5 General Design Criterion 49, 1967 - Containment Design Basis

The auxiliary steam containment penetrations are designed and analyzed to withstand the pressures and temperatures that could result from a LOCA without exceeding the design leakage rates (refer to Section 3.8.2.1.1.3).

9.3.7.1.3.6 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

Isolation valves that are required for containment closure are periodically tested for operability and leakage and are contained in the PG&E Design Class I portion of the auxiliary steam system. Testing of the components required for the CIS is discussed in Section 6.2.4. Test connections are provided in the piping to verify valve leakages are within prescribed limits.

9.3.7.1.3.7 General Design Criterion 56, 1971 - Primary Containment Isolation

The PG&E Design Class I containment penetrations for the auxiliary steam system are penetration group E (refer to Section 6.2.4). A description of the isolation valves and piping for each penetration is provided in Table 6.2-39. Group E piping complies with the requirements of GDC 56, 1971 (refer to Section 6.2.4).

9.3.7.1.3.8 Auxiliary Steam System Safety Function Requirement

(1) Protection Against High-Energy Pipe Rupture Effects

Open crack breaks are postulated in the auxiliary steam system outside containment as it contains piping at a temperature that exceeds 200 ºF and pressure less than or equal to 275 psig. High energy crack breaks in the auxiliary steam system have been evaluated for effects on essential equipment to assure that safe (cold) shutdown of the plant can be attained (refer to Sections 3.6.2.1 and 3.6.2.1.2).

The PBIS provides alarm and control for any HELB in the auxiliary steam piping (refer to Section 7.6.3.2).

(2) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the PG&E Design Class I containment isolation portion of the auxiliary steam system located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

9.3.7.1.3.9 10 CFR 50.55a(f) - Inservice Testing Requirements

The IST requirements for the PG&E Design Class I components of the auxiliary steam system are contained in the IST Program Plan.

9.3.7.1.3.10 10 CFR 50.55a(g) - Inservice Inspection Requirements

The ISI requirements for the PG&E Design Class I portion of the auxiliary steam system are contained in the DCPP ISI Program Plan and comply with ASME BPVC Section XI-2001 through 2003 Addenda.

9.3.7.1.3.11 Generic Letter 89-08, May 1989 - Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP procedures identify the interdepartmental responsibilities and interfaces for the monitoring program. Portions of the auxiliary steam system are considered in the DCPP Flow Accelerated Corrosion program for erosion/corrosion monitoring.

9.3.7.1.4 Tests and Inspections

Tests and inspections of the auxiliary steam system are done in accordance with plant procedures.

9.3.7.1.5 Instrumentation Applications

Instrumentation is provided to monitor and control the operation of the auxiliary steam system PBIS (refer to Section 7.6.3.2).

9.3.7.2 Oily Water Separator and Turbine Building Sump System

The OWS, common to both Unit 1 and Unit 2, is designed to separate oil and floating material from drains originating from the Unit 1 and Unit 2 TBSs.

The OWS system monitors the effluents from the TBS through the OWS retention tank discharge. Upon detection of radioactive concentrations in excess of pre-determined alarm setpoint limits (refer to Section 11.2.3.13.2.1), this channel will provide alarm annunciation.

9.3.7.2.1 Design Bases

9.3.7.2.1.1 General Design Criterion 3, 1971 - Fire Protection

The OWS/TBS system is designed and located to minimize, consistent with other safety requirements, the probability and effects of fires and explosions.

9.3.7.2.1.2 General Design Criterion 4, 1967 - Sharing of Systems

The OWS system is not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

9.3.7.2.1.3 General Design Criterion 11, 1967 - Control Room

The OWS system is designed to support actions to maintain and control the safe operational status of the plant from the control room.

9.3.7.2.1.4 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Instrumentation and controls are provided, as required, to monitor and maintain the OWS variables within prescribed operating ranges.

9.3.7.2.1.5 General Design Criterion 17, 1967 - Monitoring Radioactivity Releases

The OWS/TBS system is designed to provide means for monitoring the effluent discharge paths and the facility environs for radioactivity that could be released from normal operations, from anticipated transients, and from accident conditions.

9.3.7.2.2 System Description

The OWS, common to both Unit 1 and Unit 2, is designed to separate oil and floating material from drains originating from the Unit 1 and Unit 2 TBS. The clear water effluent normally is discharged to the condenser circulating water discharge tunnel. If required, it can be routed to the auxiliary building floor drain receivers. The radioactive content of liquids discharged from the turbine building is monitored by a radiation monitor and flow element in the process lines to the OWS (refer to Section 11.2.3.13.2.1).

9.3.7.2.3 Safety Evaluation

9.3.7.2.3.1 General Design Criterion 3, 1971 - Fire Protection

The OWS/TBS system is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.3.7.2.3.2 General Design Criterion 4, 1967 - Sharing of Systems

The OWS is shared by both Unit 1 and Unit 2 and is classified as PG&E Design Class II. The interface between the OWS and each unit is the PG&E Design Class II TBSs. Therefore, safety is not impaired by the sharing because neither the OWS nor the TBSs are essential to safe shutdown and isolation of the reactor; and failure of these structures and components would not result in the release of substantial amounts of radioactivity.

9.3.7.2.3.3 General Design Criterion 11, 1967 - Control Room

Instrumentation and alarms are provided in the control room for the OWS radiation monitor. Should radioactivity be detected above alarm setpoints, the discharge would be manually directed to the LRS (refer to Section 11.2.3.13.2.1).

9.3.7.2.3.4 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Instrumentation and controls for the OWS radiation monitor are provided to monitor and maintain applicable variables within prescribed operating ranges.

9.3.7.2.3.5 General Design Criterion 17, 1967 - Monitoring Radioactivity Releases

The OWS is provided with means for monitoring the release of radioactivity in facility effluent discharge paths (refer to Section 11.2.3.13.2.1).

9.3.7.2.4 Tests and Inspections

Tests and inspections of the OWS/TBS are done in accordance with plant procedures.

9.3.7.2.5 Instrumentation Applications

Instrumentation is provided to monitor and annunciate in the control room (refer to Section 9.3.7.2.3.3).

9.3.8 REFERENCES

1. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

2. NUREG-0737, Clarification of TMI Action Plan Requirements, U. S. Nuclear Regulatory Commission, November 1980.

9.4 HEATING, VENTILATION, AND AIR-CONDITIONING SYSTEMS

The design outdoor ambient air temperature for the HVAC systems described in this section is 76°F.

DCPP design outdoor ambient temperature is based on Recommended Outdoor Design Temperatures, Southern California, Arizona, and Nevada, Third Edition, Southern California Chapter, American Society of Heating, Refrigeration and Air-Conditioning Engineers, Inc., March 1964 (Reference 5). The most conservative temperature probability considered in that report is 1.0%, which are the temperature values that will be equaled or exceeded for 88 hours over a full year (8760 hours). PG&E has reviewed 40 years of onsite hourly ambient outdoor temperature data for the period May 1973 through April 2014 and determined the 1.0% probability of temperature occurrence is 70.5°F. Rounded up to 71°F and adding a 5°F margin to accommodate missing data and potential data uncertainties results in a design value of 76°F.

With a design value of 76°F and an allowable 26°F rise, the ambient indoor air temperatures will be maintained at or below 104°F at all times, except for areas as noted in subsequent sections. Outdoor ambient temperatures could exceed the design temperature for 88 hours per year; however, the 88 hours would not be continuous and would occur for a small portion of any given day. In fact, the above room temperature conditions are unlikely to be reached every year. The Class 1E electrical equipment is capable of operating for short periods at temperatures in excess of 117°F. This will have an insignificant effect on the aging of the electrical insulation.

In calculating the performance of ventilating and air conditioning systems, no credit was taken for wind cooling of buildings and structures and heat absorption by equipment at elevated temperatures. The maximum solar load was checked for selected areas that housed safety-related equipment and was found to have negligible effect on the calculated indoor temperatures in these areas.

The design classifications for the various HVAC systems are given in Table 3.2-3.

9.4.1 CONTROL ROOM

The control room ventilation system (CRVS) functions during all design accident conditions. The system permits continuous occupancy of the control room under normal and design basis accident conditions.

9.4.1.1 Design Bases

9.4.1.1.1 General Design Criterion 2, 1967 - Performance Standards

The CRVS is designed to withstand the effects of or is protected against natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

9.4.1.1.2 General Design Criterion 3, 1971 - Fire Protection

The CRVS is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.4.1.1.3 General Design Criterion 4, 1967 - Sharing of Systems

The CRVS components are not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

9.4.1.1.4 General Design Criterion 11, 1967 - Control Room

The control room is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

9.4.1.1.5 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the CRVS variables within prescribed operating ranges.

9.4.1.1.6 General Design Criterion 17, 1967 - Monitoring Radioactivity Releases

The control room is designed to provide means for monitoring the containment atmosphere, the facility effluent discharge paths, and the facility environs for radioactivity that could be released from normal operations, from anticipated transients, and from accident conditions.

9.4.1.1.7 General Design Criterion 19, 1999 - Control Room

The control room is designed to permit access and occupancy under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE for the duration of a design basis accident.

9.4.1.1.8 General Design Criterion 21, 1967 Single Failure

The PG&E Design Class I CRVS is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event shall be treated as a single failure.

9.4.1.1.9 General Design Criterion 37, 1967 - Engineered Safety Features Basis for Design

The CRVS is designed to provide backup to the safety provided by the core design, the RCPB, and their protection systems.

9.4.1.1.10 General Design Criterion 38, 1967 - Reliability and Testability of Engineered Safety Features

The CRVS is designed to provide high functional reliability and ready testability.

9.4.1.1.11 General Design Criterion 40, 1967 - Missile Protection

The CRVS is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

9.4.1.1.12 General Design Criterion 41, 1967 - Engineered Safety Features Performance Capability

The CRVS is designed to provide sufficient performance capability to accommodate a partial loss of installed capacity, such as a failure of a single active component, and still perform its required safety function.

9.4.1.1.13 Control Room Ventilation System Safety Function Requirement

(1) Cooling of PG&E Design Class I Equipment

The CRVS is designed to provide cooling to PG&E Design Class I equipment.

(2) Protection from Moderate Energy Pipe Rupture Effects

The CRVS is protected against the effects of moderate energy pipe failure events or alternate means for accomplishing and maintaining safe (cold) shutdown condition of the plant is afforded.

(3) Protection from Flooding Effects

The CRVS is designed to be protected from the effects of internal flooding to the extent necessary to assure that a safe (cold) shutdown condition of the reactor can be accomplished and maintained.

9.4.1.1.14 10 CFR 50.63 - Loss of All Alternating Current Power

The CRVS is designed to continue to support control room habitability to support systems that assure core cooling and containment integrity is maintained following a SBO event.

9.4.1.1.15 Regulatory Guide 1.52, June 1973 - Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants

The CRVS design and maintenance comply with applicable Regulatory Guide 1.52, June 1973 requirements with exceptions noted in Table 9.4-2.

9.4.1.1.16 Regulatory Guide 1.52, Revision 2, March 1978 - Design, Testing, and Maintenance Criteria for Post-Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants

The CRVS filter testing program complies with applicable Regulatory Guide 1.52, Revision 2, Regulatory Position C.5.a, C.5.c, C.5.d and C.6.a requirements as described in Table 9.4-2. The CRVS filter testing program also meets the requirements of Generic Letter 83-13, March 1983.

9.4.1.1.17 NUREG-0737 (Item II.B.2), November 1980 - Clarification of TMI Action Plan Requirements

Item II.B.2 – Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems Which May Be Used in Post-accident Operations: Adequate access to the control room is provided by design changes, increased permanent or temporary shielding, or post-accident procedural controls.

9.4.1.2 System Description

The CRVS is composed of three systems:

(1) Control room heating, ventilation, and air conditioning (CRHVAC) system

(2) Control room pressurization system (CRPS)

(3) Plant process computer room air conditioning system

The CRVS has four operating modes (Modes 1-4, described below). There are two CRVS trains, both of which are operating during normal operations. These serve the common control room, one associated with the Unit 1 area and one associated with the Unit 2 area. Each train utilizes a single filter bank for removal of particulates and toxic or radioactive gases (Modes 3 or 4) and two redundant subtrains of air handling components. Each subtrain consists of a CRPS supply fan and electrical humidity control heater (Mode 4); CRHVAC supply fan (all modes) and filter booster fan (Modes 3 and 4); and an air conditioning unit (ACU) (all modes). Ducting, valves or dampers, and monitoring instrumentation are included in the system (refer to Table 9.4-1). The arrangement is shown in Figure 9.4-1. The isolation dampers are bubble-tight-type and are PG&E Design Class I. The ductwork, ventilation fans, and filter units are PG&E Design Class I. The associated design classifications are given in Table 3.2-3. The

design data for the system components are given in the itemized list in Table 9.4-1. Design codes and standards are given in Table 9.4-8.

The Unit 1 area served by the system includes one computer room, one instrument safeguards room, one records storage room, one office, one kitchen area, one control room area, and one mechanical equipment area. The Unit 2 area served by the system includes one computer room, one instrument safeguards room, one toilet room, one control room area, one office, and one mechanical equipment area. CRPS intakes are located at the southwest and northwest ends of the turbine building.

A small PG&E Design Class II exhaust fan (also itemized in Table 9.4-1) and a PG&E Design Class I electric duct heater (the duct heater housing is PG&E Design Class I, the coil may be PG&E Design Class II) per unit are provided. The exhaust fan provides control room exhaust during normal operations (Mode 1) and for smoke removal (Mode 2).

The system is designed to provide a normal ambient temperature of 75°F with one set of redundant air conditioning equipment of each train operating. Inside air temperature will be less than 85°F except in the computer room, which is designed to have a temperature of 72 ±4°F. The cooling capacity of each HVAC train is 31 tons based on normal operating conditions. The estimated cooling load for each unit area, including a portion of the computer room load, is 19.0 tons under normal operating conditions. The air flow into each unit area is 7475 cfm which provides nine control room and fifteen computer room air changes per hour. The system also provides 325 cfm to the HVAC equipment room of each unit to maintain the ambient temperature below 104°F. Electric duct heaters reheat or temper the air as necessary to maximize personnel comfort control. The heaters are not redundant and are provided only to help balance the cooling system. In the event of heater malfunction, no vital control room air normalization functions are adversely affected.

Additionally, the computer room in each unit is provided with a supplemental PG&E Design Class II air conditioning system. The system consists of three ACUs, air cooled condensing units, and interconnecting refrigeration piping. The ACUs are staged by associated room thermostats. These units provide a suitable environment for the PG&E Design Class II computers. All redundant equipment receives power from Class 1E buses separated to meet single failure criteria.

The four modes of operation for the CRVS are:

> Mode 1: Conditioned air is supplied and returned through ducts to the designated service area of each unit. Approximately 27 percent of the return air is normally exhausted to the atmosphere and 73 percent of the return air is normally recirculated. The recirculated air is mixed with outdoor makeup air and filtered through roughing filters, cooled (or heated), and supplied to the control room.

Estimated control room area heat loads for this mode of operation are listed in Table 9.4-9.

Mode 2: In the event of a fire in the control room, provisions are made for once through, 100 percent outdoor air operation. This mode exhausts the smoke from the room, thereby making it habitable. Roughing filters are used for filtering the outdoor air. The mode is manually initiated.

Mode 3: In the event of toxic gas outside the control room, provisions are made for manual zone isolation, 100 percent recirculated air with 27 percent passing through the HEPA filters and charcoal banks. Human detection (odor/smell) is used to identify the potential hazard and the mode is manually initiated.

Mode 4: This mode of operation is used in the event of airborne radioactivity and the requirement of long-term occupancy of the control room. Mode 4 isolates and pressurizes the control room and mechanical equipment room through the HEPA and charcoal filters with air from a low activity region to reduce local infiltration. The opposite control room HVAC train operates concurrently in Mode 3 recirculation. The flow rate of return air recirculated through the HEPA and charcoal filters is controlled by technical specifications (Reference 10). In the event an accident occurs in one unit, the system automatically selects the pressurization intake train of the opposite unit. With radiation detected at both pressurization intakes, one of the trains will start. However, the operator manually switches to the intake with lower airborne radioactivity.

For each unit, two manual mode selector switches (one for each subtrain) are used to place the CRVS in the desired operating mode and two manual bus selector switches (one for each subtrain) are used to place the desired subtrain in service. In addition, manual transfer switches are provided for the control, logic and power circuits that enable operation of the CRVS from either Unit 1 or Unit 2 power in the event that one unit is not operable.

The influx of airborne contaminants through the normal supply duct is limited by monitoring devices, which, upon detection of radioactive contaminants, automatically initiate CRVS Mode 4 operation. Closure of isolation dampers for CRVS Modes 3 and 4 (refer to Figure 9.4-1) is required within 10 seconds after manual initiation. A common warning light is provided on the control room panel to alert the operator if a ventilation damper is out of position. The position of each damper is indicated on a panel in the ventilation equipment room. Flow characteristics of the dampers are such that the average flow over the closure time is less than 60 percent of full flow.

Both the Unit 1 and Unit 2 CRVSs are designed to initiate Mode 4 operation, and Mode 3 operation on the opposite unit, automatically upon any one of the following signals:

(1) Containment phase A isolation from SI Unit 1

(2) Containment phase A isolation from SI Unit 2

(3) High outside air activity from Unit 1 normal air intake radiation monitor

(4) High outside air activity from Unit 2 normal air intake radiation monitor

The control room area is provided with minimum leakage dampers, weather-stripped doors, door vestibules, and absence of outdoor windows. Administrative controls ensure that all control room entranceways are normally closed.

Further protective options are provided by self-contained breathing apparatus located in the control room as stated in Section 6.4.1.

9.4.1.3 Safety Evaluation

9.4.1.3.1 General Design Criterion 2, 1967 - Performance Standards

The CRVS components are contained in the auxiliary and turbine buildings. These structures are PG&E Design Class I and PG&E Design Class II respectively (refer to Section 3.8). These buildings or applicable portions thereof are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunami (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and to protect control room habitability SSCs from damage that may result from these events; ensuring their design function will be performed.

The portions of the CRVS that have the potential of being damaged by a tornado missile are the normal intake and exhaust louvers and the CRPS fans, ductwork, dampers and associated controls located on the turbine building operating deck and the auxiliary building roof. The ability of the normal intake and exhaust louvers to sustain tornado wind and missile damage is detailed in Section 3.3.2.5.2.1.

The CRVS, a PG&E Design Class I system, is designed to perform its safety functions under the effects of earthquakes (refer to Section 3.10.3.20).

9.4.1.3.2 General Design Criterion 3, 1971 - Fire Protection

The CRVS is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.4.1.3.3 General Design Criterion 4, 1967 - Sharing of Systems

The control room is common to DCPP Unit 1 and Unit 2, and therefore requires sharing of SSCs between units. Mechanically interlocked transfer switches allow for the transfer of power between Unit 1 and Unit 2 480-V, Class 1E switchgear buses. Refer to Section 8.3.1.1.4.3.3 for the sharing of electrical power and equipment. Safety of the CRVS is

not impaired by the sharing because the two-train CRVS meets redundancy and single failure criteria for the common control room.

In addition, the CRPS is shared between the control room and the TSC. This sharing does not impair safety functions because each of the two pressurization trains independently have the capability to provide makeup air to the entire common control room area as well as to the TSC.

9.4.1.3.4 General Design Criterion 11, 1967 - Control Room

Under normal conditions (Mode 1), the Unit 1 and Unit 2 CRHVAC system supplies conditioned air consisting of recirculated air mixed with outdoor makeup air. In the event of a fire in the control room envelope, a smoke detector located in the return air duct is capable of detecting combustion products before visible smoke is present. The presence of combustion products would be alarmed in the control room where the operator would take corrective action. In the event of a large amount of smoke, the operator has the option to switch the CRVS into the 100 percent outdoor air mode of operation (Mode 2). This mode would purge the room of smoke. The control room is equipped with an adequate number of proper types of fire extinguishers and is manned by an operator(s) trained in fire-fighting procedures.

In the event that either damper 7 or 8 (refer to Figure 9.4-1) failed to open during Mode 2 ventilation, the rate of air removal from the control room would be reduced. If damper 7 failed to open, the air removal rate would be approximately 2100 cfm. If damper 8 failed to open, the air removal rate would be approximately 5375 cfm. Reduced air removal rates would result in slower removal of smoke.

In the event of toxic gas outside the control room, 100 percent of the air would be recirculated air with a portion passing through the HEPA filters and charcoal banks (Mode 3). Mode 3 operation of the CRVS may be manually initiated on human detection of toxic gas by the control room operators. Intake closure occurs within 10 seconds after manual actuation. Infiltration of the toxic gas from outdoors and other areas of the auxiliary building would be limited by minimum leakage dampers, zero leakage penetrations, weather-stripped doors, vestibules, and the absence of outside windows. Administrative controls ensure that all control room entranceways are normally closed. The plant complies with Regulatory Guide 1.78 (Refer to Sections 2.2.3.3 and 6.4.1.3.13).

With complete recirculation of the ventilation air, the CO_2 buildup is not expected to exceed an acceptable concentration of 1 percent by volume during 800 manhours of occupancy in the control room complex (e.g., 20 persons for 40 hours). Mode 4 operation maintains acceptable CO_2 levels inside the control room area due to the influx of filtered, outside air and exfiltration.

Refer to Section 9.4.1.2 for a general discussion of CRVS modes of operation. Mode 4 is governed by GDC 19, 1999 and is evaluated in Section 9.4.1.3.7.

9.4.1.3.5 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Monitoring devices for control room HVAC systems are capable of detecting low levels of airborne contaminants:

(1) Smoke detectors have sensitivity to detect trace amounts of combustion products.

(2) The two outside air activity area monitors per intake that monitor air entering the pressurization system duct are Geiger Muller tube-type general purpose monitors with a 10^{-2} to 10^{4} mR/hr range. Each monitor has a control room readout module with instrument failure alarm. A high radiation signal provides control room annunciation, shuts down the operating CRPS train, and automatically starts the opposite unit's CRPS.

(3) One area monitor is mounted on the radiation monitoring racks in the control room. This monitor is a Geiger Muller tube-type general-purpose monitor with a 10^{-1} to 10^{4} mR/hr range. This monitor has a control room readout with instrument failure alarm, local alarm, and control room annunciation.

(4) The chlorine monitors at the pressurization outside air duct are abandoned in place as there is no bulk chlorine on site.

High smoke or airborne radioactivity is annunciated in the control room so that the operator can take appropriate action.

9.4.1.3.6 General Design Criterion 17, 1967 - Monitoring Radioactivity Releases

Monitoring devices for control room HVAC systems are capable of detecting low levels of airborne radioactivity. Two outside air activity monitors per intake monitor the air entering the control room supply duct. Two outside air activity area monitors per intake monitor the air entering the pressurization system duct (refer to Section 9.4.1.3.5). One area monitor is mounted on the radiation monitoring racks in the control room (refer to Section 9.4.1.3.5).

9.4.1.3.7 General Design Criterion 19, 1999 - Control Room

CRVS Mode 4 operation is automatically initiated on a containment phase A isolation (SI) or normal air intake radiation monitor signal. Initiation of Mode 4 operation on a CRVS train initiates Mode 3 operation on the opposite train. Intake closure is designed to occur within 10 seconds or less after initiation of closure signal. Infiltration of activity from outdoors and other areas of the auxiliary building is limited by positive pressure, minimum leakage dampers, zero leakage penetrations, weather-stripped doors, door

vestibules, and the absence of outside windows. Administrative controls ensure that all control room entranceways are normally closed.

The CRVS, in conjunction with shielding and administrative controls, is designed to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE for the duration of the most severe design basis accident. An evaluation of post-accident control room radiological exposures is presented in Section 15.5.

9.4.1.3.8 General Design Criterion 21, 1967 Single Failure

The PG&E Design Class I CRVS is designed to remain operable after sustaining a single failure (refer to Section 9.4.1.3.12).

9.4.1.3.9 General Design Criterion 37, 1967 - Engineered Safety Features Basis for Design

The CRVS is an ESF system designed to provide control room habitability in order to support systems that provide backup to the safety provided by the core design, the RCPB, and their protection systems. Refer to discussion of ESF design bases under Sections 9.4.1.3.4 and 9.4.1.3.7.

9.4.1.3.10 General Design Criterion 38, 1967 - Reliability and Testability of Engineered Safety Features

The CRVS has been designed with provisions for periodic tests, inspections, and surveillance to ensure that the systems will be dependable and effective when called upon to function. Refer to Section 9.4.1.4 for a discussion of inspection and testing requirements.

9.4.1.3.11 General Design Criterion 40, 1967 - Missile Protection

PG&E Design Class I structures and equipment outside the containment were reviewed to determine those that could be affected by potential missiles. For postulated missile sources, it was determined that release of a missile would not endanger the nuclear safety of the DCPP Unit 1 or Unit 2 CRVS (refer to Section 3.5.1.2).

DCPP is designed so that a postulated piping failure will not cause the loss of needed functions of PG&E Design Class I SSCs, so that the plant can be safely shut down in the event of such failure (refer to Section 3.6).

9.4.1.3.12 General Design Criterion 41, 1967 - Engineered Safety Features Performance Capability

The CRHVAC system consists of two trains. Each train comprises two redundant sets of full capacity active components. The two pressurization fans for each of the air intakes associated with the CRPS and the charcoal adsorber and HEPA filter units are

common to Unit 1 and Unit 2, and are fully redundant. Two independent and redundant control room HVAC trains; i.e., one train for each unit, are provided to ensure that at least one is available if a single active failure disables the other train. The source of the electrical power for each of the redundant active components is from a Class 1E bus, and active components are powered from separate Class 1E buses.

Pneumatic dampers have a designated position that they will assume upon loss of the control air supply. This position would be the same for Mode 3 or Mode 4 operation. Electric dampers that must assume a position in any mode of operation are supplied with power from Class 1E buses. Separation of the electrical supply from the Class 1E buses has been followed throughout the installation.

9.4.1.3.13 Control Room Ventilation System Safety Function Requirement

(1) Cooling of PG&E Design Class I Equipment

The design indoor ambient temperatures are:

(a) Control room and safeguard rooms	85°F
(b) HVAC equipment rooms	104°F

The upper limit of temperature environment for the control room instrumentation is 120°F. Below this point, degradation of the equipment will not be an important factor. The system is designed to meet single failure criteria, so that one train of cooling is available at all times. With only one train of cooling equipment operating, the calculated temperature in the control room area is approximately 89°F and in the instrument safeguard room of the unit without air conditioning is approximately 116°F. Local hot areas within the equipment cabinets will be identified under operating conditions and provisions made for ventilation.

(2) Protection from Moderate Energy Pipe Rupture Effects

The CRVS is not required to be protected from postulated moderate energy line break effects because the primary instrumentation and control functions required for shutdown are located on the hot shutdown panel (refer to Section 7.4), in addition to being available in the control room, and are provided for the purpose of achieving and maintaining a safe operational status in the event that an evacuation of the control room is required (refer to Section 3.6.2.2.3)

(3) Protection from Flooding Effects

The provisions taken to provide protection of the PG&E Design Class I essential systems, including CRVS from internal flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6. The CRVS however is not required to be protected from all postulated moderate energy line break

effects because the primary instrumentation and control functions required for shutdown are located on the hot shutdown panel (refer to Section 7.4), in addition to being available in the control room, and are provided for the purpose of achieving and maintaining a safe operational status in the event that an evacuation of the control room is required (refer to Section 3.6.2.2.3)

9.4.1.3.14 10 CFR 50.63 - Loss of All Alternating Current Power

Following an SBO, 100 percent cooling of the control room is provided for the 4-hour coping period, as follows: one subtrain of the CRVS is powered from the operating EDG (AAC source) in the blacked-out unit and one subtrain of the CRVS is powered from an operating EDG in the non-blacked-out unit.

Refer to Section 8.3.1.6 for further discussion of station blackout.

9.4.1.3.15 Regulatory Guide 1.52, June 1973 - Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants

The CRVS provides the capability to control airborne radioactive material that could enter the control room atmosphere during a design basis event to acceptable levels. The CRVS is an ESF habitability system. These systems are analyzed to the positions in Regulatory Guide 1.52, June 1973 (Reference 11) as discussed in Table 9.4-2, with exceptions noted for specific items. Requirements for the performance of ventilation filter testing are stated in DCPP Technical Specifications.

Individual HEPA filters have been tested and are specified by the manufacturer to be able to remove 99.97 percent of particles 0.3 microns and larger, based on dioctyl phathalate particles in a standard test procedure. The overall efficiency of the filter bank is dependent on the initial efficiency of the individual filters, the care with which the filters have been stored and installed, and the sealing effectiveness of the filter frames with the supporting members of the bank. A penetration and leakage test was performed in place prior to putting the system in operation. Plant procedures for receiving, storing, and handling HEPA filters are employed to ensure factory performance of all HEPA filters.

Individual charcoal filters have been tested and are specified by the manufacturer to be able to remove 99 percent of radioactive iodine in the form of elemental iodine and 95 percent of radioactive iodine in the form of methyl iodide. A bypass leakage test was performed in place prior to putting the system in operation.

9.4.1.3.16 Regulatory Guide 1.52, Revision 2, March 1978 - Design, Testing, and Maintenance Criteria for Post-Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants

The DCPP ventilation filter testing program (VFTP) provides the requirements for the testing of charcoal samples from the CRVS charcoal adsorbers in accordance with ASTM D 3803-1989, which complies with Regulatory Guide 1.52, Revision 2 and Generic Letter 83-13, March 1983 for laboratory testing of charcoal samples and in-place penetration and bypass leakage testing in accordance with ANSI N510-1980. The VFTP complies with Regulatory Positions C.5.a, C.5.c, C.5.d, and C.6.a requirements as described in Table 9.4-2, with exceptions noted.

9.4.1.3.17 NUREG-0737 (Item II.B.2), November 1980 - Clarification of TMI Action Plan Requirements

Item II.B.2 **-** Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems Which May Be Used in Post-accident Operations: Plant shielding has been evaluated with regard to both radiation doses at equipment locations and vital area access/occupancy requirements for post-accident plant operations. Specifically, for the CRVS, dose analyses were performed to determine gamma doses for an operator during access and occupancy of the HVAC mechanical room. Occupancy for reading the differential pressure gauge is limited by the exposure from radioactivity buildup on the ESF HVAC filter. Total dose for this activity (the only anticipated activity) is acceptable in consideration of the overall GDC 19, 1999, dose limits for duration of the accident.

9.4.1.4 Tests and Inspections

9.4.1.4.1 Initial System Inspection and Tests

Initial checks of the motors, dampers, compressors, controls, monitors, etc., are made at the time of installation. A system air balance test and adjustment to design conditions are conducted. The final tests performed prior to actual operation of the CRVS are the in-place tests of the HEPA and charcoal filter banks. Refer to Table 9.4-2 for additional testing requirements.

9.4.1.4.2 Routine System Tests

The CRVS is functionally tested periodically as required by the DCPP Technical Specifications (Reference 10) for proper operation of the modes of operation. This testing includes checking the function of the dampers in Modes 1, 3, and 4 and measuring air flow through the filter.

Control room radiation monitors are periodically tested and calibrated as required by the DCPP Technical Specifications and Equipment Control Guidelines.

The control room ventilation smoke detectors are tested and demonstrated "operable" as required by the Equipment Control Guidelines.

An in-place test of the HEPA and charcoal filter banks is performed periodically as required by the DCPP Technical Specifications. Refer to Table 9.4-2 for additional testing requirements.

9.4.1.5 Instrumentation Applications

Required controls for CRVS components for system operation and instrumentation for monitoring CRVS parameters during normal operations and accident conditions are provided (refer to Sections 9.4.1.2 and 9.4.1.3.5).

9.4.2 AUXILIARY BUILDING

The following rooms/areas of the auxiliary building are provided with separate ventilation systems and are described in the referenced sections below:

(1) Control room – refer to Section 9.4.1

(2) 125-Vdc and 480-V switchgear rooms – refer to Section 9.4.9

(3) Battery charger and inverter rooms – refer to Section 9.4.9

(4) HSP area – refer to Section 9.4.9

(5) Cable spreading rooms (CSRs) – refer to Section 9.4.9

The PG&E Design Class I ABVS described in this section includes the following rooms/areas:

(1) ESFs and PG&E Design Class I electrical equipment areas: CCW pump area, SI pumps room, containment spray pumps area, RHR pump room, boric acid transfer pump area, and CCP1 and CCP2 rooms

(2) Radwaste areas

The ABVS provides the following functions:

(1) The ESF function to reduce the amount of volatile radioactive materials that could be released to the atmosphere in the event of leakage from the RHR circulation loop following a LOCA (refer to Sections 6.1.2, 6.3.3.5.3.2, and 15.5).

(2) The PG&E Design Class I function of maintaining the temperature of the ESF pump motors within acceptable limits during their operation

(3) Ventilation to the auxiliary building

(4) A filtered flowpath which serves as a portion of one train of the containment hydrogen purge system and the containment excess pressure relief system

9.4.2.1 Design Bases

9.4.2.1.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portion of the ABVS is designed to withstand the effects of, or is protected against natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

9.4.2.1.2 General Design Criterion 3, 1971 – Fire Protection

The ABVS is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.4.2.1.3 General Design Criterion 4, 1967 – Sharing of Systems

The ABVS is not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

9.4.2.1.4 General Design Criterion 11, 1967 – Control Room

The PG&E Design Class I portion of the ABVS is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

9.4.2.1.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the ABVS variables within prescribed operating ranges.

9.4.2.1.6 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The ABVS is designed to provide means for monitoring the facility effluent discharge paths and the facility environs for radioactivity that could be released from normal operations, from anticipated transients, and from accident conditions.

9.4.2.1.7 General Design Criterion 21, 1967 – Single Failure Definition

The PG&E Design Class I portion of the ABVS is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event are treated as a single failure.

9.4.2.1.8 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

The ESF portion of the ABVS is designed to provide backup to the safety provided by the core design, the RCPB, and their protection systems.

9.4.2.1.9 General Design Criterion 38, 1967 – Reliability and Testability of Engineered Safety Features

The ESF portion of the ABVS is designed to provide high functional reliability and ready testability.

9.4.2.1.10 General Design Criterion 40, 1967 – Missile Protection

The ESF portion of the ABVS is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

9.4.2.1.11 General Design Criterion 41, 1967 – Engineered Safety Features Performance Capability

The ESF portion of the ABVS is designed to provide sufficient performance capability to accommodate a partial loss of installed capacity, including a single failure of an active component, and still perform its required safety function.

9.4.2.1.12 General Design Criterion 42, 1967 – Engineered Safety Features Components Capability

The ESF portion of the ABVS is designed so that capability of each component and system to perform its required function is not impaired by the effects of a LOCA.

9.4.2.1.13 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The ABVS is designed with provisions for maintaining control over the plant's radioactive gaseous effluents. Appropriate holdup capacity is provided for retention of gaseous effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment.

9.4.2.1.14 Auxiliary Building Ventilation System Safety Function Requirements

(1) Protection from Missiles

The PG&E Design Class I non-ESF portion of the ABVS is designed to be protected against internal missiles generated outside containment that might result from plant equipment failure and from events and conditions outside the plant to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(2) Protection Against High Energy Pipe Rupture Effects

The PG&E Design Class I non-ESF ABVS is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection from Moderate Energy Pipe Rupture Effects

The PG&E Design Class I ABVS is designed to be protected against the effects of moderate energy pipe failure to the extent necessary in order to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(4) Protection from Flooding Effects

The PG&E Design Class I ABVS is designed to be protected from the effects of internal flooding to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(5) Cooling of PG&E Design Class I Equipment

The ABVS is designed to provide heat removal to ESF equipment to maintain the environment within design conditions.

9.4.2.1.15 10 CFR 50.49 – Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

The ABVS components that require EQ are qualified to the requirements of 10 CFR 50.49.

9.4.2.1.16 Regulatory Guide 1.52, June 1973 – Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants

The ABVS design and maintenance conforms with the guidance provided in Regulatory Guide 1.52, June 1973 with exceptions noted in Table 9.4-2.

9.4.2.1.17 Regulatory Guide 1.52, Revision 2, March 1978 – Design, Testing, and Maintenance Criteria for Post-Accident Engineered Safety Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants

The VFTP conforms with the guidance provided in Regulatory Guide 1.52, Revision 2, Regulatory Positions C.5.a, C.5.c, C.5.d, and C.6.a as described in Table 9.4-2. The VFTP also conforms with the guidance provided in Generic Letter 83-13, March 1983.

9.4.2.1.18 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The ABVS provides instrumentation to monitor system variables during and following an accident.

9.4.2.1.19 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident Monitoring Instrumentation:

Position (1) – The ABVS is designed with noble gas effluent monitors that are installed with an extended range designed to function during accident conditions.

Position (2) – The ABVS is designed with provisions for sampling of plant effluents for post-accident releases of radioactive iodines and particulates and onsite laboratory capabilities.

9.4.2.2 System Description

The auxiliary building ventilating system provides all outside air supply for the auxiliary building under all operating conditions. It also serves its primary purpose of providing cooling air for the ESF pump motors.

The supply system consists of two full capacity fans, roughing filters, and duct work for distribution. The exhaust system consists of two full capacity fans, two full capacity combined roughing and HEPA filter banks, one full capacity combined electric heater, roughing, HEPA and charcoal (may also be referred to as carbon) filter bank, and exhaust duct network (refer to Figures 9.4-2 and 9.4-3). The major equipment for the system is listed in Table 9.4-5. The containment hydrogen purge line connects to the inlet plenum for the filter bank containing the charcoal filter (refer to Section 6.2.5 and Figures 6.2-20, 9.4-3, and 9.4-3A). Manually controlled valves in this line allow flow to leave the containment and exhaust to the plant vent through the charcoal filter. The containment excess pressure relief line and the alternate path for the containment hydrogen purge discharge into the plant vent through the ABVS charcoal filter.

Air Distribution

The air flow pattern is arranged so that the air flows from areas of lower potential contamination to areas of higher potential contamination, and is then discharged to the plant vent. This is accomplished by supplying air to the occupied areas then exhausting the air from each equipment area separately. The system is balanced so that the building is normally under a slight negative pressure. The exhaust ducts from potentially high activity areas are so routed as to minimize exposure to normally occupied areas.

All ductwork serving ESF equipment has been designed to withstand any internal pressure that may be generated by any fan in the system, and braced according to PG&E Design Class I criteria to prevent earthquake damage to the ducts (refer to Section 9.4.2.3.1). All static ventilation components (i.e., volume dampers and air diffusers) have locking devices to prevent accidental closing. No duct liner or other insulating substance, which might sag or fall down, thereby blocking the duct, has been installed in any ductwork.

Electrical Power

The fans for the system receive power from the Class 1E 480-V buses. The supply system consists of two full capacity fans (each powered from a separate Class 1E bus). The exhaust system consists of two full capacity fans (each powered from a separate Class 1E bus).

Modes of Operation

The ABVS has three modes of operation:

Building Only Mode: During normal plant operation the system is designed to be in the "Building Only" mode. In this mode, one of two 100 percent capacity supply fans and one of two 100 percent capacity exhaust fans operates. Outside air is drawn through intake louvers, roughing filters, and ducted to the building space through the building only ventilation mode supply duct system. In the building only ventilation operating mode, exhaust air passes through the roughing and HEPA filter train. In any mode of operation the exhaust air is discharged through the plant vent.

Building and Safeguards Mode: The system automatically shifts to Building and Safeguards Mode when the control logic receives:

(1) A SI signal

(2) An indication that any one of the motors for CCP1 or CCP2, RHR pumps, SI pumps, or containment spray pumps has started

Building and Safeguards Mode may also be manually selected from the control panel in the control room for test or for operation. In this mode, the redundant set of supply and exhaust fans are designed to operate so that two supply and two exhaust fans are operating simultaneously. As in Building Only Mode, outside air is drawn through intake louvers, roughing filters and ducted to the building via the building only ventilation mode supply duct system and also through the ESF supply duct system. Depending on the presence of a SI signal, the exhaust air is handled as follows:

(1) If the system receives a SI signal, the exhaust air from the ESF pump rooms and RHR heat exchanger rooms passes through the manually actuated electric heater, roughing, HEPA, and charcoal filters, and the exhaust air from all other areas passes through the redundant roughing and HEPA filter trains.

(2) In the absence of a SI signal, the exhaust air from all areas passes through the roughing and HEPA filter trains.

Safeguards Only Mode: This mode is automatically actuated if a supply or an exhaust fan fails while the system is in Building and Safeguards Mode. The system supplies air only through the ESF supply duct system utilizing one exhaust fan and one supply fan. Depending on the presence of a SI signal, the exhaust is handled as follows:

(1) If the system receives a SI signal, the exhaust air from the ESF pump rooms and RHR heat exchanger rooms passes through the manually actuated electric heater, roughing, HEPA, and charcoal filters.

(2) In the absence of a SI signal, the exhaust air from all areas passes through the roughing and HEPA filters trains.

Design values for the ABVS are listed in Table 9.4-10.

The design classifications for the ABVS are given in Table 3.2-3. The design codes and standards are given in Table 9.4-8.

ESF Air Flow Relative Humidity

In the unlikely event of a LOCA accompanied by RHR loop leakage in the auxiliary building, flashing of leakage water would increase the relative humidity of the auxiliary building ESF exhaust air flow. To enhance the efficient performance of the charcoal filters, a manually actuated, 54 kW electric heater located upstream of the auxiliary building charcoal filters is sized to reduce the relative humidity of the ESF air flow. Operation of this heater is not required for this system to perform its safety function.

This heater is sized on the following assumptions:

(1) Outside air conditions of 45°F and 100 percent relative humidity. These conditions represent a reasonable bound on expected conditions that maximizes the relative humidity of ESF air flow entering the auxiliary building charcoal filters.

(2) Auxiliary building heat loads that result in a temperature rise of 16.5°F due to an increase in sensible heat of the 73,500 cfm ESF air flow. The only heat loads included are those associated with equipment that is required to operate following a LOCA and that would be expected to be operating during the period of postulated RHR loop leakage. These heat loads include motor losses and heat losses from piping and equipment associated with ECCS and ESF ventilation system operation. Two trains of ECCS pumps, one containment spray system train, and two CCW pumps are assumed to be operating.

(3) Adiabatic mixing of 738 lb/hr steam (3.1 percent flashing of 50 gpm leakage, refer to Section 15.5) with that portion of the ESF air flow which passes through the RHR pump rooms. Condensation is assumed that results in 100 percent relative humidity prior to mixing this portion of the ESF airflow with the remainder of the ESF air.

Using these assumptions, and assuming operation of the 54 kW electric heater, results in less than 70 percent relative humidity for ESF air flow entering the auxiliary building charcoal filters. However, the charcoal used in the filters is tested to 95 percent relative humidity and the electric heater is not required for filter operability (refer to Section 9.4.2.3.17 and Table 9.4-2).

Differential Pressures

Regarding the differential pressures, the total auxiliary building was considered as an open building. However, the exhaust system will remove approximately 9 percent more air than the supply system will provide. The extra air quantity must be made up by infiltration. Each equipment compartment is exhausted separately or through another compartment of higher potential contamination. This flow distribution, combined with the system air flow balance, will establish a slight negative pressure within the compartments. No provision other than this has been made to maintain or monitor this negative pressure.

Containment Hydrogen Purge and Pressure Relief

The ABVS provides a filtered flow path, to the plant vent, which serves as a portion of one train of the containment hydrogen purge and the containment excess pressure relief systems (refer to Sections 6.2.5 and 9.4.5, respectively).

Containment hydrogen purging is manually controlled and, when required, operates only intermittently. No single failure can accidentally initiate flow.

Containment hydrogen purge is required for plant safety but is not required until several weeks following a LOCA (refer to Section 6.2.5.2.3). By this time, most of the ESF pumps are no longer in operation and the heat load on the ventilation system is well below its maximum. In addition, purging would be conducted only about 2 hours a day, at times desired by the operator. This further guarantees the ability to avoid peak load periods on the ventilation system. In any case, the maximum expected purge flow of only 300 cfm would not have a significant effect on the ventilation system.

9.4.2.3 Safety Evaluation

9.4.2.3.1 General Design Criterion 2, 1967 – Performance Standards

The ABVS is designed to perform its safety functions under the effects of earthquakes (refer to Section 3.10.3.33), winds and tornadoes (refer to Section 3.3.2.5.2.1), and external missiles (refer to Section 3.5.1.2). The ABVS may be vulnerable to tornado effects but does not need to be operational while the plant is brought to a safe operational status.

Various ventilation systems exhaust to the plant vent; a PG&E Design Class I structure. The plant vent is designed to perform its safety functions under the effects of earthquakes (refer to Section 3.8.2.1.1), winds and tornadoes, and external missiles. The plant vent may also be vulnerable to tornado effects; however the plant can be safely shutdown without additional radiation exposure to the public even if the plant vent and its radiation monitors are rendered inoperable by a tornado. Refer to Section 3.3.2.5.2.5 for further discussion of wind, tornado, and external missile effects on the plant vent.

ABVS equipment is located within the auxiliary and FHBs which are PG&E Design Class I structures (refer to Section 3.8.2.3). The auxiliary building, including the relevant portions of the FHB, is designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7). This design protects the ABVS, ensuring its design functions can be performed during these events.

9.4.2.3.2 General Design Criterion 3, 1971 – Fire Protection

The ABVS is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.4.2.3.3 General Design Criterion 4, 1967 – Sharing of Systems

No ABVS equipment is shared between DCPP Unit 1 and Unit 2. However, common auxiliary building areas are ventilated by both the Unit 1 and Unit 2 ABVSs.

The Building and Safeguards Mode of operation provides sufficient cooling to PG&E Design Class I equipment in the auxiliary building at all times (refer to Section 9.4.2.2). In the event of failure of a supply or exhaust fan while the system is in Building and Safeguards Mode, Safeguards Only Mode is automatically actuated to continue to provide sufficient cooling to ESF equipment (refer to Section 9.4.2.2).

Each unit's ABVS is designed for single failure protection ensuring at least one train per unit is operational at all times providing full ventilation flow to all areas of the auxiliary building (refer to Section 9.4.2.3.7).

Therefore safety is not impaired by the shared ventilation.

9.4.2.3.4 General Design Criterion 11, 1967 – Control Room

The ABVS is normally controlled from the control room. Controls are provided on the main control board which allow for system startup and shutdown, fan selection, and for the selection of system operating configuration and modes (refer to Section 9.4.2.2).

Indication is provided on the main control board to indicate fan failure or damper out of position. Annunciators in the control room alert operators to abnormal conditions and system or equipment failures (refer to Section 9.4.2.3.5).

The ABVS can be operated remotely from the ventilation control logic and relay cabinet in the CSR.

9.4.2.3.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The operation of the system is initiated from the ventilation control board in the control room. The logic control will position the dampers and start the system for normal operation. The supply fan and exhaust fan are interlocked in a manner as to ensure the building will not be subjected to an appreciable amount of positive pressure. High-temperature and fan-failure alarms and damper position are provided to the main annunciator from the supply fan room.

The logic control devices for both Unit 1 and Unit 2 control system are solid-state units providing a full selection of logic functions designed for binary system operation. The control system is based on a programmable logic controller (PLC). The basis for qualification of the Triconex PLC and associated software follows the guidance of Branch Technical Positions 7-14 and 7-18 (References 21 and 22). The logic control system has output to solenoids and dry contact relays for the control functions. Both the logic controls and relays are redundant and have power sources from Class 1E buses.

The ambient air temperatures in areas containing Class 1E electrical equipment will be monitored continuously where excessive temperatures could possibly occur.

Additional information about the temperature monitoring system is provided in Sections 3.11 and 9.4.2.3.14. Additional information about radiation monitoring is provided in Section 9.4.2.3.6.

There are three ABVS modes of operation: Building Only, Building and Safeguards, and Safeguards Only. These modes are described in Section 9.4.2.2.

9.4.2.3.6 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The air flow from the auxiliary building is monitored for abnormal radiation levels of both particulate and gaseous nature at the plant vent monitors.

The plant vent is a large duct installed on the side of the containment structure discharging to the atmosphere at the 328.5 foot elevation. The discharges from the vent are monitored for radiation from both particulate and gaseous material by the plant vent air particulate and noble gas effluent monitors, RM-28 (or RM-28R) and RM-14 (or RM-14R), respectively. Additionally, the plant vent is equipped with iodine monitors RM-24 (or RM-24R) and an extended range noble gas effluent monitor (RM-87).

In addition, effluent from the RHR equipment compartments is monitored for abnormal radiation levels (RM-13). The sample for this monitor may be taken from either RHR compartment exhaust ducts so that an evaluation of any detected leakage may be made.

The radiological monitoring system is described in Section 11.4 and Table 11.4-1. Post-accident radiation monitoring is discussed in Section 9.4.2.3.19.

9.4.2.3.7 General Design Criterion 21, 1967 - Single Failure Definition

The ABVS has redundancy for the initiation circuitry and all non-static components, except for the electric heater (which is not required for filter operability). The fans are each full capacity, sized to handle the ESF pump motor cooling. Each ABVS train consists of two full capacity supply and exhaust fans, each powered from a separate Class 1E bus. In the event of the loss of an exhaust fan coincident with a SI signal, the second exhaust fan will start and the dampers will position themselves to route the air through the ESF ducts to the combined HEPA and charcoal filter banks. All dampers fail in the positions required for emergency conditions.

The ABVS is provided with a single, full capacity roughing, HEPA, and charcoal filter bank (including an electric heater) to limit the offsite exposures from a post-LOCA RHR pump seal failure. A single charcoal filter train is provided because the failure of the charcoal filter train in conjunction with a LOCA and RHR pump seal would constitute a second failure as discussed in Section 15.5.

The power for the fans and the initiating (logic) circuitry is taken from Class 1E buses with separation of redundant components. The dampers are positioned by pneumatic actuators supplied from the plant compressed air supply. The dampers are designed to assume the position required for emergency conditions on the failure of the air supply. If a damper's fail position is open, two dampers are mounted in parallel. Conversely, if the damper's fail position is closed, two dampers are mounted in series. The initiating (logic) circuitry is redundant, including relays and solenoids required to actuate the system. Each control train serves similar control functions, in addition to switching over circuits in the event of a failure to the other train. Separation has been maintained for the electrical circuits from each Class 1E bus.

The ventilation system is designed to meet single failure criteria by having the non-static elements installed in redundancy. All dampers that must fail in the open position are redundant. Failure in the open position maintains cooling air flow through the ESF pump motor compartments.

The radwaste area is primarily that area served by the system that is not included in the "safeguards only" mode of operation. Two conditions will interrupt the air flow to the radwaste area. The first condition involves a double failure, the loss of either an exhaust or a supply fan and a coincident SI signal or the start of an ESF pump motor. The second condition is the loss of control air supply to the building exhaust duct dampers 4A and 4B (refer to Figure 9.4-3). Either case is an abnormal condition that is indicated to the control room operator who then takes action to minimize the leakage of radioactive material to the compartments and/or to the ventilation system.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Experience at the Humboldt Bay reactor has shown that normal leakage or vents from the radwaste system are not a large contributor to airborne radioactivity.

9.4.2.3.8 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

The PG&E Design Class I ABVS provides the ESF function to reduce the amount of volatile radioactive materials that could be released to the atmosphere in the event of leakage from the RHR circulation loop following a LOCA (refer to Sections 6.1.2, 6.3.3.5.3.2, and 15.5).

The ventilation system serves the auxiliary building (including the radwaste area, excluding the fuel handling area). The general flow pattern is from areas of lower potential contamination to areas of higher potential contamination. The building is under a slight negative pressure. This concept has been followed throughout. This flow pattern will be maintained under the first two modes of operation. However, when the system is operating under the "safeguards only" mode (refer to Section 9.4.2.2), the total air flow will be exhausted through the ESF motor compartments only.

The exhaust air from the auxiliary building is normally routed through roughing and HEPA filter banks for the purpose of removing particulates that may be in the ventilation air. When the system is in the "building and safeguards" or "safeguards only" modes of operation without SI signal, air that is exhausted from the ESF pump motor areas is routed through roughing and HEPA filter banks. In the presence of a SI signal in conjunction with the system in one of these two modes, the exhaust air from the ESF pump motor area passes through the combined roughing, HEPA, and charcoal filters. The specifications for the exhaust filters are given in Table 9.4-5. Refer to Section 15.5 for a discussion on dose consequences analyses.

9.4.2.3.9 General Design Criterion 38, 1967 – Reliability and Testability of Engineered Safety Features

The ESF portion of the ABVS is designed with provisions for periodic tests, inspections and surveillance to ensure that the systems will be dependable and effective when called upon to function.

The system is operationally tested in accordance with the Technical Specifications. These tests include checking the function of the dampers and controls under each mode of operation and determination of total air flow.

A functional test of the HEPA and/or charcoal filter banks is performed whenever a filter element is replaced. A charcoal sample is removed in accordance with the VFTP to determine the effectiveness of the charcoal bank (refer to Sections 9.4.2.3.16 and 9.4.2.3.17 and Table 9.4-2).

9.4.2.3.10 General Design Criterion 40, 1967 – Missile Protection

There are no credible missiles outside of containment resulting from plant equipment failures that would prevent the ESF portion of the ABVS from performing its design functions (refer to Section 3.5.1.2).

Dynamic effects as a result of plant equipment failure will not prevent the PG&E Design Class I, ESF portion of the ABVS from performing its design functions (refer to Section 3.6).

9.4.2.3.11 General Design Criterion 41, 1967 – Engineered Safety Features Performance Capability

Each full capacity fan of a redundant set receives power from a separate Class 1E bus. The dampers for the system are redundant, pneumatically operated, and designed to fail in the positions required for emergency conditions. Dampers are arranged in parallel if the fail position is open, and in series if the fail position is closed (refer to Section 9.4.2.3.7).

9.4.2.3.12 General Design Criterion 42, 1967 – Engineered Safety Features Components Capability

Following a LOCA, the ABVS can tolerate a 50 gpm RHR system leak during the recirculation phase in the auxiliary building (refer to Sections 6.1.2, 6.3.3.5.3.2, and 15.5).

9.4.2.3.13 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The normal building exhaust air is filtered through HEPA filters, and upon a SI signal, the emergency cooling exhausts air through both HEPA filters and charcoal filter banks.

The occurrence of complete failure of the auxiliary building ventilation flow would result in a slow rise in airborne activity in the building only if a significant amount of leakage existed from equipment carrying radioactive fluids prior to the failure of ventilation flow. If concentrations should rise to significant levels, personnel can be kept out of the area by administrative controls, or wear protective respiratory equipment during any required maintenance work. Specific limits on plant operation and requirements for shutdown under conditions of reduced or lost ventilation flow are contained in the Technical Specifications. The characteristics of the monitors and sampling procedures for auxiliary building areas are given in Section 11.4. There are no public safety implications of failure of the auxiliary building ventilation during normal plant operation, since reduced exhaust flow would only result in increased holdup and decay of airborne activity before release from the plant. With regard to simultaneous coincident major failures in both the ventilation system and a major radwaste component, an analysis of the most severe consequences of such events is contained in Sections 15.5.24 through 15.5.26. Assessments of long-term exposures from small equipment leakages are included in Sections 11.3.2.5 and 12.2.6.

Radioactive iodines and particulates, for the removal of which the ABVS is potentially effective, are generally stored at low pressure in the auxiliary building. Failure of a low-pressure storage vessel would be extremely unlikely and would not generate a pressure pulse sufficient to damage the ABVS.

A larger pressure pulse would result from the rupture of a gas decay tank (GDT) or the volume control tank (VCT) as discussed in Sections 11.3.3.9 and 11.2.3.12, respectively. While some momentary release of radioactivity to these areas could result from a pressure pulse, any damage to the ductwork is likely to be confined to either (a) the branch serving the gas decay tanks and waste gas compressors, or (b) the branch serving the VCT and the sample heat exchangers.

After the initial pulse of pressure and release of radioactive materials, any airborne activity in areas served by the ABVS will be drawn toward the high efficiency filters of the system. Any local damage to the duct should affect only the ventilation in the

immediate area. The ABVS design will prevent contaminants from being delivered to other areas of the auxiliary building.

In case of the spread of radioactive materials to other auxiliary building areas, the operating restrictions, described above and within Section 9.4.2.3.7, can be instituted if necessary. As described in Sections 11.3.3.9 and 11.2.3.12, no credit is taken for radioactivity removal by the ABVS in calculating offsite doses resulting from postulated failure of the GDT or VCT.

9.4.2.3.14 Auxiliary Building Ventilation System Safety Function Requirements

(1) Protection from Missiles

There are no credible missiles outside of containment resulting from plant equipment failure that would prevent the non-ESF portions of the PG&E Design Class I ABVS from performing its design functions to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained (refer to Section 3.5.1.2).

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the non-ESF portions of the PG&E Design Class I ABVS from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained as discussed in Section 3.6.

(3) Protection from Moderate Energy Pipe Rupture Effects

The provisions taken to provide protection to the PG&E Design Class I essential systems located outside containment from moderate energy pipe rupture effects (water spray) are discussed in Section 3.6.

(4) Protection from Flooding Effects

The provisions taken to provide protection to the PG&E Design Class I essential systems from flooding that might result from the effects associated with a postulated rupture of high and moderate energy piping are discussed in Section 3.6.

(5) Cooling of PG&E Design Class I Equipment

The ventilation system has been designed to maintain a maximum design room temperature of 104°F in the auxiliary building with a design outdoor ambient air temperature of 76°F (refer to Section 9.4) with the following exceptions:

(1) The LHUT rooms shall have a maximum design room temperature of 130°F.

(2) The ambient temperature in the area of the boric acid transfer pumps may reach a maximum temperature of approximately 124°F after one hour following the postulated event of one train of the ABVS being inoperable post LOCA. The boric acid transfer pump may be required to operate within this period post LOCA. During any other operating conditions, the maximum design room temperature in this area shall be 104°F.

The airflow requirements have been based on the ESF motor cooling load. The allowable ambient air temperature for continuous operation of the ESF motors is 104°F.

Although not an ESF function, the ABVS supplies cooling air for the ESF pump motors. Motors are designed for continuous operation at an ambient air temperature of 104°F. The supply fans and their associated dampers need to be in operation under both normal and accident conditions to maintain the EQ of the ESF pump motors because the cooling function of the system is important for their long-term operation.

9.4.2.3.15 10 CFR 50.49 – Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

The ABVS components required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ program and the requirements for the environmental design of the electrical and related mechanical equipment. The affected components are listed on the EQ Master List (refer to Section 3.11.2).

9.4.2.3.16 Regulatory Guide 1.52, June 1973 – Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants

The ABVS provides the capability to control the volatile radioactive material that could exit to the atmosphere. The system is analyzed to the positions in Regulatory Guide 1.52, June 1973 (Reference 11) as shown in Table 9.4-2 with exceptions noted for specific items. Requirements for the performance of ventilation filter testing are stated in the DCPP VFTP.

9.4.2.3.17 Regulatory Guide 1.52, Revision 2, March 1978 – Design, Testing, and Maintenance Criteria for Post-Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants

The VFTP provides the requirements for the testing of charcoal samples from the ABVS charcoal adsorbers in accordance with ASTM D 3803-1989, which complies with Regulatory Guide 1.52, Revision 2, and Generic Letter 83-13, March 1983 for laboratory testing of charcoal samples and in-place penetration and bypass leakage testing in accordance with ANSI N510-1980. The VFTP complies with Regulatory Positions

C.5.a, C.5.c, C.5.d, and C.6.a requirements as described in Table 9.4-2, with exceptions noted.

9.4.2.3.18 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Damper position indication in the control room provides status of the Unit 1 and Unit 2 ABVS fan suction and discharge motorized dampers in response to an ESF actuation (refer to Table 7.5-6 for a summary of compliance to Regulatory Guide 1.97, Revision 3).

9.4.2.3.19 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident Monitoring Instrumentation:

Position (1) – Extended range noble gas effluent monitoring is installed in the plant vent and is designed to function during accident conditions (refer to Sections 7.5.2.3 and 11.4.2.1.2.1).

Position (2) – Installed capability is provided in the plant to obtain samples of the particulate and iodine radioactivity concentrations which may be present in the gaseous effluent being discharged to the environment from the plant under accident and post-accident conditions. The TSC laboratory is available for onsite testing of the containment air samples.

9.4.2.4 Tests and Inspections

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

An initial checkout of the motors, dampers, fans, controls, etc., was made at the time of installation. A system air balance test and adjustment to design conditions was conducted. The final tests performed prior to actual operation of the ventilation system were the functional tests of the HEPA and charcoal filter banks. These tests determined the overall effectiveness of the filter banks.

Refer to Section 9.4.2.3.9 for additional information on testing requirements.

9.4.2.5 Instrumentation Applications

Refer to Sections 9.4.2.3.4 and 9.4.2.3.5 for a complete discussion of the instrumentation requirements and controls for the ABVS.

9.4.3 TURBINE BUILDING

The turbine building ventilation system provides for personnel comfort and is a PG&E Design Class II system (refer to Table 3.2-3).

Although the onsite TSC is adjacent to the turbine building, the TSC is provided with its own ventilation system (refer to Section 9.4.11). Separate PG&E Design Class I ventilation systems in the turbine building are provided for the diesel generator rooms (refer to Section 9.4.7), and the 4.16-kV switchgear and 4.16-kV CSRs, (refer to Section 9.4.8).

9.4.3.1 Design Bases

9.4.3.1.1 General Design Criterion 3, 1971 – Fire Protection

The turbine building ventilation system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.4.3.2 System Description

The turbine building ventilation system has been designed for the purpose of providing personnel comfort in the operation of the turbine-generator equipment. This system is generally not necessary for airborne radioactivity control because of the low potential for contamination in the steam cycle. The overall design objectives of the ventilation systems regarding control of airborne radioactive materials are discussed in Section 12.2.

Because significant airborne activity is not expected on a continuous basis in the turbine building, continuous monitoring equipment is not provided. If significant activity levels are observed in the air ejector offgas, however, periodic sampling will be initiated to determine turbine building airborne activity. If sampling indicates the need for continuous sampling, it will be provided.

The turbine building ventilation system is a PG&E Design Class II system, and its complete failure has no safety implication. Because of the many fans in the system, failure of any fan or group of fans will not cause excessive temperatures in building compartments. Furthermore, if ventilation flow were not available, doors can be opened to provide natural flow. In the event that airborne activity exists in the building at a time when ventilation flow is not available, some increase in concentrations could occur. Because of the low level of this activity, however, it is not expected that concentrations above 10 CFR 20.1-20.601 (pre-1994) maximum permissible concentration levels could exist with the building doors open. In any event, sampling or monitoring will be in effect under these conditions.

Regarding the requirements for the treatment of exhaust air from the turbine building, a detailed analysis of potential doses to the public from various sources of gaseous release is provided in Chapter 11. As a result of this analysis, it can be concluded that, at the DCPP site, treatment of turbine building exhaust air is not required to meet the exposure limits listed in Appendix I to 10 CFR Part 50.

Air is drawn into the system, through roughing filters, by the system's fifteen (15) supply fans. The supply fans direct air into the turbine building through the east wall both above and below the elevation 140-foot operating deck. An exhaust fan for the lube oil reservoir room draws air through the room from the 104-foot elevation of the turbine building, which is supplied by the turbine building ventilation system. The turbine building ventilation system provides supply air as well as a discharge path to atmosphere for the non-Class 1E battery rooms.

The four exhaust fans and their related duct systems, located on the west side of the building, ensure air flow across the building below the operating deck. The exhaust fans discharge the air vertically up above the operating deck inside the turbine building. The turbine building ventilation system provides a discharge path to atmosphere for the exhaust air from the Class 1E 4.16-kV switchgear rooms and associated CSRs (refer to Section 9.4.8), the non-Class 1E 480-V switchgear room, and the non-Class 1E battery rooms. A vent located on the top of the turbine building provides the exhaust path to atmosphere for turbine building supply air that is not discharged from the building via other paths.

Each fan can be operated independently through a manual motor starter with power from a non-Class 1E bus. Should there be single or double fan failure, the net effect on the turbine building would be negligible. Should all non-Class 1E power to fans be de-energized, all doors on the east and west walls (elevation 85 foot) could be opened, allowing the building to function on gravity ventilation.

The locations of all fans, vents, and compartments are shown in the following: Figures 1.2-13 through 1.2-20, 1.2-24 through 1.2-27, and 1.2-30 through 1.2-32. The major equipment for the turbine building (general area) ventilation system is listed in Table 9.4-7.

The requirements for system temperature design are described in Section 9.4.

9.4.3.3 Safety Evaluation

9.4.3.3.1 General Design Criterion 3, 1971 – Fire Protection

The turbine building ventilation system is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1). Specifically, fire dampers are provided for the lube oil reservoir room to maintain CO_2 gas concentration upon actuation of the CO_2 flooding gas extinguishing system provided for that room.

9.4.3.4 Tests and Inspections

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Initial checks of the fan housings, bearings, motors, bolts, controls, etc., were made at the time of installation. A system air balance test and adjustment to design conditions was conducted.

9.4.3.5 Instrumentation Applications

Each of the 15 supply fans and 4 exhaust fans can be operated independently through manual motor starters.

9.4.4 FUEL HANDLING BUILDING VENTILATION SYSTEM

The non-ESF portion of the FHBVS serves the FHB and rooms containing the motor-driven and turbine-driven AFW pumps, SFP pumps, SFP heat exchanger, makeup water transfer pumps, and fire pumps.

The ESF function of the FHBVS is to sweep radiolytic gases from the surface of the SFP and to treat the exhaust air in order to remove radioactive iodine (refer to Section 6.1). The purpose of the treatment of the exhaust air is to reduce the offsite dose in the event of a FHA. The sweeping effect of the ventilation air over the surface of the pool will also reduce personnel exposures in the event of a FHA.

9.4.4.1 Design Bases

9.4.4.1.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portion of the FHBVS is designed to withstand the effects of, or is protected against, natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

9.4.4.1.2 General Design Criterion 3, 1971 – Fire Protection

The PG&E Design Class I portion of the FHBVS is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.4.4.1.3 General Design Criterion 11, 1967 – Control Room

The PG&E Design Class I portion of the FHBVS is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

9.4.4.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the PG&E Design Class I portion of the FHBVS variables within prescribed operating ranges.

9.4.4.1.5 General Design Criterion 17, 1967 – Monitoring Radioactive Releases

The FHBVS is designed to provide means for monitoring the FHB atmosphere and the FHB effluent discharge path for radioactivity that could be released from normal operations from anticipated transients or from a FHA.

9.4.4.1.6 General Design Criterion 21, 1967 – Single Failure Definition

The PG&E Design Class I portion of the FHBVS is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event are treated as a single failure.

9.4.4.1.7 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

The ESF portion of the FHBVS provides a significant reduction in the amounts of volatile radioactive materials that could be released to the atmosphere in the event of a FHA.

9.4.4.1.8 General Design Criterion 38, 1967 – Reliability and Testability of Engineered Safety Features

The ESF portion of the FHBVS is designed to provide high functional reliability and ready testability.

9.4.4.1.9 General Design Criterion 40, 1967 – Missile Protection

The PG&E Design Class I, ESF portion of the FHBVS is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

9.4.4.1.10 General Design Criterion 41, 1967 – Engineered Safety Features Performance Capability

The ESF portion of the FHBVS is designed to provide sufficient performance capability to accommodate a partial loss of installed capacity, such as a single failure of an active component, and still perform its required safety function.

9.4.4.1.11 General Design Criterion 69, 1967 – Protection Against Radioactivity Release from Spent Fuel and Waste Storage

The ESF portion of the FHBVS provides a significant reduction in the amounts of volatile radioactive materials that could be released to the atmosphere in the event of a FHA.

9.4.4.1.12 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The ESF portion of the FHBVS is designed with provisions for maintaining control over the plant's radioactive gaseous effluents.

9.4.4.1.13 Fuel Handling Building Ventilation System Safety Function Requirements

(1) Protection from Missiles

The PG&E Design Class I, non-ESF portion of the FHBVS is designed to be protected against internal missiles generated outside containment that might result from plant equipment failure and from events and conditions outside the plant to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(2) Protection Against High Energy Pipe Rupture Effects

The PG&E Design Class I non-ESF FHBVS is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection from Moderate Energy Pipe Rupture Effects

The PG&E Design Class I FHBVS is designed to be protected against the effects of moderate energy pipe failure to the extent necessary in order to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(4) Protection from Flooding Effects

The PG&E Design Class I FHBVS is designed to be protected from the effects of internal flooding to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(5) Cooling of PG&E Design Class I Equipment

The PG&E Design Class I, non-ESF portion of the FHBVS is designed to provide cooling to PG&E Design Class I pumps.

9.4.4.1.14 Safety Guide 13, March 1971 – Fuel Storage Facility Design Basis

Regulatory Position 4:

The PG&E Design Class I, ESF portion of the FHBVS is designed to limit the potential release of radioactive iodine and other radioactive materials in the event of a significant release of radioactivity from the fuel following a FHA.

9.4.4.1.15 Regulatory Guide 1.52, June 1973 – Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants

The ESF portion of the FHBVS design and maintenance conforms with the guidance provided in Regulatory Guide 1.52, June 1973 with exceptions noted in Table 9.4-2.

9.4.4.1.16 Regulatory Guide 1.52, Revision 2, March 1978 – Design, Testing, and Maintenance Criteria for Post-Accident Engineered Safety Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants

The VFTP conforms with the guidance provided in Regulatory Guide 1.52, Revision 2, Regulatory Positions C.5.a, C.5.c, C.5.d, and C.6.a as described in Table 9.4-2. The VFTP also conforms with the guidance provided in Generic Letter 83-13, March 1983.

9.4.4.1.17 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Instrumentation is provided in the control room to monitor the FHBVS ventilation damper position status for post-accident indication.

9.4.4.1.18 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident Monitoring Instrumentation:

Position (1) – The FHBVS is designed with noble gas effluent monitors that are installed with an extended range designed to function during accident conditions.

Position (2) – The FHBVS is designed with provisions for sampling of plant effluents for post-accident releases of radioactive iodines and particulates and onsite laboratory capabilities.

9.4.4.2 System Description

Design values for the FHBVS are listed in Table 9.4-10. The requirements for the system design are as follows:

(1) Provide an air flow pattern sweeping the SFP surface

(2) Meet the single failure criteria (refer to Section 9.4.4.3.6)

(3) Remove more air than is supplied so that all potential air leakages will be inward

(4) Automatically function in the event of a FHA involving recently irradiated fuel

(5) Provide pretreatment of supply air

  (a) Roughing filters

  (b) Heating provisions

(6) Provide post-treatment of exhaust air

  (a) Particulate

  (b) Gaseous

(7) Provide ventilation to the FHB, including the equipment rooms containing the AFW pumps, SFP pumps, SFP heat exchanger, makeup water transfer pumps, and fire pumps.

(8) Design, build, and install equipment according to design classifications given in Table 3.2-3.

The evaluation of the fission product removal performance of the system is contained in Section 15.5, in connection with the description of the FHAs.

The FHBVS has the capability to provide ventilation air for the FHB separately from the auxiliary building. The FHB for each unit is physically isolated from the auxiliary building. The system as shown in Figure 9.4-3 consists of redundant supply and exhaust fans, and redundant HEPA and charcoal filter banks. A third full capacity exhaust fan and HEPA filter bank train is provided for normal operation. Each HEPA filter bank is preceded by a roughing filter bank. The major equipment for the system is listed in Table 9.4-6. The supply airflow, was selected on the basis of the heat dissipated by the equipment. The exhaust air flow (35,750 cfm) consists of approximately 81 percent exhausted from the SFP area by drawing the air flow over the

pool. The balance of the flow is ducted and exhausted by the exhaust fan from other areas in the FHB.

The heating coil is used to temper the air that is supplied to the area. The supply air is ducted to corridors and equipment compartments on the floor levels below the operating level. The air flow pattern is from these compartments through the spent fuel shipping cask decontamination area up to the SFP. Exhaust grilles over and along one side of the SFP draw the air in a sweep across the pool surface. The exhaust air is then filtered and discharged to the plant vent.

The FHB is separated from the rest of the auxiliary building by partitions and doors on all floors. The separating doors, partitions, and outside walls are of standard construction with no particular leaktight consideration. The exhaust fans remove more air than is supplied. This extra air is made up by infiltration from the outside and adjoining areas of the auxiliary building.

The system is provided with three modes of operation that affect the filtering of the exhaust air.

Normal Mode: The first mode is for normal use. The mode may be selected manually from pool side or from the control room. Under this mode all of the exhaust air passes through roughing and HEPA filter banks only. The exhaust fan for this mode is powered from a non-Class 1E 480-V bus.

Iodine Removal Mode: The second mode of operation is for the removal of potential radioactive particulates and/or radioactive gases in the exhaust air. This mode of operation is automatically initiated by an exhaust fan failure while in Normal Mode, or it may be selected manually from the pool side or from the control room. This mode routes all the exhaust air through roughing, HEPA, and charcoal filters. The fans and filter banks for this mode of operation are redundant. The fans are powered from separate Class 1E 480-V buses.

Automatic Iodine Removal Mode: The third mode of operation (emergency mode) is also for the removal of radioactive particulate and/or radioactive gases in the exhaust air. This mode is physically the same as Iodine Removal Mode except for automatic initiation by a radiation detector. The radiation detectors located near the fuel storage areas will automatically initiate this mode when radiation levels exceed the setpoint level in Table 11.4-1.

9.4.4.3 Safety Evaluation

9.4.4.3.1 General Design Criterion 2, 1967 – Performance Standards

The FHBVS is designed to perform its safety functions under the effects of earthquakes (refer to Section 3.10.3.33), winds and tornadoes (refer to Section 3.3.2.5.2.3), and external missiles (refer to Section 3.5.1.2). The metal siding and roofing of the FHB do

not provide significant missile protection for the FHBVS due to a tornado event. However, the capability of the FHBVS to maintain a negative pressure in the FHB is not required after a tornado. The FHBVS exhaust ducts and FHB radiation monitors have limited tornado resisting capabilities. Failures of these components do not affect the safe operational status of the plant and do not result in significant radiation releases since damage to the spent fuel does not occur as a result of a tornado.

The FHBVS is located within the FHB; a PG&E Design Class I structure (refer to Section 3.8.2.3). The FHB is designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7). This design protects the FHBVS, ensuring its design functions can be performed during these events.

9.4.4.3.2 General Design Criterion 3, 1971 – Fire Protection

The FHBVS is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.4.4.3.3 General Design Criterion 11, 1967 – Control Room

The FHBVS is normally controlled from the control room. Controls are provided on the main control board which allow for system startup and shutdown, fan selection, and for the selection of system operating configuration and modes (refer to Section 9.4.4.2).

Indication is provided on the main control board to indicate fan failure or damper out of position. Annunciators in the control room alert operators to abnormal conditions and system or equipment failures (refer to Section 9.4.4.3.4).

9.4.4.3.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The control logic devices for both DCPP Unit 1 and Unit 2 FHB are solid-state units providing a full selection of logic functions, designed for binary system operation. The control system is based on a PLC. The basis for qualification of the Triconex PLC and associated software follows the guidance of Branch Technical Position 7-14 and 7-18 (References 21 and 22). The logic control system has output to solenoids and dry contact relays for the control functions. Both the logic controls and relays are redundant and have power sources from Class 1E buses.

The FHBVS has manual selection for Normal Mode and Iodine Removal Mode operations. It also has an automatic initiation of the Iodine Removal Mode. The automatic initiation is from radiation monitors mounted near the fuel storage areas. Radiation levels greater than the setpoint level will change the operation of the system from Normal Mode to Automatic Iodine Removal Mode operation. For setpoint radiation level, refer to Table 11.4-1.

High temperature alarms are provided to the main annunciator for the FHB supply fan room.

9.4.4.3.5 General Design Criterion 17, 1967 – Monitoring Radioactive Releases

Radiation detection instruments are located in the SFP area and the new fuel storage area. These instruments continuously detect operating radiation levels. If the radiation levels should rise above the setpoints listed for each channel (refer to Table 11.4-1), an alarm is initiated in the control room. Local annunciation is also provided at the detectors to indicate high radiation levels to personnel in the area.

The air flow from the FHB is monitored for abnormal radiation levels of both particulate and gaseous nature at the plant vent monitor.

9.4.4.3.6 General Design Criterion 21, 1967 – Single Failure Definition

The FHBVS has redundancy for all non-static (active) components. The fans are each full capacity. The exhaust fan (E-4) and corresponding filter bank used for Normal Mode are not necessary for emergency operation and are not redundant. If the exhaust fan or its associated mode damper used in the Normal Mode were to fail, Iodine Removal Mode (fans E-5 and E-6) would be automatically initiated.

If a supply fan or its associated mode damper should fail, or if the exhaust fan or exhaust mode damper used in Iodine Removal Mode should fail, the redundant fan and damper system for that mode would be automatically started. Off-delay timers, set for a nominal time delay of 2 seconds, keep supply fans running during a change of ventilation mode to prevent the loss of supply fan air flow and the subsequent shutting down of the supply fan.

The power sources for the redundant fans are taken from Class 1E 480-V buses with separation of redundant components.

The initiating (logic) circuitry, including the relays and solenoids required to actuate the system, is redundant. Each control train serves similar control functions and switches circuits in the event of a failure to the other train. Separation has been maintained for the electrical circuits from each Class 1E bus.

All ductwork has been designed to withstand any internal pressure that may be generated by any fan in the system, and braced according to PG&E Design Class I criteria to prevent earthquake damage to the ducts (refer to Section 9.4.4.3.1). All static (passive) ventilation components (i.e., volume dampers, air diffusers) have locking devices to prevent accidental closing. No duct liner or other insulating substance that might sag or fall down, thereby blocking the duct, has been installed in any ductwork.

9.4.4.3.7 General Design Criterion 37, 1967 – Engineered Safety Features Basis for Design

9.4.4.3.7.1 Air Flow Pattern

The ventilating air is discharged from duct work into the corridors and equipment compartments below the SFP floor. The air exhausts from the FHB after passing over the pool surface. Two exhaust air headers remove the air from above and from one side of the pool to achieve a sweeping movement of gases above the pool surface.

The FHB is separated from the rest of the auxiliary building by partitions and doors on all floors. The separating doors, partitions, and outside walls are of standard construction with no particular leaktight consideration. The exhaust fans remove more air than is supplied. This extra air is made up by infiltration from the outside and adjoining areas of the auxiliary building.

The dampers are positioned with pneumatic actuators with air supplied from the plant compressed air system. The dampers are designed to assume the position required for emergency conditions on the failure of the control air supply.

9.4.4.3.7.2 Effects of Ventilation System Failure

The administrative controls specified in the Equipment Control Guidelines preclude the handling of recently irradiated fuel in the event of ventilation system inoperability or failure. Although it is conceivable that a FHA might occur coincident with a failure in the FHBVS, this combination of events is not regarded to be of sufficient likelihood to warrant system design changes. In any event, personnel will be leaving the FHB immediately following any indication of a FHA. Personnel exposure is not expected to be significant in any of these events because of the presence of the area monitor and continuous air monitor functioning during any operations involving irradiated fuel. These provisions are further described in Section 12.1.4 and the Technical Specifications.

9.4.4.3.7.3 Treatment of Air

The supply air for the FHB passes through roughing filters to remove dust and lint that may be in the atmosphere. The supply filters have a minimum dust spot efficiency of 30 percent for atmospheric dust (National Bureau of Standards or Air Filter Institute method).

The exhaust air from the FHB is filtered through roughing filters and HEPA filters during normal operation. Iodine Removal Mode operation has, in addition, charcoal filters (refer to Section 9.4.4.2). The charcoal filter banks have been sized to take the full air flow of the ventilation system without exceeding the manufacturer's recommendations for flow through each individual module of the bank. Thirty-six modules with three filter trays per module are provided for each full capacity filter bank. The total amount of activated impregnated charcoal in each filter bank is a function of the charcoal-

containing capacity and the density of the charcoal. The amount of charcoal contained in each filter bank is adequate to adsorb radioactive gases from any projected design FHA without overloading with iodine or overheating from decay heat. The exhaust air for the system is routed to the plant vent. All air flow through the plant vent is monitored for radioactivity.

9.4.4.3.8 General Design Criterion 38, 1967 – Reliability and Testability of Engineered Safety Features

The ESF portion of the FHBVS is designed with provisions for periodic tests, inspections, and surveillance to ensure that the systems will be dependable and effective when called upon to function.

Testing of the FHBVS is in accordance with the requirements of the Technical Specifications, including the VFTP as described in Sections 9.4.4.3.15 and 9.4.4.3.16.

9.4.4.3.9 General Design Criterion 40, 1967 – Missile Protection

There are no credible missiles outside of containment resulting from plant equipment failure that would prevent the PG&E Design Class I, ESF portion of the FHBVS from performing its design functions (refer to Section 3.5.1.2).

Dynamic effects as a result of plant equipment failure will not prevent the PG&E Design Class I, ESF portion of the FHBVS from performing its design function of supporting ESFs (refer to Section 3.6).

9.4.4.3.10 General Design Criterion 41, 1967 – Engineered Safety Features Performance Capability

The ESF portion of the FHBVS has redundancy for all non-static (active) components. The power sources for the redundant fans are taken from Class 1E 480-V buses with separation of redundant components (refer to Section 9.4.4.3.6). Therefore, the FHBVS provides sufficient performance capability to accommodate partial loss of installed capacity and still fulfill the required functions of sweeping radiolytic gases from the surface of the SFP and treating the exhaust air in order to remove radioactive iodine.

9.4.4.3.11 General Design Criterion 69, 1967 – Protection Against Radioactivity Release from Spent Fuel and Waste Storage

The FHBVS consists of redundant supply and exhaust fans, redundant HEPA and charcoal filter banks, and redundant controls and Class 1E 480-V power (refer to Section 9.4.4.3.6).

In the event of a FHA, radiation detectors located near the fuel storage areas will automatically initiate the iodine removal mode when radiation levels exceed the setpoint

level in Table 11.4-1. This mode routes all the exhaust air through roughing, HEPA, and charcoal filters (refer to Section 9.4.4.2).

The charcoal filters are designed to adsorb radioactive gases from any projected design FHA without overloading with iodine or overheating from decay heat. The exhaust air for the system is routed to the plant vent. All air flow through the plant vent is monitored for radioactivity (refer to Section 9.4.2.3.6).

The assumptions used in the FHA analyses are presented in Section 15.5.22.

9.4.4.3.12 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The ESF portion of the FHBVS has been designed to pass exhaust air from the FHB through HEPA filters and charcoal filter banks before reaching the plant vent

9.4.4.3.13 Fuel Handling Building Ventilation System Safety Function Requirements

(1) Protection from Missiles

There are no credible missiles outside of containment resulting from plant equipment failure that would prevent the non-ESF portion of the PG&E Design Class I FHBVS from performing its design functions (refer to Section 3.5.1.2).

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the non-ESF portions of the PG&E Design Class I FHBVS from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained as discussed in Section 3.6.

(3) Protection from Moderate Energy Pipe Rupture Effects

The provisions taken to provide protection to the PG&E Design Class I essential systems located outside containment from moderate energy pipe rupture effects (water spray) are discussed in Section 3.6.

(4) Protection from Flooding Effects

The provisions taken to provide protection to the PG&E Design Class I essential systems from flooding that might result from the effects associated with a postulated rupture of high and moderate energy piping are discussed in Section 3.6.

(5) Cooling of PG&E Design Class I Equipment

Although not an ESF function, the FHBVS supplies cooling air to the ESF AFW pump rooms.

The FHBVS provides ventilation at ambient design air temperature, as described in the introduction of Section 9.4, to the FHB operating floor and the equipment described in Section 9.4.4.2(7). The ambient indoor air temperature in the FHB will be maintained below 104°F except the Unit 1 SFP pump room has a design room temperature of 109°F and the Unit 2 SFP pump room has a design room temperature of 112°F.

9.4.4.3.14 Safety Guide 13, March 1971 – Fuel Storage Facility Design Basis

Regulatory Position 4:

The PG&E Design Class I, ESF portion of the FHBVS is designed with appropriate containment, confinement, and filtering systems to limit the potential release of radioactive iodine and other radioactive materials in the event of a FHA in which the cladding of all of the fuel rods in one fuel bundle are breached. Refer to Section 15.5.22 for the radiological consequences of a FHA.

The FHB is separated from the rest of the auxiliary building by partitions and doors on all floors. The separating doors, partitions, and outside walls are of standard construction with no particular leaktight consideration. The exhaust fans remove more air than is supplied. This extra air is made up by infiltration from the outside and adjoining areas of the auxiliary building.

The exhaust air for the FHB is filtered through roughing filters and HEPA filters during normal operation. Iodine Removal Mode operation has, in addition, charcoal filters. The charcoal filter banks have been sized to take the full air flow of the FHBVS without exceeding the manufacturer's recommendations for flow through each individual module of the bank.

The radiation detectors located near the fuel storage areas will automatically initiate this mode when radiation levels exceed the setpoint level in Table 11.4-1 (refer to Sections 9.1.2.3.5 and 11.4.2.1.4.1).

In the event of SFP cooling system failure, exhaust filters of the FHBVS are tested after the period of emergency conditions occurs. The filter efficiency tests are conducted in accordance with the FHBVS testing requirements discussed in Section 9.4.4.4.2. These tests are performed in addition to the periodic testing described in the Plant Surveillance Test Procedure.

9.4.4.3.15 Regulatory Guide 1.52, June 1973 – Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants

The ESF portion of the FHBVS provides the capability to control the volatile radioactive material that could exist to the atmosphere. The system is analyzed to the positions in Regulatory Guide 1.52, June 1973 (Reference 11) as shown in Table 9.4-2 with exceptions noted for specific items. Requirements for the performance of ventilation filter testing are stated in the DCPP VFTP.

9.4.4.3.16 Regulatory Guide 1.52, Revision 2, March 1978 – Design, Testing, and Maintenance Criteria for Post-Accident Engineered Safety Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants

The VFTP provides the requirements for the testing of charcoal samples from the FHBVS charcoal adsorbers in accordance with ASTM D 3803-1989, which complies with Regulatory Guide 1.52, Revision 2, and Generic Letter 83-13, March 1983, for laboratory testing of charcoal samples, and in-place penetration and bypass leakage testing in accordance with ANSI N510-1980. The VFTP complies with the intent of Regulatory Positions C.5.a, C.5.c, C.5.d, and C.6.a requirements as described in Table 9.4-2, with exceptions noted.

9.4.4.3.17 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Damper position indication in the control room provides status of the FHBVS supply and exhaust fan damper positions (refer to Table 7.5-6 for a summary of compliance to Regulatory Guide 1.97, Revision 3).

9.4.4.3.18 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident Monitoring Instrumentation:

Position (1) – Extended range noble gas effluent monitoring is installed in the plant vent and is designed to function during accident conditions (refer to Sections 7.5.2.3 and 11.4.2.1.2.1).

Position (2) – Installed capability is provided in the plant to obtain samples of the particulate and iodine radioactivity concentrations which may be present in the gaseous effluent being discharged to the environment from the plant under accident and post-accident conditions. The TSC laboratory is available for onsite testing of the containment air samples.

9.4.4.4 Tests and Inspections

9.4.4.4.1 Initial System Tests and Inspections

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

The system was installed under field inspection by PG&E General Construction and Quality Assurance personnel. An initial checkout of the motors, dampers, controls, etc., was made at that time. A system air balance test and adjustment to design conditions were conducted. The final tests performed prior to actual operation of the FHBVS were the functional tests of the HEPA and charcoal filter banks. These tests determined the overall efficiency of the filter banks.

9.4.4.4.2 Routine System Tests

Refer to Section 9.4.4.3.8 for information on routine system testing requirements.

9.4.4.5 Instrumentation Applications

Refer to Sections 9.4.4.3.3 and 9.4.4.3.4 for discussions of the instrumentation requirements and controls for the FHBVS.

9.4.5 CONTAINMENT

The containment HVAC system is designed to maintain temperature and pressure within the containment at acceptable levels for equipment operation and personnel access at power for inspection, maintenance, and testing. The ESF function of the containment fan coolers is to reduce the containment atmosphere temperature and pressure following a LOCA or MSLB and is addressed in Section 6.2.2.

The containment HVAC system includes the following:

(1) Containment fan cooler system (CFCS)

(2) Control rod drive mechanism (CRDM) exhaust system

(3) Iodine removal system

(4) Incore instrument room cooling system (abandoned in place)

(5) Containment purge system

(6) Pressure relief line

(7) Vacuum relief line

The CFCS is also designed to operate during accident conditions as a part of the containment heat removal system and is described in Section 6.2.2. Codes and standards applicable to the containment HVAC system are listed in Table 9.4-8.

9.4.5.1 Design Bases

9.4.5.1.1 General Design Criterion 2, 1967 - Performance Standards

The PG&E Design Class I portions of the containment HVAC system are designed to withstand the effects of, or are protected against natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

9.4.5.1.2 General Design Criterion 3, 1971 - Fire Protection

The containment HVAC system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.4.5.1.3 General Design Criterion 11, 1967 - Control Room

The PG&E Design Class I portion of the containment HVAC system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

9.4.5.1.4 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the containment HVAC variables within prescribed operating ranges.

9.4.5.1.5 General Design Criterion 17, 1967 - Monitoring Radioactive Releases

The containment HVAC system is designed to provide means for monitoring the containment atmosphere, the facility effluent discharge paths, and the facility environs for radioactivity that could be released from normal operations, from anticipated transients, and from accident conditions.

9.4.5.1.6 General Design Criterion 40, 1967 - Missile Protection

The ESF portions of the CFCS, containment purge system, and containment pressure/vacuum relief system are designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

9.4.5.1.7 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The PG&E Design Class I containment purge system isolation valves and the containment pressure/vacuum relief systems penetrating primary reactor containment are provided with leak detection, isolation and containment capabilities having redundancy, reliability and performance capabilities which reflect the importance to safety of isolating these piping systems. These systems are designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if the valve leakage is within acceptable limits.

9.4.5.1.8 General Design Criterion 56, 1971 - Primary Containment Isolation

The supply and exhaust lines connect directly to the containment atmosphere and penetrate primary containment. The supply and exhaust lines are provided with one automatic isolation valve inside and one automatic isolation valve outside containment. The purge system isolation valves outside containment are located as close to the containment as practical and upon loss of actuating power, the automatic isolation valves are designed to take the closed position.

9.4.5.1.9 Containment HVAC System Safety Function Requirements

(1) Cooling of PG&E Design Class I Equipment

The containment HVAC system is designed to provide cooling to the containment atmosphere to maintain the temperature environment within design conditions during normal operation.

(2) Protection from Jet Impingement – Inside Containment

The CFCS and CIS portion of the containment purge system and containment pressure/vacuum relief system located inside containment are designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

9.4.5.1.10 10 CFR 50.49 - Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

The containment HVAC components that require EQ are qualified to the requirements of 10 CFR 50.49.

9.4.5.1.11 10 CFR 50.55a(f) - Inservice Testing Requirements

ASME code components of the containment purge system and the containment pressure/vacuum relief system CIVs are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

9.4.5.1.12 10 CFR 50.55a(g) - Inservice Inspection Requirements

ASME code components of the containment purge system and the containment pressure/vacuum relief system piping and valves, and their supports are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

9.4.5.1.13 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The containment HVAC system provides instrumentation to monitor system variables during and following an accident.

9.4.5.1.14 NUREG-0737 (Item II.F.1), November 1980 - Clarification of TMI Action Plan Requirements

Item II.F.1 - Additional Accident Monitoring Instrumentation:

Position (1) – The containment HVAC system is designed with noble gas effluent monitors with an extended range designed to function during accident conditions.

Position (2) – The containment HVAC system is designed with provisions for sampling of plant effluents for post-accident releases of radioactive iodines and particulates and onsite laboratory capabilities.

9.4.5.2 System Description

The containment HVAC system is designed to perform as follows:

(1) Maintain the containment ambient temperature between 50 and 120°F during normal plant operation

(2) Maintain temperatures of 150°F or below in the CRDM shroud area and 135°F or below inside the primary concrete shield during normal plant operation

(3) Maintain a pressure between –1.0 psig and +1.2 psig in the containment during normal operation

(4) Provide the proper atmosphere and adequate ventilation for personnel before and during periods of personnel access for refueling operations and maintenance when the plant is shut down

(5) CFCS works in conjunction with the containment spray system to reduce the containment ambient temperature and pressure during accident conditions (refer to Section 6.2.2)

(6) Accept a single active failure and still provide adequate cooling to the components inside the containment (refer to Section 6.2.2)

The containment HVAC system shares some of these design bases with the CCS, which is described in detail in Section 6.2.3.

The containment HVAC system is designed, built, and installed according to the design classifications given in Table 3.2-3 and the DCPP Q-List (Reference 8 of Section 3.2).

The containment HVAC system is shown schematically in Figures 9.4-3 and 9.4-3A.

The fan coolers and their fan/motor couplings that limit reverse rotation (anti-reverse rotation device) are PG&E Design Class I. The connected system ductwork is PG&E Design Class II and the supports are seismically qualified.

9.4.5.2.1 Containment Fan Cooler System

The design bases for the sizing of the HVAC equipment are the normal operational heat sources in the containment as given in Table 9.4-11.

The CFCS is located inside the containment but outside the missile shield and consists of five coolers, ductwork and supports as shown in Figure 9.4-4. The fan coolers are designed to cool the containment air. The air flow for normal operation is 110,000 cfm per unit for the Westinghouse cooling coils and 98,000 cfm per unit for the Super Radiator Coil (SRC) cooling coils with a total system static pressure of 8 inches w.g. and 12 inches w.g., respectively, at 0.075-lb/ft^3 air density. This system is a total recirculation system. The cooling coils are each sized to remove 3.14 x 10^6 Btu/hr for the Westinghouse cooling coils and 2.501 x 10^6 Btu/hr for the SRC cooling coils from 120°F entering air when supplied with 90°F cooling water. The normal operational design requires that up to four out of the five fan coolers remain in operation. Normally up to four out of five fan coolers operate to recirculate and cool the air within the containment during normal plant operation by drawing the air through their inlet dampers, cooling coils, fans, and ductwork, which allows for the estimated heat removal capacity given in Table 9.4-12. The total heat load for the NSSS is given in Table 9.4-11.

The CFCS is designed to operate during accident conditions as a part of the containment heat removal system and is described in Section 6.2.2. The fan coolers will reduce the motor speed from nominal 1200 to 600 rpm, draw the high density steam through cooling coils, and provide 81 x 10^6 Btu/hr cooling capacity per cooler for the Westinghouse cooling coils and 75.489 x 10^6 Btu/hr for the SRC cooling coils during accident conditions. The safety evaluation is described in Section 6.2.2.

The fan cooler units are powered from the Class 1E 480-V system.

9.4.5.2.1.1 Evaluation of Cooling Water Supply

The normal cooling water requirements for all five fan coolers can be supplied by any two of the three CCW pumps. In addition, one of the two ASW pumps is required to provide ASW cooling water to the CCW heat exchanger.

Water flow through each fan cooler is balanced to the design flow by a manual valve on the discharge header from the cooling units.

Fouling of the waterside of the heat transfer area is minimized with the use of buffered condensate in the component cooling system. If a complete severance of a fan cooler water tube is postulated, double-ended flow must be assumed. This flow can be accommodated by the trough under the fan coolers and is piped to the containment sump.

The fan coolers are supplied by individual lines from the CCW headers. Each unit inlet and discharge line is provided with a manual shutoff valve and drain valve. This permits isolation of each cooler for testing purposes.

The evaluation of cooling water supply following accident conditions is discussed in Section 6.2.2.

9.4.5.2.2 Control Rod Drive Mechanism Exhaust System

The CRDM ventilation system consists of three exhaust fans mounted on the air plenum of the IHA. Two out of three fans operate at 73,500 cfm total, exhaust air from the area surrounding the CRDMs, and discharge to the containment atmosphere to remove heat from the CRDM area during normal plant operation. This system is not designed to operate during accident conditions.

Evaluation of the ventilation provisions for the primary shield, neutron detectors and cables, and CRDMs indicates that the present designs are adequate to ensure plant safety during normal plant operating conditions. Loss of air cooling during normal plant operation would be indicated by temperature instrumentation provided for this purpose. In general, the effects of elevated temperature on the above equipment take place gradually over a period of hours, so that sufficient time would be available to take appropriate corrective action, including an orderly plant shutdown, to avert any possible safety problem. With respect to accident conditions, none of this equipment is required to function during the post-accident recovery period.

9.4.5.2.3 Iodine Removal System

The iodine removal system consists of two one-half capacity iodine removal units that have roughing filters, HEPA filters, and charcoal filter banks. These units are provided for pre-entry cleanup of the containment atmosphere. The iodine removal system is not designed to be operated during accident conditions.

The iodine removal system is used to reduce the concentration of fission product particulate activities in the containment atmosphere prior to routine personnel access at power or in advance of a scheduled reactor shutdown. With sufficient reduction of these activities, particularly iodine and cesium, the personnel dose is due mainly to whole body and inhalation exposures from the unfilterable noble gases. Total capacity is based on the I-131 activity required to limit the occupational airborne concentration of this isotope to approximately seven times 10 CFR 20.1-20.601 maximum permissible concentration. The original design of the iodine removal system was to the pre-1994 regulation maximum permissible concentration value of 9×10^{-9} μCi/cc. The result is consistent with the total exposure limitation of 100 mR received during a 2-hour access period. On this basis, two 12,000 cfm capacity units are provided. This capacity is based on assumptions of 1 percent defective fuel cladding and a 50 pound/day leakage from the RCS. The I-131 activity is reduced to the design equilibrium value by operating the two units for 15 hours.

9.4.5.2.4 Containment Purge System

Prior to entry of personnel into the containment shortly before or after shutdown from normal power operation, the airborne radioactive concentration in the containment atmosphere can be reduced as necessary by employing the iodine cleanup and containment purge systems. After the cleanup process, the containment purge system provides the supply air to and exhaust air from the containment for purge and ventilation.

The section of duct between the containment purge exhaust isolation valve and its debris screen, including the flexible connection, is classified as PG&E Design Class I. The remaining ductwork is PG&E Design Class II and the supports are seismically qualified.

The isolation valves are air-operated valves and are designed to require air pressure to stay open, and fail closed on a loss of air or loss of power to the solenoid valves on their air supply valves. Refer to Section 9.4.5.3.8 for a discussion of GDC 56, 1971, Primary Containment Isolation.

9.4.5.2.5 Pressure Relief Line

The containment pressure relief line connects to the suction side of the containment purge fan, E-3, which then discharges into the plant vent. The pressure relief flow is driven by the pressure differential between the containment and the outside atmosphere, and does not require operation of fan E-3.

9.4.5.2.6 Vacuum Relief Line

The vacuum relief line uses suction air from the containment purge air supply fan plenum to release the vacuum inside the containment. The vacuum relief line takes air from the containment purge system supply fan plenum so that the suction air can be

filtered and heated before it goes into the containment. The function is independent of the purge system operation and manually operated.

9.4.5.2.7 Incore Instrument Room Cooling System

The incore instrument room cooling system is abandoned in place and is no longer in use.

9.4.5.2.8 Performance Objectives

The performance objectives of the containment HVAC system design are as follows:

(1) Normal Operation

(a)	Flowrates (4 of 5 fan coolers operating)	440,000 cfm
(b)	Heat transfer (4 of 5 fan coolers operating)	12.56 x 10^6 Btu/hr
(c)	Temperature range	50 to 120°F max
(d)	Humidity	no requirement
(e)	Flowrate iodine removal units (2 units operating)	24,000 cfm
(f)	Time to achieve equilibrium value I-131 - 1 percent defective cladding - 50 lb/day RCS leakage	15 hours
(g)	Flowrate CRDM ventilation (2 out of 3 fans operating)	73,500 cfm
(h)	Temperature in the cavity area above the CRDM shroud	127°F max
(i)	Heat removal for CRDM	2.26 x 10^6 Btu/hr
(j)	Containment purge flow inlet outlet	 50,000 cfm 55,000 cfm
(k)	Pressure relief flow instantaneous, maximum	4655 cfm
(l)	Incore instrument room fan coil unit (Abandoned in place)	

(2) Emergency Operation

(a)	Flowrates, fan coolers (2 out of 5 units operating)	94,000 cfm
(b)	Pressure in containment	47 psig at saturated steam-air mixture
(c)	Heat transfer - fan cooler units (2 out of 5 operating)	81×10^6 Btu/hr (each cooler)
(d)	Iodine removal units	shut down
(e)	CRDM ventilation	shut down
(f)	Containment purge system	shut down
(g)	Incore instrument room fan coil unit(Abandoned in place)	

9.4.5.2.9 Single Failure Criteria

The containment HVAC system is designed to meet single failure criteria. The fan cooler units are powered from Class 1E buses and have a standby unit. The iodine removal units are not necessary for cleanup during accident conditions, so they are neither redundant nor powered from Class 1E buses. The CRDM exhaust fans are powered from a non-Class 1E bus. The iodine cleanup system is not considered an ESF and is not designed to the requirements of Regulatory Guide 1.52. Because of its very sporadic use, it is unlikely to be operating at the time of a LOCA. If operating, the units will be manually shut off (refer to Section 6.2.2).

9.4.5.3 Safety Evaluation

9.4.5.3.1 General Design Criterion 2, 1967 - Performance Standards

The containment building and the auxiliary building are PG&E Design Class I (refer to Section 3.8). These buildings or portions thereof are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7), and to protect SSCs from damage that may result from these events.

The PG&E Design Class II CFCS ductwork and duct supports are seismically qualified to protect other equipment important to safety during a seismic event.

The containment purge and vacuum/pressure relief line containment penetration piping and isolation valves are PG&E Design Class I. The remainder of the purge system is

PG&E Design Class II. The PG&E Design Class II duct and duct supports of the purge system are seismically qualified where required for systems interaction concerns or to assure that the containment effluent flowpath is monitored by radiation monitors.

The CRDM exhaust system is PG&E Design Class II. Equipment supports are seismically qualified.

9.4.5.3.2 General Design Criterion 3, 1971 - Fire Protection

The containment HVAC system is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.4.5.3.3 General Design Criterion 11, 1967 - Control Room

The CFCS is initiated for normal operation by manual switches in the control room. The HSP also provides for remote control of the CFCS. The design details and logic of the instrumentation are discussed in Chapter 7.

Instrumentation is provided for indication and monitoring of containment air temperature in the control room.

9.4.5.3.4 General Design Criterion 12, 1967 - Instrumentation and Control Systems

The CFCS is initiated for normal operation by manual switches in the control room. The design details and logic of the instrumentation are discussed in Chapter 7.

The iodine removal units and the CRDM fans are operated by manual switches in the control room and the 480-V switchgear room area, respectively. Indication is provided to the operator as to the operation of these fans.

Evaluation of the ventilation provisions for the primary shield, neutron detectors and cables, and CRDMs indicates that the present designs are adequate to ensure plant safety during normal plant operating conditions. Loss of air cooling during normal plant operation would be indicated by temperature instrumentation provided for this purpose. In general, the effects of elevated temperature on the above equipment take place gradually over a period of hours, so that sufficient time would be available to take appropriate corrective action, including an orderly plant shutdown, to avert any possible safety problem.

9.4.5.3.5 General Design Criterion 17, 1967 - Monitoring Radioactive Releases

The purge exhaust fan takes suction from the containment ventilation distribution duct system via a branch duct off the annular ring connecting to the containment purge exhaust isolation valve. The containment purge flow, also used for ventilation during

extended outages, is routed to the plant vent for monitored exhaust. The containment atmosphere is monitored for radioactivity by the containment and plant vent air particulate and/or gas effluent monitors.

The radiological monitoring systems are further described in Section 11.4. The offsite radiological monitoring program is described in Section 11.6.

9.4.5.3.6 General Design Criterion 40, 1967 - Missile Protection

The provisions taken to protect the ESF portion of the CFCS, containment purge system, and containment pressure/vacuum relief system from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures are discussed in Sections 3.5, 3.6, and 6.2.4.

9.4.5.3.7 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The containment HVAC system isolation valves required for containment closure are periodically tested for operability. Testing of the components required for the CIS is discussed in Section 6.2.4.

9.4.5.3.8 General Design Criterion 56, 1971 - Primary Containment Isolation

The containment HVAC system containment penetrations comply with the requirements of GDC 56, 1971, as described in Section 6.2.4 and Table 6.2-39.

9.4.5.3.9 Containment HVAC System Safety Function Requirements

(1) <u>Cooling of PG&E Design Class I Equipment</u>

The CFCS is designed to cool the containment air during normal operation (refer to Section 9.4.5.2.1).

(2) <u>Protection from Jet Impingement – Inside Containment</u>

The provisions taken to provide protection of the CFCS and CIS portion of the containment purge system and containment pressure/vacuum relief system located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

9.4.5.3.10 10 CFR 50.49 - Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

Containment HVAC system SSCs required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the

DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment. The affected equipment are listed on the EQ Master List.

9.4.5.3.11 10 CFR 50.55a(f) - Inservice Testing Requirements

The DCPP IST Program applies to the PG&E Design Class I CIVs. The IST requirements for these components are contained in the IST Program Plan.

9.4.5.3.12 10 CFR 50.55a(g) - Inservice Inspection Requirements

The ISI boundary for the containment HVAC system is defined on the DCPP ISI/IST drawings. The ISI Program Plan identifies applicable inspections for the containment HVAC system.

9.4.5.3.13 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

CIV position, containment temperature, and containment cooler operation indication is provided in the control room for Regulatory Guide 1.97, Revision 3, monitoring (refer to Table 7.5-6).

9.4.5.3.14 NUREG-0737 (Item II.F.1), November 1980 - Clarification of TMI Action Plan Requirements

Item II.F.1 - Additional Accident Monitoring Instrumentation:

Position (1) – The containment purge vents to the plant vent. Instrumentation to monitor noble gas effluents is provided in the plant vent. Refer to Section 9.4.2 for discussion of the plant vent, and Section 11.4 for discussion of the plant vent radiation monitors.

Position (2) – Installed capability is provided to obtain samples of the particulate and iodine radioactivity concentrations which may be present in the gaseous effluent discharged from the containment purge system via the plant vent. The TSC laboratory is available for onsite testing of the containment air samples.

9.4.5.4 Tests and Inspections

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

9.4.5.4.1 Initial System Tests and Inspections

An initial checkout of the motors, dampers, and controls was made at the time of installation. A system air balance test and adjustment to design conditions were conducted.

9.4.5.4.2 Routine System Tests

The containment HVAC system is tested in accordance with the requirements of the Technical Specifications.

9.4.5.5 Instrumentation Applications

Instrumentation requirements are described in Chapter 7 and Sections 9.4.5.3.3 and 9.4.5.3.4.

Instrumentation is also provided in the drain line from each fan cooler unit to indicate abnormally large flow.

9.4.6 AUXILIARY SALTWATER VENTILATION SYSTEM

The ASW ventilation system has the function of maintaining the temperature of the ASW pump motors within acceptable limits during their operation. The ASW ventilation system is the only PG&E Design Class I ventilation system located within the Intake Structure and must be in operation while the ASW pumps are operating. The fans and ductwork of the ASW ventilation system are PG&E Design Class I, while the Intake Structure itself is PG&E Design Class II. The ventilation shaft (or “snorkel”) is discussed in the ASW section (refer to Section 9.2.7.3).

9.4.6.1 Design Bases

9.4.6.1.1 General Design Criterion 2, 1967 – Performance Standards

The ASW ventilation system is designed to withstand the effects of, or is protected against, natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

9.4.6.1.2 General Design Criterion 3, 1971 – Fire Protection

The ASW ventilation system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.4.6.1.3 General Design Criterion 11, 1967 – Control Room

The ASW ventilation system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

9.4.6.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the ASW ventilation system variables within prescribed operating ranges.

9.4.6.1.5 General Design Criterion 21, 1967 – Single Failure Definition

The ASW ventilation system is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event shall be treated as a single failure.

9.4.6.1.6 Auxiliary Saltwater Ventilation System Safety Function Requirements

(1) Cooling of PG&E Design Class I Equipment

The ASW ventilation system is designed to provide heat removal to ASW pumps, ASW MOVs, and ASW piping to maintain the environment within design conditions.

(2) Protection from Missiles

The PG&E Design Class I portion of the ASW ventilation system is designed to be protected against missiles that might result from plant equipment failure and from events and conditions outside the plant to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection from Moderate Energy Pipe Rupture Effects

The PG&E Design Class I portion of the ASW ventilation system is designed to be protected against the effects of moderate energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(4) Protection from Flooding Effects

The PG&E Design Class I portion of the ASW ventilation system is designed to be protected from the effects of internal flooding to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

9.4.6.1.7 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The ASW ventilation system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

9.4.6.1.8 10 CFR 50.63 – Loss of All Alternating Current Power

The ASW ventilation system is required to provide ventilation cooling for the ASW equipment in the ASW pump room needed to bring the unit to Mode 3 following an SBO and maintain ventilation for the 4 hour SBO coping period.

9.4.6.2 System Description

The ASW ventilation system must be in operation when an ASW pump is operating. The requirements for the system temperature design are discussed in Sections 9.4 and 9.4.6.3.6.

Outside air is drawn into an ASW pump room through ducting, passes through the motor area, and is exhausted to the atmosphere through the exhaust fan and related duct system.

The system is designed, built, and installed according to the design classifications given in Table 3.2-3.

As described in Section 9.2.7, each unit is provided with two 100 percent redundant ASW pumps, each of which is installed in a separate watertight compartment to ensure continued operation during combined tsunami and storm wave runup conditions. Proper ventilation of these compartments is ensured by providing each compartment with a separate ventilation system. Each system consists of a PG&E Design Class I coaxial supply and exhaust duct and an exhaust fan. The outside air is drawn into the compartment through the outer space of the coaxial ducts. The air passes through the ASW pump motor area and is exhausted to the atmosphere by the in-line exhaust fan through the inner space of the coaxial exhaust duct as shown in Figure 9.4-5. The intake and exhaust duct discharge points are located above the highest water level resulting from the combined effects of tsunami and storm wave runup (refer to Section 2.4.6.6).

Each exhaust fan starts automatically whenever its associated ASW pump is started. One pump and its associated ventilation system normally operate, with the second set providing system redundancy.

9.4.6.3 Safety Evaluation

9.4.6.3.1 General Design Criterion 2, 1967 – Performance Standards

The ASW ventilation system is located in the Intake Structure (refer to Figure 9.4-5), which is a PG&E Design Class II structure. The Intake Structure is designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Sections 2.4.6.7, 3.4 and 9.2.7.3.1), external missiles (refer to Section 3.3.2.5.2.10), and earthquakes (refer to Sections 3.7 and 3.8.3.2) to protect the PG&E Design Class I ASW ventilation system allowing it to perform its design function.

The ASW ventilation system is seismically designed to perform its safety functions under the effects of earthquakes (refer to Section 3.10.3.33).

9.4.6.3.2 General Design Criterion 3, 1971 – Fire Protection

The ASW ventilation system is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.4.6.3.3 General Design Criterion 11, 1967 – Control Room

The ASW ventilation system is activated whenever the pumps are activated. A start and stop switch is located in the control room for the ASW pumps, which also activates the ASW ventilation. The HSP also provides for remote control of the ASW pumps, and acts as a start and stop switch for the ASW ventilation system.

Indication is provided on the main control board to indicate fan failure while the pump is operating. Annunciators in the control room alert operators to high temperature conditions for the ASW ventilation.

9.4.6.3.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

In each pump room there is a temperature switch provided to monitor temperature within the ASW pump room.

High temperatures exceeding system set points are monitored and alarmed in the control room.

9.4.6.3.5 General Design Criterion 21, 1967 – Single Failure Definition

Redundant components, along with separated Class 1E power sources, give the system the capability of meeting single failure criteria. The redundant ASW pumps are located in separate vaults, are provided with a completely independent ventilation system, and therefore share no common components between trains. Each fan in the system receives power from the same Class 1E bus as its respective ASW pump. Separation has been maintained for the electrical circuits from each Class 1E bus.

9.4.6.3.6 Auxiliary Saltwater Ventilation System Safety Function Requirements

(1) <u>Cooling of PG&E Design Class I Equipment</u>

The system has been designed to maintain the inside air temperature below 104°F with an outdoor ambient design temperature described in Section 9.4. The 1 hp vane axial fans have been sized to provide a minimum air flow of 4000 cfm. The air flow requirements have been based on the ASW pump motor cooling load and the heat transfer through the coaxial duct. No credit is taken for wind cooling the intake structure. The maximum solar load on the ventilating system is negated by the heat losses through the slab floor.

(2) Protection from Missiles

The PG&E Design Class I equipment was reviewed to determine those that could possibly be affected by potential missiles. For postulation missile sources, it was determined that release of a missile would not endanger the ASW ventilation system (refer to Section 3.5.1.2).

(3) Protection from Moderate Energy Pipe Rupture Effects

The PG&E Design Class I ASW ventilation system is designed to be protected against moderate energy pipe rupture effects which may result from equipment failures (refer to Section 3.6.6.3(2)).

Provisions have been taken to protect the ASW ventilation system from the effects of moderate energy pipe failure to the extent necessary to ensure that a safe shutdown condition of the reactor can be accomplished and maintained (refer to Section 3.6). Each ASW pump and its associated ASW ventilation system is housed in a watertight compartment. The ASW ventilation system is a moderate energy system that is physically separate from high energy fluid systems.

(4) Protection from Flooding Effects

The provisions taken to protect ASW ventilation system from the effects of internal flooding to the extent necessary are discussed in Section 3.6.

9.4.6.3.7 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The ASW ventilation system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

9.4.6.3.8 10 CFR 50.63 – Loss of All Alternating Current Power

Following an SBO, 100 percent cooling of the ASW pump room containing the operating ASW pump is provided by the ASW ventilation system exhaust fan powered from the operating EDG (AAC source) in the blacked-out unit for the 4 hour SBO coping period.

Refer to Section 8.3.1.6 for further discussion of station blackout.

9.4.6.4 Inspection and Testing Requirements

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Initial checks of the motors, controls, etc., were made at the time of installation. A verification of air flow and necessary adjustments to design conditions was made.

9.4.6.5 Instrumentation Requirements

Refer to Sections 9.4.6.3.3 and 9.4.6.3.4.

9.4.7 DIESEL GENERATOR COMPARTMENTS VENTILATION SYSTEM

Ventilation of diesel generator compartments is accomplished through the use of the same engine-driven fans that provide cooling air to the diesel generator radiators. The diesel generator cooling air system is described in Section 9.5.5.

The following sections provide information on (a) design bases, (b) system description, (c) safety evaluation, and (d) inspection and testing requirements for diesel generator compartment ventilation systems.

9.4.7.1 Design Bases

9.4.7.1.1 General Design Criterion 2, 1967 - Performance Standards

The EDG compartment ventilation system is designed to withstand the effects of, or is protected against natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

9.4.7.1.2 General Design Criterion 3, 1971 - Fire Protection

The EDG compartment ventilation system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.4.7.1.3 General Design Criterion 11, 1967 - Control Room

The EDG compartment ventilation system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

9.4.7.1.4 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain EDG compartment ventilation system variables within prescribed operating ranges.

9.4.7.1.5 General Design Criterion 21, 1967 - Single Failure Definition

The EDG compartment ventilation system is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event are treated as a single failure.

9.4.7.1.6 Emergency Diesel Generator Compartment Ventilation System Safety Function Requirements

(1) Protection from Missiles

The EDG compartment ventilation system is designed and located to be protected against the effects of missiles which may result from plant equipment failure and from events and conditions outside the plant to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(2) Protection Against High Energy Pipe Rupture Effects

The EDG compartment ventilation system is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The EDG compartment ventilation system is designed to be protected against the effects of moderate energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(4) Protection from Flooding Effects

The EDG compartment ventilation system is designed to be protected from the effects of internal flooding to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

9.4.7.1.7 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The EDG compartment ventilation system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

9.4.7.2 System Description

The ventilation system for each diesel generator compartment has the function of maintaining compartment air temperature within acceptable limits during operation of

the diesel generator. The system satisfies the requirements for system temperature design as described in Section 9.4 and satisfies the following design bases:

(1)	Design compartment temperature at diesel engine	120°F
(2)	Heat removal from generator	6,830 Btu/min
(3)	Heat loss from engine surfaces	12,000 Btu/min

The above design bases are for continuous operation at rated diesel generator load. No special provision for heating diesel generator compartments is required since diesel engine generator jacket water and lubricating oil are kept warm by thermostatically controlled heaters during periods when diesel generators are not operating.

Because no significant potential for airborne radioactivity exists in the vicinity of the diesel generator compartments, no filtration or treatment of ventilating air is required.

The ventilation system for each diesel generator compartment is designed, built, and installed according to the design classifications given in Table 3.2-3.

As described in Section 8.3.1.1.6.3.1, each diesel generator is located in a separate compartment in the turbine building. Diesel engine cooling is provided by a closed-loop jacket water system with a radiator and a direct engine-driven fan. Approximately 70 percent of the required radiator cooling air is outside ambient air drawn by the fan from outside the compartment. The remaining 30 percent (approximately 36,000 cfm) of outside ambient air is drawn through duct work, providing ventilation for the diesel generator compartment. The ventilation air flow passes through the compartment, cooling the generator and absorbing surface heat losses from the diesel engine. Other heat loads in the compartment are negligible. In passing through the compartment, the design temperature of the ventilation air is raised by approximately 30°F when the diesel generators are operating continuously at rated load. The ventilation air then passes through the radiator and is exhausted outside the compartment by the direct engine-driven fan. The ventilation system for the diesel generator compartments is shown in Figure 9.4-6.

No credit is taken for wind cooling of the turbine building containing the diesel generator compartments. The maximum solar load was determined by the method in Reference 8 for the exposed outside west wall of the radiator compartment. It was found to add less than 0.1°F to the temperature of the air drawn through the radiator compartment with the ventilation system in operation. Although the air flow through the diesel generator compartment is less, the effect of the maximum solar load on that compartment will also be negligible since it has no outside walls.

The design value for outdoor ambient air temperature for the HVAC systems is 76°F as described in Section 9.4.

The design condition for the diesel generator compartment ventilation is for the long-term recirculation period when the diesel generators are required for continuous emergency power following a LOCA. It is considered highly unlikely that a LOCA and a loss of offsite power would occur simultaneously with an ambient outside air temperature in excess of the design value. It is considered incredible that the two events would occur simultaneously with the maximum recorded outside air temperature at DCPP (refer to Section 2.3.3.2.2).

However, if the outside air temperature is postulated at a peak above the maximum recorded outside air temperature when the diesel generator units are required for emergency power immediately following a LOCA, the thermal capacity and overload capability of the diesel generator units ensure satisfactory performance during the short period until the outside air temperature drops. The temperatures at only a few locations in the diesel generator compartments would rise above 120°F under these conditions, but the units are capable of operating satisfactorily for at least 4 hours, which is longer than any peak is expected to last. The diesel engine itself is not a concern since engines of this type are operated continuously at similar temperatures in hot weather environments. For example, this particular type of engine is employed in locomotive and shipboard duty where continuous operation at temperatures over 120°F is common; e.g., the Great Pacific Southwest Desert and the eastern Atlantic Ocean off the coast of Africa.

9.4.7.3 Safety Evaluation

9.4.7.3.1 General Design Criterion 2, 1967 - Performance Standards

The EDGs are located in the turbine building, which is a PG&E Design Class II structure (refer to Figures 1.2-16 and 1.2-20). This building or applicable portions have been designed not to impact PG&E Design Class I components and associated safety functions (refer to Section 3.7.2.2.2). The turbine building is designed to withstand the effects of winds and tornadoes (refer to Sections 3.3.1.2 and 3.3.2.5.2.8), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7.2.2.2) to protect the EDGs, ensuring their design function will be performed.

The EDG units and their associated auxiliary systems, as shown for Unit 1 in Figures 9.5-8 through 9.5-10, and similarly for Unit 2, are installed in separate compartments that are protected from fires, flooding, and external missiles.

An engineering review of the turbine building has shown that during a seismic event, the building may deform, but will not collapse. This analysis is discussed in Section 3.7.2. The design classifications for the walls around each engine generator compartment and for the walls isolating the engine generator compartments from other parts of the turbine building are given in Table 3.2-3.

The EDG compartments are isolated from the turbine building with normally closed fire doors. In the event of a high-energy line break in the turbine building, it is not possible that steam could flow from the turbine building into the engine generator compartments.

9.4.7.3.2 General Design Criterion 3, 1971 - Fire Protection

The EDG areas are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.4.7.3.3 General Design Criterion 11, 1967 - Control Room

The DCPP Equipment Control Guidelines identify rooms/areas monitored by the area temperature monitoring system, along with their corresponding temperature limits. The ambient air temperatures in these areas are monitored continuously. Air temperatures exceeding the established setpoints are recorded along with the times. An alarm for high temperature is also transmitted to the control room. The cause and effects of high temperature are investigated and corrected in accordance with the DCPP Equipment Control Guidelines.

Refer to Section 8.3.1.1.6.3.4 for additional discussion related to compliance to GDC 11, 1967.

9.4.7.3.4 General Design Criterion 12, 1967 - Instrumentation and Control Systems

The EDG compartment ventilation system instrumentation and controls are discussed in Sections 8.3.1.1.6.3.5 and 8.3.1.1.6.5.

9.4.7.3.5 General Design Criterion 21, 1967 - Single Failure Definition

Ventilation of a diesel generator compartment is required only when the diesel generator is operating. This is assumed because ventilation for each compartment is provided by the same direct engine-driven fan that provides cooling air to the radiator. There are no active components in the ventilation system other than the diesel generator itself and the direct engine-driven fan. Refer to Section 8.3.1.1.6.3.8 for additional discussion regarding single failure.

9.4.7.3.6 Emergency Diesel Generator Compartment Ventilation System Safety Function Requirements

(1) <u>Protection from Missiles</u>

The EDG units and their associated auxiliary systems, as shown for Unit 1 in Figures 9.5-8 through 9.5-10, and similarly for Unit 2, are installed in separate compartments that are protected from internal missiles.

Because engine generator units are separated from each other by the concrete walls of the compartments, the units are protected from postulated internal missiles. Any missile created by an explosion within a compartment would remain in that compartment.

The provisions taken to protect the EDG compartment ventilation system from missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Sections 3.5 and 8.3.1.4.10.2.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the EDG compartment ventilation system from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Sections 3.6 and 8.3.1.4.10.3.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection of the EDG compartment ventilation system portion located outside containment from the effects of moderate energy pipe failure are discussed in Section 3.6.

(4) Protection from Flooding Effects

The provisions taken to provide protection of the EDG compartment ventilation system from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

Refer to Section 8.3.1.1.6.3.9 for additional information on the possibility of flooding in the turbine building and diesel generator compartments.

9.4.7.3.7 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The EDG compartment ventilation system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

The approximate distance between air supply intakes and the nearest exhaust air outlets for the EDG area is 40 feet.

Refer to Section 8.3.1.1.6.3.12 for additional discussion on compliance to 10 CFR Part 50.48(a) and (c).

9.4.7.4 Tests and Inspections

No separate tests or inspections of the ventilation system are required because tests and inspections associated with the diesel generators will also serve the ventilation system. Initial testing of EDGs has verified the adequacy of the ventilating system.

9.4.7.5 Instrumentation Application

The criterion for monitoring air temperature in an EDG compartment is as follows:

Where only one Class 1E redundant train or division is in a given room or area and the ventilation is Class 1E, but is not redundant within the area, one temperature monitor will be used to monitor the area ambient temperature. The temperature monitor will meet Class 1E requirements for supply and separation or have two reliable and redundant non-Class 1E supplies.

Refer to Section 8.3.1.1.6.5 for additional discussion on EDG compartment ventilation system instrumentation.

9.4.8 4.16-kV SWITCHGEAR ROOM

Passive ventilation of the 4.16-kV switchgear room provides cooling to the Class 1E 4.16-kV switchgear rooms and associated CSRs. The 4.16-kV switchgear room forced ventilation system is also available to provide cooling to the Class 1E 4.16-kV switchgear rooms and associated CSRs.

9.4.8.1 Design Bases

9.4.8.1.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I 4.16-kV switchgear room ventilation system is designed to withstand the effects of, or is protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects. The effects of a tornado on the 4.16-kV switchgear room ventilation system are addressed to ensure that plant safe shutdown can be achieved.

9.4.8.1.2 General Design Criterion 3, 1971 – Fire Protection

The PG&E Design Class I 4.16-kV switchgear room ventilation system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.4.8.1.3 General Design Criterion 11, 1967 – Control Room

The PG&E Design Class I 4.16-kV switchgear room ventilation system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

9.4.8.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the PG&E Design Class I 4.16-kV switchgear room ventilation system variables within prescribed operating ranges.

9.4.8.1.5 General Design Criterion 21, 1967 – Single Failure Definition

The PG&E Design Class I 4.16-kV switchgear room ventilation system is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event shall be treated as a single failure.

9.4.8.1.6 4.16-kV Switchgear Room Ventilation System Safety Function Requirements

(1) Cooling of PG&E Design Class I Equipment

The PG&E Design Class I 4.16-kV switchgear room ventilation system is designed to provide passive or active cooling to the Class 1E 4.16-kV switchgear and associated CSR areas to maintain the temperature within acceptable limits.

(2) Protection from Missiles

The PG&E Design Class I 4.16-kV switchgear room ventilation system is designed to be protected against missiles that might result from plant equipment failure and conditions outside the plant.

(3) Protection Against High Energy Pipe Rupture Effects

The PG&E Design Class I, 4.16-kV switchgear room ventilation system is designed and located to be protected against the dynamic effects of a postulated high-energy pipe failure.

(4) Protection from Moderate Energy Pipe Rupture Effects

The PG&E Design Class I, 4.16-kV switchgear room ventilation system is designed to be protected against the effects of moderate energy pipe failure.

(5) Protection from Flooding Effects

The PG&E Design Class I, 4.16-kV switchgear room ventilation system is designed to be protected from the effects of internal flooding.

9.4.8.2 System Description

Passive ventilation provides adequate cooling of the 4.16-kV switchgear rooms under normal and accident conditions. The 4.16-kV switchgear room forced ventilation system is designed to remain functional and available for additional cooling and operational margin. Other atmospheric conditions, including humidity, atmospheric chemicals,

smoke, radiation, and other contaminants are not considered to have significant effect on the switchgear and are not controlled. However, these abnormal conditions may limit operator access to these areas.

The areas served are the switchgear and associated CSRs for the three trains of Class 1E 4.16-kV switchgear. Each ventilation train consists of a supply fan, supply duct, and a vent stack to the turbine building operating floor, as shown in Figure 9.4-7. The vent stack to the operating floor is normally isolated by a fire damper.

The 4.16-kV forced ventilation system is normally not in service. Heat generated from the 4.16-kV switchgear and cabling is rejected into adjacent areas and the atmosphere through the walls, ceiling, floor, and ductwork. Air is permitted to circulate between the 4.16-kV switchgear and the associated cable spreading room through ducting and floor openings. Air circulation is driven by buoyancy forces which promotes heat distribution and rejection. The operation of the 4.16-kV ventilation system is not required to maintain the temperature in the area served within acceptable limits. The ventilation system may be placed in service to provide additional cooling or for personnel comfort.

When the forced ventilation system is placed in service, outside air enters the ventilation equipment room through louvers on the north/south wall of the turbine building. Each fan draws air through a roughing filter integral with the fan and supplies the air through the supply duct to the associated 4.16-kV cable spreading and switchgear rooms. A fire damper in the rooms exhaust duct can be opened allowing flow to exit to the turbine building operating floor without the use of exhaust fans. The trains operate completely independently and are powered independently, receiving power from the same electrical train as the switchgear that they each serve.

The system is designed, built, and installed according to the design classifications given in Table 3.2-3. Applicable codes and standards are listed in Table 9.4-8.

9.4.8.3 Safety Evaluation

9.4.8.3.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I 4.16-kV switchgear room ventilation system equipment is located within the turbine building, as depicted in Figure 9.4-7. The turbine building is a PG&E Design Class II structure and is designed to withstand the effects of floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7), ensuring the 4.16-kV switchgear room ventilation system design function will be performed. The area of the turbine building that contains the 4.16-kV switchgear room ventilation system fans and motors is not designed to protect the ventilation system from tornado missiles; however, loss of the 4.16-kV switchgear room ventilation system due to tornado missiles will not impair the ability of the plant to achieve safe shutdown (refer to Section 3.3.2.5.1(4)(j)).

The PG&E Design Class I 4.16-kV switchgear room ventilation system is seismically designed to perform safety functions under the effects of earthquakes (refer to Section 3.10.3.33).

9.4.8.3.2 General Design Criterion 3, 1971 – Fire Protection

The PG&E Design Class I 4.16-kV switchgear room ventilation system is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1)

9.4.8.3.3 General Design Criterion 11, 1967 – Control Room

An annunciator alarm is provided at the control room indicating when the temperature within one of the monitored switchgear rooms has exceeded its setpoint.

9.4.8.3.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

A switch is provided on each local motor starter panel for manual starting and stopping of the fans and for selecting automatic operation of the fans.

9.4.8.3.5 General Design Criterion 21, 1967 – Single Failure Definition

Functional and electrical independence and physical separation and protection ensure that no single failure of any active component can affect more than one ventilation train.

Each Class 1E 4.16-kV switchgear room and associated CSR is provided with an independent ventilation train. There are no common components. Each ventilation train receives power from the same electrical train as the switchgear that it serves. This provides separate Class 1E electrical supplies to power redundant equipment.

9.4.8.3.6 4.16-kV Switchgear Room Ventilation System Safety Function Requirements

(1) <u>Cooling of PG&E Design Class I Equipment</u>

The 4.16-kV switchgear room ventilation system is designed to be available for operation at all times to provide adequate ventilation for the 4.16-kV switchgear and cabling. Each ventilation train is able to provide adequate air flow to maintain the temperature of its associated switchgear and 4.16-kV CSRs within acceptable limits. Under design basis conditions, passive ventilation of the 4.16-kV switchgear and associated CSR is able to maintain the temperature within acceptable limits. The requirements for the system temperature design are as described in Section 9.4.

The design basis of the system is to minimize temperature excursions above the temperature assumed in the EQ aging analysis (refer to Section 3.11). The heat load of

the switchgear is such that no forced ventilation is required. Wind cooling and solar effects are negligible.

(2) Protection from Missiles

The provisions taken to protect the PG&E Design Class I, 4.16-kV switchgear room ventilation system from missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Sections 3.5.

Adequate physical separation between the trains has been provided. The system design is such that no unacceptable component failures can occur and adequate physical protection is provided against physical hazards in the areas through which the system is routed.

Main turbine failure is not considered a credible event and failure of the main feedwater pump turbines would not result in missiles that could prevent fulfilment of 4.16-kV switchgear room ventilation system functions.

Refer to Section 9.4.8.3.1 for a discussion on tornado missiles.

(3) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect essential systems and components from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Sections 3.6.

(4) Protection from Moderate Energy Pipe Rupture Effects

The provisions taken to protect essential systems and components from the effects of moderate energy pipe failure are discussed in Section 3.6.

(5) Protection from Flooding Effects

The provisions taken to protect essential systems and components from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

9.4.8.4 Tests and Inspections

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Initial checks of the motors, controls, system balance, etc. were made at the time of installation. This included a verification of the adequacy of the calculated flowrates.

The system will be periodically inspected to ensure that all equipment is functioning properly.

9.4.8.5 Instrumentation Applications

Refer to Sections 9.4.8.3.3 and 9.4.8.3.4 for a discussion on the application of instrumentation and controls used for the 4.16-kV switchgear room ventilation system.

9.4.9 125-VDC AND 480-V SWITCHGEAR AREA

The 125-Vdc and 480-V switchgear area ventilation system serves the following electrical areas:

(1) 125-Vdc switchgear, inverters and battery chargers

(2) 480-V switchgear

(3) HSP

(4) Process control system and plant protection system rack area in the CSR. To provide partial backup cooling whenever the PG&E Design Class II cable spreading room air conditioning (CSR/AC) system is not functional

9.4.9.1 Design Bases

9.4.9.1.1 General Design Criterion 2, 1967 - Performance Standards

The PG&E Design Class I portion of the 125-Vdc and 480-V switchgear area ventilation system is designed to withstand the effects of, or is protected against natural phenomena such as earthquakes, tornadoes, flooding, winds tsunamis and other local site effects.

9.4.9.1.2 General Design Criterion 3, 1971 - Fire Protection

The 125-Vdc and 480-V switchgear area ventilation system and CSR/AC systems are designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.4.9.1.3 General Design Criterion 11, 1967 – Control Room

The PG&E Design Class I portion of the 125-Vdc and 480-V switchgear area ventilation system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

9.4.9.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls related to the PG&E Design Class I portion of the 125-Vdc and 480-V switchgear area ventilation system are provided as required to monitor and maintain applicable variables within prescribed operating ranges.

9.4.9.1.5 General Design Criterion 21, 1967 - Single Failure Definition

The PG&E Design Class I portion of the 125-Vdc and 480-V switchgear area ventilation system is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event are treated as a single failure.

9.4.9.1.6 125-Vdc and 480-V Switchgear Area Ventilation System Safety Function Requirements

(1) Cooling of PG&E Design Class I Equipment

The PG&E Design Class I portion of the 125-Vdc and 480-V switchgear area ventilation system is designed to provide cooling to the 480-V switchgear, the 125-Vdc switchgear and inverters, the battery chargers and the HSP areas to maintain the environment within design conditions.

(2) Protection from Missiles

The PG&E Design Class I portion of the 125-Vdc and 480-V switchgear area ventilation system is designed to be protected against missiles that might result from plant equipment failure and conditions outside the plant to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection Against High Energy Pipe Rupture Effects

The PG&E Design Class I portion of the 125-Vdc and 480-V switchgear area ventilation system is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(4) Protection from Moderate Energy Pipe Rupture Effects

The PG&E Design Class I portion of the 125-Vdc and 480-V switchgear area ventilation system is designed to be protected against the effects of moderate energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(5) Protection from Flooding Effects

The PG&E Design Class I portion of the 125-Vdc and 480-V switchgear area ventilation system is designed to be protected from the effects of internal flooding to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

9.4.9.1.7 10 CFR 50.63 - Loss of All Alternating Current Power

The 125-Vdc and 480-V switchgear area ventilation system is required to provide ventilation cooling for the 480-V switchgear, 125-Vdc switchgear, inverters, and battery chargers to bring the unit to Mode 3 following an SBO, and maintain ventilation for the 4 hour SBO coping period.

9.4.9.1.8 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The Design Class I portion of the 125-Vdc and 480-V switchgear area ventilation system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

9.4.9.2 System Description

The 125-Vdc and 480-V switchgear area ventilation system provides adequate ventilation for the switchgear. This also provides for the safety and comfort of operating personnel during normal conditions. Other atmospheric conditions, including humidity, atmospheric chemicals, smoke, radiation, and other contaminants are not considered to have significant effects on the switchgear and are not controlled. However, these abnormal conditions may limit operator access to these areas.

The areas served by the PG&E Design Class I 125-Vdc and 480-V switchgear ventilation system are the compartments housing the three redundant trains of 480-V switchgear and dc switchgear, the four redundant trains of inverters, battery chargers, and HSP areas. The system consists of two sets of redundant 100 percent capacity supply and exhaust fans, a common supply and exhaust duct, dampers, air outlets and inlets, and fire dampers as shown in Figure 9.4-8.

The ventilation system is a once-through type with 100 percent outside air supply. In Unit 1 outside air is drawn by one of the two redundant supply fans, discharging through a common supply ductwork and roughing filter and introduced to each area by supply registers. The Unit 2 configuration is the same except that the filter is located at the inlet side of the fans.

Exhaust air from each area is drawn by one of the two redundant exhaust fans and discharged to the atmosphere. The 125-Vdc and 480-V switchgear area ventilation

system supply and exhaust fans are powered from the 480-V Class 1E buses (refer to Figures 8.3-6 and 8.3-8).

The system intake louver is located in the intake plenum and the exhaust air is discharged away from the supply air intake.

The system also provides partial backup ventilation for the CSR, which is normally served by PG&E Design Class II ventilation air conditioning systems as shown in Figure 9.4-8. Normally, the CSR is cooled by a PG&E Design Class II air conditioning system (CSR/AC). The backup service in the CSR requires manual alignment of dampers in the interconnecting ductwork.

The PG&E Design Class II CSR/AC system consists of an ACU with chilled water coil that recirculates air from the CSR. One of two, redundant, 100 percent capacity, PG&E Design Class II air-cooled water chillers servicing Unit 1 and Unit 2 provides chilled water to the ACUs, one ACU per CSR, and to a condensing coil (one per unit) The CSR/AC system is interconnected with the 125-Vdc and 480-V switchgear area ventilation (PG&E Design Class I) system to provide partial back up cooling whenever the CSR/AC system is not functional.

The CSR temperature is controlled, when the CSR/AC system is in operation, by modulating the amount of chilled water flowing through the cooling coil in the ACU in response to a room thermostat. The CSR humidity is stabilized by use of a condensing cooling coil in the supply air duct bringing outside air into the room.

The chillers, circulating chilled water pumps, and ACUs are manually started through local control stations.

The system is designed, built, and installed according to the design classifications given in Table 3.2-3. Applicable codes and standards are listed in Table 9.4-8.

9.4.9.3 Safety Evaluation

9.4.9.3.1 General Design Criterion 2, 1967 - Performance Standards

The PG&E Design Class I 125-Vdc and 480-V switchgear area ventilation system equipment is located on or within the auxiliary building, a PG&E Design Class I structure (refer to Figure 1.2-6). Both redundant supply and exhaust fans are located on the roof of the auxiliary building. The supply duct is routed from the supply fans at the roof of the auxiliary building, penetrating the turbine building (a PG&E Design Class II structure) siding, then down along the wall outside the auxiliary building where it then enters the auxiliary building in the dc switchgear area. The exhaust duct is routed alongside the supply duct up to their respective penetrations in the wall of the auxiliary building and the turbine building siding.

The auxiliary building is designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), and earthquakes (refer to Sections 3.7 and 3.8.2.3) to protect the 125-Vdc and 480-V switchgear area ventilation system, ensuring its design function will be performed.

The turbine building, which contains portions of the125-Vdc and 480-V switchgear area ventilation system duct work and support is designed to withstand the effects of floods and tsunamis (refer to Section 3.4), the effects of winds (refer to Section 3.3), and the effects of earthquakes (refer to Sections 3.7 and 3.8.2.3) to protect the 125-Vdc and 480-V switchgear area ventilation system, ensuring its design function will be performed.

Loss of the125-Vdc and 480-V switchgear area ventilation system following a tornado does not compromise the capability to safely shutdown the plant (refer to Section 3.3.2.5.1(4)(h)).

The 125-Vdc and 480-V switchgear area ventilation system is seismically designed to perform its safety functions under the effects of earthquakes (refer to Section 3.10.3.33).

The interconnection between the PG&E Design Class II CSR/AC system and the 125-Vdc and 480-V switchgear area ventilation system (PG&E Design Class I) is made through normally closed manually operated dampers which are part of the PG&E Design Class I system. To avoid transfer of seismic loads between the systems, the intertie is made via a flexible connection.

9.4.9.3.2 General Design Criterion 3, 1971 - Fire Protection

The 125-Vdc and 480-V switchgear area ventilation system and CSR/AC systems are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1). Ventilation of the dc battery rooms also prevents the accumulation of hydrogen (refer to Section 8.3.2.3.2).

9.4.9.3.3 General Design Criterion 11, 1967 – Control Room

Annunciation is provided in the control room to alarm temperatures in both the 125-Vdc and 480-V switchgear areas and the CSR area.

In the event the control room is lost due to fire or other causes, the switchgear area ventilation system provides ventilation for the HSP.

9.4.9.3.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation is provided to monitor the 125-Vdc and 480-V switchgear ventilation system components.

A switch in a local control station is used to select either automatic operation or to start each fan manually. Automatic operation is for "operational convenience" and is not a design function credited in any safety analysis.

When the switch is in the automatic mode, the exhaust fan starts after its corresponding supply fan is started. The redundant set of supply and exhaust fans automatically starts if the normally operating set fails.

9.4.9.3.5 General Design Criterion 21, 1967 - Single Failure Definition

The redundant trains of supply and exhaust fans of the 125-Vdc and 480-V switchgear ventilation system are physically separated and powered from separate Class 1E electrical power supplies to ensure that any single failure of an active component will not prevent the ventilation system from supplying the required air flow.

The system design is such that no unacceptable passive component failures can occur and such that physical protection is adequately provided against physical hazards in the areas through which the system is routed.

9.4.9.3.6 125-Vdc and 480-V Switchgear Area Ventilation System Safety Function Requirements

(1) Cooling of PG&E Design Class I Equipment

The requirements for the system temperature design are described in Section 9.4. In addition, the system design indoor temperature is 104°F for the 125-Vdc switchgear and battery chargers, the 480-V switchgear, and the HSP. The ventilation system with only one set of supply and exhaust fans operating was designed to provide adequate air flow in all the areas served by the system to maintain ambient temperature below 104°F with outside ambient temperature as described in Section 9.4, except for the CSR which is also served by a PG&E Design Class II system. The system is designed to provide a relatively constant temperature and humidity within the room to enhance the service life of electronic devices installed in the room.

Indoor design temperature for the process control system and plant protection system rack area in the CSR is 72 ±5°F during normal operation of PG&E Design Class II air conditioning system and 108°F when the backup PG&E Design Class I 480-V switchgear area ventilation system serves that area.

The heat load of all electrical equipment inside the areas served by the system requires no tempering of the air supply. Wind cooling and solar effects are negligible.

(2) Protection from Missiles

The provisions taken to protect the PG&E Design Class I, 125-Vdc and 480-V switchgear area ventilation system from missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Sections 3.5.

The system design is such that physical protection is adequately provided against physical hazards in the areas through which the system is routed.

The PG&E Design Class I equipment was reviewed to determine those that could possibly be affected by potential missiles. For postulated missile sources, it was determined that release of a missile would not endanger the 125-Vdc and 480-V switchgear ventilation system (refer to Section 3.5.1.2).

(3) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the PG&E Design Class I, 125-Vdc and 480-V switchgear area ventilation system from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Sections 3.6.

Protection against the effects resulting from the rupture of HELB piping is provided for the 125-Vdc and 480-V switchgear ventilation system and such that physical protection is adequately provided against physical hazards in the areas through which the system is routed.

(4) Protection from Moderate Energy Pipe Rupture Effects

The provisions taken to provide protection of the PG&E Design Class I, 125-Vdc and 480-V switchgear room ventilation system from the effects of moderate energy pipe failure are discussed in Section 3.6.

(5) Protection from Flooding Effects

The provisions taken to provide protection of the PG&E Design Class I, 125-Vdc and 480-V switchgear room ventilation system from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

Sufficient design provisions are provided (e.g., door curbs, hatch curbs) to limit any flooding to the Elevation 115-foot area due to a chilled water line break of the CSR ACU. Cable penetrations are sealed to prevent carryover of water to other areas. The chilled water system does not have automatic makeup. Therefore, the total water volume of the chilled water system, less than 390 gallons, would cause the water to rise to a level of no more than 0.8 inches within the curbed area. The minimum height of the curbs is 2 inches.

9.4.9.3.7 10 CFR 50.63 - Loss of All Alternating Current Power

Following an SBO, 100 percent cooling for the 480-V switchgear, 125-Vdc switchgear, inverters, and battery chargers is provided by the 125-Vdc and 480-V switchgear area ventilation system powered from the operating EDG (AAC source) in the blacked-out unit for the 4 hour SBO coping period.

Refer to Section 8.3.1.6 for further discussion of station blackout.

9.4.9.3.8 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The 125-Vdc and 480-V switchgear area ventilation system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

9.4.9.4 Test and Inspections

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Initial checks of the motors, controls, system balance, etc., were made at the time of installation. This included a verification of the adequacy of the calculated flow rates. The system is periodically inspected to ensure that all normally operating equipment is functioning properly. Redundant components are periodically tested to ensure system availability.

9.4.9.5 Instrumentation Applications

Instrumentation used to control and operate the ventilation system is discussed in Sections 9.4.9.3.3 and 9.4.9.3.4.

9.4.10 POST-ACCIDENT SAMPLE ROOM

The post-accident sample room complex is located in the auxiliary building; however, it is provided with its own HVAC system. The system may also be referred to as the post-LOCA sample room HVAC system in other plant documentation.

9.4.10.1 Design Bases

9.4.10.1.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class II post-accident sample room HVAC system is designed to withstand the effects of earthquakes.

9.4.10.1.2 General Design Criterion 3, 1971 – Fire Protection

The PG&E Design Class II post-accident sample room HVAC system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.4.10.1.3 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The PG&E Design Class II post-accident sample room HVAC system has been designed based on 10 CFR Part 20 requirements for maintaining control over the plant's radioactive gaseous effluents. Appropriate holdup capacity is provided for retention of gaseous effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment.

9.4.10.1.4 NUREG-0737 (Items II.B.3.9.b and II.B.3.11.b), November 1980 – Clarification of TMI Action Plan Requirements

Item II.B.3.9.b – Post-Accident Sampling Capability: The PG&E Design Class II post-accident sample room HVAC system is designed to restrict background levels of radiation in the radiological and chemical analysis facility from sources such that the sample analysis will provide results with an acceptably small error (approximately a factor of 2). This is supported through the use of the system design, which will control the presence of airborne radioactivity.

Item II.B.3.11.b – Post-Accident Sampling Capability: The exhaust air from the panels and hoods is filtered with charcoal adsorbers and HEPA filters.

9.4.10.2 System Description

The post-accident sample room HVAC system is an independent system as shown in Figure 9.4-10.

The post-accident sample room HVAC system is designed to provide ventilation, heating, and cooling to the sample room for plant personnel comfort during normal plant operation.

During normal plant operation, a ventilation fan will deliver 300 cfm of outside air to the sample room complex.

Following an accident, the system provides protection for plant personnel from radiological contaminants.

The post-accident sample room HVAC system is a PG&E Design Class II system. The design classification of the post-accident sample room HVAC system is given in Table 3.2-3.

Redundant supply and exhaust fans and filters, the seismic design of the system, and the shielding provided for in the sample room complex will provide the required personnel protection and equipment ventilation following an accident.

The air conditioning portion of the HVAC system will maintain the sample room at a temperature ranging between 65 and 90°F during normal plant operation.

The fans are manually initiated from the PASS ventilation control panel.

9.4.10.3 Safety Evaluation

9.4.10.3.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class II post-accident sample room HVAC system equipment is located within the auxiliary building, a PG&E Design Class I structure (refer to Figure 1.2-6 and Section 3.7.2.2.1).

The design class requirements for the system, except the air conditioner, are supplemented with more stringent seismic criteria than those required for a PG&E Design Class II system; the system has been evaluated for the HE. The calculated stresses are within the allowables for PG&E Design Class I systems.

The air conditioner is so supported that it will remain in place after a HE.

9.4.10.3.2 General Design Criterion 3, 1971 – Fire Protection

The PG&E Design Class II post-accident sample room HVAC system is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.4.10.3.3 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The PG&E Design Class II post-accident sample room HVAC system has been designed with appropriate holdup capacity for the retention of radioactive gaseous effluents. Exhaust air is charcoal- and HEPA-filtered before being discharged to the atmosphere.

9.4.10.3.4 NUREG-0737 (Items II.B.3.9.b and II.B.3.11.b), November 1980 – Clarification of TMI Action Plan Requirements

Item II.B.3.9.b – Post-Accident Sampling Capability: Following an accident, one of two 100 percent capacity redundant pressurization fans will deliver 1000 cfm of charcoal-

filtered outside air to the complex and maintain it at a positive pressure with respect to surrounding plant areas.

The sample panel and the sample station hood located in the complex are maintained at a negative pressure when an exhaust fan is in operation. One of the two 100 percent capacity, redundant, manually initiated, ventilation exhaust fans will discharge 700 cfm exhaust air to atmosphere.

The post-accident sample room HVAC system supports DCPP sampling contingency plan requirements (Reference 23), and continues to meet the above original design basis requirements.

Item II.B.3.11.b – Post-Accident Sampling Capability: The exhaust air from the panels and hoods is manifolded together, charcoal-filtered, HEPA-filtered, and discharged by the exhaust fan to the atmosphere.

The post-accident sample room HVAC system supports DCPP sampling contingency plan requirements (Reference 23), and continues to meet the above original design basis requirements.

9.4.10.4 Tests and Inspections

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

The initial checks of the motors, controls, system balance, etc. were made at the time of installation. The verification of the calculated flowrates was also accomplished at this time.

The system is periodically inspected and tested to ensure that all equipment is functioning properly.

9.4.10.5 Instrumentation Applications

Instrumentation provides local indication of the system's operating parameters; i.e., filter differential pressure (indicating usage and cleanliness), and subsystem temperatures and pressures. An interlock is also provided to prevent climate control unit heater operation under a low supply air flow condition.

In addition, an area radiation monitor with local annunciation is installed in the post-accident sample room to warn personnel of high or increasing radiation. High radiation will alarm at the main annunciator (refer to Section 11.4).

9.4.11 TECHNICAL SUPPORT CENTER

The basic function of the TSC HVAC system is to provide protection for personnel working in the TSC from radiological contaminants and to provide HVAC for working areas and equipment.

9.4.11.1 Design Bases

9.4.11.1.1 General Design Criterion 4, 1967 - Sharing of Systems

The TSC HVAC system or components are not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

9.4.11.1.2 10 CFR 50.47 - Emergency Plans

The TSC HVAC system is adequate to support the use of the TSC for emergency response.

9.4.11.1.3 NUREG-0737 (Items II.B.2 and III.A.1.2), November 1980 - Clarification of TMI Action Plan Requirements

II.B.2 – Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems Which May be Used in Post-Accident Operations: Adequate access to the TSC is provided by design changes, increased permanent or temporary shielding, or post-accident procedural controls.

III.A.1.2 – Upgrade Emergency Support Facilities: NUREG-0737, Supplement 1, January 1983 provides the requirements for III.A.1.2 as follows:

> Section 8.2.1.e - The TSC is environmentally controlled to provide room air temperature, humidity, and cleanliness appropriate for personnel and equipment.
>
> Section 8.2.1.f - The TSC is provided with radiological protection and monitoring equipment necessary to assure that radiation exposure to any person working in the TSC would not exceed 5 rem TEDE for the duration of the accident.

9.4.11.2 System Description

The TSC is provided with its own PG&E Design Class II HVAC system that is schematically shown in Figure 9.4-10. The entire system is manually initiated and is designed to maintain the occupied areas of the TSC at a temperature below 85ºF. During normal operation, all the makeup air and recirculated air passes through a pre-filter, a HEPA filter, and the ACU. Makeup air in the normal operation mode is supplied via the outside air intake by a single makeup air fan. The TSC HVAC system has the capability to manually isolate the area from outside air and to recirculate air via the air conditioning system.

In the radiological accident mode of operation, the TSC HVAC system makeup air is supplied by the CRPS in order to maintain the TSC area at a minimum of +1/8 inch water gauge pressure. Penetrations into the TSC are equipped with penetration seals and floor drain traps with make-up water supplies to prevent exfiltration of the positive

pressure from within the TSC through these paths. The pressurization air, and a portion of the recirculated air, is passed through a filter bank containing a HEPA and charcoal filters for cleanup purposes and supplied to the general area rooms along with the majority of the recirculated air. Exhaust air leaves the TSC by exfiltration.

The TSC HVAC system is fed from a non-Class 1E power source, although it has the capability to be supplied power from a Class 1E bus. The ducting, duct supports, and equipment supports have been evaluated to Seismic Category I criteria. The ducting and components associated with the TSC pressurization air supply are PG&E Design Class I up to and including the manual damper upstream of the redundant duct heaters associated with the TSC filter bank (Reference 8 of Section 3.2).

The duct heaters maintain the relative humidity of the pressurization air below 70 percent.

9.4.11.3 Safety Evaluation

9.4.11.3.1 General Design Criterion 4, 1967 - Sharing of Systems

The TSC HVAC system is common to Unit 1 and Unit 2 and therefore requires sharing of SSCs between units. The TSC HVAC system serves no safety functions. The TSC HVAC system is designed to provide adequate HVAC for working areas and equipment within the TSC. In addition, the CRPS is shared between the control room and the TSC. Sharing of the CRPS by the control room and the TSC is addressed in Section 9.4.1.3.3.

9.4.11.3.2 10 CFR 50.47 - Emergency Plans

The TSC HVAC system meets applicable requirements and is maintained in support of emergency response (refer to Sections 9.4.11.1.3 and 9.4.11.3.3).

9.4.11.3.3 NUREG-0737 (Items II.B.2 and III.A.1.2), November 1980- Clarification of TMI Action Plan Requirements

Item II.B.2 - Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems Which May be Used in Post-Accident Operations: The acceptance criteria for the TSC dose is based on 10 CFR 50.67, in which dose to an operator in the TSC shall not exceed 5 rem TEDE for the duration of the accident. The adequacy of TSC shielding is evaluated for post-LOCA conditions in Sections 12.1.2.7 and 15.5.

Item III.A.1.2 - Upgrade Emergency Support Facilities: NUREG-0737, Supplement 1, January 1983 provides the requirements for III.A.1.2 as follows: Section 8.2.1.e - During normal operation, all the TSC HVAC makeup air and recirculated air passes through the climate control units. The climate control units are designed to maintain the occupied areas of the TSC below 85°F, and provide for humidity and cleanliness appropriate for personnel and equipment.

The TSC HVAC system is a PG&E Design Class II system. The pressurization air for the system is supplied by the designated PG&E Design Class I CRPS. The radiological accident mode of operation maintains the TSC area at a positive pressure. The relative humidity of the pressurization air is maintained below 70 percent. The air cleanup portion of the system is equipped with redundant fans and heaters and a power supply that may be manually switched over to a Class 1E bus source. Post-accident dose in the TSC is discussed in Section 15.5.

Section 8.2.1.f - TSC area radiation monitoring instruments provide continuous indication of the general area ambient radiation levels and provide local alarm annunciation in various areas and work spaces. TSC ventilation air monitoring instruments provide continuous sampling of the TSC HVAC return air ducts for detection of airborne radiation and provide for alarm annunciation in the TSC computation center.

The acceptance criteria for the TSC dose is based on Section 8.2.1 (f) of NUREG-0737, Supplement 1, Regulatory Guide 1.183, July 2000, Section 1.2.1, and 10 CFR 50.67. The dose to an operator in the TSC should not exceed 5 rem TEDE for the duration of the accident. TSC shielding and the ventilation system prevent post-accident doses inside the TSC from exceeding 5 rem TEDE for the duration of the accident. Refer to Section 9.4.11.2 for a description of the TSC ventilation system. The adequacy of TSC shielding and ventilation is evaluated for post-LOCA conditions in Section 15.5.

9.4.11.4 Inspection and Testing Requirements

Initial checks of the motors, controls, system balance, etc. were made at the time of installation. The system is periodically inspected to ensure that all equipment is functioning properly.

9.4.11.5 Instrumentation Requirements

TSC area radiation monitoring instruments provide continuous indication of the general area ambient radiation levels and provide local alarm annunciation in various areas and work spaces.

TSC ventilation air monitoring instruments provide continuous sampling of the TSC HVAC return air ducts for detection of airborne radioactivity and provide for alarm annunciation in the TSC computation center.

Instrumentation related to post-accident operation includes indication and alarm on low pressurization flow and an alarm for high temperature in the charcoal filter section of the charcoal/HEPA filter bank.

9.4.12 CONTAINMENT PENETRATION AREA GE/GW

The containment penetration area GE/GW ventilation system has the function of maintaining the ambient temperature and pressure of the GE/GW area within acceptable limits during normal operations. The GE/GW area ventilation system is a PG&E Design Class II draw-through type ventilation system. The system consists of both PG&E Design Class I and II components.

The following GE/GW area ventilation system components described in this section are PG&E Design Class:

(1) System isolation dampers, duct, and duct supports from the upstream, isolation damper to the plant vent connection.

(2) Isolation damper actuator, solenoid and control switches. Instrumentation and control components are classified as PG&E Instrument Design Class ID (refer to Section 3.2.2.5).

9.4.12.1 Design Bases

9.4.12.1.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portion of the containment penetration GE/GW area ventilation system is designed to withstand the effects of, or is protected against natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects. In addition, the PG&E Design Class II portion of the containment penetration GE/GW area ventilation system is designed to seismic loads to ensure compliance with the Seismically Induced Systems Interaction Program (refer to Section 3.7.3.13).

9.4.12.1.2 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

Radiation monitoring instrumentation is provided to monitor radioactive releases in the GE/GW ventilation exhaust via the plant vent.

9.4.12.2 System Description

The GE/GW area ventilation system was designed to:

(1) Provide means of monitoring GE/GW exhaust for airborne radioactivity during normal plant operation by exhausting into the plant vent

(2) Maintain the ambient temperature at maximum average temperature of 104°F during normal plant operation to support environmental requirements of PG&E Design Class I equipment (refer to Section 3.11)

(3) Maintain the GE/GW area at a slight negative pressure with respect to outdoors

(4) Maintain steam relief flow path during HELB accident

(5) Maintain pressure boundary integrity of the plant vent at the interface between the two systems.

The design classification of the containment penetration area GE/GW ventilation system is given in Table 3.2-3. Applicable codes and standards are listed in Table 9.4-8.

One of the two full capacity exhaust fans runs to exhaust air from the GE/GW areas. This running fan maintains the GE/GW areas at a slight negative pressure relative to the outdoors.

The ventilation flow consists of 100 percent outside air drawn through the intake louvers located on the wall of GW area. Four (4) recirculation fans move the entering air to the areas farthest from the intake louver.

The system is shown in Figure 9.4-11.

The ventilation function performed by the containment penetration area GE/GW ventilation system is not a safety-related function, and its complete failure has no safety implication. Two redundant 100 percent capacity fans are provided so that failure of one fan will not result in loss of ventilation for these areas during the normal plant operation.

The containment penetration area GE/GW ventilation system exhausts into the plant vent. Isolation of the Design Class I plant vent from the Design Class II portion of the GE/GW ventilation system is performed by redundant Design Class I isolation dampers. Instrument Class ID instrumentation and controls are seismically designed to ensure damper operation (refer to Section 3.10.2). The plant vent pressure boundary is further maintained by the Design Class I duct and supports that perform the tie-in between the plant vent and the GE/GW ventilation system.

9.4.12.3 Safety Evaluation

9.4.12.3.1 General Design Criterion 2, 1967 – Performance Standards

The containment penetration area GE/GW ventilation system is designed to perform its safety function under the effects of earthquakes (refer to Section 3.10.3.33), winds and tornadoes (refer to Section 3.3), and external missiles (refer to Section 3.5). The

GE/GW ventilation system may be vulnerable to tornado effects but does not need to be operational while the plant is brought to a safe operational status.

9.4.12.3.2 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The ventilation air flows to the enclosed annular gap on Elevation 140 foot, into the duct connected to the exhaust fan and discharged into the plant vent, where it is monitored for radioactivity.

For a description of the radiological monitoring system refer to Section 11.4.2.1.2.

9.4.12.4 Tests and Inspections

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Initial checks of the fan housings, bearings, motors, bolts, controls, etc., are made at the time of installation. A system air balance test and adjustment to design conditions are conducted.

The system will be periodically inspected to ensure that all equipment is functioning properly.

9.4.12.5 Instrumentation Applications

Each exhaust fan is manually turned on and off by a switch on the local control panel mounted near the exhaust fans. Switchover to standby unit is done manually. The recirculation fans are initiated by thermostat located in the area where recirculation fan is located. The isolation dampers are operated by their associated pressure differential switches. The shut-off dampers are interlocked to their corresponding exhaust fans "on-off" switches.

9.4.13 REFERENCES

1. Deleted in Revision 8.

2. Deleted in Revision 8.

3. Deleted in Revision 10.

4. Deleted in Revision 10.

5. Recommended Outdoor Design Temperatures, Southern California, Arizona, and Nevada, Third Edition, Southern California Chapter, American Society of Heating, Refrigeration and Air-Conditioning Engineers, Inc., March 1964.

6. Deleted in Revision 22.

7. Deleted in Revision 10.

8. Deleted in Revision 22.

9. R. R. Bellamy, Elemental Iodine and Methyl Iodine Adsorption on Activated Charcoal at Low Concentrations, 13th Air Cleaning Conference, 1974.

10. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

11. Regulatory Guide 1.52, Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Absorption Units of Light-Water-Cooled Nuclear Power Plants, USAEC, Revision 0, June 1973.

12. G. W. Kielholts, Filters, Sorbents, and Air Cleaning Systems as Engineered Safeguards in Nuclear Installations, ORNL-NSIC-13, October 1966.

13. NUREG-0570, "Toxic Vapor Concentrations in the Control Room Following a Postulated Accidental Release," James Wing, USNRC-ONRR, June 1979.

14. Deleted in Revision 10.

15. Deleted in Revision 10.

16. Deleted in Revision 24.

17. Deleted in Revision 8.

18. Deleted in Revision 10.

19. Deleted in Revision 10.

20. Deleted in Revision 10.

21. Branch Technical Position 7-14, Guidance on Software Reviews for Digital Computer-Based Instrumentation and Control Systems, Revision 5, March 2007.

22. Branch Technical Position 7-18, Guidance on the Use of Programmable Logic Controllers in Digital Computer-Based Instrumentation and Control Systems, Revision 5, March 2007.

23. License Amendment Nos. 149 (DPR-80) and 149 (DPR-82), "Issuance of Amendment Re: Elimination of Post-Accident Sampling Requirements," USNRC, July 13, 2001.

24. Regulatory Guide 1.52, Revision 2 - Design, Testing, and Maintenance Criteria for Post-Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants.

9.4.14 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

9.5 OTHER AUXILIARY SYSTEMS

This section provides information on plant auxiliary systems that do not otherwise apply to the preceding sections of this chapter.

9.5.1 FIRE PROTECTION

The fire protection program is based on the NRC requirements and guidelines, Nuclear Electric Insurance Limited (NEIL) Property Loss Prevention Standards and related industry standards. With regard to NRC criteria, the fire protection program meets the requirements of 10 CFR 50.48(c), which endorses, with exceptions, the National Fire Protection Association's (NFPA) 805, Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants – 2001 Edition. Diablo Canyon Power Plant (DCPP) Units 1 and 2 has further used the guidance of NEI 04-02, "Guidance for Implementing a Risk-Informed, Performance-Based Fire Protection Program under 10 CFR 50.48(c)" as endorsed by Regulatory Guide 1.205," Risk-Informed, Performance-Based Fire Protection for Existing Light-Water Nuclear Power Plants."

Adoption of NFPA 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants," 2001 Edition in accordance with 10 CFR 50.48(c) serves as the method of satisfying 10 CFR 50.48(a) and General Design Criterion 3. Prior to adoption of NFPA 805, General Design Criterion 3, "Fire Protection" of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50, "Licensing of Production and Utilization Facilities," was followed in the design of safety and non-safety related structures, systems and components, as required by 10 CFR 50.48(a).

NFPA 805 does not supersede the requirements of GDC3, 10 CFR 50.48(a), or 10 CFR 50.48(f). Those regulatory requirements continue to apply. However, under NFPA 805, the means by which GDC 3 or 10 CFR 50.48(a) requirements are met may be different than under 10 CFR 50.48(b). Specifically, whereas GDC 3 refers to SSCs important to safety, NFPA 805 identifies fire protection systems and features required to meet the Chapter 1 performance criteria through the methodology in Chapter 4 of NFPA 805. Also, under NFPA 805, the 10 CFR 50.48(a)(2)(iii) requirement to limit fire damage to SSCs important to safety so that the capability to safely shut down the plant is satisfied by meeting the performance criteria in Section 1.5.1 of NFPA 805.

A Safety Evaluation was issued on April 14th, 2016 by the NRC, that transitioned the existing fire protection program to a risk-informed, performance-based program based on NFPA 805, in accordance with 10 CFR 50.48(c).

9.5.1.1 Design Bases

Calculation FP-805 demonstrates how the Diablo Canyon Power Plant Units 1 and 2 meet the requirements of 10 CFR 50.48(a) and 10 CFR 50.48(c). This design basis document satisfies the methodology and documentation requirements of NFPA 805 (2001 Edition), Section 2.7.1.2.

9.5.1.1.1 Defense-in-Depth

The fire protection program is focused on protecting the safety of the public, the environment, and plant personnel from a plant fire and its potential effect on safe reactor operations. The fire protection program is based on the concept of defense-in-depth. Defense-in-depth shall be achieved when an adequate balance of each of the following elements is provided:

(1) Preventing fires from starting,

(2) Rapidly detecting fires and controlling and extinguishing promptly those fires that do occur, thereby limiting fire damage,

(3) Providing an adequate level of fire protection for structures, systems, and components important to safety, so that a fire that is not promptly extinguished will not prevent essential plant safety functions from being performed.

9.5.1.1.2 NFPA 805 Performance Criteria

The design basis for the fire protection program is based on the following nuclear safety and radiological release performance criteria contained in Section 1.5 of NFPA 805:

- Nuclear Safety Performance Criteria. Fire protection features shall be capable of providing reasonable assurance that, in the event of a fire, the plant is not placed in an unrecoverable condition. To demonstrate this, the following performance criteria shall be met:

  (a) Reactivity Control. Reactivity control shall be capable of inserting negative reactivity to achieve and maintain subcritical conditions. Negative reactivity inserting shall occur rapidly enough such that fuel design limits are not exceeded.

  (b) Inventory and Pressure Control. With fuel in the reactor vessel, head on and tensioned, inventory and pressure control shall be capable of controlling coolant level such that subcooling is maintained such that fuel clad damage as a result of a fire is prevented for a PWR.

  (c) Decay Heat Removal. Decay heat removal shall be capable of removing sufficient heat from the reactor core or spent fuel such that fuel is maintained in a safe and stable condition.

(d) Vital Auxiliaries. Vital auxiliaries shall be capable of providing the necessary auxiliary support equipment and systems to assure that the systems required under (a), (b), (c), and (e) are capable of performing their required nuclear safety function.

(e) Process Monitoring. Process monitoring shall be capable of providing the necessary indication to assure the criteria addressed in (a) through (d) have been achieved and are being maintained.

- Radioactive Release Performance Criteria. Radiation release to any unrestricted area due to the direct effects of fire suppression activities (but not involving fuel damage) shall be as low as reasonably achievable and shall not exceed applicable 10 CFR Part 20 Limits.

Chapter 2 of NFPA 805 establishes the process for demonstrating compliance with NFPA 805.

Chapter 3 of NFPA 805 contains the fundamental elements of the fire protection program and specifies the minimum design requirements for fire protection systems and features.

Chapter 4 of NFPA 805 establishes the methodology to determine the fire protection systems and features required to achieve the nuclear safety performance criteria outlined above. The methodology shall be permitted to be either deterministic or performance-based. Deterministic requirements shall be “deemed to satisfy” the performance criteria, defense-in-depth, and safety margin and require no further engineering analysis. Once a determination has been made that a fire protection system or feature is required to achieve the nuclear safety performance criteria of Section 1.5, its design and qualification shall meet the applicable requirement of Chapter 3.

9.5.1.1.3 Codes of Record

The codes and standards used for the design and installation of plant fire protection systems are contained in Appendix C to Calculation FP-805.

9.5.1.2 System Description

9.5.1.2.1 Required Systems

Nuclear Safety Capability Systems, Equipment, and Cables

Section 2.4.2 of NFPA 805 defines the methodology for performing the nuclear safety capability assessment. The systems, equipment, and cables required for the nuclear safety capability assessment are contained in Appendix F to Calculation FP-805.

Fire Protection Systems and Features

Chapter 3 of NFPA 805 contains the fundamental elements of the fire protection program and specifies the minimum design requirements for fire protection systems and features. Compliance with Chapter 3 is documented in Appendix D to Calculation FP-805.

Chapter 4 of NFPA 805 establishes the methodology and criteria to determine the fire protection systems and features required to achieve the nuclear safety performance criteria of Section 1.5 of NFPA 805. These fire protection systems and features shall meet the applicable requirements of NFPA 805 Chapter 3. These fire protection systems and features are documented in Appendix F to Calculation FP-805.

Radioactive Release

The locations of structures, systems, and components relied upon to meet the radioactive release criteria are contained in Section 9 of Calculation FP-805.

9.5.1.2.2 Definition of "Power Block" Structures

Where used in NFPA 805 Chapter 3, the terms "Power Block" and "Plant" refer to structures that have equipment required for nuclear plant operations. For the purposes of establishing the structures included in the fire protection program in accordance with 10 CFR 50.48(c) and NFPA 805, the plant structures considered to be part of the 'power block' are contained in Appendix B to Calculation FP-805.

9.5.1.3 Safety Evaluation

Appendix F of Calculation FP-805 documents the achievement of the nuclear safety and radioactive release performance criteria of NFPA 805 as required by 10 CFR 50.48(c). This document fulfills the requirements of Section 2.7.1.2, "Fire Protection Program Design Basis Document," of NFPA 805. The document contains or identifies the document location of the following:

- Identification of significant fire hazards in the fire area. This is based on NFPA 805 approach to analyze the plant from an ignition source and fuel package perspective.
- Summary of the Nuclear Safety Capability Assessment (at power and non-power) compliance strategies.
    - Deterministic compliance strategies
    - Performance-based compliance strategies (including defense-in-depth and safety margin)
- Summary of the Non-Power Operations Modes compliance strategies.
- Summary of the Radioactive Release compliance strategies.
- Summary of the Fire Probabilistic Risk Assessments.
- Key analysis assumptions to be included in the NFPA 805 monitoring program.

9.5.1.4 Fire Protection Program Documentation, Configuration Control, and Quality Assurance

In accordance with Chapter 3 of NFPA 805, a fire protection plan documented in Program Directive OM8 defines the management policy and program direction and defines the responsibilities of those individuals responsible for the plan's implementation. OM8:

- Designates the senior management position with immediate authority and responsibility for the fire protection program.
- Designates a position responsible for the daily administration and coordination of the fire protection program and its implementation.
- Defines the fire protection interfaces with other organizations and assigns responsibilities for the coordination of activities. In addition, OM8 identifies the various plant positions having the authority for implementing the various areas of the fire protection program.
- Identifies the appropriate authority having jurisdiction for the various areas of the fire protection program.
- Identifies the procedures established for the implementation of the fire protection program, including the post-transition change process and the fire protection monitoring program.
- Identifies the qualifications required for various fire protection program personnel.
- Identifies the quality requirements of the fire protection program.

Detailed compliance with the programmatic requirements of Chapters 2 and 3 of NFPA 805 are contained in Section 9 and Appendix D of Calculation FP-805.

9.5.2 COMMUNICATIONS SYSTEMS

The communications systems include internal (intra-plant) and external communications designed to provide convenient and effective operational communications among various plant locations and between the plant and locations external to the plant.

The communications systems are PG&E Design Class II.

The communications systems also satisfy Emergency Plan and Security Plan requirements, as discussed in Sections 13.3 and 13.7, respectively.

9.5.2.1 Design Bases

9.5.2.1.1 General Design Criterion 3, 1971 – Fire Protection

The communications systems are designed and located to minimize, consistent with other safety requirements, the probability and effects of fires and explosions.

9.5.2.1.2 General Design Criterion 4, 1967 – Sharing of Systems

The communications systems are not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

9.5.2.1.3 General Design Criterion 11, 1967 – Control Room

The communications systems are designed to support actions to maintain and control the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other cause.

9.5.2.1.4 Communications Systems Safety Function Requirements

(1) Effective Communications

The communications systems are capable of providing effective intra-plant and plant-to-offsite communications during all modes of operation, including accident conditions.

9.5.2.2 System Description

9.5.2.2.1 Intra-Plant System

The communications systems are designed to ensure continuous intra-plant operation by the use of primary, secondary, and tertiary routings as follows:

A direct dial company telephone system is the primary communications facility within the plant. It has conference call features consisting of emergency conference and regular conference circuits. The emergency conference circuit and regular conference circuits will handle a sufficient number of parties. There is a radio paging system for paging plant personnel within the plant and in surrounding communities. Fire alarms may be dialed from any telephone in the plant, and the caller verbally identifies the location of the fire to the control room operator. Response to this alarm is covered by procedures. Where background noise is high, telephones designed especially for use in high noise level areas are provided.

The plant radio system is the secondary communications facility within the plant and operates between the radio control console in the control room, the FHB, and containment building areas.

A manually initiated emergency signal is the tertiary communications facility. It is operated from the main control room control console.

Response to any of the signals mentioned will be governed by procedures.

9.5.2.2.2 Plant-to-Offsite System

Multiple communications links are available between DCPP and off-site locations, including the Emergency Operation Facility (EOF) and other operations and emergency facilities.

These communication links utilize microwave, fiber optic and public switched telephone network lines. The system is provided with battery power for emergency operation. Refer to the Emergency Plan and Security Plan for additional Plant-to-Offsite communication details and requirements.

9.5.2.3 Safety Evaluation

9.5.2.3.1 General Design Criterion 3, 1971 – Fire Protection

The communications systems are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.5.2.3.2 General Design Criterion 4, 1967 – Sharing of Systems

The communications systems are shared between DCPP Unit 1 and Unit 2. The communications systems are PG&E Design Class II. Because the communications systems are PG&E Design Class II, a failure of the system in one unit will not impair safety in the other unit.

The communications room power distribution panels in Unit 1 and Unit 2 are normally fed from their respective Class 1E 480-V bus. Refer to Section 8.3.1.1.4.3.3 for sharing of power sources.

9.5.2.3.3 General Design Criterion 11, 1967 – Control Room

Communications systems are provided to assist operators in maintaining the safe operation of the facility during normal operation, shutdown, and accident conditions. The HSP for each unit is equipped with a communications panel console containing a radio set and a plant telephone.

9.5.2.3.4 Communications Systems Safety Function Requirements

(1) Effective Communications

The communications systems include internal (intra-plant) and external communications designed to provide convenient and effective operational communications among various plant locations and between the plant and locations external to the plant.

All intra-plant systems and all plant-to-offsite communications utilize tertiary backup and multiple power sources, therefore preventing the failure of individual components from causing a discontinuity of communications (refer to Sections 9.5.2.2.1 and 9.5.2.2.2).

Emergency response communications processes and equipment are administratively controlled in accordance with the Emergency Plan (refer to Section 13.3).

Security based communications processes and equipment are administratively controlled in accordance with the Security Plan (refer to Section 13.7).

9.5.2.4 Tests and Inspections

Routine maintenance procedures require testing and lineup of microwave radio multiplex and battery equipment to take place on a regularly scheduled basis. Tests were conducted to ensure that the plant radios do not affect the instrumentation systems for the reactor protection system and ESFs for Unit 1. Those plant areas that were determined to be affected were made radio exclusion zones. Since plant similarity exists for both Unit 1 and Unit 2, plant modifications identified by these tests for Unit 1 were also implemented in Unit 2. All communications equipment serving the plant are continuously operating, thus providing operational quality checks.

9.5.2.5 Instrumentation Applications

Every critical component of the communications systems, such as the microwave radio system, the 48-V batteries, and the associated equipment, has major functions alarmed locally and at the PG&E enterprise network operations center (ENOC).

9.5.3 LIGHTING SYSTEMS

9.5.3.1 Design Bases

9.5.3.1.1 General Design Criterion 3, 1971 – Fire Protection

The lighting systems are designed and located to minimize, consistent with other safety requirements, the probability and effects of fires and explosions.

9.5.3.1.2 Lighting Systems Safety Function Requirements

(1) Normal and Emergency Lighting

Adequate lighting is provided during all plant operating conditions.

(2) Seismic Requirements

The BOLs that are provided to illuminate access and egress routes for operator actions necessary for safe shutdown are designed to withstand the effects of earthquakes.

9.5.3.2 System Description

Normal lighting is operated at 208Y/120-Vac, three-phase on a four-wire solidly grounded system, supplied from the 480-V system through dry type, delta-wye connected three-phase transformers.

The dc emergency lighting is supplied at 125-Vdc from the non-Class 1E station batteries. The dc emergency lighting fixtures are located principally in electrical equipment rooms, stairways, exits and entrances, corridors, passageways, and at lower levels in all other areas.

The ac emergency lighting is supplied from two of the three Class 1E 480-V buses through dry type, single-phase transformers, and is sized to provide a maximum load of 112-kW for Unit 1 and 100-kW for Unit 2. The ac emergency lighting fixtures are located throughout the plant to provide minimum lighting.

The ac emergency lighting in the pipe rack area is powered by an uninterruptible power supply (UPS). This UPS is powered by non-Class 1E power and has an eight-hour rated battery.

The ac emergency lighting circuits are routed in separate conduits from the normal ac lighting on the secondary transformer sides to panels and fixtures. On the primary side, the ac power from the Class 1E 480-V buses is run in separate conduits or in respective Class 1E routes. The 208Y/120-Vac circuits are routed in normal power conduits. Lighting circuits for dc emergency lighting are run in their own conduit.

BOLs for areas containing PG&E Design Class I equipment or to enable operator action to meet NFPA 805 safe shutdown requirements are seismically qualified.

After the diesel generators start and the single-phase ac emergency transformers receive power, the dc emergency lights are automatically turned off. The average period of operation of the dc lights is 18 seconds, (approximately 13 seconds for diesel generator loading and 5 seconds for time delay of contactor pick-up in the emergency dc lighting panel). DC lights in the FHB at all elevations will be on for 10 minutes. Safe shutdown equipment areas and various access routes thereto are provided with BOLs

or UPS-powered lights capable of providing 8 hours of illumination if ac power to the BOLs or UPS is lost. The batteries are continuously charged with a built-in charger.

Lighting in the containment structure and radiation areas of the SFP area and part of Area K of the auxiliary building is provided by either incandescent light fixtures or LED light fixtures. In the FHB on the 140-foot elevation in the SFP and machine shop areas, the light fixtures are either high intensity discharge pulse start metal halide lights or LED lights.

Security based lighting is administratively controlled in accordance with the Security Plan (refer to Section 13.7).

9.5.3.3 Safety Evaluation

9.5.3.3.1 General Design Criterion 3, 1971 – Fire Protection

The lighting systems are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

9.5.3.3.2 Lighting Systems Safety Function Requirements

(1) Normal and Emergency Lighting

Normal lighting, dc emergency lighting, ac emergency lighting, and BOLs are provided to ensure that adequate lighting is available for all plant operating conditions, including transients and accident conditions (refer to Section 9.5.3.2).

(2) Seismic Requirements

BOLs that are necessary to perform post-seismic operator actions or to illuminate access/egress routes to the operator action location are seismically qualified. However, those units that are not necessary to perform post-seismic operator actions or to illuminate access/egress routes to the operator action location are exempt from the requirement.

The safety function of the BOLs is to provide eight (8) hours of lighting if normal ac power is lost (for BOLs that energize on loss of normal ac power) or Class 1E ac power is lost (for BOLs that energize on loss of Class 1E ac power.

9.5.4 DIESEL GENERATOR FUEL OIL STORAGE AND TRANSFER SYSTEM

The diesel generator fuel oil system, shown in Figures 3.2-21, 9.5-8, and 9.5-9, maintains adequate storage of diesel fuel oil and supplies it to the six EDGs. The following subsections provide information on (a) design bases, (b) system description, and (c) safety evaluation for the system.

9.5.4.1 Design Bases

9.5.4.1.1 General Design Criterion 2, 1967 - Performance Standards

The EDG fuel oil storage and transfer system is designed to withstand the effects of or is protected against natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

9.5.4.1.2 General Design Criterion 3, 1971 - Fire Protection

The EDG fuel oil storage and transfer system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.5.4.1.3 General Design Criterion 4, 1967 - Sharing of Systems

The EDG fuel oil storage and transfer system or components are not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

9.5.4.1.4 General Design Criterion 11, 1967 - Control Room

The EDG fuel oil storage and transfer system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

9.5.4.1.5 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain EDG fuel oil storage and transfer system variables within prescribed operating ranges.

9.5.4.1.6 General Design Criterion 17, 1971 - Electric Power Systems

The EDG fuel oil storage and transfer system is designed with sufficient capacity, capability, independence, redundancy, and testability to perform its safety function assuming a single failure.

9.5.4.1.7 General Design Criterion 21, 1967 - Single Failure Definition

The EDG fuel oil storage and transfer system is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event shall be treated as a single failure.

9.5.4.1.8 Emergency Diesel Generator Fuel Oil Storage and Transfer System Safety Function Requirements

(1) Protection from Missiles

The PG&E Design Class I portion of the EDG fuel oil storage and transfer system is designed to be protected against missiles that might result from plant equipment failure and conditions outside the plant to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(2) Protection Against High Energy Pipe Rupture Effects

The PG&E Design Class I portion of the EDG fuel oil storage and transfer system is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection from Moderate Energy Pipe Rupture Effects

The PG&E Design Class I portion of the EDG fuel oil storage and transfer system is designed to be protected against the effects of moderate energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(4) Protection from Flooding Effects

The PG&E Design Class I portion of the EDG fuel oil storage and transfer system is designed to be protected from the effects of internal flooding to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

9.5.4.1.9 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The EDG fuel oil storage and transfer system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

9.5.4.1.10 Regulatory Guide 1.137, Revision 1, October 1979 – Fuel-Oil Systems for Standby Diesel Generators

For proper operation of the EDGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide 1.137, Revision 1, addresses the recommended fuel oil practices as supplemented by ANSI N195-1976. The fuel oil properties governed by DCPP Technical Specification Surveillance Requirements are the water and sediment content, the kinematic viscosity, specific gravity (or API gravity), and impurity level.

9.5.4.1.11 10 CFR 50.63 – Loss of All Alternating Current Power

The EDG fuel oil storage and transfer system is required to (1) maintain adequate storage of diesel fuel oil, and (2) transfer fuel oil from the storage tanks to the day tank associated with the EDG (AAC source) supplying the blacked-out unit in the event of a station blackout (SBO)

9.5.4.2 System Description

The diesel generator fuel oil system diagram is shown in Figure 3.2-21. The physical arrangement of the engine generator units is shown in Figures 9.5-10 and 9.5-11 for Unit 1; the arrangement is similar for Unit 2. Figure 9.5-12 shows the outline of the Unit 1 engine generators; the arrangement is similar for the Unit 2 generators with the exception of EDG 2-3, which is slightly different. The design data is given in Table 9.5-2. The system consists of the following major components and features:

(1) Two underground diesel fuel oil storage tanks, each with a storage capacity of 50,000 gallons.

(2) Two diesel fuel oil transfer pumps located below ground level, each adjacent to a storage tank but in separate compartments. Each transfer pump delivers more than 55 gpm at a discharge pressure of approximately 50 psig. Pumps are of the positive displacement rotary screw type with 5-hp motors. One pump is more than adequate to supply the six diesel generators of Unit 1 and Unit 2 running at rated load. A duplex-type strainer is installed upstream of each fuel oil transfer pump to protect the pump from particles that could damage it. A cartridge-type fuel oil filter is located at the discharge of the fuel oil transfer pumps to prevent any fuel oil contamination from reaching the engine-base-mounted diesel fuel oil tanks. The diagram of the engine fuel oil transfer system is shown in Figure 3.2-21. The physical arrangement of the fuel oil transfer system is shown in Figures 9.5-8 and 9.5-9.

(3) Two diesel fuel oil supply headers to each unit routed in separate trenches.

The motor controllers for the two transfer pumps are located inside the auxiliary building. Manual pump control stations and manual controls for the valves are located near each diesel generator set.

The other engine generator auxiliary systems and accessories are essentially as provided on all engine generator units of this size. Each engine generator unit is equipped with a skid-mounted fuel oil tank that has a capacity of 550 gallons, which provides about 2-1/2 hours of full load operation before fuel oil must be transferred from the underground storage tanks. Fuel is transferred to each diesel generator skid-mounted fuel oil tank via two LCVs (and two associated upstream isolation valves)

per diesel generator. Each of the two LCVs and associated upstream isolation valves on each diesel generator is associated with a separate diesel fuel oil transfer system train; however, the LCVs, the isolation valves immediately upstream from the LCVs, and the skid-mounted fuel oil tank are part of the associated diesel generator rather than the diesel fuel oil transfer system. The fuel oil transfer pumps start automatically on low level in the engine generator unit tanks. The two 50,000-gallon storage tanks provide a 7-day supply of fuel.

Each EDG day tank has the capacity for approximately 2.5 hours of continuous full-load operation. The fuel oil transfer system is designed to replenish the day tanks from the underground fuel oil storage tanks to ensure onsite power is available following a design-basis accident. Each day tank has two associated redundant fuel oil transfer system LCVs that automatically open to replenish the tank. The LCVs are air-operated by the associated diesel starting air receiver tanks. To ensure the starting air system is capable of supporting the required automatic LCV operation, the leakage of each diesel starting air system is verified periodically (Reference 4).

Experience with the PG&E transmission system indicates that in the event of complete loss of offsite power, restoration of normal power sources could be accomplished within a few hours. However, 7 days of onsite power generation has been used as a conservative upper limit for design and safety evaluations of fuel storage capacity for the tanks, even though it is highly improbable that the diesel generators would be required to furnish plant auxiliary power for this long a period.

9.5.4.3 Safety Evaluation

9.5.4.3.1 General Design Criterion 2, 1967 - Performance Standards

The EDG units and their associated auxiliary systems, as shown for Unit 1 in Figures 9.5-8 through 9.5-10, and similarly for Unit 2, are installed in separate compartments that are protected from fires, flooding, and external missiles.

The system valves, fittings, and piping are fabricated and inspected to ANSI Code for Pressure Piping B31.1 and B31.7 where applicable. The diesel fuel oil storage tanks are designed and fabricated to UL Standard 58. Seismic effects on the buried tanks are determined by a soil structure interaction analysis. Seismic effects are combined with gravity effects, including those resulting from the weight of the tanks and their contents, and the weight of the soil overburden.

Protection against corrosion problems is provided for underground portions of the system. Tank supports have firm foundations to minimize uneven settling and prevent seismic damage.

The exterior surfaces of the tanks have a corrosion-resistant fiberglass reinforced plastic wrap. Cathodic protection was provided to protect the tanks and underground piping from corrosion in case of damage to the coating. This cathodic protection system

provided minimal protection, is no longer functioning, and has been abandoned in place (Reference 5). Most jurisdictions (including San Luis Obispo County) do not require cathodic protection for fiberglass reinforced plastic clad double wall tanks. California Code of Regulations 23 CCR 2635 does not require cathodic protection for this type of tank construction. ANSI/ANS 59.51-1997 states the use of a double wall tank design is an adequate means of meeting corrosion requirements.

Underground steel piping is provided protection from the effects of long term corrosion by coating or wrapping, in accordance with NACE Standard Practice SP0169. The transfer and vent piping is electrically isolated from the tanks in accordance with NACE Standard Practice SP0169. Magnesium anodes are utilized to protect the tank hold down straps.

A calculation was performed to determine the maximum ambient temperature inside the pump vaults due to heat output of fuel oil transfer pump motor (Reference 5). The motor is rated to withstand this maximum temperature. The design outdoor design temperature is based on 9 years of onsite hourly data, and the minimum recorded onsite outdoor temperature during this 9-year period is 39°F (refer to Section 9.4). Based on the results of the calculations, and the fact that the extreme low temperature recorded at the DCPP site was above freezing point, it is concluded that neither heating nor cooling is required to perform safe operation of the fuel oil pumps. However, for personnel protection, temporary portable ventilation equipment will be used as required to restore the confined space for habitability inside the vaults during periodic inspection and maintenance, in accordance with the plant administrative procedures.

9.5.4.3.2 General Design Criterion 3, 1971 - Fire Protection

The EDG areas are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

Refer to Section 8.3.1.4.9 for further discussion on fire barriers and separation. To ensure good fire protection practice, the diesel engine generator installation was designed in accordance with NFPA Standard No. 37, Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines. This standard permits a maximum capacity of 660 gallons (550 imperial gallons) for an integral fuel oil day tank. It also provides sufficient time for all necessary operator actions to ensure that diesel generator operation is not interrupted in the event of any malfunctions in the system that transfers fuel oil from the underground storage tanks to the day tanks.

The two diesel fuel oil storage tanks are buried, and are designed to the criteria of Part 2, Bulk Underground Storage, of NFPA Standard No. 30, Standard for the Storage, Handling and Use of Flammable Liquids. The National Fire code does not require any specific fire protection system for this type of underground storage tank. Physical separation of the two tanks precludes the possibility of a fire in one storage tank from spreading to another tank. Fire risk is further minimized by the fact that the only source of oxygen to support a fire is through the 4-inch tank vent. If sufficient heat were

generated to damage and collapse the storage tank, dirt would cave in and help smother the fire. Two yard hose reel stations are available for fighting any above ground fires at the tank location.

9.5.4.3.3 General Design Criterion 4, 1967 - Sharing of Systems

The diesel generator fuel oil system is provided to supply diesel oil to the emergency diesel engine generators for Unit 1 and Unit 2. The design classification of this system is given in Table 3.2-3. The fuel storage capacity provides 7 days of onsite power generation in order to operate (a) the minimum required ESF equipment following a LOCA for one unit, and the equipment for the second unit in either the hot or cold shutdown condition, or (b) the equipment for both units in either the hot or cold shutdown condition. The supply of fuel beyond the 7-day period is ensured by the availability of offsite sources and a reliable delivery method.

Safety of the reactor facilities is not impaired by the sharing of the fuel oil systems as any combination of one storage tank and one pump is capable of serving all six-day tanks. Each unit normally supplies power to one transfer pump from one Class 1E 480-V bus (refer to Section 8.3.1.1.4.3.3). Provisions are made to manually switch both pumps to the Class 1E buses of either unit, in case one unit should be placed in a prolonged cold shutdown condition.

9.5.4.3.4 General Design Criterion 11, 1967 - Control Room

System instrumentation and control is provided on the tanks and pumps as follows:

(1) The base-mounted day tanks have two separate redundant transfer pump start-stop level switches. Each level switch starts a transfer pump and opens the supply header solenoid valve corresponding to the respective transfer pump, A or B. The start setting for the header A level switches is slightly different from those for header B, allowing one to be a backup.

(2) The start of transfer pump A or B is indicated both locally and in the control room.

(3) Local controls at each diesel generator and manual crosstie valving between headers allow manual starting of either transfer pump and filling of the base-mounted day tanks from either header system A or B.

(4) High- and low-level alarm switches are installed on all base-mounted day tanks that activate alarms both locally and in the control room to alert the operators.

(5) High- and low-level alarm switches are installed on both fuel oil storage tanks that will activate alarms in the control room. Additionally, dipstick-type indicators and a local level indicator are provided for each storage tank.

Additionally, a monitoring system to detect the leakage of oil from the fuel oil transfer system piping in the fuel oil transfer trenches is provided to comply with California Underground Storage Tank regulations.

9.5.4.3.5 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Refer to Section 9.5.4.3.4 for discussion related to instrumentation and control.

9.5.4.3.6 General Design Criterion 17, 1971 - Electric Power Systems

The EDG system has sufficient capacity, capability, independence, redundancy, and testability to perform its safety function assuming a single failure. Refer to Sections 9.5.4.2 and 9.5.4.3.7 for details on the system.

9.5.4.3.7 General Design Criterion 21, 1967 - Single Failure Definition

The diesel generator fuel oil system is designed to remain operable after sustaining a single failure of either an active or a passive component. The capability to meet the single failure criterion is met by providing redundancy in tanks, pumps, valves, piping, and power supplies. The system arrangement provides sufficient separation of the tanks and their associated transfer pumps so that the possibility of damage to both simultaneously as a result of a single event is considered highly unlikely. The fuel oil transfer piping, transfer pumps, and tank manifolding are arranged so a single failure of any pipe, valve, tank, or pump will not disable the system.

The design incorporates sufficient redundancy so that a malfunction or failure of either an active or a passive component will not impair the ability of the system to supply fuel oil.

As discussed in the preceding paragraph, the diesel fuel oil system transfer components and power sources are redundant up to and including fill valves and connections on the engine day tanks, so that a single malfunction will not prevent the transfer of oil. In the unlikely event of malfunctions in both redundant fuel oil headers, such as a pump failure in one and piping blockage in the other, low level will be alarmed when sufficient fuel oil remains in the base-mounted day tank for a nominal one hour period of operation of the engine at full load. This nominal one hour period is adequate for an operator (a) to correct a malfunction on one of the two redundant transfer headers, or (b) to line up manually the valves of the two headers into one path that will transfer oil. All the valves necessary for this action are readily accessible in the compartments for the diesel fuel oil transfer pumps.

Each diesel generator has a dedicated shaft driven fuel pump, priming tank and day tank along with instrumentation, and fuel injectors such that failure of this engine mounted fuel equipment affects its associated diesel generator only.

9.5.4.3.8 Emergency Diesel Generator Fuel Oil Storage and Transfer System Safety Function Requirements

(1) Protection from Missiles

The EDG units and their associated auxiliary systems, as shown for Unit 1 in Figures 9.5-8 through 9.5-10, and similarly for Unit 2, are installed in separate compartments that are protected from internal missiles.

The provisions taken to protect the PG&E Design Class I, EDG fuel oil storage and transfer system from missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Sections 3.5.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the PG&E Design Class I portion of the EDG fuel oil storage and transfer system from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Section 3.6.

(3) Protection from Moderate Energy Pipe Rupture Effects

The provisions taken to provide protection of the PG&E Design Class I portion of the EDG fuel oil storage and transfer system from the effects of moderate energy pipe failure are discussed in Section 3.6.

(4) Protection from Flooding Effects

The provisions taken to provide protection of the PG&E Design Class I portion of the EDG fuel oil storage and transfer system from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

The design considerations to prevent water from flooding or groundwater from entering the fuel oil storage tanks, concrete vaults, and pipe trenches were:

(1) As discussed in Section 2.4, the risk of surface water flooding at this site is essentially zero. No groundwater has been encountered at or below the buried tanks, pump vaults, or pipe trenches. Therefore, the source potential for water flooding the fuel oil system is negligible. In addition, the below-ground system is completely sealed with the vent line extending approximately 2 feet above ground.

(2) Fuel oil tank vent lines running above ground are protected by concrete boxes and are surrounded by warning posts to alert any vehicular traffic. The concrete boxes will protect redundant vent lines from any credible common-mode failure.

(3) The two transfer pumps are in separate, underground, reinforced concrete vaults with solid covers protected from surface runoff due to their location inside the west buttress and condensate polishing system structure. The vault's manway hatch covers are made of steel and are provided with concrete curbing to prevent water intrusion into the vaults. These vaults are drained to the building sump and are protected with backwater valves. Flooding of the transfer pump vaults is alarmed at the TBS local annunciator and on the Unit 1 main annunciator.

(4) The two redundant fuel oil supply headers are in separate, below-ground reinforced concrete pipe trenches with solid steel or concrete covers that are generally flush with the adjacent ground level, except as noted below. Since the trenches collect water from surface runoff, drainage is provided through floor drains to manholes, which are pumped to the TBSs or standpipes that can be connected to portable pumps. Portions of the fuel oil supply header trenches routed in the rooms housing the EDGs are provided with metal grating. The grating provides physical protection of the headers, allows for visual inspection, and provides access for manual control of the fuel oil LCVs using a wrench. Because the grating is located indoors, the potential for flooding is extremely small. The trenches, with the exception of that in the room housing EDG 2-3, drain back to the turbine building sump. The trench in the room housing EDG 2-3 main header does not drain to a sump and must be pumped out manually.

(5) The design classification for the diesel fuel oil piping within the trenches is given in Table 3.2-3.

The possibility of flooding in the turbine building and in the diesel generator compartments is discussed in Section 8.3.1.1.6.3.9.

9.5.4.3.9 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The EDG system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

9.5.4.3.10 Regulatory Guide 1.137, Revision 1, October 1979 – Fuel-Oil Systems for Standby Diesel Generators

There is no specific DCPP commitment to use Regulatory Guide 1.137, Revision 1, guidance to establish fuel oil quantity requirements for 7 day EDG operation.

The Technical Specification required fuel oil quantity for 7 day EDG operation is based on the calculated fuel oil consumption necessary to support the operation of the EDGs to power the minimum ESF systems required to mitigate a design basis LOCA in one unit and those minimum required systems for a concurrent non-LOCA safe shutdown in the other unit (both units initially in Mode 1 operation).

Proper operation of the EDGs requires following recommended fuel oil practices to ensure proper quality. Regulatory Guide 1.137, Revision 1, addresses the recommended fuel oil practices as supplemented by ANSI N195-1976. The fuel oil properties governed by DCPP Technical Specification Surveillance Requirements are the water and sediment content, the kinematic viscosity, specific gravity (or API gravity), and impurity level.

9.5.4.3.1110 CFR 50.63 – Loss of All Alternating Current Power

In the event of a SBO, a diesel fuel oil transfer pump powered from a Class 1E 480-V bus in the non-blacked-out unit takes suction from a diesel fuel oil storage tank and provides fuel oil to the day tank associated with the EDG (AAC source) supplying the blacked-out unit.

Each EDG at DCPP is served by its own separate day tank, which is supplied from a common storage tank. The fuel oil in the common tank is sampled and analyzed in accordance with Technical Specifications to ensure it meets acceptable high quality standards.

Refer to Section 8.3.1.6 for further discussion of station blackout.

9.5.4.4 Tests and Inspections

The diesel fuel supply headers are hydrostatically or pneumatically tested during construction and all active system components, pumps, valves, and controls are functionally tested during startup and periodically thereafter. The diesel fuel oil in storage will be periodically tested for any possible contamination or deterioration. The underground Diesel Fuel Oil and Transfer System is demonstrated operable as required by the Technical Specifications and by performing a visual examination of accessible piping in accordance with the Buried Piping and Tanks Program.

9.5.4.5 Instrumentation Application

Refer to Section 9.5.4.3.4 for discussion related to instrumentation application.

9.5.5 DIESEL GENERATOR COOLING WATER SYSTEM

The diesel generator cooling water system is shown schematically in Figure 3.2-21. The physical arrangement of the EDG units is shown in Figures 9.5-10 and 9.5-11 for Unit 1; the arrangement is similar for Unit 2. Figure 9.5-12 shows the outline of the Unit

1 EDGs. The arrangement is similar for the Unit 2 EDGs with the exception of EDG 2-3, which is slightly different.

9.5.5.1 Design Bases

9.5.5.1.1 General Design Criterion 2, 1967 - Performance Standards

The EDG cooling water system is designed to withstand the effects of, or is protected against natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

9.5.5.1.2 General Design Criterion 3, 1971 - Fire Protection

The EDG cooling water system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.5.5.1.3 General Design Criterion 11, 1967 - Control Room

The EDG cooling water system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

9.5.5.1.4 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain EDG cooling water system variables within prescribed operating ranges.

9.5.5.1.5 General Design Criterion 21, 1967 - Single Failure Definition

The EDG cooling water system is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event shall be treated as a single failure.

9.5.5.1.6 Emergency Diesel Generator Cooling Water System Safety Function Requirements

(1) <u>Protection from Missiles</u>

The PG&E Design Class I portion of the EDG cooling water system is designed to be protected against missiles that might result from plant equipment failure and conditions outside the plant to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(2) Protection Against High Energy Pipe Rupture Effects

The PG&E Design Class I portion of the EDG cooling water system is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection from Moderate Energy Pipe Rupture Effects

The PG&E Design Class I portion of the EDG cooling water system is designed to be protected against the effects of moderate energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(4) Protection from Flooding Effects

The PG&E Design Class I portion of the EDG cooling water system is designed to be protected from the effects of internal flooding to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

9.5.5.1.7 10 CFR 50.55a(g) - Inservice Inspection Requirements

Applicable EDG cooling water system components must meet the requirements of 10 CFR 50.55a(g). The EDG jacket water cooling system is the only EDG component included in the DCPPISI Program.

9.5.5.1.8 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The EDG cooling water system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

9.5.5.2 System Description

A closed loop jacket water-cooling system is provided for each of the six diesel engines. The engine generator skid has an integrally mounted radiator with a direct engine-driven fan for cooling the engine jacket water. Cooling air is largely outside ambient air, drawn by the fan from outside the building through the tornado missile shield into the radiator-fan portion of the engine generator compartment, and then through the radiator core. The diesel generator ventilation system is described in Section 9.4.7. This closed system allows the diesel generator unit to function in a self-contained manner, independent of outside cooling water systems and electric motor-driven fans.

The radiator is a jacket water-to-air heat exchanger of all copper and brass construction. Makeup to the jacket water cooling system can be added through a fill line after

removing the radiator cap, labeled RV-71 in Figure 3.2-21 (Sheets 13, 14, 14A, and 14B). A low jacket water level alarm notifies the operator that makeup is required.

Engine jacket water is circulated by a jacket water pump directly driven by the engine. A three-way temperature regulating valve bypasses a portion of engine jacket cooling water around the radiator to maintain proper system temperature. Lubricating oil is cooled by a shell and tube heat exchanger using the jacket water as the coolant. Thermostatically controlled immersion heaters keep the jacket water warm for fast starting while the engine is in a shutdown condition.

The generators on these units are air-cooled by a shaft-mounted blower. The cooling system is shown schematically in Figure 9.4-6.

9.5.5.3 Safety Evaluation

9.5.5.3.1 General Design Criterion 2, 1967 - Performance Standards

Refer to Section 8.3.1.1.6.3.1 for discussion regarding the protection of the EDGs, and their associated auxiliary systems from flooding and external missiles.

9.5.5.3.2 General Design Criterion 3, 1971 - Fire Protection

Refer to Section 8.3.1.1.6.3.2 for discussion regarding the design of the fire protection system for the EDGs and their associated auxiliary systems.

9.5.5.3.3 General Design Criterion 11, 1967 - Control Room

Refer to Section 8.3.1.1.6.3.4 for discussion regarding the design of the EDGs and their associated auxiliary systems to support safe shutdown and to maintain safe shutdown from the control room or from an alternate location if the control room access is lost due to fire or other causes.

9.5.5.3.4 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Refer to Sections 8.3.1.1.6.3.5 and 8.3.1.1.6.5 for discussions regarding the instrumentation and control for the EDGs and their associated auxiliary systems provided as required to monitor and maintain their variables within prescribed operating ranges.

9.5.5.3.5 General Design Criterion 21, 1967 - Single Failure Definition

Each diesel generator has a dedicated radiator/fan set, water pump and expansion tank such that failure of the cooling equipment affects its associated diesel generator only.

Refer to Section 8.3.1.1.6.3.8 for discussion regarding single failure criterion.

9.5.5.3.6 Emergency Diesel Generator Cooling Water System Safety Function Requirements

(1) Protection from Missiles

The EDG units and their associated auxiliary systems, as shown for Unit 1 in Figures 9.5-8 through 9.5-10, and similarly for Unit 2, are installed in separate compartments that are protected from internal missiles. Because EDG units are separated from each other by the concrete walls of the compartments, the units are protected from postulated internal missiles. Any missile created by an explosion within a compartment would remain in that compartment.

The provisions taken to protect the PG&E Design Class I, EDG cooling water system from missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Sections 3.5.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the PG&E Design Class I portion of the EDG cooling water system from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Section 3.6.

(3) Protection from Moderate Energy Pipe Rupture Effects

The provisions taken to provide protection of the PG&E Design Class I portion of the EDG cooling water system from the effects of moderate energy pipe failure are discussed in Section 3.6.

(4) Protection from Flooding Effects

The provisions taken to provide protection of the PG&E Design Class I portion of the EDG cooling water system from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

The possibility of flooding in the turbine building and in the diesel generator compartments is discussed in Section 8.3.1.1.6.3.9.

9.5.5.3.7 10 CFR 50.55a(g) - Inservice Inspection Requirements

Refer to Section 8.3.1.1.6.3.10 for discussion regarding compliance to the requirement of 10 CFR 50.55a(g).

9.5.5.3.8 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The EDG system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

9.5.5.4 Tests and Inspections

Refer to Section 8.3.1.1.6.4 for discussion regarding the inspection and testing associated with the EDGs and their associated auxiliary systems.

9.5.5.5 Instrumentation Applications

Instrumentation application for this system is discussed in Section 8.3.1.1.6.5.

9.5.6 DIESEL GENERATOR STARTING SYSTEM

The diesel generator starting system is shown schematically in Figure 3.2-21. The physical arrangement of the engine generator units is shown in Figures 9.5-10 and 9.5-11 for Unit 1; the arrangement is similar for Unit 2. Figure 9.5-12 shows the outline of the Unit 1 engine generators. The arrangement is similar for the Unit 2 generators with the exception of EDG 2-3, which is slightly different.

Each diesel generator is designed with two starting control circuits, one field flashing circuit, and one sensing circuit. These circuits receive Class 1E dc control power through a manual transfer switch. Normal Class 1E dc power is from the same train as the diesel generator. In the event of failure of dc power to these control circuits, an alarm appears on the main annunciator. The manual transfer switch, located near the control panel at the diesel generator can be used to transfer to backup Class 1E dc power.

9.5.6.1 Design Bases

9.5.6.1.1 General Design Criterion 2, 1967 - Performance Standards

The EDG starting system is designed to withstand the effects of, or is protected against natural phenomena such as earthquakes, tornadoes, flooding, winds, and tsunamis other local site effects.

9.5.6.1.2 General Design Criterion 3, 1971 - Fire Protection

The EDG starting system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.5.6.1.3 General Design Criterion 11, 1967 - Control Room

The EDG starting system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

9.5.6.1.4 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain EDG starting system variables within prescribed operating ranges.

9.5.6.1.5 General Design Criterion 21, 1967 - Single Failure Definition

Refer to Section 8.3.1.1.6.3.8 for discussion regarding single failure criterion.

9.5.6.1.6 Emergency Diesel Generator Starting System Safety Function Requirements

(1) Protection from Missiles

The PG&E Design Class I portion of the EDG starting system is designed to be protected against missiles that might result from plant equipment failure and conditions outside the plant to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(2) Protection Against High Energy Pipe Rupture Effects

The PG&E Design Class I portion of the EDG starting system is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection from Moderate Energy Pipe Rupture Effects

The PG&E Design Class I portion of the EDG starting system is designed to be protected against the effects of moderate energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(4) Protection from Flooding Effects

The PG&E Design Class I portion of the EDG starting system is designed to be protected from the effects of internal flooding to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

9.5.6.1.7 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The EDG starting system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

9.5.6.2 System Description

Each diesel engine of the six engine generator sets is provided with two separate air-start systems. Normally two trains, four starting air motors, operate together in combination with the turbo-charger air assist system to ensure that the engine generator set starts and accelerates to rated speed and to minimum bus voltage in less than 10 seconds. Each of the two air-starting systems consists of an air receiver; a non-Class 1E electric motor-driven air compressor to charge the receiver; two air-starting motors that engage and turn the engine flywheel; and all piping, valves, and controls necessary to provide a complete system. Each of the two redundant PG&E Design Class II air compressors for each engine generator unit is fed from different Class 1E buses so that the possibility of simultaneous loss of both air compressors is minimized. The diesel engine vendor sizing criteria for each air start receiver is to provide sufficient capacity for three consecutive 15-second cranking cycles. Additional cranking cycles can be made as the PG&E Design Class II air compressors replenish their air receivers.

In addition to the above described two air-start systems, each diesel engine is equipped with an engine turbocharger boost system. The turbocharger boost system serves two functions: it aids in acceleration of the large rotating mass of the turbocharger, and it provides extra air to the engine to improve combustion during acceleration. The additional air is necessary since the turbocharger is inefficient at low speeds. The turbocharger boost system consists of one PG&E Design Class II air compressor, one air receiver, and all piping, valves, and controls necessary to provide a complete system. The turbocharger boost system with two air-starting motors is capable of starting and accelerating the engine generator set to rated speed and to minimum bus voltage in 10 seconds. The starting air system and the turbocharger boost systems are shown schematically in Figure 3.2-21 (Sheets 3 through 6B). The physical arrangement of those systems is shown in Figures 9.5-10 and 9.5-11.

9.5.6.3 Safety Evaluation

9.5.6.3.1 General Design Criterion 2, 1967 - Performance Standards

Refer to Section 8.3.1.1.6.3.1 for discussion regarding the protection of the EDGs and their associated auxiliary systems from flooding and external missiles.

9.5.6.3.2 General Design Criterion 3, 1971 - Fire Protection

Refer to Section 8.3.1.1.6.3.2 for discussion regarding the design of the fire protection system for the EDGs and their associated auxiliary systems.

9.5.6.3.3 General Design Criterion 11, 1967 - Control Room

Refer to Section 8.3.1.1.6.3.4 for discussion regarding the design of the EDGs and their associated auxiliary systems to support safe shutdown and to maintain safe shutdown from the control room or from an alternate location if the control room access is lost due to fire or other causes.

9.5.6.3.4 General Design Criterion 12, 1967 - Instrumentation and Control

Refer to Sections 8.3.1.1.6.3.5 and 8.3.1.1.6.5 for discussions regarding the instrumentation and control for the EDGs and their associated auxiliary systems provided as required to monitor and maintain their variables within prescribed operating ranges.

9.5.6.3.5 General Design Criterion 21, 1967 - Single Failure Definition

Each diesel generator has dedicated air start receiver tanks (redundant), and a turbocharger receiver tank along with solenoid valves such that failure of this air start equipment affects its associated diesel only.

Refer to Section 8.3.1.1.6.3.8 for discussion regarding single failure criterion.

9.5.6.3.6 Emergency Diesel Generator Starting System Safety Function Requirements

(1) Protection from Missiles

The EDG units and their associated auxiliary systems, as shown for Unit 1 in Figures 9.5-8 through 9.5-10, and similarly for Unit 2, are installed in separate compartments that are protected from internal missiles. Because EDG units are separated from each other by the concrete walls of the compartments, the units are protected from postulated internal missiles. Any missile created by an explosion within a compartment would remain in that compartment.

The provisions taken to protect the PG&E Design Class I, EDG starting system from missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Sections 3.5.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the PG&E Design Class I portion of the EDG starting system from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Section 3.6.

(3) Protection from Moderate Energy Pipe Rupture Effects

The provisions taken to provide protection of the PG&E Design Class I portion of the EDG starting system from the effects of moderate energy pipe failure are discussed in Section 3.6.

(4) Protection from Flooding Effects

The provisions taken to provide protection of the PG&E Design Class I portion of the EDG starting system from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

The possibility of flooding in the turbine building and in the diesel generator compartments is discussed in Section 8.3.1.1.6.3.9.

9.5.6.3.7 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The EDG starting system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

9.5.6.4 Tests and Inspections

Refer to Section 8.3.1.1.6.4 for discussion regarding the inspection and testing associated with the EDGs and their associated auxiliary systems.

9.5.6.5 Instrumentation Applications

Instrumentation application for this system is discussed in Section 8.3.1.1.6.5.

9.5.7 DIESEL GENERATOR LUBRICATION SYSTEM

The diesel generator lubrication system is shown schematically in Figure 3.2-21. The physical arrangement of the engine generator units is shown in Figures 9.5-10 and 9.5-11 for Unit 1; the arrangement is similar for Unit 2. Figure 9.5-12 shows the outline of the Unit 1 engine generators. The arrangement is similar for the Unit 2 generators with the exception of EDG 2-3, which is slightly different.

9.5.7.1 Design Bases

9.5.7.1.1 General Design Criterion 2, 1967 - Performance Standards

The EDG lubrication system is designed to withstand the effects of, or is protected against natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

9.5.7.1.2 General Design Criterion 3, 1971 - Fire Protection

The EDG lubrication system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

9.5.7.1.3 General Design Criterion 11, 1967 - Control Room

The EDG lubrication system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

9.5.7.1.4 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain EDG lubrication system variables within prescribed operating ranges.

9.5.7.1.5 General Design Criterion 21, 1967 - Single Failure Definition

The EDG lubrication system is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event are treated as a single failure.

9.5.7.1.6 Emergency Diesel Generator Lubrication System Safety Function Requirements

(1) Protection from Missiles

The PG&E Design Class I portion of the EDG lubrication system is designed to be protected against missiles that might result from plant equipment failure and conditions outside the plant to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(2) <u>Protection Against High Energy Pipe Rupture Effects</u>

The PG&E Design Class I portion of the EDG lubrication system is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) <u>Protection from Moderate Energy Pipe Rupture Effects</u>

The PG&E Design Class I portion of the EDG lubrication system is designed to be protected against the effects of moderate energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(4) Protection from Flooding Effects

The PG&E Design Class I portion of the EDG lubrication system is designed to be protected from the effects of internal flooding to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

9.5.7.1.7 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The EDG lubrication system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

9.5.7.2 System Description

The lubricating oil system for each engine is entirely contained on that engine's baseplate. The system is schematically shown in Figure 3.2-21 (Sheets 11, 11A, 11B and 12, 12A, 12B). During engine operation, all required lubricating oil is drawn from the engine crankcase through a shaft-mounted oil pump to a lubricating oil filter with a built-in pressure relief device to bypass lubricating oil flow in the event that the filter becomes excessively dirty. The oil is then cooled in the jacket water-cooled heat exchanger and returned to the engine bearings through a duplex strainer. During normal operation, engine cooling water will not leak into the lubricating oil due to a leak in the lubricating oil heat exchanger since the operating pressure of the lubricating oil system is above 75 psig, and the operating pressure of the cooling water system is about 35 psig. Instrumentation provided in the lubricating oil circuit is described in Section 8.3.1.1.6.5.

While the engine is idle, oil is continually circulated by means of a small precirculating pump. A thermostatically controlled immersion heater on the outlet of the precirculating pump maintains a 90-110°F oil temperature to ensure rapid and safe startup of the engine at any time.

9.5.7.3 Safety Evaluation

9.5.7.3.1 General Design Criterion 2, 1967 - Performance Standards

Refer to Section 8.3.1.1.6.3.1 for discussion regarding the protection of the EDGs and their associated auxiliary systems from flooding, and external missiles.

9.5.7.3.2 General Design Criterion 3, 1971 - Fire Protection

Refer to Section 8.3.1.1.6.3.2 for discussion regarding the design of the fire protection system for the EDGs and their associated auxiliary systems.

9.5.7.3.3 General Design Criterion 11, 1967 - Control Room

Refer to Section 8.3.1.1.6.3.4 for discussion regarding the design of the EDGs and their associated auxiliary systems to support safe shutdown and to maintain safe shutdown from the control room or from an alternate location if the control room access is lost due to fire or other causes.

9.5.7.3.4 General Design Criterion 12, 1967 - Instrumentation and Control Systems

Refer to Sections 8.3.1.1.6.3.5 and 8.3.1.1.6.5 for discussions regarding the instrumentation and control for the EDGs and their associated auxiliary systems provided as required to monitor and maintain their variables within prescribed operating ranges.

9.5.7.3.5 General Design Criterion 21, 1967 - Single Failure Definition

Each diesel generator has a dedicated lubrication oil tank, cooler, recirculation pump, and pre-circulation pump such that failure of this equipment affects the associated diesel generator only.

Refer to Section 8.3.1.1.6.3.8 for discussion regarding single failure criterion.

9.5.7.3.6 Emergency Diesel Generator Lubrication System Safety Function Requirements

(1) Protection from Missiles

The EDG units and their associated auxiliary systems, as shown for Unit 1 in Figures 9.5-8 through 9.5-10, and similarly for Unit 2, are installed in separate compartments that are protected from internal missiles. Because EDG units are separated from each other by the concrete walls of the compartments, the units are protected from postulated internal missiles. Any missile created by an explosion within a compartment would remain in that compartment.

The provisions taken to protect the PG&E Design Class I, EDG lubrication system from missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Sections 3.5.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the PG&E Design Class I portion of the EDG lubrication system from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Section 3.6.

(3) Protection from Moderate Energy Pipe Rupture Effects

The provisions taken to provide protection of the PG&E Design Class I portion of the EDG lubrication system from the effects of moderate energy pipe failure are discussed in Section 3.6.

(4) Protection from Flooding Effects

The provisions taken to provide protection of the PG&E Design Class I portion of the EDG lubrication system from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

The possibility of flooding in the turbine building and in the diesel generator compartments is discussed in Section 8.3.1.1.6.3.9.

9.5.7.3.7 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The EDG system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

9.5.7.4 Tests and Inspections

Refer to Section 8.3.1.1.6.4 for discussion regarding the inspection and testing associated with the EDGs and their associated auxiliary systems.

9.5.7.5 Instrumentation Applications

Instrumentation application for this system is discussed in Section 8.3.1.1.6.5.

9.5.8 REFERENCES

1. Diablo Canyon Power Plant, Unit Nos. 1 and 2 – Issuance of Amendments Regarding Transition to a Risk–Informed Performance-Based Fire Protection Program in Accordance with 10 CFR 50.48 (c) (CAC Nos. MF2333 and MF2334), April 14, 2016.

2. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

3. Diablo Canyon Engineering Calculation HVAC 83-11, Pacific Gas and Electric Company, Nuclear Power Generation files.

4. Pacific Gas and Electric Company Probabilistic Risk Assessment Calculation File No. PRA04-11, Potential Loss of DFO Day Tank LCVs Following a Seismically Induced LOOP, July 5, 2005.

5. Pacific Gas and Electric Company Design Change Package DDP: 1000000205, Diesel Fuel Oil Storage Tank Cathodic Protection System Abandonment, April 2009

6. Calculation FP-805, NFPA 805 Design Basis Document, SAPN No. 9000041689

9.5.9 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

TABLE 9.1-1

SPENT FUEL POOL COOLING AND CLEANUP SYSTEM ANALYSIS DATA[a]

Spent Fuel Pool Permanent Storage Capacity	1,324 assemblies[b]
Spent Fuel Pool Water Volume, cubic feet	47,215
Minimum Boron Concentration of the Spent Fuel Pool Water, ppm	2,000 (Up to 2600 during MPC Loading)*
Partial core off-load (Case 1): 96 fuel assemblies from current refueling assumed to have 52,000 MWD/MTU burnup. Conservative assumptions have been used to minimize decay time and maximize base decay hear load.	
Spent fuel pool HX CCW inlet temp, °F	75
Decay heat production, Btu/hr	22.92×10^6
Spent fuel pool water temperature, °F	≤ 127
Full core off-load (Case 2): 193 fuel assemblies from current refueling separated into two burnup groups: 101 assemblies at 52,000 MWD/MTU and 92 assemblies at 25,000 MWD/MTU. Conservative assumptions have been used to minimize decay time and maximize base decay heat load.	
Spent fuel pool HX CCW inlet temp, °F	75
Decay heat production, Btu/hr	36.67×10^6
Spent fuel pool water temperature, °F	≤ 157
Emergency full core off-load (Case 3): 193 assemblies from current refueling after 36 days of operation at full power. Fuel assemblies are separated into two burnup groups: 113 assemblies at 40,000 MWD/MTU and 80 assemblies at 3,000 MWD/MTU. Conservative assumptions have been used to minimize decay time and maximize base decay heat load.	
Spent fuel pool HX CCW inlet temp, °F	75
Decay heat production, Btu/hr	38.71×10^6
Spent fuel pool water temperature, °F	≤ 162
Spent Fuel Pool Water Heat Inertia	
Time to heat from 127 to 212°F for partial offload Case 1 above and no heat loss, hr	11.27
Time to heat from 157 to 212°F for full offload Case 2	4.35

above, hr	
Time to heat from 162 to 212°F for emergency offload Case 3 above, hr	3.76

* Refer to Diablo Canyon ISFSI Technical Specifications

(a) DCPP thermal-hydraulic analyses have been changed per LAR 04-07, Enclosure 1, Section 4.3 as part of the temporary cask pit spent fuel storage rack project

(b) The maximum number of irradiated fuel assemblies stored in the SFP during normal plant operations is limited to 1433 fuel assemblies per DCPP TS LCO 3.7.17.C.

TABLE 9.1-2

SPENT FUEL POOL COOLING AND CLEANUP SYSTEM DESIGN AND OPERATING PARAMETERS

	Pumps 1-1/2-1	Pumps 1-2/2-2
Spent Fuel Pool Pump		
Number, per unit	1	1
Design pressure, psig	150	100
Design temperature, °F	225	225
Design flow, gpm	2,300	3,000
Material	Stainless steel	Stainless steel
Spent Fuel Pool Skimmer Pump		
Number, per unit	1	
Design pressure, psig	50	
Design temperature, °F	200	
Design flow, gpm	100	
Material	Stainless steel	
Refueling Water Purification Pump		
Number, per unit	1	
Design pressure, psig	150	
Design temperature, °F	200	
Design flow, gpm	400	
Material	Stainless steel	
Spent Fuel Pool Heat Exchanger		
Number, per unit	1	
Design heat transfer, Btu/hr	11.95×10^6	
	Shell	Tube
Design pressure, psig	150	150
Design temperature, °F	250	250
Design flow, lb/hr	1.49×10^6	1.14×10^6
Inlet temperature, °F	95	120
Outlet temperature, °F	103	109.5
Fluid circulated	Component cooling water	Spent fuel pool water
Material	Carbon steel	Stainless steel

TABLE 9.1-2

Spent Fuel Pool Demineralizer	
Number, per unit	1
Design pressure, psig	200
Design temperature, °F	250
Design flow, (min. to max.), gpm	27 to 109
Resin volume, ft^3	39
Material	Stainless steel
Spent Fuel Pool Filter	
Number, per unit	1
Design pressure, psig	200
Design temperature, °F	250
Design flow, gpm	150
Filtration requirement	98% retention of particles above 5 microns
Material, vessel	Stainless steel
Spent Fuel Pool Resin Trap Filter	
Number, per unit	1
Design pressure, psig	200
Design temperature, °F	250
Design flow, gpm	150
Filtration requirement	98 percent retention of particles above 5 microns
Material, vessel	Stainless steel
Spent Fuel Pool Skimmer Filter	
Number, per unit	1
Design pressure, psig	200
Design temperature, °F	250
Rated flow, gpm	150
Filtration requirement	98% retention of particles above 5 microns
Material, vessel	Stainless steel
Refueling Water Purification Filter	
Number, per unit	1
Design pressure, psig	200
Design temperature, °F	250
Design flow, gpm	400
Filtration requirement	98% retention of particles above 5 microns
Demineralizer Resin Trap	
Number, per unit	1
Slot opening, inches	0.010
Material	Stainless steel

TABLE 9.1-2

Spent Fuel Pool Strainer	
Number, per unit	1
Rated flow, gpm	2300
Perforation, inches	Approximately 0.2
Material	Stainless steel
Spent Fuel Pool Skimmer Strainer	
Number, per unit	1
Rated flow, gpm	100
Design pressure, psig	50
Design temperature, °F	200
Perforation, inches	1/8
Material	Stainless steel
Spent Fuel Pool Skimmers	
Number, per unit	2
Design flow, gpm	50
Piping and Valves	
Design pressure, psig	150
Design temperature, °F	200
Material	Stainless steel

TABLE 9.2-1

AUXILIARY SALTWATER SYSTEM
COMPONENT DESIGN DATA

Auxiliary Saltwater Pumps

Number, per unit	2
Type	Vertical, wet pit, single stage
Rated capacity, gpm	11,000
Rated head, feet of sea water	125
Efficiency, %	83
Motor horsepower	465[(a)]
Speed, rpm	900
Column and discharge head material exposed to salt water	316L stainless steel
Design temperature, °F	120
Casing rated pressure, psig	100
Submergence required, ft	3
Minimum flow to prevent overheating, gpm	1,400

(a) Nameplate rating is 400 HP; analyzed to be capable of operating at 465 brake HP

TABLE 9.2-2

AUXILIARY SALTWATER SYSTEM MALFUNCTION ANALYSIS

Component	Malfunction	Consequences and Comments
1. Auxiliary saltwater pump	Pump casing rupture	The casing is designed for 100 psig, which exceeds maximum operating conditions. Pump is inspectable. Standby pump provides redundancy.
2. Auxiliary saltwater pump	Pump fails to start	One operating pump supplies either normal or minimum postaccident flow. Second pump provides full redundancy. Indication in control room shows pump status.
3. Auxiliary saltwater pump	Manual valve at discharge closed or check valve sticks closed	This will be prevented by prestartup and operational checks. Indication in control room shows position of remotely operated valves and whether flow is established.
4. Component cooling water heat exchanger	Tube or channel rupture	Rupture is considered highly unlikely because of low operating pressures and use of corrosion resistant materials. However, the leaking heat exchanger can be identified by sequential isolation or visual inspection. If the leak is in the on-line heat exchanger, the standby heat exchanger would be placed in service and the leaking exchanger isolated.
5. Piping and general	Any leakage from system via open vent or drain valve, ruptured heat exchanger tube, or other malfunction of equipment served by the system	The leaking component can be identified by sequential isolation or visual inspection. Rupture in a main cooling header would be indicated in the control room as low differential pressure across the heat exchanger and high component cooling water temperature. The operator can remotely or manually transfer flow to the redundant supply header restoring the system's cooling function before there is a significant temperature rise in the component cooling water system.
6. Motor	Pipe rupture at pump-motor enclosure	Rupture is considered highly unlikely because of low operating pressures and use of corrosion-resistant materials in contact with the saltwater. However, each pump is located in an isolated enclosure. Rupture could flood one compartment but the other motor would be protected. Level transmitters in pump enclosures alarm to the control room when flooding is detected.
7. Traveling Screen	Screen clogging	Clogging of the ASW common traveling screen with debris is discussed in Section 9.2.7.2.3, "Intake Structure and Equipment."

TABLE 9.2-3

COMPONENT COOLING WATER SYSTEM COMPONENT DESIGN DATA

Component Cooling Water Pumps	
Number, per unit	3
Type	Horizontal centrifugal
Rated capacity, gpm	9200
Rated head, ft	145
Motor horsepower	400
Casing material	ASTM A-216 Gr. WCB carbon steel
Design pressure, psig	150
Design temperature, °F	300
Component Cooling Water Heat Exchangers	
Number, per unit	2
Type	Shell and tube
Heat transferred, Btu/hr	258.8×10^6
Shell-side	
Component cooling water outlet temperature, °F	125.0
Component cooling water inlet temperature, °F	171.7
Component cooling water flow rate, gpm	11,210
Design pressure, psig	150
Design temperature, °F	300
Tube side	
Auxiliary saltwater inlet temperature, °F	70
Auxiliary saltwater outlet temperature, °F	120
Auxiliary saltwater flow rate, gpm	10,580
Design pressure, psig	100
Design temperature, °F	200
Tube material	ASME SB-111 and/or ASME SB-543, 90-10 CuNi
Shell material	ASME SA 515 Gr. 70
Component Cooling Water Surge Tank	
Number, per unit	1
Type	Horizontal cylindrical with elliptical head: approximately 8 ft diameter x 30 ft long, internally baffled
Volume	
Total, gal	10,750
Normal operating, gal	Greater than 4,000
Design pressure, psig	150
Design temperature, °F	300
Material	ASME SA-285 Gr C

TABLE 9.2-4

COMPONENTS COOLED BY THE COMPONENT COOLING WATER SYSTEM

	Loop A	Loop B	Loop C
Containment fan coolers	2	3	
Residual heat removal heat exchangers	1	1	
Residual heat removal pump seal water coolers	1	1	
Centrifugal charging pumps CCP1 and CCP2 oil coolers	1	1	
Safety injection pump oil and seal water coolers	1	1	
Component cooling water pump oil coolers and stuffing boxes	2	1	
Post-LOCA sampling cooler	1		
Spent fuel pool heat exchanger			1
Seal water heat exchanger			1
Letdown heat exchanger			1
Excess letdown heat exchanger			1
NSSS sample heat exchangers – Unit 1			5
NSSS sample heat exchangers – Unit 2			4
Steam generator blowdown sample heat exchangers			5
Reactor coolant pump thermal barriers and motor oil coolers			4
Boric acid evaporator condenser, distillate cooler, vent condenser, and sample cooler (abandoned in place)			
Auxiliary steam drain receiver vent condenser (abandoned in place)			1
Waste gas compressors			2
Reactor vessel support coolers			4
Sample panel coolers			1

TABLE 9.2-5

COMPONENT COOLING WATER SYSTEM NOMINAL FLOWS[a]
(in gpm)

	Normal	LOCA[b]	Cooldown[c]
Containment fan coolers and motors	10,250	4,560	10,250
RHR heat exchangers	-	5,000	10,000
RHR pumps[f]	20	10	20
Centrifugal charging pumps CCP1 and CCP2[f]	30	15	30
Safety injection pumps[d][f]	48	24	48
Component cooling water pumps[e][f]	30	10	30
Spent fuel pool heat exchanger[i]	3,400	-	3,400
Seal water heat exchanger	210	-	210
Letdown heat exchanger	1,000	-	300
Excess letdown heat exchanger	-	-	-
NSSS sample heat exchanger	50	-	50
CCW sample line	10	-	10
Steam generator blowdown HX	40	-	40
Reactor coolant pumps	780	-	780
Boric acid evaporator package[h]	-	-	-
Waste concentrator package[h]	-	-	-
Auxiliary steam vent condenser[h]	-	-	-
Waste gas compressors	100	-	100
Reactor vessel support coolers	100	-	100
Sample panel coolers	40	-	40
Post-LOCA sample cooler	-	-	-
No. of pumps required	2	2	3[g]
No. of pumps normally in service	2	2 (one for each vital loop	3
No. of pumps installed	3	3	3

(a) Unless noted otherwise, the data contained in this table are nominal flows. For the purpose of design basis analyses, lower assumed flows may be used to evaluate equipment, containment heat removal capability, or different alignments (such as Section XI testing or RHR heat exchanger operation); higher assumed flows may be used to evaluate maximum CCW temperatures.

(b) Recirculation phase (flows are for vital header "B" which is greater than those of vital header "A"). The minimum required post-LOCA flow rates are shown. The flow rate for the CFCUs represents a minimum flow of 1490 gpm to the cooling coils and 30 gpm to the motor coolers. Note that during the injection phase the total minimum CFCU flow rate is 1650 gpm.

(c) 20 hours after initiation of reactor cooldown.

(d) For safety injection pumps, the minimum required cooling flow following a LOCA is 24 gpm per pump.

TABLE 9.2-5

(e) For component cooling water pumps, a minimum flow of 10 gpm per pump is required for stuffing box cooling flushing. Additional flow is required for lube oil cooling and is controlled by throttling to maintain lube oil temperature.

(f) Flow rates are minimum required following a LOCA. Flow rates during normal operation are higher, depending on system alignment.

(g) Three pumps are desirable. Loss of one extends cooldown time but does not create an unsafe condition.

(h) The waste concentrator package, boric acid evaporator package, and auxiliary steam vent condenser have been abandoned in place and are currently isolated from the CCW system.

(i) During core offload

TABLE 9.2-6

COMPONENTS WITH A SINGLE BARRIER BETWEEN COMPONENT COOLING WATER AND REACTOR COOLANT WATER

	Barrier Design Temperature, °F	Barrier Design Pressure, psig	Temperature Range of Reactor Coolant Water, °F	Pressure Range of Reactor Coolant Water, psig
RHR heat exchangers	400	630	≤ 350	≤ 600
RHR pumps (seal coolers)	800	5140	≤ 350	≤ 600
Reactor coolant pumps(thermal barrier cooling coils)	650	2485	≤ 600	≤ 2485
Letdown heat exchanger	400	600	≤ 380	≤ 600
Excess letdown heat exchanger	650	2485	≤ 600	≤ 2485
Seal water heat exchanger	250	150	≤ 200	≤ 150
Sample heat exchangers	680	2485	≤ 652.7	≤ 2485

TABLE 9.2-7

COMPONENT COOLING WATER SYSTEM MALFUNCTION ANALYSIS

Component	Malfunction	Consequences and Comments
1. Component cooling water pumps	Pump casing rupture	The casing is designed for 150 psig and 300°F which exceeds maximum operating conditions. Pump is inspectable and protected against credible missiles. Rupture is not considered credible. Standby pump provides redundancy.
2. Component cooling water pumps	Pump fails to start	Two operating pumps supply normal flow. Third standby provides redundancy.
3. Component cooling water pumps	Manual valve at pump suction or discharge closed or check valve sticks closed	This will be prevented by prestartup and operational checks. Further, periodic checks during normal operation would show that a valve was closed.
4. Component cooling water heat exchanger	Tube or shell rupture	Because of low operating pressures, rupture is considered incredible in normal or postaccident injection phase service; however, a leaking exchanger could be ascertained by sequential isolation or visual inspection. If a leak is in the on-line component cooling water heat exchanger, the standby exchanger would be put on stream and the leaking exchanger isolated and repaired. The leaking exchanger could be left in service with leakage up to the capacity of the makeup line to the system from the condensate storage tank, which is 250 gpm. During long-term postaccident recirculation the component cooling water system (CCWS) may be operated as two separate loops, either of which could sustain this failure with the other providing the minimum required engineered safety features.

TABLE 9.2-7

Component	Malfunction	Consequences and Comments
5. General	Any leakage from system via open or drain valve severed loop piping, ruptured heat exchanger tube or other malfunction of equipment served by the system	Leakage from the CCWS can be detected by a falling level in the component cooling water surge tank. Observation of the time for the water level to fall a given amount and the area of the water surface in the tank will permit a determination of the leakage rate. The leaking component can be ascertained by sequential isolation or visual inspection of equipment in the system or complete isolation of a header. The 4000 gallons remaining in the surge tank after a makeup valve open alarm and the makeup flow will provide time for the closure of valves external to the containment for the isolation of all but the largest leaks. A 200 gpm maximum leak or rupture is postulated, so the operator has at least 20 minutes to isolate the leak before the surge tank is empty. The period is extended if the automatically operated, Design Class II, normal makeup path functions as designed and adds makeup water to the system. If the operator observes a rapidly falling surge tank level, he can elect to align/start a backup makeup water flow to the system before trying to isolate the leak (a backup source of water to the CCWS is provided from the condensate storage tank). The 250 gpm, Design Class I, makeup water flowpath, described in Section 9.2.3.3.7, can be started within 10 minutes. Because the makeup rate is greater than the postulated leak, the sequential isolation of components to stop the leak can proceed in an orderly manner. The 200 gpm leak is within the capacity of the auxiliary building drainage system. The complete rupture of large pipes or equipment with rapid loss of water is considered highly unlikely in normal operation or postaccident injection phase operation since all vital system piping and heat exchangers are located in the missile protected area of the containment. However, any of the three headers can be isolated. The two vital headers may be separated in accordance with EOP E-1.4 based on plant conditions during long-term postaccident operation and a passive failure in either would not impair the minimum engineered safety features supported by the other. Leaks into the CCW system can result from heat exchanger tube failure. For the RCP thermal barrier, the system design is to contain the in-leakage to the CCW system within the containment structure. The outboard containment isolation valve returning CCW from all reactor coolant pump thermal barriers closes on a high flow signal indicating in-leakage from the higher pressure RCS. All piping and valves

required to contain this in-leakage are designed for an RCS design pressure of 2485 psig. Should a coolant leak develop from the postulated failure mode that does not result in automatic flow isolation, the corresponding increase in CCW volume is accommodated by the relief valve on the CCW surge tank. The four relief valves on the CCW returns from thermal barriers are sized to relieve volumetric expansion and are set to relieve at RCS design pressure.

Tube failure in components with design pressures / temperatures less than RCS design condition can also initiate a leak into the CCW system. The radioactivity associated with the reactor coolant would actuate the CCW system radiation monitor (see Section 9.2.2.2.12). The monitor in turn would annunciate in the control room and close the vent valve located just upstream of the CCW surge tank back-pressure regulator to prevent the regulator from venting after sensing high radiation. The operator would also receive high level and high-pressure alarms from the surge tank as it filled. Continued in-leakage would increase the pressure in the surge tank until the high surge tank pressure alarm is actuated and the relief valve setpoint is reached. The relief valve on the surge tank protects the system from overpressurization. The maximum postulated in-leakage into the CCW system is based on an RHR heat exchanger tube rupture. The relief valve can accommodate this flow. Relief valve discharge from the CCW system surge tank is routed to the skirted area under the surge tank where it enters a floor drain routed to the auxiliary building sump.

TABLE 9.2-9

MAKEUP WATER SYSTEM
EQUIPMENT DESIGN AND OPERATING PARAMETERS

Lime Tank[a]	
Coagulant Tank[a]	
Chemical Feed[a]	
Mixed Bed Demineralizers Regeneration System	
Caustic day tank	
Number, total	1
Lining	Thermo-setting resin
Size, in.	42 (dia) x 48 (straight side)
Material	Carbon steel
Caustic storage tank[a]	
Acid storage tank[a]	
Miscellaneous equipment	
Caustic dilution water heater	Electric, 125 kW @ 460 V
Caustic Feed pump	Diaphragm, 98 gph @ l30 psig
Reverse Osmosis (RO) System[a]	
RO Auxiliary Equipment[a]	
RO booster pumps (total)	2
RO prefilters	
Hypochlorite feed	
Acid feed	
Hexametaphosphate feed	
Dechlorination system	
Makeup Water Degassifier[a]	
Makeup Water Storage Tanks	
Primary water storage tank	

TABLE 9.2-9

Number, per unit	1
Type	Vertical diaphragm sealed tank
Capacity, gal.	200,000
Size, ft	30 (dia) x 40 (straight side)
Material	304L stainless steel

Condensate storage tank

Number, per unit	1
Type	Vertical tank with floating roof
Capacity, gal.	425,000
Size, ft	40 (dia) x 47 (straight side)
Material	Carbon steel with reinforced concrete wall

Fire water and transfer storage tank - serves both units

Number	1
Type	Vertical dual compartment tank
Capacity - fire water, gal.	300,000
transfer, gal.	150,000
Size - fire water, ft	33 (dia) x 51 (straight side)
transfer, ft	40 (dia) x 51 (straight side)
Material	Carbon steel Inner tank - carbon steel Outer tank - carbon steel with reinforced concrete wall

Primary water makeup pumps

Number, per unit	2
Design pressure, psia	160
Design temperature, °F	70
Operating flow, gpm	150
Operating head, ft	222
Fluid	Water
Driver, hp	15
Material	316 stainless steel
Type	Vertical in-line

Makeup water transfer pumps

Number, shared	2
Design pressure, psia	210
Design temperature, °F	70
Operating flow, gpm	250
Operating head, ft	240
Fluid	Water
Driver, hp	30

TABLE 9.2-9

Material	Class 30 cast iron
Type	Horizontal end suction

(a) These items are abandoned in place per administrative procedure. DCPP uses the MWTS.

TABLE 9.3-1

COMPRESSED AIR SYSTEM EQUIPMENT

A. INSTRUMENT AIR SYSTEM

Compressors	
Number	4
Type	Oil-free, two-stage, water-cooled, rotary screw
Capacity	300 scfm each
Pressure	100 psig
Number	2
Type	Oil-free, two stage, water cooled, rotary screw
Capacity	650 scfm (minimum) each
Pressure	110 psig
Number	1
Type	Oil-free, two stage, air cooled, rotary screw
Capacity	650 scfm each
Pressure	110 psig
Air Dryers	
Number	2
Type	Adsorbent, heat-regenerative (1) and heatless (1)
Capacity	1500 scfm each
Inlet pressure	100 psig
Inlet temperature	100°F
Exit dew point	-40°F at 100 psig and inlet air 100°F sat.
Pre-Filters	
Number	2
Type	Positive-seal
Capacity	2800 scfm each
Filtration	0.6 microns
After Filters	
Number	2
Type	Positive-seal
Capacity	3600 scfm each
Filtration	1 micron
Receivers	
Number	2
Capacity	650 cu ft each
Pressure	120 psig
Material	ASME SA 515 Gr. 70

TABLE 9.3-1

B. SERVICE AIR SYSTEM

Compressors	
Number	1
Type	Oil-free, two stage, air-cooled, rotary screw, VFD Driven
Capacity	165 cfm – 632 cfm
Pressure	125 psig
Number	1
Type	Oil-free, two stage, air-cooled, rotary screw, VFD Driven
Capacity	165 cfm – 881 cfm
Pressure	125 psig
Air Dryers	
Number	2
Type	Heatless (2)
Capacity	1400 scfm (each heatless)
Inlet pressure	100 psig
Exit dew point	-40°F
Pre-Filters	
Number	2
Type	Positive-seal
Capacity	2100 scfm
Filtration	1 micron
After Filters	
Number	2
Type	Positive-seal
Capacity	2400 scfm
Filtration	1 micron
Receiver	
Number	1
Capacity	750 cu ft
Pressure	125 psig

TABLE 9.3-2

NUCLEAR STEAM SUPPLY SYSTEM
SAMPLING SYSTEM COMPONENT DESIGN DATA

Sample Heat Exchanger

Number, per unit	3
Design heat transfer rate (duty for 652.7°F sat. steam to 127°F liquid), each, Btu/hr	2.12×10^5

	Shell	Tube
Design pressure, psig	150	2485
Design temperature, °F	350	680
Design flow, gpm	14.1	0.42
Temperature, in, °F	95	652.7 (max)
Temperature, out, °F	125	127 (max)
Fluid	Component cooling water	Sample
Material	Carbon steel	Austenitic stainless steel

Sample Pressure Vessel

Number, per unit	4
Volume, ml	150
Design pressure, psig	2485
Design temperature, °F	680
Material	Austenitic stainless steel

TABLE 9.3-5

CHEMICAL AND VOLUME CONTROL SYSTEM DESIGN DATA

General:	
Seal water supply flow rate, four pumps, nominal, gpm	32
Seal water return flow rate, four pumps, nominal, gpm	12
Letdown flow:	
Normal, gpm	75
Minimum, gpm	45
Maximum, gpm	120
Charging flow (excludes seal water):	
Normal, gpm	55
Minimum, gpm	25
Maximum, gpm	100
Temperature of letdown reactor coolant entering system, °F	545
Temperature of charging flow directed to reactor coolant system, °F	495
Centrifugal charging pump (CCP1 and 2) bypass flow (each), gpm	60
Centrifugal charging pump (CCP3) bypass flow (each), gpm	50
Amount of 4% boric acid solution required to meet design basis shutdown requirements, gal. (fuel cycle dependent)	14,042
Maximum pressurization required for hydrostatic testing of reactor coolant system, psig	3107

TABLE 9.3-6

CHEMICAL AND VOLUME CONTROL SYSTEM
PRINCIPAL COMPONENT DATA SUMMARY

Centrifugal Charging Pumps CCP1 and CCP2	
Number, per unit	2
Design pressure, psig	2800
Design temperature, °F	300
Design flow, gpm	150
Design head, ft	5800
Material	Austenitic stainless steel
Centrifugal Charging Pump CCP3	
Number, per unit	1
Design pressure, psig	3200
Design temperature, °F	300 [(a)]
Design flow, gpm	150
Design head, ft	5700
Material	Austenitic stainless steel
Boric Acid Transfer Pump	
Number, per unit	2
Design pressure, psig	150
Design temperature, °F	250
Design flow, gpm	75
Design head, ft	254
Material	Austenitic stainless steel
Gas Stripper Feed Pumps	
Number, per unit	2
Design pressure, psig	150
Design temperature, °F	200
Design flow, gpm	30
Design head, ft	320
Material	Austenitic stainless steel
Liquid Holdup Tank Recirculation Pump	
Number, per unit	1
Design pressure, psig	75
Design temperature, °F	200
Design flow, gpm	500
Design head, ft	100
Material	Austenitic stainless steel

Boric Acid Reserve Tank Pumps	
Number, shared	2
Design pressure, psig	150
Design temperature, °F	200
Design flow, gpm	150
Design head, ft	200
Material	Austenitic stainless steel
Boric Acid Reserve Tank Recirculation Pump	
Number, shared	2 per tank
Design pressure, psig	300
Design temperature, °F	400
Design flow, gpm	25
Design head, ft.	100
Material	Austenitic stainless steel
Concentrates Holding Tanks 0-1,0-2 Transfer Pumps (abandoned in place)	
Regenerative Heat Exchanger	
Number, per unit	1
Heat transfer rate at design conditions, Btu/hr	10.3×10^6
Shell side	
Design pressure, psig	2485
Design temperature, °F	650
Fluid	Borated reactor coolant
Material	Austenitic stainless steel
Tube side	
Design pressure, psig	2735
Design temperature, °F	650
Fluid	Borated reactor coolant
Material	Austenitic stainless steel
Shell side (Letdown)	
Flow, lb/hr	37,050
Inlet temperature, °F	545
Outlet temperature, °F	290
Tube Side (Charging)	
Flow, lb/hr	27,170
Inlet temperature, °F	130
Outlet temperature, °F	495

Letdown Heat Exchanger

Number, per unit	1	
Heat transfer rate at design conditions, Btu/hr	14.8×10^6	
Shell side		
Design pressure, psig	150	
Design temperature, °F	250	
Fluid	Component cooling water	
Material	Carbon steel	
Tube side		
Design pressure, psig	600	
Design temperature, °F	400	
Fluid	Borated reactor coolant	
Material	Austenitic stainless steel	
Shell side	Design	Normal
Flow, lb/hr	492,000	203,000
Inlet temperature, °F	95	95
Outlet temperature, °F	125	125
Tube Side (Letdown)		
Flow, lb/hr	59,280	37,050
Inlet temperature, °F	380	290
Outlet temperature, °F	127	127

Excess Letdown Heat Exchanger

Number, per unit	1	
Heat transfer rate at design conditions, Btu/hr	4.61×10^6	
	Shell Side	Tube Side
Design pressure, psig	150	2485
Design temperature, °F	250	650
Design flow, lb/hr	115,000	12,380
Inlet temperature, °F	95	545
Outlet temperature, °F	135	195
Fluid	Component cooling water	Borated reactor coolant
Material	Carbon steel	Austenitic stainless steel

Seal Water Heat Exchanger

Number, per unit	1	
Heat transfer rate at design conditions, Btu/hr	2.49×10^6	
	Shell side	Tube Side
Design pressure, psig	150	150
Design temperature, °F	250	250
Design flow, lb/hr	99,500	160,600
Inlet temperature, °F	95	143
Outlet temperature, °F	120	127
Fluid	Component cooling water	Borated reactor coolant
Material	Carbon steel	Austenitic stainless steel

Volume Control Tank

Number, per unit	1
Volume, ft^3	400
Design pressure, psig	75
Design temperature, °F	250
Spray nozzle flow (maximum), gpm	120
Material	Austenitic stainless steel

Boric Acid Tank

Number, per unit	2
Capacity, gal.	8,060
Design pressure	Atmospheric
Design temperature, °F	180
Material	Austenitic stainless steel

Boric Acid Batching Tank

Number, shared	1
Capacity, gal.	800
Design pressure	Atmospheric
Design temperature, °F	300
Material	Austenitic stainless steel

Chemical Mixing Tank

Number, per unit	1
Capacity, gal.	5
Design pressure, psig	150
Design temperature, °F	200
Material	Austenitic stainless steel

Liquid Holdup Tanks

Number, shared	5
Volume, gal.	83,220
Design pressure, psig	15
Design temperature, °F	200
Material	Austenitic stainless steel

Boric Acid Reserve Tanks

Number, shared	2
Capacity, gal.	24,610
Design pressure	Atmospheric
Design temperature, °F	150
Material	Austenitic stainless steel with membrane seal

Concentrates Holding Tank (abandoned in place)

Mixed Bed Demineralizers

Number, per unit	2
Design pressure	200
Design temperature, °F	250
Design flow, gpm	120
Normal resin volume, each, ft^3	30
Maximum resin volume, each, ft^3 (flush only)	39
Material	Austenitic stainless steel

Boric Acid Reserve Tank Recirculation Heater

Number, shared	1 per tank
Design pressure, psig	150
Design temperature, °F	500
Design flow, gpm	25
Material	Austenitic stainless steel

Cation Bed Demineralizer

Number, per unit	1
Design pressure, psig	200
Design temperature °F	250
Design flow, gpm	120
Resin volume, each, ft^3	27
Material	Austenitic stainless steel

Deborating Demineralizers

Number, per unit	2
Design pressure	200
Design temperature, °F	250
Design flow, gpm	120
Normal resin volume, each, ft^3	30
Maximum resin volume, each, ft^3 (flush only)	39
Material	Austenitic stainless steel

Evaporator Feed Ion Exchangers

Number, per unit	4
Design pressure, psig	200
Design temperature, °F	250
Design flow, gpm	30
Resin volume (maximum), ft^3	16
Material	Austenitic stainless steel

Evaporator Condensate Demineralizers (abandoned in place)

Reactor Coolant Letdown Filters

Number, per unit	2
Design pressure, psig	200 (1-1, 2-1), 300 (1-2, 2-2)
Design temperature, °F	250
Design flow, gpm	150 (1-1, 2-1), and 250 (1-2, 2-2)
Particle retention	98% of 25 micron size 100% of 50 micron size
Material, vessel	Austenitic stainless steel

Seal Water Injection Filters

Number, per unit	2
Design pressure, psig	2,735
Design temperature, °F	200
Design flow, gpm	80
Particle retention	98% of 5 micron size
Material, vessel	Austenitic stainless steel

Seal Water Return Filter

Number, per unit	1
Design pressure, psig	200
Design temperature, °F	250
Design flow, gpm	150
Particle retention	98% of 25 micron size
Material, vessel	Austenitic stainless steel

Boric Acid Filter

Number, per unit	1
Design pressure, psig	200
Design temperature, °F	250
Design flow, gpm	150
Particle retention	5 micron or less
Material, vessel	Austenitic stainless steel

Ion Exchanger Filter

Number, per unit	1
Design pressure, psig	200
Design temperature, °F	250
Design flow, gpm	35
Particle retention	98% of 25 micron size
Material, vessel	Austenitic stainless steel

Condensate Filter (abandoned in place)

TABLE 9.3-6

Concentrates Filter (abandoned in place)

Boric Acid Blender

Number, per unit	1
Design pressure, psig	150
Design temperature, °F	250
Material	Austenitic stainless steel

Letdown Orifice	45 gpm	75 gpm
Number, per unit	1	2
Design flow, lb/hr	22,230	37,050
Differential pressure at design flow, psia	1,900	1,900
Design pressure, psig	2,500	2,500
Design temperature, °F	650	650
Material	Austenitic stainless steel	Austenitic stainless steel

Gas Stripper - Boric Acid Evaporator Package (abandoned in place)

(a) The design temperature of 300°F is for the structural integrity of the pump but not the limitation for operation.

TABLE 9.3-7

NITROGEN REQUIREMENTS

Equipment	Supply Pressure, psig	Supply Flow, scfm	Comments
Pressurizer relief tank	6	12	Initial gas cover
Unit 1 Reactor coolant drain tank	<15	20 (27 max.)	Gas cover/purge (refueling outage)
Unit 2 Reactor coolant drain tank	<15	20 (40 max.)	Gas cover/purge
Volume control tank	18	8.3	Initial gas cover (2950 scf total for all 3 tanks above, per refueling cycle)
Spray additive tank	5	5	
Gas decay tanks	5	15	
Waste concentrator condenser	2	10	(abandoned in place)
Boric acid concentrator	2	10	(abandoned in place)
Boric acid tanks	1	10	
Concentrates holding tank 0-1	1	6	(abandoned in place)
Concentrates holding tank 0-2	1	8	(abandoned in place)
Liquid holdup tank	3	4 (70 max.)	
Accumulators	650	22	103,000 scf initial fill, based on 700 psig and 40% gas space per refueling cycle
Boric acid reserve tanks	1.5	1	
Various replenishment requirements			Degasification purging during cold shutdown, 8400 scf per cold shutdown
Nitrogen layup system for steam generators			400 lb of nitrogen gas required to purge 4 main steam lines and provide initial charge of nitrogen on steam generators at 5 psig

TABLE 9.3-7

Equipment	Supply Pressure, psig	Supply Flow, scfm	Comments
Nitrogen layup for 12 feedwater heaters			Same requirement as for steam generators except need 760 lb of nitrogen
CCW surge tank pressurization with N_2	20	25 (max)	Intermittent (to maintain surge tank pressure)
Condenser	30 (max)	20	Continuous
Zinc Tank	2” H_2O	<1	Intermittent (to maintain N_2 blanket in the zinc tank)

TABLE 9.3-8

HYDROGEN REQUIREMENTS

Equipment	Supply Pressure, psig	Supply Flow, scfm	Comments
Generator	75 (max.)	200 (makeup)	Initial fill of 34,390 scf
Volume control tank	15 to 26	8.3	960 scf required for purge and initial fill

TABLE 9.4-1

CONTROL ROOM VENTILATION SYSTEM (CRVS) COMPONENT DESIGN DATA

Filter Unit (per unit)

	No.	Size, in.	Efficiency, %[d]	Rated Air Flow Per Filter, cfm
Roughing filters	2	24 x 24 x 6[g]	80-85[a]	1000 @ 0.30"SP
HEPA filters	2	24 x 24 x 11-1/2	99.97[b]	1150 @ 1.00"SP
Charcoal filters (cells or trays)	6	26 x 26 x 6	99/85[c]	333 @ 1.3"SP

Charcoal Filter Humidity Control Heater (per unit)

	No.	Capacity, kW	Voltage, V
Electric heater	2	5.0	480

Fans (per unit)

	No.	Static Pressure, in H_2O	Air Flow, cfm	Motor, hp
Main supply	2	1.75	7800	7.5
Filter booster	2	5.40	2100	3
Exhaust	1	1.00	1700	3/4
Pressurization[e]	2	5.00	2100	7.5

Air Conditioning Units (per unit)

Two full-capacity air conditioning units are provided, each consisting of a reciprocating compressor, cooling coil, and fan air-cooled condenser. The refrigeration capacity for each condenser is 31.0 tons using Freon 22 at 37°F suction temperature and 107°F condenser temperature. The cooling coils are each capable of handling 7800 cfm of air at 400 fpm face velocity. The air conditions for the cooling coil are:

Entering air: 84.0°F D.B./64.8°F W.B.
Leaving air: 54°F D.B./53°F W.B.
Friction drop through the coil: 0.41 in. H_2O

TABLE 9.4-1

Airborne Contaminant Detectors (per unit)

	No.	Location	Sensitivity
Smoke	2	Return air duct	Trace amounts of combustion products
	2	Control room normal intake	Trace amounts of combustion products
Radioactivity	2	Control room normal intake	1×10^{-2} to 10^{+3} mR/hr
	2	Pressurization intakes	10^{-2} mR/hr (Sensitivity range is 10^{-2} to 10^{+4} mR/hr with setting point of 2 mR/hr)
Chlorine[f]	-	-	-

(a) Minimum efficiency requirements. Efficiency based on American Filter Institute (AFI) dust spot test

(b) Based on standard DOP test 0.3 micron particles

(c) Radioactive elemental iodine and radioactive iodide as methyl iodide, respectively (Efficiency rates are for filters as originally specified. Replacement filters shall comply with the requirements of the Ventilation Filter Test Program.

(d) Efficiency rates for HEPA and charcoal filters are for individual components (for filter efficiency rates during a DBA, refer to the respective accident analysis in Chapter 15)

(e) All four fans are common to both Unit 1 and Unit 2

(f) Chlorine monitors are abandoned in place or removed as there is no bulk chlorine onsite

(g) Table shows original filter size. Replacement filter depth dimension may vary.

TABLE 9.4-2

COMPLIANCE WITH REGULATORY GUIDE 1.52, JUNE 1973
DESIGN, TESTING, AND MAINTENANCE CRITERIA FOR ATMOSPHERE CLEANUP SYSTEM
AIR FILTRATION AND ADSORPTION UNITS OF LIGHT-WATER COOLED NUCLEAR POWER PLANTS

Regulatory Position	Compliance	Reasons or Comments
2. SYSTEM DESIGN CRITERIA		
a. Redundant systems and required components	Yes, except:	
	(1) No demisters.	(1) Demisters are not provided since they are not required for this filtration system design. In the control room, the outside air intake plenum is designed to present a tortuous path for flow in order to remove entrained water. At the time of operating the hydrogen vent system, several weeks after the DBA, no moisture will be entrained in the containment. Filters in the fuel handling building and the auxiliary building are not in direct contact with outside air.
	(2) No HEPA after-filters.	(2) Charcoal is thoroughly cleaned before insertion in filter trays. Formation of charcoal fines is not considered significant.
	(3) Auxiliary building ventilation system does not have redundant charcoal filters.	(3) As discussed in Section 15.5.17, failure of an RHR pump seal was already assumed as the single failure, an additional failure of the auxiliary building charcoal filter need not be postulated. Therefore, the charcoal filters need not be redundant.
	(4) Auxiliary building ventilation system does not have redundant electric heaters. Fuel handling building ventilation system does not have electric heaters (refer to 3.b below).	(4) Installation of one electric heater for the auxiliary building ventilation system is consistent with the commitments made as discussed in Section 15.5.17.

TABLE 9.4-2

Regulatory Position	Compliance	Reasons or Comments
2. SYSTEM DESIGN CRITERIA		
b. Physical separation, including missile protection	Yes, except some ventilation systems in the plant are not specifically designed against tornadoes (refer to Section 3.3.2) or against local damage of ducting by missiles. However, the control room positive pressurization system is specifically designed for protection against tornado missiles (Refer to Section 9.4.1.3.1). The remainder of the control room ventilation system is enclosed within reinforced concrete structures.	No damage to components essential to safe plant shutdown or to protection of the public.
d. Protection against pressure surges	Not applicable.	Auxiliary building ventilation system not specifically designed for pressure surge due to failure of gas decay tank. Since insignificant amounts of radioiodine are contained in the tank, loss of this system will not affect offsite exposures.
f. Maximum air flow rate per train and preferred filter array	Air flow rate for the fuel handling building ventilation system is 35,750 cfm and auxiliary building ventilation system is 73,500 cfm versus recommended 30,000 cfm.	In either case, filters are easily replaced. Structural platforms and traveling hoists are permanently installed in filter rooms. In only one case are filters aligned more than three high above the floor or a platform.
g. Flow and ΔP signal, alarm and record in control room	No control room recorders or alarms.	Systems are tested at least once each 31 days when required to be operable per Technical Specifications. Fan status and damper position indicator lights are provided in the control room for the auxiliary and fuel handling buildings ventilation systems. The control room HVAC system is provided with a system trouble alarm in the control room.
j. Total enclosure and intact replacement	Not replaceable intact.	Each filter train consists of a totally enclosed unit, which cannot be replaced intact due to the as-built dimensions of the filter train room and access doors. Filter train components can be individually replaced.

TABLE 9.4-2

Regulatory Position	Compliance	Reasons or Comments
3. COMPONENT DESIGN CRITERIA & QUALIFICATION TESTING		
a. Demisters quality to MSAR 71-45 & UL Class I	Not applicable.	No demisters.
b. Heaters to reduce RH to 70% under DBA	The fuel handling building ventilation system does not have electric heaters. Heaters are installed for the control room and the auxiliary building ventilation systems.	Heaters not required for the fuel handling building, control room, and auxiliary building ventilation systems. Charcoal samples are tested to 95% RH. Relative humidity of the exhaust air of these systems is not expected to exceed the tested condition.
4. MAINTENANCE		
i. Entire standby atmosphere cleanup train should be operated at least 10 hours per month, with the heaters on (if so equipped), in order to reduce the buildup of moisture.	No.	Site climate should not lead to an excessive buildup of moisture on the filters; however, at least once per 31 days, when required by the Technical Specifications for operability, flow is initiated through the filters for at least 15 minutes to verify flow (refer to Section 9.4.1.4.2)
5. IN-PLACE TESTING CRITERIA		
b. In-place penetration of HEPA filters should conform to ANSI N101.1-1972.	No. Visual inspection, in-place penetration and bypass leakage testing of HEPA filter performed in accordance with ANSI N510-1980.	The in-place testing criteria are established in the Technical Specifications. The 1980 revision of ANSI N510 encompasses the testing criteria required by ANSI N101.1-1972.
HEPA filter sections should be tested in place initially and semiannually thereafter, to confirm a penetration of less than 0.05% at rated flow.	No. An in place test of the CRVS, ABVS and FHBVS HEPA filters shows a penetration and system bypass < 1.0% when tested at least once per 24 months.	The in-place testing criteria are established in the Technical Specifications.
c. Adsorber banks should be leak tested in accordance with USAEC Report DP-1082.	No. Visual inspection, in-place penetration and bypass leakage testing of adsorber banks for CRVS, ABVS and FHBVS is performed in accordance with ANSI N510-1980.	The in-place testing criteria are established in the Technical Specifications. The 1980 revision of ANSI N510 encompasses the testing criteria required by USAEC Report DP-1082.

Regulatory Position	Compliance	Reasons or Comments
Adsorber leak testing should be conducted whenever DOP testing is done.	No. An in place test of the CRVS, ABVS and FHBVS charcoal adsorbers shows a penetration and system bypass < 1.0% when tested at least once per 24 months.	The in-place testing criteria are established in the Technical Specifications.
6. LABORATORY TESTING CRITERIA FOR ACTIVATED CARBON		
a. Activated carbon adsorber section should be assigned the decontamination efficiencies given in Table 2.	No. The control room ventilation system decontamination efficiencies assumed in the accident analysis are 93% / 93% for elemental and organic iodine respectively. The control room HVAC system charcoal samples are tested at 30°C/95% RH per ASTM D3803-89 with a 2.5% acceptance criteria versus using RDT M16-1T (1972) at DBA conditions.	The laboratory test acceptance criteria are established in the Ventilation Filter Test Program, which is controlled by the Technical Specifications. Testing per RDT M16-1T (1972) has been superseded by the more conservative test requirements in ASTM D3803-1989. In accordance with Generic Letter 99-02, June 1999 a safety factor of 2 is used in determining the charcoal filter efficiency for use in safety analyses.
	The auxiliary building ventilation system decontamination efficiencies assumed in the accident analysis are 88%/88% for elemental and organic iodine, respectively, versus 95%/95% as assigned by Regulatory Guide 1.52, June 1973 Table 2. Additionally, the charcoal samples are tested at 30°C/95% RH per ASTM D3803-89 with a 5% acceptance criterion versus using RDT M16-1T (1972) at DBA conditions.	The decontamination efficiencies used in the accident analysis are more conservative than the values stated in Regulatory Guide 1.52, June 1973. The laboratory test acceptance criteria are established in the Technical Specifications. Testing per RDT M16-1T (1972) has been superseded by the more conservative test requirements in ASTM D3803-1989. In accordance with Generic Letter 99-02, June 1999 a safety factor of 2 is used in determining the charcoal filter efficiency for use in safety analyses.
	The fuel handling building ventilation system decontamination efficiencies are 95%/95% as assigned by Regulatory Guide 1.52, June 1973 Table 2. Refer to Table 15.5-45 for a discussion of assumed efficiencies in the accident	The decontamination efficiencies used in the accident analysis are more conservative than the values stated in Regulatory Guide 1.52, June 1973. The laboratory test acceptance criteria are established in the Technical Specifications. Testing per RDT M16-1T (1972) has been superseded by the more Conservative test requirements in ASTM D3803-1989.

Regulatory Position	Compliance	Reasons or Comments
	analysis. Additionally, the charcoal samples are tested at 30°C/95% RH per ASTM D3803-89 with a 15% acceptance criterion versus using RDT M16-1T (1972) at DBA conditions.	

TABLE 9.4-5

AUXILIARY BUILDING VENTILATION SYSTEM
COMPONENTS DESIGN DATA

Filters, per unit

	No.	Size, in	Efficiency, %[d]	Rated Air Flow Per Filter, cfm
Supply roughing[e]	70	24x24x26	30 (minimum)[e]	2,000 @ 0.17" SP
Exhaust roughing	172	24x24x12	80-85[a]	2,000 @ 0.55" SP
Exhaust HEPA	273	24x24x 11-1/2	99.97[b]	1,150 @ 1.00" SP
Exhaust charcoal (module composed of 3 cells or trays)	77	27-5/32 x 26-3/8 x 28-1/2	99/85[c]	1,000 @ 1.3" SP (Air enters from rear of tray)

Fans, per unit

	No.	Max. Static Pressure H_2O, in	Air Flow, cfm	Motor, hp
Supply (S31 & S32, Unit 1) (S33 & S34, Unit 2)	2	2.80	67,500	60
Exhaust (1E1 & 1E2,Unit 1) (2E1 & 2E2,Unit 2)	2	10.00	73,500	150

Electric Heaters, per unit

	No.	Rating
Exhaust (1EH-30, Unit 1) (2EH-30, Unit 2)	1	54 kW, 480 V, 3d

(a) Minimum efficiency requirements (Efficiency based on National Bureau of Standard (NBS) methods, dust spot test.)

(b) Based on standard DOP test 0.3 micron particles

(c) Radioactive elemental iodine and radioactive iodide as methyl iodide, respectively. Efficiency rates are for filters as originally specified. Replacement filters shall comply with the requirements of Regulatory Guide 1.52, June 1973 and ANSI N509.

(d) Efficiency rates for HEPA and charcoal filters are for individual components.

(e) Average dust spot efficiency requirement (Efficiency based on ASHRAE Standard 52.1 test)

(f) Supply filters are nominal values and may not reflect the as-built conditions.

TABLE 9.4-6

FUEL HANDLING BUILDING VENTILATION SYSTEM
COMPONENTS DESIGN DATA

Filters, per unit

	No.	Size, in.	Efficiency, %	Rated Air Flow Per Filter, cfm
Supply roughing	21	24x24x13	30[a]	2,500 @ 0.35" SP
Exhaust roughing	120	24x24x12	80-85[a]	2,000 @ 0.55" SP
Exhaust HEPA	107	24x24x 11-1/2	99.97[b]	1,150 @ 1.00" SP
Exhaust charcoal (module composed of 3 cells or trays)	72	27-5/32 x 26-3/8 x 28-1/2	99/85[c]	1,000 @ 1.3" SP (Air enters from rear of tray)

Fans, per unit

	No.	Max. Static Pressure H_2O, in.	Air Flow, cfm	Motor, hp
Supply (S1 & S2)	2	2.90-3.30	23,300	25
Exhaust (E4)	1	6.75	35,750	75
(E5 & E6)	2	7.55	35,750	75

Heating Coils, per unit

Heating Capacity, Btu/hr	Area, sq ft	Air Flow, cfm	Entering Temp., °F	Leaving Temp., °F	Steam Press., psig
1,400,000	61.8	23,300	35	70	15

TABLE 9.4-6

(a) Minimum efficiency requirements (Efficiency based on National Bureau of Standards (NBS) methods, dust spot test.)

(b) Based on standard DOP test 0.3 micron particles

(c) Radioactive elemental iodine and radioactive iodide as methyl iodide, respectively (Efficiency rates are for filters as originally specified. Replacement filters shall comply with the requirements of Regulatory Guide 1.52 and ANSI N509.)

TABLE 9.4-7

DESIGN VALUES FOR TURBINE BUILDING (GENERAL AREA) VENTILATION SYSTEM,

Turbine building volume, ft^3	5,125,000
15 Supply fans rating, cfm/fan	28,000
4 Exhaust fans rating, cfm/fan	40,000

TABLE 9.4-8

DESIGN CODES AND STANDARDS FOR VENTILATION SYSTEMS

Building or Area	Code
Control room	State of California, Industrial Safety Orders, Title 8, Sub-Chapter 7
	American Society of Heating, Refrigerating and Air Conditioning Engineers (ASHRAE) Guide
	Sheet Metal, Air Conditioning Contractors' National Association (SMACNA) Code
	Air Movement and Control Association (AMCA) - Standards for Air Moving Devices
Auxiliary building (excluding fuel handling area)	State of California, Industrial Safety Orders, Title 8, Sub-Chapter 7
	ASHRAE Guide
	SMACNA Code
	AMCA - Standards for Air Moving Devices
	American Conference of Governmental Industrial Hygienists - Industrial Ventilation Manual
Turbine building	State of California, Industrial Safety Orders, Title 8, Sub-Chapter 7
	ASHRAE Guide
	SMACNA Code
	AMCA - Standards for Air Moving Devices
Fuel handling area of the auxiliary building	State of California, Industrial Safety Orders, Title 8, Sub-Chapter 7
	ASHRAE Guide
	SMACNA Code
	AMCA - Standards for Air Moving Devices

TABLE 9.4-8

Building or Area	Code
Containment	State of California, Industrial Safety Orders, Title 8, Sub-Chapter 7
	ASHRAE Guide
	SMACNA Code
	AMCA - Standards for Air Moving Devices
Auxiliary saltwater pump vaults	State of California, Industrial Safety Orders, Title 8, Sub-Chapter 7
	ASHRAE Guide
	SMACNA Code
	AMCA - Standards for Air Moving Devices
125-Vdc/480-V switchgear area	State of California, Industrial Safety Orders, Title 8, Sub-Chapter 7
	ASHRAE Guide
	SMACNA Code
	AMCA - Standards for Air Moving Devices
4.16-kV Switchgear room	State of California, Industrial Safety Orders, Title 8, Sub-Chapter 7
	ASHRAE Guide
	SMACNA Code
	AMCA - Standards for Air Moving Devices
Post-accident sample room	ASHRAE Guide
	SMACNA Code
	AMCA - Standards for Air Moving Devices

TABLE 9.4-8

Building or Area	Code	
Technical support center	ASHRAE Guide	
	SMACNA Code	
	AMCA - Standards for Air Moving Devices	
Containment Penetration Area GE/GW	AMCA 99 (1972) -	Standards Handbook
	AMCA 210 (1974) -	Test Code For Air Moving Devices
	AMCA 500 (1975) -	Test Methods for Louvers, Dampers and Shutters
	ANSI N509-1980 -	Nuclear Power Plants Air Cleaning Units and Components
	SMACNA -	HVAC Duct Construction Standards 1985
	SMACNA -	Round Industrial Duct Construction Standard

TABLE 9.4-9

ESTIMATED CONTROL ROOM AREA HEAT LOADS[a]

(NORMAL OPERATING CONDITIONS - MODE 1)

Area	Btu/hr	
Control Room		
Floor and wall	14,990	
Occupants	3,200	
Lighting	35,495	
Annunciators, control boards, and nuclear instrumentation	109,365	
Computer Room		
Floor and wall	8,900	
Occupants	1,280	
Lighting	8,765	
Computers and analog control system	3,865	67,580[b]
Record Storage and Office		
Floor and wall	3,450	
Occupants	1,150	
Lighting	5,300	
Safeguard Room		
Floor and walls	2,545	
Occupants	640	
Lighting	3,030	
Solid state protection system	18,770	
Control Room Area Outside Air	2,835	
Total Heat Loads	223,580	
Total Tonnage - 19.0 Tons		

(a) All loads are given for Unit 1. Unit 2 heat loads are considered the same. The information contained in this table is “representative” of Units 1 and 2. Refer to the applicable design calculations for the current heat loads. This table will not be revised to reflect current design bases heat loads.

(b) Unit 1 computer room cooling load handled by supplemental computer room air conditioning units.

TABLE 9.4-10

DESIGN VALUES FOR AUXILIARY BUILDING VENTILATION SYSTEM[a]

Auxiliary Building Ventilation System (per unit)

Mode 1: Building Ventilation

1 Supply fan	Rating, cfm/fan	67,500
1 Exhaust fan	Rating, cfm/fan	73,500

Item	Heat Load, Btu/hr
Lighting	286,500
Equipment, piping, and cables	780,200
Electric motors	526,300
TOTAL	1,593,000

Mode 2: Building and Engineered Safety Ventilation

2 Supply fans	Rating, cfm/fan	67,500
2 Exhaust fans	Rating, cfm/fan	73,500

Item	Heat Load, Btu/hr
Lighting	286,500
Equipment, piping, and cables	1,194,000
Electric motors	1,271,200
TOTAL	2,751,700

Mode 3: Engineered Safety Ventilation

1 Supply fan	Rating, cfm/fan	67,500
1 Exhaust fan	Rating, cfm/fan	73,500

Item	Heat Load, Btu/hr
Lighting	286,500
Equipment, piping, and cables	1,194,000
Electric motors	1,103,400
TOTAL	2,583,900

TABLE 9.4-10

Fuel Handling Building Ventilation System (per unit)

Normal and Iodine Removal Modes (not including auxiliary feed pumps)

1 Supply fan	Rating, cfm/fan	23,300
1 Exhaust fan	Rating, cfm/fan	35,750

Item	Heat Load, Btu/hr
Lighting	114,700
Equipment, piping, and cables	245,500
Electric motors	209,000
TOTAL	569,200

Normal and Iodine Removal Modes (including auxiliary feed pumps)

1 Supply fan	Rating, cfm/fan	23,300
1 Exhaust fan	Rating, cfm/fan	35,750

Item	Heat Load, Btu/hr
Lighting	114,700
Equipment, piping, and cables	245,500
Electric motors	352,900
TOTAL	713,100

(a) The information contained in this table is “representative” of Units 1 and 2 and is provided for information only. Refer to the applicable design calculations for the current heat loads. This table will not be revised to reflect current design bases heat loads.

TABLE 9.4-11

ESTIMATED NSSS HEAT LOSSES INSIDE CONTAINMENT

Piping	Btu/hr (x 10^6)
Reactor Coolant System	0.09
Other Piping	0.04
Equipment	
Reactor Vessel[a]	
Above seal	0.037
Below seal	0.125
Reactor Coolant Pumps[b]	3.600
Steam Generators	0.800
Pressurizer[c]	0.133
Control Rod Drive Mechanisms[d]	2.260
Pressurizer Relief Tank	0.022
Primary Concrete Shield	0.015
Regenerative Heat Exchanger	0.022
Excess Letdown Heat Exchanger	0.010
Total	7.154
Contingency	1.106
Total[e]	8.260

(a) Does not include supports

(b) Each pump: motor - 0.75 x 10^6 Btu/hr; uninsulated section - 0.15 x 10^6 Btu/hr

(c) Includes supports and heater terminal connections

(d) Includes heat losses from control rod drive mechanisms, and control rod penetration housings

(e) The following heat losses have not been included

Heat losses from piping and equipment not considered part of NSSS
Daily and seasonal ambient temperature changes
Solar heat load
Fan input power

TABLE 9.4-12

ESTIMATED TOTAL HEAT SOURCES INSIDE CONTAINMENT

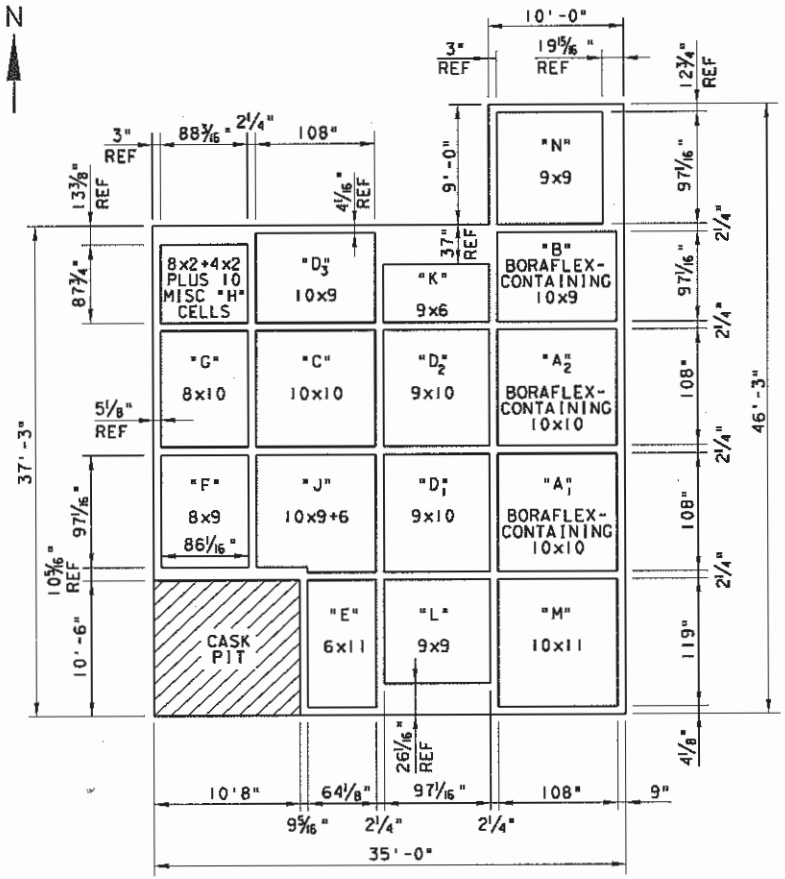
Heat Sources	Btu/hr (x 10^6)
a. Steam and feedwater lines	0.30
b. Solar	0.10
c. Control rod drive fans	0.35
d. Ventilation fans (4 running)	2.94
e. NSSS[(a)]	8.26
f. Contingency for heat sources a, b, c, & d	0.37
Total	12.32

(a) The assumed NSSS sources of heat losses are shown in Table 9.4-11

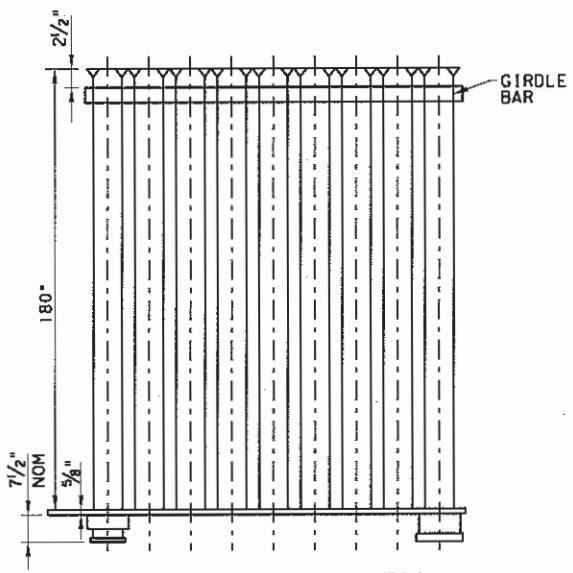
TABLE 9.5-2

DIESEL GENERATOR FUEL OIL SYSTEM COMPONENT DESIGN DATA

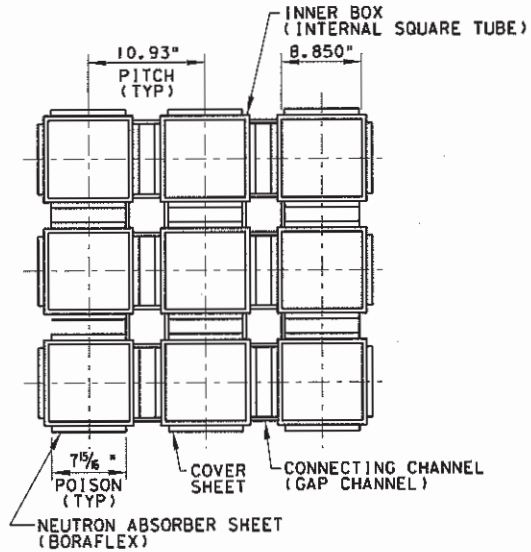
Storage Tanks	
Number, shared	2
Type	Horizontal, underground
Capacity, gal	50,000
Pressure	Atmospheric
Temperature	Ambient ground temperature
Material	Carbon steel/fiberglass
Transfer Pumps	
Number, shared	2
Type	Rotary, two-screw
Viscosity range, ssu	35 - 100
Rated capacity, gpm	58
Discharge pressure, psig	50
Suction pressure, in Hg	20
Casing material	Nodular iron
Motor horsepower	5



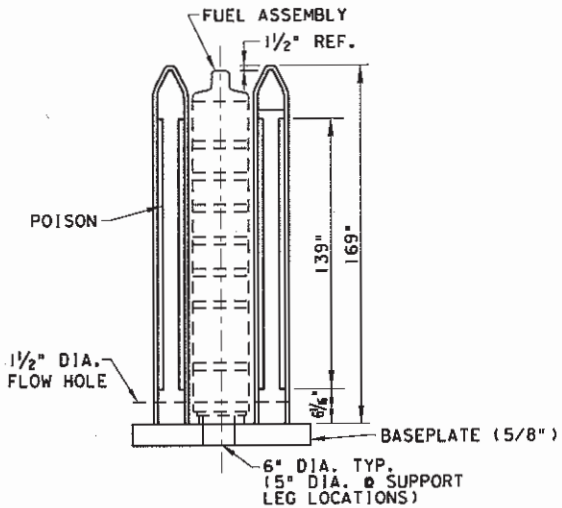
POOL LAYOUT
UNIT 1



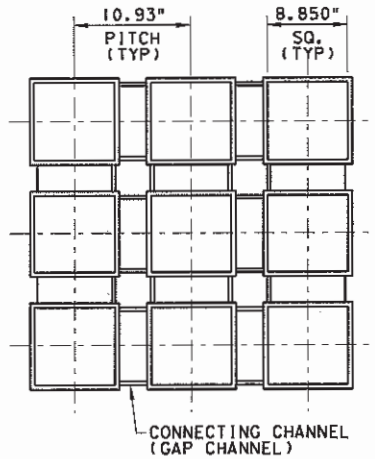
TYPICAL RACK ELEVATION



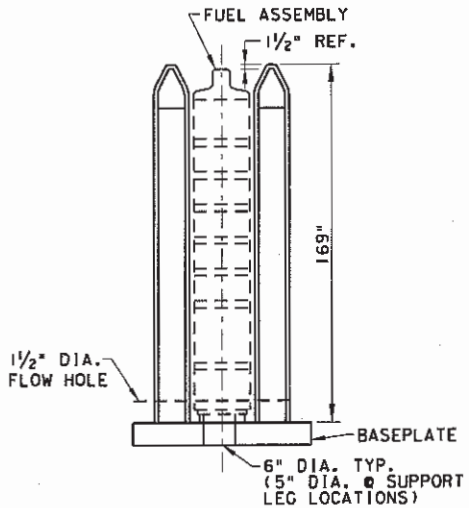
3 x 3 TYPICAL ARRAY
BORAFLEX - CONTAINING
(POISONED CELLS)



TYPICAL CELL ELEVATION
BORAFLEX - CONTAINING
(POISONED CELLS)



TYPICAL ARRAY
NON BORAFLEX - CONTAINING
(UNPOISONED CELLS)

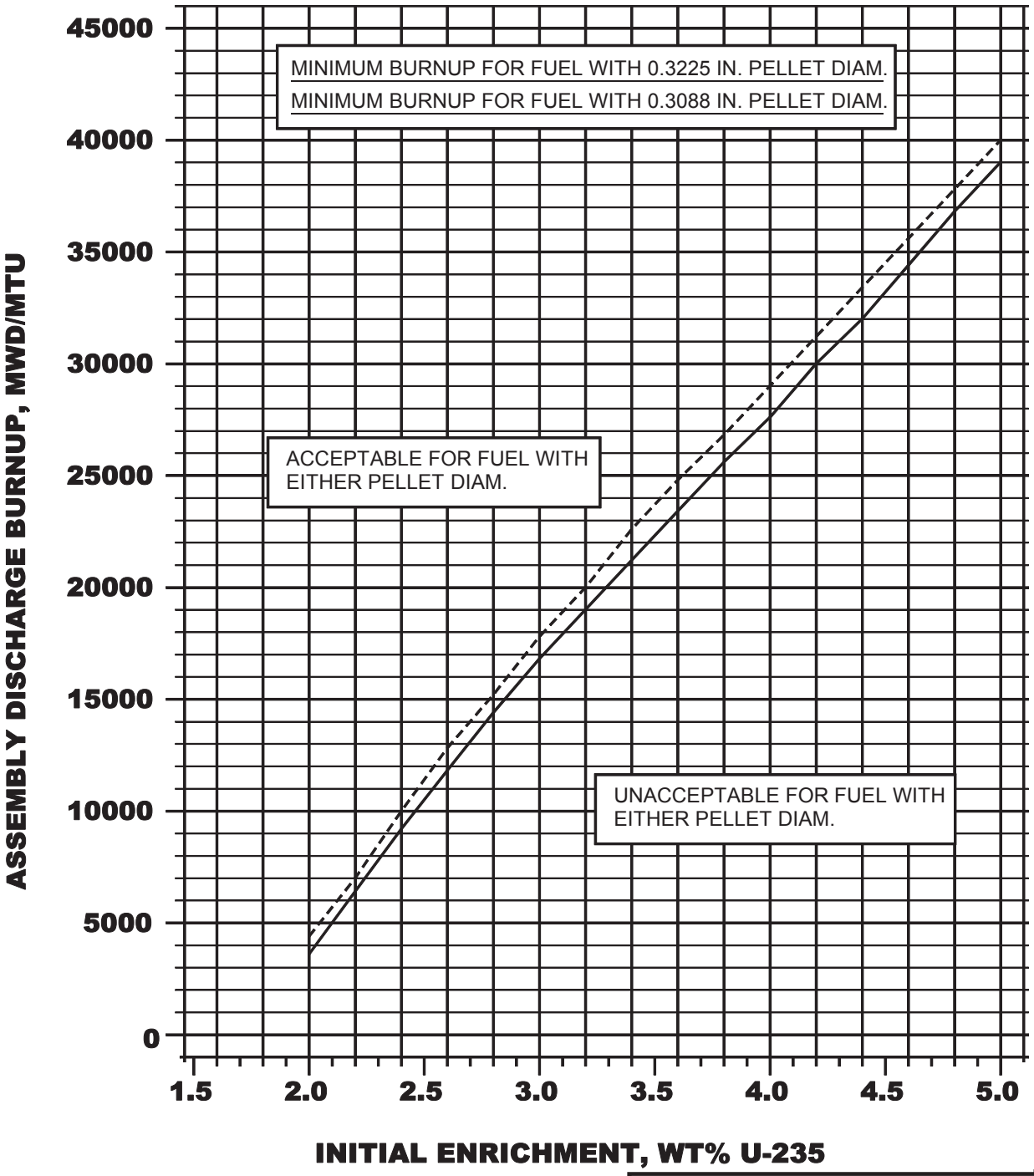


TYPICAL CELL ELEVATION
NON BORAFLEX - CONTAINING
(UNPOISONED CELLS)

FSAR UPDATE
UNITS 1 AND 2
DIABLO CANYON SITE

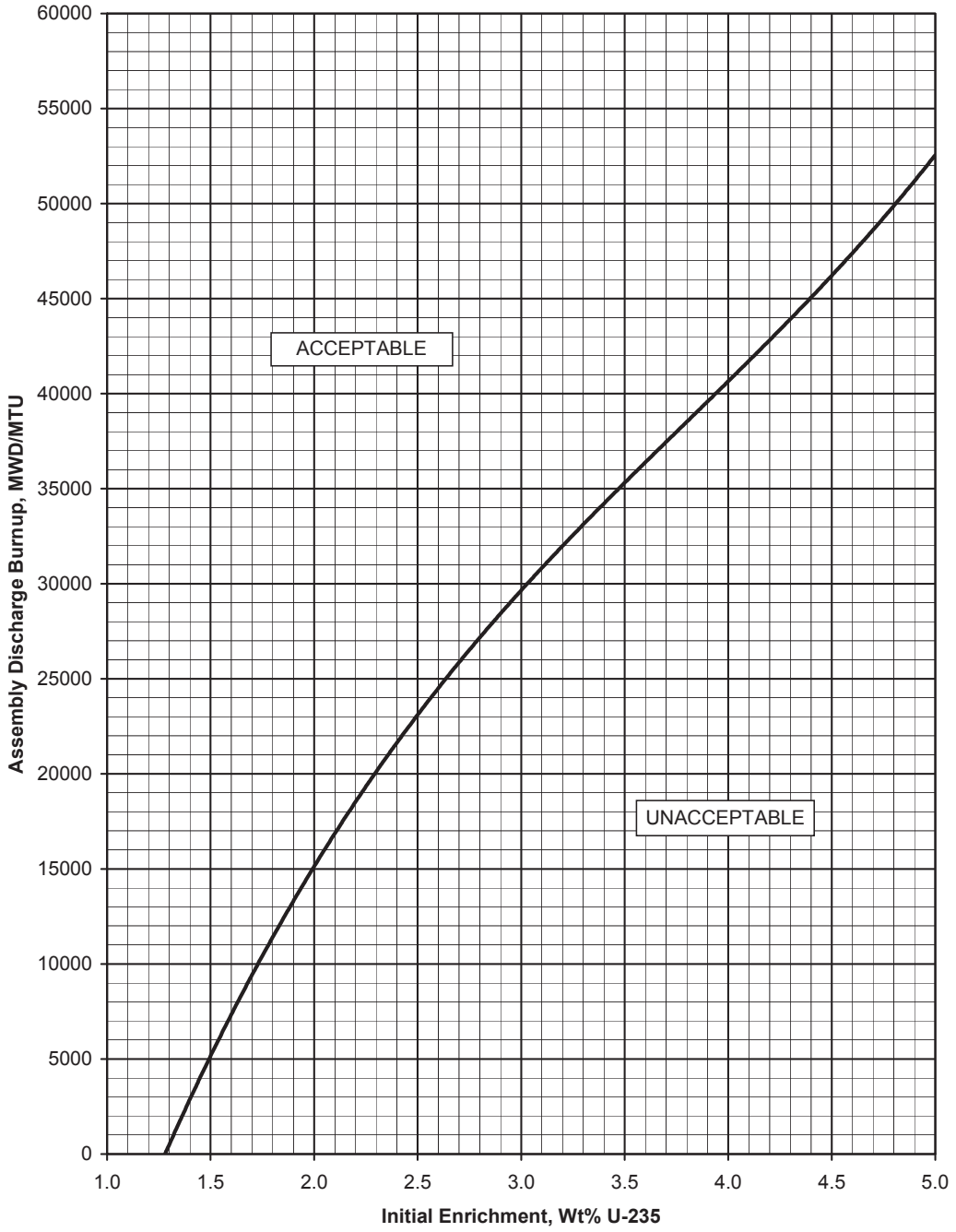
FIGURE 9.1-2
SPENT FUEL STORAGE

September 1988 Revision 4



MINIMUM REQUIRED ASSEMBLY DISCHARGE BURNUP AS A FUNCTION OF INITIAL ENRICHMENT AND FUEL PELLET DIAMETER FOR AN ALL CELL STORAGE CONFIGURATION.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 9.1-2A BURNUP VS. ENRICHMENT (ALL CELL)



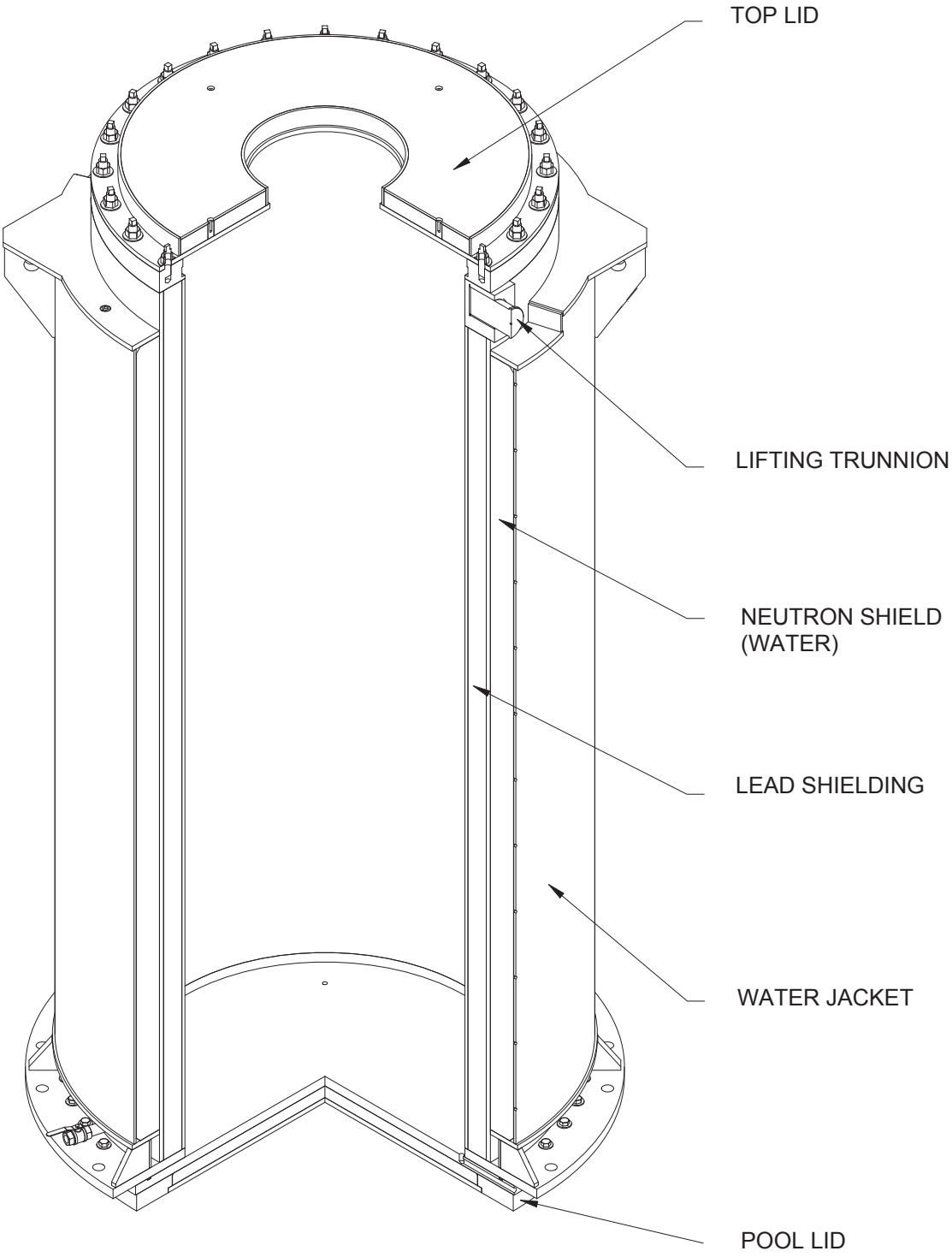
MINIMUM REQUIRED ASSEMBLY DISCHARGE BURNUP
AS A FUNCTION OF INITIAL ENRICHMENT
FOR A 2X2 ARRAY STORAGE CONFIGURATION

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 9.1-2B
BURNUP VS. ENRICHMENT
(2 X 2 ARRAY)

Revision 15 September 2003

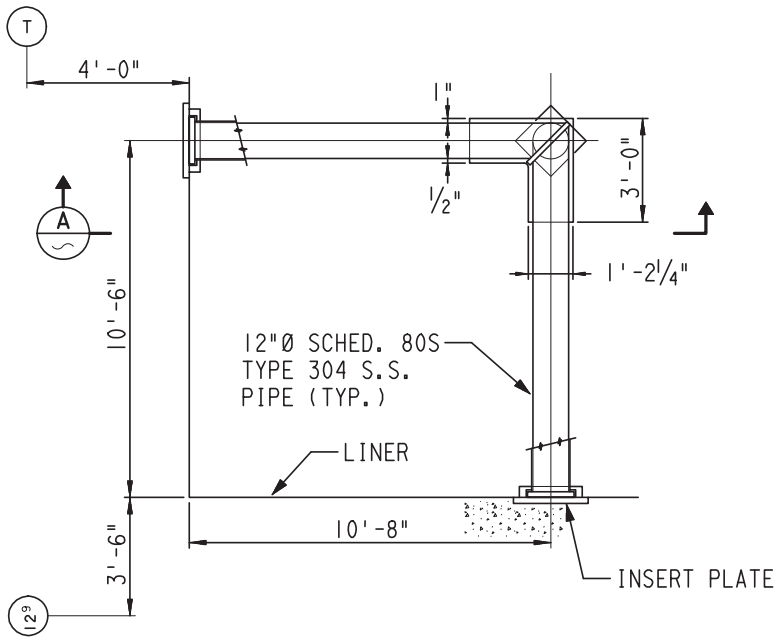


FSAR UPDATE

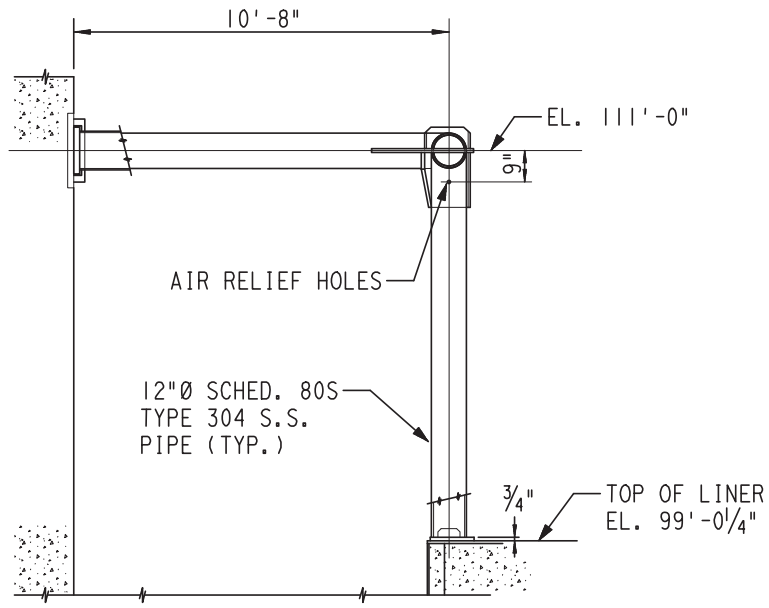
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 9.1-4
HI-TRAC 125D TRANSFER CASK

Revision 19 May 2010



PLAN - SPENT FUEL CASK RESTRAINT

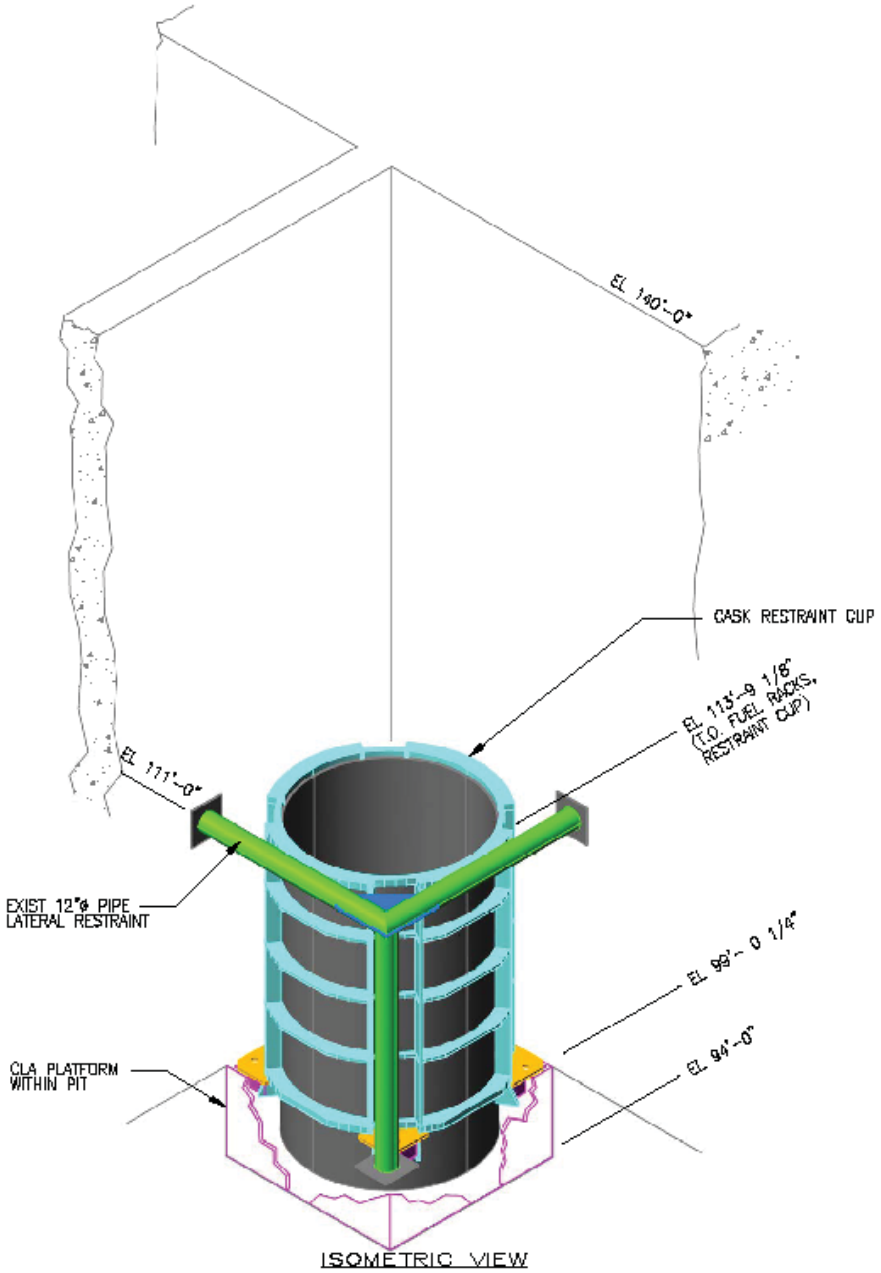


SECTION A

NOTE:
THIS FIGURE IS FOR UNIT 1
COLUMN LINES FOR UNIT 2 ARE DIFFERENT

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 9.1-5 SPENT FUEL CASK RESTRAINT SPENT FUEL POOL

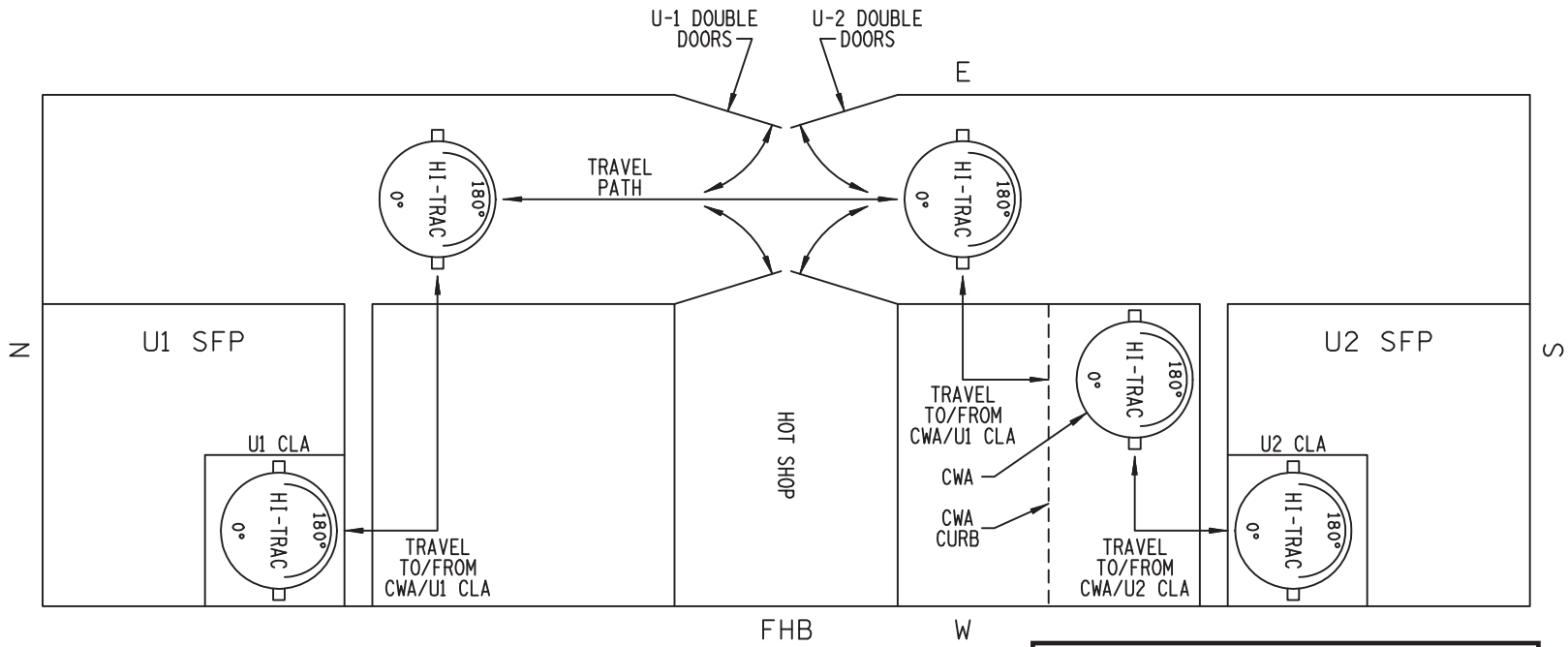
Revision 18 October 2008



Dimensions and elevations are estimates

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 9.1-6 SPENT FUEL POOL TRANSFER CASK RESTRAINT CUP

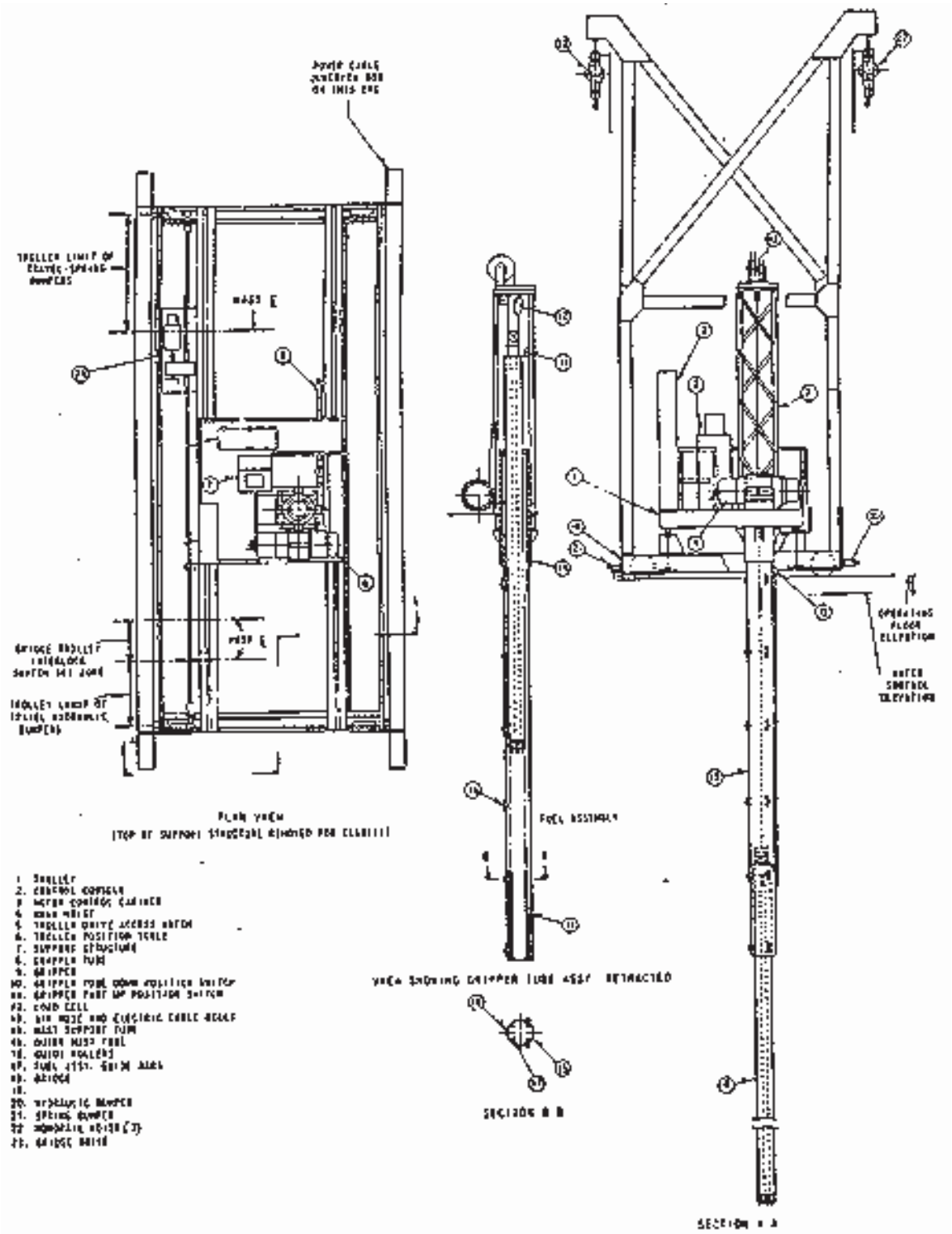
TRAVEL PATH
INSIDE FHB



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 9.1-7
HEAVY LOAD HANDLING PATHS FOR THE TRANSFER CASK/MPC

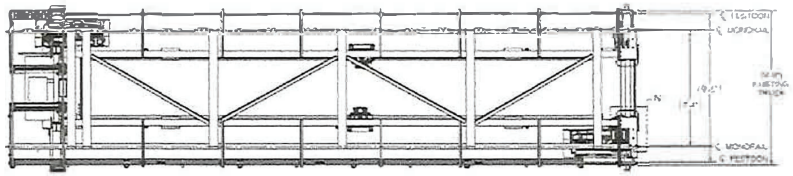


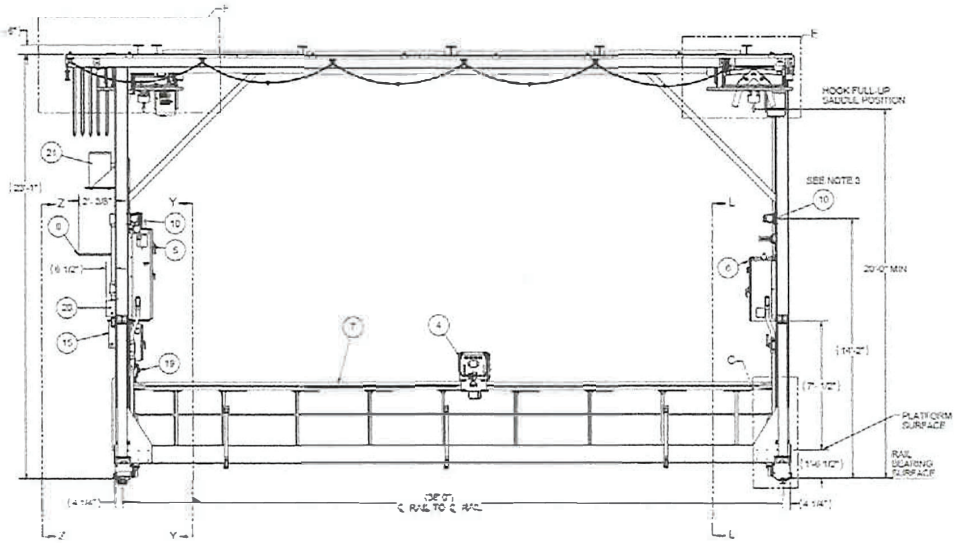
FSAR UPDATE

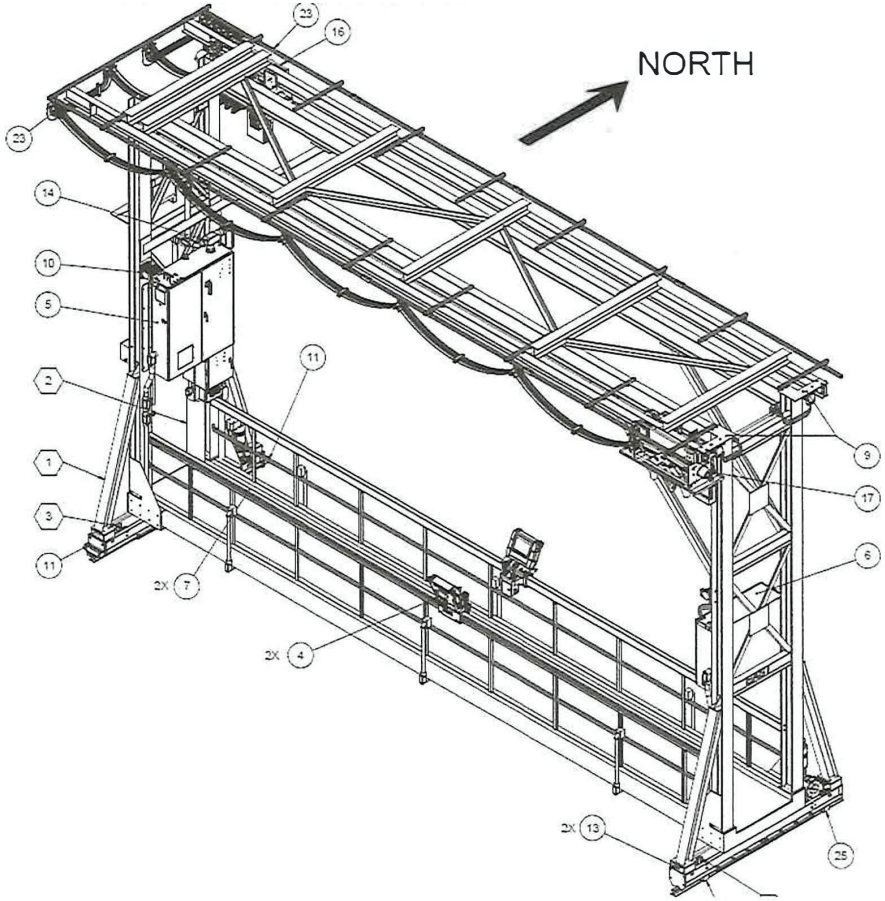
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 9.1-8

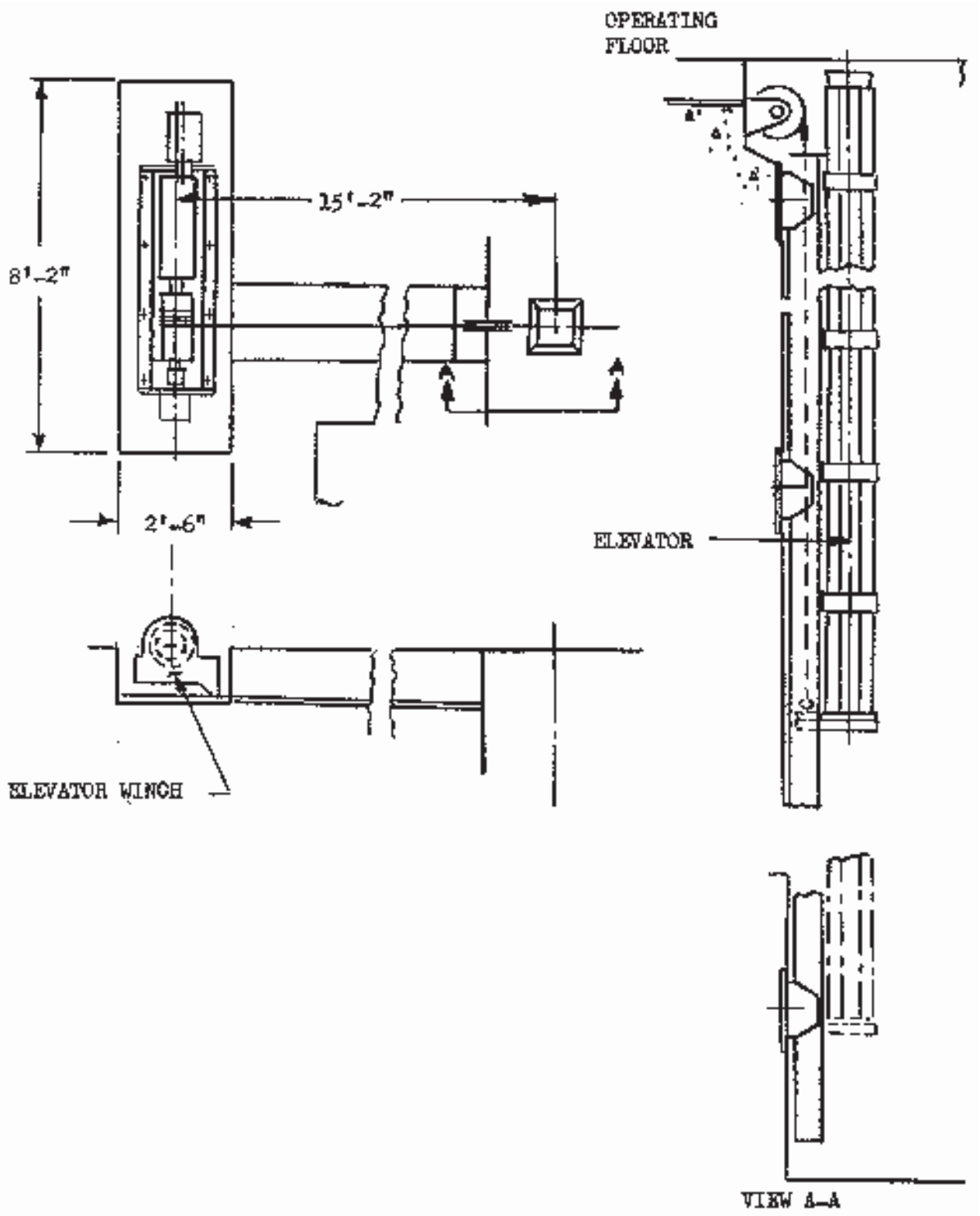
MANIPULATOR CRANE



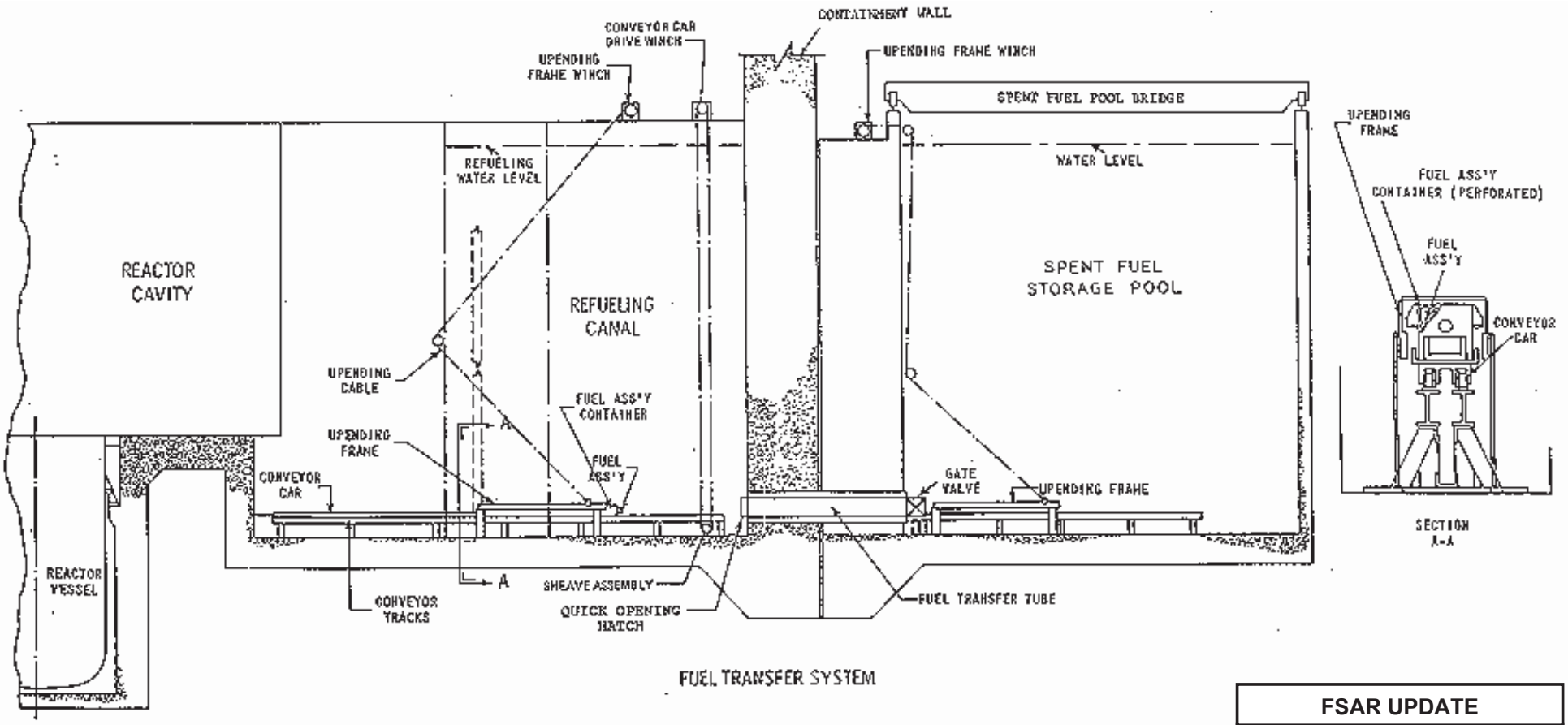




FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 9.1-9 SPENT FUEL POOL BRIDGE

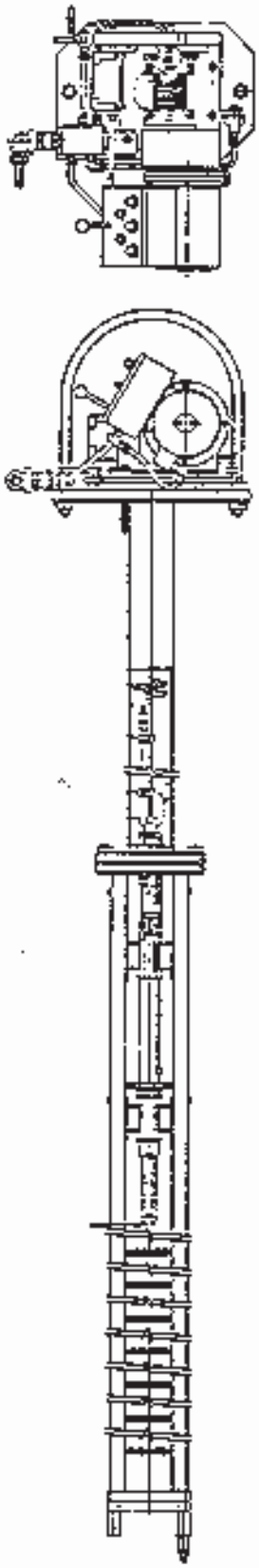


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 9.1-10 NEW FUEL ELEVATOR

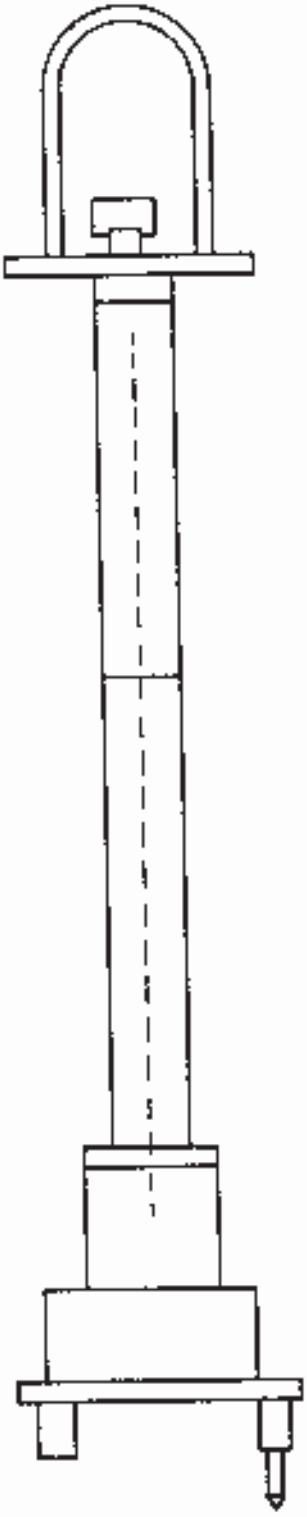


FUEL TRANSFER SYSTEM

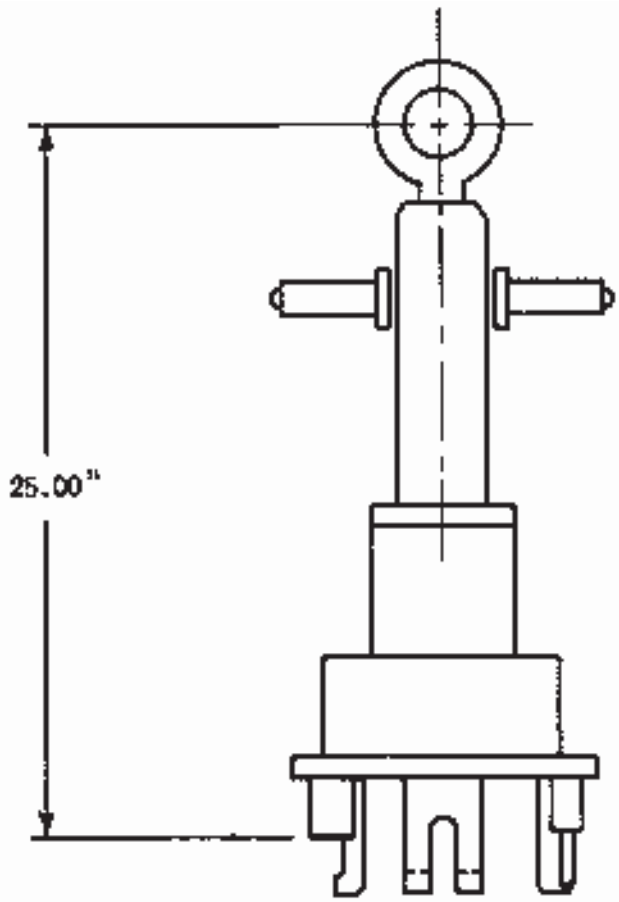
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 9.1-11 FUEL TRANSFER SYSTEM



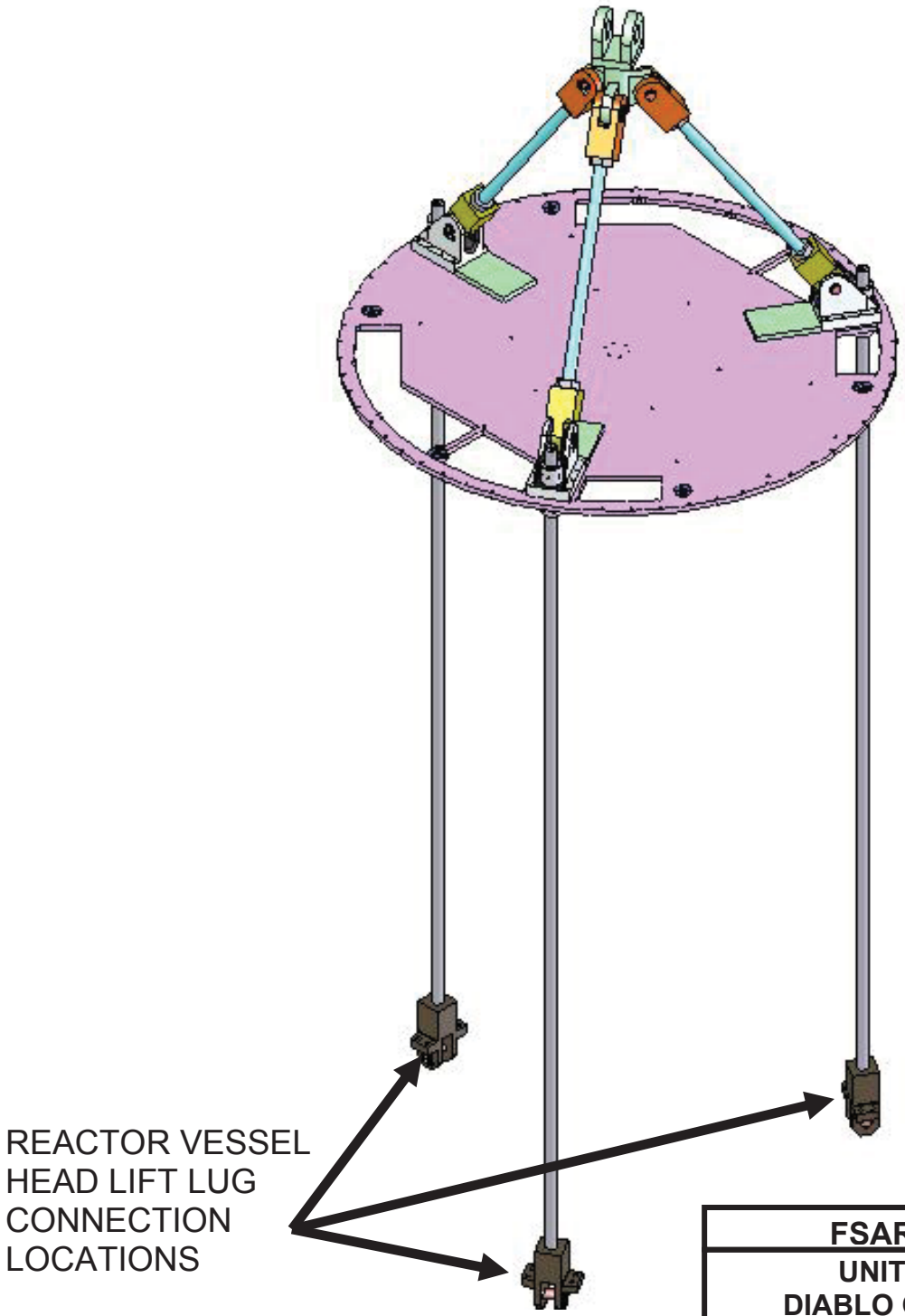
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 9.1-12a ROD CLUSTER CONTROL CHANGING TOOL



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 9.1-13 SPENT FUEL HANDLING TOOL



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 9.1-14 NEW FUEL ASSEMBLY HANDLING FIXTURE

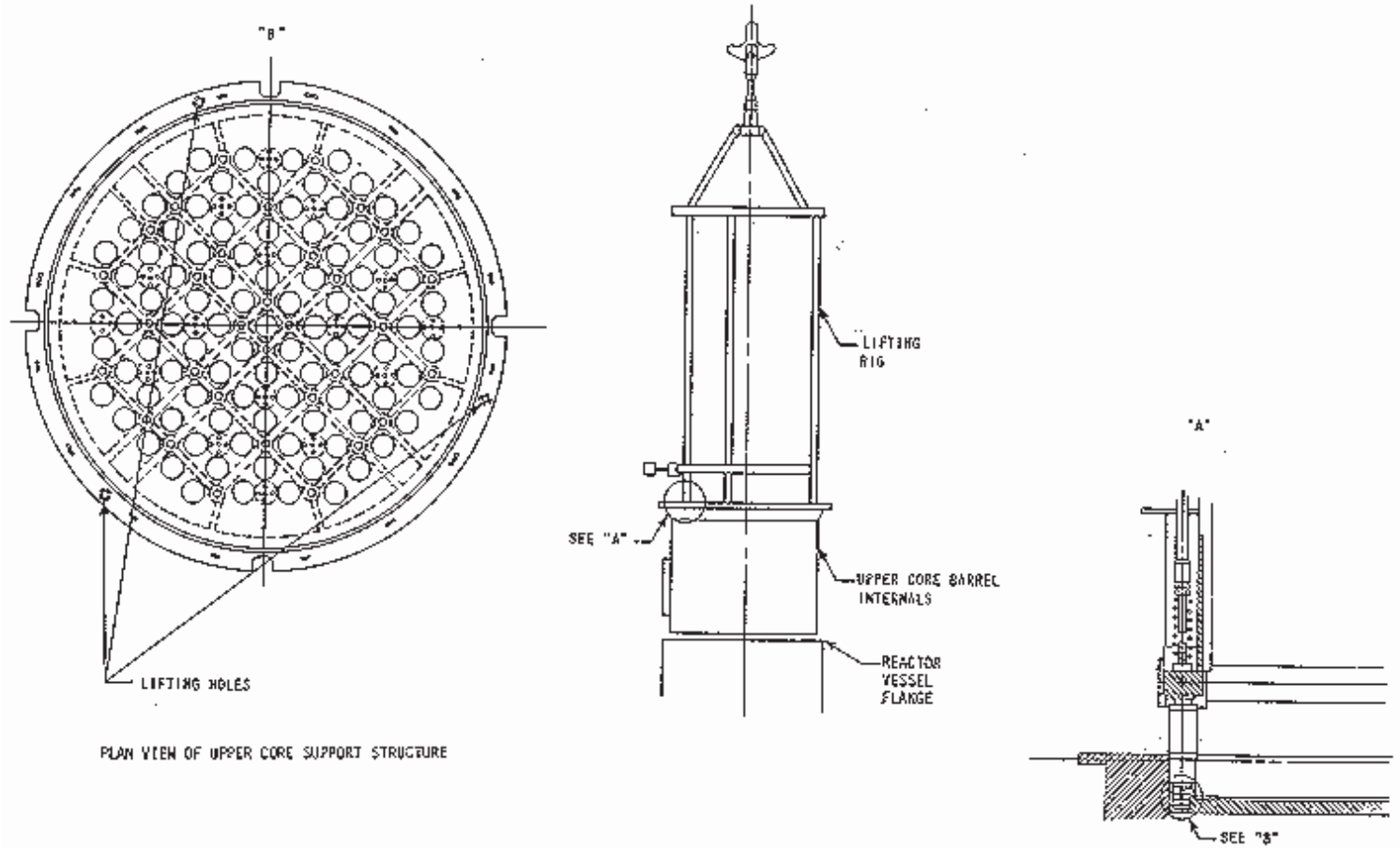


FSAR UPDATE

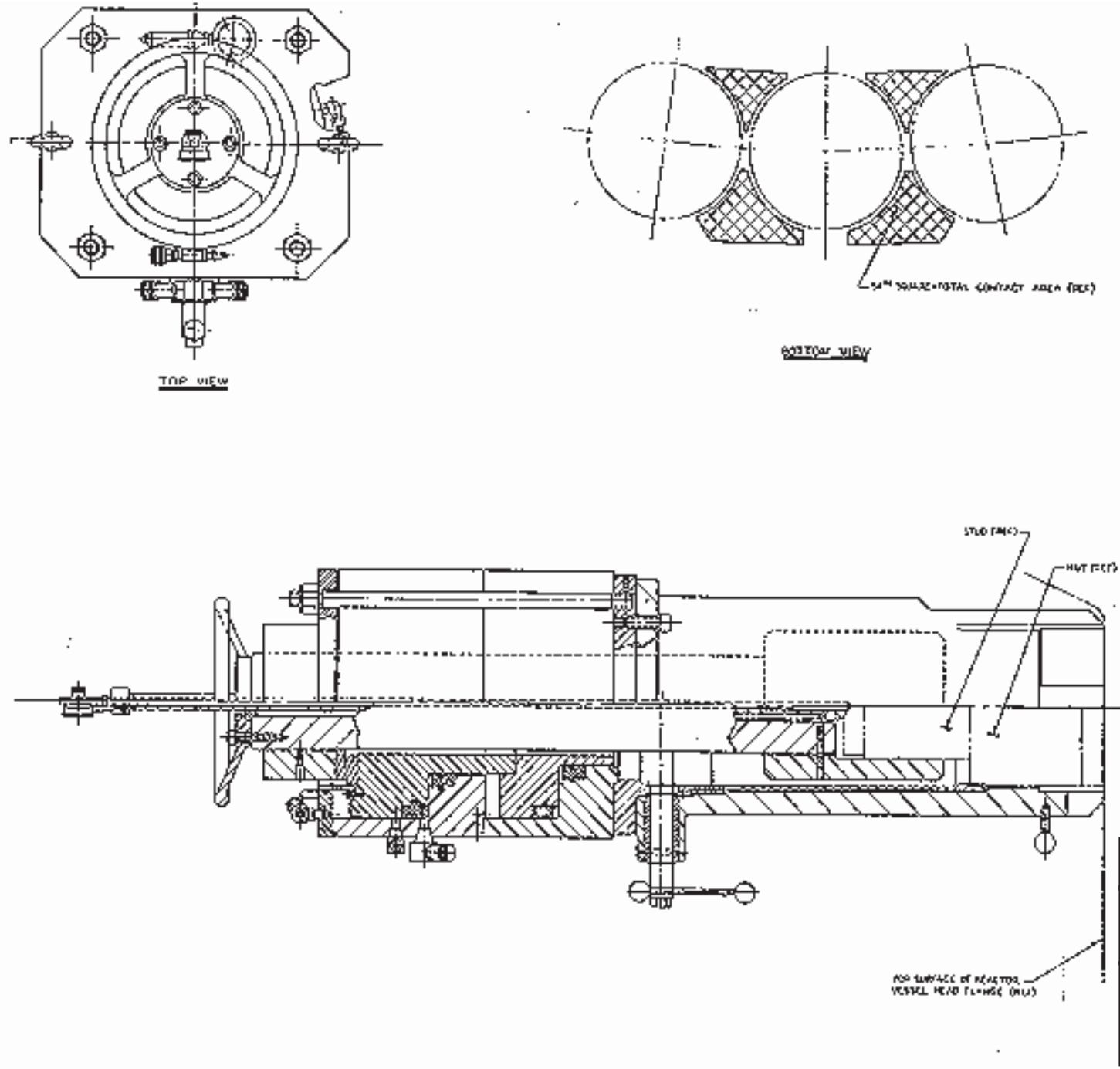
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 9.1-15

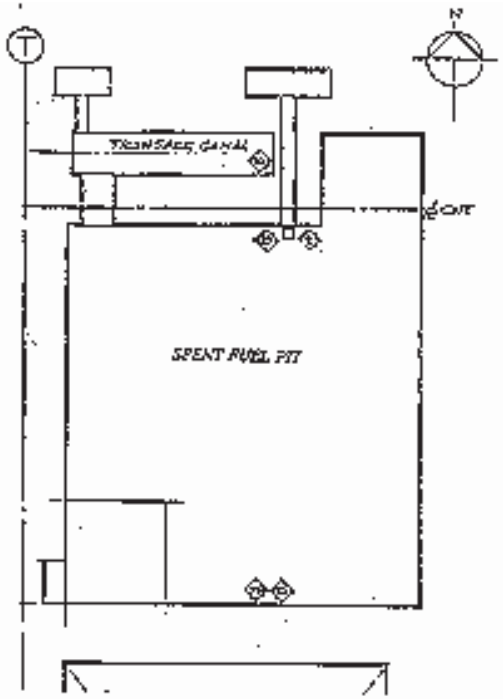
REACTOR VESSEL HEAD LIFT RIG ASSEMBLY



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 9.1-16 REACTOR INTERNALS LIFTING DEVICE



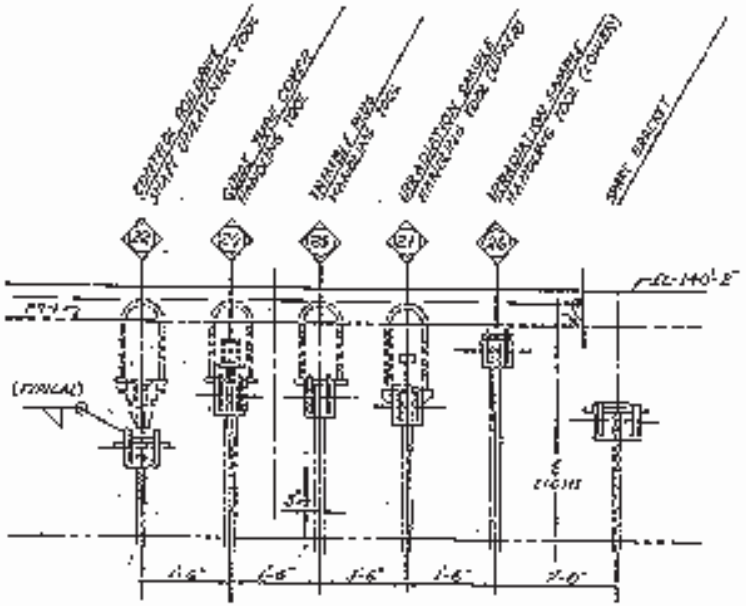
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 9.1-17 REACTOR VESSEL STUD TENSIONER



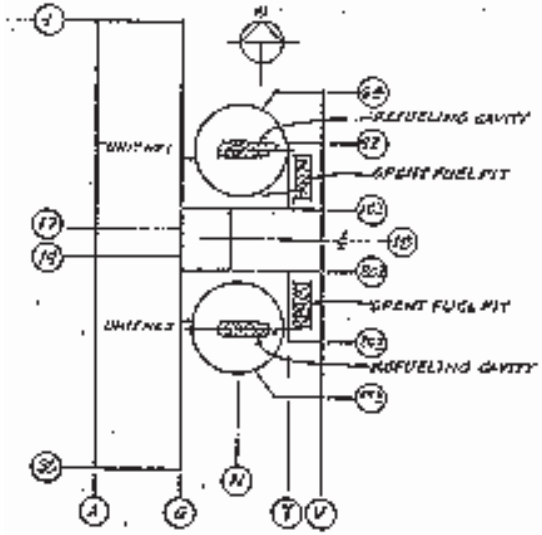
TOOL LOCATION PLAN
FUEL HANDLING BLDG.
UNIT No. 1 SHOWN / UNIT No. 2 OPPOSITE HAND

	NAME	LENGTH	HEIGHT
	IRRADIATION CANISTER/SPACER	23'-10"±	110 LBS
	CONT. ROD & CL UNLATCHING	17'-3"±	260 LBS
	TOOL DEPTH		
	GUIDE TUBE GAUGE	28'-6"±	185 LBS
	THIMBLE PLUG	30'-8"±	250 LBS
	IRRADIATION CANISTER/SPACER	21'-8"±	120 LBS
	CROSS STORAGE RACK LATCHING	14'-0"	10 LBS
	17x17 SPENT FUEL ASSEMBLY	14'-4"	1386 LBS
	BURNABLE POISON ROD	36'-3 1/4"	602 LBS.
	CROSS STORAGE RACK TOP		135 LBS
	CROSS STORAGE RACK BOTTOM		
	GUIDE PIN SUPPORT TOP	19'-6"±	1800 LBS
	GUIDE PIN SUPPORT BOTTOM		
	NEW FUEL ASSEMBLY	21'-0"±	35 LBS
	NEW ROD CLEANING FIXTURE	33'-1"±	1045 LBS
	STUD HOLE PLUG	4'-0"±	
	THIMBLE PLUG	32'-6"±	356 LBS.

