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Cogeneration and Small Power Production Quarterly Report

Donated By:
Herbert Rogers Jr.
Rogers Engineering Co.

Fourth Quarter
1983

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PACIFIC GAS AND ELECTRIC COMPANY

COGENERATION

and

SMALL POWER PRODUCTION

QUARTERLY REPORT

to the

CALIFORNIA PUBLIC UTILITIES COMMISSION

FOURTH QUARTER
1983

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SUMMARY OF ACTIVITY

At the end of 1983, the number of signed contracts and letter agreements for cogeneration and small power production projects was 305, with a total estimated nominal capacity of 2,389 MW. Of these totals, 202 projects, capable of producing 566 MW, are operational (Table A). A map indicating the location of operational facilities under contract with PGandE is provided as Figure A.

Developers of cogeneration, solid waste, or biomass projects had signed 101 contracts with a potential of 1,408 MW. In total, 106 contracts and letter agreements had been signed with projects capable of producing 1,479 MW. PGandE also had under active discussion 29 cogeneration projects that could generate a total of 402 MW to 444 MW, and 13 solid waste or biomass projects with a potential of 84 MW to 89 MW.

One contract had been signed for a geothermal project, capable of producing 80 MW.

There were 7 solar projects with signed contracts and a potential of 37 MW, as well as 3 solar projects under active discussion for 31 MW.

Wind farm projects under contract numbered 28, with a generating capability of 618 MW. Also, discussions were being conducted with 14 wind farm projects, totaling 365 MW. There were 100 wind projects of 100 kW or less with signed contracts and a potential of 1 MW, as well as 8 other small wind projects under active discussion.

There were 59 hydroelectric projects with signed contracts and a potential of 146 MW, as well as 72 projects under active discussion for 169 MW. In addition, there were 31 hydroelectric projects, with a nominal capacity of 185 MW, that PGandE was planning to construct.

Table B displays the above information. In tabular form, in Appendix A, are status reports of the projects as of December 31, 1983.

TABLE A
SUMMARY OF
OPERATIONAL PROJECTS UNDER CONTRACT
FOURTH QUARTER 1983

<u>Project Type</u>	<u>Number of Projects</u>	<u>kW</u>
Cogeneration/Solid Waste/Biomass	45	315,689
Geothermal	0	0
Solar (greater than 100 kW)	1	2,000
Solar (100 kW or less)	1	4
Wind (greater than 100 kW)	16	154,330
Wind (100 kW or less)	98	980
Hydroelectric (greater than 100 kW)	25	84,875
Hydroelectric (100 kW or less)	14	588
Other	<u>2</u>	<u>7,900</u>
TOTAL	<u>202</u>	<u>566,366 kW</u>

TABLE B
SUMMARY OF PROJECTS
FOURTH QUARTER
1983

<u>Projects With Signed Contracts*</u>	<u>Number of Projects</u>	<u>kW</u>
Cogeneration/Solid Waste/Biomass	101	1,407,908
Geothermal	1	80,000
Solar (greater than 100 kW)	4	36,500
Solar (100 kW or less)	3	9
Wind (greater than 100 kW)	28	618,355
Wind (100 kW or less)	100	1,084
Hydroelectric (greater than 100 kW)	39	144,455
Hydroelectric (100 kW or less)	20	1,078
Other	<u>3</u>	<u>8,400</u>
TOTAL	<u>299</u>	<u>2,297,789 kW</u>
<u>Projects With Signed Letter Agreements</u>		
Cogeneration/Solid Waste/Biomass	5	70,900
Other	<u>1</u>	<u>20,000</u>
TOTAL	<u>6</u>	<u>90,900 kW</u>
<u>PGandE-Owned Projects</u>		
PGandE-Owned	<u>3</u>	<u>6,203</u>
GRAND TOTAL	<u>308</u>	<u>2,394,892 kW</u>

* Includes operational projects.

TABLE B

(Continued)

SUMMARY OF PROJECTS
FOURTH QUARTER
1983

<u>Projects Under Active Discussion</u>	<u>Number of Projects</u>	<u>kW Range</u>
Cogeneration	29	401,790 - 444,290
Solid Waste/Biomass	13	84,295 - 89,295
Solar (greater than 100 kW)	2	31,000
Solar (100 kW or less)	1	2
Wind (greater than 100 kW)	14	365,330
Wind (100 kW or less)	8	55
Hydroelectric (greater than 100 kW)	63	168,095
Hydroelectric (100 kW or less)	9	461
Hydroelectric Projects Planned to be Constructed by PGandE	31	185,300
TOTAL	<u>170</u>	<u>1,236,328 - 1,283,828 kW</u>

ENERGY PURCHASE PRICES

PGandE has published the prices that it will pay for electric energy received from qualified cogeneration and small power production facilities, from January 1984 through April 1984, in the Company's "Announcement for Cogenerators and Small Power Producers for Energy Prices Effective January 1 - April 30, 1984" (Appendix B).

PGandE updates these prices every three months. The prices depend on the costs PGandE avoids by purchasing energy from these facilities. An explanation of PGandE's energy purchase prices is provided in the announcement.

Table C shows PGandE's energy purchase prices from February 1980 through April 1984.

FIRM CAPACITY PRICE - STANDARD OFFER #2

Based on the California Public Utilities Commission (CPUC) Decision 83-12-068 (dated December 22, 1983), a new firm capacity price schedule for Standard Offer #2 (Table E) became effective January 1, 1984. The specific firm capacity price applicable to a given Qualifying Facility is a function of the date the Qualifying Facility begins firm capacity deliveries and the length of time the Qualifying Facility agrees to deliver firm capacity.

This same CPUC decision is the basis for the following allocation factors which also became effective on January 1, 1984:

Seasonal Period A (May-September)	.18540
Seasonal Period B (October-April)	.01043

These revised allocation factors are used to convert the annual firm capacity prices (Table E) to monthly payments by seasonal period of delivery under Standard Offer #2 (Option 2) and Standard Offer #4. These revised allocation factors are applicable to all firm capacity contracts, regardless of when the contract was signed.

AS-DELIVERED CAPACITY PRICE

The annual as-delivered capacity price that will form the basis of as-delivered capacity payments for deliveries between January 1, 1984 and December 31, 1984 is \$156 per kW-year. This figure is based upon the economic assumptions adopted by the CPUC in Decision 83-12-068 (dated December 22, 1983).

Table F indicates the prices in cents per kilowatt hour for as-delivered capacity, using the 1984 price of \$156/kW-year, adjusted for losses at the transmission and distribution level.

TABLE C

PACIFIC GAS AND ELECTRIC COMPANY

PURCHASE PRICES (¢/kWh) FOR ENERGY FROM QUALIFYING FACILITIES
FEBRUARY 1980 THROUGH APRIL 1984

<u>Seasonal Period*</u>	<u>Time of Delivery Basis**</u>			<u>Average</u>
	<u>On-Peak</u>	<u>Partial-Peak</u>	<u>Off-Peak</u>	<u>Basis</u>
				<u>All kWh</u>
<u>Period B</u>				
February '80 thru April '80	4.496	4.250	3.794	4.121
<u>Period A</u>				
May '80 thru July '80	5.675	5.459	4.700	4.994
August '80 thru September '80	6.100	5.868	5.052	5.368
<u>Period B</u>				
October '80	5.858	5.536	4.943	5.368
November '80 thru January '81	6.226	5.884	5.254	5.706
February '81 thru April '81	6.580	6.219	5.553	6.030
<u>Period A</u>				
May '81 thru July '81	7.783	7.487	6.446	6.850
August '81 thru September '81	8.072	7.765	6.685	7.104
<u>Period B</u>				
October '81	7.752	7.326	6.542	7.104
November '81 thru January '82	7.725	7.302	6.519	7.080
February '82 thru April '82	7.759	7.334	6.548	7.111
<u>Period A</u>				
May '82 thru July '82	6.397	6.102	5.895	6.178
August '82 thru September '82	5.967	5.692	5.499	5.641
<u>Period B</u>				
October '82	6.049	5.912	5.769	5.854
November '82 thru January '83	6.049	5.912	5.769	5.854
February '83 thru April '83	6.209	6.068	5.922	6.009

* Seasonal Period A comprises the months of May through September, and
Seasonal Period B comprises the months of October through April.

** Time periods are defined in Table D.

TABLE C
(continued)

PACIFIC GAS AND ELECTRIC COMPANY

PURCHASE PRICES (¢/kWh) FOR ENERGY FROM QUALIFYING FACILITIES
FEBRUARY 1980 THROUGH APRIL 1984

<u>Seasonal Period*</u>	<u>Time of Delivery Basis**</u>			<u>Average</u>
	<u>On-Peak</u>	<u>Partial-Peak</u>	<u>Off-Peak</u>	<u>Basis</u> <u>All kWh</u>
<u>Period A</u>				
May '83 thru July '83	6.108	5.826	5.629	5.774
August '83 thru September '83	6.175	5.891	5.691	5.838
<u>Period B</u>				
October '83	6.261	6.118	5.790	6.059
November '83 thru December '83	6.265	6.123	5.975	6.063
January '84 thru April '84	8.371	8.002	6.166	7.110

* Seasonal Period A comprises the months of May through September, and Seasonal Period B comprises the months of October through April.

** Time periods are defined in Table D.

TABLE D¹

PACIFIC GAS AND ELECTRIC COMPANY

TIME PERIODS

	<u>Monday through Friday²</u>	<u>Saturdays²</u>	<u>Sundays and Holidays</u>
<u>Seasonal Period A</u> (May 1 through September 30)			
On-Peak	12:30 p.m. to 6:30 p.m.		
Partial-Peak	8:30 a.m. to 12:30 p.m. 6:30 p.m. to 10:30 p.m.	8:30 a.m. to 10:30 p.m.	
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	All Day
<u>Seasonal Period B</u> (October 1 through April 30)			
On-Peak	4:30 p.m. to 8:30 p.m.		
Partial-Peak	8:30 p.m. to 10:30 p.m. 8:30 a.m. to 4:30 p.m.	8:30 a.m. to 10:30 p.m.	
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	All Day

¹ This table is subject to change to accord with the on-peak, partial-peak, and off-peak period as defined in PGandE's own rate schedules for the sale of electricity to its large industrial customers.

² Except the following holidays: New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day and Christmas Day, as specified in Public Law 90-363 [5 U.S.C.A. Section 6103(a)].

TABLE E
PACIFIC GAS AND ELECTRIC COMPANY
FIRM CAPACITY PRICE SCHEDULE
(Levelized \$/kW-Year)
STANDARD OFFER #2
EFFECTIVE JANUARY 1, 1984

Actual Operation Date (Year)	Term of Agreement																	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	20	25	30
1983	72	111	96	88	84	85	88	91	93	96	98	100	102	104	106	115	122	128
1984	156	111	95	88	89	92	95	98	100	103	105	108	110	112	114	124	131	137
1985	60	58	59	66	73	79	84	88	92	95	99	102	104	107	110	121*	127*	135
1986	56	58	69	78	85	90	95	99	103	106	110	113	116	118	121	132	141	148
1987	61	77	88	95	101	105	109	113	117	120	124	127	130	132	135	147	156	163
1988	96	104	110	115*	119	122	126	129	133	136	139	142	145	148	151	163	173	180

* In its Application for Rehearing and/or Petition for Modification of CPUC Decision 83-12-068 (December 22, 1983) filed on February 6, 1984, PGandE requests correction of three numbers which were incorrectly presented in the Firm Capacity Price Schedule included in that decision (page 349, Table VI-4). The correct number for 1985 for a 20-year contract life should be \$120/kW-year; and for a 25-year contract life, the correct number should be \$129/kW-year. The correct number for 1988 for a 4-year contract life should be \$114/kW-year. When the CPUC issues an order correcting these numbers, PGandE shall correct the Firm Capacity Price Schedule accordingly.

TABLE F
PACIFIC GAS AND ELECTRIC COMPANY
PAYMENT (¢/kWh) FOR AS-DELIVERED CAPACITY
FROM NON-REMOTE* QUALIFYING FACILITIES
JANUARY 1, 1984 THROUGH DECEMBER 31, 1984

<u>Time Period**</u>	<u>Transmission Level</u>		<u>Distribution Level</u>	
<u>With Time-of-Delivery Metering</u>	<u>Seasonal Period A***</u>	<u>Seasonal Period B</u>	<u>Seasonal Period A</u>	<u>Seasonal Period B</u>
On-Peak	16.717	1.382	16.750	1.385
Partial Peak	3.171	0.168	3.177	0.169
Off-Peak	0.003	0.002	0.003	0.002
<u>Without Time-of-Delivery Metering</u>				
Weighted Average	1.948	0.111	1.952	0.111

* As defined by the CPUC.

** Time periods are defined in Table D.

*** Seasonal Period A comprises the months of May through September, and Seasonal Period B comprises the months of October through April.

ENVIRONMENTAL REGULATIONS ASSISTANCE GUIDE

PGandE has available an Environmental Regulations Assistance Guide for Cogenerators and Small Power Producers.

The guide explains environmental regulations and helps the individual, through flow charts and checklists, determine the permits and approvals required. The guide also provides details on agency contacts and sources of additional information.

If you wish more information about the guide, please contact Mr. Joseph G. Meyer, 77 Beale Street, San Francisco, CA 94106.

FINANCIAL ANALYSIS PROGRAM

PGandE has developed a cogeneration financial analysis computer program that performs a confidential economic analysis of a cogeneration investment with user-supplied data. The program computes useful measures of investment performance, including internal rate of return, net present value, and capital repayment.

Accessible in the PGandE service area through Control Data Corporation Cybernet offices, this program is designed to be user-oriented, with little or no outside assistance necessary. The cost to the user for running the program will vary depending on the complexity of the cogeneration analysis and the number of investment sensitivities performed.

A guide is available to assist the cogeneration entity in using the program. It is a complete workbook showing the user how to run the program with a step-by-step procedure. In addition, the guide includes all necessary worksheets, examples, and documentation.

If you wish more information about this program, please contact Mr. Joseph G. Meyer, 77 Beale Street, San Francisco, CA 94106.

STANDARD OFFERS #1, 2, & 3

On December 5, 1983, pursuant to the order in CPUC Decision 83-10-093 (dated October 19, 1983), PGandE filed three Standard Offers for the purchase of power from qualifying facilities with the California Public Utilities Commission, replacing those of February 14, 1983. These three Standard Offers; namely those for:

As-Delivered Capacity and Energy (Standard Offer #1);

Firm Capacity and Energy (Standard Offer #2); and

As-Delivered Capacity and Energy from Facilities of
100 Kilowatts or Less (Standard Offer #3);

are set out in Appendices C, D, and E, respectively.

STANDARD OFFER #4 POWER PURCHASE AGREEMENT FOR LONG-TERM ENERGY AND CAPACITY

On December 5, 1983, PGandE filed Standard Offer #4, which is set out in Appendix F, pursuant to the order in CPUC Decision 83-10-093, replacing the offer of September 7, 1983. This standard offer was approved on an interim basis pending further hearings which are anticipated in early 1984. Therefore, the availability of Standard Offer #4 is subject to a number of conditions imposed by the CPUC's decision. These include: (1) Standard Offer #4 will be available for a minimum of six months and for a maximum of two years after the effective date of the decision (September 7, 1983); (2) energy payment option 1 (forecast prices) will be available for a maximum of two years from the effective date of the decision; (3) energy payment options 2 (levelized prices) and 3 (incremental energy rate) will be available for a maximum of one year from the effective date of the decision; (4) any qualifying facility (QF) already under a power purchase agreement, whether standard or non-standard, cannot enter into a contract based on Standard Offer #4 until the existing contract term has expired; (5) a QF under a power purchase agreement, whether standard or non-standard, which includes an option to amend to a subsequent standard offer contract approved by the CPUC cannot amend to Standard Offer #4 until the CPUC issues a further decision, presumably at the conclusion of the forthcoming evidentiary hearings; and (6) any QF which signs the interim Standard Offer #4 will not be able to switch to the Standard Offer #4 contract resulting from the evidentiary hearings or any other standard or non-standard offer contract until the term of the existing contract has expired. Further reference should be made to Decisions 83-09-054 and 83-10-093.

INTERCONNECTION OF COGENERATION AND
SMALL POWER PRODUCTION PROJECTS

Due to limited surplus capacity in certain parts of PGandE's electric transmission system, it is essential that interested parties review their proposals with PGandE at an early stage to determine if the power to be developed by the proposed project can be accommodated by our system. Studies with respect to these constraints are currently being performed. This factor should be taken into consideration in the preparation of a project schedule and budget.

APPENDIX A

STATUS REPORT OF PROJECTS

TABLES I THROUGH XXIV

Table I
SUMMARY OF SIGNED CONTRACTS
COGENERATION/SOLID WASTE/BIOMASS PROJECTS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>MW</u>	<u>Projected Date of Operation</u>
1.	Pyro Sol, Inc. - Redwood City	Electric power/steam project fueled by solid waste converted by a pyrolysis process to produce a low Btu gas	June 12, 1979 amended December 24, 1981	Energy Purchase	3.5	Operational*
2.	Georgia Pacific Corporation - Fort Bragg	Electric power project fueled by woodwaste	June 1, 1980	Energy Purchase	10.0	Operational
3.	Optimum Energy Partners - Kern River Oil Field	Electric power/steam projects; thermally enhanced oil recovery	July 18, 1980	Capacity and Energy Purchase	66.0	Operational (7.4 MW)
4.	Dow Chemical USA - Pittsburg	Electric power/steam project using a gas turbine topping cycle	July 22, 1980	Energy Purchase	35.0	Operational
5.	Louisiana-Pacific Corporation - Samoa	Electric power/steam project fueled by woodwaste	July 22, 1980	Capacity and Energy Purchase	11.0	Operational
6.	California Power and Light Corporation - Firebaugh	Electric power project fueled by biomass	July 22, 1980 amended December 30, 1983	Capacity and Energy Purchase	49.9	January 1986
7.	Stauffer Chemical Company - Martinez	Electric power project fueled by waste heat	August 28, 1980	Energy Purchase	2.0	Operational
8.	Paul Bunyan Lumber Company - Anderson	Electric power/steam project fueled by woodwaste	September 8, 1980	Energy Purchase	3.0	Operational
9.	Roseburg Lumber Company - Anderson	Electric power/steam project fueled by woodwaste	September 23, 1980	Energy Purchase	3.0	Operational
10.	City of Santa Clara - Santa Clara	Electric power project using a gas turbine topping cycle with waste heat boilers	September 30, 1980	Standby Service	5.8	Operational

* Currently not operating; facility undergoing modification.

Table I (continued)
SUMMARY OF SIGNED CONTRACTS
COGENERATION/SOLID WASTE/BIOMASS PROJECTS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>MW</u>	<u>Projected Date of Operation</u>
11.	Diamond Walnut Growers, Inc. - Stockton	Electric power/steam project fueled by walnut shells	October 30, 1980	Capacity and Energy Purchase	4.5	Operational
12.	University of California - Davis	Electric power/steam project using a distillate-fueled combustion turbine topping cycle	December 2, 1980 amended March 11, 1982	Capacity and Energy Purchase	3.5	Operational
13.	Redwood Food Packing Company - Modesto	Electric power/steam project fueled by biomass	March 16, 1981	Energy Purchase	4.5	Operational
14.	Paul Masson Vineyards - Saratoga	Electric power/hot water project using a reciprocating natural gas engine topping cycle	July 28, 1981	Standby Service	0.3	Operational
15.	City of Turlock - Turlock	Electric power project fueled by digester gas from a waste-water treatment plant	September 8, 1981	Energy Purchase	0.5	Operational
16.	American Chemurgic Industries - Fields Landing	Electric power/steam project fueled by woodwaste	September 18, 1981	Capacity and Energy Purchase	3.5	Not yet determined
17.	Hudson Lumber Company - Anderson	Electric power/steam project fueled by woodwaste	September 29, 1981	Capacity and Energy Purchase	6.0	Operational
18.	Sierra Pacific Industries - Susanville	Electric power/steam project fueled by woodwaste/solid waste	September 30, 1981	Capacity and Energy Purchase	5.5	Operational
19.	Ukiah Energy, Inc. (formerly Vichy Hills Power Company) - Ukiah	Electric power project fueled by solid waste	October 22, 1981	Capacity and Energy Purchase	3.0	Not yet determined
20.	Imotek, Inc. - Sacramento	Electric power/steam project fueled by biomass	November 9, 1981 amended March 11, 1983	Capacity and Energy Purchase	8.5	Operational
21.	Marindale Dairy - Novato	Electric power project fueled by digester gas	December 3, 1981	Capacity and Energy Purchase	0.04	Operational

Table I (continued)
SUMMARY OF SIGNED CONTRACTS
COGENERATION/SOLID WASTE/BIOMASS PROJECTS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>MW</u>	<u>Projected Date of Operation</u>
22.	Grass Valley Group - Grass Valley	Electric power/hot water project using a diesel-fueled internal combustion engine topping cycle	December 31, 1981	Energy Purchase	1.6	Operational
23.	Contra Costa County Sanitation District No. 7A - Antioch	Electric power project fueled by digester gas	January 2, 1982	Capacity and Energy Purchase	0.96	Operational
24.	Simpson Paper Company - Anderson	Electric power/steam project using a gas turbine topping cycle	February 8, 1982	Capacity and Energy Purchase	36.0	Operational
25.	Farmers Cooperative Gins, Inc. - Buttonwillow	Electric power project fueled by agricultural waste	February 25, 1982	Energy Purchase	1.7	Operational
26.	Community Linen Rental Service, Inc. - Stockton	Electric power/steam project using a gas turbine topping cycle	March 4, 1982	Capacity and Energy Purchase	0.5	Operational
27.	Turbo Resources/TOSCO Refinery - Bakersfield	Electric power/steam project using gas turbines and a back pressure steam turbine	March 11, 1982	Capacity and Energy Purchase	48.0	Not yet determined
28.	Jacobs Service Company/Witco Refinery (formerly Turbo Resources) - Oildale	Electric power/steam project using a gas turbine topping cycle	March 11, 1982 assigned December 6, 1983	Capacity and Energy Purchase	35.0	December 1984
29.	University Energy/Lockheed - Sunnyvale	Electric power/steam project using a gas/steam turbine topping cycle	March 19, 1982	Capacity and Energy Purchase	49.9	Not yet determined
30.	Continental White Cap, Inc. - Hayward	Electric power project using a toluene rankine bottoming cycle	March 30, 1982	Capacity and Energy Purchase	0.6	Operational
31.	Louisiana-Pacific Corporation - Standard	Electric power/steam project fueled by woodwaste	April 7, 1982	Energy Purchase	3.0	Operational
32.	American Mobile Power Corporation - Nipomo	Electric power/hot water project using a gas turbine topping cycle	April 15, 1982	Capacity and Energy Purchase	1.04	February 1984

Table I (continued)
SUMMARY OF SIGNED CONTRACTS
COGENERATION/SOLID WASTE/BIOMASS PROJECTS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>MW</u>	<u>Projected Date of Operation</u>
33.	Gas Recovery Systems, Inc. - Menlo Park	Electric power project fueled by methane gas recovered from a landfill	April 15, 1982 amended August 18, 1983	Capacity and Energy Purchase	2.0	Operational
34.	Gas Recovery Systems, Inc. - Newby Island	Electric power project fueled by methane gas recovered from a landfill	April 15, 1982 amended November 16, 1983	Capacity and Energy Purchase	4.2	March 1984
35.	Pacific Carbons, Inc. - Blue Lake	Electric power/steam project using a gas turbine topping cycle	April 30, 1982	Energy Purchase	1.0	Not yet determined
36.	Superior Farming Company - Bakersfield	Electric power/steam project fueled by biomass	May 5, 1982	Capacity and Energy Purchase	5.7	Operational
37.	Sierra Pacific Industries - Quincy	Electric power/steam project fueled by woodwaste	May 6, 1982 amended August 3, 1983	As-delivered Capacity and Energy Purchase	3.0	Operational
38.	Monterey Regional Water Pollution Control Agency - Monterey	Electric power project fueled by digester gas	May 24, 1982	Energy Purchase	1.0	April 1985
39.	<u>1/</u>	Electric power project fueled by methane gas recovered from a landfill	June 17, 1982 amended August 18, 1983	Capacity and Energy Purchase	6.0	December 1984
40.	Gas Recovery Systems, Inc. (Guadalupe Landfill) - San Jose	Electric power project fueled by landfill gas	June 17, 1982 amended November 16, 1983	Capacity and Energy Purchase	5.0	January 1984
41.	Caterpillar Tractor Co. - San Leandro	Electric power/steam project using a gas turbine topping cycle	July 12, 1982	Energy Purchase	2.5	Operational

1/ Project name and location not authorized for release.

Table I (continued)
SUMMARY OF SIGNED CONTRACTS
COGENERATION/SOLID WASTE/BIOMASS PROJECTS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>MW</u>	<u>Projected Date of Operation</u>
42.	Chevron USA - Taft Maricopa	Electric power/steam project using a gas turbine topping cycle; enhanced oil recovery	July 22, 1982	As-delivered Capacity and Energy Purchase	10.0	Operational
43.	Chevron USA - Cymric	Electric power/steam project using a gas turbine topping cycle; enhanced oil recovery	July 22, 1982	As-delivered Capacity and Energy Purchase	10.0	Operational
44.	Dauvergne Brothers, Inc. - Pleasanton	Electric power project fueled by solid waste	July 29, 1982	Capacity and Energy Purchase	1.5	June 1984
45.	Simpson Paper Company - Fairhaven	Electric power/steam project fueled by biomass	August 24, 1982	As-delivered Capacity and Energy Purchase	9.9	Operational
46.	Ultrapower I - Burney	Electric power project fueled by woodwaste	September 15, 1982 amended December 19, 1983	Capacity and Energy Purchase	9.75	September 1984
47.	Koppers Company, Inc. - Oroville	Electric power/steam project fueled by woodwaste	October 14, 1982	Capacity and Energy Purchase	5.5	Operational
48.	J. R. Wood, Inc. - Atwater	Electric power project fueled by digester gas	October 29, 1982	As-delivered Capacity and Energy Purchase	1.05	Operational
49.	Meadow Glen Farms - Orland	Electric power project fueled by digester gas	November 3, 1982	As-delivered Capacity and Energy Purchase	0.1	Operational
50.	Langerwerf Dairy, Inc. - Durham	Electric power project fueled by digester gas	November 4, 1982	As-delivered Capacity and Energy Purchase	0.09	Operational
51.	City of Fairfield - Fairfield	Electric power/steam project using a gas turbine topping cycle	November 19, 1982	As-delivered Capacity and Energy Purchase	0.8	June 1984

Table I (continued)
SUMMARY OF SIGNED CONTRACTS
COGENERATION/SOLID WASTE/BIOMASS PROJECTS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>MW</u>	<u>Projected Date of Operation</u>
52.	City of San Luis Obispo - San Luis Obispo	Electric power project fueled by methane gas	December 29, 1982 amended August 2, 1983	As-delivered Capacity and Energy Purchase	0.05	October 1984
53.	Crown Zellerbach - Antioch	Electric power/steam project using a gas turbine topping cycle	December 29, 1982	Capacity and Energy Purchase	49.7	Operational
54.	Sutter Gas Processing Corp. - Robbins	Electric power/steam project using a gas turbine topping cycle	January 28, 1983	As-delivered Capacity and Energy Purchase	0.3	August 1984
55.	Chevron USA - Kern River	Electric power/steam project using a steam turbine topping cycle	February 2, 1983	As-delivered Capacity and Energy Purchase	4.0	Operational
56.	Husky Oil Company - Santa Maria	Electric power/steam project using a gas turbine topping cycle	March 15, 1983	As-Delivered Capacity and Energy Purchase	0.999	Operational
57.	Big Valley Lumber Company - Bieber	Electric power/steam project fueled by woodwaste	March 21, 1983	Capacity and Energy Purchase	3.0	Operational
58.	Union Oil Company - Rodeo	Electric power project fueled by waste heat	April 4, 1983	Capacity and Energy Purchase	27.3	Operational
59.	Resource Conservation Energy Joint Powers Agency - Gilroy	Electric power project fueled by digester gas	April 18, 1983	Capacity and Energy Purchase	0.25	November 1984
60.	North San Mateo County Sanitation District - Daly City	Electric power project fueled by methane gas	May 9, 1983	Paralleling Agreement	0.4	Operational
61.	Tenneco Oil Company - Kern County	Electric power/steam project using a gas turbine topping cycle; enhanced oil recovery	May 24, 1983	As-delivered Capacity and Energy Purchase	0.6	Operational

Table I (continued)
SUMMARY OF SIGNED CONTRACTS
COGENERATION/SOLID WASTE/BIOMASS PROJECTS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>MW</u>	<u>Projected Date of Operation</u>
62.	Siskiyou Hardwoods, Inc. - Redding	Electric power project fueled by woodwaste	June 17, 1983	Capacity and Energy Purchase	6.0	March 1985
63.	Monterey Peninsula G&RDD - Marina	Electric power project fueled by landfill gas	July 7, 1983	Capacity and Energy Purchase	1.15	Operational
64.	Heublin Wines - Madera	Electric power/hot water project using a reciprocating natural gas engine topping cycle	July 29, 1983	As-delivered Capacity and Energy Purchase	0.33	January 1984
65.	California Agricultural Power Co. - Chowchilla	Electric power project fueled by agricultural waste	August 3, 1983	Capacity and Energy Purchase	6.6	March 1985
66.	City of Hayward - Hayward	Electric power project using a topping cycle fueled by methane gas	September 1, 1983	Paralleling Agreement	0.7	February 1984
67.	J. R. Simplot - Helm	Electric power/steam project using a steam turbine topping cycle	September 9, 1983	As-delivered Capacity and Energy Purchase	4.0	February 1984
68.	Catalyst/IPT Cogeneration Partnership (San Jose State University) - San Jose	Electric power/steam project using a gas-fired Cheng cycle turbine system	September 27, 1983	As-delivered Capacity and Energy Purchase	6.0	September 1984
69.	On Site Electric International - Half Moon Bay	Electric power project using natural gas reciprocating engine with heat recovery	September 28, 1983	Capacity and Energy Purchase	0.23	April 1984
70.	Luiz & Sons Dairy, Inc. - Lodi	Electric power project fueled by methane gas	October 28, 1983	Capacity and Energy Purchase	0.14	January 1984
71.	Procter & Gamble Co. - Sacramento	Electric power/steam project using a gas turbine topping cycle	November 8, 1983	Capacity and Energy Purchase	20.3	Operational
72.	Collins Pine Company (Phase I) - Chester	Electric power/steam project fueled by woodwaste	November 18, 1983	As-delivered Capacity and Energy Purchase	0.999	January 1984

Table I (continued)
SUMMARY OF SIGNED CONTRACTS
COGENERATION/SOLID WASTE/BIOMASS PROJECTS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>MW</u>	<u>Projected Date of Operation</u>
73.	TOSCO Corporation - Avon	Electric power/steam project using a topping cycle fueled by refinery fuel-gas	November 22, 1983	Capacity and Energy Purchase	92.0	December 1985
74.	Napa State Hospital - Napa	Electric power/steam project using a reciprocating internal combustion engine	December 6, 1983	As-delivered Capacity and Energy Purchase	1.3	February 1984
75.	Pacific Thermonetics, Inc./ C&H Sugar Company - Crockett	Electric power/steam project using a gas turbine topping cycle	December 12, 1983	Capacity and Energy Purchase	260.0	June 1986
76.	University Cogeneration Partners, Ltd., 1983-1 - South Belridge Oil Field	Electric power/steam project fueled by field produced gas; enhanced oil recovery	December 14, 1983	Capacity and Energy Purchase	7.7	August 1984
77.	Getty Oil Company - McKittrick	Electric power/steam project using gas turbines with heat recovery steam generators; enhanced oil recovery	December 19, 1983	Capacity and Energy Purchase	8.7	April 1984
78.	Getty Oil Company - Lost Hills	Electric power/steam project using gas turbines with heat recovery steam generators; enhanced oil recovery	December 19, 1983	Capacity and Energy Purchase	10.18	October 1984
79.	Getty Oil Company - North Midway	Electric power/steam project using gas turbines with heat recovery steam generators; enhanced oil recovery	December 19, 1983	Capacity and Energy Purchase	9.9	April 1984
80.	Pacific Thermonetics, Inc./ Gilroy Foods, Inc. -	Electric power/steam project using a gas-fired combined cycle system	December 19, 1983	Capacity and Energy Purchase	130.0	April 1986
81.	Central Plants - Stockton	Electric power project fueled by low Btu landfill gas	December 19, 1983	Capacity and Energy Purchase	1.0	January 1985
82.	Central Plants - Bakersfield	Electric power project fueled by low Btu landfill gas	December 19, 1983	Capacity and Energy Purchase	4.0	July 1984

Table I (continued)
SUMMARY OF SIGNED CONTRACTS
COGENERATION/SOLID WASTE/BIOMASS PROJECTS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>MW</u>	<u>Projected Date of Operation</u>
83.	Central Plants - Lompoc	Electric power project fueled by low Btu landfill gas	December 19, 1983	Capacity and Energy Purchase	0.75	January 1985
84.	Central Plants - San Quentin	Electric power project fueled by low Btu landfill gas	December 19, 1983	Capacity and Energy Purchase	0.5	January 1985
85.	Ultrapower II - Westwood	Electric power project fueled by woodwaste	December 19, 1983	Capacity and Energy Purchase	10.5	August 1984
86.	Ultrapower - Quincy	Electric power project fueled by woodwaste	December 21, 1983	Capacity and Energy Purchase	10.5	April 1986
87.	Ultrapower - Blue Lake	Electric power project fueled by woodwaste	December 21, 1983	Capacity and Energy Purchase	10.5	June 1985
88.	Ultrapower - Cloverdale	Electric power project fueled by woodwaste	December 21, 1983	Capacity and Energy Purchase	10.5	June 1986
89.	Ultrapower - Fortuna	Electric power project fueled by woodwaste	December 21, 1983	Capacity and Energy Purchase	10.5	July 1986
90.	Ultrapower - El Dorado	Electric power project fueled by woodwaste	December 21, 1983	Capacity and Energy Purchase	13.5	September 1986
91.	Ultrapower - Tuolumne	Electric power project fueled by woodwaste	December 21, 1983	Capacity and Energy Purchase	19.8	October 1986
92.	General Mills - Lodi	Electric power/steam project using a gas turbine topping cycle	December 21, 1983	Firm Capacity, As-delivered Capacity and Energy Purchase	3.2	March 1984
93.	Applied Power Technology - Hayfork	Electric power/steam project fueled by woodwaste	December 28, 1983	Capacity and Energy Purchase	15.0	December 1984
94.	Applied Power Technology - Oroville	Electric power/steam project fueled by woodwaste	December 28, 1983	Capacity and Energy Purchase	18.0	December 1984
95.	Sierra Pacific Industries - Hayfork	Electric power/steam project fueled by woodwaste/coke	December 28, 1983	Capacity and Energy Purchase	9.0	December 1984

Table I (continued)

SUMMARY OF SIGNED CONTRACTS

COGENERATION/SOLID WASTE/BIOMASS PROJECTS

FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>MW</u>	<u>Projected Date of Operation</u>
96.	Ultrapower - McCloud	Electric power project fueled by woodwaste	December 29, 1983	Capacity and Energy Purchase	19.8	December 1986
97.	West Contra Costa Sanitation District - Richmond	Electric power project fueled by solid waste	December 30, 1983	Capacity and Energy Purchase	20.0	December 1984
98.	Energy Finance Corp. (formerly OPC Bio-Energy Corp.) - Williams	Electric power/steam project fueled by rice mills and biomass	December 30, 1983	Capacity and Energy Purchase	17.5	December 1985
99.	Feather River Energy, Inc. - Marysville	Electric power/steam project fueled by woodwaste	December 30, 1983	Capacity and Energy Purchase	23.0	March 1986
100.	Red Top Cogeneration, L.P. - Red Top	Electric power project using a gas turbine with heat recovery	December 30, 1983	Capacity and Energy Purchase	3.6	September 1984
101.	Gunnison Land Corporation ^{2/}	Electric power project using waste fuels	December 30, 1983	Capacity and Energy Purchase	47.5	June 1986
TOTAL					<u>1407.908 MW</u>	
OPERATIONAL TOTAL					<u>315.689 MW</u>	

^{2/} Project location not authorized for release.

Table I (continued)
SUMMARY OF SIGNED CONTRACTS
COGENERATION/SOLID WASTE/BIOMASS PROJECTS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>MW</u>	<u>Projected Date of Operation</u>
83.	Central Plants - Lompoc	Electric power project fueled by low Btu landfill gas	December 19, 1983	Capacity and Energy Purchase	0.75	January 1985
84.	Central Plants - San Quentin	Electric power project fueled by low Btu landfill gas	December 19, 1983	Capacity and Energy Purchase	0.5	January 1985
85.	Ultrapower II - Westwood	Electric power project fueled by woodwaste	December 19, 1983	Capacity and Energy Purchase	10.5	August 1984
86.	Ultrapower - Quincy	Electric power project fueled by woodwaste	December 21, 1983	Capacity and Energy Purchase	10.5	April 1986
87.	Ultrapower - Blue Lake	Electric power project fueled by woodwaste	December 21, 1983	Capacity and Energy Purchase	10.5	June 1985
88.	Ultrapower - Cloverdale	Electric power project fueled by woodwaste	December 21, 1983	Capacity and Energy Purchase	10.5	June 1986
89.	Ultrapower - Fortuna	Electric power project fueled by woodwaste	December 21, 1983	Capacity and Energy Purchase	10.5	July 1986
90.	Ultrapower - El Dorado	Electric power project fueled by woodwaste	December 21, 1983	Capacity and Energy Purchase	13.5	September 1986
91.	Ultrapower - Tuolumne	Electric power project fueled by woodwaste	December 21, 1983	Capacity and Energy Purchase	19.8	October 1986
92.	General Mills - Lodi	Electric power/steam project using a gas turbine topping cycle	December 21, 1983	Firm Capacity, As-delivered Capacity and Energy Purchase	3.2	March 1984
93.	Applied Power Technology - Hayfork	Electric power/steam project fueled by woodwaste	December 28, 1983	Capacity and Energy Purchase	15.0	December 1984
94.	Applied Power Technology - Oroville	Electric power/steam project fueled by woodwaste	December 28, 1983	Capacity and Energy Purchase	18.0	December 1984
95.	Sierra Pacific Industries - Hayfork	Electric power/steam project fueled by woodwaste/coke	December 28, 1983	Capacity and Energy Purchase	9.0	December 1984

Table I (continued)
SUMMARY OF SIGNED CONTRACTS
COGENERATION/SOLID WASTE/BIOMASS PROJECTS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>MW</u>	<u>Projected Date of Operation</u>
96.	Ultrapower - McCloud	Electric power project fueled by woodwaste	December 29, 1983	Capacity and Energy Purchase	19.8	December 1986
97.	West Contra Costa Sanitation District - Richmond	Electric power project fueled by solid waste	December 30, 1983	Capacity and Energy Purchase	20.0	December 1984
98.	Energy Finance Corp. (formerly OPC Bio-Energy Corp.) - Williams	Electric power/steam project fueled by rice mills and biomass	December 30, 1983	Capacity and Energy Purchase	17.5	December 1985
99.	Feather River Energy, Inc. - Marysville	Electric power/steam project fueled by woodwaste	December 30, 1983	Capacity and Energy Purchase	23.0	March 1986
100.	Red Top Cogeneration, L.P. - Red Top	Electric power project using a gas turbine with heat recovery	December 30, 1983	Capacity and Energy Purchase	3.6	September 1984
101.	Gunnison Land Corporation ^{2/}	Electric power project using waste fuels	December 30, 1983	Capacity and Energy Purchase	47.5	June 1986
TOTAL					<u>1407.908 MW</u>	
OPERATIONAL TOTAL					<u>315.689 MW</u>	

^{2/} Project location not authorized for release.

