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Decision 97-12-044 December 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 Decrease Its Rates and Charges for Electric and Gas Service, and Increase Rates and Charges for Pipeline Expansion Service. Electric and Gas (U 39 M)	Application 94-12-005 (Filed December 9, 1994)

(See Decision (D.) 97-03-017 for appearances.)

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OPINION ON REVENUE ALLOCATION AND RATE DESIGN PRINCIPLES

Summary

This decision addresses the revenue allocation and rate design issues remaining in Phase 2 of Pacific Gas and Electric Company's (PG&E) 1996 general rate case.[1] The decision provides guidance to parties if they wish to pursue these issues in other proceedings, particularly in regard to the electric rate freeze required by Assembly Bill (AB) 1890. Also, the decision addresses holdover compliance items remaining from PG&E's 1993 general rate case.

Specifically, PG&E requested modifications to existing tariff schedules as follows:

- The closure to new customers of residential time-of-use (TOU) Schedules E-7, EL-7, E-A7, and EL-A7.
- The closure to new customers of seasonal service Schedules E-8 and EL-8.
- The closure to new customers of low emission vehicle residential TOU Schedule E-9.
- The establishment of new Schedule E-19V migration eligibility requirements.
- A revision to the demand interval for Schedule A-10 and E-19V customers with maximum demands between 400 and 500 kW.
- A revision to nonfirm pre-emergency curtailment requirements.

While there are good reasons for implementing PG&E's proposals, we conclude that except for the revision to the uniform pre-emergency curtailment requirements, the rate freeze mandated by AB 1890 precludes PG&E from immediately implementing

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[1] On June 14, 1996, pursuant to Public Utilities (PU) Code § 311, the administrative law judge's (ALJ) proposed decision was filed in the Commission's Docket Office and mailed to all parties for comments. Comments were filed and the proposed decision was placed on the Commission's Meeting Agenda for its July 17, 1996 meeting. In view of the then-pending AB 1890, the proposed decision was withdrawn. On March 11, 1997, the Commission issued Decision (D.) 97-03-017 covering the marginal cost issues in Phase 2. This decision covers the remaining revenue allocation and rate design issues.

these proposed changes to its existing tariff rules. PG&E, at its option, may file these proposed revisions after March 31, 2002, or the date on which the Commission-authorized costs for utility generation-related assets and obligations have been fully recovered.

Also, PG&E requested new tariff schedules as follows:

- Residential TOU Schedules E-10, E-11, E-12, EL-10, EL-11, and EL-12 (available to new customers upon the closure of Schedules E-7, EL-7, E-A7, and EL-A7).

- Residential seasonal service Schedules E-13 and EL-13 (available to new customers upon the closure of Schedules E-8 and EL-8).

- Low emission vehicle residential TOU Schedule E-6 (available to new customers upon the closure of Schedule E-9).

AB 1890 allows the utilities to add new optional tariff schedules meeting specified criteria (PU Code § 378). However, PG&E's proposed schedules are contingent on closure to additional customers of related existing schedules. Since PG&E may not close the existing schedules to additional customers until the AB 1890 rate freeze has ended, PG&E may not wish to implement some or all of these new schedules while the schedules it intended to close remain open. Accordingly, we leave it to PG&E to decide whether to implement the proposed new schedules at this time.

In many respects this decision has been caught in the transition from our current regulatory environment to the competitive environment we are creating through the implementation of our Preferred Policy Decision (D.95-12-063, D.96-01-011) and AB 1890. AB 1890 has frozen rates at levels in effect as of June 10, 1996 and requires that the allocation of transition costs are recovered in substantially the same proportion as similar costs are recovered as of June 10, 1996. Therefore, the two main purposes of this decision – revenue allocation and rate design – have largely been precluded by AB 1890. Additionally, as pointed out throughout this decision, many policy issues that were raised in this proceeding have subsequently been addressed in a variety of other proceedings relating to the implementation of AB 1890. In this decision, we identify those disputed issues that have been made moot.

Nonetheless, this decision reviews the applicable record and establishes certain rate design principles, based solely on this record, that may be applicable after the AB 1890 transition period is over. We must caution, however, that the usefulness of these principles will depend on a number of factors. First, many of the underlying assumptions regarding revenue allocation, particularly the use of the Equal Percent of Marginal Cost (EPMC) methodology, may no longer be appropriate in the post transition period competitive marketplace. The EPMC methodology assumes the calculation of energy, transmission, and distribution marginal costs which are then scaled upwards (or downwards if appropriate) to meet the utility's adopted revenue requirement. This methodology therefore assumes that calculated marginal costs can be scaled upwards and then collected from end-use customers. This basic premise is severely undermined by the competitive marketplace and unbundled rates envisioned by AB 1890 and our policy decision. Energy prices will be set by the marketplace (either through the Power Exchange or by direct access transactions), transmission services will be regulated and priced by the Federal Energy Regulatory Commission (FERC), and the Commission's main jurisdiction for setting rates will be for distribution services. Even in distribution services, however, we are envisioning opening up portions of this market, such as metering and billing, to competition. (See D.97-05-039.) For each of these competitive portions of utility service, it is unclear, how competitive prices in these markets can be scaled up or adjusted to meet the EPMC revenue requirement.

Second, the usefulness of the principles we adopt today are dependent upon when they may be implemented. If the transition period were to end in the next year or so, then the principles we adopt today would be useful. If the rate freeze instead runs out to its statutory end date of March 31, 2002, then the principles we have determined here will probably be either outdated or at least in need of updating.

For both of the above reasons, the guidance that we give today may be largely superseded by later Commission investigations that can address, on a policy basis applicable to all utilities, the rate design and revenue allocation principles that are appropriate after the AB 1890 transition period.

Finally, we address certain issues that have been caught up in the rate freeze adopted by AB 1890. Our rate design policies tend to evolve over time. For example, where we find that rates for one class of customers are either significantly higher or lower than they otherwise would be, we usually adopt a phase-in period in which we realign rates to better reflect the underlying costs. Similarly, an issue will sometime be identified during one General Rate Case (GRC) for which we are unable to reach resolution due to an insufficient record. Often in these cases, we will direct the utility to address this issue in its subsequent GRC. AB 1890, has taken a "snapshot" of our rate design process, freezing rates at their June 10, 1996 levels. As a result, some rates, which were in the process of being phased-in, and some issues (such as streetlighting rates) which were supposed to be addressed in detail in this GRC, have been caught up in this snapshot. For these issues, we identify what the appropriate ratemaking treatment would have been absent the rate freeze.

I. Revenue Allocation

Consistent with the desire of all active parties, we will not adopt a new overall revenue allocation in this proceeding. We will, however, identify the principles that will govern PG&E's next revenue allocation, to the extent permitted by AB 1890. To allocate revenues to the various customer classes, we first calculate marginal cost revenues for each class by multiplying marginal cost by the class' expected usage. Since the current system revenue requirement exceeds marginal cost, we must assign additional revenues to each class to make up the difference. In recent years, we have used an Equal Percentage of Marginal Cost (EPMC) approach, where the marginal cost revenue requirement for each class is scaled up proportionately in order to generate the system revenue requirement. The EPMC factor is calculated by dividing the system revenue requirement by the total marginal cost revenues.

In the various sections below, we adopt certain revenue allocation principles, none of which are being implemented at this time. We will defer until such time as implementation actually occurs any consideration of whether AB 1890 precludes or requires modification to the principles we adopt here.

A. Marginal Cost Revenue Development

PG&E calculates marginal cost revenue for the following categories:

(1) Energy
(2) Customer
(3) Generation Capacity
(4) Bulk Transmission Capacity
(5) Transmission Planning Project Capacity
(6) Transmission Planning Area Capacity
(7) Primary Distribution Capacity
(8) Secondary Distribution Capacity

The company starts with marginal costs that it develops for each category. It also calculates causative factors that are associated with these categories and distinguished by customer class. These factors include load data, kilowatt-hour usage data, customer months and other billing determinants. It then multiplies the marginal costs (expressed in dollars per unit of causative factor) by their respective causative factors to produce marginal cost revenues (in dollars) for each class and schedule.

1. Energy Marginal Cost Revenue

For revenue allocation, PG&E multiplies TOU period sales by TOU energy loss factors and the unit marginal energy costs at the generation level. The products are the loss-adjusted energy marginal cost revenues for each class. PG&E proposes to continue using the same method adopted in D.92-12-057. Its proposal is unopposed. For both reasons, we will adopt it.

2. Customer Marginal Cost Revenue

PG&E separately calculates revenues related to new hookups and revenues related to the ongoing cost of serving all customers. To develop customer marginal cost revenue for new hookups in each class, first PG&E multiplies the full lump-sum hookup marginal cost by the three-year average number of new customers by region and class. The company then calculates the sum across all regions for a given class. To develop marginal cost revenue for the ongoing costs in each class, PG&E multiplies the ongoing portion of marginal customer costs by the total number of customers by region and class in 1993.[2] PG&E then adds together the costs from each region for a given class.

The Office of Ratepayer Advocates (ORA) objects to PG&E's method of allocating revenues for new customer hookups. This is because there is no apparent relationship between the costs imposed for access by a particular customer and the growth attributable to that customer's assigned class in earlier years. ORA raises a valid issue. Why should all of the customers in a particular class face higher or lower customer costs just because a certain number of new customers might be expected to join that class in the future? There is no causative relationship between the existing members of a particular rate class and the cost of a new hookup. Of course, the most efficient way to assign new hookup costs would be to charge each new customer the full cost of its new hookup. For several reasons, the Commission has not historically done that. Yet if we will not assign these costs directly, then what is the second-best approach?

ORA would use what it sees as a more evenhanded way of calculating customer costs in the first place, which would involve using the Rental method rather than the New Customer Only method. However, we have previously rejected this proposal. We did so, among other reasons, because this method appears to overstate the cost of access and service for all customers. The concern is not so much with the way that PG&E determines the costs as with the way it allocates them. If new customer hookup costs are to be borne by the greater body of ratepayers, then they should be borne equitably. For now, we will adopt PG&E's approach. However, in

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[2] 1993 was the most recent year for which PG&E had complete customer count data when it filed its application.

future proceedings, we will ask parties to help the Commission to respond more effectively to the equity concerns raised by this issue.

We do not face a similar issue when considering the allocation of ongoing customer access costs. All customers cause these costs to be incurred, over time. All customers should bear a reasonable portion of these costs. It is reasonable to determine and apply such costs on a class-specific basis. Thus, we will adopt PG&E's proposal in this area.

3. System-level Marginal Capacity Cost Revenues

Currently, certain costs are not allocated based on a customer's physical location. These include generation and bulk transmission costs. These costs are generally allocated systemwide (as opposed to being allocated by region). All parties support this approach. With one exception, all parties also support PG&E's methodology for allocating these costs,[3] which employs the same assumptions for allocating revenues to each class. That exception is the agricultural customers, who propose that class-specific value-of-service factors be developed and used to allocate marginal generation capacity costs.

The Agricultural Energy Consumers Association (AECA) and the California Farm Bureau Federation (agricultural customers) point out that PG&E uses its understanding of the value its customers place on reliability as one of the factors that influence its investments in new generating facilities. They argue that, while the cost of new generating capacity does not vary by customer class, both contribution to peak

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[3] PG&E calculates generation capacity marginal cost revenue by applying marginal generation capacity costs to an estimate of coincident loads. The method of determining these loads has remained largely unchanged since PG&E's 1990 general rate case, with the exception of hourly reliability information known as shortage values, which replaced loss-of-load probabilities as the load-weighting scheme as a result of D.92-12-057.

PG&E calculates bulk transmission marginal cost revenue by multiplying the marginal bulk transmission capacity cost by system-average loss factors and by the shortage value-weighted loads.

loads and the value of reliability are class-specific. Thus, they argue, it is appropriate to charge customers based on the value they place on reliability.

We note that under a restructured electric market, each customer may be able to include service reliability as one of the factors influencing its purchase decisions, and the independent system operator will be charged with maintaining system reliability and compliance with reliability standards. Because the new market is only embryonic, it would be premature to change PG&E's revenue allocation for the reasons cited by AECA.

Finally, even if we were persuaded that class-differentiated value-of-service should affect the allocation of marginal generation capacity costs, we would not agree to make such a distinction based on the current value-of-service methodology. As discussed earlier, we are not convinced that the current value-of-service methodology produces meaningful results. We will adopt PG&E's approach for allocating revenues as derived from the adopted marginal cost of generation capacity and bulk transmission capacity.

B. Direct Schedule Allocation for E-20

PG&E normally accomplishes revenue allocation in two broad steps. First it allocates revenues to each of several classes. Then, it allocates revenues to the various rate schedules within the class. In the last general rate case, ORA urged that the Commission require PG&E to allocate revenues directly to certain rate schedules. PG&E persuaded the Commission that it lacked sufficient data to support direct allocation for all but Schedules E-19 and E-20. The Commission concluded as follows.

> "We support and encourage reasonable efforts towards direct allocations, but we neither decide now that direct allocations will necessarily be the rule in the next [general rate case] nor order PG&E to develop all necessary data. While PG&E undoubtedly has at its disposal the resources necessary to produce data to support some degree of direct allocation, we are not persuaded that such efforts by PG&E would be sufficiently cost-effective to justify a Commission order requiring such production. PG&E asserts that it will continue to strive to improve its marginal cost estimates. We are satisfied with PG&E's commitment in this area, and

> agree that it should be entrusted to exercise its judgment in deciding the scope and level of efforts to achieve direct allocations and in producing information for all parties' use." (D.93-06-087, 50 CPUC2d 1,18 (1993).)

In this proceeding, PG&E has proposed employing direct allocation for Schedule E-20. This is consistent with the Commission's directive cited above, and we will adopt this approach. ORA asks this Commission to direct PG&E to develop direct allocations for one of its agricultural schedules, as well. In keeping with the Commission's 1993 decision, we will not require PG&E to expand its use of direct allocation into areas where it is not prepared to do so.

C. Creation of a Separate Standby Class

Standby customers are those who generate electricity for their own use and wish to use PG&E as its back-up supplier. We further describe the nature of PG&E's standby customers in Section II.E., below. Both PG&E and ORA propose grouping all standby schedules into a separate standby class for the purpose of allocating revenues. It is appropriate to form a rate class for customers that create distinctive costs for the utility system. Standby customers appear to meet this criterion. As Kathryn Auriemma testified on behalf of ORA:

> "The cost of standby service is not entirely comparable to that associated with service provided to otherwise similarly situated customers. Standby service is more costly than otherwise similar service. The main feature that distinguishes standby service from that provided to any other customer group is the uncertainty that characterizes standby load."

Thus, it is appropriate to separate these customers from those that are otherwise similar in order to more directly allocate the costs of serving standby customers. For this reason, we will adopt the proposal to do so.

D. Allocation of California Alternative Rates for Energy (CARE) Revenues

CARE (formerly known as the Low Income Rate Assistance program) allows qualifying customers to pay 85 percent of the residential Tier 1 and Tier 2 rates for their electricity. This program was created in 1989. The resulting subsidy is absorbed by most other customers. Currently, CARE surcharge revenue is allocated based on an equal-cents-per-kWh basis. In its most recent general rate case, Southern California Edison Company (Edison) proposed an alternative CARE allocation methodology very similar to a System Average Percentage Change approach. In this proceeding, PG&E endorsed Edison's CARE proposal and asked that it be applied to PG&E and others, if it were adopted for Edison.

D.97-08-056 addresses care allocation for PG&E, Edison, and SDG&E and adopts a system average percent method to allocate costs. Therefore, PG&E's proposal in this docket is accepted.

E. Allocation of Nonfirm Credit Revenues

Nonfirm customers are those large electric consumers who buy power at a discount in return for their agreement to receive service subject to interruption. For PG&E, these customers are in the classes that qualify for service under Schedules E-19 and E-20. Nonfirm credit revenue is the sum of discounts received by nonfirm customers. Until now, the entire cost of the credits has been spread among all classes as an equal percentage of marginal cost. PG&E and the California Large Energy Consumers Association and California Manufacturers Association (CLECA/CMA) propose to continue this arrangement.

After the current nonfirm tariffs were put in place, the Legislature and Governor approved amendments to PU Code § 743.1 which, in effect, require the continuance of nonfirm tariffs at the current levels until January 1, 1999. However, subpart (c) of that section concludes by declaring, "Any extension of these pricing incentives beyond January 1, 1996, shall not involve any shifting of recovery of costs to other customer classes." ORA and The Utility Reform Network (TURN) argue that this language requires that only the cost-based portions of the nonfirm discounts be spread across other customer classes. They would argue that other portions of the discounts must be absorbed by Schedule E-19 and E-20 customers.

The ORA and TURN position is consistent with our interpretation of § 743.1 as expressed in D.96-04-050,[4] an interpretation that applies here as well. PG&E argues that the cited portion of § 743.1 prohibits any reallocation of costs. We disagree. Prior to the most recent amendment of that section, the Commission limited the nonfirm discount to the marginal cost that is avoided by a customer's willingness to be interruptible. Now, we are required to keep the discount at its existing level even if the avoided marginal costs are lower. Any portion of the discount in excess of marginal cost is a subsidy. If we require other ratepayer groups to absorb this subsidy, then we would have "shifted" a new cost on to other ratepayer groups. This is expressly forbidden by the statute.

We are left to determine which portion of the current incentive is cost-based. ORA proposes that the cost-based contribution be determined by adding together the marginal cost of a combustion turbine and a significant portion of the marginal transmission cost. Because it did not have the resources needed to calculate the appropriate apportionment in this proceeding, ORA would multiply the marginal transmission cost by 87.5%, relying on a proxy that was applied by the Commission in D.92-05-031 and add this to the product of the value-of-service index and the combustion turbine cost. This yields a credit of $68.98/kW, which is 82% of the $84 credit adopted in D.92-05-031.

TURN argues that no transmission costs should be included in the cost basis for nonfirm incentives. It asserts that the record shows that the only costs clearly avoided by PG&E's interruptible customers are generation costs. PG&E's transmission planning witness testified that both the bulk and area transmission systems are planned in order to serve a peak demand that includes the demand for nonfirm customers. Under the current nonfirm tariff, the only criteria for interruption are generation-

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[4] See mimeo., pp. 152-153 where we state, "only the cost-based portion is recovered from all rate groups in the revenue allocation process. The difference between the present interruptible credit and the cost-based level of the interruptible credit is to be allocated to the large power customer group, consistent with the requirements of PU Code § 743.1."

related. Thus, PG&E plans and operates its transmission system to be able to serve interruptible customers even under conditions of very high peak loads on the transmission system. Thus, it would appear that the nonfirm program does not allow the utility to avoid any transmission costs.

Faced with similarly compelling evidence, however, the Commission recently determined that transmission costs should be included in the cost-based portion of Edison's interruptible discount.[5] Thus, the Commission appears to have endorsed such treatment as a matter of policy. For consistency, we will adopt similar treatment here, allocating both marginal generation and coincident transmission costs[6] stemming from the nonfirm discounts to all customer classes. All other costs will be allocated to the Schedule E-19 and E-20 rate classes based on the amount of credit provided to each class and voltage level category.

F. Future Escalation of Marginal Cost

Currently, marginal transmission, distribution and customer costs are automatically escalated in the Energy Cost Adjustment Clause (ECAC) proceedings between general rate cases. Also, the six-year average marginal generation capacity cost is moved forward a year based on the twenty-year forecast approved in the general rate case, and the marginal energy cost is entirely recalculated and apportioned to TOU periods according to the most recently approved Zero-Intercept Method ratios from the general rate case. ORA proposes to eliminate of the current practice by allowing marginal costs to be updated between general rate cases only when parties can document that significant changes in marginal costs have occurred. PG&E supports the elimination of automatic escalation of marginal transmission, distribution and customer costs, but asks that adjustments to marginal generation and energy costs still be made. As indicated earlier, we intend to allow PG&E to adjust its marginal costs to reflect new resource additions from year-to-year, but only when PG&E can demonstrate that

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[5] Ibid., pp. 155-156.

[6] Using the 87.5% formula proposed by ORA to calculate the coincident transmission cost.

significant changes in marginal costs have occurred. It is consistent with the approach to eliminate automatic adjustments and allow PG&E to continue to recalculate the generation and energy costs each year. Thus, we adopt this proposal, as modified by PG&E.

G. Agricultural Customer Load Study

One of the causative factors that influence the allocation of revenues is the estimate of loads for each customer class. There is little disagreement with the acceptability of PG&E's proposed load projections. They are based on a study that involves the direct collection of load data from customers in each class. The agricultural customers object to the type of study used to project agricultural loads because they feel that the study does not reflect the unusual nature of electric service to such customers.

Because multiple irrigation pumps on a given farm are typically located far apart, each pump may have its own meter. The usage on each meter is recorded in a separate account. Thus, one agricultural customer may have several accounts. The agricultural customers are critical of PG&E's load study because it did not involve the direct measurement of load through each meter of a multi-account agricultural customer. Wendy Illingworth, testifying for the agricultural customers, stated that as a result, "PG&E may have overstated agriculture's coincident peak demand." On that basis, Illingworth asks that PG&E be required to initiate a pilot aggregation program under which 50 agricultural customers would be allowed to use metering equipment that would record the usage for individual accounts and calculate the combined demand from all of a customer's accounts. PG&E would be responsible for analyzing the recorded data to determine whether the program induces customers to change their usage patterns and whether the new information should be used to adjust marginal cost and allocation methods.

PG&E objects to this proposal, arguing that its current study accurately reflects the load patterns of multi-account customers. PG&E's major problem with the pilot aggregation proposal is that it will not develop sufficient data to produce statistically significant results. This is a valid concern and is sufficient reason for this

Commission to avoid mandating that PG&E undertake any particular experiment and apply any particular technique. Since the agricultural customers are not proposing any specific changes to the allocations in this proceeding as a result of their concerns, this issue does not affect current allocations.

