STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

April 14, 2007 Advice Letter 2878-E

Rose de la Torre
Pacific Gas & Electric
77 Beale Street, Room 1088
Mail Code B10C
San Francisco, CA 94105

Subject: Notice of Federal Energy Regulatory Commission Rate Increase Filing (TO9)

Dear Ms. de la Torre:

Advice Letter 2878-E is effective March 01, 2007. A copy of the advice letter is returned herewith for your records.

Sincerely,

Sean H. Gallagher, Director
Energy Division

Pacific Gas and Electric Company®

Brian K. Cherry
Vice President
Regulatory Relations

77 Beale Street, Room 1087
San Francisco, CA 94105

Mailing Address
Mail Code B10C
Pacific Gas and Electric Company
P.O. Box 770000
San Francisco, CA 94177

415.973.4977
Internal: 223.4977
Fax: 415.973.7226
Internet: BKC7@pge.com

August 8, 2006

Advice 2878-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: **Notice of Federal Energy Regulatory Commission Rate Increase Filing (TO9)**

Purpose

Pacific Gas and Electric Company (PG&E) hereby submits this advice to provide the Commission with notice of PG&E's recent filing with the Federal Energy Regulatory Commission (FERC) requesting a transmission rate increase for its retail electric customers. The purpose of PG&E's FERC filing is to request rates that reflect PG&E's most current estimates of the cost of providing transmission service.

Background

PG&E's ninth FERC-jurisdictional transmission revenue requirement request (TO9) was filed with the FERC on August 1, 2006, and assigned to FERC Docket No. ERO6-1325-000.

The Commission has long recognized that FERC has jurisdiction over unbundled retail electric transmission rates in California, including transmission services provided under the FERC-approved California Independent System Operator Corporation (ISO) Tariff. To the extent that FERC decisions addressing ISO or other transmission service have been issued, they are deemed reasonable for purposes of inclusion in retail electric rates. (See New York v. FERC (2002) 535 US 1.) That decision states, "when a bundled retail sale is unbundled and becomes separate transmission and power sales transactions, the resulting transmission transaction falls within the Federal Sphere of regulation," Id., at page 12 (citing FERC Order 888 approvingly, citations omitted.)

Commission Resolution E-3930, approved on May 26, 2005, established a new process for CPUC notification and review of transmission-related changes, and embodies this understanding in new Process Element 1, where it states, "The Commission recognizes that under the filed rate doctrine, the Commission should allow a pass through of these transmission rates that are filed with and become effective at the FERC."

In its TO9 docket, PG&E has requested a $113.1 million increase over its currently effective retail transmission rates, which would represent, approximately, an 18.7 percent increase over currently-authorized transmission access rates. However, because transmission access rates account for a relatively small fraction (approximately 6 percent) of total bundled service rates, the resulting system average bundled service rate increase would be only approximately 1 percent. PG&E has requested an effective date of October 1, 2006 for this rate change. Between now and that date, PG&E expects FERC to either accept the filed rates and authorize these rates to become effective on the requested date (subject to refund), or to accept the filing but suspend the effective date for a period of up to five months, with a possible effective date of March 1, 2007.

<u>Compliance with Resolution E-3930</u>

PG&E submits this advice letter pursuant to Process Element 3 of Resolution E-3930. Consistent with past practice, PG&E has also provided the Commission with a complete copy of the multiple-volume FERC filing on the same date that it was filed with FERC, by service to Mr. Randolph L. Wu of the Commission's Legal Division.

Pursuant to Process Elements 3 through 5 of Resolution E-3930, PG&E provides as Attachment A a complete copy of its Exhibit PGE-19, as filed in the TO9 docket. Exhibit PGE-19 provides a complete statement of PG&E's current and proposed retail transmission rates. In this advice, PG&E requests authority to revise each corresponding transmission rate component of its CPUC-jurisdictional tariffs on the date on which FERC ultimately authorizes these changes to become effective (subject to refund), and to make corresponding adjustments to PG&E's total applicable CPUC-jurisdictional rates, with exceptions only as described below for the residential tariffs.

As described under Process Elements 5 and 6 of Resolution E-3930, California Assembly Bill 1X (AB 1X) constraints continue to apply to total rates for residential usage up to 130 percent of baseline ("Tier 1 and 2 usage"). As shown in Attachment A, PG&E's TO9 filing would increase the transmission access component of total rates under each of PG&E's applicable residential tariffs, from $0.00815 to $0.00949 per kilowatt-hour (kWh).[1] PG&E proposes to meet AB 1X

[1] The applicable residential tariff of $0.00815 per KWh represents the final approved rate in Order Approving Uncontested Settlement, Docket No. ER05-1284-000, Pacific Gas and Electric Co., 115 FERC ¶ 61,220 (2006). PG&E presented the rates ultimately approved in that decision to the CPUC

requirements for the TO9 rate change by: (1) making the indicated adjustment to the transmission rate component of each residential tariff (increase of $0.00134 per kWh); (2) applying offsetting decreases to the Tier 1 and Tier 2 generation rates applicable under each such tariff (decrease of $0.00134 per kWh); and (3) applying corresponding increases to generation rates for residential usage above 130 percent of baseline, in such a way as to preserve the total amount of all applicable generation rates paid by bundled service residential customers.

The result of these adjustments will be to hold PG&E's total bundled service rates fixed for residential Tier 1 and Tier 2 usage under 130 percent of baseline, as required by AB 1X. The method adopted in Decision (D.) 05-11-005 in PG&E's 2003 General Rate Case (GRC) Phase 2 proceeding (A.04-06-024) will be used to develop the necessary adjustments to the generation component of rates for usage in excess of 130 percent of baseline.

As anticipated under Process Element 4 of Resolution E-3930, PG&E will supplement this advice letter when the requested TO9 rate changes are approved, modified, denied or have been otherwise acted upon by FERC. When FERC authorizes rates to become effective, PG&E will also provide complete updated tariff sheets, including final adjustments to the generation rate components of the residential tariffs based on the specific method for adjusting upper-tier generation rates that is in effect on the date the FERC rate changes are to become effective.

Protests

Anyone wishing to protest this filing may do so by sending a letter by **August 28, 2006**, which is 20 days from the date of this filing. The protest must state the grounds upon which it is based, including such items as financial and service impact, and should be submitted expeditiously. Protests should be mailed to:

IMC Branch Chief – Energy Division
California Public Utilities Commission
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: jjr@cpuc.ca.gov and jnj@cpuc.ca.gov

Protests also should be sent by e-mail and facsimile to Mr. Jerry Royer, Energy Division, as shown above, and by U.S. mail to Mr. Royer at the above address.

