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Decision 89-09-093 September 27, 1989

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for authority, among other things, to increase its rates and charges for electric and gas service.	Application 88-12-005 (Filed December 5, 1988)
Order Instituting Investigation into the rates, charges, and practices of the Pacific Gas and Electric Company.	I.89-03-033 (Filed March 22, 1989)

(See Appendix A for appearances.)

OPINION

I. Background

In this decision, we adopt a method for calculating the operations and maintenance (O&M) costs that Pacific Gas and Electric Company (PG&E) avoids because of its purchases from variably priced qualifying facilities (QFs). QFs are certain cogeneration and small power production facilities that qualify for specified benefits under the federal Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA establishes that the prices a utility pays for power generated by QFs are to be based on the costs the utility avoids by purchasing the QFs' power rather than generating the electricity from the utility's own plants. Avoided O&M costs are one component of PG&E's avoided costs and thus one portion of the prices paid to QFs.

Some QFs' contracts with PG&E fix the prices PG&E pays for energy delivered to PG&E's system. For example, some options of Interim Standard Offer (SO) No. 4, as approved by this Commission, fix portions of the energy prices. Most QFs' contracts, however, allow the price of purchased energy to vary with changes in the utility's marginal fuel prices and operating characteristics. The determinations of this decision primarily affect variably priced QFs.

The issue of PG&E's avoided O&M costs arose during last year's Energy Cost Adjustment Clause (ECAC) proceeding. We determined in Decision (D.) 88-11-052 that the avoided O&M payment should be calculated separately from other elements of avoided cost and paid as an "adder" to the base energy payment. PG&E had previously combined the avoided O&M cost with the calculation of the incremental energy rate (IER), which was determined by computer models that simulated the operation of PG&E's system.

We also noted in D.88-11-052 that a lack of information made it difficult to calculate the value of the O&M payment with confidence. We therefore directed PG&E to present a study of the O&M costs avoided by QFs' generation in this proceeding. We elaborated on the contents of this study:

> "At a minimum, the study should examine the reductions in costs--including materials costs, labor costs, and any other appropriate costs--that occur when generation is reduced at its existing conventional fossil plants. The study should also calculate the savings in O&M that have resulted from the retiring or removal to standby status of similar plants in the last five years. PG&E should attempt to identify and quantify the O&M costs that vary in one-, three-, and five-year time frames and should expand on these minimum requirements and present any other relevant information available to it." (D.88-11-052, mimeo. p. 63.)

The ruling of April 4, 1989, by the administrative law judge (ALJ) clarified the relation between consideration of this issue in this proceeding (the general rate case or GRC) and in PG&E's 1989 ECAC case:

> "In terms of the GRC, the primary function of this information is to assure that the avoided O&M costs are excluded from PG&E's O&M expenses

for the test year. If we assume that the presence of QFs has enabled PG&E to reduce its O&M costs, then the trend in its O&M costs since QFs began supplying electricity to the system should decline relative to historic trends. The GRC should examine the savings over one, three, and five years, should sort out the other influences that may account for part of the change in the trend, should make a finding of the amount of variable and avoided O&M costs over one, three, and five years, and should review the O&M figures for the test year to ensure that none of the avoided costs are included.

"PG&E's 1989 ECAC case will adopt an appropriate O&M adder. The adder will be based on the information developed in the GRC and may take into account issues such as the appropriate time frame to be considered in establishing avoided O&M payments."

Thus, the initial purpose of this decision is to adopt a method of calculating the adder that can be incorporated in our decision in PG&E's 1989 ECAC case (Application (A.) 89-04-001). A further goal is to settle on a method for determining the adder that can be regularly used, without much controversy, in subsequent ECAC cases for PG&E.

PG&E presented its report as Ex. 46. This issue was addressed by witnesses for PG&E; the California Cogeneration Council (CCC); Ultrapower, Incorporated and the Independent Energy Producers Association (Ultrapower) and Unocal Corporation, Santa Fe Geothermal, Inc., and Freeport-McMoRan Resource Partners (Geothermal QFs) in hearings held on May 15 and 17, 1989. Because of a need to adopt a method for calculating the O&M payment in time for specific figures to be introduced into evidence in PG&E's 1989 ECAC case, this issue was separated from the other issues in the general rate case. PG&E, CCC, Ultrapower, the Geothermal QFs, and the Commission's Division of Ratepayer Advocates (DRA) filed opening briefs on July 7 and reply briefs on July 19.

The procedures of Public Utilities Code § 311(d) were followed in developing this decision. The ALJ's proposed decision was issued on August 15, 1989. PG&E, DRA, CCC, Ultrapower, the Geothermal QFs, and Southern California Edison Company filed comments on the proposed decision. We have reviewed and carefully considered the comments. We have incorporated appropriate changes from these comments in this decision.

II. Positions of the Parties

Generally speaking, the line in this dispute was drawn between PG&E, on the one hand, and representatives of the QFs, on the other, with DRA falling somewhere between these parties. We will follow this division in presenting the parties' positions.

A. PG&E

1. Recommended Method

PG&E believes that the method chosen for calculating avoided O&M costs must comply with PURPA's requirement that payments to QFs must be just and reasonable to ratepayers; payments to QFs should not exceed the actual O&M costs avoided by PG&E.

In addition, PG&E thinks it necessary to recognize the two separate components of avoided O&M costs: fixed costs associated with capacity and variable costs. The former is already included in capacity payments to QFs, PG&E says, and only the latter costs should be paid on the basis of the quantity of kilowatt-hours (kWh) generated by variably priced QFs.

PG&E's recommended method has several steps. First, PG&E calculates the amount of longer-term recorded O&M savings. In this case, PG&E used recorded accounting data from 1984 through 1988 to develop the amount of longer-term savings. Next, these longer-term savings are allocated between variably priced QFs and other new generating resources that have begun operation since 1984, such as the Diablo Canyon nuclear power plant, several geothermal units, some small hydroelectric projects, and fixed-price QFs (Ex. 46, p. C-1). PG&E allocates the longer-term savings in proportion to the generation each group provided to PG&E's system from 1984 through 1988. PG&E determined that the share of these longer-term avoided costs attributable to generation by variably priced QFs is 23%. The next step considers the forecast of the cost of "consumables"--items such as lubricants and water treatment chemicals--that are directly reduced when short-term generation decreases. PG&E uses one year of data and estimates that the cost of consumables averages 0.37 mills/kWh. Using its production simulation model, PG&E then calculates the extent to which generation by variably priced QFs allows PG&E to back down conventional steam units. In the 1988 ECAC case, this percentage was 49.3%. The cost of consumables is multiplied by this percentage and further multiplied by the energy delivered to PG&E by variably priced QFs, which PG&E estimates to be 6,992 gigawatt-hours (gWh). The resulting product is added to the variably priced QFs' share of the longer-term savings. Finally, the sum of the longer-term avoided costs and the avoided consumables, with the adjustments mentioned, are divided by the forecasted energy deliveries by QFs.

Using recent figures, PG&E calculates the appropriate O&M adder to be 0.4 mills/kWh. However, PG&E acknowledges that its calculation should be revised in the 1989 ECAC case to reflect a more recent forecast of generation by variably priced QFs and the percent of that generation that is made up by conventional steam units in computer runs that simulate the operation of PG&E's system in the absence of variably priced QFs (QFs-out runs).

PG&E argues that its estimate is fair to ratepayers because O&M savings from reduced operations at its conventional generating units have already been reflected in the level of expenses it seeks to recover in this case. These savings result from placing units on cold standby status, the retirements of the Avon, Martinez, and Oleum plants, its voluntary employee retirement program, and other improvements in productivity. These reductions are either already reflected in recorded data or are incorporated in PG&E's estimates for the 1990 test year, according to PG&E.

Although some of these savings should be transferred to QFs, PG&E argues, the savings from the retirements of the Avon, Martinez, and Oleum plants should remain with ratepayers. These plants operated beyond their useful lives, and PG&E retired them for economic and safety reasons. The availability of generation from QFs had no influence on the decision to take these plants out of service, according to PG&E.

PG&E also points out that the deliveries from QFs cause PG&E's steam generation units to go through more cycles of increased and decreased output. It is established throughout the electric industry that such cycling accelerates the aging of these units. Thus, PG&E argues, QFs may cause some O&M costs to increase even if generation is reduced.

PG&E concludes that its method of calculating avoided O&M costs is logical and consistent with PURPA, and that its estimate of 0.4 mills/kWh is reasonable.

2. Other Parties' Criticisms of PG&E's Method

a. CCC

CCC has two major criticisms of PG&E's method.

First, CCC believes that PG&E ignores the fact that its new generating resources have allowed PG&E to improve the reliability of its system and to meet load growth. Testimony in this case demonstrated that the reliability of PG&E's system was unsatisfactory in the early 1980s but is now considered acceptable, according to CCC. In addition, total area load has increased by nearly 16,700 gWh since 1982, and PG&E's other new resources were needed to meet this increased load.

The effect of PG&E's ignoring the need for its new resources, CCC argues, is to expand greatly the pool of resources that are considered marginal. This, in turn, allows PG&E to claim that all the O&M savings from its retirements and conversions to standby status should be attributed to its new generating resources.

CCC believes that this assertion contradicts the facts. If these new resources were needed to meet load, then they cannot be considered marginal units and given credit for saving O&M costs by allowing old units to be retired, placed on standby, or curtailed. According to CCC, the evidence in this proceeding shows that QFs are the marginal generating resources that permit reductions in generation by older, inefficient units. PG&E's approach denies these QFs credit for the full extent of the O&M costs that they permit PG&E to avoid.

CCC's second criticism is that PG&E's approach is difficult to implement and verify. The method appears to require a determination of which resources are responsible for avoiding which costs, but PG&E has not suggested a way to make that determination. In addition, CCC argues that this method will require the Commission's continuing monitoring of PG&E's decisions to reduce generation at its older units.

Third, CCC points out that PG&E has miscalculated the adder under its own method. As noted previously, CCC disagrees with PG&E's contention that the retirements of the Avon, Martinez, and Oleum plants were not attributable to generation from variably priced QFs. Similarly, CCC faults PG&E for giving QFs no credit for allowing Moss Landing Units 4 and 5 to be placed on standby status or permitting reduced service hours at PG&E's Contra Costa 4 and 5 units. In addition, CCC notes, the percentage that PG&E applied to the cost of consumables to develop its short-term avoided O&M cost was taken from its witness' testimony in the 1988 ECAC proceeding, not from the Commission's decision in that case. The correct percentage is 58.2%, rather than 49.3% used by PG&E.

CCC calculated avoided O&M costs using PG&E's method but making the corrections it advocated. The result was an O&M adder of 2.3 mills/kWh.

b. Ultrapower

Ultrapower also criticizes PG&E's method.

Ultrapower first notes that PG&E's method, based on historical data, is inadequate for the purposes of this proceeding. Reliance on historical costs in these circumstances is incorrect, Ultrapower argues, because trends based on those costs will predict incurred costs, not avoided costs. Costs that are avoided are not reflected in recorded data, so historical figures will always undervalue avoided O&M costs.

Ultrapower also believes that the lack of patterns in PG&E's recorded data supports its views on the inadequacy of historical figures. PG&E's own testimony (Ex. 46, App. B) has consumables, its recommended measure of short-term O&M costs, varying in all possible manners with marginal generation. Thus, Ultrapower argues, PG&E's fundamental assumption, that consumables are an appropriate measure of short-term avoided O&M costs, is disapproved by its own data.

PURPA and this Commission's decisions require utilities to pay QFs the full costs the utility avoids because of the QFs' production, according to Ultrapower. Ultrapower believes that PG&E's approach violates this standard. In recent years, generation from QFs has allowed PG&E to avoid O&M costs by retiring some plants and placing other units on standby, Ultrapower argues. Rather than crediting QFs with those savings, PG&E allocates these O&M savings between QFs and other new sources of generation. But PG&E's method contains a fundamental inconsistency, Ultrapower contends. In deciding whether or not to remove units from service temporarily or permanently, PG&E looks to its forecasted capacity requirements. But its proposed allocation of reduced O&M costs is based on the energy produced by the various units, rather than their capacity.

Ultrapower thinks the most compelling argument against PG&E's method was PG&E's witness' testimony about how the method would be applied over the next few years. Even if current conditions remained the same, O&M payments to QFs would decline over time, because of the three- and five-year time frames assumed in PG&E's approach. Ultrapower finds it even more strange that if conditions on PG&E's system required standby units to return to service, the O&M adder could become a negative number, with the result that payments to QFs would decline at the same time that the energy and capacity that they supply became more valuable.

For all these reasons, Ultrapower urges the rejection of PG&E's method.

c. <u>Geothermal QFs</u>

Like other representatives of QFs, the Geothermal QFs believe that QFs should be credited with the full amount of the O&M savings from the retirements of the Avon, Martinez, and Oleum plants. The Geothermal QFs argue that PG&E could not have retired these units in the absence of QFs' contribution to meeting load and improving reliability.

The Geothermal QFs also point out that PG&E's calculation of avoided O&M costs is inconsistent with other estimates of O&M costs that it is required to file in other regulatory proceedings, such as the California Energy Commission's Seventh Common Forecasting Methodology (CFM-7) proceeding.

The Geothermal QFs argue that PG&E also errs in allocating O&M savings between QFs and other new resources. The Commission has determined that variably priced QFs should be treated as the marginal resource, the Geothermal QFs state. As PG&E's system efficiency improves, for example, payments to QFs based on the marginal efficiency of generation decline. Consistent and fair treatment requires that QFs also get the credit for increased O&M savings that accrue as less efficient units are retired or used less.

Finally, the Geothermal QFs note, as did CCC, that PG&E's calculations of the costs of consumables was based on an incorrect figure for the extent to which conventional steam units were backed down in the modeling runs in the 1988 ECAC proceeding. PG&E used 49.3% in its calculation; the decision in that case was based on 58.2%.

d. DRA

DRA does not engage in much direct criticism of PG&E's method. DRA agrees with PG&E's single-year approach to short-term avoided O&M costs, but DRA thinks PG&E has included these costs twice in its calculation. PG&E has developed estimates of avoided O&M costs for three and five years, but these estimates already include the one-year cost of consumables. DRA sees this as a flaw in PG&E's method. DRA finds PG&E's concern about the allocation of O&M savings to energy or capacity payments to be somewhat overblown, since the distinction is arbitrary. For DRA, a more important concern is that none of these savings are lost in the allocation.

B. QFs

1. Recommended Methods

a. CCC

CCC's proposed method for calculating the avoided O&M payments is based on a five-year average of PG&E's total O&M costs for its operating oil- and gas-fueled generating units, calculated in mills/kWh. This average would be prorated to reflect the extent to which generation from QFs displaces generation from PG&E's oil- and gas-fueled units.

This displacement percentage would be calculated through use of the QFs-in/QFs-out model runs that are currently used in ECAC proceedings to calculate PG&E's IER. (The IER is calculated by performing two model runs--one based on all resources forecasted to be available to PG&E (QFs-in) and one that simulates the operation of PG&E's system without any energy from variably priced QFs (QFs-out). (See D.88-03-079.)

This method has the advantage of being easy to implement and verify, according to CCC. In addition, it takes into account the effect of new resources on reliability and load growth. CCC criticizes PG&E's approach for assuming that new resources made no contribution to improving system reliability and meeting increased load. It is clear to CCC that these new resources were nearly entirely needed to meet load growth and improve reliability. QFs lower O&M costs by permitting PG&E to retire old generating units and to place other units on standby, and PG&E's approach unfairly underestimates this contribution. CCC believes that its method overcomes these deficiencies in PG&E's approach.

CCC also requests that the Commission acknowledge that almost all of a unit's O&M costs can be avoided when a unit is retired or placed on standby status.

b. Ultrapower

Ultrapower presented several alternative methods in addition to its preferred approach.

Ultrapower first offers a calculation based on corrections and improvements to PG&E's method.

Like PG&E, Ultrapower cites the provisions of PURPA and defines avoidable O&M cost as the expense that PG&E would incur but for the generation of variably priced QFs. Ultrapower finds it useful to break down total O&M costs into short-term and long-term costs. Short-term O&M costs are those that are avoided when purchases from QFs allow reduced operation of PG&E's generation units. For purposes of this issue, Ultrapower views long-term O&M costs as the costs that are avoided when generation from QFs allows PG&E to take generation units out of service temporarily or permanently.

In Ultrapower's scheme, avoided short-term O&M costs include the consumables identified by PG&E. However, Ultrapower notes that other costs are also avoided in the short term. For example, operating units in a single or two-shift mode, rather than around the clock, or lengthening the time between required major maintenance, also reduces O&M costs in the short term. Ultrapower suggests that estimates of short-term avoided O&M costs may be derived by applying the technique used in PG&E's 1988 ECAC case for calculating avoided O&M costs. The necessary underlying data could be taken from various regulatory filings PG&E is required to make or from research sponsored by the Electric Power Research Institute (EPRI).

In the long term, Ultrapower believes PG&E can avoid O&M costs by removing units from service. Ultrapower develops three categories of these removals.

The shortest-term removals from service are classified as reserve outages. Units on reserve status are not operating and do not require a full operating crew, according to Ultrapower.

When a unit is placed in standby reserve status, it is removed from service for a longer term but not permanently shut down. Such units require at least two months to be returned to service, and more labor and operating costs are avoided than for reserve outages.

The longest term removal from service is, of course, retirement. Significant O&M costs can be avoided when plants are retired, according to Ultrapower.

