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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Second application of Pacific Gas and Electric Company for approval of certain standard offers pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2.	Application 82-04-44 (Filed April 21, 1982; amended April 28, 1982, July 19, 1982, July 11, 1983, August 2, 1983, and August 21, 1986)
And Related Matters.	Application 82-04-46 Application 82-04-47 Application 82-03-26 Application 82-03-37 Application 82-03-62 Application 82-03-67 Application 82-03-78 Application 82-04-21

OPINION ON GAS COSTS AVOIDABLE BY QUALIFYING FACILITIES

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OPINION ON GAS COSTS AVOIDABLE BY QUALIFYING FACILITIES

I. Introduction

Today's decision addresses the calculation of energy prices for Qualifying Facilities (QFs) that receive variable energy payments. These payments are calculated using the following formula: the energy price for QF generation equals the purchasing utility's fuel-burning efficiency (expressed as British thermal units per kilowatt-hour) multiplied by the cost of fuel that the utility would have burned to replace such generation. The resulting cents per kilowatt-hour figure represents utility costs "avoided" by QFs. Deriving the cost of fuel in this formula has been complicated by recent developments in the natural gas industry, and corresponding changes that we have made in gas rate design. (See, e.g., Decision (D.) 86-12-009.) Today, we examine our new rate design to determine what gas costs are avoidable by QFs (and so are properly included in variable energy payments to QFs).

We conclude that most of the gas utility fixed costs that we have allocated to utility electric generation (UEG) customers are avoidable by QFs. The reason is that these costs (except for customer costs) are allocated on the basis of throughput. We therefore exclude only those costs not allocated by throughput in calculating the avoidable portion of gas costs. This will slightly reduce prices for QF energy. Prices for QF capacity are not affected.

II. The Relation of UEG Gas Costs to Avoided Costs

Electric utilities burn various fuels and also receive energy from nonthermal resources such as hydro. However, gas has been, and is expected to continue to be, the most important fuel from the standpoint of QF pricing. This is because gas-fired plants generally have the highest running costs on the utility system, and so these are the plants whose output a utility would choose to reduce in order to accept electricity generated by QFs.[1]

Thus, UEG gas costs generally provide the basis for computing prices for QF energy at this time. We stress that this results solely from economic dispatch, given existing utility systems and fuel mixes. In other words, gas has not been administratively ordained to be the avoided fuel. We have long recognized that both the fuel and the fuel price factored into the avoided-cost formula could vary over time. (See, e.g., D.82-01-103, 8 CPUC 2d 20, 44.)

III. The Relation of Gas Rate Design to Avoided Costs

The gas utility traditionally provided and charged for service on a "bundled" basis. The customer of such a service had relatively few choices, and the utility had relatively narrow options for responding to customer preferences. We had made

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1 During certain seasons and hours, when demand is low, an electric utility may be able to meet demand on its system without dispatching its gas-fired plants. This could happen, e.g., if the utility has available lower running-cost resources and power purchases from non-QF sellers. However, through the efficiency part of the avoided-cost formula, namely, the incremental energy rate (IER), we are able to account for times when the utility would not burn gas in the absence of QF generation. Thus, the price paid for QF energy is weighted to reflect times when QFs replace relatively low running-cost resources on the purchasing utility's system.

Generally, gas-fired plants can also burn oil. Because oil and gas can substitute for each other in many applications, their prices tend to be closely related, although significant transitory disjunctions occur. However, gas is generally preferable from an environmental standpoint, so (except when oil has a significant price advantage and is acceptable after air-quality considerations) gas would generally be the avoided fuel whenever oil/gas-fired plants are on the margin.

gradual changes to traditional service, largely to accommodate customers capable of using alternative fuels. However, in Order Instituting Investigation (I.) 86-06-005, we developed a new gas rate design, based on our perception that the gas industry had become more competitive, and that the competitive nature of the industry now required "flexible, market-responsive" rates. (D.86-12-009, mimeo., p. 2.)

By the term "market-responsive," we mean an "unbundling of the traditional combination service provided by the distribution utility and a de-averaging of rates." (Id.) The former bundled service had included both procuring gas (a merchant function) and moving it to the burner tip (a transportation or transmission function). The new rate design separates these two functions on the basis that "the merchant function is clearly competitive in nature, and the transmission function has natural monopoly characteristics with economies of scale." (Id.) We also saw that both alternative fuels and alternative gas supplies could compete with the distribution utility in its merchant function. This led to our adoption of a hybrid regulatory approach taking into account both monopolistic and competitive aspects of the market.

The UEG customers are deeply affected by the new rate design. Southern California Edison Company (Edison) and the electric departments of Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) are very large consumers of gas from the respective gas distribution utilities (generally referred to as "local distribution companies" or LDCs). These UEG customers have alternative fuel capability for the majority of uses for which they burn gas. Moreover, their consumption does not display the winter peak that characterizes the core gas market; the size of their load and their high summer load factor enables them to bargain aggressively with suppliers and brokers in competition with the LDC. "Market-responsive" gas rates help pass on the benefits of competition in the gas industry to the end-user of electricity (through lower costs of generation), and at the same time help the LDC to compete to serve the UEG load.

The differentiation of traditional gas service into discrete elements raises the issue in today's decision. Where the UEG customer had essentially one choice and one price for its gas service, using the UEG gas rate for fuel price in the avoided-cost formula was logical and simple, if not analytically rigorous. But the new rate design breaks out fixed and variable costs of the LDC, separately categorizes procurement and transmission service, and spreads the LDC's revenue requirement over a variety of fixed and volumetric charges. In this changed context, we find it both appropriate and timely to reexamine the question of what gas costs incurred by UEG customers are avoidable by QFs.