Table II
SUMMARY OF SIGNED CONTRACTS
GEOTHERMAL PROJECTS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>MW</u>	<u>Projected Date of Operation</u>
1.	Occidental Geothermal, Inc. - The Geysers, Lake County	Geothermal generation facility	March 18, 1982	Capacity and Energy Purchase	80.0	June 1984
TOTAL					<u>80.0 MW</u>	
OPERATIONAL TOTAL					<u>0.0 MW</u>	

Table III
SUMMARY OF SIGNED CONTRACTS
SOLAR PROJECTS GREATER THAN 100 kW
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>MW</u>	<u>Projected Date of Operation</u>
1.	Roan Corporation - Carrisa Plain	Solar Thermal	December 21, 1982	15.0	1984
2.	United Energy (formerly Renewable Power Corp.) - Davis	Photovoltaic Cogeneration	January 28, 1983	0.5	July 1984
3.	ARCO Solar Power Production - Carrisa Plain	Photovoltaic	February 10, 1983	16.0	Operational (2 MW)
4.	K. Reilly & Associates - Kern County	Solar Thermal	March 4, 1983	5.0	January 1985
TOTAL				<u>36.5 MW</u>	
OPERATIONAL TOTAL				<u>2.0 MW</u>	

Table IV
SUMMARY OF SIGNED CONTRACTS
SOLAR PROJECTS 100 kW OR LESS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>kW</u>	<u>Projected Date of Operation</u>
1.	POCO Power Corporation - San Luis Obispo	Photovoltaic generation facility	June 28, 1982	Energy Purchase	4.0	Operational
2.	G. Rizza & M. Dunn - San Jose	Photovoltaic generation facility	July 12, 1983	As-delivered Capacity and Energy Purchase	2.0	March 1984
3.	Dr. Jose D. Villarica - Roseville	Photovoltaic generation facility	December 13, 1983	As-delivered Capacity and Energy Purchase	2.5	February 1984
TOTAL					<u>8.5 kW</u>	
OPERATIONAL TOTAL					<u>4.0 kW</u>	

Table V
SUMMARY OF SIGNED CONTRACTS
WIND PROJECTS GREATER THAN 100 kW
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>MW</u>	<u>Projected Date of Operation*</u>
1.	U.S. Windpower - Altamont Pass	Wind farm	April 30, 1981	30.0	Operational
2.	Farrell-O'Keefe Properties - Altamont Pass	Wind farm	December 22, 1981 amended June 30, 1983	16.8	Operational (10.8 MW)
3.	WindMaster, Inc. - Altamont Pass	Wind farm	June 3, 1982	0.275	Operational
4.	California Wind Energy Systems - Altamont Pass	Wind farm	September 20, 1982	1.5	Operational
5.	CWES Ltd. - Altamont Pass	Wind farm	September 20, 1982	1.5	1984
6.	Turbo Wind - Altamont Pass	Wind farm	September 20, 1982	4.0	Not yet determined
7.	GE ₃ - Pacheco Pass	Wind farm	October 11, 1982	11.2	Operational (6.2 MW)
8.	Altamont-American Partners Ltd. (formerly American Windpower) - Altamont Pass	Wind farm	October 11, 1982	0.6	Operational
9.	Fayette Manufacturing Corp. - Altamont Pass	Wind farm	November 4, 1982 amended March 10, 1983	30.0	Operational
10.	Coastal Wind Farms - Bodega Bay	Wind farm	November 11, 1982	3.0	Not yet determined
11.	NFC Energy ^{1/} (formerly Unique Wind Investments) - Altamont Pass	Wind farm	December 2, 1982	36.0	Operational (6.8 MW)
12.	Aero Turbine - Solano County	Wind farm	December 3, 1982	126.0	Not yet determined

* Operational totals provided by developers.

^{1/} NFC assigned 10 MW to FloWind Corp. 8/22/83; also assigned 10 MW to First Source Energy Corp. 8/22/83.

Table V (continued)
SUMMARY OF SIGNED CONTRACTS
WIND PROJECTS GREATER THAN 100 kW
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>MW</u>	<u>Projected Date of Operation*</u>
13.	Alternate Energy Development Intl./ OMTEC I - Soledad	Wind farm	December 26, 1982	0.9	Operational
14.	West Coast Wind Power - Altamont Pass	Wind farm	December 30, 1982	13.0	Not yet determined
15.	Casas del Sol I - King City	Wind farm	January 12, 1983	0.95	1984
16.	Powell Brothers, Inc. - Solano County	Wind farm	January 19, 1983	0.375	1984
17.	U.S. Windpower - Altamont Pass	Wind farm	March 4, 1983	60.0	Operational (16.3 MW)
18.	WindMaster, Inc. - Altamont Pass	Wind farm	May 5, 1983	60.0	Operational (10.2 MW)
19.	Transworld Wind Corp. - Pacheco Pass	Wind farm	May 13, 1983	80.0	1984
20.	ALTECH - Altamont Pass	Wind farm	July 29, 1983	5.76	Operational
21.	American Energy Projects - Altamont Pass	Wind farm	August 20, 1983	52.5	1984-1986
22.	Best Wind Lands - Pacheco Pass	Wind farm	September 23, 1983	20.0	Not yet determined
23.	American Development Corp. - Altamont Pass	Wind farm	September 23, 1983	2.7	Operational
24.	Casas del Sol II - King City	Wind farm	September 23, 1983	9.0	1984
25.	Fayette Manufacturing Corp. - Altamont Pass	Wind farm	December 12, 1983	30.0	Operational
26.	Viking 83 - Altamont Pass	Wind farm	December 21, 1983	2.015	Operational
27.	California Wind Energy Systems - Altamont Pass	Wind farm	December 21, 1983	0.28	Operational

* Operational totals provided by developers.

Table V (continued)
 SUMMARY OF SIGNED CONTRACTS
 WIND PROJECTS GREATER THAN 100 kW
 FOURTH QUARTER
 1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>MW</u>	<u>Projected Date of Operation*</u>
28.	Altamont Energy Corporation - Altamont Pass	Wind farm	December 28, 1983	20.0	1984
			TOTAL	<u>618.355 MW</u>	
			OPERATIONAL TOTAL*	<u>154.33 MW</u>	

* Operational totals provided by developers.

Table VI
SUMMARY OF SIGNED CONTRACTS
WIND PROJECTS 100 kW OR LESS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>kW</u>	<u>Projected Date of Operation</u>
1.	Bloom Dairy - Petaluma	Wind-powered generator	July 15, 1980	Energy Purchase	18.0	Operational
2.	Robert P. Scheibach - Mill Valley	Wind-powered generator	September 19, 1980	Energy Purchase	1.5	Operational
3.	Slater Associates/McDonalds - Daly City	Wind-powered generator	October 17, 1980	Paralleling Agreement	10.0	Operational
4.	RIMAR/McDonalds - Daly City	Wind-powered generator	November 6, 1980	Paralleling Agreement	10.0	Operational
5.	Jens Dybdahl - Arroyo Grande	Wind-powered generator	December 1, 1980	Energy Purchase	20.0	Operational
6.	Joseph P. Richardson - Soquel	Wind-powered generator	January 5, 1981	Energy Purchase	1.5	Operational
7.	Billy C. Maher - Suisun	Wind-powered generator	February 18, 1981	Energy Purchase	10.0	Operational
8.	Harvey M. Harris - Watsonville	Wind-powered generator	April 1, 1981	Energy Purchase	1.5	Operational
9.	A. Dalton James - Orinda	Wind-powered generator	April 20, 1981	Energy Purchase	2.9	Operational
10.	Paul Dennett - Lakeport	Wind-powered generator	May 6, 1981	Energy Purchase	10.0	Operational
11.	Lee Swanson - Paso Robles	Wind-powered generator	May 7, 1981	Energy Purchase	10.0	Operational
12.	City of Fairfield - Fairfield	Wind-powered generator	May 14, 1981	Energy Purchase	25.0	Operational
13.	Robert S. Landing - Pleasant Hill	Wind-powered generator	June 19, 1981	Energy Purchase	10.0	Operational
14.	Donald R. Telford - Sausalito	Wind-powered generator	July 7, 1981	Energy Purchase	25.0	Operational
15.	Robert & Joyce Vieux - Livermore	Wind-powered generator	July 8, 1981	Energy Purchase	10.0	Operational
16.	Roger D. Wood - Vacaville	Wind-powered generator	July 14, 1981	Energy Purchase	1.8	Operational
17.	Peter Lemos - San Pablo	Wind-powered generator	July 15, 1981	Energy Purchase	1.8	Operational
18.	Dr. Harold N. Fogel - Concord	Wind-powered generator	July 16, 1981	Energy Purchase	10.0	Operational

Table VI (continued)
SUMMARY OF SIGNED CONTRACTS
WIND PROJECTS 100 kW OR LESS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>kW</u>	<u>Projected Date of Operation</u>
19.	L. P. Reinhard - Hayward	Wind-powered generator	July 16, 1981	Energy Purchase	10.0	Operational
20.	Helen L. Trotter Gass - Cambria	Wind-powered generator	August 4, 1981	Energy Purchase	1.8	Operational
21.	L. E. Webb - Nipomo	Wind-powered generator	August 5, 1981 amended June 1, 1982	Energy Purchase	20.0	Operational
22.	William Denneen - Nipomo	Wind-powered generator	August 16, 1981	Energy Purchase	5.0	Operational
23.	Miller Pump Company - Templeton	Wind-powered generator	September 3, 1981	Energy Purchase	20.0	Operational
24.	Peter G. Pardini - Vacaville	Wind-powered generator	September 13, 1981	Energy Purchase	10.0	Operational
25.	Marvin Schrock - Point Arena	Wind-powered generator	September 15, 1981	Energy Purchase	1.5	Operational
26.	Robert & Renate Johnson - Benecia	Wind-powered generator	September 18, 1981	Energy Purchase	1.5	Operational
27.	Harold & Donna Wells - Soquel	Wind-powered generator	September 23, 1981	Energy Purchase	1.5	Operational
28.	John R. Rinaudo - Pittsburg	Wind-powered generator	September 30, 1981	Energy Purchase	1.8	Operational
29.	Bertha Noll - Woodacre	Wind-powered generator	October 3, 1981	Energy Purchase	10.0	Operational
30.	Coastal Mountain Power - Arcata	Wind-powered generator	October 8, 1981	Energy Purchase	1.8	Operational
31.	Eleanor T. Harder - Carmel Valley	Wind-powered generator	October 19, 1981	Energy Purchase	1.5	Operational
32.	David L. Lafferty - Vacaville	Wind-powered generator	October 22, 1981	Energy Purchase	10.0	Operational
33.	Francine Mathers - Union City	Wind-powered generator	October 26, 1981	Energy Purchase	1.5	Operational
34.	Enerspec - Bangor	Wind-powered generator	October 29, 1981	Energy Purchase	1.5	Operational
35.	Myra J. Wise - Elk	Wind-powered generator	November 11, 1981	Energy Purchase	1.0	Operational
36.	Daniel W. Schuette - Antioch	Wind-powered generator	November 16, 1981	Energy Purchase	1.8	Operational
37.	Melburn Swafford - Oakley	Wind-powered generator	November 20, 1981	Energy Purchase	4.0	Operational

Table VI (continued)
SUMMARY OF SIGNED CONTRACTS
WIND PROJECTS 100 kW OR LESS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>kW</u>	<u>Projected Date of Operation</u>
38.	Scott Dagenhart - Pinole	Wind-powered generator	November 23, 1981	Energy Purchase	1.8	Operational
39.	Thomas A. Frisbie, Sr. - El Sobrante	Wind-powered generator	December 3, 1981	Energy Purchase	10.0	Operational
40.	Richard L. LaFon - Templeton	Wind-powered generator	December 6, 1981	Energy Purchase	10.0	Operational
41.	Wallace H. Butler - Salinas	Wind-powered generator	December 14, 1981	Energy Purchase	4.0	Operational
42.	Ronald L. Burrow - El Sobrante	Wind-powered generator	December 18, 1981	Energy Purchase	1.8	Operational
43.	Evelyn Wanek - Pacifica	Wind-powered generator	December 24, 1981	Energy Purchase	1.8	Operational
44.	Orin S. Lambert & Lloyd Langdon - Clearlake Park	Wind-powered generator	December 28, 1981	Energy Purchase	10.0	Operational
45.	J. S. Byers - Tomales	Wind-powered generator	December 28, 1981	Energy Purchase	4.0	Operational
46.	Insta-Tune - Fairfield	Wind-powered generator	January 8, 1982	Energy Purchase	10.0	Operational
47.	Louis & Yvonne Greer - Tracy	Wind-powered generator	January 13, 1982	Energy Purchase	1.5	Operational
48.	California Polytechnic State University - San Luis Obispo	Wind-powered generator	January 18, 1982	Paralleling Agreement	1.5	Operational
49.	G. W. & G. L. Womack - Tracy	Wind-powered generator	February 18, 1982	Energy Purchase	4.0	Operational
50.	Vassa Wysinger, Jr. - Berkeley	Wind-powered generator	March 6, 1982	Energy Purchase	1.5	Operational
51.	James Towery - Gilroy	Wind-powered generator	March 9, 1982	Energy Purchase	1.5	Operational
52.	Dahle and Lord Associates, Inc. - Kneeland	Wind-powered generator	March 12, 1982	Energy Purchase	100.0	January 1984
53.	Dennis and Cindy Amen - Eureka	Wind-powered generator	March 31, 1982	Energy Purchase	1.0	Operational

Table VI (continued)
SUMMARY OF SIGNED CONTRACTS
WIND PROJECTS 100 kW OR LESS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>kW</u>	<u>Projected Date of Operation</u>
54.	Malcolm and Betty Minahen - Vallejo	Wind-powered generator	April 20, 1982	Energy Purchase	10.0	Operational
55.	William Shakin, M.D. - Suisun	Wind-powered generator	April 21, 1982	Energy Purchase	4.0	Operational
56.	Everett and Bernice Hart - Banta	Wind-powered generator	April 21, 1982	Energy Purchase	4.0	Operational
57.	The Frank Chounet Ranch - Firebaugh	Wind-powered generator	April 28, 1982	Energy Purchase	12.5	Operational
58.	Vivian Engle - Nipomo	Wind-powered generator	June 19, 1982	Energy Purchase	10.0	Operational
59.	Lewis Nixon Co. - Ryer Island	Wind-powered generator	June 26, 1982	Energy Purchase	4.0	Operational
60.	Joseph A. Heidrick, Sr. - Woodland	Wind-powered generator	June 30, 1982	Energy Purchase	10.0	Operational
61.	Michael or Karen Rippey - Vallejo	Wind-powered generator	June 30, 1982	Energy Purchase	4.0	March 1984
62.	J. R. Nighswonger - San Luis Obispo	Wind-powered generator	July 6, 1982	Energy Purchase	1.8	Operational
63.	Michael A. Stenson - Nipomo	Wind-powered generator	July 7, 1982	Energy Purchase	5.0	Operational
64.	Charles Alldrin - Chico	Wind-powered generator	July 9, 1982	Energy Purchase	3.0	Operational
65.	Marshall Hendren - Bodega Bay	Wind-powered generator	July 9, 1982	Energy Purchase	10.0	Operational
66.	Alternate Energy Development International - Buellton	Wind-powered generator	August 6, 1982	As-delivered Capacity and Energy Purchase	40.0	Operational
67.	Joe T. Hernandez - Davis	Wind-powered generator	August 6, 1982	As-delivered Capacity and Energy Purchase	1.8	Operational

Table VI (continued)
SUMMARY OF SIGNED CONTRACTS
WIND PROJECTS 100 kW OR LESS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>kW</u>	<u>Projected Date of Operation</u>
68.	Marion Acquistapace - Suisun	Wind-powered generator	August 30, 1982	Energy Purchase	10.0	Operational
69.	Gregory Merwin - Sacramento Ship Channel	Wind-powered generator	August 31, 1982	As-delivered Capacity and Energy Purchase	1.8	Operational
70.	Ian Anderson - Birdslanding	Wind-powered generator	August 31, 1982	Energy Purchase	10.0	Operational
71.	Donnie Huffman - Vacaville	Wind-powered generator	September 9, 1982	Energy Purchase	10.0	Operational
72.	Edward Anderson, Jr. - Birdslanding	Wind-powered generator	September 9, 1982	Energy Purchase	10.0	Operational
73.	Mr. & Mrs. Clarence Shaffer - Oakdale	Wind-powered generator	November 5, 1982	As-delivered Capacity and Energy Purchase	20.0	Operational
74.	David W. McAvenia - Vacaville	Wind-powered generator	November 5, 1982	As-delivered Capacity and Energy Purchase	10.0	Operational
75.	Coastal Windfarms, Ltd. - Bodega Bay	Wind-powered generator	November 5, 1982	As-delivered Capacity and Energy Purchase	30.0	Operational
76.	Harry Hawn - San Ramon	Wind-powered generator	November 5, 1982	Energy Purchase	1.8	Operational
77.	Mendocino Unified School District - Elk	Wind-powered generator	November 8, 1982	As-delivered Capacity and Energy Purchase	10.0	Operational
78.	Anthony & Frances Merlonghi - Suisun	Wind-powered generator	December 10, 1982	Energy Purchase	1.5	Operational
79.	Donald R. Chenoweth - Livermore	Wind-powered generator	December 29, 1982	As-delivered Capacity and Energy Purchase	10.0	Operational

Table VI (continued)
SUMMARY OF SIGNED CONTRACTS
WIND PROJECTS 100 kW OR LESS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>kW</u>	<u>Projected Date of Operation</u>
80.	Michael W. Stephens - Dixon	Wind-powered generator	December 29, 1982	As-delivered Capacity and Energy Purchase	10.0	Operational
81.	Donald Herzog - Vacaville	Wind-powered generator	December 29, 1982	As-delivered Capacity and Energy Purchase	10.0	Operational
82.	Donald Homan - Livermore	Wind-powered generator	January 27, 1983	As-delivered Capacity and Energy Purchase	4.0	Operational
83.	Kenneth R. Enos - Union City	Wind-powered generator	January 28, 1983	As-delivered Capacity and Energy Purchase	1.5	Operational
84.	Louis A. Huebsch - San Bruno	Wind-powered generator	January 28, 1983	As-delivered Capacity and Energy Purchase	2.2	Operational
85.	Real Gas & Electric Co., Inc. - Santa Rosa	Wind-powered generator	February 15, 1983	As-delivered Capacity and Energy Purchase	1.0	Operational
86.	Owens Illinois Plastics - Fairfield	Wind-powered generator	February 17, 1983	Paralleling Agreement	25.0	Operational
87.	Sally White - Arroyo Grande	Wind-powered generator	March 9, 1983	As-delivered Capacity and Energy Purchase	4.0	Operational
88.	Keith Miller - Fairfield	Wind-powered generator	April 21, 1983	As-delivered Capacity and Energy Purchase	10.0	Operational
89.	James & Pauline McCord - San Pablo	Wind-powered generator	April 26, 1983	As-delivered Capacity and Energy Purchase	1.8	Operational

Table VI (continued)
SUMMARY OF SIGNED CONTRACTS
WIND PROJECTS 100 kW OR LESS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>kW</u>	<u>Projected Date of Operation</u>
90.	Windfield, Ltd. - Concord	Wind-powered generator	May 17, 1983	As-delivered Capacity and Energy Purchase	90.0	Operational
91.	Golden Gate Bridge - San Francisco	Wind-powered generator	June 17, 1983	Paralleling Agreement	15.0	Operational
92.	Half Moon Bay Airport - Half Moon Bay	Wind-powered generator	August 2, 1983	As-delivered Capacity and Energy Purchase	20.0	Operational
93.	Valley Christian Center - Dublin	Wind-powered generator	August 23, 1983	Paralleling Agreement	15.0	Operational
94.	California Department of Parks & Recreation - Angel Island	Wind-powered generator	August 25, 1983	As-delivered Capacity and Energy Purchase	40.0	Operational
95.	City of Benecia - Benecia	Wind-powered generator	October 11, 1983	As-delivered Capacity and Energy Purchase	75.0	Operational
96.	T. V. Schuhart - Winters	Wind-powered generator	October 14, 1983	As-delivered Capacity and Energy Purchase	10.0	Operational
97.	Richard Clayton - Fairfield	Wind-powered generator	October 18, 1983	As-delivered Capacity and Energy Purchase	17.5	Operational
98.	John Naylor - Orinda	Wind-powered generator	October 31, 1983	As-delivered Capacity and Energy Purchase	15.0	Operational
99.	Joseph DaCruz, Jr. - Twitchell Island	Wind-powered generator	November 1, 1983	As-delivered Capacity and Energy Purchase	1.8	Operational

Table VI (continued)
SUMMARY OF SIGNED CONTRACTS
WIND PROJECTS 100 kW OR LESS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>kW</u>	<u>Projected Date of Operation</u>
100.	California Department of Parks & Recreation - Brannon Island	Wind-powered generator	November 7, 1983	As-delivered Capacity and Energy Purchase	20.0	Operational
				TOTAL	<u>1083.6 kW</u>	
				OPERATIONAL TOTAL	<u>979.6 kW</u>	

Table VII
SUMMARY OF SIGNED CONTRACTS
HYDROELECTRIC PROJECTS GREATER THAN 100 kW
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Owner</u>	<u>Date Contract Signed</u>	<u>MW</u>	<u>Projected Date of Operation</u>
1.	Rollins - Bear River near Colfax	Nevada Irrigation District	June 30, 1978	11.0	Operational
2.	Pardee - Mokelumne River near Ione	East Bay Municipal Utility District	February 10, 1981	29.0 ^{1/}	Operational
3.	Camanche - Mokelumne River near Ione	East Bay Municipal Utility District	February 10, 1981	11.0	Operational
4.	Sly Creek - Lost Creek near Forbestown	Oroville - Wyandotte Irrigation District	March 26, 1981	13.0	January 1984
5.	Hell Hole - Rubicon River near Foresthill	Placer County Water Agency	June 3, 1981	0.5	Operational
6.	Iron Mountain Mines - 12 miles northeast of Redding	T. W. Arman/ Iron Mountain Mines, Inc.	July 20, 1981	6.2	Not yet determined
7.	Monticello - Putah Creek near Winters	Solano Irrigation District	September 1, 1981	11.5	Operational

^{1/} Total plant capacity after adding a new unit of approximately 10 MW.

Table VII (continued)
SUMMARY OF SIGNED CONTRACTS
HYDROELECTRIC PROJECTS GREATER THAN 100 kW
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Owner</u>	<u>Date Contract Signed</u>	<u>MW</u>	<u>Projected Date of Operation</u>
8.	Matthews - Trinity County near Ruth on Mad River	Humboldt Bay Municipal Utility District	October 13, 1981	1.2	Operational
9.	Lake Amador - below Lake Amador Dam near Ione	Jackson Valley Irrigation District & Hydro Electric Constructors	December 4, 1981	0.5	Operational
10.	Trinity Alps Creek - Trinity County near Trinity Creek	George F. and Barbara Jo Mallett	January 4, 1982	0.3	Operational
11.	Bailey Creek Ranch - Battle Creek near Shingletown	Consolidated Hydroelectric, Inc.	January 28, 1982	0.8	Operational
12.	Woodward - Stanislaus County at Woodward Dam	South San Joaquin Irrigation District	February 23, 1982	2.8	Operational
13.	Parker - Merced County near Snelling Road	Merced Irrigation District	March 9, 1982	2.7	Operational
14.	City of San Luis Obispo - San Luis Obispo at Salinas Reservoir	City of San Luis Obispo	June 1, 1982	0.8	1984

Table VII (continued)
SUMMARY OF SIGNED CONTRACTS
HYDROELECTRIC PROJECTS GREATER THAN 100 kW
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Owner</u>	<u>Date Contract Signed</u>	<u>MW</u>	<u>Projected Date of Operation</u>
15.	Indian Valley - Lake County near Clear Lake	Indian Valley Hydro- Electric Partnership	September 13, 1982	2.9	Operational
16.	Fairfield - Merced County near Merced on MID Canal System	Merced Irrigation District	October 28, 1982	0.9	Operational
17.	Canal Creek - Merced County near Snelling Road on MID Canal System	Merced Irrigation District	October 28, 1982	0.9	Operational
18.	Frankenheimer - Stanislaus County above Woodward Reservoir on SSJID Canal System	South San Joaquin Irrigation District	November 16, 1982	5.0	Operational
19.	Mud Creek - Butte County near Richardson Spring	Perry Logging Company	December 27, 1982	0.3	Operational
20.	Pond & Dardanelles Creek - Placer County south of Foresthill	Sierra Energy Co.	January 12, 1983	0.2	Operational
21.	Goose Valley - Shasta County near Burney	Mega Hydro, Inc.	March 30, 1983	0.2	Operational
22.	Digger Creek - Tehama County on Digger Creek	Forward Power & Energy	April 12, 1983	0.6	Operational
23.	Buckeye - El Dorado County near Georgetown	Buckeye "82" Investors	May 5, 1983	0.375	Operational
24.	Virginia Ranch Dam - Yuba County near Browns Valley	Yuba Hydro Partners	May 13, 1983	0.995	April 1984

Table VII (continued)
SUMMARY OF SIGNED CONTRACTS
HYDROELECTRIC PROJECTS GREATER THAN 100 kW
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Owner</u>	<u>Date Contract Signed</u>	<u>MW</u>	<u>Projected Date of Operation</u>
25.	Stovall #2 - Colusa County near Williams	Glenn- Colusa Irrigation District	May 13, 1983	0.2	Operational
26.	Camp Creek - Butte County on Camp Creek	Frontier Land & Power	May 13, 1983	2.19	1985
27.	McFadden Farms - Mendocino County near Potter Valley	Eugene McFadden	May 13, 1983	0.35	Operational
28.	Cedar Flat - near Burnt Ranch	Mega Hydro, Inc.	May 16, 1983	0.3	January 1984
29.	Lateral 6.2 Canal - Madera County near Madera	Madera Irrigation District & Hydro Electric Constructors	June 2, 1983	0.85	March 1984
30.	Weber Flat - Trinity County near Weaverville	Pan-Pacific Hydro, Inc.	June 3, 1983	0.75	Operational
31.	Baker (Kosk Creek) - Shasta County near Big Bend	Dr. & Mrs. Pfeiffer	June 14, 1983	0.3	Operational
32.	Madera Canal Drop - Madera County on Madera Canal at Station 980+65	Madera- Chowchilla Power Authority	June 17, 1983	1.8	June 1984

Table VII (continued)
SUMMARY OF SIGNED CONTRACTS
HYDROELECTRIC PROJECTS GREATER THAN 100 kW
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Owner</u>	<u>Date Contract Signed</u>	<u>MW</u>	<u>Projected Date of Operation</u>
33.	Mill & Sulphur Creek - Dinsmore	David DeMera	July 18, 1983	0.995	March 1984
34.	Friant - San Joaquin River near Madera	Friant Power Authority	October 7, 1983	25.0	1985
35.	Combie South - Lake Combie near Auburn	Nevada Irrigation District	December 8, 1983	1.5	1984
36.	Big Creek (Xenophone) - Trinity County near Hyampom	Ultrapower X	December 19, 1983	4.8	March 1985
37.	Tunnel Hill - El Dorado County near Georgetown	Tunnel Hill '83 Investors	December 29, 1983	0.6	Operational
38.	Arbuckle Mountain - Shasta County near Platina	R.F. and C.A. Ott	December 29, 1983	0.3	November 1984
39.	Scotts Flat - Nevada County near Dear Creek	Nevada Irrigation District	December 30, 1983	0.85	January 1985
TOTAL				<u>144.455</u>	<u>MW</u>
OPERATIONAL TOTAL				<u>84.875</u>	<u>MW</u>

Table VIII
SUMMARY OF SIGNED CONTRACTS
HYDROELECTRIC PROJECTS 100 kW OR LESS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>kW</u>	<u>Projected Date of Operation</u>
1.	North Valley Baptist Church - Viola	Low-head hydroelectric facility	February 20, 1981	Paralleling Agreement	10	Operational
2.	Old Bell Powerhouse - Auburn	Low-head hydroelectric facility	October 27, 1981	Energy Purchase	100	Not yet determined
3.	North Valley Baptist Church - Viola	Low-head hydroelectric facility	March 25, 1982	Energy Purchase	50	Operational
4.	Edward F. Burgess - Zenia	Low-head hydroelectric facility	April 9, 1982	Energy Purchase	25	Operational
5.	Robert W. Lee - Manton	Low-head hydroelectric facility	April 29, 1982	Energy Purchase	30	Operational
6.	Adrian B. Haemming - Grass Valley	Low-head hydroelectric facility	May 3, 1982	Energy Purchase	15	Operational
7.	William R. Poulton - Shasta County	Low-head hydroelectric facility	June 25, 1982	Energy Purchase	100	Operational
8.	Redwood Trails, Inc. - Stone Lagoon	Low-head hydroelectric facility	July 11, 1982 amended October 26, 1983	As-delivered Capacity and Energy Purchase	10	Operational
9.	Whale Rock Commission - San Luis Obispo	Low-head hydroelectric facility	November 3, 1982	As-delivered Capacity and Energy Purchase	54	Operational
10.	Richard E. Akin - Placerville	Low-head hydroelectric facility	November 4, 1982	As-delivered Capacity and Energy Purchase	100	Operational
11.	Fred & Janice Sutter - Shasta County on Mill Seat Creek	Low-head hydroelectric facility	November 4, 1982	As-delivered Capacity and Energy Purchase	100	May 1984
12.	Hat Creek Hereford Ranch - Hat Creek	Low-head hydroelectric facility	December 3, 1982	As-delivered Capacity and Energy Purchase	100	Operational

Table VIII (continued)
SUMMARY OF SIGNED CONTRACTS
HYDROELECTRIC PROJECTS 100 kW OR LESS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>kW</u>	<u>Projected Date of Operation</u>
13.	Sterling Beckwith - Paradise	Low-head hydroelectric facility	January 3, 1983 amended September 14, 1983	As-delivered Capacity and Energy Purchase	40	Operational
14.	F. Biber & S. Spellenberg - Bidden Creek near Eureka	Low-head hydroelectric facility	February 1, 1983	As-delivered Capacity and Energy Purchase	28	Operational
15.	General Plastics Mfg. Co. - Maple Creek near Eureka	Low-head hydroelectric facility	March 3, 1983	As-delivered Capacity and Energy Purchase	100	April 1984
16.	Robert Irvine - Alta	Low-head hydroelectric facility	March 14, 1983	As-delivered Capacity and Energy Purchase	10	Operational
17.	California Fish Growers, Inc. - Bodega Bay	Low-head hydroelectric facility	September 10, 1983	As-delivered Capacity and Energy Purchase	16	Operational
18.	Neocene Explorations, Inc. - Sierra County	Low-head hydroelectric facility	September 26, 1983	As-delivered Capacity and Energy Purchase	75	June 1984
19.	James B. Peters - Greenville	Low-head hydroelectric facility	November 9, 1983	As-delivered Capacity and Energy Purchase	15	April 1984
20.	San Luis Obispo County FC&WCD - Arroyo Grande	Low-head hydroelectric facility	November 14, 1983	As-delivered Capacity and Energy Purchase	100	February 1984
TOTAL					<u>1078 kW</u>	
OPERATIONAL TOTAL					<u>588 kW</u>	

Table IX
SUMMARY OF SIGNED CONTRACTS
OTHER PROJECTS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>MW</u>	<u>Projected Date of Operation</u>
1.	Transamerica Delaval Turbine - Oakland	Electric power from a diesel test engine	February 12, 1982	Energy Purchase	7.3	Operational
2.	Wellhead Energy Partnership I/ On Site Energy - Woodland	Electric power project fueled by wellhead natural gas	April 22, 1983	As-delivered Capacity and Energy Purchase	0.6	Operational
3.	<u> </u> ^{1/}	Electric power project fueled by wellhead natural gas	June 7, 1983	As-delivered Capacity and Energy Purchase	0.5	January 1984
TOTAL					<u>8.4 MW</u>	
OPERATIONAL TOTAL					<u>7.9 MW</u>	

^{1/} Project name and location not authorized for release.

Table X

SUMMARY OF SIGNED LETTER AGREEMENTS
COGENERATION/SOLID WASTE/BIOMASS PROJECTS

FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Letter Agreement Signed</u>	<u>MW</u>	<u>Projected Date of Operation</u>
1.	RMR Associates/HARP Energy - Madera	Electric power project fueled by biomass	November 4, 1981	4.4	September 1985
2.	Diamond H Ranch - Covelo	Electric power project fueled by biomass	December 18, 1981	15.0	Not yet determined
3.	American Lignite Products - Ione	Electric power/steam project fueled by lignite	September 20, 1982	14.0	October 1985
4.	Sanger Energy Co., Inc. - Sanger	Electric power/steam project fueled by municipal solid waste	September 27, 1983	7.5	January 1985
5.	California Co-Energy Partnership - Hanford	Electric power/steam project using a gas turbine topping cycle	November 23, 1983	30.0	August 1985
TOTAL				<u>70.9 MW</u>	

Table XI
SUMMARY OF SIGNED LETTER AGREEMENTS
OTHER PROJECTS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Letter Agreement Signed</u>	<u>MW</u>	<u>Projected Date of Operation</u>
1.	<u>1/</u>	Electric power project fueled by wellhead natural gas	May 23, 1983	20.0	Not yet determined
TOTAL				<u>20.0 MW</u>	

1/ Project name and location not authorized for release.

Table XII
SUMMARY OF PGandE-OWNED PROJECTS
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>MW</u>	<u>Status</u>
1.	Solano Wind Turbine - Solano County	Boeing horizontal axis wind turbine	2.5	Operational May 1982
2.	PGandE Gerber Compressor Station - Gerber	Electric power project using waste heat from a gas compressor	3.7	Operational November 1982
3.	PGandE Department of Engineering Research - San Ramon	Photovoltaic generation facility	0.003	Operational December 1982
TOTAL			<u>6.203 MW</u>	

Table XIII
COGENERATION PROJECTS UNDER ACTIVE DISCUSSION
STATUS REPORT
FOURTH QUARTER
1983

No.	Project Name and Location	Project Description	Date Discussions Began	Maximum Estimated Project Size MW	Electric Demand MW	Status	Projected Date of Operation
1.	Oakland City Center - Oakland	Electric power/steam project using a reciprocating internal combustion engine	March 1979	38.5	21.4 (est.)	The City of Oakland has asked Kaiser Engineers to proceed with the project.	Not yet determined
2.	Atascadero State Hospital - Atascadero	Electric power/steam project using a reciprocating engine topping cycle	January 1983	25.0	1.5	G.E. will install and maintain cogeneration system. Preliminary interconnection discussions conducted.	Not yet determined
3.	PGandE Moss 6 and 7 Gas Expander - Moss Landing	Electric power from a natural gas expander turbine	June 1980	3 - 6	N/A	Third party development and alternative financing under study.	1985
4.	<u>1/</u>	Electric power/steam project using a gas turbine topping cycle	January 1982	24 - 48	31.6	Preliminary discussions underway.	October 1985
5.	City of San Jose - San Jose	Electric power/steam project using a gas turbine	September 1981	4.8	Not yet determined	PGandE advanced the funds for a feasibility study of a cogeneration project in the downtown area. The City of San Jose is currently evaluating the results of the feasibility study.	Not yet determined
6.	Lassen College - Susanville	Electric power/steam project fueled by woodwaste	March 1982	1.5	N/A	Negotiations ongoing for purchase of power.	June 1984
7.	City of Oakland and County of Alameda - Oakland	Electric power/steam project using a natural gas reciprocating engine	December 1981	1 - 3	Not yet determined	PGandE advanced the funds for a feasibility study of a cogeneration project for the city and county court and jail buildings.	Not yet determined

1/ Project name and location not authorized for release.

Table XIII (continued)
 COGENERATION PROJECTS UNDER ACTIVE DISCUSSION
 STATUS REPORT
 FOURTH QUARTER
 1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Discussions Began</u>	<u>Maximum Estimated Project Size MW</u>	<u>Electric Demand MW</u>	<u>Status</u>	<u>Projected Date of Operation</u>
8.	Stanford University - Palo Alto	Electric power/steam project using a gas turbine topping cycle	October 1981	45.0	15.8	Negotiations ongoing for purchase of power. Final design stage.	January 1986
9.	Veterans Home - Yountville	Electric power/steam project using a gas turbine topping cycle	April 1982	25.0	1.1	Department of Veteran's Affairs expects to release an RFP for third-party development.	Not yet determined
10.	City of Santa Clara/ International Power Technology, Inc. - Santa Clara	Electric power/steam project using a gas turbine topping cycle	June 1981	10.0	N/A	City of Santa Clara and Inter- national Power Technology have signed a Letter of Intent which will lead to an agreement to construct a cogeneration project.	1985
11.	PGandE, Station "T" - San Francisco	Electric power/steam project using a gas turbine topping cycle	March 1979	37.1	N/A	Engineering possibilities and economics under review.	Not yet determined
12.	Jeld-Wen, Inc. - Susanville	Electric power/steam project fueled by woodwaste	March 1980	2.5	1.8	Discussions ongoing for the purchase of power.	June 1984
13.	California Polytechnic Institute - San Luis Obispo	Electric power/steam project using a gas-fired combined cycle system	January 1983	25.0	N/A	Discussions ongoing for the purchase of power.	July 1985
14.	Agnews State Hospital - San Jose	Electric power/steam project using a gas-fired topping cycle	February 1983	27.0	N/A	Discussions ongoing for the purchase of power.	June 1985
15.	United Airlines - San Francisco	Electric power/steam project using a gas-fired combined cycle system	September 1980	49.0	N/A	Discussions ongoing for the purchase of power.	December 1984
16.	U.C. Santa Cruz - Santa Cruz	Electric power/steam project using a reciprocating natural gas engine	August 1983	2.7	N/A	Preliminary interconnection study completed.	1985

Table XIII (continued)
 COGENERATION PROJECTS UNDER ACTIVE DISCUSSION
 STATUS REPORT
 FOURTH QUARTER
 1983

No.	Project Name and Location	Project Description	Date Discussions Began	Maximum Estimated Project Size MW	Electric Demand MW	Status	Projected Date of Operation
17.	Valley Medical Center - San Jose	Electric power/steam project using a gas-fired turbine	May 1983	1.3	3.0	PGandE cofunding a feasibility study.	January 1985
18.	Hilton Hotel/ Planned Energy Int'l. - Stockton	Electric power/steam project using a gas-fired reciprocating engine	November 1982	0.23	0.4	Discussions ongoing for the purchase of power.	June 1984
19.	American Forest Products Company - Martell	Electric power/steam project fueled by woodwaste/coke	December 1981	22.0	10.0	Discussions ongoing for the purchase of power.	July 1985
20.	<u> </u> ^{1/}	Electric power/steam project using a gas turbine topping cycle	March 1982	3.5 - 10	0.7	Preliminary discussions underway.	January 1985
21.	San Francisco State University - San Francisco	Electric power/steam project using a gas turbine topping cycle	August 1979	0.75	5.0	Project under construction. Paralleling agreement being prepared.	April 1984
22.	U.C. Medical Center - San Francisco	Electric power/steam project using a gas turbine topping cycle	August 1981	1.5	7.2	Interested in paralleling agreement.	April 1984
23.	Univ. of San Francisco - San Francisco	Electric power/steam project using a gas-fired combined cycle system	September 1982	9.0	N/A	Interconnection study completed by PGandE.	1986
24.	Collins Pine Company (Phase II) - Chester	Electric power/steam project fueled by woodwaste	September 1983	10 - 12	3 - 5	Preliminary discussions underway.	October 1985
25.	Clarke Swim Center - Walnut Creek	Electric power project using a gas reciprocating engine	September 1983	0.1	N/A	Preliminary discussions underway.	1984

^{1/} Project name and location not authorized for release.