The protest should be sent via both e-mail and facsimile to PG&E on the same date it is mailed or delivered to the Commission at the address shown below.

---

in Advice 2820-E. PG&E will request the final TO8 rates be incorporated in retail rates effective September 1, 2006, by a separate Advice.

Pacific Gas and Electric Company
Attention: Brian Cherry
Vice President, Regulatory Relations
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-7226
E-mail: PGETariffs@pge.com

Effective Date

PG&E requests that this advice filing become effective on either October 1, 2006, or as soon as practicable after FERC authorizes these changes to become effective. PG&E proposes to consolidate the electric rate changes resulting from the transmission rate change, to the extent practicable, with the first planned rate change after FERC authorizes PG&E's requests.

Notice

In accordance with General Order 96-A, Section III, Paragraph G, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list. Address changes should be directed to Rose de la Torre at (415) 973-4716. Advice letter filings can also be accessed electronically at:

http://www.pge.com/tariffs/

Brian K. Cherry / TEM

Vice President - Regulatory Relations

Attachment A – Exhibit PGE-19 from FERC Docket No. ERO6-1325-000

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No. Pacific Gas and Electric Company U39E

Utility type:	Contact Person: Ted Maguire
☒ ELC ☒ GAS	Phone #: (415) 973-0888
☐ PLC ☐ HEAT ☐ WATER	E-mail: temn@pge.com

EXPLANATION OF UTILITY TYPE	(Date Filed/ Received Stamp by CPUC)
ELC = Electric GAS = Gas PLC = Pipeline HEAT = Heat WATER = Water	

Advice Letter (AL) #: 2878-E

Subject of AL: Notice of Federal Energy Regulatory Commission Rate Increase Filing (TO9)

Keywords (choose from CPUC listing): Compliance, Transmission Rates

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☒ One-Time ☐ Other ____________

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: Resolution E-3930

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL No

Summarize differences between the AL and the prior withdrawn or rejected AL[1]: N/A

Resolution Required? ☐ Yes ☒ No

Requested effective date: **10/1/2006** No. of tariff sheets: N/A

Estimated system annual revenue effect: (%): 18.7% increase over currently authorized transmission access rates

Estimated system average rate effect (%): average bundled service rate increase approximately 1%

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: Residential, Commercial and Industrial, Agricultural, and Streetlighting rate schedules in future supplement

Service affected and changes proposed[1]: See advice letter

Pending advice letters that revise the same tariff sheets: N/A

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Ave.,
San Francisco, CA 94102
jjr@cpuc.ca.gov and jnj@cpuc.ca.gov

Pacific Gas and Electric Company
Attn: Brian K. Cherry
Vice President, Regulatory Relations
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177
E-mail: PGETariffs@pge.com

[1] Discuss in AL if more space is needed.

FILING WITH THE FEDERAL ENERGY REGULATORY COMMISSION

PACIFIC GAS AND ELECTRIC COMPANY

TRANSMISSION OWNER TARIFF
2007

EXHIBIT PGE-19

TRANSMISSION OWNER TARIFF

PG&E

FERC DOCKET NO. ____________________

PACIFIC GAS AND ELECTRIC COMPANY

TRANSMISSION OWNER TARIFF

TO9

Clean Version

APPENDIX I

Transmission and Reliability Services Revenue Requirements [1]

1. **The Transmission Revenue Requirement for purposes of calculating End-User transmission rates shall be $716,442,669, which is composed of the Base Transmission Revenue Requirement of $719,497,360, and the TRBAA of ($3,054,691).**

2. **For purposes of the ISO's calculation of Access Charges under Section 7.1 of the ISO Tariff:**

   a. **The High Voltage Transmission Revenue Requirement shall be $321,731,546, which is composed of a base High Voltage Transmission Revenue Requirement of $350,947,892, Standby Transmission Demand Revenue credit of ($0), and a High Voltage TRBAA of ($29,216,346).**

   b. **The Low Voltage Transmission Revenue Requirement shall be $358,596,984, which is composed of a base Low Voltage Transmission Revenue Requirement of $357,396,976, Standby Transmission Demand Revenue credit of ($0), and a Low Voltage TRBAA of $1,200,008.**

   c. **The High Voltage Transmission Revenue Requirement associated with New High Voltage Transmission Facilities is $162,425,895 , which is composed of a base High Voltage Transmission Revenue Requirement of $177,156,201, Standby Transmission Demand Revenue credit of ($0), and a High Voltage TRBAA of ($14,730,306).**

   d. **The forecast of Gross Load at the High Voltage/Low Voltage interface is 89,438,787,419 megawatt-hours.**

3. **The amounts stated in sections 1. and 2. above shall be effective until changed by the Participating TO or modified by FERC.**

4. **The Reliability Services Balancing Account shall be equal to $220,503,215, which includes the forecast of Reliability Services payments PG&E will make to the ISO during 2005 of $252,664,631, plus an adjustment of ($32,161,417). This amount shall be effective until amended by PG&E in accordance with Appendix V to this Tariff.**

[1] Total revenue requirement associated with transmission facilities and entitlements turned over to the operational control of the ISO by the Participating TO, which reflects a reduction or increase for Transmission Revenue Credits.

APPENDIX II

Access Charges for Wholesale Transmission

Per kWh

High Voltage Access Charge ....See ISO Tariff

Low Voltage Access Charge.. $0.0040094

High Voltage Utility-Specific Access Charge................ $0.0035972

High Voltage Wheeling Access Charge

High Voltage Wheeling Access Charge.........................See ISO Tariff

Low Voltage Wheeling Access Charge

High Voltage Wheeling Access Charge.........................See ISO Tariff

Low Voltage Wheeling Access Charge....................... $0.0040094

APPENDIX III

Access Charges for End-Use Service [1,2]

Table of Contents

1These charges represent the rates for recovery of the Base Transmission Revenue Requirement. A TRBAA Rate of $(0.00003) per kWh [Docket No. ER06-836-000] and a TACBAA Rate of $0.00033 per kWh [Docket No. ER06-480-000] shall also apply to all of the rate schedules described in this Appendix.

