Pacific Gas and Electric Company

James R. Becker
Vice President-Diablo Canyon
Operations and Station Director

Diablo Canyon Power Plant
P.O. Box 56
Avila Beach, CA 93424

805.545.3462
Fax: 805.545.4234

November 5, 2003

PG&E Letter DCL-03-142

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Response to NRC Request for Additional Information Regarding License Amendment Request 03-06, "Revision to Technical Specification 3.8.1, 'AC Sources - Operating'"

Dear Commissioners and Staff:

Pacific Gas and Electric (PG&E) Letter DCL-03-060, dated May 29, 2003, submitted License Amendment Request (LAR) 03-06, "Revision to Technical Specification 3.8.1, 'AC Sources - Operating,'" which would extend the completion time for restoring an inoperable diesel generator from 7 days to 14 days.

On August 25, 2003, the NRC staff requested additional information required to complete their review of LAR 03-06. PG&E's responses to the staff's questions are provided in Enclosures 1, 2, 3, and 4.

This additional information does not affect the results of the technical evaluation and no significant hazards consideration determination previously transmitted in PG&E Letter DCL-03-060.

If you have any questions or require additional information, please contact Stan Ketelsen at (805) 545-4720.

Sincerely,

James R. Becker

jer/3664
Enclosures

A001

cc: Edgar Bailey, DHS
Bruce S. Mallett
David L. Proulx
Diablo Distribution
cc/enc: Girija S. Shukla

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of PACIFIC GAS AND ELECTRIC COMPANY	)	Docket No. 50-275 Facility Operating License No. DPR-80
Diablo Canyon Power Plant Units 1 and 2	)	Docket No. 50-323 Facility Operating License No. DPR-82

AFFIDAVIT

James R. Becker, of lawful age, first being duly sworn upon oath states that he is Vice President Operations and Station Director - Diablo Canyon of Pacific Gas and Electric Company; that he has executed this supplement to License Amendment Request 03-06 on behalf of said company with full power and authority to do so; that he is familiar with the content thereof; and that the facts stated therein are true and correct to the best of his knowledge, information, and belief.

James R. Becker
Vice President Operations and Station Director - Diablo Canyon

Subscribed and sworn to before me this 5th day of November 2003.

Notary Public
County of San Luis Obispo
State of California

CHUCK MACKEY
Commission # 1397547
Notary Public - California
San Luis Obispo County
My Comm. Expires Feb 1, 2007

PG&E Response to NRC Request for Additional Information Regarding License Amendment Request 03-06, "Revision to Technical Specification 3.8.1, 'AC Sources - Operating'"

NRC Question 1

Discuss and provide information on the reliability and availability of offsite power sources relating to the proposed change. The discussion should include duration, cause, date and time of each loss-of-offsite power (partial or complete) event. In addition, discuss the current reliability of all DGs at Diablo Canyon.

PG&E Response to Question 1 on Offsite Power Sources

Summary

Operating Procedure OP J-2:VIII, "Guidelines for Reliable Transmission Service for DCPP," includes the operating instructions for the transmission system contained in Pacific Gas and Electric (PG&E) Transmission System Operating Instruction O-23, "Operating Instructions for Reliable Transmission Service for Diablo Canyon P. P." The boundaries of jurisdiction and extent of control of these procedures are the same as listed in the Diablo Canyon Power Plant (DCPP) Final Safety Analysis Report Update (FSARU) Section 8.2, "Offsite Power System." See attached Figures 1 and 2. In the figures, the boundary of procedural control is at the Midway and Gates Substations and includes:

- 500 kV transmission lines from DCPP to Midway and Gates, and
- 230 kV transmission lines from DCPP to Midway and Gates. In the year 2000 the Morro Bay–Gates No. 1 Line was renamed Morro Bay-Templeton, and Templeton-Gates.

Table 1, "Availability History," summarizes the number of minutes and percentage of time that each line was available each year. Table 2, "Maintenance Outage History," provides the maintenance outage summary for October 2000 to September 9, 2003. Availability is not calculated for 1999 or January through August 2000 because of the lack of maintenance data in the PG&E Outage Coordination Database. Table 3, "Forced Outage History," lists the forced outage summary from January 1, 1999, through September 9, 2003.

For the period from January 1, 1999, through September 9, 2003, there have been no events that caused a complete loss of offsite power from the transmission systems supplying DCPP. During that period there was one incident on the 500 kV system and two incidents on the 230 kV system where power was interrupted from the transmission system. One event at DCPP Unit 1 on May 15, 2000, is characterized as a complete loss of offsite power to that unit. This event was due to an internal 12 kV bus fault that resulted in a loss of both offsite power connections to the 4 kV safety loads for

33.6 hours. During this time both the 500 kV and 230 kV transmission systems were available and Unit 2 remained in operation. (Reference PG&E Letter DCL-00-115, "Licensee Event Report 1-2000-004-01, Unit 1 Unusual Event Due to a 12kV Bus Fault," dated August 30, 2000).

500 kV System

On September 22, 1999, lightning struck the static ground wire protecting the tie line from Unit 1 to the 500 kV switchyard. No damage was sustained. The tie line remained deenergized for 8.2 hours. (Reference PG&E Letter DCL-99-118, "Licensee Event Report 1-1999-006-00, Reactor Trip Due to Lightning Strike," dated October 15, 1999). A follow-on event occurred on September 23, 1999, when the tie line was reenergized and tripped due to a cut-in 500 kV overvoltage protective relay with a trip signal picked up. (Reference PG&E Letter DCL-99-131, "Licensee Event Report 1-1999-008-00, Engineered Safety Feature Actuation - Auxiliary Feedwater Pump 1-1 Started on 12 kV Undervoltage Due to Personnel Error," dated October 22, 1999). The tie line remained deenergized for 6.1 hours while the event was analyzed. Unit 2 was not affected by this event.

230 kV System

On April 5, 2001, a prescribed burn in Diablo Canyon, east of the plant, generated heavy smoke that caused both 230 kV lines to trip. Offsite power from the 230 kV system was restored after 1.2 hours. Both units remained in operation during this event. (Reference PG&E Letter DCL-01-065, "Licensee Event Report 1-2001-001-00, Automatic Emergency Diesel Generator Start Upon Loss of Startup Power Due to 230 kV Line Arcing in Heavy Smoke from Escaped Fire Caused by Inadequate Administrative Controls," dated June 4, 2001).

On August 4, 2001, a fault on the grounding transformer fuse box for the 230/12 kV Startup Transformer 1-1 caused a loss of startup (230 kV) power to both units. Power was restored to the Unit 2 startup bus on August 5, 2001 (13.8 hour outage). Power was restored to the Unit 1 startup bus on August 6, 2001 by a crosstie to Unit 2 (44.0 hour outage). Full restoration was completed on August 22, 2001. Both units remained in operation during this event. (Reference PG&E Letter DCL-01-099, "Licensee Event Report 1-2001-002-00, System Actuation: Unplanned Diesel Start Due to Loss of Startup Power," dated October 4, 2001).

Discussion

Forced outage data for offsite power sources has been collected and reported for 5 years: 1999-2003. The five-year period is based on the following considerations.

In 1996 PG&E discovered that there were 47 past instances where the 230 kV system may have been degraded. (PG&E Letter DCL-96-158, "Licensee Event Report

1-95-007-01, 230 kV System May Not Be Able to Meet its Design Requirements for All Conditions Due to Personnel Error," dated August 6, 1996.) Corrective actions were taken over the next several years to improve the 230 kV system. On April 29, 1999, the NRC issued License Amendments No. 132 (Unit 1) and No. 130 (Unit 2) to incorporate modifications to the 230 kV offsite power system. The changes included installation of two new 230/12 kV startup transformers with automatic load tap changers, and capacitor banks at Diablo 230 kV and Mesa 115 kV switchyards. Figure 1 shows a single line diagram of the 230 kV system. The purpose of these changes was to improve the reliability of the 230 kV offsite power system and prepare for deregulation in California. By starting the reporting in 1999, this encompasses the period of implementation of the 230 kV system improvements, the California energy crisis years of 2000 and 2001, and the initial period of PG&E bankruptcy.

Table 4, "Transmission Forced Outage Data," lists the detailed outage data. Note that the reported forced outage data includes an entry for Outage Class = "N" (None) - "zero outage." This is an entry for a transmission line that had zero outages for that year. Table 5, "Primary and Secondary Outage Cause Codes, Outage Class Codes," lists the outage class and cause codes.

DCPP FSARU Section 8.2, "Offsite Power System," states that the minimum requirements for operable 500 kV and 230 kV offsite systems are:

- Either 230 kV circuit feeding DCPP, and
- One 500 kV circuit feeding DCPP.

In addition, the capacitors at DCPP and Mesa, along with the 230/12 kV startup transformers with automatic load tap changers enable the 230 kV transmission system to be independent of Morro Bay generation. FSARU Section 8.2.1.1, "230-kV System," identifies the occurrences that could result in a loss of power to the 230/12 kV startup transformers.

The only forced outage event related to the 230/12 kV startup transformers is discussed above under the 230 kV System. Routine maintenance of the transformers and their automatic load tap changers is performed during unit outages and controlled under the outage safety plan issued for each outage.

There were no forced outages of the capacitors at the Diablo 230 kV switchyard. There were two forced outage events involving the capacitors at the Mesa 115 kV substation.

- On September 16, 1999, at 13:20 PDT, a single capacitor faulted on a string of capacitors in C phase at Mesa. The single capacitor was replaced and returned to service in approximately 24 hours.

- On October 13, 1999, at 18:49 PDT, a fault in C phase caused severe damage to 3 capacitors (out of 20), a potential transformer, a resistor pack and collateral damage to bus and conductors. The capacitors were returned to service after a 36 day outage.

Both faults were limited to one-half of the installed 50 megavolt-ampere reactive (MVAR) capacity. Although 25 MVAR remained in service, procedurally the entire capacitor bank is considered out of service during this event. During these forced outages, the 230 kV supply to DCPP remained operable. Detailed data on the forced and maintenance outages of the capacitors at Mesa and Diablo are listed at the end of Tables 4 and 5.

The PG&E Transmission Operations Center in conjunction with the California Independent System Operator (CAISO) controls the operability of the transmission lines serving DCPP. The Diablo Canyon Control Center (Switchyard) personnel use common procedures with DCPP Operations to administer the operability of the transmission lines. PG&E and CAISO criteria control the periods for maintenance. Maintenance is typically performed when the system can allow the maintenance outage and the next contingency. Table 6, "Transmission Line Maintenance Outage Data," lists the maintenance outage data from November 1, 2000, through September 9, 2003. Maintenance data for 1999 and for January through October 2000 is not available in the PG&E Outage Coordination database.

It is important to note that during the "California energy crisis" of 2000 and 2001, the offsite power supplies into Diablo Canyon remained stable and reliable. Even when generation reserves dropped below the 7 percent level[1], the transmission systems serving DCPP remained stable due to system load control and selective load shedding. The CAISO did not allow elective maintenance during these years. Any transmission line maintenance was performed with the lines energized.

Since August of 1996, when problems in Oregon set off a chain of events that caused outages throughout California and other western states, PG&E has made many improvements to its electric transmission system. They include:

- Transmission substation equipment that boosts voltage and prevents oscillation,
- Sophisticated computer-based systems that sense abnormalities and disturbances and instantly correct for them,
- Major upgrades to and reinforcement of the transmission system - PG&E has invested about $1.4 billion since 1996 to expand capacity and improve reliability of the grid, and

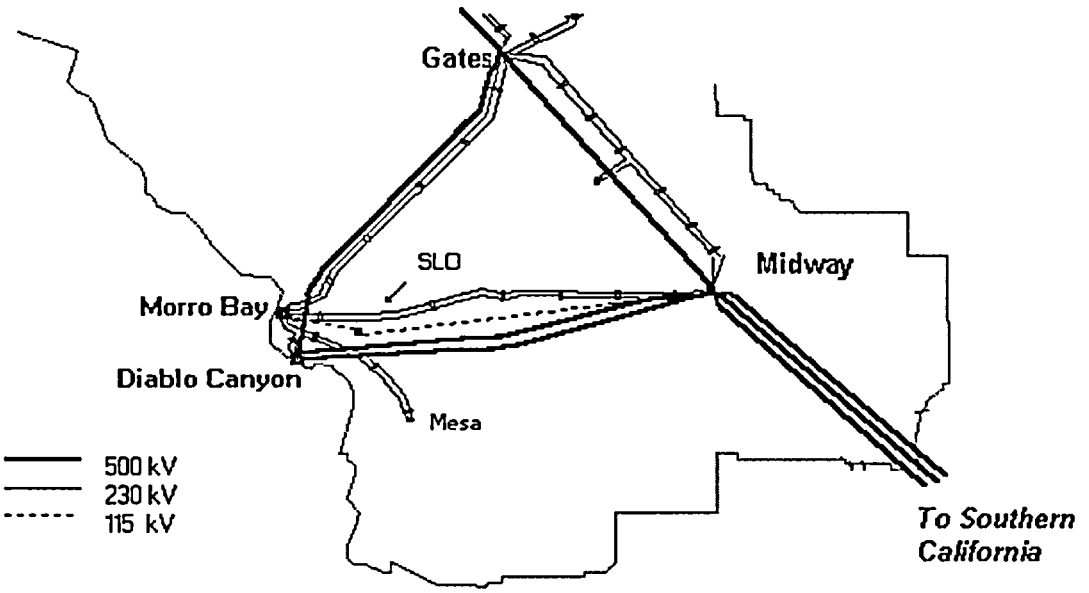
[1] CAISO declares a Stage 1 Emergency when reserves drop to 7 percent, Stage 2 at 5 percent, and Stage 3 at 1.5 percent.

- Greater coordination of load shedding plans with the 14 western states, two Canadian provinces and the parts of northern Mexico under the Western Electricity Coordinating Council regional transmission umbrella.

The Oregon event discussed above occurred on August 10, 1996, and caused a 500 kV system transient that resulted in both DCPP units tripping off-line. However, the 230 kV system was available to safely shutdown the units. Subsequent to the 1996 event, PG&E installed generator out-of-step protection for each unit. The purpose is to protect the turbine-generator during severe grid transients. This protective function increases the likelihood of tripping the units and transferring to the 230 kV system during severe grid transients. However, the 230 kV and 500 kV switchyards are not inter-connected at DCPP. Consequently the loss of DCPP generation has negligible impact on the 230 kV voltage.

Figure 1

Geographic Layout Of 500 And 230 kV Transmission Lines & Substations



Single Line Diagram of 230 kV System

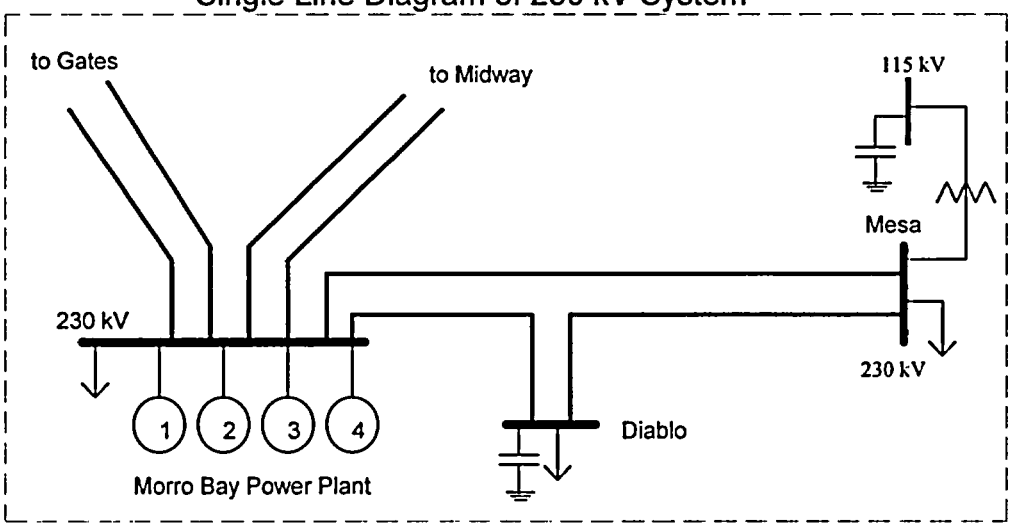


Figure 2

Electrical Distribution Overview

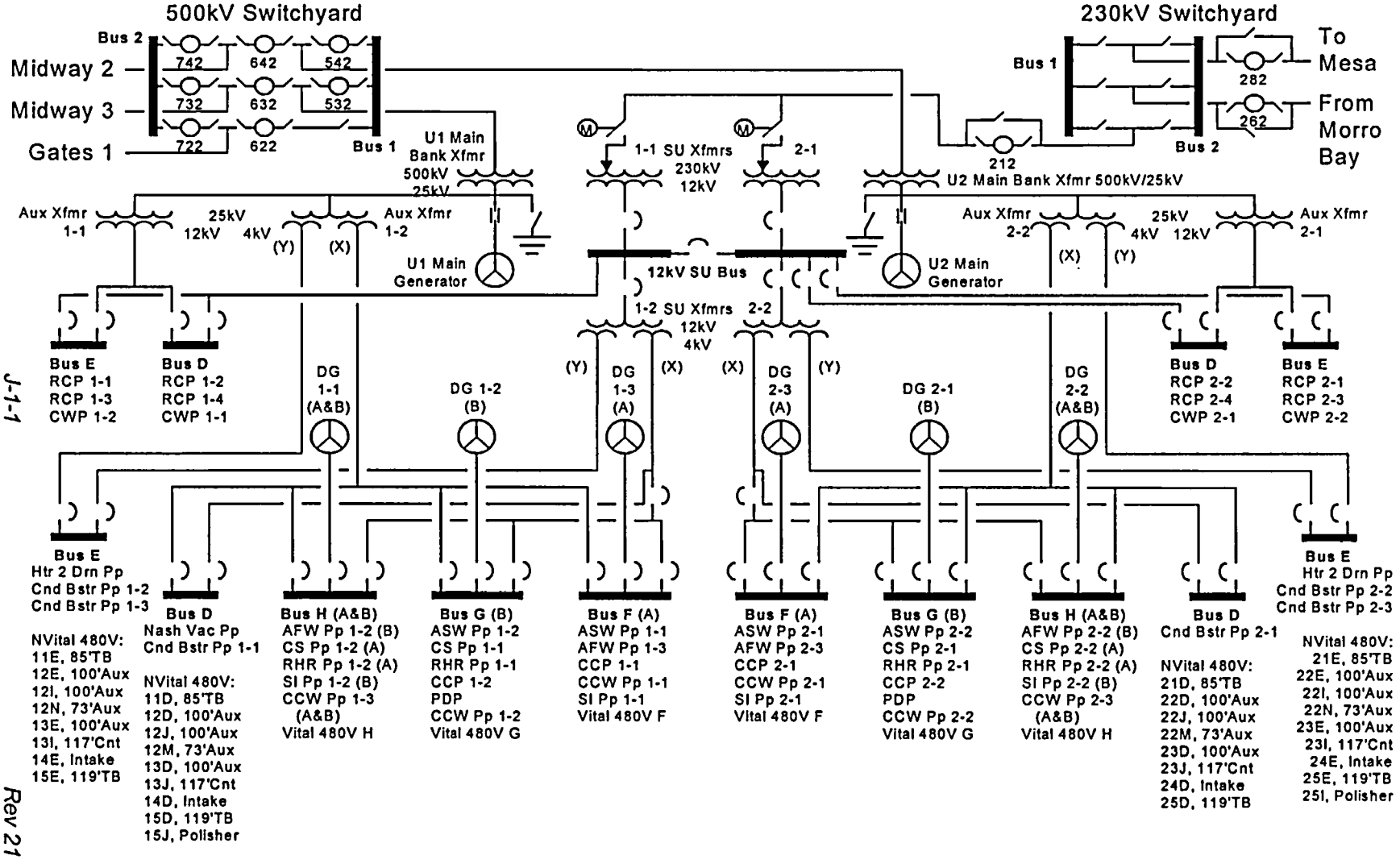


Table 1
Availability History

		1999 *		2000 *		2001		2002		2003**	
Voltage	Line_ID	minutes	% of yr	minutes	% of yr	minutes	% of yr	minutes	% of yr	minutes	% of yr
500	Diablo-GatesNo1	N/A		N/A		525600	100.000%	525600	100.000%	525600	100.000%
500	Diablo-MidwayNo2	N/A		N/A		525600	100.000%	524866	99.860%	525180	99.920%
500	Diablo-MidwayNo3	N/A		N/A		525561	99.993%	524719	99.832%	524880	99.863%
230	Diablo-Mesa	N/A		N/A		525554	99.991%	524773	99.843%	523380	99.578%
230	MorroBay-Diablo	N/A		N/A		525555	99.991%	525600	100.000%	525600	100.000%
230	MorroBay-GatesNo1	N/A		N/A		N/A	N/A	N/A	N/A	N/A	N/A
230	MorroBay-GatesNo2	N/A		N/A		525600	100.000%	524027	99.701%	525360	99.954%
230	MorroBay-Mesa	N/A		N/A		525600	100.000%	524700	99.829%	524099	99.714%
230	MorroBay-MidwayNo1	N/A		N/A		525585	99.997%	523860	99.669%	524819	99.851%
230	MorroBay-MidwayNo2	N/A		N/A		523925	99.681%	523019	99.509%	524879	99.863%
230	MorroBay-Templeton	N/A		N/A		525600	100.000%	525600	100.000%	525600	100.000%
230	Templeton-Gates	N/A		N/A		525600	100.000%	525600	100.000%	522599	99.429%

* Availability History is not calculated for 1999 or 2000 because of the lack of maintenance data in the PG&E Outage Coordination Database

** For 2003, data covers the period through September 9, 2003.

Table 2
Maintenance Outage History

		1999 *		2000 *		2001		2002		2003**	
Voltage	Line_ID	minutes	% of yr	minutes	% of yr	minutes	% of yr	minutes	% of yr	minutes	% of yr
500	Diablo-GatesNo1	N/A		0	0.0000%	0	0.0000%	0	0.0000%	0	0.0000%
500	Diablo-MidwayNo2	N/A		0	0.0000%	0	0.0000%	360	0.0685%	420	0.0799%
500	Diablo-MidwayNo3	N/A		0	0.0000%	0	0.0000%	0	0.0000%	720	0.1370%
230	Diablo-Mesa	N/A		0	0.0000%	0	0.0000%	660	0.1256%	2220	0.4224%
230	MorroBay-Diablo	N/A		0	0.0000%	0	0.0000%	0	0.0000%	0	0.0000%
230	MorroBay-GatesNo1	N/A		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
230	MorroBay-GatesNo2	N/A		0	0.0000%	0	0.0000%	1320	0.2511%	240	0.0457%
230	MorroBay-Mesa	N/A		0	0.0000%	0	0.0000%	900	0.1712%	1500	0.2854%
230	MorroBay-MidwayNo1	N/A		0	0.0000%	0	0.0000%	1740	0.3311%	780	0.1484%
230	MorroBay-MidwayNo2	N/A		0	0.0000%	0	0.0000%	2580	0.4909%	720	0.1370%
230	MorroBay-Templeton	N/A		0	0.0000%	0	0.0000%	0	0.0000%	0	0.0000%
230	Templeton-Gates	N/A		0	0.0000%	0	0.0000%	0	0.0000%	3001	0.5710%

* Data for 1999 and January through August 2000 was not available in the PG&E Outage Coordination Database

** For 2003, data covers the period through September 9, 2003.

Table 3
Forced Outage History

		1999		2000		2001		2002		2003*	
Voltage	Line_ID	minutes	% of yr	minutes	% of yr	minutes	% of yr	minutes	% of yr	minutes	% of yr
500	Diablo-GatesNo1	48	0.0091%	429	0.0814%	0	0.0000%	0	0.0000%	0	0.0000%
500	Diablo-MidwayNo2	43	0.0082%	0	0.0000%	0	0.0000%	374	0.0712%	0	0.0000%
500	Diablo-MidwayNo3	161	0.0306%	160	0.0304%	39	0.0074%	881	0.1676%	0	0.0000%
230	Diablo-Mesa	0	0.0000%	29	0.0055%	46	0.0088%	167	0.0318%	0	0.0000%
230	MorroBay-Diablo	144	0.0274%	0	0.0000%	45	0.0086%	0	0.0000%	0	0.0000%
230	MorroBay-GatesNo1	0	0.0000%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
230	MorroBay-GatesNo2	0	0.0000%	0	0.0000%	0	0.0000%	253	0.0481%	0	0.0000%
230	MorroBay-Mesa	360	0.0685%	1	0.0002%	0	0.0000%	0	0.0000%	1	0.0002%
230	MorroBay-MidwayNo1	359	0.0683%	58	0.0110%	15	0.0029%	0	0.0000%	1	0.0002%
230	MorroBay-MidwayNo2	0	0.0000%	805	0.1527%	1675	0.3187%	1	0.0002%	1	0.0002%
230	MorroBay-Templeton	N/A	N/A	303	0.0575%	0	0.0000%	0	0.0000%	0	0.0000%
230	Templeton-Gates	N/A	N/A	0	0.0000%	0	0.0000%	0	0.0000%	0	0.0000%

* For 2003, data covers the period through September 9, 2003.

Table 4
Transmission Forced Outage Data
1/1/1999 through 9/9/2003

Voltage Class	Line_ID	Outage Start Date	Outage Start Time	DUR (Min)	Outage End Date	Outage End Time	Outage Class	Primary Cause	Secondary Cause	Comments
500	Diablo-GatesNo1	1/13/1999	23:35	46	1/14/1999	0:21	F	PROT	NONE	Diablo CBs 622 & 722 relayed by transfer trip - cutout channel "C" transfer trip relays.
500	Diablo-GatesNo1	9/22/1999	12:41	2	9/22/1999	12:43	F	LIGT	NONE	Unknown - lightning.
500	Diablo-GatesNo1	1/15/2000	9:39	429	1/15/2000	16:48	F	CNTM	INSL	De-energized wash of contaminated "V" string insulators on towers 67/176 to 72/297.
500	Diablo-GatesNo1	1/1/2001	0:00	0	1/1/2001	0:00	N	NONE	NONE	zero outage
500	Diablo-GatesNo1	1/1/2002	0:00	0	1/1/2002	0:00	N	NONE	NONE	zero outage
500	Diablo-MidwayNo2	1/7/1999	9:53	43	1/7/1999	10:36	F	OPER	NONE	Relay test error while working on Midway CB 912 breaker failure relay.
500	Diablo-MidwayNo2	1/1/2000	0:00	0	1/1/2000	0:00	N	NONE	NONE	zero outage
500	Diablo-MidwayNo2	1/1/2001	0:00	0	1/1/2001	0:00	N	NONE	NONE	zero outage
500	Diablo-MidwayNo2	2/9/2002	3:37	374	2/9/2002	9:51	F	SEQP	NONE	Open ended when feed pump regulator valve unexpectedly closed.
500	Diablo-MidwayNo3	8/19/1999	13:44	161	8/19/1999	16:25	F	FIRE	COND	Structure fire started grass fire that burned through conductor between 17/66 and 17/67 - CDF delayed restoration.
500	Diablo-MidwayNo3	1/13/2000	5:23	98	1/13/2000	7:01	F	CB	NONE	To remove Midway CB 802 from service due to loss of all air pressure.
500	Diablo-MidwayNo3	11/25/2000	6:38	62	11/25/2000	7:40	F	DIST	NONE	Out of section trip (Midway-Vincent #3-500kV line trouble).

Table 4
Transmission Forced Outage Data
1/1/1999 through 9/9/2003

Voltage Class	Line_ID	Outage Start Date	Outage Start Time	DUR (Min)	Outage End Date	Outage End Time	Outage Class	Primary Cause	Secondary Cause	Comments
500	Diablo-MidwayNo3	5/31/2001	20:48	39	5/31/2001	21:27	F	SEQP	ARRS	Trip occurred when Midway #11-500/230 kV bank failed.
500	Diablo-MidwayNo3	7/24/2002	14:48	97	7/24/2002	16:25	F	CB	NONE	Open ended when Midway CB 902 was forced out to repair the compressor regulator.
500	Diablo-MidwayNo3	11/15/2002	10:10	784	11/15/2002	23:14	F	LEQP	NONE	Forced out due to failure of PT insulator column.
230	Diablo-Mesa	1/1/1999	0:00	0	1/1/1999	0:00	N	NONE	NONE	ZERO OUTAGE
230	Diablo-Mesa	3/24/2000	12:22	1	3/24/2000	12:23	F	CB	NONE	Mesa CB 212 forced out of service to adjust hydraulic pump control governor.
230	Diablo-Mesa	3/24/2000	13:07	28	3/24/2000	13:35	F	CB	NONE	Mesa 212 out of service to adjust hydraulic pump control governor..
230	Diablo-Mesa	4/5/2001	15:10	46	4/5/2001	15:56	F	FIRE	NONE	Control burn under line.
230	Diablo-Mesa	12/16/2002	9:36	1	12/16/2002	9:37	F	OPER	NONE	Relayed when conductor came out of fitting, contacted CT cover on CB 212 "A" Phase.
230	Diablo-Mesa	12/16/2002	12:37	166	12/16/2002	15:23	F	OPER	NONE	Forced out to repair conductor that came out of fitting, contacted CT cover on CB 212 "A" Phase.
230	MorroBay-Diablo	5/3/1999	22:49	143	5/4/1999	1:12	F	LATE	INSL	Applied additional silicone to CB 612 at MB, washing and replace support insulators.
230	MorroBay-Diablo	9/22/1999	12:41	1	9/22/1999	12:42	F	PROT	RELY	Diablo Canyon CB 262 relayed and reclosed OK with power remaining on line.
230	MorroBay-Diablo	1/1/2000	0:00	0	1/1/2000	0:00	N	NONE	NONE	zero outage

Table 4
Transmission Forced Outage Data
1/1/1999 through 9/9/2003

Voltage Class	Line_ID	Outage Start Date	Outage Start Time	DUR (Min)	Outage End Date	Outage End Time	Outage Class	Primary Cause	Secondary Cause	Comments
230	MorroBay-Diablo	4/5/2001	15:10	45	4/5/2001	15:55	F	FIRE	NONE	Control burn under line.
230	MorroBay-Diablo	1/1/2002	0:00	0	1/1/2002	0:00	N	NONE	NONE	zero outage
230	MorroBay-GatesNo1	1/1/1999	0:00	0	1/1/1999	0:00	N	NONE	NONE	zero outage
230	MorroBay-GatesNo2	1/1/1999	0:00	0	1/1/1999	0:00	N	NONE	NONE	zero outage
230	MorroBay-GatesNo2	1/1/2000	0:00	0	1/1/2000	0:00	N	NONE	NONE	zero outage
230	MorroBay-GatesNo2	1/1/2001	0:00	0	1/1/2001	0:00	N	NONE	NONE	zero outage
230	MorroBay-GatesNo2	1/24/2002	7:03	253	1/24/2002	11:16	F	LEQP	NONE	Forced out to permanently jumper out Sw 247 that was burning
230	MorroBay-Mesa	5/1/1999	6:19	41	5/1/1999	7:00	F	UNKN	NONE	Line relayed, 0700 started pre-scheduled line work. 1512 tested OK (temp jumpers at MB).
230	MorroBay-Mesa	5/7/1999	7:48	318	5/7/1999	13:06	F	UNKN	INSL	Replaced flashed and broken insulators due to trouble 5/1/99 - Temp Jumpers MB.
230	MorroBay-Mesa	12/4/1999	11:17	1	12/4/1999	11:18	F	OPER	NONE	Mesa CB's 172, 182, 202, 222 relayed, reclosed OK by breaker failure during work on CB 212.
230	MorroBay-Mesa	2/11/2000	22:12	1	2/11/2000	22:13	F	PROT	RELY	Mesa CB 222 relayed due to out of section fault.
230	MorroBay-Mesa	1/1/2001	0:00	0	1/1/2001	0:00	N	NONE	NONE	zero outage
230	MorroBay-Mesa	1/1/2002	0:00	0	1/1/2002	0:00	N	NONE	NONE	zero outage
230	MorroBay-Mesa	7/30/2003	5:45	1	7/30/2003	5:46	F	LIGT	NONE	Relayed, tested OK; no interruptions, lightning in area.
230	MorroBay-MidwayNo1	5/1/1999	6:19	41	5/1/1999	7:00	F	UNKN	NONE	Line relayed, 0700 started pre-scheduled line work. 1512 tested OK temp jumpers at MB.