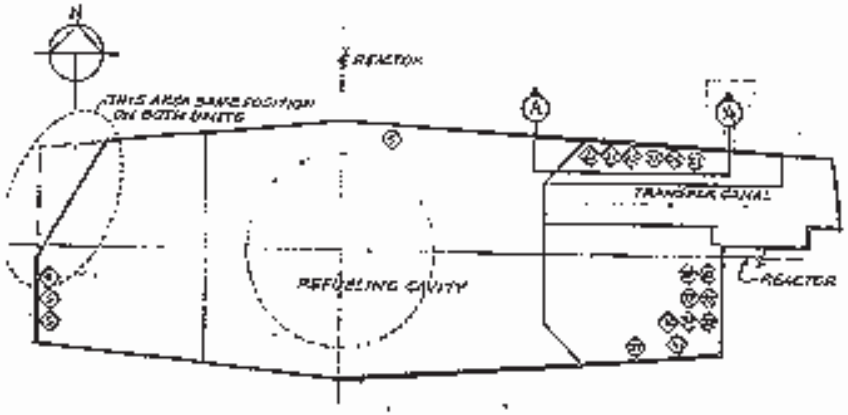
HANDLING TOOL RACK SCHEDULE



HANDLING TOOL - SUPPORT RACKS
SECTION A - A



KEY PLAN

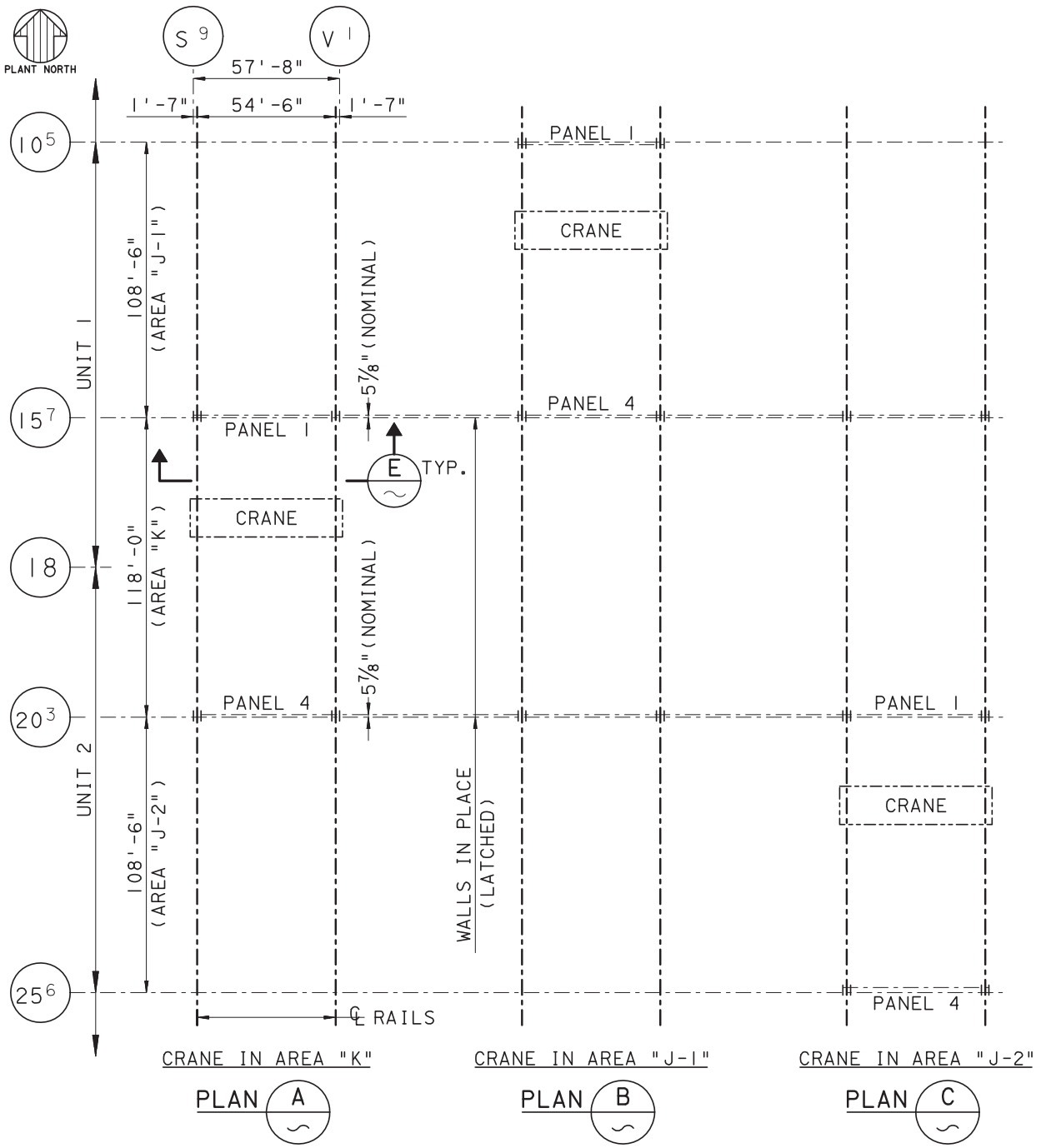


TOOL LOCATION PLAN - CONTAINMENT STRUCTURE
UNIT No. 1 SHOWN / UNIT No. 2 OPPOSITE HAND EXCEPT AS NOTED

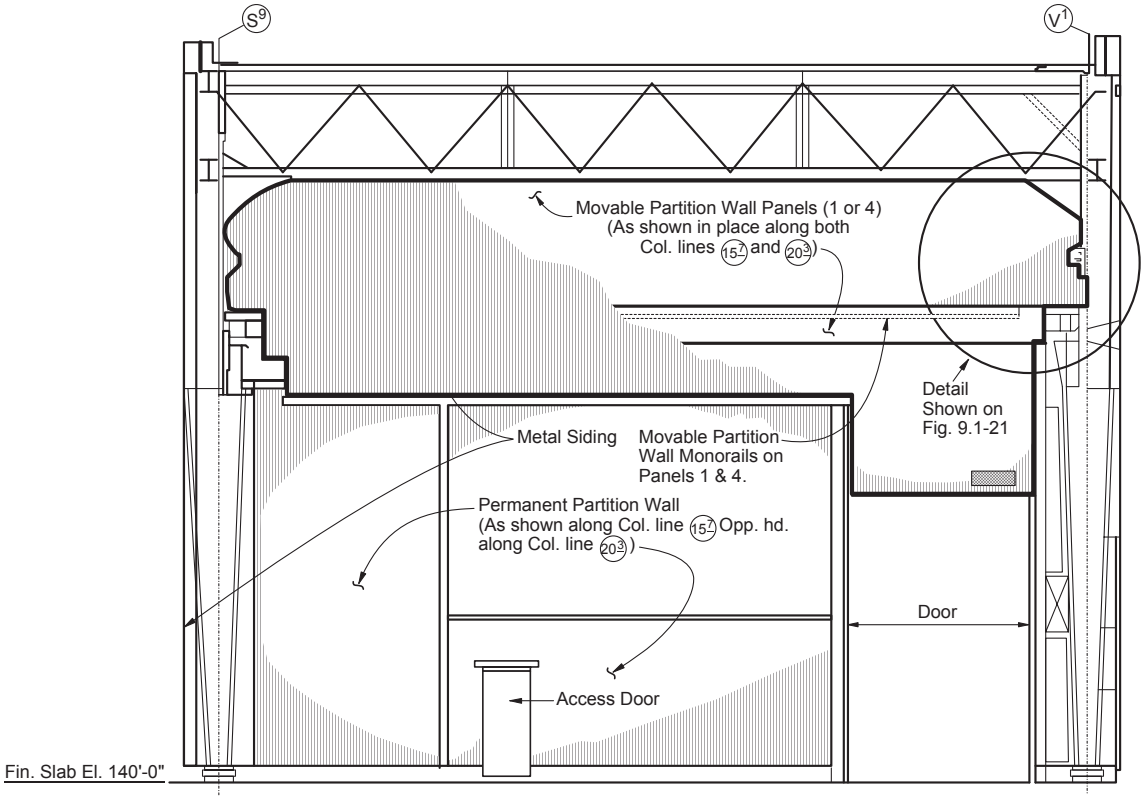
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 9.1-18
FUEL HANDLING
TOOL LOCATIONS

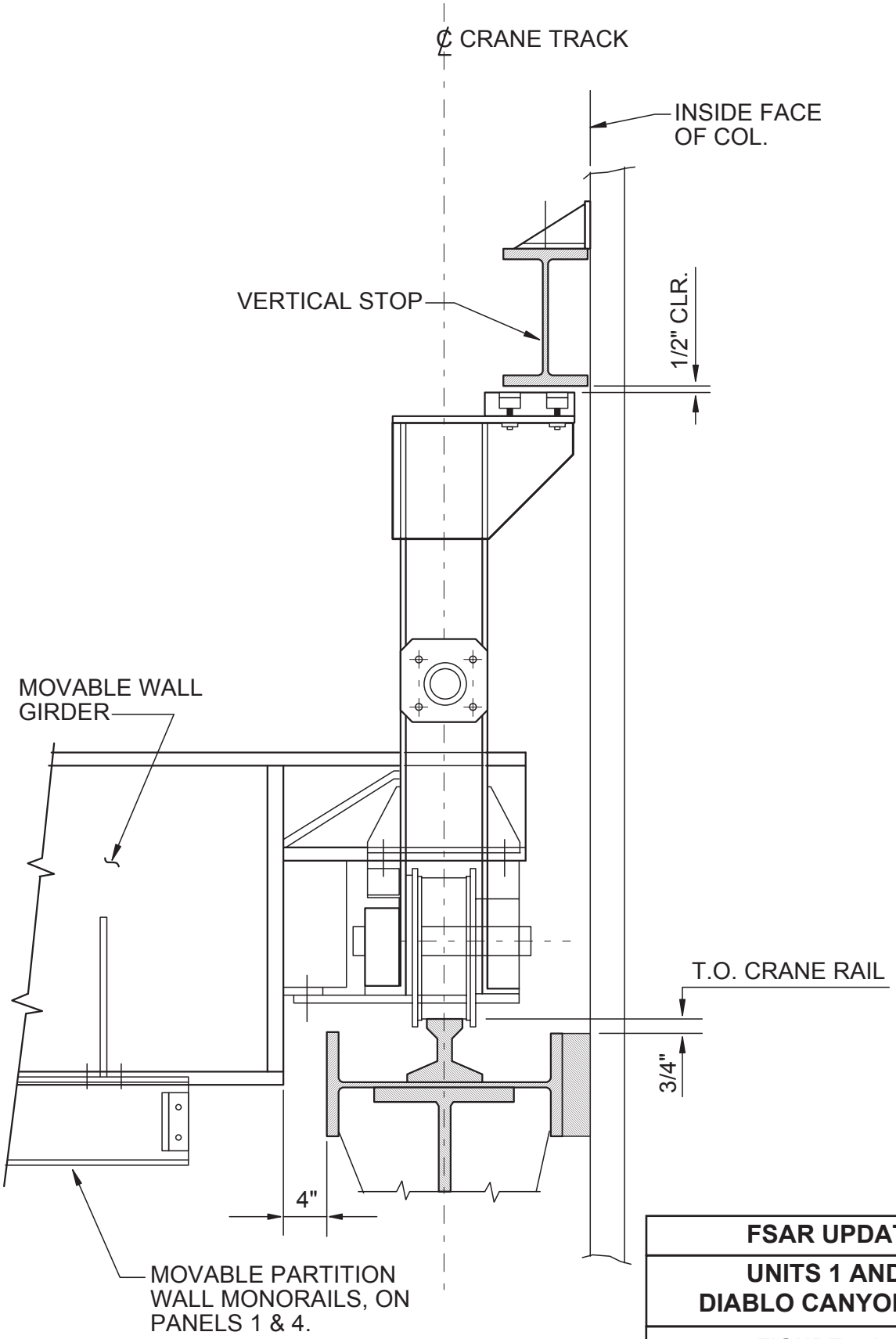


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 9.1-19 MOVEABLE PARTITION WALLS LOCATION PLANS



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 9.1-20 MOVEABLE PARTITION WALLS ELEVATION AT COLUMN LINE 15-7 OR 20-3

Revision 19 May 2010

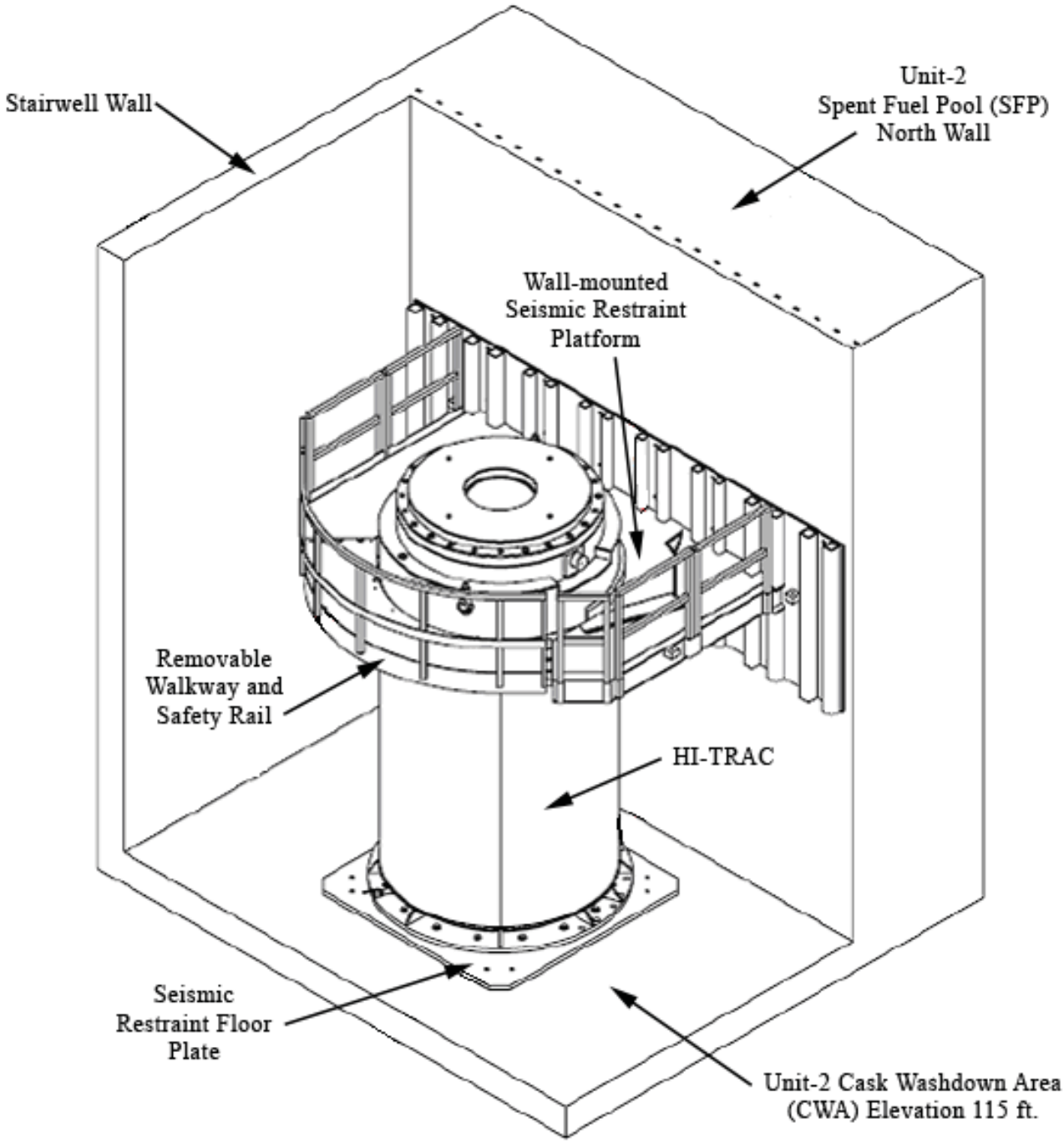


FSAR UPDATE

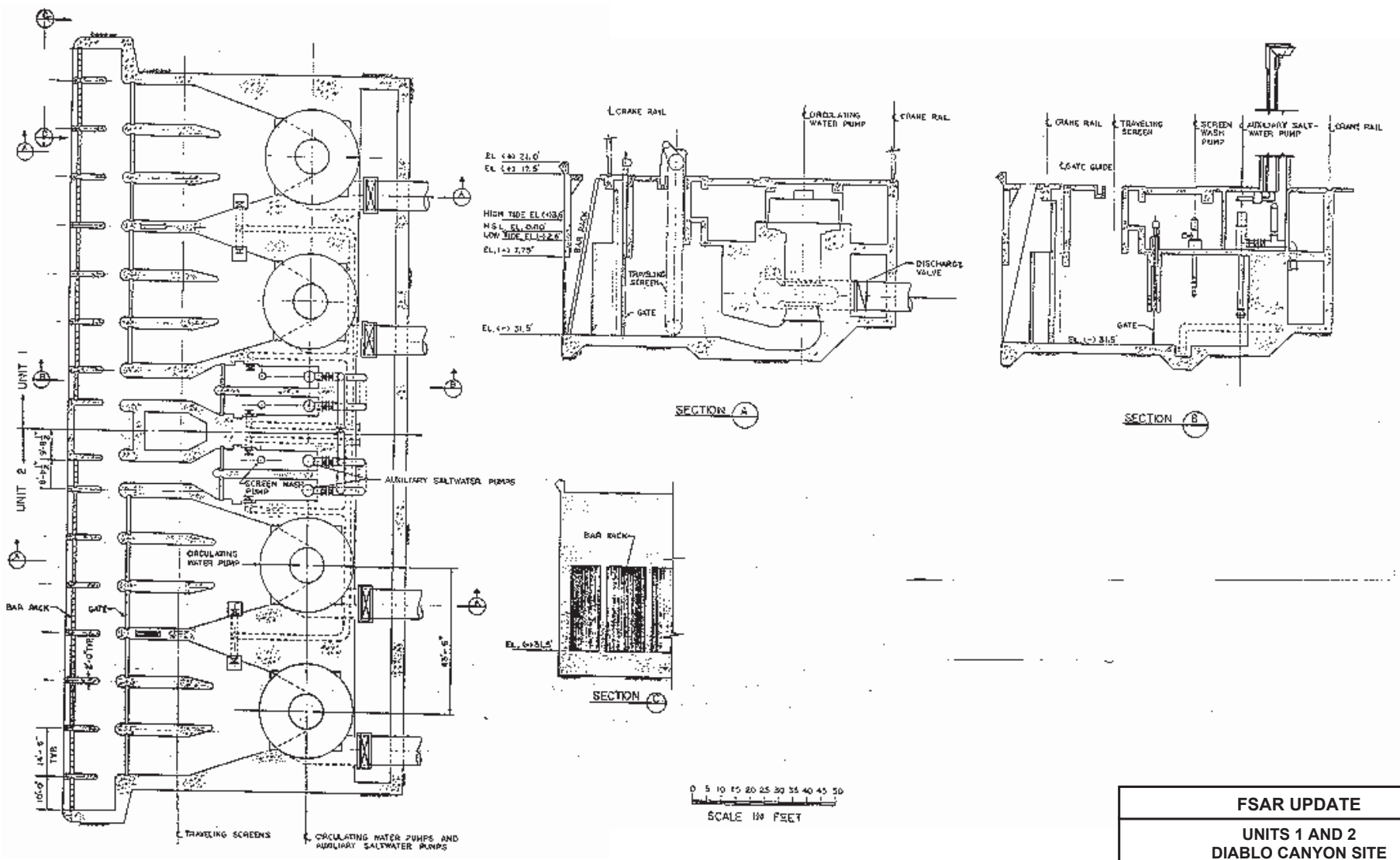
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 9.1-21
MOVEABLE PARTITION WALLS
DETAILS SHOWING WALL,
TRACK, AND VERTICAL STOP

Revision 19 May 2010



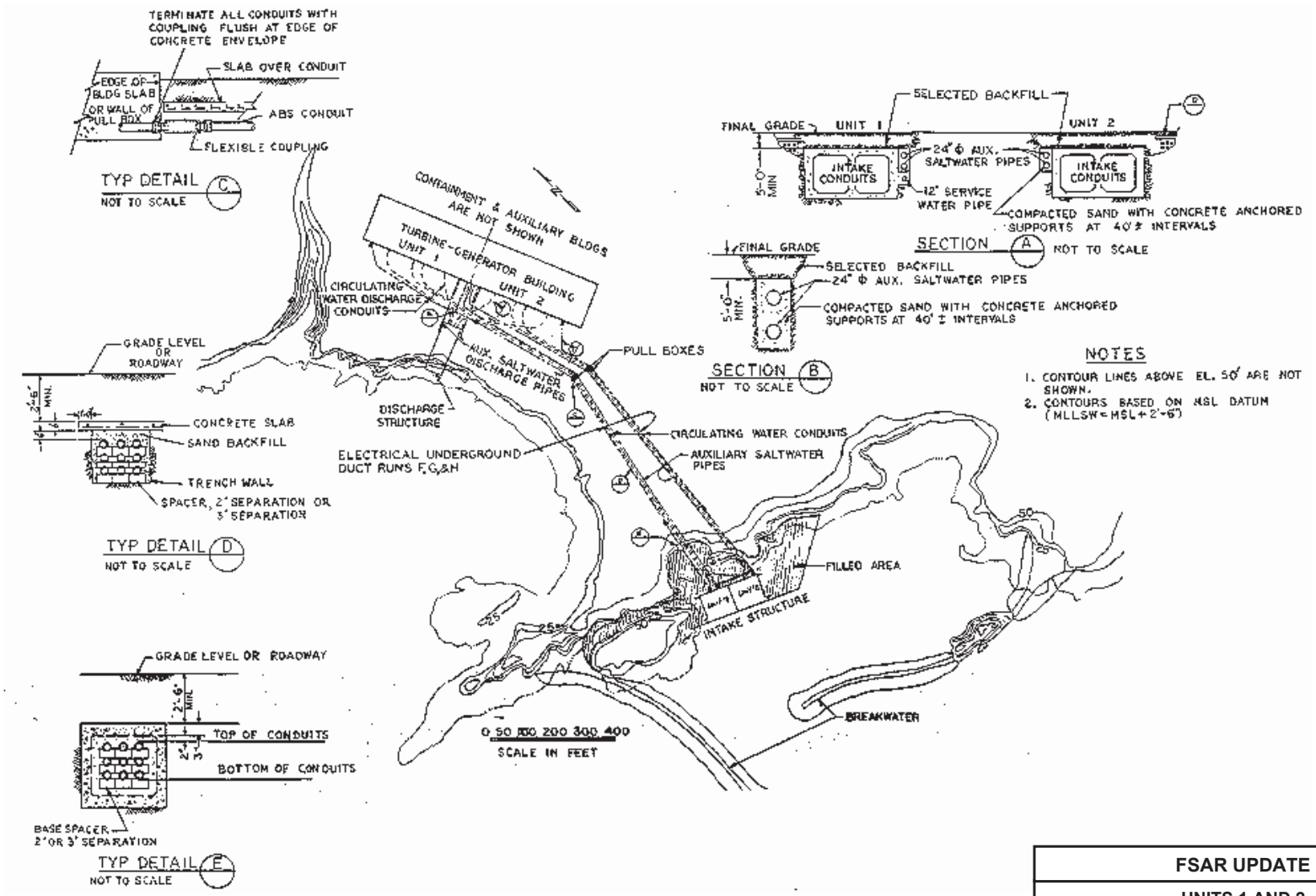
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 9.1-24 CASK WASHDOWN AREA RESTRAINT



PLAN AT ELEVATION (-) 31.5'

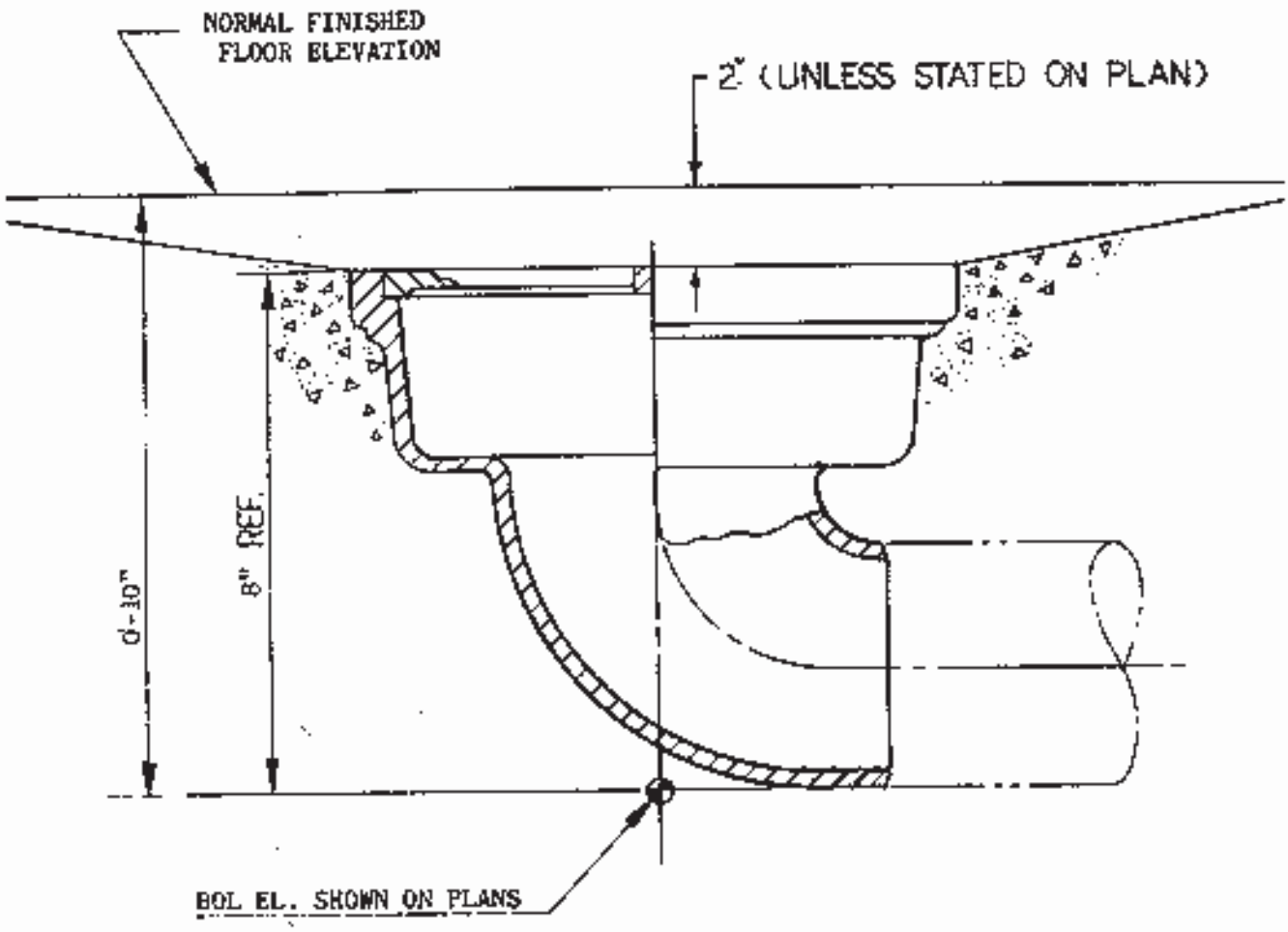
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 9.2-2 ARRANGEMENT OF INTAKE STRUCTURE

Revision 12 September 1998



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 9.2-3 ARRANGEMENT OF AUXILIARY SALTWATER SYSTEM PIPING

Revision 12 September 1998

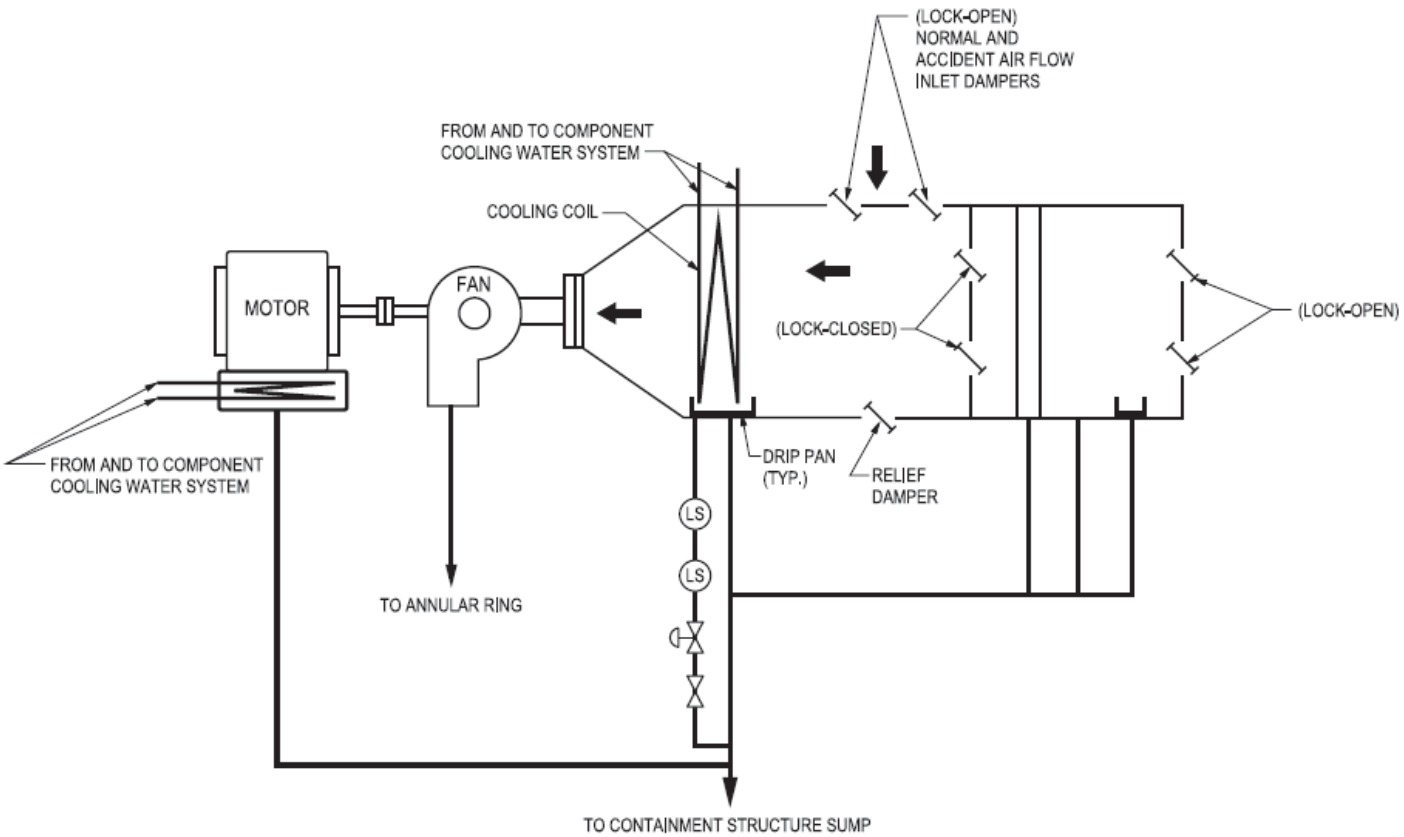


NOTES:

1. Represented by Symbol (U) on Drainage Piping Drawings.
2. It Shall be Furnished with Stainless Steel Grate.
3. Butt-Weld Connection to Match Schedule 10S
4. See Drainage Drawings for Pipe Size, Elevation, Etc.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 9.3-5 FLOOR DRAIN

Revision 11 November 1996



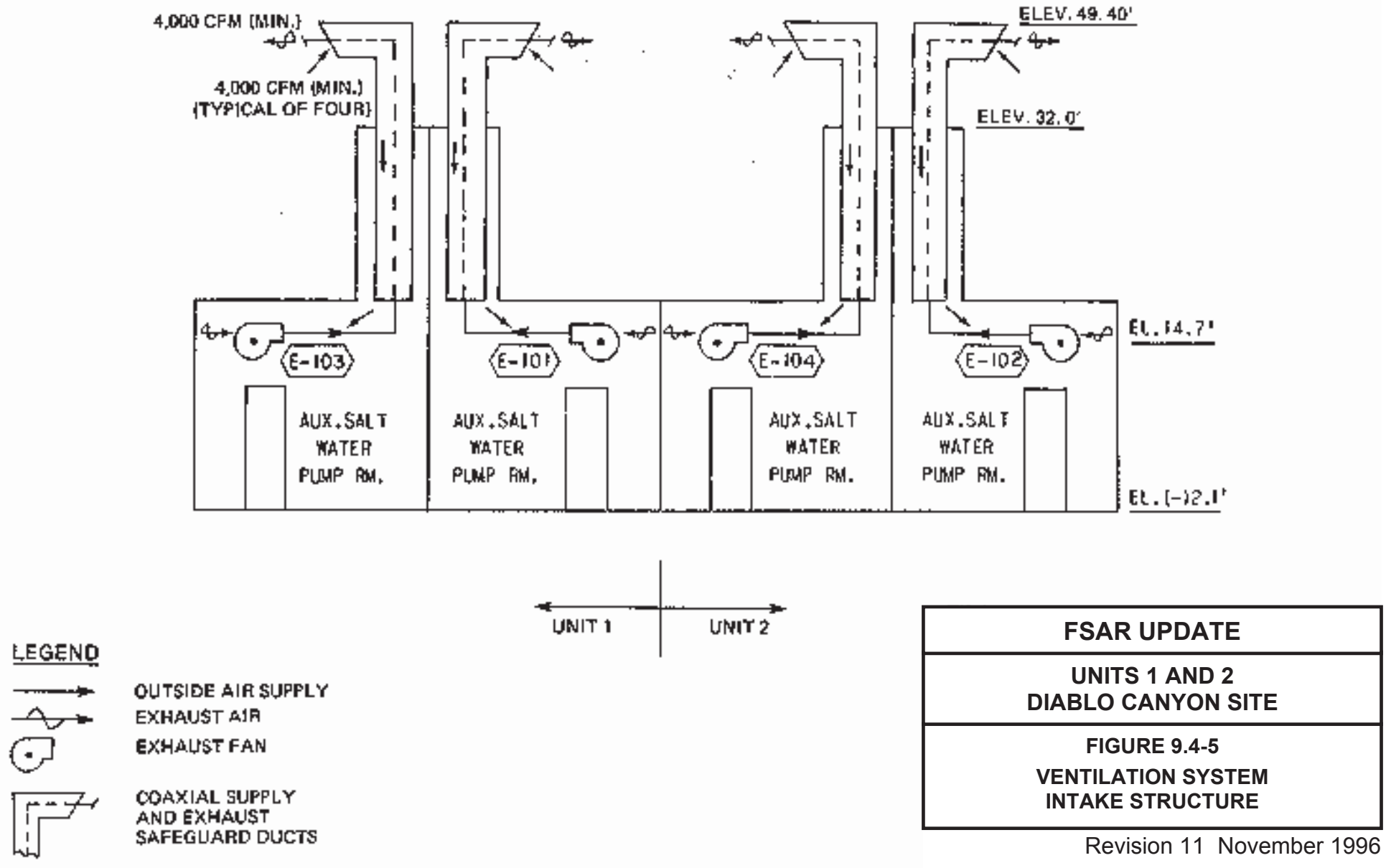
UNIT 1 CONTAINMENT FAN COOLER UNIT 1-1 (TYPICAL OF 5)
UNITS 1 AND 2 CONTAINMENT FAN COOLER UNITS ARE SIMILAR

LEGEND

- OPPOSED OR PARALLEL BLADE DAMPERS
- FAN
- BUTTERFLY VALVE
- SUPPLY AIR FLOW
- NORMAL OR ACCIDENT AIR FLOW

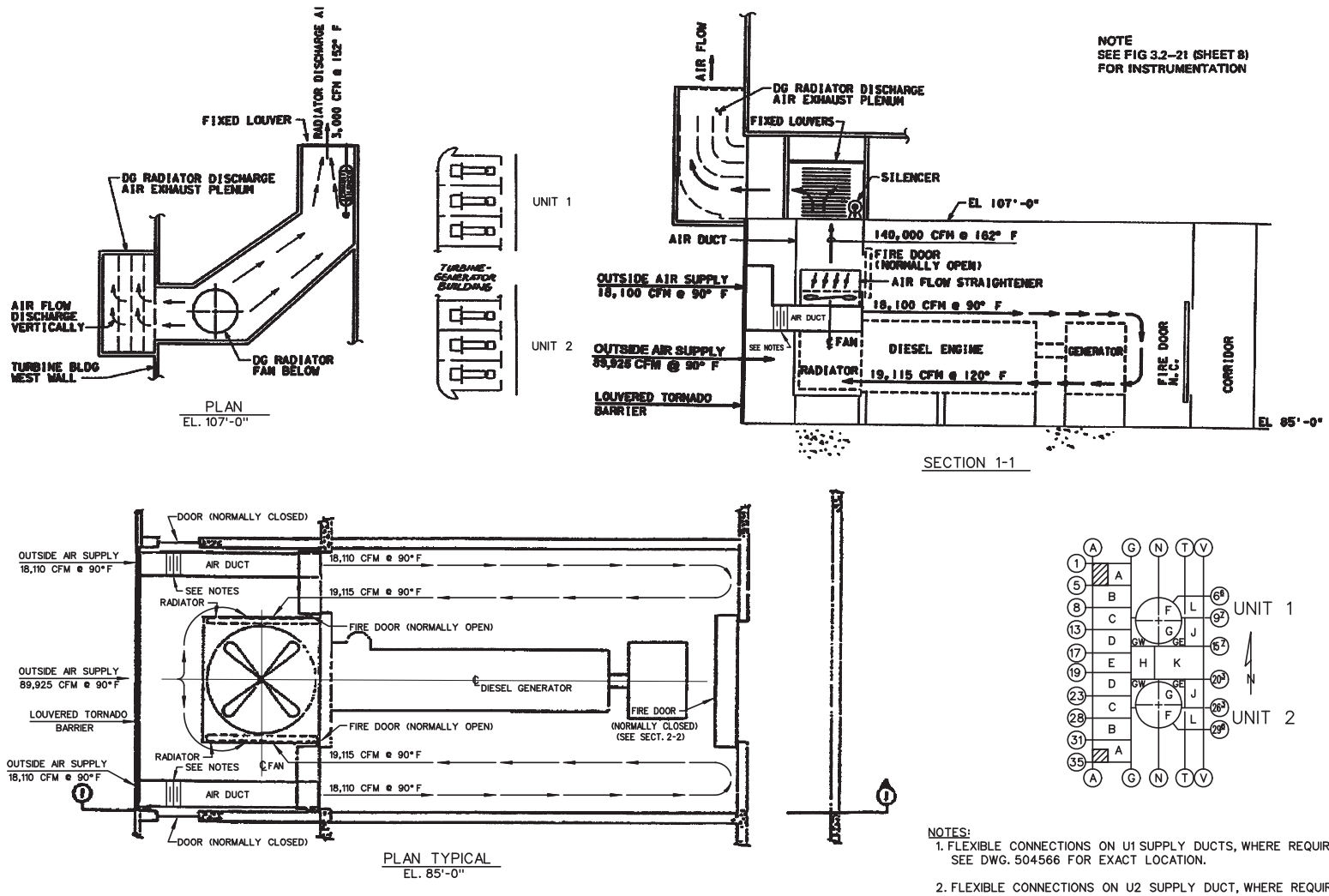
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 9.4-4 CONTAINMENT FAN COOLER UNIT CONTAINMENT STRUCTURE

Revision 20 November 2011



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 9.4-5 VENTILATION SYSTEM INTAKE STRUCTURE

Revision 11 November 1996



NOTE
SEE FIG 3.2-21 (SHEET 8) FOR INSTRUMENTATION

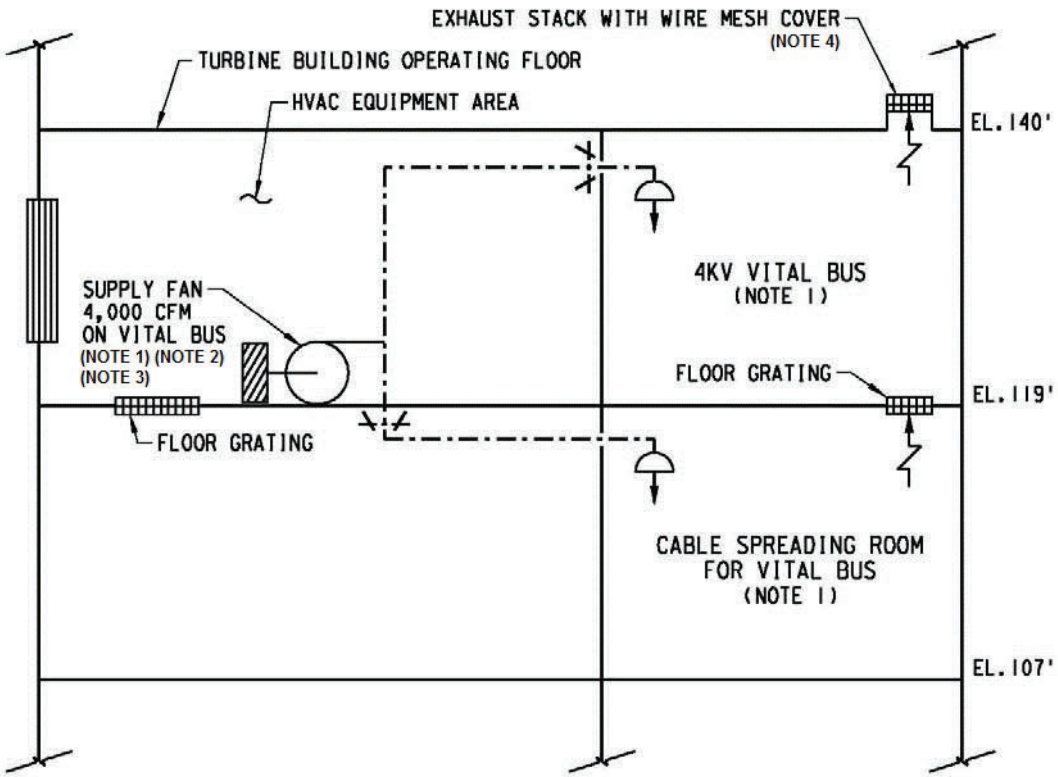
NOTES:

1. FLEXIBLE CONNECTIONS ON U1 SUPPLY DUCTS, WHERE REQUIRED. SEE DWG. 504566 FOR EXACT LOCATION.
2. FLEXIBLE CONNECTIONS ON U2 SUPPLY DUCT, WHERE REQUIRED. SEE DWG'S 521777 & 502591 FOR EXACT LOCATION.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 9.4-6
VENTILATION SYSTEM
DIESEL GENERATION



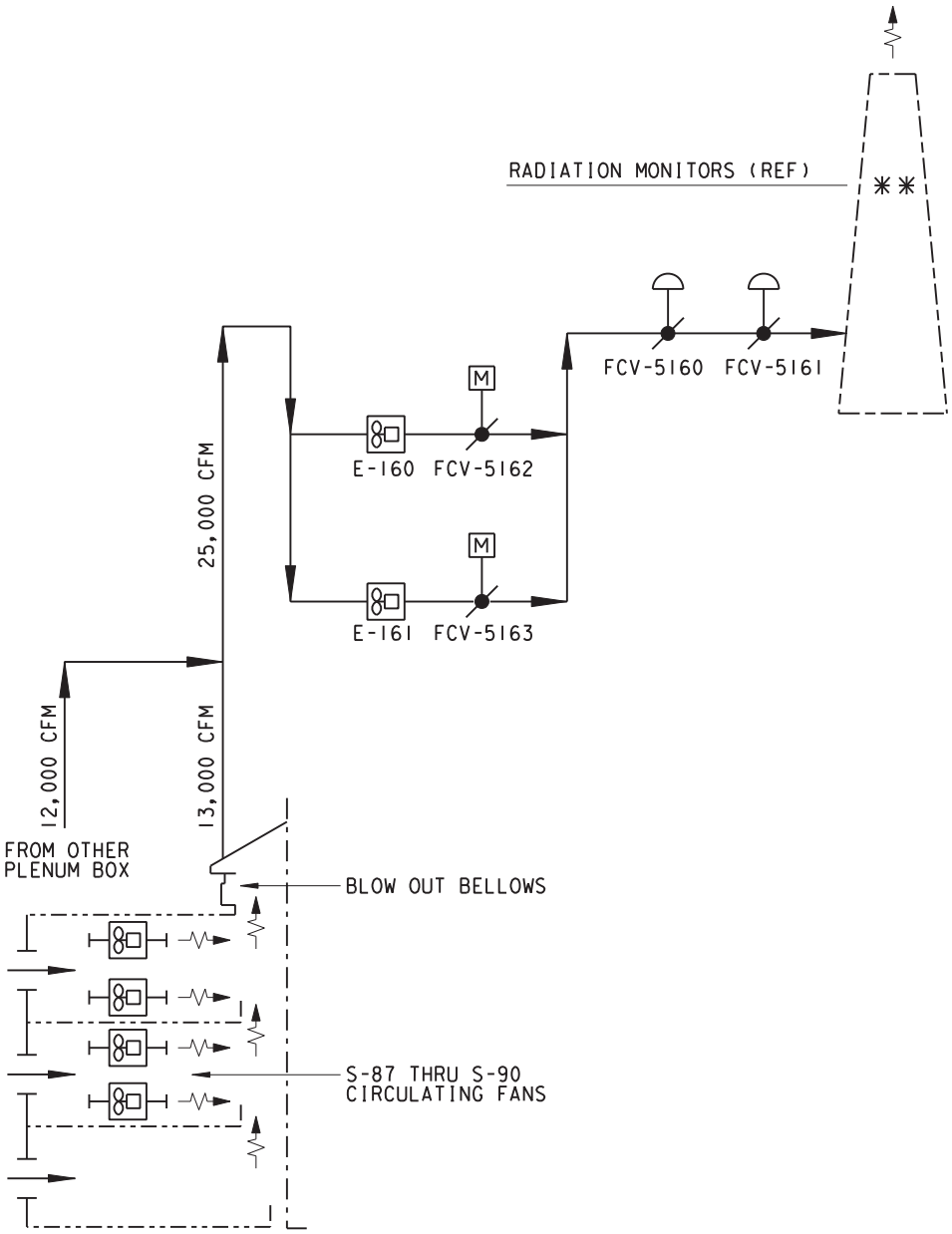
LEGEND:

- SUPPLY DUCT SAFETY RELATED VENTILATION SYSTEM
- OUTSIDE AIR INTAKE LOUVER
- SUPPLY FAN
- SUPPLY AIR OUTLET
- EXHAUST AIR INLETS
- ROUGHING FILTER
- FIRE DAMPER

NOTES:

1. TYPICAL VITAL BUSES ARE "F", "G" & "H".
2. SUPPLY FAN NUMBERS: "S-67", "S-68" & "S-69".
3. OPERATION OF SUPPLY FAN NOT REQUIRED FOR COOLING OF 4KV VITAL BUS.
4. EXHAUST FIRE DAMPER NORMALLY CLOSED.
5. APPICABLE FOR UNIT 1 & UNIT 2.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 9.4-7 VENTILATION SYSTEM 4KV SWITCHGEAR ROOMS



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 9.4-11

VENTILATION SYSTEMS
CONTAINMENT PENETRATION
AREA GE/GW

Chapter 10

STEAM AND POWER CONVERSION SYSTEM

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NOTE:

[a] This figure corresponds to a controlled engineering drawing that is incorporated by reference into the FSAR Update. See Table 1.6-1 for the correlation between the FSAR Update figure number and the corresponding controlled engineering drawing number.

Chapter 10

STEAM AND POWER CONVERSION SYSTEM

This chapter provides information concerning the plant steam power conversion (heat utilization) system. The steam and power conversion system (SPCS) includes the turbine-generator, steam supply system, feedwater system, main condenser, and related subsystems. The auxiliary feedwater (AFW) system is discussed in Section 6.5.

Descriptive information is provided to allow understanding of the system, with emphasis on those aspects of design and operation that affect the reactor and its safety features, or contribute to the control of radioactivity. The radiological aspects of normal system operation are summarized in this chapter and are presented in detail in Chapter 11. Design and quality code classifications applied to the SPCS are discussed in Chapter 3.

10.1 SUMMARY DESCRIPTION

The SPCS is designed to convert the heat produced in the reactor to electrical energy. In each unit, reactor heat absorbed by the reactor coolant system (RCS) produces sufficient steam in four steam generators (SGs) to supply the turbine-generator.

The SPCS is designed to operate on a closed, condensing cycle, with full flow condensate demineralization, and six stages of regenerative feedwater heating. Turbine exhaust steam is condensed in a single shell, surface-type condenser and returned to the SGs through three stages of feedwater pumping. All three low-pressure turbine elements exhaust into a common condenser steam space. The arrangement of the equipment associated with the SPCS is shown in Figures 3.2-2 through 3.2-4 and 10.3-6.

The SPCS is designed to receive the heat absorbed by the RCS during normal power operation, as well as following an emergency shutdown of the turbine-generator from full load. Heat rejection under the latter condition is accomplished by steam bypass to the condenser and pressure relief to the atmosphere. Either the turbine bypass or the pressure relief system (without operation of safety valves) can dissipate the heat from the RCS following a turbine trip and a reactor trip. Trips, automatic control actions, and alarms are initiated by deviations of system variables from preset values. In every instance, automatic control functions are programmed so that appropriate corrective action is taken to protect the RCS (refer to Chapter 7).

The SPCS does not normally contain radioactivity. The vents and drains associated with the secondary cycle are arranged in a manner similar to those in a conventional fossil fuel generating station. However, the condenser air removal equipment will handle radioactive noncondensable gases during a SG primary-to-secondary tube leak. Means are provided to monitor (refer to Section 11.6) the discharge of radioactive material to the environment, to ensure that it is within the limits of 10 CFR Part 20 under

normal operating conditions, or in the event of anticipated system malfunctions or accident conditions. Detection of these gases is described in Sections 10.4.2 and 11.4.

All SPCS equipment required for nuclear safety is classified as PG&E Design Class I, and the appropriate systems are sufficiently redundant to ensure maintenance of their safety functions. Specifically, the AFW system and portions of the main steam and main feedwater systems are required to perform various safety functions involving removal of decay heat and are classified as PG&E Design Class I. Safety functions relative to the AFW system are presented in Section 6.5.

Turbine heat balances at maximum calculated and full load conditions are shown, respectively, in Figures 10.1-1 and 10.1-2 for Unit 2, and Figures 10.1-5 and 10.1-6 for Unit 1. Typical operating parameters for the secondary system are listed in Table 10.1-2.

Tables 10.1-1 and 10.1-2 summarize important design and performance characteristics of equipment upon which the safety of the SPCS operation depends. The design performance characteristics and PG&E Design Class I design features are described in the remainder of Chapter 10.

10.1.1 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by Diablo Canyon Power Plant (DCPP) procedures.

10.2 TURBINE-GENERATOR

The basic function of the turbine-generator is to convert thermal energy initially to mechanical energy and finally to electrical energy. The turbine-generator receives saturated steam from the four SGs through the main steam system. Steam is exhausted from the turbine-generator to the main condenser.

10.2.1 DESIGN BASES

10.2.1.1 Turbine-Generator System Safety Function Requirements

(1) Protection from Missiles

The turbine-generator is designed to ensure that failure of the turbine-generator is minimized and will not result in the generation of missiles that could affect safe shutdown of either unit.

10.2.1.2 10 CFR 50.62 – Requirements for Reduction of Risk from Anticipated Transients Without Scram Events for Light-Water-Cooled Nuclear Power Plants

The turbine-generator meets the requirement of 10 CFR 50.62 by responding to an anticipated transients without scram (ATWS) mitigation system actuation circuitry (AMSAC) signal to trip the turbine under ATWS conditions.

10.2.1.3 Generic Letter 89-08, May 1989 – Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP has implemented formalized procedures and administrative controls in accordance with Generic Letter 89-08, May 1989 to assure long-term implementation of its erosion/corrosion monitoring program for the turbine-generator.

10.2.2 SYSTEM DESCRIPTION

The Siemens-Westinghouse BB96 high pressure (HP) turbine is coupled to three Alstom ND56R low pressure (LP) turbines in a four-casing, tandem-compound, six-flow exhaust, 1800 rpm unit, with 57-inch last-stage blades. The ac generator is connected to the turbine shaft, and a brushless exciter is coupled to the generator.

10.2.2.1 Turbine

The turbine consists of one double-flow, high-pressure element in tandem with three double-flow, low-pressure elements. Moisture separation and reheating of the steam are provided between the high-pressure and LP turbines by six horizontal axis, two-stage reheat cylindrical shell combined moisture separator-reheater (MSR) assemblies. Three of these assemblies are located on each side of the low-pressure turbine elements.

Steam from the exhaust of the high-pressure turbine element enters one end of each MSR assembly, where internal manifolds in the lower section distribute the wet steam. The steam then flows through a moisture separator where the moisture is removed and the condensate drained to a drain tank from which it is pumped to the suction of the main feedwater pumps. The steam leaving the separator flows over two tube bundles where it is reheated in two stages. The reheated steam leaves through nozzles in the top of the assemblies and flows to the LP turbines through a stop valve and an intercept valve in each reheat steam line. Two MSR assemblies furnish steam to each of the three low-pressure turbine elements. The first stage tube bundle in the reheater is supplied with extraction steam from the high-pressure turbine, and the second-stage tube bundle is supplied from the main steam lines ahead of the high-pressure turbine. The supply steam condenses in the tubes; the condensate from the high-pressure tube bundle flows to the shell of the high-pressure feedwater heaters, while the condensate from the low-pressure tube bundle flows to the heater 2 drain tank.

A turbine shaft sealing system, using steam to seal the annular openings where the shaft penetrates the casings, prevents steam outleakage or air inleakage along the shaft. Turbine steam extraction connections are provided for six stages of feedwater heating.

10.2.2.2 Performance Requirements

The main turbine-generators and their auxiliary systems are designed for steam flow corresponding to 3,500 MWt and 3,580 MWt, which in turn correspond to the maximum calculated thermal performance data of the Unit 1 and Unit 2 nuclear steam supply systems (NSSSs), respectively, at the original design ultimate expected thermal power. The Unit 2 turbine-generator has a higher power rating because of subsequent uprating of the Unit 2 NSSSs. The intended mode of operation of both Unit 1 and Unit 2 is base loaded at levels limited to the lower licensed reactor level of 3,411 MWt (refer to Table 15.1-1).

10.2.2.3 Operating Characteristics

The SG characteristic pressure curves (refer to Figure 10.2-1) are the bases for design of the turbine. The SG pressure curve shown in Figure 10.2-1 corresponds to the SG outlet pressure. The calculated curve is based on thermal design conditions with vessel T_{avg} of 577.6ºF and 10 percent SG tube plugging (Reference 1). The pressure at the

turbine main steam valves does not exceed the pressure shown on the steam characteristic pressure curve for the corresponding turbine load. With a pressurized water reactor, it is recognized that the pressure at the turbine steam valves rises as the load on the turbine is reduced below rated load. During abnormal conditions at any given load, the pressure may exceed the pressure on the SG characteristic pressure curve by 30 percent on a momentary basis, but the total aggregate duration of such momentary swings above characteristic pressure over the whole turbine load range does not exceed a total of 12 hours per 12-month operating period.

The turbine inlet pressure is not directly controlled. A load index from the turbine first-stage pressure is compared to the reactor coolant loop T_{avg}; the control rods are then positioned accordingly (refer to Section 7.7.2.8).

10.2.2.4 Functional Limitations

The plant is designed to sustain sudden large load decreases, as described in Section 5.1.7.2. This capability is provided by the use of controlled steam dump (turbine bypass) from the secondary system. This dump serves as a short-term artificial load, allowing the reactor to automatically cut back power without tripping. The reactor control system itself is not rapid enough to follow a sudden loss of load without allowing certain reactor plant variables (e.g., pressure and temperature) to exceed allowable operating limits. Therefore, a sufficiently large controlled steam dump, capable of simulating an external load on the reactor, is used to prevent the reactor from tripping.

The rates at which electrical load may be increased or decreased without tripping the reactor, including operation of the steam dump (bypass system), are as follows:

(1) Without steam bypass - If electrical load decrease does not exceed a step change of 10 percent, or a sustained ramp load decrease of 5 percent per minute, then the steam bypass will not operate. Steam bypass is not used to control load increases.

(2) With steam bypass - If electrical load decrease does exceed a step change of 10 percent or a sustained ramp load decrease of 5 percent per minute, then a combination of steam dump groups 1, 2, and 3 of the turbine bypass system(TBS) (refer to Section 10.4.4.2) will operate. If the decrease is less than 50 percent, then a step change with control rods will account for a 10 percent load decrease, and the TBS will operate and control up to 40 percent of the remaining load decrease.

(3) Electrical load increases are limited by the reactor control system to 5 percent full power per minute, or step changes of 10 percent of full power within the power range of 15 to 100 percent of full power.

For further explanation of the steam bypass and relief system, refer to Section 10.4.4. Steam bypass and relief valves are listed in Table 10.1-1. For electrical loading, refer to Chapter 8, Electric Power.

The functional limitations imposed by the design or operational characteristics of the turbine-generator are:

(1) Retrofitted with Alstom LP turbines, the units are suitable for continuous full load underfrequency operation down to 56.4 Hz. Operation below 56.4 Hz is limited to 10 seconds per event. There is no specific accumulated time limit for operation below 56.4 Hz. A trip within 0.5 seconds is required below 54.9 Hz.

(2) Under frequency set points and time delays are coordinated with PG&E's Under Frequency Load Shedding Program, per Utility Operations Standard UO S1426, which conservatively bounds turbine vendor requirements.

(3) Load changes cause thermal stress in the turbine rotor, which persists as long as there are differences between the surface and interior temperatures of the rotor body. Operational procedures for changing load, that tend to ensure a maximum time period before the appearance of fatigue cracking, are required. Load changing recommendations are based on 10,000 cycles of general turbine operation. For example, the following load changes can be made instantaneously, without exceeding the 10,000-cycle recommendations: 0-10 percent, 10-30 percent, 20-53 percent, 30-78 percent, 40-85 percent, and 50-100 percent.

(4) Operation at less than 5 percent rated load should be avoided; however, when necessary, auxiliary load may be carried indefinitely on the main generator following rejection of the main load, provided;

(a) Low-pressure turbine exhaust hood spray is placed in service when hood temperature exceeds 175°F; and if hood temperature increases to 250°F for more than 15 minutes, the turbine is tripped

(b) All supervisory instrument readings are within allowable alarm limits

10.2.2.5 Lubrication

Turbine-generator bearings are lubricated by a conventional oil system. The volute type, centrifugal main oil pump is mounted on the turbine rotor and supplies all of the oil requirements for the lubrication system during normal operation. An ac motor-driven centrifugal pump supplies bearing oil for operating the turbine-generator on turning gear during coastdown after a trip, and during startup. A backup dc motor-driven bearing oil pump operates, in case of loss of ac power or if the ac pump fails to start, to lubricate

the turbine-generator bearings during coastdown of the unit after tripout. Air-side and hydrogen-side ac motor-driven seal oil pumps are provided to supply oil to the generator hydrogen seal oil systems. An air side dc motor-driven seal oil backup pump operates in case of loss of ac power, to prevent leakage of the generator hydrogen. A lift pump is provided for bearings 3, 4, 5, 6, and 7 to lift the turbine rotor shaft off the journal bearing to reduce the starting load on the turning gear motor. Bearing 8 was retrofitted with an integral bearing lift system.

10.2.2.6 Cooling

The cooling water requirements of the turbine-generator are met partially by the service cooling water system (refer to Section 9.2.1), and partially by the main condensate and feedwater system (refer to Section 10.4.7).

The following main turbine-generator heat exchangers are cooled by the service cooling water system:

(1) Turbine lubricating oil coolers

(2) Generator hydrogen seal oil coolers

(3) Exciter air-to-water heat exchangers

(4) Electrohydraulic (EH) control fluid cooler

(5) Main generator isophase bus duct cooler

The following main turbine-generator heat exchangers are cooled by the main condensate and feedwater system:

(1) Generator hydrogen coolers

(2) Generator stator water coolers

(3) Gland steam condenser

10.2.2.7 Turbine Electrohydraulic Control System

The turbine is equipped with a digital electrohydraulic (DEH) control system that uses programmable triple modular redundant digital controllers, dual redundant digital servo position controllers, input/output modules, and a high-pressure, fire-resistant, fluid supply system to operate the turbine control valves. By regulating the flow of steam through the turbine, the control system regulates turbine speed prior to the time that the generator is synchronized, and controls unit power output when the generator is connected to the PG&E transmission system. The control system also provides

overspeed protection. Retrofitted with Alstom LP turbines, the control system also provides low condenser vacuum and low bearing oil protection.

Unit electrical loading is completely under the control of the reactor operator except when automatic runbacks are in progress. No automatic offsite load dispatching is utilized.

10.2.2.8 Turbine Steam Flow Control

The flow control of the main inlet steam is accomplished by four main stop valves in series with four governor control valves.

Each main stop valve operates in either a fully opened or fully closed position. The valve is opened when high-pressure fluid enters the hydraulic actuator cylinder and forces the piston to overcome spring closing pressure. It is closed immediately upon the dumping of main stop valve emergency trip fluid to provide quick closing independent of the electrical system. The valve may also be closed upon activation of the solenoid valve for periodic test of valve stem freedom. The purpose of the main stop valve, which is installed in the main steam line ahead of the governor control valve, is to provide an additional safety device to limit turbine overspeed. On a unit trip, stop and governing valves are spring-closed to provide redundancy for turbine overspeed protection.

Each governor control valve is of the single-seat, plug type design. The valve is opened when high pressure EH fluid enters the actuator and overcomes the spring force of the valve as transmitted by the operating levers. During normal operation, control of the governor control valve is by a servo valve that regulates oil pressure in the actuator, based on information supplied from the DEH system controller. A linear variable differential transformer (LVDT) develops an analog signal proportional to the valve position, which is fed back to the controller to complete the control loop. The controller signal positions the control valves over a wide range of turbine speeds during startup and for load control after the unit is synchronized. The governor control valve is closed by reducing pressure on the dump valve. The dump valve can be activated by means of the emergency trip system, or by the auxiliary governor trip, to provide quick closing independent of the electrical system.

The flow control of steam to the low-pressure sections of the turbine is accomplished by six reheat stop valves in series with six interceptor valves.

Each reheat stop valve operates in either the fully opened or fully closed position. The valve is opened when high-pressure fluid enters the actuator hydraulic cylinder and forces the piston to overcome spring closing pressure. It is closed immediately upon dumping of main stop valve emergency trip fluid, on actuation of the emergency trip device. It may also be closed upon activation of the solenoid valve for periodic testing of valve stem freedom. The major function of the reheat stop valves is to shut off the flow of steam to the low-pressure turbines, when required.

Each interceptor valve normally operates in a fully opened position. The valve is opened when high-pressure fluid is admitted through an orifice to the hydraulic cylinder operating piston. As the fluid pressure increases beneath the piston, it overcomes the force of the closing springs and opens the steam valve. It is quickly closed when the emergency trip fluid is released to drain. The purpose of this valve is to limit the flow of steam from the MSRs to the low-pressure turbines after a sudden load reduction.

10.2.2.9 Partial Loss of Load

A feature called close-intercept valve (CIV) was built into the original turbine control system to close the intercept valves. This CIV feature was designed to sense a load mismatch between HP exhaust pressure and generated power. CIV actuation would close the intercept valves for a preset time period. This feature was disabled on the original Westinghouse-supplied turbine control system and is not present in the new system.

10.2.2.10 Complete Loss of Load

When a mismatch of LP turbine inlet pressure and generator output megawatts occurs, and the breaker opens, this condition is detected as a complete load loss. When the generator breaker opens, the load drop anticipation (LDA) is set, requesting overspeed protection control (OPC) action. Refer to Section 10.2.3.1 for a description of the OPC system.

All governor and interceptor valves are then rapidly closed. The LDA load loss circuit is inoperable below 22 percent of load, as measured by LP turbine inlet pressure.

10.2.2.11 Overspeed Action

OPC action also occurs when turbine speed is equal to, or greater than, 103 percent of rated speed. Governor and interceptor valves are closed until the speed drops below 103 percent.

The OPC system may be tested by using the OPC test function. If the breaker is open and the OPC test function is activated, a signal is generated; this signal indicates that the speed of the turbine is over 103 percent. The OPC system then closes the valves as though an actual overspeed condition had occurred.

10.2.2.12 Speed Channel System

Three separate electromagnetic pickups input speed information to the turbine control system. These inputs are validated against a high and low reference to determine when a transducer fails high or low. The control system uses a median signal select logic to determine the controlling speed signal for turbine speed control, OPC, and redundant overspeed protection.

10.2.2.13 Automatic Runbacks and Programmed Ramps

The turbine control system implements protective runbacks and programmed ramps (load reductions). The OTΔT and OPΔT protective runbacks are described in Section 7.7.2.4.2. The loss of main generator stator cooling protective runback is discussed in Section 10.2.2.15. Main turbine programmed ramps anticipating loss of steam flow are main feedwater pump trip and heater drip pump trip. A turbine runback anticipating a loss of heat sink is a trip of a circulating water pump.

10.2.2.14 Trip System Operability

The operability of the main turbine inlet valves and turbine trip system is verified by periodic functional tests. Operability of the trip system in the event of postulated accidents has also been reviewed. The trip system is protected from falling debris and will remain operational during and following postulated accidents (refer to Section 3.5.2.2.2.1).

Administrative operating requirements ensure that the turbine building crane is parked away from the steam inlet valves during turbine operation, to preclude damage to the valves from a postulated crane fall.

10.2.2.15 Protective Features

Post Alstom LP turbine retrofit, the low vacuum mechanical trip feature has been removed and low vacuum trip is now provided through the DEH. The following other protective devices are independent of the electronic controller and, when initiated, will cause tripping of all turbine valves:

(1) Mechanical overspeed trip (refer to description in Section 10.2.3.1)

(2) Low bearing oil pressure trip (this is provided by both the mechanical trip, independent of the electronic controller, as well as through the DEH).

(3) Thrust bearing trip

(4) Electrical solenoid trip, actuated by:

(a) Safety injection (SI) system or SG high-high level

(b) Generator loss of field

(c) Reactor trip

(d) Unit trip

(e) Manual trip switches in control room

(f) Turbine speed 111.5 percent or dc bus trip (DEH)

(g) AMSAC

(5) Manual lever located at the turbine

Each of the above tripping devices releases autostop oil. The oil release results in a decrease of autostop oil pressure that opens a diaphragm-operated trip valve in the EH high-pressure fluid system to release the pressure and close all steam valve actuators.

The generator is protected by a load runback feature on loss of cooling water to the generator stator. The runback is accomplished at a rate of approximately 40 percent load drop per minute by the turbine control system. If the generator runback fails to start in 45 seconds, the generator is additionally protected by a time delay trip, which results in a unit trip. Reverse power and antimotoring protection is also provided for the generator.
High-high SG water level signals in two-out-of-three channels for any SG actuate a turbine trip, trip the main feedwater pumps, and close the main feedwater control valves and feedwater bypass valves. The purpose is to protect the turbine and steam piping from excessive moisture carryover caused by high-high SG water level.

In addition to the devices described above, the turbine and steam system are protected by the following indicators and design features:

(1) Dropped reactor control rod signal light on the main control board

(2) Isolation valve in each SG steam line

(3) Check valve in each SG steam line

(4) Safety valves in each SG steam line

(5) Safety valves in the MSR inlet (cold reheat) piping

(6) Extraction line nonreturn valves

(7) Exhaust casing rupture diaphragms

(8) Turbine steam and casing drains which open automatically at loads less than 20 percent

The turbine-generator and associated steam handling equipment have received extensive mechanical, electrical, and radiological safety evaluations. Protective features regarding personnel and equipment safety are presented in this section. Safety features for reactor protection, in the event of a turbine-generator trip or sudden load reduction, are presented in Section 10.4.4.

10.2.2.16 Design Codes

The turbine-generator and associated components are classified as PG&E Design Class II. Section 3.2 presents a discussion of design classifications and code requirements.

10.2.3 SAFETY EVALUATION

10.2.3.1 Turbine-Generator System Safety Function Requirements

(1) Protection from Missiles

Tests and analyses regarding the potential generation and effects of missiles, caused by the turbine-generator are discussed in Section 3.5.2.2.1. Criteria for determining the turbine inspection scope and frequency required to prevent missile generation are also discussed in Section 3.5.2.2.1.

The OPC system controls turbine overspeed in the event of a partial or complete loss of load, or if the turbine reaches or exceeds 103 percent of rated speed. In the event that turbine shaft speed exceeds 103 percent of rated speed, overspeed protection is afforded through information (in rpm) supplied by three speed transducers to the OPC system. The signals from the transducers are validated against a high and low reference to determine when a transducer fails high or low. The turbine control system uses a median signal select logic to determine the controlling speed signal.

A mechanical overspeed trip device is also provided that will automatically trip the unit at 111 percent of rated speed. The mechanism consists of a spring-loaded plunger located in the turbine shaft, which extends radially outward when 111 percent of rated speed is reached. When extended, the plunger contacts a lever, which in turn dumps control hydraulic fluid (autostop oil), causing all turbine steam inlet control and stop valves to close.

An electronic trip signal is generated by the DEH control system, at 111.5 percent of rated speed, as redundant overspeed protection. With the retrofitted Alstom LP turbines, this trip signal is used to energize two solenoid valves, either of which dumps

autostop oil. This trip signal is set approximately 10 rpm higher than the mechanical overspeed device previously described.

Overspeed protection is necessary to preclude turbine rotor failure and associated turbine generated missiles (refer to Section 3.5.2.2.1).

10.2.3.2 10 CFR 50.62 – Requirements for Reduction of Risk from Anticipated Transients Without Scram Events for Light-Water-Cooled Nuclear Power Plants

The turbine-generator meets the requirement of 10 CFR 50.62 by responding to an AMSAC signal to trip the turbine under ATWS conditions. The main turbine must have equipment from sensor output to final actuation device, that is diverse from the reactor trip system, to automatically initiate the auxiliary (or emergency) feedwater system and initiate a turbine trip under conditions indicative of an ATWS (refer to Section 7.6.3.6).

10.2.3.3 Generic Letter 89-08, May 1989 – Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP has implemented formalized procedures and administrative controls in accordance with Generic Letter 89-08, May 1989 to assure long-term implementation of its erosion/corrosion monitoring program for the turbine-generator.

10.2.4 TESTS AND INSPECTIONS

Turbine-generator tests and inspections are described in Sections 3.5.2.2.2.1, 10.2.2.11, 10.2.2.14, and 10.2.3.1.

10.2.5 INSTRUMENTATION APPLICATIONS

Instrumentation is provided to continuously monitor and alarm the following turbine-generator parameters:

(1) Shaft vibration at main bearings

(2) Shaft eccentricity

(3) Shell expansion

(4) Differential expansion between turbine shell and rotor

(5) Turbine speed

(6) Turbine metal temperatures

(7) Bearing temperatures

(8) Hydrogen gas and stator cooling water temperatures

(9) Exhaust hood temperatures

(10) Condenser vacuum

(11) Thrust bearing wear

10.2.6 REFERENCES

1. Delta 54 Replacement Steam Generator Thermal and Hydraulic Design Analysis Report for Diablo Canyon, WCAP-16573-P, August 2007.

10.3 MAIN STEAM SYSTEM

The main steam system conveys the generated steam from the NSSS to the turbine generator, turbine driven feedwater pumps, steam dump, reheaters, and via the auxiliary steam system, to the gland steam system and air ejectors. Main steam is also provided to the turbine driven AFW pump.

Refer to Section 10.4.4 for details on the 10 percent atmospheric dump valves.

The main steam system structures, systems and components (SSCs) from the SGs up to and including the main steam isolation valves (MSIVs) outside of the containment are PG&E Design Class I. The main steam system SSCs downstream of the MSIVs are PG&E Design Class II.

10.3.1 DESIGN BASES

10.3.1.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portion of the main steam system is designed to withstand the effects of, or is protected against, natural phenomena such as earthquakes, winds, floods and tsunamis, and other local site effects. The effects of a tornado on the main steam system are addressed to ensure plant safe shutdown can be achieved.

10.3.1.2 General Design Criterion 3, 1971 – Fire Protection

The PG&E Design Class I portion of the main steam system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

10.3.1.3 General Design Criterion 4, 1967 – Sharing of Systems

The PG&E Design Class I portion of the main steam system and its components are not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

10.3.1.4 General Design Criterion 11, 1967 – Control Room

The PG&E Design Class I portion of the main steam system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

10.3.1.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the PG&E Design Class I portion of the main steam system variables within prescribed operating ranges.

10.3.1.6 General Design Criterion 15, 1967 – Engineered Safety Features Protection Systems

The PG&E Design Class I portion of the main steam system is provided with instrumentation for sensing accident conditions and initiating the operation of necessary engineered safety features.

10.3.1.7 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The main steam system is designed to provide means for monitoring the facility effluent discharge paths, and the facility environs for radioactivity that could be released from normal operations, from anticipated transients, and from accident conditions. The effluent discharge path includes both the PG&E Design Class I and PG&E Design Class II portions of the system.

10.3.1.8 General Design Criterion 21, 1967 – Single Failure Definition

The PG&E Design Class I portion of the main steam system is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event are treated as a single failure.

10.3.1.9 General Design Criterion 40, 1967 – Missile Protection

The engineered safety feature (ESF) containment isolation portion of the main steam system is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

10.3.1.10 General Design Criterion 49, 1967 – Containment Design Basis

The main steam system is designed so that the containment structure can accommodate, without exceeding the design leakage rate, pressures and temperatures resulting from the largest credible energy release following a loss-of-coolant accident (LOCA), including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of emergency core cooling systems.

10.3.1.11 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The PG&E Design Class I portion of the main steam system that penetrates containment is provided with leak detection, isolation, redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The piping is designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

10.3.1.12 General Design Criterion 57, 1971 – Closed System Isolation Valves

The PG&E Design Class I portion of the main steam system is designed such that each line that penetrates containment and is neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere has at least one containment isolation valve which is either automatic or locked closed or capable of remote-manual operation. This valve is outside containment and located as close to the containment as practical. A simple check valve is not used as the automatic isolation valve.

10.3.1.13 Main Steam System Safety Function Requirements

(1) Protection from Missiles

The PG&E Design Class I non-ESF portion of the main steam system is designed to be protected against the effects of missiles which may result from plant equipment failure and from events and conditions outside the plant.

(2) Protection Against High Energy Pipe Rupture Effects

The PG&E Design Class I non-ESF portion of the main steam system is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The PG&E Design Class I portion of the main steam system located outside containment is designed to be protected against the effects of moderate energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(4) Protection from Jet Impingement – Inside Containment

The PG&E Design Class I portion of the main steam system located inside containment is designed to be protected against the effects of jet impingement which may result from

high energy pipe rupture to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(5) Protection from Flooding Effects – Outside Containment

The PG&E Design Class I portion of the main steam system located outside containment is designed to be protected from the effects of internal flooding to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(6) Decay Heat Removal

The PG&E Design Class I portion of the main steam system is designed to remove decay heat from the RCS through the SG safety valves and by providing steam to power the AFW pump turbine.

(7) Main Steam Isolation

The MSIVs are designed to isolate automatically in the event of a main steam line break (MSLB) either upstream or downstream of the MSIVs to prevent uncontrolled steam release and limit the steam release to the contents of a single SG.

(8) Secondary Side Pressure Control

The main steam system is designed with safety valves to protect the system from overpressurization.

(9) Steam Flow Restriction

The main steam system is designed with flow restrictors that limit the steam flow in the event of a MSLB at any location on the steam line.

10.3.1.14 10 CFR 50.49 – Environmental Qualification

The PG&E Design Class I main steam system components that require environmental qualification (EQ) are qualified to the requirements of 10 CFR 50.49.

10.3.1.15 10 CFR 50.55a(f) – Inservice Testing Requirements

ASME code components within the PG&E Design Class I portion of the main steam system are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

10.3.1.16 10 CFR 50.55a(g) – Inservice Inspection Requirements

ASME code components within the PG&E Design Class I portion of the main steam system are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

10.3.1.17 10 CFR 50.63 – Loss of All Alternating Current Power

In the event of a station blackout (SBO), positive isolation of the main steam system is required to control secondary system inventory. The PG&E Design Class I portion of the main steam system provides a means for removing decay heat from the RCS by discharging steam from the SGs to the atmosphere via the 10 percent atmospheric dump valves (refer to Section 10.4.4).

10.3.1.18 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The PG&E Design Class I portion of the main steam system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

10.3.1.19 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The main steam system provides instrumentation to monitor main steam flow and radiation release from the SG safety valves during and following an accident.

10.3.1.20 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident Monitoring Instrumentation:

Position (1) – The PG&E Design Class I display instrumentation is designed to include the noble gas effluent radiological monitor. The radiation monitoring system provides instrumentation to monitor venting from the SG safety valves during and following an accident.

10.3.1.21 Generic Letter 89-08, May 1989 – Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP has implemented formalized procedures and administrative controls to assure long-term implementation of its erosion/corrosion monitoring program for the main steam system.

10.3.2 SYSTEM DESCRIPTION

The arrangement of the equipment associated with the main steam system is shown in Figures 3.2-4 and 10.3-6. Steam from the four SGs is supplied to the turbine-generator (refer to Section 10.2).

Saturated steam from the four SGs passes through the containment wall in carbon steel pipes arranged to satisfy flexibility and PG&E Design Class I requirements. Each main steam line is anchored to the containment wall at the penetration.

The measured steam flow has a functional PG&E Design Class II application. The flow signal is used by the PG&E Design Class II three-element feedwater controller and as a PG&E Design Class II load index signal for the main feedwater pumps (refer to Section 7.7.2.7).

Steam flow restrictors are installed in each steam line inside the containment. The pressure drop at rated load between the SGs and the turbine throttle is approximately 40 psi. Steam flow is measured by monitoring dynamic head in nozzles inside the steam pipes. The nozzles, which are of smaller diameter than the main steam pipe, are located inside the containment near the SGs.

Connections are provided in the four main steam lines, between the containment and the isolation valves, for spring-loaded safety valves and power-operated relief valves, and (in two of the four) steam lines to the auxiliary feed pump drive turbine, as shown in Figures 3.2-4 and 10.3-6.

The steam supply to the AFW pump turbine is PG&E Design Class I because of the ESF requirements of the AFW system (refer to Section 6.5). The steam supply lines from two of the four SGs are interconnected upstream of the steam line stop valve to provide both redundancy and balanced steam flow. Both isolation and check valves in series in each of these lines provide the required valve redundancy that acts to prevent reverse flow.

The function of the MSIV is provided by a quick-acting isolation valve and a check valve installed in each main steam line. These valves are located outside of the containment structure and downstream of the safety valves. This design ensures that steam line isolation occurs for breaks either upstream or downstream of the valves. These check valves prevent reverse flow from an unfaulted SG in the event of a pipe break upstream of the check valves. Additional data on these valves are provided in Section 10.3.2.1 regarding a discussion of the capability of the main steam isolation and check valves to withstand closure loads following a postulated MSLB.

The main steam system is designed so that a failure of a main steam line at any point along its length, or a malfunction of a valve installed therein, or any consequential damage, will not:

(1) Reduce the flow capacity of the AFW system

(2) Render inoperable any ESF (i.e., controls, power or instrumentation cables, emergency core cooling, or containment heat removal piping)

(3) Cause gross failure of any other steam or feedwater line valve

(4) Initiate a LOCA

Discussion of containment integrity for an MSLB is presented in Chapters 6 and 15. Furthermore, an MSLB between the exterior of the containment and the quick-acting isolation valve will not compromise the effectiveness of any containment barrier other than the broken steam line itself. Since the MSIVs are a secondary barrier that serve to back up the SG tubes, containment leaktight integrity will not be degraded as a result of a steam line break in this case.

The steam lines and the shell-sides of the SGs are considered an extension of the containment boundary and, as such, are not to be damaged as a consequence of damage to the RCS. The SG shells and steam lines are, therefore, designed to be protected against RCS missiles (refer to Section 3.5.2.4).

Applicable design and quality code classifications are discussed in Chapter 3. The classification and applicable codes for the main steam system are identified in Table 3.2-3. Faults involving the main steam system are discussed in Sections 15.3.2 and 15.4.2.

The MSIVs can be operated manually from the control room as described in Section 10.3.3.4. There are also manual bypass valves around those air-operated MSIV bypass valves on main steam leads 2 and 3. These local manual bypass valves can be used to drain condensate accumulated in piping upstream of the MSIVs upon a loss of instrument air supply prior to the startup of the AFW pump turbine.

10.3.2.1 Capability of Main Steam Isolation and Check Valves to Withstand Closure Loads following a Postulated Main Steam Line Break

10.3.2.1.1 Summary

During the postulated event of a pipe rupture in the main steam system, the check and isolation valves close under loading conditions that are much more severe than those encountered during normal plant operation. The analyses presented here demonstrate that both the main steam line check and isolation valves are capable of successfully performing their functions during this event.

10.3.2.1.2 Results

Impact energy levels for the most severe pipe rupture conditions are given in Table 10.3-2. The highest level is 0.888 x 10^6 in-lb for the isolation valve disc. The disc is capable of absorbing energy levels exceeding twice this predicted value without developing excessive deflections. The check valve disc, which has the same capability, is subjected to lower energy levels.

The bearing stress at the valve seat is determined from the disc-to-seat reaction. The results are within the typical allowable stresses for this type of application.

For the most part, the tail link is not stressed beyond the elastic limit; where the elastic limit is exceeded, the incursion into the plastic range is slight. The maximum tail link deflection is determined to be 0.0425 inches. This deflection will not prevent proper valve closure.

The maximum shearing stress developed in the rockshaft is 21.5 ksi, well within the elastic range of the material. The deflection in the rockshaft will be insignificant.

10.3.2.1.3 Basic Criteria and Assumptions

The following criteria and assumptions were used in the analysis:

(1) The initial angle of the isolation and check valve discs are 80 and 70° from the closed position, respectively.

(2) The postulated break locations that were selected will result in the most severe disc impact energy for each valve. Postulated break locations are established and defined in Reference 2, page 3.6A-41.

(3) The postulated break type that will result in the most severe disc impact energy is used. Types of breaks considered include circumferential, longitudinal, and crack as defined in Reference 3. The circumferential break is used in this analysis.

(4) The ruptured pipe is assumed to separate to full flow area instantaneously. A discharge coefficient of 1 is conservatively assumed for flow through the break area.

(5) It is conservatively assumed that there is no obstruction to discharging flow from the break that would prevent maximum blowdown flow from being developed.

(6) Isolation valve trip is conservatively assumed to occur 0.5 seconds (minimum) after a pipe rupture. Evaluation of larger time delays between pipe rupture and disc release shows that the shorter time is a more severe

condition on the valve; and therefore, the shortest possible release time is used in the analysis.

(7) It is assumed that there is no frictional resistance to the valve rockshaft rotation; and that the pneumatic actuators offer no resistance to closure after a trip signal.

(8) Initial steam conditions used in the analysis are as follows:

Hot Standby:	Line pressure	=	1020 psia
	Line flow	=	0 lb/sec
Full Load:	Line pressure	=	800 psia
	Line flow	=	1010 lb/sec

Under a postulated pipe rupture, the maximum flow through the isolation valve occurs under a plant hot standby condition. This results in a maximum acceleration of the valve disc. For the check valve, the plant operating condition that will result in the maximum disc impact energy is full load.

10.3.2.1.4 Analysis

10.3.2.1.4.1 Maximum Disc Impact Energy

The check valve computer program used to solve the equations of motion for the valve disc to determine angular velocity and energy at impact is a modification of RELAP 3 (Reference 4). The modification consists of incorporating the equations of motion for the valve disc.

The equations incorporated into the program to mathematically describe the valve disc motion include the equations of motion, valve pressure drop as a function of flow rate, actuator return spring forces, and valve flow area as a function of disc position. Because of the similarity in construction, these equations are the same (except for spring forces) for both the isolation and check valves. The isolation valve calculations are initiated following a trip signal. For the check valve, initiation is when the flow reverses in the pipe creating forces to close the disc.

The disc angular acceleration and velocity and the maximum disc impact energy are calculated as a function of the torque acting on the disc. This torque is comprised of gravitational, fluid flow, actuator, frictional, and viscous components. In this analysis, the frictional and viscous torque components act to delay the closure and thus are conservatively neglected. The gravity torque is a function of disc position and the actuator torque is a function of spring displacement. The fluid flow torque is caused by pressure differential across the disc. The pressure differential across the disc, in the non-choking flow region, is the frictional pressure drop across the disc calculated from the valve loss coefficients established by the valve manufacturer (Schutte and Koerting

Company). To determine the pressure drop across the disc in the choking flow region, a static pressure difference in volumes upstream and downstream of the disc is used.

10.3.2.1.5 Component Analysis

10.3.2.1.5.1 Load Generation

The loads acting on the valve components are generated by the disc angular velocity, disc angular acceleration, and the kinetic energy developed in the disc at instant of impact. These quantities are given in Table 10.3-2. The maximum of these values for the isolation of check valves were used in the analysis.

10.3.2.1.5.2 Disc Analysis

Analysis of disc closure is accomplished by an equivalent static method whereby the disc is loaded with a pseudoloading which approximates the inertia forces acting on the disc. The magnitude of this loading is varied and a relationship between the strain energy developed in the disc and the pseudoloading is established. The maximum displacements experienced by the disc are taken to correspond to the point at which the strain energy developed under the pseudoloading equals the kinetic energy at instant of impact.

Subsequently, a reanalysis was performed for evaluating an alternative valve disc material with lower material strengths.

10.3.2.1.5.3 Valve Body Seat Area Analysis

The valve body seat area is analyzed by determining the reaction of the valve seat due to the impact of the disc. This reaction is found from the load-energy relationship derived in the analysis for the valve disc as described above. The load corresponding

to the initial kinetic energy in the disc is determined from this load-energy relationship. The reaction at the valve disc is determined by dividing this load by the circumferential area of the valve seat.

10.3.2.1.5.4 Tail Link Analysis

The critical loading conditions on the tail link occur during travel when the tail link is acted upon by centrifugal forces. In this mode the tail link structure may be considered statically determinate with the centrifugal force resultant applied at the rock shaft and reacted at the disc connection. The maximum loads in the travel mode occur just prior to disc impact, and since the tail link structure is taken as statically determinate, the moment and force resultants throughout for this condition are determined from equilibrium considerations. With the axial and moment resultants known throughout the tail link, deflections are determined by dividing the structure into an appropriate number of sections, then determining and summing the deflections of these individual sections.

10.3.2.1.5.5 Rockshaft Analysis

The design loading condition occurs just prior to valve closure when the rockshaft sees the peak centrifugal forces developed in the tail link. These centrifugal forces are applied as shearing forces to the rockshaft. No coupling between this loading condition and the torque carried by the rockshaft in the open position is considered, since this torque diminishes as the valves close and is zero at instant of valve closure.

10.3.3 SAFETY EVALUATION

10.3.3.1 General Design Criterion 2, 1967 – Performance Standards

The main steam lines, together with their supports and structures between each SG and its associated isolation valves (including the check valves), are PG&E Design Class I.

The main steam lines are designed to perform their safety functions under the effects of earthquakes (refer to Section 3.7.2.2.1.3). The main steam system downstream of the MSIVs is PG&E Design Class II, however the main steam piping downstream of the MSIVs up to the column line G pipe anchor is considered PG&E QA Class S, and seismic analyses of piping up to the column line G pipe anchor have determined that a seismic event will not prevent the MSIVs from performing their PG&E Design Class I isolation function.

The main steam lines are designed to perform their safety functions under the effects of floods and tsunamis (refer to Section 2.4.3.2).

The containment structure, pipeway structure, and auxiliary building, which contain the main steam system's PG&E Design Class I SSCs, are PG&E Design Class I (refer to Section 3.8). These buildings, or applicable portions thereof, are designed to withstand the effects of winds (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), and earthquakes (refer to Section 3.7). These designs protect the main steam system, ensuring its safety functions will be performed.

Portions of main steam lines, including the MSIVs, are located outside and on the roof of the auxiliary building and are partially resistant to tornadoes, however, the capability of the system to support plant safe shutdown is maintained (refer to Section 3.3.2.5.2.7).

10.3.3.2 General Design Criterion 3, 1971 – Fire Protection

The main steam system is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

10.3.3.3 General Design Criterion 4, 1967 – Sharing of Systems

Each DCPP unit can supply portions of the other unit's auxiliary steam from its PG&E Design Class II portion of the main steam system downstream of the MSIVs. Check valves in the supply lines prevent cross-flow of the main steam if this feature is utilized. Failure of this check valve would not affect either unit because both units operate within the same design parameters.

The PG&E Design Class I portion of the main steam system is not affected by this feature.

10.3.3.4 General Design Criterion 11, 1967 – Control Room

The MSIVs can be operated manually from the control room. The MSIVs have remote-manual, air-operated bypass valves for the pressure equalization that is necessary to open the valves. The bypass valves are operated from the control room and automatically close on the same signals that automatically close the MSIVs.

Position indication is provided on the main control board for all MSIVs and bypass valves. Additionally, the main control board provides indications of main steam flow and SG pressure.

If access to the control room is lost, necessary main steam system valves can be operated locally with SG pressure indicated on the HSP.

10.3.3.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The MSIVs automatically close on high negative steam line pressure rate, low steam line pressure, or on a high-high containment pressure signal. Instrumentation and controls for the main steam system are discussed in Sections 6.2.4, 7.3, and 9.3.1.2.2.

Refer to Section 10.3.3.7 for radiation monitoring instrumentation.

10.3.3.6 General Design Criterion 15, 1967 – Engineered Safety Features Protection Systems

The main steam system monitors steam pressure and provides the signal to engineered safety features actuation system (ESFAS) (refer to Section 7.3).

10.3.3.7 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The radiation monitoring system continuously monitors the main steam system (refer to Section 11.4.2.1.2.1).

Steam generated in the SGs is not normally radioactive. However, in the event of primary-to-secondary system leakage due to a SG tube leak, it is possible for the main steam to become radioactively contaminated. A full discussion of the radiological aspects of primary-to-secondary leakage, including anticipated operating concentration of radioactive contaminants, means of detection of radioactive contamination, anticipated releases to the environment, and limiting conditions for operation, is included in Sections 7.5.2.3, 11.1.6, 11.4.2.1.2.1, and 15.5.

10.3.3.8 General Design Criterion 21, 1967 – Single Failure Definition

The instrumentation and control circuits for steam line isolation (refer to Section 7.3) are redundant in the sense that a single failure cannot prevent isolation. Each MSIV is opened by air and closes when either of the solenoid valves (powered from separate Class 1E 125-Vdc sources) in its vent line is energized, releasing the air.

The instrumentation and control circuits for the main steam system pressure provided to ESFAS are redundant in that a single failure cannot prevent the SI signal actuation. Each steam header employs two-out-of-three logic for its signal.

The main steam supply to the turbine-driven AFW pump is provided from both the number 2 and number 3 steam headers.

10.3.3.9 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the ESF containment isolation portion of the main steam system from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures are discussed in Sections 3.5, 3.6, and 6.2.4.

10.3.3.10 General Design Criterion 49, 1967 – Containment Design Basis

The main steam line containment penetrations are designed and analyzed to withstand the pressures and temperatures that could result from a LOCA without exceeding design leakage rates. Refer to Section 3.8.2.1.1.3 for additional details.

10.3.3.11 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The main steam system isolation valves required for containment closure are periodically tested for operability. Testing of the components required for the containment isolation system (CIS) is discussed in Section 6.2.4.1.4.

10.3.3.12 General Design Criterion 57, 1971 – Closed System Isolation Valves

The main steam system containment penetrations and isolation valves are part of the CIS. Refer to Section 6.2.4 and Table 6.2.-39 for penetration details.

10.3.3.13 Main Steam System Safety Function Requirements

(1) Protection from Missiles

The provisions taken to protect the PG&E Design Class I non-ESF portion of the main steam system from the effects of missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Sections 3.5.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the PG&E Design Class I portion of the main steam system from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Section 3.6.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection of the PG&E Design Class I non-ESF portion of the main steam system located outside containment from the effects of moderate energy pipe failure are discussed in Section 3.6.

(4) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the PG&E Design Class I portion of the main steam system located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

(5) Protection from Flooding Effects

The provisions taken to provide protection of the PG&E Design Class I portion of the main steam system from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

(6) Decay Heat Removal

The main steam system provides means for removing decay heat from the RCS by discharging steam from the SGs to the atmosphere through the SG safety valves and also by providing steam to power the AFW pump turbine (refer to Sections 6.5.2 and 7.4.2).

(7) Main Steam Isolation

The MSIVs and check valves (MSIV/CV) are located outside of the containment structure and downstream of the safety valves. The fast-acting isolation valves are provided in each main steam line and will fully close within 10 seconds of a large steam line break. This design ensures that steam line isolation occurs for breaks either upstream or downstream of the valves. The MSIV/CV are credited to prevent reverse

flow from the steamline header and intact SGs. For breaks downstream of the isolation valves, closure of all valves would completely terminate the blowdown. For any break, in any location, no more than one SG would blow down even if one of the isolation valves fails to close. Cases that postulate the failure of the MSIV/CV are discussed in Section 6.2D.4.1.4. The MSIVs automatically close on high negative steam line pressure rate, low steam line pressure, or on a high-high containment pressure signal and can also be operated from the control room (refer to Sections 10.3.3.4 and 10.3.3.5).

Uncontrolled steam release as a result of a main steam line failure is therefore limited to the contents of one SG, thus keeping the related effect upon the reactor core within the prescribed bounds. (The main steam line rupture event is discussed in detail in Appendix 6.2D and Sections 15.3.2 and 15.4.2.) This results in the need for both isolation valves and check valves, as well as special design considerations for the main steam lines themselves. These considerations are necessary to ensure that damage to a portion of one steam line does not result in damage to the corresponding portion of the other steam lines or the other SGs. They are covered in detail in the MSLB discussion (refer to Section 15.4.2).

(8) Secondary Side Pressure Control

Five spring loaded safety valves are installed on each main steam line, upstream of the MSIVs, to protect the main steam system from overpressurization. The pressure setpoints for these valves are progressively set from 1065 psig to 1115 psig as shown in Table 10.1-1. Refer to Section 3.9.2.2.5 for additional discussion regarding the safety valves.

(9) Steam Flow Restriction

Each main steam line includes an in-line 16-inch diameter flow restrictor that acts to limit the maximum flow and the resulting thrust forces created by a steam line break. The flow restrictors are discussed in more detail in Sections 5.5.4 and 15.4.2. These flow restrictors are separate from the integral flow restrictors in the SG outlet nozzles. Refer to Section 5.1.8.17(6) for a discussion of the SG integral flow restrictor.

10.3.3.14 10 CFR 50.49 – Environmental Qualification

Main steam system components required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. The affected equipment is listed on the EQ Master List. Main steam EQ components include solenoid valves and position switches for the MSIVs and MSIV bypass valves, and steam flow and pressure transmitters. Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment.

10.3.3.15 10 CFR 50.55a(f) – Inservice Testing Requirements

Main steam system components that are within the inservice testing (IST) program are the MSIVs, MSIV bypass valves, the isolation valves for the 10% steam dumps (the steam dump valves themselves are discussed in Section 10.4.4), and the safety valves.

The IST requirements for these components are contained in the IST Program Plan and comply with the ASME code for Operation and Maintenance of Nuclear Power Plants.

10.3.3.16 10 CFR 50.55a(g) – Inservice Inspection Requirements

The main steam system piping has a periodic inservice inspection (ISI) program in accordance with the ASME BPVC Section XI.

10.3.3.17 10 CFR 50.63 – Loss of All Alternating Current Power

In the event of a SBO, closure of the main steam isolation valves provides positive isolation of the main steam system. Refer to Section 10.4.4 for evaluation of the 10 percent atmospheric dump valves following a SBO.

Refer to Section 8.3.1.6 for further discussion of SBO.

10.3.3.18 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The PG&E Design Class I portion of the main steam system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

10.3.3.19 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Category 2 main steam flow indication and radiation monitoring for the vents from the SG safety valves are provided in the control room for Regulatory Guide 1.97, Revision 3 monitoring (refer to Table 7.5-6).

10.3.3.20 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident Monitoring Instrumentation:

Position (1) – The PG&E Design Class I display instrumentation for main steam line activity monitoring when venting from the SG safety valves during and following an accident is provided and is described in Sections 7.5.2.3 and 11.4.2.1.2.1.

10.3.3.21 Generic Letter 89-08, May 1989 – Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP procedures identify the interdepartmental responsibilities and interfaces for the flow-accelerated corrosion (FAC) monitoring program for all plant systems, including the main steam system.

10.3.4 TESTS AND INSPECTIONS

The piping from the SG, up to and including the main steam line isolation valves, is equipped with removable insulation for ISI of welds. The tests and inspections that apply to the main steam line isolation valves are in accordance with the DCPP Technical Specifications (Reference 1). Main steam line isolation valves are tested periodically to verify their ability to close within the required time (refer to Section 7.3 for a discussion of the response times for the steam line isolation signal).

Preoperational and startup testing requirements applicable to the main steam system are discussed in Chapter 14.

Since the major components of the SPCS are accessible during normal power operation, leakage from the valves located upstream of the MSIVs is monitored by routine visual inspection by the operators.

The MSIVs, and the valves upstream of them and outside the containment, are designed and packed to have the capability of limiting gland leakage along the stem to no more than one cubic centimeter of water per hour per inch of stem diameter, when subjected to a hydrostatic test pressure of 1100 psig, or 0.03 scf of air per hour per inch of stem diameter with a differential pressure of 80 psi. They are designed to have the capability to limit the valve seat leakage rate to 0.1 scf per hour per inch of seat diameter, when subjected to a pneumatic pressure of 80 psig. Table 10.3-1 summarizes the potential leakages for valves located upstream of the steam line isolation valves, and lists the leak rates measured through these leak paths during initial plant startup testing.

However, since the secondary system is a closed system inside containment whose integrity is not damaged by a LOCA, the offsite dose consequences via the leak paths identified in Table 10.3-1 are small when compared to the consequences from the containment atmosphere leakage assumed in the offsite dose analysis. Hence, pursuant to Table 6.2-39, there are no local leak rate limits established for these leakage paths, since in accordance with 10 CFR Part 50 Appendix J, this leakage is not required to be measured.

10.3.5 WATER CHEMISTRY

The secondary water chemistry control program is discussed in Section 5.5.2.3.5. SG blowdown for chemistry control is discussed in Section 10.4.8. The main steam

sampling system is discussed in Section 9.3. Chemical treatment of the secondary system water for corrosion control is discussed in Section 10.4.9.

10.3.6 INSTRUMENTATION APPLICATIONS

Instrumentation for the main steam system is discussed in Sections 10.3.3.4 and 10.3.3.5.

10.3.7 REFERENCES

1. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

2. Nuclear Services Corporation, Evaluation for Effects of Postulated Pipe Break Outside Containment for Diablo Canyon Unit 1, Revision 2, June 26, 1974.

3. Letter (Docket Nos. 50-275 and 50-323) from A. Giambusso of the U.S. Atomic Energy Commission to F.T. Searls of the Pacific Gas and Electric Company, dated December 18, 1972, including the attachment "General Information Required for Consideration of the Effects of Piping System Break Outside Containment."

4. W.H. Rettig, et al, "RELAP 3 - A Computer Program for Reactor Blowdown Analysis," IN-1321, June 1970. Also Supplement of June 1971.

10.3.8 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

10.4 OTHER FEATURES OF STEAM AND POWER CONVERSION SYSTEM

10.4.1 MAIN CONDENSER

The main condenser provides a heat sink and collection volume for steam and condensate discharged from the main turbine, feedwater pump turbines, TBS, feedwater heater drains, and other miscellaneous flows, drains, and vents.

10.4.1.1 Design Bases

The main condenser is classified as PG&E Design Class II. There are no regulatory requirements associated with the main condenser. Radioactive leak detection is discussed in Section 10.4.2.

10.4.1.2 System Description

The main condenser is designed to condense full load steam and maintain a nominal absolute pressure of 1.71 inches of mercury at 85 percent cleanliness. Sufficient surface (618,150 square feet) is provided to condense TBS steam (up to 40 percent of maximum calculated capability flow), following a load reduction, or under controlled startup conditions, or from residual and decay heat at shutdown.

The condenser hotwells are sized to provide adequate storage of water (138,000 gallons) to allow for the water lost to the atmosphere and "shrinkage" on a 50 percent load reduction. The condensate leaving the hotwells is deaerated to 0.005 cc/liter dissolved oxygen level. The main condenser is provided with a means of detecting saltwater leakage.

During operation, air is removed from the condenser by steam jet air ejectors and discharged to the plant vent. The discharged air is continuously monitored for radioactivity. No control functions are associated with this radiation monitor. For drawing initial vacuum, the condenser is evacuated by a wet-type rotary vacuum pump which discharges air to the atmosphere. The condenser vacuum pump may also be placed into service in the event of degraded condenser vacuum. Refer to Section 10.4.2 for a discussion of the main condenser evacuation system (MCES).

The main condensing surface is mounted beneath the low-pressure turbine elements in two shells with interconnected steam spaces. The tubes are arranged parallel to the turbine shaft. The performance data for both the Unit 1 and Unit 2 condensers are summarized in Table 10.4-1.

The following materials are used in the condenser:

(1) Shell and tube supports - carbon steel, ASTM A285, Grade C

(2) Tubesheets - 90-10 copper nickel, ASTM B171 (with corrosion-resistant coating on the saltwater side)

(3) Water boxes - carbon steel, ASTM A285, Grade C, lined with corrosion resistant coating on the saltwater side

(4) Tubes - titanium

The condenser will condense up to 40 percent of the full load main steam flow during a load reduction, startup, or shutdown. As discussed in Chapter 15, the SG safety valves protect the NSSS from overpressure if the condenser is not available or if the steam flow exceeds the capacity of the condenser. The secondary system is normally not radioactive. However, in the event of primary-to-secondary leakage through leaking SG tubes, it is possible for the main steam to become radioactively contaminated. A discussion of the assumed leakage rates, treatment methods, and calculated activity levels is included in Section 11.1.6, and an inventory of radionuclides in the condenser for an assumed leak rate is shown in Table 11.1-27.

10.4.1.3 Safety Evaluation

The main condenser is classified as PG&E Design Class II. There are no regulatory requirements associated with the main condenser. Radioactive leak detection is discussed in Section 10.4.2.

10.4.1.4 Tests and Inspections

Tests and inspections of the main condenser are done in accordance with plant procedures.

10.4.1.5 Instrumentation Applications

Instrumentation is provided to monitor and control main condenser operation.

10.4.2 MAIN CONDENSER EVACUATION SYSTEM

The MCES removes noncondensable gases from the main condenser during plant startup, cooldown, and normal operation. The system is classified as PG&E Design Class II.

10.4.2.1 Design Bases

10.4.2.1.1 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The MCES is designed to provide means for monitoring the facility effluent discharge paths, and the facility environs for radioactivity that could be released from normal operations, from anticipated transients, and from accident conditions.

10.4.2.1.2 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident-Monitoring Instrumentation:

Position (1) – The MCES is designed with noble gas effluent monitors that are installed with an extended range designed to function during accident conditions.

Position (2) – The MCES is designed with provisions for sampling of plant effluents for post-accident releases of radioactive iodines and particulates and onsite laboratory capabilities.

10.4.2.2 System Description

The MCES consists of a wet-type rotary vacuum pump and steam jet air ejectors. The vacuum pump is common to both units and is used to draw an initial vacuum in the condenser of either unit and may be used during degraded vacuum conditions. The steam jet air ejectors are used after the initial pumpdown and are designed to remove air that may degrade the ability of the condenser to maintain a nominal absolute pressure of 1.71 inches of mercury, as described in Section 10.4.1.2.

The wet-type rotary vacuum pump has a capacity of approximately 7000 cubic feet per minute.

The steam jet air ejector system consists of two stages of steam jets mounted on a combined inter-after surface condenser. The air ejector system is designed to remove 360 pounds per hour of air saturated with water vapor at 71.5°F, and a suction pressure of 1 inch of mercury absolute pressure when supplied with steam at 85 psig. The first stage consists of eight 25 percent capacity jets and the second stage consists of twin 100 percent capacity jets.

Refer to Section 5.5.2 for information on PG&E's implementation of Electric Power Research Institute primary-to-secondary leak guidelines.

10.4.2.3 Safety Evaluation

10.4.2.3.1 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

Air is discharged from the vacuum pump through a local vent. During vacuum pump operation, grab samples are taken at the local vent in support of the Radioactive Effluent Controls Program. In addition, evaluations have been performed that demonstrate potential radioactive discharges remain within 10 CFR Part 20 limits. Noncondensables vented from the steam jet air ejectors while the plant is at power operation are discharged through the plant vent that is continuously monitored for radioactivity. Further discussion of releases due to SG leakage and the radiation monitoring of the plant vent is given in Sections 7.5.2.3, 9.4.2, 11.1.6, and 11.4.

10.4.2.3.2 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident-Monitoring Instrumentation:

Position (1) – Extended range noble gas effluent monitoring is installed in the plant vent, which includes exhaust from the steam jet air ejectors, and is designed to function during accident conditions. Refer to Section 9.4.2 for information on the plant vent and Figures 3.2-2 and 3.2-23 for a depiction of steam jet air ejector after-condenser exhaust routing to the plant vent. Refer to Section 11.4 for discussion of radiation monitors.

Position (2) – Installed capability is provided in the plant to obtain samples of the particulate and iodine radioactivity concentrations that may be present in the gaseous effluent being discharged to the environment from the plant vent, which includes the steam jet air ejector exhaust, under accident and post-accident conditions. The technical support center laboratory is available for onsite testing of the air samples. Refer to Section 9.4.2 for information on the plant vent and Figures 3.2-2 and 3.2-23 for a depiction of steam jet air ejector after-condenser exhaust routing to the plant vent. Refer to Section 11.4 for discussion of radiation monitors.

10.4.2.4 Tests and Inspections

Tests and inspections of the MCES are done in accordance with plant procedures.

10.4.2.5 Instrumentation Applications

Instrumentation is provided to monitor and control MCES operation.

10.4.3 TURBINE GLAND SEALING SYSTEM

The turbine gland sealing system provides shaft sealing for the main turbine and feedwater pump turbine.

10.4.3.1 Design Bases

The turbine gland sealing system is designed to prevent the leakage of air into, or steam out of, the turbines along the turbine shaft. The system has no PG&E Design Class I functions and is classified as PG&E Design Class II.

10.4.3.1.1 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The turbine gland sealing system is designed to provide means for monitoring the facility effluent discharge paths, and the facility environs for radioactivity that could be released from normal operations, from anticipated transients, and from accident conditions.

10.4.3.1.2 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 - Additional Accident-Monitoring Instrumentation:

Position (1) - Item II.F.1, Position (1) requires monitoring of post-accident effluent noble gas releases from the turbine gland sealing system.

Position (2) - Item II.F.1, Position (2) requires monitoring of post-accident effluent radioactive iodine and particulate releases from the turbine gland sealing system.

10.4.3.2 System Description

The turbine glands are of the labyrinth type. When the unit is being started, and partially during normal operation, steam is supplied to the gland header from the main steam line to seal the high-pressure and low-pressure turbine glands. The auxiliary boiler also can be used to supply sealing steam during startup. When the turbine is operating under load, the steam pressure inside the high-pressure turbine increases and steam leaks outward toward the rotor ends. The leakage from the high-pressure glands partially supplies the steam requirements for the low-pressure glands, while the remainder is furnished by the main steam gland regulator. Adequate steam pressure is maintained in the gland area at all times to prevent the leakage of air into, or steam out of, the turbine along the turbine shaft.

At normal operating conditions, the exhaust from the gland seals is approximately 3000 pounds per hour of air saturated with water vapor at 150°F. The gland steam condenser maintains a pressure slightly below atmosphere in the gland leak-off system to prevent the escape of steam from the glands. The air and noncondensable gases from the turbine gland seal condenser are exhausted to the plant vent, which is continuously monitored (refer to Section 11.4.2.1.2.1).

10.4.3.3 Safety Evaluation

10.4.3.3.1 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The turbine gland sealing system has no PG&E Design Class I function. In the event of SG leakage and continued plant operation, the gland sealing system prevents the release of radioactive steam to the turbine building. If gland seals are lost due to a malfunction of the system, a small amount of steam could be released depending on the type of equipment malfunction. Upon the loss of gland sealing steam, the turbine would be tripped to prevent seal or rotor damage. A turbine trip would prevent additional radioactive steam from entering the turbine.

The air and noncondensable gases from the gland seal condenser are routed to the plant vent (refer to Sections 9.4.2 and 11.4.2.1.2.1). In the event that the gland steam becomes contaminated, it will be detected by radiation detectors located in the plant vent (normal range and redundant normal range radiation monitors). The turbine building is not monitored for leakage from the glands. Details of the radiological evaluation of the system are included in Section 11.3.2.3.

10.4.3.3.2 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 - Additional Accident-Monitoring Instrumentation:

Position (1) - Radiation detection instruments are provided in the plant vent to monitor post-accident effluent noble gas releases from the turbine gland sealing system. Refer to Section 9.4.2 for information on the plant vent and Figure 3.2-23 for a depiction of turbine gland steam condenser exhaust routing to the plant vent. Refer to Section 11.4 for discussion of radiation monitors.

Position (2) - Radiation detection instruments are provided in the plant vent to monitor post-accident effluent radioactive iodine and particulate releases from the turbine gland sealing system. Refer to Section 9.4.2 for information on the plant vent and Figure 3.2-23 for a depiction of turbine gland steam condenser exhaust routing to the plant vent. Refer to Section 11.4 for discussion of radiation monitors.

10.4.4 TURBINE BYPASS SYSTEM

The TBS bypasses main steam directly to the main condenser and atmosphere, depending on the required capacity, during the emergency condition caused by a sudden load reduction by the turbine-generator or turbine trip, and during plant startup and shutdown.

10.4.4.1 Design Bases

Of the 25 turbine bypass valves (refer to Section 10.4.4.2), only the four 10 percent atmospheric dump valves have a safety function (refer to Section 10.4.4.3.8). Therefore, the design bases in this section apply only to these valves and their associated upstream piping systems.

10.4.4.1.1 General Design Criterion 2, 1967 – Performance Standards

The 10 percent atmospheric dump valves are designed to withstand the effects of, or are protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

10.4.4.1.2 General Design Criterion 3, 1971 – Fire Protection

The 10 percent atmospheric dump valves are designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

10.4.4.1.3 General Design Criterion 11, 1967 – Control Room

The 10 percent atmospheric dump valves are designed to or contain instrumentation that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

10.4.4.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the 10 percent atmospheric dump valves' variables within prescribed operating ranges.

10.4.4.1.5 General Design Criterion 40, 1967 – Missile Protection

The ESF containment isolation portion of the TBS (10 percent atmospheric dump valves) is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

10.4.4.1.6 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The piping system associated with the 10 percent atmospheric dump valves that penetrates containment is provided with leakage detection, isolation, redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The piping is designed with a capability to test periodically the

operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

10.4.4.1.7 General Design Criterion 57, 1971 – Closed System Isolation Valves

The main steam system headers associated with the 10 percent atmospheric dump valves are designed such that each line that penetrates containment and is neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere has at least one containment isolation valve which is either automatic or locked closed or capable of remote-manual operation. This valve is outside containment and located as close to the containment as practical. A simple check valve is not used as the automatic isolation valve.

10.4.4.1.8 Turbine Bypass System Safety Function Requirements

(1) Protection from Missiles

The PG&E Design Class I non-ESF portion of the TBS (10 percent atmospheric dump valves) is designed to be protected against the effects of missiles which may result from plant equipment failure and from events and conditions outside the plant to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(2) Protection from High Energy Pipe Rupture Effects

The PG&E Design Class I non-ESF portion of the TBS (10 percent atmospheric dump valves) is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection from Moderate Energy Pipe Rupture Effects

The PG&E Design Class I non-ESF portion of the TBS (10 percent atmospheric dump valves) is designed to be protected against the effects of moderate energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(4) Protection from Flooding Effects

The PG&E Design Class I non-ESF portion of the TBS (10 percent atmospheric dump valves) is designed to be protected from the effects of internal flooding to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(5) Reactor Coolant System Cooldown

The 10 percent atmospheric dump valves are designed to provide a method for RCS cooldown.

10.4.4.1.9 10 CFR 50.55a(f) – Inservice Testing Requirements

The 10 percent atmospheric dump valves are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

10.4.4.1.10 10 CFR 50.55a(g) – Inservice Inspection Requirements

The 10 percent atmospheric dump valves are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

10.4.4.1.11 10 CFR 50.63 – Loss of All Alternating Current Power

The 10 percent atmospheric dump valves are required to perform their function of heat removal from the secondary side of the steam generators to maintain the unit in Hot Standby (Mode 3) in the event of a SBO.

10.4.4.1.12 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The 10 percent atmospheric dump valves are designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

10.4.4.2 System Description

The TBS consists of 25 power relief valves. Four of these valves (10 percent dump valves) take steam from each main steam line and discharge to the atmosphere. The remaining 21 valves take steam from the dump headers (connected to all main steam lines)and discharge either into spray distribution headers in the condenser (40 percent dump valves) or to the atmosphere (35 percent dump valves). The system thus provides an artificial load on the RCS during the emergency condition of a sudden load reduction by the turbine-generator or a turbine trip (four of the 40 percent dump valves are used during cooldown).

The valve groups are opened in the following sequence:

(1) Cooldown valves (four of twelve 40 percent dump valves)

(2) Bypass valves (remaining eight of twelve 40 percent dump valves)

NOTE: Plant capability is provided to use all 12 valves for cooldown during Mode 3 after boration to cold shutdown conditions.

(3) Atmospheric relief valves (nine 35 percent atmospheric dump valves downstream of the MSIVs)

(4) Atmospheric relief valves (four 10 percent atmospheric dump valves upstream of the MSIVs)

NOTE: Group 4 of the atmospheric dump valves are set at a lower pressure than the spring-loaded safety valves.

The TBS is thus designed with a capacity to bypass a range of approximately 66 to 79 percent of the full load steam flow over the range of full load operating conditions to the main condenser and the atmosphere combined. The exact capacities of these relief valves depend on the full load operating conditions. Valve groups 1, 2, and 3 are credited in determining this capacity. The steam dump capacity to the main condenser alone (groups 1 and 2) has a range of approximately 35 to 41 percent of the full load steam flow over the range of full load operating conditions.

The capacity of the TBS, combined with the 10 percent step-load-change characteristics of the reactor, provides the capability of accepting a sudden load reduction of up to 50 percent, without reactor trip or operation of the spring-loaded safety valves or 10 percent atmospheric dump valves.

The total amount of steam released to the atmosphere during a loss of generator external load assuming that the condenser is not available for steam dump is discussed in Section 15.5.10.2.

With the exception of group 4 of the atmospheric dump valves, the TBS is not essential to the safe operation of the plant; it is required to give the plant flexibility of operation and a controlled cooldown. The SG safety valves provide relieving capacity during a period when all valves are out of service (refer to Section 10.3.2).

Failure of the 40 percent dump valves, the 35 percent atmospheric dump valves downstream of the MSIVs, or any pipe downstream of the MSIVs could result in a rapid cooldown and depressurization of the SGs until the MSIVs close on high negative steam line pressure rate or low steam line pressure signals. The transients and radiological consequences associated with such a failure would not be as severe as the double-ended severance of a main steam line, as discussed in Section 15.5.18. Failure of any of these components (or pipe associated with them) downstream of the MSIVs could not cause overpressurization of a SG because of the location of the spring-loaded safety valves upstream of the MSIVs.

The TBS has been analyzed for potential effects of piping rupture on nearby safety-related equipment. Details of this analysis are presented in Section 3.6.4.

10.4.4.2.1 Design Codes and Standards

The piping and valves associated with the 40 percent and 35 percent dump valves are classified as PG&E Design Class II because they are not required for RCS cooldown, as discussed in Section 10.4.4.3.

The 10 percent atmospheric dump valves and associated upstream piping are classified as PG&E Design Class I because they are required for RCS cooldown, as discussed in Section 10.4.4.3.8.

Applicable codes and standards for piping, valves, and fittings are discussed in Section 3.2.

10.4.4.3 Safety Evaluation

10.4.4.3.1 General Design Criterion 2, 1967 – Performance Standards

The 10 percent atmospheric dump valves are PG&E Design Class I components and are located either on the roof of the PG&E Design Class I auxiliary building at elevation 143 feet (steam leads 3 and 4) or on a support structure external to the containment at elevation 112 feet-6 inches (steam leads 1 and 2). These elevations are above the level affected by floods and tsunamis.

PG&E Design Class I SSCs in locations exposed to the weather are evaluated against tornado-related effects including impact by tornado-induced missiles. Refer to Section 3.3.2.3 for the results of the evaluation.

The 10 percent atmospheric dump valves are required to function following a Design Earthquake, Double Design Earthquake, and Hosgri Earthquake (refer to Sections 3.7.1 and 3.7.6).

10.4.4.3.2 General Design Criterion 3, 1971 – Fire Protection

The 10 percent atmospheric dump valves are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

10.4.4.3.3 General Design Criterion 11, 1967 – Control Room

The 10 percent atmospheric dump valves can be controlled manually from within the control room in order to maintain safe operational status of the plant. In the event that control room access is lost due to fire or other causes, the valves can be controlled manually from the HSP (refer to Section 7.4.2.1.2.3).

10.4.4.3.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation for manually operating the 10 percent atmospheric dump valves is provided in the main control room, at the HSP, and locally at the valve (refer to Section 7.4.2.1.2.3). Valve position indication is provided on the emergency response facility data system (ERFDS) (refer to Section 7.5.2.9).

10.4.4.3.5 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the ESF containment isolation portion of the TBS from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures, respectively are discussed in Sections 3.5, 3.6, and 6.2.4.

10.4.4.3.6 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The 10 percent atmospheric dump valves, required for containment closure, are periodically tested for operability. Testing of the components required for the CIS is discussed in Section 6.2.4.

10.4.4.3.7 General Design Criterion 57, 1971 – Closed System Isolation Valves

The containment penetrations associated with the 10 percent atmospheric dump valves comply with the requirements of GDC 57, 1971, as described in Section 6.2.4 and Table 6.2-39.

10.4.4.3.8 Turbine Bypass System Safety Function Requirements

(1) Protection from Missiles

The provisions taken to protect the PG&E Design Class I non-ESF portion of the TBS (10 percent atmospheric dump valves) from the effects of missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Sections 3.5.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the PG&E Design Class I portion of the TBS (10 percent atmospheric dump valves) from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Section 3.6.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection for the PG&E Design Class I TBS (10 percent atmospheric dump valves) from the effects of moderate energy pipe failure are discussed in Section 3.6.

(4) Protection from Flooding Effects

The provisions taken to provide protection for the PG&E Design Class I TBS (10 percent atmospheric dump valves) from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

(5) Reactor Coolant System Cooldown

The 10 percent atmospheric dump valves provide a means for plant cooldown by discharging steam to the atmosphere when the condenser, the condenser circulating water pumps, or steam dump to the condenser is not available. Under such circumstances, the 10 percent atmospheric dump valves, in conjunction with the AFW system, permit the plant to be cooled down from the pressure setpoint of the lowest-set main steam safety valves to the point where the residual heat removal system can be placed in service. In the event of a steam generator tube rupture event in conjunction with loss of offsite power, the 10 percent atmospheric dump valves are used to cool down the RCS to a temperature that permits equalization of the primary and secondary pressures at a pressure below the lowest-set main steam safety valve.

With the loss of both the normal air supply and the backup nitrogen supply to the 10 percent atmospheric dump valves, the normal supplies are blocked and the PG&E Design Class I backup air bottle system is activated (refer to Section 9.3.1.2). With the backup air bottle system activated, control of the valves is remote manual via the PG&E Design Class I control circuit from the control room ensuring the valves can cooldown the RCS.

10.4.4.3.9 10 CFR 50.55a(f) – Inservice Testing Requirements

The TBS components that are within the IST program are the four 10 percent atmospheric dump valves.

The IST requirements for these components are contained in the IST Program Plan and comply with the ASME code for Operation and Maintenance of Nuclear Power Plants.

10.4.4.3.10 10 CFR 50.55a(g) – Inservice Inspection Requirements

The 10 percent atmospheric dump valves have a periodic ISI program in accordance with the ASME BPVC Section XI (refer to Section 5.2.3.15).

10.4.4.3.11 10 CFR 50.63 – Loss of All Alternating Current Power

During an SBO, decay heat is removed from the core by natural circulation of the reactor coolant. This heat is then transferred to the secondary side of the SGs and discharged to the atmosphere through the 10 percent atmospheric dump valves. The 10 percent atmospheric dump valves have adequate capacity for decay heat removal to maintain the unit in Hot Standby for the 4 hour SBO coping duration.

Refer to Section 8.3.1.6 for further discussion of station blackout.

10.4.4.3.12 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The 10 percent atmospheric dump valves are designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

10.4.4.4 Tests and Inspections

Local test facilities for the bypass flow control valves are not provided. The 40 percent dump valves and the 35 percent dump valves are PG&E Design Class II and are tested at reactor low power levels.

Each 10 percent atmospheric dump valve , associated block valve, and associated remote manual controls, including the backup air bottles, is demonstrated operable on a frequency interval required by the Technical Specifications.

Additionally, each 10 percent atmospheric dump block valve is verified open at least once per 31 days

Should evidence indicate that radioactivity is being released as a result of leakage through these valves during the post-accident recovery period, action such as tightening packing will be taken to eliminate the source.

10.4.4.5 Instrumentation Applications

During normal operating transients for which the plant is designed, the TBS is automatically regulated by the reactor coolant temperature control system to maintain the programmed coolant temperature.

When a transient results in a plant trip, the operator transfers bypass control to the pressure control mode and regulates the system to maintain no-load steam pressure. Lower pressures can be maintained automatically by adjustment of the pressure setpoint. During a plant cooldown, the bypass system is manually controlled to achieve the required cooling rate. This is accomplished by manual adjustment of the pressure

setpoint in the control room and requires a minimum operation of four bypass valves to the condenser.

Refer to Section 10.4.4.3.4 for additional information on instrumentation and controls.

10.4.5 CIRCULATING WATER SYSTEM

The circulating water system provides the heat sink required for removal of waste heat in the power plant's thermal cycle. The system has the principal function of removing heat by absorbing this energy in the main condenser.

10.4.5.1 Design Bases

10.4.5.1.1 Circulating Water System Safety Function Requirements

(1) Protection from Flooding Effects

The flooding effects from a circulating water system pipe rupture do not prevent essential equipment from safely shutting down and maintaining shutdown conditions of the reactor.

10.4.5.2 System Description

The circulating water system is designed to provide cooling water necessary to condense the steam entering the main condenser. The system also serves the intake coolers, condensate cooler, and service cooling water heat exchangers. The design temperature rise in the circulating water system at full load operation is 18°F. The design flow per unit is nominally 862,000 gpm.

The circulating water system is classified as PG&E Design Class II.

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

A curtain wall at the front of the intake structure limits the amount of floating debris entering the intake structure. Bar racks near the front of the intake structure intercept large submerged debris. The bar racks have 3/8-inch thick bars at 3-3/8 inch centers. Traveling screens intercept all material larger than the screen mesh opening (3/8 inch clear square openings).

The total flow in each unit's circulating water system is nominally 862,000 gpm, which is pumped by two circulating water pumps per unit through two circulating water conduits per unit to the condenser inlet water boxes. Each pump has a discharge valve and bypass line around the valve. Approximately 4000 gpm of the circulating water flow is

used per unit to cool the service cooling water heat exchangers and 1000 gpm to cool the pump motor cooling water.

At the intake structure, each circulating water system consists of two circulating water pumps with 12-kV motors cooled by an air-to-water heat exchanger. The cooling water is provided from a closed-loop cooling system.

The chlorination system provides chemical treatment of the circulating water to control macro and micro fouling in the intake tunnels, piping, and the condenser tubes. The system is used as needed.

The chlorination system, which is shown as part of Figure 3.2-17, provides an oxidizing biocide to the suction of the circulating water pumps for control of macro and micro fouling. Liquid sodium hypochlorite and a supplemental chemical are stored in tanks at the intake structure (common to both units). Adequate valving is provided for isolating any of the tanks from the system. Each tank is within a containment tank sized to contain the entire contents of the storage tank. When chlorination is required (based on a time schedule), the chemicals are injected via metering pumps and injected into the intake structure. In addition, dechlorinating injections are made between the outlet of the main condenser and the discharge structure as required to ensure national pollutant discharge elimination system (NPDES) permit requirements are met. Concentrations of chlorine in the circulation water system outfall are discussed in detail in Reference 1 and the NPDES permit.

The circulating water pumps are not required for safety of the units. Dependable pump operation is necessary, however, for reliable operation of electric generating plants and provisions to ensure their operation are incorporated in the design.

10.4.5.3 Safety Evaluation

10.4.5.3.1 Circulating Water System Safety Function Requirements

(1) Protection from Flooding Effects

The failure of circulating water system piping is evaluated for the effects of flooding on PG&E Design Class I essential safe shutdown equipment located in the turbine building. The provisions taken to provide protection for the safe shutdown equipment from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

Due to the low operating pressure of the circulating water system, the probability of a line, expansion joint, or waterbox failure is very low. The differential head across the circulating water pumps at shutoff is a nominal 160 feet. At high tide, the pump discharge head at shutoff would be 163.4 feet (refer to Section 10.4.5.2), measured at elevation zero, MSL datum. However, provisions exist in the design of the circulating water system that prevent the circulating water pumps from operating at shutoff head.

The design of the inlet and outlet of the circulating water to the condenser consists of several components. The circulating water flows through the embedded supply conduit, the inlet transition spool piece, the inlet expansion joint, and inlet condenser water box prior to entering the condenser tubes. Similarly, upon exiting the tubes, the circulating water passes through the outlet waterbox, expansion joint, transition spool piece, and embedded discharge conduit prior to being discharged to the ocean. The transition spool pieces, expansion joints, and condenser (including waterboxes) are located in the turbine building. The discharge gates are located in the embedded discharge conduit in the yard.

The design pressure of the rubber expansion joints on the inlet and outlet of the condenser (located at an elevation of 85 feet) is 81 feet.

Thus, if a circulating water pump were to pump against closed discharge gates, the pressure on the expansion joint (the pump discharge head minus the static elevation head) would be less than the design pressure. The design pressure of the transition inlet and outlet spool pieces (located at an elevation of 81 feet) is 58 feet. Similarly, the design pressure of the condenser water boxes (located at an elevation of 85 feet) is 58 feet. To prevent operating the circulating water pump and system in a configuration that could result in overpressurizing the transition spool pieces and waterboxes, mechanical stops on the condenser discharge gate operators and structural stops on the gate guide tracks inhibit the complete closing of the discharge gates. Dynamic water hammer pressures will not occur due to inadvertent closing of the water gates because the motor operators close the gates at a rate of only 15 inches per minute. These measures make circulating water system overpressurization a highly improbable event.

Inlet spool pieces and water boxes are constructed of ductile carbon steel with a corrosion-resistant internal coating, and their catastrophic failure, such that significant seawater could flood the turbine building, is not a credible assumption. The cast iron outlet spool piece was hydrotested to 1.5 times the maximum attainable circulating water system pressure.

A flooding analysis was performed based on the failure of an operator to properly secure a condenser waterbox manway cover. In order to obtain a conservative flooding rate for this scenario, waterbox manhole cover failure was assumed to be coincident with an operating error in which both circulating water pumps were running and both discharge gates were closed to the stops. In this event, approximately 43,000 gpm or 5,700 cfm of water could be expected to flow from a lower inlet waterbox manhole (the manholes with the greatest incident head of water). This flow would fill the sump and equipment pit storage areas below elevation 85 feet in 15 minutes, if the building drains are assumed to be functioning, and in 10 minutes, if the drains are not functioning. During this time, alarms would be given for turbine building sump high level and for water in the condenser pit. It may be assumed that the condensate pumps, being flooded, would have tripped, giving dramatic indication of an irregular condition.

In order to provide additional time for operators to react to this flooding casualty, a fire door was installed between the main condensers and the corridor to the emergency diesel generator rooms in order to minimize the amount of water that could enter the compartments. The door is locked closed and monitored through the security system. This door will allow at least 12 more minutes (assuming no flow of water from the building) for the postulated manhole failure flow after sumps and pits are flooded.

Subsequent to the fire door installation, a float switch system was mounted on the walls of the condenser pit. This instrumentation system eliminated the need for operator action in order to protect PG&E Design Class I equipment from any type of circulating water system leakage. The system will automatically trip the circulating water pumps if water fills the condenser pit thereby assuring that the turbine building cannot be flooded by a circulating water system leak. The system employs two-out-of-three logic for a high degree of reliability and it provides a high condenser pit level alarm indication in the control room.

10.4.5.4 Tests and Inspections

Tests and inspections of the circulating water system are done in accordance with plant procedures.

10.4.5.5 Instrumentation Applications

Instrumentation is provided to monitor and control circulating water system operation. As described in Section 10.4.5.3.1(1), high water level in the turbine building condenser pit will trip the circulating water pumps and provide an alarm in the control room.

10.4.6 CONDENSATE POLISHING SYSTEM

The PG&E Design Class II condensate polishing system removes both dissolved and suspended corrosion products and impurities from the condensate. The system is important to maintaining secondary water chemistry and minimizes the buildup of sludge in the SGs.

10.4.6.1 Design Bases

10.4.6.1.1 General Design Criterion 3, 1971 – Fire Protection

The condensate polishing system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

10.4.6.1.2 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The materials of construction of the pressure-retaining boundary of the SG tubes are protected by control of secondary chemistry from corrosion that might otherwise reduce the system structural integrity during its service lifetime. The condensate polishing system functions to contribute to the secondary chemistry control.

10.4.6.1.3 Condensate Polishing System Safety Function Requirement

(1) Protection from Flooding Effects

The flooding effects from a condensate polishing system pipe rupture do not prevent essential equipment from safely shutting down and maintaining shutdown conditions of the reactor.

10.4.6.2 System Description

The condensate polishing system is comprised of seven mixed bed demineralizers. Either six or seven demineralizers are in service processing the full condensate flow (approximately 21,000 gpm) depending on whether any one of the demineralizers is in the regeneration mode or not. The demineralizer in the regeneration mode is taken out of service and is regenerated externally in order to minimize the possibility of introducing regenerant chemicals in the condensate and feedwater system. The external regeneration process for one demineralizer normally takes about 12 to 16 hours.

Components of the condensate polishing system, including demineralizers, regenerators, and associated equipment, are located in the turbine building buttresses. The system is capable of either automatic or manual operation, and can be bypassed if necessary.

The vessels are designed to ASME BPVC Section VIII. The system piping is designed to ANSI B31.1 (refer to Section 3.2).

The condensate polishing system is classified as PG&E Design Class II. Although located within the PG&E Design Class I turbine building buttresses, the system and component supports, including enclosures, do not compromise the PG&E Design Class I seismic requirement of the turbine building buttress structure.

Personnel safety provisions include smoke detectors and portable fire extinguishers in compartments where potential for fire exists. Eyewashes and a safety shower are also provided in the chemical storage and chemical feed pump areas.

10.4.6.3 Safety Evaluation

10.4.6.3.1 General Design Criterion 3, 1971 – Fire Protection

The chemicals of the condensate polishing system (sodium hydroxide and sulfuric acid) are stored in accordance with Chapter 3 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

10.4.6.3.2 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The condensate polishing system is designed to polish the full condensate flow during startup and normal plant operation. During startup, the system allows recirculation of condensate at approximately 5500 gpm through the condensate polishing demineralizers and feedwater heaters, returning it to the main condenser. This design provision allows a more complete cleanup of secondary water prior to system startup.

The condensate polishing system monitors the secondary chemistry to protect the SG tubes which are a part of the reactor coolant pressure boundary from degradation during the course of its lifetime. This is in compliance with the SG tube integrity requirements of Generic Letter 85-02.

10.4.6.3.3 Condensate Polishing System Safety Function Requirement

(1) Protection from Flooding Effects

The failure of condensate polishing system piping is evaluated for the effects of flooding on PG&E Design Class I essential safe shutdown equipment located in the turbine buttress building. The provisions taken to provide protection for the safe shutdown equipment from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

10.4.6.4 Tests and Inspections

Tests and inspections of the condensate polishing system are done in accordance with plant procedures.

10.4.6.5 Instrumentation Applications

Instrumentation is provided to monitor and control the condensate polishing system operation.

10.4.7 CONDENSATE AND FEEDWATER SYSTEMS

The condensate and main feedwater systems, shown in Figures 3.2-2 and 3.2-3, receive condensate from the main condenser hotwells and deliver it as feedwater to the

SG at the required pressure and temperature. In the SG, the feedwater removes heat from the reactor coolant and is converted into steam.

The PG&E Design Class I portion of the main feedwater system extends from the upstream side of the main feedwater check valves to the SG nozzles. Additionally the main feedwater regulating valves (MFRVs) that are located upstream of the main feedwater check valves, along with their respective MFRV bypass valves, are PG&E Design Class I and are located in PG&E Design Class II piping that has been seismically qualified. Refer to Table 3.2-3 for a listing of PG&E Design Class II equipment that is included in the condensate and main feedwater systems.

The AFW system connects to the main feedwater lines outside of containment between the motor-operated main feedwater isolation valves (MFIVs) and the containment penetrations. This interface provides a PG&E Design Class I flow path for the AFW system to feed the SGs.

The main feedwater ring and SG tubes are further discussed in Section 5.5.2.

10.4.7.1 Design Bases

10.4.7.1.1 General Design Criterion 2, 1967 – Performance Standards

Certain portions of the main feedwater system are designed to withstand the effects of, or are protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis, or other local site effects. The effects of a tornado on the main feedwater system are addressed to ensure that plant safe shutdown can be achieved.

10.4.7.1.2 General Design Criterion 3, 1971 – Fire Protection

The condensate and main feedwater systems are designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

10.4.7.1.3 General Design Criterion 11, 1967 – Control Room

The condensate and main feedwater systems are designed or contain instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other cause.

10.4.7.1.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the condensate and main feedwater systems variables within prescribed operating ranges.

10.4.7.1.5 General Design Criterion 15, 1967 – Engineered Safety Features Protection Systems

The SG level transmitters provide for sensing accident conditions and initiating the operation of necessary engineered safety features.

10.4.7.1.6 General Design Criterion 21, 1967 – Single Failure Definition

The PG&E Design Class I portion of the main feedwater system is designed to remain operable after sustaining a single failure. Multiple failures resulting from a single event are treated as a single failure.

10.4.7.1.7 General Design Criterion 40, 1967 – Missile Protection

The ESF containment isolation portion of the main feedwater system is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

10.4.7.1.8 General Design Criterion 49, 1967 – Containment Design Basis

The PG&E Design Class I portion of the main feedwater system is designed to support the capability of the containment structure to accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a LOCA, including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of emergency core cooling systems.

10.4.7.1.9 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The PG&E Design Class I portion of the main feedwater system that penetrates containment is provided with leak detection, isolation, redundancy, reliability and performance capabilities which reflect the importance to safety of isolating this system. The piping is designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

10.4.7.1.10 General Design Criterion 57, 1971 – Closed System Isolation Valves

The PG&E Design Class I portion of the main feedwater system is designed to provide isolation valves outside the containment capable of automatic and manual closure.

10.4.7.1.11 Condensate and Feedwater Systems Safety Function Requirements

(1) <u>Protection from Missiles</u>

The PG&E Design Class I non-ESF portion of the main feedwater system is designed to be protected against the effects of missiles that may result from equipment failures and from events and conditions outside the plant to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(2) Protection Against High Energy Pipe Rupture Effects

The PG&E Design Class I non-ESF portion of the main feedwater system is designed and located to accommodate the dynamic effects of a postulated high-energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The PG&E Design Class I portions of the main feedwater system located outside containment are designed to be protected against the effects of moderate energy pipe failure to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(4) Protection from Jet Impingement – Inside Containment

The PG&E Design Class I portion of the main feedwater system located inside containment is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(5) Protection from Flooding Effects – Outside Containment

Rupture of the PG&E Design Class II portion of the condensate and main feedwater systems would not impact PG&E Design Class I SSCs.

The PG&E Design Class I portions of the main feedwater system located outside containment are designed to be protected from the effects of internal flooding to the extent necessary to assure that a safe shutdown condition of the reactor can be accomplished and maintained.

(6) Main Feedwater Isolation

The main feedwater system is capable of isolating main feedwater flow to the SGs to prevent overfilling the SGs or over-cooling the RCS, and to minimize mass and energy release following a secondary system pipe rupture.

10.4.7.1.12 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

Main feedwater system components that require EQ are qualified to the requirements of 10 CFR 50.49.

10.4.7.1.13 10 CFR 50.55a(f) – Inservice Testing Requirements

The main feedwater system ASME Code components are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

10.4.7.1.14 10 CFR 50.55a(g) – Inservice Inspection Requirements

The main feedwater system ASME Code components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

10.4.7.1.15 10 CFR 50.62 – Requirements for Reduction of Risk from Anticipated Transients Without Scram Events for Light-Water-Cooled Nuclear Power Plants

The SG level transmitters provide signals to initiate AMSAC following an ATWS transient.

10.4.7.1.16 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The PG&E Design Class I portion of the main feedwater system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

10.4.7.1.17 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

PG&E Design Class I motor-operated valves (MOVs) in the main feedwater system meet the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996.

10.4.7.1.18 Generic Letter 89-08, May 1989 – Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP has implemented formalized procedures and administrative controls to assure long-term implementation of its erosion/corrosion monitoring program for the condensate and main feedwater systems.

10.4.7.1.19 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The main feedwater system provides instrumentation to monitor system variables during and following an accident.

10.4.7.1.20 Branch Technical Position ASB 10-2, March 1978 – Design Guidelines for Water Hammers in Steam Generators with Top Feedring Designs

The main feedwater system is designed to eliminate or reduce possible water hammer in the system, as follows:

1) The main feedwater system is designed to prevent or delay water draining from the feedring following a drop in SG level.

2) The main feedwater system is designed to minimize the volume of feedwater piping external to the SG that could pocket steam by using the shortest possible (less than seven feet) horizontal run of inlet piping to the SG feedring.

3) Tests acceptable to the U.S. Nuclear Regulatory Commission (NRC) were performed to verify that unacceptable feedwater hammer would not occur using the plant operating procedures for normal and emergency restoration of SG water level following a loss of feedwater and possible draining of the feedring.

10.4.7.2 System Description

The condensate and main feedwater systems are primarily PG&E Design Class II systems except for a part of the main feedwater system that supplies heated water to the SGs. The main feedwater pumps are designed for maximum calculated load operating conditions (refer to Figures 10.1-5 and 10.1-1 for DCPP Unit 1 and Unit 2, respectively), and are capable of supplying the required main feedwater flow to the SGs under transient load reduction conditions. The condensate pumps and condensate booster pumps provide adequate suction pressure to the main feedwater pumps under load transient conditions. During a main turbine control system load drop anticipate transient or a loss of feedwater pump load reduction, the standby condensate pump / condensate booster pump set will start, the stator coil and cooling water flow for valve FCV-31 will open, and hotwell rejection valve LCV-12 will close to provide adequate suction to the feedwater pumps.

The pressure-retaining components, or compartments of components, conform to the following codes as minimum design criteria:

(1) System pressure vessels and feedwater heaters – ASME BPVC Section VIII.

(2) System valves, fittings, and piping – ANSI Code for Pressure Piping B31.1 and B31.7 where applicable. The main feedwater lines from the MFIVs to the SGs are covered by the ASME BPVC Section I.

The condensate and main feedwater systems are of the closed type, with deaeration accomplished in the main condenser. Condensate is pumped through the generator hydrogen coolers and stator coolers, the gland steam condenser, and the air ejector condensers to the suction of the condensate booster pumps, which pump the condensate though the condensate polishing system and five stages of low-pressure feedwater heaters to the main feedwater pumps. The water discharged from the main feedwater pumps flows through the single stage of high-pressure feedwater heaters into the SGs. All feedwater heaters are horizontal, one-third-size units (three in parallel), except the No. 6 heater drain cooler, which is a single, full-size, straight-tubed heat exchanger.

Three nominal half-capacity, three-stage, vertical, can-type, centrifugal, motor-driven condensate pumps are provided with separate hotwell suction lines and a common discharge manifold. Three condensate booster pumps are provided. These are nominal half-capacity, horizontal, split-case, centrifugal, motor-driven pumps with common suction and discharge manifolds. Two nominal half-capacity, high-speed, turbine-driven main feedwater pumps are provided, with common suction and discharge manifolds. All pumps are equipped with minimum flow protective devices.

Main feedwater flows to the SGs through four lines penetrating the containment, one line for each SG. An MFRV with an MFRV bypass valve, a check valve, and an MFIV are installed in each line outside the containment.

Warmup lines are provided on the discharge of the feedwater pumps to circulate heated feedwater back through an idle feedwater pump to keep it warm and ready for service.

Drains from the No. 1 and No. 2 feedwater heaters flow to the No. 2 heater drain tank, with the flashed steam from the drain tank vented to the No. 2 heater. The No. 2 heater drain pump takes suction from the No. 2 heater drain tank and discharges to the main feedwater pump suction manifold. Drains from the four lower pressure feedwater heaters cascade to the No. 6 heater drain cooler and then to the main condenser.

The condensate and main feedwater systems do not have to operate to ensure safe shutdown of the NSSS. The AFW system, described in Section 6.5, provides adequate feedwater to the SGs from the condensate storage tank (CST) in the event of a loss of main feedwater. The reactor transient and radiological consequences of a main feedwater line break are discussed in Section 15.4.2.

In the event leakage develops from one of the feedwater heaters, that heater can be isolated and repaired while the generating unit remains on line. Since the secondary side is normally not radioactive, most leakage through valve seals will not present any

radiological problems. The consequences of having the secondary side of the plant radioactive due to SG leakage are discussed in Chapters 11 and 15.

The active components in the main feedwater system required to operate in the event of a design basis accident are the check valves upstream of the AFW nozzles on the main feedwater lines, the MFIVs, the MFRVs, and the MFRV bypass valves.

The main feedwater control system consists of, in addition to the MFRVs, MFRV bypass valves, and the main feedwater pump turbine governor, individual manual controls for each MFRV and MFRV bypass valve, main feedwater pump turbine startup and speed governor controls, and the digital main feedwater control system (DFWCS). The DFWCS controls SG level using SG level, main feedwater flow, and SG density-compensated steam flow measurements. The main feedwater pump is controlled by the DFWCS using main feedwater header pressure and SG pressure. The DFWCS includes signal validation algorithms that will prevent an input channel failure from causing a control system transient requiring protective action (refer to Sections 7.2.2.11.5 and 7.7.2.7).

10.4.7.3 Safety Evaluation

10.4.7.3.1 General Design Criterion 2, 1967 – Performance Standards

The containment structure, pipeway structure, and auxiliary building, which contain the PG&E Design Class I portion of the main feedwater system, are PG&E Design Class I (refer to Section 3.8 and Table 3.2-3). These structures or applicable portions thereof and exterior components are designed to withstand the effects of winds (refer to Section 3.3.1), floods and tsunamis (refer to Section 3.4), and earthquakes (refer to Section 3.7), and to protect the PG&E Design Class I portion of the main feedwater system to ensure its safety functions are maintained. The tornado resistance capability for certain PG&E main feedwater system components supports plant safe shutdown as discussed in Section 3.3.2.

The PG&E Design Class I components and associated feedwater piping has been seismically qualified.

Portions of feedwater system are located outside are partially resistant to tornadoes, however, the capability of the system to support plant safe shutdown is maintained (refer to Section 3.3.2.5.2.7).

The main feedwater system components required to perform their PG&E Design Class I functions are located at higher elevations such that they are not affected by floods and tsunamis.

10.4.7.3.2 General Design Criterion 3, 1971 – Fire Protection

The condensate and main feedwater systems are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

10.4.7.3.3 General Design Criterion 11, 1967 – Control Room

PG&E Design Class I controls and indications for the main feedwater system are provided in the control room such that the system may be operated to perform its design function. If access to the control room is lost, the MFIVs can be operated locally. Indication of SG level and pressure are available in the control room and on the HSP.

10.4.7.3.4 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls for the condensate and main feedwater systems, including the MFIVs, MFRVs, and MFRV bypass valves, along with SG level indication, are discussed in Sections 6.2.4, 7.3, 10.4.7.3.11(6), and 10.4.7.5.

10.4.7.3.5 General Design Criterion 15, 1967 – Engineered Safety Features Protection Systems

A main feedwater isolation signal is initiated when 2-out-of-3 SG channels in any loop read SG levels that are at the high-high actuation setpoint.

A low-low SG level signal is provided as input to the ESFAS.

Any SI signal develops a feedwater isolation signal.

10.4.7.3.6 General Design Criterion 21, 1967 – Single Failure Definition

The PG&E Design Class I portion of the main feedwater system is designed with a diverse Class 1E power supply for the MFIVs. Additionally the main feedwater system provides independent flow paths for AFW to the SGs.

Redundant main feedwater isolation is provided by the MFRVs with their respective MFRV bypass valves and the MFIVs, along with trip of the main feedwater pumps (refer to Sections 15.2.14 and 15.4.2).

The redundancy and single failure features of the SG level instrumentation are addressed in Section 7.3.3.

10.4.7.3.7 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the ESF containment isolation portion of the main feedwater system from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures, respectively are discussed in Sections 3.5, 3.6, and 6.2.4.

10.4.7.3.8 General Design Criterion 49, 1967 – Containment Design Basis

The PG&E Design Class I portion of the main feedwater piping routed into containment and the associated containment penetrations are designed and analyzed to withstand the pressures and temperatures that could result from a LOCA without exceeding containment design leakage rates. Refer to Section 3.8.2.1.1.3 for additional details.

10.4.7.3.9 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

Isolation valves that are required for containment closure are periodically tested for operability and are contained in the PG&E Design Class I portion of the main feedwater system (refer to DCPP Technical Specification 3.7.3). Testing of the components required for the CIS is discussed generally in Section 6.2.4. However, note that leak testing of the MFIVs is not required under Option B of 10 CFR Part 50 Appendix J, as noted in Table 6.2-39.

10.4.7.3.10 General Design Criterion 57, 1971 – Closed System Isolation Valves

The containment penetrations for the main feedwater system are part of penetration Group C. A description of the isolation valves and piping configuration for each penetration is provided in Table 6.2-39. Group C piping conforms to the requirements of GDC 57, 1971.

10.4.7.3.11 Condensate and Feedwater Systems Safety Function Requirements

(1) <u>Protection from Missiles</u>

The provisions taken to protect the PG&E Design Class I non-ESF portion of the main feedwater system from internal missiles resulting from plant equipment failures and from events and conditions outside the plant are discussed in Section 3.5.

The main feedwater pump turbines are located to minimize the likelihood of generation of missiles that could affect the safe shutdown of either unit.

(2) Protection Against High Energy Pipe Rupture Effects

The provisions taken to protect the PG&E Design Class I non-ESF portion of the main feedwater system from damage that might result from dynamic effects associated with a postulated rupture of high-energy piping are discussed in Section 3.6.

The rupture of a main feedwater line is one of the principal breaks considered in the analysis of dynamic effects of pipe breaks outside the containment. Additional barriers and restraints have been added, as required, to protect PG&E Design Class I SSCs from a main feedwater line rupture, or protect the feedwater line from another line rupture.

A rupture of a feedwater line within the turbine building will result in a temperature and humidity rise. Environmental effects due to high energy pipe ruptures outside the containment are more fully evaluated and discussed in Section 3.6.4.

(3) Protection from Moderate Energy Pipe Rupture Effects – Outside Containment

The provisions taken to provide protection of the PG&E Design Class I portion of the main feedwater system located outside containment from the effects of moderate energy pipe failure are discussed in Section 3.6.

(4) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the PG&E Design Class I portion of the main feedwater system located inside containment from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

(5) Protection from Flooding Effects

The provisions taken to provide protection of the PG&E Design Class I portion of the main feedwater system from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

The PG&E Design Class I portion of the main feedwater system is physically located well above ground elevation and is not susceptible to failure by flooding from other ruptured systems.

A postulated failure of the condensate or main feedwater PG&E Design Class II piping in the turbine building would result in approximately 19,800 cubic feet of the water being released to the turbine building floor, if the entire contents of the hotwell and heater drain tank were discharged. Maloperation of the condensate or main feedwater system due to a broken pipe would be detected by changes in plant variables, alarms, feedwater heater temperature transients, or pump trips due to runout overcurrent. In addition, level switches, which alarm in the control room, are installed in the turbine building sump and in the condenser pit near the diesel generators of each unit to alert

the operator to the flooding condition. Spillage from most broken pipes could be detected and isolated before significant flooding occurred.

In the event that the entire contents of the hotwell and heater drain tanks are discharged to the turbine building, the operability of PG&E Design Class I equipment (diesel generators and component cooling water heat exchangers) in the building is not endangered. The volume of water that would be discharged is within the capacity of the turbine building drain system. This system includes one 18-inch drain line from the turbine building sump of each unit to the circulating water system discharge canal (refer to Figure 3.2-27). If this drain were clogged, the water flow would begin to fill the turbine building sumps and equipment pits below 85 feet (refer to Figures 1.2-16 and 1.2-20). The entire quantity of discharge water can be accommodated in the sumps. Water would not endanger the operability of the diesel generators since a fire door is installed at the entrance to the corridor to the emergency diesel generator rooms for purposes of protection from circulating water system ruptures in the turbine building (refer to Section 10.4.5.3.1). The door is locked closed and monitored through the security system. Because of their elevation above the turbine building floor, the component cooling water heat exchangers are not susceptible to flooding damage.

These provisions also protect PG&E Design Class I equipment from flooding damage caused by the failure of other PG&E Design Class II piping or components located in the turbine building.

The PG&E Design Class I equipment in the auxiliary building is not endangered by turbine building flooding. The area of the auxiliary building housing PG&E Design Class I equipment is separated from the turbine building by 70 feet of doors and passageways. If water does enter the auxiliary building, it will drain to the building pipe tunnel, which has a capacity of approximately 345,000 gallons. The auxiliary building drain system is completely separate from the turbine building system so back flow through the drain system is not possible.

(6) Main Feedwater Isolation

SG high-high level signal (P-14 interlock) or an SI signal closes the MFRVs, MFRV bypass valves, and MFIVs, and trips both main feedwater pumps to prevent SG overfill and excessive overcooling.

A low T_{avg} signal coincident with a reactor trip (P-4 interlock) initiates main feedwater isolation by closing the MFRVs and MFRV bypass valves in order to protect the reactor from excessive cooldown.

Main feedwater isolation minimizes the mass and energy release into containment following a MSLB event by isolating feedwater within 9 seconds (refer to Section 6.2D.4.1.3).

10.4.7.3.12 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

Main feedwater system SSCs required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment. The affected equipment includes valves and switches and is listed on the EQ Master List.

10.4.7.3.13 10 CFR 50.55a(f) – Inservice Testing Requirements

The IST requirements for the PG&E Design Class I components of the main feedwater system are contained in the IST Program Plan and comply with the ASME BPVC.

10.4.7.3.14 10 CFR 50.55a(g) – Inservice Inspection Requirements

The PG&E Design Class I portion of the main feedwater system piping has a periodic ISI program in accordance with ASME BPVC Section XI.

10.4.7.3.15 10 CFR 50.62 – Requirements for Reduction of Risk from Anticipated Transients Without Scram Events for Light-Water-Cooled Nuclear Power Plants

The AMSAC is initiated by an AMSAC low SG water level signal, which is derived separately from the low-low SG water level signal (refer to Sections 7.6.2.3 and 7.6.3.6).

10.4.7.3.16 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The PG&E Design Class I portion of the main feedwater system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

10.4.7.3.17 Generic Letter 89-10, June 1989 – Safety-Related Motor-Operated Valve Testing and Surveillance

The PG&E Design Class I main feedwater system MOVs are included in the DCPP MOV Program, which was developed to meet the requirements of Generic Letter 89-10, June 1989, and associated Generic Letter 96-05, September 1996.

10.4.7.3.18 Generic Letter 89-08, May 1989 – Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP procedures implement the DCPP FAC monitoring program requirements. Portions of the condensate and main feedwater systems are considered in the program for erosion/corrosion monitoring.

10.4.7.3.19 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Table 7.5-6 summarizes DCPP's compliance with Regulatory Guide 1.97, Revision 3. Main feedwater flow is a Type D variable, and SG level is both a Type A and a Type D variable. Additionally, position indication for the MFIVs is designated as a Type B variable, but is not credited for compliance with Regulatory Guide 1.97, Revision 3, Category 1 criteria.

10.4.7.3.20 Branch Technical Position ASB 10-2, March 1978 – Design Guidelines for Water Hammers in Steam Generators with Top Feedring Designs

The SGs include top-discharge spray nozzles that reduce the possibility of steam pockets being trapped in the feedwater ring (refer to Section 5.5.2).

The main feedwater system has been designed to minimize the length of horizontal feedwater piping that could be emptied when the SG water level drops below the level of the feedwater ring. This piping has been modified as shown in Figures 10.4-2 and 10.4-3 to minimize the possibility of a damaging water hammer.

Testing was performed to verify that feedwater hammer will not occur using the plant operating procedures for normal and emergency restoration of SG water level following a loss of feedwater and possible draining of the feedring.

10.4.7.4 Tests and Inspections

Tests and inspections of the condensate and main feedwater systems are done in accordance with plant procedures.

10.4.7.5 Instrumentation Applications

A main feedwater pump control system controls the speed of the turbine-driven main feedwater pumps to achieve a programmed pressure differential between the main feedwater header leaving the No. 1 feedwater heaters and the main steam common header. The programmed pressure differential varies as a function of unit load. Main feedwater header-steam-header differential pressure indication is also provided in the control room.

SG level and feedwater flow indication is also provided.

Each MFRV and MFRV bypass valve is positioned by its own digital control system (refer to Section 7.7.2.7).

10.4.8 STEAM GENERATOR BLOWDOWN SYSTEM

The SG blowdown system is used in conjunction with the condensate and feedwater chemical injection system and the condensate polishing system to maintain SG water chemistry within the plant-specific limits.

The SG blowdown system functions are primarily PG&E Design Class II. The only PG&E Design Class I function performed by the system is containment isolation. The portions of the system from the SG nozzles to the isolation valves outside containment that perform this function are PG&E Design Class I.

10.4.8.1 Design Bases

10.4.8.1.1 General Design Criterion 2, 1967 - Performance Standards

The PG&E Design Class I portion of the SG blowdown system is designed to withstand the effects of, or is protected against, natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis and other local site effects.

10.4.8.1.2 General Design Criterion 3, 1971 - Fire Protection

The PG&E Design Class I portion of the SG blowdown system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

10.4.8.1.3 General Design Criterion 9, 1967 - Reactor Coolant Pressure Boundary

The materials of construction of the pressure-retaining boundary of the SG tubes are protected by control of secondary chemistry from corrosion that might otherwise reduce the system structural integrity during its service lifetime. The SG blowdown system functions to contribute to the secondary chemistry control.

10.4.8.1.4 General Design Criterion 11, 1967 - Control Room

The PG&E Design Class I portion of the SG blowdown system is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

10.4.8.1.5 General Design Criterion 12, 1967 - Instrumentation and Control

Instrumentation and controls are provided as required to monitor and maintain the PG&E Design Class I portion of the SG blowdown system variables within prescribed operating ranges.

10.4.8.1.6 General Design Criterion 16, 1967 - Monitoring Reactor Coolant Pressure Boundary

The SG blowdown system provides means for monitoring the reactor coolant pressure boundary to detect leakage.

10.4.8.1.7 General Design Criterion 17, 1967 - Monitoring Radioactivity Releases

The SG blowdown system is designed to provide means for monitoring the facility effluent discharge paths, and the facility environs for radioactivity that could be released from normal operations, from anticipated transients and from accident conditions.

10.4.8.1.8 General Design Criterion 21, 1967 - Single Failure Definition

The PG&E Design Class I portion of the SG blowdown system is designed to tolerate a single failure during the period of recovery following an accident without loss of its protective function, including multiple failures resulting from a single event, which is treated as a single failure.

10.4.8.1.9 General Design Criterion 40, 1967 – Missile Protection

The ESF containment isolation portion of the SG blowdown system is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

10.4.8.1.10 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The SG blowdown piping that penetrates containment is provided with leakage detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The piping is designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

10.4.8.1.11 General Design Criterion 57, 1971 - Closed System Isolation Valves

The SG blowdown system contains piping connected to containment penetrations that are neither part of the reactor coolant pressure boundary nor connected directly to the

containment atmosphere. These penetrations are provided with one local or remote-manual valve outside the containment.

10.4.8.1.12 Steam Generator Blowdown System Safety Function Requirements

(1) Protection from Jet Impingement – Inside Containment

The PG&E Design Class I containment isolation portion of the SG blowdown system located inside containment is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

(2) Decay Heat Removal

The SG blowdown system is designed to facilitate the removal of decay heat from the RCS.

10.4.8.1.13 10 CFR 50.49 - Environmental Qualification

SG blowdown system components that require EQ are qualified to the requirements of 10 CFR 50.49.

10.4.8.1.14 10 CFR 50.55a(f) - Inservice Testing Requirements

SG blowdown system ASME Code components are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

10.4.8.1.15 10 CFR 50.55a(g) - Inservice Inspection Requirements

SG blowdown system ASME Code components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

10.4.8.1.16 10 CFR 50.62 – Requirements for Reduction of Risk from Anticipated Transients Without Scram Events for Light-Water-Cooled Nuclear Power Plants

The PG&E Design Class I portion of the SG blowdown system is isolated upon receipt of a signal from the AMSAC.

10.4.8.1.17 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The PG&E Design Class I portion of the SG blowdown system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

10.4.8.1.18 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The SG blowdown system containment isolation valve position status is required for post-accident instrumentation.

10.4.8.1.19 Generic Letter 89-08, May 1989 - Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP has implemented formalized procedures and administrative controls to assure long-term implementation of its erosion/corrosion monitoring program for the SG blowdown system.

10.4.8.2 System Description

A piping and instrumentation schematic for the SG blowdown system is shown in Figure 3.2-4.

The SG blowdown system for each unit is composed of two processing paths. One path discharges blowdown flow via the SG blowdown tank to the circulating water discharge tunnel. The other path recycles blowdown flow to the main condenser via the blowdown treatment system and/or the blowdown treatment bypass line. The recycle path can discharge a portion of blowdown flow to the discharge tunnel. Blowdown flow for each unit can be directed to either blowdown path alone, or to both paths simultaneously. The blowdown piping is also used as the interface between the SGs and the rapid fill and drain system that was added to facilitate operation of the SGs during unit outages.

Blowdown flow in the discharge path is processed via the SG blowdown tank; approximately 35 percent of the blowdown flow flashes to steam inside the tank and is vented to the atmosphere. The remaining liquid, approximately 65 percent of the blowdown flow, is discharged by gravity to the condenser circulating water discharge.

Blowdown flow in the recycle path may be processed by the blowdown treatment system or the blowdown treatment bypass line. This treatment system reduces the temperature and pressure of the water. The treatment system may also demineralize and recycle the blowdown water to the condensate system. In the treatment system, blowdown enters a flash tank where it is reduced in pressure. Flashed water vapor is vented from the tank through a pressure control valve to either a feedwater heater to improve cycle thermal efficiency or to the main condenser. The blowdown liquid then passes through a heat exchanger where the temperature is further reduced to approximately 110°F. The liquid may then enter a prefilter and demineralizer before being recycled to the main condenser. If required, a portion of the flash tank liquid flowing out of the heat exchangers can be routed to the plant outfall via the blowdown overboard drain line to improve the secondary water chemistry.

Blowdown water first passes through a prefilter and is then directed through one of two 60 cubic foot mixed bed demineralizers. The demineralizer removes both radioactive and nonradioactive ionic impurities. The liquid is then recycled to the main condenser. The blowdown treatment bypass line routes the depressurized, undemineralized blowdown directly to the condenser.

The blowdown tank process path and the blowdown treatment portion of the recycle process path are designed to accommodate 150 gpm of blowdown water total from four SGs on a continuous basis. The blowdown tank process path also allows a total flow of 320 gpm temporarily during certain plant conditions.

The blowdown treatment bypass portion of the recycle path, including the flash tank, is designed for 1 percent of the main steaming rate at 100 percent plant load from four SGs on a continuous basis (approximately 400 gpm total).

The SG blowdown system is classified as PG&E Design Class I from the SG nozzles up to and including the isolation valves outside of the containment and PG&E Design Class II downstream of the containment isolation valves. The classification and applicable codes for the SG blowdown system are identified in Table 3.2-3.

The blowdown system's effect on plant safety is minimal, since neither the blowdown function nor the treatment function is required continuously. Either function may be interrupted temporarily to replace failed components. Neither function is required to operate following a LOCA.

Ruptured components or failed-open valves could cause unplanned blowdown of secondary steam. Since blowdown piping in this system is 6 inches or smaller, such pipe break accidents fall within the category of minor secondary system pipe breaks. Consequences of this type of accident are detailed in Sections 15.2.14 and 15.3.2. The probability of radiation leakage is small since the system is normally nonradioactive. If, however, a failure of a blowdown pipe occurs while SG leakage is also taking place, the consequences are within the limits described in Section 15.3.2 for minor secondary system pipe breaks.

All filter and demineralizer components are located in the auxiliary building, from which leakage is processed through the liquid radwaste system. An automatically controlled isolation valve provides shutoff of the blowdown discharge path to the plant outfall if significant activity is detected. In any case, the results of failure are bounded by those of the pipe break referred to above (refer to Section 10.4.8.3.7).

The evaluation of radiological and environmental effects is treated in Section 11.2.

10.4.8.3 Safety Evaluation

10.4.8.3.1 General Design Criterion 2, 1967 - Performance Standards

The containment structure and auxiliary building, which contain the SG blowdown system's PG&E Design Class I components, are PG&E Design Class I (refer to Section 3.8). These buildings or applicable portions thereof are designed to withstand the effects of winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), external missiles (refer to Section 3.5), earthquakes (refer to Section 3.7), and other natural phenomena (refer to Sections 3.8.2.1 and 3.8.2.3 for the containment and auxiliary buildings, respectively), and to protect the system SSCs to ensure their safety functions and designs are maintained.

The PG&E Design Class I portions of the SG blowdown system are designed to perform their safety functions under the effects of earthquakes.

10.4.8.3.2 General Design Criterion 3, 1971 - Fire Protection

The SG blowdown system is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

10.4.8.3.3 General Design Criterion 9, 1967 - Reactor Coolant Pressure Boundary

Suspended and dissolved solids that are brought in by the feedwater concentrate in the SG shell-side water during plant operation. Water must be blown down using the SG blowdown system to maintain water chemistry as specified in plant procedures. Sampling and monitoring of nonradioactive solids is accomplished by continuous conductivity measurements and grab sample analysis.

The SG blowdown system protects the SG tubes, which are a part of the reactor coolant pressure boundary, from degradation during their lifetime. This is in compliance with the SG tube integrity requirements of Generic Letter 85-02.

10.4.8.3.4 General Design Criterion 11, 1967 - Control Room

Controls, and position indication, for the SG blowdown system containment isolation valves are provided in the control room such that the system may be manually operated to perform its safety function.

The system isolation valves can be operated manually from the main control room. These valves can also be closed by locally venting air from the valve operator solenoids if access to the control room is lost.

10.4.8.3.5 General Design Criterion 12, 1967 - Instrumentation and Control

The outboard containment isolation valves close on the containment isolation signal, Phase A. The inboard containment isolation valves close on the steam line isolation signal (refer to Table 6.2-39).

The outboard containment isolation valves also close automatically on an AFW pump start (refer to Section 6.5.2.1.2), AMSAC actuation (refer to Section 7.6.2.3), and high radioactivity in the blowdown system (refer to Sections 10.4.8.3.7 and 11.4.2.1.2).

10.4.8.3.6 General Design Criterion 16, 1967 - Monitoring Reactor Coolant Pressure Boundary

SG blowdown radiation detectors are available to detect SG tube leakage as described in Section 5.2.3.23 and Table 5.2-16. The radiation monitoring system is described in Section 11.4.

10.4.8.3.7 General Design Criterion 17, 1967 - Monitoring Radioactivity Releases

The SG blowdown system is continuously monitored for radioactivity. The sampling system parallels the blowdown flow from each SG. Continuous sampling and monitoring for radioactivity is accomplished with a single composite sample taken from the four SG sample lines and passed through a radiation monitor.

The criterion used for isolation of the blowdown system is based on the concentration of activity in the blowdown. When the sampling system radiation monitor detects a preset activity level, the SG blowdown isolation valves and the blowdown tank effluent valve close. The isolation system has been designed so that the blowdown tank effluent valve closes before any significant radioactive liquid reaches the effluent isolation valve. Upon detection of activity, plant personnel may process the blowdown via the blowdown treatment system as directed by Chemistry.

The radiation monitoring system is described in Section 11.4.

10.4.8.3.8 General Design Criterion 21, 1967 - Single Failure Definition

The instrumentation and control circuits for the SG blowdown system containment isolation function are redundant in the sense that a single failure cannot prevent containment isolation (refer to Section 6.2.4.4.5). The valve control circuits are supplied with separate Class 1E 125-Vdc power. The isolation valves will fail closed on a loss of air or power.

10.4.8.3.9 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the ESF containment isolation portion of the SG blowdown system from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures, respectively are discussed in Sections 3.5, 3.6, and 6.2.4.

10.4.8.3.10 General Design Criterion 54, 1971 - Piping Systems Penetrating Containment

The SG blowdown system isolation valves required for containment closure are periodically tested for operability. Testing of the components required for the CIS is discussed in Section 6.2.4.

10.4.8.3.11 General Design Criterion 57, 1971 - Closed System Isolation Valves

The SG blowdown system containment penetrations comply with the requirements of GDC 57, 1971, as described in Section 6.2.4 and Table 6.2-39.

10.4.8.3.12 Steam Generator Blowdown System Safety Function Requirements

(1) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the inside containment PG&E Design Class I portion of the SG blowdown system from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

(2) Decay Heat Removal

The SG blowdown system facilitates the removal of decay heat from the RCS by isolating on an AFW pump start or an AMSAC actuation (refer to Sections 6.5 and 7.6.2.3, respectively) and maintaining SG inventory.

10.4.8.3.13 10 CFR 50.49 - Environmental Qualification

The SG blowdown system containment isolation valves are required to function in harsh environments under accident conditions and are qualified to the applicable environmental conditions to ensure that they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment. The valves are listed on the EQ Master List.

10.4.8.3.14 10 CFR 50.55a(f) - Inservice Testing Requirements

SG blowdown system components that are within the IST program are the four inboard containment blowdown isolation valves, the four outboard containment blowdown isolation valves, and the four outboard containment sample isolation valves.

The IST requirements for these components are contained in the IST Program Plan and comply with the ASME code for Operation and Maintenance of Nuclear Power Plants.

10.4.8.3.15 10 CFR 50.55a(g) - Inservice Inspection Requirements

The SG blowdown system piping has a periodic ISI program in accordance with the ASME BPVC Section XI.

10.4.8.3.16 10 CFR 50.62 – Requirements for Reduction of Risk from Anticipated Transients Without Scram Events for Light-Water-Cooled Nuclear Power Plants

The blowdown flow from the SGs is automatically isolated as a result of an AMSAC actuation (refer to Section 7.6.2.3).

10.4.8.3.17 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The SG blowdown system is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

10.4.8.3.18 Regulatory Guide 1.97, Revision 3, May 1983 - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The SG blowdown system's outboard containment isolation valves' indications are credited for compliance with Regulatory Guide 1.97, Revision 3. The SG blowdown tank vent does not require monitoring (refer to Table 7.5-6, Notes 56 and 59).

10.4.8.3.19 Generic Letter 89-08, May 1989 - Erosion/Corrosion-Induced Pipe Wall Thinning

DCPP procedures identify the interdepartmental responsibilities and interfaces for the FAC monitoring program for the SG blowdown system.

10.4.8.4 Tests and Inspections

The SG blowdown system is operated continuously during plant operation, thereby demonstrating system operability without the special inspections or testing required for standby systems. Equipment evaluations and inspections are performed periodically on the blowdown systems.

10.4.8.5 Instrumentation Applications

Instrumentation for the SG blowdown system is discussed in Sections 10.4.8.3.4 and 10.4.8.3.5.

10.4.9 CONDENSATE AND FEEDWATER CHEMICAL INJECTION SYSTEM

Chemical feed equipment is provided for chemical additions to the discharge of the condensate polishing system, to the main feedwater pumps' suction header, and to the discharge of the AFW pumps (refer to Figure 3.2-3 for the location of the injection points). The chemicals are injected into the condensate and feedwater system to prevent corrosion in the feedwater system and the SGs. The condensate and feedwater chemical injection system has no safety function and is classified as PG&E Design Class II.

10.4.9.1 Design Bases

10.4.9.1.1 General Design Criterion 3, 1971 – Fire Protection

The condensate and feedwater chemical injection system is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

10.4.9.1.2 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The materials of construction of the pressure-retaining boundary of the SG tubes are protected by control of secondary chemistry from corrosion that might otherwise reduce the system structural integrity during its service lifetime. The condensate and feedwater chemical injection system functions to contribute to the secondary chemistry control.

10.4.9.1.3 Condensate and Feedwater Chemical Injection System Safety Function Requirement

(1) Protection from Flooding Effects

Flooding effects from a condensate and feedwater chemical injection system pipe rupture do not prevent essential equipment from safely shutting down and maintaining shutdown conditions of the reactor.

10.4.9.2 System Description

The SG blowdown system protects the SG tubes, which are a part of the reactor coolant pressure boundary, from degradation during their lifetime. This is in compliance with the SG tube integrity requirements of Generic Letter 85-02.

Three sets of chemical feed pumps are available in each unit for the main feedwater system. The first set consists of 3 chemical feed pumps used to inject chemicals. Individual pumps are dedicated to ethanolamine and hydrazine/carbohydrazine injection, with the third pump on standby for either service. The pumps are not used under normal operating conditions.

During normal operation, a second chemical injection feed system in each unit is used to inject concentrated ethanolamine and hydrazine solutions.

The condensate hydrazine and ethanolamine feed system for each unit consists of a 250-gallon stainless steel hydrazine day tank with two chemical feed pumps, one in operation and one standby, and a 250-gallon stainless steel ethanolamine day tank with two chemical feed pumps, one in operation and one standby. Bulk 35 percent (by weight) hydrazine is stored in liquibins and is pumped by a transfer pump to the hydrazine day tank. A 6,000 gallon closed vertical pressure vessel, with a fume scrubber and two transfer pumps, stores and supplies the ethanolamine hydroxide chemical (85 percent aqueous solution of ethanolamine) for both units. The concentrated solution is pumped as needed to the ethanolamine day tank. The four chemical feed pumps output is manually controlled. The desired ethanolamine and hydrazine concentration in the condensate can be controlled manually. The water is monitored for conductivity and dissolved oxygen at the condensate pump discharge. Conductivity and dissolved oxygen, plus pH and hydrazine concentration, are also monitored at the final feedwater header before branching to the four SGs.

A third chemical feed system is available, but not normally used. It is similar to the 2nd chemical system described above, except the hydrazine day tank is 200 gallons, the ethanolamine day tank is 300 gallons, and has 4 chemical feed pumps. Condensate from the condensate pump discharge header can be used to dilute the hydrazine and ethanolamine in the respective chemical day tank.

The AFW pump chemical feed system for each unit consists of a 500 gallon stainless steel tank, a 300 gallon stainless steel tank, and five chemical feed pumps that are piped so that the fifth pump is used as a shared spare. The chemical feed rate will be manually controlled. The chemical feed pumps pump into the discharge side of the AFW pumps. An injection line runs to the discharge of each of the three AFW pumps.

The secondary boric acid system consists of two boric acid mix/feed tanks (each tank having a capacity of 1325 gallons), three 50 percent feed pumps (each pump having a capacity of 60 gallons per hour), and a screw feeder for loading the boric acid to the mix/feed tanks. Also provided are two tank mixers (mechanical agitators) for ensuring a complete and thorough mixing of the boric acid solution in the tanks. The pumping injection flow rate will be manually controlled, primarily based on the boric acid concentration in the SG blowdown.

10.4.9.3 Safety Evaluation

10.4.9.3.1 General Design Criterion 3, 1971 – Fire Protection

The chemicals of the condensate and feedwater chemical injection system (Hydrazine/Carbohydrazine, Ethanolamine and Boric Acid) are stored in accordance with the requirements of Chapter 3 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

10.4.9.3.2 General Design Criterion 9, 1967 – Reactor Coolant Pressure Boundary

The condensate and feedwater chemical injection system is designed to provide the following chemical additions to the condensate and feedwater systems to reduce SG tube corrosion:

(1) Ethanolamine to the discharge line of each demineralizer in the condensate polishing system or to the condensate pumps' discharge header when the condensate polisher system is out of service, as required, to control the pH of the feedwater and SG water.

(2) Hydrazine, or a mixture of hydrazine and carbohydrazide, to the main feedwater pump suction piping to scavenge oxygen from the feedwater to a level within procedural guidelines with a residual of hydrazine at the inlet to the SGs. Because of the similarity with hydrazine and carbohydrazide being bounded, from a safety and environmental perspective, by hydrazine, the mixture will be handled as if it were hydrazine.

(3) Ethanolamine and hydrazine, or other chemicals as specified by chemistry procedures, to the AFW pumps discharge to control the chemistry in the SGs when the AFW pumps are used to supply water to SGs.

(4) Boric acid solution to the main feedwater pump suction piping to reduce denting of tubes in the SG.

(5) Other chemicals as specified by chemistry procedures.

The system provides the capability to condition the water in the SG during wet lay-up, hydrotesting, and other times when the main feedwater system is not in operation.

The condensate and feedwater chemical injection systems are designed to provide adequate amounts of conditioning chemicals to the secondary system, as required, for the prevention of corrosion in the condensate and feedwater systems and the SG tubes.

The condensate and feedwater chemical injection system protects the SG tubes, which are a part of the reactor coolant pressure boundary, from degradation during their lifetime. This is in compliance with the SG tube integrity requirements of Generic Letter 85-02.

10.4.9.3.3 Condensate and Feedwater Chemical Injection System Safety Function Requirement

(1) Protection from Flooding Effects

The failure of condensate and feedwater chemical injection system piping is evaluated for the effects of flooding on PG&E Design Class I essential safe shutdown equipment located in the auxiliary and turbine buildings. The provisions taken to provide protection for the safe shutdown equipment from flooding that might result from the effects associated with a postulated rupture of piping are discussed in Section 3.6.

The ethanolamine/hydrazine injection pumps and supply tanks for the condensate system are located in the turbine building west buttress and the turbine building. The concentrations in the ethanolamine and hydrazine supply tanks can be up to 85 percent and 35 percent, respectively. The tanks are vented to the outside of the building. There are no ESFs in the vicinity that would be damaged or rendered inaccessible by a ruptured supply tank.

The bulk ethanolamine storage tank, its fume scrubber, and its two transfer pumps are located in the turbine building west buttress, which houses the condensate polishers. Toppling of this vertical tank is not expected to damage the nearby PG&E Design Class I diesel fuel oil lines which are inside an adequately covered recessed pipe trench. Any accidental chemical spill, which is harmless to the steel pipes, would be confined within the trench and be prevented from reaching the diesel generator room by firestops.

The AFW pump chemical injection system supply tanks are located in the auxiliary building over a ventilation opening at the 115 foot elevation floor. The AFW pumps served are located below on the 100-foot elevation floor. A ruptured supply tank could cause 300 or 500 gallons of solution to fall partially on motor-driven AFW pump 1-3 or

2-3. The motor has a drip-proof enclosure and the centerline of the pump motor unit is 2 feet-6 inches above the 100-foot floor elevation. The area is drained by two 4 inch floor drains. The floor area in the vicinity of the AFW pumps is in excess of 1000 square feet so that 500 gallons would cause less than 1 inch of depth on the floor. Motor-driven AFW pump 1-3 or 2-3 could be impacted, due to water in the motor, by this accident; however, the second motor-driven pump and the turbine-driven pump would still be available.

The boric acid mix/feed tanks are located in the turbine building at the 85-foot elevation (ground level). The boric acid feed pumps are also located at this elevation. The floor area at this elevation (ground level) is large enough so that a ruptured feed tank would cause only a negligible depth of water on the floor, even though up to 1100 gallons of solution could be released. The only PG&E Design Class I component that could be affected by water is the diesel generator fire protection controls for Unit 1 only. These controls are wall mounted in a splash-proof box. In addition, the feed tanks are constrained to prevent any lateral movement or overturning and resist a seismic event. There are no other ESFs in the vicinity that would be damaged or rendered inaccessible by a ruptured feed tank. The feed tanks are purged with nitrogen and vented to the building.

10.4.9.4 Tests and Inspections

Tests and inspections of the condensate and feedwater chemical injection system are done in accordance with plant procedures.

10.4.9.5 Instrumentation Applications

The rate of feed of the chemical injection pumps into the main condensate and feedwater systems is proportioned to feedwater flow with manual adjustment of rate of chemical injection to rate of feedwater flow. The main condensate and feedwater supply tanks are equipped with level gauge glasses. The AFW supply tanks are equipped with low level alarm switches in addition to level gauge glasses. The chemical feed pump motors will alarm on overcurrent.

The pumping injection flow rate for the boric acid injection system will be manually controlled based on the boric acid concentration in the SG blowdown. The feed tanks are equipped with level indicators and the feed pumps include thermal overload protection.

10.4.10 REFERENCES

1. Final Environmental Statement for Diablo Canyon Power Plant, U.S. Nuclear Regulatory Commission, Washington, D.C., May 1973.

10.4.11 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

DCPP UNITS 1 & 2 FSAR UPDATE

TABLE 10.0-1

APPLICABLE DESIGN BASIS CRITERIA

CRITERIA	TITLE	APPLICABILITY										
Steam and Power Conversion		Turbine-Generator	Main Steam System	Main Condenser	Main Condenser Evacuation System	Turbine Gland Sealing System	Turbine Bypass System	Circulating Water System	Condensate Polishing System	Condensate and Feedwater System	Steam Generator Blowdown System	Condensate and Feedwater Chemical Injection System
Section		10.2	10.3	10.4.1	10.4.2	10.4.3	10.4.4	10.4.5	10.4.6	10.4.7	10.4.8	10.4.9
1. General Design Criteria												
Criterion 2, 1967	Performance Standards		X				X			X	X	
Criterion 3, 1971	Fire Protection		X				X		X	X	X	X
Criterion 4, 1967	Sharing of Systems		X									
Criterion 9, 1967	Reactor Coolant Pressure Boundary								X		X	X
Criterion 11, 1967	Control Room		X				X			X	X	
Criterion 12, 1967	Instrumentation and Control System		X				X			X	X	
Criterion 15, 1967	Engineered Safety Features Protection Systems		X							X		
Criterion 16, 1967	Monitoring Reactor Coolant Pressure Boundary										X	
Criterion 17, 1967	Monitoring Radioactivity Releases		X		X	X					X	
Criterion 21, 1967	Single Failure Definition		X							X	X	
Criterion 49, 1967	Containment Design Basis		X							X		
Criterion 54, 1971	Piping Systems Penetrating Containment		X				X			X	X	

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TABLE 10.0-1

CRITERIA	TITLE	APPLICABILITY										
Steam and Power Conversion		Turbine-Generator	Main Steam System	Main Condenser	Main Condenser Evacuation System	Turbine Gland Sealing System	Turbine Bypass System	Circulating Water System	Condensate Polishing System	Condensate and Feedwater System	Steam Generator Blowdown System	Condensate and Feedwater Chemical Injection System
Section		10.2	10.3	10.4.1	10.4.2	10.4.3	10.4.4	10.4.5	10.4.6	10.4.7	10.4.8	10.4.9
1. General Design Criteria (cont'd.)												
Criterion 57, 1971	Closed System Isolation Valves		X				X			X	X	
2. System Safety Functional Requirements												
Protection from Missiles		X										
Protection from Missiles and Dynamic Effects			X				X			X	X	
Decay Heat Removal			X								X	
Main Steam Isolation			X									
Secondary Side Pressure Control			X									
Steam Flow Restriction			X									
Reactor Coolant System Cooldown							X					
Internal Flooding								X	X	X		X
Main Feedwater Isolation										X		
3. 10 CFR Part 50												
50.48(c)	10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805		X				X			X	X	

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TABLE 10.0-1

CRITERIA	TITLE	APPLICABILITY										
Steam and Power Conversion		Turbine-Generator	Main Steam System	Main Condenser	Main Condenser Evacuation System	Turbine Gland Sealing System	Turbine Bypass System	Circulating Water System	Condensate Polishing System	Condensate and Feedwater System	Steam Generator Blowdown System	Condensate and Feedwater Chemical Injection System
Section		10.2	10.3	10.4.1	10.4.2	10.4.3	10.4.4	10.4.5	10.4.6	10.4.7	10.4.8	10.4.9
3. 10 CFR Part 50 (cont'd.)												
50.49	Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants		X							X	X	
50.55a(f)	Inservice Testing Requirements		X				X			X	X	
50.55a(g)	Inservice Inspection Requirements		X				X			X	X	
50.62	Requirements of Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants	X								X	X	
50.63	Loss of All Alternating Current Power		X				X					

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TABLE 10.0-1

CRITERIA	TITLE	APPLICABILITY										
Steam and Power Conversion		Turbine-Generator	Main Steam System	Main Condenser	Main Condenser Evacuation System	Turbine Gland Sealing System	Turbine Bypass System	Circulating Water System	Condensate Polishing System	Condensate and Feedwater System	Steam Generator Blowdown System	Condensate and Feedwater Chemical Injection System
Section		10.2	10.3	10.4.1	10.4.2	10.4.3	10.4.4	10.4.5	10.4.6	10.4.7	10.4.8	10.4.9
4. Regulatory Guides												
Regulatory Guide 1.97, Revision 3, May 1983	Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident		X							X	X	
5. NRC NUREG												
NUREG-0737, November 1980	Clarification of TMI Action Plan Requirements		X		X	X						
6. NRC Generic Letters												
Generic Letter 89-08, May 1989	Erosion/Corrosion-Induced Pipe Wall Thinning	X	X							X	X	
Generic Letter 89-10, June 1989	Safety-Related Motor-Operated Valve Testing and Surveillance									X		

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TABLE 10.0-1

CRITERIA	TITLE	APPLICABILITY										
Steam and Power Conversion		Turbine-Generator	Main Steam System	Main Condenser	Main Condenser Evacuation System	Turbine Gland Sealing System	Turbine Bypass System	Circulating Water System	Condensate Polishing System	Condensate and Feedwater System	Steam Generator Blowdown System	Condensate and Feedwater Chemical Injection System
Section		10.2	10.3	10.4.1	10.4.2	10.4.3	10.4.4	10.4.5	10.4.6	10.4.7	10.4.8	10.4.9
7. Branch Technical Position												
Branch Technical Position ASB 10-2, March 1978	Design Guidelines for Water Hammers in Steam Generators with Top Feedring Designs									X		

TABLE 10.1-1

STEAM BYPASS AND RELIEF VALVES

Design Class[a]	Relieves to	Pressure Mode	Pressure[b]	Capacity ± 10%
Main Steam Power-operated Valves (10% Atmospheric Dump Valves):				
I	Atmosphere	Operating	790 psia	327,255 lb/hr
		Maximum	1,179 psia	495,949 lb/hr
Turbine Bypass Valves (40% Cooldown and Bypass Valves):				
II	Condenser	Operating	790 psia	527,099 lb/hr
		Maximum	1,165 psia	789,875 lb/hr
Power-operated Steam Relief Valves (35% Atmospheric Dump Valves):				
II	Atmosphere	Operating	790 psia	612,014 lb/hr
		Maximum	1,165 psia	917,123 lb/hr

Main Steam Spring-loaded Safety Valves:

Design Class	Relieves to	Set Pressure	At 3% Accumulation	Valve Full Open	Orifice Size (inches)
I	Atmosphere	1,065 psig	803,790 lb/hr	867,431 lb/hr	4.515
I	Atmosphere	1,078 psig	813,471 lb/hr	877,875 lb/hr	4.515
I	Atmosphere	1,090 psig	822,408 lb/hr	887,516 lb/hr	4.515
I	Atmosphere	1,103 psig	832,090 lb/hr	897,960 lb/hr	4.515
I	Atmosphere	1,115 psig	841,027 lb/hr	907,601 lb/hr	4.515

(a) PG&E Design Class; refer to Table 3.2-1

(b) Ref.: DCMs M-46 (U-1) and M-71 (U-2)
10% pressure values from envelopes of lines 227 and 228, which have the highest accident pressure
35% pressure values from envelope of line 590, which supplies the PORVs
40% pressure values from envelope of line 587 supplying the valves

TABLE 10.1-2

SECONDARY SYSTEM OPERATING PARAMETERS
AT 100 PERCENT RATED POWER

Mass of water in one steam generator, lb	102,600
Mass of steam in one steam generator, lb	6,900
Secondary side operating temperature, °F	522
Steam generator blowdown tank capacity, ft^3	641
Air ejector flowrate - rated, scfm	25
- expected average, scfm	2.5
Total mass of water in secondary system, lb	2,800,000
Total mass of steam in secondary system, lb	60,000

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 10.3-1

MAIN STEAM LINE VALVE PLANT STARTUP LEAKAGE TEST RESULTS

Valve Type and Leakage Path	*Quantity*	*Leakage per Valve*
Leakage to atmosphere through seat of 6-inch safety valves[(a)]	*20*	*10 bubbles/min*
Leakage to atmosphere through seat of 8-inch power-operated relief valves	*4*	*24 cc/hr*
Leakage to auxiliary feed pump turbine through seat of 4-inch isolation valves	*2*	*6 cc/hr*
Leakage to atmosphere through stems of gate valves in series with power-operated relief valves[(b)]	*4*	*12 cc/hr*
Leakage to atmosphere through stems of main steam isolation valves[(c)]	*4*	*4 cc/hr*
Leakage to atmosphere through stems of globe valves bypassing the main steam isolation valves	*4*	*negligible*

(a) Tested in accordance with API Standard 527. Test made after popping with nitrogen and then pressure reduced to 92 percent of nitrogen popping pressure.

(b) Tested seat at 1500 psig for 3 minutes. Result shown is maximum of all valves tested - hydro test.

(c) Requirement: leakage per valve shall not exceed 2 cc of water per hour when subjected to hydrostatic pressure of 1100 psig, or 0.06 scfh of air with a differential pressure of 80 psi. There are two valves per valve assembly. These are purchase specifications, not operational test requirements.

10.3-2

SUMMARY OF RESULTS UNDER PIPE RUPTURE CONDITIONS

	Check Valve	Isolation Valve
Velocity at disk impact, rad/sec	74.7	77.6
Acceleration at disk impact, rad/sec^2	6373	5474
Energy at disk impact, 10^6 in-lb	0.817	0.888
Maximum flowrate through valve, lb/sec	2767	3220

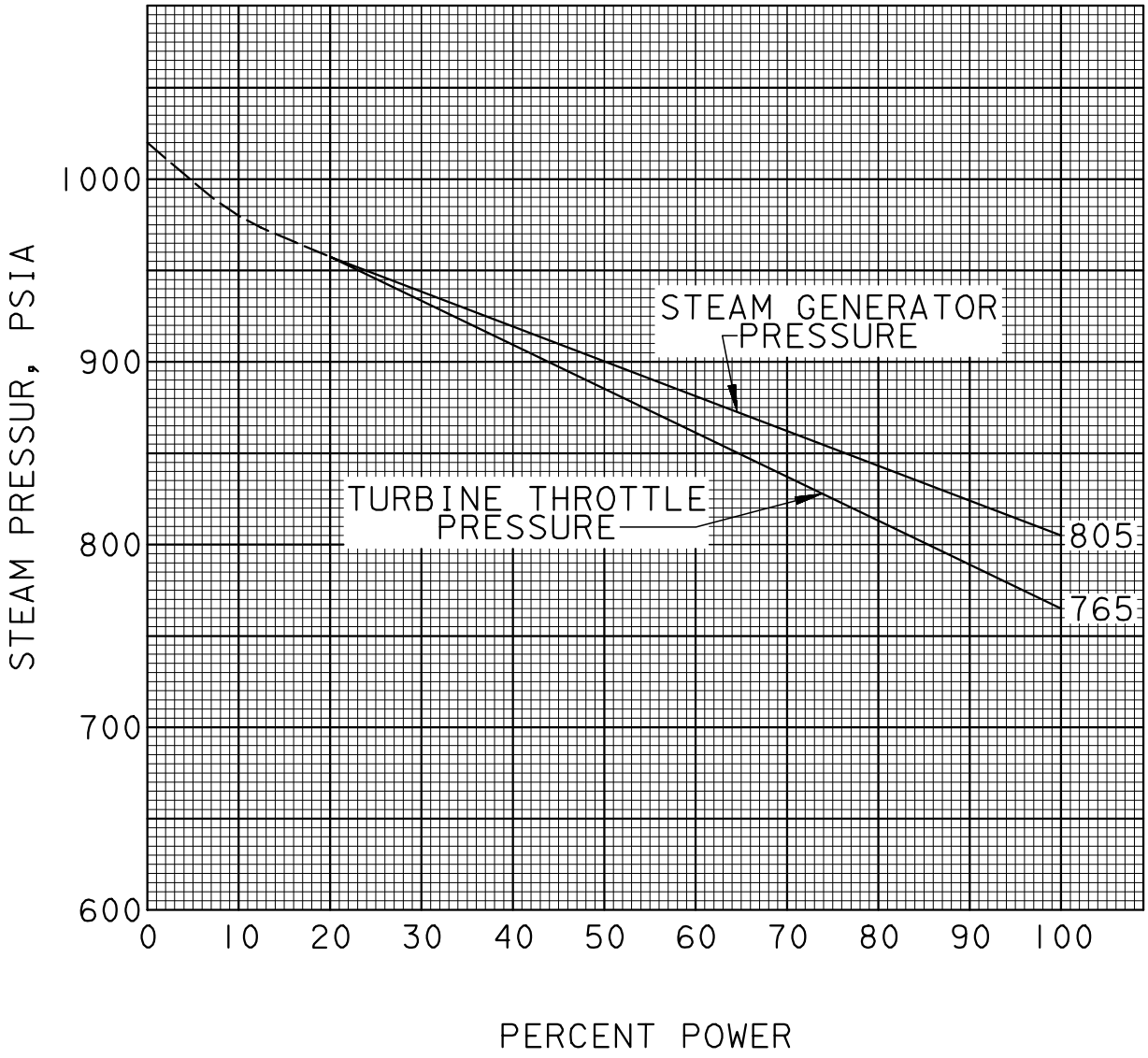
TABLE 10.4-1

MAIN CONDENSER PERFORMANCE DATA

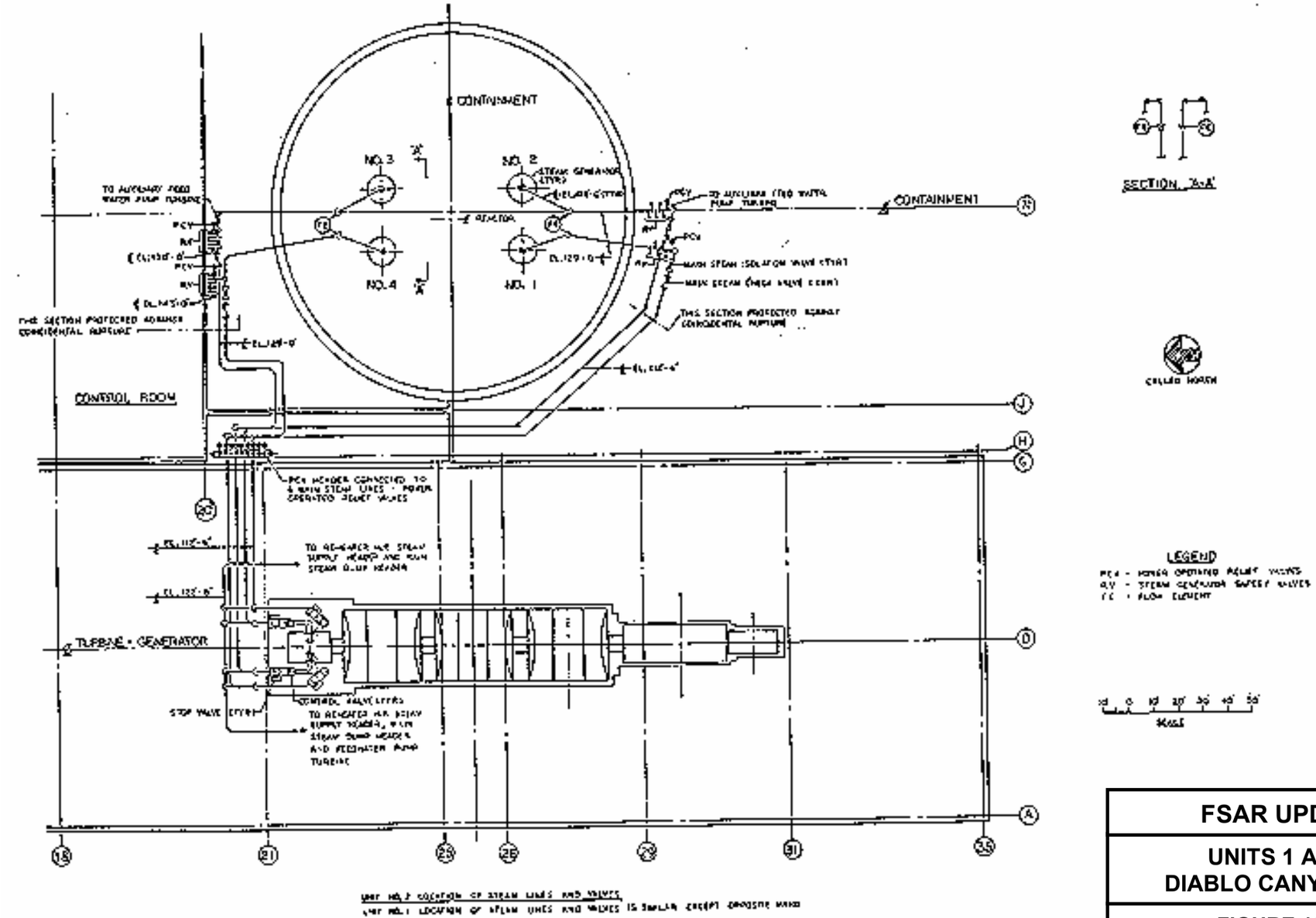
The condenser for each unit has two shells. The data given below are based on the full load heat balance.

Characteristics	Unit 1 Shell	Unit 2 Shell
Total heat load, Btu/hr[c]	8.19×10^9	8.19×10^9
Absolute pressure in condensing zone, in. Hg (with 56.5°F circulating water temperature at inlet to condenser)	1.71	1.71
Circulating water flow, gpm[d]	862,000	862,000
Average velocity in tube, ft/sec	6.8	6.8
Effective surface area, ft^2 [e]	618,150	618,150
Cleanliness factor, % [a]	85	85
Tube outside diameter, in.	1	1
Tube BWG	22	22
Tube overall length, ft	40 ft 9 in.	40 ft 9 in.
Tube effective length, ft	40.56	40.56
Number of tubes	58,216	58,216
Total condensate stored at maximum operating level (82 ft-6 in.), cu ft	18,880[b]	18,880[b]

(a) This is the percent of clean tube heat transfer coefficient used in the design of the condenser.
(b) There is a single hotwell for each unit.
(c) The Unit 1 and Unit 2 condensers were originally rated for a nominal heat load of 7.6×10^9 Btu/hr. The post Alstom LP Turbine Retrofit heat loads based upon the Alstom supplied “Full Load” heat balance diagrams for Unit 1 and Unit 2 are bounded by the Westinghouse approximated value shown in the table. Refer to Figures 10.1-6 and 10.1-2 for the full load heat balances, Unit 1 and Unit 2, respectively.
(d) This is a nominal value based on pump design documents and impacts on flow due to varying tidal conditions.
(e) Vendor supplied value. It is considered a nominal value.



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 10.2-1 STEAM GENERATOR CHARACTERISTIC PRESSURE CURVES



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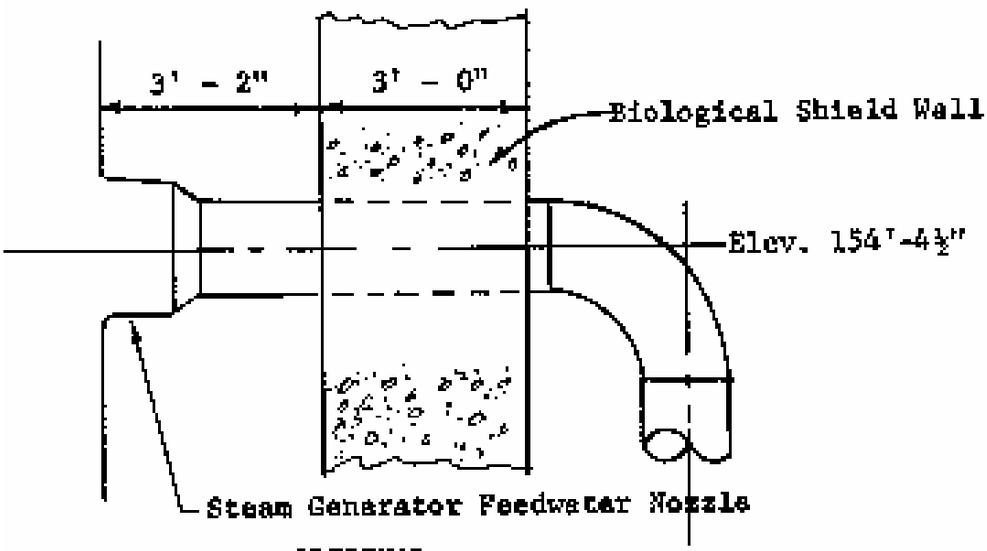
UNITS 1 AND 2
DIABLO CANYON SITE

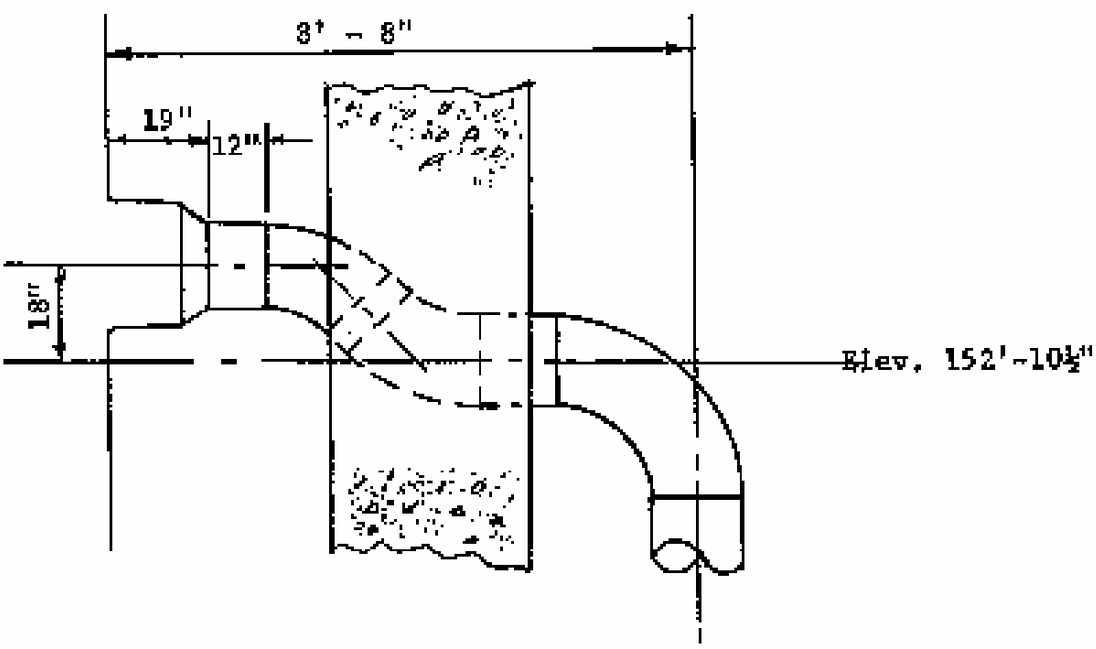
FIGURE 10.3-6
LOCATION OF STEAM LINES AND VALVES

Revision 11 November 1996

STEAM GENERATORS 1 and 4



ORIGINAL



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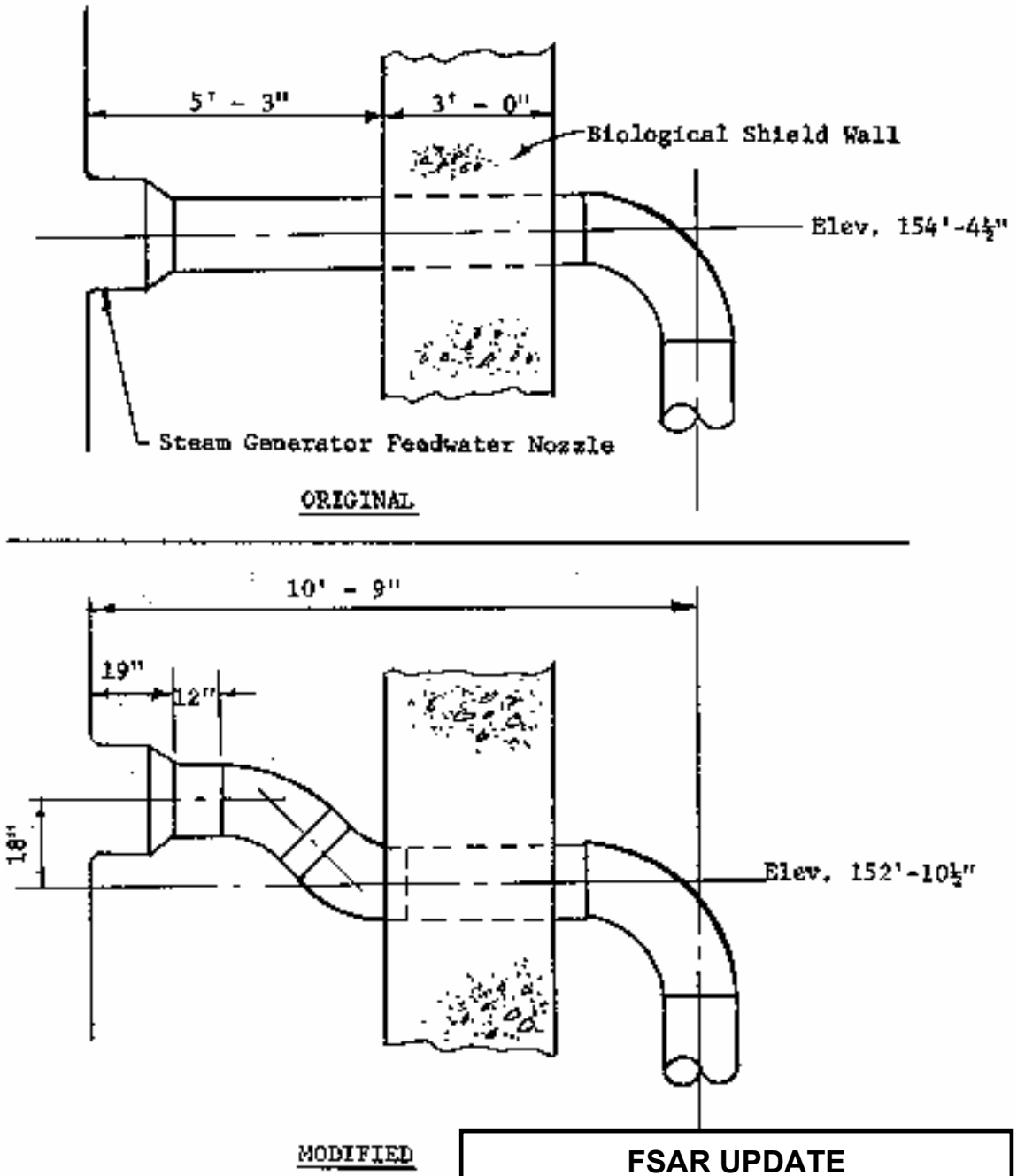
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 10.4-2 REVISION OF STEAM GENERATOR FEEDWATER PIPING STEAM GENERATORS 2 AND 3

STEAM GENERATORS 2 and 3



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UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 10.4-3 REVISION OF STEAM GENERATOR FEEDWATER PIPING STEAM GENERATORS 2 AND 3

Chapter 11

RADIOACTIVE WASTE MANAGEMENT

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FIGURES

Figure	Title
11.1-1	R. E. Ginna Plant Tritium Sources - Measured and Predicted *(HISTORICAL)*
11.2-1	Deleted in Revision 18
11.2-2	*Liquid Waste Process Flow Diagram: Design Basis (HISTORICAL)*
11.2-3	*Liquid Waste Process Flow Diagram: Normal Operation (HISTORICAL)*
11.2-4	Blowdown System Flow Diagram - Discharge Mode
11.2-5	Blowdown System Flow Diagram Recycle Path
11.2-6	*Tritium Concentration in Water Versus Time (HISTORICAL)*
11.2-7	*Tritium Airborne Concentration in Fuel Handling Area Versus Time (HISTORICAL)*
11.2-8	*Tritium Airborne Concentration in Containment Versus Time (HISTORICAL)*
11.2-9	Site Plot Plan - Radwaste Discharge
11.3-1	Deleted in Revision 1
11.3-2	Deleted in Revision 1
11.3-3	Deleted in Revision 1
11.3-4	Gaseous Waste Systems' Release Points
11.4-1	Radiation Monitoring System
11.5-1	Solid Radwaste System
11.5-2	Deleted in Revision 3
11.5-3	Spent Resin Flow Diagram
11.5-4	Location of Onsite Storage Facility

FIGURES

Figure	Title
11.5-5[a]	Solid Radwaste Storage Building
11.5-5A	Deleted in Revision 11
11.5-6	Chemical and Volume Control System Displaying Filters
11.5-7	Spent Fuel Pool Displaying Filters
11.5-8	Liquid Radwaste System Displaying Filters
11.5-9	System for Capturing Expended Filter Cartridges
11.5-10	Cover of Filter Vessel
11.5-11	Spent Resin Storage Area
11.5-12	Load Out Station
11.6-1	Deleted in Revision 11
11.6-2	Deleted in Revision 11
11.6-3	Deleted in Revision 4
11.6-4	Deleted in Revision 11
11.6-5	Deleted in Revision 11

NOTE:

[a] This figure corresponds to a controlled engineering drawing that is incorporated by reference into the FSAR Update. See Table 1.6-1 for the correlation between the FSAR Update figure number and the corresponding controlled engineering drawing number.

Chapter 11

RADIOACTIVE WASTE MANAGEMENT

The purpose of this chapter is to provide a complete description and state the design objectives of the radioactive waste systems to demonstrate compliance with the general provisions of 10 CFR Part 20 and 10 CFR Part 50. Performance evaluation of the radioactive waste treatment systems is described.

This chapter is divided into the following sections:

11.1 Source Terms
11.2 Liquid Radwaste System (LRS)
11.3 Gaseous Radwaste System (GRS)
11.4 Process and Effluent Radiological Monitoring System (RMS)
11.5 Solid Radwaste System (SRS)
11.6 Offsite Radiological Monitoring Program

In the sections on liquid and gaseous radwaste systems, all significant release pathways of radioactive liquids and gases are identified and discussed, including those not directly associated with radwaste treatment systems; for example, blowdown system releases and steam leakage.

The principles and guidelines used in the design, construction, and operation of the radioactive waste management systems described in Chapter 11 are specified in the individual sections of Chapter 11 and in Table 11.0-1.

A pre-operation evaluation of the liquid and gaseous radwaste systems was performed to demonstrate the systems' abilities to maintain releases within regulatory limits. To carry out an activity analysis of the plant that covers different combinations of basic operating parameters, two cases were selected:

(1) Design Basis Case – source term analysis used as input into the design of plant systems and topical areas (e.g., shielding and radwaste) to ensure compliance with 10 CFR Part 20. Inputs and assumptions were conservative.

(2) Normal Operation Case – source term analysis used for pre-operational evaluations to ensure compliance with the minimum equipment requirements of 10 CFR Part 50, Appendix I. Inputs and assumptions included anticipated operational occurrences and were more realistic than those for the design basis case.

These cases do not represent the typical results of actual plant operation, and the operational basis and resulting values for either case are not license limits. They were

developed for initial plant licensing and are not expected to be updated, therefore they are considered historical.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

For the Design Basis Case, the plant was assumed to have been operated for a full year at full thermal power of 3568 MWt with a capacity factor of 80 percent and a fuel defect level of 1 percent. The radwaste systems were assumed to be in operation as designed, and primary system leakage was assumed to be negligible. The complete set of other assumptions associated with this case are listed in Table 11.1-2 and discussed in detail in the following sections.

For the Normal Operation Case the plant was assumed to have been operated for a full year at full power with a capacity factor of 80 percent and a fuel defect level of 0.12 percent. Coincident with this condition, it was assumed that there existed primary system leakage of 100 pounds per day to the secondary system, 1 percent of primary coolant noble gas inventory and 0.001 percent of primary coolant iodine inventory to the containment, and 160 pounds per day to the auxiliary building. These assumptions are in agreement with those provided in NUREG-0017, April 1976 for normal operation of a pressurized water reactor (PWR) (refer to Reference 9 of Section 11.1). The complete set of assumptions for this case is also discussed in the following sections. As a result of the analyses of these cases, the following conclusions can be drawn.

Diablo Canyon Power Plant (DCPP) Unit 1 and Unit 2 can be operated under normal conditions, including the consideration of anticipated operational occurrences, in conformance with:

(1) The general provisions of 10 CFR Part 20 and 10 CFR Part 50

(2) The annual dose limits established in 10 CFR Part 20 for the release of radioactive materials

(3) The annual radiation dose limits specified in 10 CFR Part 50, Appendix I.

The radioactive waste release values provided in this chapter are nominal values. Actual release values are reported to the NRC in the DCPP Annual Radioactive Effluent Release Report.

11.1 SOURCE TERMS

This section describes the routine (or operational) source term and the pre-operational evaluation of source term for the Design Basis Case and the Normal Operation Case.

Routine Source Term:

Primary coolant concentrations, leakage rates, and effluent release rates based on the routine source term are used for evaluation of the LRS and GRS to determine whether these systems meet the dose design objectives of 10 CFR Part 50 Appendix I.

The operational source term in the reactor coolant system (RCS) and supporting systems are monitored on a routine basis in accordance with plant Technical Specifications and plant-approved procedures. The information is readily available to site personnel for evaluating source term and trends.

The station policy is to operate the plant with zero fuel defects to achieve a low source term in the primary coolant.

The plant operating philosophy is to maintain leakage from the primary system well below Technical Specification limits.

This operating philosophy is fundamental to minimizing the input of radioactive material into the LRS and the GRS, and thereby minimizes activity that may be released from the station.

There have been periods when a fuel leak develops and the RCS Dose Equivalent I-131 specific activity (DEI) has been near the Technical Specification value of 1.0 μCi/gm for periods of time. The station has demonstrated that the LRS and GRS operating per station procedures have maintained plant releases at a fraction of Technical Specification and 10 CFR Part 20 limits.

Routine operating RCS DEI is normally only a fraction of the Technical Specification value of 1.0 μCi/gm.

The routine operating source term is much lower than the cases described below.

Tritium is produced as part of the fission process of the reactor and its production is a direct function of power produced and capacity factor. Tritiated water is not removed in the treatment systems. Given that tritium has a 12.3 year half-life, essentially all the tritium produced is released from the plant via the LRS or through evaporation via the plant vent.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Pre Operation Source Term Evaluations:

The pre-operational evaluation of radioactive materials produced and stored in the reactor system is reported and discussed in this section. These sources have been computed for two basic sets of plant operating conditions: the Design Basis Case and the Normal Operation Case.

The complete isotopic source terms are presented in tabular form along with the basic assumptions used in the computations. The activities and concentrations were calculated with the EMERALD-NORMAL (Reference 8) digital computer program. A detailed discussion of the physical data and assumptions used is contained in the following paragraphs:

11.1.1 BASIC PHYSICAL DATA AND CONSTANTS

The values of isotopic physical data used in the radiological effects analyses are listed in Table 11.1-1. The values of half-lives and fission yields were taken from the Meek and Rider report (Reference 1) and from Tobias (Reference 10) and are in general agreement with those in TID-14844 (Reference 2) and ORNL-2127 (Reference 3). The values for average beta energies are those provided in Perkins and King (Reference 4) and the average gamma energies are taken from Tobias. The values of decay constants were calculated from the half-lives with the standard formula. The fission yields were modified to account for plutonium buildup by using the values for uranium and plutonium fissioned during an equilibrium core cycle as follows:

$$\text{Yield (U + Pu)} = \frac{[\text{Fissions (U) x Yield (U)}] + [\text{Fissions (Pu) x Yield (Pu)}]}{\text{Fissions (U + Pu)}}$$

The number of fissions per megawatt-second is taken to be 3.15×10^{16}, which agrees well with the value of 3.2×10^{16} used in Reference 2.

11.1.2 DETERMINATION OF ACTIVITY INVENTORIES IN REACTOR CORE

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

The EMERALD-NORMAL program was run for 11 months with zero initial activities, and the result was decayed one month. The resulting core activities (assuming one-third of the core was replaced at refueling) were then set equal to the initial activities and the process repeated. Taking one-third of the activities after the first cycle, plus one-third of the activities after the second cycle, gives an approximation to the initial activities for an equilibrium core cycle. The core inventories for the year's operating cycle were then computed using an 80 percent capacity factor to ensure a realistic inventory of Kr-85. The power level and other basic assumptions are provided in Tables 11.1-2 and 11.1-3. The resulting core inventories are listed in Tables 11.1-4 and 11.1-5. These calculated core inventories are in general agreement with those tabulated in TID-14844, with those listed in the Reactor Safety Study (WASH-1400) (Reference 12), and with those listed in the DCPP Preliminary Safety Analysis Report (Reference 5).

The actual maximum operating configuration is 21 months of operation, with a mixture of fuel with enrichments up to 5 percent, and with a maximum burnup of 50,000 MWD/MTU. The updated equilibrium isotopic core inventory of dose significant isotopes is presented in Table 15.5-77. A summary of key assumptions and a description of the method used to determine the updated core inventory is provided in Table 11.1-2A and Section 15.5.3.1, respectively.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

11.1.3 DETERMINATION OF INVENTORIES IN FUEL ROD GAPS

The computed gap activities are based on buildup in the fuel from the fission process and diffusion to the fuel rod gap at rates dependent on the operating temperature. For this analysis, the fuel pellets were divided into five concentric rings, each with a release rate dependent on the mean fuel temperature within that ring. The diffusing isotope is assumed present in the gas gap when it has diffused to the boundary of the outer ring. The core temperature distribution used in this analysis, based on hot channel factors of F_H = 1.70 and F_q = 2.82, is presented in Table 11.1-6.

The diffusion coefficient, D', for Xe and Kr in UO_2, varies with temperature in accordance with the following expression:

$$D'_T = D'_{(1673)} \exp^{-\frac{E}{R}\left(\frac{1}{T} - \frac{1}{1673}\right)} \qquad (11.1\text{-}1)$$

where:

E	*= activation energy*
$D'_{(1673)}$	*= diffusion coefficient at 1673 K = 1 x 10^{-11} sec^{-1}*
T	*= temperature in K*
R	*= gas constant*

This expression is valid for temperatures above 1100°C. Below this temperature, fission gas release occurs mainly by two temperature-independent phenomena, recoil and knock-out, and is predicted by using D' at 100°C. The value used for D' (1673 K), based on data at burnups greater than 10^{19} fission/cc, is used to account for possible fission gas release by other mechanisms and pellet cracking during irradiation.

The diffusion coefficients for iodine isotopes are assumed to be the same as those for Xe and Kr (References 6 and 7).

The resulting fractions of core activity present in the fuel rod gaps are listed in Table 11.1-7, along with the total inventories of activity in the gaps.

As part of the implementation of Alternative Source Terms to assess post-accident dose consequences to the public as well as habitability of the control room and technical support center, the isotopic inventories in fuel rod gaps have been updated as discussed in Section 15.5.3.3. The isotopic activity in the gap assumed for the Locked Rotor Accident and the Control Rod Ejection Accident are provided in Table 15.5-80. The isotopic activity in the gap assumed for the Fuel Handling Accident is presented in Table 15.5-47C.

11.1.4 DETERMINATION OF PRIMARY COOLANT ACTIVITIES

The basic data and assumptions used in calculating the coolant concentrations for the Design Basis Case and the Normal Operation Case are provided in Tables 11.1-2, 11.1-3, 11.1-8, 11.1-9, and 11.1-10. The coolant concentrations and activities, listed in Tables 11.1-11, 11.1-12, and 11.1-13, are provided for the operating temperature. The activities of corrosion products deposited in the steam generator are provided in Table 11.1-14. The total amounts of activity produced and removed from the coolant during the operating period are provided in Tables 11.1-16 and 11.1-17. All models and equations, including parent-daughter production, purification terms, boron feed-bleed terms, and coolant leakage terms, are provided in detail in Reference 8, and are generally consistent with those provided in NUREG-0017, April 1976 (Reference 9). The demineralizer decontamination factors assumed are listed in Table 11.1-15. The basic assumptions and data used in calculating the activities in the pressurizer are listed in Table 11.1-18, and the calculated activities for the two cases are provided in Tables 11.1-19 and 11.1-20.

The method used to develop the reactor coolant concentration associated with the updated equilibrium isotopic core inventory discussed in Section 11.1.2 is summarized in Section 15.5.3.2. The updated coolant concentrations with 1 percent fuel defects is presented in Table 11.1-11A. A summary of key assumptions used in developing the coolant concentrations is provided in Table 11.1-2A.

11.1.5 DETERMINATION OF TRITIUM ACTIVITIES IN PRIMARY COOLANT

Tritium atoms are generated in the fuel at a rate of approximately 8×10^{-5} atoms per fission, or 1.05×10^{-2} curies/MWt/day. Any boron-bearing control rods in the core are a potential source of tritium.

A direct source of tritium is the reaction of neutrons with dissolved boron in the reactor coolant. Boron is used in the reactor coolant for reactivity control. Neutron reactions with lithium are also a direct source of tritium. Lithium hydroxide is used for pH control.

Figure 11.1-1 shows calculated versus measured tritium production in the reactor coolant for the R. E. Ginna plant. A 10 percent release from the fuel rods was assumed for the calculation.

11.1.5.1 Ternary Fissions - Cladding Diffusion

With zirconium alloy cladding, approximately 10 percent of the tritium produced in the fuel will diffuse through the cladding into the coolant (Reference 11).

11.1.5.2 Tritium Produced from Boron Reactions

The neutron reactions with boron that result in the production of tritium are:

B^{10} (n, 2 α) T
B^{10} (n, α) Li^{7} (n, n α) T
B^{11} (n, T) Be^{9}
B^{10} (n, d) Be^{9*} (n, α) Li^{6} (n, α)T

Of the above reactions, only the first two contribute significantly to the tritium production. The B^{11} (n, T) Be^{9} reaction has a threshold of 14 MeV and a cross section of 5 mb. Since the neutrons produced at this energy result in a flux of less than 10^{9} n/cm^{2}-sec, the tritium produced from this reaction is negligible. The B^{10} (n,d) reaction may be neglected since Be^{9*} has been found to be unstable.

11.1.5.3 Tritium Produced from Lithium Reactions

The neutron reactions with lithium resulting in the production of tritium are:

Li^{7} (n, n α) T
Li^{6} (n, α) T

Lithium hydroxide is used for pH adjustment of the reactor coolant. Lithium concentrations may reach a value of 6.0 ppm at the beginning-of-cycle. During normal plant operations the lithium is maintained within an operational band per plant procedure. At the end-of-cycle, the lithium concentrations may decrease to 0.0 ppm. This is accomplished by the addition of Li^{7} OH and by a cation demineralizer included in the chemical and volume control system. This demineralizer will remove any excess of lithium such as could be produced in the B^{10} (n, α) Li^{7} reaction.

The Li^{6} (n,α) T reaction is controlled by limiting the Li^{6} impurity in the Li^{7} OH used in the reactor coolant and by lithiating the demineralizers with 99.9 atom percent Li^{7}.

11.1.5.4 Control Rod Sources

In a fixed burnable poison rod, there are two primary sources of tritium generation: the B^{10} (n, 2 α) T and the B^{10} (n, α) Li^{7} (n, n α) T reactions. Unlike the coolant, where the Li^{7} level is controlled, there is a buildup of Li^{7} in the burnable poison rods. The burnable poison rods are required during the first year of operation only. During this time, the tritium production is 72 curies/pound B^{10}.

The control rod materials used at DCPP are Ag-In-Cd; there are no tritium sources in these materials.

11.1.5.5 Tritium Production from Deuterium Reactions

Since the fraction of naturally occurring deuterium in water is less than 0.0015, the tritium produced from this reaction is negligible (less than 1 curie per year).

11.1.5.6 Total Tritium Sources in Coolant

A summary of the sources of tritium in the RCS are listed in Table 11.1-22, and all basic data and assumptions used are provided in Table 11.1-21. The calculated total tritium produced in the reactor plant, 1640 curies/year, agrees fairly well with the NUREG-0017, April 1976 value of 0.4 Ci/MWt/year, which gives 1427 curies/year, the difference being conservative.

11.1.6 DETERMINATION OF SECONDARY SYSTEM ACTIVITIES

In order to estimate the potential plant releases as a result of secondary system leakage or discharges, during periods when significant activity exists in the steam system, the steam system activity levels have been determined. As discussed earlier, the range of possible combinations of plant operating conditions has been represented by making an activity analysis on the basis of 0.12 percent fuel defects, coincident with a leakage of 100 pounds per day to the secondary system. The projected plant releases for this condition are based on the assumption that these conditions persist throughout the full year. The steam system operating conditions assumed for the activity analysis are listed in Tables 11.1-23, 11.1-24, and 11.1-25, and the results of the analysis are provided in Tables 11.1-26 through 11.1-31. The equations and models for the activity balances and transport calculations are detailed in Reference 8, and they are generally consistent with those provided in NUREG-0017, April 1976.

11.1.7 REFERENCES

1. M.E. Meek and B.F. Rider, Summary of Fission Product Yields for U-235, U-238, Pu-239, and Pu-241 at Thermal, Fission Spectrum, and 14 MeV Neutron Energies, Report Number APED-5398, March 1, 1968.

2. J.J. DiNunno, et al, Calculation of Distance Factors for Power and Test Reactor Sites, AEC Report Number TID-14844, March 23, 1962.

3. J.O. Blomeke and M.F. Todd, Uranium-235 Fission - Product Production as a Function of Thermal Neutron Flux, Irradiation Time, and Decay Time, AEC Report ORNL-2127, August 19, 1957.

4. J.F. Perkins and R.W. King, "Energy Release from the Decay of Fission Products," Nuclear Science and Engineering, 1958.

5. Preliminary Safety Analysis Report, Nuclear Units Number 1 & 2, Diablo Canyon Site, Pacific Gas and Electric Company.

6. D.F. Toner and J.S. Scott, "Fission Product Release From UO_2," Nuclear Safety, Vol. 3, No. 2, December 1961.

7. J. Belle, Uranium Dioxide: Properties and Nuclear Applications, Naval Reactors, DRD of USAEC, 1961.

8. S.G. Gillespie and W.K. Brunot, EMERALD NORMAL - A Program for the Calculation of Activity Releases and Doses from Normal Operation of a Pressurized Water Plant, Program Description and User's Manual, Pacific Gas and Electric Company, Revision 1, December 1974.

9. NUREG-0017, Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors, USNRC, (PWR-GALE Code), April 1976.

10. A. Tobias, Data from the Calculation of Gamma Radiation Spectra and Beta Heating from Fission Products, (Revision 2), RD/B/M2453, Central Electricity Generating Board, England, October 1972.

11. WCAP 8253, Source Term Data for Westinghouse Pressurized Water Reactors, May 1974.

12. Reactor Safety Study (WASH-1400), An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants, Appendix VI, U.S. Nuclear Regulatory Commission, October 1975.

11.2 LIQUID RADWASTE SYSTEM

The LRS collects and processes the radioactive liquid wastes generated from the primary side of the plant during operation. The LRS reduces the activity of these liquid radwastes to levels acceptable for discharge to the environment. The system is designed to minimize dose to plant personnel and the general public in accordance with applicable regulations.

The LRS interfaces with the plant's liquid drain systems as follows:

(1) The equipment drain subsystem terminates at the inlet to the reactor coolant drain tank (RCDT) in containment or the miscellaneous equipment drain tank (MEDT) in the auxiliary building (refer to Section 9.3.3). The LRS processing equipment includes these tanks and associated downstream process piping and equipment.

(2) The floor drain subsystem terminates at the inlet to the containment structure sumps in containment or the auxiliary building and residual heat removal (RHR) system sumps in the auxiliary building (refer to Section 9.3.3). The LRS processing equipment includes these sumps and associated downstream process piping and equipment.

The portions of the LRS between and including the LRS containment isolation valves (CIVs) are PG&E Design Class I. The LRS CIVs are supplied by 125-Vdc, Class 1E power. The remainder of the LRS is PG&E Design Class II.

Applicable codes and standards for process equipment used in the LRS are presented in Table 3.2-3. The seismic and quality group classifications for these components and associated piping are also described in Section 3.2.2.

Three other major liquid radwaste streams that may be radiologically contaminated are included in this chapter, although they are not technically part of the LRS (refer to Section 11.2.3.13.2).

11.2.1 DESIGN BASES

11.2.1.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portion of the LRS is designed to withstand the effects of, or is protected against, natural phenomena such as earthquakes, tornadoes, flooding, winds, tsunamis, and other local site effects.

11.2.1.2 General Design Criterion 3, 1971 – Fire Protection

The LRS is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

11.2.1.3 General Design Criterion 4, 1967 – Sharing of Systems

The LRS is not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

11.2.1.4 General Design Criterion 11, 1967 – Control Room

The LRS is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

11.2.1.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the LRS variables within prescribed operating ranges.

11.2.1.6 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The LRS is designed to provide means for monitoring the facility effluent discharge paths, and the facility environs for radioactivity that could be released from normal operations, from anticipated transients, and from accident conditions.

11.2.1.7 General Design Criterion 40, 1967 – Missile Protections

The engineered safety feature (ESF) containment isolation portion of the LRS is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

11.2.1.8 General Design Criterion 49, 1967 – Containment Design Basis

The PG&E Design Class I portion of the LRS is designed so that the containment can accommodate, without exceeding the design leakage rate, pressures and temperatures resulting from the largest credible energy release following a loss-of-coolant accident (LOCA), including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of emergency core cooling systems.

11.2.1.9 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The LRS piping that penetrates containment is provided with leak detection, isolation, redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The piping is designed with capabilities to test

periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

11.2.1.10 General Design Criterion 56, 1971 – Primary Containment Isolation

The PG&E Design Class I portion of the LRS contains valves in piping that penetrate containment and that are connected directly to the containment atmosphere. To ensure containment integrity is maintained, each penetration contains one automatic isolation valve or one check valve inside containment and one automatic isolation valve outside containment.

11.2.1.11 General Design Criterion 68, 1967 – Fuel and Waste Storage Radiation Shielding

The LRS is designed to provide shielding for radiation protection to meet the requirements of 10 CFR Part 20.

11.2.1.12 General Design Criterion 69, 1967 – Protection Against Radioactivity Release from Spent Fuel and Waste Storage

The LRS is designed to provide containment of radioactive releases to the public environs as a result of an accident.

11.2.1.13 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The LRS includes those means necessary to maintain control over the plant radioactive effluents during normal operation, including anticipated operational occurrences, and during accidents.

11.2.1.14 Liquid Radwaste System Safety Function Requirements

(1) <u>Protection from Jet Impingement – Inside Containment</u>

The PG&E Design Class I containment isolation portion of the LRS located inside containment is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

11.2.1.15 10 CFR Part 20 – Standards for Protection Against Radiation

The LRS supports the protection of personnel from radiation sources such that occupational doses and doses to individual members of the public are maintained below the annual limits prescribed in 10 CFR Part 20.

11.2.1.16 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

The LRS components that require environmental qualification (EQ) are qualified to the requirements of 10 CFR 50.49.

11.2.1.17 10 CFR 50.55a(f) – Inservice Testing Requirements

The LRS ASME code valves are tested to the requirements of 10 CFR 50.55a(f)(4) and 10 CFR 50.55a(f)(5) to the extent practical.

11.2.1.18 10 CFR 50.55a(g) – Inservice Inspection Requirements

The LRS ASME components are inspected to the requirements of 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(5) to the extent practical.

11.2.1.19 10 CFR Part 50, Appendix I – Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion "As Low as is Reasonably Achievable" for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents

The LRS is designed to support maintaining offsite annual doses from liquid effluents below the limits specified in 10 CFR Part 50, Appendix I.

11.2.1.20 40 CFR Part 190 – Environmental Radiation Protection Standards for Nuclear Power Operations

The LRS supports the protection of members of the public from radiation sources from the uranium fuel cycle such that annual doses are maintained below the limits specified in 40 CFR Part 190.

11.2.1.21 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The LRS provides instrumentation to monitor system variables during and following an accident.

11.2.1.22 Regulatory Guide 1.143, Revision 1, October 1979 – Design Guidance for Radioactive Waste Management Structures, Systems, and Components Installed In Light-Water-Cooled Nuclear Power Plants

The LRS design follows the guidance of Regulatory Guide 1.143, Revision 1 as it relates to the quality group classification of components.

11.2.1.23 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident Monitoring Instrumentation:

Position (5) – The LRS provides continuous instrumentation to monitor containment sump wide-range water level in the control room.

11.2.1.24 Generic Letter 96-06, September 1996 – Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions

LRS piping has been evaluated for the issue of thermal overpressurization of isolated piping sections that could affect containment integrity during design-basis accident conditions, as described in Generic Letter 96-06, September 1996.

11.2.2 SYSTEM DESCRIPTION

11.2.2.1 General

DCPP Unit 1 and Unit 2 share a common LRS, except for equipment located inside containment. A detailed piping and instrumentation schematic of the LRS is shown in Figure 3.2-19. The common LRS consists of the following five collection subsystems:

(1) Equipment drain subsystem (refer to Section 9.3.3)

(2) Floor drain subsystem (refer to Section 9.3.3)

(3) Chemical drain subsystem (refer to Section 11.2.2.1.3)

(4) Laundry and hot shower and laundry/distillate subsystem (refer to Section 11.2.2.1.4)

(5) Demineralizer regenerant subsystem (refer to Section 11.2.2.1.5)

These five collection subsystems are described in the following sections.

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

Following treatment, effluents from the LRS are released to the environment at the discharge structure via either unit's auxiliary saltwater (ASW) system (refer to Figure 11.2-9). The LRS releases are diluted in the ASW system and main circulating

water system flows. Releases require positive operator action, are continuously monitored, and are automatically isolated in the event of a high radiation alarm or a power failure.

A major source of liquid radwaste is the RCS. The bulk of these wastes are processed and retained within the CVCS, with a portion being routed to the LRS. A piping and instrumentation schematic of the CVCS is shown in Figure 3.2-8. A complete description of the CVCS is included in Section 9.3.4.

11.2.2.1.1 Equipment Drain or Closed Drain Subsystem

Closed drainage from equipment in the containment building flows to the RCDT as described in Section 9.3.3.2.1.1.

When the RCDT reaches a preset liquid level, the wastes are automatically pumped to the liquid holdup tanks (LHUTs)for processing in the CVCS. The pumps may also be manually started prior to reaching the preset level. The wastes may also be pumped to the equipment drain receiver tanks or the refueling water storage tanks (RWSTs) when required. An integrating flow meter on the reactor coolant drain pump discharge reads out on the auxiliary building control board digital system, and RCDT high and low level alarms to the main annunciator are provided.

Closed drainage from equipment in the auxiliary building is collected in the MEDT as described in Section 9.3.3.2.1.2.

When the MEDT reaches a preset liquid level, the wastes are automatically pumped to the equipment drain receiver tanks. A high level alarm function is provided.

Closed drain wastes being transferred to the equipment drain receiver tanks are routed to one of the two tanks. When that tank reaches its high level setpoint, incoming flow is automatically diverted to the second equipment drain receiver tank. The filled tanks are normally recirculated, sampled, and analyzed before further batch processing. A high and low level alarm function is provided for each tank.

11.2.2.1.2 Floor Drains and Open Drain Subsystem

Inside containment floor drain wastes are collected in the containment sumps and the reactor cavity sump as described in Section 9.3.3.2.2.1.

Integrating flow meters in the discharge lines from the reactor cavity sumps and containment sumps are provided to detect leakage from in-containment sources.

Potentially contaminated auxiliary building floor drain wastes are collected in the auxiliary building sump as described in Section 9.3.3.2.2.2.

The RHR compartments' spills collect in the RHR sumps that are normally discharged to the floor drain receivers.

When a sump has filled to a preset level, the radwastes are automatically pumped to one of two floor drain receiver tanks. When a tank has reached its high level setpoint, sump flow will automatically be diverted to the second floor drain receiver tank. The filled tank is normally recirculated, sampled, and analyzed before further batch processing. A high level alarm function is provided for each sump. A high level and low level alarm function is provided for each floor drain receiver tank.

11.2.2.1.3 Chemical Drain Subsystem

Chemical wastes are generated due to routine chemical and radiochemical sampling and analyses. Chemical wastes from both units drain by gravity to a divided chemical drain tank. The filled section is recirculated, sampled, and analyzed before discharge.

11.2.2.1.4 Laundry and Hot Shower, and Laundry/Distillate Subsystem

Laundry, hot shower, and treated CVCS liquids are generally very low in activity. The laundry and hot shower wastes are generated by laundering contaminated protective clothing and by personnel decontamination. CVCS LHUT water is routed to the LRS when reuse in the reactor cavity or spent fuel pool is not possible.

The hot shower wastes flow by gravity to one of the laundry and hot shower tanks. When one of the laundry and hot shower tanks is filled, the flow is manually diverted to the second tank. The filled tank is recirculated, sampled, and analyzed before further batch processing or discharge.

The laundry waste will normally drain to one of the laundry/distillate tanks for discharge. Treated LHUT water may be drained to one of the laundry/distillate tanks or to one of the demineralizer regenerant receiver tanks for further treatment by the LRS. When one of the laundry/distillate tanks is filled, the flow is manually diverted to the second tank. The filled tank is recirculated, sampled, and analyzed before further batch processing or discharge.

11.2.2.1.5 Demineralizer Regenerant Subsystem

The demineralizer regenerant subsystem consists of two 15,000 gallon demineralizer regenerant receivers (arranged in parallel) located adjacent to the equipment drain receivers in the auxiliary building. Originally, it was intended that regeneration wastes from the steam generator blowdown (SGBD) treatment system, deborating demineralizers, or evaporator distillate demineralizers were to be routed to these tanks, and neutralized by concentrated sulfuric acid or sodium hydroxide. The SGBD regeneration system never operated and changes in California environmental regulations halted neutralization of other regenerants in the demineralizer regenerant receivers.

The demineralizer regenerant receivers collect equipment or floor drain liquid and function as surge capacity for these subsystems. In addition, treated LHUT liquid can be drained to the demineralizer regenerant receivers for additional processing.

11.2.2.2 Liquid Radwaste System Operation

The LRS is operated on a batch basis. When a floor drain receiver, equipment drain receiver, chemical drain, laundry/distillate tank, laundry and hot shower tank, or demineralizer regenerant receiver is filled, it is isolated to prevent accumulation of additional contaminated waste. Control interlocks prevent tanks from being simultaneously filled and discharged. The tanks are normally recirculated, sampled, and analyzed to determine whether additional treatment is required. Batches of equipment and floor drains are normally processed to reduce radioactivity concentrations prior to discharge.

11.2.2.2.1 Liquid Radwaste Processing Sub System

Batches that require further treatment are processed through the radwaste media filters, ion exchangers, filters, and/or mobile liquid process systems. The radwaste media filters and ion exchangers are normally operated in series. Mobile liquid process systems may be used to augment LRS in-plant components. The mobile liquid process systems meet the requirements of the associated LRS in-plant components. Treated liquid is collected in the processed waste receivers. In addition, treated LHUT liquid can be routed to the processed waste receivers. These batches are then sampled and analyzed prior to discharge.

11.2.2.2.2 Liquid Radwaste Discharge Sub System

Batches that contain sufficiently low quantities of radioactivity to meet discharge limits are treated by filtration and discharged to the outfall of the circulating water system via the ASW discharge. Circulating water flow is verified prior to initiating a release.

Written operating procedures govern the mechanics of discharging liquid radwaste to the unrestricted area (Reference 8).

As part of the procedures, records of plant water inventories, circulating water flow rates, and radwaste batch analysis data sheets are kept to ensure that the discharges are maintained below the applicable regulatory limits.

11.2.2.3 System Design

The components of the LRS are listed in Table 11.2-10. A similar listing for the CVCS is provided in Table 9.3-6. Included are equipment size or capacity, applicable flowrate, material of construction, and design temperature and pressure.

Applicable codes and standards for process equipment used in the LRS are presented in Table 3.2-3. Equivalent data for the CVCS are shown in Table 9.3-5.

The seismic and quality group classifications for these components and associated piping are also described in Section 3.2.2. Radiological monitoring is discussed in detail in Section 11.4.

The routing of LRS piping is strictly controlled by the design engineers and is specified on the piping drawings. Consequently, there are field-fabricated lines, but no field-routed lines. Lines that are field-fabricated have the following characteristics:

(1) the lines are routed to minimize operator dose, all deviations from the specified routing require prior approval of the piping engineer, and as-built drawings are made showing final dimensions,

(2) the sizes, schedules, materials, and code classes are specified on the piping drawings,

(3) the field-fabricated piping is similar to shop-fabricated piping in design, quality assurance procedures, and inspection,

(4) pipe hanger placement is not specified on piping drawings, but a maximum spacing between hangers is specified as a design standard, and

(5) a design review is conducted in accordance with the quality assurance procedures described in the Diablo Canyon Quality Assurance Program Description in the same manner as for shop-fabricated piping.

11.2.2.4 Performance Data

LRS process equipment is evaluated for its effectiveness in removing radioactivity on a batch basis. Approved plant procedures govern concentrations of activity that must be processed and limits the activity in any individual batch prior to release. When the process equipment removal efficiency no longer produces water to meet these requirements, the filters, media, or ion exchange resin is replaced.

11.2.2.5 Plant Releases

11.2.2.5.1 Current Operational Releases

Refer to Section 11.2.3.13.1 for a discussion of current operational releases from the LRS.

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11.2.2.5.2 Pre-Operational Estimated Release Evaluation

The following information provides historical perspective demonstrating that DCPP's anticipated operation would result in releases within applicable regulatory limits. This information does not necessarily reflect current operating conditions or practices.

The estimated releases based on the original design were calculated with the EMERALD-NORMAL computer program, supplemented by hand calculations. Two process flow diagrams of the LRS are presented to depict the modes of operation for the two cases used for radiation release analysis: the Design Basis Case, and the Normal Operation Case. The flow diagram for the Design Base Case (refer to Figure 11.2-2) shows the waste stream sources and processing route of liquid radwaste for the assumptions of this case. The numbered waste input streams have their annual flow and isotopic spectra listed in Table 11.2-5. The numbered process streams are listed in Table 11.2-8, along with flows and isotopic concentrations. The flow diagram for the Normal Operation Case is shown in Figure 11.2-3. Flows and isotopic parameters for this case are listed in Tables 11.2-5 and 11.2-9.

The detailed assumptions used in calculation of estimated activity release from the LRS are listed in Table 11.2-1. Tables 11.2-3 and 11.2-4 list the activity concentration spectrum for the input sources. A tabulation of the estimated annual release by isotope is provided in Tables 11.2-14 and 11.2-15 for the two cases.

For the Normal Operation Case with anticipated operational occurrences, as defined in Regulatory Guide 1.112, April 1976 (Reference 7), an additional release of 0.15 Ci/yr per reactor with the same isotopic makeup as in Table 11.2-15 was assumed. This annual release is provided in Table 11.2-18 for one unit. Since an average of 2 days holdup time is available upstream of both the boric acid and waste treatment systems, no additional release, assuming the systems are out of service, was postulated.

The detailed assumptions used in the calculation of estimated activity release from the CVCS to the LRS are listed in Table 11.2-2. A tabulation of the isotopic flows through the system components is provided in Tables 11.2-6 and 11.2-7, and the estimated annual releases to the LRS are provided in Tables 11.2-8 and 11.2-9 for the Design Basis and Normal Operation Cases.

For purposes of estimating annual average plant radionuclide releases, approximately two-thirds of the boric acid evaporator distillate produced was assumed to be recycled to the primary water storage tank, and the rest routed to the LRS. This release (350,000 gallons/year for each unit) is primarily for tritium control purposes.

A list of assumed decay times for system tanks is provided in Table 11.2-13. Demineralizer DFs are listed in Table 11.1-15.

During conditions corresponding to the Design Basis Case, which assumes a 1 percent fuel defect level with negligible primary system leakage, the floor drain wastes will have an approximate activity level of 0.0015 mCi/cc. These wastes are normally filtered and released to the main condenser circulating water discharge tunnel.

During conditions corresponding to the Normal Operation Case, which assumes a 0.12 percent fuel defect level with primary system leakage, the activity level of the floor drain wastes is approximately 0.1 mCi/cc. Under this operating condition, the wastes would be processed through the filters and/or ion exchangers.

The chemical drain wastes would have an approximate activity level of 9×10^{-4} μCi/cc during conditions corresponding to the Design Basis Case. During conditions corresponding to the Normal Operation Case, the wastes would be approximately 1×10^{-4} μCi/cc.

During conditions corresponding to the assumptions of Design Basis Case, the approximate activity level in the processed effluent from the equipment drain receiver tanks would be 0.007 μCi/cc. The activity level of the processed effluent would be 0.002 μCi/cc during conditions corresponding to the Normal Operation Case.

The SGBD system is depicted on two process flow diagrams that show the two paths of operation of the system and the assumptions used in the radiation release analyses. Figure 11.2-4 shows the discharge path with blowdown directed to the blowdown tank and the circulating water discharge structure. Figure 11.2-5 shows the recycle path with blowdown directed to the blowdown treatment system. For the Design Basis Case, it was assumed that the blowdown is processed via the discharge path because this case assumes no primary-to-secondary leakage and no activity is present in the secondary system. For the Normal Operation Case, it was assumed that the blowdown is processed only via the recycle path and the discharge path is isolated since the assumptions for this case result in significant levels of activity in the secondary system. Table 11.2-16 shows the total annual volumetric flows for one unit and the activity concentrations corresponding to the alphabetically labeled process streams in these two figures for the Normal Operation Case.

The estimated annual activity releases from the turbine building sump for one unit are listed in Tables 11.2-14 and 11.2-15 for the Design Basis Case and the Normal Operation Case, respectively. Table 11.2-17 lists the total annual estimated volumes released from the LRS for two units for both cases and includes the turbine building sump discharge.

The tritium concentration in the RCS is controlled by bleeding coolant from the RCS to the LRS via the CVCS (refer to Section 9.3.4). Other losses from the RCS are through radioactive decay and mixing of the primary coolant with refueling cavity water during refueling. The calculation of the tritium concentration in the various plant water sources was based on the following assumptions:

(1) Tritium activity in the RCS is provided in Table 11.1-22 for the anticipated operational occurrences case.

(2) The total volume of water released from the RCS for the analysis of the Design Basis Case and the anticipated operational occurrences case is 350,000 gallons per year per unit.

(3) The temperature of the spent fuel pool is constant at 100°F throughout the life of the plant except during refueling when the temperature rises to 125°F. The air above the spent fuel pool is 80°F at 70 percent relative humidity.

(4) The water temperature of the refueling tunnel, when filled with borated water from the RWST, is 125°F. The air above the refueling tunnel is 80°F at 70 percent relative humidity. Mixing with 15 percent of the water from the spent fuel pool occurs during each refueling period.

(5) During refueling, the containment purge fans are in continuous operation.

(6) No water is lost from the spent fuel pool or RWST, except through evaporation.

(7) Evaporation from the spent fuel pool is calculated by the equation (Reference 3):

$$\frac{V}{A} = \frac{95.0 + 0.425\,V_a}{W}\,(p_w - p_a) \qquad (11.2\text{-}1)$$

where:

V = *loss rate from the water volume, lbm/hr*
A = *exposed area of the water volume, ft^2*
W = *latent heat of vaporization of the water, Btu/lbm*
V_a = *velocity of the air across the surface of the water, ft/min*
p_w = *vapor pressure of the water, in. of Hg*
p_a = *vapor pressure of the water in air, in. of Hg*

The important parameters for evaluating tritium losses and distribution in the plant are provided in Table 11.2-11.

The resulting tritium concentrations in various plant areas are shown in Figures 11.2-6 through 11.2-8. It should be noted that the tritium concentrations plotted in these figures are yearly averages or, in the case of airborne concentrations during refueling, are averages during the refueling periods, based on a 1 year fuel cycle with 11 months operation and 1 month refueling. The tritium management procedures are designed to ensure that tritium airborne concentrations in all normally occupied plant areas are

significantly below levels required to ensure compliance with 10 CFR Part 20, Subparts C and D. The restriction of primary coolant tritium concentration by releasing demineralized water from the RCS is intended to reduce in-plant personnel radiation dose.

The above analysis was performed to demonstrate that DCPP "normal operation" radiological effluents meet the criteria of 10 CFR Part 50, Appendix I. This analysis is conservative and bounds DCPP current operation. The analysis was performed prior to plant operation and will be modified only if a design change or operational change rendered it non-conservative.

11.2.2.6 Dilution Factors

11.2.2.6.1 Current Operational Doses

The main condenser cooling water and the ASW system of Unit 1 and Unit 2 are used for dilution of released liquid radwastes. The dilution flow available per unit is 862,000 gallons per minute. Refer to Section 10.4.5 for a description of the circulating water system and Section 9.2.7 for a description of the ASW system.

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11.2.2.6.2 Pre-Operational Dose Factors

The pre-operational estimated activity concentrations listed in Tables 11.2-21 through 11.2-23 are for one unit's turbine building wastes and LRS diluted with one unit's annual circulating water flow. It should be noted that this method of calculation yields a maximum annual average concentration within the circulating water discharge structure.

For the calculation of all internal and external doses from liquid effluent releases, a dilution factor of 5 was used from the point of release to the organism or dose point. This value was taken from Table A-1 of Regulatory Guide 1.109, March 1976 (Reference 5) as a conservative estimate of the dilution at the edge of the initial mixing zone for a high-velocity surface discharge. This factor is considered very conservative; experimental dye studies (Reference 2) have determined that the average dilution factor for fish, invertebrate, and sediment exposure to liquid effluents is 100. The dilution factor of 5 was confirmed by the NRC staff in the Final Environmental Statement for DCPP Unit 1 and Unit 2 (Reference 4).

11.2.2.7 Calculated Doses

11.2.2.7.1 Current Operation Doses

Refer to Sections 11.2.3.15, 11.2.3.19, and 11.2.3.20 for discussions of current operational doses from the LRS.

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11.2.2.7.2 Pre-Operation Estimated Doses

Pre-operational radiation dose calculations are presented in Tables 11.2-24 through 11.2-26 for the Design Basis Case, the Normal Operation Case, and the Normal Operation Case with anticipated operational occurrences, respectively. These tables list the doses from one unit. The dose via water pathways was calculated with the EMERALD-NORMAL program, which uses liquid dose models and assumptions based on Regulatory Guide 1.109, March 1976.

Pre-operational calculations included direct exposures through contact with water by swimming or by exposures in shoreline areas where minute quantities of radioactivity may be deposited.

The usage factor for fish and invertebrate consumption and sediment exposure time were taken from Regulatory Guide 1.109, March 1976, as were the bioaccumulation factors for fish, invertebrates, and plants. The complete set of bioaccumulation factors used is listed in Table 11.2-20. A list of effluent concentrations after dilution is provided in Tables 11.2-21 through 11.2-23.

The individual doses from fish consumption were based on rockfish caught and eaten by a sport fisherman, with a one day delay between the time of catch and consumption. The individual doses from invertebrate consumption were based on abalone, caught non-commercially and eaten with a one day delay between the time of catch and consumption. The possible doses from swimming or boating were based on the exposure periods listed in Regulatory Guide 1.109, March 1976. A summary of the dose assumptions for liquid pathways exposures is provided in Table 11.2-19.

On the basis of the calculated estimates of radiation dose presented in Tables 11.2-24 through 11.2-26, it was concluded that under normal conditions, including the consideration of anticipated operational occurrences, the potential dose from liquid effluents from DCPP Unit 1 and Unit 2 would be well within the dose limits specified in 10 CFR Part 50, Appendix I.

11.2.3 SAFETY EVALUATION

11.2.3.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portion of the LRS is designed to perform its safety functions under the effects of earthquakes (refer to Section 3.7), winds and tornadoes (refer to Section 3.3), floods and tsunamis (refer to Section 3.4), and external missiles (refer to Section 3.5).

11.2.3.2 General Design Criterion 3, 1971 – Fire Protection

The PG&E Design Class I LRS CIVs are designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

11.2.3.3 General Design Criterion 4, 1967 – Sharing of Systems

Portions of the LRS outside containment are shared by Unit 1 and Unit 2. None of the LRS performs a safety function for either unit; therefore the sharing does not impair safety on either unit.

11.2.3.4 General Design Criterion 11, 1967 – Control Room

The PG&E Design Class I LRS CIVs are provided with controls in the main control room consisting of control switches and position indication on the monitor light panels (refer to Section 6.1.2). If access to the control room is lost, these valves can be monitored and operated locally in the auxiliary building.

LRS radiation indication and high radiation alarms are provided in the main control room (refer to Section 11.2.3.6).

Signals from the RHR sump levels, RCDT level, containment structure sump levels, reactor cavity sump level, and turbine building sump level are provided to common system annunciator locations on the main control board to indicate abnormal conditions (refer to Section 11.2.3.5).

11.2.3.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The LRS is controlled from the auxiliary building control board digital system and the main control room panels where the following system instruments provide signals to alarm and warn of abnormal conditions.

(1) Containment Structure Sumps and Reactor Cavity Sump

(a) Three level switches are provided; one switch for high level alarm to the main annunciator and two switches that are spared in place

(b) Level indicators are provided for both containment sumps and for the reactor cavity sump

(c) An integrating flow meter on the containment sump pumps discharge line

(2) RCDT

(a) Level switches to initiate automatic pump starts on high level

(b) Pump trips for low level

(c) High and low level alarms to the main annunciator

(d) Local and remote level indication and a level controller to maintain a set level

(e) An integrating flow meter on the RCDT pumps discharge line

(3) MEDT and Auxiliary Building Sump

(a) Level indicators are provided for both the MEDT and the auxiliary building sump

(4) Equipment Drain Receivers and Floor Drain Receivers

(a) Level switches for high and low level alarms to the main annunciator

(b) Pump trips for low level

(c) High level switches to actuate three-way control valves to transfer liquids from one tank to another

(d) Level indicators to provide local and remote indication

(5) Chemical Drain and Laundry Drain Tanks

(a) Level switches for high and low alarm to the main annunciator

(b) Level switches for transfer control

(c) Level indicators for local and remote indication

Refer to Section 11.2.3.6 for radiation monitoring instrumentation.

11.2.3.6 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

Batch preparation and sampling is used to document LRS discharge to the environment. In addition, instrumentation is provided in the control room to monitor LRS radioactive releases.

The liquid radwaste effluent monitor (R-18) continuously monitors discharges from the LRS. A high-radiation signal initiates automatic valve closure and flow is diverted to the equipment drain receiver tanks.

The SGBD sample monitor (R-19) monitors the liquid phase of the secondary side of the SG for radioactivity. A high-radiation signal causes the isolation valves in the blowdown and sample lines, acting with the valve in the line from the blowdown tank to the discharge structure, to close and the blowdown tank liquid effluent to be diverted to the equipment drain receiver tank.

The SGBD tank liquid effluent monitor (R-23) continuously measures liquid effluent from the SGBD tank. A high-radiation signal isolates the blowdown discharge, and diverts blowdown tank liquid effluent to the equipment drain receiver tank.

Refer to Section 11.4.2.1.2.1 and Table 11.4-1 for additional information.

11.2.3.7 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the ESF containment isolation portion of the LRS from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures, respectively are discussed in Sections 3.5, 3.6, and 6.2.4.

11.2.3.8 General Design Criterion 49, 1967 – Containment Design Basis

The LRS containment penetrations, including the system piping and valves required for containment isolation, are designed and analyzed to withstand the pressures and temperatures that could result from a LOCA without exceeding containment design leakage rates (refer to Sections 3.8.2.1.1.3 and 11.2.4).

11.2.3.9 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The LRS CIVs required for containment closure are periodically tested for operability. Testing of the components required for the containment isolation system is discussed in Section 6.2.4.

11.2.3.10 General Design Criterion 56, 1971 – Primary Containment Isolation

The PG&E Design Class I containment penetrations for the LRS are penetration group A or E (refer to Section 6.2.4). A description of the isolation valves and piping for each penetration is provided in Table 6.2-39. Group A and group E piping comply with the requirements of GDC 56, 1971.

11.2.3.11 General Design Criterion 68, 1967 – Fuel and Waste Storage Radiation Shielding

Radiation shielding in the auxiliary building protects personnel working near waste storage facilities from doses in excess of 10 CFR Part 20 limits (refer to Section 12.1.7.3).

11.2.3.12 General Design Criterion 69, 1967 – Protection Against Radioactivity Release from Spent Fuel and Waste Storage

The PG&E Design Class I LRS CIVs are designed to ensure that the containment atmosphere will be isolated in the event of a release of radioactive material inside containment. The isolation time limits specified ensure that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses of a LOCA (refer to Section 6.2.4).

In accordance with UFSAR Section 3.2.2.1.2, fluid systems and fluid system components that contain or may contain radioactive material, but whose failure would not result in calculated potential exposures in excess of 0.5 rem whole body (or its equivalent to parts of the body) at the site boundary, may be classified as PG&E Design Class II.

As part of the acceptability of tanks that contain liquid waste that have a PG&E Design Class II classification, an evaluation was performed of the dose consequences at the site boundary of a Liquid Holdup Tank (LHUT) failure accident.

Radioactive liquid waste holdup tanks are used as part of the chemical and volume control system (CVCS) to collect and permit decay of radioactive liquids drawn from the reactor primary coolant for reactivity control. The CVCS is described in detail in Section 9.3.4.

Five liquid holdup tanks are provided for the two units to afford operating flexibility and allow one or more tanks to be isolated from the rest of the system for extended periods of time. The liquid processed through the holdup tanks contains dissolved fission and activation products, as well as radioactive noble gases mixed with nitrogen cover gas used in the tanks.

The liquid holdup tanks are located in vaults which are Design Class I structures, so that in the event of a rupture or spill all liquids are retained in the vaults. The volume of holdup tank vaults is sufficient to contain the full contents of the holdup tank without spillage from the vaults. Any gases released from the liquid holdup tanks are collected by the auxiliary building ventilation system and discharged via the auxiliary building vent.

In the evaluation of the liquid waste holdup tank rupture accident, the following fission product accumulation and release assumptions are used for the design basis case.

(1) The reactor has been operating at full power with 1 percent defective fuel for an equilibrium core cycle.

(2) A liquid holdup tank has been filled with primary coolant at a rate of 132 gpm, with credit for decay as the tank is filling.

(3) The failure occurs immediately upon completion of the liquid transfer, releasing the entire contents of the tank to the LHUT vault. The assumption of the release of the contents of only a single tank is based on a design that allows all liquid holdup tanks to be isolated from each other when they are in use.

(4) All of the noble gases and varying amounts of the iodines are released, unfiltered, from the LHUT vault to the environment, via the plant vent. The release is treated as a ground level release.

(5) All of the noble gases are exhausted to the environment over a 2-hour time period, or at the rate of the LHUT ventilation exhaust flow, whichever results in a more rapid release rate.

(6) The iodine concentration in the LHUT vault air space and ventilation exhaust flow is based on an equilibrium iodine distribution balance between the spilled LHUT liquid and the air, and is dependent on the temperature, pH, and concentration of iodine in the spilled fluid. The iodines are released to the environment as they evolve out of the spilled liquid at the rate of the LHUT vault ventilation exhaust flow over a 30-day period. No liquids escape from the vaults during the accident.

Computer code RADTRAD 3.03 (Reference 9) is used to calculate the whole body dose resulting from the LHUT rupture using the semi-infinite cloud submersion model, and using air submersion dose coefficients provided in Table III.1 of Federal Guidance Report 12 (Reference 10) and inhalation dose conversion factors provided in Table 2.1 of Federal Guidance Report 11 (Reference 11). The reactor coolant isotopic concentrations based on 1% fuel defects are provided in Table 11.1-11A. Atmospheric dispersion factors used in the analysis are given in Table 2.3-145. The dose consequences at both the Exclusion Area Boundary (EAB) and the Low Population Zone (LPZ) due to airborne releases following a LHUT Rupture are estimated to be below the acceptance criteria of 0.5 rem whole body and 3 rem thyroid.

A similar assessment was also performed for the Volume Control Tank (VCT) rupture. Though the VCT tank is PG&E Design Class I, the dose consequence analysis for the VCT tank rupture conservatively uses an acceptance criteria, the commitment provided

in DCPP UFSAR Section 3.2.2.1.2 for acceptability of dose consequences at the site boundary for a failure in a PG&E Design Class II system.

The VCT is used as part of the CVCS to collect the excess water released from the RCS during modes 1 through 6, which is not accommodated by the pressurizer. For a complete description of the CVCS and the VCT in all modes of operation refer to Section 9.3.4.

The liquid processed through the volume control tank contains dissolved fission and activation products, as well as undissolved radioactive noble gases. A spray nozzle located inside the tank on the inlet line strips part of the nobles gases from the incoming liquid, and these gases are retained in the VCT vapor space. In addition, an overpressure of hydrogen cover gas is provided for the tank to control the hydrogen concentration in the reactor coolant.

The VCT is located in a vault which is a PG&E Design Class I structure, so that in the event of a rupture or spill all liquids are retained in the vault. The volume of the tank vault is sufficient to contain the full contents of the tank without spillage from the vault. Any gases released from the VCT are collected by the auxiliary building ventilation system and discharged via the auxiliary building vent.

In the evaluation of the VCT rupture accident, the following fission product accumulation and release assumptions are used for the design basis case:

(1) The reactor has been operating at full power with 1 percent defective fuel for an equilibrium core cycle.

(2) The volume control tank contains its maximum equilibrium inventory of radioactivity at the time of the accident. The failure of the tank releases the entire tank contents to the VCT vault.

(3) All of the noble gases and varying amounts of the iodines are released, unfiltered, from the VCT vault to the environment, via the plant vent. The release is treated as a ground level release.

(4) All of the noble gases are exhausted to the environment over a 2-hour time period, or at the rate of the VCT ventilation exhaust flow, whichever results in a more rapid release rate.

(5) The iodine concentration in the VCT vault air space and ventilation exhaust flow is based on an equilibrium iodine distribution balance between the spilled VCT liquid and the air, and is dependent on the temperature, pH, and concentration of iodine in the spilled fluid. The iodines are released to the environment as they evolve out of the spilled liquid at the rate of the VCT vault ventilation exhaust flow over a 30-day period. No liquids escape from the vaults during the accident.

Computer code RADTRAD 3.03 (Reference 9) is used to calculate the whole body dose resulting from the VCT rupture using the semi-infinite cloud submersion model, and using air submersion dose coefficients provided in Table III.1 of Federal Guidance Report 12 (Reference 10) and inhalation dose conversion factors provided in Table 2.1 of Federal Guidance Report 11 (Reference 11). The reactor coolant isotopic concentrations based on 1% fuel defects are provided in Table 11.1-11A. Atmospheric dispersion factors used in the analysis are given in Table 2.3-145. The dose consequences at both the EAB and the LPZ due to airborne releases following a VCT Rupture are estimated to be below the acceptance criteria of 0.5 rem whole body and 3 rem thyroid.

11.2.3.13 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

11.2.3.13.1 Current Operational Releases

The actual releases from the plant site are summarized in the Annual Radioactive Effluent Release Report to the NRC. The report summarizes the liquid, gaseous, and solid radwastes that were released from the site for the past year and provides the calculated dose to the public, which is calculated using the offsite dose calculation manual (ODCM). Releases from DCPP have routinely demonstrated compliance within the general provisions of, and dose limits established in, 10 CFR Part 20 and 10 CFR Part 50.

11.2.3.13.2 Release Points

The four major release pathways are as follows:

(1) from the LRS to the discharge structure via either the Unit 1 or Unit 2 ASW discharge lines (refer to Figures 11.2-2, 11.2-3, and 11.2-9);

(2) from the Unit 1 or Unit 2 SGBD:

  (a) via the SGBD tanks to the discharge structure via the respective unit's discharge conduit (refer to Figures 11.2-4 and 11.2-9);

  (b) via diversion from the SGBD recycle line to the main condenser circulating water discharge.

(3) from the turbine building sump to the discharge structure via either the Unit 1 or Unit 2 turbine-generator building sump discharge line (refer to Figure 11.2-5).

(4) from the condensate demineralizer regenerant system via either the high conductivity tank (HCT) or the low conductivity tank (LCT).

Other minor discharge pathways exist. Those identified pathways, monitored radiologically, are included in the ODCM and/or implementing procedures.

The LRS is described in Section 11.2.2. The other three main discharge pathways are described in Sections 11.2.3.13.2.1 through 11.2.3.13.2.3 below.

11.2.3.13.2.1 Turbine Building Drain System

The concentration of radioactivity in the turbine building drains is expected to be low, even in the event of significant primary-to-secondary SG leakage. The radiation level and flow of liquid from the turbine building drains are monitored at the oily water separator to verify that there are no unaccounted for or unexpected releases from the turbine building drains. If significant radioactivity is detected coming from the turbine building drains, the discharge can be routed for evaluation and disposition. The monitoring system is in conformance with Regulatory Guide 1.21, Revision 1 (Reference 8) and General Design Criterion 4, 1967.

Turbine building sump wastes are normally released to the environment via each unit's circulating water discharge structure (refer to Figure 11.2-9). A detailed piping and instrumentation schematic of the turbine building sump systems is shown in Figure 3.2-27.

11.2.3.13.2.2 Steam Generator Blowdown System

The SGBD system for each unit provides two processing paths. One path discharges blowdown flow to the environment via the SGBD tank and the circulating water discharge tunnel. The other path recycles blowdown flow to the main condenser circulating water discharge via the blowdown treatment system and/or the blowdown treatment bypass line. The recycle path can discharge a portion of blowdown flow to the discharge tunnel. Blowdown flow for each unit can be directed to either blowdown path alone, or to both paths simultaneously.

During plant operation, SG water collects suspended and dissolved solids that are brought in by the feedwater. Water must be blown down from the SGs to maintain low solids concentration for efficient operation (Reference 1).

The blowdown flow may be directed to either or both the discharge and recycle paths for a total blowdown flow of approximately 400 gpm per unit to maintain water chemistry and low solids concentration. If activity is detected at preset levels in the blowdown system, the blowdown will be automatically isolated from the discharge path and blowdown flow will be limited to the recycle path at up to 150 gpm per unit.

Activity in the blowdown that is discharged to the circulating water tunnel is continuously recorded by R-23. In the event that activity is released via the SGBD tank vent, the

quantity is calculated based on the continuous readings recorded by R-19. Activity released to the environment is calculated as described in the ODCM.

The SGBD system in the recycle configuration is typically used to recover blowdown for return to the condensate system. The normal flow path for blowdown recycling is through the flash tank to the heat exchanger and to the main condenser. A prefilter and a mixed bed demineralizer, which are normally bypassed, are available as part of the system for use in the event of a primary-to-secondary leak. When used, the prefilter removes both radioactive and non-radioactive suspended solids and the mixed bed demineralizer removes both radioactive and non-radioactive dissolved anions and cations. Effluent from the filter and demineralizer set could be returned through a resin trap filter to the condensate. The mixed bed resin is replaced when exhausted.

A description of the design bases, on-line monitoring, isolation criteria, design codes, system description, safety evaluation, inspection, and testing of the SGBD system is provided in Section 10.4.8.

11.2.3.13.2.3 Condensate Demineralizer Regenerant Solution

The condensate demineralizer regenerant solution is the waste created from regenerating anion and cation resin used to clean water in the main condenser. The resin is regenerated with sulfuric acid and sodium hydroxide. The HCT normally receives the initial rinse water that may contain most of the acid, caustic, and contaminants removed from the resin. The LCT normally receives cleaner water used as a final rinse of the resin. The concentration of radioactivity in both the HCT and the LCT is typically not detected, unless blowdown is isolated or if a primary-to-secondary leak is present.

The HCT is discharged as a discrete batch. The tank pH is adjusted within an acceptable range consistent with national pollutant discharge elimination system (NPDES) and other state requirements. The tank is then recirculated, sampled and analyzed prior to issuing a discharge permit.

The LCT is normally discharged as a discrete batch. The tank is recirculated, sampled and analyzed prior to issuing a discharge permit. In some cases, the LCT is allowed to discharge as a continuous discharge for a period of time. In this configuration, more than one sample is taken during the discharge period to ensure that the discharge remains within limits.

11.2.3.13.2.4 Typical Volumes Released

The following tables provide an approximation of routine plant discharge volumes. These are not limiting volumes. Volumes can change as defined in the site procedures as long as 10 CFR Part 20, and 10 CFR Part 50, Appendix I criteria are maintained.

Typical LRS Annual Release Volumes:

Source	UFSAR Section	Nominal Quantity (gallons)
Equipment Drains	11.2.2.1.1	400,000 to 500,000
Floor Drains	11.2.2.1.2	200,000 to 400,000
Treated CVCS	11.2.2.1; Table 11.2-1 #27	470,000 to 750,000
Laundry & Hot Shower Drains	11.2.2.1.4	50,000 to 250,000
Chemical Drains	11.2.2.1.3	13,000 to 30,000
Sub Total		1.1 M to 1.9 M

Typical Plant Annual Release Volumes:

Pathways	Nominal Quantity (gallons)
LRS	1.1 M to 1.9 M
U-1 SGBD	30M
U-2 SGBD	30M
Turbine Bldg Sump	15M
U-1 Condensate Demineralizer Regenerant Tanks	5M
U-2 Condensate Demineralizer Regenerant Tanks	5M

Only trace amounts of activity are in the pathways that are not LRS.

11.2.3.14 Liquid Radwaste System Safety Function Requirements

(1) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the inside containment PG&E Design Class I portion of the LRS from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

11.2.3.15 10 CFR Part 20 – Standards for Protection Against Radiation

Occupational doses to plant personnel from the LRS are maintained as low as is reasonably achievable (ALARA) by:

(1) Shielding in locations that contain LRS piping and equipment (refer to Section 12.1.2)

(2) Heating, ventilation and air-conditioning (HVAC) systems that direct air flows for controlled discharge and provide filtration of radioactive materials (refer to Section 12.2.2)

(3) Monitoring and alarming of potentially radioactive releases from the LRS (refer to Section 11.2.3.6)

(4) Administrative controls for working in areas of potentially high radioactivity (refer to Section 5 of the Diablo Canyon Quality Assurance Program Description).

Current operational offsite doses are calculated in accordance with the ODCM contained in site-approved procedures in accordance with 10 CFR Part 20 and appropriate U.S. Nuclear Regulatory Commission (NRC) regulatory guides.

The only significant pathways to man from liquid radwastes are through food chains involving marine organisms. Liquid releases have been examined for the possible effects on man and on aquatic organisms. For man, the pathways considered are the intake of aquatic foods that were grown within the radiological influence of the plant.

Technical Specifications require programs for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents within the regulatory limits of 10 CFR Part 20. Doses are reported on quarterly and annual bases. The programs are implemented by plant procedures, and include remedial actions to be taken whenever the program limits are exceeded.

11.2.3.16 10 CFR 50.49 – Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

The LRS components required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure that they perform their safety functions. These components include solenoid and air operated valves for the CIVs, limit switches for the CIVs, sump level transmitters, and temperature elements and are listed on the EQ Master List.

Section 3.11 describes the DCPP EQ Program and the requirements for the environmental design of electrical and related mechanical equipment.

11.2.3.17 10 CFR 50.55a(f) – Inservice Testing Requirements

The inservice testing (IST) requirements for the LRS are contained in the IST Program Plan.

11.2.3.18 10 CFR 50.55a(g) – Inservice Inspection Requirements

The inservice inspection (ISI) requirements for the LRS are contained in the DCPP ISI Program Plan.

11.2.3.19 10 CFR Part 50, Appendix I – Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion "As Low as is Reasonably Achievable" for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents

The LRS maintains control over the releases of radioactive materials in effluents by:

(1) Providing appropriate holdup capacity for retention of liquid effluents containing radioactive material (refer to Section 11.2.2.5.2)

(2) Continuously monitoring the LRS for leakage (refer to Section 11.2.2.1)

(3) Sampling all discharges prior to release to the environment and using acceptable dilution factors (refer to Section 11.2.2.1)

(4) Processing batches that require further treatment through the radwaste media filters, ion exchangers, filters, and/or mobile liquid process systems (refer to Section 11.2.2.2.1)

Technical Specifications require programs for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents within the regulatory limits of 10 CFR Part 50, Appendix I. Doses are reported on quarterly and annual bases. The programs are implemented by plant procedures, and include remedial actions to be taken whenever the program limits are exceeded.

11.2.3.20 40 CFR Part 190 – Environmental Radiation Protection Standards for Nuclear Power Operations

Current operational doses from all sources to members of the public are summarized in Annual Radioactive Effluent Release Reports and are demonstrated to be within the limits specified by 40 CFR Part 190, as implemented under 10 CFR 20.1301(e) (refer to Section 11.2.3.13.1).

11.2.3.21 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

LRS post-accident instrumentation for meeting Regulatory Guide 1.97, Revision 3, requirements consist of CIV position and containment sump wide-range water level (refer to Table 7.5-6).

11.2.3.22 Regulatory Guide 1.143, Revision 1, October 1979 – Design Guidance for Radioactive Waste Management Structures, Systems, and Components Installed In Light-Water-Cooled Nuclear Power Plants

The LRS is PG&E Design Class II with the exception of the containment penetrations and associated valves which are PG&E Design Class I (refer to Section 11.2).

The PG&E Design Class II LRS equipment and piping that are applicable to Regulatory Guide 1.143, Revision 1 are designated PG&E QA Class R, PG&E Piping Symbol H.

11.2.3.23 NUREG-0737 (Item II.F.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident Monitoring Instrumentation:

Position (5) – Continuous instrumentation to monitor containment sump wide-range water level is provided in the control room (refer to Section 7.5.2.1.3 and Figures 7.5-1 and 7.5-1B). Instrument ranges and accuracies are provided in Table 7.5-4.

11.2.3.24 Generic Letter 96-06, September 1996 – Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions

Valves FCV-500 and FCV-253, the inboard CIVs for penetrations 49 and 50, respectively, are installed with a hole drilled through the ball.

These ball valves have a hollow ball that rotates between two valve seats. When the valve sees pressure, the ball is pushed into the valve away from the first valve seat and forms a tight seal against the second valve seat.

The hole drilled through the ball allows for unidirectional pressure relief (one end of the hole sees the environment inside the pipe while the other end of the hole sees the inside of the valve body). This ensures that the valves meet the requirements of Generic Letter 96-06, September 1996.

11.2.4 TESTS AND INSPECTIONS

Tests and inspections of the LRS are done in accordance with plant procedures.

11.2.5 INSTRUMENTATION APPLICATIONS

Refer to Section 11.2.3.5 for a discussion of the instrumentation requirements and controls for the LRS.

11.2.6 REFERENCES

1. A.B. Sisson, et al., Evaluation for Removal of Radionuclides from PWR Steam Generator Blowdowns, International Water Conference, November 2, 1971.

2. Preliminary Safety Analysis Report, Nuclear Unit Number 2, Diablo Canyon Site, Pacific Gas and Electric Company, Docket Number 50-323.

3. Handbook of Fan Engineering, 6th Ed., Buffalo Forge Company.

4. Diablo Canyon Final Environmental Statement, U.S. Atomic Energy Commission, May 1973, Docket Numbers 50-275 and 50-323.

5. Regulatory Guide 1.109, Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I, USNRC, March 1976.

6. EMERALD-NORMAL, a Program for the Calculation of Activity Releases and Potential Doses from the Normal Operation of a Pressurized Water Reactor Plant, Revision 2, Pacific Gas and Electric Company, July 1976.

7. Regulatory Guide 1.112, Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Light-Water Cooled Power Reactors, USNRC, April 1976.

8. Regulatory Guide 1.21, Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants, Revision 1, USNRC, June 1974.

9. RADTRAD 3.03 (GUI Mode Version), A Simplified Model for RADionuclide Transport and Removal And Dose Estimation, NUREG/CR-6604, Users' Guide – Supplement 2, October 2002.

10. K.F. Eckerman and J.C. Ryman, External Exposure to Radionuclides in Air, Water, and Soil, Federal Guidance Report 12, EPA-402-R-93-081, Environmental Protection Agency, 1993.

11. K.F. Eckerman et. al., Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion, Federal Guidance Report 11, EPA-520/1-88-020, Environmental Protection Agency, 1988.

11.2.7 REFERENCES DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

11.3 GASEOUS RADWASTE SYSTEM

The GRS provides controlled handling and disposal of gaseous radwastes generated during plant operation. The system is designed to minimize dose to plant personnel and the general public in accordance with applicable regulations.

The GRS, including the gas analyzer package, is designed and fabricated as PG&E Design Class II. The equipment and piping code classifications are listed in Table 3.2-3.

11.3.1 DESIGN BASES

11.3.1.1 General Design Criterion 2, 1967 – Performance Standards

The GRS is designed to withstand the effects of, or is protected against, the Design Earthquake (DE).

11.3.1.2 General Design Criterion 3, 1971 – Fire Protection

The GRS is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

11.3.1.3 General Design Criterion 4, 1967 – Sharing of Systems

The GRS is not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

11.3.1.4 General Design Criterion 11, 1967 – Control Room

The GRS is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room or from an alternate location if control room access is lost due to fire or other causes.

11.3.1.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

Instrumentation and controls are provided as required to monitor and maintain the GRS variables within prescribed operating ranges.

11.3.1.6 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The GRS is designed to provide means for monitoring the facility effluent discharge paths and the facility environs for radioactivity that could be released from normal operations, from anticipated transients, and from accident conditions.

11.3.1.7 General Design Criterion 18, 1967 – Monitoring Fuel and Waste Storage

The GRS is provided with monitoring and alarm instrumentation for conditions that might contribute to radiation exposures.

11.3.1.8 General Design Criterion 68, 1967 – Fuel and Waste Storage Radiation Shielding

The GRS is designed to provide shielding for radiation protection to meet the requirements of 10 CFR Part 20.

11.3.1.9 General Design Criterion 69, 1967 – Protection Against Radioactivity Release from Spent Fuel and Waste Storage

The GRS is designed to provide containment of radioactive releases to the public environs as a result of an accident.

11.3.1.10 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The GRS includes those means necessary to maintain control over the plant gaseous radioactive effluents during normal operation, including anticipated operational occurrences.

11.3.1.11 10 CFR Part 20 – Standards for Protection Against Radiation

The GRS supports the protection of personnel from radiation sources such that occupational doses and doses to individual members of the public are maintained below the annual limits prescribed in 10 CFR Part 20.

11.3.1.12 10 CFR Part 50 Appendix I – Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion "As Low as is Reasonably Achievable" for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents

The GRS is designed to support maintaining offsite annual doses from gaseous effluents below the limits specified in 10 CFR Part 50 Appendix I. In the event that half of those radiation dose levels are exceeded in any calendar quarter, DCPP initiates investigations into the cause and reports corrective actions within 30 days from the end of the quarter to the NRC.

11.3.1.13 40 CFR Part 190 – Environmental Radiation Protection Standards for Nuclear Power Operations

The GRS supports the protection of members of the public from radiation sources from

the uranium fuel cycle such that annual doses are maintained below the limits specified in 40 CFR Part 190.

11.3.1.14 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The GRS provides instrumentation to monitor system variables during and following an accident.

11.3.1.15 Regulatory Guide 1.143, Revision 1, October 1979 – Design Guidance for Radioactive Waste Management Structures, Systems, and Components Installed In Light-Water-Cooled Nuclear Power Plants

The GRS design follows the guidance of Regulatory Guide 1.143, Revision 1 as it relates to the seismic design and quality group classification of components.

11.3.1.16 NUREG-0737 (Items II.F.1 and III.D.1.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident Monitoring Instrumentation:

Position (1) – The GRS is designed with noble gas effluent monitors that are installed with an extended range (ER) designed to function during accident conditions.

Position (2) – The GRS is designed with provisions for sampling of plant effluents for post-accident releases of radioactive iodines and particulates and onsite laboratory capabilities.

Item III.D.1.1 – Integrity of Systems Outside Containment Likely to Contain Radioactive Material for Pressurized-Water Reactors and Boiling-Water Reactors: Appropriate portions of the GRS are periodically pressure leak tested and visually inspected for leakage into the building environment.

11.3.2 SYSTEM DESCRIPTION

The GRS is designed to collect, store, monitor, and release plant waste gas streams that may contain radioactive noble gases, iodine, and radioactive particulate material.

In addition to releases from the GRS, other releases of radioactive gases from the plant are possible under some operating conditions; for example, in periods during which primary coolant system leakage occurs. These additional pathways that can, under some plant operating conditions, release radioactive gases are:

(1) Containment purge (refer to Section 9.4.5)

(2) Auxiliary building ventilation (refer to Section 9.4.2)

(3) Fuel handling building ventilation (refer to Section 9.4.4)

(4) Main condenser air ejector (refer to Section 10.4.1)

(5) Gland steam condenser (refer to Section 10.4.3)

(6) SGBD system (refer to Section 10.4.8)

(7) 10 percent atmospheric dump valves (refer to Section 10.4.4)

(8) Main steam and reheat relief valves (refer to Sections 10.2 and 10.3)

(9) Solid radwaste storage building (RSB) ventilation (refer to Section 11.5)

(10) Laundry facility ventilation (refer to Section 11.3.3.10)

(11) Condenser vacuum pump (refer to Section 10.4.2)

The GRS is designed to process radioactive gases consisting primarily of nitrogen and hydrogen with low levels of oxygen. The gases are collected by the vent header system from various primary and auxiliary systems. Radioactive or potentially radioactive gaseous wastes result from collection of excess cover gas in the LHUTs, degasification in the volume control tank, and cover gas displaced in the pressurizer relief tank and RCDT. A piping schematic for the GRS is shown in Figure 3.2-24.

Each unit has a vent header network and surge tank. Gases collected by the vent header system are routed to the surge tank, which is equipped with a safety relief valve to prevent overpressurization.

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

The compressor discharge is routed into a network of valves feeding the gas decay tanks. Based on downstream conditions and operator selection, the system controls the positioning of these valves. One tank will be filling, with one tank on standby, and one tank being used for cover gas. The system will automatically switch to the standby tank when the fill tank reaches 100 psig. Should this fail to happen, the system will alarm when the tank reaches 105 psig.

The gas decay tanks are provided for the holdup of radioactive gases prior to release to the environment. The size and number of gas decay tanks was selected to provide capability to hold gases for 45 days when necessary (to allow decay). The holdup time required is that which would result in releases that are in compliance with release rate and dose limits. Each gas decay tank may be operated as a cover gas supply for the LHUTs. Normal coolant letdown then displaces the gases back into the GRS. This process effectively increases the volume of storage available for gaseous holdup.

The sampling system associated with the GRS is used to monitor oxygen content of the gases in the system and to collect grab samples for oxygen concentration analysis. Sample points exist in this system including all influent sources and each of the gas decay tanks. These sample points may be monitored via grab samples which may be taken from manual sample taps. The gas analyzer is equipped with a sample tap for taking bottled samples to undergo radiological testing.

11.3.2.1 Gaseous Radwaste System Operation

The GRS handles gaseous discharge from the various sources. The volume of gases originates from displaced cover gas in the LHUTs. The gaseous flow is discharged to the vent header and routed to the surge tank.

The suction pressure to the normally operating compressor is maintained at approximately 0.5 psig via a pressure regulator on the surge tank outlet. During normal operation, the waste gas compressor starts and stops based on surge tank pressure to maintain a nominal 1.1 psig to 2.0 psig in the surge tank. If a control malfunction occurs causing the compressor to continuously operate, a recycle valve would open at a nominal 0.9 psig pressure in the surge tank, returning gases from the moisture separator. This supplies gases back to the compressor suction preventing evacuation of the compressor suction piping. In addition, if the LHUT header pressure is at or below the setpoint (nominally 0.75 psig), a recycle valve from the gas decay tanks opens to maintain the cover gases in the LHUTs.

A shared Unit 1 and Unit 2 spare compressor will start on a high surge tank pressure of a nominal 3 psig. The waste gas compressor discharges into a gas decay tank through a series of automatic valves. When the decay tank is filled to a nominal 100 psig, the inlet valve to the filled tank closes and the inlet valve to a standby tank opens. Should this fail to happen, a high pressure alarm sounds at a nominal 105 psig. The remaining tank is now positioned as the standby tank with the filled tank isolated for decay and release.

11.3.2.2 System Design

The GRS, including the gas analyzer package, is designed and fabricated as PG&E Design Class II. The equipment and piping code classifications are listed in Table 3.2-3. The design and operating parameters for the GRS equipment are shown in Table 11.3-1.

11.3.2.3 Plant Releases

11.3.2.3.1 Current Operational Releases

Refer to Section 11.3.3.10 for a discussion of current operational releases from the GRS.

11.3.2.3.2 Pre-Operational Estimated Release Evaluation

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

The following information provides historical perspective demonstrating that DCPP's anticipated operation would result in releases within applicable regulatory limits. This information does not necessarily reflect current operating conditions or practices.

The potential release pathways for radioactive gases have been described in previous paragraphs. Table 11.3-2 lists the estimated annual releases for the Design Basis Case, and Table 11.3-3 lists the estimated annual releases for the Normal Operation Case. The assessments of total curies released via each of the various pathways are discussed below. All release calculations were performed using the EMERALD-NORMAL (Reference 1) computer code.

Table 11.3-4 lists the estimated annual gaseous radwaste flows. Tables 11.3-5 through 11.3-8 list the estimated activities in the gas decay tanks and the volume control tank for the Design Basis and Normal Operation Cases.

For the release from venting of the gas decay tanks, it was assumed that the full volume of primary coolant is degassed twice a year, and the quantities of radioactive gases released are listed in Table 11.3-2 for the Design Basis Case and in Table 11.3-3 for the Normal Operation Case.

Containment venting releases are based on an assumed leakage of 1 percent of the primary coolant noble gas inventory and 0.001 percent of the primary coolant iodine inventory per day to the containment. It was assumed that the containment air is purged 24 times a year, and that the containment air is first circulated through the charcoal filters (refer to Section 9.4.5) if the plant has been operating with significant primary coolant leakage to the containment. This recirculation is assumed to reduce the airborne iodine content by 98 percent, based on a filter DF of 10 for iodine, a circulation flowrate of 24,000 cfm for 16 hours, a containment free volume of 2.6 x 10^6 cubic feet, and a mixing efficiency of 70 percent. The resulting releases of iodine and noble gases for the Normal Operation Case are provided in Table 11.3-3.

In the event of leakage of primary coolant to the auxiliary building, the auxiliary building ventilation system can become a release pathway. In the calculation of release via this pathway, in the Normal Operation Case, it was assumed that primary coolant leakage is 160 pounds per day, with a partition factor of 1 for noble gases and 0.0075 for iodine,

with no iodine filtration in the ventilation system. The calculated releases via this pathway are provided in Table 11.3-3.

Because of the cleanup of the spent fuel pool water, the very large iodine removal capability of the water, the long decay times for noble gases and iodines in fuel rods handled in the pool, low fuel temperatures, and opportunity for prior release of gases in the containment, the amounts of iodine and noble gases released from the spent fuel pool to the environment under normal conditions are small. In the calculation of the release via this pathway, it was assumed that one-third of a core of spent fuel with 100 hours decay is placed in the spent fuel pool at the beginning of an operating cycle. Radionuclides diffuse through defects in fuel elements when cold at a rate 10^5 less than at normal core operating temperature. A partition factor of 0.001 was assumed for iodine and 1 for noble gases in the pool. The fuel handling building ventilation charcoal filter system was assumed to be 90 percent efficient for iodine removal. The calculated releases via this pathway are provided in Table 11.3-3.

Releases from the waste concentrator condenser vent were assumed to be negligible, and small amounts of gas that are released via this mechanism were included in the analysis by conservatively assuming that they are vented to the atmosphere before entering the GRS.

During periods when primary-to-secondary leakage exists, some release of noble gases and iodine will occur via the main condenser air ejector. To calculate these releases, it was assumed that all noble gases are transferred directly to the condenser vapor space, where they are released through the ejector after some decay. The parameters used in the calculation are provided in Tables 11.1-23 through 11.1-25. These assumptions are consistent with those provided in NUREG-0017, April 1976 (Reference 2). Five percent of the iodine leakage from the primary to the secondary system is assumed to be in volatile form and to behave in a manner similar to a noble gas at SG operating temperatures. A partition factor of 0.15 is assumed for volatile iodine in the condenser, and zero for nonvolatile iodine, so the iodine release from this pathway is entirely in volatile form. The activity releases via this pathway are provided in Table 11.3-3.

A small potential source of activity release exists from the gland steam condenser. Because of the small steam flowrate used, however, both the noble gas and the iodine release rates via this mechanism were assumed to be negligible compared with the air ejector releases, and this mechanism was not calculated separately.

The SGBD tank vent was not considered to be a significant source of iodine release for the purposes of the offsite dose calculations since the blowdown tank was not expected to be used during periods when significant activity is present in the blowdown.

Significant release via the 10 percent atmospheric dump valves and main steam and reheat relief valves was not expected under normal operating conditions.

A small potential source of gaseous activity release exists from the laundry/RSB and solid radwaste storage facility (SRSF) ventilation systems. However, because of the degassed nature of contaminated materials that enter these facilities, noble gas release rate via these pathways were assumed to be negligible compared with other listed pathways, and therefore were not included. Similarly, since iodine will not be gaseous, iodine releases via these pathways were not included.

As a result of normal secondary system steam and water leakage, some iodines and noble gases will escape to the environment if significant activity exists in the secondary system. For the Normal Operation Case, a water leakage of 5 gpm was assumed, along with a steam leakage of 1700 lb/hr. The releases via this pathway are also listed in Table 11.3-3.

During plant startup after a cold shutdown, small quantities of radioactive gases may be released from the vacuum pumps (when the condenser is pumped down) and from the cover gas of the LHUTs. Gases from the LHUTs are processed by the GRS, but the discharge from the condenser is vented directly to the atmosphere. Calculations were performed to evaluate the contribution to the total annual air dose at the site boundary in the NW sector of gases released from the condenser during startup. The results of these calculations are listed in Table 11.3-9. Additional assumptions used in the calculations are:

(1) Initial secondary system activity equal to equilibrium levels with 0.12 percent fuel defects and 100 pounds per day primary-to-secondary leakage (Normal Operation Case).

(2) An "equivalent downtime" was used that is equal to a step change from full power to cold shutdown, a 24-hour down-time, and a step change back to full power.

(3) During shutdown, all noble gases were assumed to accumulate in the condenser vapor space; an effective partition factor of 0.15 is assumed for iodine between the secondary system water and the condenser vapor space for volatile iodine species, and zero for nonvolatile iodine.

(4) All airborne condenser activity is immediately released to the environment on startup. All iodine released was assumed to be volatile, and therefore not to be absorbed into food pathways. The critical dose point is considered to be the site boundary in the NW sector.

This analysis was performed to demonstrate that DCPP “normal operation” radiological effluents meet the criteria of 10 CFR Part 50 Appendix I. This analysis is conservative and bounds DCPP current operation. This analysis was performed prior to plant operation and would be modified only if a design change or operational change rendered it non-conservative.

11.3.2.4 Dilution Factors

11.3.2.4.1 Current Operational Dilution Factors

The meteorological program is discussed in detail in Section 2.3. All current plant releases are calculated in the Annual Radioactive Effluent Release Report, using meteorological conditions derived from 5-year average meteorological data.

11.3.2.4.2 Pre-Operational Dilution Factors

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

The pre-operational evaluation values of dilution factor (χ/Q) used in the calculation of annual average offsite radiation dose are provided in Table 11.3-11 for the locations specified in Table 11.3-10. The values of deposition rate (D/Q) used in the calculation of annual average offsite radiation dose are provided in Table 11.3-12 for the locations specified in Table 11.3-10. The D/Q values were derived from Figure 7 of Regulatory Guide 1.111, March 1976 (Reference 3) for a ground level release.

The resulting pre-operational evaluation maximum offsite annual average atmospheric activity concentrations in each onshore sector are provided in Table 11.3-13 for the Design Basis Case and in Table 11.3-14 for the Normal Operation Case.

11.3.2.5 Doses

11.3.2.5.1 Current Operational Doses

Refer to Section 11.3.3.11 for a discussion of current operational doses from the GRS.

11.3.2.5.2 Pre-Operational Doses

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Pre-operational dose calculations were performed at the critical distances for each age group and existing dose pathways in each onshore sector within 5 miles of Unit 1. The critical distances assumed in each sector are provided in Table 11.3-10. The milk cow and milk goat food pathways were not identified within 5 miles of the plant and were therefore not considered.

The models used to calculate the offsite radiation doses are those discussed in Regulatory Guide 1.109, March 1976 (Reference 4) for a ground level release. The standard usage factors provided in Regulatory Guide 1.109, March 1976 were used, as well as the standard decay times, transfer factors, and dose conversion factors. Since a ground level release was assumed, the gamma total body and air doses were calculated using the semi-infinite cloud model described in Regulatory Guide 1.109, March 1976, which gives generally conservative results.

The results of the offsite dose calculations are presented in Tables 11.3-15 through 11.3-29 for the Design Base Case, and in Tables 11.3-30 through 11.3-44 for the Normal Operation Case. Actual results obtained from the environmental radiological monitoring program are discussed in Section 11.6. On the basis of the calculated estimates of radiation dose presented in Tables 11.3-15 through 11.3-44 and the results of the radiological monitoring program, it can be concluded that, under normal conditions, including consideration of anticipated operational occurrences, the potential dose from gaseous effluents from DCPP Unit 1 and Unit 2 will be well within the dose limits provided in 10 CFR Part 50, Appendix I.

11.3.3 SAFETY EVALUATION

11.3.3.1 General Design Criterion 2, 1967 – Performance Standards

The GRS is designed to withstand the DE (refer to Section 11.3.3.15). This design protects the GRS, ensuring its design functions can be performed during the DE.

The waste gas compressor seal water coolers are analyzed to meet DE, Double Design Earthquake (DDE) and Hosgri Earthquake (HE) as detailed in Section 9.2.2.3.1.

11.3.3.2 General Design Criterion 3, 1971 – Fire Protection

The gases directed into the decay tanks being filled during waste gas compressor operation are continuously monitored for oxygen content via oxygen analyzer CEL 75 and 76, which alarm at 2 percent oxygen concentration. However, hydrogen concentration in the system is not monitored as its concentration is assumed at all times to be 4 percent (the flammability limit for hydrogen is 6 percent oxygen concentration) or more by volume for all plant operating modes. In this manner, the potential for explosive hydrogen/oxygen mixtures will be mitigated.

The capability exists for diluting the gas with nitrogen (refer to Figure 3.2-24) using pneumatically operated valves controlled from the auxiliary building control board digital system. In the event that dilution with nitrogen is necessary, a grab sample could be taken for isotopic analyses from the gas decay tanks and waste gas sources as required by the plant Technical Specifications.

11.3.3.3 General Design Criterion 4, 1967 – Sharing of Systems

One of the three waste gas compressors, the swing compressor, is shared between DCPP Unit 1 and Unit 2. Cross-tie valve FCV-417 allows any waste gas compressor outlet to be directed to either unit's waste gas decay tanks. The swing compressor and the waste gas storage tanks have no safety functions; therefore the sharing does not impair safety on either unit.

11.3.3.4 General Design Criterion 11, 1967 – Control Room

Radiation indication and high radiation alarms for gas decay tank effluent are provided in the main control room. Operator actions in the event of high radiation indication are controlled by plant procedures.

11.3.3.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The GRS is controlled from the auxiliary building control board digital system. System instruments provide signals to alarm on the auxiliary building control board digital system to warn of abnormal conditions.

11.3.3.6 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

Batch preparation and sampling is used to document GRS discharge to the environment. In addition, instrumentation is provided in the control room and on the auxiliary building control board digital system to monitor GRS radioactive releases.

The gas decay tank discharge gas monitor (R-22) continuously monitors the gaseous discharge from the gas decay tanks. A high-radiation signal alarms on the main control board and on the auxiliary building control board digital system and closes the gas decay tanks' discharge valves.

Refer to Section 11.4.2.1.2.1 and Table 11.4-1 for additional information.

11.3.3.7 General Design Criterion 18, 1967 – Monitoring Fuel and Waste Storage

Instrumentation is provided in the control room and on the auxiliary building control board digital system for conditions that might contribute to radiation exposures from the GRS.

The auxiliary building control board digital system area monitor (R-10) continuously monitors for high radiation in the auxiliary building that may indicate a rupture of a LHUT or other storage tank. Indication is provided in the control room and on the auxiliary building control board digital system.

The gas decay tank cubicle radiation monitors (R-41, R-42, and R-43) continuously monitor noble gas activity in gas decay tanks 1, 2, and 3, respectively. The detectors are located in compartments adjacent to the decay tanks and provide indication on the auxiliary building control board digital system.

Refer to Section 11.4.2.1.2.1 and Table 11.4-1 for additional information.

11.3.3.8 General Design Criterion 68, 1967 – Fuel and Waste Storage Radiation Shielding

Each waste gas decay tank is located in an individual shielded vault and is equipped with a safety relief valve that discharges to the plant vent.

11.3.3.9 General Design Criterion 69, 1967 – Protection Against Radioactivity Release from Spent Fuel and Waste Storage

As discussed in Section 11.3.2.2, the GRS is designed and fabricated as PG&E Design Class II. In accordance with UFSAR Section 3.2.2.1.2, fluid systems and fluid system components that contain or may contain radioactive material, but whose failure would not result in calculated potential exposures in excess of 0.5 rem whole body (or its equivalent to parts of the body) at the site boundary, may be classified as PG&E Design Class II.

As part of the acceptability of its PG&E Design Class II classification, an evaluation was performed of the dose consequences at the site boundary of a Gas Decay Tank (GDT) failure accident. Three gas decay tanks are provided for each unit to afford operating flexibility and allow one or more tanks to be isolated from the rest of the system for an extended period of time. Most of the gas stored in the decay tanks is nitrogen cover gas displaced from the liquid waste holdup tanks. The radioactive components are principally the noble gases krypton and xenon, the particulate daughters of some of the krypton and xenon isotopes, and trace quantities of halogens.

In the evaluation of the GDT failure accident, the fission product accumulation and release assumptions for the tank rupture are consistent with those of NRC Safety Guide 24, March 1972 (Reference 5). These assumptions are:

(1) The reactor has been operating at full power with 1 percent defective fuel and a shutdown to cold condition has been conducted at the end of an equilibrium core cycle.

(2) All noble gases have been removed from the primary cooling system and volume control tank and transferred to the gas decay tank that is assumed to fail. Credit is taken for radioactive decay during transfer.

(3) The failure occurs immediately on completion of the waste gas transfer, releasing the entire maximum contents of the tank to the auxiliary building and exhausted to the environment via the plant vent assuming a ground level release. The assumption of the release of the noble gas inventory from only a single tank is based on a design that allows all gas decay tanks to be isolated from each other when they are in use.

(4) All of the noble gases are exhausted from the auxiliary building over a 2-hour time period or at the rate of the ventilation exhaust flow whichever results in a more rapid release rate.

Computer code RADTRAD 3.03 (Reference 6) is used to calculate the whole body dose resulting from the GDT rupture using the semi-infinite cloud submersion model and using air submersion dose coefficients provided in Table III.1 of Federal Guidance Report 12 (Reference 7). The reactor coolant isotopic concentrations based on 1% fuel defects are provided in Table 11.1-11A. Atmospheric dispersion factors used in the analysis are given in Table 2.3-145. The dose consequences at both the Exclusion Area Boundary (EAB) and the Low Population Zone (LPZ) due to airborne releases following a GDT Rupture are estimated to be below the acceptance criteria of 0.5 rem whole body and 3 rem thyroid.

The quantity of radioactive material contained in each gas decay tank is limited to less than or equal to 10^5 curies noble gases (considered as Xe-133 equivalent), to ensure that in the event of an uncontrolled release of the tank's contents, the resulting whole body exposure to a member of the public at the nearest site boundary will be less than 0.5 rem.

11.3.3.10 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

Each gas decay tank is equipped with a flow control valve connected to the plant vent. The discharge of each valve is routed into a common flow control valve that provides redundant means of isolation and requires manual operation to ensure no inadvertent venting may take place.

Downstream of the common flow control valve is a radiation monitor that controls a downstream control valve. If the activity in the discharging waste gas exceeds its upper limit, the control valve closes, terminating the release. The final processing of waste gas prior to release to the atmosphere is by a high-efficiency particulate air (HEPA) filter located just downstream of the radiation control valve and just upstream of the plant vent.

Most radwaste gas releases are routed to the plant vent, with the exception of any release from the 10 percent atmospheric dump valves, main steam relief valves, reheat valves, SRSF, RSB/laundry facility exhaust, chemical laboratories exhaust, turbine building exhaust, condenser vacuum pump exhaust, and any miscellaneous steam leakage. Locations of the release points in the plant are shown in Figure 11.3-4. The design exit velocity at the plant vent is 17 m/sec during normal plant operation.

The actual gaseous releases are performed in accordance with approved plant procedures. The plant vent pathway is continuously monitored for noble gases, particulates, and iodines (refer to Section 11.3.3.12).

The containment atmosphere is sampled and evaluated prior to release via the plant vent pathway during power operations. During periods of maintenance and refueling outages most releases continue via the plant vent pathway. However the containment equipment hatch may be open at times during maintenance resulting in direct communication between the air inside containment and the outside air. If flow out of the containment equipment hatch is detected, containment air is evaluated per plant procedures to characterize the release for reporting.

Tritium is also released via the plant vent system mainly due to evaporation from the spent fuel pool.

11.3.3.11 10 CFR Part 20 – Standards for Protection Against Radiation

Occupational doses to plant personnel from the GRS are maintained ALARA by:

(1) Shielding in locations that contain GRS equipment (refer to Section 12.1.2)

(2) HVAC systems that direct air flows for controlled discharge and provide filtration of radioactive materials (refer to Section12.2.2)

(3) Monitoring and alarming of potentially radioactive releases from the GRS (refer to Section 11.3.3.4)

(4) Administrative controls for working in areas of potentially high radioactivity (refer to Section 5 of the Diablo Canyon Quality Assurance Program Description)

Current operational offsite doses are calculated in accordance with the ODCM contained in site-approved procedures in accordance with 10 CFR Part 20 and appropriate NRC regulatory guides.

Technical Specifications require programs for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents within the regulatory limits of 10 CFR Part 20. Doses are reported on quarterly and annual bases. The programs are implemented by plant procedures, and include remedial actions to be taken whenever the program limits are exceeded.

11.3.3.12 10 CFR Part 50 Appendix I – Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion "As Low as is Reasonably Achievable" for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents

The GRS maintains control over the releases of radioactive materials in effluents by:

(1) Providing appropriate holdup capacity for retention of gaseous effluents containing radioactive material (refer to Section 11.3.2)

(2) Continuously monitoring the GRS for leakage (refer to Section 11.3.2)

(3) Sampling all discharges prior to release to the environment and using acceptable dilution factors (refer to Section 11.3.2)

Technical Specifications require programs for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents within the regulatory limits of 10 CFR Part 50, Appendix I. Doses are reported on quarterly and annual bases. The programs are implemented by plant procedures, and include remedial actions to be taken whenever the program limits are exceeded.

11.3.3.13 40 CFR Part 190 – Environmental Radiation Protection Standards for Nuclear Power Operations

Current operational doses from all sources to members of the public are summarized in Annual Radioactive Effluent Release Reports. During preparation of the report, operational doses are compared to the respective 40 CFR Part 190 limit, as implemented under 10 CFR 20.1301(e) (refer to Section 11.3.3.11).

11.3.3.14 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

GRS post-accident instrumentation for meeting Regulatory Guide 1.97, Revision 3, requirements consist of radioactive gas holdup tank pressure, releases of airborne radioactive materials, and releases of radiation and radioactivity to the environs (refer to Table 7.5-6).

11.3.3.15 Regulatory Guide 1.143, Revision 1, October 1979 – Design Guidance for Radioactive Waste Management Structures, Systems, and Components Installed In Light-Water-Cooled Nuclear Power Plants

The GRS is PG&E Design Class II (refer to Section 11.3).

The PG&E Design Class II GRS equipment and piping that are applicable to Regulatory Guide 1.143, Revision 1 are designated PG&E QA Class R. The portions of the GRS

that are intended to store or delay the release of gaseous radioactive waste are seismically supported to withstand the DE and are designated PG&E Piping Symbol F. The remaining portions of the GRS are designated PG&E Piping Symbol H or E, as applicable.

11.3.3.16 NUREG-0737 (Items II.F.1 and III.D.1.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident Monitoring Instrumentation:

Position (1) – The GRS primarily discharges to the plant vent. ER noble gas effluent monitoring is installed in the plant vent and is designed to function during accident conditions (refer to Sections 7.5.2.3 and 11.4.2.1.2.1).

Position (2) – Installed capability is provided in the plant to obtain samples of the particulate and iodine radioactivity concentrations that may be present in the gaseous effluent being discharged to the environment from the plant under accident and post-accident conditions. The technical support center (TSC) laboratory is available for onsite testing of the containment air samples (refer to Section 11.3.2).

Item III.D.1.1 – Integrity of Systems Outside Containment Likely to Contain Radioactive Material for Pressurized-Water Reactors and Boiling-Water Reactors: The integrity of the GRS is continuously evaluated by monitoring the auxiliary building ventilation exhaust for levels of radiation that may indicate leakage from the GRS (refer to Section 5.2.3.26).

11.3.4 TESTS AND INSPECTIONS

All GRS radiation and chemical monitors used in system evaluation are functionally tested and calibrated periodically to ensure the accuracy of measurements. The types of radiation monitors and locations are described in Section 11.4.

Measurements are made on a continuous basis and records are maintained of the quantity of radioactive gases released. Comparison of results provides a check on the continuing performance of the waste gas systems. This approach proves effective in documenting deficiencies and their corrections. The routine radiation monitoring program also detects leakage from the GRS by detecting minute changes in the activity of air in the areas occupied by the system. Appropriate means are used to locate and correct any increase in leakage.

11.3.5 INSTRUMENTATION APPLICATIONS

Refer to Section 11.3.3.5 for a discussion of the instrumentation requirements and controls for the GRS.

11.3.6 REFERENCES

1. S.G. Gillespie and W.K. Brunot, EMERALD-NORMAL - A Program for the Calculation of Activity Releases and Doses from Normal Operation of a Pressurized Water Plant, Revision 1, Pacific Gas and Electric Company, December 1974.

2. NUREG-0017, Calculation of Releases of Radioactive Materials in Liquid and Gaseous Effluents from Pressurized Water Reactors (PWR-GALE code), USNRC, April 1976.

3. Regulatory Guide 1.111, Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light Water-Cooled Reactors, USNRC, March 1976.

4. Regulatory Guide 1.109, Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I, USNRC, March 1976.

5. Safety Guide 24, Assumptions Used for Evaluating the Potential Radiological Consequences of a Pressurized Water Reactor Radioactive Gas Storage Tank Failure, USNRC, March 1972.

6. RADTRAD 3.03 (GUI Mode Version), A Simplified Model for RADionuclide Transport and Removal And Dose Estimation, NUREG/CR-6604, Users' Guide – Supplement 2, October 2002.

7. K.F Eckerman and J.C. Ryman, External Exposure to Radionuclides in Air, Water, and Soil, Federal Guidance Report 12, EPA-402-R-93-081, Environmental Protection Agency, 1993.

11.4 PROCESS AND EFFLUENT RADIOLOGICAL MONITORING SYSTEM

The RMS is designed to provide radioactivity measurements, recording capability, alarms, and/or automatic line isolation in order to control and/or process, the release of radioactive fluids in compliance with applicable regulations.

In the event of an accident, the process and effluent RMS, in conjunction with the area RMS, provides information on the concentration and dispersion of radioactivity throughout the plant, thereby enabling operating personnel to evaluate the severity and mitigate the consequences of an accident.

11.4.1 DESIGN BASES

11.4.1.1 General Design Criterion 2, 1967 – Performance Standards

Certain portions of the RMS are designed to withstand the effects of, or are protected against, natural phenomena, such as earthquakes, tornadoes, flooding, winds, tsunamis, or other local site effects.

11.4.1.2 General Design Criterion 3, 1971 – Fire Protection

The PG&E Design Class I portions of the RMS are designed and located to minimize, consistent with other safety requirements, the probability and effects of fires and explosions.

11.4.1.3 General Design Criterion 4, 1967 – Sharing of Systems

The RMS is not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

11.4.1.4 General Design Criterion 11, 1967 – Control Room

The RMS is designed to or contains instrumentation and controls that support actions to maintain the safe operational status of the plant from the control room.

11.4.1.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

RMS instrumentation and controls are provided as required to monitor and maintain radiation levels within prescribed operating ranges.

11.4.1.6 General Design Criterion 16, 1967 – Monitoring Reactor Coolant Pressure Boundary

The RMS provides means for monitoring the reactor coolant pressure boundary (RCPB) to detect leakage.

11.4.1.7 General Design Criterion 17, 1967 – Monitoring Radioactive Releases

The RMS is designed to provide means for monitoring the containment atmosphere, the facility effluent discharge paths and the facility environs for radioactivity that could be released from normal operations, from anticipated transients, and from accident conditions.

11.4.1.8 General Design Criterion 18, 1967 – Monitoring Fuel and Waste Storage

The RMS is provided with monitoring and alarm instrumentation for fuel and waste storage and handling areas for conditions that might contribute to radiation exposures.

11.4.1.9 General Design Criterion 19, 1971 – Control Room

The RMS is designed to permit access and occupancy of the control room for operating the plant without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of design basis accidents.

11.4.1.10 General Design Criterion 21, 1967 – Single Failure Definition

The portions of the RMS that support ESF functions are designed to perform their safety functions after sustaining a single failure. Multiple failures resulting from a single event are treated as a single failure.

11.4.1.11 General Design Criterion 40, 1967 – Missile Protection

The ESF containment isolation portion of the RMS is designed to be protected against dynamic effects and missiles that might result from plant equipment failures.

11.4.1.12 General Design Criterion 49, 1967 – Containment Design Basis

The RMS piping that penetrates the containment is designed to accommodate the pressures and temperatures resulting from the largest credible energy release following a LOCA without exceeding the design leakage rate.

11.4.1.13 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The RMS piping that penetrates containment is provided with leak detection, isolation, redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating this system. The piping is designed with capabilities to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

11.4.1.14 General Design Criterion 56, 1971 – Primary Containment Isolation

The PG&E Design Class I portion of the RMS contains valves in piping that penetrate containment and that are connected directly to the containment atmosphere. To ensure containment integrity is maintained, each penetration contains one automatic isolation valve or one check valve inside containment and one automatic isolation valve outside containment.

11.4.1.15 General Design Criterion 69, 1967 – Protection Against Radioactivity Release from Spent Fuel and Waste Storage

The RMS is designed to support containment of radioactive releases from the spent fuel and waste storage areas to the public environs as a result of an accident.

11.4.1.16 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The RMS is designed with provisions for maintaining control over the plant's radioactive effluents such that the requirements of 10 CFR Part 20 are met for normal operation, and the requirements of 10 CFR 100.11 are met for accident conditions.

11.4.1.17 Radiological Monitoring System Safety Function Requirements

(1) <u>Protection from Jet Impingement – Inside Containment</u>

The PG&E Design Class I containment isolation portion of the RMS located inside containment is designed to be protected against the effects of jet impingement which may result from high energy pipe rupture.

11.4.1.18 10 CFR Part 20 – Standards for Protection Against Radiation

The RMS supports the protection of personnel from radiation sources such that occupational doses and doses to individual members of the public are maintained below the annual limits prescribed in 10 CFR Part 20.

11.4.1.19 10 CFR 50.49 – Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

RMS components that require EQ are qualified to the requirements of 10 CFR 50.49.

11.4.1.20 10 CFR 50.68(b) – Criticality Accident Requirements

The RMS is designed to support compliance with the applicable requirements of 10 CFR 50.68(b) to prevent inadvertent criticality.

11.4.1.21 10 CFR Part 50, Appendix I – Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion "As Low as is Reasonably Achievable" for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents

The RMS is designed to support maintaining offsite annual doses from effluents below the limits specified in 10 CFR Part 50, Appendix I.

11.4.1.22 Safety Guide 13, March 1971 – Fuel Storage Facility Design Basis

Regulatory Position 7:

The RMS includes monitors that alarm locally and in the control room if high radiation levels are experienced in the spent fuel pool area. The RMS also actuates the Automatic Iodine Removal Mode of the fuel handling building ventilation system (FHBVS).

11.4.1.23 Regulatory Guide 1.21, Revision 1, June 1974 – Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants

The RMS provides radiological monitoring of all major and potentially significant paths for release of radioactive material during normal plant operation, including anticipated operational occurrences.

11.4.1.24 Regulatory Guide 1.45, May 1973 – Reactor Coolant Pressure Boundary Leakage Detection Systems

Leakage detection systems are designed with acceptable methods to detect and identify the location of the source of RCPB leakage. The designs of the containment radioactivity monitors meet the requirements of Regulatory Guide 1.45, May 1973, with the following exceptions:

(1) The containment air particulate and containment radiogas detectors are not constructed to withstand DDE accelerations; however, they are housed in a PG&E Design Class I structure and protected from external damage associated with a seismic event. Therefore, it is considered that these monitors can be returned to operational status within 36 hours of a DDE.

(2) For low RCS activities, the containment atmosphere gaseous radioactivity monitors may not be capable of detecting a RCS leak of 1 gpm within one hour.

11.4.1.25 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

The RMS provides instrumentation to monitor radiation levels and radioactivity concentrations in plant process streams, effluent paths, and areas during and following an accident.

11.4.1.26 NUREG-0737 (Items II.F.1, III.A.1.2, and III.D.1.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident Monitoring Instrumentation

Position (1) – The RMS is designed with noble gas effluent monitors with an ER designed to function during accident conditions.

Position (2) – The RMS is designed with provisions for sampling of plant effluents for post-accident releases of radioactive iodines and particulates.

Position (3) – The RMS is designed with containment high-range radiation monitors.

Item III.A.1.2 – Upgrade Emergency Support Facilities: NUREG-0737, Supplement 1, January 1983 provides the requirements for III.A.1.2 as follows.

Section 8.2.1(f) – The TSC is provided with radiological monitoring equipment necessary to assure that radiation exposure to any person working in the TSC would not exceed 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident.

Item III.D.1.1 – Integrity of Systems Outside Containment Likely to Contain Radioactive Material for Pressurized-Water Reactors and Boiling Water Reactors: The RMS supports a program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as-low-as-practical levels.

11.4.2 SYSTEM DESCRIPTION

11.4.2.1 Continuous Monitoring

11.4.2.1.1 General Description

The components of the RMS are designed for operation in the following ranges of conditions:

(1) Temperature - An ambient temperature range of 40° to 120°F.

(2) Humidity - 0 to 95 percent relative humidity.

(3) Pressure - Components in the auxiliary building and control room are designed for normal atmospheric pressure. Area monitoring system components inside the containment are designed to withstand containment test pressure.

(4) Radiation - Process and area radiation monitors are of a non-saturating design so that they will register full-scale or over range if exposed to radiation levels up to 100 times full-scale indication.

(5) Radiation monitoring equipment is designed and located such that radiation damage to electrical insulation and other materials will not affect their usefulness over the life of the plant.

(6) The RMS is designed such that it can be checked, tested, and recalibrated as required.

The only components of the RMS that are exposed to a wider range of conditions are located in the containment. This includes detectors and associated local alarm and indication equipment for the area-type monitoring channels there. Some of these, namely the low level-normal ops monitors are not expected to operate following a major LOCA. Post-accident high-range gamma monitors are used for post-accident situations.

Most of the control room RMS equipment used for normal operation and anticipated operational occurrences are centralized in cabinets. Data loggers are provided in the RMS cabinets in the control room (refer to Table 11.4-1). Each monitoring channel on the data loggers is sequentially recorded.

Equipment used solely for post-accident monitoring (PAM) is located in additional cabinets in the control room. The digital RMS equipment is located in a six-bay cabinet while the control room pressurization system (CRPS) monitors are in a separate control room rack. Sliding channel drawers are normally used to facilitate maintenance and allow replacement of units, assemblies, and entire channels if needed. It is possible to completely remove the various chassis from the cabinet after disconnecting the cable connectors from the rear of these units.

Detector output is usually measured in either counts per minute (cpm), milliroentgens per hour (mR/hr), roentgens per hour (R/hr), or microcuries per cubic centimeter (μCi/cc). Each channel has a minimum range of three decades. Radiation monitors are listed in Tables 5.2-16 and 11.4-1. The iodine monitors are isotopic I-131 process monitors and read in cpm or μCi/cc.

The RMS is divided into the following subsystems:

(1) The process RMS that monitors radiation levels in various plant process streams and effluent paths

(2) The area RMS that monitors radioactivity in various areas within the plant

The locations of all detectors with respect to plant equipment for Unit 1 are listed in Table 11.4-1. Unit 2 detectors are in corresponding locations. Piping sequence and locations of process detectors are found in appropriate piping schematics, shown as figures in Section 3.2.

11.4.2.1.2 Process Radiation Monitoring System

11.4.2.1.2.1 Description

This system, as illustrated in Figure 11.4-1, consists of multiple channels that monitor radiation levels in various plant operating systems. The output from each channel detector except the digital radiation monitors is transmitted to the RMS cabinets where the radiation level is indicated on a meter and recorded by a multipoint recorder (refer to Table 11.4-1). Except for the air particulate/iodine/noble gas monitors in the TSC and the adjacent laboratory, the gas decay tank cubicles, and the SGBD overboard monitor, the RMS cabinets for most process radiation monitors are located in the control room. The RMS cabinets for the TSC and the adjacent laboratory are located in the computation center. High radiation level alarms are indicated on the RMS cabinets with annunciation on main annunciators. Except for the monitors in the TSC, the adjacent laboratory and some supplementary monitors, the main annunciator for process monitors is at the control board in the control room.

The control board annunciator provides several windows that alarm for input channels (process or area) detecting high radiation. The main annunciator for the TSC and the adjacent laboratory is in the TSC panel annunciator in the computation center.

Verification of which channel has alarmed is done at the RMS cabinets serving that annunciator (refer to Table 11.4-1).

A tabulation of the process radiation monitoring channels is found in Table 11.4-1. The minimum sensitivity is based on a Co-60 background level of 2 mR/hr.

A typical channel contains a completely integrated modular assembly that includes the following:

(1) Log Level Amplifier

Accepts detector pulses, performs a log integration (converts total pulse rate to a logarithmic analog signal), and amplifies the resulting output for suitable indicating and recording.

(2) Power Supplies

Furnishes electrical power for the circuits, relays, alarm lights, and detectors.

(3) Test-Calibration Circuitry

Provides a pre-calibrated pulse signal to test channel electronics and a solenoid-operated radiation check source to verify channel operation. A common annunciator on the main control board indicates when a channel is in the test mode.

(4) Radiation Level Meter

Provides a dual scale calibrated logarithmically from 10^1 to 10^4, and 10^1 to 10^6 cpm. The wide-range level signal is also recorded by the data logger recorder.

(5) Indicating Lights

Indicate high-radiation alarms, tests, and circuit failures. A number of annunciator windows on the main control board are actuated either on high radiation signal from the channels or from any channel failure. A separate window is lit when channels are placed in the test mode. However, the digital radiation monitoring system and a few other monitors do not have this “test” alarm feature.

(6) Bistable Circuits

Two bistable circuits are provided: one to alarm on high radiation (actuation point may be set at any level within the range of the instruments), and one to alarm on loss of signal (circuit failure).

(7) Check Source

A remotely operated long half-life radiation check source is furnished for each channel. The check source simulates the radiation being monitored. The check source interaction is sufficient to cause an upscale indication. The main steam line radiation monitors and the CRPS radiation monitors have a fixed “keep alive” source mounted directly on the detector. It is used only to keep the channel out of a low fail condition.

The process RMS consists of the radiation monitoring channels described in Items 1 through 28 below. (The prefix numbers, where used with channel identification, indicate monitors associated with Unit 1 or Unit 2; 0 indicates a shared monitor or no unit designation.)

The sample lines for the air particulate and gaseous radiation monitors (containment, RHR heat exchanger compartment exhaust, control room, TSC, laboratories, and plant vent) are designed and installed in accordance with the recommendations of Reference 2.

The flow in each of the sample lines is turbulent. Particle deposition due to gravity and Brownian diffusion are assumed to be small since the horizontal runs of the sample lines are short and the sample velocity is high. Long-radius bends are used for all sample lines, including the inlet lines to the monitors, to preclude deposition due to extreme turns. Isokinetic probes are used wherever the sample is taken from a moving airstream. Deposition in the basically vertical sample line runs are assumed to be largely due to turbulent deposition.
The following are process radiation monitors that do not support ESF functions. For those that do support ESF functions, refer to Section 11.4.2.1.4.

(1) Containment - Air Particulate Monitor (1-R-11 and 2-R-11)

This monitor is provided to measure air particulate gamma radioactivity in the containment.

The sampler for this channel takes a continuous air sample from the containment atmosphere. The inlet line from inside the containment is routed through the containment penetration to the monitor, which is located adjacent to the penetration.

The sample is monitored by a scintillation counter-filter paper detector assembly. The filter paper has a collection efficiency of approximately 99% for particles of 0.3 microns or larger.
The particulate matter is collected on the filter paper's constantly moving surface and is viewed by a gamma scintillation detector. The sample is returned to the containment after it passes through the series-connected gas monitor.

The pulse signal is transmitted to the RMS cabinets in the control room. For activity releases inside containment, the air particulate and gas monitors RE-11 and RE-12 will alarm in the control room.

Lead shielding is provided to reduce the background level to where it does not interfere with the detector's sensitivity.

(2) Containment - Radioactive Gas Monitor (1-R-12 and 2-R-12)

This monitor is provided to measure gaseous beta-gamma radioactivity in the containment. The detector consists of a beta-gamma sensitive Geiger-Mueller (G-M) tube mounted in the monitor container.

This channel takes a continuous air sample from the containment atmosphere that passes through the air particulate monitor (1-R-11, 2-R-11), and then through the gas monitor assembly. The sample is circulated in a fixed volume where it is monitored by the radiation detector. The sample is then returned to the containment. Its output is transmitted to the RMS cabinets in the control room. For activity releases inside containment, the air particulate and gas monitors RE-11 and RE-12 will alarm in the control room.

(3) RHR Heat Exchanger Compartment Exhaust Duct Air Particulate Detector Monitor (1-R-13 and 2-R-13)

This monitor is provided to measure air particulate gamma radioactivity in the RHR heat exchanger compartments' exhaust ducts to detect a leaking recirculation loop component in the event of a LOCA. It operates in the same manner as the containment air particulate monitor.

The sampler for this channel takes a continuous common air sample from the exhaust ducts of both RHR compartments.

An isokinetic probe is installed in each RHR compartment exhaust duct. The monitor is located in proximity to the sample points.

The sample is monitored by a scintillation counter-filter paper detector assembly. The sample is then returned to the exhaust ducts. Ducts may be sampled individually by use of a selector switch at the console. High radiation is annunciated at the main control board.

(4) Plant Noble Gas Vent Monitor (1-R-14, 2-R-14) (1-R-14R, 2-R-14R)

Each channel consists of a pressurized three liter volume monitored by a beta scintillation detector. RM-14 is part of the normal range (NR) skid. RM-14R is part of the redundant normal range (RNR) skid. Local indication for these channels is provided by the local radiation processors (LRPs) mounted on their respective skids. Remote indication for these channels is provided by the radiation display units (RDUs) for their respective skids. The RDUs are mounted in the RMS panels in the control room.

(5) Condenser Air Ejector Gas Monitor (1-R-15, 1-R-15R, 2-R-15, 2-R-15R)

These channels monitor the discharge from the air ejector exhaust header of the condensers. Gaseous radiation is indicative of a primary-to-secondary system leak. The gas discharge is routed to the plant vent. Both RM-15 and RM-15R share the same detector skid. Local indication for these channels is provided by the wall-mounted LRPs associated with each detector. Remote indication for these channels is provided by RDUs. The RDUs are mounted in the RMS panels in the control room. High radiation is annunciated at the main control board.

(6) Component Cooling Liquid Monitors (1-R-17A, 2-R-17A, 1-R-17B, 2-R-17B)

These channels continuously monitor the component cooling water (CCW) system for radiation indicative of a leak of reactor coolant from the RCS and/or the RHR loop to the CCW. Each channel employs an off-line detector using a bypass line from CCW pump discharge to suction. Due to the discharge piping configuration, however, only one monitor is sampling flow representative of the bulk system when only one CCW heat exchanger is in service. A high-radiation-level signal initiates closure of the valve located in the component cooling surge tank vent line to prevent gaseous radiation release. Adequate lead shielding is provided to reduce the effect of background radiation so that it does not interfere with the detector's sensitivity.

(7) Liquid Radwaste Effluent Monitor (0-R-18)

This channel continuously monitors discharges from the LRS. Automatic valve closure is initiated to prevent further release after a high radiation level is indicated and alarmed, and flow is diverted to the equipment drain receiver tanks. A scintillation detector located in an in-line sampler monitors these effluent discharges. An alarm function is provided on the main control board and the auxiliary building control board digital system. Adequate lead shielding is provided to reduce the effect of background radiation so that it does not interfere with the detector's sensitivity. In addition, samples from the LRS batches are analyzed in the laboratory.

(8) SGBD Sample Monitor (1-R-19, 2-R-19)

This channel monitors the liquid phase of the secondary side of the SG for radioactivity (which would indicate a primary-to-secondary system leak) providing backup information to that of the condenser air ejector gas monitors. Blowdown samples from each of the four SGs are combined in a common header and the common sample is continuously monitored by a scintillation detector in an in-line sampler assembly.

Adequate lead shielding is provided to reduce the effect of background radiation so that it does not interfere with the detector's sensitivity. High activity alarm indications are displayed locally and at the RMS cabinets, with annunciation at the main control board in the control room.

If a high activity alarm occurs, isolation valves in the blowdown and sample lines acting with the valve in the line from the blowdown tank to the discharge structure will close and the blowdown tank liquid effluent will be diverted to the equipment drain receiver tank. Subsequent identification of the leaking SG would then be made by manual override of sample line isolation and drawing separate samples from each SG for analysis.

(9) Gas Decay Tank Discharge Gas Monitor (1-R-22, 2-R-22)

This channel monitors the gaseous discharge from the gas decay tanks. The detector consists of a G-M tube inserted into an in-line fixed volume container that includes adequate shielding to reduce the background radiation low enough not to interfere with the detector's sensitivity. This channel will alarm on the main control board and auxiliary building control board digital system and close the gas decay tanks discharge valve on a high radiation level signal.

(10) Plant Vent Particulate Monitors (1-R-28, 2-R-28)(1-R-28R, 2-R-28R)

Each channel consists of a fixed particulate filter monitored by a beta scintillation detector. RM-28 is part of the NR skid. RM-28R is part of the RNR skid. The sample for each skid is isokinetically drawn from the plant vent stack. Local indication for these channels is provided by the LRPs mounted on their respective skids. Remote indication for these channels is provided by the RDUs for their respective skids. The RDUs are mounted in the RMS panels in the control room.

(11) Plant Vent Iodine Monitors (1-R-24, 2-R-24)(1-R-24R, 2-R-24R)

Each channel consists of a charcoal cartridge filter monitored by a gamma scintillation detector. Iodine is discriminated using a single channel analyzer. RM-24 is part of the NR skid. RM-24R is part of the RNR skid. The sample for each skid is isokinetically drawn from the plant vent stack. Local indication for these channels is provided by the LRPs mounted on their respective skids. Remote indication for these channels is provided by the RDUs for their respective skids. The RDUs are mounted in the RMS panels in the control room.

(12) SGBD Tank Liquid Effluent Monitor (1-R-23, 2-R-23)

This channel is provided to continuously measure liquid effluent from the blowdown tank. The channel employs a scintillation detector located in an off-line sample chamber. Adequate shielding is employed to reduce effects of background radiation.

The count rate is handled in the same manner as for the basic RMS. Output is recorded in conjunction with, and parallel to, the recorded outputs of the flow elements related to the blowdown tank inputs and effluents at a local panel specifically provided for that function. Output is also recorded at the data logger in the RMS cabinets in the control room.

Alarms are provided on the main control board for high and low radiation (instrument failure). A high-radiation signal isolates the blowdown discharge, and diverts blowdown tank liquid effluent to the equipment drain receiver tank.

