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Decision 90-12-128 December 27, 1990 (Revised)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of PACIFIC GAS AND ELECTRIC COMPANY for Authority to Adjust its Electric Rates Effective November 1, 1989; And for Commission Order Finding that PG&E's Gas and Electric Operations During the Reasonableness Review Period from February 1, 1988 to December 31, 1988 Were Prudent. (U 39 M)	Application 89-04-001 (Filed April 3, 1989)

(See D.89-12-015 for appearances.)

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OPINION ON SPECIAL CONTRACTS PHASE

Summary

In this decision, we consider, for the first time, the reasonableness of special electric rate contracts entered into by Pacific Gas and Electric Company (PG&E) to avoid bypass of certain large customers. All of these customers were capable of installing generation equipment to serve their own needs. The contracts were developed by PG&E and conditionally approved by the Commission with the intention of retaining customers with rates that are attractive enough to dissuade those customers from self-generating, while assuring that the customers continue to pay at least the marginal cost of the service they were provided. The condition placed on the initial approval of these contracts by the Commission is that the contracts would later be subject to reasonableness review. In this decision, we review the first nine such contracts signed by PG&E and find a number of them unreasonable for failure to assure payment to cover the marginal cost of providing service.

Finally, a number of the contracts provide rate discounts for all customer load, including that in excess of the amount which was in danger of bypassing. We do not find these contract provisions per se unreasonable, but we are concerned that the provisions result in loss of revenue. Accordingly, we order PG&E to renegotiate those contracts which provide rate discounts for loads in excess of the amount in danger of bypassing.

I. Background

As early as November 17, 1986, PG&E began entering into agreements with large electric customers, offering them lower electric rates in exchange for a promise not to generate their own electricity. PG&E offered these special contracts to customers that it thought were particularly likely to begin self-generating in the near future. Each of these special contracts was submitted to the Commission for prior approval. In each instance, PG&E sought an unusually rapid response from the Commission, within a time frame that did not allow for careful scrutiny of the contract terms. The first two series of contracts were submitted to the Commission as advice letter filings, which were approved subject to numerous conditions. The condition of most relevance to this proceeding is that each contract would be subject to reasonableness review at a later time. In response to each Commission resolution approving a special contract, PG&E expressly agreed to all of the added conditions, including the requirement of a future reasonableness review.

The Commission also told PG&E that all future requests for special contract approval should be submitted as applications. We created the Expedited Application Docket (EAD) to allow for rapid response to requests for approval of special contracts.

In Decision (D.) 87-05-071, the Commission discussed the appropriateness of allowing for the limited use of such special contracts. At 24 CPUC 412, 413-414, the Commission said:

> "Many of the current challenges facing these utilities result from a confluence of independent events. First, we are beginning to recover in rates the high capital costs of large nuclear generating units. Because conventional ratemaking practice allows the utility to recover a return on the undepreciated portion of the original cost of an asset, and because we follow straight-line depreciation for ratemaking purposes, the effect on rates from return on investment for a plant is highest in the early years of the plant's useful life. At the same time, fossil fuel prices have remained at a relatively low level following an unanticipated decline in late 1985 and early 1986. Also, federal and state encouragement of independent generation over the last decade has taken hold in recent years, and electricity generation is no longer the exclusive domain of the utilities.

"This combination of rates reflecting the high capital costs of the nuclear plants and low fossil fuel prices has resulted in rates well above the utilities' long-run marginal costs. For many customers, rates are also above what the customer calculates as the cost of self-generation. Because of lower fossil fuel prices and revitalized generation technology, self-generation has become attractive to many customers. The loss of customers from the system when capacity exceeds demand plus a reasonable reserve margin usually affects other customers, since the fixed costs of the utility system must be borne by a smaller sales base, further driving up rates."

At the same time, in Finding of Fact 10, the Commission added:

"When customers with self-generation costs exceeding long-run marginal cost leave the system, an inefficient allocation of resources occurs."

The Commission concluded that appropriately applied special contracts can help assure a more efficient allocation of resources. At page 417, the Commission added:

"The use of special contracts also presents several problems. We would like to be assured, for example, that the utility has negotiated a contract that recovers the maximum revenue from the customer, since additional revenues reduce the effect of special contracts on other customers. We want a utility to negotiate special contracts that at least recover the utility's cost of serving the customer. Conversely, the utilities should not make efforts to retain economic bypassers on the system. Special contracts also raise the issue of unreasonable discrimination among customers by the utility, a practice that is forbidden by law (Public Utilities Code Section 453) and is against our policy..."

The Commission then committed itself to develop guidelines which, if met, would assure the approval of a special contract in response to an EAD application. The Commission issued the guidelines on March 8, 1988, in D.88-03-008.

Before the Commission issued the guidelines, PG&E requested approval of four special contracts through conventional applications and two special contracts through EAD applications. In each instance, the contract was allowed to be implemented with the understanding that its reasonableness would be reviewed in a future proceeding. The Commission directed PG&E to keep account of revenue lost due to the contracts pending reasonableness determination. In D.89-05-067 (signed May 26, 1989), we ordered that the reasonableness of special contracts be addressed in the reasonableness phase of each electric utility's annual Energy Cost Adjustment Clause (ECAC) proceeding.

PG&E filed its application in this ECAC proceeding almost two months before we issued D.89-05-067. On October 2, 1989, in response to that decision, the Division of Ratepayer Advocates (DRA) issued a report on the reasonableness of the first ten special contracts signed by PG&E. A supplemental report on those contracts was issued on November 20, 1989. Hearings were held November 30, December 1, and December 11, 1989. This matter was submitted with the filing of reply briefs on March 2, 1990.

PG&E and DRA filed comments on the proposed decision. This decision incorporates various changes in response to those comments.

II. The Scope of the Reasonableness Inquiry

As mentioned earlier, each resolution and decision allowing for the implementation of a special contract stated, unequivocally, that PG&E remained at risk for a subsequent finding that any or all of the agreements were unreasonable. PG&E now argues that if every aspect of the agreements was subject to reasonableness review, it would render meaningless the decisions approving the agreements. PG&E further states that virtually every argument raised by DRA in this hearing was also raised by DRA in protests to the contracts. The implication is that if DRA was unable to convince the Commission that its concerns were sufficient to block initial approval of the agreements, then it should not prevail on (or perhaps even raise) the same arguments now. PG&E acknowledges that at least some reasonableness issues were preserved, but seems to suggest that there is a line dividing issues that can be revisited from those that cannot. Nonetheless, PG&E does not suggest where that line should be drawn.

DRA responds to these arguments by citing language from each of the relevant resolutions and decisions warning PG&E that the reasonableness of the agreements was subject to later review (Resolution E3017, p. 9; Resolution E3021, p. 9; D.87-07-089, Finding 8, p. 12 and Conclusion 3; D.87-09-082 Conclusion 3, p. 5; D.88-02-016, p. 8 and Conclusion 2, p. 9; D.88-08-056, p. 4; and D.88-08-058, p. 5).

The Commission gave expedited permission for PG&E to implement each of the subject contracts in order to facilitate the utility's efforts to preserve its large electric customers. This enabled PG&E to provide electric service at rates that otherwise may have been found to be unfairly discriminatory. However, because these innovative arrangements deserved closer scrutiny, we told PG&E that by offering these rates it would be proceeding at its own risk. PG&E acknowledged and accepted that risk. For instance, in D.88-08-056, which permitted PG&E to proceed with a special contract for the Union Oil Company (Unocal), the Commission stated (at p. 5):

> "PG&E believes that while the uncertainty associated with the above approach creates risks for PG&E, failure to retain UNOCAL as its customer would result in major rate increases for its other ratepayers. PG&E also believes that it will have to take such a risk in order to receive timely approval of the Agreement."

We directed PG&E to record the differences between its standard tariffs and the payments received under the special contracts so that amounts found to be unreasonable could later be recovered. All in all, PG&E had clear notice that the reasonableness of the contracts would be subject to full review.

III. Reasonableness Criteria

In D.88-03-008 (signed March 9, 1988), we issued guidelines to be applied to review special contracts in EAD proceedings. The purpose of the guidelines was to provide the utilities with one set of factors which, if present in an agreement, would assure expedited Commission approval. Because of the timing of their issuance, only the Unocal and Shell agreements were initially measured against these guidelines.

In order to assess the reasonableness of the agreements before us today, it is necessary first to determine the standards that should apply. DRA has proposed a set of reasonableness criteria which are similar to the 1988 guidelines. PG&E argues that it would not be fair to use 1988 standards to assess the utility's conduct in formulating special contracts in 1986 and 1987. DRA responds that the important question is not when the guidelines were issued but whether or not a reasonable utility representative should have applied similar criteria when the agreements were formed.

