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Decision 97-03-017 March 7, 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)	)	ORIGINAL Application 94-12-005 (Filed December 9, 1994)

(See Appendix A for List of Appearances.)

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OPINION ON MARGINAL COST

Modifications to Administrative Law Judge's Proposed Decision to Comply With Assembly Bill 1890

This decision sets forth the marginal cost principles developed for Pacific Gas and Electric Company (PG&E) in its Phase 2, 1996 General Rate Case (GRC). Essentially, we adopt the Administrative Law Judge's (ALJ) proposed decision modified to conform with Assembly Bill (AB) 1890, (Stats. 1996, Ch. 854), signed by Governor Wilson on September 23, 1996.[1]

Having reviewed the comments of the parties, we summarize below our modifications to the ALJ's proposed decision:

- In view of AB 1890, we adopt the marginal cost principles as set forth in the proposed decision for the limited purposes of payments to qualifying facilities (through capacity allocation factors), evaluation of demand-side management (DSM) cost effectiveness and price floors for discounted special contracts.

- We deny PG&E's request to use the discounted total investment method for calculating marginal transmission and

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[1] On June 14, 1996, pursuant to Public Utilities (PU) Code § 311, the ALJ's 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 In view of the then pending AB 1890, the proposed decision was withdrawn. Following the signing of AB 1890, PG&E served on all parties a "redlined" version of the proposed decision. On December 4, 1996, pursuant to an ALJ ruling, the parties submitted comments on their views of the impact of AB 1890 on the proposed decision. Comments were received from the Office of Ratepayer Advocates (ORA) previously known as Division of Ratepayer Advocates; The Utility Reform Network (TURN) previously known as Toward Utility Rate Normalization; the Agricultural Energy Consumers' Association (AECA); the California Farm Bureau Federation (CFBF); the City and County of San Francisco (CCSF); the California City and County Streetlight Association (CAL-SLA); and the Independent Energy Producers Association (IEP). On December 20, 1996, PG&E submitted its response to the comments of the parties.

distribution costs. As noted herein, if PG&E is to get reliable marginal cost estimates, it must improve the breadth, accuracy, and texture of its data. PG&E is directed to use the regression method rather than the present worth method or the discounted total investment method.

- Regression will be the appropriate estimation method for calculating area-specific costs as well, once the accuracy and completeness of the data collection has been improved. Consistent with the Legislature's desire for rates "that accurately reflect the loads, locations, ..." and other factors related to the provision of electricity, we will require PG&E to improve its area-specific data collection methods and to report to us on these methods.

- We reject the proposal of IEP to leave capacity allocation factors (CAFs) unchanged and will adjust them to reflect the specific modeling assumptions which underlie the marginal cost results we present here. In particular, we find that the utility's resource plan, a major component of the CAF calculations, is unchanged by its decision to sell some of its fossil-fueled generation assets.

- In view of AB 1890, we delete the chapters on revenue allocation and rate design principles contained in the ALJ's proposed decision. The assigned administrative law judge in PG&E's Rate Design Window Proceeding should review the record in this proceeding and issue a proposed decision covering tariff modifications addressed in Phase 2 which are not in conflict with AB 1890.

- The experimental agricultural anti-bypass rate schedules to encourage water well pumping customers to use electricity rather than natural gas or diesel fuel, which had an availability of one year, will continue to remain open until a review of the need for these schedules is completed in the Rate Design Window Phase of this proceeding.

- Although parties generally agree that new streetlighting rates should be implemented, we cannot implement the proposed new rates at this time since AB 1890 precludes us from doing so.

I. Background

In the first phase of this proceeding, the Commission issued D.95-12-055 approving a reduction in PG&E's revenue requirement. The resulting revenues were incorporated in PG&E's most recent ECAC decision, D.95-12-051, and passed on to ratepayers in the form of an interim rate reduction.

Hearings in the initial portion of Phase 2 began on January 8, 1996 and concluded January 22, 1996. Rebuttal hearings were held February 5 through February 9, 1996. The second phase was submitted with the receipt of reply briefs on March 15, 1996. A proposed decision was mailed June 14, 1996. Active parties filed opening comments on July 5, 1996 and reply comments on July 12, 1996. Subsequent to the litigation of this case, AB 1890 was approved by the State Assembly on August 30, 1996, the State Senate on August 31, 1996, and was signed into law on September 23, 1996. The final decision responds to the comments by making changes, where appropriate, and has also been revised to ensure compliance with AB 1890.

II. Marginal Cost

In view of AB 1890, we depart from the traditional Rate Case Plan expectations by not establishing new revenue allocations and rate design. We recognize that the rate freeze ordered by AB 1890 through the addition of Section 368(a) to the Public Utilities Code now precludes the January 1, 1997 or other rate changes we previously thought possible. However, the marginal costs and other principles we adopt here are consistent with AB 1890 and are necessary because they may affect demand-side management (DSM) cost-effectiveness evaluation, payments to qualifying facilities, marginal cost floors, and other factors.

A. Marginal Energy Cost

Marginal energy cost reflects the change in the utility's total operating costs resulting from the production of an additional kilowatt hour (kWh) of electricity. This cost varies by time of day and by season. Using a production cost computer model called PROMOD, PG&E simulates the dispatch of various resources in a manner that balances costs and reliability. PG&E applies a Zero Intercept method to this model to determine unit (generating plant) commitment changes in response to load changes. The electric resource plan and the cost of fuel for the marginal facility are among the most significant assumptions affecting marginal energy cost development. Resource plan assumptions are also critical to the development of generation capacity cost. The following table presents the marginal energy costs which result from different resource and fuel cost assumptions.

Marginal Energy Costs
Under Alternative Scenarios
Test year 1996
(Mills per kWh)

Assumption	Summer on-peak	Summer partial-peak	Summer off-peak	Winter partial-peak	Winter off-peak	Annual
Built-out plan Gas=$1.97/MMBtu	25.3	19.8	17.5	21.5	18.5	19.5
Built-out plan Gas=$2.03/MMBtu *(primary PG&E plan)*	23.9	18.8	16.7	22.9	19.7	19.7
Built-out with earlier standby of 170 MW units Gas=$2.30/MMBtu *(primary ORA plan)*	36.7	30.3	23.7	22.4	19.8	24.1
Bare bones plan Gas=$1.97/MMBtu *(adopted here)*	25.5	21.3	17.6	21.5	18.6	19.7
Bare bones plan Gas=$2.03/MMBtu	24.3	19.4	16.8	22.9	19.8	19.8
Bare bones plan Gas=$2.30/MMBtu	28.8	23.2	19.8	23.6	20.2	21.8

Derived from CACD data request to PG&E #CACD-ORAL-04

1. Resource Planning Philosophy

a. "Bare-Bones" vs. "Built-Out"

In its last general rate case (D.92-12-057), the Commission allowed PG&E to make several changes to the way it calculates marginal energy costs. One such change is that the Commission allowed PG&E to use a "built-out" resource plan for its PROMOD calculations instead of a "bare-bones" plan. A "built-out" resource plan results in a lower marginal energy cost estimate than does a "bare-bones" plan. This is because in calculating marginal energy cost, PG&E estimates Expected Unserved Energy, which is derived from the Loss of Load Probability. PG&E uses the EGRET model to perform this calculation. The higher the Expected Unserved Energy, the higher the marginal energy cost. However, as the company adds production units to this plan, overall reliability increases which in turn reduces the Loss of Load Probability and Expected Unserved Energy. This, in turn, decreases the marginal energy cost. Thus, as production capacity increases, marginal cost decreases.

Using a "bare-bones" plan, PG&E would start with its existing generating resources and add new resources to the plan if the company has already committed to build them, or contract for them. As PG&E uses the term, a "bare-bones" plan includes (1) generic supply-side resources, including purchased power, (2) estimates of incremental self-generation projects, and (3) unfunded DSM programs. Using a "built-out" approach, PG&E would start with the "bare-bones" plan and then assume various changes needed to provide "least-cost" service. PG&E would test all new generating resources that are available under current technology to determine which would be most cost-effective. PG&E would include in its assumptions only those resources that are cost-effective.

PG&E links its use of a "built-out" resource plan to its understanding that the Commission wants long-run planning assumptions to apply to the development of marginal energy costs. This is not the Commission's policy, as was reaffirmed most recently in the SCE general rate case decision (D.96-04-050). In that decision, the Commission concluded,

> "Reaching an optimal long-run equilibrium is the theoretical result of market pricing over time, but industries seldom stand still long enough for this equilibrium to be achieved.... Consumers and suppliers constantly interact on the basis of short-run price signals, and we believe that electric rate setting should follow suit." (Mimeo., p. 29.)

