ALJ/BDP/sid

Mailed

SEP 5 1997

Decision 97-09-047 September 3, 1997

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY For Authority, Among Other Things, To Change Its Rates And Charges For Electric Service. (Electric and Gas) (U 39 M)	Application 94-12-005 (Filed December 9, 1994)

ORIGINAL

(See Appendix A for appearances.)

OPINION ON CONTESTED ISSUES IN 1997 ELECTRIC RATE DESIGN WINDOW FILING

1. Summary

In its 1997 Electric Rate Design Window proceeding, Pacific Gas and Electric Company (PG&E) proposes five new optional rate schedules under the provisions of Public Utilities (PU) Code § 378, enacted as part of Assembly Bill (AB) 1890, which allows the Commission to authorize "new optional rate schedules and tariffs, including new service offerings, that accurately reflect the loads, locations, conditions of service, cost of service, and market opportunities of customer classes and subclasses." Specifically, Schedule AG-7 is an optional agricultural tiered rate; Schedules E-36 and E-37 are optional oil pumping rates; Schedules E-TD and E-TDI are optional rates for pricing flexibility to help avoid the uneconomic bypass of PG&E's transmission and distribution (T&D) system; and Schedule AG-8 is an optional rate schedule for avoiding fuel-switching by certain agricultural customers.

The Commission adopts all the above proposed schedules with modifications designed to ensure that these tariffs are consistent with state law, previous Commission decisions and the Commission's overriding policy goal to promote competition in the electric industry.

The major changes from PG&E's original proposal relate to PG&E's Schedules E-TD and E-TDI designed to prevent "uneconomic bypass" of its distribution system. Today's decision requires PG&E, prior to offering a discount under this tariff to provide the customer with an "unbundled " bill that shows each of the following components:

- Energy Cost
- Competition Transition Charge (CTC)
- Public Benefit Program Charge (§ 381)
- Transmission Charge
- Distribution Charge

PG&E is only allowed to discount the distribution component of a customer's bill. PG&E is not allowed to discount the energy, CTC, public purpose program charge, or transmission components. To allow PG&E to discount the energy portion of the bill would be a violation of the fundamental goal of the Commission's restructuring policy of promoting competition and separating the merchant function of energy from the delivery function. Discounting of either the CTC or the public purpose program charge is precluded by AB 1890 which specifies that these charges are non-bypassable and must be recovered from all customers (§§ 371(a) and 381(a).) Transmission rates as of January 1, 1998 will be set by the Federal Energy Regulatory Commission (FERC), and cannot be discounted as well.

Because PG&E is planning to offer this discounted service prior to the start of market competition on January 1, 1998, PG&E is required to immediately comply with our Cost Separation proceeding decision (D.97-08-056) and PG&E Interim CTC decision (D.96-11-041) as a basis for calculating (prior to January 1, 1998) the distribution portion of PG&E's rate that may be discounted.

These safeguards will ensure that direct access providers offering energy services will know each component of a customer's bill and the portions that are subject to competitive pressure. Customers on the new rate schedules that we adopt today are free to choose direct access at any time. PG&E shall not in any way impede that customer's eligibility for direct access.

In order to ensure that PG&E's ratepayers are not harmed by PG&E's ability to offer discounted distribution rates, PG&E may not offer these discounts to customers to compete against an irrigation district that is utilizing a valid CTC exemption to serve that customer (§§ 374(a)(1) and (a)(2).) To allow PG&E to compete for CTC-exempt load could result in PG&E losing more revenues through discounting than it retains through keeping customers on the system.

PG&E's authority to offer these new rate schedules as modified, is based on the evidentiary record developed in this proceeding. We appreciate the time the active parties put into efforts to reach an all-party settlement. The result of these efforts was a Settlement Agreement, filed by a majority of the parties on July 3, 1997. While we found great merit in many of the proposals put forth in the settlement, we are unable to adopt the settlement because in several key areas it conflicts with regulatory policies that are critical to ensuring fair and open competition in the restructured electric industry. Many of the same concerns that the Commission has with the Settlement Agreement were raised in comments on the settlement filed by the two active parties who were not signatories to the settlement.

We believe, however, that the safeguards that we have added to PG&E's proposed tariffs result in an outcome that is substantially fair to all active parties in the proceeding.

Finally, we note that this decision was classified as a Senate Bill (SB) 960 experimental case.

2. Procedural Summary

A prehearing conference was held on January 29, 1997. Evidentiary hearing on the contested issues[1] was held throughout the week of April 7-11, 1997. Concurrent opening briefs and reply briefs were filed on May 2 and May 12, 1997, respectively. Briefs were filed by Agricultural Energy Consumers Association (AECA), California Independent Petroleum Association (CIPA), Farm Bureau Federation (Farm Bureau), Laguna Irrigation District (Laguna), Merced Irrigation District (Merced), Modesto Irrigation District (Modesto), Office of Ratepayer Advocates (ORA), PG&E, and SoCalGas.

Pursuant to § 311(d), the Administrative Law Judge's (ALJ) Proposed Decision was mailed on June 2, 1997. Comments and reply comments on the Proposed Decision were filed by AECA, CIPA, Laguna, Merced, Modesto, ORA, PG&E and SoCalGas.

Oral argument before the Commission was held on June 19, 1997. At the close of the oral argument, pursuant to President Conlon's encouragement to the parties to

---

[1] On June 11, 1997, the Commission issued Decision (D.) 97-06-024 on the uncontested issues.

pursue settlement, the parties held discussions including a noticed Settlement Conference.

On July 3, 1997, the Settling Parties[2] filed a Settlement Agreement along with a motion requesting that the Commission waive portions of Rule 51, so that the Commission could consider the Settlement Agreement at its August 1, 1997 meeting.

On July 14, 1997, Enron Corporation (Enron) filed its opposition to the Settlement Agreement. ORA filed its opposition to the Settlement Agreement on July 18, 1997. PG&E filed its response to Enron and ORA on July 21 and 25, 1997, respectively.

3. The Settlement Agreement

In negotiating the Settlement Agreement, the Settling Parties agreed to the following points:

- PG&E should be allowed to engage in fair T&D competition subject to specified limitations intended to ensure consistency with AB 1890.

- The Legislature intended that irrigation districts have the best possible opportunity to utilize their § 374 CTC exemptions and therefore PG&E's Schedules E-TD and E-TDI rates should not apply when these exemptions are being validly utilized.

- Greater customer choice and enhanced competition result when PG&E is allowed to make matching counter offers where § 374 exemptions are <u>not</u> being exercised and where T&D competition exists.

- The Settlement Agreement complies with AB 1890, §§ 367, 368, 375 and 376, and benefits remaining ratepayers by clarifying that PG&E will not discount non-bypassable CTCs when making offers to match a competitor's T&D service offer unless the competitor is offering to pay the customer's CTC.

- The Settlement Agreement complies with § 378 of AB 1890 by offering new tariffs that comport with the five factors listed in § 378.

---

[2] The Settling Parties are: AECA, CIPA, Farm Bureau, Laguna, Merced, Modesto, SoCalGas, and PG&E. Although ORA and Enron attended and actively participated in the noticed Settlement Conference, and were included in the subsequent negotiations, they were the only active parties that ultimately did not join in the Settlement Agreement.

- The Settlement Agreement affirms that none of the new optional rates affects a customer's choice of generation provider, or otherwise limits the customer's ability to enter into Direct Access transactions, and that unbundling of the new rates will occur consistent with how existing rates are unbundled by the Commission in the Cost Separation proceeding.

- The Settlement Agreement leaves in place the other recommendations in the Proposed Decision, including the adoption of a zero/one T&D adjustment to marginal costs. This approach is consistent with Commission precedents adjusting system marginal costs to better reflect customer-specific marginal costs of service, and more accurately reflects T&D marginal costs in unconstrained areas. Without this adjustment, Schedule AG-8, which is designed to combat uneconomic agricultural bypass, would become virtually useless due to the abnormally high agricultural marginal costs adopted in PG&E's 1996 General Rate Case, the validity of which the Commission itself has already questioned.

- Because the Rate Design Window options are highly time-sensitive (e.g., Schedules AG-7 and AG-8 are needed for this year's growing season, and continued uneconomic T&D bypass could result in millions of dollars in lost revenues to the detriment of ratepayers), the Settling Parties request a final Commission decision by August 1, 1997.

The primary focus of the Settlement Agreement is a recommendation to amend the Proposed Decision to limit PG&E's use of its proposed new optional Schedules E-TD and E-TDI to situations in which the T&D competitor is not using a CTC exemption under § 374(a)(1) and (a)(2). Specifically, the Settling Parties agree that the irrigation district exemptions in § 374 should not be subject to competition from PG&E through Schedules E-TD and E-TDI during the transition period. In addition, in situations in which no § 374 CTC exemption is being used, clarifying language was added noting that PG&E's offer under Schedule E-TD or E-TDI will never go below the sum of its customer-specific marginal cost plus 20% plus the customer's CTC obligation.

Also, the Settlement Agreement includes a modification requested by Enron to clarify PG&E's original intent that customers on Schedules AG-7, E-36, E-37, E-TD, E-TDI, and AG-8 are free to choose direct access at any time. If otherwise eligible, both new customers and new load taking direct access service shall be eligible for these tariffs. Any customer taking direct access service, if on any of these tariffs, shall receive on the bill, Power Exchange (PX) charges (including but not limited to charges for commodity and ancillary services), T&D charges, public purpose program charges, transmission charges, CTCs and charges for competitive or unbundled services (including but not limited to billing, metering and credits) to the extent that the calculation and presentation of this information is approved by the Commission in the Cost Separation proceeding (A.96-12-009 et al.), consistent with methods approved by the Commission for all other direct access customers.

To address SoCalGas' concerns raised in comments and at the oral argument, the Settling Parties recommend that SoCalGas be afforded an opportunity to propose expedited amendments to its competitive options in an advice filing seeking customer-specific marginal costs and ratemaking treatment similar to that which the Settling Parties find reasonable for adoption here.

Lastly, the Settling Parties agree that each of PG&E's proposed tariffs comport with the five factors in § 378.

Opposition of Enron to Settlement Agreement

Enron argues that the proposed rate schedules, if implemented at this time, would act as barriers to competition because direct access service providers such as Enron cannot now formulate and offer complete direct access services and products so long as PG&E withholds unbundled information on the tariffs.

Enron contends that if the Settlement Agreement is approved by the Commission, PG&E could offer these bundled discount rates for nearly six months before a unbundled direct access version of these tariffs would be available. According to Enron, since direct access service providers cannot offer customers accurate direct access proposals absent unbundling of the tariffs into discrete components with discrete prices, it is concerned that PG&E will "lock-in" customers and enjoy a virtual monopoly in offering the tariffs for the remainder of 1997.

Enron acknowledges that prior to the filing of the Settlement Agreement, which Enron declined to join, Enron and PG&E engaged in discussions regarding these proposed tariff schedules. Enron agrees that PG&E made alterations to the proposed tariff schedules based upon Enron's concerns. PG&E, specifically at Enron's request, included text to indicate that the proposed rates will be "available" to otherwise qualified direct access customers. However, upon detailed review and analysis of the Proposed Decision and the Settlement Agreement itself, including the modified tariff schedules, Enron concludes that neither it nor any other energy service provider (ESP) can effectively offer direct access products in competition against the bundled discount pricing tariffs of PG&E, until certain basic aspects of the tariffs are clearly explained and unbundled tariffs are in place.

Enron submits that if the Commission does not reject PG&E's proposed tariffs, it should at the very least not permit them to become effective until PG&E has filed a unbundled direct access tariff for each of the discount tariffs which are the subject of this proceeding. In addition, Enron submits that the Commission should not permit the tariffs to become effective until they are modified to specifically identify: (1) the rate component which PG&E is discounting to "meet the competitive rate," and (2) who bears the cost responsibility for the discount. Enron contends that PG&E should specifically disclose whether the revenue shortfall from the discounted tariffs will be recovered from other customers or from PG&E itself.

Opposition of ORA to Settlement Agreement

ORA argues that the Settlement Agreement is not consistent with law, not reasonable and not in the public interest. According to ORA, the Settlement Agreement is not consistent with law because it has not been shown that PG&E's rate proposals comport with § 378 and because the Settlement Agreement yields a result that modifies D.97-03-017 in contravention of § 1708.

According to ORA, Schedules E-36 and E-37 in effect circumvent the rate freeze, offer lower rates to oil producers, and set a standard whereby corporate welfare satisfies § 378.

ORA contends that the Settlement Agreement is not in the public interest because it prevents the Commission from resolving issues of first impression that were raised at hearing, thus parties will unnecessarily relitigate the same matters in future proceedings, and it allows PG&E to discount CTC with ratepayers possibly at risk.

Lastly, ORA asserts that the Settlement Agreement is not reasonable because it fails to properly explain the basis for its adoption.

Response of PG&E to Enron and ORA

PG&E disputes Enron's assertion that its proposed Schedules E-TD and E-TDI are intended to lock customers into bundled utility service. According to PG&E, Enron's intention is to prevent PG&E from having the pricing flexibility to compete in situations where Enron may wish to build duplicative T&D bypass systems to serve selected PG&E customers.[3]

PG&E states that customers taking service on Schedules E-TD and E-TDI will have the same opportunity as all other PG&E customers to take advantage of direct access service arrangements with third-party suppliers beginning January 1, 1998. PG&E points out that as stated in the tariff language submitted with the Settlement

[3] PG&E states that last month Enron entered into a contract with Pittsburg Power Company to provide a number of products and services including "design and installation of electric transmission and distribution facilities" and "operation and maintenance of physical assets, including cogeneration plants, steam lines, electric transmission and distribution facilities, and gas pipelines." (Section 7.1 of contract between Enron and Pittsburg Power Company approved by the Board of Directors of Pittsburg Power Company on June 26, 1997, emphasis added.)

Agreement, Schedules E-TD and E-TDI will be available to either bundled service or direct access customers so long as they meet defined, supply-neutral eligibility requirements. Customers that decide to take service on Schedules E-TD or E-TDI will have the opportunity to enter into direct access arrangements at any time after January 1, 1998 while continuing to remain on Schedule E-TD or E-TDI.[4] For customers that choose to do so, PG&E will provide bill credits equal to its avoided energy supply costs). The Schedule E-TD and E-TDI bills will continue to be priced at a discount (relative to full tariff rates) to prevent uneconomic T&D bypass, but the bill credit calculation methodology will be identical to that used for customers on all other PG&E schedules. PG&E also points out that customers can terminate Schedule E-TD and E-TDI service without paying any adders, exit fees, liquidated damages or other charges.

PG&E submits that, furthermore, during the rate freeze period (which is the period during which Schedules E-TD and E-TDI would be offered) PG&E has no financial interest in persuading customers to remain as bundled service customers, and is indifferent to their choice of electric supply providers. However, PG&E and its ratepayers do have a financial interest in retaining customers on its T&D system and in avoiding uneconomic bypass where possible. According to PG&E, having the flexibility to price competitively in situations where full tariff prices would lead to uneconomic bypass results in additional revenues compared to the alternative, where the customer leaves because these rates are not available. As the Commission recognized in Edison's Flexible Pricing Options case, full tariff revenue is not achievable in competitive situations, and thus competitive rate options should be more appropriately viewed as sources of incremental revenues, rather than as "discounts" from an unachievable

[4] Alternatively, customers can easily cancel their Schedule E-TD or E-TDI contract on short notice (as described below), return to full tariff service and make direct access arrangements.

full tariff revenue standard. (D. 96-08-025.) PG&E argues that these increased revenues will help increase the amount of headroom available for paying off transition costs, thus benefiting either customers (through an earlier end to the rate freeze) or shareholders (in the form of reduced transition cost write-offs), depending upon whether PG&E ultimately has sufficient headroom to amortize its transition costs. PG&E submits that this symmetric ratemaking treatment is entirely appropriate given the alignment of ratepayer and shareholder interests which now exists as a result of the rate freeze and date-certain for transition cost collection mandated by AB 1890.[5]

Addressing Enron's request for unbundled rate information, PG&E states that Schedules E-TD and E-TDI will be unbundled to the same extent as the Commission decides is appropriate in its Cost Separation decision. Further, PG&E argues that if Enron's intent is merely to be a direct access provider competing to supply generation, no such unbundling of T&D and other charges is required to allow Enron to tender the customer a supply offer, nor is there a justification for requiring any different unbundling for Schedules E-TD and E-TDI than for any other PG&E tariff.

Responding to ORA's argument that the settlement is not in the public interest, PG&E repeats that the Settlement Agreement benefits ratepayers and shareholders by increasing revenue, thereby accelerating CTC recovery, and is consistent with the Commission's settlement guidelines as set forth in the joint motion requesting approval of the Settlement Agreement.

---

[5] PG&E states that under post-AB 1890 ratemaking now in effect, the burden of uneconomic bypass, should PG&E's rates not be approved, will similarly fall on either ratepayers (in the form of a later end to the rate freeze) or shareholders (in the form of a larger transition cost write-off) depending upon headroom.

Regarding Schedules E-36 and E-37, PG&E contends that these schedules are designed to increase revenues, benefiting both ratepayers and shareholders, and to further state and federal policy objectives, not, as ORA claims to support failing businesses. Further, PG&E points out that it has presented quantitative studies, which ORA did not contest, demonstrating that these schedules will increase PG&E's net revenues by approximately $2 million due to increased oil production and electric usage. Thus, according to PG&E, if the Commission adopts the Settlement Agreement, the Commission will not establish a precedent that "corporate welfare" is a justification for approving a new tariff under § 378.

PG&E disputes ORA's argument that the marginal cost floors used in the settlement are unacceptable because they ignore the marginal costs that the Commission adopted in PG&E's 1996 General Rate Case D.97-03-017. PG&E states that the marginal costs floors used in the Settlement Agreement are not new. They are the same floors proposed in this proceeding by PG&E and adopted in the Proposed Decision, and are completely consistent with the marginal costs adopted in D.97-03-017. In fact, as PG&E has already explained, the marginal costs adopted in D.97-03-017 are adjusted only where appropriate in unconstrained areas where the system average cost estimate clearly overstates the actual costs that would be avoided by PG&E should selected customers bypass.

Further, according to PG&E, its proposed marginal cost floors are in conformance with § 1708, which states that the Commission may, at any time, upon notice to the parties, alter or amend any order or decision that it has previously made. PG&E points out that the parties had ample notice of PG&E's proposal and had a full opportunity to respond through five days of hearing, and briefs. Thus, PG&E submits that the Commission may adopt the Settlement Agreement, which includes PG&E's proposed marginal cost floors with an adjustment for unconstrained areas as fully supported in the record of this proceeding.

Next, PG&E addresses ORA's argument that the Settlement Agreement is not in the public interest because it will prevent the Commission from deciding an issue of first impression (the interpretation of § 378), thereby causing parties to unnecessarily relitigate the interpretation of § 378 in the future.

PG&E points out that the original Proposed Decision discusses the applicability and interpretation of § 378 and that the Settlement Agreement does not change the original Proposed Decision's outcome on this issue, except for two minor changes[6] for clarification.

Lastly, PG&E addresses ORA's argument that the Commission should reject the Settlement Agreement because it does not adequately explain the basis of the settlement, or the trade-offs that were made in reaching settlement. PG&E points out that disclosing each trade-off, and the reasons for each trade-off, is inconsistent with Rule 51.9, which provides that settlement discussions, including admissions and concessions, are confidential.[7] PG&E points out that there is ample record evidence to support the result reached through settlement in this case. PG&E submits that the Commission would only discourage settlements if it required parties to separately justify every trade-off made in reaching settlement.

Discussion

While we do not adopt the Settlement Agreement, we find merit in much of what it proposes. PG&E should be allowed to engage in fair competition with alternative distribution providers. To the extent that PG&E retains distribution customers on its

---

[6] The Settlement Agreement proposed the following minor revisions to the Proposed Decision's discussion of § 378 interpretation: "At page 6, at the end of the first full paragraph, at line 7, after "new service offerings" insert the word "only." Then insert the following at the end of the paragraph "Nevertheless, we find that PG&E has fully explained in its opening brief at pages 8-10 how each proposed tariff meets each of Section 378's five factors."

[7] Rule 51.9 states, in part, that "Participating parties and their representatives shall hold such [settlement] discussions, admissions, concessions and offers to stipulate or settle confidential and shall not disclose them outside the negotiations without the consent of the parties participating in the negotiations."

system, the costs of PG&E's distribution system (which are relatively fixed, at least in the short term) can be allocated over a larger group of customers. This keeps the distribution component of each customer's rate lower than it otherwise would be, thus increasing the amount of headroom for transition cost recovery. We also agree with the settlement that PG&E should not compete for distribution load that is served by irrigation districts using their CTC exemptions. We believe that this limitation protects ratepayer interests by preventing the potential "exemption chasing" problem identified by Merced. Today's decision, based on the evidentiary record, reaches these same conclusions.

Moreover, we note that the Settlement Agreement includes modifications to the tariffs, requested by Enron, to clarify PG&E's original intent that customers under Schedules E-TD, E-TDI, AG-8, AG-7, E-36 and E-37 are free to choose direct access at any time. If otherwise eligible, both new customers and new load taking direct access service shall be eligible for these tariffs.

The proposed Settlement Agreement, however, does not comply with this Commission's criteria for reviewing settlements: "First, that the settlement commands broad support among participants fairly reflective of the affected interests. Second, that it does not contain terms which contravene statutory provisions or prior Commission decisions." (46 CPUC2d at 552, quoting *Natural Gas Procurement and Reliability Issues*, R.90-02-008, 41 CPUC2d 668, 127 PUR 4th 417, 463 (1991). Settlements "whether contested or uncontested" will also not be approved by the Commission "unless the stipulation or settlement is reasonable in light of the whole record, consistent with law, and in the public interest." (Rules of Practice and Procedure, Rule 51.1(e).)

Neither of these criteria is met in the present case. Although the Settlement Agreement is supported by a broad coalition of parties, including narrowly-based customer groups such as the AECA, Farm Bureau, and the CIPA, as well as some competitors such as SoCalGas and the irrigation districts, it is not supported by either ORA, which represents all ratepayers, or Enron, a major competitor in the electric industry.

Second, although the Commission can approve settlements that are not "all-party," we find serious merit in some of the concerns raised by both Enron and ORA.

We share Enron's concerns that when PG&E offers a customer a discount pursuant to the proposed new schedules, PG&E should provide the customer with an "unbundled" bill that shows each component of the customer's bill (energy, CTC, transmission, distribution, and public benefit program charge). Such information is essential to understanding which portions of the total bill PG&E is proposing to discount and in what amount.

As both ORA and Enron point out that it is necessary to know which of the unbundled elements of the total bill are being discounted because each component is subject to different ratemaking treatment and statutory limitations. As Enron notes, as of January 1, 1998, PG&E's transmission rates will be set by FERC, not this Commission. Therefore, it is unclear how PG&E can propose to discount these rates. Similarly, under our own jurisdiction, we are statutorily required to ensure that both the CTC and public benefit programs charge components of the energy bill are collected on a non-bypassable basis. This precludes any discounting of these elements.

Even more troubling, the Settlement agreement specifically allows for the discounting of CTC in cases where "a competitor is offering to pay the customer's CTC." This provision is open to potential abuse and violates our policy on discounting CTC. In addition, it is unclear what valid public purpose this goal serves. To the extent a competitor chooses to pay a customer's CTC, it will be paying that money to PG&E. Thus it is unclear what advantage PG&E gains by trying to match this discount. If cost-effective, PG&E can discount its distribution component to retain a customer. If, after discounting its distribution component, the total rate offered by PG&E is still higher than that offered by its competitor, than we see only two potential outcomes. Either PG&E's competitor is a lower cost provider, in which case it is engaging in "economic bypass," or perhaps the competitor is engaging in predatory pricing, in which case PG&E's remedy lies in forums outside this Commission.

This decision resolves this issue by requiring PG&E to provide unbundled bills each time it offers a discounted contract. Because PG&E is allowed to offer these contracts prior to January 1, 1998, it is necessary for PG&E have unbundled rates for these tariffs prior to January 1, 1998 as well. This provision is not in the Settlement Agreement.

Also, we are troubled by the recommendation in the Settlement Agreement to allow SoCalGas to make an expedited proposal through an <u>advice filing</u>, to amend its competitive options to include customer-specific marginal costs and ratemaking treatment similar to that which the Settling Parties find reasonable for PG&E. This proposal raises due process and notice requirements. Additionally, the Commission, in its SoCalGas performance-based ratemaking decision (D.97-07-054). has just addressed at its meeting of July 16, 1997, the ability of SoCalGas to offer discounted contracts. Therefore, we reject this recommendation.

Finally, in not accepting the Settlement Agreement we are choosing to be more circumspect about many issues that have potentially broad consequences. This is one of the first proceedings where the Commission has had to address the issue of interpreting § 378 relating to the provision of new tariff and service options. Because interpretation of this issue has potential implications for other proceedings, we prefer to adopt our own interpretation of this statute rather than rely on other parties to define it for us. Similarly, the Settlement Agreement reaches conclusions over the State Legislature's intent regarding the role of irrigation districts in competing in the electricity distribution market. We do not need to address this issue in this decision.

The decision we are adopting is based on the evidentiary record developed in this proceeding. In many respects, it reaches the same conclusions and outcomes recommended by the Settling parties. Where it differs from the Settlement Agreement, is where we address valid concerns raised by ORA and Enron in their comments.

Under Rule 51.9 of our Rules of Practice and Procedure, where a settlement is not adopted by the Commission, "the terms of the proposed stipulation or settlement are also inadmissible unless their admission is agreed to by all parties joining in the proposal." Therefore, we must reach our decision based not on the proposed settlement but instead on the evidentiary record prepared in this proceeding. Unlike most other settlement offer which are filed during the early stages of a proceeding, this settlement offer came after the close of hearings and and an oral argument before the full Commission. Therefore, we have an ample record upon which to base our decision. The following sections outline each issue, the positions of the parties, and our resolution.

4. PU Code § 378

Several parties claim that some or all of PG&E's rate design window proposals are prohibited by AB 1890.

Position of ORA

ORA argues that PG&E is prohibited from offering several of its rate design window proposals. It requests that the Commission consider whether such rate design window proposals are consistent with AB 1890 and § 378.

ORA suggests that PG&E's rate design window proposals might not meet the requirements of § 378. According to ORA, PG&E's discounted bypass options are contracts rather than tariffs or rate schedules; PG&E's proposals do not pre-identify the rates that will be applicable; and they do not comply with § 378 language allowing "new optional rate schedules and tariffs." In addition, ORA questions whether the proposals meet the § 378 requirements of serving a customer class or subclass.

Position of Merced

Merced argues that the proposed Schedules E-TD and E-TDI violate AB 1890 in at least three ways. First, it would give PG&E the discretion to discount a customer's CTC obligation in violation of § 371(a), which makes the CTC obligation mandatory except for specific exemptions authorized by the Legislature in §§ 372 and 374.

Second, Merced argues that these schedules violate § 378, in that the proposals involve individualized contracts for specific customers and not the "rate schedules or tariffs" for "customer classes or subclasses" authorized by that statute.

Third, Merced argues that these schedules violate the rate freeze provisions of § 368(a), which expressly state that rates must be set at June 10, 1996 levels. According to Merced, the explicit purpose of PG&E's proposals is to offer discounts below the rate freeze levels, under the guise of creating a "new" rate for specified customers.

Position of PG&E

PG&E contends that all its proposals are consistent with the plain language of § 378 in that they are all "new optional rate schedules" fitting the broad criteria of accurately reflecting "loads, locations, conditions of service, cost of service, and market opportunities of customer classes and subclasses."

PG&E notes that the Commission has already interpreted § 378 as follows:

> "Section 378 allows the Commission to authorize new optional rate schedules and tariffs that 'accurately reflect the loads, locations, conditions of service, cost of service, and market opportunities of customer classes and subclasses.' <u>The ability to fit new services and options to changing market conditions will be particularly important after direct access becomes available</u>." (D.96-12-077, mimeo. p. 10, emphasis added.)

PG&E argues that with direct access now imminent, "market opportunities" and "market conditions" will change considerably during the transition period and beyond; therefore, the Commission should not now unnecessarily burden itself and the utilities it regulates with rigid, preset definitions of § 378 that may later prove too narrow to allow flexible responses to future developments. PG&E believes that the Commission should instead construe § 378 broadly in accordance with its plain language's meaning and on a case-by-case basis, in light of the facts relating to each instance of "changing market conditions." According to PG&E, this is consistent with the principle of statutory construction, that a statute is to be interpreted as broadly and liberally as possible given the words and intention of the Legislature. (*Pasadena Univ. v. County of L.A.*, 190 Cal. 786, 790-01 (1923); *Gay Law Students Assn. v. Pac. T. & T. Co.*, 24 Cal. 3d 458, 478 (1979).)

Further, PG&E disputes the contentions of ORA and Merced that its rate proposals are barred under § 378 because they are "contracts" for one customer not constituting a "subclass." PG&E argues that § 378 authorizes such flexibility because the Legislature is deemed to have been aware of the Commission's long-standing administrative practice of allowing discounts to avoid uneconomic bypass by an entire subclass of customers, such as in PG&E's 1995 Rate Design Window proceeding

(D.95-10-033) and Southern California Edison Company's (Edison) Flexible Pricing options proceeding (D.96-08-025), in which the Commission adopted tariffs which included pre-approved, discounted generic contracts similar to those proposed here.

Position of AECA

AECA argues that both ORA and Merced overlook the clear language of § 378. According to AECA, there is no need to cipher whether these proposed services are being authorized as "rate schedules" or "tariffs," or to discern the "true nature" of a rate schedule or tariff. Nor is it necessary to debate whether a class, by definition, must have more than one member.

AECA submits that the rate design window options proposed by PG&E are by any rational definition "new service offerings." They are applicable to entire classes in some instances, or to a subclass within the class.

AECA disputes the claim that the Rate Design Window proposals are being offered to individual customers that meet certain criteria, not to a customer class or subclass. First, according to AECA, by describing the criteria of those customers that are eligible, PG&E has, in essence, created a subclass of customers. It has not identified specific customers. And AECA argues that, moreover, the fact that the class or subclass of customers may be small is of no consequence. Having a rate schedule that is applicable to a single customer is not unheard of. For example, PG&E's electric department is the only entity that is eligible for Schedule G-EG – Intrastate Gas Transportation Service for PG&E's Electric Generation Departments. Also, AECA points out that in the past, utilities have had individual tariff sheets for sales to specific customers, such as SoCalGas' tariff for Long Beach. According to AECA, the claim that a single customer cannot be a subclass for ratemaking purposes is contrary to past and present practice.

Discussion

Because this is the first case to interpret § 378, we disagree with PG&E's and AECA's recommendation to broadly interpret this section. Instead, for the present time, we choose to err on the side of caution and narrowly interpret this section. This is particularly important since we have not yet adopted any major decisions addressing rate design in our restructured electric industry. The overall purpose of AB 1890 is set forth in the initial paragraph of the legislation:

> "... It is the intent of the legislature to ensure that California's transition to a more competitive electricity market structure allows its citizens and businesses to achieve the economic benefits of industry restructuring at the earliest possible date, creates a new market structure that provides competitive, low cost and reliable electric service, provides assurances that electricity customers in the new market will have sufficient information and protection, and preserves California's commitment to developing diverse, environmentally sensitive electricity resources." (AB 1890, Section 1(a).)