Just as it would be unfair to hold PG&E to a retroactive standard simply because it was adopted by the Commission, it would be illogical to reject a standard simply because it was subsequently adopted by the Commission. Instead, before considering the specific contracts at issue, we will examine DRA's criteria one at a time and consider the appropriateness of applying them as contemporary standards for the development of special contracts in 1986, 1987, and 1988.

A. **Feasibility of Self-Generation**

DRA argues that, in order for a special contract to be acceptable, a customer must be a legitimate candidate for bypass. PG&E does not object to this criterion. We agree that a strong bypass potential is an absolute prerequisite to receiving a special contract. However, since all nine contracts were found to meet this test, it does not form the basis of a recommendation for disallowance.

B. **Contract Term**

DRA argues that because accurate long-term forecasting of capacity needs is difficult, long-term contracts are risky for the utility and its ratepayers. DRA questions the reasonableness of contracts that exceed five years. PG&E appears to argue that this standard is inappropriate, at least for the earliest agreements (which happen to have been 15-year contracts) because they were the first contracts of their type to have been negotiated and because, according to PG&E, utility and staff forecasters at the time were predicting excess capacity for at least ten years. DRA argues that there was no unanimity of opinion, at the time, as to the extent of any existing excess capacity.

By discussing the forecasts at the time, PG&E appears to be missing the point. DRA is arguing that long-term forecasting is inherently risky business. It may not be sensible to rely on long-term predictions even if everyone is predicting the same thing. On the other hand, there is nothing magical about a 5-year limit. While this factor alone would not be sufficient to find an agreement unreasonable, we agree that a reasonable decision-maker at the time who was willing to agree to a longer contract term should have received other concessions to offset this risk.

C. **Applicable Load**

DRA argues that, since the purpose of the special rate offering is to avoid bypass, the special rate should only apply to the portion of the customer's load that is at risk of bypass. This portion of the load is equal to the effective net plant output (ENPO) expected to be produced by the customer's own generating facility. DRA argues that discounting more of the customer's load may result in giving more of a discount than necessary to keep the customer on line. This is because the lower rate may stimulate more usage, which in turn may reduce or remove the desirability of the contract over the bypass option from the utility point of view. DRA argues that the lack of a load limit might subvert the contract's floor provision, which is discussed further below. It is DRA's position that contracts that fail to limit the load to which the discounted rates apply should be found unreasonable unless other beneficial contract terms outweigh the resulting risk.

PG&E responds that if the discount rate applies to all of the customer's requirements, other ratepayers may stand to benefit. When the total discount required to avoid bypass is spread over a greater amount of load, the discount per kilowatt-hour (kWh) is lower. If load subsequently grows, the effective discount will be greater than it would be if the special rate only applied to the ENPO. But if load diminishes, the effective discount may be lower than it would be if the special rate was limited to the ENPO.

Consider a customer who normally uses 100 kWh per month at a cost of 10 cents/kWh. The total bill would normally be $10/month. Further, assume that the customer could generate 50 kWh per month on its own at a net savings of $2. The customer should be willing to forgo building its own facility if it is able to purchase 50 kWh per month at a rate of 6 cents/kWh. Its monthly bill would be 10 cents X 50 plus 6 cents X 50, totaling $8. If the discount was spread across all of the customer's usage, its rate would be 8 cents/kWh for all of its usage.

If usage remains constant, the effective discount would be the same either way. However, as consumption increases, the second approach creates more and more of a discount for the customer. That is DRA's concern. PG&E argues that if consumption is reduced, instead, the effective discount is reduced. In the example discussed above, the net savings to the customer is only $2 if 100 kWh or more are consumed.

PG&E then points to two of the contracts that applied the discount to more than the ENPO and asserts that while the usage went up for one facility, it went down for another more than enough to make up the lost revenue. PG&E argues that it is, therefore, reasonable to apply the discount to more than the ENPO.

PG&E's argument fails for two reasons. First, PG&E is employing a hindsight argument: everything worked out fine, so the contracts are reasonable. It is inappropriate to apply a hindsight test to determine if the utility acted reasonably at an earlier time. In addition, the hindsight here is incomplete. While the greater-than-ENPO provisions may have cancelled each other out up until now, they may not offset each other for the remainder of the lives of the contracts. In addition, for a contract to be found reasonable, it must stand on its own. If contract A is unreasonable, it cannot be found otherwise simply because contract B worked out particularly well.

A discount that applies to all customer usage creates greater risk of revenue loss. We do not find these contract provisions to be per se unreasonable, but our concern that the provisions may result in greater revenue loss suggests that these provisions should be modified. Accordingly we will order PG&E to renegotiate those contracts which are not limited to ENPO.

D. <u>Floor Revenues</u>

In adopting guidelines in D.88-03-008 for review of special contracts in EAD applications, the Commission concluded that, in order to receive expedited approval, a contract should include a floor price designed to assure that the utility recovers from the customers no less than the lowest price possible that does not disadvantage other ratepayers in either the short or long run. The Commission required that the Standard Offer 1 (SO1) energy formula be used to determine the minimum required energy costs. The Commission determined that the floor price should include a component reflecting the rental value of transmission and distribution (T&D) facilities--the marginal T&D cost established in each utility's general rate case would serve as the T&D component of the floor. Finally, the Commission required that the floor payment reflect capacity costs, calculated by using the ERI-adjusted SO1 generation capacity costs.

The ERI (Energy Reliability Index) was developed in connection with purchases from independent power producers. The ERI varies to reflect the value of additional capacity to the system. When the ERI is 1.0, the value of additional capacity is equivalent to the value of an additional combustion turbine. As additional capacity becomes necessary to meet reserve margin requirements, the index rises and generation by independent power producers should be stimulated by higher capacity prices. The index approaches 0.0 to reflect increasingly lower needs for additional generation for purposes of system reliability.

The use of this index was found to be appropriate for the floor price, because utilities plan for additional generating plants based on the demand patterns that are established today. If the price of power sold under special contracts is artificially low, greater than appropriate demand will result, and the need for additional generation will be accelerated.

DRA argues that these floor payment requirements should be applied to determine the reasonableness of the contracts before us in this proceeding. Of all the reasonableness criteria applied by DRA, this is the one that has engendered the most disagreement between DRA and PG&E. PG&E seems to concede that assurance of minimal revenue is appropriate, but argues that it should not be found unreasonable for having failed to assure recovery of T&D and generation capacity costs. In addition, PG&E and DRA disagree as to how marginal energy costs should be calculated.

<u>Energy Costs</u>

DRA recommends using the S01 energy price to set the energy cost portion of the floor revenues because the S01 price includes all components of the avoided cost of energy. PG&E argues that the S01 energy cost overstates the forecasted and actual marginal energy costs. The S01 energy price is calculated by applying to the cost of fuel a factor referred to as the Incremental Energy Rate (IER). The IER is calculated by comparing the cost of producing the electricity needed to meet system demand under two sets of assumptions. In one scenario, it is assumed that all variably priced QFs are producing at full net output (QFs-in). In the other, it is assumed that none of the QFs are producing net output (QFs-out). The difference in system fuel efficiency under the two scenarios represents the value of variably priced QF production to the system. PG&E argues that the energy cost derived in this manner is inapplicable to special contract pricing because its calculation assumes the need for over 1000 megawatts (MW) of additional energy (the level of variably priced QF production) although the special contracts at issue here represent only 207 MW.

Instead, PG&E argues that the energy component of a special contract should be found reasonable so long as it reflects the "actual" energy cost faced by the utility. DRA appropriately points out that what PG&E refers to as "actual" marginal energy cost includes only the commodity portion of the gas tariff. To more accurately use natural gas costs to represent the energy cost of electric service, the calculation must include gas transportation costs, incremental gas demand charges, marginal operation and maintenance costs, increment to cash working capital, and an adjustment to reflect losses.

The need to include a broad range of energy costs drives DRA to use the S01 energy rate, as we did in establishing standards for expedited review of special contracts. As we noted in approving those standards, S01 energy prices cover all of the

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short-run costs of the fuel required to produce electricity sold to the customer under the contract. Appropriate as the S01 energy rate may be for an expedited review of a special contract, it is a different matter to base a disallowance on a comparison with the S01 energy rate for contracts signed before the guidelines went into effect. While PG&E should have been expected to only sign special contracts that cover the full range of the customer's marginal energy costs, the S01 rate was not the only reasonable guidance available. However, PG&E should have clearly understood its responsibility for assuring that each customer contribute no less than the adopted marginal energy cost in effect at a given time. The adopted marginal cost was developed to guide the ratesetting process and formed the commonly accepted basis for measuring the cost of serving additional customers. In addition, while PG&E's "actual" marginal cost does not reflect a broad range of energy costs, the adopted marginal cost does. We will apply adopted marginal energy costs to determine the adequacy of the floor revenue provisions and to calculate the energy component of any resulting disallowance.