No other parties spoke in support of PG&E's request to continue the use of a "built-out" resource plan for marginal cost calculations. ORA expressed reservations about the use of a "built-out" plan for the calculation of marginal generation capacity costs. TURN argues that the built-out plan embodies too many assumptions that are demonstrably wrong or so likely to become wrong that it makes little sense to rely upon them now to determine generation costs today. In addition, TURN argues that marginal costs calculated with a "built-out" resource plan give today's customers an inaccurate pricing signal, by making it appear that resources which have not been developed are nonetheless available. The California Large Energy Consumers Association and California

Manufacturers Association (CLECA/CMA) also oppose the use of the "built-out" plan, arguing that it is unlikely that any additional utility resources will be added in light of the transition to a competitive market. PG&E argues, in response, that the use of a "bare-bones" approach would produce marginal costs that are unreasonably high, spurring overdevelopment, and remaining unrevised even when new resources have been added to the system.

If a "bare-bones" approach accurately reflects the short-run cost of providing additional service, we cannot agree that it produces marginal costs that are unreasonably high. We do expect the utility to provide least-cost, adequately reliable service. However, the utility's planning functions should be distinct from the price signals it is sending to its current customers. Just as one would expect a competitive enterprise to price its goods or services to reflect current costs, we expect PG&E to focus on what is, as opposed to what optimally should be. For this reason, we will require that PG&E use a "bare-bones" approach to calculating marginal costs. PG&E raises an excellent question, however, when it asks whether marginal costs should remain unchanged in the face of actual resource additions. It is unnecessary to freeze marginal costs in a way that ignores the cost effects of new resources. We will allow PG&E to adjust its marginal costs in each ECAC starting in 1997, to reflect the effect of new resource additions during the prior year.

b. Should Uncommitted DSM be Included in the "Bare-Bones" Calculation?

As mentioned above, in preparing its "bare-bones" resource analysis, PG&E would include theoretical benefits from demand-side management activities which have not yet occurred and have not yet produced any efficiency gains. TURN and CLECA/CMA argue against including uncommitted DSM because the changes prompted by electric restructuring increase the uncertainty that the forecasted efficiency gains will be achieved and because the resulting lower marginal energy costs might discourage customers from pursuing appropriate efficiency improvements. PG&E responds that a failure to include uncommitted DSM assumptions in the marginal cost calculation would send inappropriate economic signals, since customers then would continue to face the same higher marginal cost signal, even after some of the DSM activities had been successfully undertaken.

In an effort to treat DSM-derived resources in a manner consistent with the supply-side resources discussed above, we will direct PG&E to calculate its marginal costs without including the benefits of uncommitted DSM. Because PG&E will be able to adjust its marginal costs annually to reflect actual available resources, PG&E's marginal costs will continue to reflect the benefits of DSM activities once they are undertaken.

c. **The Stand-by Status of Various Generating Units**

For the purposes of calculating marginal costs as well as operation and maintenance costs, PG&E assumes that certain generating units would be placed on standby on the following schedule:

End of Year	Unit	Megawatts (MW)
2001	Morro Bay 1	163
2002	Morro Bay 2	163
2003	Pittsburg 2&4	326
2004	Pittsburg 1&3	326
2008	Hunters Point 4	163

PG&E says that the units are cost-effective to operate through the specified years. It states that it has scheduled the Morro Bay and Pittsburg units for standby status 12 months prior to the deadlines the company would otherwise face for reducing nitrogen oxides (NOx) emissions as required by the respective air districts with jurisdiction over each plant. For the Hunters Point plant, PG&E chose the date for standby status based on the unit's 50-year service life, NOx retrofit requirements, and operating criteria.

For the purpose of calculating marginal costs, ORA would place the Morro Bay and Pittsburg units on standby status in January 1997. ORA identifies four questions that it suggests the Commission should consider in deciding whether to exclude certain generating capacity from the adopted planning assumptions: (1) does surplus capacity exist, (2) with the exclusion of the resources in question, would the utility's reserve margin continue to exceed the target reserve margin, (3) does the utility intend to place the capacity in question on standby status in the near future and (4) would excluding the resources result in ratepayer savings? The implication is that if all four questions can be answered affirmatively, then the resources should be excluded. These are reasonable questions to apply to such a determination.

PG&E has a target reserve margin (the percentage by which available generating resources should exceed peak demand) of 15.5%. Under PG&E's proposed "built-out" plan, its reserve margin is expected to exceed this target in 1997 and 1998, with or without the generating units under consideration here. However, under the "bare-bones" approach that we adopt in this decision, a blunt conversion of all of these units in one year would have an apparent detrimental effect on the reserve margin, even in the earliest years. Thus, we cannot say that the adoption of ORA's proposed early standby status allows for each of ORA's criteria to be met.

PG&E may very well be able to reduce its overall costs by accelerating the standby conversion schedule so that the conversions would still occur gradually, although sooner. We will not create such a requirement, here, because it is largely a moot issue in the context of this proceeding. The adoption of a "bare-bones" plan has a significant impact on the calculation of marginal generation capacity cost and on the determination of the value of service index. Adding an assumption of accelerated standby conversion of the units at issue, here, has no additional impact on either figure and only minimal impact on operation and maintenance cost in the next two years. While we will not force the issue, here, PG&E, of course, remains responsible to pursue a least-cost strategy for meeting its generation and energy needs. If that strategy includes earlier standby conversion, then PG&E should pursue it.

d. <u>Spot Capacity in the ECAC</u>

As part of its "built-out" resource plan, PG&E proposed that its resource planning assumptions include the availability of 500 MW of generic Pacific Northwest spot capacity with energy (200 MW initially, increasing to 500 MW by the year 2000) and 1200 MW of Northwest and Southwest spot capacity with no energy (to ensure reliability during summer peaks). ORA argues that, for the purposes of logical consistency, PG&E should be required to include similar assumptions in its future ECAC filings. In other words, if PG&E uses these spot capacity resources to calculate its marginal costs, then it should also use them to determine its anticipated energy costs. PG&E disagrees, arguing that while assumptions concerning spot capacity are appropriate for long-run planning purposes, it is illogical, and potentially harmful to ratepayers, to lock the company into purchasing spot energy. PG&E points out that the major benefit it sees in spot capacity arrangements is the flexibility that they provide and argues that by requiring that these resources be included in ECAC resource assumptions, the Commission would be undermining that flexibility. ORA responds that since the availability of these resources does influence PG&E's operating decisions, PG&E should at least be required to discuss these resources in its ECAC filings.

The nature of this debate changes somewhat in light of the fact that we are directing PG&E to use a "bare-bones" resource plan for the purposes of developing marginal costs. While it is appropriate to include certain spot market resources in long-run analysis, the inclusion of these resources is not consistent with a short-run analysis. In D.96-04-050, we stated:

> "The 'short-run' refers to a situation in which the utility's plant or fixed cost obligations remain constant, but the operation of the system can be varied. In the 'long-run,' all aspects of the economic equation can be changed, including fixed assets (plant), fixed obligations under contracts, and all variable inputs." (Mimeo., p. 25.)

The Northwest spot purchases are more consistent with the definition of a long-run resource, although a relatively dependable one, since commitments to use them would only be made if needs and cost-effectiveness analysis so dictate at the time. Thus, they are not part of a "bare-bones" analysis.

Keeping in mind that these spot market resources will not be directly considered here, we can still address ORA's concern as it relates to future ECACs. We agree with PG&E that the ratepayers may not be best served by forcing the company to include energy from its spot capacity sources in its ECAC calculations. At the same time, we agree that it is appropriate for PG&E to account for these resources and to justify its decision to rely or not rely on them for energy as available. In any and all ECAC future applications, PG&E should provide documentation concerning its spot capacity-related energy resources and justify its proposed treatment.