Table 4
Transmission Forced Outage Data
1/1/1999 through 9/9/2003

Voltage Class	Line_ID	Outage Start Date	Outage Start Time	DUR (Min)	Outage End Date	Outage End Time	Outage Class	Primary Cause	Secondary Cause	Comments
230	MorroBay-MidwayNo1	5/7/1999	7:48	318	5/7/1999	13:06	F	UNKN	INSL	Replaced flashed and broken insulators due to trouble of 5/1/99 - temp. jumper MB.
230	MorroBay-MidwayNo1	11/26/2000	7:57	58	11/26/2000	8:55	F	PROT	NONE	Open ended at Midway due to CB 572 breaker failure relay misoperation.
230	MorroBay-MidwayNo1	1/11/2001	10:12	1	1/11/2001	10:13	F	LIGT	NONE	Unknown - lightning.
230	MorroBay-MidwayNo1	2/13/2001	9:32	14	2/13/2001	9:46	F	CB	NONE	Unusual snow & Morro Bay CB 522 failed to close by autos
230	MorroBay-MidwayNo1	1/1/2002	0:00	0	1/1/2002	0:00	N	NONE	NONE	zero outage
230	MorroBay-MidwayNo1	7/30/2003	5:17	1	7/30/2003	5:18	F	LIGT+J2	None	Relayed, tested OK; no interruptions, lightning in area
230	MorroBay-MidwayNo2	1/1/1999	0:00	0	1/1/1999	0:00	N	NONE	NONE	zero outage
230	MorroBay-MidwayNo2	12/21/2000	19:02	805	12/22/2000	8:27	F	CB	RELY	Open ended at Morro Bay to repair hydraulic leak on CB 522.
230	MorroBay-MidwayNo2	2/13/2001	9:40	237	2/13/2001	13:37	F	CB	CB	Snow; repaired Morro Bay CB 522.
230	MorroBay-MidwayNo2	10/23/2001	19:56	1438	10/24/2001	19:54	F	SEQP	INSL	Cleaned flashed insulators and adjusted Midway switch 545.
230	MorroBay-MidwayNo2	2/11/2002	16:42	1	2/11/2002	16:43	F	CB	NONE	Momentarily open ended at Morro Bay when Midway #11-500/230 Bk relayed, did not test.
230	MorroBay-MidwayNo2	7/30/2003	5:17	1	7/30/2003	5:18	F	LIGT	None	Relayed, tested OK; no interruptions, lightning in area.
230	MorroBay-Templeton	2/11/2000	22:12	117	2/12/2000	0:09	F	WEAT	COND	Patrol found 115 kV undercrossing top phase conductor contacted bottom phase 230 kV.

Table 4
Transmission Forced Outage Data
1/1/1999 through 9/9/2003

Voltage Class	Line_ID	Outage Start Date	Outage Start Time	DUR (Min)	Outage End Date	Outage End Time	Outage Class	Primary Cause	Secondary Cause	Comments
230	MorroBay-Templeton	6/14/2000	9:26	186	6/14/2000	12:32	F	LEQP	HDWR	Cleared to replace compression sleeve at tower 0/1.
230	MorroBay-Templeton	1/1/2001	0:00	0	1/1/2001	0:00	N	NONE	NONE	zero outage
230	MorroBay-Templeton	1/1/2002	0:00	0	1/1/2002	0:00	N	NONE	NONE	zero outage
230	Templeton-Gates	1/1/2000	0:00	0	1/1/2000	0:00	N	NONE	NONE	zero outage
230	Templeton-Gates	1/1/2001	0:00	0	1/1/2001	0:00	N	NONE	NONE	zero outage
230	Templeton-Gates	1/1/2002	0:00	0	1/1/2002	0:00	N	NONE	NONE	zero outage

Table 5
Primary and Secondary Outage Cause Codes, Outage Class Codes

PRIMARY CAUSE TRANSLATION TABLE			SECONDARY CAUSE	
PG&E Outage Root Cause Detail	CAISO Outage Primary Cause Code*	CAISO Outage Primary Cause Code Description	CAISO & PG&E Outage Secondary Cause Code*	CAISO & PG&E Outage Secondary Cause Code Description
Animal-bird	ANIM	Animal Contact	ARRS	Arrestor
Animal-ground	ANIM	Animal Contact	AUX	Station auxiliary equip (e.g., CT, PT, CCVT)
Contamination-agriculture	CNTM	Contamination	BATT	Battery system
Contamination-animal waste	CNTM	Contamination	BUSH	Bushing
Contamination-environmental	CNTM	Contamination	CB	Circuit breaker/Circuit switch
Contamination-industrial waste	CNTM	Contamination	COMM	Communication facility (no relay)
Disaster-earthquake	ND	Natural Disasters	COND	Conductor/shield wire/splice
Disaster-fire	FIRE	Fire	DISC	Disconnect
Disaster-flood	ND	Natural Disasters	ENCR	Encroachment
Disaster-other	ND	Natural Disasters	GUYS	Guy/anchor
Equipment Failure-arrestor	SEQP	Other Substation Equip Trouble	HDWR	Hardware, fittings, accessories
Equipment Failure-bus	SEQP	Other Substation Equip Trouble	INSL	Insulator (station/line)
Equipment Failure-bushing	SEQP	Other Substation Equip Trouble	LS	Line switch
Equipment Failure-ccvt	SEQP	Other Substation Equip Trouble	NONE	None
Equipment Failure-circuit breaker	CB	Circuit Breaker Trouble	REAC	Reactive device (e.g., capacitors, condensers)
Equipment Failure-conductor	LEQP	Line Equipment Failure	REG	Regulator
Equipment Failure-connector/hardware	LEQP	Line Equipment Failure	RELY	Relay/communications for relay
Equipment Failure-CT	SEQP	Other Substation Equip Trouble	STRU	Structure/foundation
Equipment Failure-insulator-line	LEQP	Line Equipment Failure	XFRM	Transformer/LTC
Equipment Failure-insulator-station	SEQP	Other Substation Equip Trouble	UG	Underground transmission component
Equipment Failure-other-line	LEQP	Line Equipment Failure	PROC	Work Procedure/Human error
Equipment Failure-other-station	SEQP	Other Substation Equip Trouble		
Equipment Failure-PT	SEQP	Other Substation Equip Trouble	*NOTE: Reference is the California ISO Maintenance Procedure No. 2 entitled "Outage Data File Format for the CAISO--Availability Performance Monitoring System", effective date 5/27/99, pages 2-8 through 2-11.	
Equipment Failure-reactive equipment	SEQP	Other Substation Equip Trouble		
Equipment Failure-regulator/LTC	SEQP	Other Substation Equip Trouble		
Equipment Failure-relay	PROT	Protection		

Table 5
Primary and Secondary Outage Cause Codes, Outage Class Codes

PRIMARY CAUSE TRANSLATION TABLE			SECONDARY CAUSE	
PG&E Outage Root Cause Detail	CAISO Outage Primary Cause Code*	CAISO Outage Primary Cause Code Description	CAISO & PG&E Outage Secondary Cause Code*	CAISO & PG&E Outage Secondary Cause Code Description
Equipment Failure-structure-line	LEQP	Line Equipment Failure		
Equipment Failure-structure-station	SEQP	Other Substation Equip Trouble	**OUTAGE CLASS**	
Equipment Failure-switch-line	LEQP	Line Equipment Failure	C Capped (at a 72 hour outage)	
Equipment Failure-switch-station	SEQP	Other Substation Equip Trouble	F Forced Outage	
Equipment Failure-transformer	SEQP	Other Substation Equip Trouble	N None (Zero Outage for that Year)	
External Contact-aircraft	AIR	Aircraft		
External Contact-car pole	VEH	Vehicles		
External Contact-foreign object	OTHR	Other		
External Contact-system disturbance	DIST	System Disturbance		
External Contact-vandalism	OTHR	Other		
Other-customer/IPP caused	OTHR	Other		
Other-distribution caused	UC	Utility Contact		
Other-generation caused	GEN	Generation Trouble		
Other-overload situation	DIST	System Disturbance		
Other-safety clearance	OTHR	Other		
Scheduled-approved	SCHD	Scheduled Outage		
Scheduled-disapproved	LATE	Late Notification		
Scheduled-extended	LATE	Late Notification		
Tree-3rd party	OTHR	Other		
Tree-failure	VEGA	Vegetation		
Tree-tree contact	VEGA	Vegetation		
Unknown-no patrol conducted	UNKN	Unknown		
Unknown-patrol found nothing	UNKN	Unknown		
Weather-lightning	LIGT	Lightning		
Weather-rain	WEAT	Weather		
Weather-snow/ice	WEAT	Weather		
Weather-wind	WEAT	Weather		
Work Procedure-design error	OPER	Operation Error		
Work Procedure-equipment incorrectly set	OPER	Operation Error		
Work Procedure-inattention or carelessness	OPER	Operation Error		
Work Procedure-miscommunications or unclear expectations	OPER	Operation Error		
Work Procedure-not following prescribed procedures	OPER	Operation Error		

Table 6
Transmission Line Maintenance Outage Data
11/1/2000 through 9/9/2003

Line Name	Voltage	Clearance Boundary	Actual Out Time	Actual Return Time	Duration (minutes)
Diablo-Midway #2	500	Midway 813, 913; Diablo 643, 741	03/14/2002 04:03	03/14/2002 10:03	360
Diablo-Midway #2	500	911, 913	06/03/2003 08:06	06/03/2003 15:06	420
Diablo-Midway #3	500	Midway 801, 901; Diablo 633, 733	03/06/2003 06:03	03/06/2003 18:03	720
Morro Bay-Gates #2	230	Morro Bay 483, 485; Gates 223, 225	05/15/2002 07:05	05/15/2002 12:05	300
Morro Bay-Gates #2	230	Morro Bay 483, 485; Gates 223, 225	07/23/2002 07:07	07/23/2002 16:07	540
Morro Bay-Gates #2	230	Morro Bay 483, 485; Gates 223, 225	07/24/2002 07:07	07/24/2002 15:07	480
Morro Bay-Gates #2	230	Morro Bay 483, 485; Gates 223, 225	06/11/2003 09:06	06/11/2003 13:06	240
Morro Bay-Mesa	230	Morro Bay 543, 545; Mesa 223, 225	05/22/2002 07:05	05/22/2002 15:05	480
Morro Bay-Mesa	230	Morro Bay 543, 545; Mesa 223, 225.	12/03/2002 07:12	12/03/2002 14:12	420
Morro Bay-Mesa	230	Mesa 223, 225; Morro Bay 543, 545	05/21/2003 08:05	05/21/2003 17:05	540
Morro Bay-Mesa	230	Mesa 223, 225; Morro Bay 543, 545	05/22/2003 08:05	05/22/2003 16:05	480
Morro Bay-Mesa	230	Morro Bay 223, 225; Mesa 543, 545	06/03/2003 07:06	06/03/2003 15:06	480
Morro Bay-Midway #1	230	Morro Bay 513, 515; Midway 533, 535	06/24/2002 07:06	06/24/2002 17:06	600
Morro Bay-Midway #1	230	Morro Bay 513, 515; Midway 533, 535	06/25/2002 07:06	06/25/2002 16:06	540
Morro Bay-Midway #1	230	Morro Bay 513, 515; Midway 533, 535	06/26/2002 10:06	06/26/2002 14:06	240
Morro Bay-Midway #1	230	Morro Bay 513, 515; Midway 533, 535	11/18/2002 08:11	11/18/2002 14:11	360
Morro Bay-Midway #1	230	Morro Bay 513, 515; Midway 537, 539	07/15/2003 00:07	07/15/2003 07:07	420
Morro Bay-Midway #1	230	Morro Bay 513, 515; Midway 537, 539	07/15/2003 23:07	07/16/2003 05:07	360
Morro Bay-Midway #2	230	Morro Bay 525, 523; Midway 543, 545	03/18/2002 07:03	03/18/2002 15:03	480
Morro Bay-Midway #2	230	Morro Bay 523, 525; Midway 547, 549, CB 542 and T-Tap	06/18/2002 07:06	06/18/2002 16:06	540
Morro Bay-Midway #2	230	Morro Bay 523, 525; Midway 547, 549, CB 542 and T-Tap	06/19/2002 07:06	06/19/2002 16:06	540
Morro Bay-Midway #2	230	Morro Bay 523, 525; Midway 547, 549, CB 542 and T-Tap	06/20/2002 07:06	06/20/2002 16:06	540
Morro Bay-Midway #2	230	Morro Bay 523, 525; Midway 547, 549, CB 542 and T-Tap	06/21/2002 07:06	06/21/2002 15:06	480
Morro Bay-Midway #2	230	Morro Bay 523, 525; Midway 547, 549	07/15/2003 00:07	07/15/2003 07:07	420
Morro Bay-Midway #2	230	Morro Bay 523, 525; Midway 547, 549	07/16/2003 00:07	07/16/2003 05:07	300

Table 6
Transmission Line Maintenance Outage Data
11/1/2000 through 9/9/2003

Line Name	Voltage	Clearance Boundary	Actual Out Time	Actual Return Time	Duration (minutes)
Diablo-Mesa	230	Diablo 283, 285; Mesa 213, 215	10/17/2002 07:10	10/17/2002 15:10	480
Diablo-Mesa	230	Diablo 283, 285; Mesa 277, 201, 287	12/16/2002 12:12	12/16/2002 15:12	180
Diablo-Mesa	230	Diablo 283, 285; Mesa 213, 215.	08/26/2003 09:08	08/27/2003 15:08	1800
Diablo-Mesa	230	Diablo 283, 285; Mesa 213, 215	09/19/2003 08:09	09/19/2003 15:09	420
Templeton-Gates	230	Gates 217, 219; Templeton 293	03/25/2003 08:03	03/25/2003 20:03	720
Templeton-Gates	230	Gates 217, 219; Templeton 293	04/30/2003 11:04	05/01/2003 16:05	1741
Templeton-Gates	230	Templeton 293; Gates 213, 215	06/12/2003 08:06	06/12/2003 17:06	540

PG&E Response to Question 1 on Diesel Generator Reliability

Reliability of the DCPP diesel generator (DGs) can be addressed in three ways; (1) DG hours unavailable due to planned and unplanned events, (2) DG failures to meet starting requirements on demand, and (3) maintenance related failures requiring a DG or related system to be placed in 10 CFR 50.65(a)(1) (Maintenance rule goal setting) status. DG hours unavailable is addressed in the regulatory assessment performance indicator (PI) data reported quarterly to the NRC in accordance with NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 2, dated November 2001. The PI values for the DCPP DGs for the period from the third quarter, 2001 through the second quarter, 2003 range from 0.7 percent to 0.9 percent for Unit 1 and from 0.5 percent to 0.6 percent for Unit 2. Actual planned and unplanned unavailable hours and PI values for the last eight quarters are shown in Table 7, "Unit 1 Safety System Unavailability, Emergency AC Power," and Table 8, "Unit 2 Safety System Unavailability, Emergency AC Power." The PI values are well below "Increased Regulatory Response Band" threshold of 2.5 percent specified by NEI 99-02. The DG PI values are calculated each quarter based on data from the previous 12 quarters. They reflect system unavailability due to both planned and unplanned unavailability and are calculated for each unit by summing the quarterly unavailability for all three trains and dividing by three, the number of trains in each unit.

Table 7
Unit 1 Safety System Unavailability, Emergency AC Power

	3Q/01	4Q/01	1Q/02	2Q/02	3Q/02	4Q/02	1Q/03	2Q/03
Train 1								
Planned unavailable hours	16.90	0.10	0	4.40	0	13.20	0	0
Unplanned unavailable hours	0	0	0	0	0	0	0	0
Fault exposure hours	0	0	0	0	0	0	0	0
Effective Reset hours	0	0	0	0	0	0	0	0
Required hours	2208.00	2209.00	2160.00	2183.00	2208.00	2209.00	2160.00	2183.00
Train 2								
Planned unavailable hours	32.20	0.10	0.10	2.20	0	18.00	0	0
Unplanned unavailable hours	0	0	0	11.90	0.10	0	0	0.20
Fault exposure hours	0	0	0	0	0	0	0	0
Effective Reset hours	0	0	0	0	0	0	0	0
Required hours	2208.00	2209.00	2160.00	2183.00	2208.00	2209.00	2160.00	2183.00
Train 3								
Planned unavailable hours	0.10	0.20	19.90	5.20	0	0	0	0
Unplanned unavailable hours	0	0	0	2.40	79.00	0	120.30	28.90
Fault exposure hours	0	0	0	0	0	0	0	0
Effective Reset hours	0	0	0	0	0	0	0	0
Required hours	2208.00	2209.00	2160.00	2183.00	2208.00	2209.00	2160.00	2183.00
Indicator value	**0.9%**	**0.8%**	**0.8%**	**0.7%**	**0.7%**	**0.7%**	**0.8%**	**0.8%**

Table 8
Unit 2 Safety System Unavailability, Emergency AC Power

	3Q/01	4Q/01	1Q/02	2Q/02	3Q/02	4Q/02	1Q/03	2Q/03
Train 1								
Planned unavailable hours	0.10	0.10	29.90	6.80	0	6.90	0	0
Unplanned unavailable hours	0	0	0	0	5.50	2.00	0	0.10
Fault exposure hours	0	0	0	0	0	0	0	0
Effective Reset hours	0	0	0	0	0	0	0	0
Required hours	2208.00	2209.00	2160.00	2183.00	2208.00	2209.00	2160.00	2183.00
Train 2								
Planned unavailable hours	0.30	0.10	29.00	1.90	0	0	0	0
Unplanned unavailable hours	0	0	0	3.10	0	0	0	52.30
Fault exposure hours	0	0	0	0	0	0	0	0
Effective Reset hours	0	0	0	0	0	0	0	0
Required hours	2208.00	2209.00	2160.00	2183.00	2208.00	2209.00	2160.00	2183.00
Train 3								
Planned unavailable hours	0.10	0.10	29.90	5.70	0	0	0	0
Unplanned unavailable hours	0	0	0	0	0	0	0	0
Fault exposure hours	0	0	0	0	0	0	0	0
Effective Reset hours	0	0	0	0	0	0	0	0
Required hours	2208.00	2209.00	2160.00	2183.00	2208.00	2209.00	2160.00	2183.00
Indicator value	**0.6%**	**0.6%**	**0.6%**	**0.6%**	**0.6%**	**0.6%**	**0.5%**	**0.5%**

DG failures to meet starting or surveillance test requirements is tracked by PG&E for each DG start. Such requirements include accelerating to 900 rpm within 10 seconds or less, reaching rated voltage and frequency in 13 seconds or less, and maintaining rated voltage and loading for the duration of the test or event. Provided below is a table showing DG failures for the last 20, 50, and 100 starts for each DG.

	Failure to meet starting or loading requirements in last number of starts (reliability* shown in parentheses)		
DG	Last 20 starts	Last 50 starts	Last 100 starts
1-1	0 (1.00)	0 (1.00)	2 (0.980)
1-2	0 (1.00)	1 (0.980)	1 (0.990)
1-3	2 (0.909)	3 (0.943)	4 (0.962)
2-1	0 (1.00)	1 (0.980)	2 (0.980)
2-2	1 (0.952)	1 (0.980)	1 (0.990)
2-3	0 (1.00)	0 (1.00)	0 (1.00)

The DG failure data presented above is consistent with the DG target reliability of 0.950 assumed for the DCPP station blackout (SBO) analysis submitted by PG&E Letter DCL-92-084, dated April 13, 1992, and approved by the NRC in a supplemental safety evaluation dated May 29, 1992. The DCPP SBO analysis was performed in accordance with NUMARC 87-00, Revision 1, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," dated August 1991. NUMARC 87-00 prescribes allowed target reliabilities to be:

Evaluation Criteria

Last 20 demands	>	0.90 reliability
Last 50 demands	>	0.94 reliability
Last 100 demands	>	0.95 reliability

*Where total reliability = $\frac{\text{total valid tests}}{\text{total valid tests + total valid failures}}$

(This reliability equation is used in PG&E Letter DCL-85-375, "License Amendment Request 85-15, Technical Specification 3.8.1.1, Electrical Power Systems, A.C. Sources," dated December 26, 1985, approved by License Amendments No. 9 (Unit 1) and No. 7 (Unit 2), dated June 20, 1986.)

NUMARC 87-00 further prescribes that for the class of plants to which DCPP is assigned, if any of the above three criteria are met; the unit may select a DG reliability target of 0.95 for determining the required SBO coping period. Therefore the current DG reliability status is consistent with previous analyses.

Finally, since 2001, there have been two DG or related systems placed in 10 CFR 50.65(a)(1) status. On March 28, 2001, Diesel Fuel Oil Transfer Pump No. 1 was placed in 10 CFR 50.65(a)(1) status due to age related degradation of the motor thermal overload relay. It was removed from 10 CFR 50.65(a)(1) status on October 1, 2002, following revision of the preventive maintenance procedure and successful testing for three quarters. On April 17, 2003, DG 1-2 was placed in 10 CFR 50.65(a)(1) status due to maintenance activities that allowed the lubricating oil to cool to an unacceptably low temperature.

NRC Question 2

It is the staff's understanding that the purpose of the requested amendment is to allow an increased outage time during plant power operation for performing DG inspection, maintenance, and overhaul, which would include disassembly of the DG. DG operability verification after a major maintenance or overhaul may require a full load rejection test. If a full load rejection test is performed at power, please address the following:

(a) What would be the typical and worse-case voltage transients on the 4160-V safety buses as a result of a full-load rejection?

(b) If a full-load rejection test is used to test the DG governor after maintenance, what assurance would there be that an unsafe transient condition on the safety bus (i.e., load swing or voltage transient) due to improperly performed maintenance or repair of a governor would not occur?

(c) Using maintenance and testing experience on the DG, identify possible transient conditions caused by improperly performed maintenance on the DG governor and voltage regulator. Discuss the electrical system response to these transients.

(d) Provide the tests to be performed after the overhaul to declare the DG operable and provide justification for performing those tests at power.

PG&E Response

2(a) The typical voltage response recorded on the 4 kV busses during full load rejection testing in accordance with Surveillance Test Procedure (STP) M-9D1, "Diesel Generator Load Rejection Test," is a small drop from the DG supported voltage to the off-site power source voltage. The largest drop yet recorded is 54 volts.

2(b) Maintenance testing that PG&E performs following any DG governor or voltage regulator maintenance is designed to preclude creating any transient conditions that would challenge a safety bus with the DG loaded. Normally, maintenance is not performed on the DG governors that would necessitate full load rejection testing. In cases where full load rejection testing is necessary, such as following replacement or tune-up of the governor, the governor's response is first verified during an idle run prior to paralleling the DG to the bus. This is performed by "bumping" the fuel rack and causing a speed transient. The transient is observed both visually using attached instruments and physically by observing the fuel rack's return to a stable state. This ensures that prior to paralleling, the governor is working correctly. Electrical Maintenance Procedure MP E-21.6, "Diesel Generator Governor and Voltage Regulator Adjustment," is used for governor tune-up. It directs the technician to ask the operator in the control room to raise the DG frequency to 61 Hz, then to lower it to 59 Hz and then to raise it back to 60 Hz to ensure proper operation of the motor-operated potentiometer. This procedure also verifies proper null voltage, stability and gain of the electronic governor with the engine idling. Each of these items could cause load swings during parallel operation and therefore they are set and verified prior to parallel operation.

2(c) Except for tune-up maintenance per MP E-21.6, there is no maintenance performed on the DG electronic governors. Unless governor replacement is required due to failure, usually no adjustments are necessary and MP E-21.6 is followed to verify proper governor response (stability, amplifier gain) and proper set-up values for droop and load gain. Based on experience, once the values of droop and load gain are set, no adjustments are needed unless the governor is replaced.

The only maintenance performed on the mechanical governor is oil change-out. This maintenance does not affect the performance of the mechanical governor. If the mechanical governor is replaced, then set-up of governor linkages and electronic governor null voltage is performed in accordance with MP E-21.6. Proper operation of the governor is verified prior to paralleling the DG to the bus.

Except for periodic inspection of the solder joints on the automatic voltage regulator card there is no maintenance involved on the voltage regulator. After the voltage regulator is initially set for stability and voltage range, it does not require any adjustments.

Since proper operation of the governors is verified prior to paralleling the DG to the bus, no electrical transients are expected, nor have been experienced, as a result of maintenance.

2(d) Normally, after maintenance is completed, the DG is started manually and is run to ensure proper operation and control of the voltage regulator and the governor. During this run, voltage regulator and governor tune-up verification is performed. Post maintenance testing to determine DG operability is performed using monthly test STP M-9A, "Diesel Engine Generator Routine Surveillance Test." The DG is paralleled and loaded to 2600 kW and run for one hour. If the governor or voltage regulator was replaced, or tune-up was required, then full load rejection testing would be performed at the end of the STP M-9A test by opening of the emergency diesel generator (EDG) output breaker in accordance with STP M-9D1. Historically, no problems have been encountered resulting in unacceptable plant transients due to DG full load rejection testing, including performance of the test at power.

Copies of STP M-9A and STP M-9D1 are provided in Enclosure 4.

NRC Question 3

What type of communication has been established between the control room operator at Diablo Canyon Plant and the System Load Dispatcher? Is the System Load Dispatcher notified in advance that the DG is going to be out for extended period of time?

PG&E Response

DCPP Operating Procedure OP J-6B:VII, "Diesel Generator - Clearing," Prerequisite 4.2 provides the following guidance:

> *"The potential for a loss of off-site power should be minimized during a Diesel Generator out-of-service time. The Diablo Switchyard Operator should be notified as far in advance as reasonable prior to clearing a Diesel Generator for planned maintenance work and again when a Diesel Generator has been made available. This will limit the instances of simultaneous maintenance on off-site transmission equipment and the diesel generators."*

NRC Question 4

Other licensees who requested for DG AOT extension provided the following Regulatory Commitments in their requests:

A. *Weather conditions will be evaluated prior to entering the extended DG AOT for voluntary planned maintenance. An extended DG AOT will not be entered for voluntary planned maintenance purposes if official weather forecasts are predicting severe conditions (tornado or thunderstorm warnings).*

B. *The condition of the offsite power supply and switchyard will be evaluated prior to entering the extended AOT.*

C. *No discretionary switchyard maintenance will be allowed. In addition, no discretionary maintenance will be allowed on the main, auxiliary or startup transformers associated with the unit.*

D. *No maintenance or testing that affects the reliability of the train associated with the OPERABLE DG will be scheduled during the extended AOT. If any testing and maintenance activities must be performed while the extended AOT is in effect, a 10CFR50.65 (a)(4) evaluation will be performed.*

E. *The steam driven emergency feedwater pump will not be taken out of service for planned maintenance activities and will be treated as protected equipment.*

F *The system dispatcher will be contacted once per day and informed of the DG status along with the power needs of the facility.*

G. *The on-shift Operations crews will discuss and review appropriate normal and emergency operating procedures upon or prior to assuming the Watch for the first time after having scheduled days off while the AOT is in effect.*

H. *The Operations crews will be briefed concerning the unit activities, including compensatory measures established and the importance of the alternate ac source following instruction of the Shift Manager upon the loss of power event. This briefing will be performed upon or prior to assuming the Watch for the first time after having scheduled days off while the AOT is in effect.*

Please provide the provisions, limitations and compensatory actions that you will be committing to implement to assure adequate defense in depth, during the extended DG AOT.

PG&E Response

On-line DG maintenance utilizing the extended completion time proposed by LAR 03-06 will be controlled in accordance DCPP Administrative Procedure AD7.DC6, "On-Line Maintenance Risk Management." AD7.DC6 guidance includes evaluating risk in accordance with 10 CFR 50.65(a)(4) (maintenance rule), establishing compensatory measures, and assuring the work is scheduled in the appropriate train/bus/set workweek. A copy of AD7.DC6 is provided in Enclosure 2.

In addition, as has been done for past for major DG on-line maintenance, operational instructions and contingency plans will be provided by a temporary procedure (TP) or other appropriate procedure. The procedure will include prerequisites, precautions and limitations, and compensatory measures similar in scope to the examples provided in the NRC question above. An example TP is provided in Enclosure 3 (TP TO-0105, "Diesel Generator 2-1 On-Line Maintenance").

Rather than prescribing a specific set of provisions, limitations, and compensatory measures in advance for future extended DG maintenance periods, such limitations will be evaluated based on the plant and grid conditions present at the time of each extended DG maintenance period, and will comply with AD7.DC6 and will be similar in scope to those identified in TP TO-0105.