Table XIII (continued)
COGENERATION PROJECTS UNDER ACTIVE DISCUSSION

STATUS REPORT

FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Discussions Began</u>	<u>Maximum Estimated Project Size MW</u>	<u>Electric Demand MW</u>	<u>Status</u>	<u>Projected Date of Operation</u>
26.	Providence Merritt- Peralta Hospitals - Oakland	Electric power/steam project using a gas-fired combined cycle system	May 1983	5 - 10	N/A	Feasibility study completed.	1985
27.	Redwoods Retirement Center - Mill Valley	Electric power/hot water project using a gas-fired reciprocating engine	October 1983	0.75	N/A	Preliminary discussions underway.	May 1984
28.	Mt. Tam Raquet Club - Larkspur	Electric power/hot water project using a gas-fired reciprocating engine	October 1983	0.06	N/A	Preliminary discussions underway.	May 1984
29.	University of California - Berkeley	Electric power/steam project using a gas turbine topping cycle	October 1982	26.5	N/A	Discussions ongoing for the purchase of power.	January 1986
TOTAL				<u>401.79 - 444.29 MW</u>			

Table XIV
SOLID WASTE/BIOMASS PROJECTS UNDER ACTIVE DISCUSSION
STATUS REPORT
FOURTH QUARTER
1983

No.	Project Name and Location	Project Description	Date Discussions Began	Maximum Estimated Project Size MW	Electric Demand MW	Status	Projected Date of Operation
1.	Humboldt Bay Power Company - Eureka	Electric power project fueled by solid waste and woodwaste	1975	25.0	N/A	Discussions ongoing for purchase of power.	Not yet determined
2.	San Francisco Resource Recovery Project ^{1/}	Electric power project fueled by solid waste	1967	34 - 39	N/A	City and County of San Francisco has selected Combustion Engineering (CE) to develop the project. Discussions with CE have been initiated. Brisbane voters rejected rezoning for project on November 2, 1982. CE now seeking a new site.	January 1987
3.	Dublin/San Ramon Service District - Dublin	Electric power project using a topping cycle fueled by methane gas	April 1981	0.6	1.0	Agreements sent to customer.	January 1984
4.	Tri-Cities Solid Waste - Fremont	Electric power project fueled by solid waste	February 1981	9.2	N/A	Final EIR certified by Fremont Planning Commission on August 27, 1982. Use Permit approved by City Council. Oakland Scavengers now negotiating with a vendor.	1986
5.	City of Sunnyvale - Sunnyvale	Electric power project fueled by methane gas	March 1982	0.75	N/A	Project under construction. Paralleling agreement under discussion.	February 1984
6.	San Jose/Santa Clara Waste Treatment Plant - San Jose	Electric power project fueled by sludge gas and natural gas	February 1982	5.5	N/A	Project under construction. Preliminary discussions underway.	1984
7.	Grant Amen Dairy - Anderson	Electric power project fueled by digester gas	March 1983	0.065	N/A	Negotiations ongoing for purchase of power.	January 1984

^{1/} Project location not yet determined.

Table XIV (continued)
 SOLID WASTE/BIOMASS PROJECTS UNDER ACTIVE DISCUSSION
 STATUS REPORT
 FOURTH QUARTER
 1983

No.	Project Name and Location	Project Description	Date Discussions Began	Maximum Estimated Project Size MW	Electric Demand MW	Status	Projected Date of Operation
8.	<u>2/</u>	Electric power project fueled by methane gas	May 1981	0.65	1.7	Project under construction. Paralleling agreement under discussion.	June 1984
9.	Millbrae Sewage Treatment Plant - Millbrae	Electric power project fueled by methane gas	August 1982	0.08	N/A	Interested in paralleling agreement.	April 1984
10.	Darwin Farms - Lodi	Electric power project fueled by methane gas	February 1983	0.75	N/A	Negotiations ongoing for the purchase of power.	March 1984
11.	City of Stockton Wastewater Plant - Stockton	Electric power project fueled by methane gas	January 1982	1.5	2.4	Negotiations ongoing for the purchase of power.	1984
12.	San Francisco Solid Waste Treatment Plant - San Francisco	Electric power project fueled by methane gas	January 1982	5.2	N/A	Negotiations ongoing for the purchase of power.	1985
13.	Genstar - Marysville	Electric power project fueled by landfill gas	December 1983	1.0	N/A	Preliminary discussions underway.	December 1984
TOTAL				<u>84.295 - 89.295 MW</u>			

2/ Project name and location not authorized for release.

Table XV
SOLAR PROJECTS GREATER THAN 100 KW UNDER ACTIVE DISCUSSION
STATUS REPORT
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Discussions Began</u>	<u>Maximum Estimated Project Size MW</u>	<u>Status</u>	<u>Projected Date of Operation</u>
1.	Rockwell/ARCO - Carrisa Plain	Solar thermal	August 1982	30.0	Negotiations ongoing.	1986
2.	<u> </u> ^{1/}	Photovoltaic	August 1983	1.0	Negotiations ongoing.	1984
				TOTAL	<u>31.0 MW</u>	

^{1/} Project name and location not authorized for release.

Table XVI
SOLAR PROJECTS 100 KW OR LESS UNDER ACTIVE DISCUSSION
STATUS REPORT
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Discussions Began</u>	<u>Maximum Estimated Project Size kW</u>	<u>Status</u>	<u>Projected Date of Operation</u>
1.	<u>1/</u>	Residential photovoltaic	July 1983	2	Under construction.	April 1984
			TOTAL	<u>2 kW</u>		

1/ Project name and location not authorized for release.

Table XVII
WIND PROJECTS GREATER THAN 100 kW UNDER ACTIVE DISCUSSION
STATUS REPORT
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Discussions Began</u>	<u>Maximum Estimated Project Size MW</u>	<u>Status</u>	<u>Projected Date of Operation</u>
1.	Wind Energy Company - Altamont Pass	Wind farm	April 1981	58.0	Discussions ongoing.	1984-1986
2.	Powell Brothers, Inc. - Solano County	Wind farm	January 1982	0.5	Discussions ongoing.	1984
3.	City of Santa Clara - Altamont Pass	Wind farm	May 1982	19.7	Discussions ongoing.	1984-1985
4.	WindMaster, Inc. - Altamont Pass	Wind farm	May 1982	10.3	Discussions ongoing.	1985-1986
5.	CWES - Altamont Pass	Wind farm	September 1982	0.955	Discussions ongoing.	1984
6.	American Alternate Energy Ltd. (formerly American Windpower - Altamont Pass	Wind farm	February 1983	6.0	Discussions ongoing.	1984-1985
7.	U.S. Windpower - Altamont Pass	Wind farm	February 1983	200.0	Discussions ongoing.	1985
8.	GE ₃ /Consolidated Turbine - Pacheco Pass	Wind farm	April 1983	40.0	Discussions ongoing.	1984-1985
9.	<u>1/</u>	Wind farm	April 1983	0.95	Discussions ongoing.	1984
10.	Casas del Sol I - King City	Wind farm	June 1983	3.25	Discussions ongoing.	1984

1/ Project name and location not authorized for release.

Table XVII
WIND PROJECTS GREATER THAN 100 kW UNDER ACTIVE DISCUSSION

STATUS REPORT

FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Discussions Began</u>	<u>Maximum Estimated Project Size MW</u>	<u>Status</u>	<u>Projected Date of Operation</u>
11.	Dinosaur Point - Pacheco Pass	Wind farm	June 1983	10.0	Discussions ongoing.	1984
12.	Alternative Energy Development Intl./OMTEC I - Soledad	Wind farm	July 1983	1.425	Discussions ongoing.	1984
13.	Alternative Energy Development Intl./OMTEC II - Soledad	Wind farm	July 1983	1.65	Discussions ongoing.	1984
14.	Wind Energy Specialties - Altamont Pass	Wind farm	September 1983	12.6	Discussions ongoing.	1984-1985
TOTAL				<u>365.33 MW</u>		

Table XVIII
WIND PROJECTS 100 kW OR LESS UNDER ACTIVE DISCUSSION
STATUS REPORT
FOURTH QUARTER
1983

No.	Project Name and Location	Project Description	Date Discussions Began	Maximum Estimated Project Size kW	Status	Projected Date of Operation
1.	_____ 1/	Wind-powered generator	June 1982	4	Standard Offer #3 prepared for signature.	March 1984
2.	_____ 1/	Wind-powered generator	August 1982	10	Standard Offer #3 prepared for signature.	March 1984
3.	_____ 1/	Wind-powered generator	October 1982	10	Standard Offer #3 prepared for signature.	March 1984
4.	_____ 1/	Wind-powered generator	October 1982	4	Standard Offer #3 prepared for signature.	March 1984
5.	Marie Fostiak - Westport	Wind-powered generator	August 1982	2	Project under construction.	March 1984
6.	David Shepard - Benicia	Wind-powered generator	August 1982	6	Standard Offer #3 prepared for signature.	March 1984
7.	City College of S.F. - San Francisco	Wind-powered generator	February 1982	1	Interested in paralleling agreement. Interconnection being designed.	June 1984
8.	Aaron Rasmussen - Byron	Wind-powered generator	December 1983	18	Project under construction.	February 1984
				TOTAL	55 kW	

1/ Project name and location not authorized for release.

Table XIX
HYDROELECTRIC PROJECTS GREATER THAN 100 kW UNDER ACTIVE DISCUSSION

STATUS REPORT					
FOURTH QUARTER 1983					
<u>No.</u>	<u>Project Name and Location</u>	<u>Owner</u>	<u>Approximate Installed Capacity - MW</u>	<u>Status</u>	<u>Projected Date of Operation</u>
1.	Sand Bar - Middle Fork Stanislaus River	Oakdale and South San Joaquin Irrigation District	15.0	Districts received FERC license. Memorandum of Understanding signed November 29, 1982. Undergoing economic reevaluation.	1986
2.	Bowman - Bowman Reservoir	Nevada Irrigation District	3.0	Memorandum of Understanding signed October 25, 1982. Undergoing economic reevaluation.	1986
3.	Rock Creek #2 - North Fork Feather River at Rock Creek	Oroville- Wyandotte Irrigation District	15.0	Negotiations underway. Funding for preliminary feasibility studies has been approved.	1988
4.	Pyramid - South Fork American River at Pyramid Creek	Joseph M. Keating	0.8	Preliminary interconnection study underway.	1985
5.	Rock Creek - South Fork American River at Rock Creek	Joseph M. Keating	3.0	Preliminary interconnection information given to developer.	1985
6.	Sayles Flat - South Fork American River near Strawberry	Joseph M. Keating	2.0	Preliminary interconnection study underway.	1985
7.	Bluford Creek (Ross Burgess) - Trinity County near Fort Seward	Ross Burgess	1.3	Developer requested non-standard contract, but has decided to sign Standard Offer #4.	1984
8.	Auburn Ravine - Placer County near South Canal	Placer County Water Agency	1.8	Under study.	1985

Table XIX (continued)

HYDROELECTRIC PROJECTS GREATER THAN 100 kW UNDER ACTIVE DISCUSSION

STATUS REPORT					
FOURTH QUARTER 1983					
<u>No.</u>	<u>Project Name and Location</u>	<u>Owner</u>	<u>Approximate Installed Capacity - MW</u>	<u>Status</u>	<u>Projected Date of Operation</u>
9.	Foottrail - Silver Fork American River northwest of Silver Lake	Joseph M. Keating	3.2	Preliminary interconnection information given to developer.	1986
10.	Browns Valley Ditch - Yuba County	Browns Valley Irrigation District	0.25	Negotiations ongoing for purchase of power. Final interconnection study completed.	1984
11.	Harding Canal - Yuba County	Browns Valley Irrigation District	1.7	Feasibility study stage.	Not yet determined
12.	Montgomery Creek - Shasta County near PGandE Pit 7 Powerhouse	Consolidated Hydroelectric, Inc.	2.6	Final interconnection study in progress.	1984
13.	Salmon Creek - Sierra County near Sierra City	Henwood Associates	0.5	Final interconnection study completed.	Not yet determined
14.	Swift Creek - Trinity County near Trinity Center	Southern Pacific Land Company	4.6	Interconnection study needed. Awaiting action from developer.	Not yet determined
15.	Horseshoe Bar - Placer County on Middle Fork American River	Horseshoe Bar Associates	4.0	Power purchase negotiations deferred while developer negotiates with DF&G.	1984
16.	French Creek - North Fork Feather River near Lake Oroville	Oroville- Wyandotte Irrigation District	8.5	Negotiations underway. Funding for preliminary feasibility studies has been approved.	1986
17.	Fleming Hill Conduit - Vallejo Water Treatment Plant	City of Vallejo	0.3	Power purchase negotiations underway.	March 1984

Table XIX (continued)

HYDROELECTRIC PROJECTS GREATER THAN 100 kW UNDER ACTIVE DISCUSSION

STATUS REPORT

FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Owner</u>	<u>Approximate Installed Capacity - MW</u>	<u>Status</u>	<u>Projected Date of Operation</u>
18.	Calaveras Reservoir - Alameda County near Sunol	City and County of San Francisco	1.0	Preliminary discussions held. Awaiting action from developer.	Not yet determined
19.	Bluff Springs - Shasta County near Manton	Donald Lee	0.1	Contract for use of PGandE land and water finalized. Awaiting further action by developer.	1984
20.	Canyon Creek - El Dorado County	Robert T. Suter	0.65	Interconnection study defined. Awaiting action by developer.	Not yet determined
21.	North Yuba - Sierra County near Sierra City	Sierra County	7.5	Interconnection study defined. Awaiting action by developer.	February 1986
22.	AC Hydro at Roaring Creek - Shasta County near Montgomery Creek	Fred Adams	3.5	Interconnection study defined. Awaiting action by developer.	1984
23.	Boyd's Hat Creek - Shasta County near Old Station	James Boyd	1.9	Preliminary interconnection study completed. Other interconnection alternatives that could be studied have been defined. Awaiting action by developer.	Not yet determined
24.	Mega Hydro #1 (Clover Creek) - east of Oak Run	Mega Hydro, Inc.	1.0	Preliminary interconnection study completed.	February 1984
25.	Deerlick Springs Resort - Trinity County near Hayfork	Deerlick Springs Resort	4.5	Preliminary discussions held. Interconnection study defined. Awaiting action by developer.	October 1984
26.	Kerlin Creek - Trinity County near Hyampom	VG Enterprises	0.6	Preliminary discussions held. Interconnection study defined. Awaiting action by developer.	1984
27.	Little Boulder Creek - Trinity County near Trinity Center	D.W. & L.M. Saulsberry	0.5	Final interconnection study underway.	1984

Table XIX (continued)
HYDROELECTRIC PROJECTS GREATER THAN 100 kW UNDER ACTIVE DISCUSSION

STATUS REPORT					
FOURTH QUARTER 1983					
<u>No.</u>	<u>Project Name and Location</u>	<u>Owner</u>	<u>Approximate Installed Capacity - MW</u>	<u>Status</u>	<u>Projected Date of Operation</u>
28.	Pelletreau Creek - Trinity County near Hyampom	Hyampom Valley Ranch	1.0	Preliminary discussions held. Interconnection study defined. Awaiting action by developer.	1984
29.	Lower Haypress - Sierra County near Sierra City	Southern Pacific Land Company	4.0	Preliminary discussions held. Study cost estimate requested.	December 1985
30.	Middle Haypress - Sierra County near Sierra City	Southern Pacific Land Company	4.9	Preliminary discussions held. Study cost estimate requested.	December 1985
31.	Upper Haypress - Sierra County near Sierra City	Mac Hydro- Power Company, Inc.	1.4	Preliminary discussions held.	1985
32.	Ladies Canyon - Sierra County near Sierra City	Mac Hydro- Power Company, Inc.	2.5	Preliminary discussions held.	1985
33.	Warm Springs Dam - Sonoma County near Geyserville	Sonoma County Water Agency	3.7	Preliminary interconnection study completed.	April 1986
34.	Digger/Battle Creeks - Tehama County near Manton	David Scott	2.8	Discussions in progress. Interconnection study defined.	1984-1985
35.	Whiskey Creek 1 & 2 - Madera County near Northfork	West Slope Power Co.	4.2	Interconnection study requested. Developer waiting for completion of environmental studies.	December 1984
36.	Whiskey Creek 3 - Madera County near Northfork	West Slope Power Co.	4.0	Interconnection study requested. Developer waiting for completion of environmental studies.	December 1985
37.	Sand & Browns Creek - Madera County near Northfork	West Slope Power Co.	5.0	Interconnection study requested. Developer waiting for completion of environmental studies.	June 1985

Table XIX (continued)

HYDROELECTRIC PROJECTS GREATER THAN 100 kW UNDER ACTIVE DISCUSSION

STATUS REPORT

FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Owner</u>	<u>Approximate Installed Capacity - MW</u>	<u>Status</u>	<u>Projected Date of Operation</u>
38.	Stoney Creek - Trinity County near Clair Engle Lake	Pan-Pacific Hydro, Inc.	0.4	Preliminary interconnection study completed.	December 1984
39.	Concow - Butte County near Paradise	Thermalito Irrigation District	1.1	Interconnection study requested.	1985
40.	Clear Lake Powerhouse - below Clear Lake Dam	Yolo County	1.6	Final interconnection study completed.	1984
41.	Combie North - Lake Combie near Auburn	Nevada Irrigation District	0.3	Interconnection study requested.	1984
42.	Mendota Dam - Merced County near Los Banos	Central California Irrigation District	0.3	Preliminary interconnection study completed.	March 1985
43.	Lost Creek #1 - Shasta County near Hat Creek	Jim Simpson/ Floyd Bidwell	1.5	Final interconnection study defined. Awaiting action by developer.	Not yet determined
44.	McMillan - Shasta County near Round Mountain	Bob McMillan	0.975	Final interconnection study in progress.	February 1984
45.	San Luis Bypass - Merced County near Los Banos	Central California Irrigation District	0.5	Preliminary interconnection study completed.	March 1985
46.	Strickler/Bilstein - PGandE Potter Valley Powerhouse Tailrace Channel	Bruce Strickler & Warren Bilstein	0.25	Final interconnection study in progress. Operating agreement has been signed.	Not yet determined

Table XIX (continued)

HYDROELECTRIC PROJECTS GREATER THAN 100 kW UNDER ACTIVE DISCUSSION

STATUS REPORT

FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Owner</u>	<u>Approximate Installed Capacity - MW</u>	<u>Status</u>	<u>Projected Date of Operation</u>
47.	Wolfsen Bypass - Merced County near Los Banos	Central California Irrigation District	0.7	Preliminary interconnection study completed.	March 1985
48.	San Antonio Creek - Sonora	Snider Lumber Co.	0.3	Preliminary interconnection study in progress.	1984
49.	Schaads Reservoir - Calaveras County	Calaveras Public Utility District	0.25	Preliminary interconnection study in progress.	1984
50.	Bullard's Bar Dam - Yuba County	Yuba County Water Agency	0.15	Final interconnection study in progress.	July 1984
51.	Stovall #1 - Colusa County near Williams	Glenn- Colusa Irrigation District	0.12	Contract negotiations underway.	April 1984
52.	Anderson Dam - Morgan Hill	Santa Clara Valley Water District	0.8	Preliminary interconnection study completed.	1986
53.	Kirk Canal - Los Gatos	Santa Clara Valley Water District	0.35	Preliminary interconnection study completed.	1986
54.	Gansner Bar - Plumas County near Quincy	Leroy Austin	0.25	Preliminary interconnection study in progress.	December 1984

Table XIX (continued)
HYDROELECTRIC PROJECTS GREATER THAN 100 kW UNDER ACTIVE DISCUSSION

STATUS REPORT					
FOURTH QUARTER 1983					
<u>No.</u>	<u>Project Name and Location</u>	<u>Owner</u>	<u>Approximate Installed Capacity - MW</u>	<u>Status</u>	<u>Projected Date of Operation</u>
55.	Dayton Butler - Butte County near Paradise	Dayton Butler	0.5	Preliminary interconnection study in progress.	December 1984
56.	Forks of Butte - Butte County near Paradise	Butte Creek Improvement Company	12.6	Preliminary interconnection study in progress. Operating Agreement being developed for water rights concerns.	1986
57.	Roaring Creek - Shasta County near Hillcrest	John Downs	2.0	Preliminary interconnection study in progress.	December 1985
58.	<u>1/</u>	<u>1/</u>	1.0	Preliminary interconnection study in progress.	September 1985
59.	Hatchet Creek/Cove - Shasta County near Hillcrest	North Valley Land Company	6.0	Preliminary interconnection study in progress.	December 1985
60.	Roseburg Hatchet Creek - Shasta County near Hillcrest	Roseburg Lumber Company	7.0	Preliminary interconnection study in progress.	December 1985
61.	Kekawaka - Trinity County near Alderpoint	Calvin Stewart	5.0	Final interconnection study in progress.	September 1984
62.	Vanjop #1 - Sheridan	South Sutter Water District	0.35	Preliminary estimate provided to developer.	1984
63.	Baker Creek - Dinsmore	Al Hunt	1.5	Contract negotiations underway.	1985
TOTAL			<u>168.095 MW</u>		

1/ Project name, location and owner not authorized for release.

Table XX
HYDROELECTRIC PROJECTS 100 kW OR LESS UNDER ACTIVE DISCUSSION
STATUS REPORT
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Owner</u>	<u>Approximate Installed Capacity - kW</u>	<u>Status</u>	<u>Projected Date of Operation</u>
1.	Shasta Powerhouse - Berkeley	James Sungar	1	Power purchase agreement prepared for signature. Project under construction.	September 1984
2.	Magoon - Middleton	Orville Magoon	75	Negotiations ongoing for purchase of power.	March 1984
3.	Weingar - Mad Creek	Michael Weingar	10	Negotiations ongoing for purchase of power.	November 1984
4.	Plumb - Willow Creek	Whitson Plumb	100	Negotiations ongoing for purchase of power.	November 1984
5.	Calaveras No. 1 - CPUD Pipeline near Mokelumne Hill	Calaveras PUD	80	Interconnection cost study completed.	Early 1984
6.	Calaveras No. 2 - CPUD Pipeline near Mokelumne Hill	Calaveras PUD	80	Interconnection cost study completed.	Early 1984
7.	Calaveras No. 3 - CPUD Pipeline near Mokelumne Hill	Calaveras PUD	80	Interconnection cost study completed.	Early 1984
8.	Cron - Paradise	Oliver Cron	5	Project under construction.	June 1984
9.	Arnold - Bangor	Jim Arnold	30	Engineering cost estimate sent to developer.	September 1984
TOTAL			<u>461 kW</u>		

Table XXI
HYDROELECTRIC PROJECTS PLANNED TO BE CONSTRUCTED BY PGandE

STATUS REPORT
FOURTH QUARTER
1983

No.	Project Name and Location	Owner	Approximate Installed Capacity - MW	Status	Projected Date of Operation ^{1/}
1.	Newcastle - Placer County on North Fork American River arm of Folsom Lake	PGandE	10.2	Awaiting FERC license (application filed August 1981).	1986
2.	Oak Flat Powerhouse - Belden Forebay Dam near Belden	PGandE	1.3	FERC license issued March 1983.	1985
3.	Project C ^{2/}	PGandE	3.4	Application for FERC license to be filed in 1984.	1985
4.	Emigrant Gap Powerhouse - Drum Canal using flows from Lake Valley Canal	PGandE	1.7	Awaiting FERC license (application filed July 1982).	1987
5.	Christian Valley Powerhouse - Bear River Canal; drop into Halsey Forebay	PGandE	0.9	Awaiting FERC license (application filed July 1982).	1987
6.	Fiddler Green Powerhouse - Wise Canal; drop into Rock Creek Reservoir	PGandE	1.0	Awaiting FERC license (application filed July 1982).	1987
7.	Mokelumne River Project Additions				
	a. Doaks Ridge Powerhouse - at release from Tiger Creek Regulator near Pioneer	PGandE	0.7	Awaiting FERC license (application filed April 1981).	1986
	b. Mokelumne Powerhouse - Electra Afterbay on Mokelumne River near Jackson	PGandE	1.4	Awaiting FERC license (application filed April 1981).	1987

Table XXI (continued)
 HYDROELECTRIC PROJECTS PLANNED TO BE CONSTRUCTED BY PGandE
 STATUS REPORT
 FOURTH QUARTER
 1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Owner</u>	<u>Approximate Installed Capacity - MW</u>	<u>Status</u>	<u>Projected Date of Operation^{1/}</u>
7.	Mokelumne River Project Additions				
	c. West Point Powerhouse Unit 2 - near West Point	PGandE	7.0	Awaiting FERC license (application filed April 1981).	1987
	d. Salt Springs Powerhouse Unit 3 - near Pioneer	PGandE	7.6	Awaiting FERC license (application filed April 1981).	1987
	e. Mokelumne River Project Energy Improvements	PGandE	0.0 ^{3/}	Awaiting FERC license (application filed April 1981).	1987
8.	Scott Powerhouse - Scott Dam near Potter Valley	PGandE	3.0	Awaiting FERC license (application filed May 1981).	1986
9.	Rock Creek-Cresta Additions				
	a. Powerhouse at Rock Creek Dam - near Pulga	PGandE	0.8	Awaiting FERC license (application filed May 1981).	1989
	b. Powerhouse at Cresta Dam - near Pulga	PGandE	0.4	Awaiting FERC license (application filed May 1981).	1989
	c. Rock Creek Powerhouse Unit 3 - near Pulga	PGandE	37.0	Awaiting FERC license (application filed May 1981).	1989
	d. Cresta Powerhouse Unit 3 - near Pulga	PGandE	17.5	Awaiting FERC license (application filed May 1981).	1989
10.	Wise Powerhouse Unit 2 - near Auburn	PGandE	2.7	Awaiting FERC license (application filed December 1982).	1986
11.	Project L ^{2/}	PGandE	15.3	Application for FERC license under study.	1987

Table XXI (continued)

HYDROELECTRIC PROJECTS PLANNED TO BE CONSTRUCTED BY PGandE

STATUS REPORT

FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Owner</u>	<u>Approximate Installed Capacity - MW</u>	<u>Status</u>	<u>Projected Date of Operation^{1/}</u>
12.	Yellow Creek Diversion Project - new diversion to Belden Tunnel and Powerhouse near Belden	PGandE	0.0 ^{3/}	Awaiting FERC license (application filed October 1981).	1988
13.	Project N ^{2/}	PGandE	2.3	Application for FERC license to be filed in 1984.	1986
14.	Bucks Creek Project Additions				
	a. Maidu Powerhouse - Bucks Dam near Storrie	PGandE	1.0	Awaiting FERC license (application filed December 1981).	1987
	b. Grizzly Powerhouse - Grizzly Forebay near Storrie	PGandE	18.5	Awaiting FERC license (application filed December 1981).	1988
15.	Chambers and Jackass Diversion Project - new diversions to Rock Creek Tunnel and Powerhouse near Storrie	PGandE	0.0 ^{3/}	Awaiting FERC license (application filed December 1981).	1988
16.	DeSabra-Centerville Project Additions				
	a. Toadtown Powerhouse - on Hendricks Canal	PGandE	1.7	FERC order amending license issued August 1983.	1986
	b. DeSabra Powerhouse Unit 2 - next to existing DeSabra Powerhouse	PGandE	4.4	Application for FERC license to be filed in 1984.	1988
	c. New Centerville Powerhouse - replacement of Centerville Powerhouse	PGandE	8.3	Application for FERC license to be filed in 1984.	1988

Table XXI (continued)

HYDROELECTRIC PROJECTS PLANNED TO BE CONSTRUCTED BY PGandE

STATUS REPORT

FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Owner</u>	<u>Approximate Installed Capacity - MW</u>	<u>Status</u>	<u>Projected Date of Operation</u> ^{1/}
17.	Haas-Kings River Project Additions				
	a. Kings River Powerhouse Improvements	PGandE	2.6	Awaiting FERC license (application filed March 1982).	1987
	b. New diversions and tunnels from North Fork Kings River to Courtright Lake	PGandE	0.0 ^{3/}	Awaiting FERC license (application filed March 1982).	1992
	c. New diversions of flow from small streams into Haas Tunnel	PGandE	0.0 ^{3/}	Awaiting FERC license (application filed March 1982).	1990
	d. Rancheria Creek Diversion	PGandE	0.0 ^{3/}	Awaiting FERC license (application filed September 1983).	1987
	e. Haas Powerhouse Improvements	PGandE	34.6	Awaiting FERC license (application filed September 1983).	1988
		TOTAL	<u>185.3 MW</u>		

^{1/} Subject to change and FERC approval.^{2/} Project name and location will not be identified until regulatory applications are submitted.^{3/} Energy only project.

Table XXII
SUMMARY OF
INDUSTRY-OWNED COGENERATION IN PGandE SERVICE AREA
AND
AUXILIARY POWER SOURCES PROGRAM - CAPACITY UNDER CONTRACT TO PGandE
STATUS REPORT
FOURTH QUARTER
1983

Total Amount of Industry-Owned Cogeneration in PGandE Service Area	515,789 kW
Auxiliary Power Sources Program - Capacity Under Contract to PGandE	59,524 kW

Table XXIII
INACTIVE PROJECTS
STATUS REPORT
FOURTH QUARTER
1983

No.	Project Name and Location	Project Description	Date Discussions Began	Estimated Project Size MW	Date Project Became Inactive	Status
1.	Louisiana-Pacific Corporation - Rocklin	Electric power/steam project fueled by woodwaste	May 1977	5.0	August 1978	Project withdrawn at L-P's request.
2.	Worthington Industries - Fresno	Electric power project fueled by solid waste	February 1978	2.9	August 1978	Project withdrawn at Worthington Industries' request.
3.	^{1/}	Electric power project fueled by waste heat	November 1977	11.0	March 1979	Project withdrawn at request of proponent.
4.	Mobil Chemical Company - Woodland	Electric power/steam project	August 1977	4.0	September 1979	Project withdrawn at request of proponent.
5.	Husky Oil Company - Cat Canyon Oil Fields near Santa Maria	Electric power/steam project using gasification process returning steam for secondary recovery of oil; or a combined cycle project	September 1976	200.0 (assumed minimum)	February 1980	Husky investigating alternatives.
6.	PGandE, 77 Beale Street - San Francisco	Electric power/steam project using a gas turbine topping cycle	January 1979	0.4 - 0.7	April 1980	Project uneconomical compared with alternatives. Not currently under active consideration.
7.	California Products Company - Fresno	Electric power plant fueled by solid waste	September 1978	5.0	April 1980	Project withdrawn at request of proponent.
8.	U.S. Steel Corporation - Pittsburg	Electric power/steam project fueled by solid waste	October 1977	Not yet determined	March 1980	State Solid Waste Management Board canceled its allocated funds for the feasibility study. U.S. Steel is considering other alternatives.
9.	Harwood Products - Willits	Electric power/steam project fueled by woodwaste	October 1980	3 - 5	March 1981	Harwood does not wish to pursue the project at this time.

^{1/} Project name and location not authorized for release.

Table XXIII (continued)

INACTIVE PROJECTS

STATUS REPORT

FOURTH QUARTER
1983

No.	Project Name and Location	Project Description	Date Discussions Began	Estimated Project Size MW	Date Project Became Inactive	Status
10.	E. I. Dupont DeNemours and Company, Inc. - Antioch	Electric power/steam project using a gas turbine topping cycle	March 1979	9.1	December 1981	Dupont does not plan to consider cogeneration further at this time.
11.	Southern California Gas Company and PGandE Underground Natural Gas Storage Reservoir - Ten Section Field, Kern County	Electric power project fueled by waste heat from a gas compressor	January 1980	7.7	January 1982	Project suspended. Further field development questionable.
12.	E. Bruce & Elna B. Barron - Manton	Low-head hydroelectric facility	January 1981	0.01	March 1982	Project proponent will not be pursuing the project at this time.
13.	Exxon/PGandE/Martin Marietta/Badger Energy, Inc. - Edison	Industrial Process Heat/Solar Thermal (Central Receiver Cogeneration)	Early 1980	15.0	March 1982	Parties involved decided not to proceed with project.
14.	Foster Farms - Livingston	Electric power/steam project fueled by agricultural waste	July 1979	8.4	March 1982	Foster Farms has postponed the project indefinitely.
15.	Pacific Lumber Company - Scotia	Electric power/steam project fueled by woodwaste	September 1978	Not yet determined	March 1982	Project withdrawn at request of proponent.
16.	Spreckels Sugar - Woodland	Electric power/steam project using a gas turbine topping cycle	December 1979	5.0	May 1982	Spreckels does not wish to pursue the project at this time.
17.	San Francisco General Hospital - San Francisco	Electric power/steam project using a gas turbine topping cycle	March 1979	2.5	May 1982	Project undergoing lengthy review by the City and County of San Francisco.
18.	Windfarms, Ltd. - Solano County	Wind farm	March 1981	350.0	September 1982	Windfarms, Ltd. has postponed the project indefinitely.
19.	Stauffer Chemical Company - San Jose	Electric power/steam project using a gas turbine topping cycle	October 1978	12.7	December 1982	Stauffer is not considering cogeneration at this time.

Table XXIII (continued)

INACTIVE PROJECTS

STATUS REPORT

FOURTH QUARTER
1983

No.	Project Name and Location	Project Description	Date Discussions Began	Estimated Project Size MW	Date Project Became Inactive	Status
20.	<u>1/</u>	Electric power/steam project using a gas turbine topping cycle	September 1980	3.0	December 1982	Management disapproved proposed installation. Currently considering smaller facility.
21.	Brett Wakefield - Vallejo	Wind-powered generator	December 1981	1.8 kW	December 1982	Project postponed due to local government action.
22.	<u>1/</u>	Wind-powered generator	November 1981	1.8 kW	December 1982	Project postponed due to local government action.
23.	Biomass Corp. - Marysville	Electric power/steam project fueled by biomass	January 1981	0.4	March 1983	Project proponent will not be pursuing the project at this time.
24.	Frontier Industries - Santa Maria	Electric power/steam project using a steam turbine topping cycle fueled by bunker fuel oil	April 1982	5.4	March 1983	Project proponent will not be pursuing the project at this time.
25.	American Enertech Flotation Generator - Sacramento River near Colusa	Hydroelectric facility	January 1982	0.2	June 1983	Project proponent will not be pursuing the project at this time.
26.	Rio Bravo - Kern River near Bakersfield	Hydroelectric facility	February 1982	7.0	June 1983	Project not under active discussion at this time.
27.	<u>1/</u>	Electric power project fueled by digester gas	December 1981	0.05	June 1983	Project proponent will not be pursuing the project at this time. No parallel operation anticipated.

1/ Project name and location not authorized for release.

Table XXIII (continued)

INACTIVE PROJECTS

STATUS REPORT

FOURTH QUARTER
1983

No.	Project Name and Location	Project Description	Date Discussions Began	Estimated Project Size MW	Date Project Became Inactive	Status
28.	International Power Technology, Inc. - Sunnyvale	Electric power/steam project fueled by natural gas	November 1981	1.0	September 1983	Project proponent will not be pursuing the project at this time.
29.	McClellan Air Force Base Energy Showcase - Sacramento	Electric power/steam project using coal-fired fluidized bed boilers	August 1980	12.0	September 1983	Project proponent will not be pursuing the project at this time.
30.	The Wind Alliance - Altamont Pass	Wind farm	February 1982	13.3	September 1983	Developer plans are uncertain.
31.	North American Windpower - Altamont Pass	Wind farm	February 1982	12.0	September 1983	Developer plans are uncertain.
32.	Kelly Ridge II - South Fork Feather River	Hydroelectric facility	January 1982	2.3	December 1983	Project proponent will not be pursuing the project at this time.
33.	Ponderosa I - South Fork Feather River	Hydroelectric facility	April 1982	7.7	December 1983	Project proponent will not be pursuing the project at this time.
34.	Louisiana-Pacific Corporation - Antioch	Electric power/steam project fueled by woodwaste	May 1977	18 - 20	December 1983	Project proponent will not be pursuing the project at this time.
35.	Industrial Agrico, Inc. - San Joaquin	Electric power/steam project fueled by agricultural waste	September 1982	7.5 - 11.5	December 1983	Project proponent will not be pursuing the project at this time.
36.	EBC Company - Willits	Electric power project fueled by woodwaste	May 1980	0.3	December 1983	Project proponent will not be pursuing the project at this time.
37.	Battle Creek - Trinity County near Carrville	Hydroelectric facility	July 1982	0.55	December 1983	Project proponent will not be pursuing the project at this time.
38.	Red Crown Burner Systems - Oroville	Electric power/steam project fueled by agricultural waste	April 1981	11.0	December 1983	Project proponent will not be pursuing the project at this time.

Table XXIII (continued)

INACTIVE PROJECTS

STATUS REPORT

FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Discussions Began</u>	<u>Estimated Project Size MW</u>	<u>Date Project Became Inactive</u>	<u>Status</u>
39.	Red Crown Burner Systems - Blue Lake	Electric power project fueled by woodwaste	April 1981	11.0	December 1983	Project proponent will not be pursuing the project at this time.
40.	Red Crown Burner Systems - San Joaquin	Electric power project fueled by woodwaste	April 1981	11.0	December 1983	Project proponent will not be pursuing the project at this time.
41.	California Pacific Forest Products - Dinuba	Electric power/steam project fueled by woodwaste	October 1981	10.0	December 1983	Project proponent will not be pursuing the project at this time.
42.	Louisiana-Pacific Corp. - Oroville	Electric power/steam project fueled by woodwaste	March 1977	5 - 10	December 1983	Project proponent will not be pursuing the project at this time.
43.	Geothermal Power Co. - The Geysers, Lake County	Geothermal generation facility	February 1982	2.5	December 1983	Project proponent will not be pursuing the project at this time.
44.	Tenney Construction Co. - Hayfork	Electric power project fueled by woodwaste	November 1982	20.0	December 1983	Project proponent will not be pursuing the project at this time.
45.	Agro-Energy - Delano	Electric power project fueled by biomass	February 1982	12.0	December 1983	Project proponent will not be pursuing the project at this time.

TABLE XXIV
TERMINATED CONTRACTS
STATUS REPORT
FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>Size</u>	<u>Date Contract Terminated</u>
1.	Warm Springs Dam - Warm Springs	Regenerative braking of downhill earth conveyor	July 29, 1980	Energy Purchase	2.0 MW	September 25, 1981
2.	<u>1/</u>	Wind-powered generator	August 4, 1981	Energy Purchase	20 kW	May 7, 1982
3.	Rupert B. Adam - Nipomo Mesa	Wind-powered generator	August 1, 1981	Energy Purchase	5 kW	June 15, 1982
4.	<u>1/</u>	Wind-powered generator	August 7, 1981	Energy Purchase	10 kW	June 15, 1982
5.	Diamond O Ranch - Soledad	Wind-powered generator	May 11, 1981	Energy Purchase	20 kW	August 13, 1982
6.	Joe J. Jess - Livermore	Wind-powered generator	June 18, 1981	Energy Purchase	20 kW	January 27, 1983
7.	Great Falls Wind Energy - Altamont Pass	Wind-powered generator	January 8, 1982	Energy Purchase	20 kW	January 27, 1983
8.	American Mobile Power Corporation - Marina	Electric power project fueled by landfill gas	June 22, 1982	Capacity and Energy Purchase	1.2 MW	February 10, 1983
9.	Schneider Corp. - Richvale	Low-head hydroelectric facility	August 6, 1980	Energy Purchase	96 kW	June 23, 1983
10.	First Chowchilla, Inc. - Chowchilla	Electric power project fueled by low Btu gas	July 31, 1981	Capacity and Energy Purchase	10.0 MW	July 14, 1983
11.	Anthony Pearson - Fairfield	Wind-powered generator	June 17, 1982	Energy Purchase	10 kW	October 15, 1983

1/ Project name and location not authorized for release.