2. <u>The Cost of Natural Gas</u>

As we will discuss below, the conventional assumption is that if the utility needs to build a generating facility to serve incremental demand, that facility would be a combustion turbine that is expected to use natural gas as its fuel. The incremental cost of that gas is a significant component of the marginal energy cost. All parties agree that the commodity cost of gas from the Permian Basin in the Southwest comprises the appropriate proxy for the incremental cost of gas in 1996 and for the next several years. For 1996, PG&E has used the Permian Basin price of $1.66/MMBtu. This was part of the commodity gas price adopted by the Commission in PG&E's 1996 ECAC (D.95-12-051, mimeo., p.14) and is, therefore, appropriate for adoption here, as well. For years after 1996, PG&E proposes to use a multi-year forecast. CLECA/CMA object to this, urging the use of a single year price estimate because gas prices are simply too volatile to permit an acceptable level of comfort with multi-year forecasts. We agree that it is more consistent with short-run marginal costs to look at the forecast for each year in turn. We will direct PG&E to use gas cost forecasts as adopted in each subsequent ECAC for marginal costs to apply to the following year for revenue allocation and rate design purposes. However, PG&E may continue to use a multi-year forecast for investment planning purposes.

There is considerable disagreement among the active parties, however, as to what additional costs should be included in the calculation. PG&E advocates including the cost of delivery to the California border, adjusted for compressor losses. There is little opposition to the use of this price as a starting point. A more contentious question is how the intrastate cost of transporting gas to the burner tip should be calculated. PG&E would use the long-run marginal cost of intrastate gas transportation. CLECA/CMA agree with PG&E. ORA and TURN would apply to the marginal energy cost calculation the full Utility Electric Generation (UEG) rate paid by the electric side of PG&E to the gas side.

The UEG rate has three components: a customer charge, a demand charge and a volumetric charge. Until recently, the volumetric charge had two tiers. The Tier 1 rate was 45.37¢/MMBTU and the Tier 2 rate was 8.81¢/MMBTU. In D.95-12-053, the Commission agreed to eliminate the second tier and reduce the first tier rate to 12.78¢/MMBTU. At the same time, the Demand Charge revenues were significantly increased (from $102 million to $140 million), and revenues from the customer charge were decreased from $752,030 to $141,666. ORA and TURN argue that, with the exception of customer costs, all cost components faced by PG&E through the UEG rate are affected by throughput levels. Thus, all UEG rate elements, other than customer charges, should be included in the marginal energy cost calculation.

It is clear that the volumetric charges are sensitive to the current throughput level. However, the relationship of the demand charge to current throughput is less clear. The demand charge is currently established in the Biennial Cost Allocation Proceeding (BCAP), with rates remaining in effect for two years. Fluctuations in throughput during that period have no direct and immediate impact on the demand charge. If the demand charge were calculated based on prior usage, then an increase in usage in one year would generate an additional cost which would simply be deferred to another year. A decade ago, the Commission struggled with the issue of whether to use an historic or forecasted throughput level to set the UEG demand charge and chose to rely on a forecast (D.87-12-039, 26 CPUC2d 213, 276).

Whether or not an additional increment of throughput this year will be included in a UEG demand charge forecast for next year depends on the factors that caused the increased usage. For instance, higher gas consumption prompted by drought conditions may not be reflected in a subsequent forecast. Similarly, increased demand for electricity which might be met in the short-run through the increased use of a fossil plant may be met in some other way as the utility adjusts its generating mix to meet current demand. This is why we must continue to focus on the short-run goal of having the marginal energy cost reflect the expected cost of providing a particular added increment of power, rather than try to anticipate what effect this increment will have on throughput levels as projected in the next BCAP. Thus, for the purpose of calculating the incremental cost of gas, we will not include the UEG demand charge.

PG&E would have the Commission disregard all aspects of the UEG rates for the purpose of setting marginal costs, because the UEG represents a "rate" as opposed to a cost. We agree with TURN and ORA that this argument inappropriately confuses the economic perspective of the PG&E gas planners with that of the PG&E electric planners. The rate vs. cost distinction is meaningful to a gas planner, since the marginal cost of providing additional gas is likely to differ from the rate charged to a gas customer. However, as a gas customer, it is the rate paid for gas service that reflects the cost of gas to the electric planner. PG&E would have the marginal energy cost for electric power include the long-run marginal cost of gas faced by the gas planners. This is not a logical approach, since the electric planners do not face this cost. As a gas customer, the electric planner does face a UEG volumetric charge that applies to each additional increment of gas that is purchased. Thus, it is the UEG volumetric charge, and not the long-run marginal cost of gas, which should be included in the marginal energy cost for electricity. We note that this conclusion represents a departure from the approach adopted by the Commission in the last PG&E general rate case. However, it is a conclusion that is more consistent with marginal cost principles.

This discussion reveals the influence of PG&E's gas rate design on PG&E's electric marginal energy cost. Because the Commission elected to place more of the UEG revenue requirement in the demand charge and less in the volumetric charge, the electric marginal energy cost is reduced, even though PG&E's overall cost of gas remains the same. This demonstrates that it is doubly important for the Commission to get the mix right when it designs UEG rates. When the Commission goes through that exercise again, we will expect the parties to clearly demonstrate that demand charges are limited to reflect those costs that do not change when there is an incremental change in throughput.

3. Emission Adders

Public Utilities (PU) Code § 701.1(c) requires that, "[i]n calculating the cost effectiveness of energy resources, including conservation and load management options, the commission shall include in addition to other ratepayer protection objectives, a value for any costs and benefits to the environment, including air quality...." Consistent with this requirement, PG&E had proposed using emission values calculated by the California Energy Commission in its 1994 Electricity Report as part of the development of its "built-out" resource plan. By influencing the resource choices, this may have had an indirect effect on marginal energy costs. Since we have rejected PG&E's proposal to use a "built-out" plan for marginal cost purposes, the issue of an emissions adder is not an immediate concern here. However, it is appropriate for PG&E to use emission values when performing future resource planning analysis.

4. Applying the Zero Intercept Methodology in Each ECAC

As mentioned earlier, PG&E uses the Zero Intercept Methodology to estimate its marginal energy costs. PG&E begins with base-case resource planning assumptions and then constructs two different cases for each Time of Use period by adding or subtracting a 400 MW load. For each Time of Use period, the difference in total production costs from these two cases is the net operating cost due to the total imposed load change. This net operating cost is then divided by the total change in load to produce the average marginal cost for the time period. Since 1990, PG&E has carried forward the results of its Zero Intercept Methodology calculations from its last general rate case for use in each ECAC. CLECA/CMA propose that PG&E be directed to produce new Zero Intercept Methodology calculations in each ECAC. This would allow for the calculation of new marginal energy costs based on current gas prices. PG&E opposes this proposal, saying that there is simply not enough time available in the ECAC schedule to perform such new calculations.

In support of its position, PG&E cites D.90-12-066, in which it says the Commission recognized this problem. This may be more than can be reasonably inferred from the language of that decision, in which the Commission merely reported that PG&E said there was not enough time in the ECAC schedule to support such new calculations. PG&E has not provided, for this record, evidence that demonstrates how much time the company reasonably needs to perform new runs using the Zero Intercept Methodology. We will require them to prepare such runs for upcoming ECAC's or equivalent marginal cost-related proceedings to the extent allowed by AB 1890, because doing so is consistent with our goal of deriving accurate, "bare-bones" short-run marginal costs on an annual basis.

B. Marginal Demand Cost

An electric utility's level of demand is the amount of power the utility must be prepared to provide at any given time. The amount the utility can provide is defined by the limits of its transmission, distribution and generation resources. Marginal demand cost reflects the expected change in the total system cost for generation, transmission and distribution resulting from a unit change in the demand.

1. Marginal Generation Capacity Cost

Marginal generation capacity cost represents the generation-related cost of serving an additional increment of demand. The Commission has traditionally used the cost of a combustion turbine generator as a proxy for the cost of new generation. The Commission derives an annual portion of the installed cost of a combustion turbine and adds operation and maintenance costs to develop a yearly marginal cost for generation capacity which is adjusted for inflation over a six-year period. It has become customary for the Commission to develop a six-year average marginal generation capacity cost which is based on these combustion turbine estimates as adjusted by a factor which discounts the cost to reflect the existence of excess generating capacity.

The differences in the marginal generation capacity costs proposed in this proceeding are primarily a result of the amount of resources assumed to be included in the resource plan. The other inputs that affect the costs, such as the cost of a combustion turbine, have only a very minor impact on the results.

a. <u>The Cost of a Combustion Turbine Generator</u>

PG&E estimates the cost of a combustion turbine to be $56.53/kW-year. Most other parties have relied on that number in performing their marginal cost calculations. TURN derives a slightly higher cost ($58.30/kW-year) because it makes different assumptions about the portion of general plant cost and materials and supplies costs that should be attributed to incremental demand.