(13) High-Range Plant Vent Gas Monitor (1-R-29, 2-R-29) Post-accident Monitor

This monitor measures high-range gross gamma radioactivity in the plant vent. The detector consists of a shielded ion chamber contiguous to the plant vent and mounted on an adjacent support structure. A control room readout, with an associated recording device, is provided on the PAM panel. Also provided on this panel are the high and low (instrument failure) radiation alarms. The high and fail radiation alarms are also provided on the main control board. The high alarm also alarms in the State of California Office of Emergency Services in Sacramento.

(14) Deleted

(15) ER Noble Gas Monitor (1-R-87, 2-R-87)

The ER channel, RM-87, uses a beta scintillation detector operated in the current mode. The ER noble gas detector is less sensitive and the volume of the detection chamber is smaller than those of the NR noble gas channel. The ER chamber is not pressurized. The sample is isokinetically drawn off the plant vent stack at approximately 1/20th the rate of the sample for the NR and RNR skids. The chamber is downstream of two identical trains of particulate and iodine roughing filters/grab samplers. Alternating between the trains allows removing a grab sample while continuing to monitor the stack. The grab samplers are to be used for assessing post-accident releases of particulates and iodine using laboratory instruments. All of this equipment is mounted on the ER skid. Local indication for RM-87 is provided on the LRP for the NR Skid.

Remote indication for RM-87 is provided on the RDU for the NR skid. The RDU is mounted in the RMS panels in the control room. Indication for RM-87 is on the same indicating channel used for RM-14.

(16) TSC Air Supply Radioactive Particulate Monitor (0-R-66)

This monitor is provided to measure air particulate gamma radioactivity in the ventilation air supply to the TSC. The isokinetic flow sampler for this channel takes a continuous air sample from the TSC ventilation air supply duct.

(17) TSC Air Supply Noble Gas Monitor (0-R-67)

This monitor is provided to measure the noble gas activity in the ventilation air supply to the TSC. The same isokinetic flow as described in item (16) above is used.

(18) TSC Air Supply Iodine Radiation Monitor (0-R-82)

This monitor is provided to measure the iodine activity in the ventilation air supply to the TSC. The same isokinetic flow as described in item (16) above is used.

(19) Laboratory Adjacent to the TSC Radioactive Particulate Monitor (0-R-68)

This monitor is provided to measure air particulate gamma radioactivity in the laboratory. The sample is drawn directly from the room.

(20) Laboratory Adjacent to the TSC Noble Gas Monitor (0-R-69)

This monitor is provided to measure the noble gas activity in the laboratory. The sample is drawn directly from the room.

(21) Laboratory Adjacent to the TSC Iodine Radiation Monitor (0-R-83)

This monitor is provided to measure the iodine activity in the laboratory. The sample is drawn directly from the room.

(22) SRSF and RSB Ventilation Exhaust Air Particulate Samplers (0-RX-55, 0-RX-56)

These samplers consist of in-line particulate filter assemblies that provide the capability to sample and subsequently assess (via laboratory analysis) the, concentrations of radioactive material present in the exhaust from the SRSF and RSB. RX-55 samples the exhaust from the SRSF, and RX-56

samples the exhaust from the laundry/respirator cleaning facility and RSB prior to the discharge of these effluent points to the environment.

(23) Oily Water Separator Effluent Monitor (0-R-3)

This channel continuously monitors the turbine building sump retention tank discharge into the oily water separator.

(24) Deleted

(25) Main Steam Line Activity Monitors (1-R-71 through 1-R-74 and 2-R-71 through 2-R-74)

These monitors consist of gamma-sensitive G-M tubes and are provided to continuously monitor the main steam lines. The detectors are located next to each main steam line and measure the steam activity from the line's shine.

(26) Gas Decay Tank Cubicle Radiation Monitors (1-R-41, 1-R-42, 1-R-43, 2-R-41, 2-R-42, 2-R-43)

These monitors are for detecting noble gas activity in the gas decay tanks. The detectors are located in compartments adjacent to the decay tanks and provide indication on the auxiliary building control board digital system.

(27) Solid Radwaste Inspection Station Radiation Monitors (0-R-84, 0-R-85)

These radiation monitors are provided to permit the assessment of the contact (R-84) and one-meter (R-85) radiation dose rates being given off from material containers being prepared for storage and shipment as solid radioactive waste. The detectors are located at the decontamination/inspection station in the RSB.

(28) Laundry Processing Room Radiation Monitoring Assembly (0-R-92)

The laundry processing room radiation monitoring channel (R-92) extracts a sample from the air space in the laundry processing room and monitors this sample to determine the radioactivity concentration in the air. Samples are extracted by a sampling nozzle located in the room and returned to the laundry processing room.

11.4.2.1.2.2 Design Evaluation

For ruptures or leaks in the waste processing system, plant area monitors and the vent stack monitor will alarm on an increase in radiation over a preset level. For cases where leaks are involved, the operator may control activity release by system isolation. For inadvertent releases relative to violation of administrative procedures, monitors provide alarms and the means for limiting radioactive releases. The gas decay tank discharge monitor will close the flow control valve in the waste decay tanks discharge line when the radiation level in the line exceeds a preset level. Where liquid waste releases are involved, the liquid radwaste discharge monitor trips shut a valve in the discharge line when the radioactivity in the discharge line exceeds a preset level and redirects the flow to the equipment drain receiver tanks.

For SGBD releases, the blowdown effluent monitor and the blowdown sample monitor isolate the blowdown discharge and will divert the blowdown tank liquid effluent to the equipment drain receiver tanks.

11.4.2.1.3 Area Radiation Monitoring System

11.4.2.1.3.1 Description

This system consists of multiple channels that monitor radiation levels in various areas of the plant. The system has low-range monitors for normal operation and high-range monitors for post-accident conditions. These monitors and their locations are listed in Table 11.4-1.

The selection and location of the monitoring areas are based on multiple considerations, including occupancy status of various plant zones, potential for increase in background activity levels due to operations carried out in a particular location, and desirability of surveillance of infrequently visited areas.

A typical channel of the area RMS consists of a fixed-position, gamma-sensitive G-M tube detector. The detector count rate is amplified, and its log count rate is displayed by the readout in the RMS cabinets. The radiation level is indicated locally at the detector and at the RMS cabinets and it is also recorded. Except for the area monitors in the TSC and the adjacent laboratory, most RMS cabinets are located in the control room (refer to Table 11.4-1). The RMS cabinet for the area monitors in the TSC and laboratory is located in the TSC computation center. High-radiation alarms are displayed on main annunciators, on the RMS cabinets, and at the detector location. The control room annunciator provides several windows that alarm for channels detecting high radiation, except for the monitors in the TSC and laboratory. The main annunciator for high radiation detected by the TSC and laboratory area monitors is the TSC HVAC annunciator located in the computation center. Verification of which

channel has alarmed is done at the RMS cabinets. Each channel contains a completely integrated modular assembly (refer to Section 11.4.2.1.2).

The log level amplifier module amplifies the radiation level signal for indication and recording. The module also provides controls for actuation of the channel check source.

A meter is mounted on the front of each readout module and is scaled to read logarithmically (refer to Table 11.4-1). A local meter, scaled logarithmically, is mounted at the detector assembly.

Two mutually redundant high-range containment monitors RE-30 and RE-31 are provided for each unit, each consisting of a detector mounted inside the containment liner to mitigate the effects of local hot spots and to obtain the best "view" of the containment free volume. The units are powered from separate instrument power channels (refer to Section 8.3.1.1.5).

Each detector is a hermetically sealed, stacked, parallel plate, three-terminal guarded ionization chamber, operated in the saturated mode. The detector and its special cable are environmentally qualified to IEEE 323-1974.

Each readout has a range of 1 to 10^7 R/hr and has high alarm, failure alarm, logarithmic scale recorder, and electronic system and detector checks.

For those radiation monitors that support ESF functions, refer to Section 11.4.2.1.4.

11.4.2.1.3.2 Design Evaluation

Radiation detection instruments are located in areas of the plant that house equipment containing or processing radioactive materials. These instruments continually detect, display, and, as appropriate, record operating radiation levels. If the radiation level should rise above the channel’s pre-determined high alarm setpoint, an alarm is initiated in a control room.

Local annunciation is provided at the detector, with the exception of the high-range containment detectors, to indicate high radiation levels to personnel in the area. The monitoring system is operated in conjunction with regular and special radiation surveys and with chemical and radiochemical analyses performed by the plant staff. Adequate information and warning is thereby provided for the continued safe operation of the plant and assurance that personnel dose does not exceed 10 CFR Part 20 limits.

11.4.2.1.4 Radiation Monitoring Channels that Support Engineered Safety Features

11.4.2.1.4.1 Description

Radiation monitoring channels that support ESF functions include the following:

(1) Main Control Room Air Intake Monitor (1-R-25, 1-R-26) (2-R-25, 2-R-26)

These channels monitor air entering the normal air intakes for the control room ventilation system (CRVS) to support the ESF function to initiate Mode 4 CRVS operation.

These monitors use a scintillation type general-purpose detector and have a range of 10^{-2} to 10^{3} mR/hr. Each monitor has a control room readout module with instrument failure alarm. A high radiation signal provides control room annunciation and automatic actuation.

(2) Containment Purge Exhaust (CPE) Monitors (1-R-44A, 2-R-44A)(1-R-44B, 2-R-44B)

Each channel consists of a beta scintillation detector mounted to the side of the CPE duct. The detectors are mounted diametrically opposed on the 48-inch CPE duct. Their location is downstream of the CPE fan, E-3. Local indication for each channel is provided by the wall mounted LRPs associated with each detector. Remote indication for each channel is provided by the RDUs. The RDUs are mounted in the RMS panels in the control room. These monitors support an ESF function to close the containment ventilation isolation (CVI) valves in the case of high radioactivity exhausting the containment.

(3) CRPS Ventilation Intake Air Monitor (1-R-51, 1-R-52) (2-R-53, 2-R-54)

These channels monitor air entering the CRPS ducts and support the ESF function to shut down the operating CRPS train and automatically start the opposite unit's CRPS.

These monitors use G-M tube-type general purpose detectors and have ranges of 10^{-2} to 10^{4} mR/hr. Each monitor has a control room readout module with instrument failure alarm. A high radiation signal provides control room annunciation and automatic actuation.

(4) Spent Fuel Pool Area Monitor (1-R-58, 2-R-58)

This channel is located near the spent fuel pool and supports the ESF function to transfer the FHBVS to the Automatic Iodine Removal Mode should the pre-determined setpoint be exceeded.

This monitor uses a G-M detector and has an indicating range of 10^{-1} to 10^{4} mR/hr. It provides continuous monitoring and indication with alert and high radiation level alarms in the main control room. Local audible and visual indicators are also provided.

(5) New Fuel Storage Area Monitor (1-R-59, 2-R-59)

This monitor is located near the new fuel storage area and supports the ESF function to transfer the FHBVS to the Automatic Iodine Removal Mode should the pre-determined setpoint be exceeded.

This channel uses a G-M detector and has an indicating range of 10^{-1} to 10^{4} mR/hr. It provides continuous monitoring and indication with alert and high radiation level alarms in the main control room. Local audible and visual indicators are also provided.

11.4.2.1.4.2 Design Evaluation

An evaluation of instrumentation function relative to monitoring and controlling releases of radioactivity from various plant systems is discussed below.

(1) Fuel Handling Inside Containment

The air exhausted from the containment through the containment purge and exhaust lines is monitored by RM-44A and RM-44B. In the event that the pre-determined high alarm setpoint levels are exceeded, these radiation monitoring channels will initiate a signal that would cause the closure of the CVI valves and mitigate the consequences of the accident.

(2) Fuel Handling Outside Containment

Radiological conditions local to the spent and new fuel storage areas are monitored by RM-58 and RM-59, respectively. These monitors provide local and control room alarm annunciation, and will initiate a change in the mode of operation of the FHBVS to Automatic Iodine Removal Mode in the event that a high alarm setpoint is exceeded.

An evaluation of instrumentation functions relative to monitoring and controlling radiological exposures to control room operators is discussed below.

(1) CRVS Normal Air Supply Monitoring

The normal air intakes to the CRVS are monitored by RM-25 and RM-26. MODE 4 operation of the CRVS is automatically initiated upon detection of radioactive contaminants at the normal air intakes.

(2) CRPS Air Supply Monitoring

The CRPS air supply piping is monitored for radioactivity by RM-51 and RM-52 (Unit 1) and RM-53 and RM-54 (Unit 2). In the event an accident occurs in one unit, the system automatically selects the pressurization intake train of the opposite unit. With radiation detected at both pressurization intakes, one of the trains will start. However, the operator manually switches to the intake with lower airborne radioactivity.

11.4.2.2 Sampling

11.4.2.2.1 Basis for Selection of Sample Locations

Locations for periodic sampling are based on the following:

(1) Sampling of process fluids that contain radioactivity

(2) Sampling of process fluids not normally radioactive that may become radioactively contaminated due to some component failure

11.4.2.2.2 Expected Composition and Concentration

Because of the diversity of sources of sampled fluids, the activity levels are expected to range from negligible to the reactor coolant concentrations. Concentrated liquid samples may have specific activities higher than that of the RCS.

11.4.2.2.3 Quantity to Be Measured

Samples expected to contain radioactivity are analyzed periodically as specified in the radiological monitoring and controls procedures and the chemical analysis procedures of the Plant Manual.

11.4.2.2.4 Sampling Frequency and Procedures

Sampling frequency varies according to the sample being analyzed and previous activity level of the sample. The sampling frequency for effluents is specified in the radiological and monitoring procedures of the Plant Manual. The sampling frequency for non-effluent samples is specified in the chemical analysis procedures of the Plant Manual.

11.4.2.2.5 Analytical Procedures and Sensitivity

Analytical procedures are in accordance with the Plant Chemistry Manual. The required sensitivities are specified in the radiological and monitoring procedures of the Plant Manual.

Equipment used for radiation analysis is located near the primary chemical laboratory and the laboratory near the TSC.

11.4.2.2.6 Influence of Results on Plant Operations

The Technical Specifications lists the appropriate radioactive contamination limits on the pertinent systems, as well as the required actions if the limits are exceeded.

11.4.3 SAFETY EVALUATION

11.4.3.1 General Design Criterion 2, 1967 – Performance Standards

The PG&E Design Class I portions of the RMS are seismically qualified (refer to Section 3.7), except for those that are classified as Regulatory Guide 1.97, Revision 3, Category 2 which are not required to be seismically qualified (refer to Table 7.5-6). The CCW discharge radiation monitors, which are PG&E Design Class I, are seismically qualified for the purpose of maintaining CCW pressure boundary integrity only (refer to Section 3.2.2.5).

The PG&E Design Class I portions of the RMS are protected from the effects of floods and tsunamis (refer to Section 3.4) and external missiles (refer to Section 3.5).

With the exception of certain PG&E Design Class I portions of the RMS that are located in structures that are vulnerable to tornadoes, PG&E Design Class I RMS equipment are designed to perform their safety functions under the effects of winds and tornadoes (refer to Section 3.3). Those portions that are located in structures that are vulnerable to tornadoes are not required for plant safe shutdown (refer to Section 3.3.2).

11.4.3.2 General Design Criterion 3, 1971 – Fire Protection

The RMS is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1)

11.4.3.3 General Design Criterion 4, 1967 – Sharing of Systems

Certain RMS components, as designated in Table 11.4-1, are common to both Unit 1 and Unit 2. All shared RMS components are PG&E Design Class II, perform no safety function, and are isolated from PG&E Design Class I components as described in Sections 7.1.3 and 8.3.1.1.5; therefore safety is not impaired by the sharing.

11.4.3.4 General Design Criterion 11, 1967 – Control Room

The RMS provides indication and alarms in the control room on PAM panels PAM-1 and PAM-2; and on radiation monitoring racks RNRMA, RNRMB, RNRMC, RNRMD, RNRME, RNRMS1, RNRMS2, RNRMS3, RNRMS4, RNGFFD, and RCRM (refer to Table 11.4-1).

11.4.3.5 General Design Criterion 12, 1967 – Instrumentation and Control Systems

The RMS provides indication and recording of radiation levels within plant areas and process streams (refer to Sections 11.4.2.1.2 and 11.4.2.1.3). In addition, the RMS provides signals that support automatic functions for controlling radiation within plant effluents (refer to Sections 11.4.2.1.2 through 11.4.2.1.4).

11.4.3.6 General Design Criterion 16, 1967 – Monitoring Reactor Coolant Pressure Boundary

The RMS monitors the containment building for elevated airborne activity levels that may be indicative of RCPB leakage (refer to Sections 5.2.3.23.1.1 and 11.4.3.24).

11.4.3.7 General Design Criterion 17, 1967 – Monitoring Radioactive Releases

The containment is continuously sampled for particulate and gaseous radioactivity during normal operations and anticipated transients (refer to Section 11.4.2.1.2.1).

The ODCM identifies the RMS channels required to be operable during normal operations and anticipated transients that monitor all releases from the units, and the methodology to determine their respective alarm and trip setpoints.

Refer to Section 11.4.3.25 for a discussion of the RMS channels required to monitor radioactivity under accident conditions.

11.4.3.8 General Design Criterion 18, 1967 – Monitoring Fuel and Waste Storage

The fuel and waste storage and handling areas are provided with monitoring and alarm systems for radioactivity (refer to Sections 9.1.1.3.5, 9.1.2.3.5, 11.3.3.7, 11.4.2.1.4, and 11.5.3.4).

11.4.3.9 General Design Criterion 19, 1971 – Control Room

CRPS operation is automatically initiated on a normal air intake radiation monitor signal (refer to Sections 6.4.1.3.6 and 9.4.1.3.7). Two radiation monitors are provided for each CRPS air intake. Evaluations of post-accident control room radiological exposures are presented in Section 15.5.

11.4.3.10 General Design Criterion 21, 1967 – Single Failure Definition

The portions of the RMS that support the ESF functions of the FHBVS, the CRVS, and CVI are designed to provide redundant logic channels (refer to Section 11.4.2.1.4). These redundant channels are electrically isolated and physically separated (refer to Sections 7.1.3 and 8.3.1.4); therefore a single failure within a channel will not prevent the ESF support function of the RMS from being accomplished.

11.4.3.11 General Design Criterion 40, 1967 – Missile Protection

The provisions taken to protect the ESF containment isolation portion of the RMS from damage that might result from missiles and dynamic effects associated with equipment and high-energy pipe failures, respectively are discussed in Sections 3.5, 3.6, and 6.2.4.

11.4.3.12 General Design Criterion 49, 1967 – Containment Design Basis

The RMS containment penetrations, including the system piping and valves required for containment isolation, are designed and analyzed to withstand the pressures and temperatures that could result from a LOCA without exceeding containment design leakage rates. Refer to Sections 3.8.1.13 and 11.2.3.24 for additional details.

11.4.3.13 General Design Criterion 54, 1971 – Piping Systems Penetrating Containment

The RMS CIVs required for containment closure are periodically tested for operability. Testing of the components required for the containment isolation system is discussed in Section 6.2.4.

11.4.3.14 General Design Criterion 56, 1971 – Primary Containment Isolation

The PG&E Design Class I containment penetrations for the RMS are penetration Group A or E (refer to Section 6.2.4). A description of the isolation valves and piping for each penetration is provided in Table 6.2-39. Group A and Group E piping comply with the requirements of GDC 56, 1971.

11.4.3.15 General Design Criterion 69, 1967 – Protection Against Radioactivity Release from Spent Fuel and Waste Storage

In the event of an accident in the fuel handling building, high radioactivity would be detected by the RMS, and the exhaust air would be diverted through charcoal filters (refer to Sections 9.1.2.3.8, 9.4.4.3.11, and 15.5.22).

The RMS allows for early detection of a release from a waste gas decay tank, allowing operator action to terminate release (refer to Section 15.5.24).

11.4.3.16 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The RMS provides annunciation and actuation signals to support the control of radioactivity releases such that offsite doses do not exceed the annual limits of 10 CFR Part 20 for normal operations and anticipated transients and the limits of 10 CFR 100.11 for accidents (refer to Section 11.4.2).

11.4.3.17 Radiological Monitoring System Safety Function Requirements

(1) Protection from Jet Impingement – Inside Containment

The provisions taken to provide protection of the inside containment PG&E Design Class I containment isolation portion of the RMS from the effects of jet impingement which may result from high energy pipe rupture are discussed in Section 3.6.

11.4.3.18 10 CFR Part 20 – Standards for Protection Against Radiation

The RMS provides local and remote indications and is operated in conjunction with routine radiation surveys to provide adequate information of radiation levels in the plant. This supports the safe operation of the plant and the assurance that occupational doses to plant personnel are maintained below the annual limits prescribed in 10 CFR Part 20 (refer to Section 11.4.2.1.3.2).

The RMS provides annunciation and actuation signals to support the control of radioactivity releases such that offsite doses to members of the public do not exceed the annual limits of 10 CFR Part 20 and 40 CFR Part 190 for normal operations and anticipated transients (refer to Sections 11.2, 11.3, and 11.5).

11.4.3.19 10 CFR 50.49 – Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants

The Class 1E RMS components required to function in harsh environments under accident conditions are qualified to the applicable environmental conditions to ensure they will continue to perform their safety functions. Section 3.11 describes the DCPP EQ program and the requirements for the environmental design of the electrical and related mechanical equipment. The affected components are listed in the EQ Master List.

11.4.3.20 10 CFR 50.68(b) – Criticality Accident Requirements

In accordance with 10 CFR 50.68(b)(6), radiation monitors are provided in storage and associated handling areas when fuel is present to detect excessive radiation levels and to initiate appropriate safety actions (refer to Sections 9.1.1.3.8 and 9.1.2.3.10).

11.4.3.21 10 CFR Part 50 Appendix I – Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion "As Low as is Reasonably Achievable" for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents

Effluent monitor setpoints are established to close isolation valves such that annual average releases of radioactive material in gaseous effluents remain within the dose values specified in 10 CFR Part 50 Appendix I.

11.4.3.22 Safety Guide 13, March 1971 – Fuel Storage Facility Design Basis

Regulatory Position 7:

Radiation levels are monitored locally in the spent fuel pool area. Signal inputs are provided to local alarms and control room annunciators, and to the FHBVS to initiate the automatic iodine removal mode of operation (refer to Sections 9.1.2.3.5 and 9.4.4.3.14).

11.4.3.23 Regulatory Guide 1.21, Revision 1, June 1974 – Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants

The RMS continuously monitors all significant plant radiological effluents. A summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the plant is reported in the Annual Radioactive Effluent Release Report administered by the ODCM.

11.4.3.24 Regulatory Guide 1.45, May 1973 – Reactor Coolant Pressure Boundary Leakage Detection Systems

The containment radioactivity monitors support the detection of RCPB leakage (refer to Sections 5.2.3.23.1.1 and 11.4.3.6).

11.4.3.25 Regulatory Guide 1.97, Revision 3, May 1983 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

RMS post-accident instrumentation for meeting Regulatory Guide 1.97, Revision 3, requirements consists of (refer to Table 7.5-6):

(1) Condenser air removal system exhaust noble gas monitors

(2) Containment area high range radiation monitors

(3) Radiation exposure rate monitors (inside buildings or areas)

(4) Plant vent noble gas, particulates, and iodine monitors

(5) Plant vent particulate filters installed on post-accident grab sampling equipment

(6) Vent from SG safety relief valves or 10 percent atmospheric dump valves

11.4.3.26 NUREG-0737 (Items II.F.1, III.A.1.2, and III.D.1.1), November 1980 – Clarification of TMI Action Plan Requirements

Item II.F.1 – Additional Accident Monitoring Instrumentation

Position (1) – ER noble gas effluent monitoring is installed for the plant vent and is designed to function during accident conditions (refer to Sections 7.5.2.3 and 11.4.2.1.2.1).

Position (2) – Installed capability is provided in the plant to obtain samples of the particulate and iodine radioactivity concentrations that may be present in the gaseous effluent being discharged to the environment from the plant under accident and post-accident conditions. The TSC laboratory is available for onsite testing of the plant vent air samples.

Position (3) – High-range radiation monitoring is installed in the containment to monitor ambient gamma radiation following a LOCA (refer to Table 7.5-6).

Item III.A.1.2 – Upgrade Emergency Support Facilities: NUREG-0737, Supplement 1, January 1983 provides the requirements for III.A.1.2.

Section 8.2.1(f) – Radiation monitors with continuous indication and alarm capabilities are installed in the TSC. The ability to distinguish radioiodines at the required low concentration is provided by a dedicated monitor. The RMS provides warning of high radiation levels thereby, in conjunction with shielding and ventilation, assuring that radiation exposure to any person working in the TSC would not exceed 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident (refer to Sections 6.4.2.3.4 and 12.1.7.8).

Item III.D.1.1 – Integrity of Systems Outside Containment Likely to Contain Radioactive Material for Pressurized-Water Reactors and Boiling Water Reactors: During operation a routine radiation monitoring program has been implemented to detect changes in activity of air in the areas occupied by the GRS. If leakage is indicated by an increase in airborne activity, specific tank check methods are used to identify the location of the leak. For portions of the charging and letdown systems, excessive leakage into controlled areas is indicated by off normal radioactivity levels.

11.4.4 TESTS AND INSPECTIONS

11.4.4.1 Alarm Setpoints

The alarm/trip setpoints for radioactive liquid and gaseous effluent radiation monitors (as defined in Technical Specifications and Equipment Control Guidelines) are determined in accordance with the methodology and parameters in the ODCM. The alarm/trip setpoints for all other process and area radiation monitors are established by administrative procedures and controlled in Volume 9B, Table T-IIC-2, "I&C RMS Data Book for Radiation Monitoring and Allied System Data," and are based on protection of public health and safety, plant personnel health and safety, and maintaining efficient plant operation.

Table 11.4-3 lists those monitors that affect valve control operations, together with their effect.

11.4.4.2 Definitions

Radiation Monitor Channel Functional Test - Injection of a simulated signal into the channel as close to the sensor as practicable to verify operability including alarm and/or trip functions.

Radiation Monitor Channel Source Check - The qualitative assessment of channel response when the channel sensor is exposed to a radiological source.

Other definitions are listed in Section 1 of the Technical Specifications.

11.4.4.3 Calibration Procedure

Area and process monitors were initially calibrated by their original manufacturer. Response curves for each detector were provided with the instrument. These curves essentially relate detector performance to the energy spectrum that the detector would see in operation.

11.4.4.3.1 Area Monitors

Based upon the requirements of the plant Technical Specifications, traceable radioactive sources are used to calibrate the area monitors. The monitors are also functionally checked periodically in accordance with the plant Technical Specifications.

11.4.4.3.2 Process Monitors

For the process monitors the, detectors are calibrated with traceable radioactive sources on the frequency defined in the plant Technical Specifications or Equipment Control Guidelines (refer to Chapter 16). Further, the detector response is correlated to the results of analysis of the process stream with calibrated counting room equipment.

11.4.4.4 Test Frequencies

Calibration and functional checks of the process and area monitors are performed at frequencies that are in accordance with the plant Technical Specifications and Equipment Control Guidelines.

11.4.4.5 System Summary

It is concluded that the administrative controls imposed on the operator, combined with the RMS design, provide a high degree of assurance against accidental release of radioactivity to the environment.

11.4.5 INSTRUMENTATION APPLICATIONS

Refer to Section 11.4.3.5 for a discussion of the instrumentation requirements and controls for the RMS.

11.4.6 REFERENCES

1. Deleted in Revision 23.

2. ANSI N13.1-1969, American National Standard Guide to Sampling Airborne Radioactive Materials in Nuclear Facilities.

11.5 SOLID RADWASTE SYSTEM

The SRS is designed to process, package, and store the radioactive wastes generated by plant operations until they are shipped offsite to a licensed waste processing or disposal facility.

The SRS is a PG&E Design Class II and III system. Figure 11.5-1 is a flow diagram of the SRS.

11.5.1 DESIGN BASES

11.5.1.1 General Design Criterion 3, 1971 – Fire Protection

The SRS is designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.

11.5.1.2 General Design Criterion 4, 1967 – Sharing of Systems

The SRS is not shared by the DCPP units unless it is shown safety is not impaired by the sharing.

11.5.1.3 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The SRS is designed to provide means for monitoring the effluent discharge paths, and the facility environs for radioactivity that could be released from normal operations, from anticipated transients, and from accident conditions.

11.5.1.4 General Design Criterion 18, 1967 – Monitoring Fuel and Waste Storage

The SRS is provided with monitoring and alarm instrumentation for conditions that might contribute to radiation exposures.

11.5.1.5 General Design Criterion 68, 1967 – Fuel and Waste Storage Radiation Shielding

The SRS is designed to provide shielding for radiation protection to meet the requirements of 10 CFR Part 20.

11.5.1.6 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The SRS includes those means necessary to maintain control over the plant solid radioactive effluents during normal operation, including anticipated operational occurrences.

11.5.1.7 10 CFR Part 20 – Standards for Protection Against Radiation

The SRS supports the protection of personnel from radiation sources such that occupational doses and doses to individual members of the public are maintained below the annual limits prescribed in 10 CFR Part 20.

11.5.1.8 10 CFR 61.55 – Waste Classification

At DCPP, the classification of solid radioactive waste prior to shipment for disposal is in accordance with the requirements of 10 CFR 61.55.

11.5.1.9 10 CFR Part 71 – Packaging and Transportation of Radioactive Material

The SRS ensures that packaging, preparation for shipment, and transportation of licensed material is accomplished in accordance with the requirements of 10 CFR Part 71.

11.5.1.10 40 CFR Part 190 – Environmental Radiation Protection Standards for Nuclear Power Operations

The SRS supports the protection of members of the public from radiation sources from the uranium fuel cycle such that annual doses are maintained below the limits specified in 40 CFR Part 190.

11.5.1.11 49 CFR Parts 171-178 – Subchapter C-Hazardous Materials Regulations

The SRS ensures the safe and secure transportation of hazardous materials in accordance with the requirements of 49 CFR Part 171 through 49 CFR Part 178.

11.5.1.12 Regulatory Guide 1.143, Revision 1, October 1979 – Design Guidance for Radioactive Waste Management Structures, Systems, and Components Installed In Light-Water-Cooled Nuclear Power Plants

The SRS design follows the guidance of Regulatory Guide 1.143, Revision 1 as it relates to the quality group classification of components.

11.5.1.13 IE Bulletin 79-19, August 1979 – Packaging of Low-Level Radioactive Waste for Transport and Burial

DCPP assures the safe transfer, packaging, and transport of low-level radioactive waste in accordance with IE Bulletin 79-19, August 1979.

11.5.1.14 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The SRS is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition.

11.5.2 SYSTEM DESCRIPTION

11.5.2.1 System Inputs

The SRS collects the following inputs for processing, packaging, and disposal:

(1) Spent filter/ion exchange media

(2) Spent ion exchange resin

(3) Spent filter cartridges

(4) Miscellaneous dry active wastes (i.e., contaminated paper, rags, clothing, tools, etc.)

The SRS input from each of the plant solid radioactive waste streams is presented in Table 11.5-1.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Tables 11.5-2 and 11.5-4 list the activities of the spent ion exchange resins, the spent filter media, and the spent cartridge filters for both the Normal Operation Case and the Design Basis Case.

11.5.2.2 Components

The SRS has five major subsystems:

(1) Spent resin processing system

(2) Spent filter/ion exchange media processing system

(3) Spent filter cartridge processing system

(4) Mobile radwaste processing system (MRPS)

(5) Dry active waste processing system

The function of each of these subsystems is described in the following paragraphs.

11.5.2.2.1 Spent Resin Processing System

The system for transferring spent resins from any of the ion exchangers to the spent resin storage tanks (SRSTs) consists of four separate headers connected to four eductors and discharge systems that permit the transfer of resin from any of the 30 ion exchanger units to either of two SRSTs. Pressurized air is used to transfer resin from either SRST to the loadout station (LS) to which the MRPS container is connected. Pressurized air can also be used to transfer resin from one SRST to the other. Two SRST eductors are provided to transfer resin from one SRST to the other. Figure 11.5-3 is a flow diagram of the spent resin processing system.

The general layout of the system is shown in Figure 11.5-11. The SRSTs are located in shielded cells. All of the valves, instruments, and the discharge eductor are located in a separately shielded area (valve gallery) adjacent to the SRST cells. The spent resin LS is located on the east outside wall of the auxiliary building.

A spent resin sampling system allows for the collection of grab samples as resins enter the SRSTs or while the spent resins are being transferred out of the SRSTs to the MRPS.

All of the equipment associated with this system is considered potentially highly radioactive. None of the equipment, which is located behind shielding, will be approached either for operation or maintenance except under the direction of plant radiation protection personnel under the special work permit rules of the plant.

11.5.2.2.2 Spent Filter/Ion Exchange Media Processing System

Pressurized air is used to transfer exhausted media from either of the two radwaste media filters to the LS to which the MRPS container is connected.

11.5.2.2.3 Spent Filter Cartridge Processing System

This system is designed to remove and handle spent filter cartridges generated in the CVCS, spent fuel storage system, and LRS. The radioactively contaminated spent filter cartridges can be removed from the filter housing or vessels with the operator remaining behind shielding. The spent cartridges are transferred to storage or to the MRPS in shielded transfer casks. Transfer casks are provided to move underwater vacuum filters from the SFP to the MRPS.

It is assumed that the whole change-out procedure takes one hour. This includes loading clean filter cartridges. Half an hour can be spent with the operator protected from radioactive spent cartridges by the transfer cask. For the remaining time, the operator is protected from the filter cartridges by concrete, steel, and/or lead shields.

Figures 11.5-6 through 11.5-8 show the location of filters in the system.

Figure 11.5-9 illustrates the system for capturing the filters using the grappling hook, cask, pulley, and mirrors. Figure 11.5-10 shows the cover of the filter vessel.

11.5.2.2.4 Mobile Radwaste Processing System

The MRPS is a skid-mounted mobile radwaste dewatering/solidification system. The MRPS for media and resin is located on a concrete pad as shown in Figure 11.5-12 and in Bay 2 of the SRSF for filters. This space will accommodate the spillage of resins via concrete sloped to a drain within the area.

The MRPS is operated on a batch basis to solidify concentrates, to dewater or solidify spent ion exchange or filtration media, and to encapsulate spent cartridge filters. Slurries from the media filter vessels are sluiced out to the MRPS and dewatered or solidified. Spent resin slurries are sluiced to the MRPS (refer to Section 11.5.2.5) from the SRST and dewatered or solidified. Filter cartridges are transferred to the MRPS container in a shielded spent filter transfer cask, if required. Waste concentrates, ion exchange media, filtration media, and cartridge filters are dewatered or solidified in accordance with the process control program detailed in the Plant Procedures Manual.

Normally, containers are dewatered or solidified in processing shields. The containers are stored in the shields until shipment. The containers are transferred by mobile cranes into the shipping casks. Containers may be dewatered and/or solidified while in casks on the trailers by which they will be shipped. When processing is finished in shipping casks, the containers are shipped immediately so that no in-plant handling is required.

Complete waste solidification or absence of free liquid prior to shipment is ensured by the implementation of a process control program consistent with the recommendations of NUREG-0472, March 1979 (Reference 1). For medium and high activity waste, level sensors monitor the levels in the waste containers and provide alarm signals to alert the MRPS operator to take action to prevent filling beyond preset levels. Low activity waste level may be monitored by sight by the MRPS operator. Potential waste container overflows are contained by the curbed processing pad, then flow into a sump that will return the spill to the radwaste system.

11.5.2.2.5 Dry Active Waste Processing System

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

Large or highly radioactive components and equipment that have been contaminated during reactor operation and that are not amenable to compaction are handled either by

qualified plant personnel or by outside contractors specializing in radioactive materials handling, and the components and equipment are packaged in shipping containers of an appropriate size and design.

11.5.2.3 Mixed Waste

Mixed waste is liquid or solid waste that is both hazardous and radioactive. Mixed waste is segregated and accumulated in drums in Bay 6 of the SRSF. Filled drums of mixed waste are placed in storage in Bay 5 of the SRSF.

11.5.2.4 Component Failures and System Malfunctions

Analyses have been performed to evaluate potential dose to operating personnel should the SRSs malfunction or components fail. The components and systems considered most likely to fail are discussed below.

During the transfer of spent resin to the SRSTs, a failure of the motive water pump could result in lines becoming clogged with resin. The lines may be cleaned out by starting up the second motive water pump and using the normal operating procedure. The CVCS resin transfer piping system includes cleanout flanges, which can be used if the lines cannot be cleaned by using the normal procedure. The cleanout flanges are located in areas that are shielded from the main resin transfer lines, and minimize the dose to operating personnel during a cleanout operation.

During the transfer of spent resin from a demineralizer to an SRST, failure of a pneumatically operated valve on the outlet of the demineralizer would require special operator action. The valves have reach-rods extending through the shield wall, permitting manual operation of the valve. After flushing the demineralizer completely and allowing sufficient time for decay of any residual activity, the operating personnel would perform the required repair on the valve. A maximum dose of 800 mR is estimated to occur in the repair of a valve on a CVCS mixed bed demineralizer.

As a backup in the event the pneumatically operated tank outlet valve fails during transfer of spent resin from one of the SRSTs, the valve can be controlled by manual operators extending through a second shield wall to the operating area.

11.5.2.5 Packaging

Disposable mild steel liners are used for packaging dewatered, solidified, or encapsulated wastes. The typical liner sizes may range from 80 to 300 cubic feet. High -integrity containers (HICs) are also used for packaging dewatered or encapsulated wastes. Typical HIC sizes range from 75 to 200 cubic feet. Wet solid waste may be packaged for further offsite treatment, onsite storage, or offsite disposal.

Dry active wastes may be packaged for further offsite treatment, onsite storage, or offsite disposal. For onsite storage, 55-gallon steel drums, 4 x 4 x 6 foot steel boxes, or

bags are typically used. Drums, boxes, and intermodal containers classified as Industrial Package Type 1 or Type 2 containers are utilized for transportation offsite, as applicable.

11.5.2.6 Storage Facilities

Onsite storage for packaged wastes is provided by the SRSF and the RSB. These buildings are located east of the auxiliary building, as shown in Figure 11.5-4. Unpackaged activated metals and underwater vacuum cleaner filters are stored in the spent fuel pools. Disused radiation monitors may also be stored in the new fuel storage vaults.

The SRSF provides a storage area for metal boxes, drums, and shielded filters. The SRSF can hold 580 drums or a combination of 65 boxes and 60 drums. The arrangement of the rooms in the SRSF is shown in Figure 11.5-5. A forklift is used for moving the containers into and within the storage area. Concrete walls provide shielding between the various vaults in the SRSF. Encapsulation or dewatering of filters may occur in the SRSF. Segregation and compaction of dry active waste is also performed in the SRSF.

The RSB provides storage areas for 180 liners or HICs and for compacted dry active waste in 4 x 4 x 6 foot boxes or 55-gallon drums. The liner storage vaults are sized to accommodate 80 ft^3 containers stacked 3 wide by 2 high.

An overhead crane assembly is used for moving liners or HICs to their respective storage areas in the RSB. A shielded cask rail car is used to transport liners or HICs from the load-out area to the storage vaults. Encapsulation of filters and dewatering of resin may occur in the shielded cask rail car in the RSB truck bay. A liner-inspection/decontamination station is also provided for preparing containers for storage or shipping.

The compacted dry active waste storage area (DAW vault) is sized to accommodate 522 boxes at 93 ft^3 each, totaling 48,546 ft^3 of storage. Drums can also be stored in this facility. A forklift is used for moving the containers into and within the DAW vault.

The SGs and reactor vessel head assemblies (RVHAs) were removed from DCPP Unit 1 and Unit 2 during the SG and RVH replacement projects. These ten large components are temporarily stored in the steam generator storage facility (SGSF) specifically constructed for this purpose. The SGSF meets the radwaste storage requirements for temporary storage of the SGs and RVHAs until site decommissioning. The SGSF is designed to be used as a non-occupied mausoleum for the temporary storage of the SGs and RVHAs. No other radwaste storage is permitted within this facility.

11.5.2.7 Shipment

The shipment of pre-packaged solid radwaste from the plant site to licensed waste processing or disposal facilities is contracted to firms licensed to transport radioactive material in accordance with applicable Department of Transportation (DOT) regulations. All shipping containers and transportation casks are in conformance with 49 CFR Part 171 through 49 CFR Part 178 and 10 CFR Part 71, as applicable. Table 11.5-5 summarizes the expected quantities to be shipped.

11.5.3 SAFETY EVALUATION

11.5.3.1 General Design Criterion 3, 1971 – Fire Protection

The SRS is designed to meet the requirements of 10 CFR 50.48(a) and (c) (refer to Section 9.5.1).

11.5.3.2 General Design Criterion 4, 1967 – Sharing of Systems

The SRS is shared between DCPP Unit 1 and Unit 2. Because the SRS has no safety functions, the sharing does not impair safety on either unit.

11.5.3.3 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

Instrumentation is provided in the SRS buildings to monitor SRS radioactive releases.

The RSB ventilation exhaust air particulate samplers (RX-55 and RX-56) are in-line particulate filter assemblies for sampling the exhaust from the SRSF and the RSB, respectively, prior to discharge to the environment. These filters provide the capability to sample and subsequently assess (via laboratory analysis) the concentrations of radioactive material present in the exhaust from the respective buildings.

Refer to Section 11.4.2.1.2.1 and Table 11.4-1 for additional information.

11.5.3.4 General Design Criterion 18, 1967 – Monitoring Fuel and Waste Storage

Instrumentation is provided in the SRS buildings for conditions that might contribute to radiation exposures from the SRS.

The solid radwaste inspection station radiation monitors (R-84 and R-85) are area radiation monitors that permit the assessment of the radiation dose rates from waste containers being prepared for storage and shipment. The detectors are located at the decontamination/inspection station in the RSB.

The radwaste storage monitor (R-90) is an area radiation monitor located in the truck bay of the RSB.

The laundry facility monitor (R-92) is a process radiation monitor located in the laundry processing room of the SRSF. Samples are extracted by a sampling nozzle located in the room and then returned to the laundry processing room.

Refer to Section 11.4.2.1.2.1 and Table 11.4-1 for additional information.

11.5.3.5 General Design Criterion 68, 1967 – Fuel and Waste Storage Radiation Shielding

Radiation shielding in the auxiliary building and the SRS buildings protects personnel working near systems containing radioactivity from doses in excess of 10 CFR Part 20 limits (refer to Sections 11.5.2.2 and 12.1.7.3).

11.5.3.6 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

Solid radwastes are collected and contained in dedicated radwaste storage facilities.

Control of releases of radioactivity to the environment from the SRS is provided by HEPA filters in the SRSF and RSB ventilation systems and monitoring of the SRS effluents (refer to Sections 11.5.2.2.5 and 11.5.3.3). Baling of dry wastes is carried out inside a closed dust shroud.

For shipping purposes, wastes are packaged in containers that meet DOT requirements, and are shipped to licensed waste processing or disposal facilities in accordance with NRC and DOT regulations (refer to Sections 11.5.2.5, 11.5.2.7, 11.5.3.9, and 11.5.3.11).

11.5.3.7 10 CFR Part 20 – Standards for Protection Against Radiation

Occupational doses to plant personnel from the SRS are maintained ALARA by:

(1) Shielding in locations that contain SRS equipment (refer to Section 11.5.2)

(2) HVAC systems that direct air flows for controlled discharge and provide filtration of radioactive materials (refer to Section12.2.2)

(3) Monitoring of potentially radioactive releases from the SRS (refer to Sections 11.5.3.3 and 11.5.3.4)

(4) Packaging that is in accordance with regulatory guidelines for radioactive material (refer to Section 11.5.2.5)

(5) Protecting operating personnel in the event of a malfunction or component failure (refer to Section 11.5.2.4)

(6) Administrative controls for working in areas of potentially high radioactivity (refer to Section 5 of the Diablo Canyon Quality Assurance Program)

11.5.3.8 10 CFR 61.55 – Waste Classification

Plant administrative controls ensure that the classification of solid radwastes is in conformance with the requirements of 10 CFR 61.55.

11.5.3.9 10 CFR Part 71 – Packaging and Transportation of Radioactive Material

Plant administrative controls ensure that shipping containers and transportation casks for solid radwaste transportation to offsite waste processing or disposal facilities are in conformance with 10 CFR Part 71 (refer to Section 11.5.2.7).

11.5.3.10 40 CFR Part 190 – Environmental Radiation Protection Standards for Nuclear Power Operations

Current operational doses from all sources to members of the public are summarized in Annual Radioactive Effluent Release Reports and are demonstrated to be within the limits specified by 40 CFR Part 190, as implemented under 10 CFR 20.1301(e).

11.5.3.11 49 CFR Parts 171-178 – Subchapter C-Hazardous Materials Regulations

Plant administrative controls ensure that all shipping containers and transportation casks for solid radwaste transportation to offsite waste processing or disposal facilities are in conformance with 49 CFR Part 171 through 49 CFR Part 178 (refer to Section 11.5.2.7).

11.5.3.12 Regulatory Guide 1.143, Revision 1, October 1979 – Design Guidance for Radioactive Waste Management Structures, Systems, and Components Installed In Light-Water-Cooled Nuclear Power Plants

The SRS is PG&E Design Class II and III (refer to Section 11.5).

The PG&E Design Class II SRS equipment and piping that are used for processing radwaste liquids (spent resins) and are applicable to Regulatory Guide 1.143, Revision 1 are designated PG&E QA Class R, PG&E Piping Symbol H.

11.5.3.13 IE Bulletin 79-19, August 1979 – Packaging of Low-Level Radioactive Waste for Transport and Burial

DCPP maintains copies of applicable NRC and DOT regulations for transportation of low-level radioactive materials, including those requirements for the offsite processing or disposal facilities.

Designated personnel on site who are responsible for transportation of low-level radioactive materials and operation of the SRS are regularly trained on their respective responsibilities and on the governing NRC and DOT regulations.

DCPP maintains an audit program to ensure continued compliance with applicable NRC and DOT regulations for the transfer, packaging, and transportation of low-level radioactive material.

11.5.3.14 10 CFR 50.48(c) – National Fire Protection Association Standard NFPA 805

The SRS is designed to meet the nuclear safety and radioactive release performance criteria of Section 1.5 of NFPA 805, 2001 Edition (refer to Section 9.5.1).

11.5.4 TESTS AND INSPECTIONS

Tests and inspections of the SRS are done in accordance with plant procedures.

11.5.5 INSTRUMENTATION APPLICATIONS

Refer to Sections 11.5.3.3 and 11.5.3.4 for discussions of the instrumentation requirements and controls for the SRS.

11.5.6 REFERENCES

1. NUREG-0472, Radiological Effluent Technical Specifications for PWRs, Revision 3, USNRC, March 1979.

11.5.7 REFERENCE DRAWINGS

Figures representing controlled engineering drawings are incorporated by reference and are identified in Table 1.6-1. The contents of the drawings are controlled by DCPP procedures.

11.6 OFFSITE RADIOLOGICAL MONITORING PROGRAM

The offsite radiological monitoring program complies with the requirements of the State of California Department of Health Services, Radiological Health Section, and the NRC.

The monitoring program, required by the DCPP Technical Specifications, includes monitoring, sampling, analysis, and reporting, including performance of a Land Use Census and participation in an Interlaboratory Comparison Program.

11.6.1 DESIGN BASES

11.6.1.1 10 CFR Part 50, Appendix I – Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion "As Low as is Reasonably Achievable" for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents

The offsite radiological monitoring program provides data on measurable levels of radiation and radioactive materials in the environment in order to evaluate the relationship between quantities of radioactive materials released in effluents and resultant radiation doses to individuals from principal pathways of exposure.

The program identifies changes in the use of unrestricted areas (e.g., for agricultural purposes) to permit modifications in monitoring programs for evaluating doses to individuals from principal pathways of exposure.

11.6.2 PROGRAM DESCRIPTION

11.6.2.1 Expected Background

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

The 1984 results of the pre-operational monitoring program are shown in Table 11.6-4 and Reference 1. Table 11.6-4 summarizes measurements of external dose with thermoluminescent dosimeters (TLDs), gross beta, gamma isotopic, and I-131 activities in air samples and gamma isotopic and I-131 and/or tritium activities (as appropriate for particular samples) in marine and terrestrial samples. There were no known local man-made sources of radioactivity in the vicinity of DCPP; therefore, the variations shown in these tables are considered to be either natural variations or fallout from weapons testing. Gamma isotopic analyses were made of all marine and terrestrial samples. Only a few showed measurable activities above background. The results of all samples with detected activity during the pre-operational period of January 1, 1981, through March 31, 1984, are included in the Pre-operational Environmental Report (Reference 8).

The data, presented on an annual basis in the Annual Radiological Environmental Operating Report, show local differences in activity as well as seasonal variations.

Terrestrial variations may be attributable to such factors as variation in the spatial distribution of radionuclides in the soil, the amount of rainfall, TLD locations in valleys as contrasted to hillsides, and secondary sources of airborne dust from such activities as construction or farming.

These data and those for previous years serve as a baseline during plant operation.

11.6.2.2 Critical Pathways

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Based on the expected radiological releases from Unit 1 and Unit 2 (refer to Sections 11.2 and 11.3), and the tabulated estimates of dose, none of the releases were expected to significantly increase the total dose to man relative to natural background. Calculations showed which principal pathways for atmospheric releases will give the maximum doses. All doses through aquatic releases were expected to be negligible.

The levels of radiation in environmental samples were expected to be very low and, for many isotopes, below the minimum detectable level, using the best techniques available at original plant licensing. For this reason, dose analyses are performed based principally on plant effluent data, with secondary analyses based on environmental data.

For airborne releases, the ODCM is used with measured local meteorological data, measured release data of the gases and particulates, plus local demographic data, to estimate individual dose.

From the gamma dosimeter stations for the direct radiation measurements, in general, the offsite stations are used to serve as reference points for natural background and manmade environmental radiation that is not associated with plant operations. Onsite and fenceline stations are used to measure dose from the plant. Therefore, direct radiation dose above background is obtained and compared to calculated doses.

For radiological releases to the ocean, the ODCM is used in conjunction with effluent data to estimate dose from the consumption of aquatic foods grown within the radiological influence of the plant.

Bioaccumulation factors for species in the vicinity of Diablo Cove are obtained from Regulatory Guide 1.109, Revision 1 (Reference 7).

Aquatic food intake is based on the parameters provided in Reference 7 via the ODCM.

Consideration is also given to any group that has unusually high per capita consumption.

11.6.2.3 Sampling Media, Location and Frequency

11.6.2.3.1 Marine Samples

The types of marine samples, the frequency of collection, and the sampling locations are presented in the ODCM. These samples were selected to represent various food products.

11.6.2.3.2 Terrestrial Samples

Possible dose to man could result from atmospheric immersion and inhalation, and consumption of radionuclides deposited as particulates from the gaseous effluent of DCPP. To monitor the above pathways, various types of terrestrial samples are collected and analyzed. Air samples using particulate filters and iodine cartridges are taken continuously at a minimum of four sample locations. The sites were selected to provide data at downwind locations, major population centers, and areas that are not influenced by plant operations. It should be noted that eight of 16 sectors surrounding DCPP are located over water; therefore the five air sampling stations recommended by the Branch Technical Position for Radiological Environmental Monitoring Program (Revision 1, 1979) were reduced to four air sampling stations.

Gamma dosimetry measurements are made at environmental monitoring stations using TLDs. The TLDs were selected because of their sensitivity and the ease of readout.

Drinking water samples are collected from the domestic water system. Surface water samples are collected from the plant outfall.

Samples of various foodstuffs produced in the area are also collected when available.

The terrestrial sampling frequency reflects the areas that are most sensitive to changes in radioactive levels and in dose measurements. Thus, the airborne sampling is weekly, the TLD measurements are quarterly, and the terrestrial foods measurements are monthly, quarterly, or in season.

11.6.2.4 Analytical Sensitivity

11.6.2.4.1 Types of Analyses

The types of radiological analyses performed on each sample are presented in the ODCM. The offsite radiological monitoring program emphasizes analyses for those radionuclides expected to be present in the DCPP effluent and those that will be the major contributors to dose to the public.

The effluent from DCPP is expected to contain radionuclides whose identity and activity can be determined by gamma spectrometry. Thus, all samples are placed in a fixed

geometry and analyzed by gamma spectrometry. Other analysis techniques can be utilized as deemed necessary.

11.6.2.4.2 Measuring Equipment

The equipment presently in use for the radiological monitoring program typically includes, but is not limited to:

(1) Gas-flow proportional counter for gross beta analyses

(2) High purity intrinsic germanium detectors (or equivalent)

(3) TLDs for external dose measurements

(4) Beta-gamma coincidence spectrometer

(5) Liquid scintillation spectrometer

11.6.2.4.3 Sample Detection Sensitivity

The ability to accurately determine the radioactivity in a sample is a function of many variables including the following: (a) sample size, (b) self-absorption in the sample, (c) detector counting efficiency, (d) counting time background count rate, (e) half-life of the isotope, (f) loss of radionuclides in sample preparation, and (g) ability to distinguish between isotopes with similar gamma emission energies. Consistent results are obtained by standardizing procedures that maintain as many of the above variables constant as practicable.

11.6.2.5 Data Analysis and Presentation

The data acquired from the environmental monitoring program falls into the categories of:

(1) Information on the distribution of radioactivity in lower trophic levels in the physical environs of DCPP

(2) Information on external radiation in the vicinity of DCPP

(3) Information on radionuclides in foodstuffs that may result in a dose to man

In examining the distribution of radionuclides in the environment and lower trophic levels, comparisons are made to the preoperational data to determine if there are any biological or physical compartments in nature that are accumulating radioactivity. Similarly, external radioactivity measurements during plant operation are compared with the average and range of data obtained in the preoperational program.

If radionuclides due to plant effluents are found in foodstuffs, estimates of radiation dose are made that utilize the best estimates of food consumption. These dose calculations are compared with those based on plant emission data with the appropriate meteorological and aquatic dispersion models as discussed in Section 11.6.2.2.

The data from the offsite radiological monitoring program are reported in the Annual Radiological Environmental Operating Report. The report includes the basic data on sampling locations, organisms collected, counting data, gross activity levels, identification of gamma emitting isotopes, and the associated counting errors. Tables 11.6-13 and 11.6-14 present estimated concentrations and depositions based on the monitoring program.

11.6.2.6 Program Statistical Sensitivity

The activity in environmental samples is low after dilution and dispersion of radionuclides released by the power plant. For many isotopes, the radioactivity is below the lower limits of detection (LLD) that are listed in Table 11.6-11. With dose estimated from effluent data as shown in Sections 11.2 and 11.3, much lower dose levels can be estimated even though large errors may be introduced in the dispersion modeling. Thus, doses estimated using effluent data provide a more detailed definition of the dose increments due to the operation of DCPP than dose estimates calculated from the environmental measurements.

Counting errors for effluent data and errors associated with the calculational models are used to determine the overall sensitivity of estimated dose.

11.6.3 SAFETY EVALUATION

11.6.3.1 10 CFR Part 50, Appendix I – Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion "As Low as is Reasonably Achievable" for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents

The ODCM provides data on measurable levels of radiation and radioactive materials in the environment. The data are reported in the Annual Radiological Environmental Operating Report.

Annual land use censuses are conducted in the vicinity of DCPP, and reported in the Annual Radiological Environmental Operating Report, in order to provide compliance with 10 CFR 50 Part Appendix I, Section IV(B)(3).

11.6.4 REFERENCES

1. 1984 Annual Environmental Radiological Report, Diablo Canyon Power Plant, Pacific Gas and Electric Company, San Ramon, CA, Report 411-85.123, 1985.

2. Deleted in Revision 1.

3. Deleted in Revision 1.

4. Deleted in Revision 1.

5. Deleted in Revision 1.

6. Deleted in Revision 23.

7. Regulatory Guide 1.109, Revision 1, Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I, USNRC, October 1977.

8. Preoperational Radiological Environmental Report, Diablo Canyon Power Plant, Pacific Gas and Electric Company, San Ramon, CA, Report 411-84.530, 1985.

TABLE 11.0-1

APPLICABLE DESIGN BASIS CRITERIA

CRITERION	TITLE	APPLICABILITY					
Radioactive Waste Management		Source Terms[a]	Liquid Radwaste System	Gaseous Radwaste System	Process and Effluent Radiological Monitoring System	Solid Radwaste System	Offsite Radiological Monitoring Program
Section		11.1	11.2	11.3	11.4	11.5	11.6
1. General Design Criteria							
Criterion 2, 1967	Performance Standards		X	X	X		
Criterion 3, 1971	Fire Protection		X	X	X	X	
Criterion 4, 1967	Sharing of Systems		X	X	X	X	
Criterion 11, 1967	Control Room		X	X	X		
Criterion 12, 1967	Instrumentation and Control System		X	X	X		
Criterion 16, 1967	Monitoring Reactor Coolant Pressure Boundary				X		
Criterion 17, 1967	Monitoring Radioactivity Releases		X	X	X	X	
Criterion 18, 1967	Monitoring Fuel and Waste Storage			X	X	X	
Criterion 19, 1971	Control Room				X		
Criterion 21, 1967	Single Failure Definition				X		
Criterion 49, 1967	Containment Design Basis		X				
Criterion 54, 1971	Piping Systems Penetrating Containment		X				
Criterion 56, 1971	Primary Containment Isolation		X				
Criterion 68, 1967	Fuel and Waste Storage Radiation Shielding		X	X		X	
Criterion 69, 1967	Protection Against Radioactivity Release from Spent Fuel and Waste Storage		X	X	X		
Criterion 70, 1967	Control of Releases of Radioactivity to the Environment		X	X	X	X	

TABLE 11.0-1

CRITERION	TITLE	APPLICABILITY					
Radioactive Waste Management		Source Terms[a]	Liquid Radwaste System	Gaseous Radwaste System	Process and Effluent Radiological Monitoring System	Solid Radwaste System	Offsite Radiological Monitoring Program
Section		11.1	11.2	11.3	11.4	11.5	11.6
2. System Safety Function Requirements							
Protection from Missiles and Dynamic Effects			X		X		
3. Code of Federal Regulations							
10 CFR Part 20	Standards for Protection Against Radiation		X	X	X	X	
10 CFR 50.48(c)	National Fire Protection Association Standard NFPA 805					X	
10 CFR 50.49	Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants		X		X		
10 CFR 50.55a(f)	Inservice Testing Requirements		X				
10 CFR 50.55a(g)	Inservice Inspection Requirements		X				
10 CFR 50.68(b)	Criticality Accident Requirements				X		
10 CFR Part 50, Appendix I	Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion "As Low as is Reasonably Achievable" for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents		X	X	X		X
10 CFR 61.55	Waste Classification					X	
10 CFR Part 71	Packaging and Transportation of Radioactive Material					X	
40 CFR Part 190	Environmental Radiation Protection Standards for Nuclear Power Operations		X	X		X	
49 CFR Parts 171-178	Subchapter C-Hazardous Materials Regulations					X	

TABLE 11.0-1

CRITERION	TITLE	APPLICABILITY					
Radioactive Waste Management		Source Terms[a]	Liquid Radwaste System	Gaseous Radwaste System	Process and Effluent Radiological Monitoring System	Solid Radwaste System	Offsite Radiological Monitoring Program
Section		11.1	11.2	11.3	11.4	11.5	11.6
4. Atomic Energy Commission (AEC) Safety Guides							
Safety Guide 13, March 1971	Fuel Storage Facility Design Basis				X		
5. Regulatory Guides							
Regulatory Guide 1.21, Revision 1, June 1974	Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants				X		
Regulatory Guide 1.45, May 1973	Reactor Coolant Pressure Boundary Leakage Detection Systems				X		
Regulatory Guide 1.97, Revision 3, May 1983	Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident		X	X	X		
Regulatory Guide 1.143, Revision 1, October 1979	Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed In Light-Water-Cooled Nuclear Power Plants		X	X		X	
6. NRC NUREGs							
NUREG-0737, November 1980	Clarification of TMI Action Plan Requirements		X	X	X		
7. NRC Generic Letters							
Generic Letter 96-06, September 1996	Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions		X				

TABLE 11.0-1

CRITERION	TITLE	APPLICABILITY					
Radioactive Waste Management		Source Terms[(a)]	Liquid Radwaste System	Gaseous Radwaste System	Process and Effluent Radiological Monitoring System	Solid Radwaste System	Offsite Radiological Monitoring Program
Section		11.1	11.2	11.3	11.4	11.5	11.6
8. Bulletins							
IE Bulletin 79-19, August 1979	Packaging of Low-Level Radioactive Waste for Transport and Burial					X	

(a) There are no design basis criteria applicable to the source terms

TABLE 11.1-1

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

LIBRARY OF PHYSICAL DATA FOR ISOTOPES

Number	*Nuclide*	*Half-life, hours*	*Yield Fract*	*Beta Energy, MeV/Dis*	*Gamma Energy, MeV/Dis*	*Decay Const., hr^{-1}*
1	*H-3*	*0.108E 06*	*0.800E-04*	*0.00620*	*0.0*	*0.642E-05*
2	*Cr-51*	*0.667E 03*	*0.0*	*0.00055*	*0.02900*	*0.104E-02*
3	*Mn-54*	*0.727E 04*	*0.0*	*0.00590*	*0.83500*	*0.953E-04*
4	*Fe-55*	*0.648E 02*	*0.0*	*0.0*	*0.00600*	*0.107E-01*
5	*Co-58*	*0.171E 04*	*0.0*	*0.03100*	*0.98100*	*0.405E-03*
6	*Fe-59*	*0.108E 04*	*0.0*	*0.12900*	*1.17000*	*0.642E-03*
7	*Co-60*	*0.461E 05*	*0.0*	*0.10400*	*2.49000*	*0.150E-04*
8	*Kr-83M*	*0.186E 01*	*0.470E-02*	*0.03900*	*0.00050*	*0.373E 00*
9	*Kr-85M*	*0.440E 01*	*0.103E-01*	*0.25200*	*0.16000*	*0.157E 00*
10	*Kr-85*	*0.941E 05*	*0.0*	*0.22100*	*0.00200*	*0.736E-05*
11	*Kr-87*	*0.127E 01*	*0.194E-01*	*1.34000*	*0.76400*	*0.546E 00*
12	*Kr-88*	*0.277E 01*	*0.279E-01*	*0.37200*	*2.03000*	*0.250E 00*
13	*Sr-89*	*0.123E 04*	*0.369E-01*	*0.55600*	*0.0*	*0.563E-03*
14	*Sr-90*	*0.245E 06*	*0.455E-01*	*0.16900*	*0.0*	*0.283E-05*
15	*Y-90*	*0.639E 02*	*0.0*	*0.91200*	*0.0*	*0.208E-01*
16	*Sr-91*	*0.972E 01*	*0.461E-01*	*0.62400*	*0.84000*	*0.713E-01*
17	*Y-91*	*0.147E 04*	*0.120E-02*	*0.59300*	*0.00400*	*0.471E-03*
18	*Sr-92*	*0.270E 01*	*0.453E-01*	*0.21400*	*1.29000*	*0.257E 00*
19	*Y-92*	*0.360E 01*	*0.390E-02*	*1.39000*	*0.48500*	*0.192E 00*
20	*Zr-95*	*0.157E 04*	*0.585E-01*	*0.11100*	*0.73900*	*0.441E-03*
21	*Nb-95*	*0.841E 03*	*0.136E-02*	*0.04500*	*0.76000*	*0.824E-03*
22	*Mo-99*	*0.680E 02*	*0.607E-01*	*0.40500*	*0.12600*	*0.102E-01*
23	*I-131*	*0.193E 03*	*0.319E-01*	*0.18300*	*0.39200*	*0.359E-02*
24	*Te-132*	*0.779E 02*	*0.464E-01*	*0.06100*	*0.23100*	*0.890E-02*
25	*I-132*	*0.240E 01*	*0.530E-03*	*0.48500*	*2.28000*	*0.289E 00*
26	*I-133*	*0.210E 02*	*0.620E-01*	*0.49300*	*0.62400*	*0.330E-01*
27	*Xe-133M*	*0.552E 02*	*0.0*	*0.20700*	*0.02100*	*0.126E-01*
28	*Xe-133*	*0.127E 03*	*0.0*	*0.15500*	*0.04500*	*0.546E-02*
29	*Cs-134*	*0.180E 05*	*0.410E-04*	*0.16800*	*1.57000*	*0.385E-04*
30	*I-134*	*0.866E 00*	*0.764E-01*	*0.94100*	*2.58000*	*0.800E 00*
31	*I-135*	*0.670E 01*	*0.600E-01*	*0.31600*	*1.56000*	*0.103E 00*
32	*Xe-135M*	*0.260E 00*	*0.0*	*0.10400*	*0.42100*	*0.267E 01*
33	*Xe-135*	*0.920E 01*	*0.313E-02*	*0.30400*	*0.26200*	*0.753E-01*
34	*Cs-136*	*0.312E 03*	*0.377E-03*	*0.11900*	*2.21000*	*0.222E-02*
35	*Cs-137*	*0.236E 06*	*0.633E-01*	*0.17300*	*0.56200*	*0.294E-05*
36	*Xe-138*	*0.233E 00*	*0.558E-01*	*0.5900*	*1.28000*	*0.297E 01*
37	*Ba-140*	*0.307E 03*	*0.596E-01*	*0.27400*	*0.21200*	*0.226E-02*
38	*La-140*	*0.401E 02*	*0.103E-02*	*0.43900*	*2.31000*	*0.173E-01*
39	*Ce-144*	*0.685E 04*	*0.485E-01*	*0.09300*	*0.01600*	*0.101E-03*
40	*Pr-144*	*0.292E 00*	*0.0*	*1.20000*	*0.06400*	*0.237E 01*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-2

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

BASIC ASSUMPTIONS FOR CORE
AND COOLANT INVENTORIES FOR DESIGN BASIS CASE

Reactor core thermal power, mw	*3568.0*
Duration of cycle, hr	*8760.0*
Capacity factor during period	*0.800*
Number of fissions per megawatt-second	*0.315E17*
Total mass of uranium in core, lb	*1.97E5*
Total mass of plutonium in core, lb	*6.05E2*
Reload uranium enrichment, percent	*3.18*
Reload mass of fissile plutonium, lb	*0.0*
Primary-to-secondary leakrate, gpm	*0.0*
Primary coolant leakage to containment, gpm	*0.0*
Primary coolant leakage to auxiliary building, gpm	*0.0*
Fraction of fuel with defective cladding	*0.01*
Weight of water in primary system, lb	*5.66E5*
Volume of water in primary system, gal.	*9.40E4*
Letdown flowrate, gpm	*75.0*
Capacity factor of primary cation demineralizer	*0.1*
Average shim bleed flowrate, gpm	*1.0*
Fraction of shim bleed flow discharged to environment	*0.667*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-2A

BASIC ASSUMPTIONS FOR UPDATED CORE
AND 1% FUEL DEFECTS COOLANT INVENTORIES

Reactor core thermal power, MWth	3580
Duration of cycle, months (based on EFPDs)	19
Capacity factor during period	1.0
Maximum Core Average Burnup	50 GWD/MTU
Total mass of uranium in core, MTU	81.37
Number of Cycles	3 cycles in a 5 year period
Uranium enrichment, percent	4.2 to 5.0
Primary-to-secondary leakrate, gpm	0.0
Primary coolant leakage to containment, gpm	0.0
Primary coolant leakage to auxiliary building, gpm	0.0
Fraction of fuel with defective cladding	0.01
Weight of water in primary system, lb	6.07E5
Volume of water in primary system, gal	7.37E4
Letdown flowrate, gpm	75.0
Capacity factor of primary cation demineralizer	0.1
Average shim bleed flowrate, gpm	1.0
DF for Mixed-bed demineralizer	
- Cs, Rb	1
- Others	10
DF for Cation-bed Demineralizer	
- Cs, Rbr	10
- Other	1
Fission product escape rate coefficient (sec^{-1})	
- Noble gases	6.5E-08
- I, Br, Rb, Cs	1.3E-08
- Mo	2.0E-09
- Te	1.0E-09
- Sr, Ba	1.0E-11
- All others	1.6E-12
Corrosion product concentrations in RCS (μCi/g)	3 times expected values from NUREG 0017 R1
Tritium Concentrations (μCi/g)	3.5 times expected values from NUREG 0017 R1

TABLE 11.1-3

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

BASIC ASSUMPTIONS FOR CORE AND COOLANT INVENTORIES FOR NORMAL OPERATION CASE

Reactor core thermal power, mw	*3568.0*
Duration of cycle, hr	*8760.0*
Capacity factor during period	*0.800*
Number of fissions per megawatt-second	*0.315E17*
Total mass of uranium in core, lb	*1.97E5*
Total mass of plutonium in core, lb	*6.05E2*
Reload uranium enrichment, percent	*3.18*
Reload mass of fissile plutonium, lb	*0.0*
Primary-to-secondary leakrate, gpm	*0.0115*
Primary coolant leakage to containment, gpm	*0.0385*
Primary coolant leakage to auxiliary building, gpm	*0.0184*
Fraction of fuel with defective cladding	*0.0012*
Weight of water in primary system, lb	*5.66E5*
Volume of water in primary system, gal.	*9.40E4*
Letdown flowrate, gpm	*75.0*
Capacity factor of primary cation demineralizer	*0.1*
Average shim bleed flowrate, gpm	*1.0*
Fraction of shim bleed flow discharged to environment	*0.667*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-4
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
CORE ACTIVITY INVENTORIES FOR DESIGN BASIS CASE (CURIES)

Nuclide	Initial Act.	Produced	Decayed	Lkge to Coolt.	Inventory	Equil Inven.	Curies/Megawatt
Cr-51	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mn-54	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fe-55	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Co-58	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fe-59	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Co-60	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kr-83M	0.0	0.4660E 11	0.4658E 11	0.2340E 06	0.1428E 08	0.1428E 08	0.4001E 04
Kr-85M	0.0	0.4317E 11	0.4314E 11	0.5127E 06	0.3129E 08	0.3129E 08	0.8769E 04
Kr-85	0.4007E 06	0.4639E 06	0.3932E 05	0.1249E 05	0.8128E 06	0.5461E 07	0.2278E 03
Kr-87	0.0	0.2817E 12	0.2816E 12	0.9662E 06	0.5893E 08	0.5893E 08	0.1652E 05
Kr-88	0.0	0.1857E 12	0.1856E 12	0.1389E 07	0.8475E 08	0.8475E 08	0.2375E 05
Sr-89	0.4946E 06	0.5532E 09	0.4910E 09	0.2510E 03	0.1116E 09	0.1121E 09	0.3129E 05
Sr-90	0.3073E 07	0.3425E 07	0.1173E 06	0.1194E 02	0.6380E 07	0.1382E 09	0.1786E 04
Y-90	0.3073E 07	0.4497E 09	0.4464E 09	0.1897E 01	0.6346E 07	0.1382E 09	0.1779E 04
Sr-91	0.4745E-14	0.8746E 11	0.8732E 11	0.3527E 03	0.1400E 09	0.1400E 09	0.3925E 05
Y-91	0.6767E 08	0.5924E 09	0.5177E 09	0.5060E 02	0.1424E 09	0.1437E 09	0.3992E 05
Sr-92	0.0	0.3094E 12	0.3093E 12	0.3470E 03	0.1376E 09	0.1376E 09	0.3857E 05
Y-92	0.0	0.2519E 12	0.2518E 12	0.6027E 02	0.1495E 09	0.1495E 09	0.4189E 05
Zr-95	0.8460E 08	0.6871E 09	0.5960E 09	0.6221E 02	0.1758E 09	0.1777E 09	0.4926E 05
Nb-95	0.1083E 09	0.1142E 10	0.1073E 10	0.6000E 02	0.1777E 09	0.1818E 09	0.4981E 05
Mo-99	0.8000E 05	0.1646E 11	0.1628E 11	0.9199E 05	0.1844E 09	0.1844E 09	0.5168E 05
I-131	0.4937E 07	0.3048E 10	0.2956E 10	0.3082E 06	0.9689E 08	0.9689E 08	0.2715E 05
Te-132	0.1553E 06	0.1098E 11	0.1084E 11	0.3510E 05	0.1409E 09	0.1409E 09	0.3950E 05
I-132	0.1602E 06	0.3560E 12	0.3559E 12	0.4614E 06	0.1426E 09	0.1426E 09	0.3995E 05
I-133	0.6024E-02	0.5444E 11	0.5425E 11	0.6155E 06	0.1883E 09	0.1883E 09	0.5278E 05
Xe-133M	0.1593E 04	0.4954E 09	0.4908E 09	0.7318E 05	0.4519E 07	0.4519E 07	0.1267E 04
Xe-133	0.3309E 07	0.8969E 10	0.8780E 10	0.3012E 07	0.1882E 09	0.1882E 09	0.5276E 05
Cs-134	0.1460E 01	0.3605E 07	0.1284E 07	0.1248E 05	0.3116E 07	0.3116E 07	0.8734E 03
I-134	0.0	0.1627E 13	0.1627E 13	0.7610E 06	0.2321E 09	0.2321E 09	0.6504E 05
I-135	0.0	0.1651E 12	0.1650E 12	0.5971E 06	0.1823E 09	0.1823E 09	0.5108E 05
Xe-135M	0.0	0.6164E 12	0.6163E 12	0.4329E 06	0.2643E 08	0.2643E 08	0.7407E 04
Xe-135	0.9747E-15	0.1264E 12	0.1838E 11	0.4567E 06	0.2789E 08	0.2789E 08	0.7816E 04
Cs-136	0.1542E 06	0.7228E 08	0.2129E 08	0.3588E 04	0.1145E 07	0.1145E 07	0.3209E 03
Cs-137	0.4430E 07	0.4946E 07	0.1753E 06	0.2235E 05	0.9173E 07	0.1658E 09	0.2571E 04
Xe-138	0.0	0.4416E 13	0.4416E 13	0.2779E 07	0.1695E 09	0.1695E 09	0.4751E 05
Ba-140	0.2375E 08	0.3580E 10	0.3423E 10	0.4367E 03	0.1810E 09	0.1610E 09	0.5074E 05
La-140	0.2732E 08	0.2668E 11	0.2652E 11	0.7071E 02	0.1642E 09	0.1842E 09	0.5162E 05
Ce-144	0.6129E 08	0.1306E 09	0.7999E 08	0.3644E 02	0.1119E 09	0.1473E 09	0.3135E 05
Pr-144	0.6127E 08	0.1877E 13	0.1876E 13	0.3643E 02	0.1119E 09	0.1473E 09	0.3135E 05

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-5
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
CORE ACTIVITY INVENTORIES FOR NORMAL OPERATION CASE (CURIES)

Nuclide	Initial Act.	Produced	Decayed	Lkge to Coolt.	Inventory	Equil Inven.	Curies/Megawatt
Cr-51	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Mn-54	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Fe-55	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Co-58	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Fe-59	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Co-60	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Kr-83M	*0.0*	*0.4660E 11*	*0.4658E 11*	*0.2809E 05*	*0.1428E 08*	*0.1428E 08*	*0.4001E 04*
Kr-85M	*0.0*	*0.4317E 11*	*0.4314E 11*	*0.6152E 05*	*0.3129E 08*	*0.3129E 08*	*0.8769E 04*
Kr-85	*0.4007E 06*	*0.4639E 06*	*0.3963E 05*	*0.1511E 04*	*0.8235E 06*	*0.6932E 07*	*0.2308E 03*
Kr-87	*0.0*	*0.2817E 12*	*0.2816E 12*	*0.1159E 06*	*0.5893E 08*	*0.5893E 08*	*0.1652E 05*
Kr-88	*0.0*	*0.1857E 12*	*0.1857E 12*	*0.1667E 06*	*0.8475E 08*	*0.8475E 08*	*0.2375E 05*
Sr-89	*0.4946E 08*	*0.5532E 09*	*0.4910E 09*	*0.3012E 02*	*0.1116E 09*	*0.1121E 09*	*0.3129E 05*
Sr-90	*0.3073E 07*	*0.3425E 07*	*0.1173E 06*	*0.1433E 01*	*0.6380E 07*	*0.1382E 09*	*0.1788E 04*
Y-90	*0.3073E 07*	*0.4497E 09*	*0.4465E 09*	*0.2276E 00*	*0.6346E 07*	*0.1382E 09*	*0.1779E 04*
Sr-91	*0.4745E-14*	*0.8746E 11*	*0.8732E 11*	*0.4233E 02*	*0.1400E 09*	*0.1400E 09*	*0.3925E 05*
Y-91	*0.6767E08*	*0.5924E 09*	*0.5177E 09*	*0.6072E 01*	*0.1424E 09*	*0.1437E 09*	*0.3992E 05*
Sr-92	*0.0*	*0.3094E 12*	*0.3093E 12*	*0.4164E 02*	*0.1376E 09*	*0.1376E 09*	*0.3857E 05*
Y-92	*0.0*	*0.2519E 12*	*0.2518E 12*	*0.7232E 01*	*0.1495E 09*	*0.1495E 09*	*0.4189E 05*
Zr-95	*0.8460E 08*	*0.6871E 09*	*0.5960E 09*	*0.7466E 01*	*0.1758E 09*	*0.1777E 09*	*0.4926E 05*
Nb-95	*0.1083E 09*	*0.1142E 10*	*0.1073E 10*	*0.7200E 01*	*0.1777E 09*	*0.1818E 09*	*0.4981E 05*
Mo-99	*0.8000E 05*	*0.1646E 11*	*0.1628E 11*	*0.1104E 05*	*0.1844E 09*	*0.1844E 09*	*0.5168E 05*
I-131	*0.4937E 07*	*0.3048E 10*	*0.2956E 10*	*0.3699E 05*	*0.9690E 08*	*0.9690E 08*	*0.2716E 05*
Te-132	*0.1553E 06*	*0.1098E 11*	*0.1084E 11*	*0.4212E 04*	*0.1409E 09*	*0.1409E 09*	*0.3950E 05*
I-132	*0.1602E 06*	*0.3560E 12*	*0.3559E 12*	*0.5537E 05*	*0.1426E 09*	*0.1426E 09*	*0.3995E 05*
I-133	*0.6024E 02*	*0.5444E 11*	*0.5425E 11*	*0.7387E 05*	*0.1883E 09*	*0.1883E 09*	*0.5278E 05*
Xe-133M	*0.1593E 04*	*0.4954E 09*	*0.4908E 09*	*0.8783E 04*	*0.4520E 07*	*0.4520E 07*	*0.1267E 04*
Xe-133	*0.3309E 07*	*0.8969E 10*	*0.8784E 10*	*0.3616E 06*	*0.1883E 09*	*0.1883E 09*	*0.5278E 05*
Cs-134	*0.1460E 01*	*0.3605E 07*	*0.1298E 07*	*0.1514E 04*	*0.3121E 07*	*0.3121E 07*	*0.8749E 03*
I-134	*0.0*	*0.1627E 13*	*0.1627E 13*	*0.9132E 05*	*0.2321E 09*	*0.2321E 09*	*0.6504E 05*
I-135	*0.0*	*0.1651E 12*	*0.1650E 12*	*0.7165E 05*	*0.1823E 09*	*0.1823E 09*	*0.5108E 05*
Xe-135M	*0.0*	*0.6164E 12*	*0.6163E 12*	*0.5195E 05*	*0.2643E 08*	*0.2643E 08*	*0.7407E 04*
Xe-135	*0.9747E-15*	*0.1264E 12*	*0.1838E 11*	*0.5481E 05*	*0.2789E 08*	*0.2789E 08*	*0.7816E 04*
Cs-136	*0.1542E 06*	*0.2228E 08*	*0.2129E 08*	*0.4307E 03*	*0.1145E 07*	*0.1145E 07*	*0.3210E 03*
Cs-137	*0.4430E 07*	*0.4946E 07*	*0.1755E 06*	*0.2686E 04*	*0.9197E 07*	*0.1887E 09*	*0.2578E 04*
Xe-138	*0.0*	*0.4416E 13*	*0.4416E 13*	*0.3335E 06*	*0.1695E 09*	*0.1695E 09*	*0.4751E 05*
Ba-140	*0.2375E 08*	*0.3580E 10*	*0.3423E 10*	*0.5240E 02*	*0.1810E 09*	*0.1810E 09*	*0.5074E 05*
La-140	*0.2732E 08*	*0.2668E 11*	*0.2652E 11*	*0.8486E 01*	*0.1842E 09*	*0.1842E 09*	*0.5162E 05*
Ce-144	*0.6129E 08*	*0.1306E 09*	*0.7999E 08*	*0.4372E 01*	*0.1119E 09*	*0.1473E 09*	*0.3135E 05*
Pr-144	*0.6127E 08*	*0.1877E 13*	*0.1876E 13*	*0.4372E 01*	*0.1119E 09*	*0.1473E 09*	*0.3135E 05*

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TABLE 11.1-6

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

BASIC ASSUMPTIONS FOR FUEL ROD GAP INVENTORIES

Percent of Core Fuel Within Given Temperature Range[a]	*Power, MWt*	*Fuel Temperature Range, °F*
0.0	*0.1961*	*>3400*
0.1	*3.1373*	*3400 - 3200*
0.3	*10.3922*	*3200 - 3000*
0.7	*25.1*	*3000 - 2800*
1.6	*58.333*	*2800 - 2600*
2.9	*104.61*	*2600 - 2400*
4.3	*152.55*	*2400 - 2200*
5.9	*211.275*	*2200 - 2000*
84.1	*2999.02*	*<2000*

(a) Based on hot channel factors of F_H = 1.70 and F_q = 2.82.

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-7

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ACTIVITY IN FUEL ROD GAPS

Nuclide	*Pellet Release Fraction*	*Gap Inventory, Ci*
Kr-83M	*0.000824*	*0.118E 05*
Kr-85M	*0.001240*	*0.388E 05*
Kr-85	*0.167000*	*0.138E 06*
Kr-87	*0.000668*	*0.394E 05*
Kr-88	*0.000998*	*0.846E 05*
I-131	*0.008220*	*0.797E 06*
I-132	*0.000901*	*0.128E 06*
I-133	*0.002710*	*0.510E 06*
Xe-133M	*0.004370*	*0.198E 05*
Xe-133	*0.006670*	*0.126E 07*
I-134	*0.000557*	*0.129E 06*
I-135	*0.001540*	*0.281E 06*
Xe-135M	*0.000303*	*0.801E 04*
Xe-135	*0.001800*	*0.502E 05*
Xe-138	*0.000316*	*0.536E 05*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-8

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

INPUT CONSTANTS FOR COOLANT ACTIVITIES FOR DESIGN BASIS CASE

Nuclide	Fuel to Coolant, Ci/hr	Fuel Escape Rate, sec^{-1}	Pur. Rate, hr^{-1}	P-S Leak Rate, hr^{-1}	Prim-Cont Lk Rate, hr^{-1}	Prim-Aux Lk Rate hr^{-1}
H-3	0.0	0.0	0.5897E-03	0.0	0.0	0.0
Cr-51	0.3010E-01	0.0	0.6034E-01	0.0	0.0	0.0
Mn-54	0.4820E-02	0.0	0.6034E-01	0.0	0.0	0.0
Fe-55	0.2890E-01	0.0	0.6034E-01	0.0	0.0	0.0
Co-58	0.2500E 00	0.0	0.6034E-01	0.0	0.0	0.0
Fe-59	0.1570E-01	0.0	0.6034E-01	0.0	0.0	0.0
Co-60	0.3090E-01	0.0	0.6034E-01	0.0	0.0	0.0
Kr-83M	0.3340E 02	0.6500E-07	0.8840E-03	0.0	0.0	0.0
Kr-85M	0.7316E 02	0.6500E-07	0.8840E-03	0.0	0.0	0.0
Kr-85	0.1426E 01	0.6500E-07	0.8840E-03	0.0	0.0	0.0
Kr-87	0.1379E 03	0.6500E-07	0.8840E-03	0.0	0.0	0.0
Kr-88	0.1982E 03	0.6500E-07	0.8840E-03	0.0	0.0	0.0
Sr-89	0.3582E-01	0.1000E-10	0.6034E-01	0.0	0.0	0.0
Sr-90	0.1704E-02	0.1000E-10	0.6034E-01	0.0	0.0	0.0
Y-90	0.2707E-03	0.1600E-11	0.8840E-03	0.0	0.0	0.0
Sr-91	0.5033E-01	0.1000E-10	0.6034E-01	0.0	0.0	0.0
Y-91	0.7220E-02	0.1600E-11	0.8840E-03	0.0	0.0	0.0
Sr-92	0.4952E-01	0.1000E-10	0.6034E-01	0.0	0.0	0.0
Y-92	0.8600E-02	0.1600E-11	0.8840E-03	0.0	0.0	0.0
Zr-95	0.8878E-02	0.1600E-11	0.6034E-01	0.0	0.0	0.0
Nb-95	0.8562E-02	0.1600E-11	0.6034E-01	0.0	0.0	0.0
Mo-99	0.1313E 02	0.2000E-08	0.8840E-03	0.0	0.0	0.0
I-131	0.4398E 02	0.1300E-07	0.5976E-01	0.0	0.0	0.0
Te-132	0.5009E 01	0.1000E-08	0.5976E-01	0.0	0.0	0.0
I-132	0.6584E 02	0.1300E-07	0.5976E-01	0.0	0.0	0.0
I-133	0.8783E 02	0.1300E-07	0.5576E-01	0.0	0.0	0.0
Xe-133M	0.1044E 02	0.6500E-07	0.8840E-03	0.0	0.0	0.0
Xe-133	0.4298E 03	0.6500E-07	0.8840E-03	0.0	0.0	0.0
Cs-134	0.1781E 01	0.1300E-07	0.3637E-01	0.0	0.0	0.0
I-134	0.1086E 03	0.1300E-07	0.5976E-01	0.0	0.0	0.0
I-135	0.8520E 02	0.1300E-07	0.5976E-01	0.0	0.0	0.0
Xe-135M	0.6177E 02	0.6500E-07	0.8840E-03	0.0	0.0	0.0
Xe-135	0.6517E 02	0.6500E-07	0.8840E-03	0.0	0.0	0.0
Cs-136	0.5120E 00	0.1300E-07	0.3637E-01	0.0	0.0	0.0
Cs-137	0.3189E 01	0.1300E-07	0.3637E-01	0.0	0.0	0.0
Xe-138	0.3988E 03	0.6500E-07	0.8840E-01	0.0	0.0	0.0
Ba-140	0.8231E-01	0.1000E-10	0.6034E-01	0.0	0.0	0.0
La-140	0.1009E-01	0.1000E-11	0.6034E-01	0.0	0.0	0.0
Ce-144	0.5199E-02	0.1600E-11	0.6034E-01	0.0	0.0	0.0
Pr-144	0.5199E-02	0.1600E-11	0.6034E-01	0.0	0.0	0.0

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TABLE 11.1-9

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

INPUT CONSTANTS FOR COOLANT ACTIVITIES FOR NORMAL OPERATION CASE

Nuclide	*Fuel to Coolant, Ci/hr*	*Fuel Escape Rate, sec^{-1}*	*Pur. Rate, hr^{-1}*	*P-S Leak Rate, hr^{-1}*	*Prim-Cont Lk Rate, hr^{-1}*	*Prim-Aux Lk Rate hr^{-1}*
H-3	*0.0*	*0.0*	*0.5897E-03*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Cr-51	*0.3010E-01*	*0.0*	*0.6034E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Mn-54	*0.4820E-02*	*0.0*	*0.6034E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Fe-55	*0.2890E-01*	*0.0*	*0.6034E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Co-58	*0.2500E 00*	*0.0*	*0.6034E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Fe-59	*0.1570E-01*	*0.0*	*0.6034E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Co-60	*0.3090E-01*	*0.0*	*0.6034E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Kr-83M	*0.4008E 01*	*0.6500E-07*	*0.8840E-03*	*0.7340E-05*	*0.4167E-03*	*0.1174E-04*
Kr-85M	*0.8779E 01*	*0.6500E-07*	*0.8840E-03*	*0.7340E-05*	*0.4167E-03*	*0.1174E-04*
Kr-85	*0.1725E 00*	*0.6500E-07*	*0.8840E-03*	*0.73403-05*	*0.4167E-03*	*0.1174E-04*
Kr-87	*0.1854E 02*	*0.6500E-07*	*0.8840E-03*	*0.7340E-05*	*0.4167E-03*	*0.1174E-04*
Kr-88	*0.2379E 02*	*0.6500E-07*	*0.8840E-03*	*0.7340E-05*	*0.4167E-03*	*0.1174E-04*
Sr-89	*0.4298E-02*	*0.1000E-10*	*0.6034E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Sr-90	*0.2045E-03*	*0.1000E-10*	*0.6034E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Y-90	*0.3248E-04*	*0.1600E-11*	*0.8840E-03*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Sr-91	*0.6040E-02*	*0.1000E-10*	*0.6034E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Y-91	*0.8664E-03*	*0.1600E-11*	*0.8840E-03*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Sr-92	*0.5942E-02*	*0.1000E-10*	*0.6034E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Y-92	*0.1032E-02*	*0.1600E-11*	*0.8840E-03*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Zr-95	*0.1065E-02*	*0.1600E-11*	*0.6034E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Mb-95	*0.1027E-02*	*0.1600E-11*	*0.6034E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Mb-99	*0.1575E 01*	*0.2000E-08*	*0.8840E-03*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
I-131	*0.5278E 01*	*0.1300E-07*	*0.5976E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Te-132	*0.6011E 00*	*0.1000E-08*	*0.5976E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
I-132	*0.7901E 01*	*0.1300E-07*	*0.5976E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
I-133	*0.1054E 02*	*0.1300E-07*	*0.5976E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Me-133M	*0.1253E 01*	*0.6500E-07*	*0.8840E-03*	*0.7340E-05*	*0.4167E-03*	*0.1174E-04*
Mn-133	*0.5160E 02*	*0.6500E-07*	*0.8840E-03*	*0.7340E-05*	*0.4167E-03*	*0.1174E-04*
Cs-134	*0.2161E 00*	*0.1300E-07*	*0.3637E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
I-134	*0.1303E 02*	*0.1300E-07*	*0.5976E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
I-135	*0.1022E 02*	*0.1300E-07*	*0.5976E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Xe-135M	*0.7412E 01*	*0.6500E-07*	*0.8840E-03*	*0.7340E-05*	*0.4167E-03*	*0.1174E-04*
Xe-135	*0.7821E 01*	*0.6500E-07*	*0.8840E-03*	*0.7340E-05*	*0.4167E-03*	*0.1174E-04*
Cs-136	*0.6145E-01*	*0.1300E-07*	*0.3637E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Cs-137	*0.3832E 00*	*0.1300E-07*	*0.3637E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Xe-138	*0.4759E 02*	*0.6500E-07*	*0.8840E-03*	*0.7340E-05*	*0.4167E-03*	*0.1174E-04*
Ba-140	*0.7477E-02*	*0.1000E-10*	*0.6034E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
La-140	*0.1211E-02*	*0.1600E-11*	*0.6034E 01*	*0.73403-05*	*0.2457E-04*	*0.1174E-04*
Ce-144	*0.6239E-03*	*0.1600E-11*	*0.6034E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*
Pr-144	*0.6239E-03*	*0.1600E-11*	*0.6034E-01*	*0.7340E-05*	*0.2457E-04*	*0.1174E-04*

Note: The information presented in the above table was developed in support of the original license and is considered historical

TABLE 11.1-10

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

BASIC DATA FOR CORROSION PRODUCT ACTIVITIES

Core Wetted Areas, Effective, in^2	
Zirconium	*9.42×10^6*
Stainless steel	*6.09×10^5*
Inconel	*1.01×10^6*
Out-of-core Wetted Area, Inconel, in^2	*2.74×10^7*
Coolant velocity, ft/sec	
Core	*15.0*
Steam generator	*18.6*
Nominal Base Metal Release Rates, mg/dm^2-mo	
Zirconium	*0.0*
Stainless steel	*0.5*
Inconel	*1.0*
Coolant Crud Level, ppm	*0.1*
Permanent Crud Film, Nominal, mg/dm^2	
Incore	*50*
Out-of-core	*50*
Transient Crud Layer, Nominal, mg/dm^2	
Incore	*50*
Out-of-core	*50*
Total mass of metal in contact with primary coolant, lb	*2.2×10^6*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-11
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
PRIMARY COOLANT ACTIVITIES FOR DESIGN BASIS CASE

Nuclide	*Concentration, µCi/cc*	*Activity, Ci*
H-3	*0.7934E 00*	*0.2823E 03*
Cr-51	*0.1378E-02*	*0.4904E 00*
Mn-54	*0.2241E-03*	*0.7976E-01*
Fe-55	*0.1143E-02*	*0.4069E 00*
Co-58	*0.2600E-01*	*0.9250E-01*
Fe-59	*0.7236E-03*	*0.2575E 00*
Co-60	*0.1439E-02*	*0.5120E 00*
Kr-83M	*0.2513E 00*	*0.8943E 02*
Kr-85M	*0.1298E 01*	*0.4619E 03*
Kr-85	*0.4166E 01*	*0.1482E 04*
Kr-87	*0.7089E 00*	*0.2522E 03*
Kr-88	*0.2219E 01*	*0.7895E 03*
Sr-89	*0.1653E-02*	*0.5881E 00*
Sr-90	*0.7937E-04*	*0.2824E-01*
Y-90	*0.1382E-03*	*0.4919E-01*
Sr-91	*0.1075E-02*	*0.3824E 00*
Y-91	*0.1534E-01*	*0.5460E 01*
Sr-92	*0.4390E-03*	*0.1562E 00*
Y-92	*0.5619E-03*	*0.2000E 00*
Zr-95	*0.4105E-03*	*0.1461E 00*
Nb-95	*0.3989E-03*	*0.1420E 00*
Mo-99	*0.3331E 01*	*0.1185E 04*
I-131	*0.1951E 01*	*0.6941E 03*
Te-132	*0.2050E 00*	*0.7296E 02*
I-132	*0.7008E 00*	*0.2494E 03*
I-133	*0.2661E 01*	*0.9469E 03*
Xe-133M	*0.2243E 01*	*0.7983E 03*
Xe-133	*0.1947E 03*	*0.6927E 05*
Cs-134	*0.1375E 00*	*0.4893E 02*
I-134	*0.3549E 00*	*0.1263E 03*
I-135	*0.1467E 01*	*0.5221E 03*
Xe-135M	*0.2778E 00*	*0.9884E 02*
Xe-135	*0.3918E 01*	*0.1394E 04*
Cs-136	*0.3729E-01*	*0.1327E 02*
Cs-137	*0.2464E 00*	*0.8767E 02*
Xe-138	*0.3746E 00*	*0.1333E 03*
Ba-140	*0.2798E-02*	*0.9955E 00*
La-140	*0.9882E-03*	*0.3516E 00*
Ce-144	*0.2418E-03*	*0.8602E-01*
Pr-144	*0.2418E-03*	*0.8603E-01*
Zn-65	*0.8000E-02*	*0.2846E-01*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-11A
UPDATED PRIMARY COOLANT ACTIVITIES
(Based on 3580 MWt, 600 EFPDs, 1% Fuel Defects)

Nuclide	Activity Conc. (μ/Ci/g)	Nuclide	Activity Conc. (μ/Ci/g)	Nuclide	Activity Conc (μ/Ci/g)
Kr-83m	3.77E-01	Y93	3.00E-04	Te134	2.92E-02
Kr-85m	1.36E+00	Y94	2.61E-05	Cs134m	5.29E-02
Kr-85	1.12E+01	Y95	1.11E-05	Cs134	7.39E+00
Kr-87	8.87E-01	Zr95	6.24E-04	Cs136	1.67E+00
Kr-88	2.49E+00	Zr97	3.87E-04	Cs137	4.21E+00
Kr-89	6.97E-02	Nb95m	6.97E-06	Cs138	9.99E-01
Xe-131m	4.06E+00	Nb95	6.30E-04	Cs139	8.96E-02
Xe-133m	4.18E+00	Nb97m	3.66E-04	Cs140	9.08E-03
Xe-133	2.81E+2	Nb97	4.12E-04	Cs142	1.07E-04
Xe-135m	8.14E-01	Mo99	7.65E-01	Ba137m	3.97E+00
Xe-135	7.89E+00	Mo101	2.05E-02	Ba139	7.85E-02
Xe-137	1.94E-01	Mo102	1.51E-02	Ba140	4.38E-03
Xe-138	6.54E-01	Mo105	7.67E-04	Ba141	1.21E-04
		Tc99m	4.08E-01	Ba142	1.74E-04
Br83	7.20E-02	Tc101	2.00E-02	La140	1.43E-03
Br84	3.51E-02	Tc102	1.51E-02	La141	2.66E-04
Br85	3.67E-03	Tc105	7.85E-04	La142	2.34E-04
Br87	1.89E-03	Ru103	6.26E-04	La143	1.38E-05
I129	1.24E-07	Ru105	1.48E-04	Ce141	6.04E-04
I130	6.30E-02	Ru106	2.54E-04	Ce143	4.46E-04
I131	2.92E+00	Ru107	2.09E-06	Ce144	4.78E-04
I132	1.11E+00	Ru103m	5.69E-04	Ce145	2.08E-06
I133	4.30E+00	Rh105m	4.17E-05	Ce146	7.72E-06
I134	6.19E-01	Rh105	3.55E-04	Pr143	5.63E-04
I135	2.48E+00	Rh106	2.54E-04	Pr144	4.78E-04
I136	6.69E-03	Rh107	1.25E-05	Pr145	1.53E-04
		Sn127	2.59E-06	Pr146	2.04E-05
Se81	5.84E-07	Sn128	5.16E-06	Nd147	2.42E-04
Se83	7.95E-07	Sn130	8.25E-07	Nd149	2.34E-05
Se84	4.58E-07	Sb127	3.16E-05	Nd151	1.72E-06
Rb86	6.40E-02	Sb128	2.89E-06	Pm147	1.19E-04
Rb88	2.54E+00	Sb129	3.92E-05	Pm149	2.12E-04
Rb89	1.41E-01	Sb130	2.75E-06	Pm151	6.02E-05
Rb90	1.11E-02	Sb131	1.16E-05	Sm151	6.11E-07

TABLE 11.1-11A
UPDATED PRIMARY COOLANT ACTIVITIES
(Based on 3580 MWt, 600 EFPDs, 1% Fuel Defects)

Nuclide	Activity Conc. (μ/Ci/g)	Nuclide	Activity Conc. (μ/Ci/g)	Nuclide	Activity Conc (μ/Ci/g)
Rb91	5.66E-03	Sb132	8.97E-07	Sm153	1.92E-04
Rb92	3.88E-04	Sb133	1.04E-06		
Sr89	3.21E-03	Te125m	5.02E-04	Na24 *	1.41E-01
Sr90	2.30E-04	Te127m	3.50E-03	Cr51 *	9.30E-03
Sr91	1.36E-03	Te127	1.25E-02	Mn54 *	4.80E-03
Sr92	9.56E-04	Te129m	1.48E-02	Fe55 *	3.60E-03
Sr93	4.39E-05	Te129	1.64E-02	Fe59 *	9.00E-04
Sr94	7.48E-06	Te131m	3.71E-02	Co58 *	1.38E-02
Y90	6.32E-05	Te131	1.63E-02	Co60 *	1.59E-03
Y91m	7.46E-04	Te132	3.01E-01	Zn65 *	1.53E-03
Y91	4.59E-04	Te133m	1.92E-02	Np-239 *	6.60E-03
Y92	8.21E-04	Te133	8.00E-03		

* Concentration values for corrosion products and Np-239 are assumed to be 3 times the expected values listed in NUREG-0017 R1.

TABLE 11.1-12
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
PRIMARY COOLANT ACTIVITIES FOR NORMAL OPERATION CASE

Nuclide	*Concentration, µCi/cc*	*Activity, Ci*
H-3	*0.7377E 00*	*0.2625E 03*
Cr-51	*0.1377E-02*	*0.4901E 00*
Mn-54	*0.2240E-03*	*0.7970E-01*
Fe-55	*0.1143E-02*	*0.4066E 00*
Co-58	*0.1156E-01*	*0.4113E 01*
Fe-59	*0.7230E-03*	*0.2573E 00*
Co-60	*0.1438E-02*	*0.5116E 00*
Kr-83M	*0.3012E-01*	*0.1072E 02*
Kr-85M	*0.1553E 00*	*0.5528E 02*
Kr-85	*0.3579E 00*	*0.1273E 03*
Kr-87	*0.8500E-01*	*0.3025E 02*
Kr-88	*0.2658E 00*	*0.9458E 02*
Sr-89	*0.1982E-03*	*0.7052E-01*
Sr-90	*0.9517E-05*	*0.3387E-02*
Y-90	*0.1652E-04*	*0.5879E-02*
Sr-91	*0.1289E-03*	*0.4587E-01*
Y-91	*0.1784E-02*	*0.6347E 00*
Sr-92	*0.5267E-04*	*0.1874E-01*
Y-92	*0.6741E-04*	*0.2399E-01*
Zr-95	*0.4922E-04*	*0.1752E-01*
Nb-95	*0.4784E-04*	*0.1702E-01*
Mo-99	*0.3981E 00*	*0.1417E 03*
I-131	*0.2340E 00*	*0.8325E 02*
Te-132	*0.2459E-01*	*0.8749E 01*
I-132	*0.8408E-01*	*0.2992E 02*
I-133	*0.3192E 00*	*0.1136E 03*
Xe-133M	*0.2608E 00*	*0.9280E 02*
Xe-133	*0.2186E 02*	*0.7778E 04*
Cs-134	*0.1666E-01*	*0.5929E 01*
I-134	*0.4258E-01*	*0.1515E 02*
I-135	*0.1760E 00*	*0.6263E 02*
Xe-135M	*0.3332E-01*	*0.1186E 02*
Xe-135	*0.4674E 00*	*0.1663E 03*
Cs-136	*0.4470E-02*	*0.1591E 01*
Cs-137	*0.2958E-01*	*0.1052E 02*
Xe-138	*0.4495E-01*	*0.1599E 02*
Ba-140	*0.3355E-03*	*0.1194E 00*
La-140	*0.1185E-03*	*0.4215E-01*
Ce-144	*0.2899E-04*	*0.1032E-01*
Pr-144	*0.2899E-04*	*0.1032E-01*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-13

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

REACTOR COOLANT NITROGEN-16 ACTIVITY

Location	*Activity, μCi/cc*
Core outlet	*87*
Reactor outlet nozzle	*71*
Steam generator inlet	*67*
Steam generator outlet	*45*
Reactor coolant pump inlet	*43*
Reactor coolant pump outlet	*42*
Reactor inlet nozzle	*40*
Core inlet	*33*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-14

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

DEPOSITED CORROSION PRODUCT ACTIVITY
IN STEAM GENERATOR

	Concentration, μCi/cm^2				
	Operating Time, months				
Isotope	*0*	*6*	*12*	*24*	*36*
Mn-54	*1.0×10^{-5}*	*0.15*	*0.60*	*1.5*	*2.0*
Mn-56	*1.0×10^{-5}*	*3.3*	*3.3*	*3.3*	*3.3*
Co-58	*1.0×10^{-2}*	*4.5*	*10.2*	*11.0*	*11.0*
Fe-59	*1.0×10^{-4}*	*1.4*	*3.0*	*3.0*	*3.0*
Co-60	*1.0×10^{-3}*	*0.20*	*0.80*	*2.0*	*3.5*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-15

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

DEMINERALIZER AND EVAPORATOR DECONTAMINATION FACTORS

Nuclide	*Primary Mxd Bed*	*Primary Cation*	*Letdown Mxd Bed*	*Letdown Cation*	*Letdown Anion*	*BA Evap Feed Ion Exchangers*[(b)]	*Waste Mxd. Beds*[(a)]
H-3	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*
Cr-51	*1.000E 01*	*1.000E 02*	*1.000E 02*	*1.000E 02*	*1.000E 00*	*1.000E 03*	*1.000E 03*
Mn-54	*1.000E 01*	*1.000E 02*	*1.000E 02*	*1.000E 02*	*1.000E 00*	*1.000E 03*	*1.000E 03*
Fe-55	*1.000E 01*	*1.000E 02*	*1.000E 02*	*1.000E 02*	*1.000E 00*	*1.000E 03*	*1.000E 03*
Co-58	*1.000E 01*	*1.000E 02*	*1.000E 02*	*1.000E 02*	*1.000E 00*	*1.000E 03*	*1.000E 03*
Fe-59	*1.000E 01*	*1.000E 02*	*1.000E 02*	*1.000E 02*	*1.000E 00*	*1.000E 03*	*1.000E 03*
Co-60	*1.000E 01*	*1.000E 02*	*1.000E 02*	*1.000E 02*	*1.000E 00*	*1.000E 03*	*1.000E 03*
Kr-83M	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*
Kr-85M	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*
Kr-85	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*
Kr-87	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*
Kr-88	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*
Sr-89	*1.000E 01*	*1.000E 02*	*1.000E 02*	*1.000E 02*	*1.000E 00*	*1.000E 03*	*1.000E 03*
Sr-90	*1.000E 01*	*1.000E 02*	*1.000E 02*	*1.000E 02*	*1.000E 00*	*1.000E 03*	*1.000E 03*
Y-90	*1.000E 00*	*1.000E 00*	*1.000E 01*	*1.000E 00*	*1.000E 00*	*1.000E 03*	*1.000E 03*
Sr-91	*1.000E 01*	*1.000E 02*	*1.000E 02*	*1.000E 02*	*1.000E 00*	*1.000E 03*	*1.000E 03*
Y-91	*1.000E 00*	*1.000E 00*	*1.000E 01*	*1.000E 00*	*1.000E 00*	*1.000E 03*	*1.000E 03*
Sr-92	*1.000E 01*	*1.000E 02*	*1.000E 02*	*1.000E 02*	*1.000E 00*	*1.000E 03*	*1.000E 03*
Y-92	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 03*	*1.000E 03*
Zr-95	*1.000E 01*	*1.000E 02*	*1.000E 02*	*1.000E 02*	*1.000E 00*	*1.000E 03*	*1.000E 03*
Nb-95	*1.000E 01*	*1.000E 02*	*1.000E 02*	*1.000E 02*	*1.000E 00*	*1.000E 03*	*1.000E 03*
Mo-99	*1.000E 00*	*1.000E 00*	*1.000E 02*	*1.000E 00*	*1.000E 00*	*1.000E 03*	*1.000E 03*
I-131	*1.000E 01*	*1.000E 00*	*1.000E 02*	*1.000E 00*	*1.000E 02*	*1.000E 02*	*1.000E 03*
Te-132	*1.000E 01*	*1.000E 00*	*1.000E 02*	*1.000E 00*	*1.000E 02*	*1.000E 03*	*1.000E 03*
I-132	*1.000E 01*	*1.000E 00*	*1.000E 02*	*1.000E 00*	*1.000E 02*	*1.000E 02*	*1.000E 03*
I-133	*1.000E 01*	*1.000E 00*	*1.000E 02*	*1.000E 00*	*1.000E 02*	*1.000E 02*	*1.000E 03*
Xe-133M	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*
Xe-133	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*
Cs-134	*2.000E 00*	*1.000E 01*	*2.000E 00*	*1.000E 01*	*1.000E 00*	*1.000E 03*	*2.000E 01*
I-134	*1.000E 01*	*1.000E 00*	*1.000E 02*	*1.000E 00*	*1.000E 02*	*1.000E 02*	*1.000E 03*
I-135	*1.000E 01*	*1.000E 00*	*1.000E 02*	*1.000E 00*	*1.000E 02*	*1.000E 02*	*1.000E 03*
Xe-135M	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*
Xe-135	*1.000E 00*	*1.000E00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*
Cs-136	*2.000E 00*	*1.000E 01*	*2.000E 00*	*1.000E 01*	*1.000E 00*	*1.000E 03*	*2.000E 01*
Cs-137	*2.000E 00*	*1.000E 01*	*2.000E 00*	*1.000E 01*	*1.000E 00*	*1.000E 03*	*2.000E 01*
Xe-138	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*	*1.000E 00*
Ba-140	*1.000E 01*	*1.000E 02*	*1.000E 02*	*1.000E 02*	*1.000E 00*	*1.000E 03*	*1.000E 03*
La-140	*1.000E 01*	*1.000E 02*	*1.000E 02*	*1.000E 02*	*1.000E 00*	*1.000E 03*	*1.000E 03*
Ce-144	*1.000E 01*	*1.000E 02*	*1.000E 02*	*1.000E 02*	*1.000E 00*	*1.000E 03*	*1.000E 03*
Pr-144	*1.000E 01*	*1.000E 02*	*1.000E 02*	*1.000E 02*	*1.000E 00*	*1.000E 03*	*1.000E 03*

(a) Two waste mixed beds in series.
(b) Boric Acid Evaporator has been abandoned in place.

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-16

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PRODUCTION AND REMOVALS IN PRIMARY COOLANT FOR DESIGN BASIS CASE

Nuclide	Produced, Ci	Decayed, Ci	Cleaned Up, Ci	Lked to Sec, Ci	Lked to Cont, Ci	Lked to Aux, Ci
H-3	0.1642E 04	0.1463E 02	0.1345E 04	0.0	0.0	0.0
Cr-51	0.2637E 03	0.4455E 01	0.2070E 03	0.0	0.0	0.0
Mn-54	0.4222E 02	0.6647E-01	0.3366E 02	0.0	0.0	0.0
Fe-55	0.2532E 03	0.3805E 02	0.1718E 03	0.0	0.0	0.0
Co-58	0.2190E 04	0.1458E 02	0.1737E 04	0.0	0.0	0.0
Fe-59	0.1375E 03	0.1445E 01	0.1087E 03	0.0	0.0	0.0
Co-60	0.2707E 03	0.6729E-01	0.2161E 03	0.0	0.0	0.0
Kr-83M	0.2926E 06	0.2916E 06	0.5535E 03	0.0	0.0	0.0
Kr-85M	0.6409E 06	0.6359E 06	0.2855E 04	0.0	0.0	0.0
Kr-85	0.1250E 05	0.6654E 02	0.7987E 04	0.0	0.0	0.0
Kr-87	0.1208E 07	0.1205E 07	0.1562E 04	0.0	0.0	0.0
Kr-88	0.1736E 07	0.1728E 07	0.4885E 04	0.0	0.0	0.0
Sr-89	0.3138E 03	0.2897E 01	0.2482E 03	0.0	0.0	0.0
Sr-90	0.1493E 02	0.6984E-03	0.1192E 02	0.0	0.0	0.0
Y-90	0.5049E 01	0.4623E 01	0.3015E 00	0.0	0.0	0.0
Sr-91	0.4409E 03	0.2386E 03	0.1615E 03	0.0	0.0	0.0
Y-91	0.6483E 02	0.2065E 02	0.3098E 02	0.0	0.0	0.0
Sr-92	0.4338E 03	0.3511E 03	0.6602E 02	0.0	0.0	0.0
Y-92	0.3386E 03	0.3369E 03	0.1238E 01	0.0	0.0	0.0
Zr-95	0.7777E 02	0.5637E 00	0.6165E 02	0.0	0.0	0.0
Nb-95	0.7605E 02	0.1023E 01	0.5991E 02	0.0	0.0	0.0
Mo-99	0.1150E 06	0.1047E 06	0.7267E 04	0.0	0.0	0.0
I-131	0.3852E 06	0.2179E 05	0.2902E 06	0.0	0.0	0.0
Te-132	0.4388E 05	0.5676E 04	0.3050E 05	0.0	0.0	0.0
I-132	0.7610E 06	0.6303E 06	0.1044E 06	0.0	0.0	0.0
I-133	0.7694E 06	0.2734E 06	0.3961E 06	0.0	0.0	0.0
Xe-133M	0.9896E 05	0.8554E 05	0.4819E 04	0.0	0.0	0.0
Xe-133	0.3935E 07	0.3131E 07	0.4059E 06	0.0	0.0	0.0
Cs-134	0.1560E 05	0.1645E 02	0.1243E 05	0.0	0.0	0.0
I-134	0.9513E 06	0.8851E 06	0.5288E 05	0.0	0.0	0.0
I-135	0.7464E 06	0.4727E 06	0.2185E 06	0.0	0.0	0.0
Xe-135M	0.5840E 07	0.2304E 07	0.6113E 03	0.0	0.0	0.0
Xe-135	0.1519E 07	0.9150E 06	0.8591E 04	0.0	0.0	0.0
Cs-136	0.4485E 04	0.2574E 03	0.3372E 04	0.0	0.0	0.0
Cs-137	0.2793E 05	0.2248E 01	0.2227E 05	0.0	0.0	0.0
Xe-138	0.3474E 07	0.3473E 07	0.8258E 03	0.0	0.0	0.0
Ba-140	0.5458E 03	0.1965E 02	0.4202E 03	0.0	0.0	0.0
La-140	0.2388E 03	0.5309E 02	0.1483E 03	0.0	0.0	0.0
Ce-144	0.4554E 02	0.7609E-01	0.3631E 02	0.0	0.0	0.0
Pr-144	0.1831E 04	0.1785E 04	0.3631E 02	0.0	0.0	0.0

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-17

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PRODUCTION AND REMOVALS IN PRIMARY COOLANT FOR NORMAL OPERATION CASE

Nuclide	Produced, Ci	Decayed, Ci	Cleaned Up, Ci	Lked to Sec, Ci	Lked to Cont, Ci	Lked to Aux, Ci
H-3	*0.1642E 04*	*0.1384E 02*	*0.1271E 04*	*0.1583E 02*	*0.5299E 02*	*0.2532E 02*
Cr-51	*0.2637E 03*	*0.4452E 01*	*0.2068E 03*	*0.2516E-01*	*0.8424E-01*	*0.4026E-01*
Mn-54	*0.4222E 02*	*0.6643E-01*	*0.3364E 02*	*0.4092E-02*	*0.1370E-01*	*0.6547E-02*
Fe-55	*0.2532E 03*	*0.3803E 02*	*0.1717E 03*	*0.2088E-01*	*0.6991E-01*	*0.3341E-01*
Co-58	*0.2190E 04*	*0.1457E 02*	*0.1736E 04*	*0.2112E 00*	*0.7070E 00*	*0.3379E 00*
Fe-59	*0.1375E 03*	*0.1443E 01*	*0.1086E 03*	*0.1321E-01*	*0.4423E-01*	*0.2114E-01*
Co-60	*0.2707E 03*	*0.6725E-01*	*0.2159E 03*	*0.2627E-01*	*0.8794E-01*	*0.4203E-01*
Kr-83M	*0.3511E 05*	*0.3495E 05*	*0.6634E 02*	*0.5509E 00*	*0.3127E 02*	*0.8814E 00*
Kr-85M	*0.7691E 05*	*0.7610E 05*	*0.3417E 03*	*0.2837E 01*	*0.1611E 03*	*0.4540E 01*
Kr-85	*0.1512E 04*	*0.6269E 01*	*0.7526E 03*	*0.6249E 01*	*0.3547E 03*	*0.9998E 01*
Kr-87	*0.1449E 06*	*0.1445E 06*	*0.1873E 03*	*0.1555E 01*	*0.8826E 02*	*0.2488E 01*
Kr-88	*0.2084E 06*	*0.2070E 06*	*0.5852E 03*	*0.4859E 01*	*0.2758E 03*	*0.7774E 01*
Sr-89	*0.3765E 02*	*0.3474E 00*	*0.2976E 02*	*0.3621E-02*	*0.1212E-01*	*0.5794E-02*
Sr-90	*0.1791E 01*	*0.8376E-04*	*0.1429E 01*	*0.1739E-03*	*0.5821E-03*	*0.2782E-03*
Y-90	*0.6057E 00*	*0.5525E 00*	*0.3603E-01*	*0.2992E-03*	*0.1002E-02*	*0.4787E-03*
Sr-91	*0.5291E 02*	*0.2862E 02*	*0.1938E 02*	*0.2357E-02*	*0.7892E-02*	*0.3772E-02*
Y-91	*0.7779E 01*	*0.2407E 01*	*0.3611E 01*	*0.2999E-01*	*0.1004E 00*	*0.4798E-01*
Sr-92	*0.5205E 02*	*0.4212E 02*	*0.7922E 01*	*0.9637E-03*	*0.3226E-02*	*0.1542E-02*
Y-92	*0.4063E 02*	*0.4041E 02*	*0.1485E 00*	*0.1233E-02*	*0.4127E-02*	*0.1973E-02*
Zr-95	*0.9332E 01*	*0.6760E-01*	*0.7392E 01*	*0.8993E-03*	*0.3011E-02*	*0.1439E-02*
Nb-95	*0.9126E 01*	*0.1226E 00*	*0.7184E 01*	*0.8740E-03*	*0.2926E-02*	*0.1398E-02*
Mo-99	*0.1380E 05*	*0.1252E 05*	*0.8687E 03*	*0.7213E 01*	*0.2415E 02*	*0.1154E 02*
I-131	*0.4623E 05*	*0.2614E 04*	*0.3480E 05*	*0.4275E 01*	*0.1431E 02*	*0.6840E 01*
Te-132	*0.5285E 04*	*0.6807E 03*	*0.3658E 04*	*0.4493E 00*	*0.1504E 01*	*0.7189E 00*
I-132	*0.9131E 05*	*0.7562E 05*	*0.1252E 05*	*0.1538E 01*	*0.5148E 01*	*0.2461E 01*
I-133	*0.9233E 05*	*0.3279E 05*	*0.4751E 05*	*0.5835E 01*	*0.1954E 02*	*0.9336E 01*
Xe-133M	*0.1188E 05*	*0.9952E 04*	*0.5607E 03*	*0.4655E 01*	*0.2643E 03*	*0.7448E 01*
Xe-133	*0.4722E 06*	*0.3629E 06*	*0.4574E 05*	*0.3798E 03*	*0.2156E 05*	*0.6077E 03*
Cs-134	*0.1093E 04*	*0.1993E 01*	*0.1506E 04*	*0.3040E 00*	*0.1018E 01*	*0.4865E 00*
I-134	*0.1142E 06*	*0.1062E 06*	*0.6345E 04*	*0.7793E 00*	*0.2609E 01*	*0.1247E 01*
I-135	*0.8958E 05*	*0.5671E 05*	*0.2621E 05*	*0.3220E 01*	*0.1078E 02*	*0.5152E 01*
Xe-135M	*0.7006E 06*	*0.2764E 06*	*0.7333E 02*	*0.6089E 00*	*0.3456E 02*	*0.9742E 00*
Xe-135	*0.1823E 06*	*0.1092E 06*	*0.1025E 04*	*0.8511E 01*	*0.4831E 03*	*0.1362E 02*
Cs-136	*0.5383E 03*	*0.3086E 02*	*0.4042E 03*	*0.8158E-01*	*0.2731E 00*	*0.1305E 00*
Cs-137	*0.3357E 04*	*0.2699E 00*	*0.2674E 04*	*0.5397E 00*	*0.1807E 01*	*0.8635E 00*
Xe-138	*0.4168E 06*	*0.4167E 06*	*0.9908E 02*	*0.8227E 00*	*0.4670E 02*	*0.1316E 01*
Ba-140	*0.6550E 02*	*0.2356E 01*	*0.5038E 02*	*0.6130E-02*	*0.2052E-01*	*0.9807E-02*
La-140	*0.2865E 02*	*0.6365E 01*	*0.1778E 02*	*0.2163E-02*	*0.7241E-02*	*0.3461E-02*
Ce-144	*0.5465E 01*	*0.9124E-02*	*0.4354E 01*	*0.5296E-03*	*0.1773E-02*	*0.8474E-03*
Pr-144	*0.2195E 03*	*0.2141E 03*	*0.4354E 01*	*0.5297E-03*	*0.1773E-02*	*0.8474E-03*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-18

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

BASIC ASSUMPTIONS FOR PRESSURIZER ACTIVITIES

Pressurizer liquid volume, gal.	*8080*
Pressurizer vapor volume, gal.	*5400*
Flowrate, gpm	*1*
Stripping fraction for noble gases	*1*
Stripping fraction for other isotopes	*0.0*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-19

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ACTIVITY IN PRESSURIZER FOR DESIGN BASIS CASE

	Liquid Phase	
Nuclide	*Activity, Ci*	*Concent, μCi/cc*
H-3	*0.224E 02*	*0.731E 00*
Cr-51	*0.369E-01*	*0.121E-02*
Mn-54	*0.676E-02*	*0.221E-03*
Fe-55	*0.143E-01*	*0.468E-03*
Co-58	*0.335E 00*	*0.109E-01*
Fe-59	*0.203E-01*	*0.665E-03*
Co-60	*0.438E-01*	*0.143E-02*
Kr-83M	*0.0*	*0.0*
Kr-85M	*0.0*	*0.0*
Kr-85	*0.0*	*0.0*
Kr-87	*0.0*	*0.0*
Kr-88	*0.0*	*0.0*
Sr-89	*0.469E-01*	*0.153E-02*
Sr-90	*0.242E-02*	*0.792E-04*
Y-90	*0.314E-02*	*0.103E-03*
Sr-91	*0.310E-02*	*0.101E-03*
Y-91	*0.404E 00*	*0.132E-01*
Sr-92	*0.377E-03*	*0.123E-04*
Y-92	*0.100E-02*	*0.327E-04*
Zr-95	*0.118E-01*	*0.387E-03*
Nb-95	*0.121E-01*	*0.397E-03*
Mo-99	*0.425E 02*	*0.139E 01*
I-131	*0.401E 02*	*0.131E 01*
Te-132	*0.285E 01*	*0.931E-01*
I-132	*0.331E 01*	*0.108E 00*
I-133	*0.149E 02*	*0.488E 00*
Xe-133M	*0.0*	*0.0*
Xe-133	*0.0*	*0.0*
Cs-134	*0.417E 01*	*0.136E 00*
I-134	*0.998E-01*	*0.326E-02*
I-135	*0.300E 01*	*0.982E-01*
Xe-135M	*0.0*	*0.0*
Xe-135	*0.0*	*0.0*
Cs-136	*0.875E 00*	*0.286E-01*
Cs-137	*0.751E 01*	*0.246E 00*
Xe-138	*0.0*	*0.0*
Ba-140	*0.655E-01*	*0.214E-02*
La-140	*0.549E-01*	*0.179E-02*
Ce-144	*0.728E-02*	*0.238E-03*
Pr-144	*0.728E-02*	*0.238E-03*

	Steam Phase	
Nuclide	*Activity, Ci*	*Concent μCi/cc*
Kr- 83M	*0.510E-01*	*0.250E-02*
Kr- 85M	*0.623E 00*	*0.305E-01*
Kr- 85	*0.186E 04*	*0.913E 02*
Kr- 87	*0.983E-01*	*0.482E-02*
Kr- 88	*0.671E 00*	*0.329E-01*
Xe-133M	*0.135E 02*	*0.664E 00*
Xe-133	*0.258E 04*	*0.127E 03*
Xe-135M	*0.443E 00*	*0.217E-01*
Xe-135	*0.693E 01*	*0.340E 00*
Xe-138	*0.954E 02*	*0.468E-03*

Pressurizer Deposited Activity

Nuclide	*Activity, μCi/c²*
Cr-51	*9.80E-02*
Mn-54	*1.50E-01*
Mn-56	*2.20E-02*
Co-58	*3.80E 00*
Co-60	*1.60E-01*
Fe-59	*1.40E-01*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-20

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ACTIVITY IN PRESSURIZER FOR NORMAL OPERATION CASE

Nuclide	Liquid Phase Activity, Ci	Concent, μCi/cc
H-3	0.211E 02	0.691E 00
Cr-51	0.349E-01	0.121E-02
Mn-54	0.675E-02	0.221E-03
Fe-55	0.143E-01	0.468E-03
Co-58	0.335E 00	0.109E-01
Fe-59	0.203E-01	0.664E-03
Co-60	0.438E-01	0.143E-02
Kr-83M	0.0	0.0
Kr-85M	0.0	0.0
Kr-85	0.0	0.0
Kr-87	0.0	0.0
Kr-88	0.0	0.0
Sr-89	0.562E-02	0.184E-03
Sr-90	0.290E-03	0.950E-05
Y-90	0.376E-03	0.123E-04
Sr-91	0.272E-03	0.121E-04
Y-91	0.471E-01	0.154E-02
Sr-92	0.453E-04	0.148E-05
Y-92	0.120E-03	0.393E-05
Zr-95	0.142E-02	0.464E-04
Nb-95	0.146E-02	0.476E-04
Mo-99	0.508E 01	0.166E 00
I-131	0.481E 01	0.157E 00
Te-132	0.342E 00	0.112E-01
I-132	0.397E 00	0.130E-01
I-133	0.179E 01	0.586E-01
Xe-133M	0.0	0.0
Xe-133	0.0	0.0
Cs-134	0.505E 00	0.165E-01
I-134	0.120E-01	0.391E-03
I-135	0.360E 00	0.118E-01
Xe-135M	0.0	0.0
Xe-135	0.0	0.0
Cs-136	0.105E 00	0.343E-02
Cs-137	0.901E 00	0.295E-01
Xe-138	0.0	0.0
Ba-140	0.785E-02	0.257E-03
La-140	0.658E-02	0.215E-03
Ce-144	0.873E-03	0.285E-04
Pr-144	0.873E-03	0.285E-04

Nuclide	Steam Phase Activity, Ci	Concent μCi/cc
Kr- 83M	0.612E-02	0.300E-03
Kr- 85M	0.745E-01	0.365E-02
Kr- 85	0.175E 03	0.860E 01
Kr- 87	0.118E-01	0.578E-03
Kr- 88	0.803E-01	0.394E-02
Xe-133M	0.158E-01	0.773E-01
Xe-133	0.291E 03	0.143E 02
Xe-135M	0.532E-01	0.261E-02
Xe-135	0.829E 00	0.406E-01
Xe-138	0.114E-02	0.561E-04

Pressurizer Deposited Activity

Nuclide	Activity mCi/c^2
Cr-51	9.80E-02
Mn-54	1.50E-01
Mn-56	2.20E-02
Co-58	3.80E 00
Co-60	1.60E-01
Fe-59	1.40E-01

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-21

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

BASIC ASSUMPTIONS FOR TRITIUM ACTIVITY IN PRIMARY COOLANT

1.	*Core Thermal Power*	*3568 MWt*
2.	*Plant Load Factor*	*0.8*
3.	*Core Volume*	*1153 ft^3*
4.	*Core Volume Fractions*	
	a. UO_2	*0.3052*
	b. Zr + SS	*0.1000*
	c. H_2O	*0.5948*
5.	*Initial Reactor Coolant Boron Level*	
	a. Initial cycle	*840 ppm*
	b. Equilibrium cycle	*1200 ppm*
6.	*Reactor Coolant Volume*	*12,560 ft^3*
7.	*Reactor Coolant Transport Times*	
	a. Incore	*0.77 sec*
	b. Out-of-core	*10.87 sec*
8.	*Reactor Coolant Peak Lithium Level (99% pure Li^7)*	*2.2 ppm*
9.	*Core Average Neutron Fluxes, n/cm^2-sec*	
	a. $E > 6$ MeV	*2.91×10^{12}*
	b. $E > 5$ MeV	*7.90×10^{12}*
	c. $3 \text{ MeV} \leq E \leq 6 \text{ MeV}$	*2.26×10^{13}*
	d. $1 \text{ MeV} \leq E \leq 5 \text{ MeV}$	*5.31×10^{13}*
	e. $E < 0.625$ eV	*2.26×10^{13}*
10.	*Neutron Reaction Cross Sections*	
	a. B^{10} (n, 2α) T: $\sigma(1 \text{ MeV} \leq E \leq 5 \text{ MeV})$ =	*31.6 mb (spectrum weighted)*
	$\sigma(E > 5 \text{ MeV})$ =	*75 mb*
	b. Li^7 (n, n α V) T: $\sigma(3 \text{ MeV} \leq E \leq 6 \text{ MeV})$ =	*39.1 mb (spectrum weighted)*
	$\sigma(E > 6 \text{ MeV})$ =	*400 mb*
11.	*Fraction of Ternary Tritium Diffusing Through Zirconium Cladding*	
	a. Design value	*0.30*
	b. Expected value	*0.01*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-22

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TRITIUM ACTIVITY IN PRIMARY COOLANT

Tritium Source	*Core Activity, Ci*	*Coolant Activity, Ci*	*Total Produced in Coolant, Ci*
Cycle = 8760 Hours			
Ternary fissions	*0.196E05*	*0.121E03*	*1092.76*
Burnable poison rods	*0.0*	*0.0*	*0.0*
Control rods	*0.0*	*0.0*	*0.0*
Boron shim control	*0.0*	*0.270E02*	*442.40*
Lithium-7 reaction	*0.0*	*0.100E01*	*9.05*
Lithium-6 reaction	*0.0*	*0.105E02*	*94.97*
Deuterium reaction	*0.0*	*0.294E00*	*2.66*
Total	*0.196E05*	*0.160E03*	*1641.84*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-23

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

STEAM SYSTEM OPERATING CONDITIONS ASSUMED FOR ACTIVITY ANALYSIS FOR NORMAL OPERATION CASE

Parameter	*Value*			
	Steam Gen. 1	*Steam Gen. 2*	*Steam Gen. 3*	*Steam Gen. 4*
Steam flowrate to condenser from unit (lb/hr)	*3804300.0*	*3804300.0*	*3804300.0*	*3804300.0*
Feedwater flowrate to unit (lb/hr)	*3804725.0*	*3804725.0*	*3804725.0*	*3804725.0*
Blowdown flowrate from unit (lb/hr)	*17647.5*	*17647.5*	*17647.5*	*17647.5*
Steam venting flowrate from unit (lb/hr)	*0.0*	*0.0*	*0.0*	*0.0*
Total weight of steam vented from unit during period-lb	*0.0*	*0.0*	*0.0*	*0.0*
Weight of water in unit (lb)	*81500.0*	*81500.0*	*81500.0*	*81500.0*
Volume of water in unit (ft^3)	*1680.4*	*1680.4*	*1680.4*	*1680.4*
Density of water in unit (lb/ft^3)	*48.5*	*48.5*	*48.5*	*48.5*
Fraction of primary to secondary leakage to this unit	*0.25*	*0.25*	*0.25*	*0.25*
Leakage flowrate to this unit (computed) (gal./min)	*0.0029*	*0.0029*	*0.0029*	*0.0029*
Total gallons of prim. cool. leaked into unit in period	*1208.8*	*1208.8*	*1208.8*	*1208.8*
Total steam flowrate of condenser (lb/hr)	*15217200.0*			
Total condensate flowrate from condenser (lb/hr)	*15221402.0*			
Weight of water in condenser (lb)	*1700000.0*			
Volume of water in condenser (ft^3)	*27243.58*			
Density of water in condenser (lb/ft^3)	*62.39*			
Total primary to secondary leak rate (gal./min)	*0.0115*			
Water leakage rate from secondary system (gal./min)	*5.0*			
Steam leakage rate from secondary system (lb/hr)	*1700.0*			
Flowrate of water to blowdown cleanup system (lb/hr)	*51763.78*			
Capacity factor of blowdown cleanup system	*1.0*			

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-24

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ADDITIONAL SECONDARY SYSTEM OPERATING PARAMETERS

Mass of water in one steam generator, lb	*81,500*
Mass of steam in one steam generator, lb	*7,200*
Secondary side operating temperature, °F	*519*
Steam generator blowdown tank capacity, ft^3	*641*
Air ejector flowrate - rated, scfm	*25*
- expected average, scfm	*2.5*
Total mass of water in secondary system, lb (minus condenser)	*1,000,000*
Total mass of steam in secondary system, lb	*61,200*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-25

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

STEAM GENERATOR PARTITION FACTORS[(a)]

Nuclide	*St.Gen.1*	*St.Gen.2*	*St.Gen.3*	*St.Gen.4*
H-3	*1.0000*	*1.0000*	*1.0000*	*1.0000*
Cr-51	*0.0007*	*0.0007*	*0.0007*	*0.0007*
Mn-54	*0.0007*	*0.0007*	*0.0007*	*0.0007*
Fe-55	*0.0007*	*0.0007*	*0.0007*	*0.0007*
Co-58	*0.0007*	*0.0007*	*0.0007*	*0.0007*
Fe-59	*0.0007*	*0.0007*	*0.0007*	*0.0007*
Co-60	*0.0007*	*0.0007*	*0.0007*	*0.0007*
Kr-83M	*1.0000*	*1.0000*	*1.0000*	*1.0000*
Kr-85M	*1.0000*	*1.0000*	*1.0000*	*1.0000*
Kr-85	*1.0000*	*1.0000*	*1.0000*	*1.0000*
Kr-87	*1.0000*	*1.0000*	*1.0000*	*1.0000*
Kr-88	*1.0000*	*1.0000*	*1.0000*	*1.0000*
Sr-89	*0.0007*	*0.0007*	*0.0007*	*0.0007*
Sr-90	*0.0007*	*0.0007*	*0.0007*	*0.0007*
Y-90	*0.0007*	*0.0007*	*0.0007*	*0.0007*
Sr-91	*0.0007*	*0.0007*	*0.0007*	*0.0007*
Y-91	*0.0007*	*0.0007*	*0.0007*	*0.0007*
Sr-92	*0.0007*	*0.0007*	*0.0007*	*0.0007*
Y-92	*0.0007*	*0.0007*	*0.0007*	*0.0007*
Zr-95	*0.0007*	*0.0007*	*0.0007*	*0.0007*
Nb-95	*0.0007*	*0.0007*	*0.0007*	*0.0007*
Mo-99	*0.0007*	*0.0007*	*0.0007*	*0.0007*
I-131	*0.0065*	*0.0065*	*0.0065*	*0.0065*
Te-132	*0.0007*	*0.0007*	*0.0007*	*0.0007*
I-132	*0.0065*	*0.0065*	*0.0065*	*0.0065*
I-133	*0.0065*	*0.0065*	*0.0065*	*0.0065*
Xe-133M	*1.0000*	*1.0000*	*1.0000*	*1.0000*
Xe-133	*1.0000*	*1.0000*	*1.0000*	*1.0000*
Cs-134	*0.0007*	*0.0007*	*0.0007*	*0.0007*
I-134	*0.0065*	*0.0065*	*0.0065*	*0.0065*
I-135	*0.0065*	*0.0065*	*0.0065*	*0.0065*
Xe-135M	*1.0000*	*1.0000*	*1.0000*	*1.0000*
Xe-135	*1.0000*	*1.0000*	*1.0000*	*1.0000*
Cs-136	*0.0007*	*0.0007*	*0.0007*	*0.0007*
Cs-137	*0.0007*	*0.0007*	*0.0007*	*0.0007*
Xe-138	*1.0000*	*1.0000*	*1.0000*	*1.0000*
Ba-140	*0.0007*	*0.0007*	*0.0007*	*0.0007*
La-140	*0.0007*	*0.0007*	*0.0007*	*0.0007*
Ce-144	*0.0007*	*0.0007*	*0.0007*	*0.0007*
Pr-144	*0.0007*	*0.0007*	*0.0007*	*0.0007*

(a) Iodine partition factors are for nonvolatile species only and include partitioning in moisture separators.

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-26

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
TOTAL ADDITIONS AND REMOVALS OF ACTIVITY IN EACH STEAM GENERATOR FOR NORMAL OPERATION CASE (CURIES)

Nuclide	*Leakage in*	*From Feedwater*	*To Main Stm*	*To Blowdown*	*Vented*	*Decayed*	*Leaked*
H-3	*0.3007E 01*	*0.6511E 04*	*0.6513E 04*	*0.0*	*0.0*	*0.8954E-03*	*0.7276E 00*
Cr-51	*0.5976E-02*	*0.5983E-03*	*0.8659E-03*	*0.5681E-02*	*0.0*	*0.2753E-04*	*0.9674E-07*
Mn-54	*0.9719E-03*	*0.9793E-04*	*0.1414E-03*	*0.9280E-03*	*0.0*	*0.4126E-06*	*0.1580E-07*
Fe-55	*0.4960E-02*	*0.4651E-03*	*0.6877E-03*	*0.4512E-02*	*0.0*	*0.2251E-03*	*0.7683E-07*
Co-58	*0.5015E-01*	*0.5043E-02*	*0.7288E-02*	*0.4782E-01*	*0.0*	*0.9040E-04*	*0.8142E-04*
Fe-59	*0.3137E-02*	*0.3150E-03*	*0.4554E-03*	*0.2988E-02*	*0.0*	*0.8944E-05*	*0.5088E-07*
Co-60	*0.6239E-02*	*0.6290E-03*	*0.9083E-03*	*0.5959E-02*	*0.0*	*0.4179E-06*	*0.1015E-06*
Sr-89	*0.8600E-03*	*0.8638E-04*	*0.1249E-03*	*0.8193E-03*	*0.0*	*0.2153E-05*	*0.1395E-07*
Sr-90	*0.4130E-04*	*0.4164E-05*	*0.6013E-05*	*0.3945E-04*	*0.0*	*0.5205E-09*	*0.6717E-09*
Y-90	*0.7106E-04*	*0.1159E-04*	*0.1160E-04*	*0.6919E-04*	*0.0*	*0.3850E-05*	*0.1296E-08*
Sr-91	*0.5599E-03*	*0.3580E-04*	*0.6114E-04*	*0.4011E-03*	*0.0*	*0.1334E-03*	*0.6831E-08*
Y-91	*0.7122E-02*	*0.1191E-02*	*0.1191E-02*	*0.7105E-02*	*0.0*	*0.1719E-04*	*0.1331E-06*
Sr-92	*0.2289E-03*	*0.4779E-05*	*0.1516E-04*	*0.9944E-04*	*0.0*	*0.1191E-03*	*0.1693E-08*
Y-92	*0.2928E-03*	*0.3159E-04*	*0.3218E-04*	*0.1919E-03*	*0.0*	*0.1896E-03*	*0.3595E-08*
Zr-95	*0.2136E-03*	*0.2147E-04*	*0.3103E-04*	*0.2036E-03*	*0.0*	*0.4192E-06*	*0.3467E-08*
Nb-95	*0.2076E-03*	*0.3162E-04*	*0.3163E-04*	*0.2075E-03*	*0.0*	*0.7978E-06*	*0.3534E-08*
Mo-99	*0.1713E 01*	*0.1612E 00*	*0.2381E 00*	*0.1562E 01*	*0.0*	*0.7425E-01*	*0.2660E-04*
I-131	*0.1015E 01*	*0.1372E 01*	*0.1418E 01*	*0.9519E 00*	*0.0*	*0.1678E-01*	*0.1584E-03*
Te-132	*0.1067E 00*	*0.1013E-01*	*0.1492E-01*	*0.9786E-01*	*0.0*	*0.4061E-02*	*0.1666E-05*
I-132	*0.3652E 00*	*0.2914E 00*	*0.3006E 00*	*0.2018E 00*	*0.0*	*0.2861E 00*	*0.3358E-04*
I-133	*0.1386E 01*	*0.1620E 01*	*0.1689E 01*	*0.1133E 01*	*0.0*	*0.1837E 00*	*0.1887E-03*
Cs-134	*0.7721E-01*	*0.2177E-01*	*0.2178E-01*	*0.7217E-01*	*0.0*	*0.2567E-04*	*0.2433E-05*
I-134	*0.1851E 00*	*0.4043E-01*	*0.5234E-01*	*0.3513E-01*	*0.0*	*0.1380E 00*	*0.5847E-05*
I-135	*0.7647E 00*	*0.6716E 00*	*0.7138E 00*	*0.4791E 00*	*0.0*	*0.2433E 00*	*0.7974E-04*
Cs-136	*0.1938E-01*	*0.4603E-02*	*0.5473E-02*	*0.1813E-01*	*0.0*	*0.3720E-03*	*0.6114E-06*
Cs-137	*0.1282E 00*	*0.3120E-01*	*0.3695E-01*	*0.1224E 00*	*0.0*	*0.3320E-05*	*0.4128E-05*
Ba-140	*0.1456E-02*	*0.1445E-03*	*0.2097E-03*	*0.1976E-02*	*0.0*	*0.1449E-04*	*0.2343E-07*
La-140	*0.5137E-03*	*0.8819E-04*	*0.8811E-04*	*0.5781E-03*	*0.0*	*0.4660E-04*	*0.9843E-08*
Ce-144	*0.1258E-03*	*0.1267E-04*	*0.1831E-04*	*0.1201E-03*	*0.0*	*0.5668E-07*	*0.2045E-08*
Pr-144	*0.1258E-03*	*0.1717E-04*	*0.1836E 04*	*0.1205E-03*	*0.0*	*0.1334E-02*	*0.2051E-08*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-27

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

EQUILIBRIUM ACTIVITIES AND CONCENTRATIONS IN EACH STEAM GENERATOR FOR NORMAL OPERATION CASE

Nuclide	*Activity, Ci*	*Concentration, μCi/cc*
H-3	*0.1991E-01*	*0.4184E-03*
Cr-51	*0.3782E-05*	*0.7947E-07*
Mn-54	*0.6177E-06*	*0.1298E-07*
Fe-55	*0.3003E-05*	*0.6312E-07*
Co-58	*0.3183E-04*	*0.6689E-06*
Fe-59	*0.1989E-05*	*0.4180E-07*
Co-60	*0.3967E-05*	*0.8336E-07*
Sr-89	*0.5454E-06*	*0.1146E-07*
Sr-90	*0.2626E-07*	*0.5518E-09*
Y-90	*0.4584E-07*	*0.9633E-09*
Sr-91	*0.2670E-06*	*0.5611E-08*
Y-91	*0.4683E-05*	*0.9842E-07*
Sr-92	*0.6619E-07*	*0.1391E-08*
Y-92	*0.1331E-06*	*0.2797E-08*
Zr-95	*0.1355E-06*	*0.2848E-08*
Nb-95	*0.1381E-06*	*0.2903E-08*
Mo-99	*0.1030E-02*	*0.2164E-04*
I-131	*0.6670E-03*	*0.1402E-04*
Te-132	*0.6514E-04*	*0.1369E-05*
I-132	*0.1414E-03*	*0.2971E-05*
I-133	*0.7942E-03*	*0.1669E-04*
Cs-134	*0.9512E-04*	*0.1999E-05*
I-134	*0.2462E-04*	*0.5173E-06*
I-135	*0.3357E-03*	*0.7055E-05*
Cs-136	*0.2390E-04*	*0.5023E-06*
Cs-137	*0.1614E-03*	*0.3391E-05*
Ba-140	*0.9160E-06*	*0.1925E-07*
La-140	*0.3848E-06*	*0.8087E-08*
Ce-144	*0.7994E-07*	*0.1680E-08*
Pr-144	*0.8019E-07*	*0.1685E-08*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-28

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
TOTAL ADDITIONS AND REMOVALS OF ACTIVITY IN THE CONDENSER
FOR NORMAL OPERATION CASE (CURIES)

Nuclide	*From Mainsteam*	*To Feedwater*	*Decayed*	*Water Leakage*
H-3	*0.2605E-05*	*0.2605E 05*	*0.1867E-01*	*0.4283E 01*
Cr-51	*0.3464E-02*	*0.2394E-02*	*0.2777E-06*	*0.3935E-06*
Mn-54	*0.5658E-03*	*0.3918E-03*	*0.4171E-08*	*0.6442E-07*
Fe-55	*0.2751E-02*	*0.1861E-02*	*0.2223E-05*	*0.3060E-06*
Co-58	*0.2915E-01*	*0.2017E-01*	*0.9131E-06*	*0.3317E-05*
Fe-59	*0.1822E-02*	*0.1260E-02*	*0.9030E-07*	*0.2072E-06*
Co-60	*0.3633E-02*	*0.2516E-02*	*0.4225E-08*	*0.4137E-06*
Sr-89	*0.4995E-03*	*0.3456E-03*	*0.2174E-07*	*0.5682E-07*
Sr-90	*0.2405E-04*	*0.1666E-04*	*0.5262E-11*	*0.2739E-08*
Y-90	*0.4640E-04*	*0.4636E-04*	*0.5615E-07*	*0.7622E-08*
Sr-91	*0.2446E-03*	*0.1432E-03*	*0.1140E-05*	*0.2355E-07*
Y-91	*0.4765E-02*	*0.4764E-02*	*0.2508E-06*	*0.7833E-04*
Sr-92	*0.6063E-04*	*0.1912E-04*	*0.5481E-06*	*0.3144E-08*
Y-92	*0.1287E-03*	*0.1264E-03*	*0.2717E-05*	*0.2078E-07*
Zr-95	*0.1241E-03*	*0.8590E-04*	*0.4235E-08*	*0.1412E-07*
Nb-95	*0.1265E-03*	*0.1265E-03*	*0.1164E-07*	*0.2080E-07*
Mo-99	*0.9523E 00*	*0.6449E 00*	*0.7340E-03*	*0.1060E-03*
I-131	*0.5673E 01*	*0.5488E 01*	*0.2201E-02*	*0.9023E-03*
Te-132	*0.5967E-01*	*0.4052E-01*	*0.4026E-04*	*0.6663E-05*
I-132	*0.1202E 01*	*0.1166E 01*	*0.3760E-01*	*0.1917E-03*
I-133	*0.6755E 01*	*0.6482E 01*	*0.2389E-01*	*0.1066E-02*
Cs-134	*0.8715E-01*	*0.8711E-01*	*0.3746E-06*	*0.1432E-04*
I-134	*0.2094E 00*	*0.1618E 00*	*0.1446E-01*	*0.2660E-04*
I-135	*0.2855E 01*	*0.2687E 01*	*0.3104E-01*	*0.4418E-03*
Cs-136	*0.2189E-01*	*0.1842E-01*	*0.4569E-05*	*0.3028E-05*
Cs-137	*0.1478E 00*	*0.1248E 00*	*0.4094E-07*	*0.2052E-04*
Ba-140	*0.8390E-03*	*0.5782E-03*	*0.1458E-06*	*0.9507E-07*
La-140	*0.3524E-03*	*0.3528E-03*	*0.4610E-06*	*0.5801E-07*
Ce-144	*0.7322E-04*	*0.5070E-04*	*0.5729E-09*	*0.8337E-08*
Pr-144	*0.7345E-04*	*0.6860E-04*	*0.1020E-04*	*0.1129E-07*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-29

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

EQUILIBRIUM ACTIVITIES AND CONCENTRATIONS IN THE CONDENSER FOR NORMAL OPERATION CASE

Nuclide	*Activity, Ci*	*Concentration, μCi/cc*
H-3	*0.4151E 00*	*0.5381E-03*
Cr-51	*0.3815E-07*	*0.4945E-10*
Mn-54	*0.6244E-08*	*0.8093E-11*
Fe-55	*0.2966E-07*	*0.3844E-10*
Co-58	*0.3215E-06*	*0.4168E-09*
Fe-59	*0.2008E-07*	*0.2603E-10*
Co-60	*0.4010E-07*	*0.5198E-10*
Sr-89	*0.5507E-08*	*0.7139E-11*
Sr-90	*0.2655E-09*	*0.3441E-12*
Y-90	*0.6685E-09*	*0.8665E-12*
Sr-91	*0.2282E-08*	*0.2959E-11*
Y-91	*0.6835E-07*	*0.8859E-10*
Sr-92	*0.3047E-09*	*0.3950E-12*
Y-92	*0.1908E-08*	*0.2473E-11*
Zr-95	*0.1369E-08*	*0.1774E-11*
Nb-95	*0.2016E-08*	*0.2613E-11*
Mo-99	*0.1013E-04*	*0.1314E-07*
I-131	*0.8746E-04*	*0.1134E-06*
Te-132	*0.6458E-06*	*0.8372E-09*
I-132	*0.1858E-04*	*0.2409E-07*
I-133	*0.1033E-03*	*0.1339E-06*
Cs-134	*0.1388E-05*	*0.1800E-08*
I-134	*0.2578E-05*	*0.3342E-08*
I-135	*0.4282E-04*	*0.5550E-07*
Cs-136	*0.2935E-06*	*0.3805E-09*
Cs-137	*0.1989E-05*	*0.2579E-08*
Ba-140	*0.9215E-08*	*0.1195E-10*
La-140	*0.5623E-08*	*0.7289E-11*
Ce-144	*0.8081E-09*	*0.1047E-11*
Pr-144	*0.1094E-08*	*0.1419E-11*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-30

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TOTAL ADDITIONS AND REMOVALS OF ACTIVITY IN THE CONDENSER VAPOR SPACE FOR NORMAL OPERATION CASE

Nuclide	*Inleak Rate, Ci/hr*	*Tot. Inleakage, Ci*	*Vent Rate, hr^{-1}*	*Vent Rate, Ci/hr*	*Tot. Vented, Ci*	*Decayed, Ci*
Kr-83	*0.7861E-04*	*0.5509E 00*	*0.1650E 00*	*0.2413E-04*	*0.1690E 00*	*0.3817E 00*
Kr-85M	*0.4049E-03*	*0.2837E 01*	*0.1650E 00*	*0.2071E-03*	*0.1451E 01*	*0.1385E 01*
Kr-85	*0.7133E-03*	*0.6249E 01*	*0.1650E 00*	*0.7133E-03*	*0.6244E 01*	*0.2787E-03*
Kr-87	*0.2219E-03*	*0.1555E 01*	*0.1650E 00*	*0.5151E-04*	*0.3610E 00*	*0.1194E 01*
Kr-88	*0.6933E-03*	*0.4859E 01*	*0.1650E 00*	*0.2755E-03*	*0.1930E 01*	*0.2927E 01*
I-131	*0.4575E-05*	*0.3206E-01*	*0.1650E 00*	*0.4477E-05*	*0.3136E-01*	*0.6824E-03*
I-132	*0.1646E-05*	*0.1153E-01*	*0.1650E 00*	*0.5985E-06*	*0.4193E-02*	*0.7338E-02*
I-133	*0.6245E-05*	*0.4376E-01*	*0.1650E 00*	*0.5204E-05*	*0.3645E-01*	*0.7290E-02*
Xe-133M	*0.6653E-03*	*0.4662E 01*	*0.1650E 00*	*0.6182E-03*	*0.4330E 01*	*0.3294E 00*
Xe-133	*0.5421E-01*	*0.3799E 03*	*0.1650E 00*	*0.5248E-01*	*0.3675E 03*	*0.1215E 02*
I-134	*0.8341E-06*	*0.5845E-02*	*0.1650E 00*	*0.1426E-06*	*0.9991E-03*	*0.4845E-02*
I-135	*0.3446E-05*	*0.2415E-01*	*0.1650E 00*	*0.2118E-05*	*0.1484E-01*	*0.9301E-02*
Xe-135M	*0.6224E-03*	*0.4362E 01*	*0.1650E 00*	*0.3628E-04*	*0.2543E 00*	*0.4107E 01*
Xe-135	*0.1304E-02*	*0.9136E 01*	*0.1650E 00*	*0.8951E-03*	*0.6270E 01*	*0.2862E 01*
Xe-138	*0.1174E-03*	*0.8227E 00*	*0.1650E 00*	*0.6170E-05*	*0.4324E-01*	*0.7794E 00*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.1-31

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

EQUILIBRIUM ACTIVITIES AND CONCENTRATIONS IN THE CONDENSER VAPOR SPACE FOR NORMAL OPERATION CASE

Nuclide	*Activity, Ci*	*Concentration, mCi/cc*
Kr-83M	*0.1462E-03*	*0.5164E-07*
Kr-85M	*0.1255E-02*	*0.4434E-06*
Kr-85	*0.4323E-02*	*0.1527E-05*
Kr-87	*0.3122E-03*	*0.1103E-06*
Kr-88	*0.1670E-02*	*0.5897E-06*
I-131	*0.2697E-04*	*0.9524E-08*
I-132	*0.3618E-05*	*0.1278E-08*
I-133	*0.3141E-04*	*0.1109E-07*
Xe-133M	*0.3746E-02*	*0.1323E-05*
Xe-133	*0.3180E 00*	*0.1123E-03*
I-134	*0.8637E-06*	*0.3050E-09*
I-135	*0.1281E-04*	*0.4522E-08*
Xe-135M	*0.2194E-03*	*0.7747E-07*
Xe-135	*0.5419E-02*	*0.1914E-05*
Xe-138	*0.3740E-04*	*0.1321E-07*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-1
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ASSUMPTIONS USED FOR INPUT WASTE STREAMS AND ACTIVITY CALCULATIONS BASED ON ORIGINAL SYSTEM DESIGN

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1. *Each stream of liquid waste input is categorized by one of the following isotopic concentration spectra, which are shown for the two analyses cases in Tables 11.2-3 and 11.2-4:*

   Spectrum I - Degassed primary coolant
   Spectrum II - Degassed primary coolant with 48 hours of decay
   Spectrum III - 1.0% of degassed primary coolant with 48 hours of decay
   Spectrum IV - 0.01% of degassed primary coolant with 48 hours of decay
   Spectrum V - 0.001% of primary coolant with 48 hours of decay; principally component cooling water.

2. *Heat exchangers are periodically drained producing 25 gallons/inch inlet piping/year for the Design Basis Case and 1.5 times the above for the Normal Operation Case.*

3. *Pumps are periodically drained producing 10 gallons/inch suction/year for the Design Basis Case and 1.5 times the above for the Normal Operation Case.*

4. *Pump baseplate leakage of 0.10 gallons/day for the Design Basis Case and 1.5 times the above for the Normal Operation Case*

5. *Tanks are periodically drained producing 100 gallons/5 feet diameter/year for the Design Basis Case and 1.5 times the above for the Normal Operation Case.*

6. *Filter cartridge replacement three times per year, producing 15 gallons/replacement for the Design Basis Case and 1.5 times the above volume for the Normal Operation Case.*

7. *Sampling produces 4 gallons/sample (2 gallons/sample to laboratory drain and 2 gallons/sample due to line purging, 7 samples/day/unit).*

8. *Valve stem leakage of 10 cc/day for the Design Basis Case and 1.5 times the above for the Normal Operation Case.*

9. *No waste from relief valve discharges for the Design Basis Case and 50 gallons/year for the Normal Operation Case.*

10. *Laundry waste of 3 washloads per week producing 210 gallons/washload for the Design Basis Case and 1.5 times the above volume for the Normal Operation Case.*

11. *Personnel decontamination showers of 4 showers/day producing 5 gallons/shower for the Design Basis Case and 1.5 times the above volume for the Normal Operation Case.*

12. *Personnel handwashes of 25 per day producing 0.5 gallons/wash for the Design Basis Case and 1.5 times the above volume for the Normal Operation Case.*

13. *Periodic system piping drains of 200 gallons/year/system/unit for the Design Basis Case and 1.5 times the above volume for the Normal Operation Case.*

TABLE 11.2-1
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

14. *Containment fan cooler drains of 1,000 gallons/year/unit for the Design Basis Case and 1.5 times the above volume for the Normal Operation Case.*

15. *Each reactor coolant pump 3 seal leaks 100 cc/hour for the Design Basis Case and the Normal Operation Case.*

16. *Spent resin loadout area washdown of 200 gallons/year for the Design Basis Case and 1.5 times the above for the Normal Operation Case.*

17. *Demineralizer overflow produces 500 gallons/backwash and resin replacement of one demineralizer per set annually for the Design Basis Case and the Normal Operation Case.*

18. *Reactor coolant drain tank wastes are processed through the CVCS for the Design Basis Case and 500 gallons/year/unit to the liquid waste system for the Normal Operation Case.*

19. *Miscellaneous floor drain leakage of 5,000 gallons/year for the Design Basis Case and 1.5 times the above volume for the Normal Operation Case.*

20. *Miscellaneous leakage of 160 pounds/day/unit of Spectrum I wastes to the auxiliary building for the Normal Operation Case.*

21. *Miscellaneous leakage of 40 gallons/day/unit of Spectrum I wastes to the containment building for the Normal Operation Case.*

22. *RHR pump leakage of 0.25 gallons/pump for the Normal Operation Case.*

23. *Waste will be allowed 48 hours of decay before processing from the chemical drain, laundry and hot shower, miscellaneous equipment drain, and reactor coolant drain tanks. (This includes fill time and discharge time.)*

24. *Waste will be allowed 336 hours of decay in the floor drain receiver and equipment drain receiver tanks before processing. (This includes one-half of the fill time plus one-half of the discharge time.)*

25. *Waste will be allowed 24 hours of decay in the waste condensate tank before processing.*

26. *No decay credit is taken for sumps.*

27. *For tritium control, 350,000 gallons/unit will be discharged annually.*

28. *Primary-to-secondary steam generator leakage of 100 lb/day of primary coolant for the Normal Operation Case.*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-2

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ASSUMPTIONS FOR CALCULATIONS OF ACTIVITY RELEASED FROM CVCS BASED ON ORIGINAL SYSTEM DESIGN

Average Shim Bleed Flowrate, gpm	*1.0*
Capacity of Liquid Holdup Tank, gal.	*83000*
DFs for CVC Demineralizers	*(Given in Table 11.1-15)*
DF for Boric Acid Evaporator [(a)] - iodine	*10^2*
- other nuclides	*10^3*
Capacity of Monitor Tank, gal.	*25000*
Fraction of Boric Acid Evaporator Distillate Recycled [(a)]	*0.333*

(a) Boric acid evaporator has been abandoned in place

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-3

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ACTIVITY CONCENTRATION SPECTRUM I THROUGH V FOR INPUT WASTE SOURCES, DESIGN BASIS CASE (μCi/cc)[a]

Nuclide	*Spectrum I*	*Spectrum II*	*Spectrum III*	*Spectrum IV*	*Spectrum V*
H-3	*0.11E+01*	*0.11E+01*	*0.11E-01*	*0.11E-03*	*0.11E-04*
Cr-51	*0.19E-02*	*0.19E-02*	*0.19E-04*	*0.19E-06*	*0.19E-07*
Mn-54	*0.31E-03*	*0.30E-03*	*0.30E-05*	*0.30E-07*	*0.30E-08*
Fe-55	*0.15E-02*	*0.92E-03*	*0.92E-05*	*0.92E-07*	*0.92E-08*
Co-58	*0.17E-01*	*0.16E-01*	*0.16E-03*	*0.16E-05*	*0.16E-06*
Fe-59	*0.10E-02*	*0.97E-03*	*0.97E-05*	*0.97E-07*	*0.97E-08*
Co-60	*0.19E-02*	*0.19E-02*	*0.19E-04*	*0.19E-06*	*0.19E-07*
Kr-83M	*0.35E+00*	*0.0*	*0.0*	*0.0*	*0.0*
Kr-85M	*0.18E+01*	*0.0*	*0.0*	*0.0*	*0.0*
Kr-85	*0.58E+01*	*0.0*	*0.0*	*0.0*	*0.0*
Kr-87	*0.99E+00*	*0.0*	*0.0*	*0.0*	*0.0*
Kr-88	*0.31E+01*	*0.0*	*0.0*	*0.0*	*0.0*
Sr-89	*0.24E-02*	*0.23E-02*	*0.23E-04*	*0.23E-06*	*0.23E-07*
Sr-90	*0.11E-03*	*0.11E-03*	*0.11E-05*	*0.11E-07*	*0.11E-08*
Y-90	*0.19E-04*	*0.16E-04*	*0.16E-06*	*0.16E-08*	*0.16E-09*
Sr-91	*0.15E-02*	*0.50E-04*	*0.50E-06*	*0.50E-08*	*0.50E-09*
Y-91	*0.21E-02*	*0.20E-02*	*0.20E-04*	*0.20E-06*	*0.20E-07*
Sr-92	*0.61E-03*	*0.27E-08*	*0.27E-10*	*0.27E-12*	*0.27E-13*
Y-92	*0.78E-04*	*0.25E-07*	*0.25E-09*	*0.25E-11*	*0.25E-12*
Zr-95	*0.57E-03*	*0.56E-03*	*0.56E-05*	*0.56E-07*	*0.56E-08*
Nb-95	*0.56E-03*	*0.56E-03*	*0.56E-05*	*0.56E-07*	*0.56E-08*
Mo-99	*0.46E-01*	*0.28E-01*	*0.28E-03*	*0.28E-05*	*0.28E-06*
I-131	*0.28E+01*	*0.23E+01*	*0.23E-01*	*0.23E-03*	*0.23E-04*

TABLE 11.2-3

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Nuclide	*Spectrum I*	*Spectrum II*	*Spectrum III*	*Spectrum IV*	*Spectrum V*
Te-132	*0.29E+00*	*0.19E+00*	*0.19E-02*	*0.19E-04*	*0.19E-05*
I-132	*0.97E+00*	*0.20E+00*	*0.20E-02*	*0.20E-04*	*0.20E-05*
I-133	*0.38E+01*	*0.77E+00*	*0.77E-02*	*0.77E-04*	*0.77E-05*
Xe-133M	*0.31E+01*	*0.0*	*0.0*	*0.0*	*0.0*
Xe-133	*0.20E+03*	*0.0*	*0.0*	*0.0*	*0.0*
Cs-134	*0.19E+00*	*0.19E+00*	*0.19E-02*	*0.19E-04*	*0.19E-05*
I-134	*0.49E+00*	*0.10E-16*	*0.10E-18*	*0.10E-20*	*0.10E-21*
I-135	*0.21E+01*	*0.15E-01*	*0.15E-03*	*0.15E-05*	*0.15E-06*
Xe-135M	*0.39E+00*	*0.0*	*0.0*	*0.0*	*0.0*
Xe-135	*0.54E+01*	*0.0*	*0.0*	*0.0*	*0.0*
Cs-136	*0.51E-01*	*0.46E-01*	*0.46E-03*	*0.46E-05*	*0.46E-06*
Cs-137	*0.35E+00*	*0.35E+00*	*0.35E-02*	*0.35E-04*	*0.35E-05*
Xe-138	*0.51E+00*	*0.0*	*0.0*	*0.0*	*0.0*
Ba-140	*0.39E-02*	*0.35E-02*	*0.35E-04*	*0.35E-06*	*0.35E-07*
La-140	*0.14E-02*	*0.27E-02*	*0.27E-04*	*0.27E-06*	*0.27E-07*
Ce-144	*0.33E-03*	*0.33E-03*	*0.33E-05*	*0.33E-07*	*0.33E-08*
Pr-144	*0.33E-03*	*0.33E-03*	*0.33E-05*	*0.33E-07*	*0.33E-08*

(a) A plateout decontamination factor of 10 for yttrium and 100 for molybdenum is assumed for all waste streams.

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-4

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ACTIVITY CONCENTRATION SPECTRUM I THROUGH V FOR INPUT WASTE SOURCES, DESIGN BASIS CASE

(μCi/cc)[a]

Nuclide	*Spectrum I*	*Spectrum II*	*Spectrum III*	*Spectrum IV*	*Spectrum V*
H-3	*0.11E+01*	*0.10E+01*	*0.10E-01*	*0.10E-03*	*0.10E-04*
Cr-51	*0.19E-02*	*0.19E-02*	*0.19E-04*	*0.19E-06*	*0.19E-07*
Mn-54	*0.31E-03*	*0.30E-03*	*0.30E-05*	*0.30E-07*	*0.30E-08*
Fe-55	*0.15E-02*	*0.92E-03*	*0.92E-05*	*0.92E-07*	*0.92E-08*
Co-58	*0.17E-01*	*0.16E-01*	*0.16E-03*	*0.16E-05*	*0.16E-06*
Fe-59	*0.10E-02*	*0.97E-03*	*0.97E-05*	*0.97E-07*	*0.97E-08*
Co-60	*0.19E-02*	*0.19E-02*	*0.19E-04*	*0.19E-06*	*0.19E-07*
Kr-83M	*0.42E-01*	*0.0*	*0.0*	*0.0*	*0.0*
Kr-85M	*0.22E+00*	*0.0*	*0.0*	*0.0*	*0.0*
Kr-85	*0.67E+00*	*0.0*	*0.0*	*0.0*	*0.0*
Kr-87	*0.12E+00*	*0.0*	*0.0*	*0.0*	*0.0*
Kr-88	*0.38E+00*	*0.0*	*0.0*	*0.0*	*0.0*
Sr-89	*0.28E-03*	*0.27E-03*	*0.27E-05*	*0.27E-07*	*0.23E-08*
Sr-90	*0.13E-04*	*0.13E-04*	*0.13E-06*	*0.13E-08*	*0.13E-09*
Y-90	*0.24E-05*	*0.19E-05*	*0.19E-07*	*0.19E-09*	*0.19E-10*
Sr-91	*0.18E-03*	*0.59E-07*	*0.59E-07*	*0.59E-09*	*0.59E-10*
Y-91	*0.25E-03*	*0.24E-03*	*0.24E-05*	*0.24E-07*	*0.24E-08*
Sr-92	*0.74E-04*	*0.33E-09*	*0.33E-11*	*0.33E-13*	*0.33E-14*
Y-92	*0.93E-05*	*0.30E-08*	*0.30E-10*	*0.30E-12*	*0.30E-13*
Zr-95	*0.68E-04*	*0.67E-04*	*0.67E-06*	*0.67E-08*	*0.67E-09*
Nb-95	*0.67E-04*	*0.67E-04*	*0.67E-06*	*0.67E-08*	*0.67E-09*
Mo-99	*0.56E-02*	*0.34E-02*	*0.34E-04*	*0.34E-06*	*0.34E-07*
I-131	*0.32E+00*	*0.27E+00*	*0.27E-02*	*0.27E-04*	*0.27E-05*

TABLE 11.2-4

Nuclide	Spectrum I	Spectrum II	Spectrum III	Spectrum IV	Spectrum V
Te-132	0.35E-01	0.23E+01	0.23E-03	0.23E-05	0.23E-06
I-132	0.12E+00	0.23E+01	0.23E-03	0.23E-05	0.23E-06
I-133	0.44E+00	0.91E+01	0.91E-03	0.91E-05	0.91E-06
Xe-133M	0.38E+00	0.0	0.0	0.0	0.0
Xe-133	0.32E+02	0.0	0.0	0.0	0.0
Cs-134	0.24E+01	0.24E+01	0.24E-03	0.24E-05	0.24E-06
I-134	0.60E+01	0.12E-17	0.12E-19	0.12E-21	0.12E-22
I-135	0.25E+00	0.17E-02	0.17E-04	0.17E-06	0.17E-07
Xe-135M	0.46E+01	0.0	0.0	0.0	0.0
Xe-135	0.65E+00	0.0	0.0	0.0	0.0
Cs-136	0.63E-02	0.56E-02	0.56E-04	0.56E-06	0.56E-07
Cs-137	0.42E+01	0.42E+01	0.42E-03	0.42E-05	0.42E-06
Xe-138	0.63E+01	0.0	0.0	0.0	0.0
Ba-140	0.47E-03	0.42E-03	0.42E-05	0.42E-07	0.42E-08
La-140	0.17E-03	0.32E-03	0.32E-05	0.32E-07	0.32E-08
Ce-144	0.40E-04	0.40E-04	0.40E-06	0.40E-08	0.40E-09
Pr-144	0.40E-04	0.40E-04	0.40E-06	0.40E-08	0.40E-09

(a) A plateout decontamination factor of 10 for yttrium and 100 for molybdenum is assumed for all waste streams.

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-5 Sheet 1 of 4

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ANNUAL FLOW AND ISOTOPIC SPECTRA FOR LIQUID WASTE INPUTS
THIS TABLE APPLIES TO THE ESTIMATED RELEASES AND RADIOLOGICAL CONSEQUENCES CALCULATED, BASED ON ORIGINAL DESIGN
(REFER TO FIGURES 11.2-2 and 11.2-3)

Stream Number[a]	*Stream Identification*	*Design Basis Case Flow[b]*	*Normal Operation Case Flow[b]*	*Concentration Spectrum*
1A	*Safety injection tank drain*	*80*	*120*	*IV*
1B	*Safety injection tank drain*	*80*	*120*	*IV*
2A	*Safety injection system piping drains*	*200*	*300*	*IV*
2B	*Safety injection system piping drains*	*200*	*300*	*IV*
3A	*Spray additive tank relief and drain*	*140*	*260*	*III*
3B	*Spray additive tank relief and drain*	*140*	*260*	*II*
4A	*Containment spray pump drains*	*200*	*300*	*II*
4B	*Containment spray pump drains*	*200*	*300*	*III*
5A	*Component cooling water (CCW) surge tank relief valve*	*0*	*50*	*V*
5B	*CCW surge tank relief valve*	*0*	*50*	*V*
6A	*RHR heat exchanger (CCW) drain*	*600*	*900*	*V*
6B	*RHR heat exchanger (CCW) drain*	*600*	*900*	*V*
7A	*Waste gas compressor seal cooler relief valve (CCW)*	*0*	*100*	*V*
7B	*Waste gas compressor seal cooler relief valve (CCW)*	*0*	*50*	*V*
8A	*Sample sink drains*	*2,920*	*4,380*	*IV*
8B	*Sample sink drains*	*2,920*	*4,380*	*IV*
(c)	*Chemical drain tank drain and overflow*	*-*	*-*	*-*
(c)	*Laundry and hot shower tank drain and overflow*	*-*	*-*	*-*
(c)	*Radwaste filter drains*	*-*	*-*	*-*
(c)	*Floor drain receiver tank drain and overflow*	*-*	*-*	*-*
9	*Spent resin loadout area drain*	*200*	*300*	*IV*
10A	*Charging pump (CCP1) baseplate drain*	*135*	*165*	*III*
10B	*Charging pump (CCP2) baseplate drain*	*135*	*165*	*III*
11A	*Chemical mixing tank drain*	*20*	*30*	*IV*
11B	*Chemical mixing tank drain*	*20*	*30*	*IV*
12A [f]	*Boric acid and concentrates filter drain*	*90*	*135*	*IV*
12B [f]	*Boric acid and concentrates filter drain*	*90*	*135*	*IV*
13 [f]	*Concentrates holding tank drain and overflow*	*120*	*180*	*IV*
14 [f]	*Concentrates holding tank pump drains*	*20*	*30*	*IV*
15A	*Boric acid tank drain and overflow*	*400*	*600*	*IV*
15B	*Boric acid tank drain and overflow*	*400*	*600*	*IV*
16	*Batching tank drain and overflow*	*100*	*150*	*IV*
17A [f]	*Boric acid evaporator heat exchanger drains*	*300*	*450*	*IV*
17B [f]	*Boric acid evaporator heat exchanger drains*	*300*	*450*	*IV*

TABLE 11.2-5 Sheet 2 of 4

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ANNUAL FLOW AND ISOTOPIC SPECTRA FOR LIQUID WASTE INPUTS
THIS TABLE APPLIES TO THE ESTIMATED RELEASES AND RADIOLOGICAL CONSEQUENCES CALCULATED, BASED ON ORIGINAL DESIGN
(REFER TO FIGURES 11.2-2 and 11.2-3)

Stream Number[a]	*Stream Identification*	*Design Basis Case Flow[b]*	*Normal Operation Case Flow[b]*	*Concentration Spectrum*
18A [f]	*Boric acid evaporator pump drains*	*80*	*120*	*IV*
18B [f]	*Boric acid evaporator pump drains*	*80*	*120*	*IV*
19A	*Monitor tank drain and overflow*	*800*	*1,200*	*IV*
19B	*Monitor tank drain and overflow*	*800*	*1,200*	*IV*
20	*Miscellaneous leakage (Units 1 and 2)*		*14,600*	*I*
21	*Miscellaneous floor drains (Units 1 and 2)*	*5,000*	*7,500*	*IV*
22A	*Containment fan cooler drain*	*1,000*	*1,500*	*IV*
22B	*Containment fan cooler drain*	*1,000*	*1,500*	*IV*
23A	*Reactor coolant pump labyrinth seal relief valve (CCW)*	*0*	*50*	*V*
23B	*Reactor coolant pump labyrinth seal relief valve (CCW)*	*0*	*50*	*V*
24A	*Reactor coolant pump thermal barrier relief (CCW)*	*-*	*50*	*V*
24B	*Reactor coolant pump thermal barrier relief (CCW)*	*-*	*50*	*V*
25A	*Biological shield plate relief (CCW)*	*-*	*50*	*V*
25B	*Biological shield plate relief (CCW)*		*50*	*V*
26A	*Reactor coolant pump upper and lower bearing relief (CCW)*	*-*	*50*	*V*
06B	*Reactor coolant pump upper and lower bearing relief (CCW)*	*-*	*50*	*V*
27A	*Reactor vessel support coolers relief (CCW)*	*-*	*50*	*V*
27B	*Reactor vessel support coolers relief (CCW)*	*-*	*50*	*V*
28A	*Reactor coolant pump No. 3 seal*	*925*	*1,400*	*III*
28B	*Reactor coolant pump No. 3 seal*	*925*	*1,400*	*III*
29A	*Excess letdown heat exchanger relief (CCW)*	*-*	*50*	*V*
29B	*Excess letdown heat exchanger relief (CCW)*	*-*	*50*	*V*
30A	*Miscellaneous equipment leakages*	*-*	*11,700*	*I*
30B	*Miscellaneous equipment leakages*	*-*	*11,700*	*I*
31A	*Reactor coolant drain tank relief valve*	*-*	*50*	*II*
31B	*Reactor coolant drain tank relief valve*	*-*	*50*	*II*
33A	*Miscellaneous pump leakage*	*70*	*10*	*III*
33B	*Miscellaneous pump leakage*	*70*	*110*	*III*
34	*Laboratory drains*	*10,220*	*15,330*	*IV*
35	*Laundry drains*	*32,760*	*49,140*	*V*
36	*Personnel decontamination*	*11,860*	*16,340*	*V*
37A	*CVCS valve leakoffs*	*6*	*9*	*II*

TABLE 11.2-5 Sheet 3 of 4

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ANNUAL FLOW AND ISOTOPIC SPECTRA FOR LIQUID WASTE INPUTS
THIS TABLE APPLIES TO THE ESTIMATED RELEASES AND RADIOLOGICAL CONSEQUENCES CALCULATED, BASED ON ORIGINAL DESIGN
(REFER TO FIGURES 11.2-2 and 11.2-3)

Stream Number[a]	*Stream Identification*	*Design Basis Case Flow[b]*	*Normal Operation Case Flow[b]*	*Concentration Spectrum*
37B	*CVCS valve leakoffs*	*6*	*9*	*II*
38A	*Letdown heat exchanger tube side drain*	*75*	*110*	*II*
38B	*Letdown heat exchanger tube side drain*	*75*	*110*	*II*
39A	*Volume control tank drain*	*150*	*225*	*II*
39B	*Volume control tank drain*	*150*	*225*	*II*
40A	*Charging pump (CCP1) drains*	*140*	*210*	*II*
40B	*Charging pump (CCP2) drains*	*140*	*210*	*II*
41A	*Reactor coolant filter*	*45*	*60*	*II*
41B	*Reactor coolant filter*	*45*	*60*	*II*
42A	*Seal water injection filter*	*90*	*135*	*II*
42B	*Seal water injection filter*	*90*	*135*	*II*
43A	*Seal water filter*	*45*	*60*	*II*
43B	*Seal water filter*	*45*	*60*	*II*
44A	*Ion exchange filter*	*45*	*60*	*IV*
44B	*Ion exchange filter*	*45*	*60*	*IV*
45A	*Liquid holdup tank drain*	*1,050*	*1,575*	*II*
45B	*Liquid holdup tank drain*	*700*	*1,050*	*II*
46A	*CVCS miscellaneous piping drains*	*200*	*300*	*II*
46B	*CVCS miscellaneous piping drains*	*200*	*300*	*II*
47A	*RHR heat exchanger drain*	*700*	*1,050*	*II*
47B	*RHR heat exchanger drain*	*700*	*1,050*	*II*
48A	*RHR pump drain*	*280*	*420*	*II*
48B	*RHR pump drain*	*280*	*420*	*II*
49A	*RHR piping drains*	*200*	*300*	*II*
49B	*RHR piping drains*	*200*	*300*	*II*
50A	*Spent fuel pit cooling system piping drains*	*200*	*300*	*III*
50B	*Spent fuel pit cooling system piping drains*	*200*	*300*	*III*
51A	*Spent fuel pit cooling system filter drains*	*225*	*340*	*III*
51B	*Spent fuel pit cooling system filter drains*	*225*	*340*	*III*
52A	*Containment sump pump discharge piping drain*	*200*	*300*	*III*
52B	*Containment sump pump discharge piping drain*	*200*	*300*	*III*
(c)	*Equipment drain receiver tank drain and overflow*	*-*	*-*	*-*
(c)	*Equipment drain receiver tank pump drain*	*-*	*-*	*-*
(c)	*Waste Concentrator Condensate tank drain and overflow*	*-*	*-*	*-*

TABLE 11.2-5 Sheet 4 of 4

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ANNUAL FLOW AND ISOTOPIC SPECTRA FOR LIQUID WASTE INPUTS
THIS TABLE APPLIES TO THE ESTIMATED RELEASES AND RADIOLOGICAL CONSEQUENCES CALCULATED, BASED ON ORIGINAL DESIGN
(REFER TO FIGURES 11.2-2 and 11.2-3)

Stream Number[a]	*Stream Identification*	*Design Basis Case Flow[b]*	*Normal Operation Case Flow[b]*	*Concentration Spectrum*
(c)	*Waste Concentrator Condensate tank pump drain*	-	-	-
(c)	*Radwaste concentrator heat exchanger drains*	-	-	-
(c)	*Radwaste concentrator pump drains*	-	-	-
(c)	*Waste concentrates tank drain and overflow*	-	-	-
53	*Spent resin motive water pump drains*	*60*	*90*	*III*
54A	*Waste gas moisture separator drain*	*40*	*60*	*III*
54B	*Waste gas moisture separator drain*	*20*	*30*	*III*
55A	*Waste gas decay tank drain*	*420*	*630*	*III*
55B	*Waste gas decay tank drain*	*420*	*630*	*III*
56A	*Waste gas compressor inlet piping drain*	*200*	*300*	*III*
56B	*Waste gas compressor inlet piping drain*	*200*	*300*	*III*
57A	*Sample sink drains*	*2,190*	*3,290*	*III*
57B	*Sample sink drains*	*2,190*	*3,290*	*III*
58A	*CVCS demineralizer overflow*	*5,500*	*5,500*	*III*
58B	*CVCS demineralizer overflow*	*5,500*	*5,500*	*III*
59A	*Steam generator blowdown tank drain*	*(d)*	*(d)*	*(d)*
59B	*Steam generator blowdown tank drain*	*(d)*	*(d)*	*(d)*
(c)	*Spent resin tank overflow*	-	-	-
60A	*Waste regenerant tank discharge*	-	*121,700*	*(e)*
60B	*Waste regenerant tank discharge*	-	*121,700*	*(e)*

(a) The letters "A" and "B" on the stream numbers refer to Units 1 and 2 inputs, respectively.

(b) Annual estimated flow in gallons per year.

(c) These streams are intra-system leakages and are not counted as input.

(d) The steam generator blowdown tank will have significant activity only when significant primary to secondary leakage occurs.

(e) Calculated from secondary system activity concentrations and blowdown flowrate.

(f) Equipment is abandoned in place and no longer in use.

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-6

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ISOTOPIC FLOWS THROUGH CVC SYSTEM, DESIGN BASIS CASE

	Liquid Holdup Tank		*BA Evap Feed Ion Exchangers*		*Monitor Tank*	
Nuclide	*Inflow, Ci/hr*	*Outflow, Ci/hr*	*Inflow, Ci/hr*	*Liq Outflow, Ci/hr*	*Inflow, Ci/hr*	*To Wst Cond Tank, Ci/hr*
H-3	*0.230E-00*	*0.229E-00*	*0.229E-00*	*0.223E-00*	*0.223E-00*	*0.149E-00*
Cr-51	*0.318E-05*	*0.188E-05*	*0.188E-09*	*0.188E-12*	*0.188E-12*	*0.124E-12*
Mn-54	*0.517E-06*	*0.492E-06*	*0.492E-10*	*0.492E-13*	*0.492E-13*	*0.328E-13*
Fe-55	*0.264E-05*	*0.120E-07*	*0.120E-11*	*0.120E-14*	*0.120E-14*	*0.705E-15*
Co-58	*0.267E-04*	*0.217E-04*	*0.217E-08*	*0.217E-11*	*0.217E-11*	*0.144E-11*
Fe-59	*0.167E-05*	*0.121E-05*	*0.121E-09*	*0.121E-12*	*0.121E-12*	*0.799E-13*
Co-60	*0.332E-05*	*0.329E-05*	*0.329E-09*	*0.329E-12*	*0.329E-12*	*0.219E-12*
Kr-83	*0.211E-01*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Kr-85M	*0.109E-00*	*0.365E-35*	*0.365E-35*	*0.0*	*0.0*	*0.0*
Kr-85	*0.243E-00*	*0.242E-00*	*0.242E-00*	*0.0*	*0.0*	*0.0*
Kr-87	*0.594E-01*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Kr-88	*0.186E-00*	*0.323E-55*	*0.323E-55*	*0.0*	*0.0*	*0.0*
Sr-89	*0.381E-05*	*0.287E-05*	*0.287E-09*	*0.287E-12*	*0.287E-12*	*0.190E-12*
Sr-90	*0.183E-06*	*0.183E-06*	*0.183E-10*	*0.183E-13*	*0.183E-13*	*0.122E-13*
Y-90	*0.344E-04*	*0.327E-06*	*0.327E-06*	*0.327E-09*	*0.327E-09*	*0.192E-10*
Sr-91	*0.248E-05*	*0.615E-21*	*0.615E-25*	*0.615E-28*	*0.615E-28*	*0.174E-28*
Y-91	*0.354E-02*	*0.279E-02*	*0.279E-02*	*0.279E-05*	*0.279E-05*	*0.185E-06*
Sr-92	*0.101E-05*	*0.669E-62*	*0.669E-66*	*0.669E-69*	*0.669E-69*	*0.205E-70*
Y-92	*0.141E-03*	*0.106E-45*	*0.106E-45*	*0.106E-48*	*0.106E-48*	*0.700E-51*
Zr-95	*0.946E-06*	*0.757E-06*	*0.757E-10*	*0.757E-13*	*0.757E-13*	*0.502E-13*
Nb-95	*0.919E-06*	*0.893E-06*	*0.893E-10*	*0.893E-13*	*0.893E-13*	*0.595E-13*
Mo-99	*0.830E-00*	*0.488E-02*	*0.488E-02*	*0.488E-05*	*0.488E-05*	*0.288E-07*
I-131	*0.490E-01*	*0.802E-02*	*0.802E-04*	*0.802E-06*	*0.802E-08*	*0.513E-08*
Te-132	*0.515E-02*	*0.582E-04*	*0.582E-06*	*0.582E-09*	*0.582E-11*	*0.349E-11*

TABLE 11.2-6

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

	Liquid Holdup Tank		*BA Evap Feed Ion Exchangers*		*Monitor Tank*	
Nuclide	*Inflow, Ci/hr*	*Outflow, Ci/hr*	*Inflow, Ci/hr*	*Liq Outflow, Ci/hr*	*Inflow, Ci/hr*	*To Wst Cond Tank, Ci/hr*
I-132	*0.176E-01*	*0.600E-04*	*0.600E-06*	*0.600E-08*	*0.600E-10*	*0.472E-11*
I-133	*0.669E-01*	*0.400E-08*	*0.400E-10*	*0.400E-12*	*0.400E-14*	*0.180E-14*
Xe-133M	*0.183E-00*	*0.329E-03*	*0.329E-03*	*0.0*	*0.0*	*0.0*
Xe-133	*0.154E-02*	*0.997E-00*	*0.997E-00*	*0.0*	*0.0*	*0.0*
Cs-134	*0.908E-02*	*0.890E-02*	*0.445E-03*	*0.445E-06*	*0.445E-06*	*0.297E-06*
I-134	*0.893E-02*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
I-135	*0.369E-01*	*0.846E-24*	*0.846E-26*	*0.846E-28*	*0.846E-30*	*0.163E-30*
Xe-135M	*0.233E-01*	*0.128E-24*	*0.128E-24*	*0.0*	*0.0*	*0.0*
Xe-135	*0.327E-00*	*0.139E-16*	*0.139E-16*	*0.0*	*0.0*	*0.0*
Cs-136	*0.246E-02*	*0.804E-03*	*0.402E-04*	*0.402E-07*	*0.402E-07*	*0.261E-07*
Cs-137	*0.163E-01*	*0.162E-01*	*0.812E-03*	*0.812E-06*	*0.812E-06*	*0.542E-06*
Xe-138	*0.314E-01*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Ba-140	*0.645E-05*	*0.207E-05*	*0.207E-09*	*0.207E-12*	*0.207E-12*	*0.134E-12*
La-140	*0.228E-05*	*0.238E-05*	*0.238E-09*	*0.238E-12*	*0.238E-12*	*0.154E-12*
Ce-144	*0.557E-06*	*0.529E-06*	*0.529E-10*	*0.529E-13*	*0.529E-13*	*0.353E-13*
Pr-144	*0.557E-06*	*0.529E-06*	*0.529E-10*	*0.529E-13*	*0.529E-13*	*0.353E-13*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-7

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ISOTOPIC FLOWS THROUGH CVC SYSTEM, NORMAL OPERATION CASE

	Liquid Holdup Tank		*BA Evap Feed Ion Exchangers*		*Monitor Tank*	
Nuclide	*Inflow, Ci/hr*	*Outflow, Ci/hr*	*Inflow, Ci/hr*	*Liq Outflow, Ci/hr*	*Inflow, Ci/hr*	*To Wst Cond Tank, Ci/hr*
H-3	*0.218E 00*	*0.217E 00*	*0.217E 00*	*0.211E 00*	*0.211E 00*	*0.140E 00*
Cr-51	*0.317E-05*	*0.188E-05*	*0.188E-09*	*0.188E-12*	*0.188E-12*	*0.124E-12*
Mn-54	*0.516E-06*	*0.492E-06*	*0.492E-10*	*0.492E-13*	*0.492E-13*	*0.328E-13*
Fe-55	*0.263E-05*	*0.120E-07*	*0.120E-11*	*0.120E-14*	*0.120E-14*	*0.705E-15*
Co-58	*0.266E-04*	*0.217E-04*	*0.217E-08*	*0.217E-11*	*0.217E-11*	*0.144E-11*
Fe-59	*0.167E-05*	*0.121E-05*	*0.121E-09*	*0.121E-12*	*0.121E-12*	*0.790E-13*
Co-60	*0.331E-05*	*0.329E-05*	*0.329E-09*	*0.329E-12*	*0.329E-12*	*0.219E-12*
Kr-83M	*0.252E-02*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Kr-85M	*0.130E-01*	*0.436E-36*	*0.436E-36*	*0.0*	*0.0*	*0.0*
Kr-85	*0.229E-01*	*0.228E-01*	*0.228E-01*	*0.0*	*0.0*	*0.0*
Kr-87	*0.713E-02*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Kr-88	*0.223E-01*	*0.386E-56*	*0.386E-56*	*0.0*	*0.0*	*0.0*
Sr-89	*0.457E-06*	*0.344E-06*	*0.344E-10*	*0.344E-13*	*0.344E-13*	*0.228E-13*
Sr-90	*0.219E-07*	*0.219E-07*	*0.219E-11*	*0.219E-14*	*0.219E-14*	*0.146E-14*
Y-90	*0.411E-05*	*0.392E-07*	*0.392E-07*	*0.392E-10*	*0.392E-10*	*0.230E-11*
Sr-91	*0.297E-06*	*0.737E-22*	*0.737E-26*	*0.737E-29*	*0.737E-29*	*0.209E-29*
Y-91	*0.412E-03*	*0.325E-03*	*0.325E-03*	*0.325E-06*	*0.325E-06*	*0.216E-07*
Sr-92	*0.122E-06*	*0.803E-63*	*0.803E-67*	*0.803E-70*	*0.803E-70*	*0.246E-71*
Y-92	*0.169E-04*	*0.127E-46*	*0.127E-46*	*0.127E-49*	*0.127E-49*	*0.840E-52*
Zr-95	*0.113E-06*	*0.908E-07*	*0.908E-11*	*0.908E-14*	*0.908E-14*	*0.602E-14*
Nb-95	*0.110E-06*	*0.107E-06*	*0.107E-10*	*0.107E-13*	*0.107E-13*	*0.713E-14*
M0-99	*0.992E-01*	*0.583E-03*	*0.583E-03*	*0.583E-06*	*0.583E-06*	*0.344E-08*
I-131	*0.588E-02*	*0.962E-03*	*0.962E-05*	*0.962E-07*	*0.962E-09*	*0.615E-09*

TABLE 11.2-7

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

	Liquid Holdup Tank		*BA Evap Feed Ion Exchangers*		*Monitor Tank*	
Nuclide	*Inflow, Ci/hr*	*Outflow, Ci/hr*	*Inflow, Ci/hr*	*Liq Outflow, Ci/hr*	*Inflow, Ci/hr*	*To Wst Cond Tank, Ci/hr*
Te-132	*0.618E-03*	*0.698E-05*	*0.698E-07*	*0.698E-10*	*0.698E-12*	*0.418E-12*
I-132	*0.211E-02*	*0.720E-05*	*0.720E-07*	*0.720E-09*	*0.720E-11*	*0.567E-12*
I-133	*0.802E-02*	*0.480E-09*	*0.480E-11*	*0.480E-13*	*0.480E-15*	*0.215E-15*
Xe-133M	*0.213E-01*	*0.383E-04*	*0.383E-04*	*0.0*	*0.0*	*0.0*
Xe-133	*0.174E 01*	*0.112E 00*	*0.112E 00*	*0.0*	*0.0*	*0.0*
Cs-134	*0.110E-02*	*0.108E-02*	*0.539E-04*	*0.539E-07*	*0.539E-07*	*0.360E-07*
I-134	*0.107E-02*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
I-135	*0.443E-02*	*0.101E-24*	*0.101E-26*	*0.101E-28*	*0.101E-30*	*0.196E-31*
Xe-135M	*0.279E-02*	*0.153E-25*	*0.153E-25*	*0.0*	*0.0*	*0.0*
Xe-135	*0.390E-01*	*0.166E-17*	*0.166E-17*	*0.0*	*0.0*	*0.0*
Cs-136	*0.295E-03*	*0.964E-04*	*0.482E-05*	*0.482E-08*	*0.482E-08*	*0.313E-08*
Cs-137	*0.195E-02*	*0.195E-02*	*0.975E-04*	*0.975E-07*	*0.975E-07*	*0.650E-07*
Xe-138	*0.377E-02*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Ba-140	*0.773E-06*	*0.248E-06*	*0.248E-10*	*0.248E-13*	*0.248E-13*	*0.161E-13*
La-140	*0.273E-06*	*0.285E-06*	*0.285E-10*	*0.285E-13*	*0.285E-13*	*0.185E-13*
Ce-144	*0.668E-07*	*0.635E-07*	*0.835E-11*	*0.635E-14*	*0.635E-14*	*0.423E-14*
Pr-144	*0.668E-07*	*0.635E-07*	*0.635E-11*	*0.635E-14*	*0.635E-14*	*0.423E-14*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-8

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ANNUAL FLOW AND ACTIVITY CONCENTRATION OF PROCESS STREAMS FOR DESIGN BASIS CASE

Stream Number[a]	*1*	*2*	*3*	*4*	*5*
Annual Flow, gal./yr	*3850*	*17370*	*0.0*	*140*	*44620*
Nuclide	*Concentration, μCi/cc*				
H-3	*0.533E-02*	*0.697E-03*	*0.0*	*0.110E-01*	*0.110E-04*
Cr-51	*0.899E-05*	*0.118E-05*	*0.0*	*0.185E-04*	*0.176E-07*
Mn-54	*0.148E-05*	*0.193E-06*	*0.0*	*0.304E-05*	*0.303E-08*
Fe-55	*0.444E-04*	*0.581E-06*	*0.0*	*0.915E-05*	*0.548E-08*
Co-58	*0.795E-04*	*0.104E-04*	*0.0*	*0.164E-03*	*0.160E-06*
Fe-59	*0.471E-05*	*0.616E-06*	*0.0*	*0.970E-05*	*0.941E-08*
Co-60	*0.945E-05*	*0.124E-05*	*0.0*	*0.194E-04*	*0.194E-07*
Sr-89	*0.112E-04*	*0.146E-05*	*0.0*	*0.230E-04*	*0.224E-07*
Sr-90	*0.533E-06*	*0.697E-07*	*0.0*	*0.110E-05*	*0.110E-08*
Y-90	*0.778E-07*	*0.102E-07*	*0.0*	*0.160E-06*	*0.541E-09*
Sr-91	*0.242E-06*	*0.317E-07*	*0.0*	*0.499E-06*	*0.163E-10*
Y-91	*0.991E-05*	*0.130E-05*	*0.0*	*0.204E-04*	*0.199E-07*
Sr-92	*0.133E-10*	*0.173E-11*	*0.0*	*0.273E-10*	*0.122E-18*
Y-92	*0.119E-09*	*0.156E-10*	*0.0*	*0.245E-09*	*0.314E-16*
Zr-95	*0.271E-05*	*0.354E-06*	*0.0*	*0.558E-05*	*0.546E-08*
Nb-95	*0.270E-05*	*0.353E-06*	*0.0*	*0.556E-05*	*0.556E-08*
M0-99	*0.137E-03*	*0.179E-04*	*0.0*	*0.281E-03*	*0.172E-06*
I-131	*0.114E-01*	*0.149E-02*	*0.0*	*0.234E-01*	*0.197E-04*
Te-132	*0.925E-03*	*0.121E-03*	*0.0*	*0.190E-02*	*0.124E-05*
I-132	*0.954E-03*	*0.125E-03*	*0.0*	*0.197E-02*	*0.128E-05*
I-133	*0.374E-02*	*0.489E-03*	*0.0*	*0.770E-02*	*0.158E-05*
Cs-134	*0.943E-03*	*0.123E-03*	*0.0*	*0.194E-02*	*0.194E-05*
I-134	*0.492E-19*	*0.643E-20*	*0.0*	*0.101E-18*	*0.211E-38*
I-135	*0.707E-04*	*0.924E-05*	*0.0*	*0.146E-03*	*0.102E-08*
Cs-136	*0.225E-03*	*0.294E-04*	*0.0*	*0.462E-03*	*0.416E-06*
Cs-137	*0.169E-02*	*0.221E-03*	*0.0*	*0.347E-02*	*0.347E-05*
Ba-140	*0.170E-04*	*0.222E-05*	*0.0*	*0.349E-04*	*0.313E-07*
La-140	*0.129E-04*	*0.169E-05*	*0.0*	*0.266E-04*	*0.301E-07*
Ce-144	*0.161E-05*	*0.211E-06*	*0.0*	*0.332E-05*	*0.330E-08*
Pr-144	*0.161E-05*	*0.211E-06*	*0.0*	*0.332E-05*	*0.330E-08*

TABLE 11.2-8

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Stream Number[a]	*6*	*7*	*8*	*9*	*10*
Annual Flow, gal./yr	*10220*	*21360*	*76200*	*0.0*	*12690*
Nuclide	*Concentration, μCi/cc*				
H-3	*0.110E-03*	*0.160E-02*	*0.469E-03*	*0.0*	*0.491E+00*
Cr-51	*0.176E-06*	*0.190E-05*	*0.567E-06*	*0.0*	*0.029E-03*
Mn-54	*0.303E-07*	*0.430E-06*	*0.126E-06*	*0.0*	*0.136E-03*
Fe-55	*0.548E-07*	*0.367E-07*	*0.208E-07*	*0.0*	*0.414E-03*
Co-58	*0.160E-05*	*0.208E-04*	*0.614E-05*	*0.0*	*0.733E-02*
Fe-59	*0.941E-07*	*0.114E-05*	*0.338E-06*	*0.0*	*0.435E-03*
Co-60	*0.194E-06*	*0.282E-05*	*0.828E-06*	*0.0*	*0.871E-03*
Sr-89	*0.224E-06*	*0.277E-05*	*0.821E-06*	*0.0*	*0.103E-02*
Sr-90	*0.110E-07*	*0.160E-06*	*0.469E-07*	*0.0*	*0.492E-04*
Y-90	*0.541E-08*	*0.156E-06*	*0.449E-07*	*0.0*	*0.720E-05*
Sr-91	*0.163E-09*	*0.287E-17*	*0.314E-10*	*0.0*	*0.328E-04*
Y-91	*0.199E-06*	*0.254E-05*	*0.750E-06*	*0.0*	*0.913E-03*
Sr-92	*0.122E-17*	*0.0*	*0.235E-16*	*0.0*	*0.434E-05*
Y-92	*0.314E-15*	*0.0*	*0.605E-16*	*0.0*	*0.563E-06*
Zr-95	*0.546E-07*	*0.701E-06*	*0.207E-06*	*0.0*	*0.250E-03*
Nb-95	*0.556E-07*	*0.797E-06*	*0.234E-06*	*0.0*	*0.249E-03*
Mo-99	*0.172E-05*	*0.134E-05*	*0.707E-06*	*0.0*	*0.127E-01*
I-131	*0.197E-03*	*0.102E-02*	*0.324E-03*	*0.0*	*0.105E+01*
Te-132	*0.124E-04*	*0.140E-04*	*0.631E-05*	*0.0*	*0.860E-01*
I-132	*0.128E-04*	*0.144E-04*	*0.651E-05*	*0.0*	*0.935E-01*
I-133	*0.158E-04*	*0.172E-07*	*0.305E-05*	*0.0*	*0.366E+00*
Cs-134	*0.194E-04*	*0.279E-03*	*0.821E-04*	*0.0*	*0.870E-01*
I-134	*0.211E-37*	*0.0*	*0.406E-38*	*0.0*	*0.345E-02*
I-135	*0.102E-07*	*0.171E-19*	*0.196E-08*	*0.0*	*0.212E-01*
Cs-136	*0.416E-05*	*0.319E-04*	*0.976E-05*	*0.0*	*0.207E-01*
Cs-137	*0.347E-04*	*0.506E-03*	*0.149E-03*	*0.0*	*0.156E+00*
Ba-140	*0.313E-06*	*0.238E-05*	*0.729E-06*	*0.0*	*0.157E-02*
La-140	*0.301E-06*	*0.274E-05*	*0.825E-06*	*0.0*	*0.118E-02*
Ce-144	*0.330E-07*	*0.468E-06*	*0.137E-06*	*0.0*	*0.149E-03*
Pr-144	*0.330E-07*	*0.468E-06*	*0.137E-06*	*0.0*	*0.149E-03*

TABLE 11.2-8

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Stream Number[a]	*58A&B*	*59A&B*	*60A&B*	*11*	*12*
Annual Flow, gal./yr	*11000*	*0.0*	*0.0*	*23990*	*0.0*
Nuclide	*Concentration, μCi/cc*				
H-3	*0.110E-01*	*0.0*	*0.0*	*0.264E+00*	*0.0*
Cr-51	*0.185E-04*	*0.0*	*0.0*	*0.315E-03*	*0.0*
Mn-54	*0.304E-05*	*0.0*	*0.0*	*0.712E-04*	*0.0*
Fe-55	*0.915E-05*	*0.0*	*0.0*	*0.614E-05*	*0.0*
Co-58	*0.164E-03*	*0.0*	*0.0*	*0.345E-02*	*0.0*
Fe-59	*0.970E-05*	*0.0*	*0.0*	*0.189E-03*	*0.0*
Co-60	*0.194E-04*	*0.0*	*0.0*	*0.467E-03*	*0.0*
Sr-89	*0.230E-04*	*0.0*	*0.0*	*0.460E-03*	*0.0*
Sr-90	*0.110E-05*	*0.0*	*0.0*	*0.265E-04*	*0.0*
Y-90	*0.160E-06*	*0.0*	*0.0*	*0.259E-04*	*0.0*
Sr-91	*0.499E-06*	*0.0*	*0.0*	*0.694E-15*	*0.0*
Y-91	*0.204E-04*	*0.0*	*0.0*	*0.420E-03*	*0.0*
Sr-92	*0.273E-10*	*0.0*	*0.0*	*0.0*	*0.0*
Y-92	*0.245E-09*	*0.0*	*0.0*	*0.0*	*0.0*
Zr-95	*0.558E-05*	*0.0*	*0.0*	*0.116E-03*	*0.0*
Nb-95	*0.556E-05*	*0.0*	*0.0*	*0.132E-03*	*0.0*
Mo-99	*0.281E-03*	*0.0*	*0.0*	*0.223E-03*	*0.0*
I-131	*0.234E-01*	*0.0*	*0.0*	*0.170E+00*	*0.0*
Te-132	*0.190E-02*	*0.0*	*0.0*	*0.233E-02*	*0.0*
I-132	*0.197E-02*	*0.0*	*0.0*	*0.241E-02*	*0.0*
I-133	*0.770E-02*	*0.0*	*0.0*	*0.301E-05*	*0.0*
Cs-134	*0.194E-02*	*0.0*	*0.0*	*0.463E-01*	*0.0*
I-134	*0.101E-18*	*0.0*	*0.0*	*0.0*	*0.0*
I-135	*0.146E-03*	*0.0*	*0.0*	*0.910E-17*	*0.0*
Cs-136	*0.462E-03*	*0.0*	*0.0*	*0.530E-02*	*0.0*
Cs-137	*0.347E-02*	*0.0*	*0.0*	*0.838E-01*	*0.0*
Ba-140	*0.349E-04*	*0.0*	*0.0*	*0.396E-03*	*0.0*
La-140	*0.266E-04*	*0.0*	*0.0*	*0.454E-03*	*0.0*
Ce-144	*0.332E-05*	*0.0*	*0.0*	*0.775E-04*	*0.0*
Pr-144	*0.332E-05*	*0.0*	*0.0*	*0.775E-04*	*0.0*

TABLE 11.2-8

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Stream Number[a]	*13*	*14*	*15*	*16*	*17*
Annual Flow, gal./yr	*0.0*	*23990*	*700,000*	*723,990*	*800,190*
Nuclide	*Concentration, μCi/cc*				
H-3	*0.0*	*0.264E+00*	*0.101E+01*	*0.985E-00*	*0.891E+00*
Cr-51	*0.0*	*0.315E-06*	*0.806E-12*	*0.104E-07*	*0.634E-07*
Mn-54	*0.0*	*0.712E-07*	*0.217E-12*	*0.236E-08*	*0.141E-07*
Fe-55	*0.0*	*0.614E-08*	*0.468E-14*	*0.203E-09*	*0.216E-08*
Co-58	*0.0*	*0.345E-05*	*0.957E-11*	*0.114E-06*	*0.688E-06*
Fe-59	*0.0*	*0.189E-06*	*0.503E-12*	*0.626E-08*	*0.379E-07*
Co-60	*0.0*	*0.467E-06*	*0.146E-11*	*0.155E-07*	*0.929E-07*
Sr-89	*0.0*	*0.460E-06*	*0.126E-11*	*0.152E-07*	*0.919E-07*
Sr-90	*0.0*	*0.265E-07*	*0.806E-13*	*0.878E-09*	*0.526E-08*
Y-90	*0.0*	*0.259E-07*	*0.126E-09*	*0.980E-09*	*0.516E-08*
Sr-91	*0.0*	*0.694E-18*	*0.116E-27*	*0.0*	*0.299E-11*
Y-91	*0.0*	*0.420E-06*	*0.121E-05*	*0.118E-05*	*0.114E-05*
Sr-92	*0.0*	*0.0*	*0.136E-69*	*0.0*	*0.224E-17*
Y-92	*0.0*	*0.0*	*0.463E-50*	*0.0*	*0.576E-17*
Zr-95	*0.0*	*0.116E-06*	*0.332E-12*	*0.384E-08*	*0.232E-07*
Nb-95	*0.0*	*0.132E-06*	*0.393E-12*	*0.437E-08*	*0.262E-07*
Mo-99	*0.0*	*0.223E-06*	*0.191E-06*	*0.192E-06*	*0.241E-06*
I-131	*0.0*	*0.170E-03*	*0.337E-07*	*0.567E-05*	*0.360E-04*
Te-132	*0.0*	*0.233E-05*	*0.232E-10*	*0.772E-07*	*0.673E-06*
I-132	*0.0*	*0.241E-05*	*0.312E-10*	*0.799E-07*	*0.690E-06*
I-133	*0.0*	*0.301E-08*	*0.121E-13*	*0.997E-10*	*0.291E-06*
Cs-134	*0.0*	*0.232E-02*	*0.196E-05*	*0.788E-04*	*0.791E-04*
I-134	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
I-135	*0.0*	*0.910E-20*	*0.187E-09*	*0.0*	*0.187E-09*
Cs-136	*0.0*	*0.265E-03*	*0.171E-05*	*0.898E-05*	*0.903E-05*
Cs-137	*0.0*	*0.419E-02*	*0.357E-05*	*0.142E-03*	*0.143E-03*
Ba-140	*0.0*	*0.396E-06*	*0.906E-12*	*0.131E-07*	*0.183E-07*
La-140	*0.0*	*0.454E-06*	*0.101E-11*	*0.150E-07*	*0.921E-07*
Ce-144	*0.0*	*0.775E-07*	*0.232E-12*	*0.257E-08*	*0.154E-07*
Pr-144	*0.0*	*0.776E-07*	*0.232E-12*	*0.257E-08*	*0.154E-07*

TABLE 11.2-8

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Stream Number[(a)]	*18*	*19*
Annual Flow, gal./yr	*800,190*	*(Refer to Section 11.2.3.13.2.4)*
Nuclide	*Concentration, μCi/cc*	
H-3	*0.891E+00*	*0.774E-06*
Cr-51	*0.634E-07*	*0.551E-13*
Mn-54	*0.141E-07*	*0.123E-13*
Fe-55	*0.216E-08*	*0.188E-14*
Co-58	*0.688E-06*	*0.598E-12*
Fe-59	*0.379E-07*	*0.329E-13*
Co-60	*0.929E-07*	*0.807E-13*
Sr-89	*0.919E-07*	*0.799E-13*
Sr-90	*0.526E-08*	*0.457E-14*
Y-90	*0.516E-08*	*0.448E-14*
Sr-91	*0.299E-11*	*0.260E-17*
Y-91	*0.114E-05*	*0.991E-12*
Sr-92	*0.224E-19*	*0.195E-23*
Y-92	*0.576E-17*	*0.501E-23*
Zr-95	*0.232E-07*	*0.202E-13*
Nb-95	*0.262E-07*	*0.228E-13*
Mo-99	*0.241E-06*	*0.209E-12*
I-131	*0.360E-04*	*0.313E-10*
Te-132	*0.673E-06*	*0.585E-12*
I-132	*0.690E-06*	*0.600E-12*
I-133	*0.291E-06*	*0.253E-12*
Cs-134	*0.791E-04*	*0.687E-10*
I-134	*0.0*	*0.0*
I-135	*0.187E-09*	*0.164E-15*
Cs-136	*0.903E-05*	*0.785E-11*
Cs-137	*0.143E-03*	*0.124E-09*
Ba-140	*0.813E-07*	*0.706E-13*
La-140	*0.921E-07*	*0.800E-13*
Ce-144	*0.154E-07*	*0.134E-13*
Pr-144	*0.154E-07*	*0.134E-13*

(a) Refer to Figure 11.2-2 for waste stream number identification.

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-9

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ANNUAL FLOW AND ACTIVITY CONCENTRATION OF PROCESS STREAMS FOR NORMAL OPERATION CASE

Stream Number[a]	*1*	*2*	*3*	*4*	*5*
Annual Flow, gal./yr	*29800*	*37530*	*100*	*220*	*65480*
Nuclide	*Concentration, μCi/cc*				
H-3	*0.009E+00*	*0.307E+00*	*0.103E+01*	*0.103E-01*	*0.103E-04*
Cr-51	*0.153E-02*	*0.582E-03*	*0.185E-02*	*0.185E-04*	*0.176E-07*
Mn-54	*0.240E-03*	*0.914E-04*	*0.304E-03*	*0.304E-05*	*0.303E-08*
Fe-55	*0.120E-02*	*0.457E-03*	*0.915E-03*	*0.915E-05*	*0.548E-08*
Co-58	*0.131E-01*	*0.499E-02*	*0.164E-01*	*0.164E-03*	*0.160E-06*
Fe-59	*0.787E-03*	*0.299E-03*	*0.970E-03*	*0.970E-05*	*0.941E-08*
Co-60	*0.153E-02*	*0.582E-03*	*0.194E-02*	*0.194E-04*	*0.194E-07*
Sr-89	*0.219E-03*	*0.831E-04*	*0.271E-03*	*0.271E-05*	*0.263E-08*
Sr-90	*0.104E-04*	*0.395E-05*	*0.132E-04*	*0.132E-06*	*0.132E-09*
Y-90	*0.186E-05*	*0.706E-06*	*0.194E-05*	*0.194E-07*	*0.651E-10*
Sr-91	*0.142E-03*	*0.539E-04*	*0.590E-05*	*0.590E-07*	*0.193E-11*
Y-91	*0.197E-03*	*0.748E-04*	*0.245E-03*	*0.245E-05*	*0.239E-08*
Sr-92	*0.578E-04*	*0.220E-04*	*0.329E-09*	*0.329E-11*	*0.147E-19*
Y-92	*0.731E-05*	*0.278E-05*	*0.295E-08*	*0.295E-10*	*0.378E-17*
Zr-95	*0.535E-04*	*0.204E-04*	*0.667E-04*	*0.667E-06*	*0.653E-09*
Nb-95	*0.525E-04*	*0.199E-04*	*0.667E-04*	*0.667E-06*	*0.667E-09*
Mo-99	*0.437E-02*	*0.166E-02*	*0.341E-02*	*0.341E-04*	*0.209E-07*
I-131	*0.251E+00*	*0.955E-01*	*0.269E+00*	*0.269E-02*	*0.226E-05*
Te-132	*0.273E-01*	*0.104E-01*	*0.227E-01*	*0.227E-03*	*0.148E-06*
I-132	*0.917E-01*	*0.349E-01*	*0.234E-01*	*0.234E-03*	*0.153E-06*
I-133	*0.349E+00*	*0.133E+00*	*0.913E-01*	*0.913E-01*	*0.187E-06*
Cs-134	*0.186E-01*	*0.706E-02*	*0.236E-01*	*0.236E-03*	*0.235E-06*
I-134	*0.469E-01*	*0.178E-01*	*0.124E-17*	*0.124E-19*	*0.259E-39*
I-135	*0.196E+00*	*0.747E-01*	*0.175E-02*	*0.175E-04*	*0.122E-09*
Cs-136	*0.492E-02*	*0.187E-02*	*0.562E-02*	*0.562E-04*	*0.505E-07*
Cs-137	*0.328E-01*	*0.125E-01*	*0.417E-01*	*0.417E-03*	*0.417E-06*
Ba-140	*0.372E-03*	*0.141E-03*	*0.424E-03*	*0.424E-05*	*0.381E-08*
La-140	*0.131E-03*	*0.499E-04*	*0.323E-03*	*0.323E-05*	*0.366E-08*
Ce-144	*0.317E-04*	*0.120E-04*	*0.401E-04*	*0.401E-06*	*0.399E-09*
Pr-144	*0.317E-04*	*0.120E-04*	*0.401E-04*	*0.401E-04*	*0.399E-09*

TABLE 11.2-9
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Stream Number[a]	*6*	*7*	*8*	*9*	*10*
Annual Flow, gal./yr	*15330*	*67650*	*80100*	*1000*	*19000*
Nuclide	*Concentration, μCi/cc*				
H-3	*0.103E-03*	*0.527E+00*	*0.278E-04*	*0.103E-01*	*0.459E+00*
Cr-51	*0.176E-06*	*0.705E-03*	*0.477E-07*	*0.195E-02*	*0.828E-03*
Mn-54	*0.303E-07*	*0.152E-03*	*0.820E-08*	*0.306E-03*	*0.136E-03*
Fe-55	*0.548E-07*	*0.216E-04*	*0.148E-07*	*0.153E-02*	*0.413E-03*
Co-58	*0.160E-05*	*0.748E-02*	*0.434E-06*	*0.167E-01*	*0.731E-02*
Fe-59	*0.941E-07*	*0.414E-03*	*0.255E-07*	*0.100E-02*	*0.434E-03*
Co-60	*0.194E-06*	*0.994E-03*	*0.526E-07*	*0.195E-02*	*0.869E-03*
Sr-89	*0.263E-07*	*0.118E-03*	*0.713E-08*	*0.278E-03*	*0.121E-03*
Sr-90	*0.132E-08*	*0.678E-05*	*0.357E-09*	*0.132E-04*	*0.590E-05*
Y-90	*0.651E-09*	*0.663E-05*	*0.176E-09*	*0.236E-05*	*0.869E-06*
Sr-91	*0.193E-10*	*0.365E-14*	*0.521E-11*	*0.181E-03*	*0.374E-05*
Y-91	*0.239E-07*	*0.110E-03*	*0.648E-08*	*0.250E-03*	*0.109E-03*
Sr-92	*0.147E-18*	*0.0*	*0.397E-19*	*0.737E-04*	*0.465E-06*
Y-92	*0.378E-16*	*0.0*	*0.102E-16*	*0.931E-05*	*0.601E-07*
Zr-95	*0.653E-08*	*0.302E-04*	*0.177E-08*	*0.681E-04*	*0.298E-04*
Nb-95	*0.667E-08*	*0.338E-04*	*0.181E-08*	*0.667E-04*	*0.298E-04*
Mo-99	*0.209E-06*	*0.929E-04*	*0.566E-07*	*0.556E-02*	*0.154E-02*
I-131	*0.226E-04*	*0.491E-01*	*0.613E-05*	*0.320E+00*	*0.121E+00*
Te-132	*0.148E-05*	*0.897E-03*	*0.400E-06*	*0.347E-01*	*0.102E-01*
I-132	*0.153E-05*	*0.926E-03*	*0.413E-06*	*0.117E+00*	*0.110E-01*
I-133	*0.187E-05*	*0.348E-05*	*0.507E-06*	*0.445E+00*	*0.430E-01*
Cs-134	*0.235E-05*	*0.120E-01*	*0.637E-06*	*0.236E-01*	*0.105E-01*
I-134	*0.259E-38*	*0.0*	*0.701E-39*	*0.598E-01*	*0.377E-03*
I-135	*0.122E-08*	*0.103E-15*	*0.330E-09*	*0.250E+00*	*0.235E-02*
Cs-136	*0.505E-06*	*0.152E-02*	*0.137E-06*	*0.625E-02*	*0.252E-02*
Cs-137	*0.417E-05*	*0.214E-01*	*0.113E-05*	*0.417E-01*	*0.186E-01*
Ba-140	*0.381E-07*	*0.114E-03*	*0.103E-07*	*0.473E-03*	*0.190E-03*
La-140	*0.366E-07*	*0.130E-03*	*0.991E-08*	*0.167E-03*	*0.143E-03*
Ce-144	*0.399E-08*	*0.200E-04*	*0.108E-08*	*0.403E-04*	*0.179E-04*
Pr-144	*0.399E-08*	*0.200E-04*	*0.108E-08*	*0.403E-04*	*0.179E-04*

TABLE 11.2-9
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Stream Number[a]	*58A&B*	*59A&B*	*60A&B*	*11*	*12*
Annual Flow, gal./yr	*11000*	*300*	*0*	*98650*	*0*
Nuclide	*Concentration, μCi/cc*				
H-3	*0.1832-01*	*0.0*	*0.0*	*0.461E+00*	*0.0*
Cr-51	*0.185E-04*	*0.0*	*0.0*	*0.469E-03*	*0.0*
Mn-54	*0.304E-05*	*0.0*	*0.0*	*0.130E-03*	*0.0*
Fe-55	*0.915E-05*	*0.0*	*0.0*	*0.305E-05*	*0.0*
Co-58	*0.164E-05*	*0.0*	*0.0*	*0.587E-02*	*0.0*
Fe-59	*0.970E-05*	*0.0*	*0.0*	*0.305E-03*	*0.0*
Co-60	*0.194E-04*	*0.0*	*0.0*	*0.867E-03*	*0.0*
Sr-89	*0.271E-05*	*0.0*	*0.0*	*0.889E-04*	*0.0*
Sr-90	*0.132E-06*	*0.0*	*0.0*	*0.593E-05*	*0.0*
Y-90	*0.194E-07*	*0.0*	*0.0*	*0.590E-05*	*0.0*
Sr-91	*0.590E-07*	*0.0*	*0.0*	*0.101E-15*	*0.1*
Y-91	*0.245E-05*	*0.0*	*0.0*	*0.849E-04*	*0.0*
Sr-92	*0.329E-11*	*0.0*	*0.0*	*0.0*	*0.0*
Y-92	*0.295E-10*	*0.0*	*0.0*	*0.0*	*0.0*
Zr-95	*0.667E-06*	*0.0*	*0.0*	*0.234E-04*	*0.0*
Nb-95	*0.667E-06*	*0.0*	*0.0*	*0.286E-04*	*0.0*
Mo-99	*0.341E-04*	*0.0*	*0.0*	*0.137E-04*	*0.0*
I-131	*0.269E-02*	*0.0*	*0.0*	*0.181E-01*	*0.0*
Te-132	*0.227E-03*	*0.0*	*0.0*	*0.149E-03*	*0.0*
I-132	*0.234E-03*	*0.0*	*0.0*	*0.154E-03*	*0.0*
I-133	*0.913E-03*	*0.0*	*0.0*	*0.197E-06*	*0.0*
Cs-134	*0.236E-03*	*0.0*	*0.0*	*0.104E-01*	*0.0*
I-134	*0.124E-19*	*0.0*	*0.0*	*0.0*	*0.0*
I-135	*0.175E-04*	*0.0*	*0.0*	*0.241E-17*	*0.0*
Cs-136	*0.562E-04*	*0.0*	*0.0*	*0.758E-03*	*0.0*
Cs-137	*0.417E-03*	*0.0*	*0.0*	*0.187E-01*	*0.0*
Ba-140	*0.424E-05*	*0.0*	*0.0*	*0.561E-04*	*0.0*
La-140	*0.323E-05*	*0.0*	*0.0*	*0.645E-04*	*0.0*
Ce-144	*0.401E-06*	*0.0*	*0.0*	*0.170E-04*	*0.0*
Pr-144	*0.401E-06*	*0.0*	*0.0*	*0.170E-04*	*0.0*

TABLE 11.2-9
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Stream Number[a]	*13*	*14*	*15*	*16*	*17*
Annual Flow, gal./yr	*0*	*98650*	*7000000*	*798650*	*878950*
Nuclide	*Concentration, μCi/cc*				
H-3	*0.0*	*0.461E+00*	*0.906E+00*	*0.851E+00*	*0.773E+00*
Cr-51	*0.0*	*0.469E-06*	*0.806-12*	*0.579E-07*	*0.570E-07*
Mn-54	*0.0*	*0.130E-06*	*0.217E-12*	*0.161E-07*	*0.154E-07*
Fe-55	*0.0*	*0.305E-08*	*0.468E-14*	*0.377E-09*	*0.169E-08*
Co-58	*0.0*	*0.587E-05*	*0.957E-11*	*0.725E-06*	*0.698E-06*
Fe-59	*0.0*	*0.305E-06*	*0.503E-12*	*0.377E-07*	*0.366E-07*
Co-60	*0.0*	*0.867E-06*	*0.146E-11*	*0.107E-06*	*0.102E-06*
Sr-89	*0.0*	*0.889E-07*	*0.151E-12*	*0.110E-07*	*0.106E-07*
Sr-90	*0.0*	*0.593E-08*	*0.957E-14*	*0.732E-09*	*0.698E-09*
Y-90	*0.0*	*0.590E-08*	*0.151E-10*	*0.742E-09*	*0.690E-09*
Sr-91	*0.0*	*0.101E-18*	*0.136E-28*	*0.125E-19*	*0.475E-12*
Y-91	*0.0*	*0.849E-07*	*0.141E-06*	*0.134E-06*	*0.122E-06*
Sr-92	*0.0*	*0.0*	*0.161E-70*	*0.0*	*0.0*
Y-92	*0.0*	*0.0*	*0.554E-51*	*0.0*	*0.0*
Zr-95	*0.0*	*0.234E-07*	*0.398E-13*	*0.289E-08*	*0.279E-08*
Nb-95	*0.0*	*0.286E-07*	*0.473E-13*	*0.353E-09*	*0.337E-09*
Mo-99	*0.0*	*0.137E-07*	*0.227E-07*	*0.216E-07*	*0.248E-07*
I-131	*0.0*	*0.181E-04*	*0.408E-08*	*0.224E-05*	*0.259E-05*
Te-132	*0.0*	*0.149E-06*	*0.277E-11*	*0.184E-07*	*0.532E-07*
I-132	*0.0*	*0.154E-06*	*0.373E-11*	*0.190E-07*	*0.549E-07*
I-133	*0.0*	*0.197E-09*	*0.141E-14*	*0.235E-10*	*0.462E-07*
Cs-134	*0.0*	*0.520E-03*	*0.237E-06*	*0.644E-04*	*0.586E-04*
I-134	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
I-135	*0.0*	*0.241E-20*	*0.131E-30*	*0.0*	*0.301E-10*
Cs-136	*0.0*	*0.379E-04*	*0.206E-07*	*0.470E-05*	*0.428E-05*
Cs-137	*0.0*	*0.935E-03*	*0.428E-06*	*0.116E-03*	*0.106E-03*
Ba-140	*0.0*	*0.561E-07*	*0.106E-12*	*0.693E-08*	*0.724E-08*
La-140	*0.0*	*0.654E-07*	*0.121E-12*	*0.797E-08*	*0.815E-08*
Ce-144	*0.0*	*0.170E-07*	*0.282E-13*	*0.210E-08*	*0.201E-08*
Pr-144	*0.0*	*0.170E-07*	*0.282E-13*	*0.210E-08*	*0.201E-08*

TABLE 11.2-9
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Stream Number[(a)]	*18*	*19*
Annual Flow, gal./yr	*878750*	*(Refer to Section 11.2.3.13.2.4)*
Nuclide	*Concentration, μCi/cc*	
H-3	*0.773E+00*	*0.738E-06*
Cr-51	*0.570E-07*	*0.543E-13*
Mn-54	*0.154E-07*	*0.147E-13*
Fe-55	*0.169E-08*	*0.161E-14*
Co-58	*0.698E-06*	*0.666E-12*
Fe-59	*0.366E-07*	*0.349E-13*
Co-60	*0.102E-06*	*0.973E-13*
Sr-89	*0.106E-07*	*0.101E-13*
Sr-90	*0.698E-09*	*0.635E-15*
Y-90	*0.690E-09*	*0.658E-15*
Sr-91	*0.475E-12*	*0.453E-18*
Y-91	*0.122E-06*	*0.116E-12*
Sr-92	*0.0*	*0.0*
Y-92	*0.0*	*0.0*
Zr-95	*0.279E-08*	*0.266E-14*
Nb-95	*0.337E-09*	*0.306E-15*
Mo-99	*0.248E-07*	*0.237E-13*
I-131	*0.259E-05*	*0.247E-12*
Te-132	*0.532E-07*	*0.508E-13*
I-132	*0.549E-07*	*0.524E-13*
I-133	*0.462E-07*	*0.441E-13*
Cs-134	*0.586E-04*	*0.559E-10*
I-134	*0.0*	*0.0*
I-135	*0.301E-10*	*0.287E-16*
Cs-136	*0.428E-05*	*0.408E-11*
Cs-137	*0.106E-03*	*0.101E-09*
Ba-140	*0.724E-08*	*0.691E-14*
La-140	*0.815E-08*	*0.778E-14*
Ce-144	*0.201E-08*	*0.192E-14*
Pr-144	*0.201E-08*	*0.192E-14*

(a) Refer to Figure 11.2-3 for waste stream number identification.

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-10

EQUIPMENT DESIGN SUMMARY DATA
LIQUID RADWASTE SYSTEM

Tank	Quantity	Type	Volume gal	Pressure, psig	Temperature, °F	Material
Reactor coolant drain	1[f]	Horiz	400	25	267	SS
Laundry and hot shower	2[a]	Vert	1,000	5	300	CS
Chemical drain	1[a]	Horiz	1,000	0	150	SS
Aux. Building sump	1[a]	-	7,300	0	120	SS
Misc. equip. drain	1[a]	-	5,500	0	180	SS
Processed waste receiver	2[a]	Vert	15,000	0	180	SS
Floor drain receiver	2[a]	Vert	15,000	0	180	SS
Equipment drain receiver	2[a]	Vert	15,000	0	180	SS
Demineralizer regenerant receiver	2[a]	Vert	15,000	0	180	[b]
Laundry/distillate	2[a]	Vert	25,000	0	150	SS
Containment structure sump	2[f]	NA	700	0	140	[g]
Reactor cavity sump	1[f]	NA	300	0	140	[g]
RHR pump room sump	1[f]	NA	500	0	180	[g]

TABLE 11.2-10

Pump	Qty.	Type	Flow, gpm	Head, ft	Pressure, psig	Temp, °F	Mtl.[d]
Reactor coolant drain tank	2[f]	Vert Cent.	150	170	150	300	SS
Chemical drain	1[a]	Horiz Cent.[c]	20	122	150	180	SS
Laundry and hot shower drain	2[a]	Horiz Cent.[c]	20	122	150	180	SS
Misc. equip. drain tank	2[a]	Vert Cent.[c]	50	45	150	180	CI[h]
Floor drain receiver	2[a]	Vert. Cent.[c]	50	300	150	180	SS
Equipment drain receiver	2[a]	Vert Cent.[c]	50	300	150	180	SS
Processed waste receiver	2[a]	Vert Cent.[c]	50	122	150	180	SS
Containment structure sump	4[f]	Vert Cent.[c]	50	45	150	140	CI[h]
Demineralizer regenerant receiver	2[a]	Vert Cent.[c]	50	300	150	180	SS
Reactor cavity sump	2[f]	Horiz Cent.[e]	30	75	150	140	CI[h]
RHR pump room sumps	4[f]	Vert Cent .	50	40	150	180	CI[h]
Aux. Building sump	2[a]	Vert Cent.	50	45	150	180	CI[h]
Laundry/distillate	2[a]	Horiz Cent.	150	200	150	115	SS

TABLE 11.2-10

Miscellaneous	Quantity	Capacity	Type
Radwaste filters	5[(a)]	50 gpm	Cartridge
Media filters	2[(a)]	50 gpm	Media bed
Ion exchangers	2[(a)]	50 gpm	Bead resin
Spent Resin Transfer Filters	2[(a)]	120 gpm	Cartridge

(a) Equipment common to Units 1 and 2
(b) Carbon steel with a neoprene lining
(c) Mechanical seal provided
(d) Wetted surfaces only
(e) Deep well jet pump
(f) Per unit
(g) Concrete
(h) Cast iron (CI) Ni Resist Type D2 (original material). Replacement materials may vary.

TABLE 11.2-11
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PARAMETERS USED IN TRITIUM ANALYSIS FOR PLANT WATER SOURCES

Parameter	*Value*
Primary system volume, gal.	*94,000*
Volume of water in primary water storage tank, gal.	*200,000*
Volume of water in refueling water storage tank, gal.	*450,000*
Volume of water in spent fuel pool, gal.	*442,000*
Percent of mixing of spent fuel pool water with refueling canal during refueling	*15*
Evaporative loss from spent fuel pool during operation, gal./day	*500*
Evaporative loss from spent fuel pool during refueling, gal./day	*1,360*
Evaporative loss from refueling canal during refueling, gal./day	*485*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-13

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

CALCULATED AND ASSUMED HOLDUP TIMES FOR LIQUID WASTE SYSTEM TANKS

Tank	*Qty.*	*Capacity, gal.*	*Fill Time, Days*	*Release Time, Days*	*Assumed Decay Time, Days*	*Assumed Decay Time, Hours*
Liquid holdup	*5[(a)]*	*83,000*	*46.1*	*3.07*	*21.0*	*504.0*
Monitor	*2*	*25,000*	*0.93*	*0.093*	*0.5*	*12.0*
Waste Condensate	*1*	*15,000*	*2.23*	*0.56*	*1.0*	*24.0*
Reactor coolant drain	*1*	*400*	*116.8*	*7.4E-4*	*2.0*	*48.0*
Laundry and hot shower	*2[(a)]*	*1,000*	*3.6*	*0.03*	*2.0*	*48.0*
Chemical drain	*1[(a)]*	*1,000*	*7.6*	*0.014*	*2.0*	*48.0*
Miscellaneous equipment drain	*1[(a)]*	*20,000*	*123.0*	*0.3*	*2.0*	*48.0*
Equipment drain receiver	*1*	*15,000*	*42.5*	*0.56*	*14.0*	*336.0*
Floor drain receiver	*1*	*15,000*	*33.7*	*0.08*	*14.0*	*336.0*
Waste regenerant	*1*	*15,000*	*-*	*-*	*18.0*	*432.0*

(a) Equipment common to both units.

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-14

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ESTIMATED ANNUAL ACTIVITY RELEASE FOR DESIGN BASIS CASE (ONE UNIT)

Nuclide	*Radwaste System, Ci/yr*	*Turbine Bldg Sump, Ci/yr*	*Condensate Polishing System, Ci/yr*	*One Unit Total, Ci/yr*
H-3	*0.135E+04*	*0.0*	*0.0*	*0.135E+04*
Cr-51	*0.960E-04*	*0.0*	*0.0*	*0.960E-04*
Mn-54	*0.213E-04*	*0.0*	*0.0*	*0.213E-04*
Fe-55	*0.327E-05*	*0.0*	*0.0*	*0.327E-05*
Co-58	*0.104E-02*	*0.0*	*0.0*	*0.104E-02*
Fe-59	*0.574E-04*	*0.0*	*0.0*	*0.574E-04*
Co-60	*0.141E-03*	*0.0*	*0.0*	*0.141E-03*
Sr-89	*0.139E-03*	*0.0*	*0.0*	*0.139E-03*
Sr-90	*0.797E-03*	*0.0*	*0.0*	*0.797E-03*
Y-90	*0.781E-05*	*0.0*	*0.0*	*0.781E-05*
Sr-91	*0.453E-08*	*0.0*	*0.0*	*0.453E-08*
Y-91	*0.173E-02*	*0.0*	*0.0*	*0.173E-02*
Sr-92	*0.339E-14*	*0.0*	*0.0*	*0.339E-14*
Y-92	*0.872E-14*	*0.0*	*0.0*	*0.872E-14*
Zr-95	*0.351E-04*	*0.0*	*0.0*	*0.351E-04*
Mb-95	*0.397E-04*	*0.0*	*0.0*	*0.397E-04*
Mo-99	*0.365E-03*	*0.0*	*0.0*	*0.365E-03*
I-131	*0.545E-01*	*0.0*	*0.0*	*0.545E-01*
Te-132	*0.102E-02*	*0.0*	*0.0*	*0.102E-02*
I-132	*0.104E-02*	*0.0*	*0.0*	*0.104E-02*
I-133	*0.441E-03*	*0.0*	*0.0*	*0.441E-03*
Cs-134	*0.120E-02*	*0.0*	*0.0*	*0.120E-02*
I-134	*0.0*	*0.0*	*0.0*	*0.0*
I-135	*0.284E-06*	*0.0*	*0.0*	*0.284E-06*
Cs-136	*0.137E-01*	*0.0*	*0.0*	*0.137E-01*
Cs-137	*0.216E+00*	*0.0*	*0.0*	*0.216E+00*
Ba-140	*0.123E-03*	*0.0*	*0.0*	*0.123E-03*
La-140	*0.139E-03*	*0.0*	*0.0*	*0.139E-03*
Ce-144	*0.233E-04*	*0.0*	*0.0*	*0.233E-04*
Pr-144	*0.233E-04*	*0.0*	*0.0*	*0.233E-04*
Total (excluding H-3)				*0.411E+00*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-15

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ESTIMATED ANNUAL ACTIVITY RELEASE FOR NORMAL OPERATION CASE (ONE UNIT)

Nuclide	*Radwaste System, Curies/yr*	*Turbine Bldg Sump, Curies/yr*	*Condensate Polishing System[(a)], Curies/yr*	*One Unit Total, Curies/yr*
H-3	*0.129E+04*	*0.430E+01*	*0.0*	*0.129E+04*
Cr-51	*0.948E-04*	*0.390E-06*	*0.106E-02*	*0.126E-02*
Mn-54	*0.256E-04*	*0.645E-07*	*0.246E-03*	*0.297E-03*
Fe-55	*0.281E-05*	*0.302E-06*	*0.120E-03*	*0.788E-03*
Co-58	*0.116E-02*	*0.334E-05*	*0.113E-01*	*0.136E-01*
Fe-59	*0.609E-04*	*0.207E-06*	*0.644E-03*	*0.771E-03*
Co-60	*0.170E-03*	*0.414E-06*	*0.163E-02*	*0.197E-02*
Sr-89	*0.176E-04*	*0.565E-07*	*0.183E-03*	*0.220E-03*
Sr-90	*0.111E-05*	*0.271E-08*	*0.108E-04*	*0.130E-04*
Y-90	*0.115E-05*	*0.764E-08*	*0.751E-05*	*0.948E-05*
Sr-91	*0.790E-09*	*0.239E-07*	*0.607E-07*	*0.934E-07*
Y-91	*0.203E-03*	*0.780E-06*	*0.232E-02*	*0.276E-02*
Sr-92	*0.0*	*0.310E-08*	*0.0*	*0.339E-08*
Y-92	*0.0*	*0.207E-07*	*0.0*	*0.226E-07*
Zr-95	*0.464E-05*	*0.143E-07*	*0.473E-04*	*0.568E-04*
Nb-95	*0.530E-06*	*0.207E-07*	*0.720E-04*	*0.794E-04*
Mo-99	*0.412E-04*	*0.103E-03*	*0.356E-01*	*0.391E-01*
I-131	*0.431E-02*	*0.895E-03*	*0.114E+01*	*0.125E+01*
Te-132	*0.885E-04*	*0.668E-05*	*0.288E-02*	*0.325E-02*
I-132	*0.913E-04*	*0.191E-03*	*0.0*	*0.309E-03*
I-133	*0.768E-04*	*0.103E-02*	*0.371E-01*	*0.418E-01*
Cs-134	*0.975E-03*	*0.143E-04*	*0.310E-01*	*0.141E+00*
I-134	*0.0*	*0.263E-04*	*0.0*	*0.288E-04*
I-135	*0.501E-07*	*0.446E-03*	*0.162E-03*	*0.488E-03*
Cs-136	*0.712E-02*	*0.302E-05*	*0.312E-02*	*0.112E-01*
Cs-137	*0.176E-00*	*0.207E-04*	*0.452E-01*	*0.242E+00*
Ba-140	*0.120E-04*	*0.955E-07*	*0.174E-04*	*0.323E-04*
La-140	*0.136E-04*	*0.501E-07*	*0.403E-04*	*0.114E-03*
Ce-144	*0.334E-05*	*0.796E-08*	*0.317E-04*	*0.383E-04*
Pr-144	*0.334E-05*	*0.111E-07*	*0.317E-04*	*0.383E-04*
Total (excluding H-3)				*0.160E+01*

(a) Resin regenerant discharge.

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-16
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
ANNUAL FLOW AND ACTIVITY CONCENTRATION OF PROCESS STREAMS
FOR STEAM GENERATOR BLOWDOWN SYSTEM FOR NORMAL OPERATION CASE
BASED ON ORIGINAL SYSTEM DESIGN

Stream Number	*A*	*B*	*C*	*D*	*E*
Annual Flow, gal./yr	*76,300,000*	*0.0*	*42,865,000*	*42,865,000*	*0.0*
Nuclide	*Concentration, μCi/cc*				
H-3	*0.420E-03*	*0.0*	*0.303E-03*	*0.303E-03*	*0.0*
Cr-51	*0.790E-07*	*0.0*	*0.102E-06*	*0.102E-08*	*0.0*
Mn-54	*0.130E-07*	*0.0*	*0.168E-07*	*0.168E-09*	*0.0*
Fe-55	*0.630E-07*	*0.0*	*0.013E-07*	*0.813E-09*	*0.0*
Co-58	*0.670E-06*	*0.0*	*0.864E-06*	*0.864E-08*	*0.0*
Fe-59	*0.420E-07*	*0.0*	*0.542E-07*	*0.542E-07*	*0.0*
Co-60	*0.830E-07*	*0.0*	*0.107E-06*	*0.107E-08*	*0.0*
Sr-89	*0.110E-07*	*0.0*	*0.142E-07*	*0.142E-09*	*0.0*
Sr-90	*0.550E-09*	*0.0*	*0.709E-09*	*0.709E-11*	*0.0*
Y-90	*0.960E-09*	*0.0*	*0.124E-08*	*0.124E-08*	*0.0*
Sr-91	*0.560E-08*	*0.0*	*0.722E-08*	*0.722E-10*	*0.0*
Y-91	*0.980E-07*	*0.0*	*0.126E-06*	*0.126E-06*	*0.0*
Sr-92	*0.140E-08*	*0.0*	*0.181E-08*	*0.181E-10*	*0.0*
Y-92	*0.280E-08*	*0.0*	*0.361E-08*	*0.361E-08*	*0.0*
Zr-95	*0.280E-08*	*0.0*	*0.361E-08*	*0.361E-10*	*0.0*
Nb-95	*0.290E-08*	*0.0*	*0.374E-08*	*0.374E-10*	*0.0*
Mo-99	*0.220E-04*	*0.0*	*0.284E-04*	*0.284E-04*	*0.0*
I-131	*0.140E-04*	*0.0*	*0.172E-04*	*0.172E-06*	*0.0*
Te-132	*0.140E-05*	*0.0*	*0.181E-05*	*0.181E-07*	*0.0*
I-132	*0.300E-05*	*0.0*	*0.368E-05*	*0.368E-07*	*0.0*
I-133	*0.170E-04*	*0.0*	*0.208E-04*	*0.208E-06*	*0.0*
Cs-134	*0.200E-05*	*0.0*	*0.258E-05*	*0.129E-05*	*0.0*
I-134	*0.520E-06*	*0.0*	*0.637E-06*	*0.637E-08*	*0.0*
I-135	*0.710E-05*	*0.0*	*0.870E-05*	*0.870E-07*	*0.0*
Cs-136	*0.500E-06*	*0.0*	*0.645E-06*	*0.322E-06*	*0.0*
Cs-137	*0.340E-05*	*0.0*	*0.439E-05*	*0.219E-05*	*0.0*
Ba-140	*0.190E-07*	*0.0*	*0.245E-07*	*0.245E-09*	*0.0*
La-140	*0.810E-08*	*0.0*	*0.104E-07*	*0.104E-09*	*0.0*
Ce-144	*0.170E-08*	*0.0*	*0.219E-08*	*0.219E-10*	*0.0*
Pr-144	*0.170E-08*	*0.0*	*0.219E-08*	*0.219E-10*	*0.0*

TABLE 11.2-16
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Stream Number	*F*	*G*	*H*	*I*
Annual Flow, gal./yr	*0.0*	*42,865,000*	*0.0*	*2,600,00*
Nuclide	*Concentration, μCi/cc*			
H-3	*0.0*	*0.303E-03*	*0.0*	*0.540E-03*
Cr-51	*0.0*	*0.102E-08*	*0.0*	*0.490E-10*
Mn-54	*0.0*	*0.168E-09*	*0.0*	*0.810E-11*
Fe-55	*0.0*	*0.813E-09*	*0.0*	*0.380E-10*
Co-58	*0.0*	*0.864E-08*	*0.0*	*0.420E-09*
Fe-59	*0.0*	*0.542E-09*	*0.0*	*0.260E-10*
Co-60	*0.0*	*0.107E-08*	*0.0*	*0.520E-10*
Sr-89	*0.0*	*0.142E-09*	*0.0*	*0.710E-11*
Sr-90	*0.0*	*0.709E-11*	*0.0*	*0.340E-12*
Y-90	*0.0*	*0.124E-08*	*0.0*	*0.870E-12*
Sr-91	*0.0*	*0.722E-10*	*0.0*	*0.300E-11*
Y-91	*0.0*	*0.126E-06*	*0.0*	*0.890E-10*
Sr-92	*0.0*	*0.181E-10*	*0.0*	*0.390E-12*
Y-92	*0.0*	*0.361E-08*	*0.0*	*0.250E-11*
Zr-95	*0.0*	*0.361E-10*	*0.0*	*0.180E-11*
Nb-95	*0.0*	*0.374E-10*	*0.0*	*0.260E-11*
Mo-99	*0.0*	*0.284E-04*	*0.0*	*0.130E-07*
I-131	*0.0*	*0.172E-06*	*0.0*	*0.110E-06*
Te-132	*0.0*	*0.101E-07*	*0.0*	*0.840E-09*
I-132	*0.0*	*0.368E-07*	*0.0*	*0.240E-07*
I-133	*0.0*	*0.208E-06*	*0.0*	*0.130E-06*
Cs-134	*0.0*	*0.129E-05*	*0.0*	*0.180E-08*
I-134	*0.0*	*0.637E-08*	*0.0*	*0.330E-08*
I-135	*0.0*	*0.870E-07*	*0.0*	*0.560E-07*
Cs-136	*0.0*	*0.322E-06*	*0.0*	*0.380E-09*
Cs-137	*0.0*	*0.219E-05*	*0.0*	*0.260E-08*
Ba-140	*0.0*	*0.245E-09*	*0.0*	*0.120E-10*
La-140	*0.0*	*0.104E-09*	*0.0*	*0.730E-11*
Ce-144	*0.0*	*0.219E-10*	*0.0*	*0.100E-11*
Pr-144	*0.0*	*0.219E-10*	*0.0*	*0.140E-11*

(a) Refer to Figures 11.2-4 and 11.2-5 for stream number identification.

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-17

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

SUMMARY OF ESTIMATED LIQUID WASTE SYSTEM ANNUAL WASTE VOLUMES FOR UNITS 1 AND 2

	Stream Number[a]	*Total Annual Volume, Gallons (Design Basis Case)*	*Total Annual Volume, Gallons (Normal Operation Case)*
Laundry, showers, handwashers	*5*	*44,620*	*65,480*
Chemical laboratory drains	*6*	*10,220*	*15,330*
Floor drain subsystem	*7*	*21,360*	*-[b]*
Equipment drain subsystem	*11*	*23,990*	*98,650*
Steam generator blowdown treatment system	*F & H*	*-*	*-[c]*
CPS regenerant wastes	*-*	*-*	*2,360,000*
Turbine-generator building sump	*1*	*-*	*5,200,000*
CVCS (tritium control)	*15*	*700,000*	*700,000*
Total plant discharge for two units		*800,190*	*8,439,460*

(a) Refer to Figures 11.2-2, 11.2-3, and 11.2-5.

(b) Floor drain volume included in equipment drain volume (stream 11) for treatment in normal operation case.

(c) Analysis assumed no resin regeneration for steam generator blowdown treatment system.

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-18

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ESTIMATED ANNUAL LIQUID EFFLUENT RELEASE FOR NORMAL OPERATION CASE WITH ANTICIPATED OPERATIONAL OCCURRENCES (ONE UNIT)

Nuclide	*Release, curies*
H-3	*1.29 E+03*
Cr-51	*1.26 E-03*
Mn-54	*2.97 E-04*
Fe-55	*7.88 E-04*
Co-58	*1.36 E-02*
Fe-59	*7.71 E-04*
Co-60	*1.97 E-03*
Sr-89	*2.20 E-04*
Sr-90	*1.30 E-05*
Y-90	*9.48 E-06*
Sr-91	*9.34 E-08*
Y-91	*2.76 E-03*
Sr-92	*3.39 E-09*
Y-92	*2.26 E-08*
Zr-95	*5.68 E-05*
Nb-95	*7.94 E-05*
Mo-99	*3.91 E-02*
I-131	*1.25 E00*
Te-132	*3.25 E-03*
I-132	*3.09 E-04*
I-133	*4.18 E-02*
Cs-134	*1.44 E-01*
I-134	*2.88 E-05*
I-135	*4.88 E-04*
Cs-136	*1.12 E-02*
Cs-137	*2.42 E-01*
Ba-140	*3.23 E-05*
La-140	*1.14 E-04*
Ce-144	*3.83 E-05*
Pr-144	*3.83 E-05*
Total (excluding H-3)	*1.75 E00*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-19

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
BASIC ASSUMPTIONS FOR LIQUID PATHWAYS EXPOSURES

Plant dilution flow	*876000 gpm*
Length of plant cycle	*8760.00 hr*

Biological and Environmental Parameters

Receiving body of water	*Pacific Ocean*
Receiving water type	*Ocean*

Dilution factor from discharge to swimming water	*5.0E 00*
Dilution factor from discharge to drinking water	*5.0E 00*
Dilution factor from discharge to fish	*5.0E 00*
Dilution factor from discharge to invertebrates	*5.0E 00*
Dilution factor from discharge to aquatic plants	*5.0E 00*

Decay time from environment to water = 5.0E-01 *Fish = 1.0E 00* *Invertebrates = 1.0E 00* *Aquatic Plants = 1.0E 00*
Consumption by Man, days

Decay time from discharge to sediment, days =	*1.00E 00*
Accumulation time for sediment activity, days =	*1.10E 04*

	Food Consumption Rates, kg/yr				*Exposure Time Hours/Year*	
Age Group	*Water*	*Fish*	*Invertebrates*	*Aquatic Plants*	*Swimming*	*Shore*
Adult	*0.0*	*2.10E 01*	*5.00E 00*	*0.0*	*5.20E 01*	*1.20E 01*
Teenager	*0.0*	*1.60E 01*	*3.80E 00*	*0.0*	*5.20E 01*	*6.70E 01*
Child	*0.0*	*6.90E 00*	*1.70E 00*	*0.0*	*2.90E 01*	*1.40E 01*
Infant	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-20

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

BIOACCUMULATION FACTORS

Nuclide	*Fish*	*Inverteb.*	*Aq. Plants*
H-3	*9.00E-01*	*9.30E-01*	*9.30E-01*
Cr-51	*4.00E 02*	*2.00E 03*	*2.00E 03*
Mn-54	*5.50E 02*	*4.00E 02*	*5.50E 03*
Fe-55	*3.00E 03*	*2.00E 04*	*7.30E 02*
Co-58	*1.00E 02*	*1.00E 03*	*1.00E 03*
Fe-59	*3.00E 03*	*2.00E 04*	*7.30E 02*
Co-60	*1.00E 02*	*1.00E 03*	*1.00E 03*
Sr-89	*2.00E 00*	*2.00E 01*	*1.00E 01*
Sr-90	*2.00E 00*	*2.00E 01*	*1.00E 01*
Y-90	*2.50E 01*	*1.00E 03*	*5.00E 03*
Sr-91	*2.00E 00*	*2.00E 01*	*1.00E 01*
Y-91	*2.50E 01*	*1.00E 03*	*5.00E 03*
Sr-92	*2.00E 00*	*2.00E 01*	*1.00E 01*
Y-92	*2.50E 01*	*1.00E 03*	*5.00E 03*
Zr-95	*2.00E 02*	*8.00E 01*	*1.00E 03*
Nb-95	*3.00E 04*	*1.00E 02*	*5.00E 02*
Mo-99	*1.00E 01*	*1.00E 01*	*1.00E 01*
I-131	*1.00E 01*	*5.00E 01*	*1.00E 03*
Te-132	*1.00E 01*	*1.00E 02*	*1.00E 03*
I-132	*1.00E 01*	*5.00E 01*	*1.00E 03*
I-133	*1.00E 01*	*5.00E 01*	*1.00E 03*
Cs-134	*4.00E 01*	*2.50E 01*	*5.00E 01*
I-134	*1.00E 01*	*5.00E 01*	*1.00E 03*
I-135	*1.00E 01*	*5.00E 01*	*1.00E 03*
Cs-136	*4.00E 01*	*2.50E 01*	*5.00E 01*
Cs-137	*4.00E 01*	*2.50E 01*	*5.00E 01*
Ba-140	*1.00E 01*	*1.00E 02*	*5.00E 02*
La-140	*2.50E 01*	*1.00E 03*	*5.00E 03*
Ce-144	*1.00E 01*	*6.00E 02*	*6.00E 02*
Pr-144	*2.50E 01*	*1.00E 03*	*5.00E 03*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-21

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

EFFLUENT CONCENTRATIONS AFTER INITIAL DILUTION: DESIGN BASIS CASE

Nuclide	*Release Rate[a], Ci/yr*	*Average Yearly Concentration in Discharge, μCi/cc*
H-3	*1.35E+03*	*7.75E-07*
Cr-51	*9.60E-05*	*5.51E-14*
Mn-54	*2.13E-05*	*1.22E-14*
Fe-55	*3.27E-06*	*1.88E-15*
Co-58	*1.04E-03*	*5.97E-13*
Fe-59	*5.74E-05*	*3.29E-14*
Co-60	*1.41E-04*	*8.09E-14*
Sr-89	*1.39E-04*	*7.98E-14*
Sr-90	*7.97E-06*	*4.57E-15*
Y-90	*7.81E-06*	*4.48E-15*
Sr-91	*4.53E-09*	*2.60E-18*
Y-91	*1.73E-03*	*9.93E-13*
Sr-92	*3.39E-15*	*1.95E-24*
Y-92	*8.72E-15*	*5.00E-24*
Zr-95	*3.51E-05*	*2.01E-14*
Nb-95	*3.97E-05*	*2.28E-14*
Mo-99	*3.65E-04*	*2.09E-13*
I-131	*5.45E-02*	*3.13E-1*
Te-132	*1.02E-03*	*5.85E-13*
I-132	*1.09E-03*	*5.97E-13*
I-133	*4.41E-04*	*2.53E-13*

TABLE 11.2-21

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Nuclide	*Release Rate[(a)], Ci/yr*	*Average Yearly Concentration in Discharge, μCi/cc*
Cs-134	*1.20E-01*	*6.89E-11*
I-134	*0.0*	*0.0*
I-135	*2.84E-07*	*1.63E-16*
Cs-136	*1.37E-02*	*7.86E-12*
Cs-137	*2.16E-01*	*1.24E-10*
Ba-140	*1.23E-04*	*7.06E-14*
La-140	*1.39E-04*	*7.98E-14*
Ce-144	*2.33E-05*	*1.34E-14*
Pr-144	*2.33E-05*	*1.34E-14*
Totals	*1.35E+03*	*7.75E-07*
Totals excluding H-3	*4.11E-01*	*2.36E-10*

(a) One unit

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-22

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

EFFLUENT CONCENTRATIONS AFTER INITIAL DILUTION: NORMAL OPERATION CASE

Nuclide	*Release Rate[(a)], Ci/yr*	*Average Yearly Concentration in Discharge, μCi/cc*
H-3	*1.29E+03*	*7.42E-07*
Cr-51	*1.16E-03*	*6.66E-13*
Mn-54	*2.72E-04*	*1.56E-13*
Fe-55	*1.23E-04*	*7.06E-14*
Co-58	*1.25E-02*	*7.17E-12*
Fe-59	*7.05E-04*	*4.05E-13*
Co-60	*1.80E-03*	*1.13E-12*
Sr-89	*2.01E-04*	*1.15E-13*
Sr-90	*1.19E-05*	*6.83E-15*
Y-90	*8.67E-06*	*4.97E-15*
Sr-91	*8.54E-08*	*4.90E-17*
Y-91	*2.52E-03*	*1.45E-12*
Sr-92	*0.31E-08*	*1.78E-18*
Y-92	*0.21E-07*	*1.20E-17*
Zr-95	*5.20E-05*	*2.98E-14*
Nb-95	*7.26E-05*	*4.17E-14*
Mo-99	*3.57E-02*	*2.05E-11*
I-131	*1.15E-00*	*6.60E-10*
I-132	*2.82E-04*	*1.62E-13*
I-133	*3.82E-02*	*2.19E-11*
Cs-134	*1.29E-01*	*7.40E-11*
I-134	*0.26E-04*	*1.49E-14*
I-135	*6.08E-04*	*3.49E-13*
Cs-136	*1.02E-02*	*5.85E-12*
Cs-137	*2.21E-01*	*1.27E-10*
Ba-140	*2.95E-05*	*1.69E-14*
La-140	*1.04E-04*	*5.97E-14*
Ce-144	*3.51E-05*	*2.01E-14*
Pr-144	*3.51E-05*	*2.01E-14*
Totals	*1.29E+03*	*7.42E-07*
Totals excluding H-3	*1.60E+00*	*9.24E-10*

(a) One unit

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-23
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
EFFLUENT CONCENTRATIONS AFTER INITIAL DILUTION: NORMAL OPERATION WITH ANTICIPATED OPERATIONAL OCCURRENCES

Nuclide	*Release Rate[(a)], Ci/yr*	*Average Yearly Concentration in Discharge, μCi/cc*
H-3	*1.29E+03*	*7.42E-07*
Cr-51	*1.26E-03*	*7.23E-13*
Mn-54	*2.99E-04*	*1.70E-13*
Fe-55	*7.88E-04*	*4.52E-13*
Co-58	*1.36E-02*	*7.80E-12*
Fe-59	*7.71E-04*	*4.42E-13*
Co-60	*1.97E-03*	*1.13E-12*
Sr-89	*2.20E-04*	*1.26E-13*
Sr-90	*1.30E-05*	*7.46E-15*
Y-90	*9.48E-06*	*5.44E-15*
Sr-91	*9.34E-08*	*5.36E-17*
Y-91	*2.76E-03*	*1.58E-12*
Sr-92	*3.39E-09*	*1.95E-18*
Y-92	*2.26E-08*	*1.30E-17*
Zr-95	*5.68E-05*	*3.26E-14*
Nb-95	*7.94E-05*	*4.56E-14*
Mo-99	*3.91E-02*	*2.24E-11*
I-131	*1.25E+00*	*7.17E-10*
Te-132	*3.25E-03*	*1.86E-12*
I-132	*3.09E-04*	*1.77E-13*
I-133	*4.18E-02*	*2.40E-10*
Cs-134	*1.41E-01*	*8.09E-11*
I-134	*2.88E-05*	*1.65E-14*
I-135	*4.88E-04*	*2.80E-13*
Cs-136	*1.12E-02*	*6.43E-12*
Cs-137	*2.42E-01*	*1.39E-10*
Ba-140	*3.23E-05*	*1.85E-14*
La-140	*1.14E-04*	*6.54E-14*
Ce-144	*3.83E-05*	*2.20E-14*
Pr-144	*3.83E-05*	*2.20E-14*
Totals	*1.29E+03*	*7.43E-07*
Totals excluding H-3	*1.75E+00*	*2.64E-03*

(a) One unit
Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-24

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

DOSES RESULTING FROM RADIOACTIVE RELEASES IN LIQUID WASTES: DESIGN BASIS CASE (mrem/yr)

Age Group = Adult

Exposure Pathway	*Whole Body*	*Skin*	*Bone*	*GI Tract*	*Thyroid*	*Lung*	*Kidney*	*Liver*
Drinking water	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Consumption of fish	*7.22E-3*	*0.0*	*2.39E-3*	*4.30E-4*	*2.56E-3*	*7.51E-4*	*1.66E-3*	*4.33E-3*
Consumption of invertebrates	*5.17E-4*	*0.0*	*3.65E-4*	*2.09E-4*	*2.76E-3*	*1.43E-4*	*2.90E-4*	*6.89E-4*
Consumption of aquatic plants	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Exposure to contaminated sediment	*4.18E-4*	*4.87E-4*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Swimming in water	*4.67E-6*	*5.39E-5*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Total	*4.16E-4*	*5.41E-4*	*2.76E-3*	*6.39E-4*	*5.31E-3*	*8.94E-4*	*1.95E-3*	*5.02E-3*

Age Group = Teenager

Drinking water	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Consumption of fish	*1.89E-3*	*0.0*	*2.53E-3*	*3.27E-4*	*2.34E-3*	*7.63E-4*	*1.62E-3*	*4.38E-3*
Consumption of invertebrates	*3.12E-4*	*0.0*	*3.85E-4*	*1.61E-4*	*2.56E-3*	*1.38E-4*	*2.77E-4*	*6.87E-4*
Consumption of aquatic plants	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Exposure to contaminated sediment	*2.33E-3*	*2.72E-3*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Swimming in water	*4.67E-6*	*5.39E-5*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Total	*4.54E-3*	*2.77E-3*	*2.91E-3*	*4.88E-4*	*4.89E-3*	*9.01E-4*	*1.90E-3*	*5.06E-3*

Age Group = Child

Drinking water	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Consumption of fish	*8.42E-4*	*0.0*	*3.14E-3*	*2.30E-4*	*2.37E-3*	*6.11E-4*	*1.37E-3*	*3.83E-3*
Consumption of invertebrates	*1.58E-4*	*0.0*	*4.96E-4*	*9.23E-5*	*2.72E-3*	*1.15E-4*	*2.43E-4*	*6.22E-4*
Consumption of aquatic plants	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Exposure to contaminated sediment	*4.87E-4*	*5.68E-4*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Swimming in water	*2.60E-6*	*3.01E-5*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Total	*1.49E-3*	*5.98E-4*	*3.64E-3*	*3.22E-4*	*5.09E-3*	*7.27E-4*	*1.61E-3*	*4.45E-3*

TABLE 11.2-24

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Age Group = Infant

Exposure Pathway	*Whole Body*	*Skin*	*Bone*	*GI Tract*	*Thyroid*	*Lung*	*Kidney*	*Liver*
Drinking water	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Consumption of fish	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Consumption of invertebrates	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Consumption to aquatic plants	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Exposure to contaminated sediment	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Swimming in water	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Total	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-25

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

DOSES RESULTING FROM RADIOACTIVE RELEASES IN LIQUID WASTES: NORMAL OPERATION CASE (mrem/yr)

Age Group = Adult

Exposure Pathway	*Whole Body*	*Skin*	*Bone*	*GI Tract*	*Thyroid*	*Lung*	*Kidney*	*Liver*
Drinking water	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Consumption of fish	*3.49E-3*	*0.0*	*2.61E-3*	*8.36E-4*	*4.77E-2*	*7.74E-4*	*1.94E-3*	*4.77E-3*
Consumption of invertebrates	*6.74E-4*	*0.0*	*5.48E-4*	*7.66E-4*	*5.65E-2*	*1.72E-4*	*5.79E-4*	*1.11E-3*
Consumption of aquatic plants	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Exposure to contaminated sediment	*4.36E-4*	*5.09E-4*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Swimming in water	*1.03E-5*	*5.88E-5*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Total	*4.56E-3*	*5.68E-4*	*3.16E-3*	*1.60E-3*	*1.04E-1*	*9.46E-4*	*2.52E-3*	*5.88E-3*

Age Group = Teenager

Drinking water	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Consumption of fish	*2.06E-3*	*0.0*	*2.76E-3*	*5.83E-4*	*4.45E-2*	*7.96E-4*	*1.92E-3*	*4.75E-3*
Consumption of invertebrates	*4.61E-4*	*0.0*	*5.78E-4*	*5.05E-4*	*5.26E-2*	*1.73E-4*	*5.81E-4*	*9.82E-4*
Consumption of aquatic plants	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Exposure to contaminated sediment	*2.44E-3*	*2.84E-3*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Swimming in water	*1.03E-5*	*5.88E-5*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Total	*4.97E-3*	*2.90E-3*	*3.34E-3*	*1.09E-3*	*9.71E-2*	*9.69E-4*	*2.50E-3*	*5.73E-3*

Age Group = Child

Drinking water	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Consumption of fish	*9.64E-4*	*0.0*	*3.43E-3*	*3.19E-4*	*4.59E-2*	*6.37E-4*	*1.636-3*	*4.16E-3*
Consumption of invertebrates	*3.07E-4*	*0.0*	*7.49E-4*	*2.23E-4*	*5.63E-2*	*1.45E-4*	*5.17E-4*	*8.95E-4*
Consumption of aquatic plants	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Exposure to contaminated sediment	*5.09E-4*	*5.94E-4*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Swimming in water	*5.74E-6*	*3.28E-5*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Total	*1.79E-3*	*6.27E-4*	*4.18E-3*	*5.42E-4*	*1.02E-1*	*7.82E-4*	*2.15E-3*	*5.05E-3*

TABLE 11.2-25

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Age Group = Infant

Exposure Pathway	*Whole Body*	*Skin*	*Bone*	*GI Tract*	*Thyroid*	*Lung*	*Kidney*	*Liver*
Drinking water	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Consumption of fish	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Consumption of invertebrates	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Consumption of aquatic plants	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Exposure to contaminated sediment	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Swimming in water	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Total	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.2-26

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

DOSES RESULTING FROM RADIOACTIVE RELEASES IN LIQUID WASTES:
NORMAL OPERATIONAL WITH ANTICIPATED OPERATIONAL OCCURRENCES (mrem/yr)

Age Group = Adult

Exposure Pathway	*Whole Body*	*Skin*	*Bone*	*GI Tract*	*Thyroid*	*Lung*	*Kidney*	*Liver*
Drinking water	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Consumption of fish	*3.74E-3*	*0.0*	*2.86E-3*	*8.86E-4*	*5.20E-2*	*8.20E-4*	*2.10E-3*	*5.20E-3*
Consumption of invertebrates	*7.32E-4*	*0.0*	*6.00E-4*	*8.30E-4*	*6.16E-2*	*1.82E-4*	*6.26E-4*	*1.21E-3*
Consumption of aquatic plants	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Exposure to contaminated sediment	*4.78E-4*	*5.58E-4*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Swimming in water	*1.13E-5*	*5.99E-5*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Total	*4.96E-3*	*6.18E-4*	*3.46E-3*	*1.72E-3*	*1.14E-1*	*1.00E-1*	*2.73E-3*	*6.41E-3*

Age Group = Teenager

Drinking water	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Consumption of fish	*2.23E-3*	*0.0*	*3.02E-3*	*6.17E-4*	*4.85E-2*	*8.51E-4*	*2.08E-3*	*5.18E-3*
Consumption of invertebrates	*4.99E-4*	*0.0*	*6.32E-4*	*5.47E-4*	*5.74E-2*	*1.85E-4*	*6.31E-4*	*1.07E-3*
Consumption of aquatic plants	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Exposure to contaminated sediment	*2.67E-3*	*3.11E-3*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Swimming in water	*1.13E-5*	*5.99E-5*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Total	*5.41E-3*	*3.17E-3*	*3.66E-3*	*1.16E-3*	*1.06E-1*	*1.04E-3*	*2.71E-3*	*6.25E-3*

Age Group = Child

Drinking water	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Consumption of fish	*1.04E-3*	*0.0*	*3.76E-3*	*3.32E-4*	*5.01E-2*	*6.80E-4*	*1.77E-3*	*4.54E-3*
Consumption of invertebrates	*3.31E-4*	*0.0*	*8.19E-4*	*2.40E-4*	*6.15E-2*	*1.54E-4*	*5.61E-4*	*9.75E-4*
Consumption of aquatic plants	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Exposure to containment sediment	*5.58E-4*	*6.51E-4*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Swimming in water	*6.28E-6*	*3.34E-5*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Total	*1.95E-3*	*6.84E-4*	*4.58E-3*	*5.71E-4*	*1.12E-1*	*8.34E-4*	*2.33E-4*	*5.51E-3*

TABLE 11.2-26

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Age Group = Infant

Exposure Pathway	*Whole Body*	*Skin*	*Bone*	*GI Tract*	*Thyroid*	*Lung*	*Kidney*	*Liver*
Drinking water	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Consumption of fish	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Consumption of invertebrates	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Consumption of aquatic plants	*0.0*	*--*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Exposure to contaminated sediment	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Swimming in water	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Total	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-1

EQUIPMENT DESIGN AND OPERATING PARAMETERS
FOR GASEOUS RADWASTE SYSTEM, UNITS 1 AND 2

---

1. Waste Gas Compressor
   Number used: 3; 1 each unit, 1 shared
   Type: horizontal, centrifugal compressor
   Temperature: 70°F - 130°F
   Inlet pressure: 0.5 psig - 2.0 psig
   Capacity: 40 cfm at inlet pressure 2.0 psig and discharge pressure 110 psig
   Cooling water rate: 42.5 gpm
   Driver: 25 hp

2. Surge Tank
   Number used: 2; 1 each unit
   Type: horizontal
   Size: 18' x 1'
   Volume: 14 ft^3
   Design pressure: 405 psig/Design temperature: 650°F
   Operating maximum pressure: 10 psig
   Material: ASTM A106 Carbon Steel (PG&E pipe specification K2)

3. Gas Decay Tank
   Number used: 6; 3 each unit
   Type: vertical
   Size: 13' x 8'
   Volume: 760 ft^3
   Design temperature: 150°F

3. Gas Decay Tank (continued)
   Design pressure: 150 psig
   Operating maximum pressure: 105 psig
   Material: SA285C, carbon steel
   Design as per ASME Boiler and Pressure Vessel Code, Section III, Class C

4. Waste Gas Analyzer
   Number used: 2; 1 each unit
   Oxygen analyzer:
      Range: 0-5% (±2% of full range)
      Alarm: 2% oxygen
   Hydrogen analyzer:
      Range: 0-5% (±2% of full range)
             0-50% (±2% of full range)
             0-100% (±2% of full range)
      Alarm: 3.5% hydrogen
   Sample channel: 16

5. Discharge filter
   Number used: 2; 1 each unit
   Type: HEPA filter
   Size: 8" x 8" x 5-7/8"
   Efficiency: 99.97% on 0.3 micron particles
   Capacity: 55 cfm at 1" water gauge differential

TABLE 11.3-2
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

GASEOUS WASTE SYSTEM RELEASE: DESIGN BASIS CASE
(CURIES)

Nuclide	*Gas Decay Tank Venting*	*Steam Containment Venting*	*Condenser System Leakage*	*Auxiliary Offgas Venting*	*Spent Building Venting*	*Secondary Fuel Pool Release*	*System Water Leakage*	*Total Release*
Kr- 83M	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.197E-19*	*---*	*0.197E-19*
Kr- 85M	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.224E-09*	*---*	*0.224E-09*
Kr- 85	*0.505E 04*	*0.0*	*0.0*	*0.0*	*0.0*	*0.538E-01*	*---*	*0.505E 04*
Kr- 87	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.169E-26*	*---*	*0.169E-26*
Kr- 88	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.360E-13*	*---*	*0.360E-13*
Xe-133M	*0.210E-02*	*0.0*	*0.0*	*0.0*	*0.0*	*0.127E-02*	*---*	*0.337E-02*
Xe-133	*0.411E 03*	*0.0*	*0.0*	*0.0*	*0.0*	*0.189E 00*	*---*	*0.411E 03*
Xe-135M	*0.482E-46*	*0.0*	*0.0*	*0.0*	*0.0*	*0.668E-07*	*---*	*0.668E-07*
Xe-135	*0.262E-31*	*0.0*	*0.0*	*0.0*	*0.0*	*0.276E-06*	*---*	*0.276E-04*
Xe-138	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*---*	*0.0*
I -131	*---*	*0.0*	*0.0*	*0.0*	*0.0*	*0.112E-04*	*0.0*	*0.112E-04*
I -132	*---*	*0.0*	*0.0*	*0.0*	*0.0*	*0.167E-05*	*0.0*	*0.167E-05*
I -133	*---*	*0.0*	*0.0*	*0.0*	*0.0*	*0.194E-06*	*0.0*	*0.194E-06*
I -134	*---*	*0.0*	*0.0*	*0.0*	*0.0*	*0.310E-08*	*0.0*	*0.310E-08*
I -135	*---*	*0.0*	*0.0*	*0.0*	*0.0*	*0.177E-07*	*0.0*	*0.177E-07*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-3

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

GASEOUS WASTE SYSTEM RELEASE: NORMAL OPERATION CASE (CURIES)

Nuclide	*Gas Decay Tank Venting*	*Containment Venting*	*Condenser Offgas Venting*	*Auxiliary Building Venting*	*Spent Fuel Pool Release*	*Steam System Leakage*	*Secondary System Water Leakage*	*Total Release*
Kr - 83	*0.0*	*0.287E 00*	*0.169E 00*	*0.110E-01*	*0.236E-20*	*0.615E-04*	*---*	*0.156E 01*
Kr - 85M	*0.0*	*0.350E 01*	*0.145E-01*	*0.567E 01*	*0.269E-10*	*0.317E-03*	*---*	*0.106E 02*
Kr - 85	*0.439E 03*	*0.443E 03*	*0.624E 01*	*0.100E 02*	*0.654E-02*	*0.558E-03*	*---*	*0.898E 03*
Kr - 87	*0.0*	*0.554E 00*	*0.361E 00*	*0.311E 01*	*0.203E-27*	*0.174E-03*	*---*	*0.402E 01*
Kr - 88	*0.0*	*0.378E 01*	*0.193E 01*	*0.972E 01*	*0.432E-14*	*0.543E-03*	*---*	*0.154E 02*
Xe - 133M	*0.244E-03*	*0.721E 02*	*0.433E 01*	*0.931E 01*	*0.152E-03*	*0.521E-03*	*---*	*0.858E 02*
Xe - 133	*0.434E 02*	*0.118E 05*	*0.367E 03*	*0.760E 03*	*0.227E-01*	*0.424E-01*	*---*	*0.129E 05*
Xe - 135M	*0.577E-47*	*0.920E 00*	*0.254E 00*	*0.122E 01*	*0.001E-08*	*0.486E-03*	*---*	*0.239E 01*
Xe - 135	*0.313E-32*	*0.280E 02*	*0.626E-01*	*0.170E 02*	*0.331E-05*	*0.102E-02*	*---*	*0.513E 02*
Xe - 138	*0.0*	*0.530E-01*	*0.432E-01*	*0.165E 01*	*0.0*	*0.919E-04*	*---*	*0.174E 01*
I - 131	*---*	*0.336E-01*	*0.312E-01*	*0.637E-01*	*0.859E-05*	*0.630E-03*	*0.897E-06*	*0.129E 00*
I - 132	*---*	*0.188E 00*	*0.418E-02*	*0.230E-01*	*0.752E-06*	*0.134E-03*	*0.191E-06*	*0.215E 00*
I - 133	*---*	*0.685E-02*	*0.363E-01*	*0.872E-01*	*0.165E-06*	*0.751E-03*	*0.106E-05*	*0.131E 00*
I - 134	*---*	*0.378E-04*	*0.999E-03*	*0.117E-01*	*0.310E-08*	*0.234E-04*	*0.266E-07*	*0.127E-01*
I - 135	*---*	*0.121E-02*	*0.148E-01*	*0.482E-01*	*0.177E-07*	*0.318E-03*	*0.441E-06*	*0.645E-01*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-3

Nuclide	*Total Release*
H - 3	*0.33E 03*
Cr - 51	*0.0*
Mn - 54	*0.44E-01*
Fe - 55	*0.0*
Co - 58	*0.15E-00*
Fe - 59	*0.15E-01*
Co - 60	*0.68E-01*
Sr - 89	*0.33E-02*
Sr - 90	*0.56E-03*
Y - 90	*0.0*
Sr - 91	*0.0*
Y - 91	*0.0*
Sr - 92	*0.0*
Y - 92	*0.0*
Zr - 95	*0.0*
Nb - 95	*0.0*
Mo - 99	*0.0*
Te - 132	*0.0*
Cs - 134	*0.44E-01*
Cs - 136	*0.0*
Cs - 137	*0.75E-01*
Ba - 140	*0.0*
La - 140	*0.0*
Ce - 144	*0.0*
Pr - 144	*0.0*
C - 14	*0.80E 01*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-4
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ANNUAL GASEOUS RADWASTE FLOWS
(Standard Cubic Feet Per Year)

Source			*Flow*
Liquid holdup tanks:	*Displaced*	*60,300*	
	Recycled	*15,300*	
			45,000
Volume control tank			*19,000*
Boric acid gas stripper[(b)]			*7,400*
Reactor coolant drain tank			*250*
Pressurizer relief tank			*350*
Nitrogen added to gas decay tanks			*28,000*
Total annual discharge			*100,000[(a)]*

(a) Assumes:
1. *Two cold shutdowns per year*
2. *Base loaded plant operation*
3. *Hydrogen controlled to less than 4%*

(b) Equipment is abandoned in place and no longer in use.

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-5

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

MAXIMUM ACTIVITY IN GAS DECAY TANK: DESIGN BASIS CASE

Nuclide	*Activity, Ci*	*Concentration, μCi/cc*
Kr-83M	*0.894E 02*	*0.421E 01*
Kr-85M	*0.462E 03*	*0.217E 02*
Kr-85	*0.160E 04*	*0.754E 02*
Kr-87	*0.252E 03*	*0.119E 02*
Kr-88	*0.790E 03*	*0.372E 02*
Xe-133M	*0.798E 03*	*0.376E 02*
Xe-133	*0.693E 05*	*0.326E 04*
Xe-135M	*0.988E 02*	*0.465E 01*
Xe-135	*0.139E 04*	*0.656E 02*
Xe-138	*0.133E 03*	*0.628E 01*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-6

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

MAXIMUM ACTIVITY IN GAS DECAY TANK:
NORMAL OPERATION CASE

Nuclide	*Activity, Ci*	*Concentration, μCi/cc*
Kr-83M	*0.107E 02*	*0.505E 00*
Kr-85M	*0.553E 02*	*0.260E 01*
Kr-85	*0.130E 03*	*0.612E 01*
Kr-87	*0.302E 02*	*0.142E 01*
Kr-88	*0.946E 02*	*0.445E 01*
Xe-133M	*0.928E 02*	*0.437E 01*
Xe-133	*0.778E 04*	*0.366E 03*
Xe-135M	*0.119E 02*	*0.558E 00*
Xe-135	*0.166E 03*	*0.783E 01*
Xe-138	*0.160E 02*	*0.753E 00*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-7

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ACTIVITY IN VOLUME CONTROL TANK: DESIGN BASIS CASE

	Liquid Phase		*Vapor Phase*		
Nuclide	*Activity, Ci*	*Concentration, μCi/cc*	*Activity, Ci*	*Concentration, μCi/cc*	*Total Act, Ci*
H - 3	*0.497E 01*	*0.732E 00*	*0.0*	*0.0*	*0.497E 01*
Cr- 51	*0.935E-02*	*0.138E-02*	*0.0*	*0.0*	*0.935E-02*
Mn- 54	*0.152E-02*	*0.224E-03*	*0.0*	*0.0*	*0.152E-02*
Fe- 55	*0.773E-02*	*0.114E-02*	*0.0*	*0.0*	*0.773E-02*
Co- 58	*0.785E-01*	*0.115E-01*	*0.0*	*0.0*	*0.785E-01*
Fe- 59	*0.491E-02*	*0.722E-03*	*0.0*	*0.0*	*0.491E-02*
Co- 60	*0.976E-02*	*0.144E-02*	*0.0*	*0.0*	*0.976E-02*
Kr- 83M	*0.0*	*0.0*	*0.495E 00*	*0.109E 00*	*0.495E 00*
Kr- 85M	*0.0*	*0.0*	*0.276E 01*	*0.609E 00*	*0.276E 01*
Kr- 85	*0.0*	*0.0*	*0.657E 01*	*0.145E 01*	*0.657E 01*
Kr- 87	*0.0*	*0.0*	*0.132E 01*	*0.291E 00*	*0.132E 01*
Kr- 88	*0.0*	*0.0*	*0.456E 01*	*0.101E 01*	*0.456E 01*
Sr- 89	*0.112E-01*	*0.165E-02*	*0.0*	*0.0*	*0.112E-01*
Sr- 90	*0.538E-03*	*0.792E-04*	*0.0*	*0.0*	*0.538E-03*
Y - 90	*0.928E-03*	*0.137E-03*	*0.0*	*0.0*	*0.928E-03*
Sr- 91	*0.710E-02*	*0.104E-02*	*0.0*	*0.0*	*0.710E-02*
Y - 91	*0.955E-01*	*0.140E-01*	*0.0*	*0.0*	*0.955E-01*
Sr- 92	*0.271E-02*	*0.398E-03*	*0.0*	*0.0*	*0.271E-02*
Y - 92	*0.374E-02*	*0.550E-03*	*0.0*	*0.0*	*0.374E-02*
Zr- 95	*0.278E-02*	*0.410E-03*	*0.0*	*0.0*	*0.278E-02*
Nb- 95	*0.271E-02*	*0.398E-03*	*0.0*	*0.0*	*0.271E-02*
Mo- 99	*0.223E 02*	*0.328E 01*	*0.0*	*0.0*	*0.223E 02*
I -131	*0.132E 02*	*0.194E 01*	*0.0*	*0.0*	*0.132E 02*
Te-132	*0.139E 01*	*0.204E 00*	*0.0*	*0.0*	*0.139E 01*
I -132	*0.441E 01*	*0.649E 00*	*0.0*	*0.0*	*0.441E 01*
I -133	*0.178E 02*	*0.262E 01*	*0.0*	*0.0*	*0.178E 02*
Xe-133M	*0.213E-02*	*0.314E-03*	*0.493E 01*	*0.109E 01*	*0.493E 01*
Xe-133	*0.378E-01*	*0.556E-02*	*0.416E 03*	*0.919E 02*	*0.416E 03*
Cs-134	*0.932E 00*	*0.137E 00*	*0.0*	*0.0*	*0.932E 00*
I -134	*0.183E 01*	*0.269E 00*	*0.0*	*0.0*	*0.183E 01*
I -135	*0.957E 01*	*0.141E 01*	*0.0*	*0.0*	*0.957E 01*
Xe-135M	*0.715E 00*	*0.105E 00*	*0.304E 00*	*0.672E-01*	*0.102E 01*
Xe-135	*0.260E 00*	*0.382E-01*	*0.858E 01*	*0.189E 01*	*0.884E 01*
Cs-136	*0.252E 00*	*0.371E 01*	*0.0*	*0.0*	*0.252E 00*
Cs-137	*0.167E 01*	*0.246E 00*	*0.0*	*0.0*	*0.167E 01*
Xe-138	*0.0*	*0.0*	*0.388E 00*	*0.857E-01*	*0.388E 00*
Ba-140	*0.190E-01*	*0.279E-02*	*0.0*	*0.0*	*0.190E-01*
La-140	*0.678E-02*	*0.998E-03*	*0.0*	*0.0*	*0.678E-02*
Ce-144	*0.164E-02*	*0.241E-03*	*0.0*	*0.0*	*0.164E-02*
Pr-144	*0.164E-02*	*0.241E-03*	*0.0*	*0.0*	*0.164E-02*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-8

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ACTIVITY IN VOLUME CONTROL TANK: NORMAL OPERATION CASE

	Liquid Phase		*Vapor Phase*		
Nuclide	*Activity, Ci*	*Concentration, μCi/cc*	*Activity, Ci*	*Concentration, μCi/cc*	*Total Act, Ci*
H - 3	*0.470E 01*	*0.692E 00*	*0.0*	*0.0*	*0.470E 01*
CR- 51	*0.934E-02*	*0.137E-02*	*0.0*	*0.0*	*0.934E-02*
Mn- 54	*0.152E-02*	*0.224E-03*	*0.0*	*0.0*	*0.152E-02*
Fe- 55	*0.772E-02*	*0.114E-02*	*0.0*	*0.0*	*0.772E-02*
Co- 58	*0.784E-01*	*0.115E-01*	*0.0*	*0.0*	*0.784E-01*
Fe- 59	*0.490E-02*	*0.772E-03*	*0.0*	*0.0*	*0.490E-02*
Co- 60	*0.975E-02*	*0.144E-02*	*0.0*	*0.0*	*0.975E-02*
Kr- 83M	*0.0*	*0.0*	*0.594E-01*	*0.131E-01*	*0.594E-01*
Kr- 85M	*0.0*	*0.0*	*0.330E 00*	*0.729E-01*	*0.330E 00*
Kr- 85	*0.0*	*0.0*	*0.619E 00*	*0.137E 00*	*0.619E 00*
Kr- 87	*0.0*	*0.0*	*0.158E 00*	*0.349E-01*	*0.158E 00*
Kr- 88	*0.0*	*0.0*	*0.547E 00*	*0.121E 00*	*0.547E 00*
Sr- 89	*0.134E-02*	*0.198E-03*	*0.0*	*0.0*	*0.134E-02*
Sr- 90	*0.646E-04*	*0.950E-05*	*0.0*	*0.0*	*0.646E-04*
Y - 90	*0.111E-03*	*0.163E-04*	*0.0*	*0.0*	*0.111E-03*
Sr- 91	*0.851E-03*	*0.125E-03*	*0.0*	*0.0*	*0.851E-03*
Y - 91	*0.111E-01*	*0.164E-02*	*0.0*	*0.0*	*0.111E-01*
Sr- 92	*0.325E-03*	*0.478E-04*	*0.0*	*0.0*	*0.325E-03*
Y - 92	*0.448E-03*	*0.660E-04*	*0.0*	*0.0*	*0.448E-03*
Zr- 95	*0.334E-03*	*0.491E-04*	*0.0*	*0.0*	*0.334E-03*
Nb- 95	*0.325E-03*	*0.477E-04*	*0.0*	*0.0*	*0.325E-03*
Mo- 99	*0.267E 01*	*0.392E 00*	*0.0*	*0.0*	*0.267E 01*
I -131	*0.158E 01*	*0.233E 00*	*0.0*	*0.0*	*0.158E 01*
Te-132	*0.166E 00*	*0.245E-01*	*0.0*	*0.0*	*0.166E 00*
I -132	*0.529E 00*	*0.779E-01*	*0.0*	*0.0*	*0.529E 00*
I -133	*0.214E 01*	*0.315E 00*	*0.0*	*0.0*	*0.214E 01*
Xe-133M	*0.256E-03*	*0.376E-04*	*0.573E 00*	*0.127E 00*	*0.574E 00*
Xe-133	*0.453E-02*	*0.667E-03*	*0.469E 02*	*0.104E 02*	*0.469E 02*
Cs-134	*0.113E 00*	*0.166E-01*	*0.0*	*0.0*	*0.113E 00*
I -134	*0.219E 00*	*0.323E-01*	*0.0*	*0.0*	*0.219E 00*
I -135	*0.115E 01*	*0.169E 00*	*0.0*	*0.0*	*0.115E 01*
Xe-135M	*0.858E-01*	*0.126E-01*	*0.365E-01*	*0.806E-02*	*0.122E 00*
Xe-135	*0.311E-01*	*0.458E-02*	*0.102E 01*	*0.226E 00*	*0.105E 01*
Cs-136	*0.303E-01*	*0.445E-02*	*0.0*	*0.0*	*0.303E-01*
Cs-137	*0.200E 00*	*0.295E-01*	*0.0*	*0.0*	*0.200E 00*
Xe-138	*0.00*	*0.0*	*0.466E-01*	*0.103E-01*	*0.446E-01*
Ba-140	*0.227E-02*	*0.335E-03*	*0.0*	*0.0*	*0.227E-02*
La-140	*0.813E-03*	*0.120E-03*	*0.0*	*0.0*	*0.813E-03*
Ce-144	*0.197E-03*	*0.289E-04*	*0.0*	*0.0*	*0.197E-03*
Pr-144	*0.197E-03*	*0.289E-04*	*0.0*	*0.0*	*0.197E-03*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-9
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

GASEOUS RELEASES DUE TO COLD SHUTDOWN AND STARTUPS
(Released from Condenser)

Nuclide	*Released, Ci*	*Fraction of Total Annual Release*
Kr-83m	*1.89E-8*	*1.21E-8*
Kr-85m	*2.91E-5*	*2.75E-6*
Kr-85	*4.32E-3*	*4.75E-6*
Kr-87	*6.36E-10*	*1.58E-10*
Kr-88	*4.14E-6*	*2.69E-7*
I-131[(a)]	*4.32E-5*	*3.32E-4*
I-132[(a)]	*7.69E-9*	*2.79E-7*
I-133[(a)]	*2.51E-5*	*1.90E-4*
Xe-133m	*2.80E-3*	*3.29E-5*
Xe-133	*2.80E-1*	*2.17E-5*
I-134[(a)]	*7.34E-15*	*5.73E-13*
I-135[(a)]	*1.98E-6*	*3.06E-5*
Xe-135m	*1.89E-5*	*1.20E-5*
Xe-135	*1.20E-3*	*2.63E-5*
Xe-138	*0.0*	*0.0*
Totals	*2.89E-1*	*6.54E-4*

(a) Volatile form only.

Notes:
Beta air dose at 0.5 miles NW of plant = 1.55E-5 mrem/yr
Gamma air dose at 0.5 miles NW of plant = 5.12E-6 mrem/yr
Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-10

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

DISTANCES IN MILES FROM DCPP UNIT 1 REACTOR CENTERLINE TO THE NEAREST MILK COW, MEAT ANIMAL, MILK GOAT, RESIDENCE, VEGETABLE GARDEN, AND SITE BOUNDARY[c]

	22-1/2° Radial Sectors[a]								
Nearest	*NW*	*NNW*	*N*	*NNE*	*NE*	*ENE*	*E*	*ESE*	*SE*
Milk cow	*None[b]*	*None*	*None*	*None*	*None*	*None*	*None*	*None*	*None*
Meat animal	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.7*	*1.0*	*1.0*	*1.1*
Milk goat	*None*	*None*	*None*	*None*	*None*	*None*	*None*	*None*	*None*
Residence	*None*	*1.5*	*None*	*None*	*None*	*4.5*	*None*	*None*	*None*
Vegetable garden	*3.6*	*3.6*	*None*	*None*	*None*	*None*	*None*	*3.7*	*3.7*
Site boundary	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.7*	*1.0*	*1.0*	*1.1*

(a) Sectors not shown contain no land beyond the site boundary, other than islets not used for the purposes indicated in this table.

(b) None within 5 miles, typical of other places where "None" is used.

(c) This table presents pre-operational data. Current operational data reside in the ODCM.

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-11

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ESTIMATES OF RELATIVE CONCENTRATION (χ/Q)[(a)] AT LOCATIONS SPECIFIED IN TABLE 11.3-10[(b)]

	22-1/2° Radial Sectors								
Nearest	*NW*	*NNW*	*N*	*NNE*	*NE*	*ENE*	*E*	*ESE*	*SE*
Milk cow	*None*	*None*	*None*	*None*	*None*	*None*	*None*	*None*	*None*
Meat animal	$1.58X10^{-6}$	$8.67X10^{-7}$	$4.93X10^{-7}$	$2.44X10^{-7}$	$1.62X10^{-7}$	$9.18X10^{-8}$	$1.07X10^{-7}$	$5.20X10^{-7}$	$1.32X10^{-6}$
Milk goat	*None*	*None*	*None*	*None*	*None*	*None*	*None*	*None*	*None*
Residence	*None*	$3.30X10^{-7}$	*None*	*None*	*None*	$1.40X10^{-8}$	*None*	*None*	*None*
Vegetable garden	$1.50X10^{-7}$	$1.50X10^{-7}$	*None*	*None*	*None*	*None*	*None*	$1.00X10^{-7}$	$1.00X10^{-7}$
Site boundary	$1.58X10^{-6}$	$8.67X10^{-7}$	$4.93X10^{-7}$	$2.44X10^{-7}$	$1.62X10^{-7}$	$9.18X10^{-8}$	$1.07X10^{-7}$	$5.20X10^{-7}$	$1.32X10^{-6}$

(a) In units of seconds per cubic meter.

(b) This table presents pre-operational data. Current operational data reside in the ODCM.

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-12

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ESTIMATES OF DEPOSITION (D/Q)[(a)] AT LOCATIONS SPECIFIED IN TABLE 11.3-10[(b)]

	22-1/2° Radial Sectors								
Nearest	*NW*	*NNW*	*N*	*NNE*	*NE*	*ENE*	*E*	*ESE*	*SE*
Milk cow	*None*	*None*	*None*	*None*	*None*	*None*	*None*	*None*	*None*
Meat animal	$2.54X10^{-8}$	$1.33X10^{-8}$	$5.50X10^{-9}$	$3.27X10^{-9}$	$4.13X10^{-9}$	$1.77X10^{-9}$	$1.65X10^{-9}$	$8.47X10^{-9}$	$2.90X10^{-8}$
Milk goat	*None*	*None*	*None*	*None*	*None*	*None*	*None*	*None*	*None*
Residence	*None*	$2.08X10^{-9}$	*None*	*None*	*None*	$6.49X10^{-11}$	*None*	*None*	*None*
Vegetable garden	$8.13X10^{-10}$	$4.27X10^{-10}$	*None*	*None*	*None*	*None*	*None*	$7.91X10^{-10}$	$3.20X10^{-9}$
Site boundary	$2.54X10^{-8}$	$1.33X10^{-8}$	$5.50X10^{-9}$	$3.27X10^{-9}$	$4.13X10^{-9}$	$1.77X10^{-9}$	$1.65X10^{-9}$	$8.47X10^{-9}$	$2.90X10^{-8}$

(a) In units of meters^{-2}, includes sector width and frequency of winds in each sector.

(b) This table presents pre-operational data. Current operational data reside in the ODCM.

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-13
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ANNUAL AVERAGE ATMOSPHERIC ACTIVITY CONCENTRATIONS AT SITE BOUNDARY FOR DESIGN BASIS CASE (μCi/cc)

	Sector								
Nuclide	*NW*	*NNW*	*N*	*NNE*	*NE*	*ENE*	*E*	*ESE*	*SE*
I-135	*7.633E-22*	*4.189E-22*	*2.382E-22*	*1.179E-22*	*7.826E-23*	*4.277E-23*	*4.806E-23*	*2.336E-22*	*5.864E-22*
H-3	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Cr-51	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Mn-54	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Fe-55	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Co-58	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Fe-59	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Co-60	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Kr-83M	*9.868E-34*	*5.415E-34*	*3.079E-34*	*1.524E-34*	*1.012E-34*	*5.734E-35*	*6.683E-35*	*3.248E-34*	*8.245E-34*
Kr-85M	*1.121E-23*	*6.153E-24*	*3.499E-24*	*1.732E-24*	*1.150E-24*	*6.515E-25*	*7.594E-25*	*3.691E-24*	*9.369E-24*
Kr-85	*2.528E-10*	*1.387E-10*	*7.887E-11*	*3.903E-11*	*2.592E-11*	*1.469E-11*	*1.712E-11*	*8.318E-11*	*2.112E-10*
Kr-87	*8.455E-41*	*4.639E-41*	*2.638E-41*	*1.306E-41*	*8.669E-42*	*4.912E-42*	*5.726E-42*	*2.783E-41*	*7.063E-41*
Kr-88	*1.805E-27*	*9.905E-28*	*5.632E-28*	*2.788E-28*	*1.851E-28*	*1.049E-28*	*1.222E-28*	*5.941E-28*	*1.508E-27*
Sr-89	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Sr-90	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Y-90	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Sr-91	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Y-91	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Sr-92	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Y-92	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Zr-95	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Nb-95	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Mo-99	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
I-131	*4.819E-19*	*2.644E-19*	*1.504E-19*	*7.442E-20*	*4.941E-20*	*2.700E-20*	*3.034E-20*	*1.474E-19*	*3.702E-19*
Te-132	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
I-132	*7.214E-20*	*3.959E-20*	*2.251E-20*	*1.114E-20*	*7.397E-21*	*4.042E-21*	*4.542E-21*	*2.207E-20*	*5.542E-20*
I-133	*8.355E-21*	*4.585E-21*	*2.607E-21*	*1.290E-21*	*8.567E-22*	*4.681E-22*	*5.260E-22*	*2.556E-21*	*6.419E-21*
Xe-133M	*1.688E-16*	*9.265E-17*	*5.268E-17*	*2.607E-17*	*1.731E-17*	*9.810E-10*	*1.143E-17*	*5.557E-17*	*1.411E-16*
Xe-133	*2.058E-11*	*1.129E-11*	*6.420E-12*	*3.178E-12*	*2.110E-12*	*1.196E-12*	*1.393E-12*	*6.772E-12*	*1.719E-11*
Cs-134	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
I-134	*1.336E-22*	*7.332E-23*	*4.169E-23*	*2.064E-23*	*1.370E-23*	*7.486E-24*	*8.413E-24*	*4.088E-23*	*1.027E-22*

TABLE 11.3-13
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

	Sector								
Nuclide	*NW*	*NNW*	*N*	*NNE*	*NE*	*ENE*	*E*	*ESE*	*SE*
Xe-135M	*3.345E-21*	*1.835E-21*	*1.044E-21*	*5.165E-22*	*3.429E-22*	*1.943E-22*	*2.265E-22*	*1.101E-21*	*2.794E-21*
Xe-135	*1.382E-18*	*7.582E-19*	*4.311E-19*	*2.134E-19*	*1.417E-19*	*8.028E-20*	*9.357E-20*	*4.547E-19*	*1.154E-18*
Cs-136	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Cs-137	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Xe-138	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Ba-140	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
La-140	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Ce-144	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Pr-144	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
C-14	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-14
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ANNUAL AVERAGE ATMOSPHERIC ACTIVITY CONCENTRATIONS
AT SITE BOUNDARY FOR NORMAL OPERATION CASE (μCi/cc)

	Sector								
Nuclide	NW	NNW	N	NNE	NE	ENE	E	ESE	SE
H-3	1.401E-11	7.687E-12	4.371E-12	2.163E-12	1.436E-12	7.848E-13	8.820E-13	4.286E-12	1.076E-11
Cr-51	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mn-54	1.918-15	1.053E-15	5.985E-14	2.967E-16	1.967E-16	1.075E-16	1.208E-16	5.869E-16	1.474E-15
Fe-55	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Co-58	4.466E-15	3.548E-15	2.017E-15	9.985E-16	6.629E-16	3.622E-16	4.071E-16	1.978E-15	4.967E-15
Fe-59	6.466E-16	3.548E-16	2.017E-16	9.985E-17	6.629E-17	3.622E-17	4.071E-17	1.978E-16	4.967E-16
Co-60	2.931E-15	1.608E-5	9.146E-16	4.526E-16	3.005E-16	1.642E-16	1.845E-16	8.968E-16	2.252E-15
Kr-83M	7.805E-14	4.283E-14	2.435E-14	1.205E-14	8.002E-15	4.535E-15	5.286E-15	2.569E-14	6.521E-14
Kr-85M	5.323E-13	2.921E-13	1.661E-13	8.221E-14	5.458E-14	3.093E-14	3.605E-14	1.752E-13	4.447E-13
Kr-85	4.558E-11	2.501E-11	1.422E-11	7.039E-12	4.674E-12	2.648E-12	3.087E-12	1.500E-11	3.808E-11
Kr-87	2.016E-13	1.104E-13	6.290E-14	3.113E-14	2.067E-14	1.171E-14	1.365E-14	6.635E-14	1.684E-13
Kr-88	7.725E-13	4.239E-13	2.410E-13	1.193E-13	7.921E-14	4.488E-14	5.232E-14	2.542E-13	6.454E-13
Sr-89	1.422E-16	7.805E-17	4.438E-17	2.197E-17	1.458E-17	7.969E-18	8.955E-10	4.352E-17	1.093E-16
Sr-90	2.414E-17	1.325E-17	7.532E-18	3.720E-18	2.475E-18	1.352E-18	1.520E-18	7.386E-18	1.854E-17
Y-90	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sr-91	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Y-91	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sr-92	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Y-92	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Zr-95	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nb-95	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mo-99	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-131	5.601E-15	3.073E-15	1.748E-15	8.649E-16	5.742E-16	3.138E-16	3.526E-16	1.714E-15	4.303E-15
Te-132	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I-132	1.190E-15	6.529E-16	3.712E-16	1.837E-16	1.220E-16	6.666E-17	7.491E-17	3.640E-14	9.141E-16
I-133	5.673E-15	3.113E-15	1.770E-15	8.761E-16	5.816E-16	3.178E-16	3.572E-17	1.736E-15	4.358E-15
Xe-133M	4.259E-12	2.337E-12	1.329E-12	6.577E-13	4.367E-13	2.475E-13	2.884E-13	1.402E-12	3.558E-12
Xe-133	6.468E-10	3.549E-10	2.018E-10	9.989E-11	6.632E-11	3.758E-11	4.381E-11	2.129E-10	5.404E-10
Cs-134	1.918E-15	1.053E-15	5.985E-16	2.962E-16	1.967E-16	1.075E-16	1.208E-16	5.869E-16	1.474E-15
I-134	5.496E-16	3.016E-16	1.715E-16	8.487E-17	5.635E-17	3.079E-17	3.460E-17	1.682E-16	4.222E-16
I-135	2.787E-15	1.529E-15	8.697E-16	4.304E-16	2.858E-16	1.562E-16	1.755E-16	8.528E-16	2.141E-15

TABLE 11.3-14
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

	Sector								
Nuclide	*NW*	*NNW*	*N*	*NNE*	*NE*	*ENE*	*E*	*ESE*	*SE*
Xe-135M	*7.857E-14*	*4.311E-14*	*2.452E-14*	*1.213E-14*	*8.056E-15*	*4.565E-15*	*5.321E-15*	*2.586E-14*	*6.564E-14*
Xe-135	*2.287E-12*	*1.255E-12*	*7.135E-13*	*3.532E-13*	*2.345E-13*	*1.329E-13*	*1.549E-13*	*7.526E-13*	*1.911E-12*
Cs-136	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Cs-137	*3.254E-15*	*1.786E-15*	*1.015E-15*	*5.026E-16*	*3.337E-16*	*1.823E-16*	*2.049E-16*	*9.957E-16*	*2.500E-15*
Xe-138	*8.728E-14*	*4.789E-14*	*2.723E-14*	*1.348E-14*	*8.948E-15*	*5.071E-15*	*5.910E-15*	*2.872E-14*	*7.291E-14*
Ba-140	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
La-140	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Ce-144	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Pr-144	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
C-14	*3.448E-13*	*1.892E-13*	*1.076E-13*	*5.325E-14*	*3.536E-14*	*1.932E-14*	*2.171E-14*	*1.055E-13*	*2.649E-13*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-15

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR NW SECTOR AT DISTANCE 0.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*4.406E-08*	*3.486E-08*	*6.434E-08*	*0.0*
Ingestion liver	*6.312E-08*	*4.925E-08*	*6.592E-08*	*0.0*
Ingestion whole body	*3.611E-08*	*2.935E-08*	*4.974E-08*	*0.0*
Ingestion thyroid	*2.065E-05*	*1.421E-05*	*2.143E-05*	*0.0*
Ingestion kidney	*1.080E-07*	*6.383E-08*	*4.026E-08*	*0.0*
Ingestion lung	*0.0*	*0.0*	*0.0*	*0.0*
Ingestion GI	*1.663E-08*	*9.324E-09*	*5.645E-09*	*0.0*
Total bone	*4.406E-08*	*3.486E-08*	*6.434E-08*	*0.0*
Total liver	*6.312E-08*	*4.925E-08*	*6.592E-08*	*0.0*
Total whole body	*3.611E-08*	*2.935E-08*	*4.974E-08*	*0.0*
Total thyroid	*2.065E-05*	*1.421E-05*	*2.143E-05*	*0.0*
Total kidney	*1.080E-07*	*6.383E-08*	*4.026E-08*	*0.0*
Total lung	*0.0*	*0.0*	*0.0*	*0.0*
Total GI	*1.663E-08*	*9.324E-09*	*5.645E-09*	*0.0*
Gamma air	*5.145E-01*	*5.145E-01*	*5.145E-01*	*5.145E-01*
Beta air	*1.161E-02*	*1.161E-02*	*1.161E-02*	*1.161E-02*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-16

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR NW SECTOR AT DISTANCE 3.6 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*5.578E-10*	*9.049E-10*	*2.186E-09*	*0.0*
Ingestion liver	*7.992E-10*	*1.279E-09*	*2.289E-09*	*0.0*
Ingestion whole body	*4.573E-10*	*7.619E-10*	*1.690E-09*	*0.0*
Ingestion thyroid	*2.615E-07*	*3.688E-07*	*7.281E-07*	*0.0*
Ingestion kidney	*1.368E-09*	*1.657E-09*	*1.368E-09*	*0.0*
Ingestion lung	*0.0*	*0.0*	*0.0*	*0.0*
Ingestion GI	*2.105E-10*	*2.421E-10*	*1.918E-10*	*0.0*
Total bone	*5.578E-10*	*9.049E-10*	*2.186E-09*	*0.0*
Total liver	*7.992E-10*	*1.279E-09*	*2.239E-09*	*0.0*
Total whole body	*4.573E-10*	*7.619E-10*	*1.690E-09*	*0.0*
Total thyroid	*2.615E-07*	*3.688E-07*	*7.281E-07*	*0.0*
Total kidney	*1.368E-09*	*1.657E-09*	*1.368E-09*	*0.0*
Total lung	*0.0*	*0.0*	*0.0*	*0.0*
Total GI	*2.105E-10*	*2.421E-10*	*1.918E-10*	*0.0*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-17

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR NNW SECTOR AT DISTANCE 0.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*2.312E-08*	*1.829E-08*	*3.377E-08*	*0.0*
Ingestion liver	*3.313E-08*	*2.585E-08*	*3.460E-08*	*0.0*
Ingestion whole body	*1.895E-08*	*1.540E-08*	*2.610E-08*	*0.0*
Ingestion thyroid	*1.084E-05*	*7.455E-06*	*1.125E-05*	*0.0*
Ingestion kidney	*5.669E-08*	*3.350E-08*	*2.113E-08*	*0.0*
Ingestion lung	*0.0*	*0.0*	*0.0*	*0.0*
Ingestion GI	*8.726E-09*	*4.894E-09*	*2.962E-09*	*0.0*
Total bone	*2.312E-08*	*1.829E-08*	*3.377E-08*	*0.0*
Total liver	*3.313E-08*	*2.585E-08*	*3.460E-08*	*0.0*
Total whole body	*1.895E-08*	*1.540E-08*	*2.610E-08*	*0.0*
Total thyroid	*1.084E-05*	*7.455E-06*	*1.125E-05*	*0.0*
Total kidney	*5.669E-08*	*3.350E-08*	*2.113E-08*	*0.0*
Total lung	*0.0*	*0.0*	*0.0*	*0.0*
Total GI	*8.726E-09*	*4.894E-09*	*2.962E-09*	*0.0*
Gamma air	*2.823E-01*	*2.823E-01*	*2.823E-01*	*2.823E-01*
Beta air	*6.371E-03*	*6.371E-03*	*6.371E-03*	*6.371E-03*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-18

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR NNW SECTOR AT DISTANCE 1.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Inhalation bone	*2.077E-09*	*1.937E-09*	*2.985E-09*	*4.420E-09*
Inhalation liver	*2.971E-09*	*2.732E-09*	*3.047E-09*	*5.218E-09*
Inhalation whole body	*1.687E-09*	*1.617E-09*	*2.294E-09*	*3.049E-09*
Inhalation thyroid	*9.794E-07*	*7.988E-07*	*1.009E-06*	*1.722E-06*
Inhalation kidney	*5.094E-09*	*3.559E-09*	*1.884E-09*	*1.326E-09*
Inhalation lung	*0.0*	*0.0*	*0.0*	*0.0*
Inhalation GI	*5.289E-10*	*3.526E-10*	*1.810E-10*	*1.360E-10*
External whole body	*1.692E-03*	*1.692E-03*	*1.692E-03*	*1.692E-03*
External skin	*7.394E-02*	*7.394E-02*	*7.394E-02*	*7.394E-02*
Total bone	*1.692E-03*	*1.692E-03*	*1.692E-03*	*1.692E-03*
Total liver	*1.692E-03*	*1.692E-03*	*1.692E-03*	*1.692E-03*
Total whole body	*1.692E-03*	*1.692E-03*	*1.692E-03*	*1.692E-03*
Total thyroid	*1.693E-03*	*1.693E-03*	*1.693E-03*	*1.694E-03*
Total kidney	*1.692E-03*	*1.692E-03*	*1.692E-03*	*1.692E-03*
Total lung	*1.692E-03*	*1.692E-03*	*1.692E-03*	*1.692E-03*
Total GI	*1.692E-03*	*1.692E-03*	*1.692E-03*	*1.692E-03*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-19

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR NNW SECTOR AT DISTANCE 3.6 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*2.926E-10*	*4.746E-10*	*1.146E-09*	*0.0*
Ingestion liver	*4.192E-10*	*6.706E-10*	*1.175E-09*	*0.0*
Ingestion whole body	*2.398E-10*	*3.996E-10*	*8.862E-10*	*0.0*
Ingestion thyroid	*1.371E-07*	*1.934E-07*	*3.819E-07*	*0.0*
Ingestion kidney	*7.174E-10*	*8.692E-10*	*7.174E-10*	*0.0*
Ingestion lung	*0.0*	*0.0*	*0.0*	*0.0*
Ingestion GI	*1.104E-10*	*1.270E-10*	*1.006E-10*	*0.0*
Total bone	*2.926E-10*	*4.746E-10*	*1.146E-09*	*0.0*
Total liver	*4.192E-10*	*6.706E-10*	*1.175E-09*	*0.0*
Total whole body	*2.398E-10*	*3.996E-10*	*8.862E-10*	*0.0*
Total thyroid	*1.371E-07*	*1.934E-07*	*3.819E-07*	*0.0*
Total kidney	*7.174E-10*	*8.692E-10*	*7.174E-10*	*0.0*
Total lung	*0.0*	*0.0*	*0.0*	*0.0*
Total GI	*1.104E-10*	*1.270E-10*	*1.006E-10*	*0.0*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-20

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR N SECTOR AT DISTANCE 0.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*9.551E-09*	*7.557E-09*	*1.395E-08*	*0.0*
Ingestion liver	*1.368E-08*	*1.068E-08*	*1.429E-08*	*0.0*
Ingestion whole body	*7.829E-09*	*6.363E-09*	*1.078E-08*	*0.0*
Ingestion thyroid	*4.477E-06*	*3.080E-06*	*4.647E-06*	*0.0*
Ingestion kidney	*2.342E-08*	*1.384E-08*	*8.729E-09*	*0.0*
Ingestion lung	*0.0*	*0.0*	*0.0*	*0.0*
Ingestion GI	*3.605E-09*	*2.022E-09*	*1.224E-09*	*0.0*
Total bone	*9.551E-09*	*7.557E-09*	*1.395E-08*	*0.0*
Total liver	*1.368E-08*	*1.068E-08*	*1.429E-08*	*0.0*
Total whole body	*7.829E-09*	*6.363E-09*	*1.078E-08*	*0.0*
Total thyroid	*4.477E-06*	*3.080E-06*	*4.647E-06*	*0.0*
Total kidney	*2.342E-08*	*1.384E-08*	*8.729E-09*	*0.0*
Total lung	*0.0*	*0.0*	*0.0*	*0.0*
Total GI	*3.605E-09*	*2.022E-09*	*1.224E-09*	*0.0*
Gamma air	*1.605E-01*	*1.605E-01*	*1.605E-01*	*1.605E-01*
Beta air	*3.623E-03*	*3.623E-03*	*3.623E-03*	*3.623E-03*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-21

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR NNE SECTOR AT DISTANCE 0.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*5.688E-09*	*4.500E-09*	*8.306E-09*	*0.0*
Ingestion liver	*8.148E-09*	*6.358E-09*	*8.510E-09*	*0.0*
Ingestion whole body	*4.662E-09*	*3.789E-09*	*6.421E-09*	*0.0*
Ingestion thyroid	*2.666E-06*	*1.834E-06*	*2.767E-06*	*0.0*
Ingestion kidney	*1.395E-08*	*8.240E-09*	*5.198E-09*	*0.0*
Ingestion lung	*0.0*	*0.0*	*0.0*	*0.0*
Ingestion GI	*2.146E-09*	*1.204E-09*	*7.287E-10*	*0.0*
Total bone	*5.688E-09*	*4.500E-09*	*8.306E-09*	*0.0*
Total liver	*8.148E-09*	*6.358E-09*	*8.510E-09*	*0.0*
Total whole body	*4.662E-09*	*3.789E-09*	*6.421E-09*	*0.0*
Total thyroid	*2.666E-06*	*1.834E-06*	*2.767E-06*	*0.0*
Total kidney	*1.395E-08*	*8.240E-09*	*5.198E-09*	*0.0*
Total lung	*0.0*	*0.0*	*0.0*	*0.0*
Total GI	*2.146E-09*	*1.204E-09*	*7.287E-10*	*0.0*
Gamma air	*7.945E-02*	*7.945E-02*	*7.945E-02*	*7.945E-02*
Beta air	*1.793E-03*	*1.793E-03*	*1.793E-03*	*1.793E-03*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-22

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR NE SECTOR AT DISTANCE 0.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*7.178E-09*	*5.679E-09*	*1.048E-08*	*0.0*
Ingestion liver	*1.028E-08*	*8.024E-09*	*1.074E-08*	*0.0*
Ingestion whole body	*5.884E-09*	*4.782E-09*	*8.104E-09*	*0.0*
Ingestion thyroid	*3.365E-06*	*2.315E-06*	*3.492E-06*	*0.0*
Ingestion kidney	*1.760E-08*	*1.040E-08*	*6.560E-09*	*0.0*
Ingestion lung	*0.0*	*0.0*	*0.0*	*0.0*
Ingestion GI	*2.709E-09*	*1.519E-09*	*9.197E-10*	*0.0*
Total bone	*7.178E-09*	*5.679E-09*	*1.048E-08*	*0.0*
Total liver	*1.028E-08*	*8.024E-09*	*1.074E-08*	*0.0*
Total whole body	*5.884E-09*	*4.782E-09*	*8.104E-09*	*0.0*
Total thyroid	*3.365E-06*	*2.315E-06*	*3.492E-06*	*0.0*
Total kidney	*1.760E-08*	*1.040E-08*	*6.560E-09*	*0.0*
Total lung	*0.0*	*0.0*	*0.0*	*0.0*
Total GI	*2.709E-09*	*1.519E-09*	*9.197E-10*	*0.0*
Gamma air	*5.275E-02*	*5.275E-02*	*5.275E-02*	*5.275E-02*
Beta air	*1.190E-03*	*1.190E-03*	*1.190E-03*	*1.190E-03*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-23

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR ENE SECTOR AT DISTANCE 0.7 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*3.068E-09*	*2.427E-09*	*4.481E-09*	*0.0*
Ingestion liver	*4.395E-09*	*3.430E-09*	*4.591E-09*	*0.0*
Ingestion whole body	*2.515E-09*	*2.044E-09*	*3.464E-09*	*0.0*
Ingestion thyroid	*1.438E-06*	*9.892E-07*	*1.493E-06*	*0.0*
Ingestion kidney	*7.522E-09*	*4.445E-09*	*2.804E-09*	*0.0*
Ingestion lung	*0.0*	*0.0*	*0.0*	*0.0*
Ingestion GI	*1.158E-09*	*6.493E-10*	*3.931E-10*	*0.0*
Total bone	*3.068E-09*	*2.427E-09*	*4.481E-09*	*0.0*
Total liver	*4.395E-09*	*3.430E-09*	*4.591E-09*	*0.0*
Total whole body	*2.515E-09*	*2.044E-09*	*3.464E-09*	*0.0*
Total thyroid	*1.438E-06*	*9.892E-07*	*1.493E-06*	*0.0*
Total kidney	*7.522E-09*	*4.445E-09*	*2.804E-09*	*0.0*
Total lung	*0.0*	*0.0*	*0.0*	*0.0*
Total GI	*1.158E-09*	*6.493E-10*	*3.931E-10*	*0.0*
Gamma air	*2.989E-02*	*2.989E-02*	*2.989E-02*	*2.989E-02*
Beta air	*6.746E-04*	*6.746E-04*	*6.746E-04*	*6.746E-04*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-24

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR ENE SECTOR AT DISTANCE 4.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Inhalation bone	*7.466E-11*	*6.962E-11*	*1.073E-10*	*1.589E-10*
Inhalation liver	*1.068E-10*	*9.819E-11*	*1.095E-10*	*1.876E-10*
Inhalation whole body	*6.065E-11*	*5.813E-11*	*8.247E-11*	*1.096E-10*
Inhalation thyroid	*3.521E-08*	*2.872E-08*	*3.628E-08*	*6.191E-08*
Inhalation kidney	*1.831E-10*	*1.279E-10*	*6.772E-11*	*4.766E-11*
Inhalation lung	*0.0*	*0.0*	*0.0*	*0.0*
Inhalation GI	*1.901E-11*	*1.267E-11*	*6.505E-12*	*4.890E-12*
External whole body	*7.179E-05*	*7.179E-05*	*7.179E-05*	*7.179E-05*
External skin	*3.137E-03*	*3.137E-03*	*3.137E-03*	*3.137E-03*
Total bone	*7.179E-05*	*7.179E-05*	*7.179E-05*	*7.179E-05*
Total liver	*7.179E-05*	*7.179E-05*	*7.179E-05*	*7.179E-05*
Total whole body	*7.179E-05*	*7.179E-05*	*7.179E-05*	*7.179E-05*
Total thyroid	*7.183E-05*	*7.182E-05*	*7.183E-05*	*7.185E-05*
Total kidney	*7.179E-05*	*7.179E-05*	*7.179E-05*	*7.179E-05*
Total lung	*7.179E-05*	*7.179E-05*	*7.179E-05*	*7.179E-05*
Total GI	*7.179E-05*	*7.179E-05*	*7.179E-05*	*7.179E-05*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-25

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR E SECTOR AT DISTANCE 1.0 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*2.867E-09*	*2.268E-09*	*4.186E-09*	*0.0*
Ingestion liver	*4.107E-09*	*3.204E-09*	*4.289E-09*	*0.0*
Ingestion whole body	*2.350E-09*	*1.910E-09*	*3.236E-09*	*0.0*
Ingestion thyroid	*1.344E-06*	*9.243E-07*	*1.395E-06*	*0.0*
Ingestion kidney	*7.028E-09*	*4.153E-09*	*2.620E-09*	*0.0*
Ingestion lung	*0.0*	*0.0*	*0.0*	*0.0*
Ingestion GI	*1.082E-09*	*6.067E-10*	*3.673E-10*	*0.0*
Total bone	*2.867E-09*	*2.268E-09*	*4.186E-09*	*0.0*
Total liver	*4.107E-09*	*3.204E-09*	*4.289E-09*	*0.0*
Total whole body	*2.350E-09*	*1.910E-09*	*3.236E-09*	*0.0*
Total thyroid	*1.344E-06*	*9.243E-07*	*1.395E-06*	*0.0*
Total kidney	*7.028E-09*	*4.153E-09*	*2.620E-09*	*0.0*
Total lung	*0.0*	*0.0*	*0.0*	*0.0*
Total GI	*1.082E-09*	*6.067E-10*	*3.673E-10*	*0.0*
Gamma air	*3.484E-02*	*3.484E-02*	*3.484E-02*	*3.484E-02*
Beta air	*7.863E-04*	*7.863E-04*	*7.863E-04*	*7.863E-04*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-26

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR ESE SECTOR AT DISTANCE 1.0 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*1.472E-08*	*1.165E-08*	*2.150E-08*	*0.0*
Ingestion liver	*2.109E-08*	*1.646E-08*	*2.203E-08*	*0.0*
Ingestion whole body	*1.207E-08*	*9.807E-09*	*1.662E-08*	*0.0*
Ingestion thyroid	*6.900E-06*	*4.746E-06*	*7.162E-06*	*0.0*
Ingestion kidney	*3.609E-08*	*2.133E-08*	*1.345E-08*	*0.0*
Ingestion lung	*0.0*	*0.0*	*0.0*	*0.0*
Ingestion GI	*5.555E-09*	*3.116E-09*	*1.886E-09*	*0.0*
Total bone	*1.472E-08*	*1.165E-08*	*2.150E-08*	*0.0*
Total liver	*2.109E-08*	*1.646E-08*	*2.203E-08*	*0.0*
Total whole body	*1.207E-08*	*9.807E-09*	*1.662E-08*	*0.0*
Total thyroid	*6.900E-06*	*4.746E-06*	*7.162E-06*	*0.0*
Total kidney	*3.609E-08*	*2.133E-08*	*1.345E-08*	*0.0*
Total lung	*0.0*	*0.0*	*0.0*	*0.0*
Total GI	*5.555E-09*	*3.116E-09*	*1.886E-09*	*0.0*
Gamma air	*1.693E-01*	*1.693E-01*	*1.693E-01*	*1.693E-01*
Beta air	*3.821E-03*	*3.821E-03*	*3.821E-03*	*3.821E-03*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-27

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR ESE SECTOR AT DISTANCE 3.7 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*5.431E-10*	*8.810E-10*	*2.128E-09*	*0.0*
Ingestion liver	*7.781E-10*	*1.245E-09*	*2.180E-09*	*0.0*
Ingestion whole body	*4.452E-10*	*7.418E-10*	*1.645E-09*	*0.0*
Ingestion thyroid	*2.546E-07*	*3.590E-07*	*7.089E-07*	*0.0*
Ingestion kidney	*1.332E-09*	*1.613E-09*	*1.332E-09*	*0.0*
Ingestion lung	*0.0*	*0.0*	*0.0*	*0.0*
Ingestion GI	*2.050E-10*	*2.357E-10*	*1.867E-10*	*0.0*
Total bone	*5.431E-10*	*8.810E-10*	*2.128E-09*	*0.0*
Total liver	*7.781E-10*	*1.245E-09*	*2.180E-09*	*0.0*
Total whole body	*4.452E-10*	*7.418E-10*	*1.645E-09*	*0.0*
Total thyroid	*2.546E-07*	*3.590E-07*	*7.089E-07*	*0.0*
Total kidney	*1.332E-09*	*1.613E-09*	*1.332E-09*	*0.0*
Total lung	*0.0*	*0.0*	*0.0*	*0.0*
Total GI	*2.050E-10*	*2.357E-10*	*1.867E-10*	*0.0*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-28

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR SE SECTOR AT DISTANCE 1.1 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*5.046E-08*	*3.992E-08*	*7.369E-08*	*0.0*
Ingestion liver	*7.229E-08*	*5.641E-08*	*7.550E-08*	*0.0*
Ingestion whole body	*4.136E-08*	*3.361E-08*	*5.696E-08*	*0.0*
Ingestion thyroid	*2.365E-05*	*1.627E-05*	*2.455E-05*	*0.0*
Ingestion kidney	*1.237E-07*	*7.311E-08*	*4.611E-08*	*0.0*
Ingestion lung	*0.0*	*0.0*	*0.0*	*0.0*
Ingestion GI	*1.904E-08*	*1.068E-08*	*6.465E-09*	*0.0*
Total bone	*5.046E-08*	*3.992E-08*	*7.369E-08*	*0.0*
Total liver	*7.229E-08*	*5.641E-08*	*7.550E-08*	*0.0*
Total whole body	*4.136E-08*	*3.361E-08*	*5.696E-08*	*0.0*
Total thyroid	*2.365E-05*	*1.627E-05*	*2.455E-05*	*0.0*
Total kidney	*1.237E-07*	*7.311E-08*	*4.611E-08*	*0.0*
Total lung	*0.0*	*0.0*	*0.0*	*0.0*
Total GI	*1.904E-08*	*1.068E-08*	*6.465E-09*	*0.0*
Gamma air	*4.298E-01*	*4.298E-01*	*4.298E-01*	*4.298E-01*
Beta air	*9.700E-03*	*9.700E-03*	*9.700E-03*	*9.700E-03*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-29

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR SE SECTOR AT DISTANCE 3.7 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
DESIGN BASIS CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*2.200E-09*	*3.569E-09*	*8.620E-09*	*0.0*
Ingestion liver	*3.152E-09*	*5.043E-09*	*8.832E-09*	*0.0*
Ingestion whole body	*1.803E-09*	*3.005E-09*	*6.664E-09*	*0.0*
Ingestion thyroid	*1.031E-06*	*1.454E-06*	*2.872E-06*	*0.0*
Ingestion kidney	*5.394E-09*	*6.535E-09*	*5.394E-09*	*0.0*
Ingestion lung	*0.0*	*0.0*	*0.0*	*0.0*
Ingestion GI	*8.303E-10*	*9.547E-10*	*7.563E-10*	*0.0*
Total bone	*2.200E-09*	*3.569E-09*	*8.620E-09*	*0.0*
Total liver	*3.152E-09*	*5.043E-09*	*8.832E-09*	*0.0*
Total whole body	*1.803E-09*	*3.005E-09*	*6.664E-09*	*0.0*
Total thyroid	*1.031E-06*	*1.454E-06*	*2.872E-06*	*0.0*
Total kidney	*5.394E-09*	*6.535E-09*	*5.394E-09*	*0.0*
Total lung	*0.0*	*0.0*	*0.0*	*0.0*
Total GI	*8.303E-10*	*9.547E-10*	*7.563E-10*	*0.0*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-30

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR NW SECTOR AT DISTANCE 0.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*6.470E-02*	*5.040E-02*	*8.703E-02*	*0.0*
Ingestion liver	*1.065E-01*	*8.164E-02*	*1.019E-01*	*0.0*
Ingestion whole body	*8.301E-02*	*4.040E-02*	*3.180E-02*	*0.0*
Ingestion thyroid	*2.400E-01*	*1.651E-01*	*2.491E-01*	*0.0*
Ingestion kidney	*3.293E-02*	*1.946E-02*	*1.227E-02*	*0.0*
Ingestion lung	*1.215E-02*	*1.041E-02*	*1.146E-02*	*0.0*
Ingestion GI	*1.136E-01*	*5.889E-02*	*3.272E-02*	*0.0*
Total bone	*6.470E-02*	*5.040E-02*	*8.703E-02*	*0.0*
Total liver	*1.065E-01*	*8.164E-02*	*1.019E-01*	*0.0*
Total whole body	*8.301E-02*	*4.040E-02*	*3.180E-02*	*0.0*
Total thyroid	*2.400E-01*	*1.651E-01*	*2.491E-01*	*0.0*
Total kidney	*3.293E-02*	*1.946E-02*	*1.227E-02*	*0.0*
Total lung	*1.215E-02*	*1.041E-02*	*1.146E-02*	*0.0*
Total GI	*1.136E-01*	*5.889E-02*	*3.272E-02*	*0.0*
Gamma air	*7.859E-01*	*7.859E-01*	*7.859E-01*	*7.859E-01*
Beta air	*2.496E-01*	*2.496E-01*	*2.496E-01*	*2.496E-01*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-31

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR NW SECTOR AT DISTANCE 3.6 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*3.185E-02*	*5.189E-02*	*1.052E-01*	*0.0*
Ingestion liver	*3.432E-02*	*5.455E-02*	*9.099E-02*	*0.0*
Ingestion whole body	*2.788E-02*	*2.742E-02*	*2.522E-02*	*0.0*
Ingestion thyroid	*3.039E-03*	*4.286E-03*	*8.463E-03*	*0.0*
Ingestion kidney	*1.127E-02*	*1.365E-02*	*1.127E-02*	*0.0*
Ingestion lung	*3.721E-02*	*1.365E-02*	*1.127E-02*	*0.0*
Ingestion GI	*1.088E-02*	*1.168E-02*	*8.568E-03*	*0.0*
Total bone	*3.185E-02*	*5.189E-02*	*1.052E-01*	*0.0*
Total liver	*3.432E-02*	*5.455E-02*	*9.099E-02*	*0.0*
Total whole body	*2.788E-02*	*2.742E-02*	*2.522E-02*	*0.0*
Total thyroid	*3.039E-03*	*4.286E-03*	*8.463E-03*	*0.0*
Total kidney	*1.127E-02*	*1.365E-02*	*1.127E-02*	*0.0*
Total lung	*3.721E-03*	*6.847E-03*	*1.030E-02*	*0.0*
Total GI	*1.088E-02*	*1.168E-02*	*8.568E-03*	*0.0*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-32

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR NNW SECTOR AT DISTANCE 0.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*3.396E-02*	*2.645E-02*	*4.568E-02*	*0.0*
Ingestion liver	*5.590E-02*	*4.285E-02*	*5.346E-02*	*0.0*
Ingestion whole body	*4.357E-02*	*2.120E-02*	*1.669E-02*	*0.0*
Ingestion thyroid	*1.260E-01*	*8.665E-02*	*1.307E-01*	*0.0*
Ingestion kidney	*1.728E-02*	*1.021E-02*	*6.442E-03*	*0.0*
Ingestion lung	*6.378E-03*	*5.463E-03*	*6.017E-03*	*0.0*
Ingestion GI	*5.964E-02*	*3.091E-02*	*1.717E-02*	*0.0*
Total bone	*3.396E-02*	*2.645E-02*	*4.568E-02*	*0.0*
Total liver	*5.590E-02*	*4.285E-02*	*5.346E-02*	*0.0*
Total whole body	*4.357E-02*	*2.120E-02*	*1.669E-02*	*0.0*
Total thyroid	*1.260E-01*	*8.665E-02*	*1.307E-01*	*0.0*
Total kidney	*1.728E-02*	*1.021E-02*	*6.442E-03*	*0.0*
Total lung	*6.378E-03*	*5.463E-03*	*6.017E-03*	*0.0*
Total GI	*5.964E-02*	*3.091E-02*	*1.717E-02*	*0.0*
Gamma air	*4.312E-01*	*4.312E-01*	*4.312E-01*	*4.312E-01*
Beta air	*1.370E-01*	*1.370E-01*	*1.370E-01*	*1.370E-01*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-33

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR NNW SECTOR AT DISTANCE 1.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Inhalation bone	*1.892E-03*	*1.164E-03*	*1.037E-03*	*1.221E-03*
Inhalation liver	*6.453E-03*	*4.281E-03*	*3.282E-03*	*3.440E-03*
Inhalation whole body	*3.269E-03*	*1.809E-03*	*1.646E-03*	*1.686E-03*
Inhalation thyroid	*1.736E-02*	*1.368E-02*	*1.719E-02*	*2.823E-02*
Inhalation kidney	*3.043E-03*	*2.126E-03*	*1.125E-03*	*7.919E-04*
Inhalation lung	*7.415E-03*	*6.104E-03*	*5.589E-03*	*7.540E-03*
Inhalation GI	*3.073E-03*	*1.751E-03*	*1.594E-03*	*1.630E-03*
External whole body	*2.043E-01*	*2.043E-01*	*2.043E-01*	*2.043E-01*
External skin	*2.950E-01*	*2.950E-01*	*2.950E-01*	*2.950E-01*
Total bone	*2.062E-01*	*2.054E-01*	*2.053E-01*	*2.055E-01*
Total liver	*2.107E-01*	*2.085E-01*	*2.075E-01*	*2.077E-01*
Total whole body	*2.075E-01*	*2.061E-01*	*2.059E-01*	*2.059E-01*
Total thyroid	*2.216E-01*	*2.179E-01*	*2.214E-01*	*2.325E-01*
Total kidney	*2.073E-01*	*2.064E-01*	*2.054E-01*	*2.050E-01*
Total lung	*2.117E-01*	*2.104E-01*	*2.098E-01*	*2.118E-01*
Total GI	*2.073E-01*	*2.060E-01*	*2.059E-01*	*2.059E-01*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-34

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR NNW SECTOR AT DISTANCE 3.6 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*1.672E-02*	*2.723E-02*	*5.521E-02*	*0.0*
Ingestion liver	*1.801E-02*	*2.863E-02*	*4.776E-02*	*0.0*
Ingestion whole body	*1.463E-02*	*1.439E-02*	*1.324E-02*	*0.0*
Ingestion thyroid	*1.594E-03*	*2.248E-03*	*4.439E-03*	*0.0*
Ingestion kidney	*5.915E-03*	*7.166E-03*	*5.915E-03*	*0.0*
Ingestion lung	*1.953E-03*	*3.594E-03*	*5.404E-03*	*0.0*
Ingestion GI	*5.711E-03*	*6.131E-03*	*4.497E-03*	*0.0*
Total bone	*1.672E-02*	*2.723E-02*	*5.521E-02*	*0.0*
Total liver	*1.801E-02*	*2.863E-02*	*4.776E-02*	*0.0*
Total whole body	*1.463E-02*	*1.439E-02*	*1.324E-02*	*0.0*
Total thyroid	*1.594E-03*	*2.248E-03*	*4.439E-03*	*0.0*
Total kidney	*5.915E-03*	*7.166E-03*	*5.915E-03*	*0.0*
Total lung	*1.953E-03*	*3.594E-03*	*5.404E-03*	*0.0*
Total GI	*5.711E-03*	*6.131E-03*	*4.497E-03*	*0.0*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-35

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR N SECTOR AT DISTANCE 0.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*1.403E-02*	*1.093E-02*	*1.887E-02*	*0.0*
Ingestion liver	*2.309E-02*	*1.770E-02*	*2.209E-02*	*0.0*
Ingestion whole body	*1.800E-02*	*8.761E-03*	*6.895E-03*	*0.0*
Ingestion thyroid	*5.204E-02*	*3.580E-02*	*5.401E-02*	*0.0*
Ingestion kidney	*7.140E-03*	*4.219E-03*	*2.661E-03*	*0.0*
Ingestion lung	*2.635E-03*	*2.257E-03*	*2.486E-03*	*0.0*
Ingestion GI	*2.464E-02*	*1.277E-02*	*7.096E-03*	*0.0*
Total bone	*1.403E-02*	*1.093E-02*	*1.887E-02*	*0.0*
Total liver	*2.309E-02*	*1.770E-02*	*2.209E-02*	*0.0*
Total whole body	*1.800E-02*	*8.761E-03*	*6.895E-03*	*0.0*
Total thyroid	*5.204E-02*	*3.580E-02*	*5.401E-02*	*0.0*
Total kidney	*7.140E-03*	*4.219E-03*	*2.661E-03*	*0.0*
Total lung	*2.635E-03*	*2.257E-03*	*2.486E-03*	*0.0*
Total GI	*2.464E-02*	*1.277E-02*	*7.096E-03*	*0.0*
Gamma air	*2.452E-01*	*2.452E-01*	*2.452E-01*	*2.452E-01*
Beta air	*7.789E-02*	*7.789E-02*	*7.789E-02*	*7.789E-02*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-36

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR NNE SECTOR AT DISTANCE 0.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*8.356E-03*	*6.509E-03*	*1.124E-02*	*0.0*
Ingestion liver	*1.375E-02*	*1.054E-02*	*1.315E-02*	*0.0*
Ingestion whole body	*1.072E-02*	*5.217E-03*	*4.106E-03*	*0.0*
Ingestion thyroid	*3.099E-02*	*2.131E-02*	*3.216E-02*	*0.0*
Ingestion kidney	*4.252E-03*	*2.513E-03*	*1.585E-03*	*0.0*
Ingestion lung	*1.569E-03*	*1.344E-03*	*1.481E-03*	*0.0*
Ingestion GI	*1.468E-02*	*7.605E-03*	*4.226E-03*	*0.0*
Total bone	*8.356E-03*	*6.509E-03*	*1.124E-02*	*0.0*
Total liver	*1.375E-02*	*1.054E-02*	*1.315E-02*	*0.0*
Total whole body	*1.072E-02*	*5.217E-03*	*4.106E-03*	*0.0*
Total thyroid	*3.099E-02*	*2.131E-02*	*3.216E-02*	*0.0*
Total kidney	*4.252E-03*	*2.513E-03*	*1.585E-03*	*0.0*
Total lung	*1.569E-03*	*1.344E-03*	*1.481E-03*	*0.0*
Total GI	*1.468E-02*	*7.605E-03*	*4.226E-03*	*0.0*
Gamma air	*1.214E-01*	*1.214E-01*	*1.214E-01*	*1.214E-01*
Beta air	*3.855E-02*	*3.855E-02*	*3.855E-02*	*3.855E-02*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-37

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR NE SECTOR AT DISTANCE 0.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*1.055E-02*	*8.215E-03*	*1.418E-02*	*0.0*
Ingestion liver	*1.736E-02*	*1.331E-02*	*1.660E-02*	*0.0*
Ingestion whole body	*1.353E-02*	*6.585E-03*	*5.182E-03*	*0.0*
Ingestion thyroid	*3.911E-02*	*2.690E-02*	*4.059E-02*	*0.0*
Ingestion kidney	*5.367E-03*	*3.171E-03*	*2.000E-03*	*0.0*
Ingestion lung	*1.980E-03*	*1.696E-03*	*1.868E-03*	*0.0*
Ingestion GI	*1.852E-02*	*9.598E-03*	*5.333E-03*	*0.0*
Total bone	*1.055E-02*	*8.215E-03*	*1.418E-02*	*0.0*
Total liver	*1.736E-02*	*1.331E-02*	*1.660E-02*	*0.0*
Total whole body	*1.353E-02*	*6.585E-03*	*5.182E-03*	*0.0*
Total thyroid	*3.911E-02*	*2.690E-02*	*4.059E-02*	*0.0*
Total kidney	*5.367E-03*	*3.171E-03*	*2.000E-03*	*0.0*
Total lung	*1.980E-03*	*1.696E-03*	*1.868E-03*	*0.0*
Total GI	*1.852E-02*	*9.598E-03*	*5.333E-03*	*0.0*
Gamma air	*8.058E-02*	*8.058E-02*	*8.058E-02*	*8.058E-02*
Beta air	*2.559E-02*	*2.559E-02*	*2.559E-02*	*2.559E-02*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-38

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR ENE SECTOR AT DISTANCE 0.7 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*4.508E-03*	*3.512E-03*	*6.064E-03*	*0.0*
Ingestion liver	*7.420E-03*	*5.688E-03*	*7.097E-03*	*0.0*
Ingestion whole body	*5.784E-03*	*2.815E-03*	*2.215E-03*	*0.0*
Ingestion thyroid	*1.671E-02*	*1.150E-02*	*1.735E-02*	*0.0*
Ingestion kidney	*2.294E-03*	*1.356E-03*	*8.551E-04*	*0.0*
Ingestion lung	*8.467E-04*	*7.252E-04*	*7.988E-04*	*0.0*
Ingestion GI	*7.918E-03*	*4.103E-03*	*2.280E-03*	*0.0*
Total bone	*4.508E-03*	*3.512E-03*	*6.064E-03*	*0.0*
Total liver	*7.420E-03*	*5.688E-03*	*7.097E-03*	*0.0*
Total whole body	*5.784E-03*	*2.815E-03*	*2.215E-03*	*0.0*
Total thyroid	*1.671E-02*	*1.150E-02*	*1.735E-02*	*0.0*
Total kidney	*2.294E-03*	*1.356E-03*	*8.551E-04*	*0.0*
Total lung	*8.467E-04*	*7.252E-04*	*7.988E-04*	*0.0*
Total GI	*7.918E-03*	*4.103E-03*	*2.280E-03*	*0.0*
Gamma air	*4.566E-02*	*4.566E-02*	*4.566E-02*	*4.566E-02*
Beta air	*1.450E-02*	*1.450E-02*	*1.450E-02*	*1.450E-02*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-39

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR ENE SECTOR AT DISTANCE 4.5 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Inhalation bone	*6.802E-05*	*4.186E-05*	*3.728E-05*	*4.388E-05*
Inhalation liver	*2.320E-04*	*1.539E-04*	*1.180E-04*	*1.236E-04*
Inhalation whole body	*1.175E-04*	*6.502E-05*	*5.915E-05*	*6.060E-05*
Inhalation thyroid	*6.241E-04*	*4.919E-04*	*6.180E-04*	*1.015E-03*
Inhalation kidney	*1.094E-04*	*7.641E-05*	*4.045E-05*	*2.847E-05*
Inhalation lung	*2.665E-04*	*2.194E-04*	*2.009E-04*	*2.710E-04*
Inhalation GI	*1.105E-04*	*6.296E-05*	*5.729E-05*	*5.859E-05*
External whole body	*6.780E-03*	*6.780E-03*	*6.780E-03*	*6.780E-03*
External skin	*1.031E-02*	*1.031E-02*	*1.031E-02*	*1.031E-02*
Total bone	*6.848E-03*	*6.822E-03*	*6.817E-03*	*6.824E-03*
Total liver	*7.012E-03*	*6.934E-03*	*6.898E-03*	*6.903E-03*
Total whole body	*6.897E-03*	*6.845E-03*	*6.839E-03*	*6.840E-03*
Total thyroid	*7.404E-03*	*7.272E-03*	*7.398E-03*	*7.795E-03*
Total kidney	*6.889E-03*	*6.856E-03*	*6.820E-03*	*6.808E-03*
Total lung	*7.046E-03*	*6.999E-03*	*6.981E-03*	*7.051E-03*
Total GI	*6.890E-03*	*6.843E-03*	*6.837E-03*	*6.838E-03*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-40

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR E SECTOR AT DISTANCE 1 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*4.214E-03*	*3.283E-03*	*5.668E-03*	*0.0*
Ingestion liver	*6.936E-03*	*5.317E-03*	*6.634E-03*	*0.0*
Ingestion whole body	*5.406E-03*	*2.631E-03*	*2.071E-03*	*0.0*
Ingestion thyroid	*1.562E-02*	*1.074E-02*	*1.621E-02*	*0.0*
Ingestion kidney	*2.144E-03*	*1.267E-03*	*7.993E-04*	*0.0*
Ingestion lung	*7.914E-04*	*6.779E-04*	*7.467E-04*	*0.0*
Ingestion GI	*7.401E-03*	*3.835E-03*	*2.131E-03*	*0.0*
Total bone	*4.214E-03*	*3.283E-03*	*5.668E-03*	*0.0*
Total liver	*6.936E-03*	*5.317E-03*	*6.634E-03*	*0.0*
Total whole body	*5.406E-03*	*2.631E-03*	*2.071E-03*	*0.0*
Total thyroid	*1.562E-02*	*1.074E-02*	*1.621E-02*	*0.0*
Total kidney	*2.144E-03*	*1.267E-03*	*7.993E-04*	*0.0*
Total lung	*7.914E-04*	*6.779E-04*	*7.467E-04*	*0.0*
Total GI	*7.401E-03*	*3.835E-03*	*2.131E-03*	*0.0*
Gamma air	*5.322E-02*	*5.322E-02*	*5.322E-02*	*5.322E-02*
Beta air	*1.690E-02*	*1.690E-02*	*1.690E-02*	*1.690E-02*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-41

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR ESE SECTOR AT DISTANCE 1 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*2.163E-02*	*1.685E-02*	*2.909E-02*	*0.0*
Ingestion liver	*3.560E-02*	*2.729E-02*	*3.404E-02*	*0.0*
Ingestion whole body	*2.775E-02*	*1.350E-02*	*1.063E-02*	*0.0*
Ingestion thyroid	*8.020E-02*	*5.517E-02*	*8.324E-02*	*0.0*
Ingestion kidney	*1.101E-02*	*6.503E-03*	*4.102E-03*	*0.0*
Ingestion lung	*4.061E-03*	*3.479E-03*	*3.832E-03*	*0.0*
Ingestion GI	*3.798E-02*	*1.968E-02*	*1.094E-02*	*0.0*
Total bone	*2.163E-02*	*1.685E-02*	*2.909E-02*	*0.0*
Total liver	*3.560E-02*	*2.729E-02*	*3.404E-02*	*0.0*
Total whole body	*2.775E-02*	*1.350E-02*	*1.063E-02*	*0.0*
Total thyroid	*8.020E-02*	*5.517E-02*	*8.324E-02*	*0.0*
Total kidney	*1.101E-02*	*6.503E-03*	*4.102E-03*	*0.0*
Total lung	*4.061E-03*	*3.479E-03*	*3.832E-03*	*0.0*
Total GI	*3.798E-02*	*1.968E-02*	*1.094E-02*	*0.0*
Gamma air	*2.586E-01*	*2.586E-01*	*2.586E-01*	*2.586E-01*
Beta air	*8.215E-02*	*8.215E-02*	*8.215E-02*	*8.215E-02*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-42

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR ESE SECTOR AT DISTANCE 3.7 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*3.101E-02*	*5.052E-02*	*1.024E-01*	*0.0*
Ingestion liver	*3.341E-02*	*5.311E-02*	*8.859E-02*	*0.0*
Ingestion whole body	*2.714E-02*	*2.669E-02*	*2.456E-02*	*0.0*
Ingestion thyroid	*2.959E-03*	*4.173E-03*	*8.239E-03*	*0.0*
Ingestion kidney	*1.097E-02*	*1.329E-02*	*1.097E-02*	*0.0*
Ingestion lung	*3.623E-03*	*6.667E-03*	*1.003E-02*	*0.0*
Ingestion GI	*1.059E-02*	*1.137E-02*	*8.341E-03*	*0.0*
Total bone	*3.101E-02*	*5.052E-02*	*1.024E-01*	*0.0*
Total liver	*3.341E-02*	*5.311E-02*	*8.859E-02*	*0.0*
Total whole body	*2.714E-02*	*2.669E-02*	*2.456E-02*	*0.0*
Total thyroid	*2.959E-03*	*4.173E-03*	*8.239E-03*	*0.0*
Total kidney	*1.097E-02*	*1.329E-02*	*1.097E-02*	*0.0*
Total lung	*3.623E-03*	*6.667E-03*	*1.003E-02*	*0.0*
Total GI	*1.059E-02*	*1.137E-02*	*8.341E-03*	*0.0*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-43

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR SE SECTOR AT DISTANCE 1.1 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*7.411E-02*	*5.773E-02*	*9.968E-02*	*0.0*
Ingestion liver	*1.220E-01*	*9.351E-02*	*1.167E-01*	*0.0*
Ingestion whole body	*9.508E-02*	*4.627E-02*	*3.642E-02*	*0.0*
Ingestion thyroid	*2.749E-01*	*1.891E-01*	*2.853E-01*	*0.0*
Ingestion kidney	*3.771E-02*	*2.229E-02*	*1.406E-02*	*0.0*
Ingestion lung	*1.392E-02*	*1.192E-02*	*1.313E-02*	*0.0*
Ingestion GI	*1.302E-01*	*6.745E-02*	*3.748E-02*	*0.0*
Total bone	*7.411E-02*	*5.773E-02*	*9.968E-02*	*0.0*
Total liver	*1.220E-01*	*9.351E-02*	*1.167E-01*	*0.0*
Total whole body	*9.508E-02*	*4.627E-02*	*3.642E-02*	*0.0*
Total thyroid	*2.749E-01*	*1.891E-01*	*2.853E-01*	*0.0*
Total kidney	*3.771E-02*	*2.229E-02*	*1.406E-02*	*0.0*
Total lung	*1.392E-02*	*1.192E-02*	*1.313E-02*	*0.0*
Total GI	*1.302E-01*	*6.745E-02*	*3.748E-02*	*0.0*
Gamma air	*6.566E-01*	*6.566E-01*	*6.566E-01*	*6.566E-01*
Beta air	*2.085E-01*	*2.085E-01*	*2.085E-01*	*2.085E-01*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.3-44

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

OFFSITE DOSES FOR SE SECTOR AT DISTANCE 3.7 MI
(MREM/YEAR - AIR DOSES IN MRAD/YEAR)
NORMAL OPERATION CASE

Dose	*Adult*	*Teen*	*Child*	*Infant*
Ingestion bone	*1.255E-01*	*2.044E-01*	*4.144E-01*	*0.0*
Ingestion liver	*1.352E-01*	*2.149E-01*	*3.584E-01*	*0.0*
Ingestion whole body	*1.098E-01*	*1.080E-01*	*9.935E-02*	*0.0*
Ingestion thyroid	*1.199E-02*	*1.690E-02*	*3.338E-02*	*0.0*
Ingestion kidney	*4.439E-02*	*5.378E-02*	*4.439E-02*	*0.0*
Ingestion lung	*1.466E-02*	*2.697E-02*	*4.056E-02*	*0.0*
Ingestion GI	*4.286E-02*	*4.602E-02*	*3.375E-02*	*0.0*
Total bone	*1.255E-01*	*2.044E-01*	*4.144E-01*	*0.0*
Total liver	*1.352E-01*	*2.149E-01*	*3.584E-01*	*0.0*
Total whole body	*1.098E-01*	*1.080E-01*	*9.935E-02*	*0.0*
Total thyroid	*1.199E-02*	*1.690E-02*	*3.338E-02*	*0.0*
Total kidney	*4.439E-02*	*5.378E-02*	*4.439E-02*	*0.0*
Total lung	*1.466E-02*	*2.697E-02*	*4.056E-02*	*0.0*
Total GI	*4.286E-02*	*4.602E-02*	*3.375E-02*	*0.0*

Note: The information presented in the above table was developed in support of the original license and is considered historical.