TABLE XXIV (continued)

TERMINATED CONTRACTS

STATUS REPORT

FOURTH QUARTER
1983

<u>No.</u>	<u>Project Name and Location</u>	<u>Project Description</u>	<u>Date Contract Signed</u>	<u>Type</u>	<u>Size</u>	<u>Date Contract Terminated</u>
12.	United Energy (formerly Renewable Power Corp.) - Davis	Photovoltaic	December 20, 1982	As-delivered Capacity and Energy Purchase	6 kW	October 31, 1983
13.	Ray Ratzlaff - Eureka	Wind-powered generator	November 6, 1981	Energy Purchase	1 kW	November 1, 1983

APPENDIX B

ANNOUNCEMENT
FOR
COGENERATORS
AND
SMALL POWER PRODUCERS
ENERGY PRICES
EFFECTIVE
JANUARY 1 - APRIL 30, 1984
AND
1984 AS-DELIVERED CAPACITY PRICE

PACIFIC GAS AND ELECTRIC COMPANY

PG&E

77 BEALE STREET • SAN FRANCISCO, CALIFORNIA 94106 • (415) 781-4211 • TWX 910-372-6587

ANNOUNCEMENT FOR COGENERATORS AND SMALL POWER PRODUCERS

ENERGY PRICES EFFECTIVE JANUARY 1 - APRIL 30, 1984 AND 1984 AS-DELIVERED CAPACITY PRICE

You requested that PG&E notify you of changes in the energy prices applicable to purchases by PG&E from qualified generation facilities using cogeneration, fuels derived from biomass, woodwastes or refuse and certain renewable resources.

The energy prices are the product of the rate for natural gas under Schedule No. G-55 (effective January 1, 1984), \$0.53978/therm and the new system incremental energy rates adopted by the California Public Utilities Commission (CPUC) in Decision No. 83-12-068, effective December 22, 1983, including an adjustment for the revenue requirement associated with cash working capital.

The energy purchase price calculations which will apply to energy deliveries determined from meter readings taken during January 1 to April 30 are as follows:

TIME PERIOD(a)	INCREMENTAL ENERGY RATE(b) (1)	COST OF ENERGY(c) (2)	REVENUE REQUIREMENT FOR CASH WORKING CAPITAL(d) (3)	ENERGY PURCHASE PRICE(e) (4)=(1)x(2)+(3)
<u>Time-of-Delivery Basis:</u>				
On-Peak	15,410 Btu/kWh	\$5.3978/10 ⁶ Btu	\$0.00053/kWh	\$0.08371/kWh
Partial-Peak	14,730	\$5.3978	\$0.00051/kWh	\$0.08002/kWh
Off-Peak	11,353	\$5.3978	\$0.00038/kWh	\$0.06166/kWh
<u>Without Time-of-Delivery Metering:</u>				
Seasonal Average (Period B)	13,089 Btu/kWh	\$5.3978/10 ⁶ Btu	\$0.00045/kWh	\$0.07110/kWh

In addition, the current shortage cost used to calculate the annual as-delivered capacity purchase price is \$156 per kW-year for deliveries during 1984. The current shortage cost is based upon the assumptions adopted by the CPUC in Decision No. 83-12-068. The methodology for computing the as-delivered capacity purchase price is described in Attachment B.

If you have any questions about these calculations, PG&E will make every effort to assist you. Please direct your inquiries to Mr. William Malcolm at (415) 781-4211, extension 2933. Written inquiries may be directed to Mr. S. P. Reynolds, Manager, Rate Department, PG&E, 77 Beale Street, San Francisco, CA 94106.

FOOTNOTES:

- Time periods are defined in Attachment A.
- Incremental energy rates in Btu/kWh derived from marginal energy costs (including variable operating and maintenance expense) adopted by the CPUC in Decision No. 83-12-068. They are based upon natural gas as the incremental fuel and average hydroelectric power conditions. Previously, incremental energy rates had been referred to as incremental heat rates. The terminology adopted in Decision Nos. 83-09-054 and 83-12-068 is now being used.
- Cost of natural gas under PG&E Gas Schedule No. G-55 (applicable to steam electric plants) in Decision No. 83-12-069 effective January 1, 1984.
- Revenue requirement for cash working capital as prescribed by the CPUC in Decision No. 83-12-068.
- Energy Purchase Price = (Incremental Energy Rate x Cost of Energy) + Revenue Requirement for Cash Working Capital. The energy purchase price excludes the applicable energy line loss adjustment factors. However, as ordered by Ordering Paragraph No. 12(j) of Decision No. 82-12-120, this figure is currently 1.0 for transmission and primary distribution loss adjustments and is equal to marginal cost line loss adjustment factors for the secondary distribution voltage level. These factors may be changed by the CPUC in the future. The current applicable energy loss adjustment factors are shown in Attachment A.

	<u>TIME PERIODS¹</u>		
	<u>Monday through Friday²</u>	<u>Saturdays²</u>	<u>Sundays and Holidays</u>
<u>Seasonal Period A</u> (May 1 through September 30)			
On-Peak	12:30 p.m. to 6:30 p.m.		
Partial-Peak	8:30 a.m. to 12:30 p.m. 6:30 p.m. to 10:30 p.m.	8:30 a.m. to 10:30 p.m.	
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	All Day
<u>Seasonal Period B</u> (October 1 through April 30)			
On-Peak	4:30 p.m. to 8:30 p.m.		
Partial-Peak	8:30 p.m. to 10:30 p.m. 8:30 a.m. to 4:30 p.m.	8:30 a.m. to 10:30 p.m.	
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	All Day

ENERGY LOSS ADJUSTMENT FACTORS³

	<u>Transmission</u>	<u>Primary Distribution</u>	<u>Secondary Distribution</u>
<u>Seasonal Period A</u> (May 1 through September 30)			
On-Peak	1.0	1.0	1.0148
Partial-Peak	1.0	1.0	1.0131
Off-Peak	1.0	1.0	1.0093
<u>Seasonal Period B</u> (October 1 through April 30)			
On-Peak	1.0	1.0	1.0128
Partial-Peak	1.0	1.0	1.0119
Off-Peak	1.0	1.0	1.0087

¹ This table is subject to change to accord with the on-peak, partial-peak, and off-peak periods as defined in PGandE's own rate schedules for the sale of electricity to its large industrial customers.

² Except the following holidays: New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, and Christmas Day, as specified in Public Law 90-363 (5 U.S.C.A. Section 6103(a)).

³ Marginal cost line loss adjustment factors at the secondary distribution voltage level as prescribed by the CPUC in Decision No. 83-12-068. The energy loss adjustment factors may be revised pursuant to orders of the CPUC.

PURCHASE PRICE FOR AS-DELIVERED CAPACITY FROM QUALIFYING FACILITIES FOR 1984

For Facilities which have time-of-delivery metering from which PGandE is contractually obligated to purchase as-delivered capacity at its annually published as-delivered capacity price, the as-delivered capacity payment for power delivered by the Facility to PGandE and accepted by PGandE is based on 100 percent of the shortage value of such power. The payment will be made at a rate which will vary by time of delivery and will be paid for each kWh produced and delivered by the Facility. The as-delivered capacity purchase price shown in Attachment B, page two is the product of three factors: (a) the current shortage cost, (b) the capacity loss adjustment factor and (c) the allocation factor, all of which are described below:

- (a) Current shortage cost in the year that the Facility is operating
The shortage cost, \$156 per kW-year in 1984 dollars, is the product of the annualized gas turbine cost and the Energy Reliability Index (ERI) adjustment factor, as prescribed by the California Public Utilities Commission (CPUC) in Decision No. 83-12-068.^{1/}
- (b) Capacity loss adjustment factor^{2/}
The current shortage cost is adjusted for the effect of the deliveries on PGandE's transmission and distribution losses based on the Seller's interconnection voltage level. The applicable capacity loss adjustment factors by voltage level are shown below:

<u>Voltage Level</u>	<u>Loss Adjustment Factor</u>
Transmission	.989
Primary Distribution	.991
Secondary Distribution	.991

- (c) Allocation factor^{3/}
The allocation factors account for the different values of as-delivered capacity in different time periods. The time periods to which they apply are shown in Attachment A. The allocation factors for Facilities for which time-of-delivery metering is installed are shown below:

<u>With Time-of-Delivery Metering</u>	<u>Allocation Factors</u> ^{3/}		
	<u>On-Peak</u> (¢-yr/\$-hr)	<u>Partial Peak</u> (¢-yr/\$-hr)	<u>Off-Peak</u> (¢-yr/\$-hr)
Period A	0.10835	0.02055	0.00002
Period B	0.00896	0.00109	0.00001

For facilities for which time-of-delivery metering is not installed, a weighted average allocation factor reflecting Period A or Period B, is shown below:

<u>Without Time-of-Delivery Metering</u>	<u>Weighted Average Allocation Factor</u> (¢-yr/\$-hr)
Period A	0.02525
Period B	0.00144

^{1/} The ERI is used to adjust the full gas turbine cost to reflect year-to-year changes in the system reliability levels.

^{2/} The capacity loss adjustment factors for non-remote Facilities (as defined by the CPUC) are subject to change pursuant to orders of the CPUC. The capacity factors for remote Facilities are determined individually.

^{3/} These allocation factors were prescribed by the CPUC in Decision No. 83-12-068. The units for the allocation factors, ¢-yr/\$-hr, are derived from the conversion of \$/kW-yr into ¢/kWh as follows:

$$\frac{\text{¢/kWh}}{\$/\text{kW-yr}} = \frac{\text{¢/kW-hr}}{\$/\text{kW-yr}} = \frac{\text{¢-yr}}{\$/\text{hr}}$$

PURCHASE PRICE FOR AS-DELIVERED CAPACITY

The purchase price for as-delivered capacity from non-remote qualifying Facilities is the product of three factors: the current shortage cost, the capacity loss adjustment factor and the allocation factor, shown on page one of Attachment B.

<u>Time Period</u>	<u>Transmission Level</u>		<u>Primary and Secondary Distribution Levels</u>	
	<u>Period A</u>	<u>Period B</u>	<u>Period A</u>	<u>Period B</u>
<u>Time-of-Delivery Basis:</u>				
On-Peak	\$0.16717/kWh	\$0.01382/kWh	\$0.16750/kWh	\$0.01385/kWh
Partial-Peak	\$0.03171/kWh	\$0.00168/kWh	\$0.03177/kWh	\$0.00169/kWh
Off-Peak	\$0.00003/kWh	\$0.00002/kWh	\$0.00003/kWh	\$0.00002/kWh

The purchase price for as-delivered capacity from Facilities for which time-of-delivery metering is not installed is 50 percent of the current shortage cost multiplied by the capacity loss adjustment factor and multiplied by a weighted average allocation factor, shown on page one of Attachment B.

<u>Without Time-of-Delivery Metering</u>				
Weighted Average	\$0.01948/kWh	\$0.00111/kWh	\$0.01952/kWh	\$0.00111/kWh

TOTAL PAYMENT FOR AS-DELIVERED CAPACITY AND ENERGY

<u>January 1 - April 30, 1984:</u>	<u>Transmission Level</u>	<u>Primary and Secondary Distribution Levels</u>
	<u>Period B</u>	<u>Period B</u>
<u>Time-of-Delivery Basis:</u>		
On-Peak	\$0.09753/kWh	\$0.09756/kWh
Partial-Peak	\$0.08170/kWh	\$0.08171/kWh
Off-Peak	\$0.06168/kWh	\$0.06168/kWh
<u>Without Time-of-Delivery</u>		
Seasonal Average (Period B)	\$0.07221/kWh	\$0.07221/kWh

APPENDIX C

STANDARD OFFER #1
POWER PURCHASE AGREEMENT
FOR
AS-DELIVERED CAPACITY AND ENERGY

PACIFIC GAS AND ELECTRIC COMPANY

STANDARD OFFER #1

POWER PURCHASE AGREEMENT

FOR

AS-DELIVERED CAPACITY AND ENERGY

DECEMBER 1983

STANDARD OFFER #1:
AS-DELIVERED CAPACITY AND ENERGY
POWER PURCHASE AGREEMENT

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AS-DELIVERED CAPACITY AND ENERGY
POWER PURCHASE AGREEMENT
BETWEEN

AND
PACIFIC GAS AND ELECTRIC COMPANY

____ ("Seller"), and PACIFIC GAS AND ELECTRIC COMPANY ("PGandE"), referred to collectively as "Parties" and individually as "Party", agree as follows:

ARTICLE 1 QUALIFYING STATUS

Seller warrants that, at the date of first power deliveries from Seller's Facility¹ and during the term of agreement, its Facility shall meet the qualifying facility requirements established as of the effective date of this Agreement by the Federal Energy Regulatory Commission's rules (18 Code of Federal Regulations 292) implementing the Public Utility Regulatory Policies Act of 1978 (16 U.S.C.A. 796, et seq.).

ARTICLE 2 PURCHASE OF POWER

- (a) Seller shall sell and deliver and PGandE shall purchase and accept from the Facility having a nameplate rating of _____ kW located at _____

_____ the as-delivered capacity and energy at the voltage level of _____ kV. Seller has chosen _____² as its energy sale option. Seller may convert its energy sale option as provided in Section A-3 of Appendix A.

- (b) The scheduled operation date when Seller estimates first delivery of electric energy from the Facility to PGandE is _____. At the end of each calendar quarter Seller shall [Date] give to PGandE written notice of any change in the scheduled operation date.

- (c) To avoid exceeding the physical limitations of the interconnection facilities, Seller shall limit the Facility's actual rate of delivery into the PGandE system to _____ kW.

- (d) The primary energy source for the Facility is _____.

- (e) If Seller does not begin construction of its Facility by _____, PGandE may reallocate [Date] the existing capacity on PGandE's transmission and/or distribution system which would have been used to accommodate Seller's power deliveries to other uses. In the event of such reallocation, Seller shall pay PGandE for the cost of any upgrades or additions to PGandE's system necessary to accommodate the output from the Facility. Such additional facilities shall be installed, owned, and maintained in accordance with the applicable PGandE tariff.

ARTICLE 3 PURCHASE PRICE

PGandE shall pay Seller for as-delivered capacity at prices authorized from time to time by the CPUC and which are derived from PGandE's full avoided costs as approved by the CPUC. PGandE shall pay Seller for energy at prices equal to PGandE's full short run avoided operating costs as approved by the CPUC. PGandE's current as-delivered capacity price calculation is shown in Appendix C. PGandE's current energy price calculation is shown in Table A, Appendix B.

¹ Underlining identifies those terms which are defined in Section A-1 of Appendix A.

² Insert either "net energy output" or "surplus energy output" to show the energy sale option selected by Seller.

ARTICLE 4 NOTICES

All written notices shall be directed as follows:

to PGandE: Pacific Gas and Electric Company
Attention: Vice President -
Electric Operations
77 Beale Street
San Francisco, CA 94106

to Seller: _____

ARTICLE 5 DESIGNATED SWITCHING CENTER

The designated PGandE switching center shall be unless changed by PGandE:

(Name)

(Location)

(Phone number)

ARTICLE 6 TERMS AND CONDITIONS

This Agreement includes the following appendices which are attached and incorporated by reference:

Appendix A - GENERAL TERMS AND CONDITIONS
Appendix B - ENERGY PRICES
Appendix C - AS-DELIVERED CAPACITY PRICES
Appendix D - INTERCONNECTION

ARTICLE 7 TERM OF AGREEMENT

This Agreement shall be binding upon execution and remain in effect thereafter for _____ years from the date of execution; provided, however, that it shall terminate if Seller does not commence deliveries of as-available capacity and energy within five years of this Agreement's execution date.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized representatives and effective as of the last date set forth below.

(SELLER)

PACIFIC GAS AND ELECTRIC COMPANY

BY: _____

BY: _____

(Type Name)

(Type Name)

TITLE: _____

TITLE: _____

DATE SIGNED: _____

DATE SIGNED: _____

APPENDIX A
GENERAL TERMS AND CONDITIONS

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APPENDIX A
GENERAL TERMS AND CONDITIONS

A-1 DEFINITIONS

Whenever used in this Agreement, appendices, and attachments hereto, the following terms shall have the following meanings:

CPUC - The Public Utilities Commission of the State of California.

Designated PGandE switching center - That switching center or other PGandE installation identified in Article 5.

Facility - That generation apparatus described in Article 2 and all associated equipment owned, maintained, and operated by Seller.

Interconnection facilities - All means required and apparatus installed to interconnect and deliver power from the Facility to the PGandE system including, but not limited to, connection, transformation, switching, metering, communications, and safety equipment, such as equipment required to protect (1) the PGandE system and its customers from faults occurring at the Facility, and (2) the Facility from faults occurring on the PGandE system or on the systems of others to which the PGandE system is directly or indirectly connected. Interconnection facilities also include any necessary additions and reinforcements by PGandE to the PGandE system required as a result of the interconnection of the Facility to the PGandE system.

Net energy output - The Facility's gross output in kilowatt-hours less station use and transformation and transmission losses to the point of delivery into the PGandE system. Where PGandE agrees that it is impractical to connect the station use on the generator side of the power purchase meter, PGandE may, at its option, apply a station load adjustment.

Prudent electrical practices - Those practices, methods, and equipment, as changed from time to time, that are commonly used in prudent electrical engineering and operations to design and operate electric equipment lawfully and with safety, dependability, efficiency, and economy.

Special facilities - Those additions and reinforcements to the PGandE system which are needed to accommodate the maximum delivery of energy and capacity from the Facility as provided in this Agreement and those parts of the interconnection facilities which are owned and maintained by PGandE at Seller's request, including metering and data processing equipment. All special facilities shall be owned, operated, and maintained pursuant to PGandE's electric Rule No. 21, which is attached hereto.

Station use - Energy used to operate the Facility's auxiliary equipment. The auxiliary equipment includes, but is not limited to, forced and induced draft fans, cooling towers, boiler feed pumps, lubricating oil systems, plant lighting, fuel handling systems, control systems, and sump pumps.

Surplus energy output - The Facility's gross output, in kilowatt-hours, less station use, and any other use by the Seller, and transformation and transmission losses to the point of delivery into the PGandE system.

Term of agreement - The period of time during which this Agreement will be in effect as provided in Article 7.

Voltage level - The voltage at which the Facility interconnects with the PGandE system, measured at the point of delivery.

A-2 CONSTRUCTION

A-2.1 Land Rights

Seller hereby grants to PGandE all necessary rights of way and easements to install, operate, maintain, replace, and remove the special facilities, including adequate and continuing access rights on property of Seller. Seller agrees to execute such other grants, deeds, or documents as PGandE may require to enable it to record such rights of way and easements. If any part of PGandE's equipment is to be installed on property owned by other than Seller, Seller shall, at its own cost and expense, obtain from the owners thereof all necessary rights of way and easements, in a form satisfactory to PGandE, for the construction, operation, maintenance, and replacement of PGandE's equipment upon such property. If Seller is unable to obtain these rights of way and easements, Seller shall reimburse PGandE for all costs incurred by PGandE in obtaining them. PGandE shall at all times have the right of ingress to and egress from the Facility at all reasonable hours for any purposes reasonably connected with this Agreement or the exercise of any and all rights secured to PGandE by law or its tariff schedules.

A-2.2 Design, Construction, Ownership, and Maintenance

- (a) Seller shall design, construct, install, own, operate, and maintain all interconnection facilities, except special facilities, to the point of interconnection with the PGandE system as required for PGandE to receive as-delivered capacity and energy from the Facility. The Facility and interconnection facilities shall meet all requirements of applicable codes and all standards of prudent electrical practices and shall be maintained in a safe and prudent manner. A description of the interconnection facilities for which Seller is solely responsible is set forth in Appendix D or if the interconnection requirements have not yet been determined at the time of the execution of this Agreement, the description of such facilities will be appended to this Agreement at the time such determination is made.
- (b) Seller shall submit to PGandE all specifications for the interconnection facilities (except special facilities) for review and written acceptance prior to their release for construction purposes. PGandE's review and acceptance of these specifications shall not be construed as confirming or endorsing the design or as warranting their safety, durability, or reliability. PGandE shall not, by reason of such review or lack of review, be responsible for strength, details of design, adequacy, or capacity of equipment built pursuant to such specifications, nor shall PGandE's acceptance be deemed to be an endorsement of any of such equipment. Seller shall change the interconnection facilities as may be reasonably required by PGandE to meet changing requirements of the PGandE system.
- (c) In the event it is necessary for PGandE to install interconnection facilities for the purposes of this Agreement, they shall be installed as special facilities.
- (d) Upon the request of Seller, PGandE shall provide a binding estimate for the installation of interconnection facilities by PGandE.

A-2.3 Meter Installation

- (a) PGandE shall specify, provide, install, own, operate, and maintain as special facilities all metering and data processing equipment for the registration and recording of energy and other related parameters which are required for the reporting of data to PGandE and for computing the payment due Seller from PGandE.
- (b) Seller shall provide, construct, install, own, and maintain at Seller's expense all that is required to accommodate the metering and data processing equipment, such as, but not limited to, metal-clad switchgear, switchboards, cubicles, metering panels, enclosures, conduits, rack structures, and equipment mounting pads.

A-3 ENERGY SALE OPTIONS

A-3.1 General

Seller has two energy sale options, net energy output or surplus energy output. Seller has made its initial selection in Article 2(a).

A-3.2 Energy Sale Conversion

- (a) Seller is entitled to convert from one option to the other 12 months after execution of this Agreement, and thereafter at least 12 months after the effective date of the most recent conversion, subject to the following conditions:
 - (1) Seller shall provide PGandE with a written request to convert its energy sale option.
 - (2) Seller shall comply with all applicable tariffs on file with the CPUC and contracts in effect between the Parties at the time of conversion covering the existing and proposed (i) facilities used to serve Seller's premises and (ii) interconnection facilities.
 - (3) Seller shall install and operate equipment required by PGandE to prevent PGandE from serving any part of Seller's load which is served by the Facility and not under contract for PGandE standby service. At Seller's request, PGandE shall provide this equipment as special facilities.
- (b) If, as a result of an energy sales conversion, Seller no longer requires the use of interconnection facilities installed and/or operated and maintained by PGandE as special facilities under a Special Facilities Agreement, Seller may reserve these facilities, for its future use, by continuing its performance under its Special Facilities Agreement. If Seller does not wish to reserve such facilities, it may terminate its Special Facilities Agreement.

If Seller's energy sale conversion results in its discontinuation of its use of PGandE facilities not covered by Seller's Special Facilities Agreement, Seller cannot reserve those facilities for future use. Seller's future use of such facilities shall be contingent upon the availability of such facilities at the time Seller requests such use. If such facilities are not available, Seller

shall bear the expense necessary to install, own, and maintain the needed additional facilities in accordance with PGandE's applicable tariff.

- (c) PGandE shall process requests for conversion in the order received. The effective date of conversion shall depend on the completion of the changes required to accommodate Seller's energy sale conversion.

A-4 OPERATION

A-4.1 Inspection and Approval

Seller shall not operate the Facility in parallel with PGandE's system until an authorized PGandE representative has inspected the interconnection facilities, and PGandE has given written approval to begin parallel operation. Seller shall notify PGandE of the Facility's start-up date at least 45 days prior to such date. PGandE shall inspect the interconnection facilities within 30 days of the receipt of such notice. If parallel operation is not authorized by PGandE, PGandE shall notify Seller in writing within five days after inspection of the reason authorization for parallel operation was withheld.

A-4.2 Facility Operation and Maintenance

Seller shall operate and maintain its Facility according to prudent electrical practices, applicable laws, orders, rules, and tariffs and shall provide such reactive power support as may be reasonably required by PGandE to maintain system voltage level and power factor. Seller shall operate the Facility at the power factors or voltage levels prescribed by PGandE's system dispatcher or designated representative. If Seller fails to provide reactive power support, PGandE may do so at Seller's expense.

A-4.3 Point of Delivery

Seller shall deliver the energy at the point where Seller's electrical conductors (or those of Seller's agent) contact PGandE's system as it shall exist whenever the deliveries are being made or at such other point or points as the Parties may agree in writing. The initial point of delivery of Seller's power to the PGandE system is set forth in Appendix D.

A-4.4 Operating Communications

- (a) Seller shall maintain operating communications with the designated PGandE switching center. The operating communications shall include, but not be limited to, system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, levels of operating voltage or power factors, and daily capacity and generation reports.
- (b) Seller shall keep a daily operations log for each generating unit which shall include information on unit availability, maintenance outages, circuit breaker trip operations requiring a manual reset, and any significant events related to the operation of the Facility.
- (c) If Seller makes deliveries greater than one megawatt, Seller shall measure and register on a graphic recording device power in kW and voltage in kV at a location within the Facility agreed to by both Parties.
- (d) If Seller makes deliveries greater than one and up to and including ten megawatts, Seller shall report to the designated PGandE switching center, twice a day at agreed upon times for the current day's operation, the hourly readings in kW of capacity delivered and the energy in kWh delivered since the last report.
- (e) If Seller makes deliveries of greater than ten megawatts, Seller shall telemeter the delivered capacity and energy information, including real power in kW, reactive power in kVAR, and energy in kWh to a switching center selected by PGandE. PGandE may also require Seller to telemeter transmission kW, kVAR, and kV data depending on the number of generators and transmission configuration. Seller shall provide and maintain the data circuits required for telemetering. When telemetering is inoperative, Seller shall report daily the capacity delivered each hour and the energy delivered each day to the designated PGandE switching center.

A-4.5 Meter Testing and Inspection

- (a) All meters used to provide data for the computation of the payments due Seller from PGandE shall be sealed, and the seals shall be broken only by PGandE when the meters are to be inspected, tested, or adjusted.
- (b) PGandE shall inspect and test all meters upon their installation and annually thereafter. At Seller's request and expense, PGandE shall inspect or test a meter more frequently. PGandE shall give reasonable notice to Seller of the time when any inspection or test shall take place, and Seller may have representatives present at the test or inspection. If a meter is found to be inaccurate or defective, PGandE shall adjust, repair, or replace it at its expense in order to provide accurate metering.

A-4.6 Adjustments to Meter Measurements

If a meter fails to register, or if the measurement made by a meter during a test varies by more than two percent from the measurement made by the standard meter used in the test, an adjustment shall be made correcting all measurements made by the inaccurate meter for (1) the actual period during which inaccurate measurements were made, if the period can be determined, or if not, (2) the period immediately preceding the test of the meter equal to one-half the time from the date of the last previous test of the meter, provided that the period covered by the correction shall not exceed six months.

A-5 PAYMENT

PGandE shall mail to Seller not later than 30 days after the end of each monthly billing period (1) a statement showing the kilowatt-hours delivered to PGandE during on-peak, partial-peak, and off-peak periods during the monthly billing period, (2) PGandE's computation of the payment due Seller, and (3) PGandE's check in payment of said amount. Except as provided in Section A-6, if within 30 days of receipt of the statement Seller does not make a report in writing to PGandE of an error, Seller shall be deemed to have waived any error in PGandE's statement, computation, and payment, and they shall be considered correct and complete.

A-6 ADJUSTMENTS OF PAYMENTS

- (a) In the event adjustments to payments are required as a result of inaccurate meters, PGandE shall use the corrected measurements described in Section A-4.6 to recompute the amount due from PGandE to Seller for the as-delivered capacity and energy delivered under this Agreement during the period of inaccuracy.
- (b) The additional payment to Seller or refund to PGandE shall be made within 30 days of notification of the owing Party of the amount due.

A-7 ACCESS TO RECORDS AND PGandE DATA

Each Party, after reasonable written notice to the other Party, shall have the right of access to all metering and related records including the operations logs of the Facility. Data filed by PGandE with the CPUC pursuant to CPUC orders governing the purchase of power from qualifying facilities shall be provided to Seller upon request; provided that Seller shall reimburse PGandE for the costs it incurs to respond to such request.

A-8 CURTAILMENT OF DELIVERIES AND HYDRO SPILL CONDITIONS

- (a) PGandE shall not be obligated to accept or pay for and may require Seller to interrupt or reduce deliveries of as-delivered capacity and energy (1) when necessary in order to construct, install, maintain, repair, replace, remove, investigate, or inspect any of its equipment or any part of its system, or (2) if it determines that interruption or reduction is necessary because of emergencies, forced outages, force majeure, or compliance with prudent electrical practices.
- (b) In anticipation of a period of hydro spill conditions, as defined by the CPUC, PGandE may notify Seller that any purchases of energy from Seller during such period shall be at hydro savings prices quoted by PGandE. If Seller delivers energy to PGandE during any such period, Seller shall be paid hydro savings prices for those deliveries in lieu of prices which would otherwise be applicable. The hydro savings prices shall be calculated by PGandE using the following formula:

$$\frac{AQF - S}{AQF} \times PP$$

where: AQF = Energy, in kWh, projected to be available during hydro spill conditions from all qualifying facilities under agreements containing hydro savings price provisions.

S = Potential energy, in kWh, from PGandE hydro facilities which will be spilled if all AQF is delivered to PGandE.

PP = Prices published by PGandE for purchases during other than hydro spill conditions.

- (c) PGandE shall not be obligated to accept or pay for and may require Seller with a Facility with a nameplate rating of one megawatt or greater to interrupt or reduce deliveries of as-delivered capacity and energy during periods when purchases under this Agreement would result in costs greater than those which PGandE would incur if it did not make such purchases but instead generated an equivalent amount of energy itself.
- (d) Whenever possible, PGandE shall give Seller reasonable notice of the possibility that interruption or reduction of deliveries under subsections (a) or (c), above, may be required. PGandE shall give

Seller notice of general periods when hydro spill conditions are anticipated, and shall give Seller as much advance notice as practical of any specific hydro spill period and the hydro savings price which will be applicable during such period. Before interrupting or reducing deliveries under subsection (c), above, and before invoking hydro savings prices under subsection (b) above, PGandE shall take reasonable steps to make economy sales of the surplus energy giving rise to the condition. If such economy sales are made, while the surplus energy condition exists Seller shall be paid at the economy sales price obtained by PGandE in lieu of the otherwise applicable prices.

- (e) If Seller is selling net energy output to PGandE and simultaneously purchasing its electrical needs from PGandE, energy curtailed pursuant to subsections (b) or (c) above shall not be used by Seller to meet its electrical needs. When Seller elects not to sell energy to PGandE at the hydro savings price pursuant to subsection (b) or when PGandE curtails deliveries of energy pursuant to subsection (c), Seller shall continue to purchase all its electrical needs from PGandE. If Seller is selling surplus energy output to PGandE, subsections (b) or (c) shall only apply to the surplus energy output being delivered to PGandE, and Seller can continue to internally use that generation it has retained for its own use.

A-9 FORCE MAJEURE

- (a) The term force majeure as used herein means unforeseeable causes beyond the reasonable control of and without the fault or negligence of the Party claiming force majeure including, but not limited to, acts of God, labor disputes, sudden actions of the elements, actions by federal, state, and municipal agencies, and actions of legislative, judicial, or regulatory agencies which conflict with the terms of this Agreement.
- (b) If either Party because of force majeure is rendered wholly or partly unable to perform its obligations under this Agreement, that Party shall be excused from whatever performance is affected by the force majeure to the extent so affected provided that:
 - (1) the non-performing Party, within two weeks after the occurrence of the force majeure, gives the other Party written notice describing the particulars of the occurrence,
 - (2) the suspension of performance is of no greater scope and of no longer duration than is required by the force majeure,
 - (3) the non-performing Party uses its best efforts to remedy its inability to perform (this subsection shall not require the settlement of any strike, walkout, lockout, or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to its interest. It is understood and agreed that the settlement of strikes, walkouts, lockouts, or other labor disputes shall be at the sole discretion of the Party having the difficulty), and
 - (4) when the non-performing Party is able to resume performance of its obligations under this Agreement, that Party shall give other Party written notice to that effect.
- (c) In the event a Party is unable to perform due to legislative, judicial, or regulatory agency action, this Agreement shall be renegotiated to comply with the legal change which caused the non-performance.

A-10 INDEMNITY

Each Party as indemnitor shall save harmless and indemnify the other Party and the directors, officers, and employees of such other Party against and from any and all loss and liability for injuries to persons including employees of either Party, and property damages, including property of either Party, resulting from or arising out of (1) the engineering, design, construction, maintenance, or operation of or (2) the making of replacements, additions, or betterments to, the indemnitor's facilities. This indemnity and save harmless provision shall apply notwithstanding the active or passive negligence of the indemnitee. Neither Party shall be indemnified hereunder for liability or loss resulting from its sole negligence or willful misconduct. The indemnitor shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity and shall pay all costs, including reasonable attorney fees, that may be incurred by the other Party in enforcing this indemnity.

A-11 LIABILITY; DEDICATION

- (a) Nothing in this Agreement shall create any duty to, any standard of care with reference to, or any liability to any person not a Party to it. Neither Party shall be liable to the other Party for consequential damages.
- (b) Each Party shall be responsible for protecting its facilities from possible damage by reason of electrical disturbances or faults caused by the operation, faulty operation, or nonoperation of the other Party's facilities, and such other Party shall not be liable for any such damages so caused.

- (c) No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public nor affect the status of PGandE as an independent public utility corporation or Seller as an independent individual or entity and not a public utility.

A-12 SEVERAL OBLIGATIONS

Except where specifically stated in this Agreement to be otherwise, the duties, obligations, and liabilities of the Parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership, or joint venture or impose a trust or partnership duty, obligation, or liability on or with regard to either Party. Each Party shall be liable individually and severally for its own obligations under this Agreement.

A-13 NON-WAIVER

Failure to enforce any right or obligation by either Party with respect to any matter arising in connection with this Agreement shall not constitute a waiver as to that matter or any other matter.

A-14 ASSIGNMENT

Neither Party shall voluntarily assign its rights nor delegate its duties under this Agreement, or any part of such rights or duties, without the written consent of the other Party, except in connection with the sale or merger of a substantial portion of its properties. Any such assignment or delegation made without such written consent shall be null and void. Consent for assignment will not be withheld unreasonably. Such assignment shall include, unless otherwise specified therein, all of Seller's rights to any refunds which might become due under this Agreement.

A-15 CAPTIONS

All indexes, titles, subject headings, section titles, and similar items are provided for the purpose of reference and convenience and are not intended to affect the meaning of the contents or scope of this Agreement.

A-16 CHOICE OF LAWS

This Agreement shall be interpreted in accordance with the laws of the State of California, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

A-17 GOVERNMENTAL JURISDICTION AND AUTHORIZATION

Seller shall obtain any governmental authorizations and permits required for the construction and operation of the Facility. Seller shall reimburse PGandE for any and all losses, damages, claims, penalties, or liability it incurs as a result of Seller's failure to obtain or maintain such authorizations and permits.

A-18 NOTICES

Any notice, demand, or request required or permitted to be given by either Party to the other, and any instrument required or permitted to be tendered or delivered by either Party to the other, shall be in writing and so given, tendered, or delivered, as the case may be, by depositing the same in any United States Post Office with postage prepaid for transmission by certified mail, return receipt requested, addressed to the Party, or personally delivered to the Party, at the address in Article 4 of this Agreement. Changes in such designation may be made by notice similarly given.

A-19 INSURANCE

A-19.1 General Liability Coverage

- (a) Seller shall maintain during the performance hereof, General Liability Insurance¹ of not less than \$1,000,000 if the Facility is over 100 kW, \$500,000 if the Facility is over 20 kW to 100 kW, and \$100,000 if the Facility is 20 kW or below of combined single limit or equivalent for bodily injury, personal injury, and property damage as the result of any one occurrence.
- (b) General Liability Insurance shall include coverage for Premises-Operations, Owners and Contractors Protective, Products/Completed Operations Hazard, Explosion, Collapse, Underground, Contractual Liability, and Broad Form Property Damage including Completed Operations.

¹ Governmental agencies which have an established record of self-insurance may provide the required coverage through self-insurance.

- (c) Such insurance, by endorsement to the policy(ies), shall include PGandE as an additional insured if the Facility is over 100 kW insofar as work performed by Seller for PGandE is concerned, shall contain a severability of interest clause, shall provide that PGandE shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for payment of premium for such insurance, and shall provide for 30-day's written notice to PGandE prior to cancellation, termination, alteration, or material change of such insurance.

A-19.2 Additional Insurance Provisions

- (a) Evidence of coverage described above in Section A-19.1 shall state that coverage provided is primary and is not excess to or contributing with any insurance or self-insurance maintained by PGandE.
- (b) PGandE shall have the right to inspect or obtain a copy of the original policy(ies) of insurance.
- (c) Seller shall furnish the required certificates¹ and endorsements to PGandE prior to commencing operation.
- (d) All insurance certificates¹, endorsements, cancellations, terminations, alterations, and material changes of such insurance shall be issued and submitted to the following:

PACIFIC GAS AND ELECTRIC COMPANY
Attention: Manager - Insurance Department
77 Beale Street, Room E280
San Francisco, CA 94106

¹ A governmental agency qualifying to maintain self-insurance should provide a statement of self-insurance.

APPENDIX B

ENERGY PRICES

TABLE A

Energy Prices Effective January 1 - April 30, 1984

The energy purchase price calculations which will apply to energy deliveries determined from meter readings taken during January, February, March, and April 1984 are as follows:

Time Period	(a) Incremental Energy Rate ¹ (Btu/kWh)	(b) Cost of Energy ² (\$/10 ⁶ Btu)	(c) Revenue Requirement for Cash Working Capital ³ (\$/kWh)	(d) Energy Purchase Price ⁴ (d)=[(a)x(b)]+(c) (\$/kWh)
Jan. 1 - April 30 (Period B)				
Time of Delivery Basis:				
On-Peak	15,410	5.3978	0.00053	0.08371
Partial-Peak	14,730	5.3978	0.00051	0.08002
Off-Peak	11,353	5.3978	0.00038	0.06166
Seasonal Average (Period B)	13,089	5.3978	0.00045	0.07110

¹ Incremental energy rates in Btu/kWh are derived from marginal energy costs (including variable operating and maintenance expense) adopted by CPUC Decision No. 83-12-068. They are based upon natural gas as the incremental fuel and weighted average hydro electric power conditions.

² Cost of natural gas under PGandE Gas Schedule No. G-55 (applicable to steam electric plants) in CPUC Decision No. 83-12-069 effective January 1, 1984.

³ Revenue requirement for cash working capital as prescribed by the CPUC in Decision No. 83-12-068.

⁴ Energy Purchase Price = (Incremental Energy Rate x Cost of Energy) + Revenue Requirement for Cash Working Capital. The energy purchase price excludes the applicable energy line loss adjustment factors. However, as ordered by Ordering Paragraph No. 12(j) of Decision No. 82-12-120, this figure is currently 1.0 for transmission and primary distribution loss adjustments and is equal to marginal cost line loss adjustment factors for the secondary distribution voltage level. These factors may be changed by the CPUC in the future. The currently applicable energy loss adjustment factors are shown in Table C.

TABLE B¹
Time Periods

	<u>Monday through Friday²</u>	<u>Saturdays²</u>	<u>Sundays and Holidays</u>
Seasonal Period A (May 1 through September 30)			
On-Peak	12:30 p.m. to 6:30 p.m.		
Partial-Peak	8:30 a.m. to 12:30 p.m. 6:30 p.m. to 10:30 p.m.	8:30 a.m. to 10:30 p.m.	
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	All Day
Seasonal Period B (October 1 through April 30)			
On-Peak	4:30 p.m. to 8:30 p.m.		
Partial-Peak	8:30 p.m. to 10:30 p.m. 8:30 a.m. to 4:30 p.m.	8:30 a.m. to 10:30 p.m.	
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	All Day

TABLE C
Energy Loss Adjustment Factors³

	<u>Transmission</u>	<u>Primary Distribution</u>	<u>Secondary Distribution</u>
Seasonal Period A (May 1 through September 30)			
On-Peak	1.0	1.0	1.0148
Partial-Peak	1.0	1.0	1.0131
Off-Peak	1.0	1.0	1.0093
Seasonal Period B (October 1 through April 30)			
On-Peak	1.0	1.0	1.0128
Partial-Peak	1.0	1.0	1.0119
Off-Peak	1.0	1.0	1.0087

¹ This table is subject to change to accord with the on-peak, partial-peak, and off-peak periods as defined in PGandE's own rate schedules for the sale of electricity to its large industrial customers.