IV. Procedural Setting

As we were making various changes to traditional gas service, electric utilities were asking us to examine the impact of these changes on the method adopted in D.82-12-120 for the calculation of avoidable gas costs. We will not review the whole history of this question.[2] We have postponed our examination for various reasons: in part, because these changes raise a methodological issue that is not appropriately handled in the quarterly fuel price update for QFs (see D.86-08-053, mimeo., p. 4); in part, because the changes that the utilities were asking us to examine were themselves still in the preliminary stage of implementation. With our new gas rate design fully implemented in

2 However, witness Bolthouse in her prepared testimony on behalf of the Division of Ratepayer Advocates (DRA) includes a "History of Gas Avoided Cost Issue in PG&E Proceedings." (See Appendix B of Exhibit 501.)

D.87-12-039, we are now ready to reconsider the calculation of avoidable gas costs.

DRA conducted public workshops on this issue in January 1988. Hearings before Administrative Law Judge (ALJ) Kotz began on February 22, 1988, and continued for four days. The hearings included direct and rebuttal testimony from DRA, PG&E, SDG&E, Edison, California Cogeneration Council (CCC), Cogenerators of Southern California (CSC), Kelco Division of Merck & Co., Inc. (Kelco), and (jointly) Independent Energy Producers Association/Santa Fe Geothermal, Inc./Union Oil Company of California/Freeport-McMoRan Resource Partners (collectively referred to as IEP et al.). All of these parties filed briefs. Also, the California Energy Commission (CEC) and Alenco Resources, Inc. (Alenco) participated through cross-examination, and Alenco and the California Department of General Services filed briefs.

At DRA's request, the assigned ALJ allowed a round of rebuttal briefs on a point raised by Alenco's brief. DRA, Alenco, and Edison took advantage of this rebuttal opportunity.

After the hearings but before briefs were due, DRA invited the parties to a settlement conference. The conference did not produce unanimity, but it did succeed in narrowing the number of positions. DRA and the utilities now jointly recommend, as an "Interim Methodology," the approach that DRA witness Bolthouse advocated during the hearings. The QF representatives and Alenco (whose activities include marketing natural gas in the United States) recommend no change to the existing gas cost methodology, under which payments to QFs reflect the full weighted average cost of gas (WACOG) to the UEG customer.

V. The Adopted Method

We adopt a simple method for calculating the avoidable portion of UEG gas costs. Basically, all gas utility fixed costs are 100% avoidable except for customer costs. The latter are allocated, not by throughput, but on the basis of weighted number of customers. (D.86-12-009, mimeo., pp. 32-33.) We therefore exclude customer costs in calculating the avoided energy cost payment. All parties agree that the commodity component of UEG gas costs is 100% avoidable. If the electric utility buys from the noncore gas portfolio, the noncore WACOG should be used as the commodity cost of gas for calculating energy payments to QFs. If the electric utility elects procurement from both the core and noncore portfolios, the average of the two WACOGs, considering the relative volumes taken from each portfolio, should be used.

The electric utilities should implement this method in the first quarterly avoided energy price posting that follows the effective date of today's decision by at least 30 days.

Our method falls between the two positions advocated by the parties. We cannot accept the joint DRA/utility position because it does not reflect the UEG customer's cost incurrence under our gas rate design. We cannot accept the QFs' position because it essentially requires the electric utility (and ultimately that utility's ratepayers) to pay customer-related expenses twice, once to the LDC and once to QFs.

The method applies only to the energy payments to QFs receiving the quarterly posted short-run energy price. Currently, the standard offers affected are Standard Offers 1, 2, and 3. Also, final Standard Offer 4 QFs that come on-line during Period 1 (i.e., before the projected on-line date of the avoidable resource) are paid on a short-run basis during that period. There are no such QFs at this time; however, if there were, the methodology would also apply to them. The method does <u>not</u> apply to QFs holding interim Standard Offer 4 contracts during any period for which the energy payment is fixed by forecast or formula in those contracts.

Our method is only an interim approach in recognition of the current status of our gas cost policies. The current approach to setting gas rates for large users is based on negotiated rates capped at the embedded cost of service; thus, the rate for an individual user can be tailored to that user's demand elasticity. We have indicated our desire to investigate a rate design based on marginal costs. Marginal gas cost studies are still to be submitted for CPUC review. Some of the parties express strong interest in a marginal cost methodology as the measure of the UEG customer's avoided cost of gas. We make no commitment at this time to marginal cost for this purpose, but we will reconsider the adopted method after reviewing the marginal gas cost studies. (See Section VIII below.)

VI. QF Objections to the Adopted Method

QF representatives and Alenco insist that avoided energy cost payments use the full UEG WACOG. They make two basic objections. The first objection rests on assertions regarding California law and QF policy. The second objection relies on technical analysis of cogenerators' impact on gas rates, and the social benefits of QFs in general, to back the conclusion that the full UEG WACOG more closely approximates "true" avoided costs than does the joint DRA/utility methodology or (implicitly) our adopted method.

A. Applicable Law and Policy

Under this heading we include those arguments that make up the first basic objection, to the effect that California statutes and Commission decisions have set in concrete the use of the full UEG WACOG for calculating avoided energy costs.