Table 11.4-1

RADIATION MONITORS AND READOUTS

RMS Channel	RMS Description	Elevation	Range	Detector Type	Location	Unit(e) No.	Indication	Readout(s) Location	Recorder	Location
R -1	Control room area monitor	140 ft	0.1 to E4 mR/hr	G-M	NE area rad rack behind main control panel	0 0	RI-1 RM-1	Local RNRMA	RR-1	RNRMA
R -2	Containment area monitor	140 ft	0.1 to E4 mR/hr	G-M	West containment wall at personnel hatch	1 1 2 2	RI-2 RM-2 RI-2 RM-2	Local RNRMA Local RNRMC	RR-2 RR-2	RNRMA RNRMC
R -3	Oily water separator effluent monitor	85 ft	10 to E6 cpm	Gamma Scint.	Oily water separator room	0	RM-3	RNRMA	RR-3	RNRMA
R -4	Centrifugal charging pump CCP3 (room #2) monitor	73 ft	0.1 to E4 mR/hr	G-M	SE corner at charging pump 1-3, pump outside of SE corner (N-wall at charging pump 2-3)	1 1 2 2	RI-4 RM-4 RI-4 RM-4	Local RNRMA Local RNRMC	RR-4 RR-4	RNRMA RNRMC
R -6	NSSS sampling room area monitor	100 ft	0.1 to E4 mR/hr	G-M	SW corner on U-1 (NW corner on U-2)	1 1 2 2	RI-6 RM-6 RI-6 RM-6	Local RNRMA Local RNRMC	RR-6 RR-6	RNRMA RNRMC
R -7	Incore seal table area monitor	115 ft	0.1 to E4 mR/hr	G-M	South hatch at upper internals laydown area on U-1 (North on U-2)	1 1 2 2	RI-7 RM-7 RI-7 RM-7	Local RNRMA Local RNRMC	RR-7 RR-7	RNRMA RNRMC
R -10	Auxiliary building control board digital system area monitor	85 ft	0.1 to E4 mR/hr	G-M	South wall	0 0	RI-10 RM-10	Local RNRMA	RR-10	RNRMA
R -11	Containment air particulate monitor	100 ft	10 to E6 cpm	Gamma Scint.	Area GE	1 2	RM -11 RM -11	RNRMB RNRMD	RR-11 RR-11	RNRMA RNRMC
R -12	Containment air radioactive gas monitor	100 ft	10 to E6 cpm	G-M	Area GE	1 2	RM -12 RM -12	RNRMB RNRMD	RR-12 RR-12	RNRMA RNRMC
R -13	RHR exhaust duct air particulate monitor	100 ft	10 to E6 cpm	Gamma Scint	Wall in north corridor at RHR ht exchg.area - area K for U-1 (South for U-2)	1 2	RM -13 RM -13	RNRMB RNRMD	RR-13 RR-13	RNRMA RNRMC

Table 11.4-1

RMS Channel	RMS Description	Elevation	Range	Detector Type	Location	Unit(e) No.	Indication	Readout(s) Location	Recorder	Location
R -14 and R-14R	Plant vent radioactive gas monitors	85ft	10 to 5E6 cpm	Beta Scint	Plant vent at NE wall/ penetration room - area L for U-1 (SE for U-2)	1 1 2 2	RM-14 RM-14R RM-14 RM-14R	RNRMS3 RNRMS4 RNRMS3 RNRMS4	EARS EARS EARS EARS	TSC TSC TSC TSC
R -15 and R-15R	Steam jet air ejector radioactive gas dischg. monitors	104ft	10 to 5E6 cpm	Beta Scint.	Turb. Bldg., Area C on wall at Col. line 10 between Col. lines C&D for U-1 (line 26 for U-2)	1 1 2 2	RM-15 RM-15R RM-15 RM-15R	RNRMS4 RNRMS4 RNRMS4 RNRMS4	EARS EARS EARS EARS	TSC TSC TSC TSC
R -17A and R -17B	CCW discharge header effluent monitors	73 ft	10 to E6 cpm	Gamma Scint.	Outside door on wall at component cooling pump room	1 1 2 2	RM -17A RM -17B RM -17A RM -17B	RNRMB RNRMB RNRMD RNRMD	RR-17A RR-17B RR-17A RR-17B	RNRME RNRME RNRMC RNRMC
R -18	Liquid radwaste discharge line effluent monitor	55 ft	10 to E6 cpm	Gamma Scint.	Pipe tunnel from radwaste (north corridor)	0	RM -18	RNRME	RR-18	RNRME
R -19	Steam generator blowdown sample effluent monitor	100 ft	10 to E6 cpm	Gamma Scint.	SE side of containment structure/penetration room - area GE for U-1 (NE for U-2)	1 1 2 2	RI-19 RM -19A RI-19 RM -19A	SGSP RNRMB SGSP RNRMD	RR-19 RR-19	RNRME RNRMC
R -22	Gas decay tank radioactive gas discharge monitor	55 ft	10 to E6 cpm	G-M	Pipe tunnel	1 2	RM-22 RM-22	RNRME RNRMC	RR-22 RR-22	RNRME RNRMC
R -23	Steam generator blowdown tank effluent to out-fall monitor	100 ft	1 to E6 cpm	Gamma Scint.	Area GE	1 1 2 2	RI-23 RI-23	PM205 PM205	RR-23 RR-23A RR-23 RR-23A	PM205 RNRME PM205 RNRMC
R -24 and R-24R	Plant vent iodine monitor	85ft	10 to 5E6 cpm	Gamma Scint.	Plant vent at area L	1 1 2 2	RM-24 RM-24R RM-24 RM-24R	RNRMS3 RNRMS4 RNRMS3 RNRMS4	EARS EARS EARS EARS	TSC TSC TSC TSC
R -25	Main control room air intake monitor	160 ft	0.01 to E3 mR/hr	Gamma Scint.	Auxiliary bldg. control room air intake	1 2	RI-25 RI-25	RCRM RCRM	-	-
R -26	Main control room air intake monitor	160 ft	0.01 to E3 mR/hr	Gamma Scint.	Auxiliary bldg. control room air intake	1 2	RI-26 RI-26	RCRM RCRM	-	-

Table 11.4-1

RMS Channel	RMS Description	Elevation	Range	Detector Type	Location	Unit(e) No.	Indication	Readout(s) Location	Recorder	Location
R -28 and R-28R	Plant vent air particulate monitors	85ft	10 to 5E6 cpm	Beta Scint.	Plant vent at NE wall to containment structure/penetration room - area L, for U-1 (SE for U-2)	1 1 2 2	RM-28 RM-28R RM-28 RM-28R	RNRMS3 RNRMS4 RNRMS3 RNRMS4	EARS EARS EARS EARS	TSC TSC TSC TSC
R -29	Plant vent high radiation gross gamma monitor	155 ft	0.1 to E7 mR/hr	ION	Plant vent on platform on NW side of duct for U-1 (SW for U-2)	1 2	RI-29 RI-29	PAM-2 PAM-2	RR-29 RR-29	PAM-2 PAM-2
R -30	Containment high range area radiation monitor - 1	140 ft	1 to E7 R/hr	ION	East stairway	1 2	RI-30 RI-30	PAM-2 PAM-2	RR-30 RR-30	PAM-1 PAM-1
R -31	Containment high range area radiation monitor - 2	140 ft	1 to E7 R/hr	ION	West stairway	1 2	RI-31 RI-31	PAM-2 PAM-2	RR-31 RR-31	PAM-1 PAM-1
R -34	Area Monitor for Plant Vent Monitoring Skid	85ft	0.1 to E7 mR/hr	ION	Plant vent at NE wall penetration room - Area L for U-1 (SE for U-2)	1 1 2 2	RC-22 RI-34 RC-22 RI-34	Local Local Local Local	RR-34 RR-34	PAM-2 PAM-2
R-41	Gas decay tank cubicle radiation monitor (1-1, 2-1) -	64 ft	1 to E4 mR/hr	ION	Gas decay tank 1	1 2 2	RI-41 RI-41	ABCBDS ABCBDS	-	-
R-42	Gas decay tank cubicle radiation monitor (1-2, 2-2)	64 ft	1 to E4 mR/hr	ION	Gas decay tank 2	1 2	RI-42 RI-42	ABCBDS ABCBDS	-	-
R-43	Gas decay tank cubicle radiation monitor (1-3, 2-3)	64 ft	1 to E4 mR/hr	ION	Gas decay tank 3	1 2	RI-43 RI-43	ABCBDS ABCBDS	-	-
R-44A and R-44B	Containment Purge Exhaust	100 ft	10 to 5E6 cpm	Beta Scint.	Area L	1 1 2 2	RM-44A RM-44B RM-44A RM-44B	RNRMS1 RNRMS2 RNRMS1 RNRMS2	EARS EARS EARS EARS	TSC TSC TSC TSC
R -48	HRSS (Sentry) post-accident sampling room	85 ft	0.1 to E7 mR/hr	ION	HRSS	1 2	RI-48 RI-48	POPLSI POPLSI	-	-

Table 11.4-1

RMS Channel	RMS Description	Elevation	Range	Detector Type	Location	Unit[e] No.	Indication	Readout(s) Location	Recorder	Location
R -51	Control room pressurization system ventilation intake air monitor	140ft	0.01 to E4 mR/hr	G-M	NW corner of turbine building	1	RI-51	RCRM	-	-
R -52	Control room pressurization system ventilation intake air monitor	140 ft	0.01 to E4 mR/hr	G-M	NW corner of turbine building	1	RI-52	RCRM	-	-
R -53	Control room pressurization system ventilation intake air monitor	140ft	0.01 to E4 mR/hr	G-M	SW corner of turbine building	2	RI-53	RCRM	-	-
R -54	Control room pressurization system ventilation intake air monitor	140 ft	0.01 to E4 mR/hr	G-M	SW corner of turbine building	2	RI-54	RCRM	-	-
R -58	Spent Fuel Pool Area Monitor	140 ft	0.1 to E4 mR/hr	G-M	West wall column line 11[1] and 25[1]	1 1 2 2	RI-58 RI-58A RI-58 RI-58A	Local PAM-2 Local PAM-2	RR-58 RR-58	RNRMA RNRMC
R -59	New Fuel Storage Area Monitor	140 ft	0.1 to E4 mR/hr	G-M	West wall column line 15[3] and 20[3]	1 1 2 2	RI-59 RI-59A RI-59 RI-59A	Local PAM-2 Local PAM-2	RR-59 RR-59	RNRMA RNRMC
R -60	TSC-Office Area Radiation Monitor	104 ft	0.1 to E4 mR/hr	G-M	East wall at exit door	0	RI-60	Local	RR-60	Local
R -61	TSC-Operations/RMS Area Monitor	104 ft	0.1 to E4 mR/hr	G-M	South wall at doorway	0	RI-61	Local	RR-61	Local
R -62	TSC-Computations Center Area Monitor	104 ft	0.1 to E4 mR/hr	G-M	South wall at doorway	0	RI-62	Local	RR-62	Local
R -63	TSC-OSC Area Monitor	104 ft	0.1 to E4 mR/hr	G-M	North wall at doorway	0	RI-63	Local	RR-63	Local
R -64	TSC-HVAC Equipment room area monitor	104 ft	0.1 to E4 mR/hr	G-M	East wall at midpoint	0	RI-64	Local	RR-64	Local
R -65	TSC-laboratory area monitor	104 ft	0.1 to E4 mR/hr	G-M	North wall at midpoint	0	RI-65	Local	RR-65	Local

Table 11.4-1

RMS Channel	RMS Description	Elevation	Range	Detector Type	Location	Unit[e] No.	Indication	Readout(s) Location	Recorder	Location
R -66	TSC-air particulate monitor	104 ft	10 to E6 cpm	Beta Scint.	TSC-HVAC equipment room	0	RI-66	Local	RR-66	Local
R -67	TSC-noble gas monitor	104 ft	10 to E6 cpm	Beta Scint.	TSC-HVAC equipment room	0	RI-67	Local	RR-67	Local
R -68	TSC-laboratory air particulate monitor	104 ft	10 to E6 cpm	Beta Scint.	TSC-HVAC equipment room	0	RI-68	Local	RR-68	Local
R -69	TSC-laboratory noble gas monitor	104 ft	10 to E6 cpm	Beta Scint.	TSC-HVAC equipment room	0	RI-69	Local	RR-69	Local
R -71	Main steam line noble gas radiation monitor (lead 1)	130 ft	10 to E6 cpm	G-M	Outside NW side of containment - area FW for U-1 (SW for U-2)	1 2	RI-71 RI-71	RNGFFD RNGFFD	RR-71 RR-71	RNRME RNRMC
R-72	Main steam line noble gas radiation monitor (lead 2)	130 ft	10 to E6 cpm	G-M	Outside NW side of containment - area FW for U-1 (SW for U-2)	1 2	RI-72 RI-72	RNGFFD RNGFFD	RR-72 RR-72	RNRME RNRMC
R-73	Main steam line noble gas radiation monitor (lead 3)	130 ft	10 to E6 cpm	G-M	Outside containment area GW	1 2	RI-73 RI-73	RNGFFD RNGFFD	RR-73 RR-73	RNRME RNRMC
R-74	Main steam line noble gas radiation monitor (lead 4)	130 ft	10 to E6 cpm	G-M	Outside containment area GW	1 2	RI-74 RI-74	RNGFFD RNGFFD	RR-74 RR-74	RNRME RNRMC
R-82	TSC-iodine monitor	104 ft	10 to E6 cpm	Gamma Scint.	TSC-HVAC equipment room	0	RI-82	Local	RR-82	RMPTSC
R-83	TSC-laboratory iodine monitor	104 ft	10 to E6 cpm	Gamma Scint.	TSC-HVAC equipment room	0	RI-83	Local	RR-83	RMPTSC
R-84	Contact inspection station radiation monitor	115 ft	0.1 to E3 R/hr	ION	Solid radwaste storage area	0	RM-84	Local	-	-
R-85	One-meter inspection station radiation monitor	115 ft	0.1 to E3 R/hr	ION	Solid radwaste storage area	0	RM-85	Local	-	-
R-87	Plant vent extended range radioactive gas monitors	85 ft	1E-12 to 1E-4 amps	Beta Scint.	Plant vent at NE walls/penetration room - area L for U-1 (SE for U-2)	1 2	RM-14 RM-14	RNRMS3 RNRMS3	EARS EARS	TSC TSC

Table 11.4-1

RMS Channel	RMS Description	Elevation	Range	Detector Type	Location	Unit(e) No.	Indication	Readout(s) Location	Recorder	Location
R-90	R/W Storage	115 ft	0.1 to E4 mR/hr	G-M	R/W Storage Truck Bay	0	RI-90A RI-90B	Local Mechanical RM Control RM	-	-
R-92	Laundry facility	132 ft	6 to 6E4 cpm	Proportnl Counter	Laundry room	0	-	-	-	-
RF-87A and RF-87B	Particulate and iodine grab sampling assembly (post-accident)	85 ft			Plant vent at NE wall/penetration room - area L for U-1 (SE for U-2)	1 2	- -	- -	- -	- -
RX-55	Laundry and Radwaste Facility Exhaust Sampler	115 ft			Ventilation room Solid Radwaste Storage Facility	0				
RX-56	Radwaste Storage Building and Laundry Facility Exhaust Sampler	142 ft			Mezzanine Area Radwaste Storage Building	0				

(a) Deleted in Revision 4
(b) Deleted in Revision 9
(c) Deleted in Revision 11
(d) Post-LOCA sampling control panel
(e) Units designation: 0 = 1 monitor common to both Units
1 = Unit 1 monitor
2 = Unit 2 monitor

Symbol	Location		
1 ABCBDS	Auxiliary building control board digital system, elevation 85 ft	11 RNRMA	Radiation monitor rack A, control room
2 ABRV	Auxiliary building roof vent access area	12 RNRMB	Radiation monitor rack B, control room
3 RNGFFD	Main steam line radiation monitor rack, control room	13 RNRMC	Radiation Monitor rack C, control room
4 HRSS	Sentry high radiation sampling room	14 RNRMD	Radiation Monitor rack D, control room
5 PAM-1	Post accident monitor panel 1, control room	15 RNRME	Radiation monitor rack E, control room
6 PAM-2	Post accident monitor panel 2, control room	16 SGSP	Steam generation sample panel
7 POPLSI	Post-LOCA sampling control panel	17 RMPTSC	Radiation monitor panel, TSC
8 PM197	Panel 197, access area of auxiliary building		
9 PM205	Mechanical panel 205, auxiliary building		
10 RCRM	Rack chlorine and radiation monitor - Unit 2 side control room		

TABLE 11.4-3

RADIATION MONITOR - VALVE CONTROL OPERATIONS

Radiation Element	Affected Valves	Effect
RE-17A and RE-17B	SV225, RCV16	Close CCW surge tank vent.
RE-18	SV233, RCV18, FCV477	Liquid radwaste control valves: Close liquid radwaste over-board and open liquid radwaste equipment drain receiver dump.
RE-23	SV237, FCV160, SV238, FCV157, SV239, FCV154, SV240, FCV151, SV242, FCV498, SV241, FCV499	(a) High radiation (1) close steam generators 1 to 4 blowdown tank inlet and sample, (2) close steam generator blowdown tank outlet, (3) close blowdown tank outlet to discharge tunnel and open blowdown tank outlet to equipment drain receiver; (b) Power loss to RE-23 - (1) close steam generators 1 to 4 blowdown tank inlet and sample, (2) close steam generator blowdown tank outlet, (3) close blowdown tank outlet to discharge tunnel and open blowdown tank outlet to equipment drain receiver.
RE-19	SV237, FCV160, SV238, FCV157, SV239, FCV154, SV240, FCV151, SV242, FCV498, SV241, FCV499	High radiation (1) close steam generators 1 to 4 blowdown tank inlet and sample, (2) close steam generator blowdown tank outlet, (3) close blowdown tank outlet to discharge tunnel and open blowdown tank outlet to equipment drain receiver.
RE-51, RE-52, RE-53, and RE-54	-	Initiate control room pressurization system.
RE-44A and RE-44B	Trains A and B containment vent isolation valves	Closure.
RE-22	SV218, RCV17	Gaseous radwaste vent closure.

TABLE 11.5-1

SOLID RADWASTE SYSTEM INPUT VOLUMES

Source	Design Basis Volume	Normal Operation Volume	Bases
Boric acid waste Concentrates[(a)]	11,700 gal/yr	23,190 gal/yr	EPRI NP-3370
Spent ion exchange resin	1,600 ft^3/yr	1,600 ft^3/yr	EPRI NP-3370
Expended filtration/ion exchange media	400 ft^3/yr	400 ft^3/yr	12 beds/yr
Spent filter cartridges (requiring encapsulation)	240/yr	240/yr	EPRI NP-3370
Dry active waste	210 boxes	180 boxes	EPRI NP-3370, EPRI NP-2900

(a) Boric acid evaporator has been abandoned in place

TABLE 11.5-2

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ACTIVITY IN RADWASTE SYSTEM DEMINERALIZERS NORMAL OPERATION CASE

(CURIES/YEAR)

Nuclide	*Primary Mxd Bed Demin*	*Primary Cation Demin*	*Letdown Mxd Bed Demin*	*Letdown Cation Demin*	*Letdown Anion Demin*	*Spent Fuel Pool Demin*
H-3	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Cr-51	*0.281E 02*	*0.309E-00*	*0.179E-02*	*0.179E-04*	*0.0*	*0.119E-04*
Mn-54	*0.282E 02*	*0.310E-00*	*0.289E-02*	*0.289E-04*	*0.0*	*0.693E-04*
Fe-55	*0.227E 01*	*0.249E-01*	*0.111E-05*	*0.111E-07*	*0.0*	*0.856E-13*
Co-58	*0.587E 03*	*0.646E 01*	*0.515E-01*	*0.515E-03*	*0.0*	*0.863E-03*
Fe-59	*0.238E 02*	*0.262E 00*	*0.185E-02*	*0.185E-04*	*0.0*	*0.225E-04*
Co-60	*0.250E 03*	*0.275E 01*	*0.267E-01*	*0.267E-03*	*0.0*	*0.983E-04*
Sr-89	*0.740E 01*	*0.814E-01*	*0.600E-03*	*0.600E-05*	*0.0*	*0.190E-04*
Sr-90	*0.175E 01*	*0.192E-01*	*0.188E-03*	*0.188E-05*	*0.0*	*0.113E-04*
Y-90	*0.173E 01*	*0.190E-01*	*0.186E-03*	*0.186E-05*	*0.0*	*0.112E-04*
Sr-91	*0.384E-01*	*0.422E-03*	*0.102E-20*	*0.102E-22*	*0.0*	*0.976E-10*
Y-91	*0.377E-01*	*0.415E-03*	*0.101E-20*	*0.101E-22*	*0.0*	*0.960E-10*
Sr-92	*0.436E-02*	*0.479E-04*	*0.310E-62*	*0.310E-64*	*0.0*	*0.934E-12*
Y-92	*0.436E-02*	*0.479E-04*	*0.310E-62*	*0.310E-64*	*0.0*	*0.934E-12*
Zr-95	*0.231E 01*	*0.255E-01*	*0.199E-03*	*0.199E-05*	*0.0*	*0.248E-04*
Nb-95	*0.349E 01*	*0.384E-01*	*0.323E-03*	*0.323E-05*	*0.0*	*0.391E-04*
Mo-99	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
I-131	*0.138E 04*	*0.0*	*0.265E 00*	*0.0*	*0.265E-04*	*0.216E-02*
Te-132	*0.586E 02*	*0.0*	*0.776E-03*	*0.0*	*0.776E-08*	*0.472E-04*
I-132	*0.648E 02*	*0.0*	*0.801E-03*	*0.0*	*0.102E-07*	*0.487E-04*
I-133	*0.205E-03*	*0.0*	*0.144E-07*	*0.0*	*0.144E-11*	*0.165E-05*
Cs-134	*0.146E 04*	*0.131E 03*	*0.401E 01*	*0.361E 01*	*0.0*	*0.817E-02*
I-134	*0.113E 01*	*0.0*	*0.0*	*0.0*	*0.0*	*0.730E-10*
I-135	*0.361E 02*	*0.0*	*0.971E-24*	*0.0*	*0.971E-28*	*0.225E-07*
Cs-136	*0.237E 02*	*0.213E 01*	*0.217E-01*	*0.195E-01*	*0.0*	*0.119E-04*
Cs-137	*0.301E 04*	*0.271E 03*	*0.843E 01*	*0.759E 01*	*0.0*	*0.255E-01*
Ba-140	*0.315E 01*	*0.346E-01*	*0.109E-03*	*0.109E-05*	*0.0*	*0.422E-05*
La-140	*0.330E 01*	*0.362E-01*	*0.125E-03*	*0.125E-05*	*0.0*	*0.476E-05*
Ce-144	*0.357E 01*	*0.393E-01*	*0.365E-03*	*0.365E-05*	*0.0*	*0.159E-04*
Pr-144	*0.357E-01*	*0.393E-01*	*0.365E-03*	*0.365E-05*	*0.0*	*0.159E-04*

TABLE 11.5-2

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

ACTIVITY IN RADWASTE SYSTEM DEMINERALIZERS NORMAL OPERATION CASE

(CURIES/YEAR)

Nuclide	Primary Mxd Bed Demin	Primary Cation Demin	Letdown Mxd Bed Demin	Letdown Cation Demin	Letdown Anion Demin	Spent Fuel Pool Demin
H-3	0.0	0.0	0.0	0.0	0.0	0.0
Cr-51	0.281E 02	0.309E-00	0.179E-02	0.179E-04	0.0	0.119E-04
Mn-54	0.282E 02	0.310E-00	0.289E-02	0.289E-04	0.0	0.693E-04
Fe-55	0.227E 01	0.249E-01	0.111E-05	0.111E-07	0.0	0.856E-13
Co-58	0.588E 03	0.646E 01	0.516E-01	0.516E-03	0.0	0.863E-03
Fe-59	0.238E 02	0.262E 00	0.185E-02	0.185E-04	0.0	0.225E-04
Co-60	0.250E 03	0.275E 01	0.267E-01	0.267E-03	0.0	0.983E-04
Sr-89	0.617E 02	6.679E 00	0.500E-02	0.500E-04	0.0	0.566E-04
Sr-90	0.146E 02	0.160E 00	0.156E-02	0.156E-04	0.0	0.684E-04
Y-90	0.144E 02	0.158E 00	0.155E-02	0.155E-04	0.0	0.677E-04
Sr-91	0.320E 00	0.352E-02	0.853E-20	0.853E-22	0.0	0.980E-10
Y-91	0.315E 00	0.346E-02	0.840E-20	0.840E-22	0.0	0.964E-10
Sr-92	0.363E-01	0.399E-03	0.258E-61	0.258E-63	0.0	0.934E-12
Y-92	0.363E-01	0.399E-03	0.258E-61	0.258E-63	0.0	0.934E-12
Zr-95	0.193E 02	0.212E 00	0.166E-02	0.166E-04	0.0	0.401E-04
Nb-95	0.291E 02	0.320E 00	0.270E-02	0.270E-04	0.0	0.672E-04
Mo-99	0.0	0.0	0.0	0.0	0.0	0.0
I-131	0.115E 05	0.0	0.221E 01	0.0	0.221E-03	0.280E-02
Te-132	0.489E 03	0.0	0.647E-02	0.0	0.647E-07	0.525E-04
I-132	0.540E 03	0.0	0.668E-02	0.0	0.853E-07	0.543E-04
I-133	0.171E 04	0.0	0.120E-06	0.0	0.120E-10	0.194E-05
Cs-134	0.120E 05	0.108E 04	0.331E 02	0.298E 02	0.0	0.345E-01
I-134	0.941E 01	0.0	0.0	0.0	0.0	0.730E-10
I-135	0.301E 03	0.0	0.809E-23	0.0	0.809E-27	0.225E-07
Cs-136	0.197E 03	0.178E 02	0.181E 00	0.163E 00	0.0	0.336E-04
Cs-137	0.251E 05	0.226E 04	0.702E 02	0.632E 02	0.0	0.131E 00
Ba-140	0.263E 02	0.289E 00	0.906E-03	0.906E-05	0.0	0.713E-05
La-140	0.275E 02	0.302E 00	0.104E-02	0.104E-04	0.0	0.792E-05
Ce-144	0.298E 02	0.327E 00	0.305E-02	0.305E-04	0.0	0.868E-04
Pr-144	0.289E 02	0.327E 00	0.305E-02	0.305E-04	0.0	0.869E-04

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.5-4
HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
ACTIVITY COLLECTED IN RADWASTE FILTER
CARTRIDGES AT TIME OF REPLACEMENT[(a)]
(CURIES)

DESIGN BASIS CASE

	RCC Letdown[(b)]				*Radwaste[(c)]*		
Nuclide	*Primary Loop*	*Ion Exchge*	*Concentrates*	*Condensate*	*0-1*	*0-2*	*0-3*
H-3	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Cr-51	*0.148E 00*	*0.429E-07*	*0.214E-07*	*0.214E-10*	*0.418E-05*	*0.731E-03*	*0.212E-05*
Mn-54	*0.669E-01*	*0.312E-07*	*0.156E-07*	*0.156E-10*	*0.268E-05*	*0.475E-03*	*0.136E-05*
Fe-55	*0.125E-01*	*0.280E-10*	*0.140E-10*	*0.140E-13*	*0.165E-07*	*0.153E-05*	*0.833E-08*
Co-58	*0.232E 01*	*0.925E-06*	*0.462E-06*	*0.462E-09*	*0.827E-04*	*0.146E-01*	*0.421E-04*
Fe-59	*0.112E 00*	*0.396E-07*	*0.198E-07*	*0.198E-10*	*0.365E-05*	*0.643E-03*	*0.186E-05*
Co-60	*0.481E 00*	*0.234E-06*	*0.117E-06*	*0.117E-09*	*0.198E-04*	*0.352E-02*	*0.101E-04*

NORMAL OPERATION CASE

	RCC Letdown[(b)]				*Radwaste[(c)]*		
Nuclide	*Primary Loop*	*Ion Exchge*	*Concentrates*	*Condensate*	*0-1*	*0-2*	*0-3*
H-3	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Cr-51	*0.148E 00*	*0.428E-07*	*0.214E-07*	*0.214E-10*	*0.372E-06*	*0.446E-02*	*0.441E-06*
Mn-54	*0.669E-01*	*0.312E-07*	*0.156E-07*	*0.156E-10*	*0.184E-06*	*0.356E-02*	*0.301E-06*
Fe-55	*0.125E-01*	*0.280E-10*	*0.140E-10*	*0.140E-13*	*0.125E-07*	*0.313E-05*	*0.637E-08*
Co-58	*0.232E 01*	*0.924E-06*	*0.462E-06*	*0.462E-09*	*0.620E-05*	*0.102E 00*	*0.904E-05*
Fe-59	*0.112E 00*	*0.396E-07*	*0.198E-07*	*0.198E-10*	*0.292E-06*	*0.427E-02*	*0.393E-06*
Co-60	*0.481E 00*	*0.234E-06*	*0.117E-06*	*0.117E-09*	*0.134E-05*	*0.269E-01*	*0.225E-05*

(a) Three cartridge replacements per cycle.
(b) As Designated on Figure 11.5-6.
(c) As Designated on Figure 11.5-8.
Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.5-5

SUMMARY OF RADWASTE MATERIALS SHIPMENT

Material	Quantity per Year	Quantity Possible per Shipment	Shipments per Year	Shipment Method
Packaged wastes				
Solidified liquid concentrates	0 ft^3	100 ft^3	0	truck
Class B/C Resins	160 ft^3	80 ft^3	2	truck
Class A Resin	400 ft^3	200 ft^3	2	truck
Spent filter cartridges	240	100	2	truck
Filtration/ion exchange media	60 ft^3	200 ft^3	1/2	truck
Dry active wastes	50 boxes	10 boxes	5	truck

TABLE 11.6-4

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
ENVIRONMENTAL RADIOLOGICAL MONITORING PROGRAM SUMMARY (PRE-OPERATIONAL RESULTS)

Medium or Pathway Sampled (Unit of Measurement)	*Type and Total Number of Analyses Performed*	*Lower Limit of Detection[a] (LLD)*	*Location*		*All Control Locations Mean(1)[b] Range[b]*	*Number of Reportable Occurrences*
			Name, Distance[d] and Direction	*Mean(1)[b] Range[b]*		
Seawater, (pCi. L^{-1})	*Tritium (12)*	-	-	*None detected*	-	*0*
	Gamma Isotopic (36)	-	-	*None detected*	-	*0*
	54Mn			*None detected*		
	59Fe	*$3.79x10^{2}$[c]*		*None detected*		
	58Co			*None detected*		
	60Co			*None detected*		
	65Zn			*None detected*		
	95Zr			*None detected*		
	95Nb			*None detected*		
	131I			*None detected*		
	134Cs			*None detected*		
	137Cs			*None detected*		
	140Ba	*$2.14x10^{3}$[c]*		*None detected*		
	140La	*$6.09x10^{2}$[c]*		*None detected*		
Surface water (pCi. L^{-1})	*Tritium (12)*	-	-	*None detected*	-	*0*
	Gross Beta (12)	-	*Sta. 5S2, 0.6 mi, 65°*	*2.94(12/12) 2.24-3.58*	-	*0*
	Gamma Isotopic	-				*0*
	54Mn			*None detected*		
	59Fe			*None detected*		
	58Co			*None detected*		
	60Co			*None detected*		
	65Zn			*None detected*		

TABLE 11.6-4

Medium or Pathway Sampled (Unit of Measurement)	Type and Total Number of Analyses Performed	Lower Limit of Detection[a] (LLD)	Location Name, Distance[d] and Direction	Location Mean(1)[b] Range[b]	All Control Locations Mean(1)[b] Range[b]	Number of Reportable Occurrences
	95Zr			None detected		
	95Nb			None detected		
	131I			None detected		
	134Cs			None detected		
	137Cs			None detected		
	140Ba	$1.35x10^{2}$[c]		None detected		
	140La	$3.48x10^{1}$[c]		None detected		
Drinking water (pCi. L^{-1})	Tritium (12)		-	None detected	-	0
	Gross Beta (12)		Sta. D W1, 0.0 mi, in plant	2.4 (8/12) 2.24-4.09	-	0
	131-Iodine (12)			None detected	-	0
	Gamma Isotopic (12)				-	0
	54Mn			None detected		
	59Fe			None detected		
	58Co			None detected		
	60Co			None detected		
	65Zn			None detected		
	95Zr			None detected		
	95Nb			None detected		
	131I			None detected		
	134Cs			None detected		
	137Cs			None detected		
	140Ba			None detected		
	140La			None detected		

TABLE 11.6-4

Medium or Pathway Sampled (Unit of Measurement)	Type and Total Number of Analyses Performed	Lower Limit of Detection[a] (LLD)	Location: Name, Distance[d] and Direction	Location: Mean(1)[b] Range[b]	All Control Locations Mean(1)[b] Range[b]	Number of Reportable Occurrences
Outfall (pCi. L^{-1})	Tritium (18)		-	None detected	-	0
	Gamma Isotopic (18)			None detected		
	54Mn			None detected		
	59Fe			None detected		
	58Co			None detected		
	60Co			None detected		
	65Zn			None detected		
	95Zr			None detected		
	95Nb			None detected		
	131I			None detected		
	134Cs			None detected		
	137Cs			None detected		
	140Ba	2.74×10^{3}[c]		None detected		
	140La	8.35×10^{2}[c]		None detected		
Airborne (pCi. m^{-3})	131I (507)		-	None detected	0.108 (3/211) 0.0137-0.159	0
	Gross Beta (507)		-	0.012(296/296) 0.004-0.033	0.010(211/211) 0.005-0.033	
	Gamma Isotopic (507)		-		-	0
	134Cs			None detected	None detected	
	137Cs			None detected	None detected	
Fish and seafood (pCi. kg^{-1})	Gamma Isotopic (79)		-		-	0
	54Mn	1.46×10^{2}		None detected	None detected	

TABLE 11.6-4

Medium or Pathway Sampled (Unit of Measurement)	Type and Total Number of Analyses Performed	Lower Limit of Detection[a] (LLD)	Location: Name, Distance[d] and Direction	Location: Mean(1)[b] Range[b]	All Control Locations Mean(1)[b] Range[b]	Number of Reportable Occurrences
	59Fe	5.19×10^2		None detected	None detected	
	58Co	1.74×10^2		None detected	None detected	
	60Co	2.02×10^2		None detected	None detected	
	65Zn	-		None detected	None detected	
	134Cs	1.50×10^2		None detected	None detected	
	137Cs	1.46×10^2		None detected	16.4 (5/57)	
Milk ($pCi.\ L^{-1}$)	131I (30)		-	None detected	None detected	0
	Gamma Isotopic (30)		-			0
	134Cs			None detected	None detected	
	137Cs			None detected	None detected	
	140Ba			None detected	None detected	
	140La			None detected	None detected	
Food products ($pCi.\ kg^{-1}$)	Gamma Isotopic (36)		-		-	0
	131I	6.65×10^1			None detected	None detected
	134Cs				None detected	None detected
	137Cs				None detected	None detected

TABLE 11.6-4

Medium or Pathway Sampled (Unit of Measurement)	Type and Total Number of Analyses Performed	Lower Limit of Detection[a] (LLD)	Location		All Control Locations Mean(1)[b] Range[b]	Number of Reportable Occurrences
			Name, Distance[d] and Direction	Mean(1)[b] Range[b]		
Direct radiation (mR)	TLD Packets (335)	1 mR/mo[e]	Sta. 3S1[f] 0.4 mi, 23°	77.2(313/313) 49.6-106.9 mR/yr	Sta. 2F2 and 4D1 62.0(22/22) 67.8-66.2 mR/yr	0
				8.9 (11/11[f] 7.9-10.1 mR/mo (106.9 mR/yr)		

(a) Unless specified, all required LLDs were met.
(b) Mean and range based upon detectable measurements only. Fraction of detectable measurements at specified locations is indicated in parentheses (1); e.g., (10/12) means 10 samples out of 12 collected showed activity.
(c) A priori LLD not met due to elapse time between collection and count dates, short half-life of nuclide involved, and equipment failure. Value listed is worst case.
(d) Only one station location for this sample type; therefore, no control or indicator stations are listed.
(e) Sensitivity of TLD system.
(f) Indicator location with Highest Annual Mean.

Note: The information presented in the above table was developed in support of the original license and is considered historical.

TABLE 11.6-11

MAXIMUM VALUES FOR THE LOWER LIMITS OF DETECTION (LLD)

Analysis	Water (pCi/l)	Airborne Particulate or Gases (pCi/m^3)	Fish (pCi/kg, wet)	Milk (pCi/l)	Food Products (pCi/kg, wet)	Sediment (pCi/kg, dry)
Gross beta	4	0.01				
H-3	2000*					
Mn-54	15		130			
Fe-59	30		260			
Co-58, 60	15		130			
Zn-65	30		260			
Zr- Nb -95	15					
I-131	1**	0.07		1	60	
Cs-134	15	0.05	130	15	60	150
Cs-137	18	0.06	150	18	80	180
Ba- La -140	15			15		

* For surface water samples, a value of 3000 pCi/l may be used.
** If no drinking water pathway exists, a value of 15 pCi/l may be used.

Table Notation

The LLD is defined, for purposes of these specifications, as the smallest concentration of radioactive material in a sample that will yield a net count, above system background, that will be detected with 95 percent probability with only 5 percent probability of falsely concluding that a blank observation represents a "real" signal.

For a particular measurement system (which may include radiochemical separation):

$$LLD = \frac{4.66 S_b}{E \times V \times 2.22 \times Y \exp(-\lambda t)}$$

where:

LLD is "a priori" the lower limit of detection as defined above (as pCi per unit mass or volume)

S_b is the standard deviation of the background counting rate or of the counting rate of a blank sample as appropriate (as counts per minute)

E is the counting efficiency (as counts per transformation)

V is the sample size (in units of mass or volume)

2.22 is the number of transformations per minute per picocurie

Y is the fractional radiochemical yield (when applicable)

λ is the radioactive decay constant for the particular radionuclide

t is the elapsed time between sample collection (or end of the sample collection period) and time of counting

The value of S_b used in the calculation of the LLD for a detection system will be based on the actual observed variance of the background counting rate or of the counting rate of the blank samples (as appropriate) rather than on an unverified theoretically predicted variance. In calculating the LLD for a radionuclide determined by gamma ray spectrometry, the background will include the typical contributions of other radionuclides normally present in the samples (e.g., potassium-40 in milk samples).

Analyses will be performed in such a manner that the stated LLDs will be achieved under routine conditions. Occasionally, background fluctuations, unavoidably small sample sizes, the presence of interfering nuclides, or other uncontrollable circumstances may render these LLDs unachievable. In such cases, the contributing factors will be identified and described in the Annual Environmental Radiological Operating Report.

TABLE 11.6-13

ESTIMATED RELATIVE CONCENTRATIONS $(\overline{\chi/Q})$ [a]

	22-1/2° Radial Sectors								
Nearest	NW	NNW	N	NNE	NE	ENE	E	ESE	SE
Milk cow	None	None	None	None	None	None	None	None	None
Meat animal	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Milk goat	None	None	None	None	None	None	None	None	None
Residence	$1.53X10^{-7}$	$4.16X10^{-7}$	None	$3.89X10^{-8}$	$2.00X10^{-8}$	$3.64X10^{-8}$	$5.89X10^{-8}$	$7.07X10^{-7}$ [b]	None
Vegetable garden	None	None	None	None	None	None	None	None	None
Site boundary	$3.44X10^{-6}$	$2.70X10^{-6}$	$1.51X10^{-6}$	$8.25X10^{-7}$	$1.62X10^{-7}$	$9.18X10^{-8}$	$1.07X10^{-7}$	$5.20X10^{-7}$	$1.32X10^{-6}$

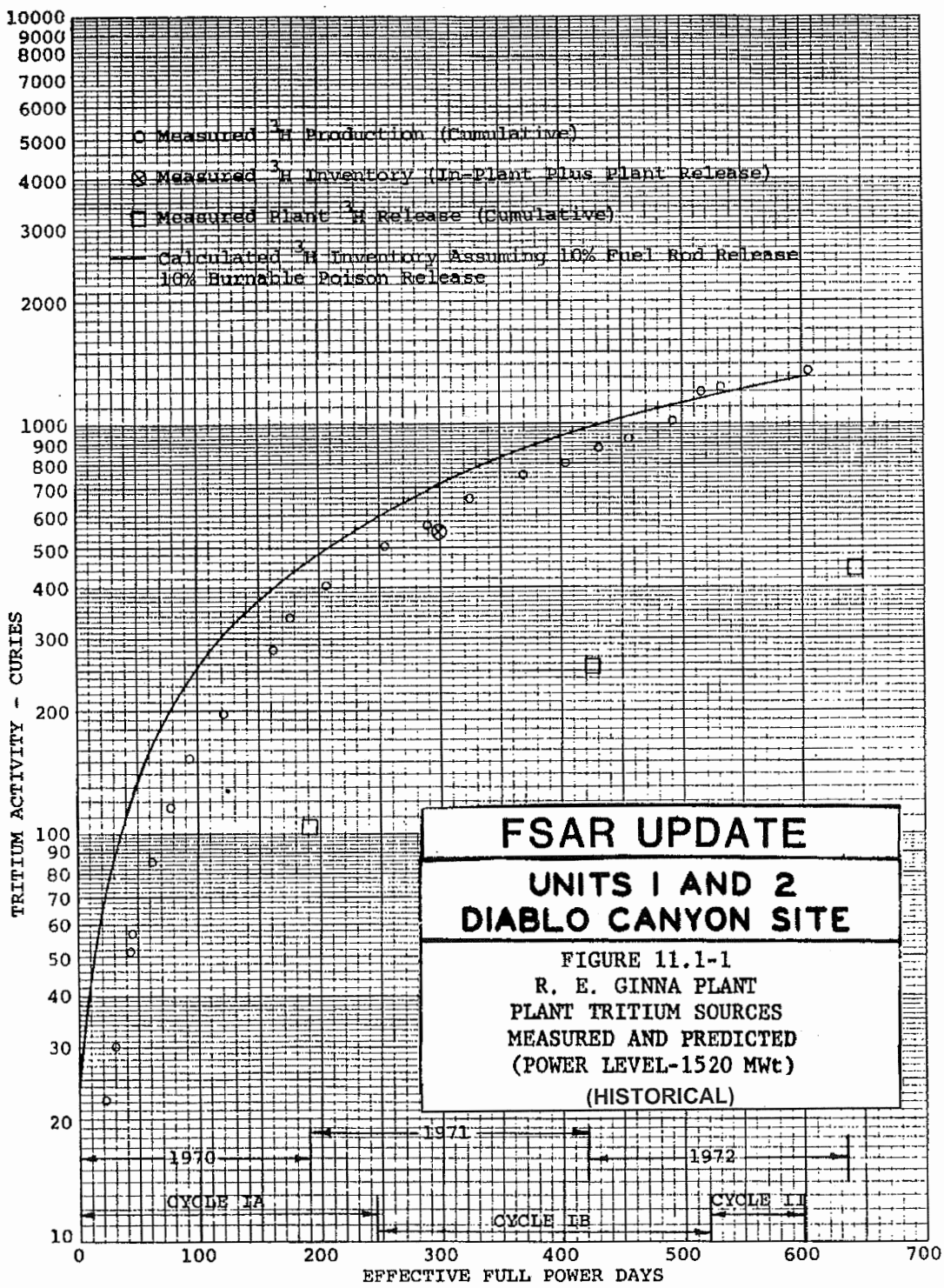
(a) In units of seconds per cubic meter.
(b) Vegetable farm has workers with residence occupancy factor of 1/2 for inhalation and group plane pathway.

TABLE 11.6-14

ESTIMATED DEPOSITIONS (χ/Q)[a]

	22-1/2° Radial Sectors								
Nearest	NW	NNW	N	NNE	NE	ENE	E	ESE	SE
Milk cow	None	$1.21X10^{-10}$	$6.52X10^{-11}$	$4.09X10^{-11}$	$4.48X10^{-11}$	$6.13X10^{-11}$	$1.13X10^{-10}$	$3.79X10^{-10}$	
Meat animal	$1.50X10^{-8}$	$6.71X10^{-9}$	$3.47X10^{-9}$	$2.18X10^{-9}$	$1.43X10^{-9}$	$1.64X10^{-9}$	$1.67X10^{-9}$	$5.53X10^{-9}$	$3.55X10^{-8}$
Milk goat	None	None	None	None	None	None	None	None	None
Residence	$3.83X10^{-10}$	$8.15X10^{-10}$	None	$8.75X10^{-11}$	$4.00X10^{-11}$	$7.85X10^{-11}$	$1.41X10^{-10}$	$4.77X10^{-9}$	None
Vegetable garden	None	None	None	None	None	None	$1.41X10^{-10}$	$4.77X10^{-9}$	None
Site boundary	$1.50X10^{-8}$	$6.81X10^{-9}$	$3.47X10^{-9}$	$2.18X10^{-9}$	$1.43X10^{-9}$	$1.64X10^{-9}$	$1.67X10^{-9}$	$5.53X10^{-9}$	$3.55X10^{-8}$

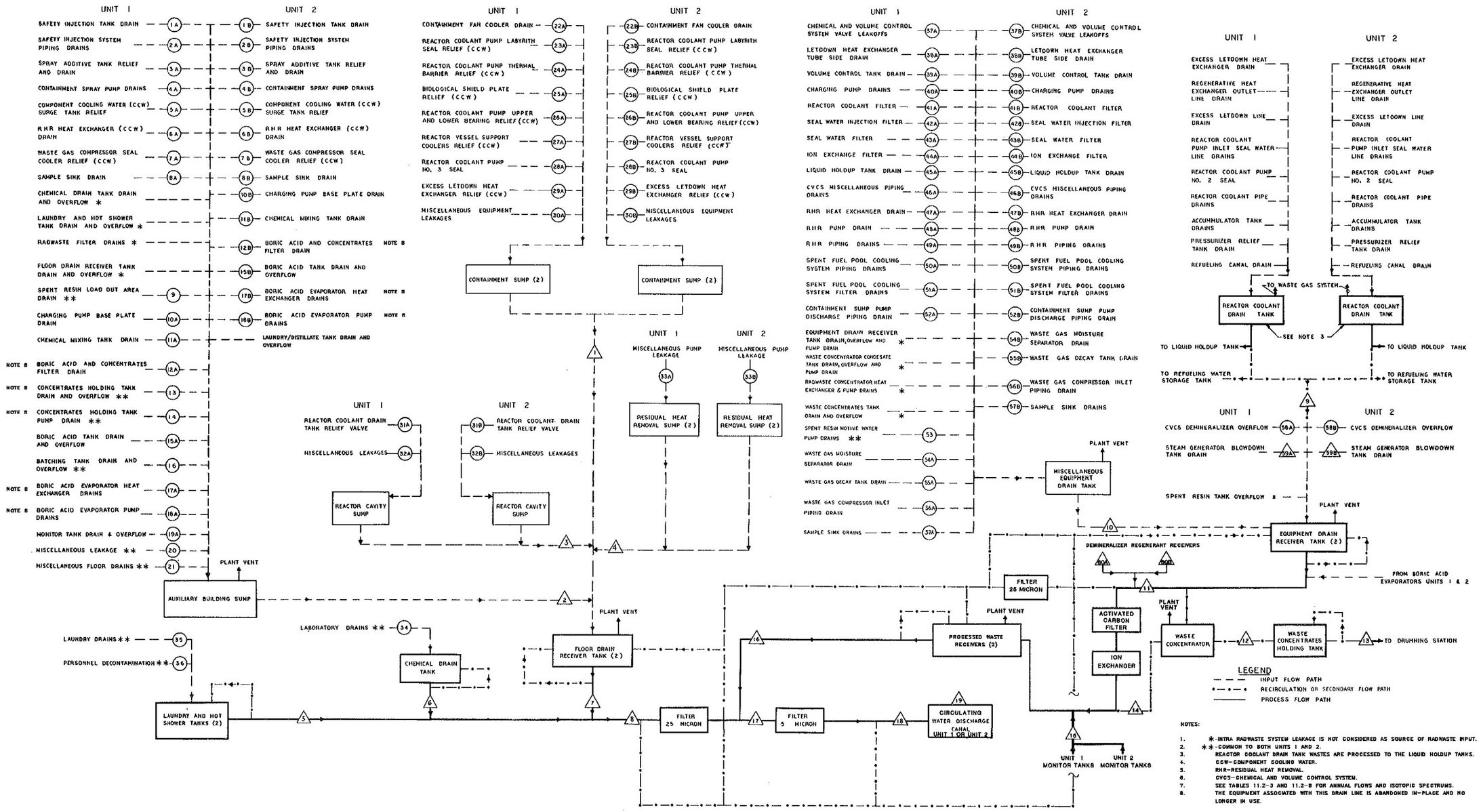
(a) In units of meters^{-2}, includes sector width and frequency of winds in each sector.



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.1-1
R. E. GINNA PLANT
PLANT TRITIUM SOURCES
MEASURED AND PREDICTED
(POWER LEVEL-1520 MWt)
(HISTORICAL)



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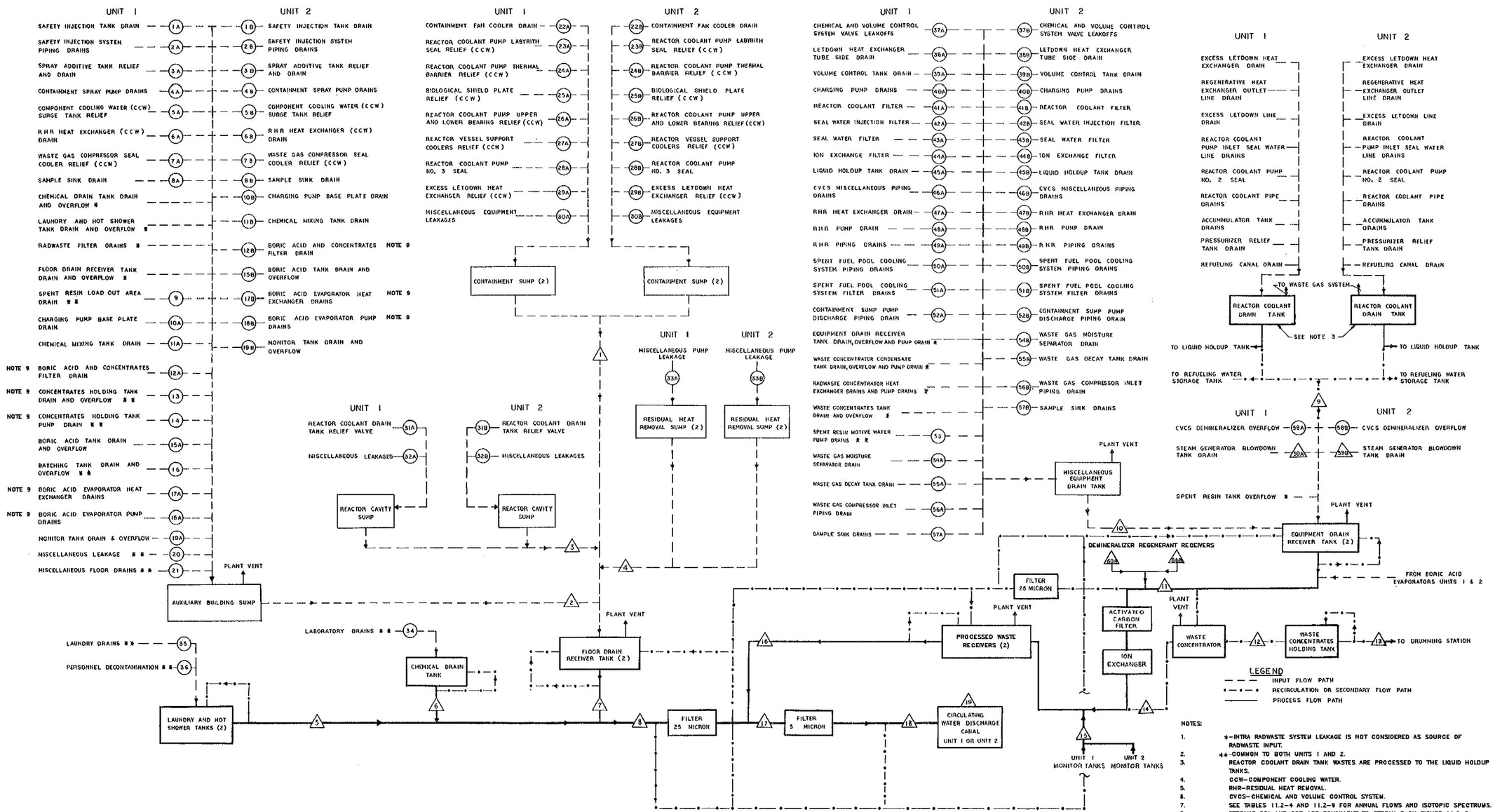
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.2-2

LIQUID WASTE PROCESS FLOW DIAGRAM
DESIGN BASIS CASE

(HISTORICAL)



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UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.2-3

LIQUID WASTE PROCESS FLOW DIAGRAM
NORMAL OPERATIONS CASE

(HISTORICAL)

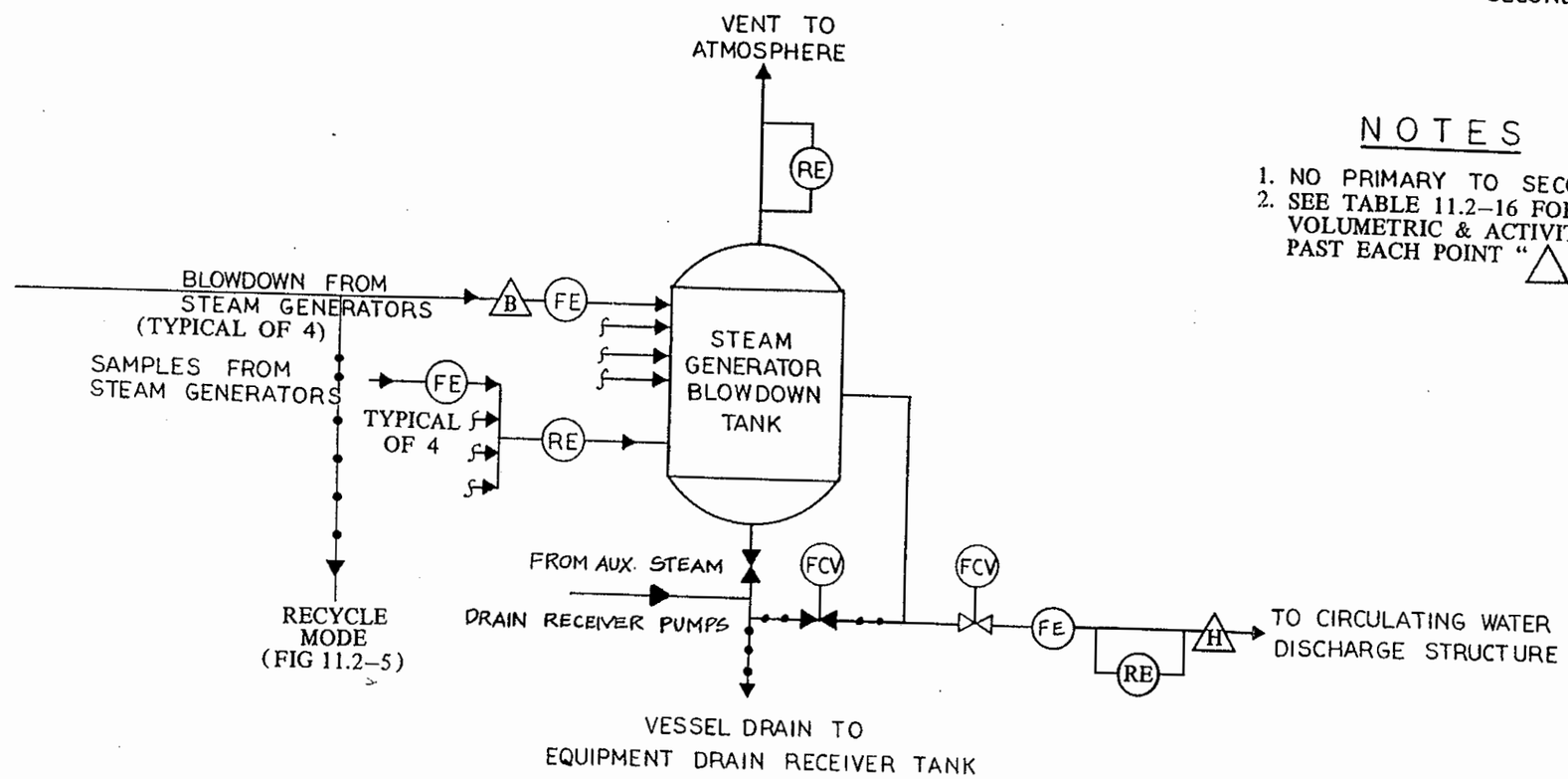
LEGEND

PROCESS FLOW PATH

SECONDARY FLOW PATH

NOTES

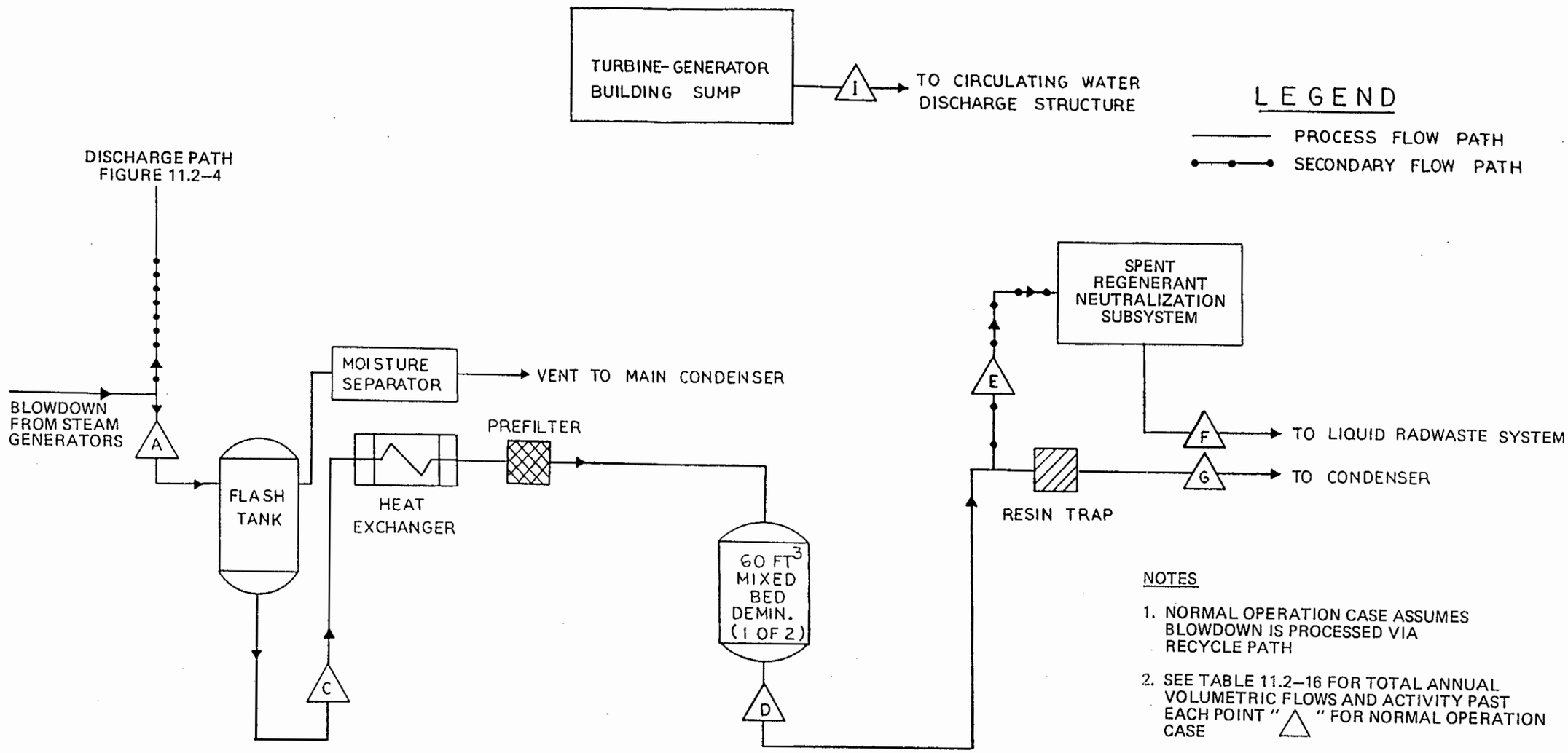
1. NO PRIMARY TO SECONDARY LEAKAGE
2. SEE TABLE 11.2–16 FOR TOTAL ANNUAL VOLUMETRIC & ACTIVITY FLOW PAST EACH POINT "△"



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.2-4
BLOWDOWN SYSTEM FLOW DIAGRAM
DISCHARGE MODE



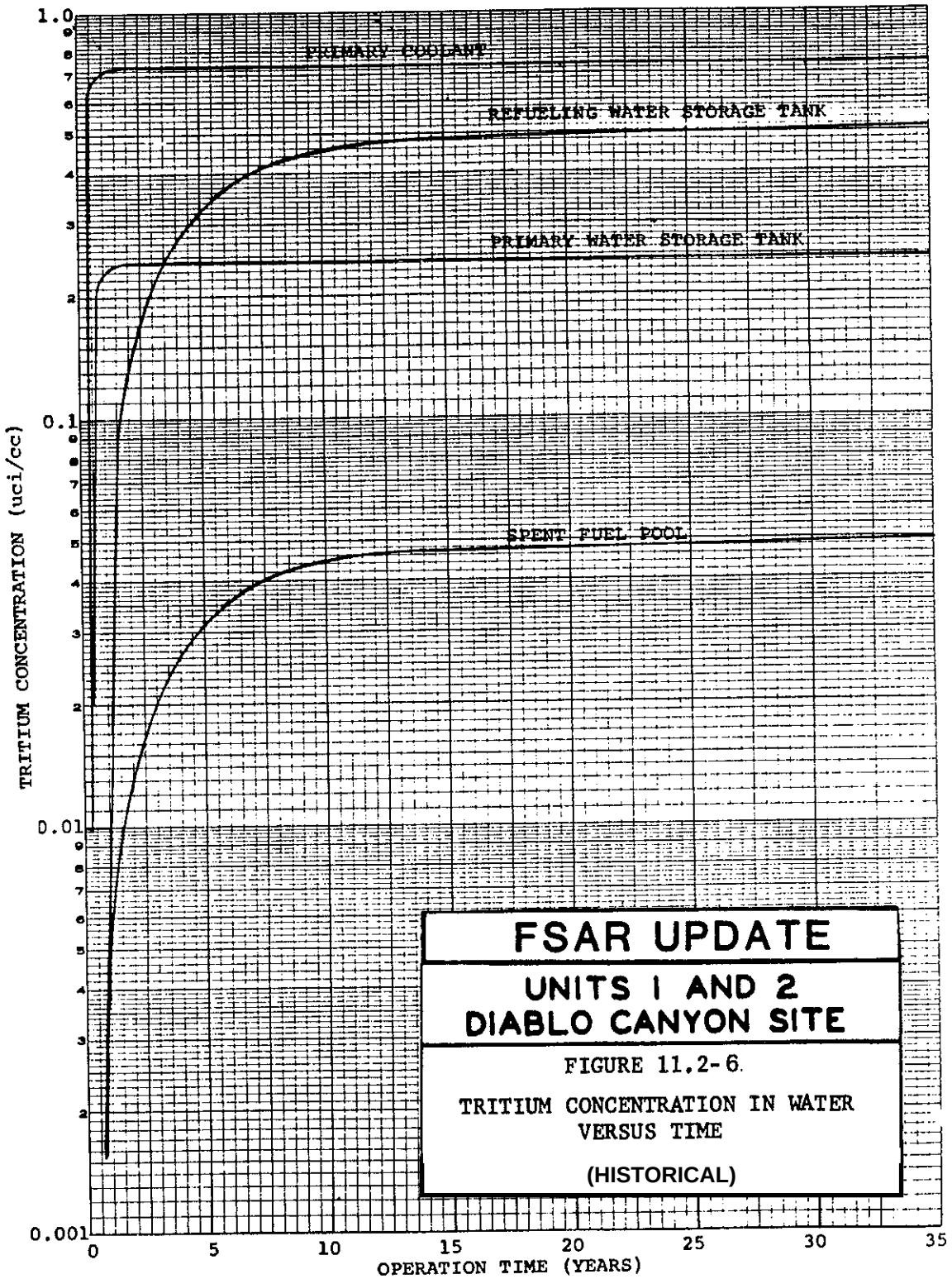
NOTES

1. NORMAL OPERATION CASE ASSUMES BLOWDOWN IS PROCESSED VIA RECYCLE PATH
2. SEE TABLE 11.2–16 FOR TOTAL ANNUAL VOLUMETRIC FLOWS AND ACTIVITY PAST EACH POINT " △ " FOR NORMAL OPERATION CASE
3. STREAM F IS EQUIVALENT TO STREAM 60 A AND 60 B ON FIGURE 11.2–3.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.2–5
BLOWDOWN SYSTEM FLOW DIAGRAM
RECYCLE PATH



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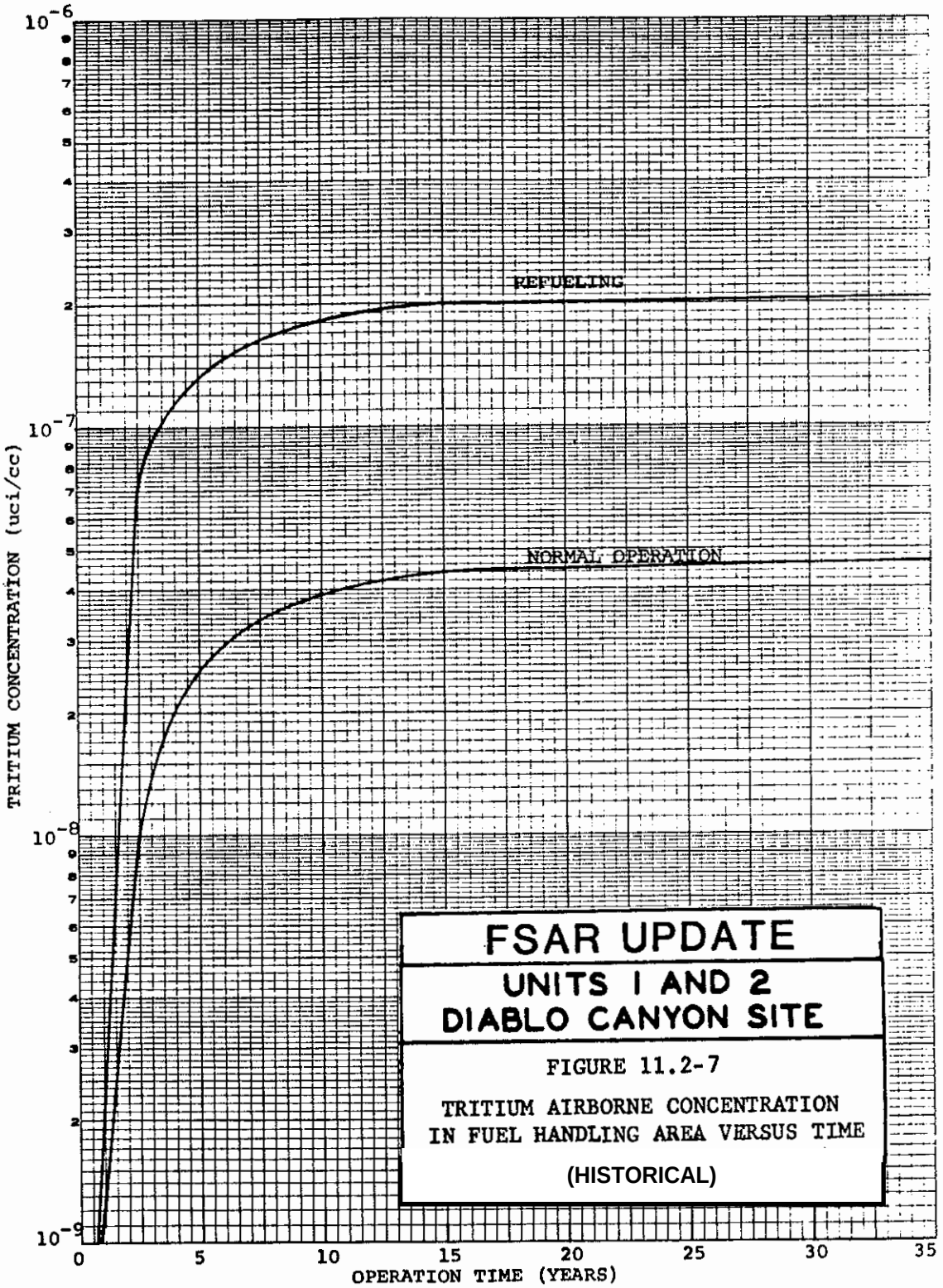
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.2-6

TRITIUM CONCENTRATION IN WATER VERSUS TIME

(HISTORICAL)



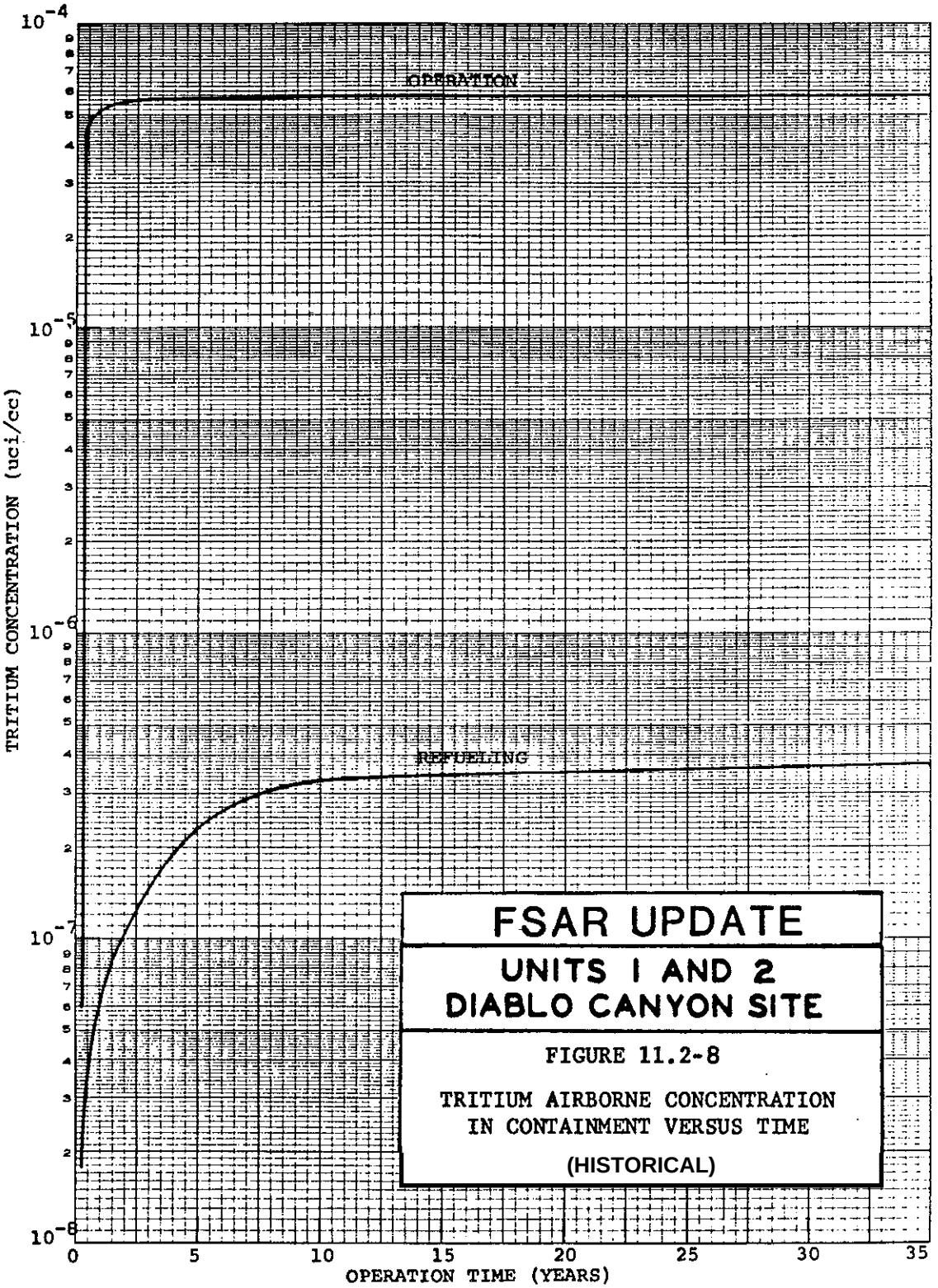
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.2-7

TRITIUM AIRBORNE CONCENTRATION
IN FUEL HANDLING AREA VERSUS TIME

(HISTORICAL)



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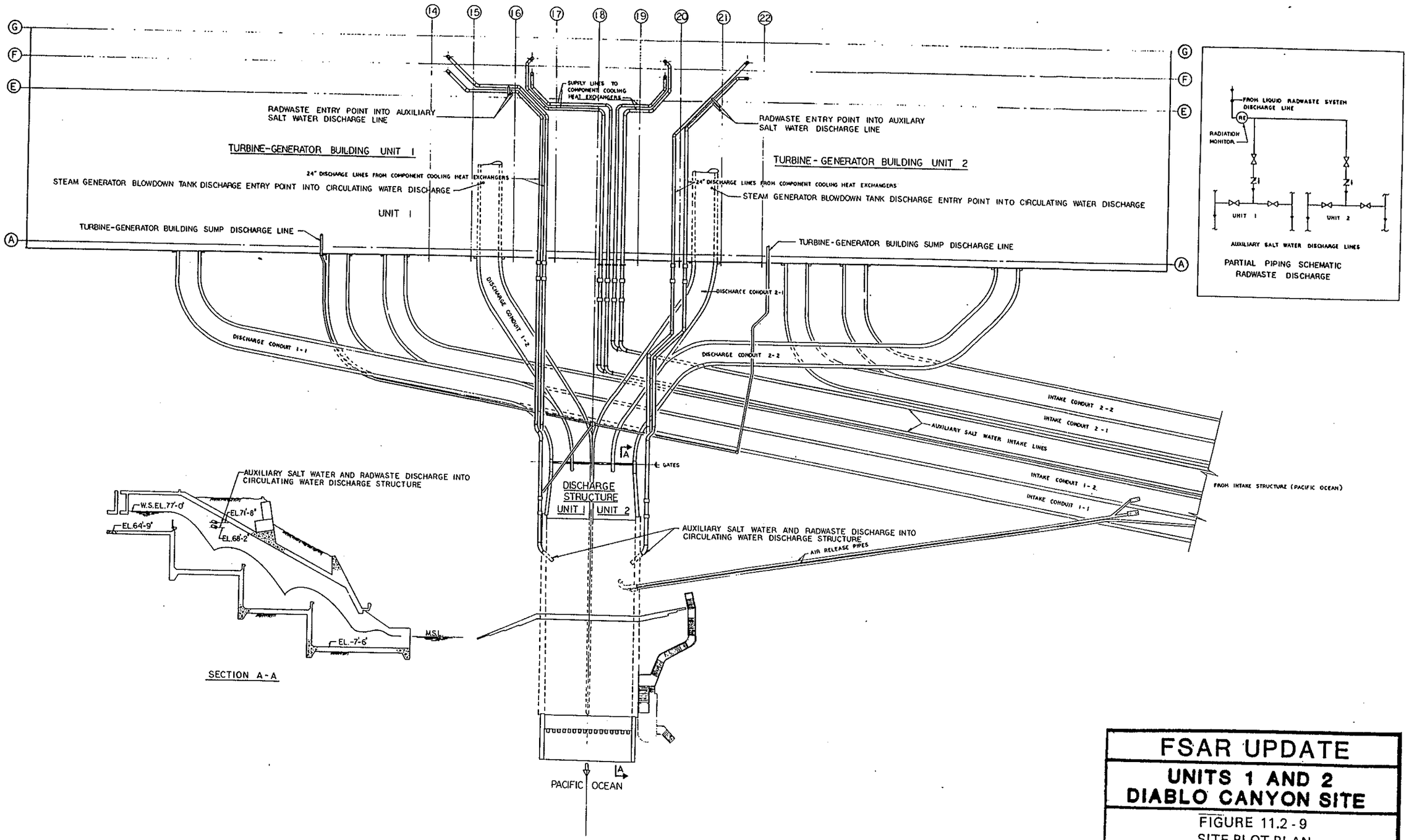
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.2-8

TRITIUM AIRBORNE CONCENTRATION
IN CONTAINMENT VERSUS TIME

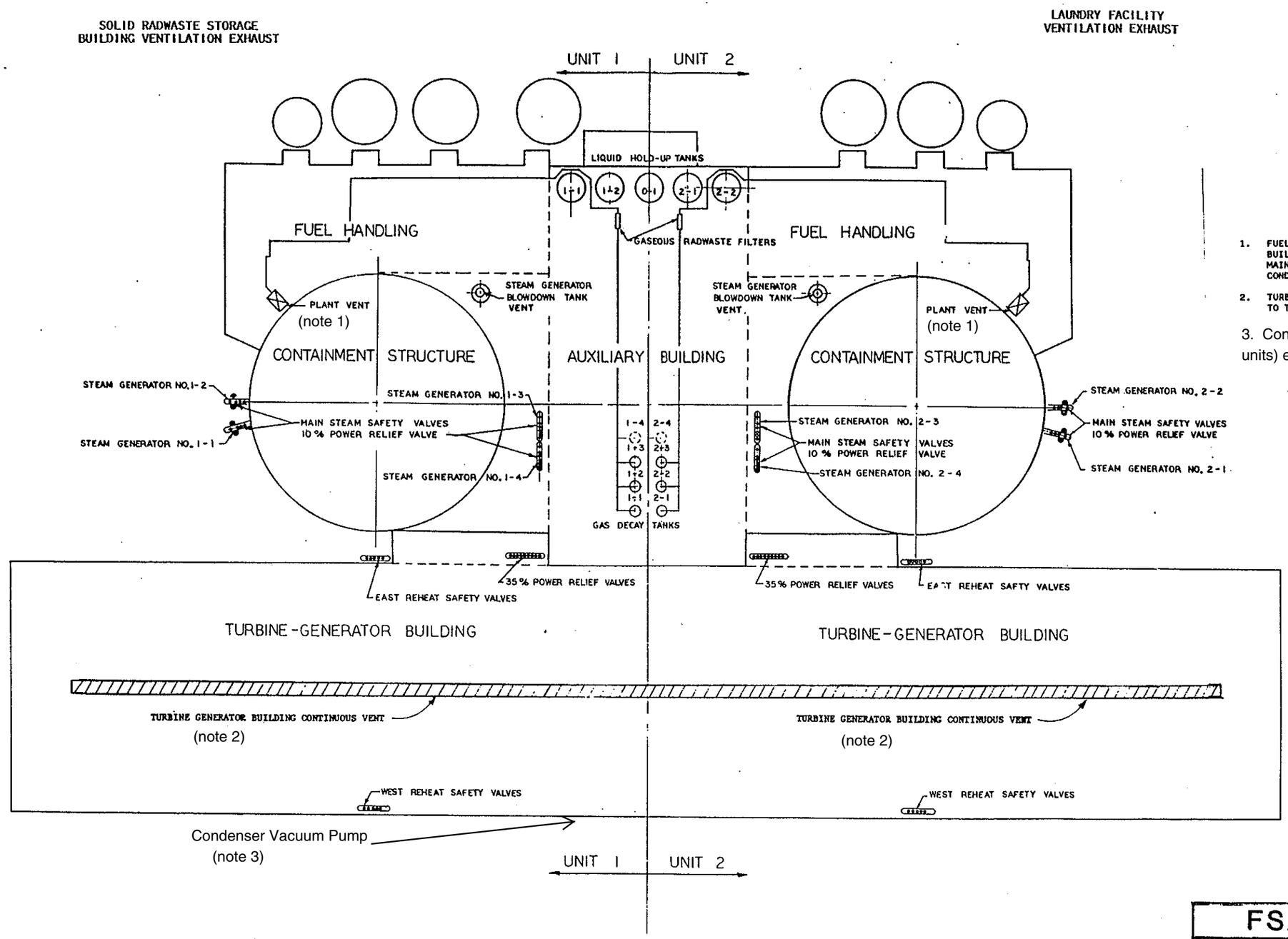
(HISTORICAL)



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.2-9
SITE PLOT PLAN
RADWASTE DISCHARGE



NOTES

1. FUEL HANDLING BUILDING VENTILATION, AUXILIARY BUILDING VENTILATION, CONTAINMENT VENTILATION, MAIN CONDENSER AIR EJECTOR, AND GLAND STEAM CONDENSER DISCHARGE TO PLANT VENT.
2. TURBINE-GENERATOR BUILDING VENTILATION DISCHARGE TO THE ATMOSPHERE.
3. Condenser vacuum pump (shared between units) exhausts to the atmosphere.

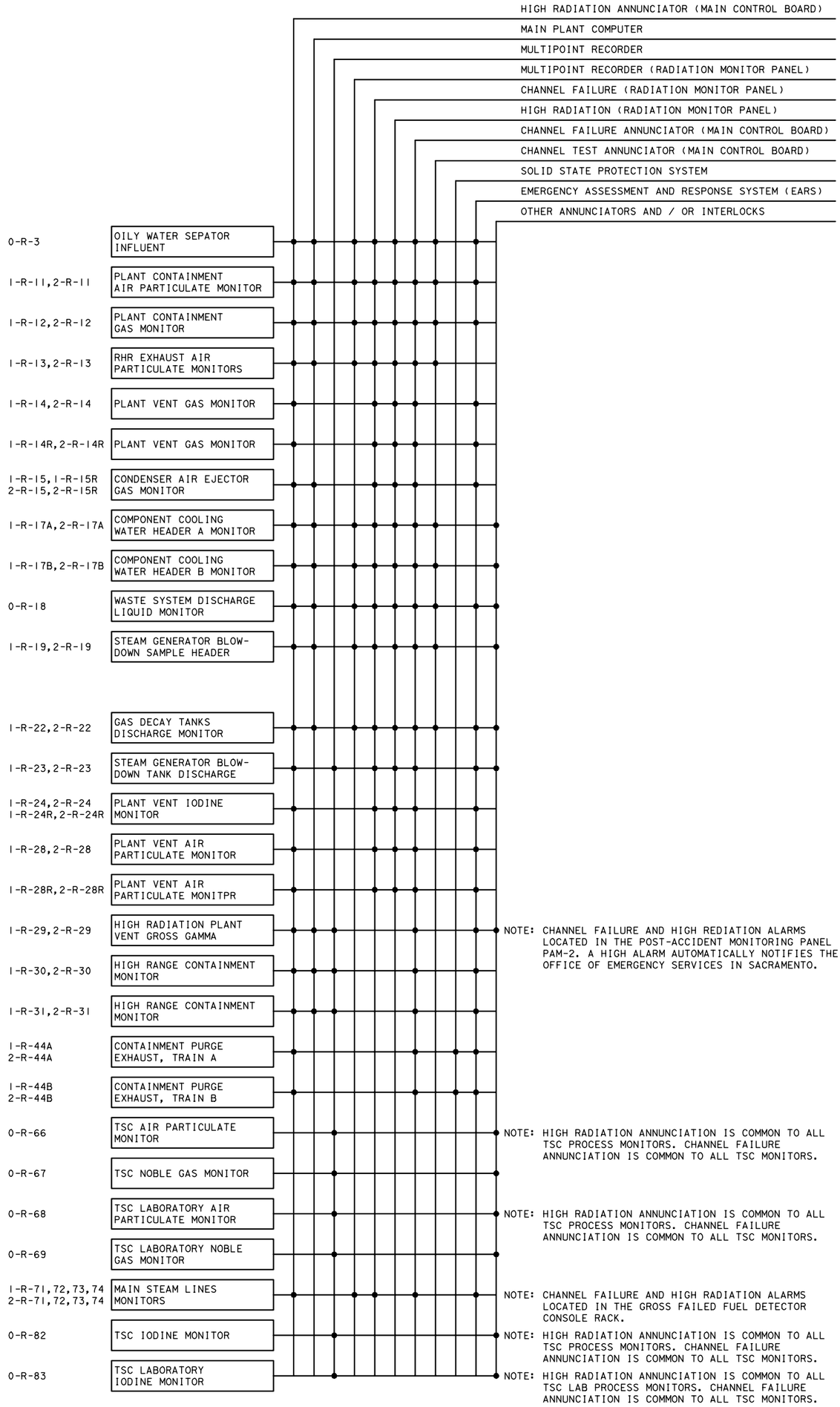
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

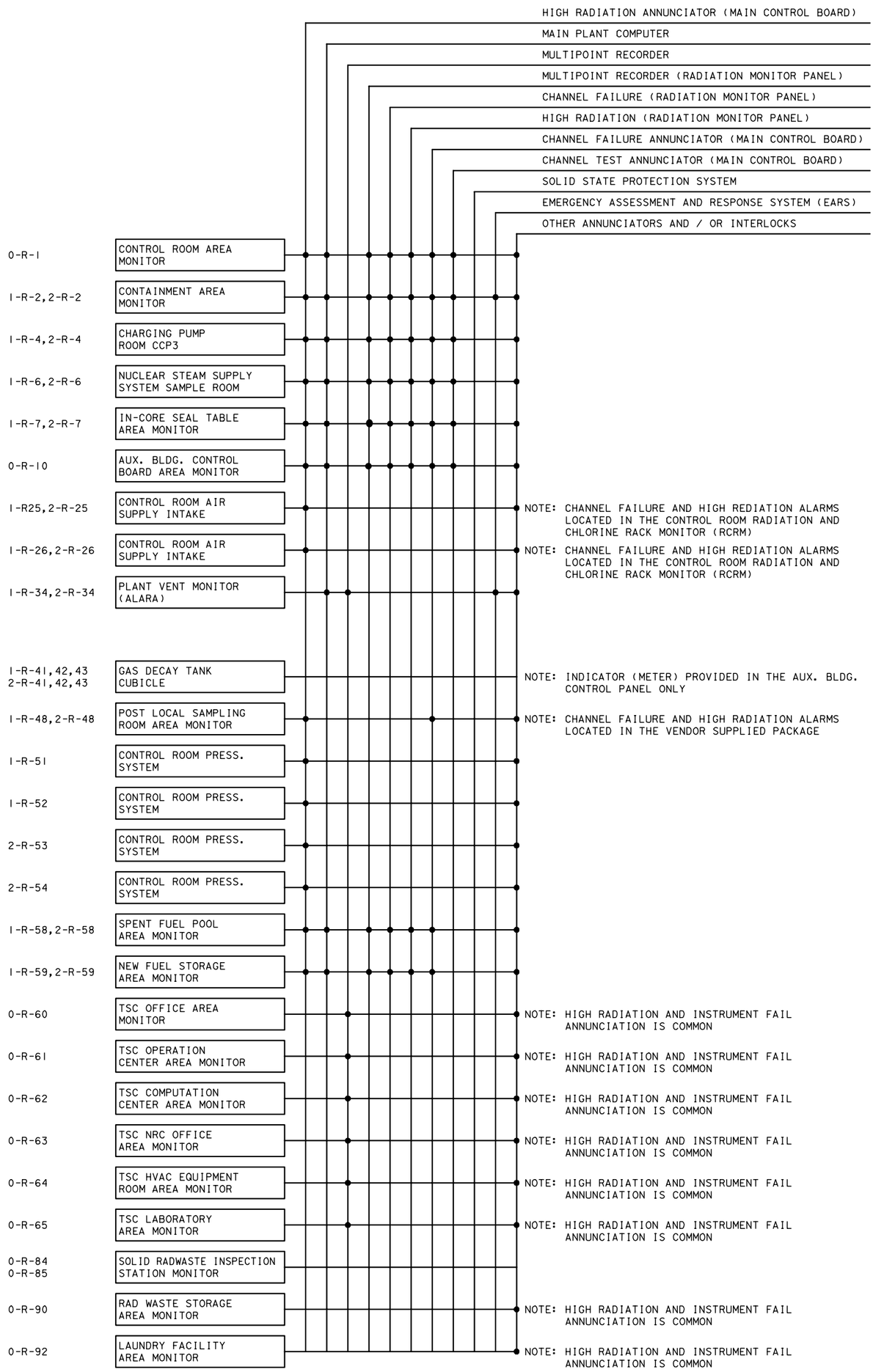
FIGURE 11.3-4

GASEOUS WASTE SYSTEMS' RELEASE POINTS

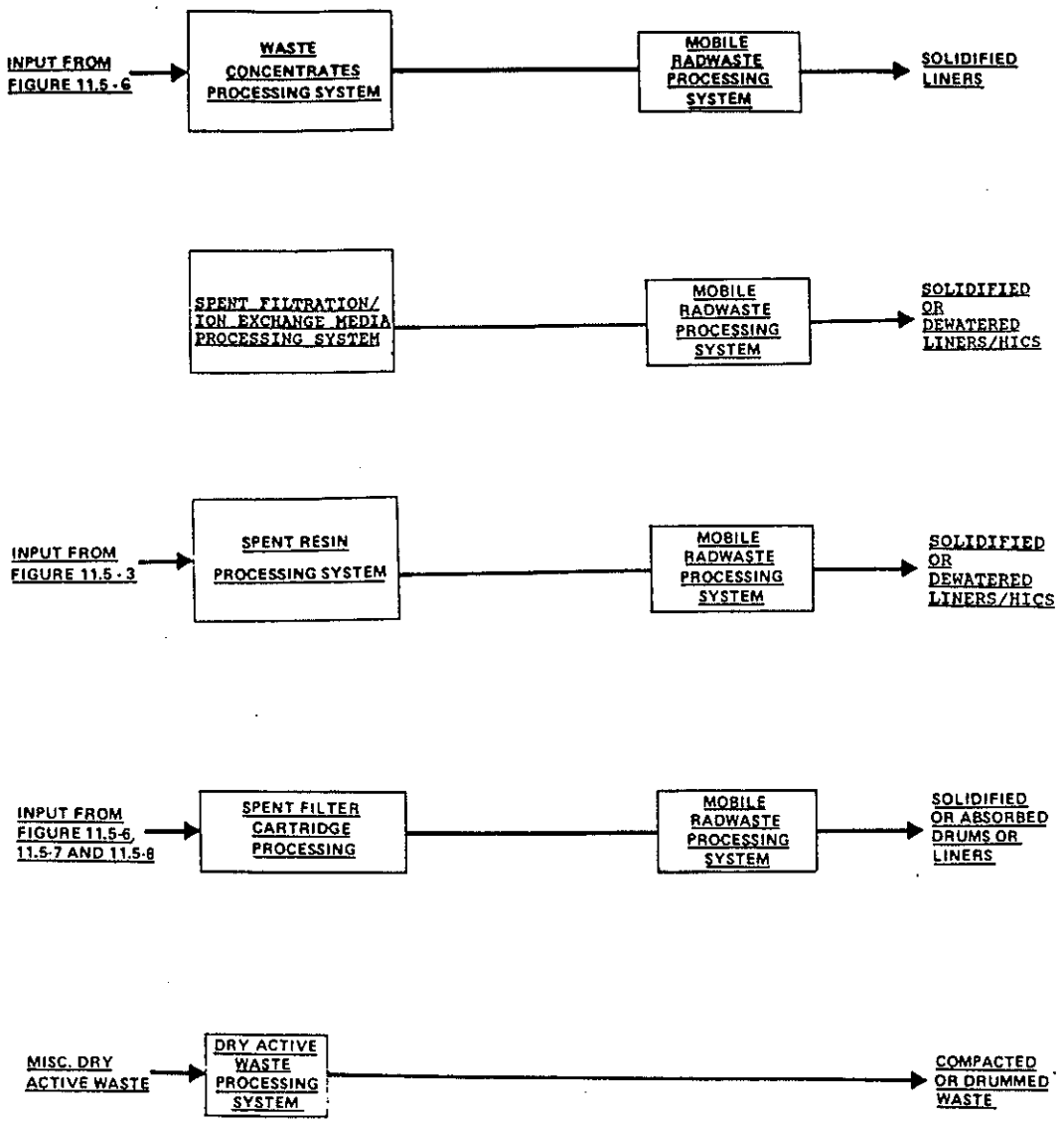
Revision 22 May 2015



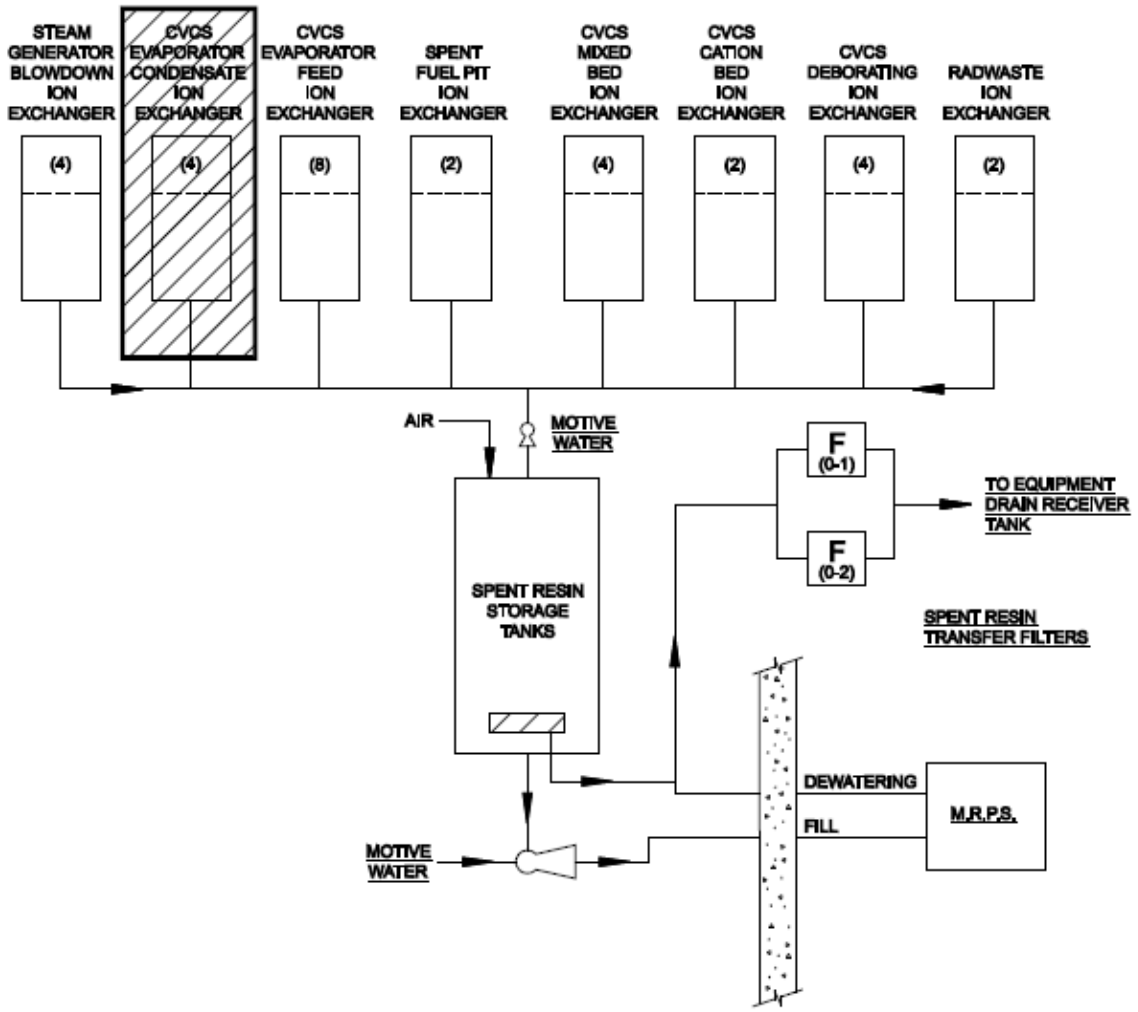
FSAR UPDATE
UNITS 1 AND 2
DIABLO CANYON SITE
FIGURE 11.4-1 Sheet 1 of 2
RADIATION MONITORING SYSTEM



FSAR UPDATE
UNITS 1 AND 2
DIABLO CANYON SITE
FIGURE 11.4-1 Sheet 2 of 2
RADIATION MONITORING SYSTEM



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 11.5 - 1 SOLID RADWASTE SYSTEM

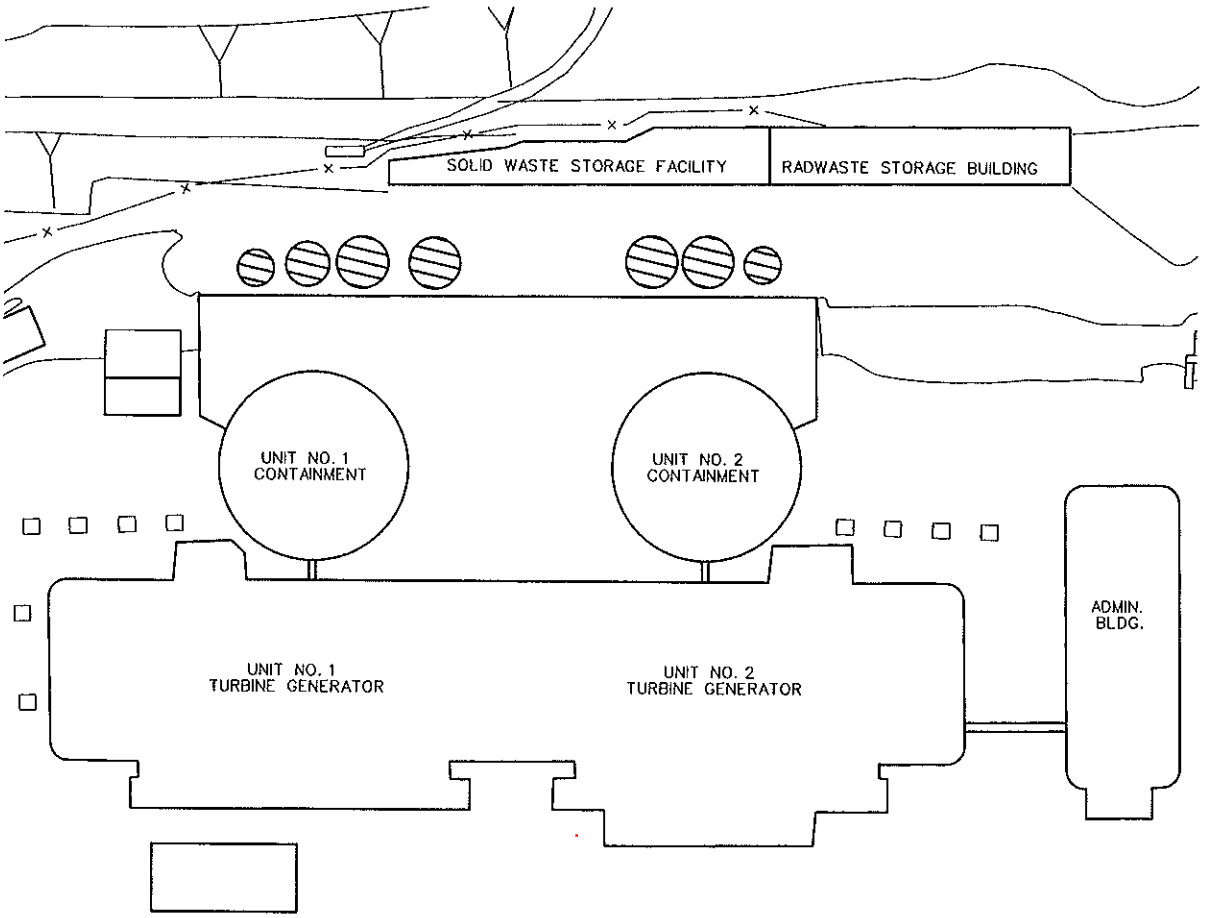


NOTES:

1. SHADED AREA DENOTES ABANDONED EQUIPMENT.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 11.5-3 SPENT RESIN FLOW DIAGRAM

Revision 20 November 2011

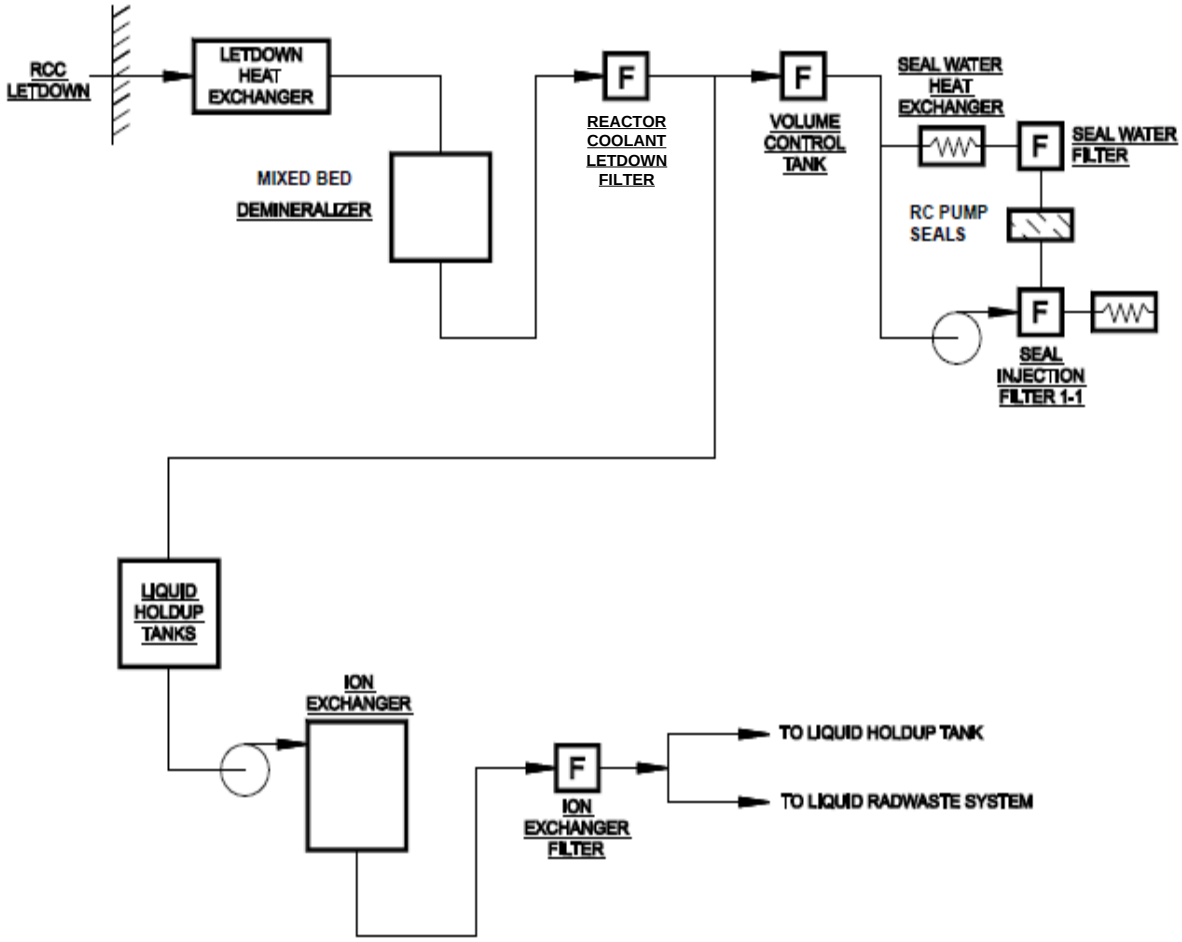


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

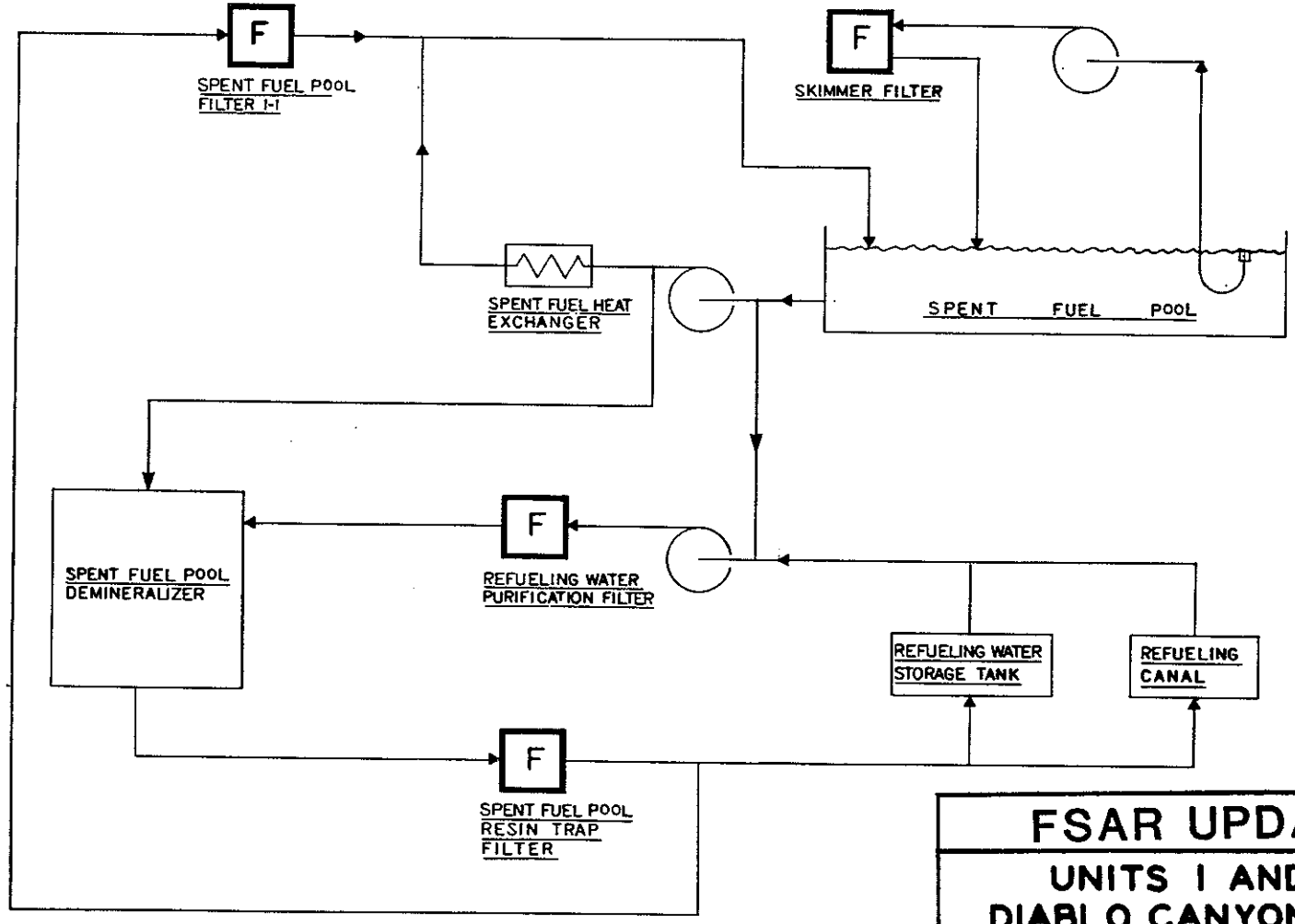
FIGURE 11.5-4
LOCATION OF ONSITE
STORAGE FACILITY

Revision 16 June 2005



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 11.5-6 CHEMICAL AND VOLUME CONTROL SYSTEM DISPLAYING FILTERS

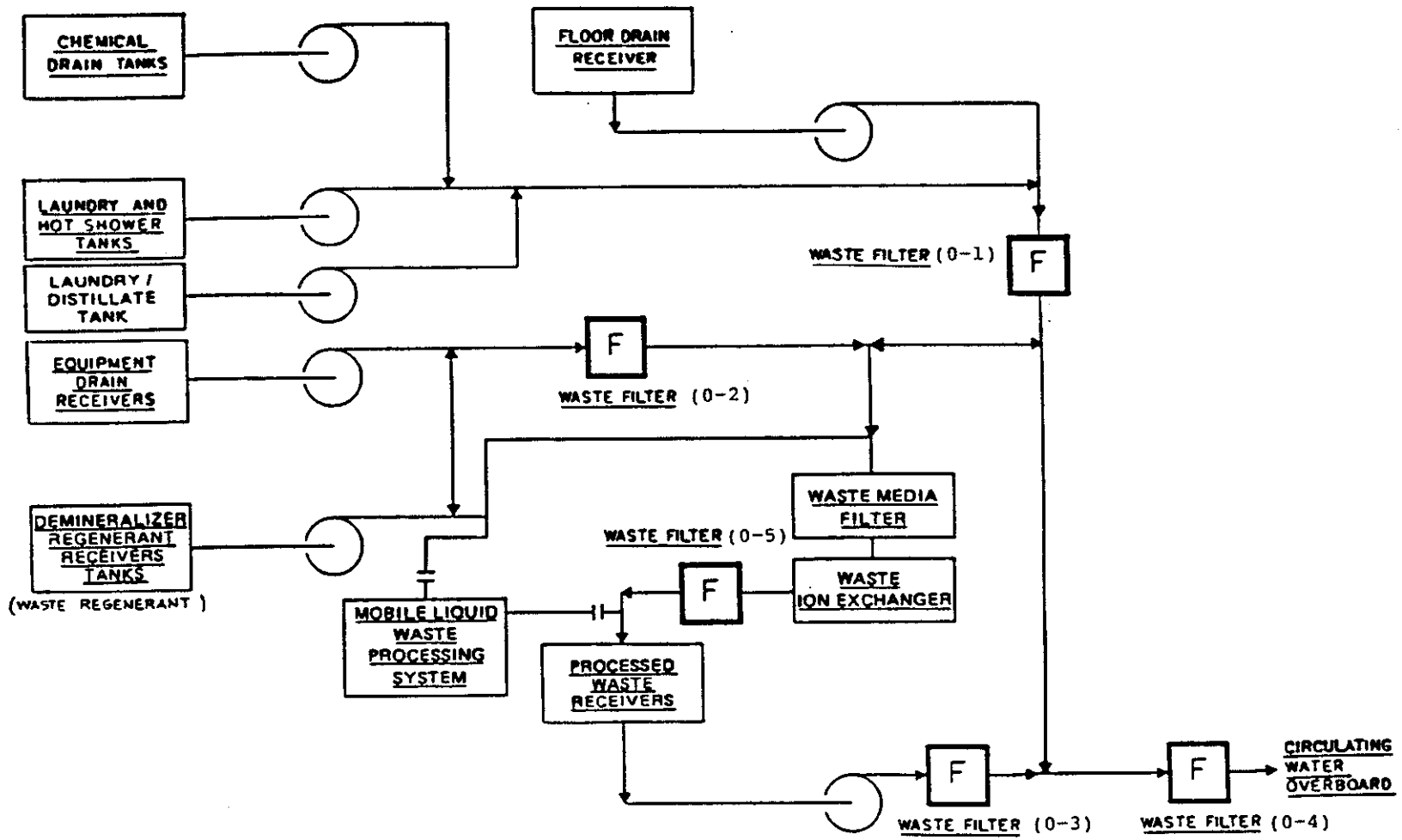
Revision 23 December 2016



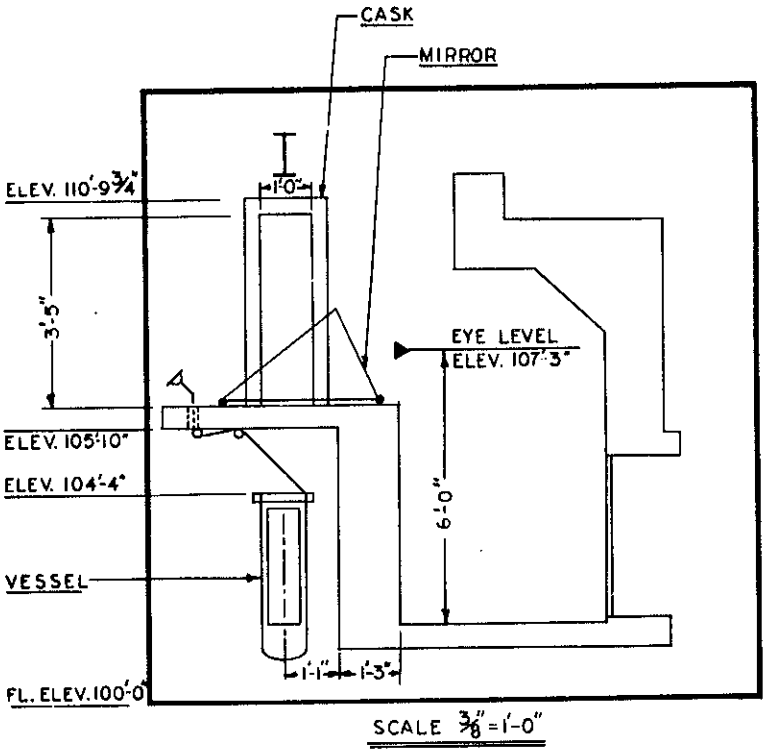
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.5-7
SPENT FUEL POOL DISPLAYING FILTERS



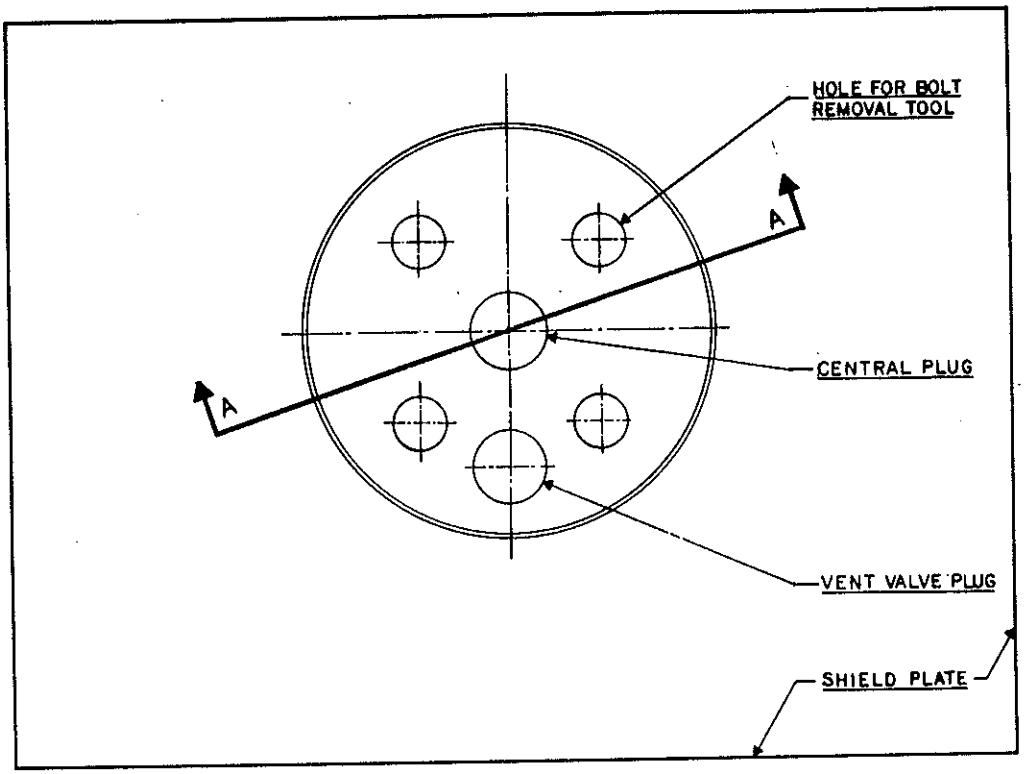
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 11.5-8 LIQUID RADWASTE SYSTEM DISPLAYING FILTERS

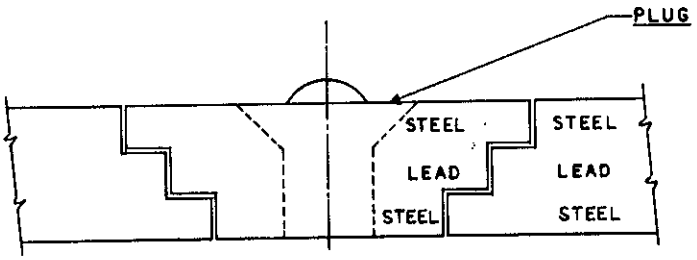


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

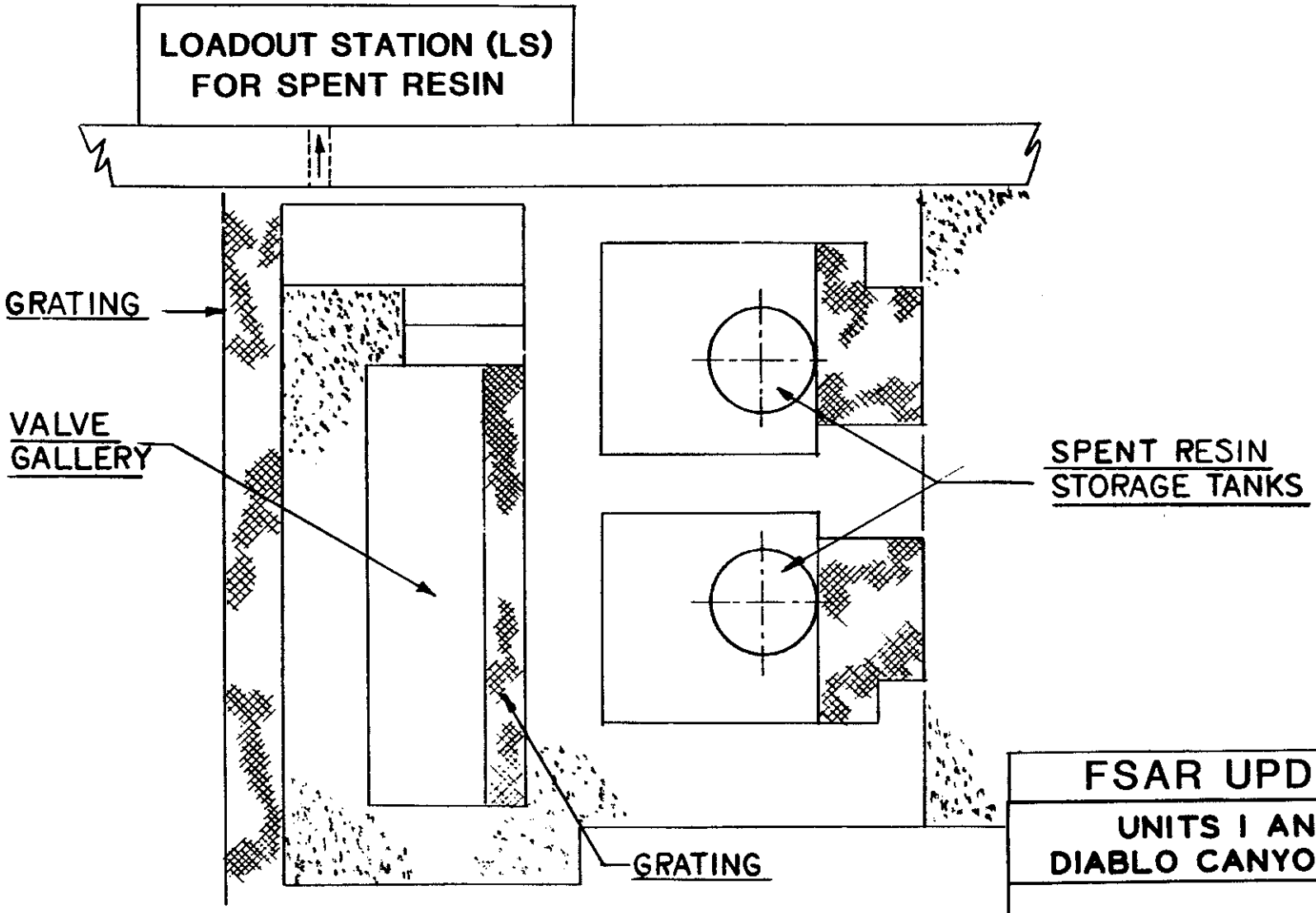
FIGURE 11.5 - 9
SYSTEM FOR CAPTURING
EXPENDED FILTER CARTRIDGES





SECTION A-A

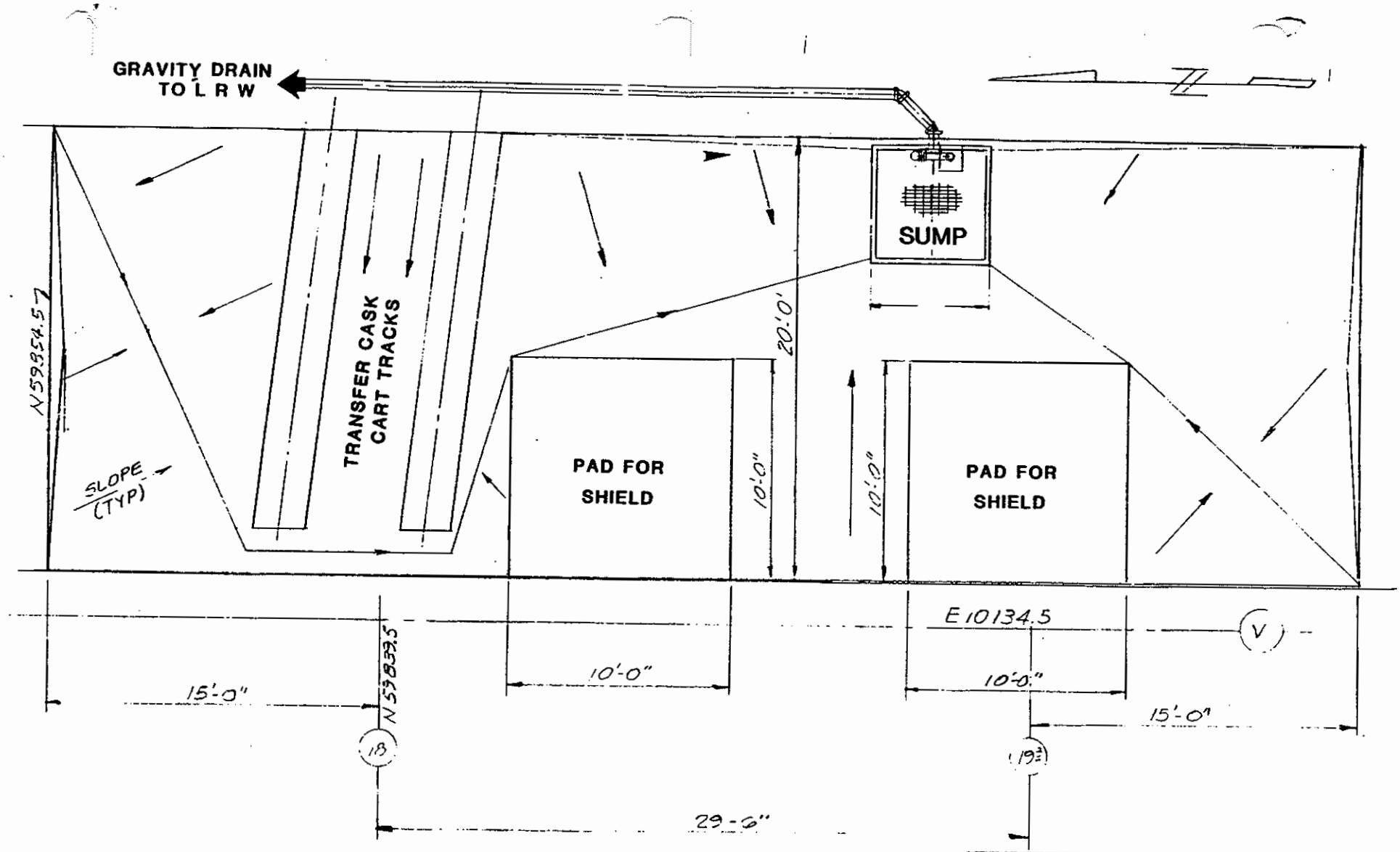
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 11.5 - 10 COVER OF FILTER VESSEL



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.5–11
SPENT RESIN STORAGE AREA



FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 11.5-12
LOAD OUT STATION

Chapter 12

RADIATION PROTECTION

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Chapter 12

RADIATION PROTECTION

The purpose of this chapter is to demonstrate that both external and internal radiation dose resulting from operation of the Diablo Canyon Power Plant (DCPP) will be kept as low as is reasonably achievable (ALARA) and within applicable limits.

The principles and guidelines used in the design, construction, and operation of the radiation protection (RP) systems and programs described in Chapter 12 are specified in the individual sections of Chapter 12 and in Table 12.0-1.

12.1 RADIATION SHIELDING

This section describes the radiation shielding objectives and design configuration, identifies and characterizes source terms, summarizes important features of the area radiation monitoring system, describes those operating procedures that ensure external dose is kept ALARA, and gives estimates of dose to operating personnel and persons proximate to the DCPP site boundary.

12.1.1 DESIGN BASES

12.1.1.1 General Design Criterion 11, 1967 – Control Room

Adequate radiation shielding is provided to permit access to equipment in the control room or other areas as necessary to shut down and maintain safe control of the facility without radiation exposures of personnel exceeding 10 CFR Part 20 limits.

12.1.1.2 General Design Criterion 19, 1999 – Control Room

Adequate radiation shielding is provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE for the duration of the accident.

12.1.1.3 General Design Criterion 68, 1967 – Fuel and Waste Storage Radiation Shielding

Radiation shielding is provided in the design of spent fuel and waste storage facilities as required to meet the requirements of 10 CFR Part 20.

12.1.1.4 Radiation Shielding Safety Function Requirements

(1) Neutron Radiation Attenuation

The radiation shielding designs reduce potential neutron activation of equipment and mitigate the possibility of radiation-induced material damage.

(2) Non-Accident Unit Operation

The radiation shielding designs permit the continued operation of the other unit on the site in the unlikely event that a design basis accident (DBA) occurs at one unit.

12.1.1.5 10 CFR Part 20 – Standards for Protection Against Radiation

The radiation shielding designs support the protection of personnel from radiation sources such that doses are maintained below the limits prescribed in 10 CFR Part 20 and are ALARA. Note: Although personnel exposure limits must comply with the current regulation, the original shielding designs were to the pre-1994 regulation.

12.1.1.6 10 CFR 100.11 – Determination of Exclusion Area, Low Population Zone, and Population Center Distance

The radiation shielding designs provide adequate RP under tank rupture accident conditions to assure that direct radiation from plant structures is sufficiently low so that the total dose at the site boundary from both direct radiation and effluents is within the limits specified in 10 CFR 100.11.

12.1.1.7 10 CFR 50.67 – Accident Source Term

The radiation shielding designs provide adequate radiation protection under accidents analyzed using AST methodology, including a loss of primary coolant, to assure that direct radiation from plant structures is sufficiently low so that the total dose at the site boundary from both direct radiation and effluents is within the limits specified in 10 CFR 50.67.

12.1.1.8 Regulatory Guide 8.8, July 1973 – Information Relevant to Maintaining Occupational Radiation Exposure as Low as Practicable (Nuclear Reactors)

The radiation shielding designs support the maintenance of occupational doses as low as practicable (i.e., ALARA).

12.1.1.9 NUREG-0737 (Items II.B.2, II.F.1, III.A.1.2, and III.D.3.4), November 1980 – Clarification of TMI Action Plan Requirements

Item II.B.2 – Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems Used in Post-accident Operations: The plant radiation shielding configuration provides adequate access to vital areas and protection of PG&E Design Class I equipment during a postulated degraded core accident.

Item II.F.1 – Additional Accident-Monitoring Instrumentation

Position (2) – The radiation shielding designs support provisions for continuous sampling of plant effluents for post-accident releases of radioactive iodines and particulates and onsite laboratory capabilities.

Item III.A.1.2 – Upgrade Emergency Support Facilities: NUREG-0737, Supplement 1, January 1983 provides the requirements for III.A.1.2 as follows:

Section 8.2.1(f) - The technical support center (TSC) is provided with radiation shielding necessary to assure that radiation exposure to any person working in the TSC would not exceed 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident.

Item III.D.3.4 – Control Room Habitability Requirements: The radiation shielding for the control room is designed to ensure that the plant can be safely operated or shut down under DBA conditions.

It is noted that DCPP has incorporated a full implementation of Alternative Source Terms (AST) as defined in Regulatory Guide 1.183, July 2000, Section 1.2.1. The adequacy of the shielding associated with the control room and the technical support center have been re-evaluated using AST (refer to Section 15.5).

12.1.2 DESIGN DESCRIPTION

This section discusses the specific design criteria for individual radiation shielding systems required to achieve the overall objectives and describes the actual shielding design.

12.1.2.1 Radiation Shielding Locations and Basic Configurations

Figure 1.2-1 shows a plot plan of the site and indicates the location of roads, major plant buildings, and switchyards. It should be noted that the plant site is not served by railroad facilities. Figure 1.2-2 presents a detail of the plant layout and shows the location of outside tanks that could house potentially radioactive materials.

Figures 1.2-4 through 1.2-9 provide scaled plan views of Unit 1 buildings that contain process equipment for treatment of radioactive fluids, and indicate locations and basic configurations of the shielding provided. Figures 1.2-10 through 1.2-12 show similar views of Unit 2 structures. Corresponding sectional views of Unit 1 structures including shielding are shown in Figures 1.2-21 through 1.2-26. Comparable sectional views of Unit 2 structures are shown in Figures 1.2-28 through 1.2-30. Unit 1 and Unit 2 are similar with respect to radiation shielding design.

12.1.2.2 General Radiation Shielding Design Criteria and Features

One of the principal design objectives for plant radiation shielding is to reduce the expected radiation levels within plant structures to values that will allow plant personnel

to gain access to normal work areas and remain there for sufficient time to perform required routine work without exceeding normal occupational dose limits. To implement this objective, plant areas capable of personnel occupancy are classified into one of five zones on the basis of expected frequency and duration of occupancy during routine operation, refueling, and maintenance. Note that zone maps show general zones and are not utilized within the RP program. A maximum design dose rate criterion is defined for each zone. Plant radiation shielding is designed to ensure that radiation dose rates in all plant areas are below the classified zone limits.

The radiation zone criteria are summarized in Table 12.1-1. The specific zoning for all plant areas during normal operation in Unit 1 is shown in Figures 12.1-1 through 12.1-12. Radiation zones for Unit 2 are similar to those for Unit 1.

Typical Zone 0 areas are the turbine building and turbine plant service areas, the control room, and the TSC. Typical Zone I areas are the auxiliary building work stations and corridors and the outer surfaces of the containment and auxiliary building, excluding penetration areas. Typical Zone II areas include some auxiliary building work stations and corridors, most areas of the FHB, and most areas on the 140 foot level of containment during reactor shutdown. Typical Zone III areas include most areas in the auxiliary building and containment outside the bioshield (during refueling) not previously identified as Zones I or II, excluding areas in close proximity to system components associated with dose rates more typical of Zone IV areas. These typical Zone IV areas are containment inside the bioshield during refueling and all of containment during power operations, areas that contain concentrating media such as demineralizers and filters, and all areas in close proximity o the following system components: CVCS, RCS, LRW, RHR, SI, and Charging. The post-accident radiation levels within the plant structures are discussed in Reference 1.

The radiologically controlled areas (RCAs) within plant structures (Zones I, II, III, and IV) are separated by barriers from the uncontrolled areas (Zone 0) to avoid inadvertent entry of unauthorized personnel. Entrance into the RCAs is normally made from a single access control station at the 85 foot elevation of the auxiliary building and is under procedural control. An auxiliary access control, located on the 140 foot elevation, may be utilized to provide more efficient access into the RCA, including containment buildings. Other access control stations may be temporarily established to support plant operations on an ad hoc basis. Within the RCAs, all areas are appropriately marked and/or barricaded in accordance with 10 CFR Part 20 and other applicable regulations. Areas designated Zone IV, such as the room containing the equipment and floor drain receiver tanks and the waste concentrator tanks, are accessible to plant personnel only at infrequent intervals, for limited periods of time, and then under strict radiological control. The dry active waste and resin liner storage areas in the radwaste storage building are also designated as Zone IV.

Care has been taken to ensure that RCA zones that are normally relatively low dose rate areas (i.e., Zones I and II) are not likely to be subjected to unexpected increases in dose rate due to the rapid introduction of radioactive materials into nearby process

piping or other means. The routing of all plant piping is strictly controlled. Pipes that carry radioactive materials are routed in RCAs properly zoned for that level of activity.

Radiation shielding is arranged to protect personnel from direct gamma radiation that could otherwise stream through piping penetrations. Reach rods are provided where necessary to permit the operator to remain behind shielding while operating valves. For the radwaste storage building, exposure of site workers is minimized through the use of concrete shielding around the stored material, remote handling of high activity liners, and controlled access to the storage building.

12.1.2.3 Containment Radiation Shielding Design

Containment shielding is divided into four categories according to functions: primary shield, secondary shield, fuel handling shield, and accident shield. Each of these is discussed below.

12.1.2.3.1 Primary Radiation Shield

The primary shield consists of the core baffle, water annuli, barrel-thermal shield (all of which are within the reactor vessel), the reactor vessel wall, and a concrete structure surrounding the reactor vessel.

The primary shield (or parts thereof) performs the following functions:

(1) Reduces the energy-dependent neutron flux incident on the reactor vessel to prevent material property changes that might unduly restrict operation of the plant

(2) Attenuates reactor core neutron flux to prevent excessive activation of plant components and structures outside the primary shield

(3) Limits the gamma flux in both the reactor vessel and primary shield concrete to avoid large temperature gradients and/or dehydration of the concrete

(4) Reduces the radiation levels from reactor sources so that limited access is possible to certain areas within the reactor containment building during full power operation

(5) Reduces the residual radiation from the core to levels that will permit access to the region between the primary and secondary shields at a reasonable time after shutdown

The concrete structure immediately surrounding the reactor vessel extends up from the base of the containment and is an integral part of the main structural concrete support for the reactor vessel. It extends upward to join the reactor cavity. The reactor cavity, which is approximately rectangular in shape, extends upward to the operating floor.

The primary concrete shield is air-cooled to prevent overheating and dehydration from the heat generated by radiation absorption in the concrete. Eight "windows" are provided in the primary shield for insertion of the out-of-core nuclear instrumentation. Cooling for this instrumentation is also provided by air.

12.1.2.3.2 Secondary Radiation Shield

The secondary shield surrounds the primary shield and the reactor coolant loops and consists of the annular polar crane support wall, the concrete operating floor over the primary coolant loops, and the shell of the containment structure. The shell of the containment structure also serves as the accident shield.

The main function of the secondary shielding is to attenuate the radiation originating in the reactor and reactor coolant. Although the interior of the containment is a Zone IV area during full power operation, the secondary shielding is designed to reduce radiation levels to a point where limited access to certain areas within the containment is possible. The areas where limited accessibility is intended include the operating floor at elevation 140 feet and the annular areas between the crane wall and the containment shell on elevations 91 and 115 feet. The radiation levels in these areas are generally less than 15 mrem/hr. The secondary shield will also limit the full power dose rate outside the containment building to less than 1 mrem/hr.

12.1.2.3.3 Fuel Handling Radiation Shield

The reactor cavity, flooded during refueling operations, provides a temporary water shield above the components being withdrawn from the reactor vessel. The water height during movement of fuel assemblies is at least 23 feet above the reactor vessel flange. This height ensures that a minimum of 8 feet of water will be above the top of a withdrawn fuel assembly (about 9 feet of water above the active fuel). With upper internals in place, the water height during the unlatching of control rods is at least 23 feet above the fuel assemblies (at least 12 feet above the reactor vessel flange).

The fuel handling shield is designed to facilitate the removal and transfer of spent fuel assemblies and rod cluster control assemblies (RCCAs) from the reactor vessel to the spent fuel pool. It is designed to attenuate direct radiation from spent fuel and RCCAs to less than 2.5 mrem/hr at the refueling cavity water surface except during movement of a fuel assembly and as noted below. (Note that surface dose rates may typically be as high as 15 mrem/hr due to radioactive corrosion products in the water which is typically a much greater dose contributor than the fuel and RCCAs.

The fuel handling shield also provides attenuation of radiation from the reactor vessel internals. During removal of the upper internals package, the control rod drive shafts and guide tube assemblies must be raised above the water surface producing temporary radiation levels in excess of 1 R/hr. In the stored position, the very top of the control rod drive shafts extend from the surface producing localized dose rates to operators in the immediate area of less than 100 mrem/hr. The general area dose rate at the side of the pool is less than 5 mrem/hr near the upper internals. However, as noted above, surface dose rates may typically be as high as 15 mrem/hr due to radioactive corrosion products in the water.

The refueling canal is a passageway connected to the refueling cavity and extending to the inside surface of the reactor containment. The canal is formed by two concrete walls that extend upward to the same height as the refueling cavity. During refueling, the canal is flooded with borated water to the same height as the refueling cavity.

The spent fuel assemblies and RCCAs are remotely removed from the reactor containment through the horizontal spent fuel transfer tube and placed in the spent fuel pool. Concrete shielding and barriers protect personnel from radiation during the time a spent fuel assembly is being transferred from the containment to the spent fuel pool.

12.1.2.3.4 Accident Radiation Shield

The accident shield consists of the reinforced concrete cylindrical containment shell that is capped by a hemispherical reinforced concrete dome. This includes supplemental shielding for equipment and personnel hatches and the fuel transfer tube.

The equipment access hatch is shielded by a solid concrete block shadow shield. The main function of the accident shield is to reduce radiation levels outside the containment building to an acceptable level following a DBA.

12.1.2.4 Fuel Handling Area Radiation Shielding Design

Spent fuel is stored in the spent fuel pool located in the fuel handling area which is adjacent to the containment. The basic shield configuration for the Unit 1 spent fuel pool is shown in plan views in Figure 1.2-5 and in sectional views in Figures 1.2-23 and 1.2-24.

Water is used to provide shielding over the spent fuel assemblies so visual observation of fuel handling operations can be realized. The depth of the pool provides a submergence for the top of a fuel assembly of at least 8 feet during normal fuel handling operations and 23 feet submergence while fuel is stored in the fuel racks. Pool water level is indicated, and any water removed from the pool must be pumped out since there are no gravity drains.

The shielding for the fuel handling area restricts the dose rate to less than or equal to 5 mrem/hr in normally occupied areas.

Dose rates at the surface of the spent fuel pool will normally be less than or equal to10 mrem/hr.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

During transfer of a spent fuel assembly, the minimum water level above the active fuel is about 9 feet. With a peak fuel assembly (1.55 times full power level) being transferred, the maximum calculated dose rate at the surface of the pool is 50 mrem/hr. However, dose rates to the operator on the refueling platform are less than 20 mrem/hr. The calculated doses exclude any contribution to dose from radioactivity contained in the spent fuel pool water.

For additional information on the spent fuel pool water, refer to Section 9.1.3.2.

12.1.2.5 Auxiliary Building Radiation Shielding Design

The purpose of the radiation shielding in the auxiliary building is to protect personnel working near various system components in the chemical and volume control system (CVCS), the residual heat removal system, the waste disposal system, and the sampling system. The general layout of the shielding in the auxiliary building is shown on plan views of Figures 1.2-4 through 1.2-9. Sectional views are included in Figures 1.2-21 through 1.2-23, 1.2-25, and 1.2-26.

The shielding provided for the auxiliary building is designed to limit the dose rate during normal operation to less than 1 mrem/hr in normally occupied areas, and at or below 2.5 mrem/hr in areas requiring periodic occupancy. In addition, the auxiliary building shielding is designed to provide limited access to areas within the building during the long-term recirculation phase following a loss-of-coolant accident (LOCA).

The auxiliary building radiation shielding consists of concrete walls around equipment and piping that contain significant quantities of activity. Each equipment compartment is individually shielded so that compartments may be entered without having to shut down and/or decontaminate the adjacent system. In some cases, such as the tube withdrawal spaces for the abandoned boric acid and waste evaporators (refer to Figure 1.2-7), removable concrete block walls are provided to allow personnel access to equipment during maintenance periods. The shield material provided throughout the auxiliary building is regular concrete except for some of the shielding around the reactor coolant letdown filter, which is high-density concrete. The principal auxiliary building shielding provided is tabulated in Table 12.1-2.

12.1.2.6 Control Room Radiation Shielding Design

The control room radiation shielding consists of the concrete walls and roof of the control room. A plan view of the control room is shown in Figure 1.2-4, and sectional views are shown in Figures 1.2-25 and 1.2-26.

Normal radiation levels in the control room are less than 0.5 mrem/hr.

The limiting case for radiation shielding design is post-LOCA conditions. The control room radiation shielding limits the integrated doses under post-LOCA conditions to less than or equal to 5 rem Total Effective Dose Equivalent (TEDE) as specified in 10 CFR 50.67, GDC 19, 1999 and NUREG-0737, November 1980, Item III.D.3.4. For a discussion on post-accident shielding adequacy refer to Sections 6.4.1 and 15.5.17.2.4.

12.1.2.7 Technical Support Center Radiation Shielding Design

The TSC is designed to be habitable throughout the course of a DBA. Concrete shielding in the walls, roof, and floor limits the integrated doses under post-accident conditions to less than or equal to 5 rem TEDE consistent with the criterion for the TSC in Section 8.2.1(f) of NUREG-0737, Supplement 1, as amended by Regulatory Guide 1.183, Section 1.2.1, and 10 CFR 50.67. For a discussion on post-accident shielding adequacy refer to Section 15.5. Special labyrinth shields are furnished to cover each TSC doorway entrance to preclude significant dose contributions from radiation streaming.

12.1.2.8 Post-accident Sampling Compartment Radiation Shielding Design

The sampling compartment is shielded from external sources by concrete walls and concrete support columns.

12.1.2.9 Old Steam Generator Storage Facility

The old steam generators (OSGs) and old reactor vessel head assemblies (ORVHAs) were removed from DCPP Unit 1 and Unit 2 during the steam generator and reactor vessel head replacement projects. These ten large components are temporarily stored in the OSG storage facility (OSGSF) specifically constructed for this purpose. The OSGSF meets the radwaste storage requirements for temporary storage of the OSGs and ORVHAs until site decommissioning. The radiological design of the OSGSF meets the radiation shielding requirements of 40 CFR Part 190 and 10 CFR Part 20. The building is designed to have a maximum contact dose rate of 0.2 mrem/hr on the exterior wall surface. This value is less than and is bounded by the 0.5 mrem/hr radiation dose rate limitation requirement stated in Table 12.1-1 for the plant occupancy zone in which the OSGSF is located (Zone 0 – Unlimited Access). The building design also provides entrance doors with concrete labyrinths designed to provide shielding.

12.1.3 SOURCE TERMS

The normal full power sources utilized for shielding and dose calculations discussed in this this chapter are based on operation for 1 year at a core thermal power of 3568 MWt with an 85 percent capacity factor. The source terms were calculated using the EMERALD-NORMAL (Reference 2) computer code, and the source terms are assumed to be the maximum that would occur under either the design basis case or the normal operation case (including anticipated operational occurrences); both of these conditions are defined in Chapter 11. The isotopic source terms applicable to dose calculations are listed in the tables in Section 11.1 and Tables 12.1-3 through 12.1-13.

Maximum actual operating configuration is up to 21 months of operation, with a mixture of fuel with enrichments up to 5 percent, with maximum analyzed burnup of 50,000 MWD/MTU. Refer to the end of this section for an assessment of the impact of the actual maximum operating configuration on the adequacy of plant shielding.

The adequacy of shielding thickness for the shielded compartments was established during the original license application using computer code ISOSHLD (Reference 3). ISOSHLD performs gamma ray shielding calculations for isotopic sources in a wide variety of source and shield configurations. Attenuation calculations were performed by point kernel integration, with attenuation and buildup factors provided for shields with an effective atomic number of from 4 to 82. Section 15.5.8.4 provides a more detailed description of the code. For these shielding calculations, source and shield configurations were approximated by cylindrical or slab geometry, and the radiation exposure rates were calculated, using ISOSHLD, at all locations outside the shielded compartments where exposure to plant personnel is possible.

In addition, radiation dose rates were calculated for the storage tanks outside the auxiliary building; i.e., the primary water storage tank and the refueling water storage tank. Exposure rates were calculated, using ISOSHLD, immediately outside the tanks and at the site boundary (800 meters).

The results of these calculations are shown in Table 12.1-14. The calculations are for direct gamma exposure only; at distances such as 800 meters, the contribution from air-scattered gamma rays can increase the total dose rate by as much as a factor of 2 (Reference 4). The calculated exposure rates at the site boundary are small enough that any contribution from air-scattered gamma rays will still produce a negligible result.

A review was performed of the effect of the updated core inventory reported in Table 15.5-77, and the associated reactor coolant activity inventory with 1 percent fuel defects reported in Table 11.1-11A, on shielding adequacy. The assessment took into consideration the limit imposed on the reactor coolant concentrations by the plant technical specifications. The review demonstrated that the existing plant shielding remains adequate for safe plant operation, and that the current normal operation radiation zones are unaffected.

Refer to Section 12.2.3 for airborne radioactive source terms.

12.1.4 AREA MONITORING

The plant's area radiation monitoring system is described in detail in Section 11.4.

The area radiation monitoring system consists of fixed detectors mounted at the locations listed in Table 11.4-1.

The area radiation monitoring system is not required for safe shutdown of the plant. The principal purpose of the system is to alert personnel of increasing radiation levels in the monitored areas. Upon receipt of an alarm, the normal procedure is for operations personnel to investigate the cause and then take any action that is warranted. In general, the area radiation monitors have no automatic functions other than their alarm function. The exceptions to this are the instruments in the spent fuel and new fuel storage areas that automatically transfer the fuel handling building ventilation system (FHBVS) to the Iodine Removal Mode (refer to Section 9.4.4.2) and sound an alarm.

12.1.5 OPERATING PROCEDURES

The operating procedures that ensure external exposures will be kept ALARA can be grouped into three broad categories:

(1) Routine surveillance of the dose rate at various plant locations

(2) Preplanning and procedural control of radiation work

(3) Analysis of dose actually received

Each of these is discussed below:

(1) During the initial startup test program, a series of neutron and gamma dose rate measurements were performed to verify that there are no defects or inadequacies in the shielding that might hinder normal operation and/or maintenance activities. In addition, a comprehensive program of routine gamma dose rate measurements is an integral part of the plant RP program. This information is used to identify areas where special measures may be required to avoid unnecessary radiation exposure, to assist in the preplanning of work, and to help identify equipment malfunctions that lead to increased dose rates. Radiation areas are appropriately posted and/or barricaded in accordance with the requirements of 10 CFR Part 20 and the plant Technical Specifications (Reference 6).

(2) Under the provisions of the plant RP program, all radiation work is carried out under a radiation work permit. These work permits are instruction

sheets intended to ensure that appropriate precautions will be taken during the performance of all radiation work. As such, they specify protective clothing requirements, monitoring requirements, dosimetry requirements, expected radiation conditions, and any special measures required to control the dose received by personnel. Such special measures might include limiting the stay time in an area, erection of temporary shielding, use of remote handling tools, or other techniques appropriate to the specific situations. Personnel are instructed in RP in accordance with specific procedures established in Volume I of the Plant Manual.

(3) Self-reading dosimeters, coupled with the results of the thermoluminescent dosimeters (TLDs), are routinely checked by RP personnel to verify that each individual's exposure, as shown on the individual's permanent record, is within expected values. If a person's exposure appears to be higher than estimated, RP personnel investigate and initiate corrective action. Radiation workers are responsible for remaining cognizant of their current exposure status.

HISTORICAL INFORMATION IN ITALICS BELOW, NOT REQUIRED TO BE REVISED

12.1.6 ESTIMATES OF EXPOSURE

An assessment of the expected radiation dose to individuals as a result of DCPP operations was performed as part of the original license application. Provided below is a summary of the results and general conclusions:

(1) The annual man-rem external exposure in offsite locations resulting from direct shine from plant structures containing radioactive materials was extremely small. For example, the annual continuous occupancy dose at a distance of 800 meters contributed by direct shine from the containment was calculated to be approximately 1.5 mrem using the conservative assumption that the dose rate on its exterior surface was the maximum design value of 1 mrem/hr.

(2) The man-rem exposure to the general public was, for all practical purposes, the result of airborne and liquid releases from the radioactive waste disposal system. Although this exposure was very low, numerical estimates were made and are presented in Sections 11.2.2.7 and 11.3.2.5 for liquid and gaseous releases, respectively.

(3) Estimates of personnel exposures were obtained from surveys of exposure at other operating plants and from calculations based on anticipated occupancy times for various job classifications in various areas within the plant. The calculated exposures compared reasonably well with those experienced at other plants.

12.1.6.1 Calculated Exposure Estimates

The annual exposure to plant personnel for normal operation of the two units was calculated to be about 50 man-rem. This value was derived from anticipated occupancy times for various job classifications in various areas within the plant. The dose rates assigned to the various areas were based on normal plant operation assuming approximately 0.2 percent fuel defects. Table 12.1-15 presents a summary of the calculated values of man-rem exposure on the basis of occupancy factors listed in Table 12.2-17 and dose rates in various areas.

Experience at other pressurized water reactors has shown that normal operational activities generally account for only part of a plant's total exposure. Hence, the total estimated annual dose with both units operating, and including special maintenance and refueling activities, was about 400 man-rem.

12.1.6.2 Exposure Estimates Based on Operating Plant Experience

Reference 5 reports that for 1981 the annual average collective dose from a pressurized water reactor was 652 man-rem.

12.1.6.3 Exposure Estimates for Diablo Canyon Power Plant

Based on the above described exposure estimates from both analytical predictions and records of exposures at actual operating plants, it was believed that 200 man-rem per year per unit represented a reasonable estimate of the maximum total exposure to be expected for performance of all normal operations, testing, and maintenance at DCPP. The exposure for two-unit operation should be somewhat less than double the value for operation of one unit, since certain facilities, such as the radwaste treatment system, are common to both units.

12.1.7 SAFETY EVALUATION

12.1.7.1 General Design Criterion 11, 1967 – Control Room

The radiation dose in the control room under normal conditions is well below the limits specified in 10 CFR Part 20 (refer to Sections 12.1.2 and 12.1.3).

Areas outside the control room that are necessary to shut down and maintain safe control of the facility under normal operating conditions are provided with adequate radiation shielding such that operator dose is well below the limits specified in 10 CFR Part 20 (refer to Sections 12.1.2 and 12.1.3).

12.1.7.2 General Design Criterion 19, 1999 – Control Room

The control room shielding, in conjunction with the control room ventilation system (CRVS) and administrative controls, is designed to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE for the duration of the most severe DBA (refer to Sections 12.1.2 and 12.1.3). An evaluation of post-accident control room radiological exposures is presented in Section 15.5.

12.1.7.3 General Design Criterion 68, 1967 – Fuel and Waste Storage Radiation Shielding

Radiation shielding from spent fuel storage is provided by the concrete walls of the spent fuel pool and the depth of the water in the pool (refer to Sections 12.1.2, 12.1.3, and 9.1.2).

The purpose of the radiation shielding in the auxiliary building is to protect personnel working near various systems containing radioactivity from doses in excess of 10 CFR Part 20 limits (refer to Section 12.1.2.5). The purpose of radiation shielding in the radwaste building is to protect personnel working around the stored radwaste material (refer to Section 12.1.2.2).

12.1.7.4 Radiation Shielding Safety Function Requirements

(1) Neutron Radiation Attenuation

Refer to Section 4.2.2.5.4 for an evaluation of neutron radiation attenuation inside the concrete primary shield. Outside the concrete primary shield, neutron radiation is reduced to levels where neutron activation of equipment is not a concern (refer to Section 12.1.2.3.1).

(2) Non-Accident Unit Operation

During accident conditions, continued operation of the non-accident unit is made possible by the habitability of the shared control room (refer to Sections 6.4.1, 12.1.2, and 15.5).

12.1.7.5 10 CFR Part 20 – Standards for Protection Against Radiation

The regulations of 10 CFR Part 20 limit the Total Effect Dose Equivalent (TEDE) to 5 rem per year. Pacific Gas and Electric Company limits TEDE to 5 rem per year with guidelines for maintaining doses at levels below this value (refer to Sections 12.1.2 through 12.1.4).

If operating experience reveals areas where exposure problems exist, appropriate changes will be made in plant shielding, source strengths, locations, or operating practices as required to maintain personnel doses ALARA (refer to Section 12.1.5).

Refer to Section 12.1.3 for a discussion of the determination of radiation levels and radioactive material concentrations within structures, systems and components of the plant that could affect direct radiation exposures to members of the public.

12.1.7.6 10 CFR 100.11 – Determination of Exclusion Area, Low Population Zone, and Population Center Distance

Radiation shielding designs ensure that direct radiation from plant structures is sufficiently low so that the total dose at the site boundary from both direct radiation and effluents is within the limits specified in 10 CFR 100.11 for tank rupture accident conditions (refer to Sections 12.1.2 and 15.5).

12.1.7.7 10 CFR 50.67 – Accident Source Term

Radiation shielding designs ensure that direct radiation from plant structures is sufficiently low so that the total dose at the site boundary from both direct radiation and effluents is within the limits specified in 10 CFR 50.67 for accidents analyzed using AST methodology (refer to Sections 12.1.2 and 15.5).

12.1.7.8 Regulatory Guide 8.8, July 1973 – Information Relevant to Maintaining Occupational Radiation Exposure as Low as Practicable (Nuclear Reactors)

The radiation shielding designs, where practicable, separate radiation sources from areas where personnel have normal or routine access. Movable shielding is provided where permanent shielding is impractical. Shielding is provided in areas containing radioactive wastes. Refer to Section 12.1.2 for detailed discussions of the plant shielding designs.

12.1.7.9 NUREG-0737 (Items II.B.2, II.F.1, III.A.1.2, and III.D.3.4), November 1980 – Clarification of TMI Action Plan Requirements

Item II.B.2 – Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems Which May Be Used in Post-accident Operations: A post-accident radiation shielding design review for DCPP, as required by NUREG-0737, November 1980 (Reference 7), was performed and is reported in Reference 1.

Adequate radiation shielding is provided to prevent the degradation of PG&E Design Class I equipment. Also, the control room, TSC, and switchgear rooms are the vital areas requiring access and occupancy during post-accident conditions. All three of these rooms, as well as access pathways, are sufficiently shielded from external sources of radiation such that personnel access and occupancy would not be unduly

limited by the radiation environment caused by a degraded core accident (refer to Sections 6.4.1.3.16, 12.1.2, and 12.1.3).

Item II.F.1 – Additional Accident Monitoring Instrumentation

Position (2) – Plant vent high range iodine and particulate sampling may be performed by transferring the radiation monitor filter cartridges to the TSC laboratory. A lead transfer carriage is utilized to minimize personnel dose during the transfer of the cartridges.

Item III.A.1.2 – Upgrade Emergency Support Facilities:

Section 8.2.1(f) – Radiation shielding for the TSC, in conjunction with the TSC ventilation system, maintains TSC radiation exposures within 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident, consistent with the criteria for habitability provided in NUREG-0737, Supplement 1, January 1983, Item 8.2.1(f) (refer to Sections 6.4.2.3.4, 12.1.2, and 12.1.3).

Item III.D.3.4 – Control Room Habitability Requirements: Calculations indicate that shielding thicknesses are adequate to limit post-LOCA dose rates inside the control room from all potential direct shine radiation sources in the auxiliary building, containment building, and containment penetration area to less than 1 mrem/hr. In addition, although radiation streaming from a possible radiation cloud could result in local hot spots near the control room doorway entrance adjoining the turbine building, the radiation shielding provided by the design of the control room is sufficient to permit unlimited personnel occupancy of the control room during post-LOCA operations (refer to Sections 12.1.2, 12.1.3, and 15.5.17).

It is noted that DCPP has incorporated a full implementation of Alternative Source Terms (AST) as defined in Regulatory Guide 1.183, July 2000, Section 1.2.1. The adequacy of the shielding associated with the control room and technical support center have been re-evaluated using AST (refer to Section 15.5). However, the estimated short-term operator mission doses while performing vital functions post-LOCA, continue to be based on TID-14844 assumptions as documented in Reference 1. This approach is acceptable based on the AST benchmarking study reported in SECY-98-154 (Reference 8) which concluded that results of analyses based on TID-14844 would be more limiting earlier on in the event, after which time the AST results would become more limiting. Post-LOCA access to vital areas usually occurs within the first one or two weeks when the original TID-14844 source term remains limiting.
Comparison of the missions documented in Reference 1, to the missions required per the current Emergency Operating Procedures (EOPs) indicates that a) there are no new destinations or access paths, b) many of the previously evaluated actions are deemed either nonessential or no longer required, and c) of the access requirements that are still valid, the required time for access and/or the access duration has changed in some instances. Review of the impact of the updated access requirements as well as the impact of changes in fuel design, enrichment and burnup implemented since issuance

of Reference 1 indicate that the operator mission doses associated with actions required by the current EOPs continue to remain below the regulatory limits provided in NUREG 0737, Item II.B.2.

12.1.8 REFERENCES

1. Diablo Canyon Units 1 and 2 Radiation Shielding Review, Revision 3, June 1984.

2. S. G. Gillespie and W. K. Brunot, EMERALD NORMAL - A program for the Calculation of Activity Releases and Doses from Normal Operation of a Pressurized Water Plant, Program Description and User's Manual, Pacific Gas and Electric Company, March 1973.

3. R. L. Engel, et al, ISOSHLD - A Computer Code for the General Purpose Isotope Shielding Analysis, BNWL-236, UC-34, Physics, Pacific Northwest Laboratory, Richland, Washington, June 1966.

4. Reactor Handbook, Second Edition, Volume III, Part B, Oak Ridge National Laboratory, 1962.

5. Occupational Radiation Exposure at Commercial Nuclear Power Reactors 1981, NUREG-0713, Vol. 3, Nov. 1982.

6. Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.

7. NUREG 0737, Clarification of TMI Plan Requirements, USNRC, November 1980.

8. SECY-99-154, “Results of the Revised (NUREG-1465) Source Term Rebaselining for Operating Reactors,“ June 30, 1998.

12.2 VENTILATION

The ventilation systems at DCPP are designed to provide a suitable environment for personnel and equipment and also remove radioactive materials from the ventilation flows prior to release to the atmosphere during normal plant operation, including anticipated operational occurrences. These ventilation systems are described in this section, including the associated airborne radioactivity monitoring functions. Also included are the assumptions that were made as part of the original license to calculate normal operation airborne activity concentrations as well as estimates of inhalation exposure. The cooling function of the ventilation systems, including post-accident fission product removal functions, if any, are described in detail in Section 9.4.

In performing these atmospheric cleanup functions, the plant ventilation systems support the RP Program (refer to Section 12.3) by keeping radiation doses ALARA.

Parts of the ventilation systems also perform PG&E Design Class I functions such as cooling of engineered safety feature (ESF) motors, post-accident containment heat removal, and ensuring post-accident control room and TSC habitability. These are described in detail in Sections 6.4 and 9.4.

12.2.1 DESIGN BASES

12.2.1.1 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The ventilation systems are designed to provide means for monitoring the containment atmosphere, the facility effluent discharge paths, and the facility environs for radioactivity that could be released from normal operations, from anticipated transients and from accident conditions.

12.2.1.2 General Design Criterion 18, 1967 – Monitoring Fuel and Waste Storage

The ventilation systems are provided with monitoring and alarm instrumentation for fuel and waste storage and handling areas for conditions that might contribute to radiation exposures.

12.2.1.3 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The ventilation systems include those means necessary to maintain control over the plant radioactive effluents during normal operation, including anticipated operational occurrences and during accidents.

12.2.1.4 10 CFR Part 20 – Standards for Protection Against Radiation

The ventilation systems maintain airborne radioactive material concentrations in normal work areas in the auxiliary building, fuel handling area, and turbine building within the maximum permissible concentration (MPC) values given in 10 CFR 20.1-20.601, Appendix B, Table I. Note: Although personnel exposure limits must comply with the current regulation, the original ventilation designs were to the pre-1994 regulation.

In addition, the ventilation systems provide the ability to maintain and/or reduce the airborne radioactive material concentrations in normally unoccupied areas within the plant structure to levels that will allow periodic access as required for nonroutine work.

12.2.1.5 10 CFR Part 50 Appendix I – Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion "As Low as is Reasonably Achievable" for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents

The ventilation systems operate in conjunction with other gaseous waste disposal equipment to ensure that the dose from concentrations of airborne radioactive materials in unrestricted areas beyond the site boundary are within the limits specified in 10 CFR Part 50, Appendix I.

12.2.1.6 Regulatory Guide 8.8, July 1973 – Information Relevant to Maintaining Occupational Radiation Exposure as Low as Practicable (Nuclear Reactors)

The ventilation systems are designed to support the maintenance of occupational doses as low as practicable (i.e., ALARA).

12.2.2 DESIGN DESCRIPTION

The following paragraphs present brief descriptions of the ventilation systems for each of the major plant structures. The descriptions include building volumes, flowrates, and filter characteristics that were used when estimating airborne activity concentrations in the various plant areas in support of the original licensing. As noted, more complete design descriptions of the ventilation systems can be found in Section 9.4.

12.2.2.1 Containment Ventilation Systems

Detailed descriptions of the containment iodine removal and ventilation systems, including design criteria, are provided in Section 9.4.5. In terms of RP during normal operation, these systems include:

(1) Containment purge supply and exhaust system

(2) Iodine removal units

The containment purge system includes a single supply fan and a single exhaust fan. Supply air is drawn from the atmosphere through a roughing filter. The purge exhaust fan draws air from the main ventilation header in the containment and exhausts it to the plant vent, from which it is released to atmosphere at the top of the containment. The purge exhaust air is not filtered. This system is not in operation during power operation, but is provided for use as required prior to personnel entry during modes 5 and 6.

Each containment building is provided with two iodine removal units consisting of a recirculation fan complete with roughing filter, high-efficiency particulate air (HEPA) filter, and charcoal filter on the fan suction. These units are operated as required during normal operation to control airborne iodine and particulate concentrations in the containment atmosphere.

Parameters used for the normal operation containment airborne activity concentration analysis developed in support of the original licensing are presented in Table 12.2-1.

12.2.2.2 Control Room Ventilation System

A detailed description of the CRVS, including design criteria, is provided in Section 9.4.1. During normal operation, the quantity of potentially radioactively contaminated air entering the control room is controlled by CRVS MODE 1 in which 73 percent of the control room air is recirculated, 27 percent of the air is outside makeup, and 100 percent of the air is passed through roughing filters.

Parameters used for the normal operation airborne activity concentration analysis developed in support of the original licensing are presented in Table 12.2-2.

12.2.2.3 Auxiliary Building Ventilation System

A detailed description of the auxiliary building ventilation system (ABVS), including design criteria, is provided in Section 9.4.2. Briefly, the system for each unit contains two full-capacity supply fans that draw air from the atmosphere just above the auxiliary building and then discharge it to the occupied areas of the building and to the ESF pump compartments whenever they are in operation. Two full-capacity exhaust fans draw air from various locations throughout the building and discharge it to the plant vent, where it is released at the top of the containment.

Under normal circumstances (i.e., Building Only Mode), the exhaust air is passed through a roughing filter and HEPA filter prior to entering the vent.

In all modes of operation, the ventilation flow patterns are designed so that the air flows from areas of lower potential contamination to areas of higher potential contamination. The system is balanced so that the building is normally under a slight negative pressure.

Parameters used for the normal operation airborne activity concentration analysis developed in support of the original licensing are presented in Table 12.2-3.

12.2.2.4 Fuel Handling Building Ventilation System

A detailed description of the FHBVS, including design criteria, is provided in Section 9.4.4. Two full-capacity supply fans discharge into duct work in the corridors and equipment compartments below the spent fuel pool floor. Three full-capacity exhaust fans are provided. They collect air from along one side of the pool, just above the surface. In this manner, the air provides a sweeping action over the surface of the pool. During the normal mode operation, one non-Class 1E exhaust fan is in operation and the air is passed through a roughing and HEPA filter before being discharged to the plant vent.

Parameters used for the normal operation airborne activity concentration analysis developed in support of the original licensing are given in Table 12.2-4.

12.2.2.5 Turbine Building Ventilation

A detailed description of the turbine building ventilation system, including design criteria, is provided in Section 9.4.3. Ventilation in the turbine building is provided by a number of cabinet fans mounted on the exterior wall of the building. These fans draw air from the surrounding atmosphere into the building through roughing filters. The air is discharged from the roof of the building without treatment. This system is intended primarily to provide personnel comfort since the potential for introduction of airborne radioactivity into the turbine building, as a result of water or steam leakage from the steam system, is very low.

The volume of the turbine building served by the cabinet fans is 5.125×10^6 cubic feet (one unit). The ventilation flowrate is 420,000 cfm.

12.2.2.6 Technical Support Center Ventilation

A detailed description of the TSC ventilation system, including design criteria, is provided in Section 9.4.11. The TSC is provided with its own ventilation system. Self-contained air conditioning units are also provided for the operations center and laboratory area.

12.2.2.7 Post-Accident Sampling Compartment Ventilation

A detailed description of the post-accident sampling compartment ventilation system, including design criteria, is provided in Section 9.4.10. During normal operation, a ventilation fan delivers 300 cfm of outside air to the post-accident sampling compartment. This 300 cfm then exits the compartment through exfiltration.

12.2.3 SOURCE TERMS

12.2.3.1 Auxiliary Building Source Terms

The ABVS has been designed to prevent the transport of airborne radioactive materials into normal work areas. For example, equipment representing potential sources is located in compartments off the main corridors, with the ventilation flow directed from the corridors to the compartments and then to the plant vent. As a result, the occurrence of a situation wherein an equipment leak would introduce radioactive materials into the air of a normally occupied area is minimized. However, in support of the original plant design, for purposes of estimating the maximum air activity concentrations that could occur in normally occupied operating spaces of the auxiliary building, the following source terms were assumed:

(1) Two-unit leakage of 20 gpd per unit of primary coolant at 0.2 percent fuel defects uniformly distributed in the auxiliary building main corridors (volume = 370,000 cubic feet) with a ventilation exhaust flow of 75,000 cfm

(2) Partition factors of 0.005 for iodines, 1 for noble gases, and 0.26 for tritium as tritiated water.

No credit was taken for condensation of tritiated water or plateout of iodines.

The results of this analysis are presented in Table 12.2-5.

The maximum expected airborne activity concentrations during normal operation occur within the CVCS letdown heat exchanger room, the volume control tank room, the charging pump rooms, and the gas decay tank rooms. Occasional entry may be required into these areas during the course of normal operations. Access to these areas will be under procedural control at all times. Thorough radiation surveys will be conducted prior to access to these spaces so that necessary controls can be prescribed to limit personnel exposure. It should be emphasized that the airborne activity concentrations calculated as part of the original plant design for these rooms are the maximum that could occur in spaces where access is controlled, and do not reflect the anticipated concentrations in areas of normal occupancy.

The source term for the CVCS letdown heat exchanger room was based on the following assumptions:

(1) CVCS leakage of 1 gpd of hot primary coolant at 0.2 percent fuel defects occurs upstream of the letdown heat exchanger

(2) The volume of the compartment is taken to be 6500 cubic feet with a ventilation flowrate of 1200 cfm

(3) Partition factors of 0.10 for iodines, 1 for noble gases, and 0.35 for tritium as tritiated water are assumed

The source term for the volume control tank room was based on the following assumptions:

(1) CVCS leakage of 10 gpd of cold primary coolant at 0.2 percent fuel defects occurs upstream of the tank

(2) The room volume is taken to be 2140 cubic feet with a ventilation flowrate of 600 cfm

(3) Partition factors are assumed to be 0.001 for iodines, 1 for noble gases, and 0.01 for tritium as tritiated water

The source term for the charging pump compartment was based on the following assumptions:

(1) CVCS leakage of 10 gpd of cold primary coolant at 0.2 percent fuel defects occurs upstream of the pump

(2) The compartment volume is taken to be 3900 cubic feet with a ventilation flowrate of 400 cfm

(3) Partition factors of 0.001 for iodines, 1 for noble gases, and 0.01 for tritium as tritiated water are assumed

The source term for the gas decay tank compartment is based on the following assumptions:

(1) Gas decay tank leakage of 0.01 scfm is assumed with tank activity inventory as shown in Table 11.3-5

(2) The compartment volume is taken to be 3490 cubic feet with a ventilation flowrate of 40 cfm

(3) A partition factor of 1 is assumed for noble gases at the leakage point

The resulting maximum airborne activity concentrations in these spaces during normal operation are summarized in Tables 12.2-6 through 12.2-9. (Note that the actual ventilation flowrates for the above rooms are higher than the assumed values used for the source term analysis. The higher flowrates would result in lower airborne activity concentrations in these spaces and would be enveloped by the values shown in Tables 12.2-6 through 12.2-9.)

12.2.3.2 Fuel Handling Area Source Term

Airborne activity in the fuel handling area is produced primarily from tritium evaporation and iodine and noble gas partitioning from the spent fuel pool. The evaporation of tritium is discussed in Section 11.2.2.5.2, and the calculated airborne tritium concentrations above the spent fuel pool as a function of plant operating time, developed as part of original plant design, are shown in Figure 11.2-7. The iodine and noble gas releases from the spent fuel pool were based on the following assumptions:

(1) Fuel handling area volume of 4700 cubic feet with a ventilation flowrate of 35,750 cfm

(2) Partition factors of 0.001 for iodines and 1 for noble gases

(3) Spent fuel pool activity concentrations and production rates are listed in Table 12.2-10

The resulting airborne activity concentrations during normal operation in the fuel handling areas are summarized in Table 12.2-11.

12.2.3.3 Containment Source Term

The source term developed as a part of original plant design for containment airborne activity during normal operation was based on the following assumptions:

(1) Leakage of 240 lb/day of primary coolant at 0.2 percent fuel defects

(2) Partition factors of 0.10 for iodines, 1 for noble gases, and 0.35 for tritium as tritiated water at the leakage point

(3) Ninety days of activity accumulation. No credit taken for plateout, containment leakage, cleanup recirculation unit operation, or other activity removal except natural decay

The resulting airborne activity concentrations developed as part of original plant design are listed in Table 12.2-12.

12.2.3.4 Turbine Building Source Term

The source term developed as part of original plant design for the turbine building was based on the following assumptions:

(1) Two-unit main steam leakage of 1700 lb/hr per unit and condenser water leakage of 5 gpm per unit into the turbine building based on 20 gpd per unit of primary-to-secondary system leakage of primary coolant with 0.2 percent fuel defects

(2) Partition factors of 1 for noble gases, iodines, and tritium for steam leakage at the point of leakage

(3) Partition factors of 0.001 for iodines and 0.01 for tritium as tritiated water for condenser water leakage

(4) Turbine building volume of 10.25×10^6 cubic feet with a ventilation flowrate of 840,000 cfm (two units)

The resulting airborne activity concentrations during normal operation developed as part of original plant design are listed in
Table 12.2-13.

12.2.3.5 Control Room Source Term

The source terms developed as part of original plant design for the control room are assumed to result from the total plant gaseous waste releases as indicated in Table 11.3-3. The airborne activity concentration at the control room intake was calculated using an assumed annual average χ/Q of 1.78×10^{-4} sec/m^3, and the total gaseous release from both units.

The source term for the control room itself was calculated using the following assumptions:

(1) Intake airborne activity concentrations developed as part of original plant design are provided in Table 12.2-14

(2) Control room MODE 1 operation with intake and exhaust flowrates assumed to be 4200 cfm. The control room volume is taken as 125,000 cubic feet

(3) No credit is taken for filtration or other removal of activity from the incoming air

The resulting control room airborne activity concentrations for normal operation developed in support of original plant design are presented in Table 12.2-15.

12.2.3.6 Technical Support Center Source Term

The TSC airborne activity concentrations for normal operation are expected to be similar to those in the control room.

12.2.4 AIRBORNE RADIOACTIVITY MONITORING

The instruments and methods used for airborne radioactivity monitoring include certain channels in the process monitoring system, the plant area monitoring system, continuous air monitors (CAMs), and portable low volume air samplers.

12.2.4.1 Process and Area Monitoring Systems

The process and area monitoring systems (including particulate collection) are described in detail in Section 11.4. The monitors, with their readout locations, are listed in Table 11.4-1.

Based on operational data, permanently installed air particulate and gas monitors (APGMs) may be correlated against air samples collected in close proximity to the sample collection point. Grab samples are gross counted and analyzed for isotopic and quantification as appropriate. The response of the APGMs during the period of grab sampling may be correlated to the total μCi/cc measured in the grab sample and this correlation may be used to develop the instrument response in counts per minute versus concentration in μCi/cc. The effect of ambient background is taken into account. Experience has shown that the vast majority of such samples are statistically indistinguishable from background.

Correlation frequencies may be established that are appropriate for the specific instrument involved based on considerations such as likely variation in isotopic mixture, history of the instrument in terms of calibration shift, use of the instrument for quantitative work, and the potential for a statistically significant measured value above background resulting from licensed material.

12.2.4.2 Grab Sampling Program

The grab sampling program consists of collection of air moisture for tritium analysis and air for noble gas particulate and halogen analysis. The location and frequency of the samples are determined based on the potential for a statistically significant measured value above background resulting from licensed material. Some samples may be scheduled on a periodic basis.

12.2.4.2.1 Tritium and Noble Gas Analyses

Collection of air moisture for tritium analysis and air for noble gas analysis may be performed during certain activities such as flood up of the reactor cavity and subsequent fuel movement. DCPP radiation control procedures define the scope, procedure, and frequency of these analyses.

12.2.4.3 Continuous Air Monitors

Portable CAMs may be used at selected locations as part of the airborne radioactivity surveillance program. Use of the CAMs is based on the potential for airborne radioactivity as a result of plant conditions or work activities.

12.2.5 OPERATING PROCEDURES

The grab air sampling program and the use of portable CAMs are described in DCPP procedures.

12.2.6 ESTIMATES OF INHALATION DOSES

The calculations of in-plant inhalation and immersion doses to plant operating and maintenance personnel are based on the estimated airborne concentrations for plant areas presented in Tables 12.2-5 through 12.2-15 and on the estimated occupancy factors for these areas presented in Table 12.2-17. The dose to plant personnel also depends on engineering controls to minimize airborne concentrations, on the type of respiratory protection equipment, if any, being worn, and on other administrative procedures such as purging of contaminated areas, limiting occupancy, etc. Note: These calculations are historical in nature and were completed prior to the 1994 new 10 CFR Part 20. At that time the concept of MPC based on a presumed chronic uptake and resultant body burdens over the years was dropped and replaced by the concept of the derived air concentration (DAC) based on annual dose limits and the assumption of acute rather than chronic exposures. Although prior to 1994 compliance was demonstrated by the number of MPC hours accumulated in a week, Table 12.2-18 reflects doses that are very conservatively calculated and far higher than what has historically been encountered during more than 2 decades of operation. These doses are still bounding and the MPC values will not be replaced with DACs.

The newer values and definitions are currently contained in 10 CFR Part 20 and included in plant procedures as appropriate.

Respiratory protective equipment may be used to limit dose from iodine, and particulates in accordance with 10 CFR Part 20 requirements. Tritium dose may be limited by either respiratory protection and protective suits to reduce the effective concentration below the 10 CFR Part 20 level, or by limiting personnel occupancy in areas of high concentration.

The estimated inhalation and immersion doses to plant personnel for normal full power operation are presented in Table 12.2-18 in units of person-rem/year.

It should be noted that the calculated doses to plant personnel in Table 12.2-18 are conservative estimates and, in view of the administrative controls over personnel dose due to the conservative assumptions used in the calculation of the source terms listed in Section 12.2.3, are much higher than would be expected under normal operating conditions. In particular, the assumptions for primary coolant leakage to the auxiliary building are extremely conservative, since continuous leakage of 20 gpd into the corridors and into three compartments simultaneously is assumed, giving a total leakage rate twice that of the anticipated operational occurrences case.

It is expected that personnel inhalation dose will be low and essentially negligible in comparison to external dose.

12.2.7 SAFETY EVALUATION

12.2.7.1 General Design Criterion 17, 1967 – Monitoring Radioactivity Releases

The containment ventilation systems, CRVS, ABVS, and FHBVS are provided with means for monitoring containment atmosphere, the facility effluent discharge paths, and the facility environs for the release of radioactivity as described in Sections 12.2.2.1 through 12.2.2.4 and 12.2.4.

12.2.7.2 General Design Criterion 18, 1967 – Monitoring Fuel and Waste Storage

The fuel and waste storage and handling areas are provided with monitoring and alarm systems for radioactivity, and the plant vents are monitored for radioactivity as described in Sections 12.2.2.2, 12.2.2.4, 12.2.4, and 11.5.2.6.

12.2.7.3 General Design Criterion 70, 1967 – Control of Releases of Radioactivity to the Environment

The ABVS, FHBVS, and post-accident sampling compartment ventilation system control the release of airborne radioactive materials during normal operation and anticipated operational occurrences as described in Sections 12.2.2.3, 12.2.2.4, and 12.2.2.7.

12.2.7.4 10 CFR Part 20 – Standards for Protection Against Radiation

The containment ventilation systems, CRVS, ABVS, FHBVS, and turbine building ventilation systems control airborne radioactive materials during normal operation and anticipated operational occurrences such that doses to plant personnel are maintained ALARA and below the limits of 10 CFR Part 20 refer to Section 12.2.2.1 through 12.2.2.5.

In addition to the ventilation systems described above, the plant radiation shielding (refer to Section 12.1) supports ALARA principles as described in the RP Program (refer to Section 12.3).

12.2.7.5 10 CFR Part 50 Appendix I – Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion "As Low as is Reasonably Achievable" for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents

The ABVS, FHBVS, and post-accident sampling compartment ventilation system control the release of airborne radioactive materials during normal operation and anticipated operational occurrences as described in Sections 12.2.2.3, 12.2.2.4, and 12.2.2.7.

The inhalation doses during normal operation at offsite locations are the result of releases of gaseous radioactive waste. These doses meet the criteria of 10 CFR Part 50, Appendix I as described in Section 11.3.

12.2.7.6 Regulatory Guide 8.8, July 1973 – Information Relevant to Maintaining Occupational Radiation Exposure as Low as Practicable (Nuclear Reactors)

The ventilation systems control airborne contaminants to protect personnel during normal operations and maintenance activities and are designed for easy access and service in order to maintain doses ALARA (refer to Sections 12.2.1.4, 12.2.6, and 12.2.7).

12.3 RADIATION PROTECTION PROGRAM

This section describes the objectives, facilities and equipment, and dosimetry methods and procedures related to radiation protection of personnel at DCPP.

12.3.1 DESIGN BASES

12.3.1.1 10 CFR Part 19 – Notices, Instructions and Reports to Workers; Inspection and Investigations

DCPP has established requirements for notices, instructions and reports to individuals participating in U.S. Nuclear Regulatory Commission (NRC) licensed and regulated activities in accordance with 10 CFR Part 19.

12.3.1.2 10 CFR Part 20 – Standards for Protection Against Radiation

The RP Program supports the protection of personnel from radiation sources such that doses are maintained below the limits prescribed in 10 CFR Part 20 with noted exemptions.

Noted exemptions from the requirements of 10 CFR Part 20, as approved by the NRC, are:

- Exemption from Appendix A, Footnote d-2(c) allows the use of a radioiodine protection factor of 50 for Mine Safety Appliances GMR-I canisters.

- Authorization to: (1) use French-designed respiratory protection equipment that has not been tested and certified by the National Institute for Occupational Safety and Health; (2) not provide standby rescue persons whenever this equipment is used; and, (3) take credit for an assigned protection factor of 5,000 for this equipment.

12.3.1.3 Regulatory Guide 1.8, Revision 2, April 1987 – Qualification and Training of Personnel for Nuclear Power Plants

The Radiation Protection Manager (RPM) meets or exceeds the qualifications of Regulatory Guide 1.8, Revision 2 for RPM.

12.3.1.4 Regulatory Guide 8.8, July 1973 – Information Relevant to Maintaining Occupational Radiation Exposure as Low as Practicable (Nuclear Reactors)

The RP Program supports the maintenance of occupational doses as low as practicable (i.e., ALARA).

12.3.2 FACILITIES AND EQUIPMENT

The principal RP facilities for the plant are discussed below.

(1) Access Control

Entrance and exit from the main RCAs of the plant are normally made through a central access control point on the 85 foot elevation. This area is used for administratively processing personnel in and out of the RCA, as well as providing a final contamination control point between the RCA and the rest of the plant. An auxiliary access control, located on the 140 foot elevation, may be utilized to provide more efficient access into the RCA, including containment buildings. Other access control stations may be temporarily established to support plant operations on an ad hoc basis.

The access controls on the 85 foot and 140 foot elevations include provisions for logging personnel in and out of the RCAs on radiation work permits. There is a portal monitor located at the exit of these access controls to serve as a final contamination monitor for personnel exiting the RCA. The 85 foot access control area has a decontamination facility that drains into the liquid radwaste system.

(2) Radiochemical Laboratory and Counting Room

These facilities are used for plant chemistry and radiochemistry programs as well as for processing samples for RP analyses. These facilities include detectors tied into a gamma spectroscopy system. Other counters and detectors are available and are used for gross alpha and beta counting and for tritium analyses.

(3) Calibration Facility

A calibration facility is provided for onsite calibration of most of the portable radiation monitoring instrumentation and some of the process monitors. The calibration facility is equipped with an irradiator for routine calibration of gamma-sensitive dose rate instruments. The irradiator is designed so that instruments can be accurately positioned for reproducible dose rates. The irradiator is traceable to the National Institute for Standards and Technology (NIST). Another irradiator is used for calibration of self-reading dosimeters. The irradiator is traceable to the NIST. Other irradiators, traceable to the NIST are also be used for calibration activities at DCPP. Calibration of instruments is performed using controlled vendor manuals or approved procedures. The RP Program also provides for instruments to be returned to the manufacturer or other appropriate contractors for calibration.

In addition to the sources located in the calibration facility, additional sources for calibration of some process radiation monitoring instruments are stored in the calibration facility or shielded safes near the chemistry laboratory.

(4) First Aid and Medical Facilities

The medical facility is staffed with trained emergency medical personnel. The medical facility serves as a general first aid area for minor injuries and an interim treatment area for seriously injured personnel until they can be transported to an offsite hospital or care facility. The medical facility has the capability of responding to injured persons who are also radiologically contaminated.

(5) Laboratory

A laboratory adjacent to the TSC may be used for counting in-plant samples if the normal counting room facilities become unusable following a postulated accident. The laboratory is equipped with a gamma spectroscopy system.

(6) Laundry Facility

An onsite laundry facility is provided for on-site cleaning and monitoring of protective clothing and respirators. The laundry facility is located above the solid radwaste storage facility.

The major categories of RP equipment are described below.

(1) Portable radiation survey instruments for alpha, beta, and gamma radiation detection and dose rate instruments for measuring beta, gamma, and neutron dose rates are described in Table 12.3-1. Some of the dose rate instruments are extended-range instruments to provide emergency monitoring capability.

(2) Air sampling equipment and CAMs are described in Table 12.3-2. This equipment is described further in Section 12.2.4.

(3) Respiratory protection equipment available for routine and emergency use is described in Table 12.3-3.

(4) Protective clothing is available for routine and emergency use.

(5) Several types of emergency, evacuation, and decontamination kits are available at the plant site and at key offsite locations. The contents of the

kits vary according to their intended use and include some or all of the following:

(a) Portable radiation monitoring instruments

(b) Air sampling equipment - some with batteries

(c) Environmental sampling and labeling equipment

(d) Protective clothing and respiratory protection equipment

(e) Portable radio communication equipment

(f) Decontamination supplies

(g) Procedures, maps, area drawings, etc.

12.3.3 PERSONNEL DOSIMETRY

The official and permanent record of accumulated external radiation dose received by individuals is obtained from interpretation of the TLDs. All individuals who are required to be monitored by 10 CFR Part 20 are issued beta-gamma TLDs and are required to wear them in the RCAs. TLDs are typically supplied and processed by a contractor. Dosimetry badges are changed on a routine basis, although the TLD of any individual may be processed at any time to determine the individual’s dose status. Extremity or neutron dosimetry, as well as additional TLDs, are available and are issued as required.

Personnel working in the RCAs are provided with a means of estimating their accumulated external dose. Ordinarily, this is accomplished with the use of self-reading dosimeters. Dose estimates are updated daily, or more frequently when conditions warrant. These estimates are replaced by official dose records when the TLDs are analyzed. Information regarding an individual's dose is available so that personnel may keep themselves informed of their current dose status. Reports giving official personnel dose information are available to supervisors. These reports serve as a tool for the supervisor in making future job assignments. Individuals are closely monitored and may be restricted from further radiation work if their dose estimate reaches the administrative guideline, which is set below the dose limits established by 10 CFR Part 20.

The control of internal exposure to radioactive material is supplemented by a routine bioassay program consisting of whole body counting and passive monitoring using personnel contamination and portal monitors. Whole body counting is normally performed onsite. Urinalysis performed by an outside contractor may be used on a non-routine confirmatory basis as required. The frequency of sampling depends on the person's potential dose to airborne hazards.

Although engineering controls are normally used to control airborne radioactivity, use of respiratory protection equipment, control of access, limitation of exposure times, or other controls may be required to help maintain personnel exposure ALARA.

12.3.4 STORAGE OF RADIOACTIVE MATERIALS

In addition to the areas described in Section 12.3.2, which describes the principal radiation protection facilities for the plant, DCPP utilizes the following facilities and areas for the storage of radioactive materials:

12.3.4.1 Warehouse A Radioactive Material Storage Area

Warehouse A is located at the north end of the protected area outside the contiguous RCA. Inside the building, at the east end, is a caged area controlled by Radiation Protection and used to store radioactive material. Typical items stored in this area include, but are not limited to, outage related materials, materials associated with used fuel storage, and radioactive warehouse spare parts.

Materials stored in Warehouse A are contaminated with low leve3ls of radioactive material typically found in low level radioactive waste streams at DCPP. The radioactive content of the Warehouse A radioactive material storage area is managed such that the 10 CFR 20.1301, member of the public dose limits, are not challenged.

12.3.4.2 Area 10 Turbine Rotor Storage Building Radioactive Material Area

The turbine rotor storage building is located in Area 10, an area outside the protected area in the southern area of the owner controlled area. Inside the turbine rotor storage building, in the west end of the building, is a caged area controlled by Radiation Protection for the storage of radioactive material. Material stored in this area includes, but is not limited to, the spare reactor coolant pump rotor, and controlled warehouse items.

Materials in this area are contaminated with low levels of radioactive material typically found in low level radioactive waste streams at DCPP. The radioactive content of the Area 10 turbine rotor storage building radioactive material area is managed such that the 10 CFR 20.1301, member of the public dose limits, are not challenged.

12.3.4.3 Radioactive Material Storage Building

The radioactive material storage building is located along the southwest contiguous RCA inside the fence line. Normally, items stored in this area include, but are not limited to, contaminated and non-contaminated equipment used for online and outage maintenance.

Materials in this area are contaminated with low levels of radioactive material typically found in low level radioactive waste streams at DCPP. The radioactive content of the

radioactive material storage building is managed such that the 10 CFR 20.1301, member of the public dose limits, are not challenged.

12.3.4.4 85' Elevation Unit 2 Turbine Building Well Source Room

The 85' elevation Unit 2 turbine building well source room is normally used for, but is not limited to, overflow storage of radiation protection instruments.

Items stored in the well source room may be contaminated with low levels of radioactive material typically found in low level radioactive waste streams at DCPP. The radioactive content of the 85' elevation Unit 2 turbine building well source room is managed such that the 10 CFR 20.1301, member of the public dose limits, are not challenged.

12.3.4.5 Main Warehouse JD Room

The JD room is located on the southwest end of the first floor of the main warehouse. Typical items stored in this area include, but are not limited to, warehouse manufactured items containing small amounts of radioactivity. The JD room may also be used for the staging and holding area for incoming or outgoing radioactive material packages.

The radioactive content of the main warehouse JD room is managed such that the 10 CFR 20.1301, member of the public dose limits, are not challenged.

12.3.4.6 Main Warehouse Environmental Storage Area

The main warehouse environmental storage area is located on the northwest end of the first floor of the main warehouse. The main warehouse environmental storage area is typically used to store, but is not limited to, warehouse items containing small amounts of radioactivity which require controlled conditions for storage.

The radioactive content of the main warehouse environmental storage area is managed such that the 10 CFR 20.1301, member of the public dose limits, are not challenged.

12.3.4.7 RCA East Yard

Various containers are housed in the east yard which typically contain, but are not limited to, storage of radioactive material used for outages and online maintenance. A modular building in the north end of the RCA east yard is used by the Instrument and Control Group as a contaminated calibration facility.

Materials stored in the RCA east yard are contaminated with low levels of radioactive material typically found in low level waste streams at DCPP. The radioactive content of the RCA east yard is managed such that the 10 CFR 20.1301, member of the public dose limits, are not challenged.

12.3.5 SAFETY EVALUATION

12.3.5.1 10 CFR Part 19 – Notices, Instructions and Reports to Workers; Inspection and Investigations

The RP Program ensures the instructions provided to workers are commensurate with the potential radiological health problems present in the work place in accordance with the requirements of 10 CFR 19.12.

The RP Program maintains procedures that ensure routine reports to workers are provided in accordance with the requirements 10 CFR 19.13.

12.3.5.2 10 CFR Part 20 – Standards for Protection Against Radiation

The RP Program ensures that the radiation dose to personnel is ALARA in accordance with 10 CFR Part 20.

Program elements include:

- Instructions (refer to Sections 12.1.5 and 12.3.5.1)
- Dosimetry (refer to Section 12.3.3)
- Access control and protective equipment (refer to Sections 12.3.2 and 12.3.4)

The plant radiation shielding and ventilation systems, as described in Sections 12.1 and 12.2 respectively, support the ALARA principles.

In addition, the RP Program supports compliance with 40 CFR Part 190 as specified in 10 CFR 20.1301 (refer to Section 12.3.4).

12.3.5.3 Regulatory Guide 1.8, Revision 2, April 1987 – Qualification and Training of Personnel for Nuclear Power Plants

As a minimum, qualification requirements, including education, experience, and previous training for the RPM meet or exceed the qualifications of Regulatory Guide 1.8, Revision 2 in accordance with Technical Specification 5.3.1(a). Qualification requirements for other positions are described in Chapter 13.

12.3.5.4 Regulatory Guide 8.8, July 1973 – Information Relevant to Maintaining Occupational Radiation Exposure as Low as Practicable (Nuclear Reactors)

The RP Program for the plant is carried out in accordance with PG&E's program directives. The program directives are statements of the policy covering each aspect of the RP Program and are based on appropriate NRC regulations. The program

directives are implemented by various interdepartmental and department level administrative procedures and working level procedures contained in the Plant Manual.

The plant operating organization is described in the Diablo Canyon Quality Assurance Program Description, Section 1.2 and Appendix A. The RPM is responsible for administering, coordinating, planning, and scheduling all RP activities at the plant. The Chemistry and Environmental Operations Manager is responsible for administrating, coordinating, planning and scheduling all chemistry, radiochemistry, and environmental activities at the plant.

TABLE 12.0-1

APPLICABLE DESIGN BASIS CRITERIA

CRITERION	TITLE	APPLICABILITY		
Radiation Protection		Radiation Shielding	Ventilation	Radiation Protection Program
Section		12.1	12.2	12.3
1. General Design Criteria				
Criterion 11, 1967	Control Room	X		
Criterion 17, 1967	Monitoring Radioactivity Releases		X	
Criterion 18, 1967	Monitoring Fuel and Waste Storage		X	
Criterion 19, 1971	Control Room	X		
Criterion 68, 1967	Fuel and Waste Storage Radiation Shielding	X		
Criterion 70, 1967	Control of Releases of Radioactivity to the Environment		X	
2. System Safety Function Requirements				
Neutron Radiation Attenuation		X		
Non-Accident Unit Operation		X		
3. Code of Federal Regulations				
10 CFR Part 19	Notices, Instructions and Reports to Workers; Inspection and Investigations			X
10 CFR Part 20	Standards for Protection Against Radiation	X	X	X
10 CFR Part 50 Appendix I	Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion “As Low as is Reasonably Achievable” for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents		X	
10 CFR 100.11	Determination of Exclusion Area, Low Population Zone, and Population Center Distance	X		
4. Regulatory Guides				
Regulatory Guide 1.8, Revision 2, April 1987	Qualification and Training of Personnel for Nuclear Power Plants			X
Regulatory Guide 8.8, July 1973	Information Relevant to Maintaining Occupational Radiation Exposure as Low as Practicable (Nuclear Reactors)	X	X	X
5. NRC NUREGs				
NUREG-0737, November 1980	Clarification of TMI Action Plan Requirements	X		

TABLE 12.1-1

PLANT ZONE CLASSIFICATIONS

Zone	Condition of Occupancy	Design Maximum Dose Rate, mrem/hr[a]
O	Unlimited access - areas that do not require controlled access for radiological reasons and can be occupied by plant personnel or visitors on an unlimited time basis	≤ 0.5
I	Normal access - areas to which access is controlled for radiological reasons, but which require, or would permit, continuous occupancy by radiation workers during normal working hours	≤ 1.0
II	Controlled access requiring periodic occupancy	≤ 2.5
III	Controlled access requiring short-term occupancy	≤ 15
IV	Controlled access requiring infrequent occupancy	> 15

(a) Basis: These are typical dose rates expected in the various zones based on full power operation of both Units with 1 percent failed fuel.

TABLE 12.1-2

PRINCIPAL AUXILIARY BUILDING SHIELDING

Component	Shielding Thickness, ft-in.					
	Walls					
	N[a]	S[a]	E[a]	W(a)	Floor	Ceiling
Demineralizers	4-0[b]	1-0	4-0	3-0	3-0	2-6
Charging pump	2-0	2-0[b]	2-6[b]	2-6	2-0	2-0
Liquid holdup tanks	2-6[b]	2-6	Ground	2-6[b]	Ground	2-0
Spent resin tanks	3-4	3-4	3-10	3-10[b]	3-0	4-0
Volume control tank	3-0[b]	2-6[b]	3-0[b]	3-0	2-6	2-0
Reactor coolant filter	2-6	2-6	2-0	2-0	2-0	2-0
Gas stripper (on boric acid evaporator) [c]	2-0	3-0[b]	3-0[b]	3-0[b]	2-0	3-0
Gas decay tanks	4-0[b]	4-0	4-0	3-0	Ground	5-0
Gas compressors	2-0[b]	2-0	3-0	2-0[b]	Ground	5-0
Waste concentrators	3-0[b]	3-0[b]	2-0[b]	2-0[b]	2-0	2-0

(a) Refer to orientation of Unit 1 equipment for directions.

(b) Dimensions identified with (b) are the thicknesses separating the component from potentially occupied areas, and are the limiting thickness from the standpoint of dose rate to personnel.

(c) Equipment is abandoned in place and no longer in service.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.1-3

MAXIMUM ACTIVITY IN LIQUID HOLDUP TANK

Nuclide	*Activity, Curies*	*Concentration, µCi/cc*
Cr-51	*0.202E 00*	*0.713E-03*
Mn-54	*0.167E 00*	*0.589E-03*
Mn-56	*0.213E 01*	*0.752E-02*
Co-58	*0.537E 01*	*0.190E-01*
Fe-59	*0.223E 00*	*0.787E-03*
Co-60	*0.169E 00*	*0.597E-03*
Sr-89	*0.543E 00*	*0.192E-02*
Sr-90	*0.259E-01*	*0.916E-04*
Sr-91	*0.274E 00*	*0.969E-03*
Sr-92	*0.510E-01*	*0.180E-03*
Y-90	*0.315E-01*	*0.111E-03*
Y-91	*0.106E 01*	*0.375E-02*
Y-92	*0.159E 00*	*0.563E-03*
Zr-95	*0.693E 00*	*0.245E-02*
Nb-95	*0.687E 00*	*0.242E-02*
Mo-99	*0.144E 03*	*0.509E 00*
Te-132	*0.518E 02*	*0.183E 00*
Cs-134	*0.402E 02*	*0.142E 00*
Cs-136	*0.153E 01*	*0.539E-02*
Cs-137	*0.623E 02*	*0.220E-00*
Ba-140	*0.750E 00*	*0.265E-02*
La-140	*0.289E 00*	*0.102E-02*
Ce-144	*0.688E-01*	*0.243E-03*
Pr-144	*0.688E-01*	*0.243E-03*
I-131	*0.492E 03*	*0.174E 01*
I-132	*0.944E 02*	*0.333E 00*
I-133	*0.707E 03*	*0.250E 01*
I-134	*0.418E 01*	*0.147E-01*
I-135	*0.281E 03*	*0.994E 00*
Kr-83M	*0.163E 02*	*0.574E-01*
Kr-85	*0.175E 04*	*0.617E 01*
Kr-85M	*0.223E 03*	*0.789E 00*
Kr-87	*0.273E 02*	*0.965E-01*
Kr-88	*0.260E 03*	*0.920E 00*
Xe-133	*0.510E 05*	*0.180E 03*
Xe-133M	*0.575E 03*	*0.203E 01*
Xe-135	*0.188E 04*	*0.664E 01*
Xe-135M	*0.877E-03*	*0.310E-05*
Xe-138	*0.747E-03*	*0.264E-05*

Note: The radiation source terms presented above were part of the original plant licensing application and are retained here for the purpose of historical record.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.1-4

MAXIMUM ACTIVITY IN RCS CHARGING PUMP

Nuclide	*Concentrations, μCi/cc*
Cr-51	*0.7160E-03*
Mn-54	*0.5890E-03*
Mn-56	*0.2210E-01*
Co-58	*0.1900E-01*
Fe-59	*0.7890E-03*
Co-60	*0.5970E-03*
Sr-89	*0.1922E-02*
Sr-90	*0.9162E-04*
Sr-91	*0.1289E-02*
Sr-92	*0.5030E-03*
Y-90	*0.1121E-03*
Y-91	*0.3755E-02*
Y-92	*0.6316E-03*
Zr-95	*0.2450E-02*
Nb-95	*0.2424E-02*
Mo-99	*0.5301E 00*
Te-132	*0.1895E 00*
Cs-134	*0.1420E 00*
Cs-136	*0.5440E-02*
Cs-137	*0.2201E-00*
Ba-140	*0.2673E-02*
La-140	*0.9010E-03*
Ce-144	*0.2430E-03*
Pr-144	*0.2430E-03*
I-131	*0.1761E 01*
I-132	*0.6456E 00*
I-133	*0.2851E 01*
I-134	*0.3620E 01*
I-135	*0.1503E 00*
Kr-83M	*0.2547E 00*
Kr-85	*0.6158E 01*
Kr-85M	*0.1481E 01*
Kr-87	*0.8558E 00*
Kr-88	*0.2502E 01*
Xe-133	*0.1839E 03*
Xe-133M	*0.2135E 01*
Xe-135	*0.8441E 01*
Xe-135M	*0.1322E 00*
Xe-138	*0.3875E 00*

Note: The radiation source terms presented above were part of the original plant licensing application and are retained here for the purpose of historical record.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.1-5

MAXIMUM ACTIVITY IN WASTE EVAPORATOR

Nuclide	*Activity, Curies*	*Concentration, μCi/cc*
Cr-51	*0.360E-08*	*0.211E-08*
Mn-54	*0.123E-04*	*0.723E-05*
Mn-56	*0.0*	*0.0*
Co-58	*0.256E-04*	*0.150E-04*
Fe-59	*0.132E-06*	*0.777E-07*
Co-60	*0.254E-04*	*0.149E-04*
Sr-89	*0.129E-05*	*0.756E-06*
Sr-90	*0.871E-05*	*0.511E-05*
Sr-91	*0.0*	*0.0*
Sr-92	*0.0*	*0.0*
Y-90	*0.871E-05*	*0.511E-05*
Y-91	*0.572E-05*	*0.336E-05*
Y-92	*0.0*	*0.0*
Zr-95	*0.482E-05*	*0.283E-05*
Nb-95	*0.102E-04*	*0.599E-05*
Mo-99	*0.0*	*0.0*
Te-132	*0.0*	*0.0*
Cs-134	*0.980E-02*	*0.575E-02*
Cs-136	*0.160E-11*	*0.940E-12*
Cs-137	*0.208E-01*	*0.122E-01*
Ba-140	*0.569E-12*	*0.334E-12*
La-140	*0.655E-12*	*0.384E-12*
Ce-144	*0.966E-05*	*0.567E-05*
Pr-144	*0.966E-05*	*0.567E-05*
I-131	*0.290E-14*	*0.170E-14*
I-132	*0.144E-35*	*0.848E-36*
I-133	*0.0*	*0.0*
I-134	*0.0*	*0.0*
I-135	*0.0*	*0.0*

Note: The radiation source terms presented above were part of the original plant licensing application and are retained here for the purpose of historical record.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.1-6

MAXIMUM ACTIVITY IN BORIC ACID EVAPORATOR [(b)]

Gaseous Activity (In Gas Stripper Condenser)

Isotope	*Activity in Feedwater, μCi/cc*	*Activity in Condenser, μCi/cc*
Kr-83m	*5.7E-02*	*1.2E+00*
Kr-85	*6.2E+00*	*1.3E+02*
Kr-85m	*7.9E-01*	*1.7E+01*
Kr-87	*9.6E-02*	*2.0E+00*
Kr-88	*9.2E-01*	*1.9E+01*
Xe-133	*1.8E+02*	*3.8E+03*
Xe-133m	*2.0E+00*	*4.3E+01*
Xe-135	*6.6E+00*	*1.4E+02*
Xe-135m	*3.1E-06*	*6.5E-05*
Xe-138	*2.6E-06*	*5.5E-05*

Liquid Activity (In Concentrates Holding Tank) [(b)]

Isotope	*Activity in[(a)] Feedwater, μCi/cc*	*Activity in Condenser, μCi/cc*
I-131	*1.7E-02*	*2.8E-02*
I-132	*3.3E-03*	*2.8E-03*
I-133	*2.5E-02*	*3.1E-02*
I-134	*1.5E-04*	*0.0*
I-135	*9.9E-03*	*6.0E-02*
Mo-99	*5.1E-03*	*7.8E-02*
Cs-134	*7.1E-03*	*1.2E-01*
Cs-137	*1.1E-02*	*1.2E-01*

(a) Isotopes with small activity are not listed.

(b) Equipment is abandoned in place and no longer in service.

Note: The radiation source terms presented above were part of the original plant licensing application and are retained here for the purpose of historical record.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.1-7

MAXIMUM ACTIVITY IN SPENT FUEL POOL[(a)]

Nuclide	*Activity, Curies*	*Concentration, μCi/cc*
Cr-51	*9.59E-04*	*6.98E-08*
Mn-54	*8.46E-04*	*6.15E-08*
Mn-56	*1.18E-10*	*8.58E-15*
Co-58	*2.66E-02*	*1.94E-06*
Fe-59	*1.09E-03*	*7.92E-08*
Co-60	*8.59E-04*	*6.25E-08*
Kr-83M	*0.0*	*0.0*
Kr-85M	*0.0*	*0.0*
Kr-85	*0.0*	*0.0*
Kr-87	*0.0*	*0.0*
Kr-88	*0.0*	*0.0*
Sr-89	*2.96E-03*	*2.15E-07*
Sr-90	*1.47E-04*	*1.07E-08*
Y-90	*2.36E-04*	*1.72E-08*
Sr-91	*1.58E-05*	*1.15E-09*
Y-91	*9.03E-03*	*6.57E-07*
Sr-92	*1.74E-06*	*1.26E-10*
Y-92	*6.85E-07*	*4.99E-11*
Zr-95	*3.81E-03*	*2.77E-07*
Nb-95	*3.89E-03*	*2.83E-07*
Mo-99	*6.33E-01*	*4.61E-05*
I-131	*3.37E 00*	*2.46E-04*
Te-132	*2.48E-01*	*1.80E-05*
I-132	*2.57E-01*	*1.87E-05*
I-133	*6.62E-01*	*4.82E-05*
X-133M	*0.0*	*0.0*
X-133	*0.0*	*0.0*
Cs-134	*2.23E-01*	*1.62E-05*
I-134	*1.28E-03*	*9.29E-08*
I-135	*7.25E-03*	*5.28E-07*
Xe-135M	*0.0*	*0.0*
Xe-135	*0.0*	*0.0*
Cs-136	*9.55E-03*	*6.95E-07*
Cs-137	*4.60E-01*	*3.35E-05*
Xe-138	*0.0*	*0.0*
Ba-140	*3.63E-03*	*2.64E-07*
La-140	*3.19E-03*	*2.32E-07*
Ce-144	*3.87E-04*	*2.82E-08*
Pr-144	*3.87E-04*	*2.82E-08*

(a) Basis: Primary coolant with 1 percent fuel defects, three days decay, and purification by the CVCS demineralizers, at a flowrate of 120 gpm, is dispersed in the refueling water. A 15 percent mixing of the spent fuel pool with the refueling water is assumed.

Note: The radiation source terms presented above were part of the original plant design and are retained here for the purpose of historical record.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.1-8

MAXIMUM ACTIVITY IN MONITOR TANK AND WASTE CONDENSATE TANK

	Monitor Tank		*Waste Condensate Tank*	
Nuclide	*Activity, Curies*	*Concentration, μCi/cc*	*Activity, Curies*	*Concentration, μCi/cc*
H-3	*0.200E 02*	*0.211E 00*	*0.120E 02*	*0.211E 00*
Cr-51	*0.665E-07*	*0.703E-09*	*0.399E-07*	*0.703E-09*
Mn-54	*0.556E-07*	*0.588E-09*	*0.334E-07*	*0.588E-09*
Mn-56	*0.192E-07*	*0.203E-09*	*0.115E-07*	*0.203E-09*
Co-58	*0.179E-05*	*0.189E-07*	*0.107E-05*	*0.189E-07*
Fe-59	*0.738E-07*	*0.780E-09*	*0.443E-07*	*0.780E-09*
Co-60	*0.565E-07*	*0.597E-09*	*0.339E-07*	*0.597E-09*
Sr-89	*0.200E-06*	*0.211E-08*	*0.120E-06*	*0.211E-08*
Sr-90	*0.963E-08*	*0.102E-09*	*0.578E-08*	*0.102E-09*
Sr-91	*0.371E-07*	*0.392E-09*	*0.222E-07*	*0.392E-09*
Sr-92	*0.559E-09*	*0.590E-11*	*0.335E-09*	*0.590E-11*
Y-90	*0.962E-05*	*0.102E-06*	*0.577E-05*	*0.102E-06*
Y-91	*0.353E-03*	*0.373E-05*	*0.212E-03*	*0.373E-05*
Y-92	*0.329E-05*	*0.348E-07*	*0.198E-05*	*0.348E-07*
Zr-95	*0.255E-06*	*0.270E-08*	*0.153E-06*	*0.270E-08*
Nb-95	*0.255E-06*	*0.269E-08*	*0.153E-06*	*0.269E-08*
Mo-99	*0.420E-04*	*0.444E-06*	*0.252E-04*	*0.444E-06*
Te-132	*0.154E-04*	*0.162E-06*	*0.922E-05*	*0.162E-06*
Cs-134	*0.552E-02*	*0.584E-04*	*0.331E-02*	*0.584E-04*
Cs-136	*0.269E-03*	*0.284E-05*	*0.161E-03*	*0.284E-05*
Cs-137	*0.114E-01*	*0.120E-03*	*0.682E-02*	*0.120E-03*
Ba-140	*0.269E-06*	*0.284E-08*	*0.161E-06*	*0.284E-08*
La-140	*0.144E-06*	*0.152E-08*	*0.865E-07*	*0.152E-06*
Ce-144	*0.255E-07*	*0.269E-09*	*0.153E-07*	*0.269E-09*
Pr-144	*0.255E-07*	*0.269E-09*	*0.153E-07*	*0.269E-09*
I-131	*0.157E-02*	*0.165E-04*	*0.939E-03*	*0.165E-04*
I-132	*0.220E-04*	*0.233E-06*	*0.132E-04*	*0.233E-06*
I-133	*0.152E-02*	*0.161E-04*	*0.912E-03*	*0.161E-04*
I-134	*0.307E-09*	*0.325E-11*	*0.184E-09*	*0.325E-11*
I-135	*0.235E-03*	*0.248E-05*	*0.141E-03*	*0.248E-05*

Note: The radiation source terms presented above were part of the original plant design and are retained here for the purpose of historical record.

HISTORICAL INFORMATION IN *ITALICS BELOW NOT REQUIRED TO BE REVISED*

TABLE 12.1-9

MAXIMUM ACTIVITY IN SPENT RESIN TANK

Nuclide	*Activity, Curies*
Cr-51	*5.95E-01*
Mn-54	*1.40E 00*
Mn-56	*3.28E-01*
Co-58	*2.36E 01*
Fe-59	*7.92E-01*
Co-60	*1.72E 00*
Sr-89	*2.06E 00*
Sr-90	*2.75E-01*
Y-90	*2.81E-01*
Sr-91	*2.48E-01*
Y-91	*3.03E 00*
Sr-92	*3.83E-02*
Y-92	*4.49E-02*
Zr-95	*2.94E 00*
Nb-95	*3.73E 00*
Mo-99	*1.61E 02*
I-131	*6.29E 02*
Te-132	*5.89E 01*
I-132	*8.82E 01*
I-133	*6.52E 02*
Cs-134	*8.94E 00*
I-134	*2.76E 03*
I-135	*1.95E 02*
Cs-136	*3.52E 00*
Cs-137	*6.41E 02*
Ba-140	*1.77E 00*
La-140	*1.22E 00*
Ce-144	*5.38E-01*
Pr-144	*5.38E-01*

Note: The radiation source terms presented above were part of the original plant design and are retained here for the purpose of historical record.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.1-10

MAXIMUM ACTIVITY IN WASTE CONCENTRATES TANK

Nuclide	*Activity, Curies*	*Concentration, µCi/cc*
H-3	*0.216E 00*	*0.570E-01*
Cr-51	*0.719E-03*	*0.190E-03*
Mn-54	*0.627E-03*	*0.166E-03*
Mn-56	*0.222E-06*	*0.586E-07*
Co-58	*0.198E-01*	*0.524E-02*
Fe-59	*0.812E-03*	*0.214E-03*
Co-60	*0.638E-03*	*0.169E-03*
Kr-83M	*0.0*	*0.0*
Kr-85M	*0.0*	*0.0*
Kr-85	*0.0*	*0.0*
Kr-87	*0.0*	*0.0*
Kr-88	*0.0*	*0.0*
Sr-89	*0.551E-03*	*0.145E-03*
Sr-90	*0.272E-04*	*0.718E-05*
Y-90	*0.171E-04*	*0.453E-05*
Sr-91	*0.668E-05*	*0.176E-05*
Y-91	*0.121E-03*	*0.320E-04*
Sr-92	*0.194E-08*	*0.513E-09*
Y-92	*0.178E-05*	*0.470E-06*
Zr-95	*0.708E-03*	*0.187E-03*
Nb-95	*0.720E-03*	*0.190E-03*
Mo-99	*0.711E-01*	*0.188E-01*
I-131	*0.378E 00*	*0.999E-01*
Te-132	*0.295E-01*	*0.780E-02*
I-132	*0.313E-01*	*0.828E-02*
I-133	*0.109E 00*	*0.289E-01*
Xe-133M	*0.0*	*0.0*
Xe-133	*0.0*	*0.0*
Cs-134	*0.303E-01*	*0.802E-02*
I-134	*0.636E-13*	*0.168E-13*
I-135	*0.157E-02*	*0.414E-03*
Xe-135M	*0.0*	*0.0*
Xe-135	*0.0*	*0.0*
Cs-136	*0.138E-02*	*0.364E-03*
Cs-137	*0.643E-01*	*0.170E-01*
Xe-138	*0.0*	*0.0*
Ba-140	*0.689E-03*	*0.182E-02*
La-140	*0.582E-03*	*0.154E-03*
Ce-144	*0.717E-04*	*0.189E-04*
Pr-144	*0.717E-04*	*0.189E-04*

Note: The radiation source terms presented above were part of the original plant design and are retained here for the purpose of historical record.

TABLE 12.1-11

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

MAXIMUM ACTIVITY IN RADWASTE SYSTEM DRAIN TANKS

Nuclide	*Equipment Drain Receiver Tank Concentration, µCi/cc*	*Floor Drain Receiver Tank Concentration, µCi/cc*
H-3	*0.74E 01*	*0.23E-02*
Cr-51	*0.26E-03*	*0.79E-05*
Mn-54	*0.22E-03*	*0.66E-05*
Mn-56	*0.81E-02*	*0.10E-04*
Co-58	*0.70E-02*	*0.21E-03*
Fe-59	*0.29E-03*	*0.88E-03*
Co-60	*0.22E-03*	*0.68E-03*
Sr-89	*0.20E-03*	*0.59E-05*
Sr-90	*0.94E-05*	*0.29E-06*
Y-90	*0.27E-05*	*0.14E-06*
Sr-91	*0.12E-03*	*0.64E-06*
Y-91	*0.41E-04*	*0.13E-05*
Sr-92	*0.47E-04*	*0.59E-07*
Y-92	*0.47E-04*	*0.14E-05*
Zr-95	*0.25E-03*	*0.76E-05*
Nb-95	*0.25E-03*	*0.76E-05*
Mo-99	*0.45E-01*	*0.10E-02*
I-131	*0.16E 00*	*0.45E-02*
Te-132	*0.17E-01*	*0.41E-03*
I-132	*0.59E-01*	*0.59E-03*
I-133	*0.26E 00*	*0.32E-02*
Cs-134	*0.10E-01*	*0.32E-03*
I-134	*0.33E-01*	*0.40E-04*
I-135	*0.14E 00*	*0.41E-03*
Cs-136	*0.54E-03*	*0.16E-04*
Cs-137	*0.22E-01*	*0.68E-03*
Ba-140	*0.27E-03*	*0.78E-05*
La-140	*0.97E-03*	*0.51E-05*
Ce-144	*0.25E-04*	*0.76E-06*
Pr-144	*0.25E-04*	*0.76E-06*

Note: The radiation source terms presented above were part of the original plant design and are retained here for the purpose of historical record.

TABLE 12.1-11

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Nuclide	*Chemical Drain Tank Concentration, µCi/cc*	*Laundry and Hot Shower Tank Concentration, µCi/cc*
H-3	*0.22E-04*	*0.22E-05*
Cr-51	*0.68E-07*	*0.68E-08*
Mn-54	*0.59E-07*	*0.59E-08*
Mn-56	*0.53E-11*	*0.53E-12*
Co-58	*0.19E-05*	*0.19E-06*
Fe-59	*0.77E-07*	*0.77E-08*
Co-60	*0.60E-07*	*0.60E-08*
Sr-89	*0.21E-06*	*0.21E-07*
Sr-90	*0.10E-07*	*0.10E-08*
Sr-91	*0.44E-08*	*0.44E-09*
Sr-92	*0.23E-12*	*0.23E-13*
Y-90	*0.11E-07*	*0.11E-08*
Y-91	*0.37E-06*	*0.37E-07*
Y-92	*0.51E-07*	*0.51E-08*
Zr-95	*0.27E-06*	*0.27E-07*
Nb-95	*0.27E-06*	*0.27E-07*
Mo-99	*0.33E-04*	*0.33E-05*
Te-132	*0.12E-04*	*0.12E-05*
Cs-134	*0.12E-04*	*0.12E-05*
Cs-136	*0.53E-06*	*0.53E-07*
Cs-137	*0.24E-04*	*0.24E-05*
Ba-140	*0.27E-06*	*0.27E-07*
La-140	*0.21E-06*	*0.21E-07*
Ce-144	*0.27E-07*	*0.27E-08*
Pr-144	*0.27E-07*	*0.27E-08*
I-131	*0.15E-03*	*0.15E-04*
I-132	*0.19E-04*	*0.19E-05*
I-133	*0.58E-04*	*0.58E-05*
I-134	*0.75E-21*	*0.75E-22*
I-135	*0.10E-05*	*0.10E-06*

Note: The radiation source terms presented above were part of the original plant design and are retained here for the purpose of historical record.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.1-12

MAXIMUM ACTIVITY IN PRIMARY WATER STORAGE TANK

Nuclide	*Activity, Curies*	*Concentration, µCi/cc*
Cr-51	*2.27E-10*	*3.00E-13*
Mn-54	*9.21E-10*	*1.22E-13*
Mn-56	*0.0*	*0.0*
Co-58	*1.47E-07*	*1.95E-10*
Fe-59	*4.16E-10*	*5.49E-13*
Co-60	*1.18E-09*	*1.56E-12*
Sr-89	*1.27E-09*	*1.67E-12*
Sr-90	*2.09E-10*	*2.76E-13*
Y-90	*1.70E-08*	*2.25E-11*
Sr-91	*8.05E-23*	*1.06E-25*
Y-91	*2.56E-04*	*3.39E-07*
Sr-92	*0.0*	*0.0*
Y-92	*3.26E-37*	*4.30E-40*
Zr-95	*1.97E-09*	*2.60E-12*
Nb-95	*2.96E-09*	*3.91E-12*
Mo-99	*6.50E-08*	*8.58E-11*
I-131	*7.49E-05*	*9.89E-08*
Te-132	*5.01E-08*	*6.62E-11*
I-132	*5.18E-08*	*6.84E-11*
I-133	*3.55E-10*	*4.69E-13*
Cs-134	*5.35E-03*	*7.07E-06*
I-134	*0.0*	*0.0*
I-135	*5.83E-22*	*7.71E-25*
Cs-136	*3.11E-10*	*2.12E-08*
Cs-137	*3.58E-10*	*1.63E-05*
Ba-140	*4.14E-10*	*4.11E-13*
La-140	*4.14E-10*	*4.72E-13*
Ce-144	*1.60E-05*	*5.47E-13*
Pr-144	*1.23E-02*	*5.47E-13*

Note: The radiation source terms presented above were part of the original plant design and are retained here for the purpose of historical record.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.1-13

MAXIMUM ACTIVITY IN REFUELING WATER STORAGE TANK

Nuclide	*Activity, Curies*	*Concentration, μCi/cc*
Cr-51	*4.19E-07*	*2.03E-10*
Mn-54	*6.80E-07*	*3.30E-10*
Mn-56	*0.0*	*0.0*
Co-58	*1.75E-05*	*8.51E-09*
Fe-59	*6.14E-07*	*2.98E-10*
Co-60	*7.28E-07*	*3.53E-10*
Sr-89	*4.63E-06*	*2.25E-09*
Sr-90	*1.01E-06*	*4.92E-10*
Y-90	*6.39E-07*	*3.11E-10*
Sr-91	*3.31E-12*	*1.61E-15*
Y-91	*6.38E-06*	*3.10E-09*
Sr-92	*2.29E-21*	*1.11E-24*
Y-92	*3.15E-18*	*1.53E-21*
Zr-95	*7.22E-06*	*3.51E-09*
Nb-95	*1.06E-05*	*5.17E-09*
Mo-99	*9.36E-06*	*4.55E-09*
I-131	*4.93E-04*	*2.39E-07*
Te-132	*4.87E-06*	*2.36E-09*
I-132	*8.47E-06*	*4.12E-09*
I-133	*9.20E-07*	*4.47E-10*
Cs-134	*8.51E-03*	*4.13E-06*
I-134	*0.0*	*0.0*
I-135	*9.10E-11*	*4.42E-14*
Cs-136	*6.52E-05*	*3.17E-08*
Cs-137	*1.54E-02*	*7.45E-06*
Ba-140	*1.42E-06*	*6.91E-10*
La-140	*1.32E-06*	*6.41E-10*
Ce-144	*1.74E-06*	*8.43E-10*
Pr-144	*1.74E-06*	*8.43E-10*

Note: The radiation source terms presented above were part of the original plant design and are retained here for the purpose of historical record.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.1-14

RADIATION EXPOSURE RATES FROM EXTERNAL STORAGE TANKS

Tank	*Maximum Dose Rate at Tank Surface, mrem/hr*	*Maximum Dose Rate at 800 meters, mrem/hr[a]*
Primary water storage tank	*6.27 E-03*	*7.08 E-10*
Refueling water storage tank	*3.18 E-03*	*7.25 E-10*

(a) *Direct gamma radiation only (refer to Section 12.1).*

Note: The dose rates presented above were part of the original plant design and are retained here for the purpose of historical record.

TABLE 12.1-15

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

CALCULATED ANNUAL MAN-REM EXPOSURE OF PLANT PERSONNEL[a]

Due to Normal Operation

				Operators[b]		*Chemical and Radiation Protection Technicians[c]*		*Control Technicians[d]*		*Electrical and Mechanical Maint. Personnel[e]*	
	Area	*Zone*	*Expected Dose Rate r/hr*	*man-hr/ wk*	*man-rem/ wk*	*man-hr/ wk*	*man-rem/ wk*	*man-hr/ wk*	*man-rem/ wk*	*man-hr/ wk*	*man-rem/ wk*
1.	*Control Room*	*0*	*$1.0x10^{-4}$*	*2000*	*0.20*	*10*	*0.001*	*300*	*0.03*	*0.3*	*0.0*
2.	*Turbine Building*	*0*	*$1.0x10^{-4}$*	*700*	*0.07*	*10*	*0.001*	*1000*	*0.10*	*3000*	*0.30*
3.	*Outside*	*0*	*$2.0x10^{-5}$*	*150*	*0.003*	*50*	*0.001*	*100*	*0.002*	*2*	*0.0*
4.	*Aux Bldg Corridors*	*I*	*$1.0x10^{-4}$*	*700*	*0.07*	*2200*	*0.22*	*500*	*0.05*	*2600*	*0.26*
5.	*Fuel Handling Area*	*II*	*$2.5x10^{-4}$*	*2*	*0.0005*	*8*	*0.002*	*120*	*0.03*	*320*	*0.08*
6.	*Primary Sample Room*	*III*	*$1.5x10^{-2}$*	*2*	*0.03*	*3*	*0.05*	*1.00*	*0.02*	*6*	*0.09*
7.	*Containment*	*IV*	*$1.5x10^{-1}$*	*0.5*	*0.08*	*2*	*0.25*	*2*	*0.3*	*0.3*	*0.05*
8.	*Volume Control Tank Compartment*	*IV*	*5*	*0.03*	*0.15*	*0.2*	*1.00*	*0*	*0*	*0.2*	*1.0*
9.	*Charging Pumps*	*IV*	*$2x10^{-1}$*	*0.60*	*0.12*	*0.5*	*0.10*	*3*	*0.6*	*7.0*	*1.35*
10.	*Letdown HX*	*IV*	*1.5*	*0.03*	*0.05*	*0.20*	*0.30*	*0*	*0.00*	*0.30*	*0.50*
11.	*Gas Decay Tanks*	*IV*	*0.5*	*0.04*	*0.02*	*0.30*	*0.15*	*0*	*0.00*	*0.30*	*0.15*

TABLE 12.1-15

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED
CALCULATED ANNUAL MAN-REM EXPOSURE OF PLANT PERSONNEL[a]
Due to Normal Operation

Area	*Zone*	*Expected Dose Rate r/hr*	*Operators[b]*		*Chemical and Radiation Protection Technicians[c]*		*Control Technicians[d]*		*Electrical and Mechanical Maint. Personnel[e]*	
			man-hr/wk	*man-rem/wk*	*man-hr/wk*	*man-rem/wk*	*man-hr/wk*	*man-rem/wk*	*man-hr/wk*	*man-rem/wk*
Total Man-rem/wk				*0.81*		*2.08*		*1.132*		*3.78*
Total Man-rem/yr 52 wk/yr				*42.00*		*108.00*		*59.00*		*197.00*

PLANT ANNUAL TOTAL DUE TO NORMAL OPERATION (including 32 man-rems for supervisors): 406 man-rems[f]

(a) Average work week for all personnel-40 hours.
(b) Two-unit shift crew of 22 people, continuous coverage, 3696 man-hours/week.
(c) 60 chemical and radiation protection technicians, 2400 man-hours/week.
(d) 60 control technicians, 2400 man-hours/week.
(e) 149 man crew, 5960 man-hours/week.
(f) *Special maintenance and refueling activities are expected to add another 400 man-rems for a total of 800 man-rems per year.*

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.2-1

PARAMETERS FOR CONTAINMENT NORMAL OPERATION AIRBORNE ACTIVITY CONCENTRATION ANALYSIS

Containment Free Air Volume, ft^3	*2.6×10^6*
Purge Supply Fan Flow Rate, cfm	*50,000*
Purge Exhaust Fan Flow Rate, cfm	*55,000*
Fan Cooler Flow Rate, cfm/Fan Cooler Unit	
Normal operation	*110,000*
Iodine Removal Fan Flow Rate, cfm/fan	*12,000*
HEPA Filter Efficiency for 0.3 µm DOP Particles, %	*$\geq$ 99.97*

Parameter values presented above were utilized as part of original licensing to establish the normal operation airborne activity concentration in containment.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.2-2

PARAMETERS FOR CONTROL ROOM NORMAL OPERATION AIRBORNE ACTIVITY CONCENTRATION ANALYSIS

Total Room Volume[(a)], Unit 1 plus Unit 2, ft^3	*170,000*
Supply Fan Rating, cfm/fan	*7,800*
Minimum number of operable fans	*1/Unit*
Recirculation Flowrate Under Accident Conditions, cfm	*2,100*
HEPA Filter Efficiency for 0.3 µm Particles DOP, %	*≥ 99.97*

(a) *Includes all areas served by CRVS*

Parameter values presented above were utilized as part of original licensing to establish the normal operation airborne activity concentration in the control room.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.2-3

PARAMETERS FOR AUXILIARY BUILDING NORMAL OPERATION AIRBORNE ACTIVITY CONCENTRATION ANALYSIS

Auxiliary Building Volume, Unit 1 plus Unit 2, ft^3	*1,312,000*
Supply Fan Rating, cfm/fan	*67,500*
Exhaust Fan Rating, cfm/fan	*73,500*
HEPA Filter Efficiency for 0.3 µm Particles DOP, %	*≥ 99.97*

Parameter values presented above were utilized as part of original licensing to establish the normal operation airborne activity concentration in the auxiliary building.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.2-4

PARAMETERS FOR FUEL BUILDING NORMAL OPERATION AIRBORNE ACTIVITY CONCENTRATION ANALYSIS

Fuel Handling Building Volume, Each Unit, ft^3	*525,000*
Supply Fan Rating, cfm/fan	*23,300*
Exhaust Fan Rating, cfm/fan	*35,750*
HEPA Filter Efficiency for 0.3 µm Particles DOP, %	*$\geq$ 99.97*

Parameter values presented above were utilized as part of original licensing to establish the normal operation airborne activity concentration in the fuel building.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.2-5
ESTIMATED AIRBORNE ACTIVITY CONCENTRATIONS IN AUXILIARY BUILDING WORK AREAS FOR NORMAL OPERATION

Nuclide	*Concentration µCi/cc*	*MPC Air-10 CFR 20 µCi/cc*
H-3	*4.22E-09*	*5.00E-06*
Cr-51	*0.0*	*2.00E-06*
Mn-54	*0.0*	*4.00E-08*
Mn-56	*0.0*	*5.00E-07*
Co-58	*0.0*	*5.00E-08*
Fe-59	*0.0*	*5.00E-08*
Co-60	*0.0*	*9.00E-09*
Kr-83M	*4.02E-09*	*1.00E-06*
Kr-85M	*2.37E-08*	*6.00E-06*
Kr-85	*5.81E-08*	*1.00E-05*
Kr-87	*1.33E-08*	*1.00E-06*
Kr-88	*3.98E-08*	*1.00E-06*
Sr-89	*0.0*	*1.00E-08*
Sr-90	*0.0*	*1.00E-09*
Y-90	*0.0*	*1.00E-07*
Sr-91	*0.0*	*1.00E-07*
Y-91	*0.0*	*3.00E-08*
Sr-92	*0.0*	*3.00E-07*
Y-92	*0.0*	*3.00E-07*
Zr-95	*0.0*	*3.00E-08*
Nb-95	*0.0*	*1.00E-07*
Mo-99	*0.0*	*2.00E-07*
I-131	*1.43E-10*	*9.00E-09*
Te-132	*0.0*	*2.00E-07*
I-132	*5.13E-11*	*2.00E-07*
I-133	*2.31E-10*	*3.00E-08*
Xe-133M	*3.53E-08*	*1.00E-05*
Xe-133	*2.83E-06*	*1.00E-05*
Cs-134	*0.0*	*1.00E-08*
I-134	*2.76E-11*	*5.00E-07*
I-135	*1.21E-10*	*1.00E-07*
Xe-135M	*7.09E-09*	*1.00E-06*
Xe-135	*5.34E-08*	*4.00E-06*
Cs-136	*0.0*	*2.00E-07*
Cs-137	*0.0*	*1.00E-08*
Xe-138	*5.07E-09*	*1.00E-06*
Ba-140	*0.0*	*4.00E-08*
La-140	*0.7*	*4.00E-08*
Ce-144	*0.0*	*6.00E-09*
Pr-144	*0.0*	*1.00E-06*

Note: The airborne isotopic activity concentration values provided above were developed in support of the original plant design.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.2-6

ESTIMATED AIRBORNE ACTIVITY CONCENTRATIONS IN LETDOWN HEAT EXCHANGER COMPARTMENT FOR NORMAL OPERATION

Nuclide	*Concentration µCi/cc*	*MPC Air-10 CFR 20 µCi/cc*
H-3	*8.96E-09*	*5.00E-06*
Cr-51	*0.0*	*2.00E-06*
Mn-54	*0.0*	*4.00E-08*
Mn-56	*0.0*	*5.00E-07*
Co-58	*0.0*	*5.00E-08*
Fe-59	*0.0*	*5.00E-08*
Co-60	*0.0*	*9.00E-09*
Kr-83M	*6.30E-09*	*1.00E-06*
Kr-85M	*3.72E-08*	*6.00E-06*
Kr-85	*9.16E-08*	*1.00E-05*
Kr-87	*2.08E-08*	*1.00E-06*
Kr-88	*6.27E-08*	*1.00E-06*
Sr-89	*0.0*	*3.00E-08*
Sr-90	*0.0*	*1.00E-09*
Y-90	*0.0*	*1.00E-07*
Sr-91	*0.0*	*3.00E-07*
Y-91	*0.0*	*3.00E-08*
Sr-92	*0.0*	*3.00E-07*
Y-92	*0.0*	*3.00E-07*
Zr-95	*0.0*	*3.00E-08*
Nb-95	*0.0*	*1.00E-07*
Mo-99	*0.0*	*2.00E-07*
I-131	*4.49E-09*	*9.00E-09*
Te-132	*0.0*	*2.00E-07*
I-132	*1.61E-09*	*2.00E-07*
I-133	*7.27E-09*	*3.00E-08*
Xe-133M	*5.58E-08*	*1.00E-05*
Xe-133	*4.45E-06*	*1.00E-05*
Cs-134	*0.0*	*1.00E-08*
I-134	*8.63E-10*	*5.00E-07*
I-135	*3.80E-09*	*1.00E-07*
Xe-135M	*1.17E-08*	*1.00E-06*
Xe-135	*8.42E-08*	*4.00E-06*
Cs-136	*0.0*	*2.00E-07*
Cs-137	*0.0*	*1.00E-08*
Xe-138	*7.84E-09*	*1.00E-06*
Ba-140	*0.0*	*4.00E-08*
La-140	*0.0*	*1.00E-07*
Ce-144	*0.0*	*6.00E-09*
Pr-144	*0.0*	*1.00E-06*

Note: The airborne isotopic activity concentration values provided above were developed in support of the original plant design.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.2-7
ESTIMATED AIRBORNE ACTIVITY CONCENTRATIONS IN VOLUME CONTROL TANK COMPARTMENT FOR NORMAL OPERATION

Nuclide	*Concentration µCi/cc*	*MPC Air-10 CFR 20 µCi/cc*
H-3	*5.11E-09*	*5.00E-06*
Cr-51	*0.0*	*2.00E-06*
Mn-54	*0.0*	*4.00E-08*
Mn-56	*0.0*	*5.00E-07*
Co-58	*0.0*	*5.00E-08*
Fe-59	*0.0*	*5.00E-08*
Co-60	*0.0*	*9.00E-09*
Kr-83M	*1.28E-07*	*1.00E-06*
Kr-85M	*7.50E-07*	*6.00E-06*
Kr-85	*1.84E-06*	*1.00E-05*
Kr-87	*4.24E-07*	*1.00E-06*
Kr-88	*1.27E-06*	*1.00E-06*
Sr-89	*0.0*	*3.00E-08*
Sr-90	*0.0*	*1.00E-09*
Y-90	*0.0*	*1.00E-07*
Sr-91	*0.0*	*3.00E-07*
Y-91	*0.0*	*3.00E-08*
Sr-92	*0.0*	*3.00E-07*
Y-92	*0.0*	*3.00E-07*
Zr-95	*0.0*	*3.00E-08*
Nb-95	*0.0*	*1.00E-07*
Mo-99	*0.0*	*2.00E-07*
I-131	*9.02E-10*	*9.00E-09*
Te-132	*0.0*	*2.00E-07*
I-132	*3.26E-10*	*2.00E-07*
I-133	*1.46E-09*	*3.00E-08*
Xe-133M	*1.12E-06*	*1.00E-05*
Xe-133	*8.94E-05*	*1.00E-05*
Cs-134	*0.0*	*1.00E-08*
I-134	*1.77E-10*	*5.00E-07*
I-135	*7.66E-10*	*1.00E-07*
Xe-135M	*2.35E-07*	*1.00E-06*
Xe-135	*1.69E-06*	*4.00E-06*
Cs-136	*0.0*	*2.00E-07*
Cs-137	*0.0*	*1.00E-08*
Xe-138	*1.69E-07*	*1.00E-06*
Ba-140	*0.0*	*4.00E-08*
La-140	*0.0*	*1.00E-07*
Ce-144	*0.0*	*6.00E-09*
Pr-144	*0.0*	*1.00E-06*

Note: The airborne isotopic activity concentration values provided above were developed in support of the original plant design.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.2-8
ESTIMATED AIRBORNE ACTIVITY CONCENTRATIONS IN CHARGING PUMP COMPARTMENT FOR NORMAL OPERATION

Nuclide	*Concentration µCi/cc*	*MPC Air-10 CFR 20 µCi/cc*
H-3	*7.64E-09*	*5.00E-06*
Cr-51	*0.0*	*2.00E-06*
Mn-54	*0.0*	*4.00E-08*
Mn-56	*0.0*	*5.00E-07*
Co-58	*0.0*	*5.00E-08*
Fe-59	*0.0*	*5.00E-08*
Co-60	*0.0*	*9.00E-09*
Kr-83M	*1.84E-07*	*1.00E-06*
Kr-85M	*1.10E-06*	*6.00E-06*
Kr-85	*2.75E-06*	*1.00E-05*
Kr-87	*6.00E-07*	*1.00E-06*
Kr-88	*1.85E-06*	*1.00E-06*
Sr-89	*0.0*	*3.00E-08*
Sr-90	*0.0*	*1.00E-09*
Y-90	*0.0*	*1.00E-07*
Sr-91	*0.0*	*3.00E-07*
Y-91	*0.0*	*3.00E-08*
Sr-92	*0.0*	*3.00E-07*
Y-92	*0.0*	*3.00E-07*
Zr-95	*0.0*	*3.00E-08*
Nb-95	*0.0*	*1.00E-07*
Mo-99	*0.0*	*2.00E-07*
I-131	*1.35E-09*	*9.00E-09*
Te-132	*0.0*	*2.00E-07*
I-132	*4.73E-10*	*2.00E-07*
I-133	*2.18E-09*	*3.00E-08*
Xe-133M	*1.67E-06*	*1.00E-05*
Xe-133	*1.34E-04*	*1.00E-05*
Cs-134	*0.0*	*1.00E-08*
I-134	*2.46E-10*	*5.00E-07*
I-135	*1.13E-09*	*1.00E-07*
Xe-135M	*2.84E-07*	*1.00E-06*
Xe-135	*2.51E-06*	*4.00E-06*
Cs-136	*0.0*	*2.00E-07*
Cs-137	*0.0*	*1.00E-08*
Xe-138	*2.01E-07*	*1.00E-06*
Ba-140	*0.0*	*4.00E-08*
La-140	*0.0*	*1.00E-07*
Ce-144	*0.0*	*6.00E-09*
Pr-144	*0.0*	*1.00E-06*

Note: The airborne isotopic activity concentration values provided above were developed in support of the original plant design.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.2-9
ESTIMATED AIRBORNE ACTIVITY CONCENTRATIONS IN GAS DECAY TANK COMPARTMENT FOR NORMAL OPERATION

Nuclide	*Concentration μCi/cc*	*MPC Air-10 CFR 20 μCi/cc*
H-3	*0.0*	*5.00E-06*
Cr-51	*0.0*	*2.00E-06*
Mn-54	*0.0*	*4.00E-08*
Mn-56	*0.0*	*5.00E-07*
Co-58	*0.0*	*5.00E-08*
Fe-59	*0.0*	*5.00E-08*
Co-60	*0.0*	*9.00E-09*
Kr-83M	*3.29E-08*	*1.00E-06*
Kr-85M	*4.67E-07*	*6.00E-06*
Kr-85	*3.19E-04*	*1.00E-05*
Kr-87	*7.36E-08*	*1.00E-06*
Kr-88	*4.91E-07*	*1.00E-06*
Sr-89	*0.0*	*3.00E-08*
Sr-90	*0.0*	*1.00E-09*
Y-90	*0.0*	*1.00E-07*
Sr-91	*0.0*	*3.00E-07*
Y-91	*0.0*	*3.00E-08*
Sr-92	*0.0*	*3.00E-07*
Y-92	*0.0*	*3.00E-07*
Zr-95	*0.0*	*3.00E-08*
Nb-95	*0.0*	*1.00E-07*
Mo-99	*0.0*	*2.00E-07*
I-131	*0.0*	*9.00E-09*
Te-132	*0.0*	*2.00E-07*
I-132	*0.0*	*2.00E-07*
I-133	*0.0*	*3.00E-08*
Xe-133M	*8.90E-06*	*1.00E-05*
Xe-133	*1.68E-03*	*1.00E-05*
Cs-134	*0.0*	*1.00E-08*
I-134	*0.0*	*5.00E-07*
I-135	*0.0*	*1.00E-07*
Xe-135M	*7.30E-09*	*1.00E-06*
Xe-135	*2.15E-06*	*4.00E-06*
Cs-136	*0.0*	*2.00E-07*
Cs-137	*0.0*	*1.00E-08*
Xe-138	*4.64E-09*	*1.00E-06*
Ba-140	*0.0*	*4.00E-08*
La-140	*0.0*	*1.00E-07*
Ce-144	*0.0*	*6.00E-09*
Pr-144	*0.0*	*1.00E-06*

Note: The airborne isotopic activity concentration values provided above were developed in support of the original plant design.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.2-10
ESTIMATED ACTIVITY CONCENTRATIONS IN SPENT FUEL POOL
FOR ANTICIPATED OPERATIONAL OCCURRENCES CASE

Nuclide	*Rate mCi/cc*	*Activity Curies*	*MPC Air-10 CFR 20 mCi/cc*
Cr-51	*0.0*	*0.0*	*0.0*
Mn-54	*0.0*	*0.0*	*0.0*
Mn-56	*0.0*	*0.0*	*0.0*
Co-58	*0.0*	*0.0*	*0.0*
Fe-59	*0.0*	*0.0*	*0.0*
Co-60	*0.0*	*0.0*	*0.0*
Kr-83M	*0.622E-24*	*0.0*	*0.0*
Kr-85M	*0.806E-14*	*0.0*	*0.0*
Kr-85	*0.169E-05*	*0.0*	*0.0*
Kr-87	*0.621E-31*	*0.0*	*0.0*
Kr-88	*0.129E-17*	*0.0*	*0.0*
Sr-89	*0.821E-08*	*0.587E-06*	*0.351E-09*
Sr-90	*0.242E-08*	*0.180E-06*	*0.108E-09*
Y-90	*0.388E-09*	*0.216E-06*	*0.129E-09*
Sr-91	*0.679E-13*	*0.801E-12*	*0.479E-15*
Y-91	*0.196E-08*	*0.762E-05*	*0.456E-08*
Sr-92	*0.153E-21*	*0.567E-21*	*0.339E-24*
Y-92	*0.822E-19*	*0.427E-18*	*0.255E-21*
Zr-95	*0.135E-07*	*0.975E-06*	*0.583E-09*
Nb-95	*0.211E-07*	*0.154E-05*	*0.918E-09*
Mo-99	*0.454E-07*	*0.445E-05*	*0.266E-08*
I-131	*0.765E-06*	*0.449E-04*	*0.268E-07*
Te-132	*0.208E-07*	*0.931E-06*	*0.557E-09*
I-132	*0.279E-06*	*0.181E-05*	*0.108E-08*
I-133	*0.101E-07*	*0.218E-06*	*0.130E-09*
Xe-133M	*0.404E-07*	*0.0*	*0.0*
Xe-133	*0.574E-05*	*0.0*	*0.0*
Cs-134	*0.323E-05*	*0.473E-03*	*0.282E-06*
I-134	*0.0*	*0.0*	*0.0*
I-135	*0.260E-11*	*0.222E-10*	*0.133E-13*
Xe-135M	*0.365E-11*	*0.0*	*0.0*
Ye-135	*0.803E-09*	*0.0*	*0.0*
Cs-136	*0.293E-08*	*0.325E-06*	*0.194E-09*
Cs-137	*0.347E-05*	*0.511E-03*	*0.305E-06*
Xe-138	*0.0*	*0.0*	*0.0*
Ba-140	*0.232E-08*	*0.148E-06*	*0.882E-10*
La-140	*0.425E-09*	*0.969E-07*	*0.579E-10*
Ce-144	*0.393E-08*	*0.290E-06*	*0.174E-09*
Pr-144	*0.393E-08*	*0.290E-06*	*0.174E-09*

Note: The isotopic activity concentration values provided above were developed in support of the original plant design.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.2-11
ESTIMATED AIRBORNE ACTIVITY CONCENTRATIONS IN FUEL HANDLING AREAS FOR NORMAL OPERATION

Nuclide	*Concentration µCi/cc*	*MPC Air-10 CFR 20 µCi/cc*
H-3	*1.18E-08*	*5.00E-06*
Cr-51	*0.0*	*2.00E-06*
Mn-54	*0.0*	*4.00E-08*
Mn-56	*0.0*	*5.00E-07*
Co-58	*0.0*	*5.00E-08*
Fe-59	*0.0*	*5.00E-08*
Co-60	*0.0*	*9.00E-09*
Kr-83M	*3.96E-29*	*1.00E-06*
Kr-85M	*5.23E-20*	*6.00E-06*
Kr-85	*1.15E-11*	*1.00E-05*
Kr-87	*3.88E-36*	*1.00E-06*
Kr-88	*8.28E-24*	*1.00E-06*
Sr-89	*0.0*	*3.00E-08*
Sr-90	*0.0*	*1.00E-09*
Y-90	*0.0*	*1.00E-07*
Sr-91	*0.0*	*3.00E-07*
Y-91	*0.0*	*3.00E-08*
Sr-92	*0.0*	*3.00E-07*
Y-92	*0.0*	*3.00E-07*
Zr-95	*0.0*	*3.00E-08*
Nb-95	*0.0*	*1.00E-07*
Mo-99	*0.0*	*2.00E-07*
I-131	*2.01E-16*	*9.00E-09*
Te-132	*0.0*	*2.00E-07*
I-132	*7.16E-17*	*2.00E-07*
I-133	*2.66E-18*	*3.00E-08*
Xe-133M	*2.66E-13*	*1.00E-05*
Xe-133	*3.79E-11*	*1.00E-05*
Cs-134	*0.0*	*1.00E-08*
I-134	*0.0*	*5.00E-07*
I-135	*6.79E-22*	*1.00E-07*
Xe-135M	*2.54E-17*	*1.00E-06*
Xe-135	*5.24E-15*	*4.00E-06*
Cs-136	*0.0*	*2.00E-07*
Cs-137	*0.0*	*1.00E-08*
Xe-138	*0.0*	*1.00E-06*
Ba-140	*0.0*	*4.00E-08*
La-140	*0.0*	*1.00E-07*
Ce-144	*0.0*	*6.00E-09*
Pr-144	*0.0*	*1.00E-06*

Note: The airborne isotopic activity concentration values provided above were developed in support of the original plant design.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.2-12
ESTIMATED AIRBORNE ACTIVITY CONCENTRATIONS IN CONTAINMENT FOR NORMAL OPERATION

Nuclide	*Concentration μCi/cc*	*MPC Air-10 CFR 20 μCi/cc*
H-3	*1.63E-05*	*5.00E-06*
Cr-51	*0.0*	*2.00E-06*
Mn-54	*0.0*	*4.00E-08*
Mn-56	*0.0*	*5.00E-07*
Co-58	*0.0*	*5.00E-08*
Fe-59	*0.0*	*5.00E-08*
Co-60	*0.0*	*9.00E-09*
Kr-83M	*1.46E-08*	*1.00E-06*
Kr-85M	*2.00E-07*	*6.00E-06*
Kr-85	*1.66E-04*	*1.00E-05*
Yr-87	*3.33E-08*	*1.00E-06*
Kr-88	*2.13E-07*	*1.00E-06*
Sr-89	*0.0*	*3.00E-08*
Sr-90	*0.0*	*1.00E-09*
Y-90	*0.0*	*1.00E-07*
Sr-91	*0.0*	*3.00E-07*
Y-91	*0.0*	*3.00E-08*
Sr-92	*0.0*	*3.00E-07*
Y-92	*0.0*	*3.00E-07*
Zr-95	*0.0*	*3.00E-08*
Nb-95	*0.0*	*1.00E-07*
Mo-99	*0.0*	*2.00E-07*
I-131	*1.04E-06*	*9.00E-09*
Te-132	*0.0*	*2.00E-07*
I-132	*4.79E-09*	*2.00E-07*
I-133	*1.84E-07*	*3.00E-08*
Xe-133M	*3.87E-06*	*1.00E-05*
Xe-133	*6.87E-04*	*1.00E-05*
Cs-134	*0.0*	*1.00E-08*
I-134	*9.67E-10*	*5.00E-07*
I-135	*3.10E-08*	*1.00E-07*
Xe-135M	*3.53E-08*	*1.00E-06*
Xe-135	*1.00E-06*	*4.00E-06*
Cs-136	*0.0*	*2.00E-07*
Cs-137	*0.0*	*1.00E-08*
Xe-138	*2.79E-09*	*1.00E-06*
Ba-140	*0.0*	*4.00E-08*
La-140	*0.0*	*1.00E-07*
Ce-144	*0.0*	*6.00E-09*
Pr-144	*0.0*	*1.00E-06*

Note: The airborne isotopic activity concentration values provided above were developed in support of the original plant design.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.2-13
ESTIMATED AIRBORNE ACTIVITY CONCENTRATIONS IN TURBINE BUILDING FOR NORMAL OPERATION

Nuclide	*Concentration µCi/cc*	*MPC Air-10 CFR 20 µCi/cc*
H-3	*1.79E-10*	*5.00E-06*
Cr-51	*0.0*	*2.00E-06*
Mn-54	*0.0*	*4.00E-08*
Mn-56	*0.0*	*5.00E-07*
Co-58	*0.0*	*5.00E-08*
Fe-59	*0.0*	*5.00E-08*
Co-60	*0.0*	*9.00E-09*
Kr-83M	*2.81E-14*	*1.00E-06*
Kr-85M	*1.66E-13*	*6.00E-06*
Kr-85	*4.08E-13*	*1.00E-05*
Kr-87	*9.23E-14*	*1.00E-06*
Kr-88	*2.79E-13*	*1.00E-06*
Sr-89	*0.0*	*3.00E-08*
Sr-90	*0.0*	*1.00E-09*
Y-90	*0.0*	*1.00E-07*
Sr-91	*0.0*	*3.00E-07*
Y-91	*0.0*	*3.00E-08*
Sr-92	*0.0*	*3.00E-07*
Y-92	*0.0*	*3.00E-07*
Zr-95	*0.0*	*3.00E-08*
Nb-95	*0.0*	*1.00E-07*
Co-99	*0.0*	*2.00E-07*
I-131	*5.14E-13*	*9.00E-09*
Te-132	*0.0*	*2.00E-07*
I-132	*2.33E-14*	*2.00E-07*
I-133	*8.84E-14*	*3.00E-08*
Xe-133M	*2.49E-13*	*1.00E-05*
Xe-133	*2.00E-11*	*1.00E-05*
Cs-134	*0.0*	*1.00E-08*
I-134	*4.50E-16*	*5.00E-07*
I-135	*1.49E-14*	*1.00E-07*
Xe-135M	*3.91E-13*	*1.00E-06*
Xe-135	*4.19E-13*	*4.00E-06*
Cs-136	*0.0*	*2.00E-07*
Cs-137	*0.0*	*1.00E-08*
Xe-138	*3.43E-14*	*1.00E-06*
Ba-140	*0.0*	*4.00E-08*
La-140	*0.0*	*1.00E-07*
Ce-144	*0.0*	*6.00E-09*
Pr-144	*0.0*	*1.00E-06*

Note: The airborne isotopic activity concentration values provided above were developed in support of the original plant design.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.2-14

ESTIMATED AIRBORNE ACTIVITY CONCENTRATIONS AT CONTROL ROOM INTAKE FOR NORMAL OPERATION

Nuclide	*Concentration µCi/cc*	*MPC Air-10 CFR 20 µCi/cc*
H-3	*1.42 E-10*	*5.00 E-06*
Kr-83M	*3.19 E-11*	*1.00 E-06*
Kr-85M	*2.07 E-10*	*6.00 E-06*
Kr-85	*1.95 E-08*	*1.00 E-05*
Kr-87	*1.02 E-10*	*1.00 E-06*
Kr-88	*3.30 E-10*	*1.00 E-06*
I-131	*6.60 E-13*	*9.00 E-09*
I-132	*1.42 E-13*	*2.00 E-07*
I-133	*8.92 E-13*	*3.00 E-08*
Xe-133M	*3.82 E-10*	*1.00 E-05*
Xe-133	*3.68 E-08*	*1.00 E-05*
I-134	*3.84 E-14*	*5.00 E-07*
I-135	*3.68 E-13*	*1.00 E-07*
Xe-135M	*7.37 E-11*	*1.00 E-06*
Xe-135	*5.29 E-10*	*4.00 E-06*
Xe-138	*4.15 E-11*	*1.00 E-06*

Note: The airborne isotopic activity concentration values provided above were developed in support of the original plant design.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.2-15

ESTIMATED AIRBORNE ACTIVITY CONCENTRATIONS IN CONTROL ROOM FOR NORMAL OPERATION

Nuclide	*Concentration µCi/cc*	*MPC Air-10 CFR 20 µCi/cc*
H-3	*3.41E-10*	*5.00E-06*
Cr-51	*0.0*	*2.00E-06*
Mn-54	*0.0*	*4.00E-08*
Mn-56	*0.0*	*5.00E-07*
Co-58	*0.0*	*5.00E-08*
Fe-59	*0.0*	*5.00E-08*
Co-60	*0.0*	*9.00E-09*
Kr-83M	*2.77E-11*	*1.00E-06*
Kr-85M	*1.93E-10*	*6.00E-06*
Kr-85	*1.96E-08*	*1.00E-05*
Kr-87	*8.35E-11*	*1.00E-06*
Kr-88	*2.98E-10*	*1.00E-06*
Sr-89	*0.0*	*3.00E-08*
Sr-90	*0.0*	*1.00E-09*
Y-90	*0.0*	*1.00E-07*
Sr-91	*0.0*	*3.00E-07*
Y-91	*0.0*	*3.00E-08*
Sr-92	*0.0*	*3.00E-07*
Y-92	*0.0*	*3.00E-07*
Zr-95	*0.0*	*3.00E-08*
Nb-95	*0.0*	*1.00E-07*
Mo-99	*0.0*	*2.00E-07*
I-131	*6.58E-13*	*9.00E-09*
Te-132	*0.0*	*2.00E-07*
I-132	*1.28E-13*	*2.00E-07*
I-133	*8.79E-13*	*3.00E-08*
Xe-133M	*3.78E-10*	*1.00E-05*
Xe-133	*3.67E-08*	*1.00E-05*
Cs-134	*0.0*	*1.00E-08*
I-134	*2.89E-14*	*5.00E-07*
I-135	*3.53E-13*	*1.00E-07*
Xe-135M	*3.54E-11*	*1.00E-06*
Xe-135	*5.13E-10*	*4.00E-06*
Cs-136	*0.0*	*2.00E-07*
Cs-137	*0.0*	*1.00E-08*
Xe-138	*1.87E-11*	*1.00E-06*
Ba-140	*0.0*	*4.00E-08*
La-140	*0.0*	*1.00E-07*
Ce-144	*0.0*	*6.00E-09*
Pr-144	*0.0*	*1.00E-06*

Note: The airborne isotopic activity concentration values provided above were developed in support of the original plant design.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

TABLE 12.2-17

ESTIMATED OCCUPANCY FACTORS FOR PLANT AREAS
(Hours per 7-day Week)

Area	*Operators[(a)]*	*Chemical and Radiation Protection Technicians[(b)]*	*Control Technicians[(c)]*	*Elect. and Mechanical Maintenance Personnel[(d)]*
Control room	*2000*	*10*	*300*	*0.3*
Turbine building	*700*	*10*	*1000*	*3000*
Outside	*150*	*50*	*100*	*2*
Auxiliary building corridors	*700*	*2200*	*500*	*2600*
Fuel handling area	*2*	*8*	*120*	*320*
Primary sampling room	*2*	*3*	*1*	*6*
Containment	*0.5*	*2*	*2*	*0.3*
Volume control tank compartment	*0.03*	*0.2*	*-*	*0.2*
Charging pump compartment	*0.6*	*0.5*	*3*	*7*
Letdown heat exchanger compartment	*0.03*	*0.2*	*-*	*0.3*
Gas decay tank compartment	*0.04*	*0.3*	*-*	*0.3*
Offices	*141*	*116*	*374*	*24*
Total	*3,696*	*2,400*	*2,400*	*5,960*

(a) Operators - 22 men for 2 units x 168 hr/week = 3,696 man-hr/week.
(b) Chemical and radiation protection technicians - 60 men for 2 units x 40 hr/week = 2,400 man-hr/week.
(c) Control technicians - 60 men for 2 units x 40 hr/week – 2,400 man-hr/week.
(d) Maintenance personnel - electrical and mechanical - 149 men for 2 units x 40 hr/week = 5,960 man-hr/week.

TABLE 12.2-18

ESTIMATED INHALATION AND IMMERSION DOSES FOR PLANT AREAS
Plant Personnel Exposures (Man-rem/yr)[a]

Area	*Dose*	*Operators*	*Chemical and Radiation Protection Technicians*	*Control Technicians*	*Electrical and Mechanical Maintenance Personnel*	*Total*
1. Control room	*Inhalation thyroid*	*1.69 E-01*	*6.02 E-04*	*1.76 E-02*	*2.58 E-05*	*1.88 E-01*
	Inhalation whole body[b]	*2.56 E-01*	*9.03 E-04*	*2.68 E-02*	*3.86 E-05*	*2.83 E-01*
	Immersion (beta and gamma)	*1.03 E+00*	*3.68 E-03*	*1.08 E-01*	*1.58 E-04*	*1.14 E+00*
2. Turbine building	*Inhalation thyroid*	*3.64 E-02*	*2.50 E-04*	*4.85 E-02*	*1.48 E-01*	*2.33 E-01*
	Inhalation whole body[b]	*4.95 E-02*	*3.40 E-04*	*6.61 E-02*	*2.01 E-01*	*3.17 E-01*
	Immersion (beta and gamma)	*2.11 E-04*	*1.45 E-06*	*2.82 E-04*	*8.63 E-04*	*1.36 E-03*
3. Auxiliary building corridors (includes primary sampling room)	*Inhalation thyroid*	*1.46 E+01*	*4.52 E+01*	*1.08 E+01*	*5.27 E+01*	*7.59 E+01*
	Inhalation whole body[b]	*1.16 E+01*	*3.62 E+00*	*8.69 E-01*	*4.19 E+00*	*9.84 E+00*
	Immersion (beta and gamma)	*2.22 E+01*	*6.88 E+01*	*1.65 E+01*	*7.99 E+01*	*1.88 E+02*
4. Fuel handling area	*Inhalation thyroid*	*3.30 E-08*	*1.89 E-07*	*2.55 E-06*	*6.55 E-06*	*9.32 E-06*
	Inhalation whole body[b]	*7.85 E-03*	*4.50 E-02*	*6.05 E-01*	*1.56 E+00*	*2.22 E+00*
	Immersion (beta and gamma)	*6.01 E-06*	*3.43 E-05*	*4.62 E-04*	*1.19 E-03*	*1.69 E-03*

TABLE 12.2-18

Area	*Dose*	*Operators*	*Chemical and Radiation Protection Technicians*	*Control Technicians*	*Electrical and Mechanical Maintenance Personnel*	*Total*
5. Containment	*Inhalation thyroid*	*5.86 E-03*[e]	*1.69 E-02*[e]	*2.53 E-02*[e]	*3.06 E-03*[e]	*5.11 E-02*[e]
	Inhalation whole body[b]	*3.60 E-02*[f]	*1.04 E-01*[f]	*1.55 E-01*[f]	*1.86 E-02*[f]	*3.13 E-01*[f]
	Immersion (beta and gamma)	*4.03 E+00*	*1.16 E+01*	*1.73 E+01*	*2.08 E+00*	*3.50 E+01*
6. Volume control tank compartment	*Inhalation thyroid*	*4.24 E-04*	*2.52 E-03*	*0.0*	*2.11 E-03*	*5.05 E-03*
	Inhalation whole body[b]	*6.48 E-05*	*3.84 E-04*	*0.0*	*3.22 E-04*	*7.71 E-04*
	Immersion (beta and gamma)	*3.22 E-02*	*1.91 E-01*	*0.0*	*1.60 E-01*	*3.84 E-01*
7. Charging pump compartment	*Inhalation thyroid*	*1.14 E-02*[d]	*.5 E-03*[d]	*6.27 E-03*[d]	*1.26 E-01*[d]	*1.53 E-01*[d]
	Inhalation whole body[b]	*1.74 E-03*	*1.45 E-03*	*9.57 E-03*	*1.93 E-02*	*2.35 E-02*
	Immersion (beta and gamma)	*8.65 E-01*	*7.2 E-01*	*4.75 E-01*	*9.5 E+00*	*5.28 E+02*
8. Letdown heat exchanger compartment	*Inhalation thyroid*	*2.09 E-04*[c]	*1.14 E-03*[c]	*0.0*	*1.91 E-03*[c]	*3.26 E-03*[c]
	Inhalation whole body[b]	*1.02 E-04*	*5.96 E-04*	*0.0*	*9.93 E-04*	*1.69 E-03*
	Immersion (beta and gamma)	*1.62 E-04*	*8.84 E-03*	*0.0*	*1.47 E-02*	*2.37 E-02*

TABLE 12.2-18

Area	*Dose*	*Operators*	*Chemical and Radiation Protection Technicians*	*Control Technicians*	*Electrical and Mechanical Maintenance Personnel*	*Total*
9. Gas decay tank compartment	*Inhalation thyroid*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Inhalation whole body[(b)]	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Immersion (beta and gamma)	*5.12 E-01*	*4.8 E+00*	*0.0*	*4.8 E+00*	*1.01 E+01*
Total for All Areas	*Inhalation thyroid*	*1.49 E+01*	*4.52 E+01*	*1.1 E+01*	*5.3 E+01*	*1.24 E+02*
	Inhalation whole body[(b)]	*1.53 E+00*	*3.77 E+00*	*1.72 E+00*	*5.99 E+00*	*1.30 E+01*
	Immersion (beta and gamma)	*2.47 E+02*	*8.62 E+01*	*3.44 E+01*	*9.65 E+01*	*4.64 E+02*

(a) Basis: 50 weeks/year.
(b) From tritium inhalation and absorption through skin.
(c) Includes use of a respirator with a protection factor of 100.
(d) Includes use of a respirator with a protection factor of 10.
(e) Includes use of a respirator with a protection factor of 10,000.
(f) Includes use of a protective suit, hood, and respirator with a total protection from tritium factor of 100.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED[a].

TABLE 12.3-1

HEALTH PHYSICS PORTABLE INSTRUMENTATION

Item No.	*Instrument Identification*	*Nominal Quantity*	*Detector Type*	*Radiation Measured*	*Range*
Dose Rate Meters					
1.	*High Range*	*2*	*GM*	*g*	*1 R/hr - 10 Kr/hr*
2.	*Low Range*	*5*	*GM*	*g*	*Dose Rate: Bkg to 3000 mR/hr*
3.	*Dose Rate Meter*	*30*	*Ion chamber*	*b, g*	*0-5,000 mR/hr*
4.	*Condenser R-meter*	*1*	*Ion chamber*	*G*	*0-0.25, 0-2.5, 0-25 R*
Self-Reading Pocket Ion Chambers					
1.	*Direct Reading Pocket Dosimeters*	*250*	*Ion chamber*	*G*	*0-200 mR*
2.	*Direct Reading Pocket Dosimeters*	*50*	*Ion chamber*	*g*	*0-1R and 0-2R*
3.	*Direct Reading Pocket Dosimeters*	*60*	*Ion chamber*	*g*	*0-5 R*
4.	*Direct Reading Pocket Dosimeters*	*5*	*Ion chamber*	*g*	*0-50R*
5.	*Direct Reading Pocket Dosimeters*	*5*	*Ion chamber*	*g*	*0-100 R*

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED[a].

TABLE 12.3-1

Item No.	*Instrument Identification*	*Nominal Quantity*	*Detector Type*	*Radiation Measured*	*Range*
Count Rate Meters					
1.	*Count Rate Meter*	*5*	*GM*	*-*	*0-500,000 cpm*
2.	*Count Rate Meter*	*10*	*-*	*-*	*0-70,000 cpm*
3.	*Pulse Rate Meter*	*3*	*-*	*-*	*0-500,000 cpm*
4.	*Count Rate Meter*	*40*	*-*	*-*	*0-50,000 cpm*
Count Rate Meter Probes And Detectors					
1.	*Hand Probe*	*30*	*GM*	*b, g*	*-*
2.	*Shielded Hand Probe*	*10*	*GM*	*b, g*	*-*
3.	*Alpha Scintillation Probe*	*1*	*ZnS(Ag)*	*Alpha*	*-*
4.	*Gamma Scintillation Probe*	*2*	*NaI(Tl)*	*g*	*-*
Scintillation Monitors					
1.	*Rad Portal Monitor*	*4*	*Scintil.*	*b, g*	*0-9999 cpm*
2.	*Portable Gamma Monitor*	*2*	*Scintil.*	*g*	*0.1 to 1000 mR/hr*

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED[a].

TABLE 12.3-1

Item No.	*Instrument Identification*	*Nominal Quantity*	*Detector Type*	*Radiation Measured*	*Range*
Neutron Proportional Counters					
1.	*Portable Rem Counter*	*1*	*BF_3*	*n, thermal to fast*	*0-5000 mrem/hr*
Solid-State Dosimeters					
1.	*Personal Electronic Dosimeters*	*500*	*Si*	*b, g*	*0-9999 mR*
Miscellaneous					
1.	*Self-reading Dosimeter Charger*	*4*	*-*	*-*	*-*
2.	*Scaler with Ratemeter*	*1*	*-*	*-*	*Scaler, 10^6- 1 counts: Ratemeter, 0-500, 0-5K, 0-50K, 0-500K cpm*
3.	*Extendable Probe Dose Rate Meter*	*10*	*GM*	*b, g*	*0-1000 R/hr*

A variety of portable instrumentation is available for radiological monitoring. The general equipment types in this table were accurate at the time the plant was originally licensed but are not intended or expected to be updated herein;. quantities and types of specific equipment are maintained by plant administrative controls.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED[(a)].

TABLE 12.3-2

HEALTH PHYSICS AIR SAMPLING INSTRUMENTATION

Item No.	*Instrument Identification*	*Nominal Quantity*	*Detector Type*	*Radiation Measured*	*Range*
1.	*Personnel Air Sampler*	*6*	*-*	*-*	*0-4 liters/min*
2.	*Portable Air Samplers*	*10*	*-*	*-*	*1-2 cfm*
3.	*Continuous Air Monitor* *Single Channel* *Particulate / Iodine or Particulate* *Noble Gas*	*6*	*Sealed Gas - Proportional*	*Beta*	*~ 0.3-4 cfm*

(a) A variety of air sampling equipment is available for radiological monitoring. The general equipment types in this table were accurate at the time the plant was originally licensed but are not intended or expected to be updated herein; quantities and types of specific equipment are maintained by plant administrative controls.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED[a].

TABLE 12.3-3

RESPIRATORS APPROVED FOR USE AT DIABLO CANYON POWER PLANT FOR PROTECTION AGAINST RADIOACTIVE MATERIALS

Type of Respirator	*Quantity*
Air purifying, full facepiece (various sizes); Powered air purifying respirator (PAPR)	*250*
Airline respirator, constant flow	*20*
Self-contained breathing	*108*
Spare Filter Cartridges	*200*

(a) A variety of respirators are available for use during emergencies involving fires, airborne radioactive materials and chemical releases. The general types in this table provide a minimum number needed to address commitments of the approved Emergency Plan and are provided for historical purposes. Quantities and types of specific equipment are maintained by plant administrative controls.

Figures 12.1-1 Through 12.1-12
Withheld From Public Disclosure
In Accordance With 10 CFR 2.390

Chapter 13

CONDUCT OF OPERATIONS

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Chapter 13

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Chapter 13

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Chapter 13

CONDUCT OF OPERATIONS

Pacific Gas and Electric Company (PG&E) became involved in the operation of nuclear power plants in 1957 after many years of successfully operating its fossil-fueled power plants. In the operation of Humboldt Bay Power Plant (HBPP), Unit 3, and Diablo Canyon Power Plant (DCPP), Unit 1 and Unit 2, and the Humboldt Bay and Diablo Canyon Independent Spent Fuel Storage Installations (ISFSIs), PG&E has demonstrated its dedication as a competent and safety-oriented operating organization. PG&E is also committed to continually developing and enhancing the organization responsible for the operation of DCPP to meet expanded technical and regulatory requirements. In keeping with this commitment, PG&E has made significant changes since commencement of operations in its nuclear organization and operating policies to strengthen PG&E's capability to operate DCPP safely and reliably for all operating conditions.

13.1 ORGANIZATIONAL STRUCTURE

The following regulatory requirements are applicable to the organizational structure presented in this section:

(1) 10 CFR 50.40 – Common Standards

10 CFR 50.40(b) requires applicants for an operating license to be technically qualified to engage in the proposed activities in accordance with the applicable regulations. The organizational structure established by PG&E to address this requirement is presented in Section 13.1.

(2) 10 CFR 50.54 – Conditions of Licenses

10 CFR 50.54(i), (j), (k), (l), (m), and (y) specify requirements for operating shift staffing. The organizational structure established by PG&E to address these requirements is presented in Section 13.1.2.2. Note 1 in the table at 10 CFR 50.54(m)(2)(i) is applicable to DCPP in accordance with DCPP Technical Specification 5.2.2.b.

(3) Regulatory Guide 1.8, Revision 2 (Proposed) – Personnel Selection and Training

Regulatory Guide 1.8, Revision 2 (Proposed), endorses ANSI/ANS 3.1-1978, with certain enhancements. Members of the plant staff are required to meet the minimum qualifications of ANSI/ANS 3.1-1978 for comparable positions, with exceptions as identified in DCPP Technical Specification 5.3.1 and in Appendix B of the Diablo Canyon Quality Assurance Program Description.

(4) Regulatory Guide 1.8, Revision 2 – Qualification and Training of Personnel for Nuclear Power Plants

The Manager, Radiation Protection, is required to meet the minimum qualifications of Regulatory Guide 1.8, Revision 2, for radiation protection manager in accordance with DCPP Technical Specification 5.3.1.a (refer to Section 13.1.2.1).

(5) Regulatory Guide 1.8, Revision 3 – Qualification and Training of Personnel for Nuclear Power Plants

In accordance with DCPP Technical Specification 5.3.1.c, the licensed Reactor Operators (ROs) and Senior Reactor Operators (SROs) are required to meet the minimum qualifications of ANSI/ANS 3.1-1993 as endorsed by Regulatory Guide 1.8, Revision 3, with the exceptions clarified in the current revision to the Operator Licensing Examination Standards for Power Reactors, NUREG-1021, ES-202.

(6) NUREG-0737 (Item I.A.1.1), November 1980 – Clarification of TMI Action Plan Requirements

Item I.A.1.1 – Shift Technical Advisor

Item I.A.1.1 requires each licensee to provide a fully trained on-shift Shift Technical Advisor (STA) to the shift foreman. The STA provides advisory technical support to the unit operations shift crew in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to the safe operation of the unit. This position is manned in Modes 1, 2, 3, and 4 unless an individual with a SRO license meets the qualifications specified by the Commission Policy Statement on Engineering Expertise on Shift. Refer to License Condition 2.C(6)a in the DCPP Unit 1 Operating License and Section 5.2.2.f in the DCPP Technical Specifications.

(7) Generic Letter 88-06, March 1988 – Removal of Organization Charts from Technical Specification Administrative Control Requirements

The DCPP Technical Specifications and Diablo Canyon Quality Assurance Program Description contain requirements that are derived from Generic Letter 88-06, March 1988 (refer to DCPP Technical Specification Sections 5.2.1.a through 5.2.1.d).

(8) Regulatory Guide 1.8 Revision 4 - Qualification and Training of Personnel for Nuclear Power Plants

Technicians, radiation protection, are required to meet the minimum qualifications of Regulatory Guide 1.8, revision 4, for radiation protection technicians.

13.1.1 CORPORATE ORGANIZATION

PG&E's corporate organizational structure is depicted in Appendix A of the Diablo Canyon Quality Assurance Program Description. The manner in which the various PG&E departments function in performing the design, operation, and quality assurance of DCPP is described in Section 1 of the Diablo Canyon Quality Assurance Program Description.

13.1.1.1 Corporate Functions, Responsibilities, and Authorities

PG&E is a public utility and the primary operating subsidiary of PG&E Corporation, a holding company. The Board of Directors of PG&E Corporation oversees the governance of PG&E.

Refer to Section 1 of the Diablo Canyon Quality Assurance Program Description for discussion of corporate functions, responsibilities, and authorities.

13.1.1.2 Corporate Staffing and Organizational Relationships

Current operations of PG&E are organized under and responsible to the PG&E Corporation Board of Directors through the Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation.

Reporting relationships are described in Appendix A of the Diablo Canyon Quality Assurance Program Description.

13.1.1.3 Interrelationship With Contractors And Suppliers

The working interrelationships and organizational interfaces among PG&E, Westinghouse (the nuclear steam supply system manufacturer) and other suppliers and contractors are described in Chapter 1 (refer to Section 1.4).

13.1.1.4 Technical Staff

DCPP may call upon a variety of other PG&E departments, as well as outside consultants, to assist in the technical support of nuclear power plant operations as shown in Appendix A of the Diablo Canyon Quality Assurance Program Description.

PG&E's overall technical capability is such that most technical support functions for

DCPP are provided from within the PG&E organization. Outside consultants are available to provide technical support in all technical areas for plant operations and are used to assist on special problems as required. Consultant personnel interface with PG&E specialists in a variety of technical, engineering, and design areas.

13.1.2 OPERATING ORGANIZATION

The operating organization and reporting relationships are provided in the organization chart in Appendix A of the Diablo Canyon Quality Assurance Program Description. The functions, responsibilities, and authorities of key management positions in the DCPP operating organization are described in Section 1.2 of the Diablo Canyon Quality Assurance Program Description. The Operations Services Organization including the shift crew composition is described in more detail below.

13.1.2.1 Operations Services Organization

The Operations Services organization is shown in Figure 13.1-5.

The Director, Operations Services reports to the Station Director and is responsible for safe plant operation, chemistry and environmental operations, and radiological safety. The following positions directly report to the Director, Operations Services:

- Manager, Chemistry and Environmental Operations

  The Manager, Chemistry and Environmental Operations, is responsible for administering, coordinating, planning, and scheduling all chemistry activities at the plant. This individual is also responsible for coordinating DCPP environmental activities and for developing and managing programs to achieve and maintain compliance with applicable environmental regulations and requirements.

- Manager, Radiation Protection

  The Manager, Radiation Protection, is responsible for administering, coordinating, planning, and scheduling all radiation protection activities at the plant. The Manager, Radiation Protection, is also responsible for administering the Radiological Environmental Monitoring Program (REMP) and the Groundwater Protection Initiative (GPI). The Manager, Radiation Protection, has direct access to the VP, Nuclear Generation, and CNO on matters concerning radiation protection and support. (Reference Technical Specification 5.2.1.d and Regulatory Guide 8.8, July 1973)

- Manager, Operations

  The Manager, Operations, is the operations manager specified in Technical Specification 5.2.2.e. The Manager, Operations, is responsible for ensuring that

appropriate operating procedures are available and that operating personnel are familiar with the procedures. In carrying out these responsibilities, this individual provides direct supervision to the shift operating crews (or to the Operations Superintendent if the Manager, Operations, does not hold an SRO license for DCPP).

During high workload periods (such as outages), the Director, Operations Services may choose to appoint an additional operations manager in order to better fulfill the responsibilities listed above. In such cases, the division of responsibilities will be clearly identified, and establishment of that position will be communicated to all appropriate organizations.

- Manager, Operations Planning

  The Manager, Operations Planning, reports directly to the Director, Operations Services, and is responsible for Operations' role in outage and daily work control planning and clearance preparation.

The following positions directly report to the Manager, Operations:

- Operations Superintendent

  If the Manager, Operations, does not hold an SRO license for DCPP, the Operations Superintendent shall hold an SRO license for DCPP. The Operations Superintendent shall be responsible for providing operating instructions to the Shift Foremen and Shift Managers as indicated in Figure 13.1-5. The Operations Superintendent satisfies the operations middle manager position specified in Technical Specification 5.2.2.e and shall meet the requirements of ANSI 3.1-1993, Sections 4.2.2 and 4.3. This position is not intended to be filled using rotational personnel.

  If the Manager, Operations, holds an SRO license for DCPP, then the Operations Superintendent position is not required to be staffed as indicated in Figure 13.1-5.

- Shift Manager

  The Shift Manager reports to the Manager, Operations, and is responsible for overall supervision of the operation of the facility. The Shift Manager provides direct supervision to the Shift Foremen, and, in the absence of higher supervision, is in full charge of the plant. In the event of an operating emergency, the Shift Manager is authorized to take any actions deemed necessary to respond to the emergency.

- Shift Foreman

  The Shift Foreman reports to the Shift Manager and is responsible for providing direct supervision of the plant operators and the work they perform, and for ensuring administrative support is available in this area. The Shift Foreman has command and control responsibility for the control room for the assigned unit.

  The Shift Foreman may also be assisted by a work control shift foreman. The work control shift foreman is an optionally staffed position, whose function is described in the appropriate administrative procedure.

- Shift Technical Advisor

  The STA function will normally be assigned to one of the SRO licensed operators on crew. The STA function may be assigned to an STA qualified individual supplementing the crew.

  The STA provides technical and analytical support to the operating shift crew to ensure safe operation of the plant.

  During transient and emergency events, the STA qualified individual is responsible for applying knowledge and experience to the analysis of and response to the event and advising the rest of the crew, as applicable, on actions to terminate the event or mitigate its consequences.

13.1.2.2 Shift Crew Composition

With either or both units fueled and in Mode 1, 2, 3, or 4, the minimum shift crew composition is:

- One Shift Manager and one Shift Foreman, each with an SRO license pursuant to 10 CFR Part 55.

- Three licensed operators, each licensed under 10 CFR Part 55; at least one assigned to each unit.

- Three non-licensed operators (Nuclear Operators), with at least one assigned to each unit. These positions satisfy Technical Specification 5.2.2.a.

- One STA, an individual who provides technical support to the unit operations shift crew in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to safe operation of the unit. This position will be manned unless there is a crew member with an SRO license who meets the qualifications specified by the Commission Policy Statement on Engineering Expertise on Shift. This position satisfies

Technical Specification 5.2.2.f.

- One chemical and radiation protection technician. This position satisfies Technical Specification 5.2.2.c.

With both units defueled or both units in Mode 5 or 6, the minimum shift crew complement is:

- One Shift Foreman with an SRO license pursuant to 10 CFR Part 55.
- At least one individual holding an SRO license or an SRO license limited to fuel handling, and who has no other concurrent responsibilities, will be present during core alterations on either unit.
- Two licensed operators, each licensed under 10 CFR Part 55, with at least one assigned to each unit.
- Three non-licensed operators (Nuclear Operators), with at least one assigned to each reactor containing fuel. These positions satisfy Technical Specification 5.2.2.a.
- One chemical and radiation protection technician. This position satisfies Technical Specification 5.2.2.c.

The shift crew composition may be one less than the minimum requirements of 10 CFR 50.54(m)(2)(i) and Technical Specifications 5.2.2.a and 5.2.2.f for a period of time not to exceed two hours in order to accommodate unexpected absence of on duty shift crew members provided immediate action is taken to restore the shift crew composition to within the above minimum requirements. This provision does not permit any shift crew position to be unmanned upon shift change due to an oncoming shift crewman being late or absent.

The establishment of the shift organization is based on consideration of PG&E's power plant staffing philosophy, the evaluation of the operating practices of U.S. pressurized water reactor (PWR) plants, PG&E's experience with HBPP and large (up to 750 MWe) fossil-fuel units, and the expanded technical and operational regulatory requirements of nuclear power operation.

This shift organization provides effective manpower to cover the operating contingencies that can reasonably be expected to occur during normal operation of the plant. An organization of this size is also effective to monitor operation of engineered safety systems in the event of any plant accidents. Refer to the Emergency Plan for additional staffing requirements.

The shift chemical and radiation protection technician performs the chemistry sampling and analysis radiation monitoring, and other chemistry and radiation protection functions

normally encountered during both normal and nonroutine operations. In addition, all licensed operators are trained in chemistry and radiation protection as part of their operator license training.

13.1.3 QUALIFICATION REQUIREMENTS FOR NUCLEAR PLANT PERSONNEL

13.1.3.1 Minimum Qualification Requirements

PG&E is using proposed Revision 2 of Regulatory Guide 1.8 (ANSI/ANS 3.1-1978) as the basis for establishing minimum qualification requirements for comparable management, supervisory, and technical positions in the plant organization. One exception is that the Manager, Radiation Protection, shall meet or exceed the qualification requirements of Regulatory Guide 1.8, Revision 2, for the radiation protection manager. A second exception is that the operations manager shall meet or exceed the minimum qualifications as specified in Technical Specification 5.2.2.e. A third exception is that the licensed ROs and SROs shall meet or exceed the minimum qualifications of ANSI/ANS 3.1-1993 (Reference 6) as endorsed by Regulatory Guide 1.8, Revision 3, (Reference 7) with the exceptions clarified in the current revision to NUREG-1021 (Reference 8), Section ES-202. A fourth exception is that radiation protection technicians shall meet or exceed the minimum qualifications of ANSI/ANS 3.1-2014 as endorsed by Regulatory Guide 1.8, revision 4. Other exceptions are summarized in Appendix B of the Diablo Canyon Quality Assurance Program Description.

The minimum qualification processes for physical force personnel (operators, instrument technicians, maintenance personnel, and chemical and radiation protection technicians) are defined by the Institute of Nuclear Power Operation (INPO) accreditation criteria (Reference 5). PG&E has received, and will maintain, INPO accreditation of the training and qualification programs for physical force personnel.

13.1.3.2 Qualifications of Plant Personnel

PG&E has addressed NUREG-0660, May 1980 (Reference 1), NUREG-0731, September 1980 (Reference 2), and Regulatory Guide 1.8, Proposed Revision 2 (Reference 3) (ANSI/ANS-3.1-1978, Selection and Training of Nuclear Power Plant Personnel) as the basis for establishing minimum educational background and experience requirements for all management, supervisory, and professional personnel.

The key management, supervisory, and technical positions in the plant organization are filled by individuals who have been actively engaged in the nuclear power field. Qualification forms for personnel holding the key positions in the plant operating organization are maintained on file at the plant.

13.1.4 REFERENCES

1. NUREG-0660, NRC Action Plan Developed as a Result of the TMI-2 Accident, Task I.B.1

2. NUREG-0731, Guidelines for Utility Management Structure and Technical Resources

3. Regulatory Guide 1.8, Personnel Selection and Training, USNRC February 1979 (Proposed Revision 2)

4. Regulatory Guide 1.33, Quality Assurance Program Requirements (Operation), USNRC February 1978

5. ACAD 00-001, Revision 0, The Process for Accreditation of Training in the Nuclear Power Industry, INPO, January 2000

6. ANSI/ANS 3.1, American National Standard for Selection, Qualification, and Training of Personnel for Nuclear Power Plants, April 1993

7. Regulatory Guide 1.8, Qualification and Training of Personnel for Nuclear Power Plants, USNRC, Revision 3, May 2000

8. NUREG-1021, Operator Licensing Examination Standards for Power Reactors

9. Regulatory Guide 1.8, Qualification and Training of Personnel for Nuclear Power Plants, USNRC, Revision 4, June 2019

13.2 TRAINING PROGRAM

The following regulatory requirements are applicable to the training programs described in this section:

(1) 10 CFR 50.120 – Training and Qualification of Nuclear Power Plant Personnel

DCPP is required to meet the requirements for the training and qualification of nuclear power plant personnel contained in 10 CFR 50.120.

(2) 10 CFR Part 55 – Operators' Licenses

The DCPP training program is required to meet the requirements for the preparation, approval, proctoring, grading, and security of written examinations and operating tests contained in 10 CFR Part 55, Subpart E, Written Examinations and Operating Tests. In addition, the DCPP training program is required to meet the requalification program requirements contained in 10 CFR 55.59.

On May 26, 1987, the U.S. Nuclear Regulatory Commission (NRC) revised 10 CFR Part 55 regarding training and qualifications of licensed operators. As a result of this issuance, DCPP revised its Continuing Training Program to meet the requirements of 10 CFR Part 55 utilizing a Systems Approach to Training methodology.

In accordance with Generic Letter 87-07, March 1987, PG&E submitted a response on April 28, 1988, to inform the NRC that the DCPP Continuing Training Program would be following a Systems Approach to Training methodology.

(3) NUREG-0737 (Items I.A.1.1, I.A.1.2, I.C.3, I.C.5, and II.B.4), November 1980 – Clarification of TMI Action Plan Requirements

Item I.A.1.1 – Shift Technical Advisor (STA)

This item requires the DCPP requalification training program for STAs to include review of the five elements described in DCPP's response for this item.

Item I.A.1.2 – Shift Supervisor Administrative Duties

This item requires the training program for shift foremen (i.e., the DCPP equivalent of the shift supervisor) to emphasize and reinforce (1) the responsibility for safe operation and (2) the management function the shift foreman provides for assuring safety.

Item I.C.3 – Shift Supervisor Responsibilities

This item is included with Section I.A.1.2 above.

Item I.C.5 – Procedures for Feedback of Operating Experience to Plant Staff

PG&E is required to implement procedures to assure that operating information pertinent to plant safety originating both within and outside the utility organization is continually incorporated into the training program.

Item II.B.4 – Training Program for Mitigating Core Damage

The DCPP training program is required to teach the use of installed equipment and systems to control or mitigate accidents in which the core is severely damaged. The training program is required to contain the following items, as a minimum:

(1) Incore Instrumentation
(2) Excore Instrumentation
(3) Regulatory Guide1.97, Revision 3, Instrumentation
(4) Primary Chemistry
(5) Radiation Monitoring
(6) Gas Generation

(4) Generic Letter 88-17, October 1988 – Loss of Decay Heat Removal

The DCPP training program is required to implement a commitment to include midloop operation in control room operator training, which was made in the station's response to Generic Letter 88-17, October 1988.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

13.2.1 INITIAL PROGRAM DESCRIPTION

The experience obtained by PG&E since 1956 in training personnel for operation and maintenance of nuclear power plants has enabled it to clearly define the training requirements for each position in the plant organization and to evaluate the various means of obtaining this training. Based on this experience, PG&E chose to utilize a combination of formal classroom training and on-the-job experience with operating nuclear plants to achieve its training goals. A brief summary of each of the initial training activities is given in Table 13.2-1. The extent to which each individual participated in these activities was determined based on the person's position in the plant organization and his previous experience. A training summary for the initial operating organization is presented in Table 13.2-2.

Tables 13.2-1 and 13.2-2 summarize the initial plant training program and are historical in nature.

13.2.1.1 Program Content

The training programs described in Sections 13.2.1.1.1, 13.2.1.1.2, 13.2.1.2, 13.2.1.3, 13.2.1.4, 13.2.1.5, and 13.2.1.6 were for the initial plant personnel and are retained herein for historical value. Starting with Section 13.2.1.7, the present and ongoing plant training programs are described.

13.2.1.1.1 Training for Initial Plant Supervisorial Personnel

The training programs for the initial appointees to supervisory positions in the Diablo Canyon operating organization are summarized in Table 13.2-2.

The first formal involvement by a member of the plant staff in the Diablo Canyon project occurred in early 1968, when the Power Plant Engineer was assigned to PG&E's General Office for approximately 2 months to assist in the preparation of the preliminary safety analysis report (PSAR) for Unit 1. In the spring of 1969, both the Power Plant Engineer and the Supervisor of Operations were engaged in similar work on the Unit 2 PSAR for approximately 6 months, and they also assisted in the conceptual design of several plant systems. These two individuals were then assigned to the R. E. Ginna plant in the latter part of 1969 to participate in the startup testing program. Since that time, other key plant supervisory personnel have been sent to various PWR plants that were in operation or in the startup testing program. The majority of these assignments took place in the period from 1970 to 1972.

In July 1970, the second major step in the early supervisory training activities occurred with the organization of the Diablo Canyon Task Force at Humboldt Bay. This was the first time that the majority of the supervisory staff was assembled as a group. Initially, the Task Force consisted of 14 individuals on a full- or part-time basis. During the period that the group was at Humboldt Bay, work was begun on the various Task Force assignments, including preparation of training material, operating manuals, licensing material and technical specifications, and performing an operational review of the plant design.

In August 1971, the Task Force was transferred to the site, along with several supervisors who had not previously been on the Task Force, in order to obtain maximum participation of plant staff personnel in onsite activities, including observation of equipment installation and review and comment on the system and equipment preoperational and startup test procedures prepared by the General Construction Department.

The second basic phase of the training program began with the arrival onsite of selected plant operators about 5 years before the initial anticipated core loading. At that time, the formal nuclear training courses required to prepare individuals for the operator

license examinations began. These courses were conducted by members of the plant supervisory staff. Depending on a particular individual's experience and qualifications, supervisors were either instructors or participants as appropriate during different portions of this program. In most cases, the supervisors participating in these courses had completed similar training at the HBPP.

In addition to participation in the formal training programs, the supervisors were actively engaged in preoperational testing and checkout of systems and equipment, hot functional testing, initial loading and low level testing, and in the power escalation program leading to commercial operation, as those activities took place.

13.2.1.1.2 Training for Plant Physical Force Personnel

All physical force personnel were trained in radiation protection, quality assurance, and security procedures and practices to an extent commensurate with their duties. In addition, the chemical and radiation protection technicians and control technicians participated in the nuclear technology and plant design seminars. The chemical and radiation protection technicians were also trained in chemical and radiochemical techniques.

The first physical force personnel assigned to the site were the control technicians, three of whom arrived in late 1971. They were placed on loan to the General Construction instrument staff and participated in the installation and checkout of plant equipment. An apprentice control technician was transferred to the site in December 1972 and was also placed on loan to General Construction.

13.2.1.2 Coordination with Preoperational Tests and Fuel Loading

The schedule of formal nuclear training designed to prepare candidates for NRC Operator and Senior Operator License examinations is shown in Figure 13.2-1 in relation to the schedule for preoperational testing and initial fuel loading.

13.2.1.3 Practical Reactor Operation

The senior control operators and control operators for Unit 1 were assigned to the site about five years before the initial anticipated core loading and began formal training at that time. The remaining operators were assigned as the preoperational testing work load dictated. All operators received extensive on-the-job training in the operation of plant controls during the preoperational and startup testing programs.

Other physical force personnel were assigned to the site as dictated by the work load and in time to complete any training required prior to work assignment.

13.2.1.4 Reactor Simulator Training

The simulator training program for the "Cold" license candidates is described in Table 13.2-1, Section 16, Simulator Training.

13.2.1.5 Previous Nuclear Training

The majority of the initial supervisory personnel had several years of nuclear power plant experience at HBPP or at other nuclear facilities. Thus, the initial training for this group was largely concentrated in two major areas: (a) becoming familiar with the differences between the PWR and boiling water reactor concepts, and (b) study of the design and operation of the Diablo Canyon plant itself.

13.2.1.6 Other Scheduled Training

Plant personnel were required to participate in a program of lectures, demonstrations, written assignments, and drills designed to familiarize them with fire protection procedures, security procedures, medical and first aid techniques, radiation protection principles, their actions in the event of a plant emergency, and other topics. The extent of the training that a particular individual received was dependent on the responsibilities of his or her position on the plant staff.

13.2.1.7 Training Programs for Nonlicensed Personnel

Each individual on the plant staff receives training to some degree depending on the scope of their job duties and responsibilities. This training falls into three general categories: (a) standard PG&E training programs, (b) general employee training programs related to working at DCPP, and (c) training programs specific to job-related departmental duties.

All personnel receive general employee training as discussed in Section 13.2.1.8.

Each onsite DCPP department has defined a training program directed toward the technical skills needed for job-related duties. These training programs are described in the Plant Manual.

13.2.1.8 General Employee Training Program

Training programs involving industrial safety, first aid, fire protection, security, emergency planning, radiation protection, quality control, and other general topics are conducted for onsite personnel to supplement specific job-related technical training programs.

General training for all onsite personnel is given in the following areas:

(1) General description of plant and facilities
(2) General site rules
(3) Radiological health and safety program
(4) Site emergency plans

(5) Industrial safety program (including medical emergency response notification, and general fire protection)
(6) Security program
(7) Quality assurance/orientation
(8) Fitness for Duty
(9) Hazardous Materials

The extent of training in the above topics varies from one person to another commensurate with factors such as the duties and responsibilities of the person's job, areas of the plant to be accessed, whether the access is to be escorted or unescorted, duration of the access, and prior experience.

13.2.1.9 Responsible Individual

The CNO has overall responsibility for the entire training effort for plant personnel, including ensuring that necessary training programs are established, implemented, documented, and audited.

The Director, Learning Services reports to the VP Nuclear Generation, and is responsible within the DCPP organization for conducting the majority of plant training. The director is also responsible for training coordination so that resources are used effectively and the training program content reflects the actual needs of the various departments and workers and satisfies current NRC and industry standards.

Within Learning Services, there are functional groups reporting to the Director, Learning Services that conduct operator, technical, maintenance, engineering, and general employee training. There is also an ongoing training development and administration effort.

13.2.2 LICENSED OPERATOR CONTINUING (REQUALIFICATION) TRAINING PROGRAM

The Diablo Canyon Licensed Operator Continuing Training Program was accredited by INPO in March 1986. This program is maintained in accordance with the standards specified in the accreditation criteria and is evaluated for accreditation renewal every six years.

PG&E will comply with the functional requirements identified in ANSI/ANS 3.5-2009, “Nuclear Power Plant Simulators for Use in Operator Training and Examination.” Personnel qualifications will be in accordance with the requirements specified in Appendix B of the Diablo Canyon Quality Assurance Program Description.

13.2.3 NEW OPERATOR TRAINING

13.2.3.1 Licensed Operator and Senior Operator Training Program

The Diablo Canyon Licensed Operator and Senior Licensed Operator Training Program was accredited by INPO in March 1986. These programs are maintained in accordance with the standards specified in the accreditation criteria and are evaluated for accreditation renewal every six years.

13.2.3.2 Shift Technical Advisor Training Program

The Diablo Canyon STA Training Program was accredited by INPO in March 1986. This program is maintained in accordance with the standards specified in the accreditation criteria and is evaluated for accreditation renewal every six years.

13.2.3.3 Non-Licensed Operator Training Program

The Diablo Canyon Non-Licensed Operator Training Program was accredited by INPO in March 1986. This program is maintained in accordance with the standards specified in the accreditation criteria and is evaluated for accreditation renewal every six years.

13.2.4 RECORDS

Training record files are maintained for all personnel. The files are maintained in accordance with Plant Manual procedures that state that the files shall contain records of qualifications, experience, training, and retraining for each member of the plant organization. Audits of the various plant training programs and records are conducted by the quality verification (QV) organization.

13.3 EMERGENCY PLANNING

A comprehensive Emergency Plan has been developed for DCPP as required by 10 CFR 50.47(b) and 10 CFR Part 50, Appendix E. It serves several purposes including:

(1) Establishing the emergency duties and responsibilities of the various members of the plant staff at or near the site

(2) Informing all affected agencies (including members of the plant staff) of the interfaces that have been established between the plant staff and participating PG&E and non-PG&E support groups

(3) Providing a convenient means for gathering together, by way of appendices to the Emergency Plan, the plans of the various participating offsite agencies such that plant staff personnel are made aware of the basic responsibilities and capabilities of these agencies

(4) Providing an overview of the facilities, equipment, and procedures utilized by the plant staff in the emergency in order to inform and assist those offsite agencies who must coordinate their activities with those of the plant staff

(5) Providing training and exercising of emergency plans for both licensee employees and other support groups' personnel

(6) Fulfilling licensing requirements of the NRC

The DCPP Emergency Plan has been developed in accordance with the guidance of NUREG-0654/FEMA-REP-1 (Reference 1) and has been placed on the docket of each unit.

13.3.1 REFERENCES

1. NUREG-0654/FEMA-REP-1, Revision 1, Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants, November 1980.

13.4 REVIEW AND AUDIT

Refer to Sections 2.3 and 18 of the Diablo Canyon Quality Assurance Program Description for additional information on review and audit functions.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

13.4.1 REVIEW AND AUDIT - CONSTRUCTION PHASE

The independent review and audit of construction activities was incorporated into the Quality Assurance Program during design, construction, and preoperational testing as prescribed by the Quality Assurance program as described in Chapter 17 of the FSAR Update.

13.4.2 REVIEW AND AUDIT - OPERATION PHASE

Review and audit during the operation phase is accomplished by senior members of the plant staff, independent review and audit groups, and management oversight groups as discussed below. In addition, the QV organization independently audits operation phase activities in accordance with the Diablo Canyon Quality Assurance Program Description.

13.4.2.1 Plant Staff Review Committee

A plant staff review committee (PSRC) has been established at the plant site to advise the Station Director on all matters related to nuclear safety. The PSRC's functions and responsibilities are detailed in Section 2.4 of the Diablo Canyon Quality Assurance Program Description.

13.4.2.2 Independent Review and Audit Program

A program of independent review and audit of nuclear plant operations has been in effect since the initial operation of HBPP, Unit 3 in 1963. This program, which was applied to the preoperational testing, startup testing, and operation of DCPP, has been reviewed and appropriately modified so that it conforms to the requirements and recommendations of ANSI N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants.

This program satisfies the requirements of Sections 4.3 and 4.5 of ANSI 18.7-1976. The independent review and audit program functions and responsibilities are detailed in Sections 2.3 and 18 of the Diablo Canyon Quality Assurance Program Description.

13.4.2.3 Management Oversight Groups

As a means for corporate management to be involved in nuclear plant safety considerations and to ensure that these considerations are effectively applied to plant operation, management oversight groups have been established.

13.5 PLANT PROCEDURES AND PROGRAMS

Refer to Section 5 of the Diablo Canyon Quality Assurance Program Description for more information on procedures.

13.5.1 PROCEDURES

Activities involving the design, operation, maintenance, and testing of PG&E Design Class I plant systems and equipment are carried out in accordance with written policies and detailed written procedures. These policies and procedures, as well as others involving plant activities not related to safety, are incorporated into a Diablo Canyon Plant Manual. Because of its physical size and diversity of topics, the manual has been divided into several volumes.

Except as noted in Appendix B of the Diablo Canyon Quality Assurance Program Description, these policies and procedures implement the requirements of the Regulatory Guide 1.33, Revision 2, Quality Assurance Program Requirements (Operations) (Reference 1) and the requirements and recommendations of ANSI N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants. Emergency operating procedures meet the requirements of Supplement 1 to NUREG-0737, December 1982, Clarification of TMI Action Plan Requirements: Requirements for Emergency Response Capability (Reference 2).

The review, change, and approval process for these procedures is described in Section 5 of the Diablo Canyon Quality Assurance Program Description.

13.5.2 PROGRAMS

Significant programs that are part of the DCPP licensing basis are described or referenced below. Some programs were transferred from the DCPP Technical Specifications by license amendment. Other programs that are also part of the licensing basis are included here for consistency.

In addition to the programs listed below, PG&E implements the programs described in the DCPP Technical Specifications (refer to Section 5.5).

13.5.2.1 Process Control Program

The Process Control Program (PCP) contains the current formulas, sampling, analyses, tests, and determinations to be made to ensure that processing and packaging of solid radioactive wastes based on demonstrated processing of actual or simulated wet solid wastes will be accomplished in such a way as to ensure compliance with 10 CFR Parts 20, 61, and 71 and Federal and State regulations, burial ground requirements, and other requirements governing the disposal of solid radioactive waste.

Changes to the PCP are documented and records of review for changes made to the PCP are retained. The documentation contains:

- sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s), and

- a determination that the change will maintain the overall conformance of the solidified waste product to existing requirements of Federal, State, or other applicable regulations.

PCP changes become effective after review and approval by the Station Director.

13.5.2.2 Radiation Protection Program

Procedures for personnel radiation protection are prepared consistent with the requirements of 10 CFR Part 20 and are approved, maintained, and adhered to for all operations involving personnel radiation exposure.

13.5.2.3 In-Plant Radiation Monitoring

A program, which will ensure the capability to accurately determine the airborne iodine concentration in vital areas under accident conditions is established, implemented, and maintained. The program includes:

- Personnel training
- Procedures for monitoring
- Provisions for maintenance of sampling and analysis equipment

13.5.2.4 Backup Method for Determining Subcooling Margin

A program, which will ensure the capability to accurately monitor the reactor coolant system (RCS) subcooling margin is established, implemented, and maintained. The program includes the following:

- Personnel training
- Procedures for monitoring

13.5.2.5 Containment Polar and Turbine Building Cranes

A program is established, implemented, and maintained to ensure that: (1) the parked location of the containment polar cranes precludes jet impingement from a postulated pipe rupture, and (2) the operation of the turbine building cranes is consistent with the restrictions associated with the current Hosgri seismic analysis of the turbine building. This program includes the following:

- Personnel training

- Procedures for the containment polar and turbine building cranes operation

The procedures will control the operation of the containment polar cranes in jet impingement zones.

13.5.2.6 Motor-Operated Valve Testing and Surveillance Program

A program is established to comply with Generic Letter 89-10, June 1989, “Safety-Related Motor-Operated Valve Testing and Surveillance” and its supplements and Generic Letter 96-05, September 1996, “Periodic Verification of Motor-Operated Valves.”

13.5.2.7 Fire Protection Program

A fire protection program has been established and is maintained in conformance with Condition 2.C(5) of the DCPP Unit 1 operating license and Condition 2.C(4) of the DCPP Unit 2 operating license. Refer to Sections 3.1.2.3 and 9.5.1 and Appendix B of the Diablo Canyon Quality Assurance Program Description for additional information.

The fire protection program is implemented through and controlled by plant procedures.

13.5.2.8 Control of Heavy Loads Program

A control of heavy loads program has been established consistent with commitments DCPP made in response to NUREG-0612, July 1980, and its associated generic letters. The program is designed to ensure safe handling of heavy loads and is described in Section 9.1.4.3.10.

The control of heavy loads program is implemented through and controlled by plant procedures.

13.5.2.9 Environmental Qualification Program

An environmental qualification (EQ) program has been established in accordance with 10 CFR 50.49, *Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants*. The program is designed to ensure that electric equipment relied on to remain functional during a design basis event would be able to withstand the harsh environment to which it would be exposed as a result of the event. The program is described in Section 3.11.

The EQ program is implemented through and controlled by plant procedures.

13.5.2.10 Seismically Induced Systems Interaction Program

A seismically induced system interaction (SISI) program has been established in response to NRC requirements promulgated after the accident at Three Mile Island Unit 2; refer to Task II.C.3, "Systems Interaction," in NUREG-0660, May 1980. The program establishes confidence that when subjected to seismic events of severity up to and including the postulated 7.5M Hosgri event, structures, systems, and components that are important to safety shall not be prevented from performing their intended safety functions as a result of physical interactions caused by seismically induced failures of nonsafety-related structures, systems, or components. Refer to Section 3.7.3.13 for additional information.

The SISI program is implemented through and controlled by plant procedures.

13.5.2.11 Long Term Seismic Program

A long term seismic program (LTSP) was established for the station in response to License Condition 2.C.(7) of the DCPP Unit 1 operating license (License No. DPR-80). Although a final report for the LTSP was submitted (Reference 6), along with a follow-up addendum (Reference 7), and the license condition was closed by the NRC (References 8 and 9), PG&E made certain commitments to continue the LTSP as an ongoing program at DCPP. The ongoing LTSP implements the following PG&E commitments:

- Continue to maintain a strong geosciences and engineering staff to keep abreast of new geological, seismic, and seismic engineering information and evaluate it with respect to its significance to DCPP (Reference 10 and Section 2.5.2.4 of Reference 8).

- Continue to operate the strong-motion accelerometer array and the coastal seismic network (Reference 10 and Section 2.5.2.4 of Reference 8).

- Evaluate new seismic information consistent with the evaluation process defined in Reference 11 (based on Reference 12, Commitment 2), as described in Reference 16, and endorsed by the NRC in Reference 17.

- Assess future plant additions and modifications to verify that the plant seismic risk remains acceptable (i.e., lowered or no significant increase), using the insights from the updated seismic hazard evaluation and updated seismic probabilistic risk assessment (SPRA), described in Sections 2.5.7.2.1.1 and 2.5.7.2.1.2, respectively (Reference 18, Enclosure 2). The NRC’s review and acceptance of Reference 18 is documented in Reference 19.

Refer to Sections 2.5.7 and 3.7.7.7 for additional information. The LTSP SPRA, including the assessment of the impact of future plant additions and modifications, is implemented through and controlled by plant procedures.

13.5.2.12 Inservice Inspection Program

An inservice inspection (ISI) program is in place at the station to implement the requirements of 10 CFR 50.55a(g), *Inservice Inspection Requirements*. Refer to Section 5.2.3.15 for additional information.

The ISI program is implemented through and controlled by plant procedures.

13.5.2.13 Reactor Vessel Material Surveillance Program

A reactor vessel material surveillance program is in place at the station to implement the requirements of 10 CFR Part 50, Appendix H, *Reactor Vessel Material Surveillance Program Requirements*. Refer to Section 5.2.1.19 for additional information.

The reactor vessel material surveillance program is implemented through and controlled by plant procedures.

13.5.2.14 Instrument Drift Monitoring Program

An instrument drift monitoring program has been established at the station to support 24-month fuel cycle implementation. Refer to License Amendment Request 96-10 (Reference 15) for additional information.

The instrument drift monitoring program is implemented through and controlled by plant procedures.

13.5.2.15 Heat Exchanger Program (Includes Generic Letter 89-13, July 1989, Service Water Program)

A heat exchanger program has been established at the station in response to Generic Letter 89-13, July 1989, "Service Water System Problems Affecting Safety-Related Equipment," and other regulatory requirements.

The heat exchanger program is implemented through and controlled by plant procedures.

13.5.2.16 Snubbers Program

A snubbers program has been established at the station that comprises an augmented ISI program and a snubber service life program. Refer to Equipment Control Guideline (ECG) 99.1 for additional information. Note that ECG 99.1 is a relocated Technical Specification as described in Section 16.1 and listed in Table 16.1-1.

The snubbers program is implemented through and controlled by plant procedures.

13.5.2.17 Flow-Accelerated Corrosion Monitoring Program

A flow-accelerated corrosion monitoring program has been established at the station in response to Generic Letter 89-08, May 1989, "Erosion/Corrosion-Induced Pipe Wall Thinning." The program manages wall thinning due to flow-accelerated corrosion on the internal surfaces of carbon steel piping, elbows, reducers, expanders, and valve bodies, which contain high energy fluids (both single phase and two phases). Refer to Chapter 10.

The flow-accelerated corrosion monitoring program is implemented through and controlled by plant procedures.

13.5.2.18 Boric Acid Corrosion Control Program

A boric acid corrosion control program has been established at the station to address boric acid corrosion concerns associated with the reactor coolant pressure boundary and other systems containing boric acid. The program has been established in response to Generic Letter 88-05, March 1988, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," and Bulletin 2002-01, March 2002, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity."

The boric acid corrosion control program is implemented through and controlled by plant procedures.

13.5.2.19 Maintenance Rule Program

A maintenance rule program has been established in accordance with 10 CFR 50.65, *Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants*. The program uses guidance provided in NUMARC 93-01, Revision 4A, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Regulatory Guide 1.160, Revision 3, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," endorses NUMARC 93-01, Revision 4A, and provides additional provisions and clarifications.

The maintenance rule program is implemented through and controlled by plant procedures.

13.5.2.20 Preventive Maintenance Program

A preventive maintenance program is in place at the station to ensure that plant SSCs are maintained in a condition such that they will perform their intended functions.

The preventive maintenance program is implemented through and controlled by plant procedures.

13.5.2.21 Reactor Coolant System Materials Degradation Management Program

A RCS materials degradation management program has been established in accordance with NEI 03-08, May 2003, "Guideline for the Management of Materials Issues," and its subsequent revisions and addenda.

The RCS materials degradation management program is implemented through and controlled by plant procedures.

13.5.2.22 Buried and Underground Piping and Tanks Program

A buried piping and tanks program has been established in accordance with NEI's underground piping and tanks integrity initiative. NEI 09-14, "Guideline for the Management of Underground Piping and Tank Integrity," describes the policy and practices that the industry has committed to follow in managing underground piping and tanks. NEI's underground piping and tanks integrity initiative superseded and incorporated all the elements of the previous buried piping integrity initiative.

The buried piping and tanks program is implemented through and controlled by plant procedures.

13.5.2.23 Cable Aging Management Program

A cable aging management program has been established to maximize the reliable service life of electrical cable by identifying adverse trends and planning appropriate actions. Cable is an integral part of most plant systems. It has historically proven to be very reliable.

The cable aging management program is implemented through and controlled by plant procedures.

13.5.2.24 Risk-Informed Categorization and Treatment

13.5.2.24.1 Introduction

By Federal Register Notice (69 FR 68047, dated November 22, 2004, which became effective on December 22, 2004), the NRC issued 10 CFR 50.69 that presented the opportunity to enhance equipment reliability and plant safety by focusing on those critical SSCs with the highest safety significance. The rule broadly adjusts the scope of safety-related components that are subject to the existing NRC regulations. The implementation of this new rule is strictly voluntary on the part of each licensee. The NRC staff approved License Amendments 247 and 249, that authorized PG&E to implement the provision of 10 CFR 50.69 for DCPP (Reference 20).

Current NRC regulations define the plant equipment necessary to meet the deterministic regulatory basis as "safety-related." This equipment is subject to NRC special treatment regulations. These special treatment requirements go beyond normal commercial and industrial practices and include quality assurance (QA) requirements, qualification requirements, inspection and testing requirements, and Maintenance Rule requirements. Other plant equipment is classified as "nonsafety-related" and is typically not subject to special treatment requirements. For those components that are categorized as Low Safety Significant, 10 CFR 50.69(b)(1) allows compliance with licensee determined alternative requirements in lieu of these special treatments. The provisions of 10 CFR 50.69 do not replace the existing "safety-related" and "nonsafety-related" classification. Instead, 10 CFR 50.69 divides these classifications into two subcategories based on high or low safety significance, such that there are four categories of risk-informed safety class (RISC), as follows:

RISC-1: safety-related SSCs that perform high safety significant functions.
RISC-2: nonsafety-related SSCs that perform high safety significant functions.
RISC-3: safety-related SSCs that perform low safety significant functions.
RISC-4: nonsafety-related SSCs that perform low safety significant functions.

When applying alternative treatment, 10 CFR 59.69 requires that the licensee "shall ensure, with reasonable confidence, that RISC-3 SSCs remain capable of performing their safety-related functions under design basis conditions, including seismic conditions and environmental conditions and effects throughout their service life."

13.5.2.24.2 SSC Categorization

The License Amendments 247 and 249 safety evaluation (SE) (Reference 20) has authorized PG&E to use the methodology outlined in NEI 00-04, *10 CFR 50.69 SSC Categorization Guideline*, Revision 0, with exceptions identified in Appendix D to the Operating Licenses, to categorize SSCs. Plant procedures implement the SE requirements. Section 10 CFR 50.69(f)(2) of the rule requires updating the FSAR to reflect which systems have been categorized. The following table itemizes the systems that have been categorized and is revised as part of the periodic FSAR update to reflect systems that have been categorized.

System Name	System Number (if applicable)
Control Room Ventilation System	23
Radiation Monitoring System	39, various
Containment Spray System	12

13.5.2.24.3 Treatment of Component Categories

The programs and processes that implement the special treatment requirements are revised to recognize that the special treatments no longer apply to RISC-3 components. The programs and processes either allow continued application of the special treatments or acceptable alternative treatments, as applicable, to provide reasonable

confidence that these components would perform their safety-related function under design basis conditions.

13.5.3 REFERENCES

1. Regulatory Guide 1.33, Revision 2, Quality Assurance Program Requirements (Operation), USNRC, February 1978.

2. NUREG-0737, Supplement 1, Clarification of TMI Action Plan Requirements: Requirements for Emergency Response Capability, December 1982.

3. NRC Letter to PG&E, dated May 28, 1999, granting License Amendment 135, Units 1 and 2.

4. PG&E Letter DCL-94-262, dated November 28, 1994, “Closure Response to NRC Generic Letter 89-10” and all supporting PG&E letters.

5. PG&E Letter DCL 99-031, dated March 25, 1999, “Response to Request for Additional Information Regarding NRC Generic Letter 96-05, Periodic Verification for Motor Operated Valves dated December 29, 1998” and all supporting PG&E letters.

6. PG&E Letter DCL-88-192 dated July 31, 1988, "Long Term Seismic Program Completion."

7. PG&E Letter DCL-91-027 dated February 13, 1991, "Addendum to Long Term Seismic Program Final Report."

8. NUREG-0675, "Safety Evaluation Report Related to the Operation of Diablo Canyon Nuclear Power Plant, Units 1 and 2," Supplement 34, June 1991.

9. NRC Letter to PG&E dated April 17, 1992, "Transmittal of Safety Evaluation Closing Out Diablo Canyon Long-Term Seismic Program (TAC Nos. M80670 and M80671)."

10. PG&E Letter DCL-91-091, dated April 17, 1991, "Benefits and Insights of the Long Term Seismic Program."

11. NRC Letter to All Power Reactor Licensees and Holders of Construction Permits in Active or Deferred Status, dated March 12, 2012, "Request for Information Pursuant to Title 10 of the Code of Federal Regulations 50.54(f) Regarding Recommendations 2.1, 2.3, and 9.3, of the Near-Term Task Force Review of Insights from the Fukushima Dai-Ichi Accident."

12. PG&E Letter DCL-12-108 dated October 25, 2012, "Withdrawal of License Amendment Request 11-05, 'Evaluation Process for New Seismic Information and Clarifying the Diablo Canyon Power Plant Safe Shutdown Earthquake.'"

13. PG&E Letter DCL-91-178 dated July 16, 1991, "Long Term Seismic Program – Future Plant Modifications."

14. PG&E Letter DCL-91-143 dated May 29, 1991, "Long Term Seismic Program – Implementation of the Results of the Program."

15. PG&E Letter DCL-96-213 dated December 9, 1996, "License Amendment Request 96-10, Revision of Technical Specifications to Support Extended Fuel Cycles to 24 Months."

16. Electric Power Research Institute Technical Report, “Seismic Evaluation Guidance - Screening, Prioritization and Implementation Details (SPID) for Resolution of Fukushima Near-Term Task Force Recommendation 2.1: Seismic,” Report No. 1025287, February 2013.

17. NRC Letter to Nuclear Energy Institute, “Endorsement of Electric Power Research Institute Final Draft Report 1025287, ‘Seismic Evaluation Guidance,’” February 15, 2013.

18. PG&E Letter DCL-18-027, dated April 24, 2018, "Seismic Probabilistic Risk Assessment for the Diablo Canyon Power Plant, Units 1 and 2 - Response to NRC Request for Information Pursuant to 10 CFR 50.54(f) Regarding Recommendation 2.1: Seismic of the Near-Term Task Force Review of Insights from the Fukushima Dai-Ichi Accident,” Enclosure 2, “Revised Regulatory Commitment.”

19. NRC Letter to PG&E, “Diablo Canyon Power Plant, Unit Nos. 1 and 2 – Staff Review of Seismic Probabilistic Risk Assessment Associated with Reevaluated Seismic Hazard Implementation of the Near-Term Task Force Recommendation 2.1: Seismic (EPID No. L-2018-JLD-0006),” January 22, 2019.

20. Letter from Samson Lee (NRC) to Paula Gerfen (PG&E), "Diablo Canyon Power Plant, Units 1 and 2 – Issuance of Amendment Nos. 247 and 249 RE: Adoption of 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors," dated December 11, 2024.

13.6 PLANT RECORDS

Plant records are maintained in accordance with established PG&E practices. The records management program is discussed in the Diablo Canyon Quality Assurance Program Description.

13.7 PHYSICAL SECURITY

The Security Plans for DCPP have been developed as required by 10 CFR Part 73, 10 CFR 37 and DPR-80 and DPR-82 License Condition E.

The Security Plans include the following:

(1) The Physical Security Plan (PSP), including the following appendices:

(a) Appendix A: Glossary of Terms and Acronyms

(b) Appendix B: Training and Qualification Plan (per 10 CFR Part 73, Appendix B)

(c) Appendix C: Safeguards Contingency Plan (per 10 CFR Part 73, Appendix C)

(d) Appendix D: Independent Spent Fuel Installation Security Program (per 10 CFR 73.51)

(2) The Cyber Security Plan (CSP).

(3) The Diablo Canyon Nuclear Power Plant Part 37 Security Plan for the Protection of Category 1 and Category 2 Quantities of Radioactive Material (RMSP).

The PSP establishes and maintains a physical protection system and security organization on site for the purpose of protecting against radiological sabotage and preventing the theft of special nuclear material. Portions of the information contained in the PSP are considered to be "Safeguards Information" as defined in 10 CFR 73.2 and must therefore be protected against public disclosure and disseminated on a "need-to-know" basis as required by 10 CFR 73.21.

The CSP is the program implemented to prevent damage to, prevent unauthorized access to, and allow restoration of computers, electronic communications systems, electronic communication services, wire communication, and electronic communication, including information contained therein, to ensure its availability, integrity, authenticity, confidentiality, and non-repudiation. In control systems, this includes unauthorized access that could affect operation of plant SSCs. The CSP contains information that has been designated "Security-Related Information - Withhold under 10 CFR 2.390."

The RMSP provides reasonable assurance of the security of category 1 or category 2 quantities of radioactive material by protecting these materials from theft or diversion as described in 10 CFR 37.41 – 57 (Subpart C – Physical Protection Requirements During Use).

The PSP has been approved by the NRC and is implemented at the DCPP site.

The implementation of the CSP, including the key intermediate milestone dates and the full implementation date, will be in accordance with the implementation schedule submitted to the NRC in PG&E Letter DCL-11-040, dated April 4, 2011, and approved by the NRC Staff with License Amendments (LA) 210 (Unit 1) and LA 212 (Unit 2).

The RMSP is approved by the individual with overall responsibility of the security program at DCPP.

All changes to the Security Plans require evaluation per 10 CFR 50.54(p) to determine whether prior NRC review and approval via 10 CFR 50.90, the License Amendment process, is required.

TABLE 13.2-1

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

SUMMARY OF ACTIVITIES EMPLOYED IN TRAINING PROGRAMS FOR PERSONS IN THE INITIAL DIABLO CANYON OPERATING ORGANIZATION (HISTORICAL AS SUBMITTED IN NOVEMBER 1978)

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1. Humboldt Bay Experience

Many of the key individuals in the initial plant organization were members of the Humboldt Bay staff before they transferred to Diablo Canyon Power Plant and have extensive nuclear experience in their areas of responsibility. Certain other individuals, who were not members of the Humboldt Bay staff, have been assigned there for appropriate periods to participate in operations involving their areas of responsibility.

2. PWR Experience

Key individuals were assigned to an operating PWR (or one in the process of preoperational and/or startup testing) to observe and/or participate in operations involving their areas of responsibility. The plants involved included R. E. Ginna, H. B. Robinson, Connecticut Yankee, Point Beach, and San Onofre. Assignments ranged from 3 weeks to 7 months, with most lasting approximately 1 month.

3. Participation in the Diablo Canyon Task Force

This group consists of selected technical and operating supervisory personnel and is responsible for the preparation of training material, operating manuals, licensing material and Technical Specifications, test procedures, and for performing an operational review of the plant design.

4. Design Lecture Series

This 4-week course was conducted in March 1971 at the Westinghouse Atomic Power Division in Pittsburgh, Pennsylvania. Fifteen supervisors on the plant staff and one member of the Department of Steam Generation attended this course. The trainees were given a series of lectures covering the function, design description, control and instrumentation, normal and abnormal operation, and maintenance of all principal components of the Diablo Canyon Units 1 and 2 nuclear steam supply systems. These lectures were given by Westinghouse design engineers who were closely associated with the design of the plant. The lectures were supplemented by study of written information on pressurized water reactor technology provided by Westinghouse and trips to Westinghouse manufacturing facilities where trainees were afforded an opportunity to witness actual fabrication of components.

5. *Nuclear Technology Course*

This course is taught by members of the plant staff and utilizes PG&E's Introduction To Nuclear Power training manual as a text. The purpose of this course is to provide a general background in the field of nuclear power plant technology. The major topics that are included in the course are:

a. Basic mathematics
b. Basic atomic and nuclear physics
c. Introduction to nuclear reactors and nuclear power plant cycles
d. Light water reactor physics
e. Heat transfer considerations in light water reactors
f. Operating characteristics of light water reactors
g. Nuclear instrumentation
h Chemical, radiochemical, and waste disposal considerations in light water reactor operation
i. Reactor safeguards.

These topics are treated in sufficient depth to prepare an individual for applicable portions of the Senior Operator License examination. The complete course, which is intended for license candidates, takes about 4 weeks and covers each of these topics in detail. Abbreviated versions of the course covering subjects directly related to their duties and responsibilities are given to other personnel as appropriate.

6. *Radiation Protection Training Course*

This course is taught by members of the plant staff and utilizes PG&E's Radiation Protection Training Manual, Radiation Control Standards And Procedures, and other appropriate material as texts. The standards are a compilation of technical statements of policy covering each aspect of a nuclear power plant's radiation protection program and are based on the requirements of 10 CFR 20 and other applicable regulations. The procedures provide practical information regarding the implementation of the standards and are based on adaptations to nuclear power plant requirements of procedures and practices widely used throughout the atomic energy industry.

The Training Manual is a general work that covers theory and other background material. The major topics covered in this course include:

a. Basic radiation physics and biology
b. Sources of radioactivity in nuclear power plants
c. Radiation protection instrumentation
d. Fundamentals of shielding
e. Personnel exposure limits

f. Protective clothing and equipment
g. Control and transfer of radioactive materials
h. Decontamination practices
i. Radiation monitoring techniques
j. Control of access
k. Records and reporting requirements.

The complete course for radiation and process monitors requires about 4 weeks. A similar course designed for NRC license examination candidates required about 1 week. Personnel in other classifications receive shorter courses covering those subjects directly related to their duties and responsibilities.

7. Plant Design and Operation Seminars

This seminar course is conducted by supervisory personnel on the plant staff and covers the design, description, and operation of each plant system plus related topics such as the Technical Specifications and the Site Emergency Plan. The course is primarily designed for operators and is expected to last about 8 weeks. As appropriate, personnel in other classifications will receive shorter courses covering systems and equipment related to their areas of responsibility.

8. NRC Operator and Senior Operator License Examination Seminars

These seminars are conducted by supervisory personnel on the plant staff for the benefit of license examination candidates. They consist of a review of appropriate items in activities 5, 6, and 7 above plus discussions of additional topics required to cover the items listed in 10 CFR 55.21-23. The length of this program will be determined following an evaluation of the needs of the individuals involved, but based on Humboldt Bay experience, it is expected to last about 4 weeks.

9. P-250 and P-2000 Computer Maintenance Courses

These courses, lasting a total of 16 weeks, were conducted in the fall of 1970 by Westinghouse Computer and Instrument Division personnel and were designed to provide comprehensive coverage of the construction, operation, repair, and maintenance of the P-250 and P-2000 computers. The course attended by Diablo Canyon personnel was held at PG&E's Pittsburg Power Plant where a P-250 computer was available for use by the students.

10. Instrument and Control Course

This is a 12-week course intended for instrument maintenance supervisors and technicians and is conducted by instructors from the Nuclear Instrumentation and Control

Department of Westinghouse at the department headquarters in Baltimore, Maryland. The general subjects covered include the design, maintenance, and testing of the solid-state rod control system, flux mapping system, nuclear instrumentation system, radiation monitoring system, and solid-state protection system. The course combines both formal classroom lectures on systems and modules and practical bench work with the equipment. Diablo Canyon personnel attended this course beginning in January 1972.

11. Process Controls Course

This 2-week course was conducted at the Portland General Electric Trojan site in June 1972 by Westinghouse Computer and Instrument Division personnel. The course material included lectures on both systems and modules for the various process control systems (feedwater control, steam dump, pressurizer level and pressure). In addition, the various modules were available for bench work by the students.

12. Refresher Course in Radiological Engineering

This 3-week course was conducted in 1972 by personnel from the health physics staff of the General Electric Company Vallecitos Nuclear Center. It was designed to provide graduate-level refresher training in radiological engineering topics such as internal and external radiation dosimetry, radiation biology, atmospheric diffusion modules, instrumentation, and environmental pathways. It consisted primarily of formal classroom lectures.

13. Chemistry and Radiochemistry Seminars

These seminars are conducted by supervisory personnel on the plant staff for training of radiation and process monitors, and will take about 4 months. The subject matter for these seminars will include such topics as basic chemistry, laboratory techniques, radiochemical methods, and theory and use of counting room equipment. A variety of texts will be employed, including PG&E procedures manuals, vendors' instruction manuals, and standard chemistry and radiochemistry texts. In addition, the classroom work will be supplemented by actual laboratory training as appropriate.

14. Nondestructive Testing School

This 3-week course is presented at the site by instructors from General Dynamics/Convair. The class consists of both formal lectures and practical demonstrations, and persons completing it and successfully passing the examinations are qualified as ASNT Level II inspectors for radiography, ultrasonic testing, magnetic particle testing, and liquid penetrant testing.

15. Operational Core Analysis Training

This 3-week course is presented in Pittsburgh, Pennsylvania, by Westinghouse and is intended for nuclear engineers. It discusses the theory and operation of the operational core analysis computer codes that will be used to monitor core thermal-hydraulic performance and fuel depletion.

16. Simulator Training

Candidates for "Cold" NRC licenses will attend a 14-day training program at the Westinghouse reactor simulator at Zion, Illinois.