² Except the following holidays: New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, and Christmas Day, as specified in Public Law 90-363 (5 U.S.C.A. Section 6103(a)).

³ The applicable energy loss adjustment factors may be revised pursuant to orders of the CPUC.

APPENDIX C

AS-DELIVERED CAPACITY PRICES

Purchase Price for As-Delivered Capacity from Qualifying Facilities for 1984

For Facilities with time-of-delivery metering and from which PGandE is contractually obligated to purchase as-delivered capacity at its annually published as-delivered capacity price, the as-delivered capacity payment for power delivered by the Facility to PGandE and accepted by PGandE is based on 100 percent of the shortage value of such power. The payment will be made at a rate which will vary by time of delivery and will be made for each kWh produced and delivered by the Facility. The as-delivered capacity purchase price is shown on Table C as a function of the interconnection voltage, and is the product of three factors:

- (a) The current shortage cost in each year the Facility is operating. Currently, this shortage cost, \$156 per kW-year, is the product of the annualized gas turbine cost and the Energy Reliability Index (ERI) adjustment factor, as prescribed by the CPUC in Decision No. 83-12-068 (December 22, 1983). The basis for the shortage cost may be revised by the CPUC from time to time.
- (b) A capacity loss adjustment factor. The current shortage cost is adjusted for the effect of the deliveries on PGandE's transmission and distribution losses based on the Seller's interconnection voltage level. The applicable capacity loss adjustment factors for non-remote¹ Facilities are presented in Table A. Capacity loss adjustment factors for remote Facilities shall be calculated individually.
- (c) An allocation factor, which accounts for the different values of as-delivered capacity in different time periods, and converts dollars per kW-year to cents per kWh. The allocation factors are presented in Table B. The time periods to which they apply are shown in Table B, Appendix B.

For Facilities without time-of-delivery metering, the price paid for as-delivered capacity shall be 50% of the current shortage cost (a) multiplied by a capacity loss adjustment factor (b) and multiplied by a weighted average allocation factor (c).

TABLE A

Capacity Loss Adjustment Factors²
for Non-Remote¹ Facilities

Voltage Level	Loss Adjustment Factor
Transmission	.989
Primary Distribution	.991
Secondary Distribution	.991

TABLE B

Allocation Factors for
As-Delivered Capacity³

Voltage Level	Loss Adjustment Factor	With Time-of-Delivery Metering	On-Peak	Partial-Peak	Off-Peak
			(¢-yr/\$-hr)	(¢-yr/\$-hr)	(¢-yr/\$-hr)
Transmission	.989	Seasonal Period A	0.10835	0.02055	.00002
Primary Distribution	.991	Seasonal Period B	0.00896	0.00109	.00001
Secondary Distribution	.991				
		Without Time-of-Delivery Metering		Weighted Average	
				(¢-yr/\$-hr)	
		Seasonal Period A		0.02525	
		Seasonal Period B		0.00144	

¹ As defined by the CPUC.

² The capacity loss adjustment factors for non-remote Facilities are subject to change pursuant to orders of the CPUC. The capacity loss adjustment factors for remote Facilities are determined individually.

³ The units for the allocation factor, ¢-yr/\$-hr, are derived from the conversion of \$/kW-yr into ¢/kWh as follows:

$$\frac{\text{¢/kWh}}{\text{\$/kW-yr}} = \frac{\text{¢/kW-hr}}{\text{\$/kW-yr}} = \frac{\text{¢-yr}}{\text{\$-hr}}$$

The allocation factors were described by the CPUC in Decision No. 83-12-068 and are subject to change from time to time.

TABLE C

Purchase Price for As-Delivered Capacity
from Non-Remote¹ Qualifying Facilities

(The product of the current shortage
cost (a), the capacity loss adjustment
factor (b), and the allocation factor (c))

	<u>Transmission Voltage</u>		<u>Primary Distribution Voltage</u>		<u>Secondary Distribution Voltage</u>	
	<u>Seasonal</u>	<u>Seasonal</u>	<u>Seasonal</u>	<u>Seasonal</u>	<u>Seasonal</u>	<u>Seasonal</u>
	<u>Period A</u>	<u>Period B</u>	<u>Period A</u>	<u>Period B</u>	<u>Period A</u>	<u>Period B</u>
	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)
<u>With Time-of Delivery Metering</u>						
<u>Time of Delivery</u>						
On-Peak	16.717	1.382	16.750	1.385	16.750	1.385
Partial-Peak	3.171	0.168	3.177	0.169	3.177	0.169
Off-Peak	0.003	0.002	0.003	0.002	0.003	0.002
<u>Without Time-of Delivery Metering</u>						
Weighted Average	1.948	0.111	1.952	0.111	1.952	0.111

¹ As defined by the CPUC.

APPENDIX D
INTERCONNECTION

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APPENDIX D
INTERCONNECTION

D-1 INTERCONNECTION TARIFFS

(The applicable tariffs in effect at the time of execution of this Agreement shall be attached.)

D-2 POINT OF DELIVERY LOCATION SKETCH

D-3

S.O. #1
December 5, 1983

D-3 INTERCONNECTION FACILITIES FOR WHICH SELLER IS RESPONSIBLE

APPENDIX D

STANDARD OFFER #2
POWER PURCHASE AGREEMENT
FOR
FIRM CAPACITY AND ENERGY

PACIFIC GAS AND ELECTRIC COMPANY

STANDARD OFFER #2

POWER PURCHASE AGREEMENT

FOR

FIRM CAPACITY AND ENERGY

DECEMBER 1983

STANDARD OFFER #2:
FIRM CAPACITY AND ENERGY
POWER PURCHASE AGREEMENT

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FIRM CAPACITY AND ENERGY
POWER PURCHASE AGREEMENT
BETWEEN

AND
PACIFIC GAS AND ELECTRIC COMPANY

____ ("Seller"), and PACIFIC GAS AND ELECTRIC COMPANY ("PGandE"),
referred to collectively as "Parties" and individually as "Party", agree as follows:

ARTICLE 1 QUALIFYING STATUS

Seller warrants that, at the date of first power deliveries from Seller's Facility¹ and during the term of agreement, its Facility shall meet the qualifying facility requirements established as of the effective date of this Agreement by the Federal Energy Regulatory Commission's rules (18 Code of Federal Regulations 292) implementing the Public Utility Regulatory Policies Act of 1978 (16 U.S.C.A. 796, et seq.).

ARTICLE 2 PURCHASE OF POWER

(a) Seller shall sell and deliver and PGandE shall purchase and accept delivery of firm capacity and energy at the voltage level of _____ kV as indicated below--

1. Contract capacity - _____ kW; and
2. Energy - _____².

Seller may convert its energy sale option as provided in Section A-3 of Appendix A.

(b) Seller shall provide the firm capacity and energy set forth above from its _____ kW
[Nameplate rating of
generator(s)]

Facility located at _____

(c) The scheduled operation date of the Facility is _____. At the end of each calendar quarter
[Date]
Seller shall give written notice to PGandE of any change in the scheduled operation date.

(d) To avoid exceeding the physical limitations of the interconnection facilities, Seller shall limit the Facility's actual rate of delivery into the PGandE system to _____ kW.

(e) The primary energy source for the Facility is _____.

(f) If Seller does not begin construction of its Facility by _____, PGandE may reallocate the
[Date]
existing capacity on PGandE's transmission and/or distribution system which would have been used to accommodate Seller's power deliveries to other uses. In the event of such reallocation, Seller shall pay PGandE for the cost of any upgrades or additions to PGandE's system necessary to accommodate the output from the Facility. Such additional facilities shall be installed, owned, and maintained in accordance with the applicable PGandE tariff.

¹ Underlining identifies those terms which are defined in Section A-1 of Appendix A.

² Insert either "net energy output" or "surplus energy output" to show the energy sale option selected by Seller.

ARTICLE 3 PURCHASE PRICE

- (a) PGandE shall pay Seller for firm capacity at the contract capacity price under Option ____ set forth in Section C-5 of Appendix C. The contract capacity price is derived from PGandE's full avoided costs as approved by the CPUC. PGandE's obligation to pay for the contract capacity shall begin on the actual operation date. Seller elects to have its contract capacity price determined from the firm capacity price schedule in effect on ____¹. The contract capacity price shall be subject to adjustment as provided for in Appendix D.
- (b) PGandE shall pay Seller for energy at prices equal to PGandE's full short run avoided operating costs as approved by the CPUC.
- (c) The contract capacity price is applicable to deliveries of capacity beginning after December 30, 1982.

ARTICLE 4 NOTICES

All written notices shall be directed as follows:

to PGandE: Pacific Gas and Electric Company
Attention: Vice President -
Electric Operations
77 Beale Street
San Francisco, CA 94106

to Seller: _____

ARTICLE 5 DESIGNATED SWITCHING CENTER

The designated PGandE switching center shall be unless changed by PGandE:

(Name)

(Location)

(Phone number)

ARTICLE 6 TERMS AND CONDITIONS

This Agreement includes the following appendices which are attached and incorporated by reference:

- Appendix A - GENERAL TERMS AND CONDITIONS
- Appendix B - ENERGY PRICES
- Appendix C - FIRM CAPACITY PRICE SCHEDULE
- Appendix D - ADJUSTMENT OF CAPACITY PAYMENTS IN THE EVENT OF TERMINATION OR REDUCTION
- Appendix E - INTERCONNECTION

¹ Insert either "the date of execution of this Agreement" or "the actual operation date".

ARTICLE 7 TERM OF AGREEMENT

This Agreement shall be binding upon execution and remain in effect thereafter for _____ years from the actual operation date; provided, however, that it shall terminate if the actual operation date does not occur within five years of the execution date.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized representatives and effective as of the last date set forth below.

(SELLER)

PACIFIC GAS AND ELECTRIC COMPANY

BY: _____

BY: _____

(Type Name)

(Type Name)

TITLE: _____

TITLE: _____

DATE SIGNED: _____

DATE SIGNED: _____

APPENDIX A
GENERAL TERMS AND CONDITIONS
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APPENDIX A

GENERAL TERMS AND CONDITIONS

A-1 DEFINITIONS

Whenever used in this Agreement, appendices, and attachments hereto, the following terms shall have the following meanings:

Actual operation date - The day following the day during which all features and equipment of the Facility are demonstrated to PGandE's satisfaction to be capable of operating simultaneously to deliver power continuously into PGandE's system as provided in this Agreement.

Adjusted capacity price - The \$/kW-year purchase price from Table B, Appendix C for the period of Seller's actual performance.

Capacity sale reduction - A reduction in the amount of capacity provided or to be provided under this Agreement, other than a temporary reduction during probationary periods under Section C-5.

Contract capacity - That capacity identified in Article 2(a) except as otherwise changed as provided herein.

Contract capacity price - The capacity price applicable for the period from the actual operation date through the term of agreement from either the firm capacity price schedule, Table B of Appendix C, or the successor to Table B in effect on the actual operation date. Seller has indicated its choice of firm capacity price schedule in Article 3(a).

Contract termination - The early termination of this Agreement.

CPUC - The Public Utilities Commission of the State of California.

Current firm capacity price - The \$/kW-year capacity price from the firm capacity price schedule published by PGandE at the time notice of termination or reduction of contract capacity is given, for a term equal to the period from the date of termination or reduction to the end of the term of agreement.

Designated PGandE switching center - That switching center or other PGandE installation identified in Article 5.

Dispatchable - The Facility is operable and can be called upon at any time to increase its deliveries of capacity to any level up to the contract capacity.

Facility - That generation apparatus described in Article 2 and all associated equipment owned, maintained, and operated by Seller.

Firm capacity price schedule - The periodically published schedule of the \$/kW-year prices that PGandE offers to pay for capacity. See Table B, Appendix C.

Forced outage - Any outage resulting from a design defect, inadequate construction, operator error or a breakdown of the mechanical or electrical equipment that fully or partially curtails the electrical output of the Facility.

Interconnection facilities - All means required and apparatus installed to interconnect and deliver power from the Facility to the PGandE system including, but not limited to, connection, transformation, switching, metering, communications, and safety equipment; such as equipment required to protect (1) the PGandE system and its customers from faults occurring at the Facility, and (2) the Facility from faults occurring on the PGandE system or on the systems of others to which the PGandE system is directly or indirectly connected. Interconnection facilities also include any necessary additions and reinforcements by PGandE to the PGandE system required as a result of the interconnection of the Facility to the PGandE system.

Net energy output - The Facility's gross output in kilowatt-hours less station use and transformation and transmission losses to the point of delivery into the PGandE system. Where PGandE agrees that it is impractical to connect the station use on the generator side of the power purchase meter, PGandE may, at its option, apply a station load adjustment.

Prudent electrical practices - Those practices, methods, and equipment, as changed from time to time, that are commonly used in prudent electrical engineering and operations to design and operate electric equipment lawfully and with safety, dependability, efficiency, and economy.

Scheduled operation date - The day specified in Article 2(c) when the Facility is, by Seller's estimate, expected to produce energy and capacity that will be available for delivery to PGandE.

Special facilities - Those additions and reinforcements to the PGandE system which are needed to accommodate the maximum delivery of energy and capacity from the Facility as provided in this Agreement and those parts of the interconnection facilities which are owned and maintained by PGandE at Seller's request, including metering and data processing equipment. All special facilities shall be owned, operated, and maintained pursuant to PGandE's electric Rule No. 21, which is attached hereto.

Station use - Energy used to operate the Facility's auxiliary equipment. The auxiliary equipment includes, but is not limited to, forced and induced draft fans, cooling towers, boiler feed pumps, lubricating oil systems, plant lighting, fuel handling systems, control systems, and sump pumps.

Surplus energy output - The Facility's gross output, in kilowatt-hours, less station use, and any other use by Seller, and transformation and transmission losses to the point of delivery into the PGandE system.

Term of agreement - The period of time during which this Agreement will be in effect as provided in Article 7.

Voltage level - The voltage at which the Facility interconnects with the PGandE system, measured at the point of delivery.

A-2 CONSTRUCTION

A-2.1 Land Rights

Seller hereby grants to PGandE all necessary rights of way and easements, including adequate and continuing access rights on property of Seller, to install, operate, maintain, replace, and remove the special facilities. Seller agrees to execute such other grants, deeds, or documents as PGandE may require to enable it to record such rights of way and easements. If any part of PGandE's equipment is to be installed on property owned by other than Seller, Seller shall, at its own cost and expense, obtain from the owners thereof all necessary rights of way and easements, in a form satisfactory to PGandE, for the construction, operation, maintenance, and replacement of PGandE's equipment upon such property. If Seller is unable to obtain such rights of way and easements, Seller shall reimburse PGandE for all costs incurred by PGandE in obtaining them. PGandE shall at all times have the right of ingress to and egress from the Facility at all reasonable hours for any purposes reasonably connected with this Agreement or the exercise of any and all rights secured to PGandE by law or its tariff schedules.

A-2.2 Design, Construction, Ownership, and Maintenance

- (a) Seller shall design, construct, install, own, operate, and maintain all interconnection facilities, except special facilities, to the point of interconnection with the PGandE system as required for PGandE to receive firm capacity and energy from the Facility. The Facility and interconnection facilities shall meet all requirements of applicable codes and all standards of prudent electrical practices and shall be maintained in a safe and prudent manner. A description of the interconnection facilities for which Seller is solely responsible is set forth in Appendix E, or if the interconnection requirements have not yet been determined at the time of the execution of this Agreement, the description of such facilities will be appended to this Agreement at the time such determination is made.
- (b) Seller shall submit to PGandE all specifications for the interconnection facilities (except special facilities) and, at PGandE's option, the Facility, for review and written acceptance prior to their release for construction purposes. PGandE's review and acceptance of these specifications shall not be construed as confirming or endorsing the design or as warranting their safety, durability, or reliability. PGandE shall not, by reason of such review or lack of review, be responsible for strength, details of design, adequacy, or capacity of equipment built pursuant to such specifications, nor shall PGandE's acceptance be deemed to be an endorsement of any of such equipment. Seller shall change the interconnection facilities as may be reasonably required by PGandE to meet changing requirements of the PGandE system.
- (c) In the event it is necessary for PGandE to install interconnection facilities for the purposes of this Agreement, they shall be installed as special facilities.
- (d) Upon the request of Seller, PGandE shall provide a binding estimate for the installation of interconnection facilities by PGandE.

A-2.3 Meter Installation

- (a) PGandE shall specify, provide, install, own, operate, and maintain as special facilities all metering and data processing equipment for the registration and recording of energy and other related parameters which are required for the reporting of data to PGandE and for computing the payment due Seller from PGandE.
- (b) Seller shall provide, construct, install, own, and maintain at Seller's expense all that is required to accommodate the metering and data processing equipment, such as, but not limited to, metal-clad

switchgear, switchboards, cubicles, metering panels, enclosures, conduits, rack structures, and equipment mounting pads.

A-3 ENERGY SALE OPTIONS

A-3.1 General

Seller has two energy sale options, net energy output or surplus energy output. Seller has made its initial selection in Article 2(a).

A-3.2 Energy Sale Conversion

- (a) Seller is entitled to convert from one option to the other 12 months after execution of this Agreement, and thereafter at least 12 months after the effective date of the most recent conversion, subject to the following conditions:
- (1) Seller shall provide PGandE with a written request to convert its energy sale option.
 - (2) Seller shall comply with all applicable tariffs on file with the CPUC and contracts in effect between the Parties at the time of conversion covering the existing and proposed (i) facilities used to serve Seller's premises and (ii) interconnection facilities.
 - (3) Seller shall install and operate equipment required by PGandE to prevent PGandE from serving any part of Seller's load which is served by the Facility and not under contract for PGandE standby service. At Seller's request PGandE shall provide this equipment as special facilities.
 - (4) If the energy sale conversion results in a capacity sale reduction, the provisions in Appendix D shall apply.
- (b) If, as a result of an energy sales conversion, Seller no longer requires the use of interconnection facilities installed and/or operated and maintained by PGandE as special facilities under a Special Facilities Agreement, Seller may reserve these facilities for its future use, by continuing its performance under its Special Facilities Agreement. If Seller does not wish to reserve such facilities, it may terminate its Special Facilities Agreement.

If Seller's energy sale conversion results in its discontinuation of its use of PGandE facilities not covered by Seller's Special Facilities Agreement, Seller cannot reserve those facilities for future use. Seller's future use of such facilities shall be contingent upon the availability of such facilities at the time Seller requests such use. If such facilities are not available, Seller shall bear the expense necessary to install, own, and maintain the needed additional facilities in accordance with PGandE's applicable tariff.

- (c) PGandE shall process requests for conversion in the order received. The effective date of conversion shall depend on the completion of the changes required to accommodate Seller's energy sale conversion.

A-4 OPERATION

A-4.1 Inspection and Approval

Seller shall not operate the Facility in parallel with PGandE's system until an authorized PGandE representative has inspected the interconnection facilities, and PGandE has given written approval to begin parallel operation. Seller shall notify PGandE of the Facility's start-up date at least 45 days prior to such date. PGandE shall inspect the interconnection facilities within 30 days of the receipt of such notice. If parallel operation is not authorized by PGandE, PGandE shall notify Seller in writing within five days after inspection of the reason authorization for parallel operation was withheld.

A-4.2 Facility Operation and Maintenance

Seller shall operate and maintain its Facility according to prudent electrical practices, applicable laws, orders, rules, and tariffs and shall provide such reactive power support as may be reasonably required by PGandE to maintain system voltage level and power factor. Seller shall operate the Facility at the power factors or voltage levels prescribed by PGandE's system dispatcher or designated representative. If Seller fails to provide reactive power support, PGandE may do so at Seller's expense.

A-4.3 Point of Delivery

Seller shall deliver the energy at the point where Seller's electrical conductors (or those of Seller's agent) contact PGandE's system as it shall exist whenever the deliveries are being made or at such other point or points as the Parties may agree in writing. The initial point of delivery of Seller's power to the PGandE system is set forth in Appendix E.

A-4.4 Operating Communications

- (a) Seller shall maintain operating communications with the designated PGandE switching center. The operating communications shall include, but not be limited to, system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, levels of operating voltage or power factors and daily capacity and generation reports.
- (b) Seller shall keep a daily operations log for each generating unit which shall include information on unit availability, maintenance outages, circuit breaker trip operations requiring a manual reset, and any significant events related to the operation of the Facility.
- (c) If Seller makes deliveries greater than one megawatt, Seller shall measure and register on a graphic recording device power in kW and voltage in kV at a location within the Facility agreed to by both Parties.
- (d) If Seller makes deliveries greater than one and up to and including ten megawatts, Seller shall report to the designated PGandE switching center, twice a day at agreed upon times for the current day's operation, the hourly readings in kW of capacity delivered and the energy in kWh delivered since the last report.
- (e) If Seller makes deliveries of greater than ten megawatts, Seller shall telemeter the delivered capacity and energy information, including real power in kW, reactive power in kVAR, and energy in kWh to a switching center selected by PGandE. PGandE may also require Seller to telemeter transmission kW, kVAR, and kV data depending on the number of generators and transmission configuration. Seller shall provide and maintain the data circuits required for telemetering. When telemetering is inoperative, Seller shall report daily the capacity delivered each hour and the energy delivered each day to the designated PGandE switching center.
- (f) If Seller provides dispatchable capacity greater than ten megawatts pursuant to Option 1 in Section C-5 of Appendix C, Seller may be required by PGandE to provide telemetering and control equipment to allow the Facility to respond to system load frequency requirements on digital control from PGandE.

A-4.5 Meter Testing and Inspection

- (a) All meters used to provide data for the computation of the payments due Seller from PGandE shall be sealed, and the seals shall be broken only by PGandE when the meters are to be inspected, tested, or adjusted.
- (b) PGandE shall inspect and test all meters upon their installation and annually thereafter. At Seller's request and expense, PGandE shall inspect or test a meter more frequently. PGandE shall give reasonable notice to Seller of the time when any inspection or test shall take place, and Seller may have representatives present at the test or inspection. If a meter is found to be inaccurate or defective, PGandE shall adjust, repair, or replace it at its expense in order to provide accurate metering.

A-4.6 Adjustments to Meter Measurements

If a meter fails to register, or if the measurement made by a meter during a test varies by more than two percent from the measurement made by the standard meter used in the test, an adjustment shall be made correcting all measurements made by the inaccurate meter for -- (1) the actual period during which inaccurate measurements were made, if the period can be determined, or if not, (2) the period immediately preceding the test of the meter equal to one-half the time from the date of the last previous test of the meter, provided that the period covered by the correction shall not exceed six months.

A-5 PAYMENT

PGandE shall mail to Seller not later than 30 days after the end of each monthly billing period (1) a statement showing the capacity and energy delivered to PGandE during on-peak, partial-peak, and off-peak periods during the monthly billing period, (2) PGandE's computation of the amount due Seller, and (3) PGandE's check in payment of said amount. Except as provided in Section A-6, if within 30 days of receipt of the statement Seller does not make a report in writing to PGandE of an error, Seller shall be deemed to have waived any error in PGandE's statement, computation, and payment, and they shall be considered correct and complete.

A-6 ADJUSTMENTS OF PAYMENTS

- (a) In the event adjustments to payments are required as a result of inaccurate meters, PGandE shall use the corrected measurements described in Section A-4.6 to recompute the amount due from PGandE to Seller for the firm capacity and energy delivered under this Agreement during the period of inaccuracy.

- (b) The additional payment to Seller or refund to PGandE shall be made within 30 days of notification of the owing Party of the amount due.

A-7 ACCESS TO RECORDS AND PGandE DATA

Each Party, after giving reasonable written notice to the other Party, shall have the right of access to all metering and related records including operations logs of the Facility. Data filed by PGandE with the CPUC pursuant to CPUC orders governing the purchase of power from qualifying facilities shall be provided to Seller upon request; provided that Seller shall reimburse PGandE for the costs it incurs to respond to such request.

A-8 CURTAILMENT OF DELIVERIES AND HYDRO SPILL CONDITIONS

- (a) PGandE shall not be obligated to accept or pay for and may require Seller to interrupt or reduce deliveries of energy (1) when necessary in order to construct, install, maintain, repair, replace, remove, investigate, or inspect any of its equipment or any part of its system, or (2) if it determines that interruption or reduction is necessary because of emergencies, forced outages, force majeure, or compliance with prudent electrical practices.
- (b) In anticipation of a period of hydro spill conditions, as defined by the CPUC, PGandE may notify Seller that any purchases of energy from Seller during such period shall be at hydro savings prices quoted by PGandE. If Seller delivers energy to PGandE during any such period, Seller shall be paid hydro savings prices for those deliveries in lieu of prices which would otherwise be applicable. The hydro savings prices shall be calculated by PGandE using the following formula:

$$\frac{AQF - S}{AQF} \times PP$$

where: AQF = Energy, in kWh, projected to be available during hydro spill conditions from all qualifying facilities under agreements containing hydro savings price provisions.

S = Potential energy, in kWh, from PGandE hydro facilities which will be spilled if all AQF is delivered to PGandE.

PP = Prices published by PGandE for purchases during other than hydro spill conditions.

- (c) PGandE shall not be obligated to accept or pay for and may require Seller with a Facility with a nameplate rating of one megawatt or greater to interrupt or reduce deliveries of energy during periods when purchases under this Agreement would result in costs greater than those which PGandE would incur if it did not make such purchases but instead generated an equivalent amount of energy itself.
- (d) Whenever possible, PGandE shall give Seller reasonable notice of the possibility that interruption or reduction of deliveries under subsections (a) or (c), above, may be required. PGandE shall give Seller notice of general periods when hydro spill conditions are anticipated, and shall give Seller as much advance notice as practical of any specific hydro spill period and the hydro savings price which will be applicable during such period. Before interrupting or reducing deliveries under subsection (c), above, and before invoking hydro savings prices under subsection (b), above, PGandE shall take reasonable steps to make economy sales of the surplus energy giving rise to the condition. If such economy sales are made, while the surplus energy condition exists Seller shall be paid at the economy sales price obtained by PGandE in lieu of the otherwise applicable prices.
- (e) If Seller is selling net energy output to PGandE and simultaneously purchasing its electrical needs from PGandE, energy curtailed pursuant to subsections (b) or (c) above shall not be used by Seller to meet its electrical needs. When Seller elects not to sell energy to PGandE at the hydro savings price pursuant to subsection (b) or when PGandE curtails deliveries of energy pursuant to subsection (c), Seller shall continue to purchase all its electrical needs from PGandE. If Seller is selling surplus energy output to PGandE, subsections (b) or (c) shall only apply to the surplus energy output being delivered to PGandE, and Seller can continue to internally use that generation it has retained for its own use.

A-9 FORCE MAJEURE

- (a) The term force majeure as used herein means unforeseeable causes, other than forced outages, beyond the reasonable control of and without the fault or negligence of the Party claiming force majeure including, but not limited to, acts of God, labor disputes, sudden actions of the elements, actions by federal, state, and municipal agencies, and actions of legislative, judicial, or regulatory agencies which conflict with the terms of this Agreement.
- (b) If either Party because of force majeure is rendered wholly or partly unable to perform its obligations under this Agreement, that Party shall be excused from whatever performance is affected by the force majeure to the extent so affected provided that:
- (1) the non-performing Party, within two weeks after the occurrence of the force majeure, gives the

other Party written notice describing the particulars of the occurrence,

- (2) the suspension of performance is of no greater scope and of no longer duration than is required by the force majeure,
 - (3) the non-performing Party uses its best efforts to remedy its inability to perform (this subsection shall not require the settlement of any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to its interest. It is understood and agreed that the settlement of strikes, walkouts, lockouts or other labor disputes shall be at the sole discretion of the Party having the difficulty),
 - (4) when the non-performing Party is able to resume performance of its obligations under this Agreement, that Party shall give the other Party written notice to that effect, and
 - (5) capacity payments during such periods of force majeure on Seller's part shall be governed by Section C-2(c) of Appendix C.
- (c) In the event a Party is unable to perform due to legislative, judicial, or regulatory agency action, this Agreement shall be renegotiated to comply with the legal change which caused the non-performance.

A-10 INDEMNITY

Each Party as indemnitor shall save harmless and indemnify the other Party and the directors, officers, and employees of such other Party against and from any and all loss and liability for injuries to persons including employees of either Party, and property damages including property of either Party resulting from or arising out of (1) the engineering, design, construction, maintenance, or operation of, or (2) the making of replacements, additions, or betterments to, the indemnitor's facilities. This indemnity and save harmless provision shall apply notwithstanding the active or passive negligence of the indemnitee. Neither Party shall be indemnified hereunder for its liability or loss resulting from its sole negligence or willful misconduct. The indemnitor shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity and shall pay all costs, including reasonable attorney fees, that may be incurred by the other Party in enforcing this indemnity.

A-11 LIABILITY; DEDICATION

- (a) Nothing in this Agreement shall create any duty to, any standard of care with reference to, or any liability to any person not a Party to it. Neither Party shall be liable to the other Party for consequential damages.
- (b) Each Party shall be responsible for protecting its facilities from possible damage by reason of electrical disturbances or faults caused by the operation, faulty operation, or nonoperation of the other Party's facilities, and such other Party shall not be liable for any such damages so caused.
- (c) No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public or affect the status of PGandE as an independent public utility corporation or Seller as an independent individual or entity and not a public utility.

A-12 SEVERAL OBLIGATIONS

Except where specifically stated in this Agreement to be otherwise, the duties, obligations, and liabilities of the Parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership, or joint venture or impose a trust or partnership duty, obligation, or liability on or with regard to either Party. Each Party shall be liable individually and severally for its own obligations under this Agreement.

A-13 NON-WAIVER

Failure to enforce any right or obligation by either Party with respect to any matter arising in connection with this Agreement shall not constitute a waiver as to that matter or any other matter.

A-14 ASSIGNMENT

Neither Party shall voluntarily assign its rights nor delegate its duties under this Agreement, or any part of such rights or duties, without the written consent of the other Party, except in connection with the sale or merger of a substantial portion of its properties. Any such assignment or delegation made without such written consent shall be null and void. Consent for assignment shall not be withheld unreasonably. Such assignment shall include, unless otherwise specified therein, all of Seller's rights to any refunds which might become due under this Agreement.

A-15 CAPTIONS

All indexes, titles, subject headings, section titles, and similar items are provided for the purpose of reference and convenience and are not intended to affect the meaning of the contents or scope of this Agreement.

A-16 CHOICE OF LAWS

This Agreement shall be interpreted in accordance with the laws of the State of California, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

A-17 GOVERNMENTAL JURISDICTION AND AUTHORIZATION

Seller shall obtain any governmental authorizations and permits required for the construction and operation of the Facility. Seller shall reimburse PGandE for any and all losses, damages, claims, penalties, or liability it incurs as a result of Seller's failure to obtain or maintain such authorizations and permits.

A-18 NOTICES

Any notice, demand, or request required or permitted to be given by either Party to the other, and any instrument required or permitted to be tendered or delivered by either Party to the other, shall be in writing (except as provided in Section C-3) and so given, tendered, or delivered, as the case may be, by depositing the same in any United States Post Office with postage prepaid for transmission by certified mail, return receipt requested, addressed to the Party, or personally delivered to the Party, at the address in Article 4 of this Agreement. Changes in such designation may be made by notice similarly given.

A-19 INSURANCE

A-19.1 General Liability Coverage

- (a) Seller shall maintain during the performance hereof, General Liability Insurance¹ of not less than \$1,000,000 if the Facility is over 100 kW, \$500,000 if the Facility is over 20 kW to 100 kW, and \$100,000 if the Facility is 20 kW or below of combined single limit or equivalent for bodily injury, personal injury, and property damage as the result of any one occurrence.
- (b) General Liability Insurance shall include coverage for Premises-Operations, Owners and Contractors Protective, Products/Completed Operations Hazard, Explosion, Collapse, Underground, Contractual Liability, and Broad Form Property Damage including Completed Operations.
- (c) Such insurance, by endorsement to the policy(ies), shall include PGandE as an additional insured if the Facility is over 100 kW insofar as work performed by Seller for PGandE is concerned, shall contain a severability of interest clause, shall provide that PGandE shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for payment of premium for such insurance, and shall provide for 30-day's written notice to PGandE prior to cancellation, termination, alteration, or material change of such insurance.

A-19.2 Additional Insurance Provisions

- (a) Evidence of coverage described above in Section A-19.1 shall state that coverage provided is primary and is not excess to or contributing with any insurance or self-insurance maintained by PGandE.
- (b) PGandE shall have the right to inspect or obtain a copy of the original policy(ies) of insurance.
- (c) Seller shall furnish the required certificates² and endorsements to PGandE prior to commencing operation.
- (d) All insurance certificates², endorsements, cancellations, terminations, alterations, and material changes of such insurance shall be issued and submitted to the following:

PACIFIC GAS AND ELECTRIC COMPANY
Attention: Manager - Insurance Department
77 Beale Street, Room E280
San Francisco, CA 94106

¹ Governmental agencies which have an established record of self-insurance may provide the required coverage through self-insurance.

² A governmental agency qualifying to maintain self-insurance should provide a statement of self-insurance.

APPENDIX B
ENERGY PRICES

TABLE A

Energy Prices Effective January 1 - April 30, 1984

The energy purchase price calculations which will apply to energy deliveries determined from meter readings taken during January, February, March, and April 1984 are as follows:

<u>Time Period</u>	(a) <u>Incremental Energy Rate¹</u> (Btu/kWh)	(b) <u>Cost of Energy²</u> (\$/10 ⁶ Btu)	(c) <u>Revenue Requirement for Cash Working Capital³</u> (\$/kWh)	(d) <u>Energy Purchase Price⁴</u> (d)=[(a)x(b)]+(c) (\$/kWh)
Jan. 1 - April 30 (Period B)				
Time of Delivery Basis:				
On-Peak	15,410	5.3978	0.00053	0.08371
Partial-Peak	14,730	5.3978	0.00051	0.08002
Off-Peak	11,353	5.3978	0.00038	0.06166
Seasonal Average (Period B)	13,089	5.3978	0.00045	0.07110

¹ Incremental energy rates in Btu/kWh are derived from marginal energy costs (including variable operating and maintenance expense) adopted by CPUC Decision No. 83-12-068. They are based upon natural gas as the incremental fuel and weighted average hydro electric power conditions.

² Cost of natural gas under PGandE Gas Schedule No. G-55 (applicable to steam electric plants) in CPUC Decision No. 83-12-069 effective January 1, 1984.

³ Revenue requirement for cash working capital as prescribed by the CPUC in Decision No. 83-12-068.

⁴ Energy Purchase Price = (Incremental Energy Rate x Cost of Energy) + Revenue Requirement for Cash Working Capital. The energy purchase price excludes the applicable energy line loss adjustment factors. However, as ordered by Ordering Paragraph No. 12(j) of Decision No. 82-12-120, this figure is currently 1.0 for transmission and primary distribution loss adjustments and is equal to marginal cost line loss adjustment factors for the secondary distribution voltage level. These factors may be changed by the CPUC in the future. The currently applicable energy loss adjustment factors are shown in Table C.

TABLE B¹
Time Periods

	<u>Monday through Friday²</u>	<u>Saturdays²</u>	<u>Sundays and Holidays</u>
Seasonal Period A (May 1 through September 30)			
On-Peak	12:30 p.m. to 6:30 p.m.		
Partial-Peak	8:30 a.m. to 12:30 p.m.	8:30 a.m. to 10:30 p.m.	
	6:30 p.m. to 10:30 p.m.		
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	All Day
Seasonal Period B (October 1 through April 30)			
On-Peak	4:30 p.m. to 8:30 p.m.		
Partial-Peak	8:30 p.m. to 10:30 p.m.	8:30 a.m. to 10:30 p.m.	
	8:30 a.m. to 4:30 p.m.		
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	All Day

TABLE C
Energy Loss Adjustment Factors³

	<u>Transmission</u>	<u>Primary Distribution</u>	<u>Secondary Distribution</u>
Seasonal Period A (May 1 through September 30)			
On-Peak	1.0	1.0	1.0148
Partial-Peak	1.0	1.0	1.0131
Off-Peak	1.0	1.0	1.0093
Seasonal Period B (October 1 through April 30)			
On-Peak	1.0	1.0	1.0128
Partial-Peak	1.0	1.0	1.0119
Off-Peak	1.0	1.0	1.0087

¹ This table is subject to change to accord with the on-peak, partial-peak, and off-peak periods as defined in PGandE's own rate schedules for the sale of electricity to its large industrial customers.

² Except the following holidays: New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, and Christmas Day, as specified in Public Law 90-363 (5 U.S.C.A. Section 6103(a)).

³ The applicable energy loss adjustment factors may be revised pursuant to orders of the CPUC.

APPENDIX C

FIRM CAPACITY PRICE SCHEDULE

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APPENDIX C

FIRM CAPACITY PRICE SCHEDULE

C-1 GENERAL

This Appendix C establishes conditions and prices under which PGandE shall pay for firm capacity.

C-2 MINIMUM PERFORMANCE REQUIREMENTS

(a) To receive full capacity payments the Facility must meet the following requirements:

- (1) The contract capacity shall be available¹ for all of the on-peak hours² in the peak months on the PGandE system, which are presently the months of June, July, and August, subject to a 20 percent allowance for forced outages in any month. Compliance with this provision shall be based on the Facility's total on-peak availability¹ for each of the peak months and shall exclude any energy associated with generation levels greater than the contract capacity.
- (2) If Seller selects Option 1, the contract capacity shall be dispatchable throughout the year, subject to (i) a monthly allowance for forced outages of 20% of the hours Seller is called upon to deliver power to PGandE and (ii) the allowances for scheduled maintenance outages. Except during the peak months on the PGandE system, Seller may accumulate and apply the 20 percent allowance for forced outages for any consecutive three month period. Seller shall demonstrate that the Facility is fueled by a reliable fuel supply and adequate fuel storage is available to deliver power as requested by PGandE's system dispatcher.

(b) If Seller is prevented from meeting the minimum performance requirements because of a forced outage on the PGandE system or a condition set forth in Section A-8, PGandE shall continue capacity payments. Under Option 2, capacity payments will be calculated in the same manner used for scheduled maintenance outages.

(c) If Seller is prevented from meeting the minimum performance requirements because of force majeure, PGandE shall continue capacity payments for ninety days from the occurrence of the force majeure. Thereafter, Seller shall be deemed to have failed to have met the minimum performance requirements. Under Option 2, capacity payments will be calculated in the same manner used for scheduled maintenance outages.

(d) If Seller is prevented from meeting the minimum performance requirements because of extreme dry year conditions, PGandE shall continue capacity payments. Extreme dry year conditions are drier than those used to establish contract capacity pursuant to Section C-8. Seller shall warrant to PGandE that the Facility is a hydroelectric facility and that such conditions are the sole cause of Seller's inability to meet its contract capacity obligations. Under Option 1, starting with the month in which Seller cannot provide its contract capacity, payments shall be made under Option 2 for a one-year period, and if at the end of this one-year period Seller is not able to resume the contract capacity due solely to continued extreme dry year conditions, Seller shall continue to receive payments under Option 2 for additional one-year periods as long as such conditions continue to exist.

(e) If Seller is prevented from meeting the minimum performance requirements for reasons other than those described above in Sections C-2(b), (c), or (d):

- (1) Seller shall receive the reduced capacity payments as provided in Section C-5 for a probationary period not to exceed 15 months, or as otherwise agreed to by the Parties.
- (2) If, at the end of the probationary period Seller has not demonstrated that the Facility can meet the minimum performance requirements, PGandE may derate the contract capacity pursuant to Section C-4(b).

¹ For purposes of Option 1, "available" means either dispatchable by PGandE or actually delivered to PGandE. For purposes of Option 2, "available" means actually delivered to PGandE.

² On-peak, partial-peak, and off-peak hours are defined in Table B, Appendix B.