1. Consistency with Commission Precedents

CSC and others say that the Commission has repeatedly approved the use of the full UEG WACOG for calculating avoided energy cost payments. However, our decisions for at least the past two years have consistently acknowledged the need to revisit the issue of fuel cost for this calculation. Our delay in hearing this issue arose from the need to complete the implementation of the new gas rate design and not from any prejudgment as to that rate design's impact on avoided costs.[3]

Several parties seem to assert that this Commission has always considered all gas costs to be avoidable. However, we have always recognized in our development of the standard offers that some gas costs are not avoidable. For example, QFs do not avoid gas consumption to maintain spinning reserves so that utility facilities are available in time to meet peak loads.[4]

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3 We also note that these avoided cost hearings were twice delayed at the request of QF representatives.

4 See D.82-12-120, 10 CPUC 2d 553, 623. We also discussed "whether the fuel used to warm-up facilities should be viewed as marginal and calculated in the avoided cost payment" and concluded that "the cost of warm up fuel cannot be included at this time since it is unclear that such fuel is avoided as a result of purchases from QFs." Id. at 622. The cited decision is a landmark in the development of our standard offers, and it states clearly and repeatedly that QFs receiving short-run energy payments take risks regarding changing utility fuel costs. We discuss this at greater length in Section VI.A.3 of today's decision.

Our cited examples of unavoidable gas consumption are not meant to suggest that QFs could never provide, e.g., spinning reserves. Possibly a QF could serve such a highly specialized function, but it is not contemplated under our standard offers and would undoubtedly require agreement on "additional performance features." (See D.86-07-004, mimeo., pp. 74-75.)

2. Consistency with California Statutes

CSC witness Richard claims that Public Utilities (PU) Code Section 454.4 requires that energy payments to cogenerators reflect 100% of UEG gas costs. That section reads as follows:

> "The commission shall establish rates for gas which is utilized in cogeneration technology projects not higher than the rates established for gas utilized as a fuel by an electric plant in the generation of electricity, except that this rate shall apply only to that quantity of gas which an electrical corporation serving the area where a cogeneration technology project is located, or an equivalent area, would require in the generation of an equivalent amount of electricity based on the corporation's average annual incremental heat rate and reasonable transmission losses or that quantity of gas actually consumed by the cogeneration technology project in the sequential production of electricity and steam, heat, or useful work, whichever is the lower quantity."

This statute does not expressly address energy payments to cogenerators at all. The sole stated subject is the setting of gas rates paid by cogenerators. Nevertheless, according to CSC witness Richard, the intent of the statute is to enable cogenerators to "compete with traditional electric generation primarily on the basis of efficiency" by establishing "a relatively constant relationship between cogeneration costs and UEG costs." (Exhibit 515, pp.3-4, emphasis in original.) CSC's concurrent brief cites PU Code Section 2824 and Public Resources Code Section

25004.2 as further elaborations of this alleged statutory policy.[5]

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5 PU Code Section 2824 reads as follows:

"(a) The commission shall conduct a review of the charges paid by electrical corporations for electricity generated from other than conventional power sources and furnished to such corporations. Following such review, the commission shall consider adjustments in such charges to encourage the generation of electricity from other than conventional power sources.

"(b) The commission shall conduct a review of standby charges charged by electrical corporations. Following such review, the commission shall consider adjustments in such charges to encourage the utilization of electricity generated from other than conventional power sources and to enable electrical corporations to review the costs of providing standby service.

"(c) The commission shall conduct a review of charges for transmission service made by electrical corporations for the transmission of electricity generated from other than conventional power sources. Following such review, the commission shall consider adjustments in such charges to encourage the generation of electricity from other than conventional power sources."

Public Resources Code Section 25004.2 reads as follows:

"The Legislature further finds that cogeneration technology is a potential energy resource and should be an important element of the state's energy supply mix. The Legislature further finds that cogeneration technology can assist meeting the state's energy needs while reducing the long-term use of conventional fuels, is readily available for immediate application, and reduces negative environmental impacts. The Legislature further finds that cogeneration technology is important with

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We agree with CSC that the cited sections contain fundamental policy direction for our QF program. As we understand that direction, it is wholly consistent with our program, including today's decision. Nowhere does PU Code Section 454.4, or any of the other cited sections, guarantee to cogenerators (or other QFs) that the energy payments they receive would vary, in relation to the fuel costs they incur, solely as a function of the purchasing utility's IER; nor does the legislation suggest or imply such a result.

Our new gas rate design continues to ensure that gas rates for cogenerators meet the requirements of PU Code Section 454.4. Specifically, for transmission service, the cogenerator will pay the lower of the average UEG transmission rate or the otherwise applicable industrial or commercial transmission rate; and for procurement service, the cogenerator faces the same cost of gas (either the noncore or core portfolio WACOG) as the UEG customer when buying gas from the LDC. (See D.87-12-039, mimeo., pp. 102-04.)

But PU Code Section 454.4 does not define avoided costs, nor does it require a given level of energy payments to cogenerators or other QFs, nor does it declare that all gas costs incurred by electric utilities are avoidable. PU Code Section 454.4 and the other cited statutes simply do not speak to the crucial finding of today's decision, namely, that the customer

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> respect to the providing of a reliable and clean source of energy within the state and that cogeneration technology should receive immediate support and commitment from state government."

charges incurred by UEG customers for their gas-fired generation are not avoidable by QFs.