D.97-10-086 discusses a variety of load profiling issues, and calls for an Energy Division workshop to address agricultural load profiling issues no later than February 15, 1998. With the onset of competition, it may be inappropriate to require unique metering and load profiling techniques from only one of the three large California investor-owned utilities. Therefore, this issue may be more appropriately addressed in the workshop.

H. Continued Use of the Equal Percentage of Marginal Cost Methodology

The agricultural customers object to the continued use of the EPMC method for allocating the required revenues in excess of total marginal cost. Their basic argument is that if a full EPMC adjustment is made to the agricultural rates, customers in those classes would have rates that would be inordinately higher than those applied to other classes. Based on this observation, the agricultural customers conclude that "something is very wrong" with the Commission's adopted ratemaking methods. Their proposal is to abandon the use of EPMC for the next two years and, instead, allocate any changes based on a System Average Percentage Change strategy. They reason that after two years, California will embark on a restructured electric industry and that rates will be set either by market forces or, in the case of transmission, by a federal agency.

As recently as April 1996, we reaffirmed the validity of the EPMC method (D.96-04-050, pp. 73-76). However, we also reaffirmed that where EPMC allocation produces distorted results, we will apply caps to mitigate those impacts. The arguments raised by the agricultural customers will be considered when the Commission allocates revenue responsibility. At that time, we will also be in the best position to determine if and how a cap should be applied, since we will know what the overall revenue requirement will be.

II. Rate Design and the AB 1890 Rate Freeze

Rate design encompasses the specific terms, conditions and charges to apply in each usage situation. With limited exceptions, we will not make specific changes to rate design in this proceeding. Instead, we will identify principles to apply when rates are next set. In the meantime, any adopted changes must be evaluated to ensure consistency with the rate freeze mandated by AB 1890.

The rate freeze is most clearly articulated in § 368, which requires "each electrical corporation" to propose a plan for the recovery of certain uneconomic generation-related assets and obligations. The Commission is required to approve these plans if they meet specified criteria. Among the criteria is the basic requirement for a rate freeze:

> "The cost recovery plan shall set rates for each customer class, rate schedule, contract, or tariff option, at levels equal to the level as shown on electric rate schedules as of June 10, 1996. . . ." (PU Code § 368(a).)

After establishing the basic freeze, § 368 immediately creates some exceptions. The most significant exception is that "rates for residential and small commercial customers shall be reduced so that these customers shall receive rate reductions of no less than 10 percent for 1998 continuing through 2002" (§ 368(a)), although the rate freeze can end earlier if the uneconomic costs are fully recovered. In addition, § 368(b) requires the cost recovery plan to provide for the identification and separation of individual rate components, which suggests that rates can be reconfigured within the frozen rate levels.

In addition, § 378 provides:

> "The Commission shall 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."

Also pertinent is § 367(e), which allocates the responsibility for recovery of the uneconomic costs of generation-related assets and obligations "in substantially the same proportion as similar costs are recovered as of June 10, 1996, through the regulated retail rates of the relevant electric utility," subject to certain exemptions. Moreover, "individual customers shall not experience rate increases as a result of the allocation of transition costs," unless they choose to purchase energy from suppliers other than the Power Exchange.

We addressed some of the rate freeze issues briefly in D.96-12-077, when we approved the cost recovery plans filed by PG&E, Edison, and San Diego Gas & Electric Company (SDG&E) in compliance with § 368. Our purpose in considering the rate freeze in D.96-12-077 was to determine whether these utilities' cost recovery plans met the criteria of § 368, and we made clear that our role in reviewing these plans was a general one of approving the overall framework for transition cost recovery. Because of the limited purpose of our review, we stated, "To the extent that any element of the plans or of this decision is inconsistent with § 368 or any other provision of AB 1890, the language of the statute prevails." Thus, our discussion of the rate freeze in that context was not intended to be our final word on this topic. PG&E's rate design proposals present a much more specific and concrete opportunity for us to consider the rate freeze in more detail. The following discussion analyzes some general types of rate design proposals in light of the provisions of AB 1890.

A. Adding Schedules

PU Code § 378 specifically directs the Commission to authorize "new optional rate schedules and tariffs" that meet certain criteria. Use of the word "optional" implies that customers will be free to select these new schedules but that the existing tariffs (as of June 10, 1996) must remain available as a default for customers who do not choose service under the new schedules. Any proposed new schedule or tariff would need to be evaluated according to the listed criteria, that the new schedules or tariffs "accurately reflect the loads, locations, conditions of service, cost of service, and market opportunities of customer classes and subclasses." A further limitation is that any such new schedules should not result in substantial reallocation of responsibility for transition costs in violation of § 367(e).

B. Modifying Schedules

In D.96-12-077, we recognized that under § 368(a) the freeze applies only to rates. This statement suggests that other terms and conditions of a schedule could be modified without violating the rate freeze. This conclusion unintentionally downplays the connection between rates and the terms and conditions of service. It is true that minor changes can be made to the schedules without violating the rate freeze. But it is also true that maintaining rate levels while substantially altering the terms of service would be completely contrary to the purpose of the rate freeze. To take an extreme example, if a utility maintained its June 10, 1996 rates for a particular schedule but modified the tariff's terms so that service was available at those rates only between 2 a.m. and 3 a.m. (as compared with 24-hour a day service available on June 10, 1996), there is little question that such a modification would violate the intent of the rate freeze.

Our conclusion is that modifications to the terms and conditions of existing schedules must be evaluated to determine whether they result in substantial changes to the terms, quality or value of service provided to customers under the schedule, as compared to the service offered as of June 10, 1996. Modifications that result in substantially diminish the quality or value of the service offered on June 10, 1996, are not permitted under the rate freeze. Obviously, determining whether changes are substantial is a matter of judgment, and we will exercise our judgment and apply this standard as we consider the details of particular proposed modifications.

C. Closing Existing Schedules

When a utility seeks to close a schedule, it may seek either to close the schedule to existing customers, forcing customers currently served under the schedule to take service under another schedule, or it may seek to close the schedule to additional customers, allowing current customers to continue their service under the schedule. As we discussed previously, the wording of § 378 suggests that schedules that were in effect on June 10, 1996 must remain available to existing customers during the period of the rate freeze, and we conclude that this interpretation best fulfills the requirements of § 368(a). The possibility of closing an existing schedule to additional customers raises more difficult questions.

In D.96-12-077, we touched on this issue briefly. We stated, "By referring only to a freeze of rates, § 368(a) implies that as long as the schedule remains in the tariffs for existing customers and the rate is not changed, closing the schedule to new customers is not prohibited." This statement, while correct as far as it goes, omits a discussion of the conditions that would justify closing a schedule to additional customers and, due to the general context of the decision, glosses over some of the complications of this question.

Whenever two similarly situated customers are provided different services or rates, an issue of discrimination arises. PU Code § 453(d) provides that, "No public utility shall establish or maintain any unreasonable difference as to rates, charges, facilities, or in any other respect, either as between localities or as between classes of service." For purposes of this discussion, the nondiscrimination provisions of § 453(d) require us to consider whether there is a reasonable basis for treating additional customers differently from customers currently served under a particular schedule and who are otherwise similarly situated.

We conclude that there is no reasonable basis for treating these customers differently. All customers, except those eligible for explicit statutory exemptions with certain exceptions, will bear the burden of electric industry restructuring in the form of the competition transition charge (CTC). (*See* §§ 369, 370, 371(a).) As a matter of fairness, all customers should also receive one of the primary initial benefits of restructuring: the availability of service during the transition period at the rate levels and at substantially the same terms as existed on June 10, 1996.

We conclude that all customers should be able to choose service from schedules that contain the rate levels and that offer substantially the same quality and value of service that were available to similarly situated customers on June 10, 1996. As noted above, use of the word "optional" in § 378 also suggests that schedules in effect on June 10, 1996 should remain available to all customers during the rate freeze. This conclusion does not mean that schedules may not be closed to additional customers under any circumstances. At a minimum, however, before a utility may close a schedule, it must have available a schedule that offers customers the same rates and substantially equivalent service to the schedules that were in effect on June 10, 1996.

D. Migration Between Schedules

AB 1890 freezes rates, but it does not require customers to remain on the specific schedules that they were served under on June 10, 1996. During the rate freeze, customers may continue to take service under any schedule for which they are eligible and may switch from one schedule to another, provided the stated eligibility requirements are met.

E. Residential Rate Design

1. Baseline Quantities

Regulated California energy utilities must offer a baseline rate that provides residential customers with a lower cost for gas and electricity needed to meet a significant portion of their basic energy needs. PG&E proposes to continue to offer the highest baseline quantities allowable by law.[7] PG&E proposes to continue to phase in new baseline quantities so that residential customers experience no more than a 5% bill increase. We find the proposed target quantities reasonable and adopt PG&E's recommendations. Although target gas baseline quantities are established here, the phase-in of PG&E's gas baseline quantities will be handled separately by advice letter in the spring of 1998, for implementation on May 1, 1998. However, PG&E does not seek to adjust baseline quantities now, since it hopes to avoid rate increases. PG&E estimates that with a reduction of at least 1.5% in residential rates, it could phase in new baseline quantities without raising rates. ORA does not contest the proposed targets, but urges that the revisions take place as soon as possible without increasing the amount any customer pays for electric service.

The goals of these two parties do not appear inconsistent. We agree that PG&E should use any sufficiently large revenue requirement reduction as an

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[7] 70% of average wintertime consumption for all-electric customers and 60% of average consumption for all other residential customers at all other times (PU Code § 739(d)(1)).

opportunity to further adjust baseline quantities. Such adjustments, however, are constrained by the rate freeze mandated by AB 1890 for the duration of the rate freeze period. (PU Code § 368(a).)

2. Voluntary Time-of-Use Rates

PG&E offers residential TOU rates through its Schedule E-7. This rate varies by season (summer vs. winter) and by time of day (on-peak vs. off-peak). Through this schedule, residential customers located anywhere on PG&E's system are able to use non-peak electric rates during all hours other than noon to 6:00 p.m. during the summer. However, as of 1993, over half of the Schedule E-7 customers were in distribution areas with summer peaks of 2:00 p.m. to 8:00 p.m. At least partially as a result of this discrepancy, the average rate paid by Schedule E-7 customers is only 83.6 % of the average rate paid by Schedule E-1 customers. Currently, rates on Schedule E-7 would have to be increased by 13.2% to maintain a cost-based relationship between the two schedules. No party is seeking such an increase here, because it would be inconsistent with the intention of all parties to avoid rate increases.

PG&E has chosen, instead, to preclude additional customers from using Schedule E-7 while creating Schedules E-10, E-11 and E-12, which offer for all other customers residential TOU rates that more accurately reflect marginal cost and the variations in peaks in different distribution areas. Schedule E-10 is designed for residential customers who live in distribution planning areas where the local peak is between noon and 6:00 p.m. in the summer. Schedule E-11 would apply to customers in areas where the summer peak is between 2:00 p.m. and 8:00 p.m. Schedule E-12 would apply to areas with a winter peak between 5:00 p.m. and 9:00 p.m. The creation of such new schedules is consistent with § 378 which allows the Commission to authorize new optional rates that accurately reflect the loads, location, conditions of service, and cost of service of customer classes and subclasses.

The problem PG&E's proposed new schedules seek to remedy is a short-term one. The usage patterns that are the basis for Schedule E-7 and other TOU schedules will be altered by the impending changes in the electric utility industry.

Beginning on January 1, 1998, metering for customers with demands of 20 kilowatts or greater will no longer be the exclusive domain of the utility, and competition for metering services to all customers will begin on January 1, 1999. (D.97-05-039, slip op. at 16-17, 31 (Ordering Paragraph 2).) Similarly, to be eligible for direct access, customers with demands of 20 kilowatts or more must have meters capable of hourly usage measurement beginning January 1, 1998, and other direct access customers must have hourly meters by January 1, 2002. (D.97-05-040, slip op. at 35-36, 92 (Ordering Paragraph 5(b)).) We expect that many of the new meters installed in response to these changes in the market will have the ability to measure and allow customers to respond to real time pricing signals. At the same time, also on January 1, 1998, the start of the Power Exchange will price energy hourly in response to market pressures, rather than on the basis of outdated historical patterns and costs. The combination of hourly market prices and meters that can reflect those market prices will almost certainly modify the historical usage patterns that are assumed in both the current Schedule E-7 and the proposed Schedules E-10, E-11, and E-12. Therefore, because of these expected and dramatic changes in the market, PG&E's proposals may become outdated.

However, Schedule E-7 rates were in effect on June 10, 1996, and are generally lower than the rates offered in Schedules E-10, E-11, and E-12. Since the new schedules do not offer "the same rates and substantially equivalent service" consistent with our interpretation of § 378 above, PG&E's request to close Schedule E-7 to additional customers, must be denied at this time. As required by § 368(a), Schedule E-7 should remain in effect for all qualified customers until at least the earlier of March 31, 2002, or the date on which the rate freeze is ended for the various customer classes.

Prior to the end of 1996, voluntary residential TOU customers were supplied with TOU meters by PG&E. In D.95-12-055, the Commission denied future funding for this purpose, but authorized PG&E to offer the meters at cost pursuant to approved tariffs. PG&E is considering the development of tariffs to address this issue. In the meantime, PG&E seeks approval of Schedules E-10, E-11, and E-12 with permission to postpone their implementation until PG&E files and the Commission approves an advice letter modifying both its current and proposed TOU programs. PG&E also states that it would withdraw the proposed tariffs if it decides it does not want to offer them. ORA supports the new tariffs, with the understanding that they need to be adjusted to reflect adopted marginal costs. According to PG&E, the rates in Schedules E-10, E-11, and E-12 are based on January 1, 1996 system average residential TOU marginal costs pursuant to D.97-03-017, Conclusion of Law 9, and are not designed using an area-by-area analysis or area transmission and distribution constraints. No one opposes PG&E's proposal.

Further, since introduction of new Schedules E-10, E-11, and E-12 is contingent on closure of Schedule E-7 to additional customers, and we have concluded that such closure would be in violation of the rate freeze imposed by AB 1890, PG&E may not wish to implement the proposed new schedules while Schedule E-7 remains open to additional customers.

In summary, PG&E's request to close existing Schedule E-7 to additional customers is denied. PG&E, at its option, may implement new Schedules E-10, E-11, and E-12 as set forth in Appendix B.

3. Seasonal Rates

Unlike Schedule E-7, which offers residential rates differentiated by time of day and by season, Schedule E-8 is a voluntary tariff that offers rates varying only by season (summer vs. winter). It was first approved by the Commission in 1989 as a way to help PG&E attract customers to use electric space heaters when they might otherwise rely on heaters fueled by wood or propane (see 34 CPUC2d 199, 350). Its users pay a monthly customer charge (currently $13.92) in exchange for a one-tier charge per kWh that is much smaller in the wintertime than the rates paid by more conventional (Schedule E-1) residential customers. In the summertime, this rate is approximately 10% lower than the second tier Schedule E-1 rate. Because of the relatively high customer charge, this is a tariff designed to attract those residential customers who use an exceptionally large amount of electricity. The incentive to rely heavily on electricity use in the wintertime may send the wrong signal to customers who live in winter-peaking areas. But the summer rate could also attract large summer users, such as those with big air conditioning loads.

PG&E asserts that the closure of Schedule E-7 could encourage many more customers to choose Schedule E-8. This is of concern because the current Schedule E-8 rates appear to understate the cost of service. PG&E proposes closing Schedule E-8 to additional customers and creating Schedule E-13 as a new seasonal rate. This rate would be calculated so that its average rate would be 89% of Schedule E-1, which is the same as the ratio of the current Schedule E-8 full EPMC rate to the Schedule E-1 full EPMC rate. The new rate would be limited to residential customers with usage greater than 1,500 kWh per month to promote rate stability, ensure a lower cost to serve relative to Schedule E-1 and retain a market for the proposed TOU rates among customers with lower consumption patterns. PG&E proposes to set the customer charge at $12.20 per month, to reflect the full EPMC cost for Schedule E-8.[8] The new tariff would not be made available to customers who live in winter-peaking districts.[9]

The changes proposed by PG&E make sense in that they are designed to tailor the seasonal rates to more directly focus on the class of customers that was originally of interest: those who use wood or propane for heat and would become comparatively large users of electricity if they were to switch to electric heat. What is missing from the record is any consideration of whether it makes sense to continue offering a rate for this purpose. As the utilities move into competitive markets, should we continue to encourage the utilities to maintain regulated rates for which the primary

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[8] The existing customer charge exceeds the full EPMC rate. The Commission allowed PG&E to set the customer charge above the EPMC rate to maintain rate stability and make the winter rate more competitive. See 50 CPUC2d 1, 36.

[9] The excluded customers are those served by the following offices: Angels Camp, Eureka, Fort Bragg, Fortuna, Garberville, Guerneville, Monterey, Oakland, San Luis Obispo, San Rafael, Santa Cruz and Willow Creek. These are the same customers who would be eligible for PG&E's proposed Schedule E-12 winter-peaking time-of-use tariff.

purpose is to prevent use of competing energy sources? In addition, because we are not authorizing PG&E to close Schedule E-7, as discussed above, the migration from Schedule E-7 to Schedule E-8 may not occur as PG&E expects.

Despite these reservations, we will allow PG&E to offer new Schedule E-13 as a reflection of "loads, locations, conditions of service, cost of service, and market opportunities" (§ 378). The rates for this new schedule should be designed in a manner consistent with the marginal costs adopted in this decision. However, Schedule E-8 should not be closed at this time. Closing Schedule E-8 and substituting Schedule E-13 with different rates for it would in effect amount to a rate change, in contradiction to the rate freeze called for in § 368(a).

4. Master-Meter Discounts

PU Code § 739.5 (a) states, in part,

> "The commission shall require the corporation furnishing service to the master-meter customer to establish uniform rates for master-meter service at a level which will provide a sufficient differential to cover the reasonable average costs to master-meter customers of providing submeter service, except that these costs shall not exceed the average cost that the corporation would have incurred in providing comparable services directly to the users of the service."

PG&E's tariffs provide a discount designed to reflect the cost differential as required by statute. No party has proposed changes to the electric master-meter discounts in this proceeding. We will allow PG&E to continue these discounts. In addition, PG&E seeks to update its schedule GS and GT discounts for master-meter natural gas service to reflect updated studies prepared in cooperation with the Western Mobilehome Association. We will allow PG&E to do so, utilizing 1996 authorized rate of return, expenses, plant balance, customers and adopted Schedule G-1 rates. Gas rates are not subject to the rate freeze of § 368(a). PG&E should implement its schedule GS and GT discounts at the next scheduled gas rate change.

5. Customer Charge

A customer charge is a fixed monthly payment that each customer in a particular rate class must make, separate from the charges related to the amount of electricity the customer uses. It represents some or all of the fixed cost that the customer imposes on the system simply by maintaining access to electric service. Many of PG&E's rate schedules include a customer charge. However its Schedule E-1, which is used by most of its residential customers, does not. Currently, all of the revenues associated with fixed costs for those residential customers are collected through the rates charged for each kWh of electricity sold. Schedule E-1 does currently include a minimum charge of $5. However, a minimum charge is not a reflection of any particular cost. It simply means that if a customer does not use enough power in a given month to accumulate $5 in charges, it will be billed for $5 anyway. A minimum charge has no effect on the billing rate for a kWh of power, while the imposition of a customer charge reduces the billing rate per kWh.

The Commission has considered including a customer charge in residential electric rates for many years and its failure to do so has been a source of distress for many economists. There is little argument with the assertion that each customer imposes fixed costs on the utility system and that accurate rates would separate or unbundle those fixed costs for ratemaking treatment so that customers would more clearly understand how their behavior affects the utility's costs.[19] In 1987,

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[19] While that much is undisputed, it is less clear, as a matter of public policy, what interest regulators should have in clarifying this distinction. As a matter of logic, if a separate customer charge is created, the apparent cost of being a customer would increase, while the cost of consuming greater amounts of electric power would be somewhat reduced. Economists would argue that more accurate pricing encourages more efficient consumer choices. What does it mean to make an efficient judgment about becoming a customer? Would the imposition of a customer charge discourage some people from becoming customers? If so, why should society want to do that? In theory, if costs are redistributed in such a way as to reduce the charge for a kWh of power, customers would be encouraged to consume more electricity. Is this a preferred result? Another reason for making Schedule E-1 more economically correct is that it will help customers to make more efficient choices among the various schedules available to residential customers.

the Commission approved a $4.80 per month customer charge for SDG&E (D.87-12-069, 27 CPUC 2d 201, 215-216). In response to objections from customers, the Commission repealed the customer charge seven months later and re-established a $5.00 minimum charge.

In PG&E's 1993 general rate case, ORA proposed the creation of a customer charge for Schedule E-1 customers. Both PG&E and TURN opposed this proposal out of concern for customer resistance. TURN also argued that a flat customer charge would be inconsistent with the Commission's broad demand-side management (DSM) goals. The Commission chose not to impose a customer charge in that proceeding, but set forth clear instructions for the future:

> "We have determined that a modest residential customer charge is an appropriate step to take towards rationalizing rates to their underlying cost components. Due to our concerns about customer acceptance, we will not implement a customer charge at this time. We cannot yet find that a reasonable level of customer acceptance will occur in the absence of efforts by PG&E to provide its residential customers with objective factual information about customer charges.
>
> "We remain committed to our oft-stated support for a customer charge on the basis of well-established ratemaking principles. Unfortunately, this issue has languished for half a decade or more, in large part because no party has provided us with evidence regarding acceptance which would cause us either to immediately adopt a customer charge or to abandon our quest. We are again frustrated in our efforts to move closer to cost-based residential rate design.