In order to achieve that goal, § 378 allows the Commission to "authorize new optional rate schedules and tariffs, including new service offerings." And § 378 presents a list of five factors which optional rate schedules and tariffs, including new service offerings, are to "accurately reflect" – "loads, locations, conditions of service, cost of service, and market opportunities." We will examine each proposed tariff to ensure that it complies with each of the five criteria laid out in § 378. Because we are choosing to narrowly define the applicability of § 378, we will offer only the following general guidance as to the policy issues we should consider as we review the goal of AB 1890 and § 378. First, § 378's emphasis on accurately reflecting loads, location, and cost of service all argue that any rates we adopt should be based on sound economic principles of cost-causation. The need to accurately reflect loads would also argue for rates that should increasingly be based on time-of-use principles that take into account the daily and seasonal variation of energy prices over time and reflect those costs (either through metering or load profiling) to the end-user. The requirement that rates under § 378 shall accurately reflect "market conditions" recognizes that different customers may have different competitive options available to them. AB 1890's requirement that we should "achieve the economic benefits of industry restructuring at the earliest possible date" implies that we should look for "win-win" situations in which rates better reflect cost while at the same time collection of the CTC is accomplished as expeditiously as possible. Finally, any rate schedule adopted under § 378 should be consistent with, and not conflict with, all other applicable provisions of AB 1890.

Also, we agree with PG&E and AECA that many tariffs have corresponding "contracts," "service agreement forms," or "affidavits." These include nonfirm service, standby service, agricultural DAP or GAP service, Schedules E-19 or E-20 optional optimal billing period service, and the 1995 Rate Design Window proceeding generic contracts. Section 378 and the rest of AB 1890 also allow "new service offerings" and contain no language to the effect that these types of tariff-related contracts are forbidden or that all new tariff options must have pre-existing or pre-identified specific rates. Contrary to ORA's assertion that a tariff or rate schedule cannot have "fill in the blank" results, PG&E's existing Economic Development rate (Schedule ED) has fixed discounts off otherwise-applicable rates, while the 1995 Rate Design Window proceeding generic contracts can have similar fixed discounts off otherwise-applicable rates, as well as individually varying discounts pegged to alternate providers' competing rates. PG&E's 1997 Rate Design Window proceeding bypass option proposals parallel this latter Commission-approved arrangement for varying discounts on PG&E's 1995 generic contracts.

We agree with Merced's argument that Schedules E-TD and E-TDI potentially give PG&E the opportunity to discount a customer's CTC obligation in violation of § 371(a). In reviewing PG&E's amended Schedules E-TD and E-TDI we will need to address this issue and whether these proposed tariffs accurately reflect the "market conditions" faced by the targeted customers.

On the other hand, we disagree with Merced's interpretation of § 368(a) to mean that since all rates must be frozen at June 10, 1996 levels, the rate freeze therefore precludes utilities from offering discounted rates. If the Legislature had intended to preclude utilities from offering new or discounted rate options to its customers, it would not have included § 378 in AB 1890. The § 368(a) requirement that rates be frozen at June 10, 1996, levels governs only those tariffs which already existed as of June 10, 1996. Section 378 would be meaningless if it did not give utilities the ability to offer new rates at other than the June 10, 1996 levels to respond to the "market opportunities of customer classes and subclasses."

Therefore, we will examine each individual rate design window proposal on its own merits.

5. Schedule AG-7

PG&E's proposed Schedule AG-7 agricultural tiered rate would automatically bill customers at an appropriate rate depending on the customer's monthly usage. Schedule AG-7 automatically places a customer in Tier 1 if it has low monthly operating hours or Tier 2 if it has high monthly operating hours.

Schedule AG-7 is a voluntary time-of-use (TOU) rate, designed to help many agricultural customers manage their rate schedule selections. Rainfall, floods, droughts, and unpredictable surface water availability make it difficult for agricultural users to predict pumping needs and select the least-cost rate schedule. This schedule will provide a convenient method for these customers to be assured that their rates adjust to their monthly operating hours. Although the rate may result in higher bills in certain months or years for some customers, the rate will serve as insurance against bill fluctuation for customers with varying usage.

AECA enthusiastically supports PG&E's proposed Schedule AG-7. AECA agrees with PG&E that the schedule attempts to ameliorate the vagaries of trying to predict which rate schedule one should select, based on a forecast of electric needs which is largely driven by weather-related conditions outside the control of agriculture users.

However, AECA is concerned that agricultural users make an informed choice in opting for this schedule. AECA notes that PG&E has agreed to AECA's recommendation that PG&E undertake an education program with the AG-7 rate proposal. This program would explain not only the possible benefits of the rate schedule, but should accurately discuss the risks of selecting such a rate option.

Farm Bureau also recommends adoption of Schedule AG-7. Farm Bureau believes that as the electric industry makes its transition to a new market, the affected utilities should be allowed to serve customers in ways that make sense. Farm Bureau expects many agricultural customers will continue to take bundled service through existing utilities as the transition is made, and it believes the Commission would be remiss if rate design were allowed to stagnate in the process.

Farm Bureau points out that the proposed schedule, which is directed at reducing the need for customers to switch between schedules, addresses a change in rate treatment which was instituted in 1996. That is, customers are now charged a significant processing fee for migration between TOU schedules. Thus, even if a customer predicts a usage change requiring movement to a different schedule, the customer must pay a fee. Farm Bureau agrees that the proposed schedule will reduce the necessity for such processing fee assessments.

However, SoCalGas does not share the enthusiasm of AECA and Farm Bureau for PG&E's Schedule AG-7 proposal. SoCalGas points out that this rate schedule incorporates rates for each tier that are higher than the comparable rates found in other existing agricultural schedules that are targeted at specific, consistent levels of monthly usage. And the "revenue neutrality" of this proposal is solely derivable from the assumption that at least 40% of its participating ratepayers lose money through their participation therein. According to SoCalGas, this is a win-lose proposition for PG&E's ratepayers which the Commission must not endorse.

ORA views Schedule AG-7 as PG&E's response to the pressures it is facing in the agricultural sector from alternative engine water pumping options and irrigation districts. According to ORA, from this perspective, PG&E's proposals are a marketing effort to increase the loyalty of its agricultural customers. ORA does not object to this effort but believes that any revenue loss due to the marketing of these schedules should be borne by, in the first instance PG&E shareholders, or, if the Commission rejects this ORA proposal, then by agricultural customers themselves. ORA argues that since PG&E appears confident that marketing of such schedules will not reduce its revenues, it should be willing to take on this obligation.

Discussion

There is an undisputed need by agricultural users for the type of schedule that PG&E has proposed. We believe that agricultural users are sufficiently astute to understand that the type of "insurance" offered by this schedule is not free. Properly designed educational materials discussing the down-side of this schedule should address SoCalGas' concern.

We share the concerns of ORA and SoCalGas that this program may not be revenue-neutral and thereby imposes additional costs upon other ratepayers. This assumption is achievable only if 40% of the participants who sign up for this voluntary schedule end up paying higher rates than they otherwise would have. If, in practice, this 40% is not achieved, then there could be a revenue shortfall. As AECA and Farm Bureau note, these customers have a much harder time predicting their energy usage since it is far more dependent on outside factors (e.g., weather, drought) than other customer classes. Since we have not required shareholders to be responsible for such shortfalls in the past (or credited any surplus to shareholders), we see no reason to do so in this case. To limit any potential down-side effects upon ratepayers, Schedule AG-7 will be available to a maximum of 5,000 accounts on a first-come basis, so that the impact of the schedule may be evaluated before allowing general enrollment. Schedule AG-7 is authorized only on an experimental basis, as this schedule presents a new rate concept.

With regards to Schedule AG-7's compliance with the requirements of § 378, since this is a TOU rate it is consistent with the requirement of accurately reflecting loads. This proposed tariff is also consistent with the other criteria established in AB 1890 in that it is based on an underlying agricultural tariff already adopted by the Commission, which means it should be largely reflective of the conditions of service, cost of service, and locational attributes of these customers.

We conclude that proposed Schedule AG-7 should be adopted.

6. Schedules E-36 and E-37

Schedules E-36 and E-37 are designed to stimulate oil pumping activity and are available to customers in Standard Industrial Code (SIC) 1311 (crude petroleum and natural gas extraction). Because these oil pumping operations are very similar to agricultural pumping operations, Schedules E-36 and E-37 are based on agricultural rate schedules. Schedule E-36, a non-TOU, non-demand schedule for smaller oil pumping accounts, is revenue-neutral to agricultural Schedule AG-6B. Schedule E-37, a TOU demand schedule for medium or large oil pumping accounts is based on agricultural Schedule AG-5B. Customers voluntarily selecting optional Schedules E-36 or E-37 who have maximum demands over 500 kW must take service on Schedule E-37, to equitably preserve the current Commission requirement of mandatory TOU service for customers with maximum demands over 500 kW.

PG&E estimates it currently has 1,050 oil pumping accounts classified in SIC 1311. These accounts serve approximately 60,000 active wells and 15,000 to 18,000 idle wells. PG&E estimates that Schedules E-36 and 37 will result in approximately 1,200 idle wells being returned to operation. These accounts are located primarily in low-cost rural distribution planning areas, and have an average marginal cost of service of only three cents per kWh, as opposed to five cents per kWh for Schedule AG-5B, under adopted January 1, 1996 marginal costs of service.

The California Independent Petroleum Association (CIPA) supports proposed Schedules E-36 and E-37. According to CIPA, these schedules offer oil producers, PG&E, PG&E ratepayers and the California economy a win-win situation.

CIPA points out that California has one of the highest percentages of idle wells of any of the large oil and gas producing states, yet offers few of the incentives offered by other large oil producing states. Also, over 80% of the oil producer accounts on the PG&E system pay small commercial rates which do not reflect their loads, locations, costs of service, conditions of service or market opportunities. The proposed new optional rate schedules afford oil producer customers a cumulative bill reduction of approximately 17%, which, CIPA contends, is fully justified on a traditional cost-of-service basis. This, according to CIPA, is clearly a benefit for oil producers, primarily the small operators who make up the majority of independent producers. CIPA estimates that these schedules will result in savings of between $2.5 million and $3 million dollars annually for these customers.

Further, CIPA points out that for the estimated 1,200 idle wells that would be returned to service, the total revenue increase would be approximately $4.7 million annually. There will be a net increase in PG&E electric revenues from this rate subclass that will accelerate transition cost recovery, a benefit for both ratepayers and shareholders. The amount of the net increase in revenue is estimated to be between $1.9 million and $2.2 million annually.

The Division of Oil, Gas and Geothermal Resources points to Senate Bill (SB) 2007, which provides incentives to return long-term idle wells to production, and urges the Commission to adopt PG&E's proposal.

All parties, except ORA, agree that the increased revenues will benefit both PG&E shareholders and ratepayers. We conclude that proposed Schedules E-36 and E-37 should be adopted and are consistent with § 378.

7. Schedules E-TD and E-TDI

These proposed rate options are designed to permit PG&E to offer competitive alternatives to customers who are either contemplating uneconomic bypass of PG&E's system or who might begin to take service from PG&E, but have offers from T&D competitors.

Schedule E-TD provides PG&E with pricing flexibility to compete with other T&D service providers to retain existing customers who would otherwise uneconomically bypass PG&E's T&D system.

Schedule E-TDI gives PG&E pricing flexibility to compete with other T&D service providers for new customers who could be served by PG&E's T&D system. The rate can be offered in two different situations. First, it could be offered to new customers that will be locating facilities within PG&E's service territory, but who have the option to hook up to either PG&E's or an alternative provider's T&D system.

Second, the rate might be offered to attract nearby customers of other T&D service providers under the reciprocity provisions of AB 1890.

Both schedules, as originally proposed, are limited to customers with loads above 200 kW.[8] To qualify for the rate, if not already being served by a competing T&D provider, a customer must be able to demonstrate to PG&E's satisfaction its ability and willingness to take service from the competing T&D provider. To do this, the customer must provide evidence documenting the offer it has received from PG&E's competitor. PG&E will then evaluate the offer to determine if the alternative service appears technically and financially feasible, and to ensure that there are no environmental or legal barriers to the transaction. Finally, the customer will have to sign an affidavit stating that PG&E's competitive rate offer is the deciding factor in its decision to remain on the PG&E system.

PG&E proposes to file each contract with the Commission within 30 days after execution, and it will be available for review by all without any confidentiality restrictions since none are necessary due to the nature of the information contained in the contract agreement forms (see Appendix B). All of the terms of Exhibit A to the contract agreements, with the exception of any specific customer usage information, will be publicly available as well. In addition, these contracts will be subject to reasonableness review. Both the lack of confidentiality and the presence of reasonableness reviews are significant differences from PG&E's 1995 Rate Design Window generic contract rates dealing with customer responses to out-of-state competition.

PG&E's competitive rate will be tied to published tariff rates or the customer's individual offer for the alternative service so that it just matches, but does not beat, the other offer at most. It will be subject to a floor of customer-specific marginal cost plus

[8] The Settlement Agreement, would have reduced this requirement to 20 kW to address the concerns of AECA and Farm Bureau that the schedules be available to more smaller customers.

20%,[9] to ensure positive contribution to margin. Customers may terminate their agreements at any time without penalty.

Position of PG&E

According to PG&E, a $209 million total revenue shortfall during the transition period would result if it is not allowed to offer a competitive response to current and future market activity. PG&E contends that if its proposals are not adopted, other T&D providers will have ability to construct duplicate T&D lines into PG&E's existing service territory to serve select PG&E customers, to the detriment of PG&E's remaining ratepayers. The revenue shortfall will occur not only as a result of irrigation district activity related to CTC exemptions, but also from other entities without CTC exemptions, including municipal utilities, "over-the-fence" cogeneration facilities and new T&D providers which are entering the T&D business.

PG&E points out that it has an obligation to serve all customers in its service territory under its approved tariffs. These new T&D providers do not have such an obligation and, according to PG&E, are poised to exploit their ability to pick and choose those PG&E customers which will be the most profitable to serve. These competitors often have the benefit of institutional tax advantages and federally subsidized power generation and typically have much greater pricing flexibility than PG&E, with the ability to change their prices quickly to meet market needs.

According to PG&E, of the $209 million total revenue shortfall estimate, $41 million would occur from the following irrigation districts which were recently awarded CTC exemptions by the California Energy Commission (CEC): Modesto, Fresno, South San Joaquin, and Laguna. An additional $71 million would be due to the 75 MW of CTC exemptions granted to Merced. Section 374(a)(2) provided Merced with

---

[9] In situations in which no § 374 CTC exemption is being used, clarifying language has been added to the proposed schedules noting that PG&E's offer under Schedule E-TD or E-TDI will never go below the sum of its customer-specific marginal cost plus 20% plus the customer's CTC obligation.

CTC exemptions for 75 MW of load without having to compete via the CEC allocation proceedings.

PG&E points out that Merced has been serving former PG&E customer Foster Farms since May, 1996 and is currently completing engineering and design on a duplicate distribution line to serve select PG&E customers in the City of Livingston. Merced is also conducting public hearings and environmental review on a proposed route for a 33-mile transmission line to serve select PG&E customers in the Castle, Merced and Atwater areas.

Also, according to PG&E, the remaining $97 million of the $209 million total revenue shortfall estimate will not be related to irrigation district CTC exemptions at all. This T&D bypass would occur from "over-the-fence" cogeneration, from entities that are not eligible for CTC exemptions, and from irrigation districts which, after exhausting their CTC exemptions, will continue to expand their duplicate T&D systems.

PG&E submits that it is a common perception that uneconomic bypass will somehow be limited to load served through CTC exemptions. PG&E contends that this perception is wrong. According to PG&E, there are new competitors entering the market which do not plan to use CTC exemptions at all to develop their T&D systems. The Crossroads Irrigation District is one example of an entity that was formed post-AB 1890 which acknowledges the CTC obligations of the customers it plans to serve yet which still plans to serve customers in a nearby industrial park.

Further, PG&E points out that in addition, many irrigation districts with exemptions have explicitly stated that they plan to keep growing long after their CTC exemptions are used up. For example, the Fresno Irrigation District in its CTC exemption application to CEC requested a 40 MW exemption to serve 59.3 MW of customer load by 2001. The South San Joaquin Irrigation District has stated its intent to connect new customers into the year 2006. The Pittsburg Power Company, which is not eligible for a CTC exemption, is marketing itself to industrial customers which would locate in PG&E's service territory.

Regarding the pending sale of its distribution system in four San Joaquin Valley cities to Modesto, PG&E states that if the service area agreements are approved, the shortfall during the transition period due to T&D bypass would be $162 million (78% of the original estimate) and CTC shortfall would be $38 million (83% of the original estimate). If the proposed agreements are not approved, the shortfall estimate would remain at $209 million and the CTC shortfall estimate would remain at $46 million.

PG&E argues that its proposed schedules are intended to advance fair competition. Under its schedules, PG&E would not be able to price below customers' competitive alternatives. The best PG&E could ever do would be to match each competitive alternative. Where the customer is not obligated to pay a CTC to PG&E, PG&E's offer would be, at best, equal to the documented competitive offer. In the case where the customer would still be obligated to pay PG&E a CTC should it depart, PG&E would not price below the sum of the competing price plus the customer's CTC obligation. Thus, in either case, the outcome would be the same -- PG&E can never price below the competitive alternative.

PG&E points out that the proposed schedules would not become effective prior to the date that the customer would have received service under the competing offer. In other words, if the competitive offer required construction of a duplicate distribution line that would take six months to construct, PG&E's competitive offer would not become effective for six months. Thus, PG&E's proposed competitive response would be at best equivalent, from the customer's perspective, to the competing offer, both in price and in its effective date.

PG&E contends that its proposed Schedules E-TD and E-TDI will not hinder the development of competing T&D providers. According to PG&E, these tariffs will simply provide customers with an additional choice when presented with an offer from a competing T&D provider. They will also result in increased CTC collection and contribution to margin for PG&E's remaining customers that are not within the geographic reach of these selective competitors or which do not posses the load characteristics which would make them desirable to serve. PG&E believes that rather than allowing PG&E's competitors the unfettered ability to cherry pick selected PG&E customers at the expense of remaining ratepayers, PG&E's rate proposals will provide customers with an additional choice and will encourage competitors, including PG&E,

to differentiate themselves to customers based on higher reliability, better customer service, and other non-price attributes -- the essence of a competitive marketplace.

Position of ORA

Aside from ORA's argument that PG&E's proposed schedules are in violation of § 378, ORA takes exception to PG&E's proposal to develop marginal cost floors based on classifying Transmission Planning Areas (TPA) and Distribution Planning Areas (DPA) as constrained or unconstrained. ORA points out that in PG&E's last general rate case, it also proposed area-specific marginal costs. In D.97-03-017, the Commission rejected PG&E's proposal because of concerns about the accuracy of the underlying studies. However, the Commission left open the possibility to reconsider PG&E's proposal upon production of new studies. According to ORA, PG&E has failed to produce any new studies to justify classifying TPA or DPA as constrained or unconstrained. ORA submits that pursuant to recent Commission precedent, the Commission should reject PG&E's proposal to set marginal cost floors based on classifying TPA and DPA as constrained or unconstrained because no new studies have been provided.

ORA argues that in the event the Commission approves PG&E's proposals, the Commission should also retain a liquidated damages provision, as originally proposed by PG&E, to reduce litigation and incent contract compliance. Also, ORA argues that the Commission should impose the same ratepayer protections as adopted in D.96-08-025, that is, any CTC that is not recovered should be borne by shareholders. Further, according to ORA, any CTC that is identified during the term of a contract as borne by shareholders should not be shifted back to the discount customer if the customer exercises other competitive options, either after the term of the contract or under early termination options.

Further, ORA argues that the Commission should not allow for price discrimination based upon market power. According to ORA, PG&E's discriminatory approach may result in price discrimination based upon a customer's market power.

ORA contends that rates should not be a function of the bargaining power of a particular customer, and discounts should apply to all similarly situated customers.

ORA argues that the discretionary aspect of PG&E's proposals means that California does not fully realize the fruits of true competition. For instance, lower prices are one benefit of true competition. Under PG&E's discretionary proposals, only a few customers see lower prices, and discounts will be offered only to the extent necessary to preclude entry by potential competitors. According to ORA, if PG&E's proposals are adopted, entry will be discouraged and PG&E will remain the sole T&D provider.

ORA states that it has not taken a stance on the issue of whether T&D competition should be promoted. ORA recognizes that in theory greater efficiency may result from one provider. ORA submits that in the event the Commission favors competition between irrigation districts and PG&E, the Commission should ensure that PG&E's proposals do not hinder competition.

Position of Merced

Merced argues that the concept that PG&E should have the discretion to selectively discount (or waive entirely) an individual customer's CTC obligation violates the provisions of AB 1890. According to Merced, AB 1890 explicitly addresses the application of CTC's to PG&E's customers and to irrigation districts competing to serve them. It provides specific exemptions from the CTC obligation for an expressly limited amount of load to be served by certain irrigation districts, as well as addresses in detail the application of the CTC obligation to many other competitive situations. Merced contends that this balancing of interests by the Legislature provided PG&E with many substantial benefits, a fact reflected by PG&E's support of this legislation. And, having obtained the benefits of its legislative bargain,[10] PG&E now seeks to deprive the

---

[10] According to Merced, among the most significant benefits PG&E obtained in AB 1890 is the application of CTCs to <u>any</u> customer departing to an irrigation district. Prior to AB 1890, irrigation districts had been authorized by state law to compete in the T&D market with IOUs with <u>no</u> CTC obligations. (Water Code § 22120.) These laws have been on the books for more

Footnote continued on next page

irrigation districts of their benefits. According to Merced, PG&E seeks to do so by obtaining from the Commission the discretion to discount CTC's in a manner not authorized by AB 1890.

Further, Merced argues that PG&E's proposal produces the absurd result that where PG&E's competitor has no CTC exemption, PG&E's uneconomic costs would be a mandatory obligation if a customer departed PG&E, but would be discounted if the customer remains with the company. Merced contends that in this circumstance, PG&E's proposal would place a greater obligation to collect PG&E's uneconomic costs upon PG&E's competitors than upon PG&E itself.

Lastly, Merced argues that the passage of AB 1890 has fundamentally altered the rate impacts of anti-bypass contracts such as proposed by PG&E. According to Merced, the rate freeze, the CTC exemptions and the CTC collection limitations in particular make the impacts of such contracts very different today than prior to AB 1890. Merced submits that due to these new statutes, the contribution to margin analysis which underlies PG&E's proposal here no longer assures ratepayers of benefits from these rates.

Position of Modesto

Modesto argues that Schedules E-TD and E-TDI ignore most of the elements that must be considered in adopting a rate schedule under § 378. Thus, while the Commission is required to adopt optional tariffs, those tariffs must accurately reflect the loads, locations, conditions of service, cost of service and market opportunities of customer classes and subclasses.

According to Modesto, PG&E made it clear that the only relevant factor in determining the rate to be offered to a particular customer was a competing offer, and PG&E gives none of the factors set forth in § 378 even cursory consideration. It will not

---

than a half century and have nothing to do with this Commission's restructuring efforts. Thus, according to Merced, the limited "exemption" from CTCs for some irrigation districts represent a significant compromise by such districts from their prior position in which their customers had no CTC obligation at all.

consider load, location, or the cost or conditions of service. Nor will PG&E offer the rate to a class or subclass of customer – only the customer who has received a competing offer will be eligible for the rate.

Modesto argues that even if the Commission were to allow a rate class to be defined by the competition, rather than characteristics of service, the proposed schedule must still be rejected, as it fails to accurately reflect each of the remaining elements required under § 378.

Also, Modesto argues that these schedules must be rejected because they are ambiguous. Modesto points out that under the section entitled "Applicability," the schedules provide: "This tariff is available to qualified customers, at PG&E's discretion." (Emphasis added.) According to Modesto, PG&E cannot articulate to whom the schedules would be offered, or to what extent PG&E has or may exercise discretion.

Lastly, Modesto argues that absent any specificity as to the conditions under which a rate would be offered to a customer, the Commission is not able to determine, as it must under § 451, whether the rate offered to a customer is just and reasonable, nor can PG&E establish, as required by § 453, that it is not making or granting "any preference or advantage to any corporation or person or [subjecting] any corporation or person to any prejudice or disadvantage."

Position of Laguna

According to Laguna, it is apparent from review of § 374 that the Legislature specifically intended that irrigation districts enter the power market. Laguna contends that, however, PG&E's proposed Schedules E-TD and E-TDI would have the practical effect of undercutting and rendering meaningless those exempted power allocations because PG&E's rate proposals would quash new power suppliers.

Laguna asserts that the most disruptive by-product of PG&E's proposed schedules is the effect upon new competitors facing start-up costs. Laguna will necessarily include an incremental charge in its service rate structure to recoup the cost of entering the market. The rates Laguna will charge will necessarily be higher than they would have been had Laguna already had an operational transmission and distribution system. Therefore, Laguna contends that PG&E's proposals would undercut and squeeze Laguna and other new competitors out of the market.

Further, Laguna argues that the Legislature has found that the greatest benefits which ratepayers and the state in general will enjoy will not come through a continued monopoly and rate restructuring as PG&E proposes, but rather through increased competition which will be fostered by the workings of AB 1890 itself:

> "The [Public Utilities Commission] has found, after an extensive public review process, that the interests of ratepayers and the state as a whole will be best served by moving from the regulatory framework existing on January 1, 1997 . . . to a framework under which competition would be allowed in the supply of electric power and customers would be allowed to have the right to choose their supplier of electric power." (PU Code § 330(d).)

Laguna contends that to give meaning and purpose to the Legislature's mandate to foster greater competition, PG&E cannot be allowed to dry up the market with a reduced rate structure that will eliminate new competitors.

Further, Laguna argues that § 368(a) requires a freeze on rates at the level they were at on June 10, 1996, and this freeze on rates establishes the base amount by which all future cost recovery increments and rate reductions will be measured. According to Laguna that there is no authorization for a specialized rate reduction to PG&E separate from the method established in AB 1890. Therefore, Laguna submits that the Commission is without authority to establish a rate structure different than that created by AB 1890.

Next, Laguna addresses PG&E's concern that the use of CTC-exempt power by irrigation districts will help to finance the expansion of non-exempt areas of service. Laguna notes that § 374(a)(1)(D) provides that "at least 50 percent of each year's allocation to a district shall be applied to that portion of load that is used to power pumps for agricultural purposes." Laguna contends that this restriction renders the presumed activity PG&E complains of impractical. According to Laguna, CTC exempt power cannot be used indiscriminately. It cannot be used in varied areas, or even outside of the political boundaries of the irrigation district. Laguna contends that it is appropriately constrained in use to provide relief to agricultural power users.

Further, Laguna contends that the amount of CTC-exempt power allocated to irrigation districts is not so great so as to serve as the foundation for a takeover of the power market, as PG&E would have the Commission believe. The California Energy Commission (CEC) determined that 71 of the 110 megawatts (MW) of the CTC-exempted power would be allocated to PG&E's area. The CEC determined thereafter, based on the applications and presentations of irrigation districts, to divide and allocate that exempted power to several irrigation districts. Laguna received an allocation of 8 MW of exempted power to be phased in over five years. Thus, even those irrigation districts which were allocated a portion of the CTC exempt power will not have the entirety of that exemption until the final year of the five-year term.

Addressing PG&E's contentions that new competitors, using CTC-exempt power, will target the most profitable service connections which PG&E cannot do because of its requirement to serve all connections within its designated service area, Laguna contends that PG&E will no longer be compelled to serve all power users requesting service in its service area.

Laguna argues that it is an expected result that to increase competition, as is the mandate of AB 1890, PG&E in all likelihood will lose some customer base. Laguna believes that PG&E's objective is to undo the mandate of AB 1890, retain all of its existing customer base, and attempt to close the market to new competitors. Since greater competition in the power service market is the goal of deregulation, Laguna submits that if the Commission approves PG&E's proposed rate schedules, it will undermine the ability of new competitors to enter the market, directly contrary to the purposes of AB 1890.

Position of AECA

AECA, which as a general proposition favors competition, urged the Commission to reject Schedules E-TD and E-TDI. AECA contends that the irrigation districts, are nascent competitors and competition from this sector is, by any standard, only starting to emerge and is in its infancy. AECA urges the Commission to give the irrigation districts a chance to get established. AECA believes that if PG&E is allowed to compete against irrigation districts at this time, it will ultimately lead to a lessening of competition.

AECA argues that allowing a reasonable period of time for potential competitors to establish themselves is consistent with the law and with prior court determinations. AECA contends that § 1(a) of AB 1890 acknowledges that California is transitioning to a more competitive market structure; it is not yet there. It urges that customers in the new market have sufficient information and protection. AECA submits that allowing competition to emerge and establish itself is also consistent with the approach that the courts took in the transition from a monopoly telecommunications industry dominated by American Telephone and Telegraph Company (AT&T) to a more competitive environment. According to AECA, to have long-term competition, competitors must be given a chance to emerge and develop in the short term.

Further, AECA argues that while PG&E views Schedules E-TD and E-TDI as tools to prevent cherry picking, allowing PG&E to give discounted counteroffers to potential customers of irrigation districts is sufficient to prevent any potential competitor from ever establishing a foothold to compete against PG&E. AECA contends that by aggressively competing in the early stages, PG&E can effectively maintain its monopoly distributor status. In essence, rather than fostering competition, the proposed schedules will actually lead to a lessening of competition. AECA believes that this is contrary to the intent of AB 1890 and the Commission's electric restructuring program.

AECA points out that the Legislature in AB 1890 recognized that California was in the transition to a more competitive market structure and that it was the Legislature's intent to provide assurances that electricity customers in the new market will have sufficient information and protection. (AB 1890, § 1(a).) To ensure that competition is introduced, the Legislature, as well as the Commission in D.95-12-063 and D.96-01-009, concluded that bodies such as an Independent System Operator (ISO) and Independent Power Exchange should be established. (Section 330(l)(1).) To ensure that utility market power in generation was reduced, the utilities also were ordered to divest themselves of a portion of their electric generation.

Also, AECA argues that the Commission determined and the Legislature affirmed in § 330(l)(3) that there is a need to ensure that no participant in these new market institutions has the ability to exercise significant market power so that the operation of the new market institutions would be distorted. Consequently, AECA believes that AB 1890 requires that the Commission give the emerging irrigation districts the opportunity to establish themselves in this new competitive environment. AECA contends that if an established monopoly supplier such as PG&E is allowed to meet every offer extended by an emerging irrigation district supplier, competition will never develop. AECA believes that to have meaningful competition in the long term, the Commission must at least temporarily restrict PG&E from competing for the anchor customers that are necessary to allow the irrigation districts to get into business.