In making this finding, we uphold the principle that QFs compete with utilities "primarily on the basis of efficiency;" CSC witness Richard's error is in equating gas-fired cogenerators' efficiency with their ability to avoid UEG energy costs. Richard's logic would require us to impute gas as the marginal fuel at all times. We have always refused to do that, and the standard offers all have various provisions that effectively reduce energy payments to QFs to reflect periods when gas is not on the margin. We also decline to impute certain energy cost savings to the UEG customer from the output of QFs when such output does not enable the UEG customer to realize such savings. As we elaborate in the following section, both of these imputations would violate the principle of avoided cost pricing, which is the foundation of our QF program and of California and federal law that we are implementing.[6]

3. Consistency with Avoided Cost Pricing

PURPA, the federal regulations implementing PURPA, the relevant California legislation, and this Commission's decisions share the premise that QFs assume greater risks, in return for potentially greater rewards, than those characterizing regulated utility operations. The statutory and regulatory encouragement of the QF industry derives in large part from experience with the construction of new generation resources during the 1970s and 1980s. The lesson of that experience is that the risks of developing new generation resources have grown substantially beyond the historical norm for the electric utilities. QF entrepreneurs and their representatives before this Commission have justified

6 The federal Public Utility Regulatory Policies Act (PURPA) and the California Private Energy Producers Act (see PU Code Sections 2801-2824) supply the statutory context for the development of avoided cost pricing and standard offers.

full avoided cost pricing, and unregulated profits, on the basis that QFs absorb a whole range of construction and operating risks, thus insulating utilities and their ratepayers from such risks to the extent that their needs are met by QF output.

QFs in the February 1988 hearings did not talk much about risk-taking. Their silence is not surprising, since their position (at least to the extent that CSC speaks for the QF industry) is at odds with our articulation of the avoided cost pricing principle. The essence of the QF position is that the UEG customer's gas costs should be reflected on a one-for-one basis in energy payments to QFs regardless of the extent to which QFs are able to avoid such costs.

Were we to accept this position, QFs would <u>not</u> be competing on the basis of efficiency since they would get paid an average price for their output that would exceed the utility's cost to generate the electricity itself. However, CSC accuses us of "[c]hanging regulatory horses mid-stream," with unfair consequences to cogenerators who relied "on the benchmark price [i.e., 100% of the total UEG rate] in developing projections of electric payment revenues." (CSC concurrent brief, pp. 12-13.)

We have already explained that CSC has either ignored or misconstrued the precedents that it accuses us of abandoning. (See Section VI.A.1 above.) Indeed, examination of D.82-12-120 confirms that we anticipated the problem of changes in pricing policy and that we act today consistently with the commitment made in that decision:

> "One major administrative risk [for QFs] is the possibility of a change in pricing policy by future Commissions. . . . While a future Commission may have the prerogative to implement pricing policy changes prospectively for new small power contracts, QFs which have already built projects should receive payments derived from the pricing methodology in existence when the project was built. Otherwise, far too much price uncertainty will exist. Accordingly, we will order that

> utilities include a provision in all their standard offers before us which assures QFs that they will receive payments throughout the life of the specific project derived from the utility's full short-run avoided energy costs, as approved by this Commission. This requirement will ensure that a framework is established firmly, with prices derived from a utility's full avoided costs." (10 CPUC 2d at 617, emphasis added.)

Note that the CPUC commitment is to full avoided cost pricing, not to a particular formula for calculating avoided costs. Our adopted method does not violate that commitment but rather responds to our need to reexamine the formula in light of our new gas rate design. In contrast, CSC's argument implies an energy price floor in addition to the commitment to full avoided cost. However, D.82-12-120 rejects proposals for price floors and energy price formulas written into the QF contract. (See 10 CPUC 2d at 616-17.)[7]

CSC also maintains that any reduction of avoided energy cost payments below the full UEG WACOG "ignores the long-term nature of the energy sales provided by QFs." (CSC concurrent brief, p. 15.) CSC ignores the fact that it is precisely the QFs holding short-run marginal energy cost contracts whose energy payments are subject to our adopted method; long-run QFs are not affected. (See Section V above.)

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7 Indeed, we tried to make clear that QFs receiving short-run avoided energy costs would have to accept a high degree of unpredictability: "The risks QFs take relating to energy prices in these offers [Standard Offers 1, 2, and 3] are not unlike the risks in a competitive spot market. For example, small power producers take the risk of changing utility fuel costs in future years as they influence the marginal energy rate. It is also consistent for [IERs] to fluctuate since, in fact, these rates will vary depending on future supply and demand conditions in utility operations." (D.82-12-120, 10 CPUC 2d at 616.)

B. Technical Analysis

Much of the QF technical analysis is directed against the joint DRA/utility methodology. We also reject that methodology, for reasons that we state in Section VII below. We deal with the technical analysis by QF representatives and Alenco only to the extent that such analysis purports to show that even expenses like the customer charge are avoidable by QFs.

Alenco says that UEG customer-related expenses are a function of the number of UEG plants in operation, that QFs under contracts with variable energy prices are able, in the aggregate, to defer the construction of new generating facilities, and that therefore customer-related expenses should be included in the avoided cost of gas. There are at least two errors in this line of reasoning. First, the aggregate shortage value of QFs receiving variable energy prices is already paid for in the capacity payment to such QFs. (See D.82-01-103, 8 CPUC 2d at 45-54; D.82-12-120, 10 CPUC 2d at 568; D.87-05-060, mimeo., pp. 37-39.) Second, we have held repeatedly in recent decisions that only Standard Offer 4 QFs (i.e., those QFs with long-run marginal cost contracts) are treated as deferring or avoiding new power plants. (See, e.g., D.88-03-079, mimeo., pp. 11-12.)