NRC Question 5

On Page 22, Item 3, it is stated that only one major overhaul (in excess of 7 days) will be performed per DG per refueling. It is also stated that the increase in "at-power" DG unavailability given the extension in completion time is 2.2 days per year. It is not clear to the staff how with the performance of one major overhaul per DG, per refueling (which takes in excess of seven days), the increase in unavailability will only be 2.2 days. Please explain.

PG&E Response

The discussion of the approach for calculating the change in the annual average core damage frequency due to the change in the DG completion time starts on page 19 of

PG&E Letter DCL-03-060, dated May 29, 2003. On page 20 of DCL-03-060, the following definition is provided for T_{x-x} (e.g. T_{1-1}):

> *"Additional time per year (T_{YEAR}) that DG 1-1 is out of service (OOS) as a result of extending the completion time."*

The important word in the definition is "additional."

Starting on page 21 and continuing on page 22, DCL-03-060 addresses the predicted additional time, not the total time, due to the proposed change in the DG completion time. For example, on page 21 (bottom of the page), it is stated that:

> *"The amount of time to be added to future on-line unavailability due to moving preventative maintenance work out of refueling outages is approximately 29 hours per year. Currently, a significant portion of the DG preventative maintenance is already performed on-line."*

Therefore, 2.2 days is PG&E's prediction of the average additional unavailability time per year (note that one major overhaul will be per refueling outage (i.e. once per 18-21 months). Currently, on average, a DG OOS time is 5 days annually (under the current 7-day Technical Specification completion time). With the proposed 14-day completion time, PG&E expects this yearly average OOS time to increase to 7.2 days.

It is also noted that the incremental conditional core damage probability, which is the incremental probability of a core damage event over a period of time equal to the proposed extended completion time (14 days), is discussed on pages 23-25 of DCL-03-060.

NRC Question 6

Page 8 of your submittal provides a discussion of SBO. Please provide additional information as to what is considered a SBO and how SBO is modeled.

PG&E Response

Page 8 of DCL-03-060, under "Station Blackout Capacity," presents the prescriptive definition of SBO at DCPP, and the prescriptive basis for being able to cope with such a SBO condition.

In the DCPP probabilistic risk assessment (PRA) model, consistent with the industry PRA practices, SBO is treated as the loss of all onsite and offsite AC power. In a SBO sequence, the operators are instructed to depressurize the steam generators using the 10 percent steam dump valves or the 40 percent steam dump valves to limit reactor coolant pump (RCP) seal leakage. The turbine-driven auxiliary feedwater pump is credited to cool the reactor coolant system (RCS). These actions reduce RCS

temperatures and pressures sufficiently to allow the accumulators to inject their contents into the RCS. The accumulator inventories provide additional RCS inventory, which must also leak out if the core is to be uncovered. The reduced RCS temperatures and pressures limit the rate of seal degradation and minimize the rate of subsequent leakage. Failure of these actions reduce the time available for recovery of electric power because the RCP seal leak rate would be higher. These actions are all considered in the determination of success criteria for the electric power recovery factors.

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

The following should be noted relative to SBO scenarios:

- No electric power recovery action is credited for the SBO scenarios in which a pressurizer power operated relief valve or safety valve fails to reseat, resulting in a loss-of-coolant accident path.

- Following recovery of a DG during a SBO, operator action is credited to cross-tie two vital buses.

Diablo Canyon Power Plant Administrative Procedure AD7.DC6, "On-Line Maintenance Risk Management"

TITLE: On-Line Maintenance Risk Management

10/24/02
EFFECTIVE DATE

PROCEDURE CLASSIFICATION: QUALITY RELATED
SPONSORING ORGANIZATION: OPERATIONS
REVIEW LEVEL: "A"

TABLE OF CONTENTS

1. SCOPE

1.1 This procedure provides guidance for managing plant trip, probabilistic, and safety function degradation risk from on-line maintenance, external or internal conditions, as required by 10 CFR 50.65(a)(4) of the Maintenance Rule.

1.2 These instructions shall be used for risk management when the unit is in MODES 1, 2, 3 and 4. Risk management in MODES 5 and 6 is addressed in AD8.DC50 through AD8.DC55.

1.3 Risk in the transitional MODE 4 will be controlled as follows:

1.3.1 Any maintenance on risk significant Systems, Structures, or Components (SSCs) in MODE 4 will require specific authorization of the operations manager.

1.3.2 Risk significant equipment removed from service in accordance with Tech Spec requirements (e.g., isolating a CCP and the SIPs per SR 3.4.12.1 and SR 3.4.12.2) does not require special authorization.

1.3.3 Qualitative evaluation based on Key Safety Function degradation should be performed for risk significant equipment removed from service in MODE 4. No quantitative core damage frequency values should be used since the probabilistic risk analysis is based on a full power model.

1.4 Certain risk significant components cannot be taken out of service for on-line maintenance or result in very short Tech Spec action statements. In these cases, risk insights provide limited value. Therefore, this procedure will limit itself to assessing probabilistic and safety function degradation risk on SSCs listed in Attachment 9.1. See also reference 7.7 for bases.

2. DISCUSSION

2.1 Risk from performing maintenance on-line is minimized by:

2.1.1 Performing only those preventative and corrective maintenance items on-line required to maintain the reliability of the structure, system, or component (SSC).

2.1.2 Minimizing cumulative unavailability of safety-related and risk significant SSCs by limiting the number of at-power maintenance outage windows (MOW) per cycle per train/component. Refer to AD7.ID4.

2.1.3 Minimizing the total number of SSCs out-of-service (OOS) at the same time.

2.1.4 Minimizing the risk of initiating plant transients (trips) that could challenge safety systems by implementing compensatory measures.

2.1.5 Avoiding higher risk combinations of OOS SSCs using Probabilistic Risk Assessment (PRA) insights.

2.1.6 Maintaining "defense in depth" by avoiding combinations of OOS SSCs that are related to similar safety functions or that affect multiple safety functions.

2.2 Scheduling the SSCs in the 12 week rolling matrix according to their Train/Bus/Set relationship minimizes a large part of the Tech Spec conflict and risk factor. Refer also to AD7.ID4.

2.3 Risk is managed as follows:

2.3.1 Plant trip risk activities or conditions are evaluated qualitatively and mitigated by:

a. Taking appropriate compensatory measures; and/or

b. Ensuring defense-in-depth for safety systems that are challenged by a plant trip.

2.3.2 Risk significant equipment OOS configurations (singles and pairs of components) affecting Core Damage Frequency (CDF) have been quantitatively pre-analyzed by probabilistic risk methods.

2.3.3 The ability of SSCs to support Key Safety Functions (KSFs) that protect the fission product barriers (clad, RCS, and containment) is evaluated qualitatively.

2.3.4 Compensatory measures and management authorization may be required to allow higher risk configurations for planned maintenance. Management notification may be required for emergent higher risk situations.

3. RESPONSIBILITIES

3.1 The engineering director is responsible for overall administration of the Maintenance Rule per MA1.ID17.

3.2 The scheduling supervisor is responsible for overall coordination of scheduling on-line maintenance in accordance with this instruction and AD7.ID4.

3.3 The cognizant manager is responsible for identifying and proposing compensatory measures for HIGH or VERY HIGH risk activities performed by their groups per MA1.DC10 and MA1.DC11.

3.4 The operations manager is responsible for approving higher risk OOS configurations as identified by this instruction.

3.5 The operations work control supervisor and the daily scheduling supervisor are responsible for overall implementation of the on-line risk management program.

3.6 The operations work week manager (or, in his absence, an OPS Shift Manager) is responsible for ensuring risk assessments for planned maintenance are completed in accordance with this instruction and AD7.ID4.

3.7 The operations shift foreman is responsible for:

- Verifying risk assessments for planned activities are valid; and for
- Performing risk assessments for emergent conditions affecting the plant in accordance with this instruction and AD7.ID4.

3.8 The PRA supervisor is responsible for:

- Providing the risk insights and numerical risk values for this procedure; and for
- Maintaining the ORAM-Sentinel software.

4. DEFINITIONS

4.1 **Compensatory Measures** - Actions taken to mitigate the risk from planned or emergent plant equipment conditions or external or internal conditions. Examples include:

NOTE: Deferral of elective work to avoid unacceptable risk is an assumed option.

4.1.1 Risk Awareness

- Tailboards, PA announcements, Plan of the Day, special notices, etc.
- Direct supervisory oversight.
- Upper Management authorization.
- Abnormal or infrequent evolution briefings.

4.1.2 Minimize duration of the activity or condition

- Pre-planning - Tailboards, pre-job walkdowns, pre-staging equipment and supplies, mock-up training.
- Contingency planning - Canned tailboards, JIT simulator training, temporary procedures, call-out lists, back-out criteria, etc. (plan for failure).
- Augmented coverage - Working two (2) shifts/day, around-the-clock coverage.

4.1.3 Mitigate Consequences

- Protect redundant equipment - barricading OPERABLE DEGs during redundant DEG MOWs, offsite power outages, or grid instability; restricting activities in the 500kV and 230kV yards when DEGs are out of service.

4.2 **Core Damage Frequency (CDF)** - The instantaneous risk of a core damaging accident's occurrence expressed as occurrences per year.

4.2.1 The plant specific Probabilistic Risk Analysis (PRA) calculates CDF for various plant configurations and accident scenarios.

a. For example, the CDF for operating the plant with all safety systems available (no maintenance case) is about 1E-5/yr; that is, a core damaging accident might be expected to occur about once every 100,000 years.

b. If startup power were to be removed from service for the whole year, the CDF would increase by about a factor of 10 to about 1E-4/yr, or once every 10,000 years.

4.2.2 Because the PRA model evaluates individual component failures, the CDF for Train Level SSCs in this procedure are sometimes composite values representative of the train vice specific components.

4.3 **Core Damage Probability (CDP)** - The product of the CDF and the out-of-service duration. This represents the actual risk of a core damaging event occurring during a given period of time.

4.3.1 From the above example, if startup power was to be out-of-service for six (6) hours, the core damage probability would be:

$$\frac{(1E-4/yr)(6\ hrs)}{8760\ hrs/yr} = 6.9E-8$$

4.4 **Degraded** - SSC condition or performance is below nominal. May still be considered OPERABLE, but operation may be curtailed or under increased monitoring. Examples include:

- SSCs in Maintenance Rule (a)(1) (goal setting) status or approaching performance criteria limits.
- SSCs on the Predictive Maintenance "Equipment Watch List."
- SSCs on alert frequency Surveillance Testing (PX ALRT ARs).
- SSCs requiring compensatory measures per Prompt Operability Assessments or Operability Evaluations (refer to OM7.ID8 and OM7.ID12).
- SSCs with other significant existing deficiencies (CM or AT EQPR or EVAL ARs, operator workarounds, etc.).

4.5 **External Risk** - Trip Risks from factors originating outside the plant boundaries. Severity of trip risk will be evaluated qualitatively on a case-by-case basis. The following examples should be classified as High Trip Risks:

4.5.1 Offsite power system induced trip risks:

NOTE: External risks affecting offsite power may also affect plant trip mitigation SSCs.

- Peak power demand (i.e., CAISO stage 3 or higher grid emergencies).
- Fires threatening offsite power source lines.
- Storms (wind, rain, etc.).

4.5.2 Direct trip risk from storms:

- High ocean swell warning. (Refer to OP O-28, "Intake Management.")
- Lightning strikes, etc.

4.5.3 Seismic risk factors.

- Parkfield Level A earthquake prediction. (Refer to CP M-4, "Earthquake.")
- Tsunami warning. (Refer to CP M-5, "Tsunami Warning.")

4.6 **Internal Risk** - Risks from operations, maintenance, and environment originating inside the plant boundaries.

4.6.1 Examples of environmental effects include fire, flooding, high and medium energy line breaks.

4.6.2 So long as compensatory measures are put in place per the Equipment Control Guideline actions for degraded engineered features, risk to adjacent components is considered insignificant.

4.6.3 Failure to implement ECG actions within the required time limits should require an after the fact risk assessment by the PRA Group. This includes:

- Fire protection - Barriers, doors, detection, suppression, etc. (ECG 18).
- Flooding - Doors, barriers, drains, etc. (ECG 80).
- High and Medium Energy Line Breaks - Doors, blow-out panels, etc. (ECG 80).

4.7 **Key Safety Function (KSF)** - A function required to protect the fission product barriers. Degradation of "defense in depth," the ability to maintain the KSF, is evaluated by the use of logic trees when removing Risk Significant SSCs from service for maintenance. This assessment is independent of the PRA AOT method.

4.7.1 These KSFs correspond to the critical safety functions in the Emergency Operating Procedures (EOP) Function Restoration Guidelines (FRGs) that mitigate extreme - RED, or severe - MAGENTA, challenges to the barriers.

NOTE: The RCS inventory critical safety function in the FRGs was not included because there are no RED or MAGENTA paths in that series of procedures.

4.7.2 Two additional support functions, Component Cooling and Vital Electric Power, were created in addition to those in the FRGs. Many individual components can be affected by a degradation of these support systems. For ease of use, rather than evaluate the affect on each supported component, the new KSFs were created.

4.7.3 Similar to the FRGs, KSF defense in depth degradation is represented by a color.

a.	GREEN	KSF fully satisfied
b.	YELLOW	Moderate degradation
c.	ORANGE	Significant degradation
d.	RED	Severe degradation

4.8 **Large Early Release Frequency (LERF)** - The instantaneous risk to the public from releases via penetration failures three (3) inch diameter and larger before the plant's emergency response plan has been implemented in an accident scenario. The only release pathway this large that could be affected by maintenance is the vacuum/pressure relief or containment purge and exhaust valves.

4.8.1 LERF risk is evaluated qualitatively under the Containment Key Safety Function.

a. For example, venting of containment for pressure relief should be avoided if a Train Level SSC affecting CDF was OOS giving a yellow Core Cooling or Containment Key Safety Function color (e.g., RHRP give yellow for both).

b. Alternatively, the example above would be acceptable if compensatory measures to mitigate the risk were implemented such as increased risk awareness tailboards, contingency planning in the event of a leak, etc.

c. If an inoperable penetration is isolated to comply with Tech Spec 3.6.3 actions, those compensatory measures are sufficient to mitigate the LERF risk. No other risk management actions would be required.

4.9 **Probabilistic Risk Assessment Allowable Outage Time (PRA AOT)** - The number of hours a single or combination of Risk Significant Train Level SSCs may be OOS before the time-integrated risk addition to the "no maintenance case" Core Damage Probability (CDP) exceeds 1E-6. Industry PRA guidelines define a change of less than 1E-6 as "insignificant risk increase." The PRA AOT is used as a "ruler" to compare the relative risk of removing Risk Significant Train Level SSCs from service.

4.10 **Risk Significant** - As defined by MA1.ID17, a SSC is deemed to be risk significant if:

4.10.1 It is a significant contributor to the plant specific PRA;

4.10.2 If it provides or supports a Key Safety Function; or

4.10.3 It has been judged to be risk significant by the Maintenance Rule expert panel.

NOTE: Certain risk significant components cannot be taken out of service for on-line maintenance or result in very short Tech Spec action statements. In these cases, risk insights provide limited value. Therefore, this procedure will limit itself to assessing probabilistic and safety function degradation risk on SSCs listed in Attachment 9.1. See also reference 7.7 for bases.

4.11 **Threshold PRA AOT** - The PRA AOT of the riskiest single Risk Significant Train Level SSC normally allowed to be removed from service for on-line maintenance. It is reasoned that any combination of Risk Significant Train Level SSCs may be removed from service as long as it is allowed by Tech Specs, OP1.DC17, and the combination is no riskier than the riskiest single Risk Significant Train Level SSC.

4.12 **Train Level SSC (TLS)** - Equipment name that represents the train affected by individual component maintenance or failure. For example:

OOS Component	TLSSC
FCV-95	AFWP1
8803A	CCP1*
8807B	SIP2
Opposite Unit ASW pp	FCV-601

4.13 **Trip Mitigation SSC** - The primary SSCs that are immediately challenged during a normal plant trip (no safety injection). Loss of redundancy for these SSCs present significant complications in the event of a plant trip:

- Offsite power sources (230kV initially, 500kV with delayed access)
- Emergency Diesel Generators (backup to 230kV startup)
- Auxiliary Feedwater trains
- Auxiliary Saltwater trains

4.14 **Trip Risk** - Any activity that could lead to a reactor or turbine trip. Turbine and reactor trips represent the most likely transient initiators leading to core damaging and large early release events.

4.14.1 HIGH risk activities evaluated per MA1.DC10 or MA1.DC11 are considered Trip Risks by this procedure *only* if they might lead to a transient having a significant effect on reactor power (>2%RTP). See Reference 7.9.

5. PRECAUTIONS AND LIMITATIONS

5.1 The 12 week rolling matrices shown in Attachment 9.2 are FOR INFORMATION ONLY. The Daily Work Coordination Group (DWC) keeps current versions of the matrices for each unit.

5.2 Current PRA AOT values are found using the on-line risk assessment computer program ORAM-Sentinel. PRA AOT values for single configurations are documented on Attachment 9.1.

5.3 The SFATs are based on the equipment importance in accident mitigation as described in the EOP background documents. SFATs are displayed using ORAM-Sentinel software.

6. INSTRUCTIONS

6.1 Developing the 12 Week Rolling Matrix

6.1.1 The 12 Week Rolling Matrix (Matrix) is based on the STPs performed in MODE 1 for all the major risk significant SSCs. (Refer to Attachment 9.1, List of Risk Significant Systems.)

6.1.2 The weeks are categorized by 3 methods.

a. SSPS Train relation - A, B, or A/B

b. Vital bus relation - F, G, H, or Non-bus

c. Protection Set relation - I, II, III, IV

d. Thus, the 4 week sub-cycle within the 12 week cycle is:

1.	Train A/B	Bus H
2.	Train B	Bus G
3.	Train A	Bus F
4.	Train A/B	Non-bus

e. Protection set weeks are spread over the full 12 week cycle.

6.1.3 Each week is further subdivided into two work windows; Tuesday-Wednesday, Thursday-Friday - each 48 hours long.

a. This is consistent with the AD7.ID4 requirement that T.S. SSCs out-of-service (OOS) duration be scheduled not to exceed 1/2 the Tech Spec Action Allowable Outage Time (AOT). For most ESF components, this is 1/2 of 72 hours: 36 hours.

b. This also provides time separation for working two safety related SSCs in the same week.

6.1.4 Compile a listing of the quarterly and monthly STPs for the major SSCs.

6.1.5 Classify the SSCs by SSPS train, vital bus and protection set as described above and spread out the STPs through the 12 week cycle in their appropriate train/bus/set weeks (refer to Attachment 9.2, Sample 12 Week Rolling Matrix).

a. Group the STPs at the train level if possible, for example slave relay test with pump test and associated valve tests.

b. Levelize for daily work loading, cross-discipline support required for test performance, opposite unit testing schedule, test instrumentation requirements. etc.

6.1.6 Analyze weeks for possible trip risks, train level probabilistic risk, and safety function degradation conflicts as described below and correct as required.

6.1.7 Revisions to the matrix should be minimized.

a. If changes are found to be necessary, follow above guidance and analyze for risk similarly.

b. STP performance should be short cycled as required to avoid use of surveillance interval grace period during transition to the revised matrix. (Refer to AD13.DC1.)

6.1.8 The Matrix Coordinator should mark up a long-term matrix spreadsheet (example: Attachment 9.3) or schedule with planned MOWs from the PIMS PM RTS due dates and other Daily Work Coordination (DWC) reports.

a. Identify all MOWs on the spreadsheet to help visualize the SSCs OOS at the same time for risk assessment and workload levelization.

b. Verify Risk Significant SSC MOWs are correctly scheduled in their train/bus/set week to align with the component STP. Correct the PIMS/P3 schedule if necessary or obtain Work Week Manager (WWM) approval for deviation.

c. Schedule so that the STP provides the PMT for the maintenance on the SSC.

6.2 Managing Risk in the Maintenance Planning Phase

6.2.1 The OPS work week managers shall ensure risk management actions are completed for planned work considering:

a. Expected plant conditions during the week.

b. Expected external conditions due to seasonal effects (e.g., storm or fire season, summer peak loads, etc.).

6.2.2 Determine the activities scheduled for the week that are Trip Risks.

6.2.3 Determine the Risk Significant SSCs that are scheduled to be OOS. Classify them at the train level (TLS). Refer to Attachment 9.1.

a. For each TLS, determine its current unavailability and health of its redundant train.

1. The cognizant system engineer and/or maintenance manager should give concurrence to schedule or consider deferral of maintenance.

a) If the TLS is approaching or will exceed 75% of its Maintenance Rule Availability Performance Criteria; or

b) If the TLS's redundant train is Degraded.

6.2.4 If a Trip Risk is scheduled concurrently with OOS or degraded trip mitigation TLSs, attempt to separate the activities.

6.2.5 If two or more TLSs are scheduled to be OOS in the same week, attempt to separate the work to avoid overlap.

6.2.6 Determine the risk configurations during the week (unique plant states where one or a combination of trip risks or TLSs will be OOS).

6.2.7 Manage the trip risk, probabilistic risk, and/or safety function degradation associated with each configuration as described in Steps 6.4, 6.5 and 6.6.

6.2.8 Propose risk mitigation compensatory measures, as appropriate.

6.2.9 Document risk management actions for each configuration on a TS sheet per OP1.DC17.

6.3 Managing Risk in the Maintenance Execution Phase (Real Time)

6.3.1 The SFM shall evaluate and manage the risk of all activities or conditions based on the current plant state:

a. Before any planned OR emergent maintenance is to be performed.

b. As soon as possible when an emergent plant condition is discovered.

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

6.3.2 Verify if the activity or condition is a Trip Risk and manage per step 6.4.

6.3.3 Determine if the activity removes a TLS from service, and

a. Manage probabilistic risk per step 6.5.

b. Manage safety function degradation per step 6.6.

6.3.4 If the redundant train remaining in service is degraded, implement additional compensatory measures.

6.3.5 If the evaluation reveals unacceptable risk, determine course of action based on restoration of safety function first, PRA aspects second.

6.3.6 Document risk management actions for each configuration on a TS sheet per OP1.DC17.

6.4 Plant Trip Risk Assessment

6.4.1 For pre-planned trip risk activities:

a. Ensure the work group proposing Trip Risk activities completes the appropriate authorization form from MA1.DC10 or MA1.DC11.

b. Concur with or propose compensatory measures to mitigate the trip risk, as appropriate.

c. Check for concurrent OOS or degraded plant trip mitigation TLSs using ORAM-Sentinel or TS Sheet review (offsite power, DEGs, AFW, or ASW). If present:

1. Obtain OPS manager authorization for concurrent performance.

2. Implement additional compensatory actions, as appropriate

3. Document condition and basis for approval on the appropriate TS Sheet.

6.4.2 For emergent plant trip risk activities or conditions:

NOTE: Emergent External Conditions should be treated as Trip Risks.

a. Implement immediate compensatory measures, as appropriate.

b. Check for concurrent OOS or degraded plant trip mitigation TLSs using ORAM-Sentinel or TS Sheet review. If present:

1. Implement additional compensatory measures to mitigate risk, as appropriate.

2. Notify the operations manager.

3. Document condition in an Action Request.

6.5 Probabilistic Risk Assessment

NOTE: If the OOS TLS is a Trip Mitigation TLS, also check for concurrent Trip Risk using ORAM-Sentinel or TS sheet review and evaluate per step 6.4.

6.5.1 Determine the PRA AOT for the single or combination of TLSs OOS by using ORAM-Sentinel. If ORAM-Sentinel is not available, determine PRA AOT as follows:

a. Use Attachment 9.1 to obtain PRA AOT values for a single TLS OOS.

b. Contact the PRA group for any multiple TLSs OOS.

6.5.2 If the scheduled duration of work is less than the PRA AOT, determine and implement appropriate compensatory measures.

6.5.3 If the PRA AOT is less than the threshold PRA AOT:

a. Verify operations manager approval (or notification for emergent conditions) regardless of the scheduled duration. Scheduled duration is a factor that will be of importance in the decision process.

b. Basis for approval should be documented.

c. Determine and implement additional compensatory measures, as appropriate

d. Document the higher risk configuration in on the TS sheet.

6.5.4 If the scheduled duration of work is greater than the PRA AOT, then:

NOTE: If the duration of work exceeds the PRA AOT then, by definition, the risk increase is no longer insignificant.

a. Verify operations manager approval (or notification for emergent conditions).

b. Document basis for approval.

c. Determine and implement additional compensatory measures, as appropriate.

d. Document the higher risk configuration in an action request.

6.6 Safety Function Degradation Assessment - For each configuration determined above, assess and manage the degradation of Key Safety Functions.

6.6.1 Determine the Key Safety Functions that are affected by the OOS TLS(s) by using the PC program ORAM-Sentinel. If ORAM-Sentinel is not available, use Attachment 9.1 to determine KSF score for a single SSC TLS, or contact the PRA group.

6.6.2 Determine the degree of degradation (color) of each affected Key Safety Function by selecting the affected TLS in ORAM-Sentinel.

6.6.3 If any TLS OOS combination results in a RED terminus.

a. The condition is not normally allowed and may be a Tech Spec violation.

b. Prior PSRC approval (operations manager notification for emergent conditions) is required.

c. Document the RED KSF configuration in an Action Request.

6.6.4 If any TLS OOS combination results in an ORANGE terminus:

a. Verify operations manager approval (or notification for emergent conditions).

b. Document basis for approval.

c. Determine and implement additional compensatory measures, as appropriate.

d. Document emergent ORANGE configuration in an Action Request.

6.6.5 If an OOS TLS or combination results in one or more YELLOW terminuses, evaluate as follows:

a. The Key Safety Functions yellow terminuses are assigned weighting factors in accordance with their importance IAW EOP FR F-0:

1.	Subcriticality	=5
2.	Core Cooling	=4
3.	Heat Sink	=3
4.	RCS Integrity	=2
5.	Containment	=1
6.	Vital Power	=5
7.	Component Clg	=5

b. If the sum of the weighting factors for the YELLOW terminuses is 8 or greater, then:

1. Verify operations manager approval (or notification for emergent conditions).
2. Document basis for approval.
3. Determine and implement additional compensatory measures, as appropriate.
4. Document emergent configurations with KSF ≥ 8 in an Action Request.

c. If the sum of the weighting factors for the YELLOW terminuses is less than 8, determine and implement compensatory measures, as appropriate.

7. REFERENCES

7.1 10 CFR 50.65 "The Maintenance Rule."

7.2 ERIN Engineering, "Equipment Out -of -Service Monitoring for the Maintenance Rule at Diablo Canyon - Technical Basis Document," dated 10/95.

7.3 NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," dated 7/2000.

7.4 NRC Inspection Manual, Inspection Procedure 62706, "Maintenance Rule," dated 8/31/95.

7.5 AD7.ID4, "On-Line Maintenance Scheduling."

7.6 OP1.DC17, "Control of Plant Equipment Required by the Technical Specifications or Other Designate Programs."

7.7 Procedure History Sheet for AD7.DC6 Rev 1, "Bases For Attachment 9.1, "Risk Significant Train Level SSCs."

7.8 PG&E PRA Calculation File C13, Revision 1, "PRA Evaluation of Various Maintenance Configuration to Support the On-Line Maintenance Risk Assessment Procedure (AD7.DC6)," 08/31/01.

7.9 Action Request A0551882, "AD7.DC6, RISK MANAGEMENT VS. MA1.DC11, WORK RISK ASSESSMENT".

8. RECORDS

None

9. ATTACHMENTS

9.1 "Risk Significant Train Level SSCs," 11/08/01

9.2 "Sample 12 Week Rolling Matrix," 05/23/96

9.3 "Sample MOW Planning Spreadsheet," 05/23/96

9.4 "On-Line Risk Management Summary," 11/08/01

10. SPONSOR

A.J. Chitwood

DIABLO CANYON POWER PLANT
AD7.DC6
ATTACHMENT 9.1

TITLE: Risk Significant Train Level SSCs

Sys	Trn	Bus	Train Level SSC (See Notes)	Risk Signif-icant	PC1	SFAT	PRA	PRA AOT	Sub critical-ity	Core Cool-ing	Heat Sink	RCS Integ-rity	Ctmt	Vital Power	Comp Cool-ing	SF Score	Train Level SSC (See Notes)
3	A/B	Non	AFWP 1	y	y	y	y	993			3					3	AFWP 1
3	B	H	AFWP 2	y	y	y	y	3432			3					3	AFWP 2
3	A	F	AFWP 3	y	y	y	y	2559			3					3	AFWP 3
7			PCV-455C	y	y	y	y	>8760			3	2				5	PCV-455C
7			PCV-456	y	y	y	y	>8760			3	2				5	PCV-456
8	A	F	CCP 1	y	y	y	y	2770	5	4	3	2				14	CCP 1
8	B	G	CCP 2	y	y	y	y	2459	5	4	3	2				14	CCP 2
9	A	F	SIP 1	y	y	y	y	>8760		4	3					7	SIP 1
9	B	H	SIP 2	y	y	y	y	8656		4	3					7	SIP 2
10	B	G	RHRP 1	y	y	y	y	4704		4			1			5	RHRP 1
10	A	H	RHRP 2	y	y	y	y	4755		4			1			5	RHRP 2
12	B	G	CSP 1	y	y	y	y	>8760					1			1	CSP 1
12	A	H	CSP 2	y	y	y	y	>8760					1			1	CSP 2
14			CCWHE1	y	y	y	y	336							5	5	CCWHE 1
14			CCWHE2	y	y	y	y	370							5	5	CCWHE 2
14	A	F	CCWP 1	y	y	y	y	1144							5	5	CCWP 1
14	B	G	CCWP 2	y	y	y	y	1609							5	5	CCWP 2
14	A/B	H	CCWP 3	y	y	y	y	689							5	5	CCWP 3
17	A	F	ASP 1	y	y	y	y	336							5	5	ASP 1
17	B	G	ASP 2	y	y	y	y	370							5	5	ASP 2
17			FCV-601	y	y	y	y	502							5	5	FCV-601
21	A/B	H	DEG 1 (2)	y	y	y	y	823						5		5	DEG 1
21	B	G	DEG 2 (1)	y	y	y	y	457						5		5	DEG 2
21	A	F	DEG 3	y	y	y	y	408						5		5	DEG 3
21		H*	DFOTP1	y	y	y	y	1150						5		5	DFOTP1
21		G*	DFOTP2	y	y	y	y	1023						5		5	DFOTP2
23			CFCU X	n	n	y	y	>8760					1			1	CFCU X
23			CRVS S-35	y	y	n	y	>8760								0	CRVS S-35
23			CRVS S-36	y	y	n	y	>8760								0	CRVS S-36
38	A		SSPS A	y	y	y	y	759	Orange							NA	SSPS A
38	B		SSPS B	y	y	y	y	728	Orange							NA	SSPS B
67		F	BTC_1	y	y	y	y	5000						5		5	BTC_1
67		G	BTC_2	y	y	y	y	1398						5		5	BTC_2
67		H	BTC_32	y	y	y	y	1541						5		5	BTC_32
69			S/U Pwr	y	y	y	y	119						5	-	5	S/U Pwr
70			500kV OSP	n	n	y	y	990						5		5	500kV OSP

RS - Risk significant per Maintenance Rule AND can be worked On Line
PC1 - Unavailability hours tracked as performance criteria
SFAT - Included in Safety Function logic trees
PRA - Modeled in PRA AOT spreadsheet
PRA AOT - Single component AOT to 1E-6 additional CDF

NOTES: Only those Risk Significant SSC's that are modeled in the DCPP PRA, have PC1 availability AOT's assigned, AND can be removed from service for maintenance on-line are included in this table. Examples of Risk Significant SSC's not in the table include RCS, Pzr safeties, MSIV's, S/G's, RWST, CST, etc. See reference 7.7 for bases.