2. <u>Capacity Costs</u>

a. <u>Generation</u>

DRA proposes that the avoided cost of generation capacity be viewed as a cost of service under special contracts. Without ever directly contesting the use of that assumption, PG&E asserts that there simply cannot be any capacity costs that would be applicable to these special contracts. DRA would have us require that the generation capacity cost component of QF payments be factored into the floor price for these contracts. PG&E, which in the past has strongly disagreed with our method of calculating QF capacity payments, says that this approach should be rejected because it has no relationship with reality.

PG&E argues that, when these contracts were negotiated, PG&E, the Commission, DRA, the California Energy

Commission (CEC), and the Legislature all predicted that no new capacity would be needed during the time frame of these contracts. In support for what it feels to be the appropriate standard of review, PG&E states that, since the contracts were signed, it has made no discretionary additions to its available capacity and that, when new resources are finally needed, the special contracts will be cancelled and the customers will bypass the system.

DRA asserts that, while these contracts were being negotiated, there was no unanimity among forecasters and that even PG&E claimed in at least one proceeding that it would face a capacity shortage during the relevant period. DRA rejects the notion that individual customers should be excused from paying capacity costs simply because their contributions to the system demand cannot be directly linked with the need to add new capacity. In addition, DRA argues that costs related to new capacity are always greater than zero; additional available capacity always has some value because it improves the reliability of the existing supply; there are always planning activities in progress within the utility that relate to future additions to generating capacity.

PG&E and DRA agree that all customers, whether or not they are buying electricity pursuant to special contracts, must pay the full cost of the service they are receiving. What PG&E fails to acknowledge is that it is only the extent to which average cost exceeds marginal cost that there is room to bargain with customers who are capable of self-generating. If customers are able to self-generate at a cost below the utility's marginal cost, then they should do so. Society as a whole benefits from such an arrangement. Of course, part of the cost of self-generation is the cost of creating the capacity to generate. If a customer cannot self-generate for less than marginal cost, then it certainly should be willing to pay marginal cost, at a minimum, for the privilege of receiving utility service at a special rate.

PG&E seems to be arguing that if customers who are kept on-line through the offering of special rates do not have a short-term effect on the need for new generating capacity, then they contribute no capacity-related cost to the system. Can customers contribute to the demand for power without adding to the cost of maintaining sufficient on-line capacity? Viewed in isolation, just about any customer can be added to or retained on the system without creating the need for an entire new power plant. However, we have long recognized that every firm customer contributes to the need for generating capacity. Rates that do not reflect this fact are unreasonably discriminatory.

It is fundamental that the marginal cost of capacity be reflected in each unit of demand, from the first to the last. It is not logical for a customer to have one cost-of-service when it is paying tariffed rates and suddenly have another and lower cost-of-service when it threatens to bypass. If a customer is induced to stay on the system by the offering of a special contract, it continues to contribute to the long-term growth in the demand for generating capacity. PG&E attempts to refute this aspect of reality by suggesting that a special contract customer is ephemeral, that once its special contract ends, each such customer will leave the system. This assumption defies logic and is inconsistent with the record now before us.

Once a customer builds the facilities enabling it to bypass the utility system to meet at least a part of its load requirements, the resulting bypass is likely to continue for many years. However, a bypass opportunity foregone may not occur again.

Frank Gibson testified on behalf of the hospitals collectively known as Sequoia Hospital District and the Mills-Peninsula Hospitals (the first entities to sign special contracts with PG&E). He stated that the cost-effectiveness of the cogeneration projects that the hospitals had intended to build was dependent both on the receipt of a CEC grant that would have paid for 50% of the construction costs and on the issuance of tax-exempt bonds by the California Health Facilities Authority. Gibson testified that in considering the special contracts, the hospitals assumed "that we were going to lose the grant -- the remaining dollars in the grant. It was unknown whether or not those grants could in fact be reinstated, and I don't know today whether they could." (Transcript p. 817.) Although the California Health Facilities Authority was still providing low interest loans at the time of Gibson's testimony, it is not logical to assume that such funds will always be available or that they will always carry sufficiently attractive terms. Gibson also testified that it would be more difficult to return to the communities that had previously issued permits for these facilities and have those permits reissued. Because they recognized the difficulty of reviving the cogeneration projects at a later date, the hospitals insisted that PG&E pay over a million dollars in liquidated damages if the contracts are ever cancelled.

Based on the experiences of these hospital customers, there is substantial reason to expect that special contract customers may remain on-line after their contracts expire. In fact, while the signing of special contracts virtually guaranteed that the customers would not bypass in the short term, there is no certainty that any or all of those customers would have successfully completed their bypass projects even in the first instance. There is certainly no reason to conclude that any or all of these customers will leave the system after the contracts expire.

If anything, special contracts increase the likelihood that potential bypass customers will remain on-line and contribute to long-term demand. PG&E's rebuttal witness, David Rubin, appears to agree. See, for instance, the hearing transcript at page 770, where Rubin, discussing the risks faced by customers entering into special contracts, testified:

"They also run the risk of engaging in a contract for a set period of time, say five years, and then with changing environmental regulations, not being able to build the project once the contract runs out.

"So a project that would have a 20-year life may not be able to be built after a five-year deferral period."

Even if we were not concerned with the need to spread the burden of capacity costs equitably among all customers, in the absence of other concessions, it is unreasonable to relieve customers of their share of demand charges.

DRA proposes using adopted avoided capacity costs in determining the adequacy of a contract's floor revenues. This is the logical and appropriate choice, since the contemporaneously adopted marginal capacity cost represents the Commission's determination of the relevant cost per customer and the basis for ratesetting. At a minimum, each customer on the system must pay the full marginal cost for the service it receives, whether or not it is being served under a special contract.

b. Transmission and Distribution

Just as each customer should pay its share of generation capacity costs, it should pay its share of T&D costs. PG&E argues that T&D costs were not applicable to the contracts at issue here because no additional T&D investments were made to serve the customers under the contracts. PG&E also asserts that marginal T&D capacity would not have been freed up for use elsewhere if the customers had cogenerated, so these costs would not have been "saved" if the cogeneration projects had been built. As was true in the case of generation capacity costs, by resting on these arguments, PG&E ignores the fact that each customer's presence on the system contributes to the utility's T&D costs. Its share of those costs does not go away simply because the customer signs a special contract. In addition, as DRA points out, PG&E has not supported its assertion that no additional T&D capacity and maintenance was or will be needed along any of the lines serving any of the contract customers. We agree with DRA that it is difficult to attribute the cost of T&D capacity additions to individual customers.

In the proceeding that led to the issuance of special contract guidelines in D.88-03-008, PG&E also argued that T&D capacity costs should not be included as part of the floor revenues. PG&E makes much of the Commission's comment in D.88-03-008 that PG&E's position on the T&D issue in that proceeding had some logical virtues. PG&E seems to be arguing that if its justification for ignoring T&D costs is logical that it must be reasonable. It is safe to say that the latter argument is lacking in logical virtue. Whether or not PG&E can construct a logical rationale for doing so, it is unreasonable to relieve a customer of its share of T&D costs in the absence of counterbalancing concessions. Similarly, the floor revenues should include customer costs.

E. Rate Structure

The guidelines adopted in 1988 require that special contracts seeking expedited treatment include time-of-use (TOU) rates and peak demand charges. DRA argues that all reasonable special contracts should contain these features, because they encourage high load factors and reduce the cost of providing service. DRA asserts that flat rates, which would otherwise be used, encourage peak load growth and increase the cost of service and the system's capacity constraint. The first four contracts signed by PG&E did not use TOU rates. For all subsequent contracts, the Commission refused to provide even preliminary approval for contracts that lacked TOU provisions. (See, for instance, D.87-09-082, in which we gave preliminary approval to the ARCO agreement.) PG&E acknowledges that "TOU rates may have been desirable in retrospect," but that the absence of TOU rates alone should not result in a finding of unreasonableness.