Ultrapower argues that when generation from QFs allows plants to be place in reserve outage, PG&E saves labor costs (because fewer operating personnel are required) and maintenance costs (because the period between scheduled maintenance can be extended). However, Ultrapower was unable to obtain enough information to permit it to quantify these savings.

When units are retired or placed on standby reserve, it is easier to quantify the avoided O&M. PG&E has estimated that it has saved $14.6 million in O&M expense in the past five years because of such removals from service. Ultrapower appears to accept this figure, but argues that QFs should be credited with all of these savings, because PG&E could not have removed these units from service without the capacity provided by variably priced QFs.

The result of Ultrapower's method is an avoided O&M payment of about 4 mills/kWh.

However, Ultrapower believes that this method, like any method that relies on historical data, has many shortcomings. Ultrapower's primary recommendation, therefore, is that the Commission adopt a proxy to estimate avoided O&M costs. When the Commission has faced similar theoretical problems in defining other types of avoided costs, it has found it useful to rely on a proxy to estimate full avoided cost.

Ultrapower offers several possible proxies, but it believes that a gas-fired combined cycle generating plant is the most appropriate proxy for these purposes, because its operating characteristics are close to those of variably priced QFs. Ultrapower's method for making use of this proxy is to run a simulation of PG&E's system substituting the proxy plants for variably priced QFs. Using this method, Ultrapower calculated an avoided O&M cost of 3.69 mills/kWh.

c. <u>Geothermal QFs</u>

Determining a final method for calculating avoided O&M costs is a matter that should be resolved, like other general issues, in the proceedings that have historically taken on such issues, such as the Biennial Resource Plan Update proceeding, according to the Geothermal QFs. All that the Commission should attempt to do at this time is to adopt an interim O&M adder, for use until a more permanent method has been determined.

The recommended interim figure advocated by the Geothermal QFs has two components.

The first component is based on the recorded data for the past three years and credits variably priced QFs with the O&M cost reductions for both standby and retired units in those years. The second component is designed to account for the avoided cost of consumables and is derived from the percent of generation by variably priced QFs replaced by oil- or gas-fueled generation in the QFs-out run. The sum of the two components is the total avoided O&M cost.

The Geothermal QFs have calculated this total to be 2.55 mills/kWh, but the current percentage applied to the cost of consumables included in the total would be calculated in PG&E's 1989 ECAC case.

2. <u>Other Parties' Criticisms of the QFs' Methods</u>

PG&E finds several flaws in the methods proposed by representatives of QFs.

First, PG&E believes that the proposals violate the provisions of PURPA. PG&E believes that the proposals would require ratepayers to make payments to QFs that exceed actual avoided O&M costs or that are not reasonably related to savings caused by generation by QFs. This result, according to PG&E, is contrary to PURPA's assumption that ratepayers should be indifferent about whether electricity is generated by QFs or the utility. Thus, if other resources or factors, rather than generation by QFs, are reasonable for savings, then those savings should either be allocated to those other sources or retained for the benefit of ratepayers, PG&E concludes.

Second, PG&E thinks that many of the QFs confuse total O&M costs and avoided O&M costs. This is particularly evident in some of the references to PG&E's filings in CFM-7, states PG&E. The O&M adder should be based only on avoided O&M costs, and not on total costs.

Third, many of the proposals rest on erroneous reliability studies and confuse energy and capacity payments, PG&E argues. Many QFs already receive compensation for their contributions to reliability in the form of capacity payments. PG&E believes that those QFs who contribute to the reliability of PG&E's system through their contractual commitments to supply firm capacity are already compensated for that contribution in the capacity payments they receive from PG&E. PG&E contends that the confusion between fixed O&M expenses, which if avoided should be reflected in capacity payments, and variable avoided O&M payments, the subject of this proceeding, could lead to excessive payments to QFs, at the expense of ratepayers.

PG&E also has specific criticisms of the other parties' positions.

CCC's proposed method fails to link reduced generation and reduced costs, according to PG&E. CCC attempts to make such a link by references to retired plants, which logically cannot be used to represent the reductions in generation in operating plants due to variably priced QFs, PG&E argues.

CCC also neglects the distinction between energy- and capacity-related O&M costs, and recommends allocating all avoided O&M costs on the basis of energy, in violation of PURPA. PG&E believes that failure to take into account the O&M component of capacity payments made to QFs who also supply variably priced energy will lead to unfair and unlawful overpayments to these QFs.

CCC's modeling runs in support of its recommendation, PG&E further argues, similarly confuse the nature of energy and capacity and ignore the contractual obligation of many QFs to provide capacity to support the system's reliability.

Two of the approaches suggested by Ultrapower contain the same flaws as CCC's recommendations, PG&E states. Its favored proxy approach is so radically different from any previous attempts at establishing avoided O&M costs that PG&E thinks it should be referred to one of the more general proceedings on QFs. PG&E argues that the proxy proposal is inconsistent with the reasons the Commission directed this issue to be studied in the general rate case. PG&E also criticizes the proxy for failing to take into account the fixed O&M component that QFs are already compensated for through capacity payments. PG&E's rough calculation indicates that Ultrapower's figure should be reduced by about 9% to reflect fixed O&M costs.

PG&E also criticizes the Geothermal QFs' proposal for allocating all O&M savings to variably priced QFs. PG&E points out that the Geothermal QFs' own witness acknowledged the difficulty of delegating the function of meeting load growth to one resource while crediting standby and retirement savings to other resources, but PG&E believes that that is exactly the sort of differentiation that the Geothermal QFs' method requires.

Although DRA states its general support for CCC's method, it notes that the recommendations of the representatives of QFs overstate avoided O&M costs by crediting all O&M savings from standby and retired plants to QFs. In addition, CCC's model runs resulted in excessive reliability targets, and DRA believes that CCC's method needs adjustment to overcome this problem. The model should commit only enough retired and cold standby units to meet predetermined reliability targets, according to DRA.

Ultrapower does not criticize the Geothermal QFs' method, but it opposes the suggestion that the issue of how to calculate avoided O&M costs should be transferred to the Biennial Resource Plan Update proceeding.

C. DRA

1. Recommended Method

DRA believes that a method for calculating avoided O&M costs should take into account the balance between loads and resources, load growth, and reliability without becoming unnecessarily complex. DRA recommends that production simulation models be used to determine long- and short-term O&M costs.

DRA generally supports CCC's recommended method. But DRA thinks that CCC and the Geothermal QFs have overstated avoided O&M costs by crediting all of the costs associated with retired and standby units to the generation provided by variably priced QFs. CCC's method should be refined by allowing the model to determine which standby or retired units would be committed in the absence of variably priced QFs. CCC tends to provide excessive reliability; DRA accordingly recommends that the spinning reserve criteria used in the model runs should be the basis for the appropriate level of reliability in calculating the avoided O&M costs.

For existing units, DRA generally agrees with PG&E's approach of calculating the cost of consumables for one year. But DRA believes that PG&E counts some costs twice since the cost of consumables is already included in the three- and five-year data underlying PG&E's calculations.

DRA would overcome these problems by using the cost of one-year's worth of consumables as a measure of short-run avoided O&M costs for existing plants. The difference in generation for existing units between the QFs-in and QFs-out runs would be multiplied by the average cost of consumables to develop the short-run figure. The long-run costs of avoided O&M for retired and standby units would be derived by multiplying the change in kWh between the QFs-in and QFs-out runs for these units by the three- to five-year average value of avoided O&M costs, adjusted to current year dollars. The sum of these two components would be divided by variably priced QFs' total generation to develop the final avoided O&M figure.

All units placed on standby or retired in the last three to five years would be included in the resources available for commitment in the QFs-out run under DRA's proposal. DRA agrees with some of the other parties that these units could not have been taken out of service unless new generation allowed minimum reliability requirements to be met.

DRA proposes to allocate the short-term O&M savings, resulting from the differences in generation between the QFs-in and QFs-out runs, to energy payments and the long-term savings from retirements or cold standby units to capacity payments.

DRA also notes PG&E's concerns about increases in maintenance costs that may result from increased cycling of conventional steam units because of the availability of generation from QFs. DRA agrees that these increased costs should be included in a theoretically correct calculation of avoided O&M costs, but does not recommend this adjustment now because of a lack of reliable data.

2. Other Parties' Criticisms of DRA's Method

PG&E and CCC join in stating that DRA's proposal violates due process. DRA did not articulate its proposal until its opening brief, and no witnesses testified in support of the proposal. No other party has had an opportunity to cross-examine DRA on the details of its proposal.

CCC also objects to DRA's method on substantive grounds. CCC thinks that the proposal is undeveloped and several of its elements are unclear, such as how DRA proposes to calculate long-term O&M savings and how such savings would be determined in a future period when no retirements have occurred.

PG&E argues that DRA errs in accusing it of including the one-year avoided cost of consumables in its calculation of long-term savings; short-term costs have been excluded from PG&E's long-term estimates.

PG&E finds DRA's approach illogical, because of its use of the change in kWhs generated by standby and retired units in the QFs-in and QFs-out runs. This change is minimal, because retired units are not restarted in the QFs-out run and the use of standby units is limited in a way that does not reflect their long-term benefits.

III. Discussion

Although the parties have obviously put great thought and effort into their presentations on this issue, we cannot endorse any party's recommendation wholeheartedly. Each proposed method has shortcomings or inconsistencies. We will discuss some of our general concerns before we describe the method we adopt in this case..

A. Fixed Versus Variable O&M Costs

The parties have occasionally blurred an important distinction between fixed O&M costs and variable O&M costs. Fixed O&M costs are usually included in the cost of adding new generation capacity, and capacity payments to QFs include the estimated fixed O&M costs of a combustion turbine, the current proxy used to derive avoided capacity costs. For example, PG&E and DRA recommend that firm capacity payments in the test year of 1990 should be based on a combustion turbine costs of $55.77/kW-yr, including a fixed O&M cost of $3.63/kW-yr and associated administrative and general (A&G) overhead of $1.32/kW-yr (Ex. 113-2-A).

The estimate of avoided fixed O&M costs incorporated in the capacity payment is already paid to QFs who commit to supply firm capacity under SO2 and SO4 and to many QFs with nonstandard contracts modeled after these standard offers. Even QFs who cannot guarantee to supply capacity and who sell PG&E energy on an as-available basis under SO1 receive payments that include a capacity component to reflect the diversity of generation from these sources. Some contracts, such as SO2 contracts, for QFs supplying firm capacity also provide bonus capacity payments for exceeding a specified capacity factor.

The issue in this case is how to quantify the variable O&M costs that are avoided because of the energy supplied by variably priced QFs. Most of these variably priced QFs also supply and are paid for capacity they provide under SO2, certain options of SO4, and SO1. They are differentiated from fixed priced QFs not so much by the capacity payments they receive as the way in which energy payments are calculated under their contracts. For these reasons, any method that does not separate out the fixed O&M avoided cost from total O&M costs will have the potential for paying the fixed O&M costs twice.

B. Retired Plants

Determining the proper role for retired plants in calculating the O&M adder is complicated by several circumstances. The three plants PG&E recently retired--Avon, Martinez, and Oleum--were not typical plants. They were operated in conjunction with adjacent refineries that purchased steam and electricity from PG&E. The plants were near the end of their expected useful lives when they were retired, and PG&E claims that economic and safety reasons dominated the decision to retire the plants. In addition, the contracts with the refineries were terminated, which made continued operation of the plants impractical, according to PG&E.

These facts appear to isolate the decision to retire the plants from any influence of the energy contribution of variably priced QFs. But other testimony forces us to consider the role of variably priced QFs' power. For example, it was suggested that the decision to terminate the refinery contracts was a consequence of, and not a reason contributing to, PG&E's decision to retire the plants (Tr. 41:4506-4509). Ultrapower also presented testimony that PG&E's reserve margin would fall below target levels if QFs were not present to fill in for retired and standby plants.

This issue is further complicated by the historical fact that PG&E added considerable new generation near the time of the retirements, while substantial load growth was also occurring.

PG&E has claimed that QFs had no influence on the decision to retire the plants, but if pressed into its alternative position, PG&E is willing to allocate, on the basis of historical energy production, the O&M savings from the retirements between variably priced QFs and its other new generation. The representatives of the QFs assert that PG&E would have been unable to retire the plants without the contribution of QFs, and therefore the variably priced QFs should receive the full credit for the reduced O&M costs resulting from the retirements.

The decision to retire an existing generating unit should be made primarily on the basis of economics. As a plant reaches the end of its useful life, the efficiency of converting fuel to electricity declines and the cost of maintenance increases. At some point, the cost of replacing the plant becomes less than continuing to retain the plant in operation. As that point approaches, the utility should either construct a new plant to replace the old plant or make arrangements to purchase the necessary capacity and energy from other utilities to substitute for the old plant.

When plants are retired because of aging, rather than for reasons of technological obsolescence, they frequently first go through a phase when the utility finds it economical to keep units in reserve for less frequent operation than the units' originally intended design. Units are kept in reserve for operation when other units are being repaired or serviced or when peak loads justify use of relatively more expensive units. As a general matter, retirements may occur only when the utility has secured enough replacement capacity to assure that the plant will not even be needed to meet peak load. (See Ex. 257, p. 12.)

Thus, as a general matter, the primary considerations in the decision to retire a plant concern capacity and reliability. Because aged plants are usually inefficient to operate, they are rarely the most economic source of energy, and retaining a plant on a utility's system purely to contribute energy is unusual. (See Tr. 41:4509.)

For this reason, PG&E's alternative proposal to allocate the O&M savings from its retired plants on the basis of the relative quantity of energy generated by variably priced QFs and new generation plants seems illogical. But the QFs' arguments also ask us to find that the energy supplied by variably priced QFs allowed PG&E to retire the three plants.

To be sure, the distinction between energy and capacity in the context of QF pricing is a fuzzy one. Many QFs have firm capacity contracts that require them to generate a certain amount of energy to demonstrate their ability to supply capacity, and we have acknowledged that even the energy QFs provide on an as-available basis helps the utility avoid capacity costs.

These considerations persuade us that we must first look to capacity to determine to what extent, if any, variably priced QFs should receive credit for the O&M savings when the plants were retired.

C. Standby Units

Cold standby units are maintained in a way that permits them to become operational within one week to two months of the decision to bring them back into operation. The primary functions of cold standby units are to provide capacity that can be drawn on when needed and to reinforce the system's reliability. Once a cold standby unit is brought into service, it is available for dispatching and it may also contribute energy to the extent that its energy is cheaper than other sources.

The use of standby units has declined as the contribution of variably priced QFs has grown (see Ex. 258, Tables 4 and 5), and over the last five years PG&E has recorded O&M savings of $6.5 million associated with its standby units.

Thus, the O&M costs associated with standby units can and should be considered in the calculation of the adder.

D. Operating Units

Operating units have at least two components of O&M that may be avoided by generation from variably priced QFs.

First are consumables. Although some parties question whether short-term O&M costs are limited to consumables, no one has disputed that consumables are avoided, and no party has offered an alternative to PG&E's quantification of the avoided cost of consumables.

Second are the O&M savings that may result when units operate at a lower level because of the generation from variably priced QFs. Labor costs may decrease because of reduced hours, fewer shifts, or fewer workers. The schedule of major maintenance may be spread out over a longer time, reducing the cost of labor and materials. These savings are hard to quantify exactly, but total variable O&M costs for operating plants would be expected to decrease in proportion to generation if these effects are significant.

E. Adopted Method

As we have suggested, no party presented a method that was entirely satisfactory. For use in PG&E's 1989 ECAC case, we will adopt a method that resembles proposals put forward by Ultrapower and CCC. This basic methodology should also be used in PG&E's 1990 ECAC proceeding, subject to some refinement as discussed below. Adoption of a common methodology for use by all three major electric utilities should await consideration in a future Biennial Resource Plan Update proceeding.

1. Operating Units

a. Generation Displaced by Variably Priced QFs

The method we adopt employs the QFs-in/QFs-out runs that are used to calculate the IER in the ECAC case. The QFs-out run is capable of simulating, within the limits of the particular model, how PG&E's system would operate in the absence of energy from variably priced QFs, and the results of the QFs-out run may be compared with those of the QFs-in run, which forecasts the operation of the system with variably priced QFs included.

Ultrapower suggested that such a comparison could be used to determine the extent to which power from variably priced QFs allows PG&E to reduce generation at operating units. (See Ex. 257, pp. 18-21.) In the QFs-out run, some operating units will be called on to generate more electricity to compensate for the loss of QFs' power. The QFs-in/QFs-out comparison details the increased operation of each such unit. Under Ultrapower's proposal, the change in output in each steam generation unit would be multiplied by the variable O&M cost for that unit, as reported to the Energy Commission in CFM-6 and CFM-7. The O&M costs, expressed in cents/kWh, would be escalated to 1990 dollars in the calculation.

CCC made a similar proposal. CCC would also use the QFs-in/QFs-out runs to determine the portion of variably priced QFs' generation that displaces PG&E's oil and gas units. However, the units' O&M costs would be calculated from each unit's total O&M costs, in nominal dollars, as recorded for each of the last five years. The total O&M costs would be added together and the sum divided by the total generation from PG&E's oil and gas units, to develop average O&M costs, expressed in cents/kWh, for each year. Each year's average would then be escalated to test year dollars. The total change in oil and gas generation between the QFs-in and QFs-out runs, divided by the total change in QF generation, would determine the percentage of fossil-fueled generation displaced by QFs. In addition, CCC proposes that if standby or retired units are restarted to meet demand in the QFs-out case, the calculation would be redone to include their costs. The total average O&M costs would be multiplied by the percent of displaced fossil-fueled generation to develop the O&M adder.