However, the other available tariffs involve strategic consumption, since they are tailored to time or season of use. In addition, they often require additional purchases (such as TOU meters) or are limited to those who use large amounts of electricity. One would not expect that most E-1 customers will perceive that they have meaningful choices when it comes to electing a tariff schedule.

"In order to bring this issue to eventual closure, we now announce our intention to implement a customer charge in PG&E's next general rate case in the absence of evidence of persistent and pervasive lack of customer acceptance among PG&E's customers.... We direct PG&E to include a customer charge proposal in the next general rate case application, either as its primary proposal or as an alternative. This will assure that residential customers are given adequate notice.

"The intervening years between now and the next general rate case will provide PG&E and other parties ample opportunity to work towards devising strategies for overcoming customer acceptance problems that may be found to exist after a fair analysis. We note that any surveys that might be undertaken should focus on the need for solutions rather than merely seek out evidence that solutions cannot be found. While we do not necessarily decide that $3.50 will be the proper level for a customer charge three years from now, we recognize that it may well be appropriate to set the charge at a level below the underlying full EPMC basis." (D.93-06-087, 50 CPUC 1, 29-30.)

As directed, PG&E included in its application an option for the creation of a customer charge for Schedule E-1 customers. However, PG&E opposes its adoption. PG&E's model is similar to the one proposed by Edison which formed the starting point for the customer charge we approved in April 1996. ORA continues to support the implementation of a customer charge and TURN continues to oppose it.

The customer charge that PG&E designed in response to the Commission's directive would be $3.00 per month. PG&E proposes that this rate apply to all residential schedules except for E-8, which has its own, significantly larger customer charge.[11] It would be referred to as a "basic charge" and would apply to all residential schedules other than E-8. PG&E would no longer impose a $5.00 minimum

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[11] Presumably, PG&E would also apply this exception to Schedule E-13, which it proposes to use for new customers in lieu of Schedule E-8.

charge. The customer charge would generate revenues that are attributed to the residential class. As a result, the Tier 1 and Tier 2 rates would need to be adjusted to avoid an overcollection. To do this, PG&E proposes using what is referred to as a "simple tier differential" under which the rates for both tiers would be reduced while maintaining the 1.15/1 ratio that currently exists between Tier 2 and Tier 1. CARE customers would pay a customer charge based on the current formula under which its rates are 85% of the standard tariff; thus, the CARE customer charge would be $2.55. Master meter discounts would be reduced by $3.00 per dwelling unit to prevent master meter customers from receiving a windfall from tenants who each would be required to pay them the $3.00 customer charge.

Although it agrees that a customer charge is sound from a rate design perspective, PG&E offers several reasons that such a charge should not be adopted now. First, PG&E asserts that half of its customers do not want it. PG&E worked with ORA, TURN, Western Mobilehome Association, Golden State Mobilehome Owners League and SDG&E to design a new customer charge survey, which was completed in 1994. The results of the survey suggest that 38% of PG&E's residential customers prefer a $3.00 customer charge to the current method, 33% prefer no customer charge, 18% either do not know or do not care, and 11% say that their preference would depend on the impact the charge would have on the overall bill. As is true with most such surveys, the message conveyed depend on how one looks at the numbers. PG&E argues that only a third of its customers clearly want a customer charge. The company also reports that three-fourths of the 29% undecided customers would have a firm opinion if they knew whether the change would increase or lower their bills. Since PG&E also asserts that 64% of their customers would face bill increases if the customer charge were $3.00, the company argues that about half of its customers would be opposed to the current proposal. This appears to demonstrate that gaining customer acceptance is still a major concern in PG&E's service territory.

ORA objects to this interpretation of the survey data, citing the following portion of the survey analysis which states:

> "However, when [customers] were presented with a more specific choice between the new method with a $3 customer charge and the current method, the results were reversed, with a higher percentage estimated to favor the new method. This, too, is consistent with the theory that customers' initial opposition to the new method may be based upon their uncertainty about the magnitude of the resulting bill impacts. Once they hear that the customer charge (and thus the maximum bill increase) is only $3, the opposition of many vanishes."

However, PG&E responds that the quote is subject to misinterpretation because it is offered out of context. The higher favorable percentage discussed in the quote is the same 38% that PG&E has previously cited. In addition, the statement reflects the attitude of customers who have yet to learn of the bill impact resulting from the proposed change.

Of additional concern is the prospect that a $3.00 customer charge would lead to higher bills for 64% of PG&E's customers, a matter of great import to a company that is trying to avoid any rate increases. PG&E's analysis also suggests that the increases would be disproportionately experienced by lower income customers. ORA argues that PG&E should be able to avoid rate increases by phasing in the customer charge in small amounts at times when rates are going down a sufficient amount to offset the new charge. PG&E and ORA debate just how feasible this approach would be. Regardless, it is an approach that is likely to result in duplicative implementation costs for a series of changes that would have very little impact on the economic signals.

TURN raises several objections that go to the fundamental merits of instituting a customer charge. Many of these have been previously addressed by the Commission and either rejected or used as a basis for modifying a customer charge. While this history suggests that many of TURN's concerns can be answered or overcome, TURN's continued vigorous opposition to customer charges suggests that such a charge is not in the best interests of many of TURN's constituents. This impression is consistent with PG&E's assertion that lower income and lower usage residential customers stand to be disproportionately affected by the imposition of a customer charge.

In April 1996, we chose to implement a modest and gradual customer charge for Edison's residential customers (see D.96-04-050, mimeo., pp. 107-116). Edison will impose a $2.00 per month charge on single-family customers and a $1.50 per month charge on multi-family customers. Respective charges of $1.00 and $.75 were imposed on June 1, 1996 and the full $2.00 and $1.75 charges were originally scheduled to take effect on January 1, 1997.

There are certain practical distinctions, however, between Edison's situation and that of PG&E. First, PG&E has experienced great challenges in the last year, twice dealing with some of the worst winter storms in many years. PG&E was not always successful in meeting its customers' expectations. This is not the best time to place a new item on customers' bills, especially when it is clear that many will find this to be an unwelcome change. While Edison may be prepared to introduce a modest customer charge and help its customers to understand why it represents a change for the better, the subtle improvement in economic signals that might result from a similar change for PG&E is not likely to outweigh the challenges of gaining customer acceptance.[11] Finally, it is not an insignificant factor that this is a change that was sought by Edison but fought by PG&E. If this is the time to venture beyond the failed experiment of SDG&E's customer charge, it is more prudent to send forth our most willing swimmer to test the water. PG&E is simply not willing.

Because of the specific circumstances affecting PG&E and because TURN and PG&E continue to raise legitimate doubts about the merits of instituting a customer charge for this utility, we will not require such charges in this proceeding. Moreover, it would be very difficult to incorporate a new customer change for

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[11] It should be noted that while economic theory supports the introduction of a customer charge, the record here does not show that consumers are likely to respond to this new economic signal by changing their behavior in any significant way.

residential service within the level of the rate freeze ordered by § 368(a). We will continue to review this option in future proceedings where appropriate.

6. Residential Photovoltaic Tariff

Section 2827 requires every electric utility in the state to develop a standard contract or tariff providing for net energy metering, and to make this contract available to eligible residential customer-generators on a first-come, first-served basis until the total rated generating capacity owned and operated by eligible customer-generators in the service area equals 0.1 percent of the utility's peak electricity demand forecast for 1996.[13] "Net energy metering" involves using a single, nondemand, non-time-differentiated meter to measure the difference between the electricity supplied by a utility and the electricity generated by an eligible customer-generator and fed back to the utility over an entire billing period. An eligible customer-generator is a residential customer who owns and operates a solar electrical generating facility with a capacity of not more than 10 kilowatts that is located on the customer's premises, operates in parallel with the utility's transmission and distribution facilities, and is intended primarily to offset part or all of the customer's own electrical requirements. Subsection (e) sets forth the basic requirements of a net energy metering tariff:

> "(1) Where the electricity supplied by the utility exceeds the electricity generated by the customer-generator over the applicable billing period, the customer-generator shall be billed for the net energy supplied at the customer-generator's standard rate. (2) Where the electrical energy generated by the customer-generator exceeds the energy supplied by the utility over the applicable billing period, the customer-generator shall be compensated for the net energy generated at the applicable non-time-differentiated energy payment rate for other qualifying small power producers."

In response to this new statutory requirement, PG&E has proposed Schedule E-SEG and submitted this proposal in the form of Advice Letter 1549-E, which

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[13] For PG&E, the law defines this limit as equaling 17 megawatts.

was approved by the Commission on June 23, 1996. The proposal was also discussed in this docket. As part of its new tariff, PG&E originally proposed to include a standby reservation charge. TURN and the California Energy Commission (CEC) strongly contest this portion of the tariff, arguing that the imposition of a standby charge is inconsistent with the spirit and express language of § 2827. We agree and note that PG&E refiled and the Commission adopted its tariff without a standby charge.[11] The statute carefully states that a residential solar electric generator must be paid for net output at the rates offered to other qualifying small power providers, but charged for net consumption at the customer's standard rate. The standard rate for residential customers is found in Schedule E-1, which does not require all of its customers to pay a standby charge.

If we were to approve a customer charge to be included in Schedule E-1, it would be appropriate to apply that charge to customers using Schedule E-SEG as well. However, since we are not approving such a customer charge at this time, we will apply none to Schedule E-SEG, either. We note that PG&E modified its adopted tariff in line with this decision.

7. Electric Vehicle Time-of-Use Rates

Through its Schedule E-9, PG&E currently offers electric vehicle recharging service at a rate intended to encourage customers to use electric vehicles. In D.95-11-035, the Commission directed PG&E, Edison, and SDG&E to modify their electric vehicle recharging tariffs to ensure that the rates will be revenue-neutral by January 1, 1997. Schedule E-9 is a TOU rate. PG&E proposes to define revenue-neutrality as a rate designed to recover as much revenue as would be collected if the customer received service under another residential TOU rate. Under this definition, which we find acceptable, the current Schedule E-9 is not revenue-neutral. PG&E

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[11] We note that in a letter to all parties dated May 24, 1996, PG&E withdrew its proposal for the inclusion of a standby charge for Schedule E-SEG customers in recognition of the fact that the Commission did not impose such a charge on SCE's customers.

proposes to close that schedule to additional customers, and to create Schedule E-6, which is designed to be revenue-neutral.[15] Since Schedule E-9 is not revenue-neutral, PG&E's proposal to allow those customers currently using Schedule E-9 to continue doing so is inconsistent with D.95-11-035. However, the rate freeze mandated by § 368(a) does not allow us to change rates for customers currently served on Schedule E-9, or to immediately close Schedule E-9 to additional customers. The new Schedule E-6 is consistent with the requirements set forth in D.95-11-035 and complies with the criteria set forth in § 378. However, the need for this schedule is questionable while Schedule E-9 remains open. PG&E, at its option, may implement this schedule.

F. Agricultural Rate Design

In April 1995 (D.95-04-077), the Commission approved special rate options to help PG&E encourage well water pumping customers to use electricity when they would otherwise use natural gas or diesel fuel. These special rates were approved in PG&E's 1995 Rate Design Window proceeding and were originally designed to expire on the date that this decision becomes effective. The Commission's intention was to allow PG&E to accumulate data about the special rate programs and defer to this docket a more rigorous analysis of the merits of continuing to offer these programs. These special rates are called the Diesel Alternative Power Option (DAP) and the Natural Gas Alternative Power Option (GAP). PG&E did offer these optional schedules and reported 90 participants by the close of rebuttal hearings.

Since the Commission addressed this issue in PG&E's 1996 Rate Design Window proceeding decision (D.97-09-047), there is no need to discuss these rate options here.

G. Light and Power Rates

Through its Light and Power schedules, PG&E sets the rates that apply to its commercial and industrial customer classes. The rate offerings differ according to the

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[15] PG&E also proposes to have the rates respond to both summer and winter peaks. Schedule E-6 was previously referred to as Schedule E-15.

level and patterns of customer usage and according to whether the service is considered to be firm or interruptible. Larger customers also have the ability to choose whether to use PG&E's distribution and substation services or to pay lower rates for power that they must process and distribute on their own. In light of PG&E's desire to avoid rate increases, PG&E has offered only a modest number of changes to these schedules.

1. Schedule A-6 Eligibility

This is a voluntary TOU tariff for commercial customers whose monthly maximum demand is less than 500 kW. These customers would otherwise qualify for service under Schedule A-1. PG&E claims that many Schedule A-1 customers have higher cost of service characteristics than the current basis for Schedule A-6 and that Schedule A-1 customers above 30,000 kWh per year have usage characteristics that better match the current basis for Schedule A-6. Thus, to promote more accurate cost-based ratemaking, PG&E proposes to limit new migration to Schedule A-6 to customers with usage of 30,000 kWh per year or more, and to establish a voluntary TOU option under new Schedule A-8 for customers with usage under 30,000 kWh per year. This eligibility criterion would apply to all customers seeking to migrate to Schedule A-6, based on their most recent 12 months of recorded data. PG&E estimates that there are approximately 45,000 Schedule A-1 accounts with usage of at least 30,000 kWh per year that were eligible for Schedule A-6 in 1996. PG&E would move to a waiting list for PG&E's proposed new Schedule A-8 any customers that meet this criterion, are on the waiting list for Schedule A-6 on the effective date of the decision in this proceeding, and do not have the required TOU meters installed by that date.

PG&E would allow existing Schedule A-6 customers to remain on that schedule without meeting minimum usage level criterion which would apply to new customers. The company proposes that after initially qualifying for Schedule A-6, a customer would not be required to show that its usage continues to exceed the 30,000 kWh minimum. PG&E asserts that requiring such a showing would place additional administrative burdens on PG&E and would tend to have a negative impact on customer relations. PG&E believes that customers failing to maintain usage levels above the minimum usage level would probably benefit by switching to another schedule, and would not therefore be a large enough group of customers to significantly distort the cost basis for the schedule.

No one objects to this proposal. However, PG&E has failed to demonstrate that such a restriction is justified. This proposal rests on two premises: (1) that higher usage customers impose a lower cost of service than lower usage customers, and (2) that there is an over-migration problem that needs to be corrected. PG&E has proven neither proposition. The company offers no evidence to support the first assertion and the only evidence offered about migratory trends suggests that there is no problem. For 1996, PG&E projects that the average usage for Schedule A-6 customers is 59,000 kWh, well over PG&E's target level, without the introduction of any further restrictions. We will not adopt this proposal here, but PG&E can introduce additional evidence on this point in a future proceeding, if the company so desires.

In addition, there is no apparent reason for PG&E to be maintaining a waiting list for Schedule A-6. PG&E should immediately make this schedule available to all qualified customers who elect to acquire the needed meters on their own.

We are also concerned about PG&E's current restrictions on customer access to Schedule A-6. Just as we will direct PG&E to make a decision as to whether or not it will offer to provide TOU meters to residential customers for a fee, we will direct PG&E to consider a similar offering for potential A-6 customers. However, there is no reason that commercial customers, who already have the appropriate meters or are willing to acquire them on their own, should be denied access to Schedule A-6. We will order PG&E to remove the current restrictions, and note that Advice Letter 1592-E, filed by PG&E on July 22, 1996, was approved by Resolution E-3465 on September 4, 1996, re-opening TOU service to customers who already have appropriate meters. In addition, Advice Letter 1595-E, filed by PG&E on August 9, 1996, proposing new TOU lump-sum charges for customers without appropriate meters, was adopted by the Commission in Resolution E-3469 dated October 25, 1996.

2. Schedule A-15 Facility Charge

Schedule A-15 is a direct current general service tariff open only to those customers who were receiving service on the tariff as of February 13, 1971, and is limited to certain downtown areas of San Francisco, Oakland, and Stockton where direct current is available. Based on data from late 1994, there were 938 customers taking service on Schedule A-15, with annual sales of approximately 2 million kWh.

The Schedule A-15 facility charge covers the incremental cost of providing direct current service as opposed to alternating current service. PG&E was ordered to review the cost of service associated with the Schedule A-15 facility charge and propose appropriate revisions in this proceeding. As a result of studying this issue, PG&E concludes that the current facility charge of $7.80 per meter per month should be increased to $25.00 to fully cover all incremental costs of providing direct current service. PG&E proposes no change to current Schedule A-15 rates, but recommends that the Commission adopt $25.00 as the ultimate fully cost-based target level for the facility charge. To mitigate bill impacts, PG&E suggests that a phase-in may be appropriate.

PG&E's proposal is unopposed. However, the rate freeze mandated by AB 1890 does not allow us to approve any increase to the facility charge at this time.

3. Eligibility Requirements for Schedules A-10 and E-19V

PG&E's Medium Light and Power class for customers with maximum demands of less than 500 kW consists of demand-metered Schedule A-10 and TOU demand-metered voluntary Schedule E-19V. Currently, all commercial customers with demands less than 500 kW may choose between medium commercial Schedules A-10 and E-19V and small commercial Schedules A-1 and A-6. Generally, larger customers under 500 kW select medium commercial Schedule A-10 or E-19V, while smaller customers under 500 kW select small commercial Schedules A-1 and A-6. PG&E now proposes new eligibility requirements that would restrict customer mobility between these two classes.

Similar to PG&E's proposal for a minimum usage eligibility requirement of 30,000 kWh per year on Schedule A-6, PG&E proposes to apply the current minimum Schedule A-10 usage eligibility requirement of 50,000 kWh per year for migration to Schedule E-19V. As with Schedule A-6, once on these schedules, a customer would not be required to maintain usage above the level required for migration. PG&E believes that customers failing to stay above the minimum usage level would probably benefit by switching to another schedule, and would not be a large enough group of customers to significantly distort the cost basis for the schedule.

PG&E further proposes that customers with usage above 50,000 kWh per year retain the choice of taking service on Schedules A-1 or A-6. PG&E asserts that such customers will generally not have higher cost of service characteristics than the current basis for Schedules A-1 and A-6. As with its Schedule A-6 proposal, PG&E proposes that customers that are on the waiting list for Schedule E-19V on the effective date of this decision, and have not installed the necessary metering equipment, be reviewed to determine if their recorded usage in the most recent twelve months is less than 50,000 kWh. Those whose usage is below 50,000 kWh would be advised they are no longer eligible for Schedule E-19V.

One reason PG&E proposes a cutoff of 50,000 kWh per year is that it is the current cutoff for migration to Schedule A-10. PG&E asserts that preserving this 50,000 kWh cutoff for Schedule A-10 and extending it to Schedule E-19V would reduce confusion among smaller customers regarding the numerous rate options available in the commercial class.

No one objects to these changes and they appear consistent with PG&E's overall effort to improve the relationship between its cost of commercial service and its rates. However, we conclude that limiting eligibility for Schedule E-19V in the manner proposed by PG&E would effectively close this schedule to certain customers, those with annual usages of less than 50,000 kWh. As we noted in our discussion on closing schedules, all customers should have the ability to choose service from schedules that contain the rate levels and offer substantially the same terms, quality, and value of service that were available to similarly situated customers on June 10, 1996. PG&E's proposal would prevent certain customers from choosing to take service under Schedule E-19V, a choice they had on June 10, 1996. This conflicts with the purpose of the rate freeze, and for that reason implementation of this proposal should be deferred until after the AB 1890 rate freeze has ended.

4. Uniform 15-Minute Demand Intervals

To simplify meter programming and facilitate greater efficiencies across all metering tasks for non-residential customers with usage under 500 kW, PG&E proposes to implement a uniform 15-minute demand interval by eliminating the current tariff requirement for 30-minute demand intervals for Schedules A-10 and E-19V customers over 400 kW.

PG&E asserts that this change will help it to reduce its operating costs. Of approximately 45,000 Schedule A-10 customers and 10,400 Schedule E-19V customers served by PG&E during 1994, PG&E anticipates that approximately 180 Schedule A-10 and 110 Schedule E-19V customers currently on a 30-minute interval will be switched to a 15-minute demand interval. Since shorter demand intervals produce the same or slightly higher maximum demand readings, PG&E anticipates negligible or very slight bill increases for all affected customers.

No one has objected to this proposal and it appears that it will have a negligible effect on bills and usage while freeing up operating funds for more pressing uses. However, we conclude that changing the demand interval for new customers renders the schedule substantially different to the terms, quality or value of service in effect on June 10, 1996. Therefore, this proposal is in conflict with the AB 1890 rate freeze. Implementation of this proposal should be deferred until after the AB 1890 rate freeze has ended.

5. Schedule E-25

Schedule E-25 is a special TOU tariff that is available for certain water agencies. In the last general rate case proceeding, PG&E proposed eliminating this schedule, largely because it is used by only 5 customers. By switching from Schedule E-25 to Schedule E-19 or E-20, these customers would face higher bills. The Commission has deferred this change from year-to-year in order to avoid bill increases. PG&E now asks to retain this schedule because the number of customers has remained stable. There are no objections and we will not require PG&E to eliminate Schedule E-25 at this time.

6. Optimal Billing Option

In D.95-04-077, the Commission approved a pilot program called the Optimal Billing Period Option, effective May 1, 1995. With this option, PG&E seeks to correct a problem some customers, primarily food processors, may experience with high average rates in fringe months because of a mismatch between the timing of their production cycle and the start and end dates of their meter reading or billing period. This option allows certain mandatory Schedules E-19 and E-20 primary and secondary voltage firm service customers with summer-intensive operations to redesignate up to two summer meter reading dates, one at the start and the other at the end of the customer's high production season. This option includes a special customer charge of $130 per summer month, of which approximately $60 covers the incremental costs of program administration and billing, and $70 is the amount by which the cost of a solid state recorder equipment exceeds the cost of a standard TOU demand meter. The solid state recorder is necessary to collect the detailed load and usage data needed to bill this option. The current marginal costs for Schedules E-19 and E-20 do not include the costs of solid state recorder equipment.

