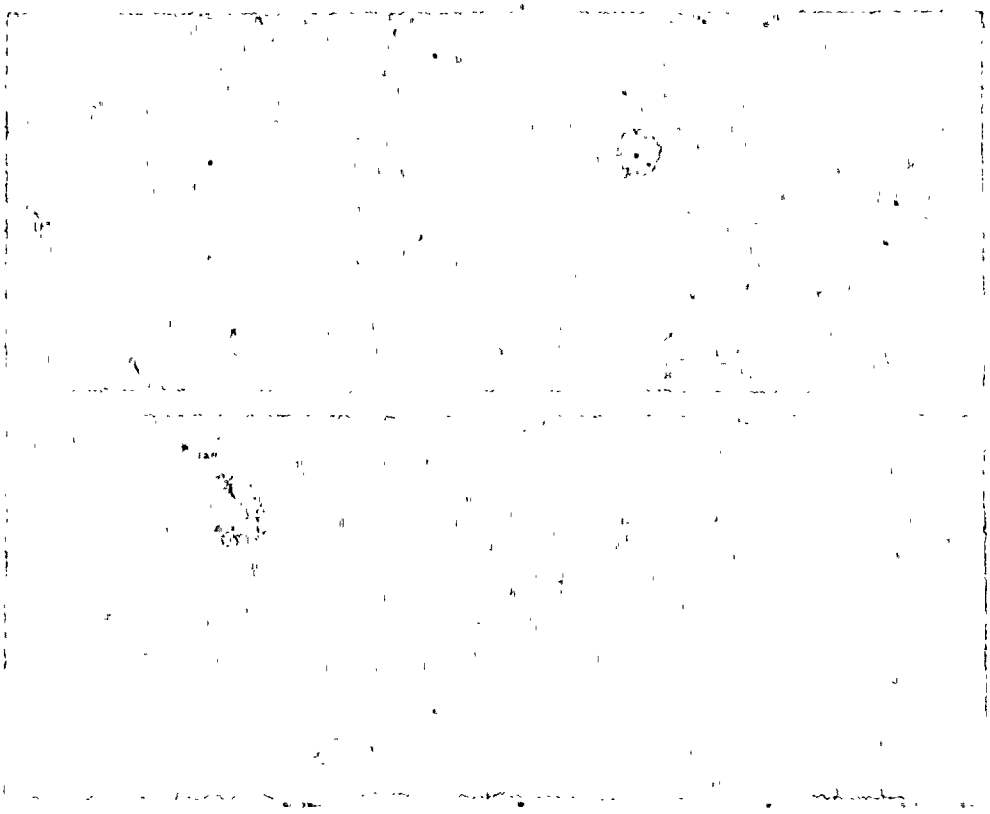
Original

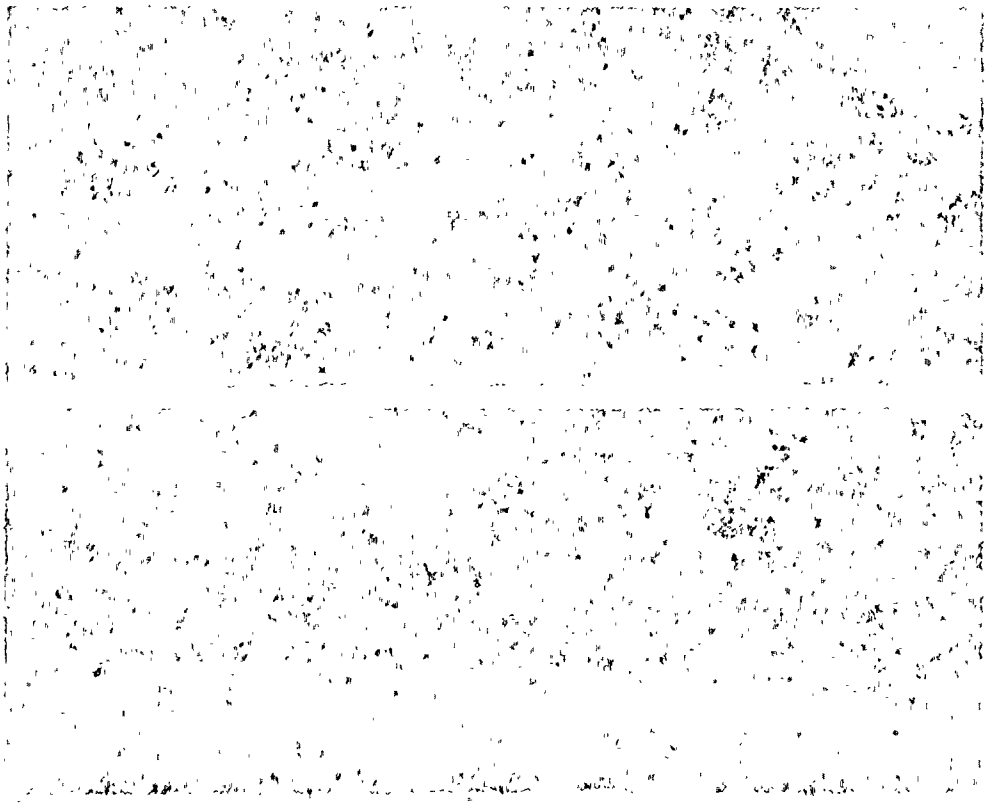
UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	
PACIFIC GAS AND ELECTRIC COMPANY	)	Docket No. 50-275
	)	
Unit 1	)	
	)	
Diablo Canyon Site	)	
	)	

PGandE Responses to NRC Request
for Additional Information





Question 1. For the years 1965 to 1977 provide actual total energy requirement and peak load demand on the PGandE coordinated system. Also, normalize above data to reflect average temperature conditions and any other unusual occurrences that effected the above results--such as interruptible loads, higher irrigation loads due to drought, major strikes, etc.

RESPONSE:

The actual peak electric load and total electric energy requirement on the PGandE area-system are shown below. The actual peak loads have been adjusted to reflect normal temperatures at the time of the peak. The impact of the drought on the 1977 peak load has not been determined. However, early in 1977 it was estimated to be +250 megawatts.

PACIFIC GAS AND ELECTRIC COMPANY
ACTUAL AREA-SYSTEM(1) ELECTRIC LOADS

Year	Peak Demands, (Megawatts)			Actual Total Energy Requirement (Million kWh)
	Actual	Temperature Adjustment(2)	Actual (Temperature Adjusted)	
1965	7268(3)	--	7268	40486
1966	7890	+14	7904	44430
1967	8435	-92	8343	46927
1968	9028	-96	8932	50670
1969	9288	+228	9516	52814
1970	9864	+90	9954	55542
1971	10913	-127	10786	59079
1972	11772	-623	11149	64054
1973	12212	+27	12239	65732
1974	12964	+379	13343	65606
1975	13129	-448	12681	68782
1976	13932	-68	13864	72703
1977	13815	+533	14348	73345(4)

(1) Excludes Modesto & Turlock Irrigation Districts' Load supplied by its own generation, USBR Central Valley Project Use served directly from its own transmission lines and deliveries to Sierra Pacific and Pacific Northwest.

(2) Adjustments are based on normal temperatures at the time of the peak.

(3) Winter Peak.

(4) 7 months actual, 5 months forecast. The 1977 load including energy sales and transfers out of the area is 75,592 million kWhrs. The load including sales and transfers is on the basis as the estimated 1978 load shown on Table 2 in response to Questions 2 and 4.

Question 2. Provide forecasted values for PGandE system for the years 1978 thru 1980 for peak load demand and total energy requirements under (a) continued drought conditions, and (b) normal rainfall conditions.

Specify whether peak load forecasts reflect normal temperature or extreme temperature.

Question 4. Provide copies of all independent forecasts you are aware of that are relevant to PGandE region over this time period. I.E., forecasts prepared for state commission, etc.

RESPONSE:

The PGandE and the California Energy Conservation and Development Commission (CERCDC) forecasts for Area-System peak demands are shown on Table 1 and forecasts for Area-System total energy requirements are shown on Table 2. The adverse water conditions forecasts for the years 1978 thru 1980 are based on the singular occurrence of 1977 conditions and not a continuation of the 1977 drought. Forecasts incorporating the compound effect of continuation of the 1977 drought have not been made.

The peak demands are based on normal temperatures at the time of the annual peak.

The copy of the CERCDC forecasts for the PGandE Area-System is attached (Table II-8). The PGandE forecasts shown on Table II-B are different because they were based on an earlier forecast. The PGandE forecasts shown on Tables 1 and 2 are based on a April, 1977 forecast.

TABLE 1

PACIFIC GAS AND ELECTRIC COMPANY
ESTIMATED AREA-SYSTEM PEAK DEMANDS, MEGAWATTS

PGandE AND CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION (CERCDC) FORECASTS

	Peak Demands, Megawatts					
	Adverse Water Conditions			Average Water Conditions		
	1978	1979	1980	1978	1979	1980
1. PGandE Forecast						
A. Basic Peak Demand	14,814	15,711	16,475	14,814	15,711	16,475
B. Ames	80	80	80	80	80	80
C. SLAC	25	25	25	25	25	25
D. State & Federal Pumping	207	187	213	226	206	232
E. Dry Year Adder	190	190	190	--	--	--
F. Sale to Sierra Pacific	108	108	108	108	108	108
G. Area Load+Del. to SPPCo.	15,424	16,301	17,091	15,253	16,130	16,920
H. Interruptible	-100	-100	-100	-100	-100	-100
I. State External Resources	-141	-117	-135	-141	-117	-135
J. Planning Peak Demand	15,183	16,084	16,856	15,012	15,913	16,685
2. CERCDC "Most Likely" Forecast						
A. Basic Peak Demand	14,684	15,299	15,940	14,684	15,299	15,940
B. Ames	80	80	80	80	80	80
C. SLAC	25	25	25	25	25	25
D. State & Federal	207	187	213	226	206	232
E. Dry Year Adder	190	190	190	--	--	--
F. Sale to Sierra Pacific	108	108	108	108	108	108
G. Area Load+Del. to SPPCo.	15,294	15,889	16,556	15,123	15,718	16,385
H. Interruptible	-100	-100	-100	-100	-100	-100
I. State External Resources	-141	-117	-135	-141	-117	-135
J. Planning Peak Demand	15,053	15,672	16,321	14,882	15,501	16,150
3. CERCDC "High" Forecast						
A. Basic Peak Demand	15,557	16,523	17,550	15,557	16,523	17,550
B. Ames	80	80	80	80	80	80
C. SLAC	25	25	25	25	25	25
D. State & Federal Pumping	207	187	213	226	206	232
E. Dry Year Adder	190	190	190	--	--	--
F. Sale to Sierra Pacific	108	108	108	108	108	108
G. Area Load & Del. to SPPCo.	16,167	17,113	18,166	15,996	16,942	17,995
H. Interruptible	-100	-100	-100	-100	-100	-100
I. State External Resources	-141	-117	-135	-141	-117	-135
J. Planning Peak Demand	15,926	16,896	17,931	15,755	16,725	17,760
4. CERCDC "Low" Forecast						
A. Basic Peak Demand	14,297	14,764	15,246	14,297	14,764	15,246
B. Ames	80	80	80	80	80	80
C. SLAC	25	25	25	25	25	25
D. State & Federal Pumping	207	187	213	226	206	232
E. Dry Year Adder	190	190	190	--	--	--
F. Sale to Sierra Pacific	108	108	108	108	108	108
G. Area Load+Del. to SPPCo.	14,907	15,354	15,862	14,736	15,183	15,691
H. Interruptible	-100	-100	-100	-100	-100	-100
I. State External Resources	-141	-117	-135	-141	-117	-135
J. Planning Peak Demand	14,666	15,137	15,627	14,495	14,966	15,456

TABLE 2

PACIFIC GAS AND ELECTRIC COMPANY

ESTIMATED AREA - SYSTEM TOTAL ELECTRIC ENERGY REQUIREMENTS
MILLION kWh

PGandE AND CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION (CERCDC) FORECASTS

	ELECTRIC ENERGY REQUIREMENTS, MILLION kWh					
	Adverse Water Conditions			Average Water Conditions		
	1978	1979	1980	1978	1979	1980
1. PGandE Forecast						
A. Electric Energy Sales	68,456	72,478	76,127	68,456	72,478	76,127
B. State & Federal Pumping	3,507	3,527	3,614	3,723	3,743	3,798
C. Modesto-Turlock Generation	- 605	- 605	- 605	- 605	- 605	- 605
D. Losses & Unaccounted For	6,942	7,223	7,483	6,942	7,223	7,483
E. Dry Year Adder	1,220	1,220	1,220	--	--	--
F. Sale to Sierra P.P.Co.	11	18	52	11	18	52
G. NW Energy Return	150	--	--	150	--	--
H. Area Load + Del to SPPCo & NW	79,681	83,861	87,891	78,677	82,857	86,855
I. State External Resources	-1,078	-1,079	-1,120	-1,078	-1,079	-1,120
J. Planning Electric Energy Requirements	78,603	82,782	86,771	77,559	81,778	85,735
2. CERCDC "Most Likely" Forecast						
A. Electric Energy Sales	67,969	70,751	73,647	67,969	70,751	73,647
B. State & Federal Pumping	3,507	3,527	3,614	3,723	3,743	3,798
C. Modesto-Turlock Generation	- 605	- 605	- 605	- 605	- 605	- 605
D. Losses & Unaccounted For	6,892	7,054	7,240	6,892	7,054	7,240
E. Dry Year Adder	1,220	1,220	1,220	--	--	--
F. Sale to Sierra P.P.Co.	11	18	52	11	18	52
G. NW Energy Return	150	--	--	150	--	--
H. Area Load + Del. to SPPCo & NW	79,144	81,965	85,168	78,140	80,961	84,132
I. State External Resources	-1,078	-1,079	-1,120	-1,078	-1,079	-1,120
J. Planning Electric Energy Requirements	78,066	80,886	84,048	77,062	79,882	83,012
3. CERCDC "High" Forecast						
A. Electric Energy Sales	72,447	77,033	81,910	72,447	77,033	81,910
B. State & Federal Pumping	3,507	3,527	3,614	3,723	3,743	3,798
C. Modesto-Turlock Generation	- 605	- 605	- 605	- 605	- 605	- 605
D. Losses & Unaccounted For	7,346	7,680	8,052	7,346	7,680	8,052
E. Dry Year Adder	1,220	1,220	1,220	--	--	--
F. Sale to Sierra P.P.Co.	11	18	52	11	18	52
G. NW Energy Return	150	--	--	150	--	--
H. Area Load + Del. to SPPCo. & NW	84,076	88,873	94,243	83,072	87,869	93,207
I. State External Resources	-1,078	-1,079	-1,120	-1,078	-1,079	-1,120
J. Planning Electric Energy Requirements	82,998	87,794	93,123	81,994	86,790	92,087
4. CERCDC "Low" Forecast						
A. Electric Energy Sales	65,609	67,495	69,435	65,609	67,495	69,435
B. State & Federal Pumping	3,507	3,527	3,614	3,723	3,743	3,798
C. Modesto-Turlock Generation	- 605	- 605	- 605	- 605	- 605	- 605
D. Losses & Unaccounted For	6,653	6,729	6,825	6,653	6,729	6,825
E. Dry Year Adder	1,220	1,220	1,220	--	--	--
F. Sale to Sierra P.P.Co.	11	18	52	11	18	52
G. NW Energy Return	150	--	--	150	--	--
H. Area Load + Del. to SPPCo. & NW	76,545	78,384	80,541	75,541	77,380	79,505
I. State External Resources	-1,078	-1,079	-1,120	-1,078	-1,079	-1,120
J. Planning Electric Energy Requirements	75,467	77,305	79,421	74,463	76,301	78,385

Table II-8

PG&E Total Sales*
(Million kWh)

Year	PG&E Recommended (8/76)	PG&E Recommended (2/77)	ERCDC Low	ERCDC High	ERCDC Adopted
1975	60,262	60,262	60,262	60,262	60,262
1980	81,797	80,941	69,435	81,910	73,647
1985	103,137	100,866	74,804	113,709	86,700
1990	126,527	122,364	80,945	140,102	101,511
1995	156,537	148,983	86,852	176,288	118,654
Percent Growth Rates:					
1975-1985	5.5	5.3	2.2	6.6	3.7
1975-1995	4.9	4.6	1.8	5.5	3.4

Table II-9

PG&E Total Peak* (Basic Peak Demand)
(Megawatts)

Year	PG&E Recommended (8/76)	PG&E Recommended (2/77)	ERCDC Low	ERCDC High	ERCDC Alternative**	ERCDC Adopted.
1975	12,983	12,983	12,983	12,983	12,983	12,983
1980	16,872	16,601	15,246	17,550	16,076	15,940
1985	21,127	20,430	15,600	23,028	19,014	18,760
1990	25,763	24,503	15,400	27,760	21,950	21,700
1995	32,081	29,799	15,760	33,485	25,038	24,900
Percent Growth Rates:						
1975-1985	5.0	4.6	1.9	5.9	3.9	3.8
1975-1995	4.6	4.2	1.0	4.9	3.3	3.3

* Includes SMUD, does not include Ames, SLAC, State and Federal Pumping, Modesto and Turlock Irrigation District Loads served by their own generation, USBR loads served directly from its own transmission lines, and deliveries to Sierra Pacific Power.