[2]The applicability of these rates is described in the California Public Utilities Commission jurisdictional retail tariffs.

RESIDENTIAL SCHEDULES

SCHEDULE E-1
SCHEDULE E-3
SCHEDULE EL-1 (CARE)
SCHEDULES E-6 AND EL-6 (CARE)
SCHEDULES E-7 AND EL-7 (CARE)
SCHEDULES E-A7 AND EL-A7 (CARE)
SCHEDULE E-8
SCHEDULE EL-8 (CARE)
SCHEDULE E-9
SCHEDULE EE
SCHEDULE EM AND EML (CARE)
SCHEDULE ES AND ESL (CARE)
SCHEDULE ESR AND ESRL (CARE)
SCHEDULE ET AND ETL (CARE)

Energy Charge ($/kWh)	$0.00949

COMMERCIAL & INDUSTRIAL SCHEDULES

SCHEDULE A-1
SCHEDULE A-6
SCHEDULE A-15
SCHEDULE TC-1

Energy Charges ($/kWh)	$0.00936

Schedule A-10

BASIS FOR DEMAND CHARGE: The customer will be billed for demand according to the customer's "maximum demand" each month. The number of kW used will be recorded over 15-minute intervals; the highest 15-minute average in the month will be the customer's maximum demand. SPECIAL CASES: (1) If the customer's use of energy is intermittent or subject to severe fluctuations, a 5-minute interval may be used, and (2) If the customer uses welders, the demand charge will be subject to the minimum demand charges for those welders' ratings, as explained in Section J of PG&E's CPUC Rule 2.

Maximum Demand Charge ($/kW/mo)	$2.95

Schedule E-19

BASIS FOR DEMAND CHARGE: Demand will be averaged over 15-minute intervals for customers whose maximum demand exceeds 499 kW. "Maximum demand" will be the highest of all the 15-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to severe fluctuations, a 5-minute interval may be used. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of PG&E's CPUC Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 15-minute intervals. The customer's maximum-peak-period demand will be the highest of all the 15-minute averages for the peak period during the billing month.

– This schedule has three **demand charges**, a maximum-peak-period-demand charge, a maximum-part-peak-period and a maximum demand charge. The maximum-peak-period demand charge per kilowatt applies to the maximum demand during the month's peak hours, the maximum part-peak-period demand charge applies to the maximum demand during the month's part-peak hours, and the maximum demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include <u>all</u> of these demand charges.

– The monthly charges may be increased or decreased based upon the power factor.

POWER FACTOR ADJUSTMENTS: Bills will be adjusted based on the power factor for all customers except those selecting voluntary E-19 service. The power factor is computed from the ratio of lagging reactive kilovolt-ampere-hours to the kilowatt-hours consumed in the month. Power factors are rounded to the nearest whole percent.

The rates in this rate schedule are based on a power factor of 85 percent. If the average power factor is greater than 85 percent, the total monthly bill will be reduced by the product of the power factor rate and the kilowatt-hour usage for each percent

For customers taking Non-Firm Service, power factor adjustments will be applied to the customer's total bill, net of charges and credits billed under Schedule E-NF.

Schedule E-19 Demand Charges ($/kW/mo)	$2.95

Schedule E-20

BASIS FOR DEMAND CHARGE: Demand will be averaged over 15-minute intervals. "Maximum demand" will be the highest of all the 15-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to severe fluctuations, a 5-minute interval may be used. If the customer has any welding macines, the diversified resistance welder load, calculated in accordance with Section J of PG&E's CPUC Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 15-minute intervals. The customer's maximum-peak-period demand will be the highest of all the 15-minute averages for the peak period during the billing month.

– Schedule E-20 has three **demand charges**, a maximum-peak-period demand charge, a maximum-part-peak-period demand charge, and a maximum-demand charge. The maximum-peak-period demand charge per kilowatt applies to the maximum demand during the month's peak hours, the maximum-part-peak demand charge applies to the maximum demand during the month's part-peak hours, and the maximum demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include all of these demand charges.

– The monthly charges may be increased or decreased based upon the power factor, using the same method as described above for Schedule E-19.

Schedule E-20 Demand Charges ($/kW/mo)	$3.16

Schedule E-37

Energy Charges ($/kWh)	$0.00707

Schedule S

RESERVATION CAPACITY: The Reservation Capacity to be used for billing under the above rates shall be as set forth in the customer's contract for service. For new or revised contracts, the Reservation Capacity shall be determined by the customer. However, if the customer's standby demand exceeds this new contracted capacity in any billing month, that standby demand shall become the new Reservation or Contract Capacity for 12 months, beginning with that month. See Special Condition 7 for the definition of Reservation Capacity for Supplemental Standby Service customers.

The **Reservation Charge**, in dollars per kilowatt (kW), applies to 85 percent of the customer's Reservation Capacity, as defined in Special Condition 1 of the tariffs.

POWER FACTOR ADJUSTMENT: When the customer's Reservation Capacity is greater than 500 kW, the bill will be adjusted based on the power factor. The power factor is derived from the ratio of kWh to kVAh consumed in the month. Power factors are averaged and rounded to the nearest whole percent.

The rates in this rate schedule are based on a power factor of 85 percent. If the average power factor is greater than 85 percent, the total monthly bill will be reduced by the product of the power factor adjustment rate and the kilowatt-hour usage for each percentage point above 85 percent. If the average power factor is less than 85 percent, the total monthly bill will be increased by the product of the power factor adjustment rate and the kilowatt-hour usage for each percentage point below 85 percent.

The customer shall pay only the greater of the power factor adjustment and the reactive demand charge.

Generators for which ISO standards apply must also meet power factor requirements specified in the ISO tariff.

Schedule S

Energy Charges ($/kWh)	$0.01180
Reservation Charge ($/kW/mo)	$0.36

AGRICULTURAL SCHEDULES

The CPUC- jurisdictional retail tariffs should be referred to for detailed descriptions of how agricultural demand charges are assessed.