The course has been established so that the typical day is divided approximately equally into classroom work and "hands-on" simulator time. Emphasis during the first week will be on taking the trainee through a simulated operational cycle from a cold shutdown through plant heatup/reactor startup/turbine-generator startup/power operation/plant shutdown/and plant cooldown. This first cycle will stress familiarization with control board and plant operation under normal operating conditions.

The second week's training will be a repeat of the training received the first week, but at an accelerated pace and will incorporate the maximum number of minor and major malfunction situations in the time allotted. The trainee will learn to identify specific malfunctions, analyze the hazards involved, and effect proper corrective actions. The second week will also incorporate simulation and evaluation of normal and abnormal plant transients and the required operator action to effect recovery from transient and accident situations.

A refresher simulator training course of seven days duration will be provided shortly before initial loading.

17. In-place Filter Testing Workshop

This 5-day workshop is conducted by the Harvard School of Public Health in Boston, Massachusetts. The subject matter deals with subjects of theory, design, and testing of HEPA and activated charcoal air filtration systems. About half of the time is devoted to classroom lectures and the other half consists of laboratory work using DOP generators and detection equipment and other filter testing devices. The Power Plant Engineer attended this course in September 1971.

TABLE 13.2-2

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

TRAINING SUMMARY FOR INDIVIDUALS IN THE INITIAL DIABLO CANYON OPERATING ORGANIZATION (HISTORICAL)

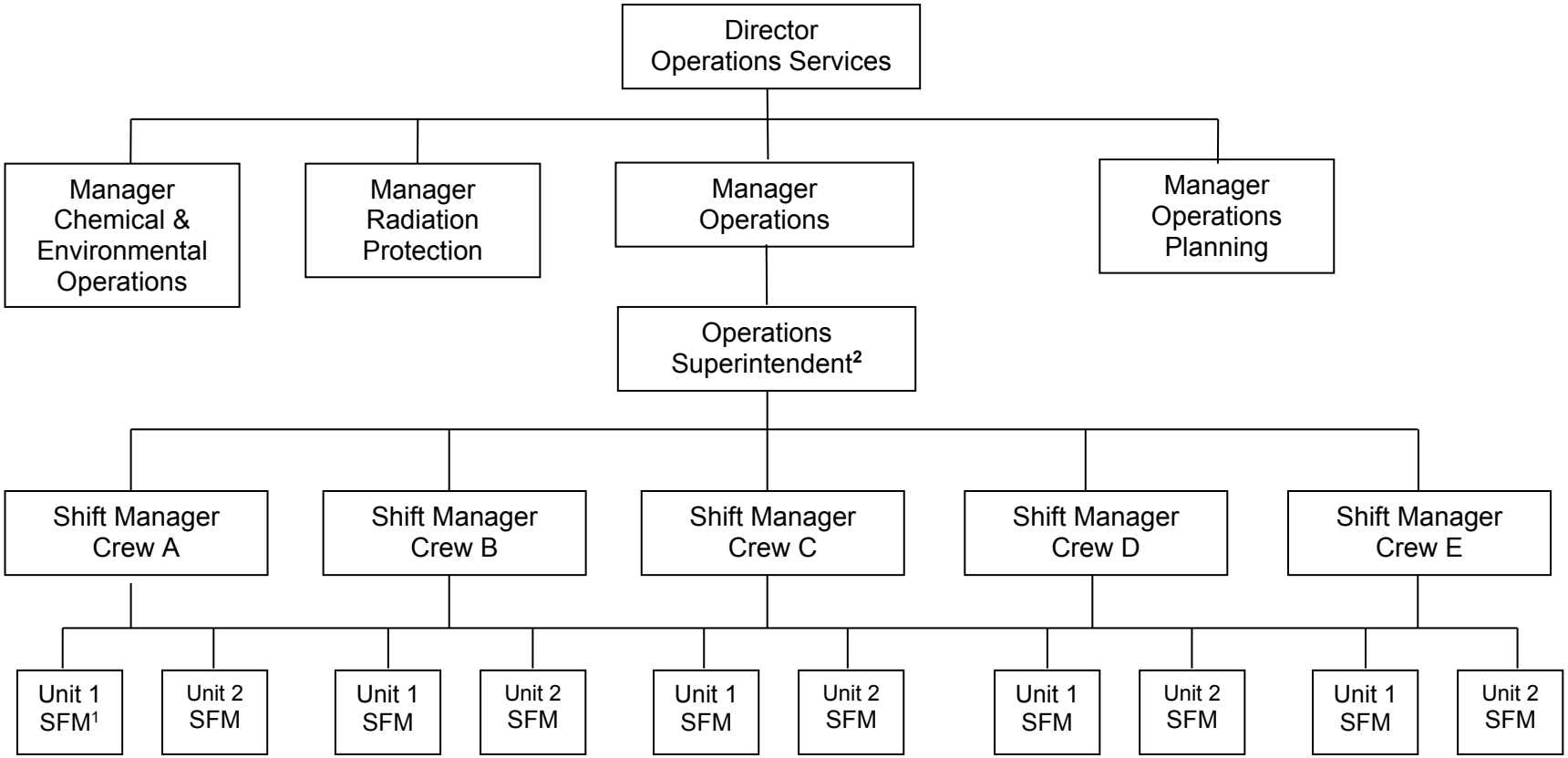
Position - Name	AEC License	Humblt. Bay Exper.	PWR Exper.	Task Force[a]	Dsgn. Lect. Series	Nuclr. Tech.	Rad. Prot. Course	Plant Dsgn. Semr.	Oper. Lic. Revw.	Comp. Maint.	I & C Course	Proc. Ctrls. Course	Rad. Engr. Refr.	Chem. Semrs.	NDT Sch.	Core Code	Anal. Trng.	Simul. Trng.
Plant Superint.	*Cold SOL,OP*	*3 y*	*2 m*	*July 1970*	*P*	*OP*	*OP*	*OP*	*OP*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*P*
Supv. of Operations	*Cold SOL*	*3 y*	*6 m*	*July 1970*	*P*	*I*	*I*	*I*	*I*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*P*
Power Plant Engr.	*Cold SOL,OP*	*8 y*	*7 m*	*July 1970*	*P*	*I*	*I*	*I*	*I*	*-*	*-*	*-*	*P*	*-*	*-*	*-*	*-*	*P*
Supv. of Maint.	*-*	*9 y*	*1 m*	*Aug. 1971*	*P*	*OP*	*OP*	*OP*	*-*	*-*	*-*	*-*	*-*	*-*	*P*	*-*	*-*	*-*
Relief Shift Supv.	*Cold SOL*	*8 y*	*1 m*	*July 1970*	*P*	*OP*	*OP*	*I*	*I*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*P*
Shift Foreman	*Cold SOL*	*6 y*	*1 m*	*Oct. 1970*	*P*	*P*	*P*	*I,P*	*I,P*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*P*
	Cold SOL	*9 y*	*1 m*	*July 1970*	*P*	*P*	*P*	*I,P*	*I,P*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*P*
	Cold SOL	*9 y*	*1 m*	*Feb. 1972*	*-*	*P*	*P*	*I,P*	*I,P*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*P*
	Cold SOL	*10 m*	*1 m*	*May 1972*	*-*	*P*	*P*	*I,P*	*I,P*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*P*
	Cold SOL	*11 y*	*1 m*	*-*	*P*	*P*	*P*	*I,P*	*I,P*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*P*
	Cold SOL	*1 y*	*1 m*	*Aug. 1971*	*P*	*P*	*P*	*I,P*	*I,P*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*P*
	Hot SOL	*-*	*-*	*-*	*-*	*P*	*P*	*P*	*P*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*
Nuclear Engineers	*Cold SOL,OP*	*2 y*	*3 m[b]*	*Aug. 1970*	*P*	*I,OP*	*I,OP*	*I,OP*	*OP*	*-*	*-*	*-*	*-*	*-*	*P*	*-*	*-*	*-*
	Cold SOL,OP	*1 m*	*1 m[b]*	*Jan. 1971*	*-*	*I,OP*	*I,OP*	*I,OP*	*OP*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*P*
	Hot SOL,OP	*1 y*	*1 m*	*Dec. 1970*	*P*	*I,OP*	*I,OP*	*I,OP*	*OP*	*-*	*-*	*-*	*-*	*-*	*-*	*[c]*	*-*	*-*
	Hot SOL,OP	*-*	*-*	*-*		*OP*	*P*	*OP*	*OP*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*
	Hot SOL,OP	*-*	*-*	*-*		*OP*	*P*	*OP*	*OP*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*
	Hot SOL,OP	*-*	*-*	*-*		*OP*	*P*	*OP*	*OP*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*
Chem. & Rad. Prot. Engr.	*-*	*5 y*	*1 m*	*July 1970*	*-*	*OP*	*I*	*I,OP*	*I*	*-*	*-*	*-*	*P*	*I*	*-*	*-*	*-*	*-*
		3 y	*3 w*	*Nov. 1972*	*P*	*OP*	*I*	*I,OP*	*I*	*-*	*-*	*-*	*P*	*I*	*-*	*-*	*-*	*-*
Instrument Engr.	*-*	*8 y*	*2 m*	*July 1970*	*P*	*OP*	*OP*	*I,OP*	*-*	*-*	*P*	*-*	*-*	*-*	*-*	*-*	*-*	*-*
Inst. & Contrls. Supv.	*-*	*1 m*	*-*	*July 1970*	*-*	*OP*	*OP*	*I*	*-*	*P*	*P*	*P*	*-*	*-*	*-*	*-*	*-*	*-*

TABLE 13.2-2

Position - Name	AEC License	Humblt. Bay Exper.	PWR Exper.	Task Force[a]	Dsgn. Lect. Series	Nuclr. Tech.	Rad. Prot. Course	Plant Dsgn. Semr.	Oper. Lic. Revw.	Comp. Maint.	I & C Course	Proc. Ctrls. Course	Rad. Engr. Refr.	Chem. Semrs.	NDT Sch.	Core Code	Anal. Trng.	Simul. Trng.
Q/A Coordinator	-	7 y	-	Aug. 1970	P	OP	I	I,P	I	-	-	-	-	-	-	-	-	-
Maintenance Engr.	-	-	-	-	-	OP	P	OP	-	-	-	-	-	-	-	-	-	-
Mechanical Foreman	-	-	-	-	-	OP	P	OP	-	-	-	-	-	-	-	-	-	-
Electrical Foreman	-	-	-	-	-	OP	P	OP	-	-	-	-	-	-	-	-	-	-
Operators	Hot L[h]	[d]	-	-	-	P	P	P	P	-	-	-	-	-	-	-	-	[i]
Control Technicians	-	[e]	-	-	-	OP	P	OP	-	[f]	[g]	-	-	-	-	-	-	-
Rad. & Proc. Monitrs.	-	OP	-	-	-	P	P	OP	-	-	-	-	-	P	-	-	-	-
Maint. Phys. Forces	-	-	-	-	-	-	P	-	-	-	-	-	-	-	-	-	-	-
Clerical	-	-	-	-	-	-	P	-	-	-	-	-	-	-	-	-	-	-

Key: y = years, m = months, w = weeks, P = participant, I = Instructor, OP = Optional Participation depends on work load and individual needs, SOL = Senior Operator License, L = Operator License

(a) Date given is date at which participation in Task Force project began. Task Force work largely complete by March 1973.
(b) Not including experience gained while not a PG&E employee.
(c) A second individual from the Steam Generation Department will also attend.
(d) It is expected that approximately 1/3 of the successful bidders will have had prior experience at Humboldt Bay. There are no plans to send others to Humboldt Bay.
(e) Two of the successful bidders have had several years of experience at Humboldt Bay. The other two have had approximately one month.
(f) Two only. A third individual has had computer experience in his previous assignment at a conventional plant. The fourth is receiving training as part of apprenticeship program.
(g) Three only. Fourth is in training as apprentice and will receive on-the-job experience prior to startup.
(h) For Assistant Control Operator and above.
(i) Three Senior Control Operators with prior Operator Licenses at Humboldt Bay.



NOTES:

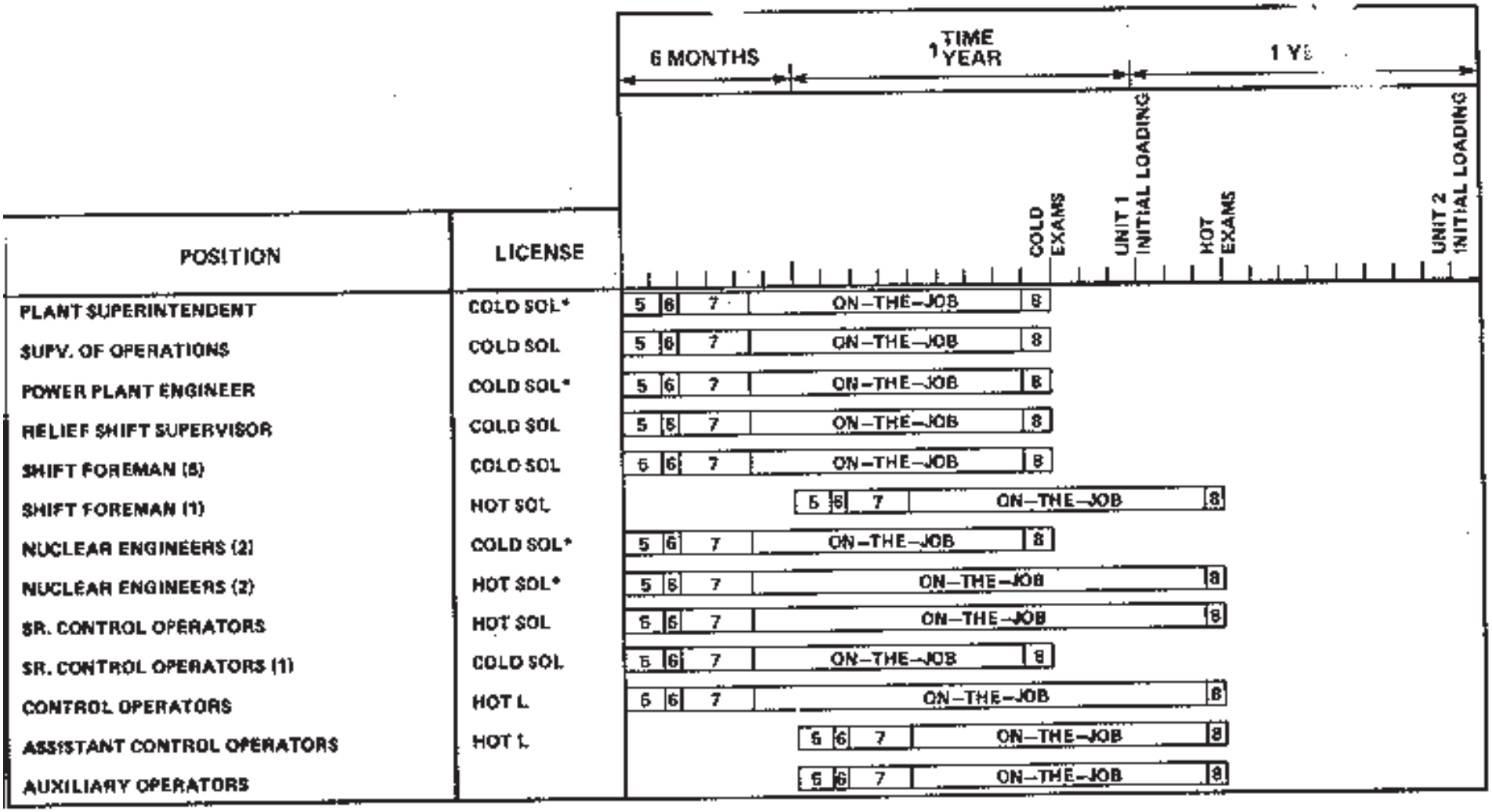
1. SFM = Shift Foreman
2. The Operations Superintendent is not required to be staffed if the Manager, Operations holds an SRO license for DCPP.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 13.1-5
OPERATIONS SERVICES ORGANIZATION

Revision 25 June 2020



NOTE: 5 – NUCLEAR TECHNOLOGY COURSE
6 – RADIATION PROTECTION COURSE
7 – PLANT DESIGN SEMINAR
8 – LICENSE REVIEW SEMINAR
* – OPTIONAL

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 13.2-1
INITIAL SCHEDULE OF PLANNED NUCLEAR TRAINING (HISTORICAL)

Chapter 14

INITIAL TESTS AND OPERATION

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Chapter 14

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Chapter 14

FIGURES

Figure	Title
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Chapter 14

INITIAL TESTS AND OPERATION

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

Sections 14.1 and 14.2 are historical in nature; they reflect the preoperational and initial startup test program through the start of commercial operation. Section 14.3 addresses the postcommercial operational test program.

14.1 TEST PROGRAM

The preoperational and initial startup program for the Pacific Gas and Electric Company's (PG&E's) Diablo Canyon Power Plant (DCPP) will demonstrate that:

(1) The plant is ready to operate in a manner that, with reasonable assurance, will not endanger the safety of the public.

(2) The procedures for operating the plant safely have been tested and demonstrated.

(3) The operating organization is knowledgeable about the plant and the procedures and is fully prepared to operate the plant safely.

The program is designed to demonstrate that structures, components, and systems meet the appropriate design criteria and otherwise operate satisfactorily. The program includes construction tests, preoperational or functional tests, initial fuel loading, and startup tests. The program will culminate in the operation of the plant at maximum guaranteed load.

The discussion of tests in this chapter generally excludes construction tests and otherwise includes only testing associated with safety-related requirements. Testing excluded from this discussion is administered in a manner consistent with the program described in this chapter.

Construction tests include hydrostatic testing, system cleaning, valve leakage tests, control valve operations, electrical continuity checks, electrical performance tests, and control instrument alignment. Construction tests are usually conducted as the components and systems are completed to ensure readiness for preoperational testing.

Preoperational tests demonstrate, insofar as possible prior to loading nuclear fuel, that those plant structures, components, and systems related to safety have been properly installed and operate according to design requirements. Preoperational tests that cannot be completed prior to fuel loading because the necessary test conditions do not exist will be completed when conditions are suitable for testing.

Preoperational testing of a system begins whenever construction is sufficiently advanced to indicate the test may be completed. This phase of testing began in 1973 and has been integrated with other construction activities.

Startup tests demonstrate that the plant will perform satisfactorily in normal operation and that, with reasonable assurance, the plant is capable of withstanding the transients analyzed in this Final Safety Analysis Report (FSAR).

14.1.1 ADMINISTRATIVE PROCEDURES -- TESTING

14.1.1.1 Organizational Responsibilities

The overall responsibility for the preoperational testing and startup program is assigned to the Lead Startup Engineer.

The Lead Startup Engineer directs other Station Construction Department personnel in preparing and conducting the testing program with technical assistance from the Engineering Department, Nuclear Plant Operations (NPO), the nuclear steam supply system (NSSS) vendor, and other equipment suppliers as appropriate. The plant operating organization performs all operations during the testing program. The Assistant Plant Manager/Plant Superintendent will designate a Startup Coordinator who will be responsible for startup operational activities. In some cases there will be procedures, administratively controlled by the NPO Department, which will be included in the Preoperational and Startup Test Program. Their inclusion will occur when they satisfy the requirements and objectives of a test that would normally be prepared at the direction of the Lead Startup Engineer.

14.1.1.2 Preparation of Procedures

Test procedures are prepared under the direction of the Lead Startup Engineer for all preoperational and startup tests. Each procedure consists of the test purpose and description, references, prerequisites, initial conditions, instructions (including acceptance criteria), and data and calculation sheets as required. The status of all preoperational and startup tests is maintained in a Startup Status Report.

The sources of information for writing the test procedures include approved drawings, specifications, technical literature, system functional descriptions, similar completed tests from other pressurized water reactor nuclear power plants, manufacturers' testing recommendations, plant operating procedures, general operating orders and instructions, and any other design or technical information available.

Test instructions are established using design and technical information and include acceptance criteria established from the functional requirements specified in the appropriate sections of this FSAR or from documents approved by the Engineering Department. Space for documenting test results is also included.

14.1.1.3 Reviewing and Approving Procedures

The Lead Startup Engineer is responsible for the preparation of each test procedure and will request review of tests by the Assistant Plant Manager/Plant Superintendent and others as considered appropriate. The Assistant Plant Manager/Plant Superintendent is responsible for obtaining comments from NPO. The Lead Startup Engineer and the Assistant Plant Manager/Plant Superintendent will indicate their review is complete by signing off the test cover sheet.

The Plant Staff Review Committee (PSRC) will review approved procedures, prior to their conduct, for units with an operating license.

14.1.1.4 Conducting Tests

The Lead Startup Engineer is responsible for conducting all preoperational and startup tests and assigns the responsibility for conducting individual tests to a Startup Engineer who, in turn, verifies that all the necessary conditions are established. The Lead Startup Engineer requests the plant Startup Coordinator to perform the operations step-by-step, following the sequence specified in the test procedure. During and subsequent to preoperational testing, power plant operating personnel will operate all switches, breakers, and valves for controlling energized equipment under the direct supervision of the Shift Foreman in accordance with the startup program, and/or at the request of the Startup Engineer.

14.1.1.5 Evaluating and Approving Results

The Startup Engineer and the Assistant Plant Manager/Plant Superintendent's representatives make an evaluation of the test results. If the results satisfy the acceptance criteria, they sign off the test as completed. The completed test procedure is reviewed by both the Lead Startup Engineer and the Assistant Plant Manager/Plant Superintendent and is signed to indicate approval of the completed test.

The results of preoperational tests of safety-related systems will undergo plant staff review prior to receipt of an operating license. Subsequent to the receipt of an operating license, the results of all completed preoperational and startup tests will be reviewed by the PSRC.

14.1.1.6 Documentation

Completed procedures and related data and test sheets will be properly identified, indexed, and retained for the plant's permanent files. The Lead Startup Engineer is responsible for the distribution of all completed test procedures. Distribution will be made as individual preoperational and startup test procedures are completed.

14.1.1.7 Personnel Qualifications

Since 1958, Station Construction Department management has selected personnel to direct the startup of eleven fossil-fueled, eight geothermal, and one nuclear-fueled steam-electric generating units. Only in the latter case was the responsibility shared and authority subordinated to direction from the NSSS supplier. The timely startup and exceptionally trouble-free performance of these units in operation demonstrates management's ability to select qualified personnel and the success of the system.

Personnel assigned to DCPP startup have been selected to meet the anticipated needs of startup service and transfer of operations to the Nuclear Power Generation Department of the units that will provide additional trouble-free generating capacity for PG&E. Their selection is based on personal backgrounds requiring minimum supplementary technical education or field experience. The Lead Startup Engineer is responsible for requesting, and the Manager of Station Construction is responsible for providing, any additional training to ensure that members of the startup organization have the abilities to satisfy management objectives and the following:

14.1.1.7.1 Lead Startup Engineer

The Lead Startup Engineer shall have a minimum of 10 years of power plant experience. Graduation in an engineering discipline shall count for 2 of these years, and a minimum of 3 years of power plant startup experience is required. Of the remaining 5 years, a maximum of 2 may be fulfilled by academic or field training in nuclear subjects. The Lead Startup Engineer shall be familiar with the design and performance of all the DCPP systems.

14.1.1.7.2 Startup Engineer

Startup Engineers shall have a minimum of 6 years of power plant experience. Graduation in an engineering discipline shall count for 2 of these years, and a minimum of 1 year of power plant startup experience is required. Of the remaining 3 years, a maximum of 1 year may be fulfilled by academic or field training in nuclear subjects. Startup Engineers shall be familiar with the design and performance objectives of the DCPP systems.

14.1.1.7.3 Assistant Startup Engineer

Assistant Startup Engineers shall have a minimum of 4 years of power plant experience. Graduation in an engineering discipline shall count for 2 of these years, and a minimum of 1 year of power plant startup experience is required. Assistant Startup Engineers shall be familiar with the design and performance objectives of assigned DCPP systems.

14.1.1.7.4 Startup Engineer Trainee

Startup Engineer Trainees shall, as a minimum, have either a degree in an engineering discipline or 2 years of power plant experience. Experience needed to fulfill the requirements for other positions within the Startup Department shall be gained by on-the-job training that includes preparation of preoperational and startup procedures and personal participation in the execution of preoperational tests of DCPP systems under the supervision of a Startup Engineer. Startup Engineer Trainees shall be familiar with the design and performance objectives of assigned DCPP systems.

14.1.1.8 Additional Qualifications

In addition, appointees to any of the above assignments may have additional qualifications that will allow them to fill the following positions:

14.1.1.8.1 Nuclear Advisor

Nuclear advisors shall have a minimum of a bachelor's degree in engineering or in physical science and 2 of years experience in such areas as reactor physics, core measurements, core heat transfer, and core physics testing programs. One year of experience may be fulfilled by academic training beyond the bachelor's degree program on a one-for-one time basis.

14.1.1.8.2 Chemistry Advisor

Chemistry advisors shall have a minimum of a bachelor's degree in engineering or in physical science, and 1 year of experience in water or wastewater treatment.

14.1.2 ADMINISTRATIVE PROCEDURES -- MODIFICATIONS

Test procedure inadequacies discovered at any time are corrected using written changes. All test procedure changes are reviewed and approved according to the administrative procedure for the original test procedure before final acceptance of the test by the Plant Superintendent. If the test results do not satisfy the acceptance criteria, or are otherwise contrary to the expected results, the Lead Startup Engineer is responsible for documenting the problem and acts as coordinator between General Construction and the Engineering Departments in resolving such problems, including any necessary system modifications. Resulting test changes shall be handled as described above. Any required retesting shall be handled according to the administrative procedure for conducting the original test. All test procedure changes for units with an operating license require PSRC review within the time frame established by the Technical Specifications[(1)].

Temporary system modifications required for testing are documented in the procedures and, following completion of testing, restoration to normal conditions is made and documented.

14.1.3 TEST OBJECTIVES AND PROCEDURES

14.1.3.1 Preoperational Testing

The testing program performed prior to fuel loading ensures that performance of equipment and systems is in accordance with design criteria. The program includes tests, adjustments, calibrations, and system operations necessary to ensure that initial fuel loading, initial criticality, and subsequent power operation can be safely undertaken. As installation of individual components and systems is completed, each is tested according to approved written procedures. The tests are designed to verify, as nearly as possible, the performance of the components and/or systems under conditions expected to be experienced during plant operation. The prerequisites for these tests include written confirmation that construction activities are complete.

During system tests for which normal plant conditions do not exist and cannot be simulated, the systems are operationally tested to the maximum extent possible. The remainder of the tests are performed when conditions are suitable for testing. Abnormal plant conditions are simulated during testing, when required, and when such conditions do not endanger personnel or equipment.

Evaluations of test results are made to verify that components and systems are performing satisfactorily and, if not, to provide a basis for recommending corrective action.

Where required, simulated signals or inputs are used to verify the full operating range of a system and to calibrate and align the system and instruments at these conditions. Later, systems that are used during normal operation are verified and calibrated under actual operating conditions. Systems that are not used during normal plant operation, but must be in a state of readiness to perform safety-related functions, are checked under all modes and test conditions prior to plant startup. Examples of these systems are the reactor trip system and engineered safety features system logic. Correct operation and setpoints are verified during this testing.

Testing performed during preoperational testing will be completed before fuel loading. In some cases, it will be necessary to defer certain preoperational tests until after fuel loading. These include tests to be performed on the complete rod control system, rod position indication, and complete incore movable detector system. These tests have been identified in Table 14.1-2, Fuel Loading and Initial Startup Testing Summary. Prior to the performance of hot testing following core loading, prerequisite cold testing will have been performed. An example of these tests is the cold rod drop time measurement test. In any event, the surveillance requirements of the Technical Specifications will be met as required for each mode transition.

14.1.3.2 Startup Testing

After satisfactory completion of final precritical tests, nuclear operation of the reactor begins. This final phase of startup and testing includes initial criticality, low power testing, and power level escalation. The purpose of these tests is to establish the operational characteristics of the plant and the core, to acquire data for the determination of setpoints, to establish administrative controls during reactor operations, and to ensure that operation is within license requirements. A brief description of the test program is presented in the following sections. Table 14.1-2 summarizes the tests that will be performed from fuel load through plant operation at rated power, and Figure 14.1-1 shows the sequence in which these tests are performed.

14.1.4 FUEL LOADING AND INITIAL OPERATIONS

14.1.4.1 Fuel Loading

The overall responsibility and direction for initial fuel loading is exercised by PG&E personnel. Fuel loading begins when all prerequisite system tests and operations have been satisfactorily completed, an operating license has been obtained from the U. S. Nuclear Regulatory Commission, and a review by the plant staff has determined that the requirements in the Technical Specifications have been met.

Access to the containment will be controlled by written procedure during fuel loading. Fuel handling tools and equipment shall have been checked out and dry runs conducted in the use and operation of equipment. The reactor vessel and associated components will be in a state of readiness to receive fuel. Water level will be maintained above the bottom of the nozzles and recirculation maintained to ensure a uniform boron concentration. Boron concentration can be increased via the recirculation system.

The as-loaded core configuration is specified as part of the core design studies conducted well in advance of fuel loading. The core is assembled in the reactor vessel that is already filled with water containing enough dissolved boric acid to maintain an effective multiplication factor of 0.95, or less, or a boron concentration greater than 2000 ppm. For initial core loading, the 2000 ppm minimum is limiting and results in an effective multiplication factor of less than 0.90. The refueling cavity is partially filled with borated water during initial fuel loading to provide lubrication for the fuel handling equipment. Coolant chemistry conditions are prescribed in the fuel loading procedure and verified periodically by chemical analysis of moderator samples prior to and during fuel loading operations.

Fuel loading instrumentation shall consist of at least two source range monitors. Normally, two permanently installed excore source range neutron channels and three temporary incore source range neutron channels will be available. The permanent channels, when responding, are monitored in the control room by licensed operators. The temporary channels installed inside the containment structure are monitored by knowledgeable test personnel who, in turn, communicate with the senior licensed

operator in charge of fuel loading. At least one channel is equipped with an audible count rate indicator audible in the control room and loading area. Both permanent channels have the capability of displaying the neutron count rate on strip chart recorders. The temporary channels indicate on count rate meters with a minimum of one channel recorded on a strip chart recorder. Minimum count rates attributable to neutrons generated in the core are required on at least two of the five (i.e., three temporary and two permanent) available neutron source range channels at all times following installation of the primary sources and the first ten fuel assemblies to continue fuel loading.

Two neutron sources are inserted into the core at locations and sequence specified in the fuel loading program to ensure a neutron population that produces a minimum of 1/2-count/sec for adequate monitoring of the core.

Fuel assemblies, together with inserted components (rod cluster control assemblies [RCCAs], burnable poison rods, source spider, or thimble plugging devices), are placed in the reactor vessel one at a time according to an approved sequence to provide reliable core monitoring that minimizes the possibility of core mechanical damage. The fuel loading procedure includes a tabular check sheet that prescribes the movements of each fuel assembly and its specified inserted components from its initial position in the fuel racks to its final position in the core. Checks are made of component serial numbers and types to guard against possible inadvertent exchanges or substitutions of components, and two reactor core fuel assembly tag boards are maintained throughout the core loading operation.

An initial increment of ten fuel assemblies, the first of which contains an active neutron source, is the minimum source-fuel increment that permits subsequent meaningful inverse count rate monitoring. This initial increment is determined by calculation and previous experience to be markedly subcritical $k_{eff} \leq 0.90$) under the required conditions of loading.

Each subsequent fuel loading increment is accompanied by detailed neutron count rate monitoring to determine that the just-loaded increment does not excessively increase the count rate and that the extrapolated inverse count rate ratio is not decreasing for unexplained reasons. The results of each loading step are evaluated according to written procedures before the next prescribed step is started.

Criteria for safe loading require that loading operations stop immediately if:

(1) An unanticipated increase in the neutron count rate by a factor of two occurs on all operating nuclear channels during any single loading step (excludes anticipated changes due to source/detector geometry)

(2) The neutron count rate on any individual nuclear channel unexpectedly increases by a factor of three during any single loading step (excludes anticipated changes due to source/detector geometry)

A "high count rate" alarm in the containment and the control room is coupled to the source range channels with a setpoint equal to or less than five times the current count rate. This alarm automatically alerts the fuel loading crew to an indication of high count rate and requires an immediate stop of all operations until the situation is evaluated. If it is immediately determined that no hazards to personnel exist, preselected personnel may remain in the containment to evaluate the cause and determine future action.

Fuel loading procedures specify alignment of fluid systems to prevent inadvertent dilution of the boron concentration in the reactor coolant, restrict the movement of fuel to preclude the possibility of mechanical damage, prescribe the conditions under which loading can proceed, identify chains of responsibility and authority, provide for continuous and complete fuel and core component accountability, and establish procedures to be observed in case of emergency.

14.1.4.2 Postloading Tests

Upon completion of fuel loading, the reactor upper internals and the pressure vessel head are installed and additional testing is performed prior to initial criticality. The final pressure tests are conducted after filling and venting of the reactor coolant system (RCS) is completed. The purpose of this phase of the program is to prepare the system for nuclear operation and to establish that design requirements necessary for operation are achieved.

Mechanical and electrical tests are performed on the RCCA drive mechanisms. A complete operational check of the RCCA drive mechanisms and the RCCA position indicator systems is performed. Tests are performed on the reactor trip circuits to verify manual trip operation and actual RCCA drop times are measured for each assembly. Whenever the RCCA drive mechanisms are being tested, the boron concentration in the RCS is such that criticality cannot be achieved with all RCCAs fully withdrawn. A complete functional electrical and mechanical check is made of the incore nuclear flux mapping system at operating temperature and pressure.

14.1.4.3 Initial Criticality

Initial criticality is established by sequentially withdrawing the shutdown and control groups of control rod assemblies from the core, leaving the last withdrawn control group inserted far enough in the core to provide effective control when criticality is achieved. Then the heavily borated reactor coolant is diluted until criticality is achieved. Successive stages of control rod assembly group withdrawal and of boron concentration reduction are monitored by observing changes in neutron count rate. Periodically, samples of the primary coolant boron concentration are obtained and analyzed.

The inverse count rate ratio is used as an indication of the nearness and rate of approach to criticality of the core during RCCA group withdrawal and during reactor coolant boron dilution. The rate of approach is reduced as the reactor approaches extrapolated criticality to ensure that effective control is maintained at all times. Written

procedures specify alignment of fluid systems, control the rate at which the approach to criticality may proceed, and predict initial values of core conditions under which criticality is expected.

14.1.4.4 Low Power Testing

A prescribed program of reactor physics measurements is undertaken to verify that the basic static and kinetic characteristics of the core are as expected and that the values of the kinetic coefficients assumed in the safety analysis are conservative.

The measurements are made at low power and at or near operating temperature and pressure. The measurements include verification of calculated control rod assembly group reactivity worths, isothermal temperature coefficient under various core conditions, differential boron concentration reactivity worth, and critical boron concentrations all as functions of control rod assembly group configuration. In addition, measurements of the power distribution are made. Concurrent tests are conducted on the instrumentation including the source and intermediate-range nuclear channels.

Written procedures specify the sequence of testing and the conditions under which each test is to be performed. This ensures both safety of operation and the relevancy and consistency of the results obtained. If significant deviations from design predictions exist, unacceptable behavior is revealed, or apparent anomalies develop, the testing is suspended while the situation is reviewed by PG&E to determine whether a question of safety is involved; the deviation is resolved prior to resumption of testing.

14.1.4.5 Power Level Escalation

When the operating characteristics of the plant have been verified by low power testing, a program of power level escalation in successive stages brings the unit to its full licensed power level. Reactor and unit operational characteristics are closely examined at each power level plateau and the relevance of the safety analysis is verified before escalation to the next programmed level.

Measurements are made to determine the relative power distribution in the core as functions of power level.

Secondary system heat balances ensure that the various indications of power level are consistent and provide a base for calibration of power range neutron channels. The ability of the reactor control system to respond effectively to signals from reactor plant and steam plant instrumentation under a variety of conditions encountered in normal operations is verified.

At prescribed power levels, the dynamic response characteristics of the reactor plant and steam plant are evaluated. The responses of system components are measured for design step and ramp changes in load, 50 percent reduction of load at design rate and normal recovery, net load rejection, and turbine trip.

Adequacy of radiation shielding is verified by gamma and neutron radiation surveys inside the containment and throughout the plant site at specified power levels. Periodic sampling of reactor coolant is performed to verify the chemical and radiochemical analysis of the reactor plant systems.

The functional performance requirements in some instances are described by specific quantitative acceptance criteria that are addressed in other sections of the FSAR. In other cases, acceptance standards may specify that a system or component perform a given action sequence. In either case, the detailed procedures or the referenced documents used in performing the test include specific acceptance criteria against which actual performance is measured. Plant conditions for each of the tests are listed in the test procedure.

When completed, this program provides assurance that plant performance is in accordance with the safety requirements established in the FSAR. The listing of the tests in Tables 14.1-1 and 14.1-2 includes specific identification of the objectives of each particular test that is required. Figure 14.1-1 gives a graphic presentation of the chronological sequence of startup testing.

14.1.5 ADMINISTRATIVE PROCEDURES -- SYSTEM OPERATION

14.1.5.1 Operating Procedures

Normal and emergency operation of all plant systems and/or major pieces of equipment are carried out in accordance with written procedures prepared by plant personnel and approved by the Plant Manager or his representative. These procedures are incorporated into the test program by the Lead Startup Engineer as appropriate. Where the prerequisite conditions for an operating procedure cannot be met during the test program, the procedure is demonstrated, under conditions simulating, as nearly as possible, the prerequisite conditions. The Assistant Plant Manager/Plant Superintendent reviews each startup test procedure to ensure that the operations specified in the test procedure are consistent with the normal and emergency operating procedures.

14.1.5.2 Safety Precautions

The measurements and operations during low power escalation testing are similar to normal unit operations at power and normal safety precautions are observed. Those tests that require special operating conditions are accomplished using test procedures that prescribe necessary limitations and precautions.

14.1.6 REFERENCES

1. *Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.*

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED.

14.2 AUGMENTATION OF APPLICANT'S STAFF FOR INITIAL TESTS AND OPERATION

The startup group, under the direction of the Lead Startup Engineer, is responsible for conducting the preoperational and startup testing programs. As such, the startup group may be considered the augmenting organization for the normal plant operating staff during the testing period. The NSSS supplier will furnish technical advice to the startup group during the initial testing period. In addition, the plant technical staff will augment the startup group during the initial test program. This augmentation will include shift supervision and shift staff engineer support.

14.2.1 ORGANIZATIONAL FUNCTIONS, RESPONSIBILITIES, AND AUTHORITIES

PG&E's organizational structure is shown in Figure 17.1-1. The Vice President-General Construction is responsible for construction of DCPP Unit 1 and Unit 2. This responsibility extends until the plant is running and released for operation, and includes the startup and acceptance of equipment.

The Nuclear Power Generation organizational structure is described in Chapter 13.

The plant operating organization, also described in Chapter 13, is responsible for the safety of operating personnel and the general public, for providing the necessary operating personnel for the power plant, for the training of those personnel, and for the direction and supervision of their work during the startup of new facilities. All activities that could affect the operation of the plant are done under the cognizance of licensed personnel as required by the Technical Specifications[(1)].

Technical advice furnished by Westinghouse Electric Corporation (Westinghouse), the NSSS designer and manufacturer, is advisory in nature since only PG&E's Operating Department plant staff will be licensed to direct or control plant operation.

14.2.2 INTERRELATIONSHIPS AND INTERFACES

The Lead Startup Engineer functions as the principal contact between the construction and operating organizations for startup activities.

The Startup Coordinator functions as the Assistant Plant Manager/Plant Superintendent's representative for startup operational activities.

The working interrelationship between the Lead Startup Engineer and the Startup Coordinator is described in Section 14.2.3.

Westinghouse will provide technical advice on site to PG&E during installation, startup, testing, and initial operation of the NSSS. This will provide additional assurance that the

NSSS is installed, started, tested, and operated in conformance with the design intent. Westinghouse personnel assigned to the site will provide technical advice and will provide technical liaison with the Westinghouse home office to promptly resolve problems within the Westinghouse scope of responsibility.

14.2.3 KEY PERSONNEL FUNCTIONS, RESPONSIBILITIES, AND AUTHORITIES

14.2.3.1 Station Construction Department

The Station Construction Department designates a Lead Startup Engineer who reports to the DCPP Senior Site Representative.

The Lead Startup Engineer is responsible for:

(1) Preparing the preoperational and startup testing programs and schedules; approval of these programs will be by the Lead Startup Engineer's signature

(2) Obtaining and preparing system test and acceptance criteria

(3) Providing necessary written test procedures

(4) Incorporating operating orders, procedures, and instructions prepared by the Assistant Plant Manager/Plant Superintendent into the test program

(5) Obtaining comments on test procedures from the Assistant Plant Manager/Plant Superintendent

(6) Arranging for startup personnel necessary to conduct the program and ensuring the adequacy of their preparation

(7) Ensuring that all prerequisites for performing tests are satisfactorily completed

(8) Directing individual preoperational and startup tests

(9) Verifying that each preoperational or startup test is satisfactorily completed

(10) Releasing accepted systems to the Assistant Plant Manager/Plant Superintendent

(11) Participating as a member in PSRC meetings during preoperational and startup testing

(12) Obtaining technical advice from Westinghouse as necessary

(13) Obtaining technical advice from PG&E's Engineering Department as necessary

14.2.3.2 Operating Department

The Plant Manager is responsible for serving as chairman of the PSRC meetings as discussed in Chapter 13.

The Assistant Plant Manager/Plant Superintendent is responsible for:

(1) Reviewing the schedules and test procedures developed by the Lead Startup Engineer and approving the overall startup schedule

(2) Preparing equipment operating orders, procedures, and instructions in accordance with standard PG&E operating practices for inclusion in the testing program

(3) Verifying that operating personnel are qualified to perform the operations required by the test program. Qualification of operating personnel is discussed in Chapter 13

(4) Supervising operation of controls of all components and systems during the test programs as requested by the Lead Startup Engineer and in accordance with the startup program

(5) Witnessing tests on apparatus and equipment and making recommendations on test results

(6) Determining that plant components and systems meet operating requirements as to safety, reliability, and economy of operation

(7) Accepting independent auxiliary equipment and systems for operation as needed after satisfactory performance has been demonstrated

The Assistant Plant Manager/Plant Superintendent designates an individual as Startup Coordinator, and that individual is responsible for startup operational activities under the Assistant Plant Manager/Plant Superintendent. For DCPP Unit 1 and Unit 2, the Operations Manager has been designated as Startup Coordinator.

14.2.3.3 Westinghouse

Early in construction, Westinghouse provided a site manager to represent Westinghouse at the site.

The site technical advice that will be provided for startup testing will be dependent upon the test being performed, the level of testing activity at any specific time, and requests by PG&E. Consequently, the personnel levels, categories, and schedules will be established by the site manager based on anticipated activities during each phase of the startup schedule. Westinghouse representatives will work in conjunction with the DCPP startup organization. A Westinghouse systems engineer will be assigned to the site for hot functional testing and other major systems testing activities. Supporting this engineer will be several field service engineers normally assigned on site during plant construction. These engineers will be augmented by specialists from the Westinghouse home office as required for adequate observation of the specific test being performed. The specialists will provide specific technical advice for specific tests.

A typical schedule for Westinghouse specialists follows:

(1) <u>RCS Hydrotest - three specialists</u>

(a) Reactor Coolant Pump Specialist

Scheduled to be on site 2 days prior to the hydrotest and for an approximate duration of 1 week or until satisfactory completion of the activity

(b) Chemist

Scheduled to be on site 2 days prior to the hydrotest and for an approximate duration of 1 week or until satisfactory completion of the activity

(c) Quality Assurance of Internals Inspector

Scheduled to be on site 2 weeks prior to the hydrotest and for an approximate duration of 2 weeks or until satisfactory completion of the activity

(2) <u>Hot Functional Test - three specialists</u>

(a) Reactor Coolant Pump Specialist

Scheduled to be on site 2 weeks prior to the hot functional test and for an approximate duration of 2 weeks or until satisfactory completion of the activity

(b) Chemist

Scheduled to be on site 2 days prior to the hot functional test and for an approximate duration of 1 week or until satisfactory completion of the activity

(c) Quality Assurance of Internals Inspector

Scheduled to be on site during the post-hot functional period and for an approximate duration of 1 week or until satisfactory completion of the activity

(3) Core Loading - three specialists

(a) Physicist

Scheduled to be on site 2 days prior to core loading and for an approximate duration of 1 week or until satisfactory completion of the activity

(b) Chemist

Scheduled to be on site 2 days prior to core loading and for an approximate duration of 1 week or until satisfactory completion of the activity

(c) Fuel Handling Specialist

Scheduled to be on site 1 week prior to core loading and for an approximate duration of 2 weeks or until satisfactory completion of the activity

(4) Plant Startup - four specialists

(a) Nuclear Test Engineer

Scheduled to be on site 1 week prior to startup and for an approximate duration of 8 weeks or until satisfactory completion of the activity

(b) Chemist

Scheduled to be on site 2 days prior to startup and for an approximate duration of 1 week or until satisfactory completion of the activity

(c) Transient Analyst

Scheduled to be on site prior to completion of each activity

(d) Reactivity Computer Instrumentation Specialist

Scheduled to be on site 1 day prior to startup and for an approximate duration of 2 weeks or until satisfactory completion of the activity

14.2.4 PERSONNEL QUALIFICATIONS

A resume for the Startup Coordinator (Operations Manager) is in the appendix to Chapter 13.

Qualifications of Westinghouse personnel providing technical advice include sufficient personal maturity, work experience, education, and specialized training to satisfy Westinghouse of their competence to adequately perform tasks assigned by the Westinghouse site manager. Due to the fluid nature of plant startup schedules, the individuals who will perform these assignments cannot be identified until specific milestones (i.e., hot functional, etc.) have actually occurred. Timing will be the principal factor in determining individual availability. Trainees and personnel with limited work experience are not used in positions of significant responsibility. Experience in the startup of nuclear power plants has indicated that the qualification of Westinghouse personnel assigned has been fully acceptable.

14.2.5 REFERENCES

1. *Technical Specifications, Diablo Canyon Power Plant Units 1 and 2, Appendix A to License Nos. DPR-80 and DPR-82, as amended.*

14.3 POSTCOMMERCIAL OPERATIONAL TEST PROGRAM

The following regulatory requirement is applicable to the Post-Commercial Operational Test Program:

> 10 CFR Part 50, Appendix B, Criterion XI – Test Control
>
> DCPP is required to establish a test program to ensure that all testing required to demonstrate that structures, systems and components will perform satisfactorily in service is identified and performed in accordance with written test procedures, which incorporate the requirements and acceptance limits contained in applicable design documents. The test program is required to include, as appropriate, proof tests prior to installation, preoperational tests, and operational tests during nuclear power plant operation of structures, systems, and components. Test procedures are required to include provisions for assuring that all prerequisites for the given test have been met, that adequate test instrumentation is available and used, and that the test is performed under suitable environmental conditions. Test results are required to be documented and evaluated to assure that test requirements have been satisfied.

This section describes the program for testing modifications to DCPP systems per approved design changes. The program ensures design changes are reviewed for postmodification operational testing requirements and that all operational tests are developed and performed prior to returning affected equipment to service.

The engineering director has overall responsibility for postmodification testing.

The scope of a modification is evaluated against plant safety features, industry codes, regulatory requirements, etc. From this evaluation, the scope of required testing is determined. Temporary test procedures are prepared when existing plant procedures will not adequately test the modification. Procedures used for performance of operational testing of design changes are reviewed and approved by appropriate DCPP management. Operational testing ensures a modification will function in accordance with the design basis by simulating normal and transient conditions when practical.

DCPP defines testing based on work category. Post modification testing (PMT) consists of maintenance verification testing (MVT), operability verification testing (OVT), and design verification testing (DVT). These tests may consist of functional tests, dry-run tests, dynamic tests, and inspections. Qualified personnel review and evaluate the test results for acceptability prior to releasing the equipment for service.

TABLE 14.1-1

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

PREOPERATIONAL TESTING SUMMARY

System Tests	*Test Objectives*
1. Electrical Systems	
1.1 Vital bus (4.16 kV, 480 V, 120 Vac)	*1. To demonstrate full plant load capability and interchangeability of all alternate power sources.*
	2. To verify automatic transfer of buses with and without offsite power available.
	3. To verify the 4.16 kV and 480 Vac vital bus load start logic.
1.2 Vital 125 Vdc system	*1. To verify proper operation in normal and emergency conditions of batteries, battery chargers, 125 Vdc switchgear, and distribution panels.*
	2. To verify battery capacities.
1.3 Communications systems	*1. To verify that the site evacuation signal can be heard from any location at the site.*
	2. To verify that the fire alarm signal can be heard from any location in the plant.
	3. To verify that communications stations for fuel loading are functional.
1.4 Emergency lighting	*1. To verify adequacy for operator transit from point to point.*
2. Diesel Engine Generator Units	*1. To verify the start signal setpoints and logic.*
	2. To verify the capability of the diesel engine generator units to supply power to vital equipment for plant cooldown during emergency conditions, such as loss of offsite power coincident with loss of turbine generator.
	3. To verify that redundant features of the system function according to the design intent.

System Tests	*Test Objectives*
2. (Continued)	*4. To verify that the diesel fuel oil transfer pump will supply fuel oil from the diesel fuel oil storage tank to the diesel engine fuel oil day tank.*
3. Fire Protection Systems	*1. To verify that the fire pumps will supply water from the fire water tank to selected stations within the DCPP and that the automatic start features operate as designed.*
	2. To verify that the low-pressure CO_2 system functions properly and that CO_2 is delivered to appropriate fire protection stations.
	3. To verify that the Halon system functions properly and that Halon is dispersed in the solid-state protection system room in acceptable concentrations.
4. Ventilation Systems	*1. To verify the operation of the containment fan coolers and dampers according to design and to measure heat removal capability during hot functional testing.*
	2. To verify that the auxiliary and fuel handling building exhaust and supply fans and the control room air conditioning units and their associated dampers, valves, and filters operate according to design.
	3. To verify the logic for postaccident condition initiation of containment pressure reduction.
	4. To verify the closure of containment purge supply and exhaust ducts and the pressure relief duct from a high radioactivity in containment signal.
5. Instrumentation and Control Systems	
5.1 Process instrumentation	*1. Applicable alarm and control set- points are checked for conformance with design values.*
5.2 Nuclear instrumentation	*1. Prior to core loading, nuclear instruments will have been aligned and source range detector response to neutron source checked.*

System Tests	Test Objectives
5.2 (Continued)	*2. All required channels will be checked to verify operability within the required Technical Specifications interval.*
5.3 Automatic reactor power control systems tests	*1. The system alignment is verified at preoperational conditions to demonstrate the response of the system to simulated inputs. These tests are performed to verify that the systems will operate satisfactorily at power.*
	2. At power, the alignment of the system is verified by programmed step changes and under actual test transient conditions.
5.4 Engineered safety features (ESF)	*1. To verify ESF, setpoints, logic, and response times.*
	2. To verify response of ESF equipment to a safety injection signal with and without offsite power available.
5.5 Reactor protection system	*1. To test redundancy, coincidence, independence, and safe failure on loss of power to process instrumentation and reactor protection equipment.*
	2. To verify reactor protection time response meets design requirements.
	3. To test automatic and manual reactor trip setpoints, logic, and reactor trip breakers.
5.6 Radiation monitoring systems	*1. To calibrate against known standards and verify the operability and alarm setpoints of all process monitors (air particulate monitors, gas monitors, and liquid monitors) located in the plant.*
6. System Functional Tests	
6.1 Reactor coolant system (RCS)	*1. To verify the integrity and leaktightness of the RCS and auxiliary primary systems at the specified test pressure and temperature.*
	2. To verify the capability of the pressurizer relief tank to function according to design.

	System Tests	Test Objectives
6.1	(Continued)	3. To verify proper operation of the nuclear steam supply system and auxiliary systems local and remote indicators, alarms, recorders, and controllers for pressure, temperature, flow, and level.
		4. To verify resistance temperature detector (RTD) bypass loop flow and correct functional operation of control and indicating equipment and the detectors.
		5. To establish baseline data for inservice inspections and verify integrity of the system.
6.2	Chemical and volume control system (CVCS)	1. To verify that the design charging, letdown, and excess letdown flowrates are attainable.
		2. To verify that the reactor coolant purification equipment operates according to design parameters.
		3. To verify charging pump (CCP1 and 2) performance and response to a safety injection signal when the RCS is depressurized.
		4. To verify ability to control RCS water volume.
		5. To verify the ability to control chemical shim concentration.
		6. To verify the design seal water flowrates to each reactor coolant pump.
		7. To verify that pumps, filters, tanks, and heat tracing used for batching, storage, and transfer of 12% boric acid function satisfactorily as a system.
		8. To verify gas stripper and boric acid evaporator operation meets design requirements.
		9. To verify chemical addition and sampling features function according to design.
		10. To verify operating capability of process instrumentation and controls under normal conditions.

	System Tests	Test Objectives
6.3	*Safety injection system*	*1. To verify the safety injection pump and accumulator performance and response to a safety injection signal when the RCS is depressurized.* *2. Test the systems to ensure capability of meeting design objectives.*
6.4	*Containment spray system*	*1. To verify the containment spray pump performance and response to a containment spray signal.* *2. Verify that the system can be tested to verify functional performance.*
6.5	*Residual heat removal system (RHRS)*	*1. To verify the RHR pump performance and response to a safety injection signal when the RCS is depressurized.* *2. To verify the system is capable of supplying emergency core cooling in the recirculation mode.* *3. To verify system capability for supplying cooling water during core loading.* *4. To verify the capability for plant cooldown assuming failure of a single active component.*
6.6	*Component cooling water system (CCWS)*	*1. To verify normal system operation according to the system description and design requirements.* *2. To verify the capability for plant cooldown assuming failure of a single active component.*
6.7	*Makeup water system*	*1. To verify the makeup water transfer pumps will transfer water from the condensate storage tank to the fire system, and to the CCW system surge tank.* *2. To verify the primary water makeup pumps will supply water from the primary water storage tank to the CCW system surge tank, to the boric acid blender, and to the chemical mixing tank in the CVCS system.*

System Tests	Test Objectives
6.8 Auxiliary saltwater system (ASWS)	*1. To verify normal system operation according to system description and design requirements.*
	2. To verify the capability for plant cooldown assuming failure of a single active component.
6.9 Liquid radwaste system	*1. To verify that liquids can be collected in the reactor coolant drain tank and transferred to other tanks per design.*
	2. To verify waste processing according to the system description (includes waste concentrator, waste concentrator pumps, and liquid radwaste filter and tanks).
	3. To verify that liquid radwaste releases can be controlled and excessive releases can be prevented.
	4. To verify proper operation of primary system leak detection features and to verify proper operation of miscellaneous equipment drain tank pumps, equipment drain receivers, and pumps.
6.10 Gaseous radwaste system	*1. To verify the collection and processing of gaseous radwaste is according to the system description.*
6.11 Auxiliary feedwater system	*1. To verify the turbine- and motor-driven auxiliary feedwater pumps deliver feedwater from the condensate storage tank to the steam generators at design flowrate and pressure and otherwise perform according to design in response to ESF signals.*
6.12 Condensate, feedwater, and main steam	*1. To check proper operation and indication of main feedwater regulating valves and main steam line isolation valves for the appropriate actuation signals.*
6.13 Hydrogen and nitrogen systems	*1. To verify valve operability, regulating and reducing station performance, and the ability to supply the appropriate gas to interconnecting systems as required.*

System Tests	*Test Objectives*
7. *Hot Functional Tests*	*The intent of planned testing shall include but not be limited to the following:* 1. *To check RCS heatup and cooldown procedures.* 2. *To demonstrate satisfactory performance of components and systems that are exposed to RCS temperature.* 3. *To verify to the extent possible proper operation of instrumentation, controllers, and alarms.* 4. *To provide design operating conditions for testing the following auxiliary systems:* a. *CVCS* b. *Sampling system* c. *CCWS* d. *RHRS* e. *ASWS* 5. *To verify that water can be charged by the CVCS at rated flow against normal reactor coolant pressure.* 6. *To check letdown design flowrate for each operating mode.* 7. *To check operation of the excess letdown and seal water flowpaths.* 8. *To check steam generator instrumentation and control systems.* 9. *To verify the ability to cool down the plant using the steam generators.* 10. *To check thermal expansion and restraint of RCS components and piping.* 11. *To perform isothermal calibration of RTDs and incore thermocouples.* 12. *To operationally test the RHRS.* 13. *To check pressurizer level and pressure*

System Tests	*Test Objectives*
	instrumentation and control systems.
7. (Continued)	*14. To check RCS instrumentation and control systems.*
	15. To verify the ability of the auxiliary feedwater system to feed the steam generators.
	16. To verify that steam generator blowdown operates according to design.
	17. To verify the capability of emergency process control from a location remote to the control room.
	18. To verify correct plant response to a safety injection signal under hot operating conditions. Verify system alignments, automatic transfer of electrical systems, and automatic sequential start of ESF equipment.
	19. Following hot functional testing, the reactor internals are removed and inspected for signs of excessive vibration.
8. Relief and Safety Valve Tests	*1. To verify setpoints of the relief and safety valves.*
9. Containment Building	*1. To conduct structural integrity and integrated leakrate tests.*
	2. To verify proper operation and leaktightness of air locks.
	3. To verify closure of all containment isolation valves for the appropriate signals.

TABLE 14.1-2

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

FUEL LOADING AND INITIAL STARTUP TESTING SUMMARY

Tests	*Objectives*
1. Startup Program Master Document	*1. To define the sequence of tests and activities from preparation for fuel load through fuel loading, low power testing, and power ascension.*
	2. To establish hold points for administrative control over proceeding into significant areas of testing or power plateaus.
2. Fuel Loading Program	
2.1 Fuel loading prerequisites and periodic checkoffs	*1. To establish and maintain the prerequisite conditions for fuel loading.*
2.2 Initial fuel loading	*1. To specify the sequence of operation for fuel loading.*
3. Precritical Test Program	
3.1 Incore movable detectors	*1. To verify correct functional operation of control and indicating equipment.*
3.2 Rod drive mechanism timing	*1. To verify the proper timing for rod drive mechanism control equipment.*
	2. To operationally check each control rod drive mechanism with a control rod attached.
3.3 Incore thermocouple-loop RTD cross calibration	*1. To check and compare incore thermocouple readings with RCS RTD readings and calibrate the system if required.*
3.4 Pressurizer spray and heater capacity and continuous spray flow setting	*1. To establish the continuous spray flowrate.*
	2. To verify the pressure control capability using spray flow and heaters.
3.5 RTD bypass loop flow measurement	*1. To establish and verify acceptable flowrates.*

Tests	Objectives
3.6 Rod drop time measurement	*1. To determine the drop time of each control rod for selected conditions.*
3.7 Rod position indication	*1. To demonstrate satisfactory system performance of indication and alarm functions.*
	2. To demonstrate that control rods operate over their entire length of travel.
3.8 Rod control system operational test	*1. To demonstrate that the rod control system performs its required control and indication functions to verify availability for use just prior to criticality.*
3.9 RCS flow measurement	*1. To verify adequacy of RCS flow.*
3.10 RCS flow coastdown	*1. To verify the rate of change of reactor coolant flow subsequent to selective reactor coolant pump trips.*
4. Initial Criticality and Low Power Physics Program	
4.1 Initial criticality	*1. To bring the reactor critical for the first time.*
	2. To compare the measured critical boron concentration with the expected critical boron concentration.
	3. To establish upper limit of flux level for zero power physics measurements.
4.2 Nuclear design checks	*1. To verify the boron endpoint concentration, the isothermal temperature coefficient of reactivity, and zero power flux distribution for various rod configurations.*
4.3 Rod and boron reactivity worth measurements	*1. To verify design values of bank differential and integral worths during boron addition and dilution.*
4.4 Rod cluster control assembly (RCCA) pseudo-ejection	*1. To verify that the RCCA reactivity worth assumed in the accident analysis is conservative.*
4.5 Minimum shutdown verification	*1. To verify the reactivity worth of the shutdown banks.*
4.5 (Continued)	*2. To measure the critical boron concentration*

Tests	*Objectives*
	with all shutdown and control banks inserted, less the most reactive rod assembly.
4.6 Conduct special test program (Unit 1 only) consisting of the following tests:	
a) Natural circulation	*1. Provide supplementary technical information and operator training. (Tests a through g.)*
b) Natural circulation with loss of pressurizer heaters	*2. Determine capability of CVCS charging and letdown to cooldown the RCS. (Test f.)*
c) Natural circulation at reduced pressure	*3. Demonstrate ability to control RCS and steam generator parameters. (Test g.)*
(d) Natural circulation with simulated loss of offsite ac power	
(e) Effect of steam generator isolation on natural circulation	
(f) Cooldown capability of the charging and letdown system	
(g) Simulated loss of all onsite and offsite ac power	
5 <u>Power Ascension Program</u>	
5.1 Thermal power measurements	*1. To ascertain level of thermal power for establishment of plateaus for testing activities.*
	2. To provide thermal power information for use in other tests.
5.2 Radiation surveys and shielding effectiveness	*1. To obtain background information to establish access restrictions .*
	2. To verify shielding adequacy.
5.3 Operational alignment of nuclear instrumentation	*1. To make necessary adjustments to the NIS as a function of reactor thermal power*

Tests	Objectives
systems (NIS)	
5.4 Operational alignment of RCS temperature instrumentation at power	*1. To make necessary adjustments to the T_{avg} and ΔT channels as a function of reactor thermal power*
5.5 Calibration of steam and feedwater flow instrumentation at power	*1. To calibrate steam and feedwater flow instrumentation as a function values determined from test instrumentation.*
5.6 Turbine overspeed trip test	*1. To test the main turbine electrical and mechanical overspeed trip mechanisms.*
5.7 Incore power distribution	*1. To verify that nuclear design predicted power distributions are valid for normal rod patterns and configurations.*
5.8 Effluents and effluents monitoring	*1. To verify level of radwaste releases.*
5.9 Chemical and radiochemical analysis	*1. To demonstrate ability to control RCS water chemistry.*
5.10 Control systems checkout	*1. To demonstrate proper operation of the:* *a. RCS* *b. Steam generator level control system* *c. Steam dump control system* *d. Turbine control system.*
5.11 Control rod pseudo-ejection and above bank position measurements	*1. To verify response of the excore detectors to a rod in above bank position.* *2. To verify the effects of a rod out of position and a pseudo-ejected rod upon neutron flux and hot channel factors.*
5.12 Static rod drop and RCCA below bank position measurements (Unit 1 only)	*1. To verify the response of excore detectors to a rod in below bank position.* *2. To verify that a single control rod assembly inserted fully or part way below the control bank results in acceptable hot channel factors.*
5.13 Rod group drop and plant trip	*1. To verify functioning of negative rate trip circuitry in the excore detector system.*

TABLE 14.1-2

Tests	*Objectives*
	2. To verify control systems performance as evidenced by plant parameter variations within acceptable limits.
5.14 Plant shutdown from outside the control room	*1. To verify shutdown capability from backup control stations*
5.15 Load swing tests	*1. To verify control systems performance as evidenced by plant parameter variations within acceptable limits.*
	2. To verify plant response to load changes.
5.16 Doppler power reactivity coefficient measurement	*1. To verify nuclear design prediction of the Doppler-only power coefficient.*
5.17 Incore-excore detector calibration	*1. To form a relationship between incore and excore neutron detector signals for generated axial offsets*
5.18 Large load reduction tests	*1. To verify ability of plant to sustain large load reductions as evidenced by parameters remaining within acceptable limits.*
5.19 Steam generator moisture carryover	*1. To verify that actual steam generator moisture carryover is equal to or less than design value.*
5.20 Nuclear steam supply system acceptance test	*1. To operate the plant at or near 100% power for 100 hours to verify plant capability at sustained load.*
5.21 Net load trip tests	*1. To verify plant response to loss of plant load at the 50% and 100% power plateaus for Unit 1 and the 50% power plateau for Unit 2.*
	2. To verify control systems performance as evidenced by plant parameter variations within acceptable limits.
5.22 Plant trip tests	*1. To verify plant response to turbine generator trips at 50% and 100% power plateaus.*
5.22 (Continued)	*2. To verify control systems performance as evidenced by plant parameter variations within acceptable limits.*

TABLE 14.1-2

Tests	*Objectives*
	3. To verify automatic transfer to offsite standby power.
5.23 Natural circulation boron mixing cooldown test (Unit 1 only)	*1. To verify ability to add and mix 12% boric acid, cooldown to RHR via natural circulation and continue cooldown to cold shutdown conditions*

.

PROCEDURE TITLE OR TEST DESCRIPTION	PRE-FUEL LOAD	LOW POWER MODES 6 2					POWER OPERATION MODE 1					
		REF	CSD	HSD	HSB	STUP	15	30	50	75	90	100
REFER TO TABLE 14.1-2												
1.0 STARTUP PROGRAM												
1.1 Startup Program Master Document	O	—	—	—	—	—	—	—	—	—	—	O
2.0 FUEL LOADING PROGRAM												
2.1 Fuel Loading Prerequisites and Periodic Checkoffs	O	O										
2.2 Operational Alignment of Nuclear Instrumentation	O											
2.3 Effluents and Effluents Monitoring	O											
2.4 Chemical and Radiochemical Analysis	O											
2.5 Initial Fuel Loading		O										

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FIGURE 14.1-1
CHRONOLOGICAL SEQUENCE OF STARTUP TESTING
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HISTORICAL

PROCEDURE TITLE OR TEST DESCRIPTION	PRE-FUEL LOAD	LOW POWER MODES 6-2					POWER OPERATION MODE 1					
		REF	CSD	HSD	HSB	STUP	≤15	30	50	75	90	100
3.0 PRECRITICAL TEST PROGRAM												
3.1 Incore Movable Detectors		O	O	O	O							
3.2 Rod Drive Mechanism Timing			O		O							
3.3 Incore Thermocouple - Loop RTD Cross Calibration				O	O							
3.4 Pressurizer Spray and Heater Capacity and Continuous Spray Flow Setting					O							
3.5 RTD Bypass Loop Flow Measurement					O							
3.6 Rod Drop Time Measurement			O		O							
3.7 Rod Position Indication System					O							
3.8 Rod Control System Operational Test					O							
3.9 Reactor Coolant System Flow Measurement					O							
3.10 Reactor Coolant System Flow Coastdown					O							
3.11 Effluents and Effluent Monitoring	O	O	—	—	O							
3.12 Chemical and Radiochemical Analysis	O	O	—	—	O							
3.13 Operational Alignment of Nuclear Instrumentation	O				O							
3.14 Operational Alignment of Reactor Coolant System Temperature Instrumentation at Power					O							
3.15 Calibration of Steam and Feedwater Flow Instrumentation at Power					O							

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FIGURE 14.1-1
CHRONOLOGICAL SEQUENCE OF STARTUP TESTING
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HISTORICAL

PROCEDURE TITLE OR TEST DESCRIPTION	PRE-FUEL LOAD	LOW POWER MODES 6-2					POWER OPERATION MODE 1					
		REF	CSD	HSD	HSB	STUP	15	30	50	75	90	100
4.0 INITIAL CRITICALITY AND LOW POWER PHYSICS PROGRAM												
4.1 Initial Criticality						O						
4.2 Nuclear Design Checks						O						
4.3 Rod and Boron Reactivity Worth Measurements						O						
4.4 Rod Control Cluster Assembly Pseudo-ejection						O						
4.5 Minimum Shutdown Verification						O						
4.6 Operational Alignment of Nuclear Instrumentation	O				O	O						
4.7 Incore Power Distribution						O						
4.8 Effluents and Effluents Monitoring	O-	-	-	-	-	O						
4.9 Chemical and Radiochemical Analysis	O-	-	-	-	-	O						
4.10 Special Test Program (Unit 1 only)					O	O						

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FIGURE 14.1-1
CHRONOLOGICAL SEQUENCE OF STARTUP TESTING
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HISTORICAL

PROCEDURE TITLE OR TEST DESCRIPTION	PRE-FUEL LOAD	LOW POWER MODES 6 - 2					POWER OPERATION MODE 1					
		REF	CSD	HSD	HSB	STUP	≤15	30	50	75	90	100
5.0 POWER ASCENSION PROGRAM												
5.1 Thermal Power Measurements							O	O	O	O	O	O
5.2 Radiation Surveys and Shielding Effectiveness (Unit 1)							O	O	O	O		O
(Unit 2)							O		O			O
5.3 Operational Alignment of Nuclear Instrumentation	O				O	O	O	O	O	O	O	O
5.4 Operational Alignment of Reactor Coolant System Temperature Instrumentation at Power					O					O		O
5.5 Calibration of Steam and Feedwater Flow Instrumentation at Power					O			O	O	O	O	O
5.6 Turbine Overspeed Trip Test							O					
5.7 Incore Power Distribution						O	O	O	O	O	O	O
5.8 Effluents and Effluents Monitoring	O						O					O
5.9 Chemical and Radiochemical Analysis	O						O					O
5.10 Automatic Control Systems Checkout							O	O	O	O		O
5.11 Control Rod Pseudo-ejection and Above Bank Position Measurement								O				
5.12 Static Rod Drop and RCCA Below Bank Position Measurements (Unit 1 Only)									O			
5.13 Rod Group Drop and Plant Trip									O			
5.14 Plant Shutdown from Outside the Control Room									O			
5.15 Load Swing Tests								O	O	O		O
5.16 Doppler Power Reactivity Coefficient Measurement								O	O	O	O	

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FIGURE 14.1-1
CHRONOLOGICAL SEQUENCE OF STARTUP TESTING
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PROCEDURE TITLE OR TEST DESCRIPTION	PRE-FUEL LOAD	LOW POWER MODES 6 - 2					POWER OPERATION MODE 1					
		REF	CSD	HSD	HSB	STUP	≤15	30	50	75	90	100
5.0 POWER ASCENSION PROGRAM (Continued)												
5.17 Incore-Excore Detector Calibration (Test shown at 50% plateau to be performed slightly below 50% power)									O	O		
5.18 Large Load Reduction Tests										O		O
5.19 Steam Generator Moisture Carryover (Tests performed between 90% and 100% power)											O	O
5.20 Nuclear Steam Supply System Acceptance Test												O
5.21 Net Load Trip Tests (Unit 1)									O			O
(Unit 2)									O			
5.22 Plant Trip from 100% Power												O
5.23 Natural Circulation Boron Mixing Cooldown Test (Unit 1 only)			O	O	O							

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FIGURE 14.1-1
CHRONOLOGICAL SEQUENCE OF STARTUP TESTING
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HISTORICAL

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15.2.8A-2	Deleted in Revision 19
15.2.8-2	Loss of Normal Feedwater - Pressurizer Water Volume and Pressurizer Pressure Transients
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15.2.9-1	Loss of Offsite Power RCS Temperatures and Steam Generator Mass Transients
15.2.9-2	Loss of Offsite Power Pressurizer Water Volume and Pressurizer Pressure Transients
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15.2.10A-1	Deleted in Revision 19
15.2.10-1	Main Feedwater Regulating Valve Malfunction – Full Power, Manual Rod Control, Nuclear Power and Average Channel Core Heat Flux Transients
15.2.10A-2	Deleted in Revision 19

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15.2.13-2	Pressurizer Pressure and Core Average Temperature Transients for Accidental Depressurization of the Reactor Coolant System
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15.2.14-1	Deleted in Revision 16.
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15.3-12	Deleted in Revision 13.
15.3-13	Clad Temperature Transient 3 inch Cold Leg Break
15.3-14	Deleted in Revision 13.
15.3-14a	Deleted in Revision 13.
15.3-14b	Deleted in Revision 13.
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15.3-14d	Deleted in Revision 13.
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15.3-15	Interchange Between Region 1 and Region 3 Assembly

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15.3-16	Interchange Between Region 1 and Region 2 Assembly - Burnable Poison Rods Being Retained by the Region 2 Assembly
15.3-17	Interchange Between Region 1 and Region 2 Assembly - Burnable Poison Rods Being Transferred to the Region 1 Assembly
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15.3-20	Deleted in Revision 3
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15.3-22	Deleted in Revision 3
15.3-23	Deleted in Revision 3
15.3-24	Deleted in Revision 3
15.3-25	Deleted in Revision 3
15.3-26	Deleted in Revision 6
15.3-27	Deleted in Revision 6
15.3-28	Deleted in Revision 6
15.3-29	Deleted in Revision 6
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15.3.4-1	Complete Loss of Forced Reactor Coolant Flow - All Loops Operating, All Loops Coasting Down - Flow Coastdown Versus Time
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15.4.1-1A	Deleted in Revision 26
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15.4.1-2A	Deleted in Revision 26
15.4.1-2B	Deleted in Revision 26
15.4.1-3A	Deleted in Revision 26
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15.4.1-7B	Deleted in Revision 26
15.4.1-8A	Deleted in Revision 26
15.4-1-8B	Deleted in Revision 26
15.4.1-9A	Deleted in Revision 26
15.4.1-9B	Deleted in Revision 26
15.4.1-10A	Deleted in Revision 26
15.4.1-10B	Deleted in Revision 26
15.4.1-11A	Deleted in Revision 26
15.4.1-11B	Deleted in Revision 26
15.4.1-12A	Deleted in Revision 26
15.4.1-12B	Deleted in Revision 26
15.4.1-13A	Deleted in Revision 26
15.4.1-13B	Deleted in Revision 26
15.4.1-14A	Deleted in Revision 26
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15.4.1.3-20A	Accumulator Injection Flow per Loop for LBLOCA (Region II)
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15.4.1.3-21A	Containment Pressure for LBLOCA (Region II)
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15.4.1.3-26A	Normalized Core Power Shape for LBLOCA (Region II)
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15.4-2	Deleted in Revision 18
15.4-3	Deleted in Revision 18
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15.4-5	Deleted in Revision 18
15.4-5A	Deleted in Revision 12
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15.4-6	Deleted in Revision 18
15.4-7	Deleted in Revision 18
15.4-8	Deleted in Revision 18
15.4-9	Deleted in Revision 18
15.4-9A	Deleted in Revision 12
15.4-9B	Deleted in Revision 12
15.4-10	Deleted in Revision 18
15.4-11	Deleted in Revision 18
15.4-12	Deleted in Revision 18
15.4-13	Deleted in Revision 18
15.4-13A	Deleted in Revision 12
15.4-13B	Deleted in Revision 12
15.4-14	Deleted in Revision 18
15.4-15	Deleted in Revision 18
15.4-16	Deleted in Revision 12
15.4-17	Deleted in Revision 12
15.4-17A	Deleted in Revision 12
15.4-18	Deleted in Revision 12
15.4-19	Deleted in Revision 12
15.4-20	Deleted in Revision 12
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15.4-21A	Deleted in Revision 12
15.4-22	Deleted in Revision 12
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15.4-24	Deleted in Revision 12
15.4-25	Deleted in Revision 12
15.4-25A	Deleted in Revision 12
15.4-26	Deleted in Revision 12
15.4-27	Deleted in Revision 12
15.4-28	Deleted in Revision 12
15.4-29	Deleted in Revision 12
15.4-29A	Deleted in Revision 12
15.4-29B	Deleted in Revision 12
15.4-30	Deleted in Revision 12
15.4-31	Deleted in Revision 12
15.4-32	Deleted in Revision 12
15.4-33	Deleted in Revision 12
15.4-33A	Deleted in Revision 12
15.4-33B	Deleted in Revision 12
15.4-34	Deleted in Revision 12
15.4-35	Deleted in Revision 12
15.4-36	Deleted in Revision 12

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Figure	Title
15.4-37	Deleted in Revision 12
15.4-37A	Deleted in Revision 12
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15.4-41	Deleted in Revision 12
15.4-41A	Deleted in Revision 12
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15.4-44	Deleted in Revision 12
15.4-45	Deleted in Revision 12
15.4-45A	Deleted in Revision 12
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15.4-47	Deleted in Revision 12
15.4-48	Deleted in Revision 12
15.4-49	Deleted in Revision 12
15.4-49A	Deleted in Revision 12
15.4-50	Deleted in Revision 12
15.4-51	Deleted in Revision 12
15.4-51A	Deleted in Revision 12
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15.4-53	Deleted in Revision 12
15.4-53A	Deleted in Revision 12
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15.4-57	Deleted in Revision 12
15.4-57A	Deleted in Revision 12
15.4-58	Deleted in Revision 12
15.4-59	Deleted in Revision 12
15.4-59A	Deleted in Revision 12
15.4-60	Deleted in Revision 12
15.4-61	Deleted in Revision 12
15.4-61A	Deleted in Revision 12
15.4-62	Deleted in Revision 12
15.4-63	Deleted in Revision 6
15.4-64	Deleted in Revision 6
15.4-65	Deleted in Revision 6
15.4-66	Deleted in Revision 6
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15.4-72	Deleted in Revision 6
15.4-73	Deleted in Revision 6
15.4-74	Deleted in Revision 6
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15.4-75a	Deleted in Revision 3
15.4-75b	Deleted in Revision 3
15.4-75c	Deleted in Revision 3
15.4-75d	Deleted in Revision 3
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15.4-75f	Deleted in Revision 3
15.4-75g	Deleted in Revision 3
15.4-75h	Deleted in Revision 3
15.4-75i	Deleted in Revision 6
15.4-75j	Deleted in Revision 6
15.4-75k	Deleted in Revision 6
15.4-75l	Deleted in Revision 6
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15.4-75n	Deleted in Revision 6
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15.4-79	Deleted in Revision 3
15.4-80	Deleted in Revision 3
15.4-81	Deleted in Revision 3
15.4-82	Deleted in Revision 3
15.4-83	Deleted in Revision 3
15.4-84	Deleted in Revision 3
15.4-85	Deleted in Revision 3
15.4-86	Deleted in Revision 3
15.4-87	Deleted in Revision 3
15.4-88	Deleted in Revision 3
15.4-89	Deleted in Revision 6
15.4-90	Deleted in Revision 6
15.4-91	Deleted in Revision 6
15.4-92	Deleted in Revision 6
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15.4-97	Deleted in Revision 6
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15.4-101	Deleted in Revision 16
15.4-102	Deleted in Revision 16
15.4-103	Deleted in Revision 16
15.4-104	Deleted In Revision 16
15.4-105	Deleted in Revision 16
15.4-106	Deleted in Revision 16
15.4-107	Deleted in Revision 16
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15.4-109	Deleted in Revision 16
15.4.2A-1	Deleted in Revision 19
15.4.2-1	Rupture of a Main Steam Line - Variation of Reactivity with Power at Constant Core Average Temperature
15.4.2A-2	Deleted in Revision 19
15.4.2-2	Rupture of a Main Steam Line – Variation of K_{eff} with Core Average Temperature
15.4.2A-3	Deleted in Revision 19
15.4.2-3	Rupture of a Main Steam Line – Safety Injection Curve

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15.4.2A-4A	Deleted in Revision 19
15.4.2A-4B	Deleted in Revision 19
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15.4.2A-4D	Deleted in Revision 19
15.4.2-4	Rupture of a Main Steam Line with Offsite Power Available – Core Heat Flux and Steam Flow Transients
15.4.2A-5	Deleted in Revision 19
15.4.2-5	Rupture of a Main Steam Line with Offsite Power Available – Loop Average Temperature and reactor Coolant Pressure Transients
15.4.2-6	Rupture of a Main Steam Line with Offsite Power Available – Reactivity and Core Boron Transients
15.4.2A-7	Deleted in Revision 19
15.4.2-7	Rupture of a Main Steam Line without Offsite Power Available – Core Heat Flux and Steam Flow Transients
15.4.2A-8	Deleted in Revision 19
15.4.2-8	Rupture of a Main Steam Line without Offsite Power Available – Loop Average Temperature and Reactor Coolant Pressure Transients
15.4.2A-9	Deleted in Revision 19
15.4.2-9	Rupture of a Main Steam Line without Offsite Power Available – Reactivity and Core Boron Transients
15.4.2A-10	Deleted in Revision 19
15.4.2-10	Main Feedline Rupture with Offsite Power Available – Nuclear Power and Core Heat Flux Transients
15.4.2A-11	Deleted in Revision 19

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15.4.2-11	Main Feedline Rupture with Offsite Power Available – Pressurizer Pressure and Core Water Volume Transients
15.4.2A-12	Deleted in Revision 19
15.4.2-12	Main Feedline Rupture with Offsite Power Available – Reactor Coolant Temperature Transients for the Faulted and Intact Loops
15.4.2A-13	Deleted in Revision 19
15.4.2-13	Main Feedline Rupture with Offsite Power Available – Steam Generator Pressure and Total mass Transients
15.4.2A-14	Deleted in Revision 19
15.4.2-14	Main Feedline Rupture without Offsite Power Available – Nuclear Power and Core Heat Flux Transients
15.4.2A-15	Deleted in Revision 19
15.4.2-15	Main Feedline Rupture without Offsite Power Available – Pressurizer Pressure and Water Volume Transients
15.4.2A-16	Deleted in Revision 19
15.4.2-16	Main Feedline Rupture without Offsite Power Available – Reactor Coolant Temperature Transients for the Faulted and Intact Loops
15.4.2A-17	Deleted in Revision 19
15.4.2-17	Main Feedline Rupture without Offsite Power Available – Steam Generator Pressure and Total Mass Transients
15.4.2A-18	Deleted in Revision 19
15.4.2-18	Main Steam Line Rupture at Full Power, 0.49 ft^2 Break – Nuclear Power and Core Heat Flux Transients
15.4.2-19	Main Steam Line Rupture at Full Power, 0.49 ft^2 Break – Pressurizer Pressure and Water Volume Transients

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15.4.2-20	Main Steam Line Rupture at Full Power, 0.49 ft^2 Break – Reactor Vessel Inlet Temperature and Loop Average Temperature Transients
15.4.2-21	Main Steam Line Rupture at Full Power, 0.49 ft^2 Break – Total Steam Flow and Steam Pressure Transients
15.4.2-22	Main Feedline Rupture for Pressurizer Filling (Unblock Pressurizer PORV)– Pressurizer Pressure and Water Volume Transients
15.4.2-23	Main Feedline Rupture for Pressurizer Filling (Unblock Pressurizer PORV) – PSV Relief Flow Rate and Enthalpy Transients
15.4.2-24	Main Feedline Rupture for Pressurizer Filling (Isolate Charging and Stop RCP Seal Injection Flow) – Pressurizer Pressure and Water Volume Transients
15.4.2-25	Main Feedline Rupture for Pressurizer Filling (Isolate Charging and Stop RCP Seal Injection Flow) – PORV and PSV Relief Flow Rate Transients
15.4.2-26	Main Feedline Rupture for Pressurizer Filling (Isolate Charging and Stop RCP Seal Injection Flow) – PORV/PSV Relief Flow Enthalpy and Total Number of PORV Cycles Transients
15.4.2-27	Main Feedline Rupture for Pressurizer Filling (Isolate Charging and Stop RCP Seal Injection Flow) – Cold Leg Injection Flow Rate Transient
15.4.3A-1	Deleted in Revision 19
15.4.3-1	Deleted in Revision 20
15.4.3-1A	Pressurizer Level – SGTR MTO Analysis
15.4.3-1B	Pressurizer Level – SGTR Dose Analysis
15.4.3A-2	Deleted in Revision 19
15.4.3-2	Deleted in Revision 20
15.4.3-2A	Pressurizer Pressure – SGTR MTO Analysis
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15.4.3A-3	Deleted in Revision 19
15.4.3-3	Deleted in Revision 20
15.4.3-3A	Secondary Pressure – SGTR MTO Analysis
15.4.3-3B	Secondary Pressure – SGTR Dose Input Analysis
15.4.3A-4	Deleted in Revision 19
15.4.3-4	Deleted in Revision 20
15.4.3-4A	Intact Loop Hot and Cold Leg RCS Temperatures – SGTR MTO Analysis
15.4.3-4B	Intact Loop Hot and Cold Leg RCS Temperatures – SGTR Dose Input Analysis
15.4.3A-5	Deleted in Revision 19
15.4.3-5	Deleted in Revision 20
15.4.3-5B	Ruptured Loop Hot and Cold Leg RCS Temperatures – SGTR Dose Input Analysis
15.4.3A-6	Deleted in Revision 19
15.4.3-6	Deleted in Revision 20
15.4.3-6A	Primary to Secondary Break Flow Rate – SGTR MTO Analysis
15.4.3-6B	Primary to Secondary Break Flow Rate – SGTR Dose Input Analysis
15.4.3A-7	Deleted in Revision 19
15.4.3-7A	Ruptured SG Water Volume – SGTR Margin-to-Overfill Analysis
15.4.3-7B	Ruptured SG Water Volume – SGTR Dose Input Analysis
15.4.3A-8	Deleted in Revision 19
15.4.3-8	Deleted in Revision 20
15.4.3-8A	Ruptured Steam Generator Water Mass – SGTR MTO Analysis

FIGURES (Continued)

Figure	Title
15.4.3-8B	Ruptured Steam Generator Water Mass – SGTR Dose Input Analysis
15.4.3A-9	Deleted in Revision 19
15.4.3-9	Ruptured SG Mass Release Rate to the Atmosphere – SGTR Dose Input Analysis
15.4.3A-10	Deleted in Revision 19
15.4.3-10	Intact SGs Mass Release Rate to the Atmosphere – SGTR Dose Input Analysis
15.4.3A-11	Deleted in Revision 19
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15.4.4-1	Single Reactor Coolant Pump Locked Rotor – Maximum RCS Pressure Versus Time
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15.4.6-3	Nuclear Power Transient, EOL, HFP, Rod Ejection Accident
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15.5-1	Ratio of Short-Term Release Concentration to Continuous Release Concentration Versus Release Duration

FIGURES (Continued)

Figure	Title
15.5-2	Revision 24 September 2018
15.5-3	Revision 24 September 2018
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15.5-7	Revision 24 September 2018
15.5-8	Revision 24 September 2018
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15.5-10	Revision 24 September 2018
15.5-11	Revision 24 September 2018
15.5-12	Revision 24 September 2018
15.5-13	Deleted in Revision 7
15.5-14	Revision 24 September 2018
15.5-15	Revision 24 September 2018
15.5-16	Deleted in Revision 24
15.5-17	Deleted in Revision 16
15.5-18	Deleted in Revision 16
15.5-19	Deleted in Revision 19
15.5-20	Deleted in Revision 16
15.5-21	Deleted in Revision 16
15.5-22	Deleted in Revision 16

Chapter 15

ACCIDENT ANALYSES

Since 1970, the American Nuclear Society (ANS) classification of plant conditions has been used to divide plant conditions into four categories in accordance with anticipated frequency of occurrence and potential radiological consequences to the public. The four categories are as follows:

(1) Condition I: Normal Operation and Operational Transients (Initial Conditions)

(2) Condition II: Faults of Moderate Frequency

(3) Condition III: Infrequent Faults

(4) Condition IV: Limiting Faults

The basic principle applied in relating design requirements to each of the conditions is that the most frequent occurrences must yield little or no radiological risk to the public, and those extreme situations having the potential for the greatest risk to the public shall be those least likely to occur. Where applicable, reactor trip system and engineered safety features (ESFs) functioning is assumed, to the extent allowed by considerations such as the single failure criterion, in fulfilling this principle.

In the evaluation of the radiological consequences associated with initiation of a spectrum of accident conditions, numerous assumptions must be postulated. In many instances these assumptions are a product of extremely conservative judgments. This is due to the fact that many physical phenomena, in particular fission product transport under accident conditions, are not understood to the extent that accurate predictions can be made. Therefore, the set of assumptions postulated would predominantly determine the accident classification.

The specific accident sequences analyzed in this chapter include those required by Regulatory Guide 1.70, Revision 1, Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants, and others considered significant for the Diablo Canyon Power Plant (DCPP). Refer to Table 15.0-1 for a comparison between Table 15-1 of Regulatory Guide 1.70, Revision 1, and the corresponding section(s) where the conditions are discussed. Because the DCPP design differs from other plants, some of the representative types of events identified in Table 15-1 of Regulatory Guide 1.70, Revision 1 are not applicable to this plant. In addition, some events are analyzed or discussed in separate chapters. The location of the analysis for each event or reason the event is not applicable to DCPP is provided in Table 15.0-1.

This section describes the acceptance criteria, input assumptions, analysis techniques, equipment performance, and analysis results of the required accident analysis but does not include details on the set points, capacity or capabilities of mitigating equipment or

operational limitations that determine the initial conditions for each analysis. For details of required reactor operational limitations and of the performance capabilities of the emergency equipment not covered in Chapter 15, refer to the following chapters:

- Reactor coefficients, power distribution, reactivity controls (refer to Chapter 4)
- Reactor coolant flow (refer to Chapter 5)
- Emergency core cooling system (ECCS), Auxiliary feed water, Containment systems (refer to Chapter 6)
- Reactor trips and permissives, ESFs actuation (refer to Chapter 7)
- Boration capabilities (refer to Chapter 9)

Additionally the availability, testing and performance criteria of the operational limits and mitigating systems are administratively controlled by the plant Technical Specifications described in Chapter 16 and Appendix A of the DCPP Unit 1 and Unit 2 Operating Licenses.

15.1 CONDITION I - NORMAL OPERATION AND OPERATIONAL TRANSIENTS (INITIAL CONDITIONS)

15.1.1 INTRODUCTION

Condition I occurrences are those that are expected frequently or regularly in the course of power operation, refueling, maintenance, or maneuvering of the plant. As such, Condition I occurrences are accommodated with margin between any plant parameter and the value of that parameter which would require either automatic or manual protective action. Since Condition I occurrences occur frequently or regularly, they must be considered from the point of view of affecting the consequences of fault conditions (Conditions II, III, and IV). In this regard, analysis of each fault condition is generally based on a conservative set of initial conditions corresponding to the most adverse set of conditions that can occur during Condition I operation.

Typical Condition I events are shown below:

(1) Steady state and shutdown operations

Mode 1 - Power operation (greater than 5 percent of rated thermal power [RTP])

Mode 2 - Startup ($k_{eff} \geq 0.99$, less than or equal to 5 percent of RTP)

Mode 3 - Hot standby (k_{eff} less than 0.99, T_{avg} greater than or equal to 350°F)

Mode 4 - Hot shutdown (subcritical, residual heat removal [RHR] system in operation, k_{eff} less than 0.99, 200°F less than T_{avg} less than 350°F)

Mode 5 - Cold shutdown (subcritical, RHR system in operation, k_{eff} less than 0.99, T_{avg} less than or equal to 200°F)

Mode 6 - Refueling (k_{eff} less than or equal to 0.95, T_{avg} less than or equal to 140°F)

(2) Operation with permissible deviations

Various deviations that may occur during continued operation as permitted by the plant Technical Specifications (Reference 1) must be considered in conjunction with other operational modes. These include:

(a) Operation with components or systems out of service

(b) Leakage from fuel with cladding defects

(c) Activity in the reactor coolant

1. Fission products

2. Corrosion products

3. Tritium

(d) Operation with steam generator (SG) leaks up to the maximum allowed by the Technical Specifications

(3) Normal Operational transients

Normal design transients which do not result in a reactor trip are listed below. Refer to Section 5.2.2.1.5.1 for additional details on these transients.

(a) Plant heatup and cooldown

(b) Step load changes (up to plus or minus 10 percent between 15 percent load and full load)

(c) Ramp load changes (up to 5 percent per minute between 15 percent load and full load)

(d) Turbine load reduction up to and including a 50 percent load rejection from full power

(e) Steady state fluctuations of the reactor coolant average temperature, for purposes of design, is assumed to increase or decrease at a maximum rate of 6°F in 1 minute.

15.1.2 COMPUTER CODES UTILIZED

Summaries of some of the principal computer codes used in transient analyses are given below. Other codes, in particular, very specialized codes in which the modeling has been developed to simulate one given accident, and which consequently have a direct bearing on the analysis of the accident itself, are summarized in their respective accident analyses sections. The codes used in the analyses of each transient event are listed in Table 15.1-4.

15.1.2.1 FACTRAN

FACTRAN calculates the transient temperature distribution in a cross-section of a metalclad UO_2 fuel rod (refer to Figure 15.1-8) and the transient heat flux at the surface

of the cladding using as input the nuclear power and the time-dependent coolant parameters (pressure, flow, temperature, and density).

The code uses a fuel model that exhibits the following features simultaneously:

(1) A sufficiently large number of finite difference radial space increments to handle fast transients such as rod ejection accidents

(2) Material properties that are functions of temperature and a sophisticated fuel-to-cladding gap heat transfer calculation

(3) The necessary calculations to handle post-departure from nucleate boiling (DNB) transients: film boiling heat transfer correlations, zirconium-water (Zr-H_2O) reaction, and partial melting of the materials

The gap heat transfer coefficient is calculated according to an elastic pellet model. The thermal expansion of the pellet is calculated as the sum of the radial (one-dimensional) expansions of the rings. Each ring is assumed to expand freely. The cladding diameter is calculated based on thermal expansion and internal and external pressures.

If the outside radius of the expanded pellet is smaller than the inside radius of the expanded cladding, there is no fuel-cladding contact and the gap conductance is calculated on the basis of the thermal conductivity of the gas contained in the gap. If the pellet outside radius so calculated is larger than the cladding inside radius (negative gap), the pellet and the cladding are pictured as exerting upon each other a pressure sufficient to reduce the gap to zero by elastic deformation of both. This contact pressure determines the heat transfer coefficient.

FACTRAN is further discussed in the licensing topical report, Section 1.6.1, Item 44.

15.1.2.2 LOFTRAN

The LOFTRAN program is used for studies of transient response of a pressurized water reactor (PWR) system to specified perturbations in process parameters. LOFTRAN simulates a multiloop system by modeling the reactor core and vessel, hot and cold leg piping, SG (tube and shell-sides), pressurizer, and reactor coolant pumps (RCPs), with up to four reactor coolant loops (RCLs). The pressurizer heaters, spray, relief and safety valves are also considered in the program. Point model neutron kinetics, and reactivity effects of the moderator, fuel, boron, and rods are included. The secondary side of the SG utilizes a homogeneous, saturated mixture for the thermal transients and a water level correlation for indication and control. The reactor protection system is simulated to include reactor trips on neutron flux, overpower and overtemperature reactor coolant ΔT, high and low pressure, low flow, and high pressurizer level. Control systems are also simulated including rod control, steam dump, feedwater control, and pressurizer pressure control. The safety injection system (SIS), including the accumulators, is also modeled.

LOFTRAN is a versatile program that is suited to both accident evaluation and control studies as well as parameter sizing. LOFTRAN also has the capability of calculating the transient value of DNB based on the input from the core limits illustrated in Figure 15.1-1. The core limits represent the minimum value of departure from nucleate boiling ratio (DNBR) as calculated for a typical or thimble cell. LOFTRAN is further discussed in the licensing topical report, Section 1.6.1, Item 47.

15.1.2.3 PHOENIX- P

The PHOENIX-P computer code is a two-dimensional, multi-group, transport based lattice code and is capable of providing all necessary data for PWR analysis. Being a dimensional lattice code, PHOENIX-P does not rely on pre-determined spatial/spectral interaction assumptions for a heterogeneous fuel lattice. The PHOENIX-P computer code is approved by the U.S. Nuclear Regulatory Commission (NRC) as the lattice code for generating macroscopic and microscopic few group cross-sections for PWR analysis.

The PHOENIX-P computer code is described in more detail in Section 4.3.3.10.2 and is further discussed in the licensing topical report, Section 1.6.1, Item 60.

15.1.2.4 ANC

With the advent of VANTAGE 5 fuel and axial features such as axial blankets and part length burnable absorbers, the three dimensional nodal codes ANC (Advanced Nodal Code) has replaced the previous two group X-Y TURTLE code. The three dimensional nature of the nodal codes provides both the radial and axial power distributions, and also determines the critical boron concentrations and power distributions. The moderator coefficient is evaluated by varying the inlet temperature in the same calculations used for power distribution and reactivity predictions.

Axial calculations are used to determine differential control rod worth curves (reactivity versus rod insertion) and axial power shapes during steady state and transient xenon conditions. Group constants are obtained from three-dimensional nodal calculations homogenized by flux volume weighting.

The ANC computer code is described in more detail in Section 4.3.3.10.3 and is further discussed in the licensing topical reports, Section 1.6.1, Items 60 and 61.

15.1.2.5 TWINKLE

The TWINKLE program is a multidimensional spatial neutron kinetics code, which was patterned after steady state codes presently used for reactor core design. The code uses an implicit finite-difference method to solve the two-group transient neutron diffusion equations in one-, two-, and three-dimensions. The code uses six delayed neutron groups and contains a detailed multiregion fuel-cladding-coolant heat transfer

model for calculating pointwise Doppler and moderator feedback effects. The code handles up to 2000 spatial points and performs its own steady state initialization. Aside from basic cross-section data and thermal-hydraulic parameters, the code accepts as input basic driving functions such as inlet temperature, pressure, flow, boron concentration, control rod motion, and others. Various edits provide channelwise power, axial offset, enthalpy, volumetric surge, pointwise power, fuel temperatures, and so on.

The TWINKLE code is used to predict the kinetic behavior of a reactor for transients that cause a major perturbation in the spatial neutron flux distribution.

TWINKLE is further described in the licensing topical report, Section 1.6.1, Item 50.

15.1.2.6 THINC

The Steady state and transient analysis using the THINC code (THINC-I, THINC-III and THINC-IV) is described in Section 4.4.3. THINC is further described in the licensing topical reports, Section 1.6.1, Item 28.

15.1.2.7 RETRAN-02

The Electric Power Research Institute (EPRI) RETRAN-02 program is used to perform the best estimate thermal-hydraulic analysis of operational and accident transients for light water reactor systems. The program is constructed with a highly flexible modeling technique that provides the RETRAN-02 program the capability to model the actual performance of the plant systems and equipment.

The main features of the RETRAN-02 program are:

(1) A one-dimensional, homogeneous equilibrium mixture thermal-hydraulic model for the reactor cooling system

(2) A point neutron kinetics model for the reactor core

(3) Special auxiliary or component models (such as non-equilibrium pressurizer temperature transport delay)

(4) Control system models

(5) A consistent steady state initialization technique

The RETRAN-02 program is further discussed in Reference 21.

15.1.2.8 RETRAN-02W

The RETRAN-02W program is the Westinghouse version of the RETRAN-02 program. RETRAN-02W is used to determine plant transient response to selected accidents, as described in Sections 15.2 and 15.4.
RETRAN-02W is further described in the licensing topical report, Section 1.6.1, Item 58.

15.1.2.9 Deleted

15.1.2.10 Deleted

15.1.2.11 Deleted

15.1.2.12 Deleted

15.1.2.13 Deleted

15.1.2.14 COCO

Containment pressure is calculated using the COCO code (WCAP-8327 and WCAP-8326), Reference 9 in Section 15.4.10) as discussed in Section 15.4.1.3.2.2A and 15.4.1.3.2.2B. The COCO code is integrated into the WCOBRA/TRAC-TF2 thermal-hydraulic code as discussed in WCAP-16996-P-A, Revision 1.

15.1.3 OPTIMIZATION OF CONTROL SYSTEMS

Prior to initial startup, a setpoint study (Reference 2) was performed in order to simulate performance of the reactor control and protection systems. Emphasis was placed on the development of a control system that will automatically maintain prescribed conditions in the plant even under the most conservative set of reactivity parameters with respect to both system stability and transient performance.

For each mode of plant operation, a group of optimum controller setpoints was determined. In areas where the resultant setpoints were different, compromises based on the optimum overall performance were made and verified. A consistent set of control system parameters was derived satisfying plant operational requirements throughout the core life and for power levels between 15 and 100 percent. The study contained an analysis of the following control systems: rod cluster assembly control, steam dump, SG level, pressurizer pressure, and pressurizer level.

Since initial startup, setpoints and control system components have been maintained to optimize performance. Plant operability margin-to-trip analyses are performed on the nuclear steam supply system (NSSS) control systems for DCPP Unit 1 and Unit 2. The purpose of these analyses is to demonstrate that the margin to relevant reactor trip and engineered safety features actuation system setpoints is adequate. The NSSS control

systems setpoints and time constants are analyzed to provide stable plant response during and following the operational (Condition I) transients:
:

- 50 percent load rejection from 100 percent power
- 10 percent step-load decrease from 100 percent power
- 10 percent step-load increase from 90 percent power
- Turbine trip without reactor trip from permissive P-9 setpoint

When changes are made, the accident analyses are reviewed and revised as necessary. The impact of maintaining pressurizer level between 22% and 35% during a shutdown to mode 3 and when power is ≤20%, has been evaluated as acceptable since it was determined that there is no adverse impact on any accident analyses (Reference 31). The impact of maintaining pressurizer level greater than or equal to 22 percent and less than or equal to 90 percent in Modes 3, 4, and 5 has been evaluated as acceptable because there is no adverse impact on any accident analyses (References 28 and 29).

The analysis for the 50 percent load reduction (References 33 and 35) shows that the DCPP control system is capable of controlling the SG water level so that a reactor trip on SG low-low level or turbine trip / feedwater isolation on SG high-high level does not occur. Specific analysis results show that the SG level is maintained within +/-20 percent of the nominal setpoint and all control system responses are smooth and have no sustained oscillations or divergence. To ensure that a load reduction transient presents no hazard to the integrity of the RCS or the main steam system (MSS), the Condition II analysis presented in Section 15.2.7 continues to assume a total loss of external electrical load without an immediate reactor trip.

15.1.4 INITIAL POWER CONDITIONS ASSUMED IN ACCIDENT ANALYSES

Reactor power-related initial conditions assumed in the accident analyses presented in this chapter are described in this section.

15.1.4.1 Power Rating

Table 15.1-1 lists the principal power rating values that are assumed in analyses performed in this section. Two ratings are given:

(1) The RTP output. The RTP is the total reactor core heat transfer rate to the reactor coolant of 3411 MWt for each unit.

(2) The NSSS thermal power output. This power output includes the RTP plus the thermal power generated by the RCPs.

(3) The ESFs design rating. The Westinghouse-supplied ESFs are designed for a thermal power higher than the NSSS value in order not to preclude

realization of future potential power capability. This higher thermal power value is designated as the ESF design rating.

Where initial power operating conditions are assumed in accident analyses, the NSSS or core RTP output (plus allowance for errors in steady state power determination for some accidents) is assumed. Where demonstration of the adequacy of the ESF is concerned, the ESF design rating plus allowance for error is assumed. The thermal power values for each transient analyzed are given in Table 15.1-4.

15.1.4.2 Initial Conditions

For most accidents, which are DNB limited, nominal values of initial conditions are assumed. The allowances on power, temperature, and pressure are determined on a statistical basis and are included in the limit DNBR, as described in Reference 3. This procedure is known as the "Improved Thermal Design Procedure" (ITDP) and these accidents utilize the WRB-1 and WRB-2 DNB correlations (References 4 and 5). ITDP allowances may be more restrictive than non-ITDP allowances. The initial conditions for other key parameters are selected in such a manner to maximize the impact on DNBR. Minimum measured flow is used in all ITDP transients. The allowances on power, temperature, pressure, and flow that were evaluated for their effect on the ITDP analyses for a 24-month fuel cycle are reported in Reference 22. These allowances are conservatively applicable for shorter fuel cycle lengths.

For accident evaluations that are not DNB limited, or for which the ITDP is not employed, the initial conditions are obtained by adding maximum steady state errors to rated values. The following steady state errors are considered:

(1)	Core power	Plus or minus 2 percent allowance calorimetric error
(2)	Average RCS	Plus or minus 4.7°F allowance for deadband and measurement error temperature
(3)	Pressurizer pressure	Plus or minus 38 psi or plus or minus 60 psi allowance for steady state fluctuations and measurement error (refer to Note)

Note: Pressurizer pressure uncertainty is plus or minus 38 psi in analyses performed prior to 1993; however, NSAL 92-005 (Reference 17) indicates plus or minus 60 psi is a conservative value for future analyses. Reference 18 evaluates the acceptability of existing analyses, which use plus or minus 38 psi.

For some accident evaluations, an additional allowance has been conservatively added to the measurement error for the average RCS temperatures to account for SG fouling.

DCPP Unit 1 and Unit 2 are expected to operate at a RCS vessel average temperature (Tavg) over a range from 565 ºF to 577.3/577.6 ºF (Unit 1/Unit 2).

15.1.4.3 Power Distribution

The transient response of the reactor system is dependent on the initial power distribution. The nuclear design of the reactor core minimizes adverse power distribution through the placement of fuel assemblies, control rods, and by operation instructions. The power distribution may be characterized by the radial peaking factor $F_{\Delta H}$ and the total peaking factor F_q. The peaking factor limits are given in the Technical Specifications.

For transients that may be DNB limited, the radial peaking factor is of importance. The radial peaking factor increases with decreasing power level due to rod insertion. This increase in $F_{\Delta H}$ is included in the core limits illustrated in Figure 15.1-1. All transients that may be DNB limited are assumed to begin with a $F_{\Delta H}$ consistent with the initial power level defined in the Technical Specifications.

The axial power shape used in the DNB calculation is discussed in Section 4.4.3.13.

For transients that may be overpower-limited, the total peaking factor F_q is of importance. The value of F_q may increase with decreasing power level so that the full power hot spot heat flux is not exceeded; i.e., F_q x Power = design hot spot heat flux. All transients that may be overpower-limited are assumed to begin with a value of F_q consistent with the initial power level as defined in the Technical Specifications.

The value of peak kW/ft can be directly related to fuel temperature as illustrated in Figures 4.4-1 and 4.4-2. For transients that are slow with respect to the fuel rod thermal time constant (approximately 5 seconds), the fuel temperatures are illustrated in Figures 4.4-1 and 4.4-2. For transients that are fast with respect to the fuel rod thermal time constant, (for example, rod ejection), a detailed heat transfer calculation is made.

15.1.5 TRIP POINTS AND TIME DELAYS TO TRIP ASSUMED IN ACCIDENT ANALYSES

A reactor trip signal acts to open two trip breakers connected in series feeding power to the control rod drive mechanisms (CRDMs). The loss of power to the mechanism coils causes the mechanism to release the rod cluster control assemblies (RCCAs), which then fall by gravity into the core. There are various instrumentation delays associated with each trip function, including delays in signal actuation, in opening the trip breakers, and in the release of the rods by the mechanisms. The total delay to trip is defined as the time delay from the time that trip conditions are reached to the time the rods are free and begin to fall. Limiting trip setpoints assumed in accident analyses and the time delay assumed for each trip function are given in Table 15.1-2. Reference is made in that table to the overtemperature and overpower ΔT trip shown in Figure 15.1-1. This figure presents the allowable RCL average temperature and ΔT for the design flow and the NSSS Design Thermal Power distribution as a function of primary coolant pressure. The boundaries of operation defined by the Overpower ΔT trip and the Overtemperature ΔT trip are represented as "protection lines" on this diagram. The protection lines are drawn to include all adverse instrumentation and setpoint errors so that under nominal conditions a trip would occur well within the area bounded by these lines. The utility of this diagram is in the fact that the limit imposed by any given DNBR can be represented as a line. The DNB lines represent the locus of conditions for which the DNBR equals the safety analysis limit values (1.68 and 1.71 for V-5 thimble cell and typical cells, respectively) for analyses using the ITDP. All points below and to the left of a DNB line for a given pressure have a DNBR greater than the limit values. The diagram shows that DNB is prevented for all cases if the area enclosed with the maximum protection lines is not traversed by the applicable DNBR line at any point.

The current fuel cycles for the DCPP Unit 1 and Unit 2 only use the Vantage 5 (V-5) fuel assembly type. However, the safety analyses performed in support of the transition to Vantage-5 fuel also considered the presence of the Standard type fuel assemblies. The DNBR values and transient results presented in the UFSAR continue to reflect the Standard limits, since they are limiting with respect to DNB margin in comparison to the Vantage-5 limits. Analyses performed subsequent to the transition to a full Vantage-5 core reflect only the Vantage-5 limits as described in Sections 15.2, 15.3, and 15.5. The area of permissible operation (power, pressure and temperature) is bounded by the combination of reactor trips: high pressurizer pressure (fixed setpoint); low pressurizer pressure (fixed setpoint); overpower and overtemperature ΔT (variable setpoints); and by a line defining conditions at which the SG safety valves open.

The limit values, which were used as the DNBR limits for all accidents analyzed with the ITDP are conservative compared to the actual design DNBR values required to meet the DNB design basis.

The difference between the limiting trip point assumed for the analysis and the normal trip point represents an allowance for instrumentation channel error and setpoint error.

During startup tests, it is demonstrated that actual instrument errors and time delays are equal to or less than the assumed values.

Accident analyses that assume the SG low-low water level to initiate protection functions may be affected by the trip time delay (Reference 19) that was developed to reduce the incidence of unnecessary feedwater related reactor trips.

Refer to Section 7.2.2.1.5 for a discussion about the low-low SG water level trip, including the trip time delay.

15.1.6 CALORIMETRIC ERRORS - POWER RANGE NEUTRON FLUX

The calorimetric error is the error assumed in the determination of core thermal power as obtained from secondary plant measurements. The total ion chamber current (sum of the top and bottom sections) is calibrated (set equal) to this measured power on a periodic basis. The secondary power is obtained from measurement of feedwater flow, feedwater inlet temperature to the SGs, and steam pressure. High-accuracy instrumentation is provided for these measurements with accuracy tolerances much tighter than those that would be required to control feedwater flow.

15.1.7 ROD CLUSTER CONTROL ASSEMBLY INSERTION CHARACTERISTICS

The negative reactivity insertion following a reactor trip is a function of the acceleration of the RCCA and the variation in rod worth as a function of rod position.

With respect to accident analyses, the critical parameter is the time of insertion up to the dashpot entry or approximately 85 percent of the rod cluster travel. For accident analyses, the insertion time to dashpot entry is conservatively taken as 2.7 seconds. The RCCA position versus time assumed in accident analyses is shown in Figure 15.1-2.

Figure 15.1-3 shows the fraction of total negative reactivity insertion for a core where the axial distribution is skewed to the lower region of the core. This curve is used as input to all point kinetics core models used in transient analyses.

There is inherent conservatism in the use of this curve in that it is based on a skewed axial power distribution that would exist relatively infrequently. For cases other than those associated with xenon oscillations, significant negative reactivity would have been inserted due to the more favorable axial power distribution existing prior to trip.

The normalized RCCA negative reactivity insertion versus time is shown in Figure 15.1-4. The curve shown in this figure was obtained from Figures 15.1-2 and 15.1-3. A total negative reactivity insertion following a trip of 4 percent Δk is assumed in the transient analyses except where specifically noted otherwise. This assumption is conservative with respect to the calculated trip reactivity worth available as shown in Tables 4.3-2 and 4.3-3.

The normalized RCCA negative reactivity insertion versus time after trip curve for an axial power distribution skewed to the bottom (refer to Figure 15.1-4) is used in transient analyses.

Where special analyses require the use of three-dimensional or axial one-dimensional core models, the negative reactivity insertion resulting from reactor trip is calculated directly by the reactor kinetic code and is not separable from other reactivity feedback effects. In this case, the RCCA position versus time of Figure 15.1-2 is used as code input.

15.1.8 REACTIVITY COEFFICIENTS

The transient response of the RCS is dependent on reactivity feedback effects, in particular the moderator temperature coefficient and the Doppler power coefficient. These reactivity coefficients and their values are discussed in detail in Chapter 4.

In the analysis of certain events, conservatism requires the use of large reactivity coefficient values, whereas in the analysis of other events, conservatism requires the use of small reactivity coefficient values. Some analyses, such as loss of reactor coolant from cracks or ruptures in the RCS, do not depend on reactivity feedback effects. The values used are given in Table 15.1-4; reference is made in that table to Figure 15.1-5 that shows the upper and lower Doppler power coefficients, as a function of power, used in the transient analysis. The justification for use of conservatively large versus small reactivity coefficient values is discussed on an event-by-event basis.

15.1.9 FISSION PRODUCT INVENTORIES

The fission product inventories existing in the core and fuel rod gaps are described in Section 15.5.3. The description of the models used for calculating fuel gap activities is included in Section 15.5.3.

15.1.10 RESIDUAL DECAY HEAT

Residual heat in a subcritical core consists of:

(1) Fission product decay energy

(2) Decay of neutron capture products

(3) Residual fissions due to the effect of delayed neutrons

These constituents are discussed separately in the following paragraphs.

15.1.10.1 Fission Product Decay

The decay heat curve used for the LOCA analyses is based on the 1979 ANS decay heat standard as described in Section 9 of Reference 32. This curve with the 20 percent factor included is shown in Figure 15.1-6.The 1979 ANS decay heat curve (Reference 11) is used for the non-LOCA analyses. Figure 15.1-7 presents this curve as a function of time after shutdown for non-LOCA analyses.

15.1.10.2 Decay of U-238 Capture Products

Betas and gammas from the decay of U-239 (23.5-minute half-life) and Np-239 (2.35-day half-life) contribute significantly to the heat generation after shutdown. The cross-sections for production of these isotopes and their decay schemes are relatively well known. For long irradiation times their contribution can be written as:

$$P_1/P_0 = \frac{(E_{\gamma 1} + E_{\beta 1})\, c\,(1+\alpha)}{200\,\text{MeV}}\, e^{-\lambda_1 t} \text{ watts/watt} \qquad (15.1\text{-}1)$$

$$P_2/P_0 = \frac{(E_{\gamma 2} + E_{\beta 2})\, c\,(1+\alpha)}{200\,\text{MeV}} \left[\frac{\lambda_2}{\lambda_1 - \lambda_2} \left(e^{-\lambda_2 t} - e^{-\lambda_1 t}\right) + e^{-\lambda_2 t} \right] \text{ watts/watt} \qquad (15.1\text{-}2)$$

where:

P_1/P_0 is the energy from U-239 decay
P_2/P_0 is the energy from Np-239 decay
t is the time after shutdown (seconds)
$c(1+\alpha)$ is the ratio of U-238 captures to total fissions = 0.6 (1 + 0.2)
λ_1 = the decay constant of U-239 = 4.91×10^{-4} per second
λ_2 = the decay constant of Np-239 decay = 3.41×10^{-6} per second
$E_{\gamma 1}$ = total γ-ray energy from U-239 decay = 0.06 MeV
$E_{\gamma 2}$ = total γ-ray energy from Np-239 decay = 0.30 MeV
$E_{\beta 1}$ = total β-ray energy from U-239 decay = 1/3[a] x 1.18 MeV
$E_{\beta 2}$ = total β-ray energy from Np-239 decay = 1/3[a] x 0.43 MeV

[a] Two-thirds of the potential β-energy is assumed to escape by the accompanying neutrinos.

For the LOCA analyses, the heat from the radioactive decay of U-239 and Np-239 is calculated as described in Section 9 of Reference 32. The decay of other actinides is neglected, as justified in Section 9.9.1 of Reference 32. The effect of neutron capture in fission products is included, as discussed in Reference 11. For the non-LOCA analysis, the decay of U-238 capture products is included as an integral part of the 1979 decay heat curve presented as Figure 15.1-7.

15.1.10.3 Residual Fissions

The time dependence of residual fission power after shutdown depends on core properties throughout a transient under consideration. Core average conditions are more conservative for the calculation of reactivity and power level than actual local conditions as they would exist in hot areas of the core. Thus, unless otherwise stated in the text, static power shapes have been assumed in the analysis and these are factored by the time behavior of core average fission power calculated by a point kinetics model calculation with six delayed neutron groups.

For the LOCA analyses, the residual fission energy is calculated as described in Section 9 of Reference 32.

15.1.10.4 Distribution of Decay Heat Following Loss-of-Coolant Accident

For the LOCA analyses, the energy deposition modeling is performed as described in Section 9 of Reference 32.

15.1.11 REFERENCES

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15.2 CONDITION II - FAULTS OF MODERATE FREQUENCY

These faults result at worst in the reactor shutdown with the plant capable of returning to operation. By definition, these faults (or events) do not propagate to cause a more serious fault; i.e., a Condition III or IV fault. In addition, Condition II events are not expected to result in fuel rod failures, RCS overpressurization, or MSS overpressurization. For the purposes of this report the following faults have been grouped into these categories:

(1) Uncontrolled RCCA bank withdrawal from a subcritical condition

(2) Uncontrolled RCCA bank withdrawal at power

(3) RCCA misoperation

(4) Uncontrolled boron dilution

(5) Partial loss of forced reactor coolant flow

(6) *Startup of an inactive RCL* (Historical)

(7) Loss of external electrical load and/or turbine trip

(8) Loss of normal feedwater

(9) Loss of offsite power (LOOP) to the station auxiliaries

(10) Excessive heat removal due to feedwater system malfunctions

(11) Sudden feedwater temperature reduction

(12) Excessive load increase incident

(13) Accidental depressurization of the RCS

(14) Accidental depressurization of the MSS

(15) Spurious operation of the SIS at power

Each of these faults of moderate frequency are analyzed in this section. In general, each analysis includes acceptance criteria, an identification of causes and description of the accident, an analysis of effects and consequences, a presentation of results, and relevant conclusions.

An evaluation of the reliability of the reactor protection system actuation following initiation of Condition II events has been completed and is presented in Reference 1 for

the relay protection logic. Standard reliability engineering techniques were used to assess the likelihood of the trip failure due to random component failures. Common-mode failures were also qualitatively investigated. It was concluded from the evaluation that the likelihood of no trip following the initiation of Condition II events is extremely small (2×10^{-7} derived for random component failures). The solid-state protection system design has been evaluated by the same methods as used for the relay system and the same order of magnitude of reliability is provided.

Hence, because of the high reliability of the protection system, no special provision is included in the design to cope with the consequences of Condition II events without trip.

The time sequence of events corresponding to the respective Condition II fault is shown in Table 15.2-1.

15.2.1 UNCONTROLLED ROD CLUSTER CONTROL ASSEMBLY BANK WITHDRAWAL FROM A SUBCRITICAL CONDITION

15.2.1.1 Acceptance Criteria

The following is the relevant specific acceptance criterion.

(1) Minimum DNBR is not less than the appropriate limit value at any time during the transient.

15.2.1.2 Identification of Causes and Accident Description

A RCCA withdrawal accident is defined as an uncontrolled increase in reactivity in the reactor core caused by withdrawal of RCCAs resulting in a power excursion. Such a transient could be caused by a malfunction of the reactor control or control rod drive systems. The Section 15.2.1 event occurs with the reactor at hot zero power (i.e., subcritical). The at-power case is discussed in Section 15.2.2.

Although the reactor can be brought to power from a subcritical condition by means of RCCA withdrawal, startup procedures following refueling also permit boron dilution. The maximum rate of reactivity increase in the case of boron dilution is less than that assumed in this analysis (refer to Section 15.2.4).

The RCCA drive mechanisms are wired into preselected bank configurations that are not altered during core reactor life. These circuits prevent the assemblies from being withdrawn in other than their respective banks. Power supplied to the banks is controlled so that no more than two banks can be withdrawn at the same time. The RCCA drive mechanisms are of the magnetic latch type and coil actuation is sequenced to provide variable speed travel. The maximum reactivity insertion rate analyzed in the detailed plant analysis is that occurring with the simultaneous withdrawal of the two control banks having the maximum combined worth at maximum speed.

The neutron flux response to a continuous reactivity insertion is characterized by a very fast rise terminated by the reactivity feedback effect of the negative Doppler coefficient. This self-limitation of the power burst is of primary importance since it limits the power to a tolerable level during the delay time for protective action. Should a continuous RCCA withdrawal accident occur, the transient will be terminated by the following automatic features of the reactor protection system.

15.2.1.2.1 Source Range High Neutron Flux Reactor Trip

The source range high neutron flux reactor trip is actuated when either of two independent source range channels indicates a neutron flux level above a preselected manually adjustable setpoint. This trip function may be manually bypassed when either intermediate range flux channel indicates a flux level above a specified level. It is automatically reinstated when both intermediate range channels indicate a flux level below a specified level.

15.2.1.2.2 Intermediate Range High Neutron Flux Reactor Trip

The intermediate range high neutron flux reactor trip is actuated when either of two independent intermediate range channels indicates a flux level above a preselected manually adjustable setpoint. This trip function may be manually bypassed when two of the four power range channels give readings above approximately 10 percent of full power and is automatically reinstated when three of the four channels indicate a power below this value.

15.2.1.2.3 Power Range High Neutron Flux Reactor Trip (Low Setting)

The power range high neutron flux trip (low setting) is actuated when two-out-of-four power range channels indicate a power level above approximately 25 percent of full power. This trip function may be manually bypassed when two of the four power range channels indicate a power level above approximately 10 percent of full power and is automatically reinstated when three of the four channels indicate a power level below 10 percent.

15.2.1.2.4 Power Range High Neutron Flux Reactor Trip (High Setting)

The power range high neutron flux reactor trip (high setting) is actuated when two-out-of-four power range channels indicate a power level above a preset setpoint. This trip function is always active.

15.2.1.2.5 Power Range High Positive Neutron Flux Rate Trip

The power range high positive neutron flux rate trip is actuated when the rate of change in power on two-out-of-four power range channels exceeds the preset setpoint. This trip function is always active.

15.2.1.3 Analysis of Effects and Consequences

This transient is analyzed by three digital computer codes. The TWINKLE (Reference 2) code is used to calculate the reactivity transient and hence the nuclear power transient. The FACTRAN (Reference 3) code is then used to calculate the thermal heat flux transient based on the nuclear power transient calculated by the TWINKLE code. FACTRAN also calculates the fuel, cladding, and coolant temperatures. A detailed thermal and hydraulic computer code, THINC (refer to Section 1.6.1, Item 28 and Section 4.4.3) (Reference 9) is used to calculate the DNB.

The event is not analyzed with the ITDP since it is analyzed with reduced flow.

In order to give conservative results for a startup accident, the following assumptions are made concerning the initial reactor conditions:

(1) Since the magnitude of the power peak reached during the initial part of the transient for any given rate of reactivity insertion is strongly dependent on the Doppler coefficient, conservative values (low absolute magnitude) as a function of power are used (refer to Section 15.1.8 and Table 15.1-4).

(2) Contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because the heat transfer time between the fuel and the moderator is much longer than the neutron flux response time. However, after the initial neutron flux peak, the succeeding rate of power increase is affected by the moderator reactivity coefficient. The conservative value, given in Table 15.1-4, is used in the analysis to yield the maximum peak heat flux.

(3) The reactor is assumed to be at hot zero power. This assumption is more conservative than that of a lower initial system temperature. The higher initial system temperature yields a larger fuel-water heat transfer coefficient, larger specific heats, and a less negative (smaller absolute magnitude) Doppler coefficient, all of which tend to reduce the Doppler feedback effect thereby increasing the neutron flux peak. The initial effective multiplication factor is assumed to be 1 since this results in maximum neutron flux peaking.

(4) Reactor trip is assumed to be initiated by power range high neutron flux (low setting). The most adverse combination of instrument and setpoint errors, as well as delays for trip signal actuation and RCCA release, is taken into account. A 10 percent increase is assumed for the power range flux trip setpoint, raising it from the nominal value of 25 to 35 percent. Previous results, however, show that the rise in neutron flux is so rapid that the effect of error on this trip setpoint on the actual time at which the rods are released is negligible. In addition, the reactor trip insertion

characteristic is based on the assumption that the highest worth RCCA is stuck in its fully withdrawn position. Refer to Section 15.1.7 for RCCA insertion characteristics.

(5) The maximum positive reactivity insertion rate assumed is greater than that for the simultaneous withdrawal of the combination of the two control banks having the greatest combined worth at maximum speed (45 inches/minute). CRDM design is discussed in Section 4.2.3.

(6) The initial power level is assumed to be below the power level expected for any shutdown condition. The combination of highest reactivity insertion rate and lowest initial power produces the highest peak heat flux.

15.2.1.4 Results

Figures 15.2.1-1 through 15.2.1-3 show the transient behavior for the indicated reactivity insertion rate with the accident terminated by reactor trip at 35 percent nominal power. This insertion rate is greater than that for the two highest worth control banks, both assumed to be in their highest incremental worth region.

Figure 15.2.1-1 shows the neutron flux transient. The neutron flux overshoots the full power nominal value but this occurs for only a very short time period. Hence, the energy release and the fuel temperature increase are relatively small. The thermal flux response, of interest for DNB considerations, is shown in Figure 15.2.1-2. The beneficial effect on the inherent thermal lag in the fuel is evidenced by a peak heat flux less than the full power nominal value. The DNBR remains above the applicable safety analysis limit value at all times.

Figure 15.2.1-3 shows the response of the average fuel, cladding, and coolant temperatures at the hot spot.

15.2.1.5 Conclusions

The analysis demonstrates that the acceptance criterion is met as follows:

(1) Minimum DNBR remains above the appropriate limit value at any time during the transient.

In the event of an RCCA withdrawal accident from the subcritical condition, the core and the RCS are not adversely affected since the combination of thermal power and the coolant temperature result in a DNBR above the limiting value.

15.2.2 UNCONTROLLED ROD CLUSTER CONTROL ASSEMBLY BANK WITHDRAWAL AT POWER

15.2.2.1 Acceptance Criteria

The following are the relevant specific acceptance criteria.

(1) The minimum DNBR must not go below the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) (refer to Section 4.4.4.1) at any time during the transient.

(2) The peak core average power (heat flux) does not exceed a value that would cause fuel centerline melt at any time during the transient (refer to Section 4.4.3.2.7).

(3) The RCS pressure does not exceed 110% of design pressure (2,750 psia) at any time during the transient.

(4) The pressurizer does not go water solid at any time during the transient.

15.2.2.2 Identification of Causes and Accident Description

Uncontrolled RCCA bank withdrawal at power results in an increase in the core heat flux. Since the heat extraction from the SG lags behind the core power generation until the SG pressure reaches the relief or safety valve setpoint, there is a net increase in the reactor coolant temperature. Unless terminated by manual or automatic action, the power mismatch and resultant coolant temperature rise would eventually result in DNB, an RCS overpressure condition, or the pressurizer filled with liquid. Therefore, the reactor protection system is designed to terminate any such transient before the DNBR falls below the safety analysis limit values, the RCS pressure exceeds 110 percent of the design value, or the pressurizer becomes filled with liquid.

The automatic features of the reactor protection system that ensure these limits are not exceeded following the postulated accident include the following:

(1) The power range neutron flux instrumentation actuates a reactor trip if two-out-of-four channels exceed a high flux or a positive flux rate high setpoint.

(2) The reactor trip is actuated if any two-out-of-four ΔT channels exceed an overtemperature ΔT setpoint.

(3) The reactor trip is actuated if any two-out-of-four ΔT channels exceed an overpower ΔT setpoint.

(4) A high pressurizer pressure reactor trip actuated from any two-out-of-four pressure channels that are set at a fixed point.

(5) A high pressurizer water level reactor trip actuated from any two-out-of-three level channels that are set at a fixed point.

The positive flux rate trip provides adequate protection to ensure that the most limiting RCCA bank withdrawal event does not result in the peak RCS pressure exceeding 110 percent of the design limit. The positive flux rate trip setpoint and response time that are credited in the evaluation of this event are listed in Table 15.1-2. Various reactor trips (e.g., High Neutron Flux) may also be credited to prevent RCS overpressurization during an RCCA bank withdrawal event.

Reference 18 documents a generic and conservatively bounding evaluation that has been performed to ensure that pressurizer overfill conditions are not a concern for this event. The evaluation demonstrates that the pressurizer water level high trip prevents a pressurizer overfill condition for those RCCA bank withdrawal events that are very slow and do not generate any other automatic protection signal. The pressurizer water level high trip response time is listed as N/A with the note indicating that the evaluation results are insensitive to the assumed response time.

The manner in which the combination of overpower and overtemperature ΔT trips provide fuel cladding protection over the full range of RCS conditions is described in Chapter 7 and Section 15.1.5.

15.2.2.3 Analysis of Effects and Consequences

This transient is analyzed by the LOFTRAN (Reference 4) code. This code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, SG, and SG safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level. The core limits as illustrated in Figure 15.1-1 are used as input to LOFTRAN to determine the minimum DNBR during the transient.

This accident is analyzed with the ITDP and the initial condition uncertainties are included in the limit DNBR as described in Reference 5. Therefore, initial conditions of nominal core power, nominal reactor coolant average temperatures (including 2.5°F for SG fouling) and nominal reactor coolant pressure are assumed.

In order to obtain conservative results, the following assumptions are made:

(1) Reactivity Coefficients - two cases are analyzed:

(a) Minimum reactivity feedback. A positive moderator coefficient of reactivity of +5 pcm/°F is assumed. A variable Doppler power

coefficient with core power is used in the analysis. A conservatively small (in absolute magnitude) value is assumed.

(b) Maximum reactivity feedback. A conservatively large positive moderator density coefficient of 0.43 Δk/gm/cc is assumed. A large (in absolute magnitude) negative Doppler power coefficient is assumed.

(2) The reactor trip on high neutron flux is assumed to be actuated at a conservative value of 118 percent of nominal full power. The ΔT trips include all adverse instrumentation and setpoint errors, while the delays for the trip signal actuation are assumed at their maximum values.

(3) The RCCA trip insertion characteristic is based on the assumption that the highest worth assembly is stuck in its fully withdrawn position.

(4) The maximum positive reactivity insertion rate is greater than that which would be obtained from the simultaneous withdrawal of the two control rod banks having the maximum combined worth at maximum speed.

The effect of RCCA movement on the axial core power distribution is accounted for by causing a decrease in overtemperature ΔT trip setpoint proportional to a decrease in margin to DNB.

15.2.2.4 Results

Figures 15.2.2-1 and 15.2.2-2 show the response of neutron flux, pressure, average coolant temperature, and DNBR (thimble cell) due to a rapid RCCA withdrawal starting from full power. Reactor trip on high neutron flux occurs shortly after the start of the accident. Since this is rapid with respect to the thermal time constants of the plant, small changes in T_{avg} and pressure result and a large margin to DNB is maintained.

The response of neutron flux, pressure, average coolant temperature, and DNBR (thimble cell) for a slow control rod assembly withdrawal from full power is shown in Figures 15.2.2-3 and 15.2.2-4. Reactor trip on overtemperature ΔT occurs after a longer period and the rise in temperature and pressure is consequently larger than for rapid RCCA withdrawal. Again, the minimum DNBR is never less than the safety analysis limit values.

Figure 15.2.2-5 shows the minimum DNBR (thimble cell) as a function of reactivity insertion rate from initial full power operation for the minimum and for the maximum reactivity feedbacks. It can be seen that two reactor trip channels provide protection over the whole range of reactivity insertion rates. These are the high neutron flux and overtemperature ΔT trip channels. The minimum DNBR is never less than the safety analysis limit values.

Figures 15.2.2-6 and 15.2.2-7 show the minimum DNBR (thimble cell) as a function of reactivity insertion rate for RCCA withdrawal incidents starting at 60 and 10 percent power, respectively. The results are similar to the 100 percent power case, except that as the initial power is decreased, the range over which the overtemperature ΔT trip is effective is increased. In neither case does the DNBR fall below the safety analysis limit values.

The shape of the curves of minimum DNB ratio versus reactivity insertion rate in the reference figures is due both to reactor core and coolant system transient response and to protection system action in initiating a reactor trip. Referring to Figure 15.2.2-7, for example, it is noted that:

(1) For reactivity insertion rates above ~30 pcm/sec reactor trip is initiated by the high neutron flux trip for the minimum reactivity feedback cases. The neutron flux level in the core rises rapidly for these insertion rates while core heat flux and coolant system temperature lag behind due to the thermal capacity of the fuel and coolant system fluid. Thus, the reactor is tripped prior to significant increase in heat flux or water temperature with resultant high minimum DNB ratios during the transient. As reactivity insertion rate decreases, core heat flux and coolant temperatures can remain more nearly in equilibrium with the neutron flux. Minimum DNBR during the transient thus decreases with decreasing insertion rate.

(2) The Overtemperature ΔT reactor trip circuit initiates a reactor trip when measured coolant loop ΔT exceeds a setpoint based on measured RCS average temperature and pressure. It is important to note that the average temperature contribution to the circuit is lead-lag compensated in order to decrease the effect of the thermal capacity of the RCS in response to power increase.

(3) For reactivity insertion rate below ~30 pcm/sec the Overtemperature ΔT trip terminates the transient.

For reactivity insertion rates between ~30 pcm/sec and ~7 pcm/sec the effectiveness of the Overtemperature ΔT trip increases (in terms of increased minimum DNBR) due to the fact that with lower insertion rates the power increase rate is slower, the rate of rise of average coolant temperature is slower and the system lags and delays become less significant.

(4) For reactivity insertion rates less than ~7 pcm/sec, the rise in the reactor coolant temperature is sufficiently high so that the SG safety valve setpoint is reached prior to trip. Opening of these valves, which act as an additional heat load on the RCS, sharply decreases the rate of increase of RCS average temperature. This decrease in rate of increase of the average RCS temperature during the transient is accentuated by the lead-

lag compensation causing the Overtemperature ΔT trip setpoint to be reached later with a resulting lower minimum DNBR.

Figures 15.2.2-5 through 15.2.2-7 illustrate minimum DNBRs calculated for minimum and maximum reactivity feedback.

Since the RCCA withdrawal at power incident is an overpower transient, the fuel temperatures rise during the transient until after reactor trip occurs. For high reactivity insertion rates, the overpower transient is fast with respect to the fuel rod thermal time constant, and the core heat flux lags behind the neutron flux response. Due to this lag, the peak core heat flux does not exceed 118 percent of its nominal value (i.e., the high neutron flux trip setpoint assumed in the analysis). Taking into account the effect of the RCCA withdrawal on the axial core power distribution, the peak fuel centerline temperature will still remain below the fuel melting temperature.

For slow reactivity insertion rates, the core heat flux remains more nearly in equilibrium with the neutron flux. The overpower transient is terminated by the Overtemperature ΔT reactor trip before a DNB condition is reached. The peak heat flux again is maintained below 118 percent of its nominal value. Taking into account the effect of the RCCA withdrawal on the axial core power distribution, the peak fuel centerline temperature will remain below the fuel melting temperature.

Since DNB is not predicted to occur at any time during the RCCA withdrawal at power transient, the ability of the primary coolant to remove heat from the fuel rod is not reduced. Thus, the fuel cladding temperature does not rise significantly above its initial value during the transient.

The calculated sequence of events for this accident is shown in Table 15.2-1. With the reactor tripped, the plant eventually returns to a stable condition. The plant may subsequently be cooled down further by following normal plant shutdown procedures.

15.2.2.5 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) There is margin to the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell). The accompanying DNBR figures for this event (refer to Figures 15.2.2-2 and 15.2.2-4 through 15.2.2-7) reflect the results for the more limiting Standard fuel (limit 1.48/1.44) previously in the core.

(2) The core heat flux is maintained below 118 percent of its nominal value. Thus the peak fuel centerline temperature will remain below the fuel melting temperature (refer to Section 4.4.3.2.7).

(3) The RCS pressure does not exceed 110 percent of design pressure (2,750 psia) at any time during the transient.

(4) The pressurizer does not become water solid during the event.

The high neutron flux and overtemperature ΔT trip channels provide adequate protection over the entire range of possible reactivity insertion rates; i.e., the minimum value of DNBR is always larger than the safety analysis limit values.

15.2.3 ROD CLUSTER CONTROL ASSEMBLY MISOPERATION

This section discusses RCCA misoperation that can result either from system malfunction or operator error.

15.2.3.1 Acceptance Criteria

The following is the relevant specific acceptance criterion.

(1) The minimum DNBR must not go below the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) (refer to Section 4.4.4.1) at any time during the transient.

15.2.3.2 Identification of Causes and Accident Description

RCCA misoperation accidents include:

(1) One or more dropped RCCAs within the same group

(2) A dropped RCCA bank

(3) Statically misaligned RCCA

Each RCCA has a position indicator channel that displays the position of the assembly. The displays of assembly positions are grouped for the operator's convenience. Fully inserted assemblies are further indicated by a rod at bottom signal, which actuates a local alarm and a control room annunciator. Group demand position is also indicated.

RCCAs are always moved in preselected banks, and the banks are always moved in the same preselected sequence. Each bank of RCCAs is divided into two groups. The rods comprising a group operate in parallel through multiplexing thyristors. The two groups in a bank move sequentially such that the first group is always within one step of the second group in the bank. A definite schedule of actuation (or deactuation of the stationary gripper, movable gripper, and lift coils of a mechanism) is required to withdraw the RCCA attached to the mechanism. Since the stationary gripper, movable gripper, and lift coils associated with the four RCCAs of a rod group are driven in parallel, any single failure that would cause rod withdrawal would affect a minimum of one group. Mechanical failures are in the direction of insertion, or immobility.

A dropped RCCA, or RCCA bank, is detected by:

(1) A sudden drop in the core power level as seen by the nuclear instrumentation system (NIS)

(2) Asymmetric power distribution as seen on out-of-core neutron detectors or core-exit thermocouples

(3) Rod at bottom signal

(4) Rod deviation alarm

(5) Rod position indication

Misaligned RCCAs are detected by:

(1) Asymmetric power distribution as seen on out-of-core neutron detectors or core-exit thermocouples

(2) Rod deviation alarm

(3) Rod position indicators

The deviation alarm alerts the operator whenever an individual rod position signal deviates from the other rods in the bank by a preset limit.

During time intervals when the Rod Position Deviation Monitor is inoperable:

(1) Each rod position indicator is determined to be operable by verifying that the demand position indication system and the digital rod position indication system agree within 12 steps at least once per four hours.

During time intervals when the rod insertion limit monitor is inoperable, the individual rod positions are verified to be within insertion limits at least once per four hours.

If one or more rod position indicator channels should be out of service, detailed operating instructions are followed to ensure the alignment of the nonindicated RCCAs. The operator is also required to take action as required by the Technical Specifications.

15.2.3.3 Analysis of Effects and Consequences

The accident is analyzed with the ITDP and the initial condition uncertainties are included in the limit DNBR as described in Reference 5. Therefore, initial conditions of nominal core power, nominal reactor coolant average temperature and nominal reactor coolant pressure are assumed.

Method of Analysis

(1) One or More Dropped RCCAs from the Same Group

For evaluation of the dropped RCCA event, the transient system response is calculated using the LOFTRAN code. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, SG, and SG safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

Statepoints are calculated and nuclear models are used to obtain a hot channel factor consistent with the primary system conditions and reactor power. By incorporating the primary conditions from the transient and the hot channel factor from the nuclear analysis, the DNB design basis is shown to be met using the THINC code (refer to Section 1.6.1, Item 28 and Section 4.4.3). The transient response, nuclear peaking factor analysis, and DNB design basis confirmation are performed in accordance with the methodology described in Reference 10.

(2) Dropped RCCA Bank

A dropped RCCA bank results in a symmetric power change in the core. As discussed in Reference 10, assumptions made for the dropped RCCA(s) analysis provide a bounding analysis for the dropped RCCA bank.

(3) Statically Misaligned RCCA

Steady state power distributions are analyzed using the computer codes as described in Table 4.1-2. The peaking factors are then used as input to the THINC code (refer to Section 1.6.1, Item 28 and Section 4.4.3) to calculate the DNBR. The analysis examines the case of the worst rod withdrawn from control bank D inserted at the insertion limit with the reactor initially at full power. The analysis assumes this incident to occur at beginning of life (BOL) or the time in core life which this results in the minimum value of moderator temperature coefficient. This assumption maximizes the power rise and minimizes the tendency of increased moderator temperature to flatten the power distribution.

15.2.3.4 Results

(1) One or More Dropped RCCAs

Single or multiple dropped RCCAs within the same group result in a negative reactivity insertion. The core is not adversely affected during this period since power is decreasing rapidly.

Power may be reestablished either by reactivity feedback or control bank withdrawal. Following a dropped rod event in manual rod control, the plant will establish a new equilibrium condition. The equilibrium process without control system interaction is monotonic, thus removing power overshoot as a concern and establishing the automatic rod control mode of operation as the limiting case.

For a dropped RCCA event in the automatic rod control mode, the rod control system detects the drop in power and initiates control bank withdrawal. Power overshoot may occur due to this action by the automatic rod controller after which the control system will insert the control bank to restore nominal power. Figures 15.2.3-1 and 15.2.3-2 show a typical transient response to a dropped RCCA(s) in automatic control. Uncertainties in the initial conditions are included in the DNB evaluation as described in Reference 10. In all cases, the minimum DNBR remains above the safety analysis limit value.

Following plant stabilization, the operator may manually retrieve the RCCA(s) by following approved operating procedures.

(2) Dropped RCCA Bank

A dropped RCCA bank typically results in a reactivity insertion of greater than 500 pcm. The core is not adversely affected during the insertion period since power is decreasing rapidly. The dropped RCCA bank transient will proceed as described in the previous section for one or more dropped RCCA(s), except the return to power will be less due to the greater worth of the entire bank. The power transient for a dropped RCCA bank is symmetric. Following plant stabilization, normal procedures are followed.

(3) Statically Misaligned RCCA

The most severe misalignment situations with respect to DNBR at significant power levels arise from cases in which one RCCA is fully inserted, or where Bank D is fully inserted with one RCCA fully withdrawn. Multiple independent alarms, including a bank insertion limit alarm, alert the operator well before the postulated conditions are approached. The bank can be inserted to its insertion limit with any one assembly fully withdrawn without the DNBR falling below the limit value.

The insertion limits in the Technical Specifications may vary from time to time depending on a number of limiting criteria. The full power insertion limits on control bank D must be chosen to be above that position which meets the minimum DNBR and peaking factor limits. The full power

insertion limits is usually dictated by other criteria. Detailed results will vary from cycle to cycle depending on fuel arrangements.

For this RCCA misalignment, with Bank D inserted to its full power insertion limit and one RCCA fully withdrawn, DNBR does not fall below the safety analysis limit value. This case is analyzed assuming the initial reactor power, pressure, and RCS temperatures are at their nominal values but with the increased radial peaking factor associated with the misaligned RCCA.

For RCCA misalignments with one RCCA fully inserted, the DNBR does not fall below the safety analysis limit value. This case is analyzed assuming the initial reactor power, pressure, and RCS temperatures are at their nominal values, but with the increased radial peaking factor associated with the misaligned RCCA.

DNB does not occur for the RCCA misalignment incident and thus the ability of the primary coolant to remove heat from the fuel rod is not reduced. The peak fuel temperature corresponds to a linear heat generation rate based on the radial peaking factor penalty associated with the misaligned RCCA and the design axial power distribution. The resulting linear heat generation is well below that which would cause fuel melting.

Following the identification of an RCCA group misalignment condition by the operator, the operator is required to take action as required by the plant Technical Specifications and operating instructions.

15.2.3.5 Conclusions

The analysis demonstrates that the acceptance criterion is met as follows:

(1) For all cases of RCCA misoperation, the DNBR remains greater than the Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell); therefore, the DNB design criterion is met.

15.2.4 UNCONTROLLED BORON DILUTION

15.2.4.1 Acceptance Criteria

(1) There is ample/adequate time for the operator to mitigate a boron dilution event.

15.2.4.2 Identification of Causes and Accident Description

Reactivity can be added to the core by feeding unborated water into the RCS via the reactor makeup portion of the chemical and volume control system (CVCS). Boron dilution is a manual operation under strict administrative controls with procedures calling for a limit on the rate and duration of dilution. A boric acid blend system is provided to permit the operator to match the boron concentration of reactor coolant makeup water to that in the RCS during normal makeup injection. The CVCS is designed to limit, even under various postulated failure modes, the potential rate of dilution to a value, which after indication through alarms and instrumentation, provides the operator with sufficient time to correct the situation in a safe and orderly manner.

The opening of the primary water makeup control valves provides makeup to the RCS that can dilute the reactor coolant. Inadvertent dilution from this source can be readily terminated by closing the control valve. In order for makeup water to be added to the RCS at pressure, at least one charging pump must be running in addition to a primary makeup water pump.

The rate of addition of unborated makeup water to the RCS when it is not at pressure is limited by the capacity of the primary water supply pumps. The maximum net addition rate in this case is 200 gpm, which is based on a conservative evaluation of two primary water pumps operating in parallel through a common flow path.

The boric acid from the boric acid tank is blended with primary grade water in the blender and the composition is determined by the preset flowrates of boric acid and primary grade water on the control board. In order to dilute, two separate operations are required:

(1) The operator must change from the automatic makeup mode to the dilute mode

(2) The operator must select start to initiate system start

Excluding either step would prevent dilution.

Information on the status of the reactor coolant makeup is continuously available to the operator. Lights are provided on the control board to indicate the operating condition of the pumps in the CVCS. Alarms are actuated to warn the operator if boric acid or demineralized water flowrates deviate from preset values as a result of system malfunction.

Consistent with the DCPP licensing basis, the acceptance criteria of meeting a minimum time before loss of SDM from the start of dilution for Modes 2-5 is 15 minutes; for Mode 6, it is 30 minutes.

In order to meet the acceptance criteria for Mode 4 on RHR and Mode 5 (for both filled and mid-loop operation), the analysis defines a required minimum critical boron concentration ratio (Cbi/Cbc) that must be confirmed on a reload basis. This is a ratio of the initial boron concentration (Cbi) in the RCS to the boron concentration at which shutdown margin is lost (Cbc). Consistent with this approach, a minimum Cbi/Cbc ratio is also defined for Mode 3 and Mode 4 with one RCP in operation, in order to provide additional margin. These limits are evaluated for the core reloads of both units as part of the normal Restart Safety Analysis Checklist process. If analysis shows that these ratios will be violated for future reload cycles, administrative and/or operating procedures will need to be revised to ensure that these limits are maintained. In such case, the Core Operating Limits Report must be revised at that time to specify either an increased SDM requirement or the required minimum Cbi/Cbc ratio(s) directly.

15.2.4.3 Analysis of Effects and Consequences

15.2.4.3.1 Method of Analysis

To cover all phases of plant operation, boron dilution during refueling, cold shutdown, hot shutdown, hot standby, startup, and power operation is considered in this analysis. Table 15.2-1 contains the time sequence of events for this accident.

15.2.4.3.2 Dilution during Refueling

During refueling the following conditions exist:

(1) One RHR pump is operating to ensure continuous mixing in the reactor vessel.

(2) The seal injection water supply to the RCPs is typically isolated for the purpose of performing RCP maintenance.

(3) Boric acid supply to the suction of the charging pumps is available for the addition of boric acid to the RCS. Alternatively, boric acid supply may be lined up to the suction of the SI pumps when all the reactor vessel head bolts are fully detensioned.

(4) The boron concentration in the refueling water is greater than or equal to 2000 ppm, corresponding to a shutdown margin of at least 5 percent Δk with all RCCAs in; periodic sampling ensures that this concentration is maintained.

(5) Neutron sources are installed in the core and the source range detectors outside the reactor vessel are active and provide an audible count rate. *During initial core loading, BF_3 detectors are installed inside the reactor*

vessel and are connected to instrumentation giving audible count rates to provide direct monitoring of the core. (Historical)

(6) A minimum water volume in the RCS of 3462 cubic feet is considered. This corresponds to the volume necessary to fill the reactor vessel above the nozzles to ensure mixing via the RHR loop.

(7) A maximum dilution flow of 200 gpm and uniform mixing are assumed.

The operator has prompt and definite indication of any boron dilution from the audible count rate instrumentation and the high flux at shutdown alarm in the control room. Count rate will increase with the subcritical multiplication factor during boron dilution.

If a SI pump is used for boration, it is aligned to take suction from the refueling water storage tank (RWST) and discharge to the cold legs of the RCS, and the boundary valves from the CVCS to the SIS are closed. These requirements ensure no new dilution flowpaths are introduced when using the SIS boration flowpath.

15.2.4.3.3 Dilution during Cold Startup

In this mode, the plant is being taken into or out of refueling or hot shutdown. Typically, the plant is maintained in the cold shutdown mode when reduced RCS inventory is necessary, ambient temperatures are required to address various plant issues, or as a result of a Technical Specification action statement. The water level can be dropped to the mid-plane of the hot leg for maintenance work that requires the SGs to be drained. The plant is maintained in cold shutdown at the beginning of the cycle for start-up testing of certain systems and components. Conditions used for the analysis are as follows:

(1) A maximum dilution flow of 200 gpm, limited by the capacity of two primary water makeup pumps operating in parallel through a common flow path, is considered.

(2) A minimum RCS water volume of 4690 cubic feet is used, corresponding to the active RCS volume excluding the pressurizer and the reactor vessel upper head. A minimum RCS water volume of 3462 cubic feet is also considered for mid-loop operation.

(3) The required operator action time for this mode is 15 minutes. To meet this requirement, a minimum critical boron concentration ratio must be maintained to ensure sufficient time is available from the initiation of the dilution event for the operators to act to prevent a loss of shutdown margin and preclude criticality.

The analysis determined that the minimum critical boron concentration ratio to meet the required operator action is 1.128 for the most limiting case, assuming mid-loop operation.

15.2.4.3.4 Dilution during Hot Shutdown

In this mode, the plant is being taken into or out of cold shutdown or hot standby. The plant is maintained in this mode at the beginning of the cycle for startup testing of certain systems and components. Throughout the cycle, the plant may enter hot shutdown if plant issues arise requiring a plant shutdown or as a result of a Technical Specification action statement. In hot shutdown, mixing of the RCS is provided by either the RHR system or a single RCP, depending on system pressure and temperature. Conditions used for the analysis are as follows:

(1) A maximum dilution flow of 200 gpm, limited by the capacity of two primary water makeup pumps operating in parallel through a common flow path, is considered.

(2) A minimum RCS water volume of 9365 cubic feet is used, corresponding to the active RCS volume excluding the pressurizer and the reactor vessel upper head with one RCP in operation. A reduced minimum RCS water volume of 4690 cubic feet is considered for the case with no RCPs operating and mixing provided by the RHR system.

(3) The required operator action time for this mode is 15 minutes. To meet this requirement, a minimum critical boron concentration ratio must be maintained to ensure sufficient time is available from the initiation of the dilution event for the operators to act to prevent a loss of shutdown margin and preclude criticality.

The analysis determined that the minimum critical boron concentration ratio to meet the required operator action time is 1.101 for the most limiting case, assuming RHR system operation only.

15.2.4.3.5 Dilution during Hot Standby

In this mode, the plant is being taken into or out of hot shutdown or startup. The plant is maintained in hot standby at the beginning of cycle for startup testing of certain systems and components, and to achieve plant heatup before entering the startup mode and going critical. During cycle operation, the plant will enter this mode following a reactor trip or as a result of a Technical Specification action statement. During hot standby, not all RCPs may be in operation. Rod control is in manual and the rods may be partially or completely withdrawn. The more limiting hot standby dilution scenario is with the control rods not withdrawn and the reactor shut down by boron to the Technical Specifications minimum requirement for this mode. Conditions used for the analysis are as follows:

(1) A maximum dilution flow of 200 gpm, limited by the capacity of two primary water makeup pumps operating in parallel through a common flow path, is considered.

(2) A minimum RCS water volume of 9365 cubic feet is used, corresponding to the active RCS volume excluding the pressurizer and the reactor vessel upper head with at least one RCP in operation.

(3) The required operator action time for this mode is 15 minutes. To meet this requirement, a minimum critical boron concentration ratio must be maintained to ensure sufficient time is available from the initiation of the dilution event for the operators to act to prevent a loss of shutdown margin and preclude criticality.

The analysis determined that the minimum critical boron concentration ratio to meet the required operator action time is 1.059.

15.2.4.3.6 Dilution during Startup

In this mode, the plant is being taken into or out of hot standby or power operation. The RCS is filled with borated water from the blender during vacuum fill. Conditions used for the analysis are as follows:

(1) The initial boron concentration is modeled as 2000 ppm boron, which is conservative.

(2) Core monitoring is by external BF_3 detectors.

(3) Mixing of the reactor coolant is accomplished by operation of all four RCPs.

(4) The High Flux at Shutdown, NIS Source Range High Flux ½ Reactor Trip, and Reactor Trip Initiated alarms are available to warn the operator of the transient.

(5) A maximum dilution flow of 200 gpm, limited by the capacity of the two primary water makeup pumps operating in parallel through a common flow path, is considered.

(6) The volume of the reactor coolant is 9883 cubic feet, which is the minimum active volume of the RCS excluding the pressurizer.

The analysis determined that to maintain a minimum critical boron concentration ratio (initial boron concentration at the most reactive time in core life to the maximum critical boron concentration) of 1.25, the operator action time is 61.6 minutes.

15.2.4.3.7 Dilution at Power

With the unit at power and the RCS at pressure, the dilution rate is limited by the capacity of the charging pumps. The effective reactivity addition rate for the reactor at full power and for a boron dilution flow of 262 gpm is shown as a function of RCS boron concentration in Figure 15.2.4-1. This figure includes the effect of increasing boron worth with dilution. The reactivity rate used in the analysis is 1.752×10^{-5} Δk/sec based on a conservatively high value for the expected boron concentration (1600 ppm) at power.

15.2.4.4 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

For dilution during refueling and startup, the analysis assumes the following.

In refueling, cold shutdown, hot shutdown, hot standby, and startup, the reactor operators are relied upon to detect and recover from an inadvertent boron dilution event. Numerous alarms from the CVCS, the reactor makeup water system, and the NIS are available to provide assistance to the reactor operators in the detection of an inadvertent boron dilution event. Analysis has demonstrated that the reactor operators have at least 15 minutes from initiation of the dilution event in cold shutdown, hot shutdown, hot standby, and startup, and at least 30 minutes in refueling, to terminate the dilution event and initiate boration of the RCS prior to the loss of the available shutdown margin.

For dilution during full power operation:

(1) With the reactor in automatic control at full power, the power and temperature increase from boron dilution results in the insertion of the RCCAs and a decrease in shutdown margin. Continuation of dilution and RCCA insertion would cause the assemblies to reach the minimum limit of the rod insertion monitor in approximately 4.7 minutes, assuming the RCCAs to be initially at a position providing the maximum operational maneuvering band consistent with maintaining a minimum control band incremental rod worth. Before reaching this point, however, two alarms would be actuated to warn the operator of the accident condition. The first of these, the low insertion limit alarm, alerts the operator to initiate normal boration.

The other, the low-low insertion limit alarm, alerts the operator to follow emergency boration procedures. The low alarm is set sufficiently above the low-low alarm to allow normal boration without the need for emergency procedures. If dilution continues after reaching the low-low alarm, it takes approximately 15.0 minutes after the low-low alarm before the total

shutdown margin (assuming 1.6 percent, consistent with the Technical Specifications) is lost due to dilution. Therefore, adequate time is available following the alarms for the operator to determine the cause, isolate the primary grade water source, and initiate boration.

(2) With the reactor in manual control and if no operator action is taken, the power and temperature rise will cause the reactor to reach the high neutron flux or overtemperature ΔT trip setpoint. The boron dilution accident in this case is essentially identical to a RCCA withdrawal accident at power. The maximum reactivity insertion rate for boron dilution is shown in Figure 15.2.4-1 and is seen to be within the range of insertion rates analyzed for a RCCA withdrawal accident. Reactor trip will occur approximately 40 seconds after event initiation. If dilution were to continue after the reactor trip, there would still be approximately 14.5 minutes left after a reactor trip for the operator to determine the cause of dilution, isolate the primary grade water sources, and initiate reboration before the reactor can return to criticality assuming a 1.6 percent shutdown margin at the beginning of dilution. Therefore, there is ample time available (approximately 40 seconds to reactor trip plus 14.5 minutes after a reactor trip).

15.2.5 PARTIAL LOSS OF FORCED REACTOR COOLANT FLOW

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

During review of this accident, it was identified that the complete loss of flow reanalysis (Westinghouse calculation note CN-TA-12-29) without undervoltage and underfrequency reactor trips credits the RCL low flow reactor trip as protection. This reactor trip is also credited in the partial loss of flow event. Since the complete loss of flow reanalysis assumes all four RCPs coasting down and the partial loss of flow analysis assumes two out of four RCPs coast down, the complete loss of flow accident, as discussed in Section 15.3.4 is bounding.

15.2.5.1 Acceptance Criteria

The following is the relevant specific acceptance criterion.

(1) The minimum DNBR must not go below the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) (refer to Section 4.4.4.1) at any time during the transient.

15.2.5.2 Identification of Causes and Accident Description

A partial loss of coolant flow accident can result from a mechanical or electrical failure in a RCP or from a fault in the power supply to the pump. If the reactor is at power at the time of the accident, the immediate effect of loss of coolant flow is a rapid increase in

the coolant temperature. This increase could result in DNB with subsequent fuel damage if the reactor is not tripped promptly.

The necessary protection against a partial loss of coolant flow accident is provided by the low primary coolant flow reactor trip that is actuated by two-out-of-three low flow signals in any RCL. Above approximately 35 percent power (Permissive 8), low flow in any loop will actuate a reactor trip. Between approximately 10 and 35 percent power (Permissive 7 and Permissive 8), low flow in any two loops will actuate a reactor trip. Reactor trip on low flow is blocked below Permissive 7.

A reactor trip on RCP breakers open is provided as a backup to the low flow signals. Above Permissive 7, a breaker open signal from any two pumps will actuate a reactor trip. Reactor trip on RCP breakers open is blocked below Permissive 7.

Normal power for the RCPs is supplied through buses connected through transformers to the generator. Two RCPs are on each bus. When a generator trip occurs, the buses are automatically transferred to a power source supplied from external power lines, and the pumps will continue to supply coolant flow to the core. Following any turbine trip where there are no electrical or mechanical faults that require immediate tripping of the generator from the network, the generator remains connected to the network for approximately 30 seconds. The RCPs remain connected to the generator thus ensuring full flow for approximately 30 seconds after the reactor trip before any transfer is made.

15.2.5.3 Analysis of Effects and Consequences

15.2.5.3.1 Method of Analysis

The following case has been analyzed:

(1) All loops operating, two loops coasting down.

This transient is analyzed by three digital computer codes. First the LOFTRAN code is used to calculate the loop and core flow during the transient. The LOFTRAN code is also used to calculate the time of reactor trip, based on the calculated flows and the nuclear power transient following reactor trip. The FACTRAN code is then used to calculate the heat flux transient based on the nuclear power and flow from LOFTRAN. Finally, the THINC code (refer to Section 1.6.1, Item 28 and Section 4.4.3) is used to calculate the minimum DNBR during the transient based on the heat flux from FACTRAN and the flow from LOFTRAN. The DNBR transient presented represents the minimum of the typical and thimble cells for Standard fuel, which bound VANTAGE 5 fuel.

15.2.5.3.2 Initial Conditions

The accident is analyzed using the ITDP and the initial condition uncertainties are included in the limit DNBR as described in Reference 5. Therefore, initial conditions of nominal core power, nominal reactor coolant average temperature (including 2.5 °F for SG fouling) and nominal reactor coolant pressure are assumed.

15.2.5.3.3 Reactivity Coefficients

A conservatively large absolute value of the Doppler-only power coefficient is used (refer to Table 15.1-4). The total integrated Doppler reactivity from 0 to 100 percent power is assumed to be -0.016 Δk.

The most positive moderator temperature coefficient (+5 pcm/°F) is assumed since this results in the maximum hot spot heat flux during the initial part of the transient when the minimum DNBR is reached.

15.2.5.3.4 Flow Coastdown

The flow coastdown analysis is based on a momentum balance around each RCL and across the reactor core. This momentum balance is combined with the continuity equation, a pump momentum balance, and the pump characteristics and is based on high estimates of system pressure losses.

15.2.5.4 Results

The calculated sequence of events is shown in Table 15.2-1. Figures 15.2.5-1 through 15.2.5-4 show the core flow coastdown, the loop flow coastdown, the heat flux coastdown, and the nuclear power coastdown. The minimum DNBR is not less than the safety analysis limit value. A plot of DNBR vs. time is given in Figure 15.2.5-5 for the most limiting thimble cell for Standard fuel, which bounds VANTAGE 5 fuel.

15.2.5.5 Conclusions

The analysis demonstrates that the acceptance criterion is met as follows:

(1) There is margin to the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell). The accompanying DNBR figure for this event (refer to Figure 15.2.5-5) reflects the results for the more limiting Standard fuel (limit 1.48/1.44) previously in the core.

The analysis shows that the DNBR will not decrease below the safety analysis limiting values at any time during the transient. Thus no core safety limit is violated.

15.2.6 STARTUP OF AN INACTIVE REACTOR COOLANT LOOP

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

In accordance with the Technical Specifications, DCPP operation during startup and power operation with less than four loops is not permitted. This analysis is presented for completeness.

15.2.6.1 Identification of Causes and Accident Description

If a plant is operating with one pump out of service, there is reverse flow through the loop due to the pressure difference across the reactor vessel. The cold leg temperature in an inactive loop is identical to the cold leg temperature of the active loops (the reactor core inlet temperature). If the reactor is operated at power, and assuming the secondary side of the SG in the inactive loop is not isolated, there is a temperature drop across the SG in the inactive loop and, with the reverse flow, the hot leg temperature of the inactive loop is lower than the reactor core inlet temperature.

Starting of an idle RCP without bringing the inactive loop hot leg temperature close to the core inlet temperature would result in the injection of cold water into the core, which causes a rapid reactivity insertion and subsequent power increase.

This event is classified as an ANS Condition II incident (an incident of moderate frequency) as defined at the beginning of this chapter.

Should the startup of an inactive RCP at an incorrect temperature occur, the transient will be terminated automatically by a reactor trip on low coolant loop flow when the power range neutron flux (two-out-of-four channels) exceeds the P-8 setpoint, which has been previously reset for three-loop operation.

15.2.6.2 Analysis of Effects and Consequences

This transient is analyzed by three digital computer codes. The LOFTRAN Code (Reference 4) is used to calculate the loop and core flow, nuclear power and core pressure and temperature transients following the startup of an idle pump. FACTRAN (Reference 3) is used to calculate the core heat flux transient based on core flow and nuclear power from LOFTRAN. The THINC Code (Reference 9) is then used to calculate the DNBR during the transient based on system conditions (pressure, temperature, and flow) calculated by LOFTRAN and heat flux as calculated by FACTRAN.

In order to obtain conservative results for the startup of an inactive pump accident, the following assumptions are made:

(1) Initial conditions of maximum core power and reactor coolant average temperatures and minimum reactor coolant pressure resulting in minimum initial margin to DNB. A 25 percent maximum steady state power level including appropriate allowances for calibration and instrument errors is assumed, however DCPP is not allowed to be at power with an inactive loop. The high initial power gives the greatest temperature difference between the core inlet temperature and the inactive loop hot leg temperature.

(2) Following the start of the idle pump, the inactive loop flow reverses and accelerates to its nominal full flow value.

(3) A conservatively large (absolute value) negative moderator coefficient associated with the end of life (EOL).

(4) A conservatively low (absolute value) negative Doppler power coefficient is used.

(5) The initial RCL flows are at the appropriate values for one pump out of service.

(6) The reactor trip is assumed to occur on low coolant flow when the power range neutron flux exceeds the P-8 setpoint, which has been reset for N-1 loop operation. The P-8 setpoint is conservatively assumed to be 84 percent of rated power, which corresponds to the nominal N-1 loop operation setpoint plus 9 percent for nuclear instrumentation errors.

15.2.6.3 Results

The results following the startup of an idle pump with the above listed assumptions are shown in Figures 15.2.6-1 through 15.2.6-5. As shown in these curves, during the first part of the transient, the increase in core flow with cooler water results in an increase in nuclear power and a decrease in core average temperature. The minimum DNBR during the transient is considerably greater than the safety analysis limit values.

Reactivity addition for the inactive loop startup accident is due to the decrease in core water temperature. During the transient, this decrease is due both to a) the increase in reactor coolant flow, and b) as the inactive loop flow reverses, to the colder water entering the core from the hot leg side (colder temperature side prior to the start of the transient) of the SG in the inactive loop. Thus, the reactivity insertion rate for this transient changes with time. The resultant core nuclear power transient, computed with consideration of both moderator and Doppler reactivity feedback effects, is shown in Figure 15.2.6-1.

The calculated sequence of events for this accident is shown in Table 15.2-1. The transient results illustrated in Figures 15.2.6-1 through 15.2.6-5 indicate that a stabilized

plant condition, with the reactor tripped, is approached rapidly. Plant cooldown may subsequently be achieved by following normal shutdown procedures.

15.2.6.4 Conclusions

The transient results show that the core is not adversely affected. There is considerable margin to the safety analysis DNBR limit values; thus, no fuel or cladding damage is predicted.

15.2.7 LOSS OF EXTERNAL ELECTRICAL LOAD AND/OR TURBINE TRIP

15.2.7.1 Acceptance Criteria

The following are the relevant specific acceptance criteria.

(1) The minimum DNBR must not go below the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) (refer to Section 4.4.4.1) at any time during the transient.

(2) The RCS pressure does not exceed 110 percent of design pressure (2,750 psia) at any time during the transient.

(3) The MSS pressure does not exceed 110 percent of design pressure (1,210 psia) at any time during the transient.

15.2.7.2 Identification of Causes and Accident Description

A major load loss on the plant can result from either a loss of external electrical load or from a turbine trip. For either case, offsite power is available for the continued operation of plant components such as the RCPs. The case of LOOP is analyzed in Section 15.2.9.

For a turbine trip, the reactor would be tripped directly (unless it is below the P-9 setpoint) from a signal derived from the turbine autostop oil pressure and turbine stop valves. The automatic steam dump system accommodates the excess steam generation. Reactor coolant temperatures and pressure do not significantly increase if the steam dump system and pressurizer pressure control system are functioning properly. If the turbine condenser were not available, the excess steam generation would be dumped to the atmosphere. Additionally, main feedwater flow would be lost if the turbine condenser were not available. For this situation, SG level would be maintained by the auxiliary feedwater (AFW) system.

For a loss of external electrical load without subsequent turbine trip, no direct reactor trip signal would be generated. A continued steam load of approximately 5 percent would exist after total loss of external electrical load because of the electrical demand of plant auxiliaries.

In the event the 10 percent atmospheric dump valves fail to open following a large loss of load (LOL), the SG safety valves may lift and the reactor may be tripped by the high pressurizer pressure signal, the high pressurizer water level signal, or the overtemperature ΔT signal. The SG shell-side pressure and reactor coolant temperatures will increase rapidly. The pressurizer safety valves (PSVs) and SG safety valves are, however, sized to protect the RCS and SG against overpressure for all load losses without assuming the operation of the steam dump system, pressurizer spray, pressurizer power-operated relief valves (PORVs), automatic RCCA control, or direct reactor trip on turbine trip.

The SG safety valve capacity is sized to remove the steam flow at the engineered safeguards design rating (105 percent of steam flow at rated power) from the SG without exceeding 110 percent of the steam system design pressure. The PSV capacity is sized based on a complete loss of heat sink with the plant initially operating at the maximum calculated turbine load along with operation of the SG safety valves. The PSVs are then able to maintain the RCS pressure within 110 percent of the RCS design pressure without direct or immediate reactor trip action.

A more complete discussion of overpressure protection can be found in Reference 8.

15.2.7.3 Analysis of Effects and Consequences

In this analysis, the behavior of the unit is evaluated for a complete loss of steam load from full power without a direct reactor trip. This is done to show the adequacy of the pressure-relieving devices and to demonstrate core protection margins. The reactor is not tripped until conditions in the RCS result in a trip. The turbine is assumed to trip without actuating all the turbine stop valve limit switches. This assumption delays reactor trip until conditions in the RCS result in a trip due to other signals. Thus, the analysis assumes a worst case transient. In addition, no credit is taken for steam dump actuation. Main feedwater flow is terminated at the time of turbine trip, with no credit taken for AFW (except for long-term recovery) to mitigate the consequences of the transient.

Total LOL transients are analyzed for DNB and overpressure concerns. The LOFTRAN computer program (refer to Section 15.1) is used to analyze the total LOL transients for the DNB concern. The RETRAN-02 computer program (refer to Section 15.1) is used to analyze the transients for the overpressure concern. Both programs simulate the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, SG, and SG safety valves. The programs compute pertinent variables, including temperatures, pressures, and power level.

The following assumptions are used in the LOFTRAN analysis for the DNB concern.

(1) Initial Operating Conditions

The accident is analyzed using the ITDP and the initial condition uncertainties are included in the limit DNBR as described in Reference 5. Therefore, initial conditions of nominal core power, nominal reactor coolant average temperature (including 2.5°F for SG tube fouling) and nominal reactor coolant pressure are assumed.

(2) Moderator and Doppler Coefficients of Reactivity

The turbine trip is analyzed with both maximum and minimum reactivity feedback. The maximum feedback for EOL cases assume a large negative moderator temperature coefficient and the most negative Doppler power coefficient. The minimum feedback for BOL cases assume a minimum moderator temperature coefficient and the least negative Doppler coefficient.

(3) Reactor Control

From the standpoint of the maximum pressures attained, it is conservative to assume that the reactor is in manual control. If the reactor were in automatic control, the control rod banks would move prior to trip and reduce the severity of the transient.

(4) Steam Release

No credit is taken for the operation of the steam dump system or SG power-operated relief valves. The SG pressure rises to the safety valve setpoint where steam release through safety valves limits secondary steam pressure at the setpoint value.

(5) Pressurizer Spray and PORVs

Two cases for both BOL and EOL are analyzed using the LOFTRAN computer program.

(a) Full credit is taken for the effect of pressurizer spray and PORVs in reducing or limiting the coolant pressure. Safety valves are also operable.

(b) No credit is taken for the effect of pressurizer spray and PORVs in reducing or limiting the coolant pressure. Safety valves are operable.

(6) Feedwater Flow

Main feedwater flow to the SGs is assumed to be lost at the time of turbine trip. No credit is taken for AFW flow since a stabilized plant condition will be reached before AFW initiation is normally assumed to occur; however, the AFW pumps would be expected to start on a trip of the main feedwater pumps. The AFW flow would remove core decay heat following plant stabilization.

The following assumptions are used in the RETRAN-02 analysis for the overpressure concern only.

(1) Initial Operating Conditions

The accident analysis assumes: maximum core power; maximum Tavg, and minimum operating RCS pressure 2189.7 psia is used in the analysis, which includes 60 psi uncertainty.

(2) Moderator and Doppler Coefficients of Reactivity

BOL minimum reactivity feedback is modeled assuming the most positive moderator temperature coefficient and the least negative Doppler temperature coefficient.

(3) Steam Release

No credit is taken for secondary heat removal from the steam dump system. Only the PSVs and the main steam safety valves (MSSVs) are credited for overpressure protection.

(4) Pressurizer Pressure Control

Since the total LOL overpressure transients result in higher peak RCS and SG pressures at BOL, two cases are analyzed using the RETRAN-02 computer program for BOL only.

(a) For the peak secondary side pressure case assumes pressurizer pressure control. This delays the reactor trip and maximizes the heat transfer to the SGs. Safety valves are also operable.

(b) For the peak RCS pressure case, no credit is taken for pressurizer pressure control, which maximizes the peak RCS pressure for the event. Safety valves are operable.

(5) Feedwater Flow

The turbine stop valves and feedwater control valves are assumed to close instantaneously at the initiation of the event to maximize the duration of the primary to secondary heat imbalance. The AFW system is conservatively not credited and assumed unavailable for decay heat removal during the event.

(6) MSSVs

The MSSV setpoints are assumed to be at their maximum 3 percent drift values. The RETRAN MSSVs are modeled to provide zero to full flow as a linear function from the lift setpoint to the full open 3 percent accumulation value.

(7) PSV Water Loop Seal

All PSVs have been converted to a steam-seat design and condensate in the loop is now continuously drained back to the pressurizer, thereby eliminating the water loop seal. Even though the water loop seal has been eliminated, the resulting benefit is not credited in the analysis. The presence of a water loop seal delays the opening of the PSV. The loop seal water starts to leak out from the safety valve when the safety valve setpoint is reached. However, no pressure is relieved from the pressurizer until the loop seal water is completely purged, after which the safety valve pops full open in less than 0.1 second. The loop seal water purge time of 1.272 seconds was used in the analysis.

(8) Maximize Reactor Power

It is conservative to maximize the reactor power. Therefore, the reactor trip due to high neutron flux is not credited in the analysis.

In all cases for DNB and overpressure concerns reactor trip is actuated by the first reactor protection system trip setpoint reached with no credit taken for the direct reactor trip on the turbine trip.

15.2.7.4 Results

The transient responses for a total LOL from full power operation are shown for four cases the DNB concern is evaluated at BOL and EOL with pressure control since this condition bounds the cases without pressure control and overpressure concern is evaluated at BOL with and without pressure control (refer to Figures 15.2.7-1 through 15.2.7-4 and 15.2.7-9 through 15.2.7-12.

Figures 15.2.7-1 and 15.2.7-2 show the transient responses for the total loss of steam load at BOL, for the DNB concern, assuming full credit for the pressurizer spray and pressurizer PORVs. No credit is taken for the steam dump. The reactor is tripped by the high pressurizer pressure trip channel. The minimum DNBR is (thimble cell) well above the limit value.

Figures 15.2.7-3 and 15.2.7-4 show the responses for the total LOL at EOL, for the DNB concern, assuming a large (absolute value) negative moderator temperature coefficient. All other plant parameters are the same as in the above case. As a result of the maximum reactivity feedback at EOL, no reactor protection system trip setpoint is reached. Because main feedwater is assumed to be lost, the reactor is tripped by the low-low SG water level trip channel. The DNBR (thimble cell) increases throughout the transient and never drops below its initial value. The PSVs are not actuated in these transients.

Figures 15.2.7-9 and 15.2.7-10 show the typical transient responses for the total LOL at BOL for the RCS overpressure concern. No credit is taken for the pressurizer spray, pressurizer PORVs, or steam dump. The pressurizer and MSSVs are modeled as described in assumptions 6 and 7. The initial pressurizer pressure includes the pressurizer pressure uncertainty to maximize the peak pressure. The reactor is tripped on the high pressurizer pressure signal. This case results in the highest RCS peak pressure among all cases. The peak RCS pressure is below 110 percent of the design value.

Figures 15.2.7-11 and 15.2.7-12 show the typical transient responses for the total LOL at BOL for the secondary side overpressure concern, assuming full credit for the pressurizer spray and the pressurizer PORVs. No credit is taken for the steam dump. The models for the pressurizer and MSSVs and the initial pressurizer pressure are the same as those used in the above case. The reactor trip due to high neutron flux is not credited in order to maximize the peak SG pressure. The reactor is tripped on the high pressurizer pressure signal. This case results in the highest SG peak pressure among all cases. The peak SG pressure is below 110 percent of the design value.

Reference 8 presents additional results for a complete loss of heat sink including loss of main feedwater. This report shows the overpressure protection that is afforded by the pressurizer and SG safety valves.

Technical Specification 3.7.1 establishes reduced plant operating power limits for off normal conditions when one or more MSSVs are inoperable to ensure a LOL event does not result in overpressurization of the SGs. When two or more MSSVs are inoperable per SG loop, the reduced power limits are established using a conservative energy balance algorithm established in the Westinghouse Nuclear Safety Advisory Letter NSAL-94-001 as documented in Reference 21. To evaluate off normal plant operation with a single inoperable MSSV on one or more SG loops, an additional spectrum of LOL analyses are performed as documented in Reference 22. These analyses use the RETRAN-02W code to analyze the BOL LOL overpressure case as

discussed in this section and which represents the limiting case for challenging the SG peak pressure limit. These analysis results, as summarized in the Technical Specification Bases 3.7.1, credit the overtemperature ΔT reactor trip to demonstrate that the specified reduced operating power limit ensures that the available relief capacity with one inoperable MSSV per loop maintains the peak SG pressure below 110 percent of the design value.

15.2.7.5 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) There is margin to the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell). The accompanying DNBR figures for this event (refer to Figures 15.2.7-1 and 15.2.7-3) reflect the results for the more limiting Standard fuel (limit 1.48/1.44) previously in the core.

(2) The calculated RCS pressure (2723 psia) does not exceed 110 percent of design pressure (2,750 psia) at any time during the transient.

(3) The calculated MSS peak pressure (1203 psia) does not exceed 110 percent of design pressure (1,210 psia) at any time during the transient.

Results of the analyses, including those in Reference 8, show that the plant design is such that a total loss of external electrical load without a direct or immediate reactor trip presents no hazard to the integrity of the RCS or the MSS. Pressure-relieving devices incorporated in the two systems are adequate to limit the maximum pressures to within the design limits.

The integrity of the core is maintained by operation of the reactor protection system; i.e., the DNBR will be maintained above the safety analysis limit values. Thus, no core safety limit will be violated.

15.2.8 LOSS OF NORMAL FEEDWATER

15.2.8.1 Acceptance Criteria

The following is the relevant specific acceptance criterion.

(1) The pressurizer does not go water solid at any time during the transient.

15.2.8.2 Identification of Causes and Accident Description

A loss of normal feedwater (resulting from pump failures, valve malfunctions, or loss of offsite ac power) results in a reduction in the ability of the secondary system to remove the heat generated in the reactor core. If the reactor were not tripped during this

accident, core damage would possibly occur from a sudden loss of heat sink. If an alternative supply of feedwater were not supplied to the SGs, residual heat following reactor trip would heat the primary system water to the point where water relief from the pressurizer would occur. A significant loss of water from the RCS could conceivably lead to core damage. Since the plant is tripped well before the SG heat transfer capability is reduced, the primary system conditions never approach a DNB condition.

The following provide the necessary protection against a loss of normal feedwater:

(1) Reactor trip on low-low water SG level in any SG

(2) Two motor-driven AFW pumps (MDAFWPs) that are started on:

  (a) Low-low SG water level in any SG

  (b) Trip of both main feedwater pumps

  (c) Any SI signal

  (d) LOOP (automatic transfer to diesel generators)

  (e) Manual actuation

(3) One turbine-driven auxiliary feedwater pump (TDAFWP) that is started on:

  (a) Low-low SG water level in any two SGs

  (b) Undervoltage on both RCP buses

  (c) Manual actuation

The MDAFWPs are connected to Class 1E buses and are supplied by the diesels if a LOOP occurs. The turbine-driven pump utilizes steam from the secondary system and exhausts it to the atmosphere. The controls are designed to start both types of pumps within 1 minute even if a loss of all ac power occurs simultaneously with loss of normal feedwater. The AFW pumps take suction from the condensate storage tank for delivery to the SGs.

The analysis shows that following a loss of normal feedwater, the AFW system is capable of removing the stored energy and residual decay heat, and RCP heat thus preventing either overpressurization of the RCS or liquid relief through the pressurizer PORVs or safety valves.

15.2.8.3 Analysis of Effects and Consequences

A detailed analysis using the RETRAN-02W code (Reference 19) is performed in order to determine the plant transient following a loss of normal feedwater. The code describes the plant neutron kinetics, RCS including factors that influence the natural circulation, pressurizer, SGs, and feedwater system, and compute pertinent variables, including the pressurizer pressure, pressurizer water level, and reactor coolant average temperature.

Major assumptions are:

(1) Reactor trip occurs on SG low-low level at 8 percent of narrow range span (NRS).

(2) The plant is initially operating at 102 percent of the NSSS rating, including a conservatively large RCP heat of 20 MWt.

(3) Conservative core residual heat generation based on long-term operation at the initial power level preceding the trip is assumed. The ANSI/ANS-5.1-1979 + 2σ was used for calculation of residual decay heat levels.

(4) The AFW system is actuated by the low-low SG water level signal and AFW flow is assumed to initiate after 60 seconds to bound both cases with an offsite power auto-bus transfer without offsite power available.

(5) The limiting single failure in the AFW system occurs (turbine-driven pump failure). The AFW system is assumed to supply a total of 600 gpm to all four SGs from the motor-driven pumps.

(6) The pressurizer sprays and heaters are assumed operable. This maximizes the peak transient pressurizer water volume. Sensitivity analyses determined that it is conservative to assume that the PORVs are inoperable (Reference 20).

(7) Secondary system steam relief is achieved through the self-actuated safety valves. The MSSVs are assumed to begin to lift 3 percent above the set pressure with a 5 psi accumulation to full open. Note that steam relief will, in fact, be through the 10 percent atmospheric dump valves or 40 percent condenser dump valves for most cases of loss of normal feedwater. However, for the sake of analysis these have been assumed unavailable.

(8) The initial reactor coolant average temperature is 5.5°F lower than the nominal value. The initial pressurizer pressure is 60 psi above the nominal value.

(9) The minimum steam generator tube plugging (SGTP) of 0 percent was assumed.

(10) The initial feedwater temperature is assumed to be 435°F.

15.2.8.4 Results

Figures 15.2.8-1 through 15.2.8-3 show plant parameters following a loss of normal feedwater at the conditions associated with Unit 2, which were determined to be limiting when compared to Unit 1. Figure 15.2.8-2 shows the pressurizer pressure as a function of time.

Following the reactor and turbine trip from full load, the water level in the SGs will fall due to the reduction of SG void fraction and because steam flow through the safety valves continues to dissipate the stored and generated heat. One minute following the initiation of the low-low SG level trip, the MDAFWPs are automatically started, reducing the rate of water level decrease.

The capacity of the MDAFWPs combined with the available secondary inventory is capable of dissipating the core residual heat without liquid water relief from the RCS PORVs or safety valves.

From Figure 15.2.8-2 it can be seen that at no time is there liquid relief from the pressurizer. If the AFW delivered is greater than that of two motor-driven pumps, the initial reactor power is less than 102 percent of the NSSS rating, or the SG water level in one or more SGs is above the low-low level trip point at the time of trip, then the results for this transient will be less limiting.

The calculated sequence of events for this accident is listed in Table 15.2-1. As shown in Figures 15.2.8-1 through 15.2.8-3, the plant approaches a stabilized condition following reactor trip and AFW initiation. Plant procedures may be followed to further cool down the plant.

15.2.8.5 Conclusions

The analysis demonstrates that the acceptance criterion is met as follows:

(1) The pressurizer does not become water solid during the event as shown in Figure 15.2.8-2.

Results of the analysis show that a loss of normal feedwater does not adversely affect the core, the RCS, or the steam system, since the AFW capacity is such that the pressurizer does not become water solid, which ultimately precludes reactor coolant liquid relief from the pressurizer relief or safety valves. This ensures a Condition III or IV event will not be generated.

15.2.9 LOSS OF OFFSITE POWER TO THE STATION AUXILIARIES

15.2.9.1 Acceptance Criteria

The following is the relevant specific acceptance criterion.

(1) The pressurizer does not go water solid at any time during the transient.

15.2.9.2 Identification of Causes and Accident Description

During a complete LOOP and a turbine trip there will be loss of power to the plant auxiliaries, i.e., the RCPs, condensate pumps, etc.

The events following a loss of ac power with turbine and reactor trip are described in the sequence listed below:

(1) Plant Instrument Class I instruments are supplied by emergency power sources.

(2) As the steam system pressure rises following the trip, the steam system PORVs are automatically opened to the atmosphere. Steam dump to the condenser is assumed not to be available. If the PORVs are not available, the SG self-actuated safety valves may lift to dissipate the sensible heat of the fuel and coolant plus the residual heat produced in the reactor.

(3) As the no-load temperature is approached, the steam system PORVs (or the self-actuated safety valves, if the PORVs are not available) are used to dissipate the residual heat and to maintain the plant at the hot standby condition.

(4) The emergency diesel generators (EDGs) started on loss of voltage on the plant emergency buses begin to supply plant Class 1E loads.

The AFW system is started automatically as discussed in the loss of normal feedwater analysis. The steam-driven AFW pump utilizes steam from the secondary system and exhausts to the atmosphere. The MDAFWPs are supplied by power from the diesel generators. The pumps take suction directly from the condensate storage tank for delivery to the SGs.

Upon the loss of power to the RCPs, coolant flow necessary for core cooling and the removal of residual heat is maintained by natural circulation in the RCLs.

15.2.9.3 Analysis of Effects and Consequences

A detailed analysis using the RETRAN-02W code (Reference 19) is performed in order to determine the plant transient following LOOP. The code describes the plant neutron kinetics, RCS including factors that influence the natural circulation, pressurizer, SGs, and feedwater system, and computes pertinent variables, including the pressurizer pressure, pressurizer water level, and reactor coolant average temperature.

Major assumptions differing from those in a loss of normal feedwater are:

(1) No credit is taken for immediate response of CRDMs caused by a LOOP.

(2) RCP coastdown to natural circulation conditions is assumed after reactor trip (i.e., rod motion), which is more limiting for long-term heat removal capability.

(3) The initial feedwater temperature is assumed to be 425°F.

(4) A nominal RCP heat input of 14 MWt.

15.2.9.4 Results

The time sequence of events for the accident at the conditions associated with Unit 2, which were determined to be limiting, is given in Table 15.2-1. This event is bounded by the complete-loss-of-flow analysis (refer to Section 15.3.4), in terms of minimum DNBR (Reference 23). Therefore, this event is not analyzed for DNB concerns, but rather, for the long-term heat removal capability. After the reactor trip, stored and residual heat must be removed to prevent damage to either the RCS or the core. The RETRAN-02W code results show that the natural circulation flow available is sufficient to provide adequate core decay heat removal following reactor trip and RCP coastdown.

Figures 15.2.9-1 through 15.2.9-3 show plant parameters following a LOOP at the conditions associated with Unit 2, which were determined to be limiting. Figure 15.2.9-2 shows the pressurizer water volume as a function of time.

15.2.9.5 Conclusions

The analysis demonstrates that the acceptance criterion is met as follows:

(1) The pressurizer does not become water solid during the event as shown in Figure 15.2.9-2.

Results of the analysis show that, for the LOOP to the station auxiliaries event, all safety criteria are met. Since the DNBR remains above the safety analysis limit, the core is not adversely affected. AFW capacity is sufficient to prevent the pressurizer from becoming water solid, which ultimately precludes reactor coolant liquid relief from the

pressurizer relief and safety valves; this assures that the RCS is not overpressurized. This ensures that a Condition III or IV event will not be generated.

Analysis of the natural circulation capability of the RCS demonstrates that sufficient long-term heat removal capability exists following RCP coastdown to prevent fuel or cladding damage.

15.2.10 EXCESSIVE HEAT REMOVAL DUE TO FEEDWATER SYSTEM MALFUNCTIONS

15.2.10.1 Acceptance Criteria

The following are the relevant specific acceptance criteria:

(1) The minimum DNBR must not go below the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) (refer to Section 4.4.4.1) at any time during the transient.

(2) The peak linear heat generation rate does not exceed a value which would cause fuel centerline melt at any time during the transient (refer to Section 4.4.3.2.7).

15.2.10.2 Identification of Causes and Accident Description

Reductions in feedwater temperature or excessive feedwater additions are means of increasing core power above full power. Such transients are attenuated by the thermal capacity of the secondary plant and of the RCS. The overpower-overtemperature protection (neutron high flux, overtemperature ΔT, and overpower ΔT trips) prevent any power increase that could lead to a DNBR that is less than the DNBR limit.

One example of excessive feedwater flow would be a full opening of a main feedwater regulating valve (MFRV) due to a feedwater control system malfunction or an operator error. At power, this excess flow causes a greater load demand on the RCS due to increased subcooling in the SG. With the plant at no-load conditions the addition of cold feedwater may cause a decrease in RCS temperature and thus a reactivity insertion due to the effects of the negative moderator temperature coefficient. Continuous excessive feedwater addition is prevented by the SG high-high level feedwater isolation and turbine trip.

15.2.10.3 Analysis of Effects and Consequences

The excessive heat removal due to a feedwater system malfunction transient is analyzed with the RETRAN-02W code. This code simulates a multiloop system, neutron kinetics, the pressurizer, pressurizer relief and safety valves, pressurizer spray, SG, and SG safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

The system is analyzed to evaluate plant behavior in the event of a feedwater system malfunction. The accident is analyzed with the ITDP and initial condition uncertainties are included in the limit DNBR as described in Reference 5. Therefore, initial conditions of nominal core power, nominal reactor coolant average temperatures and nominal reactor coolant pressure are assumed.

Excessive feedwater addition due to a control system malfunction or operator error that allows a MFRV to open fully is considered. Two conditions are evaluated as follows:

(1) Accidental opening of one MFRV with the reactor just critical at zero load conditions. The feedwater flow increase event at hot zero power conditions is not limiting with respect to DNB concerns and is bounded by the full power event; therefore, the event has not been explicitly analyzed.

(2) Accidental opening of one MFRV at full power (with automatic and manual rod control).

The reactivity insertion rate following a feedwater system malfunction is calculated with the following assumptions:

(1) For the MFRV accident at full power, one MFRV is assumed to malfunction resulting in a step increase to 250 percent of nominal feedwater flow to one SG.

(2) Coincident with the feedwater flow increase in the faulted loop, the feedwater temperature in all loops decreases approximately 23°F from the nominal full power value. This accounts for the effect of the feedwater passing through the heaters at a higher velocity.

(3) The initial water level in all the SGs is at a conservatively low level.

(4) No credit is taken for the heat capacity of the RCS and SG thick metal in attenuating the resulting plant cooldown.

(5) The feedwater flow resulting from a fully open control valve is terminated by the SG high-high level signal that closes all MFRVs, closes all feedwater bypass valves, trips the main feedwater pumps, and shuts the main feedwater isolation valves (MFIVs).

15.2.10.4 Results

The full power case (EOL, with manual rod control) gives the largest reactivity feedback and results in the greatest power increase. A turbine trip and reactor trip is actuated when the SG level reaches the high-high level setpoint. Although turbine trip and subsequent reactor trip are assumed, the results show that the DNBR remains relatively

constant prior to the time of reactor trip. This demonstrates that a reactor trip on turbine trip is not needed to protect against DNB, but is assumed as a means to terminate the transient.

Transient results (refer to Figures 15.2.10-1 through 15.2.10-3) show the core heat flux, pressurizer pressure, core T_{avg}, and DNBR (thimble cell), as well as the increase in nuclear power and loop ΔT associated with the increased thermal load on the reactor. SG level rises until the feedwater is terminated as a result of the high-high SG level trip. The DNBR does not drop below the limit safety analysis DNBR.

15.2.10.5 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) There is margin to the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) as shown on Figure 15.2.10-3.

(2) Figure 15.2.10-1 shows the total power is maintained below 118 percent of its nominal value. Thus the peak fuel centerline temperature will remain below the fuel melting temperature (refer to Section 4.4.3.2.7).

An excessive feedwater addition at no-load conditions is bounded by the analysis at full power. The DNBRs encountered for excessive feedwater addition at power are well above the safety analysis limit DNBR values.

15.2.11 SUDDEN FEEDWATER TEMPERATURE REDUCTION

15.2.11.1 Acceptance Criteria

The following are the relevant specific acceptance criteria.

(1) The minimum DNBR must not go below the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) (refer to Section 4.4.4.1) at any time during the transient.

(2) The peak linear heat generation rate does not exceed a value that would cause fuel centerline melt at any time during the transient (refer to Section 4.4.3.2.7).

15.2.11.2 Identification of Causes and Accident Description

A concern was raised during the Unit 1 power ascension test program that an inadvertent actuation of the load transient bypass relay (LTBR) might initiate a transient that exceeds analyzed reactor operating limits. An evaluation performed showed that since the expected feedwater temperature decrease due to inadvertent actuation of the LTBR was significantly less than that of the net load trip, the consequences and events

of inadvertent actuation of the LTBR were bounded by the feedwater temperature decrease event.

The automatic load transient bypass (LTB) feature has been eliminated for Unit 1 and Unit 2. Control of the feedwater heater bypass valve has been changed to manual only.

A reduction in feedwater temperature may be caused by an inadvertent manual opening of the feedwater heater bypass valve. This would divert flow around the low pressure feedwater heaters. A consequent maximum 70°F reduction in feedwater temperature to the SGs would occur.

Feedwater temperature may also be reduced during a load rejection trip. The feedwater transient data taken from a 100 percent net load trip test with LTB active showed that a maximum feedwater temperature decrease of 230°F occurred over a 400-second time period. The temperature decrease without LTB is significantly less.

Reductions in temperature of feedwater entering the SGs, if not accompanied by a corresponding reduction in steam flow, would result in an increase in core power and create a greater load demand on the RCS. The net effect on the RCS of a reduction in reactor coolant temperature is similar to the effect of increasing secondary steam flow. Such transients are attenuated by the thermal capacity of the secondary plant and of the RCS. The high neutron flux trip, overtemperature ΔT trip, and overpower ΔT trip act to prevent any power increase that could lead to a DNBR less than the limit value. The reactor may reach a new equilibrium condition at a power level corresponding to the new SG ΔT. A small temperature reduction results in only a small increase in reactor power and does not result in a reactor trip. A larger temperature reduction produces a larger increase in reactor power and may cause a power/temperature mismatch and a reactor trip.

15.2.11.3 Analysis of Effects and Consequences

The accident is analyzed with the ITDP and initial condition uncertainties are included in the limit DNBR as described in Reference 5. Therefore, initial conditions of nominal core power, nominal reactor coolant average temperatures and nominal reactor coolant pressure are assumed.

15.2.11.3.1 Temperature Drops Less than 73°F

The protection available to mitigate the consequences of a decrease in feedwater temperature is the same as that for an excessive increase in steam flow event, as discussed in Section 15.2.12. A step load increase of 10 percent from full load was analyzed, and the minimum DNBR for this event was found to be above the safety analysis limit values.

The increase in heat load resulting from a 10 percent increase in load is equivalent to a 73°F drop in feedwater temperature at the SG inlet. Thus a feedwater temperature transient that results in a feedwater temperature drop of 73°F or less at the SG inlets is less severe than the excessive load increase incident presented in Section 15.2.12 and as such does not exceed any safety limits.

15.2.11.3.2 Temperature Drops Greater than 73°F

To address feedwater temperature reductions that exceed 73°F, analyses were performed assuming instantaneous temperature drops of 175°F and 250°F at the SG, with corresponding steam load reductions of 50 percent and 100 percent, respectively. The maximum temperature drop of 250°F was chosen to bound the temperature decrease of 230°F experienced during the net load trip test when the LTBR was actuated in response to a load reduction. In this test, feedwater temperature dropped approximately 230°F over a time period of 400 seconds, which is significantly less severe than the instantaneous drop of 250°F assumed in the analysis. Since LTB has been eliminated, the feedwater temperature drop will be significantly less and is bounded by the instantaneous drop of 250°F assumed in the analysis.

15.2.11.4 Results

Both a 175°F feedwater temperature reduction concurrent with a 50 percent load reduction and a 250°F feedwater temperature reduction concurrent with a full (100 percent) load reduction were analyzed. The analysis shows that the cooldown effects of the large feedwater reduction are more than counteracted by the reduced heat removal resulting from the turbine load reduction, such that the transient causes a heatup of the RCS. As a result, the core power decreases and the DNBR increases during the transient. These cases do not challenge core thermal limits.

15.2.11.5 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) There is margin to the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell).

(2) The total power is maintained below 118 percent of its nominal value. Thus the peak fuel centerline temperature will remain below the fuel melting temperature (refer to Section 4.4.3.2.7).

All safety criteria are met for credible scenarios of sudden feedwater temperature reduction. Instantaneous feedwater temperature reductions up to 73°F result in an RCS cooldown that is bounded by the analysis of an excessive load increase incident presented in Section 15.2.12. This bounds the maximum feedwater temperature decrease of 70°F that could result from the inadvertent opening of a feedwater heater bypass valve. For feedwater temperature reductions during a load reduction transient,

analyses conclude that these cases result in a net RCS heatup and core power decrease, with no significant challenge to the core thermal limits.

15.2.12 EXCESSIVE LOAD INCREASE INCIDENT

15.2.12.1 Acceptance Criteria

The following is the relevant specific acceptance criterion.

(1) The minimum DNBR must not go below the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) (refer to Section 4.4.4.1) at any time during the transient.

15.2.12.2 Identification of Causes and Accident Description

An excessive load increase incident is defined as a rapid increase in the steam flow that causes a power mismatch between the reactor core power and the SG load demand. The reactor control system is designed to accommodate a 10 percent step-load increase or a 5 percent per minute ramp load increase in the range of 15 to 100 percent of full power. Any loading rate in excess of these values may cause a reactor trip actuated by the reactor protection system.

This accident could result from either an administrative violation such as excessive loading by the operator or an equipment malfunction in the steam dump control or turbine speed control.

Protection against an excessive load increase accident is provided by the following reactor protection system signals:

(1) Overpower ΔT

(2) Overtemperature ΔT

(3) Power range high neutron flux

15.2.12.3 Analysis of Effects and Consequences

This accident is analyzed using the LOFTRAN code. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, SG, and SG safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

Four cases are analyzed to demonstrate the plant behavior following a 10 percent step load increase from rated load. These cases are as follows:

(1) Reactor control in manual with BOL minimum moderator reactivity feedback

(2) Reactor control in manual with EOL maximum moderator reactivity feedback

(3) Reactor control in automatic with BOL minimum moderator reactivity feedback

(4) Reactor control in automatic with EOL maximum moderator reactivity feedback

For the BOL minimum moderator feedback cases, the core has the least negative moderator temperature coefficient of reactivity and the least negative Doppler only power coefficient curve; therefore the least inherent transient response capability. For the EOL maximum moderator feedback cases, the moderator temperature coefficient of reactivity has its highest absolute value and the most negative Doppler only power coefficient curve. This results in the largest amount of reactivity feedback due to changes in coolant temperature.

A conservative limit on the turbine valve opening is assumed, and all cases are studied without credit being taken for pressurizer heaters.

The accident is analyzed using the ITDP and the initial condition uncertainties are included in the limit DNBR as described in Reference 5. Therefore, initial conditions of nominal core power, reactor coolant average temperature (plus 2.5°F for SG fouling) and nominal reactor coolant pressure are assumed.

Plant characteristics and initial conditions are further discussed in Section 15.1.

Normal reactor control systems and engineered safety systems are not required to function. The reactor protection system is assumed to be operable; however, reactor trip is not encountered for most cases due to the error allowances assumed in the setpoints. No single active failure will prevent the reactor protection system from performing its intended function.

The cases, which assume automatic rod control, are analyzed to ensure that the worst case is presented. The automatic function is not required.

15.2.12.4 Results

The calculated sequence of events for the excessive load increase incident is shown in Table 15.2-1.

Figures 15.2.12-1 through 15.2.12-4 illustrate the transient with the reactor in the manual control mode. As expected, for the BOL minimum moderator feedback case, there is a slight power increase, and the average core temperature shows a large decrease. This results in a DNBR, which increases above its initial value. For the EOL maximum

moderator feedback manually controlled case, there is a much larger increase in reactor power due to the moderator feedback. A reduction in DNBR is experienced but DNBR remains above the limit value.

Figures 15.2.12-5 through 15.2.12-8 illustrate the transient assuming the reactor is in the automatic control mode. Both the BOL minimum and EOL maximum moderator feedback cases show that core power increases, thereby reducing the rate of decrease in coolant average temperature and pressurizer pressure. For both of these cases, the minimum DNBR remains above the limit value.

For all cases, the plant rapidly reaches a stabilized condition at the higher power level. Normal plant operating procedures would then be followed to reduce power.

The excessive load increase incident is an overpower transient for which the fuel temperatures will rise. Reactor trip does not occur for any of the cases analyzed, and the plant reaches a new equilibrium condition at a higher power level corresponding to the increase in steam flow.

Since DNB is not predicted to occur at any time during the excessive load increase transients, the ability of the primary coolant to remove heat from the fuel rod is not reduced. Thus, the fuel cladding temperature does not rise significantly above its initial value during the transient.

15.2.12.5 Conclusions

The analysis demonstrates that the acceptance criterion is met as follows:

(1) There is margin to the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell). The accompanying DNBR figures for this event (refer to Figures 15.2.12-2, 15.2.12-4, 15.2.12-6 and 15.2.12-8) reflect the results for the more limiting Standard fuel (limit 1.48/1.44) previously in the core. The figures represent the thimble cell results.

The analysis presented above shows that for a 10 percent step load increase, the DNBR remains above the safety analysis limit values, thereby precluding fuel or cladding damage. The plant reaches a stabilized condition rapidly, following the load increase.

15.2.13 ACCIDENTAL DEPRESSURIZATION OF THE REACTOR COOLANT SYSTEM

15.2.13.1 Acceptance Criteria

The following is the relevant specific acceptance criterion.

(1) The minimum DNBR must not go below the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) (refer to Section 4.4.4.1) at any time during the transient.

15.2.13.2 Identification of Causes and Accident Description

An accidental depressurization of the RCS could occur as a result of an inadvertent opening of a pressurizer relief or safety valve. Since a safety valve is sized to relieve approximately twice the steam flowrate of a relief valve, and will therefore allow a much more rapid depressurization upon opening, the most severe core conditions resulting from an accidental depressurization of the RCS are associated with an inadvertent opening of a PSV. Initially, the event results in a rapidly decreasing RCS pressure, which could reach the hot leg saturation pressure if a reactor trip does not occur. The pressure continues to decrease throughout the transient. The effect of the pressure decrease is to decrease the neutron flux via the moderator density feedback, but the reactor control system (if in the automatic mode) functions to maintain the power and average coolant temperature essentially constant until the reactor trip occurs. Pressurizer level increases initially due to expansion caused by depressurization and then decreases following reactor trip.

The reactor will be tripped by the following reactor protection system signals:

(1) Pressurizer low pressure

(2) Overtemperature ΔT

15.2.13.3 Analysis of Effects and Consequences

The accidental depressurization transient is analyzed with the LOFTRAN code. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, SG, and SG safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

This accident is analyzed with the ITDP and the initial condition uncertainties are included in the limit DNBR as described in Reference 5. Therefore, initial conditions of nominal core power, nominal reactor coolant average temperature (plus 2.5 °F for SG fouling) and nominal reactor coolant pressure are assumed.

In order to obtain conservative results, the following assumptions are made:

(1) A positive moderator temperature coefficient of reactivity for (+ 7 pcm/°F) BOL operation is assumed in order to provide a conservatively high amount of positive reactivity feedback due to changes in moderator temperature. The spatial effect of voids due to local or subcooled boiling is not considered in the analysis with respect to reactivity feedback or core power shape. These voids would tend to flatten the core power distribution.

(2) A low (absolute value) Doppler-only power coefficient of reactivity such that the resultant amount of negative feedback is conservatively low in order to maximize any power increase due to moderator reactivity feedback.

15.2.13.4 Results

Figure 15.2.13-1 illustrates the nuclear power transient following the RCS depressurization accident. The nuclear power increases until the time reactor trip occurs on overtemperature ΔT, thus resulting in a rapid decrease in the nuclear power. The time of reactor trip is shown in Table 15.2-1. The pressure decay transient following the accident is given in Figure 15.2.13-2. The resulting DNBR (thimble cell) never goes below the safety analysis limit value as shown in Figure 15.2.13-1.

15.2.13.5 Conclusions

The analysis demonstrates that the acceptance criterion is met as follows:

(1) There is margin to the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) shown on Figure 15.2.13-1.

The pressurizer low pressure and the overtemperature ΔT reactor protection system signals provide adequate protection against this accident, and the minimum DNBR remains in excess of the safety analysis limit value.

15.2.14 ACCIDENTAL DEPRESSURIZATION OF THE MAIN STEAM SYSTEM

15.2.14.1 Acceptance Criteria

The following is the relevant specific acceptance criterion.

(1) Minimum DNBR is not less than the applicable Safety Analysis Limit of 1.45 (W-3 DNB correlation, for coolant pressure less than 1,000 psia) at any time during the transient.

15.2.14.2 Identification of Causes and Accident Description

The most severe core conditions resulting from an accidental depressurization of the MSS are associated with an inadvertent opening of a single steam dump, relief, or safety valve. The analyses, assuming a rupture of a main steam pipe, are discussed in Section 15.4.

The steam released as a consequence of this accident results in an initial increase in steam flow that decreases during the accident as the steam pressure falls. The energy removal from the RCS causes a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in a reduction of core shutdown margin.

The analysis is performed to demonstrate that the following criterion is satisfied: Assuming a stuck RCCA and a single failure in the ESFs the limit DNBR value will be met after reactor trip for a steam release equivalent to the spurious opening, with failure to close, of the largest of any single steam dump, relief, or safety valve.

The following systems provide the necessary mitigation of an accidental depressurization of the MSS.

(1) SIS actuation from any of the following:

  (a) Two-out-of-four low pressurizer pressure signals

  (b) Two-out-of-three low steam line pressure signals on any one loop

(2) The overpower reactor trips (neutron flux and ΔT), the overtemperature ΔT reactor trip, and the reactor trip occurring in conjunction with receipt of the SI signal.

(3) Redundant isolation of the main feedwater lines: Sustained high feedwater flow would cause additional cooldown. Therefore, a SI signal will rapidly close all MFRVs, trip the main feedwater pumps, and close the MFIVs.

15.2.14.3 Analysis of Effects and Consequences

Due to the size of the break and the assumed initial conditions, an accidental depressurization of the MSS event is bounded by the Main Steam Line Rupture accident analyzed in Section 15.4.2.1. As such, no explicit analysis is performed for the accidental depressurization of the MSS. All applicable acceptance criteria are shown to be met via the results and conclusions in Section 15.4.2.1.

15.2.14.4 Conclusions

The applicable acceptance criterion is shown to be met via the results and conclusions in Section 15.4.2.1. The rupture of a main steam line at hot zero power is a Condition IV event that meets the minimum DNBR criterion of the Condition II accidental depressurization of the MSS. The Condition IV event models a large double-ended rupture, with more limiting results than the inadvertent opening of a SG PORV or dump valve, regardless of any differences in safety system actuations. Therefore, demonstrating that the Condition IV event meets the same Condition II criterion for minimum DNBR, as the calculated value is never below the limit value of 1.45 at any time during the transient, satisfies the acceptance criterion for the Condition II event discussed in Section 15.2.14.

15.2.15 SPURIOUS OPERATION OF THE SAFETY INJECTION SYSTEM AT POWER

15.2.15.1 Acceptance Criteria

The following are the relevant specific acceptance criteria.

(1) The minimum DNBR must not go below the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell) (refer to Section 4.4.4.1) at any time during the transient. This criterion is discussed in Section 15.2.15.2.

(2) The spurious safety injection (SSI) event is terminated prior to challenging the PSV liquid water (hereinafter referred to as water) relief capability. This criterion is discussed in Section 15.2.15.3.

The RCS overpressure concern is bounded by the Section 15.2.7 event.

15.2.15.2 Spurious Safety Injection Departure from Nucleate Boiling Ratio Analysis

15.2.15.2.1 Identification of Causes and Accident Description

SSI system operation at power could be caused by operator error or a false electrical actuating signal. A spurious signal may originate from any of the SI actuation channels. Refer to Section 7.2 for a description of the actuation system.

Following the actuation signal, the suction of the coolant charging pumps is diverted from the volume control tank to the RWST. The charging injection valves between the charging pumps and the injection header open automatically. The charging pumps then pump RWST water through the header and injection line and into the cold legs of each loop. The SI pumps also start automatically but provide no flow when the RCS is at normal pressure. The passive injection system and the RHR system also provide no flow at normal RCS pressure.

The analyses of the potential for DNB, loss of fuel integrity, and excessive cooldown are presented in the discussions herein.

An SIS signal normally results in a reactor trip followed by a turbine trip. However, it cannot be assumed that any single fault that actuates the SIS will also produce a reactor trip. Therefore, two different courses of events are considered.

Case A: Trip occurs at the same time spurious injection starts.

Case B: The reactor protection system produces a trip later in the transient.

For Case A, the operator should determine if the spurious signal was transient or steady state in nature; i.e., an occasional occurrence or a definite fault. The operator will determine this by following approved procedures. In the transient case, the operator would stop the SI. If the SIS must be disabled for repair, boration should continue and the plant brought to cold shutdown.

For Case B, the reactor protection system does not produce an immediate trip and the reactor experiences a negative reactivity excursion causing a decrease in the reactor power. The power unbalance causes a drop in T_{avg} and consequent coolant shrinkage, and pressurizer pressure and level drop. Load will decrease due to the effect of reduced steam pressure on load if the electrohydraulic governor fully opens the turbine throttle valve. If automatic rod control is used, these effects will be lessened until the rods have moved out of the core. The transient is eventually terminated by the reactor protection system low-pressure trip or by manual trip.

The time to trip is affected by initial operating conditions including core burnup history that affects initial boron concentration, rate of change of boron concentration, and Doppler and moderator coefficients.

Recovery from this incident for Case B is in the same manner as for Case A. The only difference is the lower T_{avg} and pressure associated with the power imbalance during this transient. The time at which reactor trip occurs is of no concern for this accident. At lighter loads coolant contraction will be slower resulting in a longer time to trip.

15.2.15.2.2 Analysis of Effects and Consequences

The spurious operation of the SIS is analyzed for DNBR with the LOFTRAN program. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, SG, SG safety valves, and the effect of the SIS. The program computes pertinent plant variables including temperatures, pressures, and power level.

Because of the power and temperature reduction during the transient, operating conditions do not approach the core limits. Analyses of several cases show that the results are relatively independent of time to trip.

A typical transient is considered representing conditions at BOL. Results at EOL are similar except that moderator feedback effects result in a slower transient.

The accident is analyzed using the ITDP and the initial condition uncertainties are included in the limit DNBR as described in Reference 5. Therefore, initial conditions of nominal core power, nominal reactor coolant average temperature (plus 2.5°F for SG fouling) and nominal reactor coolant pressure are assumed.

The assumptions used in the analysis are:

(1) Moderator and Doppler Coefficients of Reactivity

A positive BOL moderator temperature coefficient was used. A low absolute value Doppler power coefficient was assumed.

(2) Reactor Control

The reactor was assumed to be in manual control.

(3) Pressurizer Heaters

Pressurizer heaters were assumed to be inoperative in order to increase the rate of pressure drop.

(4) Boron Injection

At time zero, two charging pumps (CCP1 and CCP2) begin injection and pump borated water through the SIS and into the cold leg of each loop.

(5) Turbine Load

Turbine load was assumed constant until the electrohydraulic governor drives the throttle valve wide open. Once the throttle valve is wide open, turbine load drops as the steam pressure decreases.

(6) Reactor Trip

Reactor trip was initiated by low pressure. The trip was conservatively assumed to be delayed until the pressure reached 1860 psia.

15.2.15.2.3 Results

The transient response for the minimum feedback case is shown in Figures 15.2.15-1 and 15.2.15-2. Nuclear power starts decreasing immediately due to boron injection, but steam flow does not decrease until 25 seconds into the transient when the turbine throttle valve goes wide open. The mismatch between load and nuclear power causes Tavg, pressurizer water level, and pressurizer pressure to drop. The low-pressure trip setpoint is reached at 23 seconds and rods start moving into the core at 25 seconds.

15.2.15.2.4 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) There is margin to the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell).

Results of the DNBR analysis show that SSI with or without immediate reactor trip presents no hazard to the integrity of the RCS.

DNBR is never less than the initial value. Thus, there will be no cladding damage and no release of fission products to the RCS.

If the reactor does not trip immediately, the low-pressure reactor trip will be actuated. This trips the turbine and prevents excess cooldown thereby expediting recovery from the incident.

15.2.15.3 Spurious Safety Injection Pressurizer Filling Analysis

The purpose of the SSI pressurizer filling analysis is to demonstrate the SSI pressurizer filling event can be terminated before water is relieved through the pressurizer safety valves (PSVs). Reference 16 establishes that more than three cycles of water relief through the PSVs could potentially result in the PSVs failing open resulting in an unisolable reactor coolant pressure boundary breach. Terminating the SSI pressurizer filling event before water relief through the PSVs occurs prevents this potential failure.

15.2.15.3.1 Identification of Causes and Accident Description

The SSI pressurizer overfill event begins when a safety injection (SI) signal starts the two PG&E Design Class I charging pumps resulting in reactor coolant inventory addition. The SI signal also results in a Phase A containment isolation that causes loss of instrument air to containment, which is required to open the letdown valves to control pressurizer level. If the pressurizer subsequently fills, the pressurizer power-operated relief valves (PORVs) are available to relieve water inventory from the RCS, as long as nitrogen is available from the PG&E Design Class I backup nitrogen accumulators (since instrument air is not available). Since Technical Specifications define a PORV as operable with its block valve closed (if the PORV can be made available for automatic pressure relief), operators may need to take action to open the block valve to enable the

PORV to provide water relief. Using the PORVs to relieve water from the RCS prevents water relief through the PSVs.

Mitigation of pressurizer filling is accomplished by operators taking action to control pressurizer level by isolating charging flow and initiating letdown by re-establishing instrument air to containment, before backup nitrogen to the PORVs is depleted.

The SSI pressurizer filling analysis models the long term plant response and the operator actions needed to mitigate pressurizer filling during a SSI and thus prevent water relief through the PSVs. The operator recovery actions credited for SSI mitigation at power are included in the plant emergency operating procedures (EOPs) and include (1) ensuring a PG&E Design Class I pressurizer PORV is available and (2) controlling pressurizer level using charging and letdown.

15.2.15.3.2 Analysis of Effects and Consequences

The SSI event is analyzed for pressurizer filling in accordance with the NRC approved methodology for a 4-loop plant (Reference 19) using the Westinghouse version of the RETRAN-02 computer code (RETRAN-02W). The code simulates the neutron kinetics, RCS, pressurizer, PORVs and PSVs pressurizer spray, SG, SG safety valves, and safety injection. The code computes pertinent plant variables including temperatures, pressures, and power level.

Separate cases to accommodate different limiting assumptions are analyzed to determine the time by which the operators would need to ensure a PG&E Design Class I PORV is available and the times by which the operators would need to achieve control of pressurizer level using charging and letdown. The beginning of each SSI case is essentially identical as follows.

The SI signal occurs at time zero. This generates a concurrent reactor trip signal from full power conditions followed by a turbine trip signal. The pressurizer pressure and pressurizer level initially decrease as the RCS power and temperature reduce from full power conditions to hot no load conditions. Typically, the initiation of the emergency core cooling system (ECCS) injection flow halts the post trip pressure decrease and then rapidly increases the pressure until the pressurizer spray valves open enough to maintain the pressurizer pressure relatively constant. For this analysis, it is assumed the pressurizer spray valves are not operable and the pressurizer level continues to increase due to ECCS injection flow until the pressurizer fills.

The assumptions for the pressurizer filling analysis are conservatively chosen to minimize the time to reach a water-solid condition and maximize the predicted number of pressurizer PORV relief open/close cycles. Sensitivity studies are performed for a number of parameters to determine the appropriate conservative assumptions. The key assumptions made in the analysis are described below.

(1) Initial Operating Conditions

The initial pressurizer pressure is assumed to be 2,190 psia, which is 60 psi lower than the nominal value. This lower initial RCS pressure results in increased ECCS injection flow during the transient and maximizes the challenges to the PSVs and PORVs.

Initial RCS Tavg values of 559.5ºF and 572.1ºF were analyzed, which correspond to the minimum and maximum values of the nominal Tavg window for Unit 2, less a bounding temperature uncertainty bias. This conservatively maximizes the initial RCS mass, and minimizes the RCS volumetric shrinkage after the reactor trip. For these initial Tavg values, the corresponding programmed initial pressurizer levels are50.8 and 66.8 percent span, respectively, which bound the pressurizer level uncertainty of 5.7 percent span.

(2) Pressurizer Heaters

Both the backup and proportional pressurizer heaters are assumed to remain available during the event, which conservatively maximizes the pressurizer water volume and minimizes the time to fill the pressurizer with water.

(3) Reactor Trip / Turbine Load

The reactor trip occurs coincident with the SI actuation, which results in an immediate turbine trip. There is no credit for heat removal from the steam dump system to the condenser or atmosphere. The MSSVs are assumed to be operable and were modeled to open at conservative set pressures that account for setpoint drift and accumulation. The minimum heat transfer from the primary coolant loop to the secondary system leads to a conservatively early pressurizer fill condition.

(4) Moderator and Doppler Coefficients of Reactivity

The pressurizer filling analysis assumes a positive EOL moderator density coefficient and large absolute value Doppler power coefficient. Since the reactor trip occurs immediately for the pressurizer filling event, these reactivity coefficients have a negligible impact on the results.

(5) Reactor Decay Heat

Conservative core residual heat generation is assumed based on long-term operation at the initial power level preceding the trip. The ANS 5.1-1979 decay heat model+ 2σ is used for calculation of residual decay heat levels.

(6) Pressurizer PORVs

No credit is taken for relief through the PORV that is actuated on a compensated pressurizer pressure deviation signal (i.e., the non-safety-grade, PG&E Design Class II PORV). However, relief through the PORVs that are actuated on the indicated (measured) pressurizer pressure signal (i.e., the safety-grade, PG&E Design Class I PORVs) has been modeled with assumptions that maximize the number of PORV opening cycles experienced. The number of safety-grade PORVs available for relief depends on the single failure being considered as discussed in the results section.

Since an SI signal causes Phase A containment isolation and the instrument air is a PG&E Design Class II (non-safety-grade) system, there is a loss of instrument air to containment due to this signal. Accordingly, the PG&E Design Class I backup nitrogen accumulators are needed to maintain functionality of the PG&E Design Class I PORVs. The backup nitrogen accumulators are each sized and leak tested to ensure at least 300 PORV cycles before the backup nitrogen supply is depleted, after which the PORV would be unavailable. Therefore, transient mitigation must be demonstrated to occur before 300 PORV cycles is reached.

(7) ECCS Injection Flow

Maximum SI flow rates were conservatively modeled with a flow profile that bounds the maximum flow from the two PG&E Design Class I high-head centrifugal charging pumps (CCP1 and CCP2), plus two intermediate-head SI pumps. The SI flow profile is shown in Figure 15.2.15-6. Full SI flow was conservatively assumed to occur immediately after the SI actuation signal. The RWST fluid temperature is assumed to be 35°F to maximize the ECCS fluid density.

(8) Pressurizer Sprays

The air-operated pressurizer spray valves are assumed to be inoperable, since instrument air to containment is lost on an SI signal and normal pressurizer spray flow is unavailable following coastdown of the RCPs. There are auxiliary spray lines that are equipped with backup nitrogen if the spray valves are unavailable; however, auxiliary spray requires a manual alignment that would not be completed until after the TCOAs necessary to mitigate this transient are complete.

15.2.15.3.3 Results

The sequences of events for the three cases evaluated for the pressurizer filling cases are listed in Table 15.2-1. Typical transient responses are shown in Figures 15.2.15-3 through 15.2.15-5.

Case to establish the maximum time available to ensure a PG&E Design Class I pressurizer PORV is available

This case determines the maximum time available for operations to ensure a PG&E Design Class I pressurizer PORV is available before water relief through the PSVs occurs. Both PG&E Design Class I pressurizer PORVs are assumed to be unavailable, with one failed and the other isolated by the block valve as allowed by Technical Specifications.

Because the PORVs are unavailable the RCS experiences a rapid pressure increase to the PSV lift setpoint. The pressurizer level continues to increase until the pressurizer fills and the first water relief through the PSV occurs at 904 seconds (~15.1 minutes). This establishes the maximum time available for the operators to unblock a pressurizer PORV to prevent water relief through the PSVs.

Case to establish the minimum time to pressurizer filling

The case to establish the minimum time to pressurizer filling assumes that both PG&E Design Class I PORVs are available, which results in the earliest filling of the pressurizer and earliest initiation of water relief through the pressurizer PORVs. For this scenario, the RCS pressure increases only to the PORV lift setpoint where it is maintained within a relatively constant range as the PORV continues to cycle and relieve steam until the pressurizer becomes water solid. The minimum time to pressurizer filling was determined to be 11.5 minutes.

Case to establish the minimum time to deplete the backup nitrogen accumulators

In the case to establish the minimum time to deplete the nitrogen accumulators, one PORV is assumed to be available. The RCS pressure increases only to the pressurizer PORV lift setpoint, at which time the PORV starts to cycle and relieve steam as the pressurizer level increases due to the ECCS injection flow. Since the RCS pressure is maintained near the PORV setpoint, rather than the PSV setpoint, the pressurizer fills earlier than the case to establish the maximum allowable time to make a PORV available. Once the pressurizer becomes water solid, the PORV begins relieving water. The PORV generates less of a setpoint undershoot while relieving water. As a result, the PORV cycles at a slightly faster rate than when relieving steam. The analysis determines the minimum time to reach 300 PORV cycles and deplete the backup nitrogen accumulator for a single PORV is 45.8 minutes. This establishes the maximum time available for operators to control pressurizer level before water relief through the PSVs occurs.

The results of the SSI analysis for pressurizer filling demonstrate that, if the pressurizer fills, the following TCOAs preclude water relief through the PSVs:

(1) Ensure a PG&E Design Class I pressurizer PORV is available within 15 minutes

If no pressurizer PORV relief is available at the start of the transient because a PG&E Design Class I PORV is not available, operator action is required to ensure a PG&E Design Class I PORV is available in time to prevent water relief through the PSVs. The analysis determined that the minimum time to lift the PSVs is 15.1 minutes; therefore, the operators must ensure a PG&E Design Class I PORV is available within 15 minutes after event initiation.

(2) Control pressurizer level using charging and letdown within 45 minutes

The EOPs direct operators to reduce charging flow by stopping charging pumps and to re-establish RCS letdown by restoring instrument air to containment. Once the pressurizer level is controlled, there is no longer a concern relative to water relief through the PSVs and transient mitigation is complete. The results of the limiting case determined the operators must control pressurizer level by reducing charging flow and establishing letdown within 45 minutes after event initiation.

15.2.15.3.4 Conclusions

The analysis demonstrates the acceptance criterion is met as follows:

(1) The SSI event is terminated prior to challenging the PSV water relief capability. The SSI pressurizer filling analysis demonstrates that with timely operator actions the SSI event can be terminated before water relief through the PSVs occurs, which prevents the potential generation of a more serious plant event. For the limiting SSI event, the operators have a maximum of about 15 minutes after event initiation to ensure a PG&E Design Class I pressurizer PORV is available before water relief through the PSVs occurs. In addition, with the worst-case control system operation, the operators must terminate the SSI event within 45 minutes to prevent depleting the PG&E Design Class I pressurizer PORV backup nitrogen accumulators.

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23. Diablo Canyon Units 1 and 2 Replacement Steam Generator NSSS Licensing Report, WCAP-16638-P, Revision 1 (Proprietary), January 2008.

15.3 CONDITION III - INFREQUENT FAULTS

By definition, Condition III occurrences are faults that may occur very infrequently during the life of the plant. They will be accompanied with the failure of only a small fraction of the fuel rods although sufficient fuel damage might occur to preclude resumption of operation for a considerable outage time. The release of radioactivity will not be sufficient to interrupt or restrict public use of those areas beyond the exclusion radius. A Condition III fault will not, by itself, generate a Condition IV fault or result in a consequential loss of function of the RCS or containment barriers. For the purposes of this report the following faults have been grouped into this category:

(1) Loss of reactor coolant, from small ruptured pipes or from cracks in large pipes, that actuates the ECCS.

(2) Minor secondary system pipe breaks.

(3) Inadvertent loading of a fuel assembly into an improper position.

(4) Complete loss of forced reactor coolant flow.

(5) Single RCCA withdrawal at full power.

Each of these infrequent faults is analyzed in this section. In general, each analysis includes acceptance criteria, an identification of causes and description of the accident, an analysis of effects and consequences, a presentation of results, and relevant conclusions.

The time sequences of events during a Condition III faults of type (1) above, SBLOCA, are shown in Tables 15.4.1.3-2A and 15.4.1.3-2B.

15.3.1 LOSS OF REACTOR COOLANT FROM SMALL RUPTURED PIPES OR FROM CRACKS IN LARGE PIPES THAT ACTUATES EMERGENCY CORE COOLING SYSTEM

Small break loss-of-coolant accident (SBLOCA) analyses have been performed for Diablo Canyon Power Plant Units 1 and 2 using the FULL SPECTRUM™ loss-of-coolant accident (FSLOCA™) evaluation model (EM).

The break sizes considered in the Westinghouse FULL SPECTRUM LOCA EM include what traditionally are defined as Small and Large Break LOCA (LBLOCA). The traditional SBLOCA analysis is referred to as the Region 1 analysis, and the traditional LBLOCA analysis is referred to as the Region II analysis.

The FSLOCA EM analyses for Diablo Canyon Power Plant Units 1 and 2 are discussed in Section 15.4.1 since the LBLOCA (Region II) analysis is more limiting than the SBLOCA (Region 1) analysis.

15.3.1.1 Acceptance Criteria

15.3.1.1.1 10 CFR 50.46 - Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors

(1) *Peak cladding temperature (PCT).* The calculated maximum fuel element cladding temperature shall not exceed 2200°F.

(2) *Maximum cladding oxidation*. The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

(3) *Maximum hydrogen generation*. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react. This reduces the potential for explosive hydrogen/oxygen mixtures inside containment.

(4) *Coolable geometry*. Calculated changes in core geometry shall be such that the core remains amenable to cooling.

(5) *Long-term cooling*. After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

15.3.1.1.2 Radiological Criteria

The radiological consequences of a SBLOCA are within a small fraction of the applicable guidelines and limits specified in 10 CFR 50.67 detailed in Section 15.5.11.

15.3.1.2 DELETED

15.3.1.3 DELETED

15.3.1.4 DELETED

15.3.1.5 DELETED

15.3.2 MINOR SECONDARY SYSTEM PIPE BREAKS

15.3.2.1 Acceptance Criteria

(1) The minimum DNBR does not go below the safety analysis limit (refer to Sections 15.4.2.1.1 and 15.4.2.3.1) at any time during the transient to

ensure that the core remains geometrically intact with no loss of core cooling capability.

(2) Any activity release must be such that the calculated doses at the site boundary are a small fraction of the applicable guidelines and limits specified in 10 CFR 50.67 as detailed in Section 15.5.12.

15.3.2.2 Identification of Causes and Accident Description

Included in this grouping are ruptures of secondary system lines which would result in steam release rates equivalent to a 6-inch diameter break or smaller.

15.3.2.3 Analysis of Effects and Consequences

Minor secondary system pipe breaks must not result in more than the failure of only a small fraction of the fuel elements in the reactor. Since the results of analysis presented in Section 15.4.2 for a major secondary system pipe rupture also meet these criteria, separate analyses for minor secondary system pipe breaks is not required.
The analyses of the more probable accidental opening of a secondary system steam dump, relief, or safety valve is presented in Section 15.2.14. These analyses are illustrative of a pipe break equivalent in size to a single valve opening.

15.3.2.4 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) The analysis presented in Section 15.4.2 demonstrates that the consequences of a minor secondary system pipe break are acceptable because a DNBR of less than the design basis values does not occur even for a more critical major secondary system pipe break.

(2) Section 15.5.12 demonstrates the potential radiological exposures to the public following a minor secondary system pipe rupture are within a small fraction of the applicable guidelines and limits specified in 10 CFR 50.67.

15.3.3 INADVERTENT LOADING OF A FUEL ASSEMBLY INTO AN IMPROPER POSITION

15.3.3.1 Acceptance Criteria

(1) In the event of a fuel loading error not identified until normal operation, the offsite dose consequences should be a small fraction of the applicable guidelines and limits specified in 10 CFR 50.67 as detailed in Section 15.5.1.

15.3.3.2 Identification of Causes and Accident Description

Fuel and core loading errors such as inadvertently loading one or more fuel assemblies into improper positions, loading a fuel rod during manufacture with one or more pellets of the wrong enrichment, or loading a full fuel assembly during manufacture with pellets of the wrong enrichment will lead to increased heat fluxes if the error results in placing fuel in core positions calling for fuel of lesser enrichment. The inadvertent loading of one or more fuel assemblies requiring burnable poison rods into a new core without burnable poison rods is also included among possible core loading errors.

Any error in enrichment, beyond the normal manufacturing tolerances, can cause power shapes that are more peaked than those calculated with the correct enrichments. The incore system of movable neutron flux detectors that is used to verify power shapes at the start of life is capable of revealing any assembly enrichment error or loading error that causes power shapes to be peaked in excess of the design value.

To reduce the probability of core loading errors, each fuel assembly is marked with an identification number and loaded in accordance with a core loading diagram. For each core loading, the identification number is checked to ensure proper core configuration. The power distortion due to any combination of misplaced fuel assemblies would significantly raise peaking factors and would be readily observable with movable incore neutron flux detectors. In addition to the flux detectors, thermocouples are located at the outlet of about one-third of the fuel assemblies in the core. There is a high probability that these thermocouples would also indicate any abnormally high coolant enthalpy rise. Incore flux measurements are taken during the startup subsequent to every refueling operation. A more detailed discussion of the flux detection capabilities may be found in Section 4.3.3.2.

15.3.3.3 Analysis of Effects and Consequences

Steady state power distributions in the x-y plane of the core are calculated with the TURTLE code (refer to Section 1.6.1, Item 49, and Section 4.3.3.8.5), based on macroscopic cross-sections calculated by the LEOPARD code (refer to Section 1.6.1, Item 48, and Section 4.3.3.10.2). A discrete representation is used wherein each individual fuel rod is described by a mesh interval. The power distributions in the x-y plane for a correctly loaded core assembly are given in Chapter 4 based on enrichments given in that section.

For each core loading error case analyzed, the percent deviations from detector readings for a normally loaded core are shown at all incore detector locations (refer to Figures 15.3-15 through 15.3-19).

15.3.3.4 Results

The following core loading error cases have been analyzed:

(1) Case A

The case in which a Region 1 assembly is interchanged with a Region 3 assembly. The particular case considered was the interchange of two adjacent assemblies near the periphery of the core (refer to Figure 15.3-15).

(2) Case B

The case in which a Region 1 assembly is interchanged with a neighboring Region 2 fuel assembly. Two analyses have been performed for this case (refer to Figures 15.3-16 and 15.3-17).

In Case B-1, the interchange is assumed to take place with the burnable poison rods transferred with the Region 2 assembly mistakenly loaded into Region 1.

In Case B-2, the interchange is assumed to take place closer to core center and with burnable poison rods located in the correct Region 2 position but in a Region 1 assembly mistakenly loaded into the Region 2 position.

(3) Case C

Enrichment error: the case in which a Region 2 fuel assembly is loaded in the core central position (refer to Figure 15.3-18).

(4) Case D

The case in which a Region 2 fuel assembly instead of a Region 1 assembly is loaded near the core periphery (refer to Figure 15.3-19).

15.3.3.5 Conclusions

In the event that a single rod or pellet has a higher enrichment than the nominal value, the consequences in terms of reduced DNBR and increased fuel and cladding temperatures will be limited to the incorrectly loaded rod or rods.

Fuel assembly loading errors are prevented by administrative procedures implemented during core loading. In the unlikely event that a loading error occurs, analyses in this section confirm that resulting power distribution effects will either be readily detected by the incore movable detector system or will cause a sufficiently small perturbation to be acceptable within the uncertainties allowed between nominal and design power shapes.

The analysis demonstrates the acceptance criterion is met as follows:

(1) No events leading to environmental radiological consequences are expected as a result of loading errors (refer to Section 15.5.13).

15.3.4 COMPLETE LOSS OF FORCED REACTOR COOLANT FLOW

15.3.4.1 Acceptance Criteria

(1) Maintain the minimum DNBR greater than the safety analysis limit for fuel (refer to Section 4.4.3.1).

15.3.4.2 Identification of Causes and Accident Description

A complete loss of forced reactor coolant flow may result from a simultaneous loss of electrical supplies to all RCPs. If the reactor is at power at the time of the accident, the immediate effect of loss of coolant flow is a rapid increase in the coolant temperature. This increase could result in DNB with subsequent fuel damage if the reactor were not tripped promptly. The following reactor trips provide necessary protection against a loss of coolant flow accident:

(1) Low RCL flow (primary protection)

(2) Undervoltage or underfrequency on RCP power supply buses (backup protection to low RCL flow trip)

(3) Pump circuit breaker opening (also backup to low RCL flow trip)

The reactor trip on low RCL flow is provided as primary protection against loss-of-flow conditions. This function is generated by two-out-of-three low-flow signals per RCL. Above approximately 35 percent power (Permissive 8), low flow in any loop will actuate a reactor trip. Between approximately 10 and 35 percent power (Permissive 7 and Permissive 8), low-flow in any two loops will actuate a reactor trip.

The reactor trip on RCP bus undervoltage is provided as protection against conditions that can cause a loss of voltage to all RCPs (i.e., LOOP). This function serves as backup protection to the low RCL flow trip and is blocked below approximately 10 percent power (Permissive 7).

The reactor trip on RCP underfrequency is provided to trip the reactor for an underfrequency condition, resulting from frequency disturbances on the major power grid. Underfrequency also opens the RCP breakers that disengage the RCPs from the power grid so that the pumps flywheel kinetic energy is available for full coastdown. This function also serves as backup protection to the low RCL flow trip.

A reactor trip from opened pump breakers is also provided as a backup to the low-flow signals. Above Permissive 7 a breaker open signal from any 2 of 4 pumps will actuate a reactor trip. Reactor trip on RCP breakers open is blocked below Permissive 7.

Normal power for the RCPs is supplied through buses from a transformer connected to the generator. Two pumps are on each bus. When a generator trip occurs, the buses are automatically transferred to a transformer supplied from external power lines, and the pumps will continue to supply coolant flow to the core. Following any turbine trip, where there are no electrical or mechanical faults which require immediate tripping of the generator from the network, the generator remains connected to the network for approximately 30 seconds. The RCPs remain connected to the generator thus ensuring full flow for 30 seconds after the reactor trip before any transfer is made.

15.3.4.3 Analysis of Effects and Consequences

This transient is analyzed by three digital computer codes. First the LOFTRAN (Reference 8) code is used to calculate the loop and core flow during the transient. The LOFTRAN code is used to calculate the nuclear power transient. The FACTRAN (Reference 9) code is then used to calculate the heat flux transient based on the nuclear power and flow from LOFTRAN. Finally, the THINC-IV code (refer to Section 4.4.3.4) is used to calculate the minimum DNBR during the transient based on the heat flux from FACTRAN and flow from LOFTRAN. The transients presented represent the minimum of the typical and thimble cells.

The following cases have been analyzed:

(1) Four of four loops coasting down.

(2) RCPs power supply frequency decay at a maximum constant 3 Hz/sec rate (underfrequency).

The method of analysis and the assumptions made regarding initial operating conditions and reactivity coefficients are identical to those discussed in Section 15.2 and Table 15.1-4, except that following the loss of electrical supply to all pumps at power, the reactor trip is actuated by low RCL flow rather than bus undervoltage or bus underfrequency.

15.3.4.4 Results

The calculated sequence of events is shown in Table 15.3-3. Figures 15.3.4-1 through 15.3.4-3 show the flow coastdown, the heat flux response, and the nuclear power response for the limiting complete loss of flow event (four-loop coastdown). For analysis purposes, the reactor is assumed to trip on the low RCL flow signal, as this trip signal is PG&E Design Class I, while the undervoltage and underfrequency trips are PG&E Design Class II. Because the low RCL flow trip responds to an actual condition (while the undervoltage/underfrequency trips are anticipatory), the reactor trip is delayed and the transient is more DNBR limiting. A plot of DNBR versus time is given in Figure 15.3.4-4. This plot represents the limiting (thimble) cell for the four-loop coastdown.

Figures 15.3.4-1 through 15.3.4-4 present only the Unit 1 results; however, the Unit 2 results are nearly identical. Therefore, the figures are representative of Unit 2 response.

15.3.4.5 Conclusions

The safety analysis results described in Section 15.3.4.4 have demonstrated that for the complete loss of forced reactor coolant flow, the minimum DNBR is above the safety analysis limit values of 1.71/1.68 (typical cell/thimble cell) during the transient; therefore, no core safety limit is violated.

15.3.5 SINGLE ROD CLUSTER CONTROL ASSEMBLY WITHDRAWAL AT FULL POWER

15.3.5.1 Acceptance Criteria

(1) No more than 5 percent of the fuel rods experience a DNBR less than the limit value.

15.3.5.2 Identification of Causes and Accident Description

By design, no single electrical or mechanical failure in the rod control system could cause the accidental withdrawal of a single RCCA from the inserted bank at full power operation. The operator could deliberately withdraw a single RCCA in the control bank; this feature is necessary in order to retrieve an assembly should one be accidentally dropped. In the extremely unlikely event of simultaneous electrical failures that could result in single RCCA withdrawal, rod deviation and control rod urgent failure may be displayed on the plant annunciator, and the rod position indicators would indicate the relative positions of the assemblies in the bank. The urgent failure alarm also inhibits automatic rod motion in the group in which it occurs. Withdrawal of a single RCCA by operator action, whether deliberate or by a combination of errors, would result in activation of the same alarm and the same visual indications.

Each bank of RCCAs in the system is divided into two groups of four mechanisms each (except Group 2 of Bank D which consists of five mechanisms). The rods comprising a group operate in parallel through multiplexing thyristors. The two groups in a bank move sequentially such that the first group is always within one step of the second group in the bank. A definite schedule of actuation and deactuation of the stationary gripper, movable gripper, and lift coils of a mechanism is required to withdraw the RCCA attached to the mechanism. Since the four stationary grippers, movable grippers, and lift coils associated with the four RCCAs of a rod group are driven in parallel, any single failure that would cause rod withdrawal would affect a minimum of one group, or four RCCAs. Mechanical failures are either in the direction of insertion or immobility.

In the unlikely event of multiple failures that result in continuous withdrawal of a single RCCA, it is not possible, in all cases, to provide assurance of automatic reactor trip so that core safety limits are not violated. Withdrawal of a single RCCA results in both positive reactivity insertion tending to increase core power, and an increase in local power density in the core area covered by the RCCA.

15.3.5.3 Analysis of Effects and Consequences

Power distributions within the core are calculated by the ANC code based on macroscopic cross-sections generated by PHOENIX-P (refer to Section 4.3.3.10.2). The peaking factors calculated by ANC (refer to Section 4.3.3.10.3) are then used by THINC (refer to Section 1.6.1, Item 28, and Section 4.4.3) to calculate the minimum DNBR for the event. The plant was analyzed for the case of the worst rod withdrawn from Control Bank D inserted at the insertion limit, with the reactor initially at full power.

15.3.5.4 Results

Two cases have been considered as follows:

(1) If the reactor is in the automatic control mode, withdrawal of a single RCCA will result in the immobility of the other RCCAs in the controlling bank. The transient will then proceed in the same manner as Case 2 described below. For such cases as above, a trip will ultimately ensue, although not sufficiently fast in all cases to prevent a minimum DNBR in the core of less than the safety limit.

(2) If the reactor is in the manual control mode, continuous withdrawal of a single RCCA results in both an increase in core power and coolant temperature, and an increase in the local hot channel factor in the area of the failed RCCA. In terms of the overall system response, this case is similar to those presented in Section 15.2; however, the increased local power peaking in the area of the withdrawn RCCA results in lower minimum DNBR than for the withdrawn bank cases. Depending on initial bank insertion and location of the withdrawn RCCA, automatic reactor trip may not occur sufficiently fast to prevent the minimum core DNBR from falling below the safety limit value. Evaluation of this case to determine the most limiting DNBR condition, which would occur at the power and coolant condition at which the overtemperature ΔT trip would be expected to trip the plant shows that an upper limit for the number of rods with a DNBR less than the safety limit value is 5 percent.

15.3.5.5 Conclusions

The analysis demonstrates the acceptance criterion is met as follows:

(1) For both cases of one RCCA fully withdrawn, with the reactor in either the automatic or manual control mode and initially operating at full power with

Bank D at the insertion limit, 5 percent or less of the total fuel rods in the core will go below the minimum DNBR safety analysis limit.

For both cases discussed, the indicators and alarms mentioned would function to alert the operator to the malfunction before any DNB could occur. For Case 2 discussed above, the insertion limit alarms (low and low-low alarms) would also serve in this regard. However, operator action is not required to meet the acceptance criteria.

15.3.6 REFERENCES

1. Deleted in Revision 3.

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3. Deleted in Revision 27.

4. Deleted in Revision 27.

5. Deleted in Revision 15.

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8. T. W. T. Burnett, et al., LOFTRAN Code Description, WCAP-7907-A, April 1984.

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10. Deleted in Revision 21.

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14. Deleted in Revision 13.

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17. Deleted in Revision 12.

18. Deleted in Revision 12.

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21. Deleted in Revision 12.

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27. T. Q. Nguyen, et al., Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores, WCAP-11596-P-A, June 1988.

28. S. L. Davidson, (Ed), et al., ANC: Westinghouse Advanced Nodal Computer Code, WCAP-10965-P-A, September 1986.

29. WCAP 16-996-P-A, Revision 1, "Realistic LOCA Evaluation Methodology Applied to the Full Spectrum of Break Sizes (FULL SPECTRUM LOCA Methodology)."

15.4 CONDITION IV - LIMITING FAULTS

Condition IV occurrences are faults that are not expected to take place, but are postulated because their consequences would include the potential for the release of significant amounts of radioactive material. These are the most drastic occurrences that must be designed against and represent limiting design cases. Condition IV faults shall not cause a fission product release to the environment resulting in an undue risk to public health and safety in excess of guideline values of 10 CFR 50.67 and Regulatory Guide 1.183, July 2000. A single Condition IV fault shall not cause a consequential loss of required functions of systems needed to cope with the fault including those of the ECCS and the containment. For the purposes of this report the following faults have been classified in this category:

(1) Major rupture of pipes containing reactor coolant up to and including double-ended rupture of the largest pipe in the RCS; i.e., LOCA

(2) Major secondary system pipe ruptures

(3) Steam generator tube rupture (SGTR)

(4) Single RCP locked rotor

(5) Fuel handling accident (FHA)

(6) Rupture of a control rod mechanism housing (RCCA ejection)

Each of these six limiting faults is analyzed in this section. In general, each analysis includes acceptance criteria, an identification of causes and description of the accident, an analysis of effects and consequences, a presentation of results, and relevant conclusions.

The analyses of dose consequences, resulting from events leading to fission product release, are presented in Section 15.5. The fission product inventories that form a basis for these calculations are presented in Chapter 11 and Section 15.5. Also included is a discussion of system interdependency contributing to limiting fission product leakages from the containment following a Condition IV occurrence.

The results of the LOCA analyses are discussed in Sections 15.4.1.3.1.2A, 15.4.1.3.1.2B, 15.1.3.2.2A, and 15.4.1.3.2.2B respectively.

15.4.1 MAJOR REACTOR COOLANT SYSTEM PIPE RUPTURES (LOSS-OF-COOLANT ACCIDENT)

The reactor is designed to withstand thermal effects caused by a LOCA including the double-ended severance of the largest RCS pipe. The reactor core and internals together with the ECCS are designed so that the reactor can be safely shut down and the essential heat transfer geometry of the core preserved following the accident.

The ECCS, even when operating during the injection mode with the most severe single active failure, is designed to meet the acceptance criteria of 10 CFR 50.46.

15.4.1.1 Acceptance Criteria

15.4.1.1.1 10 CFR - Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors

It must be demonstrated that there is a high level of probability that the limits set forth in 10 CFR 50.46 are met. The acceptance criteria are listed below:

(1) Peak cladding temperature (PCT). The calculated maximum fuel element cladding temperature shall not exceed 2200 °F.

(2) Maximum cladding oxidation. The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

(3) Maximum hydrogen generation. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

(4) Coolable geometry. Calculated changes in core geometry shall be such that the core remains amenable to cooling.

(5) Long-term cooling. After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

15.4.1.1.2 Radiological Criteria

(1) The resulting potential exposures to individual members of the public and to the general population shall be lower than the applicable guidelines and

limits specified in 10 CFR Part 50.67 and Section 4.4, Table 6 of Regulatory Guide 1.183, July 2000.

15.4.1.2 FULL SPECTRUM LOCA Evaluation Model

15.4.1.2.1 Introduction

The FULL SPECTRUM LOCA EM (Reference 76) was developed to address the full spectrum of loss-of-coolant accidents (LOCAs) which result from a postulated break in the reactor coolant system (RCS) of a pressurized water reactor (PWR). The break sizes considered in the Westinghouse FULL SPECTRUM LOCA EM include any break size in which break flow is beyond the capacity of the normal charging pumps, up to and including a double ended guillotine (DEG) rupture of an RCS cold leg with a break flow area equal to two times the pipe area, including what traditionally are defined as Small and Large Break LOCAs.

The break size spectrum is divided in two regions. Region I analyzes breaks that are typically defined as Small Break LOCAs (SBLOCAs). Region II includes break sizes that are typically defined as Large Break LOCAs (LBLOCAs).

The FULL SPECTRUM LOCA EM explicitly considers the effects of fuel pellet thermal conductivity degradation (TCD) and other burnup-related effects by calibrating to fuel rod performance data input generated by the PAD5 code (Reference 77), which explicitly models TCD and is benchmarked to high burnup data in Reference 77. The fuel pellet thermal conductivity model in the WCOBRA/TRAC-TF2 code used in the FSLOCA EM explicitly accounts for pellet thermal conductivity degradation.

Three 10 CFR 50.46 criteria (peak cladding temperature (PCT), maximum local oxidation (MLO), and core-wide oxidation (CWO) are considered directly in the FSLOCA EM. A high probability statement is developed for the PCT, MLO, and CWO that is needed to demonstrate compliance with 10 CFR 50.46 acceptance criteria (b)(1), (b)(2), and (b)(3) (Reference 1) via statistical methods. The MLO is defined as the sum of pre-transient corrosion and transient oxidation consistent with the position in Reference 78. The coolable geometry acceptance criterion, 10 CFR 50.46(b)(4), is assured by compliance with acceptance criteria (b)(1), (b)(2), and (b)(3), and demonstrating that grid deformation due to combined seismic and LOCA loads does not extend to the in-board fuel assemblies such that a coolable geometry is maintained.

The FSLOCA EM has been generically approved by the Nuclear Regulatory Commission (NRC) for Westinghouse 3-loop and 4-loop plants with cold leg Emergency Core Cooling System (ECCS) injection (Reference 76). Since the Diablo Canyon Power Plant units are Westinghouse designed 4-loop plants with cold leg ECCS injection, the approved method is applicable to Diablo Canyon Power Plant Units 1 and 2.

Section 15.4.1.3 summarizes the application of the Westinghouse FSLOCA EM to Diablo Canyon Power Plant Units 1 and 2. The application of the FSLOCA EM to Diablo Canyon Power Plant Units 1 and 2 is consistent with the NRC approved methodology in WCAP-16996-P-A, Revision 1 (Reference 76) with the corrections and changes reported in LTR-NRC-18-30 (Reference 80) pursuant to 10 CFR 50.46. The application of the FSLOCA EM is also applicable for the Diablo Canyon Power Plant Units 1 and 2 plant design and operating conditions.

The major plant parameter and analysis assumptions used in the Diablo Canyon Power Plant analyses with the FSLOCA EM are provided in Table 15.4.1.2-1A for Unit 1, Table 15.4.1.2-1B for Unit 2, and Tables 15.4.1.2-2 to 15.4.1.2-7 for both Units 1 and 2,

15.4.1.2.2 Method of Analysis

15.4.1.2.2.1 FULL SPECTRUM LOCA Evaluation Model Development

In 1988, the NRC Staff amended the requirements of 10 Code of Federal Regulations (CFR) 50.46 (References 1 and 54) and Appendix K, “ECCS Evaluation Models,” to permit the use of a realistic EM to analyze the performance of the ECCS during a hypothetical LOCA. Under the amended rules, best-estimate thermal-hydraulic models may be used in place of models with Appendix K features. After the rule change, Westinghouse developed and received approval for a best-estimate LBLOCA EM, which is discussed in WCAP-12945-P-A (Reference 56). The EM is referred to as the Code Qualification Document (CQD). Then, Westinghouse developed and received approval for a best-estimate LBLOCA EM discussed in WCAP-16009-P-A (Reference 69) referred to as the Automated Statistical Treatment of Uncertainty Method (ASTRUM). Both the CQD and ASTRUM EMs were developed following Regulatory Guide (RG) 1.157 (Reference 55).

When the FSLOCA EM was being developed, the NRC issued RG 1.203 (Reference 79) which expands on the principles of RG 1.157, while providing a more systematic approach to the development and assessment process of a PWR accident and safety analysis EM. Therefore, the development of the FSLOCA EM followed the Evaluation Model Development and Assessment Process (EMDAP), which is documented in RF 1.203. While RG 1.203 expands upon RG 1.157, there are certain aspects of RG 1.157 which are more detailed than RG 1.203; therefore, both RGs were used for the development of the FSLOCA EM.

Due to the significant differences between the Unit 1 and Unit 2 reactor vessel internals, plant-specific vessel models were developed and evaluated. The significant differences between the units are summarized below:

Unit 1	Unit 2
"Top Hat"-Upper Support Plate	Flat Upper Support Plate
Domed Lower Support Plate	Flat Lower Support Plate
Thermal Shield	Neutron Pads
Diffuser Plate	No Diffuser Plate
Downflow	Upflow
T-hot Upper Head Temperature	Returned to T-Cold Upper Head Temperature

Subsequent subsections describe the respective results from the Unit 1 and Unit 2 FSLOCA EM analyses.

15.4.1.2.2.2 WCOBRA/TRAC-TF2 COMPUTER CODE

The FULL SPECTRUM LOCA EM (Reference 76) uses the WCOBRA/TRAC-TF2 code to analyze the system thermal-hydraulic response for the full spectrum of break sizes. WCOBRA/TRAC-TF2 was created by combining a 1D module (TRAC-P) with a 3D module (based on Westinghouse modified COBRA-TF). The 1D and 3D modules include an explicit non-condensable gas transport equation. The use of TRAC-P allows for the extension of a two-fluid, six-equation formulation of the two-phase flow to the 1D loop components. This new code is WCOBRA/TRAC-TF2, where "TF2" is an identifier that reflects the use of a three-field (TF) formulation of the 3D module derived by COBRA-TF and a two-fluid (TF) formulation of the 1D module based on TRAC-P.

This best-estimate computer code contains the following features:

1. Ability to model transient three-dimensional flows in different geometries inside the vessel

2. Ability to model thermal and mechanical non-equilibrium between phases

3. Ability to mechanistically represent interfacial heat, mass, and momentum transfer in different flow regimes.

4. Ability to represent important reactor components such as fuel rods, steam generators (SGs), reactor coolant pumps (RCPs), etc.

A detailed assessment of the computer code WCOBRA/TRAC-TF2 was made through comparisons to experimental data. These assessments were used to develop quantitative estimates of the ability of the code to predict key physical phenomena for a LOCA. Modeling of a LOCA introduces additional uncertainties which are identified and quantified in the plant-specific analysis. The vessel and loop noding scheme used in the FSLOCA EM is consistent with the noding scheme used for the experiment simulations that form the validation basis for the physical models in the code. Such noding choices have been justified by assessing the model against large and full scale experiments.

15.4.1.3 FSLOCA EM ANALYSIS

15.4.1.3.1 SBLOCA (Region 1) Analysis

Identification of Cause and Accident Description

A LOCA is defined as a rupture of the RCS piping or of any line connected to the system. This includes small pipe ruptures, historically a 3/8-inch diameter opening up to and including a break size of 1.0 square foot, that result in break flow rates greater than the makeup flow rate from either Centrifugal Charging Pump 1 (CCP1) or CCP2. The coolant that would be released to containment contains fission products. The small pipe break analysis for Diablo Canyon Power Plant Units 1 and 2 considers a spectrum of break sizes to ensure that the small breaks with a likelihood of the most severe core uncover are captured within the analysis.
Following the postulate break, a depressurization of the RCS and a loss of coolant would result. A reactor trip occurs when the pressurizer low pressure trip setpoint is reached. Safety injection (SI) is actuated when the low pressurizer pressure SI setpoint is reached. The consequences of the accident are mitigated in two ways:

1. The reactor trip and borated water injection complement void formation in the core resulting in a rapid reduction in nuclear power to a residual level corresponding to the delayed fission and fission product decay.

2. The injection of borated water ensures sufficient flooding of the core to prevent excessive fuel rod cladding temperatures.

Before the break occurs, the plant is in an equilibrium condition, i.e., the heat generated in the core is being removed via the steam generator into the secondary system. During the blowdown phase, heat from decay, hot reactor vessel internals, and the reactor vessel continues to be transferred to the RCS. The heat transfer between the RCS and the secondary system maybe be in either direction depending on the relative temperatures between the RCS and the steam generator secondary side. In the case of continued heat addition to the steam generator secondary side, the pressure increases and is relieved by the main steam safety valves (MSSVs). Make-up to the steam generator secondary side is automatically provided by the auxiliary feedwater pumps.

The low pressurizer pressure SI signal terminates normal feedwater flow by closing the main feedwater line insolation valves and initiates auxiliary feedwater flow by starting auxiliary feedwater pumps. The SI signal also initiates SI; for an SBLOCA, the RCS pressure can remain high for an extended period, and the high pressure SI system functions to partially mitigate the RCS inventory lost through the break.

When the RCS depressurizes below the accumulator cover pressure, the accumulators begin to inject water into the reactor coolant loops and recover the RCS inventory, effectively ending the transient.

15.4.1.3.1.1 Description of Representative Transient

The small break LOCA transient can be divided into time periods in which specific phenomena are occurring, as discussed below.

Blowdown

The rapid depressurization of the RCS coincides with subcooled liquid flow through the break. Following the reactor trip on the low pressurizer pressure setpoint, the pressurizer drains until safety injection is initiated on the low pressurizer pressure SI setpoint. After reaching this setpoint and applying the safety injection delays in Tables 15.4.1.2-1A and 15.4.1.2-1B, high pressure safety injection flow begins. Phase separation begins in the upper head and upper plenum near the end of this period until the entire RCS eventually reaches saturation, ending the rapid depressurization slightly above the steam generator secondary side pressure near the modeled MSSV setpoint as identified in Table 15.4.1.2-7.

Natural Circulation

This quasi-equilibrium phase persists while the RCS pressure remains slightly above the secondary side pressure. The system drains from the top down, and while significant mass is continually lost through the break, the vapor generated in the core is trapped in the upper regions by the liquid remaining in the crossover leg loop seals. Throughout this period, the core remains covered by a two-phase mixture and the fuel cladding temperatures remain at the saturation temperature level.

Loop Seal Clearance

As the system drains, the liquid levels in the downhill side of the pump suction (crossover leg) become depressed all the way to the bottom elevations of the piping allowing the steam trapped during the natural circulation phase to vent to the break (i.e., a process called loop seal clearance). The break flow and the flow through the RCS loops become primarily vapor. Relief of a static head imbalance allows for a quick but temporary recovery of liquid levels in the inner portion of the vessel.

Boil-Off

With a vapor vent path established after the loop seal clearance, the RCS depressurizes at a rate controlled by the critical flow, which continues to be a primarily high quality mixture of water and steam. The RCS pressure remains high enough such that safety injection flow cannot make up for the primary system fluid inventory lost through the break, leading to core uncovery and a fuel rod cladding temperature heat up.

Core Recovery

The RCS pressure continues to decrease, and once it reaches that of the accumulator gas pressure, the introduction of additional ECCS water from the accumulators replenishes the vessel inventory and recovers the core mixture level. The transient is considered over as the break flow is compensated by the injected flow.

15.4.1.3.1.2A Unit 1 Analysis Results

The Diablo Canyon Power Plant Unit 1 SBLOCA (Region I) analysis was performed in accordance with the NRC approved methodology in Reference 76 with the corrections and changes reported in Reference 80. The transient that produced the analysis PCT results is a cold leg break with a break diameter of 3.4-inches. The most limiting ECCS single failure of one ECCS train is assumed in the analysis as identified in Table 15.4.1.2-1A. Control rod drop is modeled for breaks less than 1 square foot assuming a 2 second signal delay time and a 2.7 second rod drop time. RCP trip is modeled coincident with reactor trip on the low pressurizer pressure setpoint for LOOP transients. Safety injection is actuated when the low pressurizer pressure SI setpoint is reached after the delay.

The results of the Diablo Canyon Power Plant Unit 1 SBLOCA (Region I) uncertainty analysis are summarized in Table 15.4.1.3-1A.

Table 15.4.1.3-2A contains a sequence of events for the transient that produced the SBLOCA (Region I) analysis PCT result. Figures 15.4.1.3-1A through 15.4.1.3-12A illustrate the calculated key transient response parameters for this transient.

15.4.1.3.1.2B Unit 2 Analysis Results

The Diablo Canyon Power Plant Unit 2 SBLOCA (Region I) analysis was performed in accordance with the NRC approved methodology in Reference 76 with the corrections and changes reported in Reference 80. The transient that produced the analysis PCT result is a cold leg break with a break diameter of 3.6 inches. The most limiting ECCS single failure of one ECCS train is assumed in the analysis as identified in Table 15.4.1.2-1B. Control rod drop is modeled for breaks less than 1 square foot assuming a 2 second signal delay time and a 2.7 second rod drop time. RCP trip is modeled coincident with reactor trip on the low pressurizer setpoint for LOOP transients. Safety injection is actuated when the low pressurizer pressure SI setpoint is reached after the delay.

The results of the Diablo Canyon Power Plant Unit 2 SBLOCA (Region I) uncertainty analysis are summarized in Table 15.4.1.3-1B.

Table 15.4.1.3-2B contains a sequence of events for the transient that produced the SBLOCA (Region I) analysis PCT result. Figure 15.4.1.3-1B through 15.4.1.3-12B illustrate the calculated key transient response parameters for this transient.

15.4.1.3.2 LBLOCA (Region II) Analysis

Identification of Cause and Accident Description

Should a large break occur, rapid depressurization of the RCS to a pressure nearly equal to the containment pressure occurs in approximately 40 seconds, with a nearly complete loss of RCS inventory. Rapid voiding in the core shuts down the reactor. The SI system is actuated when the low pressurizer pressure setpoint (SI signal) is reached and the accumulators inject upon RCS depressurization below the accumulator cover pressure, mitigating the consequences of the accident in two ways:

1. The borated water injection complements void formation in causing a rapid reduction in power to a residual level corresponding to fission product decay heat. The level of RCS mixed boron concentration is sufficient to ensure that the post-LOCA core remains subcritical. However, no credit is taken for the insertion of control rods to shut down the reactor in the large break analysis.

2. The injection of borated water provides core cooling and prevents excessive fuel rod cladding temperatures.

Before the break occurs, the reactor is assumed to be in a full power equilibrium condition, i.e., the heat generated in the core is being removed by the steam generators. At the beginning of the blowdown phase, the entire RCS contains sub-cooled liquid which transfers heat from the core by forced convection with some nucleate boiling. During blowdown, heat from fission product decay and stored energy in the fuel pellets continues to be transferred to the fuel rod cladding. After the break occurs, departure from nucleate boiling occurs.

The heat transfer between the RCS and the secondary system may be in either direction, based on the progression of the transient and the relative fluid temperatures. In the case of the large break LOCA, the primary pressure rapidly decreases below the secondary system pressure, and the steam generators become an additional heat source.

As the RCS pressure decreases to the accumulator cover pressure, injection of accumulator liquid into the cold leg begins. However, significant accumulator inventory is lost out of the break due to the phenomenon of emergency core cooling bypass. After the initial surge of accumulator inventory is lost out of the break, core bypass breaks down and the remaining accumulator liquid refills the lower portion of the reactor vessel. Reflood of the core and eventual quench of the fuel rods is accomplished by the injection of water from the RWST.

15.4.1.3.2.1 Description of Representative Transient

A large-break LOCA transient can be divided into phases in which specific phenomena are occurring. A convenient way to divide the transient is in terms of the various heatup and cooldown phases that the fuel assemblies undergo.

Blowdown – Critical Heat Flux (CHF) Phase

In this phase, the break flow is subcooled, the discharge rate of coolant from the break is high, the core flow reverses, the fuel rods go through departure from nucleate boiling (DNB), and the cladding rapidly heats up and the reactor is shut down due to the core voiding.

The regions of the RCS with the highest initial temperatures (upper core, upper plenum, and hot legs) begin to flash during this period. This phase is terminated when the water in the lower plenum and downcomer begins to flash. The mixture level swells and a saturated mixture is pushed into the core by the intact loop RCPs, still rotating in single-phase liquid. As the fluid in the cold leg reaches saturation conditions, the discharge flow rate at the break decreases significantly.

Blowdown – Upward Core Flow Phase

Heat transfer is increased as the two-phase mixture is pushed into the core. The break discharge rate is reduced because the fluid becomes saturated at the break. This phase ends as the lower plenum mass is depleted, the fluid in the loops becomes two-phase, and the RCP head degrades.

Blowdown – Downward Core Flow Phase

The break flow begins to dominate and pulls flow down through the core as the RCP head degrades due to increased voiding, while liquid and entrained liquid flows also provide core cooling. Once the system has depressurized to less than the accumulator cover pressure, the accumulators begin to inject cold water intro the cold legs. During this period, due to steam upflow in the downcomer, a portion of the injected ECCS water is bypassed around the downcomer and sent out through the break. As the system pressure continues to decrease, the break flow and consequently the downward core flow are reduced. The system pressure approaches the containment pressure at the end of this last period of the blowdown phase.

During this phase, the core begins to heat up as the system approaches containment pressure and the vessel begins to refill with ECCS water.

Refill Phase

The core continues to heat up as the lower plenum refills with ECCS water. This phase is characterized by a rapid increase in fuel cladding temperature at all elevations due to the lack of liquid and steam flow in the core region. The water completely refills the lower plenum and the refill phase ends. As ECCS water enters the core, the fuel rods in the lower core region begin to quench and liquid entrainment begins, resulting in increased fuel rod heat transfer.

Reflood Phase

During the early reflood phase, the accumulators begin to empty and nitrogen is discharged into the RCS. The nitrogen surge forces water into the core, which is then evaporated, causing system re-pressurization and a temporary reduction of pumped ECCS flow; this re-pressurization is illustrated by the increase in RCS pressure. During this time, core cooling may increase due to vapor generation and liquid entrainment, but conversely the early reflood pressure spike results in loss of mass out through the broken cold leg.

The pumped ECCS water aids in the filling of the downcomer throughout the reflood period. As the quench front progresses further into the core, the PCT elevation moves increasingly higher in the fuel assembly.

As the transient progresses, continued injection of pumped ECCS water refloods the core, effectively removes the vessel metal mass stored energy and core decay heat, and leads to an increase in the vessel fluid mass. Eventually the core inventory increases enough that liquid entrainment is able to quench all the fuel assemblies in the core.

15.4.1.3.2.2A Unit 1 Analysis Results

The Diablo Canyon Power Plant Unit 1 LBLOCA (Region II) analysis was performed in accordance with the NRC approved methodology in Reference 76 with the corrections and changes reported in Reference 80. The analysis was performed assuming both offsite power available (OPA) and LOOP, and the results of both of the LOOP and OPA analyses are compared to the 10 CFR 50.46 limits. The transient that produced the more limiting analysis PCT result relative to the offsite power assumption is a LOOP DEG break of the cold leg. The most limiting ECCS single failure of one ECCS train is assumed in the analysis as identified in Table 15.4.1.2-1A. The results of the Diablo Canyon Power Plant Unit 1 LBLOCA (Region II) OPA and LOOP uncertainty analyses are summarized in Table 15.4.1.3-1A.

Table 15.4.1.3-3A contains a sequence of events for the transient that produced the more limiting analysis PCT result relative to the offsite power assumption. Figures 15.4.1.3-13A through 15.4.1.3-26A illustrate the key major response parameters for this transient.

The containment pressure is calculated for each LOCA transient in the analysis using the COCO code (Reference 61). The COCO containment code is integrated into the WCOBRA/TRAC-TF2 thermal-hydraulic code. The transient-specific mass and energy releases calculated by the thermal-hydraulic code at the end of each timestep are transferred to COCO. COCO then calculates the containment pressure based on the containment model (the inputs are summarized in Tables 15.4.1.2-2, 15.4.1.2-3 and 15.4.1.2-4) and the mass and energy releases, and transfers the pressure back to the thermal-hydraulic code as a boundary condition at the break, consistent with the methodology in Reference 76. The containment model for COCO calculates a conservatively low containment pressure, including the effects of all the installed pressure reducing systems and processes such as assuming all trains of containment spray are operable and assuming fan cooler operation. The containment backpressure for the transient that produced the analysis PCT result is provided in Figure 15.4.1.3-21A.

15.4.1.3.2.2B Unit 2 Analysis Results

The Diablo Canyon Power Plant Unit 2 LBLOCA (Region II) analysis was performed in accordance with the NRC approved methodology in Reference 76 with the corrections and changes reported in Reference 80. The analysis was performed assuming both OPA and LOOP, and the results of both of the LOOP and OPA analyses are compared to the 10 CFR 50.46 limits. The transient that produced the more limiting analysis PCT result relative to the offsite power assumption is a LOOP DEG break of the cold leg. The most limiting ECCS single failure of one ECCS train is assumed in the analysis as identified in Table 15.4.1.2-1B. The results of the Diablo Canyon Power Plant Unit 1 LBLOCA (Region II) OPA and LOOP uncertainty analyses are summarized in Table 15.4.1.3-1B.

Table 15.4.1.3-3B contains a sequence of events for the transient that produced the more limiting analysis PCT result. Figures 15.4.1.3-13B through 15.4.1.3-26B illustrate the key major response parameters for this transient.

The containment pressure is calculated for each LOCA transient in the analysis using the COCO code (Reference 61). The COCO containment code is integrated into the WCOBRA/TRAC-TF2 thermal-hydraulic code. The transient-specific mass and energy releases calculated by the thermal-hydraulic code at the end of each timestep are transferred to COCO. COCO then calculates the containment pressure based on the containment model (the inputs are summarized in Tables 15.4.1.2-2, 15.4.1.2-3 and 15.4.1.2-4) and the mass and energy releases, and transfers the pressure back to the thermal-hydraulic code as a boundary condition at the break, consistent with the methodology in Reference 76. The containment model for COCO calculates a conservatively low containment pressure, including the effects of all the installed pressure reducing systems and processes such as assuming all trains of containment spray are operable and assuming fan cooler operation. The containment backpressure for the transient that produced the analyses PCT result is provided in Figure 15.4.1.3-21B.

15.4.1.3.3 10 CFR 50.46 Requirements

It must be demonstrated that there is a high level of probability that the following criteria in 10 CFR 50.46 are met:

(b)(1) The analysis PCT corresponds to a bounding estimate of the 95th percentile PCT at the 95-percent confidence level. Since the resulting PCT is less than 2,220°F, the analyses with the FSLOCA EM confirm that 10 CFR 50.46 acceptance criterion (b)(1), i.e., "Peak Cladding Temperature less than 2,220°F" is demonstrated.

The results are shown in Tables 15.4.1.3-1A and 15.4.1.3-1B for Diablo Canyon Power Plant Units 1 and 2, respectively.

(b)(2) The analysis MLO corresponds to a bounding estimate of the 95th percentile MLO at the 95-percent confidence level. Since the resulting MLO is less than 17 percent when converting the time-at-temperature to an equivalent cladding reacted using the Baker-Just correlation and adding the pre-transient corrosion, the analyses confirm that 10 CFR 50.46 acceptance criterion (b)(2), i.e., "Maximum Local Oxidation of the cladding less than 17 percent," is demonstrated.

The results are shown in Tables 15.4.1.3-1A and 15.4.1.3-1B for Diablo Canyon Power Plant Units 1 and 2, respectively.

(b)(3) The analysis CWO corresponds to a bounding estimate of the 95th percentile CWO at the 95-percent confidence level. Since the resulting CWO is less than 1 percent, the analyses confirm that 10 CFR 50.46 acceptance criterion (b)(3), i.e., "Core-Wide Oxidation less than 1 percent," is demonstrated.

The results are shown in Tables 15.4.1.3-1A and 15.4.1.3-1B for Diablo Canyon Power Plant Units 1 and 2, respectively.

(b)(4) 10 CFR 50.46 acceptance criterion (b)(4) requires that the calculated changes in core geometry are such that the core remains a coolable geometry.

This criterion is met by demonstrating compliance with criteria (b)(1), (b)(2), and (b)(3), and by assuring that fuel assembly grid deformation due to combined LOCA and seismic loads is specifically addressed. Criteria (b)(1), (b)(2), and (b)(3) have been met for the Diablo Canyon Power Plant Units 1 and 2 as previously discussed.

It is discussed in Section 32.1 of the NRC-approved FSLOCA EM (Reference 76) that the effects of LOCA and seismic loads on the core geometry do not need to be considered unless fuel assembly grid deformation extends beyond the core periphery (i.e., deformation in a fuel assembly with no sides adjacent to the core baffle plates). Inboard grid deformation due to combined LOCA and seismic loads is not calculated to occur for Diablo Canyon Power Plant Units 1 and 2.

(b)(5) 10 CFR 50.46 acceptance criterion (b)(5) requires that long-term core cooling be provided following the successful initial operation of the ECCS.

Long-term cooling is dependent on the demonstration of the continued delivery of cooling water to the core. The actions that are currently in place to maintain long-term cooling are not impacted by the application of the NRC-approved FSLOCA EM (Reference 76).

Based on the analysis results for SBLOCA (Region I) and LBLOCA (Region II) presented in Table 15.4.1.3-1A for Unit 1 and Table 15.4.1.3-1B for Unit 2, it is concluded that Diablo Canyon Power Plant Units 1 and 2 comply with the criteria in 10 CFR 50.46.

15.4.1.4 DELETED

15.4.1.4A DELETED

15.4.1.5A DELETED

15.4.1.6A DELETED

15.4.1.7A DELETED

15.4.1.8A DELETED

15.4.1.9A DELETED

15.4.1.10A DELETED

15.4.1.4B DELETED

15.4.1.5B DELETED

15.4.1.6B DELETED

15.4.1.7B DELETED

15.4.1.8B DELETED

15.4.1.9B DELETED

15.4.1.10B DELETED

15.4.1.11 DELETED

15.4.2 MAJOR SECONDARY SYSTEM PIPE RUPTURE

Three major secondary system pipe ruptures are analyzed in this section: rupture of a main steam line at hot zero power, rupture of a main feedwater pipe, and rupture of a main steam line at power. The time sequence of events for each of these events is provided in Table 15.4-8.

15.4.2.1 Rupture of a Main Steam Line at Hot Zero Power

15.4.2.1.1 Acceptance Criteria

The following limiting criteria are applicable for a main steam line rupture at hot zero power:

15.4.2.1.1.1 Fuel Damage Criteria

Any fuel damage calculated to occur must be of sufficiently limited extent that the core will remain in place and intact with no loss of core cooling capability. This is conservatively demonstrated by meeting the following criteria:

(1) DNB will not occur on the lead rod with at least a 95 percent probability at a 95 percent confidence level. The minimum DNBR must not go below the applicable limit value of 1.45 at any time during the transient.

15.4.2.1.1.2 Radiological Criteria

(1) The resulting potential exposures to individual members of the public and to the general population shall be lower than the applicable guidelines and limits specified in 10 CFR 50.67 and Section 4.4, Table 6 of Regulatory Guide 1.183, July 2000.

15.4.2.1.2 Identification of Causes and Accident Description

The steam release from a rupture of a main steam pipe would result in an initial increase in steam flow that decreases during the accident as the steam pressure falls. The energy removal from the RCS causes a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in a positive reactivity insertion and subsequent reduction of core shutdown margin. If the most reactive RCCA is assumed stuck in its fully withdrawn position after reactor trip, there is an increased possibility that the core will become critical and return to power. A return to power following a steam pipe rupture is a potential problem mainly because of the high power peaking factors that exist assuming the most reactive RCCA to be stuck in its fully withdrawn position. The core is ultimately shut down by the boric acid injection delivered by the SIS and accumulators.

In order to allow for routine plant heatups and cooldowns, plant procedures allow the SIS to be blocked per permissive P-11, provided that the RCS boron concentration is

maintained at a value greater than or equal to the cold shutdown margin requirement. As discussed in Reference 63, this additional shutdown margin ensures that there would be no return to power for a steam pipe rupture such that the analysis of a rupture of a steam line at hot zero power remains bounding.

The analysis of a main steam pipe rupture is performed to demonstrate that the following criteria are satisfied:

(1) Assuming a stuck RCCA, with or without offsite power, and assuming a single failure in the ESFs there is no consequential damage to the primary system and the core remains in place and intact.

(2) Energy release to containment from the worst steam pipe break does not cause failure of the containment structure (refer to Appendix 6.2D).

Although DNB and possible cladding perforation following a steam pipe rupture are not necessarily unacceptable, the following analysis, in fact, shows that the DNB design basis is met for any rupture assuming the most reactive assembly stuck in its fully withdrawn position.

The following functions provide protection for a steam line rupture:

(1) SIS actuation from any of the following:

(a) Two-out-of-four low pressurizer pressure signals

(b) Two-out-of-three low steam line pressure signals in any one loop

(c) Two-out-of-three high containment pressure signals

(2) The overpower reactor trips (neutron flux and ΔT), the overtemperature ΔT reactor trip, and the reactor trip occurring in conjunction with receipt of the SI signal.

(3) Redundant isolation of the main feedwater lines: sustained high feedwater flow would cause additional cooldown. Therefore, a SI signal will rapidly close all MFRVs, trip the main feedwater pumps, and close the MFIVs that backup the control valves.

(4) Closure of the fast acting main steam line isolation valves on: (refer to Figure 7.2-1 and the Technical Specifications [Reference 30])

(a) Two-out-of-three low steam line pressure signals in any one loop

(b) Two-out-of-four high-high containment pressure

(c) Two-out-of-three high negative steam line pressure rate signals in any one loop (used only during cooldown and heatup operations)

The fast-acting isolation valves are provided in each main steam line and will fully close within 10 seconds of a large steam line break. For breaks downstream of the isolation valves, closure of all valves would completely terminate the blowdown. For any break, in any location, no more than one SG would blow down even if one of the isolation valves fails to close. A description of steam line isolation is included in Chapter 10.

The effective throat area of the integral flow restrictors in the SGs is 1.388 ft^2, which is considerably smaller than the area of the main steam pipe. These restrictors serve to limit the maximum steam flow for any break at any location.

15.4.2.1.3 Analysis of Effects and Consequences

The analysis of the steam pipe rupture has been performed to determine:

(1) The plant transient conditions, including core heat flux and RCS temperature and pressure resulting from the cooldown following the steam line break. The RETRAN-02W code (Reference 70) has been used.

(2) The thermal and hydraulic behavior of the core following a steam line break. A detailed thermal and hydraulic digital-computer code, THINC (refer to Section 1.6.1, Item 28, and Section 4.4.3), has been used to determine if DNB occurs for the core conditions computed in (1) above.

The following conditions were assumed to exist at the time of a main steam line break (MSLB) accident.

(1) EOL shutdown margin at no-load, equilibrium xenon conditions, and the most reactive assembly stuck in its fully withdrawn position: Operation of the control rod banks during core burnup is restricted in such a way that addition of positive reactivity in a steam line break accident will not lead to a more adverse condition than the case analyzed.

(2) The negative moderator coefficient corresponds to the EOL rodded core with the most reactive rod in the fully withdrawn position. The variation of the coefficient with temperature and pressure has been included. The k_{eff} versus temperature at 1050 psia corresponding to the negative moderator temperature coefficient, plus the Doppler temperature effect used is shown in Figure 15.4.2-2. The effect of power generation in the core on overall reactivity is shown in Figure 15.4.2-1.

The core properties associated with the sector nearest the affected SG and those associated with the remaining sector were conservatively

combined to obtain average core properties for reactivity feedback calculations. To verify the conservatism of this method, the reactivity as well as the power distribution was checked with the advanced nodal code core model (refer to Section 4.3.3.10.3). These core analyses considered the Doppler reactivity from the high fuel temperature near the stuck RCCA, moderator feedback from the high water enthalpy near the stuck RCCA, power redistribution and non-uniform core inlet temperature effects. For cases in which steam generation occurs in the high flux regions of the core, the effect of void formation was also included. It was confirmed that the reactivity feedback model employed in the RETRAN-02W kinetics analysis was consistent with the core analysis and the overall analysis is conservative.

(3) The modeling of the SIS in RETRAN-02W is described in Reference 70. The minimum boric acid solution concentration of 2300 ppm in the RWST is assumed. The SIS piping downstream of the RWST isolation valves is assumed to contain no boron (0 ppm), which delays the delivery of boron to the RCLs from the RWST water. With this conservative assumption, the SIS and accumulators combine to limit the return to power. Cases were examined for both minimum and maximum SIS flow rates.

For the minimum SIS flow rate cases the most restrictive single failure in the SIS is considered. The SIS flow assumed conservatively corresponds to that delivered by only one high-head charging pump delivering full flow to the cold leg header. The charging pump (CCP1 or CCP2) is assumed to begin providing flow to the RCS at 25 seconds after receipt of the SI signal for the case in which offsite power is assumed available, and at 35 seconds for the case where offsite power is not available; the additional 10-second delay is assumed to start the diesels and load the necessary SI equipment onto them. The evaluation in Reference 75 documents that since the amount of SIS flow delivered is small, an increased delay time of 42 seconds has a negligible effect on the results.

For the maximum SIS flow rate cases, a flow profile was assumed that bounds the maximum flow from two high-head charging pumps (CCP1 and CCP2) plus two intermediate-head SI pumps plus the nonsafety-related CVCS charging pump (CCP3). A 2-second signal delay was assumed.

For this analysis, it was determined that the maximum SIS flow rate assumption is conservative for the more limiting case with offsite power available, due to the effect of higher SIS flow on the timing of cold leg accumulator actuation. The cold leg accumulators provide an additional source of borated water to the core when the RCS pressure decreases below the actuation setpoint. The minimum accumulator boron concentration of 2200 ppm is assumed, along with a conservatively low

actuation setpoint of 577.2 psia. Actuation of the accumulators causes a significant influx of boron, which rapidly shuts down the reactor. Assuming the maximum SIS flow rate slows down the rate of the RCS pressure decrease and thus delays the accumulator actuation. If the most reactive RCCA is assumed stuck in its fully withdrawn position after a reactor trip, there is an increased possibility that the core will become critical and return to power. A return to power following a steam pipe rupture is a potential problem mainly because of the high power peaking factors that would exist assuming the most-reactive RCCA to be stuck in its fully withdrawn position. Therefore, the limiting case presented herein conservatively assumes a maximum SIS flow rate.

(4) Because the SGs are equipped with integral flow restrictors with a 1.388 ft^2 throat area, any rupture with a break greater than this size, regardless of the location, would have the same effect on the reactor as a 1.388 ft^2 break. The following two cases have been considered in determining the core power and RCS transients:

(a) Complete severance of a pipe with the plant initially at no-load conditions and with offsite power available. Full reactor coolant flow is maintained.

(b) Complete severance of a pipe with the plant initially at no-load conditions and with offsite power unavailable. LOOP results in RCP coastdown.

(5) Power peaking factors corresponding to one stuck RCCA and non-uniform core inlet coolant temperatures are determined at EOL. The coldest core inlet temperatures are assumed to occur in the sector with the stuck rod. The power peaking factors account for the effect of the local void in the region of the stuck control assembly during the return to power phase following the steam line break. This void in conjunction with the large negative moderator coefficient partially offsets the effect of the stuck assembly. The power peaking factors depend on the core power, operating history, temperature, pressure, and flow.

All the cases above assume initial hot shutdown conditions at time zero, because this represents the most limiting initial condition. Should the reactor be just critical or operating at power at the time of a steam line break, the reactor will be tripped by the normal overpower protection system when power level reaches a trip point. Following a trip at power the RCS contains more stored energy than at no-load, the average coolant temperature is higher than at no-load, and there is appreciable energy stored in the fuel. Thus, the additional stored energy is removed via the cooldown caused by the steam line break before the no-load conditions of RCS temperature and shutdown margin assumed in the

analyses are reached. After the additional stored energy has been removed, the cooldown and reactivity insertions proceed in the same manner as in the analysis, which assumes no-load condition at time zero.

However, because the initial SG water inventory is greatest at no-load, the magnitude and duration of the RCS cooldown are less for steam line breaks occurring at power.

(6) In computing the steam flow during a steam line break, the Moody Curve (Reference 16) for fl/D = 0 is used.

(7) Perfect moisture separation in the SG is assumed. This assumption leads to conservative results because, in fact, considerable water would be discharged. Water carryover would reduce the magnitude of the temperature decrease in the core.

(8) To maximize the primary-to-secondary heat transfer rate, 0 percent SGTP is assumed.

(9) All main and AFW are assumed to be operating at full capacity when the rupture occurs. This assumption maximizes the cooldown. A conservatively high AFW flow rate of 1700 gpm at a minimum temperature of 60ºF is assumed to be delivered to the affected SG. Main feedwater is isolated 64 seconds following the SI signal by closure of the MFIVs. No credit is taken for the faster-closing MFRVs. AFW continues for the duration of the transient.

(10) The effect of heat transferred from thick metal in the RCS and the SGs is not included in the cases analyzed. The heat transferred from these sources would be a net benefit because it would slow the cooldown of the RCS.

15.4.2.1.4 Results

The double-ended rupture of a main steam line at zero power was analyzed for both Unit 1 and Unit 2; however, only the results from the slightly more limiting Unit 1 cases are presented. Unit 2 results are similar. The time sequence of events, both with and without offsite power available for Unit 1, are presented in Table 15.4-8.

Figures 15.4.2-4 through 15.4.2-6 show the plant response following a main steam pipe rupture. Offsite power is assumed to be available such that full reactor coolant flow exists. The transient shown assumes an uncontrolled steam release from only one SG.

Figures 15.4.2-7 through 15.4.2-9 show the plant response for the case with a LOOP. This assumption results in a coastdown of the RCPs. In this case, the core power increases at a slower rate and reaches a lower peak value than in the case with offsite

power available. The ability of the emptying SG to extract heat from the RCS is reduced by the decreased flow in the RCS.

It should be noted that following a steam line break only one SG blows down completely. Thus, the remaining SGs are still available for dissipation of decay heat after the initial transient is over. In the case with LOOP, this heat would be removed to the atmosphere via the MSSVs.

15.4.2.1.5 Conclusions

The analysis demonstrates the acceptance criteria are met as follows:

15.4.2.1.5.1 Fuel Limits

Based on the results of the analysis, the core will remain in place and intact with no loss of core cooling capability.

A DNB analysis was performed for the limiting steam line break case with offsite power available as described above. The analysis demonstrated that the minimum DNBR remains well above the limit value of 1.45. Therefore, the DNB design basis is met for the steam line break event initiated from zero power.

15.4.2.1.5.2 Radiological

Section 15.5.18 concludes that potential exposures from major steam line ruptures will be well below the guideline levels specified in 10 CFR Part 50.67 and Section 4.4, Table 6 of Regulatory Guide 1.183, July 2000.

15.4.2.2 Major Rupture of a Main Feedwater Pipe

15.4.2.2.1 Acceptance Criteria

The following limiting criteria are applicable for a main feedwater pipe rupture:

15.4.2.2.1.1 Fuel Damage Criteria

Any fuel damage calculated to occur must be of sufficiently limited extent that the core will remain in place and intact with no loss of core cooling capability. This is conservatively demonstrated by meeting the following criteria:

(1) With respect to fuel damage due to “dryout” where the water level in the vessel drops below the top of the core, criterion that no bulk boiling occurs in the primary coolant system prior to event “turnaround” is applied. Turnaround is defined as the point when the heat removal capability of the SGs, being fed by AFW, exceeds NSSS heat generation.

15.4.2.2.1.2 Maximum Reactor Coolant System and Main Steam System Pressure Requirements:

The maximum pressure in the RCS and MSS should be maintained below 110 percent of the design value, 2748.5 psia and 1208.5 psia, respectively.

15.4.2.2.1.3 Radiological Criteria

The resulting potential exposures to individual members of the public and to the general population shall be lower than the applicable guidelines and limits specified in 10 CFR 50.67 and Section 4.4, Table 6 of Regulatory Guide 1.183, July 2000 for the Main Steam Line Break.

15.4.2.2.2 Identification of Causes and Accident Description

A major feedwater line rupture is defined as a break in a feedwater pipe large enough to prevent the addition of sufficient feedwater to the SGs to maintain shell-side fluid inventory in the SGs. If the break is postulated in a feedline between the check valve and the SG, fluid from the SG may also be discharged through the break. Further, a break in this location could preclude the subsequent addition of AFW to the affected SG. (A break upstream of the feedline check valve would affect the NSSS only as a loss of feedwater. This case is covered by the evaluation in Section 15.2.8).

Depending on the size of the break and the plant operating conditions at the time of the break, the break could cause either an RCS cooldown (by excessive energy discharge through the break), or an RCS heatup. Potential RCS cooldown resulting from a secondary pipe rupture is evaluated in Section 15.4.2.1. Therefore, only the RCS heatup effects are evaluated for a feedline rupture.

A feedline rupture reduces the ability to remove heat generated by the core from the RCS for the following reasons:

(1) Feedwater to the SGs is reduced. Since feedwater is subcooled, its loss may cause reactor coolant temperatures to increase prior to reactor trip

(2) Liquid in the SG may be discharged through the break, and would then not be available for decay heat removal after trip

(3) The break may be large enough to prevent the addition of any main feedwater after trip

The following provide the necessary protection against a main feedwater line rupture:

(1) A reactor trip on any of the following conditions:

(a) High pressurizer pressure
(b) Overtemperature ΔT

(c) Low-low SG water level in any SG

(d) SI signals from any of the following:

- Low steam line pressure
- High containment pressure

(Refer to Chapter 7 for a description of the actuation system)

(2) An AFW system to provide an assured source of feedwater to the SGs for decay heat removal (refer to Chapter 6 for a description of the AFW system)

15.4.2.2.3 Analysis of Effects and Consequences

The feedline break transient is analyzed using the RETRAN-02W computer code described in Reference 70. The RETRAN-02W model simulates the RCS, neutron kinetics, pressurizer, pressurizer relief and safety valves, pressurizer heaters, pressurizer spray, SGs, feedwater system, and MSSVs. The code computes pertinent plant variables including SG mass, pressurizer water volume, reactor coolant average temperature, RCS pressure, and SG pressure.

The feedline rupture analysis methodology presented in Section 15.4.2.2 is not intended to minimize the predicted time to pressurizer filling, as this scenario is evaluated in Section 15.4.2.4.

Major assumptions are:

(1) The plant is initially operating at 102 percent of the NSSS rating, including a conservatively large RCP heat of 20 MWt for the case with offsite power available and a nominal (minimum guaranteed) RCP heat of 14 MWt for the case without offsite power available. These assumptions maximize the primary side heat that must be removed for each case.

(2) Initial reactor coolant average temperature is 5.0°F above the nominal value, and the initial pressurizer pressure is 60 psi above its nominal value.

(3) The initial pressurizer level is set to the nominal full power programmed level plus an uncertainty of +5.7 percent span for Diablo Canyon Unit 1 and Unit 2, resulting in an initial pressurizer level of 66.4 percent span and 66.8 percent span, respectively. Initial SG water level is at 75 percent narrow range span (NRS) in the faulted SG, and at 55 percent NRS in the intact SGs.

(4) No credit is taken for the pressurizer PORVs or pressurizer spray.

(5) No credit is taken for the high pressurizer pressure reactor trip.

(6) Main feed to all SGs is assumed to stop at the time the break occurs (all main feedwater spills out through the break).

(7) The break discharge quality is calculated by RETRAN-02W as a function of pressure and temperature.

(8) Reactor trip is assumed to be initiated when the low-low level trip setpoint in the ruptured SG is reached. A low-low level setpoint of 0 percent NRS is assumed.

(9) A double-ended break area of 0.5184 ft^2 is assumed. A break area of 0.5184 ft^2 corresponds to the flow area of the reducer leading to the feedring, and is the largest effective area of flow out of the SGs for the feedline break event. This minimizes the SG fluid inventory available for removal of long-term decay heat and stored energy following reactor trip, and thereby maximizes the resultant heatup of the reactor coolant.

(10) No credit is taken for heat energy deposited in RCS metal during the RCS heatup.

(11) No credit is taken for charging or letdown.

(12) The SG heat transfer correlation for the SG tubes is automatically adjusted by RETRAN-02W as the shell-side inventory decreases.

(13) Conservative core residual heat generation based on the ANSI/ANS-5.1-1979 (Reference 32) decay heat standard plus uncertainty was used for calculation of residual decay heat levels.

(14) The AFW is assumed to be initiated 10 minutes after the trip with a feed rate of 390 gpm which bounds both cases with an offsite power auto-bus transfer and cases without offsite power.

(15) Maximum SI flow delay times of 25 seconds after receipt of the SI signal for the case in which offsite power is assumed available, and at 35

seconds for the case where offsite power is not available; the additional 10-second delay is assumed to start the diesels and load the necessary SI equipment onto them. The evaluation in Reference 75 documents that since the amount of SIS flow delivered is small, an increased delay time of 42 seconds has a negligible effect on the results.

15.4.2.2.4 Results

Analyses were performed for both Unit 1 and Unit 2 separately; the most limiting case with offsite power and the corresponding case without offsite power are presented.

Results for two feedline break cases are presented. Results for a case in which offsite power is assumed to be available are presented in Section 15.4.2.2.4.1. Results for a case in which offsite power is assumed to be lost following reactor trip are presented in Section 15.4.2.2.4.2. The calculated sequence of events for both cases is listed in Table 15.4-8.

15.4.2.2.4.1 Feedline Rupture with Offsite Power Available

The system response following a feedwater line rupture, assuming offsite power is available, is presented in Figures 15.4.2-10 through 15.4.2-13. Results presented in Figures 15.4.2-11 and 15.4.2-13 show that pressures in the RCS and MSS remain below 110 percent of the design pressures, 2748.5 psia and 1208.5 psia, respectively. Pressurizer pressure decreases after reactor trip on low-low SG water level due to the reduction of heat input. Following this initial decrease, pressurizer pressure increases to the PSV setpoint. This increase in pressure is the result of coolant expansion caused by the reduction in heat transfer capability in the SGs. Figure 15.4.2-11 indicates a pressurizer water volume equivalent to a water-solid condition; however, this is not an acceptance criteria for the analysis. Pressurizer filling during a main feedwater pipe rupture event is evaluated in Section 15.4.2.4. At approximately 5900 seconds, decay heat generation decreases to a level such that the total RCS heat generation (decay heat plus pump heat) is less than AFW heat removal capability, and RCS pressure and temperature begin to decrease.

The results show that the core remains covered at all times and that no boiling occurs in the RCLs.

15.4.2.2.4.2 Feedline Rupture with Offsite Power Unavailable

The system response following a feedwater line rupture without offsite power available is similar to the case with offsite power available. However, as a result of the LOOP (assumed to occur at reactor trip), the RCPs coast down. This results in a reduction in total RCS heat generation by the amount produced by pump operation.

The reduction in total RCS heat generation produces a milder transient than in the case where offsite power is available. Results presented in Figures 15.4.2-14 through

15.4.2-17 show that pressure in the RCS and MSS remain below 110 percent of the design pressures, 2748.5 psia and 1208.5 psia, respectively. Pressurizer pressure decreases after reactor trip on low-low SG water level due to the reduction of heat input. Following this initial decrease, pressurizer pressure increases to a peak pressure of 2426 psia at 106 seconds. This increase in pressure is the result of coolant expansion caused by the reduction in heat transfer capability in the SGs. Figure 15.4.2-15 shows that the water volume in the pressurizer increases in response to the heatup, but does not fill the pressurizer. At approximately 2200 seconds, decay heat generation decreases to a level less than the AFW heat removal capability, and RCS temperature begins to decrease. The results show that the core remains covered at all times and that no boiling occurs in the RCLs.

15.4.2.2.5 Conclusions

Results of the analysis show that for the postulated feedline rupture, the assumed AFW system capacity is adequate to remove decay heat, to prevent overpressurizing the RCS, and to prevent uncovering the reactor core. The analysis documents that the acceptance criteria for a postulated feedline rupture are met as follows:

15.4.2.2.5.1 Fuel Damage

Any fuel damage calculated to occur is of sufficiently limited extent that the core will remain in place and intact with no loss of core cooling capability. This is conservatively demonstrated by Figures 15.4.2-12 and 15.4.2-16 that show no bulk boiling occurs in the primary coolant system prior to event “turnaround”.

15.4.2.2.5.2 Maximum Reactor Coolant System and Main Steam System Pressure

As shown in Figures 15.4.2-11 and 15.4.2-13, the maximum pressure in the RCS and MSS is maintained below 110 percent of the design value, 2748.5 psia and 1208.5 psia, respectively.

15.4.2.2.5.3 Radiological

Section 15.5.19 concludes that potential exposures from major feedwater line ruptures will be well below the guideline levels specified in 10 CFR 50.67 and Section 4.4, Table 6 of Regulatory Guide 1.183, July 2000 for the Main Steam Line Break, and that the occurrence of such ruptures would not result in undue risk to the public.

15.4.2.3 Rupture of a Main Steam Line at Full Power

15.4.2.3.1 Acceptance Criteria

The following limiting criteria are applicable for a main steam line rupture at full power:

15.4.2.3.1.1 Fuel Damage Criteria

Any fuel damage calculated to occur must be of sufficiently limited extent that the core will remain in place and intact with no loss of core cooling capability. This is conservatively demonstrated by meeting the following criteria:

(1) DNB will not occur on the lead rod with at least a 95 percent probability at a 95 percent confidence level. The minimum DNBR must not go below the DNBR Safety Analysis Limit of 1.68/1.71 (refer to Section 4.4.4.1) at any time during the transient.

(2) The peak linear heat generation rate will not exceed a 22 kW/ft (refer to Section 4.4.4.2 and Figure 4.4-2) which would cause fuel centerline melt.

15.4.2.3.1.2 Radiological Criteria

The resulting potential exposures to individual members of the public and to the general population shall be lower than the applicable guidelines and limits specified in 10 CFR 50.67 and Section 4.4, Table 6 of Regulatory Guide 1.183, July 2000.

15.4.2.3.2 Identification of Causes and Accident Description

A rupture in the MSS piping from an at-power condition creates an increased steam load, which extracts an increased amount of heat from the RCS via the SGs. This results in a reduction in RCS temperature and pressure. In the presence of a strong negative moderator temperature coefficient, typical of end-of-cycle conditions, the colder core inlet coolant temperature causes the core power to increase from its initial level due to the positive reactivity insertion. The power approaches a level equal to the total steam flow. Depending on the break size, a reactor trip may occur due to overpower conditions or as a result of a steam line break protection function actuation.

The steam system piping failure accident analysis, described in Section 15.4.2.1, is performed assuming a hot zero power initial condition with the control rods inserted in the core, except for the most reactive rod, which remains fully withdrawn out of the core. This condition could occur while the reactor is at hot shutdown at the minimum required shutdown margin, or after the plant has been tripped manually, or by the reactor protection system following a steam line break from an at-power condition. For an at-power break, the Section 15.4.2.1 analysis represents the limiting condition with respect to core protection for the time period following reactor trip. The analysis of a main steam pipe rupture at power is performed to demonstrate that the following criteria are satisfied:

(1) Assuming a stuck RCCA and a single failure in the ESFs, there is no damage to the primary system and the core remains in place and intact.

(2) Core protection is maintained prior to, and immediately following, a reactor trip, if one is required, such that the DNBR remains above the applicable

limit value for any rupture assuming the most reactive assembly stuck in its fully withdrawn position.

Depending on the size of the break, this event is classified as either an ANS Condition III (infrequent fault) or Condition IV (limiting fault) event. The main steam pipe rupture at power is protected by the same reactor protection and ESF functions as the main steam pipe rupture at hot zero power. Although DNB and possible clad perforation following a steam pipe rupture are not necessarily unacceptable, the analysis shows that the calculated DNBR remains above the applicable DNBR limit value.

15.4.2.3.3 Analysis of Effects and Consequences

The analysis of the steam line rupture is performed in the following stages:

(1) The RETRAN-02W code (Reference 70) is used to calculate the nuclear power, core heat flux, and RCS temperature and pressure transients resulting from the cooldown following the steam line break.

(2) The core radial and axial peaking factors are determined using the thermal-hydraulic conditions from the transient analysis as input to the nuclear core models. The THINC-IV code (refer to Section 4.4.3) is then used to calculate the DNBR for the limiting time during the transient.

This accident is analyzed with the ITDP as described in Reference 62.

To give conservative results in calculating the DNBR during the transient, the following assumptions are made:

(1) Initial Conditions - The initial core power, reactor coolant temperature, and RCS pressure are assumed to be at their nominal full-power values. The full power condition is more limiting than part-power with respect to DNBR. Uncertainties in initial conditions are included in the DNBR limit value, as described in Reference 62.

(2) Break size - A spectrum of break sizes is analyzed. Small breaks do not result in a reactor trip; in this case core power stabilizes at an increased level corresponding to the increased steam flow. Intermediate-size breaks may result in a reactor trip on overpower ΔT as a result of the increasing core power. Larger break sizes result in a reactor trip soon after the break from the SI signal actuated by low steam line pressure, which includes lead/lag dynamic compensation.

(3) Break flow - The steam flow out the pipe break is calculated using the Moody curve for an fL/D value of 0 (Reference 16).

(4) Reactivity Coefficients - The analysis assumes maximum EOL moderator reactivity feedback and minimum Doppler-only power reactivity feedback in order to maximize the power increase following the break.

(5) Protection System - The analysis only models those reactor protection system features that would be credited for at power conditions and up to the time a reactor trip is initiated. Section 15.4.2.1, presents the analysis of the bounding transient following reactor trip, where ESFs are actuated to mitigate the effects of a steam line break.

(6) Control Systems - The results of a main steam pipe rupture at power would be made less severe as a result of control system actuation. Therefore, the mitigation effects of control systems have been ignored in the analysis.

15.4.2.3.4 Results

A spectrum of steam line break sizes was analyzed for each unit. The results show that for break sizes up to 0.49 ft^2 (Unit 1) and 0.50 ft^2 (Unit 2) a reactor trip is not generated. In this case, the event is similar to an excessive load increase event as described in Section 15.2.12. The core reaches a new equilibrium condition at a higher power equivalent to the increased steam flow. For break sizes larger than those noted above, a reactor trip is generated within a few seconds of the break on the SI signal from low steam line pressure.

The limiting case for demonstrating DNB protection is the 0.49 ft^2 (Unit 1) break, the largest break size that does not result in an early trip on low steam pressure SI actuation. The peak linear heat rate (kW/ft) remains below a value corresponding to fuel centerline melting. The time sequence of events for this case is shown in Table 15.4-8. Figures 15.4.2-18 through 15.4.2-21 show the transient response.

15.4.2.3.5 Conclusions

The analysis demonstrates the acceptance criteria are met as follows:

15.4.2.3.5.1 Fuel Damage

Any fuel damage calculated to occur is of sufficiently limited extent that the core will remain in place and intact with no loss of core cooling capability. This is conservatively demonstrated by the following:

(1) The analysis demonstrates that there is a large margin to the DNBR Safety Analysis Limit of 1.71/1.68 (typical cell/thimble cell).

(2) The analysis calculates that the maximum linear power meets the fuel centerline melt limit of 22.0 kW/ft.

The analysis concludes that the DNB and fuel centerline design bases are met for the limiting case. Although DNB and possible clad perforation following a steam pipe rupture are not necessarily unacceptable and not precluded by the criteria, the above analysis shows that the minimum DNBR remains above the safety analysis limit.

15.4.2.3.5.2 Radiological

Section 15.5.18 concludes that potential exposures from main steam line ruptures at full power will be well below the guideline levels specified in 10 CFR 50.67 and Section 4.4, Table 6 of Regulatory Guide 1.183, July 2000, and that the occurrence of such ruptures would not result in undue risk to the public.

15.4.2.4 Major Rupture of a Main Feedwater Pipe for Pressurizer Filling

15.4.2.4.1 Acceptance Criteria

The acceptance criterion is to ensure the major rupture of a main feedwater pipe (hereinafter referred to as feedwater line break [FLB]) for pressurizer filling event does not result in liquid water (hereinafter referred to as water) relief through the PSVs in order to prevent an unisolable reactor coolant pressure boundary breach due to a PSV failing open. This can be accomplished through appropriate operator actions and equipment design/response that mitigate the consequences of the event before water relief through the PSVs occurs.

15.4.2.4.2 Identification of Causes and Accident Description

The causes and accident description for the pressurizer filling analysis of the main feedwater pipe rupture described in this section are discussed generally in Section 15.4.2.2.2. The aspects that relate specifically to pressurizer filling follow.

Following a FLB accident, secondary water level decreases in the SGs until AFW flow is initiated, after which level will begin to recover in the SGs being fed with AFW flow (i.e., the intact SGs). Depending on the AFW flow available, there is the potential for an increase in reactor coolant temperatures in the early part of the post-trip transient, along with an increase in reactor coolant volume due to thermal expansion. Also, following initiation of the FLB accident, a low steam line pressure setpoint will be reached in the faulted loop, causing actuation of the SI signal and start of the two PG&E Design Class I charging pumps. The reactor coolant inventory addition from the charging flow and RCS thermal expansion contributes to pressurizer filling.

If pressurizer filling occurs, the pressurizer PORVs are available to relieve water inventory from the RCS, as long as an air supply is available from instrument air to containment or from the PG&E Design Class I backup nitrogen accumulators. Also, since Technical Specifications define a PORV as operable with its block valve closed if

the PORV can be made available for automatic pressure relief, operators may need to take action to open the block valve to enable the PORV to provide water relief. Using the PORVs to relieve water from the RCS precludes water relief through the PSVs, which could render the PSVs inoperable.

Mitigation of the pressurizer filling condition is complete when (1) the heat removal capability of the SGs being fed by AFW exceeds NSSS heat generation and stops thermal expansion of the RCS and (2) operator actions are taken to isolate charging flow, and subsequently stop RCP seal injection flow, which terminates all remaining reactor coolant inventory addition.

The pressurizer filling analysis models the long term plant response to a FLB to demonstrate that operator actions, if taken in a timely manner, preclude water relief through the PSVs. The operator actions for mitigation of a FLB accident are included in the plant EOPs.

15.4.2.4.3 Analysis of Effects and Consequences

The FLB transient is analyzed for pressurizer filling in accordance with the NRC approved methodology for a 4-loop plant (Reference 70) using the Westinghouse version of the RETRAN-02 computer code (RETRAN-02W), which is also used for the analysis of the FLB transient described in Section 15.4.2.2.3.

Separate cases to accommodate different limiting assumptions were analyzed to determine the time by which the operators would need to ensure a PG&E Design Class I PORV is available and the times by which the operators would need to isolate charging flow and subsequently stop RCP seal injection flow. Cases were also analyzed with and without offsite power available to determine the more limiting condition.

The assumptions for the pressurizer filling analysis are conservatively chosen to minimize the time to reach a water-solid condition and maximize the number of pressurizer PORV relief open/close cycles predicted. Sensitivity studies were performed for a number of parameters to determine the appropriate conservative assumptions. Major assumptions are the same as described in Section 15.4.2.2.3 with the following changes:

(1) Initial reactor coolant average temperature is 5.5°F below the nominal value, and the initial pressurizer pressure is 60 psi below its nominal value.

(2) No credit is taken for relief through the PORV that is actuated on a compensated pressurizer pressure deviation signal (i.e., the non-safety-grade PORV). However, relief through the PORVs that are actuated on the indicated (measured) pressurizer pressure signal (i.e., the safety-grade, PG&E Design Class I PORVs) has been modeled with assumptions that maximize the number of PORV opening cycles experienced. The number of safety-grade PORVs

available for relief (i.e., either one or both of the PG&E Design Class I PORVs) depends on the single failure being considered.

Also, since an SI signal causes Phase A containment isolation and the instrument air is a PG&E Design Class II (non-safety-grade) system, there is a loss of instrument air to containment due to this signal. Accordingly, the PG&E Design Class I backup nitrogen accumulators are needed to maintain functionality of the PG&E Design Class I PORVs. The backup nitrogen accumulators are each sized and leak tested to ensure at least 300 PORV cycles before the backup nitrogen supply is depleted, after which the PORV would be unavailable. Therefore, transient mitigation must be demonstrated to occur before 300 PORV cycles is exceeded.

(3) No credit is taken for normal charging or letdown flow.

(4) The TDAFWP is aligned to all four SGs, whereas the MDAFWPs are each independently aligned to two of the four SGs. The AFW flow for each case analyzed depends on the assumed single failure.

With the single failure of the TDAFWP considered, it is assumed that 390 gpm total AFW flow will be delivered to two of the intact SGs at 1 minute after the trip and an additional 195 gpm of AFW flow will be delivered to the third intact SG at 10 minutes after the trip. The AFW flow initiated at 1 minute after the trip is delivered from the MDAFWP that is aligned to two intact SGs. All flow from the other MDAFWP aligned to both the third intact SG and the faulted SG is initially assumed to spill out the break. Subsequently, a time critical operator action (TCOA) is taken within 10 minutes to isolate the faulted SG and direct AFW flow from this MDAFWP to the third intact SG.

With the single failure of a PG&E Design Class I pressurizer PORV considered, the AFW flow from the MDAFWPs is the same as described above. However, with this scenario it is also assumed the TDAFWP will deliver an additional total 585 gpm of AFW flow to the three intact SGs at 10 minutes after the trip when the TCOA is taken to isolate the faulted SG.

(5) Maximum SI flow rates were conservatively modeled with a flow profile that bounds the maximum flow from the two PG&E Design Class I high-head CCPs (CCP1 and CCP2), plus the non-safety-related CVCS charging pump (CCP3), plus two intermediate-head SI pumps. Full SI flow was conservatively assumed to occur immediately after the SI actuation signal. The maximum SI flow profile, which includes RCP seal injection flow, is modeled until the TCOA is taken to isolate charging flow. Note that no flow is actually injected from the intermediate-head SI pumps, since RCS pressure remains above the shutoff head of these pumps during the transient.

(6) Maximum RCP seal injection flow was conservatively modeled until the TCOA is taken to stop it. A limiting FLB inside containment may cause the high-high containment pressure setpoint to be reached, resulting in Phase B isolation and a loss of component cooling water (CCW) to the RCPs. Accordingly, RCP seal injection flow must be maintained to ensure RCP cooling until operator action can be taken to reset the Phase B containment isolation and restore CCW flow to the RCPs.

(7) The air-operated pressurizer spray valves are assumed to be inoperable, since instrument air to containment is lost on an SI signal and normal pressurizer spray flow is unavailable following coastdown of the RCPs. There are auxiliary spray flow lines that are equipped with backup nitrogen if the spray valves are unavailable; however, auxiliary spray requires a manual alignment that would not be completed until after the TCOAs necessary to mitigate this transient are complete.

(8) For the cases with a LOOP, the pressurizer heaters are assumed to be inoperable, since they are not automatically loaded onto an EDG bus and will not be manually loaded onto the EDGs until after the TCOAs to mitigate this transient are complete. For cases with offsite power available, the pressurizer heaters are assumed to be operable.

(9) For cases with LOOP, the RCPs are assumed to trip automatically following reactor trip. For cases with offsite power, the RCPs continue to operate unless manually tripped by the operators. The EOPs direct the operators to trip the RCPs within 5 minutes following the Phase B containment isolation (to protect the RCP motors, which are cooled by CCW). For the case to determine time by which the operators need to ensure a pressurizer PORV is available, it is assumed the operators manually trip the RCPs at greater than 90 seconds after FLB initiation, because Phase B containment isolation from high-high containment pressure would not occur before this time. However, for the case analyzed to determine the times by which the operators would need to isolate charging flow and subsequently stop RCP seal injection flow, it was conservatively assumed that the RCPs are manually tripped following reactor trip.

15.4.2.4.4 Results

The results for Unit 2 were more limiting than those calculated for Unit 1.

With respect to the single failure scenarios, it was found the failure of the TDAFWP is limiting for the calculation of minimum time to pressurizer filling, unless one of the two PG&E Design Class I PORVs is blocked at the start of the transient. If a PORV is blocked, the failure of the other PG&E Design Class I PORV is limiting for pressurizer filling. The failure of a PG&E Design Class I PORV is also limiting for the calculation of

the operator action times required to ensure that transient mitigation is complete before the maximum number of PORV cycles is reached.

For cases with offsite power available, pressurizer pressure is maintained after the RCP seal injection flow is stopped, since the pressurizer heaters (specifically, the backup heaters, actuated on high pressurizer level deviation) continue to operate. However, as a steam bubble forms again in the pressurizer and the pressurizer water volume begins decreasing, relief flow switches from water to steam. Because there is no longer a concern relative to water relief through the PSVs, transient mitigation is complete. For cases with a LOOP, pressurizer pressure decreases after the RCP seal injection flow is stopped. Because the pressurizer PORV and PSV setpoints are no longer challenged, transient mitigation is complete for these cases.

The results of the FLB analysis for pressurizer filling demonstrate that, if the pressurizer fills, the following TCOAs preclude water relief through the PSVs:

(1) Ensure a pressurizer PORV is available within 8.6 minutes

If no pressurizer PORV relief is available at the start of the transient because of a failure of one of the PG&E Design Class I PORVs and isolation of the other by its respective block valve, operator action is required to ensure a PG&E Design Class I PORV is available in time to prevent water relief through the PSVs. The analysis determined that the minimum time to pressurizer filling is 8.3 minutes and the minimum time to subsequently lift the PSVs is 8.6 minutes; therefore, the operators must ensure a PG&E Design Class I PORV is available within 8.6 minutes of event initiation.

The system response for the limiting case with no pressurizer PORV relief available at the start of the transient is presented in Figures 15.4.2-22 and 15.4.2-23. The calculated sequence of events is listed in Table 15.4-8.

(2) Isolate the faulted SG within 10 minutes

Similar to the main feedwater pipe rupture analysis discussed in Section 15.4.2.2, the operators are assumed to isolate the faulted SG within 10 minutes after the low-low SG water level setpoint is reached in accordance with operating procedures. This directs all available AFW flow to the intact SGs.

(3) Isolate charging flow within 25 minutes and

(4) Stop RCP seal injection flow within 45 minutes

The results of the limiting case determined that in order for transient mitigation to occur before the maximum number of PORV cycles is reached, the operators must isolate charging flow within 25 minutes after the low-low SG water level setpoint is reached and subsequently stop RCP seal injection flow within 45 minutes after the low-low SG water level setpoint is reached. These actions ensure that a steam bubble is formed in the

pressurizer and the pressurizer water volume begins to decrease, causing relief flow to switch from water to steam before the capacity of the backup nitrogen accumulators is depleted. Once this occurs, there is no longer a concern relative to water relief through the PSVs and transient mitigation is complete for these cases.

The system response is presented in Figures 15.4.2-24 through 15.4.2-27.
Table 15.4-8, "Sequence of Events," indicates that a steam bubble forms again in the pressurizer at 6723 seconds. This occurs at cycle 295 before the maximum number of 300 PORV cycles is reached at 7137.6 seconds.

Summary of TCOAs

The TCOAs established for mitigation of the FLB event are summarized below. All TCOA times are from event initiation.

1. Ensure a PG&E Design Class I pressurizer PORV is available within 8.6 minutes
2. Isolate the faulted SG within 10 minutes
3. Isolate charging flow within 25 minutes
4. Stop RCP seal injection flow within 45 minutes

15.4.2.4.5 Conclusion

The results of the FLB analysis for pressurizer filling show that operator actions, when taken in a timely manner, will preclude water relief through the PSVs. Thus, the reactor coolant pressure boundary integrity is maintained.

15.4.3 STEAM GENERATOR TUBE RUPTURE

15.4.3.1 Acceptance Criteria

The following limiting criteria are applicable for a SGTR:

(1) The resulting potential exposures to individual members of the public and to the general population shall be lower than the applicable guidelines and limits specified in Section 15.5.20.

(2) There are no regulatory acceptance criteria associated with a SGTR margin to overfill (MTO) transient analysis. However, it will be demonstrated that there is sufficient margin to prevent overfill of the SG during an SGTR event. Overfill of the SG may result in significantly increased offsite dose consequences, along with damage to secondary components such as the turbine and the main steam line.

15.4.3.2 Identification of Causes and Accident Description

The accident examined is the complete severance of a single SG tube. The accident is assumed to take place at power with the reactor coolant contaminated with fission products corresponding to continuous operation with a limited amount of defective fuel rods. The accident leads to an increase in contamination of the secondary system due to leakage of radioactive coolant from the RCS. In the event of a coincident LOOP, or failure of the condenser steam dump system, discharge of activity to the atmosphere takes place via the SG PORVs (and safety valves if their setpoint is reached).

Although the SG tube material is thermally treated Inconel 690, a highly ductile material, it is assumed that complete severance could occur. The more probable mode of tube failure would be one or more minor leaks of undetermined origin. Activity in the steam and power conversion system is subject to continual surveillance and an accumulation of minor leaks that exceeds the limits established in the Technical Specifications (Reference 30) is not permitted during the unit operation.

The operator is expected to determine that a SGTR has occurred, to identify and isolate the ruptured SG, and to complete the required recovery actions to stabilize the plant and terminate the primary to secondary break flow. These actions should be performed on a restricted time scale in order to minimize contamination of the secondary system and ensure termination of radioactive release to the atmosphere from the ruptured unit. Consideration of the indications provided at the control board, together with the magnitude of the break flow, leads to the conclusion that the recovery procedure can be carried out on a time scale that ensures that break flow to the secondary system is terminated before water level in the affected SG rises into the main steam pipe. Sufficient indications and controls are provided to enable the operator to carry out these functions satisfactorily.

Assuming normal operation of the various plant control systems, the following sequence of events is initiated by a tube rupture:

(1) Pressurizer low pressure and low-level alarms are actuated and charging pump flow increases in an attempt to maintain pressurizer level. On the secondary side there is a steam flow/feedwater flow mismatch before trip as feedwater flow to the affected SG is reduced due to the break flow that is now being supplied to that unit.

(2) The main steam line radiation monitors, the air ejector radiation monitor and/or the SG blowdown radiation monitor will alarm, indicating a sharp increase in radioactivity in the secondary system, and SG blowdown will be automatically terminated.

(3) Continued loss of reactor coolant inventory leads to a reactor trip signal generated by low pressurizer pressure or overtemperature ΔT. An SI signal, initiated by low pressurizer pressure, follows soon after the reactor

trip. The SI signal automatically terminates normal feedwater supply and initiates AFW addition.

(4) The reactor trip automatically trips the turbine and, if offsite power is available, the 40 percent condenser dump valves open permitting steam dump to the condenser. In the event of a coincident LOOP, the 40 percent condenser dump valves would automatically close to protect the condenser. The SG pressure would rapidly increase resulting in steam discharge to the atmosphere through the SG PORVs and safety valves if their setpoint is reached.

(5) Following reactor trip and SI actuation, the continued action of AFW supply and borated SI flow (supplied from the RWST) provides a heat sink that absorbs some of the decay heat. This reduces the amount of steam bypass to the condenser, or in the case of LOOP, steam relief to the atmosphere.

(6) SI flow results in stabilization of the RCS pressure and pressurizer water level, and the RCS pressure trends toward the equilibrium value where the SI flow rate equals the break flow rate.

In the event of an SGTR, the plant operators must diagnose the SGTR and perform the required recovery actions to stabilize the plant and terminate the primary to secondary leakage. The operator actions for SGTR recovery are provided in the EOPs (Reference 42). The major operator actions include identification and isolation of the ruptured SG, cooldown and depressurization of the RCS to restore inventory, and termination of SI to stop primary to secondary leakage. These operator actions are described below:

(1) Identify the ruptured SG.

High secondary side activity, as indicated by the main steam line radiation monitors, the air ejector radiation monitor, or SG blowdown radiation monitor typically will provide the first indication of an SGTR event. The ruptured SG can be identified by an unexpected increase in SG level, or a high radiation indication on the corresponding main steam line monitor, or from a radiation survey of the main steam lines. For an SGTR that results in a reactor trip at high power, the SG water level may decrease off-scale on the narrow range for all of the SGs. The AFW flow will begin to refill the SGs, distributing approximately equal flow to each of the SGs. Since primary to secondary leakage adds additional liquid inventory to the ruptured SG, the water level will return to the narrow range earlier in that SG and will continue to increase more rapidly. This response, as indicated by the SG water level instrumentation, provides confirmation of an SGTR event and also identifies the ruptured SG.

(2) Isolate the ruptured SG from the intact SGs and isolate feedwater to the ruptured SG.

Once a tube rupture has been identified, recovery actions begin by isolating steam flow from and stopping feedwater flow to the ruptured SG. In addition to minimizing radiological releases, this also reduces the possibility of overfilling the ruptured SG with water by (a) minimizing the accumulation of feedwater flow and (b) enabling the operator to establish a pressure differential between the ruptured and intact SGs as a necessary step toward terminating primary to secondary leakage.

(3) Cool down the RCS using the intact SGs.

After isolation of the ruptured SG, the RCS is cooled as rapidly as possible to less than the saturation temperature corresponding to the ruptured SG pressure by dumping steam from only the intact SGs. This ensures adequate subcooling in the RCS after depressurization to the ruptured SG pressure in subsequent actions. If offsite power is available, the normal steam dump system to the condenser can be used to perform this cooldown. However, if offsite power is lost, the RCS is cooled using the PORVs on the intact SGs.

(4) Depressurize the RCS to restore reactor coolant inventory.

When the cooldown is completed, SI flow will increase RCS pressure until break flow matches SI flow. Consequently, SI flow must be terminated to stop primary to secondary leakage. However, adequate reactor coolant inventory must first be assured. This includes both sufficient reactor coolant subcooling and pressurizer inventory to maintain a reliable pressurizer level indication after SI flow is stopped. Since leakage from the primary side will continue after SI flow is stopped until the RCS and ruptured SG pressures equalize, an "excess" amount of inventory is needed to ensure pressurizer level remains on span. The "excess" amount required depends on RCS pressure and reduces to zero when RCS pressure equals the pressure in the ruptured SG.

The RCS depressurization is performed using normal pressurizer spray if the RCPs are running. However, if offsite power is lost or the RCPs are not running for some other reason, normal pressurizer spray is not available. In this event, RCS depressurization can be performed using a pressurizer PORV or auxiliary pressurizer spray.

(5) Terminate SI to stop primary to secondary leakage.

The previous actions will have established adequate RCS subcooling, a secondary side heat sink, and sufficient reactor coolant inventory to ensure that SI flow is no longer needed. When these actions have been completed, SI flow must be stopped to terminate primary to secondary leakage. Primary to secondary leakage will continue after SI flow is stopped until the RCS and ruptured SG pressures equalize. Charging flow, letdown, and pressurizer heaters will then be controlled to prevent repressurization of the RCS and reinitiation of leakage into the ruptured SG.

Following SI termination, the plant conditions will be stabilized, the primary to secondary break flow will be terminated and all immediate safety concerns will have been addressed. At this time a series of operator actions are performed to prepare the plant for cooldown to cold shutdown conditions. Subsequently, actions are performed to cooldown and depressurize the RCS to cold shutdown conditions and to depressurize the ruptured SG.

15.4.3.3 Analysis of Effects and Consequences

15.4.3.3.1 Steam Generator Tube Rupture Margin to Overfill Analysis

An SGTR results in the leakage of contaminated reactor coolant into the secondary system and subsequent release of a portion of the activity to the atmosphere. Therefore, an analysis must be performed to assure that the radiological consequences resulting from an SGTR are within allowable guidelines. Another concern for SGTR consequences is the possibility of SG overfill because this could potentially result in a significant increase in the radiological consequences. Overfill could result in water entering the main steam line. If water continues to leak into the main steam lines, the release of liquid through the SG safety valves could result in an increase in radiological doses. Therefore, an analysis was performed to demonstrate margin to SG overfill, assuming the limiting single failure relative to overfill. The results of this analysis demonstrate that there is margin to SG overfill for DCPP.

The overfill analysis is presented in Reference 72 and the major assumptions include:

(1) Complete severance of a single tube located at the top of the tube sheet on the outlet side of the SG, resulting in double ended flow

(2) Initiation of the event from full power

(3) A LOOP coincident with reactor trip

(4) Failure of an AFW control valve to close (limiting single failure)

(5) The PORVs on all three intact SGs are fully opened during the RCS cooldown

(6) Operator actions are consistent with the times shown in Table 15.4-12

The SGTR MTO analysis acceptance criterion is to maintain a positive MTO when the event is terminated. The limiting MTO analysis presented in Reference 72 demonstrates that the SG liquid volume is 30 cubic feet less than the total SG volume of 5800 cubic feet when the SGTR event is terminated. The SGTR MTO analysis sequence of events is listed in Table 15.4-13A and the transient responses are presented in Figures 15.4.3-1A through 15.4.3-4A and Figures 15.4.3-6A through 15.4.3-8A.

An analysis was also performed to determine the transient thermal hydraulic data for input into the radiological consequences analysis, assuming the limiting single failure relative to doses without SG overfill (as opposed to one that is relative to overfill). Because SG overfill does not occur, the radiation consequences (refer to Section 15.5.20) calculated using the results of this analysis represent the limiting consequences for an SGTR for DCPP. The thermal hydraulic results used by the radiological consequences (Dose) analysis are discussed below.

15.4.3.3.2 Steam Generator Tube Rupture Dose Input Analysis

A thermal and hydraulic analysis was performed to determine the plant response for a design basis SGTR, and to determine the integrated primary to secondary break flow and the mass releases from the ruptured and intact SGs to the condenser and to the atmosphere. This information was then used to calculate the quantity of radioactivity released to the environment and the resulting radiological consequences. The thermal and hydraulic analysis discussed in this section is presented in Reference 41 and the results of the radiological consequences analysis are discussed in Section 15.5.20.

The plant response following an SGTR was analyzed with the RETRAN-02W program until the primary to secondary break flow is terminated. The reactor protection system and the automatic actuation of the engineered safeguards systems were modeled in the analysis. The major operator actions which are required to terminate the break flow for an SGTR were also simulated in the analysis.

Analysis Assumptions

The accident modeled is a double-ended break of one SG tube located at the top of the tube sheet on the outlet (cold leg) side of the SG. However, as indicated subsequently, the break flow flashing fraction was conservatively calculated assuming that all of the break flow comes from the hot leg side of the SG. The combination of these conservative assumptions regarding the break flow location results in a very conservative calculation of the radiation doses. It was assumed that the reactor is

operating at full power at the time of the accident and the secondary mass was assumed to correspond to operation at the SG nominal level with an allowance for uncertainties. It was also assumed that a LOOP occurs at the time of reactor trip and the highest worth control assembly was assumed to be stuck in its fully withdrawn position at reactor trip.

The limiting single failure was assumed to be the failure of the PORV on the ruptured SG. Failure of this PORV in the open position will cause an uncontrolled depressurization of the ruptured SG which will increase primary to secondary leakage and the mass release to the atmosphere. It was assumed that the ruptured SG PORV fails open when the ruptured SG is isolated, and that the PORV was isolated by locally closing the associated block valve.

The major operator actions required for the recovery from an SGTR are discussed in Section 15.4.3.2 and these operator actions were simulated in the analysis. The operator action times which were used for the analysis are presented in Table 15.4-12. It is noted that the PORV on the ruptured SG was assumed to fail open at the time the ruptured SG was isolated. It was assumed that the operators isolate the failed open PORV by locally closing the associated block valve to complete the isolation of the ruptured SG before proceeding with the subsequent recovery operations. It was assumed that the ruptured SG PORV was isolated at 30 minutes after the valve was assumed to fail open. After the ruptured SG PORV was isolated, an additional delay time of 5 minutes (refer to Table 15.4-12) was assumed for the operator action time to initiate the RCS cooldown.

Transient Description

The RETRAN-02W (Reference 70) analysis results are described below. The sequence of events for this transient is presented in Table 15.4-13B.

Following the tube rupture, reactor coolant flows from the primary into the secondary side of the ruptured SG since the primary pressure is greater than the SG pressure. In response to this loss of reactor coolant, pressurizer level decreases as shown in Figure 15.4.3-1B. The pressurizer pressure also decreases as shown in Figure 15.4.3-2B as the steam bubble in the pressurizer expands. As the RCS pressure decreases due to the continued primary to secondary leakage, automatic reactor trip occurs on an overtemperature ΔT trip signal.

After reactor trip, core power rapidly decreases to decay heat levels. The turbine stop valves close and steam flow to the turbine is terminated. The steam dump system is designed to actuate following reactor trip to limit the increase in secondary pressure, but the 40 percent condenser dump valves remain closed due to the loss of condenser vacuum resulting from the assumed LOOP at the time of reactor trip. Thus, the energy transfer from the primary system causes the secondary side pressure to increase rapidly after reactor trip until the SG PORVs (and safety valves if their setpoints are reached) lift to dissipate the energy, as shown in Figure 15.4.3-3B. The main feedwater

flow will be terminated and AFW flow will be automatically initiated following reactor trip and the LOOP.

The RCS pressure decreases more rapidly after reactor trip as energy transfer to the secondary shrinks the reactor coolant and the tube rupture break flow continues to deplete primary inventory. Pressurizer level also decreases more rapidly following reactor trip. The decrease in RCS inventory results in a low pressurizer pressure SI signal. After SI actuation, the SI flow rate maintains the reactor coolant inventory and the pressurizer level begins to stabilize. The RCS pressure also trends toward the equilibrium value where the SI flow rate equals the break flow rate.

Because offsite power was assumed lost at reactor trip, the RCPs trip and a gradual transition to natural circulation flow occurs. Immediately following reactor trip the temperature differential across the core decreases as core power decays (refer to Figures 15.4.3-4B and 15.4.3-5B), however, the temperature differential subsequently increases as natural circulation flow develops. The cold leg temperatures trend toward the SG temperature as the fluid residence time in the tube region increases. The intact SG loop temperatures slowly decrease due to the continued AFW flow until operator actions are taken to control the AFW flow to maintain the specified level in the intact SGs. The ruptured SG loop temperatures also continue to slowly decrease until the ruptured SG is isolated, at which time the PORV is assumed to fail open.

Major Operator Actions

(1) Identify and Isolate the Ruptured SG

As indicated in Table 15.4-12, it was assumed that the ruptured SG is identified and isolated at 10 minutes after the initiation of the SGTR or when the narrow range level reaches 38 percent, whichever time is longer. Since the time to reach 38 percent narrow range level was 953 seconds, it was assumed that the actions to isolate the ruptured SG are performed at this time.

The ruptured SG PORV was also assumed to fail open at this time, and the failure was simulated at 953 seconds. The failure causes the ruptured SG to rapidly depressurize, which results in an increase in primary to secondary leakage. The depressurization of the ruptured SG increases the break flow and energy transfer from primary to secondary which results in a decrease in the ruptured loop temperatures as shown in Figure 15.4.3-5B. As noted previously, the intact SG loop temperatures also decrease, as shown in Figure 15.4.3-4B, until the AFW flow to the intact SGs is throttled. These effects result in a decrease in the RCS pressure and pressurizer level, until the failed open PORV is isolated.

It was assumed that the time required for the operator to identify that the ruptured SG PORV is open and to locally close the associated block valve

is 30 minutes. Thus, the isolation of the ruptured SG was completed at 2753 seconds, and the depressurization of the ruptured SG was terminated. At this time, the ruptured SG pressure increases rapidly and the primary to secondary break flow begins to decrease.

(2) Cool Down the RCS to establish Subcooling Margin

After the ruptured SG PORV block valve was closed, a 5 minute operator action time was imposed prior to initiation of cooldown. The depressurization of the ruptured SG affects the RCS cooldown target temperature because the temperature is dependent upon the pressure in the ruptured SG. Since offsite power was lost, the RCS was cooled by dumping steam to the atmosphere using the intact SG PORVs. The cooldown was continued until RCS was subcooled 36°F including an allowance for instrument uncertainty. Because the pressure in the ruptured SG continued to decrease during the cooldown, the associated temperature the RCS was less than the initial target temperature, which had the net effect of extending the time for cooldown. The cooldown was initiated at 3053 seconds and was completed at 4424 seconds.

The reduction in the intact SG pressures required to accomplish the cooldown is shown in Figure 15.4.3-3B, and the effect of the cooldown on the RCS temperature is shown in Figure 15.4.3-4B. The pressurizer level and pressurizer pressure also decrease during this cooldown process due to shrinkage of the reactor coolant, as shown in Figures 15.4.3-1B and 15.4.3-2B, respectively.

(3) Depressurize to Restore Inventory

After the RCS cooldown, a 4 minute operator action time was included prior to depressurization. The RCS depressurization was initiated at 4664 seconds to assure adequate coolant inventory prior to terminating SI flow. With the RCPs stopped, normal pressurizer spray is not available and thus the RCS was depressurized by opening a pressurizer PORV. The depressurization was continued until any of the following conditions are satisfied: RCS pressure is less than the ruptured SG pressure and pressurizer level is greater than the allowance of 12 percent for pressurizer level uncertainty, or pressurizer level is greater than 74 percent, or RCS subcooling is less than the 20°F allowance for subcooling uncertainty. The RCS depressurization reduces the break flow as shown in Figure 15.4.3-6B, and increases SI flow to refill the pressurizer as shown in Figure 15.4.3-1B.

(4) Terminate SI to Stop Primary to Secondary Leakage

The previous actions have established adequate RCS subcooling, verified a secondary side heat sink, and restored the reactor coolant inventory to ensure that SI flow is no longer needed. When these actions have been completed, the SI flow must be stopped to prevent repressurization of the RCS and to terminate primary to secondary leakage. The SI flow is terminated after a delay to allow for operator response if RCS subcooling is greater than the 20°F allowance for uncertainty, minimum AFW flow is available or at least one intact SG level is in the narrow range, the RCS pressure is stable or increasing, and the pressurizer level is greater than the 12 percent allowance for uncertainty.

After depressurization was completed, an operator action time of 2 minutes was assumed prior to SI termination. Since the above requirements are satisfied, SI termination was performed at this time. After SI termination, the pressurizer pressure decreases as shown in Figure 15.4.3-2B. Figure 15.4.3-6B shows that the primary to secondary leakage continues after the SI flow was stopped until the RCS and ruptured SG pressures equalize.

The ruptured SG water volume for the radiological consequences analysis is shown in Figure 15.4.3-7B. The mass of water in the ruptured SG is also shown as a function of time in Figure 15.4.3-8B.

Mass Releases

The mass releases were determined for use in evaluating the exclusion area boundary (EAB) and low population zone (LPZ) radiation exposure. The steam releases from the ruptured and intact SGs, the feedwater flows to the ruptured and intact SGs, and primary to secondary break flow into the ruptured SG were determined for the period from accident initiation until 2 hours after the accident and from 2 to 8 hours after the accident. The releases for 0-2 hours were used to calculate the radiation doses at the EAB for a 2 hour exposure, and the releases for 0-8 hours were used to calculate the radiation doses at the LPZ for the duration of the accident.

The operator actions for the SGTR recovery up to the termination of primary to secondary leakage were simulated in the RETRAN-02W analysis. Thus, the steam releases from the ruptured and intact SGs, the feedwater flows to the ruptured and intact SGs, and the primary to secondary leakage into the ruptured SG were determined from the RETRAN-02W results for the period from the initiation of the accident until the leakage was terminated.

Following the termination of leakage, it was assumed that the actions are taken to cool down the plant to cold shutdown conditions. The PORVs for the intact SGs were assumed to be used to cool down the RCS to the RHR system operating temperature of 350°F, at the maximum allowable cooldown rate of 100°F/hr. The steam releases and

the feedwater flows for the intact SG for the period from leakage termination until 2 hours were determined from a mass and energy balance using the calculated RCS and intact SG conditions at the time of leakage termination and at 2 hours. The RCS cooldown was assumed to be continued after 2 hours until the RHR system in-service temperature of 350°F is reached. Depressurization of the ruptured SG was then assumed to be performed to the RHR in-service pressure of 405 psia via steam release from the ruptured SG PORV. The RCS pressure was also assumed to be reduced concurrently as the ruptured SG is depressurized. It was assumed that the continuation of the RCS cooldown and depressurization to RHR operating conditions are completed within 8 hours after the accident since there is ample time to complete the operations during this time period. The steam releases and feedwater flows from 2 to 8 hours were determined for the intact SGs from a mass and energy balance using conditions at 2 hours and at the RHR system in-service conditions. The steam released from the ruptured SG from 2 to 8 hours was determined based on a mass and energy balance for the ruptured SG using the conditions at the time of leakage termination and saturated conditions at the RHR in-service pressure.

After 8 hours, it was assumed that further plant cooldown to cold shut down as well as long-term cooling is provided by the RHR system. Therefore, the steam releases to the atmosphere are terminated after RHR in-service conditions are assumed to be reached at 8 hours.

During the time period from initiation of the accident until leakage termination, the releases were determined from the RETRAN-02W results for the time prior to reactor trip and following reactor trip. Since the condenser is in service until reactor trip, any radioactivity released to the atmosphere prior to reactor trip would be through the condenser air ejector and/or the condenser vacuum pump exhaust (if in operation). After reactor trip, the releases to the atmosphere were assumed to be via the SG PORVs. The mass release rates to the atmosphere from the RETRAN-02W analysis are presented in Figures 15.4.3-9 and 15.4.3-10 for the ruptured and intact SGs, respectively, for the time period until leakage termination. The total flashed break flow from the RETRAN-02W analysis is presented in Figure 15.4.3-11. The mass releases calculated from the time of leakage termination until 2 hours and from 2-8 hours were also assumed to be released to the atmosphere via the SG PORVs. The mass releases for the SGTR event for the 0-2 hour and 2-8 hour time intervals are presented in Table 15.4-14.

15.4.3.4 Conclusions

The analysis demonstrates the acceptance criteria are met as follows:

15.4.3.4.1 Overfill Analysis

The SGTR MTO analysis acceptance criteria are to maintain a positive MTO when the event is terminated. Therefore, the limiting MTO analysis demonstrates that the SG

liquid volume is less than the total SG volume of 5800 cubic feet when the SGTR event is terminated.

15.4.3.4.2 Radiological

Section 15.5.20 demonstrates that the acceptance criteria for Dose Consequences of a SGTR are met. Table 15.5-64 provides the offsite and control room radiation doses from the release of airborne activity following a SGTR accident.

15.4.4 SINGLE REACTOR COOLANT PUMP LOCKED ROTOR

15.4.4.1 Identification of Causes and Accident Description

The accident postulated is an instantaneous seizure of an RCP rotor.