C-3 SCHEDULED MAINTENANCE

Outage periods for scheduled maintenance shall not exceed 840 hours (35 days) in any 12-month period. This allowance may be used in increments of an hour or longer on a consecutive or nonconsecutive basis. Seller may accumulate unused maintenance hours from one 12-month period to another up to a maximum of 1,080 hours (45 days). This accrued time must be used consecutively and only for major overhauls. Seller shall provide PGandE with the following advance notices: 24 hours for scheduled outages less than one day, one week for a scheduled outage of one day or more (except for major overhauls), and six months for a major overhaul. Seller shall not schedule major overhauls during the peak months (presently June, July and August). Seller shall make reasonable efforts to schedule or reschedule routine maintenance outside the peak months, and in no event shall outages for scheduled maintenance exceed 30 peak hours during the peak months. Seller shall confirm in writing to PGandE pursuant to Article 4, within 24 hours of the original notice, all notices Seller gives personally or by telephone for scheduled maintenance.

C-4 ADJUSTMENTS TO CONTRACT CAPACITY

- (a) Seller may increase the contract capacity with the approval of PGandE and receive payment for the additional capacity thereafter in accordance with the applicable capacity purchase price published by PGandE at the time the increase is first delivered to PGandE.
- (b) Seller may reduce the contract capacity at any time by giving notice thereof to PGandE, subject to the provisions of Appendix D if the reduction occurs after the actual operation date. PGandE may reduce the contract capacity in accordance with Section C-2(e) as a result of appropriate data showing Seller has failed to meet the minimum performance requirements of Section C-2. The amount by which the contract capacity is reduced by PGandE shall be deemed a capacity sale reduction without notice as provided in Section D-3 of Appendix D.
- (c) Either Party may request, when it reasonably appears that the capacity of the Facility may have changed for any reason, that a new contract capacity be determined.

C-5 PAYMENT OPTIONS

Seller has two options for calculation of capacity payments and Seller has made its selection in Article 3(a). As used below in this section, month refers to a calendar month. The two options are as follows:

Option 1

When Seller meets the requirements of Section C-2 the monthly payment for capacity will be one-twelfth of the product of the contract capacity price, the contract capacity, the appropriate capacity loss adjustment factor from Table A based on the Facility's interconnection voltage, and the appropriate performance bonus factor, if any, from Table C. Capacity payments will continue during scheduled maintenance outages provided that the provisions of Section C-3 are met.

During a probationary period Seller's monthly payment for capacity shall be determined by substituting for the contract capacity, the capacity at which Seller would have met the minimum performance requirements. In any month during the probationary period that Seller does not meet the minimum performance requirements at whatever capacity was determined for the previous month, Seller's monthly payment for capacity shall be determined by substituting the capacity at which Seller would have met the minimum performance requirements. The performance bonus factor shall not be applied during a probationary period.

Option 2

The monthly payment for capacity will be the product of the Period Price Factor (PPF), the Monthly Delivered Capacity (MDC), the appropriate capacity loss adjustment factor from Table A based on the Facility's interconnection voltage, and the appropriate performance bonus factor, if any, from Table C, plus any allowable payment for outages due to scheduled maintenance. Firm capacity prices shall be applied to meter readings taken during the separate times and periods as illustrated in Table B, Appendix B.

The PPF is determined by multiplying the contract capacity price by the following Option 2 Allocation Factors¹:

	Option 2 Allocation Factor	x	<u>Contract Capacity</u> <u>Price</u>	=	PPF (\$/kW-month)
Seasonal Period A	.18540		_____		_____
Seasonal Period B	.01043		_____		_____

The MDC is determined in the following manner:

- (1) Determine the Performance Factor (P), which is defined as the lesser of 1.0 or the following quantity:

$$P = \frac{A}{C \times (B-S) \times (0.8^*)} \quad (\leq 1.0)$$

Where:

A = Total kilowatt-hours delivered during all on-peak and partial-peak hours excluding any energy associated with generation levels greater than the contract capacity.

C = Contract capacity in kilowatts.

B = Total on-peak and partial-peak hours during the month.

S = Total on-peak and partial-peak hours during the month Facility is out of service on scheduled maintenance.

- (2) Determine the Monthly Capacity Factor (MCF), which is computed using the following expression:

$$MCF = P \times (1.0 - \frac{M}{D})$$

Where:

M = The number of hours during the month Facility is out of service on scheduled maintenance.

D = The number of hours in the month.

- (3) Determine the MDC by multiplying the MCF by C:

$$MDC \text{ (kilowatts)} = MCF \times C$$

The monthly payment for capacity is then determined by multiplying the PPF by the MDC, by the appropriate capacity loss adjustment factor presented from Table A, and by the appropriate performance bonus factor, if any, from Table C.

$$\text{monthly payment for capacity} = PPF \times MDC \times \text{capacity loss adjustment factor} \times \text{performance bonus factor}$$

Furthermore, the payment for a month in which there is an outage for scheduled maintenance shall also include an amount equal to the product of the average hourly capacity payment² for the most recent month in the same type of Seasonal Period (i.e., Seasonal Period A or Seasonal Period B) during which deliveries were made times the number of hours of outage for scheduled maintenance in the current month. Capacity payments will continue during the outage periods for scheduled maintenance provided that the provisions of Section C-3 are met.

During a probationary period Seller's monthly payment for capacity shall be determined by substituting for the contract capacity, the capacity at which Seller would have met the minimum performance requirements. In the event that during the probationary period Seller does not meet the minimum performance requirements at whatever capacity was established for the previous month, Seller's monthly payment for capacity shall be determined by substituting the capacity at which Seller would have met the minimum performance requirements. The performance bonus factor shall not be applied during probationary periods.

¹ These allocation factors were prescribed by the CPUC in Decision 83-12-068. All allocation factors are subject to change by PGandE based on PGandE's marginal capacity cost allocation, as determined in general rate case proceedings before the CPUC. Seasonal Periods A and B are defined in Table B, Appendix B.

* 0.8 reflects a 20% allowance for forced outage.

² Total monthly payment divided by the total number of hours in the monthly billing period.

TABLE A

If the Facility is non-remote¹ the capacity loss adjustment factors are as follows:

<u>Interconnection Voltage</u>	<u>Capacity Loss Adjustment Factor</u>
Transmission	.989
Primary Distribution	.991
Secondary Distribution	.991

If the Facility is remote the capacity loss adjustment factor is _____².

TABLE B

Firm Capacity Price Schedule

(Levelized \$/kW-year)

<u>Actual Operation Date</u>	<u>Term of Agreement</u>																	
<u>(Year)</u>	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>	<u>8</u>	<u>9</u>	<u>10</u>	<u>11</u>	<u>12</u>	<u>13</u>	<u>14</u>	<u>15</u>	<u>20</u>	<u>25</u>	<u>30</u>
1983	72	111	96	88	84	85	88	91	93	96	98	100	102	104	106	115	122	128
1984	156	111	95	88	89	92	95	98	100	103	105	108	110	112	114	124	131	137
1985	60	58	59	66	73	79	84	88	92	95	99	102	104	107	110	121*	127*	135
1986	56	58	69	78	85	90	95	99	103	106	110	113	116	118	121	132	141	148
1987	61	77	88	95	101	105	109	113	117	120	124	127	130	132	135	147	156	163
1988	96	104	110	115*	119	122	126	129	133	136	139	142	145	148	151	163	173	180

¹ As defined by the CPUC.

² Determined individually.

* In its Application for Rehearing and/or Petition for Modification of CPUC Decision 83-12-068, (December 22, 1983) filed on February 6, 1984, PGandE requests correction of three numbers which were incorrectly presented in the Firm Capacity Price Schedule included in that decision (p.349, Table VI-4). The correct number for 1985 for a 20-year contract life should be \$120/kW-yr; and for a 25-year contract life, the correct number should be \$129/kW-yr. The correct number for 1988 for a 4-year contract life should be \$114/kW-yr. When the CPUC issues an order correcting these numbers, PGandE shall correct the Firm Capacity Price Schedule accordingly.

TABLE C

Performance Bonus Factor

The following shall be the performance bonus factors applicable to the calculation of the monthly payments for capacity delivered by the Facility after it has demonstrated a capacity factor in excess of 85%.

<u>DEMONSTRATED CAPACITY FACTOR (%)</u>	<u>PERFORMANCE BONUS FACTOR</u>
85	1.000
90	1.059
95	1.118
100	1.176

After the Facility has delivered power during the span of all of the peak months on the PGandE system (presently June, July, and August) in any year (span),

- (i) the capacity factor for each such month shall be calculated in the following manner:

$$\text{CAPACITY FACTOR (\%)} = \frac{A}{B \times C} \times 100$$

Where:

- A = Total kilowatt-hours delivered by Seller in any peak month during all on-peak hours excluding any energy associated with generation levels greater than the contract capacity.
- B = Total on-peak hours during the month.
- C = Contract capacity in kilowatts.

- (ii) the arithmetic average of the above capacity factors shall be determined for that span,
- (iii) the average of the above arithmetic average capacity factors for the most recent span(s), not to exceed 5, shall be calculated and shall become the Demonstrated Capacity Factor.

To calculate the performance bonus factor for a Demonstrated Capacity Factor not shown in Table D use the following formula:

$$\text{Performance Bonus Factor} = \frac{\text{Demonstrated Capacity Factor (\%)}}{85\%}$$

THE FOLLOWING SECTIONS SHALL APPLY ONLY TO HYDROELECTRIC PROJECTS

C-6 DETERMINATION OF NATURAL FLOW DATA

Natural flow data shall be based on a period of record of at least 50 years and which includes historic critically dry periods. In the event Seller demonstrates that a natural flow data base of at least 50 years would be unreasonably burdensome, PGandE shall accept a shorter period of record with a corresponding reduction in the averaging basis set forth in Section C-8. Seller shall determine the natural flow data by month by using one of the following methods:

Method 1

If stream flow records are available from a recognized gauging station on the water course being developed in the general vicinity of the project, Seller may use the data from them directly.

Method 2

If directly applicable flow records are not available, Seller may develop theoretical natural flows based on correlation with available flow data for the closest adjacent and similar area which has a recognized gauging station using generally accepted hydrologic estimating methods.

C-7 THEORETICAL OPERATION STUDY

Based on the monthly natural flow data developed under Section C-6 a theoretical operation study shall be prepared by Seller. Such a study shall identify the monthly capacity rating in kW and the monthly energy production in kWh for each month of each year. The study shall take into account all relevant operating constraints, limitations, and requirements including but not limited to --

- (1) Release requirements for support of fish life and any other operating constraints imposed on the project;
- (2) Operating characteristics of the proposed equipment of the Facility such as efficiencies, minimum and maximum operating levels, project control procedures, etc.;
- (3) The design characteristics of project facilities such as head losses in penstocks, valves, tailwater elevation levels, etc.; and
- (4) Release requirements for purposes other than power generation such as irrigation, domestic water supply, etc.

The theoretical operation study for each month shall assume an even distribution of generation throughout the month unless Seller can demonstrate that the Facility has water storage characteristics. For the study to show monthly capacity ratings, the Facility shall be capable of operating during all on-peak hours in the peak months on the PGandE system, which are presently the months of June, July, and August. If the project does not have this capability throughout each such month, the capacity rating in that month of that year shall be set at zero for purposes of this theoretical operation study.

C-8 DETERMINATION OF AVERAGE DRY YEAR CAPACITY RATINGS

Based on the results of the theoretical operation study developed under Section C-7, the average dry year capacity rating shall be established for each month. The average dry year shall be based on the average of the five years of the lowest annual generation as shown in the theoretical operation study. Once such years of lowest annual generation are identified, the monthly capacity rating is determined for each month by averaging the capacity ratings from each month of those years. The contract capacity shown in Article 2(a) shall not exceed the lowest average dry year monthly capacity ratings for the peak months on the PGandE system, which are presently the months of June, July, and August.

C-9 INFORMATION REQUIREMENTS

Seller shall provide the following information to PGandE for its review:

- (1) A summary of the average dry year capacity ratings based on the theoretical operation study as provided in Table D;
- (2) A topographic project map which shows the location of all aspects of the Facility and locations of stream gauging stations used to determine natural flow data;
- (3) A discussion of all major factors relevant to project operation;

- (4) A discussion of the methods and procedures used to establish the natural flow data. This discussion shall be in sufficient detail for PGandE to determine that the methods are consistent with those outlined in Section C-6 and are consistent with generally accepted engineering practices; and
- (5) Upon specific written request by PGandE, Seller's theoretical operation study.

C-10 ILLUSTRATIVE EXAMPLE

- (1) Determine natural flows - These flows are developed based on historic stream gauging records and are compiled by month, for a long-term period (normally at least 50 years or more) which covers dry periods which historically occurred in the 1920's and 30's and more recently in 1976 and 77. In all but unusual situations this will require application of hydrological engineering methods to records that are available, primarily from the USGS publication "Water Resources Data for California".
- (2) Perform theoretical operation study - Using the natural flow data compiled under (1) above a theoretical operation study is prepared which determines, for each month of each year, energy generation (kWh) and capacity rating (kW). This study is performed based on the Facility's design, operating capabilities, constraints, etc., and should take into account all factors relevant to project operation. Generally such a study is done by computer which routes the natural flows through project features, considering additions and withdrawals from storage, spill past the project, releases for support of fish life, etc., to determine flow available for generation. Then the generation and capacity amounts are computed based on equipment performance, efficiencies, etc.
- (3) Determine average dry year capacity ratings - After the theoretical project operation study is complete the five years in which the annual generation (kWh) would have been the lowest are identified. Then for each month, the capacity rating (kW) is averaged for the five years to arrive at a monthly average capacity rating. The contract capacity is then set by the Seller based on the monthly average dry year capacity ratings and the minimum performance requirements of Appendix C. An example project is shown in the attached completed Table D.

EXAMPLE

TABLE D

Summary of Theoretical Operation Study

Project: New Creek 1 Dispatchable: Yes ☐ No ☒

Water Source: West Fork New Creek

Mode of Operation: Run of the river

Type of Turbine: Francis Design Flow: 100 cfs Design Head: 150 feet

Operating Characteristics:¹

	Flow (cfs)	Head (feet)		Output (kW)	Efficiency (%)	
		Gross	Net		Turbine	Generator
Normal Operation	100	160	150	1,120	90	98
Maximum Operation	110	160	148	1,150	85	98
Minimum Operation	30	160	155	290	75	98

Average Dry Year Operation - Based on the average of the following lowest generation years: 1930, 1932, 1934, 1949, 1977.

Month	Energy Generation (kWh)	Capacity Output (kW)	Percent of Total Hours Operated ²
January	855,000	1,150	100
February	753,000	1,120	100
March	818,000	1,100	100
April	727,000	1,010	100
May	699,000	940	100
June	612,000	850	100
July	484,000	650	100
August	305,000	410	100
September	245,000	340	100
October	148,800	200	100
November	468,000	650	100
December	595,000	800	100

Maximum Contract Capacity: 410 kW

¹ If Facility has a variable head, operating curves should be provided.

² For this to be less than 100%, Facility must be dispatchable.

APPENDIX D

**ADJUSTMENT OF CAPACITY PAYMENTS
IN THE EVENT OF TERMINATION OR REDUCTION**

CONTENTS

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APPENDIX D

ADJUSTMENT OF CAPACITY PAYMENTS IN THE EVENT OF TERMINATION OR REDUCTION

D-1 GENERAL PROVISIONS

- (a) This Appendix shall be applicable in the event there is a contract termination or a capacity sale reduction (each sometimes referred to as "termination" in this Appendix D).
- (b) The Parties agree that the amount which PGandE pays Seller for the capacity which Seller makes available to PGandE is based on the agreed value to PGandE of Seller's performance of capacity obligations during the full period of the term of agreement. The Parties further agree that in the event PGandE does not receive such full performance by reason of a termination:
- (1) PGandE shall be deemed damaged by reason thereof,
 - (2) it would be impracticable or extremely difficult to fix the actual damages to PGandE resulting therefrom,
 - (3) the refunds and payments as provided in Sections D-2 and D-3, as applicable, are in the nature of adjustments in capacity prices and liquidated damages, and not a penalty, and are fair and reasonable, and
 - (4) such refunds and payments represent a reasonable endeavor by the Parties to estimate a fair compensation for the reasonable losses that would result from such termination or reduction.
- (c) In the event of a capacity sale reduction, the quantity by which the contract capacity is reduced shall be used to calculate the payments due PGandE in accordance with Sections D-2 and D-3, as applicable.
- (d) Seller shall be invoiced by PGandE for all refunds and payments due under this Appendix D and the special facilities agreement. From the date of the notice of termination or the date of termination, whichever is earlier, Seller shall pay interest, compounded monthly, on all overdue amounts, at the published Federal Reserve Board three months' Prime Commercial Paper rate.
- (e) If Seller does not make payments pursuant to Section D-1(d), PGandE shall have the right to offset any amounts due it against any present or future payments due Seller.
- (f) Notices of termination shall be made in accordance with Section A-18 of Appendix A.

D-2 TERMINATION WITH PRESCRIBED NOTICE

In the event Seller terminates this entire Agreement, or all or part of the contract capacity thereof, with the following prescribed written notice:

<u>Amount of Contract Capacity Terminated</u>	<u>Length of Notice Required</u>
1,000 kW or under	3 months
over 1,000 kW through 10,000 kW	9 months
over 10,000 kW through 25,000 kW	12 months
over 25,000 kW through 50,000 kW	36 months
over 50,000 kW through 100,000 kW	48 months
over 100,000 kW	60 months

Then the following provisions shall apply:

- (1) With respect to the amount by which the contract capacity is reduced, Seller shall refund to PGandE an amount equal to the difference between (a) the capacity payments already paid by PGandE, based on the original term of agreement and (b) the total capacity payments which PGandE would have paid based on the period of Seller's actual performance using the adjusted capacity price. Additionally, Seller shall pay interest, compounded monthly, on all overpayments, at the published Federal Reserve Board three months' Prime Commercial Paper rate.
- (2) From the date PGandE receives the termination notice to the date of actual termination, PGandE shall make capacity payments based on the adjusted capacity price for the amount of contract capacity being terminated.

- (3) From the date PGandE receives the termination notice, PGandE shall continue to pay for the amount of contract capacity not being terminated, if any, at the original contract capacity price.

D-3 TERMINATION WITHOUT PRESCRIBED NOTICE

- (a) If Seller terminates this Agreement, or all or a part of the contract capacity thereof, without the notice prescribed in Section D-2, the provisions prescribed in Section D-2 will all apply. Additionally:
- (b) Seller shall pay PGandE a sum equal to the amount by which the contract capacity is being terminated times the difference between the current firm capacity price on the date of termination for a term equal to the balance of the term of agreement and the contract capacity price, pro-rated for the length of notice given by multiplying by the difference between the prescribed length of notice and the actual notice given, with the difference divided by 12. In the event that the current firm capacity price is less than the contract capacity price, no payment under this Section D-3 shall be due either Party.

This additional payment shall be computed using the following formula:

$$G = CC \times (T - CCP) \times \frac{J - H}{12}$$

where $G \geq 0$

and where:

- G = additional payment.
- CC = the amount by which the contract capacity is being terminated.
- T = the current firm capacity price.
- CCP = the contract capacity price.
- H = the actual number of months notice given.
- J = the prescribed length of notice.

D-4 TERMINATION EXAMPLES

These examples demonstrate how to calculate capacity payment adjustments when capacity sales are terminated.

(a) Termination with Prescribed Notice

(1) Example Based on Option 1

Assumptions:

- i. Term of agreement is 15 years;
- ii. Actual operation date is July 1, 1985;
- iii. Prescribed notice is given on July 1, 1986;
- iv. Contract capacity to be reduced by 10,000 kW on July 1, 1987; actual performance to be from July 1, 1985 through July 1, 1987¹;
- v. The applicable capacity loss adjustment factor is .989; and
- vi. No performance bonus for capacity has been earned.

¹ The capacity payment is adjusted upon receiving notice, so no refund is necessary for the last month of the first twelve months of operation and all of the second twelve months (June 1, 1986 to July 1, 1987). Seller performed for eleven months prior to payment adjustment. (Note that due to the 30-day interval between delivery and payment, performance in the twelfth month (June 1986) can be paid for at the adjusted capacity price.)

The amount of overpayment (E) made by PGandE to Seller during each monthly billing period is calculated as follows:

$$E = (A - B) \times C \times L \times U$$

Where:

- A = contract capacity price per month for the actual operation date (July 1, 1985) and the term of agreement which is 15 years = $\$110/\text{kW-yr} \div 12 \text{ mo/yr} = \$9.17/\text{kW-mo}$.
- B = adjusted capacity price per month for the actual operation date (July 1, 1985) and a two-year agreement term = $\$58/\text{kW-yr} \div 12 \text{ mo/yr} = \$4.83/\text{kW-mo}$.
- C = amount by which the contract capacity is being reduced = 10,000 kW.
- L = capacity loss adjustment factor = .989.
- U = performance bonus factor; when Seller does not qualify for a performance bonus factor, as in this example, U is removed from the above calculation of E.

Therefore:

$$E = (\$9.17/\text{kW-mo} - \$4.83/\text{kW-mo}) \times 10,000 \text{ kW} \times .989 = \$42,923 \text{ per month}$$

Table A shows a step-by-step derivation of the refund Seller owes PGandE for the early termination outlined above. The \$497,342 that Seller owes PGandE appears at the lower right-hand corner of the table. All other figures of this table represent intermediate calculation steps.

TABLE A

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Monthly Billing Period ¹	Date of Payment ²	Amount of Overpayment ³	Accumulated Overpayment ⁴	Interest Rate ⁵	Interest Charge ⁶ on Accumulated Overpayment (f)=(d)x(e)	Balance ⁷ (g)=(c)+(d)+(f)
		\$	\$	%	\$	\$
7/85	8/30/85	42,923	0	1.2	0	42,923
8/85	9/30/85	42,923	42,923	1.0	429	86,275
9/85	10/30/85	42,923	86,275	0.9	776	129,974
10/85	11/30/85	42,923	129,974	0.8	1,040	173,937
11/85	12/30/85	42,923	173,937	0.7	1,218	218,078
12/85	1/30/86	42,923	218,078	0.8	1,745	262,746
1/86	3/2/86	42,923	262,746	0.9	2,365	308,034
2/86	3/30/86	42,923	308,034	1.0	3,080	354,037
3/86	4/30/86	42,923	354,037	1.1	3,894	400,854
4/86	5/30/86	42,923	400,854	1.2	4,810	448,587
5/86	6/30/86	42,923	448,587	1.3	5,832	<u>497,342</u>

¹ The month in which power deliveries were made. For purposes of simplification, the monthly billing period will coincide exactly with each calendar month.

² The date on which payment for the monthly billing period stated in column (a) is made.

³ The amount of overpayment made by PGandE to Seller during each monthly billing period.

⁴ The amount of overpayment accumulated up through last month's date of payment.

⁵ The interest rate for the period between the date of payment for the previous monthly billing period and the date of payment for this monthly billing period. These interest rates are arbitrarily chosen for use in this example.

⁶ The amount of interest charge accrued between the date of payment for the previous monthly billing period and the date of payment for this monthly billing period on the accumulated overpayment balance existing as of the previous monthly billing period's date of payment.

⁷ The amount Seller owes PGandE at this stage of the calculation. The balance (g) for a given monthly billing period equals the accumulated overpayment (d) for the monthly billing period immediately following.

(2) Example Based on Option 2

Assumptions:

- i. Term of agreement is 15 years;
- ii. Actual operation date is April 1, 1985;
- iii. Prescribed notice is given on April 1, 1987;
- iv. Contract capacity is reduced by 10,000 kW on April 1, 1988; actual performance is from April 1, 1985 through April 1, 1988¹;
- v. Scheduled outage for maintenance: 18 days = 432 hours in both November 1985 and November 1986;
- vi. The applicable capacity loss adjustment factor is .989; and
- vii. Listed below is Seller's Performance Factor (P), the Demonstrated Capacity Factor (Y) in % (when measured), and where applicable, the performance bonus factor (U) earned for each of the monthly billing periods² prior to the time capacity payment is adjusted. Also listed below are the number of hours the Facility was out of service for scheduled maintenance (M) and the number of hours in the month (D) for each of these months.

Monthly Billing Period		P	Y	U	M	D
April	1985	.85	-	-	0	720
May	1985	.95	-	-	0	744
June	1985	.90	78	-	0	720
July	1985	1.00	88	-	0	744
August	1985	.90	98	-	0	744
September	1985	1.00	-	1.035*	0	720
October	1985	.96	-	1.035	0	744
November	1985	.98	-	1.035	432	720
December	1985	1.00	-	1.035	0	744
January	1986	1.00	-	1.035	0	744
February	1986	.92	-	1.035	0	672
March	1986	.85	-	1.035	0	744
April	1986	.78	-	1.035	0	720
May	1986	1.00	-	1.035	0	744
June	1986	.94	100	1.035	0	720
July	1986	.95	95	1.035	0	744
August	1986	1.00	92	1.035	0	744
September	1986	1.00	-	1.080**	0	720
October	1986	.93	-	1.080	0	744
November	1986	.84	-	1.080	432	720
December	1986	.88	-	1.080	0	744
January	1987	.94	-	1.080	0	744
February	1987	1.00	-	1.080	0	672

¹ The capacity payment is adjusted upon receiving notice, so no refund is necessary for the last month of the first twenty-four months of operation and all of the last twelve months (March 1, 1987 to April 1, 1988). Seller performed for twenty-three months prior to payment adjustment. [Note that due to the 30-day interval between delivery and payment, performance in the twenty-fourth month (March 1987) can be paid for at the adjusted capacity price.]

² For purposes of simplification, the monthly billing period will coincide exactly with each calendar month.

* This performance bonus factor was calculated by averaging the Demonstrated Capacity Factors for each of the months of June, July, and August 1985, and then dividing that average by 85(%):

$$U = \frac{78 + 88 + 98}{3} \div 85 = 1.035$$

** This performance bonus factor was calculated by averaging the Demonstrated Capacity Factors for each of the months of June, July, and August 1985, and June, July, and August 1986, and then dividing that average by 85(%):

$$U = \frac{78 + 88 + 98 + 100 + 95 + 92}{6} \div 85 = 1.080$$

The amount of overpayment (E) made by PGandE to Seller during each monthly billing period is calculated as follows:

$$E = [P \times (1 - \frac{M}{D}) \times K \times L \times U \times (A - B) \times C] + [\frac{M}{D} \times R]$$

Where:

- P = performance factor.
- M = number of hours of scheduled maintenance for that monthly billing period.
- D = number of hours in that monthly billing period.
- K = allocation factor from Section C-5.
- L = capacity loss adjustment factor = .989.
- U = performance bonus factor; when Seller does not qualify for a performance bonus factor, U is removed from the above calculation of E.
- A = contract capacity price for the actual operation date (April 1, 1985) and term of agreement which is 15 years = \$110/kW-yr.
- B = adjusted capacity price for the actual operation date and a three-year agreement term = \$59/kW-yr.
- C = amount by which the contract capacity is being reduced = 10,000 kW.
- R = amount of overpayment for the most recent monthly billing period in the same Seasonal Period (i.e., Seasonal Period A or Seasonal Period B).

The results of the calculations are:

<u>Monthly Billing Period</u>		<u>Amount of Overpayment (E)</u>
April	1985	\$ 4,472
May	1985	88,838
June	1985	84,163
July	1985	93,514
August	1985	84,163
September	1985	96,787
October	1985	5,227
November	1985	5,271
December	1985	5,445
January	1986	5,445
February	1986	5,009
March	1986	4,628
April	1986	4,247
May	1986	96,787
June	1986	90,980
July	1986	91,948
August	1986	96,787
September	1986	100,995
October	1986	5,284
November	1986	5,079
December	1986	5,000
January	1987	5,341
February	1987	5,682

Table B shows a step-by-step derivation of the refund Seller owes PGandE for the early termination outlined above. The \$1,136,015 that Seller owes PGandE appears at the lower right-hand corner of the table. All other figures of this table represent intermediate calculation steps.

TABLE B

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Monthly Billing Period ¹	Date of Payment ²	Amount of Overpayment ³	Accumulated Overpayment ⁴	Interest Rate ⁵	Interest Charge ⁶ on Accumulated Overpayment (f)=(d)x(e)	Balance ⁷ (g)=(c)+(d)+(f)
		\$	\$	%	\$	\$
4/85	5/30/85	4,472	0	1.3	0	4,472
5/85	6/30/85	88,838	4,472	1.4	63	93,373
6/85	7/30/85	84,163	93,373	1.3	1,214	178,750
7/85	8/30/85	93,514	178,750	1.2	2,145	274,409
8/85	9/30/85	84,163	274,409	1.0	2,744	361,316
9/85	10/30/85	96,787	361,316	0.9	3,252	461,355
10/85	11/30/85	5,227	461,355	0.8	3,691	470,273
11/85	12/30/85	5,271	470,273	0.7	3,292	478,836
12/85	1/30/86	5,445	478,836	0.8	3,831	488,112
1/86	3/2/86	5,445	488,112	0.9	4,393	497,950
2/86	3/30/86	5,009	497,950	1.0	4,980	507,939
3/86	4/30/86	4,628	507,939	1.1	5,587	518,154
4/86	5/30/86	4,247	518,154	1.2	6,218	528,619
5/86	6/30/86	96,787	528,619	1.3	6,872	632,278
6/86	7/30/86	90,980	632,278	1.4	8,852	732,110
7/86	8/30/86	91,948	732,110	1.4	10,250	834,308
8/86	9/30/86	96,787	834,308	1.3	10,846	941,941
9/86	10/30/86	100,995	941,941	1.2	11,303	1,054,239
10/86	11/30/86	5,284	1,054,239	1.0	10,542	1,070,065
11/86	12/30/86	5,079	1,070,065	1.1	11,771	1,086,915
12/86	1/30/87	5,000	1,086,915	1.1	11,956	1,103,871
1/87	3/2/87	5,341	1,103,871	1.0	11,039	1,120,251
2/87	3/30/87	5,682	1,120,251	0.9	10,082	<u>1,136,015</u>

¹ The month in which power deliveries were made. For purposes of simplification, the monthly billing period will coincide exactly with each calendar month.

² The date on which payment for the monthly billing period stated in column (a) is made.

³ The amount of overpayment made by PGandE to Seller during each monthly billing period.

⁴ The amount of overpayment accumulated up through last month's date of payment.

⁵ The interest rate for the period between the date of payment for the previous monthly billing period and the date of payment for this monthly billing period. These interest rates are arbitrarily chosen for use in this example.

⁶ The amount of interest charge accrued between the date of payment for the previous monthly billing period and the date of payment for this monthly billing period on the accumulated overpayment balance existing as of the previous monthly billing period's date of payment.

⁷ The amount Seller owes PGandE at this stage of the calculation. The balance (g) for a given monthly billing period equals the accumulated overpayment (d) for the monthly billing period immediately following.

(b) Termination without Prescribed Notice

If Seller terminates without prescribed notice, Seller will owe PGandE a refund [the calculation of which is described in Sections D-4(a)(1) and D-4(a)(2) of this example] and payment (G). This example demonstrates how the payment (G) is calculated.

Assumptions:

- i. Term of agreement is 15 years;
- ii. Actual operation date is July 1, 1985;
- iii. Notice is given on January 1, 1990; and
- iv. Contract capacity is to be reduced by 10,000 kW on July 1, 1990; actual performance is from July 1, 1985 through July 1, 1990.

The payment (G) is calculated as follows:

$$G = CC \times (T - CCP) \times \left(\frac{J-H}{12}\right) \quad G \geq 0$$

Where:

- CC = the amount of contract capacity being terminated = 10,000 kW.
- T = the current firm capacity price \$140/kW-yr is arbitrarily chosen for use in this example for a July 1, 1990 Operation Date and 10-year agreement term.
- CCP = the contract capacity price = \$110/kW-yr.
- H = the actual number of months notice given = six months.
- J = the prescribed notice = twelve months.

The sample calculation is:

$$G = CC \times (T - CCP) \times \left(\frac{J-H}{12}\right)$$
$$G = 10,000 \text{ kW} \times (\$140/\text{kW-yr} - \$110/\text{kW-yr}) \times \left(\frac{12 \text{ mos.} - 6 \text{ mos.}}{12 \text{ mos./yr}}\right)$$
$$G = \underline{\underline{\$150,000}}$$

APPENDIX E
INTERCONNECTION
CONTENTS

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APPENDIX E
INTERCONNECTION

E-1 INTERCONNECTION TARIFFS

(The applicable tariffs in effect at the time of execution of this Agreement shall be attached.)

E-2 POINT OF DELIVERY LOCATION SKETCH

E-3

S.O. #2
December 5, 1983

E-3 INTERCONNECTION FACILITIES FOR WHICH SELLER IS RESPONSIBLE

E-4

S.O. #2
December 5, 1983

STANDARD OFFER #3
POWER PURCHASE AGREEMENT
FOR
AS-DELIVERED CAPACITY AND ENERGY
FROM
FACILITIES OF 100 KILOWATTS OR LESS

PACIFIC GAS AND ELECTRIC COMPANY

STANDARD OFFER #3

POWER PURCHASE AGREEMENT

FOR

AS-DELIVERED CAPACITY AND ENERGY

FROM

FACILITIES OF 100 KILOWATTS OR LESS

DECEMBER 1983

AS-DELIVERED CAPACITY AND ENERGY
FROM
FACILITIES OF 100 KILOWATTS OR LESS

POWER PURCHASE AGREEMENT
BETWEEN

AND
PACIFIC GAS AND ELECTRIC COMPANY

("Seller"), and PACIFIC GAS AND ELECTRIC COMPANY ("PGandE"),
referred to collectively as "Parties" and individually as "Party", agree as follows:

1. Seller states that its facility located at _____

and described as Make _____, Model _____, Serial No. _____,
fuel or energy source _____, and having a nameplate output rating of _____ kW,
_____ volts, _____ phase, 60 hertz will be ready to deliver power for sale on or about _____.
Seller has chosen to sell PGandE _____*.
2. Seller has two options for payment for as-delivered capacity and energy delivered to PGandE. They are:

Option No. 1: Seller elects to have the value of the purchased power credited to its monthly bill from PGandE for electric service in the next billing period (assumes electric service account).

Option No. 2: Seller elects to receive payment check within approximately 30 days of the meter reading date if the value of the purchased power is at least \$50, and if less, to have the value of the purchased power credited to its monthly bill from PGandE for electric service in the next billing period.

Seller has selected Option No. _____.
3. On and after the date PGandE gives its written approval for parallel operation, PGandE shall pay Seller for as-delivered capacity at prices authorized from time to time by the California Public Utilities Commission (CPUC) and which are derived from PGandE's full avoided costs as approved by the CPUC. PGandE shall pay Seller for energy at prices equal to PGandE's full short run avoided operating costs as approved by the CPUC.
4. Seller shall pay for designing, installing, operating, and maintaining the facility in accordance with all applicable laws and regulations and shall comply with PGandE's electric Rule No. 21, which is attached hereto.
5. Seller shall deliver the as-delivered capacity and energy at the agreed point of interconnection with PGandE's system as shown in Appendix A.
6. PGandE shall, at its expense, furnish and install a standard watt-hour meter (and current transformers if required) in a meter socket and enclosure equipment provided and installed by Seller at or near the point of interconnection. At Seller's option and expense, PGandE shall furnish and install a time-of-delivery meter pursuant to a separate special facilities agreement referred to in PGandE's electric Rule No. 21.
7. Seller shall (a) maintain the facility and interconnection facilities, except facilities installed by PGandE, in conformance with all applicable laws and regulations, (b) obtain any governmental authorizations and permits required for the construction and operation thereof, and (c) maintain the facility and interconnection facilities in a safe and prudent manner. Seller shall reimburse PGandE for any and all losses, damages, claims, penalties, or liability it incurs as a result of Seller's failure to obtain or maintain any governmental authorizations and permits required for construction and operation of Seller's facility.

* Insert either "net energy output" or "surplus energy output" to show the energy sale option selected by Seller.

8. (a) PGandE may enter Seller's premises (1) to inspect at any reasonable times Seller's protective devices and read or test meters, and (2) to disconnect, without notice, the interconnection facilities if, in PGandE's opinion, a hazardous condition exists and such immediate action is necessary to protect persons, or PGandE's facilities, or other customers' facilities from damage or interference caused by Seller's facility, or lack of properly operating protective devices.
- (b) PGandE shall not be obligated to accept or pay for and may require Seller to interrupt or reduce deliveries of as-delivered capacity and energy (1) when necessary in order to construct, install, maintain, repair, replace, remove, investigate, or inspect any of its equipment or part of its system, or (2) if it determines that curtailment, interruption, or reduction is necessary because of emergencies, forced outages, force majeure, or compliance with prudent electrical practices.
- (c) Whenever possible, PGandE shall give Seller reasonable notice of the possibility that interruption or reduction of deliveries may be required.
9. Each Party as indemnitor shall save harmless and indemnify the other Party and the directors, officers, and employees of such other Party against and from any and all loss and liability for injuries to persons including employees of either Party, and damages, including property of either Party, resulting from or arising out of (a) the engineering, design, construction, maintenance, or operation of or (b) the making of replacements, additions, or betterments to the indemnitor's facilities. This indemnity and save harmless provision shall apply notwithstanding the active or passive negligence of the indemnitee. Neither Party shall be indemnified for liability or loss resulting from its sole negligence or willful misconduct. The indemnitor shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity and shall pay all costs, including reasonable attorney fees, that may be incurred by the other Party in enforcing this indemnity.
10. Nothing in this Agreement shall create any duty to, any standard of care with reference to, or any liability to any person not a Party to it. Neither Party shall be liable to the other Party for consequential damages.
11. Each Party shall be responsible for protecting its facilities from possible damage by reason of the electrical disturbances or faults caused by the operation, faulty operation, or nonoperation of the other Party's facilities, and such other Party shall not be liable for any such damages so caused.
12. This Agreement shall be in effect when signed by the Seller and PGandE for an initial term of one year and shall remain in effect thereafter month to month unless terminated by either Party on 30 (thirty) days' advance written notice to the other.
13. Any notice required under this Agreement shall be in writing and mailed at any United States Post Office with postage prepaid for transmission by certified mail, return receipt requested, addressed to the Party, or personally delivered to the Party, at the address below. Changes in such designation may be made by notice similarly given.

All written notices shall be directed as follows:

to PGandE: Pacific Gas and Electric Company
Attention: Manager, Commercial Department
77 Beale Street
San Francisco, CA 94106

to Seller: _____

14. This Agreement includes the following appendix which is attached and incorporated by reference:

Appendix A - INTERCONNECTION

15. Insurance

15.1 General Liability Coverage

- (a) Seller shall maintain during the performance hereof, General Liability Insurance* of not less than \$500,000 if the nameplate rating of Seller's facility is over 20 kW to 100 kW or \$100,000 if the nameplate rating of Seller's facility is 20 kW or below of combined single limit or equivalent for bodily injury, personal injury, and property damage as the result of any one occurrence.
- (b) General Liability Insurance shall include coverage for Premises-Operations, Owners and Contractors Protective, Products/Completed Operations Hazard, Explosion, Collapse, Underground, Contractual Liability, and Broad Form Property Damage including Completed Operations.
- (c) Such insurance, shall provide for 30-days' written notice to PGandE prior to cancellation, termination, alteration, or material change of such insurance.

15.2 Additional Insurance Provisions

- (a) Evidence of coverage described above in Paragraph 15.1 shall state that coverage provided is primary and is not excess to or contributing with any insurance or self-insurance maintained by PGandE.
- (b) PGandE shall have the right to inspect or obtain a copy of the original policy(ies) of insurance.
- (c) Seller shall furnish the required certificates** and endorsements to PGandE prior to commencing operation.
- (d) All insurance certificates**, endorsements, cancellations, terminations, alterations, and material changes of such insurance shall be issued and submitted to the following:

PACIFIC GAS AND ELECTRIC COMPANY
Attention: Manager - Insurance Department
77 Beale Street, Room E280
San Francisco, CA 94106

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized representatives as of the last date set forth below.