** Developed using peak forecasting methodology of SMUD.

(1) "California Energy Trends and Choices, Vol. 2, Electricity Forecasting and Planning, 1977 Biennial Report of the State Energy Commission"

Question 3. Provide thorough discussion of forecasting methodology (ies) employed by PGandE and its consultants in projecting energy requirements and peak load demand.

Specify all assumptions justification for for same.

RESPONSE:

The PGandE electric forecasting methodology is described in the supplemental forecast submitted to the CERCDC, August 6, 1976, "An Econometric Model and Forecast of the Demand for Electricity (1976-1995)," Docket No. 75-FOR-3. (Copy Attached) The methodology was developed in response to the CERCDC Common Forecasting Methodology (CFM) requirements, December 1975. Revised forecast assumptions which were used for the April, 1977 Company forecast are attached.

PACIFIC GAS AND ELECTRIC COMPANY
FORECAST OF LEVELS OF DEMOGRAPHIC AND ECONOMIC ACTIVITY
DEFLATED BY PRICE INDICES (1967 DOLLARS)
APRIL 1977

TABLE 1
Sheet 1 of 3

YEAR	CONSUMER PRICE INDEX CPI:SF	APPLIANCE PRICE INDEX CPIAL/ CPI:SF	EMPLOYMENT EM:NC	NEW BUSINESS INCORP. NBI:S	TAXABLE SALES ST:NC/ WPIMA	WHOLESALE PRICE INDEX WPIMA	INCOME YWS:S:NC/ CPI:SF	INCOME PER EMPLOYEE YWS:S:NC:PE/ CPI:SF	ADULT POPULATION RATIO ADULTPOP	POPULATION ELEPOP
					HISTORICAL					
65	0.949	106.798	2374.142	18906.000	14619.851	0.963	17292.452	7282.150	0.640	7999.930
66	0.974	102.489	2504.975	17660.000	15322.700	0.995	18471.695	7372.769	0.640	8154.328
67	1.003	99.800	2585.992	18378.000	15503.083	1.000	19228.036	7435.491	0.650	8282.376
68	1.049	97.275	2691.167	21570.000	16687.289	1.026	20145.064	7485.051	0.660	8375.406
69	1.107	94.196	2791.025	28200.000	17309.602	1.062	20696.027	7414.070	0.670	8469.461
70	1.163	91.894	2809.859	25654.000	17172.757	1.103	20815.335	7407.232	0.680	8545.525
71	1.203	90.630	2818.459	28007.000	18294.419	1.139	21160.615	7506.461	0.670	8677.100
72	1.247	87.955	2931.500	26546.000	20094.777	1.179	22182.192	7567.563	0.680	8793.563
73	1.323	82.984	3082.817	27115.000	21227.542	1.292	22875.655	7420.248	0.690	8895.325
74	1.458	79.292	3186.975	29518.000	19512.375	1.541	22850.918	7168.963	0.690	8992.669
75	1.601	80.030	3187.400	29068.000	19201.499	1.711	22413.580	7030.702	0.700	9091.838
76	1.686	80.206	3228.532	32490.000	20672.231	1.791	23420.592	7253.224	0.701	9231.525
					FORECASTED					
77	1.779	78.727	3371.858	33753.172	22116.700	1.903	24334.955	7215.973	0.705	9455.400
78	1.867	77.082	3504.710	34364.840	22909.665	2.009	25431.963	7255.668	0.709	9598.200
79	1.953	75.463	3646.650	34987.601	23809.846	2.115	26597.895	7292.944	0.712	9745.600
80	2.047	73.823	3771.730	35621.641	24707.874	2.245	27887.779	7392.795	0.715	9897.500
81	2.152	72.047	3898.083	36267.168	25610.449	2.378	29147.597	7476.425	0.716	10054.200
82	2.268	70.113	4011.907	36924.402	26593.443	2.505	30299.645	7551.554	0.717	10213.200
83	2.392	68.164	4110.200	37593.539	27582.220	2.632	31360.527	7629.194	0.717	10374.900
84	2.521	66.265	4198.568	38274.809	28546.159	2.759	32333.717	7700.554	0.715	10537.600
85	2.652	64.422	4283.380	38968.414	29422.892	2.890	33237.991	7759.365	0.713	10702.900
86	2.787	62.628	4368.618	39674.594	30155.108	3.026	34020.415	7787.286	0.710	10857.900
87	2.925	60.940	4442.886	40393.570	30909.385	3.168	34785.567	7829.329	0.708	11015.200
88	3.068	59.331	4509.528	41125.578	31683.185	3.317	35580.043	7891.573	0.706	11174.700
89	3.219	57.764	4568.152	41870.852	32475.802	3.473	36409.057	7970.021	0.705	11336.500
90	3.377	56.239	4627.539	42629.629	33288.505	3.637	37248.993	8049.243	0.703	11500.700
91	3.542	54.753	4687.697	43402.156	34121.697	3.807	38103.317	8129.256	0.700	11645.600
92	3.716	53.308	4748.637	44188.687	34975.302	3.986	38987.449	8210.063	0.698	11792.400
93	3.898	51.900	4810.369	44989.469	35850.507	4.174	39886.885	8291.676	0.696	11941.000
94	4.089	50.530	4872.904	45804.758	36747.594	4.370	40807.056	8374.097	0.695	12091.400
95	4.289	49.195	4936.252	46634.828	37667.402	4.575	41748.455	8457.338	0.695	12243.800

PACIFIC GAS AND ELECTRIC COMPANY
FORECAST OF LEVELS OF DEMOGRAPHIC AND ECONOMIC ACTIVITY
DEFLATED BY PRICE INDICES (1967 DOLLARS)
ANNUAL PERCENT CHANGES
APRIL 1977

YEAR	CONSUMER PRICE INDEX CPI:SF	APPLIANCE PRICE INDEX CPIAL/ CPI:SF	EMPLOYMENT EM:NC	NEW BUSINESS INCORP. NBI:S	TAXABLE SALES ST:NC/ WPIMA	WHOLESALE PRICE INDEX WPIMA	INCOME YWS:S:NC/ CPI:SF	INCOME PER EMPLOYEE YWS:S:NC:PE/ CPI:SF	ADULT POPULATION RATIO ADULTPOP	POPULATION ELEPOP
					HISTORICAL					
66	2.688	-4.035	5.511	4.058	4.807	2.777	6.819	1.244	0.000	1.930
67	2.900	-2.623	3.234	0.678	1.177	1.027	4.095	0.851	1.563	1.570
68	4.613	-2.531	4.067	12.230	7.639	2.566	4.769	0.667	1.538	1.123
69	5.554	-3.165	3.711	6.171	3.729	3.558	2.735	-0.948	1.515	1.123
70	5.036	-2.444	0.675	5.165	-0.791	3.765	0.576	-0.092	1.493	0.898
71	3.483	-1.376	0.306	13.884	6.532	3.303	1.659	1.340	-1.471	1.540
72	3.615	-2.951	4.011	19.369	9.841	3.556	4.828	0.814	1.493	1.342
73	6.096	-5.653	5.162	12.944	5.637	9.510	3.126	-1.947	1.471	1.157
74	10.225	-4.448	3.379	11.720	-8.080	19.285	-0.108	-3.386	0.000	1.094
75	9.791	0.930	0.013	10.218	-1.593	11.023	-1.914	-1.929	1.449	1.103
76	5.357	0.219	1.290	12.964	7.659	4.701	4.493	3.165	0.086	1.536
					FORECASTED					
77	5.514	-1.843	4.439	13.700	6.987	6.274	3.904	-0.514	0.628	2.425
78	4.934	-2.089	3.940	9.330	3.585	5.547	4.503	0.550	0.560	1.510
79	4.585	-2.101	4.050	9.410	3.929	5.274	4.585	0.514	0.455	1.536
80	4.795	-2.173	3.430	10.150	3.772	6.145	4.850	1.369	0.337	1.559
81	5.171	-2.406	3.350	9.790	3.653	5.919	4.517	1.131	0.234	1.583
82	5.384	-2.685	2.920	9.410	3.838	5.367	3.952	1.005	0.122	1.581
83	5.440	-2.779	2.450	8.970	3.718	5.065	3.501	1.028	-0.035	1.583
84	5.396	-2.786	2.150	8.490	3.495	4.824	3.103	0.935	-0.199	1.568
85	5.213	-2.782	2.020	7.960	3.071	4.744	2.797	0.764	-0.318	1.569
86	5.082	-2.785	1.990	7.320	2.489	4.715	2.354	0.360	-0.379	1.448
87	4.959	-2.696	1.700	7.320	2.501	4.700	2.249	0.540	-0.341	1.449
88	4.900	-2.641	1.500	7.320	2.503	4.700	2.307	0.795	-0.230	1.448
89	4.900	-2.641	1.300	7.320	2.502	4.700	2.307	0.994	-0.191	1.448
90	4.900	-2.641	1.300	7.320	2.502	4.700	2.307	0.994	-0.301	1.448
91	4.900	-2.641	1.300	7.320	2.503	4.700	2.307	0.994	-0.434	1.260
92	4.900	-2.641	1.300	7.320	2.502	4.700	2.307	0.994	-0.329	1.261
93	4.900	-2.641	1.300	7.320	2.502	4.700	2.307	0.994	-0.222	1.260
94	4.900	-2.641	1.300	7.320	2.502	4.700	2.307	0.994	-0.140	1.260
95	4.900	-2.641	1.300	7.320	2.503	4.700	2.307	0.994	-0.047	1.260

PACIFIC GAS AND ELECTRIC COMPANY
FORECAST OF LEVELS OF DEMOGRAPHIC AND ECONOMIC ACTIVITY
PERCENT CHANGE FROM JULY 1976 ESTIMATE
DEFLATED BY PRICE INDICES (1967 DOLLARS)
APRIL 1977

YEAR	CPI:SF	CPIAL/ CPI:SF	EM:NC	NBI:S	ST:NC/ WPIMA	WPIMA	YWS:S:NC/ CPI:SF	YWS:S:NC:PE/ CPI:SF	ADULTPOP	ELEPOP
					FORECASTED					
76	-3.61	3.66	-1.37	19.02	3.18	-3.32	3.08	4.51	-0.04	-0.92
77	-5.81	3.69	-0.09	23.66	7.08	-4.84	6.12	6.22	0.00	0.00
78	-7.85	3.38	0.92	25.91	9.12	-6.67	8.05	7.06	0.00	0.00
79	-9.84	3.41	2.05	28.19	9.52	-6.84	10.53	8.31	0.00	0.00
80	-10.94	3.92	3.28	30.51	9.25	-5.88	12.54	8.96	0.00	0.00
81	-11.25	4.66	4.75	32.87	9.76	-5.46	13.89	8.73	0.00	0.00
82	-11.39	5.02	5.59	35.28	10.48	-5.46	14.93	8.84	0.00	0.00
83	-11.72	5.78	5.84	37.73	11.68	-6.33	15.76	9.37	0.00	0.00
84	-11.98	6.29	5.90	40.23	13.74	-7.95	16.22	9.75	0.00	0.00
85	-12.64	6.92	5.61	42.77	14.66	-8.98	16.90	10.70	0.00	0.00
86	-12.78	6.86	5.18	45.36	14.93	-9.93	16.36	10.63	0.00	0.00
87	-12.76	6.57	4.67	47.99	14.65	-10.69	15.18	10.05	0.00	0.00
88	-13.29	7.08	3.95	50.68	14.89	-11.85	14.75	10.40	0.00	0.00
89	-13.94	7.50	3.04	53.41	15.02	-12.91	14.24	10.88	0.00	0.00
90	-14.38	7.79	2.13	56.19	15.01	-13.85	13.58	11.22	0.00	0.00
91	-14.73	7.97	1.23	59.02	14.88	-14.69	12.81	11.45	0.00	0.00
92	-15.11	8.18	0.34	61.90	14.79	-15.55	12.08	11.71	0.00	0.00
93	-15.56	8.50	-0.55	64.83	14.80	-16.48	11.46	12.08	0.00	0.00
94	-16.09	8.91	-1.42	67.82	14.92	-17.47	10.94	12.55	0.00	0.00
95	-16.60	9.31	-2.29	70.86	15.01	-18.43	10.40	13.00	0.00	0.00

PACIFIC GAS AND ELECTRIC COMPANY
FORECAST OF LEVELS OF DEMOGRAPHIC AND ECONOMIC ACTIVITY
DEFLATED BY PRICE INDICES (1967 DOLLARS)
APRIL 1977

YEAR	COST OF CAPITAL CC/ WPIMA	RENT PRICE INDEX CPIRT/ CPI:SF	POPULATION STANISLAUS COUNTY N:ST	AVERAGE HOURLY EARNINGS MFG. WHMN/ WPIMA	AVERAGE HOURLY EARNINGS RETAIL WH51/ WPIMA	INVESTMENT TAX CREDIT U.S. RITC	IMPLICIT PRICE DEFLATOR EQUIP. U.S. PIFNP	AAA BOND RATE AAA	SACRAMENTO SMSA AVG. HR. EARNINGS WHMN:SC/ WPIMA	SACRAMENTO SMSA TAXABLE SALES ST:SC/ WPIMA
					HISTORICAL					
65	15.065	102.134	175803.500	3.001	2.718	0.050	80.500	4.493	3.370	1251.864
66	15.338	100.830	180260.000	3.031	2.774	0.033	82.075	5.130	3.403	1267.479
67	15.842	99.742	184804.750	3.126	2.897	0.041	84.275	5.507	3.532	1283.098
68	16.040	97.624	188245.500	3.203	2.974	0.050	87.300	6.175	3.588	1342.113
69	16.965	95.468	191813.250	3.234	3.052	0.050	90.050	7.029	3.651	1416.991
70	18.366	94.653	195258.000	3.274	3.076	0.000	93.450	8.040	3.695	1436.113
71	17.804	95.706	198353.500	3.380	3.152	0.025	97.625	7.387	3.808	1583.214
72	17.210	95.568	199928.250	3.450	3.164	0.050	100.000	7.213	3.932	1824.966
73	16.062	93.977	203892.500	3.292	3.036	0.050	101.650	7.441	3.849	1882.184
74	13.392	89.318	207482.500	2.940	2.727	0.050	110.150	8.566	3.448	1762.820
75	14.510	85.757	211887.770	2.893	2.654	0.070	127.425	8.826	3.361	1790.037
76	15.240	85.814	217325.847	2.985	2.747	0.077	134.575	8.463	3.496	1898.141
					FORECASTED					
77	14.341	86.061	221800.000	2.976	2.736	0.100	141.950	8.053	3.625	2020.075
78	14.201	87.023	226050.000	2.981	2.751	0.100	149.174	7.702	3.664	2092.488
79	13.845	87.991	230450.000	3.004	2.783	0.100	157.344	7.415	3.690	2174.693
80	13.745	88.507	234825.000	3.004	2.796	0.100	167.421	7.398	3.688	2256.749
81	14.085	88.542	238975.000	3.016	2.820	0.100	178.147	7.700	3.699	2339.220
82	14.525	88.409	243175.000	3.049	2.863	0.100	188.634	8.113	3.737	2428.966
83	14.887	88.356	247450.000	3.097	2.917	0.100	199.087	8.495	3.794	2519.246
84	15.135	88.445	251750.000	3.153	2.979	0.100	209.381	8.678	3.860	2607.346
85	15.186	88.720	256125.000	3.209	3.040	0.100	219.547	8.672	3.926	2697.407
86	15.139	89.043	260350.000	3.262	3.099	0.100	230.006	8.593	3.989	2794.266
87	14.965	89.370	264575.000	3.314	3.153	0.100	240.954	8.355	4.050	2903.189
88	14.957	89.657	268950.000	3.367	3.218	0.100	252.424	8.300	4.113	2973.836
89	14.965	89.806	273250.000	3.420	3.279	0.100	264.439	8.300	4.177	2966.251
90	14.974	89.892	277675.000	3.475	3.341	0.100	277.026	8.300	4.241	3040.478
91	14.983	89.977	281350.000	3.530	3.405	0.100	290.213	8.300	4.307	3116.563
92	14.991	90.063	284950.000	3.587	3.469	0.100	304.027	8.300	4.375	3194.551
93	15.000	90.149	288625.000	3.644	3.535	0.100	318.498	8.300	4.443	3274.491
94	15.008	90.235	292325.000	3.702	3.602	0.100	333.659	8.300	4.512	3356.431
95	15.017	90.321	296025.000	3.761	3.671	0.100	349.541	8.300	4.583	3440.422