Following initiation of the reactor trip, heat stored in the fuel rods continues to be transferred to the coolant causing the coolant to expand. At the same time, heat transfer to the shell-side of the SGs is reduced, first because the reduced flow results in a decreased tube-side film coefficient and then because the reactor coolant in the tubes cools down while the shell-side temperature increases (turbine steam flow is reduced to zero upon plant trip). The rapid expansion of the coolant in the reactor core, combined with reduced heat transfer in the SGs causes an insurge into the pressurizer and a pressure increase throughout the RCS. The insurge into the pressurizer compresses the steam volume, actuates the automatic spray system, opens the PORVs, and opens the PSVs in that sequence. The three PORVs are designed for reliable operation and would be expected to function properly during the accident. However, for conservatism, their pressure-reducing effect as well as the pressure-reducing effect of the spray is not included in the analysis.

15.4.4.2 Analysis of Effects and Consequences

Three digital computer codes are used to analyze this transient. The LOFTRAN (Reference 26) code is used to calculate the resulting loop and core coolant flow following the pump seizure. The LOFTRAN code is also used to calculate the time of reactor trip based on the calculated flow, the nuclear power following reactor trip, and to determine the peak pressure. The thermal behavior of the fuel located at the core hot spot is investigated using the FACTRAN (Reference 17) code, using the core flow and the nuclear power calculated by LOFTRAN. The FACTRAN code includes the use of a film boiling heat transfer coefficient. The THINC (Reference 31) code (refer to Section 4.4.3) is used to calculate the DNBR during the transient based on flow calculated by LOFTRAN and heat flux calculated by FACTRAN.

At the beginning of the postulated locked rotor accident, i.e., at the time the shaft in one of the RCPs is assumed to seize, for the DNB evaluation the plant is assumed to be under steady state operating conditions consistent with use of the ITDP (Reference 62).

When the peak pressure is evaluated, the initial power is assumed as 2 percent above nominal full power, the initial coolant average temperature is assumed 5°F above nominal, and the initial pressure is conservatively assumed as 60 psi above nominal pressure (2250 psia) to allow for uncertainties. This is done to obtain the highest possible rise in the coolant pressure during the transient. The pressure response for the point in the RCS having the maximum pressure is shown in Figure 15.4.4-1.

The analysis accounts for the potential effect of asymmetric steam generator tube plugging, which results in a loop-to-loop flow asymmetry. The loop with the locked rotor is assumed to have the highest initial flow rate, which conservatively minimizes the core flow during the transient.

15.4.4.2.1 Evaluation of the Pressure Transient

After pump seizure and reactor trip, the neutron flux is rapidly reduced by the effect of control rod insertion. Rod motion is assumed to begin 1 second after the flow in the affected loop reaches 85 percent of nominal flow. No credit is taken for the pressure-reducing effect of the pressurizer relief valves, pressurizer spray, steam dump, or controlled feedwater flow after plant trip.

Although these operations are expected to occur and would result in a lower peak pressure, an additional degree of conservatism is provided by ignoring their effect.

The pressurizer safety valve model includes a +3 percent opening tolerance plus 5 psi accumulation above the nominal setpoint of 2500 psia. A purge delay of 1.272 seconds was also included to account for the presence of water-filled loop seals (Reference 75). The analysis conservatively assumes an additional +1% shift in the opening setpoint. Note that all PSVs have been concerted to a steam seat design and condensate in the loop is now continuously drained back to the pressurizer, thereby eliminating the water loop seal. Even though the water loop seal has been eliminated, the resulting benefit is not credited in the analysis.

15.4.4.2.2 Evaluation of the Effects of Departure from Nucleate Boiling in the Core During the Accident

For this accident, DNB is assumed to occur in the core and, therefore, an evaluation of the consequences with respect to fuel rod thermal transients is performed. Results obtained from analysis of this hot spot condition represent the upper limit with respect to cladding temperature and ZR-H_2O reaction.

In the evaluation, the rod power at the hot spot is conservatively assumed to be greater than or equal to 2.7 (i.e., $F_Q \geq 2.7$) at the initial core power level.

15.4.4.2.3 Film Boiling Coefficient

The film boiling coefficient is calculated in the FACTRAN code using the Bishop-Sandberg-Tong film boiling correlation. The fluid properties are evaluated at film temperature (average between wall and bulk temperatures). The program calculates the film coefficient at every time step based on the actual heat transfer conditions at the time. The neutron flux and mass flowrate, as a function of time, are used as program input.

For this analysis, the initial values of the pressure and the bulk density are used throughout the transient since they are the most conservative with respect to cladding temperature response. For conservatism, DNB was assumed to start at the beginning of the accident.

15.4.4.2.4 Fuel Cladding Gap Coefficient

The magnitude and time dependence of the heat transfer coefficient between fuel and cladding (gap coefficient) has a pronounced influence on the thermal results. The larger the value of the gap coefficient, the more heat is transferred between pellet and cladding. Based on investigations on the effect of the gap coefficient upon the maximum cladding temperature during the transient, the gap coefficient was assumed to increase from a steady state value consistent with the initial fuel temperature to 10,000 Btu/hr-ft^2-°F within 0.5 seconds after the initiation of the transient. This assumption causes energy stored in the fuel to be released to the cladding at the initiation of the transient and maximizes the cladding temperature during the transient.

15.4.4.2.5 Zirconium-steam Reaction

The zirconium-steam reaction can become significant above 1800°F (cladding temperature). The Baker-Just parabolic rate equation shown below is used to define the rate of the zirconium-steam reaction.

$$\frac{d(w^2)}{dt} = 33.3 \times 10^6 \exp\left[\frac{-45{,}500}{1.986T}\right] \qquad (15.4\text{-}1)$$

where:

w = amount reacted, mg/cm^2
t = time, sec
T = temperature, °K
and the reaction heat is 1510 cal/gm.

15.4.4.3 Results

Transient plots of maximum RCS pressure, flow coastdown, hot channel heat flux, and neutron flux are shown in Figures 15.4.4-1 and 15.4.4-3 through 15.4.4-5. Maximum RCS pressure, maximum cladding temperature, and amount of Zr-H_2O reaction are contained in Table 15.4-10. Figure 15.4.4-2 shows the cladding temperature transient for the worst case.

15.4.4.4 Conclusions

(1) Because the peak RCS pressure reached during any of the transients is less than that which would cause stresses to exceed the faulted condition stress limits, the integrity of the primary coolant system is maintained. For the MSS, the maximum pressure is bounded by the analysis of the loss of external electrical load/turbine trip event (refer to Section 15.2.7).

(2) Because the peak cladding average temperature calculated for the hot spot during the worst transient remains considerably less than 2700°F and the amount of Zr-H_2O reaction is small, the core will remain in place and intact with no consequential loss of core cooling capability.

(3) The results of the transient analysis show that less than 10 percent of the fuel rods will have DNBRs below the safety analysis limit values.

15.4.5 FUEL HANDLING ACCIDENT

15.4.5.1 Acceptance Criteria

The following limiting criterion is applicable for a FHA:

(1) The resulting potential exposures to individual members of the public and to the general population shall be lower than the applicable guidelines and limits specified in 10 CFR 50.67 and Section 4.4, Table 6 of Regulatory Guide 1.183, July 2000.

15.4.5.2 Identification of Causes and Accident Description

15.4.5.2.1 Fuel Handling Procedures

One major task that must be performed routinely as part of the operation of a nuclear power plant is the handling of the reactor fuel. The bulk of this fuel handling occurs during refueling outages, which occur every one to two years, and all of these operations are carried out with the fuel under water. A typical refueling outage would include the following major operations:

(1) Shutdown of the reactor and cooldown to ambient conditions

(2) Removal and storage of pressure vessel head

(3) Filling of refueling cavity above the pressure vessel with water to provide shielding from radioactive fuel

(4) Transfer of the reactor fuel assemblies from the reactor itself to underwater storage racks in the spent fuel pool

(5) Performance of outage tasks appropriate to the “core off-load” window

(6) Return of the appropriate number of partially burned and new fuel assemblies to the reactor

Fuel handling operations within the containment building and the fuel handling area are accomplished with overhead cranes, specially designed fuel grapples, and miscellaneous other equipment. To facilitate the transfer of the fuel between the two buildings, an underwater penetration called the transfer tube is provided through the walls where the buildings adjoin. A conveyer cart is used to transport the fuel from one building to the other through this penetration. A more detailed description of the equipment used in fuel handling operations can be found in Chapter 9.
Spent fuel remains in storage in the spent fuel pool until placed in a cask for transport to the Diablo Canyon Independent Spent Fuel Storage Installation (ISFSI) or for shipment from the site.

15.4.5.2.2 Probability of Activity Release

In the above operations, there exists the remote possibility that one or more fuel assemblies will sustain some mechanical damage. There exists an even more remote possibility that this damage will be severe enough to breach the cladding and release some of the radioactive fission products contained therein.

Both the fuel handling procedure and the fuel handling equipment design adhere to the following safety criteria:

(1) Fuel handling operations must not commence before short-lived core activity has decayed, leaving only relatively long-lived activity. Equipment control guidelines (ECGs) for refueling operations specify the minimum waiting time.

(2) Fuel handling operations must preclude any critical configuration of the core, spent fuel, or new fuel.

(3) The fuel handling system design must ensure an adequate water depth for radiation shielding of operating personnel.

(4) Active components of the fuel handling systems must be designed such that loss-of-function failures will terminate in stable modes.

(5) The design of fuel handling equipment must minimize the possibility of accidental impact of a moving fuel assembly with any structure.

(6) The design of fuel handling equipment and procedures must minimize the possibility of any massive object damaging a stationary fuel assembly.

(7) Fuel assembly design must minimize the possibility of damage in the event that portable or hand tools come into contact with a fuel assembly.

(8) The design of structures around the fuel handling system must minimize the possibility of the structures themselves failing in the event of a Design Earthquake (DE), Double Design Earthquake (DDE), or Hosgri Earthquake (HE). Furthermore, the structures must minimize the possibility of any external missile from reaching fuel assemblies.

(9) Fuel handling equipment must be capable of supporting maximum loads under seismic conditions. Furthermore, fuel handling equipment must not generate missiles during seismic conditions. The earthquake loading of the fuel handling equipment is evaluated in accordance with the seismic considerations addressed in Sections 9.1.4.3.1 and 9.1.4.3.9.

Implementation of the above safety criteria into the fuel handling system design is discussed in greater detail in Chapter 9.

Because of the above design, the probability of breaching the fuel cladding and releasing radioactive fission products is very small.

15.4.5.2.3 Accident Description

In order to assess the probable extent of fuel cladding damage from a FHA, it is necessary to look more closely at specific FHAs that might realistically occur.

Multiple assemblies are loaded into the multi-purpose canister/transfer cask assembly for movement to the ISFSI, as described in Section 9.1.4.2.6. The multi-purpose canister is subsequently drained, evacuated, backfilled with helium, and sealed. However, extensive design and analysis along with application of the ISFSI Technical Specifications ensure temperatures remain within the design basis and no fuel cladding damage occurs.

The possibility of damaging fuel cladding by overheating during fuel handling operations was considered. Because irradiated fuel is always handled under water, overheating would require draining either the refueling cavity or the spent fuel pool while irradiated fuel was located within them. Consideration has been given in design of the cavity and

pool to prevent either of these possibilities. The probability of losing coolant while an assembly is in the transfer tube is also extremely small in view of the fact that the tube is open on one end to the reactor cavity and on the other end to the pool. There is no realistic occurrence that would simultaneously block off both ends of the tube. Therefore, it is expected that there will be no radiological consequences over the lifetime of the plant that results from overheating during fuel handling operations.

The possibility of dropping a foreign object of sufficient size to produce cladding rupture onto irradiated fuel located either in the reactor or the pool is extremely remote because the design of the plant is such that only rarely are objects of this size transported over locations containing irradiated fuel. The three large objects that are routinely handled in the vicinity of irradiated fuel are the reactor head, upper internals package, which must be removed and reinstalled from the pressure vessel at each refueling outage, and the spent fuel shipment cask, which must be placed in the pool for loading. As discussed in Section 9.1.4.2.5, load drop analyses were performed for the reactor head and upper internals and are summarized in the PG&E NUREG-0612 submittal. It is not necessary to lift the cask over the fuel racks in moving it to or from the pool. Protection of nuclear fuel assemblies from overhead load handling is a key element of the control of heavy loads program described in Section 9.1.4.3.10.

The possibility has also been considered of one of the bridge cranes falling into the reactor or the pool as a result of an earthquake. However, both of these cranes are seismically qualified for the DE, DDE, and HE. Therefore, it is expected that there will be no radiological consequences over the lifetime of the plant that result from dropping objects onto radiated fuel.

If a fuel assembly were to strike an object, it is possible that the object might damage the fuel rods with which it comes into contact. If a fuel assembly were to strike against a flat, plane-like object or a linear, edge-like object, impact loads would be distributed across several fuel rods, and no cladding damage would be expected. If a fuel assembly were to strike against a sharp, corner-like object, impact loads would be concentrated, and cladding damage might occur. Thus, there is a very remote possibility that impact loads would be severe enough to rupture fuel cladding.

Analyses have been made by Westinghouse of the effects that would result from dropping a fuel assembly from an initial vertical orientation onto a flat surface, the core, or a loaded fuel rack. Westinghouse has also analyzed the case where an assembly in the holder on the conveyor car falls from the vertical to the horizontal position. The results of these analyses indicate there is only a very remote possibility of fuel cladding rupture.

The above discussion indicates that the unlikely event of a fuel cladding integrity failure would most likely result from a fuel assembly striking a sharp object or dropping a fuel assembly.

15.4.5.3 Results

15.4.5.3.1 Containment Building Accident

During fuel handling operations, the containment ventilation penetrations to the outside atmosphere are maintained in a closed or automatically isolable condition. Isolation is automatically actuated if either of the containment purge exhaust monitors, RM-44A or RM-44B, alarms due to a concentration of radioactivity in the containment purge exhaust duct that exceeds the alarm setpoint. However, these penetrations are also allowed to be open under administrative controls, which provide the capability of closure within approximately 30 minutes.

Other containment penetrations, such as the personnel airlock and equipment hatch are allowed to be open during fuel handling operations. These penetrations are capable of manual closure and will be closed in accordance with plant procedures should a FHA occur.

In addition to the functions of the above mentioned monitors, fixed area radiation monitors are located in the containment. Should a fuel assembly be dropped and release activity above a prescribed level, the area monitors would sound an audible alarm. Personnel would exit the containment and containment closure would be initiated immediately per administrative procedures.

Because of containment isolation and closure capabilities, activity released from damaged fuel rods will be managed such that both the onsite and offsite exposures are minimized. The containment iodine removal system (refer to Section 9.4.5) can be used to remove any radioactive iodine from the containment atmosphere, but is not credited for iodine removal in the radiological analysis (refer to Section 15.5.22), and controlled containment venting can be initiated with offshore winds. Thus, there is a reasonable probability that only limited onshore exposures will result from a containment FHA.

15.4.5.3.2 Fuel Handling Area Accident

A fuel assembly could be damaged in the transfer canal or the spent fuel pit in the fuel handling area. Supply air for the spent fuel pit area is swept across the fuel pit and transfer canal and exhausted through the vent. An area radiation monitor is located on the bridge over the spent fuel pit. Doors in the fuel handling area are closed to maintain controlled leakage characteristics in the spent fuel pit region during refueling operations involving irradiated fuel. Should a fuel assembly be damaged in the canal or in the pit and release radioactivity above a prescribed level, the radiation monitors sound an alarm and the spent fuel pit ventilation exhaust through charcoal filters will remove most of the halogens prior to discharging it to the atmosphere. If the discharge is greater than the prescribed levels, an alarm sounds and the supply and exhaust ventilation systems servicing the spent fuel pit area can be manually shut down from the control room, limiting the leakage to the atmosphere.

The analysis of the radiological effects of this accident is contained in Section 15.5.22.1.

15.4.5.4 Conclusions

The analysis demonstrates the acceptance criteria are met as follows:

(1) Section 15.5.22 concludes that all potential exposures from a fuel handling accident will be well below the guideline levels specified in 10 CFR 50.67 and Section 4.4, Table 6 of Regulatory Guide 1.183, July 2000, and that the occurrence of such accidents would not result in undue risk to the public. Table 15.5-47 provides a summary of doses from a fuel handling accident in the fuel handling area from a fuel handling accident inside containment.

15.4.6 RUPTURE OF A CONTROL ROD DRIVE MECHANISM HOUSING (ROD CLUSTER CONTROL ASSEMBLY EJECTION)

15.4.6.1 Acceptance Criteria

Conservative criteria are applied to ensure that there is little or no possibility of fuel dispersal in the coolant, gross lattice distortion, or severe shock waves. These criteria are:

15.4.6.1.1 Fuel Damage Criteria

(1) Average fuel pellet enthalpy at the hot spot below 225 cal/gm for unirradiated fuel and 200 cal/gm for irradiated fuel

(2) Average cladding temperature at the hot spot below the temperature at which cladding embrittlement may be expected (2700°F)

(3) Fuel melting will be limited to less than 10 percent of the fuel volume at the hot spot even if the average fuel pellet enthalpy is below the limits of Criterion (1) above

15.4.6.1.2 Maximum Reactor Coolant System Pressure Criteria

(1) Peak reactor coolant pressure less than that which would cause stresses to exceed the faulted condition stress limits

15.4.6.1.3 Radiological Criteria

(1) The resulting potential exposures to individual members of the public and to the general population shall be lower than the applicable guidelines and limits specified in 10 CFR 50.67 and Section 4.4, Table 6 of Regulatory Guide 1.183, July 2000.

15.4.6.2 Identification of Causes and Accident Description

This accident is defined as the mechanical failure of a control rod mechanism pressure housing resulting in the ejection of an RCCA and drive shaft. The consequence of this mechanical failure is a rapid positive reactivity insertion and system depressurization together with an adverse core power distribution, possibly leading to localized fuel rod damage.

15.4.6.2.1 Design Precautions and Protection

Certain features of the DCPP are intended to preclude the possibility of a rod ejection accident, or to limit the consequences if the accident were to occur. These include a sound, conservative mechanical design of the rod housings, together with a thorough quality control (testing) program during assembly, and a nuclear design that lessens the potential ejection worth of RCCAs and minimizes the number of assemblies inserted at high power levels.

15.4.6.2.2 Mechanical Design

The mechanical design is discussed in Section 4.2. Mechanical design and quality control procedures intended to preclude the possibility of an RCCA drive mechanism housing failure are listed below:

(1) Each full length CRDM housing is completely assembled and shop tested at 3107 psig.

(2) Pressure housings were individually hydrotested. The lower latch housing to nozzle connection is hydrotested during hydrotest of the completed reactor vessel closure head (RVCH).

(3) Stress levels in the mechanism are not affected by anticipated system transients at power, or by the thermal movement of the coolant loops. Moments induced by the DE, DDE, or HE can be accepted within the allowable primary working stress range specified by the ASME Code, Section III, for Class I components.

(4) The latch mechanism housing and rod travel housing are each a single length of forged Type-304 stainless steel. This material exhibits excellent notch toughness at all temperatures that will be encountered.

(5) The CRDM housing plug is an integral part of the rod travel housing.

A significant margin of strength in the elastic range together with the large energy absorption capability in the plastic range gives additional assurance that gross failure of the housing will not occur. The joints between the latch mechanism housing and rod

travel housing are threaded joints reinforced by canopy-type rod welds. Administrative regulations require periodic inspections of these (and other) welds.

15.4.6.2.3 Nuclear Design

Even if a rupture of an RCCA drive mechanism housing is postulated, the operation of a plant utilizing chemical shim is such that the severity of an ejected RCCA is inherently limited. In general, the reactor is operated with the RCCAs inserted only far enough to permit load follow. Reactivity changes caused by core depletion and xenon transients are compensated by boron changes. Further, the location and grouping of control rod banks are selected during the nuclear design to lessen the severity of an RCCA ejection accident. Therefore, should an RCCA be ejected from its normal position during full-power operation, only a minor reactivity excursion, at worst, could be expected to occur.

However, it may be occasionally desirable to operate with larger than normal insertions. For this reason, a rod insertion limit is defined as a function of power level. Operation with the RCCAs above this limit guarantees adequate shutdown capability and acceptable power distribution. The position of all RCCAs is continuously indicated in the control room. An alarm will occur if a bank of RCCAs approaches its insertion limit or if one RCCA deviates from its bank. There are low and low-low level insertion monitors with visual and audio signals. Operating instructions require boration at low-level alarm and emergency boration at the low-low alarm.

15.4.6.2.4 Reactor Protection

The reactor protection in the event of a rod ejection accident has been described in Reference 18. The protection for this accident is provided by the power range high neutron flux trip (high and low setting) and high rate of neutron flux increase trip. These protection functions are described in detail in Section 7.2.

15.4.6.2.5 Effects on Adjacent Housings

Disregarding the remote possibility of the occurrence of an RCCA mechanism housing failure, investigations have shown that failure of a housing due to either longitudinal or circumferential cracking is not expected to cause damage to adjacent housings leading to increased severity of the initial accident.

15.4.6.2.6 Limiting Criteria

Due to the extremely low probability of an RCCA ejection accident, limited fuel damage is considered an acceptable consequence.

Comprehensive studies of the threshold of fuel failure and of the threshold of significant conversion of the fuel thermal energy to mechanical energy have been carried out as part of the SPERT project by the Idaho Nuclear Corporation (Reference 19). Extensive

tests of zirconium-clad UO_2 fuel rods representative of those in PWR-type cores have demonstrated failure thresholds in the range of 240 to 257 cal/gm. However, other rods of a slightly different design have exhibited failures as low as 225 cal/gm. These results differ significantly from the TREAT (Reference 20) results, which indicated a failure threshold of 280 cal/gm. Limited results have indicated that this threshold decreases by about 10 percent with fuel burnup. The cladding failure mechanism appears to be melting for zero burnup rods and brittle fracture for irradiated rods. Also important is the conversion ratio of thermal to mechanical energy. This ratio becomes marginally detectable above 300 cal/gm for unirradiated rods and 200 cal/gm for irradiated rods; catastrophic failure, (large fuel dispersal, large pressure rise) even for irradiated rods, did not occur below 300 cal/gm.

15.4.6.3 Analysis of Effects and Consequences

The analysis of the RCCA ejection accident is performed in two stages: (a) an average core nuclear power transient calculation and (b) a hot spot heat transfer calculation.

The average core calculation is performed using spatial neutron kinetics methods to determine the average power generation with time including the various total core feedback effects; i.e., Doppler reactivity and moderator reactivity. Enthalpy and temperature transients in the hot spot are then determined by multiplying the average core energy generation by the hot channel factor and performing a fuel rod transient heat transfer calculation. The power distribution calculated without feedback is pessimistically assumed to persist throughout the transient.

A detailed discussion of the method of analysis can be found in Reference 21.

15.4.6.3.1 Average Core Analysis

The spatial kinetics computer code, TWINKLE (refer to Section 1.6.1, Item 50 and Section 15.1.2.5) is used for the average core transient analysis. This code solves the two group neutron diffusion theory kinetic equations in one, two, or three spatial dimensions (rectangular coordinates) for six delayed neutron groups and up to 2000 spatial points. The computer code includes a detailed multi-region, transient fuel-clad-coolant heat transfer model for calculating pointwise Doppler, and moderator feedback effects.

In this analysis, the code is used as a one-dimensional axial kinetics code since it allows a more realistic representation of the spatial effects of axial moderator feedback and RCCA movement and the elimination of axial feedback weighting factors. However, since the radial dimension is missing, it is still necessary to employ very conservative methods (described below) of calculating the ejected rod worth and hot channel factor. A further description of TWINKLE appears in Section 15.1.2.5.

15.4.6.3.2 Hot Spot Analysis

The average core energy addition, calculated as described above, is multiplied by the appropriate hot channel factors, and the hot spot analysis is performed using the detailed fuel and cladding transient heat transfer computer code, FACTRAN. This computer code calculates the transient temperature distribution in a cross-section of a metalclad UO_2 fuel rod, and the heat flux at the surface of the rod, using as input the nuclear power versus time and the local coolant conditions. The Zr-H_2O reaction is explicitly represented, and all material properties are represented as functions of temperature. A parabolic radial power generation is used within the fuel rod.

FACTRAN uses the Dittus-Boelter (Reference 28) or Jens-Lottes (Reference 29) correlation to determine the film heat transfer before DNB, and the Bishop-Sandberg-Tong correlation (Reference 23) to determine the film boiling coefficient after DNB. The DNB heat flux is not calculated; instead the code is forced into DNB by specifying a conservative DNB heat flux. The gap heat transfer coefficient can be calculated by the code; however, it is adjusted in order to force the full power steady state temperature distribution to agree with that predicted by design fuel heat transfer codes.

For full power cases, the design initial hot channel factor (F_Q) is input to the code. The hot channel factor during the transient is assumed to increase from the steady state design value to the maximum transient value in 0.1 seconds, and remain at the maximum for the duration of the transient. This is conservative, since detailed spatial kinetics models show that the hot channel factor decreases shortly after the nuclear power peak due to power flattening caused by preferential feedback in the hot channel. Further description of FACTRAN appears in Section 15.1.2.1.

15.4.6.3.3 System Overpressure Analysis

Because safety limits for fuel damage specified earlier are not exceeded, there is little likelihood of fuel dispersal into the coolant. The pressure surge may therefore be calculated on the basis of conventional heat transfer from the fuel and prompt heat generation in the coolant.

The pressure surge is calculated by first performing the fuel heat transfer calculation to determine the average and hot spot heat flux versus time. Using this heat flux data, a THINC calculation is conducted to determine the volume surge. Finally, the volume surge is simulated in a plant transient computer code. This code calculates the pressure transient taking into account fluid transport in the system, heat transfer to the SGs, and the action of the pressurizer spray and pressure relief valves. No credit is taken for the possible pressure reduction caused by the assumed failure of the control rod pressure housing (Reference 21).

15.4.6.3.4 Calculation of Basic Parameters

Input parameters for the analysis are conservatively selected on the basis of calculated values for this type of core. The more important parameters are discussed below. Table 15.4-11 presents the parameters used in this analysis. A summary of the values used in the reload analysis process is also provided in Table 15.4-11.

15.4.6.3.5 Ejected Rod Worths and Hot Channel Factors

The values for ejected rod worths and hot channel factors are calculated using three-dimensional calculations. Standard nuclear design codes are used in the analysis. No credit is taken for the flux-flattening effects of reactivity feedback. The calculation is performed for the maximum allowed bank insertion at a given power level as determined by the rod insertion limits. Adverse xenon distributions are considered in the calculations.

The total transient hot channel factor F_Q is then obtained by combining the axial and radial factors.

15.4.6.3.6 Reactivity Feedback Weighting Factors

The largest temperature rises, and hence the largest reactivity feedbacks, occur in channels where the power is higher than average. Since the weight of regions is dependent on flux, these regions have high weights. This means that the reactivity feedback is larger than that indicated by a simple single channel analysis. Physics calculations were carried out for temperature changes with a flat temperature distribution, and with a large number of axial and radial temperature distributions. Reactivity changes were compared and effective weighting factors determined. These weighting factors take the form of multipliers that, when applied to single channel feedbacks, correct them to effective whole core feedbacks for the appropriate flux shape. In this analysis, since a one-dimensional (axial) spatial kinetics method is employed, axial weighting is not used. In addition, no weighting is applied to the moderator feedback. A conservative radial weighting factor is applied to the transient fuel temperature to obtain an effective fuel temperature as a function of time accounting for the missing spatial dimension. These weighting factors were shown to be conservative compared to three-dimensional analysis.

15.4.6.3.7 Moderator and Doppler Coefficient

The critical boron concentrations at the BOL and EOL are adjusted in the nuclear code in order to obtain moderator density coefficient curves which are conservative compared to actual design conditions for the plant. As discussed above, no weighting factor is applied to these results.

The Doppler reactivity defect is determined as a function of power level using the one-dimensional steady state computer code with a Doppler weighting factor of 1. The

resulting curve is conservative compared to design predictions for this plant. The Doppler weighting factor should be larger than 1 (approximately 1.3), just to make the present calculation agree with design predictions before ejection. This weighting factor will increase under accident conditions, as discussed above.

15.4.6.3.8 Delayed Neutron Fraction

Calculations of the effective delayed neutron fraction (βeff) typically yield values of 0.70 percent at BOL and 0.50 percent at EOL for the first cycle. The accident is sensitive to βeff if the ejected rod worth is nearly equal to or greater than βeff as in zero power transients. In order to allow for future fuel cycles, pessimistic estimates of 0.55 percent at beginning of cycle and 0.44 percent at end of cycle were used in the analysis.

15.4.6.3.9 Trip Reactivity Insertion

The trip reactivity insertion assumed is given in Table 15.4-11 and includes the effect of one stuck rod. These values are reduced by the ejected rod reactivity. The shutdown reactivity was simulated by dropping a rod of the required worth into the core. The start of rod motion occurred 0.5 seconds after the high neutron flux trip point was reached. This delay is assumed to consist of 0.2 seconds for the instrument channel to produce a signal, 0.15 seconds for the trip breaker to open, and 0.15 seconds for the coil to release the rods. The analyses presented are applicable for a rod insertion time of 2.7 seconds from coil release to entrance to the dashpot, although measurements indicate that this value should be closer to 1.8 seconds.

The choice of such a conservative insertion rate means that there is over 1 second after the trip point is reached before significant shutdown reactivity is inserted into the core. This is particularly important conservatism for hot full power accidents.

The rod insertion versus time is described in Section 15.1.4.

15.4.6.4 Results

Typical reload values of the parameters used in the VANTAGE 5 analysis, as well as the results of the analysis, are presented in Table 15.4-11 and discussed below. Actual values vary slightly from reload to reload.

15.4.6.4.1 Beginning of Cycle, Full Power

Control Bank D was assumed to be inserted to its insertion limit. The worst ejected rod worth and hot channel factor were conservatively assumed to be 0.20 percent Δk and 6.70, respectively. The peak hot spot cladding average temperature was 2434°F. The peak hot spot fuel center temperature exceeded the BOL melting temperature of 4900°F; however, melting was restricted to less than 10 percent of the pellet.

15.4.6.4.2 Beginning of Cycle, Zero Power

For this condition, control Bank D was assumed to be fully inserted and C was at its insertion limit. The worst ejected rod is located in control Bank D and was conservatively assumed to have a worth of 0.785 percent Δk and a hot channel factor of 13. The peak hot spot cladding average temperature reached only 2660°F.

15.4.6.4.3 End of Cycle, Full Power

Control Bank D was assumed to be inserted to its insertion limit. The ejected rod worth and hot channel factors were conservatively assumed to be 0.21 percent Δk and 6.50, respectively. This resulted in an average PCT of 2218°F. The peak hot spot fuel center temperature exceeded the EOL melting temperature of 4800°F. However, melting was restricted to less than 10 percent of the pellet.

15.4.6.4.4 End of Cycle, Zero Power

The ejected rod worth and hot channel factor for this case were obtained assuming control Bank D to be fully inserted and Bank C at its insertion limit. The results were 0.85 percent Δk and 21.5, respectively. The peak cladding average and fuel center temperatures were 2632°F and 3849°F, respectively.

A summary of the cases presented above is given in Table 15.4-11. The nuclear power and hot spot fuel cladding temperature transients for these representative BOL full power and EOL zero power cases are presented in Figures 15.4.6-1 through 15.4.6-4.

15.4.6.4.5 Fission Product Release

It is assumed that fission products are released from the gaps of all rods entering DNB. In all cases considered, less than 10 percent of the rods entered DNB based on a detailed three-dimensional THINC analysis. Although limited fuel melting at the hot spot was predicted for the full power cases, in practice melting is not expected since the analysis conservatively assumed that the hot spots before and after ejection were coincident.

15.4.6.4.6 Lattice Deformations

A large temperature gradient will exist in the region of the hot spot. Since the fuel rods are free to move in the vertical direction, differential expansion between separate rods cannot produce distortion. However, the temperature gradients across individual rods may produce a force tending to bow the midpoint of the rods toward the hot spot. Physics calculations indicate that the net result of this would be a negative reactivity insertion. In practice, no significant bowing is anticipated, since the structural rigidity of the core is more than sufficient to withstand the forces produced. Boiling in the hot spot region would produce a net flow away from that region. However, the heat from fuel is released to the water relatively slowly, and it is considered inconceivable that cross flow

will be sufficient to produce significant lattice forces. Even if massive and rapid boiling, sufficient to distort the lattice, is hypothetically postulated, the large void fraction in the hot spot region would produce a reduction in the total core moderator to fuel ratio, and a large reduction in this ratio at the hot spot. The net effect would therefore be a negative feedback. It can be concluded that no conceivable mechanism exists for a net positive feedback resulting from lattice deformation. In fact, a small negative feedback may result. The effect is conservatively ignored in the analyses.

15.4.6.5 Conclusions

Even on a pessimistic basis, the analyses indicate that the described fuel and cladding limits are not exceeded. It is concluded that there is no danger of sudden fuel dispersal into the coolant. Since the peak pressure does not exceed that which would cause stresses to exceed the faulted condition stress limits, it is concluded that there is no danger of further consequential damage to the RCS. The analyses show that less than 10 percent of the fuel rods enter DNB. Even in the portion of the core which does reach DNB, there will be no excessive release of fission product activity if the limiting hot channel factors are not exceeded (Reference 21).

The analysis shows the acceptance criteria for a RCCA Ejection Accident has been met as follows:

15.4.6.5.1 Fuel Damage

(1) Table 15.4-11 shows the average fuel pellet enthalpy at the hot spot (maximum fuel stored energy) below 225 cal/gm for non-irradiated fuel and 200 cal/gm (360 Btu/lb) for irradiated fuel.

(2) Table 15.4-11 shows the average clad temperature at the hot spot (maximum cladding average temperature) below 2700°F, the temperature above which clad embrittlement may be expected.

(3) Table 15.4-11 shows the fuel melting limited to less than the innermost 10 percent of the fuel pellet at the hot spot.

15.4.6.5.2 Maximum Reactor Coolant System Pressure

(1) A detailed calculation of the pressure surge for an ejection worth of one dollar reactivity insertion at BOL, hot full power, indicates that the peak pressure does not exceed that which would cause stress to exceed the faulted condition stress limits. Because the severity of the present analysis does not exceed this worst case analysis, the accident for this plant will not result in an excessive pressure rise or further damage to the RCS.

15.4.6.5.3 Radiological

(1) Section 15.5.23 concludes that offsite exposures from a RCCA ejection accident is below the guideline levels specified in 10 CFR 50.67 and Section 4.4, Table 6 of the Regulatory Guide 1.183, July 2000, and that the occurrence of such accidents would not result in undue risk to the public. Table 15.5-52 provides a summary of offsite doses from a rod ejection accident.

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15.5 RADIOLOGICAL CONSEQUENCES OF PLANT ACCIDENTS

The purposes of this section are: (a) to identify accidental events that could cause radiological consequences, (b) to provide an assessment of the consequences of these accidents, and (c) to demonstrate that the potential consequences of these occurrences are within the limits, guidelines, and regulations established by the NRC.

An accident is an unexpected chain of events; that is, a process, rather than a single event. In the analyses reported in this section, the basic events involved in various possible plant accidents are identified and studied with regard to the performance of the ESFs. The full spectrum of plant conditions has been divided into four categories in accordance with their anticipated frequency of occurrence and risk to the public. The four categories as defined above are as follows:

Condition I: Normal Operation and Operational Transients

Condition II: Faults of Moderate Frequency

Condition III: Infrequent Faults

Condition IV: Limiting Faults

The basic principle applied in relating design requirements to each of these conditions is that the most frequent occurrences must yield little or no radiological risk to the public; and those extreme situations having the potential for the greatest risk to the public shall be those least likely to occur.

These categories and principles were developed by the ANS (Reference 1). Similar, though not identical, categories have been defined in the guide to the Preparation of Environmental Reports (Reference 3). While some differences exist in the manner of sorting the different accidents into categories in these documents, the basic principles are the same.

It should also be noted that the range of plant operating parameters included in the Condition I category, and some of those in the Condition II category, fall in the range of normal operation. For this reason, the radioactive releases and radiological exposures associated with these conditions are analyzed in Chapter 11 and are not discussed separately in this chapter. The analyses of the variations in system parameters associated with Condition I occurrences or operating modes are discussed in Chapter 7 since these states are not accident conditions. In addition, some of the events identified as potential accidents in Regulatory Guide 1.70, Revision 1 (Reference 2), have no significant radiological consequences, or result in minor releases within the range of normal releases, and are thus not analyzed separately in this chapter.

15.5.1 DESIGN BASES

The following regulatory requirements and guidance are applicable to the DCPP radiological consequence analyses presented in this chapter. They form the bases of the acceptance criteria and methodologies as described in the following sections:

(1) 10 CFR Part 100, “Reactor Site Criteria”*

(2) 10 CFR 50.67, “Accident Source Term”

(3) General Design Criterion 19, 1999 “Control Room”

(4) Regulatory Guide 1.4, Revision 1, ” Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Pressurized Water Reactors”

(5) Regulatory Guide 1.183, July 2000, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors”

*The licensing basis for acceptability of the dose consequences of the tank rupture events; i.e., the accidental release of radioactivity accumulated in tanks during normal plant operations, is 10 CFR Part 100. However, in accordance with DCPP UFSAR Section 3.2.2.1.2, the more restrictive acceptance criteria associated with a failure in a PG&E Design Class II system has been determined as applicable to the dose consequences at the site boundary for the Rupture of a Gas Decay Tank (GDT) and the Rupture of a Liquid Holdup Tank (LHUT).

In accordance with UFSAR Section 3.2.2.1.2, fluid systems and fluid system components that contain or may contain radioactive material, but whose failure would not result in calculated potential exposures in excess of 0.5 rem whole body (or its equivalent to parts of the body) at the site boundary may be classified as PG&E Design Class II.

Consistent with the design classification of the GDT and LHUT, and in accordance with the above more restrictive acceptance criteria, the description of these accident evaluations have been relocated from Section 15.5 to Chapter 11. The Rupture of the LHUT and GDT is discussed in Sections 11.2.3.12 and 11.3.2.2 respectively. It is noted that the Rupture of the Volume Control Tank (VCT) has also been relocated to Section 11.2. Since the VCT is PG&E Design Class I, the more restrictive acceptance criteria applicable to the failure in a PG&E Design Class II system is not applicable, however, PG&E has elected to use this more limiting acceptance criteria for all tank ruptures. The VCT rupture is dicscussed in Section 11.2.3.12.

15.5.1.1 List of Analyzed Accidents

The following table summarizes the accident events that have been evaluated for radiological consequences. The table identifies the applicable section describing the

analysis and results for each event, the offsite/onsite locations and applicable dose limits, and the radiological analysis and isotopic core inventory codes used.

Accident Event	FSAR Section	Boundary	Dose Limit	Radiological Analysis Code(s)	Isotopic Core Inventory Code(s)
CONDITION II					
Loss of Electrical Load	15.5.10	EAB and LPZ Control Room TSC	2.5 rem TEDE 5 rem TEDE 5 rem TEDE	RADTRAD 3.03	SAS2/ORIGEN-S
CONDITION III					
Small Break LOCA (SBLOCA)	15.5.11	EAB and LPZ Control Room	2.5 rem TEDE 5 rem TEDE	N/A Refer to Section 15.5.23	N/A Refer to Section 15.5.23
Minor Secondary System Pipe Breaks	15.5.12	EAB and LPZ Control Room	2.5 rem TEDE 5 rem TEDE	N/A Refer to Section 15.5.18	N/A Refer to Section 15.5.18
Inadvertent Loading of a Fuel Assembly	15.5.13	EAB and LPZ Control Room	2.5 rem TEDE 5 rem TEDE	N/A Refer to Section 15.5.13	N/A Refer to Section 15.5.13
Complete Loss of Forced Reactor Coolant Flow	15.5.14	EAB and LPZ Control Room	2.5 rem TEDE 5 rem TEDE	N/A Refer to Section 15.5.10	N/A Refer to Section 15.5.10
Under-Frequency	15.5.15	EAB and LPZ Control Room	2.5 rem TEDE 5 rem TEDE	N/A Refer to Section 15.5.10	N/A Refer to Section 15.5.10
Single Rod Cluster Control Assembly Withdrawal	15.5.16	EAB and LPZ Control Room	2.5 rem TEDE 5 rem TEDE	N/A Refer to Section 15.5.23	N/A Refer to Section 15.5.23
CONDITION IV					
Large Break LOCA (LBLOCA)	15.5.17	EAB and LPZ Control Room TSC	25 rem TEDE 5 rem TEDE 5 rem TEDE	RADTRAD 3.03 PERC2 SW-QADCGGP	SAS2/ORIGEN-S

Accident Event	FSAR Section	Boundary	Dose Limit	Radiological Analysis Code(s)	Isotopic Core Inventory Code(s)
Main Steam Line Break (MSLB)	15.5.18	EAB and LPZ Pre-Accident Iodine Spike Accident-initiated Iodine Spike Control Room TSC	 25 rem TEDE 2.5 rem TEDE 5 rem TEDE 5 rem TEDE	RADTRAD 3.03	SAS2/ORIGEN-S
Main Feedwater Line Break (FWLB)	15.5.19	EAB and LPZ Pre-Accident Iodine Spike Accident-initiated Iodine Spike Control Room	 25 rem TEDE 2.5 rem TEDE 5 rem TEDE	N/A Refer to Section 15.5.18	N/A Refer to Section 15.5.18
Steam Generator Tube Rupture (SGTR)	15.5.20	EAB and LPZ Pre-Accident Iodine Spike Accident-initiated Iodine Spike Control Room TSC	 25 rem 2.5 rem 5 rem 5 rem TEDE	RADTRAD 3.03	SAS2/ORIGEN-S
Locked Rotor Accident (LRA)	15.5.21	EAB and LPZ Control Room TSC	 2.5 rem TEDE 5 rem TEDE	RADTRAD 3.03	SAS2/ORIGEN-S
Fuel Handling-Accident (FHA)	15.5.22	EAB and LPZ Control Room TSC	6.3 rem TEDE 5 rem TEDE 5 rem TEDE	RADTRAD 3.03 PERC2 SW-QADCGGP	SAS2/ORIGEN-S
Control Rod Ejection Accident (CREA)	15.5.23	EAB and LPZ Control Room TSC	6.3 rem TEDE 5 rem TEDE 5 rem TEDE	RADTRAD 3.03	SAS2/ORIGEN-S

15.5.1.2 Assumptions associated with Loss of Offsite Power

The assumptions regarding the occurrence and timing of a Loss of Offsite Power (LOOP) during an accident are selected with the intent of maximizing the dose consequences. A LOOP is assumed for events that have the potential to cause grid perturbation.

i. The dose consequences of the LOCA, MSLB, SGTR, LRA, CREA, and LOL event are evaluated with the assumption of a LOOP concurrent with reactor trip.

ii. The assumption of a LOOP related to a postulated design basis accident which leads to a reactor trip does not directly correlate to an FHA. Specifically, a FHA does not directly cause a reactor trip and a subsequent LOOP due to grid instability; nor can a LOOP be the initiator of a FHA. Thus, the FHA dose consequence analyses are evaluated without the assumption of a LOOP.

In addition, in accordance with current DCPP licensing basis, the non-accident unit is assumed unaffected by the LOOP.

15.5.2 APPROACH TO ANALYSES OF RADIOLOGICAL EFFECTS OF ACCIDENTS

15.5.2.1 Introduction

The potential radiological effects of plant accidents are analyzed by the evaluation of all physical factors involved in each chain of events which might result in radiation exposures to humans. These factors include the meteorological conditions existing at the time of the accident, the radionuclide uptake rates, exposure times and distances, as well as the many factors which depend on the plant design and mode of operation. In these analyses, the factors affecting the consequences of each accident are identified and evaluated, and uncertainties in their values are discussed. Because some degree of uncertainty always exists in the prediction of these factors, it has become general practice to assume conservative values in making calculated estimates of radiation doses. For example, it is customarily assumed that the accident occurs at a time when very unfavorable weather conditions exist, and that the performance of the plant engineered safety systems is degraded by unexpected failures. The use of these unfavorable values for the various factors involved in the analysis provides assurance that each safety system has been designed adequately; that is, with sufficient capacity to cover the full range of effects to which each system could be subjected. For this reason, these conservative values for each factor have been called design basis values.

In a similar way, the specific chain of events in which all unfavorable factors are coincidentally assumed to occur has been called a DBA. The calculated doses for the DBA provide a basis for determination of the design adequacy of the plant safety systems. In the process of safety review and licensing, the radiation exposure levels

calculated for the DBA are compared to the regulatory limits established in 10 CFR 50.67 (for accidents analyzed using AST methodology) including acceptance criteria proposed in regulatory guidance, and if these calculated exposures fall below the regulatory guideline limits, the plant safety systems are judged to be adequate.

As noted in Section III.2.a of Standard Review Plan Section 15.0.1, Revision 0, (Reference 59), a full implementation of AST addresses a) all the characteristics of AST (i.e., the radionuclide composition and magnitude, chemical and physical form of the radionuclides, and the timing of the release of these nuclides), b) replaces the previous accident source term used in all design basis radiological analyses, and c) incorporates the Total Effective Dose Equivalent (TEDE) criteria of 10 CFR 50.67, and Section II of Standard Review :Plan 15.0.1, Revision 0.

The dose consequences of the following accidents have been re-evaluated using AST in accordance with Regulatory Guide 1.183, July 2000.

1. Loss of Coolant Accident (LOCA) – Section 15.5.17
2. Fuel Handling Accident (FHA) – Section 15.5.22
3. Locked Rotor Accident (LRA) – Section 15.5.21
4. Control Rod Ejection Accident (CREA) – Section 15.5.23
5. Main Steam Line Break (MSLB) – Section 15.5.18
6. Steam Generator Tube Rupture (SGTR) – Section 15.5.20
7. Loss-of Load (LOL) Event – Section 15.5.10

The dose consequences for the remaining accidents are addressed by qualitative comparison to the seven accidents listed above (with the exception of the tank rupture events).

Note reference to Regulatory Guide 1.183, July 2000 is used extensively within this section, as a result any reference to “Regulatory Guide 1.183” within Section 15.5 refers to Regulatory Guide 1.183, July 2000.

The methodology used to assess the dose consequences of the DBAs, including the specific values of all important parameters, data, and assumptions used in the radiological exposure calculations are listed in the following sections. The computer programs used to assess the dose consequences of the DBAs are described briefly in Section 15.5.8.

15.5.2.2 Dose Acceptance Criteria

<u>EAB and LPZ Dose</u>

The acceptance criteria for the Exclusion Area Boundary (EAB) and the Low Population Zone (LPZ) Dose are based on 10 CFR 50.67, and Section 4.4, Table 6 of Regulatory Guide 1.183:

(1) An individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release, shall not receive a radiation dose in excess of the accident-specific TEDE value noted in Reference 55, Table 6.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a radiation dose in excess of the accident-specific TEDE value noted in Reference 55, Table 6.

EAB and LPZ Dose Acceptance Criteria - Condition II and Condition III events:

Regulatory Guide 1.183 does not specifically address Condition II and Condition III scenarios. However, per Regulatory Guide 1.183, Section 1.2.1, a full implementation of AST allows a licensee to utilize the dose acceptance criteria of 10 CFR 50.67 in all dose consequence analyses. In addition, Section 4.4 of Regulatory Guide 1.183 indicates that for events with a higher probability of occurrence than those listed in Table 6 of Regulatory Guide 1.183, the postulated EAB and LPZ doses should not exceed the criteria tabulated in Table 6. Thus, the dose consequences at the EAB and LPZ will be limited to the lowest value reported in Table 6, i.e., a small fraction (10%) of the limit imposed by 10 CFR 50.67.

Control Room Dose

The acceptance criterion for the control room dose is based on 10 CFR 50.67.

Adequate radiation protection is provided to permit access to and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) TEDE for the duration of the accident.

This criteria ensures that the dose criteria of GDC 19, 1999 and NUREG-0737, November 1980, Item III.D.3.4 (refer to Section 6.4.1) is met.

Technical Support Center Dose

The acceptance criteria for the TSC dose is based on Section 8.2.1(f) of NUREG-0737, Supplement 1, as amended by Regulatory Guide 1.183, Section 1.2.1, which allows dose acceptance in accordance with 10 CFR 50.67. The dose to an operator in the TSC should not exceed 5 rem TEDE for the duration of the accident.

15.5.2.3 Dose Calculation Methodology

15.5.2.3.1 Inhalation and Submersion Doses from Airborne Radioactivity

Computer Code RADTRAD 3.03 is used to calculate the committed effective dose equivalent (CEDE) from inhalation and the effective dose equivalent (EDE) from

submersion due to airborne radioactivity at offsite locations and in the control room. The summation of CEDE and EDE is reported as TEDE, in accordance with Section 4.1.4 of Regulatory Guide 1.183.

The CEDE is calculated using the inhalation dose conversion factors provided in Table 2.1 of Federal Guidance Report 11 (Reference 41).

The submersion EDE is calculated using the air submersion dose coefficients provided in Table III.1 of Federal Guidance Report 12 (Reference 42). The dose coefficients are derived based on a semi-infinite cloud model. The submersion EDE is reported as the whole body dose in the RADTRAD 3.03 output.

RADTRAD 3.03 includes models for a variety of processes that can attenuate and/or transport radionuclides. It can model the effect of sprays and natural deposition that reduce the quantity of radionuclides suspended in the containment or other compartments. In addition, it can model the flow of radionuclides between compartments within a building, from buildings into the environment, and from the environment into a control room. These flows can be through filters, piping, or simply due to air leakage. RADTRAD 3.03 can also model radioactive decay and in-growth of daughters. Ultimately the program calculates the whole body dose, the thyroid dose, and the TEDE dose (rem) to the public located offsite, and to onsite personnel located in the control room due to inhalation and submersion in airborne radioactivity based on user specified, fuel inventory, nuclear data, dispersion coefficients, and dose conversion factors. Note that the code uses a numerical solution approach to solve coupled ordinary differential equations. The basic equation for radionuclide transport and removal is the same for all compartments. The program breaks its processing into 2 parts a) radioactive transport and b) radioactive decay and daughter in-growth.

Computer Code PERC2 is used to calculate the CEDE from inhalation and the EDE from submersion due to airborne radioactivity in the TSC. PERC2 is a multiple compartment activity transport code with the dose model consistent with Regulatory Guide 1.183. The decay and daughter build-up during the activity transport among compartments and the various cleanup mechanisms are included. The CEDE is calculated using the Federal Guidance Report No.11 (Reference 41) dose conversion factors. The EDE in the TSC is based on a finite cloud model that addresses buildup and attenuation in air. The dose equation is based on the assumption that the dose point is at the center of a hemisphere of the same volume as the TSC. The dose rate at that point is calculated as the sum of typical differential shell elements at a radius R. The equation utilizes the integrated activity in the TSC air space, the photon energy release rates per energy group from activity airborne in the TSC, and the ANSI/ANS 6.1.1-1991 neutron and gamma-ray fluence-to-dose factors (Reference 84).

<u>Offsite Dose</u>

In accordance with Regulatory Guide 1.183, for the first 8 hours, the breathing rate of the public located offsite is assumed to be 3.5×10^{-4} m^3/sec. From 8 to 24 hours

following the accident, the breathing rate is assumed to be 1.8×10^{-4} m^3/sec. After that and until the end of the accident, the rate is assumed to be 2.3×10^{-4} m^3/sec. The maximum EAB TEDE for any two-hour period following the start of the radioactivity release is calculated and used in determining compliance with the dose criteria in 10 CFR 50.67. The LPZ TEDE is determined for the most limiting receptor at the outer boundary of the low population zone and is calculated for the entire accident duration.

Control Room Dose

The control room inhalation CEDE is calculated assuming a breathing rate of 3.5×10^{-4} m^3/sec for the duration of the event. The following occupancy factors are credited in determining the control room TEDE: 1.0 during the first 24 hours after the event, 0.6 between 1 and 4 days, and 0.4 from 4 days to 30 days. The submersion EDE is corrected for the difference in the finite cloud geometry in the control room and the semi-infinite cloud model used in calculating the dose coefficients. The following expression obtained from Regulatory Guide 1.183 is used in RADTRAD 3.03 to correct the semi-infinite cloud dose, EDE_{∞}, to a finite cloud dose, EDE_{finite}, where the control room is modeled as a hemisphere that has a volume, V, in cubic feet, equivalent to that of the control room. As allowed in Section 4.1.4 of RG 1.183, since the submersion exposure is uniform to the whole body, the EDE is used in lieu of the deep dose equivalent in determining the contribution of the submersion dose to the TEDE.

$$Submersion - EDE_{finite} = \frac{EDE_{\infty} V^{0.338}}{1173} \qquad (15.5\text{-}1)$$

Technical Support Center Dose

The TSC inhalation CEDE is calculated by computer code PERC2 assuming the same breathing rate and occupancy factors as those used in determining the control room dose. The submersion EDE developed by PERC2 (which computes the photon fluence at the center of TSC and utilizes the ANSI/ANS 6.1.1-1991 fluence to effective dose conversion factors), is a close approximation of the dose determined using Table III.1 of Federal Guidance Report No. 12 (Reference 42) (refer to Section 4.1.4 Regulatory Guide 1.183) and adjusted by the finite volume correction factor given in Regulatory Guide 1.183, Section 4.2.7.

15.5.2.3.2 Direct Shine Dose from External and Contained Sources

Computer program SW-QADCGGP is used to calculate the deep dose equivalent in the control room, TSC and at the EAB due to external and contained sources following a LOCA. The calculated deep dose equivalent is added to the inhalation (CEDE) and the submersion (EDE) dose due to airborne radioactivity to develop the final TEDE. Conservative build-up factors are used and the geometry models are prepared to ensure that un-accounted streaming/scattering paths were eliminated. The dose albedo method with conservative albedo values is used to estimate the

scatter dose in situations where the scattering contributions are potentially significant. ANSI/ANS 6.1.1-1977 (Reference 83) is used to convert the gamma flux to the dose equivalent rate.

15.5.3 ACTIVITY INVENTORIES IN THE PLANT PRIOR TO ACCIDENTS

The fission product inventories in the reactor core, the fuel rod gaps, and the primary coolant prior to an accident have been conservatively calculated based on plant operation at 105% of the current licensed rated thermal power of 3411 MWth, with current licensed values of fuel enrichment and fuel burnup.

15.5.3.1 Core Activity Inventory

In accordance with Section 3.1 of Regulatory Guide 1.183, the inventory of fission products in the reactor core available for release to the containment following an accident should reflect maximum full power operation of the core with the current licensed values for fuel enrichment, fuel burnup, and an assumed core power equal to the current licensed rated thermal power times the ECCS evaluation uncertainty in the 10 CFR 50 Appendix K analysis (typically 1.02).

The equilibrium core inventory is calculated using computer code ORIGEN-S. The calculation is performed using the Control Module SAS2 of the SCALE 4.3 computer code package. The SAS2 control module provides a sequence to calculate the nuclide inventory in a fuel assembly by calling various neutron cross section treatment modules and the exponential matrix point-depletion module ORIGEN-S. It calculates the time-dependent neutron flux and the buildup of fissile trans-uranium nuclides. It accounts for all major nuclear interactions including fission, activation, and various neutron absorption reactions with materials in the core. It calculates the neutron-activated products, the actinides and the fission products in a reactor core.

The reactor core consists of 193 fuel assemblies with various Uranium-235 enrichments. Per control imposed by DCPP core-reload design documentation, the peak rod burnup limit at the end of cycle is not allowed to exceed 62,000 MWD/MTU. The current licensed maximum value for fuel enrichment is 5.0%. To account for variation of U-235 enrichment in fresh fuel, the radionuclide inventories were calculated for a 4.2% average enriched core (representing minimum enrichment at DCPP), and 5% average enriched core (representing maximum enrichment). The higher activity for each isotope from the above two enrichment cases is chosen to represent the inventory of that isotope in the equilibrium core.

The equilibrium core at the end of a fuel cycle is assumed to consist of fuel assemblies with three different burnups, i.e., approximately 1/3 of the core is subjected to one fuel cycle, 1/3 of the core to two fuel cycles and 1/3 of the core to three fuel cycles. This approach has been demonstrated to develop an isotopic core inventory that is a reasonable and conservative approximation of a core inventory developed using DCPP specific fuel management history data. Minor variations in fuel irradiation time and duration of refueling outages will have a slight impact on the estimated inventory of

long-lived isotopes in the core. However, these inventory changes will have an insignificant impact on the radiological consequences of postulated accidents. A 4% margin has been included in the final isotopic radioactive inventories in support of bounding analyses and to address minor changes in future fuel management schemes.

A 19 month fuel cycle length was utilized in the analysis. The 19-month average fuel cycle is an artifact of the current DCPP fuel management scheme which specifies 3 fuel cycles every 5 years and refueling outages in Spring or Fall.

In summary, the equilibrium isotopic core average inventory is based on:

i. A power level of 3580 MWth inclusive of power uncertainty.

ii. A range of enrichment of 4.2 to 5.0 w % U-235. Use of a few assemblies with lower enrichment is a common industry practice when replacing assemblies previously irradiated but proven unsuitable for continued irradiation. As these assemblies are designed to replace higher enrichment assemblies with ones of similar reactivity for the remainder of the fuel cycle, their inventory is enveloped by the isotopic core average inventory developed to support the dose consequence analyses.

iii. A maximum core average burnup of 50 GWD/MTU.

The core inventory developed by ORIGEN-S using the above methodology includes over 800 isotopes. The DCPP equilibrium core fission product inventory of dose significant isotopes relative to LWR accidents is presented in Table 15.5-77.

15.5.3.2 Coolant Activity Inventory

1. <u>Design Basis Primary and Secondary Coolant Activity Concentrations</u>

Computer code, ACTIVITY2, is used to calculate the design basis primary coolant activity concentrations for both DCPP Unit 1 and Unit 2 based on the core inventory developed using ORIGEN-S and discussed in Section 15.5.3.1. The source terms for the primary coolant fission product activity include leakage from 1% fuel defects and the decay of parent and second parent isotopes. The depletion terms of the primary coolant fission product activity include radioactive decay, purification of the letdown flow and neutron absorption when the coolant passes the reactor core. The nuclear library includes 3rd order decay chains of approximately 200 isotopes.

Computer code, IONEXCHANGER, is used to calculate the design basis halogen and remainder activity concentrations in the secondary side liquid. The source terms for the secondary side activity include the primary-to-secondary leakage in steam generators and the decay products of parent and second parent isotopes. The depletion terms of the secondary side liquid activity include radioactive decay, and purification due to the steam generator blowdown flow, and continuous condensate polishing.

The design basis noble gas concentrations in the secondary steam are calculated by dividing the appearance rate (µCi/sec) by the steam flow rate (gm/sec). The noble gas appearance rate in the steam generator steam space includes the primary-to-secondary leak contribution and the noble gas generation due to decay of halogens in the SG liquid. The activity concentrations of the other isotopes in the steam are determined by the SG liquid concentrations and the partition coefficients recommended in NUREG 0017, Revision 1 (Reference 56).

2. Technical Specification Primary and Secondary Coolant Activity Concentrations

In accordance with Technical Specifications the primary coolant Technical Specification activities for iodines and noble gases are based on 1.0 µCi/gm Dose Equivalent (DE) I-131 and 270 µCi/gm DE Xe-133, respectively.

The Technical Specification based primary coolant isotopic activity reflects the following:

a. Isotopic compositions based on the design basis primary coolant equilibrium concentrations at 1% fuel defects.

b. Iodine concentrations based on the thyroid inhalation weighting factors for I-131, I-132, I-133, I-134, and I-135 obtained from Federal Guidance Report 11 (Reference 41).

c. Noble gas concentrations based on the submersion weighting factors for Xe-133, Xe-133m, Xe-135m, Xe-135, Xe-138, Kr-85m, Kr-87, and Kr-88 obtained from Federal Guidance Report 12 (Reference 42)

The Technical Specification 1 µCi/gm DE I-131 concentrations per nuclide in the primary coolant are calculated with the following equation:

$$DEI_{131}(i)(\mu Ci/gm) = \frac{C(i) \times CT_{tot}}{\sum\{F(i)xC(i)\}} \qquad (15.5\text{-}2)$$

Where:

F(i) = DCF(i) / DCF $_{I\text{-}131}$

DCF(i)= Federal Guidance Report-11, Table 2-1 (Reference 41) Thyroid Dose Conversion Factor per Nuclide (Rem/Ci)

C(i) = design basis primary coolant equilibrium iodine concentration per nuclide (µCi/gm)

CT_{tot}= primary coolant total (DE I-131) Technical Specification iodine concentration (µCi/gm).

The CT_{tot} for the pre-accident iodine spike is 60 µCi/gm (transient Technical Specification limit for full power operation), or 60 times the primary coolant total iodine Technical Specification concentration.

The accident initiated iodine spike activities are based on an accident dependent multiplier, times the equilibrium iodine appearance rate. The equilibrium appearance rates are conservatively calculated based on the technical specification reactor coolant activities, along with the maximum design letdown rate, maximum Technical Specification based allowed primary coolant leakage, and an assumed ion-exchanger iodine efficiency of 100%.

The Technical Specification secondary liquid iodine concentration is determined using methodology similar to that described above for the primary coolant where CTtot is 0.1 µCi/gm DE I-131, and C(i) is the design basis secondary coolant equilibrium concentrations per nuclide.

The Technical Specification noble gas concentrations for the primary coolant are based on 270 µCi/gm DE Xe-133. The DE Xe-133 for noble gases is calculated as follows:

$$DEX_{133} = \Sigma\{F(i) \times C(i)\} \qquad (15.5\text{-}3)$$

Where:

F(i) = DCF(i) / DCF Xe-133

DCF(i) = EPA Federal Guidance Report No. 12 (Reference 42) Table III.1, Dose Coefficient per Nuclide [(rem-m^3)/(Ci-sec)]

C(i) = design basis primary coolant equilibrium noble gas concentration per nuclide (µCi/gm)

The noble gas and halogen primary and secondary coolant Technical Specification Activity Concentrations for Unit 1 and Unit 2 are presented in Table 15.5-78. The pre-accident iodine spike concentrations and the equilibrium iodine appearance rates (utilized to develop accident initiated iodine spike values), are presented in Table 15.5-79.

15.5.3.3 Gap Fractions for Non-LOCA Events

Regulatory Guide 1.183, July 2000, Table 3 provides the gap fractions for Non-LOCA events that are postulated to result in fuel damage for AST applications. The referenced gap fractions are contingent upon meeting Note 11 of Table 3 of Regulatory Guide 1.183. Note 11 indicates that the release fractions listed in Table 3 are “acceptable for use with currently approved LWR fuel with a peak burnup of 62,000 MWD/MTU provided that the maximum linear heat generation rate does not exceed 6.3 kw/ft peak rod average power for burnups exceeding 54 GWD/MTU.” The burnup criterion associated with the maximum allowable linear heat generation rate is applicable to the peak rod average burnup in any assembly and is not limited to assemblies with an average burnup that exceeds 54 GWD/MTU.

DCPP has three design basis non-LOCA accidents that are postulated to result in fuel damage, i.e., the Locked Rotor Accident (LRA), the Fuel Handling Accident (FHA) and the Control Rod Ejection Accident (CREA).

To support flexibility of fuel management, and establish dose consequences that take into consideration fuel rods that may exceed the Regulatory Guide 1.183, Table 3, Note 11 linear heat generation criteria, the fuel gap fractions provided in Table 3 of Draft Guide (DG)-1199 (Reference 62) for all Non-LOCA events that are postulated to result in fuel damage with the exception of the CREA. This approach is acceptable (i.e., in lieu of developing plant specific fission gas release calculations using NRC approved methods and bounding power history to establish the gap fractions), since DCPP falls within, and intends to operate within, the maximum allowable power operating envelop for PWRs shown in Figure 1 of DG-1199.

In summary, the fuel gap activity fractions used to assess the dose consequences of the FHA and LRA are as follows:

Nuclide Group	FHA /LRA (based on DG-1199)
I-131	0.08
I-132	0.23
Kr-85	0.35
Other Noble Gases	0.04
Other Halogens	0.05
Alkali Metals	0.46

In accordance with Regulatory Guide 1.183 (Appendix H and Note 11 of Table 3), the gap fraction associated with the CREA is as follows:

Noble Gases: 10%
Halogens: 10%

Refer to Tables 15.5-80 for the isotopic concentrations in the gap assumed for the LRA and CREA. The isotopic concentrations assumed for the FHA are presented in Table 15.5-47C.

15.5.4 DELETED

15.5.5 POST-ACCIDENT METEOROLOGICAL CONDITIONS

The EAB and the LPZ atmospheric dispersion factors (χ/Q) utilized in the dose consequence analyses have been developed using Regulatory Guide 1.145, Revision 1 methodology and a continuous, temporally representative 5-year period of hourly meteorological data from the DCPP onsite meteorological tower; January 1, 2007 through December 31, 2011. Refer to Section 2.3.5.2.1 and Table 2.3-145.

Using the same hourly meteorological data, the χ/Q values applicable to on-site locations such as the control room and TSC, have been calculated using the "Atmospheric Relative CONcentrations in Building Wakes" (ARCON96) methodology (Reference 61). Refer to Section 2.3.5.2.2.

All of the release point and receptor locations are provided in Figure 2.3-5, while Tables 2.3-146 and 2.3-146A provide information on the release point / receptor combinations that were evaluated. Tables 2.3-147 and 2.3-148 provide the control room χ/Q values for the individual release point-receptor combinations for Unit 1 and Unit 2, respectively. Table 2.3-149 presents the χ/Q values for the individual post-LOCA release point - TSC receptor combinations for Unit 1 and Unit 2 applicable to the TSC normal intake and the center of the TSC boundary at roof level (considered an average value for potential TSC unfiltered in-leakage locations around the envelope). The Unit 1 and Unit 2 control room pressurization air intakes also serve the TSC during the emergency mode. Thus, the χ/Qs presented in Tables 2.3-147 and 2.3-148 for the control room pressurization intakes inclusive of the credit for dual intake design and ability to select the more favorable intake are also applicable to the TSC.

Note that the specific control room χ/Q values used in each of the accident analyses (and the specific TSC χ/Q values used for the LOCA) are presented in the accident-specific tables presented in Chapter 15.5. The χ/Q values selected for use in the dose consequence analyses are intended to support bounding analyses for an accident that occurs at either unit. They take into consideration the various release points-receptors applicable to each accident in order to identify the bounding χ/Q values and reflect the allowable adjustments and reductions in the values as discussed earlier and further summarized in the notes of Tables 2.3-147 through 2.3-149.

15.5.6 RATES OF ISOTOPE INHALATION

The breathing rates used in the calculations of inhalation doses are listed in Table 15.5-7A. These values are based on the average daily breathing rates provided in Section 4.1.3 of Regulatory Guide 1.183.

The active breathing rates are used for all onsite dose calculations, which are based on expected exposure times.

15.5.7 DELETED

15.5.8 RADIOLOGICAL ANALYSIS PROGRAMS

15.5.8.1 EMERALD (Revision I)

The EMERALD program (Reference 4) is designed for the calculation of radiation releases and exposures resulting from abnormal operation of a large PWR. The approach used in EMERALD is similar to an analog simulation of a real system. Each component or volume in the plant that contains a radioactive material is represented by a subroutine, which keeps track of the production, transfer, decay, and absorption of radioactivity in that volume. During the course of the analysis of an accident, activity is

transferred from subroutine to subroutine in the program as it would be transferred from place to place in the plant. The rates of transfer, leakage, production, cleanup, decay, and release are read in as input to the program.

Subroutines are also included that calculate the onsite and offsite radiation exposures at various distances for individual isotopes and sums of isotopes. The program contains a library of physical data for 25 isotopes of most interest in licensing calculations, and other isotopes can be added or substituted. Because of the flexible nature of the simulation approach, the EMERALD program can be used for most calculations involving the production and release of radioactive materials, including design, operational and licensing studies. The complete description of the program, including models and equations, is contained in Reference 4.

The egress-ingress thyroid and whole body exposures from airborne activity following a LOCA are functions of containment activity, containment leakage, atmospheric dispersion, and excursion time. As part of original licensing basis, the EMERALD computer code was used to calculate the post-LOCA airborne activity concentrations, and then conventional exposure equations from Regulatory Guide 1.4, Revision 1, were used to calculate gamma, beta, and thyroid exposures (Reference 6).

15.5.8.2 DELETED

15.5.8.3 DELETED

15.5.8.4 DELETED

15.5.8.5 ISOSHLD II

ISOSHLD II (Reference 11) is a shielding code that is principally intended for use in calculating the radiation dose, at a field point, from bremsstrahlung and/or decay gamma rays emitted by radioisotope sources. This program, with the newly-added bremsstrahlung mode, is an extension of the earlier version (ISOSHLD). Five shield regions can be handled with up to twenty materials per shield; the source is considered to be the first shield region (i.e., bremsstrahlung and decay gamma rays are produced only in the source). Point kernel integration (over the source region) is used to calculate the radiation dose at a field point.

ISOSHLD II is used to determine the dose to the control room operator due to direct shine from the airborne activity inside the containment following a LOCA during daily egress-ingress for the duration of the accident.

15.5.8.6 DELETED

15.5.8.7 SAS2 / ORIGEN-S

ORIGEN-S is part of the SCALE 4.3 suite of codes which was developed by Oak Ridge National Laboratory (ORNL) for the NRC to perform standardized computer analyses for licensing evaluations. SAS2 is a control module that provides a sequence to calculate the nuclide inventory in a fuel assembly by calling various neutron cross section treatment modules and the exponential matrix point-depletion module ORIGEN-S. SAS2 / ORIGEN-S (Reference 64) calculates the time-dependent neutron flux and the buildup of fissile trans-uranium nuclides. It properly accounts for all major nuclear interactions including fission, activation, and various neutron absorption reactions. It can calculate accurately the neutron-activated products, the actinides and the fission products in a reactor core. SAS2/ORIGEN-S is used to develop the equilibrium core activity inventory and the decayed fuel inventories after shutdown utilized to assess the design basis accidents, excluding tank ruptures.

ACTIVITY2

ACTIVITY2 (Reference 65) calculates the concentration of fission products in the fuel, coolant, waste gas decay tanks, ion exchangers, miscellaneous tanks, and release lines to the atmosphere for a pressurized water reactor system. The program uses a library of properties of more than 100 significant fission products and may be modified to include as many as 200 nuclides. The program output presents the activity and energy spectrum at the selected part of the system for any specified operating time.

ACTIVITY2 is used to develop the reactor coolant activity inventory (design and as limited by the plant Technical Specifications) utilized to assess the design basis accidents excluding the tank ruptures.

15.5.8.8 IONEXCHANGER

IONEXCHANGER (Reference 66) calculates the activity of nuclides in an ion exchanger or tank of a nuclear reactor plant by solving the appropriate growth-decay- purification equations. Based on a known feed rate of primary coolant or other fluid with known radionuclide activities, it calculates the activity of each nuclide and its products in the ion exchanger or tank at some later time. The program also calculates the specific gamma activity for each of the seven fixed energy groups.

IONEXCHANGER is used to develop the secondary coolant activity inventory (design and as limited by the plant Technical Specifications) utilized to assess the design basis accidents excluding the tank ruptures.

15.5.8.9 EN 113, Atmospheric Dispersion Factors

EN-113 Atmospheric Dispersion Factors (Reference 73) calculates χ/Q values at the EAB and LPZ following the methodology and logic outlined in Regulatory Guide 1.145, Revision 1. The program can handle single or multiple release points for a specified time period and set of site-specific and plant-specific parameters. A release point can

be identified as either of two types of release (i.e., ground or elevated), time periods for which sliding averages are calculated (i.e., 1 to 624 hours and/or annual average), applicable short-term building wake effect, meandering plume, long-term building height wake effect, and a wind speed value to be assigned to calm conditions. Downwind distances can be assigned for each of the sixteen 22.5-degree sectors for two irregular boundaries and for ten additional concentric boundaries used only in the annual average calculation. EN-113 performs the same calculations as the NRC PAVAN code except that EN-113 calculates χ/Q values for the various averaging periods directly using hourly meteorological data whereas PAVAN uses a joint frequency distribution of wind speed, wind direction, and stability class.

EN-113 is used to develop the DCPP site boundary atmospheric dispersion factors utilized to assess the design basis accidents excluding the tank ruptures.

15.5.8.10 ARCON96

ARCON96 (Reference 74) was developed by Pacific Northwest National Laboratory (PNNL) for the NRC to calculate relative concentrations in plumes from nuclear power plants at control room air intakes in the vicinity of the release point. ARCON96 has the ability to evaluate ground-level, vent, and elevated stack releases; it implements a straight-line Gaussian dispersion model with dispersion coefficients that are modified to account for low wind meander and building wake effects. The methodology is also able to evaluate diffuse and area source releases using the virtual point source technique, wherein initial values of the dispersion coefficients are assigned based on the size of the diffuse or area source. Hourly, normalized concentrations (χ/Q) are calculated from hourly meteorological data. The hourly values are averaged to form χ/Qs for periods ranging from 2 to 720 hours in duration. The calculated values for each period are used to form cumulative frequency distributions.

ARCON96 is used to develop the control room and TSC atmospheric dispersion factors utilized to assess the design basis accidents excluding the tank ruptures.

15.5.8.11 SWNAUA

SWNAUA (Reference 67) is a derivative of industry computer code NAUA/Mod 4 which was originally developed in Germany and was based on experimental data. NAUA/Mod 4 addressed particulate aerosol transport and removal following a LOCA at an LWR. It developed removal coefficients to address physical phenomena such as gravitational settling (also called gravitational sedimentation), diffusion, particle growth due to agglomeration, etc using time-dependent airborne aerosol mass. NAUA4 (included in the NRC Source Term Code Package) was used by NRC during the initial evaluations of post-TMI data. NAUA/Mod 4 was modified to include spray removal and diffusiophoretic effects suitable for design basis accident analyses. A version of SWNAUA (SWNAUA-HYGRO) was proven to be the most reliable of more than a dozen international entries, in making predictions of aerosol removal for the LWR Aerosol Containment Experiments (LACE) series.

SWNAUA is used to develop the time dependent post LOCA particulate aerosol removal coefficients in the sprayed and unsprayed regions of containment.

15.5.8.12 RADTRAD 3.03

RADTRAD 3.03 (Reference 68) is a NRC sponsored program, developed by Sandia National Labs (SNL). It can be used to calculate radiological doses to the public, plant operators and emergency personnel due to environmental releases that resulting from postulated design basis accidents at light water reactor (LWR) power plants. The RADTRAD 3.03 (GUI Interface Mode) includes models for a variety of processes that can attenuate and/or transport radionuclides. It can model sprays and natural deposition that reduce the quantity of radionuclides suspended in the containment or other compartments. It can model the flow of radionuclides between compartments within a building, from buildings into the environment, and from the environment into a control room). These flows can be through filters, piping, or simply due to air leakage. RADTRAD 3.03 can also model radioactive decay and in-growth of daughters. Ultimately the program calculates the Thyroid and TEDE dose (rem) to the public located offsite and to onsite personnel located in the control room due to inhalation and submersion in airborne radioactivity based on user specified, fuel inventory, nuclear data, dispersion coefficients, and dose conversion factors.

RADTRAD is used to develop the TEDE dose to the public located offsite and to onsite personnel located in the control room due to inhalation and submersion in airborne radioactivity following design basis accidents excluding tank ruptures

15.5.8.13 PERC2

PERC2 (Reference 69) is a multi-region activity transport and radiological dose consequence program. It includes the following major features:

(1) Provision of time-dependent releases from the reactor coolant system to the containment atmosphere.

(2) Provision for airborne radionuclides for both TID and AST release assumptions, including daughter in growth.

(3) Provision for calculating the CEDE to individual organs as well as EDE from inhalation, deep dose equivalent and beta from submersion, and TEDE.

(4) Provisions for tracking time-dependent inventories of all radionuclides in all control regions of the plant model.

(5) Provision for calculating instantaneous and integrated gamma radiation source strengths as well as activities for the inventoried radionuclides to permit direct assessment of the dose from contained / or external sources

for equipment qualification, vital area access and control room and EAB direct shine dose estimates.

PERC2 is used to calculate the accident energy release rates and integrated gamma energy releases versus time for the various post-LOCA external and contained radiation sources. This source term information is input into SW_QADCGGP to develop the direct shine dose to the control room. PERC2 is also used to develop the decay heat in the RWST and MEDT and develop the TEDE dose to personnel located in the TSC due to inhalation and submersion in airborne radioactivity following LOCA.

15.5.8.14 SW-QADCGGP

SW-QADCGGP (Reference 70) is a variant of the QAD point kernel shielding program originally written at the Los Alamos Scientific Laboratory by R. E. Malenfant. The QADCGGP version implements combinatorial geometry and the geometric progression build-up factor algorithm. The SW-QADCGGP implements a graphical indication of the status of the computation process.

SW-QADCGGP is used to develop the direct shine dose to the operator in the control room, TSC, and EAB.

15.5.8.15 GOTHIC

GOTHIC (Reference 71) is developed and maintained by Numerical Applications Incorporated (NAI) and an integrated, general purpose thermal-hydraulics software package for design, licensing, safety, and operating analysis of nuclear power plant containments and other confinement buildings. GOTHIC solves the conservation equations for mass, momentum, and energy for multicomponent, multi-phase flow in lumped parameter and/or multi-dimensional geometries. The phase balance equations are coupled by mechanistic models for interface mass, energy, and momentum transfer that cover the entire flow regime from bubbly flow to film/drop flow, as well as single phase flows. The interface models allow for the possibility of thermal non equilibrium between phases and unequal phase velocities, including countercurrent flow. Other phenomena include models for commonly available safety equipment, heat transfer to structures, hydrogen burn, and isotope transport.

GOTHIC is used to estimate the containment and sump pressure and temperature response with recirculation spray, the temperature transient in the RWST / MEDT gas and liquid due to incoming sump water leakage / inflow / decay heat from the RWST / MEDT fission product inventory, and the volumetric release fraction transient from the RWST / MEDT gas space to the environment.

15.5.9 CONTROL ROOM DESIGN AND TRANSPORT MODEL

The control room serves both units and is located at El 140’ of the Auxiliary Building. The walls facing the Unit 1 and Unit 2 containments (i.e., the north and south walls) are made of 3’-0” concrete, whereas the control room east and west walls are made up of

2'-0" concrete. The floor and ceiling thickness / material reflect a minimum of 2'-0" and 3'-4" of concrete, respectively. The control room Mechanical Equipment and HVAC room is located adjacent to the control room (east side), at El 154'-6".

The control room has a normal intake per unit (each located on opposite sides the auxiliary building; i.e. north and south), and a pressurization flow intake per unit (each located on either side of the turbine building; i.e. north and south). The control room pressurization air intakes have dual ventilation outside air intake design as defined by Regulatory Position C.3.3.2 of Regulatory Guide 1.194, June 2003 (refer to Section 2.3.5.2.2).

During normal operation (CRVS Mode 1), both control room normal intakes are operational. Redundant PG&E Design Class I radiation monitors located at each control room normal intake have the capability of isolating the control room normal intakes on detection of high radiation and switching the control room ventilation system (CRVS) to Mode 4 operation (i.e., control room filtered intake and pressurization).

CRVS Mode 4 operation utilizes redundant PG&E Design Class I radiation monitors located at each control room pressurization air intake and the provisions of acceptable control logic to automatically select the least contaminated inlet at the beginning of the accident, and manually select the least contaminated inlet during the course of the accident in accordance with Regulatory Guide 1.194, June 2003. Thus, during Mode 4 operation the dose consequence analyses can utilize the χ/Q values for the more favorable pressurization air intake reduced by a factor of 4 to credit the "dual intake" design (refer to Section 2.3.5.2.2).

Other signals that initiate CRVS Mode 4 operation include the safety injection signal (SIS) and Containment Isolation Phase A. The SIS does not directly initiate CRVS Mode 4; however, it initiates Containment Isolation Phase A which initiates Mode 4 operation.

During normal operations, unfiltered air is drawn into the control room envelope (refer to Table 15.5-81) from the Unit 1 and Unit 2 normal intakes. In response to a control room radiation monitor or SIS, the control room switches to CRVS Mode 4 operation, and control logic ensures that the CRVS pressurization fan of the non-accident unit is initiated and air is taken from the less contaminated of the Unit 1 or Unit 2 control room pressurization air intakes. The control room pressurization flowrate used in the dose consequence analyses is selected to maximize the estimated dose in the control room. With the exception of 100 cfm which is unfiltered due to backdraft damper leakage, all pressurization flow is filtered.

The allowable methyl iodide penetration and filter bypass for the CRVS Mode 4 Charcoal Filter is controlled by Technical Specifications and the ventilation filter testing program (VFTP), and is 2.5% and <1%, respectively. In accordance with Generic Letter 99-02, June 1999 a safety factor of 2 is used in determining the charcoal filter efficiency for use in safety analyses (refer to Section 9.4.1 and Table 9.4-2). Thus, the control room charcoal filter efficiency for elemental and organic iodine used in the DCPP safety analyses is 100% - [(2.5% + 1%) x 2] = 93%. The acceptance criteria for the in-place test of the high efficiency particulate air (HEPA) filters in Technical Specifications is a "penetration plus system bypass" < 1.0%. Similar to the charcoal filters, the HEPA filter efficiency for particulates used in the DCPP safety analyses is 100% - [(1%) x 2] = 98%.

During Mode 4 operation, the control room air is also recirculated and a portion of the recirculation flow filtered through the same filtration unit as the pressurization flow. Refer to Table 15.5-81 for a summary of recirculation flow rates.

Unfiltered inleakage into the control room during Mode 1 and Mode 4 is assumed to be 70 cfm (includes 10 cfm for inleakage due to egress-ingress based on the guidance provided in SRP 6.4).

For purposes of estimating the post-accident dose consequences, the control room is modeled as a single region. When in CRVS Mode 4, the Mode 1 intakes are isolated and outside air is a) drawn into the control room through the filtered emergency intakes; b) enters the control room as infiltration, c) enters the control room during operator egress-ingress, and d) enters the control room as unfiltered leakage via the emergency intake back draft dampers. The direction of flow uncertainty on the CRVS ventilation intake flowrates (normal as well as accident), are selected to maximize the dose consequence in the control room.

The dose consequence analyses for the LOCA, MSLB, SGTR, and the CREA, assume a LOOP concurrent with reactor trip.

In addition, and as noted in Section 15.5.1.2, in accordance with current licensing basis the non-accident unit is assumed unaffected by the LOOP. Thus, to address the effect of a LOOP, and taking into consideration the fact that the time of receipt of the signal to switchover from CRVS Mode 1 to Mode 4 is accident specific:

a. Automatic isolation of the control room normal intake of the "non-accident" unit is delayed by 12 seconds from receipt of the signal, to switch to CRVS Mode 4. This delay takes into account a 2 second SIS processing time and a 10 second damper closure time.

b. Automatic isolation of the control room normal intake of the accident unit, and credit for CRVS Mode 4 operation is delayed by 38.2 seconds from receipt of the signal to switch to CRVS Mode 4. This delay takes into account a) 28.2 seconds for the diesel generator to become fully operational including sequencing delays, and b) 10 seconds for the control room ventilation dampers to re-align. The 2 second SIS processing time occurs in parallel with diesel

generator sequencing and is therefore not included as part of the delay. In addition, and as discussed earlier, the CRVS system design ensures that upon receipt of a signal to switch to Mode 4, the control room pressurization fans of the non-accident unit is initiated; thus fan ramp-up is assumed to occur well within the 38.2 seconds delay discussed above, unhampered by a LOOP.

The dose consequence analyses for the LRA and the LOL event assume that the control room remains in normal operation mode and do not credit CRVS Mode 4 operation.

Table 15.5-81 lists key assumptions / parameters associated with control room design.

15.5.10 RADIOLOGICAL CONSEQUENCES OF CONDITION II FAULTS

15.5.10.1 Acceptance Criteria

The radiological consequences of accidents analyzed in Section 15.2 (or from other events involving insignificant core damage, but requiring atmospheric steam releases) shall not exceed the dose limits of 10 CFR 50.67, and will meet the dose acceptance criteria of Regulatory Guide 1.183, July 2000, as outlined below:

<u>EAB and LPZ Dose Criteria</u>

Regulatory Guide 1.183 does not specifically address Condition II scenarios. However, per Regulatory Guide 1.183, Section 1.2.1, a full implementation of AST allows a licensee to utilize the dose acceptance criteria of 10 CFR 50.67 in all dose consequence analyses. In addition, Section 4.4 of Regulatory Guide 1.183 indicates that for events with a higher probability of occurrence than those listed in Table 6 of Regulatory Guide 1.183, the postulated EAB and LPZ doses should not exceed the criteria tabulated in Table 6. Thus, the dose consequences at the EAB and LPZ will be limited to the lowest value reported in Table 6, i.e., a small fraction (10%) of the limit imposed by 10 CFR 50.67.

(1) An individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release shall not receive a radiation dose in excess of 0.025 Sv (2.5 rem) TEDE.

(2) An individual located at any point on the outer boundary of the LPZ, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose in excess of 0.025 Sv (2.5 rem) TEDE.

Control Room Dose Criteria

(3) Adequate radiation protection is provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) TEDE for the duration of the accident.

Technical Support Center Dose Criteria

(4) The acceptance criteria for the TSC dose is based on Section 8.2.1(f) of NUREG-0737, Supplement 1, Regulatory Guide 1.183, Section 1.2.1, and 10 CFR 50.67. The dose to an operator in the TSC should not exceed 5 rem TEDE for the duration of the accident.

15.5.10.2 Identification of Causes and Accident Description

15.5.10.2.1 Activity Release Pathways

As reported in Section 15.2, Condition II faults are not expected to cause breach of any of the fission product barriers, thus preventing fission product release from the core or plant. Under some conditions, however, small amounts of radioactive isotopes could be released to the atmosphere following Condition II events as a result of atmospheric steam dumps required for plant cooldown. The particular Condition II events that are expected to result in some atmospheric steam release are:

(1) Loss of electrical load and/or turbine trip

(2) Loss of normal feedwater

(3) LOOP to the station auxiliaries

(4) Accidental depressurization of the MSS

The amount of steam released following these events depends on the time relief valves remain open and the availability of condenser bypass cooling capacity.

The mass of environmental steam releases for the Loss of Load Event bound all Condition II events.

A LOL event is different from the Loss of Alternating Current (AC) power condition, in that offsite AC power remains available to support station auxiliaries (e.g., reactor coolant pumps). The Loss of AC power condition results in the condenser being unavailable and reactor cooldown being achieved using steam releases from the SG MSSVs and 10% ADVs until initiation of shutdown cooling.

In-keeping with the concept of developing steam releases that bound all Condition II events and encompass the LRA and CREA, the analysis performed to determine the

mass of steam released following a LOL event incorporates the assumption of Loss of offsite power to the station auxiliaries.
Although Regulatory Guide 1.183 does not provide specific guidance with respect to scenarios to be assumed to determine radiological dose consequences from Condition II events, the scenario outlined below for the LOL analysis is based on the conservative assumptions outlined in Regulatory Guide 1.183 for the MSLB, and was analyzed to bound all Condition II events that result in environmental releases.

Table 15.5-9A lists the key assumptions / parameters utilized to develop the radiological consequences following a LOL event. The conservative assumptions utilized to assess the dose consequences ensure that it represents the Limiting Condition II event.

Computer code RADTRAD 3.03, is used to calculate the control room and site boundary dose due to airborne radioactivity releases following a LOL event.

15.5.10.2.2 Activity Release Transport Model

No melt or clad breach is postulated for the LOL (refer to Section 15.2.7). Thus, and in accordance with Regulatory Guide 1.183, Appendix E, Item 2, the activity released is based on the maximum coolant activity allowed by the plant Technical Specifications, which focus on the noble gases and iodines. In accordance with Regulatory Guide 1.183, two scenarios are addressed, i.e., a) a pre-accident iodine spike and b) an accident-initiated iodine spike.

a. Pre-accident Iodine Spike - the initial primary coolant iodine activity is assumed to be 60 μCi/gm of DE I-131 which is the transient Technical Specification limit for full power operation. The initial primary coolant noble gas activity is assumed to be at Technical Specification levels.

b. Accident-Initiated Iodine Spike - the initial primary coolant iodine activity is assumed to be at Technical Specification of 1 μCi/gm DE I-131 (equilibrium Technical Specification limit for full power operation). Immediately following the accident the iodine appearance rate from the fuel to the primary coolant is assumed to increase to 500 times the equilibrium appearance rate corresponding to the 1 μCi/gm DE I-131 coolant concentration. The duration of the assumed spike is 8 hours. The initial primary coolant noble gas activity is assumed to be at Technical Specification levels.

The initial secondary coolant iodine activity is the Technical Specification limit of 0.1 μCi/gm DE I-131.

Plant Technical Specification limits primary to secondary steam generator (SG) tube leakage to 150 gpd per steam generator for a total of 600 gpd in all 4 SGs. To accommodate any potential accident induced leakage, the LOL dose consequence analysis addresses a limit of 0.75 gpm from all 4 SGs (or a total of 1080 gpd).

The entire primary-to-secondary tube leakage of 0.75 gpm (maximum leak rate at STP conditions; total for all 4 SGs) is leaked into an effective SG. In accordance with Regulatory Guide 1.183, the pre-existing iodine activity in the secondary coolant and iodine activity due to reactor coolant leakage into the 4 SGs is assumed to be homogeneously mixed in the bulk secondary coolant. The effect of SG tube uncovery in intact SGs (for SGTR and non-SGTR events) has been evaluated for potential impact on dose consequences as part of a WOG Program and demonstrated to be insignificant. Therefore, per Regulatory Guide 1.183, the iodines are released to the environment via the via the main steam safety valves (MSSVs) and 10% atmospheric dump valves (ADVs) in proportion to the steaming rate and the inverse of a partition coefficient of 100. The iodine releases from the SG are assumed to be 97% elemental and 3% organic. The noble gases are released freely to the environment without retention in the SG.

The condenser is assumed unavailable due to a coincident loss of offsite power. Consequently, the radioactivity release resulting from a LOL event is discharged to the environment from the steam generators via the MSSVs / 10% ADVs. The SG releases continue for 10.73 hours, at which time shutdown cooling is initiated via operation of the Residual Heat Removal (RHR) system and environmental releases are terminated.

15.5.10.2.3 Offsite Dose Assessment

AST methodology requires that the worst case dose to an individual located at any point on the boundary at the EAB, for any 2-hr period following the onset of the accident be reported as the EAB dose. For the LOL event, the worst two hour period can occur either during the 0-2 hr period when the noble gas release rate is the highest, or during the t=8.73 hr to 10.73 hr period when the iodine level in the SG liquid peaks (SG releases are terminated at T=10.73 hrs). Regardless of the starting point of the worst 2 hr window, the 0-2 hr EAB χ/Q is utilized.

The bounding EAB and LPZ dose following a LOL event at either unit is presented in Table 15.5-9.

15.5.10.2.4 Control Room Dose Assessment

The parameter values utilized for the control room in the accident dose transport model are discussed in Section 15.5.9. A summary of the critical assumptions associated with control room response and activity transport for the LOL event is provided below:

<u>Control Room Ventilation</u>

The LOL event does not initiate any signal which could automatically start the control room pressurization air ventilation. Thus the dose consequence analysis for the LOL event assumes that the control room remains in normal operation mode.

Control Room Atmospheric Dispersion Factors

Due to the proximity of the MSSVs/10% ADVs to the control room normal intake of the affected unit and because the releases from the MSSVs/10% ADVs have a vertically upward discharge, it is expected that the concentrations near the normal operation control room intake of the affected unit (closest to the release point) will be insignificant. Therefore, only the unaffected unit's control room normal intake is assumed to be contaminated by releases from the MSSVs/10% ADVs (refer to Section 2.3.5.2.2 for detail).

The bounding atmospheric dispersion factors applicable to the radioactivity release points / control room receptors applicable to an LOL event at either unit are provided in Table 15.5-9B. The χ/Q values presented in Table 15.5-9B take into consideration the various release points-receptors applicable to the LOL to identify the bounding χ/Q values applicable to a LOL event at either unit, and reflect the allowable adjustments / reductions in the values as discussed in Section 2.3.5.2.2 and summarized in the notes of Tables 2.3-147 and 2.3-148.

The bounding Control Room dose following a LOL event at either unit is presented in Table 15.5-9.

15.5.10.3 Conclusions

It can be concluded from the results discussed that the occurrence of any of the events analyzed in Section 15.2 (or from other events involving insignificant core damage, but requiring atmospheric steam releases) will result in insignificant radiation exposures and are bounded by the LOL event.

Additionally, the analysis demonstrates that the acceptance criteria are met as follows:

(1) The radiation dose to an individual located at any point on the boundary of the exclusion area for the 2-hour period following the onset of the postulated fission product release is within 0.025 Sv (2.5 rem) TEDE as shown in Table 15.5-9.

(2) The radiation dose to an individual located at any point on the outer boundary of the LPZ, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), is within 0.02 Sv (2.5 rem) TEDE as shown in Table 15.5-9.

(3) The radiation dose to an individual in the control room for the duration of the accident is within 0.05 Sv (5 rem) TEDE as shown in Table 15.5-9.

(4) In accordance with the current licensing basis, the TSC design has been evaluated for the LOCA. The dose consequences in the TSC due to airborne radioactivity releases from the LOL is bounded by the dose reported for the

LOCA in Section 15.5.17. The atmospheric dispersion factors applicable to the TSC are presented in Table 15.5-83.

15.5.11 RADIOLOGICAL CONSEQUENCES OF A SMALL-BREAK LOSS-OF-COOLANT ACCIDENT

15.5.11.1 Acceptance Criteria

The radiological consequences of a SBLOCA shall not exceed the dose limits of 10 CFR 50.67, and will meet the dose acceptance criteria of Regulatory Guide 1.183, July 2000, as outlined below:

Regulatory Guide 1.183 does not specifically address Condition III scenarios. However, per Regulatory Guide 1.183, Section 1.2.1, a full implementation of AST allows a licensee to utilize the dose acceptance criteria of 10 CFR 50.67 in all dose consequence analyses. In addition, Section 4.4 of Regulatory Guide 1.183 indicates that for events with a higher probability of occurrence than those listed in Table 6 of Regulatory Guide 1.183, the postulated EAB and LPZ doses should not exceed the criteria tabulated in Table 6. Thus, the dose consequences at the EAB and LPZ will be limited to the lowest value reported in Table 6, i.e., a small fraction (10%) of the limit imposed by 10 CFR 50.67.

<u>EAB and LPZ Dose Criteria</u>

(1) An individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release shall not receive a radiation dose in excess of 0.025 Sv (2.5 rem) TEDE.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose in excess of 0.025 Sv (2.5 rem) TEDE.

<u>Control Room Dose Criteria</u>

(3) Adequate radiation protection is provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) TEDE for the duration of the accident.

15.5.11.2 Identification of Causes and Accident Description

As discussed in Section 15.3.1, a SBLOCA (defined in UFSAR Chapter 15.3.1 as a break that is large enough to actuate the emergency core cooling system), is not expected to cause fuel cladding failure. For this reason, the only activity release to the containment will be the dissolved noble gases and iodine in the reactor coolant water

expelled from the pipe rupture. Some of this activity could be released to the containment atmosphere as the water flashes, and some of this amount could leak from the containment as a result of a rise in containment pressure.

The possible radiological consequence of this event is expected to be bounded by the "containment release" scenario of the CREA discussed in Section 15.5.23.

The dose consequences following a SBLOCA will be significantly less than a CREA since the CREA is postulated to result in 10% fuel damage, whereas the SBLOCA has no fuel damage.

As demonstrated in Table 15.5-52, the dose consequences at the EAB and LPZ and in the Control Room following a CREA is within the acceptance criteria applicable to the SBLOCA.

15.5.11.3 Conclusions

On the basis of this conservative comparison approach, it is concluded that the dose consequences at the EAB and LPZ and in the Control Room following a SBLOCA will remain within the acceptance criteria listed in Section 15.5.11.1.

15.5.12 RADIOLOGICAL CONSEQUENCES OF MINOR SECONDARY SYSTEM PIPE BREAKS

15.5.12.1 Acceptance Criteria

The radiological consequences of accidents analyzed in Section 15.3 such as minor secondary system pipe breaks shall not exceed the dose limits of 10 CFR 50.67, and will meet the does acceptance criteria of Regulatory Guide 1.183, July 2000, as outlined below:

Regulatory Guide 1.183 does not specifically address Condition III scenarios. However, per Regulatory Guide 1.183, Section 1.2.1, a full implementation of AST allows a licensee to utilize the dose acceptance criteria of 10 CFR 50.67 in all dose consequence analyses. In addition, Section 4.4 of Regulatory Guide 1.183 indicates that for events with a higher probability of occurrence than those listed in Table 6 of Regulatory Guide 1.183, the postulated EAB and LPZ doses should not exceed the criteria tabulated in Table 6. Thus, the dose consequences at the EAB and LPZ will be limited to the lowest value reported in Table 6, i.e., a small fraction (10%) of the limit imposed by 10 CFR 50.67.

<u>EAB and LPZ Dose Criteria</u>

(1) An individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release shall not receive a radiation dose in excess of 0.025 Sv (2.5 rem) TEDE.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose in excess of 0.025 Sv (2.5 rem) TEDE.

Control Room Dose Criteria

(3) Adequate radiation protection is provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) TEDE for the duration of the accident.

15.5.12.2 Identification of Causes and Accident Description

The effects on the core of sudden depressurization of the secondary system caused by an accidental opening of a steam dump, relief or safety valve were described in Section 15.2 and apply also to the case of minor secondary system pipe breaks. As shown in that analysis, no core damage or fuel rod failure is expected to occur. In Section 15.4.2, analyses are presented that show the effects on the core of a major steam line break, and, in this case also, no fuel rod failures are expected to occur.

The analyses presented in Section 15.3.2 demonstrate that a DNBR of less than the safety analysis limit will not occur anywhere in the core in the event of a minor secondary system pipe rupture.

The steam releases following a minor secondary line break is expected to be significantly less than that associated with a main line steam break.

As demonstrated in Table 15.5-34, the dose consequences at the EAB and LPZ and in the Control Room following a MSLB is within the acceptance criteria applicable to the minor secondary line break.

15.5.12.3 Conclusions

On the basis of this conservative comparison approach, it is concluded that the dose consequences at the EAB and LPZ and in the Control Room following a minor secondary system pipe rupture will remain within the acceptance criteria listed in Section 15.5.12.1.

15.5.13 RADIOLOGICAL CONSEQUENCES OF INADVERTENT LOADING OF A FUEL ASSEMBLY INTO AN IMPROPER POSITION

15.5.13.1 Acceptance Criteria

Fuel assembly loading errors shall be prevented by administrative procedures implemented during core loading. In the unlikely event that a loading error occurs, analyses supporting Section 15.3.3 shall confirm that no events leading to radiological consequences shall occur as a result of loading errors.

15.5.13.2 Identification of Causes and Accident Description

Fuel and core loading errors such as inadvertently loading one or more fuel assemblies into improper positions, loading a fuel rod during manufacture with one or more pellets of the wrong enrichment, or loading a full fuel assembly during manufacture with pellets of the wrong enrichment will lead to increased heat fluxes if the error results in placing fuel in core positions calling for fuel of lesser enrichment. The inadvertent loading of one or more fuel assemblies requiring burnable poison rods into a new core without burnable poison rods is also included among possible core loading errors. Because of margins present, as discussed in detail in Section 15.3.3, no events leading to radiological consequences are expected as a result of loading errors.

15.5.13.3 Conclusions

Because of margins present, as discussed in detail in Section 15.3.3, no events leading to radiological consequences are expected as a result of loading errors.

15.5.14 RADIOLOGICAL CONSEQUENCES OF COMPLETE LOSS OF FORCED REACTOR COOLANT FLOW

15.5.14.1 Acceptance Criteria

The radiological consequences of small amounts of radioactive isotopes that could be released to the atmosphere as a result of atmospheric steam dumping required for plant cooldown following a complete loss of forced reactor coolant flow shall not exceed the dose limits of 10 CFR 50.67, and will meet the dose acceptance criteria of Regulatory Guide 1.183, July 2000 as outlined below:

Regulatory Guide 1.183 does not specifically address Condition III scenarios. However, per Regulatory Guide 1.183, Section 1.2.1, a full implementation of AST allows a licensee to utilize the dose acceptance criteria of 10 CFR 50.67 in all dose consequence analyses. In addition, Section 4.4 of Regulatory Guide 1.183 indicates that for events with a higher probability of occurrence than those listed in Table 6 of Regulatory Guide 1.183, the postulated EAB and LPZ doses should not exceed the criteria tabulated in Table 6. Thus, the dose consequences at the EAB and LPZ will be

limited to the lowest value reported in Table 6, i.e., a small fraction (10%) of the limit imposed by 10 CFR 50.67.

EAB and LPZ Dose Criteria

(1) An individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release shall not receive a radiation dose in excess of 0.025 Sv (2.5 rem) TEDE.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose in excess of 0.025 Sv (2.5 rem) TEDE.

Control Room Dose Criteria

(3) Adequate radiation protection is provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) TEDE for the duration of the accident.

15.5.14.2 Identification of Causes and Accident Description

As discussed in Section 15.3.4, a complete loss of forced reactor coolant flow may result from a simultaneous loss of electrical supplies to all RCPs. If the reactor is at power at the time of the accident, the immediate effect of loss of coolant flow is a rapid increase in the coolant temperature.

The analysis performed and reported in Section 15.3.4 has demonstrated that for the complete loss of forced reactor coolant flow, the DNBR does not decrease below the safety analysis limit during the transient, and thus there is no cladding damage or release of fission products to the RCS.

The possible radiological consequence of a complete loss of forced reactor coolant flow is expected to be bounded by the conservative Loss-of-Load scenario with a coincident Loss of offsite power described in Section 15.5.10.

As demonstrated in Table 15.5-9, the dose consequences at the EAB and LPZ and in the Control Room following a Loss of Load is within the acceptance criteria applicable to the complete loss of forced reactor coolant flow.

15.5.14.3 Conclusions

On the basis of this comparison approach, it is concluded that the dose consequences at the EAB and LPZ and in the Control Room following a complete loss of forced reactor coolant flow will remain with the acceptance criteria listed in Section 15.5.14.1

15.5.15 RADIOLOGICAL CONSEQUENCES OF AN UNDERFREQUENCY ACCIDENT

15.5.15.1 Acceptance Criteria

The radiological consequences of small amounts of radioactive isotopes that could be released to the atmosphere as a result of atmospheric steam dumping required for plant cooldown following an underfrequency accident shall not exceed the dose limits of 10 CFR 50.67, and will meet the dose acceptance criteria of Regulatory Guide 1.183, July 2000 as outlined below:

Regulatory Guide 1.183 does not specifically address Condition III scenarios. However, per Regulatory Guide 1.183, Section 1.2.1, a full implementation of AST allows a licensee to utilize the dose acceptance criteria of 10 CFR 50.67 in all dose consequence analyses. In addition, Section 4.4 of Regulatory Guide 1.183 indicates that for events with a higher probability of occurrence than those listed in Table 6 of Regulatory Guide 1.183, the postulated EAB and LPZ doses should not exceed the criteria tabulated in Table 6. Thus, the dose consequences at the EAB and LPZ will be limited to the lowest value reported in Table 6, i.e., a small fraction (10%) of the limit imposed by 10 CFR 50.67.

<u>EAB and LPZ Dose Criteria</u>

(1) An individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release shall not receive a radiation dose in excess of 0.025 Sv (2.5 rem) TEDE.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose in excess of 0.025 Sv (2.5 rem) TEDE.

<u>Control Room Dose Criteria</u>

(3) Adequate radiation protection is provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) TEDE for the duration of the accident.

15.5.15.2 Identification of Causes and Accident Description

A transient analysis for this unlikely event is discussed in Section 15.3.4. The analysis demonstrates that for an underfrequency accident, the DNBR does not decrease below the safety analysis limit during the transient, and thus there is no cladding damage or release of fission products to the RCS. However, small amounts of radioactive isotopes

could be released to the atmosphere as a result of atmospheric steam dumping required for plant cooldown.

The possible radiological consequence of this event is expected to be bounded by the conservative Loss-of-Load scenario with a coincident Loss of offsite power described in Section 15.5.10.

As demonstrated in Table 15.5-9, the dose consequences at the EAB and LPZ and in the Control Room following a Loss of Load is within the acceptance criteria applicable to an underfrequency accident.

15.5.15.3 Conclusions

On the basis of this comparison approach, it is concluded that the dose consequences at the EAB and LPZ and in the Control Room following an underfrequency event will remain within the acceptance criteria listed in Section 15.5.15.1.

15.5.16 RADIOLOGICAL CONSEQUENCES OF A SINGLE ROD CLUSTER CONTROL ASSEMBLY WITHDRAWAL AT FULL POWER

15.5.16.1 Acceptance Criteria

The radiological consequences of a single RCCA withdrawal shall not exceed the dose limits of 10 CFR 50.67, and will meet the dose acceptance criteria of Regulatory Guide 1.183, July 2000 as outlined below:

Regulatory Guide 1.183 does not specifically address Condition III scenarios. However, per Regulatory Guide 1.183, Section 1.2.1, a full implementation of AST allows a licensee to utilize the dose acceptance criteria of 10 CFR 50.67 in all dose consequence analyses. In addition, Section 4.4 of Regulatory Guide 1.183 indicates that for events with a higher probability of occurrence than those listed in Table 6 of Regulatory Guide 1.183, the postulated EAB and LPZ doses should not exceed the criteria tabulated in Table 6. Thus, the dose consequences at the EAB and LPZ will be limited to the lowest value reported in Table 6, i.e., a small fraction (10%) of the limit imposed by 10 CFR 50.67.

<u>EAB and LPZ Dose Criteria</u>

(1) An individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release shall not receive a radiation dose in excess of 0.025 Sv (2.5 rem) TEDE.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose in excess of 0.025 Sv (2.5 rem) TEDE.

Control Room Dose Criteria

(3) Adequate radiation protection is provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) TEDE for the duration of the accident.

15.5.16.2 Identification of Causes and Accident Description

A complete transient analysis of this accident is presented in Section 15.3.5. For the condition of one RCCA fully withdrawn with the rest of the bank fully inserted, at full power, an upper bound of the number of fuel rods experiencing DNBR less than the safety analysis limit is 5 percent of the total fuel rods in the core.

The possible radiological consequence of this event is expected to be bounded by the CREA discussed in Section 15.5.23.

The dose consequences following a single rod cluster control assembly withdrawal will be less than a CREA since the CREA is postulated to result in 10% fuel damage, whereas the condition of one rod cluster control assembly fully withdrawn with the rest of the bank fully inserted, at full power has only 5% fuel damage.

As demonstrated in Table 15.5-52, the dose consequences at the EAB and LPZ and in the Control Room following a CREA is within the acceptance criteria applicable to the condition of one rod cluster control assembly fully withdrawn with the rest of the bank fully inserted, at full power.

15.5.16.3 Conclusions

On the basis of this comparison approach, it is concluded that the dose consequences at the EAB and LPZ and in the Control Room following the condition of one rod cluster control assembly fully withdrawn with the rest of the bank fully inserted, at full power will remain within the acceptance criteria listed in Section 15.5.16.1.

15.5.17 RADIOLOGICAL CONSEQUENCES OF MAJOR RUPTURE OF PRIMARY COOLANT PIPES

15.5.17.1 Acceptance Criteria

The radiological consequences of a LOCA shall not exceed the dose limits of 10 CFR 50.67, and will meet the dose acceptance criteria of Regulatory Guide 1.183, July 2000 and outlined below:

EAB and LPZ Dose Criteria

(1) An individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release shall not receive a radiation dose in excess of 0.25 Sv (25 rem) TEDE.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose in excess of 0.25 Sv (25 rem) TEDE.

Control Room Dose Criteria

(3) Adequate radiation protection is provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) TEDE for the duration of the accident.

Technical Support Center Dose Criteria

(4) The acceptance criteria for the TSC dose is based on Section 8.2.1(f) of NUREG-0737, Supplement 1, Regulatory Guide 1.183, Section 1.2.1, and 10 CFR 50.67. The dose to an operator in the TSC should not exceed 5 rem TEDE for the duration of the accident.

15.5.17.2 Identification of Causes and Accident Description

15.5.17.2.1 Activity Release Pathways

The accidental rupture of a main coolant pipe is the event assumed to initiate a LBLOCA. Analyses of the response of the reactor system, including the ECCS, to ruptures of various sizes have been presented in Sections 15.3.1 and 15.4.1. As demonstrated in these analyses, the ECCS, using emergency power, is designed to keep cladding temperatures well below melting and to limit Zr-H_2O reactions to an insignificant level. As a result of the increase in cladding temperature and the rapid depressurization of the core, however, some cladding failure may occur in the hottest regions of the core. Following the cladding failure, some activity would be released to the primary coolant and subsequently to the inside of the containment building. Active mechanisms include radioactive particulate and iodine removal by the containment sprays inclusive of the containment air mixing provided by the CFCUs. Section 6.2 describes the design and operation of the CSS and the CFCUs.

Regulatory Guide 1.183, Appendix A, identifies the large break LOCA as the design basis case of the spectrum of break sizes for evaluating performance of release mitigation systems and the containment, and for facility siting relative to radiological consequences.

DCPP has identified six activity release paths following a LOCA:

1. Release via the Containment Pressure / Vacuum Relief pathway to the environment until the containment isolation valves are closed.

2. Containment leakage to the environment after containment isolation is achieved.

3. Sump water leakage from ESF systems that recirculate sump water outside containment.

4. Failure of the RHR pump seal at T=24 hrs resulting in a 50 gpm leak of sump water for 30 mins.

5. Releases to the environment from the Miscellaneous Equipment Drain Tank (MEDT) which collects component leakage hard-piped to the MEDT. The collected fluid includes both post-LOCA sump water and other non-radioactive fluid.

6. Releases to the environment via the refueling water storage tank (RWST) vent due to post-LOCA sump fluid back-leakage into the RWST via the mini-flow recirculation lines connecting the high head and low head safety injection pump discharge piping to the RWST.

The LOCA dose consequence analysis follows the guidance provided in the pertinent sections of Regulatory Guide 1.183 including Appendix A. Table 15.5-23A lists the key assumptions / parameters utilized to develop the radiological consequences following a LOCA at either unit.

Computer code RADTRAD 3.03, is used to calculate the control room and site boundary dose due to airborne radioactivity releases following a LOCA.

15.5.17.2.2 Activity Release Transport Model

15.5.17.2.2.1 Containment Pressure /Vacuum Relief Line Release

In accordance with Regulatory Guide 1.183, Appendix A, Section 3.8, for containments such as DCPP that are routinely purged during normal operations, the dose consequence analysis must assume that 100% of the radionuclide inventory in the primary coolant is released to the containment at the initiation of the LOCA. The inventory of the release from containment should be based on Technical Specifications primary coolant equilibrium activity (refer to Table 15.5-78). Iodine spikes need not be considered.

Thus, in accordance with the above guidance, the 12 inch containment vacuum / over pressure relief valves are assumed to be open to the extent allowed by Technical Specifications (i.e., blocked to prevent opening beyond 50 degrees), at the initiation of the LOCA, and the release via this pathway terminated as part of containment isolation. The analysis assumes that 100% of the radionuclide inventory in the primary coolant, assumed to be at Technical Specification levels, is released to the containment at T= 0 hours. It is conservatively assumed that 40% of release flashes and is instantaneously and homogeneously mixed in the containment atmosphere and that the activity associated with the volatiles, i.e., 100% of the noble gases and 40% of the iodine in the reactor coolant is available for release to the environment via this pathway.

Containment pressurization (due to the RCS mass and energy release), combined with the relief line cross-sectional area, results in a 218 acfs release of containment air to the environment for a conservatively estimated period of 13 seconds. Credit is taken for pressure boundary integrity of the containment pressure / vacuum relief system ductwork which is classified as PG&E Design Class II, and seismically qualified; thus, environmental releases are via the Plant Vent.

Since the release is isolated within 13 seconds after LOCA, i.e., before the onset of the gap phase release, releases associated with fuel damage are not postulated. The chemical form of the iodine released from the RCS to the environment is assumed to be 97% elemental and 3% organic.

15.5.17.2.2.2 Containment Leakage

The inventory of fission products in the reactor core available for release into the containment following a LOCA is provided in Table 15.5-77 which represents a conservative equilibrium reactor core inventory of the dose significant isotopes, assuming maximum full power operation at 1.05 times the current licensed thermal power, and taking into consideration fuel enrichment and burnup. The notes provided at the bottom of Table 15.5-77 provide information on isotopes used to estimate the inhalation and submersion doses following a LOCA, vs. isotopes that are considered to estimate the post-LOCA direct shine dose.

Per Regulatory Guide 1.183, the fission products released from the fuel are assumed to mix instantaneously and homogeneously throughout the free air volume of the primary containment as it is released from the core.

In accordance with Regulatory Guide 1.183:

a. Two fuel release phases are considered for DBA analyses: (a) the gap release, which begins 30 seconds after the LOCA and continues to t=30 mins and (b) the early In-Vessel release phase which begins 30 minutes into the accident and continues for 1.3 hours (i.e., t=1.8 hrs).
b. The core inventory release fractions, by radionuclide groups, for the gap and early in-vessel damage are as follows:

Group	Gap Release Phase	Early In-Vessel Release Phase
Noble gas	0.05	0.95
Halogens	0.05	0.35
Alkali Metals	0.05	0.25
Tellurium Group	-	0.05
Ba, Sr	-	0.02
Noble Metals	-	0.0025
Cerium Group	-	0.0005
Lanthanides	-	0.0002

Note: Footnote 10 criterion in Section 3.2 of RG 1.183 is met in that peak fuel rod burnup is limited to 62,000 MWD/MTU.

The elements in each radionuclide group released to the containment following a LOCA are assumed to be as follows (note that the groupings were expanded from that in Regulatory Guide 1.183 to address isotopes in the core with similar characteristics; the added isotopes are in bold font):

The elements in each radionuclide group released to the containment following a LOCA are assumed to be as follows (note that the groupings were expanded from that in Regulatory Guide 1.183 to address isotopes in the core with similar characteristics; the added isotopes are in bold font):

Noble gases: Xe, Kr
Halogens: I, Br
Alkali Metals: Cs Rb
Tellurium Grp: Te, Sb, Se, **Sn, In, Ge, Ga, Cd, As, Ag**
Ba,Sr: Ba, Sr
Noble Metals: Ru, Rh, Pd, Mo, Tc, Co
Cerium Grp: Ce, Pu, Np, **Th**
Lanthanides: La, Zr, Nd, Eu, Nb, Pm, Pr, Sm, Y, Cm, Am, **Gd, Ho, Tb**

As discussed in Section 6.2.3.3.7, the design includes chemical addition into the containment spray system which ensures a long term sump pH equal to or greater than 7.0. Thus, the chemical form of the radioiodine released from the fuel is assumed to be 95% particulate (cesium iodide (CsI)), 4.85% elemental iodine, and 0.15% organic iodine. With the exception of noble gases, elemental and organic iodine, all fission products released are assumed to be in particulate form.

The activity released from the core during each release phase is modeled as increasing in a linear fashion over the duration of the phase. The release into the containment is assumed to terminate at the end of the early in-vessel phase, approximately 1.8 hours after the LOCA.

Isotopic decay, containment leakage, selected natural removal mechanisms and spray removal are credited to deplete the inventory of fission products airborne in containment.

Isotopic decay, containment leakage, selected natural removal mechanisms and spray removal are credited to deplete the inventory of fission products airborne in containment.

Containment spray in the injection and recirculation mode is utilized as one of the primary means of fission product cleanup following a LOCA. Mixing of the effectively sprayed volume of containment, with the unsprayed volume of the containment is enhanced by operation of the PG&E Design Class I containment fan coolers. In order to quantify the effectiveness of the containment spray system, both the volume fraction of containment that is sprayed, and the mixing rate between the sprayed and unsprayed volumes are quantified.

The LOCA analysis is based on an assumed worst case single failure of loss of one ESF train. A single train ESF consists of one train of ECCS, one train of CSS, and two Containment Fan Cooling Units (CFCUs). A single train scenario is selected to be consistent with the use of reduced iodine and particulate removal coefficients associated with single train operation.

a. Containment Spray Duration: Containment Spray in the injection mode is initiated at 111 seconds after the LOCA and terminated at 3798 seconds. Manual operation is credited to initiate containment recirculation spray within twelve (12) minutes after injection spray is terminated. Thus, based on single train operation, containment spray in the recirculation mode is initiated at 4518 seconds, and terminated 5 hours later at 22,518 seconds. In summary, containment spray operation (injection plus recirculation) is credited for 6.25 hrs post-LOCA, with a twelve minute gap after injection spray is terminated.

b. Containment Spray Coverage: As discussed in Section 6.2.3.3.7.1, the containment sprays are estimated to effectively cover 82.5% of the containment free volume during the containment spray injection as well as spray recirculation mode.

c. Mixing between Sprayed and Unsprayed Regions of Containment: The containment mixing rate between the sprayed and unsprayed regions following a LOCA is determined to be 9.13 turnovers of the unsprayed regions per hour. This mixing rate is based on the operation of two CFCU with a total volumetric flow rate that addresses surveillance margins and uncertainty, between the unsprayed regions and sprayed regions. Review of the layout and arrangement of the intake and exhaust registers of the CFCUs indicate that the air intakes are all located above the operating floor (sprayed region) and the air discharge registers are all located below the operating floor in the unsprayed region. Additional review of the containment configuration including the location of the major openings in the

containment structure, and various active and passive mixing mechanisms, results in the conclusion that following a LOCA, credit can be taken for a) the entire flowrate provided by each operating CFCU to support mixing between the sprayed and unsprayed regions, and b) homogeneous mixing within the sprayed and unsprayed regions, of the volume of air transferred from one region to the other due to CFCU operation. In accordance with Regulatory Guide 1.183, Appendix A, Section 3.3, prior to CFCU initiation, the dose consequence model assumes a mixing rate attributable to natural convection between the sprayed and unsprayed regions of 2 turnovers of the unsprayed region per hour.

d. Fission Product Removal: The fission product removal coefficients developed for the LOCA reflect the following guidance documents:

   i. Elemental iodine removal coefficients are calculated using guidance provided in Standard Review Plan Section 6.5.2, Revision 4 (Reference 80), which is invoked by Regulatory Guide 1.183, Appendix A, Section 3.3.

   ii. Time dependent particulate aerosol removal coefficients are estimated using Regulatory Guide 1.183, Appendix A, Section 3.3, which permits the use of time-dependent particulate aerosol removal coefficients by invoking NUREG/CR 5966, June 1993 (Reference 81), and indicates that no reduction in particulate aerosol removal coefficients is required when a DF of 50 is reached, if the removal rates are based on the calculated time-dependent airborne aerosol mass. There are several aerosol mechanics phenomena that promote the depletion of aerosols from the containment atmosphere. For DCPP, agglomeration of the aerosol is considered in both sprayed and unsprayed regions. In the sprayed region, the particulate removal calculation takes credit for the removal effectiveness of sprays and diffusiophoresis (aerosol removal due to steam condensation). Computer program SWNAUA is used to develop the time dependent particulate aerosol removal coefficients which reflect the effect of diffusiophoresis and sprays. Gravitational settling is considered only in the unsprayed region.

The methodology used to develop the elemental iodine and particulate removal coefficients in the sprayed and unsprayed region of the containment is discussed in Section 6.2.3.3.7.2. The total elemental iodine and particulate removal coefficients in the sprayed and unsprayed region of the containment as a function of time are summarized in Table 6.2-32.

In summary, the activity transport model takes credit for aerosol removal due to steam condensation and via containment spray based on spray flowrates associated with minimum ESF during the containment spray injection and recirculation mode. It considers mixing between the sprayed and unsprayed regions of the containment, reduction in airborne radioactivity in the containment by concentration dependent aerosol removal lambdas, and isotopic in-growth due to decay.
During spray operation in the injection mode, the elemental iodine removal rate for the

sprays exceeds 20 hr-1, the maximum value permitted by NUREG-0800, Standard Review Plan Section 6.5.2; thus the elemental iodine removal rate attributable to sprays is limited to 20 hr-1. During recirculation spray operation, the elemental removal rate for the sprays is 19.34 hr-1. As discussed in 6.2.3.3.7.2, the wall deposition removal coefficient for elemental iodine has been calculated with the model provided in NUREG-0800, SRP Section 6.5.2. In sprayed and unsprayed regions, prior to spray actuation, the wall deposition removal coefficient is estimated to be 2.74 hr-1, while during spray operation, and in the sprayed region only, the wall deposition removal coefficient is estimated to be 0.57 hr-1.

In the unsprayed region, the aerosol removal lambdas reflect gravitational settling. No credit is taken for elemental iodine removal in the unsprayed region.

Since the spray removal coefficients are based on calculated time dependent airborne aerosol mass, there is no restriction on the DF for particulate iodine. The maximum DF for elemental iodine is based on Standard Review Plan Section 6.5.2 and is limited to a DF of 200.

Radioactivity is assumed to leak from both the sprayed and unsprayed region to the environment at the containment technical specification leak rate for the first day, and half that leak rate for the remaining duration of the accident (i.e., 29 days). To ensure bounding values, the atmospheric dispersion factors utilized for the containment release path reflects the worst value between the containment wall release point, the plant Vent, the Containment Penetration Area GE (EL 140') and the Containment Penetration Areas GW/FW (EL 140').

15.5.17.2.2.3 ESF System Leakage Outside Containment

The fluid that collects in the containment recirculation sump after a LOCA (i.e., the fluid contents of reactor coolant system, the RWST, the NaOH tank and the accumulators) contain radioactive fission products that has been released from the core as a result of the LOCA.

The containment recirculation sump water is circulated by the RHR pumps, cooled via the RHR heat exchangers, returned to the containment via the RHR system piping and the CSS piping, passed through the RCS and the containment spray nozzles, and finally returned to the containment recirculation sump. In the event of circulation loop leakage in the auxiliary building, post-LOCA activity has a pathway to the atmosphere.

The complete RHR system and CSS descriptions; including detection of leakage, equipment isolation, and corrective maintenance, are contained in Sections 5.5.6 and 6.2.2, respectively.

In accordance with Regulatory Guide 1.183, with the exception of noble gases, all the fission products released from the core during the gap and early in-vessel release phases are assumed to be instantaneously and homogeneously mixed in the primary

containment recirculation sump water at the time of release from the fuel. A minimum sump water volume of 480,015 gallons is utilized in this analysis.

In accordance with Regulatory Guide 1.183, the ESF systems that recirculate sump fluids outside containment are analyzed to leak at twice the sum of the administratively controlled total allowable leakage applicable to all components in the ESF recirculation systems. With the exception of iodine, all radioactive materials in the recirculating liquid are assumed to be retained in the liquid phase.

ESF leakage is assumed to occur at initiation of the recirculation mode for safety injection. Since the maximum temperature of the recirculation fluid supports a flash fraction less than 10%, per Regulatory Guide 1.183, ten percent (10%) of the halogens associated with this leakage are assumed to be airborne and are exhausted (without mixing and without holdup) to the environment. The iodine release from the core is 95% particulate (CsI), 4.85% elemental and 0.15% organic; however, after interactions with sump water the environmental release is assumed to be 97% elemental and 3% organic.

The environmental release of ESF system leakage can occur via the 2 pathways listed below.

a. Environmental release of ESF System leakage via the plant vent: The sum of the maximum allowable simultaneous leakage from all components in the ESF recirculation systems located in the auxiliary building is limited to 120 cc/min. Thus, and in accordance with the guidance provided in Regulatory Guide 1.183, the analysis addresses an ESF leakage of 240 cc/min in the auxiliary building. The areas where these components are located are covered by the PG&E Design Class I ABVS which discharges to the environment out of the plant vent. Only selected portions of the Auxiliary Building ventilation system are processed through the PG&E Design Class I AB ventilation filters. For purposes of estimating the dose consequences, it is assumed that with the exception of the RHR pump rooms (refer to Section 15.5.17.2.2.4), this release pathway bypasses the PG&E Design Class I AB ventilation filters.

b. Environmental release of ESF System leakage via Containment Penetration Area GE and Areas GW & FW: The sum of the maximum allowable simultaneous leakage from all components in the ESF recirculation systems located in the containment penetration areas is limited to 6 cc/min. Thus, and in accordance with the guidance provided in Regulatory Guide 1.183, the analysis addresses an ESF leakage of 12 cc/min in the containment penetration areas. The ventilation system covering this area is not PG&E Design Class I, thus the release path to the environment is unfiltered and could occur via the Plant Vent or via the closest structural opening in the Containment Penetration Areas GE and Areas GW & FW.

15.5.17.2.2.4 RHR Pump Seal Failure

Failure of an RHR pump seal was assumed to be the worst case single failure to be tolerated without loss of the required functioning of the RHR system, as was required by the following clauses in the addendum to the ANS Standard N18.2 proposed at the time of original license:

> "Fluid systems provided to mitigate the consequences of Condition III and Condition IV events shall be designed to tolerate a single failure in addition to the incident which requires their function, without loss of the function to the unit.
>
> "A single failure is an occurrence which results in the loss of capability of a component to perform its intended safety functions when called upon. Multiple failures resulting from a single occurrence are considered to be a single failure. Fluid and electrical systems are considered to be designed against a single failure if neither (a) a single failure of any active component (assuming passive components function properly); nor (b) a single failure of a passive component (assuming active components function properly) results in a loss of the safety function to the nuclear steam electric generating unit.
>
> "An active failure is a malfunction, excluding passive failures, of a component which relies on mechanical movement to complete its intended function upon demand.
>
> "Examples of active failures include the failure of a valve or a check valve to move to its correct position, or the failure of a pump, fan or diesel generator to start.
>
> "Spurious action of a powered component originating within its actuation system shall be regarded as an active failure unless specific design features or operating restrictions preclude such spurious action.
>
> "A passive failure is a breach of the fluid pressure boundary or blockage of a process flowpath."

The failure of auxiliary building charcoal filters, a second failure, was not assumed, in accordance with the standard.

A review of the equipment in the RHR system loop and the CSS loop indicates that the largest leakage would result from the failure of an RHR pump seal. Evaluation of RHR pump seal leakage rate, assuming only the presence of a seal retention ring around the pump shaft, shows that flows less than 50 gpm would result (refer to Section 3.1 and Chapter 6). Circulation loop piping leaks, valve packing leaks, and flange gasket leaks are much smaller and less severe than an RHR pump seal failure leak. On this basis, a 50 gpm leakrate was assumed for LOCA.

For the DBA LOCA pump seal leakage was assumed to commence 24 hours after the start of the LOCA. This assumption is consistent with the discussion in Sections 3.1.1.1 and 6.3.3.5.3, and with the guidance in SRP 15.6.5, Appendix B (Reference 77). In this context, the limiting recirculation loop long term passive failure is 50 gpm leakage at 24 hours after the start of the LBLOCA.

Evaluation of an RHR pump seal failure shows that the failure could be detected and the pump isolated well within 30 minutes (refer to Chapter 6). Thus a leakage duration of 30 minutes is conservatively assumed for the DBA LOCA.

In summary, the RHR pump seal failure resulting in a filtered release via the plant vent is DCPP's licensing basis with respect to the worst case passive single failure in the RHR system. Therefore, the RHR pump Seal Failure is retained as a release pathway for the AST LOCA dose consequence analysis.

The activity transport model is based on a 50 gpm leak of sump water activity for 30 minutes that occurs 24 hours after the LOCA. The temperature of the recirculation fluid is conservatively assumed to remain at the maximum temperature of 259.9oF. Thus as discussed above in Section 15.5.17.2.2.3 under ESF system leakage, the amount of iodine that becomes airborne is assumed to be 10% of the total iodine activity in the leaked fluid.

The ventilation exhaust from the RHR pump rooms is covered by the PG&E Design Class I Auxiliary Building ventilation system and processed through the PG&E Design Class I AB ventilation filters. Thus, credit for filtration of the release of a RHR pump seal failure by the Auxiliary Building Ventilation system is taken in determining the dose consequences to the public at the EAB and LPZ, to the operator in the control room, and to personnel in the technical support center.

The efficiency of the auxiliary building charcoal filters is determined using methodology similar to that documented in Section 15.5.9 for the CRVS Mode 4 ventilation filters. The allowable methyl iodide penetration / filter bypass for the auxiliary building charcoal filter is controlled by DCPP Technical Specification 5.5.11; and are 5% and <1%, respectively. Based on the above, an efficiency of 88% is assigned to the charcoal filters in the AB ventilation system prior to environmental release via the plant vent. Similar to the ESF system leakage, the environmental release of iodine is assumed to be 97% elemental and 3% organic.

15.5.17.2.2.5 Refueling Water Storage Tank Back Leakage

The safety injection and containment spray systems function to provide reactor core cooling and mitigate the containment pressure and temperature rise, respectively, in the event of a LOCA. Both systems initially take suction from the RWST. Once the RWST water supply is depleted, both the containment spray and safety injection systems are supplied by the RHR System. The RHR pumps take suction from the containment recirculation sump water. Under LOCA conditions, the recirculation sump water is

assumed to be radioactively contaminated by fission products, of which the main contributors to airborne dose are the various isotopes of iodine.

As discussed in NRC Information Notice 91-56, September 1991 during containment sump water recirculation, there is the potential for leakage from the mini-flow recirculation lines connecting the high head and low head safety injection pump discharge piping to the RWST. Since the RWST is vented to the atmosphere, this presents a pathway for iodine release to the atmosphere. The acceptance criteria in the DCPP administrative test procedures ensure that the total as-tested back leakage into the RWST from the containment recirculation sump is less than or equal to 1 gpm.

Dose consequences of RWST back-leakage assumes that leakage starts at the switchover to recirculation following the LOCA and continues for 30 days. Per regulatory guidance, a safety factor of 2 is applied to the leak rate, i.e., a 2-gpm leakage rate is assumed for the full duration of the event, which is two times the allowable leakage of 1 gpm. With the exception of noble gases, all fission products released from the fuel to the containment are instantaneously and homogeneously mixed in the sump water at the time of release. Only iodine and their daughter products are released through RWST back-leakage since the particulates would remain in the sump water.

A significant portion of the iodine associated with sump water back-leakage into the RWST is retained within the RWST fluid due to the equilibrium iodine distribution balance between the RWST gas and liquid phases. The time dependent iodine partition coefficient takes into consideration the temperature and pH of the RWST liquid and sump fluid, the RWST liquid and gas volumes, and the temperature, pH and volume of the incoming leakage. The iodines that evolve into the RWST gas space as a result of the equilibrium iodine distribution balance, and the noble gas daughters of iodines, are released to the environment via the RWST vent, at a vent rate established by the temperature transient in the RWST (which includes the effect of decay heat), the increase in the liquid inventory of the RWST due to the incoming leakage, the gases evolving out of incoming leakage, and the environmental conditions outside the RWST.

The average time-dependent RWST iodine release fractions along with the fractional RWST gas venting rates (may be applied to the noble gas daughters of iodines) to the atmosphere from the Unit 1 and Unit 2 RWSTs due to RWST back-leakage following switchover to the sump water recirculation mode of operation is summarized in Table 15.5-23C. As discussed earlier, the release fractions / rates presented in Table 15.5- 23C reflect a safety factor of 2 on the leak rates, i.e., are developed based on a RWST back-leakage of 2 gpm. The iodine released to the environment is assumed to be 97% elemental and 3% organic.

The equilibrium iodine concentration in the RWST gas space utilized to develop Table 15.5-23C is based on the iodine mass in the sump fluid entering the RWST vapor space as back-leakage or the total iodine mass contained in the RWST liquid, whichever results in higher RWST vapor phase concentrations. The RWST maximum venting rate averaged over an interval is primarily based on RWST back-leakage

entering the RWST gas space and thermally equilibrating, and is used in conjunction with the higher RWST gas space iodine concentration to calculate an iodine mass release rate as a function of time. An interval based averaging approach is utilized in preparing Table 15.5-23C to reduce the number of input values to the dose analysis while preserving the boundaries for the time periods used for atmospheric dispersion; the actual iodine release calculated in an interval is normalized to the iodine mass leaking into the RWST during that time interval.

Examination of the average gas space venting rates indicate that after the first day, the noble gases formed by decay of iodine will primarily remain in the RWST during the 30 day period of evaluation and not be released. However, the dose consequence analysis conservatively releases the noble gases formed by decay of iodine, directly to the environment without taking any credit for tank holdup.

15.5.17.2.2.6 Miscellaneous Equipment Drain Tank (MEDT) Leakage

The DCPP Unit 1 and Unit 2 MEDT is a covered rectangular stainless steel lined concrete tank located in the auxiliary building below El 60 foot. The MEDT tank vent is hard-piped to the auxiliary building ventilation ductwork; thus the airborne releases from the MEDT are ultimately discharged to the environment via the plant vent (refer to Section 9.4.2).

Following a LOCA, the MEDT will receive both post-LOCA sump fluids as well as non-radioactive fluids (i.e., ESF system leakage from the accident unit as well as non-radioactive fluids from equipment drains / RWST leakage from the non-accident unit) which are hard-piped to the MEDT. The acceptance criteria in the DCPP administrative test procedures ensure the total as-tested flow hard piped to the MEDT is less than 950 cc/min of ESF system leakage and 484 cc/min of non-radioactive fluid leakage.

Similar to the RWST back-leakage model, dose consequences due to releases from the MEDT assumes that leakage starts at the switchover to recirculation (829 second following the LOCA) and continues for 30 days. Per Regulatory Guide 1.183, a safety factor of 2 is applied to the leak rate, i.e., 1900 cc/min of ESF system leakage and 968 cc/min of non-radioactive fluids into the MEDT is assumed for the full duration of the event, which is two times the allowable leakage. With the exception of noble gases, all fission products released from the fuel to the containment are instantaneously and homogeneously mixed in the sump water at the time of release. Only iodine and their daughter products are released through MEDT leakage since the particulates would remain in the sump water.

The methodology used to determine the post-LOCA iodine and noble gas releases via the MEDT vent and Plant Vent is similar to that used to address RWST back-leakage. Adaptation of the methodology to address overflows/room ventilation releases is straightforward with the room ventilation rate being treated as the tank exhaust rate.

The transport model utilized to determine airborne releases from the MEDT takes into account the fact that the MEDT is a small tank with an auto-transfer capability which is PG&E Design Class II. Consequently, and for purposes of conservatism, it is assumed that a) the LOCA occurs when the MEDT water level is at the normal maximum setpoint to initiate auto transfer, b) the auto-transfer capability is not initiated because it is not a safety function, and c) the MEDT contents will spill over into the Equipment Drain Receiver Tank (EDRT) Room after the tank is full. Thus, for the post-LOCA scenario, the MEDT is conservatively assumed to overflow via its manway into the EDRT Room. The EDRT room drains into the auxiliary building sump, which ultimately overflows into the Unit 1/Unit 2 pipe tunnels. The auxiliary building sump is also a covered rectangular stainless steel lined concrete tank with a vent that is hard-piped to the auxiliary building ventilation system (ABVS) with a PG&E Design Class II auto transfer capability. The auxiliary building sump is located adjacent to the MEDT.

The bounding transient release of iodine along with the gas venting rate to the atmosphere as a result of post-LOCA leakage of radioactive and non-radioactive fluid hard-piped into the MEDT is developed in 2 parts: a) prior to MEDT overflow and b) post MEDT overflow.

a) Prior to MEDT overflow - The iodines evolve into the MEDT gas space as a result of the equilibrium iodine distribution balance between the MEDT gas and liquid phases (either the MEDT liquid inventory or the incoming leakage), and are released to the environment via the plant vent, at a vent rate established by the temperature transient in the MEDT (including the effect of decay heat), the increase in the liquid inventory of the MEDT due to the incoming leakage, and the gases evolving out of the incoming leakage.

b) After MEDT overflow – The equilibrium iodine distribution balance is conservatively assumed to be between the iodine concentrations in the MEDT overflow liquid and the EDRT room (or Unit 1/Unit 2 pipe tunnels) ventilation flow (rather than the average concentration in the EDRT room (or Unit 1/Unit 2 pipe tunnels) free volume). This maximizes the iodine release rate. Thus, the iodines released are a sum total of the following:

   i) the iodines that evolve into the EDRT room air space as a result of the equilibrium iodine distribution balance between the spilled liquid from the MEDT (at the temperature of the MEDT), and the EDRT room ventilation flow, and is released to the environment via the plant vent, at the vent rate established by the EDRT room ventilation system, and

   ii) the iodines that evolve into the Unit 1/Unit 2 Pipe Tunnel air space as a result of the equilibrium iodine distribution balance between the spilled liquid from the MEDT (at the maximum temperature of the Unit 1/Unit 2 Pipe Tunnel), and the U1/U2 Pipe Tunnel ventilation flow, and is released to the environment via the plant vent, at the vent rate established by the U1/U2 Pipe Tunnel ventilation system.

The exhaust fans servicing the EDRT room and pipe tunnel are PG&E Design Class I. There is also a potential that the non-LOCA unit's ABVS will be operating with the flow exhausting to its unit specific plant vent. Thus, it is conservatively assumed that the non-LOCA unit's ABVS is also operating, and together with the accident units' exhaust fans, are providing the motive force to exhaust the airborne releases to the respective unit vents.

The average time-dependent MEDT iodine release fractions, along with the fractional MEDT gas venting rates (which may be applied to the noble gas daughters of iodines prior to MEDT overflow) to the atmosphere following switchover to the sump water recirculation mode of operation, is summarized in Table 15.5-23D. As discussed earlier, the release fractions / rates presented in Table 15.5-23D reflect a safety factor of 2 on the leak rates, i.e., are developed based on an input of 1900 cc/min of ESF system leakage and 968 cc/min of non-radioactive fluids into the MEDT. Through the use of extremely conservative assumptions, the calculated iodine release fractions / gas venting rates presented in Table 15.5-23D when used in combination with the analyzed ESF system leak rate, bound the iodine releases of all combinations of radioactive and non- radioactive leakages less than or equal to the leak rates analyzed. The iodine released to the ventilation system is assumed to be 97% elemental and 3% organic, and is released to the environment via the plant vent. In addition, the dose consequence analysis conservatively releases the noble gases formed by decay of iodine, directly to the environment without taking any credit for tank holdup.

15.5.17.2.3 Offsite Dose Assessment

Due to the delayed post-LOCA fuel release sequence of an AST model, and the rate at which aerosols and elemental iodine are removed from the containment, the maximum 2-hour EAB dose for a PWR LOCA typically occurs between 0.5 hrs to 2.5 hrs.

To establish the "worst case 2-hour release window" for the DCPP EAB dose, the integrated dose versus time for each of the six pathways discussed in Section 15.5.17.2.2 was evaluated. The 0-2 hr EAB Atmospheric Dispersion Factor from Table 2.3-145 was utilized for all cases.

The analysis demonstrated that for DCPP the maximum 2 hour EAB dose will occur, as a result of the RHR pump seal failure, between T=24 hrs to T=26 hrs, and is unrelated to the post-LOCA fuel release sequence associated with AST.

The direct shine dose at the EAB due to a) the airborne activity inside containment, and b) the sump water collected in the RWST due to RWST back-leakage, was also evaluated. Based on the results of the EAB evaluation which determined that the dose contribution due to direct shine was minimal (<0.01 rem), the dose at the LPZ due to direct shine is deemed negligible.

The bounding EAB and LPZ dose following a LOCA at either unit is presented in Table 15.5-23.

15.5.17.2.4 Post LOCA Control Room Operator Exposure

The design basis for control room ventilation, shielding, and administration is to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE.
The control room shielding, described in Section 12.1 is designed to attenuate gamma radiation from post-accident sources to levels consistent with the requirements of GDC 19, 1999 and 10 CFR 50.67.

The control room ventilation system (CRVS) is described in Section 9.4.1. It is designed to limit the concentration of post-accident activity in the control room air to levels consistent with requirements of GDC 19, 1999 and 10 CFR 50.67.

The control room post-accident administration is described in the DCPP Manual. It is to limit post-accident control room personnel exposures to levels consistent with requirements of GDC 19, 1999 and 10 CFR 50.67.

Exposures to control room personnel during post-LOCA occupancy have been estimated for a design basis LOCA to evaluate the adequacy of the control room shielding, the adequacy of the CRVS, and the adequacy of the control room administration in limiting exposures to the specified limits.

Radiation exposures to personnel in the control room could result from the following sources:

(1) Airborne activity, which infiltrates into the control room

(2) Direct gamma radiation from the external cloud and contained sources.

The parameter values utilized for the control room in the accident dose transport model are discussed in Section 15.5.9. Provided below are the critical LOCA-specific assumptions associated with control room response and activity transport.

<u>Timing for Initiation of CRVS Mode 4</u>:

i. An SIS will be generated at t = 6 sec following a LOCA.

ii. The CRVS normal intake dampers of the accident unit start to close after a 28.2 second delay due to delays associated with diesel generator loading onto the 4kv buses. The control room dampers are fully closed 10 secs later, or at t=44.2 secs (i.e., 6 + 28.2 + 10). The 2 second SIS processing time occurs in parallel with diesel generator sequencing and is therefore not included as part of the delay.

iii. In accordance with DCPP licensing basis, the CRVS normal operation dampers of the non-accident unit are not affected by the LOOP and are isolated at t=18 secs (i.e., 6 + 2 secs signal processing time + 10 sec damper closure time).

Control Room Atmospheric Dispersion Factors:

The bounding atmospheric dispersion factors applicable to the radioactivity release points / control room receptors applicable to a LOCA at either unit are provided in Table 15.5-23B. The χ/Q values presented in Table 15.5-23B take into consideration the various release points-receptors applicable to the LOCA to identify the bounding χ/Q values applicable to a LOCA at either unit, and reflect the allowable adjustments / reductions in the values as discussed in Section 2.3.5.2.2 and summarized in the notes of Table 2.3-147 and Table 2.3-148 for Unit 1 and Unit 2, respectively.

Direct Shine from External and Contained Sources

The direct shine dose to an operator in the control room due to contained or external sources resulting from a postulated LOCA is calculated using point kernel shielding computer program SW-QADCGGP. The post-LOCA gamma energy release rates (MeV/sec) and integrated gamma energy release (MeV-hr/sec) in the various external sources are developed using computer program PERC2.

The LOCA sources that could potentially impact the control room operator dose due to direct shine are identified below.

1. Direct shine from containment – shine from the airborne source in the containment structure via the bulk shielding (3’-8” thick concrete walls below the bendline, 2’-6” thick concrete dome), including shine through one of the main steam line penetrations and the Personnel Hatch facing the control room.
2. Direct shine from the contaminated cloud outside the control room pressure boundary resulting from containment leakage, ESF system leakage, RHR pump seal leakage, RWST back- leakage, MEDT leakage - shine occurs through the control room walls, via wall penetrations such as control room doors to the outside, and from the airborne activity in cable spreading room below via control room floor penetrations.
3. Dose due to scattered gamma radiation through wall penetrations from the CRVS filters located in the adjacent mechanical equipment room.
4. Direct shine from the sump fluid that is postulated to collect in the RWST.

Cloud shine through control room doorways was found to be the most significant of all the identified contained or external post-LOCA radiation sources listed above, followed by the dose contribution through the control room floor penetrations. Note that other radiation sources were identified and deemed insignificant due to the presence of significant shielding between the operator and the radiation sources. Examples of these dose contributors include most of the large and small electrical and pipe

penetrations in the Containment outer wall that faces the control room, and the ESF system piping and components located in the Auxiliary Building.

The direct shine dose estimate in the control room takes into consideration the function of Room 506 (which serves as a control room foyer adjacent to the Shift Supervisor's office), where occupancy is deemed to be minimal; i.e., conservatively estimated at less than 5% of the total time spent daily in the control room. The above "occupancy adjustment" is utilized to determine the maximum 30-day integrated dose in control room (i.e., the total direct shine dose in the control room includes the 30-day dose in Room 506 adjusted by the referenced occupancy factor).

Control Room Operator Dose during Access

Diablo Canyon assumes that the dose received by the operator during routine access to the control room for the 30 day period following the LOCA is minimal. Thus, as long as some reasonable margin exists between the regulatory limit and the estimated dose to the operator during control room occupancy, the additional dose due to egress-ingress can be accommodated.

This approach is consistent with the approach used by other licensees, and is reasonable since a) transit to and from the control room is only expected after the first 24 hours following the accident by which time the airborne levels inside containment has reduced significantly due to the use of active fission product removal mechanisms such as containment sprays, and radioactive decay, and b) the operator is protected from radioactive ESF fluids by the shielding provided by the buildings that house such equipment. In addition, it is expected that during a postulated event, access to the control room will be controlled by Health Physics and the Emergency Plan based on real time data, with the purpose of minimizing personnel dose.

It is also noted that the dose received by the operator during transit outside the control room is not a measure of the "habitability" of the control room which is defined by the radiation protection provided to the operator by the control room shielding and ventilation system design. Thus, the estimated dose to the operator during routine post- LOCA access to the control room is addressed separately from the control room occupancy dose which is used for the demonstration of control room habitability.

in accordance with DCPP original licensing basis radiation exposures to personnel during egress and ingress (i.e., during routine access to the control room for the duration of the accident) could result from the following sources:

(1) Airborne activity in the containment leakage plume

(2) Direct gamma radiation from fission products in the containment structure

Post-accident egress-ingress exposures were based on 27 outbound excursions, from the control room to the site boundary, and 26 inbound excursions, from the site

boundary to the control room. It was estimated that each excursion would take 5 minutes, and no credit was taken for breathing apparatus or special whole body shielding.

Egress-ingress thyroid and whole body exposures from airborne activity are functions of containment activity, containment leakage, atmospheric dispersion, and excursion time. The EMERALD computer code was used to calculate the airborne activity concentrations, and then conventional exposure equations from Regulatory Guide 1.4 Revision 1, were used to calculate gamma, beta, and thyroid exposures (Reference 6). The exposure from betas was calculated on the basis of an infinite uniform cloud, and exposure from gammas was calculated on the basis of a semi-infinite cloud.

Because of the containment shielding and short excursion time, egress-ingress containment shine exposures were estimate to be small. Egress-ingress containment shine exposures were calculated using ISOSHLD-II. The shine model assumes a cylindrical radiation source having the same radius and height as the containment structure with a 3.5-foot-thick concrete shield surrounding it. The receptor point is assumed to be a distance of 10 meters from the outer surface of the containment wall.

The estimated egress-ingress exposures developed in support of DCPP original licensing basis are listed in Table 15.5-33 and summarized below.

a. The dose to control room personnel during egress-ingress from airborne fission products in the containment leakage plume: 0.0066 rem gamma, 0.0243 rem beta, and 4.72 rem thyroid.
b. The dose to control room personnel during egress-ingress as a result of direct radiation shine from the fission products in the containment structure is 0.022 rem.

Subsequent to the original licensing basis assessment described above, DCPP has identified additional post-LOCA fission product release pathways, as discussed in Section 15.5.17.2.1. The postulated effect of these additional radioactivity release paths, as well as the implementation of AST, on the estimated dose to control room personnel during routine egress-ingress takes into consideration the following:

a. The transport models used to develop the dose to the control room operator during occupancy address a control room occupancy factor of 1.0 till t=24 hours after the accident. This implies that during the first 24 hours the control room operator stays in the control room. This is also reflected in the DCPP original licensing basis which addresses one more outbound trip than the inbound trips.

b. Routine egress-ingress to the control room during the 30 day period following a LOCA falls into the mission dose category as discussed in NUREG 0737, November 1980, Item II.B.2.

c. In accordance with NUREG 0737, November 1980, Item II.B.2 leakage of systems outside containment need not be considered as potential sources.

Based on the above considerations, the dose consequences of the additional activity release paths addressed in Section 15.5.17.2.1 (and listed below), in addition to Regulatory Guide 1.183 is addressed as follows:

i. Containment Pressure /Vacuum relief release - this release occurs at accident initiation (before t=24hr), so there is no dose contribution to the control room operator during routine egress-ingress during the 30 day period following the accident.

ii. Containment leakage:

a. The airborne activity in the containment after t=24 hours with an AST source term is primarily 100% of the core noble gases and 0.06% of the core iodines that were released to containment.

Note: The iodine source term at t=24 hrs is essentially the organic iodines released to the containment which are not affected by sprays, and which per Regulatory Guide 1.183, represent 0.06% of the core iodines (i.e., 0.15% of the 40% core iodines released to containment atmosphere at accident initiation). Also, the essentially particulate nature of the radioactivity release associated with an AST source term, and the effectiveness of particulate removal by sprays / settling makes the dose contribution from the particulate source minimal after t=24 hours.

b. The corresponding airborne activity in the containment after t=24 hours for a TID-14844 source term is 100% of the core noble gases and 1% of the core iodines.

Note: Per Regulatory Guide 1.4, Revision 1, the organic iodines released to the containment is 4% of the 25% iodines released to containment atmosphere at accident initiation.

c. Based on the above it is concluded that after t=24hrs:

- Dose consequences due to containment leakage based on a TID- 14844 based scenario will bound the dose consequences based on an AST scenario.

- Thyroid dose is primarily due to iodines, the associated dose to the operator will vary proportionately to the amount of iodine airborne in containment. Thus, the thyroid dose to the operator during egress-ingress for an AST scenario may be estimated by adjusting the TID-14844 based dose by the ratio of the iodine estimated to be airborne

in containment for each of the scenarios. As noted earlier, the current licensing basis thyroid dose to the operator during egress-ingress is 4.72 rem. The corresponding thyroid dose based on an AST scenario is estimated to be 4.72 x 0.06 = 0.28 rem thyroid.

iii. The RHR Pump Seal Failure, ESF System Leakage, RWST back leakage and MEDT leakage – All of these releases are based on leakage of systems outside containment. In accordance with NUREG 0737, November 1980, Item II.B.2, the dose contribution due to these sources need not be considered for access calculations.

To address the TEDE dose acceptance criteria applicable to use of AST, the original licensing basis egress-ingress exposures have been updated as noted below in accordance with 10 CFR 20.1003.

Title 10 CFR 20.1003 defines TEDE as the sum of the deep dose equivalent for external exposures (i.e., external whole body exposure) and the committed effective dose equivalent for internal exposures (i.e., sum of the product of the weighting factor applicable to each organ irradiated and the dose to that organ). Per 10 CFR 20.1003, the weighting factor for the whole body is 1.0 and for the thyroid is 0.03. While the weighting factor for beta radiation is undefined, the contribution of the beta dose to the total effective dose equivalent is expected to be insignificant. Therefore,

a. Radiation from airborne fission products in the containment leakage plume to the control room personnel during egress-ingress is approximately 0.0066 rem + 0.28 x 0.03 rem, i.e., 0.015 rem TEDE.

b. Direct radiation from the fission products in the containment structure to control room personnel during egress-ingress is 0.022 rem TEDE.

Thus, the total dose to the control room operator during access is estimated to be 0.037 rem TEDE. This value is 1% of the estimated operator dose due to control room occupancy following a LOCA (Refer to Table 15.5-23) and is therefore considered to be minimal.

15.5.17.2.5 Post-LOCA Technical Support Center Operator Exposure

In accordance with NUREG-0737, Supplement 1, January 1983, Section 8.2.1(f) the TSC design has been evaluated for the LOCA.

Computer code PERC2 is used to calculate the dose to TSC personnel due to airborne radioactivity releases following a LOCA. The direct shine dose to an operator in the TSC due to contained or external sources resulting from a postulated LOCA is calculated using point kernel shielding computer program SW-QADCGGP. The post-LOCA gamma energy release rates (MeV/sec) and integrated gamma energy release

(MeV-hr/sec) in the various external sources are developed with computer program PERC2.

The TSC serves both units and is located at El 104' on the south-west side of the Unit 2 turbine building and is shared between Unit 1 and Unit 2.

The nominal TSC air intake flowrate during normal operations is 500 cfm. The air inflow is filtered through a HEPA filter and drawn into the TSC envelope. The TSC normal intake is isolated and the TSC ventilation placed into filtered / pressurized (CRVS Mode 4) operation by manual operator action within 2 hours of the LOCA.

The post-accident pressurization flow to the TSC is provided via the CRVS Mode 4 pressurization intakes (i.e., 1 per unit, each located on either side of the Turbine Building). As noted in Section 15.5.9, the control room pressurization air intakes have dual ventilation outside air intake design. The nominal air intake flowrate during the TSC pressurization mode is 500 cfm.

As discussed in Section 15.5.9, CRVS Mode 4 operation utilizes redundant PG&E Design Class I radiation monitors located at each pressurization air intake and has the provisions of acceptable control logic to automatically select the least contaminated inlet at the beginning of the accident, and manually select the least contaminated inlet during the course of the accident. Thus, during Mode 4 operation the TSC dose consequence analysis can utilize the χ/Q values for the more favorable pressurization air intake reduced by a factor of 4 to credit the "dual intake" design (refer to Section 2.3.5.2.2 for additional details).

The allowable methyl iodide penetration and filter bypass for the TSC Mode 4 Charcoal Filter is <2.5% and <1%, respectively. Thus, in accordance with Generic Letter 99-02, June 1999, the TSC charcoal filter efficiency for elemental and organic iodine used in the TSC dose analysis is 93%. The acceptance criteria for the TSC normal operation and Mode 4 HEPA filters is "penetration plus system bypass" < 1.0%. Thus, using methodology similar to the charcoal filters, the HEPA filter efficiency for particulates used in the TSC dose analysis is 98%.

During TSC Mode 4 operation, the TSC air is also recirculated through the same filtration unit as the pressurization flow (refer to Section 9.4.11). The air flow allowable through the pressurization charcoal / HEPA filter and minimum filtered recirculation flow for the TSC is provided in Table 15.5-82.

Unfiltered inleakage into the TSC during normal operation and Mode 4 is assumed to be 60 cfm (includes 10 cfm for egress-ingress based on the guidance provided in NUREG 0800, SRP 6.4).

For purposes of estimating the post-LOCA dose consequences, the TSC is modeled as a single region. When in TSC Mode 4, the Mode 1 intakes are isolated and outside air

is a) drawn into the TSC through the filtered emergency intakes; b) enters the TSC as infiltration, and c) enters the TSC during operator egress-ingress.

The dose assessment model utilizes nominal values for the ventilation intake flowrates since the intake pathways (normal as well as accident) are filtered; thus, the controlling dose contributor is the unfiltered inleakage. The effect of intake flow uncertainty on the TSC dose is expected to be insignificant.

The bounding atmospheric dispersion factors applicable to the radioactivity release points / TSC receptors applicable to a LOCA at either unit are provided in Table 15.5-23E. The χ/Q values presented take into consideration the various release points-receptors applicable to the LOCA to identify the bounding χ/Q values applicable to a LOCA at either unit, and reflect the allowable adjustments / reductions in the values as discussed in Section 2.3.5.2.2.

The direct shine dose into the TSC due to the external cloud and contained sources is calculated in a manner similar to that described for the control room in Section 15.5.17.2.4. The LOCA sources that could potentially impact the TSC operator dose due to direct shine are identified below.

1. Direct shine from containment – shine from the airborne source in the containment structure via the bulk shielding (3’-8” thick concrete walls below the bendline, 2’-6” thick concrete dome), including shine through the Personnel Hatch facing the TSC.
2. Direct shine from the contaminated cloud outside the TSC pressure boundary resulting from containment leakage, ESF system leakage, RWST back-leakage, RHR pump seal leakage, MEDT leakage - shine occurs through the TSC walls, and via wall penetrations such as TSC doors to the outside.
3. Dose due to scattered gamma radiation through wall penetrations from the TSC filters located in the adjacent mechanical equipment room and scatter past labyrinths provided for selected doors.

Note that other radiation sources were identified and deemed insignificant due to the presence of significant shielding between the operator in the TSC and the radiation sources.

Table 15.5-82 lists key assumptions / parameters associated with DCPP TSC design. The bounding TSC operator dose following a LOCA at either unit is presented in Table 15.5-23.

15.5.17.2.6 Summary

In the preceding sections, the potential exposures from a major primary system pipe rupture have been calculated for various possible mechanisms:

(1) Containment Pressure / Vacuum Relief

(2) Containment leakage

(3) ESF System Leakage

(4) RHR pump seal Failure

(5) RWST Back-Leakage

(6) MEDT Leakage

(7) Shine from Contained and External Sources (e.g., Contained Containment shine, RWST Shine, external clouds due to the various leakage sources, etc.)

The analyses have been carried out using the models and assumptions specified in Regulatory Guide 1.183 and other regulatory guidance identified above. In all analyses, the resulting potential exposures to plant personnel, to individual members of the public, and to the general population have been found to be lower than the applicable guidelines and limits specified in 10 CFR Part 50.67and Regulatory Guide 1.183

15.5.17.3 Conclusions

Based on the results discussed, the occurrence of a major pipe rupture in the primary system of a DCPP unit would not constitute an undue risk to the health and safety of the public. In addition, the ESF provided for the mitigation of the consequences of a LBLOCA are adequately designed.

Additionally, the analysis demonstrates that the acceptance criteria are met as follows:

(1) The radiation dose to an individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release is within 0.25 Sv (25 rem) TEDE as shown in Table 15.5-23.

(2) The radiation dose to an individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), is within 0.25 Sv (25 rem) TEDE as shown in Table 15.5-23.

(3) The radiation dose to an individual in the control room for the duration of the accident is within 0.05 Sv (5 rem) TEDE as shown in Table 15.5-23. The dose received by the operator during transit outside the control room is not a measure of the “habitability” of the control room which is defined by the radiation protection provided to the operator by the control room shielding and ventilation system design. Thus, and in accordance with DCPP current licensing basis, the dose contribution to the operator during routine access to

control room for the duration of the accident (0.037 rem TEDE), is not included with the control room occupancy dose for the demonstration of control room habitability.

(4) The radiation dose to an individual in the TSC for the duration of the accident is within 1.5 Sv (5 rem) TEDE as shown in Table 15.5-23.

15.5.18 RADIOLOGICAL CONSEQUENCES OF A MAJOR STEAM PIPE RUPTURE

15.5.18.1 Acceptance Criteria

The radiological consequences of a MSLB shall not exceed the dose limits of 10 CFR 50.67, and will meet the dose acceptance criteria of Regulatory Guide 1.183, July 2000 and outlined below.

EAB and LPZ Dose Criteria

(1) An individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release shall not receive a radiation dose in excess of the 10 CFR 50.67 limit of 0.25 Sv (25 rem) TEDE for a pre-existing accident iodine spike case and 10% of the 10 CFR 50.67 limit for the accident initiated iodine spike case.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose in excess of the 10 CFR 50.67 limit of 0.25 Sv (25 rem) TEDE for a pre-existing accident iodine spike case and 10% of the 10 CFR 50.67 limit for the accident initiated iodine spike case.

Control Room Dose Criteria

(3) Adequate radiation protection is provide to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) TEDE for the duration of the accident.

Technical Support Center Dose Criteria

(4) The acceptance criteria for the TSC dose is based on Section 8.2.1(f) of NUREG-0737, Supplement 1, Regulatory Guide 1.183, Section 1.2.1, and 10 CFR 50.67. The dose to an operator in the TSC should not exceed 5 rem TEDE for the duration of the accident.

15.5.18.2 Identification of Causes and Accident Description

15.5.18.2.1 Activity Release Pathways

As reported in Section 15.4.2, a major steam line rupture is not expected to cause cladding damage, and thus no release of fission products to the coolant is expected following this accident. If significant radioactivity exists in the secondary system prior to the accident, however, some of this activity will be released to the environment with the steam escaping from the pipe rupture. In addition, if an atmospheric steam dump from the unaffected SGs is necessitated by unavailability of condenser capacity, additional activity will be released.

This event consists of a double-ended break of one main steam line. The analysis focuses on a MSLB outside the containment since a MSLB inside containment will clearly result in a lesser dose to a control room operator or to the offsite public due to hold-up of activity in the containment.

Following a MSLB, the affected SG rapidly depressurizes and releases the initial contents to the environment via the break. Based on an assumption of a Loss of Offsite Power coincident with reactor trip, the condenser is assumed to be unavailable, and environmental steam releases via the MSSVs / 10% ADVs of the intact steam generators are used to cool down the reactor until initiation of shutdown cooling. The activity in the RCS leaks into the faulted and intact steam generators via SG tube leakage and is released to the environment from the break point, and from the MSSVs 10% ADVs, respectively.

Regulatory guidance provided for the MSLB in pertinent sections of Regulatory Guide 1.183 including Appendix E is used to develop the dose consequence model. Table 15.5-34A lists the key assumptions / parameters utilized to develop the radiological consequences following a MSLB.

Computer code RADTRAD 3.03, is used to calculate the control room and site boundary dose due to airborne radioactivity releases following a MSLB

15.5.18.2.2 Activity Release Transport Model

In accordance with Regulatory Guide 1.183, Appendix E, Item 2, since no melt or clad breach is postulated for the DCPP MSLB event, the activity released is based on the maximum coolant activity allowed by the plant technical specifications. The plant technical specifications focus on the noble gases and iodines. In addition, and per Regulatory Guide 1.183, two scenarios are addressed, i.e., a) a pre-accident iodine spike and b) an accident-initiated iodine spike.

a. Pre-accident Iodine Spike - the initial primary coolant iodine activity is assumed to be 60 μCi/gm of DE I-131 which is the transient Technical

Specification limit for full power operation. The initial primary coolant noble gas activity is assumed to be at Technical Specification levels.

b. Accident-Initiated Iodine Spike - the initial primary coolant iodine activity is assumed to be at Technical Specification of 1 μCi/gm DE I-131 (equilibrium Technical Specification limit for full power operation). Immediately following the accident the iodine appearance rate from the fuel to the primary coolant is assumed to increase to 500 times the equilibrium appearance rate corresponding to the 1 μCi/gm DE I-131 coolant concentration. The duration of the assumed spike is 8 hours. The initial primary coolant noble gas activity is assumed to be at Technical Specification levels.

The initial secondary coolant iodine activity is assumed to be at the Technical Specification limit of 0.1 μCi/gm DE I-131. Technical Specifications limit primary to secondary SG tube leakage to 150 gpd per steam generator for a total of 600 gpd in all 4 SGs. To accommodate any potential accident induced leakage, the MSLB dose consequence analysis addresses a limit of 0.75 gpm from all 4 SGs (or a total of 1080 gpd).

Following a MSLB, the primary and secondary reactor coolant activity is released to the environment via two pathways.

Faulted Steam Generator

The release from the faulted SG occurs via the postulated break point of the main-steam line. The faulted SG is estimated to dry-out almost instantaneously following the MSLB (within 10 seconds), releasing all of the iodine in the secondary coolant (at Technical Specification concentrations) that was initially contained in the steam generator. The EAB and LPZ dose to the public is calculated using an instantaneous release of the iodine inventory (Ci) in the SG liquid in the faulted SG. The secondary steam activity initially contained in the faulted steam generator is also released; however, the associated dose contribution is not included in this analysis since it is considered insignificant.

To maximize the control room and offsite doses following a MSLB, the maximum allowable primary to secondary SG tube leakage for all SGs (0.75 gpm or 1080 gpd at Standard Temperature and Pressure (STP) conditions), is conservatively assumed to occur in the faulted SG. All iodine and noble gas activities in the referenced tube leakage are released directly to the environment without hold-up or decontamination. The primary to secondary SG tube leakage is assumed to go on until the RCS reaches 212°F, which based on minimum heat transfer rates, is conservatively estimated to occur 30 hours after the event.

Intact Steam Generators

The initial iodine activities in the secondary coolant at Technical Specification levels are released to the environment in proportion to the steaming rate and the inverse of the partition coefficient (limited to 100) defined in Regulatory Guide 1.183. The noble gases are released freely to the environment without retention in the steam generators. However, there is no primary to secondary leakage into the intact SG as all primary to secondary leakage (1080 gpd or 0.75 gpm) is assumed to be occurring in the faulted SG.

The iodine releases to the environment from the SG are assumed to be 97% elemental and 3% organic. The condenser is assumed unavailable due to the loss of offsite power. The SG releases continue for 10.73 hours, at which time shutdown cooling is initiated via operation of the RHR system and environmental releases are terminated.

15.5.18.2.3 Offsite Dose Assessment

AST methodology requires that the worst case dose to an individual located at any point on the boundary at the EAB, for any 2-hr period following the onset of the accident be reported as the EAB dose.

a. The Source/Release for the Pre-incident Spike Case is at its maximum levels between 0 and 2 hours.
b. The Source/Release for the Accident-Initiated Spike Case is at its maximum levels towards the end of the spiking period.

Regardless of the starting point of the “Worst 2-hr Window,” the 0-2 hrs χ/Q is utilized.

The bounding EAB and LPZ dose following a MSLB at either unit for both scenarios are presented in Table 15.5-34.

15.5.18.2.4 Control Room Dose Assessment

The parameter values utilized for the control room in the accident dose transport model are discussed in Section 15.5.9. Provided below are the critical MSLB-specific assumptions associated with control room response and activity transport.

Timing for Initiation of CRVS Mode 4:

An SIS will be generated at t = 0.6 sec following a MSLB.

i. An SIS will be generated at t = 0.6 sec following a MSLB.

ii. The CRVS normal intake dampers of the accident unit start to close after a 28.2 second delay due to delays associated with diesel generator loading onto the 4kv buses. The control room dampers are fully closed within 10 seconds at

t=38.8 secs (i.e., 0.6 + 28.2 + 10). The 2 second SIS processing time occurs in parallel with diesel generator sequencing and is therefore not included as part of the delay.

iii. In accordance with DCPP licensing basis, the CRVS normal operation dampers of the non-accident unit are not affected by the LOOP and are isolated at t=12.6 secs (i.e., 0.6 + 2 secs signal processing time + 10 sec damper closure time).

Transport of Radioactivity from the Break Location

Since the normal operation (CRVS Mode 1) control room intake of the faulted unit is in such close proximity to the break point, an atmospheric dispersion factor (χ/Q) cannot be accurately determined. Thus, atmospheric dispersion is not credited when determining the control room operator dose from the secondary coolant discharge or the primary to secondary SG tube leakage released from the faulted SG via the break point.

Secondary Coolant Discharge: The radioactivity release due to the almost immediate dry-out of the faulted SG following a MSLB is based on a) the radioactivity concentration of the iodine in a finite cloud created by the secondary coolant liquid flash at the break point; b) conservation of total iodine activity in the SG liquid. The activity concentration at the release point is conservatively based on saturated steam at a density of 5.98E-04 gm/cm^3, (i.e., at 1 atmosphere and 212°F). The activity concentration entering the control room is assumed to be the same as the concentration at the break point until the control room normal ventilation is isolated and the CRVS re-aligned to Mode 4 Pressurization.

Primary to Secondary SG Tube Leakage: Due to the close proximity of the normal operation control room intake of the faulted unit and MSL break release point and consequent unavailability of viable atmospheric dispersion factors, the primary to secondary SG tube leakage into the faulted SG is conservatively assumed to be piped directly into the control room. This model is reasonable since the relatively small plume of steam created by the ~0.485 gallon *{i.e. (0.75 gallon/min)(38.8 s) / 60 s/min}* of reactor coolant released due to SG tube leakage via the MSL break point could easily be swept into the control room due to the close proximity of the control room normal intake to the break point.

Control Room Atmospheric Dispersion Factors

As noted in Section 2.3.5.2.2, because of the proximity of the MSSVs/10% ADVs to the control room normal intake of the affected unit, and because the releases from the MSSVs/10% ADVs have a vertically upward discharge, it is expected that the concentrations near the normal operation control room intake of the affected unit (closest to the release point) will be insignificant. Therefore, prior to switchover to CRVS Mode 4 pressurization, only the unaffected unit's control room normal intake is assumed to be contaminated by releases from the MSSVs/10% ADVs.

The bounding atmospheric dispersion factors applicable to the radioactivity release points / control room receptors applicable to a MSLB at either unit are provided in Table 15.5-34B. The χ/Q values presented in Table 15.5-34B take into consideration the various release points-receptors applicable to the MSLB to identify the bounding χ/Q values applicable to a MSLB at either unit, and reflect the allowable adjustments / reductions in the values as discussed in Chapter 2.3.5.2.2 and summarized in the notes of Tables 2.3-147 and 2.3-148.

The bounding control room dose following a MSLB at either unit is presented in Table 15.5-34.

15.5.18.3 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) The radiation dose to an individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release is within 0.25 Sv (25 rem) TEDE for a pre-existing accident iodine spike case and 10% of the 10 CFR 50.67 limit for the accident initiated iodine spike case as shown in Table 15.5-34.

(2) The radiation dose to an individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), is within 0.25 Sv (25 rem) TEDE for a pre-existing accident iodine spike case and 10% of the 10 CFR 50.67 limit for the accident initiated iodine spike case as shown in Table 15.5-34.

(3) The radiation dose to an individual in the control room for the duration of the accident is within 0.05 Sv (5 rem) TEDE as shown in Table 15.5-34.

(4) In accordance with the current licensing basis, the TSC design has been evaluated for the LOCA. The dose consequences in the TSC due to airborne radioactivity releases from the MSLB is bounded by the dose reported for the LOCA in Section 15.5.17. The atmospheric dispersion factors applicable to the TSC are presented in Table 15.5-83.

15.5.19 RADIOLOGICAL CONSEQUENCES OF A MAJOR RUPTURE OF A MAIN FEEDWATER PIPE

15.5.19.1 Acceptance Criteria

The radiological consequences of a major rupture of a main feedwater pipe (referred to herein as a feedwater line break (FWLB)) shall not exceed the dose limits of 10 CFR 50.67, and will meet the dose acceptance criteria of Regulatory Guide 1.183 July 2000 as outlined below:

<u>EAB and LPZ Dose Criteria</u>

(1) An individual located at any point on the boundary of the exclusion area for the any 2-hour period following the onset of the postulated fission product release shall not receive a radiation dose in excess of the 10 CFR 50.67 limit of 0.25 Sv (25 rem) TEDE, for a pre-existing accident iodine spike case and 10% of the 10 CFR 50.67 limit for the accident initiated iodine spike case.

(2) An individual located at any point on the outer boundary of the LPZ, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose in excess of the 10 CFR 50.67 limit of 0.25 Sv (25 rem) TEDE for a pre-existing accident iodine spike case and 10% of the 10 CFR 50.67 limit for the accident initiated iodine spike case.

<u>Control Room Dose Criteria</u>

(3) Adequate radiation protection is provide to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) TEDE for the duration of the accident.

15.5.19.2 Identification of Causes and Accident Description

As reported in Section 15.4.2, a major feedwater line rupture is not expected to cause cladding damage, and thus no release of fission products to the coolant is expected following this accident. If significant radioactivity exists in the secondary system prior to the accident, however, some of this activity will be released to the environment with the feedwater escaping from the pipe rupture. In addition, if an atmospheric steam dump from the unaffected SGs is necessitated by unavailability of condenser capacity, additional activity will be released.

Per Standard Review Plan 15.2.8, Section III, Item 6 (Reference 86), the evaluation the radiological consequences of a design basis FWLB may be based on a qualitative comparison to the results of the design basis MSLB.

The dose consequences following a FWLB will be bounded by a MSLB since the airborne environmental release via the break point is expected to be less than the MSLB.

As demonstrated in Table 15.5-34, the dose consequences at the EAB and LPZ and in the Control Room following a MSLB is within the acceptance criteria applicable to the FWLB.

15.5.19.3 Conclusions

On the basis of this comparison approach, it is concluded that the dose consequences at the EAB and LPZ and in the Control Room following a feedwater line break will remain within the acceptance criteria listed in Section 15.5.19.1.

15.5.20 RADIOLOGICAL CONSEQUENCES OF A STEAM GENERATOR TUBE RUPTURE

15.5.20.1 Acceptance Criteria

The radiological consequences of a SGTR shall not exceed the dose limits of 10 CFR 50.67, and will meet the dose acceptance criteria of Regulatory Guide 1.183, July 2000 and outlined below.

<u>EAB and LPZ Dose Criteria</u>

(1) An individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release shall not receive a radiation dose in excess of the 10 CFR 50.67 limit of 0.25 Sv (25 rem) TEDE for a pre-existing accident iodine spike case and 10% of the 10 CFR 50.67 limit for the accident initiated iodine spike case.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose in excess of the 10 CFR 50.67 limit of 0.25 Sv (25 rem) TEDE for a pre-existing accident iodine spike case and 10% of the 10 CFR 50.67 limit for the accident initiated iodine spike case.

<u>Control Room Dose Criteria</u>

(3) Adequate radiation protection is provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) TEDE for the duration of the accident.

Technical Support Center Dose Criteria

(4) The acceptance criteria for the TSC dose is based on Section 8.2.1(f) of NUREG-0737, Supplement 1, Regulatory Guide 1.183, Section 1.2.1, and 10 CFR 50.67. The dose to an operator in the TSC should not exceed 5 rem TEDE for the duration of the accident.

15.5.20.2 Identification of Causes and Accident Description

15.5.20.2.1 Activity Release Pathways

This event is caused by the instantaneous rupture of a SG tube with a resultant release of primary coolant into the lower pressure secondary system. No melt or clad breach is postulated for the SGTR event. The calculation assumes a stuck-open 10% ADV of the ruptured steam generator for 30 minutes. Based on an assumption of a Loss of Offsite Power coincident with reactor trip, the condenser is assumed to be unavailable, and environmental steam releases via the MSSVs / 10% ADVs of the intact steam generators are used to cool down the reactor until initiation of shutdown cooling. A portion of the primary coolant break flow in the ruptured SG flashes and is released a) to the condenser before reactor trip and b) directly to the environment after reactor trip, via the MSSVs and 10% ADVs. The remaining break flow mixes with the secondary side liquid, and is released to the environment via steam releases through MSSVs and 10% ADVs. The activity in the RCS also leaks into the intact steam generators via SG tube leakage and is released to the environment from the MSSVs / 10% ADVs.

Regulatory guidance provided for the SGTR in pertinent sections of Regulatory Guide 1.183 including Appendix F is used to develop the dose consequence model. Table 15.5-64A lists the key assumptions / parameters utilized to develop the radiological consequences following a SGTR. Table 15.5-64C provides the time dependent steam flow from the Ruptured and Intact SGs and the flashed and unflashed break flow in the Ruptured SG.

Computer code RADTRAD 3.03, is used to calculate the control room and site boundary dose due to airborne radioactivity releases following a SGTR.

15.5.20.2.2 Activity Release Transport Model

No melt or clad breach is postulated for the SGTR. Thus, and in accordance with Regulatory Guide 1.183, Appendix F, item 2, the activity released is based on the maximum coolant activity allowed by the plant technical specifications. The plant technical specifications focus on the noble gases and iodines. In addition, and per Regulatory Guide 1.183, two scenarios are addressed, i.e., a) a pre-accident iodine spike and b) an accident-initiated iodine spike.

a. Pre-accident Iodine Spike - the initial primary coolant iodine activity is assumed to be 60 μCi/gm of DE I-131 which is the transient Technical

Specification limit for full power operation. The initial primary coolant noble gas activity is assumed to be at Technical Specification levels.

b. Accident-Initiated Iodine Spike - the initial primary coolant iodine activity is assumed to be at Technical Specification of 1 μCi/gm DE I-131 (equilibrium Technical Specification limit for full power operation). Immediately following the accident the iodine appearance rate from the fuel to the primary coolant is assumed to increase to 335 times the equilibrium appearance rate corresponding to the 1 μCi/gm DE I-131 coolant concentration. The duration of the assumed spike is 8 hours. The initial primary coolant noble gas activity is assumed to be at Technical Specification levels.

The initial secondary coolant iodine activity is assumed to be at the Technical Specification limit of 0.1 μCi/gm DE I-131.

DCPP Plant Technical Specification 3.4.13d limits primary to secondary SG tube leakage to 150 gpd per steam generator for a total of 600 gpd in all 4 SGs. To accommodate any potential accident induced leakage, the SGTR dose consequence analysis addresses a limit of 0.75 gpm from all 4 SGs (or a total of 1080 gpd). To maximize the dose consequences, the analysis conservatively assumes that all of the 0.75 gpm SG tube leakage occurs in the intact SGs.

Following a SGTR, the primary and secondary reactor coolant activity is released to the environment via two pathways.

Ruptured Steam Generator

A SGTR will result in a large amount of primary coolant being released to the ruptured steam generator via the break location with a significant portion of it flashed to the steam space.

In accordance with the guidance provided in Regulatory Guide 1.183, the noble gases in the entire break flow and the iodine in the flashed portion of the break flow are assumed to be immediately available for release from the steam generator. The iodine in the non-flashed portion of the break flow mixes uniformly with the steam generator liquid mass and is released into the steam space in proportion to the steaming rate and the inverse of the allowable partition coefficient of 100. The iodine releases from the SGs are assumed to be 97% elemental and 3% organic.

Before the reactor trip the radioactivity in the steam is released to the environment from the air ejector which discharges into the plant vent. All noble gases and organic iodines in the steam are released directly to the environment. Only a portion of the elemental iodine carried with the steam is partitioned to the air ejector and released to the environment. The rest is partitioned to the condensate, returns to both the intact steam

generators and the ruptured steam generator and will be available for future steaming releases.

After the reactor trip, the radioactivity in the steam is released to the environment from the MSSVs/10% ADVs, due to the assumption of LOOP. To isolate the ruptured steam loop, the auxiliary feed water to the ruptured SG is secured. The calculation assumes the 10% ADV of the ruptured SG fails open for 30 minutes. The fail-open 10% ADV is isolated at t = 2653 seconds at which time the ruptured steam loop is isolated. The break flow continues until the primary system is in equilibrium with the secondary side of the ruptured SG. The iodines in the flashed break flow and the noble gases in the entire break flow is bottled up in the steam space of the ruptured SG and released to the environment during the manual depressurization of the ruptured SG after t = 2 hours.

Intact Steam Generators

The radioactivity released from the intact steam generators includes two components (a) portion of the break flow activity that is transferred to the intact steam generators via the condenser before reactor trip, and (b) due to SG tube leakage.

Approximately 75% (3 intact SGs vs 1 ruptured SG) of the flashed break flow activity that is transported and retained in the condenser before reactor trip will be transferred to the intact steam generators and released to the environment during the cool-down phase.

The total primary-to-secondary tube leak rate in the 3 intact SGs is conservatively assumed to be 0.75 gpm. The effect of SG tube uncovery in intact SGs (for SGTR and non-SGTR events) has been evaluated for potential impact on dose consequences as part of a WOG Program and demonstrated to be insignificant. Thus, all leaked primary coolant iodine activities are assumed to mix uniformly with the steam generator liquid and are released in proportion to the steaming rate and the inverse of the partition coefficient. Before the reactor trip, the activity in the main steam is released from the plant vent via the air ejector/ condenser. After the reactor trip, the steam is released from the MSSVs/10% ADVs. The reactor coolant noble gases that enter the intact steam generator are released directly to the environment without holdup. The iodine releases from the SGs are assumed to be 97% elemental and 3% organic. The intact SG steam release continues until shutdown cooling (SDC) is initiated at t = 10.73 hours.

Initial Secondary Coolant Activity Release

The initial iodine activities in the secondary coolant are released to the environment in proportion to the steaming rate and the inverse of the partition coefficient from the ruptured and intact SGs. Twenty five percent of the initial secondary coolant iodine inventory is in the ruptured SG and 75% of the initial secondary coolant iodine inventory is in the 3 intact SGs.

15.5.20.2.3 Offsite Dose Assessment

AST methodology requires that the worst case dose to an individual located at any point on the boundary at the EAB, for any 2-hr period following the onset of the accident be reported as the EAB dose.

For the SGTR, the EAB dose is controlled by the release of the flashed break flow in the ruptured SG which stops at 3402 seconds. The break flow stops at 5872 seconds and the ruptured SG is manually depressurized 2 hours after the accident. Therefore the maximum EAB dose occurs during the 0-2hr period for both the pre-accident and accident initiated iodine spike cases.

Regardless of the starting point of the "Worst 2-hr Window," the 0-2 hrs χ/Q is utilized.

The bounding EAB and LPZ dose following a SGTR at either unit for both scenarios are presented in Table 15.5-64.

15.5.20.2.3 Control Room Dose Assessment

The parameter values utilized for the control room in the accident dose transport model are discussed in Section 15.5.9. Provided below are the critical SGTR-specific assumptions associated with control room response and activity transport.

<u>Timing for Initiation of CRVS Mode 4</u>:

i. An SIS will be generated at t = 219 sec following a SGTR.

ii. The CRVS normal intake dampers of the accident unit start to close after a 28.2 second delay due to delays associated with diesel generator loading onto the 4kv buses. The control room dampers are fully closed 10 secs later, or at t=257.2 secs (i.e., 219 + 28.2 + 10). The 2 second SIS processing time occurs in parallel with diesel generator sequencing and is therefore not included as part of the delay.

iii. In accordance with DCPP licensing basis, the CRVS normal operation dampers of the non-accident unit are not affected by the LOOP and are isolated at t=231 secs (i.e., 219 + 2 secs signal processing time + 10 sec damper closure time).

<u>Control Room Atmospheric Dispersion</u> Factors

As noted in Section 2.3.5.2.2, because of the proximity of the MSSVs/10% ADVs to the control room normal intake of the affected unit, and because the releases from the MSSVs/10% ADVs have a vertically upward discharge, it is expected that the concentrations near the normal operation control room intake of the affected unit (closest to the release point) will be insignificant. Therefore, prior to switchover to

CRVS Mode 4 pressurization, only the unaffected unit's control room normal intake is assumed to be contaminated by releases from the MSSVs/10% ADVs.

The bounding atmospheric dispersion factors applicable to the radioactivity release points / control room receptors applicable to a SGTR at either unit are provided in Table 15.5-64B. The χ/Q values presented in Table 15.5-64B take into consideration the various release points-receptors applicable to the SGTR to identify the bounding χ/Q values applicable to a SGTR at either unit, and reflect the allowable adjustments / reductions in the values as discussed in Chapter 2.3.5.2.2 and summarized in the notes of Tables 2.3-147 and 2.3-148.

The bounding control room dose following a SGTR at either unit is presented in Table 15.5-64.

15.5.20.3 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) The radiation dose to an individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release is within 0.25 Sv (25 rem) TEDE for a pre-existing accident iodine spike case and 10% of the 10 CFR 50.67 limit for the accident initiated iodine spike case as shown in Table 15.5-64.

(2) The radiation dose to an individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), is within 0.25 Sv (25 rem) TEDE for a pre-existing accident iodine spike case and 10% of the 10 CFR 50.67 limit for the accident initiated iodine spike case as shown in Table 15.5-64.

(3) The radiation dose to an individual in the control room for the duration of the accident is within 0.05 Sv (5 rem) TEDE as shown in Table 15.5-64.

(4) In accordance with the current licensing basis, the TSC design has been evaluated for the LOCA. The dose consequences in the TSC due to airborne radioactivity releases from the SGTR is bounded by the dose reported for the LOCA in Section 15.5.17. The atmospheric dispersion factors applicable to the TSC are presented in Table 15.5-83.

15.5.21 RADIOLOGICAL CONSEQUENCES OF A LOCKED ROTOR ACCIDENT

15.5.21.1 Acceptance Criteria

The radiological consequences of a LRA shall not exceed the dose limits of 10 CFR 50.67, and will meet the dose acceptance criteria of Regulatory Guide 1.183, July 2000 and outlined below:

EAB and LPZ Dose Criteria

(1) An individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release shall not receive a radiation dose in excess of 0.025 Sv (2.5 rem) TEDE.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose in excess of 0.025 Sv (2.5 rem) TEDE.

Control Room Dose Criteria

(3) Adequate radiation protection is provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) TEDE for the duration of the accident.

Technical Support Center Dose Criteria

(4) The acceptance criteria for the TSC dose is based on Section 8.2.1(f) of NUREG-0737, Supplement 1, Regulatory Guide 1.183, Section 1.2.1, and 10 CFR 50.67. The dose to an operator in the TSC should not exceed 5 rem TEDE for the duration of the accident.

15.5.21.2 Identification of Causes and Accident Description

15.5.21.2.1 Activity Release Pathways

This event is caused by an instantaneous seizure of a primary reactor coolant pump (RCP) rotor. Flow through the affected loop is rapidly reduced, causing a reactor trip due to a low primary loop flow signal. Fuel damage is predicted to occur as a result of this accident. Due to the pressure differential between the primary and secondary systems and assumed SG tube leakage, fission products are discharged from the primary into the secondary system. A portion of this radioactivity is released to the outside atmosphere from the secondary coolant system via the 10% ADVs and MSSVs. Following reactor trip, and based on an assumption of a LOOP coincident with reactor trip, the condenser is assumed to be unavailable and reactor cooldown is achieved

using steam releases from the SG MSSVs and 10% ADVs until initiation of shutdown cooling. DCPP has established that the LOL event generates the maximum primary to secondary heat transfer and the LRA assumes these same conservatively bounding secondary steam releases.

Regulatory guidance provided for the LRA in pertinent sections of Regulatory Guide 1.183 including Appendix G is used to develop the dose consequence model.

The LRA is postulated to result in 10% fuel failure resulting in the release of the associated gap activity. As discussed in Section 15.5.3.1.3, the core gap activity is assumed to be comprised of 8% of the core I-131 inventory, 23% of the core I-132 inventory, 35% of the core Kr-85 inventory, 4% of the remaining core noble gas inventory, 5% of the remaining core halogen inventory, and 46% of the core alkali metal (Cesium and Rubidium) inventory. Table 15.5-42A lists the key assumptions / parameters utilized to develop the radiological consequences following a LRA.

Computer code RADTRAD 3.03, is used to calculate the control room and site boundary dose due to airborne radioactivity releases following a LRA.

15.5.21.2.2 Activity Release Transport Model

In accordance with Regulatory Guide 1.183, the activity released from the fuel is assumed to be released instantaneously and mixed homogenously through the primary coolant mass and transmitted to the secondary side via primary to secondary SG tube leakage. A radial peaking factor of 1.65 is applied to the activity release from the fuel gap. The activity associated with the release of the primary to secondary leakage of normal operation RCS, (at Technical Specification levels) via the MSSVs/10% ADVs are insignificant compared to the failed fuel release and are therefore not included in this assessment.

DCPP Plant Technical Specification 3.4.13d limits primary to secondary SG tube leakage to 150 gpd per steam generator for a total of 600 gpd in all 4 SGs. To accommodate any potential accident induced leakage, the LRA dose consequence analysis addresses a limit of 0.75 gpm from all 4 SGs (or a total of 1080 gpd).

The chemical form of the iodines in the gap are assumed to be 95% particulate (CsI), 4.85% elemental and 0.15% organic. The effect of SG tube uncovery in intact SGs (for SGTR and non-SGTR events), has been evaluated for potential impact on dose consequences as part of a Westinghouse Owners Group (WOG) Program and demonstrated to be insignificant; therefore, the gap iodines are assumed to have a partition coefficient of 100 in the SG. The iodine releases to the environment from the SG are assumed to be 97% elemental and 3% organic. The gap noble gases are released freely to the environment without retention in the SG whereas theparticulates are assumed to be carried over in accordance with the design basis SG moisture carryover fraction.

The condenser is assumed unavailable due to the loss of offsite power. Consequently, the radioactivity release resulting from a LRA is discharged to the environment from all steam generators via the MSSVs and the 10% ADVs. The SG releases continue for 10.73 hours, at which time shutdown cooling is initiated via operation of the RHR system and environmental releases are terminated.

15.5.21.2.3 Offsite Dose Assessment

AST methodology requires that the worst case dose to an individual located at any point on the boundary at the EAB, for any 2-hr period following the onset of the accident be reported as the EAB dose. For the LRA, the worst two hour period can occur either during the 0-2 hr period when the noble gas release rate is the highest, or during the t=8.73 hr to 10.73 hr period when the iodine and particulate level in the SG liquid peaks (SG releases are terminated at T=10.73 hrs). Regardless of the starting point of the worst 2 hr window, the 0-2 hr EAB χ/Q is utilized.

The bounding EAB and LPZ dose following a LRA at either unit is presented in Table 15.5-42.

15.5.21.2.4 Control Room Dose Assessment

The parameter values utilized for the control room in the accident dose transport model are discussed in Section 15.5.9. Provided below are the critical LRA-specific assumptions associated with control room response and activity transport.

<u>Timing for Initiation of CRVS Mode 4 (if applicable)</u>:

The LRA does not initiate any signal which could automatically start the control room emergency ventilation. Thus, the dose consequence analysis for the LRA assumes that the control room remains in normal operation mode.

<u>Control Room Atmospheric Dispersion Factors</u>

As noted in Section 2.3.5.2.2, because of the proximity of the MSSV/10% ADVs to the control room normal intake of the affected unit and because the releases from the MSSVs/10% ADVs have a vertically upward discharge, it is expected that the concentrations near the normal operation control room intake of the faulted unit (closest to the release point) will be insignificant. Therefore, only the unaffected unit's control room normal intake is assumed to be contaminated by a release from the MSSVs/10% ADVs.

The bounding atmospheric dispersion factors applicable to the radioactivity release points / control room receptors applicable to an LRA at either unit are provided in Table 15.5-42B. The χ/Q values presented in Table 15.5-42B take into consideration the various release points-receptors applicable to the LRA to identify the bounding χ/Q values applicable to a LRA at either unit, and reflect the allowable adjustments /

reductions in the values as discussed in Section 2.3.5.2.2 and summarized in the notes of Tables 2.3-147 and 2.3-148.

The bounding control room dose following a LRA at either unit is presented in Table 15.5-42.

15.5.21.3 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) The radiation dose to an individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release is within 0.025 Sv (2.5 rem) TEDE as shown in Table 15.5-42.

(2) The radiation dose to an individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), is within 0.025 Sv (2.5 rem) TEDE as shown in Table 15.5- 42.

(3) The radiation dose to an individual in the control room for the duration of the accident is within 0.05 Sv (5 rem) TEDE as shown in Table 15.5-42.

(4) In accordance with the current licensing basis, the TSC design has been evaluated for the LOCA. The dose consequences in the TSC due to airborne radioactivity releases from the LRA is bounded by the dose reported for the LOCA in Section 15.5.17. The atmospheric dispersion factors applicable to the TSC are presented in Table 15.5-83.

15.5.22 RADIOLOGICAL CONSEQUENCES OF A FUEL HANDLING ACCIDENT

The procedures used in handling fuel in the containment and fuel handling area are described in detail in Section 15.4.5. In addition, design and procedural measures provided to prevent FHAs are also described in that section, along with a discussion of past experience in fuel handling operations. The basic events that could be involved in a FHA are discussed in that section, and the following discussion evaluates the potential radiological consequences of such an accident.

The assumption of a LOOP related to a postulated design basis accident which leads to a reactor trip does not directly correlate to an FHA. Specifically, a FHA does not directly cause a reactor trip and a subsequent LOOP due to grid instability; nor can a LOOP be the initiator of a FHA. Thus, the FHA dose consequence analyses are evaluated without the assumption of a LOOP.

15.5.22.1 Acceptance Criteria

The radiological consequences of a FHA in the Fuel Handling Building (FHB) or in the Containment shall not exceed the dose limits of 10 CFR 50.67, as modified by Regulatory Guide 1.183, July 2000 and outlined below:

EAB and LPZ Dose Criteria

(1) An individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release shall not receive a radiation dose in excess of 0.063 Sv (6.3 rem) TEDE.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose in excess of 0.063 Sv (6.3 rem) TEDE.

Control Room Dose Criteria (10 CFR 50.67)

(3) Adequate radiation protection is provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) TEDE for the duration of the accident.

Technical Support Center Dose Criteria

(4) The acceptance criteria for the TSC dose is based on Section 8.2.1(f) of NUREG-0737, Supplement 1, Regulatory Guide 1.183, Section 1.2.1, and 10 CFR 50.67. The dose to an operator in the TSC should not exceed 5 rem TEDE for the duration of the accident.

15.5.22.2 Identification of Causes and Accident Description

15.5.22.2.1 Activity Release Pathways

This event postulates that a spent fuel assembly is dropped during refueling in the Spent Fuel Pool (SFP) located in the FHB, or in the reactor cavity located in the Containment. All of the fuel rods (264 rods) in the dropped fuel assembly are assumed to be damaged; thus, all of the activity in the fuel gap of the dropped assembly is assumed to be instantaneously released into the SFP or into the reactor cavity. As documented in the NRC SER for Amendments 8 and 6 to DCPP Facility Operating License Nos. DPR 80 and DPR-82, respectively (Reference 87), the assumption that all fuel rods in one assembly rupture is conservative because the kinetic energy available for causing damage to a fuel assembly dropped through water is fixed by the drop distance. The kinetic energy associated with the maximum drop height for a fuel

handling accident is not considered sufficient to rupture the equivalent number of fuel rods of one assembly in both the dropped assembly and the impacted assembly.

During fuel handling operations, containment closure is not required. Generally, the containment ventilation purge system is operational and exhausts air from the containment through two 48-inch containment isolation valves. These two valves are connected in series. This flow of air from the containment is discharged to the environment via the plant vent.

This exhaust stream is monitored for activity by monitors in the plant vent. In the event of a postulated fuel handling accident, the plant vent monitors will alarm and result in the automatic closure of containment ventilation isolation valves. This activity release may result in offsite radiological exposures.

In addition to radiation monitor indications, a fuel handling accident would immediately be known to refueling personnel at the scene of the accident. These personnel would initiate containment closure actions and are required by an Equipment Control Guideline to be in constant communication with control room personnel.

Containment penetrations are allowed to be open during fuel handling operations. The most prominent of these penetrations are the equipment hatch and the personnel airlock. Closure of these penetrations is achieved by manual means as discussed in Section 15.4.5. The closure of these penetrations is not credited in the design-basis fuel handling accident inside containment.

Following manual containment closure after the fuel handling accident, activity can be removed from the containment atmosphere by the redundant PG&E Design Class II Iodine Removal System (two trains at 12,000 cfm per train), which consists of HEPA/charcoal filters. This system is described in Section 9.4.5. There are no Technical Specification requirements for this filtration system.

The containment can also be purged to the atmosphere at a controlled rate of up to 300 cfm per train through the HEPA/charcoal filters of the hydrogen purge system. This system is described in Section 6.2.5.

In the very unlikely event of a serious FHA and in combination with the conservative assumptions discussed above, containment building or fuel handling area activity concentrations may be quite high. High activity concentrations necessitate the evacuation of fuel handling areas in order to limit exposures to fuel handling personnel. Upon indication of a serious FHA, the fuel handling area will be evacuated until the extent of the fuel damage and activity levels in the area can be determined. Any serious FHA would be both visually and audibly detectable via radiation monitors in the fuel handling areas that locally alarm in the event of high activity levels and would alert personnel to evacuate.

The fuel handling area has the additional safety feature of ventilation air flow that sweeps the surface of the spent fuel pool carrying any activity away from fuel handling personnel. This sweeping of the spent fuel pool is expected to considerably lower activity levels in the fuel handling area in the event of a serious FHA.

Spent fuel cask accidents in the fuel handling area causing fuel damage are precluded due to crane travel limits and design and operating features as described in Sections 9.1.4.3.9 and 9.1.4.2.6. Spent FHAs in the fuel handling area would not jeopardize the health and safety of the public.

The FHA dose assessment follows the guidance provided for the FHA in pertinent sections of Regulatory Guide 1.183 including Appendix B. As discussed in Section 15.5.3.1.3, the core gap activity is assumed to be comprised of 8% of the core I-131 inventory, 23% of the core I-132 inventory, 35% of the core Kr-85 inventory, 4% of the remaining core noble gas inventory, 5% of the remaining core halogen inventory and halogen isotopes, and 46% of the core alkali metal (Cesium and Rubidium) inventory. Table 15.5-47A lists the key assumptions / parameters utilized to develop the radiological consequences following an FHA at either location and at either unit.

DCPP procedures prohibit movement of recently irradiated fuel which is defined as fuel that has occupied part of a critical reactor core within the previous 100 hours. Table 15.5-47C provides the gap activity inventory of the noble gases, iodines, and alkali metals in a single fuel assembly at 72 hrs post reactor shutdown. This inventory conservatively bounds that associated with the 100-hour procedural fuel restriction for movement.

DCPP Technical Specification 3.7.15 requires the SFP water level to be ≥23 feet over the top of irradiated fuel assemblies seated in the storage racks. Technical Specification 3.9.7 requires the refueling cavity water level to be maintained ≥23 feet above the top of the reactor vessel flange. Additional margin is provided through operating procedures.

Computer code RADTRAD 3.03, is used to calculate the control room and site boundary dose due to airborne radioactivity releases following a FHA.

15.5.22.2.2 Activity Release Transport Model

The fission product inventory in the fuel rod gap of all the rods in the damaged assembly are assumed to be instantaneously released into the spent fuel pool or reactor cavity, both of which have a minimum of 23 ft of water above the damaged fuel assembly. A radial peaking factor of 1.65 is applied to the activity release.

Per Regulatory Guide 1.183, the radioiodine released from the fuel gap is assumed to be 95% particulate (CsI), 4.85% elemental, and 0.15% organic. Due to the acidic nature of the water in the fuel pool (pH less than 7), the CsI is assumed to immediately disassociate and re-evolve as elemental iodine; thus, changing the chemical form of iodine to 99.85% elemental and 0.15% organic. In addition, and per Regulatory

Guide 1.183, an iodine decontamination factor of 200 is assumed for the SFP / reactor cavity. Noble gases and unscrubbed iodines rise to the water surface where they are mixed in the available air space. All of the alkali metals released from the gap are retained in the pool. In accordance with Regulatory Guide 1.183, the chemical form of the iodines above the pool is 57% elemental and 43% organic.

Per Regulatory Guide 1.183, the activity released due to an FHA is assumed to be discharged to the environment in a period of 2 hrs (or less if the ventilation system promotes a faster release rate).

FHA in the FHB

The radioactivity release pathways following an FHA in the FHB are established taking into consideration the following Administration Controls:

During fuel movement in the FHB:

a. The movable wall is put in place and secured
b. No exit door is propped open
c. One FHBVS exhaust fan is operating (The supply fan flow (if operating) has been confirmed by design to have less flow than the exhaust fan)

Operation of the Fuel Handling Building Ventilation system (FHBVS) with a minimum of 1 exhaust fan operating and all significant openings administratively closed will ensure negative pressure in the FHB which will result in post-accident environmental release of radioactivity occurring via the Plant Vent. The activity release due to the FHA in the FHB is assumed to be discharged to the environment as follows:

a. A maximum release rate of 46,000 cfm via the Plant Vent due to operation of the FHBVS with a closed FHB configuration.

b. A maximum conservatively assumed outleakage of 500 cfm occurring from the closest edge of the FHB to the control room normal intake (i.e., 30 cfm outleakage is assumed for egress-ingress; 470 cfm is assumed for outleakage from miscellaneous gaps/openings in the FHB structure).

It has been determined that for the FHA in the FHB, the actual release rate lambda based on the FHBVS exhaust (i.e., 8.7 hr-1) is larger than the release rate applicable to “a 2-hr release” per Regulatory Guide 1.183 (i.e., 3.45 hr-1). Thus, the larger exhaust rate lambda associated with FHBVS operation plus the exhaust rate lambda for the 500 cfm outleakage is utilized in the analysis.

FHA in the Containment

The potential radioactivity release pathways following a FHA in the containment are established taking into consideration

a. Operation of the containment purge system which would result in radioactivity release via the plant vent

b. Plant Technical Specification Section 3.9.4 that allows for an “open containment” during fuel movement in containment during offload or reload. The most significant containment opening closest to the Control room normal operation intake is the equipment hatch. The equipment hatch is an approximately 20-ft wide circular opening in containment. In the event the containment purge system ceased to operate (a viable scenario since it is single train and has non-vital power), the density driven convective flow out of the equipment hatch (due to the thermal gradient between inside and outside containment conditions), could be significant.

It has been determined that for the FHA in the Containment, the release rate assuming a regulatory based 2 hr release is larger than that dictated by the containment purge ventilation system, or convective flow out of the equipment hatch. Thus, the regulatory based release rate (i.e., 3.45 hr-1), is utilized for this analysis. Review of the atmospheric dispersion factors associated with the plant vent vs the equipment hatch indicates that dose consequences due to releases via the equipment hatch will be bounding.

15.5.22.2.3 Offsite Dose Assessment

AST methodology requires that the worst case dose to an individual located at any point on the boundary at the EAB, for any 2-hr period following the onset of the accident be reported as the EAB dose. Since the FHA is based on a 2-hour release, the worst 2-hour period for the EAB is the 0 to 2-hour period.

The bounding EAB and LPZ dose following a FHA at either location and at either unit is presented in Table 15.5-47.

15.5.22.2.4 Control Room Dose Assessment

The parameter values utilized for the control room in the accident dose transport model are discussed in Section 15.5.9. Provided below are the critical FHA-specific assumptions associated with control room response and activity transport.

<u>Design Basis FHA (occurs at t=72 hours after reactor shutdown, which is conservative)</u>

Credit is taken for PG&E Design Class I area radiation monitors located at the control room normal intakes (1-RE-25/26, 2-RE-25/26) to initiate CRVS Mode 4 (filtered / pressurized accident ventilation) upon detection of high radiation levels at the control room normal intakes as a result of an FHA.

An analytical safety limit of 1 mR/hr for the gamma radiation environment at the control room normal operation air intakes has been used in the FHA analyses to initiate CRVS

Mode 4. Note that the actual monitor trip setpoint is lower to include the instrument loop uncertainty.

The radiation monitor response time is primarily dependent on the type of monitor, the setpoint, the background radiation levels and the magnitude of increase in the radiation environment at the detector location.

For a monitor with an instrument time constant of "τ" (2 seconds) and a background of 0.05 mR/hr, the response time "t" to a high alarm Setpoint (HASP < 1 mr/hr), for a step increase of radiation level DR (mR/hr) is determined by solving the following equation that represents the monitor reading approaching the final reading exponentially.

$$HASP = 0.05 + DR(1 - e^{-\frac{t}{\tau}}) \qquad (15.5\text{-}5)$$

It is determined that a DBA FHA (i.e., occurs at 72 hrs post shutdown) will result in a radiation environment at the control room normal operation intakes that greatly exceed the analytical limit of 1 mR/hr for initiating CRVS Mode 4. This will result in an almost instantaneous generation of a radiation monitor signal to initiate CRVS Mode 4 (radiation monitor response time is estimated to be < 1 sec). For purposes of conservatism, and since the delay in isolation of the normal intake has a significant impact on the estimated dose consequences, the analysis conservatively assumes a monitor response time to the HASP of 20 secs.

As discussed in Section 15.5.1.2, when crediting CRVS Mode 4, the FHA dose consequence analyses is not required to address the potential effects of a LOOP. Thus, delays associated with diesel generator sequencing are not addressed.

Therefore, the time delay between the arrival of radioactivity released due to a DBA FHA at both the control room normal Intakes (assumed to be instantaneous) and CRVS Mode 4 operation is estimated to be the sum total of the monitor response time (20 secs), the signal processing time (2 secs) and the damper closure time (10 secs) for a total delay of 32 seconds.

<u>Delayed FHA:</u>

It is recognized that the response time for radiation monitors are dependent on the magnitude of the radiation level / energy spectrum of the airborne cloud at the location of the detectors, which in turn are dependent on the fuel assembly decay time. Thus, an additional case is considered for each of the two FHA scenarios described above (i.e., a FHA in the FHB and a FHA in Containment) when determining the dose to the control room operator; i.e., a case that reflects a delayed FHA at Fuel Offload or a FHA during Reload, occurring at a time when the fuel has decayed to such an extent that the radiation environment at the control room normal intake radiation monitors is just below

the setpoint; thus, the control room remains in normal operation mode and CRVS Mode 4 is not initiated.

The analyses determined that the dose consequences of a DBA FHA bound that associated with the delayed FHA for both the FHA in the FHB and the FHA in the containment.

The bounding atmospheric dispersion factors applicable to the radioactivity release points / control room receptors applicable to an FHA at either location, and at either unit, are provided in Table 15.5-47B. The χ/Q values presented in Table 15.5-47B take into consideration the various release points-receptors applicable to the FHA to identify the bounding χ/Q values applicable to a FHA at either unit and at either location, and reflect the allowable adjustments / reductions in the values as discussed in Section 2.3.5.2.2 and summarized in the notes of Tables 2.3-147 and 2.3-148.

The bounding control room dose following a FHA at either location and at either unit is presented in Table 15.5-47.

15.5.22.3 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) The radiation dose to an individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release is within 0.063 Sv (6.3 rem) TEDE as shown in Table 15.5-47.

(2) The radiation dose to an individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), is within 0.063 Sv (6.3 rem) TEDE as shown in Table 15.5- 47.

(3) The radiation dose to an individual in the control room for the duration of the accident is within 0.05 Sv (5 rem) TEDE as shown in Table 15.5-47.

(4) In accordance with the current licensing basis, the TSC design has been evaluated for the LOCA. The dose consequences in the TSC due to airborne radioactivity releases from the FHA is bounded by the dose reported for the LOCA in Section 15.5.17. The atmospheric dispersion factors applicable to the TSC are presented in Table 15.5-83.

15.5.23 RADIOLOGICAL CONSEQUENCES OF A CONTROL ROD EJECTION ACCIDENT

15.5.23.1 Acceptance Criteria

The radiological consequences of a CREA shall not exceed the dose limits of 10 CFR 50.67, and will meet the dose acceptance criteria of Regulatory Guide 1.183, July 2000 and outlined below:

<u>EAB and LPZ Dose Criteria</u>

(1) An individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release shall not receive a radiation dose in excess of 0.063 Sv (6.3 rem) TEDE.

(2) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), shall not receive a total radiation dose in excess of 0.063 Sv (6.3 rem) TEDE.

<u>Control Room Dose Criteria</u>

(3) Adequate radiation protection is provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) TEDE for the duration of the accident.

<u>Technical Support Center Dose Criteria</u>

(4) The acceptance criteria for the TSC dose is based on Section 8.2.1(f) of NUREG-0737, Supplement 1, Regulatory Guide 1.183, Section 1.2.1, and 10 CFR 50.67. The dose to an operator in the TSC should not exceed 5 rem TEDE for the duration of the accident.

15.5.23.2 Identification of Causes and Accident Description

As discussed in Section 15.4.6, this event consists of an uncontrolled withdrawal of a control rod from the reactor core. The CREA results in reactivity insertion that leads to a core power level increase, and under adverse combinations of circumstances, fuel failure, and a subsequent reactor trip. In this case, some of the activity in the fuel rod gaps would be released to the coolant and in turn to the inside of the containment building. As a result of pressurization of the containment, some of this activity could leak to the environment.

Following reactor trip, and based on an assumption of a Loss of Offsite Power coincident with reactor trip, the condenser is assumed to be unavailable and reactor

cooldown is achieved using steam releases from the SG MSSVs and 10% ADVs until initiation of shutdown cooling. DCPP has established that the LOL event generates the maximum primary to secondary heat transfer and the CREA assumes these same conservatively bounding secondary steam releases.

Regulatory guidance provided for the CREA in pertinent sections of Regulatory Guide 1.183 including Appendix H is used to develop the dose consequence model. Table 15.5-52A lists the key assumptions / parameters utilized to develop the radiological consequences following a CREA.

The CREA is postulated to result in 10% fuel failure resulting in the release of the associated gap activity. Per Regulatory Guide 1.183, the core gap activity is assumed to be comprised of 10% of the core noble gases and halogens. A radial peaking factor of 1.65 is applied to the activity release from the fuel gap.

In accordance with the guidance provided in Regulatory Guide 1.183, two independent release paths to the environment are analyzed: first, via containment leakage of the fission products released due to the event from the primary system to containment, assuming that the containment pathway is the only one available; and second, via releases from the secondary system, outside containment, following primary-to-secondary leakage in the steam generators, assuming that the latter pathway is the only one available.

The actual doses resulting from a postulated CREA would be a composite of doses resulting from portions of the release going out via the containment building and, portions via the secondary system. If regulatory compliance to dose limits can be demonstrated for each of the scenarios, the dose consequence of a scenario that is a combination of the two will be encompassed by the more restrictive of the two analyzed scenarios.

Computer code RADTRAD 3.03, is used to calculate the control room and site boundary dose due to airborne radioactivity releases following a CREA.

15.5.23.2.1 Activity Release Transport Model

The CREA dose consequence analysis evaluates the following two scenarios.

Scenario 1: The failed fuel resulting from a postulated CREA is released into the RCS, which is released in its entirety into the containment via the faulted control rod drive mechanism housing, is mixed in the free volume of the containment, and then released to the environment at the containment technical specification leak rate for the first 24 hrs and at half that value for the remaining 29 days.

Scenario 2: The failed fuel resulting from a postulated CREA is released into the RCS which is then transmitted to the secondary side via steam generator tube leakage. The condenser is assumed to be unavailable due to a loss of offsite power. Environmental

releases occur from the steam generators via the MSSVs and 10% ADVs.

The chemical composition of the iodine in the gap is assumed to be 95% particulate (CsI), 4.85% elemental and 0.15% organic. However, because the sump pH is not controlled following a CREA, it is conservatively assumed that the iodine released via the containment leakage pathway has the same composition as the iodine released via the secondary system release pathway; i.e.; it is assumed that for both scenarios, 97% of all halogens available for release to the environment are elemental, while the remaining 3% is organic.

Scenario 1: Transport From Containment

The failed fuel activity released due to a CREA into the RCS is assumed to be instantaneously released into the containment where it mixes homogeneously in the containment free volume. The containment is assumed to leak at the technical specification leak rate of 0.10% per day for the first 24 hours and at half that value for the remaining 29 days after the event. Except for decay, no credit is taken for depleting the halogen or noble gas concentrations airborne in the containment. Per Regulatory Guide 1.183, the chemical composition of the iodine in the gap fuel is 95% particulate (CsI), 4.85% elemental and 0.15% organic. However, since no credit is taken for the actuation of sprays or pH control, the iodine released via containment leakage pathway is assumed to have the same composition as iodine activity released to the environment from the secondary coolant; i.e.; 97% elemental and 3% organic. Environmental releases due to containment leakage can occur unfiltered as a diffuse source from the containment wall, and as a point source via the containment penetration areas or the Plant Vent. The dose consequences are estimated based on the worst case atmospheric dispersion factors, i.e., an assumed environmental release via the containment penetration areas.

Scenario 2: Transport from Secondary System

The failed fuel activity released due to a CREA into the RCS is assumed to be instantaneously and homogeneously mixed in the reactor coolant system and transmitted to the secondary side via primary to secondary SG tube leakage. The activity associated with the release of the initial inventory in secondary steam/liquid, and primary to secondary leakage of normal operation RCS, (both at Technical Specification levels) via the MSSVs/10% ADVs are insignificant compared to the failed fuel release, and are therefore not included in this assessment.

DCPP Plant Technical Specification 3.4.13d limits primary to secondary SG tube leakage to 150 gpd per steam generator for a total of 600 gpd in all 4 SGs. To accommodate any potential accident induced leakage, the CREA dose consequence analysis addresses a limit of 0.75 gpm from all 4 SGs (or a total of 1080 gpd).

The effect of SG tube uncovery in intact SGs (for SGTR and non-SGTR events), has been evaluated for potential impact on dose consequences as part of a WOG Program

and demonstrated to be insignificant; therefore, the gap iodines have a partition coefficient of 100 in the SG. The gap noble gases are released freely to the environment without retention in the SG.

The condenser is assumed unavailable due to the loss of offsite power. Consequently, the radioactivity release resulting from a CREA is discharged to the environment from steam generators via the MSSVs and the 10% ADVs. Per Regulatory Guide 1.183, 97% of all halogens available for release to the environment via the Secondary System are elemental, while the remaining 3% are organic. The SG releases continue until shutdown cooling is initiated via operation of the RHR system (10.73 hours after the accident) and environmental releases are terminated.

15.5.23.2.2 Offsite Dose Assessment

AST methodology requires that the worst case dose to an individual located at any point on the boundary at the EAB, for any 2-hr period following the onset of the accident be reported as the EAB dose. For Scenario 1 (release via Containment leakage), the worst case 2-hour period occurs during the first 2 hours). For Scenario 2 (release via secondary side), the worst two hour period can occur either during the 0-2 hr period when the noble gas release rate is the highest, or during the t=8.73 hr to 10.73 hr period when the iodine and particulate level in the SG liquid peaks (SG releases are terminated at T=10.73 hrs). Regardless of the starting point of the worst 2 hr window, the 0-2 hr EAB χ/Q is utilized.

The bounding EAB and LPZ dose following a CREA at either unit for both scenarios are presented in Table 15.5-52.

15.5.23.2.4 Control Room Dose Assessment

The parameter values utilized for the control room in the accident dose transport model are discussed in Section 15.5.9. Provided below are the critical CREA-specific assumptions associated with control room response and activity transport.

<u>Timing for Initiation of CRVS Mode 4</u>:

The time to generate a signal to switch CRVS operation from Mode 1 to Mode 4 is based on the containment pressure response following a 2 inch small-break LOCA (SBLOCA), and the fact that at DCPP, a Containment High Pressure signal will initiate a SIS which will automatically initiate CRVS Mode 4 pressurization. The containment pressure response analysis for a 2 inch SBLOCA shows that the 5 psig setpoint for Containment High Pressure is reached in 150 seconds after the SBLOCA. As indicated earlier, releases to the containment following a CREA are through a faulted control rod drive mechanism housing. The control rod shaft diameter is 1.840 inches and the RCCA housing penetration opening is 4 inches in diameter. Based on the above and for the purposes of conservatism, the time to generate the Containment High Pressure SIS following a CREA is assumed to be double the value applicable to the 2 inch SBLOCA, or 300 seconds.

Based on the above, following a CREA,

a. An SIS will be generated at t = 300 sec following a CREA.
b. The CRVS normal intake dampers of the accident unit start to close after a 28.2 second delay due to delays associated with diesel generator loading onto the 4kv buses. The control room dampers are fully closed 10 secs later, or at t=338.2 secs (i.e., 300 + 28.2 + 10). The 2 second SIS processing time occurs in parallel with diesel generator sequencing and is therefore not included as part of the delay.
c. In accordance with DCPP licensing basis, the CRVS normal operation dampers of the non-accident unit are not affected by the LOOP and are isolated at t=312 secs (i.e., 300 + 2 secs signal processing time + 10 sec damper closure time).

Control Room Atmospheric Dispersion Factors:

As noted in Section 2.3.5.2.2, because of the proximity of the MSSV/10% ADVs to the control room normal intake of the affected unit and because the releases from the MSSVs/10% ADVs have a vertically upward discharge, it is expected that the concentrations near the normal operation control room intake of the faulted unit (closest to the release point) will be insignificant. Therefore, prior to switchover to CRVS Mode 4 pressurization, only the unaffected unit's control room normal intake is assumed to be contaminated by a release from the MSSVs/10% ADVs.

The bounding atmospheric dispersion factors applicable to the radioactivity release points / control room receptors applicable to a CREA at either unit are provided in Table 15.5-52B. The χ/Q values presented in Table 15.5-52B take into consideration the various release points-receptors applicable to the CREA to identify the bounding χ/Q values applicable to a CREA at either unit, and reflect the allowable adjustments / reductions in the values as discussed in Chapter 2.3.5.2.2 and summarized in the notes of Tables 2.3-147 and 2.3-148.

The bounding control room dose following a CREA at either unit is presented in Table 15.5-52.

15.5.23.3 Conclusions

The analysis demonstrates that the acceptance criteria are met as follows:

(1) The radiation dose to an individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release is within 0.063 Sv (6.3 rem) TEDE as shown in Table 15.5-52.

(2) The radiation dose to an individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting

from the postulated fission product release (during the entire period of its passage), is within 0.063 Sv (6.3 rem) TEDE as shown in Table 15.5- 52.

(3) The radiation dose to an individual in the control room for the duration of the accident is within 0.05 Sv (5 rem) TEDE as shown in Table 15.5-52.

(4) In accordance with the current licensing basis, the TSC design has been evaluated for the LOCA. The dose consequences in the TSC due to airborne radioactivity releases from the CREA is bounded by the dose reported for the LOCA in Section 15.5.17. The atmospheric dispersion factors applicable to the TSC are presented in Table 15.5-83.

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TABLE 15.0-1

REGULATORY GUIDE 1.70 REVISION 1, APPLICABILITY MATRIX

Event	REG GUIDE 1.70, TABLE 15-1, REPRESENTATIVE TYPES OF EVENTS TO BE ANALYZED IN CHAPTER 15.0 OF THE SAR	15.2 Section	UFSAR SECTION 15.2 CONDITION II: FAULTS OF MODERATE FREQUENCY	15.3 Section	UFSAR SECTION 15.3 CONDITION III: INFREQUENT FAULTS	15.4 Section	UFSAR SECTION 15.4 CONDITION IV: LIMITING FAULTS	Location of Analyses or Reason Why Not Applicable
1	Uncontrolled control rod assembly withdrawal from a sub-critical condition (assuming the most unfavorable reactive conditions of the core and reactor coolant system), including control rod or temporary control device removal error during refueling.	15.2.1	UNCONTROLLED ROD CLUSTER CONTROL ASSEMBLY BANK WITHDRAWAL FROM A SUBCRITICAL CONDITION					
2	Uncontrolled control rod assembly withdrawal at the critical power (assuming the most unfavorable reactive conditions of the core and reactor coolant system) which yields the most severe results (hot at zero power, full power, etc).	15.2.2	UNCONTROLLED ROD CLUSTER CONTROL ASSEMBLY BANK WITHDRAWAL AT POWER					
3	Control rod misoperation or sequence of misoperations.	15.2.3	ROD CLUSTER CONTROL ASSEMBLY MISOPERATION					
4	Chemical and volume control system malfunction.	15.2.4	UNCONTROLLED BORON DILUTION					
5	Partial and total loss of reactor coolant flow force including trip of pumps and pump shaft seizures.	15.2.5	PARTIAL LOSS OF FORCED REACTOR COOLANT FLOW	15.3.4	COMPLETE LOSS OF FORCED REACTOR COOLANT FLOW			

TABLE 15.0-1

REGULATORY GUIDE 1.70 REVISION 1, APPLICABILITY MATRIX

Event	REG GUIDE 1.70, TABLE 15-1, REPRESENTATIVE TYPES OF EVENTS TO BE ANALYZED IN CHAPTER 15.0 OF THE SAR	15.2 Section	UFSAR SECTION 15.2 CONDITION II: FAULTS OF MODERATE FREQUENCY	15.3 Section	UFSAR SECTION 15.3 CONDITION III: INFREQUENT FAULTS	15.4 Section	UFSAR SECTION 15.4 CONDITION IV: LIMITING FAULTS	Location of Analyses or Reason Why Not Applicable
6	Start-up of an inactive reactor coolant loop or recirculating loop at incorrect temperature.	15.2.6	STARTUP OF AN INACTIVE REACTOR COOLANT LOOP					Precluded in Modes 1 and 2 due to Tech Spec 3.4.4
7	Loss of external electrical load and/or turbine stop valve closure, including, for BWRs closure of main steam isolation valve.	15.2.7	LOSS OF EXTERNAL ELECTRICAL LOAD AND/OR TURBINE TRIP					
8	Loss of normal and/or emergency feedwater flow.	15.2.8	LOSS OF NORMAL FEEDWATER					
9	Loss of all a-c power to the station auxiliaries (station blackout).	15.2.9	LOSS OF OFFSITE POWER TO THE STATION AUXILIARIES					Station Blackout is beyond design basis. Refer to UFSAR Section 8.3.1.6
10	Heat removal greater than heat generation due to (1) feedwater system malfunctions, (2) a pressure regulator failure, or inadvertent opening of a relief valve or safety valve, and (3) a regulating instrument failure.	15.2.10 15.2.12	EXCESSIVE HEAT REMOVAL DUE TO FEEDWATER SYSTEM MALFUNCTIONS EXCESSIVE LOAD INCREASE INCIDENT					Regarding (2) and (3): There are no pressure regulators or regulating instruments in the Westinghouse pressurized water reactor (PWR) design whose failure could cause heat removal greater than heat generation.

TABLE 15.0-1

REGULATORY GUIDE 1.70 REVISION 1, APPLICABILITY MATRIX

Event	REG GUIDE 1.70, TABLE 15-1, REPRESENTATIVE TYPES OF EVENTS TO BE ANALYZED IN CHAPTER 15.0 OF THE SAR	15.2 Section	UFSAR SECTION 15.2 CONDITION II: FAULTS OF MODERATE FREQUENCY	15.3 Section	UFSAR SECTION 15.3 CONDITION III: INFREQUENT FAULTS	15.4 Section	UFSAR SECTION 15.4 CONDITION IV: LIMITING FAULTS	Location of Analyses or Reason Why Not Applicable
11	Failure of the regulating instrumentation, causing for example, a power-coolant mismatch. Include reactor coolant flow controller failure resulting in increasing flow.	N/A	N/A	N/A	N/A	N/A	N/A	Reactor coolant flow controller is not a feature of the Westinghouse PWR design. Treatment of the performance of the reactivity controller in a number of accident conditions is offered in this chapter. (Chapter 15)

TABLE 15.0-1

REGULATORY GUIDE 1.70 REVISION 1, APPLICABILITY MATRIX

Event	REG GUIDE 1.70, TABLE 15-1, REPRESENTATIVE TYPES OF EVENTS TO BE ANALYZED IN CHAPTER 15.0 OF THE SAR	15.2 Section	UFSAR SECTION 15.2 CONDITION II: FAULTS OF MODERATE FREQUENCY	15.3 Section	UFSAR SECTION 15.3 CONDITION III: INFREQUENT FAULTS	15.4 Section	UFSAR SECTION 15.4 CONDITION IV: LIMITING FAULTS	Location of Analyses or Reason Why Not Applicable
12	Internal and external events such as major and minor fires, flood, storms or earthquakes.	N/A	N/A	N/A	N/A	N/A	N/A	Refer to the following Sections: 3.3 - Wind & Tornado Loadings 3.4 - Water level (flood) design 3.5 - Missile protection 3.7 - Seismic design 3.8 - Design of Class I structures 9.5.1 - Fire protection system

TABLE 15.0-1

REGULATORY GUIDE 1.70 REVISION 1, APPLICABILITY MATRIX

Event	REG GUIDE 1.70, TABLE 15-1, REPRESENTATIVE TYPES OF EVENTS TO BE ANALYZED IN CHAPTER 15.0 OF THE SAR	15.2 Section	UFSAR SECTION 15.2 CONDITION II: FAULTS OF MODERATE FREQUENCY	15.3 Section	UFSAR SECTION 15.3 CONDITION III: INFREQUENT FAULTS	15.4 Section	UFSAR SECTION 15.4 CONDITION IV: LIMITING FAULTS	Location of Analyses or Reason Why Not Applicable
13	Loss of coolant accidents resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary and relief and safety valve blowdowns.	15.2.13	ACCIDENTAL DEPRESSURIZATION OF THE REACTOR COOLANT SYSTEM	15.3.1	LOSS OF REACTOR COOLANT FROM SMALL RUPTURED PIPES OR FROM CRACKS IN LARGE PIPES THAT ACTUATE EMERGENCY CORE COOLING SYSTEM	15.4.1	MAJOR REACTOR COOLANT SYSTEM PIPE RUPTURES (LOCA)	
14	Spectrum of postulated steam and feedwater system piping breaks inside and outside containment.	15.2.14	ACCIDENTAL DEPRESSURIZATION OF THE MAIN STEAM SYSTEM	15.3.2	MINOR SECONDARY SYSTEM PIPE BREAKS	15.4.2	MAJOR SECONDARY SYSTEM PIPE RUPTURE	
15	Inadvertent loading and operation of a fuel assembly into an improper position.			15.3.3	INADVERTENT LOADING OF A FUEL ASSEMBLY INTO AN IMPROPER POSITION			
16	Waste gas decay tank leakage or rupture.					N/A	Refer to Section 11.3.3	
17	Failure of air ejector lines (BWR).	N/A	N/A	N/A	N/A	N/A	N/A	This applies to BWR plants only
18	Steam generator tube rupture (PWR).					15.4.3	STEAM GENERATOR TUBE RUPTURE (SGTR)	
19	Failure of charcoal or cryogenic system (BWR).	N/A	N/A	N/A	N/A	N/A	N/A	This applies to BWR plants only

TABLE 15.0-1

REGULATORY GUIDE 1.70 REVISION 1, APPLICABILITY MATRIX

Event	REG GUIDE 1.70, TABLE 15-1, REPRESENTATIVE TYPES OF EVENTS TO BE ANALYZED IN CHAPTER 15.0 OF THE SAR	15.2 Section	UFSAR SECTION 15.2 CONDITION II: FAULTS OF MODERATE FREQUENCY	15.3 Section	UFSAR SECTION 15.3 CONDITION III: INFREQUENT FAULTS	15.4 Section	UFSAR SECTION 15.4 CONDITION IV: LIMITING FAULTS	Location of Analyses or Reason Why Not Applicable
20	The spectrum of rod ejection accidents (PWR).					15.4.6	RUPTURE OF A CONTROL ROD DRIVE MECHANISM HOUSING (ROD CLUSTER CONTROL ASSEMBLY EJECTION)	
21	The spectrum of rod drop accidents (BWR).	N/A	N/A	N/A	N/A	N/A	N/A	This applies to BWR plants only
22	Break in instrument line or other lines from reactor coolant pressure boundary that penetrate containment.	N/A	N/A	N/A	N/A	N/A	N/A	No instrument lines from the RCS boundary in the DCPP design penetrate the containment. (For definition of the RCS boundary, refer to the 1972 issue of ANS N18.2, Nuclear Safety Criteria for the Design of Stationary PWR Plants.)
23	Fuel handling accident.					15.4.5	FUEL HANDLING ACCIDENT	
24	Small spills or leaks of radioactive material outside containment.	N/A	N/A	N/A	N/A	N/A	N/A	The analysis of the consequences of such small spills and leaks is included within the cases evaluated in Chapter 11, and larger leaks and spills are analyzed in Section 15.5.

TABLE 15.0-1
REGULATORY GUIDE 1.70 REVISION 1, APPLICABILITY MATRIX

Event	REG GUIDE 1.70, TABLE 15-1, REPRESENTATIVE TYPES OF EVENTS TO BE ANALYZED IN CHAPTER 15.0 OF THE SAR	15.2 Section	UFSAR SECTION 15.2 CONDITION II: FAULTS OF MODERATE FREQUENCY	15.3 Section	UFSAR SECTION 15.3 CONDITION III: INFREQUENT FAULTS	15.4 Section	UFSAR SECTION 15.4 CONDITION IV: LIMITING FAULTS	Location of Analyses or Reason Why Not Applicable
25	Fuel cladding failure (BWR, PWR) combined with steam generator leak (PWR).	N/A	N/A	N/A	N/A	N/A	N/A	The radiological consequences of this event are analyzed in Chapter 11, for the case of "Anticipated Operational Occurrences."
26	Control room uninhabitabi1ity.	N/A	N/A	N/A	N/A	N/A	N/A	Habitability of the control room following accident conditions is discussed in Chapter 6, and potential radiological exposures are reported in Section 15.5. In addition, Chapter 7 contains an analysis showing that the plant can be brought to, and maintained in, Mode 3 from outside the control room.
27	Failure or overpressurization of low pressure residual heat removal system.	N/A	N/A	N/A	N/A	N/A	N/A	Overpressurization of the residual heat removal system (RHRS) is considered extremely unlikely. PG&E reviewed possible RHRS overpressure scenarios and qualified the system for all credible high pressure transients in DCPP design change package N-049118.

TABLE 15.0-1
REGULATORY GUIDE 1.70 REVISION 1, APPLICABILITY MATRIX

Event	REG GUIDE 1.70, TABLE 15-1, REPRESENTATIVE TYPES OF EVENTS TO BE ANALYZED IN CHAPTER 15.0 OF THE SAR	15.2 Section	UFSAR SECTION 15.2 CONDITION II: FAULTS OF MODERATE FREQUENCY	15.3 Section	UFSAR SECTION 15.3 CONDITION III: INFREQUENT FAULTS	15.4 Section	UFSAR SECTION 15.4 CONDITION IV: LIMITING FAULTS	Location of Analyses or Reason Why Not Applicable
28	Loss of condenser vacuum.	N/A	N/A	N/A	N/A	N/A	N/A	This event is covered by the analyses of Section 15.2.7. Separate event analysis is not required.
29	Turbine trip with coincident failure of turbine bypass valves to open.	N/A	N/A	N/A	N/A	N/A	N/A	This event is covered by the analyses of Section 15.2.7. Separate event analysis is not required.
30	Loss of service water system.	N/A	N/A	N/A	N/A	N/A	N/A	Malfunctions of auxiliary saltwater system and component cooling water system (CCWS) are discussed in Chapter 9, Sections 9.2.7 and 9.2.2 respectively.
31	Loss of one (redundant) d-c system.	N/A	N/A	N/A	N/A	N/A	N/A	There are no significant safety-related consequences of this event.
32	Inadvertent operation of ECCS during power operation.	15.2.15	SPURIOUS OPERATION OF THE SAFETY INJECTION SYSTEM AT POWER					
33	Turbine trip with failure of generator breaker to open.	N/A	N/A	N/A	N/A	N/A	N/A	The effects of turbine trip on the RCS are presented in Section 15.2.7. Separate event analysis is not required.

TABLE 15.0-1

REGULATORY GUIDE 1.70 REVISION 1, APPLICABILITY MATRIX

Event	REG GUIDE 1.70, TABLE 15-1, REPRESENTATIVE TYPES OF EVENTS TO BE ANALYZED IN CHAPTER 15.0 OF THE SAR	15.2 Section	UFSAR SECTION 15.2 CONDITION II: FAULTS OF MODERATE FREQUENCY	15.3 Section	UFSAR SECTION 15.3 CONDITION III: INFREQUENT FAULTS	15.4 Section	UFSAR SECTION 15.4 CONDITION IV: LIMITING FAULTS	Location of Analyses or Reason Why Not Applicable
34	Loss of instrument air system.	N/A	N/A	N/A	N/A	N/A	N/A	Malfunctions of this system are discussed in Section 9.3.2.
35	Malfunction of turbine gland sealing system.	N/A	N/A	N/A	N/A	N/A	N/A	The radiological effects of this event are not significant for PWR plants. Minor leakages are within the scope of the analysis cases presented in Chapter 11.

TABLE 15.1-1

NUCLEAR STEAM SUPPLY SYSTEM POWER RATINGS

Core Rated Thermal Power	3411
Thermal power generated by the reactor coolant pumps minus heat losses to containment and letdown system [b]	14
Nuclear steam supply system (NSSS) thermal power output[b]	3425
The engineered safety features design rating (maximum calculated turbine rating)[a]	3570

(a) The units will not be operated at this rating because it exceeds the license ratings.
(b) As noted on Table 15.1-4, some analyses assumed a full power NSSS thermal output of 3,423 MWt, based on the previous net reactor coolant pump heat of 12 MWt. An evaluation concluded that the effect of an additional 2 MWt for NSSS is negligible such that analyses based on 3,423 MWt remain valid.

TABLE 15.1-2

TRIP POINTS AND TIME DELAYS TO TRIP ASSUMED IN ACCIDENT ANALYSES

Trip Function	Limiting TripPoint Assumed In Analyses	Time Delay, sec
Power range high neutron flux, high setting	118%	0.5
Power range high neutron flux, low setting	35%	0.5
Power range high positive nuclear power rate	7% / 2 sec	0.65
Overtemperature ΔT	Variable, see Figure 15.1-1	7[a]
Overpower ΔT	Variable, see Figure 15.1-1	7[a]
High pressurizer pressure	2460 psia	2
Low pressurizer pressure	1860 psia	2
High pressurizer water level	100%	N/A[f]
Low reactor coolant flow (from loop flow detectors)	85% loop flow[b, d]	1
Undervoltage trip	[b]	N/A[b]
Low-low steam generator level	8.2% of narrow range level span	2[c]
High steam generator level trip of the feedwater pumps and closure of feedwater system valves and turbine trips	100% of narrow range level span[e]	2

(a) Total time delay consists of a maximum 5-second RTD lag time constant and a maximum 2-second electronics delay

(b) Complete loss of flow analysis assumes that reactor trips, on low reactor coolant loop flow, not undervoltage.underfrequency.

(c) When below 50% power, a variable trip time delay is utilized as discussed in Section 7.2.2.1.5.

(d) Value used in the analysis of the Locked Rotor event (Section 15.4.4) for RCS pressure and maximum cladding Temperature. Westinghouse letter PGE-96-582, Diablo Canyon Units 1 & 2 Evaluation of Revised Low Reactor Coolant Flow Reactor Trip Setpoint, June 27, 1996, concludes that a safety analysis setpoint of 85% loop flow is acceptable for the Locked Rotor event (Section 15.4.4) and the Partial Loss of Flow event (Section 15.2.5), for which 87% was assumed in the analysis.

(e) The analysis assumed 100% narrow range level span for conservatism. The plant setpoint analytical limit is 98.8% narrow range level span for Model Delta 54 steam generators due to void effects. Although the turbine trip is modeled for completeness it is not needed for DNBR analysis.

(f) Westinghouse Letter PGE-02-72, Diablo Canyon Units 1 and 2 Evaluation of Reactor Trip Functions for Uncontrolled RCCA Bank Withdrawal at Power, December 13, 2002, documents that a specific response time is not assumed since it is not a sensitive parameter for the generic evaluation results.

TABLE 15.1-4

SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED

Events	Computer Codes Utilized	Assumed Reactivity Coefficients: Moderator Temp[a], pcm/°F[d]	Assumed Reactivity Coefficients: Moderator Density[a], Δk/gm/cc	Doppler[b]	Initial NSSS Thermal Power Output Assumed[c], MWt
CONDITION II					
Uncontrolled RCCA bank withdrawal from a subcritical condition	TWINKLE, THINC, FACTRAN	+5	-	Least negative defect - 954 pcm	0
Uncontrolled RCCA bank withdrawal at power	LOFTRAN	+5	0.43	Lower and Upper	3,423
RCCA misoperation	THINC, ANC, LOFTRAN	-	-	Lower	3,425
Uncontrolled boron dilution					0 and 3,423
Partial loss of forced reactor coolant flow	LOFTRAN, THINC, FACTRAN	+5	-	Upper	3,423
Startup of an inactive reactor coolant loop	LOFTRAN, FACTRAN, THINC	-	0.43	Lower	2,396
Loss of external electrical load and/or turbine trip-DNBR	LOFTRAN, RETRAN-02	+5	0.43	Lower and Upper	3,423
Loss of external electrical load and/or turbine trip - Overpressure	RETRAN-02	+5	-	Lower	3,425

TABLE 15.1-4

Events	Computer Codes Utilized	Assumed Reactivity Coefficients: Moderator Temp[a], pcm/°F[d]	Assumed Reactivity Coefficients: Moderator Density[a], Δk/gm/cc	Assumed Reactivity Coefficients: Doppler[b]	Initial NSSS Thermal Power Output Assumed[c], MWt
CONDITION II (Cont'd)					
Loss of normal feedwater	RETRAN-02W	0	-	Upper	3,425
Loss of offsite power to the plant auxiliaries	RETRAN-02W	0	-	Upper	3,425
Excessive heat removal due to feedwater system malfunctions	RETRAN-02W	-	0.43	Lower	3,425
Excessive load increase	LOFTRAN	-	0 and 0.43	Lower and Upper	3,423
Accidental depressurization of the reactor coolant system	LOFTRAN	+7	-	Lower	3,425
Inadvertent operation of ECCS during power operation - DNBR	LOFTRAN	+5	0.43	Lower and Upper	3,423
Inadvertent operation of ECCS during power operation – Pressurizer Overfill	RETRAN-02W	-	0.43	Upper	3,425
CONDITION III					
Loss of reactor coolant from small ruptured pipes or from cracks in large pipe which actuate emergency core cooling	WCOBRA/TRAC-TF2	Function of moderator density	-	Function of fuel temp	3,479
Inadvertent loading of a fuel assembly into an improper position	PHOENIX-P, ANC	-	-	-	3,483
Complete loss of forced reactor coolant flow	LOFTRAN, THINC, FACTRAN	0	-	Upper	3,425

TABLE 15.1-4

Events	Computer Codes Utilized	Assumed Reactivity Coefficients: Moderator Temp[a], pcm/°F[d]	Assumed Reactivity Coefficients: Moderator Density[a], Δk/gm/cc	Assumed Reactivity Coefficients: Doppler[b]	Initial NSSS Thermal Power Output Assumed[c], MWt
CONDITION III (Cont'd)					
Single RCCA withdrawal at full power	ANC, THINC, PHOENIX-P	-	-	-	3,425[e]
CONDITION IV					
Major rupture of pipes containing reactor coolant up to and including double-ended rupture of the largest pipe in the reactor coolant system (loss-of-coolant accident)	WCOBRA/TRAC-TF2	Function of moderator density.	-	Function of fuel temp.	3,479
Major secondary system pipe rupture up to and including double-ended rupture (rupture of a steam pipe)	RETRAN-02W, ANC,THINC	-	Function of moderator density. See Figure 15.4.2-2.	See Figure 15.4.2-1	0.0 (Subcritical)
Major rupture of a main feedwater pipe	RETRAN-02W		0.0	Lower	3,425
Rupture of a main steam line at power	RETRAN-02W, ANC, THINC-IV		0.43	Lower	3,425
	-	-	-	-	
Steam generator tube rupture	RETRAN-02W	-	0.0	Lower and Upper	3,425
CONDITION IV (Cont'd)					
Single reactor coolant pump locked rotor	LOFTRAN,	+5 (rods in	0.0 (pressure	Upper	3,425

TABLE 15.1-4

Events	Computer Codes Utilized	Assumed Reactivity Coefficients: Moderator Temp[a], pcm/°F[d]	Assumed Reactivity Coefficients: Moderator Density[a], Δk/gm/cc	Doppler[b]	Initial NSSS Thermal Power Output Assumed[c], MWt
	THINC, FACTRAN	DNB case)	case)		
Fuel handling accident					3,580
Rupture of a control rod mechanism housing (RCCA ejection)	TWINKLE, FACTRAN PHOENIX-P	+5.2 BOL -23.EOL	-	Least negative defect. See Table 15.4-11.	0 and 3,423

(a) Only one is used in analysis, i.e., either moderator temperature or moderator density coefficient.
(b) Reference Figure 15.1-5.
(c) Two percent calorimetric error considered where applicable.
(d) Pcm means percent mille. See footnote Table 4.3-1.
(e) Analysis only models core thermal power of 3411 MWt

TABLE 15.2-1

TIME SEQUENCE OF EVENTS FOR CONDITION II EVENTS

Accident	Event	Time, sec
Uncontrolled RCCA Withdrawal from a Subcritical Condition	Initiation of uncontrolled rod withdrawal 7.5 x 10^{-4} Δk/sec reactivity insertion rate from 10^{-9} of nominal power	0.0
	Power range high neutron flux low setpoint reached	9.6
	Peak nuclear power occurs	9.8
	Rods begin to fall into core	10.1
	Peak heat flux occurs	11.9
	Peak hot spot average cladding temperature occurs	12.3
Uncontrolled RCCA Withdrawal at Power		
1. Case A	Initiation of uncontrolled RCCA withdrawal at reactivity insertion rate of7.5 x 10^{-4} Δk/sec	0.0
	Power range high neutron flux high trip point reached	1.6
	Rods begin to fall into core	2.1
	Minimum DNBR occurs	3.0
2. Case B	Initiation of uncontrolled RCCA withdrawal at a reactivity insertion rate of3.0 x 10^{-5} Δk/sec	0.0

Accident	Event	Time, sec
	Overtemperature ΔT reactor trip signal initiated	31.8
	Rods begin to fall into core	33.8
	Minimum DNBR occurs	34.2
Uncontrolled Boron Dilution		
1Dilution during refueling	Dilution begins	0.0
	Shutdown margin lost	~11884
2. Dilution during cold shutdown		
a. RCS filled	Dilution begins	0.0
	Shutdown margin lost	>900
b. RCS drained	Dilution begins	0.0
	Shutdown margin lost	>900
3. Dilution during hot shutdown		
a. One RCP operating	Dilution begins	0.0
	Shutdown margin lost	>900
b. RHR operating	Dilution begins	0.0
	Shutdown margin lost	>900
4. Dilution during hot standby	Dilution begins	0.0
	Shutdown margin lost	>900
5. Dilution during startup	Dilution begins	0.0
	Shutdown margin lost	~3696
6. Dilution during full power operation		
a. Automatic reactor control	1.6 % shutdown margin lost	~1180
b. Manual reactor control	Dilution begins	0.0

Accident	Event	Time, sec
	Reactor trip setpoint reached for high neutron flux	40
	Rods begin to fall into core	40.5
	1.6 % shutdown is lost (if dilution continues after trip)	~ 900
Historical *Partial Loss of Forced Reactor Coolant Flow*		
1. All loops operating, two pumps coasting down	*Coastdown begins*	*0.0*
	Low-flow reactor trip[(b)]	*1.43*
	Rods begin to drop	*2.43*
	Minimum DNBR occurs	*3.9*
Historical *Startup of an Inactive Reactor Coolant Loop*	*Initiation of pump startup*	*0.0*
	Power reaches high nuclear flux trip	*3.2*
	Rods begin to drop	*3.7*
	Minimum DNBR occurs	*4*

TABLE 15.2-1

Accident	Event	Time, sec
Loss of External Electrical Load-DNBR		
1. With pressurizer control (BOL)	Loss of electrical load	0.0
	High pressurizer pressure reactor trip setpoint reached	11.9
	Initiation of steam release from steam generator safety valves	12.0
	Rods begin to drop	13.9
	Peak pressurizer pressure occurs	14.5
	Minimum DNBR occurs	15
2. With pressurizer control (EOL)	Loss of electrical load	0.0
	Peak pressurizer pressure occurs	9.0
	Initiation of steam release from steam generator safety valves	12.5
	Low-low steam generator water level reactor trip	57
	Rods begin to drop	59
	Minimum DNBR occurs	(a)
3. Without pressurizer control (BOL)	Loss of electrical load	0.0
	High pressurizer pressure reactor trip point reached	6.1
	Rods begin to drop	8.1
	Minimum DNBR occurs	(a)

Accident	Event	Time, sec
	Peak pressurizer pressure occurs	9.5
	Initiation of steam release from steam generator safety valves	12.0
4. Without pressurizer control (EOL)	Loss of electrical load	0.0
	High pressurizer pressure reactor trip point reached	6
	Rods begin to drop	8
	Minimum DNBR occurs	(a)
	Peak pressurizer pressure occurs	8.5
	Initiation of steam release from steam generator safety valves	12.5
Loss of External Electrical Load-Overpressure (Peak RCS Pressure)		
1. With no pressurizer control (BOL)	Reactor Trip	9.0
	PSVs Open	9.1
	Peak RCS Pressure	9.5
	MSSVs Open	9.8
	Peak Secondary Side Pressure	16.0
Overpressure (Peak Secondary Side Pressure)		
2. With pressurizer control (BOL)	PORVs Open	3.6
	MSSVs Open	9.1
	Reactor Trip	15.1
	PSVs Open	16.3
	Peak RCS Pressure	16.5

TABLE 15.2-1

Accident	Event		Time, sec
	Peak Secondary Side pressure		20.0
		W/Power	W/O Power
Loss of Normal Feedwater and Loss of Offsite Power to the Station Auxiliaries	Main feedwater flow stops	0.0	0.0
	Low-low steam generator water level reactor trip	52.7	54.2
	Rods begin to drop	54.7	56.2
	Reactor coolant pumps begin to coast down	-	58.2
	Four SGs begin to receive aux feed from both motor-driven AFW pumps	112.7	114.2
	Peak water level in pressurizer occurs (post-trip)	1294	2030

Accident	Event	Time, sec
Excessive Feedwater at Full Load	One main feedwater regulating valve fails full open	0.0
	High-high steam generator water level is reached	33.6
	Turbine trip signal (from high-high steam generator level, turbine stop valve fully closed 0.1second later	36.0
	Reactor trip occurs from turbine trip (rod motion begins)	38.1
	Minimum DNBR occurs	39.0
	Initial pressurizer PORV opens (all PORVs closed 1.3 seconds later)	39.7
	Main feedwater isolation valves closed in all four loops (from high-high steam generator level)	99.6
Excessive Load Increase		
1. Manual reactor control (BOL minimum moderator feedback)	10% step load increase	0.0
	Equilibrium conditions reached (approximate times only)	240
2. Manual reactor control (EOL maximum moderator feedback)	10% step load increase	0.0
	Equilibrium conditions reached (approximate times only)	64
3. Automatic reactor control (BOL minimum moderator feedback)	10% step load increase	0.0
	Equilibrium conditions reached (approximate times only)	150

Accident	Event	Time, sec
4. Automatic reactor control (EOL maximum moderator feedback)	10% step load increase	0.0
	Equilibrium conditions reached (approximate times only)	150
Accidental Depressurization of the Reactor Coolant System	Inadvertent opening of one pressurizer safety valve	0.0
	Overtemperature ΔT reactor trip setpoint reached	27.5
	Rods begin to drop	29.5
	Minimum DNBR occurs	29.8
Inadvertent Operation of ECCS During Power Operation - DNBR	Charging pumps begin injecting borated water	0.0
	Low-pressure trip point reached	23
	Rods begin to drop	25
Inadvertent Operation of ECCS During Power Operation - Pressurizer Overfill		
Case to establish the maximum time available to ensure a PG&E Design Class I PORV is available	Reactor Trip/Safety injection	0
	Pressurizer fills	904
	First PSV opens after pressurizer fills	904
Case to establish the minimum time to pressurizer filling	Reactor Trip/Safety Injection	0
	PORV opens	41.2
	Pressurizer fills	690

TABLE 15.2-1

Accident	Event	Time, sec
Case to establish the minimum time to deplete the backup nitrogen accumulators	Reactor Trip/Safety Injection	0
	PORV opens	43.3
	Pressurizer fills	764
	Final available PORV cycle (300th cycle)	2748

(a) DNBR does not decrease below its initial value.
(b) Analysis assumed low flow setpoint of 87 percent loop flow. An evaluation concludes that 85 percent loop flow is acceptable. Refer to Table 15.1-2, footnote (d).

TABLE 15.3-3

TIME SEQUENCE OF EVENTS FOR CONDITION III EVENTS

Accident	Event	Time sec[a]
Complete Loss of Forced Reactor Coolant Flow		
All loops operating, all pumps coasting down	Coastdown begins	0.0
	Rod motion begins	2.85
	Minimum DNBR occurs	4.8

a) Event times are Unit 1; Unit 2 is 0.04 seconds later.

TABLE 15.4-8

TIME SEQUENCE OF EVENTS FOR
MAJOR SECONDARY SYSTEM PIPE RUPTURES

Accident	Event	Time, sec
Steam Line Rupture @ HZP		
1. With Offsite Power Available	Main steam line ruptures	0.0
	Low steam line pressure setpoint reached	0.6
	SIS flow begins(maximum flow assumed)	2.6
	Steam line isolation occurs	8.6
	Criticality attained	36.5
	Borated water from the RWST reaches the core	~40
	Main feedwater isolation occurs	64.6
	Accumulators inject	79.0
	Peak core heat flux, minimum DNBR occurs	90.5
2. Without Offsite Power Available	Main steam line ruptures	0.0
	Low steam line pressure setpoint reached	0.6
	SIS flow begins (maximum flow assumed)	2.6
	RCPs begin to coast down	3.0
	Steam line isolation occurs	8.6
	Criticality attained	44.4
	Borated water from the RWST reaches the core	~50

TABLE 15.4-8

Accident	Event	Time, sec
	Main feedwater isolation occurs	64.6
	Peak core heat flux, minimum DNBR occurs	123.4
	Accumulators inject	129.7
Rupture of Main Feedwater Pipe (Offsite Power Available)	Feedline rupture occurs	20
	Low-low steam generator level reactor trip setpoint reached in affected steam generator	32
	Rods begin to drop	34
	Auxiliary feedwater is started	623
	Pressurizer liquid water relief begins if operator action is not assumed	2053
	Total RCS heat generation (decay heat + pump heat) decreases to auxiliary feedwater heat removal capability	5900
Rupture of Main Feedwater Pipe (Offsite Power Unavailable)	Feedline rupture occurs	20
	Low-low steam generator level reactor trip setpoint reached in affected steam generator	32
	Rods begin to drop	34
	Reactor coolant pump coastdown	36
	Auxiliary feedwater is started	632
	Peak pressurizer level after initial outsurge reached	2091

TABLE 15.4-8

Accident	Event	Time, sec
	Total RCS heat generation decreases to auxiliary feedwater heat removal capability	2200
Steam Line Rupture at Power (0.49 ft2)	Steam line ruptures	0.0
	Peak core heat flux occurs	53.1
Rupture of a Main Feedwater Pipe for Pressurizer Filling	Feedwater line rupture occurs	0.0
(Unblock Pressurizer PORV)	Low-low SG water level reactor trip setpoint (0% NRS) reached in faulted SG	15.9
	Rods begin to drop	17.9
	Turbine trip occurs	18.4
	Steam line check valve closes in loop with faulted SG	18.5
	Reactor coolant pumps begin to coast down (from loss of offsite power)	19.9
	Low steam line pressure setpoint reached in loop with faulted SG	26.7
	Safety injection actuation signal generated	28.7
	Safety injection flow initation occurs	28.8
	Steam line isolation occurs on low steam line pressure safety injection signal	34.7
	Main steam safety valve relief begins	36.1
	PSV steam relief begins	56.0
	AFW flow initiation (390 gpm from a motor-driven AFW pump) occurs to intact SGs not connected to the faulted SG	75.9
	Pressurizer reaches a water-solid condition	501.0
	PSV water relief begins (maximum time for operator action to ensure a PORV is available)	518.8
	Operator action to isolate faulted SG to	615.9

TABLE 15.4-8

Accident	Event	Time, sec
	direct all available AFW flow to intact SGs	
	AFW flow initiation (195 gpm from the turbine-driven AFW pump and 195 gpm from the other motor-driven AFW pump) occurs to intact SG connected to the faulted SG	615.9
	AFW flow addition (390 gpm from the turbine-driven AFW pump) occurs to intact SGs not connected to the faulted SG	615.9
Rupture of a Main Feedwater Pipe for Pressurizer Filling	Feedline rupture occurs	0.0
(Isolate Charging Flow and Stop RCP Seal Injection Flow)	Pressurizer backup heater actuation on level deviation	13.5
	Low-low SG water level reactor trip setpoint (0% NRS) reached in faulted SG	15.9
	Rods begin to drop	17.9
	Turbine trip occurs	18.4
	Steam line check valve closes in loop with faulted SG	18.5
	Reactor coolant pumps begin to coast down (from manual trip)	19.9
	Pressurizer PORV steam relief begins	20.9
	Low steam line pressure setpoint reached in loop with faulted SG	26.8
	Safety injection actuation signal generated	28.8
	Safety injection flow initation occurs	28.9
	Steam line isolation occurs on low steam line pressure safety injection signal	34.8
	Main steam safety valve relief begins	40.1
	AFW flow initiation (390 gpm from a motor-driven AFW pump) occurs to intact SGs not connected to the faulted SG	75.9
	Pressurizer reaches a water-solid condition	408.5
	Operator action to isolate faulted SG to direct all available AFW flow to intact SGs	615.9
	AFW flow initiation (195 gpm from the turbine-driven AFW pump and 195 gpm	615.9

TABLE 15.4-8

Accident	Event	Time, sec
	from the other motor-driven AFW pump) occurs to intact SG connected to the faulted SG	
	AFW flow addition (390 gpm from the turbine-driven AFW pump) occurs to intact SGs not connected to the faulted SG	615.9
	Operator action to isolate charging/SI flow	1516.0
	Operator action to stop RCP seal injection flow	2715.9
	Steam bubble forms again in pressurizer	6723.0
	Maximum number of PORV cycles reached (capacity of backup nitrogen accumulators depleted)	7137.6

TABLE 15.4-10

SUMMARY OF RESULTS FOR LOCKED ROTOR TRANSIENT

	4 Loops Operating Initially 1 Locked Rotor
Maximum RCS pressure, psia	2729[1]
Maximum clad average temperature, °F core hot spot	1963
Amount of Zr - H_2O at core hot spot, % by weight	0.53%

(1) The locked rotor transient peak pressure of 2729 psia includes a conservative penalty of 41 psi, determined by Westinghouse in an evaluation to address Nuclear Safety Advisory Letter NSAL-09-2. "Locked Rotor Analysis for Reactor Coolant System Overpressure." May 7, 2009.

TABLE 15.4-11

TYPICAL PARAMETERS USED IN THE VANTAGE 5 RELOAD ANALYSIS OF THE ROD CLUSTER CONTROL ASSEMBLY EJECTION ACCIDENT

Time in Life	Beginning	Beginning	End	End
Generic Vantage 5 Reload Analysis Values				
Power level, %	102	0.0	102	0.0
Ejected rod worth, % Δk	0.20	0.785	0.21	0.85
Delayed neutron fraction, %	0.55	0.55	0.44	0.44
Feedback reactivity weighting	1.30	2.071	1.30	3.55
Doppler - only power defect, pcm	-955	-954	-829	-788
Trip reactivity, % Δk	4	2	4	2
F_q before rod ejection	2.60	-	2.60	-
F_q after rod ejection	6.70	13	6.50	21.50
Number of operating pumps	4	2	4	2
Generic Vantage 5 Reload Analysis Results				
Maximum fuel pellet average temperature, °F	4154	3509	3812	3408
Maximum fuel center temperature, °F	>4900 [(a)]	4025	>4800 [(a)]	3849
Maximum cladding average temperature, °F	2434	2660	2218	2632
Maximum fuel stored energy, cal/gm	183	149	165	144
Reload Analysis Evaluation Values				
Power level, %	102	0.0	102	0.0
Ejected rod worth, % Δk	0.20	0.785	0.21	0.83
Delayed neutron fraction, %	0.55	0.55	0.44	0.44
Feedback reactivity weighting	1.30	2.071	1.30	3.55
Doppler – only power defect, pcm	-995	-954	-829	-788
Trip reactivity, % Δk	4	2	4	2
F_q before rod ejection	2.60	-	2.60	-
F_q after rod ejection	6.70	13	6.50	22.50
Number of operating pumps	4	2	4	2

(a) Less than 10% fuel pellet melt (at hot spot)

TABLE 15.4-12

OPERATOR ACTION TIMES FOR DESIGN BASIS SGTR ANALYSIS

Action	Time (min)
Identify and isolate ruptured SG	10 min or RETRAN-02W calculated time to reach 38% narrow range level in the ruptured SG, whichever is longer
Operator action time to initiate cooldown	5
Cooldown	Calculated by RETRAN-02W
Operator action time to initiate depressurization	4
Depressurization	Calculated by RETRAN-02W
Operator action time to initiate SI termination	2
SI termination and pressure equalization	Calculated time for SI termination and equalization of RCS and ruptured SG pressures

TABLE 15.4-13A

TIMED SEQUENCE OF EVENTS - SGTR MTO ANALYSIS

Event	Time (sec)
SG Tube Rupture	100
Reactor Trip	274
SI Actuated	380
Turbine Driven AFW Pump Flow Isolated	700
Ruptured SG Steamline Isolation	700
Ruptured SG MDAFW Pump Flow Isolated	820
RCS Cooldown Initiated	1120
RCS Cooldown Terminated	1706
RCS Depressurization Initiated	1946
RCS Depressurization Terminated	2072
SI Terminated	2192
Break Flow Terminated	3475

TABLE 15.4-13B

TIMED SEQUENCE OF EVENTS - SGTR DOSE ANALYSIS

Event	Time (sec)
SG Tube Rupture	100
Reactor Trip	279
SI Actuated	315
Ruptured SG Isolated	953
Ruptured SG PORV Fails Open	953
Ruptured SG PORV Block Valve Closed	2753
RCS Cooldown Initiated	3053
RCS Cooldown Terminated	4424
RCS Depressurization Initiated	4664
RCS Depressurization Terminated	4839
SI Terminated	4959
Break Flow Terminated	5972

TABLE 15.4-14

MASS RELEASE RESULTS - SGTR

	0 - 2 Hrs, lbm	2 - 8 Hrs, lbm
Ruptured SG		
- Condenser	294,500	0
- Atmosphere	140,200	27,000
- Feedwater	288,700	0
Intact SGs		
- Condenser	878,100	0
- Atmosphere	367,100	922,600
- Feedwater	1,476,800	961,700
Break Flow	262,200	0
Flashed Break Flow	18,150	0

Note: The 0-2 hour releases to the condenser and feedwater flows include 100 seconds of steady state operation.

Table 15.4.1.2-1A. Plant Operating Range Analyzed and Key Parameters for Diablo Canyon Power Plant Unit 1

Parameter		As-Analyzed Value or Range
1.0	**Core Parameters**	
	a) Core power	≤ 3469 MWt ± 0.3% Uncertainty
	b) Fuel Type	17x17 VANTAGES fuel, ZIRLO® Cladding Material, Non-IFBA and IFBA
	c) Maximum total core peaking factor (F_Q), including uncertainties	2.58
	d) Maximum hot channel enthalpy rise faction (FΔH), including uncertainties	1.65
	e) Axial flux difference (AFD) band at 100% power, %	+10/-14
2.0	**Reactor Coolant System Parameters**	
	a) Thermal design flow (TDF)	87,000 gpm/loop
	b) Vessel average temperature (T_{AVG})	565.0 – 5.5°F ≤T_{avg} ≤ 577.3 = 5.0°F
	c) Pressurizer pressure	2250 – 60 psia ≤ P_{RCS} ≤ 2250 + 60 psia
	d) Reactor coolant pump (RCP) model and power	Model 93A, 6000 hp
3.0	**Containment Parameters**	
	a) Containment modeling	SBLOCA (Region I): Constant pressure equal to initial containment pressure LBLOCA (Region II): Calculated for each transient using transient-specific mass and energy releases and the information in Tables 15.4.1.2-2, 15.4.1.2-3 and 15.4.1.2-4
4.0	**Steam Generator (SG) and Secondary Side Parameters**	
	a) Steam generator tube plugging level	≤ 15%
	b) Main steam safety valve (MSSV) nominal set pressures, uncertainty and accumulation	Table 15.4.1.2-7
	c) Main feedwater temperature	435°F (the maximum value from the range is used)
	d) Main feedwater isolation time from signal to full valve closure	9.0 seconds
	e) Auxiliary feedwater temperature	Nominal (80°F)
	f) Auxiliary feedwater flow rate	97.5 gpm/SG
	g) Auxiliary feedwater delivery delay time	60 seconds

[2]ZIRLO is a registered trademark of Westinghouse Electric Company LLC, its subsidiaries and/or affiliates in the United States of America and may be registered in other countries throughout the world. All rights reserved. Unauthorized use is strictly prohibited. Other names may be trademarks of their respective owners.

Parameter		As-Analyzed Value or Range
5.0	**Safety Injection (SI) Parameters**	
	a) Single failure configuration	ECCS: Loss of one train of pumped ECCS LBLOCA (Region II) containment pressure: All SI trains
	b) Low pressurizer pressure safety injection safety analysis limit	46°F ≤ SI Temp ≤ 90°F
	c) Low pressurizer pressure safety injection safety analysis limit	1695 psia
	d) Initiation delay time from low pressurizer pressure SI setpoint to full SI flow	≤ 42 seconds (OPA) or 67 seconds (LOOP)
	e) Safety injection flow	Minimum flows in Table 15.4.1.2-5 (SBLOCA, Region I) or Table 15.4.1.2-6 (LBLOCA, Region II)
6.0	**Accumulator Parameters**	
	a) Accumulator temperature	85°F ≤ T_{ACC} ≤ 120°F
	b) Accumulator water volume	814 ft^3 ≤ V_{ACC} ≤ 886 ft^3
	c) Accumulator pressure	579 psig ≤ P_{ACC} ≤ 664 psig
	d) Accumulator boron concentration	≥ 2200 ppm
7.0	**Reactor Protection System Parameters**	
	a) Low pressurizer pressure reactor trip signal processing time	≤ 2.0 seconds
	b) Low pressurizer pressure reactor trip setpoint	1860 psia

Table 15.4.1.2-1B. Plant Operating Range Analyzed and Key Parameters for Diablo Canyon Power Plant Unit 2

Parameter		As-Analyzed Value or Range
1.0	**Core Parameters**	
	a) Core power	≤ 3469 MWt ± 0.3% Uncertainty
	b) Fuel Type	17x17 VANTAGES fuel, ZIRLO® Cladding Material, Non-IFBA and IFBA
	c) Maximum total core peaking factor (F_Q), including uncertainties	2.58
	d) Maximum hot channel enthalpy rise faction ($F_{\Delta H}$), including uncertainties	1.65
	e) Axial flux difference (AFD) band at 100% power, %	+10/-14
2.0	**Reactor Coolant System Parameters**	
	a) Thermal design flow (TDF)	88,500 gpm/loop
	b) Vessel average temperature (T_{AVG})	565.0 – 5.5°F ≤T_{avg} ≤ 577.6 = 5.0°F
	c) Pressurizer pressure	2250 – 60 psia ≤ P_{RCS} ≤ 2250 + 60 psia
	d) Reactor coolant pump (RCP) model and power	Model 93A, 6000 hp
3.0	**Containment Parameters**	
	a) Containment modeling	SBLOCA (Region I): Constant pressure equal to initial containment pressure LBLOCA (Region II): Calculated for each transient using transient-specific mass and energy releases and the information in Tables 15.4.1.2-2, 15.4.1.2-3 and 15.4.1.2-4
4.0	**Steam Generator (SG) and Secondary Side Parameters**	
	a) Steam generator tube plugging level	≤ 15%
	b) Main steam safety valve (MSSV) nominal set pressures, uncertainty and accumulation	Table 15.4.1.2-7
	c) Main feedwater temperature	435°F (the maximum value from the range is used)
	d) Main feedwater isolation time from signal to full valve closure	9.0 seconds
	e) Auxiliary feedwater temperature	Nominal (80°F)
	f) Auxiliary feedwater flow rate	97.5 gpm/SG
	g) Auxiliary feedwater delivery delay time	60 seconds
5.0	**Safety Injection (SI) Parameters**	
	a) Single failure configuration	ECCS: Loss of one train of pumped ECCS LBLOCA (Region II) containment pressure: All SI trains
	b) Low pressurizer pressure safety injection temperature analysis limit	46°F ≤ SI Temp ≤ 90°F

Parameter		As-Analyzed Value or Range
	c) Low pressurizer pressure safety injection safety analysis limit	1695 psia
	d) Initiation delay time from low pressurizer pressure SI setpoint to full SI flow	≤ 42 seconds (OPA) or 67 seconds (LOOP)
	e) Safety injection flow	Minimum flows in Table 15.4.1.2-5 (SBLOCA, Region I) or Table 15.4.1.2-6 (LBLOCA, Region II)
6.0	**Accumulator Parameters**	
	a) Accumulator temperature	85°F ≤ T_{ACC} ≤ 120°F
	b) Accumulator water volume	814 ft^3 ≤ V_{ACC} ≤ 886 ft^3
	c) Accumulator pressure	579 psig ≤ P_{ACC} ≤ 664 psig
	d) Accumulator boron concentration	≥ 2200 ppm
7.0	**Reactor Protection System Parameters**	
	a) Low pressurizer pressure reactor trip signal processing time	≤ 2.0 seconds
	b) Low pressurizer pressure reactor trip setpoint	1860 psia

Table 15.4.1.2-2. Containment Date Used for LBLOCA (Region II) Calculation of Containment Pressure for Diablo Canyon Power Plant Units 1 and 2

Parameter	Value
Maximum containment net free volume	2.63×10^6 ft^3
Minimum initial containment temperature at full power operation	85°F
Minimum RWST temperature for containment spray	46°F ≤ RWST Temp ≤ 90°F
Minimum RWST temperature for broken loop spilling SI	35°F
Minimum containment outside air / ground temperature	32.4°F
Minimum initial containment pressure at normal full power operation	13.7 psia
Minimum containment spray pump initiation delay from containment high pressure signal time	≥ 40.8 seconds (OPA) or 46.8 seconds (LOOP)
Maximum containment spray flow rate from all pumps	6800 gpm
Minimum recirculation spray pump initiation time under OPA conditions	Recirculation spray flow initiated immediately after RWST Low Level setpoint is reached
Maximum number of containment fan coolers in operation during LOCA Transient	5
Minimum fan cooler initiation delay time	≥ 0.0 seconds (OPA) or 15.0 seconds (LOOP)
Maximum heat removal rate per fan cooler as a function on containment temperature	Table 15.4.1.2-3
Maximum number of containment venting lines (including purge lines, pressure relief lines or any others) which can be OPEN at onset of transient at full power operation	1
Maximum effective valve diameter of each containment venting line	12 inches
Maximum containment pressure setpoint for venting valve closure	20 psia
Maximum delay time between reaching containment pressure setpoint and start of venting valve closure	2 seconds
Maximum venting valve closure time at normal full power operation	5 seconds
Containment walls / heat sink properties	Table 15.4.1.2-4

Table 15.4.1.2-3. Fan Cooler Performance Data Used for LBLOCA (Region II) Calculation of Containment Pressure for Diablo Canyon Power Plant Units 1 and 2

Containment Temperature (°F)	Heat Removal Rate (MBTU/hr)	Heat Removal Rate (BTU/sec)
100	14.64	4067.3
130	29.26	8128.2
160	44.27	12296.9
190	58.58	16273.1
210	67.85	18847.6
215	70.14	19483.8
240	115.35	32041.8
270	160.79	44665.1
300	196.14	54484.5

Table 15.4.1.2-4. Containment Heat Sink Data Used for LBLOCA (Region II) Calculation of Containment Pressure for Diablo Canyon Power Plant Units 1 and 2

Wall	Area (ft^2)	Thickness (in)	Material
1	65,749	42.0	Concrete
2	24,054	12.0	Concrete
3	14,313	24.0	Concrete
4	48,183	12.0	Concrete
5	15,725	12.0	Concrete
6	20,493	108.0	Concrete
7	33,867	30.0	Concrete
8	8,525	1.68	Steel
9	4,015	1.92	Steel
10	1,771	6.99	Steel
11	45,396	0.565	Steel
12	24,090	0.088	Steel
13	10,597	0.22	Steel
14	8,470	0.088	Steel
15	23,438	0.102	Steel
16	20,266	0.071	Steel
17	26,050	0.708	Steel
18	33,000	0.127	Steel
19	11,004	0.773	Steel
20	99,616	0.375	Steel
21	1,530	1.596	Steel
22	21,022	1.098	Steel
23	6,755	0.745	Steel
24	792	0.96	Steel
25	9,737	0.144	Stainless Steel
26	943	0.654	Stainless Steel
27	1373	0.642	Steel
28	575	3.0	Steel
29	17,542	0.75	Steel

Table 15.4.1.2-5. Safety Injection Flow Used for SBLOCA (Region I) Calculation for Diablo Canyon Power Plant Units 1 and 2

Pressure (psia)	High Head Safety Injection (HHSI) Flow (gpm)	Intermediate Head Safety Injection (IHSI) Flow (gpm)	Low Head Safety Injection (LHSI) Flow (gpm)
14.7	231	388	2847.6
34.7	229.6	385.2	2675.4
54.7	228.2	382.4	2492.5
74.7	226.8	379.6	2295.2
94.7	225.4	376.8	2078.6
114.7	224	374	1833.8
134.7	222.4	371	1542.5
154.7	220.8	368	1154.6
174.7	219.2	365	430
174.9	219.18	364.97	0
214.7	216	359	
314.7	208	344	
414.7	201	327	
514.7	193	310	
614.7	185	292	
714.7	176	274	
814.7	168	253	
914.7	159	230	
1014.7	150	206	
1114.7	131	177	
1214.7	112	141	
1314.7	91	98	
1414.7	69	36	
1414.71	69	0	
1514.7	46	0	
1614.7	22		
1614.71	0		
3000.0	0		

Table 15.4.1.2-6. Safety Injection Flow Used for LBLOCA (Region II) Calculation for Diablo Canyon Power Plant Units 1 and 2

Pressure (psia)	High Head Safety Injection (HHSI) Flow (gpm)	Intermediate Head Safety Injection (IHSI) Flow (gpm)	Low Head Safety Injection (LHSI) Flow (gpm)
14.7	231	388	2848.7
34.7	229.6	384.4	2306.5
54.7	228.2	380.8	1744.7
74.7	226.8	377.2	1195.8
94.7	225.4	373.6	826.9
114.7	224	370	376
126.9	223.02	367.08	0
214.7	216	352	
314.7	208	333	
414.7	201	313	
514.7	193	291	
614.7	185	268	
714.7	176	244	
814.7	168	216	
914.7	159	174	
1014.7	150	129	
1114.7	131	76	
1214.7	112	9	
1214.71	112	0	
1314.7	91	0	
1414.7	69		
1514.7	46		
1614.7	22		
1614.71	0		
3000	0		

Table 15.4.1.2-7. Steam Generator Main Steam Safety Valve Parameters for Diablo Canyon Power Plant Units 1 and 2

Stage	Set Pressure (psig)	Uncertainty (%)	Accumulation (psi)
1	1065.0	+3	+5
2	1078.0	+3	+5
3	1090.0	+3	+5
4	1103.0	+3	+5
5	1115.0	+3	+5

Table 15.4.1.3-1A. Diablo Canyon Power Plant Unit 1 Analysis Results with the FSLOCA EM

Outcome	SBLOCA (Region I) Value	LBLOCA (Region II) Value (OPA)	LBLOCA (Region II) Value (LOOP)
95/95 PCT	1,099 °F	1,632 °F	1,676°F
95/95 MLO	9.5 %	9.5 %	9.5 %
95/95 CWO	0.0 %	0.10 %	0.15 %

Table 15.4.1.3-1B. Diablo Canyon Power Plant Unit 2 Analysis Results with the FSLOCA EM

Outcome	SBLOCA (Region I) Value	LBLOCA (Region II) Value (OPA)	LBLOCA (Region II) Value (LOOP)
95/95 PCT	1,012 °F	1,558 °F	1,574°F
95/95 MLO	9.5 %	9.5 %	9.5 %
95/95 CWO	0.0 %	0.03 %	0.04 %

Table 15.4.1.3-2A. Diablo Canyon Power Plant Unit 1 Sequence of Events for SBLOCA (Region I) Analysis PCT Transient

Event	Time after Break (sec)
Start of Transient	0.0
Reactor Trip Signal	13.7
Safety Injection Signal	24.9
Safety Injection Begins	91.9
Loop Seal Clearing Occurs	608
Top of Core Uncovered	1040
Accumulator Injection Begins	1374
PCT Occurs	1506
Top of Core Recovered	1736

Table 15.4.1.3-2B. Diablo Canyon Power Plant Unit 2 Sequence of Events for SBLOCA (Region I) Analysis PCT Transient

Event	Time after Break (sec)
Start of Transient	0.0
Reactor Trip Signal	10.0
Safety Injection Signal	19.1
Safety Injection Begins	86.1
Loop Seal Clearing Occurs	407
Top of Core Uncovered	803
Accumulator Injection Begins	1198
PCT Occurs	1201
Top of Core Recovered	1296

Table 15.4.1.3-3A. Diablo Canyon Power Plant Unit 1 Sequence of Events for LBLOCA (Region II) Analysis PCT Transient Assuming LOOP

Event	Time after Break (sec)
Start of Transient	0.0
Burst Occurs	3.1
Safety Injection Signal	5.4
Accumulator Injection Begins	11.0
End of Blowdown	15.0
Accumulator Empty	52
Safety Injection Begins	72.4
PCT Occurs	124
All Rods Quenched	238

Table 15.4.1.3-3B. Diablo Canyon Power Plant Unit 2 Sequence of Events for LBLOCA (Region II) Analysis PCT Transient Assuming LOOP

Event	Time after Break (sec)
Start of Transient	0.0
Safety Injection Signal	5.7
Burst Occurs	10.3
Accumulator Injection Begins	11.1
End of Blowdown	15.0
PCT Occurs	40.0
Accumulator Empty	54.0
Safety Injection Begins	72.7
All Rods Quenched	188

TABLE 15.5-7A

BREATHING RATES[a] ASSUMED IN ANALYSIS

Period	Offsite	Onsite
0-8 hrs	3.5×10^{-4}	3.5×10^{-4}
8-24 hrs	1.8×10^{-4}	3.5×10^{-4}
1-30 days	2.3×10^{-4}	3.5×10^{-4}

(a) All breathing rates are expressed in m^3/sec. Values taken from Reference 55.

TABLE 15.5-9

SUMMARY OF OFFSITE AND CONTROL ROMM DOSES
LOSS OF ELECTRICAL LOAD

	Dose (TEDE, rem)	Regulatory Limit (TEDE, rem)
Maximum 2-hour Exclusion Area Boundary Dose[1]		
- Pre-incident iodine spike	<0.1	2.5
- Accident-initiated iodine spike	<0.1	2.5
30-day Integrated Low Population Zone Dose		
- Pre-incident iodine spike	<0.1	2.5
- Accident-initiated iodine spike	<0.1	2.5
30-day Integrated Control Room Occupancy Dose		
- Pre-incident iodine spike	<0.1	5
- Accident-initiated iodine spike	<0.1	5

Note:

1. The maximum 2-hour EAB dose occurs during the following time period :

   - Pre-incident iodine Spike 0 - 2 hours
   - Accident-Initiated Iodine Spike 8.73 – 10.73 hours

TABLE 15.5-9A LOSS OF ELECTRICAL LOAD ANALYSIS ASSUMPTIONS & KEY PARAMETER VALUES	
Parameter	Value
Power Level	3580 MWt
Reactor Coolant Mass	446,486 lbm
Primary to Secondary SG tube leakage	0.75 gpm (total for all 4 SGs); leakage density 62.4 lbm/ft^3
Failed/Melted Fuel Percentage	0%
RCS Technical Specification Iodine Levels	Table 15.5-78 (1 µCi/gm DE I-131)
RCS Technical Specification Noble Gas Levels	Table 15.5-78 (270 µCi/gm DE Xe-133)
RCS Equilibrium Iodine Appearance Rates	Table 15.5-79 (1 µCi/gm DE I-131)
Pre-Accident Iodine Spike Concentration	Table 15.5-79 (60 µCi/gm DE I-131)
Accident-Initiated Iodine Spike Appearance Rate	500 times TS equilibrium appearance rate
Duration of Accident-Initiated Iodine Spike	8 hours
Initial Secondary Coolant Iodine Concentrations	0.1 µCi/gm DE I-131 (Table 15.5-78)
Initial and Minimum SG Liquid Mass	92,301 lbm/SG
Time period of tubes uncovered	insignificant
Steam Releases	0-2 hrs: 651,000 lbm 2-8 hrs: 1,023,000 lbm 8-10.73 hrs: same release rate as that for 2- 8 hrs
Iodine Partition Coefficient in SGs	100
Iodine Species Released to Environment	97% elemental; 3% organic
Fraction of Noble Gas Released	1.0 (Released without holdup)
Termination of releases from SGs	10.73 hours
Environmental Release Point	MSSVs/10% ADVs
CR emergency Ventilation : Initiation Signal/Timing	Control Room is assumed to remain on normal ventilation for duration of the accident.
Control Room Atmospheric Dispersion Factors	Table 15.5-9B

TABLE 15.5-9B LOSS OF ELECTRICAL LOAD Control Room Limiting Atmospheric Dispersion Factors (sec/m^3)			
Release point and receptor	0-2 hr	2-8 hr	8-10.73 hr
MSSVs/10% ADVs to CR NOP Intake (Note 1)	8.12E-04	5.32E-04	5.32E-04
MSSVs/10% ADVs to CR Inleakage (CR Centerline)	2.46E-03	1.59E-03	1.59E-03

Note 1: Due to the proximity of the release from the MSSVs/10% ADVs, to the normal operation CR intake of the affected unit, and due to the high vertical velocity of the steam discharge from the MSSVs/10% ADVs, the resultant plume from the MSSVs/10% ADVs will not contaminate the normal operation CR intake of the affected unit. Thus, the χ/Qs presented reflect those applicable to the CR intake of the unaffected unit.

Note 2: The selection of the χ/Q values for the release points/ receptors listed above are intended to provide bounding dose estimates for an event at either unit.

- Releases from the MSSVs/10% ADVs to the CR Normal intake of the non-affected unit are based on Unit 1 10% ADVs to the Unit 2 CR intake.
- Releases from the MSSVs/10% ADVs to the CR Center (i.e., for CR Inleakage) are based on Unit 1 10% ADV releases for the 0-2 hrs time period, and Unit 2 10% ADV releases for the 2-10.73 hrs time period.

TABLE 15.5-23

SUMMARY OF OFFSITE, CONTROL ROOM & TECHNICAL SUPPORT CENTER DOSES
LOSS OF COOLANT ACCIDENT[3]

	Dose (TEDE, rem)	Regulatory Limit (TEDE, rem)
Maximum 2-hour Exclusion Area Boundary Dose[1]	5.6	25
30-day Integrated Low Population Zone Dose	1	25
30-day Integrated Control Room Occupancy Dose[2]	3.7 (0.7)	5
30-day Integrated TSC Occupancy Dose[2]	4.1 (1.3)	5

Note:

1. The maximum 2 hr EAB dose is based on the assumed RHR pump seal failure resulting in a 50 gpm leak of sump water occurring at t=24 hr for 30 mins. This release pathway is considered a part of DCPP licensing basis with respect to passive system failure. If this assumed release pathway were not included, the maximum 2 hr dose at the EAB would occur between t=0.5 hrs to t=2.5 hrs (i.e., during the post-LOCA ex-vessel release phase and would be 3.4 rem.

2. The dose presented represents the operator dose due to occupancy. Value shown in parenthesis represents that portion of the total dose reported that is the contribution of direct shine from contained sources/external cloud.

3. The dose received by the operator during transit outside the control room is not a measure of the “habitability” of the control room which is defined by the radiation protection provided to the operator by the control room shielding and ventilation system design. Thus, the estimated dose to the operator during routine post-LOCA access to the control room is addressed separately from the control room occupancy dose and is not included with the control room occupancy dose for the demonstration of control room habitability. As demonstrated in Section 15.5.17.2.4, the dose contribution to the operator during routine access to control room for the duration of the LOCA is minimal (~1% of the occupancy dose).

TABLE 15.5-23A LOSS OF COOLANT ACCIDENT Assumptions & Key Parameter Values	
Parameter	Value
Core Power Level (105% of the rated power of 3411 MWth)	3580 MWt
Fuel Activity Release Fractions	Per Reg. Guide 1.183 (See Section 15.5.17.2.2.2)
Fuel Release Timing (gap)	Onset: 30 sec
	Duration: 0.5 hr
Fuel Release Timing (Early-In-Vessel)	Onset: 0.5 hr
	Duration: 1.3 hr
Core Activity	Table 15.5-77
Chemical Form of Iodine released from fuel to containment atmosphere	4.85% elemental 95% particulate 0.15% organic
Chemical Form of Iodine Released from RCS and sump water	97% elemental 3% organic
<u>Containment Vacuum/Pressure Relief Parameters</u>	
Minimum Containment Free Volume:	2.550E+06 ft^3
Primary Coolant Tech Spec Activity	Table 15.5-78
Chemical Form of Iodine Released	97% elemental; 3% organic
Maximum RCS flash fraction after LOCA Noble Gases Halogens	 100% 40%
Maximum containment pressure relief line air flow rate	218 actual cubic feet per second (acfs)
Maximum duration of release via containment pressure relief line	13 sec
Release Point	Plant Vent

TABLE 15.5-23A LOSS OF COOLANT ACCIDENT Assumptions & Key Parameter Values	
Parameter	Value
Containment Leakage Parameters	
Containment Spray Coverage – Injection Spray and Recirculation Spray Modes: Sprayed Volume Unsprayed Volume	82.5% (sprayed fraction) 2.103E+06 ft^3 4.470E+05 ft^3
Minimum mixing flow rate from unsprayed to sprayed region: Before actuation of CFCUs After actuation of CFCUs	 2 unsprayed regions/hr 9.13 unsprayed regions/hr
Minimum duration of mixing via CFCUs	Start = 86 sec End = 30 days
Containment spray in injection mode Initiation time Termination time	 111 sec 3798 sec
Maximum delay between end of injection spray and initiation of recirculation spray	12 min (based on manual operator action)
Containment spray in recirculation mode Initiation time Termination time	 4518 sec 22,518 sec
Long-term Sump Water pH	≥ 7.5
Maximum allowable DF for fission product removal	Elemental Iodine: 200 Others: not applicable
Elemental iodine and particulate spray removal coefficients in sprayed region during both injection spray and recirculation spray modes	See Table 6.2-32
Elemental iodine removal coefficients due to wall deposition	See Table 6.2-32
Particulate removal coefficients in unsprayed region due to gravitational settling	See Table 6.2-32

TABLE 15.5-23A LOSS OF COOLANT ACCIDENT Assumptions & Key Parameter Values	
Parameter	Value
Containment Leak rate (0-24 hr)	0.1% weight fraction per day
Containment Leak rate (1-30 day)	0.05% weight fraction per day
Containment Leakage Release Point (Unfiltered)	From the worst case release point of the following: Diffuse source via the containment wall Via Plant Vent Via Containment Pen Area GE Via Containment Pen Areas GW & FW
<u>ESF System Environmental Leakage Parameters</u>	
Minimum post-LOCA containment water volume sources	480,015 gal.
Minimum time after LOCA when recirculation is initiated	829 sec
Duration of leakage	30 days
Maximum ECCS fluid temperature after initiation of recirculation	259.9 ºF
Maximum ECCS leak rate (including safety factor of 2)	Unfiltered via plant vent = 240 cc/min Unfiltered via Containment Penetration Areas GE or GW & FW = 12 cc/min
RHR pump seal failure	Filtered(1) via plant vent 50 gpm starting at t = 24 hrs for 30 min
Iodine Airborne Release Fraction	10%
Auxiliary Building ESF Ventilation System filter efficiency	Elemental iodine: 88% Organic iodine: 88%
<u>Refueling Water Storage Tank (RWST) Back-Leakage Parameters</u>	

TABLE 15.5-23A LOSS OF COOLANT ACCIDENT Assumptions & Key Parameter Values	
Parameter	Value
Earliest initiation time of RWST back-leakage	829 sec
Maximum ECCS / sump water back-leakage rate to RWST (includes safety factor of 2)	2 gpm
RWST back-leakage iodine release fractions	See Table 15.5-23C
RWST back-leakage noble gas, as iodine daughters, release rate from the RWST vent	See Table 15.5-23C
Miscellaneous Equipment Drain Tank (MEDT) Leakage Parameters	
MEDT inflow rate (includes safety factor of 2)	1900 cc/min
MEDT leakage Iodine release fractions	See Table 15.5-23D
MEDT leakage noble gas, as iodine daughters release rate from plant vent	See Table 15.5-23D
CR Emergency Ventilation: Initiation Signal/Timing	
Initiation time (signal)	SI signal generated: 6 sec Non-Affected Unit NOP Intake Isolated: 18 sec Affected Unit NOP Intake Isolated and CRVS Mode 4 in full Operation: 44.2 sec
Bounding Control Room Atmospheric Dispersion Factors for LOCA	Table 15.5-23B

Note:
Releases from the RHR Pump Seal failure are filtered for CR dose evaluation and filtered for Site Boundary Dose Evaluation.

TABLE 15.5-23B LOSS OF COOLANT ACCIDENT Control Room Limiting Atmospheric Dispersion Factors (sec/m^3)					
Release Location/Receptor	0-2 hr	2-8 hr	8-24 hr	24-96 hr	96-720 hr
Control Room Normal Intakes					
Plant Vent Release					
- Affected Unit Intake	1.67E-03	-----	-----	-----	-----
- Non-Affected Unit Intake	9.08E-04	-----	-----	-----	-----
Containment Penetration Areas					
- Affected Unit Intake	6.60E-03	-----	-----	-----	-----
- Non-Affected Unit Intake	2.08E-03	-----	-----	-----	-----
Control Room Infiltration					
Plant Vent	1.25E-03	9.08E-04	3.61E-04	3.65E-04	3.17E-04
Containment Penetration Areas	3.09E-03	1.83E-03	7.22E-04	7.13E-04	6.50E-04
RWST Vent	1.05E-03	5.55E-04	2.12E-04	2.12E-04	1.72E-04
Control Room Pressurization Intake					
Plant Vent	5.55E-05	3.68E-05	1.36E-05	1.38E-05	1.11E-05
Containment Penetration Areas	6.00E-05	3.98E-05	1.63E-05	1.37E-05	1.10E-05
RWST Vent	4.75E-05	3.23E-05	1.25E-05	1.14E-05	8.73E-06

Note 1: Release from the Containment penetration areas (i.e., areas GE or GW & FW): applicable to containment leakage and ESF system leakage that occurs in the Containment Penetration Area

Note 2: Release from Plant Vent: applicable to ESF system leakage that occurs in the Auxiliary building, MEDT releases, RHR Pump Seal Failure Release and Containment Vacuum/Pressure Relief Line Release

Note 3: The selection of the χ/Q values for the release points/ receptors listed above are intended to provide bounding dose estimates for an event at either unit:

- Releases from the Plant Vent to the CR Normal intakes (affected and non-affected unit) are based on Unit 1 releases.
- Releases from the containment penetration areas to the CR Normal intakes (affected and non-affected unit) are based on Unit 2 GE area releases.
- Releases from the Plant Vent to the CR Center (i.e., for CR Inleakage) are based on Unit 1 releases.
- Releases from the containment penetration areas to the CR Center are based on Unit 2 GE area releases for the 0-24 hour period and on the Unit 1 GW/FW area for the 1-30 day time period.
- Releases from the RWST vent to the CR Center are based on Unit 2 releases.
- Releases from the Plant Vent to the CR pressurization intakes are based on Unit 1 releases to the U2 CR intake.
- Releases from the containment penetration areas to the CR pressurization intakes are based on Unit 1 GW/FW area releases to the Unit 2 CR intake for the 0-2 hrs and 4-30 day time periods, from the Unit 2 GW/FW area releases to the Unit 1 CR intake for the 2-24 hrs time period and from the Unit 2 GE area releases to the Unit 1 CR intake for the 1-4 day time period.
- Releases from the RWST vent to the CR pressurization intakes are based on Unit 2 releases to the Unit 1 CR intake.

TABLE 15.5-23C
LOSS OF COOLANT ACCIDENT
RWST Iodine Releases Fraction and Gas Venting Rate to Atmosphere

From Time	To Time	Iodine Release Fraction to Atmosphere	Average Interval Weighted Gas Space Venting Rate to Atmosphere
Sec	Sec	Fraction $I_{released}$ / $I_{entering}$	Fraction V_{rwst} / day
829	7200	9.451E-05	2.610E+00
7200	28,800	6.357E-05	7.291E-01
28,800	86,400	8.796E-06	7.375E-02
86,400	345,600	4.560E-07	9.955E-03
345,600	471,600	6.347E-07	1.311E-02
471,600	1,011,600	8.231E-07	1.489E-02
1,011,600	2,048,400	1.114E-06	1.547E-02
2,048,400	2,592,000	1.483E-06	1.702E-02

Where:

$I_{released}$ = Total Iodine mass released to atmosphere during specified time interval, gm
$I_{entering}$ = Total Iodine mass entering to the RWST during specified time interval, gm
Frac. V_{rwst} = Rate of Fractional RWST gas volume vented during specified time interval

TABLE 15.5-23D
LOSS OF COOLANT ACCIDENT
MEDT Iodine Release Fraction and Gaseous Venting Rate to Atmosphere

From Time	To Time	Iodine Release Fraction to Atmosphere	Average Interval Weighted Gas Space Venting Rate to Atmosphere
Sec	Sec	Fraction $I_{released}$ / $I_{entering}$	Fraction V_{MEDT} / day
829	7200	4.521E-07	5.024E+00
7200	28,800	1.386E-08	3.024E-02
28,800	86,400	2.362E-07	3.324E-01
86,400	345,600	3.950E-07	6.497E+00
345,600	471,600	1.236E-02 (Note 2)	(Note 1)
471,600	1,011,600	2.028E-02 (Note 2)	(Note 1)
1,011,600	2,048,400	2.390E-02 (Note 2)	(Note 1)
2,048,400	2,592,000	2.166E-02 (Note 2)	(Note 1)

Where:

$I_{released}$ = Total Iodine mass released to atmosphere during specified time interval, gm
$I_{entering}$ = Total Iodine mass entering to the MEDT during specified time interval, gm
Frac. V_{MEDT} = Rate of Fractional MEDT gas volume vented during specified time interval

Note 1: After the MEDT overflows at t = 183,289 sec, the gas venting rates are 2640 cfm from the EDRT room, and 1760 cfm from the U1/U2 Pipe Tunnels (i.e., the exhaust ventilation rate from the respective rooms + 10%). To be consistent with the methodology used to determine the iodine release fractions after spillover, the noble gases generated by decay of iodines in the tank and spilled liquid after overflow occurs, should also be released instantaneously to the environment without hold-up.

Note 2: The room ventilation flows addressed in Note 1 (utilized as clean in-coming air) are incorporated into the determination of the iodine equilibrium concentration in the EDRT room and U1/U2 Pipe Tunnels air space, respectively. The bounding iodine release fractions presented above after spillover assume instantaneous release of iodines to the environment without hold-up in the room.

TABLE 15.5-23E LOSS OF COOLANT ACCIDENT TSC Limiting Atmospheric Dispersion Factors (sec/m^3)					
Release Location/Receptor	0-2 hr	2-8 hr	8-24 hr	24-96 hr	96-720 hr
TSC Normal Intakes					
Plant Vent Release	5.47E-04	-----	-----	-----	-----
Containment Penetration Areas	1.71E-03	-----	-----	-----	-----
RWST Vent	3.52E-04	-----	-----	-----	-----
TSC Infiltration					
Plant Vent	5.41E-04	2.09E-04	9.67E-05	7.95E-05	6.43E-05
Containment Penetration Areas	1.76E-03	7.16E-04	3.01E-04	2.84E-04	2.28E-04
RWST Vent	3.61E-04	1.48E-04	6.30E-05	5.80E-05	4.69E-05
CR/TSC Pressurization Intake					
Plant Vent	-----	3.68E-05	1.36E-05	1.38E-05	1.11E-05
Containment Penetration Areas	-----	3.98E-05	1.63E-05	1.37E-05	1.10E-05
RWST Vent	-----	2.93E-05	1.13E-05	1.08E-05	8.50E-06

Note 1: Release from the Containment penetration areas (i.e., areas GE or GW & FW): applicable to containment leakage and ESF system leakage that occurs in the Containment Penetration Area

Note 2: Release from Plant Vent: applicable to ESF system leakage that occurs in the Auxiliary building, MEDT releases, RHR Pump Seal Failure Release and Containment Vacuum/Pressure Relief Line Release

Note 3: The selection of the χ/Q values for the release points/ receptors listed above are intended to provide bounding dose estimates for an event at either unit:

- Releases from the Plant Vent to the TSC Normal intake are based on Unit 2 releases.
- Releases from the containment penetration areas to the TSC Normal intakes are based on Unit 2 GW/FW area releases.
- Releases from the RWST vent to the TSC Normal intake are based on Unit 2 releases.
- Releases from the Plant vent to the TSC Center (i.e., for TSC Inleakage) are based on Unit 2 releases.
- Releases from the containment penetration areas to the TSC Center are based on Unit 2 GW/FW area releases.
- Releases from the RWST vent to the TSC Center are based on Unit 2 releases.
- Releases from the Plant Vent to the CR/TSC pressurization intakes are based on Unit 1 releases to the U2 CR intake.
- Releases from the containment penetration areas to the CR/TSC pressurization intakes are based on Unit 1 GW/FW area releases to the Unit 2 CR intake for the 0-2 hrs and 4-30 day time periods, from the Unit 2 GW/FW area releases to the Unit 1 CR intake for the 2-24 hrs time period and from the Unit 2 GE area releases to the Unit 1 CR intake for the 1-4 day time period.
- Releases from the RWST vent to the CR/TSC pressurization intakes are based on Unit 2 releases to the Unit 1 CR intake.

TABLE 15.5-33

ESTIMATED POST LOCA EXPOSURE TO CONTROL ROOM PERSONNEL
DURINNG EGRESS-INGRESS (HISTORICAL)

Radiation Source	LOCA Gamma Exposure, rem	LOCA Beta Exposure, rem	LOCA Thyroid Exposure, rem
1. Not Used			
2. Not Used			
3. Not Used			
4. Radiation from airborne fission products in the containment leakage plume to control room personnel during egress-ingress	0.0066	0.0243	4.72
5. Direct radiation from fission products in the containment structure to control room personnel during egress-ingress (53 5-minute trips)	0.022	0	0

TABLE 15.5-34

SUMMARY OF OFFSITE AND CONTROL ROOM DOSES
MAIN STEAM LINE BREAK

	Dose (TEDE, rem)	Regulatory Limit (TEDE, rem)
Maximum 2-hour Exclusion Area Boundary Dose		
- Pre-Incident Iodine Spike	0.1	25
- Accident-Initiated Iodine Spike	0.7	2.5
30-day Integrated Low Population Zone Dose		
- Pre-Incident Iodine Spike	<0.1	25
- Accident-Initiated Iodine Spike	0.2	2.5
30-day Integrated Control Room Occupancy Dose		
- Pre-Incident Iodine Spike	2.0	5
- Accident-Initiated Iodine Spike	4.1	5

Note:

1. The maximum 2-hour EAB dose occurs during the following time period:

   - Pre-incident Iodine Spike 0 - 2 hours
   - Accident-Initiated Iodine Spike 7.6 – 9.6 hours

TABLE 15.5-34A MAIN STEAM LINE BREAK Analysis Assumptions & Key Parameter Values	
Parameter	Value
Power Level	3580 MWt
Reactor Coolant Mass	446.486 lbm
Leak rate to Faulted Steam Generator	0.75 gpm (conservative assumption); leakage density 62.4 lbm/ft^3
Leak rate to Intact Steam Generators	0 gpm (all leakage assumed into faulted SG)
Failed/Melted Fuel Percentage	0%
RCS Tech Spec Iodine Conc.	Table 15.5-78 (1 µCi/gm DE I-131)
RCS Tech Spec Noble Gas Conc.	Table 15.5-78 (270 µCi/gm DE Xe-133)
RCS Equilibrium. Iodine Appearance Rates	Table 15.5-79 (1 µCi/gm DE I-131)
Pre-Accident Iodine Spike Concentrations	Table 15.5-79 (60 µCi/gm DE I-131)
Accident-Initiated Iodine Spike Appearance Rate	500 times equilibrium appearance rate
Duration of Accident- Initiated Iodine Spike	8 hours
Initial Secondary Coolant Iodine Concentrations	Table 15.5-78 (0.1 µCi/gm DE I-131)
<u>Secondary System Release Parameters</u>	
Iodine Species released to Environment	97% elemental; 3% organic
Fraction of Iodine Released from Faulted SG	1.0 (Released to Environ without holdup)
Fraction of Noble Gas Released from Faulted SG	1.0 (Released to Environ without holdup)

TABLE 15.5-34A
MAIN STEAM LINE BREAK
Analysis Assumptions & Key Parameter Values

Parameter	Value
Liquid mass in each SG	Faulted: 182,544 lbm (max.) Intact: 92,301 lbm (min. and initial)
Release Rate of SG liquid activity from Faulted SG	Dryout within 10 seconds
Time period when tubes not totally submerged (intact SG)	Insignificant
Steam Releases from intact SGs	0-2 hrs: 384,000 lbm 2-8 hrs: 893,000 lbm 8-10.73 hrs: Same release rate as that for 2-8 hrs
Iodine Partition Coefficient in Intact SG	100 (SGs fully covered)
Termination of release (0.75 gpm leak): Faulted SG	30 hrs when RCS reaches 212 °F
Termination of release from Intact SG	10.73 hours
Release Point: Faulted SG	Outside containment, at the steam line break location
Release Point: Intact SG	MSSVs/10% ADVs
<u>CR Emergency Ventilation: Initiation Signal/Timing</u>	
Initiation (signal)	SIS
Unaffected Unit CRVS inlet damper fully closed	Within 12.6 seconds
Affected Unit CRVS inlet dampers fully closed	Within 38.8 seconds
<u>Control Room Atmospheric Dispersion Factors</u>	Table 15.5-34B

TABLE 15.5-34B
MAIN STEAM LINE BREAK
Control Room Limiting Atmospheric Dispersion Factors (sec/m^3)

Receptor – Release Point	0-2 hr	2-8 hr	8-10.73 hr	10.73-30 hr
CR NOP Intake – Faulted SG (Break Location)	Note 1			
CR NOP Intake – Intact SG (MSSVs/10% ADVs) – Note 2	8.12E-04			
CR InLeakage – Faulted SG (Break Location)	1.14E-02	7.22E-03	3.00E-03	3.00E-03
CR InLeakage – Intact SG (MSSVs/10% ADVs)	2.46E-03	1.59E-03	1.59E-03	-----
CR Emergency Intake & Bypass Faulted SG (Break Location)	6.85E-05	4.70E-05	1.85E-05	1.85E-05
CR Emergency Intake & Bypass - Intact SG (MSSVs/10% ADVs)	1.40E-05	9.40E-06	9.40E-06	-----

Notes:

1. ARCON96 based χ/Qs are not applicable for these cases given that the horizontal distance from the source to the receptor is 1.5 meters (which is much less than the 10 meters required by ARCON96 methodology).
2. Due to the proximity of the release from the MSSVs/10% ADVs, to the normal operation CR intake of the affected unit, and due to the high vertical velocity of the steam discharge from the MSSVs/10% ADVs, the resultant plume from the MSSVs/10% ADVs will not contaminate the normal operation CR intake of the affected unit. Thus, the χ/Qs presented reflect those applicable to the CR intake of the unaffected unit.
3. The selection of the χ/Q values for the release points/ receptors listed above are intended to provide bounding dose estimates for an event at either unit:
   - Releases from the MSSVs/10% ADVs of the Intact SG to the CR Normal intake of the non-affected unit are based on Unit 1 10% ADVs releases to the Unit 2 CR intake.
   - Releases from the MSL break point of the faulted SG to the CR Center (i.e., for CR Inleakage) are based on Unit 1 for the 0-2 hour time period and Unit 2 releases for the 2-30 hour time period.
   - Releases from the MSSVs/10% ADVs of the intact SG to the CR Center are based on Unit 1 10% ADV releases for the 0-2 hrs time period, and Unit 2 10%ADV releases for the 2-10.73 hrs time period.
   - Releases from the MSL break point of the faulted SG to the CR pressurization intakes are based on Unit 1 releases to the Unit 2 CR intake for the 0-2 hour time period and Unit 2 releases to the Unit 1 CR intake for the 2-30 hour time period.
   - Releases from the MSSVs/10% ADVs of the Intact SG to the CR pressurization intakes are based on Unit 2 MSSV releases to the Unit 1 CR intake for the 0-2 hour time period and Unit 2 10% ADV releases to the Unit 1 CR intake for the 2-10.73 hour time period.

TABLE 15.5-42

SUMMARY OF OFFSITE AND CONTROL ROOM DOSES
LOCKED ROTOR ACCIDENT

	Dose (TEDE, rem)	Regulatory Limit (TEDE, rem)
Maximum 2-hour Exclusion Area Boundary Dose[1]	0.5	2.5
30-day Integrated Low Population Zone Dose	0.1	2.5
30-day Integrated Control Room Occupancy Dose	1.7	5

Note:

1. The maximum 2-hour EAB dose occurs between 8.73 – 10.73 hours

TABLE 15.5-42A
LOCKED ROTOR ACCIDENT
Analysis Assumptions & Key Parameter Values

Parameter	Value
Power Level	3580 MWt
Reactor Coolant Mass	446,486 lbm
Primary to Secondary SG tube leakage	0.75 gpm (total for all 4 SGs); leakage density 62.4 lbm/ft^3)
Melted Fuel Percentage	0%
Failed Fuel Percentage	10%
Equilibrium Core Activity	Table 15.5-77
Radial Peaking Factor	1.65
Fraction of Core Inventory in Fuel Gap	I-131: 8% I-132: 23% Kr-85: 35% Other Noble Gases: 4% Other Halogens: 5% Alkali Metals: 46%
Isotopic Inventory in Fuel Gap	Table 15.5-80
Iodine Chemical Form in Gap	4.85% elemental
	95% particulate
	0.15% organic
<u>Secondary Side Parameters</u>	
Initial and Minimum SG Liquid Mass	92,301 lbm/SG
Iodine Species Released to Environment	97% elemental; 3% organic
Time period when tubes not totally submerged	insignificant
Steam Releases	0-2 hrs: 651,000 lbm 2-8 hrs: 1,023,000 lbm 8-10.73 hrs: same release rate as that for 2-8 hrs

TABLE 15.5-42A
LOCKED ROTOR ACCIDENT
Analysis Assumptions & Key Parameter Values

Parameter	Value
Iodine Partition Coefficient in SGs	100
Particulate Carry-Over Fraction in SGs	0.0005 by weight
Fraction of Noble Gas Released	1.0 (Released without holdup)
Termination of releases from SGs	10.73 hours
Environmental Release Point	MSSVs/10% ADVs
CR emergency Ventilation: Initiation Signal/Timing	
	Control Room is assumed to remain on normal ventilation (CRVS Mode 1) for duration of the accident.
Control Room Atmospheric Dispersion Factors	Table 15.5-42B

TABLE 15.5-42B
LOCKED ROTOR ACCIDENT
Control Room Limiting Atmospheric Dispersion Factors (sec/m^3)

Release point and receptor	0-2 hr	2-8 hr	8-10.73 hr
MSSVs/10% ADVs to CR NOP Intake (Note 1)	8.12E-04	5.32E-04	5.32E-04
MSSVs/10% ADVs to CR In-leakage (CR Centerline)	2.46E-03	1.59E-03	1.59E-03

Note 1: Due to the proximity of the release from the MSSVs/10% ADVs, to the normal operation CR intake of the affected unit, and due to the high vertical velocity of the steam discharge from the MSSVs/10% ADVs, the resultant plume from the MSSVs/10% ADVs will not contaminate the normal operation CR intake of the affected unit. Thus, the χ/Qs presented reflect those applicable to the CR intake of the unaffected unit.

Note 2: The selection of the χ/Q values for the release points/ receptors listed above are intended to provide bounding dose estimates for an event at either unit:

- Releases from the MSSVs/10% ADVs to the CR Normal intake of the non-affected unit are based on Unit 1 10%ADVs to the Unit 2 CR intake.
- Releases from the MSSVs/10% ADVs to the CR Center (i.e., for CR Inleakage) are based on Unit 1 10%ADV releases for the 0-2 hrs time period, and Unit 2 10%ADV releases for the 2-10.73 hrs time period.

TABLE 15.5-47

SUMMARY OF OFFSITE AND CONTROL ROOM DOSES
FUEL HANDLING ACCIDENT IN THE FUEL HANDLING BUILDING OR CONTAINMENT

	Dose (TEDE, rem)	Regulatory Limit (TEDE, rem)
Maximum 2-hour Exclusion Area Boundary Dose[1]		
- FHA in Fuel Handling Building	1.0	6.3
- FHA in Containment	1.0	6.3
30-day Integrated Low Population Zone Dose		
- FHA in Fuel Handling Building	0.1	6.3
- FHA in Containment	0.1	6.3
30-day Integrated Control Room Occupancy Dose		
- FHA in Fuel Handling Building	1.0	5
- FHA in Containment	4.3	5

Note:

1. The maximum 2-hour EAB dose occurs between 0 – 2 hours.

TABLE 15.5-47A
FUEL HANDLING ACCIDENT IN THE FUEL HANDLING BUILDING OR CONTAINMENT
Analysis Assumptions & Key Parameter Values

Parameter	Value
Power Level	3580 MWt
Number of Damaged Fuel Assemblies	1
Total Number of Fuel Rods	264
Decay Time Prior to Fuel Movement	72 hours
Radial Peaking Factor	1.65
Fraction of Core Inventory in gap	I-131 (8%) I-132 (23%) Kr-85 (35%) Other Noble Gases (4%) Other Halides (5%) Alkali Metals (46%)
Isotopic Inventory in Fuel Gap (Decayed 72 hours)	Table 15.5-47C
Iodine form of gap release before scrubbing	99.85% elemental
	0.15% Organic
Iodine form of gap release after scrubbing	57% elemental
	43% Organic
Scrubbing Decontamination Factors	Iodine (200, effective)
	Noble Gas (1)
	Particulates (∞)
Rate of Release from Fuel	Puff
Environmental Release Rate	All airborne activity released within a 2 hour period (or less if the ventilation system promotes a faster release rate)

TABLE 15.5-47A FUEL HANDLING ACCIDENT IN THE FUEL HANDLING BUILDING OR CONTAINMENT Analysis Assumptions & Key Parameter Values	
Parameter	Value
Environmental Release Points and Rates	
Accident in SFP in the FHB – Release flow rates	-Plant Vent – 46,000 cfm FHB Outleakage -Egress-ingress locations – 30 cfm -Miscellaneous gaps/openings – 470 cfm
Minimum free volume in FHB above SFP	317,000 ft^3
Accident in Containment - Release flow rates	-Open Equipment Hatch – All airborne activity released in 2 hrs
Minimum Free Volume in Containment above Operating Floor	2,013,000 ft^3
CR Emergency Ventilation: Initiation Signal/Timing	
Signal(s) available to switch the Control Room Ventilation System (CRVS) from normal operation (NOP) Ventilation (Mode 1) to Pressurized Filtered Ventilation (Mode 4) following a FHA	Radiation signals from gamma sensitive intake monitors that initiate closure of the CR normal intake dampers and switch the Control Room Ventilation System from normal operation Ventilation Mode 1 to Pressurized Filtered Ventilation Mode
Radiation Monitor Analytical Safety Limit	1 mR/hr
Delay time for CRVS Mode 4 operation, including monitor response, signal processing, and damper closure time	32 seconds (see below)
Radiation Monitor Response Time	20 seconds (conservative assumption) - (Refer to Section 15.5.22.2.4)
Radiation monitor signal processing time	2 seconds
NOP Ventilation Damper Closure Time	10 seconds
Bounding Control Room Atmospheric Dispersion Factors for FHA	Table 15.5-47B

TABLE 15.5-47B
FUEL HANDLING ACCIDENT IN THE FUEL HANDLING BUILDING OR CONTAINMENT
Control Room Limiting Atmospheric Dispersion Factors (sec/m^3)

Release Location/Receptor	0-22 sec	22 sec–2 hr	2-8 hr	8-24 hr	1-4 d	4-30 d
Control Room Normal Intakes						
Containment Hatch Release						
- Affected Unit Intake	2.48E-02	-----	-----	-----	-----	-----
- Non-Affected Unit Intake	2.67E-03	-----	-----	-----	-----	-----
Plant Vent Release						
- Affected Unit Intake	1.67E-03	-----	-----	-----	-----	-----
- Non-Affected Unit Intake	9.08E-04	-----	-----	-----	-----	-----
FHB Out-leakage points						
- Affected Unit Intake	6.68E-03	-----	-----	-----	-----	-----
- Non-Affected Unit Intake	2.69E-03	-----	-----	-----	-----	-----
Control Room Infiltration						
Containment Hatch Release	5.09E-03	5.09E-03	-----	-----	-----	-----
Plant Vent	1.25E-03	1.25E-03	-----	-----	-----	-----
FHB Out-leakage points	3.61E-03	3.61E-03	-----	-----	-----	-----
Control Room Pressurization Intake						
Containment Hatch Release	-----	6.15E-05	-----	-----	-----	-----
Plant Vent	-----	5.55E-05	-----	-----	-----	-----
FHB Out-leakage points	-----	6.13E-05	-----	-----	-----	-----

Note 1: Release from the Containment Hatch: applicable to FHA in Containment

Note 2: Release from Plant Vent / FHB Out-leakage: applicable to FHA in FHB

Note 3: The selection of the χ/Q values for the release points/ receptors listed above are intended to provide bounding dose estimates for an event at either unit:

- Releases from the Containment Hatch to the CR Normal intake of the affected and non-affected unit are based on Unit 2 and Unit 1 releases, respectively.
- Releases from the Plant Vent to the CR Normal intake of the affected and non-affected unit are based on Unit 1 releases
- Releases from the FHB to the CR Normal intake of the affected and non-affected unit are based on Unit 1 releases
- Releases from the Containment Hatch to the CR Center (i.e., for CR Inleakage) are based on Unit 2 releases.
- Releases from the Plant Vent to the CR Center are based on Unit 1 releases.
- Releases from the FHB to the CR Center are based on Unit 2 releases.
- Releases from the Containment Hatch to the CR pressurization intakes are based on Unit 2 releases to the U1 CR intake
- Releases from the Plant Vent to the CR pressurization intakes are based on Unit 1 releases to the Unit 2 CR intake
- Releases from the FHB to the CR pressurization intakes are based on Unit 2 releases to the Unit 1 CR intake.

TABLE 15.5-47C
ISOTOPIC GAP ACTIVITY – FUEL HANDLING ACCIDENT
Single Fuel Assembly (Decayed 72 hours)

Nuclide	Activity Per Assembly (Ci)	Gap Fraction	Gap Activity per Assembly (w/o Peaking Factor)
I-129	2.07E-02	0.05	1.04E-03
I-130	3.29E+02	0.05	1.65E+01
I-131	4.09E+05	0.08	3.27E+04
I-132	3.99E+05	0.23	9.18E+04
I-133	9.73E+04	0.05	4.87E+03
I-135	5.01E+02	0.05	2.51E+01
KR-83M	2.51E-04	0.04	1.00E-05
KR-85	5.75E+03	0.35	2.01E+03
KR-85M	1.77E+00	0.04	7.08E-02
KR-88	7.73E-03	0.04	3.09E-04
XE-127	9.64E-02	0.04	3.86E-03
XE-129M	5.28E+01	0.04	2.11E+00
XE-131M	6.96E+03	0.04	2.78E+02
XE-133	8.31E+05	0.04	3.32E+04
XE-133M	1.88E+04	0.04	7.52E+02
XE-135	1.07E+04	0.04	4.28E+02
XE-135M	8.18E+01	0.04	3.27E+00
CS-132	2.16E+01	0.46	9.94E+00
CS-134	1.25E+05	0.46	5.75E+04
CS-134M	1.04E-03	0.46	4.78E-04
CS-135	3.01E-01	0.46	1.38E-01
CS-136	3.10E+04	0.46	1.43E+04
CS-137	7.10E+04	0.46	3.27E+04

RB-86	1.16E+03	0.46	5.34E+02
RB-87	1.37E-05	0.46	6.30E-06
RB-88	8.63E-03	0.46	3.97E-03

TABLE 15.5-52

SUMMARY OF OFFSITE DOSES AND CONTROL ROOM DOSES
CONTROL ROD EJECTION ACCIDENT

	Dose (TEDE, rem)	Regulatory Limit (TEDE, rem)
Maximum 2-hour Exclusion Area Boundary Dose[1]		
- Containment Release	0.7	6.3
- Secondary Side Release	0.7	6.3
30-day Integrated Low Population Zone Dose		
- Containment Release	0.3	6.3
- Secondary Side Release	0.2	6.3
30-day Integrated Control Room Occupancy Dose		
- Containment Release	3.4	5
- Secondary Side Release	0.5	5

Note:

1. The maximum 2-hour EAB dose occurs between 0 – 2 hours.

TABLE 15.5-52A
CONTROL ROD EJECTION ACCIDENT
Analysis Assumptions & Key Parameter Values

Parameters	Value
Containment Leakage Pathway	
Power Level	3580 MWt
Free Volume	2.550E+06 ft^3
Containment leak rate (0 -24 hr)	0.1% vol. fraction per day
Containment leak rate(1-30 day)	0.05% vol. fraction per day
Failed Fuel Percentage	10%
Percentage of Core Inventory in Fuel Gap	10% (noble gases & halogens)
Melted Fuel Percentage	0%
Chemical Form of Iodine in Failed fuel	4.85% elemental 95% particulate 0.15% organic
Radial Peaking Factor	1.65
Core Activity Release Timing	Puff
Form of Failed Iodine in the Containment Atmosphere	97% elemental 3% organic
Equilibrium Core Activity	Table 15.5-77
Termination of Containment Release	30 days
Environmental Release Point	Same as LOCA Containment Leakage pathway
Secondary Side Pathway	
Reactor Coolant Mass	446,486 lbm

TABLE 15.5-52A
CONTROL ROD EJECTION ACCIDENT
Analysis Assumptions & Key Parameter Values

Parameters	Value
Primary-to-Secondary Leak rate	0.75 gpm (total for all 4 SGs); leakage density 62.4 lbm/ft^3
Failed Fuel Percentage	Same as containment leakage pathway
Percentage of Core Inventory in Fuel Gap	Same as containment leakage pathway
Minimum Post-Accident SG Liquid Mass	92,301 lbm / SG
Iodine Species released to Environment	97% elemental 3% organic
Time period when tubes not totally submerged	Insignificant
Steam Releases	0-2 hrs: 651,000 lbm 2-8 hrs: 1,023,000 lbm 8-10.73 hrs: same release rate as that for 2-8 hrs.
Iodine Partition Coefficient in SGs	100
Fraction of Noble Gas Released	1.0 (Released without holdup)
Termination of Release from SGs	10.73 hours
Environmental Release Point	MSSVs/10% ADVs
<u>CR emergency Ventilation: Initiation Signal/Timing</u>	
Initiation time (signal)	300 sec (SIS Generated) 312 sec (Non-Affected Unit NOP Intake fully Closed) 338.2 sec (Affected Unit NOP Intake fully Closed with full Mode 4 Emergency Ventilation Operation).
<u>Control Room Atmospheric Dispersion Factors</u>	Table 15.5-52B

TABLE 15.5-52B
CONTROL ROD EJECTION ACCIDENT
Control Room Limiting Atmospheric Dispersion Factors (sec/m^3)

Release Location / Receptor	0-2hr	2-8hr	8-10.73hr	10.73-24hr	24-96hr	96-720hr
CR Normal Intakes						
Containment leakage						
- Affected Unit Intake	6.60E-03	-----		-----	-----	-----
- Non-Affected Unit Intake	2.08E-03	-----		-----	-----	-----
*MSSVs/*10% ADVs						
- Affected Unit Intake	Note 3	-----	-----	-----	-----	-----
- Non-Affected Unit Intake	8.12E-04	-----	-----	-----	-----	-----
CR Infiltration						
Containment leakage	3.09E-03	1.83E-03	7.22E-04	7.22E-04	7.13E-04	6.50E-04
MSSVs/10% ADVs	2.46E-03	1.59E-03	1.59E-03	-----	-----	-----
CR Pressurization Intake						
Containment leakage	6.00E-05	3.98E-05	1.63E-05	1.63E-05	1.37E-05	1.10E-05
MSSVs/10% ADVs	1.40E-05	9.40E-06	9.40E-06	-----	-----	-----

Note 1: Containment leakage: Used for Containment release scenario; based on Containment penetration area release point.

Note 2: MSSV /10% ADVs: Used for Secondary System Release Scenario;

Note 3: Due to the proximity of the release from the MSSVs/10% ADVs, to the normal operation CR intake of the affected unit, and due to the high vertical velocity of the steam discharge from the MSSVs/10% ADVs, the resultant plume from the MSSVs/10% ADVs will not contaminate the normal operation CR intake of the affected unit.

Note 4: The selection of the χ/Q values for the release points/ receptors listed above are intended to provide bounding dose estimates for an event at either unit:

- Releases from the containment penetration areas to the CR Normal intake of the affected and non-affected units are based on Unit 2 GE area releases.
- Releases from the MSSVs/10% ADVs to the CR Normal intake of the non-affected unit are based on Unit 1 10% ADVs to the Unit 2 CR intake.
- Releases from the containment penetration areas to the CR Center are based on Unit 2 GE area releases for the 0-24 hour period and on the Unit 1 GW/FW area for the 1-30 day time period.
- Releases from the MSSVs/10% ADVs to the CR Center (i.e., for CR Inleakage) are based on Unit 1 10% ADV releases for the 0-2 hrs time period, and Unit 2 10% ADV releases for the 2-10.73 hrs time period.
- Releases from the containment penetration areas to the CR pressurization intakes are based on Unit 1 GW/FW area releases to the Unit 2 CR intake for the 0-2 hrs and 4-30 day time periods, from the Unit 2 GW/FW area releases to the Unit 1 CR intake for the 2-24 hrs time period and from the Unit 2 GE area releases to the Unit 1 CR intake for the 1-4 day time period.
- Releases from the MSSVs/10% ADVs to the CR pressurization intakes are based on Unit 2 MSSV releases to the Unit 1 CR intake for the 0-2 hour time period and Unit 2 10% ADV releases to the Unit 1 CR intake for the 2-10.73 hour time period.

TABLE 15.5-64

SUMMARY OF OFFSITE DOSES AND CONTROL ROOM DOSES
STEAM GENERATOR TUBE RUPTURE

	Dose (TEDE, rem)	Regulatory Limit (TEDE, rem)
Maximum 2-hour Exclusion Area Boundary Dose[1]		
- Pre-incident iodine Spike	1.3	25
- Accident-Initiated Iodine Spike	0.7	2.5
30-day Integrated Low Population Zone Dose		
- Pre-incident iodine Spike	0.1	25
- Accident-Initiated Iodine Spike	<0.1	2.5
30-day Integrated Control Room Occupancy Dose		
- Pre-incident iodine Spike	0.6	5
- Accident-Initiated Iodine Spike	0.3	5

Note:

1. The maximum 2-hour EAB dose occurs between 0 – 2 hours.

TABLE 15.5-64A
STEAM GENERATOR TUBE RUPTURE ACCIDENT
Analysis Assumptions & Key Parameter Values

Parameter	Value
Power Level	3580 MWt
Reactor Coolant Mass	446,486 lbm
Time of Reactor Trip	179.0 sec
Time of isolation of stuck-open 10% ADV on the Ruptured SG	2653 sec
Termination of Break Flow from Ruptured SG that flashes	3402 sec
Termination of Break Flow from Ruptured SG	5872 sec
Time of manual depressurization of the Ruptured SG	2 hours
Break Flow to Ruptured Steam Generator that flashes	Table 15.5-64C, Column “A”
Break Flow to Ruptured Steam Generator that does not flash	Table 15.5-64C, Column “B”
Tube Leakage rate to Intact Steam Generators	0.75 gpm (total for all 4 SGs; conservatively assumed for 3 intact SGs); leakage density 62.4 lbm/ft^3
Failed/Melted Fuel Percentage	0%
RCS Tech Spec Iodine Concentration	1 µCi/gm DE I-131 (Table 15.5-78)
RCS Tech Spec Noble Gas Concentration	270 µCi/gm DE Xe-133 (Table 15.5-78)

TABLE 15.5-64A
STEAM GENERATOR TUBE RUPTURE ACCIDENT
Analysis Assumptions & Key Parameter Values

Parameter	Value
RCS Equilibrium Iodine Appearance Rates	Table 15.5-79 (1 µCi/gm DE I-131)
Pre-Accident Iodine Spike Concentration	60 µCi/gm DE I-131 (Table 15.5-79)
Accident-Initiated Iodine Spike Appearance Rate	335 times TS equilibrium appearance rate
Duration of Accident-Initiated Iodine Spike	8 hours
Initial Secondary Coolant Iodine Concentrations	0.1 µCi/gm DE I-131 (Table 15.5-78)
Secondary System Release Parameters	
Initial SG liquid mass	89,707 lbm / SG
Iodine Species released to Environment	97% elemental; 3% organic
Steam flow rate to condenser from Ruptured SG before trip	63,000 lbm/min
Steam flow rate to condenser from intact SGs before trip	189,000 lbm/min
Partition Factor in Main Condenser	0.01 (elemental iodine)
	1 (organic iodine and noble gases)
Steam Releases from Ruptured SG	Table 15.5-64C, Column “C”
Steam Releases from intact SG	Table 15.5-64C, Column “D”
Post-accident minimum SG liquid mass for Ruptured SG	89,707 lbm

TABLE 15.5-64A
STEAM GENERATOR TUBE RUPTURE ACCIDENT
Analysis Assumptions & Key Parameter Values

Parameter	Value
Post-accident minimum SG liquid mass for intact SGs	89,707 lbm per SG
Time period when tubes not totally submerged (intact SG)	insignificant
Fraction of Iodine Released (flashed portion)	1.0 (Released without holdup)
Fraction of Noble Gas Released from all SGs	1.0 (Released without holdup)
Iodine Partition Coefficient	100
Termination of Release from intact SG	10.73 hrs
Environmental Release Points	Plant Vent : 0 – 179 sec MSSVs/10% ADVs:179 sec – 10.73 hr
CR emergency Ventilation : Initiation Signal/Timing	
Initiation time (signal)	SIS: 219 sec Unaffected Unit inlet damper closed: 231 sec Affected Unit inlet damper closed: 257.2 sec
Control Room Atmospheric Dispersion Factors	Table 15.5-64B

TABLE 15.5-64B STEAM GENERATOR TUBE RUPTURE ACCIDENT Control Room Limiting Atmospheric Dispersion Factors (sec/m^3)					
Release Location / Receptor	0-179 s	179-257.2 s	257.2 s- 2 h	2-8 hr	8-10.73 hr
CR Normal Intakes					
- Plant Vent	1.29E-03	-----	-----	-----	-----
- MSSVs/10% ADVs (Note 1)	-----	8.12E-04	-----	-----	-----
CR Infiltration					
- Plant Vent	1.25E-03	-----	-----	-----	-----
- MSSVs/10% ADVs	-----	2.46E-03	2.46E-03	1.47E-03[2]	1.47E-03[2]
CR Pressurization Intake					
- MSSVs/10% ADVs	-----	-----	1.40E-05	9.40E-06[2]	9.40E-06[2]

Note 1: Due to the proximity of the release from the MSSVs/10% ADVs, to the normal operation CR intake of the affected unit, and due to the high vertical velocity of the steam discharge from the MSSVs/10% ADVs, the resultant plume from the MSSVs/10% ADVs will not contaminate the normal operation CR intake of the affected unit. Thus, the χ/Qs presented reflect those applicable to the CR intake of the unaffected unit.

Note 2: Since the 0-2 hour activity intake following a SGTR controls the 30-day integrated dose, the SGTR dose model utilizes a simplified model with respect to selection of the χ/Q values for the 2-10.73 hr time period. Specifically, the bounding χ/Q value is selected for the release point / receptor for the 0-2 hr time period, but unlike the dose models used for the other accidents, the χ/Q values for time periods beyond t=2hr are not switched to the other unit if they display higher values.

Note 3: The selection of the χ/Q values for the release points/ receptors listed above are intended to provide bounding dose estimates for an event at either unit:

- Releases from the Plant Vent to the CR Normal intakes (occurs prior to reactor trip) are based on Unit 1 releases to both Unit 1 and Unit 2 CR normal intakes (i.e., an average χ/Q; applied to the combined Unit 1 and Unit 2 CR normal intake flow).
- Releases from the MSSVs/10% ADVs to the CR Normal intake of the non-affected unit are based on Unit 1 10% ADVs releases to the Unit 2 CR intake.
- Releases from the Plant Vent to the CR Center (i.e., CR inleakage) are based on Unit 1 releases.
- Releases from the MSSVs/10% ADVs to the CR Center are based on Unit 1 10% ADV releases. (Note that the χ/Q value for the Unit 2 10% ADV to CR Center during the 2-10.73 hr period is greater than the listed value. However, the dose consequences associated with the SGTR is dominated by the 0-2 hour release, and the 0-2hr χ/Q for Unit 1 is bounding).
- Releases from the MSSVs/10% to the CR pressurization intakes are based on Unit 2 MSSV releases to the Unit 1 CR intake for the 0-2 hour time period and Unit 2 10% ADV releases to the Unit 1 CR intake for the 2-10.73 hour time period.

TABLE 15.5-64C
STEAM GENERATOR TUBE RUPTURE ACCIDENT
Break Flows and Steam Releases

	Break Flow and Steam Release within each Time Interval			
	A	B	C	D
Time from Break (sec)	Flashed Break Flow (lbm)	Un-flashed Break Flow (lbm)	Ruptured SG Steam Releases (lbm)	Intact SGs Steam Releases (lbm)
0	1678	8422	187822	563100
179	2217	30003	10527	42565
853	12121	90754	113657	118
2653	1355	15906	0	146
2953	779	23177	0	85467
3402	0	45026	0	97164
4324	0	16870	0	9237
4739	0	23892	0	29103
5872	0	0	0	103300
7200	0	0	27000	1,342,400
38628	0	0	0	0

Note: Data in row for T=0 is applicable to time interval between T=0 sec to T=179 sec (typ)

TABLE 15.5-77

DCPP EQUILIRIUM CORE INVENTORY (Power Level: 3580 MWth)
Dose Significant Isotopes including the Parent, Grandparent, and 2nd Parent Isotopes

ISOTOPE*	ACTIVITY (CURIES)	ISOTOPE*	ACTIVITY (CURIES)	ISOTOPE*	ACTIVITY (CURIES)
AG-110	2.67E+07	IN-125	8.46E+05	**SB-125**	9.63E+05
AG-110M	6.92E+05	IN-127	1.86E+06	**SB-127**	9.14E+06
AG-111	7.09E+06	IN-129	3.55E+06	**SB-129**	3.25E+07
AG-111M	7.09E+06	IN-131	1.09E+06	**SB-130**	1.08E+07
AG-112	3.16E+06	IN-132	2.85E+05	**SB-130M**	4.38E+07
AG-115	6.21E+05	**KR-83M**	1.14E+07	**SB-131**	7.67E+07
AG-115M	2.60E+05	**KR-85**	1.11E+06	**SB-132**	4.70E+07
AG-239	4.90E-01	**KR-85M**	2.33E+07	**SB-132M**	4.37E+07
AG-241	1.32E+04	**KR-87**	4.65E+07	**SB-133**	6.32E+07
AG-242	9.40E+06	**KR-88**	6.43E+07	SB-134	1.14E+07
AG-242M	8.54E+02	**KR-89**	7.94E+07	SB-135	5.46E+06
AG-243	5.28E+03	**KR-90**	8.48E+07	SB-136	8.63E+05
AG-244	3.79E+07	KR-91	5.83E+07	**SE-83**	5.38E+06
AG-245	1.12E-03	KR-92	3.12E+07	SE-83M	5.65E+06
AS-76	3.05E+03	KR-93	1.07E+07	SE-84	2.04E+07
AS-83	7.02E+06	KR-94	5.00E+06	SE-85	9.54E+06
BA-137M	1.30E+07	**LA-140**	1.85E+08	SE-87	1.32E+07
BA-139	1.76E+08	**LA-141**	1.61E+08	SE-88	7.15E+06
BA-140	1.78E+08	**LA-142**	1.57E+08	SE-89	2.49E+06
BA-141	1.59E+08	**LA-143**	1.48E+08	**SM-153**	6.04E+07
BA-142	1.51E+08	LA-144	1.31E+08	SM-155	4.30E+06
BA-143	1.29E+08	**MO-99**	1.84E+08	SM-156	2.66E+06
BA-144	9.93E+07	**MO-101**	1.69E+08	SM-157	1.70E+06
BR-82	4.44E+05	MO-103	1.62E+08	**SN-121**	8.43E+05
BR-82M	3.88E+05	MO-104	1.33E+08	**SN-123**	6.43E+04
BR-83	1.13E+07	MO-105	9.97E+07	**SN-125**	5.25E+05
BR-84	2.10E+07	MO-106	5.86E+07	SN-125M	1.58E+06
BR-85	2.31E+07	NB-101	1.59E+08	**SN-127**	3.69E+06
BR-87	3.67E+07	NB-104	5.10E+07	SN-127M	4.95E+06
BR-88	3.52E+07	**NB-95**	1.66E+08	SN-129	1.28E+07
BR-89	2.45E+07	**NB-95M**	1.89E+06	SN-129M	1.17E+07
BR-90	1.35E+07	**NB-97**	1.59E+08	SN-130	3.28E+07
CD-115	9.17E+05	**NB-97M**	1.50E+08	SN-131	2.83E+07

TABLE 15.5-77

DCPP EQUILIRIUM CORE INVENTORY (Power Level: 3580 MWth)
Dose Significant Isotopes including the Parent, Grandparent, and 2nd Parent Isotopes

ISOTOPE*	ACTIVITY (CURIES)	ISOTOPE*	ACTIVITY (CURIES)	ISOTOPE*	ACTIVITY (CURIES)
CD-115M	4.43E+04	NB-99	1.07E+08	SN-132	2.28E+07
CD-121	7.67E+05	NB-99M	7.35E+07	SN-133	6.21E+06
CE-141	1.63E+08	**ND-147**	6.59E+07	SN-134	1.07E+06
CE-143	1.50E+08	ND-149	3.90E+07	**SR-89**	9.05E+07
CE-144	1.26E+08	ND-151	2.08E+07	**SR-90**	9.67E+06
CE-147	6.18E+07	NP-238	6.20E+07	**SR-91**	1.13E+08
CF-249	2.46E-02	**NP-239**	2.16E+09	**SR-92**	1.22E+08
CM-241	3.54E+00	NP-240	6.23E+06	**SR-93**	1.39E+08
CM-242	5.88E+06	**PD-109**	4.73E+07	**SR-94**	1.39E+08
CM-244	1.31E+06	PD-109M	3.12E+05	SR-95	1.25E+08
CM-245	1.26E+02	PD-111	7.09E+06	SR-97	4.68E+07
CO-58**	0.00E+00	PD-112	3.14E+06	**TB-160**	1.87E+05
CO-60**	0.00E+00	PD-115	7.84E+05	**TC-99M**	1.63E+08
CS-132	5.75E+03	**PM-147**	1.68E+07	**TC-101**	1.69E+08
CS-134	2.41E+07	**PM-148**	1.88E+07	TC-103	1.65E+08
CS-134M	5.63E+06	**PM-148M**	2.83E+06	**TC-104**	1.40E+08
CS-136	7.01E+06	**PM-149**	6.43E+07	**TC-105**	1.18E+08
CS-137	1.37E+07	**PM-151**	2.10E+07	TC-106	8.80E+07
CS-138	1.85E+08	PM-153	9.77E+06	**TE-127**	9.03E+06
CS-139	1.72E+08	**PR-142**	9.47E+06	**TE-127M**	1.52E+06
CS-140	1.54E+08	**PR-143**	1.47E+08	**TE-129**	3.10E+07
CS-141	1.17E+08	**PR-144**	1.27E+08	**TE-129M**	6.30E+06
CS-142	6.80E+07	PR-144M	1.76E+06	**TE-131**	8.28E+07
CS-143	3.41E+07	PR-147	6.52E+07	**TE-131M**	2.04E+07
DY-166	4.91E+02	PR-149	3.57E+07	**TE-132**	1.41E+08
EU-154	9.00E+05	PR-151	1.23E+07	**TE-133**	1.09E+08
EU-155	3.83E+05	**PU-238**	5.22E+05	**TE-133M**	8.93E+07
EU-156	3.90E+07	**PU-239**	3.06E+04	**TE-134**	1.75E+08
EU-157	4.12E+06	**PU-240**	4.87E+04	TE-135	9.68E+07
EU-158	1.01E+06	**PU-241**	1.36E+07	TE-136	4.29E+07
EU-159	5.15E+05	**PU-242**	3.34E+02	TE-137	1.45E+07
GA-72	1.71E+03	PU-243	7.36E+07	TE-138	3.65E+06
GA-77	1.66E+05	RA-224	5.16E-01	**TH-228**	5.14E-01
GD-159	8.91E+05	**RB-86**	2.50E+05	U-239	2.17E+09
GE-77	6.48E+04	RB-86M	2.07E+04	**XE-131M**	1.42E+06

TABLE 15.5-77

DCPP EQUILIRIUM CORE INVENTORY (Power Level: 3580 MWth)
Dose Significant Isotopes including the Parent, Grandparent, and 2nd Parent Isotopes

ISOTOPE*	ACTIVITY (CURIES)	ISOTOPE*	ACTIVITY (CURIES)	ISOTOPE*	ACTIVITY (CURIES)
GE-77M	1.70E+05	**RB-88**	6.60E+07	**XE-133**	2.01E+08
GE-83	1.24E+06	**RB-89**	8.57E+07	**XE-133M**	6.42E+06
H-3	6.10E+04	**RB-90**	7.86E+07	**XE-135**	4.92E+07
HO-166	2.58E+04	**RB-90M**	2.53E+07	**XE-135M**	4.30E+07
I-129	4.00E+00	RB-91	1.05E+08	**XE-137**	1.84E+08
I-130	3.58E+06	RB-92	9.35E+07	**XE-138**	1.70E+08
I-130M	1.92E+06	RB-93	7.89E+07	XE-139	1.25E+08
I-131	9.90E+07	RB-94	4.13E+07	XE-140	8.66E+07
I-132	1.44E+08	RB-95	2.01E+07	XE-142	1.33E+07
I-133	2.01E+08	**RH-103M**	1.66E+08	**Y-90**	1.02E+07
I-134	2.22E+08	**RH-105**	1.08E+08	Y-90M	7.71E+02
I-134M	2.07E+07	**RH-105M**	3.43E+07	**Y-91**	1.19E+08
I-135	1.92E+08	**RH-106**	7.53E+07	**Y-91M**	6.57E+07
I-136	8.73E+07	RH-109	3.65E+07	**Y-92**	1.23E+08
I-137	9.40E+07	RN-220	5.16E-01	**Y-93**	9.41E+07
I-138	4.80E+07	**RU-103**	1.66E+08	**Y-94**	1.50E+08
I-139	2.22E+07	**RU-105**	1.21E+08	**Y-95**	1.57E+08
I-140	6.06E+06	**RU-106**	6.68E+07	Y-97	1.26E+08
IN-115M	9.17E+05	RU-109	3.16E+07	ZN-72	1.71E+03
IN-121	7.55E+04	**SB-122**	1.57E+05	ZR-101	9.55E+07
IN-121M	7.82E+05	SB-122M	1.57E+04	**ZR-95**	1.65E+08
IN-123	6.87E+05	**SB-124**	1.21E+05	**ZR-97**	1.58E+08
		SB-124M	2.34E+03	ZR-99	1.66E+08

Note:

* Isotopes in **Bold** Font are dose-significant for inhalation, submersion, and direct shine. The parent, grandparent, and second parent of the isotopes in **Bold** Font are also required to address daughter product in-growth.