(SELLER)

PACIFIC GAS AND ELECTRIC COMPANY

BY: _____

BY: _____

(Type Name)

(Type Name)

TITLE: _____

TITLE: _____

DATE SIGNED: _____

DATE SIGNED: _____

Mailing Address:

* Governmental agencies which have an established record of self-insurance may provide the required coverage through self-insurance.

** A governmental agency qualifying to maintain self-insurance should provide a statement of self-insurance.

APPENDIX A
INTERCONNECTION

(a) Interconnection Tariffs

(The applicable tariffs in effect at the time of execution of this Agreement shall be attached.)

(b) Point of Delivery Location Sketch

APPENDIX F

STANDARD OFFER #4
POWER PURCHASE AGREEMENT
FOR
LONG-TERM ENERGY AND CAPACITY

ANNOUNCEMENT
ABOUT
COGENERATION AND SMALL POWER PRODUCTION
DECEMBER 1983

The California Public Utilities Commission (CPUC) has authorized PGandE to make available a new standard power purchase agreement based on long-run avoided costs to encourage the production and sale of electric power to PGandE from Qualifying Facilities (QFs).

Attached is the new form of Power Purchase Agreement, Standard Offer #4, which contains terms under which PGandE will purchase power from QFs. Standard Offer #4 was made effective by the CPUC on September 7, 1983 and is available in addition to previously approved Standard Offers #s 1, 2, and 3, which are based on short-run avoided costs.

Standard Offer #4 contains two capacity payment options and three energy payment options, and the minimum contract term is 15 years. A QF may choose to provide either as-delivered capacity or firm capacity. Energy payments for a portion of the contract term can be based on a forecast of energy prices (Energy Payment Option 1), a levelization of the forecasted prices (Energy Payment Option 2), or a forecast of incremental energy rates in Btu/kWh (Energy Payment Option 3).

As ordered by the CPUC, PGandE can use Standard Offer #4 for a minimum of six months after September 7, 1983. Unless changed by the CPUC, PGandE is authorized to offer Energy Payment Option 1 for a maximum of two years and Energy Payment Options 2 and 3 for a maximum of one year from September 7, 1983.

Energy Payment Option 1 involves a time differentiated forecasted energy price schedule, which establishes an escalating set of prices to be paid a QF during the various time periods of each year of a fixed price period. After the fixed price period, the QF receives published avoided energy cost prices for the remainder of the contract term.

Energy Payment Option 2 involves a levelized, time differentiated schedule of energy prices. A price is established for each time period. These time differentiated prices remain constant throughout the fixed price period. After the fixed price period, the QF is paid published avoided energy cost prices.

Energy Payment Option 3 involves the use of predicted energy rates in Btu/kWh. Energy rates for each year from 1984 through 1998 are set forth in the Power Purchase Agreement. The QF selects both a floor and ceiling energy rate by designating a number to create an equal band on each side of the predicted energy rate. Payments are based on PGandE's published avoided energy cost prices, and adjustments are made if the energy rates derived from these payments fall outside of the band selected by the QF. After the predicted energy rate period is over, the QF receives published avoided energy cost prices.

There are some restrictions on the use of the options in Standard Offer #4, particularly the energy pricing options. Since all options are not available to all QF projects, any party considering the use of Standard Offer #4 should contact PGandE for further information regarding its applicability for a particular project.

The CPUC order addressing Standard Offer #4 is an interim order. CPUC hearings will be held in 1984 to further examine the components of a standard offer based on long-run avoided costs. A revised Standard Offer #4 may result from those hearings.

PACIFIC GAS AND ELECTRIC COMPANY
STANDARD OFFER #4
POWER PURCHASE AGREEMENT
FOR
LONG-TERM ENERGY AND CAPACITY

DECEMBER 1983

STANDARD OFFER #4:
LONG-TERM ENERGY AND CAPACITY
POWER PURCHASE AGREEMENT

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LONG-TERM ENERGY AND CAPACITY
POWER PURCHASE AGREEMENT
BETWEEN

AND
PACIFIC GAS AND ELECTRIC COMPANY

_____, ("Seller"), and PACIFIC GAS AND ELECTRIC COMPANY ("PGandE"), referred to collectively as "Parties" and individually as "Party", agree as follows:

ARTICLE 1 QUALIFYING STATUS

Seller warrants that, at the date of first power deliveries from Seller's Facility¹ and during the term of agreement, its Facility shall meet the qualifying facility requirements established as of the effective date of this Agreement by the Federal Energy Regulatory Commission's rules (18 Code of Federal Regulations 292) implementing the Public Utility Regulatory Policies Act of 1978 (16 U.S.C.A. 796, et seq.).

ARTICLE 2 COMMITMENT OF PARTIES

The prices to be paid Seller for energy and/or capacity delivered pursuant to this Agreement have wholly or partly been fixed at the time of execution. Actual avoided costs at the time of energy and/or capacity deliveries may be substantially above or below the prices fixed in this Agreement. Therefore, the Parties expressly commit to the prices fixed in this Agreement for the applicable period of performance and shall not seek to or have a right to renegotiate such prices for any reason. As part of its consideration for the benefit of fixing part or all of the energy and/or capacity prices under this Agreement, Seller waives any and all rights to judicial or other relief from its obligations and/or prices set forth in Appendices B, D, and E, or modification of any other term or provision for any reasons whatsoever.

This Agreement contains certain provisions which set forth methods of calculating damages to be paid to PGandE in the event Seller fails to fulfill certain performance obligations. The inclusion of such provisions is not intended to create any express or implied right in Seller to terminate this Agreement prior to the expiration of the term of agreement. Termination of this Agreement by Seller prior to its expiration date shall constitute a breach of this Agreement and the damages expressly set forth in this Agreement shall not constitute PGandE's sole remedy for such breach.

ARTICLE 3 PURCHASE OF POWER

- (a) Seller shall sell and deliver and PGandE shall purchase and accept delivery of capacity and energy at the voltage level of _____ kV.
- (b) Seller shall provide capacity and energy from its _____ kw
[Nameplate rating of
generator(s)]
Facility located at _____.
- (c) The scheduled operation date of the Facility is _____. At
[Date]
the end of each calendar quarter Seller shall give written notice to PGandE of any change in the scheduled operation date.
- (d) To avoid exceeding the physical limitations of the interconnection facilities, Seller shall limit the Facility's actual rate of delivery into the PGandE system to _____ kw.
- (e) The primary energy source for the Facility is _____.

¹ Underlining identifies those terms which are defined in Section A-1 of Appendix A.

- (f) If Seller does not begin construction of its Facility by _____, PGandE [Date] may reallocate the existing capacity on PGandE's transmission and/or distribution system which would have been used to accommodate Seller's power deliveries to other uses. In the event of such reallocation, Seller shall pay PGandE for the cost of any upgrades or additions to PGandE's system necessary to accommodate the output from the Facility. Such additional facilities shall be installed, owned, and maintained in accordance with the applicable PGandE tariff.

ARTICLE 4 ENERGY PRICE

PGandE shall pay Seller for its _____¹ under the energy payment option checked below²:

_____ Energy Payment Option 1 - Forecasted Energy Prices

During the fixed price period, Seller shall be paid for energy delivered at prices equal to _____³ percent of the prices set forth in Table B-1, Appendix B, plus _____⁴ percent of PGandE's full short-run avoided operating costs.

For the remaining years of the term of agreement, Seller shall be paid for energy delivered at prices equal to PGandE's full short-run avoided operating costs.

If Seller's Facility is not an oil or gas-fired cogeneration facility, Seller may convert from Energy Payment Option 1 to Energy Payment Option 2 and be subject to the conditions therein, provided that Seller shall not change the percentage of energy prices to be based on PGandE's full short-run avoided operating costs. Such conversion must be made at least 90 days prior to the date of initial energy deliveries and must be made by written notice in accordance with Section A-17, Appendix A.

_____ Energy Payment Option 2 - Levelized Energy Prices

During the fixed price period, Seller shall be paid for energy delivered at prices equal to _____⁵ percent of the levelized energy prices set forth in Table B-2, Appendix B for the year in which energy deliveries begin and term of agreement, plus _____⁶ percent of PGandE's full short-run avoided operating costs. During the fixed price period, Seller shall be subject to the conditions and terms set forth in Appendix B, Energy Payment Option 2.

For the remaining years of the term of agreement, Seller shall be paid for energy delivered at prices equal to PGandE's full short-run avoided operating costs.

Seller may convert from Energy Payment Option 2 to Energy Payment Option 1, provided that Seller shall not change the percentage of energy prices to be based on PGandE's full short-run avoided operating costs. Such conversion must be made at least 90 days prior to the date of initial energy deliveries and must be made by written notice in accordance with Section A-17, Appendix A.

- ¹ Insert either "net energy output" or "surplus energy output" to show the energy sale option selected by Seller.
- ² Energy Payment Option 2 is not available to oil or gas-fired cogenerators.
- ³ Insert either 0, 20, 40, 60, 80, or 100, at Seller's option. If Seller's Facility is an oil or gas-fired cogeneration facility, either 0 or 20 must be inserted.
- ⁴ Insert the difference between 100 and the percentage selected under footnote 3 above.
- ⁵ Insert either 20, 40, 60, 80, or 100, at Seller's option.
- ⁶ Insert the difference between 100 and the percentage selected under footnote 5 above.

_____ Energy Payment Option 3 - Incremental Energy Rate

Beginning with the date of initial energy deliveries and continuing until _____¹, Seller shall be paid monthly for energy delivered at prices equal to PGandE's full short-run avoided operating costs, provided that adjustments shall be made annually to the extent set forth in Appendix B, Energy Payment Option 3.

The Incremental Energy Rate Band Widths specified by Seller in Table I below shall be used in determining the annual adjustment, if any.

TABLE I

<u>Year</u>	<u>Incremental Energy Rate Band Widths</u> (must be multiples of 100 or zero)
1984	_____
1985	_____
1986	_____
1987	_____
1988	_____
1989	_____
1990	_____
1991	_____
1992	_____
1993	_____
1994	_____
1995	_____
1996	_____
1997	_____
1998	_____

After _____, Seller shall be paid for energy delivered at prices equal to PGandE's full short-run avoided operating costs.

ARTICLE 5 CAPACITY ELECTION AND CAPACITY PRICE

Seller may elect to deliver either firm capacity or as-delivered capacity, and Seller's election is indicated below. PGandE's prices for firm capacity and as-delivered capacity are derived from PGandE's full avoided costs as approved by the CPUC.

_____ Firm capacity - _____ kw for _____ years from the firm capacity availability date with payment determined in accordance with Appendix E. Except for hydro-electric facilities, PGandE shall pay Seller for capacity delivered in excess of firm capacity on an as-delivered capacity basis in accordance with As-Delivered Capacity Payment Option _____ set forth in Appendix D.

OR

_____ As-delivered capacity with payment determined in accordance with As-Delivered Capacity Payment Option _____ set forth in Appendix D.

¹ Specified by Seller. Must be December 31, 1998 or prior.

ARTICLE 6 LOSS ADJUSTMENT FACTORS

Capacity Loss Adjustment Factors shall be as shown in Appendix D and Appendix E, dependent upon Seller's capacity election set forth in Article 5 of this Agreement.

Energy Loss Adjustment Factors shall be considered as unity for all energy payments related to Energy Payment Options 1 and 2 set forth in Appendix B for the entire fixed price period of this Agreement, except for the percentage of payments that Seller elected in Article 4 to have calculated based on PGandE's full short-run avoided operating costs. Energy Loss Adjustment Factors for all payments related to PGandE's full short-run avoided operating costs are subject to CPUC rulings for the entire term of agreement.

ARTICLE 7 CURTAILMENT

Seller has two options regarding possible curtailment by PGandE of Seller's deliveries, and Seller's selection is indicated below:

_____ Curtailment Option A - Hydro Spill and Negative Avoided Cost

_____ Curtailment Option B - Adjusted Price Period

The two options are described in Appendix C.

ARTICLE 8 RETROACTIVE APPLICATION OF CPUC ORDERS

Pursuant to Ordering Paragraph 1(f) of CPUC Decision No. 83-09-054 (September 7, 1983), after the effective date of the CPUC's Application 82-03-26 decision relating to line loss factors, Seller has the option to retain the relevant terms of this Agreement or have the results of that decision incorporated into this Agreement. To retain the terms herein, Seller shall provide written notice to PGandE within 30 days after the effective date of the relevant CPUC decision on Application 82-03-26. Failure to provide such notice will result in the amendment of this Agreement to comply with that decision.

As soon as practicable following the issuance of a decision in Application 82-03-26, PGandE shall notify Seller of the effective date thereof and its results.

ARTICLE 9 NOTICES

All written notices shall be directed as follows:
To PGandE: Pacific Gas and Electric Company
Attention: Vice President -
Electric Operations
77 Beale Street
San Francisco, CA 94106

To Seller: _____

ARTICLE 10 DESIGNATED SWITCHING CENTER

The designated PGandE switching center shall be, unless changed by PGandE:

(Name)

(Location)

(Phone number)

ARTICLE 11 TERMS AND CONDITIONS

This Agreement includes the following appendices which are attached and incorporated by reference:

- Appendix A - GENERAL TERMS AND CONDITIONS
- Appendix B - ENERGY PAYMENT OPTIONS
- Appendix C - CURTAILMENT OPTIONS
- Appendix D - AS-DELIVERED CAPACITY
- Appendix E - FIRM CAPACITY
- Appendix F - INTERCONNECTION

ARTICLE 12 TERM OF AGREEMENT

This Agreement shall be binding upon execution and remain in effect thereafter for _____ years¹ from the _____²; provided, however, that it shall terminate if energy deliveries do not start within five years of the execution date.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized representatives and it is effective as of the last date set forth below.

(SELLER)

PACIFIC GAS AND ELECTRIC COMPANY

BY: _____

BY: _____

(Type Name)

(Type Name)

TITLE: _____

TITLE: _____

DATE SIGNED: _____

DATE SIGNED: _____

¹ The minimum contract term is 15 years and the maximum contract term is 30 years.

² Insert "firm capacity availability date" if Seller has elected to deliver firm capacity or "date of initial energy deliveries" if Seller has elected to deliver as-delivered capacity.

APPENDIX A
GENERAL TERMS AND CONDITIONS
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APPENDIX A
GENERAL TERMS AND CONDITIONS

A-1 DEFINITIONS

Whenever used in this Agreement, appendices, and attachments hereto, the following terms shall have the following meanings:

Adjusted firm capacity price - The \$/kW-year purchase price for firm capacity from Table E-2, Appendix E for the period of Seller's actual performance.

As-delivered capacity - Capacity delivered to PGandE in excess of firm capacity or in lieu of a firm capacity commitment.

CPUC - The Public Utilities Commission of the State of California.

Current firm capacity price - The \$/kW-year capacity price from PGandE's firm capacity price schedule effective at the time PGandE derates the firm capacity pursuant to Section E-4(b), Appendix E or Seller terminates performance under this Agreement, for a term equal to the period from the date of deration or termination to the end of the term of agreement.

Designated PGandE switching center - That switching center or other PGandE installation identified in Article 10.

Facility - That generation apparatus described in Article 3 and all associated equipment owned, maintained, and operated by Seller.

Firm capacity - That capacity, if any, identified as firm in Article 5 except as otherwise changed as provided herein.

Firm capacity availability date - The day following the day during which all features and equipment of the Facility are demonstrated to PGandE's satisfaction to be capable of operating simultaneously to deliver firm capacity continuously into PGandE's system as provided in this Agreement.

Firm capacity price - The price for firm capacity applicable for the firm capacity availability date and the number of years of firm capacity delivery from the firm capacity price schedule, Table E-2, Appendix E.

Firm capacity price schedule - The periodically published schedule of the \$/kW-year prices that PGandE offers to pay for firm capacity. See Table E-2, Appendix E.

Fixed price period - The period during which forecasted or levelized energy prices, and/or forecasted as-delivered capacity prices, are in effect; defined as the first five years of the term of agreement if the term of agreement is 15 or 16 years; the first six years of the term of agreement if the term of agreement is 17, 18, or 19 years; or the first ten years of the term of agreement if the term of agreement is anywhere from 20 through 30 years.

Forced outage - Any outage resulting from a design defect, inadequate construction, operator error or a breakdown of the mechanical or electrical equipment that fully or partially curtails the electrical output of the Facility.

Full short-run avoided operating costs - CPUC-approved costs which are the basis of PGandE's published energy prices. PGandE's current energy price calculation is shown in Table B-5, Appendix B. PGandE's published off-peak hours' prices shall be adjusted, as appropriate, if Seller has selected Curtailment Option B.

Interconnection facilities - All means required and apparatus installed to interconnect and deliver power from the Facility to the PGandE system including, but not limited to, connection, transformation, switching, metering, communications, and safety equipment, such as equipment required to protect (1) the PGandE system and its customers from faults occurring at the Facility, and (2) the Facility from faults occurring on the PGandE system or on the systems of others to which the PGandE system is directly or indirectly connected. Interconnection facilities also include any necessary additions and reinforcements by PGandE to the PGandE system required as a result of the interconnection of the Facility to the PGandE system.

Net energy output - The Facility's gross output in kilowatt-hours less station use and transformation and transmission losses to the point of delivery into the PGandE system. Where PGandE agrees that it is impractical to connect the station use on the generator side of the power purchase meter, PGandE may, at its option, apply a station load adjustment.

Prudent electrical practices - Those practices, methods, and equipment, as changed from time to time, that are commonly used in prudent electrical engineering and operations to design and operate electric equipment lawfully and with safety, dependability, efficiency, and economy.

Scheduled operation date - The day specified in Article 3(c) when the Facility is, by Seller's estimate, expected to produce energy that will be available for delivery to PGandE.

Special facilities - Those additions and reinforcements to the PGandE system which are needed to accommodate the maximum delivery of energy and capacity from the Facility as provided in this Agreement and those parts of the interconnection facilities which are owned and maintained by PGandE at Seller's request, including metering and data processing equipment. All special facilities shall be owned, operated, and maintained pursuant to PGandE's electric Rule No. 21, which is attached hereto.

Station use - Energy used to operate the Facility's auxiliary equipment. The auxiliary equipment includes, but is not limited to, forced and induced draft fans, cooling towers, boiler feed pumps, lubricating oil systems, plant lighting, fuel handling systems, control systems, and sump pumps.

Surplus energy output - The Facility's gross output, in kilowatt-hours, less station use, and any other use by Seller, and transformation and transmission losses to the point of delivery into the PGandE system.

Term of agreement - The number of years this Agreement will remain in effect as provided in Article 12.

Voltage level - The voltage at which the Facility interconnects with the PGandE system, measured at the point of delivery.

A-2 CONSTRUCTION

A-2.1 Land Rights

Seller hereby grants to PGandE all necessary rights of way and easements, including adequate and continuing access rights on property of Seller, to install, operate, maintain, replace, and remove the special facilities. Seller agrees to execute such other grants, deeds, or documents as PGandE may require to enable it to record such rights of way and easements. If any part of PGandE's equipment is to be installed on property owned by other than Seller, Seller shall, at its own cost and expense, obtain from the owners thereof all necessary rights of way and easements, in a form satisfactory to PGandE, for the construction, operation, maintenance, and replacement of PGandE's equipment upon such property. If Seller is unable to obtain such rights of way and easements, Seller shall reimburse PGandE for all costs incurred by PGandE in obtaining them. PGandE shall at all times have the right of ingress to and egress from the Facility at all reasonable hours for any purposes reasonably connected with this Agreement or the exercise of any and all rights secured to PGandE by law or its tariff schedules.

A-2.2 Design, Construction, Ownership, and Maintenance

- (a) Seller shall design, construct, install, own, operate, and maintain all interconnection facilities, except special facilities, to the point of interconnection with the PGandE system as required for PGandE to receive capacity and energy from the Facility. The Facility and interconnection facilities shall meet all requirements of applicable codes and all standards of prudent electrical practices and shall be maintained in a safe and prudent manner. A description of the interconnection facilities for which Seller is solely responsible is set forth in Appendix F, or if the interconnection requirements have not yet been determined at the time of the execution of this Agreement, the description of such facilities will be appended to this Agreement at the time such determination is made.
- (b) Seller shall submit to PGandE all specifications for the interconnection facilities (except special facilities) and, at PGandE's option, the Facility, for review and written acceptance prior to their release for construction purposes. PGandE's review and acceptance of these specifications shall not be construed as confirming or endorsing the design or as warranting their safety, durability, or reliability. PGandE shall not, by reason of such review or lack of review, be responsible for strength, details of design, adequacy, or capacity of equipment built pursuant to such specifications, nor shall PGandE's acceptance be deemed to be an endorsement of any of such equipment. Seller shall change the interconnection facilities as may be reasonably required by PGandE to meet changing requirements of the PGandE system.
- (c) In the event it is necessary for PGandE to install interconnection facilities for the purposes of this Agreement, they shall be installed as special facilities.
- (d) Upon the request of Seller, PGandE shall provide a binding estimate for the installation of interconnection facilities by PGandE.

A-2.3 Meter Installation

- (a) PGandE shall specify, provide, install, own, operate, and maintain as special facilities all metering and data processing equipment for the registration and recording of energy and other related parameters which are required for the reporting of data to PGandE and for computing the payment due Seller from PGandE.
- (b) Seller shall provide, construct, install, own, and maintain at Seller's expense all that is required to accommodate the metering and data processing equipment, such as, but not limited to, metal-clad switchgear, switchboards, cubicles, metering panels, enclosures, conduits, rack structures, and equipment mounting pads.

A-3 OPERATION

A-3.1 Inspection and Approval

Seller shall not operate the Facility in parallel with PGandE's system until an authorized PGandE representative has inspected the interconnection facilities, and PGandE has given written approval to begin parallel operation. Seller shall notify PGandE of the Facility's start-up date at least 45 days prior to such date. PGandE shall inspect the interconnection facilities within 30 days of the receipt of such notice. If parallel operation is not authorized by PGandE, PGandE shall notify Seller in writing within five days after inspection of the reason authorization for parallel operation was withheld.

A-3.2 Facility Operation and Maintenance

Seller shall operate and maintain its Facility according to prudent electrical practices, applicable laws, orders, rules, and tariffs and shall provide such reactive power support as may be reasonably required by PGandE to maintain system voltage level and power factor. Seller shall operate the Facility at the power factors or voltage levels prescribed by PGandE's system dispatcher or designated representative. If Seller fails to provide reactive power support, PGandE may do so at Seller's expense.

A-3.3 Point of Delivery

Seller shall deliver the energy at the point where Seller's electrical conductors (or those of Seller's agent) contact PGandE's system as it shall exist whenever the deliveries are being made or at such other point or points as the Parties may agree in writing. The initial point of delivery of Seller's power to the PGandE system is set forth in Appendix F.

A-3.4 Operating Communications

- (a) Seller shall maintain operating communications with the designated PGandE switching center. The operating communications shall include, but not be limited to, system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, levels of operating voltage or power factors and daily capacity and generation reports.
- (b) Seller shall keep a daily operations log for each generating unit which shall include information on unit availability, maintenance outages, circuit breaker trip operations requiring a manual reset, and any significant events related to the operation of the Facility.
- (c) If Seller makes deliveries greater than one megawatt, Seller shall measure and register on a graphic recording device power in kW and voltage in kV at a location within the Facility agreed to by both Parties.
- (d) If Seller makes deliveries greater than one and up to and including ten megawatts, Seller shall report to the designated PGandE switching center, twice a day at agreed upon times for the current day's operation, the hourly readings in kW of capacity delivered and the energy in kWh delivered since the last report.
- (e) If Seller makes deliveries of greater than ten megawatts, Seller shall telemeter the delivered capacity and energy information, including real power in kW, reactive power in kVAR, and energy in kWh to a switching center selected by PGandE. PGandE may also require Seller to telemeter transmission kW, kVAR, and kV data depending on the number of generators and transmission configuration. Seller shall provide and maintain the data circuits required for telemetering. When telemetering is inoperative, Seller shall report daily the capacity delivered each hour and the energy delivered each day to the designated PGandE switching center.

A-3.5 Meter Testing and Inspection

- (a) All meters used to provide data for the computation of the payments due Seller from PGandE shall be sealed, and the seals shall be broken only by PGandE when the meters are to be inspected, tested, or adjusted.
- (b) PGandE shall inspect and test all meters upon their installation and annually thereafter. At Seller's request and expense, PGandE shall inspect or test a meter more frequently. PGandE shall give reasonable notice to Seller of the time when any inspection or test shall take place, and Seller may have representatives present at the test or inspection. If a meter is found to be inaccurate or defective, PGandE shall adjust, repair, or replace it at its expense in order to provide accurate metering.

A-3.6 Adjustments to Meter Measurements

If a meter fails to register, or if the measurement made by a meter during a test varies by more than two percent from the measurement made by the standard meter used in the test, an adjustment shall be made correcting all measurements made by the inaccurate meter for -- (1) the actual period during which inaccurate measurements were made, if the period can be determined, or if not, (2) the period immediately preceding the test of the meter equal to one-half the time from the date of the last previous test of the meter, provided that the period covered by the correction shall not exceed six months.

A-4 PAYMENT

PGandE shall mail to Seller not later than 30 days after the end of each monthly billing period (1) a statement showing the energy and capacity delivered to PGandE during on-peak, partial-peak, and off-peak periods during the monthly billing period, (2) PGandE's computation of the amount due Seller, and (3) PGandE's check in

payment of said amount. Except as provided in Section A-5, if within 30 days of receipt of the statement Seller does not make a report in writing to PGandE of an error, Seller shall be deemed to have waived any error in PGandE's statement, computation, and payment, and they shall be considered correct and complete.

A-5 ADJUSTMENTS OF PAYMENTS

- (a) In the event adjustments to payments are required as a result of inaccurate meters, PGandE shall use the corrected measurements described in Section A-3.6 to recompute the amount due from PGandE to Seller for the capacity and energy delivered under this Agreement during the period of inaccuracy.
- (b) The additional payment to Seller or refund to PGandE shall be made within 30 days of notification of the owing Party of the amount due.

A-6 ACCESS TO RECORDS AND PGandE DATA

Each Party, after giving reasonable written notice to the other Party, shall have the right of access to all metering and related records including operations logs of the Facility. Data filed by PGandE with the CPUC pursuant to CPUC orders governing the purchase of power from qualifying facilities shall be provided to Seller upon request; provided that Seller shall reimburse PGandE for the costs it incurs to respond to such request.

A-7 INTERRUPTION OF DELIVERIES

PGandE shall not be obligated to accept or pay for and may require Seller to interrupt or reduce deliveries of energy (1) when necessary in order to construct, install, maintain, repair, replace, remove, investigate, or inspect any of its equipment or any part of its system, or (2) if it determines that interruption or reduction is necessary because of PGandE system emergencies, forced outages, force majeure, or compliance with prudent electrical practices; provided that PGandE shall not interrupt deliveries pursuant to this section in order to take advantage, or make purchases, of less expensive energy elsewhere. Whenever possible, PGandE shall give Seller reasonable notice of the possibility that interruption or reduction of deliveries may be required.

A-8 FORCE MAJEURE

- (a) The term force majeure as used herein means unforeseeable causes, other than forced outages, beyond the reasonable control of and without the fault or negligence of the Party claiming force majeure including, but not limited to, acts of God, labor disputes, sudden actions of the elements, actions by federal, state, and municipal agencies, and actions of legislative, judicial, or regulatory agencies which conflict with the terms of this Agreement.
- (b) If either Party because of force majeure is rendered wholly or partly unable to perform its obligations under this Agreement, that Party shall be excused from whatever performance is affected by the force majeure to the extent so affected provided that:
 - (1) the non-performing Party, within two weeks after the occurrence of the force majeure, gives the other Party written notice describing the particulars of the occurrence,
 - (2) the suspension of performance is of no greater scope and of no longer duration than is required by the force majeure,
 - (3) the non-performing Party uses its best efforts to remedy its inability to perform (this subsection shall not require the settlement of any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to its interest. It is understood and agreed that the settlement of strikes, walkouts, lockouts or other labor disputes shall be at the sole discretion of the Party having the difficulty),
 - (4) when the non-performing Party is able to resume performance of its obligations under this Agreement, that Party shall give the other Party written notice to that effect, and

(5) capacity payments during such periods of force majeure on Seller's part shall be governed by Section E-2(c), Appendix E.

- (c) In the event a Party is unable to perform due to legislative, judicial, or regulatory agency action, this Agreement shall be renegotiated to comply with the legal change which caused the non-performance.

A-9 INDEMNITY

Each Party as indemnitor shall save harmless and indemnify the other Party and the directors, officers, and employees of such other Party against and from any and all loss and liability for injuries to persons including employees of either Party, and property damages including property of either Party resulting from or arising out of (1) the engineering, design, construction, maintenance, or operation of, or (2) the making of replacements, additions, or betterments to, the indemnitor's facilities. This indemnity and save harmless provision shall apply notwithstanding the active or passive negligence of the indemnitee. Neither Party shall be indemnified hereunder for its liability or loss resulting from its sole negligence or willful misconduct. The indemnitor shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity and shall pay all costs, including reasonable attorney fees, that may be incurred by the other Party in enforcing this indemnity.

A-10 LIABILITY; DEDICATION

- (a) Nothing in this Agreement shall create any duty to, any standard of care with reference to, or any liability to any person not a Party to it. Neither Party shall be liable to the other Party for consequential damages.
- (b) Each Party shall be responsible for protecting its facilities from possible damage by reason of electrical disturbances or faults caused by the operation, faulty operation, or nonoperation of the other Party's facilities, and such other Party shall not be liable for any such damages so caused.
- (c) No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public or affect the status of PGandE as an independent public utility corporation or Seller as an independent individual or entity and not a public utility.

A-11 SEVERAL OBLIGATIONS

Except where specifically stated in this Agreement to be otherwise, the duties, obligations, and liabilities of the Parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership, or joint venture or impose a trust or partnership duty, obligation, or liability on or with regard to either Party. Each Party shall be liable individually and severally for its own obligations under this Agreement.

A-12 NON-WAIVER

Failure to enforce any right or obligation by either Party with respect to any matter arising in connection with this Agreement shall not constitute a waiver as to that matter or any other matter.

A-13 ASSIGNMENT

Neither Party shall voluntarily assign its rights nor delegate its duties under this Agreement, or any part of such rights or duties, without the written consent of the other Party, except in connection with the sale or merger of a substantial portion of its properties. Any such assignment or delegation made without such written consent shall be null and void. Consent for assignment shall not be withheld unreasonably. Such assignment shall include, unless otherwise specified therein, all of Seller's rights to any refunds which might become due under this Agreement.

A-14 CAPTIONS

All indexes, titles, subject headings, section titles, and similar items are provided for the purpose of reference and convenience and are not intended to affect the meaning of the contents or scope of this Agreement.

A-15 CHOICE OF LAWS

This Agreement shall be interpreted in accordance with the laws of the State of California, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

A-16 GOVERNMENTAL JURISDICTION AND AUTHORIZATION

Seller shall obtain any governmental authorizations and permits required for the construction and operation of the Facility. Seller shall reimburse PGandE for any and all losses, damages, claims, penalties, or liability it incurs as a result of Seller's failure to obtain or maintain such authorizations and permits.

A-17 NOTICES

Any notice, demand, or request required or permitted to be given by either Party to the other, and any instrument required or permitted to be tendered or delivered by either Party to the other, shall be in writing (except as provided in Section E-3) and so given, tendered, or delivered, as the case may be, by depositing the same in any United States Post Office with postage prepaid for transmission by certified mail, return receipt requested, addressed to the Party, or personally delivered to the Party, at the address in Article 9 of this Agreement. Changes in such designation may be made by notice similarly given.

A-18 INSURANCE

A-18.1 General Liability Coverage

- (a) Seller shall maintain during the performance hereof, General Liability Insurance¹ of not less than \$1,000,000 if the Facility is over 100 kW, \$500,000 if the Facility is over 20 kW to 100 kW, and \$100,000 if the Facility is 20 kW or below of combined single limit or equivalent for bodily injury, personal injury, and property damage as the result of any one occurrence.
- (b) General Liability Insurance shall include coverage for Premises-Operations, Owners and Contractors Protective, Products/Completed Operations Hazard, Explosion, Collapse, Underground, Contractual Liability, and Broad Form Property Damage including Completed Operations.
- (c) Such insurance, by endorsement to the policy(ies), shall include PGandE as an additional insured if the Facility is over 100 kW insofar as work performed by Seller for PGandE is concerned, shall contain a severability of interest clause, shall provide that PGandE shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for payment of premium for such insurance, and shall provide for 30-days' written notice to PGandE prior to cancellation, termination, alteration, or material change of such insurance.

A-18.2 Additional Insurance Provisions

- (a) Evidence of coverage described above in Section A-18.1 shall state that coverage provided is primary and is not excess to or contributing with any insurance or self-insurance maintained by PGandE.
- (b) PGandE shall have the right to inspect or obtain a copy of the original policy(ies) of insurance.
- (c) Seller shall furnish the required certificates² and endorsements to PGandE prior to commencing operation.
- (d) All insurance certificates², endorsements, cancellations, terminations, alterations, and material changes of such insurance shall be issued and submitted to the following:

PACIFIC GAS AND ELECTRIC COMPANY
Attention: Manager - Insurance Department
77 Beale Street, Room E280
San Francisco, CA 94106

¹ Governmental agencies which have an established record of self-insurance may provide the required coverage through self-insurance.

² A governmental agency qualifying to maintain self-insurance should provide a statement of self-insurance.

APPENDIX B

ENERGY PAYMENT OPTIONS

Energy Payment Option 1 - Forecasted Energy Prices

Pursuant to Article 4, the energy payment calculation for Seller's energy deliveries during each year of the fixed price period shall include the appropriate prices for such year in Table B-1, multiplied by the percentage Seller has specified in Article 4. If Seller has selected Curtailment Option B in Article 7, the forecasted off-peak hours' energy prices listed in Table B-1 shall be adjusted upward by 7.7% for Period A and 9.6% for Period B.

TABLE B-1

Forecasted Energy Price Schedule

Year of Energy Deliv- eries	Forecasted Energy Prices*, ¢/kWh						Weighted Annual Average
	Period A			Period B			
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	
1983	5.36	5.12	4.94	5.44	5.31	5.19	5.18
1984	5.66	5.40	5.22	5.74	5.61	5.48	5.47
1985	5.75	5.48	5.30	5.83	5.69	5.56	5.55
1986	5.99	5.72	5.52	6.08	5.94	5.80	5.79
1987	6.38	6.08	5.88	6.47	6.32	6.17	6.16
1988	6.94	6.62	6.39	7.03	6.87	6.71	6.70
1989	7.60	7.25	7.00	7.70	7.53	7.35	7.34
1990	8.12	7.74	7.48	8.23	8.04	7.85	7.84
1991	8.64	8.24	7.96	8.75	8.56	8.35	8.34
1992	9.33	8.90	8.60	9.46	9.24	9.02	9.01
1993	10.10	9.63	9.30	10.23	10.00	9.76	9.75
1994	10.91	10.41	10.06	11.06	10.81	10.55	10.54
1995	11.79	11.25	10.87	11.96	11.68	11.40	11.39
1996	12.67	12.09	11.68	12.85	12.56	12.25	12.24
1997	13.61	12.98	12.54	13.79	13.48	13.15	13.14

* These prices are differentiated by the time periods as defined in Table B-4.

Energy Payment Option 2 - Levelized Energy Prices

Pursuant to Article 4, the energy payment calculation for Seller's energy deliveries during the fixed price period shall include the appropriate prices set forth in Table B-2 for the year in which energy deliveries begin and term of agreement, multiplied by the percentage Seller has specified in Article 4. If Seller has selected Curtailment Option B in Article 7, the levelized off-peak hours' energy prices listed in Table B-2 shall be adjusted upward by 7.7% for Period A and 9.6% for Period B. The discount specified in (c)(vi) below, if applicable, will be applied to the energy payments during the fixed price period.

During the fixed price period, Seller shall be subject to the following conditions and terms:

(a) Minimum Damages

The Parties agree that the levelized energy prices which PGandE pays Seller for the energy which Seller delivers to PGandE is based on the agreed value to PGandE of Seller's energy deliveries during the entire fixed price period. In the event PGandE does not receive such full performance by reason of a termination, Seller shall pay PGandE an amount based on the difference between the net present values, at the time of termination, of the payments Seller would receive at the forecasted energy prices in Table B-1 and the payments Seller would receive at the levelized energy prices, for the remaining years of the fixed price period. This amount shall be calculated by assuming that Seller continued to generate for the remaining years of the fixed price period at a level equal to the average annual energy generation during the period of performance, and by applying the weighted annual average levelized price applicable to Seller's Facility and the weighted annual average forecasted energy prices in Table B-1 for the remaining years of the fixed price period. The following formula shall be used to make this calculation:

$$P = \sum_{n=1}^Y \frac{(F_n)(A)(W)}{(1.15)^n} - \sum_{n=1}^Y \frac{(L)(A)(W)}{(1.15)^n}$$

where:

P = amount due PGandE.

Y = number of years remaining in the fixed price period.

F_n = weighted annual average forecasted energy price in the n^{th} year after the breach, failure to perform, or expiration of security, as shown in Table B-1 for the corresponding calendar year.

L = weighted annual average levelized energy price applicable to Seller's Facility.

A = average annual energy generation by Seller during the period of performance.

n = summation index; refers to the n^{th} year following termination.

W = percent of Seller's energy payments based on the levelized energy prices, as specified in Article 4.

(b) Performance Requirements

Seller shall operate and maintain the Facility in accordance with prudent electrical practices in order to maximize the likelihood that the Facility's output as delivered to PGandE during the part of the fixed price period when the levelized price is below the forecasted price ("last part") shall equal or exceed 70% of the Facility's output during the part of the fixed price period when the levelized price is above the forecasted price ("first part"). In the event that the Facility's output during any year or series of years in the last part of the fixed price period is less than 70% of the average annual production during the first part of the fixed price period, PGandE may, at its discretion (taking into consideration events occurring during such year or

series of years such as curtailment by PGandE, Seller's choice not to operate during adjusted price periods, or scheduled maintenance including major overhauls, and the probability that Seller's future performance will be adequate), either request payment from Seller $\frac{A-B}{A}$ or immediately draw on the security posted, up to the amount equal to $P \times \frac{A-B}{A}$, where:

P and A are as defined in Section (a) above.

B = Seller's average annual energy generation during the year or series of years in which the 70% performance requirement was not met.

PGandE shall not request payment from Seller or draw on the security posted if the Facility's output during the last part of the fixed price period falls below 70% of the average annual energy generation during the first part of the fixed price period solely because of force majeure as defined in Section A-8, Appendix A or a lack of or limited availability of the primary energy resource of the Facility, if such energy resource is wind, water, or sunlight.

(c) Security

(1) As security for amounts which Seller may be obligated to pay PGandE pursuant to Sections (a) and (b) above, Seller shall provide and maintain one or more of the following in an amount as described in Section (c)(2) below.

- (i) An irrevocable bank letter of credit delivered to and in favor of PGandE with terms acceptable to PGandE.
- (ii) A payment bond providing for payment to PGandE in the event of any failure to meet the performance requirements set forth in Section (b) above or breach of this Agreement by Seller. Such bond shall be issued by a surety company acceptable to PGandE and shall have terms acceptable to PGandE.
- (iii) Fully paid up, noncancellable Project Failure Insurance made payable to PGandE with terms of such policy(ies) acceptable to PGandE.
- (iv) A performance bond providing for payment to PGandE in the event of any failure to meet the performance requirements set forth in Section (b) above or breach of this Agreement by Seller. Such bond shall be issued by a surety company acceptable to PGandE and shall have terms acceptable to PGandE.
- (v) A corporate guarantee of payment to PGandE which PGandE deems, in its sole discretion, to provide at least the same quality of security as subsections (i) through (iv) above.
- (vi) Other forms of security which PGandE does not deem to be equivalent security to those listed in subsections (i) through (v) above, and which PGandE, in its sole discretion, deems adequate. Such other forms of security may include, for example, a corporate guarantee or a lien, mortgage or deed of trust on the Facility or land upon which it is located. A 1.5% discount will be applied against the levelized energy price portion of PGandE's payments to Seller during the fixed price period if this type of security is provided.