As we said in D.88-03-008, we agree with DRA and PG&E that it is appropriate to utilize time-differentiated rates when setting rates for large customers. Regular tariffed rates are time-differentiated, and it makes sense to provide consistent price signals to customers under special contracts. However, we also said in that decision that an overemphasis on time-differentiated rates might skew the decision of the customer toward self-generation and that contracts with undifferentiated floors or other terms may be shown to be fair to other ratepayers by a utility in a given case. While the absence of TOU rates is not conclusive proof that a contract is unreasonable, it is the utility's responsibility to justify its failure to require them. The absence of time-differentiated rates may contribute to a finding of unreasonableness when other contract deficiencies exist.

F. Rate Level

DRA argues that in order to maximize the customer's contribution to the utility's fixed costs, the contract rate should equal or exceed the customer's estimated cost of self-generation. The logic of this requirement is that a customer will generally prefer to purchase from the utility if the cost of self-generation is no lower than the cost of utility service. Although it points out that DRA may have applied a less strict standard in the past, PG&E offers no objection to this criterion. We agree that it would be unreasonable for the utility to offer service at a rate lower than the cost of self-generation in the absence of overriding circumstances.

G. Contribution to Margin

Contribution to margin (CTM) refers to the amount by which the revenues received from a customer exceed the cost of service. DRA argues that special contracts should provide a present value CTM that is greater than the CTM that would have been received if the customer had cogenerated. DRA argues that if this level of CTM is not achieved, then the contract is not in the best interest of ratepayers. PG&E offers no arguments in opposition to this criterion.

We agree that a contract that does not provide a preferable CTM is not in the best interest of ratepayers. There is always some risk that a customer signing a special contract would not have brought its cogeneration facility on line. If the CTM is not substantially better under the special contract than it would be if the customer became a cogenerator, then the utility might as well let the customer pursue its bypass strategy. Then, there is at least some chance that the cogeneration project will not be completed and a greater CTM will be achieved because the customer would still be purchasing all of its energy needs at the tariffed rate. It would be unreasonable for a utility to enter into a contract that can reasonably be foreseen as not providing a preferable CTM. In addition, it would be unreasonable for a utility to not exercise its option to cancel a contract that subsequently proves to provide an inferior CTM.

IV. Review of Individual Contracts

The first nine special contracts signed by PG&E are subject to review for reasonableness in this proceeding. With the exception of the three hospital agreements, we will discuss each of them individually.

A. Hospitals

On November 17, 1986, PG&E entered into separate agreements with three members of the Hospital Consortium of San Mateo County: Mills Hospital in San Mateo, Peninsula Hospital in Burlingame, and Sequoia Hospital in Redwood City. The agreements provide each hospital with firm service for 15 years. Cancellation may occur upon four years notice by PG&E, but if the effective contract term is less than 10 years, PG&E must pay the hospitals liquidated damages totaling $459,065 for Mills, $327,000 for

Peninsula and $454,000 for Sequoia. The parties agree that cogeneration was a feasible and economic alternative for the hospitals, which had received agreements from the CEC for a $778,000 grant to pursue their projects.

The rate for each contract is a flat energy charge and a monthly fixed charge. The rate is not adjusted to reflect the time of use. The rate is subject to a marginal energy cost floor, that equals the S01 energy charge plus $0.023 per kWh, and a ceiling set at the E-20S firm rate. The floor does not include a factor for capacity costs related to generation, transportation, or distribution. The rate applies only to usage within the ENPO of the proposed cogeneration plants at each facility, and is indexed to a combination of PG&E standby and customer charges, gas prices and rates, and consumer prices.

As of December 1988, the memorandum account which tracks revenue losses due to these contracts totalled $127,661.32 for Mills, $166,006.06 for Peninsula, and $118,769.78 for Sequoia. According to DRA, this amounts to a discount from tariffed rates of 26% for Mills, 24% for Peninsula, and 19% for Sequoia. As DRA points out, the discounts are highest in the summer period. The highest monthly discount was recorded at Peninsula, where a discount of 40% existed in September 1988.

DRA argues that the marginal cost floor in these contracts is inadequate to protect other ratepayers from losses. DRA's witness Meri Hanson testified that "while only small losses have so far been incurred, the inadequate floor places excessive risks on other ratepayers." In addition, it is DRA's position that the contracts, which have 15-year lengths and require four-year notice of cancellation, are unreasonably long. DRA points out that, about a month after these contracts were signed, the Commission adopted a forecast that showed a need for more capacity before the date when the contracts are due to expire. DRA also disapproves of the liquidated damages provisions, which are not contingent upon the CEC declining to reissue its grant, or limited to the amount of the grant.

PG&E responds that even if DRA is correct when it argues for the inclusion in floor revenues of marginal costs of energy, capacity, transmission, distribution, and customer charges, there should be no disallowance. PG&E argues that the revenues received must be compared to the actual costs incurred to serve these customers on the margin in order to determine the resulting disallowance. In addition, PG&E has uncovered a billing error, which, when corrected, will result in the hospitals being backbilled for services provided in the record period an amount which exceeds DRA's recommended disallowance.

When these contracts were conditionally approved, the Commission specifically stated that they would ultimately be judged in light of the regulatory framework developed in subsequent proceedings. (See Resolution E-3017, issued January 28, 1987, p. 11.) In accepting that condition, along with the condition that the contracts would be subject to subsequent reasonableness, PG&E explicitly accepted the risk of future disallowance. The hospital agreements fall short of the guidelines subsequently developed in D.88-03-008 in a number of respects. The 15-year contract rate is too long. The floor revenues do not include transmission, distribution and generation capacity costs. TOU rates were not required. However, even if strict adherence to the D.88-03-008 guidelines is not required, this contract is unreasonable.

As discussed above, it is unreasonable for any customer to be provided service at a rate that does not equal or exceed adopted marginal cost. The significance of PG&E's failure to insist that the rates charged to the hospitals cover marginal capacity costs is enhanced by the fact that the rates are not time-differentiated. A flat rate does not provide an incentive for off-peak use. As such, it may hasten the time when additional generation, transmission, or distribution capacity will be needed.

In addition, PG&E has agreed that the hospitals can receive these special rates for an unreasonably long period of time without receiving any apparent compensating concessions. Finally, the prudence of agreeing to high liquidated damages in the event of cancellation is questionable as well.

Any amounts in the memorandum account that reflect the difference between adopted marginal costs and the contract rates should be disallowed. The reasonableness of the liquidated damages provision will not be addressed here, because PG&E has not cancelled any of the hospital contracts and is not seeking recovery of those amounts in this proceeding.

B. Louisiana Pacific

On December 12, 1986, PG&E entered into a five-year contract with Louisiana Pacific Corporation (LP) for delivery of power to LP's Oroville, California facility in a flat rate of approximately four and a half cents per kWh. The initial term of the contract began on September 1, 1987. Two and a half cents of this rate are escalated by the Implicit Price Deflated for gross national product, and the other two cents are escalated by the gas rate for cogeneration service, and monthly billings are adjusted for power factor, similar to the E-20 rate. Both PG&E and DRA agree that cogeneration appears to have been feasible for LP.

The memorandum account for the LP contract showed a cumulative balance with interest of $1,698,469.10 by the end of December 1988.

DRA finds fault with the LP contract for three major reasons. First, the contract's floor revenue provision does not meet DRA's criteria. Secondly, the contract does not require TOU rates. Finally, the LP contract is not limited to the ENPO. Instead, LP is able to use special rates for all of its energy requirements.

We agree that the contract is unreasonable with respect to the floor provisions and the lack of TOU rates. As was the case with the hospital agreements that preceded this contract, the failure to include generation, transmission, and distribution capacity costs in the floor provision enables LP to obtain service without assurances that it will cover the cost of providing that service. Once again, by failing to apply TOU rates, PG&E enhances the likelihood that LP will contribute to future additional demand requirements. These failures are even more troublesome in terms of this contract, because LP is allowed to apply the special rate to all of its electric needs at the Oroville facility, even when those needs exceed the theoretical output of its proposed cogeneration facility. By allowing the special rates to apply to all LP purchases, PG&E creates a risk that its other ratepayers will be providing LP a discount for purchases that were not in danger of loss due to bypass. PG&E should not be allowed to recover revenue shortfalls resulting from the inadequate floor provisions. With respect to the lack of load limit, we will order PG&E to renegotiate this contract so that the rate discount applies only to the amount of load which would have bypassed.