Our method incorporates elements of both of these recommendations, but it follows Ultrapower's suggestion most closely. The method begins with the QFs-in/QFs-out runs. The QFs-out run simulates a hypothetical PG&E system that lacks the energy produced by variably priced QFs, and comparison with the QFs-in run, which simulates the operation of the actual system under forecasted conditions, gives a good measure of the energy contribution of variably priced QFs. In addition, using the QFs-in/QFs-out runs for calculation of both IERs and avoided O&M costs provides an appealing consistency.

The QFs-in/QFs-out runs allow calculation of the change in generation for each fossil-fueled unit. The unit-by-unit change in generation can then be used to develop estimates of the different components of avoided O&M.

b. Avoided O&M Costs

One of the biggest problems this issue has presented is the lack of data that would permit us to convert the change in generation into total avoided O&M costs. Ideally, information on the marginal O&M costs of each unit over a range of generation levels would be readily available, and the marginal O&M costs for each unit could be calculated from the results of the QFs-in/QFs-out runs. This ideal information was not presented in this case.

The parties have suggested three sources of data for the conversion of each operating unit's change in generation to avoided costs. Ultrapower has suggested use of the data PG&E filed in the Energy Commission's CFM-6 and CFM-7 proceedings (apparently the same data was filed in each proceeding). CCC suggested use of the average O&M, defined as total operating costs minus fuel costs, for PG&E's fossil-fueled units for 1984-1988. PG&E, DRA, and the Geothermal QFs suggested using PG&E's recorded data for the last three to five years. PG&E would rely primarily on the reduction over five years in O&M costs for standby units; DRA and the Geothermal QFs would use an average for each unit.

Each of these data sources has its shortcomings.

The CFM figures are supposed to represent average variable O&M costs for 1976-1986. These figures present several problems. First, average O&M may not represent avoided O&M accurately. We presume that a unit's O&M costs, calculated on a mills/kWh basis, will vary with the level of generation, with the lowest costs when the plant is operating near its most efficient level. At higher-than-optimal capacity factors, we would expect costs to rise because of more wear and tear on components, more frequent scheduled maintenance, and the like. At low capacity factors, the absolute costs of O&M will be lower, but those costs will be spread out over fewer kWhs, and certain costs, such as labor costs, will constitute a minimum level that cannot be avoided until the plant is retired. The portion of this cost curve that corresponds to the change in generation from the QFs-in/QFs-out runs may differ significantly from the point represented by an average.

Another problems with the CFM data is the question of precisely what they measure. PG&E has complained that the CFM definition of variable O&M costs is too broad for use in determining the avoided costs for the calculation of the adder. Other parties have asserted that the CFM figures exclude labor costs and thus understate variable O&M costs. No party has presented a detailed description of what exactly makes up the CFM figures, which leaves us with many questions about the appropriateness of basing the adder on them.

In addition, the CFM data may be somewhat out of date, and we have some concerns about basing the adder on information that may be as many as 13 years old.

CCC's suggested source shares many of these problems. It is an average, rather than a measure of avoided or marginal O&M costs. CCC defines variable O&M as the total operating costs of a unit minus fuel costs and rents. The residual category, defined as variable O&M, seems large, and we are concerned about the lack of precise description about its contents.

PG&E's quantification has the virtue of being based on recorded decreases in O&M costs. But PG&E's figures measure only the savings associated with standby or retired units and consumables. As we have discussed previously, avoided O&M costs, at least in theory, should include other components, such as the longer-term reduced costs of labor for operating plants. PG&E has presented figures that are indisputably O&M savings, but it has not quantified all O&M costs avoided by the presence of variably priced QFs.

With all these shortcomings in mind, we believe that, of the data presented in this case, the figures of CFM-6 and CFM-7 are best suited for the limited purposes of estimating the avoided O&M costs associated with operating units. Although the CFM figures are averages, they were based on costs recorded over a long term that presumably includes a fairly wide range of generation levels for each generation plant. Differences in each unit's production, which can greatly skew the mills/kWh calculation, should be lessened by the wider variety of operating conditions. The CFM figures do not include labor costs, but quantifying labor savings for operating plants has proved elusive. And as Ultrapower points out, the results of applying our general method to these figures is consistent with other filings by PG&E over several years and for many purposes. Use of the CFM data also provides a continuity and consistency with the O&M adder developed in the 1988 ECAC proceeding.

2. Retired Plants

We have previously determined that we should focus on capacity in evaluating the extent to which variably priced QFs should receive credit for the O&M savings associated with retired plants. Ultrapower has provided an analysis based on capacity considerations (Ex. 258, pp.31-36). Although we do not follow the analysis suggested by Ultrapower, the information Ultrapower presented helps us resolve and illustrate this issue.

Table 6 of Ex. 258 incorporates DRA's assumptions that PG&E's total resources in 1990, including new generation and variably priced QFs, will total 22,102 megawatts (MW) (see Ex. 138-A; Ex. 84, p. 184). Ultrapower has calculated that the capacity associated with variably priced QFs will amount to 1,322 MW. When variably priced QFs are removed from total resources and compared with the demand forecast of the Energy Commission's Seventh Electricity Report (ER-7), the resulting reserve margin is 14.9%, substantially less than the long-run target reserve margin of 17.5% that the Energy Commission has proposed for PG&E in ER-7. With the projected levels of peak demand, 21,253 MW of resources would be needed to equal the target reserve margin. Thus, without the capacity associated with variably priced QFs, PG&E would need 473 MW in additional resources to meet target reserve margins. By comparison, the capacity of the retired plants was 179 MW.

If PG&E's, rather than DRA's, assumptions are used (see Ex. 84, p. 184), the capacity without variably priced QFs (23,336 MW) exceeds the resources needed to meet the target reserve margin proposed in ER-7 (and even the 22.6% reserve margin of ER-6).

These results, though differing, suggest an approach to assessing the contribution of QFs when plants are retired. When the utility's resources (including cold standby units) are insufficient to meet target reserve margins without variably priced QFs' capacity, then the recorded O&M savings should be credited to QFs in proportion to the ratio of megawatts of the retired plants' capacity needed to meet the target reserve margin to the total capacity of the retired plants. Using DRA's figures, the entire O&M savings would be credited to varibly priced QFs, because even if the plants had not been retired, PG&E could not meet its target reserve margin without the capacity from variably priced QFs. Using PG&E's estimates, the retired plants were not needed and no credit should be given to variably priced QFs. At intermediate levels, the credit would be proportioned to the extent to which the retired plants were needed to meet target reserve margins.

We believe that this approach should be followed in the 1989 ECAC case. If part of the capacity of the retired plants is needed to meet target reserve margins in the forecast year, that proportion of the recorded O&M savings should be credited to variably priced QFs. If PG&E would have adequate capacity to meet reserve margins without the capacity associated with variably priced QFs, then none of the savings should be credited to QFs. If PG&E would fail to meet target reserve margins in the absence of QFs, even if the retired plants had been retained, then all of the recorded savings should be credited to QFs.

We have illustrated this discussion with figures from Ex. 258. For the calculation in the 1989 ECAC case, the appropriate figures should be based on the evidence and assumptions adopted in that case. The peak demand figure, the capacity of PG&E's resources, and the capacity associated with variably priced QFs should be consistent with the assumptions of the model runs. The recorded O&M savings that may be credited to QFs should be the five-year savings associated with the retired plants, or $8.1 million (Ex. 46).

In its comments to the ALJ's proposed decision, PG&E argued against removing the QFs with contracts to supply firm capacity from PG&E's available resources in the calculation of the avoided O&M costs. PG&E contends that these QFs should be treated like any other resource and should remain a part of PG&E's resources for purposes of this calculation.

The purpose of the calculation, however, is very limited. Our only purpose is to attempt to estimate the extent to which the presence of variably priced QFs has permitted PG&E to avoid O&M costs associated with certain resources. We are not increasing the capacity payments to QFs as a result of this calculation, and the fixed O&M cost that is included in these capacity payments is also unaffected. The purpose of this calculation is merely to apportion the recorded O&M savings from retired and standby units between variably priced QFs and PG&E's other new resources. For this limited purpose, we believe that our treatment of QFs' capacity is appropriate.

The record is unclear on whether the recorded reductions in O&M costs associated with the retired plants include fixed O&M costs. If fixed O&M costs are reflected in the recorded figures, they should be reduced, by the amount that fixed O&M costs are included in capacity payments to QFs, before they are credited to QFs.

Although we are adopting an approach that includes retired plants for PG&E at this time, in considering future O&M methodologies we expect to carefully re-examine the issue. There is an additional theoretical problem with including retired plants in the calculation of the adder. If no QFs existed, a utility would typically replace a worn-out plant with a newer generation plant with lower overall costs of operation. Although the details may depend on the specific plant and technology, we may assume that the O&M costs of the newer plant would tend to be lower than those of the plant it replaced. Under traditional ratemaking, ratepayers would pay only the lower costs of the new plant, and any O&M savings would be retained by ratepayers.

Under the approach to avoided cost consistently embraced by this Commission, the avoided plant in this situation is the new plant, not the retired plant, and the calculation of all aspects of avoided costs would be keyed to the costs of the new plant. (In the absence of concrete proposals for new generation plants, we have relied on the costs of a proxy plant for some purposes.) By seeking the benefit of the O&M costs of the retired plants, some parties are essentially treating the retired plant, rather than the new or proxy plant, as the basis for calculating avoided costs.

Generally speaking, this means that ratepayers would pay more to QFs for O&M than they would if the utility had constructed the new plant. This result violates the principles of avoided cost and ratepayer indifference we have repeatedly articulated.

Another way to look at this issue is to examine how long the savings from retired plants should continue to be considered in the calculation of the adder. The general answer is that such savings should be considered until the time when PG&E would have retired the plant with or without the contribution of QFs. The point when a plant would have been retired regardless of QFs' generation may vary; the reasons for the retirement can be that the plant has reached the end of its useful life, that a governmental entity has ordered it closed, that compliance with pollution control requirements would be prohibitively expensive, or numerous other circumstances.

In determining how long to view a retired plant as displaced by QFs, it would be helpful to have testimony on the factors that would affect the decision to retire a particular plant. Although there was little specific testimony on this issue in this case, we are persuaded that considering the cost savings occurring over the past five years for the Avon, Martinez, and Oleum plants is reasonable in this case.

3. Standby Units

The portion of the adder related to standby units has two components.

First are the reduced costs that PG&E has recorded for its cold standby units in recent years. As with the retired plants, the problem is sorting out the influences of variably priced O&M and new generation. A process similar to the one discussed for retired plants can be used to get a workable estimate of the QFs' contribution to these savings. That is, variably priced QFs should be credited with the O&M savings associated with cold standby plants in proportion to the capacity provided by cold standby plants that is required to meet target reserve margins when the capacity associated with variably priced QFs is removed.

This estimate is somewhat rougher than when this process was applied to the savings from retired plants. Because standby units' capacity is already included in the estimate of PG&E's resources, the units' capacity cannot be added in a second time to the resource figure to meet the target reserve margin. However, it is reasonable to assume that in the absence of QFs, cold standby units would be returned to operational status at about the level that new resources would need to be obtained to meet target reserve margins. This assumption allows us to use a proportion derived from the process described above to estimate the standby units' recorded savings that should be credited to QFs.

As we discussed in connection with the retired plants, it is necessary to ensure that the fixed O&M costs incorporated in capacity payments to QFs are removed from the recorded savings associated with standby units.

The second component of the adder related to cold standby units corresponds to the energy produced by these units when called into service. The QFs-in/QFs-out runs provide a good illustration of the role of the variably priced QFs in reducing the need for operation of cold standby units. In the runs for the 1988 ECAC case, parties were instructed to model reserve resources so that they could be restarted and called on by the model in the QFs-out run if needed and economical. (D.88-11-052, mimeo., pp.63-65.) Cold standby units should continue to be modeled so that they are available for dispatch in the QFs-out run. If the model shows that the generation from a cold standby unit is needed, then it is clear the the consumables associated with that generation are avoided by variably priced QFs. The amount of any such generation should be multiplied by the value of consumables and incorporated in the adder.

4. Recorded O&M Savings

As directed in D.88-11-052, PG&E reported the results of its attempt to identify and quantify the O&M costs that vary in one-, three-, and five-year time frames.

Over one year, PG&E reported, consistent with its arguments in this case, that only the costs of consumables varied. PG&E determined that the annual costs of consumables decreased by $1,287,000 due to reduced generation at fossil-fueled plants made possible by the contribution of variably priced QFs. Over three years, PG&E found that O&M costs associated with retired and cold standby units decreased by a total of $14,487,000, including reduced costs of consumables. Over five years, the reduced O&M costs were $8,119,000 for retired plants and $6,525,000 for standby units, for a total of $14,644,000.

Other parties argued that PG&E's figures did not include all elements of avoided cost for these time periods, but no party disputed the accuracy of PG&E's recorded data. Parties accepted PG&E's estimate of the average cost of consumables of 0.37 mills/kWh, although other parts of the total annual avoided cost of consumables depend on the results of the QFs-in/QFs-out runs. We find that the data submitted by PG&E is adequate for purposes of this decision, although other types of data may be more useful for calculating the adder, as we will discuss. In addition, we are satisfied that these O&M savings, as defined and quantified by PG&E, are not included in PG&E's requested O&M expenses for the test year.

5. Calculation of the Adder

For purposes of the 1989 ECAC, the calculation of the adder would begin with the QFs-in/QFs-out runs that are used to determine the IER. For purposes of calculating the adder, standby and reserve units should be modeled to be available for dispatch in the QFs-out run.

We will calculate the avoided O&M costs separately for three types of generating units: operating units, cold standby units, and retired plants. Operating units form a residual category that includes regularly operating units and reserve units that have not yet been placed in cold standby status.

The change in generation between the QFs-in and QFs-out runs for each operating unit should be multiplied by the appropriate variable O&M figure from PG&E's filings in CFM-6 and CFM-7 to develop a total avoided O&M cost for that unit. The avoided costs for all operating units should then be added together to arrive at the total O&M savings from operating units.

For cold standby units, the first calculation is the amount of capacity needed to meet target reserve margins, based on the peak demand assumed for the model runs. The second step is to derive the amount of capacity associated with variably priced QFs. The result of the first calculation should then be compared with PG&E's resources without the capacity of variably priced QFs. The amount of added capacity needed to meet target reserve margins divided by the total capacity of cold standby units provides the ratio (of no more than 1.0) that is multiplied by the five-year O&M savings associated with standby plants, $6,525,000, to arrive at the long-term O&M savings for standby units.

The second component for standby units is the amount of generation from any restarted standby units in the QFs-out run times the cost of consumables, 0.37 mills/kWh, to derive the short-term savings associated with standby units.

The sum of the short-term and long-term savings gives the estimated total avoided O&M costs for cold standby units.

For retired plants, the adopted method compares the two capacity-related calculations used in deriving the long-term savings associated with standby units. If resources (including cold standby units) without variably priced QFs' capacity are sufficient to meet target reserve margins, then none of the retired plants' O&M savings will be credited to QFs. If added capacity is needed to meet target reserve margins, then the amount of needed capacity should be compared to the capacity of the retired units (179 MW in this case). The ratio of needed capacity to total capacity of the retired plants (again limited to 1.0) is multiplied by the recorded five-year savings associated with the retired plants, $8.1 million, to get the O&M savings for retired plants.

Ultrapower suggested that A&G expenses are avoided in proportion to savings in labor expenses. It is unclear whether the labor savings calculated from PG&E's recorded data reflect associated decreases in pensions and benefits expenses and payroll taxes. If these related savings are not reflected in PG&E's figures, the labor portion of any reductions credited to variably priced QFs should be multiplied by 35.51%, the ratio between pensions and benefits expense and payroll tax and labor expense developed in D.86-12-095, in PG&E's last GRC. The resulting payroll tax and pensions savings should also be credited to QFs.

The savings from the three types of generating units--operating, standby, and retired--should be totaled. The sum should be divided by the energy forecasted to be generated by variably priced QFs in the 1989 ECAC proceeding.

The CFM figures are presented in 1984 dollars and PG&E's recorded numbers are in 1987 dollars, so the sum must be escalated to 1990 dollars. Ultrapower escalated the CFM figures by the Consumer Price Index-Urban (CPI-U) index through 1987. Use of the recorded nonlabor escalation of 7.01% is reasonable for converting 1984 dollars to 1987 dollars, and the 1987-90 increase should be 10.64% for labor costs and 15.39% for nonlabor costs, the increases used to develop preliminary estimates in the GRC.

The sum of the avoided O&M costs for operating, cold standby, and retired units, after appropriate escalation, should then be divided by the 1989 ECAC's forecast of generation by variably priced QFs to get the adder.

As we have mentioned, the precise components of the CFM figures for variable O&M costs were not presented in this case. We assume from the information available that the cost of consumables is included in the CFM figures. If not, the avoided O&M for fossil-fueled units used in the calculation of the adder should be adjusted, based on the 0.37 mills/kWh average developed by PG&E.

Similarly, we assume that no fixed O&M costs are included in the CFM figures. If they are, the fixed O&M cost incorporated in capacity payments to QFs should be removed from the total O&M figures before dividing by the forecast of generation from variably priced QFs.