CCC and Kelco witness Weisenmiller and IEP witness Branchcomb, among others, point to miscellaneous electric utility savings and social benefits which (they claim) result from QF generation and which they believe make up for any non-avoidable portion of UEG gas costs. Some of these savings and benefits are so speculative or remote that we accord them no weight.[8] Others

8 For example, Branchcomb says that an incremental gas source to replace QF generation is likely to cost the UEG customer more than its WACOG. That is one possible outcome, but it is also possible

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appear to be already recognized in payments to QFs.[9] Finally, we have always held that the electric ratepayer, not the QF, is entitled to the social benefits from QF generation; it is the existence of such benefits that has justified the policy of full avoided cost pricing in the first place. (See D.82-01-103, 8 CPUC 2d at 41.)

VII. Problems with the Joint DRA/Utility Methodology

DRA and the utilities agree with the QFs that commodity gas costs are 100% avoidable by QFs. Under our gas rate design, the total level of payments by a UEG customer for most categories of demand-related costs also depends on the volume of gas that is forecast to be consumed, so seemingly the costs in those categories should also be treated as 100% avoidable.

The so-called "elasticity" methodology that DRA and the utilities support measures the percentage change in gas costs (other than charges for procurement service) allocated to UEG customers that results from a 1% increase in UEG throughput. This is a function, in large part, of the lower per-unit costs that result if a constant total of gas utility fixed costs are spread over a larger number of units. We are not convinced that there is any relation between this measurement and cost avoidability under

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that the increased bargaining leverage that a UEG customer gets with gas suppliers by virtue of an increased load might enable that customer to lower its WACOG.

9 For example, Weisenmiller says that QFs enable electric utilities to realize oil inventory savings. However, PG&E witness Wuliger says that such savings are already recognized in the QF capacity payment. (See Exhibit 512.)

our gas rate design. To understand this, we will review that rate design with respect to the allocation of demand-related costs to UEG customers.

D.86-12-009 summarizes the new rate design. Noncore customers (including UEG customers) face the following rate elements: procurement charge, customer charge, and transmission charge (which has several parts). The decision also summarizes the allocation factors used to allocate system fixed costs among the customer classes for each cost category. The key fact for present purposes is that all charges except the customer charge are allocated by sales or throughput: anything that causes us to lower the forecast level of UEG gas usage thereby reduces the costs that the UEG customer incurs. We believe that a QF that enables the UEG customer to use one less therm thereby avoids the costs associated with that therm, which under our rate design are all of the gas charges except the customer charge.

We do gas cost allocation in annual proceedings for each LDC. To the extent that the adopted gas requirements forecast for a UEG customer is reduced by one therm, that customer will avoid an increment of each functionalized cost allocated by throughput. Since all cost categories except customer-related costs are allocated by throughput, we conclude that additional QF energy will cause a prospective reduction in the UEG allocation, and the UEG customer will thereby avoid some portion of all components of its gas costs except the customer-related costs. (See D.86-12-009, mimeo., pp. 32-33.) The fact that, once allocated, UEG demand charges are fixed and unavoidable for a year does not contradict our conclusion that these costs are reduced (and to that extent "avoided") by forecast QF generation during that year.

The problem with the joint DRA/utility methodology is that it focuses on the additional unit of UEG consumption. This focus obscures the actual relationship between costs allocated to the UEG customer and QF output.

QFs enable the electric utility to avoid gas consumption. This causes the utility to incur lower commodity charges (paid on a volumetric basis) and lowers the allocation to the utility of gas system fixed costs. However, the fixed costs are not paid on a volumetric basis; instead, they depend on a forecast of UEG consumption in relation to total system throughput. This in turn causes the per-unit fixed costs associated with an increment (or decrement) of UEG consumption to differ from the average fixed costs per unit.

DRA and the utilities mistakenly conclude that, because of this difference in per-unit costs, the QFs somehow are avoiding a lower portion of the UEG customer's incremental costs. This simply is not true. When cost allocation is by throughput, QFs can avoid all of the costs, so allocated, that are associated with an increment of consumption. The fact that the incremental cost per unit appears lower than the average cost per unit is irrelevant; the decisive fact for purposes of the issue here is that the incremental cost is totally avoidable.

VIII. Cost-effectiveness Analysis; Marginal Cost Studies

SDG&E and Edison, on brief, ask us to clarify the impact of today's decision on issues other than the calculation of energy payments to QFs. Specifically, these utilities want to know how to apply the new gas rate design in testing the cost-effectiveness of potential new resources. This issue may arise in utility applications for certificates of public convenience and necessity to construct new facilities, and in our biennial resource plan review. The latter proceeding follows the CEC's adoption of its latest Electricity Report and serves to identify avoidable resources for purposes of final Standard Offer 4.[10]

The cost-effectiveness testing issue is beyond the scope of the present hearings, in which we address only the gas costs avoidable by QFs. (See, e.g., ALJ Ruling, April 14, 1987.)[11] Moreover, guidance on this issue would have to be tentative at best, considering the pendency of the marginal gas cost studies (see below) and the possibility that the answer could depend on the nature of the resource being tested.

The immediate problem is a perceived inconsistency described by SDG&E. On the one hand, SDG&E cites D.87-07-079 and D.87-12-066 as decisions where we excluded demand-related gas costs in testing the cost-effectiveness of certain resources. On the other hand, both the joint DRA/utility methodology and our adopted method treat most demand-related gas costs as avoidable. We think SDG&E has paid insufficient attention to the specific characteristics of the proposed resources evaluated in those decisions. For example, D.87-07-079 concerned the differential

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10 For a summary of the biennial resource planning process, see D.87-05-060, mimeo., pp. 2-5.

