ALJ/SAW/f.s

Mailed

MAY 1 1 1992

Decision 92-05-031 May 8, 1992

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

Application of Pacific Gas and Electric Company for authority among other things, to increase its rates and charges for electric and gas service. (Electric and Gas) (U 39 M)	Application 88-12-005 (Filed December 5, 1988)
And Related Matter.	I.89-03-033 (Filed March 22, 1989)

(See D.89-09-093 for appearances. See Appendix A for additional appearances.)

I N D E X

INDEX

OPINION CONCERNING NONFIRM ELECTRIC RATE INCENTIVES

Summary

In Decision (D.) 89-12-057 (the 1990 Pacific Gas & Electric Company (PG&E) General Rate Case (GRC)), the Commission approved a series of incentive payments for nonfirm electric customers. That decision called for further study of the avoided costs underlying the incentive calculation and prompted several parties to produce a Settlement which was rejected by the Commission in D.91-07-042. In this order, we adopt a new incentive level of $84.00/kW to apply to curtailable customers and an additional $8.00/kW to apply to interruptible customers until new incentives or an alternative program are established in the currently pending GRC. These incentives are adopted in anticipation that the current program can soon be replaced with a nonfirm bidding process. In addition, we approve new program features designed to enhance the reliability of the program in its current form.

1. Background

Since the early 1980's, PG&E has offered, to certain customers who purchase an exceptionally large amount of electricity, rate discounts in exchange for their agreement to buy less power when emergency shortages occur. Customers participating in this program receive what is referred to as nonfirm service. A customer is curtailable when it agrees to reduce its load upon request. A customer is interruptible when PG&E has installed at the customer's premises a device that automatically cuts the customer's load when the system frequency slips below a certain level. About 240 of PG&E's largest electric customers currently participate in this program. As a result, about 550 MW of coincident on-peak load is subject to mandatory curtailment.

Since the right to reduce or interrupt a customer's demand helps the utility decrease its need for peak or emergency capacity, this program should help keep down capacity costs. In exchange for their agreement to reduce or interrupt their load at certain times, nonfirm customers pay rates that reflect credits for the benefits they confer on the system.

Nonfirm customers are understandably interested in making sure that the discounts they receive reflect the full value of the benefits they provide to PG&E's electric system. PG&E is equally interested in assuring that those benefits are not overstated, especially during a time when the system has excess generating capacity.

In D.89-12-057, the Commission authorized PG&E to continue its existing nonfirm electric rate program and to create a new, voluntary "economic dispatch" curtailment program. According to PG&E, there have yet to be any economic opportunities to operate the latter program. About 400 MW of the curtailable load is served on underfrequency relay devices (UFRs) that automatically shed the customers' loads when system frequency drops below 59.75 Hertz.

The customers enrolled for nonfirm service received more than $40 million per year in rate discounts during 1990 and 1991 on the basis of interim rates adopted in D.89-12-057. Substantially larger discounts were offered prior to 1990. The typical nonfirm customer currently realizes savings of 15-20%.

The incentive rates approved in D.89-12-057 were considered to be interim rates, because the Commission found the the record before it to be insufficient. Instead of setting rates in that decision to remain in effect until the effective date of PG&E's next general rate case decision, the Commission ordered PG&E to submit a study and proposal on nonfirm electric rates. In addition, the assigned Administrative Law Judge (ALJ) was ordered to arrange for meetings or hearings, as necessary, to refine PG&E's nonfirm electric rate incentives.

PG&E submitted its "Final Study and Report" at the end of June 1990. By ruling dated September 11, 1990, the ALJ set a schedule which called for prepared testimony and evidentiary hearings in the hopes of having revised rates become effective May 1, 1991. The Commission's Division of Ratepayer Advocates (DRA), Federal Executive Agencies (FEA) and California Large Energy Consumers Association (CLECA) objected to PG&E's Final Report, asserting that it did not reflect their perspectives on many relevant issues. The ALJ permitted those parties to prepare their own report, entitled the "Joint Report on Nonfirm Rate Issues," to be included in the record. The Joint Report was distributed on November 13, 1990.

On January 11, 1991, several parties active in this phase of the proceeding filed a "Notice of Settlement Conference (Rule 51.1)." Those parties are PG&E, DRA, CLECA, California Manufacturers Association (CMA), Industrial Users, FEA, and Cogeneration Service Bureau (CSB). The settlement conference was scheduled for January 18, 1991.

On January 14, 1991, the evidentiary hearings on the prepared testimony were convened as scheduled. The procedural schedule was revised to allow filing of comments on the settlement after the settlement conference. The new schedule called for: (1) filing of comments by February 4, 1991, (2) a ruling in response to the comments, (3) possible concurrent testimony on the settlement due February 26, 1991, and (4) possible hearings beginning March 5, 1991.

At the January 14 hearing, the parties generally agreed to defer hearings on the prefiled testimony. CLECA, Industrial Users, CMA, and FEA chose to defer the hearings. PG&E and Toward Utility Rate Normalization (TURN) did not oppose the deferral, and DRA had no opinion.

At the hearing, the ALJ allowed limited oral direct testimony from PG&E, CLECA, and DRA to clarify the upcoming settlement and to allow TURN in particular to better understand the settlement terms. (Tr. 7329.) No cross-examination was allowed. Further hearings on the prepared testimony were deferred indefinitely. All of the prepared testimony was received into evidence, subject to future cross-examination. The ALJ ordered the late filing of Exhibit 2019, a comparison exhibit showing the positions of the parties on the principal issues.

The Settlement (attached to this decision as Appendix B) set forth various terms and conditions for the nonfirm rate program and proposed that incentive payments for curtailable customers be based on a payment of $70/kW-yr. In D.91-07-042, issued July 24, 1991, the Settlement was rejected. The Commission explained this action as follows:

> "We are not convinced by the evidence and arguments before us that the Settlement is fair and reasonable. We do not object to the terms and conditions of the proposed incentive program, but we cannot conclude that the incentive amount, even considering the benefits of the Settlement terms and conditions, is fairly balanced against the risks of going to hearing on the merits of the parties' testimony. The record may eventually show that incentive amounts either lower or higher than the proposed $70/kW-yr. are reasonable, but from our present perspective we cannot accept the risk that $70/kW-yr. is too high. Further hearings are necessary.

The Commission set forth 12 fundamental issues to be addressed in further hearings on the prepared testimony. Those issues will be addressed below.

The proceeding was transferred to ALJ Weissman. A Prehearing Conference was held August 14, 1991. Evidentiary hearings were held October 7-10 and 16, 1991. The matter was submitted with the receipt of reply briefs on December 6, 1991.

A proposed decision was mailed on March 6, 1992. Comments on the proposed decision were filed by PG&E, DRA, FEA, TURN, CLECA, CMA and the California League of Food Processors. Changes have been made in response to comments where appropriate.

2. Discussion

We will address each of the issues identified by the Commission in D.91-07-042.

2.1 Should Nonfirm Incentives be Based on Avoided Costs? If so, the Details of Avoided Cost Calculations May Need Refinement. For Example, What is the Forecast Horizon for the Energy Reliability Index (ERI), if Adjustment for ERI is Ordered?

2.2 Should the "Supply Side" Convention, Which Requires No Adjustment of Avoided Costs By the Equal Percentage of Marginal Cost (EPMC) Ratio, Be Continued?

We consider these two issues together, because they raise related concerns.

There appear to be two basic ways to determine the appropriate rate reduction for nonfirm customers. A from-the-ground-up approach would treat nonfirm customers as a separate rate class, recognized as generating its own revenue requirement based on unique marginal costs. Rates would be based on those costs. A top-down approach would treat nonfirm customers as customers who pay standard industrial rates but receive additional incentive "payments" (bill reductions) in return for their willingness to be curtailed. Using a ground-up approach, we would view nonfirm customers as a distinct type of ratepayer creating a specialized demand for service. Using a top-down approach we would view nonfirm customers as a supply source, since the commitment of a nonfirm customer to curtail its requirements during emergency or peak periods is equally as beneficial to the electric supply system as a new source of generation.

PG&E and TURN argue that nonfirm customers should be compensated using a supply-side approach. PG&E argues that the Commission has already rejected the demand-side approach and that, at least at one time, most of the parties have supported the supply-side approach. TURN argues that by employing a supply-side approach, the Commission assures that nonfirm customers are not receiving credits in excess of the costs that they avoid, since ratepayers who pay for the incentives would prefer construction of new facilities to the offering of more expensive nonfirm incentives.

CMA suggests that by thinking in terms of reduction from firm rates as a payment for supply, the supply-side approach causes unnecessary confusion with respect to adjustments of avoided costs by the EPMC ratio. In setting rates, we normally begin by determining the marginal cost of serving a customer in a given class. However, the sum of marginal costs used to develop rates differs from the utility's revenue requirement. In order to generate more accurate revenue, we use the EPMC ratio to adjust the rates within each class. This is part of the process underlying the industrial rates that firm and nonfirm customers pay. When a supply-side-oriented incentive payment is used to offset a portion of those payments in order to compensate nonfirm customers for accepting reduced reliability, should the Commission use the EPMC ratio to increase the incentive payment? CMA, CLECA and FEA argue that it is only fair to do so, since nonfirm customers would otherwise bear more than their share of the difference between marginal and average costs. PG&E and TURN respond that this would result in payments to nonfirm customers that exceed the value of the capacity that they avoid.