F. Future Proceedings

1. 1990 ECAC Case

All of the methods presented in this case, including the one we have adopted for use in the 1989 ECAC proceeding, have shortcomings. We therefore do not view the adopted method as a final or permanent method. We will permit certain issues to be revisited in the 1990 ECAC case, and the following discussion is presented to guide the parties in their future consideration of this issue.

For the near term, the QFs-in/QFs-out runs will continue to be useful. The QFs-out simulation is still close enough to the actual operation of PG&E's system to be helpful in estimating avoided O&M costs.

Over time, as a larger proportion of PG&E's energy is supplied by variably priced QFs, it may become more difficult to simulate the operation of PG&E's system without QFs while maintaining some connection with PG&E's actual system. At some point, it may be more theoretically accurate to use a proxy to estimate avoided O&M costs.

We recognize that the methodology adopted for PG&E in this decision is linked to the types of resource planning issues addressed in our Biennial Resource Plan Update proceedings. We expect to consider adoption of a generic method for calculating the O&M adder in a future Biennial Resource Plan Update proceeding as several parties have suggested. For at least the next few years, however, we would prefer to refine this method for PG&E, based on the QFs-in/QFs-out runs. These refinements would be addressed in PG&E's ECAC cases. In developing a future methodology, we would be particularly interested in simpler approaches.

One essential refinement is to improve the data on the marginal O&M costs associated with different levels of generation for each fossil-fueled plant. We believe that this sort of data would greatly improve the accuracy of the adder in reflecting the costs PG&E actually avoids because of the presence of QFs. We recognize that assembling this data could be difficult, but we will direct PG&E to investigate whether this sort of information could be extracted or developed from existing records. The results of this investigation, including any data PG&E is able to develop, should be presented with PG&E's 1990 ECAC application.

PG&E suggested that increased cycling of existing generating units due to increased generation by QFs may increase O&M costs. If this assertion is true, these increased cycling costs should be considered in setting the adder.

Another area of refinement is the treatment of retired plants. We think that better analysis could help clarify the extent to which energy from variably priced QFs allows PG&E to retire plants and avoid some O&M costs. This analysis may lead to a different valuation of the capacity provided by QFs, rather than an increase in the adder paid on the basis of energy, but further analysis should be helpful in moving toward our goal of accurately calculating the costs avoided by QFs and making appropriate payments based on those costs.

2. <u>1989 ECAC Case</u>

Parties to PG&E's 1989 ECAC case have calculated the O&M adder according to the method described in the ALJ's proposed decision and have submitted alternative adder calculations based on their comments to the ALJ's proposed decision.

The method approved in this decision will be employed to calculate the O&M adder and the corresponding portion of the revenue requirement adopted in the 1989 ECAC case.

Findings of Fact

1. In D.88-11-052, we directed PG&E to present a study on avoided O&M costs.

2. PG&E presented its study as Ex. 46, and alternative approaches to calculating avoided O&M costs were presented by CCC, Ultrapower, the Geothermal QFs, and DRA.

3. According to PG&E's recorded data, the average cost of consumables at fossil-fueled plants is 0.37 mills/kWh, and the annual cost of consumables avoided because of the contribution of variably priced QFs can be calculated using the results of the QFs-in/QFs-out runs. Over three years, the O&M costs associated with retired and cold standby units decreased by a total of $14,487,000, including reduced costs of consumables. Over five years, the reduced O&M costs were $8,119,000 for retired plants and $6,525,000 for standby units, for a total of $14,644,000. These avoided O&M costs have not been included in PG&E's requested O&M expenses for the test year.

4. Many variably priced QFs receive capacity payments that include avoided fixed O&M costs associated with a combustion turbine.

5. The capacity associated with variably priced QFs may allow PG&E to retire generating units.

6. Generation from variably priced QFs may avoid some O&M costs of operating and cold standby units.

7. PG&E's estimates of variable O&M costs, as filed with the Energy Commission in CFM-6 and CFM-7, provide a reasonable estimate, in light of the limited purpose and record of this

proceeding, of each operational generating unit's marginal O&M costs.

Conclusions of Law

1. The basis for the O&M adder paid for energy generated by variably priced QFs should not include the fixed O&M costs that are included in the calculation of capacity payments.

2. The avoided O&M adder paid to variably priced QFs should conform to the principle of ratepayer indifference we have previously embraced to develop appropriate prices and contracts for QFs.

3. The O&M costs associated with operating units, retired plants, and standby units should be considered in the calculation of the O&M adder.

4. For purposes of PG&E's 1989 ECAC case, it is reasonable to calculate the O&M adder as set forth in this decision.

5. For purposes of PG&E's 1990 ECAC case, it is reasonable to calculate the O&M adder under the basic methodology set forth in this decision, with only minor refinements.

6. PG&E should investigate whether data on the marginal O&M costs associated with different levels of generation for each of its fossil-fueled units can be extracted or developed from existing records. PG&E should present the results of its investigation, including any data PG&E is able to develop, with the application in its 1990 ECAC case.

7. Because the method adopted in this decision must be implemented in PG&E's 1989 ECAC proceeding, this decision should be served on all parties to A.89-04-001.

ORDER

Therefore, **IT IS ORDERED** that:

1. For the 1989 Energy Cost Adjustment Clause (ECAC) proceeding for Pacific Gas and Electric Company (PG&E), the

calculation of the operation and maintenance (O&M) adder paid to variably priced qualifying facilities (QFs) shall be as follows:

> For each operating unit (including reserve units not yet converted to cold standby status), the change in generation between the QFs-in and QFs-out runs used to calculate the Incremental Energy Rate (IER) should be multiplied by the appropriate variable O&M figure from PG&E's filings in the Energy Commission's Sixth and Seventh Common Forecasting Methodology (CFM) proceeding to develop a total avoided O&M cost for each unit. The avoided costs for all operating units should then be added together to arrive at the total O&M savings from operating units.
>
> For cold standby units, the amount of capacity needed to meet target reserve margins, based on the peak demand assumed for the model runs, shall be compared with PG&E's resources without the capacity associated with variably priced QFs. The amount of added capacity needed to meet target reserve margins divided by the total capacity of cold standby units provides the ratio (of no more than 1.0) that is multiplied by the five-year O&M savings associated with standby units, $6,525,000, to arrive at the long-term O&M savings associated with standby units.
>
> The amount of generation from any restarted standby units in the QFs-out run times the cost of consumables, 0.37 mills/kWh, is the short-term savings associated with standby units. The sum of the short-term and long-term savings gives the estimated total avoided O&M costs for cold standby units.
>
> For retired plants, if resources (including cold standby units) without variably priced QFs' capacity are sufficient to meet target reserve margins, then no savings will be credited to QFs. If added capacity is needed to meet target reserve margins, then the amount of needed capacity should be compared to the capacity of the retired units (179 MW). The ratio of needed capacity to total capacity of the retired plants (again limited to 1.0) is multiplied by the recorded five-year savings

associated with the retired plants, $8.1 million, to get the O&M savings for retired plants.

After appropriate escalation to 1990 dollars and adjustment for associated savings in pensions and benefits expense and payroll taxes, the savings from the three types of plants--operational, standby, and retired--should be totaled. The sum should be divided by the energy forecasted to be generated by variably priced QFs in the 1989 ECAC proceeding to arrive at the amount of the adder.

2. Subject to minor refinements, the basic methodology adopted in this proceeding shall be used in calculating the O&M adder in PG&E's 1990 ECAC proceeding. PG&E shall investigate whether data on the marginal O&M costs associated with different levels of generation for each of its fossil-fueled units can be extracted or developed from existing records. PG&E shall present the results of its investigation, including any data PG&E is able to develop, with the application in its 1990 ECAC case.

3. This decision shall be served on all parties to Application 89-04-001, PG&E's 1989 ECAC proceeding.

This order is effective today.

Dated September 27, 1989, at San Francisco, California.

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

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

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

Wesley Franklin

WESLEY FRANKLIN, Acting Executive Director

PB

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LIST OF APPEARANCES

Applicant: Roger J. Peters, Kermit R. Kubitz, and Michelle L. Wilson, Attorneys at Law, for Pacific Gas and Electric Company.

Interested Parties: Lindsay, Hart, Neil & Weigler, by Michael P. Alcantar, Attorney at Law, for Cogenerators of Southern California; Barkovich & Yap, by Barbara R. Barkovich and Jackson, Tufts, Cole & Black, by William H. Booth, Attorney at Law, for California Large Energy Consumers Association; Morrison & Foerster, by Jerry R. Bloom, Attorney at Law, for California Cogeneration Council; Mathew V. Brady, Attorney at Law, for California Department of General Services; David R. Branchcomb, for Henwood Energy Services; Walter Cavagnaro, for Anchor Glass Container and Energy Systems Engineers, Inc.; Thomas P. Corr, Attorney at Law, for Independent Power Corporation; Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Phil Di Virgilio, for PSE, Inc.; Karen Edson, for KKE & Associates; Jeff Fabbri, for Power Users Protection Council; David B. Follett, for Southern California Gas Company; Steven Geringer and Karen Norene Mills, Attorneys at Law, for California Farm Bureau Federation; Law Office of Dian M. Grueneich, by Dian M. Grueneich and Barry H. Epstein, Attorneys at Law, for California Department of General Services and California Institute of Energy Efficiency; Biddle & Hamilton, by Richard L. Hamilton and Christian M. Keiner, Attorneys at Law, for Western Mobilehome Association; Steve Harris, for Enron/Transwestern Pipeline Company; Caryn Hough, Attorney at Law, for California Energy Commission; Jan Hamrin and Jan Smutny-Jones, Attorney at Law, for Independent Energy Producers; Roberts and Kerner, by Douglas K. Kerner, Attorney at Law, for Santa Fe Geothermal, Inc., UNOCAL Corporation, and Freeport-McMoRan Resource Partners; Lindsay, Hart, Neil & Weigler, by Paul J. Kaufman, Attorney at Law, for Kern River Cogeneration Company; Alannah Kinser, for the Office of the Public Advisor; Richard K. Durant, Carol B. Henningson, James M. Lehrer, Frank A. McNulty, and Carol A. Schmid-Frazee, Attorneys at Law, and John Hughes, for Southern California Edison Company; William G. Fleckles, Attorney at Law, for California Travel Parks Association; William B. Marcus, for JBS Energy, Inc.; Graham & James, by Martin A. Mattes, Attorney at Law, for Amerada Hess Corporation; Michael McQueen, for UNOCAL; Joseph G. Meyer, for Joseph Meyer Associates; John D. Quinley, for

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Cogeneration Service Bureau; Kathi Robertson and Wayne Meeks, for Simpson Paper Company; Donald G. Salow, for Association of California Water Agencies; Chester & Schmidt, by Reed V. Schmidt, and McCracken, Byers & Martin, by David J. Byers, Attorney at Law, for California City-County Street Light Association; Donald W. Schoenbeck, for Regulatory and Cogeneration Services; Thomas R. Sheets, Attorney at Law, and Thomas J. O'Rourke, for Southwest Gas Corporation; Law Offices of Kathryn Dickson, by Joel R. Singer, Attorney at Law, and Sylvia M. Siegel, for Toward Utility Rate Normalization; Armour St. John, Wilcox, Goodin & Schlotz, by James Squeri and John L. Clark, Attorneys at Law, for California Building Industry Association; Downey, Brand, Seymour & Rohwer, by Deborah K. Tellier and Philip A. Stohr, Attorneys at Law, for Industrial Users; Nancy Thompson, for Barakat, Howard & Chamberlin; John Vickland, Attorney at Law, for San Francisco Bay Area Rapid Transit District; Robert B. Weisenmiller, for Morse, Richard & Weisenmiller & Associates, Inc.; Alvin Pak, Attorney at Law, and Bruce J. Williams, for San Diego Gas & Electric Company; Harry K. Winters, for University of California; James Adams, for Energy and Resource Advocates; William M. Bennett, for himself; Maurice Brubaker, for Drazen-Brubaker & Associates; Stephen F. Diamond, for Electrical Workers, Local 1245; Norman J. Furuta, Attorney at Law, and Sharon K. Matsumura, for Federal Executive Agencies; Donald H. Maynor, Attorney at Law, for Northern California Power Agency; Ken Meyer, for Energy Consulting Group; Roger Poynts, for Utility Design, Inc.; Andrew Safir and Scott Tomashefsky, for Recon Research Corporation and Salmon Resources, Inc.; E. D. Yates, for California League of Food Processors; Messrs. Brady & Berliner, by John W. Simison, Attorney at Law, for Canadian Producer Group; Bryan Gaynor, Attorney at Law, for Energy and Resource Advocates; C. Hayden Ames, Attorney at Law, for Chickering & Gregory; Ben Hudnall, Jonathan Siegel, and Brian D'Arcy, Attorneys at Law, for Engineers & Scientists of California, MEBA, AFLCIO; Jane Brunner and Tom Dalzell, Attorneys at Law, for Local 1245 IBEW, Engineers and Scientists of California, and Coalition of California Utility Workers; Randolph L. Wu, Attorney at Law, and Phyllis Huckabee, for El Paso Natural Gas Company; and Charles E. Doering, for Salmon Resources, Inc.

Division of Ratepayer Advocates: Philip Scott Weismehl, Alberto Guerrero, Irene Moosen, and Judi Allen, Attorneys at Law, and David Fukutome and Lloyd Rowe.

(END OF APPENDIX A)

for the test year. If we assume that the presence of QFs has enabled PG&E to reduce its O&M costs, then the trend in its O&M costs since QFs began supplying electricity to the system should decline relative to historic trends. The GRC should examine the savings over one, three, and five years, should sort out the other influences that may account for part of the change in the trend, should make a finding of the amount of variable and avoided O&M costs over one, three, and five years, and should review the O&M figures for the test year to ensure that none of the avoided costs are included.

"PG&E's 1989 ECAC case will adopt an appropriate O&M adder. The adder will be based on the information developed in the GRC and may take into account issues such as the appropriate time frame to be considered in establishing avoided O&M payments."

Thus, the initial purpose of this decision is to adopt a method of calculating the adder that can be incorporated in our decision in PG&E's 1989 ECAC case (Application (A.) 89-04-001). A further goal is to settle on a method for determining the adder that can be regularly used, without much controversy, in subsequent ECAC cases.

PG&E presented its report as Ex. 46. This issue was addressed by witnesses for PG&E; the California Cogeneration Council (CCC); Ultrapower, Incorporated and the Independent Energy Producers Association (IEP); and Unocal Corporation, Santa Fe Geothermal, Inc., and Freeport-McMoRan Resource Partners (Geothermal QFs) in hearings held on May 15 and 17, 1989. Because of a need to adopt a method for calculating the O&M payment in time for specific figures to be introduced into evidence in PG&E's 1989 ECAC case, this issue was separated from the other issues in the general rate case. PG&E, CCC, IEP, the Geothermal QFs, and the Commission's Division of Ratepayer Advocates (DRA) filed opening briefs on July 7 and reply briefs on July 19.

II. Positions of the Parties

Generally speaking, the line in this dispute was drawn between PG&E, on the one hand, and representatives of the QFs, on the other, with DRA falling somewhere between these parties. We will follow this division in presenting the parties' positions.

A. PG&E

1. Recommended Method

PG&E believes that the method chosen for calculating avoided O&M costs must comply with PURPA's requirement that payments to QFs must be just and reasonable to ratepayers; payments to QFs should not exceed the actual O&M costs avoided by PG&E.

In addition, PG&E thinks it necessary to recognize the two separate components of avoided O&M costs: fixed costs associated with capacity and variable costs. The former is already included in capacity payments to QFs, PG&E says, and only the latter costs should be paid on the basis of the quantity of kilowatt-hours (kWh) generated by variably priced QFs.

PG&E's recommended method has several steps. First, PG&E calculates the amount of longer-term recorded O&M savings. In this case, PG&E used recorded accounting data from 1984 through 1988 to develop the amount of longer-term savings. Next, these longer-term savings are allocated between variably priced QFs and other new generating resources that have begun operation since 1984, such as the Diablo Canyon nuclear power plant, several geothermal units, some small hydroelectric projects, and fixed-price QFs (Ex. 46, p. C-1). PG&E allocates the longer-term savings in proportion to the generation each group provided to PG&E's system from 1984 through 1988. PG&E determined that the share of these longer-term avoided costs attributable to generation by variably priced QFs is 23%. The next step considers the forecast of the cost of "consumables"--items such as lubricants and water treatment chemicals--that are directly reduced when short-term generation decreases. PG&E uses one year of data and estimates that the cost of consumables averages 0.37 mills/kWh. Using its production simulation model, PG&E then calculates the extent to which generation by variably priced QFs allows PG&E to back down conventional steam units. In the 1988 ECAC case, this percentage was 49.3%. The cost of consumables is multiplied by this percentage and further multiplied by the energy delivered to PG&E by variably priced QFs, which PG&E estimates to be 6,992 gigawatt-hours (gWh). The resulting product is added to the variably priced QFs' share of the longer-term savings. Finally, the sum of the longer-term avoided costs and the avoided consumables, with the adjustments mentioned, are divided by the forecasted energy deliveries by QFs.

Using recent figures, PG&E calculates the appropriate O&M adder to be 0.4 mills/kWh. However, PG&E acknowledges that its calculation should be revised in the 1989 ECAC case to reflect a more recent forecast of generation by variably priced QFs and the percent of that generation that is made up by conventional steam units in computer runs that simulate the operation of PG&E's system in the absence of variably priced QFs (QFs-out runs).