The company calculates the annualized combustion turbine cost by starting with an estimated installation cost ($507.00/kW, as estimated in a 1994 publication) and adding sums reflecting several related costs such as overheads, operation and maintenance, working capital requirements and franchise fees. This sum is adjusted to reflect an annualized expense. Overheads are derived by calculating the generating unit's share of general plant costs. Working capital includes the cost of materials and supplies that are on hand.

TURN argues that PG&E has overallocated general plant to its distribution and customer costs and has overstated its materials and supplies loading factor. As a result, TURN argues, all of the "scalers" used to calculate marginal costs are incorrect. Correcting them would reduce distribution and customer costs, while increasing generation and transmission costs.

TURN's first objection is to PG&E's method of adjusting the combustion turbine cost to reflect general plant costs, which include such items as land and land rights, structures and improvements, office buildings, furniture and equipment, tools, area shop and garage equipment. According to TURN, the general plant loading factor is calculated as a percentage adder based on the sum of common and general plant divided by gross plant in service. PG&E allocates common plant by business unit, of which there are four: distribution, electric production, gas supply and corporate services. TURN objects to the fact that the corporate services common plant is allocated back to the other units based solely on the amount of common plant in each unit, ignoring other factors that may more closely reflect the way that corporate services relate to each of the three functions. TURN proposes that the common plant which is specifically identified by business unit be allocated to each unit, but that corporate services common plant be allocated as a percentage of gross plant across the company. TURN notes that in its Phase 1 filing, PG&E allocated $4.75 million of its general plant to the Helms facility. This represents 0.622% of the Helms gross plant in service. TURN recommends that this ratio be used to add general plant costs to the marginal generation capacity figure. The remainder, which is 1.01%, would be allocated to the distribution business unit.

PG&E objects to TURN's position, questioning whether TURN has made a sufficiently strong case for change and whether it is appropriate to apply a Helms-related ratio to a combustion turbine. In so arguing, PG&E ignores the fact that it is the company that carries the burden of proof as to the appropriateness of its methodology. Although it has explained, in general terms, how it made its calculations, PG&E has not offered a rationale for the adoption of its approach. TURN has offered a logical proposal. As for its use of a Helms-derived ratio, it provides a reasonable proxy for the ratio that might apply to a combustion turbine, in the absence of more specific evidence. For these reasons, we will adopt TURN's approach for making this adjustment.

The second factor cited by TURN is the calculation of materials and supplies. PG&E divides its total materials and supplies by its generation-related rate base to develop a ratio which it then applies to the estimated combustion turbine cost. The problem brought to light by TURN is that since the ratio is developed using depreciated plant (that which still remains in rate base) while the resulting ratio is applied to undepreciated plant (a new combustion turbine unit), it will tend to overstate the materials and supplies cost related to the new plant. TURN's interpretation is logical. The proposed solution is to develop the ratio by dividing materials and supplies cost by the utility's gross plant. This appears logical as well. PG&E, on the other hand, has not offered a rationale for its method of calculating this number. We will adopt TURN's proposal for performing this calculation.

b. Discounting the Cost of a Combustion Turbine

The availability of additional generation capacity is of less value to PG&E and its customers as the company acquires additional generating resources. The Commission uses the cost of a new combustion turbine generation as a proxy for the cost of additional capacity. In 1986, the Commission began reducing the combustion turbine cost by applying an Energy Reliability Index, designed to reflect the effects of excess generating capacity. At first, this was a linear function, based on the difference between the target reserve margin and the amount of surplus capacity. Three years later, the Commission agreed to modifications to the index that were designed to replicate an exponential relationship between changes in load or resources and the resulting changes in reliability. PG&E was also exploring ways to directly measure the economic value that its customers would place on incremental generating capacity. PG&E initially proposed a survey-based value-of-service methodology in a 1986 proceeding in which the Commission praised PG&E's efforts and encouraged the company to work further on the methodology, but decided that it was not sufficiently well developed to be adopted. In the last general rate case proceeding, the Commission did approve use of the value of service methodology, but only on a trial basis. Here, we must determine whether or not to continue with the experiment.

Using the previously approved value of service methodology, PG&E relies solely on customer survey data to determine the direct cost of an outage. The critical element is the amount each customer thinks it would be willing to pay to avoid an outage of a certain type and length. PG&E uses the value-of-service results to calculate a target reserve margin, which becomes a critical element in calculating the marginal generation capacity cost. Using the newer methodology, PG&E also includes the predicted cost of making certain short-term (spot) purchases, weighted by the probability that the spot resources will be called upon to meet day-by-day reliability requirements. In addition, instead of relying on the survey results to determine a direct cost of an outage, PG&E now creates an index which is used to adjust the combustion turbine value, much as the energy reliability index was used for this purpose in the past.

In its 1994 Energy Report, the California Energy Commission approved a 15.5% target reserve margin for PG&E, derived from use of the new methodology, implicitly endorsing its use.

The Agricultural Energy Consumers Association and the California Farm Bureau Federation (agricultural customers) join PG&E in endorsing the value-of-service methodology. In fact, the agricultural customers would expand the use of the survey results to support class-specific revenue allocations (discussed below). ORA uses the value-of-service results for calculating its marginal generating capacity costs, noting that this methodology "is rather similar" to the Energy Reliability

Index approach that is still used by other California electric utilities. Other active parties express dissatisfaction with the methodology.

The California Industrial Users (Industrial Users) point out that the Commission first approved use of the value-of-service methodology for a "trial run" (D.92-12-057), subject to change, and then argue, "[i]f the latter comment can reasonably be regarded as an invitation to PG&E to report back on the experience to date with the [value of service] approach, PG&E appears to have declined the invitation. PG&E's showing contains no additional information concerning either any beneficial or harmful effects of its trial implementation of this costing method." Industrial Users conclude that in the absence of such information, PG&E should return to the use of the Energy Reliability Index.

CLECA/CMA do not suggest returning to use of the Energy Reliability Index. However, Dr. Barkovich, testifying on behalf of CLECA/CMA, does criticize PG&E's value-of-service proposal. First, it is volatile because it is highly sensitive to forecasts of both resources and load, in some ways counteracting the stabilizing effects of using a six-year average marginal generating capacity cost. Barkovich testifies that, among other things, this volatility could have profound ramifications for class revenue allocations.

CLECA/CMA also argue that the survey results are not reliable. First, they rely on highly subjective data. PG&E asks certain members of each class to identify the value, to them, of avoiding the interruption of service under various scenarios. CLECA/CMA assert that this method is inherently unreliable and uninformed. Second, with surveys conducted many years apart, none of the surveys occurred after the serious interruptions of service experienced in 1995 and 1996 and none depicted outages of longer than four hours. Customers might have different opinions about the value of reliability after having faced a major service interruption, or be more concerned about a loss of power if it exceeds four hours.

The Industrial Consumers and CLECA/CMA raise valid concerns about the efficacy of this approach. Are most consumers sufficiently informed to give meaningful answers to survey questions? Are they sufficiently motivated to provide thoughtful and significant responses? We are also concerned about the potential staleness of some information. For instance, it has been ten years since PG&E has conducted surveys of residential customers. Have patterns of use and reliance on reliable power remained unchanged in the last ten years, despite the potentially greater use of such things as personal computers, answering machines, burglar alarms and microwave ovens? We are also concerned about the fact that as we follow the process backwards to determine how these calculations are prepared, we still run into a black box. Based on the record currently before us, we do not know how the raw survey answers are translated into numbers that are used for these calculations. On balance, we are not convinced that the current value of service methodology produces meaningful results.

Despite these concerns, we are not prepared to instruct PG&E to return to the use of the Energy Reliability Index. That is largely because the record also indicates that over the next few years, the two methodologies would produce virtually the same results. However, the concerns that we have expressed above leave us unwilling to bless the value-of-service methodology as a reliable and effective tool for setting marginal costs. We are certainly not prepared to extend its use for other purposes, as will be discussed below. Some argue that we need not be concerned about this methodology for long, since in a world of greater competition, consumers can reflect the value of service through the purchase decisions they make. If we are asked to assess the use of this method again, we will need to be given better reasons to rely on the information it produces.

c. The Importance of Good Data Selection and Analysis

The probabilistic and exponential nature of the value-of-service index formula makes it especially sensitive to small fluctuations in resource or load projections. (This is true of the Energy Reliability Index as well.) The following table demonstrates that sensitivity.