SCHEDULE AG-1
SCHEDULE AG-R
SCHEDULE AG-V
SCHEDULE AG-4
SCHEDULE AG-5
SCHEDULE AG-ICE

Energy Charges ($/kWh)	$0.00707

STREETLIGHTING SCHEDULES

SCHEDULE LS-1
SCHEDULE LS-2
SCHEDULE LS-3
SCHEDULE OL-1

Energy Charge ($/kWh)	$0.00527

THIS PAGE NOT USED

THIS PAGE NOT USED

THIS PAGE NOT USED

THIS PAGE NOT USED

THIS PAGE NOT USED

THIS PAGE NOT USED

THIS PAGE NOT USED

THIS PAGE NOT USED

THIS PAGE NOT USED

THIS PAGE NOT USED

THIS PAGE NOT USED

PACIFIC GAS AND ELECTRIC COMPANY

TRANSMISSION OWNER TARIFF

TO9

Redline Version

APPENDIX I

Transmission and Reliability Services Revenue Requirements [1]

1. **The Transmission Revenue Requirement for purposes of calculating End-User transmission rates shall be $716,442,669~~602,945,309~~, which is composed of the Base Transmission Revenue Requirement of $719,497,360~~606,000,000~~, and the TRBAA of ($3,054,691).**

2. **For purposes of the ISO's calculation of Access Charges under Section 7.1 of the ISO Tariff:**

   a. **The High Voltage Transmission Revenue Requirement shall be $321,731,546~~269,563,904~~, which is composed of a base High Voltage Transmission Revenue Requirement of $350,947,892~~298,803,467~~, Standby Transmission Demand Revenue credit of ($0), and a High Voltage TRBAA of ($29,216,346~~29,239,563~~).**

   b. **The Low Voltage Transmission Revenue Requirement shall be $358,596,984~~297,609,959~~, which is composed of a base Low Voltage Transmission Revenue Requirement of $357,396,976~~296,386,733~~, Standby Transmission Demand Revenue credit of ($0), and a Low Voltage TRBAA of $1,200,008~~1,223,226~~.**

   c. **The High Voltage Transmission Revenue Requirement associated with New High Voltage Transmission Facilities is $162,425,895 ~~123,976,486~~, which is composed of a base High Voltage Transmission Revenue Requirement of $177,156,201~~137,397,446~~, Standby Transmission Demand Revenue credit of ($0), and a High Voltage TRBAA of ($14,730,306~~13,420,960~~).**

   d. **The forecast of Gross Load at the High Voltage/Low Voltage interface is 89,438,787,419~~89,121,865~~ megawatt-hours.**

3. **The amounts stated in sections 1. and 2. above shall be effective until changed by the Participating TO or modified by FERC.**

4. **The Reliability Services Balancing Account shall be equal to $220,503,215, which includes the forecast of Reliability Services payments PG&E will make to the ISO during 2005 of $252,664,631, plus an adjustment of ($32,161,417). This amount shall be effective until amended by PG&E in accordance with Appendix V to this Tariff.**

---

[1] Total revenue requirement associated with transmission facilities and entitlements turned over to the operational control of the ISO by the Participating TO, which reflects a reduction or increase for Transmission Revenue Credits.

APPENDIX II

Access Charges for Wholesale Transmission

Per kWh

High Voltage Access Charge ....See ISO Tariff

Low Voltage Access Charge....................................... $0.0040094~~0033394~~

High Voltage Utility-Specific Access Charge................ $0.0035972~~0030247~~

High Voltage Wheeling Access Charge

High Voltage Wheeling Access Charge.........................See ISO Tariff

Low Voltage Wheeling Access Charge

High Voltage Wheeling Access Charge.........................See ISO Tariff

Low Voltage Wheeling Access Charge....................... $0.0040094~~.003394~~

~~APPENDIX III~~

~~Access Charges for End-Use Service [1,2]~~

~~Table of Contents~~

[1] ~~These charges represent the rates for recovery of the Base Transmission Revenue Requirement. A TRBAA Rate of $ (0.00003) per KWh shall also apply to all of the rate schedules described in the Appendix. A TACBAA Rate of $0.00033 kWh shall also be applied to all kWh of Gross Load.~~

[2] ~~The applicability of these rates is described in the California Public Utilities Commission jurisdictional retail tariffs.~~

~~RESIDENTIAL SCHEDULES~~

~~Where applicable, Summer season rates apply to the period between May 1 and Oct 31, and Winter season rates to the period between November 1 and April 30. "Baseline" residential energy usage quantities vary by season and geographic zone and are used to define differences between "Tier 1" and "Tier 2" energy consumption.~~

~~Schedule E-1~~

~~Minimum Bill ($/mo)~~		~~$0.37~~
~~Tier 1 Energy Charge ($/kWh)~~	~~All Year~~	~~$0.00815~~
~~Tier 2 Energy Charge ($/kWh)~~	~~All Year~~	~~$0.00815~~

~~Schedule E-2~~

~~Minimum Bill ($/mo)~~		~~$0.37~~
~~Tier 1 Energy Charge ($/kWh)~~	~~All Year~~	~~$0.00815~~
~~Tier 2 Energy Charge ($/kWh)~~	~~All Year~~	~~$0.00815~~

~~Schedule EL-1 (LIRA)~~

~~Minimum Bill ($/mo)~~		~~$0.37~~
~~Tier 1 Energy Charge ($/kWh)~~	~~All Year~~	~~$0.00815~~
~~Tier 2 Energy Charge ($/kWh)~~	~~All Year~~	~~$0.00815~~

~~Schedule E-3~~

~~Minimum Bill ($/mo)~~		~~$0.37~~
~~Tier 1 Energy Charge ($/kWh)~~	~~All Year~~	~~$0.00815~~
~~Tier 2 Energy Charge ($/kWh)~~	~~All Year~~	~~$0.00815~~

~~Schedule EL-1 (LIRA)~~

~~Minimum Bill ($/mo)~~		~~$0.37~~
~~Tier 1 Energy Charge ($/kWh)~~	~~All Year~~	~~$0.00815~~
~~Tier 2 Energy Charge ($/kWh)~~	~~All Year~~	~~$0.00815~~

~~Schedules E-7 and EL-7~~

~~TIME PERIODS: On Peak: 12:00 noon to 6:00 p.m. Monday-Friday; Off Peak: All other hours~~

~~Minimum Bill ($/mo)~~			~~$0.37~~
~~Energy Charges ($/kWh)~~			
	~~Summer~~	~~On Peak~~	~~$0.00815~~
		~~Off Peak~~	~~$0.00815~~
	~~Winter~~	~~On Peak~~	~~$0.00815~~
		~~Off Peak~~	~~$0.00815~~

~~Schedules E-A7 and EL-A7~~

~~TIME PERIODS: On Peak: 4:00 p.m. to 8:00 p.m. Monday Friday; Off Peak: All other hours~~