Position of Enron

Enron's position, as stated for the first time at the Oral Argument on June 23, 1997, is that the tariff language should be modified to clearly indicate PG&E's intent that customers under any of the proposed Schedules AG-7, E-36, E-37, E-TD, E-TDI, and AG-8 are free to choose direct access at any time, and that if otherwise eligible, both new customers taking direct access service and under any of these tariffs shall receive bills that present PX charges (including but not limited to charges for commodity and ancillary services), ISO charges and service charges, and charges for competitive or unbundled services (including but not limited to billing, metering and credits) that are unbundled consistent with methods approved by the Commission for all other direct access customers.

Background

Before considering the positions of the parties it is useful to consider the relative risks that PG&E will face if a customer leaves PG&E to take service from a competing distribution service provider. Prior to restructuring, a customer leaving PG&E's system would have resulted in PG&E losing the entire contribution to margin (CTM) made by that customer. Under electric restructuring, with unbundled rates, PG&E faces a different set of risks, and PG&E's rates will be separated into their various components: energy, CTC, public benefit programs, transmission, and distribution costs.

The goal of restructuring is to make the local utility distribution company (UDC) such as PG&E indifferent to who provides a customer with energy. A customer leaving PG&E's distribution system would have the same effect on PG&E's energy costs as if the customer had chosen direct access. Under either scenario, PG&E would no longer incur the cost of purchasing power for the customer from the Power Exchange.

Prior to restructuring, PG&E would have lost the entire CTM if a customer left its distribution system. CTM represents the difference between what it costs to serve a customer and the amount of revenue that customer brought in through his or her rates. The retention of CTM was the main justification for the utility to offer discounted rates to keep a customer on the system. Although technically different, in many respects CTM is the same as today's CTC, essentially the difference between what it costs to provide service to a customer and today's above-market rates, which include a large component of CTC.

Unlike the days prior to restructuring, PG&E is now able to collect CTC (the modern equivalent of CTM) even if the customer leaves the system to take service from a competing distribution service provider. Except for 185 megawatts of customer load that AB 1890 allows irrigation districts to offer customers exempt from CTC, almost all customers who leave PG&E to take service from another distribution provider are now obligated under AB 1890 to pay CTC to PG&E. Thus PG&E is at only minimal risk of losing CTC (primarily due to forecasting error if the departing customer's calculated CTC turns out to be lower than if the customer had stayed on the system) from distribution bypass.

It is unclear what the effect on PG&E's transmission costs would be if a customer were to leave PG&E's distribution system. After January 1, 1998, transmission rates will be set by FERC, not the Commission, and PG&E will transfer control of its transmission assets to the Independent System Operator (ISO) which will reimburse PG&E, through FERC-approved tariffs, for the cost of PG&E's transmission system. Therefore, it is possible that even if PG&E lost a customer to a competing distribution system, PG&E could still recoup all, or at least a part, of its transmission costs if the competing distribution provider utilized the ISO to transmit power to PG&E's former customer.

Finally, PG&E clearly would lose all revenues associated with distribution and the public benefit programs charge (§ 381) if a customer were to leave PG&E's distribution system. Even here, however, PG&E may be able to mitigate a part of this loss if it were to lease or sell its distribution system to a competing distribution provider that is now serving the former PG&E customer.

Therefore, in assessing the relative risks that PG&E faces if an existing customer leaves PG&E's distribution system for a competing provider, PG&E is at no risk for the energy portion of the bill, little if any risk for CTC collection (as long as the customer did not have a CTC exemption from an irrigation district), some risk for its transmission costs (depending upon its competitor's energy supply source) and is at almost total risk for the distribution and public benefit programs charge portion of the bill.

Discussion

We agree with PG&E that it should be allowed some flexibility so that it can respond fairly to the threat of distribution bypass. For the reasons stated above, we believe PG&E's estimate of lost revenue represents an overly high estimate of PG&E's potential loss. PG&E is at significant risk for the distribution, public benefit programs charge, and to a lesser extent, transmission components of that customer's bill. To the extent that PG&E retains distribution customers on its system, the costs of PG&E's distribution system (which are relatively fixed, at least in the short term) can be allocated over a larger group of customers. This keeps the distribution component of each customer's rate lower than it otherwise would be, thus increasing the amount of headroom under the rate freeze available for CTC recovery.

The Commission has long held that uneconomic bypass is not in the best interests of ratepayers. Indeed, the Commission held that preventing uneconomic bypass conferred a number of benefits on ratepayers:

> "The pre-approved generic discount contracts directly benefit ratepayers by avoiding uneconomic bypass as well as retaining contribution to the utility's fixed costs, thus either holding the line on rates or actually reducing them, whereas rates would be relatively higher if this load were lost or not attracted to PG&E's territory." (D.95-10-033, mimeo. p. 54, Finding of Fact No. 5.)

> "Further, the Commission's policy on uneconomic bypass states that the utility should be allowed to retain the load in the event that it can reduce its prices to 'meet' the competition without reducing its prices below marginal cost. (D.92-11-052, 46 CPUC 2d 446 (1992).) This policy makes sense because it recognizes that the utility should be allowed to compete to retain customers where the infrastructure is already in place to serve a customer." (D.95-04-077, mimeo. p. 20.)

Due to AB 1890, PG&E is at significantly less risk for losing the CTC component of its rate if a customer leaves its distribution system. PG&E is hurt only if that customer is taking power from an irrigation district that is utilizing a CTC exemption. Even in such cases, however, we are not persuaded that PG&E should try and compete for this customer by trying to discount its rates to retain such customers. We agree with Merced's analysis of "exemption chasing" and its conclusion that PG&E could be worse off if it tried to compete for CTC-exempt customers. We believe that preventing PG&E from competing for such customers is in the ratepayers' interest. Allowing PG&E to compete for CTC-exempt load also raises the problem of having to discount CTC (discussed further below.)

Having decided that PG&E should be given some flexibility to compete, we must decide how much flexibility PG&E should receive and how it should be structured.

We share Enron's concerns that when it offers a discounted contract PG&E must provide an "unbundled" bill to the customer that shows each component (energy, CTC, transmission, distribution, and public benefit programs charge.) Such information is essential to understanding which portions of the total bill PG&E is proposing to discount and in what amount.

As both ORA and Enron point out, it is necessary to know which of the unbundled elements of the total bill are being discounted because each component is subject to different ratemaking treatment and statutory limitations. As Enron notes, as of January 1, 1998, PG&E's transmission rates will be set by FERC, not this Commission. Therefore, it is unclear how PG&E can propose to discount these rates. Similarly, as ORA and Merced state, we are statutorily required to ensure that the CTC component of the energy bill is collected on a non-bypassable basis. This precludes any discounting of this component of the bill. Although not explicitly stated by the parties, this same logic applies to the public benefit programs charge portion of the bill which is also non-bypassable under AB 1890.

Section 374 sets the maximum CTC exemption for irrigation districts, establishing an upper bound on how much could possibly be shifted to remaining ratepayers on the same side of the firewall. In fact, other provisions of AB 1890 run contrary to the interpretation of the irrigation districts that the § 374 exemptions are somehow guaranteed to be exhausted.

We believe that the Legislature provided the § 374 CTC exemptions as a vehicle to provide the opportunity, but not a guarantee, for irrigation districts to compete. This is similar to the CTC collection provisions of AB 1890 which similarly provides utilities an opportunity but not a guarantee to collect CTCs.

Importantly, however, AB 1890 gives the Commission no mandate to foster distribution bypass in general or "nascent" distribution bypass. This Commission is under no obligation to subsidize or protect ventures into electric distribution by preventing utility competition. The evidence clearly demonstrates that near-term harm will be suffered by PG&E and its ratepayers caused by reduced CTC collections resulting from cherry-picking of existing PG&E customers by competitors. However, we will limit PG&E's use of these competitive rates to address competition without exemptions under § 374.

As PG&E has made clear, Schedules E-TD and E-TDI as originally proposed were not designed to compete just against irrigation districts with CTC exemptions under § 374. In fact, much of the competitive activity may occur from non-irrigation districts such as over-the-fence cogeneration, service by other T&D providers (e.g., the Pittsburgh Power Company), and irrigation districts not using § 374 CTC exemptions

(e.g., the Crossroads Irrigation District, which has no § 374 exemptions, or irrigation districts with such exemptions who are, for whatever reason, not using a valid exemption for a particular offer.)

Therefore, to assure that the tariffs promote fair competition, the rates should not apply where the competitive offer is made by an irrigation district using a valid CTC exemption under § 374. Not only does this limitation best carry out the Legislature's intent to allow the irrigation districts to maximize their use of such exemptions during the transition period, but it also prevents the potential "exemption chasing" problem identified by Merced. By adopting this and other limitations discussed below, we ensure that, regardless of the amount of "headroom" PG&E ultimately may have for collection of its transition costs, ratepayers will either benefit from these rates or at worse be indifferent.

Also, we require that PG&E's discount authority under Schedules E-TD and E-TDI should not extend to discounting the customer's mandatory and non-bypassable obligation to pay transition costs pursuant to AB 1890. As with the exemptions under § 374, the customer's obligation to pay such costs is an essential part of this landmark legislation. The Legislature carefully considered and crafted the exemptions from this obligation in the statute itself only last year. We need not decide whether we have the authority to permit PG&E to discount this obligation for a transmission or distribution customer, and explicitly do not resolve that issue here, because we see no compelling present need to alter the delicate balance of AB 1890 in that regard.

Another change recommended by the Settling Parties is to change the eligibility requirement of Schedules E-TD and E-TDI to address a concern of both the AECA and Farm Bureau. In its application, PG&E proposed to limit eligibility to customers with 200 kW of demand and larger. The Settling Parties proposed reducing the demand requirement to 20 kW and larger to ensure that agricultural pumping and other customers with demands under 200 kW, who may receive such offers, are also eligible to have a choice of Schedules E-TD and E-TDI, if they are otherwise qualified. The

20 kW level was used in AB 1890 as the cutoff for defining the small commercial class. We will adopt this recommendation since it will benefit PG&E's remaining customers by preventing uneconomic bypass.

With these measures in place, we are persuaded that Schedules E-TD and E-TDI are a necessary and appropriate measure which will help prevent uneconomic bypass of PG&E's transmission and distribution system without disturbing the competitive balance struck by AB 1890.

We now address Laguna's argument that it will not be able to compete with PG&E's discounted prices because it does not have an operational T&D system. We believe that Laguna appears to misunderstand a fundamental aspect of PG&E's Schedules E-TD and E-TDI proposals – the fact that PG&E cannot use these schedules to price below the customer's competitive alternative. There is no basis for Laguna's assertion that "The rate restructuring PG&E is proposing would undercut the rate that Laguna will have to charge" and that PG&E's proposals will be "undercutting the rates to be offered by new competitors ...". PG&E's proposed tariffs clearly prohibit pricing below a competing price. Thus, PG&E's T&D competitors will, without exception, always be competitive with PG&E's flexible prices under these new tariffs. Conclusions based upon the erroneous assumption that PG&E could automatically change the "floor rate" are without merit. However, since Laguna has been allocated some CTC exemptions under § 374, PG&E will not be allowed to use Schedule E-TD or E-TDI in response to offers by Laguna properly using such exemptions.

Also, we find no basis for Laguna's assertion that "PG&E will no longer be compelled to serve all power users requesting service in their area." This statement is in error -- nothing in AB 1890 relieves existing utilities of their obligation to serve all customers in their service territory under their respective tariffs. This illustrates one of the key issues to be addressed by the Commission in this proceeding: Should irrigation districts and other T&D competitors, which do not have an obligation to serve all customers, receive special protection from fair price competition so that they can have the ability to build duplicative T&D systems to select PG&E customers to the detriment of all remaining ratepayers? We conclude that, other than the megawatts of exemptions granted to certain irrigation districts under § 374, AB 1890 does not mandate us to grant such special protections.

We believe that the "protection" of "electricity customers" called for in § 1(a) of AB 1890 was not intended to "protect" T&D competitors without § 374 exemptions against competition. Nothing in the plain language of AB 1890 states that the Legislature intended to encourage the construction of duplicate T&D facilities. While AB 1890 clearly sought to establish and encourage a new market for the generation of electricity, no such encouragement was intended for T&D, which by contrast was to remain a regulated -- not a competitive -- domain. (See, PU Code §§ 330 (e), (f), (l)(2), (r), and (t); *see also* D.97-05-040, mimeo. p. 79, Finding of Fact No. 17, which states, "The Commission's electric industry restructuring initiative is based on the creation of a competitive marketplace for electric energy and its derivative products and services.")

Further, we believe that the § 330(l)(3) reduction in "market power" is only a call for divestiture of generation assets to facilitate generation competition, and not for the construction of duplicate T&D lines. As ORA notes, "in theory greater efficiency [in T&D services] may result from one provider," ORA's suggestion being that T&D lines may more appropriately be viewed as natural monopoly facilities, most efficient under economies of scale. Also, it is not environmentally desirable to build duplicative T&D facilities alongside those already in place, a factor completely outside AB 1890's intent to foster enhanced generation markets. Section 330(f) echoes these environmental concerns.[11]

If we sanction restraints on PG&E's ability to compete and if a customer is allowed to uneconomically bypass to an alternate T&D service provider, all of PG&E's remaining ratepayers would be worse off than if Schedules E-TD and E-TDI were adopted and judiciously utilized. If a customer has one more choice, as represented by

---

[11] Section 330(f) states: "The delivery of electricity over transmission and distribution systems is currently regulated, and will continue to be regulated to ensure system safety, reliability, environmental protection, and fair access for all market participants."

Schedules E-TD or E-TDI, this heightens competition rather than diminishes it. We conclude that Schedules E-TD and E-TDI have the necessary safeguards to prevent predatory pricing and should be adopted, but their use should be limited to addressing T&D competition where no valid § 374 exemption is being used.

To address Enron's concerns, for Schedules AG-7, E-36, E-37, E-TD, E-TDI, and AG-8, whether a new customer taking direct access service, or an existing PG&E customer choosing to take direct access service, the bill shall present Power Exchange charges (including but not limited to charges for commodity and ancillary services), public purpose program charges, transmission and distribution charges, CTCs, and charges for competitive or unbundled services (including but not limited to billing, metering and credits) to the extent that the calculation and presentation of this information is approved by the Commission in the Cost Separation proceeding decision (D.97-08-056) and PG&E's Interim CTC decision (D.96-11-041). This requirement will be effective immediately.

8. Schedule AG-8

Schedule AG-8 is intended to provide PG&E with pricing flexibility to compete to retain agricultural water pumping customers who are contemplating uneconomic bypass of PG&E's system by switching to natural gas or diesel fueled engines. According to PG&E, this new schedule is needed to allow it to keep pace with a rapidly changing and diverse marketplace that has adapted so as to render PG&E's experimental DAP and GAP rate schedules uncompetitive. PG&E proposes to limit this option to accounts with electric-driven pumps that are 50 horsepower or above and which operate a minimum of 1,000 hours per year. Customers must also have at least 100 horsepower of pumping load total per contract. These characteristics represent the point at which engine installations become economically viable.

To qualify for the rate, the customer must provide PG&E with information on the terms of its alternative service (fuel prices, engine purchase or lease cost, gas line extension costs, take-or-pay requirements, etc.). PG&E will then evaluate the feasibility and thus legitimacy of the alternative in terms of meeting all technical, financial, environmental and legal requirements and decide whether to proceed with a discounted rate offer. As with PG&E's other competitive rate options, the customer would be required to sign an affidavit stating that the AG-8 rate is the deciding factor in the customer's decision to remain on the PG&E system.

PG&E's competitive rate offer will be determined on a case-by-case basis using the same agricultural bypass model in each instance. This model evaluates the economics of each particular customer's technology choice, including all relevant costs and risks faced by that customer. The model calculates an equivalent average price per kWh that matches the customer's competitive alternative, plus a 5% premium to account for customers' perceived preference for electricity. By using this model to calculate its discounted rate offers, PG&E will have the flexibility to evaluate a wide range of possible deals presented to agricultural customers, and account for all relevant costs and risk factors facing the customer. This will ensure that the maximum contribution to margin is received for the benefit of both ratepayers and shareholders. As with its other competitive rates, PG&E's rate offer will never fall below a floor equal to the customer-specific marginal cost plus 20%. Schedule AG-8 customers, too, may terminate their agreements at any time without penalty.

Position of PG&E

PG&E contends that its proposed Schedule AG-8 is needed to address real, significant, and widespread uneconomic bypass by agricultural pumping customers. According to PG&E, there is significant evidence that the pace and level of uneconomic bypass by its agricultural customers to use diesel or natural gas engines for water pumping has recently increased. PG&E estimates that several hundred such electric accounts have bypassed in each of the past several years.

PG&E states that although total recent bypass to date is very difficult to ascertain, it represents at least 10 MW and possibly as much as 22 MW, the latter estimate coming from a news article from SoCalGas itself, one of PG&E's main competitors for this load. Further, PG&E states that SoCalGas is cited in yet another news article making a future projection that "this year we expect to put in more than

30,000 horsepower in natural gas engines ..." (which would represent about another 22 MW of bypass in 1997). According to PG&E, SoCalGas' ability to meet this "goal" is enhanced by their ability to "cherry pick" the most desirable agricultural loads because it has no obligation to serve other less-desirable loads. PG&E estimates that if this type of agricultural bypass continues, $64 million of revenue and $24 million of CTC are in jeopardy.

According to PG&E, since their adoption in 1995, PG&E's existing DAP and GAP rate options have proven largely ineffective because they cannot be tailored to address the dynamic agricultural marketplace. Only about 150 customer accounts are currently billed under the DAP and GAP tariffs, out of a total eligible population of approximately 5,000 customer accounts. PG&E contends that participation is low and bypass continues largely because the DAP and GAP discounts do not compare favorably to the discounts achievable with recent, creative engine alternatives.

PG&E states that the DAP and GAP discounts cannot now compete because they are based on a static and outdated model of alternative costs that assumes, among other things, the customer obtains conventional financing to purchase new engines outright. While this assumption was reasonable two years ago, today, engine suppliers have developed creative offerings combining equipment and financing with offers from fuel suppliers like SoCalGas to provide very competitive alternatives to PG&E service. According to PG&E, these dynamics, combined with PG&E's infrequent opportunity to update the DAP and GAP model and the resulting discount, clearly support the conclusion that DAP and GAP cannot keep pace with current alternative offerings.

PG&E asserts that Schedule AG-8 will help prevent uneconomic bypass, contributing to lower rates for all ratepayers, consistent with Commission precedent. By retaining customers who would otherwise uneconomically bypass, Schedule AG-8 would retain revenue available to amortize transition costs, benefiting all ratepayers. PG&E points out that the Commission's policy on uneconomic bypass states that "the utility should be allowed to retain the load in the event that it can reduce its prices to meet the competition without reducing its prices below marginal cost." (D.92-11-052, 46 CPUC2d 446 (1992).) In approving DAP and GAP in the 1995 Rate Design Window proceeding, the Commission stated, "This policy makes sense because it recognizes that the utility should be allowed to compete to retain customers where the infrastructure is already in place to serve a customer." (D.95-04-077, mimeo, p. 20.) Further, PG&E points out that the Commission has determined that "uneconomic bypass occurs whenever the customer's cost of the alternative source of energy exceeds the utility's marginal cost of service, but is below the utility's otherwise applicable tariff, and the customer intends to take advantage of that alternative energy source." (*Id.*) The marginal cost floor on Schedule AG-8 ensures that the rate is offered only in cases where the alternative price exceeds 120% of the utility's marginal cost of service, thereby ensuring that AG-8 is only offered to prevent uneconomic bypass.

PG&E argues that its Schedule AG-8 proposal should be adopted to allow PG&E to compete with new cases of engine bypass, because it is better tailored than DAP and GAP to limit uneconomic bypass. PG&E has designed the proposed AG-8 tariff to provide it with the pricing flexibility necessary to come closer to meeting its competition's current and future offerings. However, by design, the AG-8 price will never actually be able to meet the competitor's offer because PG&E's modeling calculations include a 5% premium to make its prices slightly higher than those of its competitors. This is necessary to recognize customers' general preference for electric service over internal combustion engines (the same premium concept was used in the development of the previous DAP and GAP tariffs). In addition, Schedule AG-8 contains a floor price of 120% of the site-specific marginal cost to ensure that the full marginal costs are collected. According to PG&E, this feature, although necessary, may in some cases limit ability of Schedule AG-8 to fully meet the competitive price.

PG&E states that in its Schedule AG-8 proposal, it has eliminated the pre-set alternative modeling approach used in DAP and GAP which was based on PG&E's own default assumptions that generally do not reflect the market. Instead, Schedule AG-8 will use a model that makes calculations based on inputs regarding the customer's actual competitive alternative. PG&E believes that only this tailored approach will allow it to keep up with the creative, competitive packages being offered in this dynamic market.

Position of SoCalGas

In principle, SoCalGas supports the ideas of pricing flexibility and optional rates in the marketplace to thwart uneconomic bypass. However, SoCalGas submits that simply creating a rate that prevents bypass, without regard to the consequences, is not enough; such attempts must offer real rate discounts, must be fair and must not inappropriately inhibit or discourage competition. SoCalGas further submits that unless PG&E's shareholders are themselves responsible for shortfalls in revenue occasioned by the operation of PG&E's flexible pricing options, then PG&E's ratepayers must not be put at risk when the utility attempts to retain or build load.

Further, SoCalGas contends that PG&E will unfairly inhibit competition through its method of establishing ratepayer eligibility for discounts by requiring a customer to provide a formal rate quotation from a competing energy provider. According to SoCalGas, this requirement causes the competitor to indirectly divulge to PG&E proprietary trade secret information otherwise unobtainable by PG&E. SoCalGas believes that this method of obtaining proprietary information from customers, if approved by the Commission, will act as a definite deterrent to the development of any meaningful competition to PG&E's provision of service. SoCalGas argues that if competitors do not offer their products (because of PG&E's requirement for proprietary information), then PG&E's ratepayers will be deprived of the opportunity for any meaningful choice of energy providers. SoCalGas believes that this is the primary object of PG&E's proposals, rather than mere load retention.

Also, SoCalGas argues that PG&E's proposed method of determining floor prices at the customer's distribution planning area (DPA) specific level is mathematically incorrect and will likely result in an understatement of actual marginal costs. According to SoCalGas, PG&E's method has a "downward bias" since it results in estimates below the Commission adopted system average for some DPA but never in estimates above the system average. SoCalGas' argument is based on hypothetical offers for customers located in PG&E's Jackson and Taft DPAs, respectively.

According to SoCalGas, PG&E has a great incentive and opportunity to understate its marginal costs –not, as PG&E suggests to legitimately meet a "bypass" threat—but, in reality, to thwart customer choice and smother competition. SoCalGas contends that once ratepayers opt to take PG&E's service at the "illusory or contingency" discount rate, PG&E has, at that point, defeated its competition and also effectively denied its ratepayers a true choice. SoCalGas believes that if the proposed tariff is allowed to operate as PG&E wants, ratepayers who may think they will be able to choose between an alternate energy competitor and PG&E will find that there are no such providers and any benefits from this anticipated competition will never be realized. According to SoCalGas, there will simply be no competition to leverage to gain the "benefits" of PG&E's tariff.

Further, SoCalGas argues that the proposed agricultural pumping "anti-bypass" rate frustrates the clear intent of the Legislature to permit bypass of the CTC obligation "in the course of societally efficient fuel switching activities." According to SoCalGas, AB 1890 endorses efficiency unreservedly, but supports only a fair opportunity of full CTC recovery and specifies multiple exceptions to its provenance, including one provision that explicitly exempts fuel-switching activities. Thus, SoCalGas contends that it appears to be the clear intent of AB 1890 to favor efficiency, including that achieved through fuel switching, over CTC recovery in cases where the two goals conflict. Therefore, SoCalGas believes it to be a deviation from the intent of AB 1890 for PG&E to offer Schedule AG-8 if it results in an inefficient outcome with respect to, for example, fuel switching opportunities within the state.

SoCalGas submits that efficient fuel switching arises when marginal costs of service of the competing fuel are cheaper. SoCalGas contends that in this instance, the AG-8 rate is not guaranteed, or even calculated to provide an accurate marginal cost signal to PG&E's ratepayers and is therefore defective and in conflict with the intent and language of AB 1890.

In summary, SoCalGas recommends that the Commission reject PG&E's Schedule AG-8. SoCalGas suggest the Commission address PG&E's legitimate bypass needs by: (1) placing PG&E's shareholders at risk for any revenue shortfall produced by the operation of PG&E's flexible pricing options; or (2) maintaining the existing DAP and GAP rate schedules for <u>all</u> customers; or (3) maintaining the existing DAP and GAP rate schedules, but allowing PG&E to "flex" its rates between the existing 6% and 21% discounts currently allowed for all eligible customers under GAP and DAP.

Position of AECA

AECA enthusiastically endorses PG&E's proposed Schedule AG-8 since it would allow PG&E to compete in the marketplace against suppliers of natural gas-fired engines or diesel powered engines.

AECA agrees with the testimony of Terry Scott, PG&E's business customer service director that: competition for the agricultural pumping load has become intense; SoCalGas, one of the primary competitors in this market is actively marketing to get PG&E's agricultural customers to switch to natural gas; there are other major participants in this robust market, including Cummins Engine, Detroit Diesel, Enron, Chevron, and various brokers. AECA notes that Scott's observations are verified by AECA witness Jeff Fabbri, who has switched the majority of his own wells to internal combustion engines and advised others to do the same.

AECA disputes SoCalGas' claim that PG&E's proposal is flawed because the proposed method of determining floor prices at the distribution planning area level is mathematically incorrect and will likely result in an understatement of actual marginal costs. AECA points out that PG&E's rebuttal testimony demonstrates why SoCalGas' criticism is without merit and how PG&E's proposal is, in fact, very similar to the special electric contracts program authorized in D.91-11-016 for electric utilities and the Expedited Application Decision (EAD) process authorized for the gas utilities in D.94-11-052. Further, AECA points out that SoCalGas has entered into special EAD contracts on numerous occasions, claiming that marginal costs based on customer or location specific determinants for purpose of setting marginal costs floors was appropriate. On at least one occasion involving a SoCalGas EAD contract, the Commission approved a specific gas transportation agreement which "zeroed-out" an incremental distribution cost component in setting the contract floor (D.94-04-080). Thus, AECA contends that SoCalGas' complaints are contrary to the very arguments that it has previously made to the Commission and which the Commission has approved, when SoCalGas was trying to compete to prevent system bypass.

Also, AECA disputes SoCalGas' argument that Schedule AG-8 frustrates the intent of the Legislature to permit bypass of the CTC in the course of societally efficient fuel switching activities. AECA argues that first, as noted above, § 378 allows PG&E to provide new service options that accurately reflect the loads, locations, conditions of service, cost of service and market opportunities of customer classes and subclasses.

Second, AECA contends that unlike the irrigation district exemption, there is nothing comparable to Water Code § 22115 for natural gas or diesel fired combustion engines. Third, AECA contends that, in a mature, robust market such as the market for agricultural water pumping, the competition between electric supplies and natural gas and diesel suppliers, including the suppliers of internal combustion engines is intense; therefore, PG&E should not be restrained. According to AECA, this market is not in transition, protection for electric consumers is not required, and the parties should be allowed to compete.

Discussion

We do not find persuasive SoCalGas' argument that PG&E's proposal requires customers to divulge competitor's proprietary trade secret information. As PG&E points out, customers routinely share such information as they bargain for a better offer.

Also, we do not find persuasive SoCalGas' argument that if PG&E's proposal is adopted, PG&E's ratepayers will be deprived of the opportunity for any meaningful choice of energy providers. As AECA points out, the competition from major participants, including SoCalGas and various engine manufacturers, is robust. The record confirms that the ratepayers have meaningful choices, and we believe that the availability of such choices will continue notwithstanding Schedule AG-8.

We reject SoCalGas' argument that the DAP and GAP schedules previously authorized have proven to be effective. The record confirms that these schedules are based on assumptions that are outdated because of the service options offered by competitors and PG&E has been unable to compete.

We conclude that PG&E should be given the opportunity to compete in this market against alternate energy and equipment suppliers. The competition in this market is robust, mature and innovative. It is the type of competition that the Commission has sought to foster. Accordingly, we shall adopt proposed Schedule AG-8.

We next address PG&E's request that its DAP and GAP schedules be closed to new customers, since these schedules are no longer competitive. The record in this proceeding supports a finding that Schedules DAP and GAP are ineffective, and proposed Schedule AG-8 better addresses the needs of the customer in a potential uneconomic bypass situation. Also, replacement Schedule AG-8 will, in effect, provide substantially equivalent rates and conditions of service. Therefore PG&E's request to close Schedules DAP and GAP to new customers, should be adopted.

9. Ratemaking Treatment

PG&E proposes that the revenues from the sales made to customers on its proposed Schedules E-TD, E-TDI, and AG-8 be treated in the same way as revenues received from sales at full tariff rates. Under PG&E's proposal, the revenues received from rates would be allocated first to the transmission, distribution, public benefit programs, and nuclear decommissioning accounts, based on their respective revenue requirements. Revenue would then be allocated to pay for Power Exchange (PX) and Qualifying Facilities (QF) power, Independent System Operator (ISO) services, and to compensate PG&E for output from Diablo Canyon. Finally, any remaining revenue will be credited to the CTC revenue account.

PG&E argues that since, absent the competitive rates, these sales would not have occurred at all (due to the customers uneconomically bypassing PG&E's system), the effect of PG&E's proposed revenue treatment is to increase CTC collections compared to what they otherwise would have been had these customers bypassed. The basis for PG&E's argument is that its Schedule E-TD, E-TDI, and AG-8 proposals result in greater revenue available to amortize transition costs than if PG&E remained unable to make timely discounts to customers with competitive offers who would otherwise uneconomically bypass PG&E's T&D system.

According to PG&E, a fundamental feature of the new, post-AB 1890 regulatory environment is that both shareholders and ratepayers are currently at risk for the loss of revenue if customers bypass PG&E's T&D system. Assuming a scenario where PG&E's frozen rates provide sufficient "headroom" to fully recover transition costs by December 31, 2001, any forgone transition costs due to customer bypass will be paid by remaining ratepayers, through an extension of the rate freeze period, and a delay in the date on which rates would be lowered.[12] Should this scenario come to pass, ratepayers would be poorly served if PG&E were not allowed to compete in a timely manner to retain customers. On the other hand, if PG&E is unable to fully recover transition costs by March 31, 2002, its shareholders would be at risk for the forgone transition costs due to the uneconomic bypass.[13]

PG&E points out that the Commission, in Edison's Flexible Pricing Options case, has recognized that full tariff revenue is not an achievable outcome in competitive situations, stating (in discussing Edison's business retention rate) that:

> "... the minimum discount required to keep a customer from leaving the state generates no revenue shortfall in that <u>obtaining the tariff based rate from that customer was not a realistic possibility</u>. The discount would not have been offered were it not the case that the customer would otherwise leave." (D. 96-08-025, mimeo. p. 64, emphasis added.)