PACIFIC GAS AND ELECTRIC COMPANY
FORECAST OF LEVELS OF DEMOGRAPHIC AND ECONOMIC ACTIVITY
DEFLATED BY PRICE INDICES (1967 DOLLARS)
ANNUAL PERCENT CHANGES
APRIL 1977

YEAR	COST OF CAPITAL CC/ WPIMA	RENT PRICE INDEX CPIRT/ CPI:SF	POPULATION STANISLAUS COUNTY N:ST	AVERAGE HOURLY EARNINGS MFG. WHMN/ WPIMA	AVERAGE HOURLY EARNINGS RETAIL WR51/ WPIMA	INVESTMENT TAX CREDIT U.S. .RITC	IMPLICIT PRICE DEFLATOR EQUIP. U.S. PIFNP	AAA BOND RATE AAA	SACRAMENTO SMSA AVG. HR. EARNINGS WHMN:SC/ WPIMA	SACRAMENTO SMSA TAXABLE SALE ST:SC/ WPIMA
					HISTORICAL					
66	1.812	-1.277	2.535	1.001	2.067	-33.500	1.830	14.169	0.995	1.247
67	3.289	-1.078	2.521	3.134	4.449	24.812	2.680	7.342	3.781	-0.346
68	1.251	-2.124	1.862	2.462	2.628	20.482	3.589	12.137	1.591	9.422
69	5.765	-2.208	1.895	0.973	2.631	0.000	3.150	13.833	1.745	2.524
70	8.260	-0.853	1.796	1.257	0.781	-100.000	3.776	14.381	1.216	1.349
71	-3.061	1.112	1.585	3.216	2.488	-97.500	4.468	-8.126	3.059	10.243
72	-3.339	-0.144	0.794	2.085	0.377	100.000	2.433	-2.347	3.245	15.270
73	-6.669	-1.665	1.983	-4.570	-4.055	0.000	1.650	3.154	-2.104	3.135
74	-16.621	-4.958	1.761	-10.713	-10.180	0.000	8.362	15.119	-10.420	-6.342
75	8.342	-3.987	2.123	-1.593	-2.657	40.000	15.683	3.035	-2.525	-0.725
76	5.034	0.067	2.566	3.182	3.504	10.714	5.611	-4.107	4.010	7.892
					FORECASTED					
77	-5.897	0.288	2.059	-0.301	-0.418	29.032	5.480	-4.854	3.684	6.987
78	-0.975	1.118	1.916	0.155	0.540	0.000	5.089	-4.346	1.090	3.585
79	-2.511	1.112	1.946	0.775	1.167	0.000	5.477	-3.733	0.696	3.929
80	-0.724	0.586	1.898	0.021	0.486	0.000	6.404	-0.236	-0.054	3.773
81	2.476	0.040	1.767	0.388	0.855	0.000	6.406	4.089	0.316	3.654
82	3.123	-0.151	1.758	1.099	1.507	0.000	5.887	5.357	1.028	3.837
83	2.492	-0.060	1.758	1.571	1.916	0.000	5.542	4.715	1.503	3.717
84	1.671	0.101	1.738	1.817	2.111	0.000	5.170	2.148	1.752	3.497
85	0.332	0.311	1.738	1.775	2.046	0.000	4.855	-0.058	1.716	3.071
86	-0.304	0.364	1.650	1.641	1.932	0.000	4.764	-0.922	1.587	2.488
87	-1.017	0.367	1.623	1.595	1.901	0.000	4.760	-2.764	1.545	2.502
88	-0.191	0.321	1.654	1.595	1.901	0.000	4.760	-0.658	1.548	2.502
89	0.057	0.166	1.599	1.595	1.901	0.000	4.760	0.000	1.550	2.502
90	0.057	0.095	1.619	1.595	1.901	0.000	4.760	0.000	1.553	2.502
91	0.057	0.095	1.323	1.595	1.901	0.000	4.760	0.000	1.556	2.502
92	0.057	0.095	1.280	1.595	1.901	0.000	4.760	0.000	1.558	2.502
93	0.057	0.095	1.290	1.595	1.901	0.000	4.760	0.000	1.560	2.502
94	0.057	0.095	1.282	1.595	1.901	0.000	4.760	0.000	1.562	2.502
95	0.057	0.095	1.266	1.595	1.901	0.000	4.760	0.000	1.564	2.502

PACIFIC GAS AND ELECTRIC COMPANY
FORECAST OF LEVELS OF DEMOGRAPHIC AND ECONOMIC ACTIVITY
ENERGY PRICES
DEFLATED BY PRICE INDICES (1967 DOLLARS)
APRIL 1977

YEAR	ELECTRIC					GAS		
	LIGHT AND POWER			RESI-			INTERR.	
	MEDIUM MC:ECO/ WPIMA	SMALL MC:ECO/ WPIMA	LARGE MC:EI/ WPIMA	DENTIAL MC:ERI/ CPI:SF	RESALE MC:ERS/ CPI:SF	COMMERCIAL MC:GCO/ WPIMA	INDUSTRIAL MC:GSO/ WPIMA	RESIDENTIAL MC:GRI/ CPI:SF
				HISTORICAL				
65	0.0067	0.0318	0.0034	0.0135	0.0124	0.0662	0.0423	0.0722
66	0.0066	0.0302	0.0066	0.0131	0.0121	0.0628	0.0392	0.0685
67	0.0065	0.0275	0.0065	0.0128	0.0118	0.0590	0.0373	0.0630
68	0.0063	0.0258	0.0063	0.0122	0.0113	0.0575	0.0362	0.0603
69	0.0061	0.0249	0.0061	0.0116	0.0107	0.0565	0.0350	0.0580
70	0.0059	0.0240	0.0059	0.0110	0.0103	0.0586	0.0346	0.0594
71	0.0057	0.0262	0.0057	0.0124	0.0100	0.0593	0.0358	0.0598
72	0.0055	0.0257	0.0055	0.0123	0.0096	0.0601	0.0376	0.0604
73	0.0061	0.0244	0.0061	0.0125	0.0116	0.0616	0.0393	0.0638
74	0.0073	0.0225	0.0073	0.0135	0.0117	0.0615	0.0428	0.0683
75	0.0077	0.0217	0.0076	0.0138	0.0126	0.0783	0.0685	0.0851
76	0.0090	0.0233	0.0084	0.0150	0.0166	0.0946	0.0947	0.0900
				FORECASTED				
77	0.0125	0.0263	0.0120	0.0179	0.0172	0.1118	0.1124	0.0988
78	0.0124	0.0260	0.0119	0.0178	0.0169	0.1233	0.1240	0.1096
79	0.0123	0.0260	0.0118	0.0179	0.0169	0.1287	0.1294	0.1151
80	0.0122	0.0258	0.0117	0.0180	0.0170	0.1319	0.1325	0.1194
81	0.0122	0.0257	0.0117	0.0181	0.0171	0.1372	0.1380	0.1252
82	0.0123	0.0258	0.0117	0.0181	0.0172	0.1445	0.1453	0.1318
83	0.0123	0.0260	0.0118	0.0182	0.0172	0.1490	0.1498	0.1354
84	0.0124	0.0262	0.0119	0.0182	0.0173	0.1511	0.1519	0.1366
85	0.0125	0.0263	0.0120	0.0183	0.0173	0.1526	0.1535	0.1374
86	0.0126	0.0265	0.0121	0.0183	0.0174	0.1598	0.1607	0.1433
87	0.0127	0.0266	0.0121	0.0184	0.0174	0.1672	0.1681	0.1496
88	0.0127	0.0267	0.0121	0.0184	0.0174	0.1704	0.1713	0.1522
89	0.0127	0.0267	0.0122	0.0184	0.0174	0.1752	0.1771	0.1570
90	0.0127	0.0268	0.0122	0.0184	0.0174	0.1832	0.1841	0.1629
91	0.0128	0.0268	0.0122	0.0184	0.0174	0.1850	0.1860	0.1643
92	0.0128	0.0269	0.0122	0.0184	0.0174	0.1862	0.1872	0.1650
93	0.0128	0.0269	0.0123	0.0184	0.0174	0.1880	0.1889	0.1662
94	0.0128	0.0270	0.0123	0.0184	0.0174	0.1906	0.1916	0.1683
95	0.0129	0.0270	0.0123	0.0184	0.0174	0.1927	0.1937	0.1698

PACIFIC GAS AND ELECTRIC COMPANY
FORECAST OF LEVELS OF DEMOGRAPHIC AND ECONOMIC ACTIVITY
ENERGY PRICES
DEFLATED BY PRICE INDICES (1967 DOLLARS)
ANNUAL PERCENT CHANGES
APRIL 1977

	ELECTRIC					GAS		
	LIGHT AND POWER			RESI-			INTERR.	
YEAR	MEDIUM MC:ECO/ WPIMA	SMALL MC:ECO/ WPIMA	LARGE MC:EI/ WPIMA	DENTIAL MC:ERI/ CPI:SF	RESALE MC:ERS/ CPI:SF	COMMERCIAL MC:GCO/ WPIMA	INDUSTRIAL MC:GSO/ WPIMA	RESIDENTIAL MC:GRI/ CPI:SF
				HISTORICAL				
66	-2.70	-4.87	94.60	-2.62	-2.62	-5.13	-7.21	-5.12
67	-1.02	-8.93	-1.02	-2.82	-2.82	-6.08	-4.97	-7.94
68	-2.50	-6.13	-2.50	-4.41	-4.41	-2.50	-2.68	-4.41
69	-3.44	-3.44	-3.44	-5.26	-5.26	-1.72	-3.44	-3.69
70	-3.63	-3.63	-3.63	-4.79	-3.18	3.61	-1.15	2.29
71	-3.20	9.16	-3.20	12.54	-3.37	1.18	3.45	0.76
72	-3.43	-2.11	-3.43	-1.00	-3.49	1.39	5.14	1.03
73	11.29	-5.13	11.29	1.52	20.17	2.51	4.50	5.49
74	18.61	-7.54	18.61	8.56	1.40	-0.09	9.04	7.12
75	6.22	-3.54	4.30	2.45	7.33	27.19	59.94	24.62
76	16.16	7.03	10.92	8.09	32.25	20.84	38.23	5.71
				FORECASTED				
77	39.16	12.98	42.13	19.56	3.30	18.24	18.69	9.78
78	-0.91	-0.91	-0.91	-0.33	-1.81	10.28	10.28	10.93
79	-0.32	-0.32	-0.32	0.34	0.34	4.39	4.39	5.07
80	-0.76	-0.76	-0.76	0.51	0.51	2.44	2.44	3.76
81	-0.24	-0.24	-0.24	0.47	0.47	4.08	4.08	4.82
82	0.37	0.37	0.37	0.36	0.36	5.32	5.32	5.30
83	0.62	0.62	0.62	0.26	0.26	3.10	3.10	2.73
84	0.77	0.77	0.77	0.23	0.23	1.38	1.38	0.83
85	0.75	0.75	0.75	0.31	0.31	1.05	1.05	0.60
86	0.61	0.61	0.61	0.26	0.26	4.71	4.71	4.34
87	0.39	0.39	0.39	0.14	0.14	4.63	4.63	4.38
88	0.23	0.23	0.23	0.04	0.04	1.90	1.90	1.71
89	0.19	0.19	0.19	0.00	0.00	3.39	3.39	3.19
90	0.19	0.19	0.19	-0.00	-0.00	3.95	3.95	3.75
91	0.19	0.19	0.19	0.00	0.00	1.03	1.03	0.84
92	0.19	0.19	0.19	-0.00	-0.00	0.65	0.65	0.46
93	0.19	0.19	0.19	-0.00	0.00	0.92	0.92	0.73
94	0.19	0.19	0.19	-0.00	0.00	1.41	1.41	1.22
95	0.19	0.19	0.19	0.00	-0.00	1.10	1.10	0.91

PACIFIC GAS AND ELECTRIC COMPANY
FORECAST OF LEVELS OF DEMOGRAPHIC AND ECONOMIC ACTIVITY
ENERGY PRICES
PERCENT CHANGE FROM JULY 1976 ESTIMATE
DEFLATED BY PRICE INDICES (1967 DOLLARS)
APRIL 1977

YEAR	MC:ECO/ WPIMA	MC:ECO/ WPIMA	MC:EI/ WPIMA	MC:ERI/ CPI:SF	MC:ERS/ CPI:SF	MC:GCO/ WPIMA	MC:GSO/ WPIMA	MC:GRI/ CPI:SF
					FORECASTED			
76	-6.80	53.89	14.87	15.62	61.37	16.83	9.47	1.07
77	30.78	75.32	64.65	39.41	68.11	24.64	11.24	0.12
78	29.93	74.17	63.56	38.82	64.93	28.45	12.40	3.43
79	27.58	71.03	60.61	39.07	65.23	26.46	12.94	3.88
80	24.99	67.56	57.35	39.37	65.57	26.21	13.25	6.05
81	24.03	66.27	56.14	39.38	65.59	30.66	13.80	10.65
82	25.94	66.15	56.03	39.50	65.73	37.00	14.53	16.20
83	24.92	67.46	57.26	39.84	66.14	41.47	14.98	19.35
84	26.58	69.69	59.35	39.65	65.91	44.22	15.19	19.91
85	27.35	70.72	60.32	39.99	66.31	45.52	15.35	20.55
86	28.53	72.31	61.81	40.03	66.36	52.85	16.07	25.49
87	29.20	73.20	62.65	39.53	65.77	60.15	16.81	30.33
88	30.00	74.27	63.66	39.58	65.83	63.83	17.13	32.56
89	30.74	75.26	64.59	39.58	65.83	70.02	17.71	36.79
90	31.48	76.26	65.53	39.58	65.83	77.40	18.41	41.92
91	32.24	77.27	66.47	39.58	65.83	79.91	18.69	43.11
92	32.99	78.28	67.43	39.58	65.83	81.77	18.72	43.76
93	33.75	79.30	68.38	39.58	65.83	84.13	18.89	44.81
94	34.51	80.33	69.34	39.58	65.83	87.44	19.16	46.57
95	35.28	81.36	70.31	39.58	65.82	90.22	19.37	47.90

PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
PEAK DEMAND FORECAST ASSUMPTIONS
APRIL 1977

