ALJ/BDP/tcg

Mailed

APR 25 1991

Decision 91-04-062 April 24, 1991

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

Application of PACIFIC GAS AND ELECTRIC COMPANY for authority, among other things, to increase its rates and charges for electric and gas service.

(Electric and Gas) (U 39 M)

Application 88-12-005
(Filed December 5, 1988)

(See D.89-09-093 for appearances.)

Additional Appearances

Mark Goldowitz, Attorney at Law, for Golden State Mobilehome Owners League and Armour, Goodin, Schlotz & MacBride by James Squeri, Attorney at Law, for Sonora Mining Corporation, interested parties.

Alberto Guerrero, Attorney at Law, for the Division of Ratepayer Advocates.

INDEX

O P I N I O N

I. Summary

This decision adopts seven changes for Pacific Gas and Electric Company (PG&E) rate design. First, the Commission reduces the difference between the residential Tier I and Tier II electric rates. The change will produce bill increases for low-use customers, while providing bill decreases for higher use customers. Second, Schedules E-7 and E-8 for residential time-of-use are moved closer to cost based rates. Third, the mobile home park master meter discount is adjusted to reflect flattening of Tier I-Tier II rates, and the baseline phase-in adopted in PG&E's 1990 general rate case decision (D.) 89-12-057. Fourth, lower demand charges and power factor adjustments are provided for large agricultural customers, tariff connected load provisions are clarified, and the Agricultural Interruptible Program is terminated. Fifth, PG&E's requested modifications to Schedule ED are adopted and D.89-12-057 is modified so that Schedule ED terminates on December 31, 1997. Sixth, medium and large light and power maximum and on-peak demand charges are increased by 10%. Seventh, medium and large light and power time-of-use Schedule A-11 rates are increased and Schedule A-10 rates are decreased to discourage customer migration.

The new rates become effective on May 1, 1991. There is no change in the overall revenue requirement of PG&E.

II. Procedural History

In Decision (D.) 89-01-040, the Commission established a mechanism to consider rate design changes for the major electric utilities in non-general rate case test years. This new procedure establishes for PG&E a five-day window, between November 20 and

November 25, when rate design proposals may be submitted for attrition year implementation.

On November 21, 1990, PG&E filed its rate design window proposals. On February 5 and 6, 1991, evidentiary hearings were held in San Francisco. On February 15, 1991, opening briefs were filed on non-residential class issues. On February 25, 1991, opening briefs were filed on residential class issues. On March 7, 1991, reply briefs were filed on all issues.

Briefs were filed by PG&E, Division of Ratepayer Advocates (DRA), Toward Utility Rate Normalization (TURN), and Western Mobilehome Association (WMA).

III. Residential Rates

A. Background

In 1982, the Legislature enacted Assembly Bill 2443, which set Tier I gas and electric rates at 75 to 85 percent of the System Average Rate (SAR).

In late 1987, an unseasonably cold winter in Southern California caused inordinately high Tier II gas usage by many customers and large month-to-month gas bill increases. This cold snap had similar impacts on electric customers as well.

The following year, in response to public complaints about such bill volatility, the Legislature enacted Senate Bill (SB) 987, which requires realignment of residential rates by reducing the differential between the two tiers. The legislation eliminated the formula for setting Tier I, and ordered the Commission to "reduce high nonbaseline rates as rapidly as possible" subject to "avoiding excessive rate increases for residential customers." The legislation also specified that tier realignment should "not eliminate any significant differential between baseline and nonbaseline rates for at least 30 months after the effective date of this bill." SB 987 also provided for the establishment of a program to assist low-income gas and electric customers.

The Commission initiated OII 88-07-009 for purposes of implementing this legislation. The proceeding was divided into two phases. Phase 1 addressed baseline rate design revisions. This phase culminated in D.88-10-062, which reduced the gas and electric tier differentials in absolute cents per kWh by 10% for PG&E, and by varying degress for other California energy utilities, effective November 1, 1988. Subsequent tier realignment was to be addressed separately for each utility in their respective rate proceedings.

Phase II of OII 88-07-009 addressed the development of a low-income program. This resulted in D.89-07-062 (low-income eligibility criteria) and D.89-09-044 (LIRA 15 percent discount) for a Low Income Rate Assistance (LIRA) rate effective November 1, 1989. D.89-09-044 states:

> "It is clear from the enabling legislation that the LIRA program's continued existence depends on the closure of Tier 1 and Tier 2. To ensure that such realignment will be pursued vigorously, the Commission will examine its progress in baseline reform in May of 1991, the 30-month deadline in SB 987. Adjustments to either our progress in baseline reform or the low-income program may be required after such an examination. (p. 7.)
>
> * * *
>
> "We intend that the LIRA discount replace the baseline subsidy inherent in each utility's existing Tier 1/Tier 2 differential...By today's action, we confirm our strong policy to proceed with baseline reform as needed to address the high bill problem caused by the Tier 1/Tier 2 rate differential, and to ensure that in the very near future the level of the LIRA discount and the size of the Tier 1/Tier 2 rate differential are essentially commensurate ... No timetable for continued realignment for Tier 1/Tier 2 rates was established. However, the level of the adopted LIRA discount will cause us to accelerate the pace at which further realignment occurs. (p. 8.)

In its next opportunity to alter PG&E's electric tier differential, in the 1990 general rate case, the Commission reinforced its commitment to tier closure:

> "For several reasons, we believe substantial progress should be made at this time toward reducing the differential between Tier 1 and Tier 2 rates. The Legislature has clearly directed us to reduce high Tier 2 rates by reducing this differential, although it has also intructed us to proceed at a moderate pace in closing the gap until the end of 1990. Our determinations in D.89-09-044, as we indicated in that decision, provide a significant benefit to low-income customers that mitigates the effect of lower differentials between rates for the two tiers. Our action in that case allows a more rapid movement toward closing the spread between these rates. The 10% reduction proposed by DRA and TURN moves too slowly in light of these circumstances. As we have indicated, we will review our progress in reducing the tier differential in 1991, and we would like to avoid the need for drastic action at that time. (D.89-12-057, p. 262.)

In that decision the Commission adopted a 25% tier reduction which became effective on May 1, 1990. (Conclusion of Law, No. 94, p. 447.)

B. <u>Schedule E-1 Residential Service</u>

PG&E proposes to reduce the difference between Tier I and Tier II rates to make "reasonable progress" towards the goal of reducing the differential between the two tiers of residential rates. The rates at issue are set forth below:

	Present 1/1/91 Rates	Proposed 5/1/91 Rates	Adopted 5/1/91 Rates
Energy Charge:			
Baseline (Tier I) Quantities, per kWh	$0.10658	$0.11031	$0.10924
Tier II Quantities, per kWh	0.14123	0.13502	0.13682
		(Exhibit 3006)	
Ratio Tier I:Tier II	1.325	1.224	1.252
Tier Differential ¢/kWh	0.03465	0.02471	0.02758

To develop its proposed rates, PG&E applied a 3.5% increase to its January 1, 1991 Tier I rate. According to PG&E, a Tier I increase capped at 3.5% causes minimal bill impacts while complying with SB 987, with the Commission's stated intent to continue the progress of tier closure, and with the capped EPMC procedure adopted in PG&E's 1990 Energy Cost Adjustment Clause (ECAC) decision (D.90-12-066).

DRA states that PG&E's proposed 3.5% capped Tier I approach to residential rate realignment is consistent with SB 987. Also, DRA does not believe that the 3.5% increase in the Tier I rate is unreasonable. However, DRA's alternate proposal in light of the recent ECAC rate increase is that a smaller Tier I cap, such as 1.5 or 2.5% be adopted, rather than the 3.5% proposed by PG&E. DRA asserts that a lower capped Tier I rate increase would still achieve some rate realignment but with a more moderate bill impact.

TURN takes exception to PG&E's proposal to increase Tier I rates. TURN argues that PG&E and DRA ignore the legislature's explicit recognition in SB 987 that "electricity and gas services are necessities, for which a low affordable rate is desirable." TURN points out that, without any additional tier differential reduction in this case, PG&E's Tier I rate has increased by 68% since January 1, 1987. TURN believes that increases of this magnitude are inconsistent with maintaining an affordable supply of electricity for every Californian.

TURN contends that, contrary to SB 987, PG&E's proposal would "result in the substantial elimination of any significant differential between baseline and nonbaseline residential rates" and would produce "excessive rate increases for residential customers." (SB 987, Sections 1 and 4.) According to TURN, the tier differential has already been more than cut in half since the passage of SB 987. TURN believes that PG&E has ignored the statements in SB 987 demonstrating the need for gradual tier reduction and a desire to maintain an inverted rate structure.

We are not persuaded by TURN's argument that there should be no further tier closure in this proceeding. As pointed out by PG&E, only about 22% of customers always remain within Tier I. We believe that the majority of higher usage customers should receive the benefits of further tier closure.

However, we agree that TURN has a valid argument regarding bill impacts from the recent rate increases. Also, DRA shares this concern and recommends that we exercise some moderation with regard to further tier closure.

In this instance a more moderate approach to tier closure is appropriate. Instead of the 3.5% recommended by PG&E, we shall adopt a Tier I increase capped at 2.5%. A 2.5% Tier I cap reduces the current tier differential from about 3.5 to 2.8¢/kWh. We believe that a 2.8¢/kWh differential makes reasonable progress in tier closure since at the time of SB 987's passage (June 1988), the Tier I and Tier II rates were about 6.7 and 11.7¢/kWh, respectively, a difference of about 5¢/kWh.

At the adopted rates, the typical customer who has only Tier I usage of 328 kWh/month receives an increase of 87¢ for a total bill of $35.83. With some Tier II usage, say 500 kWh/month, the customer receives an increase of 11¢ for a total bill of

$59.36. For usage of 1,000 kWh/month, the decrease is $2.09 for a total bill of $127.77.

Similarly, a residential customer on the LIRA program, who has usage of 328 kWh/month, receives an increase of 74¢ for a total bill of $30.41. For usage of 500 kWh/month, the increase is 10¢ for a total bill of $50.39. For usage of 1,000 kWh/month, there is a decrease of $1.78 for a total bill of $108.46.