---

[12] For convenience and to be concise, PG&E makes references to the rate freeze period ending on December 31, 2001. In fact, depending upon the pace of transition cost amortization, the rate freeze could be extended through March 31, 2002 to collect certain costs. (PU Code §§ 367(a) and 368(a).)

[13] If full tariff revenue were achievable, PG&E would then have little incentive to discount. Given the risk facing PG&E of having insufficient "headroom" in its frozen rates to fully recover transitions costs, it would obviously prefer the higher revenue associated with full tariff rates.

PG&E notes that in fact, as set forth in the tariffs and agreement forms for Schedules E-TD, E-TDI, and AG-8, PG&E will make a competitive offer at less than full tariff revenue only to those customers with a viable and documented offer from an alternative service provider. Thus, it is not the act of discounting that results in lower revenue being collected, but rather the presence of competitors offering prices lower than PG&E's tariffed rates. Discounting represents a means to reduce the amount of revenue and CTC loss that would otherwise occur due to uneconomic T&D bypass.

Further, PG&E points out that its proposals will increase revenues available to amortize transition costs even in situations where the customer would not be exempt from CTCs if it bypassed. PG&E's ability to offer competitive rates will also increase revenues available to amortize transition costs in situations where the courted customers would not be exempt, and would be obligated to pay PG&E a CTC upon departure.[11] In instances where the customer would be responsible for paying a CTC if it bypassed, PG&E will take that into account in calculating its matching offer, and thus in no case will be discounting CTCs. In addition, such customers contemplating uneconomic bypass can be viewed as being on the margin since, absent PG&E's matching offer, they would depart and revenue would decrease. Consequently, any net contribution to margin received from these customers (i.e., revenue above marginal cost) in excess of their CTC obligation will also effectively go into the CTC account (since it is the last one to which revenues are booked) under PG&E's proposed revenue accounting methodology. (A. 96-08-070, October 21, 1996, pp. 216-217.)

Further, PG&E argues that PG&E's proposals will help reduce future T&D rates. In addition to the benefits of increased CTC collections, the ability to discount rates and retain load that would have uneconomically bypassed PG&E's T&D system will benefit

---

[11] One way this situation will occur is if the competitor does not possess § 374(a) exemptions (e.g., it is not an irrigation district, it is an irrigation district formed too late to be eligible for exemptions, or it is an irrigation district that either did not apply to the CEC for exemptions or whose application was unsuccessful). Another way it can occur is if an irrigation district that possesses exemptions uses them all up, but still continues to make offers to PG&E customers.

all ratepayers after the transition period is over. PG&E points out that no party has disputed the fact that it is in ratepayers' long-run interest to maximize the sales over which the initially adopted distribution revenue requirement is averaged to produce the lowest possible distribution rate. PG&E submits that its proposed competitive options will do just that.

Discussion

The passage of AB1890 and the corresponding unbundling of utility bills has altered the relative risk faced by PG&E when confronted by threatened bypass. As already noted, under Schedules E-TD and E-TDI, PG&E is primarily at risk only for the lost distribution and public benefit programs charge component of its rates if a customer lacking an irrigation district CTC exemption leaves PG&E to take service from a competing T&D provider. The effect of this action upon PG&E's collection of CTC is primarily dependent upon the ratemaking treatment that the Commission adopts for PG&E's distribution revenue requirement.

Under current regulation, PG&E has the equivalent of ERAM protection for its distribution revenues. If a customer leaves PG&E's distribution system, all other customers must pick up the resulting undercollection in the distribution revenue requirement and the average distribution component of rates will be higher for all remaining customers. Since the overall level of rates are capped under the rate freeze, the higher distribution rate will result in less "headroom" for CTC collection.

The above outcome only holds true, however, if a utility has the equivalent of ERAM protection for its distribution revenue requirement. If a utility does not have this protection, then it is the utility, not its ratepayers, who would bear all of the distribution revenue shortfall. Under this circumstance there would be no effect on either the timing or the amount of CTC collection. The departing customer would continue to pay CTC charges, and the level of distribution rates for all remaining customers would not be affected by customers leaving the system. In this case, contrary to PG&E's assertions, there would not be a symmetrical treatment of risks and rewards between ratepayers and shareholders.

Currently, PG&E has the equivalent of ERAM protection for its distribution revenue requirement.. The need for continued ERAM protection for a utility's distribution revenue requirement is under active review by the Commission as noted in our Roadmap II (D.96-12-088, p. 28) and Cost Recovery Plan (D.96-12-077, p. 18-20) decisions. This issue is also scheduled to be addressed in the near future in our Streamlining proceeding (R.94-04-031).

We have already eliminated ERAM protection for Edison's transmission and distribution revenue requirement in D.96-09-092. This is an important consideration, since PG&E repeatedly references Edison's Flexible Pricing Options as a justification for its own proposals.

To conform to D.97-08-056, PG&E is allowed to discount only the distribution component of its bill for customers taking service on Schedules E-TD, E-TDI, and AG-8. As long as ERAM or its equivalent remains in effect for PG&E's distribution revenue requirement, PG&E would be able to reallocate this revenue shortfall to all other customers through the distribution component of PG&E's bill. Should the Commission in the future eliminate ERAM or its equivalent for PG&E's distribution revenue requirement, then it will be PG&E that will have to bear the risk for any contracts that it enters into.

PG&E's Schedule AG-8 is designed to address a different form of bypass than Schedules E-TD and E-TDI. Schedule AG-8 is designed to retain customers who otherwise would not only leave PG&E's system but also avoid any payment of CTC because they are fuel switching.

In the post-AB 1890 regulatory environment, this type of uneconomic bypass results in lost revenue, lost contribution to margin, and lower revenues available to amortize transition costs. Depending upon the date by which transition costs would otherwise be amortized, uneconomic bypass of this sort can harm PG&E's ratepayers, shareholders, or both. By permitting PG&E to compete to retain this type of customer, the Commission can increase CTC revenues above what they otherwise would be, and increase the probability that the freeze will end prior to December 31, 2001.

In the event that all transition costs are amortized prior to the end of the transition period (December 31, 2001), then ratepayers gain from an earlier rate decrease than would otherwise have occurred. But even in the event that amortization is not completed by then, ratepayers are no worse off, since their rates will still decrease on January 1, 2002.

Schedule AG-8 will similarly result in additional CTC collections that will benefit all customers. Although not classified as an "exemption," agricultural customers switching to natural gas- or diesel-fueled engines for their water pumping would also not be obligated to pay a CTC,[15] and the forgone CTCs due to this type of bypass would thus not be tracked. Consequently, customers retained by Schedule AG-8 will contribute additional CTC for the benefit of all customers.

The Commission's decision in the last PG&E Rate Design Window proceeding placed PG&E's shareholders at risk for a portion of any discounts, including cogeneration deferral contracts, until electric restructuring was in place. This decision was followed two months later by the Commission's electric restructuring decision, D.95-12-063 which stated:

> "In keeping with our policies in D.95-10-033, revenue shortfalls resulting from new rate discounts offered to avoid customer bypass, attract new business, or retain existing businesses should be shared between ratepayers and shareholders during the transition to a restructured industry.
>
> "We will apply these cost-sharing policies to all rate discount cases that come before us during the transition period, including those currently pending. Once restructuring is in place, utilities will not be able to pass the cost of discounts to ratepayers; instead, shareholders should fund any discounts offered to customers."

---

[15] See PU Code § 371(b) which defines fuel switching as a "normal business fluctuation" and thus not liable for CTCs.

Therefore, we will require PG&E to assume 25% of any discounts offered under Schedules E-TD, E-TDI, and AG-8 at this time pending completion of the Commission's broader review of ERAM protection and discounting policies in general. PG&E may apply for memorandum account treatment of its portion of discounted revenues to track PG&E's foregone revenues. If in the future, we decide that PG&E should be allowed to reallocated all, or less than 25% of its discounted costs to other ratepayers, PG&E may seek a refund of the difference in revenues booked to its memorandum account. If we decide at a future time that PG&E should be at risk for greater than 25% of any discounting, this policy would only apply on a prospective basis. Putting PG&E at risk for a portion of any discounts that it offers also minimizes the need for reasonableness reviews, an important consideration.

PG&E's proposed ratemaking treatment also must be modified to conform to the D.97-08-056. This means that for Schedules E-TD, E-TDI, and AG-8 PG&E cannot use its proposed hierarchy of crediting revenues under these contracts first to transmission and distribution, and then preceding through public benefit program charges, energy prices (which PG&E further breaks down into Power Exchange, QF, and Diablo Canyon components), and the residual is credited toward CTC. Consistent with PG&E's proposed calculation of its marginal cost floor, we will require PG&E to discount the distribution component of its bill first, and to not discount either CTC or public benefit program charges for Schedules E-TD, E-TDI, and AG-8.

10. Marginal Cost Based Price Floor

Traditionally, the Commission has required utilities offering competitive pricing options to ensure that their prices do not drop below customer-specific marginal cost-based floors. This requirement is designed to ensure that utilities cannot behave in a predatory fashion by discounting below marginal costs to prevent what would be economic bypass from occurring. (D.95-10-033, mimeo. p. 40.) Consistent with this requirement, PG&E has proposed a self-adjusting price floor to ensure that rates are never discounted below the customer-specific marginal cost of service, so that only uneconomic bypass is deterred and positive contribution to margin always results.

PG&E argues that estimating marginal costs based upon the system-wide unit marginal costs adopted in D. 97-03-017, PG&E's Phase 2 1996 general rate case decision, will not yield accurate avoided cost estimates. This is because actual marginal costs can vary from location to location.

According to PG&E, in many situations, when selected customers uneconomically bypass, the cost that would actually be avoided by PG&E is lower than what would be calculated by applying the system-wide unit marginal costs adopted in D. 97-03-017. When an individual customer bypasses, PG&E is likely to have some T&D assets in place that will be stranded and cannot economically be used to serve other customers. This is especially true if a local planning area already has adequate capacity to serve anticipated load growth over the relevant planning horizon. In such an unconstrained area, the freeing up of additional capacity that would result from the customer bypass would have little value in allowing PG&E to delay a planned investment and thus avoid any cost.

PG&E proposes to adjust the system average unit marginal costs adopted in D. 97-03-017 using a zero/one factor applied to T&D marginal costs to reflect PG&E's T&D capacity situation in the area where the customer is located. If a distribution planning area (DPA) is constrained, PG&E's methodology would continue to use the Commission-adopted marginal distribution capacity costs in its floor price calculation, since bypass by individual customers in this situation would permit PG&E to defer investments in distribution capacity and thus avoid some marginal distribution capacity cost. If, however, the DPA is unconstrained, then PG&E would "zero out" (i.e., multiply by zero) the distribution capacity marginal cost to reflect the fact that no distribution capacity cost would be avoided if isolated customers were to bypass. A similar zero/one factor would be used to adjust marginal transmission capacity costs, depending upon whether or not the customer is located in an area facing transmission capacity constraints. PG&E proposes to use conservative definitions in evaluating whether or not an area is constrained, defining the area as distribution-constrained if PG&E forecasted a load-related distribution investment in its 1996 general rate case filing and as transmission-constrained if a major transmission investment was forecasted.

PG&E contends that its proposal to use a zero/one factor, to make a relatively simple, straightforward adjustment to marginal T&D capacity cost estimates, appropriately accounts for the fact that T&D distribution capacity costs are not avoided when isolated bypass occurs in unconstrained areas. PG&E urges the Commission to adopt its adjustment proposal to "zero out" those marginal cost components (either marginal transmission capacity cost or marginal distribution capacity cost) which are not avoided by PG&E should the customer depart. According to PG&E, the result will be a floor price estimate which more accurately reflects its true marginal cost of service for that customer than would the use of a single system-wide estimate, which cannot possibly represent the diversity in location specific costs.[16]

PG&E asserts that ideally, the marginal costs specific to the customer's individual situation would be used to calculate the floor price applicable to that customer's competitive rate offer. PG&E notes that despite the administrative difficulty of verifying site-specific marginal costs, the Commission has recognized this principle in the past. In D.91-11-016 (41 CPUC2d 614), reviewing the reasonableness of selected PG&E special electric contracts, the Commission approved a contract floor price for Chevron which substituted a $0.00292 per kWh adder for the adopted marginal primary distribution cost, in recognition of the fact that the marginal cost of Chevron's transformation facilities were much lower than the system average figure. On the gas side, in D.92-11-052 (pp. 7, 11), the Commission approved a general policy of recognizing the appropriateness of using marginal costs based on customer- or location-specific determinants for the purpose of setting marginal cost floors for negotiated gas transportation contracts. And in D.94-04-080 (54 CPUC2d 236), the Commission

[16] Consistent with footnote 8 of D. 95-10-033, PG&E would continue to use customer-specific billing determinants to make this calculation and, in order to ensure a positive contribution to margin, would continue to add 20% to the total calculated marginal cost after adjusting T&D marginal capacity costs, where appropriate.

approved a specific gas transportation agreement between SoCalGas and J. D. Heiskell and Company which "zeroed out" an incremental distribution cost component in setting the contract floor price. Therefore, PG&E submits that such a simple "zeroing out" adjustment should be adopted here because it better reflects the true marginal costs to serve individual customers, and results in more accurate assessments of the floor price for discounting to prevent uneconomic bypass.

PG&E asserts that the use of system average marginal T&D capacity costs would effectively preclude the ability of Schedule AG-8 to deter uneconomic bypass. In agricultural engine bypass situations, the use of PG&E's system average unit marginal costs adopted in D. 97-03-017 yields price floors which frequently exceed the average rate paid by the customer. According to PG&E, in these instances, the use of such floors would effectively stifle PG&E's ability to discount to prevent uneconomic bypass to diesel- or natural gas-driven engines.

Further, PG&E notes that the Commission has already found in PG&E's 1995 Rate Design Window proceeding that a "self-correcting price floor" at 20% above the customer-specific marginal cost-to-serve "precludes predatory pricing." (D.95-10-033, mimeo. p. 40.) Since the same type of self-correcting price floor is proposed here, PG&E requests that the Commission should again, as in that case, approve its proposal for a self-correcting marginal cost based price floor.

Discussion

We agree with PG&E that its Rate Design Window proposals would be of little or no use if it is required to use its system average marginal cost to calculate its floor prices. Floor prices based upon system average costs would greatly limit PG&E's ability to compete. In the agricultural sector, in particular, the use of system average unit marginal costs typically yields price floors which exceed the average rates paid by customers.

The Commission has recognized that there are problems in applying the marginal costs adopted in Phase 2 of PG&E's 1996 general rate case to the agricultural sector, noting that they would yield a 54% increase in the agricultural equal percent of marginal cost (EPMC) target and directed PG&E to "...investigate the causes for this dramatic increase and to explore in its next general rate case alternative methods of computing marginal costs and revenue allocation that result in agricultural EPMC targets more in line with those of agricultural customers served by other California utilities." (D.97-03-017, Conclusion of Law 10.)

Therefore, we believe that rather than using PG&E system average "as is," it makes sense to calculate the floor price for PG&E's competitive rates by adjusting the system average estimates using PG&E's simple zero/one factor. Such adjustment would be limited to unconstrained areas where the system average cost clearly overstates the actual costs that would be avoided by PG&E should selected customers bypass. Accordingly, we will adopt PG&E's proposed zero/one factor for adjusting system average marginal costs in calculating floor costs for purposes of implementing the proposed rate schedules intended to avoid uneconomic bypass of PG&E's T&D system.

Findings of Fact

1. The overall intent of the Legislature in enacting AB 1890 supports the adoption of PG&E's 1997 Rate Design Window proposals as amended by this decision.

2. PG&E's 1997 Rate Design Window proposals are consistent with the plain language of § 378; comprise "new optional rate schedules and tariffs" as set forth in § 378; and satisfy the § 378 criteria of "loads, locations, conditions of service, cost service, and market opportunities of customer classes and subclasses."

3. PG&E's 1997 Rate Design Window proposals are directed at the entire subclass of customers likely to bypass rather than at individual customers and are not barred because they involve "contracts."

4. Schedule AG-7 is designed to meet the need for an agricultural rate schedule that adjusts to unpredictable fluctuating usage levels and is appropriately based on the marginal costs underlying current agricultural rate schedules.

5. Schedules E-36 and E-37, optional oil pumping rate proposals, are estimated to result in about $2 million in net increased revenue, they further State and Federal

objectives, and will benefit ratepayers and shareholders by accelerating collection of transition costs.

6. PG&E's proposed Schedules E-TD and E-TDI, as amended by this decision, are necessary to reduce uneconomic bypass. PG&E will be facing SOAQ revenue shortfall during the transition period due to uneconomic bypass. If PG&E's proposed service area agreement with the Modesto irrigation district were approved, revenue shortfalls would still occur.

7. Section 374 establishes CTC exemptions to be allocated and used during the transition period by certain irrigation districts, and it is necessary to limit PG&E's use of Schedules E-TD and E-TDI during the transition period in order to carry out the Legislature's apparent intent that the use of these exemptions be maximized.

8. Even after Schedules E-TD and E-TDI are adopted as amended by this decision, PG&E's T&D competitors without § 374 exemptions will still be able to compete and attract new customers. By design, the best PG&E could do under these proposals is meet the competitive price. In some cases, depending on the relationship between competitive price and the customer-specific marginal cost, PG&E will not be able to meet the competitive price at all and customers will likely depart. Where PG&E can meet the competitive price, customers will choose their service provider based on other, non-price attributes, just as they would in any competitive market.

9. In the current post-AB 1890 regulatory environment, with a rate freeze and defined period for utility transition cost collection, the risk of CTC shortfalls caused by customers uneconomically bypassing PG&E's system is shared by ratepayers and shareholders.

10. PG&E should not utilize Schedules E-TD and E-TDI to offer discounts to customers who are being served by an irrigation district that is utilizing a § 374 exemption from CTC to serve that customer.

11. With the enactment of AB 1890, both ratepayer and shareholders have the opportunity to benefit if PG&E is allowed flexibility in its tariff schedules.

12. If, as amended by this decision, PG&E's proposed competitive rate options are approved some customer load that otherwise would bypass will be retained, and some

new load will be added to the PG&E system which otherwise would have been served by others. This will result in additional revenue available to amortize transition costs which, under PG&E's proposed ratemaking, will benefit either ratepayers or shareholders, depending upon whether PG&E ends up having sufficient "headroom" to fully amortize transition costs prior to the end of the transition period.

13. If it turns out that PG&E has sufficient headroom, the increased revenues will benefit ratepayers by shortening the transition period and moving forward the date on which rates will decrease. If it turns out that PG&E does not to have sufficient headroom, then the increased revenues will benefit shareholders. But even if this latter outcome occurs, ratepayers will be no worse off since the transition period will still end at the same time as it would have had PG&E's competitive rate proposal not been adopted.

14. PG&E's competitive rates, as amended by this decision, will increase revenues available to amortize transition costs even in situations where the customers contemplating uneconomic bypass would be obligated to pay PG&E a CTC upon departure. PG&E's competitive rate offers will account for customers' CTC obligations should they depart, and PG&E will not discount CTCs to these customers. Any retained contribution to margin which exceeds the customers' CTC obligations will, increase CTC revenues for the benefit of ratepayers and shareholders.

15. As amended by this decision, PG&E's competitive rate proposals, Schedules E-TD, E-TDI, and AG-8, will also reduce future T&D rates under a performance-based ratemaking mechanism, by maximizing the sales over which the initially-adopted distribution revenue requirement is averaged.

16. The passage of AB 1890 substantially alters the ratemaking environment. Therefore, past decisions regarding ratepayer/shareholder responsibility for discounting must be reconsidered by the Commission in light of how the new incentives affect the utility's motives to offer competitive rates.

17. In the new post-AB 1890 regulatory environment, PG&E's proposed ratemaking, as modified to have PG&E assume 25% of any discount provides an appropriate incentive for PG&E to apply these competitive options in a manner so as to retain as

much revenue as possible from customers who would otherwise uneconomically bypass its system.

18. Schedule AG-8 is needed to address significant uneconomic bypass by agricultural customers and will contribute to lower rates for all ratepayers consistent with Commission precedent.

19. Since adoption in 1995, PG&E's existing DAP and GAP rate options have proven largely ineffective and do not address the current competition in the agricultural marketplace.

20. Following issuance of the ALJ's Proposed Decision and oral argument before the Commission, on July 3, 1997, the Settling Parties filed a joint motion for adoption of the Settlement Agreement, and a motion for waiver of portions of Rule 51.

Conclusions of Law

1. PG&E's 1997 Rate Design Window proposals, as amended by this decision, are consistent with the intent of § 378, are designed to avoid predatory pricing, and should be adopted.

2. The ratemaking treatment proposed by PG&E for its 1997 Rate Design Window proposals, as amended by this decision, is reasonable and should be adopted. However, for Schedules E-TD, E-TDI and AG-8, PG&E should not be allowed to discount the CTC and public benefit program charge. PG&E should be allowed to discount the distribution component only of the customer bill.

3. The Settlement Agreement is not in the public interest and should not be adopted.

4. PG&E should not be able to discount the CTC, energy FERC-regulated transition and public benefit charge obligations of any customer.

ORDER

IT IS ORDERED that:

1. The Joint Motion for adoption of settlement between Pacific Gas and Electric Company (PG&E), Agricultural Energy Consumers Association, Merced Irrigation District, Modesto Irrigation District, Laguna Irrigation District, Southern California Gas

Company, California Independent Petroleum Association and California Farm Bureau Federation, is denied. The Settlement Agreement is not adopted.

2. PG&E's proposed 1997 Rate Design Window proposals, as amended by this decision, are adopted.

3. PG&E is authorized to file amended Schedules AG-7, E-36, E-37, E-TD, E-TDI, and AG-8, as set forth in Appendix B attached to this decision.

4. Schedule AG-7 is authorized only on an experimental basis for up to a maximum of 5,000 accounts on a first-come basis.

5. PG&E shall not utilize Schedules E-TD and E-TDI to offer discounts to customers who are being served by an irrigation district that is utilizing a valid Public Utilities Code § 374 exemption from CTC to serve that customer.

6. Schedules E-TD and E-TD1 shall be available to customers with over 20 kW demand that satisfy the conditions of the tariff.

7. In offering a discount to any customer pursuant to Schedules AG-7, E-36, E-37, E-TD or E-TDI, and AG-8, PG&E shall provide that customer an "unbundled" bill that shows each of the following components: energy cost, competition transition charge, (CTC), public purpose program charge, transmission charge and distribution charge, to the extent that the calculation and presentation of this information is approved by the Commission in the Cost Separation proceeding decision (D.97-08-056) and PG&E Interim CTC decision (D.96-11-041).

8. In implementing Schedules E-TD, E-TDI, and AG-8, PG&E is only allowed to discount the distribution component of a customer's bill. PG&E is not allowed to discount the energy, CTC, public purpose benefit charge or transmission components of the bill. Customers on these new schedules are free to choose direct access at any time.

9. PG&E is authorized to close Schedules DAP and GAP to new customers since, at a minimum, new Schedule AG-8 will provide customers with rates and conditions of service substantially equivalent to Schedules DAP and GAP.

10. PG&E's 1997 Rate Design Window proceeding is closed.

11. PG&E shall assume 25% of any discount offered under Schedules E-TD, E-TDI, and AG-8 on an interim basis until the Commission reaches a final resolution of this

issue. If the Commission's final resolution results in PG&E being responsible for less than 25% of any discounts, PG&E may request to recover the differences in rates. PG&E may set up a memorandum account to track the amount of discounting.

This order is effective today.

Dated September 3, 1997, at San Francisco, California.

P. GREGORY CONLON
President
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
RICHARD A. BILAS
Commissioners

APPENDIX A
List of Appearances

Applicant: Gail L. Slocum, Attorney at Law, for Pacific Gas and Electric Company.

Interested Parties: Barbara R. Barkovich, for Barkovich & Yap, Inc.; William H. Booth, Attorney at Law, for California Large Energy Consumers Association (CLECA);Hal Bopp, for the Department of Conservation; McCracken & Byers, by David J. Byers, for California City-County Street Light Association (CAL-SLA); Dian M. Grueneich, Attorney at Law, for California Department of General Services; Graham & James, by Peter W. Hanschen, Attorney at Law, for Agricultural Energy Consumers Association; William Julian II, Attorney at Law, for the California Independent Petroleum Association (CIPA); Karen Norene Mills, Attorney at Law, for California Farm Bureau Federation; Theresa Mueller and Robert Finkelstein, Attorneys at Law, for The Utility Reform Network (TURN); Steven Patrick, Attorney at Law, for Southern California Gas Company; Flanagan, Mason, Robbins, Gnass & Corman, by Kenneth M. Robbins, Attorney at Law, for Merced Irrigation District; Reed V. Schmidt, for Bartle Wells Associates; James Porter Shotwell, Attorney at Law, for Southern California Edison Company; Steven T. Steffen, Attorney at Law, for Modesto Irrigation District; Downey, Brand, Seymour & Rohwer, by Philip A. Stohr and Dan L. Carroll, Attorneys at Law, for California Industrial Users; Ellison & Schneider, by Christopher T. Ellison, Attorney at Law, for Merced Irrigation District; McCormick, Kidman & Behrens, LLP, by Keith E. McCullough, Attorney at Law, for Laguna Irrigation District; and Wright & Talisman, by Michael B. Day, for Enron.

Office of Ratepayer Advocates: Joseph DeUlloa, Attorney at Law and Sean Casey.

Energy Division: Maryam Ebke, Greg Wilson and Harold Rayburn.

(END OF APPENDIX A)

PACIFIC GAS AND ELECTRIC COMPANY
1997 ELECTRIC RATE DESIGN WINDOW

AMENDED TARIFFS AND AGREEMENTS

- Schedule E-TD Tariff and Agreement
- Scheduled E-TDI Tariff and Agreement
- Schedule AG-8 Tariff and Agreement
- Schedule AG-7 Tariff
- Schedule E-36 Tariff
- Schedule E-37 Tariff

Non-Redlined Version
of July 3, 1997 Agreement Revisions
and July 9, 1997 Tariff Revisions

PG&E's amended Schedule E-TD Tariff, including attached Agreement for Discounted Rates to Avoid Uneconomic Bypass of PG&E's Transmission and/or Distribution Facilities

AMENDED

Tariff Amended July 9, 1997
Agreement Amended July 3, 1997

Original Cal. P.U.C. Sheet No.

Pacific Gas and Electric Company Cancelling Cal. P.U.C. Sheet No.
San Francisco, California

SCHEDULE E-TDI--INCREMENTAL SALES RATE FOR NEW CUSTOMERS (N)

APPLICABILITY: This tariff is available to qualified customers, at PG&E's discretion. Customers taking service on Schedule E-TDI must sign Standard Form 79-xxxx PG&E's Agreement for Incremental Sales Rate for New Customers ("Agreement"). This tariff is intended to attract incremental load that would, without this tariff, not choose to be served from PG&E's T&D system.

TERRITORY AND RECIPROCITY: This tariff applies everywhere PG&E provides electricity service. In addition, Assembly Bill (AB) 1890 has provided for a reciprocity provision which allows PG&E, where it has lost customers to other T&D service providers through the construction of duplicate T&D facilities, to sell power to that entity's customers.

ELIGIBILITY: To be eligible to take service under this tariff, a customer must: (1) have at least 20 kW demand of eligible load at its premises; (2) demonstrate to PG&E's satisfaction, by providing required documentation, its willingness and ability to receive, or continue to receive, service from a competing T&D service provider; and (3) sign an affidavit stating that the availability of this tariff is the deciding factor in its decision to be served on PG&E's transmission and/or distribution facilities.

A customer shall not be eligible to take service under this tariff if the T&D service offered to the customer is provided by an irrigation district which has promptly confirmed to PG&E that the customer, upon receiving such service, will be exempt from competitive transition charges pursuant to Public Utilities Code Section 374(a)(1), as allocated by the California Energy Commission on April 2, 1997, or Section 374(a)(2). The detailed procedure for determining which customers are eligible to receive Schedule E-TD and E-TDI offers where Section 374(a) exemptions may apply is incorporated as Attachment 1 to the Agreement.

If otherwise eligible, a customer currently taking direct access energy service from another provider shall not be denied this tariff, and a customer already under this tariff may later choose direct access and remain on this tariff. If otherwise eligible, new customers and new load taking direct access service shall not be denied this tariff.

MATERIAL FACTOR AND INFORMATION REQUIREMENTS: In addition to the required affidavit, a customer may be required to provide business operation information and T&D construction plans that are relevant to establishing its initial rate level, or verifying its subsequent rate level. The customer shall be responsible for demonstrating, to PG&E's satisfaction, the credibility of all business operation information relevant to establishing or verifying its rate level as it applies to its premises.

In cases where PG&E wishes to serve a customer of another T&D service provider under the reciprocity provisions of AB 1890, PG&E's evaluation of the competitor's ability to serve is unnecessary and PG&E only requires that the customer sign the affidavit.

In the case of a new customer locating in PG&E's territory, PG&E shall evaluate the competitive offer to determine if the competing service provider has the technical and financial ability to provide the service, and to ensure that there are no environmental or legal barriers to the transaction. Only the deferral of T&D facilities that PG&E anticipates will meet all state and federal regulatory commission standards and codes will qualify a customer for this tariff.

Information requirements are outlined in the Agreement. However, if a customer disagrees with PG&E's conclusion regarding the credibility of any information provided by the customer, the customer may contest PG&E's decision by filing a complaint with the CPUC. (N)

(Continued)

Pacific Gas and Electric Company
San Francisco, California

Original Cal. P.U.C. Sheet No.
Cancelling Cal. P.U.C. Sheet No.

SCHEDULE E-TD--TRANSMISSION AND DISTRIBUTION BYPASS DEFERRAL RATE (N)

(Continued)

RATES: An eligible customer's rates will be discounted from the otherwise applicable tariff to be competitive with the rates that would be achieved by the customer connecting to the transmission and/or distribution facilities of a competing T&D service provider.

In calculating the Competitive Rate, PG&E shall include out-of-pocket competitive transition and other non-bypassable charges that the customer would be obligated to and would itself pay PG&E upon departure, if applicable. The calculation of the Competitive Rate shall be adjusted as appropriate to reflect any agreement by Competitor or any other entity to pay all or part of the customer's obligation to pay the competitive transition or other non-bypassable charges owed to PG&E.

The initial rate will be tied to tariffed rates (or documented non-tariff rate offer, if lower) of the competing T&D service provider, using the customer's historical billing usage and demand patterns (adjusted to reflect possible new load growth, where appropriate) to calculate the minimum discounts required to meet the alternative. Each year, upon the anniversary of the Commencement Date, the rate discount will be adjusted to account for year-to-year changes in the competing T&D service provider's rate using an appropriate index of its system average rate. Under the methodology described above, the customer's Discounted Rate cannot and shall not be set below the customer's competitive alternative.

The discount and annual adjustment are described in the Agreement.

For an E-TD customer who chooses to take direct access energy services from another provider, the customer shall receive, on the bill, PX charges (including but not limited to charges for commodity and ancillary services), public purpose program charges, transmission and distribution charges, CTC charges, and charges for competitive or unbundled services (including but not limited to billing, metering, and credits) to the extent that the calculation and presentation of this information is approved by the Commission in the Cost Separation proceeding.