Effect of Changing Resource Plan on MGCC

Using VOS Index Methodology

Assume that supplies are increased by 200MW (about 1%):

Supplies	Demands	Res Marg	VOS Indx	MGCC	Change in MGCC
20136	16817	0.20	0.38	$23.59	
20336	16817	0.21	0.29	$17.92	-24%
20536	16817	0.22	0.22	$13.62	-24%
20736	16817	0.23	0.16	$10.35	-24%
20936	16817	0.24	0.13	$ 7.86	-24%
21136	16817	0.26	0.10	$ 5.97	-24%
21336	16817	0.27	0.07	$ 4.54	-24%

Assume that demands are decreased by 200MW (about .2%):

Supplies	Demands	Res Marg	VOS Indx	MGCC	Change in MGCC
20136	16817	0.20	0.38	$23.59	
20136	16617	0.21	0.27	$16.91	-28%
20136	16417	0.23	0.19	$12.02	-29%
20136	16217	0.24	0.14	$ 8.48	-29%
20136	16017	0.26	0.09	$ 5.92	-30%
20136	15817	0.27	0.07	$ .10	-31%

A simple calculation shows that a one percent increase in the resource plan or decrease in the load projection will each cause a 24% decrease in the value-of-service index, and thus the marginal generation capacity cost. This emphasizes the importance of accurate projections and the concomitant need for good and robust data.

Load data is derived through forecasting from historical experience, a technique which employs statistical regression. While regression is one of the most accurate planning tools currently available, its precision is limited by the variance in and dependability of the observed data. There are many possible sources for imprecision, ranging from the failure to include some important variables in the regression, to sampling bias, to simple measurement error.

When a number is estimated through regression the researcher can only say that the "real" number lay within a certain range and only then with a particular level of confidence. For instance, in this record PG&E has presented several regression results. In its workpapers for Exhibit (PG&E-14), Distribution Expansion Planning Process and Projected Costs, the company provides load experience and projections for its Distribution Planning Areas (DPAs). Its first summertime projection, on pages 3 and 4, is for the Santa Cruz and Watsonville area. Total peak load data for 1987 through 1993 are given in the first table. The planner has dropped the first year from the regression, apparently to improve the fit of the data, and the balance of the years yields the regression result that load growth is about 2.05 MW/year. This trend is then extrapolated over the next ten years. The standard deviation of the load growth estimate, although not presented in the testimony, is easily calculated as 0.498. Given the assumptions inherent in statistical regression of this sort, such as normal distribution and unbiased sampling, this standard deviation means that we can be 95% certain that the actual load growth in this area lay between 1.074 and 3.026. Thus the projection for this one DPA might be off by as much as 1 MW per year, or by 10 MW by the end of the planning horizon. While an error of this magnitude is highly unlikely, this example emphasizes the importance of collecting accurate and robust data for forecasting purposes, especially given the number of DPAs in PG&E's service area.

We mentioned briefly in our example above that the planner dropped one year of load experience before determining the trend for forecasting. Cursory examination of the other DPA projections presented in these workpapers reveals that this is a common practice. The discarded data is labeled "DISC."

While the planners may feel justified in their individual decisions, and while we appreciate the increasingly protean environment in which they operate, we are far from sanguine about such ad hoc practices which may act to bias, albeit unintentionally, the results. Discarding data which do not fit neatly on the graph may reduce the calculated standard deviation, but this increase in accuracy is illusory as it replaces actual experience with the particular bias, however benign, of the planner. If PG&E is to get reliable marginal cost estimates from its Distribution Planning Area and Transmission Planning Area disaggregation experiment, it must improve the breadth and texture of its data. We direct the company to study this problem and to report its findings to this Commission in time for the next appropriate proceeding. Specifically, we want the company to identify:

- areas where data can be made more reliable and predictive. For instance, can an increase in the number of years of experience improve the data? Can it help to do the analysis with quarterly or monthly figures rather than yearly?

- ways in which the regression analysis be made more complete and reliable. For instance, would it be beneficial to include more explanatory variables?

- reasonable guidelines for manual adjustments to the data sets. For instance, while the exclusion of outliers is a legitimate analytical technique when judiciously applied, the technique should be applied reasonably and evenly across all DPAs and TPAs. This is true for all other adjustments made on the basis of specific engineering knowledge of events in the area.

d. <u>Resource Assumptions</u>

In considering marginal energy costs, we have already addressed most of the resource-driven assumptions that affect the calculation of marginal generation capacity cost. We have agreed with TURN and CLECA/CMA that PG&E should use "bare-bones" resource plan assumptions and exclude the prospective results of uncommitted customer energy efficiency programs. We have agreed that PG&E should continue to rely on the target capacity factor that it proposed before (and was approved by) the Energy Commission for use in the 1994 Energy Report. However, we are left to resolve whether or not the "bare-bones" plan should include the resources approved in the Biennial Resource Planning Update (BRPU) proceeding. In performing its "built-out" resource plan analysis, PG&E assumed that the San Francisco Energy Project, approved in the BRPU proceeding, would be on line in the middle of 1997. This facility is not an issue for 1996 marginal costs. The question is whether or not it should be included in 1997 and beyond. PG&E would include it, while TURN would not.

The "bare-bones" analysis should include resources that are reasonably certain to be available during the period in question. As of today, we do not have that level of certainty that the San Francisco Energy Project will be operating in 1997. PG&E says that there is no way of assessing the probability that the project will ever come on line. PG&E has not entered into a contract for receiving the power. At least as of January 1996, when we held hearings in this matter, construction had yet to begin. Thus, we cannot conclude that the plant is reasonably likely to be available in 1997. PG&E can offer additional evidence in its 1997 ECAC if the delivery date for power from the San Francisco project becomes more certain. When the date of availability of the facility becomes reasonably certain, we will allow PG&E to reflect that availability in its marginal costs.

e. <u>Capacity Allocation Factors</u>

The Capacity Allocation Factor is the ratio created by dividing the hourly marginal generating capacity cost for a particular time-of-use period by the hourly marginal generation capacity cost for the entire year. It forms the basis for determining capacity payments to Qualifying Facilities (QFs) that provide energy and capacity to PG&E under Standard Offer Contracts. This factor is also used to facilitate rate design, as well as to test the cost effectiveness of DSM programs and to allocate bulk transmission capacity by Time of Use rating period. Currently, PG&E's Capacity Allocation Factors are 90.7% for summer and 9.3% for winter. This places a much higher value on capacity from QFs made available during summer periods. Under PG&E's proposal in this proceeding, the factors would become 72.5% for the summer and 27.5% for winter (see table below). This would increase three-fold the value placed on winter capacity. The Independent Energy Producers Association (IEP) vigorously opposes this change.

The Capacity Allocation Factor is clearly derivative. PG&E is not so much proposing factors to be adopted by the Commission as reporting numbers that emerge when it uses its proposed modeling assumptions to perform certain calculations. IEP asserts that PG&E has failed to meet its burden of proof for changing the Capacity Allocation Factors because it has not adequately supported some of its modeling assumptions and because it has failed to demonstrate why it is reasonable to adopt such a dramatic change. IEP also suggests that some QFs might change their performance in response to new price signals and criticizes PG&E for not taking this into account when setting its planning assumptions. IEP also asks that any change in the Capacity Allocation Factors be deferred to January 1, 1997 in order to ensure that all QFs are fairly compensated, regardless of differences in seasonal generating patterns.

In addressing these concerns, we must first remember that we are adopting modeling assumptions that differ, in certain key ways, from those proposed by PG&E. Thus, the resulting allocation factors will be different from those calculated by PG&E. The following table reflects the range of possible outcomes and includes, in the fourth row, the numbers derived from the assumptions adopted in this decision.

Capacity Allocation Factors
1996 Test Year

Resource Assumptions	Summer	Winter		Summer Peak	Summer Partial Peak	Summer Off Peak	Winter Partial Peak	Winter Off Peak
PG&E proposal	72.50%	27.50%		69.85%	2.61%	0.01%	27.47%	0.03%
IEP proposal from Ex. 344, pp. 12-15	93.29%	6.71%		90.27%	3.00%	0.02%	6.71%	0%
IEP proposal without commodity price change (p. 14)	89.92%	10.08%		86.45%	3.45%	0.02%	10.08%	0%
Barebones resource plan *(this decision)*	78.59%	21.41%		76.19%	2.38%	0.02%	21.25%	0.15%
Early mothball of 170 units *(ORA proposal)*	63.01%	36.99%		59.04%	3.90%	0.07%	36.56%	0.42%
Barebones AND early mothball of 170 units	68.42%	31.58%		64.31%	4.00%	0.11%	31.10%	0.48%

Derived from CACD data request to PG&E #CACD-ORAL-03

Note: Bare bones assumes no uncommitted energy efficiency, no spot capacity, no generic Northwest purchases, and no BRPU resources.