PG&E argues that its estimate is fair to ratepayers because O&M savings from reduced operations at its conventional generating units have already been reflected in the level of expenses it seeks to recover in this case. These savings result from placing units on cold standby status, the retirements of the Avon, Martinez, and Oleum plants, its voluntary employee retirement program, and other improvements in productivity. These reductions are either already reflected in recorded data or are incorporated in PG&E's estimates for the 1990 test year, according to PG&E.

Although some of these savings should be transferred to QFs, PG&E argues, the savings from the retirements of the Avon, Martinez, and Oleum plants should remain with ratepayers. These plants operated beyond their useful lives, and PG&E retired them for economic and safety reasons. The availability of generation from QFs had no influence on the decision to take these plants out of service, according to PG&E.

PG&E also points out that the deliveries from QFs cause PG&E's steam generation units to go through more cycles of increased and decreased output. It is established throughout the electric industry that such cycling accelerates the aging of these units. Thus, PG&E argues, QFs may cause some O&M costs to increase even if generation is reduced.

PG&E concludes that its method of calculating avoided O&M costs is logical and consistent with PURPA, and that its estimate of 0.4 mills/kWh is reasonable.

2. <u>Other Parties' Criticisms of PG&E's Method</u>

a. <u>CCC</u>

CCC has two major criticisms of PG&E's method.

First, CCC believes that PG&E ignores the fact that its new generating resources have allowed PG&E to improve the reliability of its system and to meet load growth. Testimony in this case demonstrated that the reliability of PG&E's system was unsatisfactory in the early 1980s but is now considered acceptable, according to CCC. In addition, total area load has increased by nearly 16,700 gWh since 1982, and PG&E's other new resources were needed to meet this increased load.

The effect of PG&E's ignoring the need for its new resources, CCC argues, is to expand greatly the pool of resources that are considered marginal. This, in turn, allows PG&E to claim that all the O&M savings from its retirements and conversions to standby status should be attributed to its new generating resources.

CCC believes that this assertion contradicts the facts. If these new resources were needed to meet load, then they cannot be considered marginal units and given credit for saving O&M costs by allowing old units to be retired, placed on standby, or curtailed. According to CCC, the evidence in this proceeding shows that QFs are the marginal generating resources that permit reductions in generation by older, inefficient units. PG&E's approach denies these QFs credit for the full extent of the O&M costs that they permit PG&E to avoid.

CCC's second criticism is that PG&E's approach is difficult to implement and verify. The method appears to require a determination of which resources are responsible for avoiding which costs, but PG&E has not suggested a way to make that determination. In addition, CCC argues that this method will require the Commission's continuing monitoring of PG&E's decisions to reduce generation at its older units.

Third, CCC points out that PG&E has miscalculated the adder under its own method. As noted previously, CCC disagrees with PG&E's contention that the retirements of the Avon, Martinez, and Oleum plants were not attributable to generation from variably priced QFs. Similarly, CCC faults PG&E for giving QFs no credit for allowing Moss Landing Units 4 and 5 to be placed on standby status or permitting reduced service hours at PG&E's Contra Costa 4 and 5 units. In addition, CCC notes, the percentage that PG&E applied to the cost of consumables to develop its short-term avoided O&M cost was taken from its witness' testimony in the 1988 ECAC proceeding, not from the Commission's decision in that case. The correct percentage is 58.2%, rather than 49.3% used by PG&E.

CCC calculated avoided O&M costs using PG&E's method but making the corrections it advocated. The result was an O&M adder of 2.3 mills/kWh.

b. <u>IEP</u>

IEP also criticizes PG&E's method.

IEP first notes that PG&E's method, based on historical data, is inadequate for the purposes of this proceeding. Reliance on historical costs in these circumstances is incorrect, IEP argues, because trends based on those costs will predict incurred costs, not avoided costs. Costs that are avoided are not reflected in recorded data, so historical figures will always undervalue avoided O&M costs.

IEP also believes that the lack of patterns in PG&E's recorded data supports its views on the inadequacy of historical figures. PG&E's own testimony (Ex. 46, App. B) has consumables, its recommended measure of short-term O&M costs, varying in all possible manners with marginal generation. Thus, IEP argues, PG&E's fundamental assumption, that consumables are an appropriate measure of short-term avoided O&M costs, is disapproved by its own data.

PURPA and this Commission's decisions require utilities to pay QFs the full costs the utility avoids because of the QFs' production, according to IEP. IEP believes that PG&E's approach violates this standard. In recent years, generation from QFs has allowed PG&E to avoid O&M costs by retiring some plants and placing other units on standby, IEP argues. Rather than crediting QFs with those savings, PG&E allocates these O&M savings between QFs and other new sources of generation. But PG&E's method contains a fundamental inconsistency, IEP contends. In deciding whether or not to remove units from service temporarily or permanently, PG&E looks to its forecasted capacity requirements. But its proposed allocation of reduced O&M costs is based on the energy produced by the various units, rather than their capacity.

IEP thinks the most compelling argument against PG&E's method was PG&E's witness' testimony about how the method would be applied over the next few years. Even if current conditions remained the same, O&M payments to QFs would decline over time, because of the three- and five-year time frames assumed in PG&E's approach. IEP finds it even more strange that if conditions on PG&E's system required standby units to return to service, the O&M adder could become a negative number, with the result that payments to QFs would decline at the same time that the energy and capacity that they supply became more valuable.

For all these reasons, IEP urges the rejection of PG&E's method.

c. Geothermal QFs

Like other representatives of QFs, the Geothermal QFs believe that QFs should be credited with the full amount of the O&M savings from the retirements of the Avon, Martinez, and Oleum plants. The Geothermal QFs argue that PG&E could not have retired these units in the absence of QFs' contribution to meeting load and improving reliability.

The Geothermal QFs also point out that PG&E's calculation of avoided O&M costs is inconsistent with other estimates of O&M costs that it is required to file in other regulatory proceedings, such as the California Energy Commission's Seventh Common Forecasting Methodology (CFM-7) proceeding.

The Geothermal QFs argue that PG&E also errs in allocating O&M savings between QFs and other new resources. The Commission has determined that variably priced QFs should be treated as the marginal resource, the Geothermal QFs state. As PG&E's system efficiency improves, for example, payments to QFs based on the marginal efficiency of generation decline. Consistent and fair treatment requires that QFs also get the credit for increased O&M savings that accrue as less efficient units are retired or used less.

Finally, the Geothermal QFs note, as did CCC, that PG&E's calculations of the costs of consumables was based on an incorrect figure for the extent to which conventional steam units were backed down in the modeling runs in the 1988 ECAC proceeding. PG&E used 49.3% in its calculation; the decision in that case was based on 58.2%.

d. DRA

DRA does not engage in much direct criticism of PG&E's method. DRA agrees with PG&E's single-year approach to short-term avoided O&M costs, but DRA thinks PG&E has included these costs twice in its calculation. PG&E has developed estimates of avoided O&M costs for three and five years, but these estimates already include the one-year cost of consumables. DRA sees this as a flaw in PG&E's method. DRA finds PG&E's concern about the allocation of O&M savings to energy or capacity payments to be somewhat overblown, since the distinction is arbitrary. For DRA, a more important concern is that none of these savings are lost in the allocation.

B. QFs

1. Recommended Methods

a. CCC

CCC's proposed method for calculating the avoided O&M payments is based on a five-year average of PG&E's total O&M costs for its operating oil- and gas-fueled generating units, calculated in mills/kWh. This average would be prorated to reflect the extent to which generation from QFs displaces generation from PG&E's oil- and gas-fueled units.

This displacement percentage would be calculated through use of the QFs-in/QFs-out model runs that are currently used in ECAC proceedings to calculate PG&E's IER. (The IER is calculated by performing two model runs--one based on all resources forecasted to be available to PG&E (QFs-in) and one that simulates the operation of PG&E's system without any energy from variably priced QFs (QFs-out). (See D.88-03-079.)

This method has the advantage of being easy to implement and verify, according to CCC. In addition, it takes into account the effect of new resources on reliability and load growth. CCC criticizes PG&E's approach for assuming that new resources made no contribution to improving system reliability and meeting increased load. It is clear to CCC that these new resources were nearly entirely needed to meet load growth and improve reliability. QFs lower O&M costs by permitting PG&E to retire old generating units and to place other units on standby, and PG&E's approach unfairly underestimates this contribution. CCC believes that its method overcomes these deficiencies in PG&E's approach.

CCC also requests that the Commission acknowledge that almost all of a unit's O&M costs can be avoided when a unit is retired or placed on standby status.

b. IEP

IEP presented several alternative methods in addition to its preferred approach.

IEP first offers a calculation based on corrections and improvements to PG&E's method.

Like PG&E, IEP cites the provisions of PURPA and defines avoidable O&M cost as the expense that PG&E would incur but for the generation of variably priced QFs. IEP finds it useful to break down total O&M costs into short-term and long-term costs. Short-term O&M costs are those that are avoided when purchases from QFs allow reduced operation of PG&E's generation units. For purposes of this issue, IEP views long-term O&M costs as the costs that are avoided when generation from QFs allows PG&E to take generation units out of service temporarily or permanently.

In IEP's scheme, avoided short-term O&M costs include the consumables identified by PG&E. However, IEP notes that other costs are also avoided in the short term. For example, operating units in a single or two-shift mode, rather than around the clock, or lengthening the time between required major maintenance, also reduces O&M costs in the short term. IEP suggests that estimates of short-term avoided O&M costs may be derived by applying the technique used in PG&E's 1988 ECAC case for calculating avoided O&M costs. The necessary underlying data could be taken from various regulatory filings PG&E is required to make or from research sponsored by the Electric Power Research Institute (EPRI).

In the long term, IEP believes PG&E can avoid O&M costs by removing units from service. IEP develops three categories of these removals.

The shortest-term removals from service are classified as reserve outages. Units on reserve status are not operating and do not require a full operating crew, according to IEP.

When a unit is placed in standby reserve status, it is removed from service for a longer term but not permanently shut down. Such units require at least two months to be returned to service, and more labor and operating costs are avoided than for reserve outages.

The longest term removal from service is, of course, retirement. Significant O&M costs can be avoided when plants are retired, according to IEP.

IEP argues that when generation from QFs allows plants to be place in reserve outage, PG&E saves labor costs (because fewer operating personnel are required) and maintenance costs (because the period between scheduled maintenance can be extended). However, IEP was unable to obtain enough information to permit it to quantify these savings.

When units are retired or placed on standby reserve, it is easier to quantify the avoided O&M. PG&E has estimated that it has saved $14.6 million in O&M expense in the past five years because of such removals from service. IEP appears to accept this figure, but argues that QFs should be credited with all of these savings, because PG&E could not have removed these units from service without the capacity provided by variably priced QFs.

The result of IEP's method is an avoided O&M payment of about 4 mills/kWh.

However, IEP believes that this method, like any method that relies on historical data, has many shortcomings. IEP's primary recommendation, therefore, is that the Commission adopt a proxy to estimate avoided O&M costs. When the Commission has faced similar theoretical problems in defining other types of avoided costs, it has found it useful to rely on a proxy to estimate full avoided cost.

IEP offers several possible proxies, but it believes that a gas-fired combined cycle generating plant is the most appropriate proxy for these purposes, because its operating characteristics are close to those of variably priced QFs. IEP's method for making use of this proxy is to run a simulation of PG&E's system substituting the proxy plants for variably priced QFs. Using this method, IEP calculated an avoided O&M cost of 3.69 mills/kWh.

c. Geothermal QFs

Determining a final method for calculating avoided O&M costs is a matter that should be resolved, like other general issues, in the proceedings that have historically taken on such issues, such as the Biennial Resource Plan Update proceeding, according to the Geothermal QFs. All that the Commission should attempt to do at this time is to adopt an interim O&M adder, for use until a more permanent method has been determined.

The recommended interim figure advocated by the Geothermal QFs has two components.

The first component is based on the recorded data for the past three years and credits variably priced QFs with the O&M cost reductions for both standby and retired units in those years. The second component is designed to account for the avoided cost of consumables and is derived from the percent of generation by variably priced QFs replaced by oil- or gas-fueled generation in the QFs-out run. The sum of the two components is the total avoided O&M cost.

The Geothermal QFs have calculated this total to be 2.55 mills/kWh, but the current percentage applied to the cost of consumables included in the total would be calculated in PG&E's 1989 ECAC case.

2. Other Parties' Criticisms of the QFs' Methods

PG&E finds several flaws in the methods proposed by representatives of QFs.

First, PG&E believes that the proposals violate the provisions of PURPA. PG&E believes that the proposals would require ratepayers to make payments to QFs that exceed actual avoided O&M costs or that are not reasonably related to savings caused by generation by QFs. This result, according to PG&E, is contrary to PURPA's assumption that ratepayers should be indifferent about whether electricity is generated by QFs or the utility. Thus, if other resources or factors, rather than generation by QFs, are reasonable for savings, then those savings should either be allocated to those other sources or retained for the benefit of ratepayers, PG&E concludes.

Second, PG&E thinks that many of the QFs confuse total O&M costs and avoided O&M costs. This is particularly evident in some of the references to PG&E's filings in CFM-7, states PG&E. The O&M adder should be based only on avoided O&M costs, and not on total costs.

Third, many of the proposals rest on erroneous reliability studies and confuse energy and capacity payments, PG&E argues. Many QFs already receive compensation for their contributions to reliability in the form of capacity payments. PG&E believes that those QFs who contribute to the reliability of PG&E's system through their contractual commitments to supply firm capacity are already compensated for that contribution in the capacity payments they receive from PG&E. PG&E contends that the confusion between fixed O&M expenses, which if avoided should be reflected in capacity payments, and variable avoided O&M payments, the subject of this proceeding, could lead to excessive payments to QFs, at the expense of ratepayers.

PG&E also has specific criticisms of the other parties' positions.

CCC's proposed method fails to link reduced generation and reduced costs, according to PG&E. CCC attempts to make such a link by references to retired plants, which logically cannot be used to represent the reductions in generation in operating plants due to variably priced QFs, PG&E argues.

CCC also neglects the distinction between energy- and capacity-related O&M costs, and recommends allocating all avoided O&M costs on the basis of energy, in violation of PURPA. PG&E believes that failure to take into account the O&M component of capacity payments made to QFs who also supply variably priced energy will lead to unfair and unlawful overpayments to these QFs.

CCC's modeling runs in support of its recommendation, PG&E further argues, similarly confuse the nature of energy and capacity and ignore the contractual obligation of many QFs to provide capacity to support the system's reliability.

Two of the approaches suggested by IEP contain the same flaws as CCC's recommendations, PG&E states. Its favored proxy approach is so radically different from any previous attempts at establishing avoided O&M costs that PG&E thinks it should be referred to one of the more general proceedings on QFs. PG&E argues that the proxy proposal is inconsistent with the reasons the Commission directed this issue to be studied in the general rate case. PG&E also criticizes the proxy for failing to take into account the fixed O&M component that QFs are already compensated for through capacity payments. PG&E's rough calculation indicates that IEP's figure should be reduced by about 9% to reflect fixed O&M costs.

PG&E also criticizes the Geothermal QFs' proposal for allocating all O&M savings to variably priced QFs. PG&E points out that the Geothermal QFs' own witness acknowledged the difficulty of delegating the function of meeting load growth to one resource while crediting standby and retirement savings to other resources, but PG&E believes that that is exactly the sort of differentiation that the Geothermal QFs' method requires.

Although DRA states its general support for CCC's method, it notes that the recommendations of the representatives of QFs overstate avoided O&M costs by crediting all O&M savings from standby and retired plants to QFs. In addition, CCC's model runs resulted in excessive reliability targets, and DRA believes that CCC's method needs adjustment to overcome this problem. The model should commit only enough retired and cold standby units to meet predetermined reliability targets, according to DRA.

IEP does not criticize the Geothermal QFs' method, but it opposes the suggestion that the issue of how to calculate avoided O&M costs should be transferred to the Biennial Resource Plan Update proceeding.

C. <u>DRA</u>

1. <u>Recommended Method</u>

DRA believes that a method for calculating avoided O&M costs should take into account the balance between loads and resources, load growth, and reliability without becoming unnecessarily complex. DRA recommends that production simulation models be used to determine long- and short-term O&M costs.

DRA generally supports CCC's recommended method. But DRA thinks that CCC and the Geothermal QFs have overstated avoided O&M costs by crediting all of the costs associated with retired and standby units to the generation provided by variably priced QFs. CCC's method should be refined by allowing the model to determine which standby or retired units would be committed in the absence of variably priced QFs. CCC tends to provide excessive reliability; DRA accordingly recommends that the spinning reserve criteria used in the model runs should be the basis for the appropriate level of reliability in calculating the avoided O&M costs.

For existing units, DRA generally agrees with PG&E's approach of calculating the cost of consumables for one year. But

DRA believes that PG&E counts some costs twice since the cost of consumables is already included in the three- and five-year data underlying PG&E's calculations.

DRA would overcome these problems by using the cost of one-year's worth of consumables as a measure of short-run avoided O&M costs for existing plants. The difference in generation for existing units between the QFs-in and QFs-out runs would be multiplied by the average cost of consumables to develop the short-run figure. The long-run costs of avoided O&M for retired and standby units would be derived by multiplying the change in kWh between the QFs-in and QFs-out runs for these units by the three- to five-year average value of avoided O&M costs, adjusted to current year dollars. The sum of these two components would be divided by variably priced QFs' total generation to develop the final avoided O&M figure.