The group of isotopes needed to determine the "submersion and inhalation" dose in the Control Room and at the Site Boundary is typically a subset of the isotopes listed above in **bold** font, and represent a small group of reasonably long half-life isotopes with significant inhalation dose conversion factors which dominate the TEDE dose.

To determine the total effective dose equivalent (TEDE) resulting from inhalation and submersion following a LOCA, the DCPP LOCA dose consequence analysis uses the default group of 60 isotopes provided with computer code RADTRAD 3.03 plus 13 additional nuclides that were deemed to be dose significant (i.e., Br-82, Br-84, Rb-88, Rb-89, Te-133, Te-133m, Te-134, I-130, Xe-131m, Xe-133m, Xe-138, Cs-138, and Np-238).

** Co-58 / Co-60 are activation products that are developed external to the core and typically do not appear in the equilibrium core inventory

TABLE 15.5-78

PRIMARY AND SECONDARY COOLANT
Technical Specification Activity Concentrations

Nuclide	Primary Coolant (µCi/gm)	Secondary Coolant (µCi/gm)
Kr-83M	1.87E-01	-----
Kr-85M	6.60E-01	-----
Kr-85	5.60E+00	-----
Kr-87	4.41E-01	-----
Kr-88	1.22E+00	-----
Xe-131M	1.88E+00	-----
Xe-133M	1.92E+00	-----
Xe-133	1.29E+02	-----
Xe-135M	4.07E-01	-----
Xe-135	3.76E+00	-----
I-131	7.87E-01	8.06E-02
I-132	3.00E-01	1.94E-02
I-133	1.16E+00	1.08E-01
I-134	1.67E-01	4.78E-03
I-135	6.68E-01	5.09E-02

TABLE15.5-79

PRIMARY COOLANT
Pre-Accident Iodine Spike Concentrations & Equilibrium Iodine Appearance Rates

Nuclide	Pre-Accident Spike RCS Concentrations (60 µCi/gm DE I-131) (µCi/gm)	Equilibrium Iodine Activity Appearance Rates into RCS (µCi/sec)
I-131	47.2	7.18E+03
I-132	17.9	7.78E+03
I-133	69.5	1.25E+04
I-134	10.0	8.91E+03
I-135	40.1	9.91E+03

TABLE 15.5-80
ISOTOPIC GAP ACTIVITY
LOCKED ROTOR ACCIDENT / CONTROL ROD EJECTION ACCIDENT

Nuclide	Core Activity (Ci)	Fraction of Core Activity in Gap LRA	Core Gap Activity w/o Peaking Factor (Ci) LRA	Fraction of Core Activity in Gap CREA	Core Gap Activity w/o Peaking Factor (Ci) CREA
KR-85	1.11E+06	0.35	3.89E+05	0.10	1.11E+05
KR-85M	2.33E+07	0.04	9.32E+05	0.10	2.33E+06
KR-87	4.65E+07	0.04	1.86E+06	0.10	4.65E+06
KR-88	6.43E+07	0.04	2.57E+06	0.10	6.43E+06
Xe-131M	1.42E+06	0.04	5.68E+04	0.10	1.42E+05
Xe-133M	6.42E+06	0.04	2.57E+05	0.10	6.42E+05
XE-133	2.01E+08	0.04	8.04E+06	0.10	2.01E+07
XE-135	4.92E+07	0.04	1.97E+06	0.10	4.92E+06
Xe-138	1.70E+08	0.04	6.80E+06	0.10	1.70E+07
I-130	3.58E+06	0.05	1.79E+05	0.10	3.58E+05
I-131	9.90E+07	0.08	7.92E+06	0.10	9.90E+06
I-132	1.44E+08	0.23	3.31E+07	0.10	1.44E+07
I-133	2.01E+08	0.05	1.01E+07	0.10	2.01E+07
I-134	2.22E+08	0.05	1.11E+07	0.10	2.22E+07
I-135	1.92E+08	0.05	9.60E+06	0.10	1.92E+07
BR-82	4.44E+05	0.05	2.22E+04	0.10	4.44E+04
BR-84	2.10E+07	0.05	1.05E+06	0.10	2.10E+06
CS-134	2.41E+07	0.46	1.11E+07	-	-
CS-136	7.01E+06	0.46	3.22E+06	-	-
CS-137	1.37E+07	0.46	6.30E+06	-	-
CS-138	1.85E+08	0.46	8.51E+07	-	-
RB-86	2.50E+05	0.46	1.15E+05	-	-
Rb-88	6.60E+07	0.46	3.04E+07	-	-
Rb-89	8.57E+07	0.46	3.94E+07	-	-

Note: Values reported reflect the core isotopic gap activity assumed for the LRA and CREA. These values have to be adjusted for a) the failed fuel percentage (10%) and b) peaking factor (1.65), prior to assessing the associated dose consequences

For the isotopic gap activity associated with the FHA refer to Table 15.5-47C

TABLE 15.5-81

CONTROL ROOM
Analysis Assumptions & Key Parameter Values

Parameter	Value
Free Volume	170,000 ft^3
Unfiltered Normal Operation Intake	Total 4200 cfm ± 10% Unit 1: 2100 cfm ± 10% Unit 2: 2100 cfm ± 10%
Emergency Pressurization Flow Rate	650 – 1300 cfm*
Maximum Unfiltered Backdraft Damper Leakage during CR Pressurization Operation	100 cfm
Carbon / HEPA Filter Flow during CR Pressurization Operation	1800 – 2800 cfm*
Emergency Filtered Recirculation Rate	1250 – 1600 cfm*
Pressurization Intake and Recirculation Carbon/HEPA Filter Efficiency (includes filter bypass)	93% (iodine) 98% (particulates)
Unfiltered Inleakage (Normal and Pressurization Mode)	70 cfm (maximum) Includes 10 cfm egress-ingress
Occupancy Factors	0-24 hr (1.0)
	1 - 4 d (0.6)
	4-30 d (0.4)
Operator Breathing Rate	0-30 d (3.50E-04 m^3/sec)

* Non-TS/ECG related

TABLE 15.5-82

TECHNICAL SUPPORT CENTER
Analysis Assumptions & Key Parameter Values

Parameter	Value
Free Volume	51,250 ft^3
Filtered (HEPA only) Normal Operation Intake Flow Rate	500 cfm
Normal Intake HEPA Filter Efficiency (includes filter bypass)	98% (particulates)
Filtered (Carbon / HEPA) Pressurization Flow Rate	500 cfm
Flow through Carbon / HEPA Filter during Pressurization mode	1000 cfm
Filtered Recirculation flow rate during Pressurization mode	500 cfm (minimum)
Pressurization Intake and Recirculation Carbon / HEPA Filter Efficiency (includes filter bypass)	93% (iodine) 98% (particulates)
Unfiltered Inleakage	60 cfm (maximum) Includes 10 cfm egress-ingress
Occupancy Factors	0-24 hr (1.0)
	1 - 4 d (0.6)
	4-30 d (0.4)
Operator Breathing Rate	0-30 d (3.50E-04 m^3/sec)

TABLE 15.5-83
NON-LOCA EVENTS
Technical Support Center Limiting Atmospheric Dispersion Factors (sec/m^3)

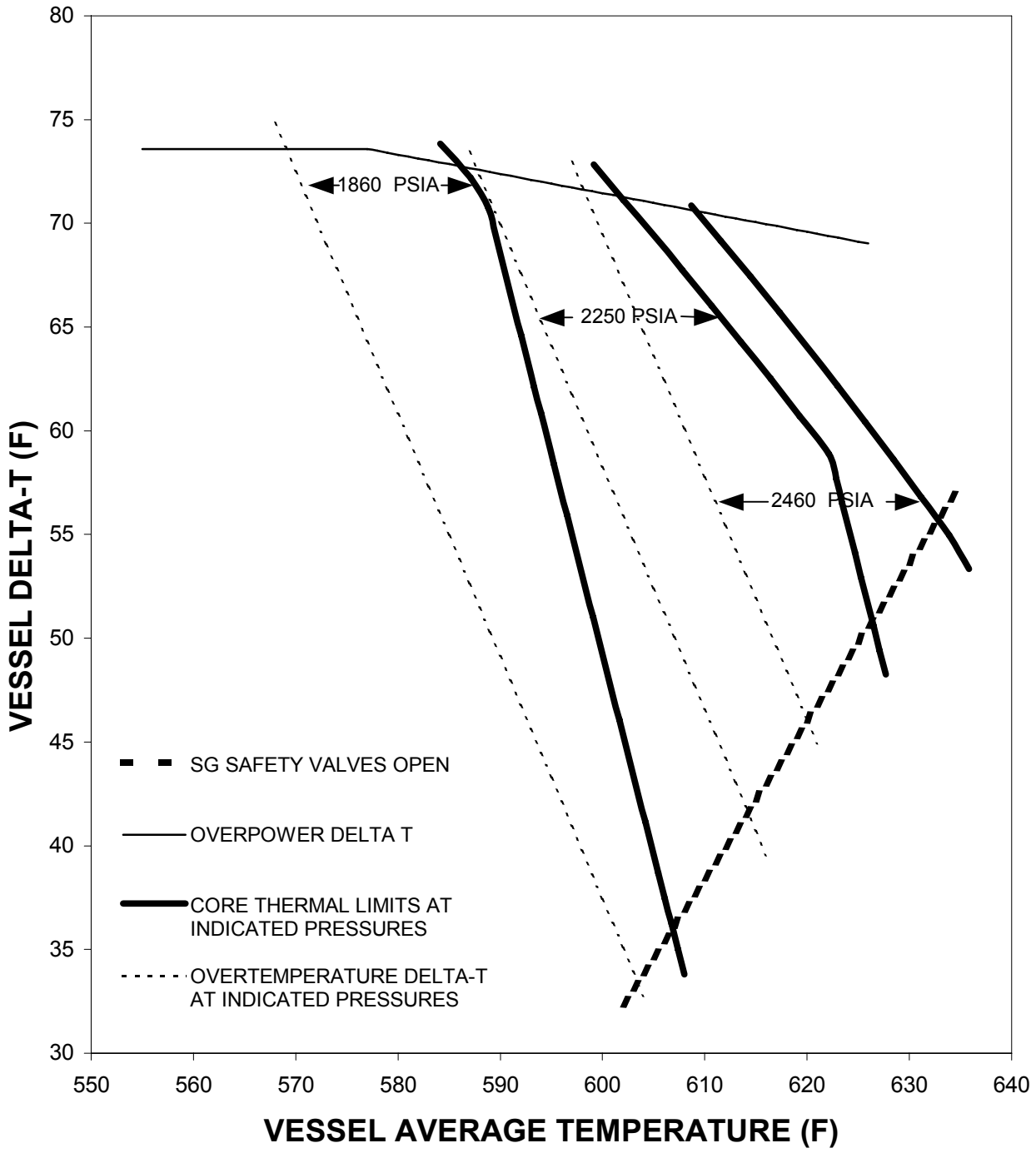
Receptor - Release Point	0-2 hr	2-8 hr	8-10.73hr	10.73-30hr	
MSLB					
TSC NOP Intake - Faulted SG (Break Location)	9.00E-04	-----	-----	-----	
TSC NOP Intake - Intact SG (MSSVs/10% ADVs)	1.80E-04	-----	-----	-----	
TSC Inleakage - Faulted SG (Break Location)	1.01E-03	4.62E-04	1.93E-04	1.93E-04	
TSC Inleakage - Intact SG (MSSVs/10% ADVs)	2.02E-04	9.24E-05	9.24E-05	-----	
CR/TSC Pressurization Intake - Faulted SG (Break Location)	-----	4.70E-05	1.85E-05	1.85E-05	
CR/TSC Pressurization Intake - Intact SG (MSSVs/10% ADVs)	-----	9.40E-06	9.40E-06	-----	
SGTR / LRA / LOL / CREA (Secondary Side Release Scenario)					
TSC Center of Roof - MSSVs/10% ADVs	2.02E-04	9.24E-05	9.24E-05	---	
FHA					
TSC Center of Roof - Equipment Hatch	7.44E-04	-----	-----	-----	
Receptor - Release Point	0-2 hr	2-8 hr	8-24hr	1-4 days	4-30 days
CREA (Containment Release Scenario)					
TSC NOP Intake - Containment Leakage	1.71E-03	-----	-----	-----	-----
TSC Inleakage - Containment Leakage	1.76E-03	7.16E-04	3.01E-04	2.84E-	2.28E-04
CR/TSC Pressurization Intake - Containment Leakage	-----	3.98E-05	1.63E-05	1.37E-05	1.10E-05

Note1: The selection of the χ/Q values for the release points/ receptors listed above are intended to provide bounding dose estimates for an event at either unit.

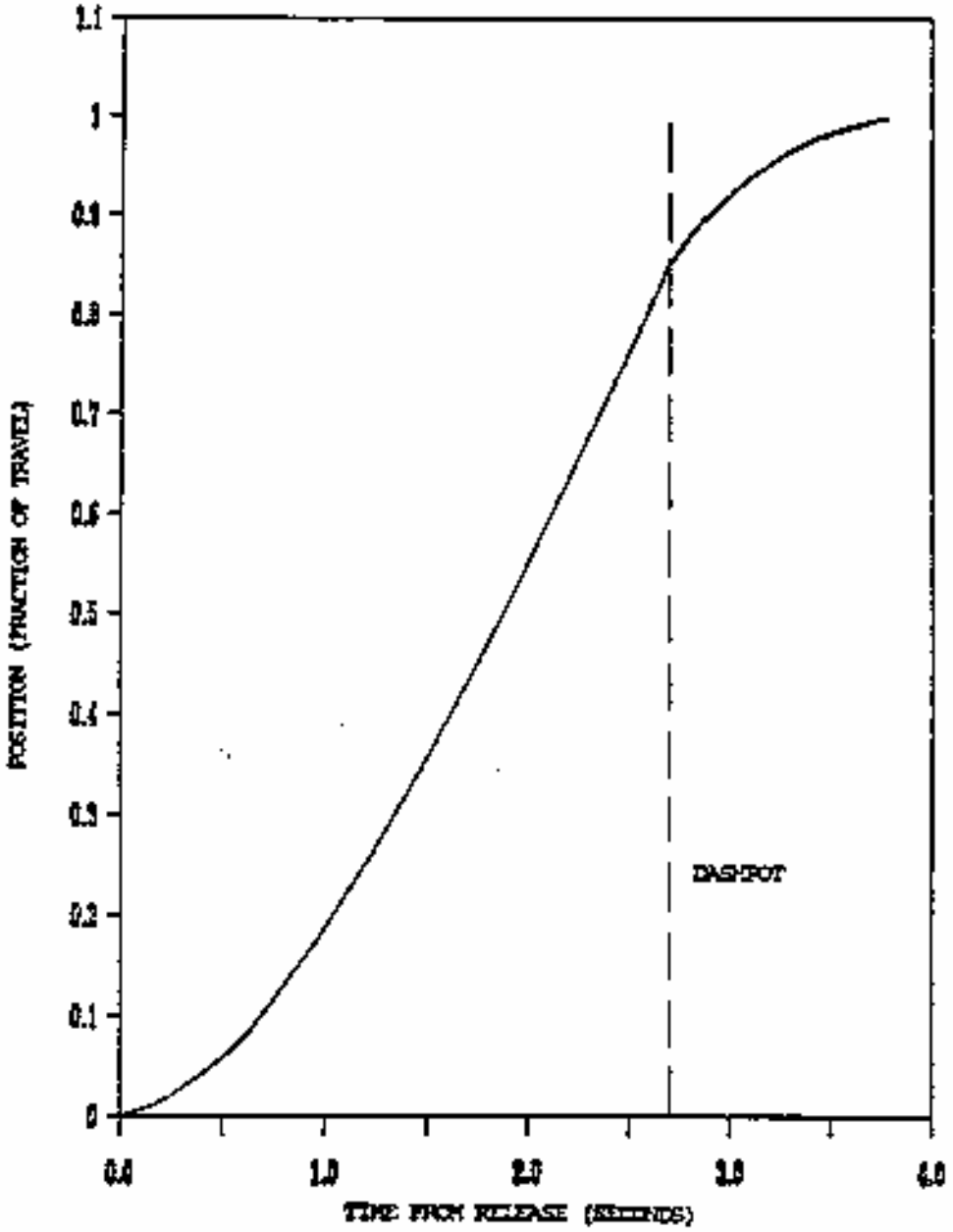
- Except as noted below for the CREA Containment leakage release point to the CR/TSC Pressurization Intakes, the χ/Q values for U2 release points are bounding for all TSC receptors (i.e., the TSC NOP Intake, the TSC Center of Roof (also used for TSC Inleakage) and the CR/TSC Pressurization Intakes). Releases from the containment penetration areas are based on the Unit 2 GW/FW area release point.
- Releases from the containment penetration areas to the CR/TSC pressurization intakes are based on the Unit 2 GW/FW area releases to the Unit 1 CR/TSC intake for the 2-24 hrs time period, from the Unit 2 GE area releases to the Unit 1 CR/TSC intake for the 1-4 day time period and from the Unit 1 GW/FW area releases to the Unit 2 CR/TSC intake for the 4-30 day time period.

Note 2: The χ/Q values presented above for MSSVs / 10% ADVs reflect a factor of 5 reduction to address the high vertical velocity discharge for the first 10.73 hours of the accident.

Note 3: The χ/Q values presented above for the CR/TSC pressurization intake reflect a factor of 4 reduction to address the availability of redundant safety related radiation monitors at each CR/TSC pressurization intake location, and the associated capability of initial selection of the less contaminated intake.

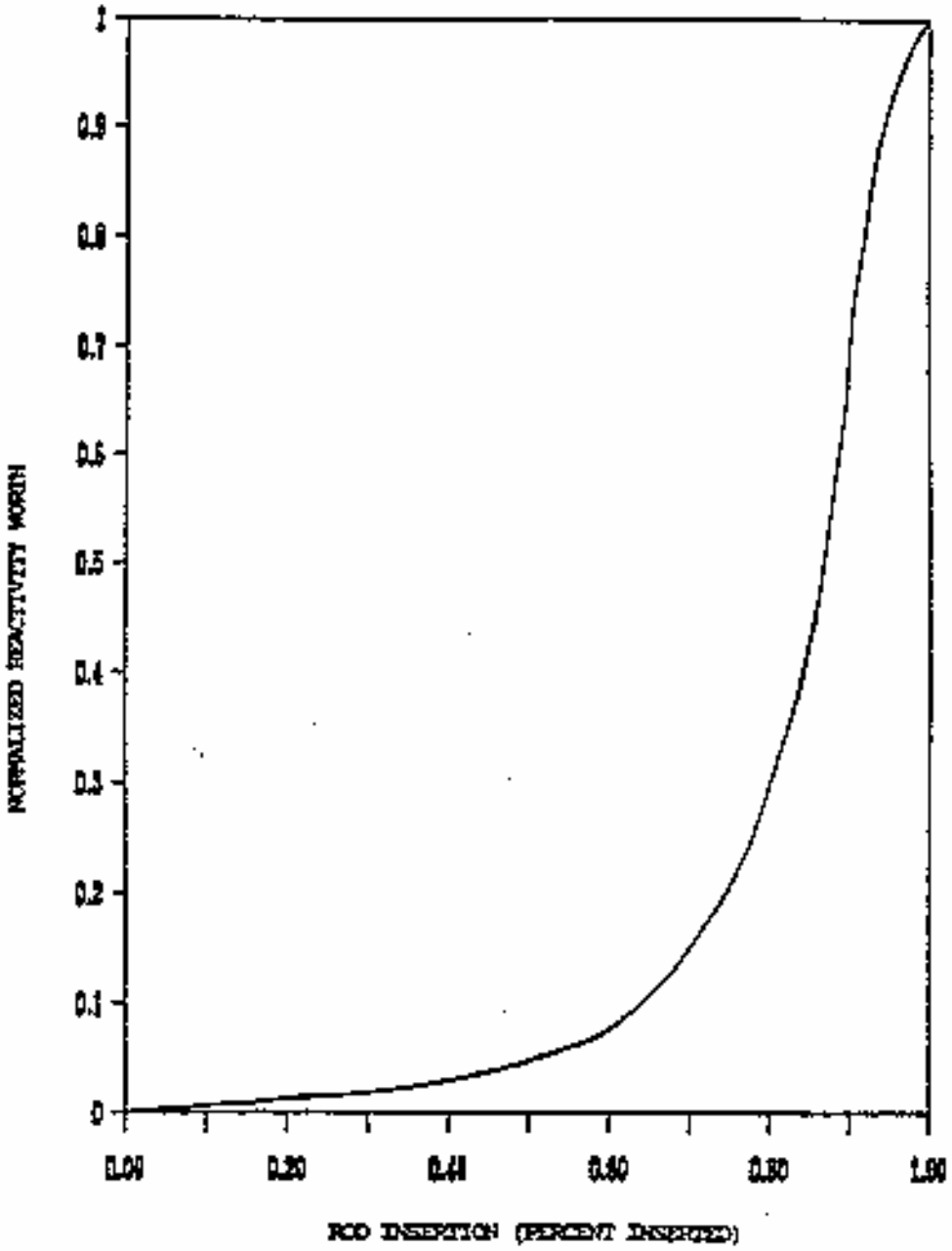


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.1-1 ILLUSTRATION OF OVERPOWER AND OVERTEMPERATURE ΔT PROTECTION

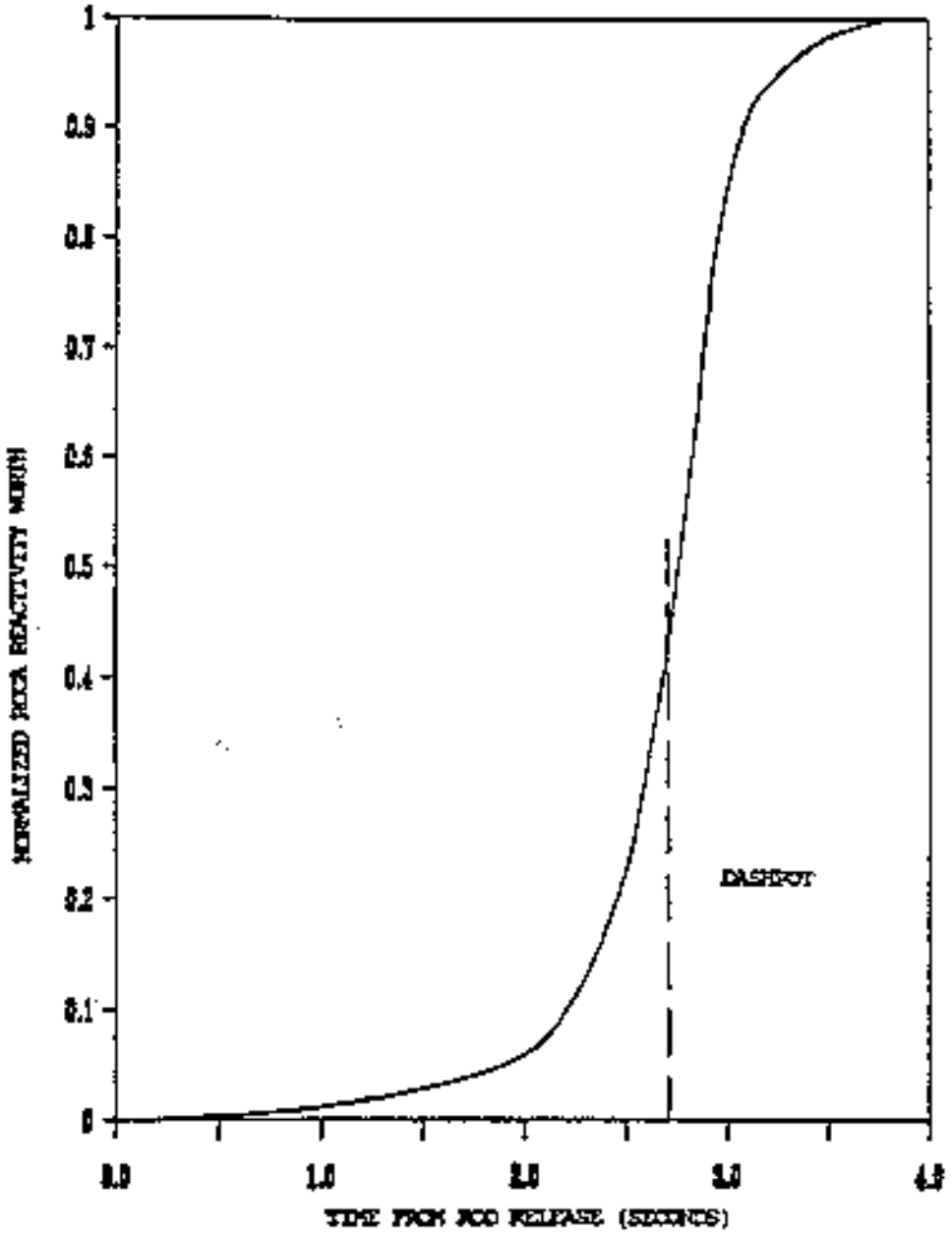


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.1-2 ROD POSITION VERSUS TIME ON REACTOR TRIP

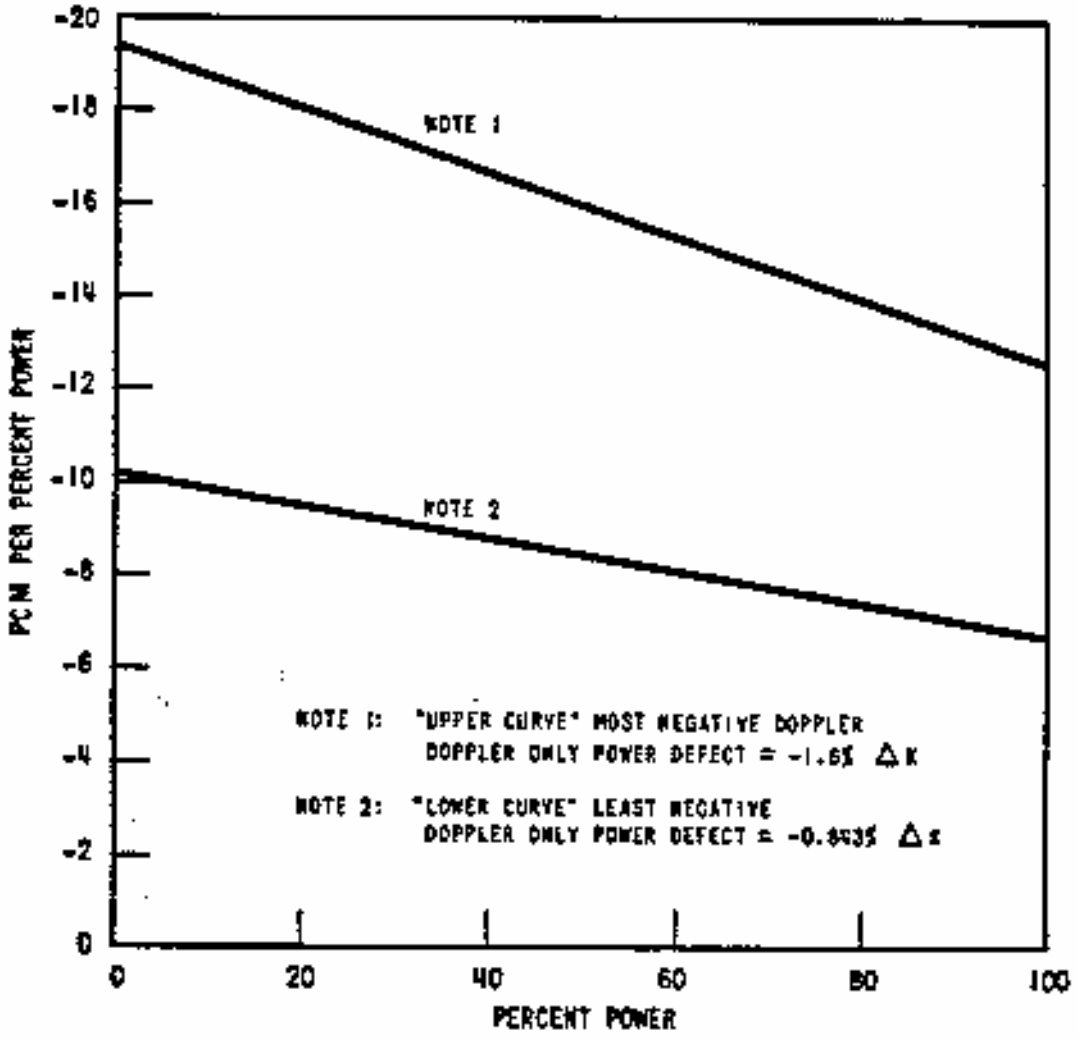
Revision 11 November 1996



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.1-3 NORMALIZED RCCA REACTIVITY WORTH VERSUS PERCENT INSERTION

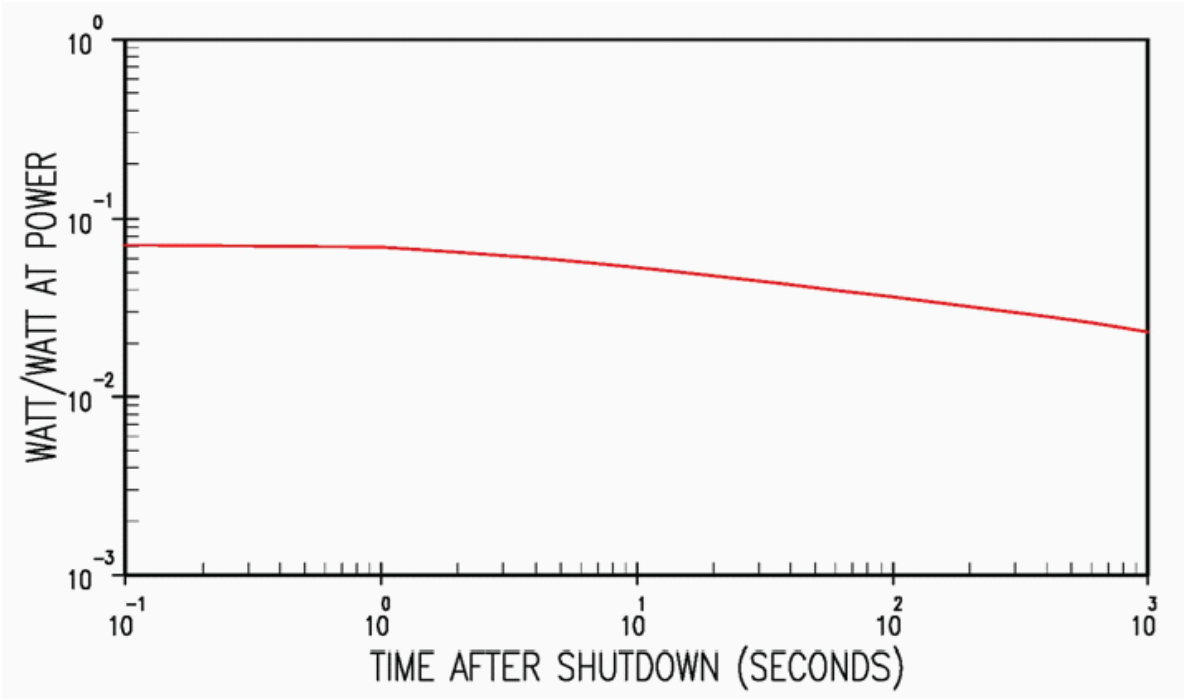


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.1-4 NORMALIZED RCCA BANK REACTIVITY WORTH VERSUS TIME AFTER TRIP



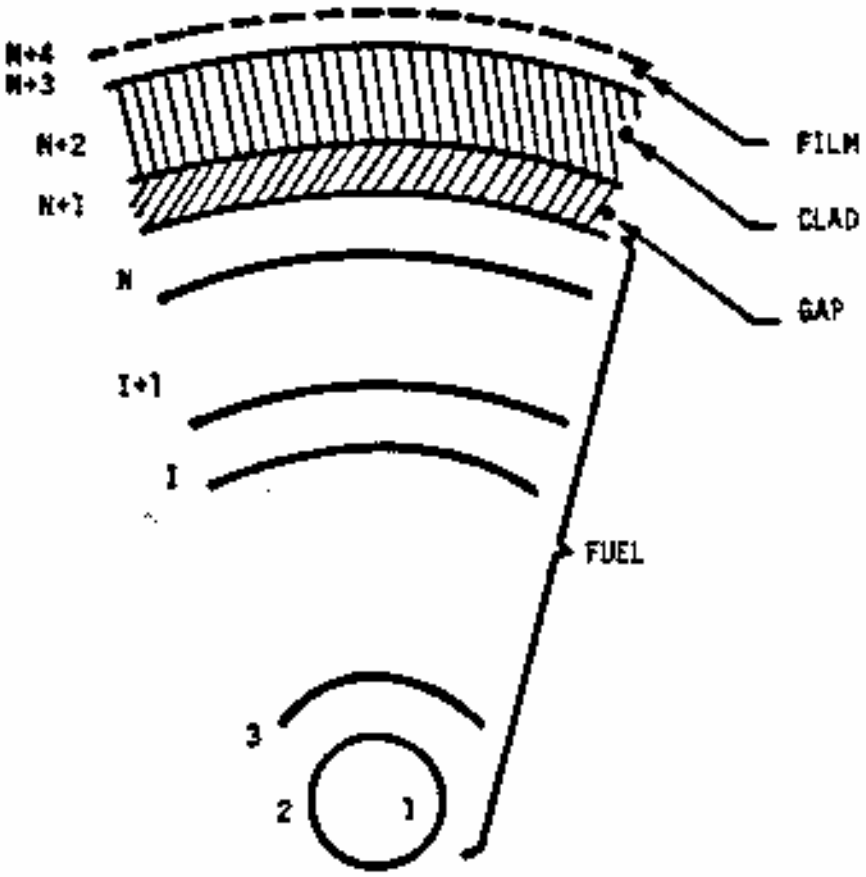
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.1-5 DOPPLER POWER COEFFICIENT USED IN ACCIDENT ANALYSIS

Revision 11 November 1996

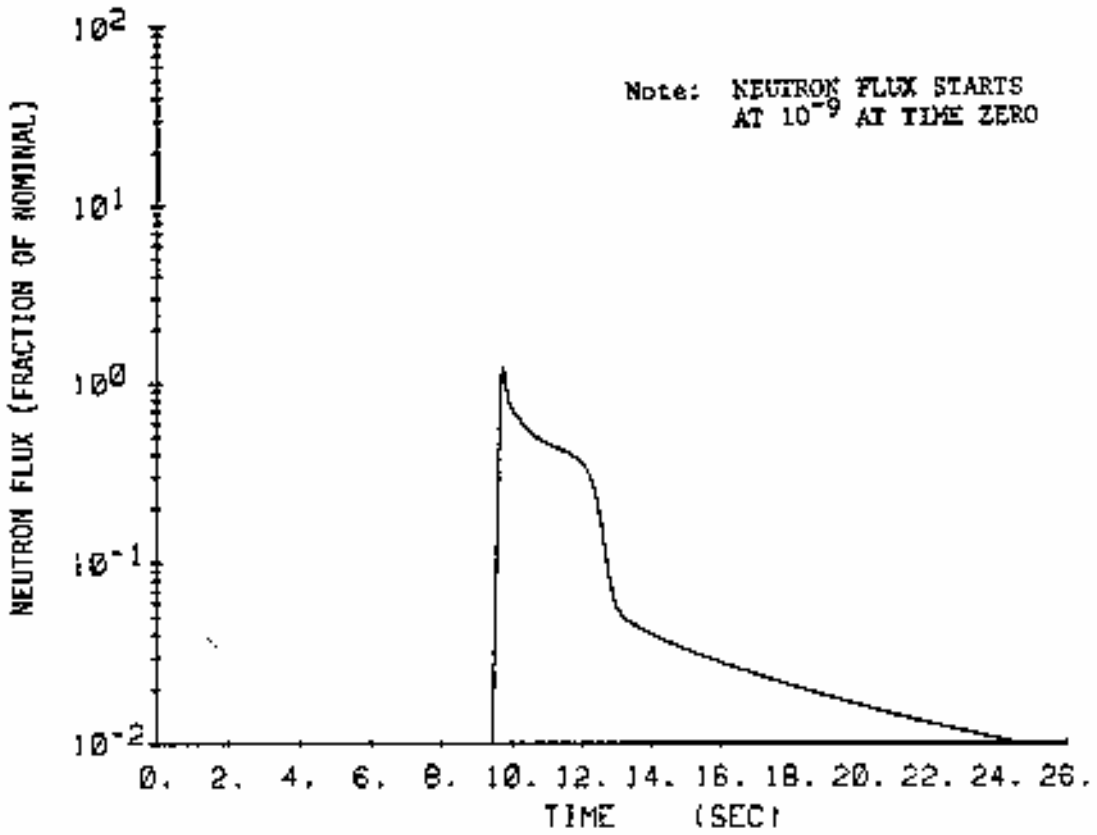


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.1-7 1979 ANS DECAY HEAT CURVE (USED FOR NON-LOCA ANALYSES)

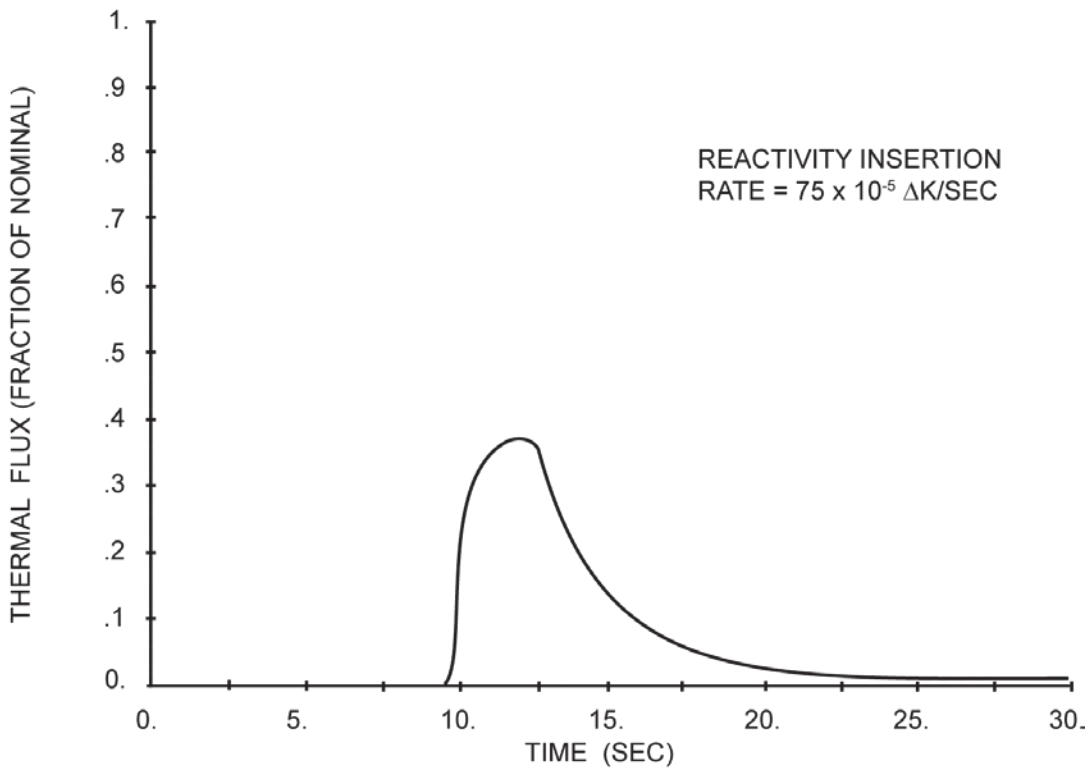
Revision 22 May 2015



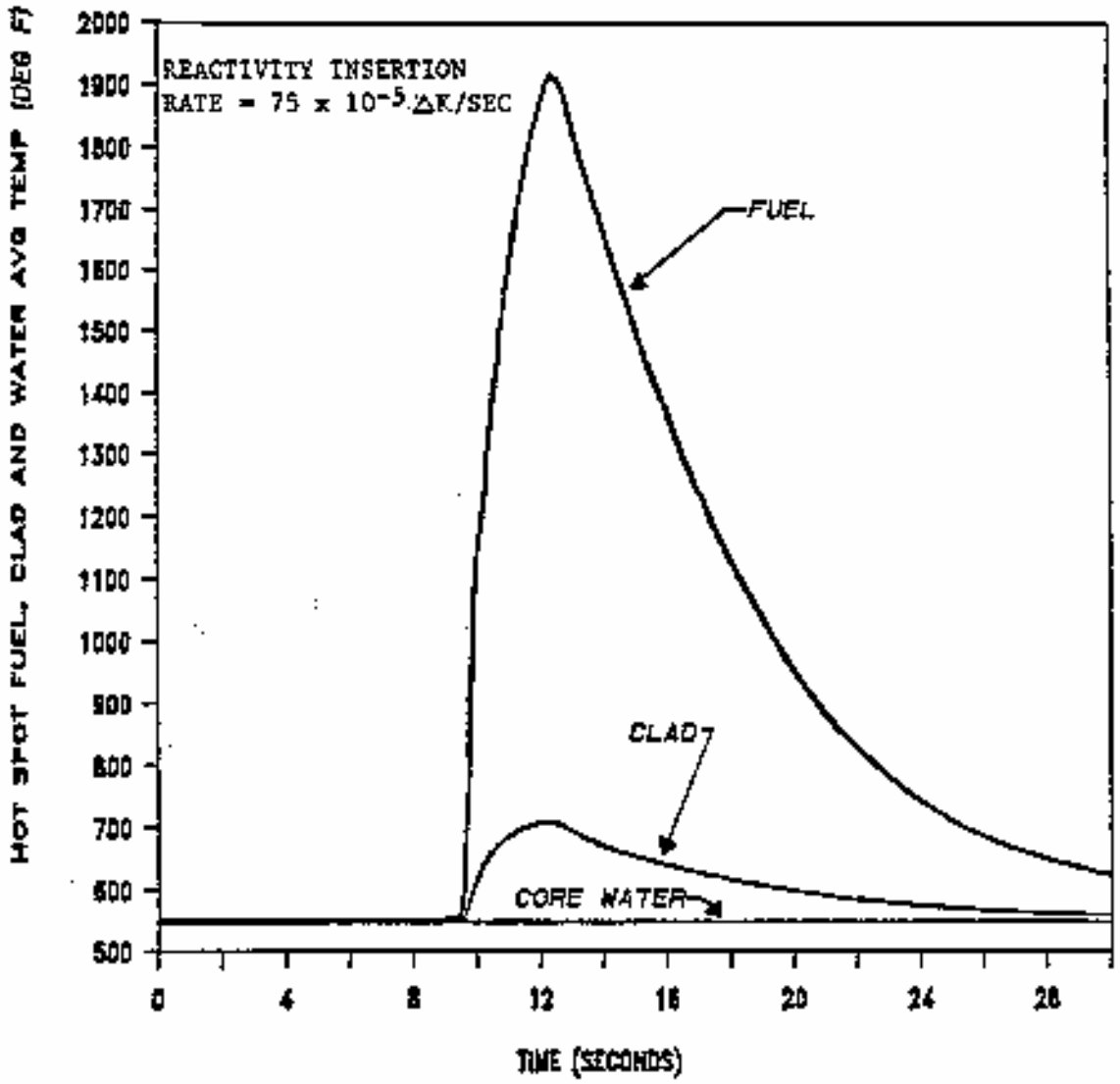
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.1-8 FUEL ROD CROSS SECTION



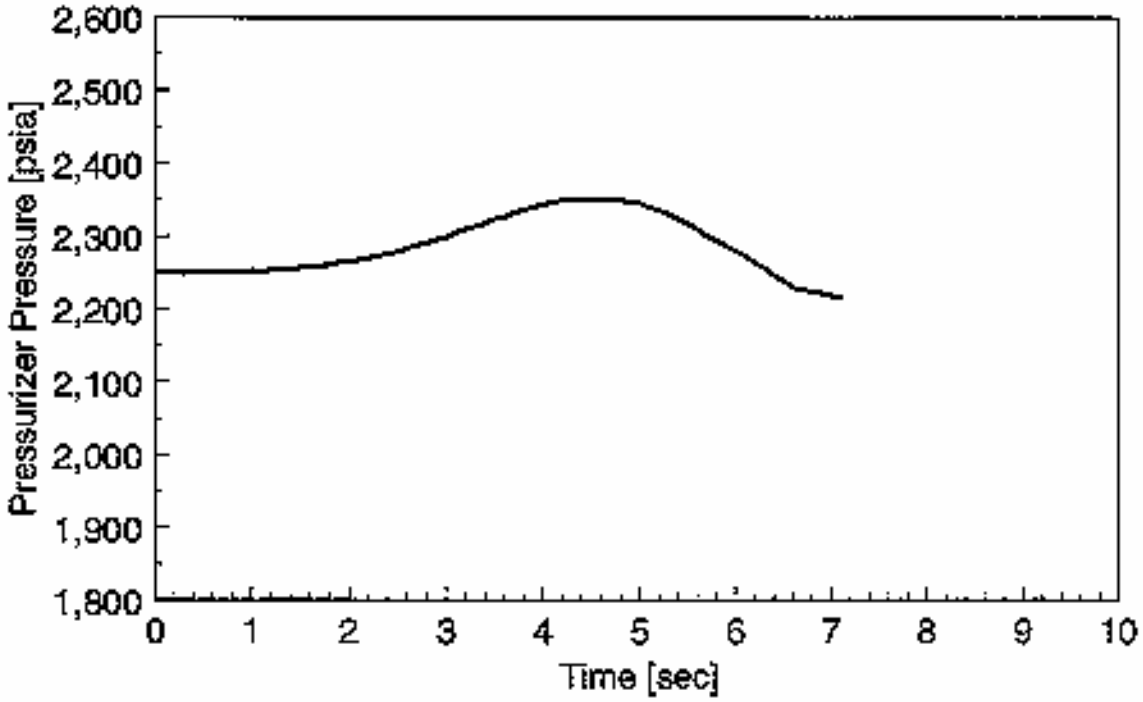
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.1-1 UNCONTROLLED ROD WITHDRAWAL FROM A SUBCRITICAL CONDITION NEUTRON FLUX VERSUS TIME

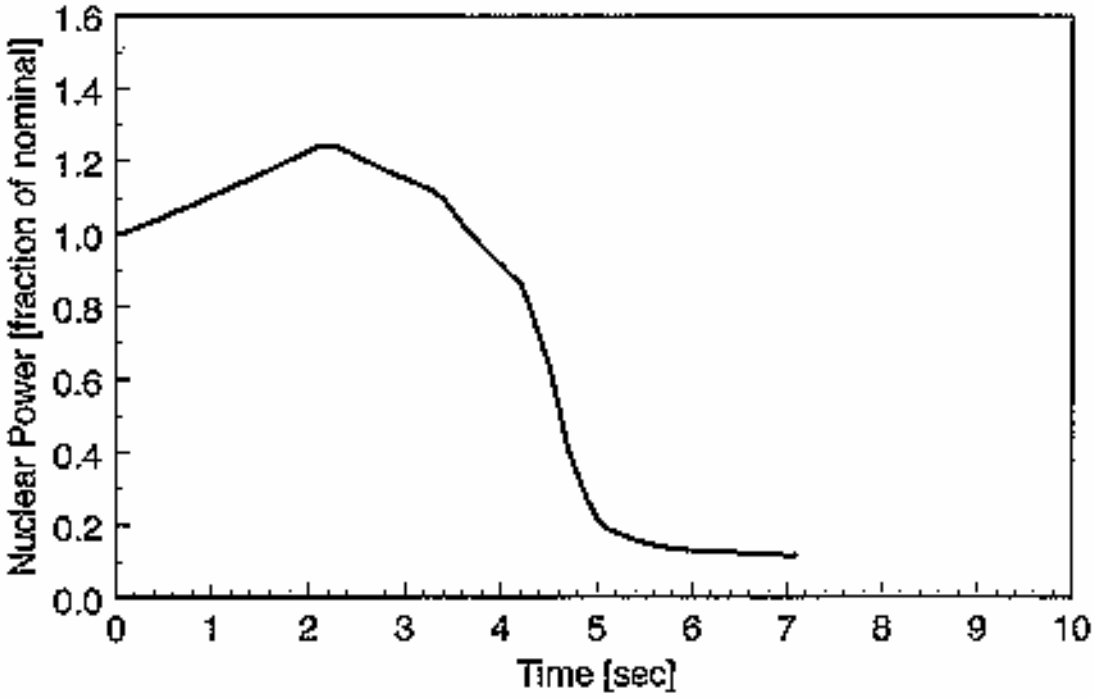


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.1-2 UNCONTROLLED ROD WITHDRAWAL FROM A SUBCRITICAL CONDITION AVERAGE CHANNEL THERMAL FLUX VERSUS TIME

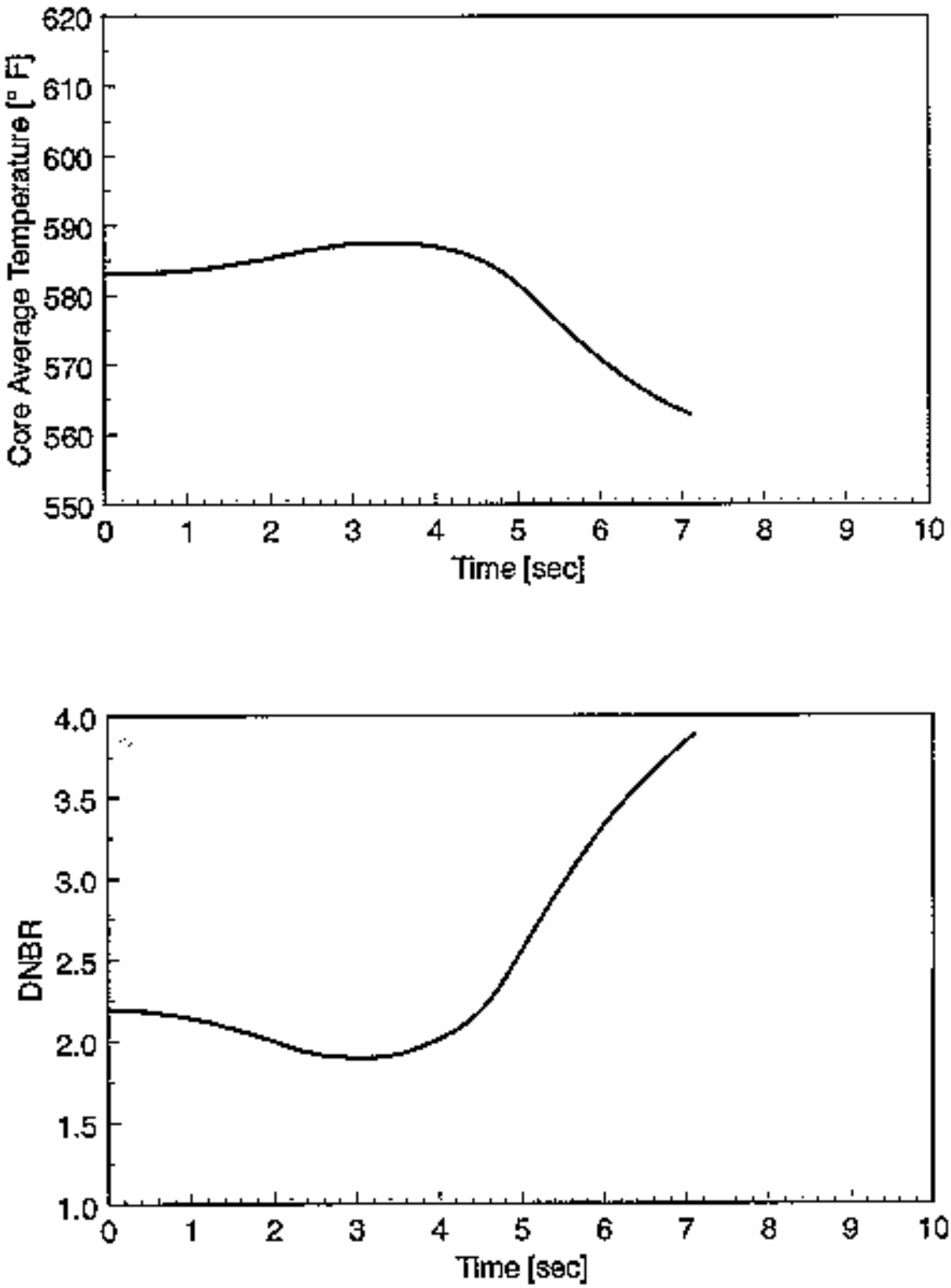


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.1-3 UNCONTROLLED ROD WITHDRAWAL FROM A SUBCRITICAL CONDITION TEMPERATURE VERSUS TIME. REACTIVITY INSERTION RATE 75 X 10^{-5} DELTA K/SEC

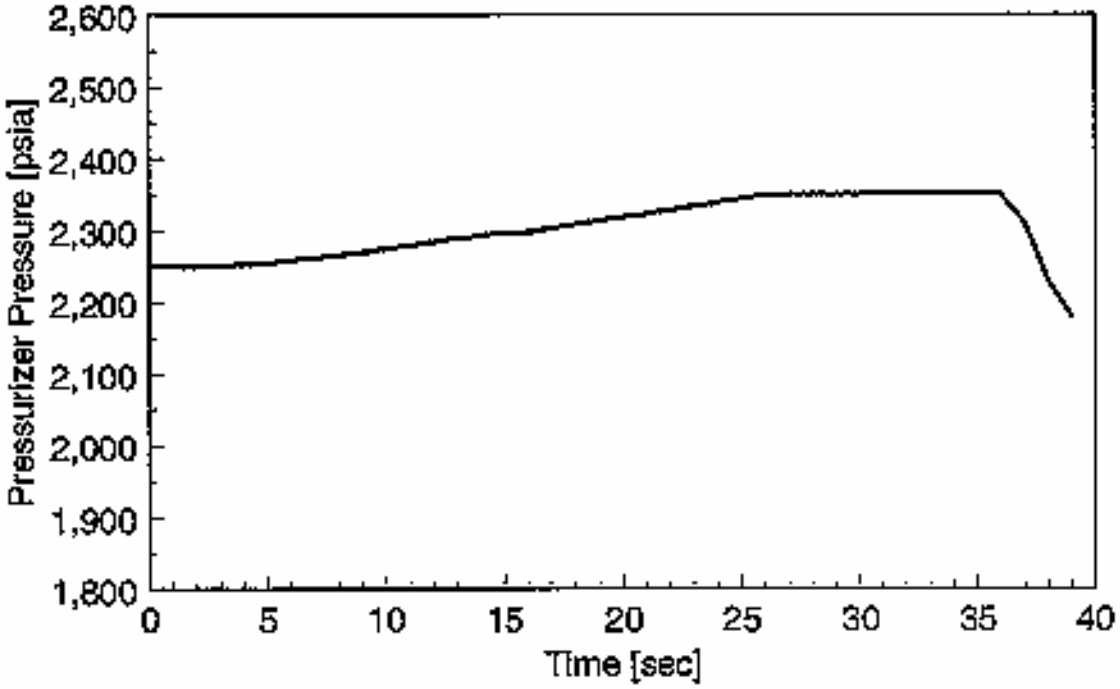


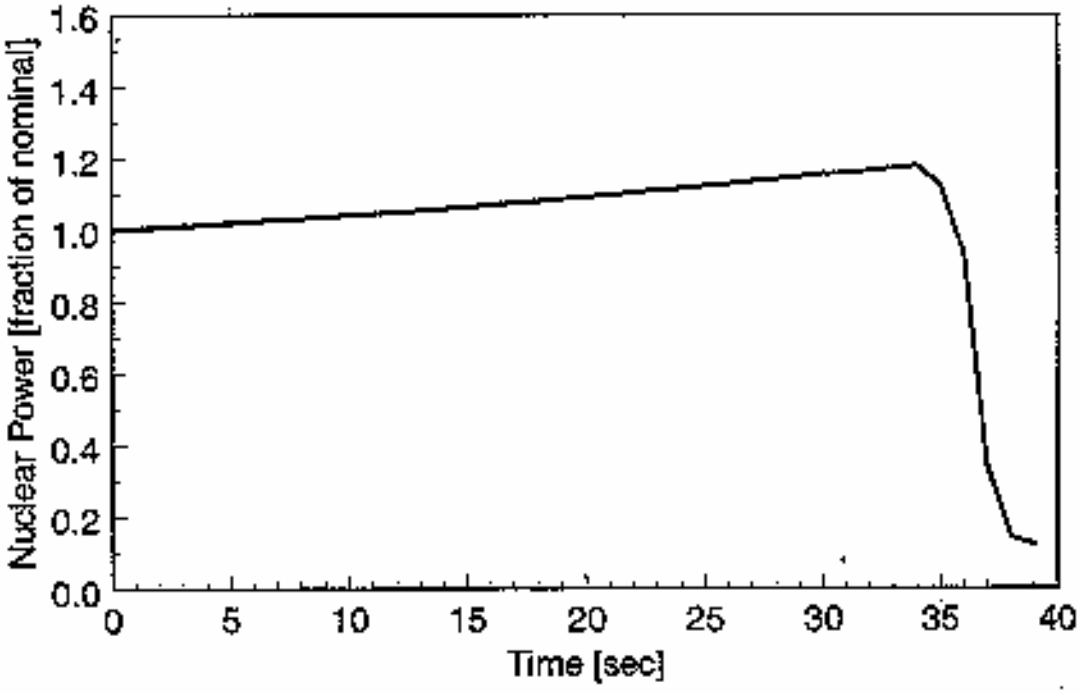


ROD WITHDRAWAL AT POWER **Minimum Feedback, 75 pcm/sec Insertion Rate**	**DIABLO CANYON UNITS 1 & 2** **FIGURE 15.2.2-1**

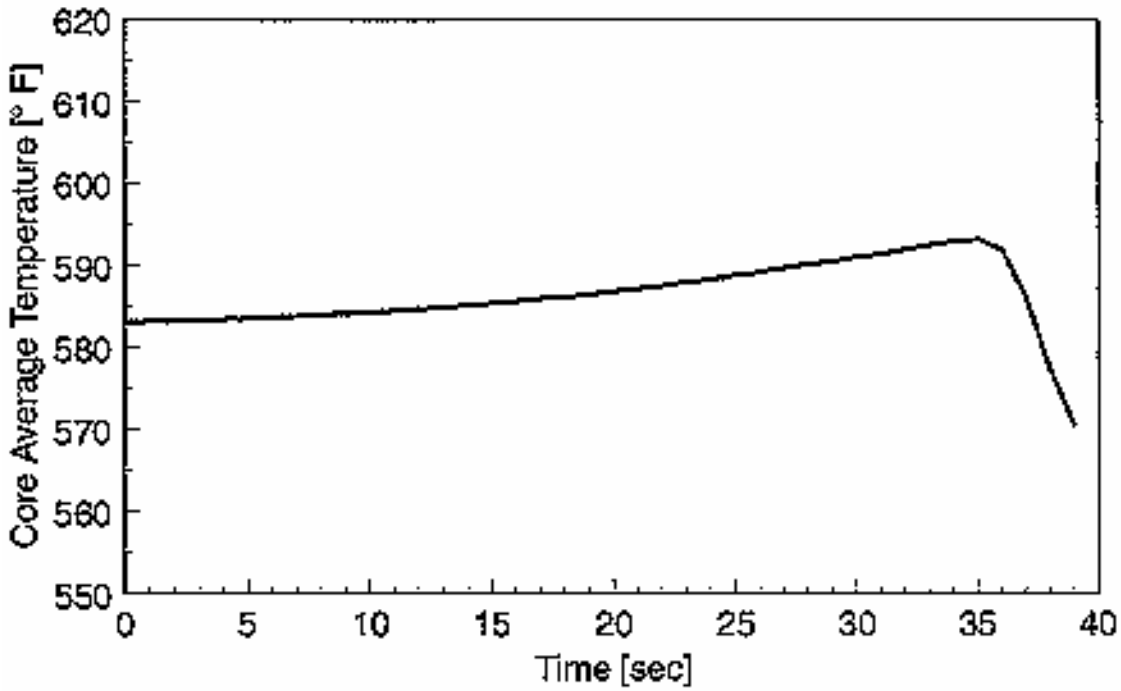


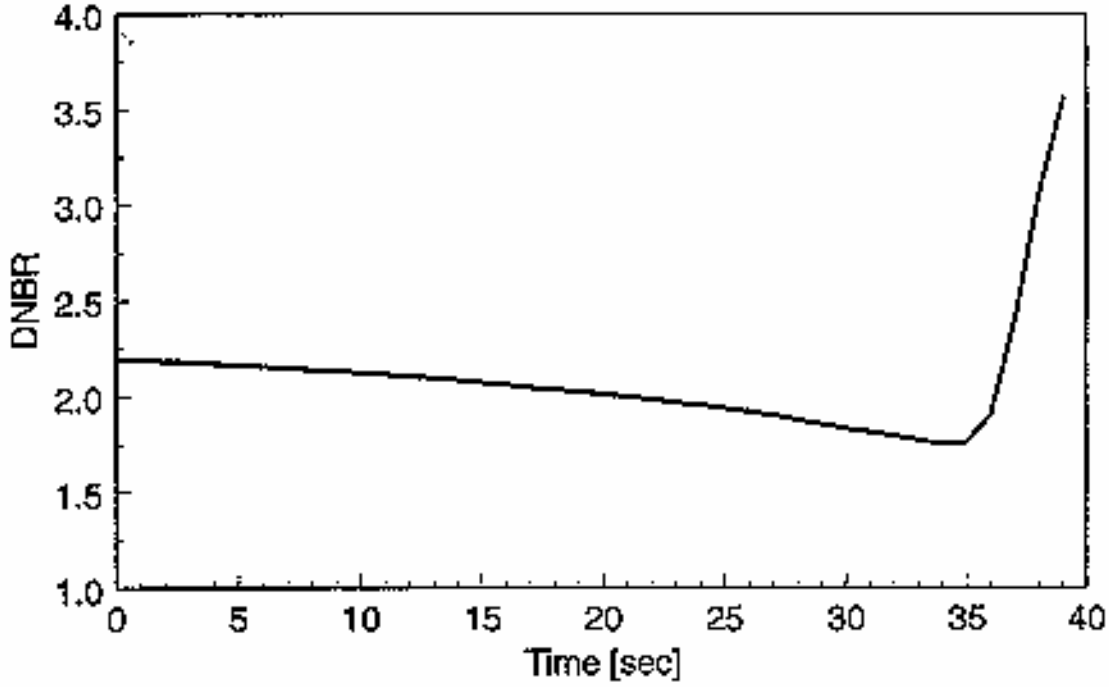
ROD WITHDRAWAL AT POWER Minimum Feedback, 75 pcm/sec Insertion Rate	DIABLO CANYON UNITS 1 & 2
	FIGURE 15.2.2-2



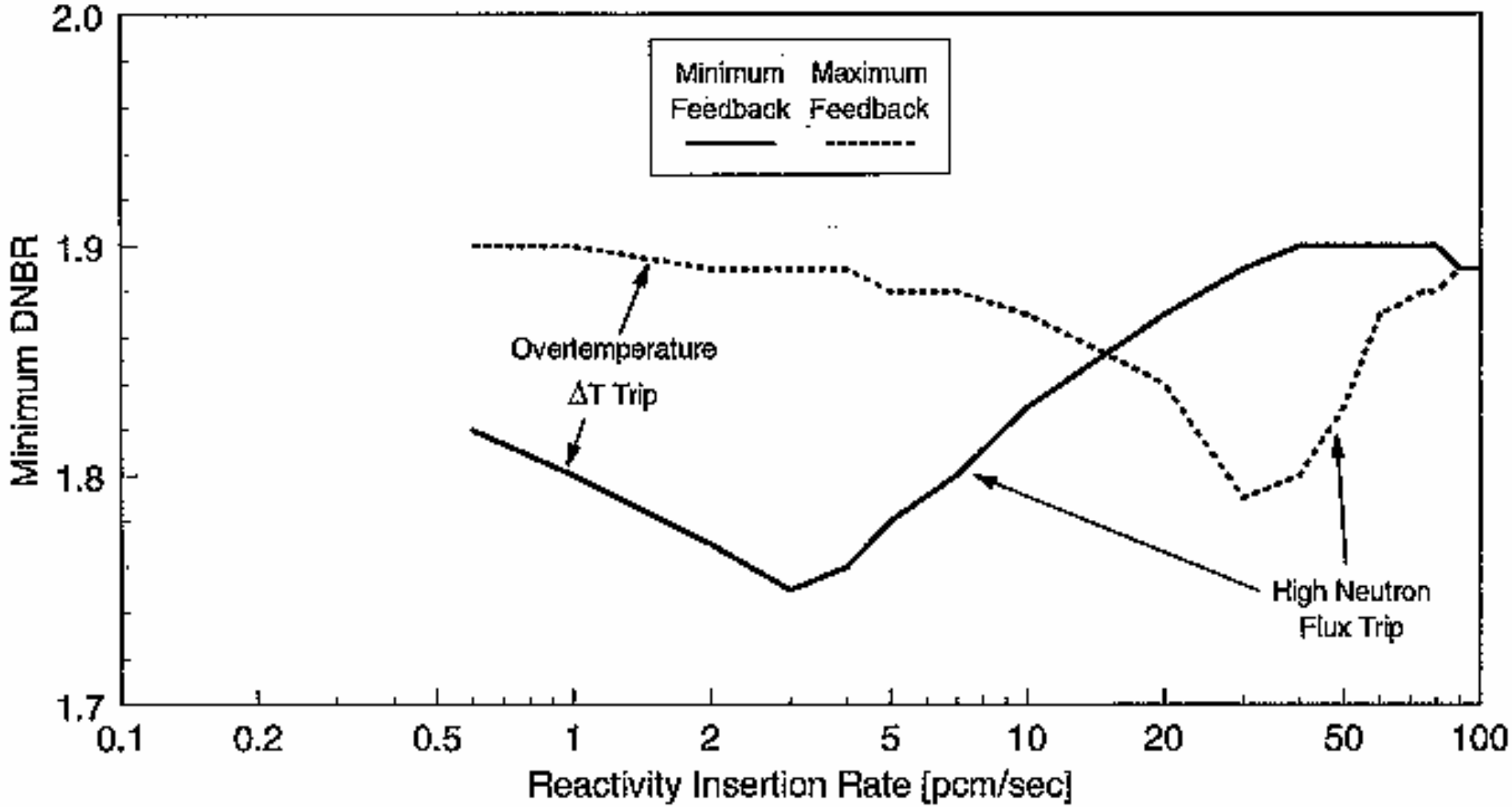


ROD WITHDRAWAL AT POWER **Minimum Feedback, 3 pcm/sec Insertion Rate**	**DIABLO CANYON UNITS 1 & 2**
	FIGURE 15.2.2-3



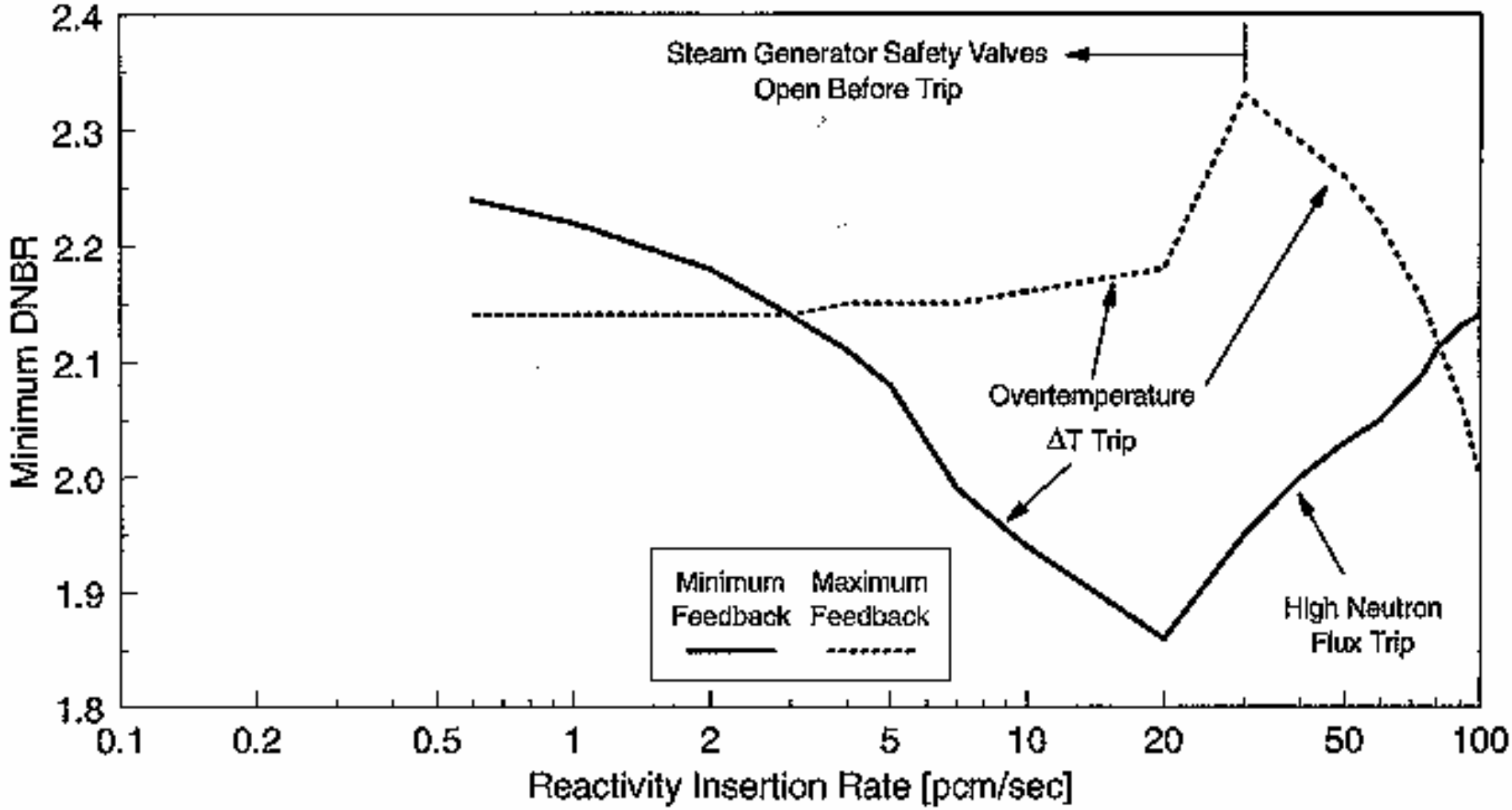


ROD WITHDRAWAL AT POWER Minimum Feedback, 3 pcm/sec Insertion Rate	DIABLO CANYON UNITS 1 & 2
	FIGURE 15.2.2-4

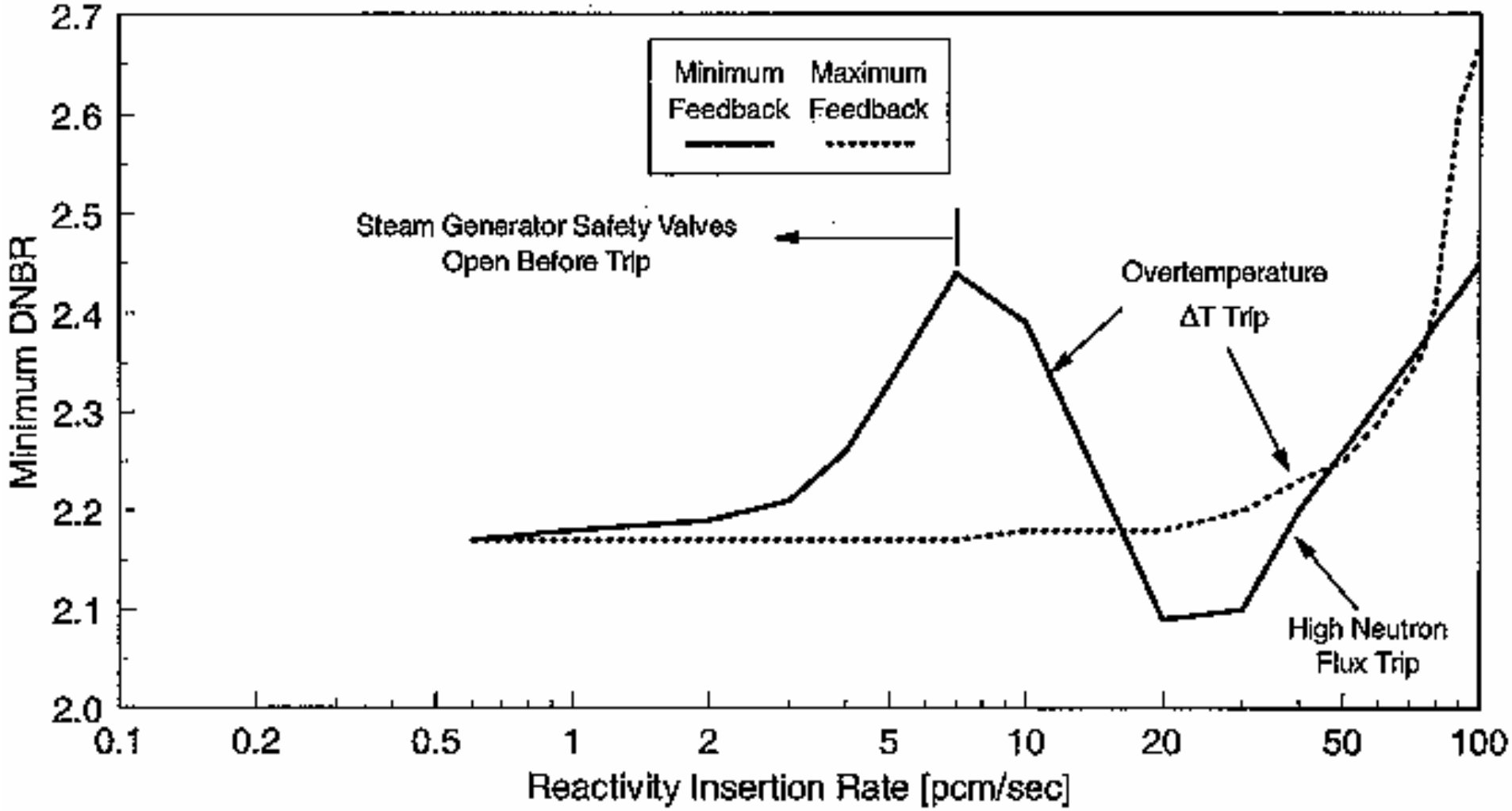


ROD WITHDRAWAL AT POWER **Reactivity Insertion Rate vs. DNBR** **For 100% Power Cases**	**DIABLO CANYON** **UNITS 1 & 2** **FIGURE 15.2.2-5**

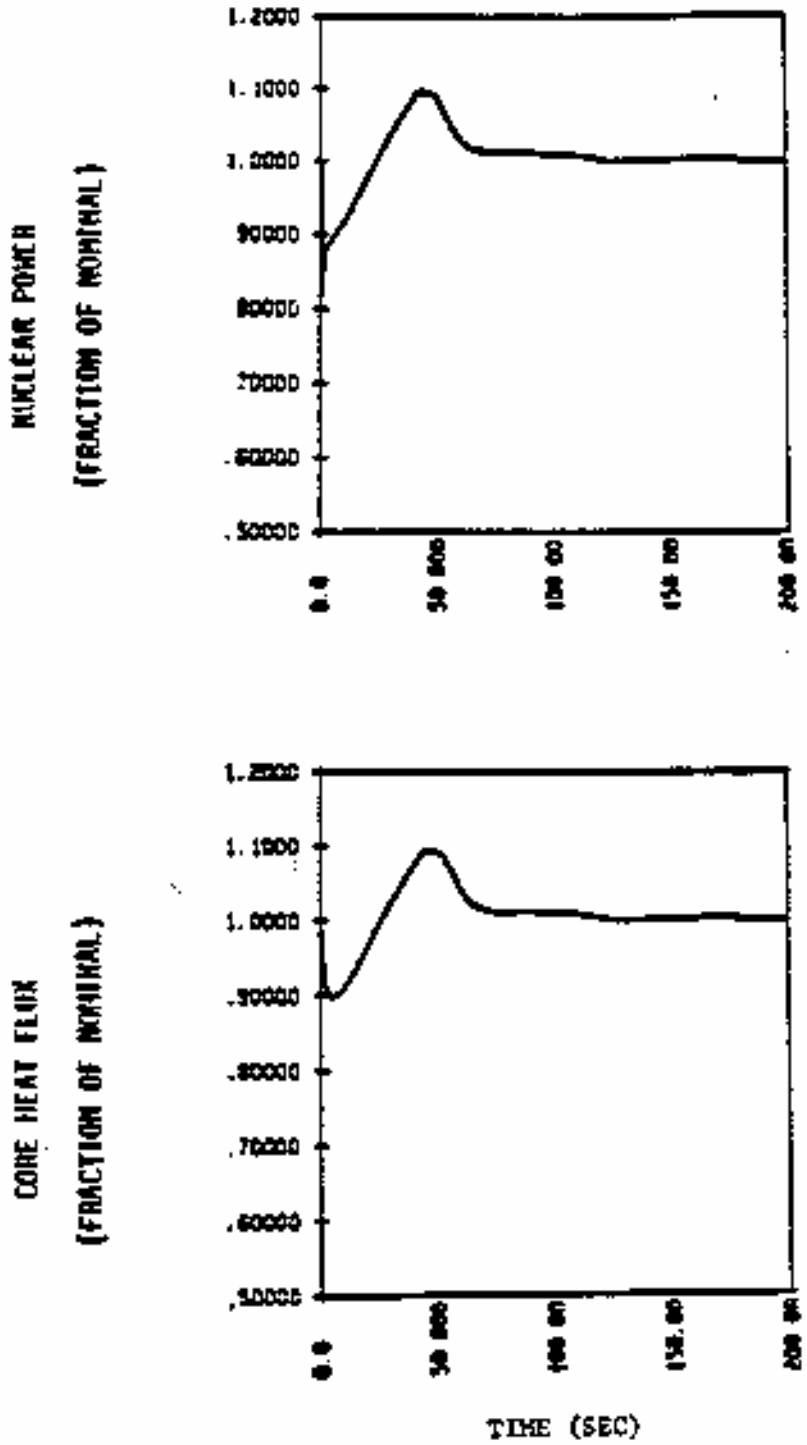
Revision 11 November 1996



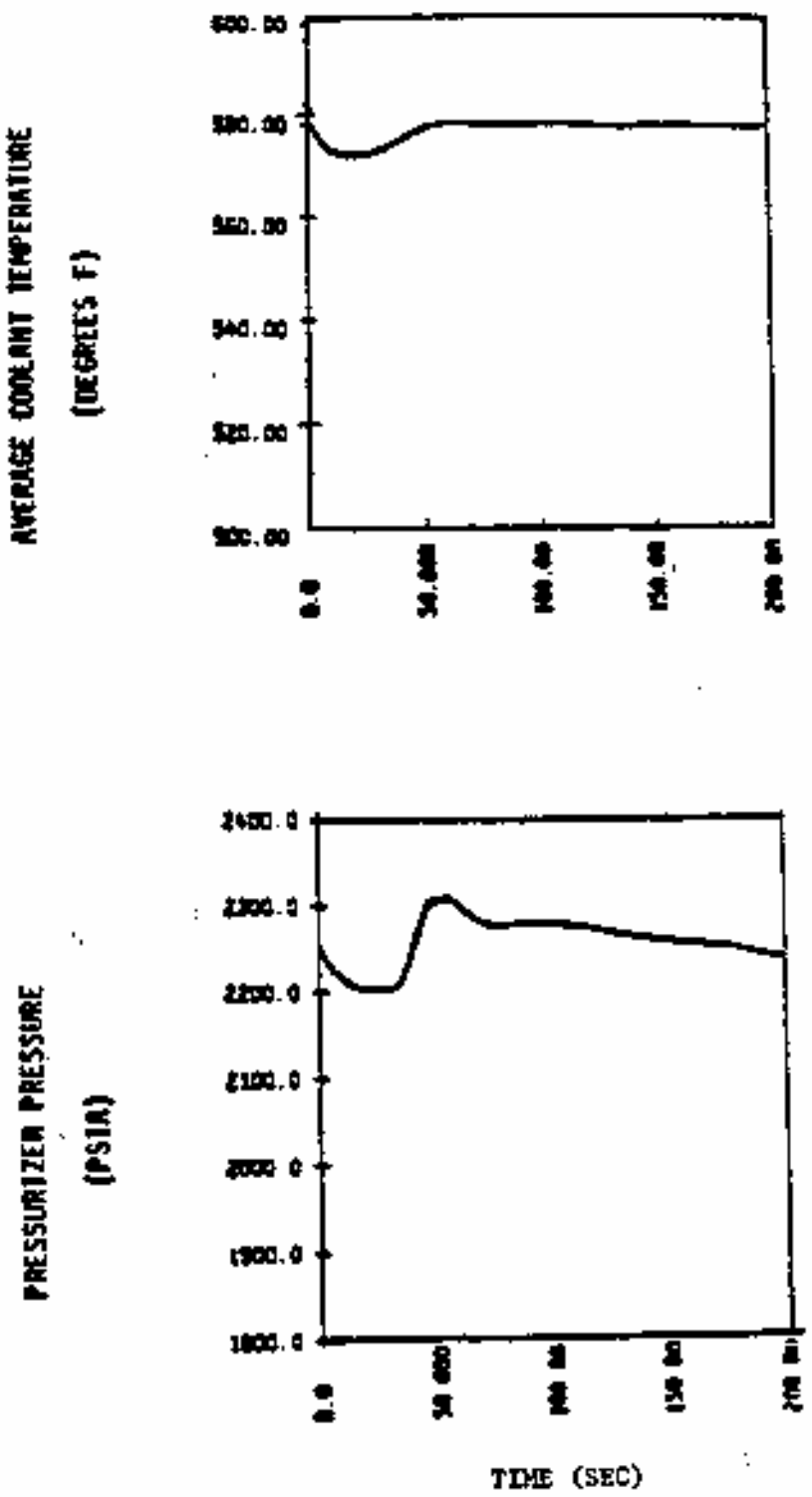
ROD WITHDRAWAL AT POWER **Reactivity Insertion Rate vs. DNBR** **For 60% Power Cases**	**DIABLO CANYON** **UNITS 1 & 2**
	FIGURE 15.2.2-6



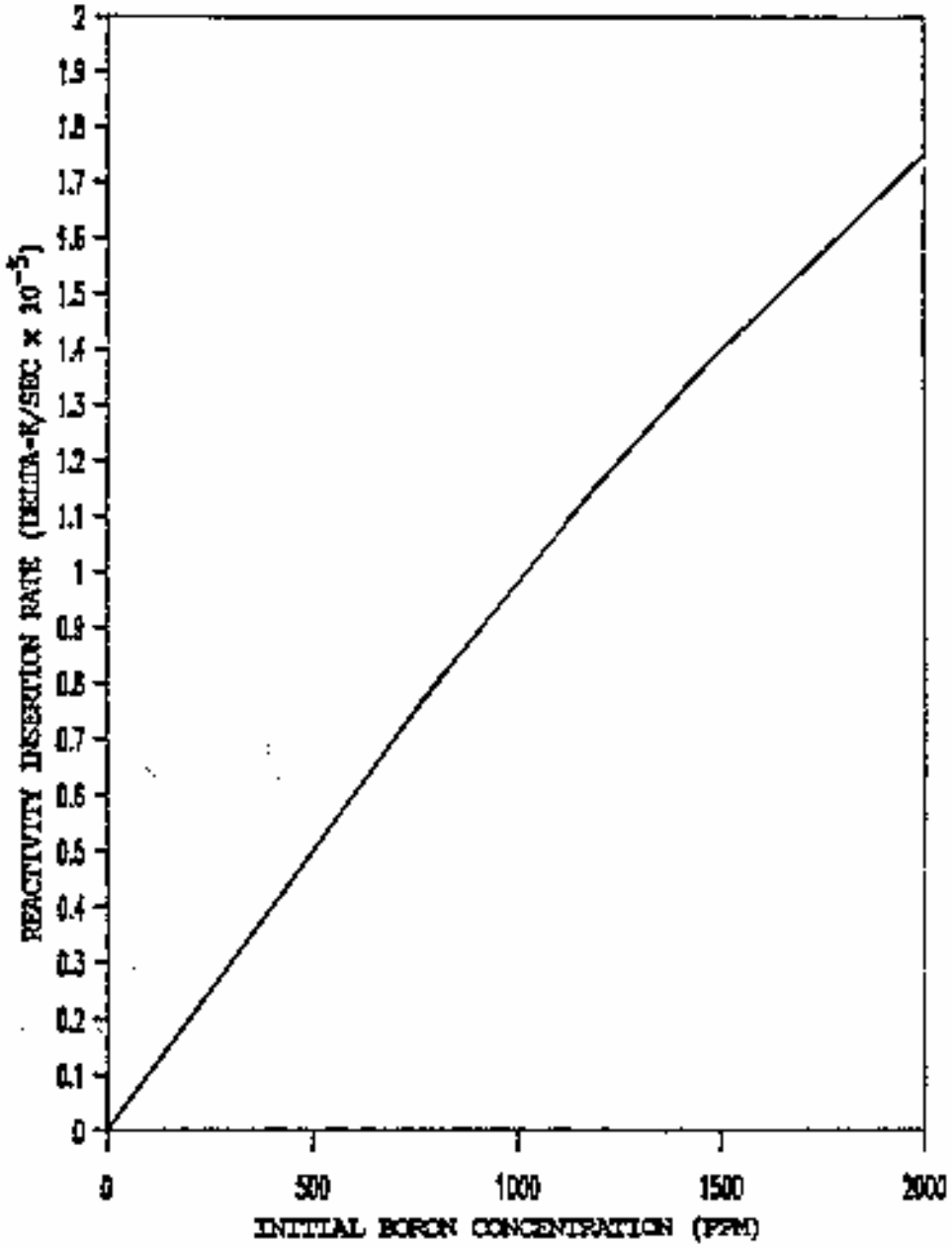
ROD WITHDRAWAL AT POWER Reactivity Insertion Rate vs. DNBR For 10% Power Cases	DIABLO CANYON UNITS 1 & 2
	FIGURE 15.2.2-7



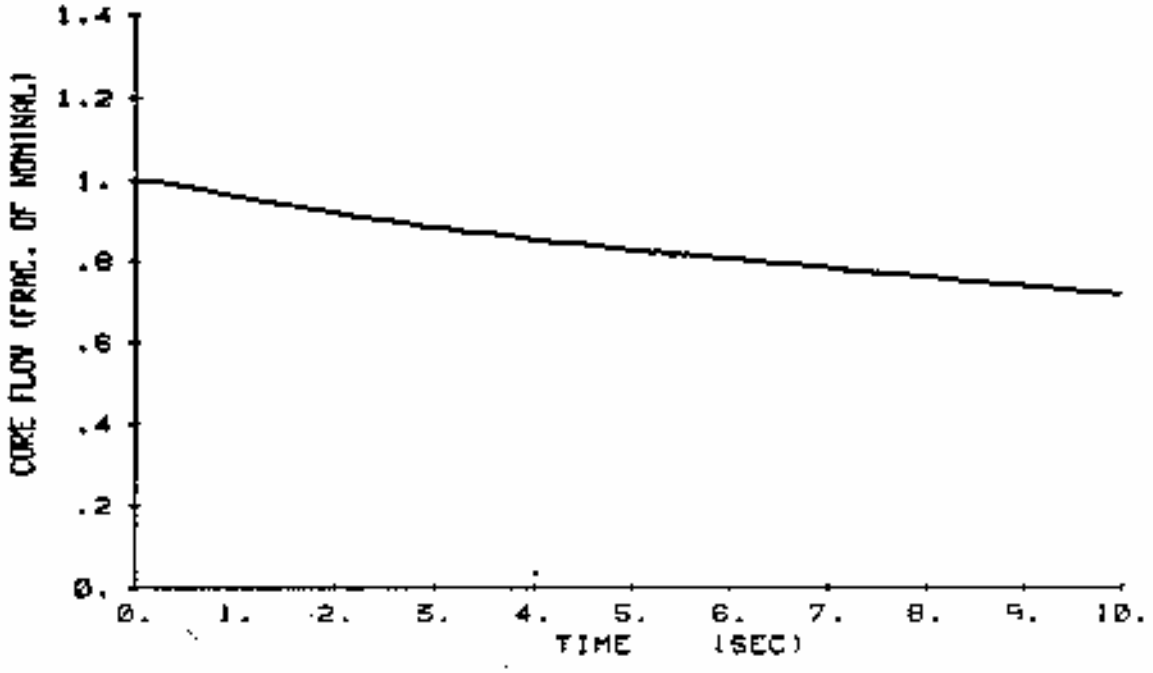
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.3-1 TRANSIENT RESPONSE TO DROPPED ROD CLUSTER CONTROL ASSEMBLY



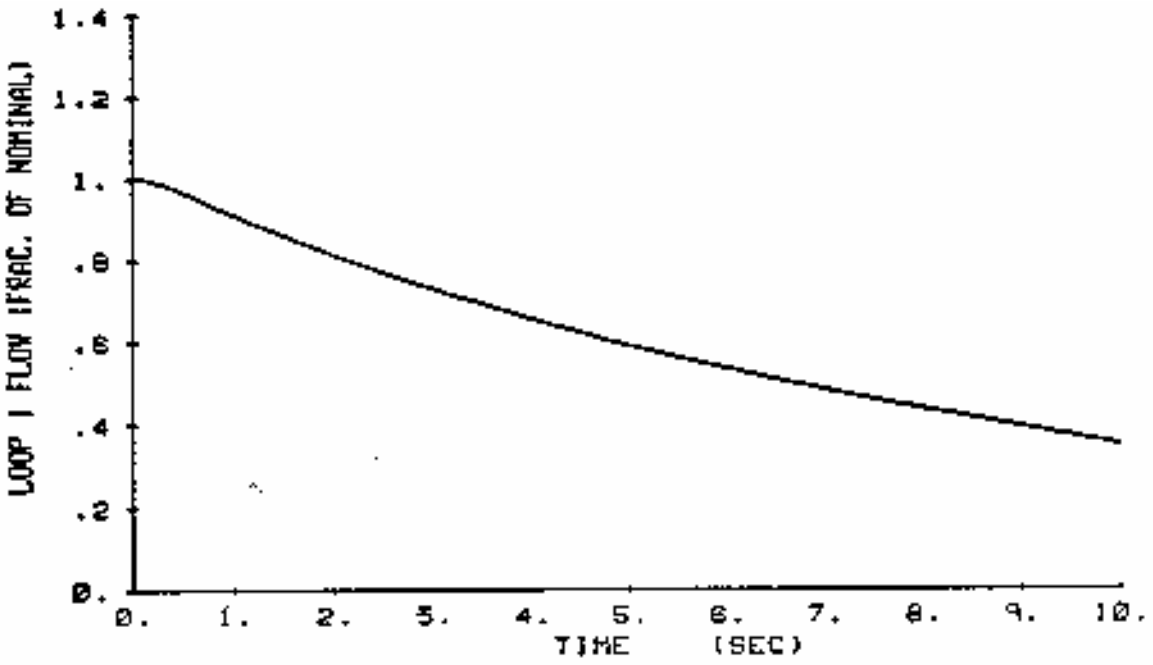
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.3-2 TRANSIENT RESPONSE TO DROPPED ROD CLUSTER CONTROL ASSEMBLY



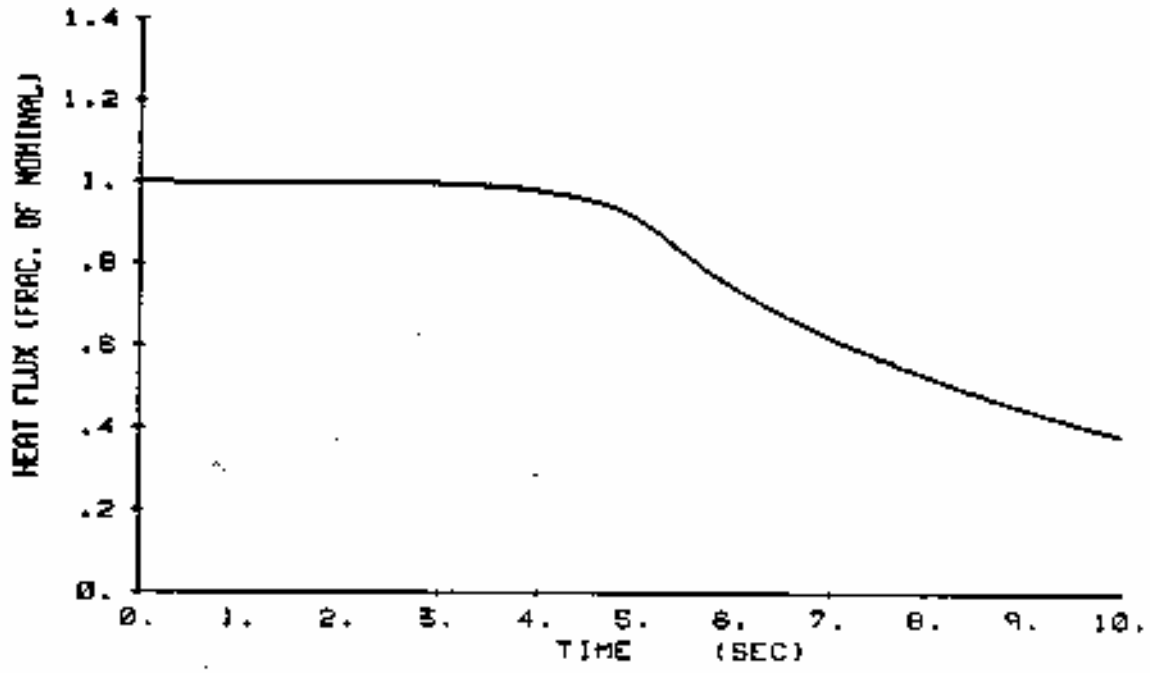
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.4-1 VARIATION IN REACTIVITY INSERTION RATE WITH INITIAL BORON CONCENTRATION FOR A DILUTION RATE OF 262 GPM



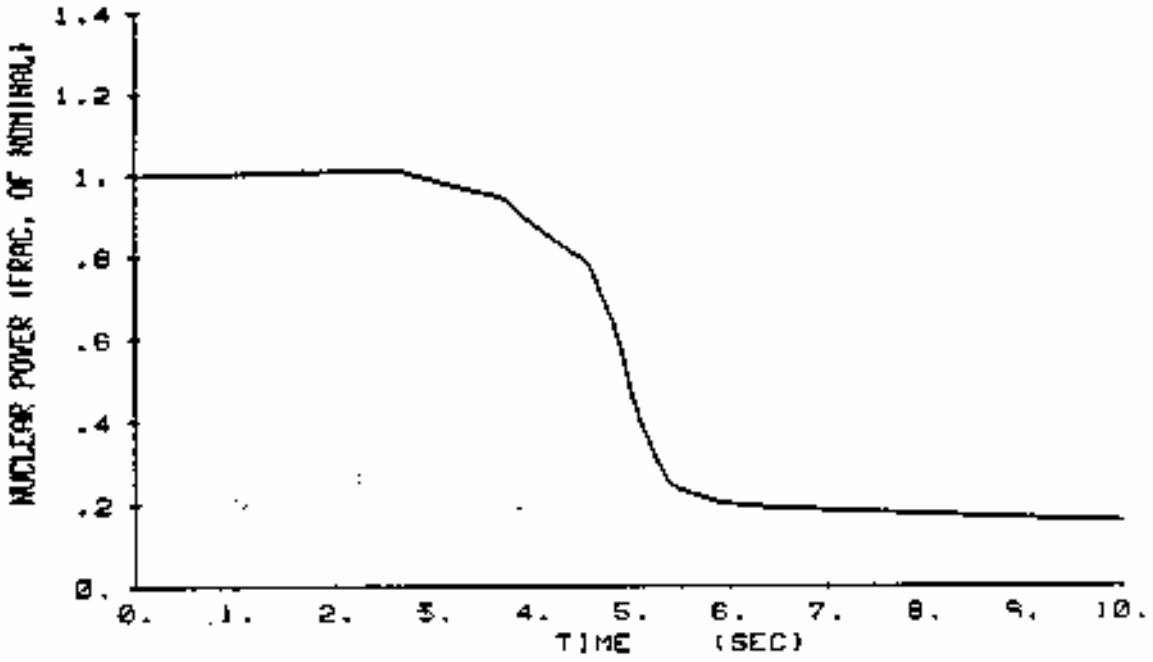
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.5-1 ALL LOOPS OPERATING TWO LOOPS COASTING DOWN CORE FLOW VERSUS TIME **HISTORICAL**



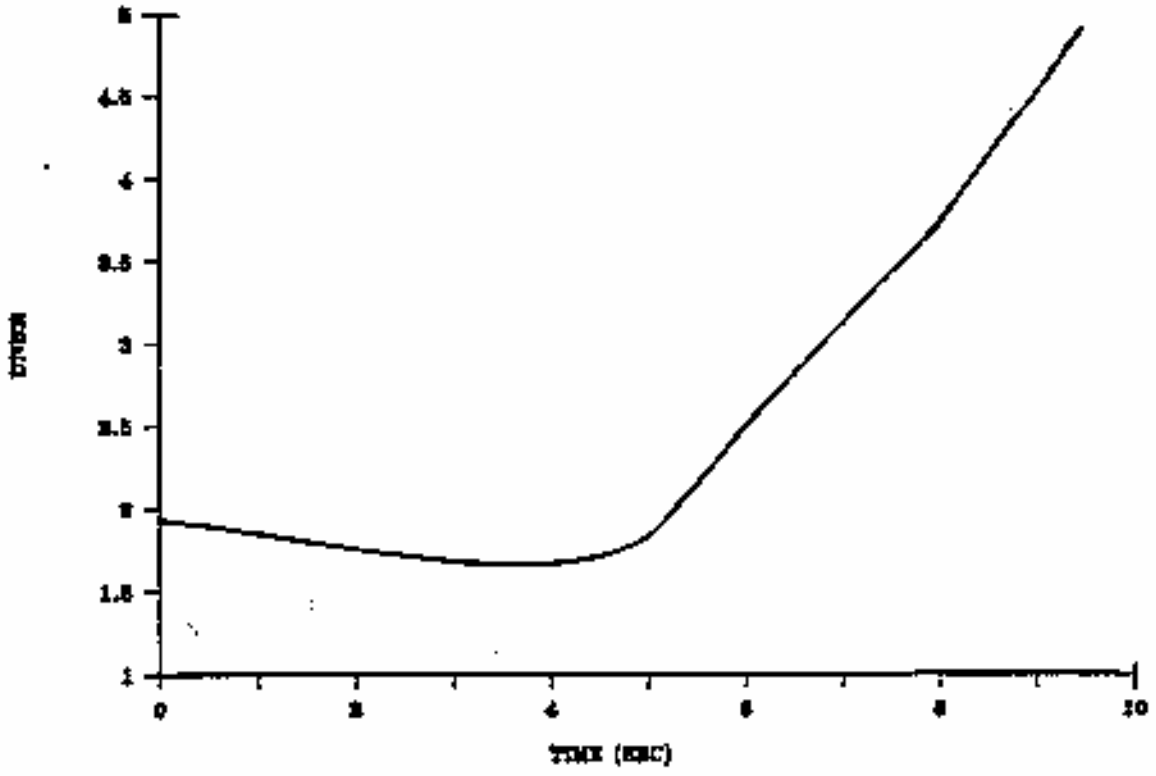
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.5-2 ALL LOOPS OPERATING TWO LOOPS COASTING DOWN FAILED LOOP FLOW VERSUS TIME **HISTORICAL**



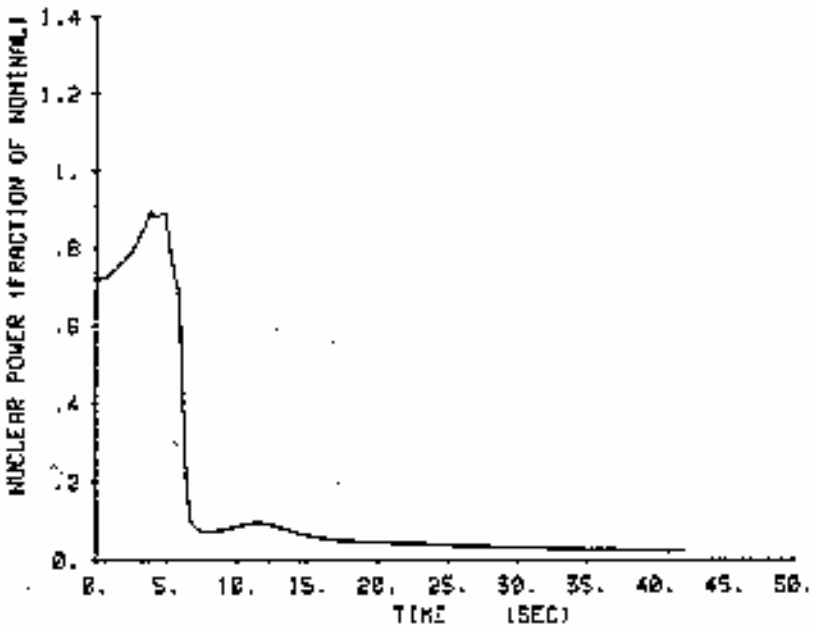
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.5-3 ALL LOOPS OPERATING TWO LOOPS COASTING DOWN HEAT FLUX VERSUS TIME **HISTORICAL**



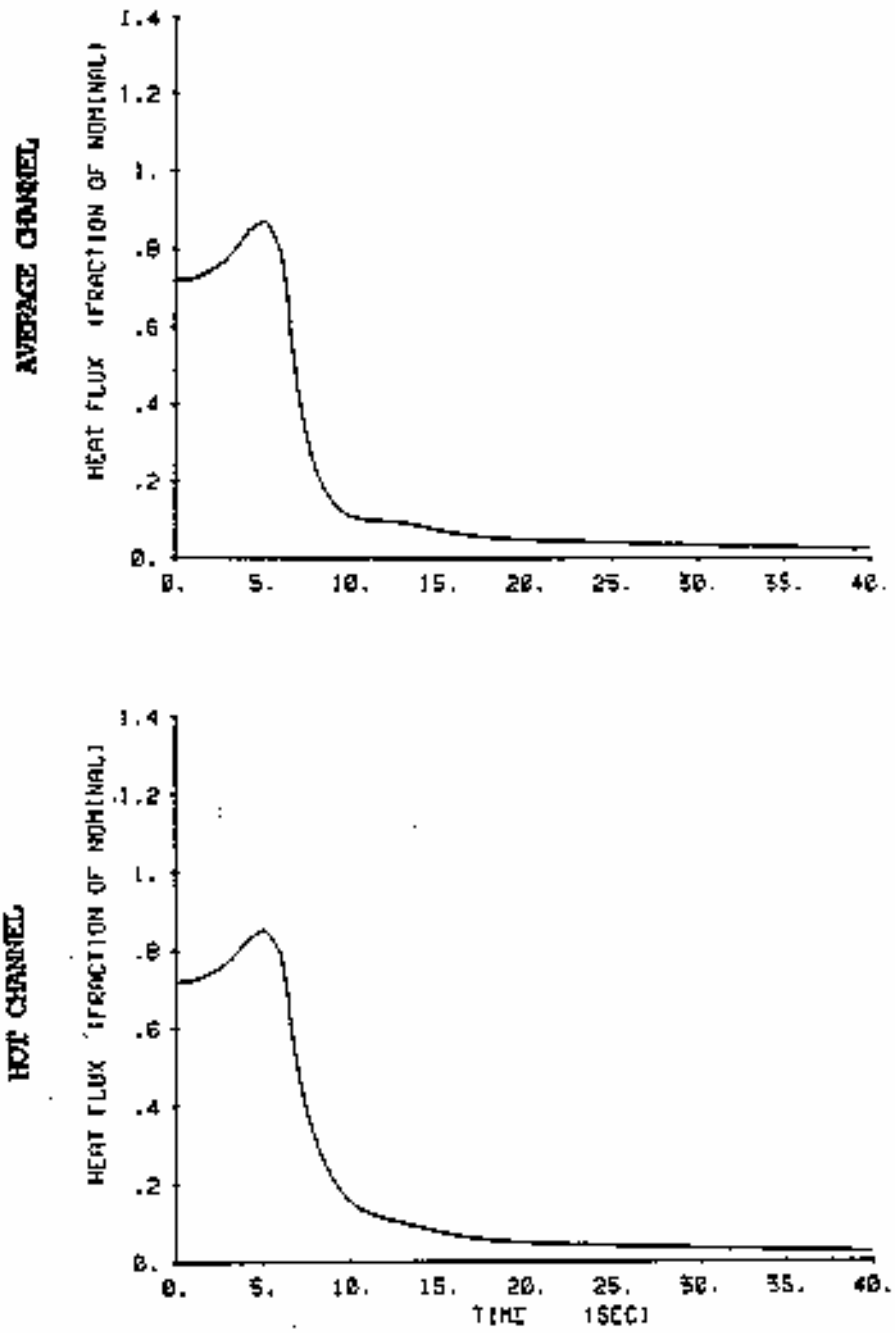
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.5-4 ALL LOOPS OPERATING TWO LOOPS COASTING DOWN NUCLEAR POWER VERSUS TIME **HISTORICAL**



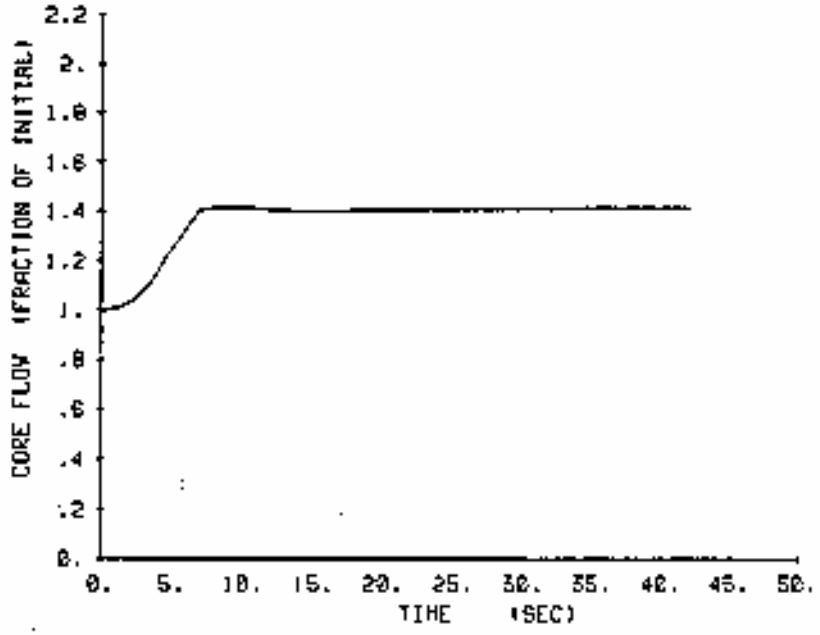
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.5-5 ALL LOOPS OPERATING TWO LOOPS COASTING DOWN DNBR VERSUS TIME **HISTORICAL**



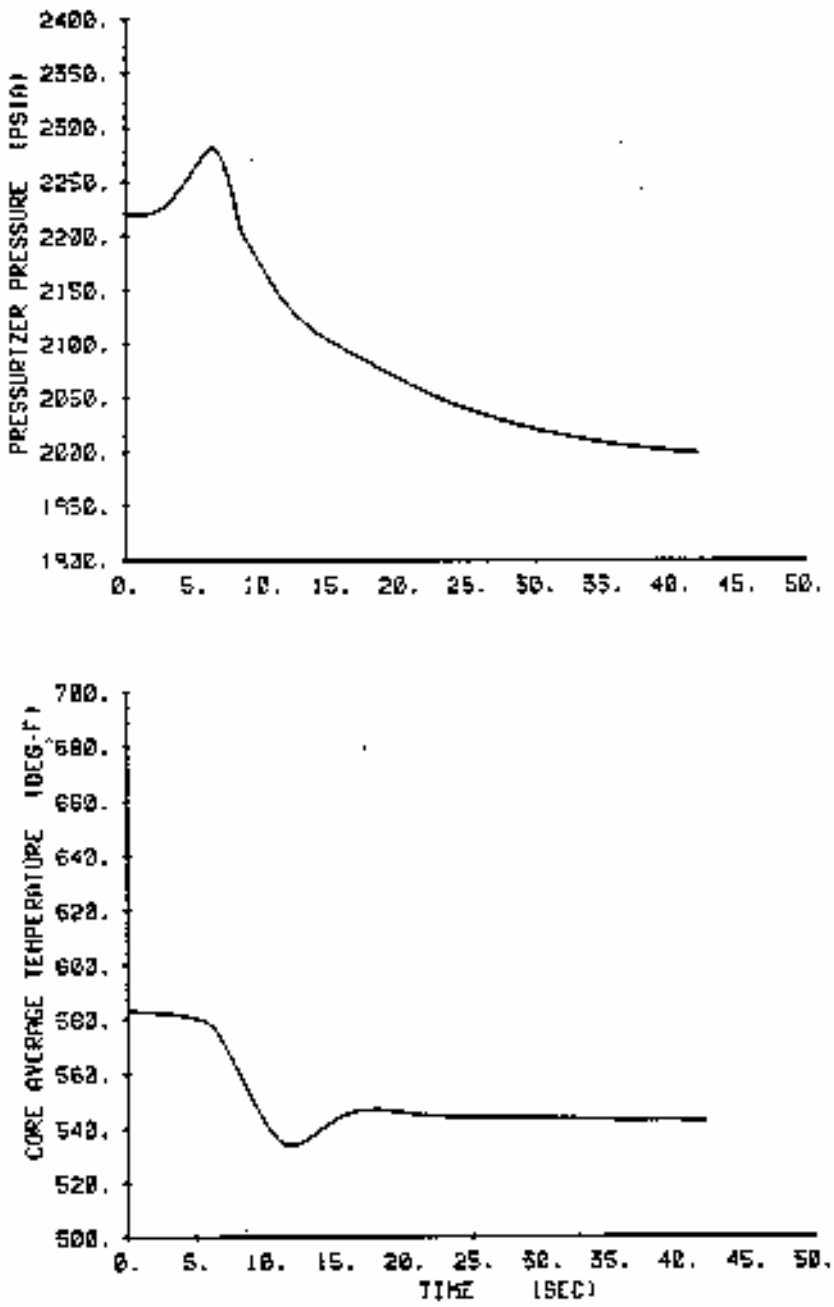
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.6-1 NUCLEAR POWER TRANSIENT DURING STARTUP OF AN INACTIVE LOOP



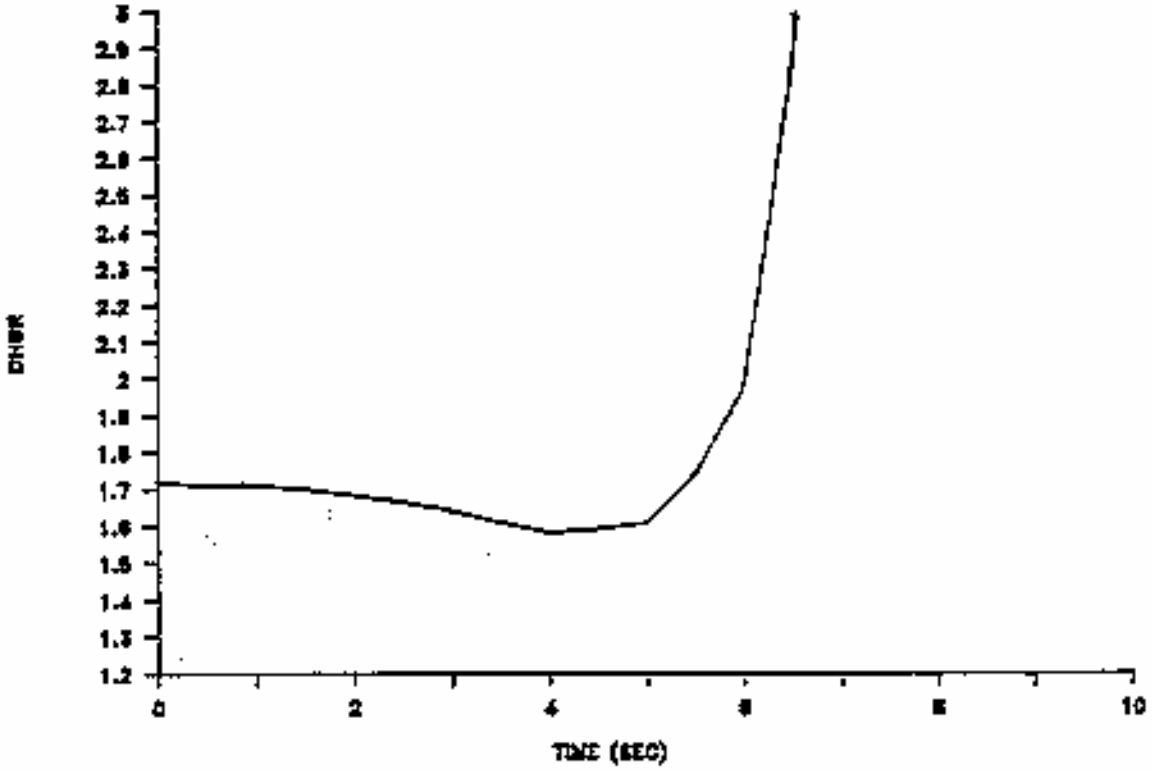
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.6-2 AVERAGE AND HOT CHANNEL HEAT FLUX TRANSIENTS DURING STARTUP OF AN INACTIVE LOOP



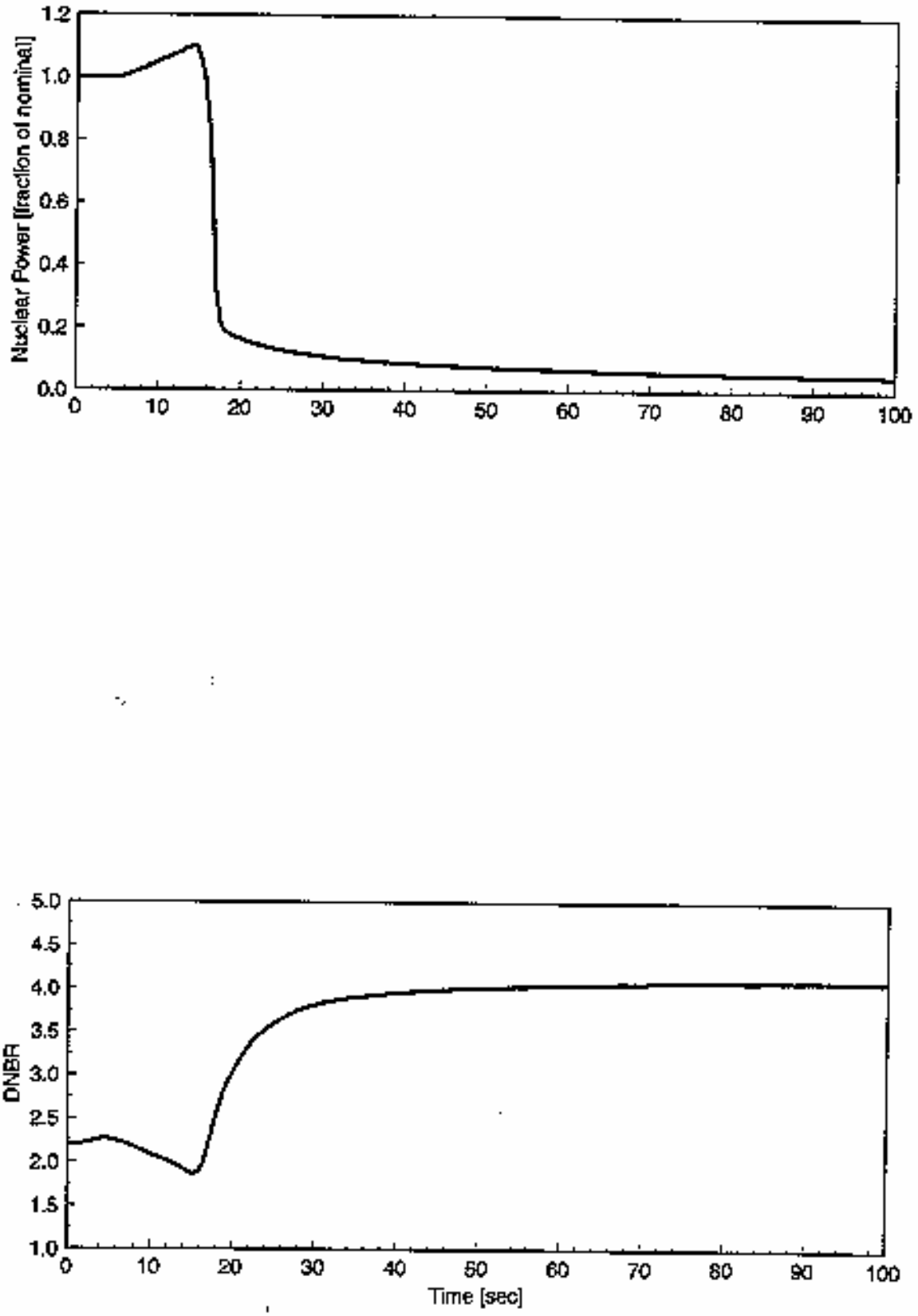
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.6-3 CORE FLOW DURING STARTUP OF AN INACTIVE LOOP



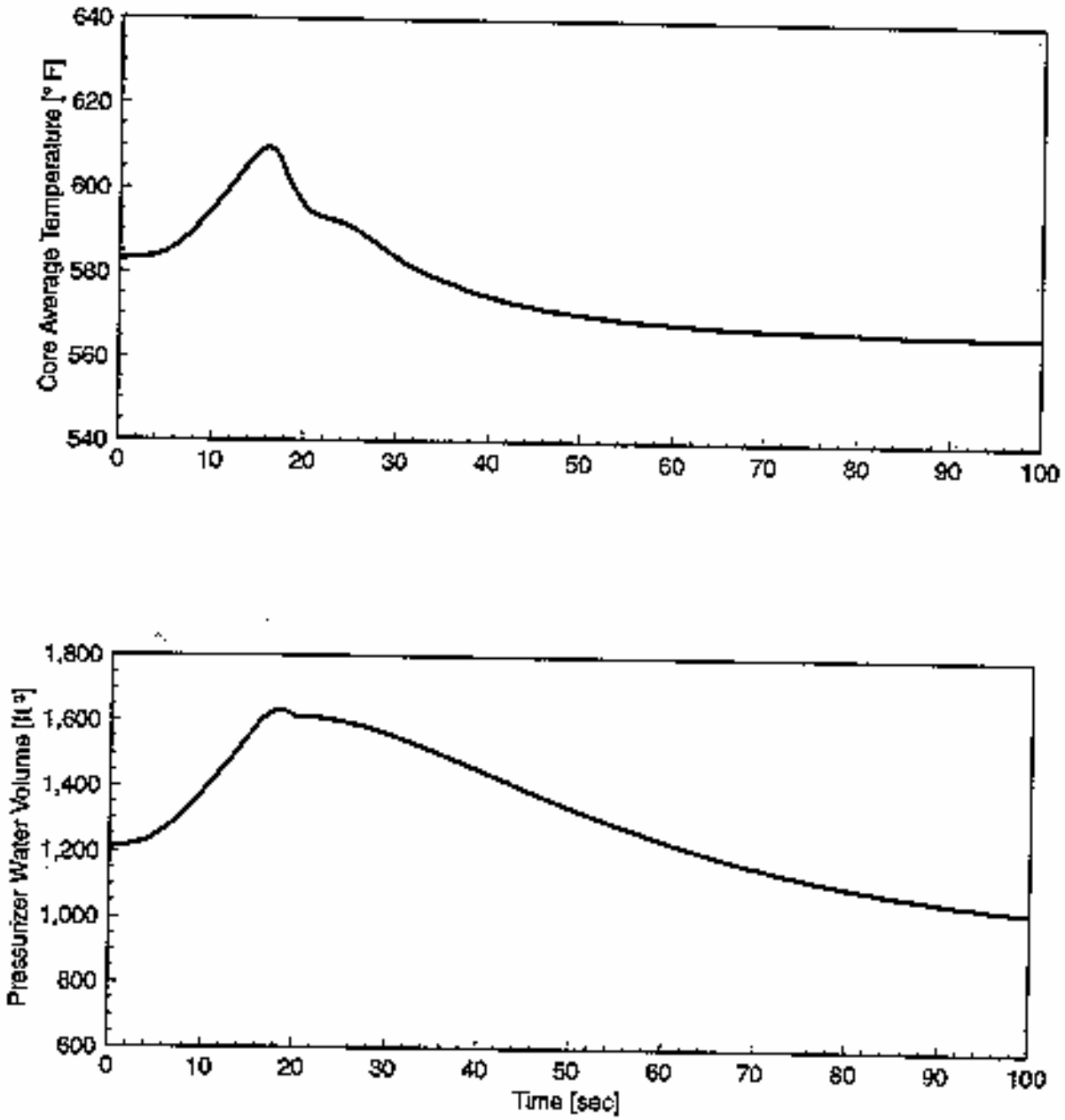
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.6-4 PRESSURIZER PRESSURE TRANSIENT AND CORE AVERAGE TEMPERATURE TRANSIENT DURING STARTUP OF AN INACTIVE LOOP



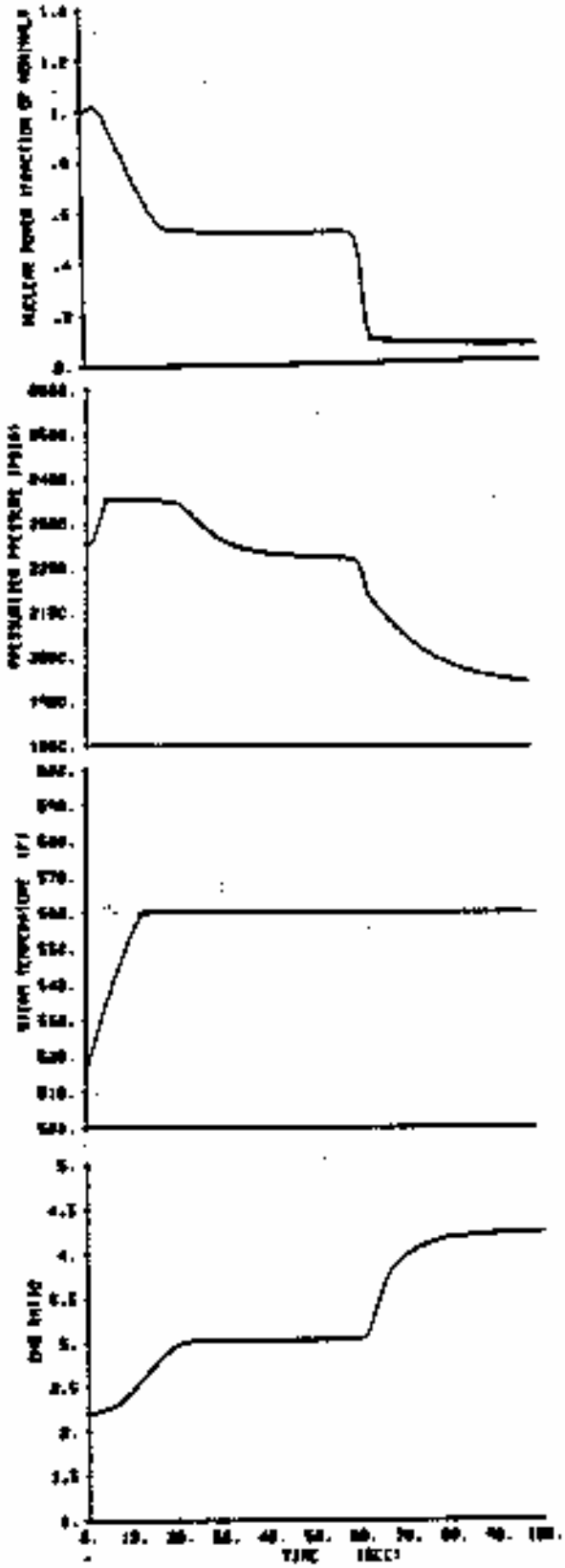
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.6-5 DNBR TRANSIENT DURING STARTUP OF AN INACTIVE LOOP



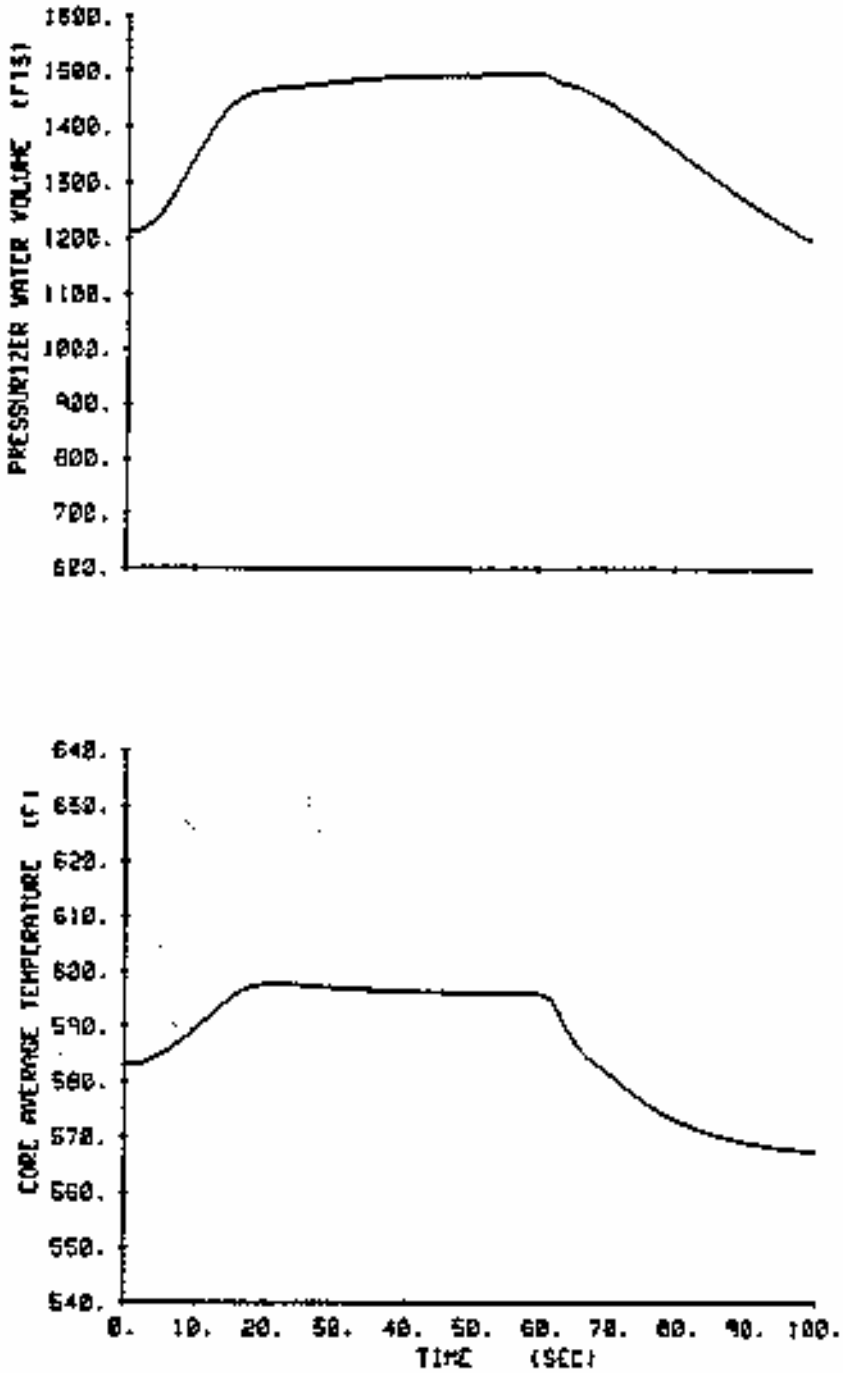
LOSS OF LOAD **With Pressurizer Spray and Power Operated Relief Valve For DNB Concern at Beginning of Life**	**DIABLO CANYON UNITS 1 & 2** **FIGURE 15.2.7-1**



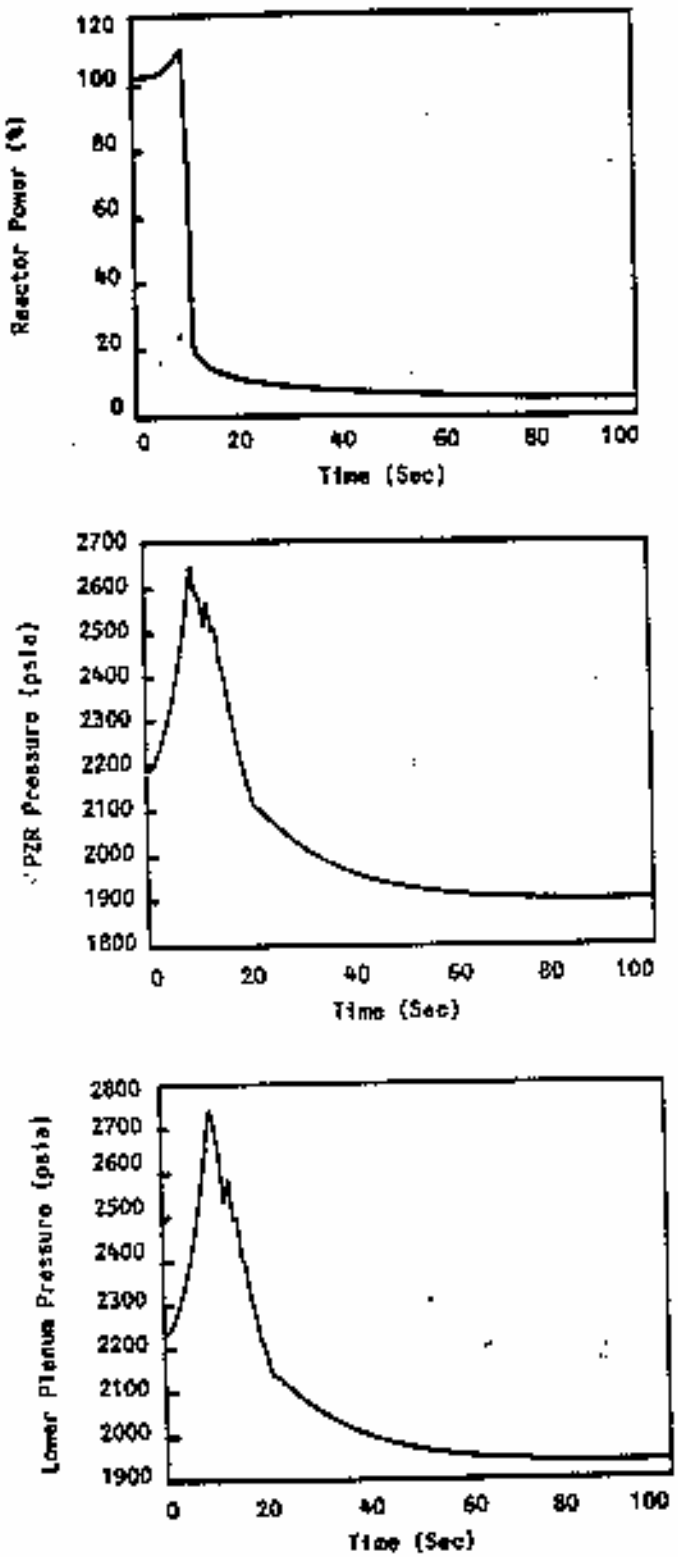
LOSS OF LOAD **With Pressurizer Spray and Power Operated Relief Valve For DNB Concern at Beginning of Life**	**DIABLO CANYON UNITS 1 & 2** **FIGURE 15.2.7-2**



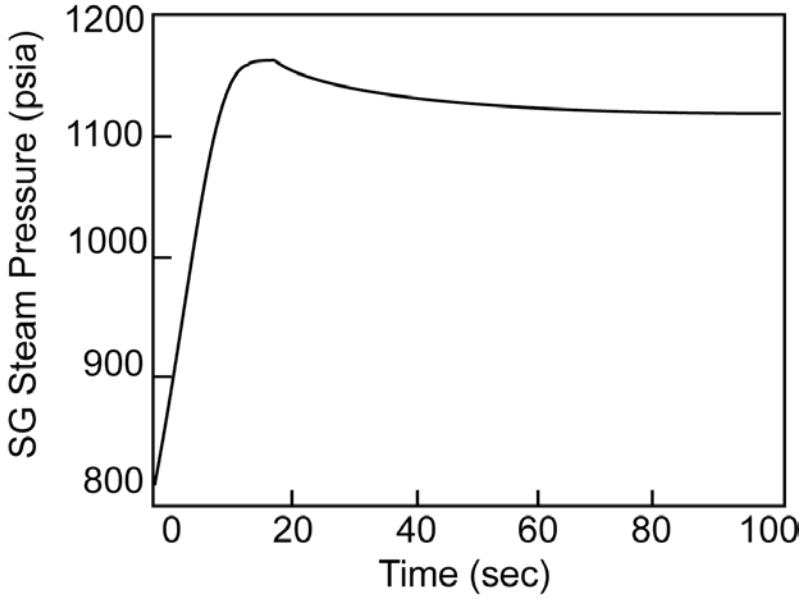
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.7-3 LOSS OF LOAD WITH PRESSURIZER SPRAY AND POWER OPERATED RELIEF VALVE FOR DNB CONCERN AT END OF LIFE

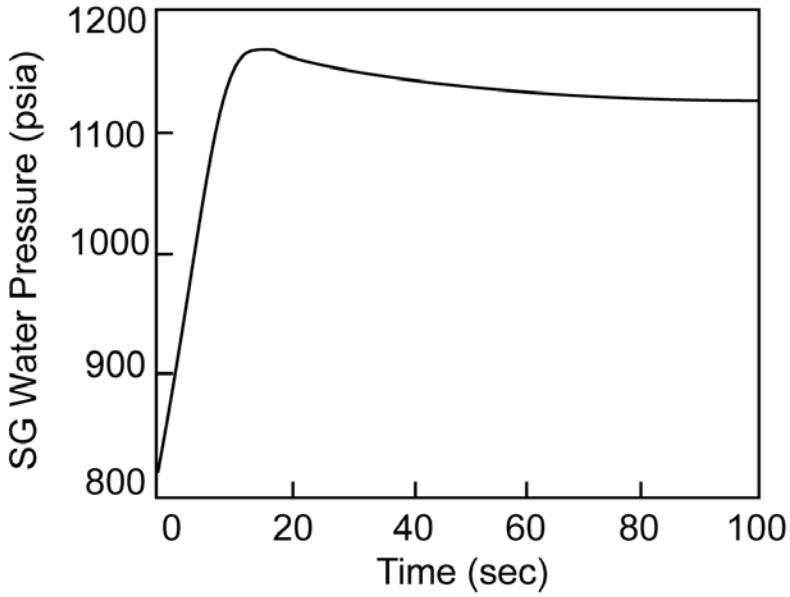


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.7-4 LOSS OF LOAD WITH PRESSURIZER SPRAY AND POWER OPERATED RELIEF VALVE FOR DNB CONCERN AT END OF LIFE

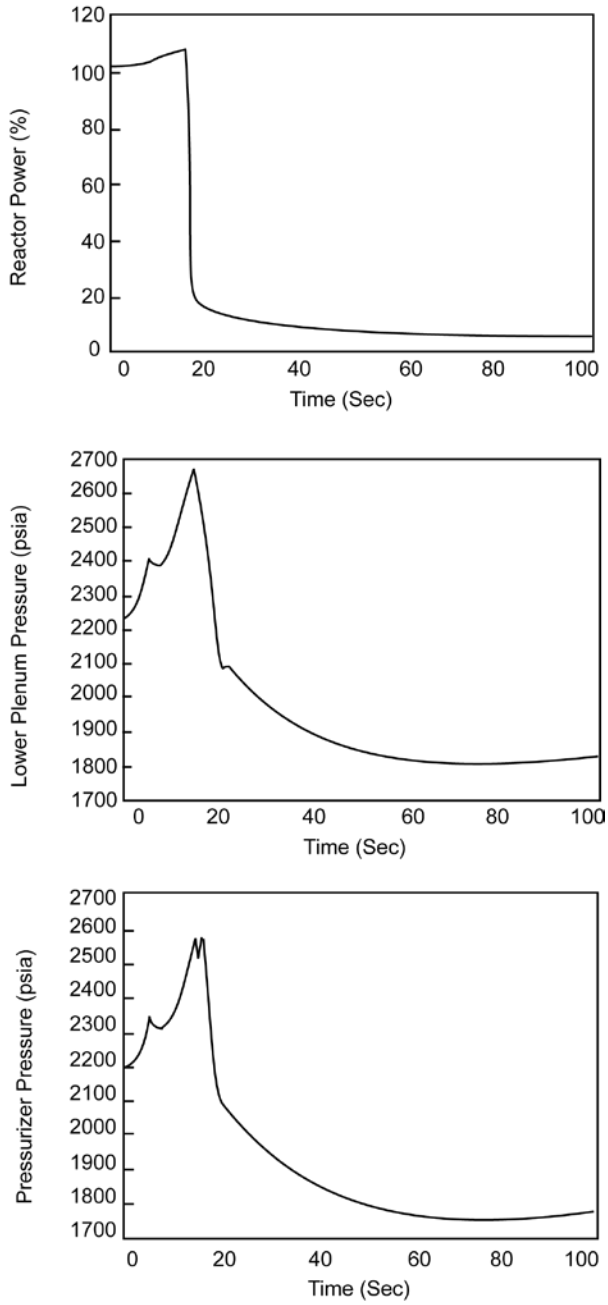


LOSS OF LOAD **Without Pressurizer Spray and Power Operated Relief Valves For Overpressure Concern at Beginning of Life**	**DIABLO CANYON UNITS 1 & 2** **FIGURE 15.2.7-9**

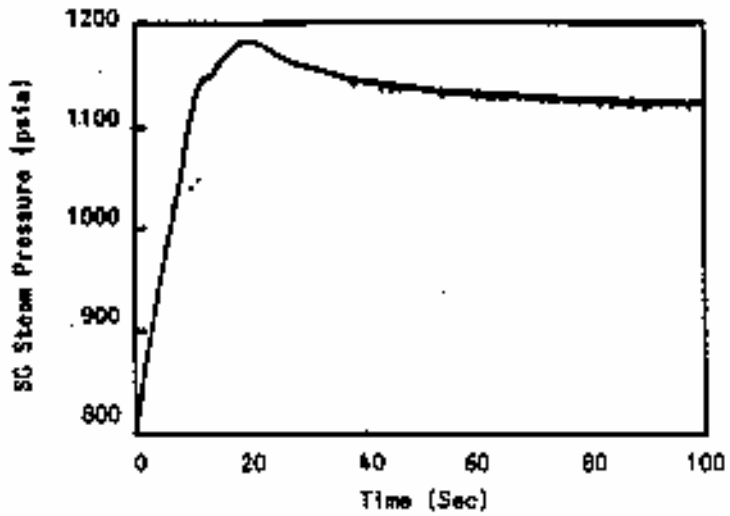


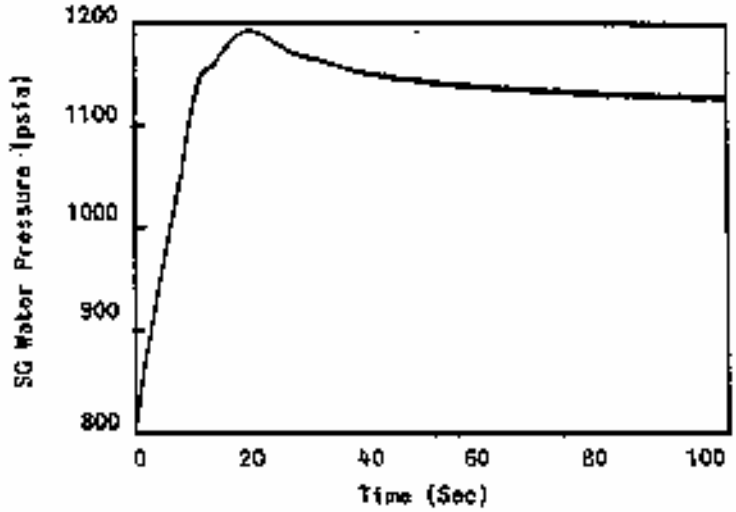


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.7-10 LOSS OF LOAD WITHOUT PRESSURIZER SPRAY AND POWER OPERATED RELIEF VALVES FOR OVERPRESSURE CONCERN AT BEGINNING OF LIFE

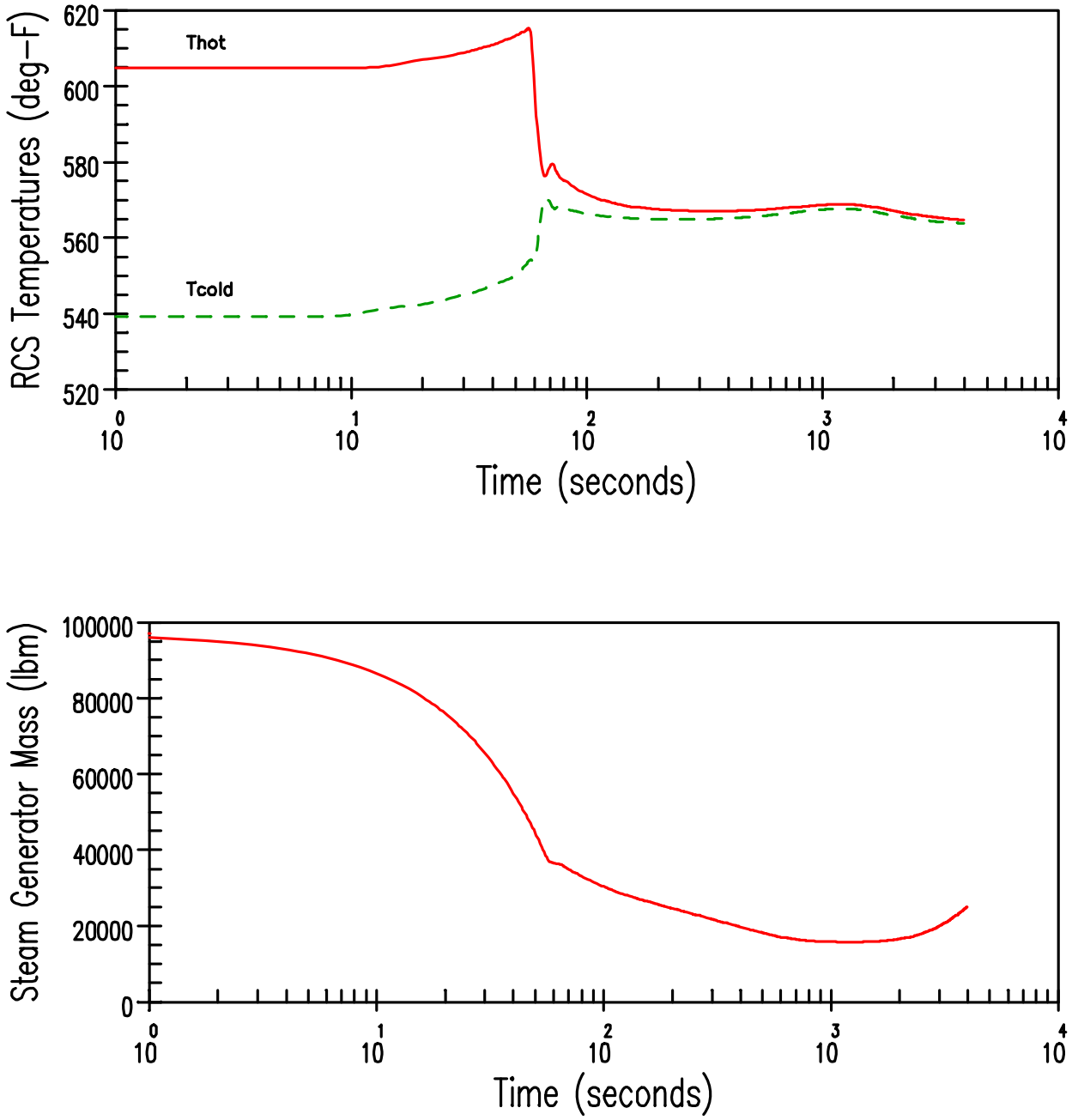


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.7-11 LOSS OF LOAD WITH PRESSURIZER SPRAY AND POWER OPERATED RELIEF VALVES FOR OVERPRESSURE CONCERN AT BEGINNING OF LIFE

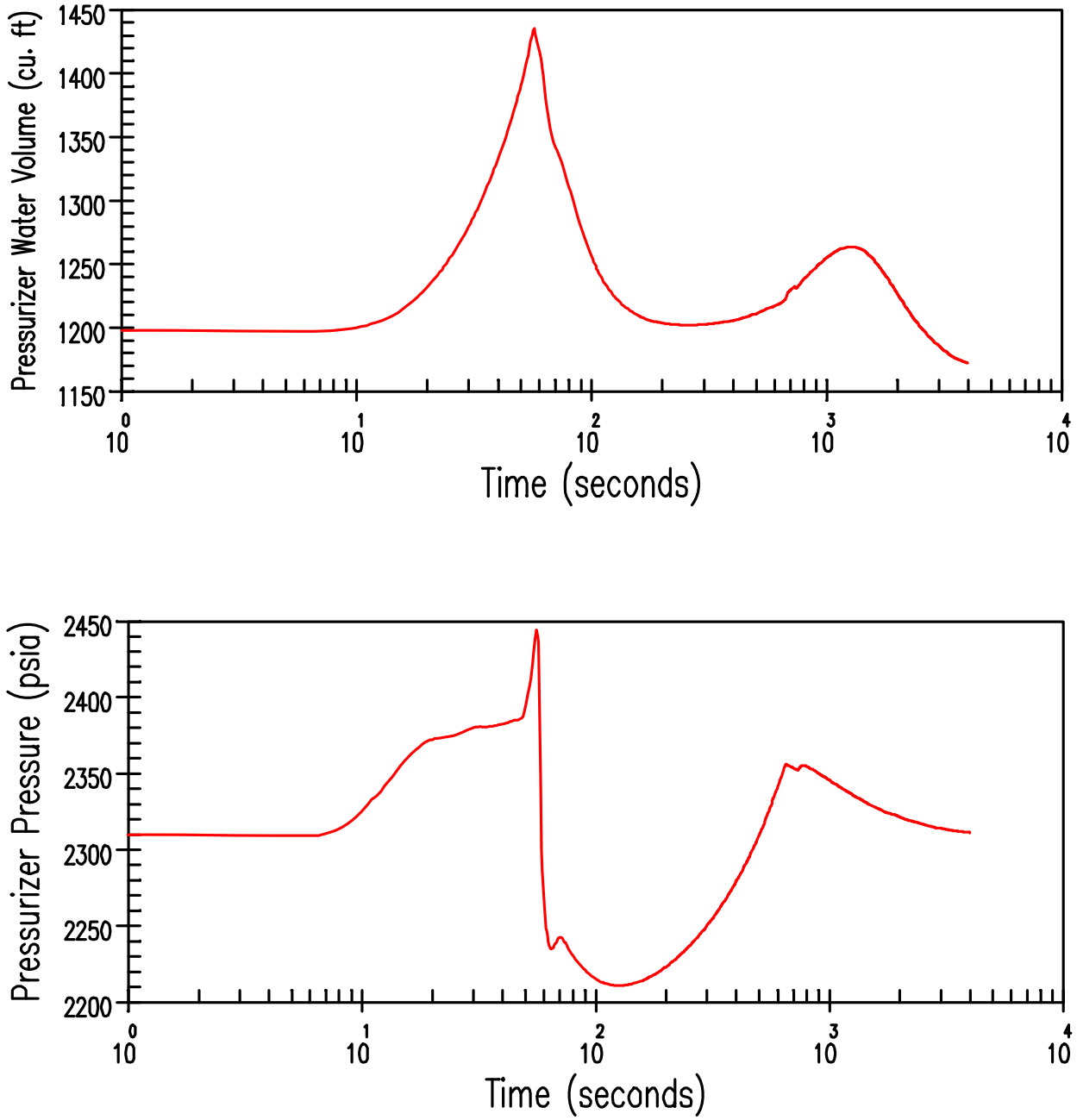




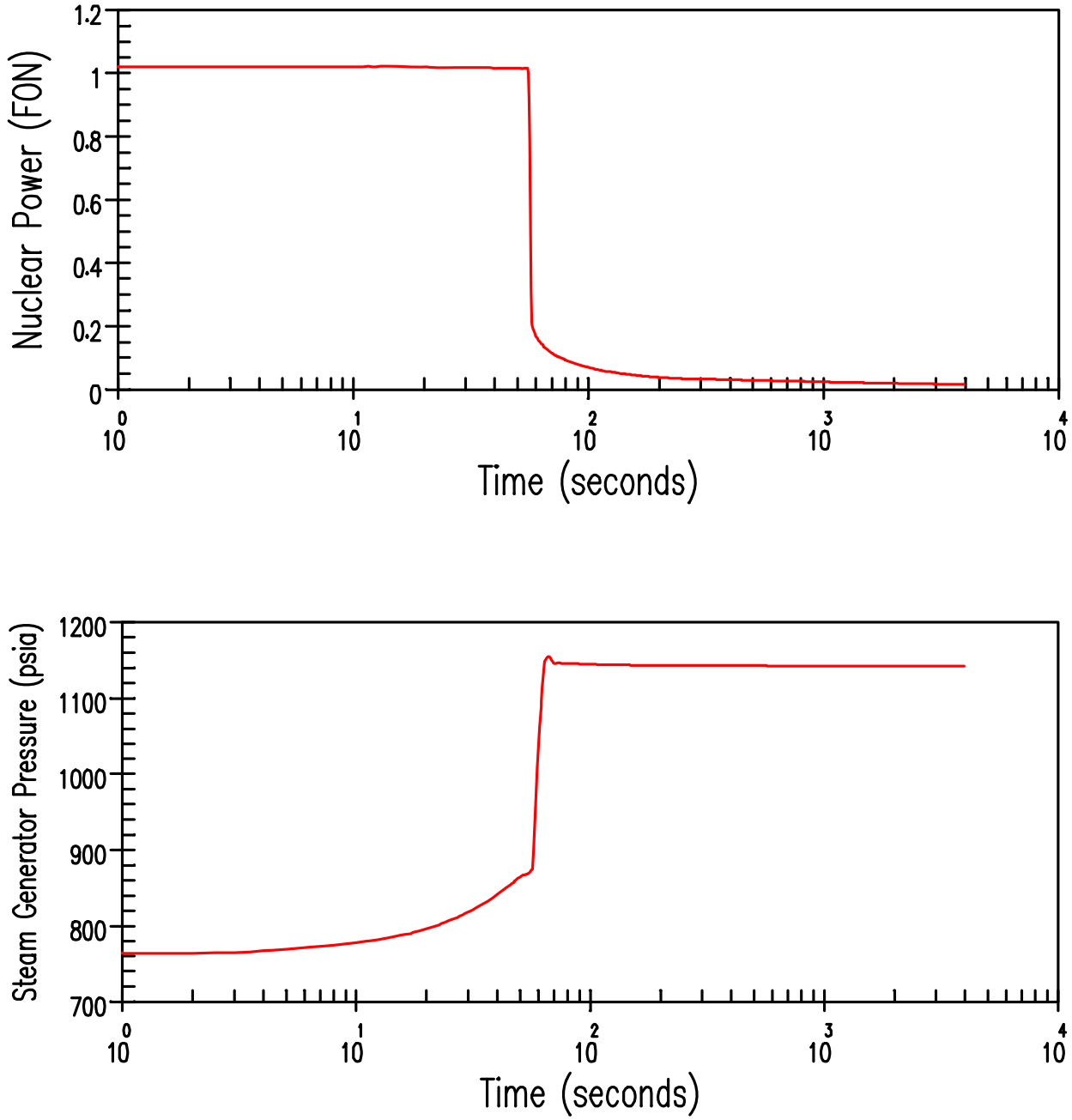
LOSS OF LOAD **With Pressurizer Spray and Power Operated Relief Valves For Overpressure Concern at Beginning of Life**	**DIABLO CANYON UNITS 1 & 2** **FIGURE 15.2.7-12**



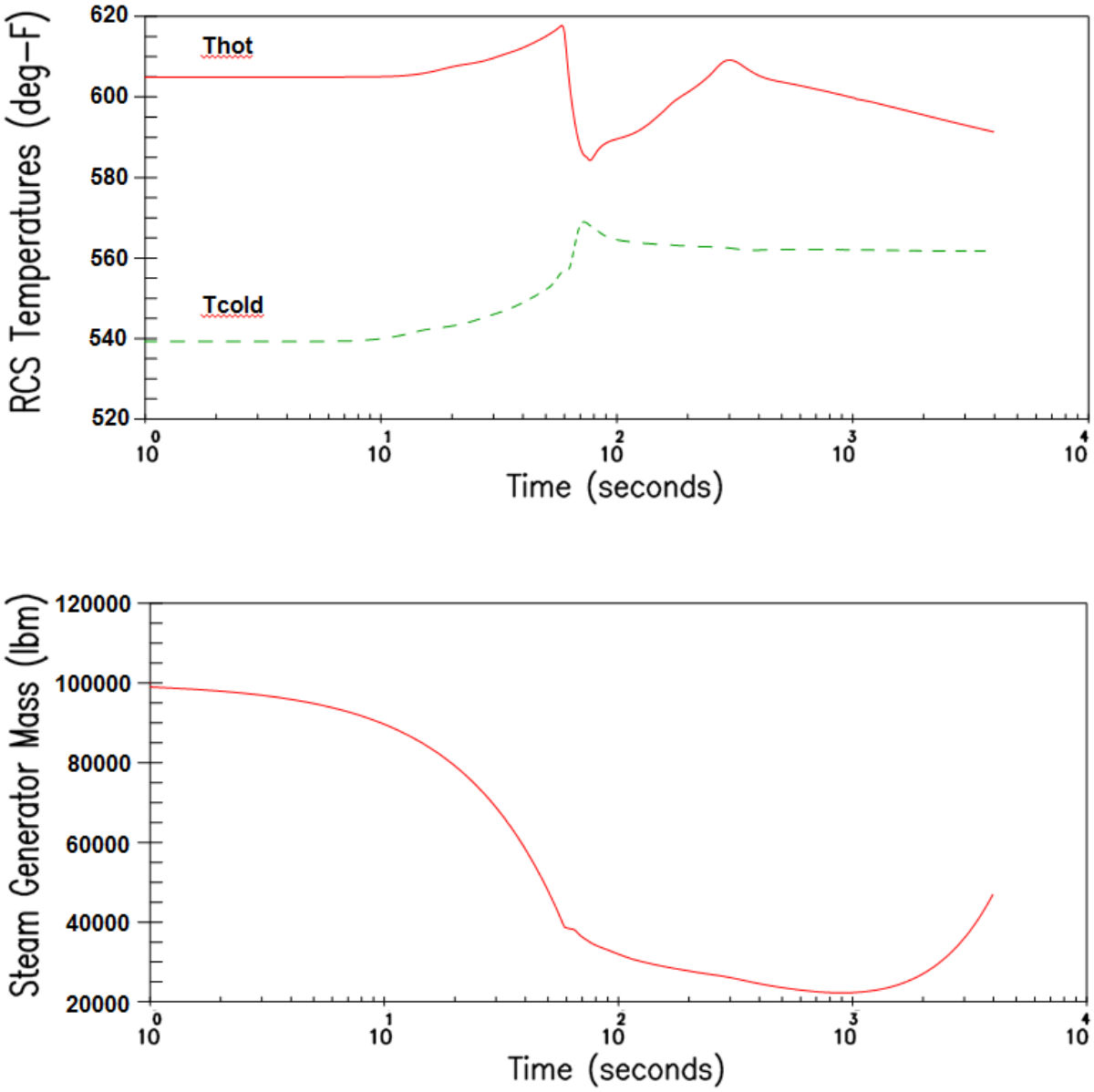
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.8-1 LOSS OF NORMAL FEEDWATER – RCS TEMPERATURES AND STEAM GENERATOR MASS TRANSIENTS



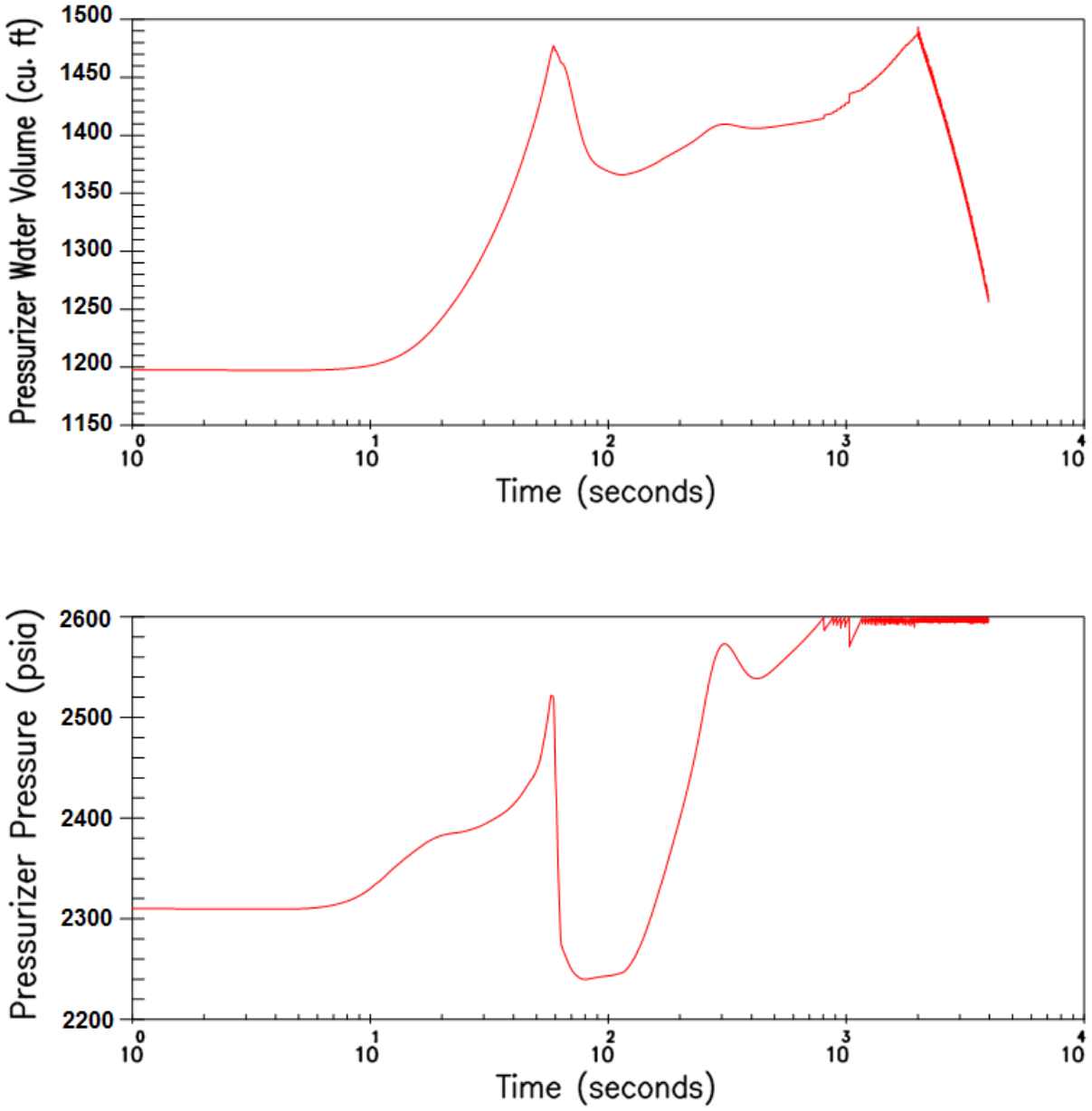
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.8-2 LOSS OF NORMAL FEEDWATER PRESSURIZER WATER VOLUME AND PRESSURIZER PRESSURE TRANSIENTS



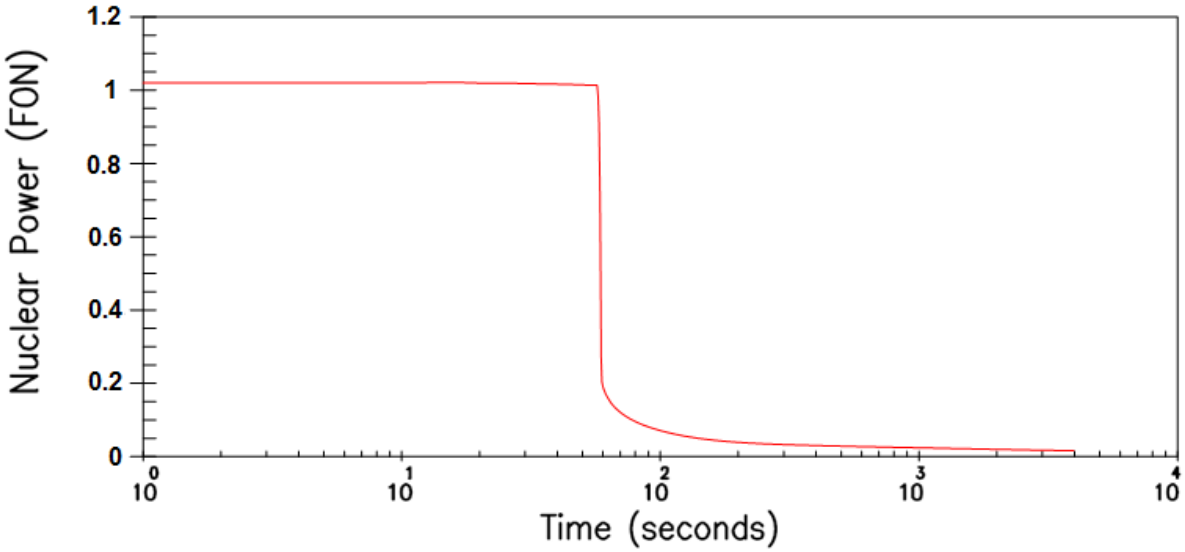
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.8-3 LOSS OF NORMAL FEEDWATER NUCLEAR POWER AND STEAM GENERATOR PRESSURE TRANSIENTS

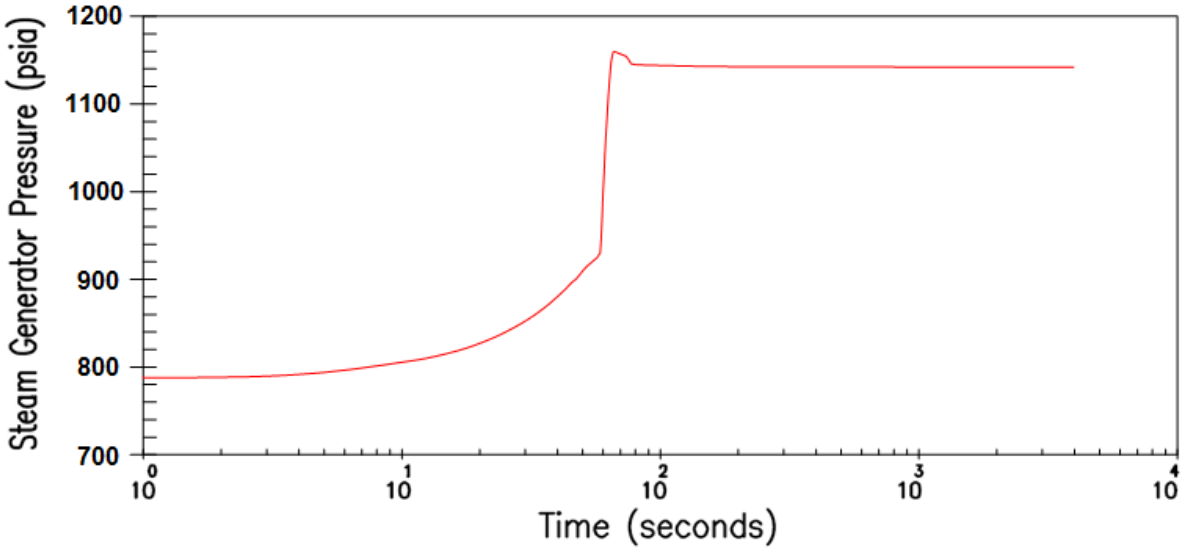


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.9-1 LOSS OF OFFSITE POWER RCS TEMPERATURES AND STEAM GENERATOR MASS TRANSIENTS

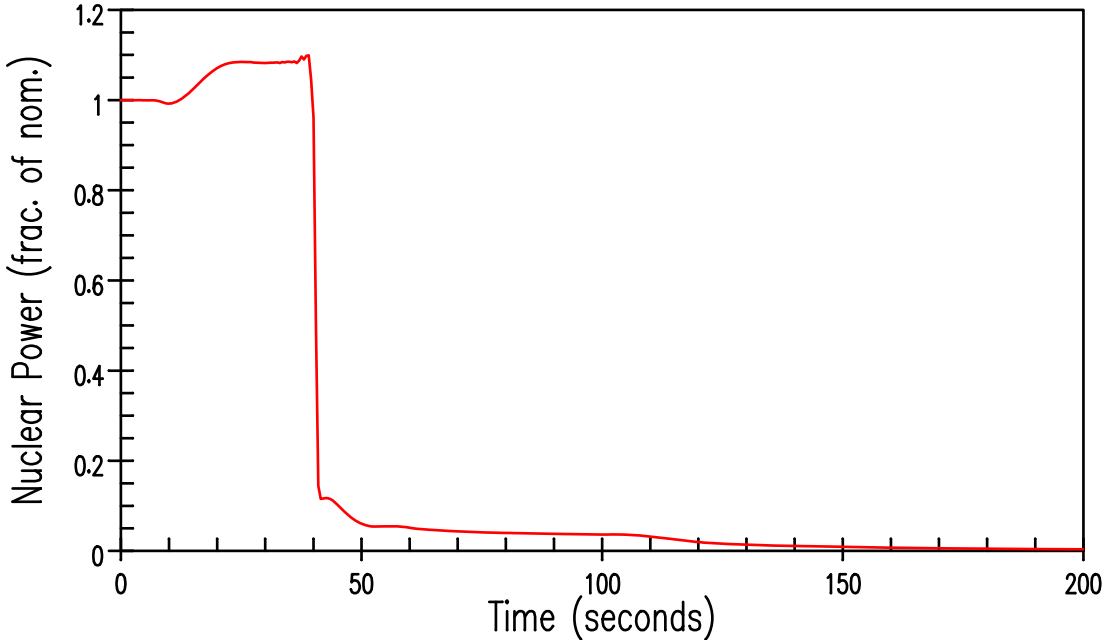


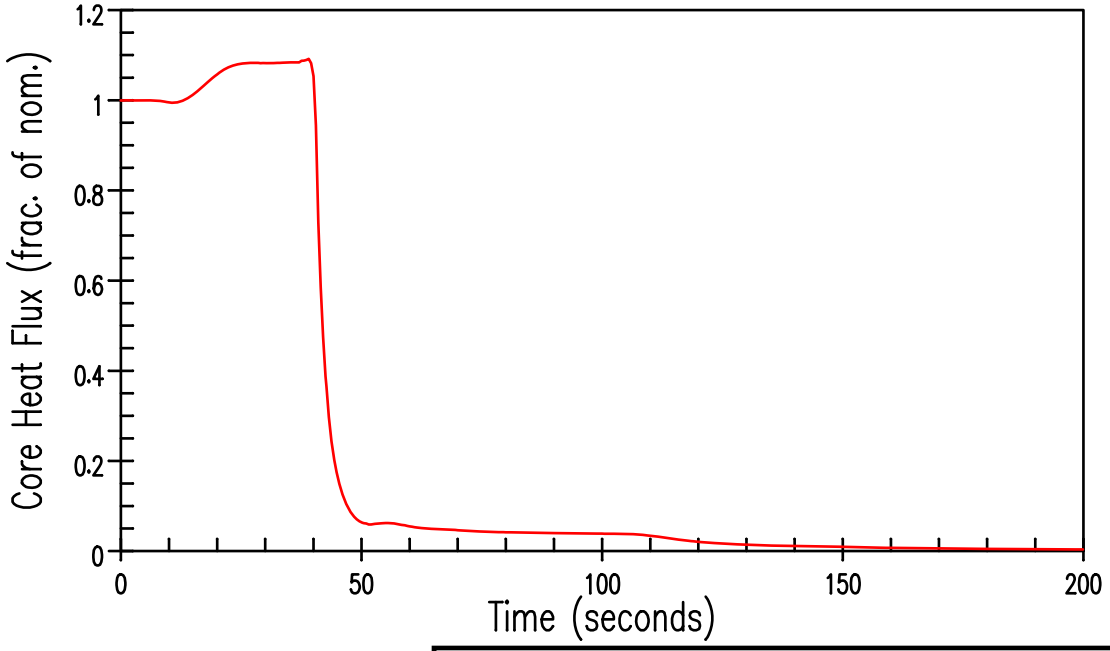
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.9-2 LOSS OF OFFSITE POWER PRESSURIZER WATER VOLUME AND PRESSURIZER PRESSURE TRANSIENTS





FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.9-3 LOSS OF OFFSITE POWER NUCLEAR POWER AND STEAM GENERATOR PRESSURE TRANSIENTS



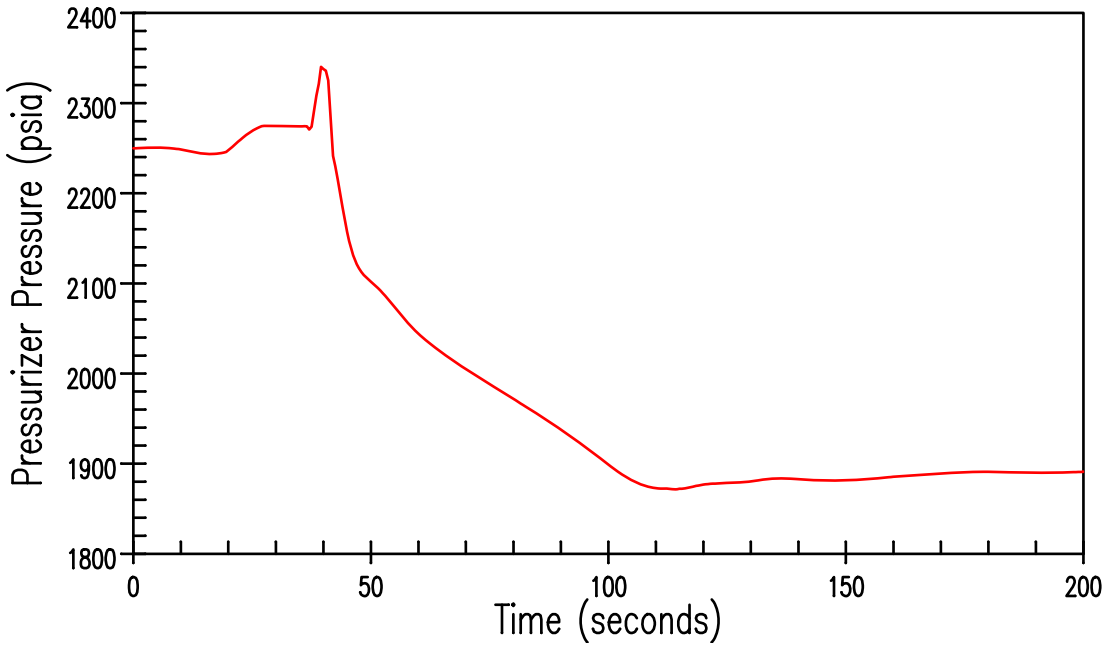


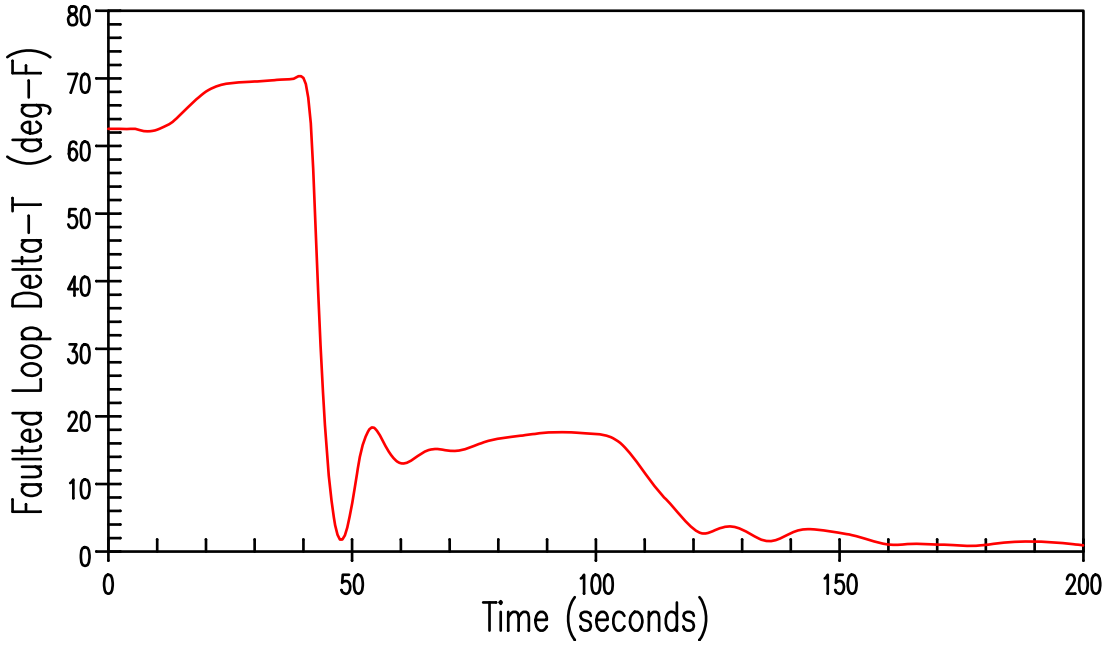
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.10-1

MAIN FEEDWATER REGULATING VALVE MALFUNCTION FULL POWER, MANUAL ROD CONTROL NUCLEAR POWER AND AVERAGE CHANNEL CORE HEAT FLUX TRANSIENTS

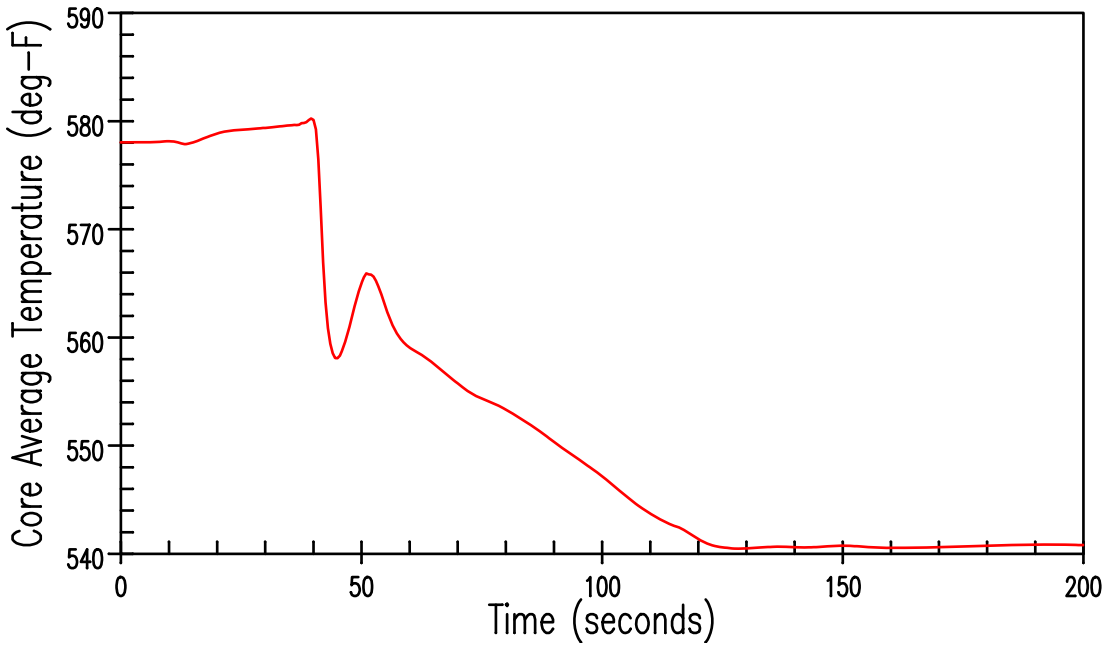


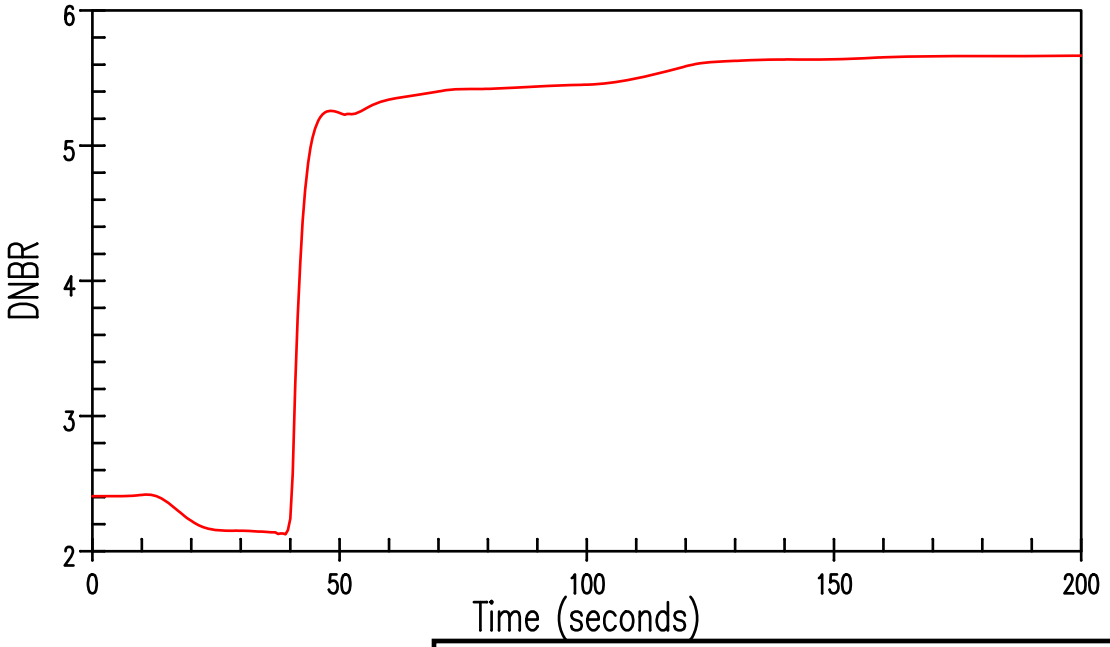


FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.10-2
MAIN FEEDWATER REGULATING VALVE MALFUNCTION FULL POWER, MANUAL ROD CONTROL PRESSURIZER PRESSURE AND FAULTED LOOP DELTA-T TRANSIENTS



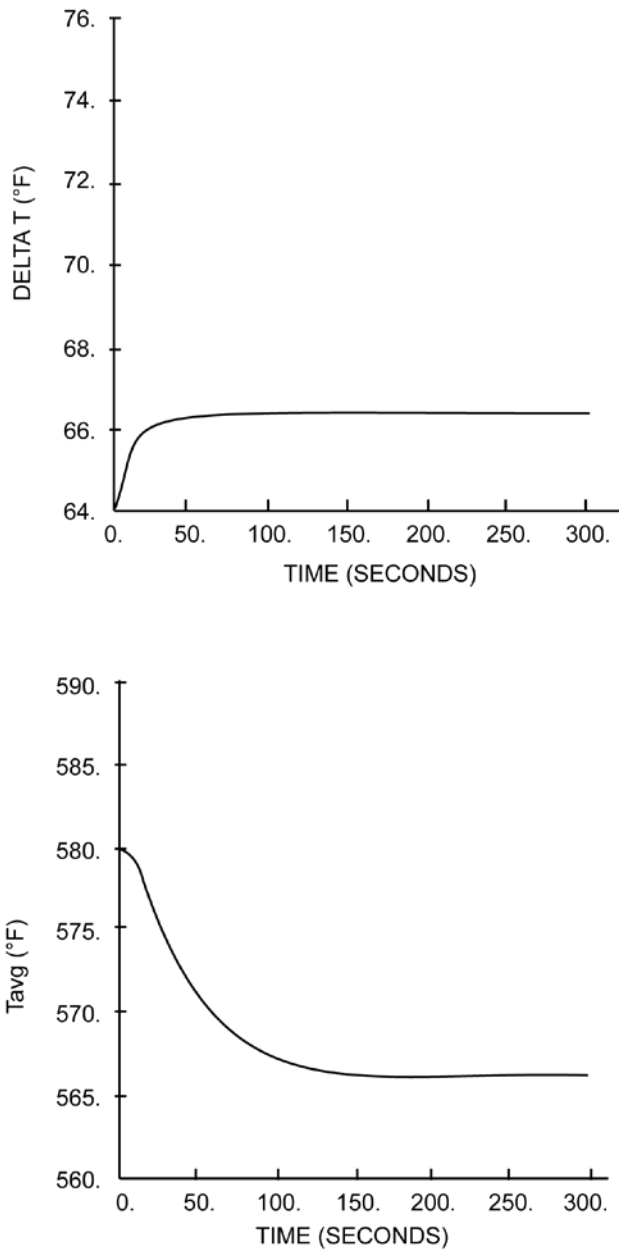


FSAR UPDATE

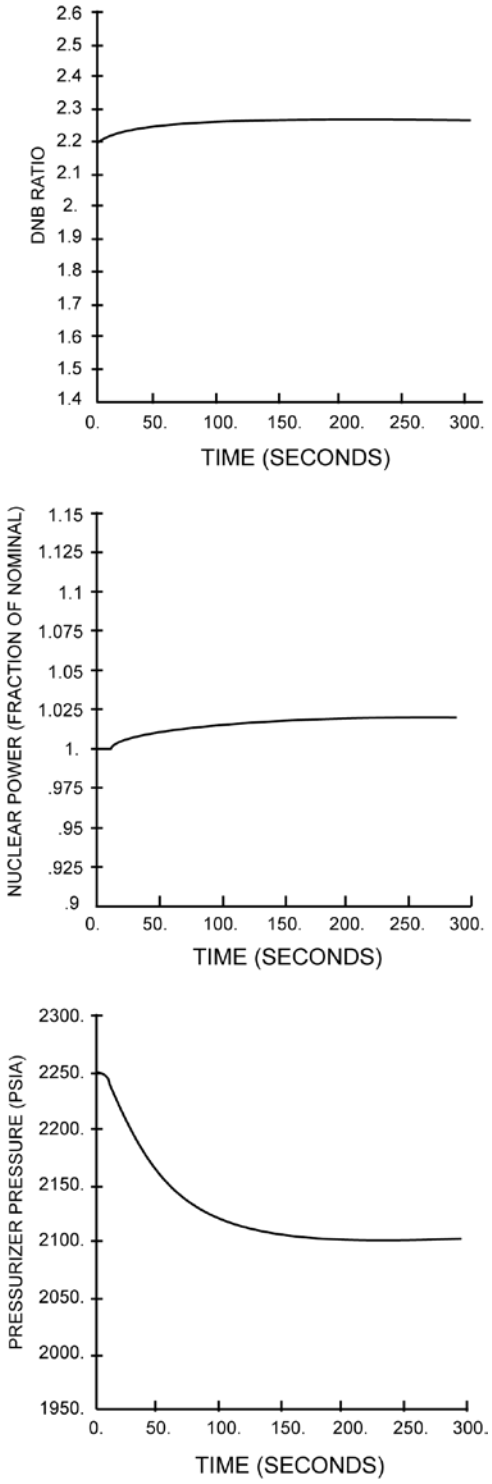
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.10-3

MAIN FEEDWATER REGULATING VALVE MALFUNCTION FULL POWER, MANUAL ROD CONTROL CORE AVERAGE TEMPERATURE AND DNBR TRANSIENTS



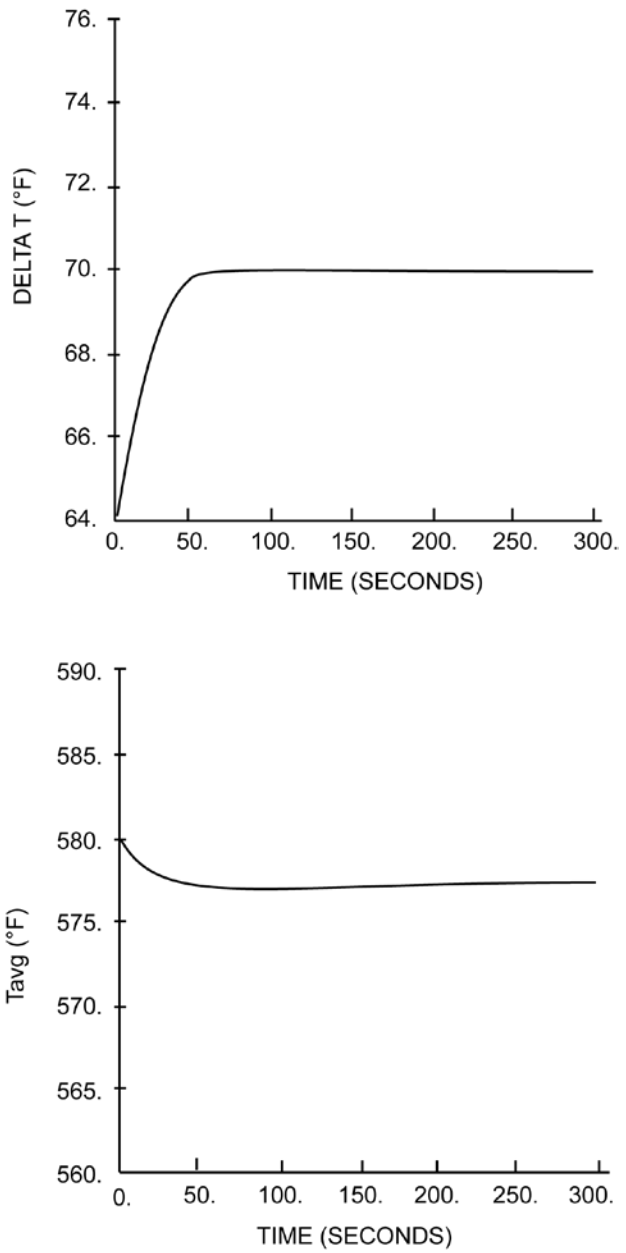
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.12-1 EXCESSIVE LOAD INCREASE WITHOUT CONTROL ACTION, BEGINNING OF LIFE, (MTC), MINIMUM FEEDBACK, DELTA-T AND TAVG AS A FUNCTION OF TIME



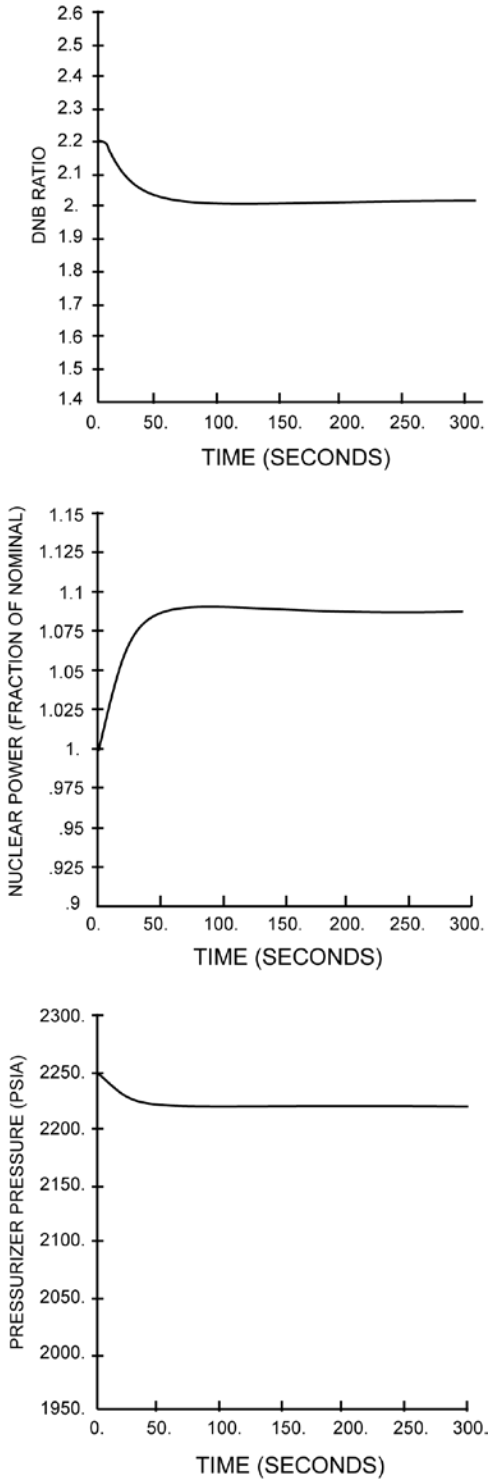
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.12-2
EXCESSIVE LOAD INCREASE WITHOUT CONTROL ACTION, BEGINNING OF LIFE, (MTC), MINIMUM FEEDBACK, DNBR, NUCLEAR POWER AND PRESSURIZER PRESSURE AS A FUNCTION OF TIME



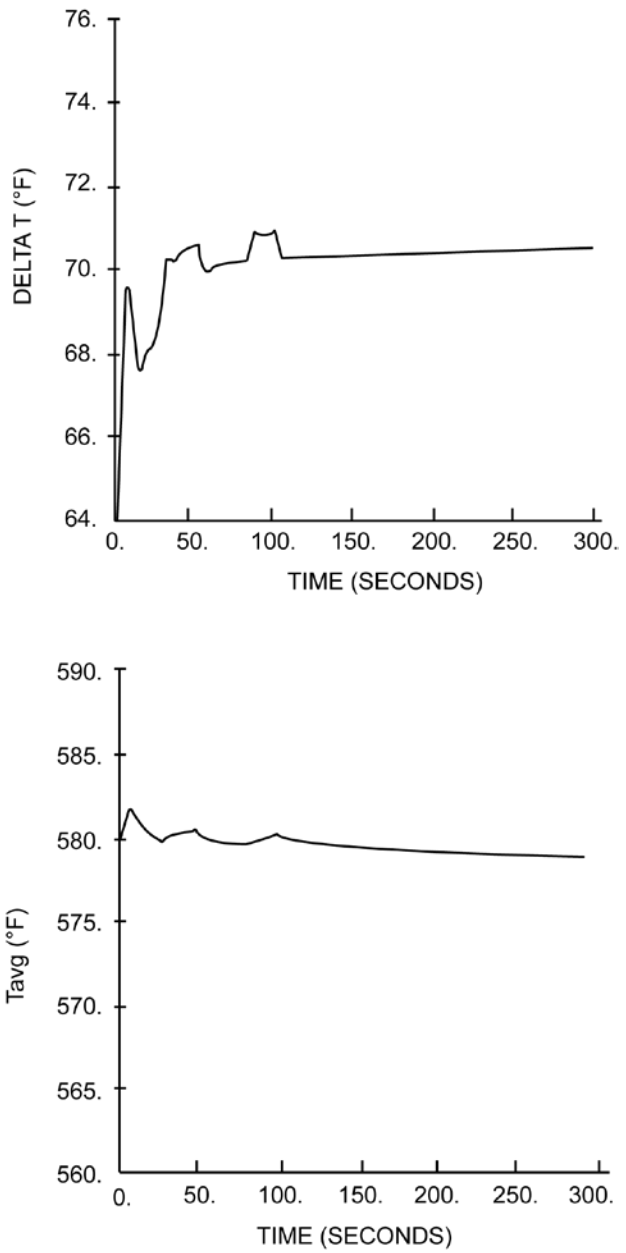
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.12-3 EXCESSIVE LOAD INCREASE WITHOUT CONTROL ACTION, END OF LIFE, (MTC), MAXIMUM FEEDBACK, DELTA-T AND TAVG AS A FUNCTION OF TIME



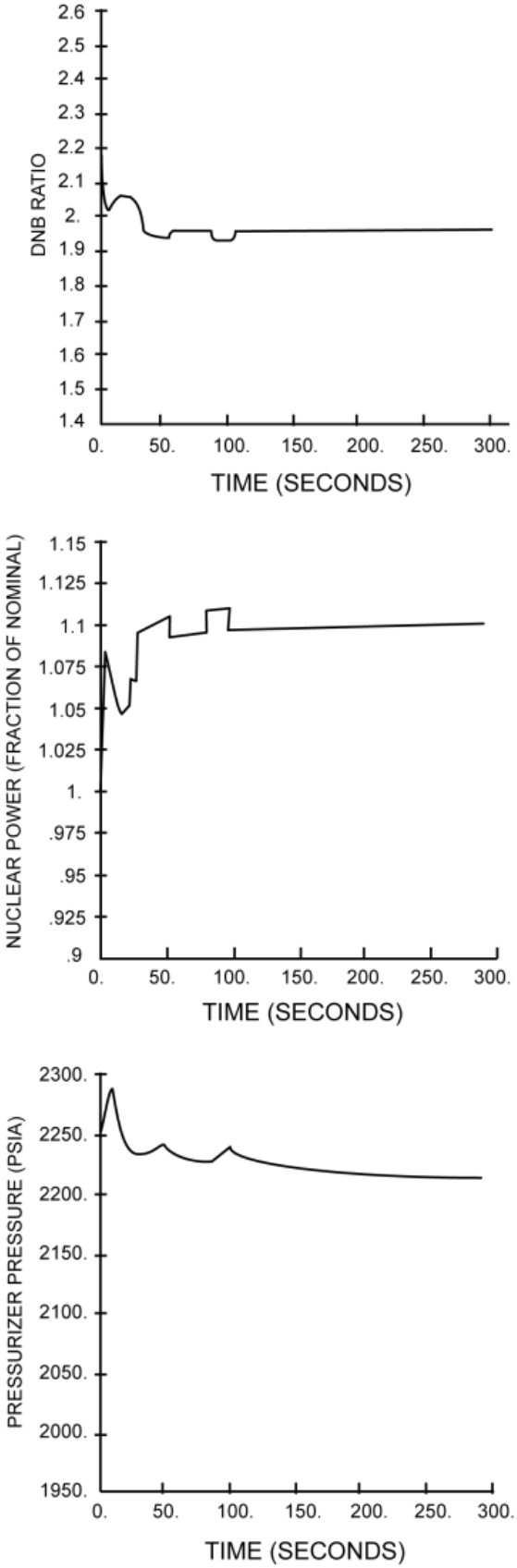
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.12-4
EXCESSIVE LOAD INCREASE WITHOUT CONTROL ACTION, END OF LIFE, (MTC), MAXIMUM FEEDBACK, DNBR, NUCLEAR POWER AND PRESSURIZER PRESSURE AS A FUNCTION OF TIME



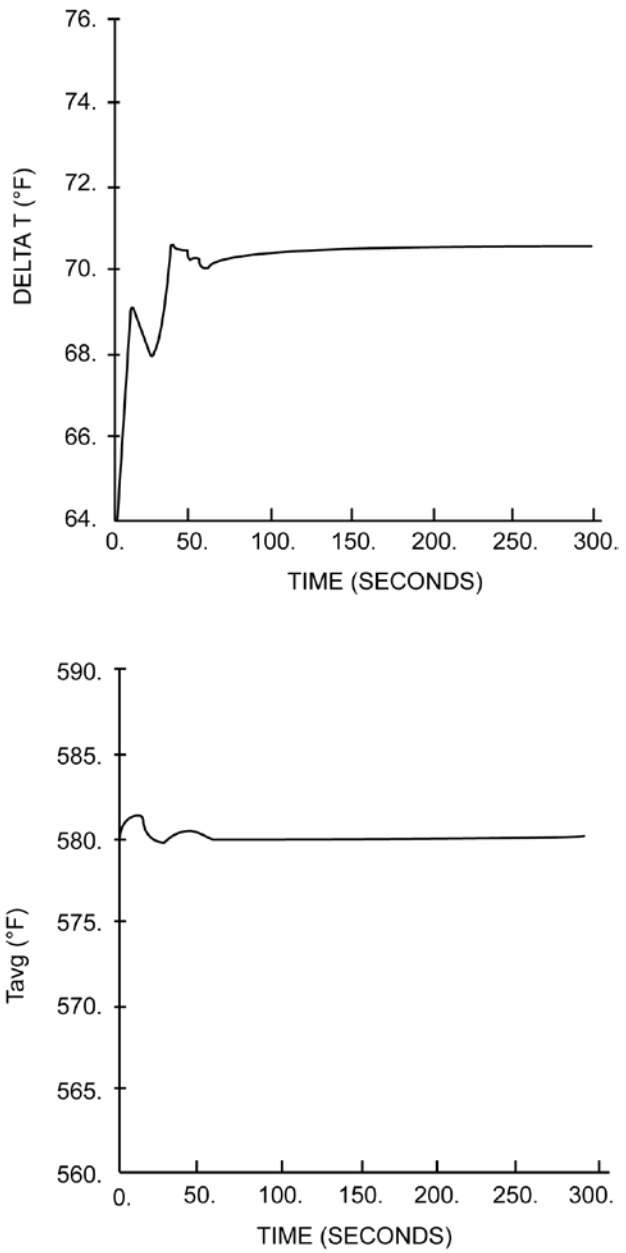
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.12-5 EXCESSIVE LOAD INCREASE WITH REACTOR CONTROL, BEGINNING OF LIFE, (MTC), MINIMUM FEEDBACK, DELTA-T AND TAVG AS A FUNCTION OF TIME



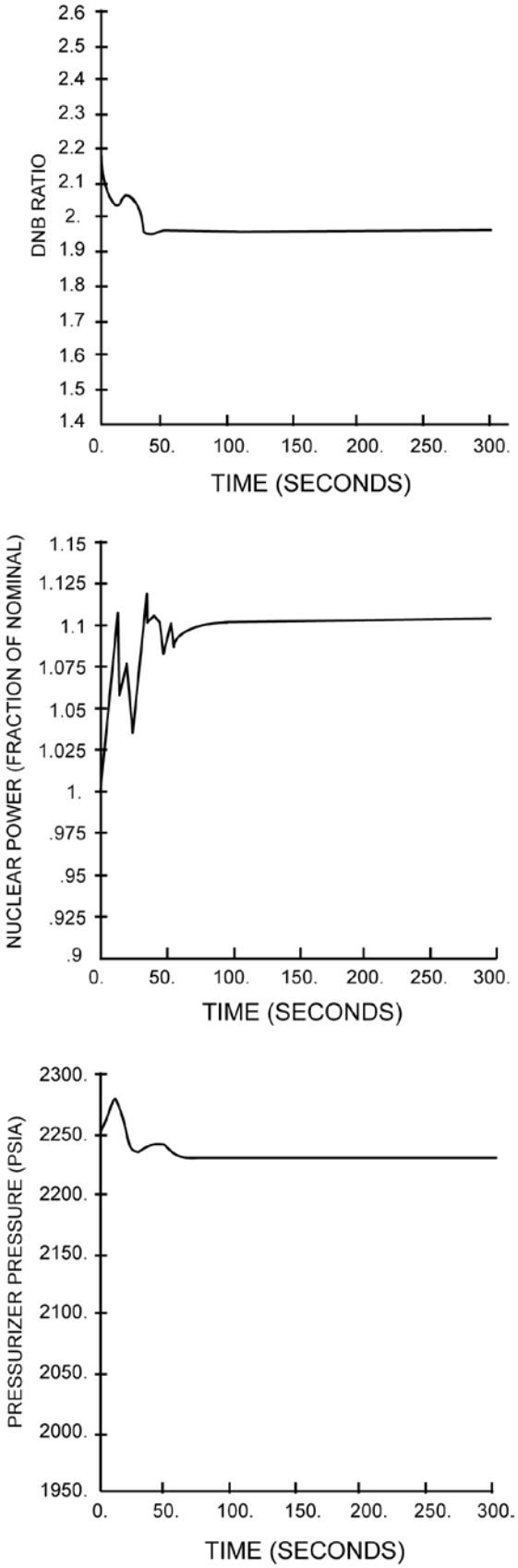
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.12-6
EXCESSIVE LOAD INCREASE WITH REACTOR CONTROL, BEGINNING OF LIFE, (MTC), MINIMUM FEEDBACK, DNBR, NUCLEAR POWER AND PRESSURIZER PRESSURE AS A FUNCTION OF TIME



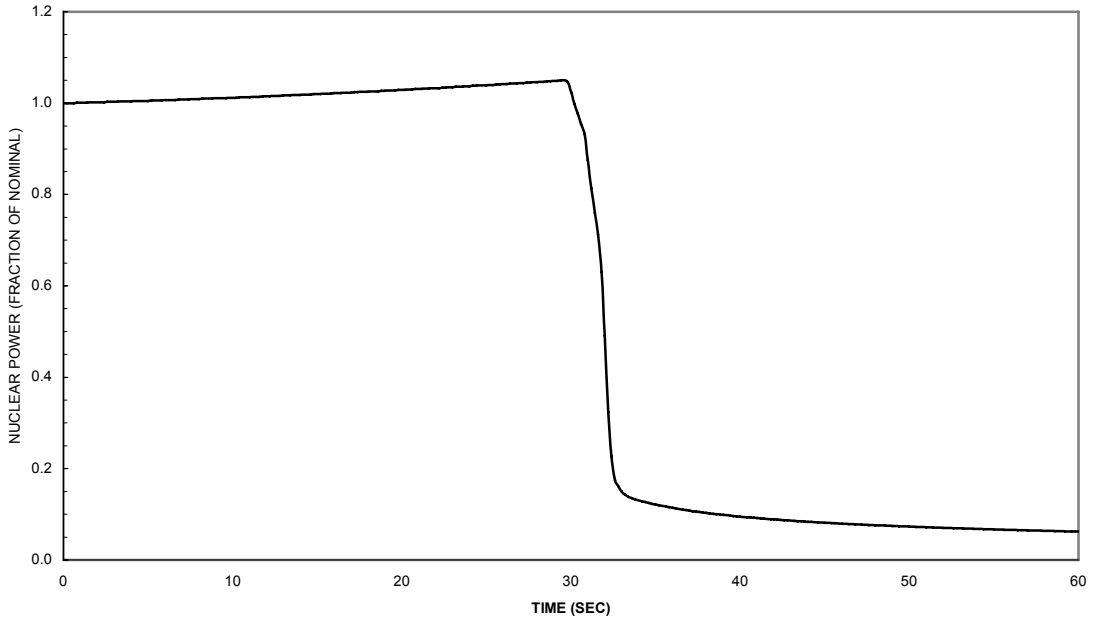
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.12-7 EXCESSIVE LOAD INCREASE WITH REACTOR CONTROL, END OF LIFE, (MTC), MAXIMUM FEEDBACK, DELTA-T AND TAVG AS A FUNCTION OF TIME

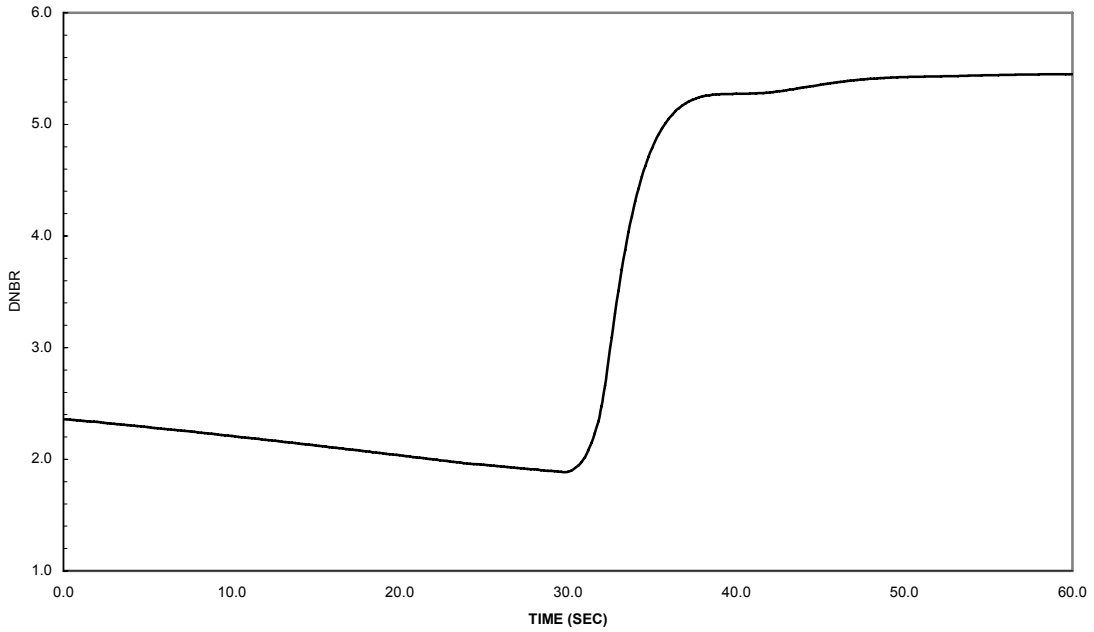


FSAR UPDATE

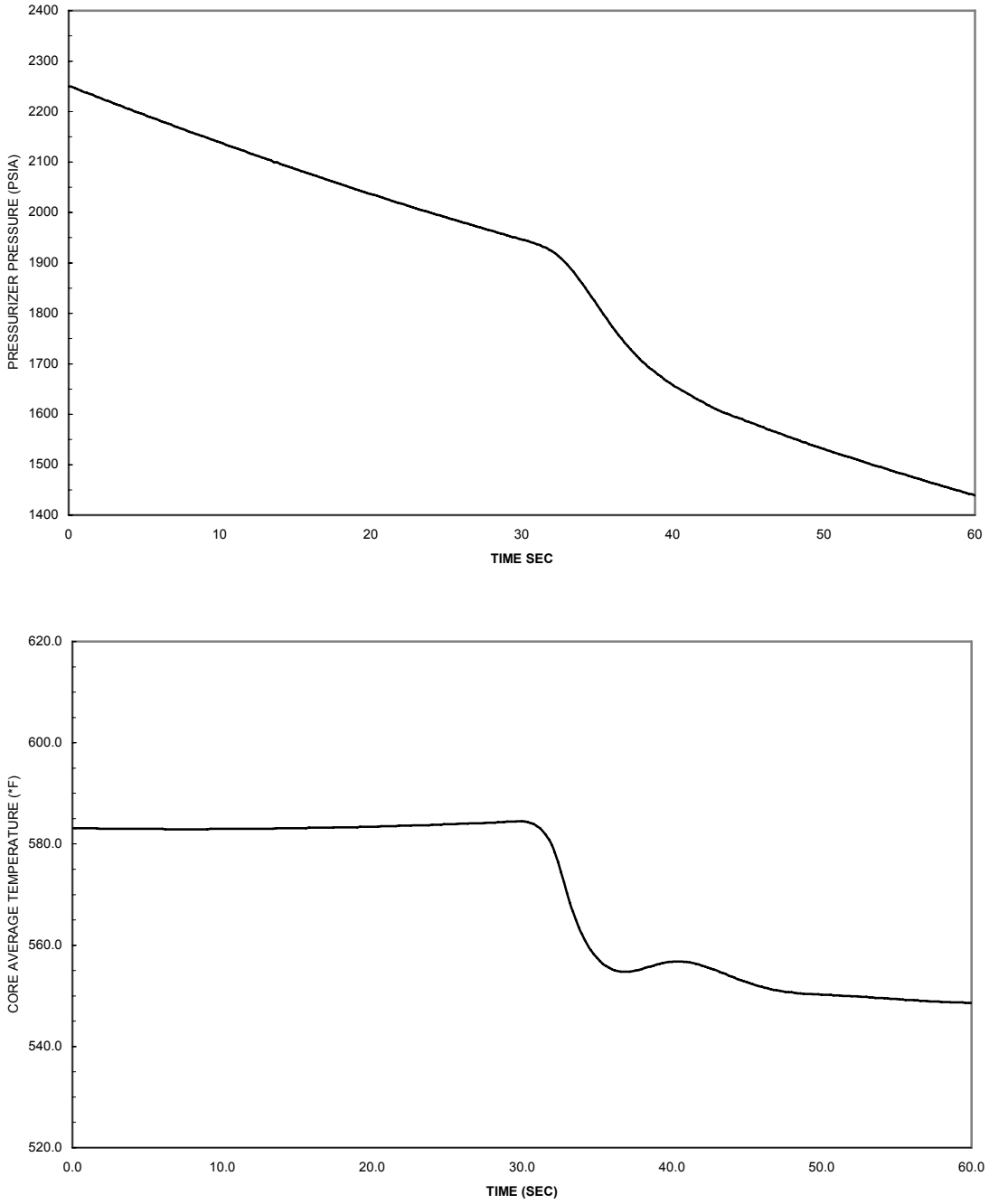
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.2.12-8
EXCESSIVE LOAD INCREASE WITH REACTOR CONTROL, END OF LIFE, (MTC), MAXIMUM FEEDBACK, DNBR, NUCLEAR POWER AND PRESSURIZER PRESSURE AS A FUNCTION OF TIME

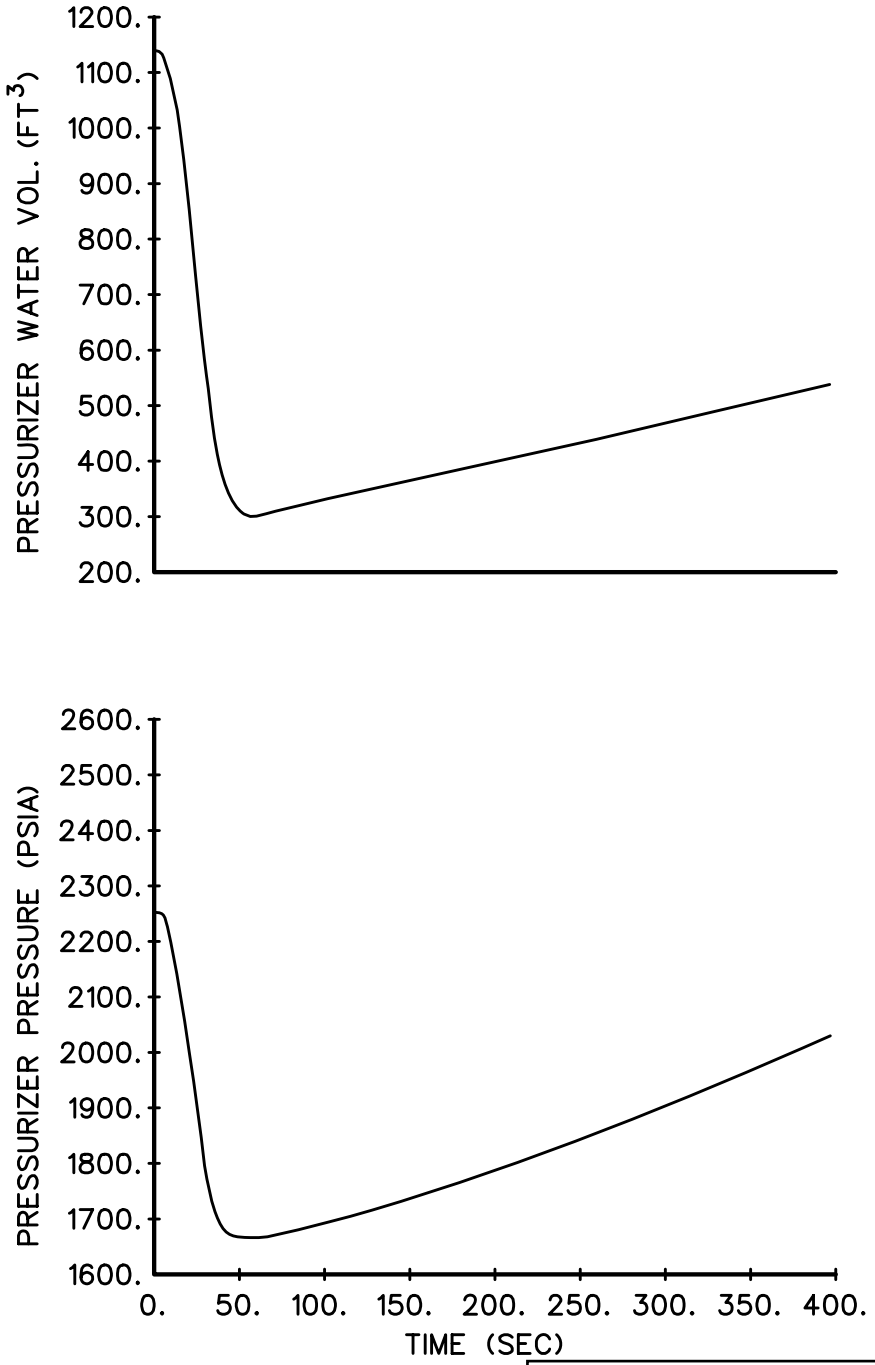




FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.13-1 NUCLEAR POWER AND DNBR TRANSIENTS FOR ACCIDENTAL DEPRESSURIZATION OF THE REACTOR COOLANT SYSTEM



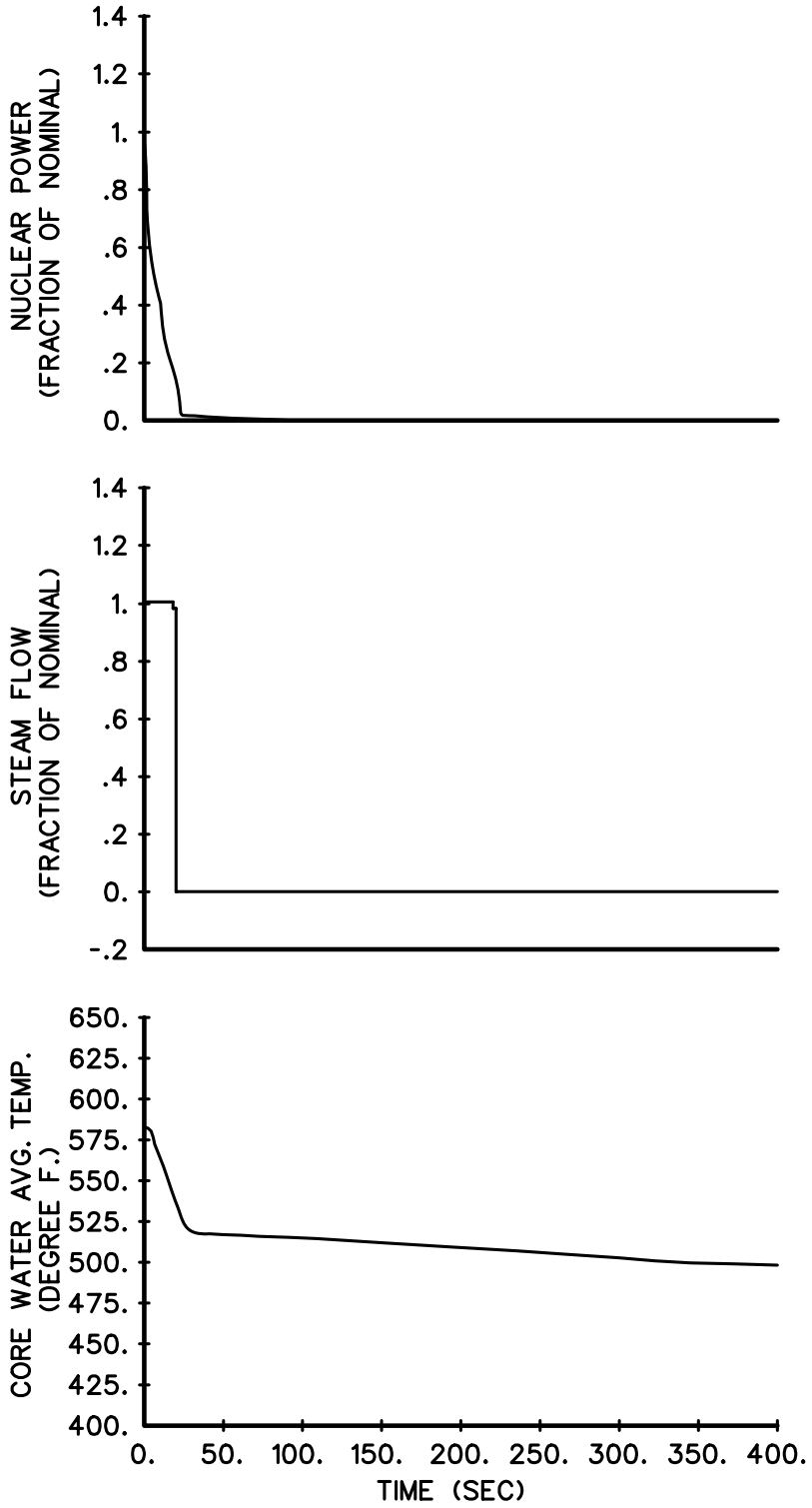
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.13-2 PRESSURIZER PRESSURE AND CORE AVERAGE TEMPERATURE TRANSIENTS FOR ACCIDENTAL DEPRESSURIZATION OF THE REACTOR COOLANT SYSTEM



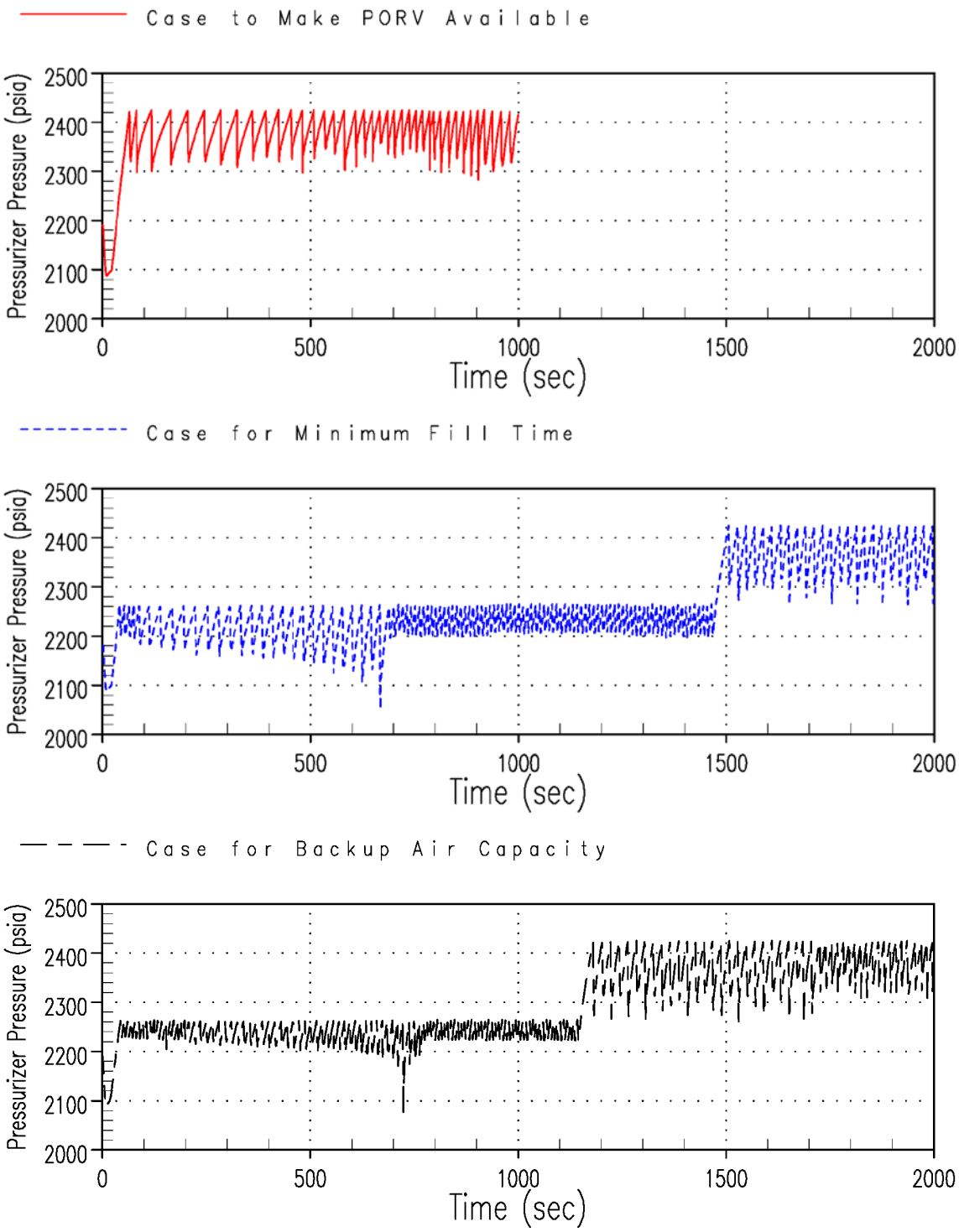
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

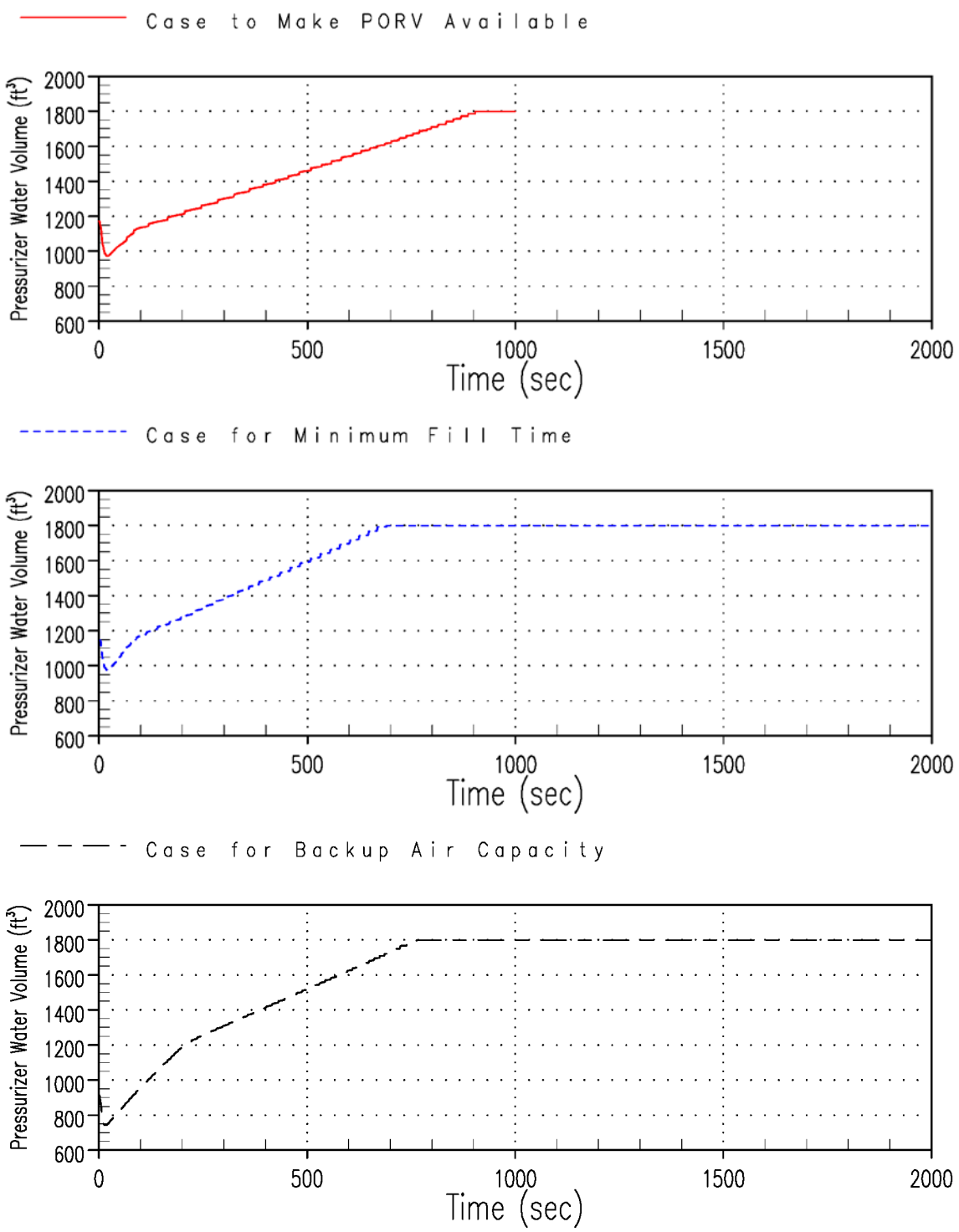
FIGURE 15.2.15-1
SPURIOUS ACTUATION OF SAFETY INJECTION SYSTEM AT POWER DNBR ANALYSIS – PRESSURIZER WATER VOLUME AND PRESSURIZER PRESSURE VERSUS TIME



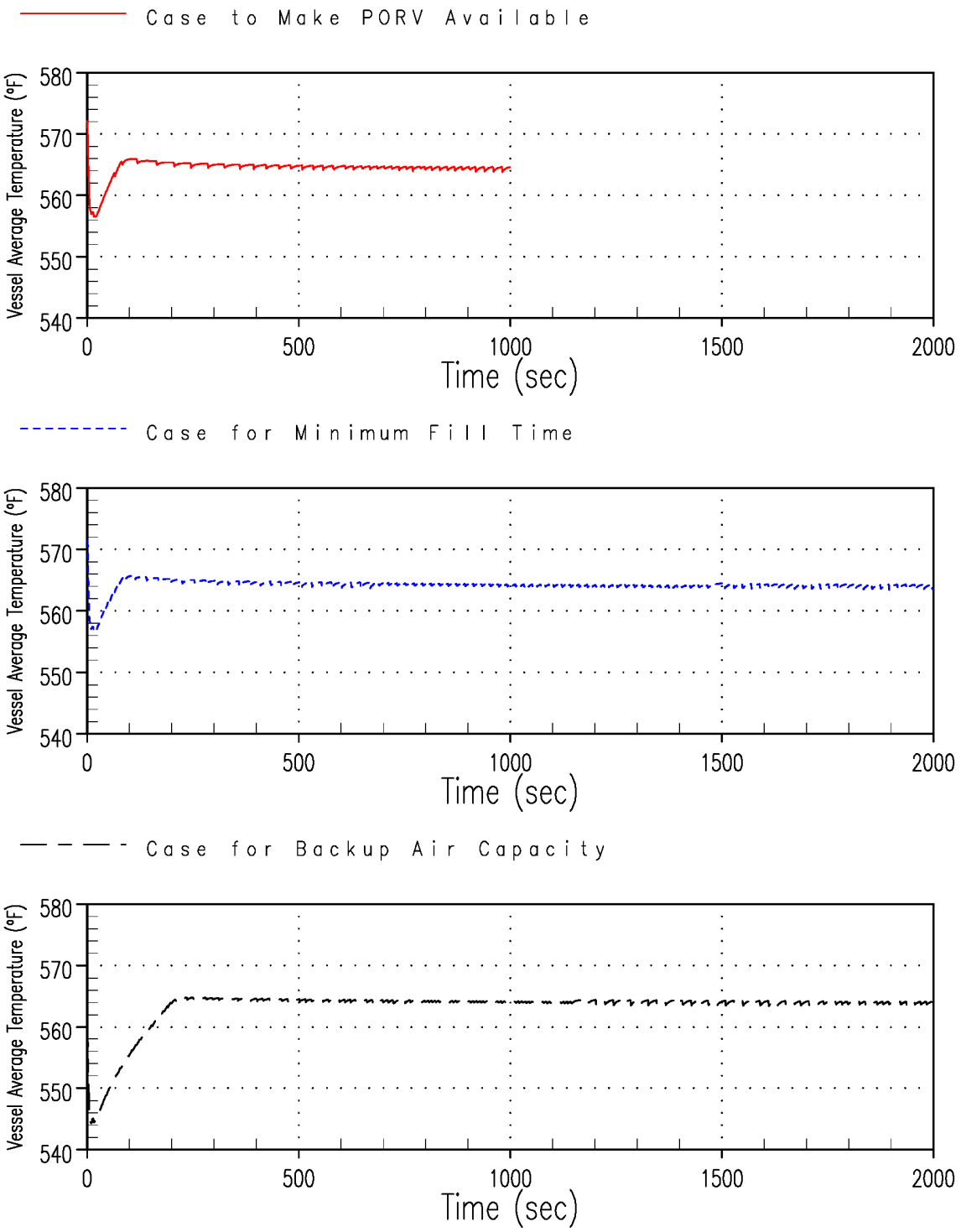
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.15-2 SPURIOUS ACTUATION OF SAFETY INJECTION SYSTEM AT POWER DNBR ANALYSIS – NUCLEAR POWER, STEAM FLOW, AND CORE WATER TEMPERATURE VERSUS TIME



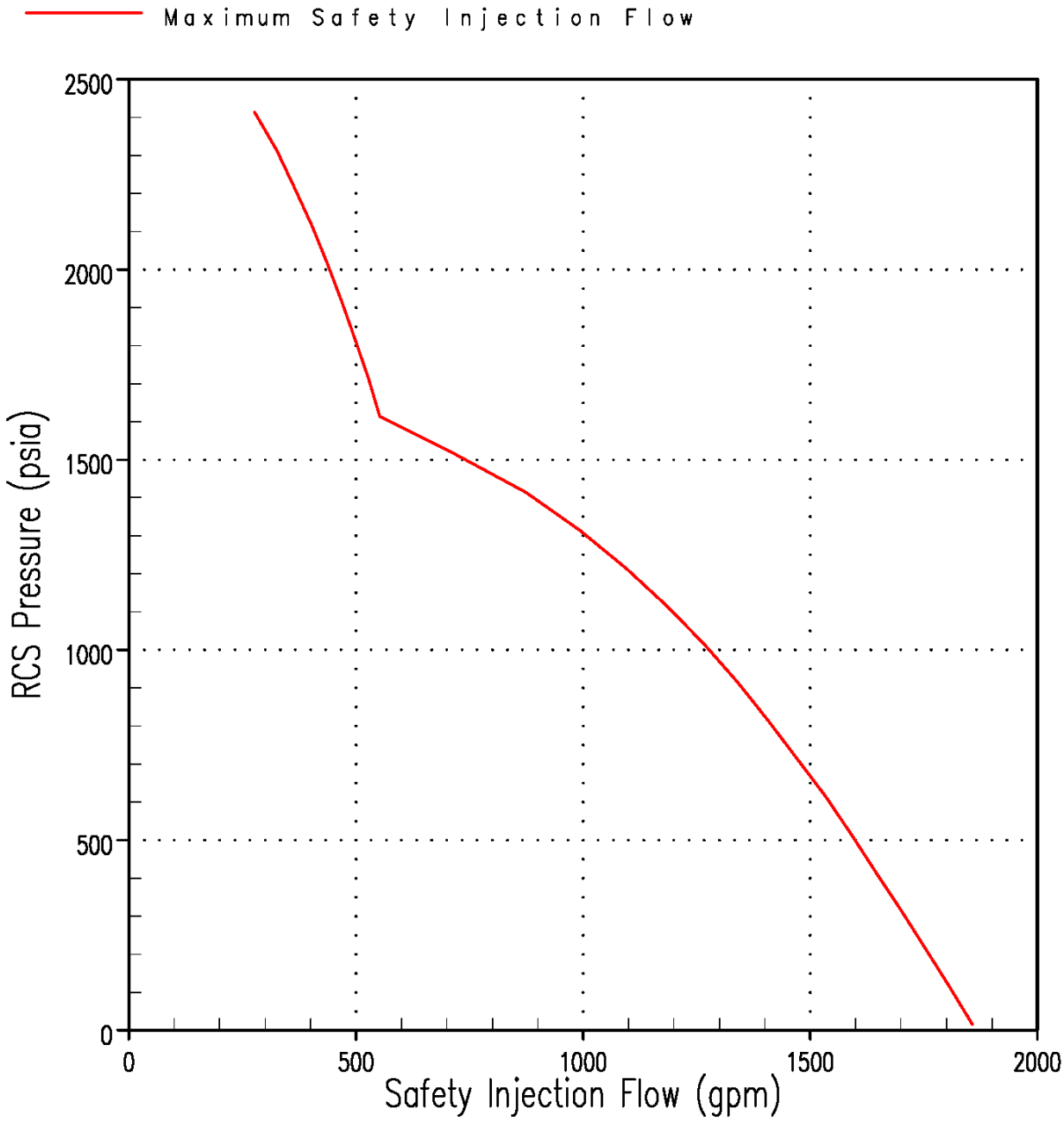
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.15-3 SSI PRESSURIZER FILLING ANALYSIS TYPICAL PRESSURIZER PRESSURE RESPONSE



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.15-4 SSI PRESSURIZER FILLING ANALYSIS TYPICAL PRESSURIZER LIQUID VOLUME RESPONSE



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.15-5 SSI PRESSURIZER FILLING ANALYSIS TYPICAL VESSEL AVERAGE TEMPERATURE RESPONSE



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.2.15-6 SSI PRESSURIZER FILLING ANALYSIS MAXIMUM SAFEGUARDS SI FLOW PROFILE

4026-385

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1							-8.9			-7.4					
2			-5.6			-9.1		-8.5							
3								-8.2		-6.8		-4.1		0.2	
4		-7.9	-8.2					-7.7							
5					-8.4				-6.0		-3.8		-1.8		
6	-8.5		-8.4			-7.4		-5.5						-0.3	
7				-7.7			-5.0			-1.2			-1.0		
8	-7.7		-7.3		-5.9		-3.2			1.5		3.2	3.4	3.6	
9		-6.9							2.7		5.9				6.0
10					-3.4		0.7					10.6			
11	-5.3				-1.8			5.9			17.1				11.4
12						1.3			12.3			24.6			
13			0.1		0.7			7.7						23.6	
14			2.5				4.7			11.1		17.6			
15					2.1			6.5							

CASE A

THE NUMBERS REPRESENT THE PERCENT DEVIATION FROM ASSEMBLY AVERAGE POWER

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.3-15

INTERCHANGE BETWEEN REGION 1 AND REGION 3 ASSEMBLY

4026-386

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1					0.3			1.5							
2			3.2				0.8			3.2		6.0			
3			1.2		0.0			1.6						10.3	
4						0.0			2.9			6.5			
5	-2.2				-1.0			2.2			6.9				6.6
6					-1.7		0.5					8.8			
7		-3.2							5.2		16.7				5.4
8	-3.5		-3.4		-2.6		-0.7			11.4		11.3	5.8	4.4	
9				-3.6			-2.0			-2.3			2.2		
10	-3.8		-3.8			-3.6		-2.9						0.5	
11					-3.9				-4.3		-4.6		-1.5		
12		-2.8	-3.1					-4.5							
13								-4.8		-4.4		-2.6		1.4	
14			-0.4			-4.8		-4.8							
15							-4.8			-4.5					

CASE B-1

THE NUMBERS REPRESENT THE PERCENT DEVIATION FROM ASSEMBLY AVERAGE POWER.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.3-16

INTERCHANGE BETWEEN REGION 1 AND REGION 2 ASSEMBLY, BURNABLE POISON RODS BEING RETAINED BY THE REGION 2 ASSEMBLY

4026-387

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1							1.0			1.1					
2			5.1			1.0		1.0							
3								1.1		1.1		1.9		4.9	
4		1.7	1.7					1.4							
5					1.1				1.8		1.1		0.7		
6	0.0		0.2			1.8		3.9						4.0	
7				0.0			5.2			2.2			-0.3		
8	-0.7		-0.6		0.3		5.1			1.5		-0.3	-0.6	-0.7	
9		-1.0							-1.1		-0.8				-0.9
10					-1.4		-3.1					-1.3			
11	-0.9				-1.7						-1.7				-0.9
12						-2.5			-2.9			-1.1			
13			0.7		-1.9			-2.9						2.5	
14			2.3				-2.8			-2.4		-0.8			
15					-2.1			-2.8							

CASE B-2

THE NUMBERS REPRESENT THE PERCENT DEVIATION FROM ASSEMBLY AVERAGE POWER.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.3-17

INTERCHANGE BETWEEN REGION 1 AND REGION 2 ASSEMBLY, BURNABLE POISON RODS BEING TRANSFERRED TO THE REGION 1 ASSEMBLY

4026-388

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1							-2.2			-2.1					
2			2.0			-2.0		-2.1							
3								-1.5		-1.6		-1.0		2.0	
4		-0.9	-1.0					-0.4							
5					-0.4				1.2		-0.5		-1.4		
6	-2.1		-1.6			2.3		5.7						-2.0	
7				-3.2			9.7			4.4			-1.7		
8	-2.3		-1.6		1.8		13.6	X		5.6		-0.4	-1.6	-2.1	
9		-2.2							9.7		1.1				-2.2
10					0.3		4.5					-0.9			
11	-1.9				-0.4			1.8			-0.5				-1.9
12						-0.9			-0.6			-1.1			
13			0.4		-1.4			-1.5						2.0	
14			2.0				-2.1			-2.0		-0.9			
15					-1.9			-2.2							

CASE C

THE NUMBERS REPRESENT THE PERCENT DEVIATION FROM ASSEMBLY AVERAGE POWER.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.3-18

ENRICHMENT ERROR: A REGION 2 ASSEMBLY LOADED INTO THE CORE CENTRAL POSITION

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1							-11.0			-14.0					
2			0.4			-9.2		-12.0							
3								-12.0		-14.0		-15.0		-13.0	
4		3.2	1.2					-11.0							
5					-1.5				-12.0		-15.0		-16.0		
6	9.8		7.1			-1.6		-8.0						-16.0	
7				9.2			-2.3			-12.0			-14.0		
8	20.0		17.8		10.8		0.8			-10.0		-14.0	-15.0	-16.0	
9		27.2							-5.5		-11.0				-15.0
10					20.7		5.8					-12.0			
11	42.0		X		23.6			1.9			-8.6				-13.0
12						14.0			-1.7			-8.9			
13			38.6		20.4			2.8						-7.0	
14			35.9				7.0			-3.3		-6.3			
15					15.3			2.9							

CASE D

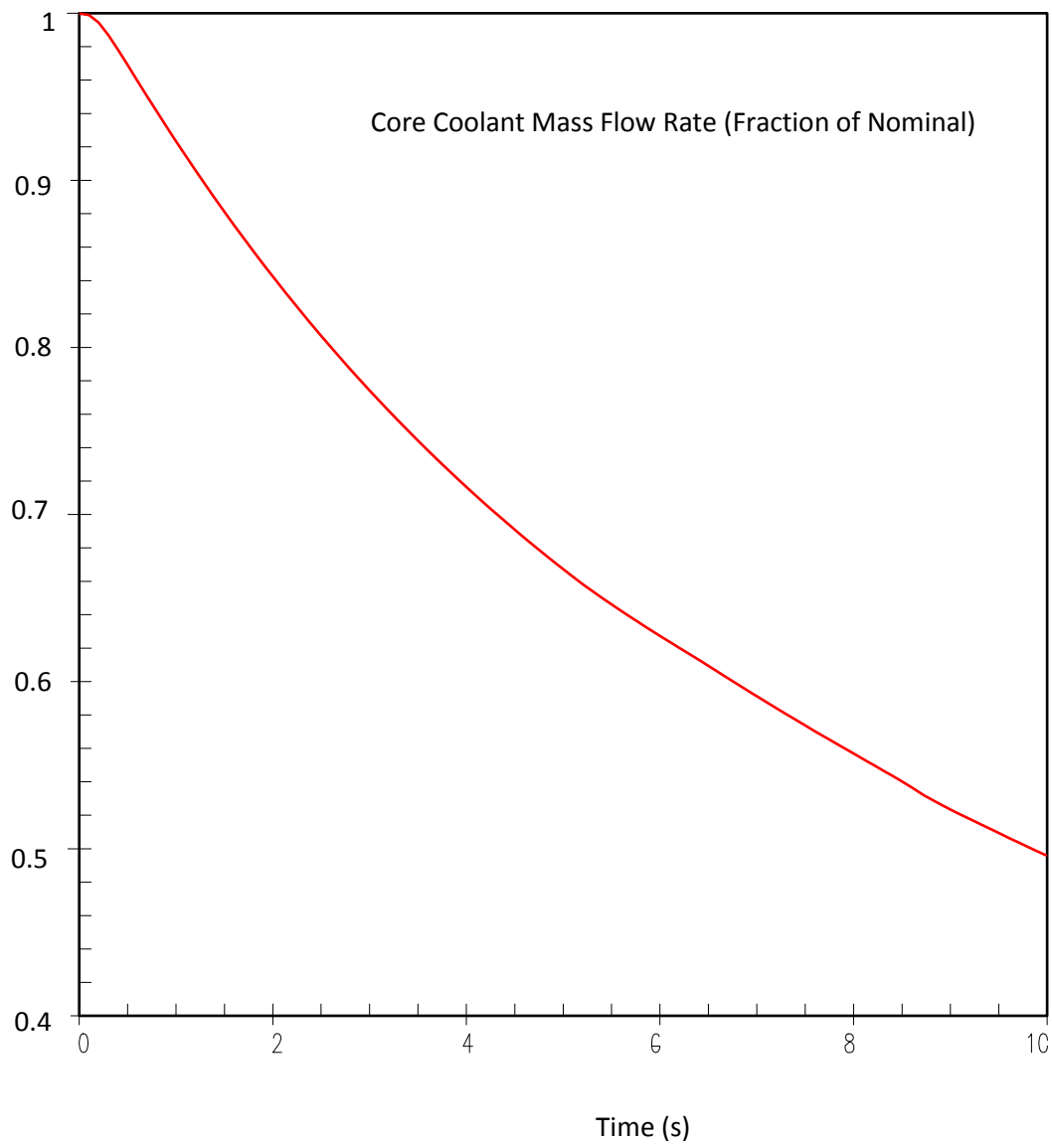
THE NUMBERS REPRESENT THE PERCENT DEVIATION FROM ASSEMBLY AVERAGE POWER.

FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

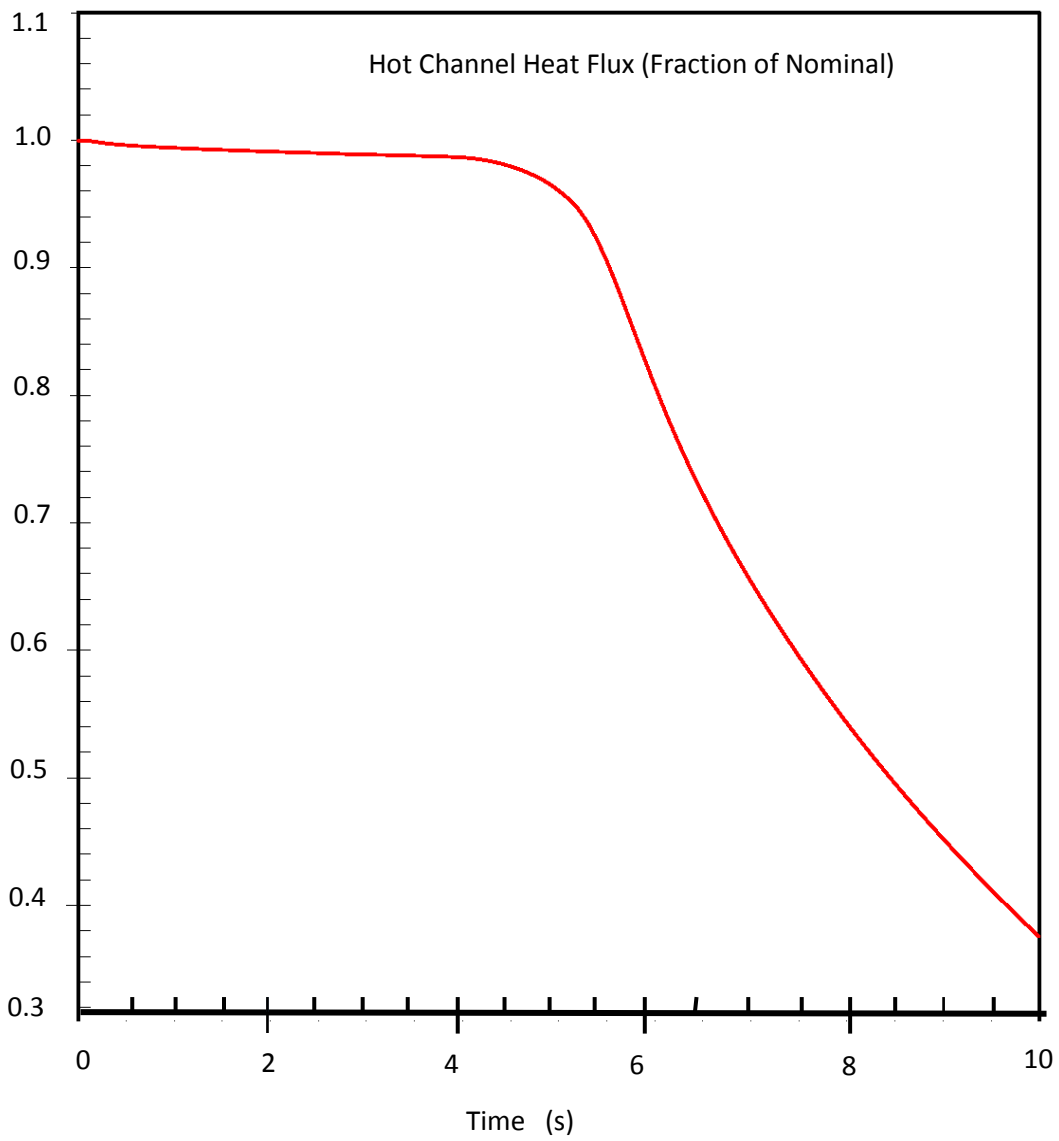
FIGURE 15.3-19

LOADING A REGION 2 ASSEMBLY INTO A REGION 1 POSITION NEAR CORE PERIPHERY



Note: The results for Unit 1 are nearly identical to those for Unit 2; therefore, the figures for Unit 1 are representative of the results for Unit 2.

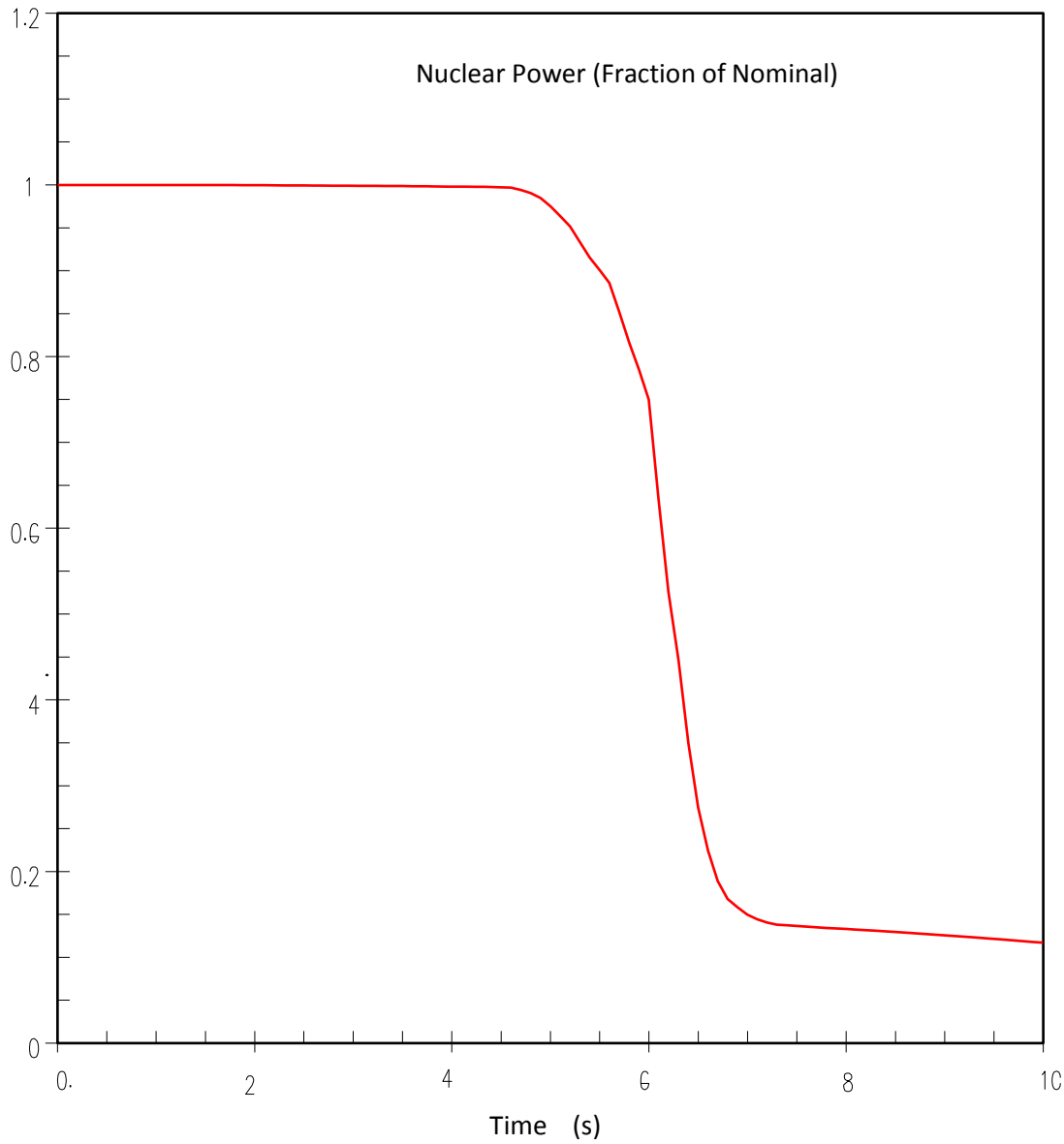
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3.4-1 COMPLETE LOSS OF FORCED REACTOR COOLANT FLOW ALL LOOPS OPERATING ALL LOOPS COASTING DOWN FLOW COASTDOWN VERSUS TIME



Note: The results for Unit 1 are nearly identical to those for Unit 2; therefore, the figures for Unit 1 are representative of the results for Unit 2.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3.4-2 COMPLETE LOSS OF FORCED REACTOR COOLANT FLOW ALL LOOPS OPERATING ALL LOOPS COASTING DOWN HEAT FLUX VERSUS TIME

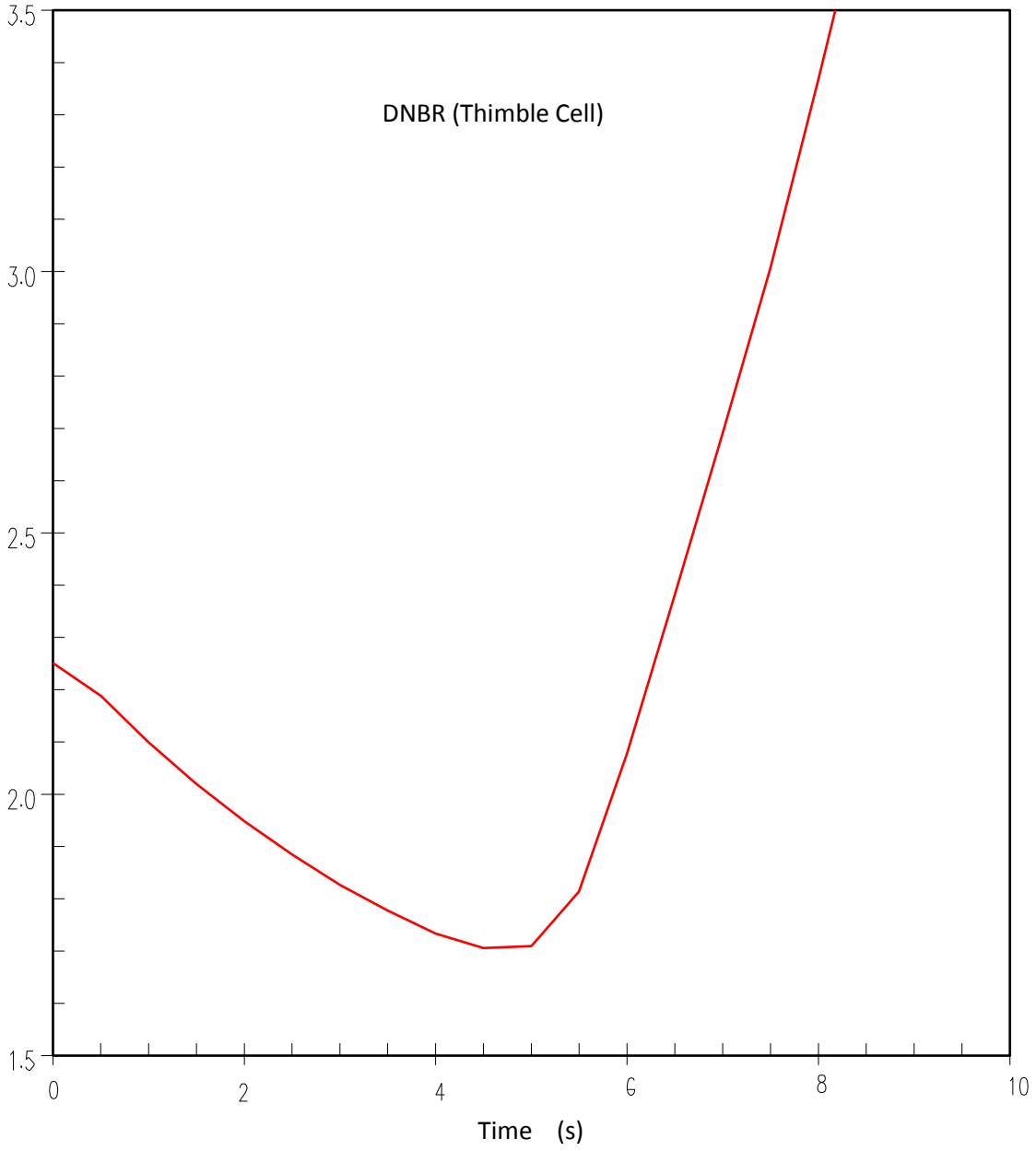
Revision 24 September 2018



Note: The results for Unit 1 are nearly identical to those for Unit 2; therefore, the figures for Unit 1 are representative of the results for Unit 2.

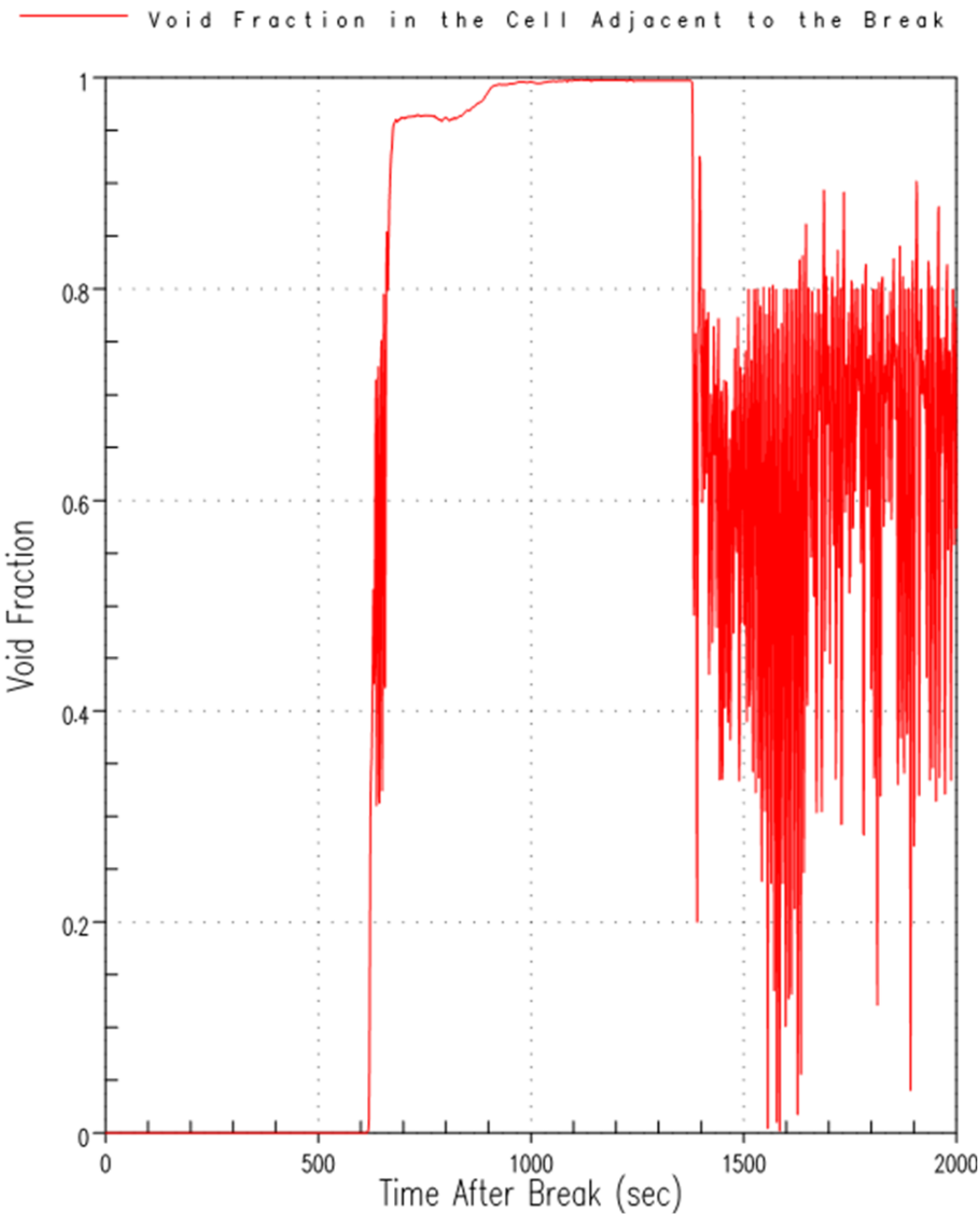
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3.4-3 COMPLETE LOSS OF FORCED REACTOR COOLANT FLOW ALL LOOPS OPERATING ALL LOOPS COASTING DOWN NUCLEAR POWER VERSUS TIME

Revision 24 September 2018



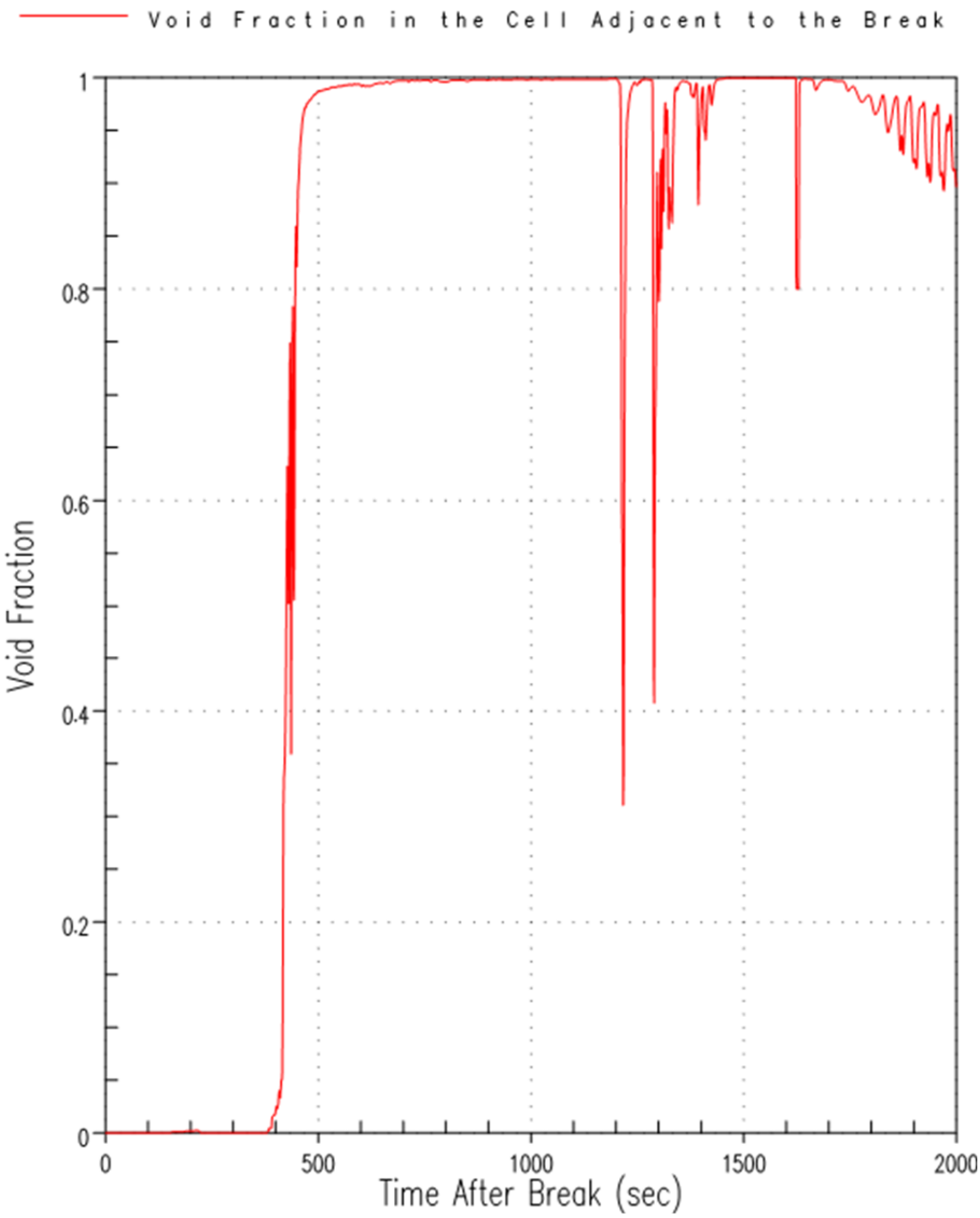
Note: The results for Unit 1 are nearly identical to those for Unit 2; therefore, the figures for Unit 1 are representative of the results for Unit 2.

FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.3.4-4 COMPLETE LOSS OF FORCED REACTOR COOLANT FLOW ALL LOOPS OPERATING ALL LOOPS COASTING DOWN DNBR VERSUS TIME



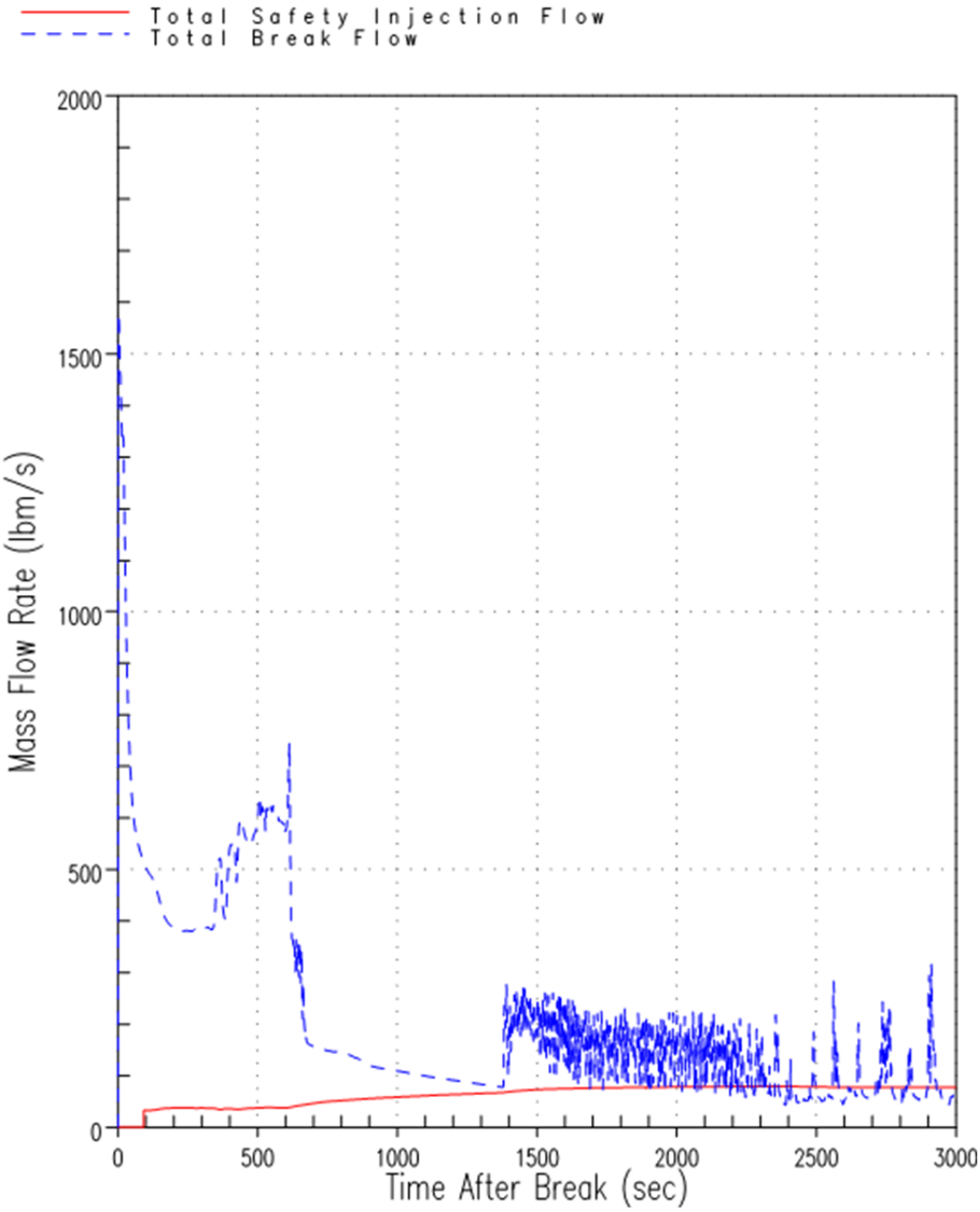
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-1A Break Flow Void Fraction for SBLOCA (Region I)

Revision 26 September 2021

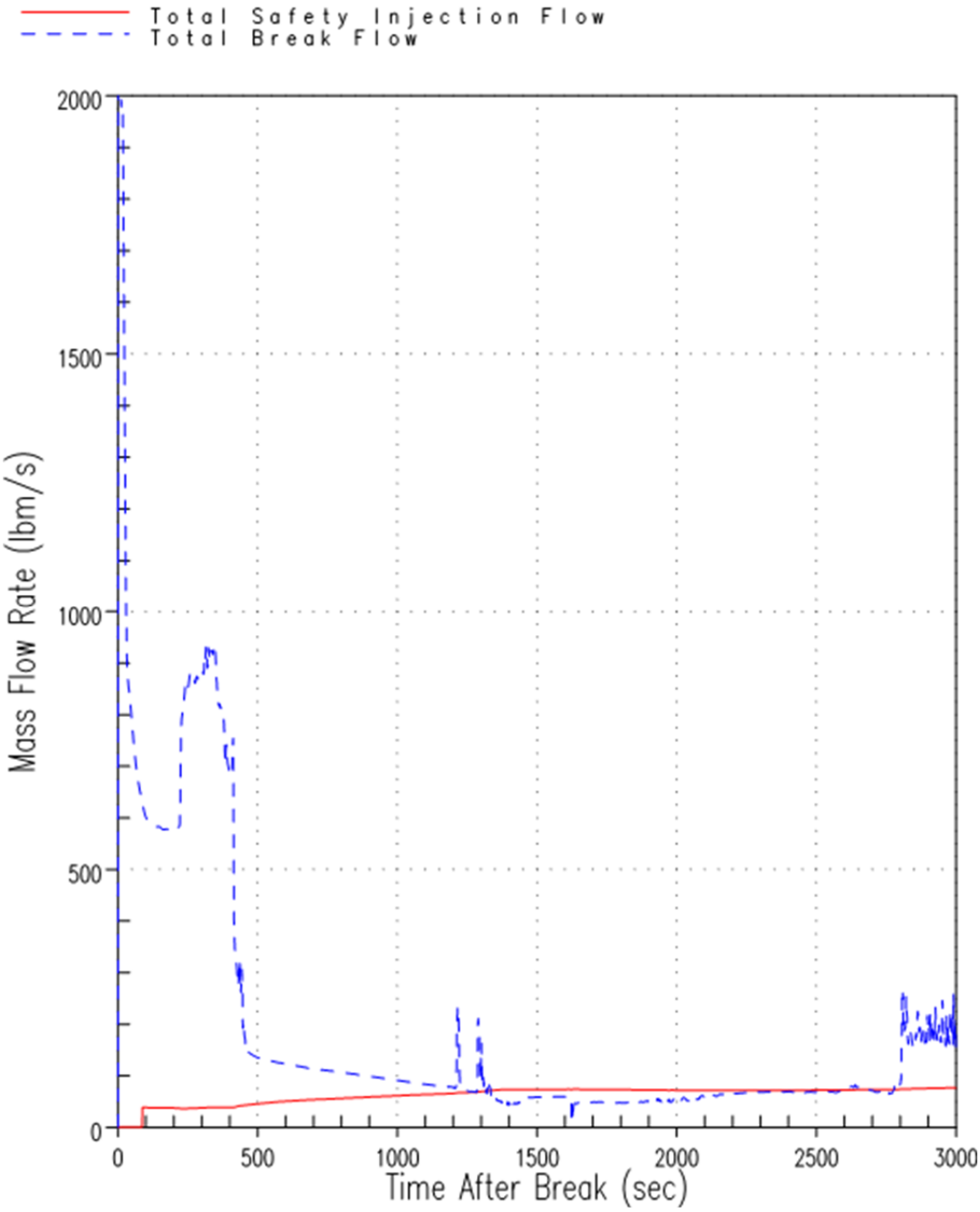


FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-1B Break Flow Void Fraction for SBLOCA (Region I)

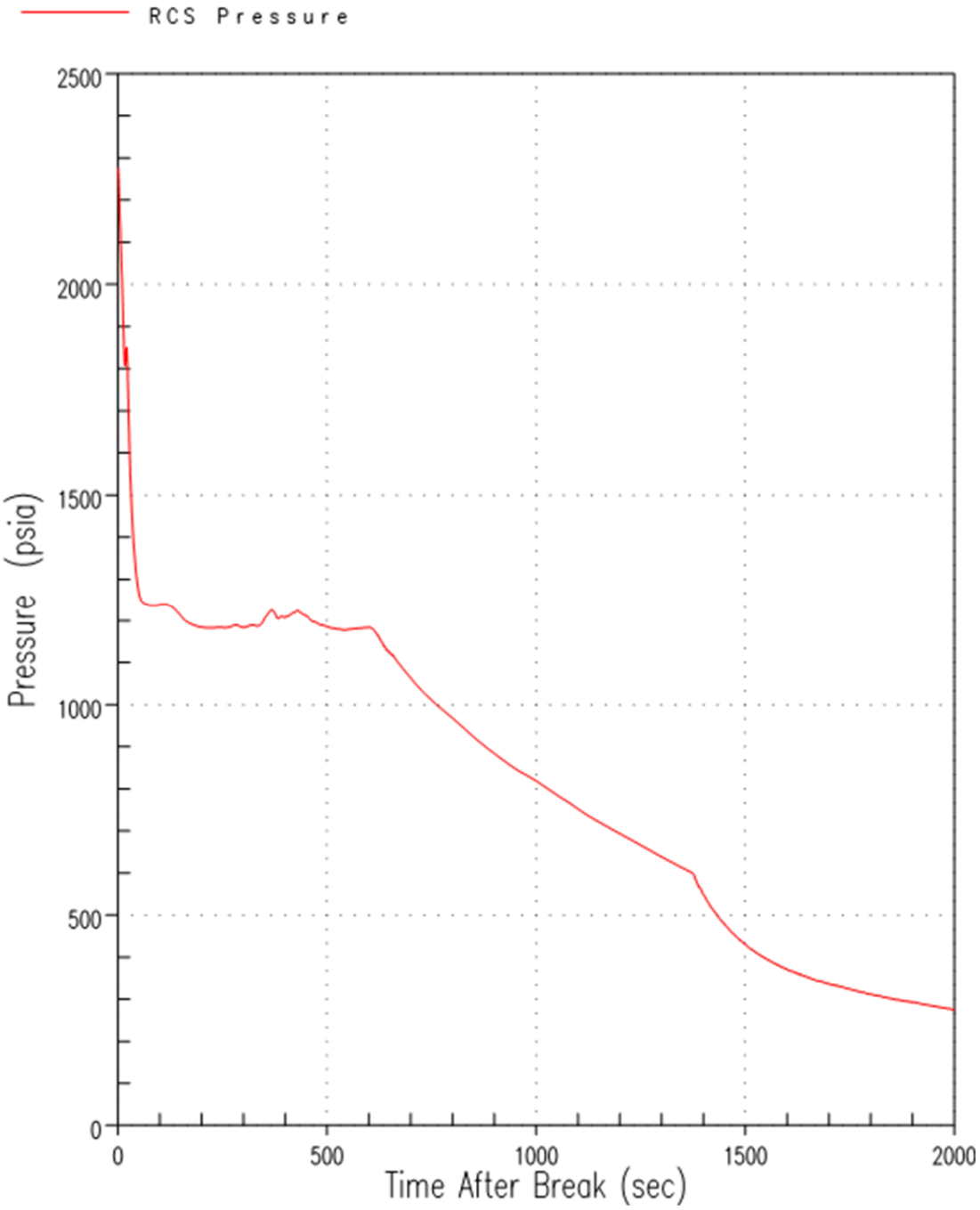
Revision 26 September 2021



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-2A **Total Safety Injection Flow and Total Break Flow for SBLOCA (Region I)**

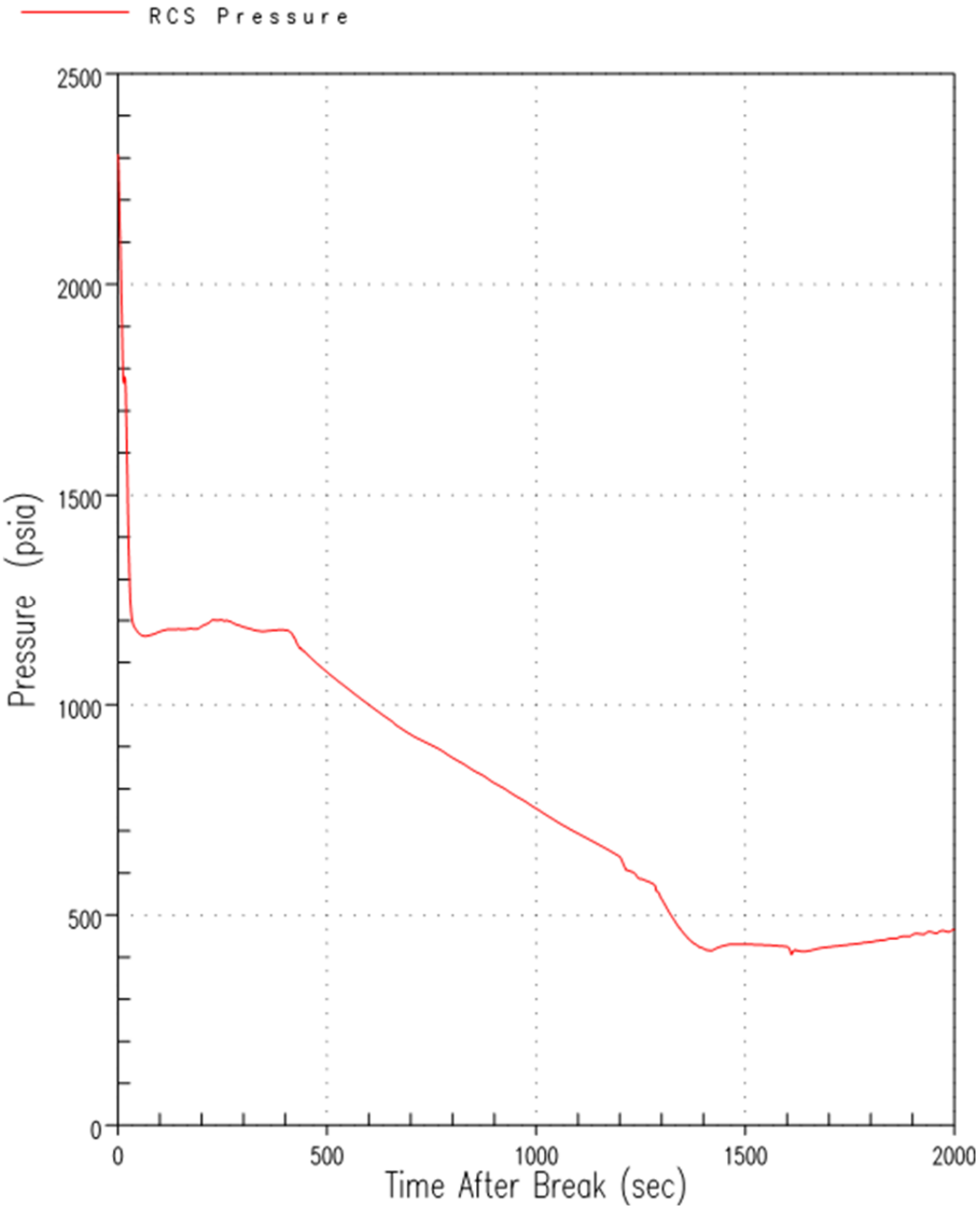


FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-2B **Total Safety Injection Flow and Total Break Flow for SBLOCA (Region I)**



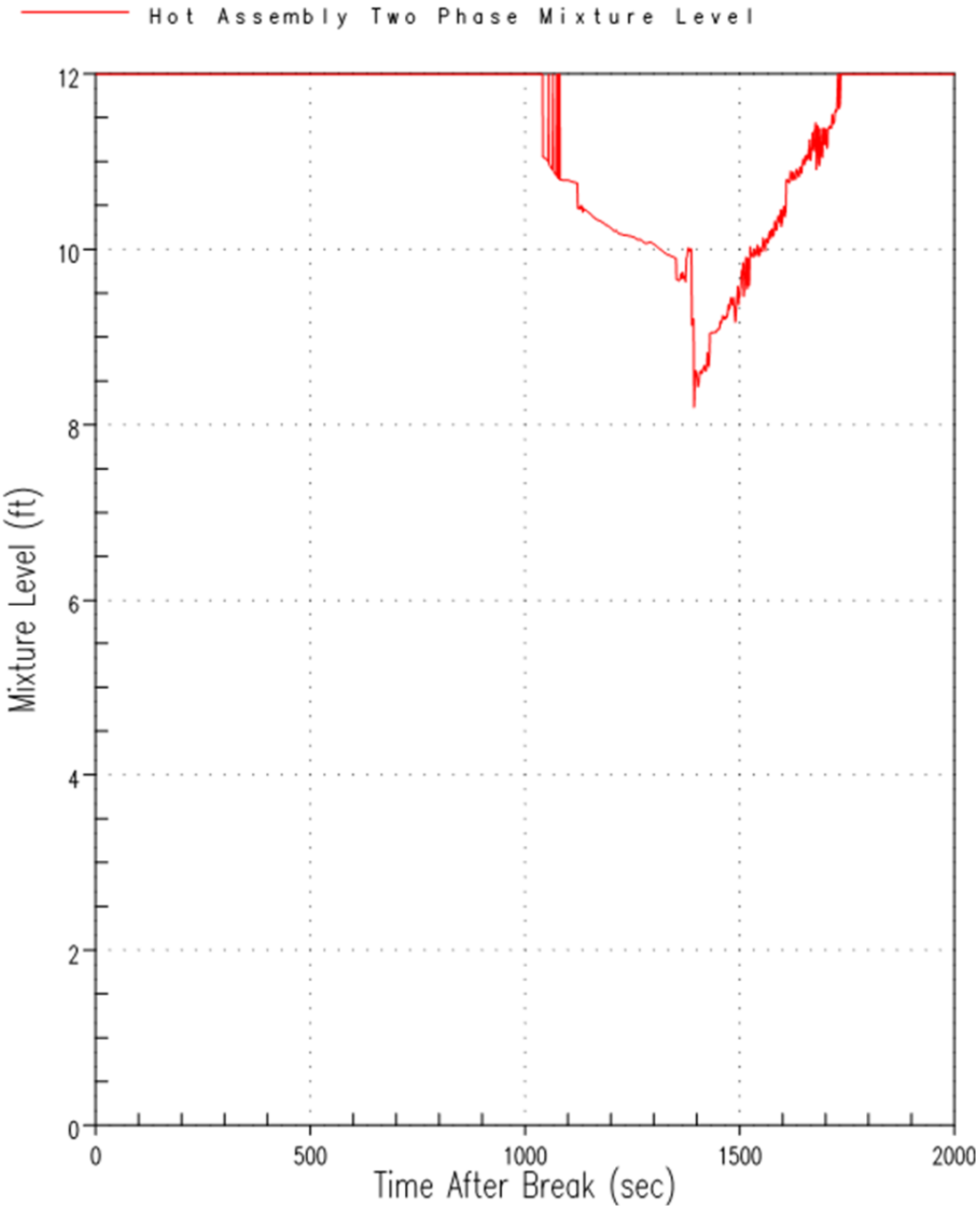
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-3A RCS Pressure for SBLOCA (Region I)

Revision 26 September 2021



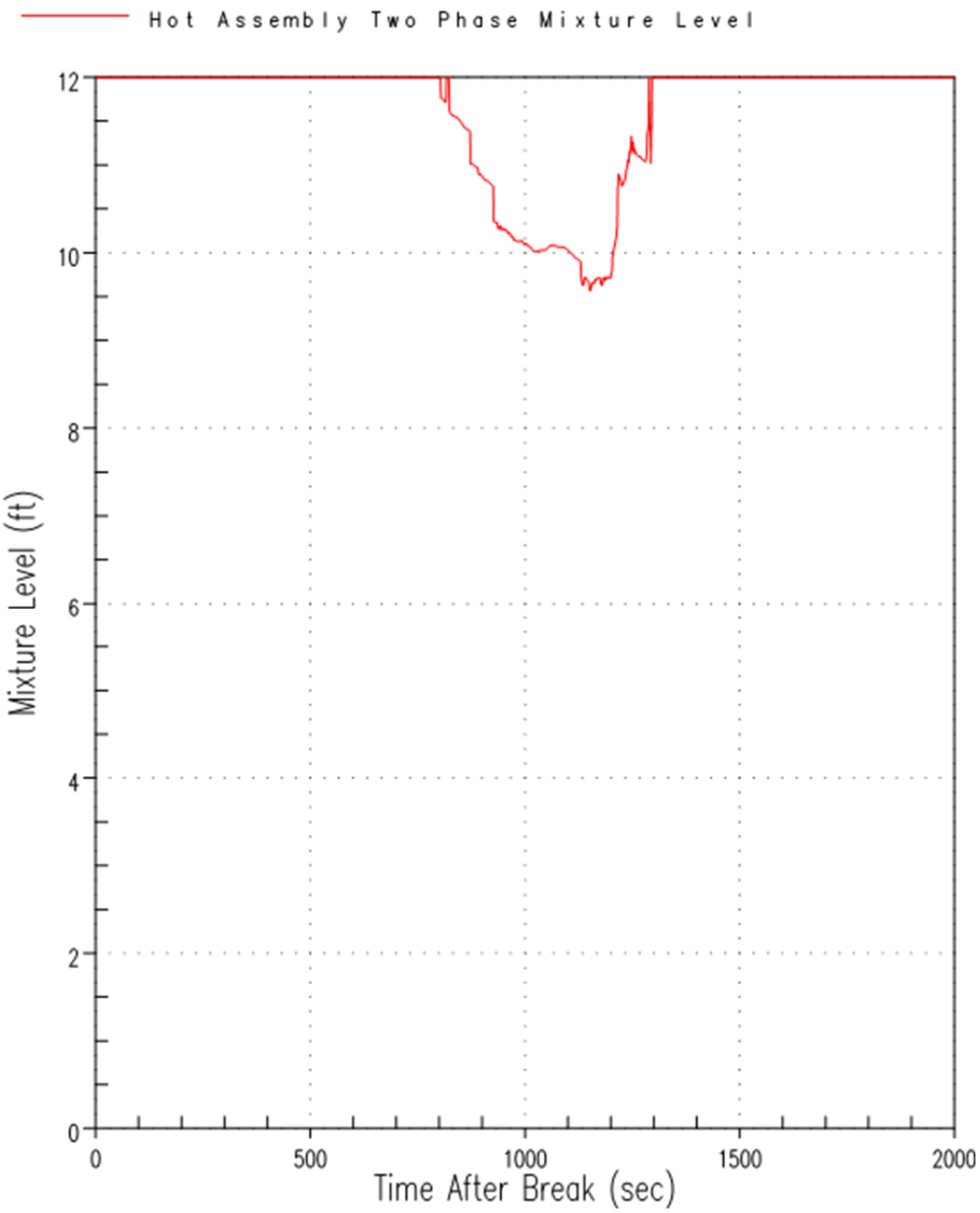
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-3B RCS Pressure for SBLOCA (Region I)

Revision 26 September 2021



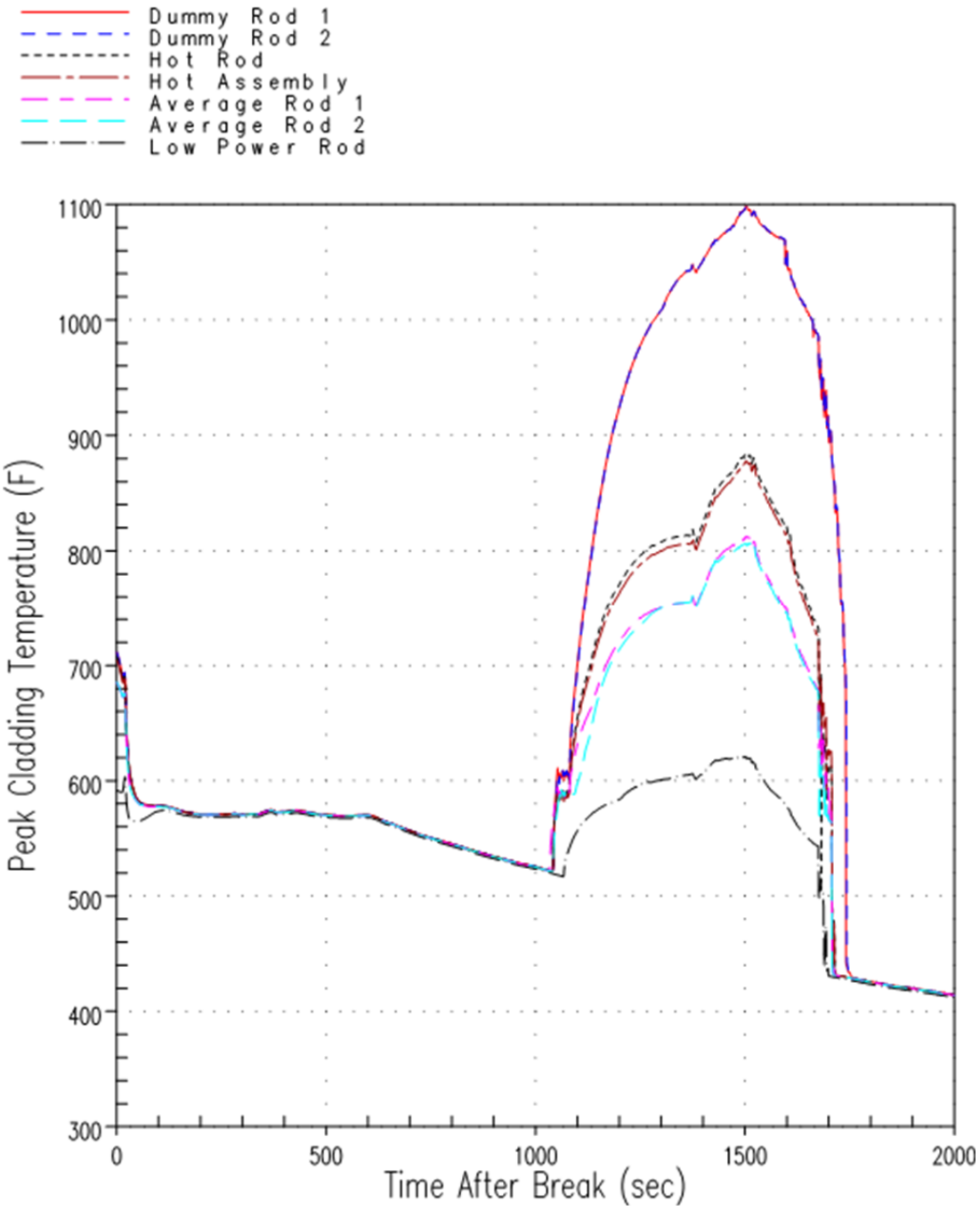
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-4A Hot Assembly Two-Phase Mixture Level for SBLOCA (Region I)

Revision 26 September 2021

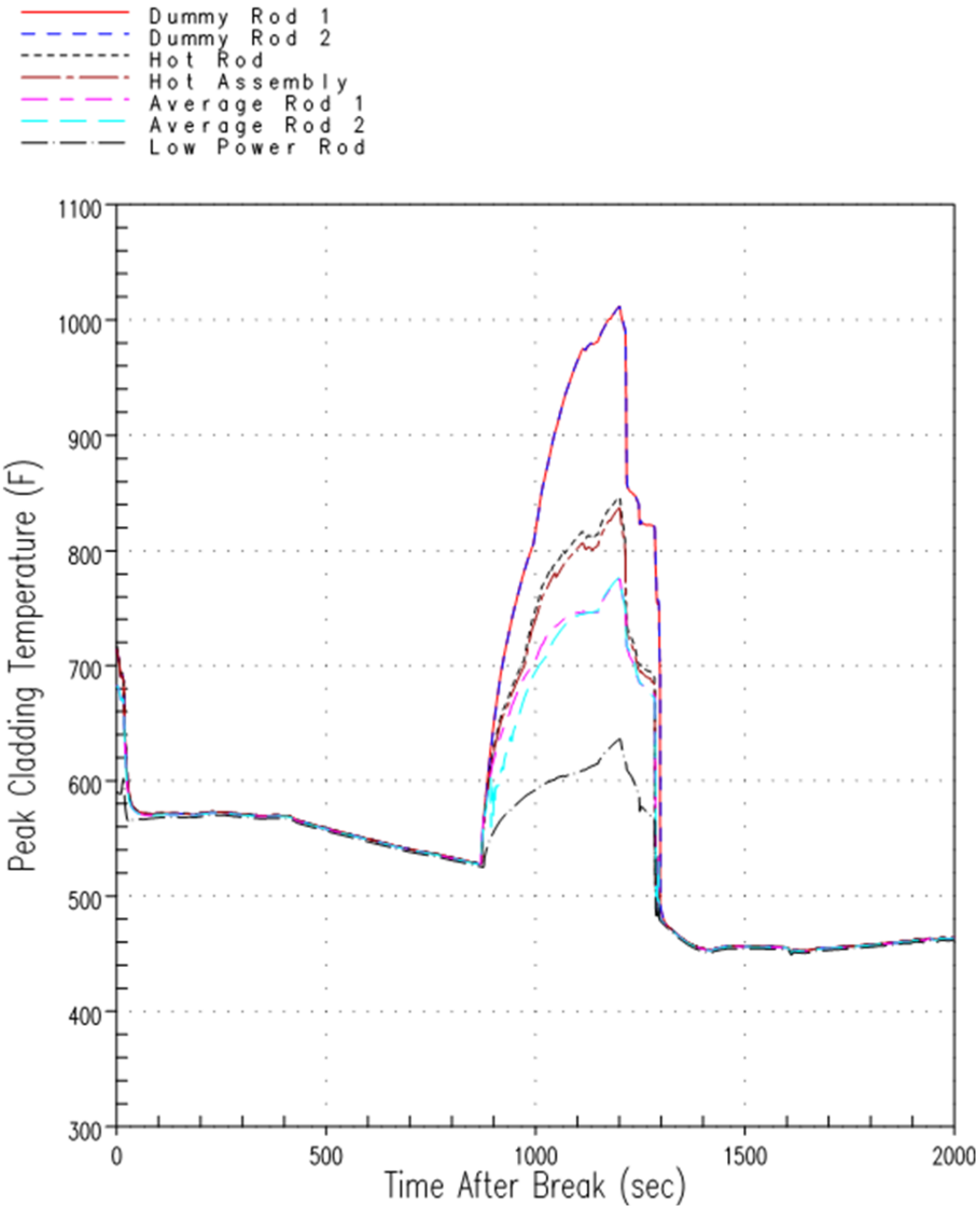


FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-4B **Hot Assembly Two-Phase Mixture Level for SBLOCA (Region I)**

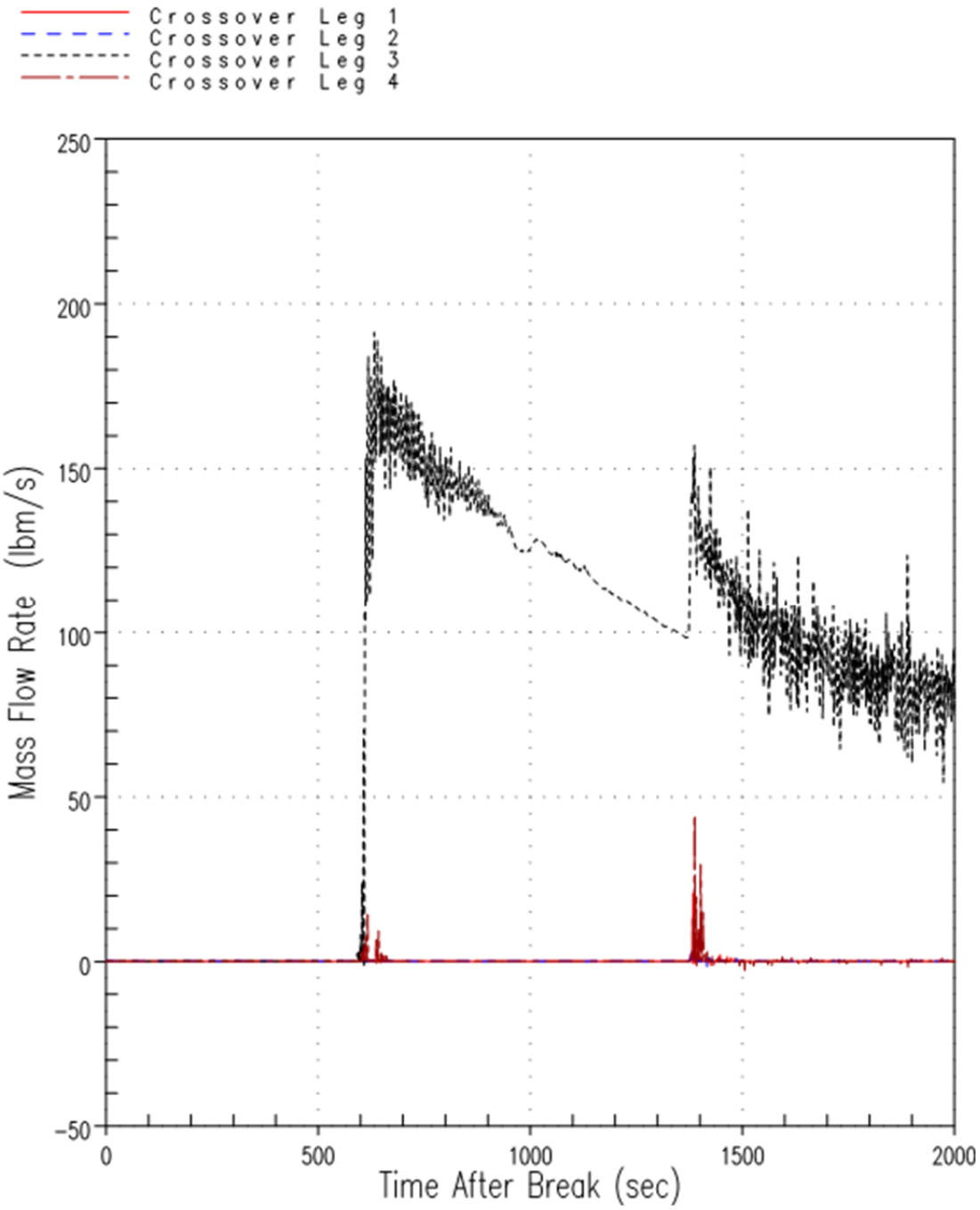
Revision 26 September 2021



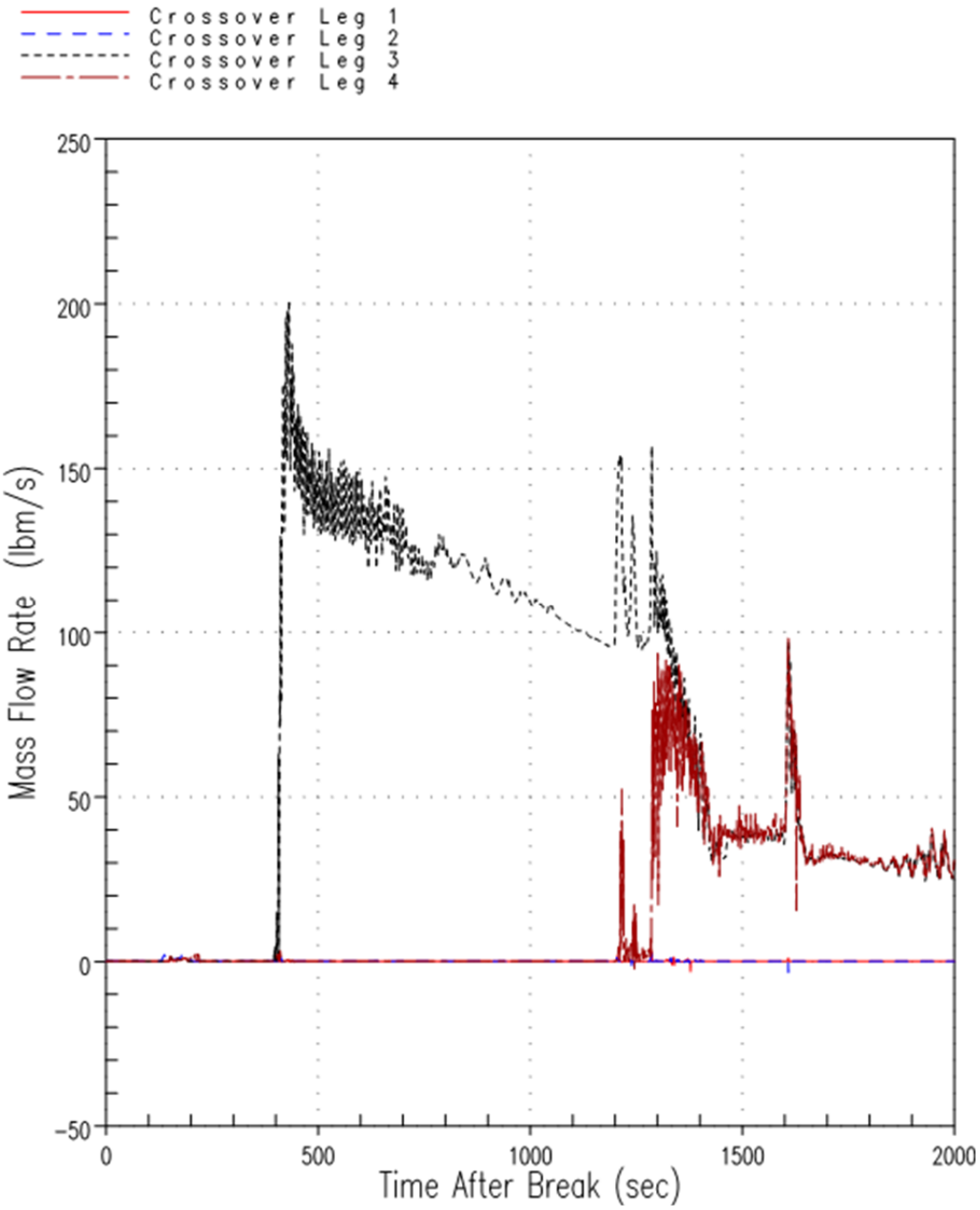
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-5A Peak Cladding Temperature for all Rods for SBLOCA (Region I)



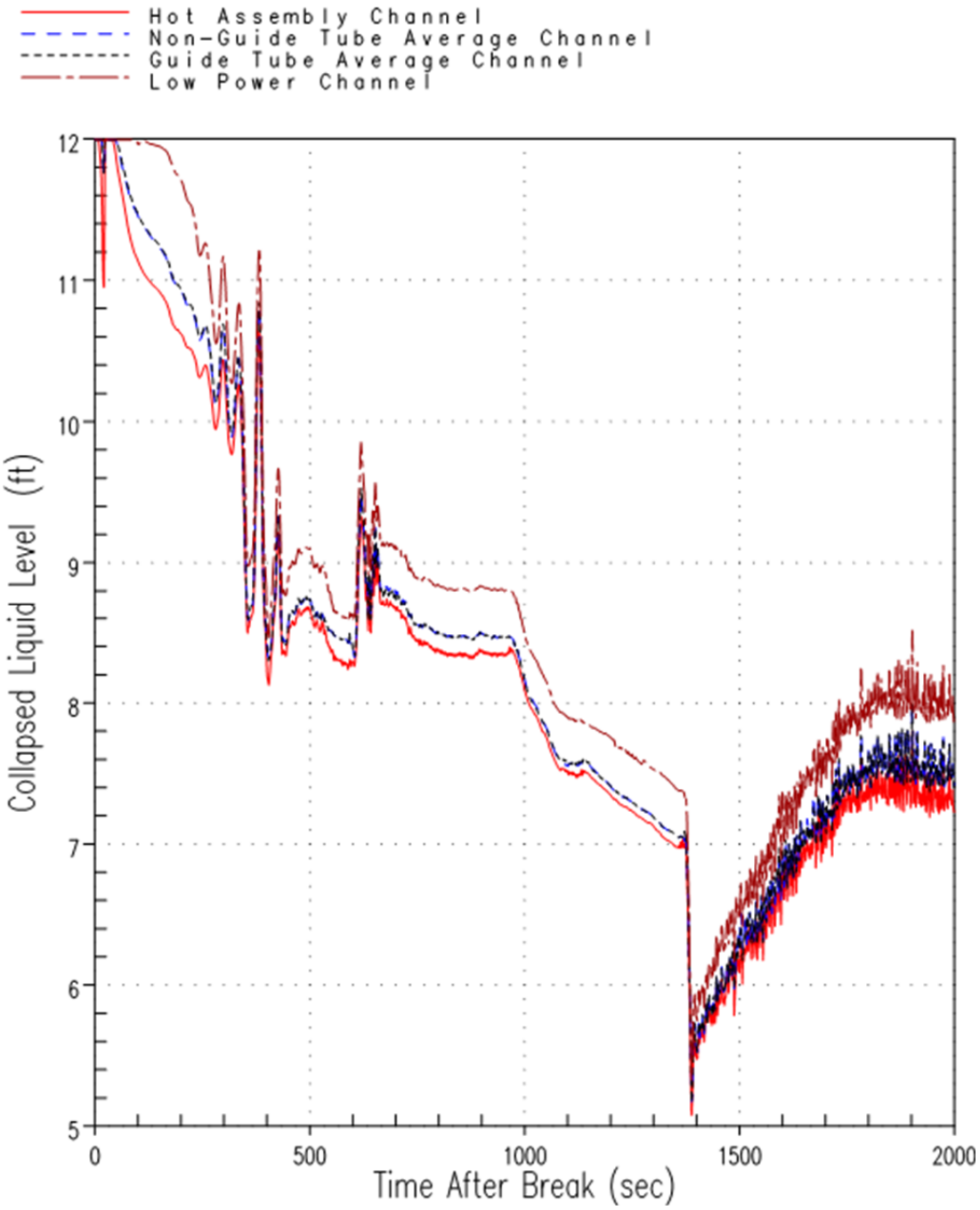
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-5B Peak Cladding Temperature for all Rods for SBLOCA (Region I)



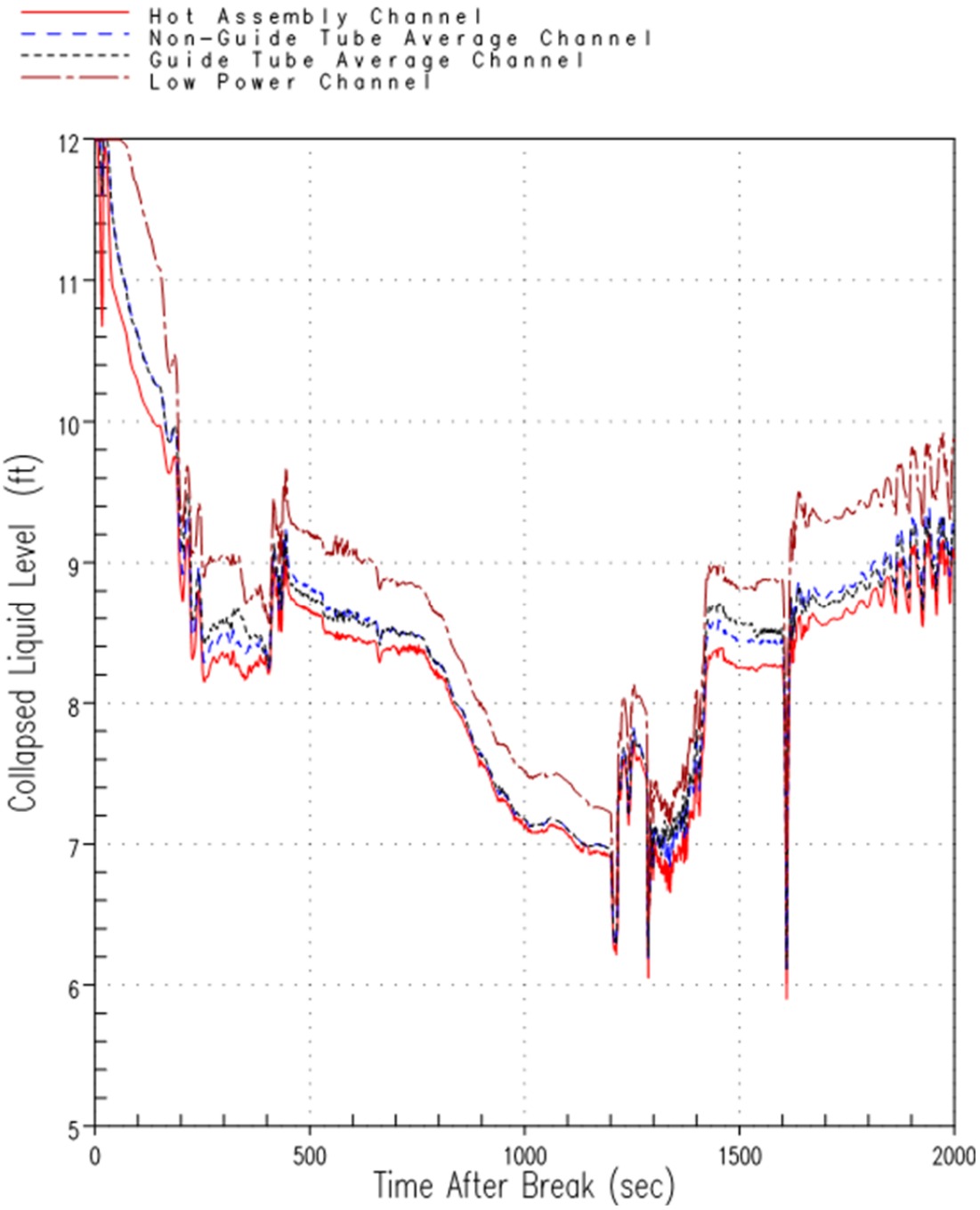
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-6A **Vapor Mass Flow Rate through the Crossover Legs for SBLOCA (Region I)**



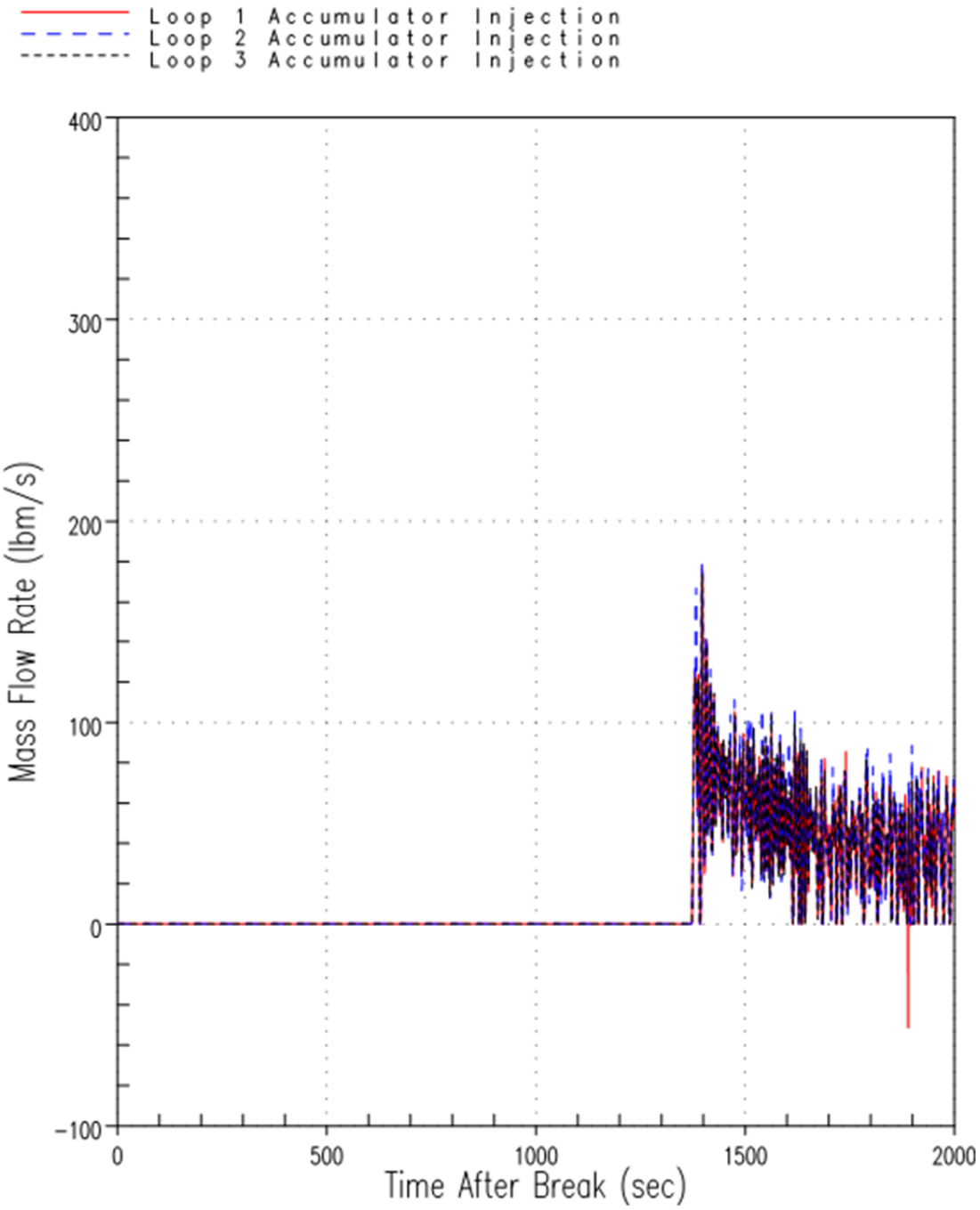
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-6B Vapor Mass Flow Rate through the Crossover Legs for SBLOCA (Region I)



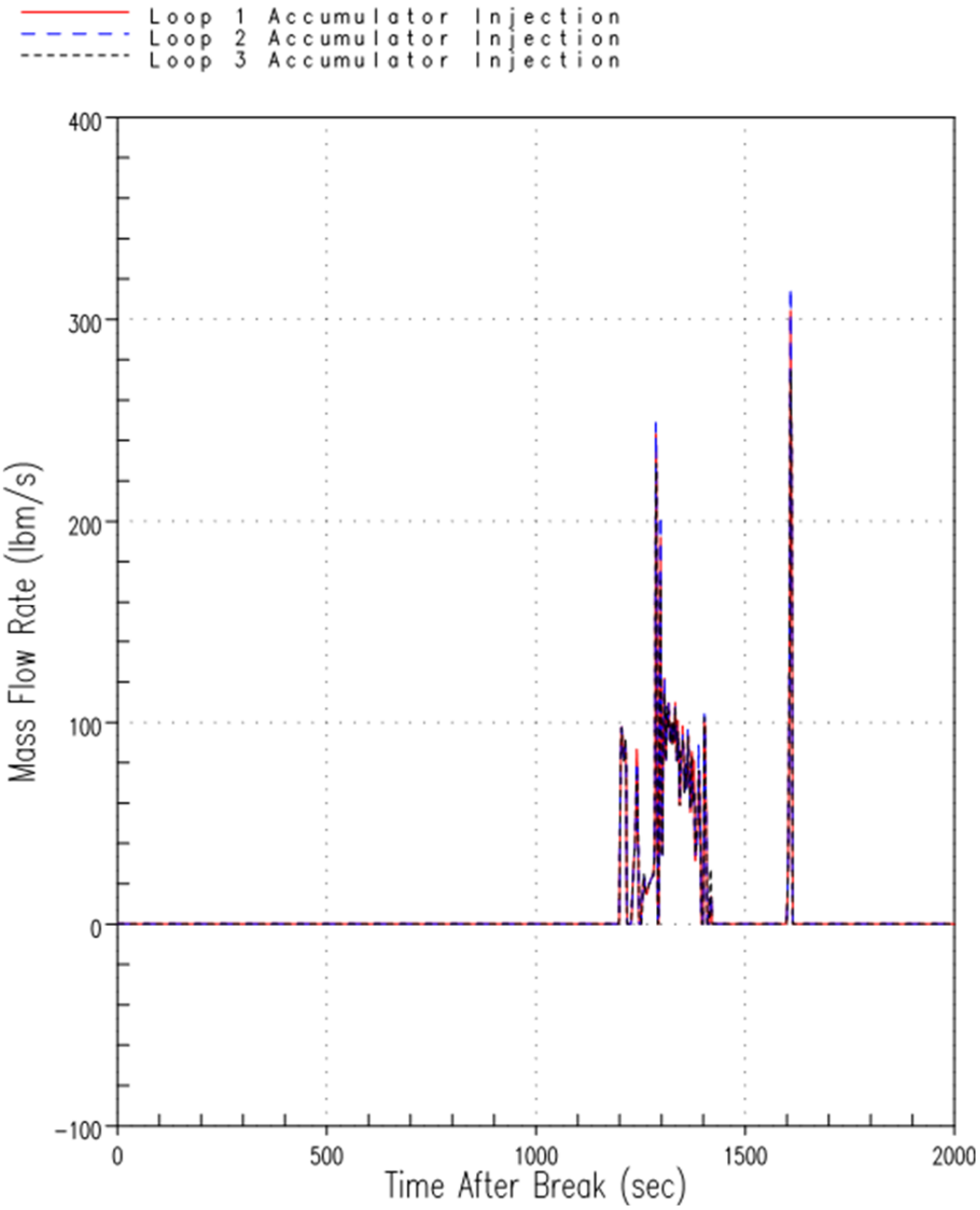
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-7A Core Collapsed Liquid Levels for SBLOCA (Region I)



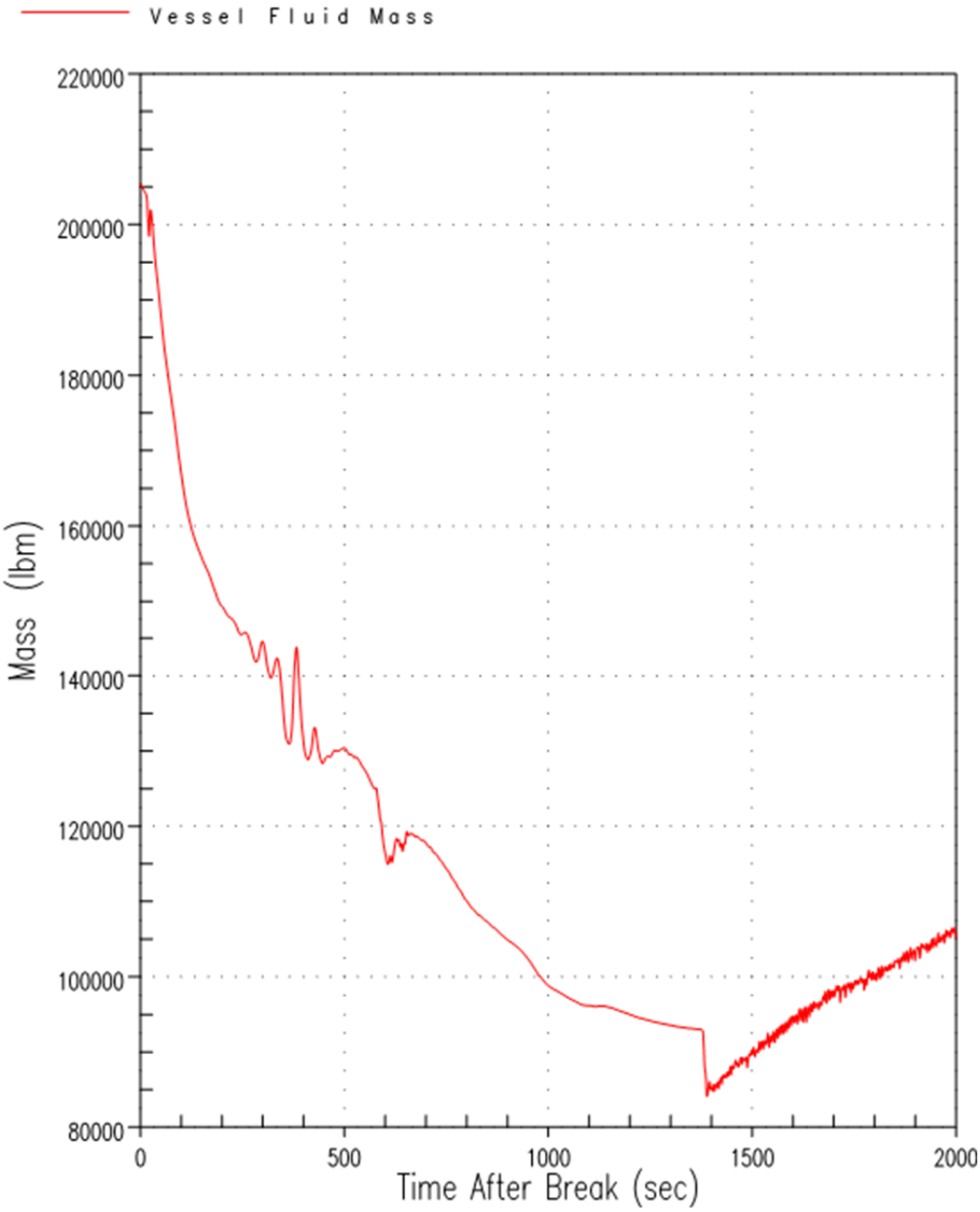
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-7B Core Collapsed Liquid Levels for SBLOCA (Region I)



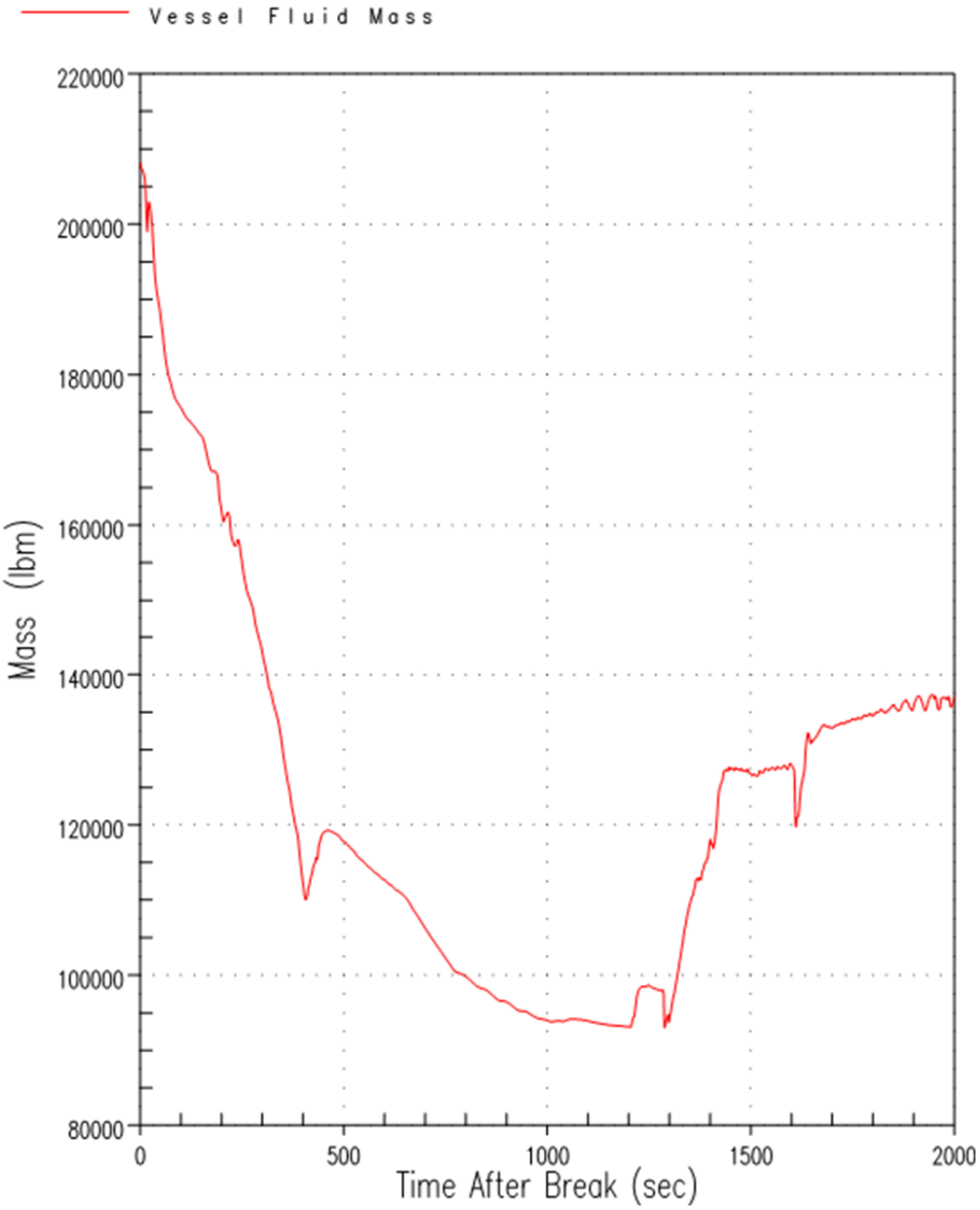
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-8A Accumulator Injection Flow for SBLOCA (Region I)



FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-8B Accumulator Injection Flow for SBLOCA (Region I)

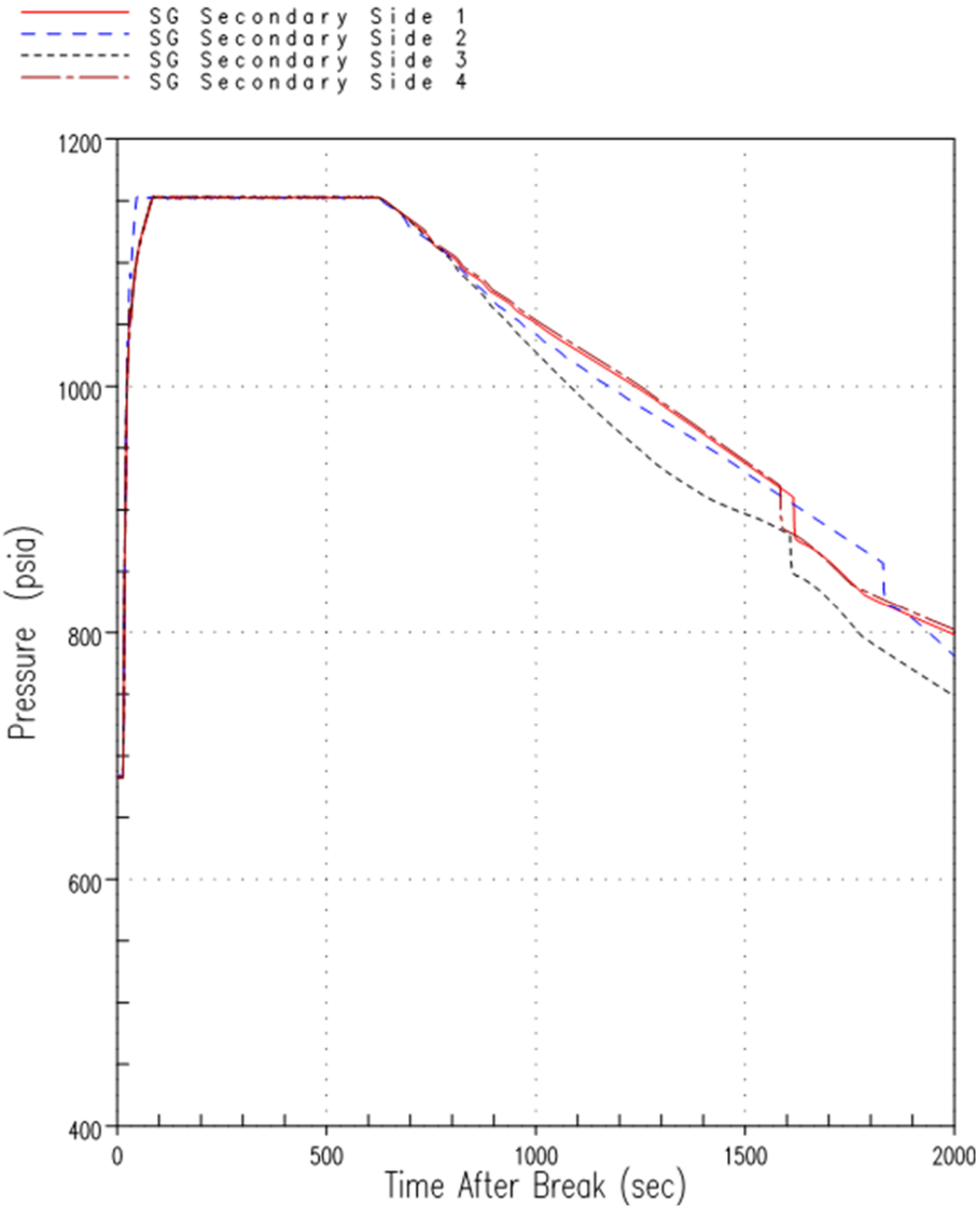


FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-9A Vessel Fluid Mass for SBLOCA (Region I)

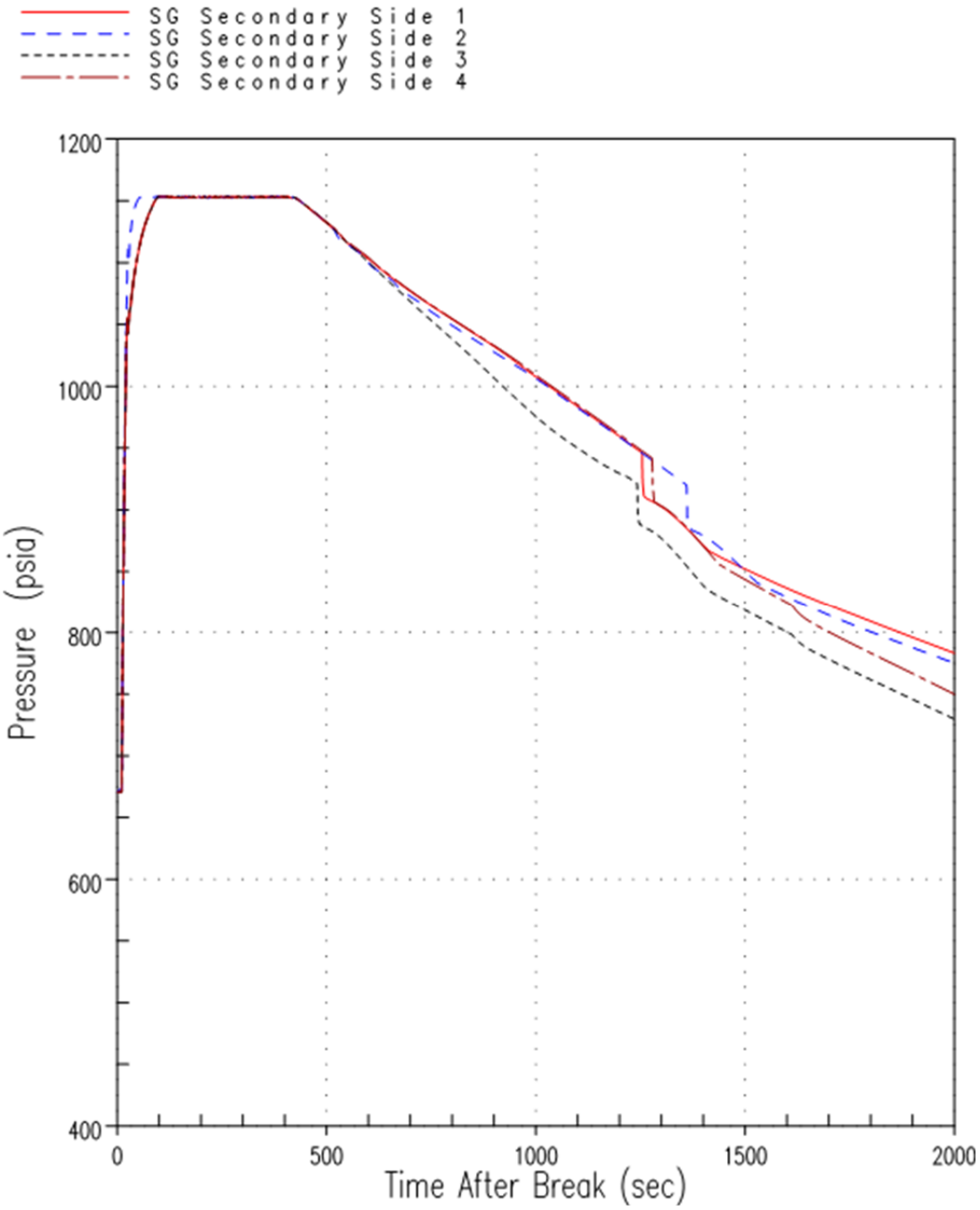


FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-9B Vessel Fluid Mass for SBLOCA (Region I)