Since the effective date of the rate change in this proceeding is the same as the May 1, 1991 effective date for PG&E's next baseline phase-in, PG&E has incorporated the May 1991 baseline phase-in into its E-1 rate design proposal. PG&E's proposal sets all electric baseline quantities at the target levels established in its 1990 general rate case (D.89-12-057).

PG&E points out that the baseline phase-in methodology adopted in D.89-12-057 has a 5% incremental bill increase constraint for any customer in any month due solely to the baseline phase-in. Based on PG&E's proposed Tier I cap of 3.5%, this presents no problem except for PG&E's individually-metered summer all-electric Territory Z which reaches its target under a 5.1% maximum increase.

PG&E believes the additional 0.1% increase for Territory Z is a minor enough deviation to the 5% rule to warrant adoption so that baseline quantities for all of PG&E's electric customers will finally equal target levels. PG&E points out that this will also eliminate the PG&E and Commission staff time and expense of requiring a May 1992 baseline phase-in electric advice letter filing.

Based on the Tier I cap of 2.5% adopted in this proceeding, Territory Z reaches its baseline target with a 5.8% maximum increase. We conclude that the 5.0% rule adopted in D.89-12-057 should be waived in this instance, since it eliminates an additional advice letter filing and completes baseline phase-in for all PG&E customers.

C. Schedule E-7 Residential Time-of-Use Service

Schedule E-7 is an optional time-of-use (TOU) schedule and is available to customers for whom Schedule E-1 applies.

PG&E proposes to move Schedule E-7 seasonal and TOU differentials halfway toward full Equal Percentage of Marginal Cost (EPMC) levels. This continues the progress made in PG&E's 1988 ECAC and 1990 general rate case toward full EPMC. Both DRA and TURN support this 50% move to full EPMC seasonal and TOU differentials. The present and proposed rates are set forth below:

	Present		Proposed	
Schedules E-7 and EL-7	1/1/91 Rates Summer	1/1/91 Rates Winter	5/1/91 Rates Summer	5/1/91 Rates Winter
On-Peak Energy ($/kWh)	$0.29729	$0.11467	$0.30802	$0.09851
Off-Peak Energy ($/kWh)	0.09298	0.07992	0.08974	0.07503
Baseline Credit ($/kWh)	0.02537	0.02537	0.01541	0.01541

(Exhibit 3006)

As a result of PG&E's proposed move to E-1 tier closure based on a 3.5% tier 1 cap and PG&E's use of the D.89-12-057 E-7 baseline credit methodology, the baseline credit (deduction) would be reduced from about 2.5¢ to 1.5¢/kWh.

TURN takes exception to any reduction in the baseline credit, arguing that it should be frozen at the current level. According to TURN, a reduction in baseline credit would be unfair and unacceptable to its constituents, many of whom are low-use customers.

DRA believes that TURN's argument has merit given the substantial reduction in the baseline credit proposed by PG&E.

PG&E contends that TURN's proposal to freeze the baseline credit would be entirely incongruous with a Schedule E-1 tier realignment, would alter TOU savings relationships versus E-1, and would violate the rate design methodology adopted in PG&E's general rate case decision (D.89-12-057).

We believe that PG&E's proposed reduction to the E-7 baseline credit causes this rate schedule to have little appeal to low-use customers. Also, we agree that PG&E has valid reasons for not freezing the baseline credit. However, as we stated in D.89-12-057, Schedule E-7 should have appeal to low-use customers. Since we need a method that is adaptable for the future, we shall adopt TURN's alternative recommendation to return to the original method of calculating the baseline credit as the difference between Tier I and Tier II rates without reduction for proration of the TOU meter charge over average E-7 baseline sales.

D. Schedule E-8 Residential Seasonal Service Option

In the 1990 general rate case, the Commission adopted a Schedule E-8 with EPMC-based, flat, seasonally-differentiated energy charges and an EPMC customer charge. This rate was intended to enable PG&E to compete with wood and propane space-heating bypass. (D.89-12-057, p. 272.)

According to PG&E, Schedule E-8 has not been successful. PG&E currently has only 12 customers on Schedule E-8. This low participation results because Schedule E-8 is not competitive with Schedule E-1, and is even less competitive with Schedule E-7. PG&E believes Schedule E-8 should strike a middle ground, providing a viable option which is competitive with Schedule E-1 and propane and wood winter space heating, but does not cause undue migration from Schedule E-7. PG&E believes that the low percentage of E-7 customers who could benefit from being on E-8 ensures that this concern is addressed.

Currently, Schedule E-8 rates exceed full EPMC. PG&E proposes that Schedule E-8 revenue allocation move halfway back to full EPMC from the allocation adopted in the 1990 ECAC proceeding. PG&E points out that this will partially correct the current residential intraclass subsidy of Schedules E-1 and E-7 by Schedule

E-8. The present and proposed Schedule E-8 rates are set forth below:

	Present		Proposed	
	1/1/91 Rates Summer	1/1/91 Rates Winter	5/1/91 Rates Summer	5/1/91 Rates Winter
Schedule E-8				
Customer Charge ($/month)	$ 13.92	$ 13.92	$ 13.92	$ 13.92
Energy Charge ($/kWh)	0.13848	0.06782	0.12212	0.06994

(Exhibit 3006)

DRA concurs with PG&E's proposal and recommends adding a Low Income Rate Assistance (LIRA) option to Schedule E-8.

TURN argues that PG&E's E-8 intraclass revenue allocation should be rejected at this time since the appropriate proceeding for setting revenue allocation is the ECAC proceeding.

We reject TURN's argument since the primary objective is a rate design change; the revenue allocation is minor, and it is an intraclass adjustment that is made to accomplish a needed rate design change.

Next, TURN argues that Schedules E-7 and E-8 are designed to give a rate break to large users, and that further departure from inverted rate blocks will cause (large user) customers to migrate from Schedule E-1 to Schedules E-7 and E-8. TURN fears that the end result of this policy may be a "death spiral" of Schedule E-1, where only the small users will remain.

We find TURN's view overly pessimistic. First, we do not expect typical E-1 customers to rush to Schedule E-8. The Customer Charge on Schedule E-8 is more than twice the Minimum Bill charge on Schedule E-1, and no baseline allowance (or Tier I rate) is available on Schedule E-8. Second, Schedules E-1 and E-7 receive negligible equal percentage increases as a result of the change to Schedule E-8. For these reasons, we do not find TURN's argument persuasive.

In summary, for Schedule E-8, we adopt PG&E's proposed 50% movement back to full EPMC intraclass revenue allocation. Also, we adopt DRA's recommendation for adding a LIRA option to Schedule E-8 since there is no reason to deny this option to any customer in this class.

E. Schedules ET and ETL Mobile Home Park Service

Schedules ET and ETL apply to residential service supplied to a mobile home park through one meter and submetered to all individual tenants. To defray the cost of submetering, the mobile home park (master meter) currently receives a $10.26 discount for each space.

Western Mobile Home Association (WMA) points out that the submetering discount is impacted by PG&E's proposed residential tier-flattening proposal and the baseline phase-in that sets all baseline quantities at the target levels adopted in D.89-12-057. According to WMA, if PG&E's proposals are adopted, the submetering discount should be $10.83 per space per month.

The discount figure is derived by subtracting the diversity adjustment from the reimbursable cost of submetering (D.89-12-057 and D.90-05-049). Currently, the diversity adjustment is $1.32. Under PG&E's Tier I-Tier II proposals in this proceeding, the diversity adjustment would be $0.75. The cost of submetering remains unchanged at $11.58.

No party disagrees that the discount figure should be recalculated to reflect the changes adopted by the Commission in this proceeding. The tier flattening and baseline phase-in causes an increase in the discount through a reduction in the baseline diversity benefit. Therefore, based on the rate design changes adopted in this proceeding, the diversity adjustment is $0.84 per space, per month. Subtracting this amount from the cost of submetering which remains unchanged at $11.58, the submetering discount is $10.74 per space, per month.

PG&E points out that adjusting the submetering discount in this proceeding results in a minor revenue shortfall. We agree that this shortfall should be applied to the Energy Rate Adjustment Mechanism (ERAM) balancing account for subsequent adjustment in the 1991 ECAC.

At the hearing, the Golden State Mobilehome Owners League (GSMOL) requested an order which would prevent mobile home park owners from "double-dipping." GSMOL alleges that park owners are being reimbursed twice, both through the utility's discount and by billing their tenants, for the costs involved in owning, maintaining, and operating submetering systems. Therefore, GSMOL apparently believes that a further adjustment should be made to the diversity factor to offset the alleged double-dipping by the mobile home park owners.

The Administrative Law Judge (ALJ) ruled that GSMOL's concerns could not be addressed in this proceeding. The adjustment to the submetering discount would reflect the impact of rate design changes only. We affirm the ALJ's ruling. GSMOL's recourse is to file a complaint with the Commission.

Before we leave the subject of the submetering discount, we wish to make it clear to WMA that, in the future, we will not examine the mobile home discount in every proceeding where a rate change is adopted. We will address adjustments to the discount in the rate design window proceeding, only if there is a significant impact from proposed rate design window changes or from significant changes adopted by the Commission in other proceedings.

F. <u>Schedule ES Multifamily Service</u>

The reasoning behind adopting a new baseline diversity adjustment for Schedule ET also applies to Schedule ES. Therefore, PG&E recommends changing the current ES discount from $2.57 to $3.00 to reflect the revised baseline diversity adjustment.

We agree.

IV. Agricultural Rates

PG&E presented four proposals to modify its agricultural tariffs. These are uncontested and are summarized below:

A. Primary Voltage Level Maximum Demand Charge

PG&E proposes to institute a separate, lower demand charge for large agricultural customers served at primary voltage. The maximum demand charge at the primary voltage level would be expressed in rates as a discount to the secondary voltage level maximum demand charge. Currently, demand charges are not distinguished by voltage level. As a result of this proposal, the average energy rates for Schedules AG-5B, AG-5C, and AG-6B will increase less than one-half of one percent.

We adopt PG&E's proposal since it will allow agricultural rates to better reflect the cost of service and be more consistent with rates for other customer classes.