~~Minimum Bill ($/mo)~~			~~$0.37~~
~~Energy Charges ($/kWh)~~	~~Summer~~	~~On Peak~~	~~$0.00815~~
		~~Off Peak~~	~~$0.00815~~
	~~Winter~~	~~On Peak~~	~~$0.00815~~
		~~Off Peak~~	~~$0.00815~~

~~Schedule E-8~~

~~Energy Charge ($/kWh)~~	~~Summer~~	~~$0.00815~~
	~~Winter~~	~~$0.00815~~

~~Schedule EL-8 (LIRA)~~

~~Energy Charge ($/kWh)~~	~~Summer~~	~~$0.00815~~
	~~Winter~~	~~$0.00815~~

~~Schedule E-9 A~~

~~Times of the year and times of the day are defined as follows:~~

~~Summer (service from May 1 through October 31):~~

~~Peak:~~ ~~2:00 p.m. to 9:00 p.m. Monday through Friday.~~

~~Partial Peak:~~ ~~7:00 a.m. to 2:00 p.m. AND 9:00 p.m. to 12:00 midnight Monday through Friday, plus 5:00 p.m. to 9:00 p.m. Saturday and Sunday.~~

~~Off Peak:~~ ~~12:00 midnight to 7:00 a.m. Monday through Friday, and 9:00 p.m. to 5:00 p.m. Saturday and Sunday.~~

~~Winter (service from November 1 through April 30):~~

~~Partial Peak:~~ ~~7:00 a.m. to 12:00 midnight Monday through Friday, and 5:00 p.m. to 9:00 p.m. Saturday and Sunday.~~

~~Off Peak:~~ ~~12:00 midnight to 7:00 a.m. Monday through Friday, and 9:00 p.m. to 5:00 p.m. Saturday and Sunday.~~

~~Minimum Bill ($/mo)~~			~~$0.37~~
~~Energy Charges ($/kWh)~~	~~Summer~~	~~On Peak~~	~~$0.00815~~
		~~Prt Peak~~	~~$0.00815~~
		~~Off Peak~~	~~$0.00815~~
	~~Winter~~	~~Prt Peak~~	~~$0.00815~~
		~~Off Peak~~	~~$0.00815~~

~~Schedule E-9 B~~

~~Minimum Bill ($/mo)~~			~~$0.37~~
~~Energy Charges ($/kWh)~~	~~Summer~~	~~On Peak~~	~~$0.00815~~
		~~Prt Peak~~	~~$0.00815~~
		~~Off Peak~~	~~$0.00815~~
	~~Winter~~	~~Prt Peak~~	~~$0.00815~~
		~~Off Peak~~	~~$0.00815~~

~~Schedule E-9 C~~

~~Minimum Bill ($/mo)~~			~~$0.37~~
~~Energy Charges ($/kWh)~~	~~Summer~~	~~On Peak~~	
		~~Prt Peak~~	~~$0.00815~~
		~~Off Peak~~	~~$0.00815~~
	~~Winter~~	~~Prt Peak~~	~~$0.00815~~
		~~Off Peak~~	~~$0.00815~~

~~Schedule E-9 D~~

~~Minimum Bill ($/mo)~~			~~$0.37~~
~~Energy Charges ($/kWh)~~	~~Summer~~	~~On Peak~~	~~n/a~~
		~~Prt Peak~~	~~$0.00815~~
		~~Off Peak~~	~~$0.00815~~
	~~Winter~~	~~Prt Peak~~	~~$0.00815~~
		~~Off Peak~~	~~$0.00815~~

~~COMMERCIAL & INDUSTRIAL SCHEDULES~~

~~Times of the year and times of the day are defined as follows (except as otherwise specified for Schedule E-25):~~

~~SUMMER (Service from May 1 through October 31):~~
~~Peak: 12:00 noon to 6:00 p.m. Monday through Friday (except holidays)~~
~~Partial Peak: 8:30 a.m. to 12:00 noon AND 6:00 p.m. to 9:30 p.m. Monday through Friday (except holidays)~~
~~Off Peak: 9:30 p.m. to 8:30 a.m. Monday through Friday; All day Saturday, Sunday, and Holidays~~

~~WINTER (Service from November 1 through April 30):~~
~~Partial Peak: 8:30 a.m. to 9:30 p.m. Monday through Friday (except holidays)~~
~~Off Peak: 9:30 p.m. to 8:30 a.m. Monday through Firday; All day Saturday, Sunday, and Holidays~~

~~Holidays: "Holidays" for the purposes of these rate schedules are New Year's Day, President's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. The dates will be those on which the holidays are legally observed.~~

~~Schedule A-1~~

~~Energy Charges ($/kWh)~~

~~Summer~~	~~$0.00827~~
~~Winter~~	~~$0.00827~~

~~Schedule A-6~~

~~Energy Charges ($/kWh)~~

~~Summer~~	~~On Peak~~	~~$0.00827~~
	~~Prt Peak~~	~~$0.00827~~
	~~Off Peak~~	~~$0.00827~~
~~Winter~~	~~Prt Peak~~	~~$0.00827~~
	~~Off Peak~~	~~$0.00827~~

~~Schedule A-15~~

~~Energy Charges ($/kWh)~~

~~Summer~~	~~$0.00827~~
~~Winter~~	~~$0.00827~~

~~Schedule TC-1~~

~~Energy Charge ($/kWh)~~

~~Summer~~	~~$0.00827~~
~~Winter~~	~~$0.00827~~

~~**Schedule A-10**~~

~~BASIS FOR DEMAND CHARGE: The customer will be billed for demand according to the customer's "maximum demand" each month. The number of kW used will be recorded over 15-minute intervals; the highest 15-minute average in the month will be the customer's maximum demand. SPECIAL CASES: (1) If the customer's use of energy is intermittent or subject to violent fluctuations, a 5-minute interval may be used. (2) If the customer uses welders, the deman charge will be subject to the minimum demand charges for those welders' ratings, as explained in Section J of Rule 2~~

~~Maximum Demand Charge ($/kW/mo)~~

~~Transmission~~	~~Summer~~	~~$2.43~~
	~~Winter~~	~~$2.43~~
~~Primary~~	~~Summer~~	~~$2.43~~
	~~Winter~~	~~$2.43~~
~~Secondary~~	~~Summer~~	~~$2.43~~
	~~Winter~~	~~$2.43~~