A significant dispute between DRA and PG&E relates to whether the Otherwise Applicable Rate (OAR) is a firm or interruptible rate. The OAR is the rate which is applied to determine the loss resulting from the absence of an appropriate load limit. Prior to entering into this agreement, LP received its service at an interruptible rate. According to PG&E, there is no doubt that LP would have continued to elect an interruptible rate if it had not entered into this contract, since it continues to take its service under interruptible rates at its other existing facilities. However, DRA points out that under its special contract, LP receives firm service. DRA argues that it is irrelevant to consider whether or not LP may have otherwise retained its status as an interruptible customer in Oroville. Instead, DRA asserts that since LP is now receiving its power in Oroville under firm conditions, it must pay for what it is getting.

In its reply brief, DRA offers a simple analogy. "A store clerk who each day sells to a certain customer an apple for 25 cents, negotiates an arrangement to increase revenues. He agrees with a customer to sell a pint of caviar each day for 30 cents. Of course, he receives more money from the customer; when the boss discovers the arrangement she demands to be reimbursed. The reimbursement should be based on the value of caviar not the value of apples. PG&E's argument that LP was receiving interruptible service prior to the contract is analogous to the store clerk's arguing that he should be responsible only for the value of apples. PG&E acknowledged that there is a cost differential between firm and interruptible service. PG&E should, therefore, be booking discounted revenues to the memorandum account based on E-20P firm, and this is the rate which should be used to calculate its allowance."

Resolution of this controversy is important for determining the loss suffered by PG&E under the contract. We agree with DRA that LP should pay for the service it is receiving. PG&E argues that interruptions are unlikely to occur, so LP would always continue to buy under the less expensive interruptible rate. This argument is only conjecture. If LP is truly indifferent to the firmness of the service it received, then PG&E should have negotiated the contract providing interruptible service. In return for receiving firm service, LP must be willing to pay more.

C. <u>USS Posco Industries</u>

PG&E's contract with USS Posco Industries (Posco) steel mill, filed with the Commission in February of 1987, extends for five years and provides discounted TOU rates for a portion of the customer's load approximately equal to that which would have been served by the deferred cogeneration facility (47 MW). The TOU rates were the result of a condition placed on initial approval of the contract by this Commission.

DRA argues that the contract is unreasonable because the floor revenue provision does not assure recovery of marginal capacity costs. However, DRA does not recommend any disallowance in this proceeding, because the contract has resulted in a positive contribution to margin during 1988. Instead, DRA suggests that the full, long-run marginal cost of service be tracked for the remainder of contract life and that disallowances be assessed in the unexpected event that revenues fall short of that level.

For all the reasons discussed above, we agree with DRA that the absence of protection in the contract's floor provision to cover generation, transmission, and distribution capacity costs is unreasonable. PG&E should not be allowed recovery for any future shortfall resulting from the inadequate floor revenue provision.

D. Arco

Arco intended to build cogeneration facilities at oil production facilities in Fairfield (.713 MW) and North Coles Levy (2.825 MW). Instead, Arco signed a special electric rate agreement with PG&E. The negotiated rates are time-differentiated. The rates escalate according to changes in natural gas transport and commodity prices, inflation, demand, standby, and customer charges in PG&E's otherwise applicable tariff and PG&E's published prices for SO1 energy. The contract provides firm service to the two facilities for ten years, but (as of November 1989) the contract can be cancelled upon one year's notice. The floor rate does not include capacity costs.

While acknowledging that the ten-year contract length is not objectionable in light of the one year's notice cancellation provision, DRA objects to the absence of capacity costs in the floor provision and recommends that the agreement be found unreasonable. At a minimum, DRA proposes, the agreement as it relates to the larger facility (North Coles) should be cancelled, unless a ratemaking approach is adopted that adequately protects ratepayers from future losses. The floor was invoked for the North

Coles project during the review period. DRA recommends that the resulting $89,503 shortfall be disallowed. DRA does not recommend a disallowance related to the Fairfield facility.

In addition to contesting the suggestion that a reasonable floor revenue provision must include capacity costs, PG&E argues that there should be no disallowance for the Arco contract, in any event. The company asserts that two factors combine to eliminate the disallowance. First, if actual marginal energy costs during the record period were applied instead of forecasted S01 energy prices, PG&E claims that DRA's recommended disallowance could drop by $74,771 to $14,733. Second, PG&E argues that since the two Arco facilities are served under a single agreement, the CTM of the two facilities should be added together. According to the company, if the CTM of the two projects was considered together, DRA's disallowance would be reduced by $20,585.

DRA's response to PG&E's suggestion that the effects of the two facilities be combined is persuasive. Although the two facilities are served under one contract, the contract establishes two independent floor provisions which do not allow losses at one site to be offset by margin at the other. The CTM analyses are done independently. The sites are billed on different accounts. We agree with DRA that costs resulting from the failure to include capacity costs in the floor revenues should be disallowed and that it is appropriate to calculate the disallowances independently.

We have adjusted DRA's proposed disallowance by substituting adopted marginal energy costs for the S01 energy costs.

E. <u>Unocal</u>

The contract between PG&E and Unocal, first offered to the Commission for approval on June 28, 1988, provides the customer with a discounted rate for all of its service needs at its Arroyo Grande site, for a period of five years. DRA recommends that the

Commission find this contract reasonable, despite the fact that it contains no load limit. DRA finds that the floor provision in this contract is adequate. The floor is defined to equal full long-run marginal cost. Although there is no load limit, the cogeneration plant that is deferred could have generated up to 7.395 MW. If there had been a load limit included in the contract, it logically would have been set at that level. According to DRA, Unocal's consumption generally is below this level. Since it is unlikely that Unocal will consume more electricity during the life of this contract than it could have generated in the deferred cogeneration facility, we agree with DRA that the lack of a load limit does not make this agreement unreasonable. Since in other key respects the contract mirrors our adopted guidelines, the contract is reasonable.

F. <u>Shell Manufacturing Complex</u>

In June of 1988, PG&E also asked the Commission for approval of a contract with the Shell Oil Company (Shell). PG&E agreed to provide all service to Shell's Martinez Manufacturing Complex for five years at a discounted rate. The rate mirrors the E-20 rate in format -- it includes TOU rates, demand charges, and a monthly customer charge. Shell qualifies for transmission voltage service at their Martinez substation. In addition, Shell has executed an operation, maintenance, and construction agreement with PG&E regarding the substation. The floor revenue provision covers full long-run marginal cost plus $0.005 per kWh, and therefore ensures that Shell will cover the cost of service.

As was true with the Unocal contract, DRA recommends that this contract be found reasonable, even though it does not contain a load limit. According to PG&E, the deferred cogeneration project would have been capable of generating 49.025 MW. In the prepared testimony of Meri Hanson (Exhibit 61 at p. 33) DRA comments as follows:

> "The Decision conditionally approving the Shell agreement claims that '...the negotiated rate

> applies up to the amount Shell would have received from the bypass facilities, 70 MW.[1] However, the Shell's ENPO was only 44 MW, and the negotiated rate actually applies '...to all electric energy purchased by Shell for use at the Shell Martinez Manufacturing Complex.' Actual usage at the facility was 76 MW in September of 1988, and 72 MW in December of 1988. It may be of concern that increasing usage at the facility, combined with the possibility for that usage to be subject to a discounted rate, may result in losses for PG&E. However, it is clear from other aspects of the contract that PG&E negotiated an agreement which contributes significant margin, and so the lack of a load limit is balanced out by corresponding benefits from the contract."

DRA found that, thus far, the negotiated rate has equalled or surpassed the otherwise applicable rate and that the contract is likely to never generate any discount. At the time of PG&E's filing in this proceeding, the memorandum account balance was zero. Because this contract is not likely to provide a discount from the otherwise applicable rates, it is clear that PG&E has obtained other valuable concessions that compensate for the failure to require a limit to the load for which the special rate applies. This contract is clearly reasonable.

G. <u>Chevron Refinery</u>

PG&E signed a five-year contract with Chevron in lieu of the oil company's completion of what PG&E describes as a 99 MW cogeneration facility at its Richmond Refinery. The contract was submitted to the Commission for preliminary approval in December 1987. The contract provides a discounted rate for all service to the refinery (there is no limit to the load for which the special rates are applicable). According to DRA, the contract rate is based on the cost of service from a 89.355 MW gas cogeneration

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1 D.88-08-058, p. 3.

unit, and is structured similarly to the E-20 tariff, with a monthly charge, demand charges, and TOU charges. Service under the contract is provided at primary service voltage. However, PG&E uses transmission voltage marginal costs plus an adder of $0.00292/kWh for the purpose of calculating the floor charges. This adder represents ownership and maintenance costs for Chevron's dedicated substation and 2% losses during transformation. The floor provision includes marginal energy, generation, transmission, and customer costs.