B. Power Factor Adjustment

PG&E proposes a power factor adjustment for the large agricultural class to provide rates which are more cost-based and more consistent with those for other customer classes. This proposed adjustment would be comparable to the power factor adjustment currently provided to the Medium Light and Power Schedules A-10 and A-11. This adjustment serves to reduce or increase monthly bills depending upon whether the customer's average power factor is above or below 85%. The average power factor information PG&E has obtained indicates that affected customers as a whole, will receive a bill increase of 0.79%, although some customers could receive bill decreases.

The resulting increase in annual revenue is estimated to be $120,000. PG&E's proposal does not alter the revenue allocated to the agricultural class, because the order in PG&E's 1990 GRC provided that power factor revenues should be treated as non-allocated revenues (D.89-12-057, p. 246.) Non-allocated revenues are excluded from the revenues upon which the rates are designed. Therefore, changes in power factor revenues will not directly alter the rate components in rate design. However, the increased revenue would reduce the allocated revenues of the total system.

This adjustment has minor implications for interclass revenue allocation. While we do not favor making rate design changes with major revenue allocation impacts in rate window proceedings, we will in this instance adopt the adjustment since it is a minor change and promotes consistency with the rates for other classes. Accordingly, PG&E's power factor adjustment proposal is adopted. The revenue allocation will be adjusted in the next ECAC proceeding.

C. <u>Connected Load Provision</u>

PG&E proposes to clarify the connected load provision in its agricultural tariffs by including language which states PG&E's long-standing practice with regard to <u>temporary</u> reductions in connected load.

PG&E proposes the following language for all agricultural schedules to clarify the existing policy:

> "The customer's account will be adjusted for <u>permanent</u> connected-load changes that take place during the contract year. It is the customer's responsibility to notify PG&E of such changes. <u>No adjustment will be made for a temporary reduction in connected load. If the load is reconnected within 12 months of being disconnected, charges will be recalculated and applied retroactively as though no reduction in load had taken place</u>. (New language underlined.) (PG&E, Exhibit 3005, p. 3-6.)

We shall adopt PG&E's proposed language since PG&E's tariffs should specifically address the question of temporary reductions in connected load.

D. Agricultural Interruptible Program

In its 1990 general rate case, PG&E requested permission to discontinue the Agricultural Interruptible Project. DRA opposed this request, and the Commission ordered PG&E to continue the program at existing levels through 1992. (D.89-12-057, p. 356.) However, PG&E states that continued operation of this program would not be economically feasible and again requests authorization to discontinue it.

According to PG&E, the program's direct load control equipment needs to be replaced. PG&E contends that the program costs are not justified since the program has poor load impact and lacks cost effectiveness. Furthermore, PG&E believes that TOU rates provide a more suitable option for agricultural customers than the current utility interruptible program.

DRA does not oppose PG&E's recommendation. DRA expressed concern that the agricultural community had not been involved during the formulation of PG&E's proposal, and ensured that the known agricultural intervenors were fully aware of the proposal.

We appreciate DRA's concern. However, we believe that the agricultural interests had the opportunity to be represented on this issue at the hearing. Since there is no objection to PG&E's proposal, we adopt PG&E's recommendation to terminate the program since it is not cost effective.

V. Economic Development Zone Schedules

In PG&E's 1990 general rate case decision (D.89-12-057, p. 342), the Commission adopted an experimental rate schedule, Schedule ED, to complement the State of California's efforts to establish Enterprise Zones in economically distressed areas for special incentives to stimulate job development and economic growth.

PG&E requests the following three modifications to Schedule ED:

1. Expand the "Applicability" section to include non-firm service;

2. Clarify that the "Territory" includes new enterprise zones designated by the State; and

3. Extend the expiration date under the current "Applicability" section from December 31, 1994 to December 31, 1997.

DRA does not oppose the first two proposed modifications; however, it does oppose PG&E's request to extend the expiration date of the tariff. DRA argues that D.89-12-057 is clear and that no further Commission action is required in this proceeding. DRA points out that PG&E's proposed 1997 extension date would extend Schedule ED beyond two rate case cycles.

PG&E states that in Exhibit 17-1-C-A in the general rate case proceeding (A.88-12-005), PG&E set forth its proposal for the availability of Schedule ED. PG&E requested: (1) to open the schedule for subscription for three years; (2) to give a subscribing customer up to 24 months for design and construction before receiving the Schedule ED discount; and (3) to provide the customer with the discount for three years. (pp. 9-10.)

Following the reasoning set forth above, PG&E argues that if a customer were to sign up for the rate on the last available date--December 31, 1992, (the last day of the three-year rate case cycle) it would then have two years to establish business before taking service under Schedule ED--or until December 31, 1994. The schedule was envisioned to have a three-year life for the customer (with the discounts declining on an annual basis--15%, 10%, and 5%), commencing from the first date of taking service. Thus, if the customer were to take service on the last possible date--December 31, 1994--the discount rate would expire on December 31, 1997.

Furthermore, PG&E contends that D.89-12-057 adopted PG&E's proposal without setting a specific expiration date. The date of December 31, 1994 was inadvertently included in PG&E's tariff filing after the issuance of the decision. PG&E requests that in this proceeding the Commission remedy PG&E's error by extending the expiration date of the tariff. PG&E believes that this extension will enable customers considering relocating in Enterprise Zones to obtain the benefits the Commission intended in adopting the rates.

We agree with PG&E that the termination date for Schedule ED was not fully addressed in D.89-12-057. No distinction was made between the last date for signing up new customers and the date for terminating the three-year discount rate period. We shall do so now.

First, it is reasonable that Schedule ED be kept open to new customers for one rate case cycle only. This means that no new customers should be signed up after December 31, 1992.

Second, as an inducement to open a factory in one of the designated areas, a large industrial customer (at least 500 kW), should have up to two years to become operational.

Third, all such industrial customers should receive the declining discount for a full three-year period. To make a three-year discount period available to all such customers, Schedule ED must remain in effect through December 31, 1997.

Conclusion of Law 175 in PG&E's general rate case decision states:

> "175. The experimental Schedule ED proposed by PG&E should be authorized, subject to the following limitations. First, the schedule <u>and the discounts</u> for economic development rates should not extend into any year when PG&E projects, based on the <u>determinations of this decision</u>, that it will need new capacity. . . ." (D.89-12-057, p. 454, emphasis added.)

The Commission did not make a determination in D.89-12-057 that PG&E needed new capacity in 1997. Therefore, PG&E is not precluded from allowing discounts through 1997. In summary, we adopt the three modifications requested by PG&E.

VI. Medium and Large Light & Power Rates

A. Distribution-Voltage Maximum Demand Charges

PG&E proposes a 10% increase in maximum demand charges for all Medium and Large Light and Power Schedules (A-10, A-11, E-14, E-19, E-20, and standby). According to PG&E, this proposal has only modest bill impacts and is consistent with the Commission's intent to move toward EPMC.

DRA agrees with the concept that maximum demand charges for distribution voltages on commercial and industrial schedules should continue to move toward cost-based levels, since these charges were set below cost in PG&E's Test Year 1990 general rate case. However, since commercial and industrial customers have received significant rate increases (between 6% and 16%, depending on the customer's tariff schedule and voltage level) in PG&E's 1990 ECAC (A.90-04-003), DRA believes that a 5% increase would be more appropriate than PG&E's proposed 10% increase.

DRA points out that some customers' bills consist largely of the maximum demand charge, and an increase in this charge would therefore, affect their entire bill. In particular, DRA is concerned about excessive charges for customers on standby rates which are not subject to the rate limiter that is part of some regular-service tariffs. D.90-12-066 in PG&E's 1990 ECAC proceeding included an increase of 7.7% in the maximum demand charge at primary distribution voltages and 9.1% at secondary distribution voltages. DRA finds acceptable an increase for the combined ECAC and rate design window proceedings of 5% more than the adopted ECAC increases, but considers combined increases of

17.7% at primary voltage and 19.1% at secondary voltage to be excessive.

PG&E argues that since for most customers the maximum demand charges constitute only a small portion of the bill, the impact of PG&E's proposal is minimal. PG&E also contends that any bill impacts would be mitigated by the corresponding decreases in energy charges. The fact that some customers will see bill decreases, PG&E believes, should not be overlooked. PG&E submits that this proposal does not change the overall amount of revenue collected from customers, but merely reallocates it to more closely reflect the cost of service.

PG&E further argues that DRA's estimated increases of 17.7% and 19.1% are based solely on the maximum demand charge, which is but one small component of the bill for virtually all customers. PG&E contends that such estimates are misleading and that any comparisons should be based on the entire customer bill.

We agree with DRA that we should consider the effects of the recent 1990 ECAC increase that became effective on January 1, 1991. However, as PG&E states among those customers who see an increase (including both standby and regular customers), only .27% receive an increase larger than 4% as a result of <u>all</u> of PG&E's proposals (i.e., the 10% increase for maximum demand charges, 10% increase for on-peak demand charges, and the shift of additional revenue burden from A-10 to A-11 which are discussed later). Having only .27% of customers see an increase greater than 4% is not unreasonable. Therefore, we adopt PG&E's proposal to increase maximum demand charges by 10%.

B. <u>Transmission-Voltage Maximum Demand Charges</u>

The Cogeneration Service Bureau (CSB) proposes to reduce the maximum demand charge at transmission voltage level, in order to move it closer to its EPMC target level. PG&E and DRA agree that symmetrical treatment of these charges is appropriate. Thus, whatever percentage increase the Commission determines is appropriate for primary and secondary voltage maximum demand charges, the same percentage decrease should apply to the transmission demand charge. We adopt CSB's proposal for symmetrical treatment of transmission voltage maximum demand charges.

The only disagreement concerns CSB's proposal to round the maximum demand rate to the nearest five cents rather than follow PG&E's current practice of rounding to the nearest ten cents. DRA supports CSB's proposal. PG&E, to be consistent, prefers to retain the rule of rounding to the nearest ten cents which was followed in the 1990 general rate case.

We are not persuaded that there is good reason to change the current practice and shall continue to round to the nearest ten cents.