DIABLO CANYON POWER PLANT
AD7.DC6
ATTACHMENT 9.2

TITLE: Sample 12 Week Rolling Matrix

UNIT ONE TWELVE WEEK ROLLING MATRIX

	MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
WEEK 1 TRAIN A/B BUS H	DAYSHIFT: M-67A FIRE VALVES		M-9A DG11	P-13B FIRE PP 02	DAYSHIFT: OP C-1 SEC. PLANT M-69C F IRE EXT	P-AFW-12 V-3P6 LC V110-113	M-51 ALL CFCUs P-12B1 DFO PP 01 DAYSHIFT: P-24 LTCW PP 01
WEEK 2 TRAIN B BUS G	V-3H12 RCV16 DAYSHIFT: M-67A FIRE VALVES V-3H11 LCV69 &70	M-26 CCW HX 12	P-CCP-12	M-16BB *M-9A DG 12 *V-3E11 8803A&B DAYSHIFT: CNTNMT ENTRY *SEAL TABLE INSP.	M-16HB *P-CSP-11 *V-313 9001A DAYSHIFT: SP S-312S SEC DG M-69B CO 2	P-MUW-02	P-12B2 DFO PP 02 DAYSHIFT: P-24 LTCW PP 02
WEEK 3 TRAIN A BUS F	DAYSHIFT: V-3R1 10% DUMPS M-67A F IRE VALVES	M-9A DG 13	M-54 SEAL FLOW DAYS HIFT: M-89 ECCS VENTING	P-SIP-11 V-3L10 8923A&B V-3L2 8821A&B V-3L3 8807A&B M-26 CCW HX 11	P-13B FIRE PP 01 DAYSHIFT: m-69A FIRE EXT	P-AFW-13	P-CCW-11 M-16K *V-3S4 *V-3S3 DAYSHIFT: P-24 LTCW PP 03
WEEK 4 TRAIN A/B BUS NON	M-21A DAYSHIFT: M-67A FIRE VALVES	P-SIP-12 DAYSHIFT: R-1A RODS	M-16J BLDN VLVS M-16N BLDN/AFW *V-3S2 BLDN DC *P-AFW-11 *V-3P5 LCV 106-109 *V-3R5 FCV 95 * V-3R6 FCV-37&38	M-16P2 PAINT/WELD RESTRICTION S FOR WEEKEND TESTING DAYSHIFT: CNTNMT ENTRY * STP I-1D	DAYSHIFT: M-67C HOSE REELS M-10A DFOST	M-4 ABVS M-5 FHBVS M-6A CRVS	
WEEK 5 TRAIN A/B BUS H	DAYSHIFT: M-67A FIRE VALVES	M-9A DG 11		P-13B FIRE PP 02	DAYSHIFT: OP C-1 SEC. PLANT M-69C FIRE EXT M-16HA *P-CSP-12 *V-313 9001B	P-AFW-12	M-51 ALL CFCUS DAYSHIFT: P-24 LTCW PP 01
WEEK 6 TRAIN B BUS G	V-3K5 8148,8147 V-3K6 8166,8167 DAYSHIFT: M-67A FIRE VALVES	P-7B ASW PP 12 M-26 CCW HX 12	PAINT/WELD RESTRICTI ONS FOR M-16D	M-9A DG 12 V-3S8 FCV361 V-3J1 BLOCK VLVS DAYSHIFT: CNTMNT ENTRY *SEAL TAB LE INSP.	M-16D *P-RHR-11 DAYSHIFT: SP S-312S SEC DG M-69B CO 2	P-CCW-12	P-BAT-12 M-16I *V-3S1 PH. A VLVS *V-3S7 PH. A VLVS *V-3S8 PH. A VLVS DAYSHIFT: P-24 LTCW PP 02
WEEK 7 TRAIN A BUS F	V-3P4 AFW VLVS DAYSHIFT: M-67A FIRE VALVES	V-3G1 GOTs M-9A DG 13	M-54 SEAL FLOW P-CCP-11 DAYSHIFT: M-89 ECCS VENTING	M-26 CCW HX 11 P-7B ASW PP11 V-3F1 FCV 495 V-3F2 FCV 496 V-3F3 FCV 601 V-3F4 FCV 602 V-3F5 FCV 603	P-13B FIRE PP 01 DAYSHIFT: m-69A FIRE EXT	M-16E *P-AFW-13	DAYSHIFT: P-24 LTCW PP 03
WEEK 8 TRAIN A/B BUS NON	M-21A DAYSHIFT: M-67A FIRE VALVES	M-16P4 V-303 DFO VLVS DAYSHIFT: R-1A RODS	P-AFW-11	PAINT/WELD RESTRICTIONS FOR TESTIN G DAYSHIFT: CNTMNT ENTRY *STP I-10	DAYSHIFT: M-10A DFOST M-67C HOSE REELS	M-4 ABVS M-5 FHBVS M-6A CRVS	DAYSHIFT: P-12B3 PORT. DFO PP 01
WEEK 9 TRAIN A/B BUS H	PAINT/WELD RESTRICTIONS FOR TESTING FOR STP M-16 U DAYSHIFT: M-67A FIRE VALVES		M-16A *M-9A DG11 *V-3E9 8801A&B M-16U *V-3S5 PH. A VLVS PAINT/WELD RESTRICTI ONS FOR M-16C	P-13B FIRE PP 02	M-16C *P-RHR-12 DAYSHIFT: OP C-1 SEC PLANT M-69C FIRE EXT	M-16F *P-AFW-12	M-51 ALL CFCUs DAYSHIFT: P-24 LTCW PP 01
WEEK 10 TRAI N B BUS G	DAYSHIFT: M-67A FIRE VALVES	M-26 CCW HX 12	STP P-MUW-01 *V-3U1 WTR VLVS *V-3U2 WTR VLVS	M-9A DG 12 DAYSHIFT: CNTMNT ENTRY *SEAL TAB LE INSP.	M-16M *V-3T1 CVI VLVS P-SFP-12 DAYSHIFT: SP S-312S SEC DG M-69B CO 2	P-17B CP 13	V-3E1 FCV 110A V-3E2 FCV 110B V-3E5 8104,8445 V-3E6 FCV 128 DAYSHIFT: P-24 LTCW PP 02
WEEK 11 TRAI N A BUS F	DAYSHIFT: M-67A FIRE VALVES	M-16BA *M-9A DG 13	M-54 SEAL FLOW DAYSHIFT: M-89 ECCS VENTING	M-26 CCW HX 11	M-16e DUMP INTRLK P-13B FIRE PP 01 DAYSHIFT: m-69A FIRE EXT	P-AFW-13	P-BAT-11 DAYSHIFT: P-24 LTCW PP 03
WEEK 12 TRAI N A/B BUS NO N	M-21A DAYSHIFT: M-67A FIRE VALVES	DAYSHIFT: R-1A RODS	P-AFW-11	V-3H7&8 CCW VLVS V-3M1,2,4 RHR VLVS PAINT/WELD RESTRICTION S DAYSHIFT: CNTMNT ENTRY *STP I-1D	P-SFP-11 M-16P3 *V-3R3 BLDN IC *V-3R4 MSIV BYP DAYSHIFT: M-10A DFOST M-67C HOSE REELS	M-4 ABVS M-5 FHBVS M-6A CRVS	P-CCW-13 P-12B4 PORT DFO PP 02

DIABLO CANYON POWER PLANT
AD7.DC6
ATTACHMENT 9.3

TITLE: Sample MOW Planning Spreadsheet

Date	10/29/95	11/5/95	11/12/95	11/19/95	11/26/95	12/3/95	12/10/95	12/17/95	12/24/95	12/31/95	1/7/96	1/14/96
Events	1R7 11/1			Thksgvg					Chrstms	New Yrs		
DWC Week	9544	9545	9546	9547	9548	9549	9550	9551	9552	9601	9602	9603
12WMtxWk	1	2	3	4	5	6	7	8	9	10	11	12
Train	A/B	B	A	A/B	A/B	B	A	A/B	A/B	B	A	A/B
Bus	H	G	F	Non	H	G	F	Non	H	G	F	Non
System												
00				I-1D				I-1D				I-1D
02												
03A							AFWP3					
03B	AFWP2											
03A/B				AFWP1				AFWP1				AFWP1
04												
07			M-54	R-1A			M-54	R-1A			M-54	R-1A
08										PDP3		
08A							CCP1				BATP1	
08B		CCP2				BATP2						
09			M89				M-89				M-89	
09A			SIP1									
09B				SIP2								
10A									RHRP2			
10B						RHR1						
11												
12A					CSP2							
12B		CSP1										
13										SFP2		SFP1
14A			CCWP1									
14B						CCWP2						
14A/B												CCWP3
14HEA			CCWHE1				CCWHE1				CCWHE1	
14HEB		CCWHE2				CCWHE2				CCWHE2		
15												
16		MUWTP2								MUWTP1		
16	LTCWP1	LTCWP2	LTCWP3		LTCWP1	LTCWP2	LTCWP3		LTCWP1	LTCWP2	LTCWP3	
17												
17A							ASP1					
17B		CCWHX2				ASP2						
18	FP2		FP1		FP2		FP1		FP2		FP1	
19												
20				M-21A				M-21A				M-21A
21	DFOTP1	DFOTP2			SAC1B			PDFOP1				PDFOP2
21A			DEG3				DEG3				OEG3	
21B		DEG2				DEG2				DEG2		
21A/B	DEG1				DEG1				DEG1			
22										-		
23	CFCS				CFCS				CFCS			
23												
23ABV				M-4				M-4				M-4
23FHB				M-5				M-5				M-5
23CRV				M-6A				M-6A				M-6A
24												
25												
26												
27			OWS1									
28												
45		CTMT		CTMT		CTMT		CTMT		CTMT		CTMT
66		SECDEG				SECDEG				SECDEG		
67												

DIABLO CANYON POWER PLANT
AD7.DC6
ATTACHMENT 9.4

TITLE: On-Line Risk Management Summary

Evaluate risk for all planned or emergent activities, equipment OOS, or external conditions as follows:

NOTE 1: For all steps below, deferring elective activities to avoid unacceptable risk is an assumed option.

NOTE 2: If all steps are answered "NO," risk evaluation documentation is not required.

Step 1. Is the activity or condition a Trip Risk?		
YES		• Emergent Trip Risk - implement compensatory measures;
		• Planned Trip Risk - concur with comp measures per MA1.DC10 or 11;
		• AND GO TO Step 2.
NO		GO TO Step 3

Step 2. Is there a Trip Risk concurrent with degraded or out of service Trip Mitigation SSCs?		
YES		• Verify OPS manager concurrence or notification to allow 1 and 2 concurrently;
		• AND implement compensatory measures;
		• AND GO TO Step 3.
NO		GO TO Step 3
N/A		GO TO Step 3

Step 3. Is the SSC out of service Risk Significant for CDF or LERF?		
YES		• Evaluate PRA and KSF;
		• Implement compensatory measures;
		• If the OOS SSC is a Trip Mitigation SSC, THEN verify Step 2 is complete;
		• AND GO TO Step 4.
NO		GO TO Step 4

Step 4. Is the remaining in-service redundant train Degraded?		
YES		Implement <u>additional</u> compensatory measures.
NO		Risk evaluation complete.

This checklist may be summarized as a lamicoid at the SFM desk for reference.

Diablo Canyon Power Plant Temporary Procedure TP TO-0105, "Diesel Generator 2-1 On-Line Maintenance

TITLE: Diesel Generator 2-1 On-Line Maintenance

2

03/09/01
EFFECTIVE DATE

PROCEDURE CLASSIFICATION: QUALITY RELATED

1. SCOPE

1.1 This procedure is intended to provide operational guidance and contingency actions during the Diesel Generator (DG) 2-1 on line maintenance.

1.2 This procedure outlines various aspects of the project including the following:

1.2.1 Prerequisite checklist should be completed prior to clearing DG 2-1 from service (see Attachment 9.1).

1.2.2 Initial plant conditions for the start and duration of the MOW.

1.3 This procedures expires March 29, 2001 or upon completion of the DG 2-1 MOW.

2. DISCUSSION

2.1 The DG 2-1 routine maintenance is scheduled between March 20 and March 23, 2001. The duration of the MOW is scheduled for approximately 61 hours.

2.2 This procedure has been written to expect success while planning for failures. Specific initial plant operating conditions and restrictions should be in effect for the duration of the project.

2.3 This procedure will address those conditions that require backing out of the maintenance window and are listed in Attachment 9.2. Once inside the maintenance window the back out time should be limited to 1 shift.

3. RESPONSIBILITIES

3.1 The Turbine Building Asset ATL for all work associated with DG 2-1 MOW.

3.2 Operations Section for ensuring this procedure is performed, including shiftly checks and compensatory measures.

3.3 Turbine Building Assistant Team Leader and DG system engineer will give daily updates to the Operations Section management on project status.

3.4 The In Service Inspection Team for ensuring availability of inspection equipment prior to and throughout the DG 2-1 maintenance window.

3.5 Diesel Generator engineer and Assistant Team Leader to inform the Unit 2 SFM in the event a required prerequisite is not being met.

4. PREREQUISITES — INIT / DATE

4.1 Prerequisites checklist (Attachment 9.1) is complete. ____/____

4.2 The following organizations have been tailboarded, discussing work scope activities and contingency plans: ____/____

4.2.1 Operations

4.2.2 Turbine Asset Team

4.2.3 Engineering

4.2.4 In Service Inspection

4.2.5 Security

4.2.6 Safety

4.2.7 Warehouse

4.3 Maintenance Services has agreed to support the DG 2-1 maintenance window on a 24 hour a day (two, 12 hour shifts per day) schedule. ____/____

4.4 A clearance has been approved to support removal of DG 2-1 from service. ____/____

5. PRECAUTIONS AND LIMITATIONS

5.1 Ensure proper compensatory measures are in effect for the current project period, based on Attachment 9.1 and 9.2, as well as guidelines throughout the body of the procedure.

5.2 If, during the course of the project, a condition changes such that it no longer meets the initial condition requirements or project restrictions, an evaluation should be performed by Engineering and Operations, with a determination being made by the Manager of Operations as to the proper course of action.

5.3 No maintenance, other than that agreed upon prior to this MOW will be performed without Engineering and Operations review for PMT requirements. All work must require no more than an STP M-9A.

6. INSTRUCTIONS

****

CAUTION: STP I-1C, Attachment 11.4 will be required to be performed in accordance with TS 3.8.1 for the duration of the DG 2-1 maintenance window.

****

		INIT / DATE
6.1	Notify the DCPP Switching Center at extension 3519 to inform them of project start. (reference OP J-6B:VII)	____/____

NOTE: Some of the routine maintenance on DG 2-1 is normally performed during refueling outages. None of the corrective maintenance is considered a common cause failure. Hence starting of the remaining DGs (2-3 and 2-2) following removal of DG 2-1 from service has been determined to be not required.

6.2	Verify redundant safety related systems, subsystems, trains, components and devices for DG 2-3 operable within 24 hours of declaring DG 2-1 inoperable.	____/____
6.3	Verify DG 2-3 Operable.	____/____
6.4	Verify redundant safety related systems, subsystems, trains, components and devices for DG 2-2 operable within 24 hours of declaring DG 2-1 inoperable.	____/____
6.5	Verify DG 2-2 Operable.	____/____

NOTE: Ensure that steps 6.6 and 6.7 are performed within 1 hour of each other to satisfy TS.

6.6	Declare DG 2-1 Inoperable and enter TS 3.8.1. Time TS entered: _____	____/____
6.7	Perform STP I-1C, Attachment 11.4, "Modes 1, 2 and 3 "As Required" Operability Checks of Independent Circuits."	____/____

****

CAUTION: Performance of the following step places the project in the inoperable status. All applicable compensatory measures should be addressed in accordance with Attachment 9.2.

****

		INIT / DATE
6.8	Hang clearance to support removing DG 2-1 from service. (reference OP J-6B:VII)	____/____
6.9	Turbine Asset Team reports on DG 2-1 clearance to begin maintenance.	____/____
6.10	Turbine Asset Team has completed work on DG 2-1 to support post maintenance testing.	____/____
6.11	Operation removes clearance on DG 2-1.	____/____
6.12	Engineering and Turbine Asset Team begin post maintenance testing on DG 2-1.	____/____
6.13	Engineering and Turbine Asset Team turn DG 2-1 over to Operations and have reported OFF of the DG 2-1 clearance.	____/____
6.14	Operations and Engineering has completed post maintenance testing on DG 2-1 to support returning DG 2-1 to service.	____/____

NOTE: Completion of the following step returns the project to the "NORMAL" compensatory measure level. This means there are no compensatory measures in effect for the DG 2-1 maintenance.

6.15	Exit T.S. 3.8.1 Time TS exited: _____	____/____
6.16	Notify the DCPP Switchyard Center at 3519 to inform them of project completion. (reference OP J-6B:VII)	____/____
6.17	Remove CAUTION signs from the following locations;	
6.17.1	DG 2-3 and 2-2	____/____
6.17.2	Vital 4KV bus F, G and H	____/____
6.17.3	Vital 480 V bus F, G and H	____/____
6.17.4	Motor driven and turbine driven AFW Pp rooms.	____/____
6.18	Return the following equipment to SFM desired configuration;	
6.18.1	Aux building ventilation supply/exhaust fans	____/____
6.18.2	Overall Aux building ventilation control room select	____/____
6.18.3	Fuel handling ventilation control room select	____/____
6.18.4	BA Transfer Pump and Primary Water Make-Up Pumps	____/____

7. REFERENCES

7.1 EOP ECA-0.3, " Restore 4KV Busses."

7.2 AD7.ID4, " On-Line Maintenance Scheduling."

7.3 OP O-13, "Transferring Equipment To/From Alternate Power Sources."

7.4 AR PK 17-17 " 4Kv Bus G or SU FDR UV"

7.5 AD7.ID6, " On-Line Maintenance Risk Management"

8. RECORDS

None

9. ATTACHMENTS

9.1 "Prerequisite Checklist," 03/02/01

9.2 "Compensatory Measures," 03/02/01

9.3 "Support Information," 03/02/01

DIABLO CANYON POWER PLANT
TP TO-0105
ATTACHMENT 9.1 **2**

TITLE: Prerequisite Checklist

1.	DG 2-1 MAINTENANCE PREREQUISITES	INIT / DATE
1.1	* A walkdown has been performed by DG system engineer or designee verifying DG 2-3 and associated area is clean and in good material condition with no work being performed which could jeopardize operation.	_____/_____
1.2	* A walkdown has been performed by DG system engineer or designee verifying DG 2-2 and associated area is clean and in good material condition with no work being performed which could jeopardize operation.	_____/_____
1.3	* Diablo Canyon Switching Center has been contacted to verify offsite power sources are not in danger of being lost due to wild land fires, other grid related transients, or scheduled work activities.	_____/_____
1.4	* No elective maintenance or testing to be performed on Unit 1 or Unit 2 components required to crosstie vital 4kV bus' as required by DCPP Emergency Operating Procedures, Appendix X, "Crosstie of Vital Bus." See Attachment 9.3 for the list of effected Appendix X breakers.	_____/_____
1.5	* No elective maintenance or testing to be performed on either unit 12kV startup bus.	_____/_____

* These items are to be maintained current for the duration of the DG 2-1 maintenance project.

TITLE: Prerequisite Checklist

		INIT / DATE
1.6	Contact Security to ensure adequate security support for DG 2-1 maintenance window.	____/____
1.7	Place 480 V equipment on alternate power supplies or select alternate equipment as described by Attachment 9.3.	____/____
1.8	Verify DG 2-3 Operable with STP M-9A, "Diesel Engine Generator Routine Surveillance Test," current for duration of project.	____/____
1.9	Verify DG 2-2 Operable with STP M-9A, "Diesel Engine Generator Routine Surveillance Test," current for duration of project.	____/____
1.10	Verify STP P-PDFOTP-01, "Routine Surveillance of Portable Diesel Fuel Oil Transfer Pump 0-1," current for duration of project.	____/____
1.11	Verify STP M-10A, "Diesel Fuel Oil Storage Tank Inventory," current for duration of project.	____/____
1.12	Verify STP V-303, "Exercising Valves LCV-85 Through LCV-90," current for duration of project.	____/____
1.13	Verify STP P-DFO-01, "Routine Surveillance Test of Diesel Fuel Oil Transfer Pump 0-1," current for duration or project.	____/____
1.14	Verify STP P-DFO-02, "Routine Surveillance Test of Diesel Fuel Oil Transfer Pump 0-2," current for duration of project.	____/____
1.15	Turbine Asset team has verified all parts and equipment necessary for the project have been procured and meet quality related checks.	____/____
1.16	Bio-fouling Group has performed an evaluation and had determined a High Swell Warning is not expected for the duration of the DG 2-1 maintenance project.	____/____
1.17	An assessment has been performed verifying there are no known maintenance related equipment problems that could result in the performance of the DG 2-1 maintenance project causing an unacceptable risk.	____/____

TITLE: Prerequisite Checklist

		INIT / DATE
1.18	CAUTION signs have been posted on the doors to the following rooms which require SFM permission to perform work within;	
1.18.1	DG 2-3, 2-2,	_____/_____
1.18.2	Vital 4kV bus F, G and H (U-2)	_____/_____
1.18.3	Vital 480 V bus F, G and H (U-2)	_____/_____
1.18.4	Motor driven and turbine driven AFW Pp rooms (U-2)	_____/_____
1.19	Verify adequate diesel fuel oil is available to perform required project PMTs.	_____/_____
1.20	Verify cold or hot wash of transformers is not required for the duration of the project.	_____/_____

Shift Foreman:_____ _____
Signature Date

DIABLO CANYON POWER PLANT
TP TO-0105
ATTACHMENT 9.2 **2**

TITLE: Compensatory Measures

Discussion: The table below summarizes the major project scope evolutions and the corresponding compensatory measures. The terminology of Normal and Level 1 periods refer to the compensatory measures in place during specified project phases.

Page two of this attachment details the compensatory measures required, based on the "Level" defined by the project evolution in progress.

The project prerequisites and the compensatory measures mitigate the probabilistic risk presented by this project. For this reason, any deviation from prerequisites and compensatory measures requires review and approval or Operations, Maintenance, Engineering and the Manager of Operations.

EVOLUTION	Pre-start	Project start	Project End
COMP MEASURE LEVEL	NORMAL	LEVEL 1	NORMAL

Pre-start: This period is defined as prior to the start of the DG 2-1 maintenance project.

Project start: This period begins when clearance removing DG 2-1 from service is hung and the Turbine Asset Team reports on the DG 2-1 clearance.

Project End: This period begins when the DG 2-1 clearance is no longer hung and DG is Operable.

COMPENSATORY MEASURES

The following compensatory measures should be in effect unless reviewed by Operations, Maintenance, Engineering, and the Manager of Operations and determined to be unnecessary.

PROJECT PERIODS	APPLICABLE COMPENSATORY MEASURES
1) Level 1	1a. Work that may cause a trip hazard on Unit 1 or 2 should not be performed. Exceptions should be authorized in accordance with AD7.DC6 On-Line-Maintenance Risk Management.
	1b. Wild land fire or other external events that may jeopardize offsite power sources need to be brought to the attention of; Operations, Maintenance, Engineering, and the Manager of Operations to determine if project postponement is warranted.
	1c. No elective maintenance or testing (other than normally scheduled surveillances) should be performed on operable Unit 1 or Unit 2 diesel generators.
	1d. No elective maintenance or testing on the 230Kv and 500Kv offsite power sources should be performed. Exceptions may be authorized by the Operations Manager.
	1e. No testing or elective maintenance should be performed on Unit 1 or Unit 2 unless approved per the T1 schedule. Exceptions approved by the Shift Manager and/or Work Week Manager may be performed.
	1f. Senior management will provide on shift support in the event conditions jeopardize plant operation (Wild land fires, High Swell Warning, electrical distribution problems.)

DIABLO CANYON POWER PLANT
TP TO-0105
ATTACHMENT 9.3 **2**

TITLE: Support Information

1. BREAKERS USED TO CROSSTIE VITAL BUS' IN EOP APPENDIX X.

1.1 4KV auxiliary feeder breakers; 52-HH-13, 52-HG-13, and 52-HF-13.

1.2 4KV startup feeder breakers; 52-HH-14, 52-HG-14, and 52-HF-14.

1.3 Startup feeder breaker to 4KV vital bus'; 52-HG-15.

2. ALTERNATE SOURCES OR EQUIPMENT FOR 480V BUS H BREAKERS/LOADS

2.1 SFM should direct the following equipment be placed in service for the duration of the DG 2-1 maintenance project.

2.1.1 Boric Acid Pump 2-1 supplying the blender.

2.1.2 Spent Fuel Pool Pump 2-2.

2.1.3 Fuel handling ventilation supply fan S-2 (w/selector switch in S-2 position).

2.1.4 Primary water pump 2-1.

2.1.5 Control Room ventilation selected to Bus 2H.

2.1.6 Aux Bldg Supply Fan S-34 (w/selector switch in S-34 position).

Diablo Canyon Power Plant Surveillance Test Procedure STP M-9A, "Diesel Engine Generator Routine Surveillance Test"

Diablo Canyon Power Plant Surveillance Test Procedure STP M-9D1, "Diesel Generator Full Load Rejection Test"

*** *ISSUED FOR USE BY:* _____ *DATE:* _____ *EXPIRES:* _____ ***

PACIFIC GAS AND ELECTRIC COMPANY
NUCLEAR POWER GENERATION
DIABLO CANYON POWER PLANT
SURVEILLANCE TEST PROCEDURE

NUMBER STP M-9A
REVISION 65
PAGE 1 OF 32
UNITS 1 AND 2

TITLE: Diesel Engine Generator Routine Surveillance Test

10-10-03
EFFECTIVE DATE

PROCEDURE CLASSIFICATION: QUALITY RELATED

1. SCOPE

1.1 This procedure is used to perform the monthly test on diesel generator (D/G) 1-1, D/G 1-2, D/G 1-3, D/G 2-1, D/G 2-2, and D/G 2-3. It may be used as a post maintenance test (PMT).

1.2 Diesel fuel oil transfer systems train A and train B are tested.

1.3 The day tank is checked for water and verified to contain ≥ 250 gallons of diesel fuel.

2. DISCUSSION

2.1 To demonstrate the OPERABILITY of the D/G, the following checks are performed.

2.1.1 Prefiring Checks

a. Cooling system level and temperature.

b. Lube oil level and temperature.

c. Day and priming tanks fuel level.

d. Compressed air availability.

e. Governor oil level.

2.1.2 Checks During Starting

a. Starting circuit OPERABILITY.

b. D/G starts with one starting train.

c. During timed starts, cranking time to start.

d. D/G starts either from control room, solid state protection system, or on a simulated UV signal (only one is proven each test).

e. Fuel system OPERABILITY.

f. Governing and control system OPERABILITY.

g. OPERABILITY of SI auto start feature when run in conjunction with STP M-16A, STP M-16BA or STP M-16BB.

2.1.3 Checks during operation while loading and loaded

a. Fuel system OPERABILITY.

b. Governing and control system OPERABILITY.

c. Cooling system OPERABILITY.

d. Ability of unit to accept and carry a sustained load ≥ 2.45 MW and ≤ 2.50 MW (≥ 2340 KW and ≤ 2600 KW Tech Spec) for one hour without apparent malfunctions.

e. Ability of fuel oil transfer system to deliver fuel oil to D/G day tank.

f. Fuel oil level in the day tank remains above the low level alarm.

2.1.4 Checks After Power Run

a. Lube oil system.

b. Cooling system.

c. Compressed air system.

d. Fuel priming system.

e. D/G alignment to associated emergency bus.

f. Day tank water accumulation.

2.2 After the D/G has operated at ≥2.45 MW, the load will be reduced on the unit to about 0.50 MW and the unit will be allowed to cool before it is separated and shutdown.

2.3 Not all of the parameters observed during this test will indicate an inoperable D/G. Those variables which directly indicate OPERABILITY are marked on data sheets. Technical Specification (Tech Spec) 3.8.1, 3.8.2 or 3.8.3 actions must be taken, management notified without delay, and an action request (AR) initiated. Other variables, if out of limits, should be reported in a routine manner in an action request.

2.4 If one or both trains of the fuel oil transfer system are found to be inoperable, the appropriate Tech Spec 3.8.1 Action F.1 or G.1 for MODES 1 - 5 must be followed.

2.5 The diesel fuel oil transfer pumps 0-1 and 0-2 discharge check valves (DEG-0-35, DEG-0-36) and the fuel oil tanks 0-1 and 0-2 suction check valves (DEG-0-1114, DEG-0-1115 for DFOST 0-1 and DEG-0-1117, DEG-0-1118 for DFOST 0-2) will be checked by the operation of the diesel fuel oil transfer pumps 0-1 and 0-2.

2.6 If the D/G starts successfully, the starting air system and turbocharger air assist system solenoid valves will be considered acceptable.

2.7 Sampling of a D/G fuel oil day tank for particulate contamination (STP M-10B2) should coincide with performance of this test.

3. RESPONSIBILITIES

3.1 Shift foreman (SFM), for scheduling test, operation of equipment, obtaining data and data reduction required by this procedure, evaluation of the results, and determination of D/G operability.