11 In the compliance phase hearings held last summer in this proceeding, DRA served testimony that advocated making certain linkages between the outcome of the biennial resource plan review and the cost-effectiveness analyses and reasonableness reviews conducted in other proceedings. The utilities objected to this testimony as going beyond the scope of the hearings, and DRA agreed to withdraw it.

With a new proceeding as ambitious as the biennial resource plan review, it is tempting, but probably a mistake, to try to tackle all the theoretical problems at once. We prefer to gain some practical experience. The review following the next CEC Electricity Report (ER-7) should help to identify any appropriate methodological or procedural modifications.

between economy energy purchases and gas-fired generation in evaluating Edison's proposed pumped-storage project (Balsam Meadow). We found that in that circumstance, the Southern California Gas Company Tier 2 gas rate to Edison was a more appropriate reference point than historic average gas prices. Balsam Meadow differs markedly from the intermediate and baseload resources potentially avoidable under final Standard Offer 4, and it may well be appropriate for different resources to be compared against different gas prices.

As we mentioned above, the gas utilities are preparing studies on marginal gas costs, to be completed later this year. We agree with PG&E and SDG&E, both that our adopted method should be reexamined in light of those studies, and that it is impossible to say at this time whether a marginal cost approach should replace our adopted method. Marginal costs do not necessarily equate to avoidable costs (see D.88-03-079, mimeo., pp. 21-34). Also, for electric resource planning purposes, there is some debate whether we should view gas costs from a social perspective (implying a marginal cost approach) or from the perspective of what gas costs the UEG customer faces directly.

Thus, although the method we adopt here is interim, we do not set a time limit for its use, nor do we take a position (one way or the other) on the use of marginal costs as the eventual basis for determining energy payments to QFs. We will revisit the issue of avoidable gas costs in the first biennial update proceeding that comes after we have completed our analysis of the marginal gas cost studies and of any refinements to those studies that we may direct.

IX. Conclusion

The electric utilities and DRA apparently anticipated that many gas utility fixed costs in an unbundled rate design would be unavoidable by QFs. However, under our new gas rate design, the UEG customer (and the consumer of its electric generation) "sees" most of these costs as varying with gas consumption even though they recover embedded costs of the LDC, and the charges, once set, are fixed for one year. Generally, the variable energy costs of electric generation, whether the charges are commodity or demand-related, are avoidable by QFs.

That these changes in gas rate design have only a small effect on avoidable gas costs is not really surprising. Logically, the primary factors that determine an electric utility's energy expenses are economic dispatch of generation facilities (which is sensitive to the UEG customer's gas costs) and changes in the electric utility fuel mix over time. The short-run avoided energy cost pricing mechanism created in D.82-01-103 and D.82-12-120 reflects these factors promptly and accurately.

X. Response to Comments on ALJ's Proposed Decision

Pursuant to PU Code Section 311 and to our Rules of Practice and Procedure (California Code of Regulations, Title 20, Rules 77 to 77.5), the Proposed Decision of ALJ Kotz was issued before today's decision. Five parties (DRA, PG&E, SDG&E, Edison, and CSC) filed timely comments on the proposed decision. We adopt SDG&E's recommended revision to Conclusion of Law 1. This revision clarifies how today's decision affects interim Standard Offer 4 QFs. Also, responding to CSC's comments, we slightly modify Section VII and Conclusion of Law 3 to clarify that it is customer-related costs, as described in D.86-12-009, that constitute the unavoidable portion of gas utility fixed costs.

Edison suggests that the proposed decision is unclear whether the long-term contract and cogeneration "shortfall" adjustments are to be excluded (along with customer-related costs) from avoidable gas costs. We see no basis for reducing energy payments to QFs on these grounds. Under our gas rate design, the long-term contracts adjustment is avoidable for the UEG customer even though it represents a category of the LDC's fixed costs. The cogeneration "shortfall" adjustment doesn't exist: in D.87-12-039, mimeo., pp. 100-04, we adopted a combined UEG/cogenerator class expressly to eliminate any "shortfall."

Findings of Fact

1. Gas utility fixed costs that are allocated to UEG customers by throughput are avoidable by QFs.

2. Customer costs are allocated on the basis of weighted number of customers and are the only gas utility fixed costs not allocated by throughput.

3. The UEG customer's gas commodity costs are 100% avoidable by QFs. For an electric utility that takes noncore procurement service, the energy payment to QFs is calculated using the LDC's noncore portfolio WACOG. For an electric utility that elects service from both the core and noncore portfolios, the energy payment to QFs is calculated using an average of the two WACOGs, considering the relative volumes purchased by the electric utility from each portfolio.

4. The joint DRA/utility proposed methodology does not reflect the UEG customer's cost incurrence under the new CPUC gas rate design.

5. The customer charge would be paid twice by the electric utility (once to the LDC and once to QFs) if the customer charge is considered avoidable.

6. Gas utilities are currently preparing studies of the marginal cost of gas. The CPUC will review these studies and may require certain refinements. The studies may have some impact on the question of gas costs avoidable by QFs.

7. The aggregate shortage value of QFs receiving variable energy prices is paid for in the capacity payment to such QFs.

Conclusions of Law

1. QFs currently receiving the quarterly posted short-run energy price are those holding power purchase agreements under Standard Offers 1, 2, or 3. Energy payments to interim Standard Offer 4 QFs are not affected by today's decision, except for payments based on short-run avoided energy cost, during any period for which the energy payment is fixed by forecast or formula in their respective power purchase agreements.