C. <u>On-Peak Demand Charges</u>

In addition to moving maximum demand charges towards EPMC, PG&E also proposes moving on-peak demand charges toward their EPMC targets by increasing the current charges by 10%. PG&E points out that the increase to the on-peak demand charges will be offset by corresponding decreases in proposed energy charges.

DRA argues that PG&E's proposal would distort the rate design adopted by D.89-12-057, by altering the relationship between demand and energy charges. DRA contends that: (1) PG&E mischaracterizes the methodology adopted by D.89-12-057 for setting on-peak demand charges, and (2) PG&E mischaracterizes the appropriate target level for these charges.

DRA further argues that the Commission in D.89-12-057 (pp. 296-298) endorsed DRA's belief that coincident demand[1] costs

1 For purposes of this discussion, coincident demand is defined as the demand of the customer during PG&E's peak hours of demand; on-peak demand (or on-peak billing demand) is defined as the maximum demand of the customer each month that occurs during the on-peak period.

should be recovered in both on-peak demand charges and on-peak energy charges, because customers may have on-peak demand that does not correspond with the instant of the system's peak. And the decision also noted that recovering a portion of coincident demand costs in on-peak energy rates reflects lack of complete coincidence. Therefore, DRA submits that D.89-12-057 adopted DRA's approach to setting the on-peak demand charges.

PG&E asserts that its proposal to increase by 10% the on-peak demand charge for all voltages is consistent with D.89-12-057. PG&E contends that in this decision the Commission endorsed an increase in the on-peak demand charges at only 13% of the difference between the then-current rates and the EPMC target rates, due to bill impact considerations. Though the decision itself does not explicitly state the EPMC target, PG&E believes that it is clear that the target is still very far away.

We find that D.89-12-057, at pages 296-298 adopted DRA's proposal because it was based on EPMC rather than on marginal cost[2] as was PG&E's proposal. D.89-12-057 did not adopt any particular split of coincident peak demand costs between peak billing demand and peak energy charges. Therefore, there is no restriction on adjusting on-peak demand charges.

In this proceeding, DRA argued that although on-peak demand is used for billing purposes, peak energy use is a better predicator of coincident demand. Based on this hypothesis, DRA

---

2 Since revenues based on marginal costs are not usually equal to the utility's revenue requirement, a method must be used that allows us to reflect marginal cost principles while still collecting the authorized revenue requirement. The method used in recent years to reconcile marginal costs with revenue requirement is EPMC. This approach allocates revenues so that each class is an equal percent of its marginal cost revenues. This is referred to as full or 100% EPMC. (See D.88-12-085, p. 39.)

concludes that PG&E's targets are too high and that on-peak demand charges should not be increased at all.

DRA has introduced a concept worthy of additional exploration. However, it was not expressly adopted by the Commission in PG&E's 1990 general rate case decision D.89-12-057 and this is not the appropriate proceeding to examine such complex concepts since rate design window proceedings are expedited and limited in scope. PG&E should address this matter in its next general rate case proceeding.

In summary, we are not persuaded by DRA's argument that on-peak demand charges should be left unchanged because, based on DRA's hypothesis, they may already be at their targets. PG&E's proposal to increase on-peak demand charges 10% should be adopted since it moves these charges closer to EPMC.

D. Schedule A-11—Medium General Demand-Metered Time-of-Use Service

Under this voluntary time-of-use schedule, there is a limit on the number of kilowatts (kW) the customer may require from the PG&E system (the customer's "demand"). If the customer's demand is 500 kW or more for three consecutive months, the account is transferred to Schedule E-19 or E-20.

PG&E has identified Schedule A-11 as an extremely attractive rate not only for current A-10 customers, but also for E-19 customers who are not eligible for the rate. PG&E now proposes to adjust A-11 rates upward in order to prevent migration by customers responding to misleading or transitory rate signals. Revenues would be reallocated between A-10 and A-11 in a way which anticipates higher average A-11 rates in the future. Specifically, PG&E proposes to exogenously increase A-11 rates by pegging the A-11 average rate at 90 percent of the A-10 average rate for a customer with the average billing determinants of the A-11 customer group. Rates for both schedules would be set to collect the same combined revenue requirement for the two schedules adopted in the revenue allocation phase of PG&E's 1990 ECAC case. The result is slightly lower A-10 rates and slightly higher A-11 rates. According to PG&E, this adjustment partially eliminates the substantial disparity between A-11 and E-19 rates.

DRA questions the quantitative basis for PG&E's proposed realignment of intraclass revenue allocation between Schedules A-10 and A-11. However, DRA accepts PG&E's proposed rate change for purposes of this proceeding.

DRA recommends that PG&E combine Schedules A-11 and E-19 in its next general rate case. PG&E recognizes that there is an A-11/E-19 problem and agrees to reevaluate the issue in the next available proceeding. We shall adopt PG&E's proposal for purposes of this proceeding.

E. Schedule A-10--Medium General Demand-Metered Time-of-Use Service

All customers served under Schedule A-1 are eligible for service under Schedule A-10. In its Supplemental Testimony, PG&E identified a problem created with the adoption of the Commission's new January 1, 1991 rates. These new rates substantially widened the difference between Schedules A-1 and A-10, making A-10 attractive to many A-1 customers. PG&E estimates that 29,000 Schedule A-1 customers could potentially save more than 10% by switching to the Schedule A-10 rate, which requires the installation of a demand meter. In fact, PG&E believes that as many as 68,000 current Schedule A-1 customers could have some savings by switching to Schedule A-10.

PG&E states that it does not have the meters or labor to handle the expected number of requests to convert to Schedule A-10. To ensure an orderly transition to this rate, PG&E recommends that minimum eligibility criteria be established for Schedule A-10. Specifically, PG&E proposes a minimum qualifying usage of 100,000 kWh/year for all prospective A-10 customers, effective May 1, 1991.

This requirement is expected to limit eligibility to approximately 6,400 Schedule A-1 customers.

PG&E further proposes to reduce the eligibility requirement to 70,000 kWh/year on May 1, 1992 and to 50,000 kWh/year on May 1, 1993. Depending upon meter and labor availability, PG&E could accelerate this plan.

DRA is not convinced that there is a problem. Even if there is a problem, DRA is opposed to eligibility criteria based on usage. Since PG&E estimates that it can convert 6,000 customers in 1991 from Schedule A-1 to Schedule A-10, but is uncertain of the actual demand for such conversions, DRA recommends that PG&E perform the first 6,000 conversion requests each year and undertake additional conversions depending on availability of meters and labor.

PG&E argues that DRA's "first come, first served" approach could be a logistical nightmare, because PG&E would not know in advance how the first 6,000 meter conversion requests would be allocated among its many division offices. In contrast, PG&E already knows where the customers who use over 100,000 kWh are located within the service territory. Furthermore, PG&E believes that eligibility based on usage is easier to explain and seems more fair to customers.

We shall adopt PG&E's proposal because it is easier to administer and allows PG&E to better allocate resources between divisions. So that this matter may be reviewed in subsequent rate design window proceedings, PG&E shall provide the Commission with an annual progress report by September 20, 1991 and 1992. PG&E should make every effort to accelerate the plan and may file an Advice Letter to reduce the eligibility criteria when it is ready to handle more conversions. PG&E, in its general rate case, should submit a plan to open Schedule A-10 to all Schedule A-1 customers.

F. Non-firm Rates

Because a separate proceeding addressing non-firm rate design proposals was underway, PG&E did not include non-firm rate design in its Rate Design Window filing. The expectation was that the non-firm proceeding would be resolved and final non-firm rates, along with the rates adopted in this proceeding, would both go into effect on May 1. Because that proceeding is still pending, PG&E recommends updating the non-firm rates adopted on January 1, 1991 for the changes to maximum and on-peak demand charges authorized in this case. These components of non-firm rates have always mirrored the same components of firm rates and this revision is consistent with past practice in establishing non-firm rates. PG&E points out that when the Commission adopts a final decision in the non-firm rate design proceeding, these rates can be revised consistent with that decision.

We agree.

Comments on Proposed Decision

Pursuant to PU Code § 311 and the Commission's Rules of Practice and Procedure, the Proposed Decision was published on March 22, 1991. Comments and reply comments were timely filed by DRA and PG&E.

After considering the comments, we affirm the Proposed Decision. Nonsubstantive corrections were made and clarification provided where necessary.

On April 10, 1991, PG&E filed supplemental comments identifying certain small or experimental rate schedules that should be revised consistent with the revisions to the larger commercial and industrial rate schedules authorized in the Proposed Decision.

Specifically, the maximum and on-peak demand charge components of Schedules E-25 and E-26, and Schedule A-RTP, should be adjusted consistent with the changes to Schedules E-19 and E-20 maximum and on-peak demand charges. These charges will maintain the rate design for these schedules previously adopted by the Commission. The E-25 and E-26 rate design was adopted by D.89-12-057 in the 1990 General Rate Case. The A-RTP rate design was adopted by Resolution No. 3215, which accepted the revised A-RTP rate design developed by PG&E and DRA.

Currently, three customers take service under Schedule E-25, and eleven customers take service under A-RTP. No customers take service under Schedule E-26. Because these schedule changes affect few customers and are entirely consistent with Commission approved rate design, PG&E believes that incorporation of these changes in the final decision is appropriate.

There is no opposition to PG&E's request. We shall adopt PG&E's proposal since these schedules should be consistent with the revisions we are adopting for the large commercial and industrial rate schedules.

Findings of Fact

1. To comply with SB 987, the Commission adopted a policy which requires that the difference between Tier I and Tier II rates be gradually reduced consistent with moderate bill impacts on residential customers. (D.89-12-057, p. 262.)

2. Currently PG&E's Tier I and Tier II rates are about 10.7 and 14.1¢/kWh, respectively, for a difference of about 3.5¢/kWh.

3. An increase capped at 2.5% applied to Tier I rates results in Tier I and Tier II rates of about 10.9 and 13.7¢/kWh, for a difference of about 2.8¢/kWh.

4. A change from a differential of 3.5 to 2.8¢/kWh in Tier I and Tier II rates causes moderate bill increases to low-use customers, while higher use customers receive bill decreases.