~~**Schedule E-19**~~

~~BASIS FOR DEMAND CHARGE: Demand will be averaged over 15-minute intervals for customers whose maximum demand exceeds 499 kW. "Maximum demand" will be the highest of all the 15-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to violent fluctuations, a 5-minute interval may be used instead of the 15-minute interval. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 15-minute intervals. The customer's maximum peak-period demand will be the highest of all the 15-minute averages for the peak period during the billing month.~~

– ~~This schedule has three **demand charges**, a maximum-peak-period-demand charge, a maximum-part-peak-period and a maximum-demand charge. The maximum-peak-period-demand charge per kilowatt applies to the maximum demand during the month's peak hours, the maximum-part-peak-period-demand charge applies to the maximum demand during the month's part-peak hours, and the maximum-demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include all of these demand charges.~~

– ~~The monthly charges may be increased or decreased based upon the power factor.~~

~~DEFINITION OF SERVICE VOLTAGE:~~

~~The following defines the three voltage classes of Schedule E-19 rates. Standard Service Voltages are listed in Rule 2.~~

~~a.~~ ~~Secondary: This is the voltage class if the service voltage is less than 2,400 volts or if the definitions of "primary" and "transmission" do not apply to the service.~~

~~b.~~ ~~Primary: This is the voltage class if the customer is served from a "single customer substation" or without transformation from PG&E's serving distribution system at one of the standard primary voltages specified in PG&E's Electric Rule 2, Section B.1.~~

~~c.~~ ~~Transmission: This is the voltage class if the customer is served B367 from PG&E's serving transmission system at one of the standard transmission voltages specified in PG&E's Rule 2, Section B.1.~~

~~CHANGE FROM SUMMER TO WINTER OR WINTER TO SUMMER: When a billing month includes both summer and winter days, PG&E will calculate demand charges as follows. It will consider the applicable maximum demands for the summer and winter portions of the billing month separately, calculate a demand charge for each, and then apply the two according to the number of billing days each represents. NOTE: If the meter is read within one work day of the season changeover date (May 1 or November 1), PG&E will use only the rates and charges from the season having the greater number of days in the billing month. Work days are Monday through Friday, inclusive.~~

~~POWER FACTOR ADJUSTMENTS: When the customer's maximum demand has exceeded 400 kW for three consecutive months and thereafter until the demand has fallen below 300 kW for 12 consecutive months, the bill will be adjusted based upon the power factor. The power factor is computed from the ratio of lagging reactive kilovolt ampere hours to the kilowatt hours consumed in the month. Power factors are rounded to the nearest whole percent.~~

~~The rates in this rate schedule are based on a power factor of 85 percent. If the average power factor is greater than 85 percent, the total monthly bill (excluding any taxes) will be reduced by 0.06 percent for each percentage point above 85 percent. If the average power factor is below 85 percent, the total monthly bill (excluding any taxes) will be increased by 0.06 percent for each percentage point below 85 percent.~~

~~**Schedule E-19 T** Demand Charges ($/kW/mo)~~

~~Summer Maximum~~	~~$2.43~~
~~Winter Maximum~~	~~$2.43~~

~~**Schedule E-19 P** Demand Charges ($/kW/mo)~~

~~Summer Maximum~~	~~$2.43~~
~~Winter Maximum~~	~~$2.43~~

~~**Schedule E-19 S** Demand Charges ($/kW/mo)~~

~~Summer Maximum~~	~~$2.43~~
~~Winter Maximum~~	~~$2.43~~

~~**Schedule E-20**~~

~~BASIS FOR DEMAND CHARGE: Demand will be averaged over 15-minute intervals. "Maximum demand" will be the highest of all the 15-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to violent fluctuations, a 5-minute interval may be used instead of the 15-minute interval.~~
~~If the customer has any welding macines, the diversified resistance welder load, calculated in accordance with Section J of Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 15-minute intervals. The customer's maximum-peak-period demand will be the highest of all the 15-minute averages for the peak period during the billing month.~~

- ~~Schedule E-20 has three **demand charges**, a maximum-peak-period demand charge, a maximum-part-peak-period demand charge, and a maximum-demand charge. The maximum-peak-period demand charge per kilowatt applies to the maximum demand during the month's peak hours, the maximum-part-peak demand charge applies to the maximum demand during the month's part-peak hours, and the maximum-demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include all of these demand charges.~~

- ~~The monthly charges may be increased or decreased based upon the power factor, using the same method as described above for Schedule E-19.~~

~~**Schedule E-20 T** Demand Charges ($/kW/mo)~~

	~~Summer Maximum~~	~~$2.61~~
	~~Winter Maximum~~	~~$2.61~~

~~**Schedule E-20 P** Demand Charges ($/kW/mo)~~

	~~Summer Maximum~~	~~$2.61~~
	~~Winter Maximum~~	~~$2.61~~

~~**Schedule E-20 S** Demand Charges ($/kW/mo)~~

	~~Summer Maximum~~	~~$2.61~~
	~~Winter Maximum~~	~~$2.61~~

~~Schedule E-25~~

~~TIME PERIODS – Seasons of the year and times of the day are defined as follows:~~

~~SUMMER:~~ ~~Service from May 1 through October 31.~~
~~*Peak:~~
~~Group I~~ ~~12:00 noon to 4:00 p.m. Monday through Friday, except holidays~~
~~Group II~~ ~~1:00 p.m. to 5:00 p.m. Monday through Friday, except holidays~~
~~Group III~~ ~~2:00 p.m. to 6:00 p.m. Monday through Friday, except holidays~~

~~Partial Peak:~~
~~Group I~~ ~~8:30 a.m. to 12:00 noon and 4:00 p.m. to 9:30 p.m. Monday through Friday~~
~~Group II~~ ~~8:30 a.m. to 1:00 p.m. and 5:00 p.m. to 9:30 p.m. Monday through Friday~~
~~Group III~~ ~~8:30 a.m. to 2:00 p.m. and 6:00 p.m. to 9:30 p.m. Monday through Friday~~

~~Off Peak:~~ ~~All other hours~~

~~WINTER:~~ ~~Service from November 1 through April 30.~~
~~Partial Peak:~~ ~~8:30 a.m. to 9:30 p.m. Monday through Friday~~
~~Off Peak:~~ ~~All other hours~~