2. The question of gas costs avoidable by QFs should be reconsidered in light of the marginal gas cost studies now in preparation by the gas utilities. The forum for such reconsideration should be the first biennial resource plan proceeding following completion of the studies and of any refinements to the studies that the Commission may direct.

3. Commencing with the first quarterly energy price revision that follows the effective date of today's decision by at least 30 days, and pending the reconsideration mentioned in Conclusion of Law 2, the energy payment to QFs receiving the quarterly posted short-run energy price should be calculated as follows. Except for the customer costs, all gas utility fixed costs allocated to the UEG customer are avoidable. Also, the UEG customer's gas commodity costs are 100% avoidable by QFs. For an electric utility that takes noncore procurement service, the energy payment to QFs is calculated using the LDC's noncore portfolio WACOG. For an electric utility that elects service from both the core and noncore portfolios, the energy payment to QFs is calculated using an average of the two WACOGs, considering the relative volumes purchased by the electric utility from each portfolio.

4. PU Code Sections 454.4 and 2824 and Public Resources Code Section 25004.2 do not require the imputation of energy cost savings to the UEG customer from the output of QFs when such output does not enable the UEG customer to realize such savings. The

principle of avoided cost pricing is consistent with those sections and precludes such an imputation.

5. The short-run energy pricing approach described in Conclusion of Law 3 is consistent with the methodology adopted in D.82-01-103 and D.82-12-120, and followed by the Commission ever since those decisions.

6. The electric ratepayer, not the QF, is entitled to the social benefits from QF generation; it is the existence of such benefits that has justified the policy of full avoided cost pricing.

7. This order should be made effective today so as to promptly implement the adopted adjustment to QFs' variable energy payments.

ORDER ON GAS COSTS AVOIDABLE
BY QUALIFYING FACILITIES

IT IS ORDERED that all electric utilities contracting with Qualifying Facilities (QFs) under contracts providing for energy payments to QFs at the respective utility's short-run avoided cost shall prospectively adjust such payments. The timing, duration, and method for this adjustment shall be as set forth in Conclusion of Law 3.

This order is effective today.

Dated JUL 8 1988, at San Francisco, California.

STANLEY W. HULETT
President
DONALD VIAL
G. MITCHELL WILK
JOHN B. OHANIAN
Commissioners

Commissioner Frederick R. Duda, being necessarily absent, did not participate.

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

Victor Weisser

Victor Weisser, Executive Director

APPENDIX
Table of Acronyms and Abbreviations

This table has an expansion of the technical acronyms and abbreviations used in today's decision. The parenthetical after the expansion refers to the section in the body of the decision where the acronym or abbreviation first appears.

Alenco	Alenco Resources, Inc. (IV)
ALJ	Administrative Law Judge (IV)
CCC	California Cogeneration Council (IV)
CEC	California Energy Commission (IV)
CPUC or Commission	California Public Utilities Commission (V)
CSC	Cogenerators of Southern California (IV)
D.	Decision (I)
DRA	Division of Ratepayer Advocates (part of CPUC staff) (IV)
Edison	Southern California Edison Company (III)
ER-7	The CEC's Seventh Electricity Report (VIII)
I.	Order Instituting Investigation (III)
IEP et al.	Independent Energy Producers Association, Santa Fe Geothermal, Inc., Union Oil Company of California, and Freeport-McMoRan Resource Partners (IV)
IER	Incremental Energy Rate (II)
Kelco	Kelco Division of Merck & Co., Inc. (IV)
LDC	Local [Gas] Distribution Company (III)
PG&E	Pacific Gas and Electric Company (III)
PU Code	Public Utilities Code (VI.A.2)
PURPA	Public Utility Regulatory Policies Act (VI.A.2)
QF	Qualifying Facility (I)
SDG&E	San Diego Gas & Electric Company (III)
UEG	Utility electric generation (I)
WACOG	Weighted average cost of gas (IV)

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are 100% avoidable except for customer costs. The latter are allocated, not by throughput, but on the basis of weighted number of customers. (D.86-12-009, mimeo., pp. 32-33.) We therefore exclude customer costs in calculating the avoided energy cost payment. All parties agree that the commodity component of UEG gas costs is 100% avoidable. If the electric utility buys from the noncore gas portfolio, the noncore WACOG should be used as the commodity cost of gas for calculating energy payments to QFs. If the electric utility elects procurement from both the core and noncore portfolios, the average of the two WACOGs, considering the relative volumes taken from each portfolio, should be used.

The electric utilities should implement this method in the first quarterly avoided energy price posting that follows the effective date of today's decision by at least 30 days.

Our method falls between the two positions advocated by the parties. We cannot accept the joint DRA/utility position because it does not reflect the UEG customer's cost incurrence under our gas rate design. We cannot accept the QFs' position because it essentially requires the electric utility (and ultimately that utility's ratepayers) to pay customer-related expenses twice, once to the LDC and once to QFs.

The method applies only to the energy payments to QFs receiving the quarterly posted short-run energy price. Currently, the standard offers affected are Standard Offers 1, 2, and 3. Also, final Standard Offer 4 QFs that come on-line during Period 1 (i.e., before the projected on-line date of the avoidable resource) are paid on a short-run basis during that period. There are no such QFs at this time; however, if there were, the methodology would also apply to them. The method does not apply to QFs holding interim Standard Offer 4 contracts during any period for which the energy payment is fixed by forecast or formula in those contracts.