YEAR	WEATHER SENSITIVITY COEFFICIENTS SAC. WSC:S	SAN JOSE WSC:SJ	FRESNO WSC:F	PG&E RESI. CUST. PECRM	ADJUSTMENTS TO AREA HOUSEHOLDS PRESCR (1)	HHACU (2)	AREA HOUSE-HOLDS HH	AIR C. SAT. ACSAT:P	TOTAL PNACU:T	NUMBER OF AIR CONDITIONING UNITS SAC. PNACU:S	SAN JOSE PNACU:SJ	FRESNO PNACU:F	% REDUCTION EFFICIENCY STANDARDS CAWSD
						HISTORICAL							
65	0.1123	0.0066	0.0270	1918189	1.1637	1.0190	2274608	0.1521	341831	211935	41020	88876	0.0000
66	0.1735	0.0218	0.0537	1978175	1.1638	1.0190	2345942	0.1626	376865	233279	45224	98362	0.0000
67	0.1632	0.0249	0.0339	2044202	1.1625	1.0190	2421536	0.1778	425161	263175	50594	111392	0.0000
68	0.1425	0.0182	0.0455	2106610	1.1611	1.0190	2492459	0.1928	474453	293212	56460	124781	0.0000
69	0.1485	0.0194	0.0327	2154235	1.1612	1.0190	2549026	0.2177	548013	338672	64666	144675	0.0000
70	0.1574	0.0258	0.0415	2207518	1.1619	1.0220	2621343	0.2431	627101	387140	74121	165840	0.0000
71	0.1638	0.0250	0.0501	2265405	1.1635	1.0250	2701694	0.2521	668564	412555	78814	177195	0.0000
72	0.1473	0.0203	0.0390	2345767	1.1656	1.0190	2786176	0.2592	712770	439639	83804	189327	0.0000
73	0.1685	0.0255	0.0512	2424348	1.1674	1.0150	2872637	0.2670	759898	468500	89109	202289	0.0000
74	0.2271	0.0324	0.0714	2501362	1.1675	1.0140	2961225	0.2759	810148	499257	94751	216140	0.0000
75	0.1808	0.0241	0.0558	2566293	1.1703	1.0160	3051386	0.2861	863720	532032	100750	230938	0.0000
76	0.1842	0.0199	0.0748	2624529	1.1643	1.0240	3129077	0.2998	919783	565299	108718	245766	0.0000
						FORECASTED							
77	0.2031	0.0270	0.0708	2696586	1.1643	1.0247	3217184	0.3042	978657	600217	117244	261206	0.0000
78	0.2072	0.0273	0.0738	2769685	1.1643	1.0241	3302461	0.3148	1039615	636140	126209	277265	0.0000
79	0.2111	0.0276	0.0768	2840218	1.1643	1.0252	3390199	0.3255	1103510	673803	135732	293975	0.0000
80	0.2101	0.0274	0.0779	2909878	1.1643	1.0272	3480124	0.3361	1169670	712563	145741	311366	2.3000
81	0.2101	0.0272	0.0793	2969758	1.1643	1.0262	3548281	0.3441	1220963	742102	153841	325020	4.0600
82	0.2102	0.0271	0.0807	3027153	1.1643	1.0264	3617561	0.3520	1273382	772179	162229	338974	5.7100
83	0.2103	0.0270	0.0821	3084551	1.1643	1.0270	3688309	0.3600	1327791	803314	171020	353458	7.2800
84	0.2105	0.0269	0.0835	3141947	1.1643	1.0280	3760598	0.3679	1383524	835095	180135	368294	8.7600
85	0.2108	0.0267	0.0848	3198761	1.1643	1.0294	3833812	0.3759	1441130	867849	189653	383485	10.1700
86	0.2114	0.0268	0.0863	3248528	1.1643	1.0285	3890056	0.3824	1487557	893873	197696	395988	11.3900
87	0.2121	0.0267	0.0878	3296513	1.1643	1.0284	3947133	0.3888	1534645	920173	205949	408523	12.5700
88	0.2127	0.0266	0.0892	3344498	1.1643	1.0286	4005367	0.3953	1583322	947460	214540	421322	13.7100
89	0.2134	0.0266	0.0905	3392483	1.1643	1.0289	4064019	0.4017	1632516	974776	223328	434413	14.8300
90	0.2140	0.0266	0.0918	3439972	1.1643	1.0296	4123712	0.4082	1683299	1002910	232464	447926	15.9200
91	0.2146	0.0265	0.0932	3481465	1.1643	1.0290	4171020	0.4141	1727220	1027523	240429	459268	16.9500
92	0.2162	0.0266	0.0949	3521445	1.1643	1.0291	4219329	0.4200	1772118	1052815	248628	470675	17.5800
93	0.2178	0.0267	0.0967	3561427	1.1643	1.0293	4268064	0.4258	1817342	1078047	256790	482504	18.1900
94	0.2194	0.0268	0.0983	3601407	1.1643	1.0296	4317234	0.4317	1863750	1104086	265398	494267	18.8000
95	0.2210	0.0269	0.1000	3641415	1.1643	1.0301	4367314	0.4376	1911137	1130437	274248	506451	19.3900

(1) Adjustment factor converting the number of PG&E residential customers to number of Area residential customers.

(2) Adjustment factor converting the number of Area residential customers to the number of Area households.

PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
PEAK DEMAND FORECAST ASSUMPTIONS
ANNUAL PERCENT CHANGES
APRIL 1977

YEAR	WEATHER SENSITIVITY COEFFICIENTS SAC. WSC:S	SAN JOSE WSC:SJ	FRESNO WSC:F	PG&E RESI, CUST. PECRH	AREA HOUSE-HOLDS HH	AIR C. SAT. ACSAT:P	TOTAL PNACU:T	NUMBER OF AIR CONDITIONING UNITS SAC. PNACU:S	SAN JOSE PNACU:SJ	FRESNO PNACU:F
					HISTORICAL					
66	54.50	230.30	98.89	3.13	3.14	6.92	10.25	10.07	10.25	10.67
67	-5.94	14.22	-36.87	3.34	3.22	9.32	12.82	12.82	11.87	13.25
68	-12.68	-26.91	34.22	3.05	2.93	8.43	11.59	11.41	11.59	12.02
69	4.21	6.59	-28.13	2.26	2.27	12.96	15.50	15.50	14.53	15.94
70	5.99	32.99	26.91	2.47	2.84	11.63	14.43	14.31	14.62	14.63
71	4.07	-3.10	20.72	2.62	3.07	3.74	6.61	6.56	6.33	6.85
72	-10.07	-18.80	-22.16	3.55	3.13	2.79	6.61	6.56	6.33	6.85
73	14.39	25.62	31.28	3.35	3.10	3.02	6.61	6.56	6.33	6.85
74	34.78	27.06	39.45	3.18	3.08	3.34	6.61	6.56	6.33	6.85
75	-20.39	-25.62	-21.85	2.60	3.04	3.69	6.61	6.56	6.33	6.85
76	1.88	-17.43	34.06	2.27	2.55	4.79	6.49	6.25	7.91	6.42
					FORECASTED					
77	10.27	35.73	-5.32	2.75	2.82	1.47	6.40	6.18	7.84	6.28
78	1.99	1.18	4.20	2.71	2.65	3.48	6.23	5.99	7.65	6.15
79	1.90	1.17	4.03	2.55	2.66	3.40	6.15	5.92	7.54	6.03
80	-0.48	-0.80	1.49	2.45	2.65	3.26	6.00	5.75	7.37	5.92
81	-0.00	-0.69	1.73	2.06	1.96	2.38	4.39	4.15	5.56	4.39
82	0.05	-0.62	1.82	1.93	1.95	2.30	4.29	4.05	5.45	4.29
83	0.07	-0.21	1.76	1.90	1.96	2.27	4.27	4.03	5.42	4.27
84	0.11	-0.52	1.71	1.86	1.96	2.19	4.20	3.96	5.33	4.20
85	0.13	-0.48	1.54	1.81	1.95	2.17	4.16	3.92	5.28	4.12
86	0.30	0.05	1.75	1.56	1.47	1.73	3.22	3.00	4.24	3.26
87	0.30	-0.29	1.68	1.48	1.47	1.67	3.17	2.94	4.17	3.17
88	0.30	-0.27	1.62	1.46	1.48	1.67	3.17	2.97	4.17	3.13
89	0.32	0.06	1.44	1.43	1.46	1.62	3.11	2.88	4.10	3.11
90	0.27	-0.27	1.49	1.40	1.47	1.62	3.11	2.89	4.09	3.11
91	0.30	-0.23	1.47	1.21	1.15	1.45	2.61	2.45	3.43	2.53
92	0.75	0.56	1.88	1.15	1.16	1.42	2.60	2.46	3.41	2.48
93	0.75	0.24	1.83	1.14	1.16	1.38	2.55	2.40	3.28	2.51
94	0.72	0.22	1.67	1.12	1.15	1.39	2.55	2.42	3.35	2.44
95	0.72	0.55	1.72	1.11	1.16	1.37	2.54	2.39	3.33	2.47

TABLE 5

PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
CONSERVATION ADJUSTMENT FACTORS
APRIL 1977
(PERCENT REDUCTIONS)

YEAR	PGandE RESIDENTIAL CARI	SMUD CASH	RESALE CARS	USBR CVP CAVP	SANTA CLARA CASC	MODESTO-TURLOCK CAMT	WEATHER SENSITIVE DEMAND CAWSD	VOLTAGE REDUCTION CAVOLR
77	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.7500
78	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.7500
79	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.7500
80	2.0000	2.0000	0.7800	0.9800	0.3600	0.9000	2.3000	0.7500
81	3.8000	3.8000	1.4820	1.8620	0.6840	1.7100	4.0600	0.7500
82	5.5000	5.5000	2.1450	2.6950	0.9900	2.4750	5.7100	0.7500
83	7.1000	7.1000	2.7690	3.4790	1.2780	3.1950	7.2800	0.7500
84	8.4000	8.4000	3.2760	4.1160	1.5120	3.7800	8.7600	0.7500
85	9.7000	9.7000	3.7830	4.7530	1.7460	4.3650	10.1700	0.7500
86	10.9000	10.9000	4.2510	5.3410	1.9620	4.9050	11.3900	0.7500
87	11.9000	11.9000	4.6410	5.8310	2.1420	5.3550	12.5700	0.7500
88	13.0000	13.0000	5.0700	6.3700	2.3400	5.8500	13.7100	0.7500
89	14.0000	14.0000	5.4600	6.8600	2.5200	6.3000	14.8300	0.7500
90	14.8000	14.8000	5.7720	7.2520	2.6640	6.6600	15.9200	0.7500
91	15.3000	15.3000	5.9670	7.4970	2.7540	6.8850	16.9500	0.7500
92	15.7000	15.7000	6.1230	7.6930	2.8260	7.0650	17.5800	0.7500
93	16.0000	16.0000	6.2400	7.8400	2.8800	7.2000	18.1900	0.7500
94	16.3000	16.3000	6.3570	7.9870	2.9340	7.3350	18.8000	0.7500
95	16.2000	16.2000	6.3180	7.9380	2.9160	7.2900	19.3900	0.7500

5. Provide complete listing of all capacity presently available to PG&E's coordinated system. Show all planned capacity changes through 1980 (additions, retirements, deratings, uprating, purchases and sales.) Provide estimates of hydro capacity under continued drought conditions and under normal rain conditions.

RESPONSE:

Table 1 presents all the non-hydro capacity available to the PGandE area system. Included therein are the Humboldt Bay #3 unit which is currently not operating and whose restarting date is indefinite. Geysers Unit 12 (106 MW) scheduled for July 1 and Geysers Unit 15 (55 MW) scheduled for September 1 which are under construction and will be delayed from two to three months.

Table 2 presents area hydro capacity assuming 1977 runoff recurs in 1978; this can be described as the "continuing drought case."

Table 3 presents area hydro capacity assuming average precipitation occurs in 1978; this can be described as the "dourght recovery case", or "normal" for 1978.

Table 4 presents average hydro capacity base on long-term (based on available records, usually beginning in the 1920's) theoretical operating studies; this can be described as "normal" hydro electric capacity. These levels of capacity in 1978 will require greater amounts of precipitation than average.

Table 5 presents the areas planned system additions, retirements, rerates, and changes in purchases. There are no changes in sales.

Table 6 presents changes in availability to area resources. The USBR's Central Valley Project constitutes the only changes not included in Table 5.

PACIFIC GAS AND ELECTRIC COMPANY AREA

AREA RESOURCES FOR 1978
EXCEPT HYDROELECTRIC AND DIABLO CANYON
MEGAWATTS

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Pacific Gas and Electric Company Conventional Fossil Steam Plants												
Contra Costa	1260	1260	1260	1260	1260	1260	1260	1260	1260	1260	1260	1260
Humboldt Bay	105	105	105	105	105	105	105	105	105	105	105	105
Hunters Point	377	377	377	377	377	377	377	377	377	377	377	377
Kern	180	180	180	180	180	180	180	180	180	180	180	180
Morro Bay	1002	1002	1002	1002	1002	1002	1002	1002	1002	1002	1002	1002
Moss Landing	2060	2060	2060	2060	2060	2060	2060	2060	2060	2060	2060	2060
Pittsburg	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002
Potrero	323	323	323	323	323	323	323	323	323	323	323	323
Subtotal	7309	7309	7309	7309	7309	7309	7309	7309	7309	7309	7309	7309
Less Long Term Limitations	31	31	31	31	31	31	31	31	31	31	31	31
Total, Conventional Fossil Steam	7278	7278	7278	7278	7278	7278	7278	7278	7278	7278	7278	7278
Pacific Gas and Electric Company Refinery Plants												
Avon	46	46	46	46	46	46	46	46	46	46	46	46
Martinez	46	46	46	46	46	46	46	46	46	46	46	46
Oleum	87	87	87	87	87	87	87	87	87	87	87	87
Total, Refinery Plants	179	179	179	179	179	179	179	179	179	179	179	179
Pacific Gas and Electric Company Geothermal at Geysers 1/	502	502	502	502	502	502	608	608	663	663	663	663
Pacific Gas and Electric Company Gas Turbines												
Potrero	168	165	162	159	150	144	147	147	147	147	162	168
Hunters Point	56	55	54	53	50	48	49	49	48	49	54	56
Oakland	(Commercial Operation May 1, 1978)				162	150	153	162	153	162	186	192
Mobile Emergency	45	45	45	45	45	45	45	45	45	45	45	45
Total, Gas Turbines	269	265	261	257	407	387	394	403	390	403	447	461
Pacific Gas and Electric Company Nuclear												
Humboldt Bay #3 2/	63	63	63	63	63	63	63	63	63	63	63	63
SMUD												
Rancho Seco #1	903	902	899	895	883	873	875	875	875	889	900	903
Purchases to Meet Area Load												
State purchases and resources outside of area to supply State Pumping under long term contracts	163	204	209	172	78	101	106	141	139	50	88	63
PG&E from BPA	0	0	0	0	0	600	600	600	600	600	0	0
PG&E from Portland General Electric	0	0	0	0	400	400	400	400	400	0	0	0
Northwest Power by USBR	400	400	400	400	400	400	400	400	400	400	400	400
Total Area Resources Except Hydro Before Overhaul	9757	9793	9791	9746	10190	10783	10903	10947	10987	10525	10018	10010
Overhaul (1978, Preliminary Estimate)	900	1100	1200	1350	900	200	0	0	400	1889	1700	400
Available Area Resources Except Hydro After Overhaul	8857	8693	8591	8396	9290	10583	10903	10947	10587	8636	8318	9610

1/ Includes Geysers Unit 12 (106 MW) scheduled for July 1 and Geysers Unit 15 (55 MW) scheduled for September 1 which are under construction and will be delayed from two to three months.

2/ Currently not operating and whose restarting date is indefinite.

TABLE 1

PACIFIC GAS AND ELECTRIC COMPANY AREA
1978 HYDROELECTRIC RESOURCES
ASSUMING 1977 RUNOFF
MEGAWATTS

1978 "CONTINUED DROUGHT"

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Pacific Gas and Electric Company Owned Hydro	2360.6	2358.3	2358.9	2360.6	2363.8	2365.8	2356.1	2350.0	2349.6	2339.0	2339.1	2337.4
Area Hydro Owned by Others and Available as Area Resource												
USBR-CVP	721.0	759.0	766.0	794.0	763.0	744.0	470.0	422.0	393.0	399.0	400.0	401.0
DWR-Hyatt and Thermalito (PG&E Share)	256.0	251.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
EBMUD	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Merced Irrigation District	32.0	32.1	32.3	33.7	34.0	34.5	32.3	0.0	0.0	0.0	0.0	0.0
Nevada Irrigation District	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5
Oakdale and South San Joaquin Irrigation Districts	35.0	35.0	35.0	60.0	60.0	60.0	35.0	35.0	35.0	35.0	35.0	35.0
Oroville - Wyandotte Irrigation District	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0
Placer County Water Agency	234.6	233.6	232.8	232.8	232.9	233.5	231.7	229.8	228.3	226.5	224.9	223.6
City and County of San Francisco	119.0	56.0	56.0	57.0	87.0	117.0	117.0	117.0	117.0	87.0	57.0	57.0
Sacramento MUD	627.0	632.0	635.0	639.0	644.0	646.0	643.0	640.0	636.0	635.0	634.0	632.0
Yuba County Water AGency	244.5	244.5	247.0	251.5	254.0	258.5	257.5	255.0	251.5	248.9	242.5	242.0
Total	4782	4754	4564	4629	4639	4660	4343	4249	4211	4171	4133	4128
Capacity Not Usable Due to Energy Limitations	1275	1146	1529	1267	624	0	0	0	28	482	316	274
Usable Area Hydro	3507	3608	3035	3362	4015	4660	4343	4249	4183	3689	3817	3854
1978 Non Hydro Resources 2/	8857	8693	8591	8396	9290	10583	10903	10947	10587	8636	8318	9610
Total Resources excluding Diablo Canyon	12364	12301	11626	11758	13305	15243	15246	15196	14770	12325	12135	13464

1/ Usable hydro capacity can be increased by purchasing energy from outside area sources if available.
2/ From Table 1.