All units placed on standby or retired in the last three to five years would be included in the resources available for commitment in the QFs-out run under DRA's proposal. DRA agrees with some of the other parties that these units could not have been taken out of service unless new generation allowed minimum reliability requirements to be met.

DRA proposes to allocate the short-term O&M savings, resulting from the differences in generation between the QFs-in and QFs-out runs, to energy payments and the long-term savings from retirements or cold standby units to capacity payments.

DRA also notes PG&E's concerns about increases in maintenance costs that may result from increased cycling of conventional steam units because of the availability of generation from QFs. DRA agrees that these increased costs should be included in a theoretically correct calculation of avoided O&M costs, but does not recommend this adjustment now because of a lack of reliable data.

2. Other Parties' Criticisms of DRA's Method

PG&E and CCC join in stating that DRA's proposal violates due process. DRA did not articulate its proposal until its opening brief, and no witnesses testified in support of the proposal. No other party has had an opportunity to cross-examine DRA on the details of its proposal.

CCC also objects to DRA's method on substantive grounds. CCC thinks that the proposal is undeveloped and several of its elements are unclear, such as how DRA proposes to calculate long-term O&M savings and how such savings would be determined in a future period when no retirements have occurred.

PG&E argues that DRA errs in accusing it of including the one-year avoided cost of consumables in its calculation of long-term savings; short-term costs have been excluded from PG&E's long-term estimates.

PG&E finds DRA's approach illogical, because of its use of the change in kWhs generated by standby and retired units in the QFs-in and QFs-out runs. This change is minimal, because retired units are not restarted in the QFs-out run and the use of standby units is limited in a way that does not reflect their long-term benefits.

III. Discussion

Although the parties have obviously put great thought and effort into their presentations on this issue, we cannot endorse any party's recommendation wholeheartedly. Each proposed method has shortcomings or inconsistencies. We will discuss some of our general concerns before we describe the method we adopt in this case.

A. Fixed Versus Variable O&M Costs

The parties have occasionally blurred an important distinction between fixed O&M costs and variable O&M costs. Fixed

O&M costs are usually included in the cost of adding new generation capacity, and capacity payments to QFs include the estimated fixed O&M costs of a combustion turbine, the current proxy used to derive avoided capacity costs. For example, PG&E and DRA recommend that firm capacity payments in the test year of 1990 should be based on a combustion turbine costs of $55.77/kW-yr, including a fixed O&M cost of $3.63/kW-yr and associated administrative and general (A&G) overhead of $1.32/kW-yr (Ex. 113-2-A).

The estimate of avoided <u>fixed</u> O&M costs incorporated in the capacity payment is already paid to QFs who commit to supply firm capacity under SO2 and SO4 and to many QFs with nonstandard contracts modeled after these standard offers. Even QFs who cannot guarantee to supply capacity and who sell PG&E energy on an as-available basis under SO1 receive payments that include a capacity component to reflect the diversity of generation from these sources. Some contracts, such as SO2 contracts, for QFs supplying firm capacity also provide bonus capacity payments for exceeding a specified capacity factor.

The issue in this case is how to quantify the <u>variable</u> O&M costs that are avoided because of the energy supplied by variably priced QFs. Most of these variably priced QFs also supply and are paid for capacity they provide under SO2, certain options of SO4, and SO1. They are differentiated from fixed priced QFs not so much by the capacity payments they receive as the way in which energy payments are calculated under their contracts. For these reasons, any method that does not separate out the fixed O&M avoided cost from total O&M costs will have the potential for paying the fixed O&M costs twice.

B. <u>Retired Plants</u>

Determining the proper role for retired plants in calculating the O&M adder is complicated by several circumstances. The three plants PG&E recently retired--Avon, Martinez, and Oleum--were not typical plants. They were operated in conjunction with adjacent refineries that purchased steam and electricity from PG&E. The plants were near the end of their expected useful lives when they were retired, and PG&E claims that economic and safety reasons dominated the decision to retire the plants. In addition, the contracts with the refineries were terminated, which made continued operation of the plants impractical, according to PG&E.

These facts appear to isolate the decision to retire the plants from any influence of the energy contribution of variably priced QFs. But other testimony forces us to consider the role of variably priced QFs' power. For example, it was suggested that the decision to terminate the refinery contracts was a consequence of, and not a contributing reason in, PG&E's decision to retire the plants (Tr. 41:4506-4509). IEP also presented testimony that PG&E's reserve margin would fall below target levels if QFs were not present to fill in for retired and standby plants.

This issue is further complicated by the historical fact that PG&E added considerable new generation near the time of the retirements, while substantial load growth was also occurring.

PG&E has claimed that QFs had no influence on the decision to retire the plants, but if pressed into its alternative position, PG&E is willing to allocate, on the basis of historical energy production, the O&M savings from the retirements between variably priced QFs and its other new generation. The representatives of the QFs assert that PG&E would have been unable to retire the plants without the contribution of QFs, and therefore the variably priced QFs should receive the full credit for the reduced O&M costs resulting from the retirements.

The decision to retire an existing generating unit should be made primarily on the basis of economics. As a plant reaches the end of its useful life, the efficiency of converting fuel to electricity declines and the cost of maintenance increases. At some point, the cost of replacing the plant becomes less than continuing to retain the plant in operation. As that point

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The decision to retire an existing generating unit should be made primarily on the basis of economics. As a plant reaches the end of its useful life, the efficiency of converting fuel to electricity declines and the cost of maintenance increases. At some point, the cost of replacing the plant becomes less than continuing to retain the plant in operation. As that point approaches, the utility should either construct a new plant to replace the old plant or make arrangements to purchase the necessary capacity and energy from other utilities to substitute for the old plant.

When plants are retired because of aging, rather than for reasons of technological obsolescence, they frequently first go through a phase when the utility finds it economical to keep units in reserve for less frequent operation than the units' originally intended design. Units are kept in reserve for operation when other units are being repaired or serviced or when peak loads justify use of relatively more expensive units. As a general matter, retirements may occur only when the utility has secured enough replacement capacity to assure that the plant will not even be needed to meet peak load. (See Ex. 257, p. 12.)

Thus, as a general matter, the primary considerations in the decision to retire a plant concern capacity and reliability. Because aged plants are usually inefficient to operate, they are rarely the most economic source of energy, and retaining a plant on approaches, the utility should either construct a new plant to replace the old plant or make arrangements to purchase the necessary capacity and energy from other utilities to substitute for the old plant.

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Thus, as a general matter, the primary considerations in the decision to retire a plant concern capacity and reliability. Because aged plants are usually inefficient to operate, they are rarely the most economic source of energy, and retaining a plant on a utility's system purely to contribute energy is unusual. (See Tr. 41:4509.)

For this reason, PG&E's alternative proposal to allocate the O&M savings from its retired plants on the basis of the relative quantity of <u>energy</u> generated by variably priced QFs and new generation plants seems illogical. But the QFs' arguments also ask us to find that the energy supplied by variably priced QFs allowed PG&E to retire the three plants.

To be sure, the distinction between energy and capacity in the context of QF pricing is a fuzzy one; many QFs have firm capacity contracts that require them to generate a certain amount of energy to demonstrate their ability to supply capacity, and we have acknowledged that even the energy QFs provide on an as-available basis helps the utility avoid capacity costs.

These considerations persuade us that we must first look to capacity to determine to what extent, if any, variably priced QFs should receive credit for the O&M savings when the plants were retired.

C. Standby Units

Cold standby units are maintained in a way that permits them to become operational within one week to two months of the decision to bring them back into operation. The primary functions of cold standby units are to provide capacity that can be drawn on when needed and to reinforce the system's reliability. Once a cold standby unit is brought into service, it is available for dispatching and it may also contribute energy to the extent that its energy is cheaper than other sources.

The use of standby units has declined as the contribution of variably priced QFs has grown (see Ex. 258, Tables 4 and 5), and over the last five years PG&E has recorded O&M savings of $6.5 million associated with its standby units.

Thus, the O&M costs associated with standby units can and should be considered in the calculation of the adder.

D. Operating Units

Operating units have at least two components of O&M that may be avoided by generation from variably priced QFs.

First are consumables. Although some parties question whether short-term O&M costs are limited to consumables, no one has disputed that consumables are avoided, and no party has offered an alternative to PG&E's quantification of the avoided cost of consumables.

Second are the O&M savings that may result when units operate at a lower level because of the generation from variably priced QFs. Labor costs may decrease because of reduced hours, fewer shifts, or fewer workers. The schedule of major maintenance may be spread out over a longer time, reducing the cost of labor and materials. These savings are hard to quantify exactly, but a utility's system purely to contribute energy is unusual. (See Tr. 41:4509.)

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total variable O&M costs for operating plants would be expected to decrease in proportion to generation if these effects are significant.

E. Adopted Method

As we have suggested, no party presented a method that was entirely satisfactory. For use in PG&E's 1989 ECAC case, we will adopt a method that resembles proposals put forward by IEP and CCC.

1. Operating Units

a. Generation Displaced by Variably Priced QFs

The method we adopt employs the QFs-in/QFs-out runs that are used to calculate the IER in the ECAC case. The QFs-out run is capable of simulating, within the limits of the particular model, how PG&E's system would operate in the absence of energy from variably priced QFs, and the results of the QFs-out run may be compared with those of the QFs-in run, which forecasts the operation of the system with variably priced QFs included.

IEP suggested that such a comparison could be used to determine the extent to which power from variably priced QFs allows PG&E to reduce generation at operating units. (See Ex. 257, pp. 18-21.) In the QFs-out run, some operating units will be called on to generate more electricity to compensate for the loss of QFs' power. The QFs-in/QFs-out comparison details the increased operation of each such unit. Under IEP's proposal, the change in output in each steam generation unit would be multiplied by the variable O&M cost for that unit, as reported to the Energy Commission in CFM-6 and CFM-7. The O&M costs, expressed in cents/kWh, would be escalated to 1990 dollars in the calculation.

CCC made a similar proposal. CCC would also use the QFs-in/QFs-out runs to determine the portion of variably priced QFs' generation that displaces PG&E's oil and gas units. However, the units' O&M costs would be calculated from each unit's total O&M costs, in nominal dollars, as recorded for each of the last five

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E. Adopted Method

As we have suggested, no party presented a method that was entirely satisfactory. For use in PG&E's 1989 ECAC case, we will adopt a method that resembles proposals put forward by Ultrapower and CCC. This basic methodology should also be used in PG&E's 1990 ECAC proceeding, subject to some refinement as discussed below. Adoption of a common methodology for use by all three major electric utilities should await consideration in a future Biennial Resource Plan Update proceeding.

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Our method incorporates elements of both of these recommendations, but it follows IEP's suggestion most closely. The method begins with the QFs-in/QFs-out runs. The QFs-out run simulates a hypothetical PG&E system that lacks the energy produced by variably priced QFs, and comparison with the QFs-in run, which simulates the operation of the actual system under forecasted conditions, gives a good measure of the energy contribution of variably priced QFs. In addition, using the QFs-in/QFs-out runs for calculation of both IERs and avoided O&M costs provides an appealing consistency.

The QFs-in/QFs-out runs allow calculation of the change in generation for each fossil-fueled unit. The unit-by-unit change in generation can then be used to develop estimates of the different components of avoided O&M.

b. <u>Avoided O&M Costs</u>

One of the biggest problems this issue has presented is the lack of data that would permit us to convert the change in generation into total avoided O&M costs. Ideally, information on the marginal O&M costs of each unit over a range of generation levels would be readily available, and the marginal O&M costs for allows PG&E to reduce generation at operating units. (See Ex. 257, pp. 18-21.) In the QFs-out run, some operating units will be called on to generate more electricity to compensate for the loss of QFs' power. The QFs-in/QFs-out comparison details the increased operation of each such unit. Under Ultrapower's proposal, the change in output in each steam generation unit would be multiplied by the variable O&M cost for that unit, as reported to the Energy Commission in CFM-6 and CFM-7. The O&M costs, expressed in cents/kWh, would be escalated to 1990 dollars in the calculation.

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The parties have suggested three sources of data for the conversion of each operating unit's change in generation to avoided costs. IEP has suggested use of the data PG&E filed in the Energy Commission's CFM-6 and CFM-7 proceedings (apparently the same data was filed in each proceeding). CCC suggested use of the average O&M, defined as total operating costs minus fuel costs, for PG&E's fossil-fueled units for 1984-1988. PG&E, DRA, and the Geothermal QFs suggested using PG&E's recorded data for the last three to five years. PG&E would rely primarily on the reduction over five years in O&M costs for standby units; DRA and the Geothermal QFs would use an average for each unit.

Each of these data sources has its shortcomings.

The CFM figures are supposed to represent average variable O&M costs for 1976-1986. These figures present several problems. First, average O&M may not represent avoided O&M accurately. We presume that a unit's O&M costs, calculated on a mills/kWh basis, will vary with the level of generation, with the lowest costs when the plant is operating near its most efficient level. At higher-than-optimal capacity factors, we would expect costs to rise because of more wear and tear on components, more frequent scheduled maintenance, and the like. At low capacity factors, the absolute costs of O&M will be lower, but those costs will be spread out over fewer kWhs, and certain costs, such as labor costs, will constitute a minimum level that cannot be avoided until the plant is retired. The portion of this cost curve that corresponds to the change in generation from the QFs-in/QFs-out runs may differ significantly from the point represented by an average.

Another problems with the CFM data is the question of precisely what they measure. PG&E has complained that the CFM definition of variable O&M costs is too broad for use in contribution of variably priced QFs. In addition, using the QFs-in/QFs-out runs for calculation of both IERs and avoided O&M costs provides an appealing consistency.

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In addition, the CFM data may be somewhat out of date, and we have some concerns about basing the adder on information that may be as many as 13 years old.

CCC's suggested source shares many of these problems. It is an average, rather than a measure of avoided or marginal O&M costs. CCC defines variable O&M as the total operating costs of a unit minus fuel costs and rents. The residual category, defined as variable O&M, seems large, and we are concerned about the lack of precise description about its contents.

PG&E's quantification has the virtue of being based on recorded decreases in O&M costs. But PG&E's figures measure only the savings associated with standby or retired units and consumables. As we have discussed previously, avoided O&M costs, at least in theory, should include other components, such as the longer-term reduced costs of labor for operating plants. PG&E has presented figures that are indisputably O&M savings, but it has not quantified all O&M costs avoided by the presence of variably priced QFs.

With all these shortcomings in mind, we believe that figures of CFM-6 and CFM-7 are best suited for the limited purposes of estimating the avoided O&M costs associated with operating units. Although the CFM figures are averages, they were based on costs recorded over a long term that presumably includes a fairly wide range of generation levels for each generation plant. Differences in each unit's production, which can greatly skew the mills/kWh calculation, should be lessened by the wider variety of operating conditions. The CFM figures do not include labor costs, level. At higher-than-optimal capacity factors, we would expect costs to rise because of more wear and tear on components, more frequent scheduled maintenance, and the like. At low capacity factors, the absolute costs of O&M will be lower, but those costs will be spread out over fewer kWhs, and certain costs, such as labor costs, will constitute a minimum level that cannot be avoided until the plant is retired. The portion of this cost curve that corresponds to the change in generation from the QFs-in/QFs-out runs may differ significantly from the point represented by an average.

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2. Retired Plants

We have previously determined that we should focus on capacity in evaluating the extent to which variably priced QFs should receive credit for the O&M savings associated with retired plants. IEP has provided an analysis based on capacity considerations (Ex. 258, pp. 31-36). Although we do not follow the analysis suggested by IEP, the information IEP presented helps us resolve and illustrate this issue.

Table 6 of Ex. 258 incorporates DRA's assumptions that PG&E's total resources in 1990, including new generation and variably priced QFs, will total 22,102 megawatts (MW) (see Ex. 138-A; Ex. 84, p. 184). IEP has calculated that the capacity associated with variably priced QFs will amount to 1,322 MW. When variably priced QFs are removed from total resources and compared with the demand forecast of the Energy Commission's Seventh Electricity Report (ER-7), the resulting reserve margin is 14.9%, substantially less than the long-run target reserve margin of 17.5% that the Energy Commission has proposed for PG&E in ER-7. With the projected levels of peak demand, 21,253 MW of resources would be needed to equal the target reserve margin. Thus, without the capacity associated with variably priced QFs, PG&E would need 473 MW in additional resources to meet target reserve margins. By comparison, the capacity of the retired plants was 179 MW.

If PG&E's, rather than DRA's, assumptions are used (see Ex. 84, p. 184), the capacity without variably priced QFs (23,336 MW) exceeds the resources needed to meet the target reserve margin proposed in ER-7 (and even the 22.6% reserve margin of ER-6).

longer-term reduced costs of labor for operating plants. PG&E has presented figures that are indisputably O&M savings, but it has not quantified all O&M costs avoided by the presence of variably priced QFs.

With all these shortcomings in mind, we believe that, of the data presented in this case, the figures of CFM-6 and CFM-7 are best suited for the limited purposes of estimating the avoided O&M costs associated with operating units. Although the CFM figures are averages, they were based on costs recorded over a long term that presumably includes a fairly wide range of generation levels for each generation plant. Differences in each unit's production, which can greatly skew the mills/kWh calculation, should be lessened by the wider variety of operating conditions. The CFM figures do not include labor costs, but quantifying labor savings for operating plants has proved elusive. And as Ultrapower points out, the results of applying our general method to these figures is consistent with other filings by PG&E over several years and for many purposes. Use of the CFM data also provides a continuity and consistency with the O&M adder developed in the 1988 ECAC proceeding.