In calculating the marginal costs approved in this decision, PG&E includes the cost of the solid state recorder equipment. Consequently, to prevent possible double recovery of costs, PG&E proposes that the Optimal Billing Period Option customer charge of $130 per summer month be decreased to $60 per summer month upon adoption of the Schedules E-19 and E-20 marginal customer cost revisions proposed in this Phase 2 Consolidated Exhibit. We agree with PG&E that continuing to collect the $70 portion of the Optimal Billing Period customer charge related to solid state recorder equipment would amount to double recovery and will, therefore, adopt this proposal. PG&E asks that this change become effective immediately. However, since we are not adopting new rates for E-19 and E-20 customers in this decision, the double-counting problem does not yet exist. We will defer this change to the decision in which we adopt new E-19 and E-20 rates that are consistent with the marginal costs adopted herein. In the future, any such changes must comply with AB 1890.

7. Mandatory Time-of-Use Threshold

PG&E's larger commercial and industrial customers take service under mandatory TOU schedules E-19 and E-20. Based on forecasted 1996 data, 1,600 customers with maximum demands over 500 kW but less than 1,000 kW will take service on Schedule E-19, with annual sales of 4.1 billion kWh, and 1,200 customers with demands over 1,000 kW will take service on Schedule E-20, with annual sales of 17.9 billion kWh. In D.93-06-087 in Phase 2 of PG&E's 1993 general rate case, the Commission approved the reduction of the mandatory TOU threshold from 500 kW to 200 kW. However, the Commission deferred the implementation of this change due to PG&E's ongoing electric rate freeze, since affected customers would in many cases receive substantial bill increases. ORA argues that the Commission did not intend that the implementation of the mandatory 200 kW TOU threshold be deferred indefinitely, and proposes that it be implemented in conjunction with a new bill limiter.

PG&E recommends that the Commission reconsider the 200 kW threshold as part of the electric industry restructuring proceeding, for three primary reasons. First, in Phase 1 of this proceeding (D.95-12-055, mimeo., p. 89), the Commission rejected the expansion of voluntary and mandatory TOU programs out of concern for the possible obsolescence of TOU meters under electric industry restructuring.

Second, in D.95-12-063, as modified by D.96-01-009 (mimeo., pp. 64, 76 to 80), the Commission specified that the electric industry restructuring Working Group should address issues surrounding metering standards, but was unclear regarding its intentions for the expansion of voluntary as opposed to mandatory TOU service. PG&E asks the Commission to further clarify its policy on TOU rates in the restructuring proceeding before the company takes steps that would move a large number of customers into a mandatory TOU class.

Third, implementation of the 200 kW threshold has been deferred for three years, and PG&E argues there is no compelling reason to implement it now. PG&E also argues that it would be unfair to single out the group of approximately 3,000 customers affected by the 200 kW criterion for sometimes substantial bill increases while all other customers are receiving no increase or a bill decrease.

We agree with PG&E that this is not the time to expand upon mandatory TOU requirements. While it is appropriate to offer additional TOU options, such as those we are approving for residential customers, the currently pending questions about the reliance on new metering technologies underscore the need to resist forcing a new class of customers to move to time-differentiated rates. There is no reason to require a new class of customers to invest in potentially outdated meters and develop consumption strategies that rely on an approach to time-differentiated charges that may be superseded within the next few years. However, we note that any customer with a demand over 50 kW that seeks to pursue direct access must install an hourly meter, pursuant to D.97-10-086. We accept PG&E's proposal to defer implementation of the 200 kW criterion pending further clarification of our TOU metering policy in the electric industry restructuring proceeding. In addition, the provisions of AB 1890 may prevent implementation of a new mandatory TOU threshold until the end of the transition period.

8. Rate Limiters

A rate limiter is the maximum or minimum rate per kilowatt-hour that applies to electric service under certain rate schedules. The average rate limiter and peak-period rate limiter both set a maximum rate for electric power purchased in the summer months by larger commercial and industrial customers. PG&E applies these rate limiters if the average rate or peak-period average rate that a customer would be required to pay during a specific month exceeds the set rate limiter figure. Currently, a summer season average rate limiter of $0.14881 per kWh applies to primary and secondary firm service on Schedules E-19, E-20, and E-25. A summer peak-period rate limiter also applies at varying levels to transmission, primary, and secondary firm service on Schedules E-19, E-20, and E-25.

In D.93-06-087, the Commission adopted a fixed peak load factor of 12 percent as the basis for PG&E's summer-season peak rate limiter[16] and a load factor of 34 percent for summer-season average rate limiter and directed PG&E to reduce the average rate limiter load factor criterion to 30 percent in 1994 and 26 percent in 1995. In the 1994 and 1995 Rate Design Window Proceeding decisions, the Commission agreed to postpone these adjustments to avoid rate changes. PG&E seeks the same result here.

PG&E asks to have no adjustments made to the load factors prior to the time when rates are revised under restructuring. The company argues that it would be unfair to single out the mandatory Schedules E-19, E-20, and E-25 customers affected by the summer-season average rate limiter for bill increases. PG&E asserts that based on January 1, 1996 rates, the phase-out of the rate limiter under 30 and 26 percent load factors would increase the maximum average rate to which Schedule E-19, E-20, and E-25 customers are subject by increasing the Schedule E-19 and E-25 average rate limiter from its current level of 14.043 to 15.052 and 16.373 cents per kWh in successive years, and increase the Schedule E-20 average rate limiter from its current level of 13.995 to 15.005 and 16.325 cents per kWh in successive years.

ORA argues that the Commission never intended that the phase-out of the rate limiter be deferred indefinitely, and proposes that the specified underlying load factor reductions be implemented beginning when the E-19 and E-20 classes are likely to receive a decrease in revenue allocation in 1996 or 1997.

It is premature to reach a decision on this point. If we choose to adopt a new rate design in a future proceeding, we will then decide whether or not to begin phasing out the rate limiter based on an understanding of the rates that would

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16 The load factor percentage equals [actual kWh usage/(peak kW demand x time)] x 100. For a fixed level of peak demand, a lower load factor corresponds to lower kWh usage, and a higher average rate per kWh. Thus, the average rate per kWh increases as the load factor basis is reduced.

otherwise result under the adopted revenue requirement. Since AB 1890 mandates a rate freeze through March 31, 2002, or until uneconomic generation costs are recovered, the issue is moot.

9. Nonfirm Rates

As we reported in the Revenue Requirements section, above, recently enacted legislation requires that nonfirm rates remain unchanged. However, PG&E has proposed changing one requirement under its current nonfirm tariffs. PG&E seeks to remove the requirement that PG&E's nonfirm customers undergo several periodic non-emergency or pre-emergency curtailments. The Commission established this requirement in D.92-05-031 to ensure that participating customers would be ready and able to curtail their load when requested by PG&E. PG&E reports that since the institution of this requirement, there have been two significant and successful load management program operations: an emergency operation (of six hours) that was called on August 10, 1992, and one pre-emergency operation (of five hours) that was required for all participants on August 2, 1993. CLECA reports that there have been seven curtailments in all during the four years from 1992 through 1995.

PG&E asserts that participating customers have now demonstrated a high level of compliance, and that continued enforcement of the pre-emergency curtailment requirement is neither reasonable nor necessary. PG&E argues that any additional tests would have too high a societal and economic cost (as measured in terms of customers' lost production time, lost productivity, lost output, workforce and production scheduling disruptions, and negative customer relations impacts), relative to the limited benefit that it now perceives in conducting additional test operations.

Based on PG&E's experience in the several curtailments that have occurred, it does not appear necessary to continue to require PG&E to undertake pre-emergency curtailments. However, PG&E remains ultimately responsible to ensure that any emergency curtailments will be effective. ORA proposes that nonfirm customers continue to be required to accept pre-emergency curtailments as a condition of receiving the nonfirm rate discount, but that PG&E be given the discretion to undertake these tests if and when the company deems such a test necessary to ensure the effectiveness of its nonfirm program. This is a sensible proposal because it provides PG&E with a tool to ensure a high level of compliance. In addition, the fact that participating customers will know that a pre-emergency curtailment is possible may serve to increase the likelihood that those customers will comply with the need to curtail whenever it occurs. For both of these reasons, we will adopt ORA's modification to PG&E's proposed nonfirm customer requirements. We conclude that such a revision does not conflict with AB 1890.

10. Real-Time Pricing

PG&E has offered a Real-Time Pricing program as an experimental service option for Schedules E-19 and E-20 customers since January 1, 1985. There are currently 25 program participants, with 24 taking service at secondary voltage, none at primary, and one at the transmission voltage level.

PG&E operated the program on a Pilot Phase basis during 1986 and 1987, and a three-year Demonstration Phase extended between 1988 and 1990. PG&E worked with ORA during 1990 to define substantial modifications to the rate design and load management price signal criteria to better reflect costs and actual system conditions. In late 1990, the Commission approved these modifications (Resolution E-3215, approving PG&E's Advice Letter 1324-E) and extended authorization for the program through December 31, 1992. PG&E prepares an annual report on the status of the program. Eight Schedule E-19 and 17 Schedule E-20 customers are presently enrolled under this program, for a total of 25 customers, while total participation is limited to 50 customers. In the course of PG&E's 1993 general rate case, PG&E and ORA agreed on rate design changes, adding a temperature-related component to improve the method for collecting time-related local transmission and distribution capacity cost responsibility.

PG&E proposes continuing the Real-Time Pricing program without any rate design changes. PG&E does ask, however, that the Commission eliminate the separate requirement for a detailed annual report covering program operations, load impact results, recruitment efforts, equipment modifications, rate design changes, administrative, and other program developments. PG&E argues that the ten annual reports that have been filed sufficiently cover the details and results of the program, and that the substantial ongoing expense and analysis required to produce this report is no longer warranted. ORA opposes the reduction of the reporting requirement and proposes extending the availability of the program to E-19V customers.

We are not persuaded that the annual report needs to be continued since the Real-Time Pricing program will be continued without any rate design changes at least until the AB 1890 mandated rate freeze ends.

H. Streetlight Rates

Streetlighting service is different from most of PG&E's offerings, because customers have the option of either owning their own equipment or renting it from PG&E. Most streetlight accounts are unmetered, with monthly flat rates assessed on a per-lamp basis. The costs that must be considered in setting rates include those for lamps, poles, support arms, wiring, energy, and operation and maintenance.

In this proceeding, PG&E proposes developing streetlight rates using a methodology similar to the one authorized by the Commission in D.93-06-087. In addition, all parties agree that it would be appropriate to make new streetlighting rates effective as soon as possible. For 1996, PG&E proposes that streetlight rates be maintained at the January 1, 1996 rates or set to reflect adjustments made in this decision, whichever results in lower rates. The adoption of PG&E's proposal would result in rate decreases for its Schedules LS-1, LS-2, and OL-1 streetlights for 1996. PG&E also proposes that certain "special" streetlight rates be included in the LS-1 or LS-2 rate schedules and that the kWh use per month for certain streetlights be changed to reflect PG&E's mix of ballasts it uses in providing streetlight service.

PG&E proposes refining its previously adopted streetlight rate design to reflect an allocation of common plant, uncollectibles, superfund tax, payroll tax, business tax and other taxes to the LS-2 rates. In the absence of a cap on rates, this allocation would increase LS-2 rates. For this reason PG&E proposes that the non-energy portion of LS-2 rates remain at 1995 levels. PG&E also updated its costs to provide streetlight service to 1996 Test Year levels, resulting in a lower revenue requirement for the streetlight rate class.

For the energy portion of streetlight rates PG&E proposes to extend the January 1, 1996 streetlight energy rates through the end of 1996. Energy use projections for Schedules LS-1, LS-2 and OL-1 streetlights are based on the type and size of lamp and number of hours the lamp is on each month. For the 1996 general rate case proceeding, PG&E proposes no change in hours of operation. It has recalculated the number of kWh per lamp per month for high-pressure sodium vapor, mercury vapor and metal halide lamps using manufacturers' specifications and ballast data from its Electric Distribution department. Kilowatt-hours for low-pressure sodium vapor and incandescent lamps remain unchanged.

Costs for streetlighting facilities can be divided into three categories: capital, operation and maintenance. PG&E determines capital costs through a revenue requirement calculation based on the Test Year balances of the streetlight plant accounts plus an allocation of common plant. By using this approach PG&E also calculates costs for uncollectibles, superfund tax, payroll tax, business tax and other tax. Currently, these costs are allocated to LS-1 and OL-1 streetlight schedules by lamp type and lamp size based on the "replacement cost new" of the facilities required for the particular service, as described in PG&E's streetlight rate schedules. The Commission approved this method in D.83-12-068 and affirmed it in subsequent general rate case decisions: D.86-12-091; D.89-12-057; and D.93-06-087.

Because PG&E incurs these costs to establish service and bill LS-2 customers and to maintain customer-owned streetlights, PG&E modified its rate design to allocate a portion of these costs to LS-2 rates. An allocation of common plant and associated taxes, which supports these activities, is necessary to better reflect the cost to serve LS-2 streetlights. PG&E uses its Test Year estimates of labor costs for maintenance and operations and customer accounts to make the allocations.

For 1996, in light of its proposal not to increase rates, PG&E proposes that the pole painting fee remain at the 1995 level, or $0.89 per pole per month.

Streetlight service to San Francisco differs from PG&E's standard service in that San Francisco streetlights get their energy from the city's Hetch Hetchy Project. Consequently, PG&E does not include energy costs in its San Francisco streetlight rates. PG&E provides only maintenance and operation services for streetlights located in San Francisco. In Resolution E-3203, the Commission authorized PG&E to phase-in rate increases for those San Francisco streetlights which are LS-1 or LS-2 equivalent. These rate increases became effective on May 1, 1991. In D.93-06-087 the Commission authorized continued phase-in of these streetlights based on PG&E's updated costs over a five-year period. In addition, the Commission then adopted new rates for streetlights in San Francisco that have no LS-1 or LS-2 equivalent and established a six-year phase-in schedule for these streetlights.

PG&E proposes updating all of its San Francisco streetlight rates to reflect Test Year costs and, where appropriate, continuing the phase-in by including a one-fifth increase for San Francisco's LS-1 or LS-2 equivalent streetlights and a one-sixth increase for the nonstandard streetlights (i.e., those with no LS-1 or LS-2 equivalent) which include, for example, Triangle and Chinatown streetlights. Since PG&E proposes no increase for its streetlight rates in 1996, its San Francisco streetlight rates would remain at 1995 rates. Because the updated rates for certain LS-1 equivalent rates are lower than rates currently in effect, PG&E proposes that these rates be decreased for 1996. PG&E proposes no change to its LS-3 rates.

PG&E reports that it occasionally receives service requests for streetlights that are of a different wattage or operating period than is delineated in PG&E's LS-1 or LS-2 rate schedule. It calculates rates for these "special streetlights" by relying on approved LS-1 and LS-2 base and energy rates. In D.93-06-087, the Commission approved the special streetlight rates that are currently in effect. For 1996, PG&E

requests authorization to transfer the following special streetlight rates to the LS rate schedule designated below:

Lamp Type & Size	Transfer To
Mercury Vapor Lamps	
250 Watts	LS-1C
400 Watts	LS-1C
700 Watts	LS-1C
Incandescent Lamps	
58 Watts	LS-2A
High Pressure Sodium Vapor Lamps	
35 Watts (120 Volts)	LS-2A
50 Watts (120 Volts)	LS-2A
200 Watts (120 Volts)	LS-2A
50 Watts (240 Volts)	LS-2A
70 Watts (240 Volts)	LS-2A
Metal Halide Lamps	
175 Watts	LS-2A

PG&E asserts that it seeks this change because it currently provides streetlight service for the lamp types shown above in its LS rates and that since the operating hours are for all night operation, special rate authorization is not required. PG&E also proposes to eliminate Schedule LS-1F.1 and merge the LS-1F.1 lamps into Schedule LS-1F because there is no difference in price or service on these two schedules.

As it did in the 1993 general rate case, PG&E recomputed the streetlight rates using 1996 Phase 1 decision Maintenance and Operation and Administrative and General Expense amounts, the 1996 escalation rates, the 1996 rate of return, and 1996 streetlight energy charges. Where as a result of its recalculation certain rates rise above January 1, 1996 rates, PG&E proposes to continue the January 1, 1996 rate.

In subsequent rate designs, PG&E proposes to continue the transition of its streetlight rates to cost-based rates using the updated costs and rate design methodology it presents in this proposal.

Most parties did not address PG&E's proposals in this area. California Streetlighting Association (CAL-SLA) recommends the Commission use PG&E's cost-of-service study, after it has been updated to reflect the most recent decisions in other applicable PG&E proceedings. Additionally CAL-SLA asks the Commission to authorize new streetlight rates as soon as possible in 1996 using the most recently updated cost study.

The record supports the adoption of PG&E's proposed ratesetting methodology. Thus, we will approve PG&E's approach and, but for the rate freeze, would adjust the resulting rates to reflect marginal costs adopted in Phase 1 of this proceeding. Because the streetlighting class experiences discrete costs and because of the relatively modest impact of this class on system revenues, we had planned to adhere to the wishes of the active parties and allow new streetlighting rates to be implemented when this decision becomes effective. However, we now conclude that § 368(a) prevents us from implementing any such change to streetlighting rates. Section 368(a) freezes rates at June 10, 1996 levels and precludes any shifting of transition cost responsibility from one class to another. In this instance providing a rate reduction to the Streetlighting Class would require the other customer classes within the firewall to assume the CTC shortfall resulting from such a rate reduction. To preserve the record, the following tables set forth the rates we would have adopted had AB 1890 not precluded us from doing so.

STREETLIGHT RATES - SCHEDULES LS-1, LS-2 AND OL-1

ALL NIGHT RATES PER LAMP PER MONTH

NOMINAL LAMP RATINGS: LAMP WATTS	KWh Per Mo. (A)	KWh Per Mo. (B)	LUMENS	SCHEDULE LS-2 A	SCHEDULE LS-2 B	SCHEDULE LS-2 C	SCHEDULE LS-1 A	SCHEDULE LS-1 B	SCHEDULE LS-1 C	SCHEDULE LS-1 D	SCHEDULE LS-1 E	SCHEDULE LS-1 F	OL-1	HALF-HOUR ADJ. (A)	HALF-HOUR ADJ. (B)	HALF-HOUR ADJ. OL-1
MERCURY VAPOR LAMPS																
100	40	40	3,500	$3.015	$3.919	$4.376	$7.109	–	$7.405	–	–	–	–	$0.129	$0.129	–
175	68	69	7,500	$5.002	$5.651	$6.308	$9.615	$7.932	$9.795	–	$13.414	$14.605	$9.646	$0.219	$0.223	$0.224
250	97	99	11,000	$7.060	$7.936	$8.394	$12.034	$9.996	$11.681	–	–	–	–	$0.313	$0.319	–
400	152	151	21,000	$10.963	$11.894	$12.352	$16.107	$14.177	$15.725	–	–	–	$16.175	$0.490	$0.487	$0.490
700	266	257	37,000	$18.523	$20.686	$21.041	$24.619	$22.960	$24.311	–	–	–	–	$0.858	$0.829	–
1,000	377	369	57,000	$26.472	$28.383	$28.752	–	–	–	–	–	–	–	$1.216	$1.190	–
INCANDESCENT LAMPS																
58	20	20	600	$1.595	–	–	$8.531	–	–	–	–	–	–	$0.065	$0.065	–
92	31	31	1,000	$2.376	$5.333	$5.790	$9.312	–	–	–	–	–	–	$0.100	$0.100	–
189	65	65	2,500	$4.789	$7.741	$8.198	$12.315	$10.107	–	–	–	–	–	$0.210	$0.210	–
295	101	101	4,000	$7.344	$10.393	$10.850	$14.549	$12.765	–	–	–	–	–	$0.326	$0.326	–
405	139	139	6,000	$10.041	$13.586	$14.043	$17.530	–	–	–	–	–	–	$0.448	$0.448	–
620	212	212	10,000	$15.222	$19.649	$20.106	–	–	–	–	–	–	–	$0.684	$0.684	–
860	294	294	15,000	$21.041	$26.176	–	–	–	–	–	–	–	–	$0.948	$0.948	–
LOW PRESSURE SODIUM VAPOR LAMPS																
35	21	21	4,800	$1.666	–	–	–	–	–	–	–	–	–	$0.068	$0.068	–
55	29	29	8,000	$2.234	–	–	–	–	–	–	–	–	–	$0.094	$0.094	–
90	45	45	13,500	$3.370	–	–	–	–	–	–	–	–	–	$0.145	$0.145	–
135	62	62	21,500	$4.576	–	–	–	–	–	–	–	–	–	$0.200	$0.200	–
180	78	78	33,000	$5.712	–	–	–	–	–	–	–	–	–	$0.252	$0.252	–
HIGH PRESSURE SODIUM VAPOR LAMPS AT 120 VOLTS*																
35	15	14	2,200	$1.240	–	–	–	–	–	–	–	–	–	$0.048	$0.045	–
50	21	20	3,300	$1.666	–	–	–	–	–	–	–	–	–	$0.068	$0.065	–
70	29	28	5,800	$2.234	$3.193	$3.650	$5.994	–	$6.344	$9.535	$9.424	$11.684	$6.006	$0.094	$0.090	$0.091
100	41	40	9,500	$3.066	$4.072	$4.529	$6.905	–	$7.170	$10.069	$10.250	$12.536	$6.923	$0.132	$0.129	$0.130
150	60	59	16,000	$4.434	$5.447	$5.905	$8.375	–	$8.555	$11.622	$11.635	$14.124	–	$0.194	$0.190	–
200	81	80	22,000	$5.653	–	–	–	–	–	–	–	–	–	$0.261	$0.258	–
AT 240 VOLTS*																
50	24	22	3,300	$1.845	–	–	–	–	–	–	–	–	–	$0.077	$0.071	–
70	34	32	5,800	$2.555	$3.547	$4.005	–	–	–	–	–	–	–	$0.110	$0.103	–
100	47	45	9,500	$3.478	$4.497	$4.955	–	–	–	–	–	–	–	$0.152	$0.145	–
150	69	67	16,000	$5.039	$6.086	$6.543	–	–	–	–	–	–	–	$0.223	$0.216	–
200	81	82	22,000	$5.924	$6.938	$7.395	$10.313	–	$10.358	–	$13.438	$15.986	$10.350	$0.261	$0.265	$0.266
250	100	100	27,500	$7.273	$8.314	$8.771	$12.026	–	$11.604	–	$14.584	$17.668	–	$0.323	$0.323	
310	119	121	37,000	$8.621	–	–	–	–	–	–	–	–	–	$0.384	$0.390	–
400	154	159	50,000	$11.105	$12.146	$12.603	$16.510	–	$15.935	–	$19.015	$22.037	–	$0.497	$0.513	–
METAL HALIDE LAMPS																
100	42	41	8,500	$3.157	–	–	–	–	–	–	–	–	–	$0.135	$0.132	–
175	72	71	14,000	$5.286	–	–	–	–	–	–	–	–	–	$0.232	$0.229	–
400	162	158	30,000	$11.497	–	–	–	–	–	–	–	–	–	$0.523	$0.510	–
1,000	387	372	90,000	$26.685	–	–	–	–	–	–	–	–	–	$1.248	$1.200	–