Transmission voltage customers receive power that has not been transformed for distribution. In order to use power received at transmission voltages, a customer needs expensive processing equipment. Apparently, prior to signing this contract, Chevron was prepared to purchase the PG&E substation that is dedicated to providing power to the Richmond refinery and shift its purchases from primary voltage to transmission voltage. However, Chevron has not purchased the substation and continues to buy power at primary voltage. The use of transmission voltage assumptions becomes significant because transmission voltage service costs less and the resulting rates are lower than primary voltage rates. A floor revenue formula based on an assumption that PG&E only faces transmission voltage costs provides less protection than a calculation based on primary voltage assumptions. Similarly, if the otherwise applicable rate is a primary service rate, then ratepayers stand to lose more in the absence of a meaningful load limit than they would if transmission service rates would otherwise apply.

In the proceeding in which PG&E sought preliminary approval for this project, DRA conceded to the use of transmission service costs for the determination of the adequacy of the floor revenue provision. At the same time, DRA argued that, if the contract had included a reasonable load limit, the usage beyond the expected net output of the deferred cogeneration facility would have been billed at the primary service rate. Therefore, DRA has used the primary service rate to calculate its suggested disallowance stemming from the absence of a load limit.

PG&E argues that, since Chevron appeared ready to buy its substation prior to signing this special contract, its otherwise applicable rate would have been the transmission service rate. DRA appropriately responds that PG&E would have received substantial additional revenues if Chevron had sold the substation. DRA criticizes PG&E for arguing that a transmission rate should be used to calculate otherwise applicable revenues, while failing to count the revenues that would have come from the sale of the substation. This criticism is well placed. It is illogical to assume customer ownership of a substation without assuming that the sale would produce revenues. It is not surprising, in light of the fact that the special contract allows Chevron to meet all of its energy needs with primary service, that Chevron has not followed through on its reported plans to buy the substation. It is illogical to assume that transmission rates should apply when the customer has in the past, and now continues, to receive its electricity under primary service conditions. PG&E has not persuasively demonstrated the reasonableness of assuming transmission rates in calculating floor revenues. However, DRA has agreed with this assumption. While we are not prepared to pass the resulting undercollection through in rates as reasonable, we will hold off on disallowing any costs related to floor revenues until parties can expand on their positions in the next reasonableness review.

During the course of this proceeding, Chevron announced that it is proceeding with a flexicoker project which will remove the necessity for the originally planned cogeneration project. Because the cogeneration project is no longer a viable option, PG&E exercised its discretion to cancel the special contract. As a result, electric service during the last 16-month period that would have been covered by the contract will instead be billed at tariffed rates. PG&E argues that the contract cancellation makes the results of the contract look exceedingly better. In its brief, PG&E argues:

> "It will accelerate the higher-priced index period forward in time, reduce the discount period, and permit the collection of tariff rates from 1992 through 1994 instead of the cogen CTM since the flexicoker will not be built until 1995. These changes increased the contract CTM by over $19 million compared to the cogen CTM.... If DRA's analysis in Ex. 91 had included tariff rate CTM for 1992 (which are higher than the contract rates), and used the Cogen CTM for 1992 found in the original Table 7 in Ex. 61, even DRA's contract lifetime CTM would be higher than the Cogen CTM under any scenario."

DRA answers that it has responded to the cancellation by revising its CTM analysis to reflect the shortened term of the contract. DRA argues that its analysis is consistent in quantifying only the benefits and costs during the term of PG&E's contracts, and that including in its analysis the calculation of margin during the 16 months after the contract expires would only affect the relative margin if it were assumed that the margin under the the cogeneration scenario should be unaffected by the new information. DRA points out that Chevron's decision to build the flexicoker leaves open the question of what would have happened if PG&E had failed to negotiate an agreement with Chevron. In its reply brief, DRA argues:

> "It is unclear whether Chevron would have built the originally-planned cogeneration facility or stayed on tariff rates and pursued the flexicoker project instead. Furthermore, any additional margin attributable to PG&E's decision to cancel the Chevron agreement only proves that the decision to cancel was reasonable. It is not material to the question of whether PG&E was reasonable in its negotiation of the contract."

It is pure conjecture and irrelevant to suggest that Chevron may have stayed on tariff rates and pursued the flexicoker if it had not received the special contract. Yet, it is equally inappropriate to use the higher revenues that may be received after cancellation of the contract in an effort to prove that the terms within the contract are reasonable. It is reasonable to cancel a special contract when bypass is no longer likely. However, that cancellation does nothing to overcome the risk of losses resulting from the absence of load limit in the contract. If the special rate had been limited to the cogeneration output it was designed to avoid, then the otherwise applicable tariffs would have been assessed against the remaining usage and the risk of revenue shortfall would have been avoided. As it affects the load limit problem, the cancellation of the contract does nothing more than mitigate the risk of revenue loss.

V. Calculation of the Disallowance

The calculation of the disallowance is based on the following assumption. We agree with DRA's recommendation that the disallowance should be set where the CTM balance at the end of the year was negative.

Further, we have recalculated the disallowance to reflect our conclusion that adopted marginal energy costs should be used in lieu of SO1 energy costs. These costs are based on using marginal energy costs exclusively from D.86-12-091 (A.86-04-012), Appendix C-1. The marginal energy costs found in D.88-12-100 (A.88-04-020), Appendix C, were not used in rate design prior to January 1, 1989.

In addition, we have added to the disallowance figures the interest necessary to bring nominal dollars up to current value. Interest was calculated using the 3-month Commercial Paper rate for October 1990 found in Federal Reserve Statistical Release G.13, which is the publication used for updating the ERAM and ECAC account balances, as outlined in PG&E's Preliminary Statement, Section B(6)(1) and Section D(6)(f).

All amounts to be disallowed are reflected in the following table. The figures shown in this table are exemplary of the costs found unreasonable and disallowed. PG&E shall file an updated table with CACD that reflects the contents of this decision and serve the updated table on all the parties to this proceeding. After review by CACD, the amounts shown in the updated table will be disallowed in the form of a reduction of the Electric Revenue Adjustment Mechanism revenues otherwise being allocated to rates in conjunction with PG&E's next rate adjustment.

PG&E SPECIAL CONTRACT DISALLOWANCES
(With Interest Thru October 1990)

		Disallowance Due to Inadequate Floor ($)
Mills Hospital	1987	
Mills Hospital	1988	5,285
Peninsula Hospital	1987	
Peninsula Hospital	1988	39,968
Sequoia Hospital	1987	
Sequoia Hospital	1988	31,737
Louisiana-Pacific	1987	11,670
Louisiana-Pacific	1988	
ARCO-Coles	1987	1,162
ARCO-Coles	1988	134,167
GRAND TOTAL		223,989

Figures shown above are exemplary in nature for purposes of this decision.

Figures shown above include interest using the 3-month Commercial Paper rate for October 1990 found in Federal Reserve Statistical Release G.13, which is the publication used for updating the ERAM account balance.

VI. Status of the Contracts After This Review

DRA has recommended that PG&E be required to track the long-run marginal cost for service up to the ENPO levels at the hospitals, LP, POSCO, both ARCO sites, and Chevron and recover in the future only discounted revenues above a reasonable floor revenue level. PG&E would not be allowed to collect shortfalls resulting from sales above ENPO. In addition, DRA argues that PG&E should be ordered to give notice of cancellation under the terms of the hospitals and ARCO agreements, and to give notice that the LP, UPI, and Chevron agreements will not be renewed in their present forms, in order to minimize losses to other ratepayers. Issues concerning the future status of the Chevron contract would appear to be moot due to its cancellation.

We agree that PG&E should not be allowed future rate recovery for portions of the contracts that have been found to be unreasonable. However, we will not require PG&E to exercise its cancellation options. To do so would be to act in disregard for the good faith efforts of the customers involved in these contracts. The testimony of Gibson exposed us to the plight of the hospitals which were on the verge of developing their cogeneration projects when approached by PG&E about the special contract option. To be certain, the hospital representatives were tough negotiators and struck a favorable deal. While they should be expected to bear the risk of the business decision that drove them to forgo the cogeneration option and sign special contracts, these parties are not necessarily knowledgeable players in the utility regulatory sphere. It is likely that other special contracts customers are relative strangers to rate regulation as well. On the other hand, it is fair to assume that PG&E was involved in the negotiations as a knowledgeable player.