CMA's point is that if a ground-up approach is used instead, this issue disappears. The marginal cost of serving nonfirm customers would be calculated and then adjusted by the EPMC ratio. Nonfirm rates would then be set at the same percentage above the marginal cost of serving nonfirm customers as the rates for all classes of firm service customers are set above their marginal costs.

As is often the case, both perspectives are logical and supportable. Why should nonfirm customers not pay rates calculated in a manner consistent with all other rate classes? At the same time, why should the utility pay nonfirm customers more than its avoided cost?

In order to find the proper balance of these valid interests for the current proceeding, we need to keep certain points in mind. First, no matter how the balance of payments between the utility and nonfirm customers is calculated, the impact of this program on other ratepayers should not exceed the costs that the program avoids. As this Commission stated in D.89-12-057 (34 CPUC 2d 199, at 372), "[i]f the costs of nonfirm options exceed the marginal costs of coincident demand-related capacity..., it would be cheaper for the utility to go ahead and obtain the extra capacity at the marginal cost than to pay the more costly incentives to nonfirm customers for the same amount of capacity." Second, a ground-up rate design might be the most equitable basis for calculating nonfirm rates, so long as they do not exceed avoided cost. Regardless, we are not prepared to create such rates based on the record in this proceeding. Finally, we plan to eventually replace the current incentive program with one in which those customers interested in receiving nonfirm incentives will bid for the right to receive them. A bidding approach should lead to incentive payments less than full avoided costs and thereby provide the most benefit for the greater body of ratepayers. We will seek to adopt a bidding program for PG&E in our demand-side management (DSM) Rulemaking/Investigation (R.91-08-003/I.91-08-002) before new rates go into effect in May, 1993.

Since we are neither prepared in this proceeding to adopt a bidding system nor equipped to design nonfirm rates from the ground up, we will continue to offer incentive payments. The logical way to assure that incentive payments do not exceed avoided cost is to use avoided costs as the basis for those payments.

PG&E argues that there is no legislative or regulatory requirement that the utility offer incentives equal to full avoided cost, and that the Commission can consider the sharing of risks and rewards in setting the incentive level. DRA advocates offering incentives at full avoided cost until there is proof (such as the results of a pilot bidding program) that adequate participation can be obtained with smaller incentives. Until such a time as a bidding program or other mechanism allows potential nonfirm customers to express a price preference, we will not know whether rates set at a particular level below full avoided cost would substantially undercut participation in the program. Therefore, at least for the purposes of setting incentive levels for the summer of 1992, we will continue to direct PG&E to offer full avoided cost payments.

Nonetheless, we want to make clear that one reason for moving from an incentive payment approach to a bidding approach is to allow for a reduction in payments to nonfirm customers. Although adherance to full avoided cost payments may raise the level of incentive payments in the short term, program participants should be prepared for a precipitous drop in payments if and when a bidding program is adopted. It is unlikely that a phase-in program, such at that currently provided for continuing nonfirm customers pursuant to PG&E's schedule E-20, would apply to a transition from full avoided cost incentive payments to a bidding program.

2.3 Should Avoided Generation Costs be Adjusted for the ERI, and if So How?

"The ERI is a way of expressing whether the value of additional capacity on an electric utility system in a given year is the same as, or greater or less than, the utility's marginal capacity investment, assumed to be a combustion turbine." (D.86-11-071, 22 CPUC 2d 311, 315.) It is a fraction that is multiplied by the cost of a combustion turbine to produce the avoided capacity cost payments to variably priced qualifying facilities (QFs) and to produce marginal generation costs for rate design purposes. For PG&E, the fraction can be no lower than 0.4 and no higher than 1.0. The ERI used for calculating QFs payments is developed in the annual Energy Cost Adjustment Clause (ECAC) proceeding based on short-run assumptions. The ERI used for rate design is developed in the triennial general rate case for each electric utility based on long-run assumptions. For PG&E, the result has been that ERIs with different values are used in different situations, depending on the purpose. Currently, the ERI adopted for QF payments is 1.0, and the ERI adopted for rate design purposes in 1992 is 0.56. (D.91-12-061). The latter number reflects a six-year average long-run ERI.

The first question is whether or not an ERI should be used to adjust the incentive level. Since the ERI allows us to adjust the cost of a combustion turbine to reflect our best judgment of the utility's current need for a new source of generation, it is appropriate to use an ERI in calculating the upper limit for incentive payments.

CLECA opposes the use of an ERI, asserting that (1) the ERI is extremely sensitive to changes in input assumptions and its use is likely to lead to substantial and frequent changes in the incentive levels and (2) the ERI systematically understates the value of the nonfirm resource because it reflects forecasts of loads and resources that by definition cannot take into account emergency situations which make nonfirm resources so valuable. PG&E responds that the use of a rolling six-year average ERI would minimize fluctuations in the incentive level. In addition, PG&E denies CLECA's assertion that an ERI cannot reflect emergencies, arguing that consideration of emergencies underlies the development of all utility reliability indices, including the adopted target reserve margin.

CLECA's concern with fluctuations in incentives speaks more to the advisability of smoothing out ERI changes through the use of averaging techniques than to the merits of adjusting the cost of a combustion turbine by a factor reflecting the need for additional generation capacity. Further, we are not convinced by CLECA's assertion that the ERI fails to consider emergency needs.

As CLECA itself explains, the ERI is a measure of the difference between the utility's existing reserve margin and its target reserve margin. Perhaps the most significant reason for a utility to maintain enough generation capacity to meet its target reserve margin is that emergency outages are unpredictable and therefore must be guarded against. As such, we cannot agree with CLECA that the potential for emergencies undercuts the value of the ERI.

FEA contests the use of an ERI to adjust an incentive payment. FEA argues that since the ERI reflects the existence of excess generating capacity and nonfirm customers did not cause PG&E to acquire excess capacity, it is unfair to single out nonfirm customers by reducing their incentive payments. However, we reject this view of the world. We are encouraging PG&E to offer nonfirm incentives in order to avoid resource additions. There is less value in taking steps to avoid new resources when there is excess capacity on the system. Rather than singling out nonfirm customers for some type of demerit, the use of an ERI helps us assure that other ratepayers are not required to bear unnecessary costs.

The remaining question is what ERI should be used. In D.89-12-057, the Commission rejected the use of a six-year average ERI, for two reasons. First, it observed that, in many ways, nonfirm customers are the demand-side equivalent of QFs who supply firm capacity, and that it makes some sense to value the two resources' capacity contributions on an equivalent basis. Second, the Commission remarked that applying the six-year ERI used for purposes of revenue allocation and rate design would dramatically reduce the incentives for nonfirm customers. The Commission concluded that it was reluctant to take this step without a more careful consideration of the issue.

We have now had an opportunity to consider this issue in more detail, but remain uncomfortable with the options. TURN has proposed a sliding scale of ERIs from 0.4 to 1.0 depending on the level of commitment the customer makes to curtailment. PG&E

supports the use of the 0.56 figure adopted in its last ECAC for revenue allocation and rate design purposes. CLECA, California League of Food Processors (CLFP) and DRA suggest that the data underlying the 0.56 number are stale and would have us create a new ERI based on compliance filings received in the Biennial Resource Plan Update Proceeding (BRPU). CLECA and CLFP, therefore, suggest that 0.756 would be the appropriate number.

The problem with using existing ERIs is that when they are calculated, it is assumed that the nonfirm incentive is in place and that nonfirm customers are not contributing to peak demand. As a result, the perceived demand level already reflects benefits derived from the incentive program and the reserve margin looks larger than it would if the program was not offered. This tends to understate the ERI. It would be unfair to customers who agree to curtailment if the nonfirm incentive was reduced to reflect the benefits of nonfirm customers. So long as rate incentives are offered for nonfirm customers, a separate ERI should be calculated to determine the ERI that would result if the nonfirm incentive program was not in place. We reject the suggestion of CLECA, CLFP and DRA that we use an ERI based on filings in the BRPU because an ERI for PG&E has not been adopted in that docket. Instead, we will rely on currently available ERIs in this proceeding and direct PG&E to file the results of a comparison of the operation of its system with and without its nonfirm rate program (nonfirm in-out calculation) in the current GRC to more accurately reflect the benefits of nonfirm customers in avoiding new generation.