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Table 6 of Ex. 258 incorporates DRA's assumptions that PG&E's total resources in 1990, including new generation and variably priced QFs, will total 22,102 megawatts (MW) (see Ex. 138-A; Ex. 84, p. 184). Ultrapower has calculated that the capacity associated with variably priced QFs will amount to 1,322

These results, though differing, suggest an approach to assessing the contribution of QFs when plants are retired. When the utility's resources (including cold standby units) are insufficient to meet target reserve margins without variably priced QFs' capacity, then the recorded O&M savings should be credited to QFs in proportion to the ratio of megawatts of the retired plants' capacity needed to meet the target reserve margin to the total capacity of the retired plants. Using DRA's figures, the entire O&M savings would be credited to varibly priced QFs, because even if the plants had not been retired, PG&E could not meet its target reserve margin without the capacity from variably priced QFs. Using PG&E's estimates, the retired plants were not needed and no credit should be given to variably priced QFs. At intermediate levels, the credit would be proportioned to the extent to which the retired plants were needed to meet target reserve margins.

We believe that this approach should be followed in the 1989 ECAC case. If part of the capacity of the retired plants is needed to meet target reserve margins in the forecast year, that proportion of the recorded O&M savings should be credited to variably priced QFs. If PG&E would have adequate capacity to meet reserve margins without the capacity associated with variably priced QFs, then none of the savings should be credited to QFs. If PG&E would fail to meet target reserve margins in the absence of QFs, even if the retired plants had been retained, then all of the recorded savings should be credited to QFs.

We have illustrated this discussion with figures from Ex. 258. For the calculation in the 1989 ECAC case, the appropriate figures should be based on the evidence and assumptions in that case. The peak demand figure, the capacity of PG&E's resources, and the capacity associated with variably priced QFs should be consistent with the assumptions of the model runs. The recorded O&M savings that may be credited to QFs should be the

MW. When variably priced QFs are removed from total resources and compared with the demand forecast of the Energy Commission's Seventh Electricity Report (ER-7), the resulting reserve margin is 14.9%, substantially less than the long-run target reserve margin of 17.5% that the Energy Commission has proposed for PG&E in ER-7. With the projected levels of peak demand, 21,253 MW of resources would be needed to equal the target reserve margin. Thus, without the capacity associated with variably priced QFs, PG&E would need 473 MW in additional resources to meet target reserve margins. By comparison, the capacity of the retired plants was 179 MW.

If PG&E's, rather than DRA's, assumptions are used (see Ex. 84, p. 184), the capacity without variably priced QFs (23,336 MW) exceeds the resources needed to meet the target reserve margin proposed in ER-7 (and even the 22.6% reserve margin of ER-6).

These results, though differing, suggest an approach to assessing the contribution of QFs when plants are retired. When the utility's resources (including cold standby units) are insufficient to meet target reserve margins without variably priced QFs' capacity, then the recorded O&M savings should be credited to QFs in proportion to the ratio of megawatts of the retired plants' capacity needed to meet the target reserve margin to the total capacity of the retired plants. Using DRA's figures, the entire O&M savings would be credited to varibly priced QFs, because even if the plants had not been retired, PG&E could not meet its target reserve margin without the capacity from variably priced QFs. Using PG&E's estimates, the retired plants were not needed and no credit should be given to variably priced QFs. At intermediate levels, the credit would be proportioned to the extent to which the retired plants were needed to meet target reserve margins.

We believe that this approach should be followed in the 1989 ECAC case. If part of the capacity of the retired plants is needed to meet target reserve margins in the forecast year, that proportion of the recorded O&M savings should be credited to five-year savings associated with the retired plants, or $8.1 million (Ex. 46).

The record is unclear on whether the recorded reductions in O&M costs associated with the retired plants include fixed O&M costs. If fixed costs are reflected in the recorded figures, they should be removed before they are credited to QFs, at least to the extent that fixed O&M costs are included in capacity payments to QFs.

There is an additional theoretical problem with including retired plants in the calculation of the adder. If no QFs existed, a utility would typically replace a worn-out plant with a newer generation plant with lower overall costs of operation. Although the details may depend on the specific plant and technology, we may assume that the O&M costs of the newer plant would tend to be lower than those of the plant it replaced. Under traditional ratemaking, ratepayers would pay only the lower costs of the new plant, and any O&M savings would be retained by ratepayers.

Under the approach to avoided cost consistently embraced by this Commission, the avoided plant in this situation is the new plant, not the retired plant, and the calculation of all aspects of avoided costs would be keyed to the costs of the new plant. (In the absence of concrete proposals for new generation plants, we have relied on the costs of a proxy plant for some purposes.) By seeking the benefit of the O&M costs of the retired plants, some parties are essentially treating the retired plant, rather than the new or proxy plant, as the basis for calculating avoided costs. Generally speaking, this means that ratepayers would pay more to QFs for O&M than they would if the utility had constructed the new plant. This result violates the principles of avoided cost and ratepayer indifference we have repeatedly articulated.

Another way to look at this issue is to examine how long the savings from retired plants should continue to be considered in the calculation of the adder. The general answer is that such variably priced QFs. If PG&E would have adequate capacity to meet reserve margins without the capacity associated with variably priced QFs, then none of the savings should be credited to QFs. If PG&E would fail to meet target reserve margins in the absence of QFs, even if the retired plants had been retained, then all of the recorded savings should be credited to QFs.

We have illustrated this discussion with figures from Ex. 258. For the calculation in the 1989 ECAC case, the appropriate figures should be based on the evidence and assumptions adopted in that case. The peak demand figure, the capacity of PG&E's resources, and the capacity associated with variably priced QFs should be consistent with the assumptions of the model runs. The recorded O&M savings that may be credited to QFs should be the five-year savings associated with the retired plants, or $8.1 million (Ex. 46).

In its comments to the ALJ's proposed decision, PG&E argued against removing the QFs with contracts to supply firm capacity from PG&E's available resources in the calculation of the avoided O&M costs. PG&E contends that these QFs should be treated like any other resource and should remain a part of PG&E's resources for purposes of this calculation.

The purpose of the calculation, however, is very limited. Our only purpose is to attempt to estimate the extent to which the presence of variably priced QFs has permitted PG&E to avoid O&M costs associated with certain resources. We are not increasing the capacity payments to QFs as a result of this calculation, and the fixed O&M cost that is included in these capacity payments is also unaffected. The purpose of this calculation is merely to apportion the recorded O&M savings from retired and standby units between variably priced QFs and PG&E's other new resources. For this limited purpose, we believe that our treatment of QFs' capacity is appropriate.

savings should be considered until the time when PG&E would have retired the plant with or without the contribution of QFs. The point when a plant would have been retired regardless of QFs' generation may vary; the reasons for the retirement can be that the plant has reached the end of its useful life, that a governmental entity has ordered it closed, that compliance with pollution control requirements would be prohibitively expensive, or numerous other circumstances.

In determining how long to view a retired plant as displaced by QFs, it would be helpful to have testimony on the factors that would affect the decision to retire a particular plant. Although there was little specific testimony on this issue in this case, we are persuaded that considering the cost savings occurring over the past five years for the Avon, Martinez, and Oleum plants is reasonable in this case.

3. Standby Units

The portion of the adder related to standby units has two components.

First are the reduced costs that PG&E has recorded for its cold standby units in recent years. As with the retired plants, the problem is sorting out the influences of variably priced O&M and new generation. A process similar to the one discussed for retired plants can be used to get a workable estimate of the QFs' contribution to these savings. That is, variably priced QFs should be credited with the O&M savings associated with cold standby plants in proportion to the capacity provided by cold standby plants that is required to meet target reserve margins when the capacity associated with variably priced QFs is removed.

This estimate is somewhat rougher than when this process was applied to the savings from retired plants. Because standby units' capacity is already included in the estimate of PG&E's resources, the units' capacity cannot be added in a second time to the resource figure to meet the target reserve margin. However, it fixed O&M cost that is included in these capacity payments is also unaffected. The purpose of this calculation is merely to apportion the recorded O&M savings from retired and standby units between variably priced QFs and PG&E's other new resources. For this limited purpose, we believe that our treatment of QFs' capacity is appropriate.

The record is unclear on whether the recorded reductions in O&M costs associated with the retired plants include fixed O&M costs. If fixed O&M costs are reflected in the recorded figures, they should be reduced, by the amount that fixed O&M costs are included in capacity payments to QFs, before they are credited to QFs.

Although we are adopting an approach that includes retired plants for PG&E at this time, in considering future O&M methodologies, we expect to carefully re-examine the issue. There is an additional theoretical problem with including retired plants in the calculation of the adder. If no QFs existed, a utility would typically replace a worn-out plant with a newer generation plant with lower overall costs of operation. Although the details may depend on the specific plant and technology, we may assume that the O&M costs of the newer plant would tend to be lower than those of the plant it replaced. Under traditional ratemaking, ratepayers would pay only the lower costs of the new plant, and any O&M savings would be retained by ratepayers.

Under the approach to avoided cost consistently embraced by this Commission, the avoided plant in this situation is the new plant, not the retired plant, and the calculation of all aspects of avoided costs would be keyed to the costs of the new plant. (In the absence of concrete proposals for new generation plants, we have relied on the costs of a proxy plant for some purposes.) By seeking the benefit of the O&M costs of the retired plants, some parties are essentially treating the retired plant, rather than the new or proxy plant, as the basis for calculating avoided costs.

is reasonable to assume that in the absence of QFs, cold standby units would be returned to operational status at about the level that new resources would need to be obtained to meet target reserve margins. This assumption allows us to use a proportion derived from the process described above to estimate the standby units' recorded savings that should be credited to QFs.

As we discussed in connection with the retired plants, it is necessary to ensure that fixed O&M costs are removed from the recorded savings associated with standby units.

The second component of the adder related to cold standby units corresponds to the energy produced by these units when called into service. The QFs-in/QFs-out runs provide a good illustration of the role of the variably priced QFs in reducing the need for operation of cold standby units. In the runs for the 1988 ECAC case, parties were instructed to model reserve resources so that they could be restarted and called on by the model in the QFs-out run if needed and economical. (D.88-11-052, mimeo., pp.63-65.) Cold standby units should continue to be modeled so that they are available for dispatch in the QFs-out run. If the model shows that the generation from a cold standby unit is needed, then it is clear the the consumables associated with that generation are avoided by variably priced QFs. The amount of any such generation should be multiplied by the value of consumables and incorporated in the adder.

4. Recorded O&M Savings

As directed in D.88-11-052, PG&E reported the results of its attempt to identify and quantify the O&M costs that vary in one-, three-, and five-year time frames.

Over one year, PG&E reported, consistent with its arguments in this case, that only the costs of consumables varied. PG&E determined that the annual costs of consumables decreased by $1,287,000 due to reduced generation at fossil-fueled plants made possible by the contribution of variably priced QFs. Over three point when a plant would have been retired regardless of QFs' generation may vary; the reasons for the retirement can be that the plant has reached the end of its useful life, that a governmental entity has ordered it closed, that compliance with pollution control requirements would be prohibitively expensive, or numerous other circumstances.

In determining how long to view a retired plant as displaced by QFs, it would be helpful to have testimony on the factors that would affect the decision to retire a particular plant. Although there was little specific testimony on this issue in this case, we are persuaded that considering the cost savings occurring over the past five years for the Avon, Martinez, and Oleum plants is reasonable in this case.

3. <u>Standby Units</u>

The portion of the adder related to standby units has two components.

First are the reduced costs that PG&E has recorded for its cold standby units in recent years. As with the retired plants, the problem is sorting out the influences of variably priced O&M and new generation. A process similar to the one discussed for retired plants can be used to get a workable estimate of the QFs' contribution to these savings. That is, variably priced QFs should be credited with the O&M savings associated with cold standby plants in proportion to the capacity provided by cold standby plants that is required to meet target reserve margins when the capacity associated with variably priced QFs is removed.

This estimate is somewhat rougher than when this process was applied to the savings from retired plants. Because standby units' capacity is already included in the estimate of PG&E's resources, the units' capacity cannot be added in a second time to the resource figure to meet the target reserve margin. However, it is reasonable to assume that in the absence of QFs, cold standby units would be returned to operational status at about the level years, PG&E found that O&M costs associated with retired and cold standby units decreased by a total of $14,487,000, including reduced costs of consumables. Over five years, the reduced O&M costs were $8,119,000 for retired plants and $6,525,000 for standby units, for a total of $14,644,000.

Other parties argued that PG&E's figures did not include all elements of avoided cost for these time periods, but no party disputed the accuracy of PG&E's recorded data. Parties accepted PG&E's estimate of the average cost of consumables of 0.37 mills/kWh, although other parts of the total annual avoided cost of consumables depend on the results of the QFs-in/QFs-out runs. We find that the data submitted by PG&E is adequate for purposes of this decision, although other types of data may be more useful for calculating the adder, as we will discuss. In addition, we are satisfied that these O&M savings, as defined and quantified by PG&E, are not included in PG&E's requested O&M expenses for the test year.

5. <u>Calculation of the Adder</u>

For purposes of the 1989 ECAC, the calculation of the adder would begin with the QFs-in/QFs-out runs that are used to determine the IER. For purposes of calculating the adder, standby and reserve units should be modeled to be available for dispatch in the QFs-out run.

We will calculate the avoided O&M costs separately for three types of generating units: operating units, cold standby units, and retired plants. Operating units form a residual category that includes regularly operating units and reserve units that have not yet been placed in cold standby status.

The change in generation between the QFs-in and QFs-out runs for each operating unit should be multiplied by the appropriate variable O&M figure from PG&E's filings in CFM-6 and CFM-7 to develop a total avoided O&M cost for that unit. The that new resources would need to be obtained to meet target reserve margins. This assumption allows us to use a proportion derived from the process described above to estimate the standby units' recorded savings that should be credited to QFs.

As we discussed in connection with the retired plants, it is necessary to ensure that the fixed O&M costs incorporated in capacity payments to QFs are removed from the recorded savings associated with standby units.

The second component of the adder related to cold standby units corresponds to the energy produced by these units when called into service. The QFs-in/QFs-out runs provide a good illustration of the role of the variably priced QFs in reducing the need for operation of cold standby units. In the runs for the 1988 ECAC case, parties were instructed to model reserve resources so that they could be restarted and called on by the model in the QFs-out run if needed and economical. (D.88-11-052, mimeo., pp.63-65.) Cold standby units should continue to be modeled so that they are available for dispatch in the QFs-out run. If the model shows that the generation from a cold standby unit is needed, then it is clear the the consumables associated with that generation are avoided by variably priced QFs. The amount of any such generation should be multiplied by the value of consumables and incorporated in the adder.

4. Recorded O&M Savings

As directed in D.88-11-052, PG&E reported the results of its attempt to identify and quantify the O&M costs that vary in one-, three-, and five-year time frames.

Over one year, PG&E reported, consistent with its arguments in this case, that only the costs of consumables varied. PG&E determined that the annual costs of consumables decreased by $1,287,000 due to reduced generation at fossil-fueled plants made possible by the contribution of variably priced QFs. Over three years, PG&E found that O&M costs associated with retired and cold avoided costs for all operating units should then be added together to arrive at the total O&M savings from operating units.

For cold standby units, the first calculation is the amount of capacity needed to meet target reserve margins, based on the peak demand assumed for the model runs. The second step is to derive the amount of capacity associated with variably priced QFs. The result of the first calculation should then be compared with PG&E's resources without the capacity of variably priced QFs. The amount of added capacity needed to meet target reserve margins divided by the total capacity of cold standby units provides the ratio (of no more than 1.0) that is multiplied by the five-year O&M savings associated with standby plants, $6,525,000, to arrive at the long-term O&M savings for standby units.

The second component for standby units is the amount of generation from any restarted standby units in the QFs-out run times the cost of consumables, 0.37 mills/kWh, to derive the short-term savings associated with standby units.

The sum of the short-term and long-term savings gives the estimated total avoided O&M costs for cold standby units.

For retired plants, the adopted method compares the two capacity-related calculations used in deriving the long-term savings associated with standby units. If resources (including cold standby units) without variably priced QFs' capacity are sufficient to meet target reserve margins, then none of the retired plants' O&M savings will be credited to QFs. If added capacity is needed to meet target reserve margins, then the amount of needed capacity should be compared to the capacity of the retired units (179 MW in this case). The ratio of needed capacity to total capacity of the retired plants (again limited to 1.0) is multiplied by the recorded five-year savings associated with the retired plants, $8.1 million, to get the O&M savings for retired plants.

IEP suggested that A&G expenses are avoided in proportion to savings in labor expenses. It is unclear whether the labor standby units decreased by a total of $14,487,000, including reduced costs of consumables. Over five years, the reduced O&M costs were $8,119,000 for retired plants and $6,525,000 for standby units, for a total of $14,644,000.

Other parties argued that PG&E's figures did not include all elements of avoided cost for these time periods, but no party disputed the accuracy of PG&E's recorded data. Parties accepted PG&E's estimate of the average cost of consumables of 0.37 mills/kWh, although other parts of the total annual avoided cost of consumables depend on the results of the QFs-in/QFs-out runs. We find that the data submitted by PG&E is adequate for purposes of this decision, although other types of data may be more useful for calculating the adder, as we will discuss. In addition, we are satisfied that these O&M savings, as defined and quantified by PG&E, are not included in PG&E's requested O&M expenses for the test year.