BILLING DETERMINANTS: To calculate the discount, the customer's annual usage will be determined using PG&E's billing data from the twelve (12) months immediately preceding the date the customer requests to be considered for service under this tariff. If such billing data are not available or if the customer's operation is expected to significantly change within the next year, PG&E's estimate of the customer's upcoming twelve (12) months of usage will be used for purposes of calculating the discount.

DISQUALIFICATION: PG&E may, at its sole discretion, disqualify a customer from obtaining this discount if (1) PG&E believes that the costs to provide adequate T&D facilities makes discounting to a particular customer uneconomic (that is, the discounted rate does not exceed the marginal costs to serve the customer plus 20 percent); or (2) a customer severely constrains the existing T&D system in such a way that the customer's marginal costs in the future are expected to be above the price that would otherwise result from this tariff.

CONTRACT TERM: The T&D Bypass Agreement established by this tariff has a term of up to 5 years, but in no case shall any such Agreement entered into under this tariff remain in effect after December 31, 2001.

COMMENCEMENT DATE: The start date of the discount rate period shall commence within six (6) months from the date of execution of the contract for service and shall be designated by PG&E. The start date shall be no earlier than the date at which, in PG&E's judgment, the customer would have begun taking service from the competing T&D service provider. The customer will be billed at the initial Discounted Rate on the customer's first regular scheduled meter read date after the Agreement is fully executed. (N)

Advice Letter No.
Decision No.

Issued by
Steven L. Kline
Vice President
Regulation

Date Filed
Effective
Resolution No.

25161

Pacific Gas and Electric Company
San Francisco, California

Original Cal. P.U.C. Sheet No.
Cancelling Cal. P.U.C. Sheet No.

SCHEDULE E-TD--TRANSMISSION AND DISTRIBUTION BYPASS DEFERRAL RATE (N)

(Continued)

DISCOUNT FLOOR: Over the term of the Agreement, the sum of the electric charges collected by PG&E from the customer, exclusive of any additional applicable taxes or surcharges, shall not fall below the sum of the following: (1) a level one hundred and twenty percent (120 percent) of PG&E's total customer-specific marginal cost to serve; plus (2) the portion of the customer's otherwise applicable PG&E tariff comprising PG&E's uneconomic costs pursuant to the Public Utilities Code sections 367, 368, 375, and 376. Part (2) of this floor shall not prevent PG&E from matching a Competitor's offer where the Competitor of any other entity has agreed to pay the customer's competitive transition or other non-bypassable charges owed to PG&E, provided PG&E's matching offer: (a) does not fall below part (1) above of the floor; and (b) does not result in less revenue to PG&E from competitive transition or other non-bypassable charges than would occur under the Competitor's offer. The Discount Floor is further defined in the Agreement.

RATES AND RULES: All applicable rates, rules, and tariffs shall remain in force for a customer that signs the Agreement. In the event of a conflict, the terms and conditions provided within this tariff shall supersede those set forth in the standard CPUC-approved tariffs. All other provisions of the customer's otherwise applicable rate schedule shall remain in force. (N)

Advice Letter No.
Decision No.

25152

Issued by
Steven L. Kline
Vice President
Regulation

Date Filed________
Effective________
Resolution No.________

Distribution:
[] Applicant (Original)
[] Division (Original)
[] Field Applications Support (Original)
[] Customer Accounting

Reference:
Elec. Acct. No.: ______________
Premises No.: ______________
Control No.: ______________

PACIFIC GAS AND ELECTRIC COMPANY'S AGREEMENT FOR DISCOUNTED RATES TO AVOID UNECONOMIC BYPASS OF PG&E'S TRANSMISSION AND/OR DISTRIBUTION FACILITIES

This Agreement for Discounted Rates to Avoid Uneconomic Bypass of PG&E's Transmission and/or Distribution System (Agreement) is made between ______________________________, ("Customer" or "The Customer"), a(n) __________________________ Corporation, and PACIFIC GAS AND ELECTRIC COMPANY ("PG&E"), a California corporation. PG&E and the Customer will be referred to collectively herein as the "Parties" or individually as "Party." Customer is deferring its decision to accept service from a competing utility, irrigation district, or other service provider ("Competitor") through the use of Competitor's transmission and/or distribution facilities, thus bypassing the delivery of electricity through PG&E's system at the Customer's premises, located at ____, hereafter referred to as "Premises."

This Agreement provides for a discount to be applied to Customer's otherwise-applicable non-discounted bundled rate schedule, or succeeding unbundled rate schedule(s), to establish an average electric rate comparable to that which would be achieved if the Customer were to obtain its electricity through the Competitor's Transmission and/or Distribution facilities ("Discount Percentage"). This discount is determined by a standardized price calculation and is intended to attract Customer to use PG&E's system by making PG&E's rates to Customer competitive with the rates offered by Competitor.

The Parties agree to the following terms and conditions:

AGREEMENT

1. **Supplemental Agreement.** This Agreement supplements and is part of the Electric General Service Agreement between PG&E and the Customer dated __________.

2. **Initial Discounted Rate.** The Customer's initial Discounted Rate under this Agreement will be calculated as follows:

   The "Competitive Rate" is:

   > The average rate that would be charged to Customer by Competitor including out-of-pocket competitive transition and other non-bypassable charges that Customer would be obligated to and would itself pay PG&E upon departure, if applicable.

The calculation of the Competitive Rate shall be adjusted as appropriate to reflect any agreement by Competitor or any other entity to pay all or part of Customer's obligation to pay the competitive transition or other non-bypassable charges owed to PG&E.

The "Competitive Rate" will be calculated using the Competitor's tariff rates (or other documented, non-tariff rate offer) and Customer's historical billing determinants over the preceding twelve months. Customer's usage will be adjusted for projected load growth.

In situations where PG&E deems that the Competitor's tariff rates do not effectively represent the true electric costs that the Customer will encounter at its site due to receipt by the Customer of a written non-tariff rate offer from the Competitor, the non-tariff rate offer may be used to make this calculation. The Competitive Rate shall not include any surcharges or taxes. The procedures in Attachment 1 to this Agreement shall govern whether a customer is eligible for PG&E's Schedule E-TD.

The "Average Rate" is:

Customer's projected total revenues, using the same usage patterns as derived in the above paragraphs, paid to PG&E divided by the Customer's projected total use. The Customer's otherwise-applicable rate is defined as PG&E's approved rate that applies to the Customer's total projected load at the time that the Average Rate is calculated. The Average Rate shall not include any surcharges or taxes.

The difference between Customer's Average Rate and its Competitive Rate, divided by the Average Rate, will be defined as the Customer's "Discount Percentage." Mathematically, the Discount Percentage equals (Average Rate - Competitive Rate) / Average Rate. The Discount Percentage shall be applied to all of the energy and demand components of Customer's otherwise-applicable rate schedule. These discounted energy and demand components, along with the other non-discounted billing components found in the Customer's otherwise-applicable rate schedule, shall be combined to establish the Customer's initial "Discounted Rate." This initial Discounted Rate will be subject to possible future escalation as described in Section 2. The Customer's initial Discounted Rate, and its subsequent changes, shall be subject to a Discount Floor (see Section 9).

The Discount Percentage and the Customer's initial Discounted Rate are shown in Exhibit A. Under the methodology required above, the Customer's Discounted Rate cannot and shall not be set below the Customer's Competitive Rate.

Customer's otherwise-applicable rate schedule is ________________ (Include Voltage Level).

If otherwise eligible, a customer currently taking direct access energy service from another provider shall not be denied this tariff, and a customer already under this tariff may later choose direct access and remain on this tariff. If otherwise eligible, new customers and new load taking direct access service shall not be denied this tariff.

3. **Rate Index.** The Competitive Rate component of Customer's initial Discounted Rate will be adjusted annually by an index. The index will be equal to the percent change in the system-average rate charged by the Competitor for service to its customers.

Mathematically, the index is equal to "(new Competitor Average Rate - current Competitor Average Rate)/current Competitor Average Rate", where "new Competitor Average Rate" and "current Competitor Average Rate" are both designated from the EEI publication, Competitor's published annual report, or any other publicly available source of information.

One year following, and on each anniversary of the Commencement Date (defined below), the Customer's Discounted Rate will be adjusted. This adjustment will be done by multiplying the Customer's Competitive Rate from the previous year, by the newly calculated Index, and adding the product to the prior Competitive Rate. The newly revised Competitive Rate and the most current PG&E CPUC-approved rate schedule(s) will then be used to calculate the new, adjusted Discounted Rate for Customer.

4. **Informational Requirements.** To qualify for this Agreement, Customer must first provide PG&E with the following information and demonstrate, to PG&E's satisfaction, the credibility of the same as it applies to the Premises:

- Written rate offer from Competitor;
- Any other Customer cost or operational information that PG&E deems pertinent to the analysis.

Customer will sign under the penalty of perjury, have notarized, and deliver to PG&E an affidavit attesting to the fact that without the discounted PG&E rate, it would switch to the Competitor for electric transmission and/or distribution service (Exhibit B). PG&E shall evaluate the information provided by Customer and any other available information and determine in its sole discretion whether Customer qualifies for this Agreement. Should PG&E conclude that Competitor's proposed T&D bypass is not viable for Customer, resulting in denial of a discounted rate to Customer, Customer may file a complaint with the CPUC contesting PG&E's conclusion.

5. **Requirement of Delivery of Electricity through PG&E's System.** Customer shall use PG&E-delivered electricity for its total electrical load requirement throughout the term of this Agreement. Customer shall not use any electricity that is not delivered by PG&E unless the Customer is:

- utilizing emergency generation in the event of an outage;
- testing emergency generation facilities (not to exceed 10 hours per month); or
- given prior written permission by PG&E for similar operational events.

If Customer utilizes any electricity not delivered by PG&E other than as provided above, PG&E may terminate this Agreement as specified in Section 10 ("Termination").

If Customer chooses to take direct access energy services from another provider, Customer shall receive, on the bill, PX charges (including but not limited to charges for commodity and ancillary services), public purpose program charges, transmission and distribution charges, CTC charges, and charges for competitive or unbundled services (including but not limited to billing, metering, and credits) to the extent that the calculation and presentation of this information is approved by the Commission in the Cost Separation proceeding.

GENERAL TERMS AND CONDITIONS

6. **Commencement Date.** This Agreement shall take effect no earlier than the date at which, in PG&E's judgment, the customer would have begun taking service from Competitor. The Customer will be billed at the initial Discounted Rate on the Customer's first regular scheduled meter read date after this Agreement is fully executed. This date shall be deemed the "Commencement Date."

7. **Term.** This Agreement shall remain in effect until December 31, 2001.

8. **Regulatory Authority.** This Agreement shall at all times be subject to such changes or modification by the Public Utilities Commission of the State of California (CPUC) as said Commission may direct from time to time in the exercise of its jurisdiction. Such action by the CPUC may be grounds for termination of this Agreement by either Party.

9. **Discount Floor.** Over the term of this Agreement, the sum of the electric charges collected by PG&E from the Customer, exclusive of any additional applicable taxes or surcharges, shall not fall below the sum of the following: (1) a level one hundred and twenty percent (120%) of PG&E's total, customer-specific, marginal cost to serve; plus (2) the portion of Customer's otherwise applicable PG&E tariff comprising PG&E's uneconomic costs pursuant to Public Utilities Code Sections 367, 368, 375 and 376. Part (2) of this floor shall not prevent PG&E from matching Competitor's offer where Competitor or any other entity has agreed to pay Customer's competitive transition or other non-bypassable charges owed to PG&E, provided PG&E's matching offer: (a) does not fall below part (1) above of the floor; and (b) does not result in less revenue to PG&E from competitive transition or other non-bypassable charges than would occur under

Competitor's offer ("Discount Floor"). These marginal costs will be determined using the CPUC-approved methodology for such calculations in force for this Agreement as these may change or be amended from time to time. On each anniversary of the Commencement Date, PG&E shall compute the total revenue it has collected to date from the Customer, and the sum of the monthly overpayments and underpayments by the Customer relative to PG&E's Discount Floor to ensure that PG&E has collected, at a minimum, the Discount Floor amount. The Parties agree that if at any time the revenues collected up to the review date fall below the Discount Floor, Customer shall pay PG&E a lump sum equal to that shortfall amount. PG&E shall notify customer of any lump sum payment obligation, according to Section 11, no later than thirty (30) days after the anniversary of the Commencement date. This payment will be due and payable in full, without interest, thirty (30) days after PG&E has notified the Customer in writing of its payment obligation.

If a shortfall occurs, and after all shortfall payments described above have been made by Customer, the Customer may request that PG&E simply bill the Customer at a rate equal to the Discount Floor. PG&E will continue to do so until such time as the Customer's Discounted Rate exceeds the Discount Floor, at which time the Customer will once again be billed at the Discounted Rate established in this Agreement. This provision is intended to eliminate the potential for any future lump sum shortfall payments by the Customer.

10. **Termination.** The Customer may terminate this Agreement at any time prior to the end of its term by giving PG&E a minimum of thirty (30) days written notice of such termination.

PG&E may terminate this Agreement upon thirty (30) days written notice to Customer if Customer uses electricity not delivered by PG&E to supply the electrical load at the Premises for a total of nine hundred (900) hours during the term of this Agreement.

Either Party may terminate this Agreement upon thirty (30) days written notice in the event any regulatory body or court of competent jurisdiction finds that a provision of this Agreement, or a portion thereof is unenforceable or invalid, and the terminating Party determines, in good faith, that the remaining provisions of this Agreement have been rendered unenforceable or disadvantageous.

11. **Notice.** Any notice either PG&E or Customer may wish to give to the other must be in writing. Such notice must be either hand delivered, or sent by U.S. registered mail, postage prepaid, to the person designated to receive notice for the other Party, or to such other address as either may designate by written notice. Notices delivered by hand shall be deemed effective when delivered. Notices delivered by mail shall be deemed effective when received, as acknowledged by the receipt of the certified or registered mailing.

To: (Customer)

____
____
____
____

To: PG&E:

Pacific Gas and Electric Company
Tariff Applications
123 Mission Street, Mail Code H28H
San Francisco, CA 94106

12. **Service Reliability.** PG&E's standard for reliability of service for Customer shall be as dictated in PG&E's Electric Rule 14 or its successor; a copy is attached as Exhibit C and is incorporated by reference herein.

13. **Assignment.** Customer may not assign this Agreement to a third party without the prior written permission of an authorized representative of PG&E. Any assignment is subject to any applicable CPUC authorization or regulation except as waived by the CPUC.

14. **Applicable Laws.** This Agreement shall be subject to and interpreted under the laws, rules, and regulations of the State of California and the CPUC, and PG&E's Electric Rules.

15. **Agreements Submitted to the CPUC. A copy of this Agreement will be submitted to the CPUC. PG&E shall use reasonable efforts to protect Customer's identity and information the Customer has identified in writing as proprietary.**

16. **Severability.** In the event that any of the provisions, or portions thereof, of this Agreement are held to be unenforceable or invalid by any court of competent jurisdiction, the validity and enforcement of the remaining provisions or portions thereof shall not be affected thereby; provided, however, that should either Party determine, in good faith, that such unenforceability or invalidity renders the remaining provisions of this Agreement economically infeasible or disadvantageous, such Party may terminate this Agreement upon thirty (30) days prior written notice to the other.

17. **Conflicting Provisions.** This Agreement shall supersede the terms and conditions set forth in the Customer's otherwise-applicable rate schedule and any other applicable standard CPUC approved tariff in the event of conflict. Otherwise, all other CPUC-approved standard tariff terms and conditions shall remain in force and be applicable to this Agreement.

18. **Force Majeure.** Neither Party hereto shall be liable for any failure of performance, other than the continuing obligation to make payments due hereunder for periods prior to the event of force majeure, owing to causes beyond its reasonable control and the occurrence of which could not have prevented by the exercise of due diligence. Refusal by either Party to accede to demands of laborers or labor unions that it considers unreasonable shall not deny it the benefits of this provision. If either Party hereto is unable, for any reason, to deliver or receive full or partial quantities of electricity contemplated by this Agreement due to force majeure, the Party so unable to perform shall promptly advise the other Party that such condition exists, and the Parties shall suspend operations under this Agreement to the extent dictated by the force majeure event, until the event of force majeure is remedied and both Parties can once again deliver and receive electricity, respectively. Any force majeure event shall be remedied as far as possible with all reasonable dispatch. The term "force majeure" as employed herein shall include, but is not be limited to: acts of God; strikes or other industrial disturbances; acts of a public enemy; the direct or indirect effect of governmental orders, actions, or interferences; civil disturbances; explosions; breakage of or accidents to machinery or power lines; power outages; the necessity of making repairs to or alterations of machinery or power lines; landslides; lighting; earthquakes; fires; storms; floods; and washouts. Force majeure shall not include financial considerations.

19. **No Consequential or Incidental Damages.** PG&E shall not be liable for any consequential, incidental, indirect, or special damages, including but not limited to lost profits and loss of power related in any way with the performance of either Party under this Agreement.

20. **Waiver.** A waiver by either Party or any one or more defaults by the other hereunder shall not operate as a waiver of any future default or defaults, whether of a like or of a different character.

IN WITNESS THEREOF, the Parties have executed this Agreement in multiple originals of equal dignity by their respective duly authorized representatives.

Executed this_________day of ________________, 19____.

______________________________ Customer	PACIFIC GAS AND ELECTRIC COMPANY (PG&E)
BY:__________________________ Signature	BY:______________________________ Signature
______________________________ (Type or print name)	__________________________________ (Type or print name)
TITLE:_________________________	TITLE:_____________________________

ATTACHMENT 1
Page 1

Procedure for Determining Which Customers Are Eligible to Receive Schedule E-TD and E-TDI Offers Where Section 374(a) CTC Exemptions May Apply

The procedure described below will be used to determine customers' CTC exemption status for the limited purpose of determining which customer accounts are eligible to receive Schedule E-TD and E-TDI offers from PG&E. The procedure does not supersede any other Commission-adopted tariffs or rules including those for determining departing customers' responsibilities and obligations to pay CTCs and other non-bypassable charges.

1. For each irrigation district (ID) with Section 374 exemptions (either allocated by the California Energy Commission (CEC) through Section 374(a)(1) or granted directly by Section 374(a)(2)), PG&E will maintain two lists: an Exempt Customer List (Exempt List) and a Non-Exempt Customer List (Non-Exempt List). These two lists will officially document the exemption status of customer accounts, as designated by the ID, and their associated loads. For IDs that are subject to the 50 percent agricultural pumping requirement of Section 374(a)(1), the Exempt List will also separately track ag pumping and non-ag pumping loads. The order in which customer accounts are added to the Exempt List will determine their priority for receiving exemptions in situations where either the total load of the accounts on the Exempt List exceeds the ID's cumulative allocation for the year, or the 50 percent agricultural pumping requirement is not met (see Section 12 below). Except as noted in Section 12 below, exemptions apply to the entire load of the customer account, and may not be shared between accounts.

2. Pursuant to Section 374(a)(1) and the CEC's April 2, 1997 decision, cumulative exemption allocations for IDs other than Merced ID are as follows (in megawatts):

ID	1997	1998	1999	2000	2001
Modesto	14.0	15.0	22.0	30.0	35.0
Fresno	0.0	9.0	13.0	15.0	20.0
Laguna	0.0	2.0	4.0	6.0	8.0
S. San Joaquin	0.0	2.0	4.0	6.0	8.0
Total	14.0	28.0	43.0	57.0	71.0

Pursuant to Section 374(a)(1)(D), at least half of each year's allocation to an irrigation district shall be applied to that portion of load that is used to power pumps for agricultural purposes.

ATTACHMENT 1

Page 2

3. Pursuant to Section 374(a)(2), cumulative exemption allocations for Merced ID are as follows (in megawatts):

ID	1997	1998	1999	2000	2001
Merced	23.8	36.6	49.4	62.2	75.0

4. An ID can assign a customer account to the Exempt List at any time by notifying PG&E in writing via panafax. Prior to adding the account to the Exempt List, PG&E will check to see whether the addition of the account to the Exempt List would cause either:

   (a) the total load of all accounts on the Exempt List to exceed the ID's cumulative exemption allocation (shown in Section 2 or 3) for that year by an amount greater than 20 percent of the account's load; or

   (b) (for IDs that are subject to the 50 percent agricultural pumping requirement only) the total load of all non-ag pumping accounts on the Exempt List to exceed half of the ID's cumulative exemption allocation (shown in Section 2) for that year by an amount greater than 20 percent of the account's load.

   If the addition of the account would cause either (a) or (b) to occur, the customer will not be added to the Exempt List (although it may be added the following year, if additional exemptions become available). Otherwise, the account will be added to the Exempt List

5. If a customer approaches PG&E with a competitive offer from an ID with Section 374(a)(1) or Section 374(a)(2) exemptions, either to solicit a counter-proposal or to notify PG&E of its plans to disconnect (pursuant to Section 4.A of PG&E's CTC tariff), or if PG&E otherwise learns that the customer has departed (i.e., the customer violates Section 9601 (b)), PG&E will follow the procedure described below to assign the customer's account to either the Exempt List or the Non-Exempt List:

   a. PG&E will make a written panafaxed inquiry to the ID regarding the exemption status of the customer account. The ID must designate in writing via panafax within five working days whether to place the account on the Exempt List or the Non-Exempt List.

   b. If the ID designates the account for the Exempt List, PG&E will check to see whether the addition of the account to the Exempt List would cause either:

      (i) the total load of all accounts on the Exempt List to exceed the ID's cumulative exemption allocation (shown in Section 2 or 3) for that year by an amount greater than 20 percent of the account's load; or

(ii) (for IDs that are subject to the 50 percent agricultural pumping requirement only) the total load of all non-ag pumping accounts on the Exempt List to exceed half of the ID's cumulative exemption allocation (shown in Section 2) for that year by an amount greater than 20 percent of the account's load.

If the addition of the account would cause either (i) or (ii) to occur, the customer will not be added to the Exempt List (although it may be added the following year, if additional exemptions become available). Otherwise, the account will be added to the Exempt List.

c. If the ID designates the account for the Non-Exempt List, then the customer will be placed on the Non-Exempt List.

d. If the ID does not respond in writing via panafax within the stipulated time period, the default assumption is that the ID does not intend to offer a CTC exemption, and the account will be placed on the Non-Exempt List.

6. If a dispute arises about the assignment of a customer to the Exempt List (including the assignment of its load to the ag pumping vs. non-ag pumping categories), the customer will temporarily be assigned to a third list, the Disputed List. The dispute will be referred to a grievance committee, who will issue a decision within 30 days of the notice of the dispute. The decision of the grievance committee will be final.

   The dispute resolution process will be as follows:

   a. If PG&E contests the assignment of the customer's load to the Exempt List, it will notify the ID within 3 days of receipt of the notice of the assignment that it contests the status, with copies to the members of the grievance committee.

   b. The grievance committee will be composed of a representative from PG&E, a representative from the ID, and a representative from either the CEC or from a private judging service that is agreeable to both parties. Within 15 days of the issuance of a final decision in this proceeding, the settling parties will designate the third representative via a filing to the CPUC.

   c. Once the grievance committee has received written notice of the dispute, it may investigate the facts through written requests for information, but must hold a meeting within 14 days of the notice of the dispute. At the meeting both parties will have an opportunity to present what each considers to be pertinent facts for resolution of the dispute. The parties will cooperate to provide prompt and reasonable discovery prior to the meeting. Any disputes regarding discovery will be resolved by conference call with the grievance committee.

d. A written decision of the proper assignment of the customer's load to either the Exempt List or Non-Exempt List must be issued within 10 days of the meeting.

Once the dispute is resolved, the account's load will be assigned to the Exempt List or Non-Exempt List pursuant to the outcome of the dispute resolution process.

If PG&E issues a notice of a dispute pursuant to Section 6.a above, then during the 30-day resolution period the customer cannot be connected to the ID's system.

7. For purposes of determining exemption status, and to assess compliance with the 50 percent agricultural pumping requirement in Section 374(a)(1)(D), customer loads will be estimated on a one-time basis at the time they are placed on the list using the method prescribed by the CEC's December 24, 1996 Instructions for Applications For Irrigation District Exemption Allocations.[1] These load estimates will remain fixed throughout the transition period regardless of subsequent changes in customer usage patterns.

8. PG&E will update both the Exempt List and the Non-Exempt List on an ongoing basis as additional customer accounts have their status designated by the ID. All ID designations are binding and cannot subsequently be changed, with the following two exceptions. If a customer on the Exempt List that is taking service from an ID subsequently either: (a) ceases doing business; or (b) returns to PG&E service; then the customer will be removed from the Exempt list and the customer's exemption allocation will revert back to the ID for possible use elsewhere.

9. Both lists will be maintained on a confidential basis, but will be made available by PG&E upon request to the ID and Commission staff. At the time they are added to the Exempt List, customers will be provided with information pertaining to their individual accounts' loads and exemptions, with copy sent to the ID.

10. PG&E agrees not to offer Schedule E-TD or E-TDI to any customer account on the Exempt List or the Disputed List.

11. PG&E may offer Schedule E-TD or E-TDI to any customer account on the Non-Exempt List, so long as all tariff eligibility requirements are met.

---

[1] Pursuant to Section 374(b)(2)(D), the loads already served by Merced ID as of June 1, 1996 shall be deducted from its 75 MW allocation, and the remaining allocation phased in over five years in accordance with Section 374(b)(2)(A). These statutory provisions mean that Merced's Exemption List already includes 11 MW of load that departed PG&E's system prior to June 1, 1996, and Merced's remaining exemption allocation totals 64 MW. The 11 MW allocation is assumed to start in 1997, while the remaining 64 MW allocation is phased in equally over the five-year transition period.

ATTACHMENT 1
Page 5

12. The last account added to the Exempt List may still be obligated to pay CTCs for the portion of its load that, in combination with the loads of all other accounts on the Exempt List, exceeds the ID's cumulative exemption allocation for the year. In addition, some or all customer accounts on the Exempt List may be obligated to pay CTCs until such time as the 50 percent agricultural pumping requirement under Section 374(a)(1)(D) has been met.

EXHIBIT A

DISCOUNT AMOUNT WORKSHEET

I. CUSTOMER'S COMPETITIVE RATE
(reference Tariff Sheet(s) or other written offer, attach calculations) ________________

II. CUSTOMER'S AVERAGE STANDARD RATE
(under otherwise applicable rate, attach calculations) ________________

III. DISCOUNT PERCENTAGE
(Average Rate - Competitive Rate)/ Average Rate ________________

Apply Discount Percentage to energy and demand charges to determine Customer's initial Discounted Rate.

Customer's initial Discounted Rate, less non-energy and non-demand components of otherwise-applicable rate is listed below:
Mark "N/A" if the charges is not applicable:

SUMMER

	Demand Charges	Energy Charges
Maximum	________________per kW	________________per kWh
On-Peak	________________per kW	________________per kWh
Partial-Peak	________________per kW	________________per kWh
Off-Peak	________________per kW	________________per kWh

WINTER

	Demand Charges	Energy Charges
Maximum	________________per kW	________________per kWh
On-Peak	________________per kW	________________per kWh
Partial-Peak	________________per kW	________________per kWh
Off-Peak	________________per kW	________________per kWh

EXHIBIT B

MATERIAL FACTOR
AFFIDAVIT

Under penalty of perjury, I, __________________________, hereby state:

I am the _______________________________ of ______________________________,
(Title) (Parent Company)

a _______________________ corporation, and am authorized to make this affidavit
(State)

on behalf of __________________________ ("Company").
(Company)

Pacific Gas and Electric Company (PG&E) and Company propose to enter into an agreement under which PG&E would deliver electric service to Company's premises. This Proposed Agreement for Discounted Rate to Avoid Uneconomic Bypass of PG&E's Transmission and/or Distribution Facilities ("Agreement") conveys PG&E's offer of an electric service pricing discount at our premises, if we decide not to take delivery of electricity at our Premises through Competitor's proposed Transmission and/or Distribution facilities. My current electric load already being served by PG&E, or soon to be served by PG&E by the year ________, which is at risk of bypass by Competitor's proposed system, is approximately _________ kWh/yr.

Premises Location__________________________

Company has decided not to proceed with receiving electric service from the Competitor's proposed transmission and/or distribution facility at this time: Furthermore, the pricing discount offered by PG&E in the Agreement is the sole material factor in Company's decision not to proceed with receiving service from the Competitor's proposed transmission and/or distribution facility at this time.

Executed at ___________________, California, this ________ day of _______, 19___.

Notarized by:

____
(enter full Company name)

By: _________________________

Title: ________________________

EXHIBIT C

RULE 14 -- SHORTAGE OF SUPPLY AND INTERRUPTION OF DELIVERY

PG&E Pacific Gas and Electric Company
San Francisco, California

Revised Cal. P.U.C. Sheet No. 11326-E
Cancelling Revised Cal. P.U.C. Sheet No. 1079-E

RULE 14--SHORTAGE OF SUPPLY AND INTERRUPTION OF DELIVERY (T)

PG&E will exercise reasonable diligence and care to furnish and deliver a continuous and sufficient supply of electric energy to the customer, but does not guarantee continuity or sufficiency of supply. PG&E will not be liable for interruption or shortage or insufficiency of supply, or any loss or damage of any kind of character occasioned thereby, if same is caused by inevitable accident, act of God, fire, strikes, riots, war, or any other cause except that arising from its failure to exercise reasonable diligence.

PG&E, whenever it shall find it necessary for the purpose of making repairs or improvements to its system, will have the right to suspend temporarily the delivery of electric energy, but in all such cases, as reasonable notice thereof as circumstances will permit, will be given to the customers, and the making of such repairs or improvements will be prosecuted as rapidly as may be practicable, and, if practicable, at such times as will cause the least inconvenience to the customers.

In case of shortage of supply and during the period of such shortage, PG&E will make such apportionment of its available supply of energy among its customers as shall be ordered or directed from time to time by the Railroad Commission of the State of California, acting either directly or by a power administrator or other official appointed by it for that purpose. In the absence of such order or direction by the Railroad Commission, PG&E will, in times of shortage, apportion its available supply of energy among all customers in the most reasonable manner possible.

Advice Letter No. 1306-E
Decision No.

6784

Issued by
Gordon R. Smith
Vice President and
Chief Financial Officer

Date Filed July 12, 1990
Effective August 21, 1990
Resolution No. ________

PG&E's amended Schedule E-TDI Tariff, including attached Agreement for Incremental Sales to New Customers

AMENDED

Tariff Amended July 9, 1997
Agreement Amended July 3, 1997

(N)

SCHEDULE E-TD--TRANSMISSION AND DISTRIBUTION BYPASS DEFERRAL RATE

APPLICABILITY: This tariff is available to qualified customers, at PG&E's discretion. Customers taking service on Schedule E-TD must sign Standard Form 79-xxxx PG&E's Agreement for Discounted Rates to Avoid Uneconomic Bypass of PG&E's Transmission and/or Distribution Facilities ("Agreement"). This tariff is intended to retain existing load that would, without this tariff, not remain on PG&E's T&D System.