The use of a six-year average ERI would help stabilize the incentives. While we may use such an average in future proceedings in the absence of a bidding program, there are two problems with PG&E's currently proposed ERI. First, as discussed above, it understates the value of nonfirm customers because when the calculations are made the nonfirm customers are not assumed to place peak demand on the system. Second, we agree with the Commission's earlier conclusion that the incentive program provides supply side benefits, similar to those offered by a QF. In fact, since QFs are subject to reliability constraints of their own, some QFs may provide a less reliable resource than some nonfirm customers. Since a nonfirm customer provides supply-side benefits, where the long-run ERI is lower than the short-run ERI developed in the ECAC, the latter should apply. In this instance, the short-run ERI of 1.0 would be used. As a result, all of the $56.17/kw marginal generation cost would be included in the incentive payment.

TURN contests the use of the short-run ERI for nonfirm customers, asserting that this ERI is high largely because the resource plan on which it is based does not assume that spot market purchases are contributing to PG&E's generation capacity. However, TURN points out that the QFs receiving payments based on this ERI are deferring PG&E's need to buy spot capacity. In contrast, according to TURN, nonfirm customers do not cause PG&E to avoid spot capacity purchases. To the contrary, TURN states, it is part of PG&E's dispatch to purchase spot capacity before calling for curtailments. FEA responds to TURN by pointing out that TURN's assertions are without reference to the record and that even if true, the spot capacity issue is irrelevant. FEA argues that while as-available QFs (those receiving payments reflecting the short-run ERI) sell power to the utility whenever they want to, nonfirm customers must curtail their demand precisely when the utility tells them to. It is this factor that makes nonfirm customers a resource that is at least as valuable as the as-available QFs. We agree with FEA on this point.

2.4 Should Incentive Amounts Include Transmission and Distribution (T&D) Costs?

In D.89-12-057, the Commission concluded that the incentives paid to nonfirm customers should include avoided transmission and distribution costs. These payments were modified to reflect the extent of coincidence between the peak on the bulk transformers and the system-wide peak.

There is no factual support for the suggestion that distribution costs are avoided when a customer becomes interruptible. Even CLECA now acknowledges this. While curtailments are triggered by system-wide problems, the utility has to be prepared to serve each customer to the full extent of its individual demand. It is unlikely that any customer's individual peak demand will always coincide with the system-wide peak.

On the other hand, it is logical to assume that virtually any new addition to generation will require some new transmission (generation tie). Thus, if nonfirm customers enable PG&E to avoid any generation capacity, then they should enable PG&E to avoid some transmission costs. PG&E argues that since it is serving nonfirm customers on demand anyway, it must not be avoiding any transmission costs. This argument supports the exclusion of distribution costs from the incentive payment, as discussed above. However, if the nonfirm program allows the utility to plan for less generation (as it should), then it should allow the utility to plan for less transmission. TURN disputes this fact, pointing out that no one has produced a shred of evidence that a single transmission line has been avoided due to the existence of the nonfirm incentive program. CLECA correctly points out that TURN is asking other parties to prove a negative. If a transmission line was avoided, it is probably nowhere to be found. However, just how much new transmission will be needed to deliver new generation is, at a minimum, extremely difficult to determine in the abstract.

As power moves through the transmission system toward the customer, the relationship between a new generating plant and the need for new transmission becomes more circumstantial. Whether and where new bulk or area lines may be needed is dependent on where bottlenecks exist and where demand has grown. PG&E has suggested that we arbitrarily assume that the costs of bulk transmission lines are avoided while the costs of area transmission lines are not. However, the distinction between those classes of lines is not well enough defined for us to rely on. The appropriate costs may include less than the full array of bulk lines, or some portion of the area lines.

For the time being, we will not attempt to make such a distinction. However, since the transmission costs included in this class are most likely broader than those that are avoided, we must adopt some means of reducing the transmission portion of the incentive payment. DRA, CLECA, CMA, FEA and CLFP suggest that we continue to apply the coincident peak estimate of 0.875 employed in D.89-12-057. This number reflects the fact that there does not appear to be a perfect relationship between the generation peak and the transmission peak. We will use this factor, for lack of something better. The result is a transmission-related incentive payment of $27.83/kW.

However, we are uncomfortable with continuing to rely on a proxy of this type for calculating a number that has such a substantial effect on the incentive level. This discomfort is borne from the possibility that future transmission additions may not reflect the same relationship to peak demand as the embedded system. CLECA tried to address this issue by looking at the stated purposes for recent PG&E transmission additions. CLECA found that for 1985 through 1987, PG&E's 1990 GRC workpapers show $271 million in transmission investments, of which $138 million were for major one-time transmission facility additions. CLECA asserts that one-time transmission facilities are those needed to connect new power sources to the grid.

These numbers do not directly support the use of the 0.875 coincident peak ratio, since they suggest that only 50% of PG&E's transmission investments in those years were related to new generation capacity. CLECA goes on to submit that this 50% level is only a floor, since other transmission facilities have to be expanded as well to accommodate new generation. However, CLECA presents no evidence to suggest what portion of the 1985-1987 costs related to such facilities. CLECA also points out that DRA took the position, earlier in this proceeding, that $85 million of a total of $100 million spent for new transmission facilities were load growth related and that PG&E accepted this assessment. However, PG&E's witness in this proceeding explained that PG&E found only $15 million of the $100 million expenditures to be growth-related and settled for the DRA estimate only for the limited purposes of the case at hand.

The conclusion that CLECA reaches based on the evidence it presented is that the 0.875 coincident factor proxy is likely to be closer to reality than PG&E's 50/50 split. With the current record, we lack the precision to agree even with this limited assertion. However, the 0.875 proxy at least has an historical basis and should be used in the hopes that a better factual bases can be applied to this calculation in the currently pending GRC.

We are faced with another challenge as well. In calculating the incentive payment, we assume that there is some probability that new generation could be needed and are adjusting the generation costs by an ERI to reflect that probability. We are also assuming that there are added transmission costs because it is likely that transmission will be needed to serve new generation. However, there is no method available for adjusting the transmission value to reflect the probability of new generation being needed. This suggests that, over time, the transmission costs avoided by a nonfirm customer will be overstated. Since the ERI applied in this decision is 1.0, the problem is moot for our current purposes. However, it suggests another aspect of the avoided transmission calculation that must be reconsidered in future proceedings.

2.5 Do System Planners Adequately Consider Nonfirm Loads?

The guidelines currently used by PG&E for implementing the nonfirm program are attached to this decision as Appendix C. PG&E acknowledges that it is quite conservative in interpreting these rules. This may be an understatement, in that PG&E has not curtailed a nonfirm customer since 1987.

Just as a doctor might feel compelled to maintain life support for a failing patient, electric utilities take seriously their commitment to serve. In PG&E's case, this commitment may be so thoroughly ingrained that it has difficulty cutting off service even to those customers who have asked to be curtailed in exchange for incentive payments. CLECA says that there are several instances since 1987 when, even under the current guidelines, curtailments should have occurred. PG&E responds that CLECA is reaching its conclusion by examining historical reserve margins, which, of course, were unavailable to PG&E when it decided not to order curtailments.

PG&E argues that customers who sign up for the program expect that they are unlikely to be curtailed. Apparently, however, at least some of the nonfirm customers have no such expectation. CLECA argues that since the program is valuable, and since its incentives are based on the resource value it provides, the utilities should manage the program in such a way as to maximize its value. DRA argues that regardless of the rules reflected in PG&E's guidelines, the actual basis for calling curtailments has remained somewhat unclear.

In the hearings leading up to this decision, we found that while PG&E's nonfirm program might provide a means of reducing demand in the most dire of emergencies, PG&E is not using its curtailment option as it might use its reserve generating facilities. As such, PG&E may be under-utilizing the program as a resource. In D.89-12-057, we considered the characteristics of a perfectly interruptible customer. For a moment, let us consider the perfectly planned electric system. Put most simply, in such a system, a customer who is paid an incentive in exchange for curtailment during system peak would in fact be curtailed during system peak. Then, the utility would know with confidence that it need not consider the demand otherwise generated by participating customers not only when planning its system, but also when making operating decisions.

There are at least two aspects of real life that differ from the imagined world of the perfect planner. First, during the last several years, this utility has had the luxury of capacity in excess of its target reserve margin. If excess capacity is available and economically attractive at the time of system peak, it may make sense for the utility to use it before ordering curtailments. As the current excess capacity diminishes, an appropriately planned system should not present this option as often. Second, it may be difficult to precisely anticipate the timing of system peak. Nonetheless, implementation guidelines designed to remove nonfirm demand at the time of system peak would reflect an effort to keep the nonfirm resource in the forefront of the system planner's thinking, instead of encasing it in glass labelled "Break Only If All Else Fails."

PG&E and TURN suggest that the lack of curtailments in the last few years supports the notion that the incentives are too high. CLECA and others argue that rather than lowering the incentives, PG&E should be encouraged to take greater advantage of the resource it has available. We have already chosen to set the incentives based on potential savings. Later in this decision, we will discuss ways of bringing the program closer to meeting its potential.