The adopted CAFs, 78.59% for the six summer months and 21.41% for the six winter months, are higher during summer peak than those proposed by PG&E, but significantly lower than the current level. In addition, these adopted factors must be adjusted to take into account that this decision is implemented after the beginning of 1997. Rather than order these new CAFs to be applied retroactively, we will have them effective beginning on April 1, 1997. The following tables show the appropriate CAFs for this implementation schedule:

Winter 1997 CAFs

January/ February March 1997	Other Winter Months 1997	Other Winter Partial Peak	Other Winter Off Peak
4.65%[1]	10.71%[2]	10.63%[3]	.08%[3]

Summer 1997 CAFs

Summer 1997	Summer Peak	Summer Partial Peak	Summer Off Peak
84.64%[4]	82.06%[5]	2.56%[5]	0.02%[5]

Logically, if QFs are at all sensitive to price changes, the new capacity allocation factors will alter the pattern of QF generation in summer versus winter. PG&E is remiss for failing to reflect these changes in its modeling assumptions. IEP has offered two suggested means for reflecting potential QF behavioral changes in the modeling assumptions. One would involve eliminating the average summer-winter seasonal difference from the assumed capacity in each summer month. The other would set each summer month's total QF deliveries at the highest QF deliveries for any winter

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[1] The current winter CAF is 9.3%, or 1.55% per month for six months, or 4.65% for three months.

[2] The adopted winter CAF is 21.41%. Prorating this to the remaining three months: 3/6*21.41% = 10.71%.

[3] These prorate the 10.71% based on the adopted schedule.

[4] 100.00% - 4.65% - 10.71% = 84.64%.

[5] These prorate the 84.64% summer CAF based on the adopted schedule.

month. Each of these methods suggests that the changes in capacity allocation factors will cause a dramatic change in QF behavior. Without more evidence, we cannot agree or disagree with that assumption. Thus, we adopt neither proposal. However, we will direct PG&E to propose a basis for adjusting seasonal QF generation in the next appropriate proceeding.

f. Class-Specific Marginal Generation Capacity Costs

TURN points out that the value-of-service survey results stand for the proposition that different classes have different needs that affect the utility's target reserve margin. Accordingly, TURN has suggested that the Commission consider developing class-specific marginal generation capacity costs. The record in this proceeding is not sufficient to resolve this issue, so TURN asks the Commission to direct PG&E to explore the possibility of refining its marginal cost methodology to allow for such class-specific costs. Since this request would have no effect on current rates, the critical question is whether this concept is sufficiently promising to justify directing PG&E to look into it.

PG&E argues that it would be fundamentally inappropriate to explore this concept because the centralized nature of generation planning can lead to only one marginal generation capacity cost for the entire system -- for instance, PG&E cannot plan separate resources for residential versus commercial customers. While this comment reflects the current nature of electric utility planning, it does not immutably reflect its future nature. New technologies such as fuel cells may make decentralized generation a much more attractive notion. However, the centralized nature of current planning, coupled with both the evolving competitive market for electric generation and the concerns we have expressed about the current value-of-service approach, suggest that this is not the time to require PG&E to undertake such an inquiry.

2. Marginal Transmission and Distribution Capacity Costs

We are faced with four issues related to the development of marginal costs in this area:

1. What marginal cost methodology should be used?

2. Should marginal costs be determined by area, or as a system average?

3. What should become of the class density study

that PG&E was directed to undertake by the Commission in D.92-12-057?

4. How should PG&E develop transmission and distribution expansion plans for use in developing marginal costs?

The answer to the first question is pivotal. The other three questions remain relevant only if we choose to adopt an area-specific methodology as proposed by PG&E and the agricultural customers.

PG&E and ORA propose two different methods to calculate marginal transmission and distribution costs. PG&E's present worth method first requires Transmission Planning Area and Distribution Planning Area load projections by its area planners, using simple ordinary least squares regressions of 7 years of recorded data. This is projected over a 10-year planning horizon for each area. The planners then adjust these projections for planned additions or reductions of any significance, including load transfers to other areas. When this process is completed, they note areas in which capacity is overtaken by load growth sometime in the planning horizon, and estimate the type, size, timing, and cost of the investments necessary to meet this deficiency.

The present worth method calculates the net present discounted value of these planned investments over the planning horizon using a discount rate of 9.79%, the weighted cost of capital for PG&E. Another net present value is then calculated, but this time assuming that all investments will be deferred by one year. The difference in these two calculations is then divided by the projected average load growth over the planning horizon. When annualized, this quotient yields the marginal transmission or distribution cost. These marginal costs are then multiplied by the loads in each area to allocate revenues by area and class. PG&E and the agricultural customers support the use of this method. All other active parties oppose the present worth method and support the use of what is called the regression method.

ORA's regression method uses the same load and investment data and forecasts PG&E uses for its present worth methodology. Using a smoothing technique developed by NERA, the ORA method regresses these two data series over ten years of historical data and five years of projected data. The result, once annualized, gives the marginal costs for transmission and distribution. These costs are then multiplied by projected loads in order to allocate revenues. The results of the regression method can be found in PG&E's marginal cost workpapers, Chapter 4, Marginal Transmission and Distribution Capacity Costs, pages 1-33 and 1-34, and pages 2-101 through 2-104. Note that these regressions yield systemwide transmission and distribution cost estimates. ORA advocates that, if the Commission adopts PG&E's proposal to disaggregate marginal cost determination to the transmission and distribution planning area levels, the regression method should be used to estimate area-specific marginal transmission and distribution costs. Otherwise, these systemwide estimates should be used.

Using the regression method, there are four basic steps to calculating marginal transmission and distribution costs :

1. Load growth is predicted using ten years of historical and five years of forecasted data.

2. Marginal investment is determined by applying regression analysis to load growth-related investment.[3]

3. The marginal investment is scaled for general plant overhead and then annualized using a constant dollar capital recovery factor called a Real Economic Carrying Charge, which incorporates the depreciation expense, return on rate base, taxes and insurance associated with adding a dollar of plant to the system.

4. These results are adjusted for additional costs related to transmission and distribution.

Prior to the marginal cost decision in PG&E's last general rate case, PG&E used the regression method for calculating transmission and distribution marginal costs. The regression method is still used by SCE (A.93-12-025) and San Diego Gas & Electric Company (SDG&E) (D.93-06-088).

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[3] Risking the collective rolling of eyes by those who have studied such things, we will simplistically explain "regression analysis" as a statistical method of estimating a trend on the basis of a series of data points.

It was also adopted by the Commission to develop gas distribution marginal cost (D.92-12-058). In that decision, the Commission rejected the use of the present worth method, explaining:

> "[The present worth] method's feature of signaling future costs in current rates is outweighed by its two primary disadvantages: it produces volatile rate spikes and it fails to recover full investment costs.... [T]he type of rate volatility demonstrated by the [Present Worth] method would encourage long-term anti-bypass contracts when the rates are low that would prove to be uneconomic in later years." (D.92-12-058, 47 CPUC2d 438, 460.)

In another decision issued the same day, the Commission approved PG&E's use of the present worth method on the electric side, saying:

> "We will adopt PG&E's present worth method for estimating marginal transmission and distribution costs. By doing so in this decision, we are not determining that this is necessarily the appropriate approach to use in our long-run marginal cost gas proceeding, because the records developed in these two cases are different. We agree with PG&E that the [present worth] method captures the lumpiness of capacity additions to the [transmission and distribution] system. Secondly, the [present worth] method does not assume [that] the change in demand which drives capacity additions lasts forever. A third reason for adopting the [present worth] method is that it makes use of data that is forward-looking.
>
> "We find that the record in support of the methodological change developed in this proceeding is full and complete and justifies our adoption of the present worth method." (D.92-12-057, 47 CPUC2d 143, 288.)

The present worth method does tend to reflect the fact that the company would expect to spend significantly more on transmission and distribution additions in some years than in others. However, a fundamental question is whether the short-run price signals received by customers should mimic a forecast with volatility of this type. We most recently considered this issue in D.96-04-050, in which we approved SCE's continued use of the Regression Method and highlighted, as one of its positive features, that it "accounts for lumpiness from year to year" by considering the relationship of new plant investment to transmission load growth "over a time frame considerably longer than the test year" (ibid., mimeo., p. 56). We continue to agree with those who argue that a price signal driven by volatile transmission and distribution forecasts will send an inappropriate short-run price signal to consumers. It would be counterproductive to encourage customers to respond to a relative high marginal cost today (by entering into a special contract, or making some other investment decision) when we know that these costs will go up and down from year to year.