TABLE 2

1978 Drought Recovery
OR
"1978 Normal"

PACIFIC GAS AND ELECTRIC COMPANY AREA
1978 HYDROELECTRIC RESOURCES
ASSUMING AVERAGE PRECIPITATION

MEGAWATTS

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Pacific Gas & Electric Co. Owned Hydro	2396.5	2407.4	2410.0	2421.1	2426.6	2436.3	2428.3	2425.4	2412.8	2413.7	2412.1	2409.3
Area Hydro Owned by Others and Available as Area Resource												
USBR-CVP	832.0	873.0	870.0	882.0	875.0	901.0	908.0	894.0	862.0	865.0	862.0	865.0
DWR-Hyatt and Thermalito (PG&E share)	251.0	259.0	301.0	332.0	456.0	470.0	456.0	442.0	358.0	346.0	346.0	349.0
EBMUD	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Merced Irrigation District	32.5	35.4	40.9	51.2	61.9	78.9	81.9	77.7	72.8	66.5	60.8	56.5
Nevada Irrigation District	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5
Oakdale and So. San Joaquin Irrig. Dists.	35.0	36.8	38.2	58.1	75.5	87.8	96.8	91.3	83.5	76.7	74.9	71.4
Oroville-Wyandotte Irrig. District	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0
Placer County Water Agency	235.1	234.9	234.9	235.7	237.5	240.8	241.1	239.8	239.0	237.5	236.2	235.5
City and County of San Francisco	303.6	302.7	302.0	302.0	306.1	309.0	315.2	312.6	309.9	307.3	305.2	302.6
Sacramento MUD	638.0	641.0	645.0	647.9	650.3	652.2	652.8	652.2	646.4	645.9	648.9	649.6
Yuba County Water Agency	242.0	247.4	261.7	286.1	290.2	328.1	314.3	304.1	297.4	283.3	274.4	280.5
Total	5125	5197	5263	5376	5539	5664	5654	5599	5441	5401	5380	5379
Capacity Not Usable Due to Energy Limitations 1/	783	617	945	924	191	0	0	0	0	664	0	0
Usable Area Hydro	4342	4580	4318	4452	5348	5664	5654	5599	5441	4737	5380	5379
1978 Non Hydro Resources After Overhaul 2/	8857	8693	8591	8396	9290	10583	10903	10947	10587	8636	8318	9610
Total 1978 Resources Without Diablo Canyon	13199	13273	12909	12848	14638	16247	16557	16546	16028	13373	13698	14989

1. Usable hydro capacity can be increased by purchasing energy from outside area sources, if available.

2. From Table 1

TABLE 3

PACIFIC GAS AND ELECTRIC COMPANY AREA
LONG TERM THEORTICAL AVERAGE CAPACITY
1978 LEVELS OF OPERATION
MEGAWATTS

"NORMAL HYDRO CAPACITY"

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Pacific Gas & Electric Co. Owned Hydro	2427.6	2426.3	2428.8	2437.7	2452.6	2454.5	2437.9	2426.8	2417.4	2413.3	2418.1	2421.2
Area Hydro Owned by Others and Available as Area Resource												
USBR-CVP	899.0	875.0	870.0	882.0	875.0	901.0	908.0	894.0	862.0	865.0	862.0	865.0
DWR-Hyatt and Thermalito (PG&E Share)	494.8	498.4	501.1	503.1	504.4	503.6	502.8	501.3	495.1	491.8	491.5	492.3
EBMUD	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8
Merced Irrigation District	89.3	90.5	93.6	94.5	95.6	96.9	96.1	94.3	91.8	89.3	88.4	88.2
Nevada Irrigation District	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5	67.5
Oakdale and South San Joaquin Irrigation Districts	83.6	85.8	87.6	92.9	98.2	100.9	98.8	93.7	86.8	84.2	82.6	82.4
Oroville - Wyandotte Irrigation District	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0
Placer County Water Agency	237.8	237.9	238.0	238.5	240.4	243.5	243.1	241.9	240.1	238.7	238.1	237.9
City and County of San Francisco	303.6	302.7	302.0	302.0	306.1	309.0	315.2	312.6	309.9	307.3	305.2	302.6
Sacramento MUD	647.3	648.4	650.5	652.6	653.2	653.0	652.6	651.5	644.5	645.7	649.4	649.4
Yuba County Water Agency	33300	338.1	336.0	338.2	345.5	341.5	331.4	324.4	317.8	315.1	315.3	321.8
Total	5688	5674	5679	5713	5743	5776	5757	5712	5636	5621	5622	5632
Capacity Not Usable Due to Energy Limitations	0	0	0	0	0	0	0	0	0	0	0	0
Usable Area Hydro, 1978	5688	5674	5679	5713	5743	5776	5757	5712	5636	5621	5622	5632
Changes to 1979 Levels	-19	-23	-23	-21	-21	-20	-20	-21	-22	-21	-14	-21
Usable Area Hydro, 1979	5669	5651	5656	5692	5722	5756	5737	5691	5614	5600	5608	5611

TABLE 4

PACIFIC GAS AND ELECTRIC COMPANY AREA SYSTEM

SCHEDULE OF RESOURCE ADDITIONS
FOR 1978-1980

YEAR	INDENTIFICATION	TYPE OF RESOURCE(1)	DRY YEAR AUGUST MEGAWATTS	NORMAL OPERATING CAPACITY(2)	MONTH
1978	CANADIAN ENTITLEMENT CHANGE	P	-100		JANUARY
	DIABLO CANYON 1 (3)	N	1060		MARCH
	OAKLAND 1	GT	54	57	MAY
	OAKLAND 2	GT	54	57	MAY
	OAKLAND 3	GT	54	57	MAY
	GEYSERS 12	G	106		JULY
	GEYSERS 15	G	55		SEPTEMBER
	DIABLO CANYON 2 (3)	N	1060		DECEMBER
1979	GEYSERS 14	G	110		FEBRUARY
	DIABLO CANYON 1 RERATE (3)	N	40		MARCH
	GEYSERS 13	G	135		JULY
	DIABLO CANYON 2 RERATE (3)	N	40		DECEMBER
1980	THERMAL A & B (PART OF GT PORTION) (4)	CC	528	560	JULY
	BAY AREA COMBINED CYCLE (GT PORTION)	CC	288	300	JULY
	N.I.D: ROLLINS	H	5	11	SEPTEMBER
	RETIRE POTRERO 1 (5)	F	-58		OCTOBER
	RETIRE POTRERO 2 (5)	F	-58		OCTOBER

(1) H-HYDRO, F-FOSSIL STEAM, N-NUCLEAR, G-GEOTHERMAL, GT-GAS TURBINE, CC-COMBINED CYCLE, PS-PUMPED STORAGE, P-PURCHASE.
(2) SHOWN ONLY WHEN DIFFERENT THAN AUGUST RATING.
(3) DATE DEPENDENT UPON TIME OF ISSUANCE OF OPERATING LICENSE BY N.R.C.
(4) DATE DEPENDENT UPON RECEIVING REGULATORY APPROVALS TO START CONSTRUCTION BY OCTOBER 1979.
(5) SCHEDULE IS RELATED TO CONSTRUCTION OF BAY AREA COMBINED CYCLE STEAM TURBINE AT POTRERO SITE.

TABLE 5

CHANGES IN AVAILABILITY

		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1979													
	1979 CVP VALUES (LONG TERM AVERAGE)	880	852	847	861	854	881	888	873	840	844	848	844
	CHANGE FROM 1978	-19	-23	-23	-21	-21	-20	-20	-21	-22	-21	-14	-21
1980													
	1980 CVP VALUES (LONG TERM AVERAGE)	875	852	849	864	857	883	894	877	839	840	841	847
	CHANGE FROM 1977	-5	0	+2	+3	+3	+2	+6	+4	-1	-4	-7	+3

TABLE 6

6. Estimate reserve margins on PGandE system for the summer of 1978 and 1979 under drought and normal rain conditions. Assume Diablo Canyon is not operating.

RESPONSE:

Exhibit A, which was included in the motion for interim operating license, develops reserve margins under the "drought", 1977 runoff in 1978 conditions for 1978.

Exhibit B develops reserve margins for 1978 assuming average rainfall in 1978. This case, because of the low reservoir carryovers, best fits the normal description for 1978.

Exhibit C develops reserve margins for 1979 assuming the same hydro capacity as 1978 drought conditions. This is only an indication of the degree of the adverse situation in 1979. If runoff in 1978 approximated that of 1977 and 1979 runoff was again similar to 1977, then 1979 hydroelectric capacity would be even lower resulting in a worse situation. No studies have been done to quantify this amount.

Exhibit D develops reserve margins for 1979 utilizing the long term average hydroelectric capacity. To obtain this amount of capacity in 1979 would at least require near normal runoffs in 1978 and 1979. However, no studies have been done to quantify this amount.

1978 LOADS AND RESOURCES
ADVERSE YEAR (1977 RUNOFF) OUTLOOK
WITHOUT DIABLO CANYON

CAPACITY (MEGAWATTS)	JAN	FEB	MARCH	APRIL	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC
LOADS AND TRANSFERS (1)	12410	12097	11825	11672	13028	14550	15428	15424	13881	11928	12261	12995
RESOURCES AFTER OVERHAUL												
USABLE AREA HYDRO (2)	3507	3608	3039	3362	4015	4660	4343	4249	4183	3689	3817	3854
N.W. FIRM (USBR)	400	400	400	400	400	400	400	400	400	400	400	400
N.W. PEAKING (BPA & PGE)	0	0	0	0	400	1000	1000	1000	1000	600	0	0
N.W. NON-FIRM	0	0	0	0	0	0	0	0	0	0	0	0
GEOTHERMAL	502	502	502	502	502	502	608	608	663	663	663	663
GAS TURBINES	269	265	261	257	407	387	394	403	390	403	447	461
REFINERY PLANTS	179	179	179	179	179	179	179	179	179	179	179	179
HUMBOLDT BAY #3	63	63	63	63	63	63	63	63	63	63	63	63
RANCHO SECO	903	902	899	895	883	873	875	875	875	0	0	903
STATE EXTERNAL RESOURCES	163	204	209	172	78	101	106	141	139	50	88	63
DIABLO CANYON	0	0	0	0	0	0	0	0	0	0	0	0
CONVENTICNAL THERMAL AVAILABLE	6378	6178	6078	5928	6378	7078	7278	7278	6878	6278	6478	6878
TOTAL	12364	12301	11626	11758	13305	15243	15246	15196	14770	12325	12135	13464
MARGIN, MW	-46	204	-199	86	277	693	-182	-228	889	397	-126	469
%	-0.4	1.7	-1.7	0.7	2.1	4.8	-1.2	-1.5	6.4	3.3	-1.0	3.6
CONVENTICNAL THERMAL												
TOTAL	7309	7309	7309	7309	7309	7309	7309	7309	7309	7309	7309	7309
SCHEDULED OVERHAUL	900	1100	1200	1350	900	200	0	0	400	1000	800	400
LONG TERM LIMITATIONS	31	31	31	31	31	31	31	31	31	31	31	31
CONVENTICNAL THERMAL AVAILABLE	6378	6178	6078	5928	6378	7078	7278	7278	6878	6278	6478	6878

(1) 100 MW OF INTERRUPTIBLE LOAD INCLUDED.

(2) HYDRO CAPACITY AND ENERGY ARE BASED ON CURRENT ESTIMATES OF RESERVOIR STORAGE AT THE END OF 1977 AND INFLOWS IN 1978 AS THEY HAVE OCCURRED OR ARE EXPECTED TO OCCUR IN 1977. THIS RESULTS IN REDUCED HYDRO CAPABILITY VARYING FROM ABOUT 750 TO 1250 MEGAWATTS (1198 IN JULY, 1237 IN AUGUST) AND LARGER-THAN-NORMAL DISCOUNTED CAPACITY DURING JANUARY THROUGH MAY AND SEPTEMBER THROUGH DECEMBER. IN THESE MONTHS (JANUARY THROUGH MAY AND SEPTEMBER THROUGH DECEMBER) USABLE HYDRO CAPACITY CAN BE INCREASED BY PURCHASING ENERGY FROM OUTSIDE AREA SOURCES IF AVAILABLE.

AUGUST 9, 1977

EXHIBIT A

1978 LOADS AND RESOURCES
ADVERSE YEAR (1977 RUNOFF) OUTLOOK
WITHOUT DIABLO CANYON

ENERGY (MILLION KILOWATT HOURS)

	JAN	FEB	MARCH	APRIL	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
LOADS AND TRANSFERS	6454	6028	6454	6278	6661	6963	7597	7607	6626	6366	6127	6520	79681
RESOURCES AFTER OVERHAUL													
AREA HYDRO	590	573	629	747	760	866	1078	1001	817	686	506	480	8733
NORTHWEST - FIRM	236	208	228	252	252	252	252	252	252	252	232	152	2820
NORTHWEST - PEAKING	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTHWEST - NON-FIRM	0	0	0	0	0	0	0	0	0	0	0	0	0
GEOTHERMAL (90% CF)	336	304	336	325	336	325	407	407	429	444	429	444	4522
GAS TURBINES (30% CF)	60	53	58	55	91	84	87	90	84	90	97	103	952
REFINERY PLANTS (75% CF)	100	90	100	97	100	97	100	100	97	100	97	100	1178
HUMBOLDT BAY #3	42	38	42	41	42	41	42	42	41	42	41	42	496
RANCHO SECO	554	500	552	532	542	519	537	537	520	70	0	501	5364
STATE EXTERNAL RESOURCES	127	133	139	101	43	59	77	95	92	63	82	67	1078
DIABLO CANYON	0	0	0	0	0	0	0	0	0	0	0	0	0
CONVENTIONAL THERMAL (85% CF)	4033	3529	3844	3628	4033	4332	4603	4603	4209	3970	3965	4350	49099
TOTAL	6079	5428	5928	5778	6199	6575	7183	7127	6541	5717	5449	6239	74242
MARGIN WITH CONVENTIONAL THERMAL AT 85% MONTHLY CAPACITY FACTOR													
0 MW FORCED OUTAGE	-376	-600	-526	-500	-462	-388	-414	-480	-85	-649	-678	-281	-5439
400 MW FORCED OUTAGE (1)	-629	-829	-779	-745	-715	-633	-667	-733	-329	-902	-923	-534	-8418
739 MW FORCED OUTAGE (2)	-843	-1022	-994	-952	-929	-841	-882	-948	-537	-1116	-1131	-749	-10944

(1) EXPECTED AVERAGE LEVEL OF FORCED OUTAGE ON CONVENTIONAL THERMAL UNITS FOR THE PURPOSE OF ESTIMATING ENERGY MARGINS.

(2) LARGEST CONVENTIONAL THERMAL UNIT ON PG&E SYSTEM IS 739 MW.

AUGUST 9, 1977

EXHIBIT A

1978 LOADS AND RESOURCES
AVERAGE PRECIPATATION OUTLOOK
WITHOUT DIABLO CANYON

	CAPACITY (MEGAWATTS)											
	JAN	FEB	MARCH	APRIL	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC
LOADS AND TRANSFERS (1)	12318	11890	11594	11420	12801	14331	15231	15253	13738	11874	12204	12923
RESOURCES AFTER OVERHAUL												
USABLE AREA HYDRO (2)	4342	4580	4318	4452	5348	5664	5654	5599	5441	4737	5380	5379
N.W. FIRM (USBR)	400	400	400	400	400	400	400	400	400	400	400	400
N.W. PEAKING (BPA & PGE)	0	0	0	0	400	1000	1000	1000	1000	600	0	0
N.W. NON-FIRM	0	0	0	0	0	0	0	0	0	0	0	0
GEOTHERMAL	502	502	502	502	502	502	608	608	663	663	663	663
GAS TURBINES	269	265	261	257	407	387	394	403	390	403	447	461
REFINERY PLANTS	179	179	179	179	179	179	179	179	179	179	179	179
HUMBOLDT BAY #3	63	63	63	63	63	63	63	63	63	63	63	63
RANCHO SECO	903	902	899	895	883	873	875	875	875	0	0	903
STATE EXTERNAL RESOURCES	163	204	209	172	78	101	106	141	139	50	88	63
DIABLO CANYON	0	0	0	0	0	0	0	0	0	0	0	0
CONVENTIONAL THERMAL AVAILABLE	6378	6178	6078	5928	6378	7078	7278	7278	6878	6278	6478	6878
TOTAL	13199	13273	12909	12848	14638	16247	16557	16546	16028	13373	13698	14989
MARGIN, MW	881	1383	1315	1428	1837	1916	1326	1293	2290	1499	1494	2066
%	7.2	11.6	11.3	12.5	14.4	13.4	8.7	8.5	16.7	12.6	12.2	16.0
CONVENTIONAL THERMAL												
TOTAL	7309	7309	7309	7309	7309	7309	7309	7309	7309	7309	7309	7309
SCHEDULED OVERHAUL	900	1100	1200	1350	900	200	0	0	400	1000	800	400
LONG TERM LIMITATIONS	31	31	31	31	31	31	31	31	31	31	31	31
CONVENTIONAL THERMAL AVAILABLE	6378	6178	6078	5928	6378	7078	7278	7278	6878	6278	6478	6878

(1) 100 MW OF INTERRUPTIBLE LOAD INCLUDED.
(2) HYDRO CAPACITY AND ENERGY ARE BASED ON CURRENT ESTIMATES OF RESERVOIR STORAGE AT THE END OF 1977 AND AVERAGE PRECIPATATION IN 1978. IN THE MONTHS OF JANUARY THROUGH MAY AND OCTOBER HYDRO CAPACITY IS NOT FULLY USABLE DUE TO LIMITED ENERGY. USABLE HYDRO CAPACITY CAN BE INCREASED BY PURCHASING ENERGY FROM OUTSIDE AREA SOURCES IF AVAILABLE.