As PG&E points out, although DRA and CLECA advocate more frequent usage of the curtailment option, no one has proposed specific revisions to the implementation guidelines. However, DRA recommends that PG&E's operation of its nonfirm program be subject to annual reasonableness review to ensure that (1) curtailments are being called when needed to ensure reliable service to firm customers, (2) any additional mandatory curtailments are being used to maximize the value of the nonfirm program, and (3) additional voluntary economic curtailments are being offered when the cost of power purchases exceeds the rates paid by customers. We agree with DRA that PG&E bears this burden. In its ECAC proceedings, we expect PG&E to demonstrate the reasonableness of its implementation of the nonfirm customer program. In addition, DRA would have the results of curtailments which avoid emergency power purchases used in the GRC following the one that is currently underway to further evaluate the economic curtailment program (if a system like demand-side bidding has not already superceded the current nonfirm program). We will consider this requirement in light of our further review of the nonfirm rate program in the now-pending GRC.

2.6 Should Incentive Amounts be Reduced to Reflect Curtailment Limitations?

Of all the parties participating in this portion of the proceeding, only TURN would answer this question "yes." TURN proposes that the Commission adopt a pay-for-performance method that would work as follows:

The nonfirm customer would receive a floor payment equal to PG&E's current ERI floor of 0.4 ($22.47/kW-yr.). Payments would increase based on the number of curtailments. If the system is more reliable, fewer curtailments would be called and less money would be paid automatically. If reliability becomes worse, more curtailments would be called and participants would be paid more.

The intended effect is to base the payment on PG&E's actual reliability without the need to calculate an ERI adjustment.

TURN would offer two options, one with audit curtailments and one without. With successful completion of two audit curtailments, the customer choosing those curtailments would receive 50% of the cost of the combustion turbine ($28.08/kW-yr.). These customers would then receive 10% of the cost of a combustion turbine for every additional curtailment up to 100% of the value of a combustion turbine. Customers unwilling to accept audit curtailmnents would be required to provide their first two curtailments for free and would then receive 10% of the cost of a combustion turbine for each additional curtailment.

TURN says that it offers this proposal for three reasons:

1. to circumvent the ERI debate, discussed above,

2. to determine the nonfirm customers who will reliably agree to curtailment when the need arises, and

3. to assure that incentive payments reflect the value of the program.

It is DRA's position that no reductions in incentive levels should be made. DRA argues that customers should receive credits equal to the costs that are avoided by being nonfirm, and PG&E's nonfirm program should then be administered so as to assure that the costs are actually avoided. DRA asserts that no evidence suggests that the current curtailment limitations reduce the value of the nonfirm program and that, therefore, no reduction in credits would be appropriate.

In addition, DRA argues that there are logical flaws in TURN's proposal. First, while TURN would never allow more than 100% of avoided cost to be paid to a nonfirm customer in a given year, it would pay far less than full avoided cost in years with few curtailments. Because of all the contingencies included when calculating the target reserve margin, there will be years when few curtailments are needed. DRA argues that TURN's proposal would cause customers to leave the program, causing it to fail because the incentive payments in many years would be quite low. Second, increasing the credit given to nonfirm customers by 10% of the value of a combustion turbine for each curtailment would produce an incremental cost of calling a curtailment of $5.62 per kW. DRA points out that if a curtailment lasts six hours, the incremental cost would be 94 cents per kWh ($5.62 kW/6 hours) plus whatever revenue would be lost in sales to nonfirm customers. DRA then argues that since emergency power is likely to be available for less than 94 cents per kWh, PG&E's system operators would always save money by buying emergency power and would never call a curtailment, causing the nonfirm program to fail.

There is much initial appeal to the TURN proposal. TURN would address concerns about PG&E's operation of the program by linking payments to actual curtailments as it addresses the twin concerns that some nonfirm customers may be undependable and that they may be receiving useless payments by assuring that pay would be linked to performance. However, we will not adopt this proposal for several reasons. First, this proposal introduces uncertainty for the nonfirm customer as to the stream of incentive payments in a given year. Greater stability might be needed in order to retain customers in the program. Second, as DRA has pointed out, this approach creates an economic disincentive for PG&E to call curtailments and assure that the revenues would be sufficient to keep customers on the program. Finally, this degree of emphasis on each curtailment decision standing alone does not directly reflect the value of nonfirm customers for resource planning purposes. We want PG&E's planners to be able to rely on nonfirm customers to offset the need for some peak generation capacity. Ultimately, we want the payments to reflect the value of that capacity as opposed to the value of individual curtailments.

2.7 Should Penalties for Noncompliance with Curtailments be Assessed to Classes of Customers (e.g., by Reduced Incentive Amounts Based on Compliance Expectations) or to Individual Customers (e.g., Through Direct Penalties)? What are Appropriate Penalties?

In rejecting the Settlement in D.91-07-042, the Commission emphasized that it did not object to the terms and conditions that accompanied the proposed incentive payment level. Those terms and conditions included consideration of penalties for noncompliance. The parties are virtually unanimous in supporting adoption of the penalty provisions found in paragraph 7(c) of the Settlement. We find that penalties designed to ensure performance are a vital element of an effective program and that a system of penalties agreed upon by the program participants is most likely to be successful and should be adopted.

2.8 Should the UFR Program be Continued, and if so, at What Incentive Amount?

The UFR program automatically interrupts customers when there is a sufficient drop in system frequency. These interruptions seem to occur a few times every year. PG&E proposes phasing out this program because it only provides minimal system benefits. In its Final Report, PG&E estimated those benefits as equalling $8/kW per year. The current incentive payment is $16. All other parties advocate retaining the UFR program and setting the incentive payment at a level that reflects the program's value to the system. Most agree with PG&E's assessment of its current value.

Many interruptible customers have invested in additional equipment to provide back-up capability for the times when the UFR is tripped. This appears to make those customers more reliable participants in the curtailment program as well and thereby adds value to the entire nonfirm program. We will expect the parties to continually monitor the costs and benefits of the UFR program. For now, we will approve its continuation, allowing an $8/kW payment, which appears to be the reasonable value of the program at this time.

2.9 What Mandatory Curtailments are Reasonable?

As discussed earlier, PG&E has not called for a curtailment under its nonfirm program since 1987. PG&E proposes adoption of the pre-emergency curtailment program included as part of the Settlement. Pre-emergency conditions would correspond to system operation conditions in which forecasted temperatures are high and/or two-hour system reserves are expected to be low. Such conditions existed 18 times in 1988, five times in 1989, five times in 1990, and six times in 1991. PG&E would invoke a minimum of six pre-emergency curtailments for non-UFR customers in any three-year period. UFR customers would receive a minimum of three pre-emergency curtailments in any three-year period. PG&E could call no more than three pre-emergency curtailment for UFR customers and five for non-UFR customers in any given year. No pre-emergency operations would be called in any given year if there had already been two or more actual emergency curtailments that year.

PG&E argues that there is uncertainty about the physical and economic ability of many of PG&E's nonfirm customers to respond consistently to curtailments if they were to be called with any regularity. Of the 240 customers currently enrolled, 200 have signed up since 1984, a period during which incentive payments have been high and there have been only two curtailments. PG&E estimates that up to 30% of the nonfirm customers may leave the program if required to curtail more frequently. Data from other states lend support to this estimate.

CLECA contests most aspects of this proposal. It argues that no mandatory curtailments should be necessary for UFR customers (who comprise about 80% of the nonfirm customers) since they are interrupted several times a year, thus demonstrating their commitment to participating in the program. DRA, which wants there to be mandatory curtailments but sees no reason to treat UFR customers differently, points out that UFR interruptions are usually 30 minutes or less. DRA argues that it is important to assure that those receiving nonfirm incentives will be able and willing to curtail for longer periods such as 6 to 12 hours.

CLECA further argues that pre-emergency curtailments would hardly be necessary if PG&E would install a direct control system as part of its nonfirm program. Currently, when PG&E calls for a curtailment, it has to literally pick up the telephone or otherwise contact the nonfirm customer and ask it to curtail its demand. If the customer refuses to cooperate or simply does not answer the telephone, there is little that PG&E can do. The use of direct control technology would enable PG&E to push a button and cut off the customer's curtailable demand. SCE uses this type of technology for some of its nonfirm customers. However, SCE's control over demand is still less than perfect, since an uncooperative customer could override SCE's control by pushing a button of its own.

The advantages to installing a direct control system will be considered below. However, in the near-term, PG&E does not have one installed. Even with direct control, however, customers that have not had to face lengthy curtailments in several years may learn, when the first such event occurs, that they do not want or cannot afford to stay in the program.

CLECA advocates reliance on stiff penalties and a threat to return to firm status anyone who refuses to shed load more than once. Although penalties are appropriate, they do not test the reliability of the nonfirm program if curtailments do not occur for several years at a stretch. CMA and CLFP object to pre-emergency curtailments because they create costs for the curtailed customers and for other ratepayers (through lost revenue). While we do not take lightly the implementation of cost-generating programs, we feel that a pre-emergency curtailment program is appropriate in light of the ratepayer investment to date in the form of annual incentive payments. We agree with PG&E that it is better to test the reliability of program participants in advance, than to find out that some customers are not dependable when it is too late. However, since a bidding program may be adopted within a year, it may be premature to begin calling pre-emergency curtailments. Thus, we will not approve the pre-emergency curtailment program as set forth in the Settlement for use in the next 12 months.