TERRITORY: This tariff applies everywhere PG&E provides electricity service.

ELIGIBILITY: To be eligible to take service under this tariff, a customer must: (1) have at least 20 kW demand of eligible load at its premises on PG&E's system; (2) demonstrate to PG&E's satisfaction, by providing required documentation, its willingness and ability to receive service from a competing T&D service provider; and (3) sign an affidavit stating that the availability of this tariff is the deciding factor in its decision not to connect with a competing T&D service provider.

A customer shall not be eligible to take service under this tariff if the T&D service offered to the customer is provided by an irrigation district which has promptly confirmed to PG&E that the customer, upon receiving such service, will be exempt from competitive transition charges pursuant to Public Utilities Code Section 374(a)(1), as allocated by the California Energy Commission on April 2, 1997, or Section 374(a)(2). The detailed procedure for determining which customers are eligible to receive Schedule E-TD and E-TDI offers where Section 374(a) exemptions may apply is incorporated as Attachment 1 to the Agreement.

If otherwise eligible, a customer currently taking direct access energy service from another provider shall not be denied this tariff, and a customer already under this tariff may later choose direct access and remain on this tariff. If otherwise eligible, new customers and new load taking direct access service shall not be denied this tariff.

MATERIAL FACTOR AND INFORMATION REQUIREMENTS: In addition to the required affidavit, a customer may be required to provide business operation information and T&D construction plans that are relevant to establishing its initial rate level, or verifying its subsequent rate level. The customer shall be responsible for demonstrating, to PG&E's satisfaction, the credibility of all business operation information relevant to establishing or verifying its rate level as it applies to its premises.

PG&E shall evaluate the competitive offer to determine if the competing service provider has the technical and financial ability to provide the service, and to ensure that there are no environmental or legal barriers to the transaction. Only the deferral of the construction of T&D facilities that PG&E anticipates will meet all state and federal regulatory commission standards and codes will qualify a customer for this tariff.

Information requirements are outlined in the Agreement. However, if a customer disagrees with PG&E's conclusion regarding the credibility of any information provided by the customer, the customer may contest PG&E's decision by filing a complaint with the CPUC. (N)

(Continued)

SCHEDULE E-TOI--INCREMENTAL SALES RATE FOR NEW CUSTOMERS (N)

(Continued)

RATES: An eligible customer's rates will be discounted from the otherwise applicable tariff to be competitive with the rates offered by the competing T&D service provider.

In calculating the Competitive Rate, PG&E shall make any necessary adjustments to account for any out-of-pocket competitive transition and other non-bypassable charges that the customer would be obligated to and would itself pay Competitor upon departure, if applicable. The calculation of the Competitive Rate shall be adjusted as appropriate to reflect any agreement by PG&E or any other entity to pay all or part of the customer's obligation to pay the competitive transition or other non-bypassable charges owed to Competitor.

In addition, in calculating the Competitive Rate, PG&E shall include out-of-pocket competitive transition and other non-bypassable charges that the customer would be obligated to and would itself pay PG&E upon departure, if applicable. The calculation of the Competitive Rate shall also be adjusted as appropriate to reflect any agreement by Competitor or any other entity to pay all or part of the customer's obligation to pay the competitive transition or other non-bypassable charges owed to PG&E.

The initial rate will be tied to tariffed rates (or documented non-tariff rate offer, if lower) of the competing T&D service provider, using the customer's historical billing usage and demand patterns (adjusted to reflect possible load growth, where appropriate) to calculate the minimum discounts required to meet the alternative. Each year, upon the anniversary of the Commencement Date, the rate discount will be adjusted to account for year-to-year changes in the competing T&D service provider's rate using an appropriate index of its system average rate. Under the methodology described above, the customer's Discounted Rate cannot and shall not be set below the customer's competitive alternative.

The discount and annual adjustment are described in the Agreement.

For an E-TOI customer who chooses to take direct access energy services from another provider, the customer shall receive, on the bill, PX charges (including but not limited to charges for commodity and ancillary services), public purpose program charges, transmission and distribution charges, CTC charges, and charges for competitive or unbundled services (including but not limited to billing, metering, and credits) to the extent that the calculation and presentation of this information is approved by the Commission in the Cost Separation proceeding.

BILLING DETERMINANTS: To calculate the discount, the customer's annual usage will be determined using PG&E's billing data from the twelve (12) months immediately preceding the date the customer requests to be considered for service under this tariff. If such billing data are not available or if the customer's operation is expected to significantly change within the next year, PG&E's estimate of the customer's upcoming twelve (12) months of usage will be used for purposes of calculating the discount. (N)

Pacific Gas and Electric Company
San Francisco, California

Original Cal. P.U.C. Sheet No.
Cancelling Cal. P.U.C. Sheet No.

SCHEDULE E-TDI--INCREMENTAL SALES RATE FOR NEW CUSTOMERS (N)

(Continued)

DISQUALIFICATION: PG&E may, at its sole discretion, disqualify a customer from obtaining this discount if (1) PG&E believes that the costs to provide adequate transmission and distribution facilities make discounting to a particular customer uneconomic (that is, the discounted rate does not exceed the marginal costs to serve that customer plus 20 percent); or (2) a customer severely constrains the existing transmission and distribution system in such a way that the customer's marginal costs in the future are expected to be above the price that would otherwise result from this tariff.

CONTRACT TERM: The Incremental Sales Agreement established under this tariff has a term of up to 5 years, but in no case shall any such Agreement entered under this tariff remain in effect after December 31, 2001.

COMMENCEMENT DATE: The start date of the discount rate period shall commence within six (6) months from the date of execution of the contract for service and shall be designated by PG&E. For customers not currently taking service with either PG&E or the competing T&D service provider, the start date shall be no earlier than the date at which, in PG&E's judgment, the customer would have begun taking service from the competing T&D service provider. The customer will be billed at the initial Discounted Rate on the customer's first regular scheduled meter read date after the Agreement is fully executed.

DISCOUNT FLOOR: Over the term of the Agreement, the sum of the electric charges collected by PG&E from the customer, exclusive of any additional applicable taxes or surcharges, shall not fall below the sum of the following: (1) a level one hundred and twenty percent (120 percent) of PG&E's total customer-specific marginal cost to serve; plus (2) the portion of the customer's otherwise applicable PG&E tariff comprising PG&E's uneconomic costs pursuant to the Public Utilities Code sections 367, 368, 375, and 376. Part (2) of this floor shall not prevent PG&E from matching a Competitor's offer where the Competitor of any other entity has agreed to pay the customer's competitive transition or other non-bypassable charges owed to PG&E, provided PG&E's matching offer: (a) does not fall below part (1) above of the floor; and (b) does not result in less revenue to PG&E from competitive transition or other non-bypassable charges than would occur under the Competitor's offer. The Discount Floor is further defined in the Agreement.

RATES AND RULES: All applicable rates, rules, and tariffs shall remain in force for a customer that signs the Agreement. In the event of a conflict, the terms and conditions provided within this tariff shall supersede those set forth in the standard CPUC-approved tariffs. All other provisions of the customer's otherwise applicable rate schedule shall remain in force. (N)

Advice Letter No.
Decision No.

Issued by
Steven L. Kline
Vice President
Regulation

Date Filed
Effective
Resolution No.

25155

Distribution:
[] Applicant (Original)
[] Division (Original)
[] Field Applications Support (Original)
[] Customer Accounting

Reference:
Elec. Acct. No.: ______________
Premises No.: ______________
Control No.: ______________

PACIFIC GAS AND ELECTRIC COMPANY'S AGREEMENT FOR INCREMENTAL SALES TO NEW CUSTOMERS

This Agreement for Incremental Sales to New Customers (Agreement) is made between ____________________________ ("Customer" or "The Customer"), a(n) __________________________ corporation, and PACIFIC GAS AND ELECTRIC COMPANY ("PG&E"), a California corporation. PG&E and the Customer will be referred to collectively herein as the "Parties" or individually as "Party." Customer currently receives, or potentially could receive, electric service from a competing utility, irrigation district or other electric service provider ("Competitor"), and wishes to receive electric service from PG&E for its premises located at ____, hereafter referred to as "Premises."

This Agreement provides for a discount to be applied to Customer's otherwise-applicable bundled PG&E rate schedule, or succeeding unbundled schedule(s), to establish an average PG&E electric rate comparable to that which would be achieved if the Customer were to either begin to use, or continue to use Competitor to meet its electric service requirements. This discount is determined by a standardized price calculation and is intended to attract Customer to use PG&E's system by making PG&E's rates to Customer competitive with the rates offered by Competitor.

The Parties agree to the following terms and conditions:

AGREEMENT

1. **Supplemental Agreement.** This Agreement supplements and is part of the PG&E's Electric General Service Agreement.

2. **Initial Discounted Rate.** The Customer's initial Discounted Rate under this Agreement will be calculated as follows:

   The "Competitive Rate" is:

   > The average rate that is (or would be) charged to Customer by Competitor, minus out-of-pocket competitive transition and other non-bypassable charges that Customer would be obligated to and would itself pay Competitor upon departure, if applicable. The calculation of the Competitive Rate shall be adjusted as appropriate to reflect any agreement by PG&E or any other entity to pay all or

part of Customer's obligation to pay the competitive transition or other non-bypassable charges owed to Competitor.

In addition, in calculating the Competitive Rate, PG&E shall include out-of-pocket competitive transition and other non-bypassable charges that Customer would be obligated to and would itself pay PG&E upon departure, if applicable. The calculation of the Competitive Rate shall be adjusted as appropriate to reflect any agreement by Competitor or any other entity to pay all or part of Customer's obligation to pay the competitive transition or other non-bypassable charges owed to PG&E.

The "Competitive Rate" is calculated using the Competitor's tariff rates (or other documented non-tariff rate) and, where available, Customer's historical billing usage and demand patterns. Customer's usage may be adjusted for projected load growth. Where historical billing usage is not available, as with the case of a new customer, PG&E will use Customer's projected usage patterns over the next twelve (12) months.

In situations where PG&E deems that the Competitor's tariff rates do not effectively represent the true electric costs that the Customer is currently receiving, or will encounter, at its premises due to receipt by the Customer of a written non-tariff rate offer from the Competitor, the non-tariff rate offer will be used to make this calculation. The Competitive Rate shall not include any surcharges or taxes. The procedures in Attachment 1 to this Agreement shall govern whether a customer is eligible for PG&E's Schedule E-TDI.

The "Average Rate" is:

Customer's projected total revenues, using the same usage patterns as derived in the above paragraphs, paid to PG&E divided by the Customer's projected total use. The Customer's otherwise-applicable rate is defined as PG&E's approved rate that applies to the Customer's total projected load at the time that the Average Rate is calculated. The Average Rate shall not include any surcharges or taxes.

The difference between Customer's Average Rate and its Competitive Rate, divided by the Average Rate, will be defined as the Customer's "Discount Percentage." Mathematically, the Discount Percentage equals (Average Rate - Competitive Rate) / Average Rate. The Discount Percentage shall be applied to all of the energy and demand components of Customer's otherwise-applicable rate schedule. These discounted energy and demand components, along with the other non-discounted billing components found in the Customer's otherwise-applicable rate, shall be combined to establish the Customer's initial Discounted Rate. This initial Discounted Rate will be subject to possible future adjustment as described in Section 2. The Customer's Discounted Rate, and its subsequent adjustment, shall be subject to a Discount Floor (see Section 9).

The Discount Percentage and the Customer's initial Discounted Rate are shown in Exhibit A. Under the methodology required above, the Customer's Discounted Rate cannot and shall not be set below the Customer's Competitive Rate.

PG&E's otherwise-applicable rate schedule that applies to the Premises is:
_____________________ (Include Voltage Level).

If otherwise eligible, a customer currently taking direct access energy service from another provider shall not be denied this tariff, and a customer already under this tariff may later choose direct access and remain on this tariff. If otherwise eligible, new customers and new load taking direct access service shall not be denied this tariff.

3. **Rate Index.** The Competitive Rate component of Customer's initial Discounted Rate will be adjusted annually by an index. The index will be equal to the percent change in the average rate charged by the Competitor for service to its customers.

Mathematically, the index is equal to "(new Competitor Average Rate - current Competitor Average Rate)/current Competitor Average Rate", where "new Competitor Average Rate" and "current Competitor Average Rate" are both designated from the EEI publication, Competitor's published annual report, or any other publicly available source of information.

One year following, and on each anniversary of the Commencement Date (defined below), the Customer's Discounted Rate will be adjusted. This adjustment will be done by multiplying the Customer's Competitive Rate from the previous year, by the newly calculated Index, and adding the product to the prior Competitive Rate. The newly revised Competitive Rate and the most current PG&E CPUC-approved rate schedule(s) will then be used to calculate the new, adjusted Discounted Rate for Customer.

4. **Informational Requirements.** To qualify for this Agreement, Customer must first provide PG&E with the following information as it applies to its Premises:

- written rate offer from Competitor;
- projected electric usage requirements from PG&E's system;
- any other Customer operational information that PG&E deems pertinent to the analysis.

Customer will sign under the penalty of perjury, have notarized, and deliver to PG&E an affidavit attesting to the fact that without the discounted PG&E rate, it would take service from, or continue to take service from, the Competitor for electric transmission and/or distribution service (Exhibit B). PG&E shall evaluate the information provided by Customer and any other available information and determine in its sole discretion whether Customer qualifies for this Agreement. Should PG&E conclude that Customer's proposed T&D service alternative is not viable for Customer, resulting in denial of a discounted rate to Customer, Customer may file a complaint with the CPUC contesting PG&E's conclusion.

5. **Requirement of Delivery of Electricity through PG&E's System.** Customer shall use PG&E-delivered electricity for its total electrical load requirement throughout the term of this Agreement. Customer shall not use any electricity that is not delivered by PG&E unless the Customer is:

- utilizing emergency generation in the event of an outage;
- testing such emergency generation facilities (not to exceed 10 hours per month); or
- given prior written permission by PG&E for similar operational events.

If Customer utilizes any electricity not delivered by PG&E other than provided above, then PG&E may terminate this Agreement as specified in Section 10 ("Termination"). If Customer chooses to take direct access energy services from another provider, Customer shall receive, on the bill, PX charges (including but not limited to charges for commodity and ancillary services), public purpose program charges, transmission and distribution charges, CTC charges, and charges for competitive or unbundled services (including but not limited to billing, metering, and credits) to the extent that the calculation and presentation of this information is approved by the Commission in the Cost Separation proceeding.

GENERAL TERMS AND CONDITIONS

6. **Commencement Date.** For customers not currently taking service with either PG&E or Competitor, this Agreement shall take effect no earlier than the date at which, in PG&E's judgment, the customer would have begun taking service from Competitor. The Customer will be billed at the initial Discounted Rate on the Customer's first regular scheduled meter read date after this Agreement is fully executed. This date shall be deemed the "Commencement Date."

7. **Term.** This Agreement shall remain in effect until December 31, 2001.

8. **Regulatory Authority.** This Agreement shall at all times be subject to such changes or modification by the Public Utilities Commission of the State of California (CPUC) as said Commission may, from time to time, direct in the exercise of its jurisdiction. Such action by the CPUC may be grounds for termination of this Agreement by either Party.

9. **Discount Floor.** Over the term of this Agreement, the sum of the electric charges collected by PG&E from the Customer, exclusive of any additional applicable taxes or surcharges, shall not fall below the sum of the following: (1) a level one hundred and twenty percent (120%) of PG&E's total, customer-specific, marginal cost to serve; plus (2) the portion of Customer's otherwise applicable PG&E tariff comprising PG&E's uneconomic costs pursuant to Public Utilities Code Sections 367, 368, 375 and 376. Part (2) of this floor shall not prevent PG&E from matching Competitor's offer where Competitor or any other entity has agreed to pay Customer's competitive transition or other non-bypassable charges owed to PG&E, provided PG&E's matching offer: (a) does not fall below part (1) above of the floor; and (b) does not result in less revenue to PG&E from competitive transition or other non-bypassable charges than would occur under Competitor's offer ("Discount Floor"). These marginal costs will be determined using the CPUC-approved methodology for such calculations in force for this Agreement as these may change or be amended from time to time. On each anniversary of the Commencement Date, PG&E shall compute the total revenue it has collected to date from the Customer, and the sum of the monthly overpayments and underpayments by the Customer relative to PG&E's Discount Floor to ensure that PG&E has collected, at a minimum, the Discount Floor amount. The Parties agree that if at any time the revenues collected up to the review date fall below the Discount Floor, Customer shall pay PG&E a lump sum equal to that shortfall amount. PG&E shall notify customer of any lump sum payment obligation, according to Section 11, no later than thirty (30) days after the anniversary of the Commencement date. This payment will be due and payable in full, without interest, thirty (30) days after PG&E has notified the Customer in writing of its payment obligation.

If a shortfall occurs, and after all shortfall payments described above have been made by Customer, the Customer may request that PG&E simply bill the Customer at a rate equal to the Discount Floor. PG&E will continue to do so until such time as the Customer's Discounted Rate exceeds the Discount Floor, at which time the Customer will once again be billed at the Discounted Rate established in this Agreement. This provision is intended to eliminate the potential for any future lump sum shortfall payments by the Customer.

10. **Termination.** The Customer may terminate this Agreement at any time prior to the end of its term by giving PG&E a minimum of thirty (30) days written notice of such termination.

PG&E may terminate this Agreement upon thirty (30) days written notice to Customer if Customer uses electricity not delivered by PG&E to supply the electrical load at the Premises for a total of nine hundred (900) hours during the term of this Agreement.

Either Party may terminate this Agreement upon thirty (30) days written notice in the event any regulatory body or court of competent jurisdiction finds that a provision of this Agreement, or a portion thereof is unenforceable or invalid, and the terminating Party determines, in good faith, that the remaining provisions of this Agreement have been rendered unenforceable or disadvantageous.

11. **Notice.** Any notice either PG&E or Customer may wish to give to the other must be in writing. Such notice must be either hand delivered, or sent by U.S. registered mail, postage prepaid, to the person designated to receive notice for the other Party, or to such other address as either may designate by written notice. Notices delivered by hand shall be deemed effective when delivered. Notices delivered by mail shall be deemed effective when received, as acknowledged by the receipt of the certified or registered mailing.

To: (Customer)

____

____

____

____

To: PG&E:

Pacific Gas and Electric Company
Tariff Applications
123 Mission Street, Mail Code H28H
San Francisco, CA 94106

12. **Service Reliability.** PG&E's standard for reliability of service for Customer shall be as dictated in PG&E's Electric Rule 14 or its successor; a copy is attached as Exhibit C and is incorporated by reference herein.

13. **Assignment.** Customer may not assign this Agreement to a third party without the prior written permission of an authorized representative of PG&E. Any assignment is subject to any applicable CPUC authorization or regulation except as waived by the CPUC.

14. **Applicable Laws.** This Agreement shall be subject to and interpreted under the laws, rules, and regulations of the State of California and the CPUC, and PG&E's Electric Rules.

15. **Agreements Submitted to the CPUC. A copy of this Agreement will be submitted to the CPUC. PG&E shall use reasonable efforts to protect Customer's identity and information the Customer has identified in writing as proprietary.**

16. **Severability.** In the event that any of the provisions, or portions thereof, of this Agreement are held to be unenforceable or invalid by any court of competent jurisdiction, the validity and enforcement of the remaining provisions or portions thereof shall not be affected thereby; provided, however, that should either Party determine, in good faith, that such unenforceability or invalidity renders the remaining provisions of this Agreement economically infeasible or disadvantageous, such Party may terminate this Agreement upon thirty (30) days prior written notice to the other.

17. **Conflicting Provision.** This Agreement shall supersede the terms and conditions set forth in the Customer's otherwise-applicable rate schedule and any other applicable standard CPUC approved tariff in the event of conflict. Otherwise, all other CPUC-approved standard tariff terms and conditions shall remain in force and be applicable to this Agreement.

18. **Force Majeure.** Neither Party hereto shall be liable for any failure of performance, other than the continuing obligation to make payments due hereunder for periods prior to the event of force majeure, owing to causes beyond its reasonable control and the occurrence of which could not have prevented by the exercise of due diligence. Refusal by either Party to accede to demands of laborers or labor unions that it considers unreasonable shall not deny it the benefits of this provision. If either Party hereto is unable, for any reason, to deliver or receive full or partial quantities of electricity contemplated by this Agreement due to force majeure, the Party so unable to perform shall promptly advise the other Party that such condition exists, and the Parties shall suspend operations under this Agreement to the extent dictated by the force majeure event, until the event of force majeure is remedied and both Parties can once again deliver and receive electricity, respectively. Any force majeure event shall be remedied as far as possible with all reasonable dispatch. The term "force majeure" as employed herein shall include, but is not be limited to: acts of God; strikes or other industrial disturbances; acts of a public enemy; the direct or indirect effect of governmental orders, actions, or interferences; civil disturbances; explosions; breakage of or accidents to machinery or power lines; power outages; the necessity of making repairs to or alterations of machinery or power lines; landslides; lighting; earthquakes; fires; storms; floods; and washouts. Force majeure shall not include financial considerations.

19. **No Consequential or Incidental Damages.** PG&E shall not be liable for any consequential, incidental, indirect, or special damages, including but not limited to lost profits and loss of power related in any way with the performance of either Party under this Agreement.

20. **Waiver.** A waiver by either Party or any one or more defaults by the other hereunder shall not operate as a waiver of any future default or defaults, whether of a like or of a different character.

IN WITNESS THEREOF, the Parties have executed this Agreement in multiple originals of equal dignity by their respective duly authorized representatives.

Executed this_________day of _______________, 19____.

________________________ Customer	PACIFIC GAS AND ELECTRIC COMPANY (PG&E)
BY:______________________ Signature	BY:______________________ Signature
________________________ (Type or print name)	________________________ (Type or print name)
TITLE:____________________	TITLE:____________________

ATTACHMENT 1

Page 1

Procedure for Determining Which Customers Are Eligible to Receive Schedule E-TD and E-TDI Offers Where Section 374(a) CTC Exemptions May Apply

The procedure described below will be used to determine customers' CTC exemption status for the limited purpose of determining which customer accounts are eligible to receive Schedule E-TD and E-TDI offers from PG&E. The procedure does not supersede any other Commission-adopted tariffs or rules including those for determining departing customers' responsibilities and obligations to pay CTCs and other non-bypassable charges.

1. For each irrigation district (ID) with Section 374 exemptions (either allocated by the California Energy Commission (CEC) through Section 374(a)(1) or granted directly by Section 374(a)(2)), PG&E will maintain two lists: an Exempt Customer List (Exempt List) and a Non-Exempt Customer List (Non-Exempt List). These two lists will officially document the exemption status of customer accounts, as designated by the ID, and their associated loads. For IDs that are subject to the 50 percent agricultural pumping requirement of Section 374(a)(1), the Exempt List will also separately track ag pumping and non-ag pumping loads. The order in which customer accounts are added to the Exempt List will determine their priority for receiving exemptions in situations where either the total load of the accounts on the Exempt List exceeds the ID's cumulative allocation for the year, or the 50 percent agricultural pumping requirement is not met (see Section 12 below). Except as noted in Section 12 below, exemptions apply to the entire load of the customer account, and may not be shared between accounts.

2. Pursuant to Section 374(a)(1) and the CEC's April 2, 1997 decision, cumulative exemption allocations for IDs other than Merced ID are as follows (in megawatts):

ID	1997	1998	1999	2000	2001
Modesto	14.0	15.0	22.0	30.0	35.0
Fresno	0.0	9.0	13.0	15.0	20.0
Laguna	0.0	2.0	4.0	6.0	8.0
S. San Joaquin	0.0	2.0	4.0	6.0	8.0
Total	14.0	28.0	43.0	57.0	71.0

Pursuant to Section 374(a)(1)(D), at least half of each year's allocation to an irrigation district shall be applied to that portion of load that is used to power pumps for agricultural purposes.

ATTACHMENT 1
Page 2

3. Pursuant to Section 374(a)(2), cumulative exemption allocations for Merced ID are as follows (in megawatts):

ID	1997	1998	1999	2000	2001
Merced	23.8	36.6	49.4	62.2	75.0

4. An ID can assign a customer account to the Exempt List at any time by notifying PG&E in writing via panafax. Prior to adding the account to the Exempt List, PG&E will check to see whether the addition of the account to the Exempt List would cause either:

    (a) the total load of all accounts on the Exempt List to exceed the ID's cumulative exemption allocation (shown in Section 2 or 3) for that year by an amount greater than 20 percent of the account's load; or

    (b) (for IDs that are subject to the 50 percent agricultural pumping requirement only) the total load of all non-ag pumping accounts on the Exempt List to exceed half of the ID's cumulative exemption allocation (shown in Section 2) for that year by an amount greater than 20 percent of the account's load.

    If the addition of the account would cause either (a) or (b) to occur, the customer will not be added to the Exempt List (although it may be added the following year, if additional exemptions become available). Otherwise, the account will be added to the Exempt List

5. If a customer approaches PG&E with a competitive offer from an ID with Section 374(a)(1) or Section 374(a)(2) exemptions, either to solicit a counter-proposal or to notify PG&E of its plans to disconnect (pursuant to Section 4.A of PG&E's CTC tariff), or if PG&E otherwise learns that the customer has departed (i.e., the customer violates Section 9601 (b)), PG&E will follow the procedure described below to assign the customer's account to either the Exempt List or the Non-Exempt List:

    a. PG&E will make a written panafaxed inquiry to the ID regarding the exemption status of the customer account. The ID must designate in writing via panafax within five working days whether to place the account on the Exempt List or the Non-Exempt List.

    b. If the ID designates the account for the Exempt List, PG&E will check to see whether the addition of the account to the Exempt List would cause either:

        (i) the total load of all accounts on the Exempt List to exceed the ID's cumulative exemption allocation (shown in Section 2 or 3) for that year by an amount greater than 20 percent of the account's load; or

(ii) (for IDs that are subject to the 50 percent agricultural pumping requirement only) the total load of all non-ag pumping accounts on the Exempt List to exceed half of the ID's cumulative exemption allocation (shown in Section 2) for that year by an amount greater than 20 percent of the account's load.

If the addition of the account would cause either (i) or (ii) to occur, the customer will not be added to the Exempt List (although it may be added the following year, if additional exemptions become available). Otherwise, the account will be added to the Exempt List.

c. If the ID designates the account for the Non-Exempt List, then the customer will be placed on the Non-Exempt List.

d. If the ID does not respond in writing via panafax within the stipulated time period, the default assumption is that the ID does not intend to offer a CTC exemption, and the account will be placed on the Non-Exempt List.

6. If a dispute arises about the assignment of a customer to the Exempt List (including the assignment of its load to the ag pumping vs. non-ag pumping categories), the customer will temporarily be assigned to a third list, the Disputed List. The dispute will be referred to a grievance committee, who will issue a decision within 30 days of the notice of the dispute. The decision of the grievance committee will be final.

   The dispute resolution process will be as follows:

   a. If PG&E contests the assignment of the customer's load to the Exempt List, it will notify the ID within 3 days of receipt of the notice of the assignment that it contests the status, with copies to the members of the grievance committee.

   b. The grievance committee will be composed of a representative from PG&E, a representative from the ID, and a representative from either the CEC or from a private judging service that is agreeable to both parties. Within 15 days of the issuance of a final decision in this proceeding, the settling parties will designate the third representative via a filing to the CPUC.

   c. Once the grievance committee has received written notice of the dispute, it may investigate the facts through written requests for information, but must hold a meeting within 14 days of the notice of the dispute. At the meeting both parties will have an opportunity to present what each considers to be pertinent facts for resolution of the dispute. The parties will cooperate to provide prompt and reasonable discovery prior to the meeting. Any disputes regarding discovery will be resolved by conference call with the grievance committee.

d. A written decision of the proper assignment of the customer's load to either the Exempt List or Non-Exempt List must be issued within 10 days of the meeting.

Once the dispute is resolved, the account's load will be assigned to the Exempt List or Non-Exempt List pursuant to the outcome of the dispute resolution process.

If PG&E issues a notice of a dispute pursuant to Section 6.a above, then during the 30-day resolution period the customer cannot be connected to the ID's system.

7. For purposes of determining exemption status, and to assess compliance with the 50 percent agricultural pumping requirement in Section 374(a)(1)(D), customer loads will be estimated on a one-time basis at the time they are placed on the list using the method prescribed by the CEC's December 24, 1996 Instructions for Applications For Irrigation District Exemption Allocations.[1] These load estimates will remain fixed throughout the transition period regardless of subsequent changes in customer usage patterns.

8. PG&E will update both the Exempt List and the Non-Exempt List on an ongoing basis as additional customer accounts have their status designated by the ID. All ID designations are binding and cannot subsequently be changed, with the following two exceptions. If a customer on the Exempt List that is taking service from an ID subsequently either: (a) ceases doing business; or (b) returns to PG&E service; then the customer will be removed from the Exempt list and the customer's exemption allocation will revert back to the ID for possible use elsewhere.

9. Both lists will be maintained on a confidential basis, but will be made available by PG&E upon request to the ID and Commission staff. At the time they are added to the Exempt List, customers will be provided with information pertaining to their individual accounts' loads and exemptions, with copy sent to the ID.

10. PG&E agrees not to offer Schedule E-TD or E-TDI to any customer account on the Exempt List or the Disputed List.

11. PG&E may offer Schedule E-TD or E-TDI to any customer account on the Non-Exempt List, so long as all tariff eligibility requirements are met.

---

[1] Pursuant to Section 374(b)(2)(D), the loads already served by Merced ID as of June 1, 1996 shall be deducted from its 75 MW allocation, and the remaining allocation phased in over five years in accordance with Section 374(b)(2)(A). These statutory provisions mean that Merced's Exemption List already includes 11 MW of load that departed PG&E's system prior to June 1, 1996, and Merced's remaining exemption allocation totals 64 MW. The 11 MW allocation is assumed to start in 1997, while the remaining 64 MW allocation is phased in equally over the five-year transition period.

ATTACHMENT 1
Page 5

12. The last account added to the Exempt List may still be obligated to pay CTCs for the portion of its load that, in combination with the loads of all other accounts on the Exempt List, exceeds the ID's cumulative exemption allocation for the year. In addition, some or all customer accounts on the Exempt List may be obligated to pay CTCs until such time as the 50 percent agricultural pumping requirement under Section 374(a)(1)(D) has been met.

EXHIBIT A

DISCOUNT AMOUNT WORKSHEET

I. CUSTOMER'S COMPETITIVE RATE
(reference Tariff Sheet(s) or other written offer, attach calculations) ________________

II. CUSTOMER'S AVERAGE STANDARD RATE
(under otherwise-applicable rate, attach calculations) ________________

III. DISCOUNT PERCENTAGE
(Average Rate - Competitive Rate)/ Average Rate ________________

Apply Discount Percentage to energy and demand charges to determine Customer's initial Discounted Rate.