While it is appropriate to place PG&E at risk for its failure to insist on reasonable contract provisions, we must keep in mind that there was no disputing the likelihood that all of these customers were on the verge of self-generating. PG&E should attempt to negotiate contract revisions that would bring the contracts in line with the standards discussed in this order. Failing to do so, if PG&E is unwilling to absorb the risk of future disallowance, it should exercise its cancellation options.

<u>Findings of Fact</u>

1. As early as November 17, 1986, PG&E began entering into agreements with large electric customers, offering them lower electric rates in exchange for a promise not to generate their own electricity.

2. Each of these special contracts was submitted to the Commission for prior approval.

3. Each contract was approved subject to reasonableness review at a later time.

4. In D.88-03-008, the Commission issued guidelines which, if met, would assure the approval of a special contract in response to an EAD application.

5. The Commission directed PG&E to keep account of revenue lost due to the contracts pending reasonableness determination.

6. In D.89-05-067 (signed May 26, 1989), we ordered that the reasonableness of special contracts be addressed in the reasonableness phase of each electric utility's annual ECAC proceeding.

7. Because of the timing of their issuance, only the Unocal and Shell agreements were initially measured against the D.88-03-008 guidelines.

8. PG&E argues that it would not be fair to use 1988 standards to assess the utility's conduct in formulating special contracts in 1986 and 1987.

9. DRA argues that because accurate long-term forecasting of capacity needs is difficult, long-term contracts are risky for the utility and its ratepayers. DRA questions the reasonableness of contracts that exceed five years.

10. PG&E appears to argue that this standard is inappropriate, at least for the earliest agreements (which happen to have been 15 contracts) because they were the first contracts of their type to have been negotiated and because, according to PG&E, utility and staff forecasters at the time were predicting excess capacity for at least ten years.

11. DRA argues that, since the purpose of the special rate offering is to avoid bypass, the special rate should only apply to the portion of the customer's load that is at risk of bypass.

12. DRA argues that discounting more of the customer's load may result in giving more of a discount than necessary to keep the customer on line.

13. PG&E responds that if the discount rate applies to all of the customer's requirements, other ratepayers may stand to benefit. If load subsequently grows, the effective discount will be greater than it would be if the special rate only applied to the ENPO. But if load diminishes, the effective discount may be lower than it would be if the special rate was limited to the ENPO.

14. A discount that applies to all customer usage creates greater risk of revenue loss.

15. In adopting guidelines in D.88-03-008 for review of special contracts in EAD applications, the Commission concluded that, in order to receive expedited approval, a contract should include a floor price designed to assure that the utility recovers from the customers no less than the lowest price possible that does not disadvantage other ratepayers in either the short or long run.

16. DRA argues that these floor payment requirements should be applied to determine the reasonableness of the contracts before us in this proceeding.

17. DRA recommends using the S01 energy price to set the energy cost portion of the floor revenues because the S01 price includes all components of the avoided cost of energy.

18. PG&E argues that the energy cost derived in this manner is inapplicable to special contract pricing because its calculation assumes the need for over 1,000 MW of additional energy (the level of variably priced QF production) although the special contracts at issue here represent only 207 MW.

19. PG&E argues that the energy component of a special contract should be found reasonable so long as it reflects the "actual" energy cost faced by the utility.

20. What PG&E refers to as "actual" marginal energy cost includes only the commodity portion of the gas tariff.

21. To accurately use natural gas costs to represent the energy cost of electric service, the calculation must include gas commodity costs, transportation costs, incremental gas demand charges, marginal operation and maintenance costs, increment to cash working capital, and an adjustment to reflect losses.

22. While PG&E should have been expected to only sign special contracts that cover the full range of the customer's marginal energy costs, the S01 rate was not the only reasonable guidance available.

23. The adopted marginal cost was developed to guide the ratesetting process and formed the commonly accepted basis for measuring the cost of serving additional customers.

24. DRA proposes that the avoided cost of generation capacity be viewed as a cost of service under special contracts.

25. PG&E asserts that there simply cannot be any capacity costs that would be applicable to these special contracts.

26. DRA would have us require that the generation capacity cost component of QF payments be factored into the floor price for these contracts.

27. PG&E argues that, when these contracts were negotiated, PG&E, the Commission, DRA, the CEC, and the Legislature all

predicted that no new capacity would be needed during the time frame of these contracts.

28. PG&E states that, since the contracts were signed, it has made no discretionary additions to its available capacity and that, when new resources are finally needed, the special contracts will be cancelled and the customers will bypass the system.

29. DRA asserts that, while these contracts were being negotiated, there was no unanimity among forecasters and that even PG&E claimed in at least one proceeding that it would face a capacity shortage during the relevant period.

30. DRA rejects the notion that individual customers should be excused from paying capacity costs simply because their contributions to the system demand cannot be directly linked with the need to add new capacity.

31. DRA argues that costs related to new capacity are always greater than zero; additional available capacity always has some value because it improves the reliability of the existing supply; there are always planning activities in progress within the utility that relate to future additions to generating capacity.

32. It is only the extent to which average cost exceeds marginal cost that there is room to bargain with customers who are capable of self-generating.

33. We have long recognized that every customer contributes to the need for generating capacity.

34. It is fundamental that the marginal cost of capacity be reflected in each unit of demand, from the first to the last.

35. If a customer is induced to stay on the system by the offering of a special contract, it continues to contribute to the long-term growth in the demand for generating capacity.

36. There is substantial reason to expect that special contract customers may remain on-line after their contracts expire.

37. Just as each customer should pay its share of generation capacity costs, it should pay its share of T&D and customer costs.

38. Each customer's presence on the system contributes to the utility's T&D costs. Its share of those costs does not go away simply because the customer signs a special contract.

39. DRA argues that all reasonable special contracts should contain TOU rates and peak-demand charges because they encourage high load factors and reduce the cost of providing service.

40. The first four contracts signed by PG&E did not use TOU rates. For all subsequent contracts, the Commission refused to provide even preliminary approval for contracts that lacked TOU provisions.

41. PG&E acknowledges that "TOU rates may have been desirable in retrospect," but argues that the absence of TOU rates alone should not result in a finding of unreasonableness.

42. It is appropriate to utilize time-differentiated rates when setting rates for large customers.

43. A customer will generally prefer to purchase from the utility if the cost of self-generation is no lower than the cost of utility service.

44. It would be unreasonable for the utility to offer service at a rate lower than the cost of self-generation in the absence of overriding circumstances.

45. A contract that does not provide a preferable CTM is not in the best interest of ratepayers.

46. On November 17, 1986, PG&E entered into separate agreements with three members of the Hospital Consortium of San Mateo County: Mills Hospital in San Mateo, Peninsula Hospital in Burlingame, and Sequoia Hospital in Redwood City.

47. On December 12, 1986, PG&E entered into a five-year contract with LP for delivery of power to LP's Oroville, California facility in a flat rate of approximately 4.5 cents per kWh.

48. The failure to include generation, transmission, and distribution capacity costs in the floor provision enables LP to obtain service without assurances that it will cover the cost of providing that service. By failing to apply TOU rates, PG&E

enhances the likelihood that LP will contribute to future additional demand requirements.

49. By allowing the special rates to apply to all LP purchases, PG&E creates a risk that its other ratepayers will be providing LP a discount for purchases that were not in danger of loss due to bypass.

50. If LP is truly indifferent to the firmness of the service it received, then PG&E should have negotiated the contract providing interruptible service. In return for receiving firm service, LP must be willing to pay more.

51. PG&E's contract with Posco steel mill, filed with the Commission in February of 1987, extends for five years and provides discounted TOU rates for a portion of the customer's load approximately equal to that which would have been served by the deferred cogeneration facility (47 MW).

52. DRA argues that the contract is unreasonable because the floor revenue provision does not assure recovery of marginal capacity costs. However, DRA does not recommend any disallowance in this proceeding, because the contract has resulted in a positive contribution to margin during 1988.

53. Arco intended to build cogeneration facilities at oil production facilities in Fairfield (.713 MW) and North Coles Levy (2.825 MW). Instead, Arco signed a special electric rate agreement with PG&E.

54. The contract between PG&E and Unocal, first offered to the Commission for approval on June 28, 1988, provides the customer with a discounted rate for all of its service needs at its Arroyo Grande site, for a period of five years.

55. The floor provision in the Unocal contract is adequate.

56. Since it is unlikely that Unocal will consume more electricity during the life of this contract than it could have generated in the deferred cogeneration facility, the lack of a load limit does not make this agreement unreasonable.

57. In June of 1988, PG&E also asked the Commission for approval of a contract with Shell. PG&E agreed to provide all

service to Shell's Martinez Manufacturing Complex for five years at a discounted rate.