5. PG&E's general rate case decision D.89-12-057 approved a methodology that assures that residential baseline quantities will finally equal prescribed target levels.

6. Except for Territory Z, PG&E's baseline phase-in proposals are in accordance with this methodology. A minor

deviation is required for Territory Z, so that all baseline quantities will reach their targets in this proceeding.

7. PG&E's proposal to move Schedule E-7 seasonal and TOU differentials halfway toward full EPMC continues the progress made in PG&E's 1990 general rate case.

8. The Schedule E-1 tier flattening 3.5% capped Tier I proposal, in conjunction with the 1990 general rate case E-7 baseline credit methodology, causes the Schedule E-7 baseline credit to be reduced from about 2.5¢/kWh to 1.5¢/kWh and this makes the Schedule E-7 less attractive to low-use customers. For this reason, the method of calculating the baseline credit needs to be changed.

9. Schedule E-8 revenue allocation should move halfway toward full EPMC to continue the progress made in PG&E's 1990 general rate case. This would correct the current residential intraclass subsidy of Schedules E-1 and E-7 by Schedule E-8.

10. The Tier I-Tier II flattening proposal and the baseline phase-in adopted in D.89-12-057 cause a reduction in the mobile-home and multifamily baseline diversity adjustment.

11. The mobile home submetering discount should be calculated by subtracting a revised diversity adjustment of $0.84 from the current cost of submetering of $11.58 to derive a new submetering discount of $10.74 per space, per month.

12. The Schedule ES submetering discount should be calculated by subtracting a revised diversity adjustment of $.68 from the current cost of metering of $3.68 to derive a new submetering discount of $3.00 per space, per month.

13. PG&E presented four proposals to modify its agricultural tariffs, and these proposals are uncontested.

14. A separate lower demand charge for large agricultural customers served at primary voltage will allow agricultural rates to better reflect the cost of service and be more consistent with rates for other customer classes.

15. A power factor adjustment for the large agricultural class will provide rates which are more cost-based and more consistent with those for other customer classes.

16. PG&E's agricultural tariffs need to be clarified to specifically address the question of temporary reductions in connected load.

17. The Agricultural Interruptible program costs are not justified since the program has poor load impact and lacks cost effectiveness.

18. The Commission in PG&E's 1990 general rate case decision intended that Schedule ED should be available for one rate case cycle, there would be two years for the customer to establish operations, and thereafter, a discount would be available for three years.

19. A 10% increase of distribution maximum demand charges and peak-demand charges and 10% decrease of transmission maximum demand charges for commercial and industrial rates continues the progress toward full EPMC rates adopted in PG&E's 1990 general rate case decision.

20. There is no indication in D.89-12-057 that the on-peak demand charge is anywhere near its EPMC target.

21. PG&E proposes to adjust Schedule A-11 rates upward to avoid migration of customers from Schedules A-10 and E-19 into Schedule A-11.

22. The Commission's new January 1, 1991 rates have made Schedule A-10 more attractive to Schedule A-1 customers and PG&E does not have meters and labor available to accommodate the needs of all customers who might change schedules.

23. An eligibility requirement, as proposed by PG&E, is an appropriate method to efficiently manage the transfer of customers into Schedule A-10 because PG&E will be better able to allocate its resources between divisions.

24. The maximum and on-peak demand charge components of Schedules E-25 and E-26, and Schedule A-RTP, should be adjusted consistent with the changes to Schedules E-19 and E-20 maximum and on-peak demand charges. These changes will maintain the rate design for these schedules previously adopted by the Commission.

25. A final decision has not been issued in the separate non-firm rate design proceeding arising from the 1990 general rate case.

Conclusions of Law

1. For residential rate design, a 2.5% capped Tier I approach is consistent with SB 987, and achieves some rate realignment with moderate bill impact to residential customers.

2. An increase capped at 2.5% should be applied to Tier I residential rates to reduce the Tier I-Tier II differential from about 3.5 to 2.8¢/kWh.

3. A complete phase-in of the target residential baseline quantities adopted in the 1990 general rate case decision should be implemented in this proceeding.

4. A 50% move toward full EPMC time-of-use Schedule E-7 revenue allocation is reasonable and should be adopted.

5. The baseline credit should be the difference between Tier I and Tier II rates with no reduction for proration of the TOU meter charge over average E-7 baseline sales.

6. A 50% move back to full EPMC intraclass revenue allocation for Schedule E-8 should be adopted since it continues the progress made in PG&E's 1990 general rate case toward EPMC.

7. Since the LIRA option is available in other residential class schedules, DRA's proposal to add this option to Schedule E-8 is reasonable and should be adopted.

8. Because of the residential tier closure adopted in this proceeding and phase-in of baseline quantities, the mobile home park submetering discount should be changed to $10.74 per space,

per month, and the multifamily submetering discount should be changed to $3.00 per unit, per month.

9. PG&E's four proposals to modify its agricultural tariffs are reasonable and should be adopted.

10. Since Schedule ED should terminate by December 31, 1997, PG&E's 1990 general rate case decision (D.89-12-057) should be modified accordingly.

11. The three modifications to Schedule ED requested by PG&E are appropriate and should be adopted.

12. Maximum demand charges and on-peak demand charges for commercial and industrial customers should be increased by 10% to continue the progress made in PG&E's 1990 general rate case in moving toward EPMC.

13. Non-firm rates should be updated consistent with this decision, and revised when the Commission issues a final decision in the non-firm rate design proceeding.

14. Transmission-voltage maximum demand charges should receive symmetrical treatment so that when primary and secondary voltage maximum demand charges are increased, there is corresponding decrease to the transmission demand charge.

15. PG&E's proposal to adjust Schedule A-11 rates upward, to avoid migration of customers from Schedules A-10 and E-19, should be adopted for purposes of this proceeding.

16. The Schedule A-10 minimum use eligibility criteria proposed by PG&E should be adopted.

17. The supplemental changes proposed by PG&E to Schedules E-25 and E-26, and Schedule A-RTP should be adopted to make these schedules consistent with the revisions to the larger commercial and industrial rate schedules authorized in this decision.

18. All transcript corrections submitted by the parties should be received and incorporated in the record.

19. To avoid multiple rate changes, this order should be made effective on the date signed so that the new rates may be effective on May 1, 1991, when PG&E's summer rates come into effect.

20. PG&E should be ordered to file the new rates set forth in Appendix A, which incorporates all the rate design changes adopted in this decision.

ORDER

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) shall file with this Commission on or after the effective date of this order, and at least three days prior to their effective date, revised tariff schedules for electric rates as set forth in Appendix A.

2. The revised tariff schedules shall become effective on or after May 1, 1991 and shall comply with General Order 96-A. The revised tariffs shall apply to service rendered on or after their effective date.

3. PG&E shall provide the Commission with an annual progress report on the Schedule A-10 eligibility restriction by September 20, 1991 and by September 20, 1992.

4. PG&E, in its general rate case, shall submit a plan to open Schedule A-10 to all Schedule A-1 customers.

5. PG&E's 1990 general rate case D.89-12-057 is modified to reflect a December 31, 1997 termination date for Schedule ED.

6. This proceeding remains open for consideration of other matters.

This order is effective today.

Dated April 24, 1991, at San Francisco, California.

PATRICIA M. ECKERT
President
G. MITCHELL WILK
JOHN B. OHANIAN
DANIEL Wm. FESSLER
NORMAN D. SHUMWAY
Commissioners

I CERTIFY THAT THIS DECISION WAS APPROVED BY THE ABOVE COMMISSIONERS TODAY

NEAL J. SHULMAN, Executive Director

APPENDIX A
PAGE - 1
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED RESIDENTIAL RATES

LINE NO.		1/1/91 RATES SUMMER	1/1/91 RATES WINTER	5/1/91 RATES SUMMER	5/1/91 RATES WINTER	LINE NO.
	SCHEDULE E-1					
1	MINIMUM BILL ($/MONTH)	$5.00	$5.00	$5.00	$5.00	1
2	ES UNIT DISCOUNT ($/UNIT/MONTH)	$2.57	$2.57	$3.00	$3.00	2
3	ET UNIT DISCOUNT ($/UNIT/MONTH)	$10.26	$10.26	$10.74	$10.74	3
4	ET MINIMUM RATE LIMITER ($/KWH)	$0.05317	$0.05317	$0.05317	$0.05317	4
5	TIER 1 ENERGY ($/KWH)	$0.10658	$0.10658	$0.10924	$0.10924	5
6	TIER 2 ENERGY ($/KWH)	$0.14123	$0.14123	$0.13682	$0.13682	6
	SCHEDULE EL-1 (LIRA)					
7	MINIMUM BILL ($/MONTH)	$4.25	$4.25	$4.25	$4.25	7
8	TIER 1 ENERGY ($/KWH)	$0.09045	$0.09045	$0.09271	$0.09271	8
9	TIER 2 ENERGY ($/KWH)	$0.11990	$0.11990	$0.11615	$0.11615	9
	SCHEDULES E-7 AND EL-7					
10	MINIMUM BILL ($/MONTH)	$5.00	$5.00	$5.00	$5.00	10
11	E-7 METER CHARGE ($/MONTH)	$4.40	$4.40	$4.40	$4.40	11
12	EL-7 METER CHARGE($/MONTH)	$0.00	$0.00	$0.00	$0.00	12
13	ON-PEAK ENERGY ($/KWH)	$0.29729	$0.11467	$0.31251	$0.10330	13
14	OFF-PEAK ENERGY ($/KWH)	$0.09298	$0.07992	$0.09423	$0.07982	14
15	BASELINE DISCOUNT ($/KWH)	$0.02537	$0.02537	$0.02758	$0.02758	15
	SCHEDULE E-8					
16	CUSTOMER CHARGE ($/MONTH)	$13.92	$13.92	$13.92	$13.92	16
17	ENERGY CHARGE ($/KWH)	$0.13848	$0.06782	$0.12212	$0.06994	17
	SCHEDULE EL-8 (LIRA)					
18	CUSTOMER CHARGE ($/MONTH)	NA	NA	$11.83	$11.83	18
19	ENERGY CHARGE ($/KWH)	NA	NA	$0.10365	$0.05930	19