2.10 Should Authorization for Economic Curtailment, Based on PG&E's Daily or Hourly Cost of Service, be Continued?

The economic dispatch option was first proposed by DRA during the initial rate design phase in this proceeding and was authorized by the Commission in D.89-12-057. Under this option, PG&E would offer economic incentives for voluntary load reductions (to be paid on a per kWh basis) in order to avoid certain power purchase costs. The incentives would be offered only when avoidable transactions were conducted at costs in excess of PG&E's tariffed energy rates.

These incentives have yet to be used and most parties seem to agree that they are unlikely to be invoked in the near future. However, no one objects to the continuation of the program (although TURN expressed some concern that any expenses to administer or operate the program may be futile). It may be appropriate to reconsider this program in the pending GRC. For now, we will allow it to continue, subject to the reporting requirements contained in Paragraph 5 of the Settlement.

2.11 What Other Terms and Conditions are Reasonable (Contract Duration, Number of Mandatory Curtailments, Rate Design, Standby Service, Amnesty Periods, etc.)?

2.11.1 Limits on Curtailments

The Settlement would have continued the current tariff language concerning limits on PG&E's use of the curtailment option. Nonetheless, in its testimony, PG&E suggested reducing the maximum annual number of curtailments from 30 to 18, arguing that it is not realistic to expect more curtailments in any given year. DRA objected to this change, saying that it would create an unnecessary limit to PG&E's flexibility in operating the program. In response, PG&E said that it has no objection to maintaining the current tariff provisions, as embodied in Paragraph 7(d) of the Settlement. No other party has addressed this issue. We will approve the adoption of Paragraph 7(d).

2.11.2 Eligibility Requirements

Currently, a customer wishing to participate in this program must have an average on-peak load of at least 500 kW. Paragraph 7(f) of the Settlement would maintain this requirement. Although it signed and continues to endorse the Settlement, DRA would eliminate this provision, arguing that it unnecessarily discourages customers from shifting load out of the on-peak period. PG&E responds that the present combination of on-peak demand and time-of-use energy charges already provides economic incentive for customers to shift usage off peak where appropriate. The utility also argues that if the usage limitation was lifted, hundreds of new participants might join the program at a time when there is no demonstrated need for additional nonfirm load.

This does not appear to be the time to increase program eligibility. One of the greatest advantages of limiting this offering to the largest customers is that the potential exists for achieving sizable demand reductions while dealing with relatively few firms and individuals. Perhaps of greatest concern is the possibility of adding several hundred new participants while obtaining a much smaller amount of new potential demand reduction. The additional effort and cost involved in administering the program might not be justified in terms of the incremental gain in potential demand reduction. We will approve continuation of the 500 kW average on-peak load requirement.

A controversy also exists as to the appropriate eligibility requirements to apply to standby service customers.

Standby customers are self-generators or QFs who rely on PG&E to provide either back-up or supplemental power. Under the eligibility requirements currently in place, standby service customers are able to qualify for nonfirm incentives. Nonetheless, PG&E and CSB report a common concern that enforcing the requirement for 500 kW of average on-peak load, all to be served by PG&E, can cause problems when applied to nonfirm customers.

The Settlement would have allowed the 500 kW requirement to be met by combined on-site load, whether served by PG&E or by the customer's own generation. CSB proposed that the Commission adopt this provision. Earlier, PG&E had instead proposed that a 50% on-peak load factor be required in order to assure that standby customers do not receive rate credits far out of proportion to the value of their interruptibility. CSB strongly objects to this provision, arguing that it would deny interruptible service to many QFs and thereby violate federal Public Utility Regulatory Policies Act (PURPA) guidelines. PG&E now proposes that this issue be deferred for more extensive discussion in the currently pending GRC.

We are not prepared, in this proceeding, to determine the significance of CSB's arguments about our responsibilities under the PURPA guidelines. In addition, discussions between PG&E and CSB on issues concerning standby customers appeared to continue throughout the hearings in this case. In the months available before rate design hearings will be held in the current GRC, perhaps PG&E and CSB will be able to take further steps to resolve their concerns. Since the current eligibility guidelines do not preclude standby customers from participating in the program, we will allow them to continue unchanged, for now.

2.11.3 Annual Redesignation of Service Levels

No party opposes adoption of Paragraph 7(a) of the Settlement, which requires PG&E's concurrence for customers to increase their firm service levels, but does not require such concurrence for a customer that wishes to decrease its firm service level. This language appears reasonable and satisfies the concerns of all of the parties. We will approve Paragraph 7(a).

2.11.4 Remote Metering and Direct Control

PG&E has asked for authorization and funding for the development of a system of meters with remote monitoring capability, located at each nonfirm customer's site. Approval would be subject to Commission approval of an Advice Letter filing to be prepared by PG&E by May 1, 1992, or soon thereafter.

The goal of PG&E's metering program would be to create monitoring capabilities broadly similar to those it enjoys for all conventional power plants and most QFs. The system would be funded through the monthly incremental customer charge for nonfirm service, which would be increased by no more than $100.

PG&E is also interested in pursuing the development of a direct control program. Any approval granted here for such a program would be subject to approval of an Advice Letter filing by PG&E, expected to occur by January 1, 1993. As PG&E explains it, such a system would provide a means by which, after notification from PG&E, in order to avoid actual curtailment of loads, direct control customers would have to activate an override switch within a certain period of time in order to avoid shedding all of its load. The current program works in the opposite manner, requiring nonfirm customers to manually shut down their on-site loads in order to comply with a curtailment request.

Participation in the direct control program would be at the option of the nonfirm customer, who would pay any additional costs in the form of either a one-time payment or additional monthly charges. Paragraph 6(a) of the Settlement would subject participants in this program to fewer pre-emergency operations.

No one objects to either the remote metering program or direct control proposals. To the contrary, CLECA, CMA and DRA strongly encourage the creation of a direct control program as a means of increasing confidence in the reliability of the program. DRA, however, would have us require that the remote metering effort be accompanied by a direct control program. PG&E suggests that the two programs be kept separate for two reasons. First, the company can apparently set up the metering program more quickly. Second, the direct control program will be optional and may take more time and effort to sell to participants. We will allow PG&E to use its discretion inserting the pace for both the metering and direct control programs. The remote metering may provide benefits to the operation of the program in the short-term and the direct control program would be absorbed by those choosing to participate. However, we will expect PG&E to exercise prudent judgment in light of the likelihood that a bidding system will soon replace the existing program.

2.11.5 Contract Duration

In its current form, the contract under which individual customers participate in the nonfirm incentive program has a rolling three-year duration, under which PG&E retains the option of requiring customers to give up to three years' written notice before returning to firm service. Paragraph 7(b) of the Settlement would continue this provision. CLECA supports making the commitment longer (five years, instead of three) in exchange for higher incentive payments. FEA supports the three-year period. Most other parties are silent on this issue. For the purposes of this proceeding, we will approve continuation of the three-year provision.

2.11.6 Amnesty Period

Under the contract, PG&E could always choose to waive the three-year notice requirement discussed above. However, in anticipation that some current program participants may wish to return to firm status after receiving notice of new incentive payments and conditions, PG&E proposes, and all other parties support, a one-time three-month amnesty period after the effective date of this decision during which participants could announce their intention to leave the program. Paragraph 7(e) of the Settlement reflects this proposal. PG&E points out, however, that its agreement to a three-month amnesty is contingent on a March 1, 1992 effective date for this decision in order to allow the amnesty period to run prior to the start of PG&E's summer operating system. Since this decision is being issued after March 1, 1992, we will limit the formal amnesty period to the time between this decision and July 1, 1992. PG&E maintains the discretion to waive the three-year requirement at other times, where reasonable.

2.11.7 Rate Design

The Settlement included (as Table 1) an agreement as to how the incentive payments should be offset against charges to nonfirm customers for their usage at various times during the year. PG&E proposes adopting the rate design included in the settlement, with a pro-rata adjustment to reflect the difference between the incentive level proposed in the Settlement ($70.00/kW)) and the level approved in this decision ($84.00/kW).

The proposed rate design involves the allocation of 10% of the annual credit to the winter season and summer off-peak period, on an equal cents per kWh basis. The remaining 90% of annual credit would be allocated between the summer on-peak and partial-peak period in proportion to loss-of-load probability, with the on-peak credit in turn allocated 50% to the on-peak demand charge and 50% to the on-peak energy charge. However, a floor on the energy charges by time-of-use would be applied, so that time-of-use energy charges are at least as time-differentiated as marginal energy costs.

In order to determine the appropriate incremental change in rates, it is necessary to make certain assumptions as to how much electricity nonfirm customers are going to buy at particular times during the year (billing determinants information). For the rate design in the Settlement, the parties used an average of three years' actual purchases to establish a pattern of consumption. Although DRA agrees with PG&E that the rate design proposal from the Settlement should be adopted, DRA would update the billing determinants by using 1991 consumption figures as introduced by PG&E in its ECAC proceeding instead of the older three-year average numbers.