Customer's initial Discounted Rate, less non-energy and non-demand components of Customer's otherwise-applicable rate schedule

Mark "N/A" if the charges is not applicable:

SUMMER

	Demand Charges	Energy Charges
Maximum	________ per kW	________ per kWh
On-Peak	________ per kW	________ per kWh
Partial-Peak	________ per kW	________ per kWh
Off-Peak	________ per kW	________ per kWh

WINTER

	Demand Charges	Energy Charges
Maximum	________ per kW	________ per kWh
On-Peak	________ per kW	________ per kWh
Partial-Peak	________ per kW	________ per kWh
Off-Peak	________ per kW	________ per kWh

EXHIBIT B

MATERIAL FACTOR AFFIDAVIT

Under penalty of perjury, I, ______________________________, hereby state:

I am the __________________________ of ________________________,
(Title) (Company)

a ____________________ Corporation, and am authorized and am authorized to make
(State)

this affidavit on behalf of ______________________ ("Company").
(Company)

Pacific Gas and Electric Company (PG&E) and Company propose to enter into an agreement under which PG&E would deliver electric service to Company's premises. This Proposed Agreement for Discounted Rates For Incremental Sales to New Customers ("Agreement") conveys PG&E's offer of an electric service pricing discount at our Premises if Company decides to receive electric service through PG&E's transmission and/or distribution system. Currently we estimate that our Premises would require approximately _________ kWh/yr. of new electric load to be served by PG&E's transmission and/or distribution system.

Premises Location______________________

Company has decided to proceed to receive electric service from PG&E's proposed transmission and/or distribution facility at this time. Furthermore, the pricing discount offered by PG&E in the Agreement is the sole material factor in Company's decision to elect to receive service from PG&E.

Executed at ________________, California, this _______ day of ______, 19___.

Notarized by:

____
(enter full Company name)

By: ______________________

Title: ______________________

EXHIBIT C

RULE 14 -- SHORTAGE OF SUPPLY AND INTERRUPTION OF DELIVERY

Pacific Gas and Electric Company
San Francisco, California

Revised Cal. P.U.C. Sheet No. 11326-E
Cancelling Revised Cal. P.U.C. Sheet No. 1079-E

RULE 14--SHORTAGE OF SUPPLY AND INTERRUPTION OF DELIVERY

(T)

PG&E will exercise reasonable diligence and care to furnish and deliver a continuous and sufficient supply of electric energy to the customer, but does not guarantee continuity or sufficiency of supply. PG&E will not be liable for interruption or shortage or insufficiency of supply, or any loss or damage of any kind of character occasioned thereby, if same is caused by inevitable accident, act of God, fire, strikes, riots, war, or any other cause except that arising from its failure to exercise reasonable diligence.

PG&E, whenever it shall find it necessary for the purpose of making repairs or improvements to its system, will have the right to suspend temporarily the delivery of electric energy, but in all such cases, as reasonable notice thereof as circumstances will permit, will be given to the customers, and the making of such repairs or improvements will be prosecuted as rapidly as may be practicable, and, if practicable, at such times as will cause the least inconvenience to the customers.

In case of shortage of supply and during the period of such shortage, PG&E will make such apportionment of its available supply of energy among its customers as shall be ordered or directed from time to time by the Railroad Commission of the State of California, acting either directly or by a power administrator or other official appointed by it for that purpose. In the absence of such order or direction by the Railroad Commission, PG&E will, in times of shortage, apportion its available supply of energy among all customers in the most reasonable manner possible.

PG&E's amended Schedule AG-8 Tariff, including attached Agreement for Deferring the Installation of Engine-Driven Agricultural Pumping

AMENDED

Tariff Amended July 9, 1997
Agreement Amended July 3, 1997

SCHEDULE AG-8--DEFERRAL OF GAS AND DIESEL ENGINE-DRIVEN PUMPING FACILITIES (N)

APPLICABILITY: This tariff is available to new and existing agricultural water pumping customers who would otherwise replace their electric motor, or motors, with internal combustion engine(s) powered by natural gas or diesel fuel.

A customer may be served under this tariff if 70 percent or more of the energy use is for pumping water for agricultural end-uses. Agricultural end-uses include growing crops, raising livestock, pumping water for agricultural irrigation, or other uses which involve production for sale, and which do not change the form of the agricultural product. This schedule is not applicable to service for which a residential or commercial/industrial tariff is applicable.

Service under this tariff and terminology included in the following sections is further defined in Standard Form 79-XXXX Pacific Gas and Electric Company's Agreement for Deferring the Installation of Engine-Driven Agricultural Pumping and its accompanying exhibits ("Agreement"). An account served under the DAP or GAP programs or on Schedules AG-6 or AG-7 is not eligible for this tariff.

TERRITORY: This tariff applies everywhere PG&E provides electricity service.

ELIGIBILITY: To be eligible for service under this tariff, a customer must meet all of the following conditions: (1) qualify as an agricultural water pumping customer as defined above; (2) the total load of the accounts listed in Exhibit A of the Agreement must be at least 100 horsepower (nominal engine) and each load must be at least 50 horsepower (nominal engine) and operate a minimum of 1,000 hours per year; (3) demonstrate to PG&E's satisfaction, by providing required documentation, the validity and viability of all elements of the customer's Competitive Rate offer or alternative; and (4) sign the Agreement (including affidavit stating that the availability of this tariff is the deciding factor in the customer's decision not to install the engine-driven pumping facilities).

If otherwise eligible, a customer currently taking direct access energy service from another provider shall not be denied this tariff, and a customer already under this tariff may later choose direct access and remain on this tariff. If otherwise eligible, new customers and new load taking direct access service shall not be denied this tariff.

MATERIAL FACTOR AND INFORMATION REQUIREMENTS: In addition to the required affidavit, a customer will be required to provide business operation information and engine driven pumping facility plans that are relevant to establishing the competitive rate level, or verifying its subsequent rate level, as it applies to the customer's premises.

PG&E shall evaluate the competitive offer to determine its credibility and viability, and to ensure that there are no environmental or legal barriers to the transaction. Only the deferral of installation of engine-driven pumping facilities that meet all state and federal standards and codes will qualify a customer for this tariff.

Information requirements are outlined in the Agreement. However, if a customer disagrees with PG&E's conclusion regarding the credibility of any information provided by the customer, the customer may contest PG&E's decision by filing a complaint with the CPUC. (N)

SCHEDULE AG-8--DEFERRAL OF GAS AND DIESEL ENGINE-DRIVEN PUMPING FACILITIES (N)

(Continued)

RATES: For each qualifying account included in Exhibit A of the Agreement, an eligible customer's rates will be discounted from the otherwise applicable tariff as described in the Agreement. Each rate is based on the account-specific historical or projected billing determinants, the rate schedule in effect at the time the Agreement is executed, the Competitive Rate, and the calculated Discount Percentage, and is subject to the provisions of the Discount Floor and the Index referenced below. In calculating the Competitive Rate, PG&E shall include out-of-pocket non-bypassable charges that the customer would be obligated to and would itself pay PG&E upon departure, if applicable. The method of calculation of the initial Discounted Rate is described in the Agreement.

Each account will receive an initial Discounted Rate that results in an annual average electric rate comparable to that which would be achieved by the customer installing the engine-driven pumping facility. PG&E's Discounted Rate shall include a 5 percent premium to account for the perceived value of electricity relative to other fuels in agricultural pumping applications. In no event will the initial Discounted Rate result in an average rate that is below that which would be achieved by the customer installing the engine-driven pumping facility.

On January 1 of each year of the Agreement term the initial Discounted Rate will be adjusted by an index applied to the determinants of the Competitive Rate. The index will be equal to the percent change in the indices of the average cost to own and operate engine-driven pumping facilities. The method of calculation is described in the Agreement.

For a customer who chooses to take direct access energy services from another provider, the customer shall receive, on the bill, PX charges (including but not limited to charges for commodity and ancillary services), public purpose program charges, transmission and distribution charges, CTC charges, and charges for competitive or unbundled services (including but not limited to billing, metering, and credits) to the extent that the calculation and presentation of this information is approved by the Commission in the Cost Separation proceeding.

BILLING DETERMINANTS: Annual energy usage and demand for each eligible account will be determined using PG&E's billing data from the twelve (12) months immediately preceding the date the customer requests to be considered for service under this tariff. If such billing data are not available, or if the customer's operation is expected to significantly change within the next year, PG&E's estimate of the customer's upcoming twelve (12) months of usage and demand will be used for purposes of calculating the discount.

DISQUALIFICATION: PG&E may, at its sole discretion, disqualify a customer from obtaining this discount if (1) PG&E believes that the costs to provide adequate T&D facilities makes discounting to a particular customer uneconomic (that is, the Discounted Rate does not exceed the marginal costs to serve the customer plus 20 percent); or (2) a customer severely constrains the existing T&D system in such a way that the customer's marginal costs in the future are expected to be above the price that would otherwise result from this tariff.

CONTRACT TERM: The Agreement established by this tariff has a term of up to five (5) years, but in no case shall any such Agreement entered into under this tariff remain in effect after December 31, 2001.

COMMENCEMENT DATE: Service under this rate schedule will commence with the customer's first regular scheduled meter read date after the agreement is fully executed. The start date shall be no earlier than the date at which, in PG&E's judgment, the customer would have begun taking service from the competitor. (N)

(Continued)

Original Cal. P.U.C. Sheet No.
Pacific Gas and Electric Company Cancelling Cal. P.U.C. Sheet No.
San Francisco, California

SCHEDULE AG-8--DEFERRAL OF GAS AND DIESEL ENGINE-DRIVEN PUMPING FACILITIES (N)

(Continued)

DISCOUNT FLOOR: Over the term of the Agreement, the sum of the charges collected by PG&E from the customer, exclusive of any additional applicable taxes or surcharges, shall not fall below a level one hundred and twenty percent (120%) of PG&E's total, customer-specific, marginal cost to serve. The Discount Floor is defined in the Agreement.

RATES AND RULES: All applicable rates, rules and tariffs shall remain in force for a customer that signs the Agreement. In the event of a conflict, the terms and conditions provided within this tariff shall supersede those set forth in the standard CPUC-approved tariffs. All other provisions of the customer's otherwise applicable rate schedule(s) shall remain in force. (N)

Distribution:
[] Applicant (Original)
[] Division (Original)
[] Field Applications Support (Original)
[] Customer Accounting

Reference:

PACIFIC GAS AND ELECTRIC COMPANY'S AGREEMENT FOR DEFERRING THE INSTALLATION OF ENGINE-DRIVEN AGRICULTURAL PUMPING

This Agreement for Deferring the Installation of Engine-Driven Agricultural Pumping (Agreement) is made between ____________________________, ("Customer" or "The Customer"), a(n) ____________________________ corporation, and PACIFIC GAS AND ELECTRIC COMPANY ("PG&E"), a California corporation. PG&E and the Customer will be referred to collectively herein as the "Parties" or individually as "Party." The Customer is deferring the installation of engine-driven pumping facilities for bypassing the delivery of electricity by PG&E at the Customer's qualifying account(s) serving agricultural pumping load as listed in Exhibit A.

This Agreement provides for a discount to be applied to Customer's otherwise-applicable non-discounted PG&E agricultural bundled rate schedule, or succeeding PG&E agricultural unbundled rate schedule(s). The discount will establish an average electric rate comparable to that which would be achieved if the Customer were to obtain its energy from a competing utility or vendor ("Competitor") through the installation of an engine-driven pumping facility which is fueled either by natural gas or diesel fuel ("Discount"). This Discount is determined by a standardized price calculation on an account by account basis and is intended to, in whole or in part, compensate the Customer for the deferral of such installation. The Parties agree to the following terms and conditions:

AGREEMENT

1. **Initial Discounted Rate.** The Customer's initial Discounted Rate for each account under this Agreement will be calculated as follows:

   The "Competitive Rate" is:

   The average rate that would be charged to Customer by Competitor including out-of-pocket non-bypassable charges that the customer would be obligated to and would itself pay PG&E upon departure, if applicable. The "Competitive Rate" will be calculated using the Competitor's price offer and other terms and conditions for the engine-driven pumping facility (or other documented non-tariff rate offer) and Customer's projected billing determinants which are consistent with those contained in the Competitor's offer. The calculation of the "Competitive Rate" will include a five percent premium to account for the perceived value of electricity relative to other fuels in agricultural pumping applications.

In situations where PG&E deems that the Competitor's tariff does not effectively represent the true energy costs that the Customer will encounter at its site due to receipt by the Customer of a written non-tariff rate, or other competitive, offer from the Competitor, the non-tariff rate, or other competitive offer, will be used to make this calculation. The Competitive Rate shall not include any surcharges or taxes.

The "Average Rate" is:

The Customer's "Average Rate" is calculated as Customer's projected total revenues paid to PG&E divided by the Customer's projected total kWh use, during the first calendar year of the Agreement. Calculation of total revenues will be based on the Customer's non-discounted otherwise-applicable rate schedule in effect upon execution of this agreement. Because agricultural electric usage can fluctuate widely, agricultural customers have the option, once a year, to change their rate schedule(s) to best reflect their current usage patterns. If the Customer chooses a new non-discounted rate schedule, they must notify PG&E in writing pursuant to section 10 of this agreement by December 1 prior to recalculation of the next year's Rate Index. The change in rate schedule(s) will only be made coincident with the annual Rate Index changes to the Customer's Discount Percentage. In such cases, the Customer's new selected rate schedule(s) will be used to re-calculate the Average Rate. The Average Rate shall not include any surcharges or taxes.

The difference between Customer's Average Rate and its Competitive Rate, divided by the Average Rate, will be defined as the Customer's "Discount Percentage." Mathematically, the Discount Percentage equals (Average Rate - Competitive Rate) / Average Rate. The Discount Percentage shall be applied to all of the energy and demand components of Customer's otherwise-applicable rate schedule for each of the Customer's accounts. These discounted energy and demand components, along with the other non-discounted billing components found in each of the accounts' rate schedule, shall be combined to establish the Customer's initial "Discounted Rate." This initial Discounted Rate will be subject to possible future adjustment as described in Section 2. Customer's initial Discounted Rate, and any subsequent adjustment, shall be subject to a Discount Floor (see Section 8).

The Discount Percentage(s) and the Customer's initial Discounted Rate(s) are shown in Exhibit A. Under the methodology required above, the Customer's Discounted Rate cannot and shall not be set below the Customer's Competitive Rate.

The Customer's otherwise-applicable rate schedule for each account is shown in Exhibit A.

If otherwise eligible, a customer currently taking direct access energy service from another provider shall not be denied this tariff, and a customer already under this tariff may later choose direct access and remain on this tariff. If otherwise eligible, new customers and new load taking direct access service shall not be denied this tariff.

2. **Rate Index.** The Competitive Rate components of the Customer's initial Discounted Rate may be adjusted every calendar year by an index ("Index"). The Index will be equal to the percent change in the indices of the average cost to own and operate engine-driven pumping facilities.

Mathematically, the Index is equal to (new Natural Gas, or Diesel, Cost - current Natural Gas, or Diesel, Cost)/current Natural Gas, or Diesel, Cost), where new "Natural Gas, or Diesel, Cost" and current "Natural Gas, or Diesel, Cost" are designated by one of the applicable following indices:

For customers who were considering an engine-driven pumping facility powered by natural gas:

> The Natural Gas Cost will be based upon a forty-five percent (45%) weight of the consumer price index (CPI) as posted by the Department of Labor, and a fifty-five percent (55%) weight of the change in Southern California Gas Company's gas engine irrigation rate (transportation and commodity.)

For customers who were considering an engine-driven pumping facility powered by diesel fuel:

> The Diesel Cost will be based upon a thirty-three percent (34%) of the consumer price index (CPI) as posted by the Department of Labor, and a sixty-six percent (66%) weight of the change in annual average price of Platt's #2 diesel fuel oil, San Francisco, California.

Effective with the Customer's first meter read date after January 1 of each year within the contract term, the Customer's Discount Percentage will be adjusted only if the change in the newly calculated Index is greater than, plus or minus, ten percent (+/-10%). Any adjustment will be done by multiplying the Customer's Competitive Rate from the previous calendar year by the newly calculated Index to yield an "Updated Competitive Rate." The rate schedule(s) applicable to the accounts listed in Exhibit A shall be used to calculate an "Updated Average Rate." The adjusted Discount Percentage shall equal: (Updated Average Rate - Updated Competitive Rate)/Updated Average Rate. A new Exhibit A will be created and attached to this contract each year.

3. **Informational Requirements.** To qualify for service under this Agreement, Customer must first provide PG&E with the following information and demonstrate, to PG&E's

satisfaction, the credibility of the information as it applies to Customer's accounts listed in Exhibit A:

- Written offer from Competitor(s);
- Customer's (or Competitor's) economic analysis of the viability of installing an engine-driven pumping facility, including equivalent average cost expressed in "Dollars per kWh";
- Acquisition of, or evidence of Customer's (or Competitor's) ability to acquire all necessary rights-of-way, certificates, and permits (including applicable air quality permits) required for the construction and operation of the engine-driven pumping facility; and
- Any other Customer cost or operational information that PG&E deems pertinent to the analysis.

Customer will sign under the penalty of perjury, have notarized, and deliver to PG&E an affidavit attesting to the fact that without the discounted PG&E rate, Customer would switch to the Competitor for engine driven pumping service (Exhibit B). PG&E shall evaluate the viability of the diesel or natural gas alternative for those accounts listed in Exhibit A using the information provided by the Customer and any other information available to PG&E. Should PG&E, in its sole discretion, conclude that the alternative is not viable and deny the discounted rate to Customer, Customer may file a complaint with the CPUC contesting PG&E's conclusion.

4. **Requirement of Delivery of Electricity through PG&E's System.** Customer shall use PG&E delivered electricity for its total electrical load requirement throughout the term of this Agreement. Accordingly, Customer shall not use electricity delivered through a non-PG&E distribution system. Additionally, Customer shall not use engine-driven pumping facilities unless the Customer:

- is utilizing emergency generation, only in the event of an outage;
- is testing such emergency generation, (not to exceed 10 hours per month); or
- is given prior written permission by PG&E for similar operational events.

If Customer utilizes: (1) any electricity not delivered through PG&E's distribution system, or (2) engine-driven pumping equipment, other than as provided above, then PG&E may terminate this Agreement as specified in Section 9.

If, on a calendar-year basis Customer's use of electricity for any of the accounts listed in Exhibit A of this Agreement falls below seventy-five percent (75%) of the amount of electricity specified for each account in the Exhibit A, the Discount Percentage for the following year will be reduced by a percentage point for each percentage point below seventy-five percent (75%) of the amounts found in Exhibit A.

If Customer chooses to take direct access energy services from another provider, Customer shall receive, on the bill, PX charges (including but not limited to charges for commodity and ancillary services), public purpose program charges, transmission and distribution charges, CTC charges, and charges for competitive or unbundled services (including but not limited to billing, metering, and credits) to the extent that the calculation and presentation of this information is approved by the Commission in the Cost Separation proceeding.

GENERAL TERMS AND CONDITIONS

5. **Commencement Date.** This Agreement shall take effect no earlier than the date at which, in PG&E's judgment, the customer would have begun taking service from Competitor. The Customer will be billed at the initial Discounted Rate on the Customer's first regularly scheduled meter read date after this Agreement is fully executed. This date shall be deemed the "Commencement Date."

6. **Term.** This Agreement shall remain in effect until December 31, 2001.

7. **Regulatory Authority.** This Agreement shall at all times be subject to such changes or modification by the Public Utilities Commission of the State of California (CPUC) as said Commission may, from time to time, direct in the exercise of its jurisdiction. Such action by the CPUC may be grounds for termination of this Agreement by either Party.

8. **Discount Floor.** Over the term of this Agreement, the sum of the electric charges collected by PG&E from the Customer, exclusive of any additional applicable taxes or surcharges, shall not fall below a level one hundred and twenty percent (120%) of PG&E's total, account-specific, marginal cost to serve ("Discount Floor"). These marginal costs will be determined using the CPUC-approved methodology for such calculations in force for this Agreement as these may change or be amended from time to time. On each anniversary of the Commencement Date, PG&E shall compute the total revenue it has collected to date from the Customer, and the sum of the monthly overpayments and underpayments by the Customer relative to PG&E's marginal costs to ensure that PG&E has collected, at a minimum, twenty percent (20%) more than its account-specific marginal costs of service. The Parties agree that if at any time the revenues collected up to the review date fall below the Discount Floor, Customer shall pay PG&E a lump sum equal to that shortfall amount. PG&E shall notify customer of any lump sum payment obligation, according to Section 10, no later than thirty (30) days after the anniversary of the Commencement date. This payment will be due and payable in full, without interest, thirty (30) days after PG&E has notified the Customer in writing of its payment obligation.

If a shortfall occurs, and after all shortfall payments described above have been made by Customer, the Customer may request that PG&E simply bill the Customer at a rate equal to one hundred and twenty percent (120%) of its current account-specific marginal cost of service, or the Discount Floor. PG&E will continue to do so until such time as the Customer's Discounted Rate exceeds the Discount Floor, at which time the Customer will once again be billed at the Discounted Rate established in this Agreement. This provision is intended to eliminate the potential for any future lump sum shortfall payments by the Customer.

9. **Termination.**
The Customer may terminate this Agreement at any time prior to the end of its term by giving PG&E a minimum of thirty (30) days written notice of such termination.

PG&E may terminate this Agreement upon thirty (30) days written notice to Customer if Customer uses electricity not delivered by PG&E, or engine driven pumping facilities to replace the electrical load, at the accounts listed in Exhibit A for purposes other than those listed in section 4.

Either Party may terminate this Agreement upon thirty (30) days written notice in the event any regulatory body or court of competent jurisdiction finds that a provision of this Agreement, or a portion thereof is unenforceable or invalid, and the terminating Party determines, in good faith, that the remaining provisions of this Agreement have been rendered unenforceable or disadvantageous.

10. **Notice.** Any notice either PG&E or Customer may wish to give one another must be in writing. Such notice must be either hand delivered, or sent by U.S. registered mail, postage prepaid, to the person designated to receive notice for the other Party, or to such other address as either Party may designate by written notice. Notices delivered by hand shall be deemed effective when delivered. Notices delivered by mail shall be deemed effective when received, as acknowledged by the receipt of the certified or registered mailing.

To: (Customer)

____
____
____
____

To: PG&E:

Pacific Gas and Electric Company
Director, Tariff Applications
123 Mission Street, Mail Code H28H
San Francisco, CA 94106

11. **Service Reliability.** PG&E's standard for reliability of service for Customer shall be as dictated in PG&E's Electric Rule 14 or its successor; a copy is attached as Exhibit C and incorporated by reference herein.

12. **Assignment.** Customer may not assign this Agreement to a third party without the prior written permission of an authorized representative of PG&E. Any assignment is subject to any applicable CPUC authorization or regulation except as waived by the CPUC.

13. **Applicable Laws.** This Agreement shall be subject to and interpreted under the laws, rules, and regulations of the State of California and the CPUC, and PG&E's Electric Rules.

14. **Agreements Submitted to the CPUC. A copy of this Agreement will be submitted to the CPUC. PG&E shall use reasonable efforts to protect Customer's identity and information the Customer has identified in writing as proprietary.**

15. **Severability.** In the event that any of the provisions, or portions thereof, of this Agreement are held to be unenforceable or invalid by any court of competent jurisdiction, the validity and enforcement of the remaining provisions or portions thereof shall not be affected thereby; provided, however, that should either Party determine, in good faith, that such unenforceability or invalidity renders the remaining provisions of this Agreement economically infeasible or disadvantageous, such Party may terminate this Agreement upon thirty (30) days prior written notice to the other.

16. **Conflicting Provisions.** This Agreement shall supersede the terms and conditions set forth in the Customer's otherwise-applicable rate schedule(s) and any other applicable standard CPUC approved tariff in the event of conflict. Otherwise, all other CPUC-approved standard tariff terms and conditions shall remain in force and be applicable to this Agreement.

17. **Force Majeure.** Neither Party hereto shall be liable for any failure of performance, other than the continuing obligation to make payments due hereunder for periods prior to the event of force majeure, owing to causes beyond its reasonable control and the occurrence of which could not have prevented by the exercise of due diligence. Refusal by either Party to accede to demands of laborers or labor unions that it considers unreasonable shall not deny it the benefits of this provision. If either Party hereto is unable, for any reason, to deliver or receive full or partial quantities of electricity contemplated by this Agreement due to force majeure, the Party so unable to perform shall promptly advise the other Party that such condition exists, and the Parties shall suspend operations under this Agreement to the extent dictated by the force majeure event, until the event of force majeure is remedied and both Parties can once again deliver and receive electricity, respectively. Any force majeure event shall be remedied as far as possible with all reasonable dispatch. The term "force majeure" as employed herein shall include, but is not be limited to: acts of God; strikes or other industrial disturbances; acts of a public enemy; the direct or indirect effect of governmental orders, actions, or interferences; civil

disturbances; explosions; breakage of or accidents to machinery or power lines; power outages; the necessity of making repairs to or alterations of machinery or power lines; landslides; lighting; earthquakes; fires; storms; floods; and washouts. Force majeure shall not include financial considerations.

18. **No Consequential or Incidental Damages.** PG&E shall not be liable for any consequential, incidental, indirect, or special damages, including but not limited to lost profits and loss of power related in any way with the performance of either Party under this Agreement.

19. **Waiver.** A waiver by either Party or any one or more defaults by the other hereunder shall not operate as a waiver of any future default or defaults, whether of a like or of a different character.

IN WITNESS THEREOF, the Parties have executed this Agreement in multiple originals of equal dignity by their respective duly authorized representatives.

Executed this________day of ______________, 19___.

____________________________ Customer	PACIFIC GAS AND ELECTRIC COMPANY (PG&E)
BY:_________________________ Signature	BY:_________________________ Signature
____________________________ (Type or print name)	____________________________ (Type or print name)
TITLE:______________________	TITLE:______________________

EXHIBIT A

Pacific Gas and Electric Company

Engine-Driven Agricultural Pumping Option Yearly Discount Percentage Calculation Sheet

January 1, 19____

	PG&E Account No. Example: AAA-00-99999	Otherwise-Applicable Rate Schedule* Example: Ag 4b	Horsepower Example: 250 hp	Operating Hours (by PG&E) Example: 1241 hours	Annual kwh	Customer's Competitive Rate (by PG&E) ($/kwh)	Customer's Average Standard Rate (by PG&E) ($/kwh)	Discount Percentage (Average Rate - Competitive Rate/ Average Rate) Percent (%)
1)								
2)								
3)								
4)								
5)								
6)								
7)								
8)								
9)								
10)								

* Customer's Otherwise-Applicable Rate may change by either Commission order or by Customer request. The change in rate schedule(s) will take effect upon yearly Rate Index/Discount Percentage Calculations pursuant to Section 1 in this Agreement.

Field Applications Support
Standard Form 79-XXX
Revision Date:xx/xx/xx
(Every calendar year - when applicable)
Effective xx/xx/xx

A.94-12-005

APPENDIX B
Page 58

EXHIBIT A
Pacific Gas and Electric Company
Engine-Driven Agricultural Pumping Option - Initial Discounted Rate Components

				Demand Charges						
	PG&E Account No.	Cust Chg. ($)	Meter Chg. ($)	Season, Summer ($/kW)	Season, Winter ($/kW)	Season Off-Peak, Summer ($/kW)	Season Off-Peak, Winter ($/kW)	Max. Peak, Summer ($/kW)	Max. Part-Peak, Summer ($/kW)	Max. Part-Peak, Winter ($/kW)
1)										
2)										
3)										
4)										
5)										
6)										
7)										
8)										
9)										
10)										

Enter "N/A" where not applicable

Field Applications Support
Standard Form 79-XXX
Revision Date:xx/xx/xx
Effective xx/xx/xx

EXHIBIT A

Pacific Gas and Electric Company

Engine-Driven Agricultural Pumping Option - Initial Discounted Rate Components

		Energy Charges						
		Non-TOU	Non-TOU	TOU				
	PG&E Account No.	Summer ($/kwh)	Winter ($/kwh)	Peak, Summer ($/kW)	Part-Peak, Summer ($/kW)	Off-Peak, Summer ($/kW)	Part-Peak, Winter ($/kW)	Off-Peak, Winter ($/kW)
1)								
2)								
3)								
4)								
5)								
6)								
7)								
8)								
9)								
10)								

Enter "N/A" where not applicable

Field Applications Support
Standard Form 79-XXX
Revision Date:xx/xx/xx
Effective xx/xx/xx

EXHIBIT B

MATERIAL FACTOR AFFIDAVIT

Under penalty of perjury, I, _________________________, hereby state:

I am the ______________________________ of _____________________________,
(Title) (Parent Company)

a _______________________ Corporation, and am authorized to make this affidavit
(State)

this affidavit on behalf of _________________________ ("Company").
(Company)

Pacific Gas and Electric Company (PG&E) and Company propose to enter into an Agreement for Deferring the Installation of Engine-Driven Agricultural Pumping ("Agreement") to grant Company an electric service pricing discount at our accounts listed in Exhibit A, if Company decides to defer the installation of the engine-driven pumping facilities proposed by the competing utility or vendor ("Competitor"). Currently Company estimates that such engine-driven pumping facilities would bypass approximately ________ kWh/yr. of electric load currently being served by PG&E at all of the accounts listed in Exhibit A.

Each account listed in Exhibit A serves at least one (1) electric driven pump, each of which is rated fifty (50) horsepower (nominal engine) or above and each of which will operate a minimum of 1,000 hours per year. There is at least 100 (nominal engine) horsepower of pumping load listed in Exhibit A.

Company has decided not to proceed with the Competitor's proposal for installation of the engine-driven pumping facilities at the accounts listed on Attachment A, of the Agreement, at this time. Furthermore, the pricing discount offered by PG&E, in the Agreement, is the sole material factor in Company's decision not to take action at this time that would cause the engine-driven pumping facility to be installed.

Executed at __________________, California, this ________ day of ______, 19___.

Notarized by:

____
(enter full Company name)

By: ______________________

Title: ______________________

EXHIBIT C

RULE 14 -- SHORTAGE OF SUPPLY AND INTERRUPTION OF DELIVERY

Pacific Gas and Electric Company
San Francisco, California

Revised Cal. P.U.C. Sheet No. 11326-E
Cancelling Revised Cal. P.U.C. Sheet No. 1079-E

RULE 14--SHORTAGE OF SUPPLY AND INTERRUPTION OF DELIVERY

(T)

PG&E will exercise reasonable diligence and care to furnish and deliver a continuous and sufficient supply of electric energy to the customer, but does not guarantee continuity or sufficiency of supply. PG&E will not be liable for interruption or shortage or insufficiency of supply, or any loss or damage of any kind of character occasioned thereby, if same is caused by inevitable accident, act of God, fire, strikes, riots, war, or any other cause except that arising from its failure to exercise reasonable diligence.

PG&E, whenever it shall find it necessary for the purpose of making repairs or improvements to its system, will have the right to suspend temporarily the delivery of electric energy, but in all such cases, as reasonable notice thereof as circumstances will permit, will be given to the customers, and the making of such repairs or improvements will be prosecuted as rapidly as may be practicable, and, if practicable, at such times as will cause the least inconvenience to the customers.