APPENDIX A
PAGE - 2
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED MEDIUM L&P RATES

LINE NO.		1/1/91 RATES SUMMER	1/1/91 RATES WINTER	5/1/91 RATES SUMMER	5/1/91 RATES WINTER	LINE NO.
	SCHEDULE A-10					
1	CUSTOMER CHARGE ($/MONTH)	$63.00	$63.00	$63.00	$63.00	1
2	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$3.60	$3.60	$4.00	$4.00	2
3	PRIMARY DISCOUNT ($/KW/MONTH)	$0.80	$0.80	$0.90	$0.90	3
4	TRANS. DISCOUNT ($/KW/MONTH)	$2.90	$2.90	$3.40	$3.40	4
5	ENERGY CHARGE($/KWH)	$0.09915	$0.07684	$0.09673	$0.07497	5
	SCHEDULES A-11 AND E-14					
6	CUSTOMER CHARGE ($/MONTH)	$63.00	$63.00	$63.00	$63.00	6
7	METER CHARGE ($/MONTH)	$5.10	$5.10	$5.10	$5.10	7
8	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$3.60	$3.60	$4.00	$4.00	8
9	PRIMARY DISCOUNT ($/KW/MONTH)	$0.80	$0.80	$0.90	$0.90	9
10	TRANS. DISCOUNT ($/KW/MONTH)	$2.90	$2.90	$3.40	$3.40	10
11	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$10.00		$11.00		11
12	ON-PEAK ENERGY ($/KWH)	$0.10959		$0.11131		12
13	PART-PEAK ENERGY ($/KWH)	$0.08374	$0.06294	$0.08506	$0.06393	13
14	OFF-PEAK ENERGY ($/KWH)	$0.05621	$0.05451	$0.05709	$0.05537	14
15	E-14 ON-PEAK ENERGY ($/KWH)	$0.13545		$0.13757		15

APPENDIX A
PAGE - 3
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED E-19 FIRM RATES

LINE NO.		1/1/91 RATES SUMMER	1/1/91 RATES WINTER	5/1/91 RATES SUMMER	5/1/91 RATES WINTER	LINE NO.
	SCHEDULE E-19 T FIRM					
1	CUSTOMER CHARGE ($/MONTH)	$510.00	$510.00	$510.00	$510.00	1
2	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$0.70	$0.70	$0.60	$0.60	2
3	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$7.80		$8.60		3
4	ON-PEAK ENERGY ($/KWH)	$0.10914		$0.10637		4
5	PARTIAL-PEAK ENERGY ($/KWH)	$0.07408	$0.06334	$0.07220	$0.06173	5
6	OFF-PEAK ENERGY ($/KWH)	$0.05655	$0.05486	$0.05512	$0.05347	6
7	ON-PEAK RATE LIMIT ($/KWH)	$0.62907		$0.62907		7
	SCHEDULE E-19 P FIRM					
8	CUSTOMER CHARGE ($/MONTH)	$250.00	$250.00	$250.00	$250.00	8
9	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$2.80	$2.80	$3.10	$3.10	9
10	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$9.50		$10.50		10
11	ON-PEAK ENERGY ($/KWH)	$0.11170		$0.10820		11
12	PARTIAL-PEAK ENERGY ($/KWH)	$0.07582	$0.06482	$0.07344	$0.06279	12
13	OFF-PEAK ENERGY ($/KWH)	$0.05787	$0.05614	$0.05606	$0.05439	13
14	AVERAGE RATE LIMIT ($/KWH)	$0.14595		$0.14595		14
15	ON-PEAK RATE LIMIT ($/KWH)	$0.85889		$0.85889		15
	SCHEDULE E-19 S FIRM					
16	CUSTOMER CHARGE ($/MONTH)	$280.00	$280.00	$280.00	$280.00	16
17	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$3.60	$3.60	$4.00	$4.00	17
18	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$10.20		$11.20		18
19	ON-PEAK ENERGY ($/KWH)	$0.12386		$0.11982		19
20	PARTIAL-PEAK ENERGY ($/KWH)	$0.08407	$0.07188	$0.08133	$0.06953	20
21	OFF-PEAK ENERGY ($/KWH)	$0.06418	$0.06226	$0.06208	$0.06023	21
22	AVERAGE RATE LIMIT ($/KWH)	$0.14595		$0.14595		22
23	ON-PEAK RATE LIMIT ($/KWH)	$0.86394		$0.86394		23

APPENDIX A
PAGE - 4

PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED E-19 NONFIRM RATES

LINE NO.		1/1/91 RATES SUMMER	1/1/91 RATES WINTER	5/1/91 RATES SUMMER	5/1/91 RATES WINTER	LINE NO.
	SCHEDULE E-19 T NONFIRM					
1	CUSTOMER CHARGE ($/MONTH)	$510.00	$510.00	$510.00	$510.00	1
2	CURTAILABLE METER CHARGE ($/MONTH)	$190.00	$190.00	$190.00	$190.00	2
3	INTERUPTABLE METER CHARGE ($/MONTH)	$200.00	$200.00	$200.00	$200.00	3
4	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$0.70	$0.70	$0.60	$0.60	4
5	PEAK DEMAND CHARGE ($/KW/MONTH)	$2.06		$2.86		5
6	ON-PEAK ENERGY ($/KWH)	$0.10674		$0.10397		6
7	PARTIAL-PEAK ENERGY ($/KWH)	$0.07245	$0.06195	$0.07057	$0.06034	7
8	OFF-PEAK ENERGY ($/KWH)	$0.05531	$0.05365	$0.05388	$0.05226	8
9	UFR CREDIT ($/KWH)UFR CREDIT ($/KWH)	$0.00186	$0.00186	$0.00186	$0.00186	9
10	EXCESS ENERGY CHARGE ($/KWH/EVENT)	$6.77200	$6.77200	$6.77200	$6.77200	10
	SCHEDULE E-19 P NONFIRM					
11	CUSTOMER CHARGE ($/MONTH)	$250.00	$250.00	$250.00	$250.00	11
12	CURTAILABLE METER CHARGE ($/MONTH)	$190.00	$190.00	$190.00	$190.00	12
13	INTERUPTABLE METER CHARGE ($/MONTH)	$200.00	$200.00	$200.00	$200.00	13
14	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$2.80	$2.80	$3.10	$3.10	14
15	PEAK DEMAND CHARGE ($/KW/MONTH)	$4.83		$5.83		15
16	ON-PEAK ENERGY ($/KWH)	$0.10325		$0.09975		16
17	PARTIAL-PEAK ENERGY ($/KWH)	$0.07009	$0.05992	$0.06771	$0.05789	17
18	OFF-PEAK ENERGY ($/KWH)	$0.05349	$0.05189	$0.05168	$0.05014	18
19	UFR CREDIT ($/KWH)UFR CREDIT ($/KWH)	$0.00186	$0.00186	$0.00186	$0.00186	19
20	EXCESS ENERGY CHARGE ($/KWH/EVENT)	$8.64933	$8.64933	$8.64933	$8.64933	20
	SCHEDULE E-19 S NONFIRM					
21	CUSTOMER CHARGE ($/MONTH)	$280.00	$280.00	$280.00	$280.00	21
22	CURTAILABLE METER CHARGE ($/MONTH)	$190.00	$190.00	$190.00	$190.00	22
23	INTERUPTABLE METER CHARGE ($/MONTH)	$200.00	$200.00	$200.00	$200.00	23
24	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$3.60	$3.60	$4.00	$4.00	24
25	PEAK DEMAND CHARGE ($/KW/MONTH)	$4.08		$5.08		25
26	ON-PEAK ENERGY ($/KWH)	$0.12225		$0.11821		26
27	PARTIAL-PEAK ENERGY ($/KWH)	$0.08298	$0.07095	$0.08024	$0.06860	27
28	OFF-PEAK ENERGY ($/KWH)	$0.06335	$0.06145	$0.06125	$0.05942	28
29	UFR CREDIT ($/KWH)UFR CREDIT ($/KWH)	$0.00186	$0.00186	$0.00186	$0.00186	29
30	EXCESS ENERGY CHARGE ($/KWH/EVENT)	$8.64933	$8.64933	$8.64933	$8.64933	30

APPENDIX A

PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED E-20 FIRM RATES

LINE NO.		1/1/91 RATES SUMMER	1/1/91 RATES WINTER	5/1/91 RATES SUMMER	5/1/91 RATES WINTER	LINE NO.
	SCHEDULE E-20 T FIRM					
1	CUSTOMER CHARGE ($/MONTH)-FIRM	$510.00	$510.00	$510.00	$510.00	1
2	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$0.70	$0.70	$0.60	$0.60	2
3	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$7.80		$8.60		3
4	ON-PEAK ENERGY ($/KWH)	$0.08461		$0.08351		4
5	PARTIAL-PEAK ENERGY ($/KWH)	$0.05743	$0.04910	$0.05668	$0.04846	5
6	OFF-PEAK ENERGY ($/KWH)	$0.04384	$0.04253	$0.04327	$0.04198	6
7	ON-PEAK RATE LIMIT ($/KWH)	$0.62907		$0.62907		7
	SCHEDULE E-20 P FIRM					
8	CUSTOMER CHARGE ($/MONTH)	$220.00	$220.00	$220.00	$220.00	8
9	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$2.80	$2.80	$3.10	$3.10	9
10	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$9.50		$10.50		10
11	ON-PEAK ENERGY ($/KWH)	$0.10335		$0.10032		11
12	PARTIAL-PEAK ENERGY ($/KWH)	$0.07015	$0.05998	$0.06809	$0.05822	12
13	OFF-PEAK ENERGY ($/KWH)	$0.05355	$0.05195	$0.05198	$0.05043	13
14	AVERAGE RATE LIMIT ($/KWH)	$0.12663		$0.12663		14
15	ON-PEAK RATE LIMIT ($/KWH)	$0.85889		$0.85889		15
	SCHEDULE E-20 S FIRM					
16	CUSTOMER CHARGE ($/MONTH)	$330.00	$330.00	$330.00	$330.00	16
17	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$3.60	$3.60	$4.00	$4.00	17
18	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$10.20		$11.20		18
19	ON-PEAK ENERGY ($/KWH)	$0.11193		$0.10828		19
20	PARTIAL-PEAK ENERGY ($/KWH)	$0.07598	$0.06496	$0.07350	$0.06284	20
21	OFF-PEAK ENERGY ($/KWH)	$0.05800	$0.05626	$0.05610	$0.05443	21
22	AVERAGE RATE LIMIT ($/KWH)	$0.12663		$0.12663		22
23	ON-PEAK RATE LIMIT ($/KWH)	$0.86394		$0.86394		23