PG&E objects to this change, prefering to use the three-year average numbers and expressing a desire to avoid any changes that might complicate or delay implementation of a new rate design in response to this decision. We agree that, for the purposes of these rates which are likely to be in place for only one year and need be put into effect without delay, it is important to simplify the rate design process. Toward that end, we will adopt PG&E's proposal to use the rate design proposed by all the parties to the Settlement and to adjust the Settlement figures on a pro-rata basis to reflect the $14.00 difference between the incentive level proposed in the Settlement and the level adopted in this decision.

Even with the increased incentive payments approved in this order, the incentives are lower than they have been in some past years. In order to provide some stability for nonfirm customers in times of reduced incentive payments, the Commission, in D.89-12-057, adopted a phase-in mechanism. No customer's bill is increased by more than 10% (after adjusting for other post-1990 rate changes) over what its bill would have been for the same usage during the same month of the previous year. Also, under the phase-in mechanism, very few customers' bills are actually increased by more than 5 to 7% per year, relative to firm service rates. This is because rates applicable during the winter billing periods have held relatively flat, with the largest increases occuring during the summer billing months. As a result, the overall impact of the phase-in mechanism has been similar to the five percent standard for revenue allocation caps that has been used by the Commision in PG&E's recent ECAC cases.

PG&E proposes that the present phase-in be left in place until at least May 1, 1993, when it is anticipated that rates stemming from the now-pending GRC will go into effect. Based on the information in the current record, we do not know what nonfirm customers, if any, will face rate increases exceeding the 10% phase-in limit as a result of this decision. However, we continue to seek the program stability that can only be maintained if precipitous changes in incentive payments can be avoided. In order to promote stability, we will approve an extension of the phase-in mechanism until May 1, 1993. Questions related to use of a phase-in mechanism beyond that date can be addressed in the currently pending GRC.

The nonfirm incentive program will continue to create a revenue shortfall that must be absorbed by other customers. As in the past, because the benefits from the program accrue to all customers, the additional revenues will be absorbed by all ratepayers. We expect the next new rate design affecting all customer classes will not be adopted before PG&E's next ECAC proceeding. In the interim, we will expect PG&E to track any revenue shortfall resulting from the changes in the incentive payments in its Electric Revenue Adjustment Mechanism (ERAM) account.

2.12 What is a Reasonable Incentive Amount, Reflecting a Fair Balance with Program Terms and Conditions?

The assumptions adopted in this decision for calculating the nonfirm incentive payments result in a flat \$84.00/kW for each customer class. There is no difference in incentives between transmission, primary and secondary customers because we are not including coincident peak distribution costs in the incentive payment. UFR customers will receive an additional \$8.00/kW for a total incentive payment of \$92.00/kW. This represents a sizable increase over the the $67.07/kW incentive for transmission customers and $81.15/kW incentive for distribution customers adopted in D.89-12-057. The increase is largely the result of the fact that we are no longer imputing a portion of the avoided cost to represent payments for economic dispatch. We do not anticipate that conditions will necessarily require PG&E to exercise its economic dispatch option while these incentives are in effect.

In exchange for these higher incentives, nonfirm customers will experience more curtailments and stiffer fines if they fail to perform. Nonetheless, this re-examination of the incentives has emphasized the inadequacy of currently available ERIs (suggesting that a more suitable ERI must be calculated if we are to continue authorizing avoided cost incentive payments) and the importance of more fully exploring the bidding alternative.

3. <u>Conclusion</u>

The parties are to be congratulated for their efforts to work together in resolving their differences in this proceeding. While the Settlement has not been adopted in its entirety, it has provided the Commission with a rich base of options for this decision. The program approved in this order will remain in effect until the adoption of new incentives or an alternative nonfirm customer program in the currently pending GRC.

<u>Findings of Fact</u>

1. About 240 of PG&E's largest electric customers currently participate in the nonfirm service program.

2. Approximately 550 MW of coincident on-peak load is subject to mandatory curtailment.

3. Since the right to reduce or interrupt a customer's demand helps the utility decrease its need for peak or emergency capacity, this program should help keep down capacity costs.

4. Approximately 400 MW of the curtailable load is served on underfrequency relay devices (UFRs) that automatically shed the customers' loads when system frequency drops below 59.75 Hertz.

5. The customers enrolled for nonfirm service received more than $40 million per year in rate discounts during 1990 and 1991 on the basis of interim rates adopted in D.89-12-057.

6. A number of parties filed a settlement which was rejected by the Commission because it could not conclude that the incentive amount, even considering the benefits of the Settlement terms and conditions, is fairly balanced against the risks of going to hearing on the merits of the parties' testimony.

7. No matter how the balance of payments between the utility and nonfirm customers is calculated, the impact of this program on other ratepayers should not exceed the costs that the program avoids.

8. A ground-up rate design might be the most equitable basis for calculating nonfirm rates, so long as they do not exceed avoided cost.

9. While the merits of nonfirm incentive bidding will be considered in other proceedings, it should be remembered that a bidding system would make moot the more subtle issues of nonfirm rate design.

10. Until such a time as a bidding program or other mechanism allows potential nonfirm customers to express a price preference, we will not know whether rates set at a particular level below full avoided cost would substantially undercut participation in the program.

11. The ERI allows us to adjust the cost of a combustion turbine to reflect our best judgment of the utility's current need for a new source of generation.

12. The ERI reflects the potential for emergencies.

13. The use of an ERI helps us assure that other ratepayers are not required to bear unnecessary costs.

14. When current ERI's are calculated, it is assumed that the nonfirm incentive is in place and that nonfirm customers are not contributing to peak demand.

15. It would be unfair to customers who agree to curtailment if the nonfirm incentive was reduced to reflect the benefits of nonfirm customers.

16. Since QFs are subject to reliability constraints of their own, some QFs may provide a less reliable resource than some nonfirm customers.

17. While as-available QFs (those receiving payments reflecting the short-run ERI) sell power to the utility whenever they want to, nonfirm customers must curtail their demand precisely when the utility tells them to.

18. There is no factual support for the suggestion that distribution costs are avoided when a customer becomes interruptible.

19. It is logical to assume that virtually any new addition to generation will require some new transmission (generation tie).

20. If the nonfirm program allows the utility to plan for less generation (as it should), then it should allow the utility to plan for less transmission.

21. The coincident peak estimate of 0.875 reflects the fact that there does not appear to be a perfect relationship between the generation peak and the transmission peak.

22. The 0.875 coincident peak transmission proxy at least has an historical basis and should be used in the hopes that a better factual basis can be applied to this calculation in the currently pending GRC.

23. PG&E has not curtailed its nonfirm customers since 1987.

24. While PG&E's nonfirm program might provide a means of reducing demand in the most dire of emergencies, PG&E is not using its curtailment option as it might use its reserve generating facilities, and may be under-utilizing the program as a resource.

25. In its ECAC proceedings, we expect PG&E to demonstrate the reasonableness of its implementation of the nonfirm customer program.

26. TURN would address concerns about PG&E's operation of the program by linking payments to actual curtailments as it addresses the twin concerns that some nonfirm customers may be undependable and that they may be receiving useless payments by assuring that pay would be linked to performance.

27. TURN's proposal would introduce great uncertainty for the nonfirm customer as to the stream of incentive payments in a given year.

28. TURN's approach would create an economic disincentive for PG&E to call curtailments and assure that the revenues would be sufficient to keep customers on the program.

29. Penalties designed to ensure performance are a vital element of an effective program.

30. A system of penalties agreed upon by the program participants is most likely to be successful.

31. The estimated benefit of the UFR program is equal to no more than $8/kW per year.

32. Of the 240 customers currently enrolled, 200 have signed up since 1984, a period during which incentive payments have been high and there have been only 2 curtailments.

33. It is better to test the reliability of program participants now, while the company may still enjoy excess capacity, than to find out when it is too late that some customers are not dependable.

34. The economic dispatch incentives have yet to be used and most parties seem to agree that they are unlikely to be invoked in the near future.

35. No one objects to the continuation of the economic dispatch program (although TURN expressed some concern that any expenses to administer or operate the program may be futile).

36. There is no objection to maintaining the current tariff provisions for limits on curtailments as embodied in Paragraph 7(d) of the Settlement.

37. Currently, a customer wishing to participate in this program must have an average on-peak load of at least 500 kW.

38. This does not appear to be the time to increase program eligibility.

39. No party opposes adoption of Paragraph 7(a) of the Settlement, which requires PG&E's concurrence for customers to increase their firm service levels, but does not require such concurrence for a customer that wishes to decrease its firm service level. We should approve Settlement Paragraph 7(a).

40. The goal of PG&E's metering program would be to create monitoring capabilitites broadly similar to those it enjoys for all conventional power plants and most QFs.

41. Direct control systems would provide a means by which, after notification from PG&E, in order to avoid actual curtailment of loads, a direct control customer would have to activate an override switch within a certain period of time in order to avoid shedding all of its load.