Energy Rate @ $0.07097 per kwh LS-1 & LS-2
Energy Rate @ $0.07142 per kwh OL-1

Pole Painting Charge @ $0.89 Per Pole Per Month
*LS-2 HPSV Rates at 120 or 240 Volts.
(A) Applicable to rates within boxed-in areas. (B) Applicable to rates outside boxed-in areas.
Note: Boxed-in areas indicates kWh/lamp/mo., base rate and pole painting charge at 93 adopted

PACIFIC GAS AND ELECTRIC COMPANY
STREETLIGHT RATES FOR
CITY AND COUNTY OF SAN FRANCISCO

Rate Schedule	Lamp Type & Size	Proposed Rate	Phase In*
CCSF Rate Schedule No. 1			
LS-1A	MERCURY VAPOR		
	175 WATTS 7,500 LUMENS	$4.056	
	250 WATTS 11,000 LUMENS	$4.170	
	400 WATTS 21,000 LUMENS	$4.589	
CCSF Rate Schedule No. 1			
LS-1A	INCANDESCENT		
	189 WATTS 2,500 LUMENS	$5.691	
	295 WATTS 4,000 LUMENS	$5.778	
	405 WATTS 6,000 LUMENS	$6.127	
CCSF Rate Schedule No. 3			
LS-1A	MERCURY VAPOR		
	175 WATTS 7,500 LUMENS	$4.056	
	250 WATTS 11,000 LUMENS	$4.170	
	400 WATTS 21,000 LUMENS	$4.589	
CCSF Rate Schedule No. 3			
LS-1A	INCANDESCENT		
	189 WATTS 2,500 LUMENS	$5.691	
	295 WATTS 4,000 LUMENS	$5.778	
	405 WATTS 6,000 LUMENS	$6.127	
	620 WATTS 10,000 LUMENS	$3.891	
CCSF Rate Schedule No. 4			
LS-1E	High Pressure Sodium Vapor		
	200 WATTS 22,000 LUMENS	$7.618	
CCSF Rate Schedule No. 4E			
LS-1E	High Pressure Sodium Vapor		
	70 WATTS 5,800 LUMENS	$7.437	
	100 WATTS 9,500 LUMENS	$7.411	
	150 WATTS 16,000 LUMENS	$7.448	
CCSF Rate Schedule No. 4			
LS-1E	MERCURY VAPOR		
	175 WATTS 7,500 LUMENS	$7.928	
CCSF Rate Schedule No. 4E			
LS-1E	MERCURY VAPOR		
	175 WATTS 7,500 LUMENS	$8.518	
CCSF Rate Schedule No. 6			
LS-2B	INCANDESCENT		
	92 WATTS 1,000 LUMENS	$2.520	
LS-1A (Equivalent)	HIGH PRESSURE SODIUM VAPOR		
	70 WATTS 5,800 LUMENS	$4.006	–
	100 WATTS 9,500 LUMENS	$4.066	–
	150 WATTS 16,000 LUMENS	$4.188	–
	200 WATTS 22,000 LUMENS	$4.493	–
	250 WATTS 25,500 LUMENS	$4.929	–
	400 WATTS 46,000 LUMENS	$5.226	–

Rate Schedule	Lamp Type & Size	Proposed Rate	Phase In*
CCSF Rate Schedule No. 4			
	Fluorescent: 23,000 LUMENS	$8.473	
	Incandescent:		
	2,500 LUMENS	$4.106	
	4,000 LUMENS	$4.173	
	4,000 LUMENS DUPLEX (1)	$4.844	
	4,000 LUMENS DUPLEX (2)	$1.087	
	6,000 LUMENS	$4.285	
	6,000 LUMENS DUPLEX (1)	$4.964	
	6,000 LUMENS DUPLEX (2)	$1.175	
	10,000 LUMENS	$4.524	
	Mercury Vapor:		
	11,000 LUMENS	$6.201	
	11,000 LUMENS DUPLEX (1)	$6.798	
	11,000 LUMENS DUPLEX (2)	$2.216	
	21,000 LUMENS	$6.361	
CCSF Rate Schedule No. 4E			
	Mercury Vapor:		
	11,000 LUMENS	$6.201	
CCSF Rate Schedule No. 5			
	Incandescent.		
	6,000 LUMENS	$5.066	
	6,000 LUMENS DUPLEX (1)	$5.439	
	6,000 LUMENS DUPLEX (2)	$1.200	
	10,000 LUMENS	$5.259	
	10,000 LUMENS DUPLEX (1)	$5.640	
	10,000 LUMENS DUPLEX (2)	$1.360	
CCSF Rate Schedule No. 6A (Chinatown Area)			
	High Pressure Sodium Vapor		
	27,500 LUMENS	$10.336	
CCSF Rate Schedule No. 7			
	Incandescent.		
	2,500 LUMENS	D&C	
	4,000 LUMENS	D&C	
	6,000 LUMENS	D&C	
	10,000 LUMENS	D&C	
	Mercury Vapor:		
	7,500 LUMENS	D&C	
	11,000 LUMENS	D&C	
	21,000 LUMENS	D&C	
CCSF Rate Schedule No. 9 (Triangle District)			
	High Pressure Sodium Vapor		
	9,500 LUMENS DUPLEX (1)	$7.202	
	9,500 LUMENS DUPLEX (2)	$2.039	
CCSF Rate Schedule No. 12			
	Incandescent.		
	4,000 LUMENS	$3.260	

$0.89 Per Pole Per Month (painting)

Phase-in. F.C. Identifies lamps already at full cost. No phase-in necessary.
Numerator of fraction identifies number of years the phase-in has occured
Denominator of fraction identifies span of years for the phase-in period

STREETLIGHT RATES - SCHEDULES LS-1, LS-2 AND OL-1
Facilities Charges Only

NOMINAL LAMP RATINGS				ALL NIGHT RATES PER LAMP PER MONTH											HALF-HOUR ADJ.		
LAMP	kWh Per Mo.			SCHEDULE LS-2			SCHEDULE LS-1										
WATTS	LS-1	LS-2	LUMENS	A	B	C	A	B	C	D	E	F	OL-1		LS-1	LS-2	OL-1
MERCURY VAPOR LAMPS																	
100			3,500	$0.176	$1.000	$1.537	$4.271	–	$4.566	–	–	–	–		$0.000	$0.000	–
175			7,500	$0.176	$1.025	$1.482	$4.718	$3.106	$4.969	–	$8.516	$9.708	$4.718		$0.000	$0.000	$0.000
250			11,000	$0.176	$1.052	$1.510	$5.150	$3.112	$4.655	–	–	–	–		$0.000	$0.000	–
400			21,000	$0.176	$1.107	$1.564	$5.390	$3.340	$5.008	–	–	–	$5.390		$0.000	$0.000	$0.000
700			37,000	$0.176	$1.928	$2.385	$6.379	$4.721	$6.071	–	–	–	–		$0.000	$0.000	–
1,000			57,000	$0.176	$1.627	$2.084	–	–	–	–	–	–	–		–	$0.000	–
INCANDESCENT LAMPS																	
58			600	$0.176	–	–	$7.112	–	–	–	–	–	–		$0.000	$0.000	–
92			1,000	$0.176	$3.133	$3.590	$7.112	–	–	–	–	–	–		$0.000	$0.000	–
189			2,500	$0.176	$3.128	$3.585	$7.702	$5.494	–	–	–	–	–		$0.000	$0.000	–
295			4,000	$0.176	$3.225	$3.682	$7.381	$5.597	–	–	–	–	–		$0.000	$0.000	–
405			6,000	$0.176	$3.721	$4.178	$7.666	–	–	–	–	–	–		$0.000	$0.000	–
620			10,000	$0.176	$4.603	$5.060	–	–	–	–	–	–	–		–	$0.000	–
860			15,000	$0.176	$5.311	–	–	–	–	–	–	–	–		–	$0.000	–
LOW PRESSURE SODIUM VAPOR LAMPS																	
35			4,800	$0.176	–	–	–	–	–	–	–	–	–		–	$0.000	–
55			8,000	$0.176	–	–	–	–	–	–	–	–	–		–	$0.000	–
90			13,500	$0.176	–	–	–	–	–	–	–	–	–		–	$0.000	–
135			21,500	$0.176	–	–	–	–	–	–	–	–	–		–	$0.000	–
180			33,000	$0.176	–	–	–	–	–	–	–	–	–		–	$0.000	–
HIGH PRESSURE SODIUM VAPOR LAMPS																	
AT 120 VOLTS*																	
35			2,200	$0.176	–	–	–	–	–	–	–	–	–		–	$0.000	–
50			3,300	$0.176	–	–	–	–	–	–	–	–	–		–	$0.000	–
70			5,800	$0.176	$1.134	$1.592	$4.006	–	$4.357	$7.548	$7.437	$9.697	$4.006		$0.000	$0.000	$0.000
100			9,500	$0.176	$1.162	$1.619	$4.066	–	$4.331	$7.250	$7.411	$9.697	$4.066		$0.000	$0.000	$0.000
150			16,000	$0.176	$1.189	$1.646	$4.188	–	$4.368	$7.435	$7.448	$9.937	–		$0.000	$0.000	–
200			22,000	$0.176	–	–	–	–	–	–	–	–	–		–	$0.000	–
AT 240 VOLTS*																	
50			3,300	$0.176	–	–	–	–	–	–	–	–	–		–	$0.000	–
70			5,800	$0.176	$1.134	$1.592	–	–	–	–	–	–	–		$0.000	$0.000	–
100			9,500	$0.176	$1.162	$1.619	–	–	–	–	–	–	–		–	$0.000	–
150			16,000	$0.176	$1.189	$1.646	–	–	–	–	–	–	–		–	$0.000	–
200			22,000	$0.176	$1.189	$1.646	$4.493	–	$4.536	–	$7.616	$10.167	$4.493		$0.000	$0.000	$0.000
250			27,500	$0.176	$1.217	$1.674	$4.929	–	$4.507	–	$7.587	$10.571	–		$0.000	$0.000	
310			37,000	$0.176	–	–	–	–	–	–	–	–	–		–	$0.000	–
400			50,000	$0.176	$1.217	$1.674	$5.226	–	$4.651	–	$7.731	$10.752	–		$0.000	$0.000	–
METAL HALIDE LAMPS																	
100			8,500	$0.176	–	–	–	–	–	–	–	–	–		–	$0.000	–
175			14,000	$0.176	–	–	–	–	–	–	–	–	–		–	$0.000	–
400			30,000	$0.176	–	–	–	–	–	–	–	–	–			$0.000	–
1,000			90,000	$0.176	–	–	–	–	–	–	–	–	–		–	$0.000	–

Energy Rate @ $0.00000 per kwh LS-1 & LS-2
Energy Rate @ $0.00000 per kwh OL-1

Pole Painting Charge @ $0.89 Per Pole Per Month

*LS-2 HPSV Rates at 120 or 240 Volts.

Note: Boxed-in areas indicates kWh/lamp/mo., base rate and pole painting charge at 93 adopted.

PG&E Special Streetlight Rates

NOMINAL LAMP RATINGS				RATE SCHEDULE		
LAMP WATTS	AVERAGE kWhr PER MONTH	INITIAL LUMENS		LS-1	LS-2A	LS-2A1
MERCURY VAPOR LAMPS						
		1300				$1.453
		1650			$1.737	
175		7500	*		$10.696	
HIGH PRESSURE SODIUM VAPOR LAMPS AT 120 VOLTS						
70		5800	*	$8.334	$4.611	
150		16000	*			$9.411
AT 240 VOLTS						
70		5800		$6.277		
70		5800	*		$5.233	
150		16000	*		$10.655	
		36000				$8.871
METAL HALIDE						
250		20500				$7.381
INCANDESCENT						
		2500	*		$10.249	

*24 Hour Operation

Energy Rate @ $0.07097 per kWhr

STREETLIGHT LS-3 RATES

Service Charge ($/meter/month	$3.00
Switching Charge ($/meter/month)	$3.25
Energy Charge ($/kWh)	$0.07097

I. Standby Rates

Standby customers are usually cogenerators or other Qualifying Facilities (QFs) that can supply most or all of their own power needs. There are approximately 350 such customers on PG&E's system. Those who can meet virtually all of their normal power needs from their own generating facilities rely on PG&E for back-up or maintenance power. A small segment of PG&E's standby customers can supply only a portion of the power they need and must rely on PG&E to supply the rest.

Customers who only require back-up and maintenance power now receive all service under the provisions of Schedule S. A customer with supplemental power requirements in addition to its needs for back-up and maintenance power can choose a special metering arrangement, which makes it possible for PG&E to bill it for back-up and maintenance power requirements under Schedule S and for supplemental power requirements under either Schedule E-19 or E-20. In the alternative, all of its electric service is billed under an otherwise-applicable service schedule--together with the applicable contract reservation charges from Schedule S, which then function essentially as riders on each of the otherwise-applicable tariffs.

Currently, any standby customer with supplemental power requirements whose otherwise-applicable tariff is Schedule E-19 or E-20 can choose the mixed-use metering and billing alternative. The Commission first approved this option in D.93-06-087. PG&E reports, however, that just three of the first 14 eligible customers have opted for the mixed-use billing alternative and none of the next 40 eligible

Schedule E-19 and E-20 standby customers have chosen to participate. PG&E asserts that this relatively low degree of interest can be attributed both to the additional costs and complexity associated with mixed-use billing, and to lower benefits (relative to these costs) of mixed-use billing when cogeneration plays a relatively smaller role in the overall operation of a customer's facility.

When the Commission approved this option, it left for later proceedings the issue of whether or not the option should also be offered to smaller customers. Based on its experience with the program thus far, PG&E does not propose broader eligibility criteria. There is no evidence supporting an expansion of the program. Therefore, we will not implement any changes at this time. ORA asks that ratepayers be given the opportunity to propose such an expansion in a subsequent rate design window proceeding, if it appears fruitful. We will permit this issue to be raised by any interested party in a rate design window proceeding, where appropriate.

J. Environmental and Social Program Line Item

In Phase 1, the Natural Resources Defense Council (NRDC) proposed what it called a Universal System Benefits Charge. NRDC proposed that this would be usage-based charge on customer electric bills designed to permit recovery of certain identified costs. It would be a method of "unbundling" certain costs from commodity rates so that those costs would not promote system bypass as electric markets become more competitive. No party opposed the concept.

During the course of the proceeding, NRDC and PG&E reached an agreement as to the type of costs that should be recovered through the special charge. Using this agreement as a starting point, the Commission concluded as follows:

> "We agree with NRDC and PG&E that now is a good time to begin the process of unbundling electric rates and thereby identify certain program costs separately from commodity costs. We will direct PG&E to estimate the costs of DSM programs, ERAM adjustments, low-income rate discounts, electric distribution undergrounding, and CIEE contributions which would be included in the charge. Our endorsement here of the charge should not be interpreted to mean that we will change the ratemaking status of any of

these programs in the process of unbundling costs. Thus, the undergrounding program that is funded as part of base rates will continue to be funded through base rates. DSM, low-income discounts, and CIEE contributions will continue to be funded through balancing accounts.

"We cannot determine from the record why NRDC and PG&E propose to include CIEE contributions in the surcharge but not other RD&D costs. We will consider whether all RD&D costs should be included in the surcharge during implementation of industry restructuring.

"Finally, while we appreciate NRDC's proposed title for the charge, we are concerned that the term 'Universal System Benefits Charge' does not simply or adequately describe the charge for the benefit of customers. We will use the term "Environmental and Social Program Surcharge." (D.95-12-055, mimeo., pp. 16-17.)

In an effort to respond to this directive, PG&E introduced additional testimony in this proceeding. In that testimony, however, PG&E did not propose a surcharge. Instead, it proposed a "line item." Where a surcharge would be (in NRDC's words) "an additional amount added to the usual charge," the "line item" proposed by PG&E would be no more than a statement, contained on a customer's bill, identifying the portion of the bundled charge that relates to certain activities. PG&E acknowledges that it has not offered a surcharge because to do so might increase some customers' bills, increase the time needed to put the bill change into effect and increase customer confusion.

NRDC supports the implementation of PG&E's proposed line item, but asks that the Commission require PG&E to move quickly to unbundle its rates and place the identified costs in a true unbypassable surcharge. NRDC asks the Commission to rename this charge the "Public Resources Trust." The California Energy Commission (CEC) objects to the inclusion of the Electric Revenue Adjustment Mechanism (ERAM) in the surcharge or line item, arguing that there is no clear connection between ERAM and social or environmental goals. TURN opposes the immediate implementation of the surcharge or line item, arguing that it would add to customer confusion to introduce something like this on customer bills before the long-term nature of such a charge has been determined in the Commission's electric restructuring proceeding. ORA proposes that if a line item is adopted now, the word "Environmental" should be eliminated from its title, because it asserts that environmental costs are not as yet included in the charge.

All of the parties raise valid issues. However, we note that in D.97-08-056 the Commission implemented unbundling, including unbundling of environmental and social programs into the public purpose surcharge. Therefore, we need not adopt the proposed Environmental and Social Program Line Item in this decision.

K. Employee Discounts

In the recent Edison rate design decision (D.96-04-050), we ordered Edison to begin phasing out the discounts for electric service that it currently provides to its employees through tariffed rates. On January 1, 1997, the tariffed employee discount was to be reduced by one-third. On January 1, 1998, it was to be reduced by another third, and it was to be eliminated by June 1, 1998.[17] This represents a significant shift in the Commission's long-standing policy concerning employee discounts. However, the issue was not squarely addressed by the parties to this proceeding. With the rate freeze ordered by the legislature in § 368(a), we conclude that this issue is currently moot, at least through the end of the rate freeze.

III. Conclusion

In this decision, we have established principles that will apply to revenue allocation and rate design in future cases to the extent permitted by AB 1890. Appendix A includes illustrative tables to create a context for the conclusions we have made above. When reviewing these tables, it is important to remember, for most purposes, that we are not allocating revenues or designing rates in this decision. The changes illustrated here do not reflect decisions we have yet to make, such as whether

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[17] See D.96-04-050, mimeo., p. 140.

to apply revenue caps to certain classes. In addition, it must be remembered that future changes to PG&E's revenue requirement will also affect the ultimate rates.

IV. Comments on the ALJ's Proposed Decision

On May 2, 1997, the ALJ's proposed decision was issued for further comments on the AB 1890 related revisions to the ALJ's original proposed decision. Comments and/or reply comments were received from AECA, CLECA, CMA, Farm Bureau, ORA, PG&E, and TURN.

Again, on September 17, 1997, the ALJ's proposed decision was issued for comments. Coments were filed by PG&E, Edison, SDG&E, ORA, and California City-County Street Light Association. Reply comments were filed by PG&E, SDG&E, ORA, Utility Reform Network, California Manufacturers Association, and Enron. We have reviewed the comments and where appropriate made changes to the ALJ's revised proposed decision.

Findings of Fact

1. PG&E's proposal for allocating energy marginal cost revenue is consistent with currently adopted practice.

2. There is no causative relationship between the existing members of a particular rate class and the cost of a new hookup.

3. If new customer hookup costs are to be borne by the greater body of ratepayers, then they should be borne equitably.

4. All customers cause customer access costs to be incurred over time, and should bear a reasonable portion of these costs.

5. Even if we were persuaded that class-differentiated value-of-service should affect the allocation of marginal generation capacity costs, we would not agree to make such a distinction based on the current value-of-service methodology.

6. It is consistent with the Commission's directive in the last general rate case to employ direct allocation for the E-20 schedules.

7. It is appropriate to separate standby customers from those that are otherwise similar in order to more directly allocate the costs of serving standby customers.

8. D.97-08-056 adopts a system average percent method to allocate CARE costs.

9. Any portion of the nonfirm customer discount in excess of marginal cost is a subsidy.

10. If we require other ratepayer groups to absorb the nonfirm customer subsidy, then we would have shifted a new cost onto other ratepayer groups.