APPENDIX A
PAGE - 6

PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED E-20 NONFIRM RATES

LINE NO.		1/1/91 RATES SUMMER	1/1/91 RATES WINTER	5/1/91 RATES SUMMER	5/1/91 RATES WINTER	LINE NO.
	SCHEDULE E-20 T NONFIRM					
1	CUSTOMER CHARGE ($/MONTH)	$510.00	$510.00	$510.00	$510.00	1
2	CURTAILABLE METER CHARGE ($/MONTH)	$190.00	$190.00	$190.00	$190.00	2
3	INTERUPTABLE METER CHARGE ($/MONTH)	$200.00	$200.00	$200.00	$200.00	3
4	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$0.70	$0.70	$0.60	$0.60	4
5	PEAK DEMAND CHARGE ($/KW/MONTH)	$3.01		$3.81		5
6	ON-PEAK ENERGY ($/KWH)	$0.08256		$0.08146		6
7	PARTIAL-PEAK ENERGY ($/KWH)	$0.05602	$0.04789	$0.05527	$0.04725	7
8	OFF-PEAK ENERGY ($/KWH)	$0.04276	$0.04147	$0.04219	$0.04092	8
9	UFR CREDIT ($/KWH)	$0.00186	$0.00186	$0.00186	$0.00186	9
10	EXCESS ENERGY CHARGE ($/KWH/EVENT)	$6.77200	$6.77200	$6.77200	$6.77200	10
	SCHEDULE E-20 P NONFIRM					
11	CUSTOMER CHARGE ($/MONTH)	$220.00	$220.00	$220.00	$220.00	11
12	CURTAILABLE METER CHARGE ($/MONTH)	$190.00	$190.00	$190.00	$190.00	12
13	INTERUPTABLE METER CHARGE ($/MONTH)	$200.00	$200.00	$200.00	$200.00	13
14	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$2.80	$2.80	$3.10	$3.10	14
15	PEAK DEMAND CHARGE ($/KW/MONTH)	$6.43		$7.43		15
16	ON-PEAK ENERGY ($/KWH)	$0.09590		$0.09296		16
17	PARTIAL-PEAK ENERGY ($/KWH)	$0.06516	$0.05571	$0.06310	$0.05395	17
18	OFF-PEAK ENERGY ($/KWH)	$0.04974	$0.04825	$0.04817	$0.04673	18
19	UFR CREDIT ($/KWH)	$0.00186	$0.00186	$0.00186	$0.00186	19
20	EXCESS ENERGY CHARGE ($/KWH/EVENT)	$8.64933	$8.64933	$8.64933	$8.64933	20
	SCHEDULE E-20 S NONFIRM					
21	CUSTOMER CHARGE ($/MONTH)	$330.00	$330.00	$330.00	$330.00	21
22	CURTAILABLE METER CHARGE ($/MONTH)	$190.00	$190.00	$190.00	$190.00	22
23	INTERUPTABLE METER CHARGE ($/MONTH)	$200.00	$200.00	$200.00	$200.00	23
24	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$3.60	$3.60	$4.00	$4.00	24
25	PEAK DEMAND CHARGE ($/KW/MONTH)	$5.28		$6.28		25
26	ON-PEAK ENERGY ($/KWH)	$0.10701		$0.10336		26
27	PARTIAL-PEAK ENERGY ($/KWH)	$0.07264	$0.06210	$0.07016	$0.05998	27
28	OFF-PEAK ENERGY ($/KWH)	$0.05545	$0.05379	$0.05355	$0.05196	28
29	UFR CREDIT ($/KWH)	$0.00186	$0.00186	$0.00186	$0.00186	29
30	EXCESS ENERGY CHARGE ($/KWH/EVENT)	$8.64933	$8.64933	$8.64933	$8.64933	30

A.88-12-005 ALJ/BDP/tcg *
CACD/scl/1

APPENDIX A
PAGE - 7
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED E-25 RATES

LINE NO.		1/1/91 RATES SUMMER	1/1/91 RATES WINTER	5/1/91 RATES SUMMER	5/1/91 RATES WINTER	LINE NO.
	SCHEDULE E-25T					
1	CUSTOMER CHARGE ($/MONTH)	$510.00	$510.00	$510.00	$510.00	1
2	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$0.70	$0.70	$0.60	$0.60	2
3	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$7.80		$8.60		3
4	ON-PEAK ENERGY ($/KWH)	$0.12667		$0.12346		4
5	PART-PEAK ENERGY ($/KWH)	$0.07408	$0.06334	$0.07220	$0.06173	5
6	OFF-PEAK ENERGY ($/KWH)	$0.05655	$0.05486	$0.05512	$0.05347	6
7	ON-PEAK RATE LIMIT ($/KWH)	$0.62907		$0.62907		7
	SCHEDULE E-25P					
8	CUSTOMER CHARGE ($/MONTH)	$250.00	$250.00	$250.00	$250.00	8
9	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$2.80	$2.80	$3.10	$3.10	9
10	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$9.50		$10.50		10
11	ON-PEAK ENERGY ($/KWH)	$0.12964		$0.12558		11
12	PART-PEAK ENERGY ($/KWH)	$0.07582	$0.06482	$0.07344	$0.06279	12
13	OFF-PEAK ENERGY ($/KWH)	$0.05787	$0.05614	$0.05606	$0.05439	13
14	AVERAGE RATE LIMIT ($/KWH)	$0.12663		$0.12663		14
15	ON-PEAK RATE LIMIT ($/KWH)	$0.85889		$0.85889		15
	SCHEDULE E-25S					
16	CUSTOMER CHARGE ($/MONTH)	$280.00	$280.00	$280.00	$280.00	16
17	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$3.60	$3.60	$4.00	$4.00	17
18	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$10.20		$11.20		18
19	ON-PEAK ENERGY ($/KWH)	$0.14376		$0.13907		19
20	PART-PEAK ENERGY ($/KWH)	$0.08407	$0.07188	$0.08133	$0.06953	20
21	OFF-PEAK ENERGY ($/KWH)	$0.06418	$0.06226	$0.06208	$0.06023	21
22	AVERAGE RATE LIMIT ($/KWH)	$0.12663		$0.12663		22
23	ON-PEAK RATE LIMIT ($/KWH)	$0.86394		$0.86394		23

APPENDIX A
PAGE - 8
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED E-26 RATES

LINE NO.		1/1/91 RATES SUMMER	1/1/91 RATES WINTER	5/1/91 RATES SUMMER	5/1/91 RATES WINTER	LINE NO.
	SCHEDULE E-26T					
1	CUSTOMER CHARGE ($/MONTH)	$510.00	$510.00	$510.00	$510.00	1
2	CURTAILABLE METER CHARGE ($/MONTH)	$190.00	$190.00	$190.00	$190.00	2
3	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$0.70	$0.70	$0.60	$0.60	3
4	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$4.33		$5.13		4
5	ON-PEAK ENERGY ($/KWH)	$0.11360		$0.08202		5
6	PART-PEAK ENERGY ($/KWH)	$0.05641	$0.04823	$0.05566	$0.04758	6
7	OFF-PEAK ENERGY ($/KWH)	$0.04306	$0.04176	$0.04249	$0.04121	7
8	EXCESS DEMAND CHARGE / KWH	$4.90970	$4.90970	$4.90970	$4.90970	8
	SCHEDULE E-26P					
9	CUSTOMER CHARGE ($/MONTH)	$220.00	$220.00	$220.00	$220.00	9
10	CURTAILABLE METER CHARGE ($/MONTH)	$190.00	$190.00	$190.00	$190.00	10
11	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$2.80	$2.80	$3.10	$3.10	11
12	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$7.27		$8.27		12
13	ON-PEAK ENERGY ($/KWH)	$0.12968		$0.09498		13
14	PART-PEAK ENERGY ($/KWH)	$0.06659	$0.05694	$0.06447	$0.05512	14
15	OFF-PEAK ENERGY ($/KWH)	$0.05083	$0.04931	$0.04922	$0.04775	15
16	EXCESS DEMAND CHARGE / KWH	$6.27077	$6.27077	$6.27077	$6.27077	16
	SCHEDULE E-26S					
17	CUSTOMER CHARGE ($/MONTH)	$330.00	$330.00	$330.00	$330.00	17
18	CURTAILABLE METER CHARGE ($/MONTH)	$190.00	$190.00	$190.00	$190.00	18
19	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$3.60	$3.60	$4.00	$4.00	19
20	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$6.63		$7.63		20
21	ON-PEAK ENERGY ($/KWH)	$0.14339		$0.10471		21
22	PART-PEAK ENERGY ($/KWH)	$0.07366	$0.06297	$0.07108	$0.06077	22
23	OFF-PEAK ENERGY ($/KWH)	$0.05623	$0.05454	$0.05425	$0.05264	23
24	EXCESS DEMAND CHARGE / KWH	$6.27077	$6.27077	$6.27077	$6.27077	24

APPENDIX A

PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED STANDBY RATES

LINE NO.		1/1/91 RATES SUMMER	1/1/91 RATES WINTER	5/1/91 RATES SUMMER	5/1/91 RATES WINTER	LINE NO.
	SCHEDULE S - TRANSMISSION					
1	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$0.70	$0.70	$0.60	$0.60	1
2	ON-PEAK RATE LIMITER ($/KWH)	$0.62907		$0.62907		2
	SCHEDULE S - PRIMARY					
3	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$2.80	$2.80	$3.10	$3.10	3
4	ON-PEAK RATE LIMITER ($/KWH)	$0.85889		$0.85889		4
	SCHEDULE S - SECONDARY					
5	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$3.60	$3.60	$4.00	$4.00	5
6	ON-PEAK RATE LIMITER ($/KWH)	$0.86394		$0.86394		6