Our method is only an interim approach in recognition of the current status of our gas cost policies. We have shifted from value-of-service to cost-based rates; however, marginal gas cost studies are still to be submitted for CPUC review, and some of the parties express strong interest in a marginal cost methodology as the measure of the UEG customer's avoided cost of gas. We make no commitment at this time to marginal cost for this purpose, but we will reconsider the adopted method after reviewing the marginal gas cost studies. (See Section VIII below.)

VI. QF Objections to the Adopted Method

QF representatives and Alenco insist that avoided energy cost payments use the full UEG WACOG. They make two basic objections. The first objection rests on assertions regarding California law and QF policy. The second objection relies on technical analysis of cogenerators' impact on gas rates, and the social benefits of QFs in general, to back the conclusion that the full UEG WACOG more closely approximates "true" avoided costs than does the joint DRA/utility methodology or (implicitly) our adopted method.

A. Applicable Law and Policy

Under this heading we include those arguments that make up the first basic objection, to the effect that California statutes and Commission decisions have set in concrete the use of the full UEG WACOG for calculating avoided energy costs. CSC is the most vocal proponent of these arguments, although the other QF representatives and Alenco endorse CSC's position. This is disappointing because CSC's position contains fundamental errors regarding the history and nature of the QF program.

1. Consistency with Commission Precedents

CSC and others say that the Commission has repeatedly approved the use of the full UEG WACOG for calculating avoided energy cost payments. In fact, our decisions for at least the past two years have consistently acknowledged the need to revisit the issue of fuel cost for this calculation. Our delay in hearing this issue arose from the need to complete the implementation of the new gas rate design and not from any prejudgment as to that rate design's impact on avoided costs.[3]

Several parties seem to assert that this Commission has always considered all gas costs to be avoidable. In fact, we have always recognized in our development of the standard offers that some gas costs are not avoidable. For example, QFs do not avoid gas consumption to maintain spinning reserves so that utility facilities are available in time to meet peak loads.[4]

We do not imply that any party has deliberately made misrepresentations. We emphasize, however, that avoided energy cost is a difficult subject with a long history before this Commission. Any party venturing a broad generalization on this subject (or any other QF matter) had better do its homework.

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3 We also note that these avoided cost hearings were twice delayed at the request of QF representatives.

4 See D.82-12-120, 10 CPUC 2d 553, 623. We also discussed "whether the fuel used to warm-up facilities should be viewed as marginal and calculated in the avoided cost payment" and concluded that "the cost of warm up fuel cannot be included at this time since it is unclear that such fuel is avoided as a result of purchases from QFs." Id. at 622. The cited decision is a landmark in the development of our standard offers, and it states clearly and repeatedly that QFs receiving short-run energy payments take risks regarding changing utility fuel costs. We discuss this at greater length in Section VI.A.3 of today's decision.

Our cited examples of unavoidable gas consumption are not meant to suggest that QFs could never provide, e.g., spinning reserves. Possibly a QF could serve such a highly specialized function, but it is not contemplated under our standard offers and would undoubtedly require agreement on "additional performance features." (See D.86-07-004, mimeo., pp. 74-75.)

our gas rate design. To understand this, we will review that rate design with respect to the allocation of demand-related costs to UEG customers.

D.86-12-009 summarizes the new rate design. Noncore customers (including UEG customers) face the following rate elements: procurement charge, customer charge, and transmission charge (which has several parts). The decision also summarizes the allocation factors used to allocate system fixed costs among the customer classes for each cost category. The key fact for present purposes is that all charges except the customer charge are allocated by sales or throughput: anything that causes us to lower the forecast level of UEG gas usage thereby reduces the costs that the UEG customer incurs. We believe that a QF that enables the UEG customer to use one less therm thereby avoids the costs associated with that therm, which under our rate design are all of the gas charges except the customer charge.

We do gas cost allocation in annual proceedings for each LDC. To the extent that the adopted gas requirements forecast for a UEG customer is reduced by one therm, that customer will avoid an increment of each functionalized cost allocated by throughput. Since all cost categories except customer-related costs are allocated by throughput, we conclude that additional QF energy will cause a prospective reduction in the UEG allocation, and the UEG customer will thereby avoid some portion of all components of its gas costs <u>except</u> the customer charge. The fact that, once allocated, UEG demand charges are fixed and unavoidable for a year does not contradict our conclusion that these costs are reduced (and to that extent "avoided") by forecast QF generation during that year.

The problem with the joint DRA/utility methodology is that it focuses on the additional unit of UEG consumption. This focus obscures the actual relationship between costs allocated to the UEG customer and QF output.

be unavoidable by QFs. However, under our new gas rate design, the UEG customer (and the consumer of its electric generation) "sees" most of these costs as varying with gas consumption even though they recover embedded costs of the LDC, and the charges, once set, are fixed for one year. Generally, the variable energy costs of electric generation, whether the charges are commodity or demand-related, are avoidable by QFs.

That these changes in gas rate design have only a small effect on avoidable gas costs is not really surprising. Logically, the primary factors that determine an electric utility's energy expenses are economic dispatch of generation facilities (which is sensitive to the UEG customer's gas costs) and changes in the electric utility fuel mix over time. The short-run avoided energy cost pricing mechanism created in D.82-01-103 and D.82-12-120 reflects these factors promptly and accurately.

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This order is effective today.

Dated ____________________, at San Francisco, California.