4. FREQUENCY

4.1 The D/G testing frequency is once every 31 days.

4.2 Each D/G will be tested on a schedule developed for Mode 1 integrated daily schedule (MOIDS).

4.2.1 Even numbered months: A manual start from the control room should be performed. (Tech Spec SR 3.8.1.2 and Tech Spec SR 3.8.1.7)

4.2.2 During manual starts in the months of April, August and December, use starting train A. During manual starts in months of February, June and October, use starting train B.

4.2.3 Odd numbered months: A simulated loss of off-site power (undervoltage) should be performed. (Tech Spec SR 3.8.1.2).

4.2.4 During the manual starts, the D/G is started from standby condition and accelerates to 900 rpm in $\leq$ 10 seconds and the D/G voltage is $\geq$ 3785 V and $\leq$ 4400 V in $\leq$ 13 seconds after the D/G start signal (with gauge readability and instrument accuracy included, limit becomes 113 V to 121 V as read from the "Diesel Output Voltmeter" on VB4) and the D/G frequency is 60 $\pm$ 1.2 HZ in $\leq$ 13 seconds after the D/G start signal (with gauge readability and instrument accuracy included, limit becomes 59.5 HZ to 60.5 HZ). A timed start is required every 184 days but is performed more frequently for D/G performance monitoring. (Tech Spec SR 3.8.1.7)

4.2.5 If STP M-16A, M-16BA or M-16BB is being performed in conjunction with STP M-9A, the method of starting the D/G (i.e., with an SI signal) can be substituted for one of the methods in 4.2.1 or 4.2.3.

4.2.6 If plant conditions require a different starting method than that specified above, the starting method may be changed with SFM concurrence.

4.3 This test is required to be current in MODES 1 through 6.

5. TECHNICAL SPECIFICATIONS

5.1 Tech Spec SR 3.8.1.2: Verify each D/G starts from standby conditions and achieves speed ≥ 900 rpm, steady state voltage ≥ 3785 V and ≤ 4400 V, and frequency ≥ 58.8 HZ and ≤ 61.2 HZ.

5.2 Tech Spec SR 3.8.1.3: Verify each D/G is synchronized and loaded and operates for ≥ 60 minutes at a load ≥2340 KW and ≤ 2600 KW.

5.3 Tech Spec SR 3.8.1.4: Verify each day tank contains ≥ 250 GAL of fuel oil.

5.4 Tech Spec SR 3.8.1.5: Check for and remove accumulated water from each day tank.

5.5 Tech Spec SR 3.8.1.6: Verify the fuel oil transfer system operates to transfer fuel oil from storage tanks to the day tank.

5.6 Tech Spec SR 3.8.1.7: Verify every 184 days each D/G starts from standby condition and achieves:

5.6.1 in ≤ 10 seconds, speed ≥ 900 rpm; and

5.6.2 in ≤ 13 seconds, voltage ≥ 3785 V and ≤ 4400 V, and frequency ≥ 58.8 HZ and ≤ 61.2 HZ.

5.7 Tech Spec SR 3.8.3.4: Either air receiver A shall be ≥ 180 PSIG or air receiver B shall be ≥ 180 PSIG.

5.8 Tech Spec Bases for Action 3.8.3.E.1 and SR 3.8.3.4 assumes starting train A or starting train B will start the D/G. A single starting train test periodically checks this assumption.

5.9 Tech Spec SR 3.8.3.6: Verify turbocharger air receiver shall be ≥ 180 PSIG.

5.10 ECG SR 21.3.1: Verify the D/G is aligned to provide standby power to the associated emergency bus.

5.11 ECG SR 21.3.2: Verify the D/G protective relay trip cutout switch is returned to the cutout position following each D/G test.

5.12 Tech Spec SR 3.8.2.1: Establishes which of the above requirements apply with the plant in MODES 5 or 6.

6. ACCEPTANCE CRITERIA

6.1 A D/G shall be considered OPERABLE if the following acceptance criteria are met:

6.1.1 The D/G is started by either manual, startup bus undervoltage, or SI signal. (Tech Spec SR 3.8.1.2)

6.1.2 The D/G starts from standby condition and accelerates to ≥ 900 rpm. (Tech Spec SR 3.8.1.2)

6.1.3 The D/G voltage is ≥ 3785 V and ≤ 4400 V (with gauge readability and instrument accuracy included, limit becomes 113 V to 121 V as read from the "Diesel Output Voltmeter" on VB4). (Tech Spec SR 3.8.1.2)

6.1.4 The D/G frequency is ≥ 58.8 HZ and ≤ 61.2 HZ after the D/G start signal (with gauge readability and instrument accuracy included, limit becomes 59.5 HZ to 60.5 HZ). (Tech Spec SR 3.8.1.2)

6.1.5 When the D/G is started and timed from standby condition it: (Tech Spec SR 3.8.1.7)

a. Accelerates to 900 rpm in ≤ 10 seconds,

b. The D/G voltage in ≤ 13 seconds is ≥ 3785 V and ≤ 4400 V (with gauge readability and instrument accuracy included, limit becomes 113 V to 121 V as read from the "Diesel Output Voltmeter" on VB4), and

c. D/G is ≥ 58.8 HZ and ≤ 61.2 HZ in ≤ 13 seconds after the D/G start signal (with gauge readability and instrument accuracy included, limit becomes 59.5 HZ to 60.5 HZ).

6.1.6 When D/G is started with one starting train, the D/G shall meet the requirements of step 6.1.5.

6.1.7 Operate the D/G at a power level of ≥ 2340 KW and ≤ 2600 KW for ≥ 60 minutes. The assumed power uncertainty is ± 71 KW and the power meter minor divisions are every 0.1 MW. Using these corrections the power out will be maintained ≥ 2.45 MW and ≤ 2.50 MW. Momentary transients outside the load range do not invalidate this test. (Tech Spec SR 3.8.1.3)

6.1.8 The D/G protective relay cutout switch is returned to the CUTOUT position following the test. (ECG SR 21.3.2)

6.1.9 The D/G is aligned to provide standby power to the associated emergency buses. (ECG SR 21.3.1)

6.1.10 D/G fuel oil day tank inventory is above the low level alarm (≥ 250 GAL). (Tech Spec SR 3.8.1.4)

6.1.11 Each fuel transfer pump starts and transfers fuel from the storage system to the D/G engine-mounted tank via installed lines for the unit under test. (Tech Spec SR 3.8.1.6)

6.1.12 Monthly check for removal of water from the day tank. (Tech Spec SR 3.8.1.5)

6.1.13 Either air receiver A shall be ≥ 180 PSIG or air receiver B shall be ≥ 180 PSIG. With instrument inaccuracy, at least one air receiver shall be ≥ 195 PSIG. (Tech Spec SR 3.8.3.4)

6.1.14 Turbocharger air receiver shall be ≥ 180 PSIG. With instrument inaccuracy the air receiver shall be ≥ 195 PSIG. (Tech Spec SR 3.8.3.6)

6.2 Check valves and solenoid valves shall be considered acceptable as follows:

6.2.1 The diesel fuel oil transfer pumps 0-1 and 0-2 discharge check valve (DEG-0-35, DEG-0-36) shall be considered acceptable if the diesel fuel oil transfer pumps 0-1 and 0-2 deliver fuel into the day tank.

6.2.2 The fuel oil tanks 0-1 and 0-2 suction check valves (DEG-0-1114, DEG-0-1115 for DFOST 0-1 and DEG-0-1117, DEG-0-1118 for DFOST 0-2) shall be considered acceptable if the diesel fuel oil transfer pump delivers fuel into the day tank.

6.2.3 The starting air system and turbocharger air assist system solenoid valves shall be considered acceptable if the D/G starts and accelerates to at least 900 rpm in ≤ 10 seconds. Timing the D/G is required every 184 days (≈ 6 months). Administratively the D/Gs are timed on every manual start.

7. REFERENCES

7.1 PG&E Drawing No. 437579 Unit 1, 4KV Diesel Generator Control No. 11 and 12.

7.2 PG&E Drawing No. 437667 Unit 1, 4KV Diesel Generator Control No. 13.

7.3 PG&E Drawing No. 437546 Unit 1, 125 Volt DC System.

7.4 PG&E Drawing No. 106721 Unit 1.

7.5 PG&E Drawing No. 441357 Unit 2, 4KV Diesel Generator Control No. 21 and 22.

7.6 PG&E Drawing No. 496277 Unit 2, 4KV Diesel Generator Control No. 23.

7.7 PG&E Drawing No. 441240 Unit 2, 125 Volt DC System.

7.8 PG&E Drawing No. 107721 Unit 2.

7.9 NCR DCO-90-EN-N032.

8. APPENDICES

8.1 KW-KVAR, Power Factor Relations for Diesel Generators

8.2 Combined Engine and Generator Operating Limits

9. ATTACHMENTS

9.1 "Data Sheet - Routine Surveillance Test of Unit 1 Diesel Generators," 10/07/03.

9.2 "Data Sheet - Routine Surveillance Test of Unit 2 Diesel Generators," 10/07/03

9.3 "Unit 1 Undervoltage Test at Switchgear Room," 10/07/03

9.4 "Unit 2 Undervoltage Test at Switchgear Room" 10/07/03

START DATA SECTION

OPERATING MODE _____ DATE/TIME _____ / _____

DIESEL GENERATOR NO. _____

10. PRECAUTIONS AND LIMITATIONS — INITIALS

(Some of the following are repeated in the OP J-6B series on D/G manual operations)

10.1 If the D/G is paralleled to the auxiliary transformer and the main unit trips, the aux bus feeder breaker will automatically open and the D/G will carry the bus load. Verify that the bus feeder breaker opened and place the D/G MODE SEL switch into AUTO. _____

10.2 If the D/G is paralleled to startup power and a loss of offsite power occurs, the startup feeder breaker will not automatically open. The D/G will attempt to supply power to loads connected to the grid. Open the startup feeder breaker or verify the D/G breaker tripped. Place the D/G MODE SEL switch into AUTO if the feeder breaker was opened. _____

10.3 When paralleling a D/G to any off-site power source or the D/G MODE SEL switch is in MANUAL and the D/G is not running, declare the D/G inoperable. In MODES 1, 2, 3, and 4, perform the actions required for Tech Spec 3.8.1. In MODES 5, 6, and irradiated fuel movement, perform the actions required for Tech Spec 3.8.2. _____

10.4 The D/G should not be operated for an extended period of time below 0.65 MW. _____

10.4.1 If a D/G is operated < 0.65 MW for < one hour, no action is necessary.

10.4.2 If a D/G is operated < 0.65 MW for ≥ one hour but < 10 hours, then the D/G should be operated ≥ 1.30 MW for ≥ one hour.

10.4.3 If the D/G is to be operated for longer than 10 hours ≤ 0.65 MW, the D/G should be loaded to ≥ 1.3 MW for > one hour at the end of each 10 hour period.

NOTE: Operation of D/G < 0.65 MW for an extended period of time can expose the engine to undesirable conditions which may be detrimental to engine performance and component life.

		INITIALS
10.5	Do not operate the D/G below rated speed with the field energized. Excessive field currents and rotor temperatures may occur.	_____
10.6	When paralleling a D/G, pick up load (0.50 MW) as soon as possible (< 15 seconds) after the breaker is closed. This will prevent the D/G breaker from tripping on directional power (DIR PWR).	_____
10.7	There should be fuel oil in the priming tank. If there is not, the priming tank should be filled using the magnetic pump. Document problem in an AR.	_____
10.8	The fuel oil pressure should increase to above 40 PSIG within 60 seconds of engine start. Gauge response is about 15 seconds.	_____
10.9	Do not violate the following limits during normal steady-state operation:	
10.9.1	Maximum continuous generator current is 451 amperes.	_____
10.9.2	Maximum stator temperature is 240°F.	_____
10.9.3	Minimum lube oil pressure is 60 PSIG.	_____
10.9.4	Maximum lube oil temperature is 195°F.	_____
10.9.5	Power factor: 1.0 to 0.8 lag (see Appendix 8.1).	_____
10.9.6	Load: 2.60 MW at 0.8 PF (see Appendix 8.2 for maximum limits).	_____
	NOTE: The D/G may operate at > 2.5 and ≤ 2.75 MW at 0.8 PF for up to 2000 hours per year.	
10.10	Normal shutdown of a D/G requires DC control power. If it becomes necessary to shutdown the D/G without control power, manually operate the trip lever on the north west corner of the engine, forward of the fuel oil filters.	_____
10.11	Do not operate more than one D/G at a time paralleled to any transformer (startup or unit auxiliary) in MODE 1, 2, 3, or 4 (SR 3.8.1.3 Note 3).	_____
10.12	The applicable D/G MODE SEL switch on VB4 shall be in MANUAL prior to paralleling the D/G to the bus.	_____

INITIALS

10.13 EQD Panel, Control Power Selection

10.13.1 The D/G shall have its NORMAL DC source energized and selected in MODES 1-4. If the BACKUP source is selected in these MODES, the D/G is considered inoperable. _____

10.13.2 The preferred alignment in MODE 5, 6 or defueled is for the D/G to have its NORMAL DC source energized and selected. _____

10.13.3 The D/G may have its BACKUP source selected in MODE 5, 6 or defueled and still be considered OPERABLE, provided cross tie capability exists (i.e., capable to supply power to the battery charger aligned to the D/G's DC source.) _____

10.14 Verification signoff spaces in this procedure may be for concurrent or independent verification. Concurrent verification is required when the letters "CV" are present between the "PERF" and "VERIF" signoff spaces. When no "CV" is present, independent verification is required. _____

10.15 Day tank level columns respond very slowly to a level change. To avoid overflowing the day tank, use caution when manually filling the tank. _____

10.16 The procedure is written to test all 6 D/Gs which is further broken down into a series of Unit 1 and Unit 2 component IDs in steps which require clear and specific designations of the intended components. For example a listing for a Unit 1 relay may be 27HHU (27HGU) (27HFU). The first device (27HHU) is the applicable component when D/G 1-1 is being tested, 27HGU applies to D/G 1-2 testing, etc. Similar logic applies to Unit 2 devices. _____

10.17 Crankcase exhausters should be operating while engine is running. If they are not operating, the D/G is still OPERABLE. An AR shall be initiated and repairs should be made in a timely fashion. The D/G may experience more oil leakage from the block than normal if crankcase exhausters are not running. _____

10.18 The D/G should not be started if the lubricating oil temperature is < 95°F unless engineering has evaluated the condition. _____

10.19 Starting air header and turbo air pressure should be monitored as described in Attachments 9.1 and 9.2, step 1.13. _____

PERF

11. PREREQUISITES

11.1 Shift foreman's permission given to perform the test.

Signature: _____ Date/Time _____ / _____
Shift Foreman

11.2 D/G CO_2 fire protection system OPERABLE or portable dry powder fire extinguishers are available. _____

11.3 One of the following conditions is met:

11.3.1 The D/G is aligned for normal operation in accordance with OP J-6B. _____

OR

11.3.2 The D/G is aligned for normal operation in accordance with OP J-6B, except the EDQ panel is switched to backup and the battery charger aligned to the backup power supply is cross tied to the D/G bus. This option is available only in MODE 5, 6 or defueled.

N/A [ ] _____

11.4 The bus to which the D/G is to be paralleled shall be energized. _____

11.5 Utilizing the information in the control room (i.e., clearance logs, annunciators, etc.), check to see if the other D/Gs for the unit are OPERABLE. _____

11.5.1 Verify the action requirements in Tech Spec 3.8.1, in MODES 1-4 or Tech Spec 3.8.2, in MODES 5, 6 and irradiated fuel movement are being followed. _____

PERF

11.6 The following test equipment is available and is in current calibration:

11.6.1 Three stopwatches if timing the start.

N/A [ ] _____

ID #	Cal Due Date
_____	_____
_____	_____
_____	_____

11.6.2 Vibration meter and pickup with ± 5% of full scale accuracy or better. _____

a. Vibration Meter ID No. _____

Cal Due Date _____

11.7 When a vertical board recorder or instrument is not functioning properly, equivalent or more accurate M&TE equipment may be used. Install M&TE per CF4.ID7, "Temporary Modifications." Record in REMARKS the meter or recorder number, the parameter measured, the M&TE equipment number, and the calibration due date.

N/A [ ] _____

11.8 If this test is being performed after work was conducted on the D/G, verify that no ground buggy is installed in the D/G output breaker switchgear cubicle.

N/A [ ] _____

11.9 If test is used to satisfy Tech Spec SR 3.8.1.2 or Tech Spec SR 3.8.1.7, jacket water and lubricating oil temperature must be ≥ 95°F and ≤ 170°F. If M&TE is used to satisfy Tech Spec, use 90°F + M&TE uncertainty and 175 - M&TE uncertainty. (Reference Tech Spec Basis SR 3.8.1.2 and SR 3.8.1.7)

N/A [ ] _____

11.10 If the plant is in MODE 1, 2, 3 or 4, obtain an issued for use copy of STP I-1C, Attachment 12.4.

N/A [ ] _____

PERF

11.11 Obtain an issued for use STP M-9I. Every time a D/G starts or a D/G start is attempted, STP M-9I shall be performed. _____

11.12 Communications are established between the control room, the D/G, switchgear rooms, and SSPS as appropriate. _____

11.13 During manual starts, isolate starting train A or starting train B per step below, or as directed by the shift foreman.

Isolate Starting Train A in: February June October [ ]

Isolate Starting Train B in: April August December [ ]

N/A [ ] _____

11.13.1 Based on the month or shift foreman's direction, select the air supply valve to be closed. _____

D/G	1-1 (2-1)	1-2 (2-2)	1-3 (2-3)
Train "A" Valve	DEG-63 [ ]	DEG-89 [ ]	DEG-115 [ ]
Train "B" Valve	DEG-52 [ ]	DEG-78 [ ]	DEG-104 [ ]

11.13.2 Based on the month or shift foreman's direction, select the blow-down valve to be uncapped and opened in the table below. When the valve is opened, PK16-09, 17-09, or 18-09, will alarm. _____

D/G	1-1 (2-1)	1-2 (2-2)	1-3 (2-3)
Train "A" Valve	DEG-227 [ ]	DEG-249 [ ]	DEG-271 [ ]
Train "B" Valve	DEG-216 [ ]	DEG-238 [ ]	DEG-260 [ ]

NOTE 1: When train "A" valves are manipulated, starting train "B" is being tested. When train "B" valves are manipulated, train A is being tested.

NOTE 2: This testing schedule supports taking credit for one starting train being able to start the D/G in the required time. See Tech Spec Bases B3.8.3.E.1. Tech Spec Bases B SR 3.8.3.4 assumes one D/G starting train will start the D/G.

PERF

12. PROCEDURE

Diesel Generator No. _____

12.1 Notify the control operator that testing is ready to commence. _____

NOTE: Some steps within this procedure are for specific starting methods and loading. If the step does not apply to the starting method and loading, mark the step N/A.

12.2 Prestart Checks/Alignment

12.2.1 Have the field operator perform the "PRETEST DATA" section. If this is to be a single starting train start, refer to step 11.13 and inform the field operator which valves are to be manipulated. _____

12.2.2 Mw-Hr meter reading before test _____Mw-Hr _____

12.2.3 List alarms in prior to test _____

_____

_____

_____

12.2.4 Record the appropriate D/G MODE SEL switch position. _____ _____

12.2.5 The following D/G protective relays are cutin:

	RELAY FEATURE	LOCATION	
a.	Differential	on VB4 D/G PROT RELAYS CUT-IN, DIFF light on.	_____
b.	Directional power, Loss of field, and Overcurrent*	Feature cutout switch on VB4, CUT-IN, directional power and loss of field lights are on.	_____
c.	4KV bus differential	on VB4 4KV BUS DIFF PROT RLY C/I light on.	_____

* These features are required by the Technical Specifications to be cutout for normal service; however, these features should be cutin for the duration of this test to provide protection to the D/G when paralleled to the bus. While the relays are cutin for testing the D/G is considered operable.

PERF

12.2.6 Place the D/G stator temperature on PPC trend. _____

D/G 1-1 T2802A	D/G 2-1 T2802A
D/G 1-2 T2803A	D/G 2-2 T2803A
D/G 1-3 T2804A	D/G 2-3 T2804A

12.2.7 If the plant is in MODE 1, 2, 3, or 4, perform visual check of offsite power supplies per standing orders. STP I-1C, Attachment 12.4 is required < 1 hour after D/G is inoperable.

N/A [ ] _____

PERF

12.3 Starting

NOTE: The D/G will normally be started manually or on an undervoltage signal. This test may be performed in conjunction with STP M-16A, M-16BA or M-16BB and started on an SI signal. If plant conditions require a different starting method than specified, the starting method may be changed with SFM approval.

12.3.1 Refer to step 4.2 to determine the starting method. _____

MANUAL	(Even Months)	[ ]
UNDERVOLTAGE	(Odd Months)	[ ]
SI	(With STP M-16xx)	[ ]

NOTE: On steps 12.3.7, 12.3.8, and 12.3.9, the times to reach speed, voltage, and frequency vary with each D/G. Likewise, the overshoot varies depending upon the individual D/G governor. On steps 12.3.8 and 12.3.9, be aware that there may or may not be an overshoot in voltage and frequency; therefore, it will be necessary to carefully monitor these parameters.

12.3.2 Designate a person to observe or time D/G speed while starting. _____

12.3.3 Before starting D/G, be in direct communication with the operator in the D/G area so start-up data can be taken within 60 seconds of D/G start. _____

a. If required, verify the D/G starting train valves have been closed and opened.

N/A [ ] _____

b. If M&TE is installed, inform maintenance so the M&TE may be started or monitored as necessary.

N/A [ ] _____

PERF

NOTE 1: If the D/G was operated in manual mode and the frequency was not set to ≥ 60 HZ and ≤ 60.25 HZ when the D/G was shutdown, the frequency may stabilize outside the frequency range of ≥ 59.5 HZ and ≤ 60.5 HZ on the next manual start. If the speed attained 900 RPM in ≤ 10 seconds and the voltage stabilized in ≤ 13 seconds, the D/G is functioning as designed. (AR A0562732).

NOTE 2: A timed start is required every 184 days. Every manual start should be timed for trending purposes. Simulated undervoltage starts and safety injection start signals may be timed per shift foreman's direction.

12.3.4 If starting the D/G manually, perform the following:

N/A [ ]

a. Place the D/G appropriate D/G MODE SEL switch in MAN on VB4. _____

b. Declare D/G inoperable. _____

c. Simultaneously start the stopwatches and the D/G from the control room. _____

NOTE: If the undervoltage start is timed, there is an 0.8 second delay.

12.3.5 If starting the D/G on an undervoltage, perform the following:

N/A [ ]

a. Station an operator in the appropriate vital 4KV switchgear room with Attachment 9.3 (9.4). _____

b. Establish communications between the D/G, control room, and appropriate vital 4KV switchgear room. _____

c. Verify the appropriate D/G MODE SEL switch is in AUTO on VB4. _____

d. Cutout the appropriate startup bus undervoltage (UV) relay per Attachment 9.3 (9.4). _____

12.3.6 If starting the D/G on an SI signal, use STP M-16A, M-16BA or M-16BB to start the engine.
Procedure used _____

N/A [ ] _____

NOTE: STP M-16A starts D/G 1-1 and 2-2, STP M-16BB starts D/G 1-2 and 2-1, and STP M-16BA starts D/G 1-3 and 2-3.

PERF

NOTE: When timing any start, record the stopwatch time. Eight tenths of a second will be subtracted when evaluating UV start time in steps 12.3.10, 15.1.2, 15.1.3 and 15.1.4.

12.3.7 When the D/G starts, verify that the D/G speed reached ≥ 900 RPM. _____

a. Record the no-load stable speed prior to operator adjustment: _____ RPM _____

NOTE: It is acceptable for the stable speed to be ≤ 900 RPM or ≥ 900 RPM so long as the frequency is within the required limits.

b. If applicable, record the starting time to reach 900 rpm.
_____ seconds (must be ≤ 10 seconds).
N/A [ ] _____

Stop Watch ID _____

12.3.8 Verify that the D/G voltage is stable ≥ 113 V and ≤ 121 V. _____

a. If applicable, record the time for stable voltage ≥ 113 V and ≤ 121 V.
_____ seconds (must be ≤ 13 seconds).
N/A [ ] _____

Stop Watch ID _____

12.3.9 Verify that the D/G frequency is stable ≥ 59.5 HZ and ≤ 60.5 HZ. _____

a. If applicable, record the time for stable frequency ≥ 59.5 HZ and ≤ 60.5 HZ.
_____ seconds (must be ≤13 seconds).
N/A [ ] _____

Stop Watch ID_____

		PERF	VERIF
	NOTE: When evaluating a UV timed start in step 12.3.10, subtract 0.8 seconds.		
12.3.10	If speed and voltage did not reach their required values, evaluate the D/G for operability. Submit an action request and contact the system engineer for further review. Otherwise mark this step N/A. N/A [ ] AR#_____	_____	
12.3.11	If frequency did not reach its value it may be due to a frequency setting error. Refer to AR A0562732. Submit an action request and contact the system engineer for further review. It may be required to adjust the frequency and reperform the test. Otherwise mark this step N/A. N/A [ ] AR#_____	_____	
12.3.12	Have the field operator record data in the "STARTUP DATA" section of Attachment 9.1 (9.2).	_____	
12.3.13	If the D/G was started on an undervoltage signal, have the operator at the vital 4KV switchgear room cut-in the startup bus relay per Attachment 9.3 (9.4). N/A [ ]	_____	
12.3.14	If the D/G was started on an undervoltage signal or an SI signal, record the D/G ISOC frequency as indicated by the frequency meter on VB4. N/A [ ] _____ HZ	_____	
	a. Isoc frequency between 59.75 and 60.25 HZ. (Admin) YES [ ] NO [ ]		
	b. If the indicated frequency is outside the 59.75 to 60.25 HZ range, record the D/G ISOC frequency as indicated by the frequency meter at the D/G exciter cubicle. N/A [ ] _____ HZ	_____	

			PERF
12.4	Paralleling		
	12.4.1	Verify the D/G MODE SEL switch in MANUAL.	_____
	12.4.2	Verify the D/G has been declared inoperable.	_____
	12.4.3	Check D/G output voltage on each phase. Otherwise, when synchroscope is turned ON (next step) the voltmeter will lock on to phase C.	_____
	12.4.4	Cut in the FEEDER SYNC Switch.	_____
	12.4.5	Verify synchroscope working.	_____
		a. Lights OFF at the 12 o'clock position.	
		b. Lights FULL BRIGHT at the 6 o'clock position.	
	12.4.6	Adjust engine speed up and down to verify manual governor control.	_____
	12.4.7	Adjust engine speed so the synchroscope is turning slowly in the clockwise (FAST) direction. This will allow the D/G to pick up load when paralleled to the bus.	_____
	12.4.8	Adjust D/G voltage to within ±2 volts of bus voltage.	_____
	12.4.9	When the synchroscope pointer is slightly before the 12 o'clock position, turn generator breaker control switch to the CLOSE position. Pick up load (0.5MW) promptly after the breaker is closed. This will prevent the D/G breaker from tripping.	_____
		Clock time D/G paralleled: _____ hrs.	
	12.4.10	Adjust voltage with voltage control switch to maintain VARS-OUT.	_____
	12.4.11	Cut out the FEEDER SYNC Switch.	_____
	12.4.12	Increase the load to ≥2.45 MW and ≤2.50 MW at a rate of ≤ 0.50 MW every 2 minutes and record clock time D/G reaches ≥2.45 MW load:	
		Date/Time _____/_____	_____
	12.4.13	If the plant is in MODE 1, 2, 3, or 4, perform STP I-1C, Attachment 12.4 within 1 hour of declaring D/G inoperable.	_____

PERF

12.4.14 Mark the D/G MW/Freq recorder _____

NOTE: The strip chart from the MW/Freq recorder will be used to monitor any power variation during the steady state load run period. If recorder is not available, an equivalent or better M&TE recorder may be used. Momentary transients outside the load range do not invalidate this test.

12.4.15 Periodically monitor the D/G real power output for any spurious load change ≥ ±0.10MW (0.20MW Peak to Peak, p-p) from steady state value. If exceeding ±0.10MW (0.20MW p-p), generate an AR and route to system engineer. _____

AR # _____

PERF

12.5 Operation and Shutdown

12.5.1 Record D/G operating information as follows: _____
List alarms in _____

_____

_____

Generator

Current, Amperes A0_____ B0_____ C0_____

Load MW_____
(≥2.45 and ≤2.50 required)

Freq. HZ_____

MVAR_____

12.5.2 Operate the D/G loaded to ≥2.45 MW and ≤ 2.50 MW for ≥ 60 minutes. Momentary transients outside the load range do not invalidate this test. _____

12.5.3 Have the field operator take the data specified in the "RUN DATA" section of Attachment 9.1 (9.2). _____

12.5.4 Record steady state D/G stator temp (limit < 240°F) _____

_____°F

NOTE: Per SFM discretion, the D/G alignment (D/G paralleled to bus) may be utilized for other testing. The shutdown sequence from another procedure may be used. If the D/G is shutdown by another procedure, N/A steps 12.5.6, 12.5.8, 12.5.9. Record applicable data in steps 12.5.5a, 12.5.7, 12.5.10a, 12.5.10d and 12.5.11.

12.5.5 After all data has been recorded and the D/G has run loaded, ≥2.45 MW and ≤ 2.50 MW for ≥ 1 hr, record the date and time below. _____

a. Date/Time _____/_____

12.5.6 Reduce the D/G load to 0.50 MW at ≤ 0.50 MW every 2 minutes.

N/A [ ] _____

PERF

12.5.7 Calculate time D/G ran ≥ 2.45 MW for this test. _____

Clock time at end of test or when load was reduced ≤ 2.45 MW

_____ hrs. (Step 12.5.5a)

Clock time load reached ≥ 2.45 MW

_____ hrs. (Step 12.4.12)

Time D/G ran ≥ 2.45 MW: _____ minutes. (Must be ≥ 60 minutes for surveillance testing to satisfy Tech Spec.)

12.5.8 Allow the D/G to operate at approximately 0.50 MW for about five minutes for cooldown.

N/A [ ] _____

12.5.9 Reduce load on the D/G to ≤ 0.25 MW and ≥ 0.10 MW and separate the unit by opening the D/G output breaker.

N/A [ ] _____

12.5.10 After the unit has been separated,

a. Record MW-HR: _____ _____

b. Adjust the D/G speed so the frequency meter reads 60.0 to 60.25 HZ. _____

c. Adjust the D/G voltage to 119 V indicated (4160 V on the bus). _____

d. Record the speed, frequency and voltage. _____

_____RPM _____HZ _____V

12.5.11 Calculate MW-hrs generated during this test. _____

MW-hr meter reading after test
_____. (Step 12.5.10a)

MW-hr meter reading before test
_____. (Step 12.2.2)

MW-hrs generated
_____.