APPENDIX A
PAGE - 10
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED AGRICULTURAL RATES

LINE NO.		1/1/91 RATES SUMMER	1/1/91 RATES WINTER	5/1/91 RATES SUMMER	5/1/91 RATES WINTER	LINE NO.
	SCHEDULE AG-1B					
1	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	1
	MAXIMUM DEMAND CHARGE					
2	SECONDARY VOLTAGE ($/KW/MONTH)	$2.55	$1.75	$2.55	$1.75	2
3	PRIMARY VOLTAGE DISCOUNT ($/KW/MONTH	NA	NA	$0.40	$0.25	3
4	ENERGY CHARGE ($/KWH)	$0.11883	$0.11883	$0.11883	$0.11883	4
5	RATE LIMITER ($/KWH)	$1.12804	$1.12804	$1.12804	$1.12804	5
	SCHEDULE AG-RB					
6	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	6
7	METER CHARGE ($/MONTH)	$5.10	$5.10	$5.10	$5.10	7
8	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.55		$2.55		8
	MAXIMUM DEMAND CHARGE ($/KW/MONTH)					
9	SECONDARY VOLTAGE ($/KW/MONTH)	$2.55	$1.75	$2.55	$1.75	9
10	PRIMARY VOLTAGE DISCOUNT ($/KW/MONTH	NA	NA	$0.40	$0.25	10
11	ON-PEAK ENERGY ($/KWH)	$0.28380		$0.28380		11
12	PART-PEAK ENERGY ($/KWH)		$0.07732		$0.07732	12
13	OFF-PEAK ENERGY ($/KWH)	$0.08347	$0.06149	$0.08347	$0.06149	13
14	RATE LIMITER ($/KWH)	$1.12804	$1.12804	$1.12804	$1.12804	14

APPENDIX A

PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED AGRICULTURAL RATES

LINE NO.		1/1/91 RATES SUMMER	1/1/91 RATES WINTER	5/1/91 RATES SUMMER	5/1/91 RATES WINTER	LINE NO.
	SCHEDULE AG-VB					
1	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	1
2	METER CHARGE ($/MONTH)	$5.10	$5.10	$5.10	$5.10	2
3	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.55		$2.55		3
	MAXIMUM DEMAND CHARGE ($/KW/MONTH)					
4	SECONDARY VOLTAGE ($/KW/MONTH)	$2.55	$1.75	$2.55	$1.75	4
5	PRIMARY VOLTAGE DISCOUNT ($/KW/MONTH	NA	NA	$0.40	$0.25	5
6	ON-PEAK ENERGY ($/KWH)	$0.25229		$0.25229		6
7	PART-PEAK ENERGY ($/KWH)		$0.07501		$0.07501	7
8	OFF-PEAK ENERGY ($/KWH)	$0.07849	$0.05964	$0.07849	$0.05964	8
9	RATE LIMITER ($/KWH)	$1.12804	$1.12804	$1.12804	$1.12804	9
	SCHEDULE AG-4B					
10	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	10
11	METER CHARGE ($/MONTH)	$5.10	$5.10	$5.10	$5.10	11
12	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.55		$2.55		12
	MAXIMUM DEMAND CHARGE ($/KW/MONTH)					
13	SECONDARY VOLTAGE ($/KW/MONTH)	$2.55	$1.75	$2.55	$1.75	13
14	PRIMARY VOLTAGE DISCOUNT ($/KW/MONTH	NA	NA	$0.40	$0.25	14
15	ON-PEAK ENERGY ($/KWH)	$0.21011		$0.21011		15
16	PART-PEAK ENERGY ($/KWH)		$0.06917		$0.06917	16
17	OFF-PEAK ENERGY ($/KWH)	$0.06572	$0.05499	$0.06572	$0.05499	17
18	RATE LIMITER ($/KWH)	$1.12804	$1.12804	$1.12804	$1.12804	18
	SCHEDULE AG-4C					
19	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	19
20	METER CHARGE ($/MONTH)	$5.10	$5.10	$5.10	$5.10	20
21	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.55		$2.55		21
	MAXIMUM DEMAND CHARGE ($/KW/MONTH)					
22	SECONDARY VOLTAGE ($/KW/MONTH)	$2.55	$1.75	$2.55	$1.75	22
23	PRIMARY VOLTAGE DISCOUNT ($/KW/MONTH	NA	NA	$0.40	$0.25	23
24	ON-PEAK ENERGY ($/KWH)	$0.21011		$0.21011		24
25	PART-PEAK ENERGY ($/KWH)	$0.09451	$0.06917	$0.09451	$0.06917	25
26	OFF-PEAK ENERGY ($/KWH)	$0.06123	$0.05499	$0.06123	$0.05499	26
27	RATE LIMITER ($/KWH)	$1.12804	$1.12804	$1.12804	$1.12804	27

APPENDIX A

PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED AGRICULTURAL RATES

LINE NO.		1/1/91 RATES SUMMER	1/1/91 RATES WINTER	5/1/91 RATES SUMMER	5/1/91 RATES WINTER	LINE NO.
	SCHEDULE AG-5B					
1	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	1
2	METER CHARGE ($/MONTH)	$5.10	$5.10	$5.10	$5.10	2
3	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.50		$2.50		3
	MAXIMUM DEMAND CHARGE ($/KW/MONTH)					
4	SECONDARY VOLTAGE	$6.00	$4.05	$6.00	$4.05	4
5	PRIMARY VOLTAGE DISCOUNT	NA	NA	$0.85	$0.60	5
6	ON-PEAK ENERGY ($/KWH)	$0.13601		$0.13658		6
7	PART-PEAK ENERGY ($/KWH)		$0.04049		$0.04062	7
8	OFF-PEAK ENERGY ($/KWH)	$0.03907	$0.03220	$0.03919	$0.03230	8
9	RATE LIMITER ($/KWH)	$1.12804	$1.12804	$1.12804	$1.12804	9
10	MINIMUM BILL ($/KW/YEAR)	$0.00		$0.00		10
	SCHEDULE AG-5C					
11	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	11
12	METER CHARGE ($/MONTH)	$5.10	$5.10	$5.10	$5.10	12
13	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.50		$2.50		13
	MAXIMUM DEMAND CHARGE ($/KW/MONTH)					
14	SECONDARY VOLTAGE	$6.00	$4.05	$6.00	$4.05	14
15	PRIMARY VOLTAGE DISCOUNT	NA	NA	$0.85	$0.60	15
16	ON-PEAK ENERGY ($/KWH)	$0.13601		$0.13658		16
17	PART-PEAK ENERGY ($/KWH)	$0.05363	$0.04049	$0.05379	$0.04062	17
18	OFF-PEAK ENERGY ($/KWH)	$0.03411	$0.03220	$0.03421	$0.03230	18
19	RATE LIMITER ($/KWH)	$1.12804	$1.12804	$1.12804	$1.12804	19
20	MINIMUM BILL ($/KW/YEAR)	$0.00		$0.00		20
	SCHEDULE AG-6B					
21	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	21
	MAXIMUM DEMAND CHARGE ($/KW/MONTH)					
22	SECONDARY VOLTAGE	$6.00	$4.05	$6.00	$4.05	22
23	PRIMARY VOLTAGE DISCOUNT	NA	NA	$0.85	$0.60	23
24	ENERGY CHARGE ($/KWH)	$0.06688	$0.03552	$0.06709	$0.03563	24
25	RATE LIMITER ($/KWH)	$1.12804	$1.12804	$1.12804	$1.12804	25

APPENDIX A
PAGE - 13
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED REAL TIME PRICING RATES

LINE NO.		1/1/91 RATES SUMMER	1/1/91 RATES WINTER	5/1/91 RATES SUMMER	5/1/91 RATES WINTER	LINE NO.
	SCHEDULE A-RTP PRIMARY					
1	E-20 CUSTOMER CHARGE ($/MONTH)	$220.00	$220.00	$220.00	$220.00	1
2	OPTIONAL SERVICE CHARGE ($/MONTH)	$275.00	$275.00	$275.00	$275.00	2
3	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$2.80	$2.80	$3.10	$3.10	3
4	BASE ENERGY RATE ($/KWH)	$0.00332	$0.00332	$0.00332	$0.00332	4
5	ON-PEAK ENERGY MULTIPLIER	2.1577		2.1304		5
6	PART-PEAK ENERGY MULTIPLIER	2.1577	1.5787	2.1304	1.5500	6
7	OFF-PEAK ENERGY MULTIPLIER	1.5787	1.5787	1.5500	1.5500	7
8	LOAD MANAGEMENT PRICE SIGNAL ($/KWH)	$0.53		$0.53		8
9	TRANSMISSION & DISTRIBUTION ADDER ($/KWH)	$0.09204		$0.09235		9
	SCHEDULE A-RTP SECONDARY					
10	E-19 CUSTOMER CHARGE ($/MONTH)	$280.00	$280.00	$280.00	$280.00	10
11	E-20 CUSTOMER CHARGE ($/MONTH)	$330.00	$330.00	$330.00	$330.00	11
12	OPTIONAL SERVICE CHARGE ($/MONTH)	$275.00	$275.00	$275.00	$275.00	12
13	MAXIMUM DEMAND CHARGE ($/KW/MO.)	$3.60	$3.60	$4.00	$4.00	13
14	BASE ENERGY RATE ($/KWH)	$0.00332	$0.00332	$0.00332	$0.00332	14
15	ON-PEAK ENERGY MULTIPLIER	2.1577		2.1304		15
16	PART-PEAK ENERGY MULTIPLIER	2.1577	1.5787	2.1304	1.5500	16
17	OFF-PEAK ENERGY MULTIPLIER	1.5787	1.5787	1.5500	1.5500	17
18	LOAD MANAGEMENT PRICE SIGNAL ($/KWH)	$0.53		$0.53		18
19	TRANSMISSION & DISTRIBUTION ADDER ($/KWH)	$0.09204		$0.09235		19

(END OF APPENDIX A)