PG&E criticizes the regression method as not being "forward-looking" because it involves using several years of historical data to help identify trends. This is true as far as it goes, but the regression method also involves using several years of forecast data. It would be misleading to think that the use of either method is divorced from consideration of the historical context. The greatest benefit of the regression method is that it reduces volatility while ensuring that future trends will not be ignored. For these reasons, and because the movement toward competition furthers our resolve to send consistent short-run-oriented marginal cost price signals, we will direct PG&E to use the regression method to determine its marginal transmission and distribution costs.

While both methods use area-specific load forecasts, the regression method as implemented by ORA aggregates the data to the system level. Consistent with the short-run perspective we want utilities to apply to the marginal cost calculation, it is better to apply trended costs to transmission and distribution calculations than to place an emphasis on specific future projects. This is yet another reason that the regression method as proposed by ORA is more consistent with our marginal cost goals. Since PG&E will use the regression method as proposed by ORA, the remaining questions in this portion of the case become moot, in that they all relate to the appropriate means for producing area-specific spending plans that would have been needed if we had adopted PG&E's approach.

C. Marginal Customer Cost

This portion of the marginal cost calculation represents the change in total system cost required to connect a new customer while maintaining existing customers. It includes the cost of customer premises equipment (meters, transformers and service drops), customer service and accounting.

1. One-Time Hookup Method v. Rental Method

There are two competing methodologies -- one has become rather traditional (the Rental method), while the other has been adopted by the Commission in several recent proceedings (the One-Time Hookup Charge, or New Customer Only method). We approved PG&E's use of the New Customer Only method for electric customer costs in D.92-12-057 and for natural gas costs in D.95-12-053. We also recently ordered SCE to use the New Customer Only method (D.96-04-050). We will approve PG&E's proposal to continue using this method for its electric customer cost calculation. TURN supports PG&E's proposal, with modifications to be addressed below. ORA, CLECA/CMA and CIU support a return to use of the Rental method.

The Rental method does not distinguish between new and existing customers but rather assumes customers will pay to rent their equipment each year at an annualized charge. The rental charge is calculated in the following manner: the combined cost of a meter, service drop and transformer is multiplied by 9.2%, which represents an annual Real Economic Carrying Charge. This fraction rises over time with the rate of inflation and there is a small factor added to account for eventual replacement of equipment at the end of its useful life. This result is then increased by an estimate of class-specific installation, billing and customer accounting costs. The annualized marginal cost is then multiplied by the estimated total number of customers for the Test Year to develop marginal cost revenues by customer class.

PG&E and TURN object to the Rental method because it does not reflect the pricing that would take place in a competitive market. They argue that since utilities incur investment-related customer costs based on hooking up new customers and replacing hookups for existing customers, these are the changes in total costs that should be measured. They also argue that the Rental method overstates the price that would prevail in a competitive market by assuming that customers would continue to pay high rental costs year after year, rather than simply purchase the hookup equipment when the building is acquired or the equipment is installed. The Commission discussed these arguments in detail in D.96-04-050 and concluded,

> "Clearly, customers could get a much better deal by paying for the hookup up front, or purchasing it, particularly given the deductibility of mortgage and business interest. This is the way in which consumers purchase many durable goods which are affixed to their premises and have no other uses apart from the premises (curtains, ceiling insulation, etc.). [Citation omitted.] Moreover, electric service providers would quickly lose their business to competitors if they tried to charge a rental fee that greatly exceeded the full cost of new hookups. In our opinion, ignoring the cheaper alternative that would set prices in a truly competitive market results in inflated marginal costs. The fact that new customers do not currently pay the full cost of their hookups does not justify using this inflated calculation." (Ibid., mimeo., p. 68.)

This conclusion applies equally to the record before us here.

As proposed by PG&E, the One-Time Hookup, or New Customer Only method calculation uses two components: (1) the full lump-sum capital cost of new hookups, and (2) the ongoing costs of operating and maintaining access equipment, including replacements. This is the first proceeding in which PG&E has proposed the inclusion of replacement costs in its calculation. The first component of the calculation is attributed to new customers only, meaning that PG&E includes only new hookup costs for the projected number of new customers. The new customer costs in a given class, divided by the total load in the class, comprises the marginal cost for that class related to new hookups. The second component is attributed to all customers. TURN proposes certain modifications to PG&E's formula. These will be discussed below.

2. <u>Frequency of Equipment Replacement</u>

PG&E does not know how often its various types of customer equipment need to be replaced. This adds to the challenge of accurately forecasting the portion of marginal cost related to equipment replacement. As a proxy for historical data, PG&E recommends using the reciprocal of the equipment's depreciation rate to predict the likelihood of replacement in any given year. For example, if a piece of equipment is on a 25-year depreciation schedule, PG&E would assume that 4% of the equipment would be replaced in any given year. However, there is no proven connection between the equipment's depreciation life and the frequency of replacement.

TURN argues that PG&E's approach is conceptually flawed, because it is based on the stock of current equipment. Mr. Marcus testifies that much of the equipment that is being replaced today was installed in the 1940s, 1950s and 1960s, when PG&E's customer base was considerably smaller. He asserts that by relying on today's customer level, PG&E overstates the rate and volume of replacement. TURN recommends that PG&E use a replacement frequency of 1.5%, reflecting the likely rate of customer additions during those earlier years. This approach is not much of an improvement over PG&E's, since TURN offers little more than conjecture as to when equipment being replaced today may have been installed and cannot offer historical data to support its estimate of a 1.5% growth rate. The question is which, if either, of these proxies should be adopted.

PG&E has not met its burden of proving that its proposal is reasonable, due to its unexplained failure to offer real-life information about its replacement practices. One logical response would be to not include replacement costs in the marginal cost calculation at all. Yet, we agree with PG&E that replacement costs are an appropriate element of marginal costs. In order to move at least somewhat in the direction of reflecting the actual replacement costs in the calculation, we will adopt TURN's proposed 1.5% replacement rate, since it is the lowest positive number available in the record.

TURN also suggests that the Commission direct PG&E to develop data based on actual experience, for presentation in subsequent proceedings. This is the obvious and appropriate action, based on the observations we have just made. We will expect PG&E to develop this information to be used to adjust marginal customer cost in the next filing of an ECAC, or its equivalent.

3. <u>Customer Variable Cost</u>

TURN proposes several adjustments to PG&E's calculation of variable cost. TURN identified potential double-counting of at least $2,418,000 in operation and maintenance costs related to transformer, secondary conductor, services and meters. These are costs for installing and removing distribution transformers and revenue meter operation expenses, and were most likely included in operation and maintenance calculations. PG&E acknowledges that at least some double-counting exists, and did not respond in any other way to TURN's assertion. We will direct PG&E to remove this amount from its Customer Variable Cost calculation.

In addition, TURN proposes four adjustments to PG&E's customer accounting costs. First, TURN asks that we use the customer accounting costs adopted in the first phase of this case ($101,158,000), rather than those first proposed by PG&E ($105,439,000). Since this figure represents the applicable Test Year budget, this is a logical change to make and we will do so. Second, TURN proposes subtracting $684,000 in California Alternate Rate for Energy (CARE) administration costs from the marginal cost calculation, since these costs should be recovered through the CARE surcharge. This proposal is consistent with the Commission's actions in PG&E's recent BCAP (D.95-12-053) and SCE's recent marginal cost decision (D.96-04-050). We will adopt it here as well. Third, TURN recommends that $2,158,000 in revenue for returned check charges, and field connection and reconnection charges be removed from the calculation. TURN argues that these are costs that are collected directly from those who cause them and that they are, therefore, not marginal costs to the greater body of ratepayers. This is correct, as we have held in numerous past decisions.

Finally, TURN proposes shifting certain customer representative expenses directly to Schedule E-19 and E-20 customers, in a manner consistent with our decision in Phase 1. In that phase, PG&E proposed transferring, into customer accounting costs, expenses for Major Account Representatives which were previously part of its marketing and DSM programs. The Commission approved $1,595,000 for these purposes. TURN proposes allocating the costs to Schedule E-19 and E-20 customers, with E-20 being assigned a per-customer weighting of 5.7 times E-19 based on the overall weighting for customer contacts and orders. In its brief, PG&E objects to this proposal, but offers no evidence to support its position. TURN's proposal stands alone in the evidence and is reasonable because it appears more likely to accurately assign costs. Therefore, we will adopt it.