13. DATA REDUCTION AND EVALUATION

None

PERF

14. RESTORATION

14.1 Shutdown the D/G from the control room by placing the MAN MODE STOP/START switch to stop. _____

14.2 Return the D/G MODE SEL switch on VB4 to AUTO if required for the main unit operating mode.

D/G MODE SEL switch position _____ _____

14.3 Cut out the D/G directional power, overcurrent, and loss of field protection relays at VB4 by placing the toggle switch in the CUTOUT position. _____

14.4 Verify STP M-9I was initiated. _____

14.5 If starting train air valves were manipulated, verify a field operator has restored the valves per Attachment 9.1 (9.2). When complete, reset the alarm.

N/A [ ] _____

14.6 After the unit has been shutdown for approximately 10 minutes, have the field operator record the data in the "SHUTDOWN DATA" section of Attachment 9.1 (9.2). _____

14.7 Verify that the D/G is aligned to provide standby power to its associated emergency bus by performing the following checks:

14.7.1 D/G breaker OPERABLE (i.e., power available). _____

14.7.2 For a Unit 1 D/G, verify the following alarms are not in alarm: N/A [ ]

a. Diesel on local control. (PK16-03, PK17-03 or PK18-03) _____

b. Diesel control UV. (PK16-04, PK17-04 or PK18-04) _____

c. Diesel STRT-TURBO AIR PRESS. (PK16-09, PK17-09 or PK18-09) _____

d. Diesel engine trip. (PK16-13, PK17-13 or PK18-13) _____

e. Diesel generator breaker trip. (PK16-14, PK17-14 or PK18-14) _____

f. Diesel generator shutdown relay trip. (PK16-15, PK17-15 or PK18-15) _____

g. 4KV bus differential lockout. (PK16-16, PK17-16 or PK18-16) _____

h. Diesel voltage regulator on MANUAL. (PK16-25, PK17-25 or PK18-25) _____

PERF

14.7.3 For a Unit 2 D/G, verify the following alarms are not in alarm: N/A [ ]

a. Diesel on local control. (PK17-03, PK16-03 or PK18-03) _____

b. Diesel control UV. (PK17-04, PK16-04 or PK18-04) _____

c. Diesel STRT-TURBO AIR PRESS. (PK17-09, PK16-09 or PK18-09) _____

d. Diesel engine trip. (PK17-13, PK16-13 or PK18-13) _____

e. Diesel generator breaker trip. (PK17-14, PK16-14 or PK18-14) _____

f. Diesel generator shutdown relay trip. (PK17-15, PK16-15 or PK18-15) _____

g. 4KV bus differential lockout. (PK17-16, PK16-16 or PK18-16) _____

h. Diesel voltage regulator on MANUAL. (PK17-25, PK16-25 or PK18-25) _____

14.8 Remove the D/G stator temperature from PPC trend. (Reference step 12.2.6) _____

14.9 Verify Attachment 9.1 (9.2), field data sheets have been completed by the field operator and attached to this procedure. _____

14.10 Verify D/G fuel oil level is above low level alarm. (LOA) _____

For Unit 1:

D/G 11, PK16-07 alarm clear or alarm input 255 not in. [ ]

D/G 12, PK17-07 alarm clear or alarm input 182 not in. [ ]

D/G 13, PK18-07 alarm clear or alarm input 101 not in. [ ]

For Unit 2:

D/G 21, PK17-07 alarm clear or alarm input 182 not in. [ ]

D/G 22, PK16-07 alarm clear or alarm input 255 not in. [ ]

D/G 23, PK18-07 alarm clear or alarm input 101 not in. [ ]

14.11 If this is a monthly surveillance test, notify chemistry to perform STP M-10B2, "Diesel Generator Day Tanks Fuel Oil Analysis." Otherwise mark this step N/A.

N/A [ ] _____

PERF

14.12 Describe any malfunctions and list any discrepancies found. Otherwise mark N/A.

N/A [ ] _____

REMARKS: _____

14.13 Test performers and verifiers:

Name	Signature	Date/Time	Init
		/	
		/	
		/	
		/	
		/	
		/	
		/	
		/	
		/	
		/	
		/	

PERF

15. PRIMARY REVIEW

15.1 Verify the following acceptance criteria have been satisfied:

15.1.1 The D/G is started by either manual, startup bus undervoltage, or SI signal (steps 12.3.4, 12.3.5 or 12.3.6). _____

NOTE: When evaluating a UV timed start in steps 15.1.2, 15.1.3 and 15.1.4, subtract 0.8 seconds.

15.1.2 The D/G accelerates to ≥ 900 rpm. If performing a timed start, the D/G accelerated to ≥ 900 rpm in ≤ ten (10) seconds. (Step 12.3.7). _____

15.1.3 The D/G voltage stabilized ≥ 113 V to ≤ 121 V after start. If performing a timed start, the D/G voltage stabilized ≥ 113 V to ≤ 121 V in ≤ 13 seconds. (Step 12.3.8). _____

15.1.4 The D/G frequency stabilized between ≥ 59.5 HZ and ≤ 60.5 HZ after start. If performing a timed start, the D/G frequency stabilized ≥ 59.5 HZ and ≤ 60.5 HZ in ≤ 13 seconds. (Step 12.3.9) _____

15.1.5 If starting the D/G on a single starting train, verify the D/G started within the required times. Indicate the train that was tested. (Steps 15.1.2, 15.1.3, and 15.1.4) _____

N/A [ ]

Starting train A (starting train B isolated, step 11.13) [ ]

Starting train B (starting train A isolated, step 11.13) [ ]

15.1.6 The D/G ran for ≥ 60 minutes at ≥ 2.45 MW and ≤ 2.50 MW. (Step 12.5.7). _____

15.1.7 The D/G protective relay cutout switch is returned to the CUTOUT position. (Step 14.3) _____

15.1.8 The D/G is aligned to provide standby power to the associated emergency buses. (Step 14.7) _____

15.1.9 The fuel level in the D/G fuel oil day tank is above low level alarm. (Step 14.10) _____

PERF

15.1.10 If the day tank low level alarm is out of service, verify the fuel level in the D/G fuel oil day tank is ≥ 300 gallons or D/G 1-3 is >1/2. (Attachment 9.1 (9.2) step 4.6).

N/A [ ] _____

15.1.11 Either air receiver A OR B is ≥ 195 PSIG. (Attachments 9.1 (9.2), step 4.3, data points 34 and 40). _____

15.1.12 Turbocharger air receiver is ≥ 195 PSIG. (Attachments 9.1 (9.2), step 4.3, data point 39). _____

15.1.13 Each diesel fuel oil transfer pump starts and transfers fuel from the storage system to the D/G engine-mounted tank via installed lines for the D/G under test (Attachment 9.1 (9.2), steps 3.1.1, 3.1.3, 3.1.6, 3.1.8). _____

15.1.14 Monthly check for and removal of water from the day tank. (Attachment 9.1 (9.2), step 4.10) _____

NOTE: This NOTE applies to steps 15.1.15 and 15.1.16 below. If the frequency bands in both steps were exceeded, generate an AR to adjust D/G ISOC frequency per MP E-21.6. If only the frequency band of step 15.1.15 was exceeded, generate an AR to calibrate the frequency meter on VB4.

15.1.15 If the D/G is started from the UV or SI signal, the D/G ISOC frequency was ≥ 59.75 and ≤ 60.25 HZ as indicated by the frequency meter on VB4. (Admin Limit) (Step 12.3.14)

N/A [ ] _____

AR # _____

NOTE: Mark step 15.1.16 N/A if step 12.3.14b was marked N/A.

15.1.16 If the D/G is started from the UV or SI signal, the D/G ISOC frequency was ≥ 59.75 and ≤ 60.25 HZ as indicated by the frequency meter at the D/G exciter cubicle. (Admin Limit) (Step 12.3.14.)

N/A [ ] _____

PERF

15.2 Check valves and solenoid valves shall be considered acceptable if the following are met:

15.2.1 The starting air system and turbocharger air assist system solenoid valves stroking requirements are satisfied if the D/G started successfully. (Step 12.3.7 and Attachment 9.1 (9.2), step 2.1). _____

15.2.2 The diesel fuel oil transfer pumps 0-1 and 0-2 discharge check valve (DEG-0-35, DEG-0-36) shall be considered acceptable if the diesel fuel oil transfer pumps 0-1 and 0-2 delivers fuel into the day tank (Attachment 9.1 (9.2), steps 3.1.3 and 3.1.8). _____

15.2.3 The fuel oil tanks 0-1 and 0-2 suction check valves (DEG-0-1114, DEG-0-1115 for DFOST 0-1 and DEG-0-1117, DEG-0-1118 for DFOST 0-2) shall be considered acceptable if diesel fuel oil transfer pumps 0-1 and 0-2 delivers fuel into the day tank (Attachment 9.1 (9.2), steps 3.1.3 and 3.1.8). _____

15.3 Verify M&TE usage recorded in PIMS. _____

15.4 Review completed procedure and based on test data, make determination of D/G OPERABILITY. If any malfunctions are noted, notify management promptly, submit an action request and refer to applicable LCO.

AR#_____

REMARKS: _____

_____

_____

_____

Signature: _____ Date/Time _____ / _____
Shift Foreman

PERF

16. SECONDARY REVIEW

16.1 Review procedure for completeness and acceptability. _____

16.2 If this test was complete and the D/G are OPERABLE, then verify master schedule has been updated. _____

REMARKS: _____

_____

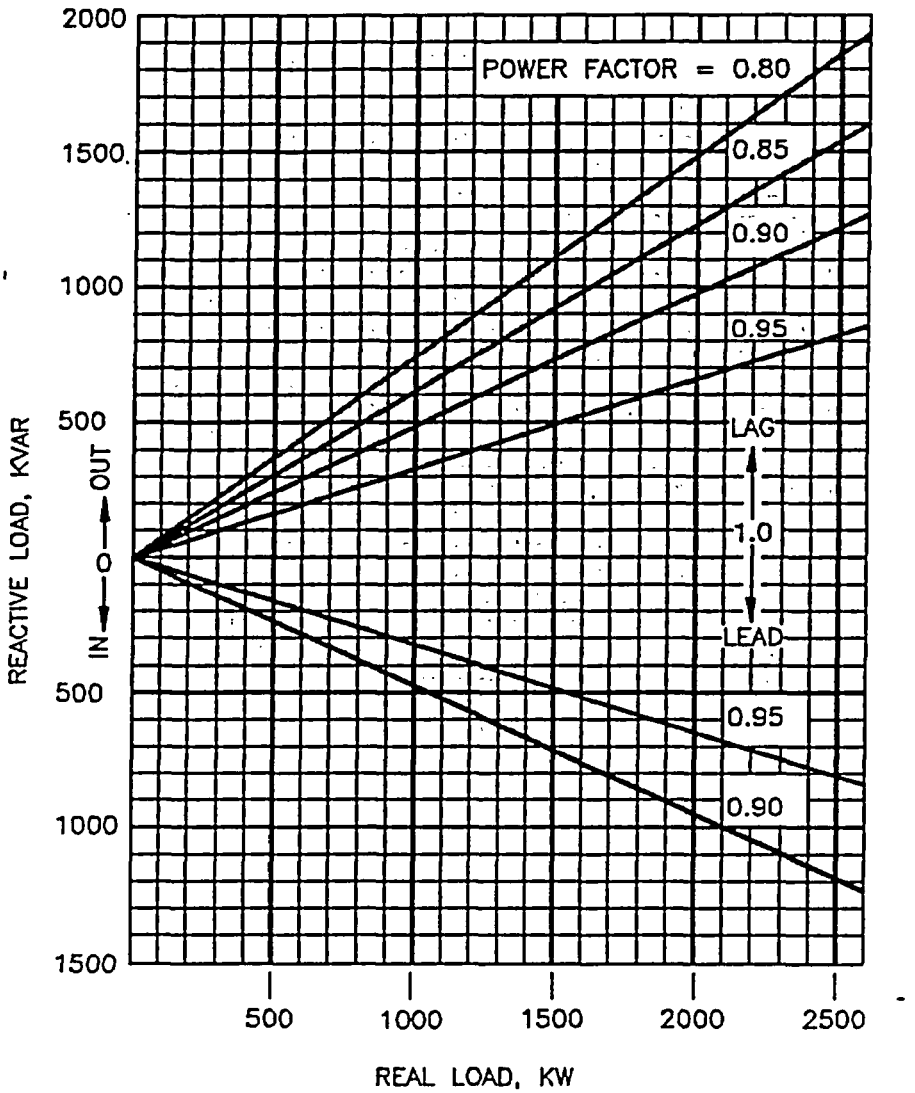
_____

_____

16.3 Reviewed By: _____ Date _____
Second Reviewer

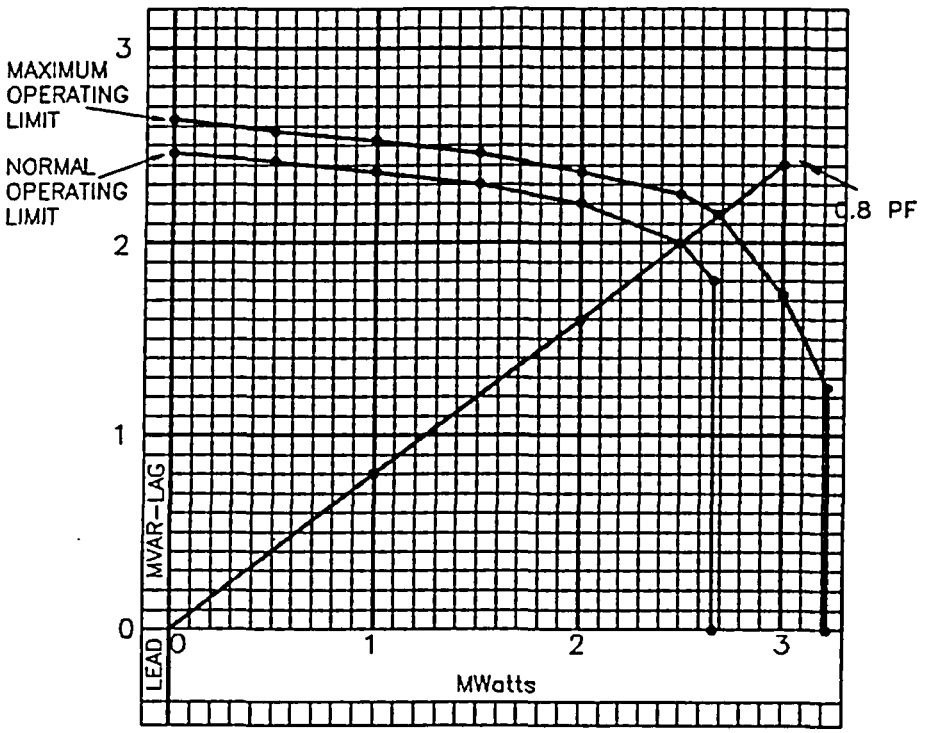
APPENDIX 8.1

KW-KVAR, POWER FACTOR RELATIONS FOR DIESEL GENERATORS



APPENDIX 8.2

COMBINED ENGINE AND GENERATOR OPERATING LIMITS



DIABLO CANYON POWER PLANT
STP M-9A
ATTACHMENT 9.1 **1**

TITLE: Data Sheet - Routine Surveillance Test of Unit 1 Diesel Generators

FIELD DATA

D.G. NO. _____ DATE _____ TIME _____

OPERATOR _____
(AT DIESEL)

1.	PRETEST DATA	ACTUAL VALUE
1.1	Engine Hours:	_____
1.2	Governor oil level (%) (minimum level = oil visible in glass*). (If below low level mark on sightglass, write an AR.) AR# _____	_____
1.3	Governor settings: Speed Droop: _____ Load Limit: _____ Speed: _____	
1.4	Record crankcase lubricating oil level, inches below high level mark on dipstick. If lubricating oil is > 2" below the high level mark, initiate an action request to add more lubricating oil. (Minimum level is 7" below high level mark.) AR# _____	_____
1.5	Priming tank level (inches from bottom of sightglass) (minimum level = oil visible in glass). If the level in the priming tank is less than minimum, refill by manual operation of the magnetic pump or with the manual priming pump. If insufficient magnetic pump run time is suspected write an action request to maintenance to adjust the magnetic pump timer. If priming tank level cannot be established declare D/G inoperable. AR# _____	_____
1.6	Day tank fuel oil level Fill tank if < 275 gallons (1/2 full for D/G 13). **AR# _____	_____

* If out of limits, declare D/G inoperable.
** If out of limits, initiate an action request.

TITLE: Data Sheet - Routine Surveillance Test of Unit 1 Diesel Generators

ACTUAL VALUE

1.7 Jacket cooling water level, inches above low point in glass. (Minimum level=water visible in glass*). _____

If the jacket cooling water level is less than the values listed below, refill the expansion tank to the appropriate fill level using demineralized water. Notify chemistry to test the jacket cooling water after D/G test.

		Level Below	Fill To
Cold		12"	15"
Hot	(≥160°F)	14.5"	17.5"

Chemistry Notified: _____ Date/Time _____ / _____

1.8 West roll up fire doors are in the full up position.*** Record Door Position _____

PERF

1.9 Connect the D/G fuel oil leak-off collection bottles as follows:

1.9.1 Obtain 2 five gallon poly bottles and tygon tubing from the storage box. _____

1.9.2 Remove the pipe cap at the end of the fuel oil leak-off return lines on each side of the D/G. _____

1.9.3 Connect the tygon tubing to the fuel oil leak-off return lines and route each to a 5 gallon poly bottle. _____

1.9.4 Open the appropriate 1/2" whitey fuel oil leak-off drain valves to the poly bottle. _____

D/G 1-1	DEG-1-1055,	DEG-1-1056
D/G 1-2	DEG-1-1053,	DEG-1-1054
D/G 1-3	DEG-1-1057,	DEG-1-1058

* If out of limits, declare D/G inoperable.

*** At least one west roll up fire door must be open to maintain the D/G OPERABLE. (AR A0330481-E04)

TITLE: Data Sheet - Routine Surveillance Test of Unit 1 Diesel Generators

PERF

1.10 If directed by the control room operator or the shift foreman, isolate starting train A or starting train B. Mark the starting train where valves will be manipulated.

Isolate Starting Train A [ ]

Isolate Starting Train B [ ]

N/A [ ] _____

1.10.1 Select the air supply valve to be closed in the table below. _____

D/G	1 - 1	1 - 2	1 - 3
Train "A" Valve	DEG-1-63 [ ]	DEG-1-89 [ ]	DEG-1-115 [ ]
Train "B" Valve	DEG-1-52 [ ]	DEG-1-78 [ ]	DEG-1-104 [ ]

1.10.2 Select the blow-down valve to be uncapped and opened in the table below. When the valve is opened, PK window 16-09, 17-09, or 18-09, will alarm. _____

D/G	1 - 1	1 - 2	1 - 3
Train "A" Valve	DEG-1-227 [ ]	DEG-1-249 [ ]	DEG-1-271 [ ]
Train "B" Valve	DEG-1-216 [ ]	DEG-1-238 [ ]	DEG-1-260 [ ]

NOTE: When train "A" valves are manipulated, starting train "B" will be tested. When train "B" valves are manipulated, train "A" will be tested.

PERF

1.11 Verify one of the following:

1.11.1 Verify the D/G control power transfer switch is in the NORMAL position with the NORMAL amber light lit on panel EQDxx, (Replace "xx" with the number of the D/G being tested for panel designation, e.g., EQD11 for D/G 11, etc.). _____

OR

1.11.2 (This option available only in MODE 5, 6 or defueled when step 11.3.2 is performed) Verify the D/G control power transfer switch is in the BACKUP position with the BACKUP amber light lit on panel EQDxx (Replace "xx" with the number of the D/G being tested for panel designation, e.g., EQD11 for D/G 11, etc.).

N/A [ ] _____

1.12 If test is used to satisfy Tech Spec SR 3.8.1.2 or SR 3.8.1.7, (Routine M-9A Test) record jacket water temperature and lubricating oil temperature. If either temperature is not ≥ 95°F and ≤ 167°F notify the shift foreman.

N/A [ ] _____

Water Temperature: _____ Oil Temperature _____

DIESEL GENERATOR	WATER TEMPERATURE	OIL TEMPERATURE
1-1	TI-1030	TI-527
1-2	TI-1035	TI-504
1-3	TI-1036	TI-505

OR

If M&TE is used, calculate the required temperature range by adding M&TE uncertainty to 90°F and subtracting M&TE uncertainty from 175°. M&TE I.D._____

	Required Temperature Range for M&TE	Measured
Water Temperature	_____°F	_____°F
Oil Temperature	_____°F	_____°F

N/A [ ] _____

STP M-9A (UNIT 1)
ATTACHMENT 9.1

TITLE: Data Sheet - Routine Surveillance Test of Unit 1 Diesel Generators

1.13 Record the following parameters:

DATA POINT	PARAMETER	INSTRUMENT NO. FOR DIESEL 11	12	13	LIMITS	ACTUAL VALUE
1	Lubricating Oil Pressure (PSIG)	PI-606	PI-629	PI-639	10-15**[4]	_____
2	Room Air Temperature (°F)	TI-97	TI-98	TI-99		_____
3	Turbo Air Header Pressure (PSIG)	PI-843	PI-844	PI-845	≥200** ≥195[2]	_____
4	Air Header B Pressure (PSIG)	PI-598	PI-620	PI-640	≥140[1] ≤160*	_____
5	Air Header A Pressure (PSIG)	PI-599	PI-621	PI-641	≥140[1] ≤160*	_____
6	Jacket Water Temperature (°F)	TI-1030	TI-1035	TI-1036	95-120**[3] (≥95*)	_____
7	Air Receiver A Pressure (PSIG)	PI-601	PI-623	PI-634	≥210** ≥195[1]	_____
8	Lubricating Oil Temperature (°F)	TI-527	TI-504	TI-505	95-120**[3] (≥95*)	_____
9	Turbo Air Receiver Pressure (PSIG)	PI-840	PI-841	PI-842	≥200** ≥195[2]	_____
10	Air Receiver B Pressure (PSIG)	PI-600	PI-622	PI-633	≥210** ≥195[1]	_____

**AR# _____

[1] NOTE: Either starting air receiver A must be ≥ 195 PSIG and starting air header A must be ≥ 140 PSIG OR starting air receiver B must be ≥ 195 PSIG and starting air header B must be ≥ 140 PSIG. If both starting air receivers are ≥ 165 PSIG and < 195 PSIG, restore one air receiver to ≥ 195 PSIG in ≤ 48 hours or declare the D/G inoperable. If both starting air receivers < 165 PSIG declare the D/G inoperable. If both air header A and air header B pressure is < 140 PSIG declare the D/G inoperable. If performing a single starting train start, either air header A or air header B will indicate 0 PSIG.

[2] NOTE: If the turbocharger receiver is ≥ 165 PSIG and < 195 PSIG, restore the air receiver to ≥ 195 PSIG ≤ 48 hours or declare the D/G inoperable. If the turbocharger < 165 PSIG, declare the D/G inoperable.

[3] NOTE: If the D/G is still hot from a previous run and the oil or jacket water temperature is > 120°F, do not write an AR.

[4] NOTE: If the D/G lube oil is> 120°F from a previous run, the lube oil pressure is > 3 psi, and the pre-lube pump is on, do NOT write an AR.

* If out of limits, declare D/G inoperable.

** If out of limits, initiate an action request.

PERF

2. STARTUP DATA

NOTE 1: If it becomes necessary to shutdown the D/G without control power, manually operate the overspeed trip lever on the northwest corner of the engine, forward of the fuel oil filters.

NOTE 2: The next four steps should be performed within 60 seconds of D/G start.

2.1 Verify D/G started. _____

2.2 Verify D/G lube oil pressure ≥ 60 PSIG within 60 seconds of starting.** (Instrument console, PI-606, PI-629 or PI-639) _____

2.3 Verify jacket water pressure increases within 60 seconds of starting.** (No pressure limit) (Instrument console, PI-612, PI-643 or PI-645) _____

2.4 Verify D/G fuel oil pressure ≥ 40 PSIG within 60 seconds of starting.** (Instrument console, PI-604, PI-626 or PI-637) _____

(Gauge response is generally about 15 seconds.)

2.5 Verify the crankcase exhausters are operating.** _____

2.6 Verify governor oil is at or above the low level mark in sightglass. If below the mark write an AR. If not visible, declare D/G inoperable. _____

** If out of limits, initiate an action request.

PERF

2.7 Verify proper fuel oil flow to the priming system.

2.7.1 Verify magnetic priming pump is NOT running. _____

2.7.2 Verify SMALL amount of fuel flowing in overflow sightglass FI-313 (314) (315) _____

NOTE: Fuel should NOT collect in the sightglass. If fuel is not flowing in the sightglass but the priming tank level is increasing, wait until the priming tank fills to the proper level. Valve DEG-1-530 (536) (542) should be approximately 1/4 turn open.

a. If there is no flow or too much flow in the sightglass, then adjust valve DEG-1-530 (536) (542) until a SMALL amount of fuel is flowing in the overflow sightglass.

N/A [ ] _____

2.8 Monitor the level in the poly bottles connected to the D/G fuel leak-off valves as needed to prevent poly bottle overfill while the drain valve is open and D/G is running. _____

TITLE: Data Sheet - Routine Surveillance Test of Unit 1 Diesel Generators

		PERF	VERIF
3.	RUN DATA		

NOTE: Steps 3.1 and 3.2 can be performed anytime after the D/G has started. The D/G does not need to have been running for at least 1 hour.

3.1 Verify OPERABILITY of the fuel oil transfer system in the following steps:

****

CAUTION: It is possible to overflow the fuel oil day tank in MANUAL control, and thus cause a fuel oil spill. Level column responds very slowly to a level change. Exercise caution when manually filling a day tank.

****

NOTE: The numbers given below are for D/G 1-1. The numbers in parentheses are for D/Gs 1-2 and 1-3 respectively.

3.1.1	Start fuel oil transfer pump 0-1 from D/G 1-1 (1-2) (1-3).	_____	
3.1.2	Open day tank fill valve LCV-88 (89) (90).	_____	
3.1.3	Observe an increase in day tank level. (Verifies foot valves DEG-0-1114, DEG-0-1115, and check valve DEG-0-35 are OPERABLE.)	_____	
3.1.4	Close LCV-88 (89) (90) and place in AUTO.	_____	_____
3.1.5	Stop fuel oil transfer pump 0-1 and place the switch in the AUTO position.	_____	_____
3.1.6	Start fuel oil transfer pump 0-2 from D/G 1-1 (1-2) (1-3).	_____	
3.1.7	Open day tank fill valve LCV-85 (86) (87).	_____	
3.1.8	Observe an increase in day tank level. (Verifies foot valves DEG-0-1117, DEG-0-1118, and check valve DEG-0-36 are OPERABLE)	_____	
3.1.9	Close LCV-85 (86) (87) and place in AUTO.	_____	_____
3.1.10	Stop fuel oil transfer pump 0-2 and place the switch in the AUTO position.	_____	_____

3.2 Verify proper operation of the fuel oil priming system by performing the following:

3.2.1	Place magnetic priming pump control switch in MANUAL and verify pump operation by increase in fuel oil flow through overflow sightglass.	_____	
3.2.2	Place magnetic priming pump control switch in AUTO.	_____	_____

STP M-9A (UNIT 1)
ATTACHMENT 9.1

TITLE: Data Sheet - Routine Surveillance Test of Unit 1 Diesel Generators

3.3 Record the following Parameters after the D/G has run ≥ 60 minutes at ≥2.45 MW and ≤ 2.50 MW load.

DATA POINT	PARAMETER	INSTRUMENT NO. FOR DIESEL 11	12	13	LIMITS	ACTUAL VALUE
	NORTH SIDE OF DIESEL					
11	Lube Oil Pressure Leaving Filter (PSIG)	PI-834	PI-836	PI-838		
12	Lube Oil Pressure Entering Filter (PSIG)	PI-607	PI-627	PI-638		
13	Secondary Fuel Oil Filter Inlet Press. (PSIG)	PI-603	PI-625	PI-636		
14	Secondary Fuel Oil Filter Outlet Press. (PSIG)	PI-829	PI-831	PI-833		
15	Primary Fuel Oil Filter dp (In. Hg.)	PIS-1021	PIS-1022	PI-1023	≤4.5**	
	INSTRUMENT CONSOLE					
16	Lube Oil Pressure (PSIG)	PI-606	PI-629	PI-639	≥60*	
17	Lube Oil Temperature Leaving Engine (°F)	TI-527	TI-504	TI-505	≤195***	
18	Jacket Water Pressure (PSIG)	PI-612	PI-643	PI-645		
19	Jacket Water Temperature Entering Radiator (°F)	TI-1030	TI-1035	TI-1036		
20	Fuel Oil Pressure (PSIG)	PI-604	PI-626	PI-637	≥40	

* If out of limits, declare D/G inoperable and the D/G should be shutdown for insufficient lube oil pressure.

** If out of limits, initiate an action request.

*** If out of limits, initiate an action request. Verify temperature is not increasing. If temperature can not be maintained below limit the D/G should be shutdown.