42. No one objects to either the remote metering program or direct control proposals.

43. In its current form, the contract under which individual customers participate in the nonfirm incentive program has a rolling three-year duration, under which PG&E retains the option of requiring customers to give up to three years' written notice before returning to firm service.

44. Under the contract, PG&E could always choose to waive the three-year notice requirement.

45. PG&E proposes, and all other parties support, a one-time three-month amnesty period after the effective date of this decision during which participants could announce their intention to leave the program.

46. The Settlement included (as Table 1) an agreement as to how the incentive payments should be offset against charges to nonfirm customers for their usage at various times during the year.

47. For the rate design in the Settlement, the parties used an average of three years' actual purchases to establish a pattern of consumption.

48. DRA would update the billing determinants by using 1991 consumption figures as introduced by PG&E in its ECAC proceeding instead of the older three-year average numbers.

49. For the purposes of these rates, which are likely to be in place for only one year and need be put into effect without delay, it is important to simplify the rate design process.

50. We continue to seek program stability.

51. PG&E has not called an emergency curtailment since 1987 and is not likely to call one in the next year.

Conclusions of Law

1. Since we are neither prepared to adopt a bidding system nor equipped to design nonfirm rates from the ground up, we should continue to offer incentive payments.

2. For the purposes of setting incentive levels for the summer of 1992, we should continue to direct PG&E to offer full avoided cost payments.

3. It is appropriate to use an ERI in calculating the upper limit for incentive payments.

4. So long as rate incentives are offered for nonfirm customers, a separate ERI should be calculated to determine the ERI that would result if the nonfirm incentive program was not in place.

5. In case a bidding program is not adopted by May 1993, PG&E should be directed to file a nonfirm in-out calculation in the current GRC to more accurately reflect the benefits of nonfirm customers in avoiding new generation.

6. Since a nonfirm customer provides supply-side benefits, where the long-run ERI is lower than the short-run ERI developed in the ECAC, the latter should apply.

7. We should continue to gauge the payments to reflect the value of that capacity as opposed to the value of individual curtailments.

8. The penalty provisions included in the settlement should be adopted.

9. For now, we should approve the continuation of the UFR program, allowing an $8/kW payment.

10. We should approve the pre-emergency curtailment program as set forth in the Settlement.

11. We should allow the economic dispatch option to continue, subject to the reporting requirements contained in Paragraph 5 of the Settlement.

12. We should approve the adoption of the limits on curtailments set forth in Settlement Paragraph 7(d).

13. Since the current eligibility guidelines do not preclude standby customers from participating in the program, we should allow them to continue unchanged, for now.

14. We should allow PG&E to work at the pace it proposes for the metering and direct control programs both because the remote metering may provide benefits to the operation of the program in the short-term and because, as proposed, additional costs for the direct control program would be absorbed by those choosing to participate.

15. For the purposes of this proceeding, we should approve continuation of the three-year notice provision for returning to firm service.

16. Since this decision is being issued after March 1, 1992, we should limit the formal amnesty period to the time between this decision and July 1, 1992.

17. Because the incentives approved in this order are intended to apply in summer of 1992, this order should be effective today.

18. The Commission should direct PG&E to use the rate design proposed by all the parties to the Settlement and to adjust the Settlement figures on a pro-rata basis to reflect the difference between the incentive level proposed in the Settlement and the level adopted in this decision.

19. We should approve an extension of the phase-in mechanism until May 1, 1993.

O R D E R

IT IS ORDERED that:

1. Pacific Gas & Electric Company (PG&E) shall revise its nonfirm electric customer program in a manner consistent with this decision.

2. Within 5 working days, PG&E shall submit an Advice Letter filing reflecting the program elements adopted in this decision.

This order is effective today.

Dated May 8, 1992, at San Francisco, California.

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

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

NEAL J. SHULMAN, Executive Director

APPENDIX A

Additional Appearances

Applicant: Robert B. McLennan, Attorney at Law, for Pacific Gas & Electric Company.

Interested Parties: Elizabeth Lowe, for Morse, Richard, Weisenmiller & Associates; Michael D. Mackness, Attorney at Law, for Southern California Edison Company and Thomas A. Tribble, for the Regents-University of California.

Commission Advisory and Compliance Division: Steve Linsey.

(END OF APPENDIX A)

EXHIBIT 1

SETTLEMENT AGREEMENT FOR PG&E NON-FIRM RATE PROCEEDING

The parties signing this settlement agree to the following terms for PG&E's non-firm rate program, to be effective May 1, 1991:

1. Incentive for non-firm service to be $70/kW-yr for emergency curtailment, with no additional incentive for UFR.

2. Incentive to apply until new rates go into effect as adopted pursuant to revenue allocation and rate design decision in PG&E's next General Rate Case ("GRC") (expected to be Test Year 1993); parties agree to work in the next GRC toward an incentive structure that fully considers rate stability for participating customers.

3. Treatment of non-firm incentives for revenue allocation purposes based on supply-side revenue allocation as adopted in Decision 89-12-057.

4. The rate design for non-firm customers to be adopted is shown in the attached Table 1. The principles on which the rate credits shown in Table 1 are based are as described in DRA's prepared direct testimony (and errata) in this proceeding.

The proposed credits by rate component are to be maintained until PG&E's next GRC decision.

5. Reporting requirements to be filed in annual ECAC reports as agreed to by PG&E and DRA as follows (subject to final agreement between PG&E and DRA):

a. Detailed accounting information on PG&E's California Power Pool transactions, and any other power purchases contracted for on an emergency basis. PG&E will provide this information in a format acceptable to DRA, as consistent as is practical with the description given in Appendix 1 of DRA's "Prepared Direct Testimony of James Price on PG&E's Non-firm Rates."

b. Daily operations reports for PG&E's summer operations period (June 1 to September 30), in the same format as was provided in Attachments 4-1 and 4-2 of PG&E's response to the CLECA data request in this proceeding. Additional information on specific operating days of interest to DRA will be provided upon request. Such information would consist of brief narrative reports that would either describe how any forecasted spinning reserve deficiency had been remedied (or why no remedial action was determined to be necessary), or note the fact that a curtailment had been called on the day in question.

6. Program operations criteria to be as follows:

a. Emergency operation up to 30 times per year (maximum 100 hours) according to the current operating criteria, as they are defined on the first page of the document entitled "Operation of Load Management Programs" (dated May 13, 1988, and as updated in the future, provided as Attachment 2 to PG&E's Final Study and Proposal filed in this proceeding). PG&E will continue its established practice of continually monitoring system conditions on critical operations days, based on the most current available forecasts of loads and resources.

b. Pre-emergency operation up to five times per year (with a minimum number of six pre-emergency operations in any rolling 3-year period). (Maximum of five hours per operation). These operations will be scheduled subject to the criteria described below. Non-firm customers electing to take service either on UFRs or under the direct control of PG&E (as described in Paragraph 9 of this agreement) will be subject only to up to three pre-emergency operations per year (with a minimum number of three pre-emergency operations in any rolling 3-year period). (Maximum of five hours per operation). The criteria used will be:

i. The 9:00 AM forecast of afternoon Central Valley temperature conditions (arithmetic average of forecasts for Sacramento and Fresno) is 100 degrees Fahrenheit or greater,

and,

Either PG&E's adjusted 10:00 AM forecast of two-hour reserves for that afternoon's peak is 12.0% or less, or the 10:00 AM forecast indicates that PG&E's afternoon peak will be within 500 MW of (or greater than) the previous record peak.

Or,

ii. The 9:00 AM forecast of afternoon Central Valley temperature conditions is that temperatures will be at least 105 degrees Fahrenheit.

Or,

iii. PG&E anticipates making discretionary emergency purchases at a price (inclusive only of all variable components of the price) greater than the tariffed E-20 Secondary non-firm on-peak energy rate.

c. No pre-emergency curtailments for any non-firm customers will be called if there have been two or more emergency curtailments to date during the year, unless required to meet the condition of the 3-year minimum operations target. Similarly, no pre-emergency curtailments for any non-firm customers will be called if there have been two or more pre-emergency curtailments and at least one emergency curtailment to date during the year, unless required to meet the condition of the 3-year minimum.

7. Terms and conditions of non-firm service will remain as they are defined in the present tariffs, except as noted below (and also in Paragraphs 6, above, and 8 and 9, below):

a. PG&E permission or three years notice required to increase firm service level. PG&E permission will be waived on re-specifications of contracted firm service levels until November 1, 1991.

b. Term of contract: three years (no change from present tariff provisions).

c. Penalty provision: 50 percent of the adopted incentive at each instance of noncompliance ($7.00/kWh); this would be reduced to 25 percent ($3.50/kWh) if a customer substantially complies with the pre-emergency and emergency curtailments for the preceding calendar year; maximum penalty equal to 200 percent of the adopted incentive in any one year; penalty to be applied on a per kWh basis.

d. Maximum of 30 emergency curtailments per year, 100 hours per year; minimum 30 minutes notice; PG&E will provide greater notice whenever possible.

e. Three-month amnesty period for customers wishing to switch to firm service beginning with the effective date of new rates in this proceeding.

f. Current eligibility requirements will continue in effect, except for those standby customers electing alternative eligibility rules, as described in Paragraph 8 below and as to be defined in the Schedule S tariff.

g. Present phase-in mechanism to remain in place until at least May 1, 1993. Present UFR customers must continue taking service under UFR option, except as specified in Paragraph 9 below to maintain eligibility for phase-in calculations based on 1989 E-19 and E-20 interruptible rate schedules.