11. The Commission recently determined that transmission costs should be included in the cost-based portion of Edison's interruptible discount.

12. We intend to allow PG&E to adjust its marginal costs to reflect new resource additions from year to year. It is consistent with this approach to eliminate automatic adjustments and allow PG&E to continue to recalculate the generation and energy costs each year.

13. The pilot aggregation program proposed by the agricultural customers would not develop sufficient data to produce statistically significant results.

14. It is inappropriate and unnecessary for us to depart from the use of the EPMC allocation methodology.

15. With a reduction of at least 1.5% in residential rates, PG&E could phase in new electric baseline quantities without raising rates.

16. Changes must be made to the voluntary residential TOU program to make it more consistent with actual costs.

17. The proposed new tariffs appear to move toward this goal, by recognizing differences in area peaks.

18. The current Schedule E-8 rates appear to understate the cost of service.

19. The changes proposed by PG&E to its seasonal residential schedules make sense in that they are designed to tailor the seasonal rates to focus more directly on the class of customers that was originally of interest: those who use wood or propane for heat and would become comparatively large users of electricity if they were to switch to electric heat.

20. No party has proposed changes to the electric master meter discounts in this proceeding.

21. Each customer imposes fixed costs on the utility system and accurate rates would separate, or unbundle, those fixed costs for ratemaking treatment so that customers would more clearly understand how their behavior affects the utility's costs.

22. As directed, PG&E included in its application an option for the creation of a customer charge for Schedule E-1 customers; however, PG&E opposes its adoption.

23. Gaining customer acceptance of a residential customer charge is still a major concern in PG&E's service territory.

24. Lower income and lower usage residential customers stand to be disproportionately affected by the imposition of a customer charge.

25. To assess the consistency of a future residential customer charge with the attainment of cost-based rates on a total per-unit cost basis, PG&E will need to collect and present data that allows for comparison of the costs of serving customers living in multi-family residences with those of serving customers living in single-family residences.

26. If we were to approve a customer charge to be included in Schedule E-1, it would be appropriate to apply that charge to customers using Schedule E-SEG as well. However, since we are not approving such a customer charge at this time, we will apply none to Schedule E-SEG, either.

27. Schedule E-9 is not revenue-neutral.

28. PG&E has not demonstrated that higher usage customers impose a lower cost of service than lower usage customers, or that there is an over-migration problem related to voluntary TOU schedules for light and power customers that needs to be corrected.

29. The current facility charge of $7.80 per meter per month for Schedule A-15 customers should be increased to $25.00 to fully cover all incremental costs of providing direct current service.

30. PG&E's proposed changes to Schedule A-10 and E-19V eligibility requirements appear consistent with its overall effort to improve the relationship between its cost of commercial service and its rates.

31. PG&E's proposed uniform 15-minute demand interval for Schedule A-10 and E-19V customers will have a negligible effect on bills and usage while freeing up operating funds for more pressing uses.

32. Continuing to collect the $70 portion of the Optimal Billing Period customer charge related to solid state recorder equipment would amount to double recovery.

33. While it is appropriate to offer additional TOU options, such as those we are approving for residential customers, the currently pending questions about the reliance on new metering technologies underscore the need to resist forcing a new class of customers to move to time-differentiated rates.

34. There is no reason to require a new class of customers to invest in potentially outdated meters and develop consumption strategies that rely on an approach to time-differentiated charges that may be superseded within the next few years.

35. Based on PG&E's experience with the seven curtailments of nonfirm customers that have occurred, it does not appear necessary to continue to require PG&E to undertake pre-emergency curtailments.

36. It is sensible for PG&E to retain discretion to perform pre-emergency curtailments because it provides PG&E with a tool to ensure a high level of compliance with the requirements of nonfirm service.

37. Neither PG&E nor ORA has provided an evidentiary basis for changing the status quo related to the real-time pricing program.

38. PG&E's proposal to change its real-time pricing program reporting requirements more appropriately should have been offered in the revenue requirements phase of this proceeding, since the implementation of the proposal would have a direct impact on PG&E's costs and its revenue requirement.

39. The record supports the adoption of PG&E's proposed ratesetting methodology for streetlight rates.

40. The streetlighting class experiences discrete costs and has a relatively modest impact on system revenues.

41. There is no evidence supporting an expansion of the standby rate program.

42. On the issue of public purpose surcharge proposal, it is not appropriate for the Commission to take a partial step toward unbundling of charges in this proceeding.

43. In the recent Edison rate design decision (D.96-04-050), we ordered Edison to begin phasing out the discounts for electric service that it currently provides to its employees through tariffed rates.

44. PG&E's proposals for target gas and electric baseline quantities are uncontested.

45. PG&E requested modifications to existing tariff schedules as follows:

- The closure to additional customers of residential TOU Schedules E-7, EL-7, E-A7, and EL-A7.
- The closure to additional customers of seasonal service Schedules E-8 and EL-8.
- The closure to additional customers of low-emission vehicle residential TOU Schedule E-9.
- The establishment of additional Schedule E-19V migration eligibility requirements.
- A revision to the demand interval for Schedule A-10 and E-19V customers with maximum demands between 400 and 500 kW.
- A revision to nonfirm pre-emergency curtailment requirements.

46. Also, PG&E requested new tariff schedules as follows:

- Residential TOU Schedules E-10, E-11, E-12, EL-10, EL-11, and EL-12 (available upon the closure of Schedules E-7, EL-7, E-A7, and EL-A7).
- Residential seasonal service Schedules E-13 and EL-13 (available upon the closure of Schedules E-8 and EL-8).
- Low-emission vehicle residential TOU Schedule E-6 (available upon the closure of Schedule E-9).

47. The diesel and natural gas anti-bypass experimental rate schedules were reviewed by the Commission in PG&E's 1996 Rate Design Window proceeding decision D.97-09-047.

Conclusions of Law

1. Subject to the constraints of the rate freeze, PG&E should use any sufficiently large revenue requirement reductions as an opportunity to further adjust baseline quantities.

2. Because of the specific circumstances affecting PG&E and because TURN and PG&E continue to raise legitimate doubts about the merits of instituting a customer charge for this utility, we will not require such charges in this proceeding.

3. PG&E has received Commission approval of a net metering tariff in line with this decision.

4. PG&E should defer implementation of the 200 kW criterion for mandatory TOU tariffs pending further clarification of our TOU metering policy in the electric industry restructuring proceeding.

5. We should approve PG&E's approach for streetlight rates and adjust the resulting rates to reflect marginal costs adopted in this proceeding. However, AB 1890 precludes us from doing so.

6. The rate freeze mandated by AB 1890 eliminates the need for PG&E to file testimony addressing the issue of whether the employee discount should be continued and, if so, in what form.

7. PG&E's proposals for target gas and electric baseline quantities are adopted.

8. The rate freeze mandated by AB 1890 precludes PG&E from immediately implementing the following:

- The closure to additional customers of residential TOU Schedules E-7, EL-7, E-A7, and EL-A7.

- The closure to additional customers of seasonal service Schedules E-8 and EL-8.

- The closure to additional customers of low emission vehicle residential TOU Schedule E-9.

- The establishment of new Schedule E-19V migration eligibility requirements.

- A revision to the demand interval for Schedule A-10 and E-19V customers with maximum demands between 400 and 500 kW.

However, the rate freeze mandated by AB 1890 does not preclude PG&E from immediately implementing a revision to nonfirm pre-emergency curtailment requirements.

ORDER

IT IS ORDERED that:

1. The revenue allocation and rate design principles set forth in this opinion shall be applied in future Pacific Gas and Electric Company (PG&E) proceedings, as permitted by Assembly Bill 1890.

2. Within thirty days, PG&E shall file tariffs that establish new residential time-of-use (TOU) rate schedules that include an option for customers to acquire meters.

3. PG&E, at its option, may file new tariff schedules to: (1) revise nonfirm pre-emergency curtailment requirements; (2) establish new residential TOU schedules E-10, E-11, E-12, EL-10, EL-11, and EL-12; and (3) establish new residential seasonal service Schedules E-13 and EL-13.

4. PG&E is ordered to file new low-emission vehicle residential TOU Schedule E-6, as attached in Appendix B.

5. PG&E's request to terminate its annual Real-Time Pricing program report is granted.

6. Phase 2 of this proceeding is closed.

This order is effective today.

Dated December 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
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PG&E 1996 GRC - Interclass Revenue Allocation

All Revenues in Thousands of Dollars

	Total Sales (MWh)	Revenue at 1/1/96 Rates	Revenue @ Full EPMC	% Change
Residential	24,881,680	$2,966,847	$2,818,615	-5.0%
Agricultural	3,547,899	$399,164	$614,516	54.0%
Streetlighting /5	318,424	$40,211	$35,137	-12.6%
Small L&P	6,613,586	$822,572	$806,213	-2.0%
Medium L&P	10,811,597	$1,087,030	$1,138,458	4.7%
E-19 Class	10,488,192	$928,763	$983,394	5.9%
E-20 T	6,617,658	$308,417	$214,090	-30.6%
E-20 P	6,138,681	$413,820	$369,891	-10.6%
E-20 S	4,800,539	$401,918	$381,246	-5.1%
Contracts	369,187	$19,740	$19,740	0.0%
Standby	142,703	$13,037	$20,217	55.1%
TOTAL SYSTEM	74,730,145	$7,401,517	$7,401,517	0.0%

1/ This table shows total revenues. Total revenues include non-allocated revenue adjustments from (a) optional TOU meter charges, (b) Streetlighting and Railway facility charges, (c) negotiated contracts, (d) standby charges, (e) load management, UCB, and nonfirm service discounts, (f) power factor revenues, (g) CCSF Hetch Hetchy Credits, (h) Residential A/C load control credit and master meter discounts, (i) CARE surcharge revenues, and (j) unconventional generation credits

2/ Negotiated contract revenues are excluded from the allocation process and estimated using escalation factors in the contracts.

3/ Large L&P sales and revenues exclude the kWh and refunded ECAC revenue associated with energy provided to CCSF customers from Hetch Hetchy.

4/ Percentage changes are relative to total revenue at present rates. Class caps, however, are based on changes in allocated revenues excluding special contracts. Allocated revenues exclude the items identified in footnote 1.

5/ Streetlight revenues at present rates reflect PG&E's Phase 2 adopted 1993 streetlight facilities charges with no 1994 phase-in.

6/ The revenue totals for E-20 schedules and for the system do not match those appearing in the revenue allocation workpapers because this table subtracts Economic Stimulus Rate (ESR) Revenue to reflect the effect of the ESR discounts.

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Interclass Distribution of Marginal Costs
(dollars in thousands)

	Sales	Energy	Generation	Transmission	Distribution	Customer	MC Rev	Percent of Total
Residential	24,881,680	$535,092	$327,744	$57,050	$1,098,012	$190,903	$2,208,800	38.1%
Agricultural	3,547,899	$77,101	$57,283	$10,620	$305,825	$22,370	$473,199	8.2%
Streetlighting	318,424	$6,358	$922	$197	$923	$4,635	$13,035	0.2%
Small L&P	6,613,586	$146,063	$102,174	$16,896	$294,389	$62,330	$621,852	10.7%
Medium L&P	10,811,597	$240,040	$166,117	$29,201	$414,419	$29,465	$879,243	15.2%
E-19 Class	10,488,192	$227,015	$135,611	$25,794	$362,160	$9,372	$759,953	13.1%
E20 T	6,599,658	$132,740	$62,143	$8,622	$0	$1,061	$204,567	3.5%
P	6,138,681	$129,294	$67,954	$11,477	$105,705	$2,906	$317,336	5.5%
S	4,390,767	$96,866	$56,290	$11,502	$115,231	$5,237	$285,125	4.9%
Contracts	369,187	$7,421	$3,565	$495	$555	$42	$12,078	0.2%
Total E-20	17,926,064	$375,956	$195,111	$33,543	$232,826	$9,526	$846,962	14.6%
Standby	142,703	$2,839	$3,726	$1,696	$6,260	$1,125	$15,647	0.3%
Total System	74,302,373	$1,600,830	$983,530	$173,551	$2,703,480	$329,446	$5,790,836	
Percent of total		28%	17%	3%	47%	6%		

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Average Rate Comparison

Class/ Rate Schedule	Volt Lvl	Sales	Average 1/1/96 Rates	Rates at EPMC	Average % Change	Average Marginal Cost
RESIDENTIAL:						
E-1	S	20,817,882	$.12242	$.11344	-6.2%	$.08924
EL-1	S	1,648,514	$.10207			
E-7	S	1,841,918	$.10237	$.11309	10.5%	$.08461
E-8	S	573,366	$.10716	$.10757	0.4%	$.08376
TOTAL		24,881,680	$.11924	$.11328	-5.0%	$.08877
AGRICULTURAL						
AG-1 A	S	179,031	$.21644	$.28387	31.2%	$.22012
AG-RA	S	30,913	$.14734	$.24936	69.2%	$.18700
AG-VA	S	38,805	$.14470	$.25645	77.2%	$.19295
AG-4A	S	132,592	$.14303	$.24625	72.2%	$.18505
AG-5A	S	85,432	$.11629	$.18662	60.5%	$.14208
AG-1 B	S	286,379	$.16326	$.28334	73.5%	$.21971
AG-RB	S	30,444	$.13854	$.24769	78.8%	$.19036
AG-VB	S	23,608	$.13542	$.25193	86.0%	$.19371
AG-4B		374,321	$.12920	$.26432	104.6%	$.20362
AG-4C	S	41,155	$.12783	$.25635	100.5%	$.19654
AG-5B		2,289,539	$.09202	$.12623	37.2%	$.09736
AG-5C	S	35,679	$.08032	$.12100	50.7%	$.09341
TOTAL		3,547,899	$.11251	$.17321	54.0%	$.13337
STREETLIGHTS		318,424	$.12628	$.11035	-12.6%	$.04093
SMALL L&P						
A-1	S	4,549,490	$.13510	$.12964	-4.0%	$.10035
A-6	S	1,918,456	$.10003	$.10621	6.2%	$.08108
A-15	S	1,578	$.27562	$.29072	5.5%	$.18223
TC-1	S	144,061	$.10816	$.08477	-21.6%	$.06583
TOTAL		6,613,586	$.12438	$.12190	-2.0%	$.09403
MEDIUM L&P						
A-10		10,811,597	$.10054	$.10531	4.7%	$.08132
E-19 CLASS						
E-19	T	5,383	$.08715	$.05793	-33.5%	$.04418
E-19/25	P	608,929	$.07707	$.08129	5.5%	$.06361
E-19/25	S	9,823,916	$.08926	$.09466	6.0%	$.07311
A-RTP-19	S	49,964	$.06980	$.07323	-18.4%	$.05582
TOTAL		10,488,192	$.08855	$.09376	5.9%	$.07246

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Average Rate Comparison

LARGE L&P						
E-20	T	6,599,658	$.04647	$.03232	-30.4%	$.03100
E-20	P	6,138,681	$.06741	$.06026	-10.6%	$.05169
E-20	S	4,390,767	$.08309	$.07899	-4.9%	$.06494
A-RTP-20	T	18,000	$.09751	$.04227	-56.7%	$.03571
A-RTP-20	S	409,772	$.09050	$.08401	-7.2%	$.06641
Large L&P Tariffs		17,556,877	$.06403	$.05498	-14.1%	$.04755
Contracts:	T	348,021	$.05092	$.05092	0.0%	$.03076
Contracts:	P	0	$.00000	$.00000	0.0%	$.00000
Contracts:	S	21,165	$.09537	$.09537	0.0%	$.06493
Total Contracts		369,187	$.05347	$.05347	0.0%	$.03272
Total Large L&P		17,926,064	$.06381	$.05495	-13.9%	$.04725
STANDBY	T	128,722	$.08320	$.08628	3.7%	$.06666
	P	10,512	$.17784	$.78461	341.2%	$.60867
	S	3,468	$.13218	$.24878	88.2%	$.19248
Total		142,703	$.09136	$.14167	55.1%	$.10965
SYSTEM TOTAL		74,730,145	$.09904	$.09904	0.0%	$.07786

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Gas Master-Meter Discounts

Per month, per unit

	Present Discount	Base Discount	Diversity Benefit Adjustment	Line Loss Adjustment	Net Discount
GT-Mobilehome Park Service	$10.49*	$8.88	$.40	N/A	$8.48
GS-Multifamily Service	$5.14*	$4.15	$.28	N/A	$3.87

*Rates in effect January 1, 1995

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RESIDENTIAL TARGET BASELINE QUANTITIES

SCHEDULE	E-1, ES, ET, E-7 (and CARE)						EM					
	SUMMER			WINTER			SUMMER			WINTER		
TERRITORY	Current Monthly	Proposed Target Monthly	Proposed Target Daily	Current Monthly	Proposed Target Monthly	Proposed Target Daily	Current Monthly	Proposed Target Monthly	Proposed Target Daily	Current Monthly	Proposed Target Monthly	Proposed Target Daily
BASIC QUANTITIES (kWh)												
P	422	426	13.9	324	342	11.3	232	214	7.0	214	204	6.8
Q	238	244	8.0	348	382	12.0	158	168	5.2	206	212	7.0
R	478	458	14.9	350	364	12.1	276	268	8.4	208	206	6.8
S	422	426	13.9	350	368	12.1	232	214	7.0	184	184	6.1
T	236	244	8.0	268	286	9.5	158	158	5.2	178	184	6.1
V	264	258	8.4	292	300	9.9	162	164	6.0	184	186	6.2
W	508	500	16.3	338	350	11.6	308	288	9.3	214	218	7.2
X	332	336	11.0	348	382	12.0	190	190	6.2	206	212	7.0
Y	288	292	9.5	324	342	11.3	164	164	5.3	214	204	6.8
Z	196	204	6.7	296	290	9.6	176	176	5.7	268	268	8.8
ALL-ELECTRIC QUANTITIES												
P	580	562	18.3	932	838	27.8	382	362	11.8	682	650	21.5
Q	320	316	10.3	658	638	21.1	242	232	7.6	536	554	18.4
R	652	620	20.2	888	864	28.6	424	372	12.1	598	572	19.0
S	580	562	18.3	922	916	30.4	382	362	11.8	586	598	19.8
T	320	318	10.3	672	576	19.1	242	232	7.6	408	408	13.5
V	470	458	14.9	700	708	23.6	262	278	9.1	444	474	15.7
W	720	680	22.2	880	874	29.0	432	394	12.8	506	700	23.2
X	348	332	10.8	658	638	21.1	298	302	9.8	638	554	18.4
Y	444	428	14.0	932	838	27.8	348	308	10.0	682	650	21.6
Z	346	334	10.9	950	978	32.4	310	388	12.7	778	890	29.5
SCHEDULE	G-1, G-S, G-T (and CARE)						GM					
GAS QUANTITY (THERMS)												
P	18	15	0.5	59	58	1.9	12	12	0.4	35	32	1.1
Q	21	20	0.7	64	59	2.0	22	21	0.7	29	30	1.0
R	15	14	0.6	67	58	1.9	16	17	0.6	68	69	2.3
S	16	15	0.5	60	59	2.0	12	12	0.4	30	28	0.9
T	21	20	0.7	68	61	1.7	22	21	0.7	41	42	1.4
V	23	22	0.7	54	52	1.7	19	20	0.7	40	43	1.4
W	16	15	0.5	67	56	1.9	12	12	0.4	39	37	1.2
X	19	17	0.6	64	59	2.0	14	14	0.5	29	30	1.0
Y	29	21	0.7	59	58	1.9	31	10	0.3	35	32	1.1

(END OF APPENDIX A)

APPENDIX B

SCHEDULE EL-10—RESIDENTIAL CARE PROGRAM TIME-OF-USE SERVICE TO SUMMER AFTERNOON PEAKING AREAS (N)

APPLICABILITY: This voluntary schedule is available to customers for whom Schedule E-1 applies where the applicant qualifies for California Alternate Rates for Energy (CARE) under the eligibility and certification criteria set forth in Rule 19.1, 19.2, or 19.3.*

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 non-utility 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-10 charges.

The customer must pay either a "processing charge" or "installation charge." The customer whose account does not have an appropriate time-of-use meter must pay an installation charge prior to taking service under this schedule. The customer whose account has an appropriate time-of-use meter, but is not currently taking time-of-use service must pay a processing charge prior to participating in the schedule.

The installation charge or processing charge must be paid 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 install the necessary meter 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 for the requried meter and not receiving commensurate benefit is entirely that of the customer.

TERRITORY: Available only in the cities or areas served by the PG&E Local Offices in Bayhill, Belmont, Cupertino, East Oakland, Fremont, Geyserville, Gilroy, Half Moon Bay, Hayward, Hollister, King City, Livermore, Los Banos, Los Gatos, Napa, Petaluma, Redding, Salinas, San Francisco, San Jose, Santa Rosa, Ukiah and Vallejo.

RATES:

	One Time Charge Per Meter
INSTALLATION CHARGE	TBD
PROCESSING CHARGE	TBD

	Per Meter Per Day
METER CHARGE	(N/A)
MINIMUM CHARGE (in addition to the meter charge)	$0.16427

ENERGY CHARGE (per kWh)	Per Meter Per Month Summer	Winter
PEAK:	$0.33899	$0.13997
OFF-PEAK:	$0.09868	$0.09710
Baseline credit, deduction per kWh of Baseline use:	$0.01732	$0.01732

* The rules referred to in this schedule are part of PG&E's electric tariffs. Copies are available at local offices. (N)

(Continued)

SCHEDULE EL-10—RESIDENTIAL CARE PROGRAM TIME-OF-USE SERVICE TO SUMMER AFTERNOON PEAKING AREAS (Continued) (N)

SPECIAL CONDITIONS:

1. BASELINE RATES: Baseline rates are applicable only to separately metered residential use. PG&E may require the customer to file with it a Declaration of Eligibility for Baseline Quantities for Residential Rates.