SEPTEMBER 22, 1977

EXHIBIT B

1978 LOADS AND RESOURCES
AVERAGE PRECIPITATION OUTLOOK
WITHOUT DIABLO CANYON

	ENERGY (MILLION KILOWATT HOURS)												
	JAN	FEB	MARCH	APRIL	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
LOADS AND TRANSFERS	6401	5941	6313	6089	6512	6843	7478	7486	6603	6368	6127	6505	78666
RESOURCES AFTER OVERHAUL													
AREA HYDRO	922	1002	1242	1346	1486	1760	2073	2020	1466	1224	1134	1456	17131
NORTHWEST - FIRM	236	208	228	252	252	252	252	252	252	252	232	152	2820
NORTHWEST - PEAKING	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTHWEST - NON-FIRM	0	0	0	0	0	0	0	0	0	0	0	0	0
GEOTHERMAL (90% CF)	336	304	336	325	336	325	407	407	429	444	429	444	4522
GAS TURBINES (30% CF)	60	53	58	55	91	84	87	90	84	90	97	103	952
REFINERY PLANTS (75% CF)	100	90	100	97	100	97	100	100	97	100	97	100	1178
HUMBOLDT BAY #3	42	38	42	41	42	41	42	42	41	42	41	42	496
RANCHO SECO	554	500	552	532	542	519	537	537	520	70	0	501	5364
STATE EXTERNAL RESOURCES	127	133	139	101	43	59	77	95	92	63	82	67	1078
DIABLO CANYON	0	0	0	0	0	0	0	0	0	0	0	0	0
CONVENTIONAL THERMAL (85% CF)	4033	3529	3844	3628	4033	4332	4603	4603	4209	3970	3965	4350	49099
TOTAL	6410	5857	6541	6377	6925	7469	8178	8146	7190	6255	6077	7215	82640
MARGIN WITH CONVENTIONAL THERMAL AT 85% MONTHLY CAPACITY FACTOR													
0 MW FORCED OUTAGE	9	-84	228	288	413	626	700	660	587	-113	-50	710	3974
400 MW FORCED OUTAGE (1)	-244	-313	-25	43	160	381	447	407	343	-366	-295	457	995
739 MW FORCED OUTAGE (2)	-458	-506	-240	-164	-54	173	232	192	135	-580	-503	242	-1531

(1) EXPECTED AVERAGE LEVEL OF FORCED OUTAGE ON CONVENTIONAL THERMAL UNITS FOR THE PURPOSE OF ESTIMATING ENERGY MARGINS.
(2) LARGEST CONVENTIONAL THERMAL UNIT ON PG&E SYSTEM IS 739 MW.

SEPTEMBER 22, 1977

EXHIBIT B

1979 LOADS AND RESOURCES
1978 DROUGHT HYDRO CAPACITY
WITHOUT DIABLO CANYON

	Capacity (Megawatts)	
	July	August
Loads and Transfers (1)	16,339	16,301
Resources After Overhaul		
Usable Area Hydro (2)	4,343	4,249
N.W. Firm (USBR)	400	400
N.W. Peaking (BPA & PGE)	1,000	1,000
N.W. Non-Firm	0	0
Geothermal (3)	908	908
Gas Turbines	394	403
Refinery Plants	179	179
Humboldt Bay #3	63	63
Rancho Seco	875	875
State External Resources	116	117
Diablo Canyon	0	0
Conventional Thermal Available (4)	7,278	7,278
Total	15,556	15,472
Margin, MW	-783	-829
%	-4.8	-5.1

(1) Includes 100 MW of interruptible load.

(2) The same hydro capacity values as for continued drought in 1978. If 1978 runoff approximated 1977 and 1979 runoff approximated 1977, capacity values would be even lower in 1979.

(3) Assumes completion of Units 12, 13, 14 and 15 now under construction.

(4) Assumes continuation of long term limitations and no overhaul during summer.

EXHIBIT C

1979 LOADS AND RESOURCES
LONG TERM AVERAGE HYDRO OUTLOOK
WITHOUT DIABLO CANYON

	Capacity (Megawatts)	
	July	August
Loads and Transfers (1)	16,143	16,130
Resources After Overhaul		
Usable Area Hydro (2)	5,737	5,691
N.W. Firm (USBR)	400	400
N.W. Peaking (BPA & PGE)	1,000	1,000
N.W. Non-Firm	0	0
Geothermal (3)	908	908
Gas Turbines	394	394
Refinery Plants	179	179
Humboldt Bay #3	63	63
Rancho Seco	875	875
State External Resources	116	117
Diablo Canyon	0	0
Conventional Thermal Available (4)	7,278	7,278
Total	16,950	16,914
Margin, MW	807	784
%	5.0	4.9

(1) Includes 100 MW of interruptible load.

(2) From long term average studies by PGandE, no specific study available for continuity between 1978 and 1979.

(3) Assumes completion of Units 12, 13, 14 and 15 now under construction.

(4) Assumes continuation of long term limitations and no overhaul during summer.

EXHIBIT D

7. Contrast above reserve margins with what PGandE's minimum acceptable reserve margin is for 1978 and 1979 under drought and normal rain conditions. Translate all reserve margins to their effect on the probability of loss of load, the probability of blackouts and the probability of brownouts.

RESPONSE:

The attached Tables 1 and 2 show PGandE's reserve requirements for the next two years. A margin of 2215 MW is needed in 1978 and 2712 MW is needed in 1979 with Diablo Canyon in order to have a reliable electric system. This is based on a (Loss of Load Probability) reliability index of 1 day in 10 years which is the most critical criteria.

With Diablo Canyon Unit 1 and a return to average precipitation in 1978 these desired levels of reliability can be achieved. Either without Diablo Canyon Unit 1 or with a continuation of the drought, the desired reliability level cannot be achieved. These conditions indicate a very difficult situation in which actions described in the answer to Question 9 would be required.

In calculation of the reserve requirement using the LOLP method, support from the Southern California Edison system is assumed under a joint pooling of reserve arrangement. The actual amount available will vary, but 600 MW of support is assumed.

The tables indicate that forced outages can exceed the margins on peak days without Diablo Canyon Unit 1. If adequate additional power cannot be purchased or obtained from other sources and the peak demand would exceed the available capacity resources, then the load will have to be reduced to a balanced level by curtailments.

Minimum PGandE operational requirements require a spinning reserve margin equal to the risk of loss of largest single source(whether it be a unit or, transmission line) plus 3 percent of the peak forecasted for each day. In addition, the California Power Pool requires that each member utility carry a minimum spinning reserve equal to 7 percent of the daily peak load.

TABLE 1

REQUIRED RESERVES
WITH DIABLO CANYON

	July 1978	Approximation for July 1979
CALCULATED MARGINS (1)		
"Continued Drought"	878(2)	1377(3)
"Normal"	2386(4)	2967(5)
RESERVE REQUIREMENT(6)		
Reliability Index (1 day in 10 years)	2215	2712
2 largest units	1935	2160
12% of planning load	1827	1935
Governing	2215	2712
RELIABILITY DATA		
Reliability Index (1 day in ___ years) with various levels of reserves, July. Assumes changes from base levels due to changes in perfect capacity.		
2500 MW	30	6
2000 MW	5	1
1500 MW	1	Less than 1
10% of time forced outage will be less than, MW	310	370
25% " " " " " " " " "	480	570
50% " " " " " " " " "	780	990
75% " " " " " " " " "	1330	1570
90% " " " " " " " " "	1750	2090
OPERATING MARGINS CRITERIA		
3% plus largest risk	1523	1590

(1) Calculated margins are taken from the answer to question 5; margins are based on a load which contains 100 MW of interruptible load.
(2) Assumes 1977 runoff in 1978 to estimate hydro capacity.
(3) Assumes same hydro capacity in 1979 as in 1978 drought case.
(4) Assumes average precipitation in 1978 to estimate hydro capacity.
(5) Assumes long term average theortical hydro capacity.
(6) Based on planning load and resources for planning purposes.

TABLE 2

REQUIRED RESERVES
WITHOUT DIABLO CANYON

	July 1978	Approximation for July 1979
CALCULATED MARGINS (1)		
"Continued Drought"	-182(2)	-783(3)
"Normal"	1326(4)	807(5)
RESERVE REQUIREMENTS (6)		
Reliability Index (1 day in 10 years)	1648	1615
2 largest units	1614	1614
12% of planning load	1827	1935
Governing	1827	1935
RELIABILITY DATA		
Reliability Index (1 day in ___ years) with various levels of reserves, July. Assumes changes from base levels due to changes in perfect capacity.		
2500 MW	Greater than 100	Greater than 100
2000 MW	50	50
1500 MW	6	7
10% of time forced outage will be less than, MW	250	250
25% " " " " " " " " "	390	380
50% " " " " " " " " "	610	600
75% " " " " " " " " "	1040	1010
90% " " " " " " " " "	1390	1370
OPERATING MARGINS CRITERIA		
3% plus largest risk	1338	1365

(1) Calculated margins are taken from the answer to question 5; margins are based on a load which contains 100 MW of interruptible load.
(2) Assumes 1977 runoff in 1978 to estimate hydro capacity.
(3) Assumes same hydro capacity in 1979 as in 1978 drought case.
(4) Assumes average precipitation in 1978 to estimate hydro capacity.
(5) Assumes long term average theortical hydro capcity.
(6) Based on planning load and resources for planning purposes.

8. Discuss all the criteria used in arriving at your conclusion regarding what constitutes a minimum acceptable reserve margin.

RESPONSE:

PGandE has three criteria to establish the minimum reserve margins used for planning future system capacity additions. These criteria yield percentage margins generally in the range of 14 to 20 percent at the time of the summer peak.

1. Reliability Criterion: This criterion requires that the future installed reserve capacity margin be sufficient such that random combined system generation forced outages will not exceed the planned resource capacity more often than on one day every ten years. This is the Loss of Load Probability (LOLP) criterion. The method used by PGandE for this criterion is similar to that used by many other utilities throughout the United States. The effect of reserve support available to PGandE over transmission interconnections with southern California utilities is considered in the analysis. This intertie support, which is presently valued as 600 MW, reduces the amount of reserve capacity needed in the PGandE system to maintain the desired degree of reliability.
2. Contingency Criterion: This criterion requires that the planned reserve capacity be equal to or greater than the combined capacity of the two largest generating units or transmission risks in the system.

3. Percentage Criterion: This criterion requires that reserve capacity each month be equal to or greater than 12 percent of the estimated firm peak load for that month.

CONTINGENCY PLANNING

Of the three criteria, the one requiring the largest amount of reserve capacity determines the minimum reserve margin to be used for system planning. Because these criteria do not specifically address future load growth uncertainty and possible delays of new capacity, it is generally prudent to plan for higher reserve capacity than indicated by the minimum criteria. This is particularly so when there is a fairly high degree of uncertainty with respect to future load growth or to completing a significant amount of planned new capacity on schedule. At present, the degree of future uncertainty is high, and because the social and economic costs of power shortages are potentially large, higher reserve margins are being planned through the 1980's than those dictated by the three reserve criteria.

The purpose of the planning reserve criteria is to have reasonable assurance that the future operating system will have a reliable supply of bulk power. Once the system is operational, the minimum acceptable reserve margin is that amount of reserves that allows the system operators to operate the system without interrupting firm load or taking emergency provisions in order to maintain a balance between supply and demand. It is nearly

impossible to determine exactly what this minimum margin should be, but experience indicates that operating a system with less than about 10 to 12 percent margin greatly increases the chances of bulk power outages.

POWER POOL REQUIREMENTS

PGandE, as a member of the California Power Pool*, is required to maintain each day in addition to a spinning reserve margin of 5%, an operating capacity reserve margin of at least 10% of the peak load ("Capacity Resources Requirement"). With respect to this requirement, the California Power Pool Agreement states:

> "The foregoing Capacity Resources Requirement is established as an absolute minimum only and is not intended to be a standard. The Parties recognize that as a matter of good operating practice it will ordinarily be necessary for each of them to provide greater installed reserve generating capacity, but this Agreement does not obligate them to do so."

On this basis, PGandE believes that a 10 percent reserve margin is less than the "minimum acceptable reserve margin". It is noted that without Diablo Unit 1 in operation next summer, the projected reserve margin is only nine percent of the forecasted summer peak if water runoff conditions should return to normal this coming winter and spring. This margin calculation assumes that Humboldt Bay 3 (63 MW) and a new unit at The Geysers (106 MW) will be on-line next summer. It now appears unlikely the Geysers unit will be in service by next summer. Whether the Humboldt Bay nuclear unit is allowed to resume operation is dependent on actions by the Nuclear Regulatory Commission.

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*Other members are the Southern California Edison Company and the San Diego Gas & Electric Company.

Deleting these uncertain resources from the 1978 available capacity drops the projected nine percent reserve margin by about one percent. In order to assure reliable service, PGandE believes that reserve margins next year should be as close as possible to those dictated by the three minimum planning criteria. The response to Question 7 shows the capacity needed to achieve this goal.

In addition to having adequate capacity which is explained above, PGandE has an energy criteria which requires that energy margins exceed one-half the largest unit in each month. This is to insure the area system can "stand alone" and still meet the energy load. Assuming firm energy purchases included as resources and adverse hydroelectric output, without Diablo Canyon Unit 1 this criteria cannot be met in 1978. Consequently the Area System will most likely have to make substantial energy purchases from sources outside the area, if such energy is available.

9(a). At what reserve margin would you expect to institute such emergency measures as voltage reductions, interruptible loads, load shedding, etc.?

RESPONSE

PGandE instituted a voltage reduction plan as part of its energy conservation program on February 8, 1977. It is in effect all of the time. Under this plan, the distribution voltage for residential and commercial customers is regulated normally in the lower half of the 114-126 volt acceptable service voltage band width. PGandE's field tests showed that for residential and commercial loads, a reduction of 1% in the service voltage would reduce the demand and long-term energy requirement by approximately 1%.

PGandE also has an Electric Load Curtailment Plan which would be accomplished in three stages should operating reserves reach critically low levels. These measures would be taken to comply with the objectives of NAPSIC (North American Power Systems Interconnection Committee) Operating Guide No. 9 and "Supplement - Minimum Criteria for Operating Reliability" dated June 1974.

Stage I: Public announcements will be made calling for voluntary customer load deferment. Residential, commercial, and industrial customers will be asked to raise air conditioning thermostat settings to 85°F., defer use of noncritical appliances and utilization equipment, and reduce water use.

Stage I will be implemented when:

1. Spinning reserve is 5% or less of the anticipated daily peak.

2. PGandE is unable to obtain additional power for purchase within the area, throughout California, or from the WSCC (Western Systems Coordinating Council) region.
3. PGandE has utilized its spinning reserve entitlement from the California Power Pool.
4. Reduction in customer load is necessary to maintain a regulating margin.

During the week of September 6-8, 1977, margins in the PGandE area were reduced to the range of 5.0% to 6.6% and Stage I of PGandE's Electric Load Curtailment Plan was implemented at noon on Thursday, September 8, It appears that this appeal resulted in a reduction of about 125 MW on Thursday.

Stage II: Customers will be requested to curtail such uses as residential air conditioning, lighting, and electric hot water heating. Customers will be told rotating outages are imminent unless immediate drastic load curtailment action is taken by all customers. Also, customers will be asked to reduce all water use to critical use levels only in order to reduce energy requirements. Industrial customers served at interruptible rates will be shut off and internal Company usage will be cut to an absolute minimum.

Stage II will be implemented when:

1. The customer actions requested in Stage I have failed to effect significantly the needed load reduction, or
2. The situation has deteriorated substantially and more drastic customer load curtailment is required immediately to avoid rotating outages. It may be

necessary to bypass Stage I entirely and immediately proceed to Stage II.

Stage III will only be implemented if Stages I and II requests for load reduction have not produced the required relief. Action under Stage III is the implementation of PGandE's Involuntary Sequential Circuit Iterruption Plan.