III. Revenue Allocation and Rate Design

Since AB 1890 mandates a rate freeze at least through the end of 2001, the implementation of many of the revenue allocation and rate design matters addressed in the ALJ's proposed decision are rendered moot. Therefore, no useful purpose would be served by issuing these sections of the ALJ's proposed decision at this time. However, we direct the assigned ALJ in PG&E's current Rate Design Window proceeding to review the record and issue a proposed decision covering tariff modifications addressed in Phase 2 which are not in conflict with AB 1890 and do not affect the rates or rate levels in effect on June 10, 1996.

We note that if the new marginal costs adopted in this decision for the limited purposes discussed above were used for revenue allocation purposes, PG&E's agricultural customers would experience a 54 percent increase in their EPMC targets. These EPMC targets are well in excess of those for other agricultural customers in this state. We direct PG&E to investigate the causes for this dramatic increase and to explore in its next General Rate Case alternative methods of computing marginal costs and revenue allocation that result in agricultural EPMC targets more in line with those of agricultural customers served by other California utilities.

Findings of Fact

1. A "bare-bones" resource planning approach accurately reflects the short-run cost of providing additional service.

2. It is unnecessary to freeze marginal costs in a way that ignores the cost effects of new resources. We will allow PG&E to adjust its marginal costs in upcoming ECACs or other equivalent marginal cost-related proceedings, to the extent allowed by AB 1890 to reflect the effect of new resource additions during the prior year.

3. It is consistent with a bare-bones plan for PG&E to calculate its marginal costs without including the benefits of uncommitted DSM.

4. Under the "bare-bones" approach that we adopt in this decision, a blunt conversion of several generating units in one year would have an apparent detrimental effect on the reserve margin, even in the earliest years.

5. While it is appropriate to include certain spot market resources in long-run analysis, the inclusion of these resources is not consistent with a short-run analysis.

6. The Northwest spot purchases are more consistent with the definition of a long-run resource, although a relatively dependable one, since commitments to use them would only be made if needs and cost-effectiveness analysis so dictate at the time.

7. It is more consistent with short-run marginal costs to look at the forecast of gas prices for each year in turn, as opposed to blending the costs based on five years' data.

8. As a gas customer, the PG&E electric planner does face a UEG volumetric charge that applies to each additional increment of gas that is purchased.

9. Since we have rejected PG&E's proposal to use a "built-out" plan for marginal cost purposes, the issue of an emissions adder is not an immediate concern here.

10. Preparing Zero Intercept Methodology runs for upcoming ECAC's or other equivalent marginal cost-related proceedings to the extent allowed by AB 1890 is consistent with our goal of deriving accurate, "bare-bones" short-run marginal costs on an annual basis.

11. PG&E has not offered a rationale for the adoption of its approach for calculating the general plant loading factor, while TURN has offered a logical proposal.

12. Since the ratio used by PG&E to calculate its materials and supplies factor is developed using depreciated plant (that which still remains in rate base) while the resulting ratio is applied to undepreciated plant (a new combustion turbine unit), it will tend to overstate the materials and supplies cost related to the new plant.

13. We are not convinced that the current value of service methodology produces meaningful results.

14. Over the next few years, the value of service and energy reliability index methods would produce virtually the same results.

15. We cannot be reasonably certain that the San Francisco Energy Project will be operating in 1997.

16. Deferring the application of new Capacity Allocation Factors until April 1, 1997, will help to ensure equitable payments to all QFs and will provide all such suppliers with more time to plan any resulting changes in their operations.

17. A price signal driven by volatile transmission and distribution marginal costs will send an inappropriate short-run price signal to consumers.

18. A benefit of the Regression method is that it reduces volatility while ensuring that future trends will not be ignored.

19. The New Customer Only method more accurately reflects the decision a customer would make in a competitive market than does the Rental method.

20. PG&E does not know how often its various types of customer equipment need to be replaced.

21. Customer equipment replacement costs are an appropriate element of marginal costs. TURN's proposed 1.5% replacement rate is the best available proxy.

22. PG&E's calculation of variable customer cost includes double-counting of at least $2,418,000 in operation and maintenance costs related to transformer, secondary conductor, services, and meters.

23. Variable customer costs should be adjusted as proposed by TURN.

<u>Conclusions of Law</u>

1. PG&E should use a bare-bones resource plan to develop marginal costs.

2. We should allow PG&E to adjust its marginal costs in each ECAC starting in 1997 to reflect the effect of new resource additions during the prior year.

3. We should direct PG&E to use gas cost forecasts as adopted in each subsequent ECAC for marginal costs to apply to the following year.

4. It is the UEG volumetric charge, and not the long-run marginal cost of gas, which should be included in the marginal energy cost for electricity.

5. PG&E's resource plan assumptions should exclude the prospective results of uncommitted customer energy efficiency programs.

6. We have agreed that PG&E should continue to rely on the target capacity factor that it proposed before (and was approved by) the Energy Commission for use in the 1994 Energy Report.

7. We should direct PG&E to use the Regression method to determine its marginal transmission and distribution costs.

8. PG&E should develop its marginal costs in the manner set forth in this decision.

9. In view of AB 1890 and the Cost Recovery Plan (CRP) decision (D.96-12-077), the Commission is correct to adopt the new unit marginal costs and annualized combustion turbine value set forth in this decision only for the limited purposes of: (1) payments to qualifying facilities (through capacity allocation factors and the capacity value), (2) evaluation of demand-side management (DSM) cost-effectiveness, and (3) price floors for discounted special contracts. Under AB 1890, these new marginal costs cannot be used for revenue allocation purposes. Instead, for purposes of revenue allocation and consistent with AB 1890, which freezes rates at June 10, 1996 levels, PG&E should continue to use the marginal costs that underlie the June 10, 1996 rates, as adopted in D.95-12-051. This approach is also consistent with the Commission's CRP decision.

10. It should be noted that if the new marginal costs adopted for the limited purposes here were used for revenue allocation purposes, PG&E's agricultural customers would experience a 54 percent increase in their EPMC targets. These EPMC targets are well in excess of those for other agricultural customers in this state. PG&E should investigate the causes for this dramatic increase and to explore in its next General Rate Case alternative methods of computing marginal costs and revenue allocation that result in agricultural EPMC targets more in line with those of agricultural customers served by other California utilities.

<u>**ORDER**</u>

IT IS ORDERED that:

1. The marginal costs for electric service by Pacific Gas and Electric Company (PG&E) as set forth in Appendix B to this order are adopted only for the limited purposes of: (1) payments to qualifying facilities (through capacity allocation factors and the capacity value), (2) evaluation of demand-side management cost-effectiveness, and (3) price floors for discounted special contracts.

2. The assigned administrative law judge in PG&E's Rate Design Window Proceeding shall review the record in this proceeding and issue a proposed decision covering tariff modifications addressed in Phase 2 which are not in conflict with AB 1890 and do not affect the rates or rate levels in effect on June 10, 1996.

3. The operation and maintenance costs for PG&E's 170 MW generating units are no longer subject to refund.

4. Prior to April 1, 1997, PG&E shall not apply the capacity allocation factors derived from its new marginal costs to payments to cogenerators and other qualifying facilities.

5. Phase 2 of this proceeding is closed.

This order is effective today.

Dated March 7, 1997, at San Francisco, California.

P. GREGORY CONLON
President
JESSIE J. KNIGHT, JR.
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(END OF APPENDIX A)

APPENDIX B

PG&E GRC - 1996
Adopted Marginal Costs

Energy (annual average)	$.01992
Generation Capacity	$64.77
Bulk Transmission (average)	$3.42
Area Transmission (average)	$8.79
Primary Distribution	$106.01
Secondary Distribution	$2.06
Customer Costs:	
Residential	$49.17
Agricultural A	$222.83
Agricultural B	$284.91
Small Light and Power	$158.63
Medium Light and Power (Primary)	$560.08
Medium Light and Power (Secondary)	$634.52
E-19 Primary	$772.58
E-19 Secondary	$1626.38
E-19 Transmission	$10,582.69
E-20 Primary	$6407.71
E-20 Secondary	$8544.93
E20 Transmission	$8186.23
Streetlights	$160.14

(END OF APPENDIX B)