(2) (i) Commencing 90 days prior to the scheduled operation date and continuing until December 1 of the following calendar year, security as described in Section (c)(1) above shall be in place in an amount calculated in accordance with the formula set forth in Section (a) above, assuming Seller delivered energy through the end of the following calendar year and then terminated this Agreement. For purposes of determining the required amount of security, it shall be assumed that Seller's deliveries through the end of the following calendar year would equal $R \times C \times H$, where:

R = nameplate rating, in kW, of the Facility.

C = estimated capacity factor of the Facility, which shall be established by mutual agreement of the Parties at the time of execution of this Agreement.

H = number of hours from the scheduled operation date through the end of the following calendar year.

- (ii) In the second calendar year of operation and each year thereafter until the end of the fixed price period, from December 1 through December 1 of the following year, security shall be in place in an amount calculated by the formula set forth in Section (a) above assuming Seller continued to deliver energy in each month through the end of the following calendar year, at a level equal to the average monthly energy deliveries to date, and then terminated this Agreement.
- (3) Security must be maintained throughout the fixed price period as specified above. Any security with a fixed expiration date must be renewed by Seller prior to that date. If such security is not renewed at least 30 days prior to its expiration, PGandE may, at its discretion, either request payment from Seller or immediately draw on the security posted, up to the amount calculated in accordance with the formula set forth in Section (a) above.
- (4) If, at any time during the fixed price period, PGandE believes Seller is in material breach of this Agreement, PGandE shall so notify Seller in writing and Seller must remedy such breach within a reasonable period of time. If Seller does not so remedy, PGandE may, at its discretion, either request payment from Seller or immediately draw upon the security posted, up to the amount calculated in accordance with the formula set forth in Section (a) above, provided that if during Seller's period to remedy, Seller disputes PGandE's conclusion that Seller is in material breach, and PGandE elects to draw upon the security, the amount drawn upon by PGandE shall be deposited in an interest earning escrow account and held in such account until the dispute is resolved in accordance with Section (c)(5) below.
- (5) Upon the written request of either Party, any controversy or dispute between the Parties concerning Section (c)(4) above shall be subject to arbitration in accordance with the provisions of the California Arbitration Act, Sections 1280-1294.2 of the California Code of Civil Procedure except as provided otherwise in this section. Either Party may demand arbitration by first giving written notice of the existence of a dispute and then within 30 days of such notice giving a second written notice of the demand for arbitration.

Within ten days after receipt of the demand for arbitration, each Party shall appoint one person, who shall not be an employee of either Party, to hear and determine the dispute. After both arbitrators have been appointed, they shall within five (5) days select a third arbitrator.

The arbitration hearing shall take place in San Francisco, California, within 30 days of the appointment of the arbitrators, at such time and place as they select. The arbitrators shall give written notice of the time of the hearing to both Parties at least ten days prior to the hearing. The arbitrators shall not be authorized to alter, extend, or modify the terms of this Agreement. At the hearing, each Party shall submit a proposed written decision, and any relevant evidence may be presented. The decision of the arbitrators must consist of selection of one of the two proposed decisions, in its entirety.

The decision of any two arbitrators shall be binding and conclusive as to disputes relating to Section (c)(4) only. Upon determining the matter, the arbitrators shall promptly execute and acknowledge their decision and deliver a copy to each Party. A judgment confirming the award may be rendered by any superior court having jurisdiction. Each Party shall bear its own arbitration costs and expenses, including the cost of the arbitrator it selected, and the costs and expenses of the third arbitrator shall be divided equally between both Parties, except as provided otherwise elsewhere in this Agreement.

Pending resolution of any controversy or dispute hereunder, performance by each Party shall continue so as to maintain the status quo prior to notice of such controversy or dispute. Resolution of the controversy or dispute shall include payment of any interest accrued in the escrow account.

TABLE B-2

Levelized Energy Price Schedule

For a term of agreement of 15-16 years:

Year in Which Energy Deliveries Begin	Levelized Energy Prices*, ¢/kwh						Weighted Annual Average
	Period A			Period B			
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	
1983	5.76	5.50	5.31	5.85	5.71	5.58	5.57
1984	6.06	5.78	5.58	6.14	6.00	5.86	5.85
1985	6.41	6.11	5.91	6.50	6.35	6.20	6.19
1986	6.85	6.54	6.32	6.95	6.79	6.63	6.62
1987	7.37	7.03	6.79	7.47	7.30	7.13	7.12
1988	7.96	7.60	7.34	8.07	7.89	7.70	7.69

For a term of agreement of 17-19 years:

Year in Which Energy Deliveries Begin	Levelized Energy Prices*, ¢/kwh						Weighted Annual Average
	Period A			Period B			
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	
1983	5.90	5.63	5.44	5.98	5.84	5.71	5.70
1984	6.23	5.95	5.74	6.32	6.18	6.03	6.02
1985	6.60	6.30	6.08	6.69	6.53	6.38	6.37
1986	7.06	6.73	6.51	7.16	7.00	6.83	6.82
1987	7.60	7.25	7.00	7.70	7.53	7.35	7.34
1988	8.21	7.83	7.57	8.32	8.13	7.94	7.93

For a term of agreement of 20-30 years:

Year in Which Energy Deliveries Begin	Levelized Energy Prices*, ¢/kWh						Weighted Annual Average
	Period A			Period B			
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	
1983	6.49	6.20	5.98	6.58	6.43	6.28	6.27
1984	6.90	6.58	6.35	6.99	6.83	6.67	6.66
1985	7.34	7.00	6.76	7.44	7.27	7.10	7.09
1986	7.88	7.51	7.26	7.99	7.81	7.62	7.61
1987	8.49	8.10	7.82	8.61	8.41	8.21	8.20
1988	9.16	8.74	8.44	9.29	9.08	8.86	8.85

* These prices are differentiated by the time periods as defined in Table B-4.

Energy Payment Option 3 - Incremental Energy Rate

During the period specified in Article 4, annual adjustments to Seller's energy payments shall be made as described below.

At the end of each calendar year, the Derived Incremental Energy Rate (with units expressed in Btu/kWh) will be calculated as follows:

$$\text{Derived Incremental Energy Rate (DIER)} = \frac{B}{A \times C}$$

where:

A = the total kWh delivered by Seller during the calendar year, excluding any kWh delivered when Seller was asked to curtail deliveries under Curtailment Option A or when Seller was asked to take adjusted prices under Curtailment Option B.

B = the total dollars paid for the energy described for A above.

C = the weighted average price paid during the calendar year by PGandE's Electric Department for oil and natural gas for PGandE's fossil steam plants, expressed in \$/Btu on a gas Btu basis.

If the DIER is between the upper and lower Incremental Energy Rate Bounds specified for that year in Table B-3 for the curtailment option selected by Seller, no additional payment is due either Party.

If the DIER is below the lower Incremental Energy Rate Bound, PGandE shall pay Seller an amount calculated as follows:

$$P_S = (\text{Lower Incremental Energy Rate Bound} - \text{DIER}) (A) (C)$$

where:

P_S = additional payment due Seller.

DIER = Derived Incremental Energy Rate.

PGandE shall add this payment to the first payment made to Seller following the calculation.

If the DIER is above the upper Incremental Energy Rate Bound, Seller shall pay PGandE an amount calculated as follows:

$$P_B = (\text{DIER} - \text{Upper Incremental Energy Rate Bound}) (A) (C)$$

where:

P_B = amount due PGandE.

DIER = Derived Incremental Energy Rate.

This amount shall be deducted from the first payment made to Seller following the calculation. If there is any remaining amount due PGandE, PGandE may, at its option, invoice Seller with such payment due within 30 days or deduct this amount from future payments due Seller.

TABLE B-3

**Forecasted Incremental Energy Rates and
Incremental Energy Rate Bounds**

Curtailment Option A:

<u>Year</u>	<u>Forecasted Incremental Energy Rates, Btu/kWh (a)</u>	<u>Incremental Energy Rate Band Width from Article 4, Btu/kWh (b)</u>	<u>Upper Incremental Energy Rate Bound, Btu/kWh [column (a) plus column (b)]</u>	<u>Lower Incremental Energy Rate Bound, Btu/kWh [column (a) minus column(b)]</u>
1984	9,000	_____	_____	_____
1985	9,050	_____	_____	_____
1986	8,840	_____	_____	_____
1987	8,850	_____	_____	_____
1988	8,960	_____	_____	_____
1989	8,820	_____	_____	_____
1990	8,540	_____	_____	_____
1991	8,540	_____	_____	_____
1992	8,540	_____	_____	_____
1993	8,540	_____	_____	_____
1994	8,540	_____	_____	_____
1995	8,540	_____	_____	_____
1996	8,540	_____	_____	_____
1997	8,540	_____	_____	_____
1998	8,540	_____	_____	_____

Curtailment Option B:

<u>Year</u>	<u>Forecasted Incremental Energy Rates, Btu/kWh (a)</u>	<u>Incremental Energy Rate Band Width from Article 4, Btu/kWh (b)</u>	<u>Upper Incremental Energy Rate Bound, Btu/kWh [column (a) plus column (b)]</u>	<u>Lower Incremental Energy Rate Bound, Btu/kWh [column (a) minus column(b)]</u>
1984	9,440	_____	_____	_____
1985	9,500	_____	_____	_____
1986	9,280	_____	_____	_____
1987	9,290	_____	_____	_____
1988	9,400	_____	_____	_____
1989	9,270	_____	_____	_____
1990	8,970	_____	_____	_____
1991	8,970	_____	_____	_____
1992	8,970	_____	_____	_____
1993	8,970	_____	_____	_____
1994	8,970	_____	_____	_____
1995	8,970	_____	_____	_____
1996	8,970	_____	_____	_____
1997	8,970	_____	_____	_____
1998	8,970	_____	_____	_____

TABLE B-4¹

Time Periods

	<u>Monday through Friday²</u>	<u>Saturdays²</u>	<u>Sundays and Holidays</u>
Seasonal Period A (May 1 through September 30)			
On-Peak	12:30 p.m. to 6:30 p.m.		
Partial-Peak	8:30 a.m. to 12:30 p.m. 6:30 p.m. to 10:30 p.m.	8:30 a.m. to 10:30 p.m.	
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	All Day
Seasonal Period B (October 1 through April 30)			
On-Peak	4:30 p.m. to 8:30 p.m.		
Partial-Peak	8:30 p.m. to 10:30 p.m. 8:30 a.m. to 4:30 p.m.	8:30 a.m. to 10:30 p.m.	
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	All Day

¹ This table is subject to change to accord with the on-peak, partial-peak, and off-peak periods as defined in PGandE's own rate schedules for the sale of electricity to its large industrial customers.

² Except the following holidays: New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, and Christmas Day, as specified in Public Law 90-363 (5 U.S.C.A. Section 6103(a)).

TABLE B-5

Energy Prices Effective January 1 - April 30, 1984

The energy purchase price calculations which will apply to energy deliveries determined from meter readings taken during January, February, March, and April 1984 are as follows:

<u>Time Period</u>	(a) <u>Incremental Energy Rate¹</u> (Btu/kWh)	(b) <u>Cost of Energy²</u> (\$/10 ⁶ Btu)	(c) <u>Revenue Requirement for Cash Working Capital³</u> (\$/kWh)	(d) <u>Energy Purchase Price⁴</u> (d)=[(a)x(b)]+(c) (\$/kWh)
Jan. 1 - April 30 (Period B)				
Time of Delivery Basis:				
On-Peak	15,410	5.3978	0.00053	0.08371
Partial-Peak	14,730	5.3978	0.00051	0.08002
Off-Peak	11,353	5.3978	0.00038	0.06116
Seasonal Average (Period B)	13,089	5.3978	0.00045	0.07110

TABLE B-6

Energy Loss Adjustment Factors⁵

	<u>Transmission</u>	<u>Primary Distribution</u>	<u>Secondary Distribution</u>
Seasonal Period A (May 1 through September 30)			
On-Peak	1.0	1.0	1.0148
Partial-Peak	1.0	1.0	1.0131
Off-Peak	1.0	1.0	1.0093
Seasonal Period B (October 1 through April 30)			
On-Peak	1.0	1.0	1.0128
Partial-Peak	1.0	1.0	1.0119
Off-Peak	1.0	1.0	1.0087

¹ Incremental energy rates in Btu/kWh are derived from marginal energy costs (including variable operating and maintenance expense) adopted by CPUC Decision No. 83-12-068. They are based upon natural gas as the incremental fuel and weighted average hydro electric power conditions.

² Cost of natural gas under PGandE Gas Schedule No. G-55 (applicable to steam electric plants) in CPUC Decision No. 83-12-069 effective January 1, 1984.

³ Revenue requirement for cash working capital as prescribed by the CPUC in Decision No. 83-12-068.

⁴ Energy Purchase Price = (Incremental Energy Rate x Cost of Energy) + Revenue Requirement for Cash Working Capital. The energy purchase price excludes the applicable energy line loss adjustment factors. However, as ordered by Ordering Paragraph No. 12(j) of Decision No. 82-12-120, this figure is currently 1.0 for transmission and primary distribution loss adjustments and is equal to marginal cost line loss adjustment factors for the secondary distribution voltage level. These factors may be changed by the CPUC in the future. The currently applicable energy loss adjustment factors are shown in Table B-6.

⁵ The applicable energy loss adjustment factors may be revised pursuant to orders of the CPUC.

APPENDIX C

CURTAILMENT OPTIONS

Seller has two options regarding curtailment of energy deliveries and Seller has made its selection in Article 7. The two options are as follows:

CURTAILMENT OPTION A - HYDRO SPILL AND NEGATIVE AVOIDED COST

- (a) In anticipation of a period of hydro spill conditions, as defined by the CPUC, PGandE may notify Seller that any purchases of energy from Seller during such period shall be at hydro savings prices quoted by PGandE. If Seller delivers energy to PGandE during any such period, Seller shall be paid hydro savings prices for those deliveries in lieu of prices which would otherwise be applicable. The hydro savings prices shall be calculated by PGandE using the following formula:

$$\frac{AQF - S}{AQF} \times PP \quad (\geq 0)$$

where:

- AQF = Energy, in kWh, projected to be available during hydro spill conditions from all qualifying facilities under agreements containing hydro savings price provisions.
- S = Potential energy, in kWh, from PGandE hydro facilities which will be spilled if all AQF is delivered to PGandE.
- PP = Prices published by PGandE for purchases during other than hydro spill conditions.

PGandE shall give Seller notice of general periods when hydro spill conditions are anticipated, and shall give Seller as much advance notice as practical of any specific hydro spill period and the hydro savings price which will be applicable during such period.

- (b) PGandE shall not be obligated to accept or pay for and may require Seller with a Facility with a nameplate rating of one megawatt or greater to interrupt or reduce deliveries of energy during periods when PGandE would incur negative avoided costs (as defined by the CPUC) due to continued acceptance of energy deliveries under this Agreement. Whenever possible, PGandE shall give Seller reasonable notice of the possibility that interruption or reduction of deliveries may be required.
- (c) Before interrupting or reducing deliveries under subsection (b), above, and before invoking hydro savings prices under subsection (a), above, PGandE shall take reasonable steps to make economy sales of the surplus energy giving rise to the condition. If such economy sales are made, while the surplus energy condition exists Seller shall be paid at the economy sales price obtained by PGandE in lieu of the otherwise applicable prices.
- (d) If Seller is selling net energy output to PGandE and simultaneously purchasing its electrical needs from PGandE and Seller elects not to sell energy to PGandE at the hydro savings price pursuant to subsection (a) or when PGandE curtails deliveries of energy pursuant to subsection (b), Seller shall not use such energy to meet its electrical needs but shall continue to purchase all its electrical needs from PGandE. If Seller is selling surplus energy output to PGandE, subsections (a) or (b) shall only apply to the surplus energy output being delivered to PGandE, and Seller can continue to internally use that generation it has retained for its own use.

CURTAILMENT OPTION B - ADJUSTED PRICE PERIOD

- (a) In each calendar year, the price which PGandE is obligated to pay Seller for energy deliveries during 1,000 off-peak hours (as defined in Table B-4, Appendix B) may be adjusted to a price equal to, but not in excess of, PGandE's available alternative source. This adjusted price shall be effective under any of the following conditions:
- (i) when PGandE's energy source at the margin is not a PGandE oil- or gas-fueled plant, and PGandE can replace Seller's energy with energy from this source at a cost less than the price paid to Seller;
 - (ii) when PGandE would incur negative avoided costs (as defined by the CPUC) due to continued acceptance of energy deliveries under this Agreement; or
 - (iii) when PGandE is experiencing minimum system operations.

During any of the conditions described above the adjusted price may be zero.

- (b) Whenever possible, PGandE shall give Seller reasonable notice of any price adjustment for energy deliveries and its probable duration.
- (c) If Seller is selling net energy output to PGandE and simultaneously purchasing its electrical needs from PGandE and Seller elects not to sell energy to PGandE at the adjusted price, Seller shall not use such energy to meet its electrical needs but shall continue to purchase all its electrical needs from PGandE.
- (d) After Seller receives notice of the probable duration of the period during which the adjusted price will be paid, Seller may elect to perform maintenance during such period and so inform the PGandE employee in charge at the designated PGandE switching center prior to the time when the adjusted price period is expected to begin. If Seller makes such election, the number of off-peak hours of probable duration quoted in PGandE's notice to Seller shall be applied to the 1,000 hour calendar year limitation set forth in this section. After an election to do maintenance, if Seller makes any deliveries of energy during the quoted probable duration period, Seller shall be paid the adjusted price quoted in its notice from PGandE without regard to any subsequent changes on the PGandE system which may alter the adjusted price or shorten the actual duration of the condition.

APPENDIX D

AS-DELIVERED CAPACITY

D-1 AS-DELIVERED CAPACITY PAYMENT OPTIONS

Seller has two options for as-delivered capacity payments and Seller has made its selection in Article 5. The two options are as follows:

AS-DELIVERED CAPACITY PAYMENT OPTION 1

PGandE shall pay Seller for as-delivered capacity at prices authorized from time to time by the CPUC. The as-delivered capacity prices in effect on the date of execution are calculated as shown in Exhibit D-1.

AS-DELIVERED CAPACITY PAYMENT OPTION 2

During the fixed price period, the as-delivered capacity prices will be calculated in accordance with Exhibit D-1 and the forecasted shortage costs in Table D-2.

For the remaining years of the term of agreement, PGandE shall pay Seller for as-delivered capacity at the higher of:

- (i) prices authorized from time to time by the CPUC;
- (ii) the as-delivered capacity prices that were paid Seller in the last year of the fixed price period; or
- (iii) the as-delivered capacity prices in effect in the first year following the end of the fixed price period, provided that the annualized shortage cost from which these prices are derived does not exceed the annualized value of a gas turbine.

D-2 AS-DELIVERED CAPACITY IN EXCESS OF FIRM CAPACITY

The amount of capacity delivered in excess of firm capacity will be considered as-delivered capacity. This as-delivered capacity is based on the total kilowatt-hours delivered each month during all on-peak, partial-peak and off-peak hours excluding any energy associated with generation levels equal to or less than the firm capacity.

Seller has the two options listed in Section D-1 for payment for such as-delivered capacity. Seller has made its selection in Article 5.

EXHIBIT D-1

The as-delivered capacity price (in cents per kW-hr) for power delivered by the Facility is the product of three factors:

- (a) The shortage cost in each year the Facility is operating. Currently this shortage cost is \$156 per kW-year.
- (b) A capacity loss adjustment factor which provides for the effect of the deliveries on PGandE's transmission and distribution losses based on the Seller's interconnection voltage level. The applicable capacity loss adjustment factors for non-remote¹ Facilities are presented in Table D-1(a). Capacity loss adjustment factors for remote Facilities shall be calculated individually.
- (c) An allocation factor which accounts for the different values of as-delivered capacity in different time periods and converts dollars per kW-year to cents per kWh. The current allocation factors are presented in Table D-1(b). The time periods to which they apply are shown in Table B-4, Appendix B. The allocation factors are subject to change from time to time.

¹ As defined by the CPUC.

TABLE D-1(a)
Capacity Loss Adjustment Factors
for Non-Remote¹ Facilities

<u>Voltage Level</u>	<u>Loss Adjustment Factor</u>
Transmission	.989
Primary Distribution	.991
Secondary Distribution	.991

If the Facility is remote, the capacity loss adjustment factor is _____².

TABLE D-1(b)
Allocation Factors
for As-Delivered Capacity³

	<u>On-Peak</u> (¢-yr/\$-hr)	<u>Partial-Peak</u> (¢-yr/\$-hr)	<u>Off-Peak</u> (¢-yr/\$-hr)
Seasonal Period A	0.10835	0.02055	0.00002
Seasonal Period B	0.00896	0.00109	0.00001

TABLE D-2
Forecasted Shortage Cost Schedule

<u>Year</u>	<u>Forecast Shortage Cost, \$/kW-Yr</u>
1983	70
1984	76
1985	81
1986	88
1987	95
1988	102
1989	110
1990	118
1991	126
1992	135
1993	144
1994	154
1995	164
1996	176
1997	188

¹ As defined by the CPUC. The capacity loss adjustment factors for remote Facilities are determined individually.

² Determined individually.

³ The units for the allocation factor, ¢-yr/\$-hr, are derived from the conversion of \$/kW-yr into ¢/kWh as follows:

$$\frac{\text{¢/kWh}}{\text{\$/kW-yr}} = \frac{\text{¢/kW-hr}}{\text{\$/kW-yr}} = \frac{\text{¢-yr}}{\text{\$-hr}}$$

The allocation factors were prescribed by the CPUC in Decision No. 83-12-068 and are subject to change from time to time.

APPENDIX E
FIRM CAPACITY

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APPENDIX E
FIRM CAPACITY

E-1 GENERAL

This Appendix E establishes conditions and prices under which PGandE shall pay for firm capacity.

PGandE's obligation to pay for firm capacity shall begin on the firm capacity availability date. The firm capacity price shall be subject to adjustment as provided for in this Appendix E.

The firm capacity prices in Table E-2 are applicable for deliveries of firm capacity beginning after December 30, 1982.

E-2 MINIMUM PERFORMANCE REQUIREMENTS

- (a) To receive full capacity payments, the firm capacity shall be delivered for all of the on-peak hours¹ in the peak months on the PGandE system, which are presently the months of June, July, and August, subject to a 20 percent allowance for forced outages in any month. Compliance with this provision shall be based on the Facility's total on-peak deliveries for each of the peak months and shall exclude any energy associated with generation levels greater than the firm capacity.
- (b) If Seller is prevented from meeting the minimum performance requirements because of a forced outage on the PGandE system, a PGandE curtailment of Seller's deliveries, or a condition set forth in Section A-7, Appendix A, PGandE shall continue capacity payments. Firm capacity payments will be calculated in the same manner used for scheduled maintenance outages.
- (c) If Seller is prevented from meeting the minimum performance requirements because of force majeure, PGandE shall continue capacity payments for ninety days from the occurrence of the force majeure. Thereafter, Seller shall be deemed to have failed to have met the minimum performance requirements. Firm capacity payments will be calculated in the same manner used for scheduled maintenance outages.
- (d) If Seller is prevented from meeting the minimum performance requirements because of extreme dry year conditions, PGandE shall continue capacity payments. Extreme dry year conditions are drier than those used to establish firm capacity pursuant to Section E-8. Seller shall warrant to PGandE that the Facility is a hydroelectric facility and that such conditions are the sole cause of Seller's inability to meet its firm capacity obligations.
- (e) If Seller is prevented from meeting the minimum performance requirements for reasons other than those described above in Sections E-2(b), (c), or (d):
 - (1) Seller shall receive the reduced firm capacity payments as provided in Section E-5 for a probationary period not to exceed 15 months, or as otherwise agreed to by the Parties.
 - (2) If, at the end of the probationary period Seller has not demonstrated that the Facility can meet the minimum performance requirements, PGandE may derate the firm capacity pursuant to Section E-4(b).

E-3 SCHEDULED MAINTENANCE

Outage periods for scheduled maintenance shall not exceed 840 hours (35 days) in any 12-month period. This allowance may be used in increments of an hour or longer on a consecutive or nonconsecutive basis. Seller may accumulate unused maintenance hours from one 12-month period to another up to a maximum of 1,080 hours (45 days). This accrued time must be used consecutively and only for major overhauls. Seller shall provide PGandE with the following advance notices: 24 hours for scheduled outages less than one day, one week for a scheduled outage of one day or more (except for major

¹ On-peak, partial-peak, and off-peak hours are defined in Table B-4, Appendix B.

overhauls), and six months for a major overhaul. Seller shall not schedule major overhauls during the peak months (presently June, July, and August). Seller shall make reasonable efforts to schedule or reschedule routine maintenance outside the peak months, and in no event shall outages for scheduled maintenance exceed 30 peak hours during the peak months. Seller shall confirm in writing to PGandE pursuant to Article 9, within 24 hours of the original notice, all notices Seller gives personally or by telephone for scheduled maintenance.

If Seller has selected Curtailment Option B, off-peak hours of maintenance performed pursuant to Section (d) of Curtailment Option B, Appendix C shall not be deducted from Seller's scheduled maintenance allowances set forth above.

E-4 ADJUSTMENTS TO FIRM CAPACITY

- (a) Seller may increase the firm capacity with the approval of PGandE and receive payment for the additional capacity thereafter in accordance with the applicable capacity purchase price published by PGandE at the time the increase is first delivered to PGandE.
- (b) Seller may reduce the firm capacity at any time prior to the firm capacity availability date by giving written notice thereof to PGandE. PGandE may derate the firm capacity in accordance with Section E-2(e) as a result of appropriate data showing Seller has failed to meet the minimum performance requirements of Section E-2.

E-5 FIRM CAPACITY PAYMENTS

The method for calculation of firm capacity payments is shown below. As used below in this section, month refers to a calendar month.

The monthly payment for firm capacity will be the product of the Period Price Factor (PPF), the Monthly Delivered Capacity (MDC), the appropriate capacity loss adjustment factor from Table E-1 based on the Facility's interconnection voltage, and the appropriate performance bonus factor, if any, from Table E-3, plus any allowable payment for outages due to scheduled maintenance. The firm capacity price shall be applied to meter readings taken during the separate times and periods as illustrated in Table B-4, Appendix B.

The PPF is determined by multiplying the firm capacity price by the following Allocation Factors¹:

	Allocation Factor	x	<u>Firm Capacity Price</u>	=	PPF (\$/kW-month)
Seasonal Period A	.18540		_____		_____
Seasonal Period B	.01043		_____		_____

The MDC is determined in the following manner:

- (1) Determine the Performance Factor (P), which is defined as the lesser of 1.0 or the following quantity:

$$P = \frac{A}{C \times (B-S) \times (0.8^*)} \quad (\leq 1.0)$$

Where:

A = Total kilowatt-hours delivered during all on-peak and partial-peak hours excluding any energy associated with generation levels greater than the firm capacity.

¹ These allocation factors were prescribed by the CPUC in Decision 83-12-068. All allocation factors are subject to change by PGandE based on PGandE's marginal capacity cost allocation, as determined in general rate case proceedings before the CPUC. Seasonal Periods A and B are defined in Table B-4, Appendix B.

* 0.8 reflects a 20% allowance for forced outage.

C = Firm capacity in kilowatts.

B = Total on-peak and partial-peak hours during the month.

S = Total on-peak and partial-peak hours during the month Facility is out of service on scheduled maintenance.

- (2) Determine the Monthly Capacity Factor (MCF), which is computed using the following expression:

$$MCF = P \times (1.0 - \frac{M}{D})$$

Where:

M = The number of hours during the month Facility is out of service on scheduled maintenance.

D = The number of hours in the month.

- (3) Determine the MDC by multiplying the MCF by C:

$$MDC \text{ (kilowatts)} = MCF \times C$$

The monthly payment for firm capacity is then determined by multiplying the PPF by the MDC, by the appropriate capacity loss adjustment factor presented from Table E-1, and by the appropriate performance bonus factor, if any, from Table E-3.

$$\begin{array}{l} \text{monthly payment} \\ \text{for } \underline{\text{firm capacity}} \end{array} = PPF \times MDC \times \begin{array}{l} \text{capacity loss} \\ \text{adjustment factor} \end{array} \times \begin{array}{l} \text{performance} \\ \text{bonus factor} \end{array}$$

Furthermore, the payment for a month in which there is an outage for scheduled maintenance shall also include an amount equal to the product of the average hourly firm capacity payment¹ for the most recent month in the same type of Seasonal Period (i.e., Seasonal Period A or Seasonal Period B) during which deliveries were made times the number of hours of outage for scheduled maintenance in the current month. Firm capacity payments will continue during the outage periods for scheduled maintenance provided that the provisions of Section E-3 are met.

During a probationary period Seller's monthly payment for firm capacity shall be determined by substituting for the firm capacity, the capacity at which Seller would have met the minimum performance requirements. In the event that during the probationary period Seller does not meet the minimum performance requirements at whatever firm capacity was established for the previous month, Seller's monthly payment for firm capacity shall be determined by substituting the firm capacity at which Seller would have met the minimum performance requirements. The performance bonus factor shall not be applied during probationary periods.

TABLE E-1

If the Facility is non-remote² the firm capacity loss adjustment factors are as follows:

<u>Voltage Level</u>	<u>Loss Adjustment Factor</u>
Transmission	.989
Primary Distribution	.991
Secondary Distribution	.991

If the Facility is remote the firm capacity loss adjustment factor is _____³.

¹ Total monthly payment divided by the total number of hours in the monthly billing period.

² As defined by the CPUC.

³ Determined individually.

TABLE E-2

Firm Capacity Price Schedule

(Levelized \$/kW-year)

<u>Firm Capacity Avail- ability Date</u>	<u>Number of Years of Firm Capacity Delivery</u>																	
<u>(Year)</u>	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>	<u>8</u>	<u>9</u>	<u>10</u>	<u>11</u>	<u>12</u>	<u>13</u>	<u>14</u>	<u>15</u>	<u>20</u>	<u>25</u>	<u>30</u>
1982	65	68	70	72	75	77	79	81	84	86	88	90	91	93	95	103	109	113
1983	70	73	75	78	80	83	85	88	90	92	94	96	98	100	102	110	117	122
1984	76	78	81	84	86	89	92	94	97	99	101	103	106	108	110	118	125	130
1985	81	84	87	90	93	96	99	101	104	106	109	111	113	115	118	127	134	140
1986	88	91	94	97	100	103	106	109	112	114	117	119	122	124	126	136	144	150
1987	95	98	101	105	108	111	114	117	120	123	125	128	130	133	135	146	154	160

TABLE E-3

Performance Bonus Factor

The following shall be the performance bonus factors applicable to the calculation of the monthly payments for firm capacity delivered by the Facility after it has demonstrated a firm capacity factor in excess of 85%.

<u>DEMONSTRATED FIRM CAPACITY FACTOR (%)</u>	<u>PERFORMANCE BONUS FACTOR</u>
85	1.000
90	1.059
95	1.118
100	1.176

After the Facility has delivered power during the span of all of the peak months on the PGandE system (presently June, July, and August) in any year (span),

- (i) the firm capacity factor for each such month shall be calculated in the following manner:

$$\text{FIRM CAPACITY FACTOR (\%)} = \frac{A}{B \times C} \times 100$$

Where:

A = Total kilowatt-hours delivered by Seller in any peak month during all on-peak hours excluding any energy associated with generation levels greater than the firm capacity.

B = Total on-peak hours during the month.

C = Firm capacity in kilowatts.

- (ii) the arithmetic average of the above firm capacity factors shall be determined for that span,
- (iii) the average of the above arithmetic average firm capacity factors for the most recent span(s), not to exceed 5, shall be calculated and shall become the Demonstrated Firm Capacity Factor.

To calculate the performance bonus factor for a Demonstrated Firm Capacity Factor not shown in Table E-3 use the following formula:

$$\text{Performance Bonus Factor} = \frac{\text{Demonstrated Firm Capacity Factor (\%)}}{85\%}$$

SECTIONS E-6 THROUGH E-10 SHALL APPLY ONLY TO HYDROELECTRIC PROJECTS

E-6 DETERMINATION OF NATURAL FLOW DATA

Natural flow data shall be based on a period of record of at least 50 years and which includes historic critically dry periods. In the event Seller demonstrates that a natural flow data base of at least 50 years would be unreasonably burdensome, PGandE shall accept a shorter period of record with a corresponding reduction in the averaging basis set forth in Section E-8. Seller shall determine the natural flow data by month by using one of the following methods:

Method 1

If stream flow records are available from a recognized gauging station on the water course being developed in the general vicinity of the project, Seller may use the data from them directly.

Method 2

If directly applicable flow records are not available, Seller may develop theoretical natural flows based on correlation with available flow data for the closest adjacent and similar area which has a recognized gauging station using generally accepted hydrologic estimating methods.

E-7 THEORETICAL OPERATION STUDY

Based on the monthly natural flow data developed under Section E-6 a theoretical operation study shall be prepared by Seller. Such a study shall identify the monthly capacity rating in kW and the monthly energy production in kWh for each month of each year. The study shall take into account all relevant operating constraints, limitations, and requirements including but not limited to --

- (1) Release requirements for support of fish life and any other operating constraints imposed on the project;
- (2) Operating characteristics of the proposed equipment of the Facility such as efficiencies, minimum and maximum operating levels, project control procedures, etc.;
- (3) The design characteristics of project facilities such as head losses in penstocks, valves, tailwater elevation levels, etc.; and
- (4) Release requirements for purposes other than power generation such as irrigation, domestic water supply, etc.

The theoretical operation study for each month shall assume an even distribution of generation throughout the month unless Seller can demonstrate that the Facility has water storage characteristics. For the study to show monthly capacity ratings, the Facility shall be capable of operating during all on-peak hours in the peak months on the PGandE system, which are presently the months of June, July, and August. If the project does not have this capability throughout each such month, the capacity rating in that month of that year shall be set at zero for purposes of this theoretical operation study.

E-8 DETERMINATION OF AVERAGE DRY YEAR CAPACITY RATINGS

Based on the results of the theoretical operation study developed under Section E-7, the average dry year capacity rating shall be established for each month. The average dry year shall be based on the average of the five years of the lowest annual generation as shown in the theoretical operation study. Once such years of lowest annual generation are identified, the monthly capacity rating is determined for each month by averaging the capacity ratings from each month of those years. The firm capacity shown in Article 5 shall not exceed the lowest average dry year monthly capacity ratings for the peak months on the PGandE system, which are presently the months of June, July, and August.

INFORMATION REQUIREMENTS

Seller shall provide the following information to PGandE for its review:

- (1) A summary of the average dry year capacity ratings based on the theoretical operation study as provided in Table E-4;
- (2) A topographic project map which shows the location of all aspects of the Facility and locations of stream gauging stations used to determine natural flow data;
- (3) A discussion of all major factors relevant to project operation;
- (4) A discussion of the methods and procedures used to establish the natural flow data. This discussion shall be in sufficient detail for PGandE to determine that the methods are consistent with those outlined in Section E-6 and are consistent with generally accepted engineering practices; and
- (5) Upon specific written request by PGandE, Seller's theoretical operation study.

ILLUSTRATIVE EXAMPLE

- (1) Determine natural flows - These flows are developed based on historic stream gauging records and are compiled by month, for a long-term period (normally at least 50 years or more) which covers dry periods which historically occurred in the 1920's and 30's and more recently in 1976 and 77. In all but unusual situations this will require application of hydrological engineering methods to records that are available, primarily from the USGS publication "Water Resources Data for California".
- (2) Perform theoretical operation study - Using the natural flow data compiled under (1) above a theoretical operation study is prepared which determines, for each month of each year, energy generation (kWh) and capacity rating (kW). This study is performed based on the Facility's design, operating capabilities, constraints, etc., and should take into account all factors relevant to project operation. Generally such a study is done by computer which routes the natural flows through project features, considering additions and withdrawals from storage, spill past the project, releases for support of fish life, etc., to determine flow available for generation. Then the generation and capacity amounts are computed based on equipment performance, efficiencies, etc.
- (3) Determine average dry year capacity ratings - After the theoretical project operation study is complete the five years in which the annual generation (kWh) would have been the lowest are identified. Then for each month, the capacity rating (kW) is averaged for the five years to arrive at a monthly average capacity rating. The firm capacity is then set by the Seller based on the monthly average dry year capacity ratings and the minimum performance requirements of this appendix. An example project is shown in the attached completed Table E-4.

EXAMPLE

TABLE E-4

Summary of Theoretical Operation Study

Project: New Creek 1

Water Source: West Fork New Creek

Mode of Operation: Run of the river

Type of Turbine: Francis Design Flow: 100 cfs Design Head: 150 feet

Operating Characteristics¹:

	Flow (cfs)	Head (feet)		Output (kW)	Efficiency (%)	
		Gross	Net		Turbine	Generator
Normal Operation	100	160	150	1,120	90	98
Maximum Operation	110	160	148	1,150	85	98
Minimum Operation	30	160	155	290	75	98

Average Dry Year Operation - Based on the average of the following lowest generation years: 1930, 1932, 1934, 1949, 1977.

Month	Energy Generation (kWh)	Capacity Output (kW)	Percent of Total Hours Operated
January	855,000	1,150	100
February	753,000	1,120	100
March	818,000	1,100	100
April	727,000	1,010	100
May	699,000	940	100
June	612,000	850	100
July	484,000	650	100
August	305,000	410	100
September	245,000	340	100
October	148,800	200	100
November	468,000	650	100
December	595,000	800	100

Maximum firm capacity: 410 kW

¹ If Facility has a variable head, operating curves should be provided.

MINIMUM DAMAGES

- (a) In the event the firm capacity is derated or Seller terminates this Agreement, the quantity by which the firm capacity is derated or the firm capacity shall be used to calculate the payments due PGandE in accordance with Section (d).
- (b) Seller shall be invoiced by PGandE for all amounts due under this section. Payment shall be due within 30 days of the date of invoice.
- (c) If Seller does not make payments pursuant to Section (b), PGandE shall have the right to offset any amounts due it against any present or future payments due Seller.
- (d) Seller shall pay to PGandE:
 - (i) an amount equal to the difference between (a) the firm capacity payments already paid by PGandE, based on the original term of agreement and (b) the total firm capacity payments which PGandE would have paid based on the period of Seller's actual performance using the adjusted firm capacity price. Additionally, Seller shall pay interest, compounded monthly from the date the excess capacity payment was made until the date Seller repays PGandE, on all overpayments, at the published Federal Reserve Board three months' Prime Commercial Paper rate; plus
 - (ii) a sum equal to the amount by which the firm capacity is being terminated or derated times the difference between the current firm capacity price on the date of termination or deration for a term equal to the balance of the term of agreement and the firm capacity price, multiplied by the appropriate factor shown in Table E-5 below. In the event that the current firm capacity price is less than the firm capacity price, no payment under this subsection (ii) shall be due either Party.

TABLE E-5

<u>Amount of Firm Capacity Terminated or Derated</u>	<u>Factor</u>
1,000 kW or under	0.25
over 1,000 kW through 10,000 kW	0.75
over 10,000 kW through 25,000 kW	1.00
over 25,000 kW through 50,000 kW	3.00
over 50,000 kW through 100,000 kW	4.00
over 100,000 kW	5.00

APPENDIX F
INTERCONNECTION
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APPENDIX F
INTERCONNECTION

F-1 INTERCONNECTION TARIFFS

(The applicable tariffs in effect at the time of execution of this Agreement shall be attached.)

F-2 POINT OF DELIVERY LOCATION SKETCH

F-3 INTERCONNECTION FACILITIES FOR WHICH SELLER IS RESPONSIBLE