~~Schedule E-25 T~~ ~~Demand Charges ($/kW/mo)~~

~~Summer - Maximum~~	~~$2.43~~
~~Winter - Maximum~~	~~$2.43~~

~~Schedule E-25 P~~ ~~Demand Charges ($/kW/mo)~~

~~Summer - Maximum~~	~~$2.43~~
~~Winter - Maximum~~	~~$2.43~~

~~Schedule E-25 S~~ ~~Demand Charges ($/kW/mo)~~

~~Summer - Maximum~~	~~$2.43~~
~~Winter - Maximum~~	~~$2.43~~

~~Schedule E-36~~

~~Energy Charges ($/kWh)~~	~~Summer~~	~~$0.00537~~
	~~Winter~~	~~$0.00537~~

~~Schedule E-37~~

~~Energy Charges ($/kWh)~~	~~Summer~~	~~$0.00537~~
	~~Winter~~	~~$0.00537~~
~~Primary Voltage Discount~~	~~Summer~~	~~$0.00000~~
	~~Winter~~	~~$0.00000~~
~~Transmission Voltage Discount~~	~~Summer~~	~~$0.00000~~
	~~Winter~~	~~$0.00000~~

~~**Schedule S**~~

~~RESERVATION CAPACITY: The Reservation Capacity to be used for billing under the above rates shall be as set forth in the customer's contract for service. For new or revised contracts, the Reservation Capacity shall be determined by the customer. However, if the customer's standby demand exceeds this new contracted capacity in any billing month, that standby demand shall become the new Reservation or Contract Capacity for 36 months, beginning with that month. See Special Condition 8 for the definition of Reservation Capacity for Supplemental Standby Service customers.~~

~~The **Reservation Charge**, in dollars per kilowatt (kW), applies to 85 percent of the customer's Reservation Capacity, as defined in Special Condition 1 of the tariffs.~~

~~The **Standby Reservation Charges** for customers who have paid for the total cost of the service transformers as special facilities under electric Rule 2 are determined by the voltage at the high side of the service transformer. All other charges will be billed on the voltage level at the low side of the service transformer.~~

~~**Schedule S- Transmission**~~

~~Energy Charges ($/kWh)~~			
	~~Summer~~	~~On-Peak~~	~~$0.01065~~
		~~Prt-Peak~~	~~$0.01065~~
		~~Off-Peak~~	~~$0.01065~~
	~~Winter~~	~~Prt-Peak~~	~~$0.01065~~
		~~Off-Peak~~	~~$0.01065~~
~~Reservation Charge ($/kW/mo)~~		~~All Year~~	~~$0.30~~

~~**Schedule S - Primary**~~

~~Energy Charges ($/kWh)~~			
	~~Summer~~	~~On-Peak~~	~~$0.01065~~
		~~Prt-Peak~~	~~$0.01065~~
		~~Off-Peak~~	~~$0.01065~~
	~~Winter~~	~~Prt-Peak~~	~~$0.01065~~
		~~Off-Peak~~	~~$0.01065~~
~~Reservation Charge ($/kW/mo)~~		~~All Year~~	~~$0.30~~

~~**Schedule S - Secondary**~~

	~~Summer~~	~~On-Peak~~	~~$0.01065~~
		~~Prt-Peak~~	~~$0.01065~~
		~~Off-Peak~~	~~$0.01065~~
	~~Winter~~	~~Prt-Peak~~	~~$0.01065~~
		~~Off-Peak~~	~~$0.01065~~
~~Reservation Charge ($/kW/mo)~~		~~All Year~~	~~$0.30~~

~~**AGRICULTURAL SCHEDULES**~~

~~Summer season rates apply to the period between May 1 and Oct 31, and Winter season rates to the period between November 1 and April 30. Service voltage definitions are as described in Rule 2 and summarized in the Commercial and Industrial Rate Schedules section of this Appendix. The CPUC jurisdictional retail tariffs should be referred to for detailed descriptions of how agricultural demand charges are assessed and definitions of the various applicable agricultural time of use rate periods.~~

~~**"A"- Series Agricultural Schedules**~~

~~**Schedule AG-1A**~~		
~~Energy Charges ($/kWh)~~	~~Summer~~	~~$0.00537~~
	~~Winter~~	~~$0.00537~~
~~**Schedule AG-RA**~~		
~~Energy Charges ($/kWh)~~	~~Summer~~	~~$0.00537~~
	~~Winter~~	~~$0.00537~~
~~**Schedule AG-VA**~~		
~~Energy Charges ($/kWh)~~	~~Summer~~	~~$0.00537~~
	~~Winter~~	~~$0.00537~~
~~**Schedule AG-4A**~~		
~~Energy Charges ($/kWh)~~	~~Summer~~	~~$0.00537~~
	~~Winter~~	~~$0.00537~~
~~**Schedule AG-5A**~~		
~~Energy Charges ($/kWh)~~	~~Summer~~	~~$0.00537~~
	~~Winter~~	~~$0.00537~~
~~**Schedule AG-6A**~~		
~~Energy Charges ($/kWh)~~	~~Summer~~	~~$0.00537~~
	~~Winter~~	~~$0.00537~~
~~**Schedule AG-7A**~~		
~~Energy Charges ($/kWh)~~	~~Summer~~	~~$0.00537~~
	~~Winter~~	~~$0.00537~~

~~"B" and "C"- Series Schedules~~

~~Schedule AG-1B~~

~~Energy Charges ($/kWh)~~		
~~Secondary Voltage~~	~~Summer~~	~~$0.00537~~
	~~Winter~~	~~$0.00537~~
~~Primary Voltage Discount~~	~~Summer~~	~~$0.00000~~
	~~Winter~~	~~$0.00000~~

~~Schedule AG-RB~~

~~Energy Charges ($/kWh)~~		
~~Secondary Voltage~~	~~Summer~~	~~$0.00537~~
	~~Winter~~	~~$0.00537~~
~~Primary Voltage Discount~~	~~Summer~~	~~$0.00000~~
	~~Winter~~	~~$0.00000~~

~~Schedule AG-VB~~

~~Energy Charges ($/kWh)~~		
~~Secondary Voltage~~	~~Summer~~	~~$0.00537~~
	~~Winter~~	~~$0.00537~~
~~Primary Voltage Discount~~	~~Summer~~	~~$0.00000~~
	~~Winter~~	~~$0.00000~~