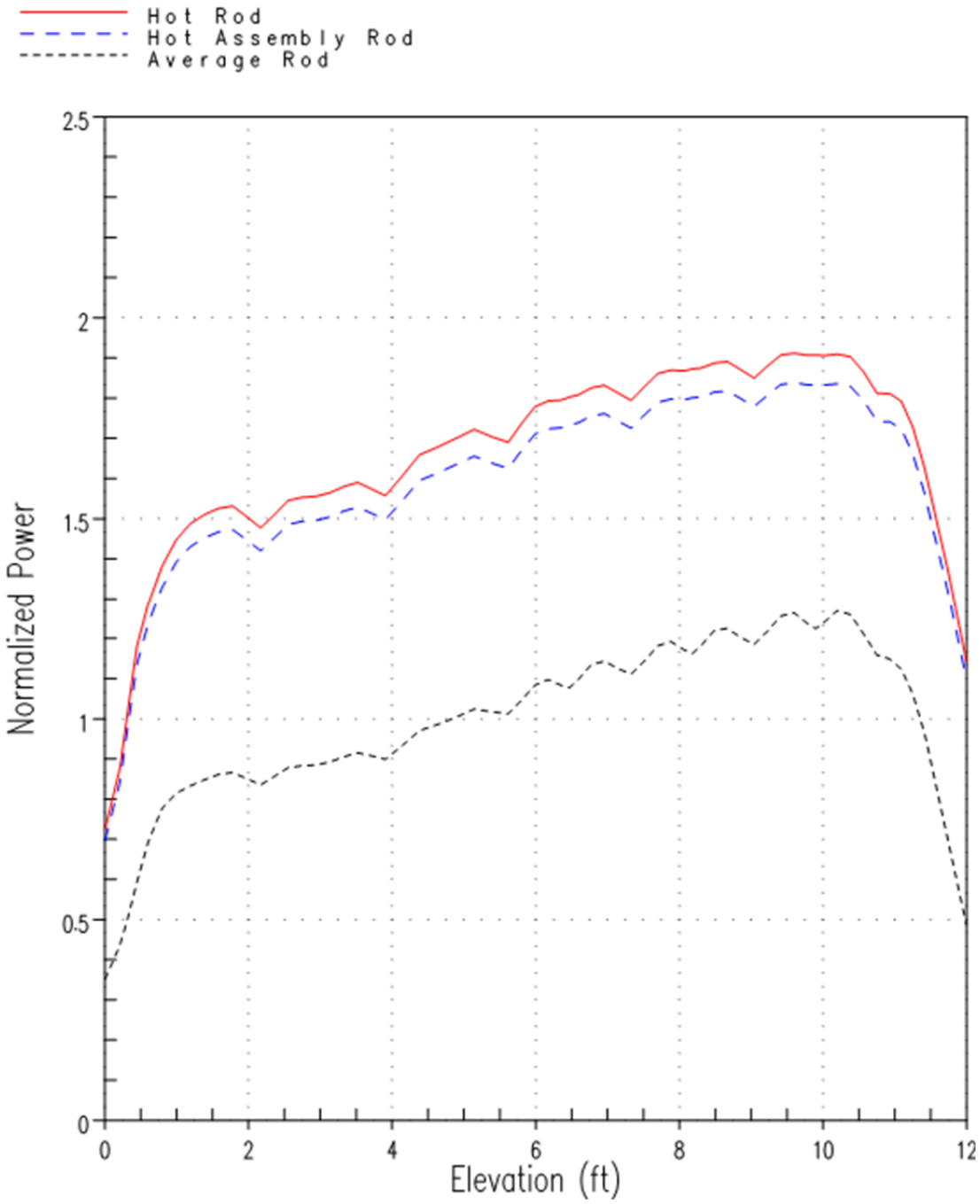
Revision 26 September 2021



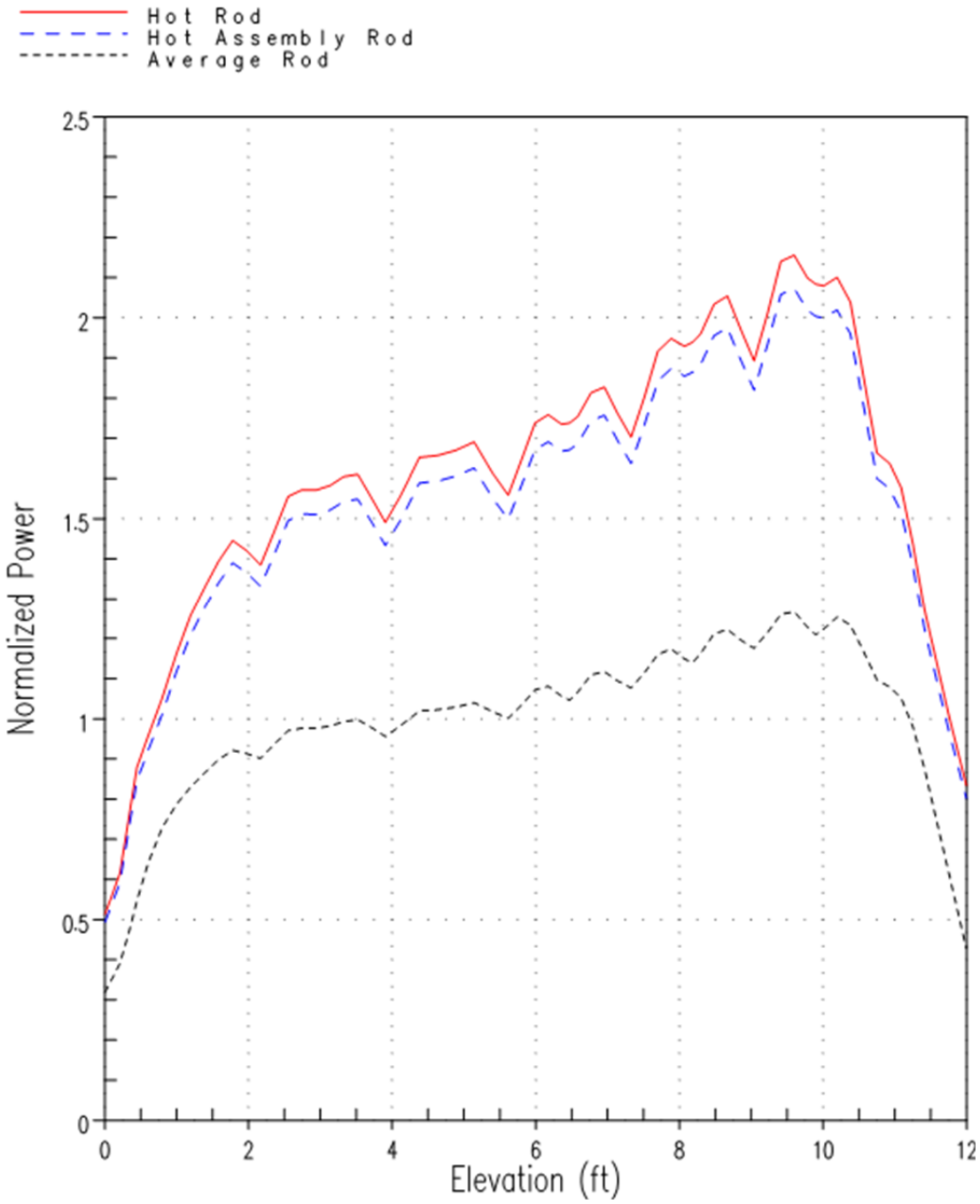
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-10A **Steam Generator Secondary Side Pressure for SBLOCA (Region I)**



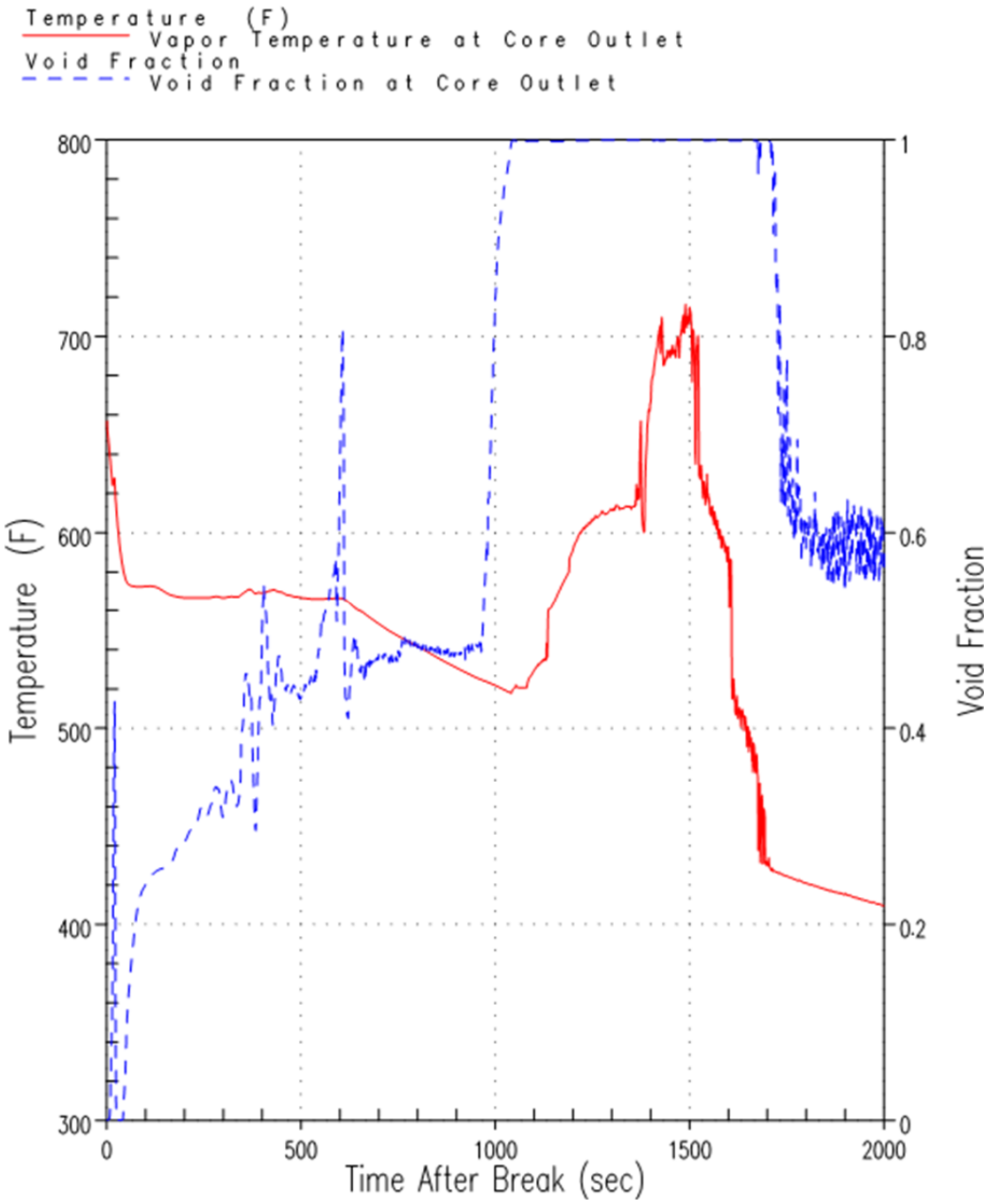
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-10B **Steam Generator Secondary Side Pressure for SBLOCA (Region I)**



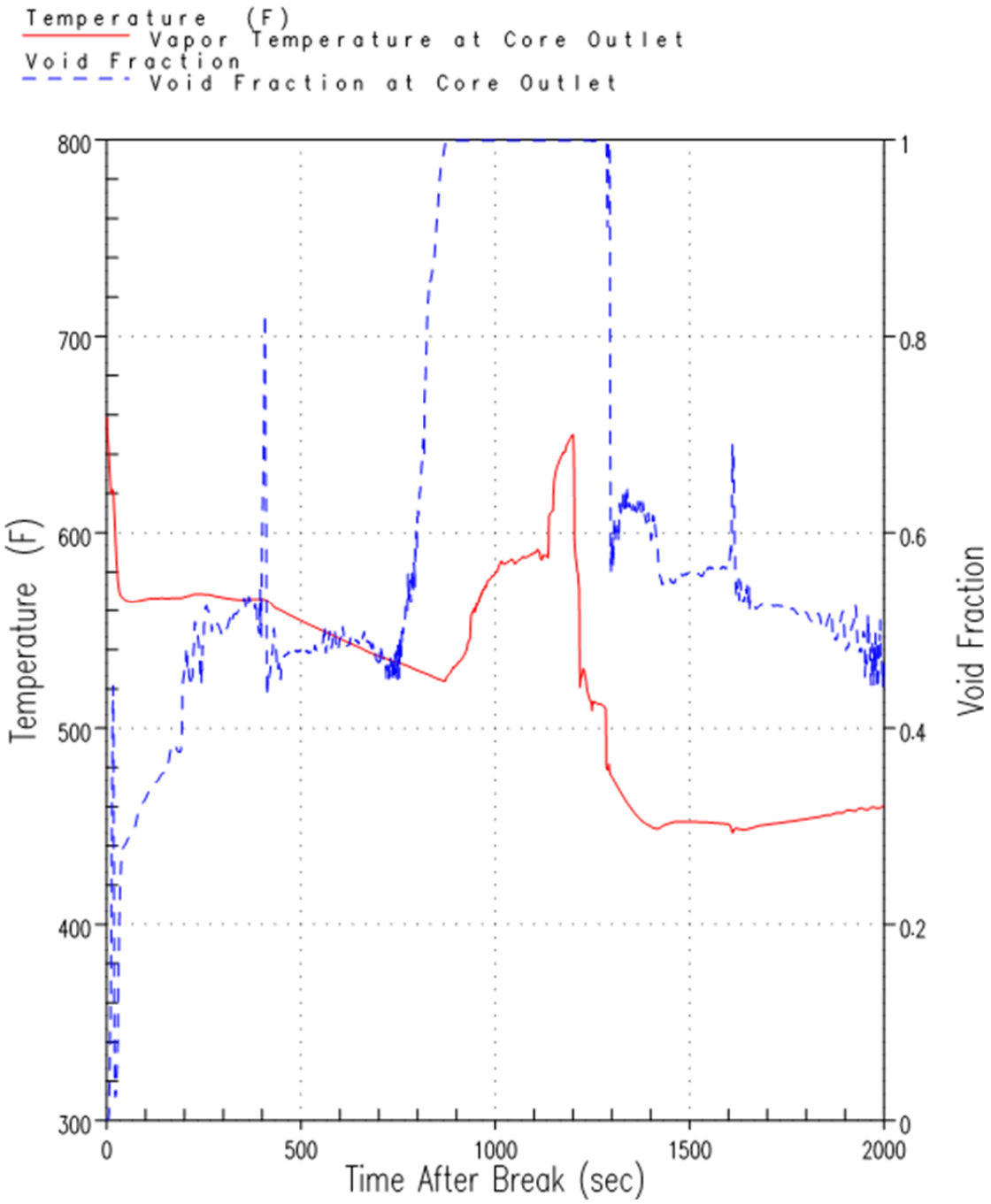
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-11A **Normalized Core Power Shape for SBLOCA (Region I)** **Note: The localized power decreases occur at grid elevations**



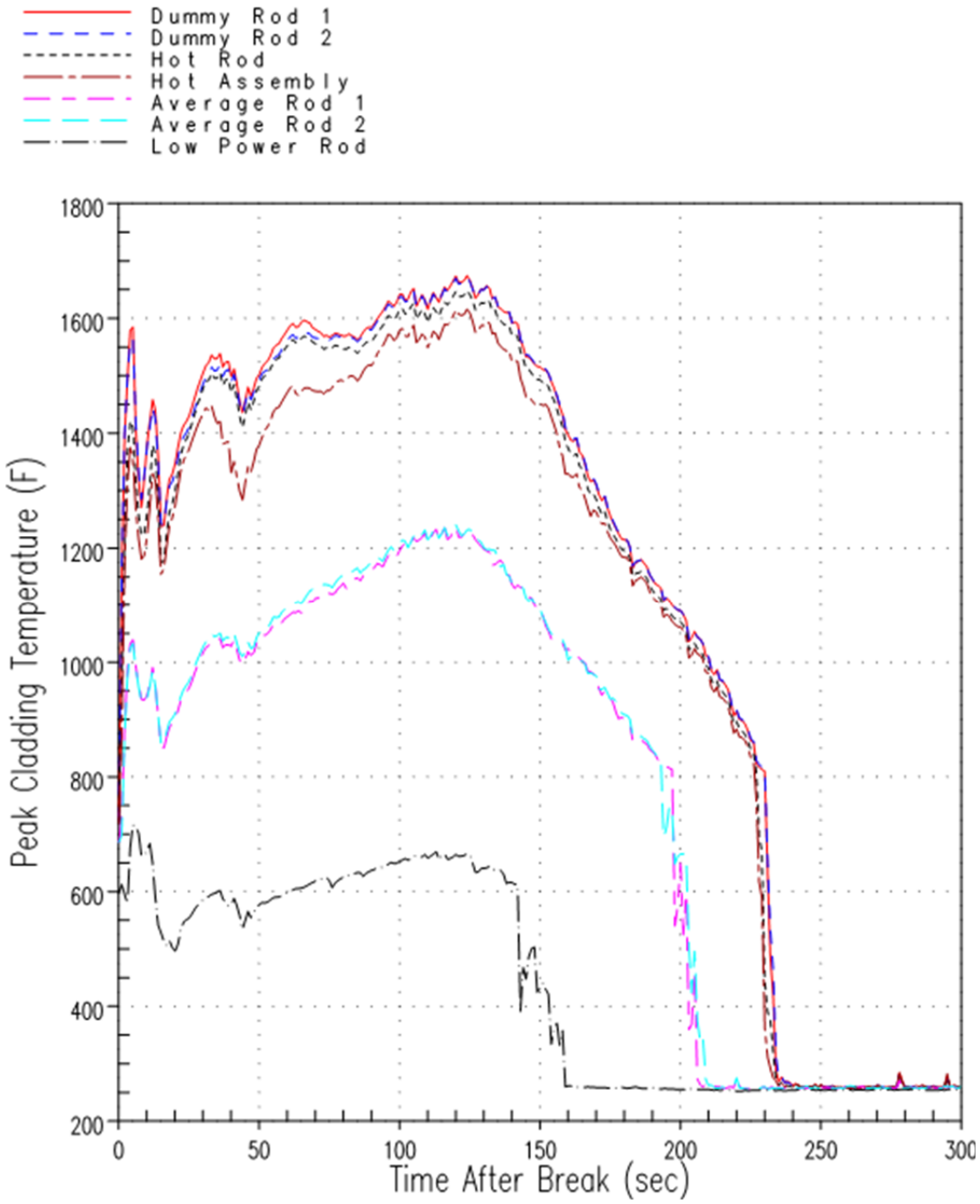
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-11B **Normalized Core Power Shape for SBLOCA (Region I)** **Note: The localized power decreases occur at grid elevations**



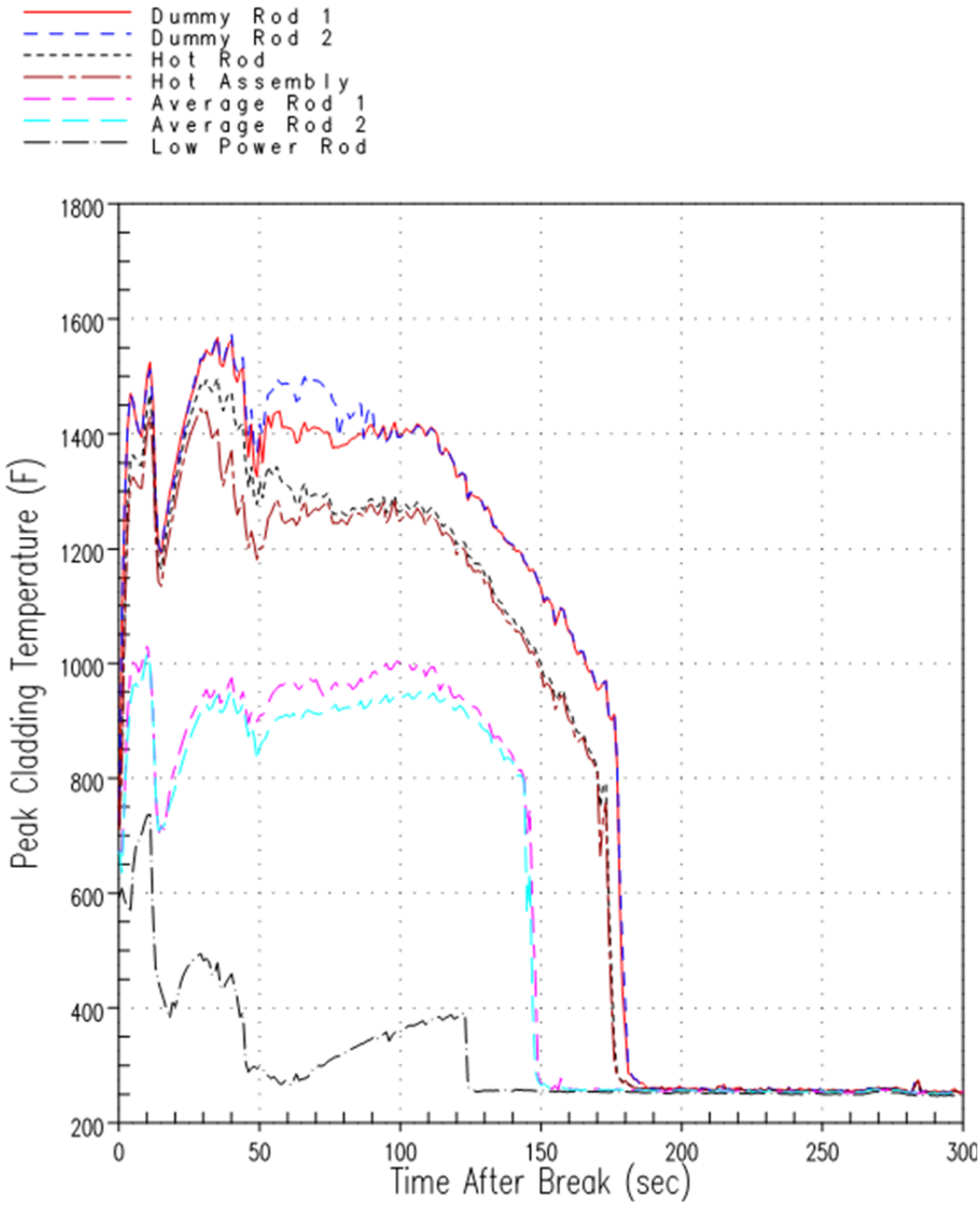
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-12A Vapor Temperature and Void Fraction at Core Outlet for SBLOCA (Region I)



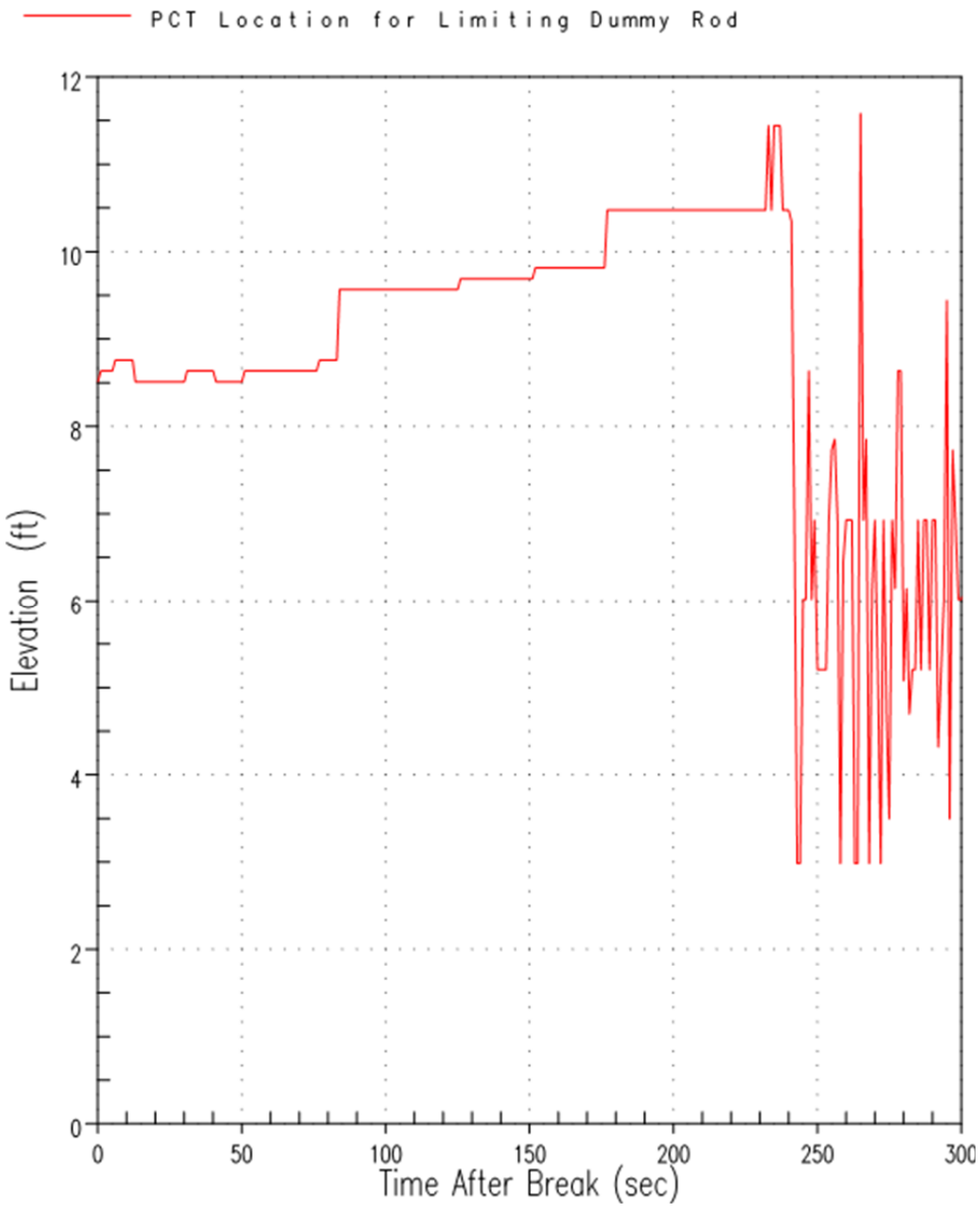
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-12B Vapor Temperature and Void Fraction at Core Outlet for SBLOCA (Region I)



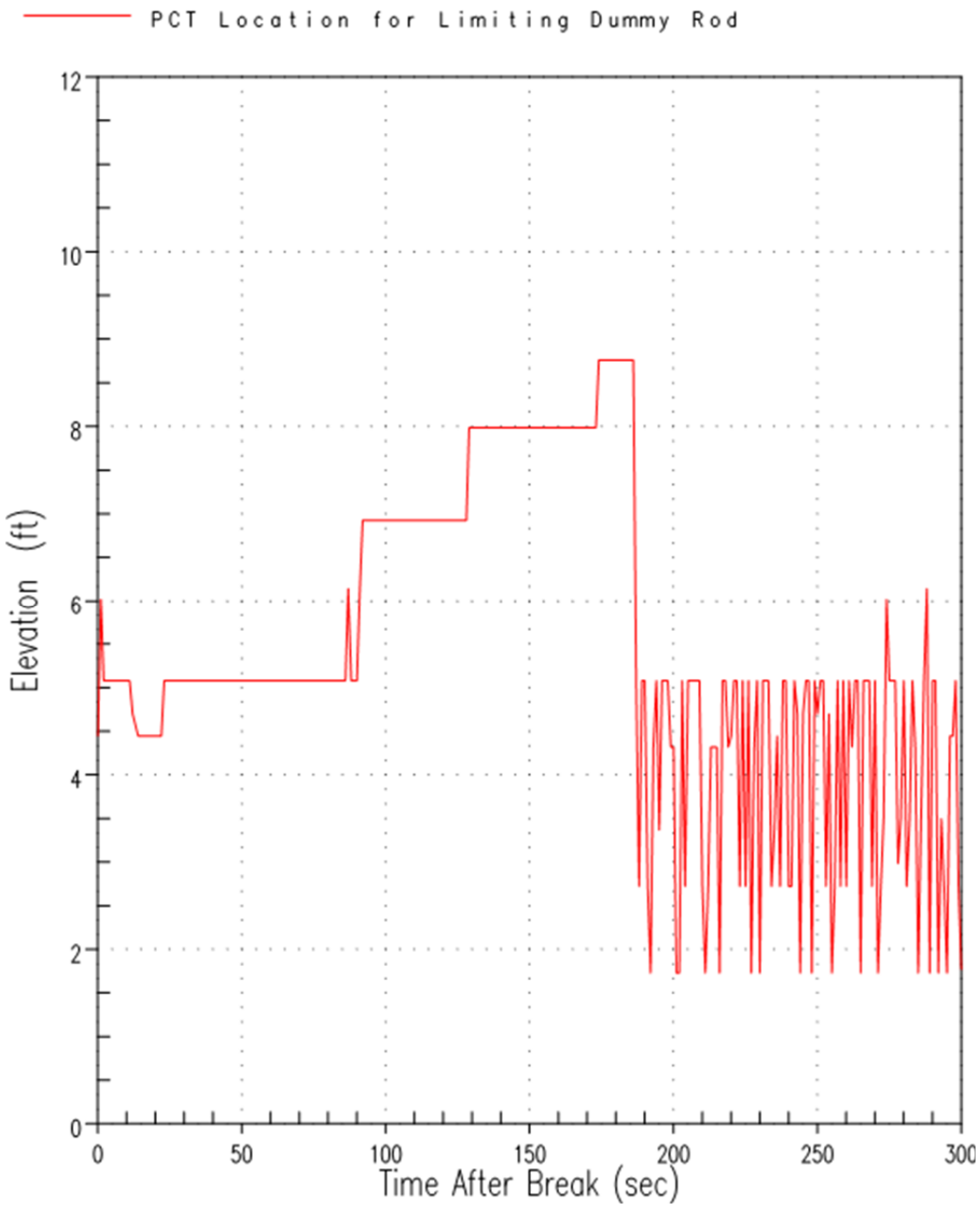
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-13A Peak Cladding Temperature for all Rods for LBLOCA (Region II)



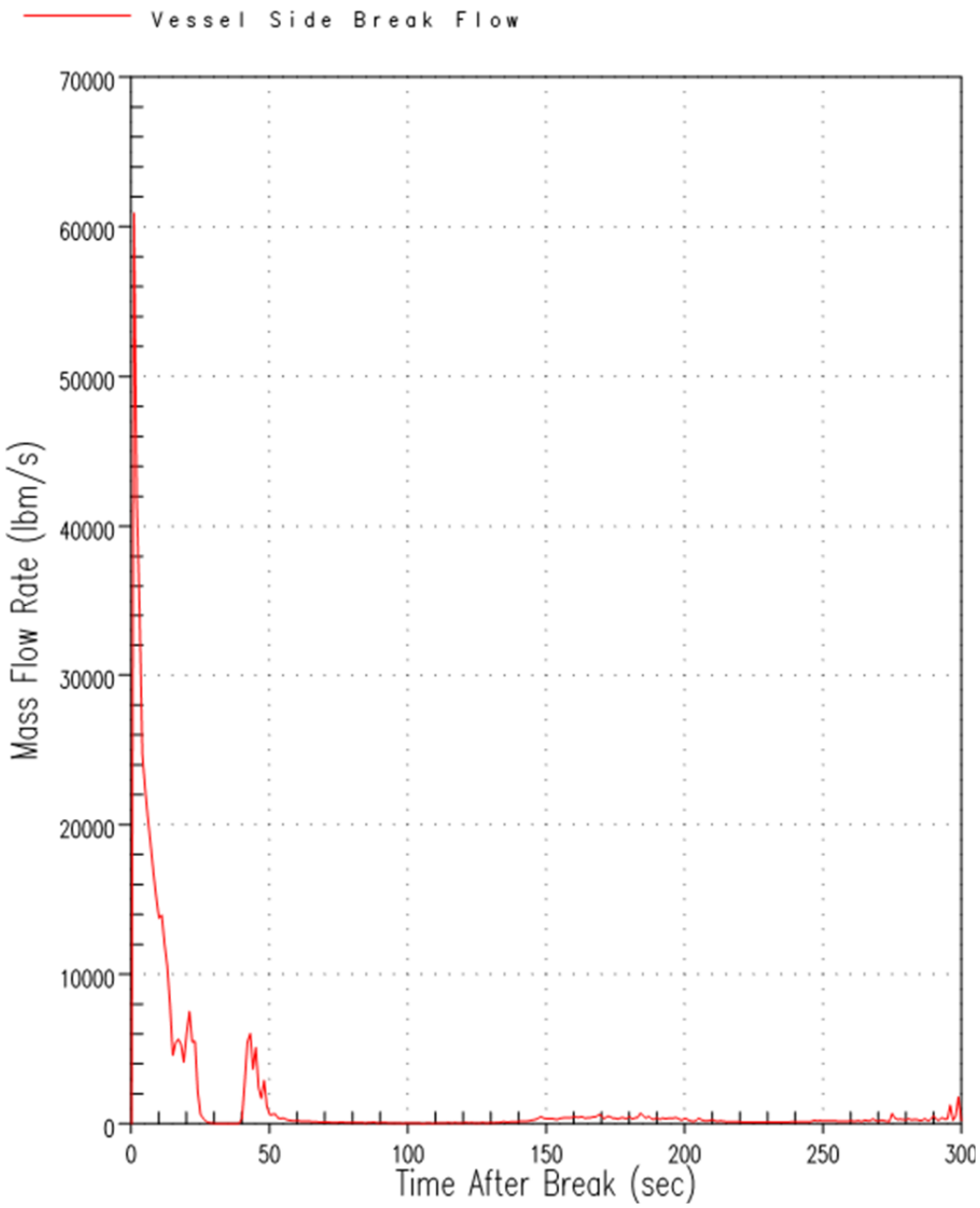
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-13B Peak Cladding Temperature for all Rods for LBLOCA (Region II)



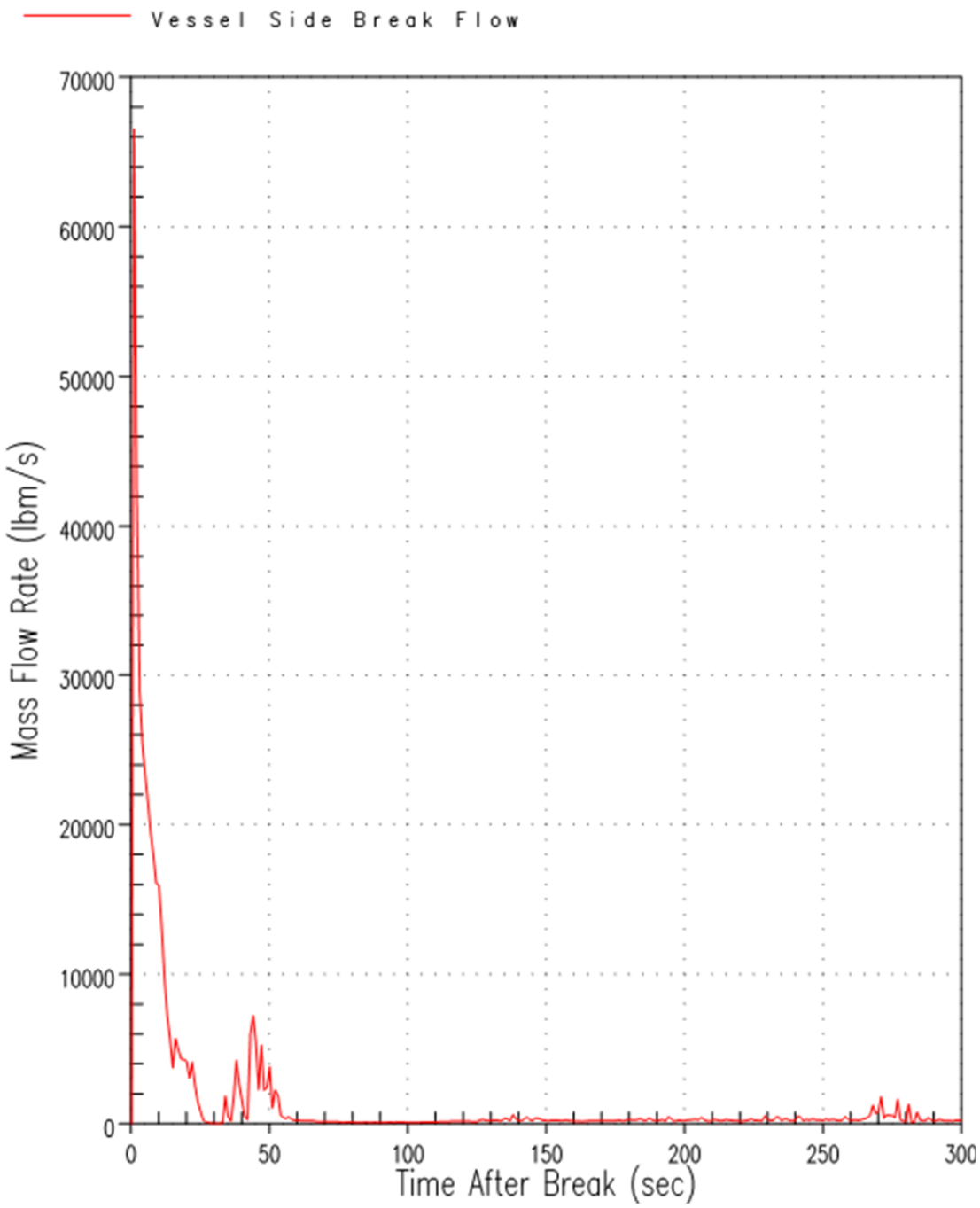
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-14A Peak Cladding Temperature Elevation for LBLOCA (Region II)



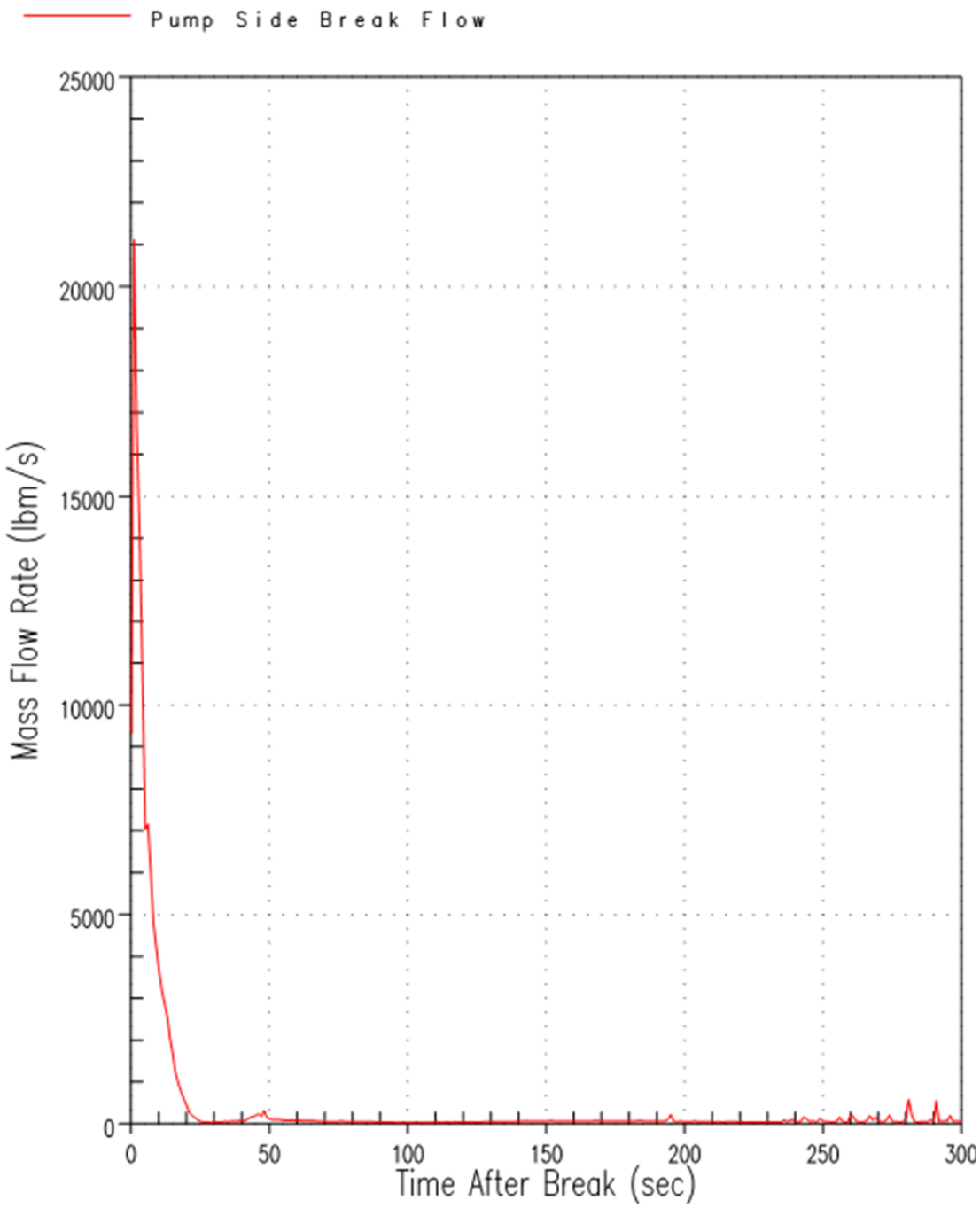
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-14B Peak Cladding Temperature Elevation for LBLOCA (Region II)



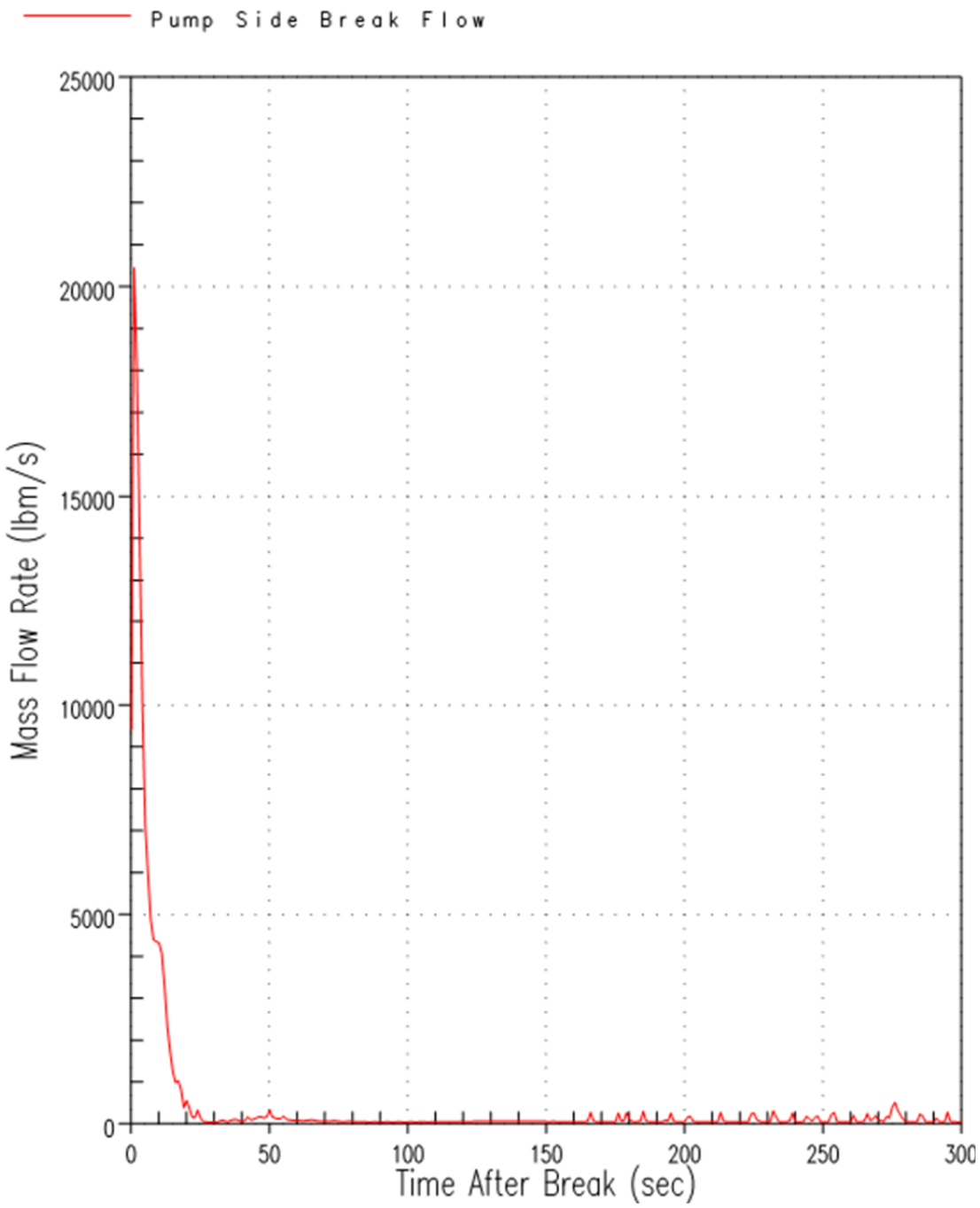
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-15A Vessel Side Break Mass Flow Rate for LBLOCA (Region II)



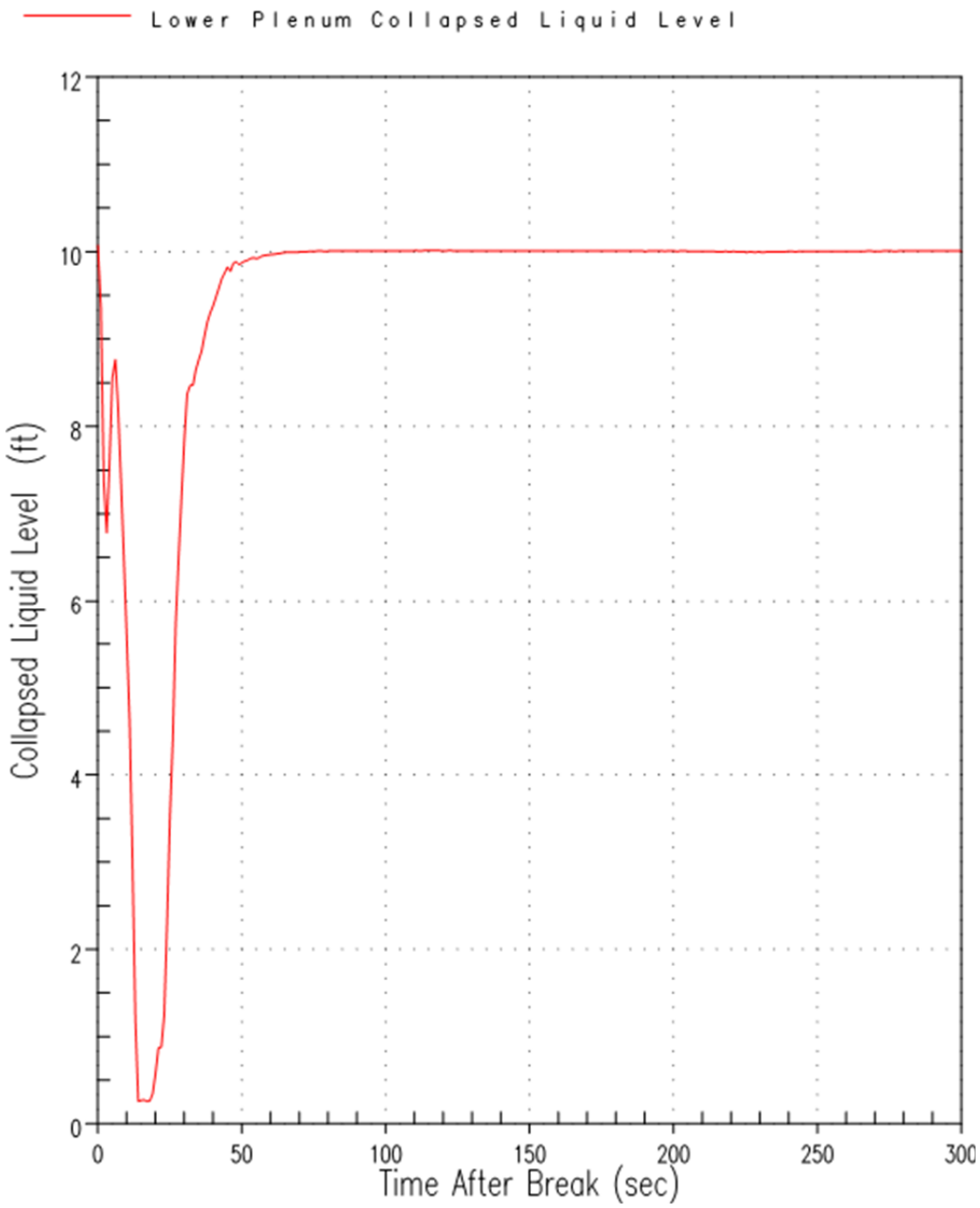
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-15B Vessel Side Break Mass Flow Rate for LBLOCA (Region II)



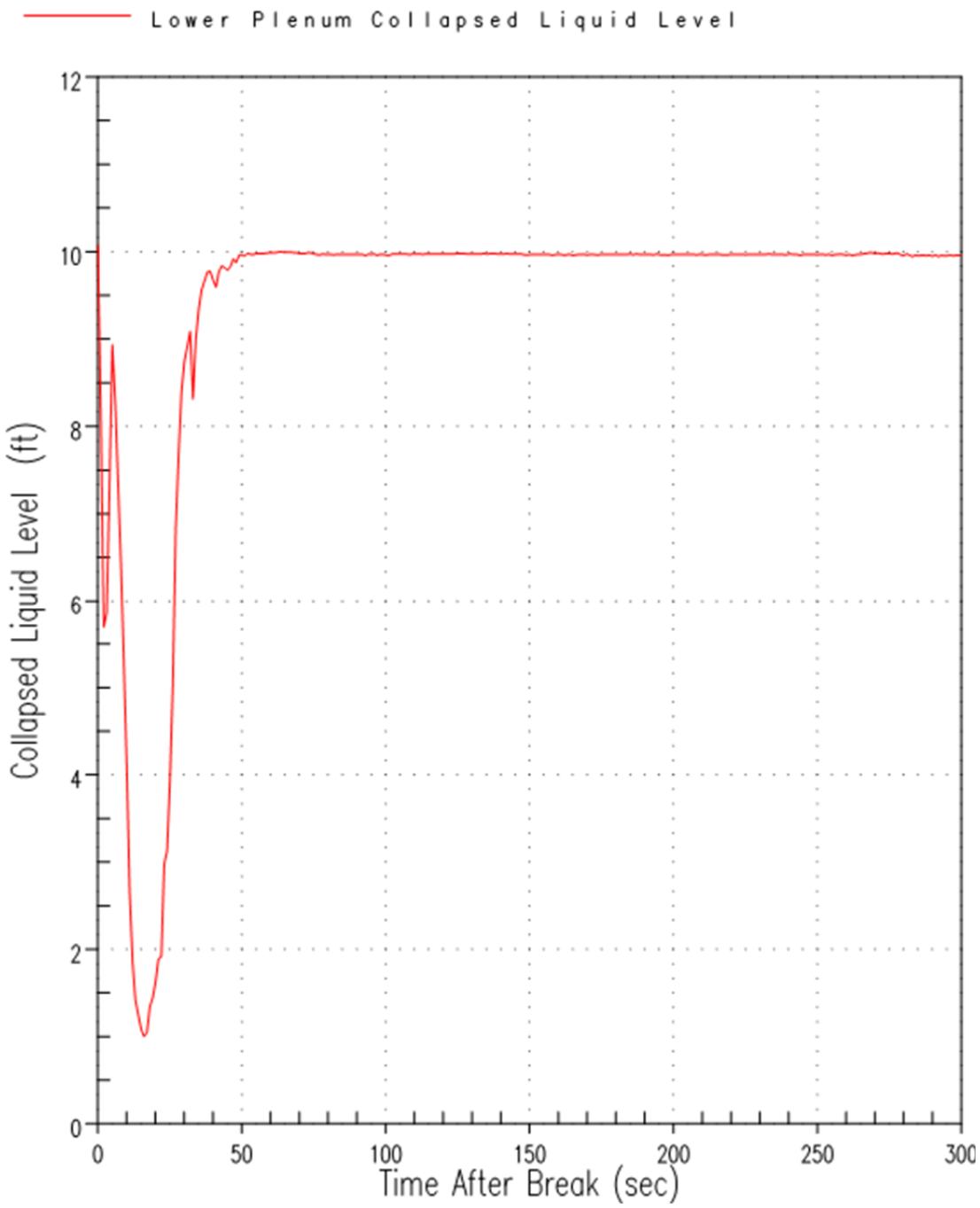
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-16A Pump Side Break Mass Flow Rate for LBLOCA (Region II)



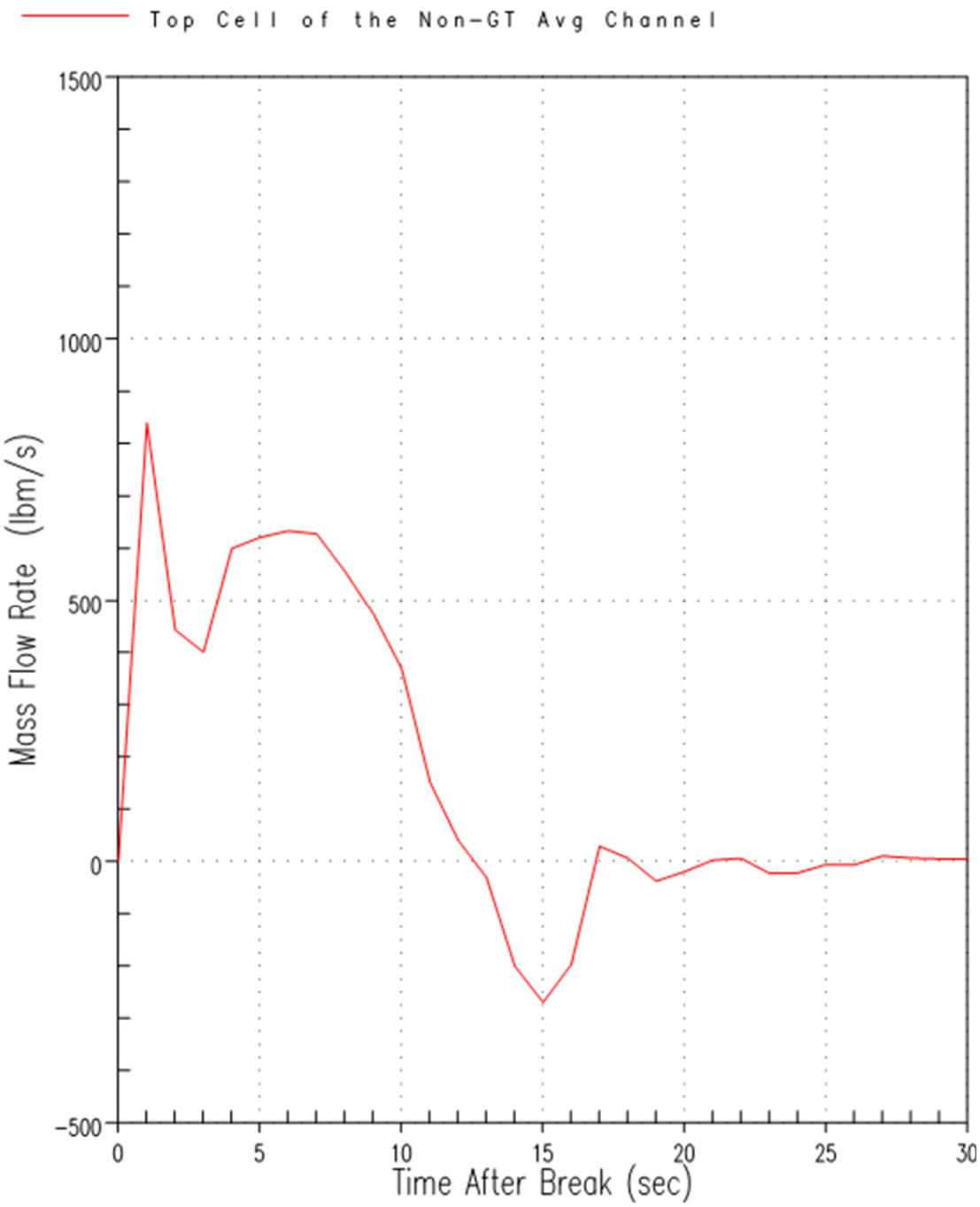
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-16B **Pump Side Break Mass Flow Rate for LBLOCA (Region II)**



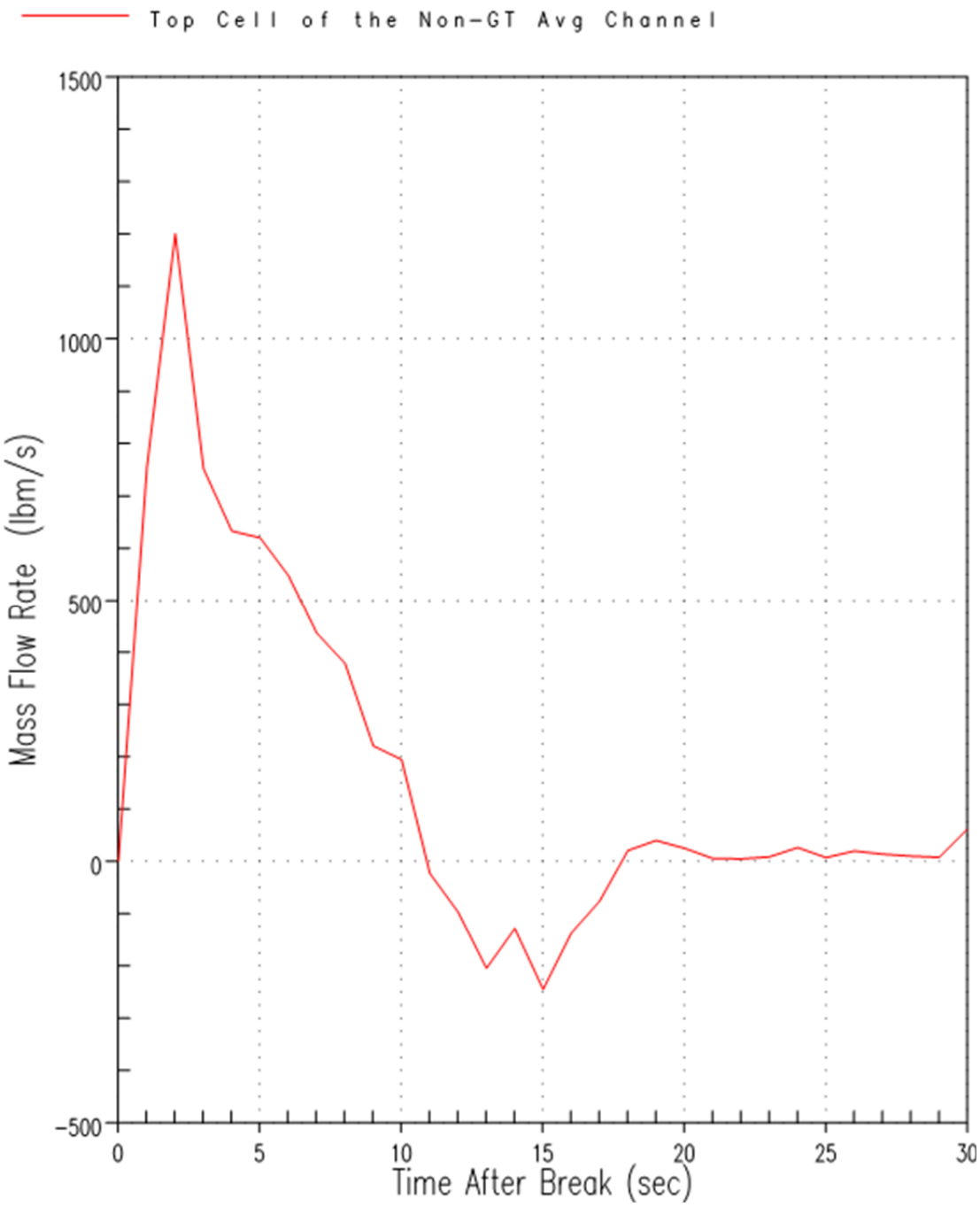
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-17A **Lower Plenum Collapsed Liquid Level for LBLOCA (Region II)**



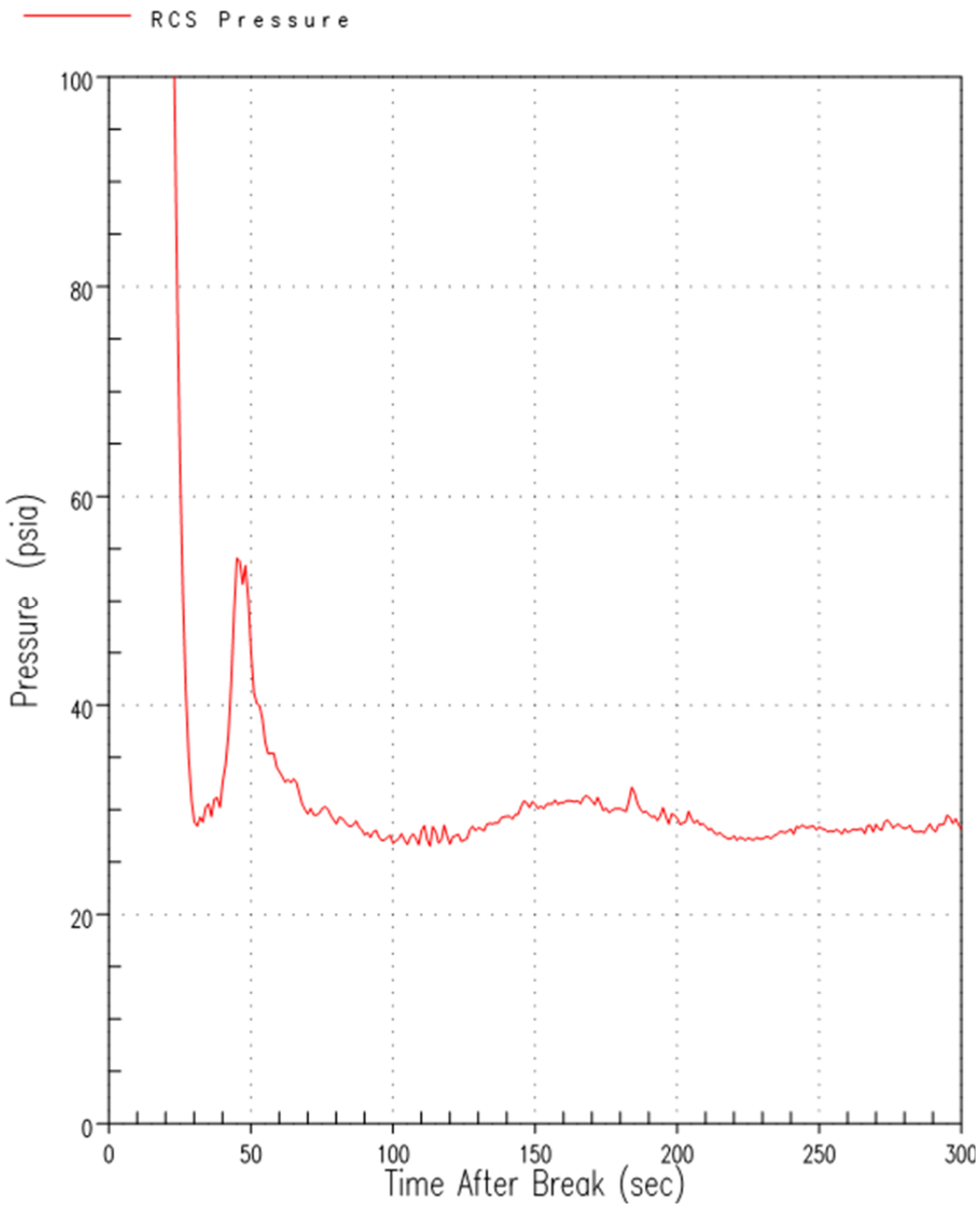
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-17B Lower Plenum Collapsed Liquid Level for LBLOCA (Region II)



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-18A **Vapor Mass Flow Rate at the Top Cell Face of the Core Average Channel not Under Guide Tubes for LBLOCA (Region II)**



FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-18B **Vapor Mass Flow Rate at the Top Cell Face of the Core Average Channel not Under Guide Tubes for LBLOCA (Region II)**



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-19A **RCS Pressure for LBLOCA (Region II)**

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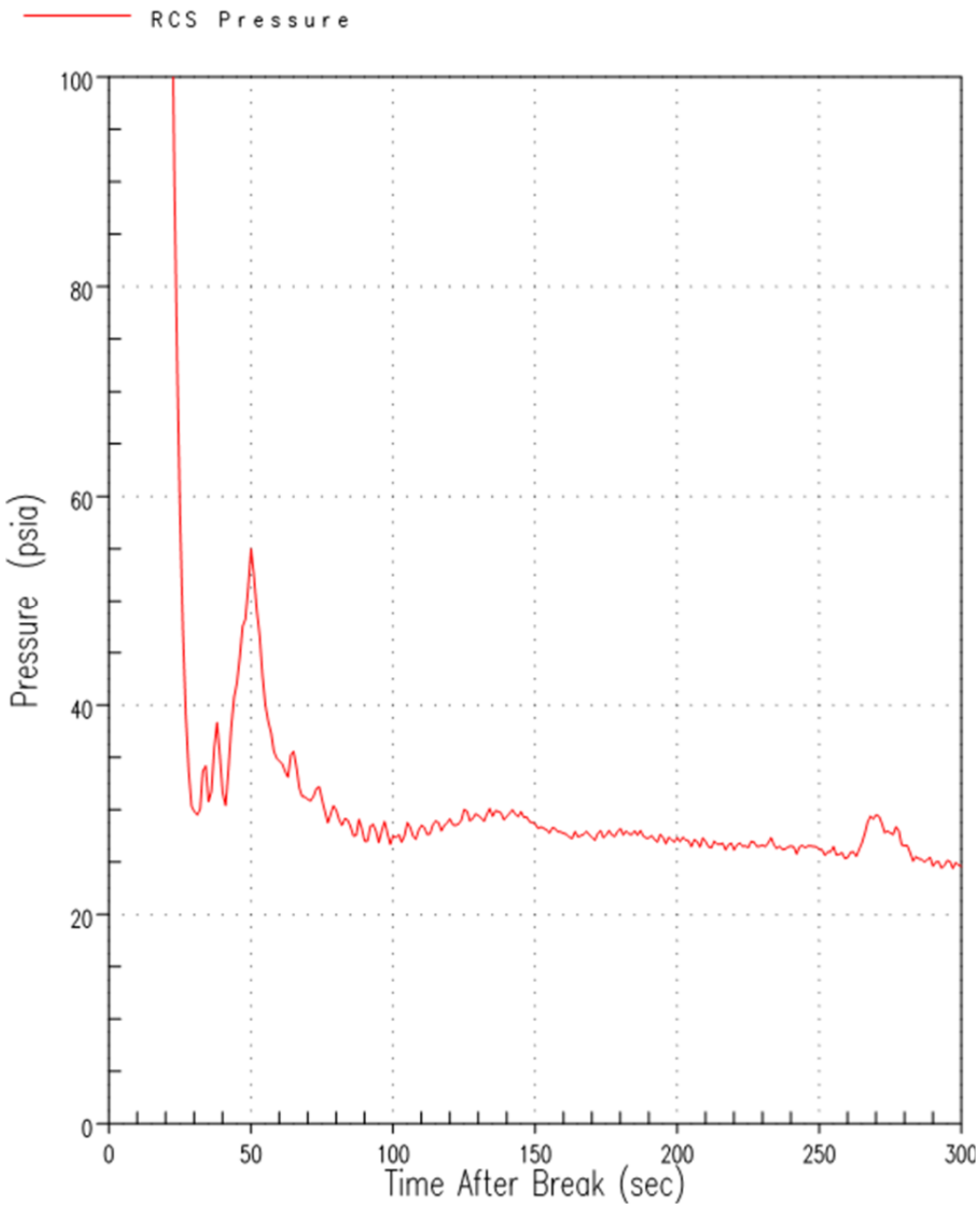
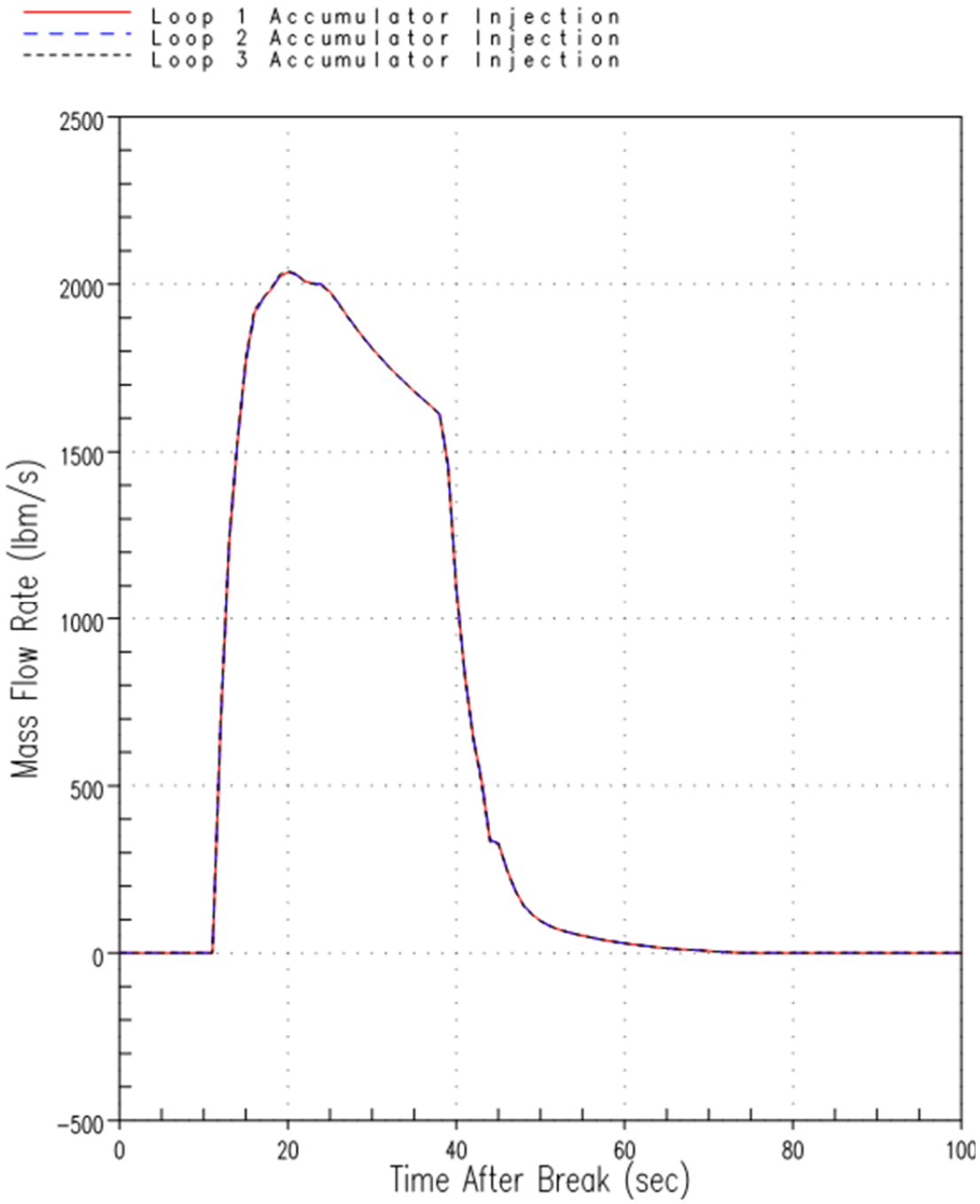
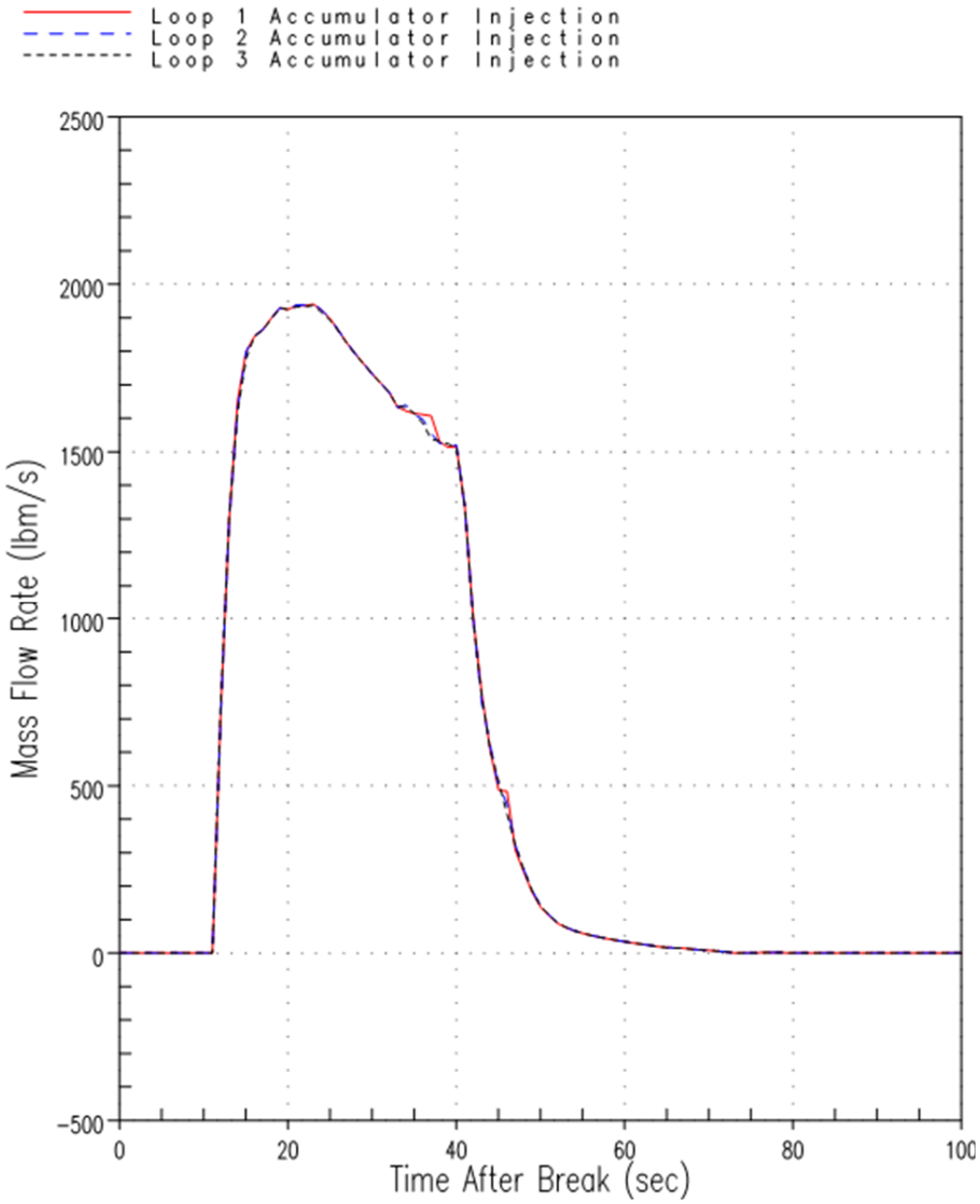


FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-19B **RCS Pressure for LBLOCA (Region II)**

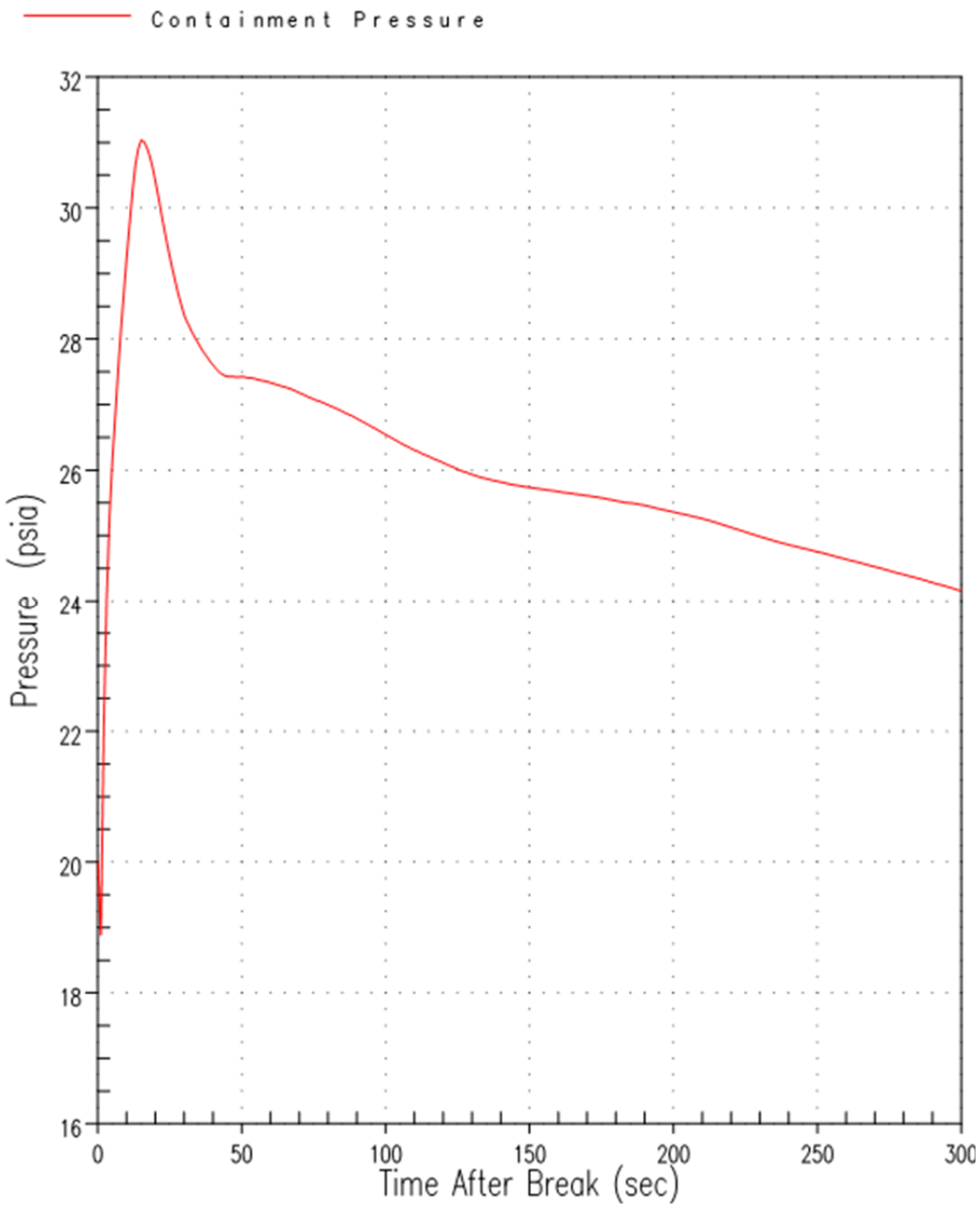
Revision 26 September 2021



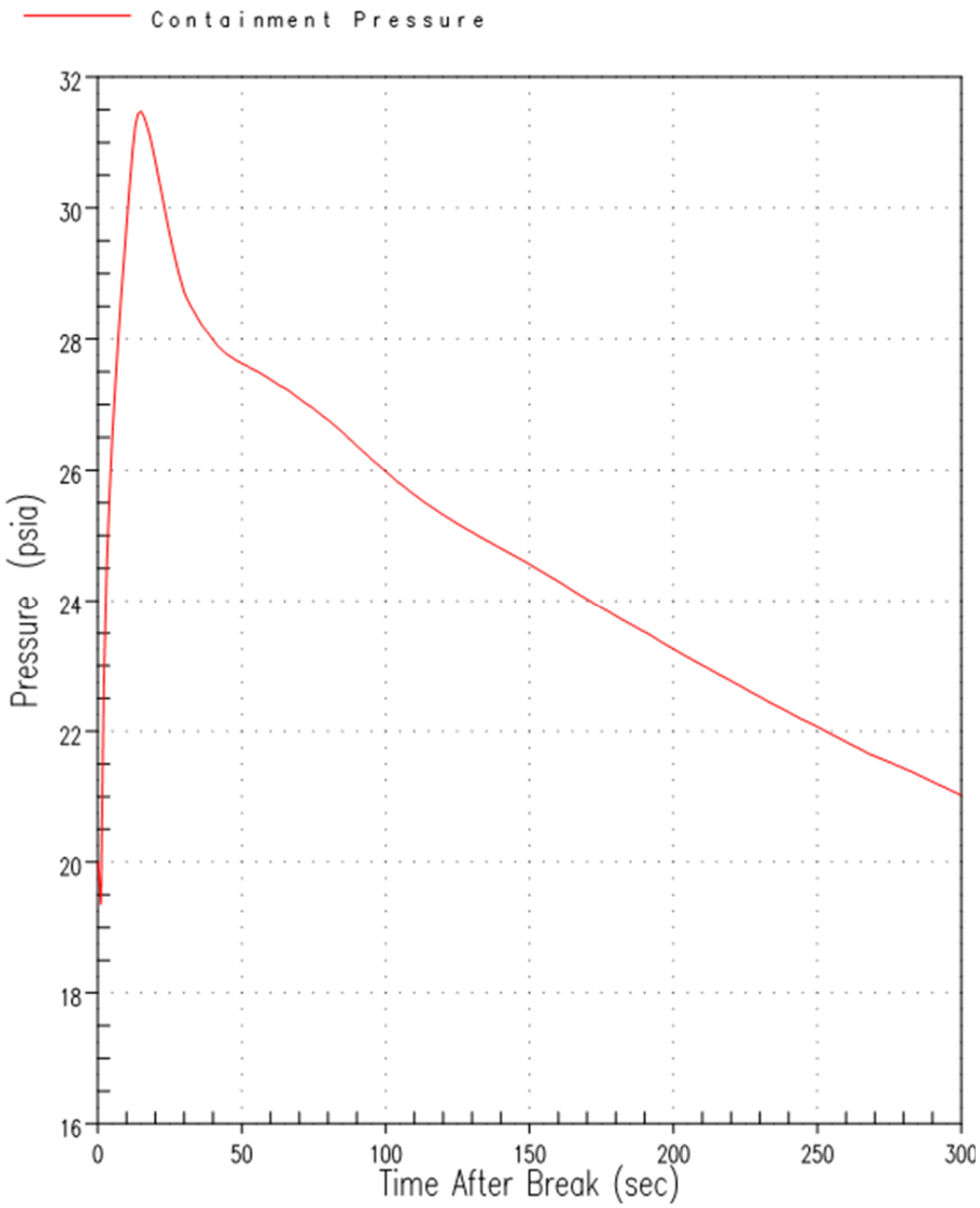
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-20A **Accumulator Injection Flow per Loop for LBLOCA (Region II)**



FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-20B **Accumulator Injection Flow per Loop for LBLOCA (Region II)**

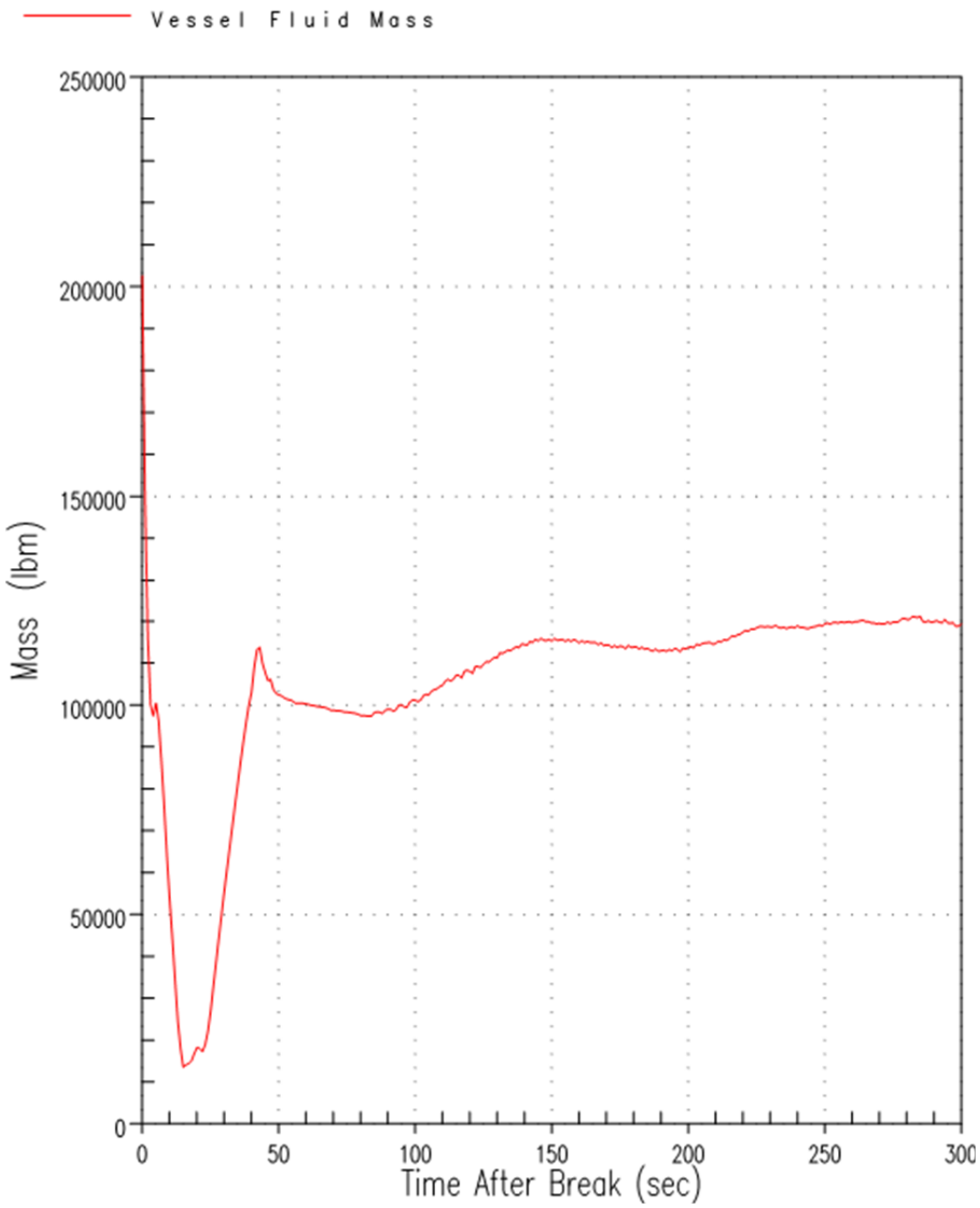


FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-21A **Containment Pressure for LBLOCA (Region II)**

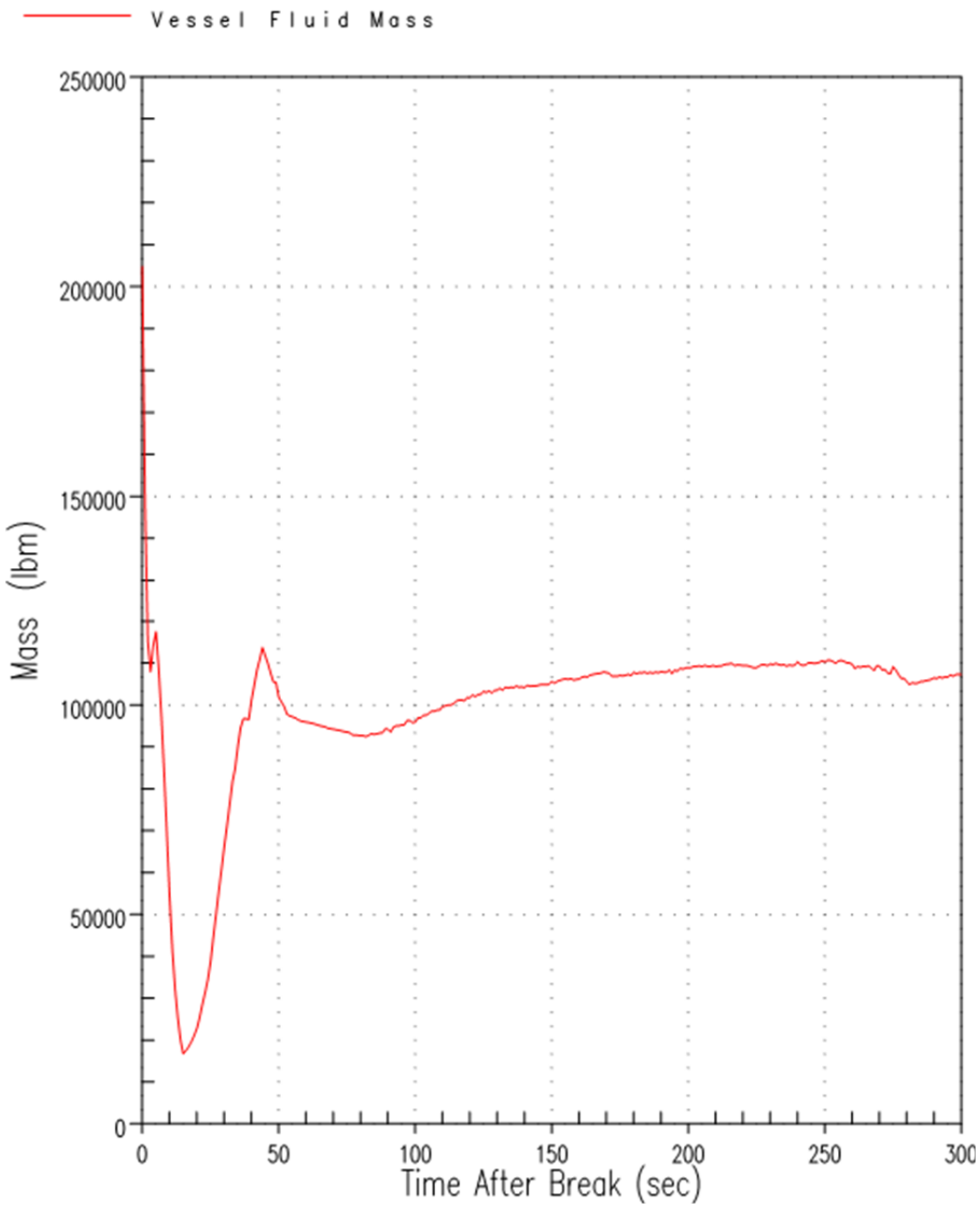


FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-21B **Containment Pressure for LBLOCA (Region II)**

Revision 26 September 2021

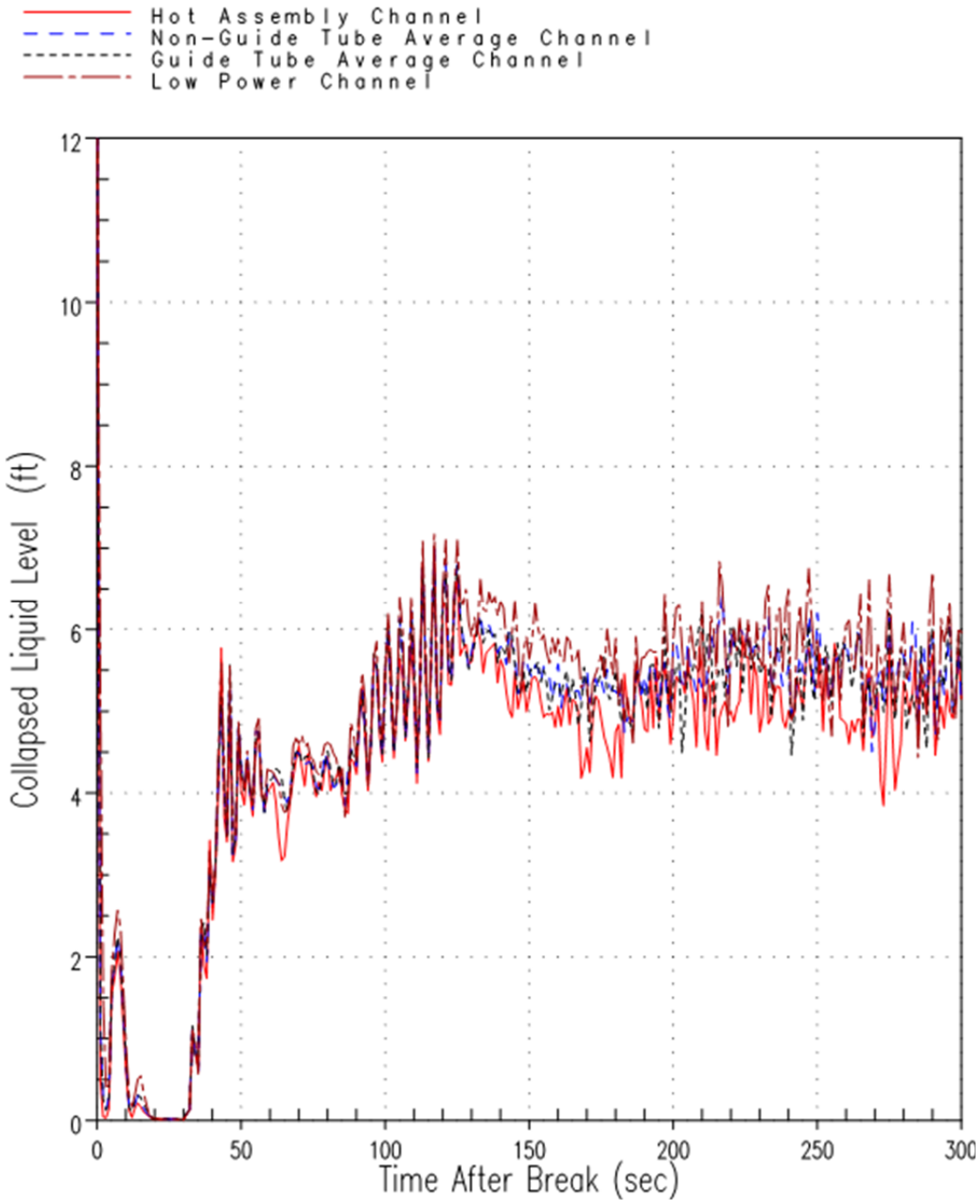


FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-22A **Vessel Fluid Mass for LBLOCA (Region II)**

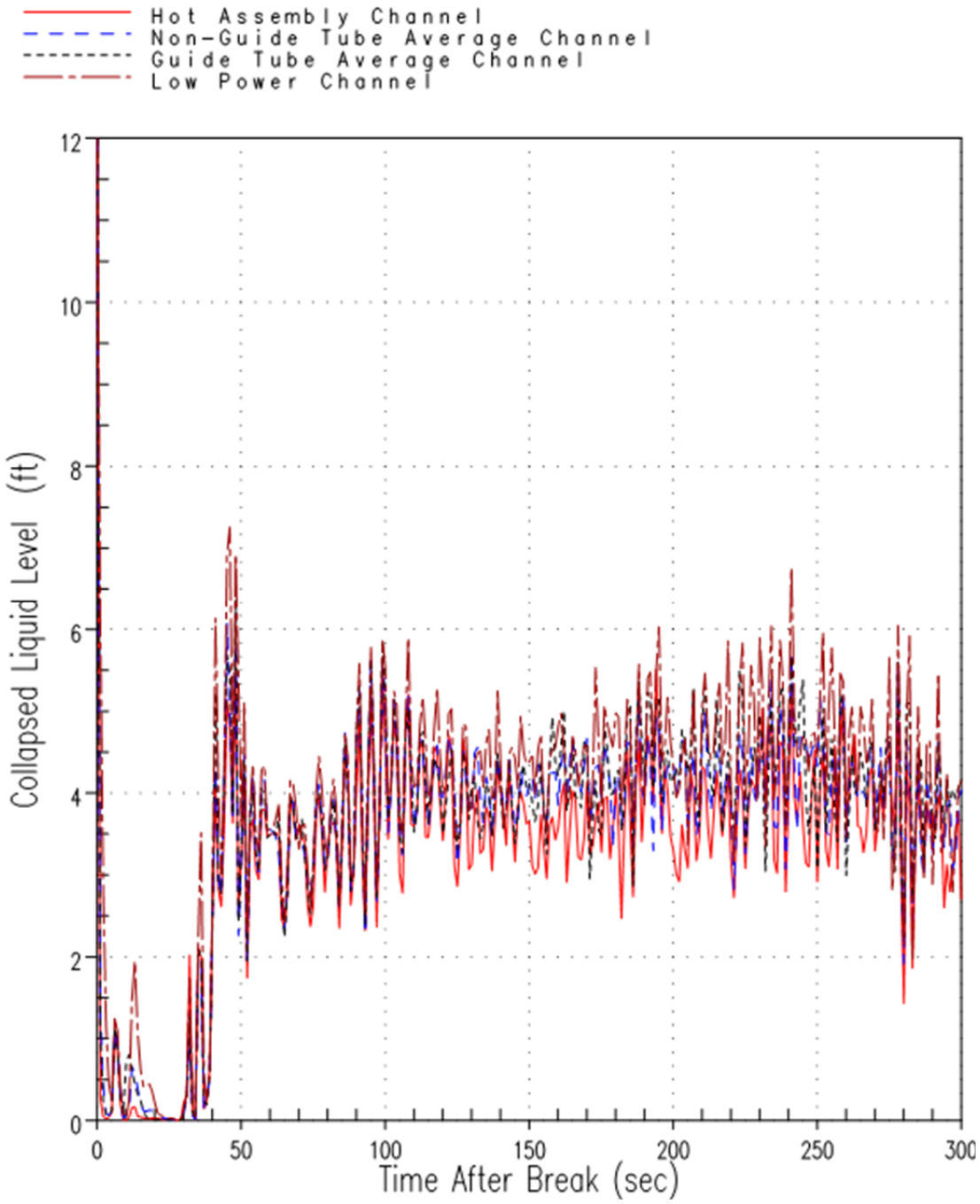


FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-22B **Vessel Fluid Mass for LBLOCA (Region II)**

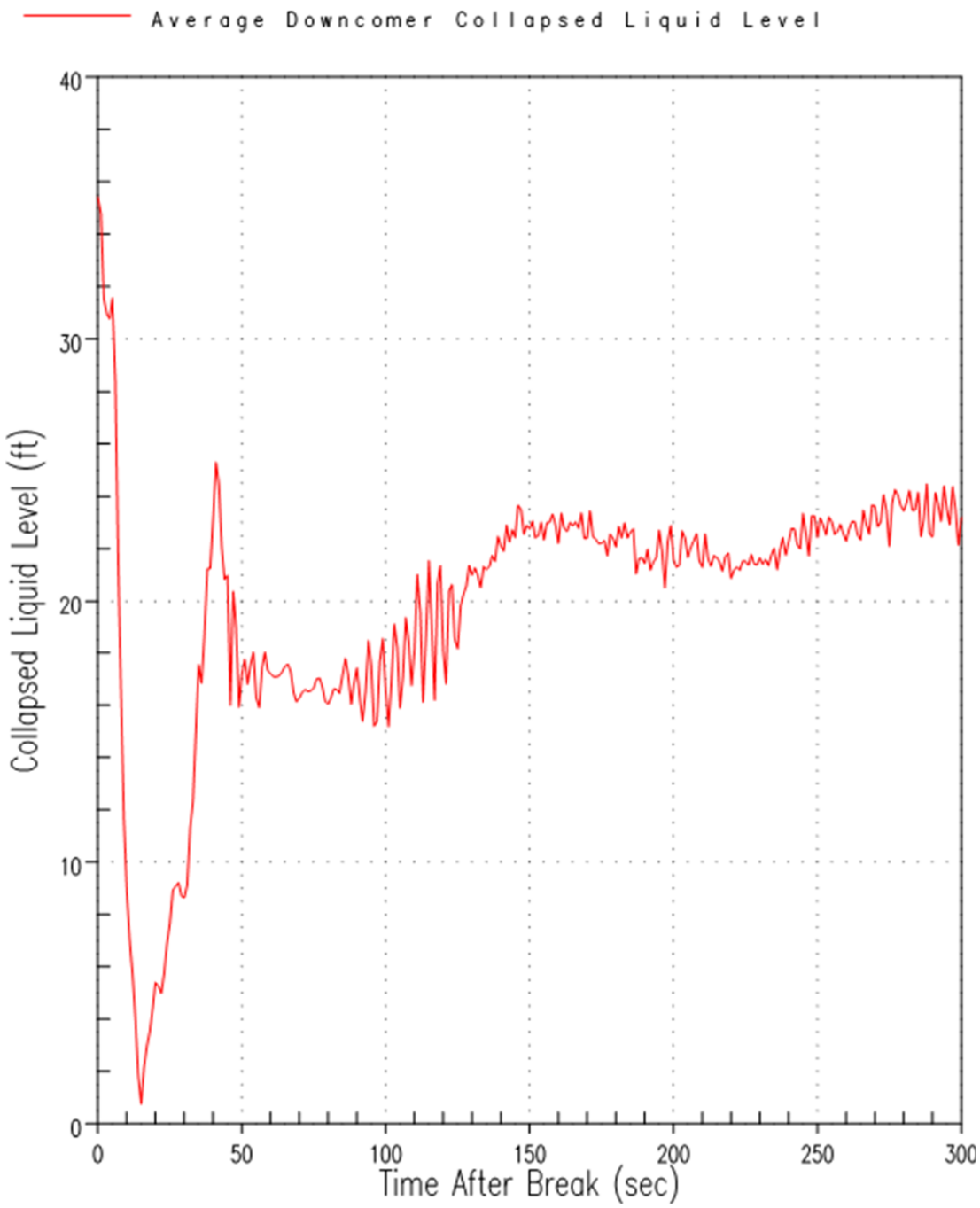
Revision 26 September 2021



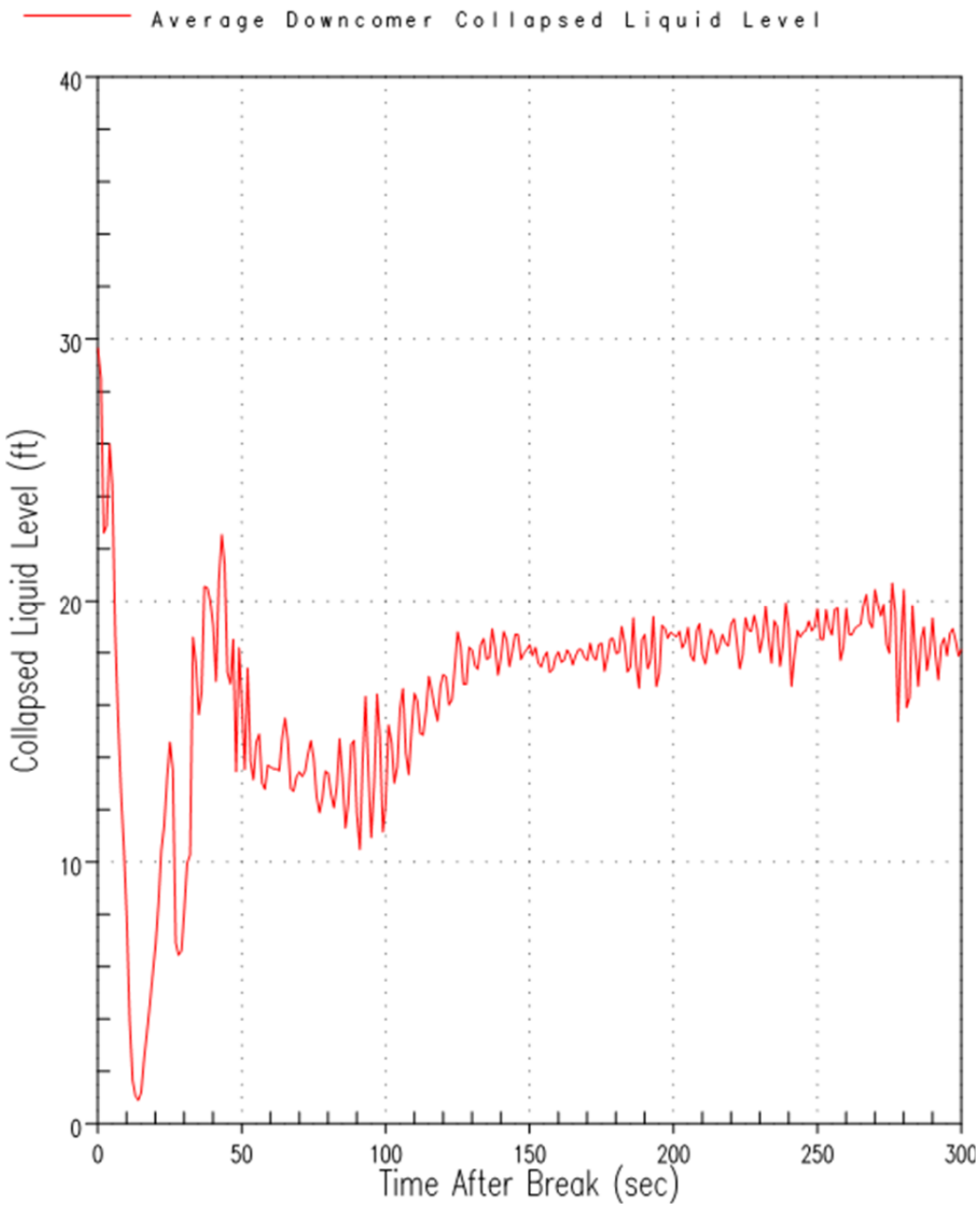
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-23A **Collapsed Liquid Level for Each Core Channel for LBLOCA (Region II)**



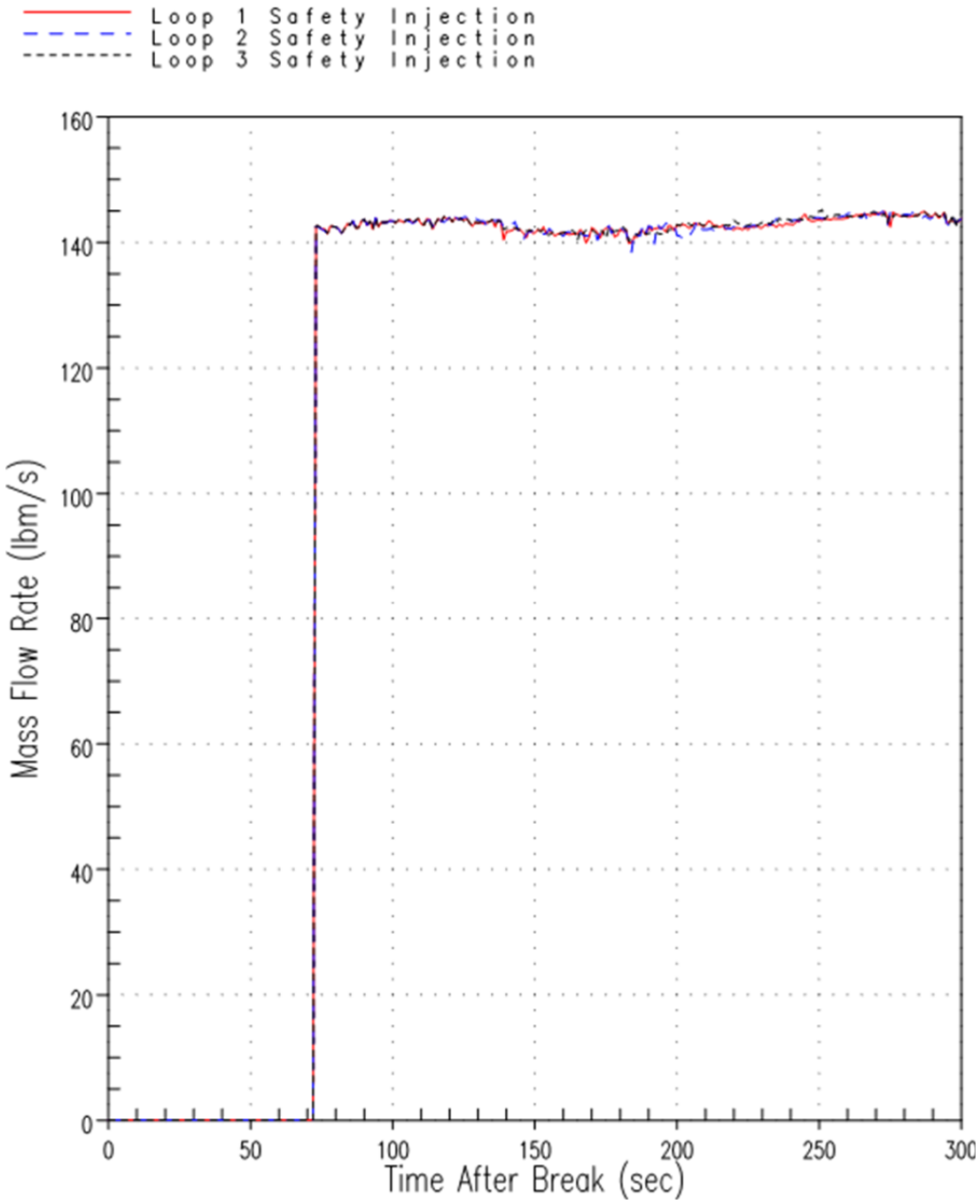
FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-23B **Collapsed Liquid Level for Each Core Channel for LBLOCA (Region II)**



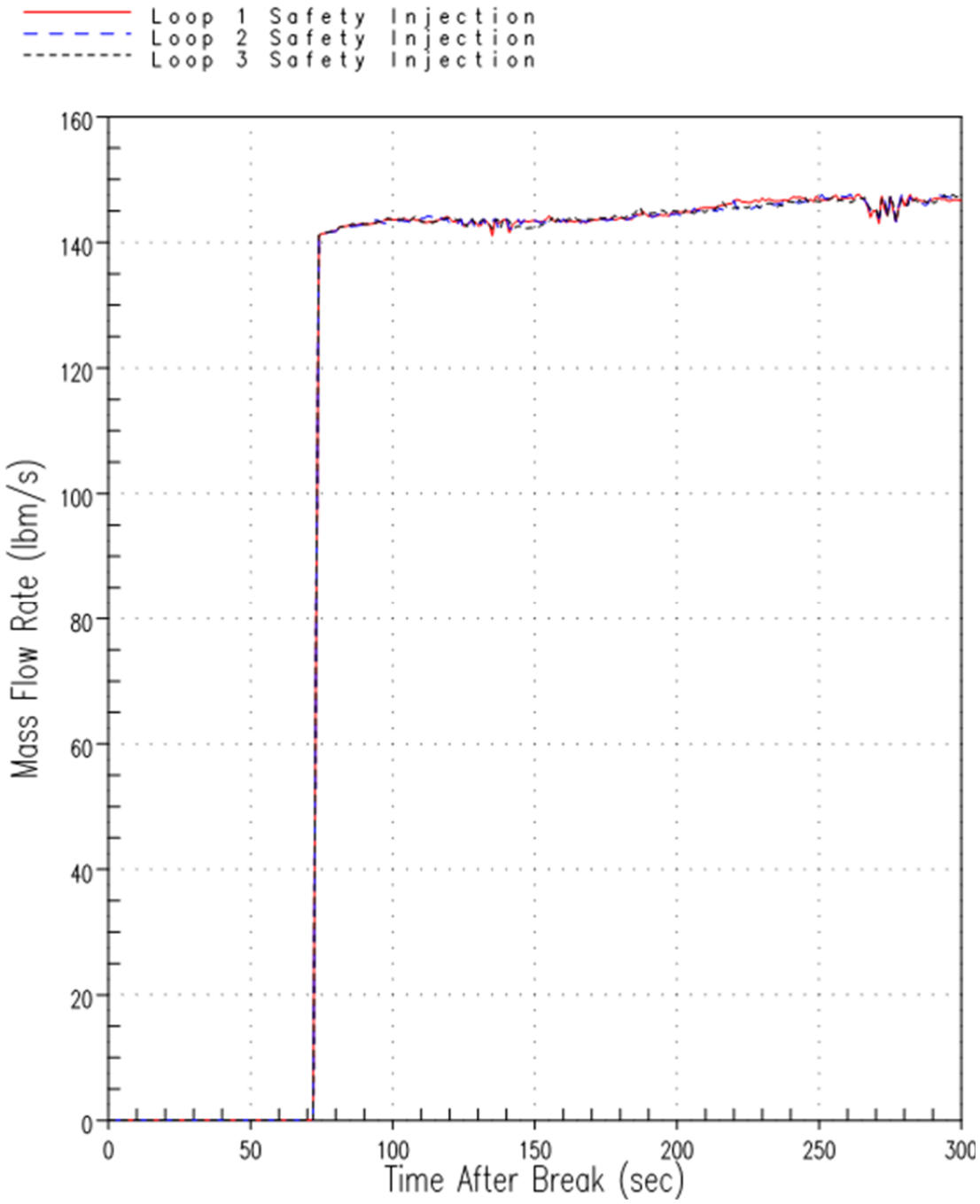
FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-24A **Average Downcomer Collapsed Liquid Level for LBLOCA (Region II)**



FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-24B Average Downcomer Collapsed Liquid Level for LBLOCA (Region II)

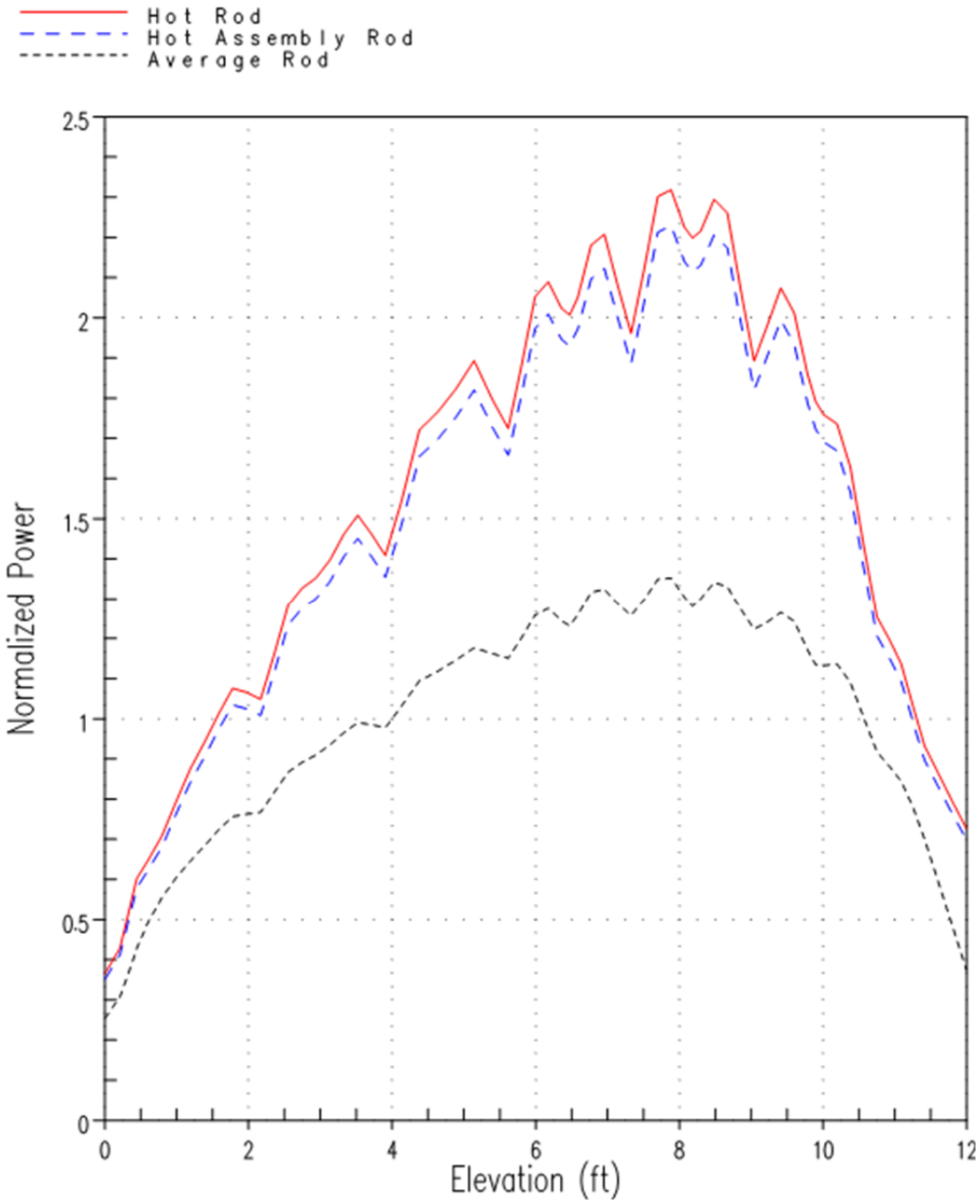


FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-25A **Total Safety Injection Flow Rate per Loop (not including Accumulator Flow) for LBLOCA (Region II)**

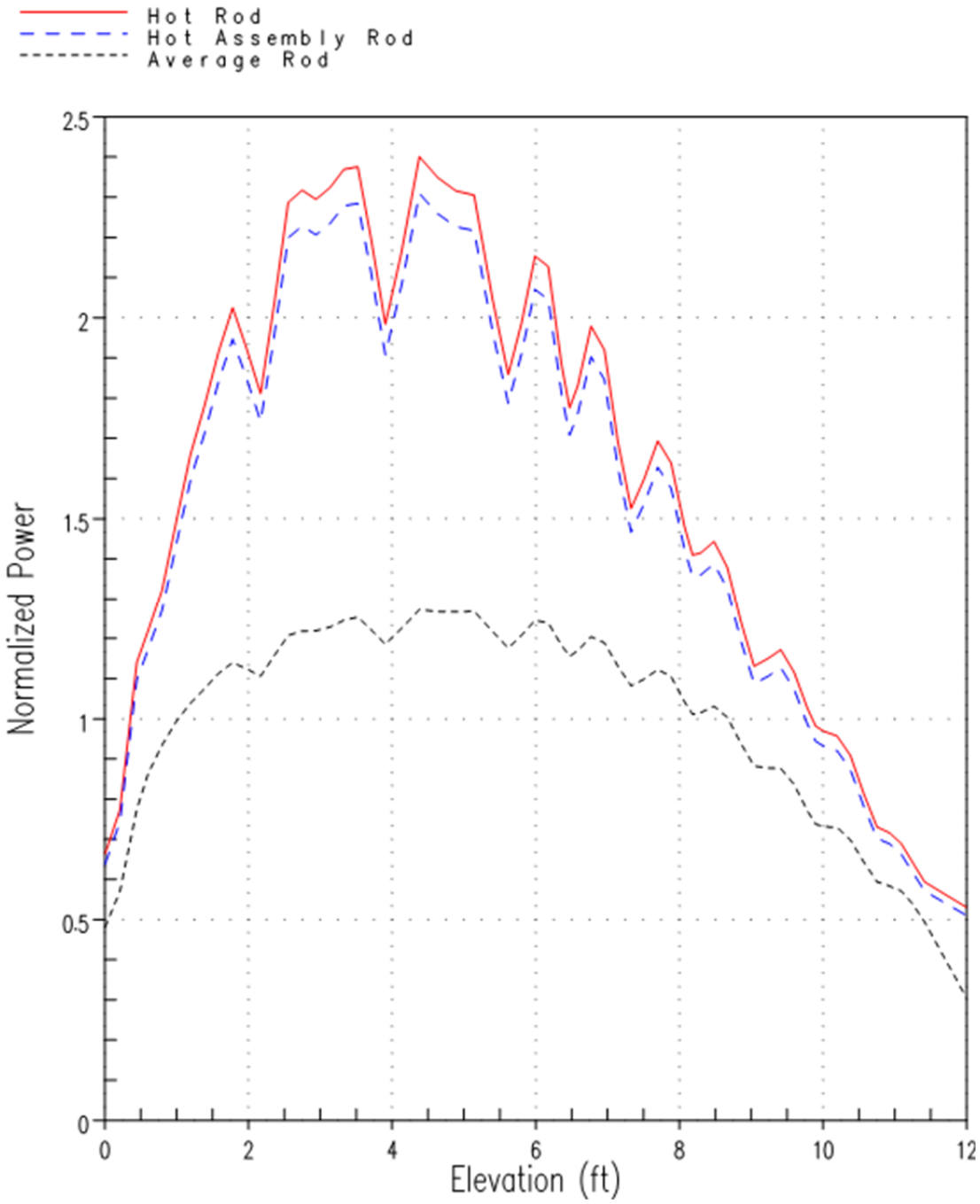


FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-25B **Total Safety Injection Flow Rate per Loop (not including Accumulator FLow) for LBLOCA (Region II)**

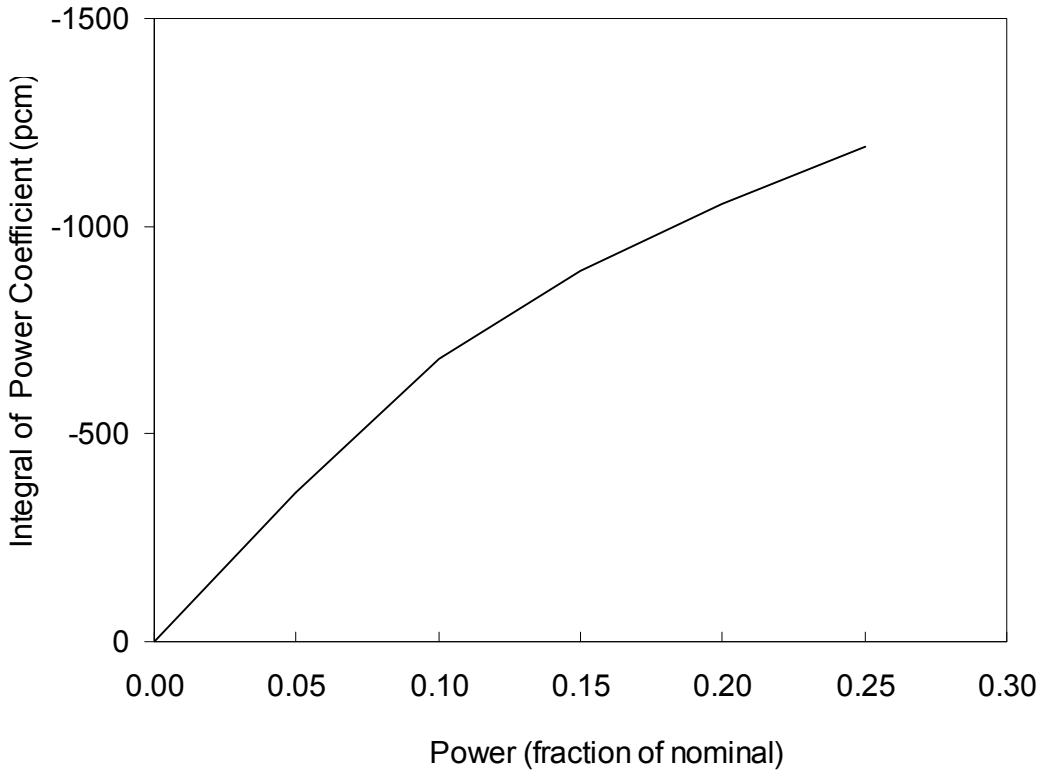
Revision 26 September 2021



FSAR UPDATE
UNIT 1 DIABLO CANYON SITE
FIGURE 15.4.1.3-26A **Normalized Core Power Shape for LBLOCA (Region II)** **Note: The localized power decreases occur at grid elevations**



FSAR UPDATE
UNIT 2 DIABLO CANYON SITE
FIGURE 15.4.1.3-26B **Normalized Core Power Shape for LBLOCA (Region II)** **Note: The localized power decreases occur at grid elevations**



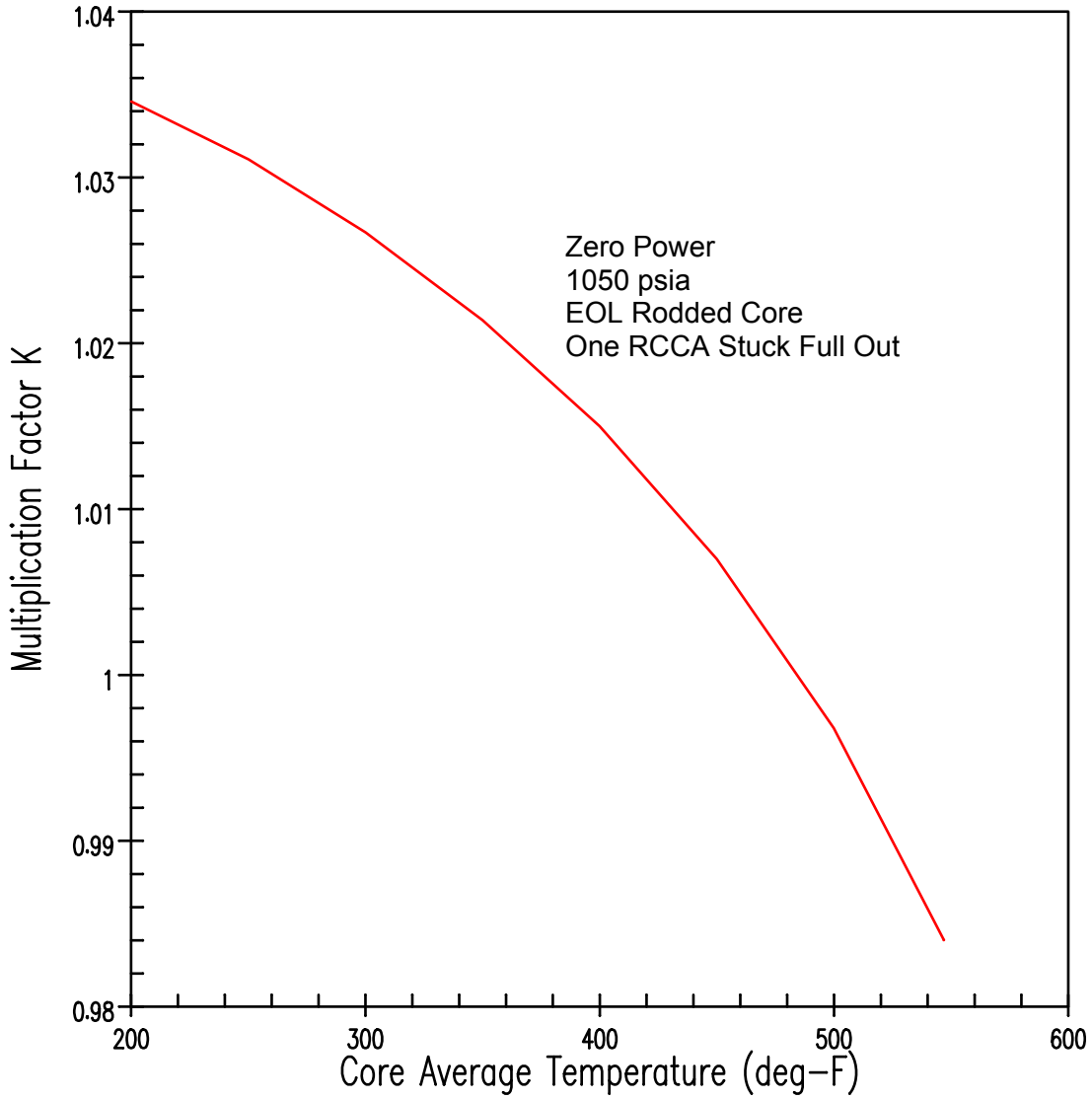
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-1

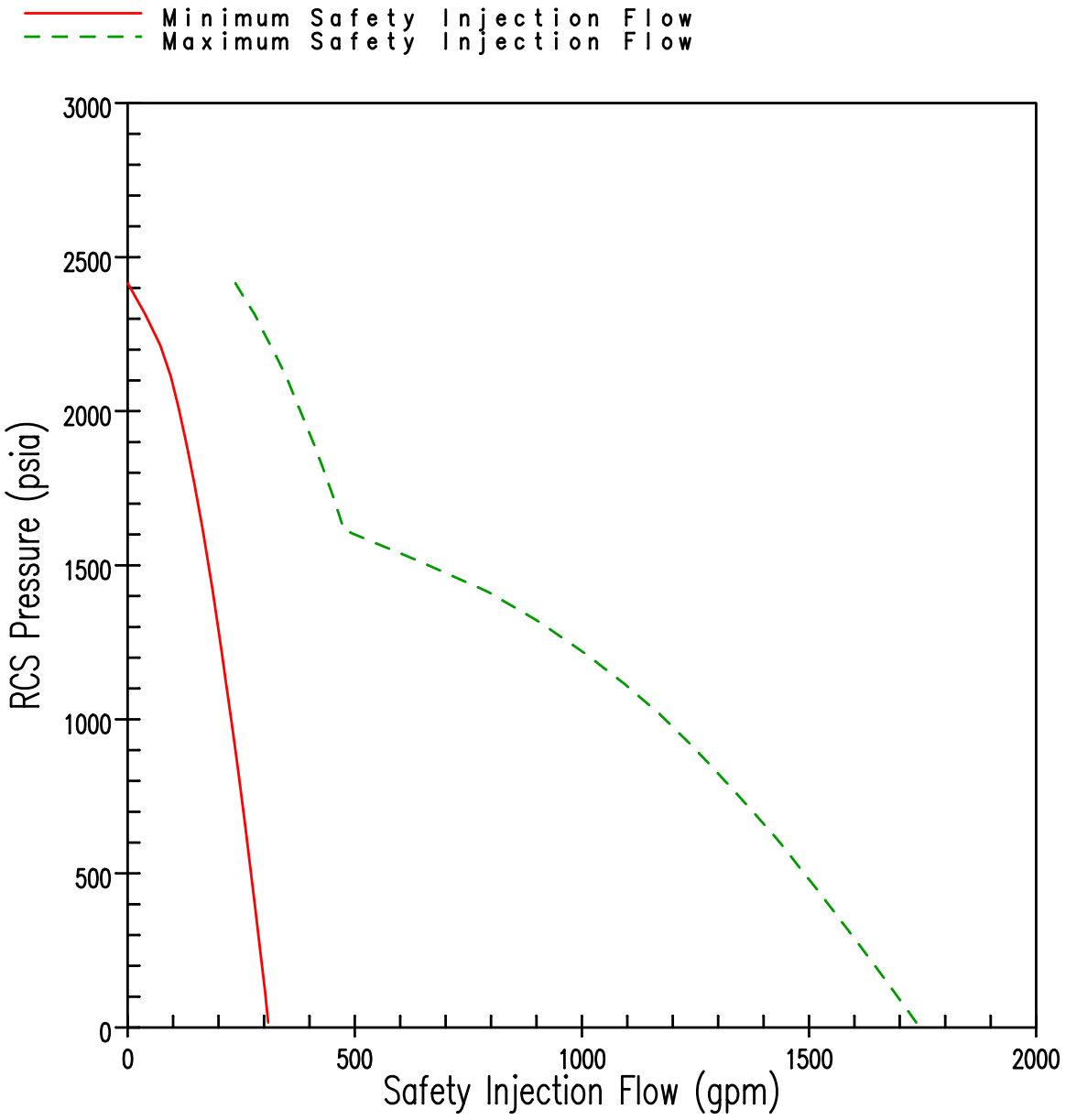
RUPTURE OF A MAIN STEAM LINE

VARIATION OF REACTIVITY WITH POWER AT CONSTANT CORE AVERAGE TEMPERATURE



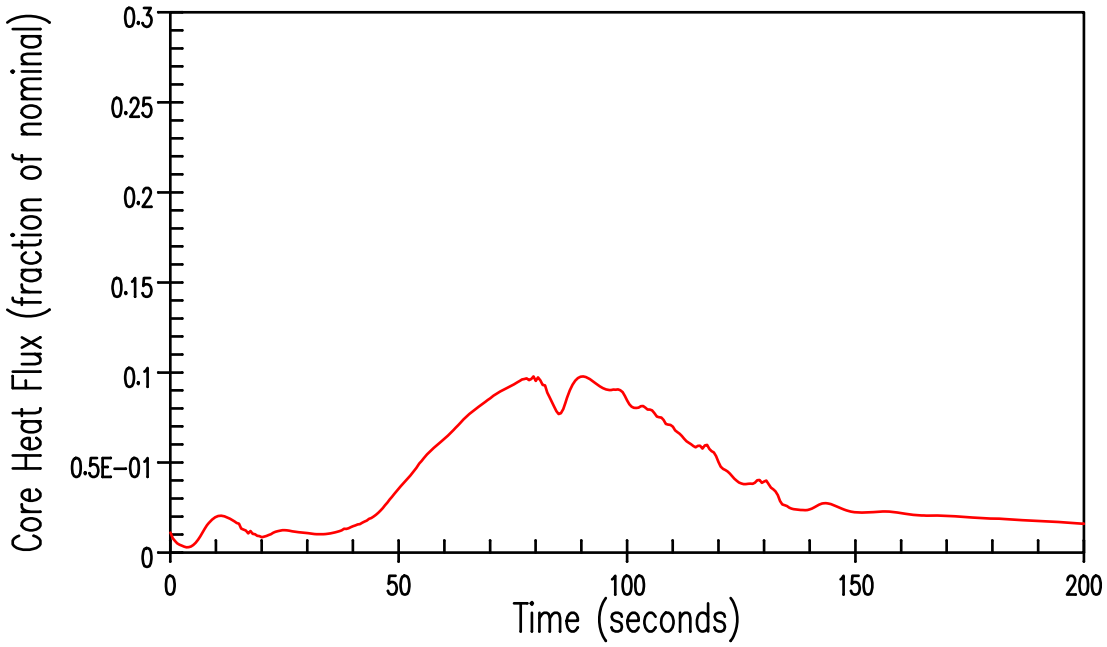
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.2-2 RUPTURE OF A MAIN STEAM LINE VARIATION OF K_{EFF} WITH CORE AVERAGE TEMPERATURE

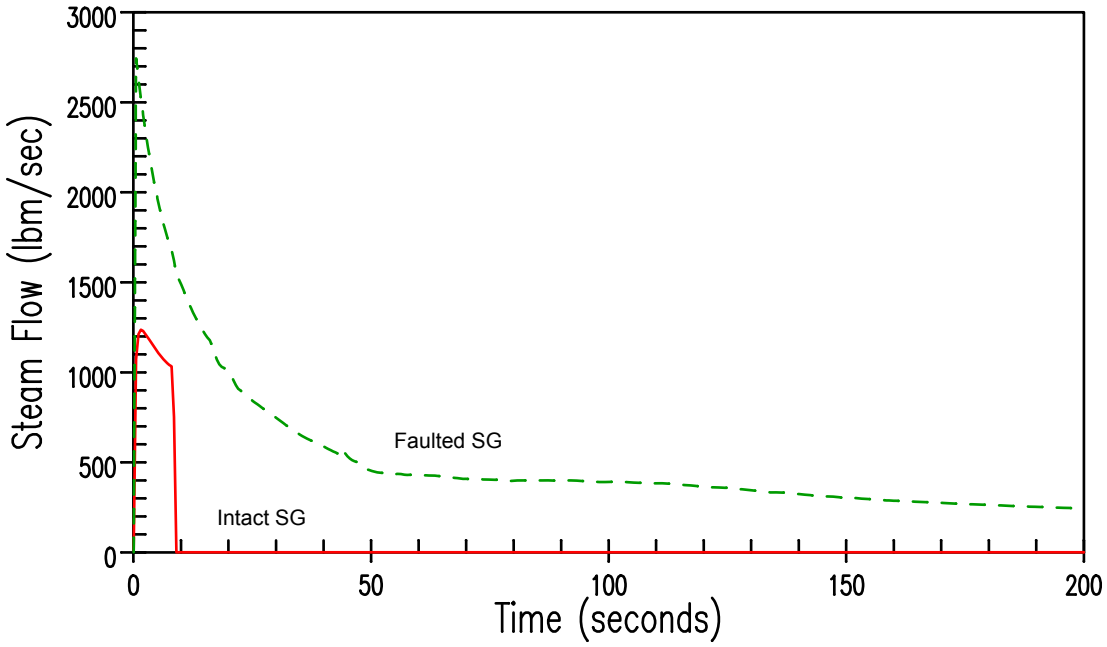
Revision 19 May 2010



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.2-3 RUPTURE OF A MAIN STEAM LINE SAFETY INJECTION CURVE

Revision 21 September 2013





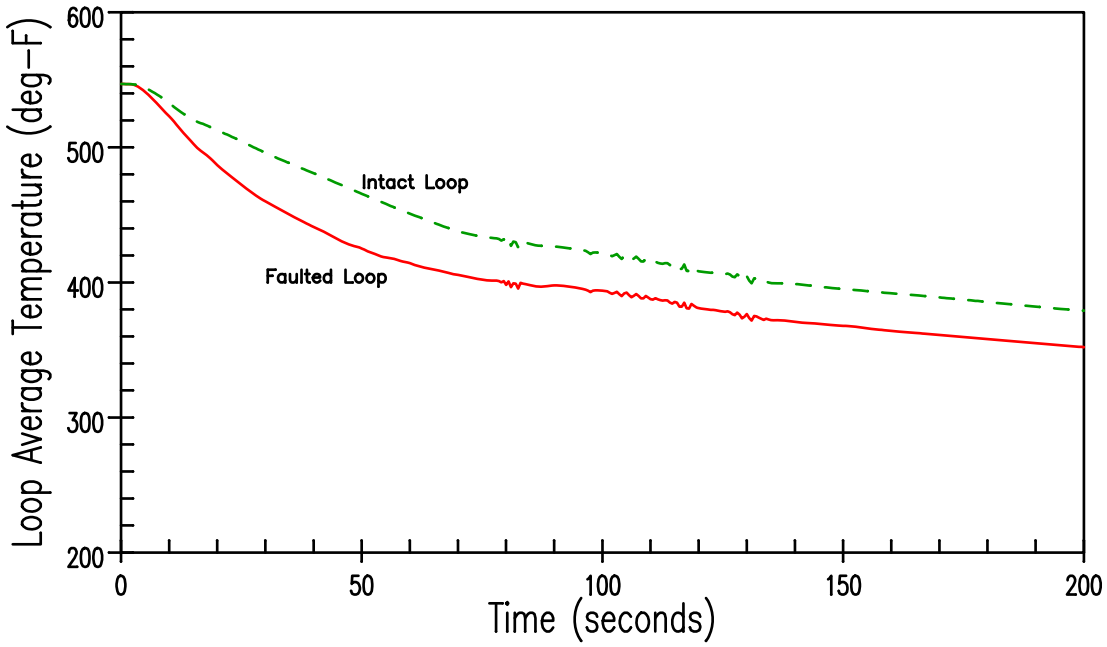
FSAR UPDATE

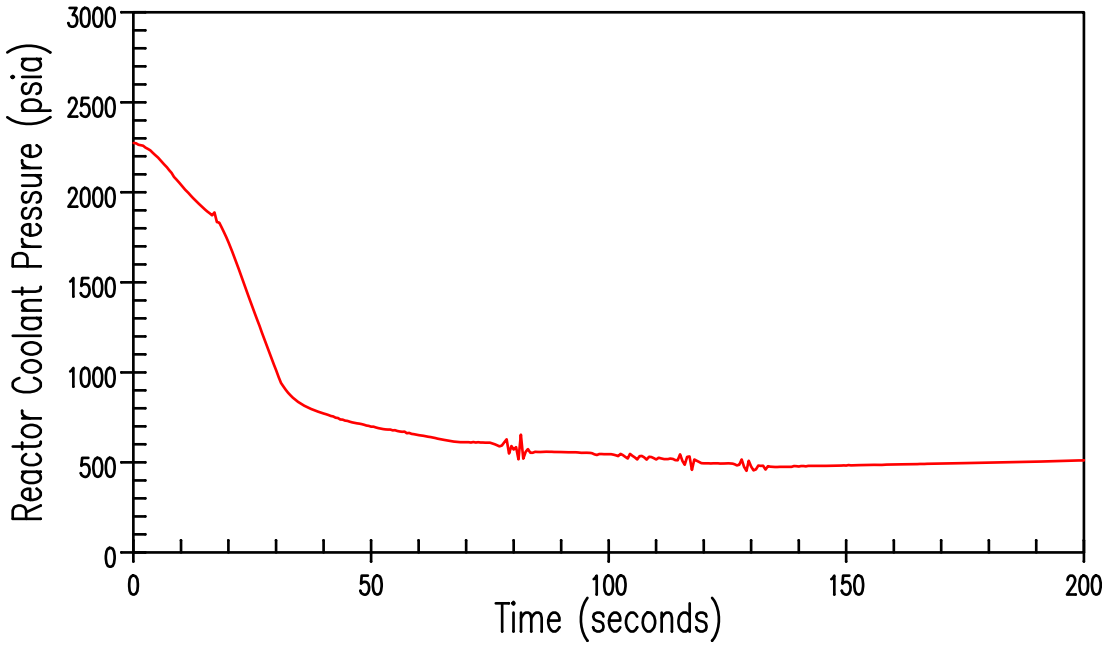
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-4

RUPTURE OF A MAIN STEAM LINE WITH OFFSITE POWER AVAILABLE

CORE HEAT FLUX AND STEAM FLOW TRANSIENTS





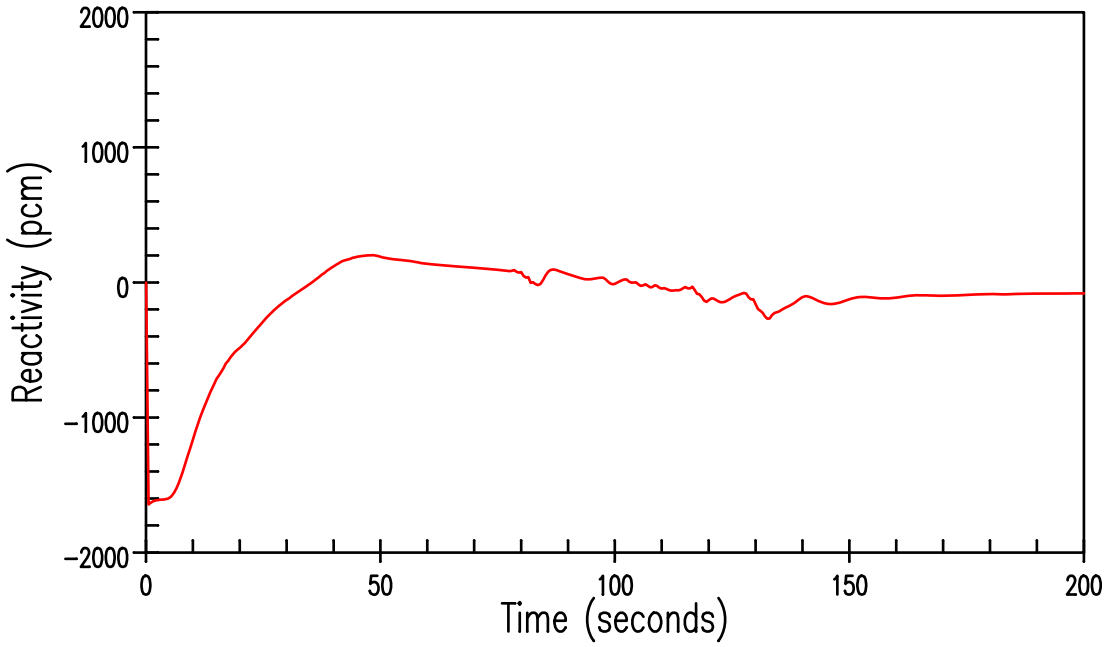
FSAR UPDATE

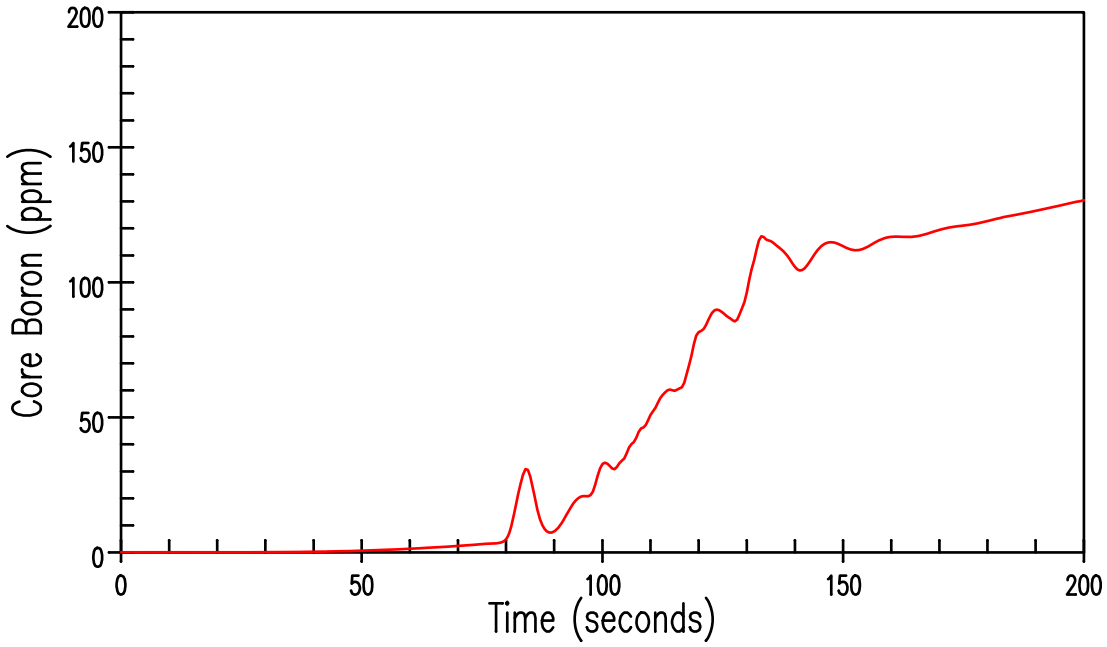
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-5

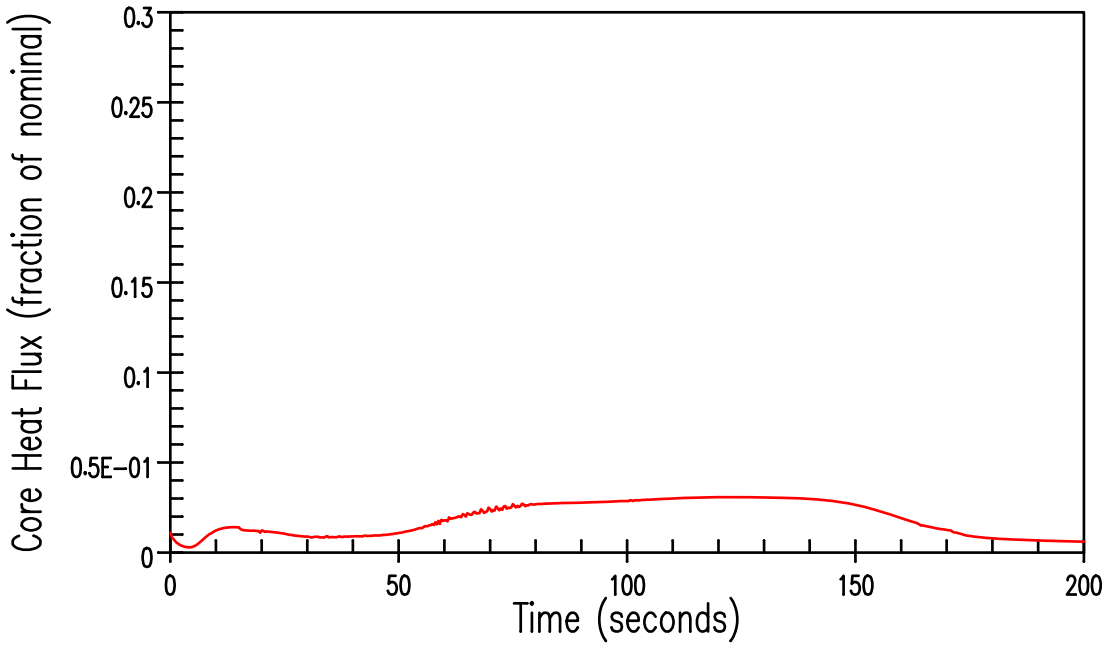
RUPTURE OF A MAIN STEAM LINE WITH OFFSITE POWER AVAILABLE

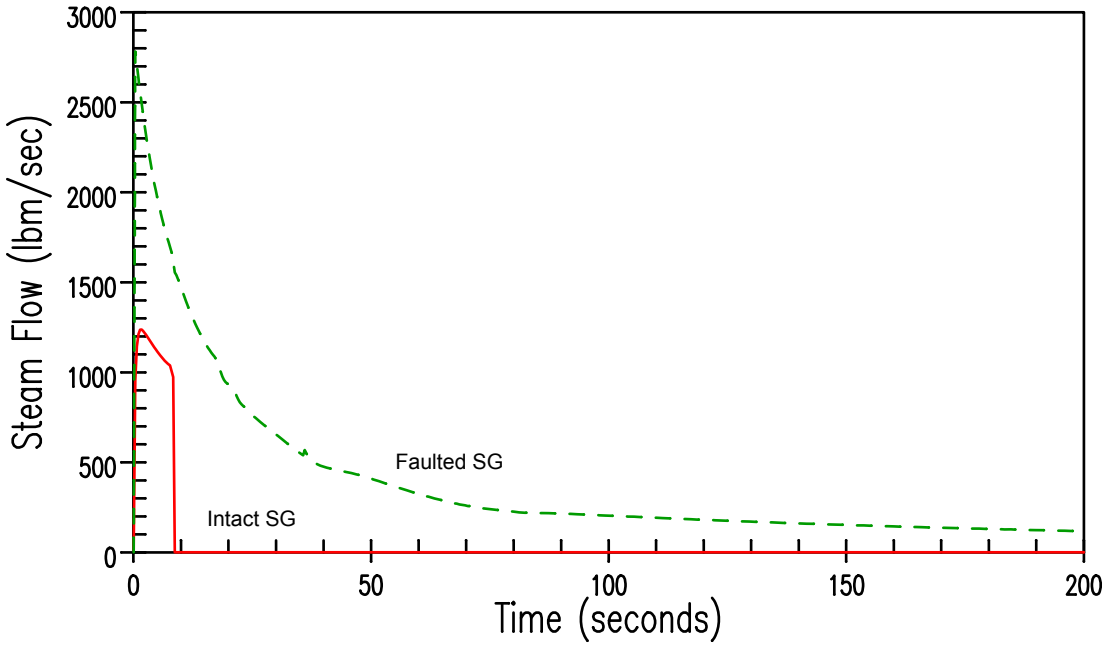
LOOP AVERAGE TEMPERATURE AND REACTOR COOLANT PRESSURE TRANSIENTS





FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.2-6 RUPTURE OF A MAIN STEAM LINE WITH OFFSITE POWER AVAILABLE REACTIVITY AND CORE BORON TRANSIENTS





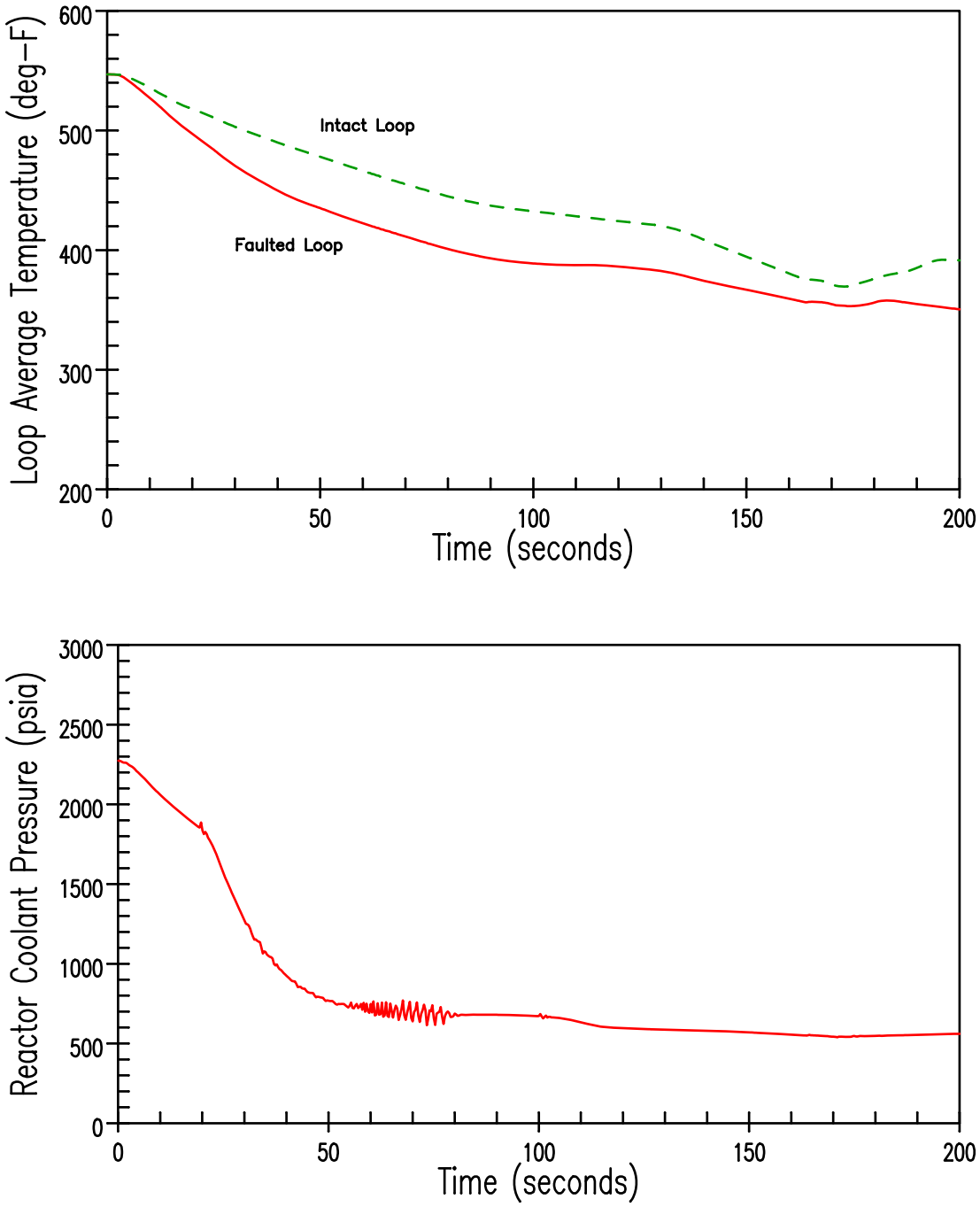
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-7

RUPTURE OF A MAIN STEAM LINE WITHOUT OFFSITE POWER AVAILABLE

CORE HEAT FLUX AND STEAM FLOW TRANSIENTS



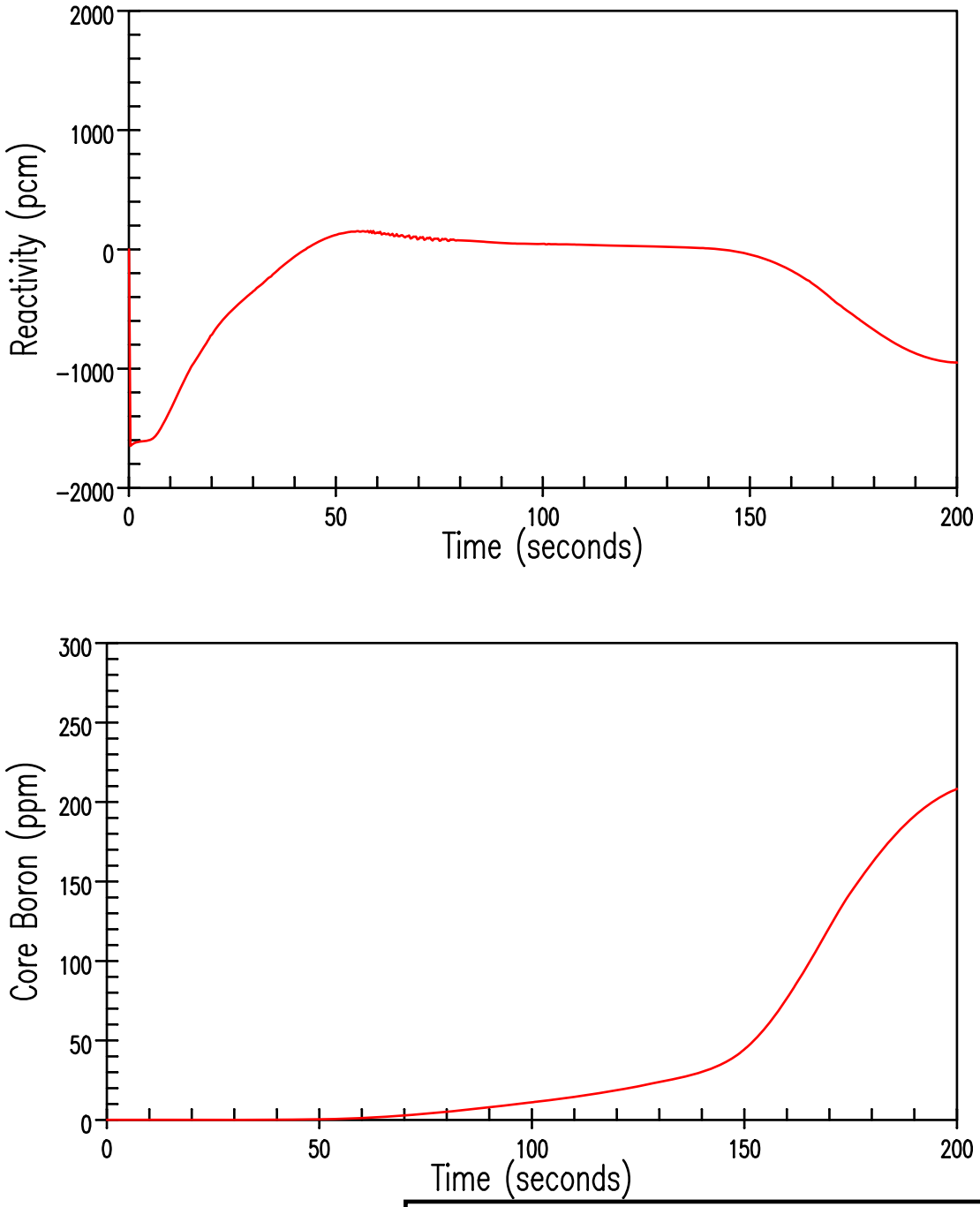
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-8

RUPTURE OF A MAIN STEAM LINE WITHOUT OFFSITE POWER AVAILABLE

LOOP AVERAGE TEMPERATURE AND REACTOR COOLANT PRESSURE TRANSIENTS

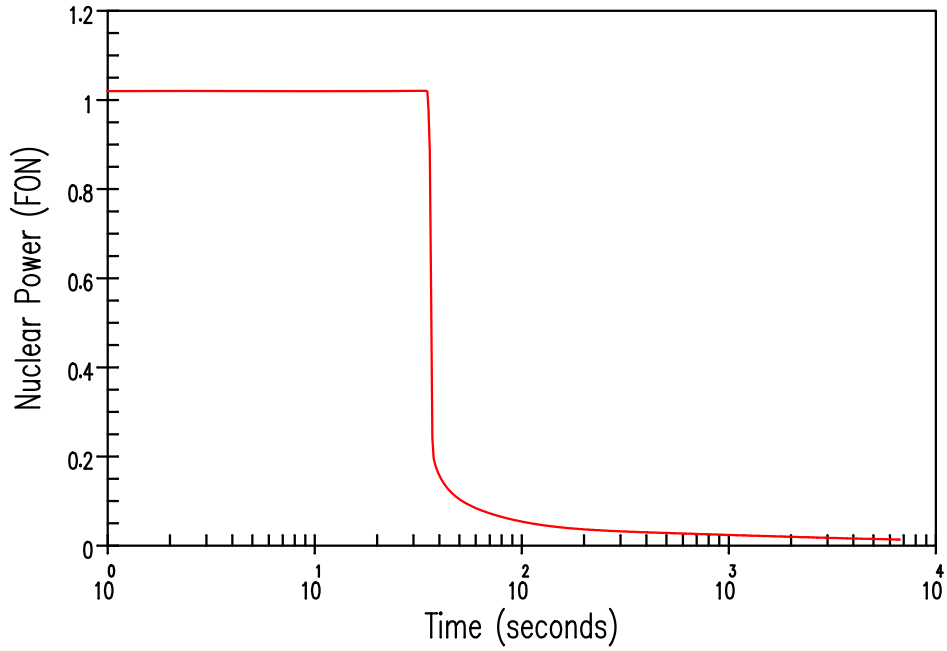


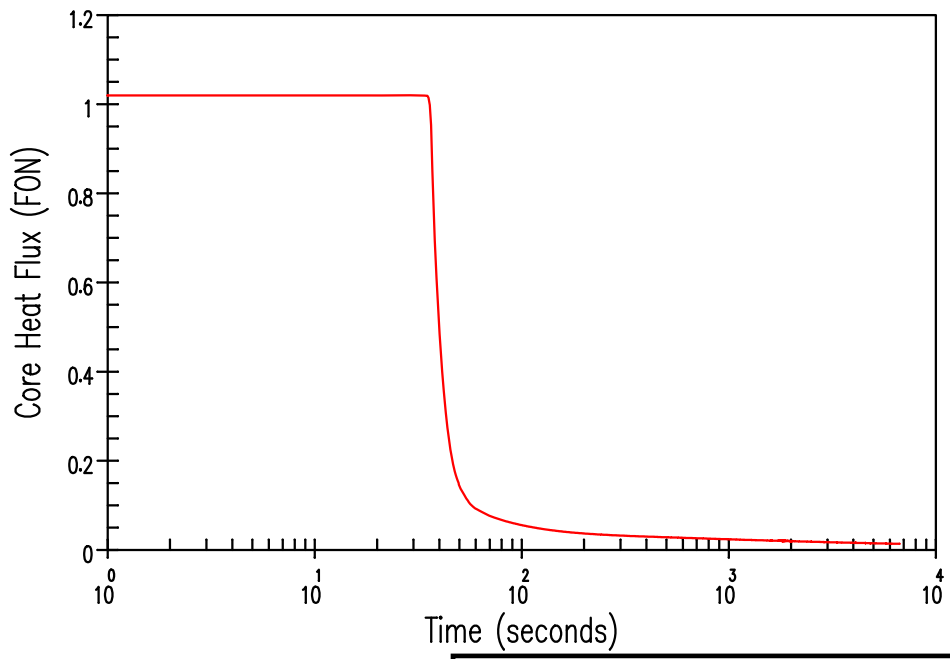
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-9
RUPTURE OF A MAIN STEAM LINE WITHOUT OFFSITE POWER AVAILABLE

REACTIVITY AND CORE BORON TRANSIENTS





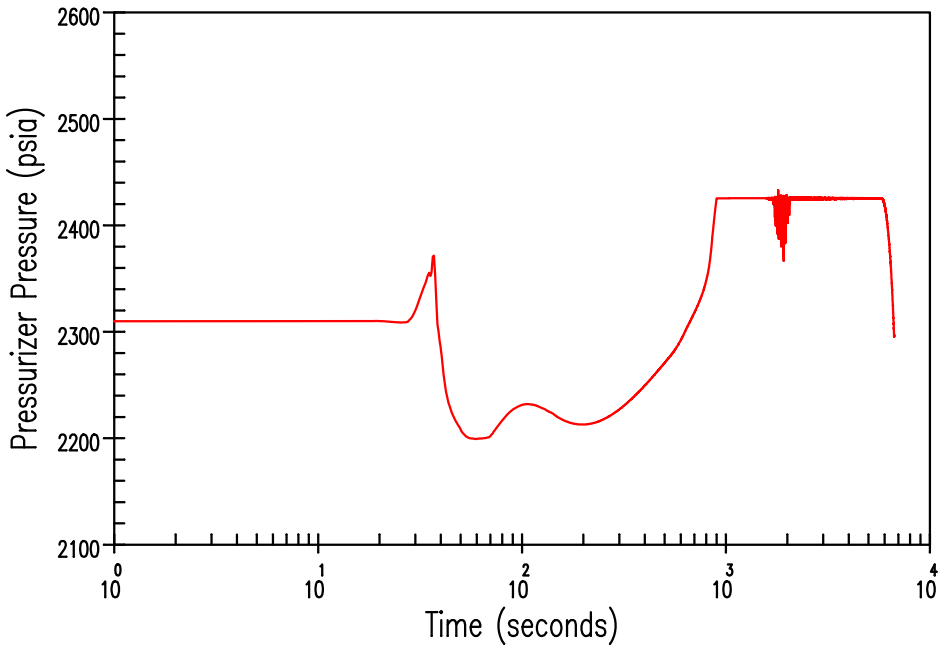
FSAR UPDATE

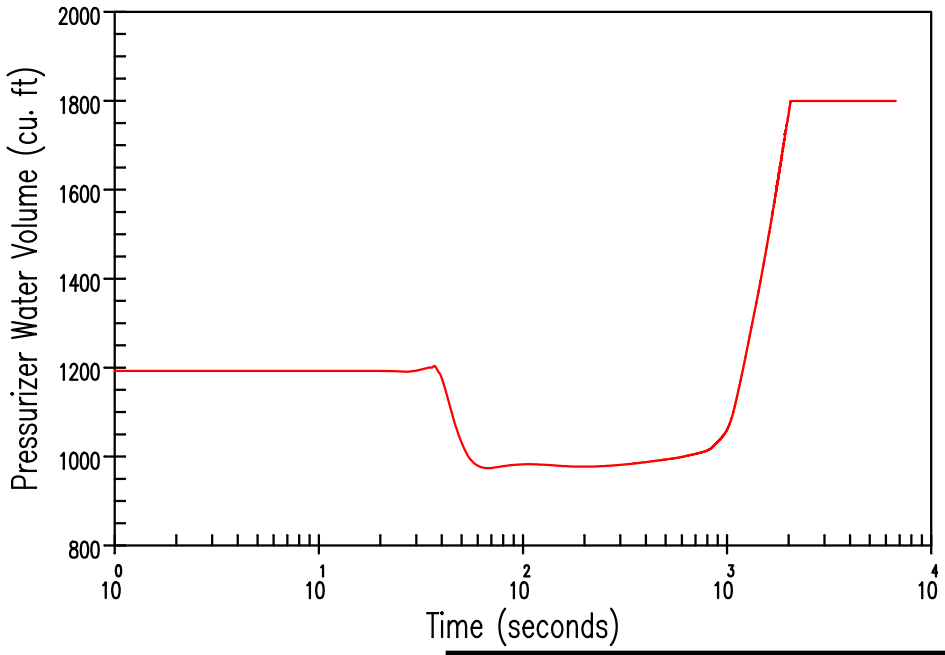
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-10

MAIN FEEDLINE RUPTURE
WITH OFFSITE POWER AVAILABLE

NUCLEAR POWER AND
CORE HEAT FLUX TRANSIENTS





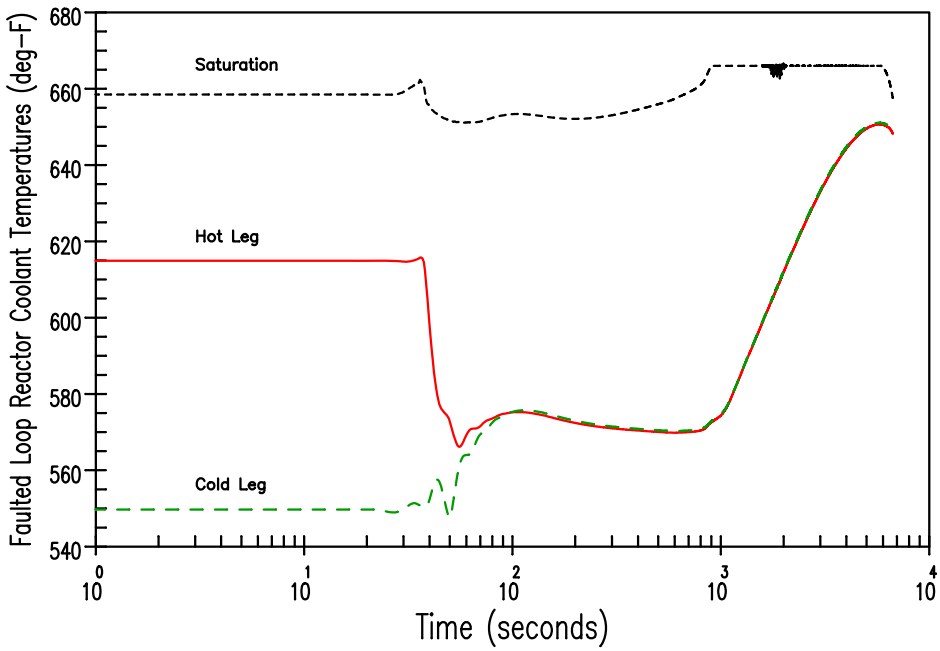
FSAR UPDATE

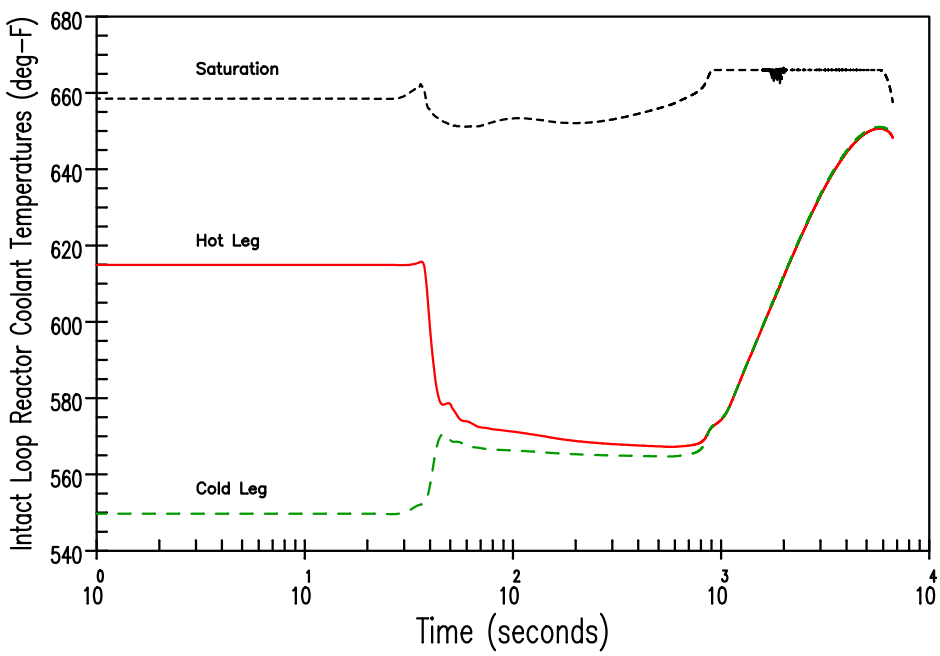
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-11

MAIN FEEDLINE RUPTURE
WITH OFFSITE POWER AVAILABLE

PRESSURIZER PRESSURE AND
WATER VOLUME TRANSIENTS





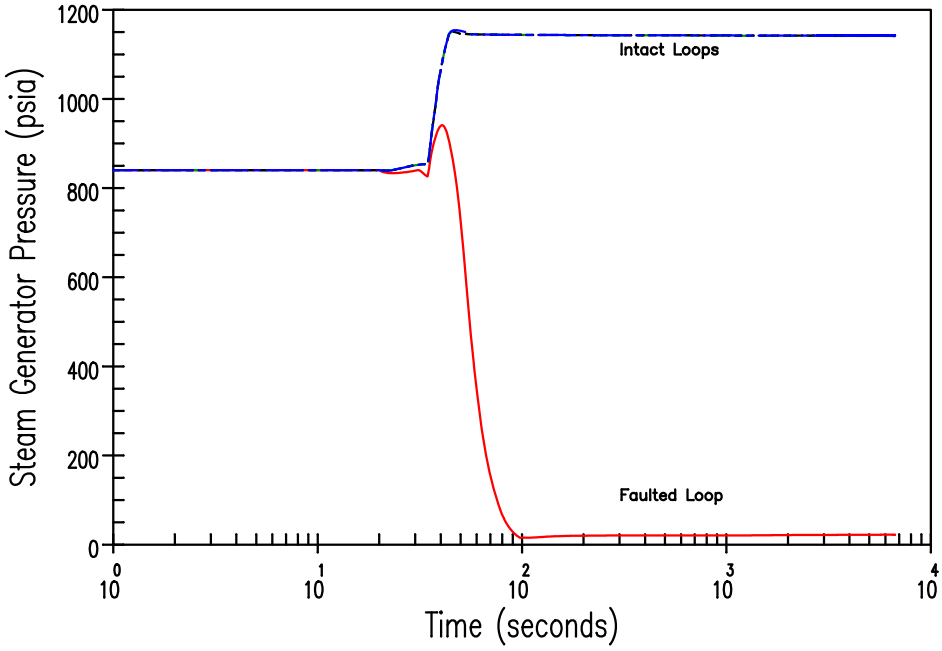
FSAR UPDATE

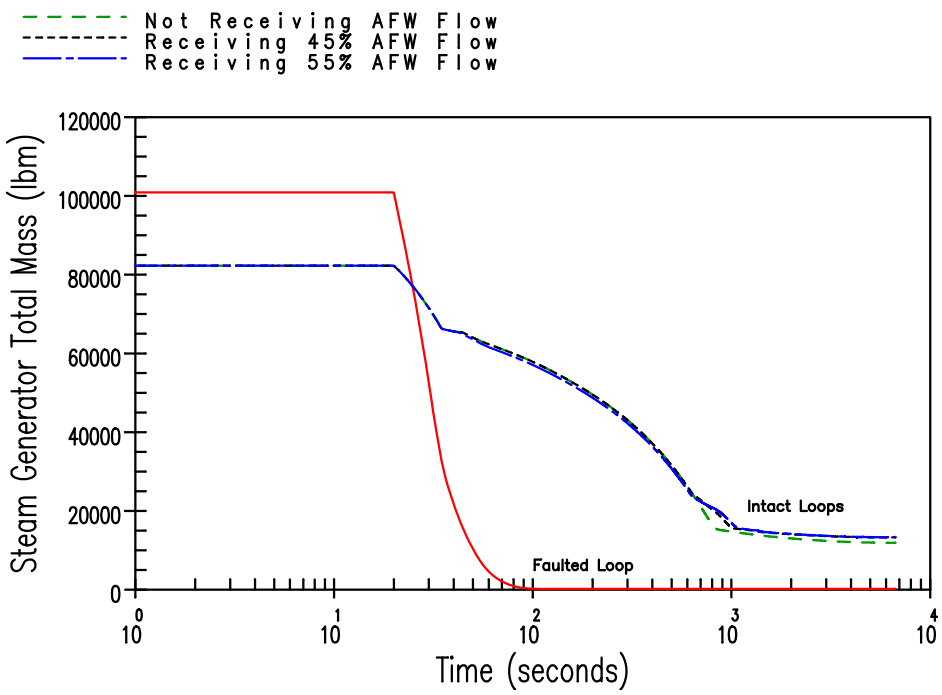
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-12

MAIN FEEDLINE RUPTURE WITH OFFSITE POWER AVAILABLE

REACTOR COOLANT TEMPERATURE TRANSIENTS FOR THE FAULTED AND INTACT LOOPS





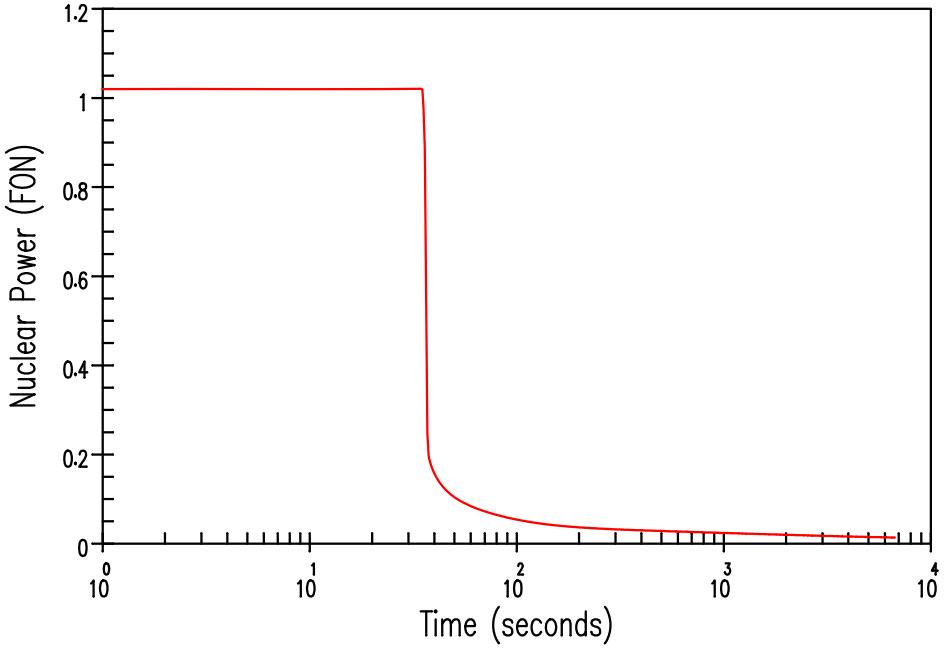
FSAR UPDATE

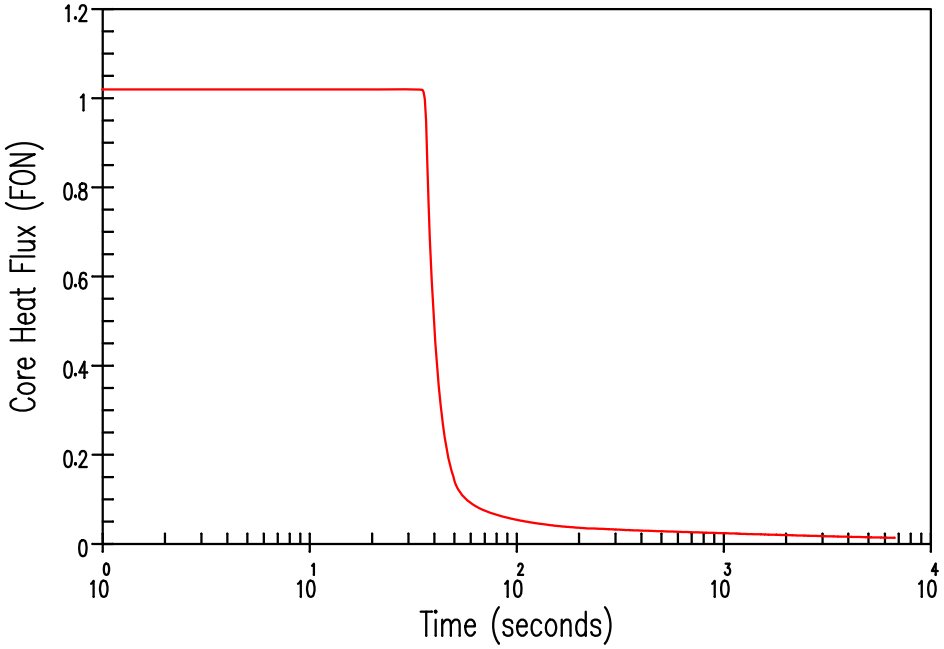
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-13

MAIN FEEDLINE RUPTURE WITH OFFSITE POWER AVAILABLE

STEAM GENERATOR PRESSURE AND TOTAL MASS TRANSIENTS





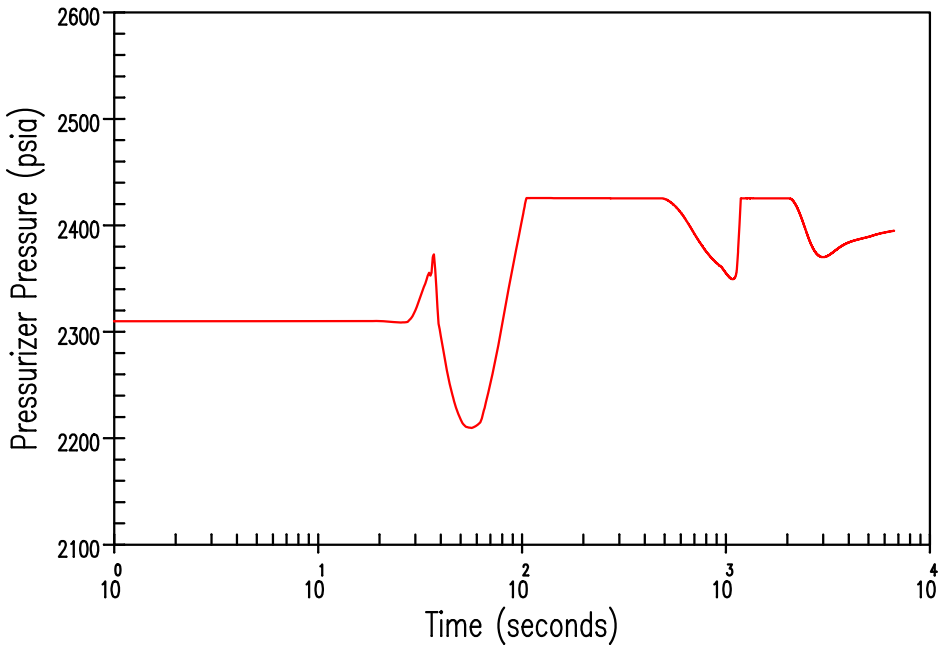
FSAR UPDATE

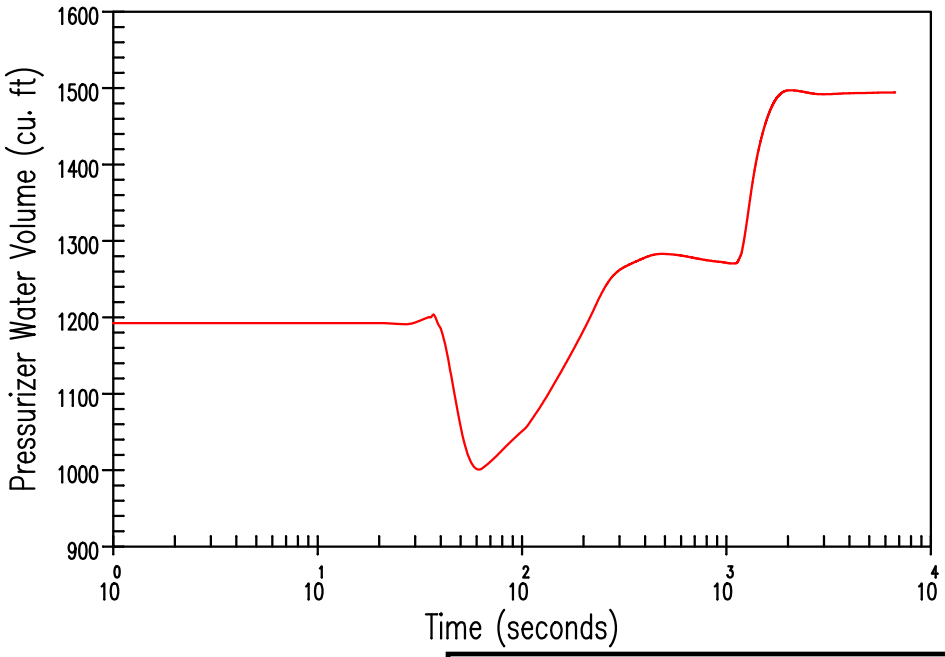
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-14

MAIN FEEDLINE RUPTURE
WITHOUT OFFSITE POWER AVAILABLE

NUCLEAR POWER AND
CORE HEAT FLUX TRANSIENTS





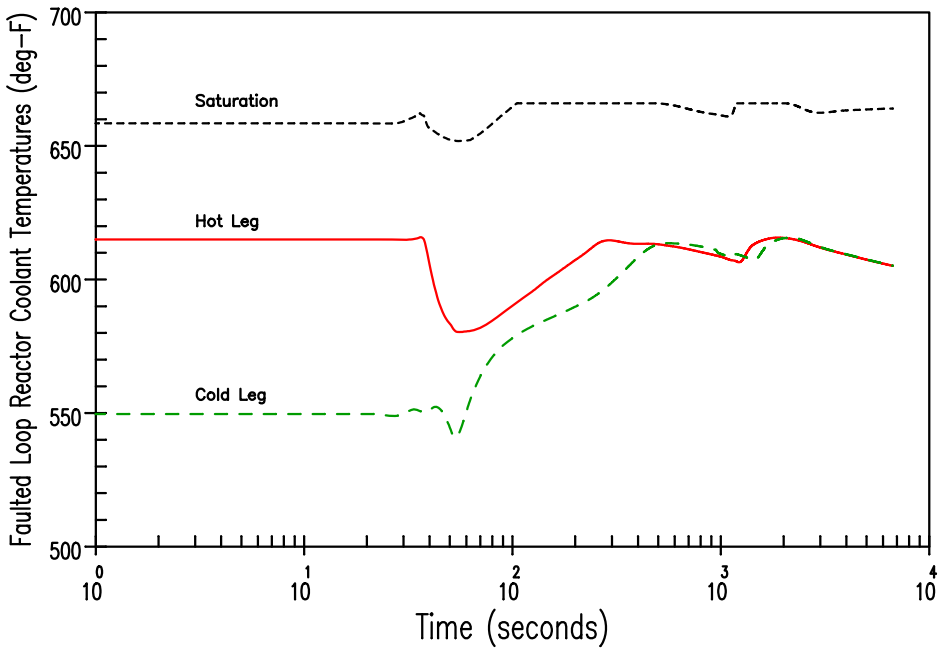
FSAR UPDATE

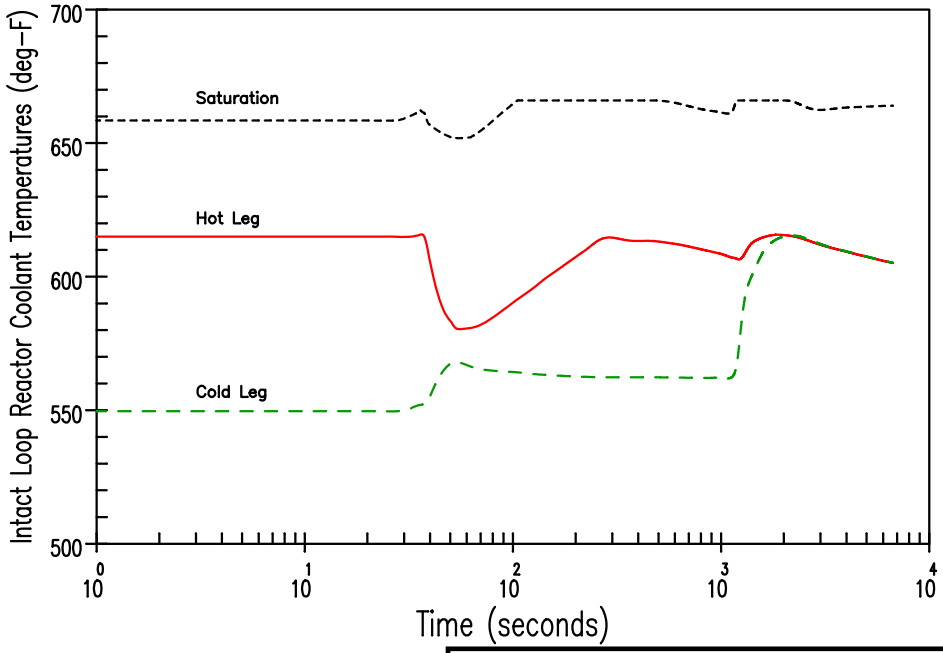
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-15

MAIN FEEDLINE RUPTURE WITHOUT OFFSITE POWER AVAILABLE

PRESSURIZER PRESSURE AND WATER VOLUME TRANSIENTS





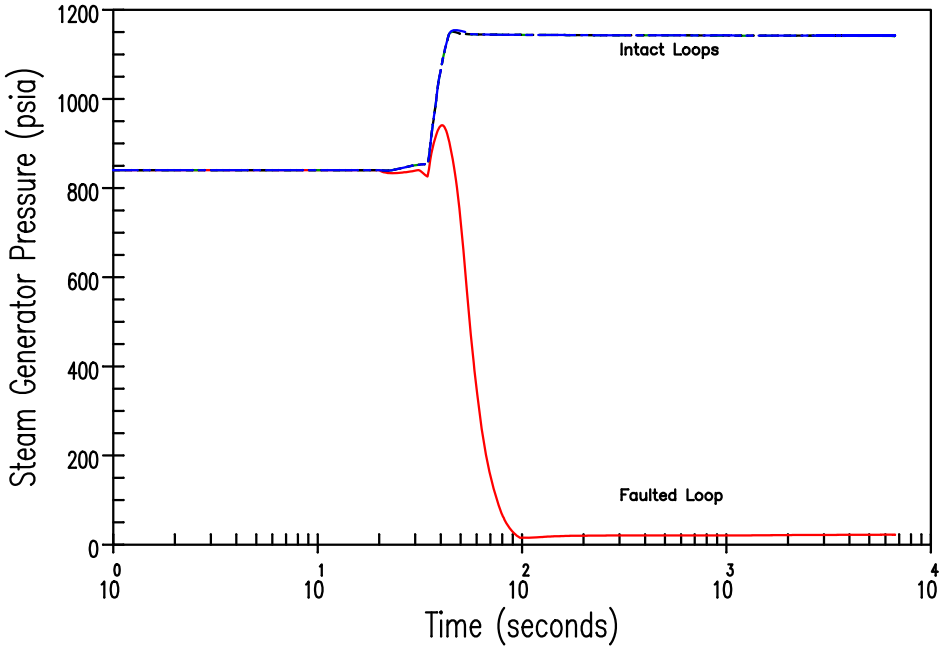
FSAR UPDATE

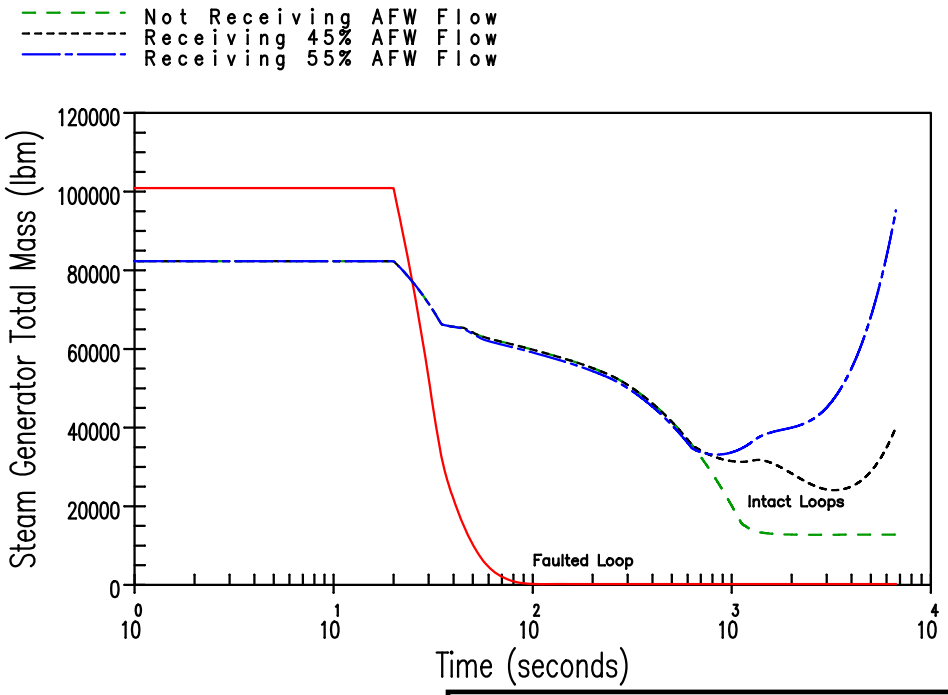
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-16

MAIN FEEDLINE RUPTURE WITHOUT OFFSITE POWER AVAILABLE

REACTOR COOLANT TEMPERATURE TRANSIENTS FOR THE FAULTED AND INTACT LOOPS





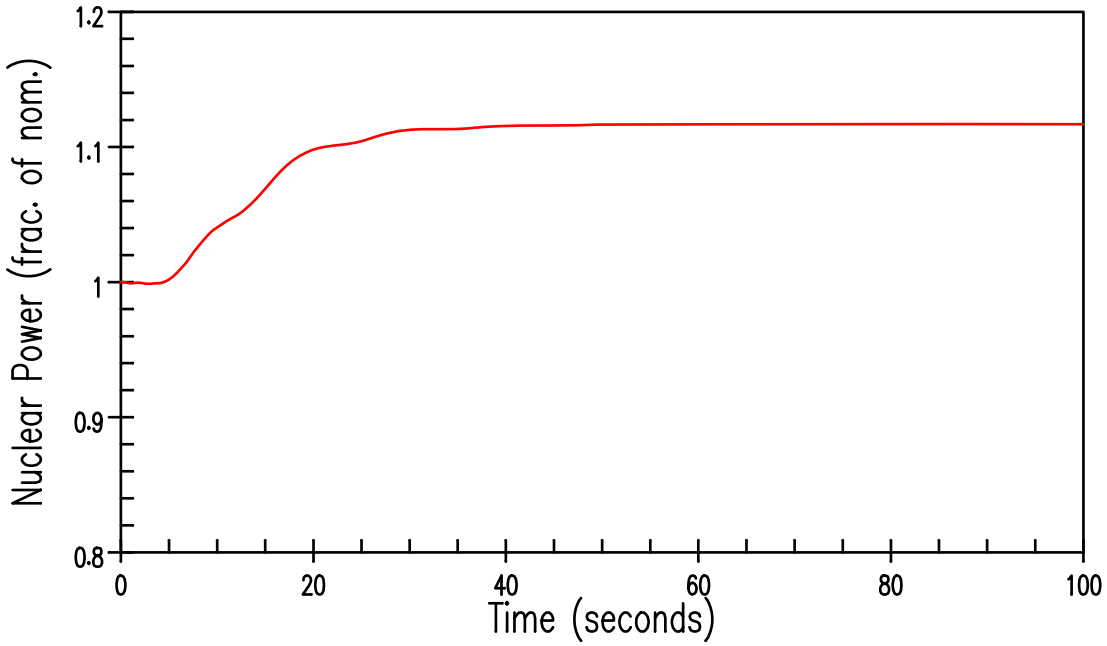
FSAR UPDATE

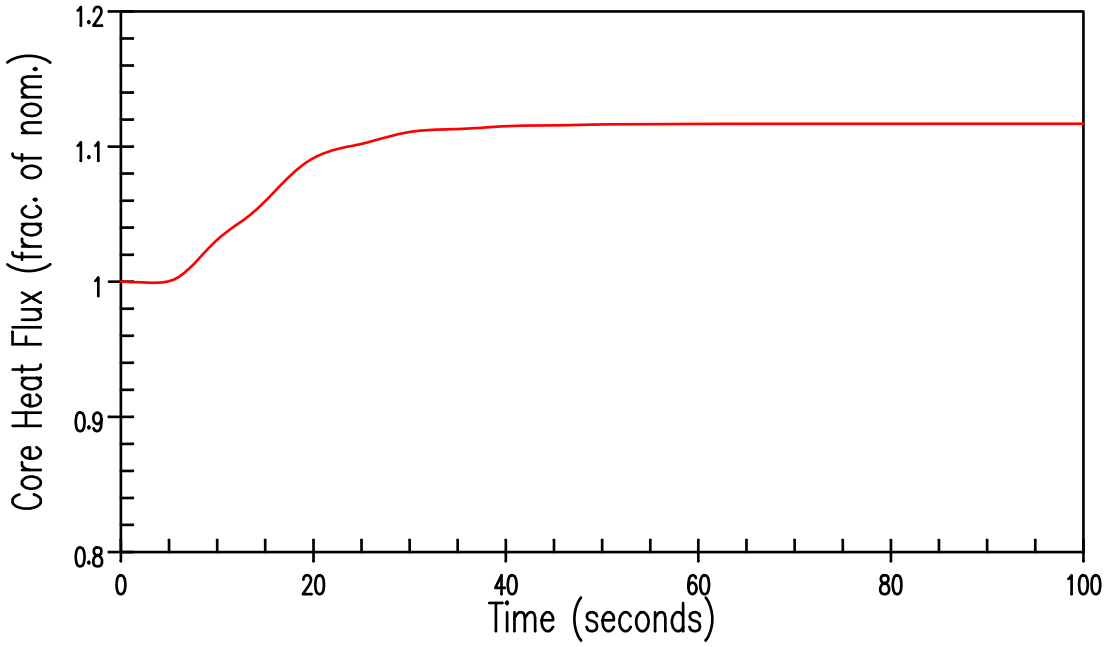
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-17

MAIN FEEDLINE RUPTURE WITHOUT OFFSITE POWER AVAILABLE

STEAM GENERATOR PRESSURE AND TOTAL MASS TRANSIENTS





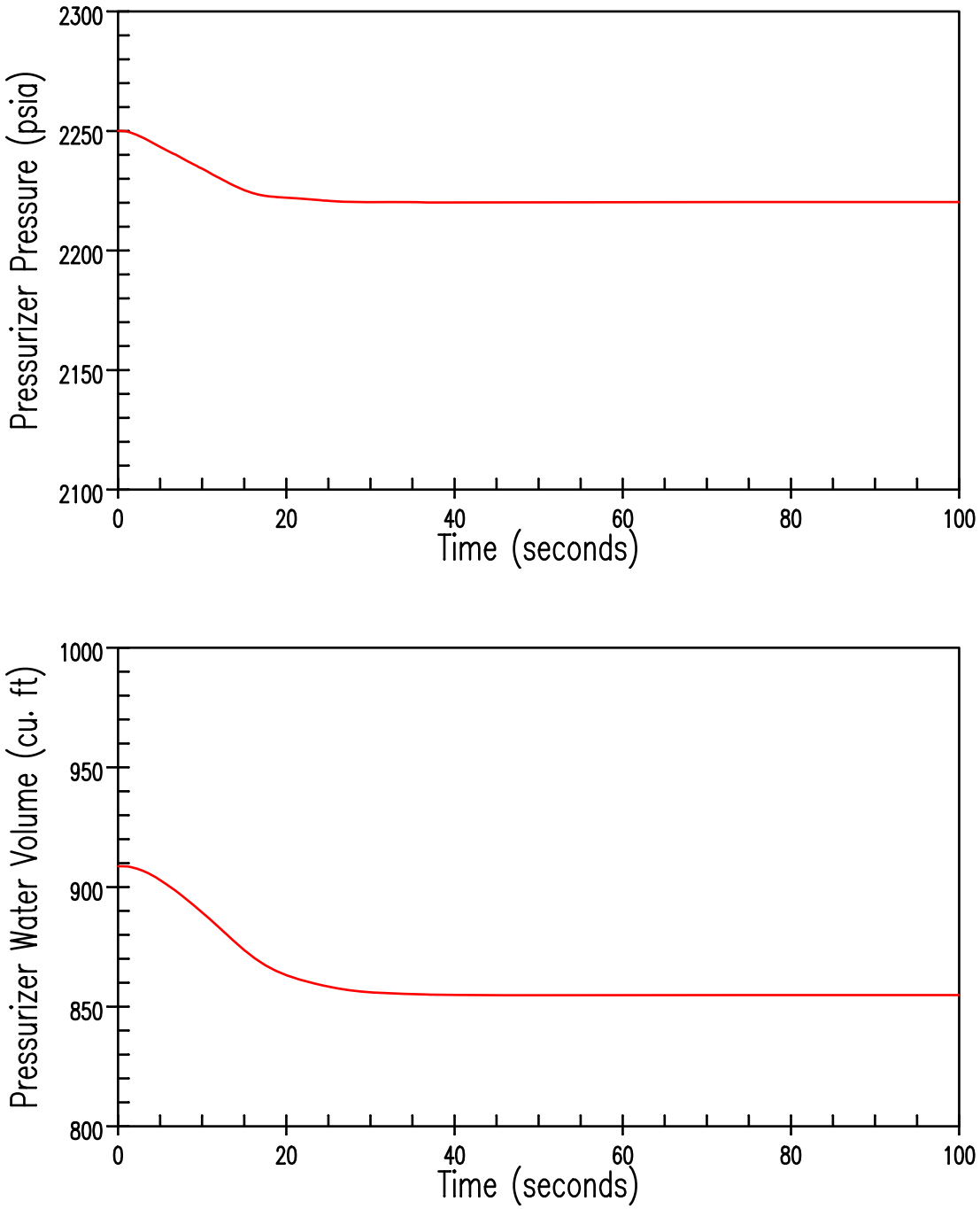
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-18

MAIN STEAM LINE RUPTURE AT FULL POWER, 0.49 ft^2 BREAK

NUCLEAR POWER AND CORE HEAT FLUX TRANSIENTS



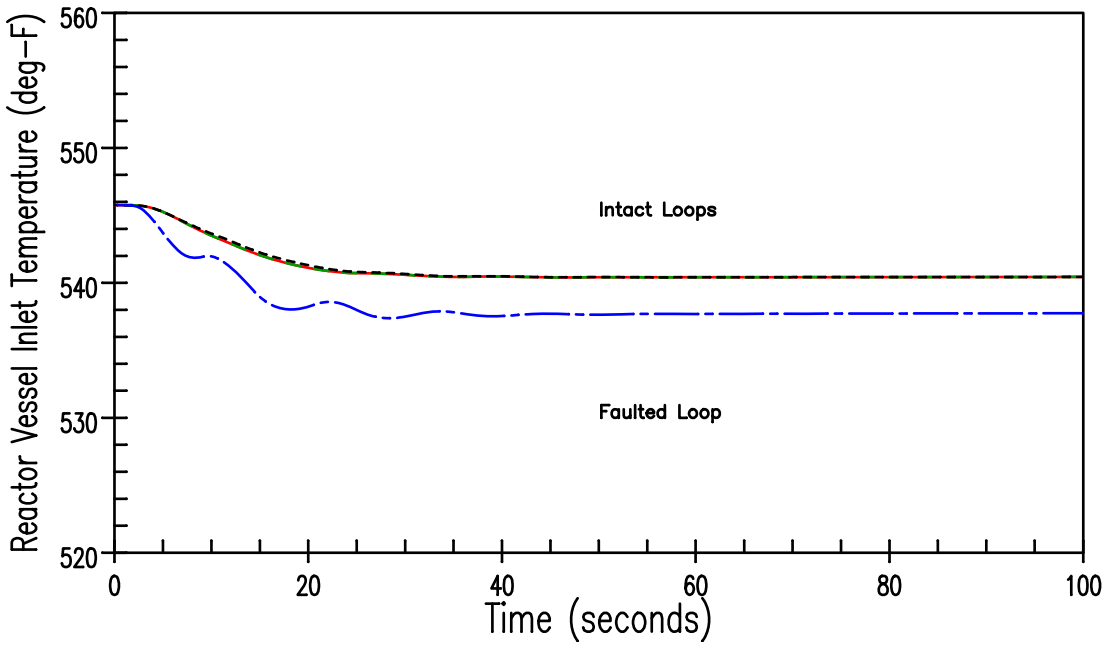
FSAR UPDATE

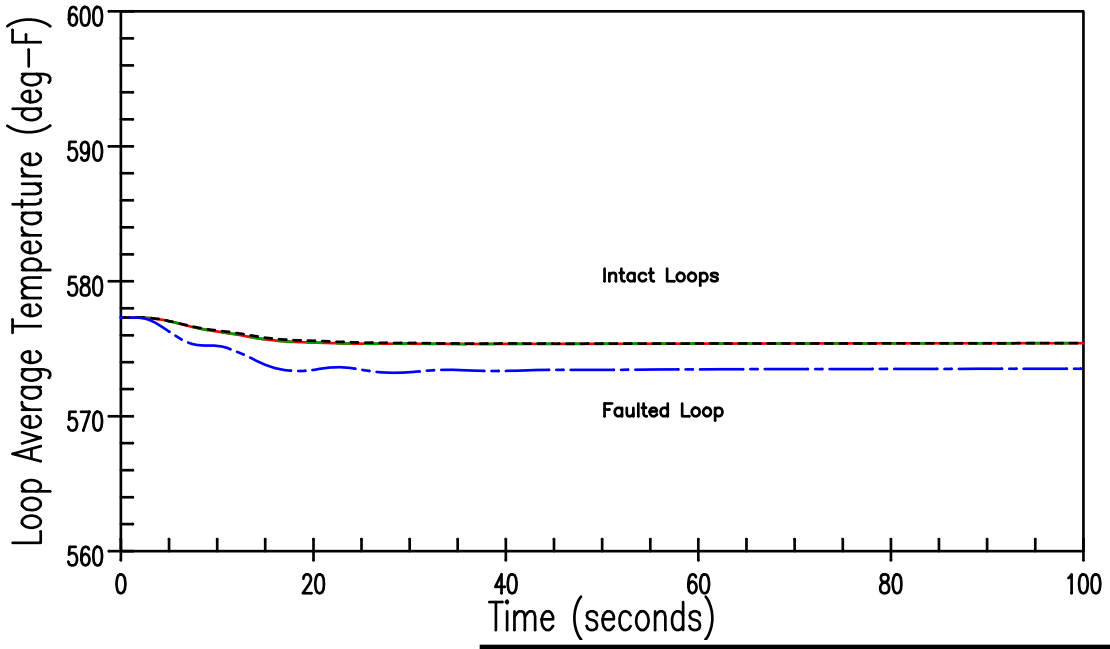
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-19

MAIN STEAM LINE RUPTURE AT FULL POWER, 0.49 ft^2 BREAK

PRESSURIZER PRESSURE AND WATER VOLUME TRANSIENTS





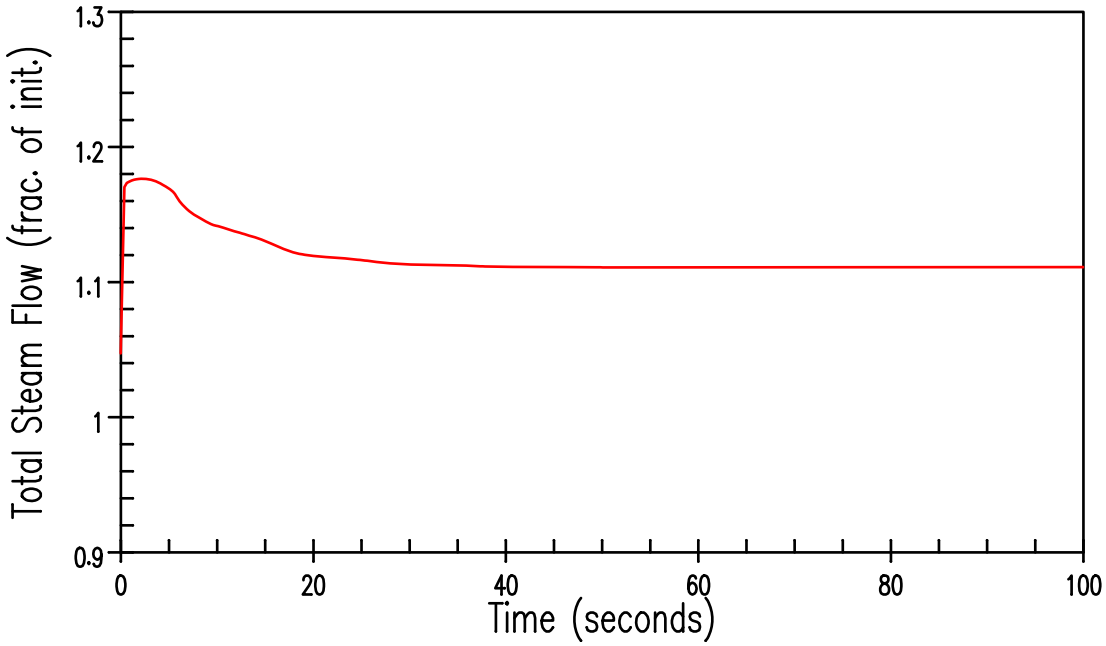
FSAR UPDATE

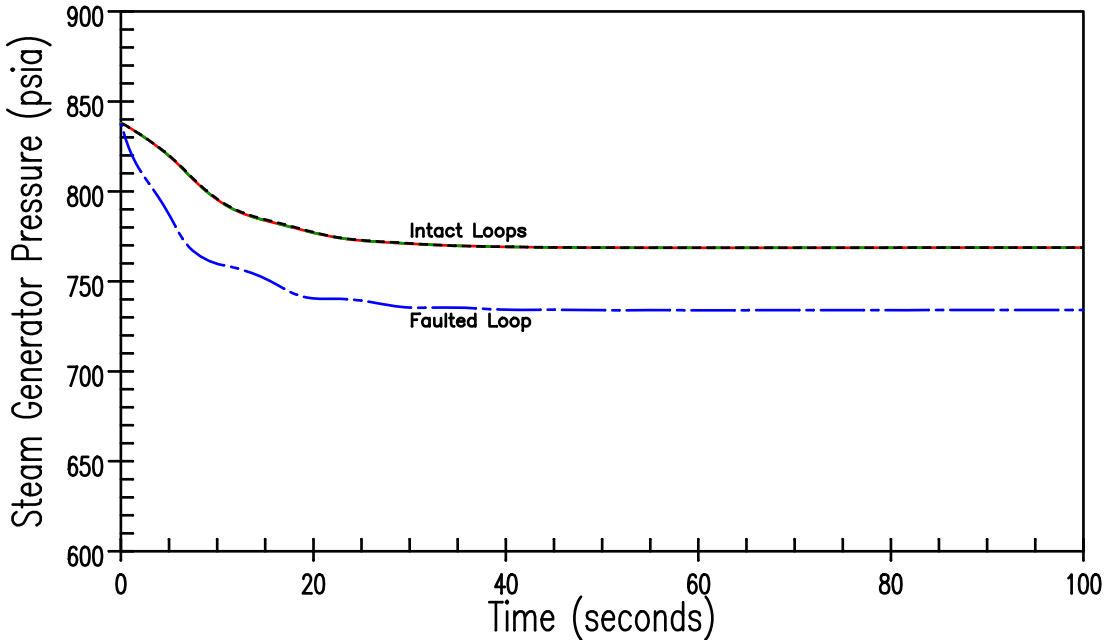
UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.2-20

MAIN STEAM LINE RUPTURE AT FULL POWER, 0.49 ft^2 BREAK

REACTOR VESSEL INLET TEMPERATURE AND LOOP AVERAGE TEMPERATURE TRANSIENTS





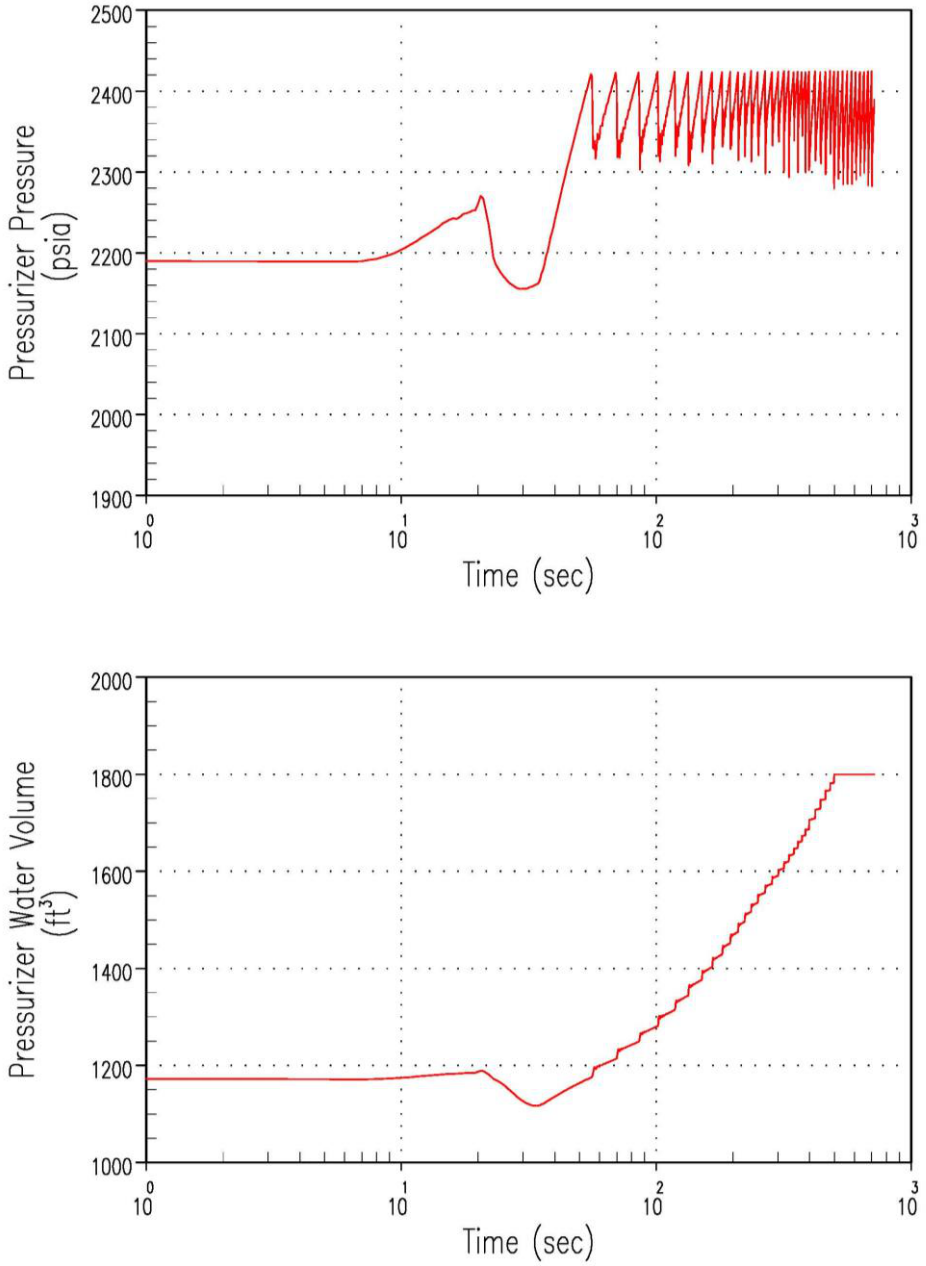
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

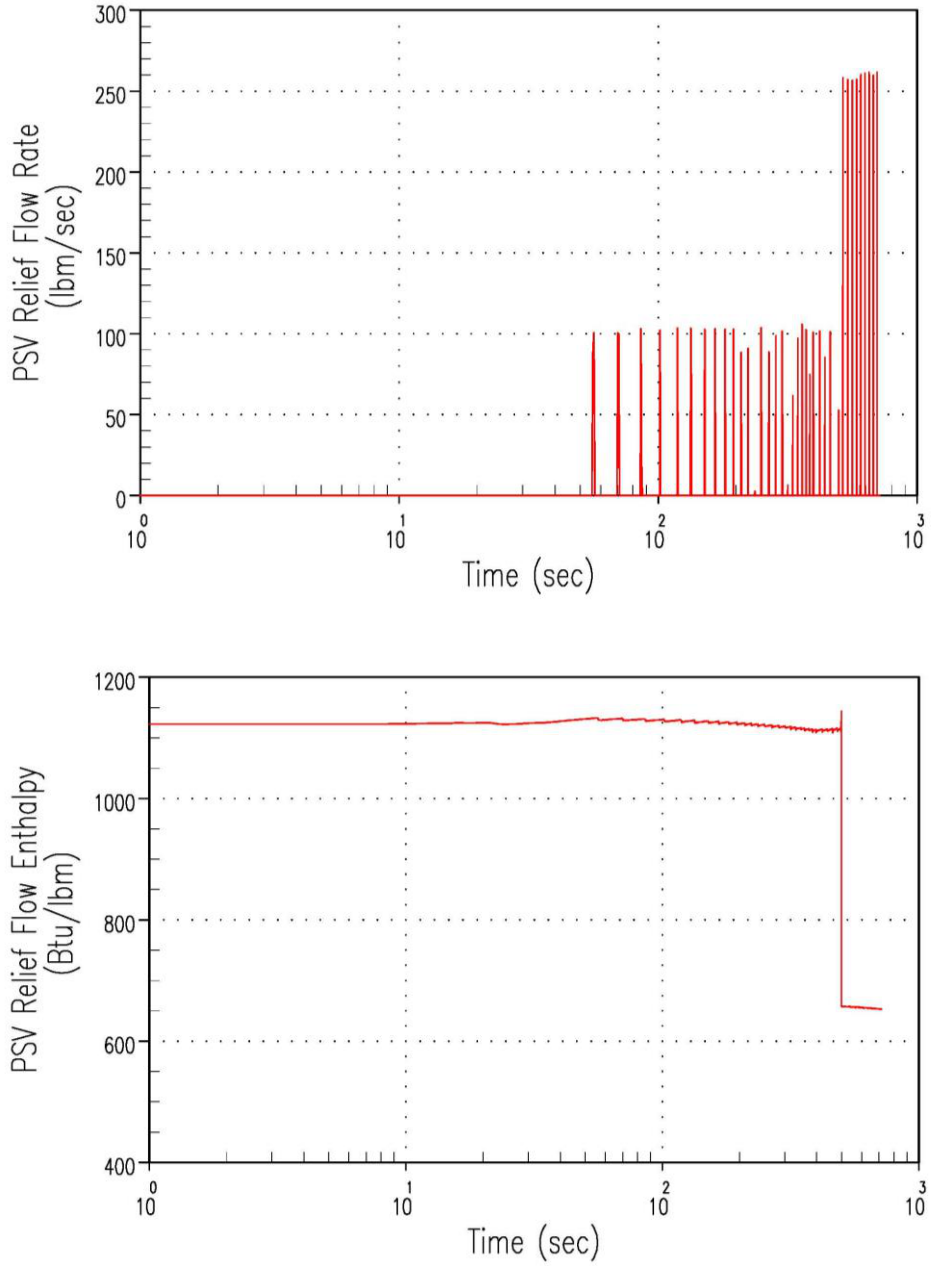
FIGURE 15.4.2-21

MAIN STEAM LINE RUPTURE AT FULL POWER, 0.49 ft^2 BREAK

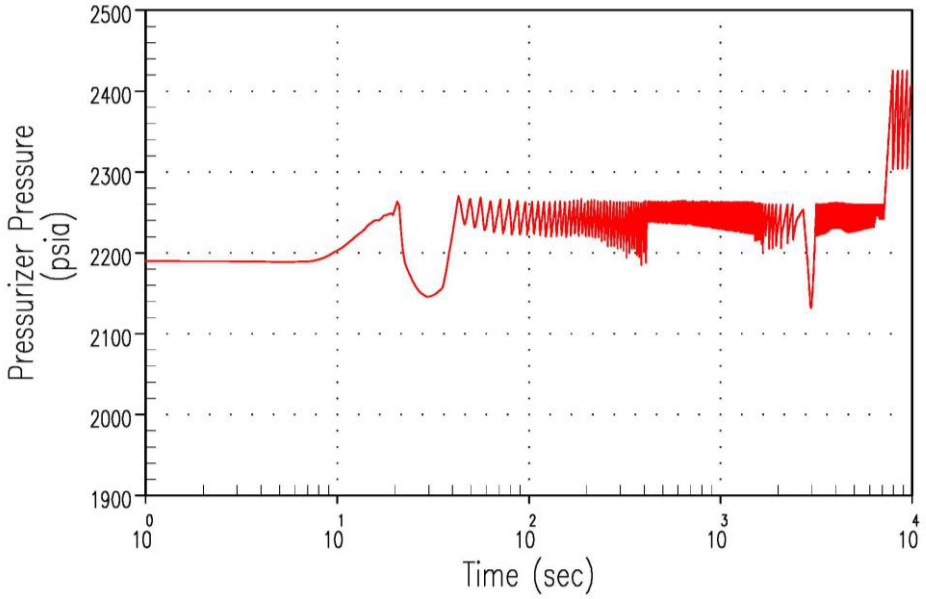
TOTAL STEAM FLOW AND STEAM PRESSURE TRANSIENTS

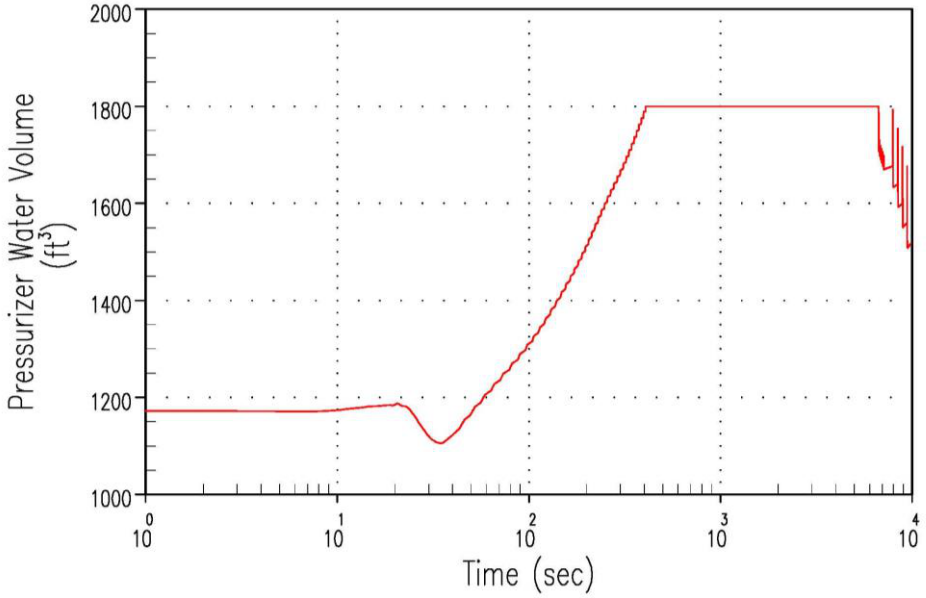


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.2-22 MAIN FEEDLINE RUPTURE FOR PRESSURIZER FILLING (UNBLOCK PRESSURIZER PORV) PRESSURIZER PRESSURE AND WATER VOLUME TRANSIENTS

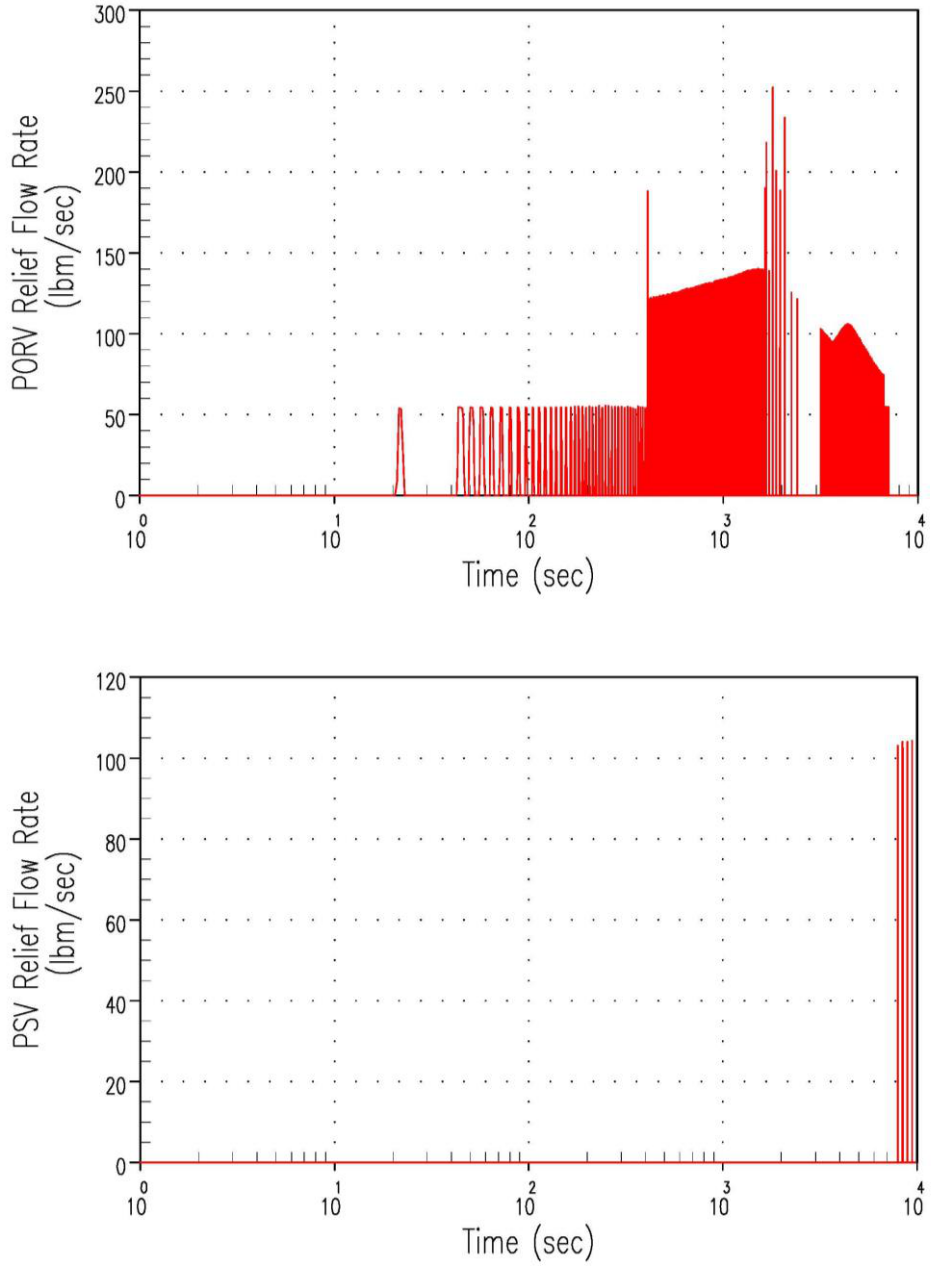


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.2-23 MAIN FEEDLINE RUPTURE FOR PRESSURIZER FILLING (UNBLOCK PRESSURIZER PORV) PSV RELIEF FLOW RATE AND ENTHALPY TRANSIENTS

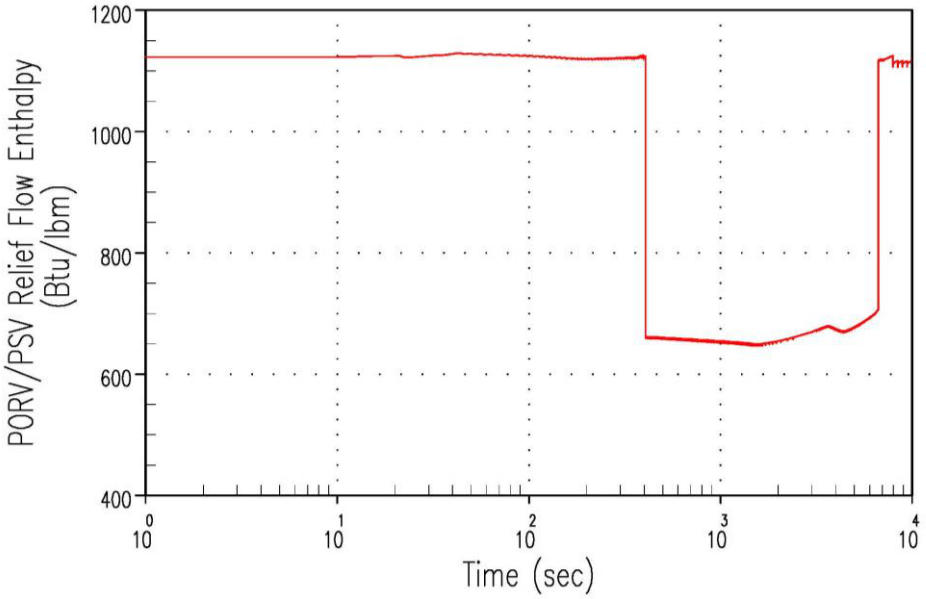


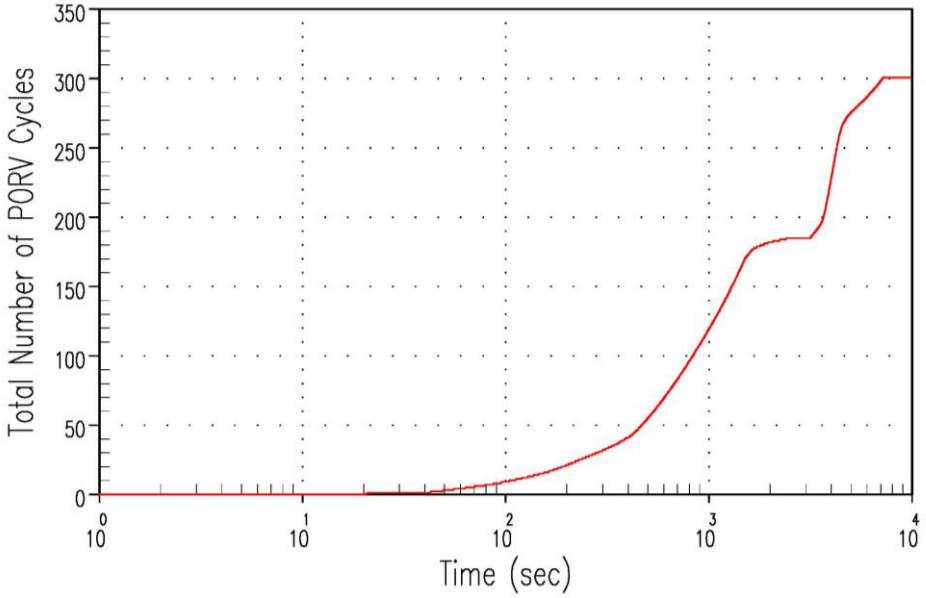


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.2-24 MAIN FEEDLINE RUPTURE FOR PRESSURIZER FILLING (ISOLATE CHARGING AND STOP RCP SEAL INJECTION FLOW) PRESSURIZER PRESSURE AND WATER VOLUME TRANSIENTS

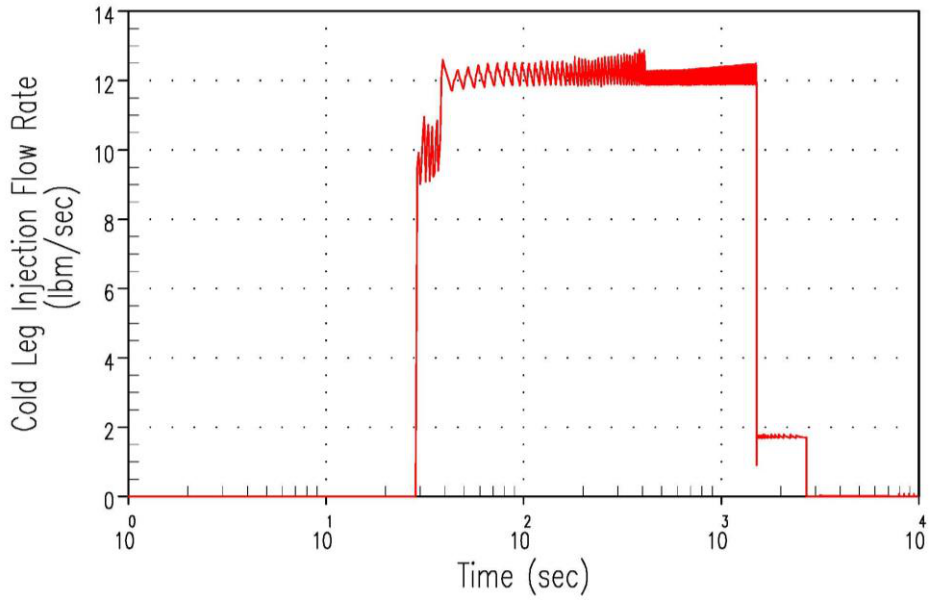


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.2-25 MAIN FEEDLINE RUPTURE FOR PRESSURIZER FILLING (ISOLATE CHARGING AND STOP RCP SEAL INJECTION FLOW) PORV AND PSV RELIEF FLOW RATE TRANSIENTS

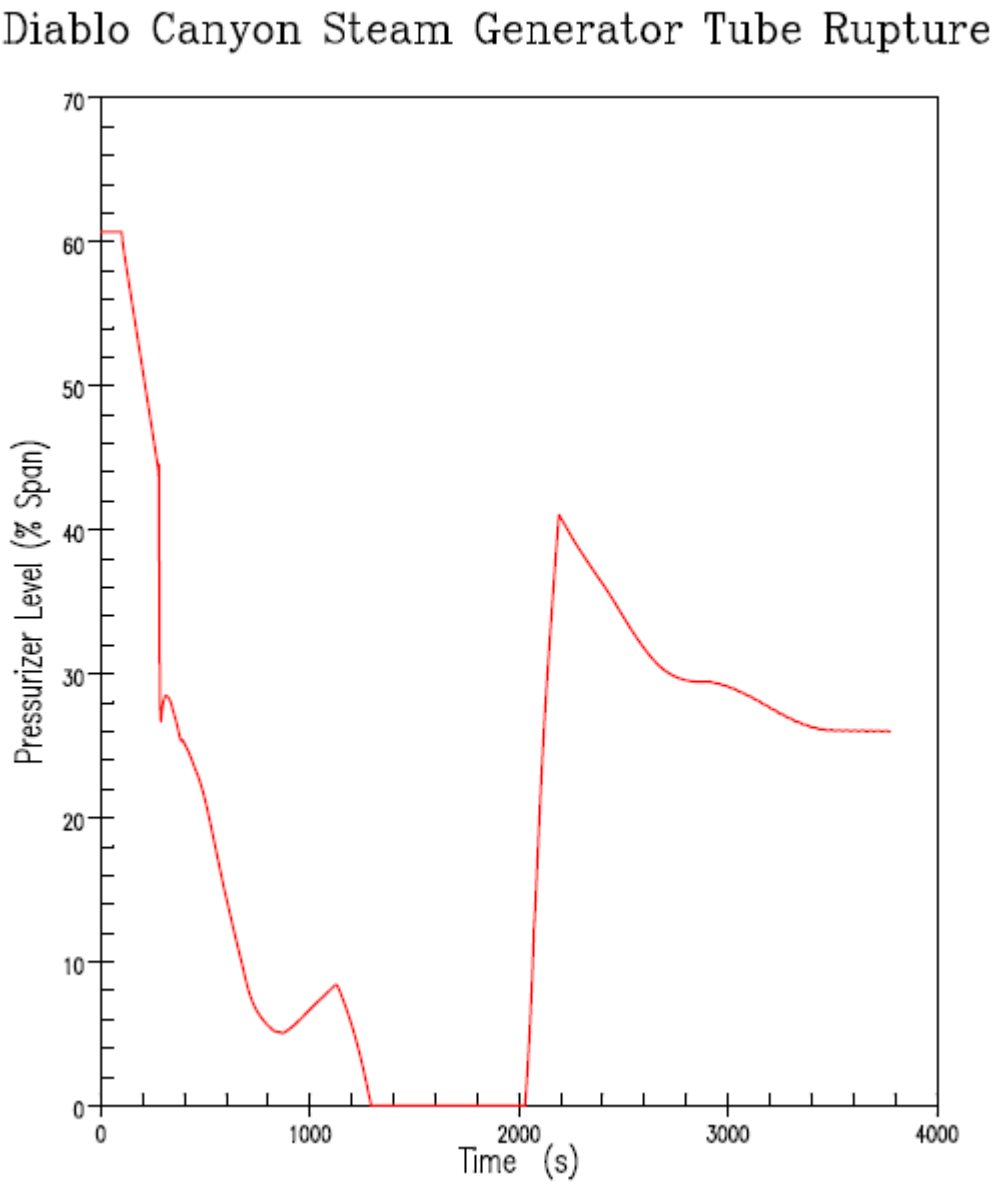




FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.2-26 MAIN FEEDLINE RUPTURE FOR PRESSURIZER FILLING (ISOLATE CHARGING AND STOP RCP SEAL INJECTION FLOW) PORV/PSV RELIEF FLOW ENTHALPY AND TOTAL NUMBER OF PORV CYCLES TRANSIENTS

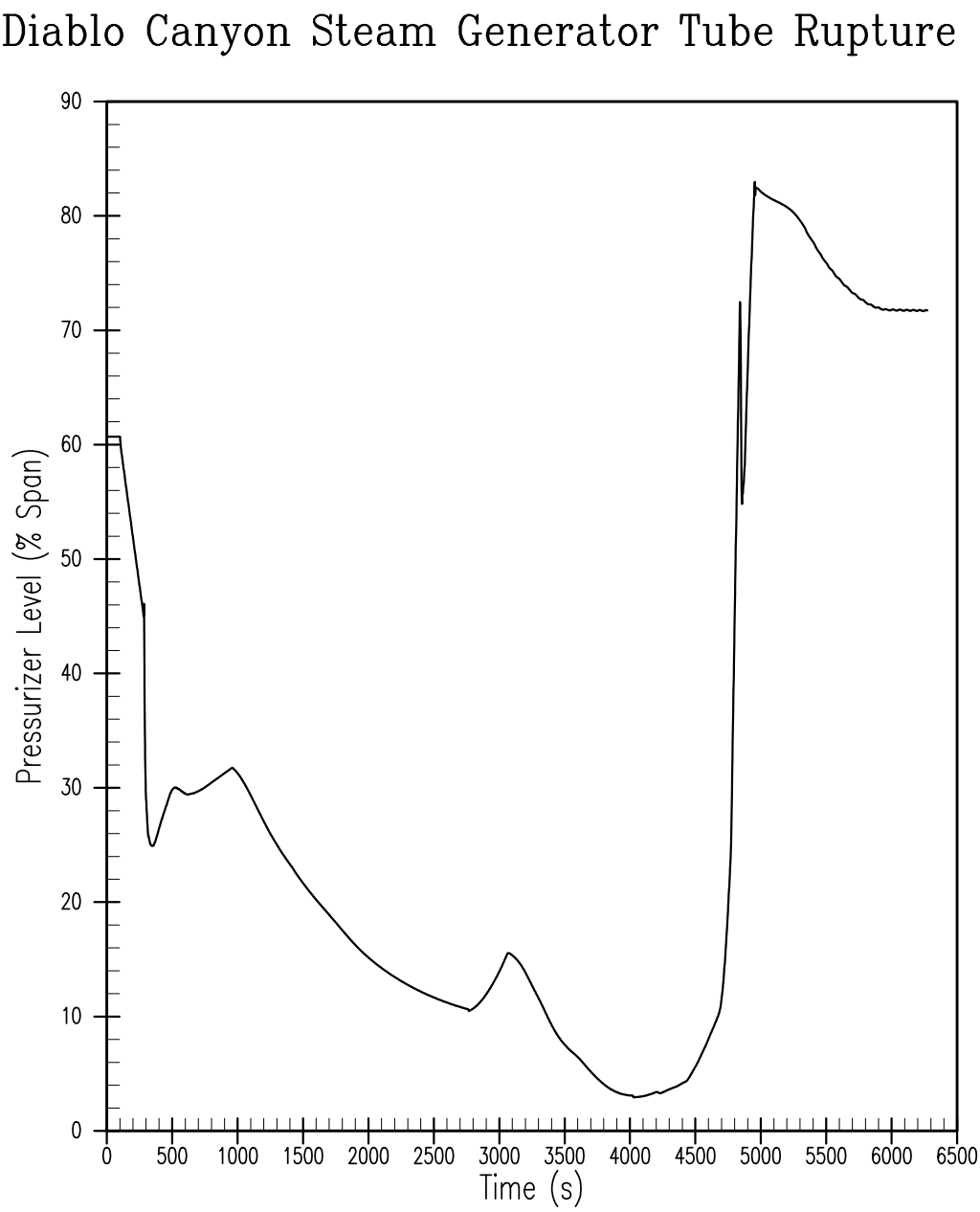


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.2-27 MAIN FEEDLINE RUPTURE FOR PRESSURIZER FILLING (ISOLATE CHARGING AND STOP RCP SEAL INJECTION FLOW) COLD LEG INJECTION FLOW RATE TRANSIENT



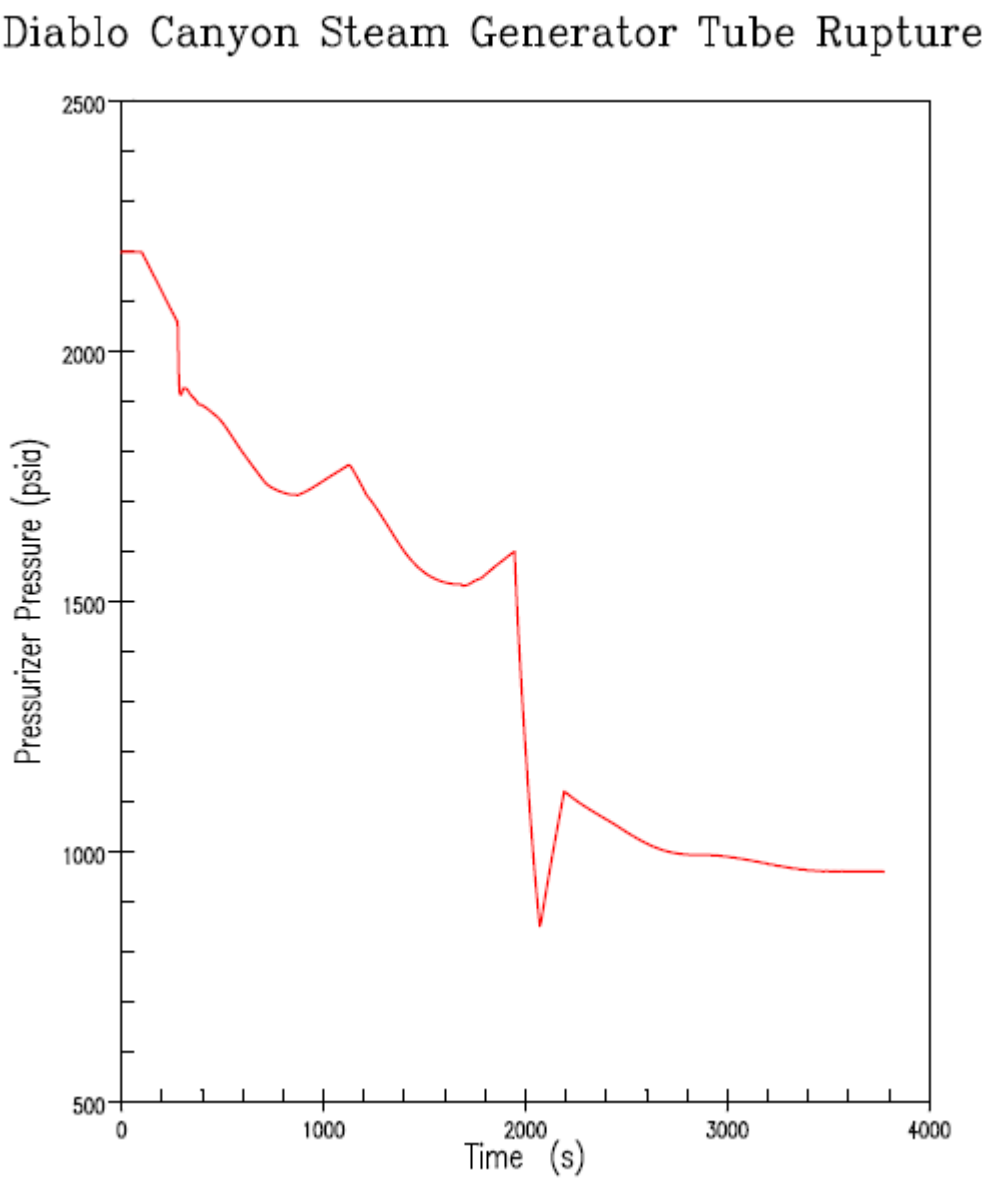
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-1A PRESSURIZER LEVEL SGTR MTO ANALYSIS

Revision 20 November 2011

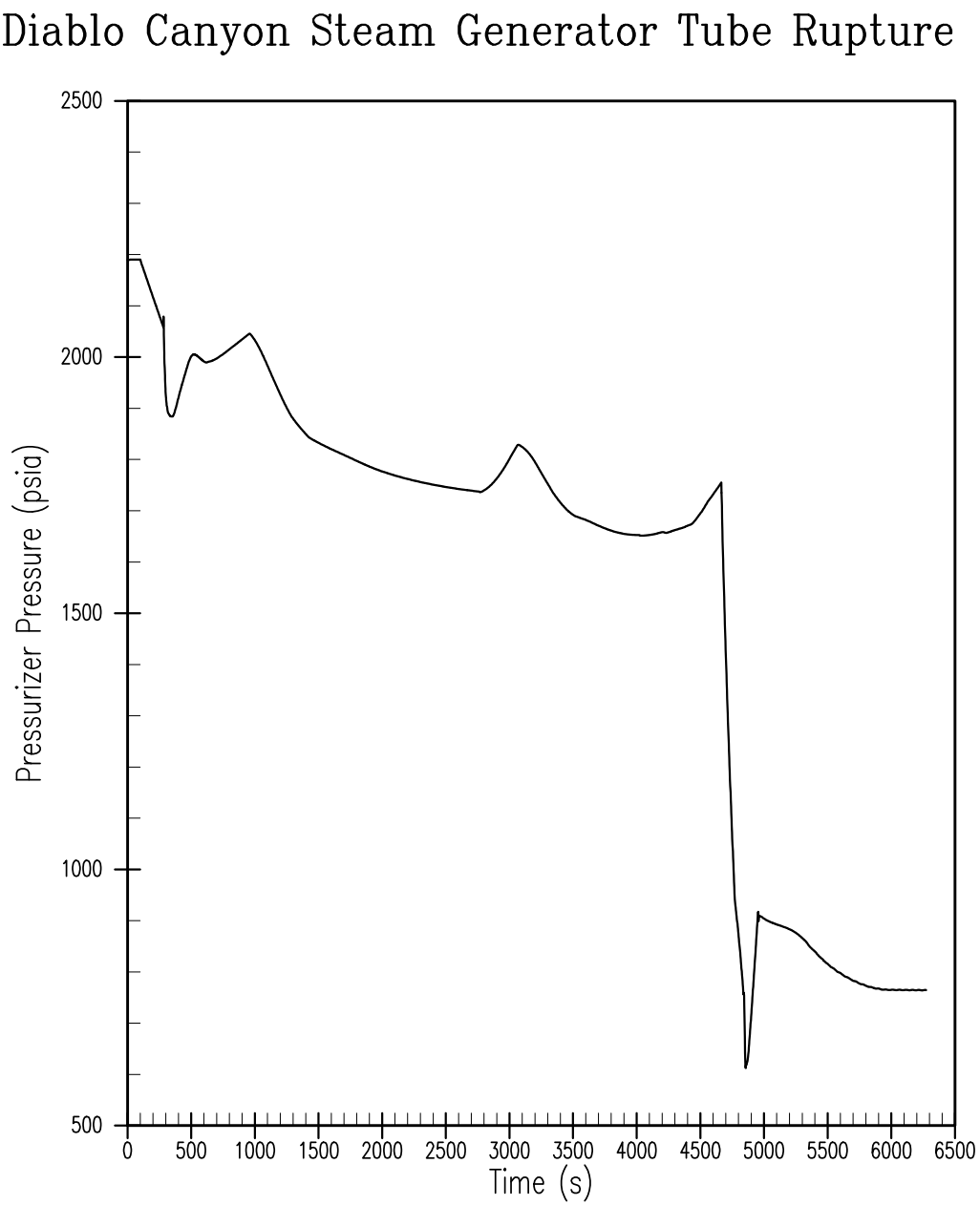


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-1B PRESSURIZER LEVEL SGTR DOSE INPUT ANALYSIS

Revision 21 September 2013

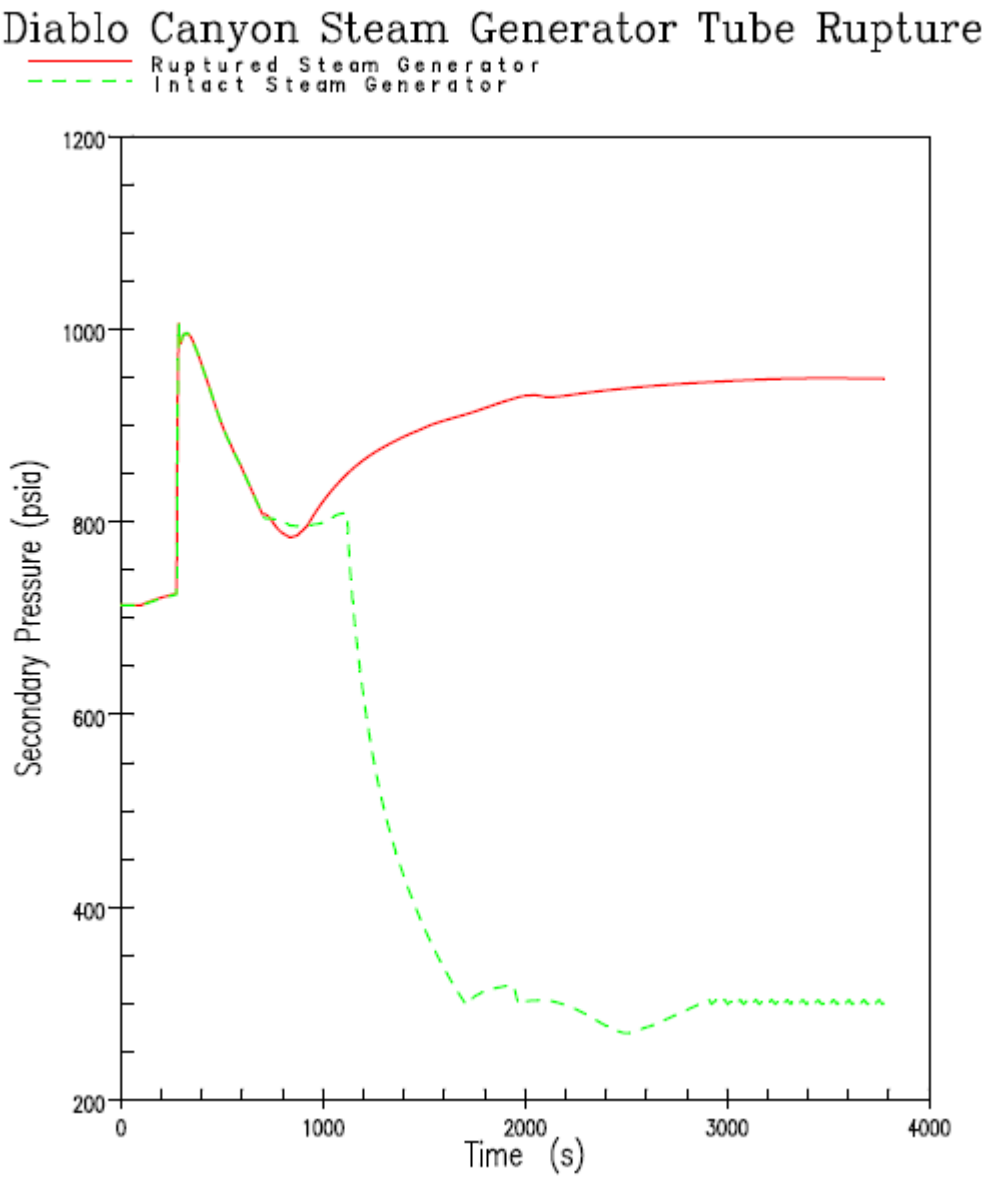


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-2A PRESSURIZER PRESSURE SGTR MTO ANALYSIS



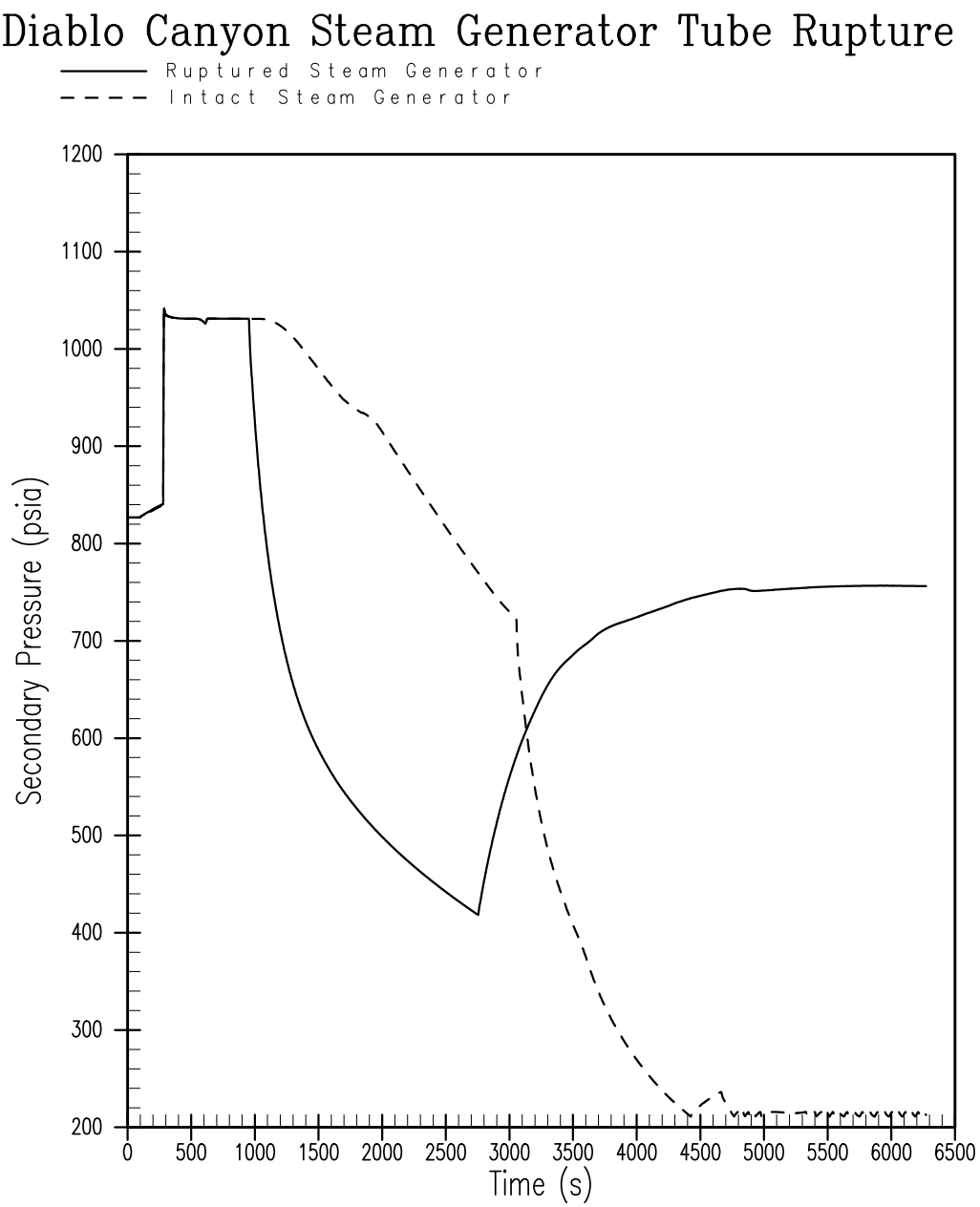
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-2B PRESSURIZER PRESSURE SGTR DOSE INPUT ANALYSIS

Revision 21 September 2013



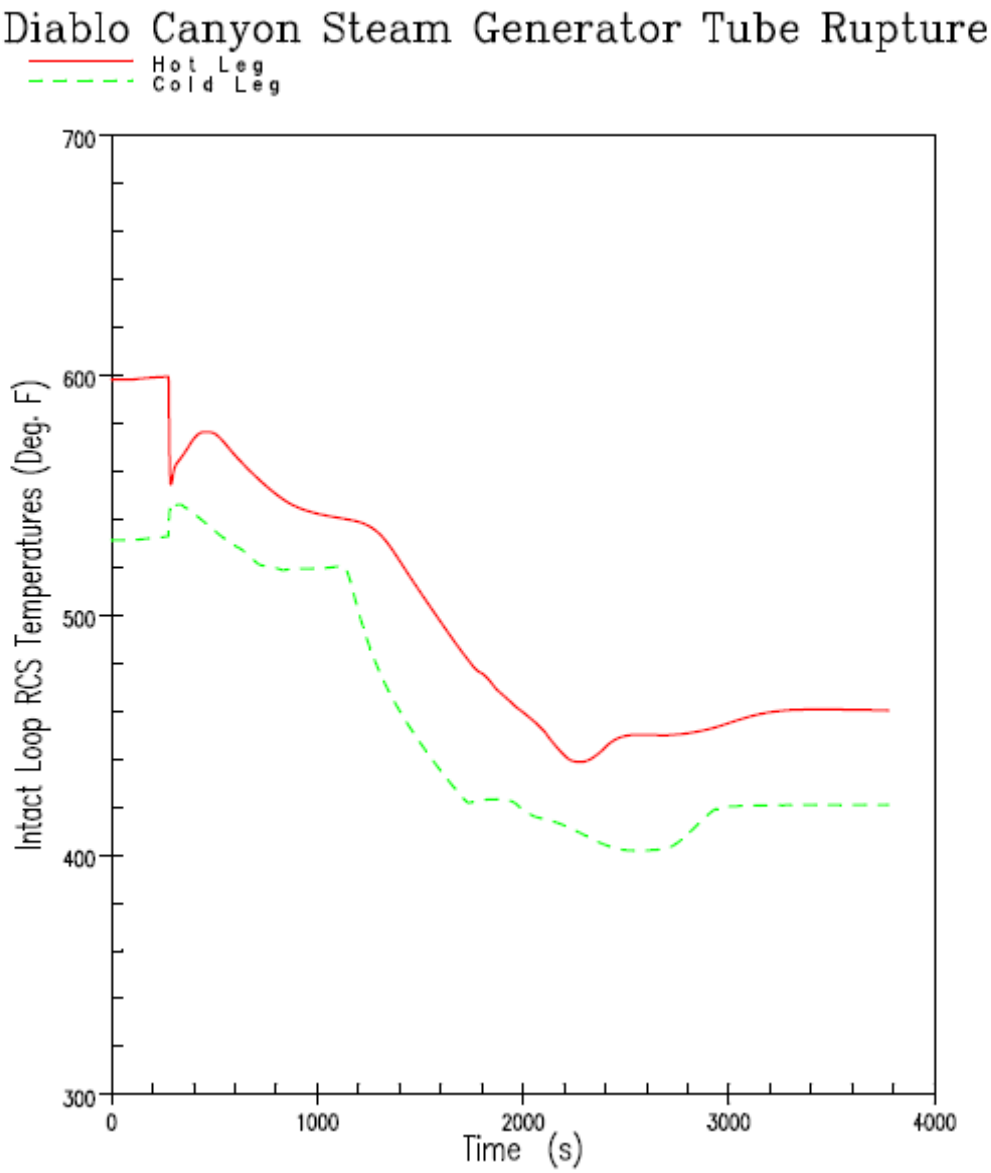
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-3A SECONDARY PRESSURE SGTR MTO ANALYSIS

Revision 20 November 2011

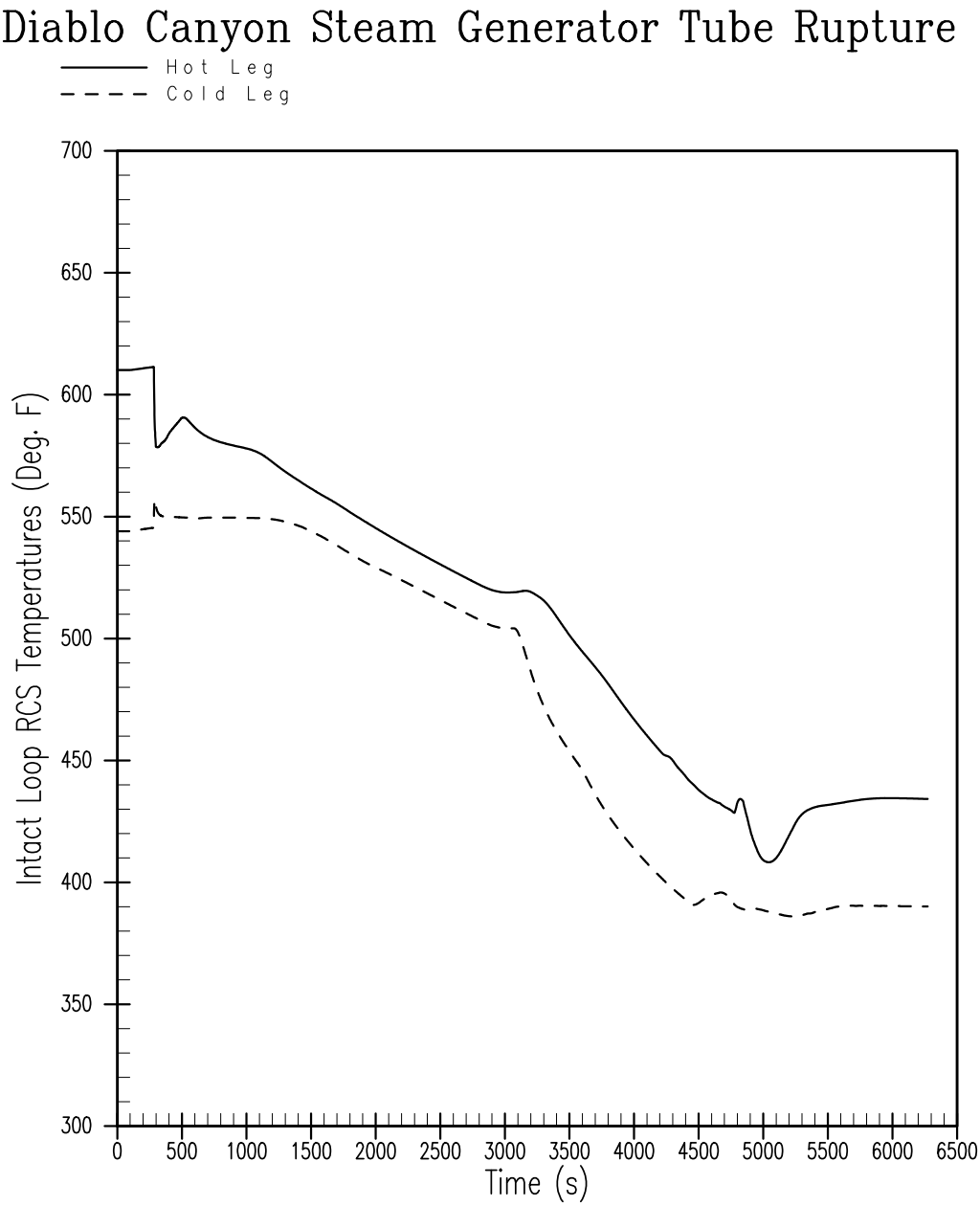


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-3B SECONDARY PRESSURE SGTR DOSE INPUT ANALYSIS

Revision 21 September 2013



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-4A INTACT LOOP HOT AND COLD LEG RCS TEMPERATURES SGTR MTO ANALYSIS



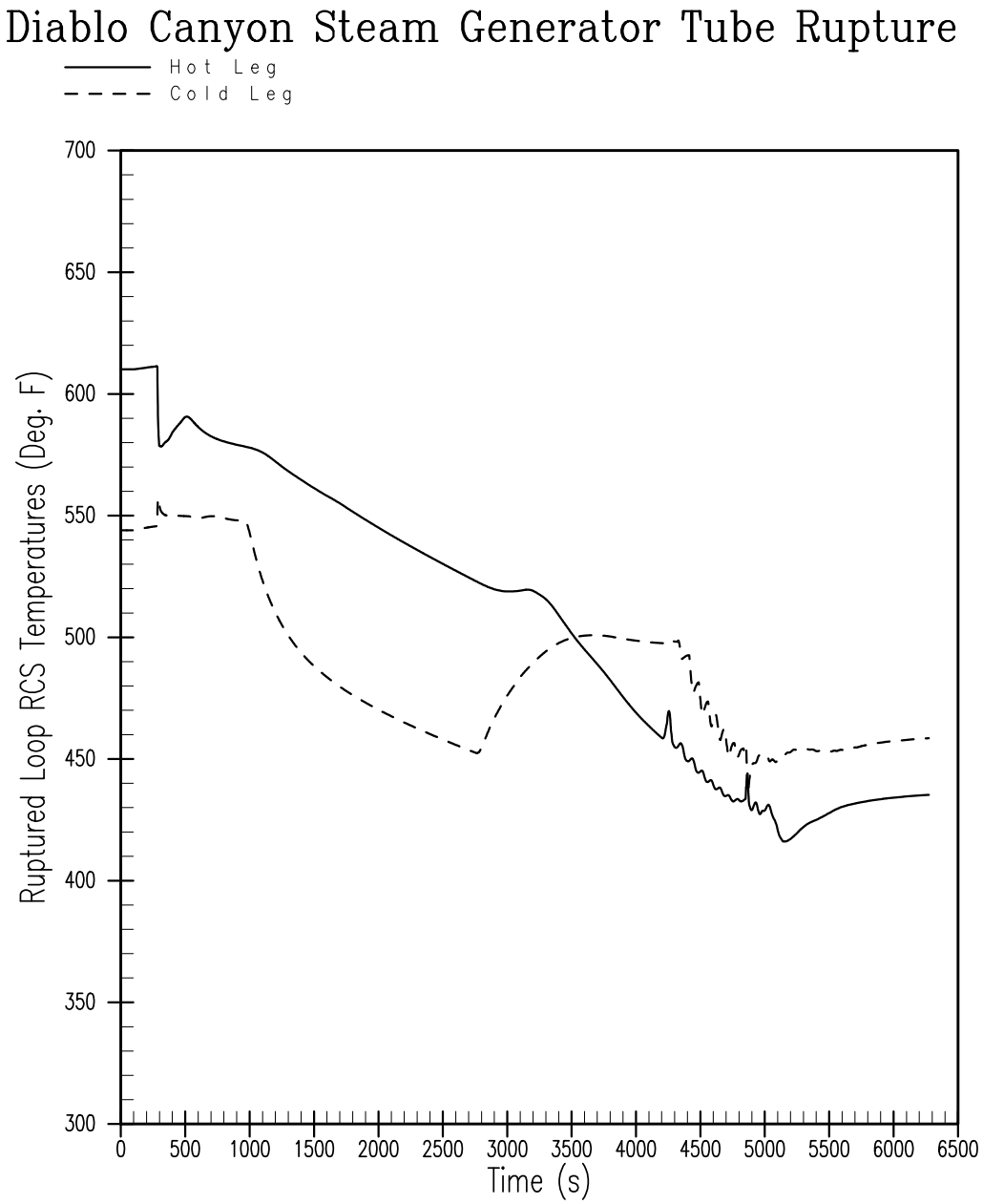
FSAR UPDATE

UNITS 1 AND 2
DIABLO CANYON SITE

FIGURE 15.4.3-4B

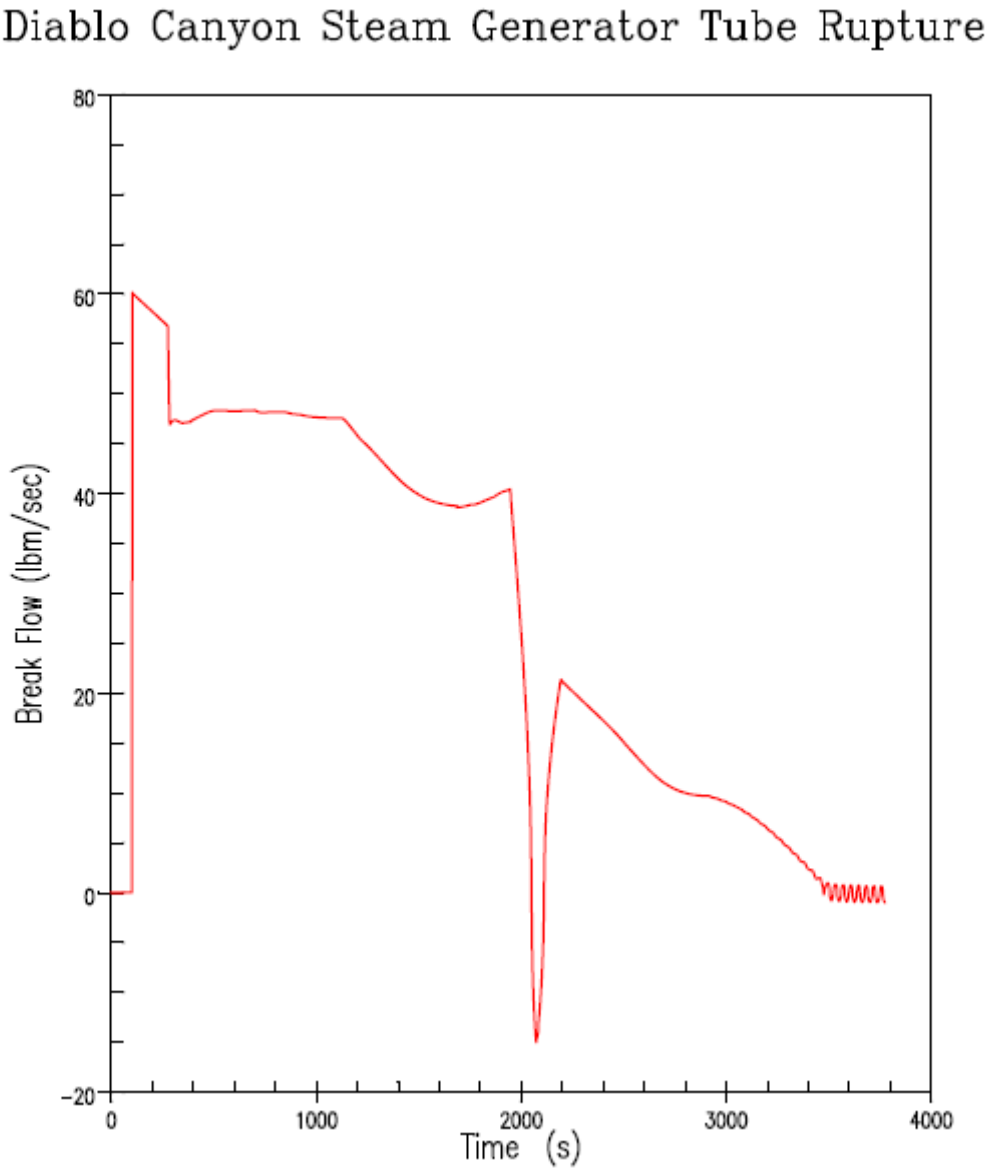
INTACT LOOP HOT AND COLD LEG RCS TEMPERATURES SGTR DOSE INPUT ANALYSIS

Revision 21 September 2013



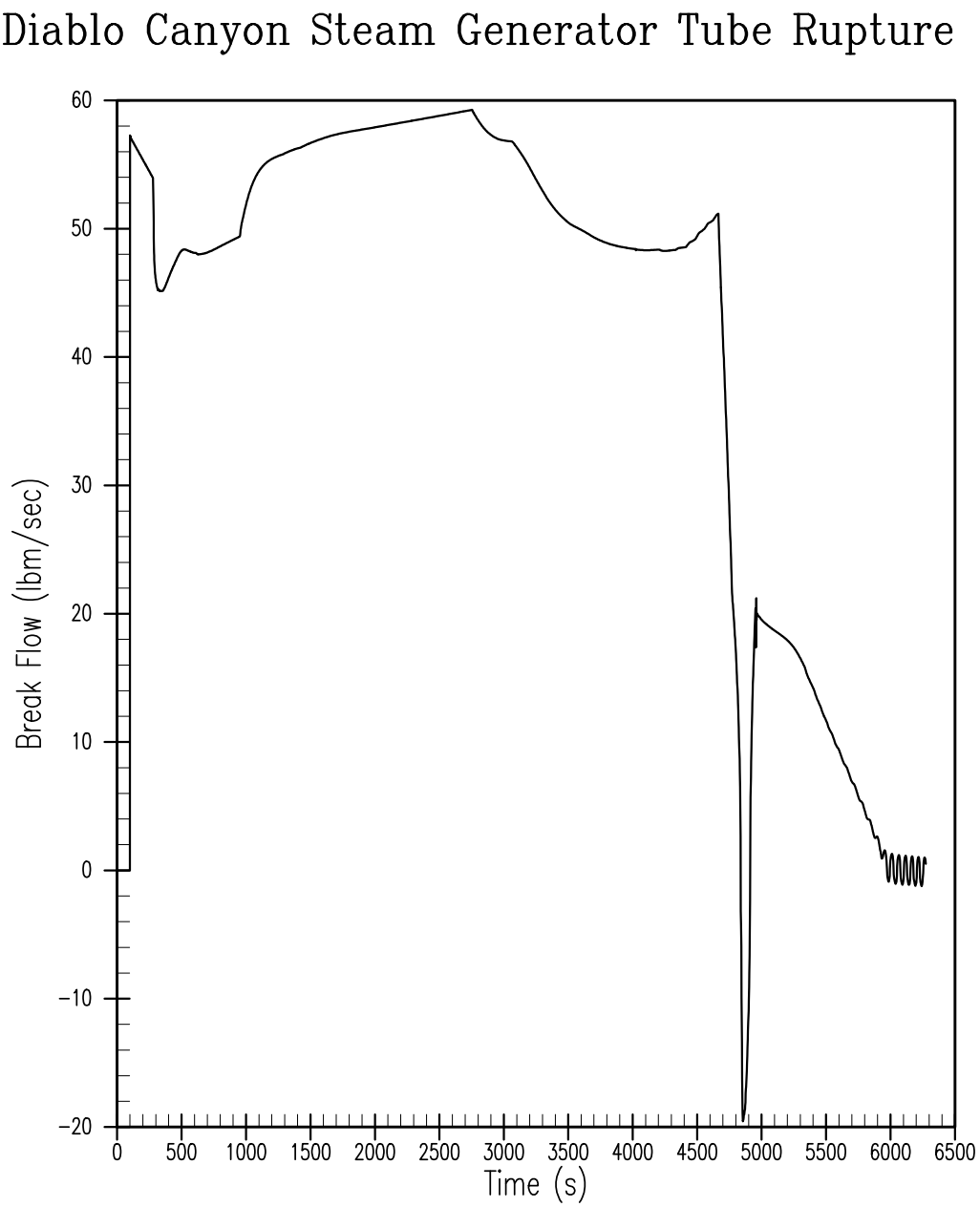
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-5B RUPTURED LOOP HOT AND COLD LEG RCS TEMPERATURES SGTR DOSE INPUT ANALYSIS

Revision 21 September 2013



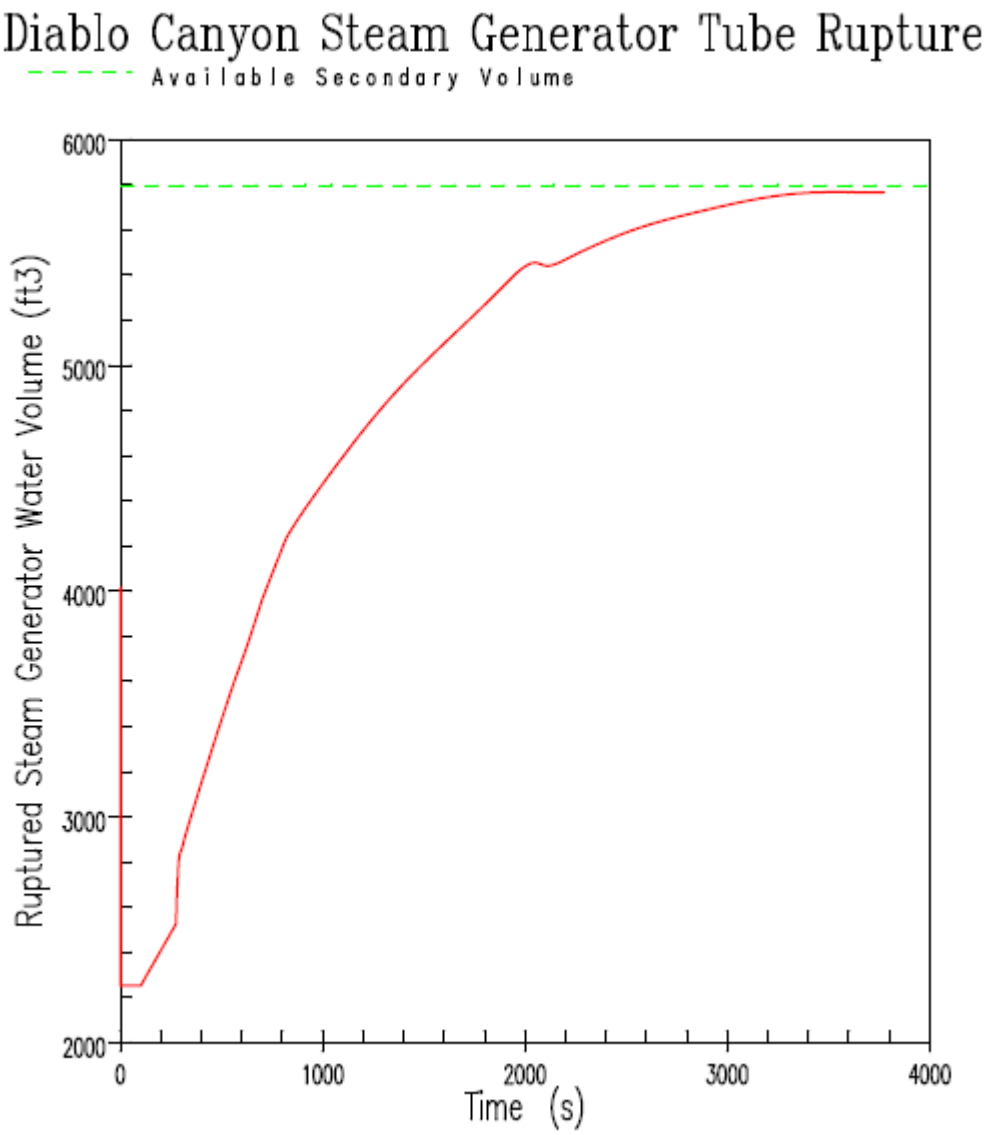
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-6A PRIMARY TO SECONDARY BREAK FLOW RATE SGTR MTO ANALYSIS

Revision 20 November 2011



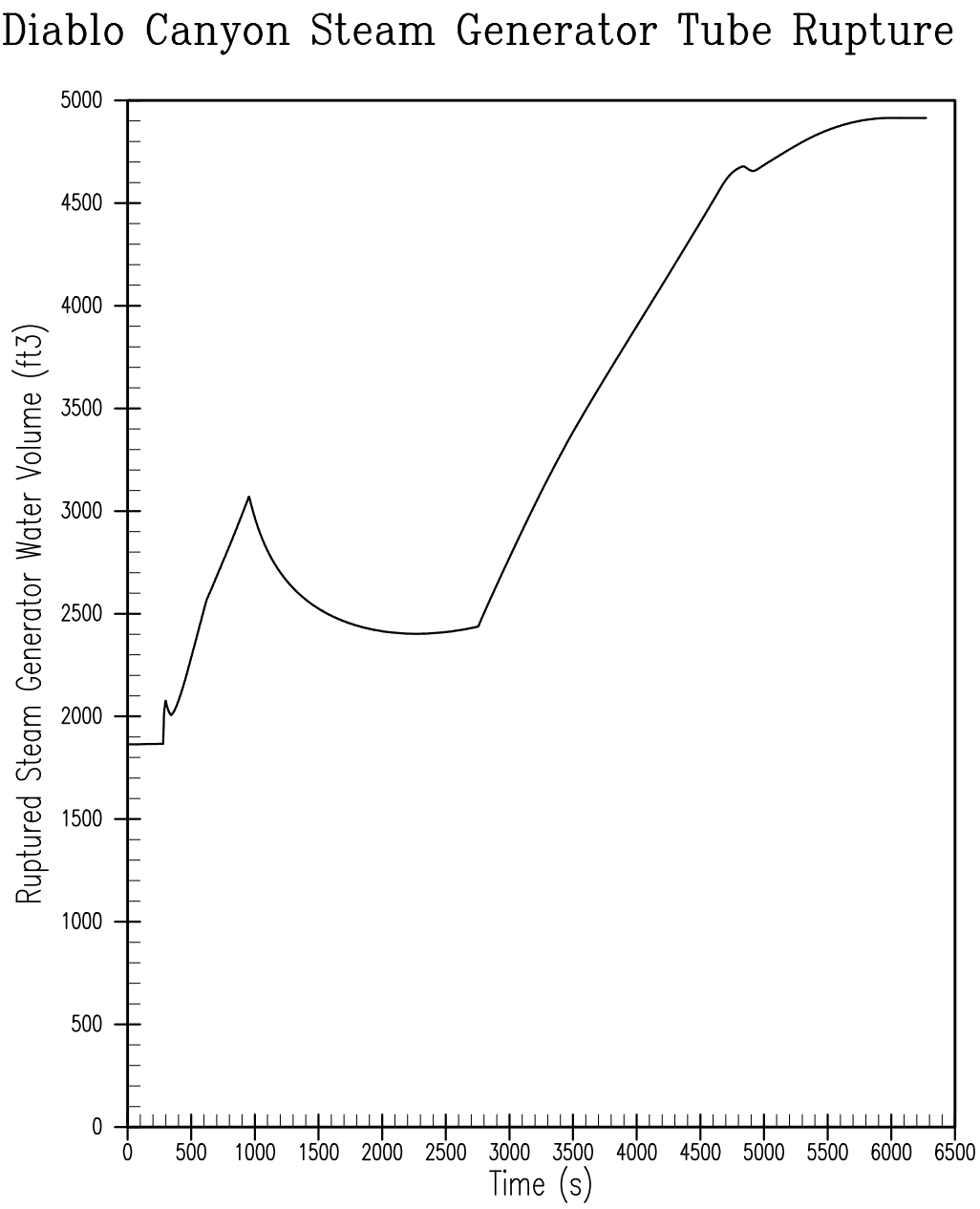
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-6B PRIMARY TO SECONDARY BREAK FLOW RATE SGTR DOSE INPUT ANALYSIS

Revision 21 September 2013



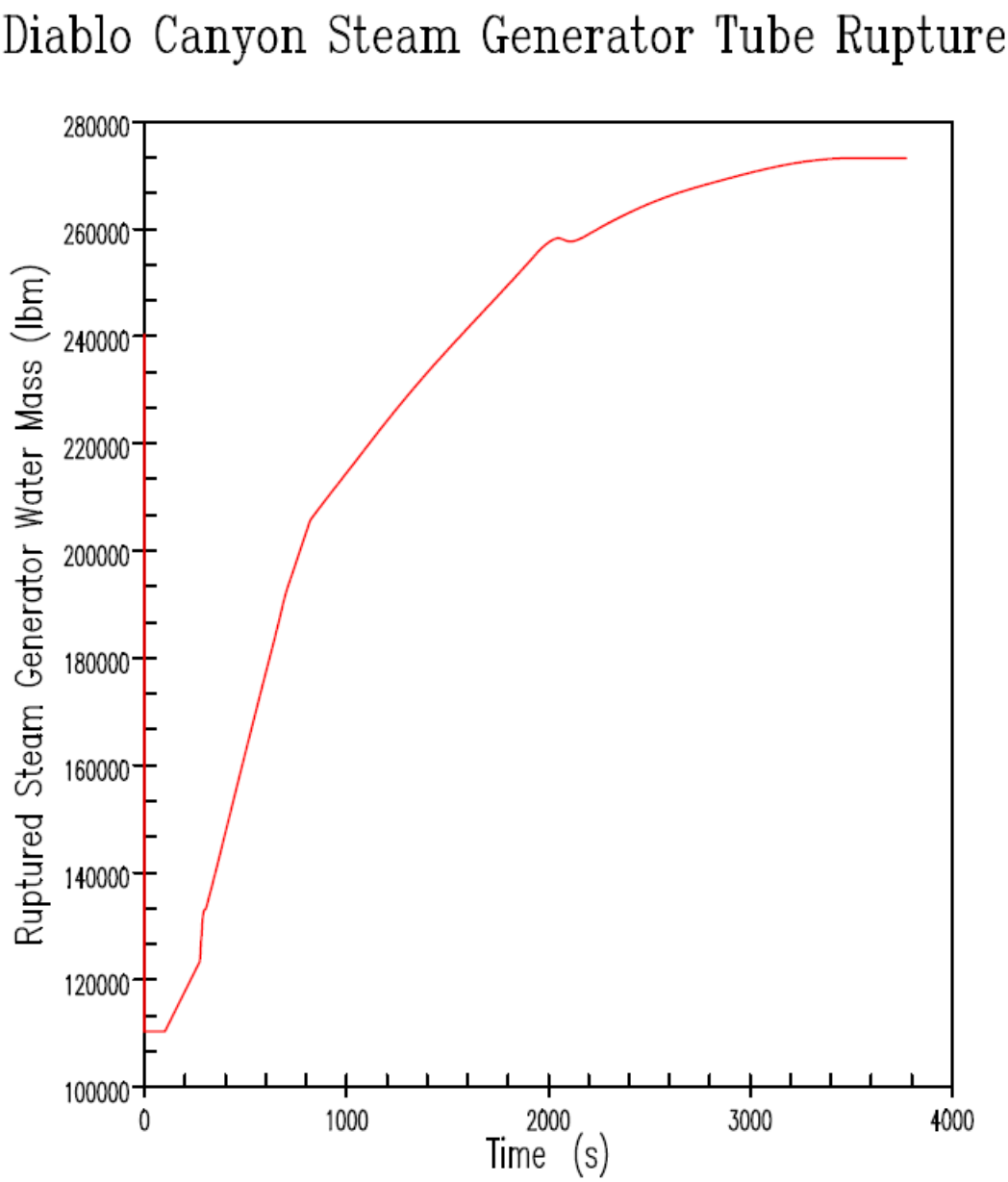
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-7A RUPTURED STEAM GENERATOR WATER VOLUME SGTR MTO ANALYSIS

Revision 20 November 2011



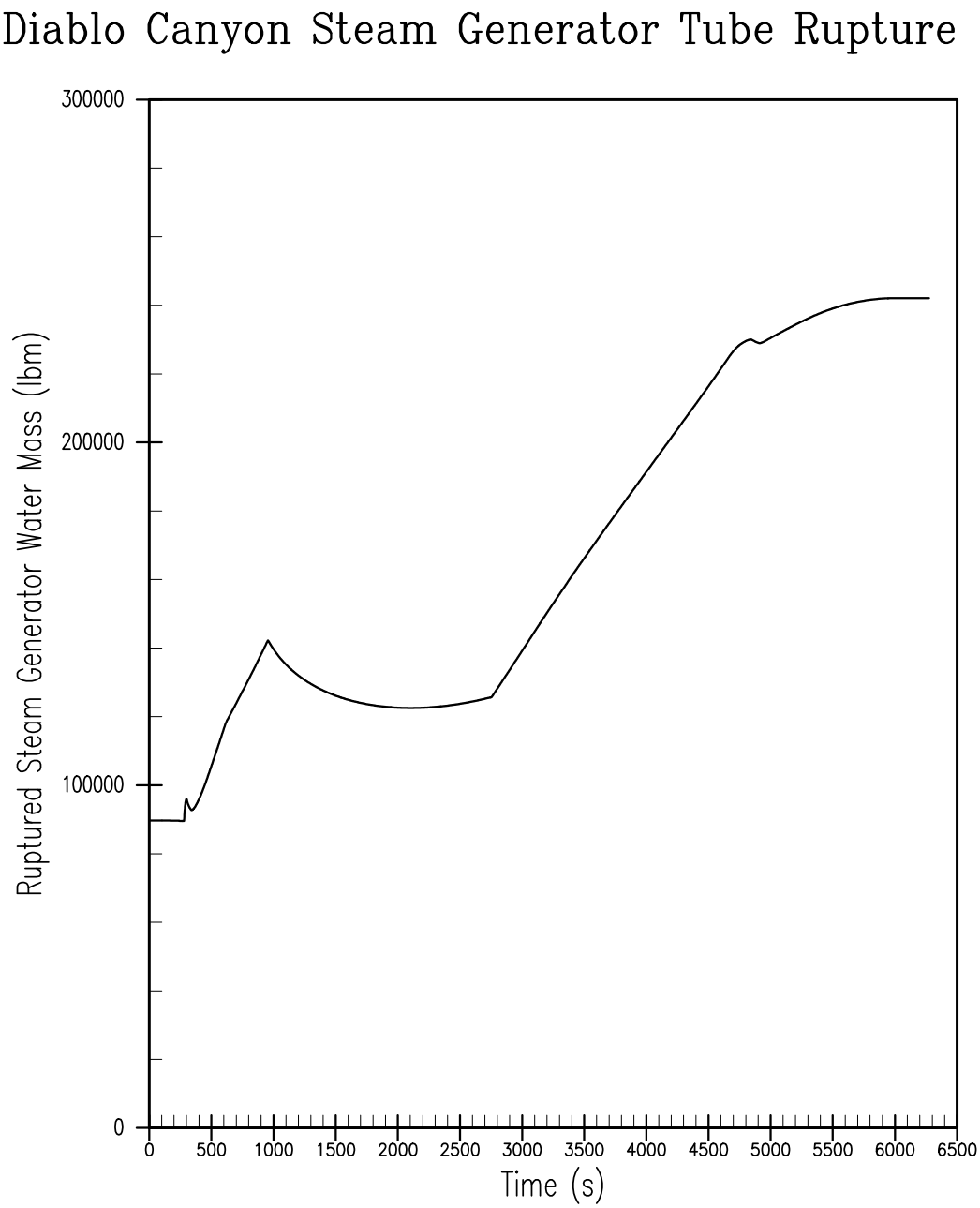
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-7B RUPTURED STEAM GENERATOR WATER VOLUME SGTR DOSE INPUT ANALYSIS

Revision 21 September 2013



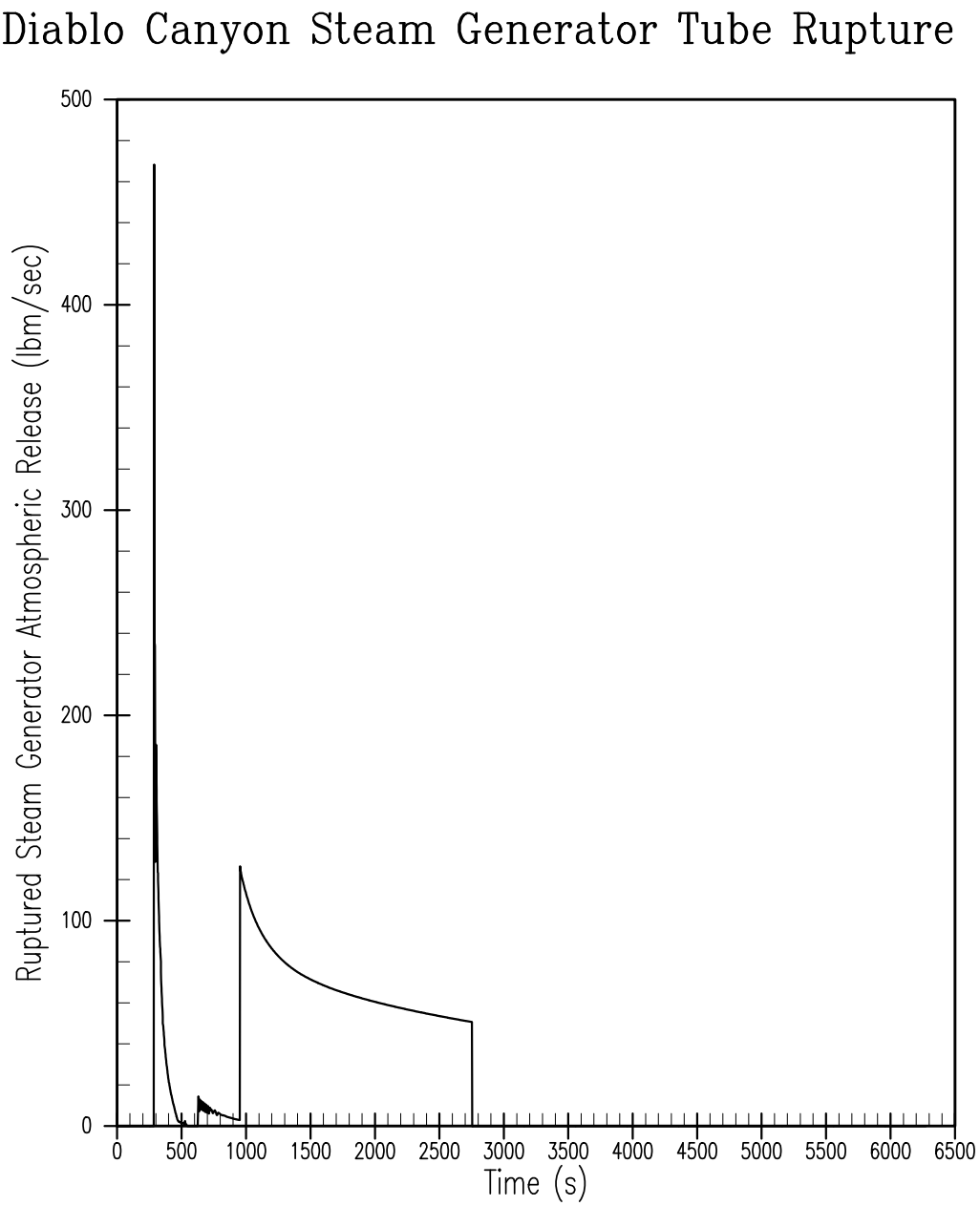
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-8A RUPTURED STEAM GENERATOR WATER MASS SGTR MTO ANALYSIS

Revision 20 November 2011



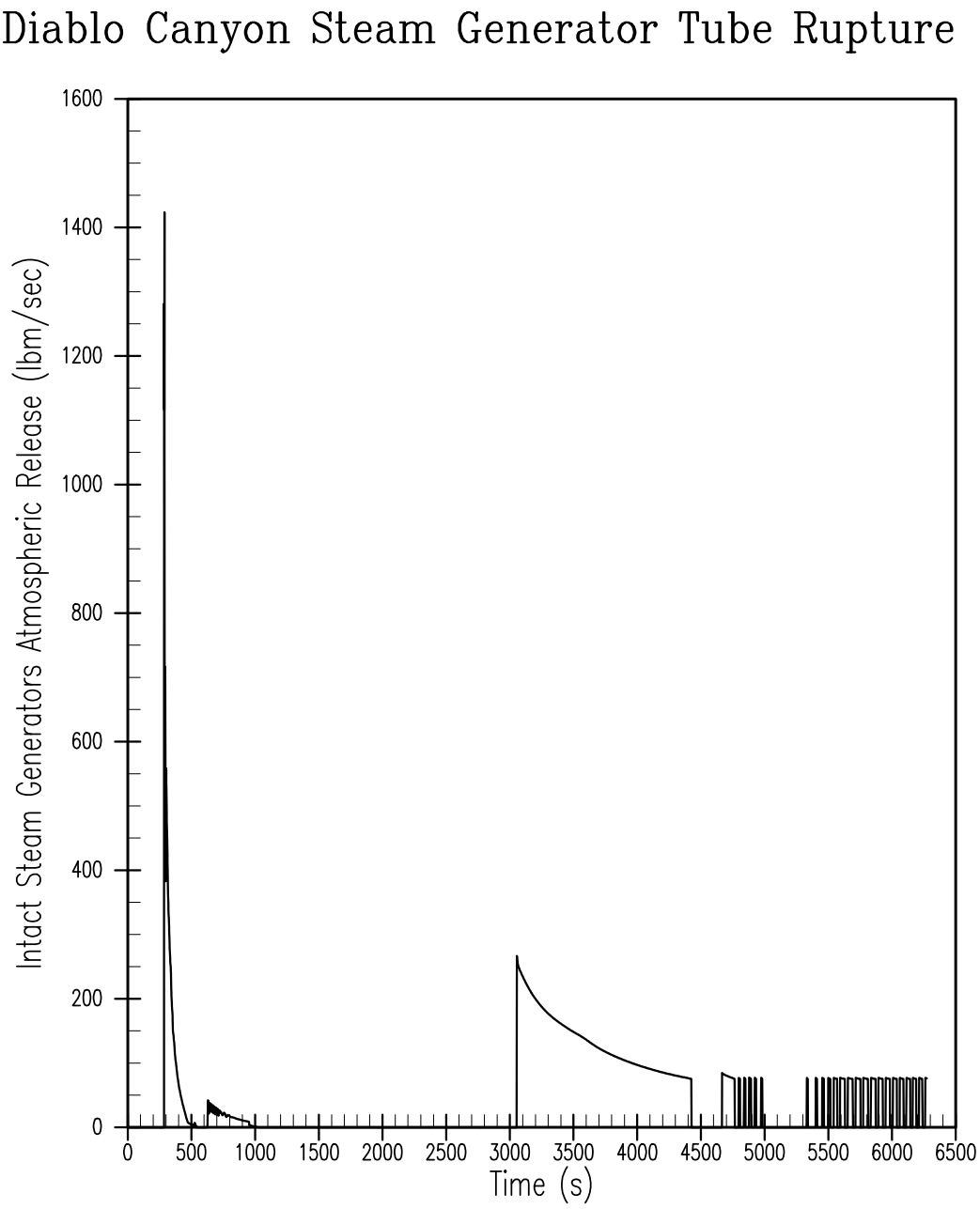
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-8B RUPTURED STEAM GENERATOR WATER MASS SGTR DOSE INPUT ANALYSIS

Revision 21 September 2013



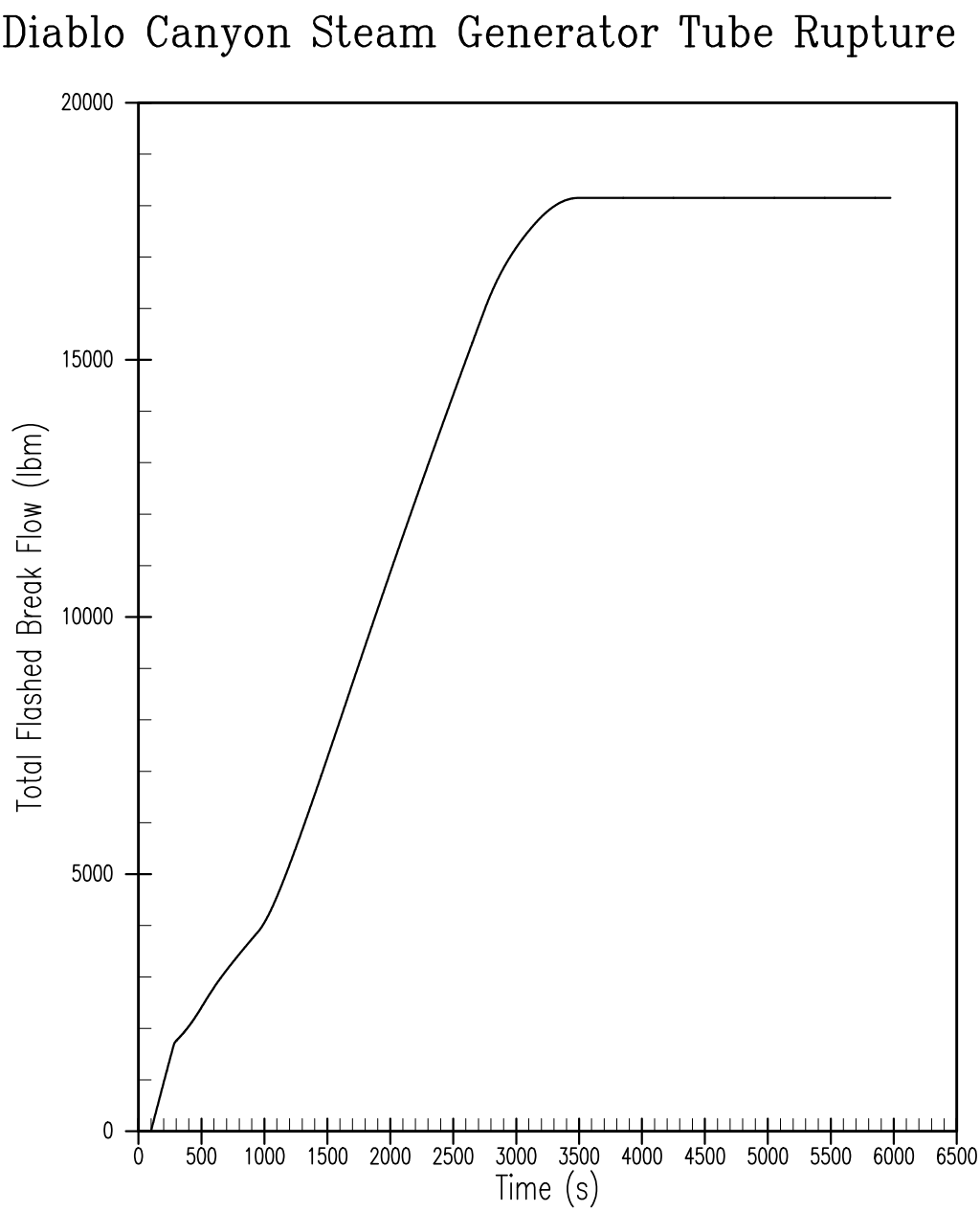
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-9 RUPTURED SG MASS RELEASE RATE TO THE ATMOSPHERE SGTR DOSE INPUT ANALYSIS

Revision 21 September 2013

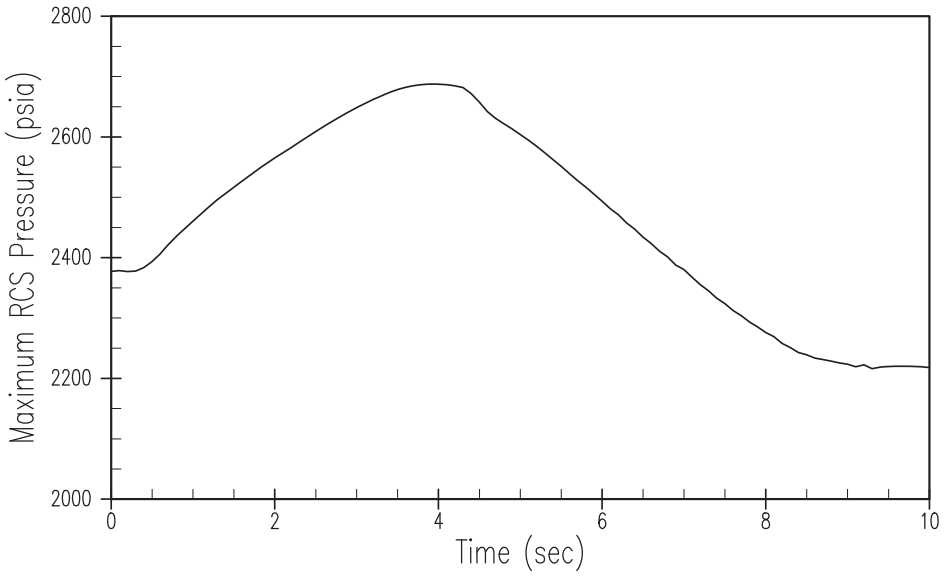


FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-10 INTACT SGs MASS RELEASE RATE TO THE ATMOSPHERE SGTR DOSE INPUT ANALYSIS

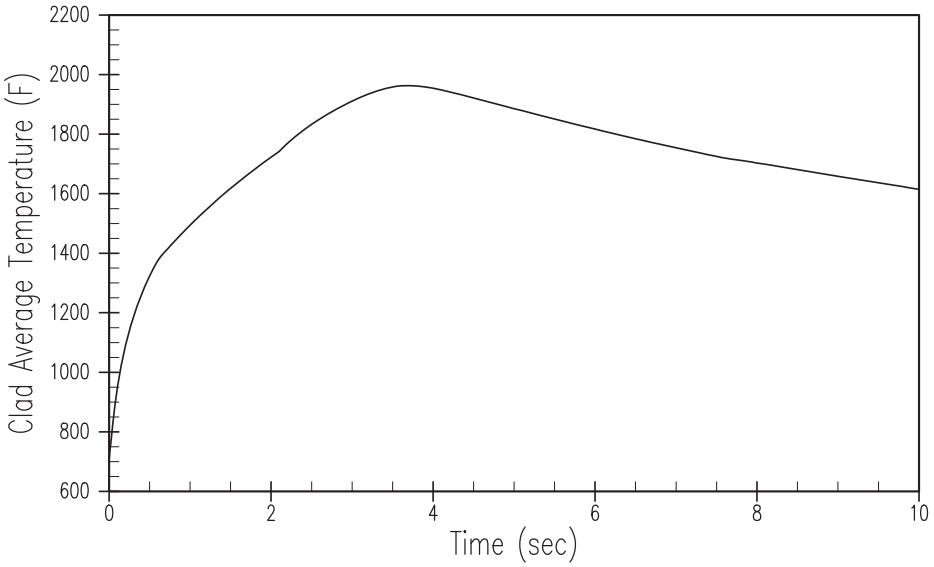
Revision 21 September 2013



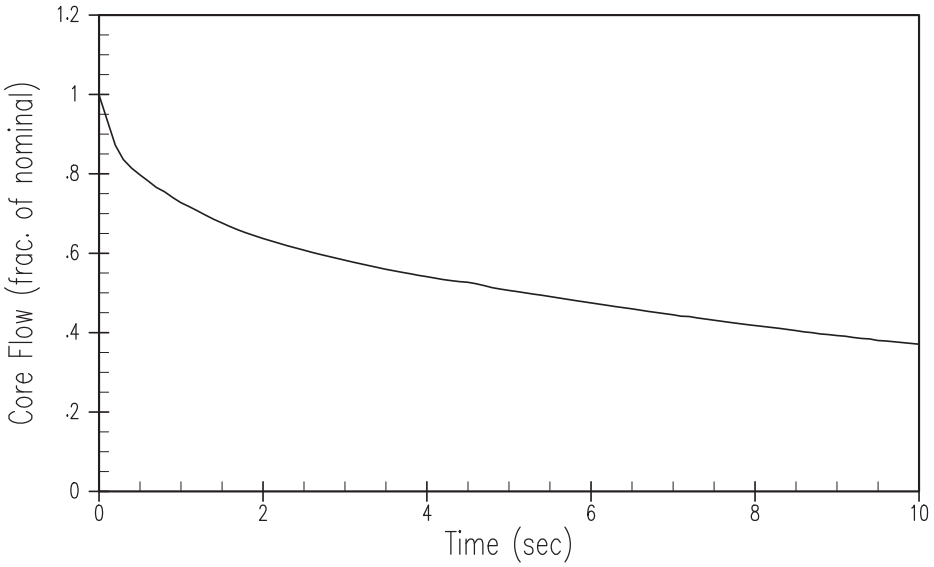
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.3-11 TOTAL FLASHED BREAK FLOW SGTR DOSE INPUT ANALYSIS



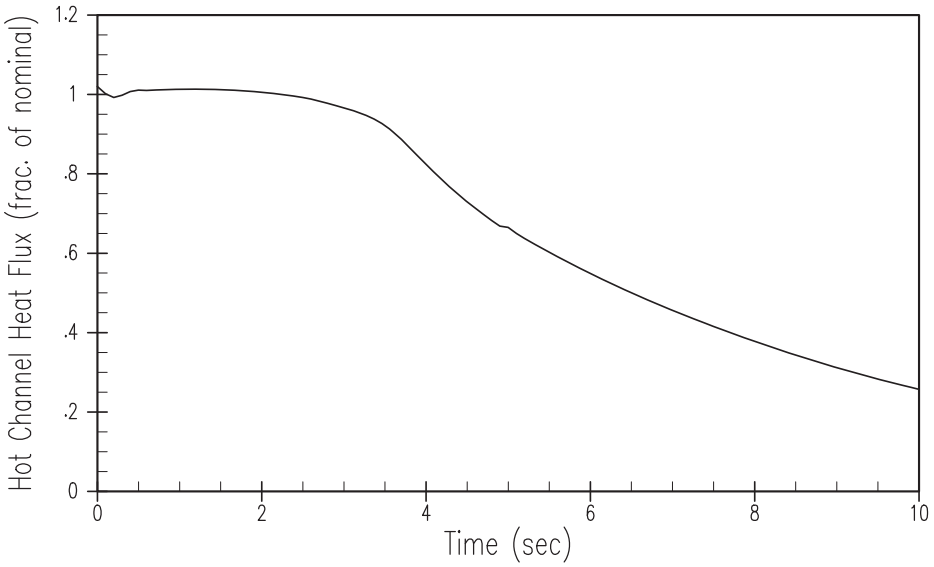
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.4-1 SINGLE REACTOR COOLANT PUMP LOCKED ROTOR MAXIMUM RCS PRESSURE VS. TIME



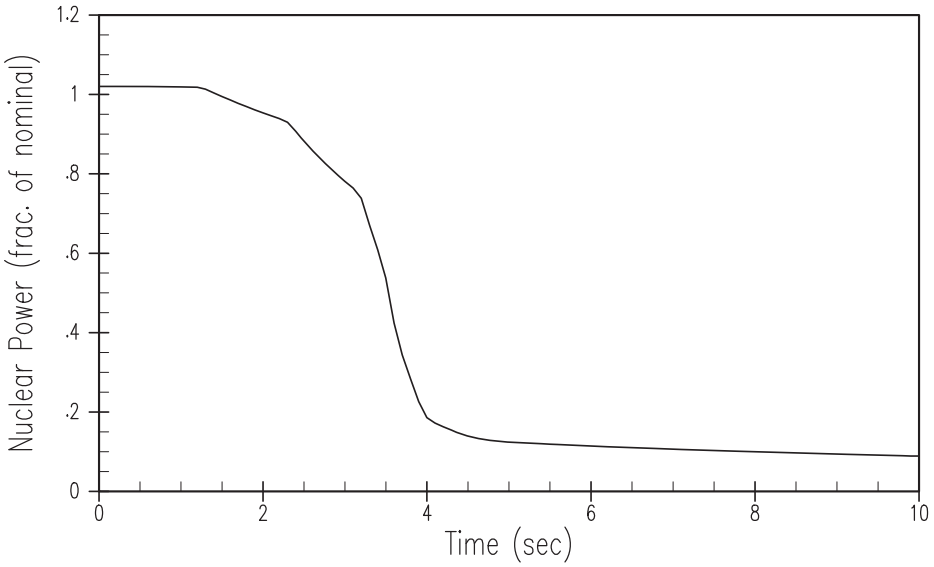
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.4-2 SINGLE REACTOR COOLANT PUMP LOCKED ROTOR CLAD AVERAGE TEMPERATURE VS. TIME



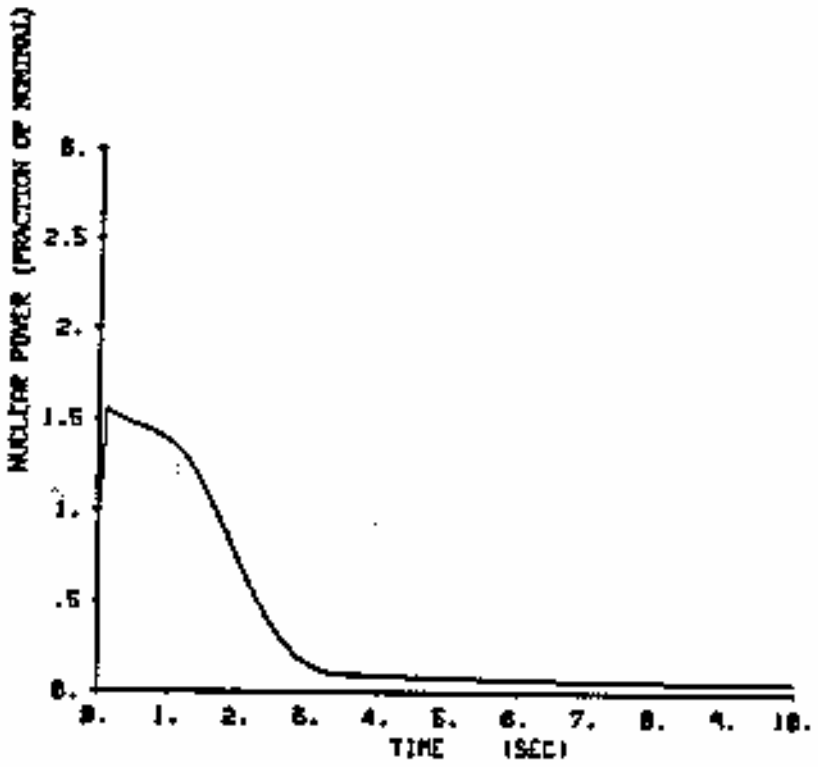
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.4-3 SINGLE REACTOR COOLANT PUMP LOCKED ROTOR CORE FLOW VS. TIME



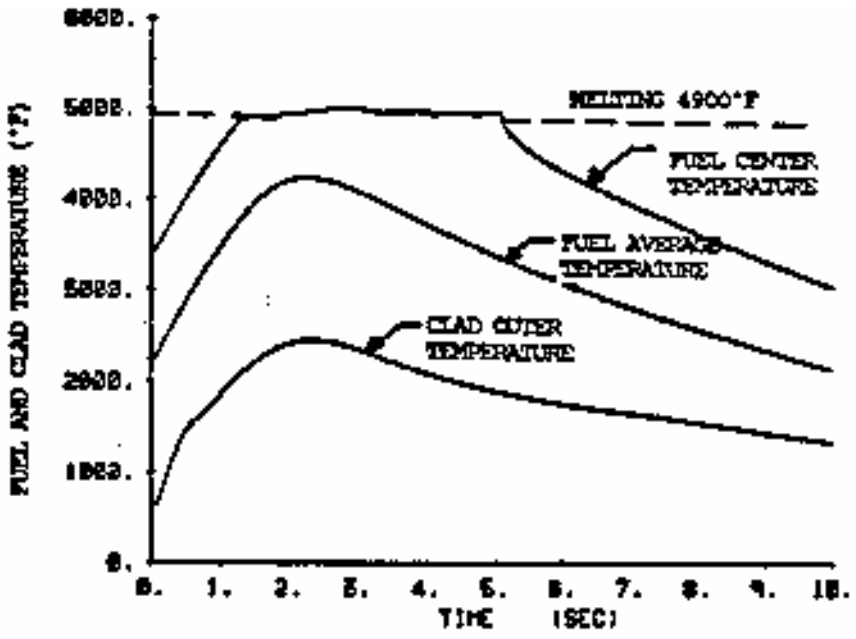
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.4-4 SINGLE REACTOR COOLANT PUMP LOCKED ROTOR HOT CHANNEL HEAT FLUX VS. TIME



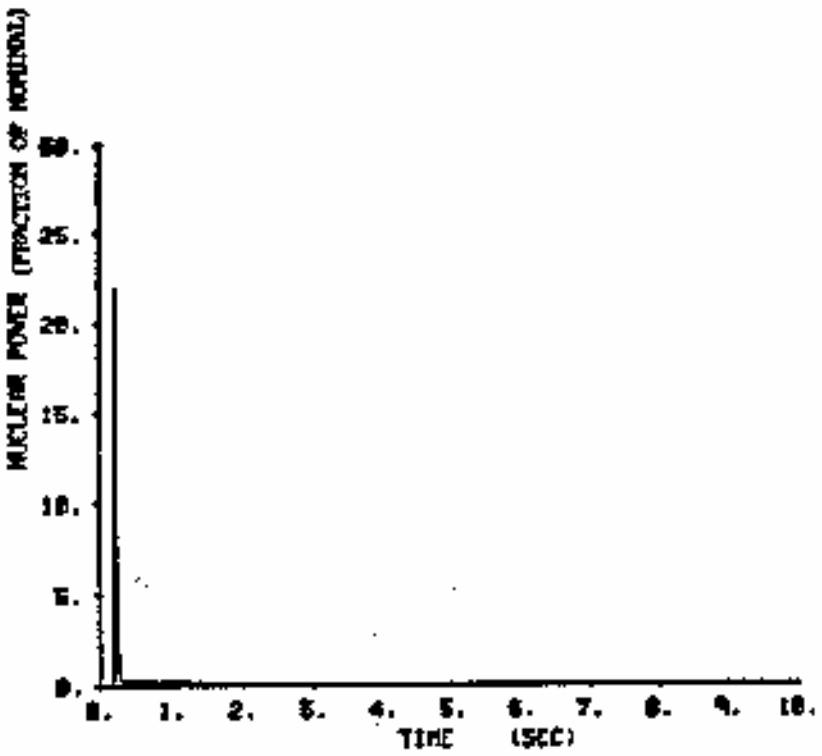
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.4-5 SINGLE REACTOR COOLANT PUMP LOCKED ROTOR NUCLEAR POWER VS. TIME



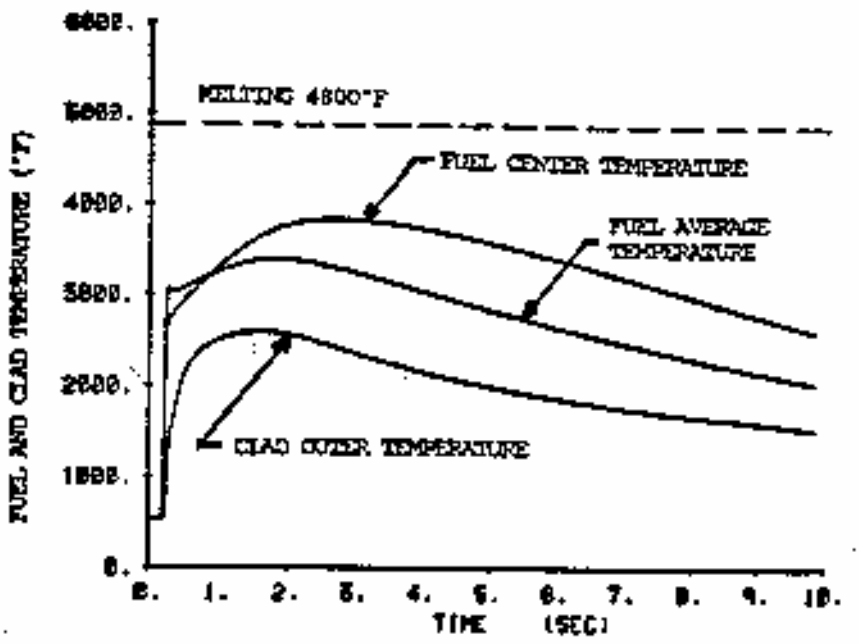
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.6-1 NUCLEAR POWER TRANSIENT, BOL, HZP, ROD EJECTION ACCIDENT



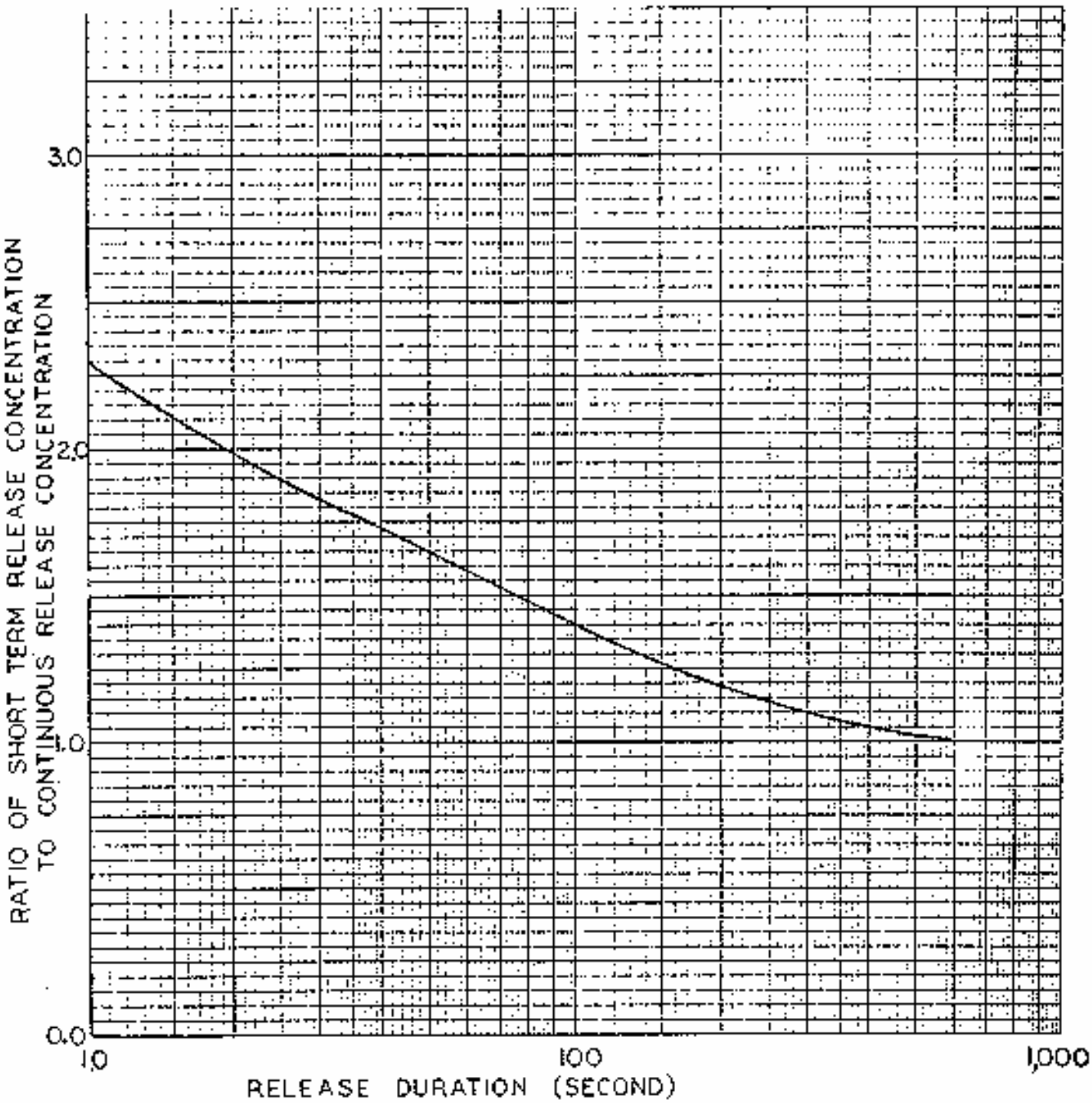
FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.6-2 HOT SPOT FUEL AND CLAD TEMPERATURES VERSUS TIME, BOL, HZP, ROD EJECTION ACCIDENT



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.6-3 NUCLEAR POWER TRANSIENT, EOL, HFP, ROD EJECTION ACCIDENT



FSAR UPDATE
UNITS 1 AND 2 DIABLO CANYON SITE
FIGURE 15.4.6-4 HOT SPOT FUEL AND CLAD TEMPERATURES VERSUS TIME, EOL, HZP, ROD EJECTION ACCIDENT



Ratio of Short-term Release Concentration to Continuous Release Concentration vs. Release Duration	**DIABLO CANYON UNITS 1 & 2**
	FIGURE 15.5-1

Revision 11 November 1996

Chapter 16

TECHNICAL SPECIFICATIONS AND EQUIPMENT CONTROL GUIDELINES

CONTENTS

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Chapter 16

TABLES

Table	Title
16.1-1	Equipment Control Guidelines

Chapter 16

TECHNICAL SPECIFICATIONS AND EQUIPMENT CONTROL GUIDELINES

16.1 TECHNICAL SPECIFICATIONS AND EQUIPMENT CONTROL GUIDELINES

The Technical Specifications (TSs) for Diablo Canyon Power Plant (DCPP) are contained in Appendix A of the Operating Licenses. The TS Bases provide the bases or reasons for these TSs other than those covering administrative controls. In accordance with 10 CFR 50.36, the TS Bases are not part of the TS, and are included by reference in this section of the UFSAR in accordance with 10 CFR 50.34 and 10 CFR 50.36. Changes to the TS Bases are processed in accordance with TS 5.5.14, “Technical Specifications (TS) Bases Control Program.”

The Equipment Control Guidelines (ECGs) provide administrative controls and operability requirements for selected equipment that is not addressed by the TSs. ECGs are developed when controls are required by regulatory commitments or when plant management determines that it is prudent to control equipment to maximize its availability. TSs that have been relocated to licensee controlled documents are generally transferred to ECGs.

Similar to TSs, ECGs provide operability requirements, action statements, and surveillance requirements. If the equipment cannot be returned to service as required by the ECG, administrative review, approval, and evaluation under the plant Quality Assurance Programs is required.

Table 16.1-1 lists those DCPP ECGs that have been implemented due to relocated TSs in accordance with the U.S. Nuclear Regulatory Commission’s (NRCs) Final Policy Statement on TS Improvements and 10 CFR 50.36, which include four criteria to be used for identifying TS requirements that may be relocated to licensee controlled documents. Several license amendments (LAs) were issued by the NRC related to relocated TSs as noted in Table 16.1-1.

The preparation and revision process for ECGs requires evaluation under 10 CFR 50.59 or other applicable requirements. All ECGs and ECG revisions are approved by the Station Director.

TABLE 16.1-1

EQUIPMENT CONTROL GUIDELINES - TECHNICAL SPECIFICATIONS RELOCATED IN ACCORDANCE WITH NRC'S FINAL POLICY STATEMENT ON TECHNICAL SPECIFICATION IMPROVEMENTS

Number	Title	Notations
ECG 4.3	Steam Generator Pressure/Temperature Limitation	1
ECG 4.4	Instrumentation – Turbine Overspeed Protection and Turbine Trip	3, 7
ECG 7.3	Reactor Coolant System – Safety Valves Shutdown	2
ECG 7.4	Reactor Coolant System – Chemistry	2
ECG 7.5	Reactor Coolant System – Pressurizer	2
ECG 7.6	Reactor Coolant System – Structural Integrity	2
ECG 7.7	Reactor Coolant System – Reactor Vessel Head Vents	2
ECG 7.8	Accident Monitoring Instrumentation	4, 5
ECG 8.4	Reactivity Control Systems – Flow Paths – Operating	3
ECG 8.5	Reactivity Control Systems – Boration Systems – Flow Path - Shutdown	4
ECG 8.6	Reactivity Control Systems – Charging Pump - Shutdown	4
ECG 8.7	Reactivity Control Systems – Charging Pumps – Operating	4
ECG 8.8	Reactivity Control Systems – Borated Water Source – Shutdown	4
ECG 8.9	Reactivity Control Systems – Borated Water Sources – Operating	4
ECG 9.1	Accumulator Pressure and Water Level Instrumentation	8
ECG 13.2	Water Level – Spent Fuel Pool	4
ECG 17.3	Flood Protection	1

TABLE 16.1-1

Number	Title	Notations
ECG 19.1	Liquid Radwaste – Temporary Outdoor Tanks	4
ECG 21.3	Miscellaneous Emergency Diesel Generator (EDG) Functions	4
ECG 23.1	Area Temperature Monitoring	1
ECG 23.2	Instrumentation – Chlorine Detection System	3
ECG 23.3	Containment Ventilation System	4
ECG 23.4	Hydrogen Recombiners	4, 5
ECG 23.5	Plant Systems – Control Room Ventilation System (CRVS)	4
ECG 24.1	Explosive Gas Effluent Monitoring Instrumentation	4
ECG 24.2	Gaseous Radwaste – Explosive Gas Mixture	4
ECG 24.3	Gaseous Radwaste – Gas Storage Tanks	4
ECG 33.1	Nuclear Instrumentation – Power Distribution Monitoring System Instrumentation	6
ECG 37.2	Axial Flus Difference (AFD) Monitor Alarm	4
ECG 37.3	Quadrant Power Tilt Ratio Alarm	4
ECG 38.1	Reactor Trip System (RTS) – Instrumentation Response Times	4
ECG 38.2	Engineered Safety Features (ESF) Response Times	4
ECG 39.6	Sealed Source Contamination	1
ECG 40.1	Meteorological Instrumentation	4
ECG 41.1	Reactivity Control Systems – Position Indication System – Shutdown	3
ECG 41.2	Special Test Exceptions – Position Indication System – Shutdown	4

TABLE 16.1-1

Number	Title	Notations
ECG 42.1	Refueling Operations – Decay Time	4
ECG 42.2	Refueling Operations – Communications	4
ECG 42.3	Refueling Operations – Manipulator Crane	4
ECG 42.4	Refueling Operations – Crane Travel – Fuel Handling Building	4
ECG 42.5	Refueling Operations – Water Level – Reactor Vessel	4
ECG 45.2	Containment Systems – Containment Structural Integrity	3
ECG 45.3	Containment Penetration Conductor Overcurrent Protective Devices	3
ECG 48.1	Movable Incore Detectors	4
ECG 51.1	Instrumentation – Seismic Instrumentation	3
ECG 64.1	MOV Thermal Overload Protection and Bypass Devices	3
ECG 99.1	Snubbers	1

Notes:

1. Technical Specifications (TS) relocated pursuant to License Amendments (LAs) 106 (Unit 1) and 105 (Unit 2), dated July 6, 1995.
2. TS relocated pursuant to LAs 98 (Unit 1) and 97 (Unit 2), dated March 9, 1995.
3. TS relocated pursuant to LAs 120 (Unit 1) and 118 (Unit 2), dated February 3, 1998.
4. TS relocated pursuant to LAs 135 (Unit 1) and 135 (Unit 2), dated May 28, 1999.
5. TS relocated pursuant to LAs 168 (Unit 1) and 169 (Unit 2), dated May 4, 2004.
6. TS changes pursuant to LAs 164 (Unit 1) and 166 (Unit 2), dated March 31, 2004.
7. TS relocated pursuant to LAs 173 (Unit 1) and 175 (Unit 2), dated September 24, 2004.
8. TS relocated pursuant to LAs 102 (Unit 1) and 101 (Unit 2), dated May 26, 1995.

Chapter 17

QUALITY ASSURANCE

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FIGURES

Figure	Title
17.1-1	Deleted in Revision 27
17.1-2	Deleted in Revision 27

Chapter 17

QUALITY ASSURANCE

17.0 QUALITY ASSURANCE PROGRAM

The purpose of this chapter is to provide a description of the Pacific Gas and Electric Company (PG&E) Quality Assurance (QA) Program. The QA Program is applicable to operation of Diablo Canyon Power Plant (DCPP) Unit 1 and Unit 2 and to the Diablo Canyon Independent Spent Fuel Storage Installation (ISFSI). The purpose of the PG&E QA Program is to provide assurance that the design, construction, and operation of DCPP Unit 1 and Unit 2 and the ISFSI are in conformance with applicable regulatory requirements and with the specified design bases.

17.1 REGULATORY REQUIREMENTS

The following regulatory requirements are applicable to DCPP and are described in the Diablo Canyon (DC) Quality Assurance Program Description (QAPD) [Reference 3]:

1. General Design Criterion 1, 1967 – Quality Standards

   DCPP systems and components that are essential to the prevention of accidents which could affect the public health and safety or to mitigate their consequences are required to be designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes or standards on design, materials, fabrication, and inspection are used, they are identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they are supplemented or modified as necessary. QA programs, test procedures, and inspection acceptance levels to be used are identified. A showing of sufficiency and applicability of codes, standards, QA programs, test procedures, and inspection acceptance levels used is made.

   The DC QAPD provides assurance that this criterion is met. Refer to UFSAR Section 3.2 for a description of classifications used to identify the importance of safety functions performed by specific structures, systems, and components (SSCs).

2. General Design Criterion 5, 1967 – Records Requirements

   Records of the design, fabrication, and construction of essential components of the plant are required to be maintained or controlled by PG&E throughout the life of the reactor.

3. 10 CFR Part 50, Appendix B - Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants

   DCPP is required to include, in its final safety analysis report, information pertaining to the managerial and administrative controls to be used to assure safe operation in accordance with 10 CFR Part 50 Appendix B Criteria I – XVIII.

4. 10 CFR 50.54 [(a) only] – Conditions of Licenses

   DCPP is required to implement the QA program described or referenced in the safety analysis report, which shall include the QA criteria in 10 CFR Part 50 Appendix B.

5. 10 CFR Part 72 Subpart G – Quality Assurance [ISFSI]

   PG&E satisfies the requirement of 10 CFR 72.140(b) of 10 CFR Part 72 Subpart G, to establish a QA program for the ISFSI by crediting the DC QAPD [Reference 3] as allowed by 10 CFR 72.140(d), which includes a provision that a QA program previously approved by the U.S. Nuclear Regulatory Commission (NRC) as satisfying the requirements of 10 CFR Part 50 Appendix B will be accepted as satisfying the requirements of 10 CFR 72.140(b). License Condition 14 of ISFSI License No. SNM-2511 documents NRC determination that the PG&E 10 CFR Part 50 Appendix B QA program [Reference 3] complies with the requirements of 10 CFR Part 72 Subpart G.

The DC QAPD is incorporated by reference into the DCPP UFSAR (refer to Section 1.6).

17.2 SELECTION AND TRAINING OF NUCLEAR POWER PLANT PERSONNEL

Staffing, training, and qualification is the single most important variable which can be controlled to achieve the nuclear generation goals of maximizing plant safety, efficiency, and reliability. Therefore, it is the policy of nuclear generation that personnel at all levels shall be qualified for the positions they fill and receive the necessary training and retraining to enable them to perform at the highest level of efficiency. Nuclear generation personnel shall meet or exceed the minimum qualifications of ANSI/ANS 3.1 1978, for comparable positions, with the following exceptions [Reference 2]:

(a) The radiation protection manager shall meet or exceed the minimum qualifications of Regulatory Guide 1.8, Revision 2, April 1987, for radiation protection manager.
(b) The operations manager shall meet or exceed the minimum qualifications as specified in Technical Specification 5.2.2.e.
(c) The licensed Reactor Operators and Senior Reactor Operators shall meet or exceed the minimum qualifications of ANSI/ANS 3.1-1993 as endorsed by Regulatory Guide 1.8, Revision 3, May 2000 with the exceptions clarified in the

current revision to the Operator Licensing Examination Standards for Power Reactors, NUREG-1021, Section ES-202 [Reference 1].

(d) For the purpose of 10 CFR 55.4, a licensed SRO and a licensed RO are those individuals who, in addition to meeting the requirements specified in (c), perform the functions described in 10 CFR 50.54(m).

(e) The radiation protection technicians shall meet or exceed the minimum qualifications of ANSI/ANS 3.1-2014 as endorsed by Regulatory Guide 1.8, revision 4, June 2019.

NOTE: These exceptions are also listed in Appendix B of the DC QAPD, Current Regulatory Requirements and PG&E Commitments Pertaining to the Quality Assurance Program, where all pertinent commitments are captured.

17.3 REFERENCES

1. License Amendment 187/189, dated May 26, 2006

2. License Amendment 237/239, dated September 11, 2020

3. Diablo Canyon Quality Assurance Program Description

4. Regulatory Guide 1.8, Personnel Selection and Training, USNRC, February 1979 (Proposed revision 2)

5. Regulatory Guide 1.8, Qualification and Training of Personnel for Nuclear Power Plants, USNRC, revision 2, April 1987

6. Regulatory Guide 1.8, Qualification and Training of Personnel for Nuclear Power Plants, USNRC, revision 3, May 2000

7. Regulatory Guide 1.8, Qualification and Training of Personnel for Nuclear Power Plants, USNRC, revision 4, June 2019

Enclosure 2 contains Sensitive Information - Withhold Under 10 CFR 2.390.
When separated from Enclosure 2, this letter is decontrolled.

Description of Information Removed from Revision 29 of the Updated Final Safety Analysis Report

Enclosure 2 contains Sensitive Information - Withhold Under 10 CFR 2.390.
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Enclosure 2 contains Sensitive Information - Withhold Under 10 CFR 2.390.
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Description of Information Removed from Revision 29 of the Updated Final Safety Analysis Report

UFSAR Sections	Description of Change
4.2.3.2.3 4.2.3.3.2 4.2.3.4.2	Removed references regarding RCCA subcomponents and materials that are no longer used.
5.2.2.4.4.5.1 5.2.2.4.4.5.2	Deleted these sections as they are no longer relevant in relation to the new calculation methodology approved by the NRC in License Amendments 246/248 (PTLR calculation).
6.2.5.2.2	Removed reference to the design life of the Hydrogen Recombiner.
9.1.4.2.1.8	Removed description of the RCC changing fixture.

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