58. DRA recommends that this contract be found reasonable, even though it does not contain a load limit.

59. Because this contract is not likely to provide a discount from the otherwise applicable rates, it is clear that PG&E has obtained other valuable concessions that compensate for the failure to require a limit to the load for which the special rate applies.

60. PG&E signed a five-year contract with Chevron in lieu of the oil company's completion of what PG&E describes as a 99 MW cogeneration facility at its Richmond Refinery. The contract was submitted to the Commission for preliminary approval in December 1987.

61. Service under the contract is provided at primary service voltage. However, PG&E uses transmission voltage marginal costs plus an adder of $0.00292/kWh for the purpose of calculating the floor charges.

62. Transmission voltage customers receive power that has not been transformed for distribution.

63. Apparently, prior to the signing this contract, Chevron was prepared to purchase the PG&E substation that is dedicated to providing power to the Richmond refinery and shift its purchases from primary voltage to transmission voltage.

64. Chevron has not purchased the substation and continues to buy power at primary voltage.

65. A floor revenue formula based on an assumption that PG&E only faces transmission voltage costs provides less protection than a calculation based on primary voltage assumptions.

66. It is illogical to assume that transmission rates should apply when the customer has in the past, and now continues, to receive its electricity under primary service conditions.

67. During the course of this proceeding, Chevron announced that it is proceeding with a flexicoker project which will remove the necessity for the originally planned cogeneration project.

Because the cogeneration project is no longer a viable option, PG&E exercised its discretion to cancel the special contract.

68. DRA has recommended that PG&E be required to track the long-run marginal cost for service up to the ENPO levels at the hospitals, LP, Posco, both ARCO sites, and Chevron and recover in the future only discounted revenues above a reasonable floor revenue level.

69. In addition, DRA argues that PG&E should be ordered to give notice of cancellation under the terms of the hospitals and ARCO agreements, and to give notice that the LP, Posco, and Chevron agreements will not be renewed in their present forms, in order to minimize losses to other ratepayers.

Conclusions of Law

1. Just as it would be unfair to hold PG&E to a retroactive standard simply because it was adopted by the Commission, it would be illogical to reject a standard simply because it was subsequently adopted by the Commission.

2. A strong bypass potential is an absolute prerequisite to receiving a special contract.

3. There is nothing magical about a 5 year limit. While this factor alone would not be sufficient to find an agreement unreasonable, we agree that a reasonable decision-maker at the time who was willing to agree to a longer payment term should have received other concessions to offset this risk.

4. Rate discounts for all customer load, including that in excess of the amount which was in danger of bypassing are not per se unreasonable, but may result in loss of revenue. Accordingly, PG&E should be ordered to renegotiate those contracts which provide rate discounts for loads in excess of the amount in danger of bypassing.

5. The adopted marginal cost in effect at the time should be used to determine reasonable floor revenues.

6. If customers are able to self-generate at a cost below the utility's marginal cost, then they should be encouraged to do so.

7. At a minimum, each customer on the system must pay the full marginal cost for the service it receives, whether or not it is being served under a special contract.

8. While the absence of TQU rates is not conclusive proof that a contract is unreasonable, it is the utility's responsibility to justify its failure to require them.

9. It would be unreasonable for a utility to enter into a contract that can reasonably be foreseen as not providing a preferable CTM.

10. Any amounts in the memorandum account for what the Hospital contracts that reflect the difference between adopted marginal costs and the contract rates should be disallowed.

11. PG&E should not be allowed to recover for revenue shortfalls in the LP and Arco contracts resulting from the inadequate floor provisions.

12. The absence of protection in the Posco contract's floor provision to cover generation, transmission, and distribution capacity costs is unreasonable. PG&E should not be allowed recovery for any future shortfall resulting from the inadequate floor revenue provision.

13. The Unocal contract should be found reasonable.

14. The Shell contract is reasonable.

15. PG&E should attempt to negotiate contract revisions that would bring the contracts in line with the standards discussed in this order.

16. PG&E should not be allowed future rate recovery for the portions of the contracts that have been found to be unreasonable.

O R D E R

IT IS ORDERED that:

1. The exemplary costs set forth in the table contained in this decision are unreasonable. Within 30 days from the effective date of this decision, Pacific Gas and Electric Company (PG&E) shall file an updated table with CACD that reflects the contents of this decision and serve the updated table on all the parties to this proceeding. After review by CACD, the amounts shown in the updated table will be disallowed in the form of a reduction of the Electric Revenue Adjustment Mechanism revenues otherwise being allocated to rates in conjunction with PG&E's next rate adjustment.

2. PG&E shall renegotiate its contracts with Louisiana Pacific Corporation, Unocal, and Shell Oil Company to limit the rate discount to the effective net plant output.

3. Costs resulting from the failure to use primary service rates on setting the floor revenues for the Chevron contract shall remain uncollected, pending reconsideration in PG&E's next ECAC reasonableness review.

4. In all other respects, the costs set forth in PG&E's application as related to special electric contracts are reasonable and may be collected in rates.

This order becomes effective 30 days from today.

Dated December 27, 1990, at San Francisco, California.

G. MITCHELL WILK
President
FREDERICK R. DUDA
STANLEY W. HULETT
JOHN B. OHANIAN
PATRICIA M. ECKERT
Commissioners

I will file a written concurring opinion.
/s/ FREDERICK R. DUDA
Commissioner

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

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

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FREDERICK R. DUDA, Commissioner, concurring:

Today's decision is illustrative of the continuing concern I have over the appropriateness of reasonableness reviews in matters pertaining to particular utility behavior where the Commission has previously endorsed, generally, the utility's actions. This is especially so when the Commission has provided little or no prospective guidance to utility actions that are later subjected to reasonableness reviews.

Starting in 1986 Pacific Gas and Electric (PG&E) entered into a number of special electric rate contracts in an attempt to avoid uneconomic bypass by certain large customers. The need for these special contracts arose as the result of the confluence of a number of independent events at the time. PG&E sought and received prior approval from the Commission for each of the special contracts.

Each of the contracts submitted to the Commission received unusually rapid approval because of the perceived acute need to act to lessen the detrimental effects impacting on the PG&E system at the time. The Commission recognized the management incentive problem associated with approval of these special contracts without making explicit a decision rule that the utilities should follow in negotiating these contracts. The concern is that without an explicit decision rule or set of guidelines, utility management may not have the correct incentive to maximize revenue contribution from these special contracts to the benefit of other existing ratepayers. The Commission explicitly recognized this problem in D.87-05-071 where it discussed the need to develop guidelines to assure the reasonableness of the contracts.

However, at the time of these initial contracts no guidelines existed. As such, the Commission conditioned approval of these contracts by requiring that each contract would be subject to a reasonableness review at a later time. That later time is today's decision.

Reasonableness reviews of contracts without established guidelines are an ineffective and costly means of monitoring utility behavior in this area. The uncertainty created by this regulatory approach provides a disservice to all involved. Explicitly defining the conditions at the time of approval upon which actions will later be judged greatly improves the process of reducing the associated uncertainty.

I recognize that in some cases it may not be possible to develop an explicit set of prospective guidelines. These contracts may represent a case in point. The combination of the set of circumstances creating a novel situation and the sense of urgency at the time may have precluded the development of a well thought out set of guidelines within the contract approval process. However, I believe it is incumbent on the Commission, to the extent possible, that it establish, at a minimum, preliminary guidelines to govern utility contracting actions. In addition, it is incumbent on utilities to notify the Commission in a timely fashion of potential changes in their business operations as it may impact either regulatory policies or procedures, e.g., in this case the need to negotiate special electric rate contracts. In this way the Commission has the time to consider the parameters associated with these changes and adopt the necessary rules or guidelines prospectively and thereby prevent the type of situation we have had to address in this decision. Both the Commission and the utilities have the responsibility to work together to reduce the uncertainties that arise from reasonableness reviews of the nature in this proceeding.

Finally, I would suggest that this is an area where the Commission, as part of its future investigation into incentive regulation of electric and natural gas utilities, can work to develop regulatory incentives to replace the type of reasonableness reviews before the Commission in this proceeding.

To the extent that an efficient incentive structure can be developed, the Commission's monitoring costs of utility actions through reasonableness reviews will be reduced. An established incentive program with decision rules in place will be an effective tool in reducing regulatory uncertainty and placing the responsibility for utility business decisions in the hands of those closest to the market.

Frederick R Duda

Frederick R. Duda, Commissioner

San Francisco, California
December 27, 1990