2. BASELINE (TIER 1) QUANTITIES: The following quantities of electricity are to be billed at the rates for baseline use (also see Rule 19 for additional allowances for medical needs):

BASELINE QUANTITIES (kWh PER DAY)

Baseline Territory**	Code B - Basic Quantities: Summer Tier I	Code B - Basic Quantities: Winter Tier I	Code H - All-Electric Quantities: Summer Tier I	Code H - All-Electric Quantities: Winter Tier I
P	13.8	10.7	18.9	30.9
Q	7.7	11.5	10.4	21.8
R	15.6	11.6	21.3	28.8
S	13.8	11.6	18.9	30.6
T	7.7	8.9	10.4	19.0
V	8.6	9.7	15.3	23.2
W	16.6	11.2	23.5	29.2
X	10.8	11.5	11.3	21.8
Y	9.3	10.7	14.5	30.9
Z	6.4	9.8	11.3	31.5

3. TIME PERIODS: PEAK: 12:00 noon. to 6:00 p.m. Monday through Friday
OFF-PEAK: All other hours

4. ALL-ELECTRIC QUANTITIES (Code H): All-electric quantities are applicable to service to customers with permanently-installed electric heating as the primary heat source. All-electric quantities are also applicable to service to customers of record as of November 15, 1984, to whom the former Code W (Basic plus Water Heating) lifeline allowance was applicable on May 15, 1984, and who thereafter maintain continuous service at the same location under this schedule. If more than one electric meter serves a residential dwelling unit, the all-electric quantities, if applicable, will be allocated only to the primary meter.

5. SEASONAL CHANGES: The summer season is May 1 through October 31 and the winter season is November 1 through April 30. Bills that include May 1 and November 1 seasonal changeover dates will be calculated by multiplying the applicable daily baseline quantity and rates for each season by the number of days in each season for the billing period.

6. ADDITIONAL METERS: If a residential dwelling unit is served by more than one electric meter, the customer must designate which meter is the primary meter and which is (are) the additional meter(s). Only the basic baseline quantities or basic plus medical allowances, if applicable, will be available for the additional meter(s)

** The applicable baseline territory is described in Part A of the Preliminary statement. (N)

SCHEDULE EL-11—RESIDENTIAL CARE PROGRAM TIME-OF-USE SERVICE TO SUMMER EVENING PEAKING AREAS (N)

APPLICABILITY: This voluntary schedule is available to customers for whom Schedule E-1 applies where the applicant qualifies for California Alternate Rates for Energy (CARE) under the eligibility and certification criteria set forth in Rule 19.1, 19.2, or 19.3.*

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 non-utility 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-10 charges.

The customer must pay either a "processing charge" or "installation charge." The customer whose account does not have an appropriate time-of-use meter must pay an installation charge prior to taking service under this schedule. The customer whose account has an appropriate time-of-use meter, but is not currently taking time-of-use service must pay a processing charge prior to participating in the schedule.

The installation charge or processing charge must be paid 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 install the necessary meter 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 for the requried meter and not receiving commensurate benefit is entirely that of the customer.

TERRITORY: Available only in the cities or areas served by the PG&E Local Offices in Antioch, Auburn, Bakersfield, Berkeley, Burney, Chico, Coalinga, Colusa, Concord, Corcoran, Davis, Dinuba, Fresno, Grass Valley, Jackson, Lakeport, Leemore, Lincoln, Madera, Manteca, Mariposa, Marysville, Merced, Modesto, Newman, Oakdale, Oakhurst, Orland, Oroville, Paradise, Placerville, Quincy, Red Bluff, Richmond, Roseville, Sacramento, Santa Maria, Selma, Sonoma, Sonora, Stockton, Taft, Templeton, Tracy, Vacaville and Wasco.

RATES:

	One Time Charge Per Meter
INSTALLATION CHARGE	TBD
PROCESSING CHARGE	TBD

	Per Meter Per Day
METER CHARGE	(N/A)
MINIMUM CHARGE (in addition to the meter charge)	$0.16427

ENERGY CHARGE (per kWh)	Per Meter Per Month Summer	Winter
PEAK:	$0.33899	$0.13997
OFF-PEAK:	$0.09657	$0.09611
Baseline Credit, deduction per kWh of Baseline use:	$0.01732	$0.01732

* The rules referred to in this schedule are part of PG&E's electric tariffs. Copies are available at PG&E's local offices. (N)

(Continued)

SCHEDULE EL-11—RESIDENTIAL CARE PROGRAM TIME-OF-USE SERVICE TO SUMMER EVENING PEAKING AREAS (Continued) (N)

SPECIAL CONDITIONS:

1. BASELINE RATES: Baseline rates are applicable only to separately metered residential use. PG&E may require the customer to file with it a Declaration of Eligibility for Baseline Quantities for Residential Rates.

2. BASELINE (TIER 1) QUANTITIES: The following quantities of electricity are to be billed at the rates for baseline use (also see Rule 19 for additional allowances for medical needs):

BASELINE QUANTITIES (kWh PER DAY)

Baseline Territory**	Code B - Basic Quantities Summer Tier I	Code B - Basic Quantities Winter Tier I	Code H - All-Electric Quantities Summer Tier I	Code H - All-Electric Quantities Winter Tier I
P	13.8	10.7	18.9	30.9
Q	7.7	11.5	10.4	21.8
R	15.6	11.6	21.3	28.8
S	13.8	11.6	18.9	30.6
T	7.7	8.9	10.4	19.0
V	8.6	9.7	15.3	23.2
W	16.6	11.2	23.5	29.2
X	10.8	11.5	11.3	21.8
Y	9.3	10.7	14.5	30.9
Z	6.4	9.8	11.3	31.5

3. TIME PERIODS:

	SUMMER	WINTER
PEAK:	2:00 p.m. to 8:00 p.m. Monday through Friday	12:00 noon to 6:00 p.m. Monday through Friday
OFF-PEAK:	All other hours	All other hours

4. ALL-ELECTRIC QUANTITIES (Code H): All-electric quantities are applicable to service to customers with permanently-installed electric heating as the primary heat source. All-electric quantities are also applicable to service to customers of record as of November 15, 1984, to whom the former Code W (Basic plus Water Heating) lifeline allowance was applicable on May 15, 1984, and who thereafter maintain continuous service at the same location under this schedule. If more than one electric meter serves a residential dwelling unit, the all-electric quantities, if applicable, will be allocated only to the primary meter.

5. SEASONAL CHANGES: The summer season is May 1 through October 31 and the winter season is November 1 through April 30. Bills that include May 1 and November 1 seasonal changeover dates will be calculated by multiplying the applicable daily baseline quantity and rates for each season by the number of days in each season for the billing period.

6. ADDITIONAL METERS: If a residential dwelling unit is served by more than one electric meter, the customer must designate which meter is the primary meter and which is (are) the additional meter(s). Only the basic baseline quantities or basic plus medical allowances, if applicable, will be available for the additional meter(s)

** The applicable baseline territory is described in Part A of PG&E's Preliminary statement. (N)

SCHEDULE EL-12—RESIDENTIAL CARE PROGRAM TIME-OF-USE SERVICE TO WINTER EVENING PEAKING AREAS (N)

APPLICABILITY: This voluntary schedule is available to customers for whom Schedule E-1 applies where the applicant qualifies for California Alternate Rates for Energy (CARE) under the eligibility and certification criteria set forth in Rule 19.1, 19.2, or 19.3.*

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 non-utility 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-10 charges.

The customer must pay either a "processing charge" or "installation charge." The customer whose account does not have an appropriate time-of-use meter must pay an installation charge prior to taking service under this schedule. The customer whose account has an appropriate time-of-use meter, but is not currently taking time-of-use service must pay a processing charge prior to participating in the schedule.

The installation charge or processing charge must be paid 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 install the necessary meter 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 for the requried meter and not receiving commensurate benefit is entirely that of the customer.

TERRITORY: Available only in the cities or areas served by the PG&E Local Offices in Angels Camp, Eureka, Fort Bragg, Fortuna, Garberville, Guerneville, Monterey, Oakland, San Luis Obispo, San Rafael, Santa Cruz, and Willow Creek.

RATES:

	One Time Charge Per Meter
INSTALLATION CHARGE	TBD
PROCESSING CHARGE	TBD

	Per Meter Per Day
METER CHARGE	(N/A)
MINIMUM CHARGE (in addition to the meter charge)	$0.16427

ENERGY CHARGE (per kWh)	Per Meter Per Month Summer	Winter
PEAK:	$0.13997	$0.33899
OFF-PEAK:	$0.09171	$0.09261
Baseline Credit, deduction per kWh of Baseline use:	$0.01732	$0.01732

* The rules referred to in this schedule are part of PG&E's electric tariffs. Copies are available at PG&E's local offices. (N)

(Continued)

SCHEDULE EL-12—RESIDENTIAL CARE PROGRAM TIME-OF-USE SERVICE TO WINTER EVENING PEAKING AREAS (Continued)

(N)

SPECIAL CONDITIONS:

1. BASELINE RATES: Baseline rates are applicable only to separately metered residential use. PG&E may require the customer to file with it a Declaration of Eligibility for Baseline Quantities for Residential Rates.

2. BASELINE (TIER 1) QUANTITIES: The following quantities of electricity are to be billed at the rates for baseline use (also see Rule 19 for additional allowances for medical needs):

BASELINE QUANTITIES (kWh PER DAY)

Baseline Territory**	Code B - Basic Quantities Summer Tier I	Code B - Basic Quantities Winter Tier I	Code H - All-Electric Quantities Summer Tier I	Code H - All-Electric Quantities Winter Tier I
P	13.8	10.7	18.9	30.9
Q	7.7	11.5	10.4	21.8
R	15.6	11.6	21.3	28.8
S	13.8	11.6	18.9	30.6
T	7.7	8.9	10.4	19.0
V	8.6	9.7	15.3	23.2
W	16.6	11.2	23.5	29.2
X	10.8	11.5	11.3	21.8
Y	9.3	10.7	14.5	30.9
Z	6.4	9.8	11.3	31.5

3. TIME PERIODS:

	SUMMER	WINTER
PEAK:	12:00 noon to 6:00 p.m. Monday through Friday	5:00 p.m. to 9:00 p.m. Monday through Friday
OFF-PEAK:	All other hours	All other hours

4. ALL-ELECTRIC QUANTITIES (Code H): All-electric quantities are applicable to service to customers with permanently-installed electric heating as the primary heat source. All-electric quantities are also applicable to service to customers of record as of November 15, 1984, to whom the former Code W (Basic plus Water Heating) lifeline allowance was applicable on May 15, 1984, and who thereafter maintain continuous service at the same location under this schedule. If more than one electric meter serves a residential dwelling unit, the all-electric quantities, if applicable, will be allocated only to the primary meter.

5. SEASONAL CHANGES: The summer season is May 1 through October 31 and the winter season is November 1 through April 30. Bills that include May 1 and November 1 seasonal changeover dates will be calculated by multiplying the applicable daily baseline quantity and rates for each season by the number of days in each season for the billing period.

6. ADDITIONAL METERS: If a residential dwelling unit is served by more than one electric meter, the customer must designate which meter is the primary meter and which is (are) the additional meter(s). Only the basic baseline quantities or basic plus medical allowances, if applicable, will be available for the additional meter(s)

** The applicable baseline territory is described in Part A of the Preliminary Statement.

(N)

SCHEDULE E-10—RESIDENTIAL TIME-OF-USE SERVICE TO SUMMER AFTERNOON PEAKING AREAS (N)

APPLICABILITY: This voluntary schedule is available to customers for whom Schedule E-1 applies.

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 non-utility 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-10 charges.

The customer must pay either a "processing charge" or "installation charge." The customer whose account does not have an appropriate time-of-use meter must pay an installation charge prior to taking service under this schedule. The customer whose account has an appropriate time-of-use meter, but is not currently taking time-of-use service must pay a processing charge prior to participating in the schedule.

The installation charge or processing charge must be paid 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 install the necessary meter 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 for the required meter and not receiving commensurate benefit is entirely that of the customer.

TERRITORY: Available only in the cities or areas served by the PG&E Local Offices in Bayhill, Belmont, Cupertino, East Oakland, Fremont, Geyserville, Gilroy, Half Moon Bay, Hayward, Hollister, King City, Livermore, Los Banos, Los Gatos, Napa, Petaluma, Redding, Salinas, San Francisco, San Jose, Santa Rosa, Ukiah and Vallejo.

RATES:

	One Time Charge Per Meter
INSTALLATION CHARGE	TBD
PROCESSING CHARGE	TBD

	Per Meter Per Day
METER CHARGE	TBD
MINIMUM CHARGE (in addition to the meter charge)	$0.16427

ENERGY CHARGE (per kWh)	Per Meter Per Month Summer	Winter
PEAK:	$0.33899	$0.13997
OFF-PEAK:	$0.09868	$0.09710
Baseline credit, deduction per kWh of Baseline use:	$0.01732	$0.01732

(N)

(Continued)

Pacific Gas and Electric Company
San Francisco, California

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

SCHEDULE E-10--RESIDENTIAL TIME-OF-USE SERVICE TO SUMMER AFTERNOON PEAKING AREAS (N)
(Continued)

SPECIAL CONDITIONS:

1. BASELINE RATES: Baseline rates are applicable only to separately metered residential use. PG&E may require the customer to file with it a Declaration of Eligibility for Baseline Quantities for Residential Rates.

2. BASELINE (TIER 1) QUANTITIES: The following quantities of electricity are to be billed at the rates for baseline use (also see Rule 19 for additional allowances for medical needs):

BASELINE QUANTITIES (kWh PER DAY)

Baseline Territory**	Code B - Basic Quantities Summer Tier I	Code B - Basic Quantities Winter Tier I	Code H - All-Electric Quantities Summer Tier I	Code H - All-Electric Quantities Winter Tier I
P	13.8	10.7	18.9	30.9
Q	7.7	11.5	10.4	21.8
R	15.6	11.6	21.3	28.8
S	13.8	11.6	18.9	30.6
T	7.7	8.9	10.4	19.0
V	8.6	9.7	15.3	23.2
W	16.6	11.2	23.5	29.2
X	10.8	11.5	11.3	21.8
Y	9.3	10.7	14.5	30.9
Z	6.4	9.8	11.3	31.6

3. TIME PERIODS: PEAK: 12:00 noon to 6:00 p.m. Monday through Friday
OFF-PEAK: All other hours

4. ALL-ELECTRIC QUANTITIES (Code H): All-electric quantities are applicable to service to customers with permanently-installed electric heating as the primary heat source. All-electric quantities are also applicable to service to customers of record as of November 15, 1984, to whom the former Code W (Basic plus Water Heating) lifeline allowance was applicable on May 15, 1984, and who thereafter maintain continuous service at the same location under this schedule. If more than one electric meter serves a residential dwelling unit, the all-electric quantities, if applicable, will be allocated only to the primary meter.

5. SEASONAL CHANGES: The summer season is May 1 through October 31 and the winter season is November 1 through April 30. Bills that include May 1 and November 1 seasonal changeover dates will be calculated by multiplying the applicable daily baseline quantity and rates for each season by the number of days in each season for the billing period.

6. ADDITIONAL METERS: If a residential dwelling unit is served by more than one electric meter, the customer must designate which meter is the primary meter and which is (are) the additional meter(s). Only the basic baseline quantities or basic plus medical allowances, if applicable, will be available for the additional meter(s)

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* The rules referred to in this schedule are part of PG&E's electric tariffs. Copies are available at PG&E's local offices.

** The applicable baseline territory is described in Part A of the Preliminary statement. (N)

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Decision No.

Issued by
Thomas E. Bottorff
Vice President
Rates & Account Services

Date Filed
Effective
Resolution No.

25715

SCHEDULE E-11—RESIDENTIAL TIME-OF-USE SERVICE TO SUMMER EVENING PEAKING AREAS (N)

APPLICABILITY: This voluntary schedule is available to customers for whom Schedule E-1 applies.

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 non-utility 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-11 charges.

The customer must pay either a "processing charge" or "installation charge." The customer whose account does not have an appropriate time-of-use meter must pay an installation charge prior to taking service under this schedule. The customer whose account has an appropriate time-of-use meter, but is not currently taking time-of-use service must pay a processing charge prior to participating in the schedule.

The installation charge or processing charge must be paid 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 install the necessary meter 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 for the required meter and not receiving commensurate benefit is entirely that of the customer.

TERRITORY: Available only in the cities or areas served by the PG&E Local Offices in Antioch, Auburn, Bakersfield, Berkeley, Burney, Chico, Coalinga, Colusa, Concord, Corcoran, Davis, Dinuba, Fresno, Grass Valley, Jackson, Lakeport, Leemore, Lincoln, Madera, Manteca, Mariposa, Marysville, Merced, Modesto, Newman, Oakdale, Oakhurst, Orland, Oroville, Paradise, Placerville, Quincy, Red Bluff, Richmond, Roseville, Sacramento, Santa Maria, Selma, Sonoma, Sonora, Stockton, Taft, Templeton, Tracy, Vacaville, and Wasco.

RATES:

	One Time Charge Per Meter
INSTALLATION CHARGE	TBD
PROCESSING CHARGE	TBD

	Per Meter Per Day
METER CHARGE	TBD
MINIMUM CHARGE (in addition to the meter charge)	$0.16427

ENERGY CHARGE (per kWh)	Per Meter Per Month Summer	Winter
PEAK:	$0.33899	$0.13997
OFF-PEAK:	$0.09657	$0.09611
Baseline credit, deduction per kWh of Baseline use:	$0.01732	$0.01732

(N)

(Continued)

SCHEDULE E-11—RESIDENTIAL TIME-OF-USE SERVICE TO SUMMER AFTERNOON PEAKING AREAS (N)
(Continued)

SPECIAL CONDITIONS:

1. BASELINE RATES: Baseline rates are applicable only to separately metered residential use. PG&E may require the customer to file with it a Declaration of Eligibility for Baseline Quantities for Residential Rates.

2. BASELINE (TIER 1) QUANTITIES: The following quantities of electricity are to be billed at the rates for baseline use (also see Rule 19 for additional allowances for medical needs):

BASELINE QUANTITIES (kWh PER DAY)

Baseline Territory**	Code B - Basic Quantities Summer Tier I	Code B - Basic Quantities Winter Tier I	Code H - All-Electric Quantities Summer Tier I	Code H - All-Electric Quantities Winter Tier I
P	13.8	10.7	18.9	30.9
Q	7.7	11.5	10.4	21.8
R	15.6	11.6	21.3	28.8
S	13.8	11.6	18.9	30.6
T	7.7	8.9	10.4	19.0
V	8.6	9.7	15.3	23.2
W	16.6	11.2	23.5	29.2
X	10.8	11.5	11.3	21.8
Y	9.3	10.7	14.5	30.9
Z	6.4	9.8	11.3	31.5

3. TIME PERIODS:

	SUMMER	WINTER
PEAK:	2:00 p.m. to 8:00 p.m. Monday through Friday	12:00 noon to 6:00 p.m. Monday through Friday
OFF-PEAK:	All other hours	All other hours

4. ALL-ELECTRIC QUANTITIES (Code H): All-electric quantities are applicable to service to customers with permanently-installed electric heating as the primary heat source. All-electric quantities are also applicable to service to customers of record as of November 15, 1984, to whom the former Code W (Basic plus Water Heating) lifeline allowance was applicable on May 15, 1984, and who thereafter maintain continuous service at the same location under this schedule. If more than one electric meter serves a residential dwelling unit, the all-electric quantities, if applicable, will be allocated only to the primary meter.

5. SEASONAL CHANGES: The summer season is May 1 through October 31 and the winter season is November 1 through April 30. Bills that include May 1 and November 1 seasonal changeover dates will be calculated by multiplying the applicable daily baseline quantity and rates for each season by the number of days in each season for the billing period.

6. ADDITIONAL METERS: If a residential dwelling unit is served by more than one electric meter, the customer must designate which meter is the primary meter and which is (are) the additional meter(s). Only the basic baseline quantities or basic plus medical allowances, if applicable, will be available for the additional meter(s)

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* The rules referred to in this schedule are part of PG&E's electric tariffs. Copies are available at PG&E's local offices.

** The applicable baseline territory is described in Part A of the Preliminary statement.

(N)

SCHEDULE E-12—RESIDENTIAL TIME-OF-USE SERVICE TO WINTER EVENING PEAKING AREAS (N)

APPLICABILITY: This voluntary schedule is available to customers for whom Schedule E-1 applies.

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 non-utility 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-11 charges.

The customer must pay either a "processing charge" or "installation charge." The customer whose account does not have an appropriate time-of-use meter must pay an installation charge prior to taking service under this schedule. The customer whose account has an appropriate time-of-use meter, but is not currently taking time-of-use service must pay a processing charge prior to participating in the schedule.

The installation charge or processing charge must be paid 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 install the necessary meter 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 for the requried meter and not receiving commensurate benefit is entirely that of the customer.

TERRITORY: Available only in the cities or areas served by the PG&E Local Offices in Angels Camp, Eureka, Fort Bragg, Fortuna, Garberville, Guerneville, Monterey, Oakland, San Luis Obispo, San Rafael, Santa Cruz, and Willow Creek.