In case of shortage of supply and during the period of such shortage, PG&E will make such apportionment of its available supply of energy among its customers as shall be ordered or directed from time to time by the Railroad Commission of the State of California, acting either directly or by a power administrator or other official appointed by it for that purpose. In the absence of such order or direction by the Railroad Commission, PG&E will, in times of shortage, apportion its available supply of energy among all customers in the most reasonable manner possible.

Advice Letter No. 1306-E
Decision No.

6784

Issued by
Gordon R. Smith
Vice President and
Chief Financial Officer

Date Filed July 12, 1990
Effective August 21, 1990
Resolution No.

PG&E's Schedule AG-7 Tariff --
Experimental Tiered Time-of-Use Agricultural Power

AMENDED

Tariff Amended July 9, 1997

SCHEDULE AG-7--EXPERIMENTAL TIERED TIME-OF-USE AGRICULTURAL POWER (N)

1. APPLICABILITY

General: A customer will be served under this schedule if 70 percent or more of the energy use is for agricultural end-uses. Agricultural end-uses include growing crops, raising livestock, pumping water for agricultural irrigation, or other uses which involve production for sale, and which do not change the form of the agricultural product. This schedule is not applicable to service for which a residential or commercial/industrial schedule is applicable.

If otherwise eligible, a customer currently taking direct access energy service from another provider shall not be denied this tariff, and a customer already under this tariff may later choose direct access and remain on this tariff. If otherwise eligible, new customers and new load taking direct access service shall not be denied this tariff.

Under this schedule customers are billed in Tier 1 or Tier 2 depending on monthly operating hours. Enrollment on this schedule will be limited to the first 5,000 accounts requesting this rate. This schedule may be modified.

Depending upon the end-use of electricity and whether or not an Installation or Processing charge applies, the customer will be served under one of the rates under Schedule AG-7: Rate A, B, D, or E.

Rates A and D: Applies to single-motor installations with a connected load rated less than 35 horsepower and to all multi-load installations aggregating less than 15 horsepower or kilowatts. Rate A applies to customers who must pay the Processing Charge; Rate D applies to customers who must pay the Installation Charge.

Rates B and E: Applies to single-motor installations rated 35 horsepower or more, to multi-load installations aggregating 15 horsepower or kilowatts or more, and to "overloaded" motors. The customer's end-use is determined to be overloaded when the measured input to any motor rated 15 horsepower or more is determined by PG&E to exceed one kilowatt per horsepower of nameplate rated output. Rate B applies to customers who must pay the Processing Charge; Rate E applies to customers who must pay the Installation Charge.

Installation Charge: If the account does not have an appropriate time-of-use meter, the customer must pay an "Installation Charge" to participate on this schedule.

Processing Charge: Once the account has the appropriate time-of-use meter, the customer will be required to pay a "Processing Charge" each time the customer:

1) establishes service on this schedule, or
2) voluntarily changes any option within this schedule.

The Installation Charge or Processing Charge must be paid in one lump sum before the customer can take service on this schedule or before an option will be changed. Payments for these charges are not transferable to another service or refundable, in whole or part. PG&E will place the account on this schedule within four weeks of receiving payment from the customer. The meters required for this schedule may become obsolete as a result of electric industry restructuring or other action by the California Public Utilities Commission. Therefore, any and all risks of paying the required charges and not receiving commensurate benefit are entirely that of the customer.

2. TERRITORY

Schedule AG-7 applies everywhere PG&E provides electricity service. (N)

(Continued)

SCHEDULE AG-7--EXPERIMENTAL TIERED TIME-OF-USE AGRICULTURAL POWER (N)

(Continued)

3. RATES

If the customer chooses to take service under Schedule AG-7, the customer will pay the following rates and charges:

	One-time Charge Per Meter
INSTALLATION CHARGE	
Rate D	$441.00
Rate E	$441.00
PROCESSING CHARGE	
Rate A	$ 85.00
Rate B	$ 85.00

	Per Meter Per Month
CUSTOMER CHARGE	
Rates A and D	$12.00
Rates B and E	$16.00
METER CHARGE	
Rate A	$ 6.80
Rate B	$ 6.00
Rate D	$ 2.00
Rate E	$ 1.20

TIER DEFINITIONS

Tier 1 will apply if monthly operating hours are less than 200, and Tier 2 will apply if monthly operating hours are 200 or greater.

For Rates A and D, monthly operating hours will be equal to the quotient of the kilowatt hours (kWh) and the connected load (hp) for the current billing month. For Rates B and E, monthly operating hours will be equal to the quotient of the kilowatt hours (kWh) and the seasonal billing demand (kW) for the current billing month.

If the billing period is shorter than 27 days or longer than 33 days, the total kilowatt hours (kWh) during the billing period will be divided by the number of days in the billing period to calculate the daily average kWh. The daily average kWh will be multiplied by 30.4 days per month. The resulting monthly average kWh will be divided by the connected load (hp) or the seasonal billing demand (kW) during the billing period to determine the monthly operating hours.

DEMAND CHARGE	Summer	Winter
Rates A and D		
Tier 1: (per hp of connected load)	$2.35	$2.15
Tier 2: (per hp of connected load)	$5.40	$5.40
Rates B and E		
Tier 1:		
(per kW of seasonal billing demand)	$3.25	$1.95
(per kW of maximum-peak-period demand)	$3.10	$ ---
Tier 2:		
(per kW of seasonal billing demand)	$7.35	$4.95
(per kW of maximum-peak-period demand)	$3.05	$ ---

(N)

(Continued)

Pacific Gas and Electric Company
San Francisco, California

Original Cal. P.U.C. Sheet No.
Cancelling Cal. P.U.C. Sheet No.

SCHEDULE AG-7--EXPERIMENTAL TIERED TIME-OF-USE AGRICULTURAL POWER (N)

(Continued)

3. RATES (Cont'd.)

ENERGY CHARGE (per kWh)

Rates A and D		
Tier 1:		
Peak	$0.34198	$ ---
Partial-Peak	$ ---	$0.11859
Off-Peak	$0.10731	$0.09428
Tier 2:		
Peak	$0.28678	$ ---
Partial-Peak	$ ---	$0.06608
Off-Peak	$0.05901	$0.05257
Rates B and E		
Tier 1:		
Peak	$0.24366	$ ---
Partial-Peak	$ ---	$0.08450
Off-Peak	$0.07646	$0.06718
Tier 2:		
Peak	$0.14251	$ ---
Partial-Peak	$ ---	$0.04647
Off-Peak	$0.04076	$0.03695
DEMAND CHARGE LIMITER	$1.19780	$1.19780

For a customer who chooses to take direct access energy services from another provider, the customer shall receive, on the bill, PX charges (including but not limited to charges for commodity and ancillary services), public purpose program charges, transmission and distribution charges, CTC charges, and charges for competitive or unbundled services (including but not limited to billing, metering, and credits) to the extent that the calculation and presentation of this information is approved by the Commission in the Cost Separation proceeding.

4. TIME PERIODS

Seasons of the year and times of the day are defined as follows:

SUMMER: Service from May 1 through October 31.

Peak: 12:00 noon to 6:00 p.m. Monday through Friday*
Off-Peak: All other hours Monday through Friday
All day Saturday, Sunday, holidays

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 Monday through Friday
All day Saturday, Sunday, holidays

"Holidays" for the purpose of this rate schedule 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.

*Except holidays.

5. ENERGY CHARGE CALCULATION

When summer and winter proration is required, charges will be based on the average daily use for the full billing period times the number of days in each period. (N)

(Continued)

Pacific Gas and Electric Company
San Francisco, California

Original Cal. P.U.C. Sheet No.
Cancelling Cal. P.U.C. Sheet No.

SCHEDULE AG-7--EXPERIMENTAL TIERED TIME-OF-USE AGRICULTURAL POWER (N)

(Continued)

6. CONTRACTS

Service under Schedule AG-7 is provided for a minimum of 12 months beginning with the date the customer's service commences. The customer may be required to sign a service contract with a minimum term of one year. After the customer's initial one-year term has expired, the customer's contract will continue in effect until it is cancelled by the customer or PG&E.

Where a line extension is required it will be installed under the provisions of Rules 15 and 16.

7. DISCONTINUANCE OF SERVICE

If the customer discontinues service before the initial one year term has expired, the customer will be held liable and billed for the balance of charges due to PG&E for each billing period for the remainder of the 12-month service contract. These charges shall consist of any applicable monthly customer charges, ratcheted monthly demand charges, and monthly minimum demand charges. These charges will be calculated using the last tier in which the customer was billed. A Processing Charge will not apply. An Installation Charge will only apply if the time-of-use meter has been removed.

The customer may discontinue taking service at any time after the expiration of the initial term of the service contract; no adjustment will be made to the bill. If the customer wishes to resume agricultural service within 12 months of cancellation, the customer will be required to pay all charges that would have been billed if service had not been discontinued.

8. CONNECTED LOAD

Connected load is defined as the sum of the rated capacities (as determined in accordance with Rule 2) of all equipment that is served through one metering point and that may be operated at the same time. When charges are based on connected load, in no case will charges be based on less than two horsepower/kilowatts for single-phase service, nor less than three horsepower/kilowatts for three-phase service.

The customer's account will be adjusted for permanent connected-load changes that take place during the contract year. It is the customer's responsibility to notify PG&E of such changes. No adjustment will be made for a temporary reduction in connected Load. If the Load is reconnected within 12 months of being disconnected, the charges will be recalculated and applied retroactively, as though no reduction in Load had taken place.

9. MAXIMUM DEMAND (Rates B and E Only)

The seasonal billing demand (defined below) will be based on the "maximum demand." The number of kW the customer is using will be recorded over 15-minute intervals; the highest 15-minute average in any month will be the maximum demand for that month. Where the customer's uses of electricity is intermittent or subject to abnormal fluctuation, a 5-minute interval may be used. (N)

(Continued)

Advice Letter No.
Decision No.

Issued by
Steven L. Kline
Vice President
Regulation

Date Filed
Effective
Resolution No.

SCHEDULE AG-7--EXPERIMENTAL TIERED TIME-OF-USE AGRICULTURAL POWER (N)

(Continued)

9. MAXIMUM DEMAND (Cont'd.)

In billing periods with use in both the summer season and winter season (April/May, October/November), the customer's total demand charge shall be calculated on a pro rata basis depending upon the demand charge and the number of days in each season. The maximum demand used in determining the customer's demand charge for each season of the billing period will be: 1) the maximum demand created in each season's portion of the billing month as measured by a meter with such capability; or 2) the maximum demand for the billing month where the installed meter is incapable of measuring time-varying demands. Maximum demands created in billing months with days in both the summer and winter seasons will not be used in determining the customer's seasonal billing demand in subsequent months for either season. In such billing periods with use in both the summer season and winter season, the customer's seasonal billing demand will be the greater of the customer's established (ratcheted) demand or the customer's maximum demand for the billing period, as described above.

10. SEASONAL BILLING DEMAND (Rates B and E Only)

The billing year is the twelve-month period consisting of the current month and the eleven previous months. The calendar year (January through December) is split into two seasons, summer months (May through October) and winter months (November through April).

The seasonal billing demand charge will be based on the greater of:

1) the highest maximum demand (defined in part 9. above) recorded in the months of the same season in the current billing year; or

2) the minimum demand (defined in part 11. below).

11. MINIMUM DEMAND (Rates B and E Only)

To provide for maintaining ready facilities where there is little or no energy use, the customer's "minimum demand" used for billing in the season in which the customer usually use energy (e.g., summer for irrigation pumps and winter for frost-control wind machines) will not be less than: a) 75 percent of the nameplate rating in horsepower/kilowatts of the two largest motors the customer has connected; or b) the diversified resistance welder load computed in accordance with Rule 2. For the purpose of the minimum-demand calculations, all customers are assumed to have primarily summer use unless otherwise designated.

12. DROUGHT-RELIEF PUMPS (Rates B and E Only)

Irrigation customers who normally operate only in drought years, but who do not expect to operate during the summer season of a specific year, may designate winter as the primary season of energy use by notifying PG&E prior to May 1 of that year. A schedule redesignation of this type will be effective for the subsequent twelve billing months, during which period the customer agrees to restrict electricity usage to the winter season only. If a customer has designated winter as the season of primary use, but during the subsequent twelve months finds it necessary to use electricity during the summer season, the election for that year will be invalidated and the customer will be re-billed for all summer season charges that would have otherwise applied.

The Demand Charge Limiter described below does not apply to pumps operated for drought relief under the provisions of this section. (N)

(Continued)

Pacific Gas and Electric Company
San Francisco, California

Original Cal. P.U.C. Sheet No.
Canceling Cal. P.U.C. Sheet No.

SCHEDULE AG-7--EXPERIMENTAL TIERED TIME-OF-USE AGRICULTURAL POWER (N)

(Continued)

13. DEMAND CHARGE LIMITER (Rates B and E Only)

The demand charge limiter is designed to prevent a seasonal billing demand when the customer tests facilities in the off-season. The off-season is assumed to be the winter season unless the customer has designated winter as its season of primary use. The demand charge limiter will apply in any off-season billing month in which: a) no seasonal billing demand charges are in effect; and b) the customer's energy use (in kWh) divided by the customer's recorded maximum demand (in kW) in the same billing month is less than or equal to three. When the demand charge limiter applies, the customer's bill will be the sum of: the monthly meter charge, the monthly customer charge, and the energy used in kWh times the demand charge limiter rate. In addition, the maximum demand the customer creates in any off-season month in which the customer's energy use (in kWh) divided by recorded maximum demand (in kW) in the same billing month is less than or equal to three, will not be considered in determining the customer's seasonal billing demand.

14. MAXIMUM-PEAK-PERIOD DEMAND (Rates B and E Only)

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.

15. MAXIMUM-PART-PEAK-PERIOD DEMAND (Rates B and E Only)

The customer's maximum-part-peak-period demand will be the highest of all the 15-minute averages for the part-peak period during the billing month.

16. VOLTAGE DISCOUNTS (Rates B and E Only)

The customer may be eligible for a discount on the charges shown above if the customer takes delivery of electric energy at primary voltage.

The voltage discount, if any, will be applied to the demand charge.

Discounts are applied in any month as follows:

1) For periods where the winter maximum demand charge applies, $0.65 per kW of seasonal billing demand when service is delivered 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.

2) For periods where the summer maximum demand charge applies, $0.95 per kW of seasonal billing demand when service is delivered 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.

PG&E retains the right to change its line voltage at any time. Customers receiving voltage discounts will get reasonable notice of any impending change. They will then have the option of taking service at the new voltage (and making whatever changes in their systems are necessary) or taking service without a voltage discount through transformers supplied by PG&E. (N)

(Continued)

SCHEDULE AG-7--EXPERIMENTAL TIERED TIME-OF-USE AGRICULTURAL POWER (N)

(Continued)

17. POWER FACTOR ADJUSTMENT (Rates B and E Only)

When the customer's maximum demand has exceeded 400 kW for three consecutive months and thereafter until it has fallen below 300 kW for 12 consecutive months, the customer's bill will be adjusted for weighted monthly average power factor as follows: If the customer's average power factor is greater than 85 percent, the customer's total monthly bill (including any voltage adjustment but excluding any taxes) will be reduced by 0.06 percent for each percentage point above 85 percent. If the customer's average power factor is below 85 percent, the customer's total monthly bill (including any voltage adjustment but excluding any taxes) will be increased by 0.06 percent for each percentage point below 85 percent. Such average power factor will be computed (to the nearest whole percent) from the ratio of lagging reactive kilovolt ampere hours to kilowatt hours consumed in the month. No power factor correction will be made for any month when the customer's maximum demand is less than ten percent of the highest such demand in the preceding 11 months. (N)

PG&E's Schedule E-36 Tariff --
Small General Service to Oil and Gas Extraction Customers

AMENDED

Tariff Amended July 9, 1997

COMMERCIAL/INDUSTRIAL/GENERAL (N)

SCHEDULE E-36--SMALL GENERAL SERVICE TO OIL AND GAS EXTRACTION CUSTOMERS

1. APPLICABILITY:

Schedule E-36 is an optional firm-service rate schedule for customers whose Standard Industrial Classification (SIC) code is 1311 (crude petroleum and natural gas extraction). An eligible customer with maximum demand under 500 kW may elect to take service under either Schedule E-36 or Schedule 37. Schedule E-37 is a demand metered time-of-use service option. Schedule E-36 is a non-demand metered non-time-of-use service option. An eligible customer with maximum demand over 499 kW may elect to take service under Schedule E-37 on a voluntary basis, rather than the otherwise applicable mandatory service under Schedule E-19 or Schedule E-20, but is not eligible to take service under Schedule E-36. A customer with more than 70 percent of the energy usage for water pumping for agricultural applications must take service under an agricultural schedule.

If otherwise eligible, a customer currently taking direct access energy service from another provider shall not be denied this tariff, and a customer already under this tariff may later choose direct access and remain on this tariff. If otherwise eligible, new customers and new load taking direct access service shall not be denied this tariff.

Initial Assignment: An eligible customer electing Schedule E-36 or E-37 must take service under Schedule E-37 if the customer's maximum billing demand has exceeded 499 kilowatts for at least three consecutive months during the most recent 12-month period. Otherwise, an eligible customer electing Schedule E-36 or E-37 may elect to take service under either Schedule E-36 or Schedule E-37.

Customer accounts which fail to qualify under these requirements will be evaluated for transfer to service under a different applicable rate schedule. Miscellaneous electrical loads incidental to the operation of the account under SIC Code 1311 will be considered SIC Code 1311 use.

The provisions of Schedule S--Standby Service Special Conditions 1 through 7 shall also apply to customers whose premises are regularly supplied in part (but not in whole) by electric energy from a nonutility source of supply. These customers will pay monthly reservation charges as specified under Section 1 of Schedule S in addition to all applicable Schedule E-36 charges.

Transfers Off of Schedule E-36: If PG&E determines that a customer is not properly classified under SIC code 1311, PG&E will transfer that customer's account off Schedule E-36 and onto a different applicable rate schedule.

Assignment of New Customers: If an eligible customer elects Schedule E-36 or E-37 but is new or lacks a sufficient usage history, and PG&E believes that the customer's maximum demand is likely to be over 499 kilowatts, PG&E will require the customer to take service under Schedule E-37. (N)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL (N)

SCHEDULE E-36--SMALL GENERAL SERVICE TO OIL AND GAS EXTRACTION CUSTOMERS

(Continued)

2. TERRITORY:

This rate schedule applies everywhere PG&E provides electricity service.

3. RATES

If the customer chooses to take service under Schedule E-36, the customer will pay the following rates and charges:

	Per Meter Per Month	
CUSTOMER CHARGE	$16.00	
	Summer	Winter
ENERGY CHARGE (per kWh)	$0.09494	$0.08035

For a customer who chooses to take direct access energy services from another provider, the customer shall receive, on the bill, PX charges (including but not limited to charges for commodity and ancillary services), public purpose program charges, transmission and distribution charges, CTC charges, and charges for competitive or unbundled services (including but not limited to billing, metering, and credits) to the extent that the calculation and presentation of this information is approved by the Commission in the Cost Separation proceeding.

4. DEFINITION OF SEASONS:

The summer rate is applicable May 1 through October 31, and the winter rate is applicable November 1 through April 30. When billing includes use in both the summer and winter periods, energy charges will be prorated based upon the number of days in each period, unless actual meter readings are available. (N)

PG&E's Schedule E-37 Tariff -- Medium General Demand-Metered Time-Of-Use Service to Oil and Gas Extraction Customers

AMENDED

Tariff Amended July 9, 1997

COMMERCIAL/INDUSTRIAL/GENERAL (N)

SCHEDULE E-37--MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE TO OIL AND GAS EXTRACTION CUSTOMERS

1. APPLICABILITY:

Schedule E-37 is an optional firm-service rate schedule for customers whose Standard Industrial Classification (SIC) code is 1311 (crude petroleum and natural gas extraction). An eligible customer with maximum demand under 500 kW may elect to take service under either Schedule E-36 or Schedule 37. Schedule E-37 is a demand metered time-of-use service option. Schedule E-36 is a non-demand metered non-time-of-use service option. An eligible customer with maximum demand over 499 kW may elect to take service under Schedule E-37 on a voluntary basis, rather than the otherwise applicable mandatory service under Schedule E-19 or Schedule E-20, but is not eligible to take service under Schedule E-36. A customer with more than 70 percent of the energy usage for water pumping for agricultural applications must take service under an agricultural schedule.

If otherwise eligible, a customer currently taking direct access energy service from another provider shall not be denied this tariff, and a customer already under this tariff may later choose direct access and remain on this tariff. If otherwise eligible, new customers and new load taking direct access service shall not be denied this tariff.

Initial Assignment: An eligible customer electing Schedule E-36 or E-37 must take service under Schedule E-37 if the customer's maximum billing demand (as defined below) has exceeded 499 kilowatts for at least three consecutive months during the most recent 12-month period. Otherwise, an eligible customer electing Schedule E-36 or E-37 may elect to take service under either Schedule E-36 or Schedule E-37.

Customer accounts which fail to qualify under these requirements will be evaluated for transfer to service under a different applicable rate schedule. Miscellaneous electrical loads incidental to the operation of the account under SIC Code 1311 will be considered SIC Code 1311 use.

The provisions of Schedule S--Standby Service Special Conditions 1 through 7 shall also apply to customers whose premises are regularly supplied in part (but not in whole) by electric energy from a nonutility source of supply. These customers will pay monthly reservation charges as specified under Section 1 of Schedule S in addition to all applicable Schedule E-37 charges.

Time-of-Use One-Time Meter Charges: Depending upon whether or not an Installation or Processing Charge applies, the customer will be served under one of these rates under Schedule E-37:

Rate W: Applies to customers whose account does not have an appropriate time-of-use meter. The customer must pay an "Installation Charge" prior to taking service under this schedule.

Rate X: Applies to customers whose account has an appropriate time-of-use meter, but is not currently being served under this schedule. The customer will be required to pay a "Processing Charge" prior to taking service under this schedule.

Transfers Off of Schedule E-37: If PG&E determines that a customer is not properly classified under SIC code 1311, PG&E will transfer that customer's account off Schedule E-37 and onto a different applicable rate schedule.

Assignment of New Customers: If an eligible customer elects Schedule E-36 or E-37 but is new or lacks a sufficient usage history, and PG&E believes that the customer's maximum demand is likely to be over 499 kilowatts, as defined below, PG&E will require the customer to take service under Schedule E-37. (N)

(Continued)

Pacific Gas and Electric Company
San Francisco, California

Original Cal. P.U.C. Sheet No.
Cancelling Cal. P.U.C. Sheet No.

COMMERCIAL/INDUSTRIAL/GENERAL (N)

SCHEDULE E-37--MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE TO OIL AND GAS EXTRACTION CUSTOMERS

(Continued)

1. APPLICABILITY: (Cont'd.)

Definition of Maximum Demand: Schedule E-37 demand will be averaged over 30-minute intervals for customers whose maximum demand exceeds 499 kW for at least three consecutive months during the most recent 12-month period. Otherwise, Schedule E-37 demand will be averaged over 15-minute intervals. "Maximum demand" will be the highest of all 30-minute averages for the billing month for customers over 499 kW, and of all 15-minute averages for customers below 500 kW. A customer over 499 kW will be switched from 30-minute to 15-minute intervals only when the maximum demand has dropped below 300 kW and remains there for 12 consecutive months.

If the customer's use of electricity is intermittent or subject to violent fluctuations, a 5-minute or 15-minute interval may be used instead of the 30-minute interval, and a 5-minute interval may be used instead of a 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 30-minute intervals if over 499 kW, or 15-minute intervals if under 500 kW. The customer's maximum-peak-period demand will be the highest of all the 30-minute averages for the peak period during the billing month if over 499 kW, or 15-minute intervals if under 500 kW. (See Section 5 for a definition of "Peak" period.)

Standby Demand: For customers for whom Schedule S--Standby Service Special Conditions 1 through 7 apply, standby demand is the portion of a customer's maximum demand in any month caused by nonoperation of the customer's alternate source of power, and for which a demand charge is paid under the regular service schedule.

If the customer imposes standby demand in any month, then the regular service maximum demand charge will be reduced by the applicable reservation capacity charge (see Schedule S Special Condition 1).

To qualify for the above reduction in the maximum demand charge, the customer must, within 30 days of the regular meter-read date, demonstrate to the satisfaction of PG&E the amount of standby demand in any month. For Schedule E-37 customers with maximum demand over 499 kW, this may be done by submitting to PG&E a completed Electric Standby Service Log Sheet (Form 79-726).

2. TERRITORY:

This rate schedule applies everywhere PG&E provides electricity service. (N)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL (N)

SCHEDULE E-37--MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE TO OIL AND GAS EXTRACTION CUSTOMERS

(Continued)

3. RATES

If the customer chooses to take service under Schedule E-37, the customer will pay the following rates and charges:

	One-time Charge Per Meter
INSTALLATION CHARGE Rate W	$443.00
PROCESSING CHARGE Rate X	$ 87.00

	Per Meter Per Month
CUSTOMER CHARGE Rates W and X	$16.00
METER CHARGE Rate W	$ 1.20
Rate X	$ 6.00

DEMAND CHARGE	Summer	Winter
Per kW of maximum demand	$6.55	$4.40
Per kW of maximum-peak-period demand	$2.70	$ --
Primary voltage discount per kW of maximum demand	$0.95	$0.65
Transmission voltage discount per kW of maximum demand	$4.85	$3.25
ENERGY CHARGE (per kWh):		
Peak	$0.14294	$ --
Partial-Peak	$ --	$0.04661
Off-Peak	$0.04088	$0.03706

a. TYPES OF CHARGES: The customer's monthly charge for service under Schedule E-37 is the sum of applicable customer charges, demand charges, energy charges, and other charges below:

- The customer charge is a flat monthly fee.

- The meter charge is a flat monthly fee for the incremental cost of ongoing time-of-use service. (N)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL (N)

SCHEDULE E-37--MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE TO OIL AND GAS EXTRACTION CUSTOMERS

(Continued)

3. RATES (Cont'd.)

a. TYPES OF CHARGES: (Cont'd.)

- Schedule E-37 has two demand charges, a maximum-peak-period-demand charge (summer only), and a maximum-demand charge (summer and winter). The maximum-peak-period-demand charge per kilowatt applies to the maximum demand during the month's peak hours, and the maximum demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include both of these applicable demand charges. (Time periods are defined in Section 5.)

- The energy charge is the sum of the energy charges from the peak, partial-peak, and off-peak periods. The customer pays for energy by the kilowatt-hour (kWh), and rates are differentiated according to time of day and time of year.

- If applicable, all Installation or Processing Charges must be paid in one lump sum before the customer can take service under time-of-use Schedule E-37. Payments for these charges are not transferable to another service, or refundable, in whole or in part. PG&E will place the account on Schedule E-37 within 4 weeks of receiving payment from the customer. The meters required for this schedule may become obsolete as a result of electric industry restructuring or other action taken by the California Public Utilities Commission. Therefore, any and all risks of paying the required charges and not receiving commensurate benefit are entirely that of the customer.

- The Schedule E-37 monthly charges may be increased or decreased based upon the power factor. (See Section 6.)

- As shown on the rate chart, which set of Schedule E-37 demand charges is paid depends on the level of the customer's voltage at which service is taken. Service voltages are defined in Section 4 below.

- For a customer who chooses to take direct access energy services from another provider, the customer shall receive, on the bill, PX charges (including but not limited to charged for commodity and ancillary services), public purpose program charges, transmission and distribution charges, CTC charges, and charges for competitive or unbundled services (including but not limited to billing, metering, and credits) to the extent that the calculation and presentation of this information is approved by the Commission in the Cost Separation proceeding.

4. DEFINITION OF SERVICE VOLTAGE:

The following defines the three voltage classes of Schedule E-37 rates. Standard Service Voltages are listed in PG&E's Electric 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 without transformation from PG&E's serving transmission system at one of the standard transmission voltages specified in PG&E's Electric Rule 2, Section B.1. (N)

(Continued)

COMMERCIAL/INDUSTRIAL/GENERAL (N)

SCHEDULE E-37--MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE TO OIL AND GAS EXTRACTION CUSTOMERS

(Continued)

5. DEFINITION OF TIME PERIODS:

Times of the year and day applicable to Schedule E-37 are defined as follows:

SUMMER Period A (service from May 1 through October 31):

Peak: 12:00 noon to 6:00 p.m. Monday through Friday (except holidays).

Off-peak: All other hours Monday through Friday
All day Saturday, Sunday, and holidays.

WINTER Period B (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 Friday (except holidays).
All day Saturday, Sunday and holidays.

HOLIDAYS: "Holidays" for the purposes of this rate schedule 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.

CHANGE FROM SUMMER TO WINTER OR WINTER TO SUMMER: When a billing month includes both summer and winter days, PG&E will calculate Schedule E-37 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. Schedule E-37 energy usage is metered separately within each season and billed accordingly. 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.

6. POWER FACTOR ADJUSTMENTS:

When the Schedule E-37 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 under Schedule E-37 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.

7. CHARGES FOR TRANSFORMER AND LINE LOSSES:

The demand and energy meter readings used in determining the charges will be adjusted to correct for transformation and line losses in accordance with Section B.4 of PG&E's Electric Rule 2. (N)

(Continued)

Pacific Gas and Electric Company
San Francisco, California

Original Cal. P.U.C. Sheet No.
Cancelling Cal. P.U.C. Sheet No.

COMMERCIAL/INDUSTRIAL/GENERAL (N)

SCHEDULE E-37--MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE TO OIL AND GAS EXTRACTION CUSTOMERS

(Continued)

8. STANDARD SERVICE FACILITIES:

If PG&E must install any new or additional facilities to provide the customer with service under this schedule the customer may have to pay some of the cost. Any advance necessary and any monthly charge for the facilities will be specified in a line extension agreement. See Rules 2, 15, and 16 for details.

Facilities installed to serve the customer may be removed when service is discontinued. The customer will then have to repay PG&E for all or some of its investment in the facilities. Terms and conditions for repayment will be set forth in PG&E's line extension agreement.

9. SPECIAL FACILITIES:

PG&E will normally install only those standard facilities it deems necessary to provide service under this schedule. If the customer requests any additional facilities, those facilities will be treated as "special facilities" in accordance with Section I of Rule 2.

10. ARRANGEMENTS FOR VISUAL-DISPLAY METERING:

If the customer wishes to have visual-display metering equipment in addition to the regular metering equipment, the customer must submit a written request to PG&E. PG&E will provide and install the equipment within 180 days of receiving the request. The visual-display metering equipment will be installed near the present metering equipment. The customer will be responsible for providing the required space and associated wiring.

PG&E will continue to use the regular metering equipment for billing purposes. (N)

Advice Letter No.
Decision No.

22892

Issued by
Steven L. Kline
Vice President
Regulation

Date Filed
Effective
Resolution No.

(END OF APPENDIX B)