STP M-9A (UNIT 1)
ATTACHMENT 9.1

TITLE: Data Sheet - Routine Surveillance Test of Unit 1 Diesel Generators

DATA POINT	PARAMETER	INSTRUMENT NO. FOR DIESEL 11	12	13	LIMITS	ACTUAL VALUE
21	Radiator Discharge Air Temperature (°F)	TI-528	TI-529	TI-540	≤160**	_____
22	Turbo Air Discharge Pressure (PSIG)	PI-822	PI-826	PI-827		_____
23	Room Air Temperature (°F)	TI-97	TI-98	TI-99	≤120°F**	_____
24	No. of Crankcase Exhausters in Operation	⇒	⇒	⇒	1**, 0**	_____
	EXCITER CUBICLE					
25	Exciter Voltage, VDC	⇒	⇒	⇒	VDC	_____
	Generator Output Voltage, V	⇒	⇒	⇒	V	_____
26	Exciter Current, Amps	⇒	⇒	⇒	AMP	_____
	SOUTH SIDE OF DIESEL					
27	Lube Oil Strainer Inlet P (PSIG)	PI-835	PI-837	PI-839		_____
28	Lube Oil Strainer Outlet P (PSIG)	PI-608	PI-628	PI-644		_____
29	Jacket Water Temperature Leaving Radiator (°F)	TI-506	TI-507	TI-508	≤185**	_____
30	Lube Oil Temperature Leaving L.O. HX (°F)	TI-1028	TI-1032	TI-1034		_____

** If out of limits, initiate an action request.

STP M-9A (UNIT 1)
ATTACHMENT 9.1

TITLE: Data Sheet - Routine Surveillance Test of Unit 1 Diesel Generators

DATA POINT	PARAMETER	INSTRUMENT NO. FOR DIESEL 11	12	13	LIMITS	ACTUAL VALUE
	GENERATOR					
31	Horizontal (x axis) Vibration taken on blue dot on south side of generator bearing housing.	(Use Portable Vibration Meter set on IPS)				_____
32	Vertical (y axis) Vibration taken on blue dot on top of generator bearing housing.	(Use Portable Vibration Meter set on IPS)				_____
33	Axial (z axis) Vibration taken on blue dot on end of generator bearing housing.	(Use Portable Vibration Meter set on IPS)				_____

Cylinder and Exhaust Temperatures - Inst. Console

Cylinder	R1	R2	R3	R4	R5	R6	R7	R8	R9	UR	LR
Temperature °F											

Cylinder	L1	L2	L3	L4	L5	L6	L7	L8	L9	UL	LL
Temperature °F											

		PERF
3.4	Verify there is no continuous or intermittent jacket cooling water leakage from turbo aftercooler tattletale.** ** AR #_____	_____
3.5	Verify cooling water or lube oil leaks ≤ 2 drops per minute (DPM) out of the water pump tattletale.** If an AR is initiated, list the type of leakage. ** AR #_____	_____
3.6	Verify governor oil is at or above the low level mark in sightglass. If below the mark write an AR. If not visible, declare D/G inoperable.	_____

** If out of limits, initiate an action request.

STP M-9A (UNIT 1)
ATTACHMENT 9.1

TITLE: Data Sheet - Routine Surveillance Test of Unit 1 Diesel Generators

4. SHUTDOWN DATA

4.1 Record engine hours: _____ hrs.

4.2 If valves were manipulated in step 1.10, close and cap the blow-down valve and open the air supply valve.

N/A [ ] _____ _____

4.2.1 Valve that was closed and capped: _____

4.2.2 Valve that was opened: _____

4.3 After the D/G has been shutdown for 10 minutes, record the following data:

DATA POINT	PARAMETER	INSTRUMENT NO. FOR DIESEL 11	12	13	LIMITS	ACTUAL VALUE
34	Air Receiver A Pressure (PSIG)	PI-601	PI-623	PI-634	≥210** ≥195[1]	
35	Lubricating Oil Pressure (PSIG)	PI-606	PI-629	PI-639	≥2**	
36	Turbo Air Header Pressure (PSIG)	PI-843	PI-844	PI-845	≥200** ≥195[2]	
37	Air Header B Pressure (PSIG)	PI-598	PI-620	PI-640	≥140[1] ≤160*	
38	Air Header A Pressure (PSIG)	PI-599	PI-621	PI-641	≥140[1] ≤160*	
39	Turbo Air Receiver Pressure (PSIG)	PI-840	PI-841	PI-842	≥200** ≥195[2]	
40	Air Receiver B Pressure (PSIG)	PI-600	PI-622	PI-633	≥210** ≥195[1]	

[1] NOTE: Either starting air receiver A must be ≥ 195 PSIG and starting air header A must be ≥ 140 PSIG OR starting air receiver B must be ≥ 195 PSIG and starting air header B must be ≥ 140 PSIG. If both starting air receivers are ≥ 165 PSIG and < 195 PSIG, restore one air receiver to ≥ 195 PSIG in ≤ 48 hours or declare the D/G inoperable. If both starting air receivers < 165 PSIG declare the D/G inoperable.

[2] NOTE: If the turbocharger receiver is ≥ 165 PSIG and < 195 PSIG, restore the air receiver to ≥ 195 PSIG ≤ 48 hours or declare the D/G inoperable. If the turbocharger < 165 PSIG, declare the D/G inoperable.

* If out of limits declare D/G inoperable.

** If out of limits initiate an action request.

STP M-9A (UNIT 1)
ATTACHMENT 9.1

TITLE: Data Sheet - Routine Surveillance Test of Unit 1 Diesel Generators

ACTUAL VALUE

4.4 Record jacket cooling water level, inches above low point in glass. (Minimum level = water visible in glass*.) (Normal level ≥ 14.5 inches and ≤ 17.5 inches.) _____

Did the level increase from step 1.7 YES [ ] NO [ ]

NOTE: This check is performed to allow detection of plugging jacket cooling water level indicator. PPE reviewing this data sheet should initiate an action request to investigate the jacket cooling water level indicator should the level indicate other than the trend stated below..

1. If the D/G is started cold, jacket cooling water level recorded in step 4.4 should increase after a normal 1 hour run.
2. If the D/G is started cold for a less than 20 minute (nominal) run, the level recorded in step 4.4 should remain relatively unchanged.
3. If the D/G is started warm, the level recorded in step 4.4 should remain unchanged after the D/G run.

If the jacket cooling water level is below 14.5 inches, refill expansion tank to 16.5 inches with demineralized water and notify chemistry to conduct a chemical test on the jacket cooling water. If chemistry was notified in step 1.7, no action is needed.

N/A [ ]

Chemistry Notified: _____ Date/Time _____ / _____

NOTE: The numbers given below are for D/G 1-1. The numbers in parentheses are for D/G's 1-2 and 1-3 respectively.

4.5 If the day tank level is less than 500 gallons (fuel oil pump AUTO stop for D/G 1-3), fill the day tank to approximately 500 gallons (fuel oil pump AUTO stop for D/G 1-3) as follows:

N/A [ ]

* If out of limits, declare D/G inoperable.
** If out of limits, initiate an action request.

		PERF	VERIF

****

CAUTION: It is possible to overflow the fuel oil day tank in MANUAL control, and thus cause a fuel oil spill. Level column responds very slowly to a level change. Exercise caution when manually filling a day tank.

****

4.5.1	If fuel oil transfer pump 0-1 is used perform the following: N/A [ ]		
	a. Start fuel oil transfer pump 0-1.	_____	
	b. Open day tank fill valve LCV-88 (89) (90).	_____	
	c. When the day tank is filled to approximately 500 gallons (fuel oil pump AUTO stop for D/G 1-3), close day tank fill valve LCV-88 (89) (90).	_____	
	d. Place day tank fill valve control switch LCV-88 (89) (90) in AUTO.	_____	_____
	e. Stop diesel fuel oil transfer pump 0-1 and place in AUTO.	_____	_____
4.5.2	If fuel oil transfer pump 0-2 is used perform the following: N/A [ ]		
	a. Start fuel oil transfer pump 0-2.	_____	
	b. Open day tank fill valve LCV-85 (86) (87).	_____	
	c. When the day tank is filled to approximately 500 gallons (fuel oil pump AUTO stop for D/G 1-3), close day tank fill valve LCV-85 (86) (87).	_____	
	d. Place day tank fill valve control switch LCV-85 (86) (87) in AUTO.	_____	_____
	e. Stop diesel fuel oil transfer pump 0-2 and place in AUTO.	_____	_____

PERF

4.6 Record day tank fuel level.

4.6.1 Fuel level for D/G 1-1 or D/G 1-2. N/A this step for D/G 1-3.

N/A [ ] _____

_____ gallons

NOTE: If the day tank low level alarm (LOA) is out of service, day tank level shall be ≥ 300 gallons.*

4.6.2 Fuel level for D/G 1-3.

N/A [ ] _____

_____ Dial reading.
(>1/2, 3/4, AUTO stop level and etc.)

NOTE: If the day tank low level alarm (LOA) is out of service, day tank level should be ≥ fuel oil pump AUTO stop level and shall be > 1/2 day tank level.*

4.7 Record actual priming tank level (inches from bottom of sightglass) _____
(minimum level = level of return line = approx. 5").

Level _____

If the level in the primary tank is less than minimum, refill by manual operation of the magnetic pump or with the manual priming pump. If insufficient magnetic pump run time is suspected write an action request to maintenance to adjust the magnetic pump timer. If priming tank level cannot be established, declare D/G inoperable.

AR #_____

4.8 Record actual crankcase lubricating oil level, inches below full mark on dipstick. If lubricating oil is > 2" below the high level mark, initiate an action request to add more lubricating oil. (Minimum level is 7" below high level mark.) _____

Level _____

* If out of limits, declare D/G inoperable.

PERF

4.9 Blowdown all three air receivers inline filters a small amount through their drain valves to check for water accumulation.

NOTE: To blowdown the filter units the screw on the bottom must be turned clockwise several turns when viewed from the bottom.

4.9.1 Air receiver systems blown down.

	Prefilter	Oil Filter	After Filter
Turbo	[ ]	[ ]	[ ]
Starting A	[ ]	[ ]	[ ]
Starting B	[ ]	[ ]	[ ]

_____

4.9.2 If water is present, write an action request. (A small amount of mist out of the prefilter is acceptable).
AR #_____
N/A [ ] _____

4.10 Perform the following to drain any accumulated water in the day tank.

4.10.1 Open drain valve(s) on D/G fuel oil day tank and check for the presence of water. Remove any accumulated water. _____

NOTE: For D/G with multiple drain valves, one or more of the following drain valves may be opened to remove any accumulated water.

4.10.2 Circle drain valve or valves opened below. _____

D/G	Valve
1-1	DEG-1-1059/1060/1061/1062/1063/1064
1-2	DEG-1-1065/1066/1067/1068/1069/1070
1-3	DEG-1-520

4.10.3 Day tank checked for presence of water.*** _____
[ ] Removed accumulated water***
[ ] No water found

4.10.4 Close the drain valve(s) opened in step 4.10.1. _____ _____

*** If check is not done or if any accumulated water is found and not removed, declare D/G inoperable.

		PERF	VERIF
4.11	Disconnect the D/G fuel oil leak-off collection bottles:		
4.11.1	Close the appropriate 1/2" whitey fuel oil leak-off drain valves to the poly bottle. (Reference step 1.9.4)	_____	_____
4.11.2	Remove the tygon tubing from the fuel oil leak-off return lines.	_____	
4.11.3	Reinstall the pipe cap at the end of the fuel oil leak-off return lines.	_____	
4.11.4	Empty the poly bottles into the protected area hazardous waste oil tank.	_____	
4.11.5	Return the poly bottles and tygon tubing to the storage box.	_____	

STP M-9A (UNIT 1)
ATTACHMENT 9.1

TITLE: Data Sheet - Routine Surveillance Test of Unit 1 Diesel Generators

4.12 REMARKS: _____

4.13 Test performers and verifiers:

Name	Signature	Date/Time	Init
		/	
		/	
		/	
		/	
		/	
		/	
		/	
		/	
		/	

TITLE: Data Sheet - Routine Surveillance Test of Unit 1 Diesel Generators

5. DATA REDUCTION

5.1 Record values out of limits by observation:

_____

_____

5.2	Calculated values	Data Point:	
	Lubricating oil filter ΔP (maximum limit 15 psid**)	12 minus 11	_____psid
	Secondary fuel oil filter ΔP (maximum limit 35 psid**)	13 minus 14	_____psid
	Calculated values:	Data Point:	
	Lube oil strainer ΔP (maximum limit 9 psid**)	27 minus 28	_____psid
	Radiator water ΔT	19 minus 29	_____°F
	D/G hours operated this test	4.1 minus 1.1	_____hrs.

** AR # _____

5.3 Misc. Data:

(See page 11 of Attachment 9.1)

Maximum cylinder exhaust temperature, _____°F in Cylinder No. _____

Minimum cylinder exhaust temperature, _____°F in Cylinder No. _____

Difference _____ (maximum limit 150°F**)

** AR # _____

		PERF
5.4	Transfer pump 0-1 increased day tank level. (Step 3.1.3)***	_____
5.5	Transfer pump 0-2 increased day tank level. (Step 3.1.8)***	_____

** If out of limits, initiate an action request.

*** An inoperable transfer pump puts the unit into an Action Statement.

DIABLO CANYON POWER PLANT
STP M-9A
ATTACHMENT 9.2

2

TITLE: Data Sheet - Routine Surveillance Test of Unit 2 Diesel Generators

FIELD DATA

D.G. NO. _____ DATE _____ TIME _____

OPERATOR _____
(AT DIESEL)

1.	PRETEST DATA		ACTUAL VALUE
1.1	Engine Hours:		_____
1.2	Governor oil level (%) (minimum level = oil visible in glass*). (If below low level mark on sightglass, write an AR.)		_____
	AR# _____		
1.3	Governor settings:		
		Speed Droop:	_____
		Load Limit:	_____
		Speed:	_____
1.4	Record crankcase lubricating oil level, inches below high level mark on dipstick. If lubricating oil is > 2" below the high level mark, initiate an action request to add more lubricating oil. (Minimum level is 7" below high level mark.)		_____
1.5	Priming tank level (inches from bottom of sightglass) (Minimum level for D/G 2-1 and D/G 2-2 is oil visible in glass. Minimum level for D/G 2-3 is 6" from bottom of sightglass).		_____
	If the level in the priming tank is less than minimum, refill by manual operation of the magnetic pump or with the manual priming pump. If insufficient magnetic pump run time is suspected write an action request to maintenance to adjust the magnetic pump timer. If priming tank level cannot be established declare D/G inoperable.		
	AR# _____		
1.6	Day tank fuel oil level Fill tank if < 275 gallons.		_____
	**AR# _____		

* If out of limits, declare D/G inoperable.
** If out of limits, initiate an action request.

STP M-9A (UNIT 2)
ATTACHMENT 9.2

TITLE: Data Sheet - Routine Surveillance Test of Unit 2 Diesel Generators

ACTUAL VALUE

1.7 Jacket cooling water level, inches above low point in glass. (Minimum level=water visible in glass*). _____

If the jacket cooling water level is less than the values listed below, refill the expansion tank to the appropriate fill level using demineralized water. Notify chemistry to test the jacket cooling water after D/G test.

		Level Below	Fill To
Cold		12"	15"
Hot	(≥160°F)	14.5"	17.5"

Chemistry Notified: _____ Date/Time _____ / _____

1.8 West roll up fire doors are in the full up position.***
Record Door Position _____

PERF

1.9 Connect the D/G fuel oil leak-off collection bottles as follows:

1.9.1 Obtain 2 five gallon poly bottles and tygon tubing from the storage box. _____

1.9.2 Remove the pipe cap at the end of the fuel oil leak-off return lines on each side of the D/G. _____

1.9.3 Connect the tygon tubing to the fuel oil leak-off return lines and route each to a 5 gallon poly bottle. _____

1.9.4 Open the appropriate 1/2" whitey fuel oil leak-off drain valves to the poly bottle. _____

D/G 2-1	DEG-2-1051, DEG-2-1052
D/G 2-2	DEG-2-1053, DEG-2-1054
D/G 2-3	DEG-2-1057, DEG-2-1058

* If out of limits, declare D/G inoperable.
*** At least one west roll up fire door must be open to maintain the D/G OPERABLE. (AR A0330481-E04)

PERF

1.10 If directed by the control room operator or the shift foreman, isolate starting train A or starting train B. Mark the starting train where valves will be manipulated.

Isolate Starting Train A [ ]

Isolate Starting Train B [ ]

N/A [ ] _____

1.10.1 Select the air supply valve to be closed in the table below. _____

D/G	2 - 1	2 - 2	2 - 3
Train "A" Valve	DEG-2-63 [ ]	DEG-2-89 [ ]	DEG-2-115 [ ]
Train "B" Valve	DEG-2-52 [ ]	DEG-2-78 [ ]	DEG-2-104 [ ]

1.10.2 Select the blow-down valve to be uncapped and opened in the table below. When the valve is opened, PK window 16-09, 17-09, or 18-09 will alarm. _____

D/G	2 - 1	2 - 2	2 - 3
Train "A" Valve	DEG-2-227 [ ]	DEG-2-249 [ ]	DEG-2-271 [ ]
Train "B" Valve	DEG-2-216 [ ]	DEG-2-238 [ ]	DEG-2-260 [ ]

NOTE: When train "A" valves are manipulated, starting train "B" will be tested. When train "B" valves are manipulated, train "A" will be tested.

PERF

1.11 Verify one of the following:

1.11.1 Verify the D/G control power transfer switch is in the NORMAL position with the NORMAL amber light lit on panel EQDxx, (Replace "xx" with the number of the D/G being tested for panel designation, e.g., EQD21 for D/G 21 etc.). _____

OR

1.11.2 (This option available only in MODE 5, 6 or defueled when step 11.3.2 is performed) Verify the D/G control power transfer switch is in the BACKUP position with the BACKUP amber light lit on panel EQDxx (Replace "xx" with the number of the D/G being tested for panel designation, e.g., EQD21 for D/G 21 etc.).

N/A [ ] _____

1.12 If test is used to satisfy Tech Spec SR 3.8.1.2 or SR 3.8.1.7, routine M-9A test, record jacket water temperature and lubricating oil temperature. If either temperature is not ≥ 95°F and ≤ 167°F notify the shift foreman.

N/A [ ] _____

Water Temperature: _____ Oil Temperature _____

DIESEL GENERATOR	WATER TEMPERATURE	OIL TEMPERATURE
2-1	TI-1035	TI-504
2-2	TI-1030	TI-527
2-3	TI-1036	TI-505

OR

If M&TE is used, calculate the required temperature range by adding M&TE uncertainty to 90°F and subtracting M&TE uncertainty from 175°. M&TE I.D._____

	Required Temperature Range for M&TE	Measured
Water Temperature	_____°F	_____°F
Oil Temperature	_____°F	_____°F

N/A [ ] _____

STP M-9A (UNIT 2)
ATTACHMENT 9.2

TITLE: Data Sheet - Routine Surveillance Test of Unit 2 Diesel Generators

1.13 Record the following parameters:

DATA POINT	PARAMETER	INSTRUMENT NO. FOR DIESEL 21	22	23	LIMITS	ACTUAL VALUE
1	Lubricating Oil Pressure (PSIG)	PI-629	PI-606	PI-639	10-15**[4]	
2	Room Air Temperature (°F)	TI-98	TI-97	TI-99		
3	Turbo Air Header Pressure (PSIG)	PI-844	PI-843	PI-845	≥200** ≥195[2]	
4	Air Header B Pressure (PSIG)	PI-620	PI-598	PI-640	≥140[1] ≤160*	
5	Air Header A Pressure (PSIG)	PI-621	PI-599	PI-641	≥140[1] ≤160*	
6	Cold Jacket Water Temperature (°F)	TI-1035	TI-1030	TI-1036	95-120**[3] (≥95*)	
7	Air Receiver A Pressure (PSIG)	PI-623	PI-601	PI-634	≥210** ≥195[1]	
8	Lubricating Oil Temperature (°F)	TI-504	TI-527	TI-505	95-120**[3] (≥95*)	
9	Turbo Air Receiver Pressure (PSIG)	PI-841	PI-840	PI-842	≥200** ≥195[2]	
10	Air Receiver B Pressure (PSIG)	PI-622	PI-600	PI-633	≥210** ≥195[1]	

**AR# _____

[1] NOTE: Either starting air receiver A must be ≥ 195 PSIG and starting air header A must be ≥ 140 PSIG OR starting air receiver B must be ≥ 195 PSIG and starting air header B must be ≥ 140 PSIG. If both starting air receivers are ≥ 165 PSIG and < 195 PSIG, restore one air receiver to ≥ 195 PSIG in ≤ 48 hours or declare the D/G inoperable. If both starting air receivers < 165 PSIG declare the D/G inoperable. If both air header A and air header B pressure is < 140 PSIG declare the D/G inoperable. If performing a single starting train start, either air header A or air header B will indicate 0 PSIG.

[2] NOTE: If the turbocharger receiver is ≥ 165 PSIG and < 195 PSIG, restore the air receiver to ≥ 195 PSIG ≤ 48 hours or declare the D/G inoperable. If the turbocharger < 165 PSIG, declare the D/G inoperable.

[3] NOTE: If the D/G is still hot from a previous run and the oil or jacket water temperature is > 120°F, do not write an AR.

[4] NOTE: If the D/G lube oil is> 120°F from a previous run, the lube oil pressure is > 3 psi, and the pre-lube pump is on, do NOT write an AR.

* If out of limits, declare D/G inoperable.

** If out of limits, initiate an action request.

PERF

2. STARTUP DATA

NOTE 1: If it becomes necessary to shutdown the D/G without control power, manually operate the overspeed trip lever on the northwest corner of the engine, forward of the fuel oil filters.

NOTE 2: The next four steps should be performed within 60 seconds of D/G start.

2.1	Verify D/G started.	_____
2.2	Verify D/G lube oil pressure ≥ 60 PSIG within 60 seconds of starting.** (Instrument console, PI-629, PI-606 or PI-639)	_____
2.3	Verify jacket water pressure increases within 60 seconds of starting.** (No pressure limit) (Instrument console, PI-643, PI-612 or PI-645)	_____
2.4	Verify D/G fuel oil pressure ≥ 40 PSIG within 60 seconds of starting.** (Instrument console, PI-626, PI-604 or PI-637) (Gauge response is generally about 15 seconds.)	_____
2.5	Verify the crankcase exhauster or exhausters are operating.**	_____
2.6	Verify governor oil is at or above the low level mark in sightglass. If below the mark write an AR. If not visible, declare D/G inoperable.	_____

** If out of limits, initiate an action request.

PERF

2.7 Verify proper fuel oil flow to the priming system.

2.7.1 Verify magnetic priming pump is NOT running. _____

2.7.2 Verify SMALL amount of fuel flowing in overflow sightglass FI-314 (313) (315) _____

NOTE: Fuel should NOT collect in the sightglass. If fuel is not flowing in the sightglass but the priming tank level is increasing, wait until the priming tank fills to the proper level. Valve DEG-2-530 (536) should be approximately 1/4 turn open. Valve DEG-2-542 for D/G 2-3 should be approximately 1/8 turn open.

a. If there is no flow or too much flow in the sightglass, then adjust valve DEG-2-530 (536) (542) until a SMALL amount of fuel is flowing in the overflow sightglass.

N/A [ ] _____

2.8 Monitor the level in the poly bottles connected to the D/G fuel leak-off valves as needed to prevent poly bottle overfill while the drain valve is open and D/G is running. _____

		PERF	VERIF
3.	RUN DATA		

NOTE: Steps 3.1 and 3.2 can be performed anytime after the D/G has been started. The D/G does not need to have been running for at least 1 hour.

3.1 Verify OPERABILITY of the fuel oil transfer system in the following steps:

****

CAUTION: It is possible to overflow the fuel oil day tank in MANUAL control, and thus cause a fuel oil spill. Level column responds very slowly to a level change. Exercise caution when manually filling a day tank.

****

NOTE: The numbers given below are for D/G 2-1. The numbers in parentheses are for D/G's 2-2 and 2-3 respectively.

3.1.1	Start fuel oil transfer pump 0-1 from D/G 2-1 (2-2) (2-3).	_____	
3.1.2	Open day tank fill valve LCV-89 (88) (90).	_____	
3.1.3	Observe an increase in day tank level. (Verifies foot valves DEG-0-1114, DEG-0-1115, and check valve DEG-0-35 are OPERABLE.)	_____	
3.1.4	Close LCV-89 (88) (90) and place in AUTO.	_____	_____
3.1.5	Stop fuel oil transfer pump 0-1 and place the switch in the AUTO position.	_____	_____
3.1.6	Start fuel oil transfer pump 0-2 from D/G 2-1 (2-2) (2-3).	_____	
3.1.7	Open day tank fill valve LCV-86 (85) (87).	_____	
3.1.8	Observe an increase in day tank level. (Verifies foot valves DEG-0-1117, DEG-0-1118, and check valve DEG-0-36 are OPERABLE)	_____	
3.1.9	Close LCV-86 (85) (87) and place in AUTO.	_____	_____
3.1.10	Stop fuel oil transfer pump 0-2 and place the switch in the AUTO position.	_____	_____

3.2 Verify proper operation of the fuel oil priming system by performing the following:

3.2.1	Place magnetic priming pump control switch in MANUAL and verify pump operation by increase in fuel oil flow through overflow sightglass.	_____	
3.2.2	Place magnetic priming pump control switch in AUTO.	_____	_____

STP M-9A (UNIT 2)
ATTACHMENT 9.2

TITLE: Data Sheet - Routine Surveillance Test of Unit 2 Diesel Generators

3.3 Record the following parameters after the D/G has run ≥ 60 minutes at ≥2.45 MW and ≤ 2.50 MW load.

DATA POINT	PARAMETER	INSTRUMENT NO. FOR DIESEL 21	22	23	LIMITS	ACTUAL VALUE
	NORTH SIDE OF DIESEL					
11	Lube Oil Pressure Leaving Filter (PSIG)	PI-836	PI-834	PI-838		_____
12	Lube Oil Pressure Entering Filter (PSIG)	PI-627	PI-607	PI-638		_____
13	Secondary Fuel Oil Filter Inlet Press. (PSIG)	PI-625	PI-603	PI-636		_____
14	Secondary Fuel Oil Filter Outlet Press. (PSIG)	PI-831	PI-829	PI-833		_____
15	Primary Fuel Oil Filter dp (In. Hg.)	PIS-1021	PIS-1022	PIS-1023	≤4.5**	_____
	INSTRUMENT CONSOLE					
16	Lube Oil Pressure (PSIG)	PI-629	PI-606	PI-639	≥60*	_____
17	Lube Oil Temperature Leaving Engine (°F)	TI-504	TI-527	TI-505	≤195***	_____
18	Jacket Water Pressure (PSIG)	PI-643	PI-612	PI-645		_____
19	Jacket Water Temperature Entering Radiator (°F)	TI-1035	TI-1030	TI-1036		_____
20	Fuel Oil Pressure (PSIG)	PI-626	PI-604	PI-637	≥40	_____

* If out of limits, declare D/G inoperable and the D/G should be shutdown for insufficient lube oil pressure.

** If out of limits, initiate an action request.

*** If out of limits, initiate an action request. Verify temperature is not increasing. If temperature cannot be maintained below limit, the D/G should be shutdown.

STP M-9A (UNIT 2)
ATTACHMENT 9.2

TITLE: Data Sheet - Routine Surveillance Test of Unit 2 Diesel Generators

DATA POINT	PARAMETER	INSTRUMENT NO. FOR DIESEL 21	22	23	LIMITS	ACTUAL VALUE
21	Radiator Discharge Air Temperature (°F)	TI-529	TI-528	TI-540	≤160**	
22	Turbo Air Discharge Pressure (PSIG)	PI-826	PI-822	PI-827		
23	Room Air Temperature (°F)	TI-98	TI-97	TI-99	≤120°F**	
24	No. of Crankcase Exhausters in Operation (D/G 23 has only one exhauster)	⇒	⇒	⇒	1**, 0** 0**(D/G 23)	
	EXCITER CUBICLE					
25	Exciter Voltage, VDC	⇒	⇒	⇒	VDC	
	Generator Output Voltage, V	⇒	⇒	⇒	V	
26	Exciter Current, Amps	⇒	⇒	⇒	AMP	
	SOUTH SIDE OF DIESEL					
27	Lube Oil Strainer Inlet P (PSIG)	PI-837	PI-835	PI-839		
28	Lube Oil Strainer Outlet P (PSIG)	PI-628	PI-608	PI-644		
29	Jacket Water Temperature Leaving Radiator (°F)	TI-507	TI-506	TI-508	≤185**	
30	Lube Oil Temperature Leaving L.O. HX (°F)	TI-1032	TI-1028	TI-1034		

** If out of limits, initiate an action request.

STP M-9A (UNIT 2)
ATTACHMENT 9.2

TITLE: Data Sheet - Routine Surveillance Test of Unit 2 Diesel Generators

DATA POINT	PARAMETER	INSTRUMENT NO. FOR DIESEL 21	22	23	LIMITS	ACTUAL VALUE
	GENERATOR					
31	Horizontal (x axis) Vibration taken on blue dot on south side of generator bearing housing.	(Use Portable Vibration Meter set on IPS)				_____
32	Vertical (y axis) Vibration taken on blue dot on top of generator bearing housing.	(Use Portable Vibration Meter set on IPS)				_____
33	Axial (z axis) Vibration taken on blue dot on end of generator bearing housing.	(Use Portable Vibration Meter set on IPS)				_____

Cylinder and Exhaust Temperatures - Inst. Console

Cylinder	R1	R2	R3	R4	R5	R6	R7	R8	R9	UR	LR
Temperature °F											

Cylinder	L1	L2	L3	L4	L5	L6	L7	L8	L9	UL	LL
Temperature °F											

PERF

3.4 Verify there is no continuous or intermittent jacket cooling water leakage from turbo aftercooler tattletale.** _____

** AR #_____

3.5 Verify cooling water or lube oil leaks ≤ 2 drops per minute (DPM) out of the water pump tattletale.** If an AR is initiated, list the type of leakage. _____

** AR #_____

3.6 Verify governor oil is at or above the low level mark in sightglass. If below the mark write an AR. If not visible, declare D/G inoperable. _____

** If out of limits, initiate an action request.

STP M-9A (UNIT 2)
ATTACHMENT 9.2

TITLE: Data Sheet - Routine Surveillance Test of Unit 2 Diesel Generators

4. SHUTDOWN DATA

4.1 Record engine hours: _____ hrs.

4.2 If valves were manipulated in step 1.10, close and cap the blow-down valve and open the air supply valve. N/A [ ] _____ _____

4.2.1 Valve that was closed and capped: _____

4.2.2 Valve that was opened: _____

4.3 After the D/G has been shutdown for 10 minutes, record the following data:

DATA POINT	PARAMETER	INSTRUMENT NO. FOR DIESEL 21	22	23	LIMITS	ACTUAL VALUE
34	Air Receiver A Pressure (PSIG)	PI-623	PI-601	PI-634	≥210** ≥195[1]	
35	Lubricating Oil Pressure (PSIG)	PI-629	PI-606	PI-639	≥2**	
36	Turbo Air Header Pressure (PSIG)	PI-844	PI-843	PI-845	≥200** ≥195[2]	
37	Air Header B Pressure (PSIG)	PI-620	PI-598	PI-640	≥140[1] ≤160*	
38	Air Header A Pressure (PSIG)	PI-621	PI-599	PI-641	≥140[1] ≤160*	
39	Turbo Air Receiver Pressure (PSIG)	PI-841	PI-840	PI-842	≥200** ≥195[2]	
40	Air Receiver B Pressure (PSIG)	PI-622	PI-600	PI-633	≥210** ≥195[1]	

[1] NOTE: Either starting air receiver A must be ≥ 195 PSIG and starting air header A must be ≥ 140 PSIG OR starting air receiver B must be ≥ 195 PSIG and starting air header B must be ≥ 140 PSIG. If both starting air receivers are ≥ 165 PSIG and < 195 PSIG, restore one air receiver to ≥ 195 PSIG in ≤ 48 hours or declare the D/G inoperable. If both starting air receivers < 165 PSIG declare the D/G inoperable.