Each of PGandE's distribution circuits has been assigned a block number from 1 to 20, inclusive, with approximately 5% of the load served represented by each block number. Plans have been formulated to manually interrupt "blocks" on a rotating sequence on orders of the System Dispatcher to achieve four levels of capacity and energy reduction -- 5%, 10%, 15% and 20%. Loads served from networks and customers served directly from transmission sources are not interrupted under the sequential plan. However, these customers are expected to reduce their use in the same proportion.

9(b). How frequently would you expect these measures to be implemented if Diablo Canyon is not on-line under (a) drought and (b) normal rain conditions? To what extent would the implementation of these measures reduce the probability of loss of load?

RESPONSE:

The monthly margins forecast for 1978 should the drought continue are shown in the tables in response to Question No. 6. These tables show negative capacity margins for five months and small positive margins of from 0.4% to 6.4% in the remaining months. In the critical summer months of July and August, the margins are negative from -1.2% to -1.5% before any allowance for forced outages. Therefore, if sufficient capacity and

energy cannot be purchased from other utilities outside of northern California (see Question No. 13), some of the load reduction procedures outlined in response to Question No. 9(a) would be required on a fairly regular basis during the year.

The monthly margins forecast for 1978 under average precipitation conditions are significantly improved. However, the margins are still well below the level required for reliable service. Depending upon the frequency of non-simultaneous peaking of possible supplying systems, availability of capacity and energy from other systems, the daily operating conditions, and forced outages of major units and facilities, PGandE would expect to have to implement the emergency load reduction procedures at times during the year.

10. Identify all quantities and sources of purchased power that are presently included in your capacity estimates for the summer of 1978 and 1979 under drought and normal rain conditions.

RESPONSE:

Purchased power by individual sources with associated monthly quantities is shown in the tables provided in answer to Question No. 5 preceding. In some cases the amounts of energy and capacity shown for some agencies do not represent power sold to PGandE. However, the totals shown are entirely used to supply loads in the PGandE northern California control area. The tables show hydroelectric resources under three different assumptions: 1978 drought conditions similar to 1977, 1978 average year

precipitation beginning January 1, 1978, and 1978 long-term average hydro generation without adjustment for the residual effects of the 1977 drought. The change between 1978 and 1979 long-term average hydro generation is shown on the bottom of Table 4 provided in answer to Question No. 5.

11. Provide estimates of any aditional purchased power not previously identified that may be available in the summers of 1978 and 1979 - under drought and normal rain conditions. Identify sources of this power and probability of obtaining it.

RESPONSE:

Several additional sources of purchased power in as yet undefined amounts may be available in the summers of 1978 and 1979. Those potential sources of power most likely to be available would consist of Pacific Northwest surplus energy and thermal electric capacity and energy from southern California or Nevada utilities.

The amounts of Pacific Northwest surplus energy available, primarily from Bonneville Power Administration, would be entirely dependent upon factors being experienced in that area; i.e., precipitation levels, load growth, conservation, and generating unit availability. Even if surplus which is interruptible on short notice is available, PGandE's share of firm intertie transmission line space needed to transport this energy is within 75 MW of full utilization during the on-peak hours from June through mid-October of 1978 and 1979. The effect of surplus energy would be primarily to reduce the off-peak generation

requirements on PGandE's thermal electric plants rather than make additional on-peak power available.

Thermal electric capacity and energy are expected to be available from southern California utilities (Southern California Edison Company, San Diego Gas & Electric Company, and Los Angeles Department of Water and Power) during 1978 and 1979. Tables provided in answer to Question No. 13 of this data request and prepared for the August 5, 1977 Combined Response to the State of California Energy Resources Conservation and Development Commission show energy and capacity margins for a dry year 1978. PGandE would attempt to purchase power available in excess of normal reserve requirements of each of the respective utilities to the extent that additional resources are needed in northern California. Two Nevada utilities, Sierra Pacific Power Company and Nevada Power Company, may also have power available during that period. The availability of this power will be dependent upon many factors. Fuel availability, generating unit capacity factors, overhaul schedules, and availability of hydro are several factors which can influence the help available to the PGandE area from outside its system. Any power purchases from Nevada are also limited by transmission line intertie capabilities. PGandE's 500 kv EHV intertie with Southern California Edison does not, under most situations, limit transfers from southern California utilities. However, internal system problems can seriously restrict the amount of power which can be acquired from other systems and transmitted through the Edison system. Since hydroelectric generation comprises a relatively small

portion of the total resources available to these Nevada and southern California utilities, variances in precipitation will have a lesser effect on their total resource availability.

No firm commitments have as yet been made with any of the southern California utilities regarding the sale of any excess power to PGandE in 1978 or 1979. However, it is reasonable to expect that some power will be available from these utilities in 1978 and possibly 1979. In addition to the question of resource availability and transfer capability, regulatory commissions are showing increasing interest and concern regarding issues relating to fuel logistics and air quality for the exporting region.

PGandE would use its contacts through the Western Systems Coordinating Council, which is comprised of some 42 electric systems, to locate any excess power which might be available.

12. Discuss problems that may affect the reliability of purchased power in the future. Support any concerns you may have based on your past experience with transmission problems, etc.

RESPONSE:

PGandE's backbone transmission system is at 500 kv a-c. PGandE interconnects with the BPA system on the north with two 500 kv lines and with the Southern California Edison Company on the south with three 500 kv lines. Two light capacity 115 kv lines interconnect with the Sierra Pacific Power Company system on the east. These lines constitute PGandE interconnections with other electric utilities in the Western Systems Coordinating Council region.

The "power" purchased from outside the area is "firm" when the buyer and seller have a firm commitment, when seller backs the power schedule with spinning reserve, and the delivery is not interruptible unless there is a failure of the interconnecting facilities. For this kind of service, the receiver pays a capacity charge as well as an energy cost. In contrast, "surplus" energy and "economy" energy sales may be interrupted by the supplier without notice. "Firm" purchases can be treated as the equivalent to a resource within one's own area system. Purchases of interruptible surplus must be covered 100% with spinning reserve by the purchaser.

PGandE shares the capacity of the 500 kv a-c backbone system and the 800 kv d-c system which are identified as the Pacific Intertie with other investor-owned and public-owned systems. In 1978 PGandE will have a firm scheduling capability over the Pacific Intertie from the north of 1,075 MW. PGandE's firm capacity purchases are 1,000 MW. Experience over the past 10 years has shown that the surplus energy from the Pacific Northwest in a given year can exceed 5 billion killowatt-hours. However, in two of the past five years there was no surplus hydro energy available for export from the Pacific Northwest to California.

The three 500 kv a-c lines interconnecting PGandE and Southern California Edison Company have a firm capability of 2,000 MW and a short-time emergency capability of about twice that amount.

There is limited transfer capability through the Southern California Edison system for power which might at times be

available from systems in the southwest to the east of California. During the 1977 year, the maximum transmission capability available PGandE to transmit energy from Nevada Power Company through the Edison system was 150 MW. This transmission service was interruptible without notice.

PGandE's interconnection with Sierra Pacific has a firm capability of 108 MW with power flow from west to east. The power transfer capability from east to west is largely governed by the hydro generation on PGandE's Yuba-Bear hydro project and may be limited to less than the west-east capability. PGandE has a firm contractual obligation of 108 MW to Sierra Pacific. Sierra Pacific has no firm obligation to sell power to PGandE. However, because PGandE is a summer peaking system and Sierra Pacific a winter peaking system, there are times when Sierra Pacific may have as much as 75 MW of capacity with associated energy available for sale to PGandE.

The operating coordination and good communications which exist among systems in the WSCC region have made it possible for PGandE to purchase limited amounts of both capacity and energy from systems two or more control areas removed from the PGandE system for potential replacement of the energy lost because of the poor hydro year in northern and central California or the loss caused by the delay in operation of a major base load unit. It is also to be remembered that the farther the load is from a resources, the more susceptible to interruption because of forced outages of resources of intervening facilities and system management problems on intervening systems.

The major electric utilities in California have become increasingly dependent on power imported from both the Pacific Northwest (hydro) and the Southwest (coal). This dependence has required extensive cooperation and coordination among California systems in establishing power transfer capabilities of EHV transmission ties. It has also required adoption of scheduling and operating policies intended to prevent blackouts such as occurred in the Northeast United States in November 1965, the blackout of ConEd on July 13 and 14, 1977, several failures of the Florida systems, and the most recent loss of 8,000 MW of customer load on the Hydro Quebec system in Canada on September 20, 1977. The coordination of protective features and the spinning reserve practices of the California electric utilities have contributed greatly to the level of bulk system reliability enjoyed by PGandE's and other California electric utility customers. Loss of incoming power in 1978 at times approaching peak conditions will pose a considerable threat to the reliability of the bulk system without Diablo Canyon No. 1 in service.

13. Provide latest estimates of projected capacity, peak demands, and reserve margins for the summers of 1978 and 1979 for:

    a. SDG&E, SCE, and LADW&P, and

    b. Any other major sources of potential power. For each utility system identified, provide estimates under (a) drought condition and (b) normal rain.

RESPONSE:

a. Tables are attached showing (energy and capacity) loads and resources for 1978 under a continuation of the drought for

SCE ENERGY AND FUEL REPORT

1978 ADVERSE CONDITIONS

LOAD - GWH	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1. Energy for Load	5,445	4,884	5,377	5,245	5,455	5,530	5,992	6,080	5,635	5,549	5,294	5,593	66,079
RESOURCES - GWH													
2. Hydro	200	207	246	276	286	432	418	370	307	262	249	274	3,527
3. Northwest													
a. Firm	0	0	0	0	0	0	0	0	0	0	0	0	0
b. Non-Firm	0	0	0	0	0	0	0	0	0	0	0	0	0
c. Total NW	0	0	0	0	0	0	0	0	0	0	0	0	0
4. Coal	874	791	741	731	674	847	874	874	773	461	647	814	9,101
5. Nuclear	223	201	223	216	223	216	0	92	216	223	216	223	2,272
6. Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0
7. Other Receipts	358	307	353	343	345	272	293	272	239	337	329	361	3,809
8. Total Available Before G & O	1,655	1,506	1,563	1,566	1,528	1,767	1,585	1,608	1,535	1,283	1,441	1,672	18,709
9. Gas & Oil Generation													
a. Capability	4,486	4,020	4,454	4,638	4,522	4,682	5,245	5,345	4,944	5,130	4,746	4,809	57,021
b. Requirement for Load	3,790	3,378	3,814	3,679	3,927	3,763	4,407	4,472	4,100	4,266	3,853	3,921	47,370
c. Margin	696	642	640	959	595	919	838	873	844	864	893	888	9,651
d. Margin %	12.8	13.1	11.9	18.3	10.9	16.6	14.0	14.4	15.0	15.6	16.9	15.9	14.6

7-25-77

SCE CAPACITY REPORT

1978 ADVERSE CONDITIONS

LOADS - MW	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1. Peak Demand	9,912	9,322	9,222	9,192	9,632	10,202	11,652	12,012	11,272	10,592	9,932	10,322
RESOURCES - MW												
2. Total Hydro	1,583	1,542	1,448	1,481	1,512	1,503	1,463	1,451	1,435	1,428	1,417	1,432
3. Northwest	550	550	550	550	650	650	650	650	650	650	550	550
4. Coal	1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653
5. Nuclear	349	349	349	349	349	349	349	349	349	349	349	349
6. Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
7. Other	301	301	301	301	307	307	307	307	307	307	301	301
8. Total Available Before G & O	4,436	4,395	4,301	4,334	4,471	4,462	4,422	4,410	4,394	4,387	4,270	4,285
9. Gas & Oil	9,827	9,827	9,827	10,076	10,049	10,049	10,049	10,283	10,283	10,283	10,325	10,325
10. Total Capability	14,263	14,222	14,128	14,410	14,520	14,511	14,471	14,693	14,677	14,670	14,595	14,610
11. Margin - Before Maintenance												
a. Resources - Peak Demand	4,351	4,900	4,906	5,218	4,888	4,309	2,819	2,681	3,405	4,078	4,663	4,288
b. % of Monthly Peak	43.9	52.6	53.2	56.8	50.7	42.2	24.2	22.3	30.2	38.5	46.9	41.5
12. Scheduled Maintenance	1,736	1,390	1,855	1,867	2,131	892	349	349	1,188	1,521	1,273	975
13. Available Capacity Resources	12,527	12,832	12,273	12,543	12,389	13,619	14,122	14,344	13,489	13,149	13,322	13,635
14. Margin - After Maintenance												
a. Available Capacity - Peak Demand	2,615	3,510	3,051	3,351	2,757	3,417	2,470	2,332	2,217	2,557	3,390	3,313
b. % of Monthly Peak	26.4	37.7	33.1	36.5	28.6	33.5	21.2	19.4	19.7	24.1	34.1	32.1

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7-29-77

SAN DIEGO GAS & ELECTRIC COMPANY

1978 ADVERSE CONDITIONS

NAME		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL TOTAL
LOAD														
1. TOT ENERGY FOR LOAD (1)	GWH	940	843	903	817	838	843	925	997	882	912	935	976	10811
RESOURCES														
2. TOTAL HYDRO (2)	GWH	1	1	0	1	1	1	1	1	0	0	0	0	7
3. NORTHWEST														
A. FIRM	GWH	29	27	30	29	30	29	-29	29	29	29	29	30	349
B. NON-FIRM	GWH	0	0	0	0	0	0	0	0	0	0	0	0	0
C. TOTAL	GWH	29	27	30	29	30	29	29	29	29	29	29	30	349
4. COAL	GWH	0	0	0	0	0	0	0	0	0	0	0	0	0
5. NUCLEAR	GWH	56	50	56	54	56	54	0	24	54	56	54	56	570
6. GEOTHERMAL	GWH	0	0	0	0	0	0	0	0	0	0	0	0	0
7. OTHER RECEIPTS	GWH	12	10	12	10	18	12	10	9	9	15	32	27	176
8. TOTAL AVAIL BEFORE G & O	GWH	98	88	98	94	105	96	40	63	92	100	115	113	1102
9. G & O GEN														
A. CAP (3)	GWH	956	846	939	865	867	889	996	1017	914	1027	984	1065	11365
B. REQ FOR LOAD	GWH	842	755	805	723	733	747	885	934	790	812	820	863	9709
C. ENERGY MARGIN	GWH	114	91	134	142	134	142	111	83	124	215	164	202	
D. PLANNED	GWH	842	755	805	723	733	747	885	934	790	812	820	863	9709
E. TRANSFERS	GWH	0	0	0	0	0	0	0	0	0	0	0	0	0

NOTES: (1) Includes area system and off-system requirements
(2) Oroville
(3) After scheduled maintenance

7-27-77

SAN DIEGO GAS & ELECTRIC COMPANY
CAPACITY REPORT

1978 ADVERSE CONDITIONS

NAME	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
LOADS												
1. TOTAL PEAK DEMANDS - MW												
A. AREA SYS	1707	1638	1621	1603	1532	1723	1819	1915	1877	1679	1715	1805
B. OTHER	4	4	4	4	4	4	4	4	4	4	4	4
C. TOTAL	1711	1642	1625	1607	1536	1727	1823	1919	1881	1683	1719	1809
RESOURCES												
2. CALIFORNIA HYDRO - MW	28	27	5	5	5	5	5	5	5	5	5	5
3. NORTHWEST HYDRO - MW	112	112	112	112	112	112	112	112	112	112	112	112
4. COAL - MW	0	0	0	0	0	0	0	0	0	0	0	0
5. NUCLEAR - MW	88	98	88	88	88	88	88	88	88	88	88	88
6. GEOTHERM - MW	0	0	0	0	0	0	0	0	0	0	0	0
7. OTHER - MW	-10	-10	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9
8. TOTAL AVAIL BEFORE GAS AND OIL - MW	218	217	196	196	196	196	196	196	196	196	196	196
9. GAS AND OIL - MW	1954	1954	1954	1911	1911	1920	1914	1912	1878	2179	2243	2246
10. TOTAL RESOURCES- MW	2172	2171	2150	2107	2107	2116	2110	2108	2074	2375	2439	2442
11. MARGIN BEFOR SCHEDULED MAINTENANCE												
A. - MW	461	529	525	500	571	389	287	189	193	692	720	633
B. - %	26.9	32.2	32.3	31.1	37.2	22.5	15.7	9.8	10.3	41.1	41.9	35.0
12. SCHEDULED MAINT - MW	162	162	307	307	240	20	88	88	0	84	218	20
13. AVAILABLE RESOURCES - MW	2010	2009	1843	1800	1867	2096	2022	2020	2074	2291	2221	2422
14. MARGIN AFTER SCHEDULED MAINTENANCE												
A. - MW	299	367	218	193	331	369	199	101	193	608	502	613
B. - %	17.5	22.4	13.4	12.0	21.5	21.4	10.9	5.3	10.3	36.1	29.2	33.9

NOTE: (1) Silver Gate 2 repowering begins November 1977
(2) San Onofre refueling begins July 1978
(3) Encina 5 commercial operation October 1978

Table 1

Los Angeles Department of Water and Power

1978 Adverse Conditions

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
LOADS (GWH)													
1. Total Energy for Load	1739	1581	1715	1662	1741	1794	1967	1983	1829	1811	1704	1814	21340
RESOURCES (GWH)													
2. Total Hydro	58	44	74	130	138	78	51	51	39	44	59	64	830
3. Total Northwest	0	0	0	0	0	0	0	0	0	0	0	0	0
4. Coal	492	370	397	397	492	476	492	492	476	410	305	397	5196
5. Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0
6. Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0
7. Other Receipts	0	0	0	0	0	15	15	15	0	0	0	0	45
8. Total Avail. before G.&O.	550	414	471	527	630	569	558	558	515	454	364	461	6071
9. G.&O. Generation													
A. Cap. after Maint. (1) (2)	1749	1470	1686	1637	1745	1904	1983	2188	2118	1994	1759	1891	22124
B. Req. for Load	1189	1167	1244	1135	1111	1225	1409	1425	1314	1357	1340	1353	15269
C. Energy Margin	560	303	442	502	634	679	574	763	804	637	419	538	6855
D. Energy Margin (%)	32.2	19.2	25.8	30.2	36.4	37.8	29.2	38.5	44.0	35.2	24.6	29.7	32.1
E. Planned	1189	1167	1244	1135	1111	1225	1409	1425	1314	1357	1340	1353	15269
F. Transfers	0	0	0	0	0	0	0	0	0	0	0	0	0

(1) Includes Scattergood Unit 3 (284 mw) during August and September when natural gas is assumed to be available.
(2) A capacity factor of 90% after scheduled maintenance is used.