8. Customers served on standby Schedule S will have the option of meeting the current eligibility requirements (500 kW average on-peak demand) and the terms and conditions described in paragraph 6 above, or they can elect to take nonfirm service

under the provisions described in this paragraph:

a. Standby customers may elect to be served, at their choice, under the conditions described in this paragraph 8 a-f. However, tc be served under the terms of this paragraph, they must have an average on-peak demand of 500 kW which can be served either by PG&E, their generator, or a combination thereof.

b. Service to be billed under the appropriate E-19 or E-20 schedule; same rate credits as defined in Table 1.

c. On-peak rate limiter on non-firm schedules to be set at the tariffed non-firm on-peak kWh rate, plus 67% of the differential between the tariffed on-peak kWh rate and the on-peak rate limiter on the corresponding firm schedule.

d. Additional metering for this option may be required at the customer's expense. Specifically, time-of-day metering (mag tape or load profile recorder) will be required on the generator output or total plant load. This metering can be owned by the customer if allowed to be regularly tested by PG&E.

e. Every standby customer served under this paragraph will be required to participate in all program operations called by PG&E, under pre-emergency or emergency conditions. (Participation, for purposes of this paragraph, means the reduction of their load served by PG&E to their contracted firm service level.) In addition, each customer must demonstrate to PG&E's satisfaction that they can reduce all plant load to their contracted firm service level for a minimum of three (3) hours (including electricity that would normally be provided by their own generator) during a curtailment operation. This may be done during an emergency or pre-emergency curtailment or at a time or manner that is agreed upon with PG&E. The minimum load drop during such a demonstration shall be 500 kW.

f. If a curtailment operation under paragraph e, above, occurs when the generator is operating, generator auxiliary station load (as specified and defined in the nonfirm service agreement) will be excluded.

9. Funding and implementation of remote metering and direct control will occur as described at pp. 33-36 of PG&E's prepared rebuttal testimony in this proceeding. Present UFR customers may retain phase-in eligibility based on 1989 E-19 and E-20 interruptible rates by transferring to direct control system, once this service option becomes available, provided that they either: (1) Agree to continue to be served under the direct control option for a term of at least three years, or (2) Reimburse PG&E for all expenses associated with the purchase and installation of all additional metering and control equipment

required by this service option, at the time the equipment is installed by PG&E.

10. In addition to the condition for pre-emergency curtailments based on avoidance of very expensive power purchases, the economic dispatch option adopted in Decision 89-12-057 will continue to be offered in the form of voluntary curtailments. Commission review of PG&E's decisions to offer such curtailments will recognize distinctions between energy and capacity payments made by PG&E for purchased power.

11. All parties signing this settlement agreement agree to sponsor and support the settlement agreement and its terms and conditions.

DATED: January 18, 1991

PACIFIC GAS & ELECTRIC COMPANY

Robert B. McLennan, Esq.

77 Beale Street
San Francisco, CA 94106

Attorney for PG&E

DIVISION OF RATEPAYER ADVOCATES

Judith Allen, Esq.

Cal. Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

JACKSON, TUFTS, COLE & BLACK

William H. Booth, Esq.
Joseph S. Faber, Esq.

650 California Street, 31st Floor
San Francisco, CA 94108

Attorneys for the California
Large Energy Consumers Association

BROBECK, PHLEGER & HARRISON

Gordon E. Davis

Gordon E. Davis, Esq.

3100 Spear Street Tower
One Market Plaza
San Francisco, CA 94105

Attorneys for the California Manufacturers Association

DOWNEY, BRAND, SEYMOUR & ROWHER

Philip A. Stohr

Philip A. Stohr, Esq.

555 Capitol Mall, Suite 1050
Sacramento, CA 95814

Attorneys for the Industrial Users

FEDERAL EXECUTIVE AGENCIES

Gilbert H. Chong 1/18/91

Norman J. Furuta, Esq.
Gilbert H. Chong, Esq.

900 Commodore Dr., Building 107
P. O. Box 727 (Attn: Code 09C)
San Bruno, CA 94066

Attorneys for the Federal Executive Agencies

COGENERATION SERVICE BUREAU

John D. Quinley

John D. Quinley

1415 Dawes Street
Novato, CA 94947

TABLE 1

Summer on-peak demand:	$4.90 per kW
Summer on-peak energy	2.414 cents per kWh
Summer pt-peak energy:	0.847 cents per kWh
All other TOU energy:	0.110 cents per kWh

Notes:

1) These credits are to be applied to the regular charges on each E-19, E-20 firm service schedule.

2) On-peak rate limiters are as defined in Paragraph 8(c) of Settlement Agreement.

(END OF APPENDIX B)

PG&E Operating Guidelines
(Load Management Programs)

PACIFIC GAS AND ELECTRIC COMPANY

POWER GENERATION - POWER CONTROL DEPARTMENT

OPERATION OF LOAD MANAGEMENT PROGRAMS

May 13, 1988

Load Management Programs will be operated by the Power Control Department to help reduce the risk of an electric generating capacity shortage. Determination of a shortage will be made based on: the forecasted California Power Pool spinning reserve margin; PGandE's ability to purchase capacity within California; the expected incidence of unscheduled statewide summer power plant outages which is provided in the California Power Pool Overhaul Schedule; and the number of remaining Load Management operations available to PGandE under each type of contract. The following procedure will be the normal method leading to a decision to implement Load Management programs:

1. The Daily Operating Loads and Resources from The California Utility Power Systems Coordinator report provides a daily forecast of peak loads and reserves. This forecast is developed based on system conditions and forecast temperatures as of the previous evening. If this report forecasts PGandE's spinning reserve less than 7%, it will be an alert that Load Management Programs may be necessary. However, unforseen conditions may develop subsequent to publication of this report which change the need for initiating Load Management Programs.

2. A final decision to operate Load Management will not be made until new morning forecasts of reserves are developed which are based upon morning temperature forecasts and current information on expected available resource conditions. The decision is normally made between 0900 and 1000.

3. A decision to operate should not be made without morning discussions with operations managers or chief system dispatchers in the other California Power Pool Companies and LADWP to verify the current status of inter-utility assistance as well as how firm the other systems are considered to be in respect to their reserves and forecasted margins. A last minute exchange of the most recent trends in statewide weather and temperature is also desirable.

4. The final decision will normally be made by the Chief System Dispatcher in collaboration with the Manager of Power Control.

The following operating criteria will be cause for the operation of Load Management programs to avoid an emergency. Spinning reserve margins are based on the 0900 forecast on the morning of the decision to operate.

Load Management Program Operation Criteria:

1. All Load Management programs are to be operated to their full contractual limit during such times as a Stage I, II, or III of the Electrical Emergency Plan is implemented.

2. In any operating month (May through September), operate all Load Management programs if the the 0900 forecast spinning reserve on peak for the California Power Pool is less than 7.0% and:

   - In May, forecast PG&E spinning reserve is less than 7.0%, and there had been 1 or no operations this season; or forecast PG&E spinning reserve is less than 5.5%.

   - In June, forecast PG&E spinning reserve is less than 7.0%, and there had been 1 or no operations this season; or forecast PG&E spinning reserve is less than 5.75%.

   - In July, forecast PG&E spinning reserve is less than 7.0%, and there had been 5 or fewer operations this season; or forecast PG&E spinning reserve is less than 6.0%.

   - In August, forecast PG&E spinning reserve is less than 7.0%, and there had been 7 or fewer operations this season; or forecast PG&E spinning reserve is less than 6.25%.

   - In September, forecast PG&E spinning reserve is less than 7.0%, and there had been 7 or fewer operations this season; or forecast PG&E spinning reserve is less than 6.5%.

3. After the 0900 forecast, the Chief System Dispatcher has discretion to operate Load Management programs if system conditions change such that PG&E spinning reserve of 5.0% or less during the daily peak is likely.

4. If a transmission overload occurs, or is anticipated during the daily peak, any Load Management participants may be operated so as to aleviate the overload after other immediately available remedial actions have been taken.

5. If the decision to operate is made after noon, the "SCRAM" order (Load Management operations are to begin immediately upon notification) will be used.

This criteria to operate Load Management programs is designed to allow a minimum of 3 full-duration operations of all programs as reserve for the case where extended use of the Electrical Emergency Plan is necessary.

The operation of any Load Management Programs for experimental and testing reasons may be scheduled by the Marketing Department based on criteria established by each project manager provided that it does not jeopardize future use for load relief needs. The time of operation must be coordinated with the Customer Service Department and other units as appropriate.

(END OF APPENDIX C)