[2] NOTE: If the turbocharger receiver is ≥ 165 PSIG and < 195 PSIG, restore the air receiver to ≥ 195 PSIG ≤ 48 hours or declare the D/G inoperable. If the turbocharger < 165 PSIG, declare the D/G inoperable.

* If out of limits, declare D/G inoperable.

** If out of limits, initiate an action request.

STP M-9A (UNIT 2)
ATTACHMENT 9.2

TITLE: Data Sheet - Routine Surveillance Test of Unit 2 Diesel Generators

ACTUAL VALUE

4.4 Record jacket cooling water level, inches above low point in glass. (Minimum level = water visible in glass*.) (Normal level ≥ 14.5 inches and ≤ 17.5 inches.) _____

Did the level increase from step 1.7 YES [ ] NO [ ]

NOTE: This check is performed to allow detection of plugging jacket cooling water level indicator. PPE reviewing this data sheet should initiate an action request to investigate the jacket cooling water level indicator should the level indicate other than the trend stated below.

1. If the D/G is started cold, jacket cooling water level recorded in step 4.4 should increase after a normal 1 hour run.
2. If the D/G is started cold for a less than 20 minute (nominal) run, the level recorded in step 4.4 should remain relatively unchanged.
3. If the D/G is started warm, the level recorded in step 4.4 should remain unchanged after the D/G run.

If the jacket cooling water level is below 14.5 inches, refill expansion tank to 16.5 inches with demineralized water and notify chemistry to conduct a chemical test on the jacket cooling water. If chemistry was notified in step 1.7, no action is needed.

N/A [ ]

Chemistry Notified: _____ Date/Time _____ / _____

NOTE: The numbers given below are for D/G 2-1. The numbers in parentheses are for D/G's 2-2 and 2-3 respectively.

4.5 If the day tank level is less than 500 gallons, fill the day tank to approximately 500 gallons as follows:

N/A [ ]

* If out of limits, declare D/G inoperable.
** If out of limits, initiate an action request.

		PERF	VERIF

****

CAUTION: It is possible to overflow the fuel oil day tank in MANUAL control, and thus cause a fuel oil spill. Level column responds very slowly to a level change. Exercise caution when manually filling a day tank.

****

4.5.1	If fuel oil transfer pump 0-1 is used perform the following: N/A [ ]			
	a.	Start fuel oil transfer pump 0-1.	_____	
	b.	Open day tank fill valve LCV-89 (88) (90).	_____	
	c.	When the day tank is filled to approximately 500 gallons, close day tank fill valve LCV-89 (88) (90).	_____	
	d.	Place day tank fill valve control switch LCV-89 (88) (90) in AUTO.	_____	_____
	e.	Stop diesel fuel oil transfer pump 0-1 and place in AUTO.	_____	_____
4.5.2	If fuel oil transfer pump 0-2 is used perform the following: N/A [ ]			
	a.	Start fuel oil transfer pump 0-2.	_____	
	b.	Open day tank fill valve LCV-86 (85) (87).	_____	
	c.	When the day tank is filled to approximately 500 gallons, close day tank fill valve LCV-86 (85) (87).	_____	
	d.	Place day tank fill valve control switch LCV-86 (85) (87) in AUTO.	_____	_____
	e.	Stop diesel fuel oil transfer pump 0-2 and place in AUTO.	_____	_____
4.6	Record day tank fuel level. _____ gallons		_____	

NOTE: If the day tank low level alarm (LOA) is out of service, day tank level shall be ≥ 300 gallons.*

* If out of limits, declare D/G inoperable.

PERF

4.7 Record actual priming tank level (inches from bottom of sightglass) (minimum level = level of return line = approx. 5").

Level _____ _____

If the level in the primary tank is less than minimum, refill by manual operation of the magnetic pump or with the manual priming pump. If insufficient magnetic pump run time is suspected write an action request to maintenance to adjust the magnetic pump timer. If priming tank level cannot be established, declare D/G inoperable.

AR #_____

4.8 Record actual crankcase lubricating oil level, inches below full mark on dipstick. If lubricating oil is > 2" below the high level mark, initiate an action request to add more lubricating oil. (Minimum level is 7" below high level mark.) _____

Level _____

4.9 Blowdown all three air receivers inline filters a small amount through their drain valves to check for water accumulation.

NOTE: To blowdown the filter units the screw on the bottom must be turned clockwise several turns when viewed from the bottom.

4.9.1 Air receiver systems blown down.

	Prefilter	Oil Filter	After Filter
Turbo	[ ]	[ ]	[ ]
Starting A	[ ]	[ ]	[ ]
Starting B	[ ]	[ ]	[ ]

_____

4.9.2 If water is present, write an action request. (A small amount of mist out of the prefilter is acceptable).

AR #_____

N/A [ ] _____

* If out of limits, declare D/G inoperable.

TITLE: Data Sheet - Routine Surveillance Test of Unit 2 Diesel Generators

		PERF	VERIF
4.10	Perform the following to drain any accumulated water in the day tank.		
4.10.1	Open drain valve(s) on D/G fuel oil day tank and check for the presence of water. Remove any accumulated water.	_____	
	NOTE: For D/G with multiple drain valves, one or more of the following drain valves may be opened to remove any accumulated water.		
4.10.2	Circle drain valve or valves opened below.	_____	
	D/G — Valve 2-1 — DEG-2-1059/1060/1061/1062/1063/1064 2-2 — DEG-2-1065/1066/1067/1068/1069/1070 2-3 — DEG-2-520/521/1078/1079/1080		
4.10.3	Day tank checked for presence of water.*** [ ] Removed accumulated water*** [ ] No water found	_____	
4.10.4	Close the drain valve(s) opened in step 4.10.1.	_____	_____
4.11	Disconnect the D/G fuel oil leak-off collection bottles:		
4.11.1	Close the appropriate 1/2" whitey fuel oil leak-off drain valves to the poly bottle. (Reference step 1.9.4)	_____	_____
4.11.2	Remove the tygon tubing from the fuel oil leak-off return lines.	_____	
4.11.3	Reinstall the pipe cap at the end of the fuel oil leak-off return lines.	_____	
4.11.4	Empty the poly bottles into the protected area hazardous waste oil tank.	_____	
4.11.5	Return the poly bottles and tygon tubing to the storage box.	_____	

*** If check is not done or if any accumulated water is found and not removed, declare D/G inoperable.

STP M-9A (UNIT 2)
ATTACHMENT 9.2

TITLE: Data Sheet - Routine Surveillance Test of Unit 2 Diesel Generators

4.12 REMARKS: _____

4.13 Test performers and verifiers:

Name	Signature	Date/Time	Init
		/	
		/	
		/	
		/	
		/	
		/	
		/	
		/	
		/	
		/	
		/	
		/	

TITLE: Data Sheet - Routine Surveillance Test of Unit 2 Diesel Generators

5. DATA REDUCTION

5.1 Record values out of limits by observation: _____

_____

_____

5.2	Calculated values:	Data Point:	
	Lubricating oil filter ΔP (maximum limit 15 psid**)	12 minus 11	_____psid
	Secondary fuel oil filter ΔP (maximum limit 35 psid**)	13 minus 14	_____psid
	Calculated values:	Data Point:	
	Lube oil strainer ΔP (maximum limit 9 psid**)	27 minus 28	_____psid
	Radiator water ΔT	19 minus 29	_____°F
	D/G hours operated this test	4.1 minus 1.1	_____hrs.

** AR # _____

5.3 Misc. Data:

(See page 11 of Attachment 9.2)

Maximum cylinder exhaust temperature, _____°F in Cylinder No. _____

Minimum cylinder exhaust temperature, _____°F in Cylinder No. _____

Difference _____ (maximum limit 150°F**)

** AR # _____

		PERF
5.4	Transfer pump 0-1 increased day tank level. (Step 3.1.3)***	_____
5.5	Transfer pump 0-2 increased day tank level. (Step 3.1.8)***	_____

** If out of limits, initiate an action request.
*** An inoperable transfer pump puts the unit into an Action Statement.

DIABLO CANYON POWER PLANT
STP M-9A
ATTACHMENT 9.3

1

TITLE: Unit 1 Undervoltage Test at Switchgear Room

PROCEDURE STEPS PERFORMED AT SWITCHGEAR

D.G. NO. _____ DATE _____ TIME _____

OPERATOR AT SWITCHGEAR _____

1. Starting the D/G on an undervoltage, perform the following:

   1.1 Establish communications between the D/G, control room, and appropriate vital 4KV switchgear room. _____

DIESEL	SWITCHGEAR
1-1	HH
1-2	HG
1-3	HF

   NOTE: The UV relays are located at the safeguard relay board. The cutout switches are labeled:

   "4KV BUS SECTION H (G) (F) STARTUP FEEDER UV AUTO-TRANSFER TEST SWITCH."

   1.2 Cutout the appropriate startup bus undervoltage (UV) relay to simulate UV on the startup bus. _____CV_____

DIESEL	S/U BUS UV
1-1	27HHU
1-2	27HGU
1-3	27HFU

2. When instructed by the control room operator:

   2.1 Cut-in the appropriate startup bus UV relay 27HHU (27HGU) (27HFU) at the safeguard relay board bus H (G) (F) by placing the appropriate auto transfer test switch labeled:

   4KV BUS SECTION H (G) (F) START-UP FEEDER UV AUTO-TRANSFER TEST SWITCH in the CUT-IN position. _____ _____

   2.2 Reset the target drop flag on UV relay 27HHU (27HGU) (27HFU) at the safeguard relay board bus H (G) (F). _____ _____

STP M-9A (UNIT 1)
ATTACHMENT 9.3

TITLE: Unit 1 Undervoltage Test at Switchgear Room

3. REMARKS: _____

4. Test performers and verifiers:

Name	Signature	Date/Time	Init
		/	
		/	
		/	
		/	

DIABLO CANYON POWER PLANT
STP M-9A
ATTACHMENT 9.4

2

TITLE: Unit 2 Undervoltage Test at Switchgear Room

PROCEDURE STEPS PERFORMED AT SWITCHGEAR

D.G. NO. _____ DATE _____ TIME _____

OPERATOR AT SWITCHGEAR _____

1. Starting the D/G on an undervoltage, perform the following:

N/A [ ]

1.1 Establish communications between the D/G, control room, and appropriate vital 4KV switchgear room. _____

DIESEL	SWITCHGEAR
2-1	HG
2-2	HH
2-3	HF

NOTE: The UV relays are located at the safeguard relay board. The cutout switches are labeled:

"4KV BUS G (H) (F) STARTUP TRANSF FEEDER UV TEST SWITCH."

1.2 Cutout the appropriate startup bus undervoltage (UV) relay to simulate UV on the startup bus. _____CV_____

DIESEL	S/U BUS UV
2-1	27HGU
2-2	27HHU
2-3	27HFU

2. When instructed by the control room operator:

2.1 Cut-in the appropriate startup bus UV relay 27HGU (27HHU) (27HFU) at the safeguard relay board bus G (H) (F) by placing the appropriate auto transfer test switch labeled:

4KV BUS G (H) (F) STARTUP TRANSF FEEDER UV TEST SWITCH in the CUT-IN position. _____ _____

2.2 Reset the target drop flag on UV relay 27HGU (27HHU) (27HFU) at the safeguard relay board bus G (H) (F). _____ _____

TITLE: Unit 2 Undervoltage Test at Switchgear Room

3. REMARKS: _____

_____

_____

_____

4. Test performers and verifiers:

Name	Signature	Date/Time	Init
_____	_____	_____ /	_____
_____	_____	_____ /	_____
_____	_____	_____ /	_____
_____	_____	_____ /	_____

TITLE: Diesel Generator Full Load Rejection Test

1 AND **2**

10-23-02
EFFECTIVE DATE

PROCEDURE CLASSIFICATION: QUALITY RELATED

1. SCOPE

1.1 This procedure is performed to test the full load rejection capability of the Diesel Generator (D/G). The D/G is paralleled to the grid and is then loaded to ≥ 2.45 MW and ≤ 2.50 MW with power factor of ≤ 0.87. The full load rejection is initiated by opening the D/G ouput breaker. The D/G is verified not to trip and the voltage remains ≤ 143.6V.

2. RESPONSIBILITIES

2.1 Power Production Engineer (PPE), for coordination of test, providing technical guidance during the test, final data reduction, reporting of results and determination of D/G OPERABILITY.

3. FREQUENCY

3.1 This test will be performed at least once per 24 months.

3.2 This test is required to be current in MODES 1, 2, 3, 4, 5 and 6.

3.3 This test shall not be performed in MODES 1 or 2 unless required to demonstrate OPERABILITY following unplanned maintenance.

4. TECHNICAL SPECIFICATIONS

4.1 Technical Specification (Tech Spec) SR 3.8.1.10 and part of SR 3.8.2.1 will be satisfied by this test.

5. ACCEPTANCE CRITERIA

5.1 Following a full load rejection of ≥ 2.45 MW and ≤ 2.50 MW (Tech Spec ≥ 2340 KW and ≤ 2600 KW) with a reactive load so the power factor is ≤ 0.87 + 128 KVARs (128 KVARs for inaccuracies) and ≥ 0.80, the D/G will remain running. See Attachment 8.2 for the reactive power setting for a given power out.

5.2 Following a full load rejection of ≥ 2.45 MW and ≤ 2.50 MW with enough reactive load so the power factor is ≤ 0.87 + 128 KVARs and ≥ 0.80, the D/G voltage will not exceed (Tech Spec ≤ 5075V) 143.6 volts.

6. REFERENCES

6.1 Instruction Manual for ALCO Diesel DC663082-80.

7. APPENDICES

None

8. ATTACHMENTS

8.1 "Data Sheet - Diesel Generator Full Load Rejection Test; Calibration of Test Recorder," 07/12/01

8.2 "D/G Power Factor vs Real Power and Reactive Power," 02/12/02

9. SPONSOR

C. Wheeler

START DATA SECTION

UNIT _____ OPERATING MODE _____ DATE/TIME _____ / _____

DIESEL _____

10.	PRECAUTIONS AND LIMITATIONS	INITIALS
10.1	Observe the Precautions & Limitations of STP M-9A when performing this test.	_____
10.2	During this test, equipment that is necessary for current plant operations should not be powered from the vital bus associated with the D/G to be tested.	_____
10.3	Utilizing the information in the Control Room (i.e., clearance logs, annunciators, etc.), check to see if the other diesels for the unit are OPERABLE.	_____
10.3.1	The directional power, overcurrent and loss of field relays for the diesel to be tested should be cutin to protect the diesel when it is paralleled to its bus. These relays shall be cutout following the test. While the relays are cutin for testing, the diesel is considered OPERABLE.	_____
10.3.2	Declare the test diesel inoperable when paralleled to the off-site power source.	_____
10.3.3	If a diesel is inoperable, verify the action requirements in Tech Spec LCO 3.8.1 in MODES 1-4 or Tech Spec LCO 3.8.2 in MODES 5 and 6 are being followed.	_____
10.4	In MODES 1, 2, 3, and 4, if paralleling a diesel to Startup Power, declare the diesel inoperable and perform the action required in Tech Spec LCO 3.8.1.	_____

		PERF	VERIF
11.	PREREQUISITES		
11.1	Obtain Shift Foreman's approval to perform this test. Signature: _____ Date/Time _____ / _____ Shift Foreman		
11.2	Request maintenance to calibrate and setup test (M&TE) recorder per Attachment 8.1.	_____	
11.3	With SFM's permission, have an electrician install the calibrated recorder set across frequency meter terminals 3 and 5 of the frequency meter of the diesel being tested on VB4 with a 1 amp fused lead.	_____	_____
	NOTE: The fused lead should be connected to the positive terminal of the diesel frequency meter which is terminal 3. The fused lead is used to protect the 6 Amp. potential transformer fuse upstream of the frequency meter if the connection to the recorder is accidentally grounded.		
11.4	Verify the following main control board meters are in current calibration:		
	Diesel to be tested is _____		
	MW/Freq recorder. Cal Due Date _____	_____	
	(1RW, 2RW, 3RW, or 2-VB4-125)		
	Volt/MVAR recorder. Cal Due Date _____	_____	
	(1RVAR, 2RVAR, 1/2-VB4-129)		
	MVAR meter. Cal Due Date _____	_____	
	(1/2-VB4-58/59/60-VAR)		
	MWATT meter. Cal Due Date _____	_____	
	(1/2-VB4-52/53/54-W)		
	NOTE: To find Cal Due Dates, use PIMS search = 3.2..11. Enter the instrument number and press enter. In the command line, type "PME" & press enter. A list of work orders will show on the screen. One of these work orders will be for calibration. Select this procedure W/O and check the due date.		

PERF

NOTE: If the diesel is already running when this test is started, mark Steps 11.5 through 11.8 N/A.

11.5 The diesel to be tested is aligned for normal operation in accordance with OP J-6B.

N/A [ ] _____

11.6 Perform a prefiring check per STP M-9A for the D/G to be tested, or per the appropriate section(s) of the Turbine Building Round Sheet.

N/A [ ] _____

11.7 Diesel CARDOX fire protection system for the Diesel to be tested should be OPERABLE or compensatory action taken.

N/A [ ] _____

11.8 Have STP M-9I data sheet(s) available to be fill out for any diesel start associated with this test.

N/A [ ] _____

PERF

12. PROCEDURE

12.1 Notify the control operator that testing is ready to commence. _____

NOTE: If the diesel was already running, mark Step 12.2 N/A.

12.2 Pre-test diesel run N/A [ ]

12.2.1 Cutin the Directional Power, Loss of Field and Overcurrent Protective features for the Diesel being tested with the FCO switch on VB4. _____

12.2.2 Manually start the Diesel to be tested per OP J-6B. _____

12.2.3 Place/Verify the appropriate D/G MODE SEL switch in the MANUAL position. _____

12.2.4 Check diesel generator output voltage on each phase. Otherwise, when synchroscope is turned ON (next step) the voltmeter will lock on to phase C. _____

12.2.5 Cut in the FEEDER SYNC Switch. _____

12.2.6 Verify synchroscope working. _____

a. Lights OFF at the 12 o'clock position.

b. Lights FULL BRIGHT at the 6 o'clock position.

12.2.7 Adjust engine speed up and down to verify the manual governor is in control. _____

12.2.8 Set engine speed so the synchroscope is turning slowly in the clockwise (FAST) direction. This will allow the diesel to pick up load when paralleled to the bus. _____

12.2.9 Adjust generator voltage to within ±2 volts of bus voltage. _____

12.2.10 When the synchroscope pointer is slightly before the 12 o'clock position, turn generator breaker control switch to the CLOSE position. Pick up load (0.5MW) promptly after the breaker is closed. This will prevent the D/G breaker from tripping open due to actuation of the cut-in reverse power relay. _____

Clock time D/G paralleled: _____ hrs.

PERF

12.2.11 Adjust voltage with voltage control switch to maintain VARS-OUT. _____

12.2.12 Cut out the FEEDER SYNC Switch. _____

12.2.13 Increase the load to ≥2.45 MW and ≤2.50 MW at a rate of ≤ 0.50 MW every 2 minutes and record clock time DG reaches ≥2.45 MW load:

Date/Time _____/_____ _____

12.2.14 Complete applicable sections of STP M-9I for the start of the diesel for this test.

N/A [ ] _____

12.3 Warmup or verify that the diesel has been warmed up for the test. _____

[ ] Run the diesel at ≥ 2.45 MW and ≤ 2.50 MW for ≥ one hour.

[ ] The Diesel was considered warmed up due to previous testing per the discretion of the PPE.

PERF

12.4 Full Load Rejection Test.

12.4.1 Verify diesel is paralleled to the grid. If not, parallel diesel per Steps 12.2.3 through 12.2.12. _____

12.4.2 Adjust diesel load to ≥ 2.45 MW and ≤ 2.50 MW with a reactive load ≥ 1.6 MVAR and ≤ 1.75 MVAR. Change load at a rate ≤ 0.50 MW every 2 minutes. _____

12.4.3 Verify that the temporary M&TE recorder set is properly set up to record the diesel voltage. _____

12.4.4 Switch or verify switched the following Control Room recorders associated with the diesel being tested to High Speed and are inking properly. _____

Diesel MW/HZ recorder in High Speed. _____

Diesel MW/HZ recorder inking properly. _____

Diesel KV/MVAR recorder in High Speed. _____

Diesel KV/MVAR recorder inking properly. _____

12.4.5 Record the Load and Reactive Load. _____

Load _____ MW

Reactive Load _____ MVARs

Date/Time _____/_____

12.4.6 Start the temporary M&TE recorder. _____

12.4.7 Open the D/G output breaker associated with the diesel being tested. _____

12.4.8 Verify the diesel engine remains running and does not trip during this full load rejection transient. If the diesel engine trips, notify SFM, take immediate recovery action and discontinue the test. _____

12.4.9 Shutdown the M&TE recorder after the diesel is stabilized. _____

12.4.10 After the transient is settled, adjust the following:

a. D/G speed to approximately 900 RPM. _____

b. D/G voltage to approximately 119V. _____

12.4.11 Parallel the D/G to its vital bus and load the D/G to 0.50 MW. See Steps 12.2.4 through 12.2.12 for paralleling guidance. _____

			PERF	VERIF
	12.4.12	Make a quick preliminary evaluation of the voltage data recorded.	_____	
		a. Peak Diesel Voltage _____ (must be ≤ 143.6V)		
	12.4.13	If the limit is exceeded, make a detailed evaluation of the trace. If the problem is determined to be from the diesel, inform the SFM and generate an Action Request. N/A [ ]	_____	
12.5	Post Test Alignment.			
	12.5.1	Have an electrician disconnect the recorder set from the diesel frequency meter.	_____	_____
	12.5.2	Per PPE's discretion, evaluate the need to take advantage of equipment and diesel alignment to continue other tests.	_____	
		[ ] Shutdown the diesel per this procedure, continue with Step 12.5.3.		
		[ ] exit to other test _____ Skip Steps 12.5.3 through 12.5.9; mark N/A and continue with the Post Test Alignment Section (Step 12.5.10).		
	12.5.3	Run the D/G at about 0.50 MW for approximately 5 minutes for cooldown.	_____	
	12.5.4	Reduce load on the diesel to ≥ 0.1 MW and ≤ 0.25 MW. Then separate the diesel from the bus.	_____	
	12.5.5	Adjust the diesel speed so the frequency meter reads > 60 HZ and < 60.25 HZ. _____ HZ.	_____	
	12.5.6	Adjust the diesel voltage to 119V AC. _____ Volts.	_____	
	12.5.7	Shutdown the D/G.	_____	
	12.5.8	Align the diesel MAN/AUTO switch per SFM's direction. [ ] AUTO [ ] MAN	_____	

PERF

12.5.9 Cut out diesel LOSS OF FIELD, OVERCURRENT & DIRECTIONAL POWER protective features using the toggle switch on VB4. _____

12.5.10 Place the MW/HZ recorders on Low Speed _____

12.5.11 Place the KV/MVAR recorders on Low Speed. _____

12.5.12 Mount the voltage trace from the M&TE recorder to regular size paper and attach it to this procedure. _____

12.6 Describe any malfunctions and list any discrepancies found. Otherwise, mark N/A.

N/A [ ] _____

REMARKS: _____

_____

_____

_____

12.7 Test performers and verifiers:

Name	Signature	Date/Time	Init
_____	_____	/	_____
_____	_____	/	_____
_____	_____	/	_____
_____	_____	/	_____

13. DATA REDUCTION AND EVALUATION

Incorporated as part of Section 12.

PERF

14. PRIMARY REVIEW

14.1 Verify if Step 12.4 was performed, the D/G Acceptance Criteria have been satisfied for Tech Spec SR 3.8.1.10 and part of Tech Spec SR 3.8.2.1. _____

14.1.1 Following a full load rejection of at least ≥ 2.45 MW and ≤ 2.50 MW with a reactive load so the power factor is ≤ 0.87 + 128 KVARs and ≥ 0.80, the diesel engine remained running and did not trip during and after the full load rejection transient. (Step 12.4.8) _____

14.1.2 Following a full load rejection of at least ≥ 2.45 MW and ≤ 2.50 MW with a reactive load so the power factor is ≤ 0.87 + 128 KVARs and ≥ 0.80, the D/G voltage during and after the transient is ≤ 143.6 volts. (Step 12.4.12a) _____

14.2 The acceptable limit for the peak diesel voltage is 143.6 volts based on the chart from the temporary recorder. If the limit is exceeded, make a detailed evaluation of the trace. If the problem is determined to be from the diesel, inform the SFM and generate an Action Request.

N/A [ ] _____

14.3 Verify M&TE usage recorded in PIMS. _____

14.4 Review completed procedure and based on test data, make determination of D/G OPERABILITY. If any malfunctions are noted, notify management promptly and submit an ACTION REQUEST. _____

14.5 Describe any malfunction, explain any NO or N/A entries in any of the data and list any discrepancies found. Indicate if this test was performed due to modifications on the D/Gs and briefly describe modifications performed.

REMARKS: _____

_____

_____

_____

Signature: _____ Date/Time _____ / _____

Power Production Engineer

PERF

15. SECONDARY REVIEW

15.1 Review procedure for completeness and acceptability. _____

15.2 If this test was a complete test and the D/Gs are OPERABLE, then update Master Schedule.

RT W/O #_____ _____

REMARKS: _____

_____

_____

_____

15.3 Reviewed By: _____ Date _____
Second Reviewer

DIABLO CANYON POWER PLANT
STP M-9D1
ATTACHMENT 8.1

1 AND 2

TITLE: Data Sheet - Diesel Generator Full Load Rejection Test; Calibration of Test Recorder

PERF

8.1 Obtain one recorder (high impedance input) such as the Gould Windograf with an AC RMS converter. _____

[ ] Gould Windograf (with AC RMS converter, preferred)

[ ] Other type of recorder

CO. ID.	Cal. Due Date
_____	_____

8.2 If Windograf is to be used, the following instruments are required to calibrate the voltage scales.

N/A [ ]

8.2.1 One high accuracy digital voltmeter such as Fluke 8842A or HP 34401A. _____

CO. ID.	Cal. Due Date
_____	_____

8.2.2 Calibrate the Windograf as follows:

NOTE: The following calibration steps are for general guideline only. The settings and steps may be modified per supervisor, maintenance or PPE's discretion. Document the changes in the REMARK Section.

a. Calibrate the Windograf with the high accurate DVM to a span from 100 VAC to 150 VAC. _____

NOTE: The scale suggested here may be changed per PPE's discretion.

b. Mark the Windograf chart paper with the calibrated scale. _____

c. Set the Windograf speed to 50mm/sec. _____

8.3 REMARKS: _____

_____

_____

_____

8.4 Calibration and Recorder Setup performed by: _____

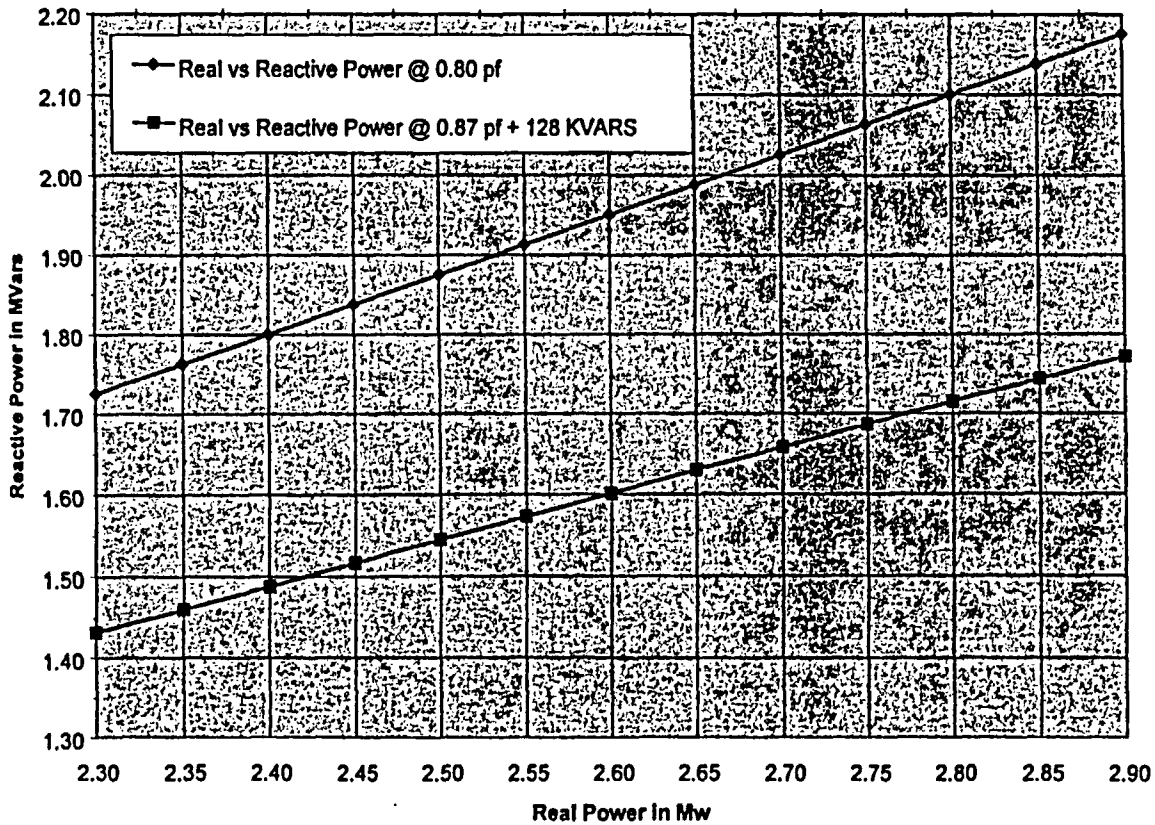
Date: _____

NOTE: Return this completed Attachment to the PPE associated with the STP M-9D1 Test.

DIABLO CANYON POWER PLANT
STP M-9D1
ATTACHMENT 8.2

1 AND 2

TITLE: D/G Power Factor vs Real Power and Reactive Power



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