7-20-77

LOS ANGELES DEPARTMENT OF WATER AND POWER
CAPACITY REPORT IN MW AND PERCENT
1978 ADVERSE CONDITIONS

TABLE 2

OADS	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1. PEAK DEMAND - MW	3074	2994	2967	2932	3047	3418	3967	4090	3874	3406	3165	3205
ESOURCES(UNITS IN MW OR %)												
2. TOTAL HYDRO(1)	455	351	446	530	576	563	728	724	772	543	471	475
3. NORTHWEST(1)	200	150	100	100	100	200	300	300	200	0	100	150
4. COAL	866	866	866	866	866	866	866	866	866	866	866	866
5. NUCLEAR	0	0	0	0	0	0	0	0	0	0	0	0
6. GEOTHERMAL	0	0	0	0	0	0	0	0	0	0	0	0
7. OTHER	0	0	0	0	0	-75	-75	-75	0	0	0	0
8. TOTAL AVAILABLE BEFORE G&D	1521	1367	1412	1496	1542	1554	1819	1815	1838	1409	1437	1491
9. GAS AND OIL(3)	2984	2984	2984	2984	2984	2984	2984	3268	3268	2984	2984	2984
10. TOTAL CAPACITY	4505	4351	4396	4480	4526	4538	4803	5083	5106	4393	4421	4475
11. MARGIN BEFORE MAINTENANCE												
A. RESOURCES - PEAK DEMAND	1431	1357	1429	1548	1479	1120	836	993	1232	987	1256	1270
B. PERCENT OF MONTHLY PEAK FOR LINE 11A	47	45	48	53	49	33	21	24	32	29	40	40
12. SCHEDULED MAINTENANCE(2)	851	765	613	607	767	344	0	0	183	341	505	343
13. AVAILABLE CAPACITY RESOURCES	3654	3586	3783	3873	3759	4194	4803	5083	4923	4052	3916	4132
14. MARGIN AFTER MAINTENANCE												
A. AVAILABLE CAPACITY - PEAK DEMAND	580	592	816	941	712	776	836	993	1049	646	751	927
B. PERCENT OF MONTHLY PEAK FOR LINE 14A	19	20	28	32	23	23	21	24	27	19	24	29
C. AVAILABLE CAPACITY - ANTICIPATED PEAK FORCED OUTAGES - PEAK DEMAND	297	150	276	442	234	254	138	137	184	-78	107	29
D. PERCENT OF MONTHLY PEAK FOR LINE 14C	10	5	9	15	8	7	3	3	5	-2	3	1
E. AVAILABLE CAPACITY - ANTICIPATED AVG. FORCED OUTAGE - AVG. DAILY PEAK	1008	984	1239	1401	1226	1138	1299	1206	1420	916	783	675
F. PERCENT OF MONTHLY PEAK FOR LINE 14E	33	33	42	48	40	33	33	29	37	27	25	21

(1) TOTAL USABLE CAPACITY FOR CARRYING LOAD. ADDITIONAL CAPACITY NOT REFLECTED IN THESE FIGURES AVAILABLE FOR USE TO MEET SPINNING RESERVE REQUIREMENTS AND TO ALLOW MAINTENANCE WORK TO BE PERFORMED WITHOUT DIMINISHING FIGURES SHOWN.
(2) EXCLUDES PACIFIC HVDC INTERTIE, CASTAIC, AND LADHP HOOVER UNITS AND OTHER HYDRO.
(3) INCLUDES SCATTERGOOD UNIT 3 (284 MW) DURING AUGUST AND SEPTEMBER WHEN NATURAL GAS IS ASSUMED TO BE AVAILABLE.

DES:07/19/77

Southern California Edison Company, San Diego Gas & Electric Company, and Los Angeles Department of Water and Power. These tables are the same as those provided as part of the August 5, 1977 combined response to the State of California Energy Resources Conservation and Development Commission. Since hydro is a relatively small proportion of the total resources of the major southern California utilities, normal precipitation conditions would not cause an appreciable change in margins.

b. Refer to the response to Question No. 11.

14. Provide a complete economic analysis showing what it will cost PGandE and its rate payers with and without the Diablo Canyon unit being operational in 1978 and 1979. Express cost on a monthly basis -- show complete analysis.

Factors to consider include:

a. incremental production costs (WASP)

b. incremental capital costs (capital charges on replacement power, higher cost for Diablo Canyon.)

c. incremental gas and oil consumption

d. incremental pollutants.

The above analysis should provide cost estimates assuming (a) drought and (b) normal rain.

RESPONSE

This information will be provided later.

15. Submit copies of:

a. PGandE's latest Annual Report to Stockholders.

b. PGandE's latest annual report to the Federal Power Commission, Form No. 1 and Form No. 12.

RESPONSE:

Copies of the above reports accompany these responses.

16. What was 1976 and 1977 (either calendar or water year; whatever was used in your study) runoff, as it pertains to hydro capacity? Express in both units (acre-feet, cfs, etc.) and as percent of normal.

RESPONSE:

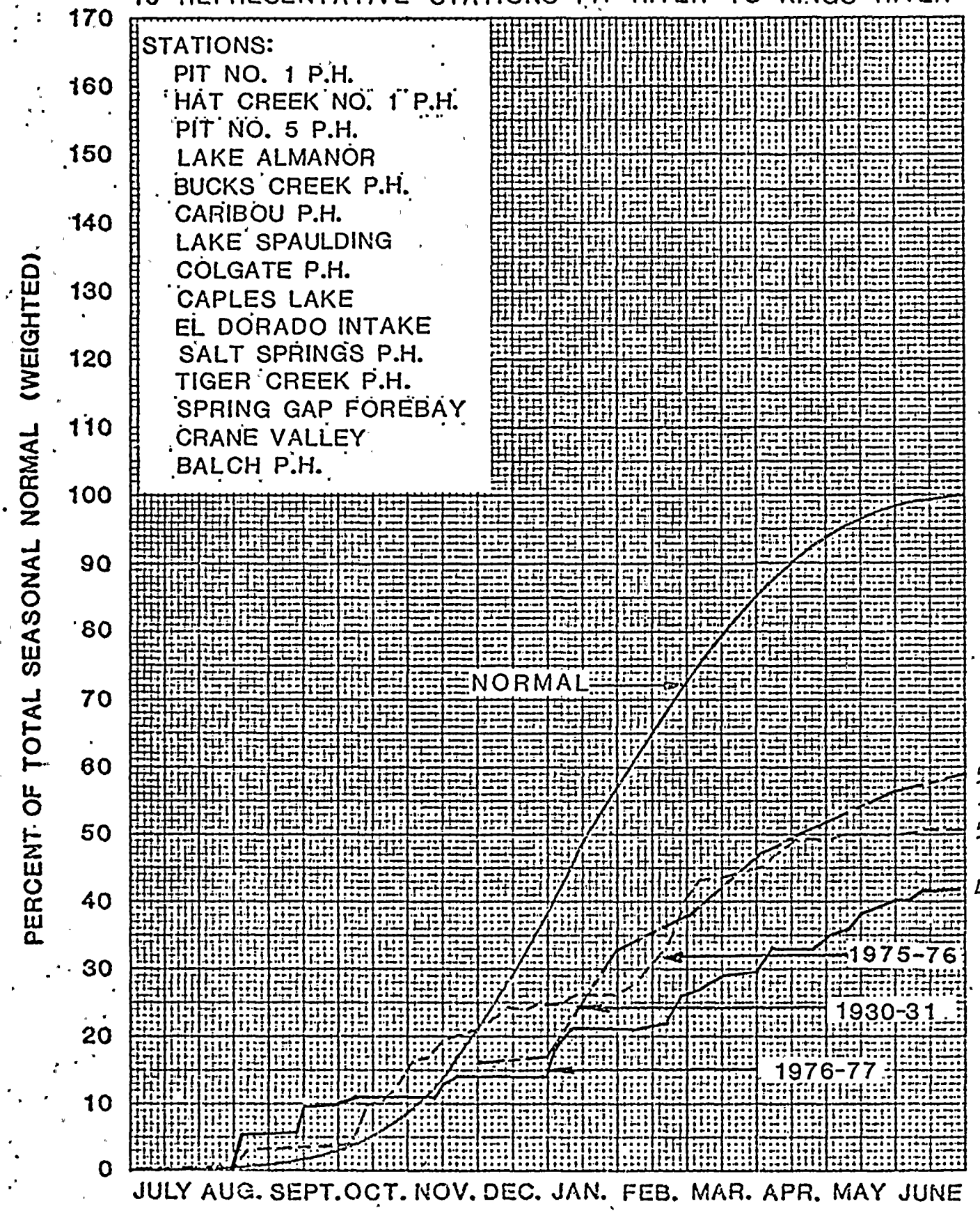
Precipitation at 15 representative stations throughout the PGandE area weighted for the hydro generation potential from the resulting runoff was:

1976 water year - 51% of normal
1977 water year - 42% of normal

The attached graph shows the monthly accumulation of the runoff potential for the above water years as well as the normal and for the 1931 dry year.

ACCUMULATED PRECIPITATION FOR SEASON IN PERCENT OF SEASONAL TOTAL AND WEIGHTED FOR HYDRO POTENTIAL

15 REPRESENTATIVE STATIONS PIT RIVER TO KINGS RIVER



WEIGHTED PRECIPITATION P.G.&E.

PG & E CO. HYDRO-ELECTRIC SYSTEM

SEASON 1976-1977

17. What was net reduction in hydro capacity in 1976 and 1977?

RESPONSE:

The 1976 hydro capacity in the PGandE area approached being normal since reservoirs were at about normal storage levels at the beginning of the year. As the year developed, energy production was less than normal. As the dry spell continued into 1977, major storage reservoirs were drawn down for irrigation and other uses. The capacity available from variable head generating units became severely limited and in some cases plants had to be shut down. These actions reduced the hydro capacity available in July 1977 to 5,019 mw, which is 738 mw less than would have been available in a normal year.

18. What is present (1/78) hydro capacity in:

a. PGandE Service Area?
b. California?
c. Pacific Northwest?
d. Beyond?

RESPONSE:

a. & b. Refer to the tables provided in response to Question No. 5. All hydro capacity shown is located in the PGandE northern California control area.

c. 1,000 mw of peaking capacity is purchased from Bonneville Power Administration and Portland General Electric Company in the Pacific Northwest.

d. None available to PGandE.

19. What would be the net reduction in hydro capacity if 1977 runoff repeated in 1978?

RESPONSE:

The reduction in usable hydro capacity from 1977, assuming 1977 runoff reoccurs in 1978, would be approximately 676 mw at the time of the July peak.

20. What would be effect on hydro capacity if normal runoff occurs in 1978?

RESPONSE:

If normal precipitation occurs in 1978, the usable hydro capacity at the time of the July peak will increase approximately 635 mw over July 1977.

21. What was 1976 and 1977 precipitation in comparison to normal for those areas which affect hydro capacity?

RESPONSE:

1976 seasonal precipitation was 54% of normal.
1977 seasonal precipitation was 44% of normal.

The attached table shows precipitation for 1976, 1977, and normal at nineteen representative stations on PGandE's hydro generation watersheds.

SEASONAL (JULY 1 TO JUNE 30) PRECIPITATION IN INCHES
AT REPRESENTATIVE LOCATIONS

Watershed	Station	1940-70 Normal	1975-76 Season	Percent of Normal	1976-77 Season	Percent of Normal
Pit-McCloud	Pit No. 1	20.02	8.78	44	10.86	54
	Hat Creek	18.98	9.73	51	10.91	57
	Pit No. 5	74.27	37.37	50	23.66	32
Feather River	Lake Almanor	39.97	19.76	49	15.14	38
	Bucks Creek Powerhouse	68.05	33.74	50	23.62	35
	Caribou Powerhouse	42.21	21.04	50	14.69	35
North Yuba	Colgate	40.95	20.71	51	15.13	37
South Yuba	Lake Spaulding	69.55	34.88	50	29.63	43
American River	Caples Lake	51.13	29.14	57	26.47	52
	El Dorado Intake	42.19	27.90	66	19.87	47
Mokelumne River	Salt Springs	45.40	25.67	57	22.82	50
	Tiger Creek	46.92	22.54	48	19.90	42
Stanislaus River	Spring Gap F.B.	42.17	22.43	53	19.46	46
San Joaquin River	Crane Valley Reservoir	40.30	21.51	53	17.49	43
	Huntington Reservoir	33.29	27.00	81	21.90	66
Kings River	Wishon Dam	46.58	20.70	44	19.30	41
	Balch Powerhouse	29.64	16.44	55	15.97	54
	Fresno	10.24	8.24	80	7.65	75
Kern River	Bakersfield	5.72	4.85	85	4.95	87
	Average	40.40	21.71	54	17.86	44

22. What precipitation would be needed in 1978 to maintain hydro capacity in present status? Express as percent of normal and as inches.

RESPONSE:

As shown in the answers to Questions No. 4 and No. 5, a repeat of 1977 dry year in 1978 will reduce hydroelectric potential in the PGandE area below that available in 1977 whereas average year precipitation during 1978 would increase the hydroelectric potential above that experienced during 1977. To maintain hydro capacity at current greatly reduced levels, precipitation slightly below normal will be required. Any attempt to determine the exact amount of precipitation required would involve considerable speculation and several iterations in order to approach an answer. Many variables which are dependent upon actions by other agencies can greatly effect the answer. State and federal reservoir releases for irrigation, municipal uses, water quantity control, Fish and Game requests for water temperature control and spawning requirements, end-of-year reservoir storage carryover, and State aqueduct water deliveries to southern California are typical factors affecting the generation potential of the large hydroelectric facilities in the PGandE area.

These and other factors are still being addressed for the current year. Possible actions to be taken in 1978 under various conditions cannot reasonably be forecast at this time.

23. What is your best estimate, and its basis, of the probability of precipitation in 1978 being less than or equal to:

a. 1977?
b. 1976?
c. The estimate of precipitation requested in previous question?
d. Normal?

RESPONSE:

PGandE does not have a 1978 precipitation estimate. Little if any skill has been achieved in the prediction of precipitation amounts for periods longer than three to five days. Therefore, it is impossible to predict the precipitation for 1978. These conclusions are supported by the "Policy Statement of the American Meteorological Society of Weather Forecasting."

Respectfully submitted this 26th day of September, 1977.

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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
	)	
PACIFIC GAS AND ELECTRIC COMPANY	)	Docket Nos. 50-275-OL
	)	50-323-OL
Units 1 and 2	)	
	)	
Diablo Canyon Site	)	
	)	

CERTIFICATE OF SERVICE

The foregoing document(s) of Pacific Gas and Electric Company has (have) been served today on the following by deposit in the United States mail, properly stamped and addressed:

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Date: September 26, 1977