RATES:

	One Time Charge Per Meter
INSTALLATION CHARGE	TBD
PROCESSING CHARGE	TBD

	Per Meter Per Day
METER CHARGE	TBD
MINIMUM CHARGE (in addition to the meter charge)	$0.16427

ENERGY CHARGE (per kWh)	Per Meter Per Month Summer	Winter
PEAK:	$0.13997	$0.33899
OFF-PEAK:	$0.09171	$0.09261
Baseline credit, deduction per kWh of Baseline use:	$0.01732	$0.01732

(N)

(Continued)

SCHEDULE E-12—RESIDENTIAL TIME-OF-USE SERVICE TO WINTER EVENING PEAKING AREAS (Continued)

(N)

SPECIAL CONDITIONS:

1. BASELINE RATES: Baseline rates are applicable only to separately metered residential use. PG&E may require the customer to file with it a Declaration of Eligibility for Baseline Quantities for Residential Rates.

2. BASELINE (TIER 1) QUANTITIES: The following quantities of electricity are to be billed at the rates for baseline use (also see Rule 19 for additional allowances for medical needs):

BASELINE QUANTITIES (kWh PER DAY)

Baseline Territory**	Code B - Basic Quantities		Code H - All-Electric Quantities	
	Summer Tier I	Winter Tier I	Summer Tier I	Winter Tier I
P	13.8	10.7	18.9	30.9
Q	7.7	11.5	10.4	21.8
R	15.6	11.6	21.3	28.8
S	13.8	11.6	18.9	30.6
T	7.7	8.9	10.4	19.0
V	8.6	9.7	15.3	23.2
W	16.6	11.2	23.5	29.2
X	10.8	11.5	11.3	21.8
Y	9.3	10.7	14.5	30.9
Z	6.4	9.8	11.3	31.5

3. TIME PERIODS:

	SUMMER	WINTER
PEAK:	12:00 noon to 6:00 p.m. Monday through Friday	5:00 p.m. to 9:00 p.m. Monday through Friday
OFF-PEAK:	All other hours	All other hours

4. ALL-ELECTRIC QUANTITIES (Code H): All-electric quantities are applicable to service to customers with permanently-installed electric heating as the primary heat source. All-electric quantities are also applicable to service to customers of record as of November 15, 1984, to whom the former Code W (Basic plus Water Heating) lifeline allowance was applicable on May 15, 1984, and who thereafter maintain continuous service at the same location under this schedule. If more than one electric meter serves a residential dwelling unit, the all-electric quantities, if applicable, will be allocated only to the primary meter.

5. SEASONAL CHANGES: The summer season is May 1 through October 31 and the winter season is November 1 through April 30. Bills that include May 1 and November 1 seasonal changeover dates will be calculated by multiplying the applicable daily baseline quantity and rates for each season by the number of days in each season for the billing period.

6. ADDITIONAL METERS: If a residential dwelling unit is served by more than one electric meter, the customer must designate which meter is the primary meter and which is (are) the additional meter(s). Only the basic baseline quantities or basic plus medical allowances, if applicable, will be available for the additional meter(s)

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* The rules referred to in this schedule are part of PG&E's electric tariff. Copies are available at PG&E's local offices.

** The applicable baseline territory is described in Part A of the Preliminary statement.

(N)

SCHEDULE E-13—RESIDENTIAL SEASONAL SERVICE OPTION (N)

APPLICABILITY: This voluntary schedule is available to customers for whom Schedules E-1 applies. Customers intially selecting Schedule E-13 must have used at least 18,000 kWh at their current premise in the most recent 12 month period.

An eligible customer requesting service under Schedule E-13 will be placed on it at the next regular meter reading date following the receipt of the customer's request.

PG&E will annually review the usage of customers on Schedule E-13 to determine if they meet the minimum usage criteria of 18,000 kWh per annum. Customers whose annual usage is less than 18,000 kWh will be notified by PG&E that they must transfer to another applicable rate schedule. Customers who have not chosen a different rate schedule within 30 days after being notified by PG&E will be assigned to Schedule E-1.

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-13 charges.

TERRITORY: Available only in the cities or areas served by the local offices in Antioch, Auburn, Bakersfield, Bayhill, Belmont, Berkeley, Burney, Chico, Coalinga, Colusa, Concord, Corcoran, Cupertino, Davis, Dinuba, East Oakland, Fremont, Fresno, Geyserville, Gilroy, Grass Valley, Half Moon Bay, Hayward, Hollister, Jackson, King City, Lakeport, Leemore, Lincoln, Livermore, Los Banos, Los Gatos, Madera, Manteca, Mariposa, Marysville, Merced, Modesto, Napa, Newman, Oakdale, Oakhurst, Orland, Orville, Paradise, Petaluma, Placerville, Quincy, Red Bluff, Redding, Richmond, Roseville, Sacramento, Salinas, San Francisco, San Jose, Santa Maria, Santa Rosa, Selma, Sonoma, Sonora, Stockton, Taft, Templeton, Tracy, Ukiah, Vacaville, Vallejo, and Wasco.

RATES: Energy Charge (per kWh):

Summer $0.13810
Winter $0.07002

Customer Charge:

$0.38111 per meter per day.

SPECIAL CONDITIONS:

1. Seasonal Charges: The summer season is May 1 through October 31. The winter season is November 1 through April 30. When billing includes use in both the summer and winter season, charges will be prorated based upon the number of days in each period.

2. Customers who enroll on this schedule may not switch to another residential schedule until service has been taken on this schedule for 12 billing periods.

3. The baseline and medical baseline quantities available under some residential rate schedules are not available on this schedule. (N)

Pacific Gas and Electric Company
San Francisco, California

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

SCHEDULE EL-13—RESIDENTIAL SEASONAL CARE PROGRAM SERVICE OPTION (N)

APPLICABILITY: This voluntary schedule is available to customers for whom Schedule E-13 applies where the applicant qualifies for California Alternate Rates for Energy (CARE) under the eligibility and certification criteria set forth in Rule 19.1, 19.2 or 19.3.*

An eligible customer requesting service under Schedule EL-13 will be placed on it at the next regular meter reading date following the receipt of the customer's request.

PG&E will annually review the usage of customers on Schedule EL-13 to determine if they meet the minimum usage criteria of 18,000 kWh per annum. Customers whose annual usage is less than 18,000 kWh will be notified by PG&E that they must transfer to another applicable rate schedule. Customers who have not chosen a different rate schedule within 30 days after being notified by PG&E will be assigned to Schedule EL-1.

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 EL-8 charges.

TERRITORY: Available only in summer peaking areas. These include the cities or areas served by the local offices in Antioch, Auburn, Bakersfield, Bayhill, Belmont, Berkeley, Burney, Chico, Coalinga, Colusa, Concord, Corcoran, Cupertino, Davis, Dinuba, East Oakland, Fremont, Fresno, Geyserville, Gilroy, Grass Valley, Half Moon Bay, Hayward, Hollister, Jackson, King City, Lakeport, Leemore, Lincoln, Livermore, Los Banos, Los Gatos, Madera, Manteca, Mariposa, Marysville, Merced, Modesto, Napa, Newman, Oakdale, Oakhurst, Orland, Orville, Paradise, Petaluma, Placerville, Quincy, Red Bluff, Redding, Richmond, Roseville, Sacramento, Salinas, San Francisco, San Jose, Santa Maria, Santa Rosa, Selma, Sonoma, Sonora, Stockton, Taft, Templeton, Tracy, Ukiah, Vacaville, Vallejo, and Wasco.

RATES: Energy Charge (per kWh):

Summer $0.11700
Winter $0.05914

Customer Charge:

$0.32394 per meter per day.

SPECIAL CONDITIONS:

1. Seasonal Charges: The summer season is May 1 through October 31. The winter season is November 1 through April 30. When billing includes use in both the summer and winter season, charges will be prorated based upon the number of days in each period.

2. Customers who enroll on this schedule may not switch to another residential schedule until service has been taken on this schedule for 12 billing periods.

3. The baseline and medical baseline quantities available under some residential rate schedules are not available on this schedule. (N)

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* The rules referred to in this Schedule are parts of PG&E's Electric Tariff Schedules. Copies are available at local offices.

Advice Letter No.
Decision No.

Issued by
Thomas E. Bottorff
Vice President
Rates & Account Services

Date Filed ________
Effective ________
Resolution No. ________

24580

SCHEDULE E-6—EXPERIMENTAL RESIDENTIAL TIME-OF-USE SERVICE FOR LOW EMISSION VEHICLE CUSTOMERS (N)

APPLICABILITY: This experimental schedule is required for customers for whom Schedule E-1 applies and who refuel a highway-legal low-emisssion vehicle (LEV) at their premises. An LEV is either an electric-powered vehicle (EV) or a natural gas-powered vehicle (NGV). Service under this schedule is based upon the availability of metering equipment and customer infrastructure improvements necessary for charging or fueling. The customer must sign Standard Forms 79-863--E-6 Electric Service Agreement Declarations and 79-864--E-6 Electric Service Agreement General Terms and Conditions in order to take service under this schedule.

The provisions of Schedule S--Standby Service Special Conditions 1 through 7, and Special Condition 9 shall also apply to customers whose premises are regularly supplied in part (but <u>not</u> 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-6 charges.

Depending on the manner in which customers will fuel their LEV, one of the following rates will apply:

Rate A: Applies to all LEV customers unless they qualify for and choose Rates B, C, D, or E.

Rate B: Applies to customers with a separately metered EV battery charger or NGV fueling station.

Rate C: Applies to customers who allow PG&E to install a time clock that limits operation of their EV battery charger or NGV fueling station for up to 917 hours per year, not to exceed 7 hours per day. These hours will be chosen by PG&E and may vary according to conditions that exist on the local PG&E distribution system on which the customer's premise is connected. This rate is not applicable for a separately metered EV battery charger or NGV fueling station.

Rate D: Applies to customers in summer peaking areas with a separately metered EV battery charger or NGV fueling station who allow PG&E to install a time clock that limits operation of their EV battery charger or NGV fueling station for up to 917 hours per year, not to exceed 7 hours per day. These hours will be chosen by PG&E and may vary according to the conditions that exist on the local PG&E distribution system to which the customer's premise is connected.

Rate E: Applies to customers in winter peaking areas with a separately metered EV battery charger or NGV fueling station who allow PG&E to install a time clock that limits operation of their EV battery charger or NGV fueling station for up to 917 hours per year, not to exceed 7 hours per day. These hours will be chosen by PG&E and may vary according to the conditions that exist on the local PG&E distribution system to which the customer's premise is connected.

Rates C, D, and E are provided at the sole option of PG&E and based upon the availability of appropriate load management equipment.

TERRITORY: The entire territory. (N)

(Continued)

SCHEDULE E-6—EXPERIMENTAL RESIDENTIAL TIME-OF-USE SERVICE FOR LOW EMISSION VEHICLE CUSTOMERS

(Continued)

(N)

RATES:

	Per Meter Per Day
MINIMUM ENERGY CHARGE:	$0.16427
METER CHARGE:	
Rate A	$0.24312
Rate B	$0.24312
Rate C	$0.24312
Rate D	$0.24312
Rate E	$0.24312

ENERGY CHARGE (per kWh per month)	Summer	Winter
Rate A:		
Peak	$0.32500	$0.16950
Part-Peak	$0.12190	$0.09079
Off-Peak	$0.04687	$0.05438
Baseline credit, deduction per kWh of baseline use:	$0.01732	$0.01732
Rate B:		
Peak	$0.32500	$0.16950
Part-Peak	$0.12190	$0.09079
Off-Peak	$0.04687	$0.05438
Rate C:		
Peak	–	$0.16950
Part-Peak	$0.19950	$0.09079
Off-Peak	$0.04687	$0.05438
Baseline credit, deduction per kWh of baseline use:	$0.01732	$0.01732
Rate D:		
Peak	–	$0.16950
Part-Peak	$0.12190	$0.09079
Off-Peak	$0.04687	$0.05438
Rate E:		
Peak	$0.32500	–
Part-Peak	$0.12190	$0.09079
Off-Peak	$0.04687	$0.05438

** The applicable baseline territory is described in Part A of the Preliminary Statement.

(N)

(Continued)

SCHEDULE E-6—EXPERIMENTAL RESIDENTIAL TIME-OF-USE SERVICE FOR LOW EMISSION VEHICLE CUSTOMERS (Continued) (N)

BASELINE CREDIT: The baseline credit is applicable only to separately metered residential use and excludes separately metered EV battery chargers or NGV fueling stations. PG&E may require the customer to file with it a Declaration of Eligibility for baseline Quantities for Residential Rates.

BASELINE (TIER 1) QUANTITIES: The following quantities of electricity are to be billed at the rates for baseline use (also see Rule 19 for additional allowances for medical needs):

BASELINE QUANTITIES (kWh PER DAY)

Baseline Territory**	Code B - Basic Quantities Summer Tier I	Code B - Basic Quantities Winter Tier I	Code H - All-Electric Quantities Summer Tier I	Code H - All-Electric Quantities Winter Tier I
P	13.8	10.7	18.9	30.9
Q	7.7	11.5	10.4	21.8
R	15.6	11.6	21.3	28.8
S	13.8	11.6	18.9	30.6
T	7.7	8.9	10.4	19.0
V	8.6	9.7	15.3	23.2
W	16.6	11.2	23.5	29.2
X	10.8	11.5	11.3	21.8
Y	9.3	10.7	14.5	30.9
Z	6.4	9.8	11.3	31.5

** The applicable baseline territory is described in Part A of the Preliminary statement. (N)

(Continued)

SCHEDULE E-6--EXPERIMENTAL RESIDENTIAL TIME-OF-USE SERVICE FOR LOW EMISSION VEHICLE CUSTOMERS (Continued) (N)

TIME PERIODS:

Peak: 2:00 p.m. to 9.00 p.m. Monday through Friday.

Partial-peak: 7:00 a.m. to 2:00 p.m. AND 9.00 p.m. to 12:00 midnight Monday through Friday, plus 5:00 p.m. to 9:00 p.m. Saturday and Sunday.

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

ALL ELECTRIC QUANTITIES (Code II): All-electric quantities are applicable to service to customers with permanently installed electric heating as the primary heat source. All-electric quantities are also applicable to service to customers of record as of November 15, 1984, to whom the former Code W (Basic plus Water Heating) lifeline allowance was applicable on May 15, 1984, and who thereafter maintain continuous service at the same location under this schedule.

If more than one electric meter services a residential dwelling unit, the all-electric quantities, if applicable, will be allocated only to the primary meter.

SEASONAL CHANGES: The summer season is May 1 through October 31 and the winter season is November 1 through April 30. When billing includes use in both the summer and winter periods, charges will be prorated based upon the number of days in each period. The baseline credit will be calculated by multiplying the applicable daily baseline quantity and rates for each season by the number of days in each season for the billing period.

ADDITIONAL METERS: If a residential dwelling unit is served by more than one electric meter, the customer must designate which meter is the primary meter and which is (are) the additional meter(s). Only the basic baseline quantities or basic plus medical allowances, if applicable, will be available for the additional meter(s). The baseline credit does not apply to additional meter(s) which separately meter an EV battery charger or NGV fueling station. (N)

Pacific Gas and Electric Company
E-6 Electric Service Agreement
General Terms and Conditions

Distribution:
☐ Customer (Original)
☐ Customer Billing
☐ Division (Original)
☐ Corporate LEV Program

References:
Account #: _____
Job #: ________

GENERAL

1. Customer agrees to purchase and PG&E agrees to provide a supply of electricity pursuant to the terms and conditions of this Agreement and of rate Schedule E-6, or its successor, as well as all applicable Electric Rules and Tariffs for PG&E on file with the California Public Utilities Commission.

2. Both Customer and PG&E agree to abide by the terms and conditions of the above referenced LEV electric rate Schedule E-6 or its successor, as well as all applicable Electric Rules and Tariffs on file for PG&E with the California Public Utilities Commission.

3. Customer represents to PG&E that the Customer or a resident at the service address for the Agreement intends to or will be refueling or recharging the LEV(s) identified in the Agreement at the service address. Customer further represents that the party engaged in the refueling or recharging of the LEV(s) has purchased or leased or has been assigned an LEV by his or her employer for a minimum period of six months, with the intent to fuel or charge the LEV(s) at the service address.

ELECTRIC SERVICE

4. In the event that any material change is made to any electric supply equipment used to refuel or recharge the vehicle with electrical power, the customer shall immediately give PG&E written notice of this fact and will provide the following charger or compressor specifications for the equipment after the change: ____Amps @ _____volts, and _____maximum current. .

5. In order to receive service under Schedule E-6, Customer's electric service for the LEV refueling or recharging equipment must be provided through a time-of-use meter.

6. Customer has been provided a copy and is aware of all the provisions of Electric Rule 2, and more specifically sections E and F that refer to Customer's responsibilities regarding protective devices and interference with service. Customer further agrees that his or her ability to receive and maintain electric service for LEV fueling is subject to the special facilities provisions of PG&E's Electric Rule 2. If special facilities are needed to provide electric service for recharging or refueling a LEV, Customer will need to enter into a separate special facilities agreement with PG&E.

POWER QUALITY AND VOLTAGE STABILITY

7. PG&E designs and operates its distribution system to deliver sustained voltage as close as economically practical to service voltages required for customer's facilities and equipment. Under normal circumstances service voltage can vary within a range set by PG&E's Electric Rule 2 on file with the Commission. Under Electric Rule 2, PG&E's service voltage can also vary outside the specified range for brief periods. If the Customer's equipment or facilities require voltages of greater stability than those specified under Electric Rule 2, it is the Customer's responsibility to take whatever actions are necessary to provide power of such stable voltage, including the design, installation and operation of any necessary

protective equipment. PG&E cannot be held liable for any injuries or damages that may occur as the results of voltage variations that are allowable pursuant to Electric Rule 2.

BILLING

8. Customer agrees to provide PG&E access to read the electric meter in accordance with Electric Rule 16.A.11.

9. PG&E will bill the Customer at the applicable LEV rate and option selected in Customer's Declaration, Form No. 79-863, for the total electric service provided under the Agreement during the billing period.

TERM AND TERMINATION

10. Either party must designate by written notice any change of address to which notice should be sent. Notice shall be deemed effective five days after it is sent.

11. Customer will give PG&E 30 days' written notice if refueling or recharging of the LEV(s) will no longer occur at the service address.

EXCLUSIVE NATURE AND INTERPRETATIONS

12. This Agreement does not change the obligations, restrictions or rights contained in other agreements between the parties unless expressly indicated in this Agreement. Customer and PG&E agree that all understandings between them regarding this Agreement are set forth or referenced in this Agreement. No Agreements, representations, memoranda, or other forms of communication, written or oral, exchanged before the signing of this Agreement, shall be grounds for altering or interpreting the terms of this Agreement.

13. This Agreement shall be interpreted under the laws of the State of California, excluding any choice of law rules which may direct the application of the laws of another jurisdiction. This Agreement and the obligations of the two parties are subject to all valid laws, orders, rules, and regulations of the authorities having jurisdiction over this Agreement (or the successors of those authorities), including without limitation, PG&E Electric Rules 2, 3, 12, 14 and 16.

REGULATORY

14. This Agreement shall at all times be subject to such changes or modifications by the California Public Utilities Commission of the state of California as said Commission may, from time to time, direct in the exercise of its jurisdiction. Such changes or modifications may be to this Agreement or to PG&E's applicable tariff schedules.

Pacific Gas and Electric Company
E-6 Electric Service Agreement
DECLARATIONS

Distribution:
- ☐ Customer (Original)
- ☐ Customer Billing
- ☐ Division (Original)
- ☐ Corporate LEV Program

References:
Account #: ______________
Job #: ________________

GENERAL

1. This Agreement, between Pacific Gas and Electric Company (PG&E), a California corporation, and ____ (Customer), is for the supply of electricity for the fueling of a highway-legal low emission vehicle (LEV) at a residence. An LEV has a propulsion system that is fueled by either electricity or natural gas.

ELECTRIC SERVICE

2. Electric service will be provided at the following address:

Service address: ____________________________________

City, State, Zip: ____________________________________

Contact Phone: ____________________________________

3. Customer elects to take the E-6 time-of-use electric rate for (check one of the following):

[ ] Option A - All residential use at the service address
[ ] Option B - The LEV charging or fueling equipment only, with separate electric service metering.

4. Please provide the following information for the LEV(s) that will be charged at the service address for this Agreement:

Vehicle make (e.g., General Motors) _________________

Vehicle model (e.g., EV1)_________________________

Vehicle model year (e.g., 1997) ____________________

Charger or compressor specifications: ________ Amps @ _______ volts; ________maximum current

BILLING

5. PG&E will send the Customer's monthly billing to the following address:

____

____

____

TERM AND TERMINATION

6. This Agreement commences on __________. This Agreement shall then continue on a month-to-month basis after initial term until terminated by either party upon thirty (30) days prior written notice, or Tariff E-6 is withdrawn or terminated, or the Customer ceases to qualify for the E-6 rate, whichever is earlier.

COMMUNICATIONS

7. Any notice concerning this Agreement shall be in writing. Notices are to be sent First Class, United States Mail, postage prepaid, or by certified delivery to the appropriate address, as follows:

To the Customer: ______________________________

____

____

To PG&E: ______________________________

____

____

Attention: Division Manager

8. This Agreement for E-6 Electric Service is subject to the General Terms and Conditions (Form 79-864), which are incorporated by reference into the Agreement.

by (For Customer)	(For Pacific Gas and Electric Company)
______________________ (Signature)	______________________ (Signature)
______________________ (Name)	______________________ (Name)
______________________ (Date)	______________________ (Date)

Attachments:

General Terms and Conditions
Rate Schedule E-6
Electric Rules 2, 3, 12,14, 16

Customer please initial here to confirm that you have received all of the attachments:______________.

(END OF APPENDIX B)