~~Schedule AG-4B~~

~~Energy Charges ($/kWh)~~		
~~Secondary Voltage~~	~~Summer~~	~~$0.00537~~
	~~Winter~~	~~$0.00537~~
~~Primary Voltage Discount~~	~~Summer~~	~~$0.00000~~
	~~Winter~~	~~$0.00000~~

~~Schedule AG-4C~~

~~Energy Charges ($/kWh)~~		
	~~Summer~~	~~$0.00537~~
	~~Winter~~	~~$0.00537~~

~~Schedule AG-5B~~

~~Energy Charges ($/kWh)~~		
~~Secondary Voltage~~	~~Summer~~	~~$0.00537~~
	~~Winter~~	~~$0.00537~~
~~Primary Voltage Discount~~	~~Summer~~	~~$0.00000~~
	~~Winter~~	~~$0.00000~~
~~Transmission Voltage Discount.~~	~~Summer~~	~~$0.00000~~
	~~Winter~~	~~$0.00000~~

~~Schedule AG-5C~~

~~Energy Charges ($/kWh)~~		
	~~Summer~~	~~$0.00537~~
	~~Winter~~	~~$0.00537~~

~~Schedule AG-6B~~

~~Energy Charges ($/kWh)~~		
~~Secondary Voltage~~	~~Summer~~	~~$0.00537~~
	~~Winter~~	~~$0.00537~~
~~Primary Voltage Discount~~	~~Summer~~	~~$0.00000~~
	~~Winter~~	~~$0.00000~~

~~Schedule AG-7B~~

~~Energy Charges ($/kWh)~~		
~~Secondary Voltage~~	~~Summer~~	~~$0.00537~~
	~~Winter~~	~~$0.00537~~
~~Primary Voltage Discount~~	~~Summer~~	~~$0.00000~~
	~~Winter~~	~~$0.00000~~

~~STREETLIGHTING SCHEDULES~~

~~Schedule LS-1~~		
~~Energy Charge ($/kWh)~~	~~All Year~~	~~$0.00434~~
~~Schedule LS-2~~		
~~Energy Charge ($/kWh)~~	~~All Year~~	~~$0.00434~~
~~Schedule LS-3~~		
~~Energy Charge ($/kWh)~~	~~All Year~~	~~$0.00434~~
~~Schedule OL-1~~		
~~Energy Charge ($/kWh)~~	~~All Year~~	~~$0.00434~~

PG&E Gas and Electric Advice Filing List
General Order 96-A, Section III(G)

ABAG Power Pool
Accent Energy
Aglet Consumer Alliance
Agnews Developmental Center
Ahmed, Ali
Alcantar & Elsesser
Ancillary Services Coalition
Anderson Donovan & Poole P.C.
Applied Power Technologies
APS Energy Services Co Inc
Arter & Hadden LLP
Avista Corp
Barkovich & Yap, Inc.
BART
Bartle Wells Associates
Blue Ridge Gas
Bohannon Development Co
BP Energy Company
Braun & Associates
C & H Sugar Co.
CA Bldg Industry Association
CA Cotton Ginners & Growers Assoc.
CA League of Food Processors
CA Water Service Group
California Energy Commission
California Farm Bureau Federation
California Gas Acquisition Svcs
California ISO
Calpine
Calpine Corp
Calpine Gilroy Cogen
Cambridge Energy Research Assoc
Cameron McKenna
Cardinal Cogen
Cellnet Data Systems
Chevron Texaco
Chevron USA Production Co.
Childress, David A.
City of Glendale
City of Healdsburg
City of Palo Alto
City of Redding
CLECA Law Office
Commerce Energy
Constellation New Energy
CPUC
Cross Border Inc
Crossborder Inc
CSC Energy Services
Davis, Wright, Tremaine LLP
Defense Fuel Support Center
Department of the Army
Department of Water & Power City
DGS Natural Gas Services
Douglass & Liddell
Downey, Brand, Seymour & Rohwer
Duke Energy
Duke Energy North America
Duncan, Virgil E.
Dutcher, John
Dynegy Inc.
Ellison Schneider
Energy Law Group LLP
Energy Management Services, LLC
Exelon Energy Ohio, Inc
Exeter Associates
Foster Farms
Foster, Wheeler, Martinez
Franciscan Mobilehome
Future Resources Associates, Inc
G. A. Krause & Assoc
Gas Transmission Northwest Corporation
GLJ Energy Publications
Goodin, MacBride, Squeri, Schlotz &
Hanna & Morton
Heeg, Peggy A.
Hitachi Global Storage Technologies
Hogan Manufacturing, Inc
House, Lon
Imperial Irrigation District
Integrated Utility Consulting Group
International Power Technology
Interstate Gas Services, Inc.
IUCG/Sunshine Design LLC
J. R. Wood, Inc
JTM, Inc
Luce, Forward, Hamilton & Scripps
Manatt, Phelps & Phillips
Marcus, David
Matthew V. Brady & Associates
Maynor, Donald H.
McKenzie & Assoc
McKenzie & Associates
Meek, Daniel W.
Mirant California, LLC
Modesto Irrigation Dist
Morrison & Foerster
Morse Richard Weisenmiller & Assoc.
Navigant Consulting
New United Motor Mfg, Inc
Norris & Wong Associates
North Coast Solar Resources
Northern California Power Agency
Office of Energy Assessments
OnGrid Solar
Palo Alto Muni Utilities
PG&E National Energy Group
Pinnacle CNG Company
PITCO
Plurimi, Inc.
PPL EnergyPlus, LLC
Praxair, Inc.
Price, Roy
Product Development Dept
R. M. Hairston & Company
R. W. Beck & Associates
Recon Research
Regional Cogeneration Service
RMC Lonestar
Sacramento Municipal Utility District
SCD Energy Solutions
Seattle City Light
Sempra
Sempra Energy
Sequoia Union HS Dist
SESCO
Sierra Pacific Power Company
Silicon Valley Power
Smurfit Stone Container Corp
Southern California Edison
SPURR
St. Paul Assoc
Stanford University
Sutherland, Asbill & Brennan
Tabors Caramanis & Associates
Tecogen, Inc
TFS Energy
Transcanada
Turlock Irrigation District
U S Borax, Inc
United Cogen Inc.
URM Groups
Utility Cost Management LLC
Utility Resource Network
Wellhead Electric Company
Western Hub Properties, LLC
White & Case
WMA