5. Calculation of the Adder

For purposes of the 1989 ECAC, the calculation of the adder would begin with the QFs-in/QFs-out runs that are used to determine the IER. For purposes of calculating the adder, standby and reserve units should be modeled to be available for dispatch in the QFs-out run.

We will calculate the avoided O&M costs separately for three types of generating units: operating units, cold standby units, and retired plants. Operating units form a residual category that includes regularly operating units and reserve units that have not yet been placed in cold standby status.

The change in generation between the QFs-in and QFs-out runs for each operating unit should be multiplied by the appropriate variable O&M figure from PG&E's filings in CFM-6 and CFM-7 to develop a total avoided O&M cost for that unit. The avoided costs for all operating units should then be added together to arrive at the total O&M savings from operating units.

savings calculated from PG&E's recorded data reflect associated decreases in pensions and benefits expenses and payroll taxes. If these related savings are not reflected in PG&E's figures, the labor portion of any reductions credited to variably priced QFs should be multiplied by 35.51%, the ratio between pensions and benefits expense and payroll tax and labor expense developed in D.86-12-095, PG&E's last GRC. The resulting payroll tax and pensions savings should also be credited to QFs.

The savings from the three types of generating units--operating, standby, and retired--should be totaled. The sum should be divided by the energy forecasted to be generated by variably priced QFs in the 1989 ECAC proceeding.

The CFM figures are presented in 1984 dollars and PG&E's recorded numbers are in 1987 dollars, so the sum must be escalated to 1990 dollars. IEP escalated the CFM figures by the Consumer Price Index for Utilities (CPI-U) index through 1987. Use of the recorded CPI-U is reasonable through 1986, and the 1987-90 increase should be 10.64% for labor costs and 15.39% for nonlabor costs, the increases used to develop preliminary estimates in the GRC.

The sum of the avoided O&M costs for operating, cold standby, and retired units, after appropriate escalation, should then be divided by the 1989 ECAC's forecast of generation by variably priced QFs to get the adder.

As we have mentioned, the precise components of the CFM figures for variable O&M costs were not presented in this case. We assume from the information available that the cost of consumables is included in the CFM figures. If not, the avoided O&M for fossil-fueled units used in the calculation of the adder should be adjusted, based on the 0.37 mills/kWh average developed by PG&E.

Similarly, we assume that no fixed O&M costs are included in the CFM figures. If they are, the appropriate fixed O&M cost should be removed from the total O&M figures before dividing by the forecast of generation from variably priced QFs.

For cold standby units, the first calculation is the amount of capacity needed to meet target reserve margins, based on the peak demand assumed for the model runs. The second step is to derive the amount of capacity associated with variably priced QFs. The result of the first calculation should then be compared with PG&E's resources without the capacity of variably priced QFs. The amount of added capacity needed to meet target reserve margins divided by the total capacity of cold standby units provides the ratio (of no more than 1.0) that is multiplied by the five-year O&M savings associated with standby plants, $6,525,000, to arrive at the long-term O&M savings for standby units.

The second component for standby units is the amount of generation from any restarted standby units in the QFs-out run times the cost of consumables, 0.37 mills/kWh, to derive the short-term savings associated with standby units.

The sum of the short-term and long-term savings gives the estimated total avoided O&M costs for cold standby units.

For retired plants, the adopted method compares the two capacity-related calculations used in deriving the long-term savings associated with standby units. If resources (including cold standby units) without variably priced QFs' capacity are sufficient to meet target reserve margins, then none of the retired plants' O&M savings will be credited to QFs. If added capacity is needed to meet target reserve margins, then the amount of needed capacity should be compared to the capacity of the retired units (179 MW in this case). The ratio of needed capacity to total capacity of the retired plants (again limited to 1.0) is multiplied by the recorded five-year savings associated with the retired plants, $8.1 million, to get the O&M savings for retired plants.

Ultrapower suggested that A&G expenses are avoided in proportion to savings in labor expenses. It is unclear whether the labor savings calculated from PG&E's recorded data reflect associated decreases in pensions and benefits expenses and payroll

F. Future Proceedings

1. 1990 ECAC Case

All of the methods presented in this case, including the one we have adopted for use in the 1989 ECAC proceeding, have shortcomings. We therefore do not view the adopted method as a final or permanent method. We will permit certain issues to be revisited in the 1990 ECAC case, and the following discussion is presented to guide the parties in their future consideration of this issue.

For the near term, the QFs-in/QFs-out runs will continue to be useful. The QFs-out simulation is still close enough to the actual operation of PG&E's system to be helpful in estimating avoided O&M costs.

Over time, as a larger proportion of PG&E's energy is supplied by variably priced QFs, it may become more difficult to simulate the operation of PG&E's system without QFs while maintaining some connection with PG&E's actual system. At some point, it may be more theoretically accurate to use a proxy to estimate avoided O&M costs. For at least the next few years, however, we would prefer to refine methods based on the QFs-in/QFs-out runs.

One essential refinement is to improve the data on the marginal O&M costs associated with different levels of generation for each fossil-fueled plant. We believe that this sort of data would greatly improve the accuracy of the adder in reflecting the costs PG&E actually avoids because of the presence of QFs. We recognize that assembling this data could be difficult, but we will direct PG&E to investigate whether this sort of information could be extracted or developed from existing records. The results of this investigation, including any data PG&E is able to develop, should be presented with PG&E's 1990 ECAC application.

PG&E suggested that increased cycling of existing generating units due to increased generation by QFs may increase taxes. If these related savings are not reflected in PG&E's figures, the labor portion of any reductions credited to variably priced QFs should be multiplied by 35.51%, the ratio between pensions and benefits expense and payroll tax and labor expense developed in D.86-12-095, in PG&E's last GRC. The resulting payroll tax and pensions savings should also be credited to QFs.

The savings from the three types of generating units--operating, standby, and retired--should be totaled. The sum should be divided by the energy forecasted to be generated by variably priced QFs in the 1989 ECAC proceeding.

The CFM figures are presented in 1984 dollars and PG&E's recorded numbers are in 1987 dollars, so the sum must be escalated to 1990 dollars. Ultrapower escalated the CFM figures by the Consumer Price Index-Urban (CPI-U) index through 1987. Use of the recorded nonlabor escalation of 7.01% is reasonable for converting 1984 dollars to 1987 dollars, and the 1987-90 increase should be 10.64% for labor costs and 15.39% for nonlabor costs, the increases used to develop preliminary estimates in the GRC.

The sum of the avoided O&M costs for operating, cold standby, and retired units, after appropriate escalation, should then be divided by the 1989 ECAC's forecast of generation by variably priced QFs to get the adder.

As we have mentioned, the precise components of the CFM figures for variable O&M costs were not presented in this case. We assume from the information available that the cost of consumables is included in the CFM figures. If not, the avoided O&M for fossil-fueled units used in the calculation of the adder should be adjusted, based on the 0.37 mills/kWh average developed by PG&E.

Similarly, we assume that no fixed O&M costs are included in the CFM figures. If they are, the fixed O&M cost incorporated in capacity payments to QFs should be removed from the total O&M figures before dividing by the forecast of generation from variably priced QFs.

O&M costs. If this assertion is true, these increased cycling costs should be considered in setting the adder.

Another area of refinement is the treatment of retired plants. We think that better analysis could help clarify the extent to which energy from variably priced QFs allows PG&E to retire plants and avoid some O&M costs. This analysis may lead to a different valuation of the capacity provided by QFs, rather than an increase in the adder paid on the basis of energy, but further analysis should be helpful in moving toward our goal of accurately calculating the costs avoided by QFs and making appropriate payments based on those costs.

2. 1989 ECAC Case

Parties to PG&E's 1989 ECAC case should calculate the O&M adder according to the method discussed in this decision. Because of the timing in that case, parties will have only the ALJ's proposed decision when testimony is due. Parties interested in this issue may also submit an alernative adder calculation based on their comments to the ALJ's proposed decision. Because of the limited time available for consideration of this issue in the 1989 ECAC case, parties are requested to keep testimony supporting their calculations brief and to the point.

The method eventually approved by the Commission following the circulation of the ALJ's proposed decision will be employed to calculate the O&M adder and revenue requirement eventually adopted in the 1989 ECAC case.

Findings of Fact

1. In D.88-11-052, we directed PG&E to present a study on avoided O&M costs.

2. PG&E presented its study as Ex. 46, and alternative approaches to calculating avoided O&M costs were presented by CCC, IEP, the Geothermal QFs, and DRA.

3. According to PG&E's recorded data, the average cost of consumables at fossil-fueled plants is 0.37 mills/kWh, and the

assume from the information available that the cost of consumables is included in the CFM figures. If not, the avoided O&M for fossil-fueled units used in the calculation of the adder should be adjusted, based on the 0.37 mills/kWh average developed by PG&E.

Similarly, we assume that no fixed O&M costs are included in the CFM figures. If they are, the fixed O&M cost incorporated in capacity payments to QFs should be removed from the total O&M figures before dividing by the forecast of generation from variably priced QFs.

F. Future Proceedings

1. 1990 ECAC Case

All of the methods presented in this case, including the one we have adopted for use in the 1989 ECAC proceeding, have shortcomings. We therefore do not view the adopted method as a final or permanent method. We will permit certain issues to be revisited in the 1990 ECAC case, and the following discussion is presented to guide the parties in their future consideration of this issue.

For the near term, the QFs-in/QFs-out runs will continue to be useful. The QFs-out simulation is still close enough to the actual operation of PG&E's system to be helpful in estimating avoided O&M costs.

Over time, as a larger proportion of PG&E's energy is supplied by variably priced QFs, it may become more difficult to simulate the operation of PG&E's system without QFs while maintaining some connection with PG&E's actual system. At some point, it may be more theoretically accurate to use a proxy to estimate avoided O&M costs.

We recognize that the methodology adopted for PG&E in this decision is linked to the types of resource planning issues addressed in our Biennial Resource Plan Update proceedings. We expect to consider adoption of a generic method for calculating the O&M adder in a future Biennial Resource Plan Update proceeding as annual cost of consumables avoided because of the contribution of variably priced QFs can be calculated using the results of the QFs-in/QFs-out runs. Over three years, the O&M costs associated with retired and cold standby units decreased by a total of $14,487,000, including reduced costs of consumables. Over five years, the reduced O&M costs were $8,119,000 for retired plants and $6,525,000 for standby units, for a total of $14,644,000. These avoided O&M costs have not been included in PG&E's requested O&M expenses for the test year.

4. Many variably priced QFs receive capacity payments that include avoided fixed O&M costs.

5. The capacity associated with variably priced QFs may allow PG&E to retire generating units.

6. Generation from variably priced QFs may avoid some O&M costs of operating and cold standby units.

7. PG&E's estimates of variable O&M costs, as filed with the Energy Commission in CFM-6 and CFM-7, provide a reasonable estimate, in lights of the limitations of this proceeding, of each operational generating unit's marginal O&M costs.

Conclusions of Law

1. The basis for the O&M adder paid for energy generated by variably priced QFs should not include the fixed O&M costs that are included in the calculation of capacity payments.

2. The avoided O&M adder paid to variably priced QFs should conform to the principle of ratepayer indifference we have previously embraced to develop appropriate prices and contracts for QFs.

3. The O&M costs associated with operating units, retired plants, and standby units should be considered in the calculation of the O&M adder.

4. For purposes of PG&E's 1989 ECAC case, it is reasonable to calculate the O&M adder as set forth in this decision.

several parties have suggested. For at least the next few years, however, we would prefer to refine this method for PG&E, based on the QFs-in/QFs-out runs. These refinements would be addressed in PG&E's ECAC cases. In developing a future methodology, we would be particularly interested in simpler approaches.

One essential refinement is to improve the data on the marginal O&M costs associated with different levels of generation for each fossil-fueled plant. We believe that this sort of data would greatly improve the accuracy of the adder in reflecting the costs PG&E actually avoids because of the presence of QFs. We recognize that assembling this data could be difficult, but we will direct PG&E to investigate whether this sort of information could be extracted or developed from existing records. The results of this investigation, including any data PG&E is able to develop, should be presented with PG&E's 1990 ECAC application.

PG&E suggested that increased cycling of existing generating units due to increased generation by QFs may increase O&M costs. If this assertion is true, these increased cycling costs should be considered in setting the adder.

Another area of refinement is the treatment of retired plants. We think that better analysis could help clarify the extent to which energy from variably priced QFs allows PG&E to retire plants and avoid some O&M costs. This analysis may lead to a different valuation of the capacity provided by QFs, rather than an increase in the adder paid on the basis of energy, but further analysis should be helpful in moving toward our goal of accurately calculating the costs avoided by QFs and making appropriate payments based on those costs.

2. <u>1989 ECAC Case</u>

Parties to PG&E's 1989 ECAC case have calculated the O&M adder according to the method described in the ALJ's proposed decision and have submitted alternative adder calculations based on their comments to the ALJ's proposed decision.

5. PG&E should investigate whether data on the marginal O&M costs associated with different levels of generation for each of its fossil-fueled units can be extracted or developed from existing records. PG&E should present the results of its investigation, including any data PG&E is able to develop, with the application in its 1990 ECAC case.

6. Because the method adopted in this decision must be implemented in PG&E's 1989 ECAC proceeding, this decision should be served on all parties to A.89-04-001.

ORDER

Therefore, IT IS ORDERED that:

1. For the 1989 Energy Cost Adjustment Clause (ECAC) proceeding for Pacific Gas and Electric Company (PG&E), the calculation of the operation and maintenance (O&M) adder paid to variably priced qualifying facilities (QFs) shall be as follows:

For each operating unit (including reserve units not yet converted to cold standby status), the change in generation between the QFs-in and QFs-out runs used to calculate the Incremental Energy Rate (IER) should be multiplied by the appropriate variable O&M figure from PG&E's filings in the Energy Commission's Sixth and Seventh Common Forecasting Methodology (CFM) proceeding to develop a total avoided O&M cost for each unit. The avoided costs for all operating units should then be added together to arrive at the total O&M savings from operating units.

For cold standby units, the amount of capacity needed to meet target reserve margins, based on the peak demand assumed for the model runs, shall be compared with PG&E's resources without the capacity associated with variably priced QFs. The amount of added capacity needed to meet target reserve margins divided by the total capacity of cold standby units provides the ratio (of no more than 1.0) that is multiplied by the five-year O&M savings associated including reduced costs of consumables. Over five years, the reduced O&M costs were $8,119,000 for retired plants and $6,525,000 for standby units, for a total of $14,644,000. These avoided O&M costs have not been included in PG&E's requested O&M expenses for the test year.

4. Many variably priced QFs receive capacity payments that include avoided fixed O&M costs associated with a combustion turbine.

5. The capacity associated with variably priced QFs may allow PG&E to retire generating units.

6. Generation from variably priced QFs may avoid some O&M costs of operating and cold standby units.

7. PG&E's estimates of variable O&M costs, as filed with the Energy Commission in CFM-6 and CFM-7, provide a reasonable estimate, in light of the limited purpose and record of this proceeding, of each operational generating unit's marginal O&M costs.

Conclusions of Law

1. The basis for the O&M adder paid for energy generated by variably priced QFs should not include the fixed O&M costs that are included in the calculation of capacity payments.

2. The avoided O&M adder paid to variably priced QFs should conform to the principle of ratepayer indifference we have previously embraced to develop appropriate prices and contracts for QFs.

3. The O&M costs associated with operating units, retired plants, and standby units should be considered in the calculation of the O&M adder.

4. For purposes of PG&E's 1989 ECAC case, it is reasonable to calculate the O&M adder as set forth in this decision.

5. PG&E should investigate whether data on the marginal O&M costs associated with different levels of generation for each of its fossil-fueled units can be extracted or developed from existing

with standby units, $6,525,000, to arrive at the long-term O&M savings associated with standby units.

The amount of generation from any restarted standby units in the QFs-out run times the cost of consumables, 0.37 mills/kWh, is the short-term savings associated with standby units. The sum of the short-term and long-term savings gives the estimated total avoided O&M costs for cold standby units.

For retired plants, if resources (including cold standby units) without variably priced QFs' capacity are sufficient to meet target reserve margins, then no savings will be credited to QFs. If added capacity is needed to meet target reserve margins, then the amount of needed capacity should be compared to the capacity of the retired units (179 MW). The ratio of needed capacity to total capacity of the retired plants (again limited to 1.0) is multiplied by the recorded five-year savings associated with the retired plants, $8.1 million, to get the O&M savings for retired plants.

After appropriate escalation to 1990 dollars and adjustment for associated savings in pensions and benefits expense and payroll taxes, the savings from the three types of plants--operational, standby, and retired--should be totaled. The sum should be divided by the energy forecasted to be generated by variably priced QFs in the 1989 ECAC proceeding to arrive at the amount of the adder.

2. PG&E shall investigate whether data on the marginal O&M costs associated with different levels of generation for each of its fossil-fueled units can be extracted or developed from existing records. PG&E shall present the results of its investigation, including any data PG&E is able to develop, with the application in its 1990 ECAC case.

1. The basis for the O&M adder paid for energy generated by variably priced QFs should not include the fixed O&M costs that are included in the calculation of capacity payments.

2. The avoided O&M adder paid to variably priced QFs should conform to the principle of ratepayer indifference we have previously embraced to develop appropriate prices and contracts for QFs.

3. The O&M costs associated with operating units, retired plants, and standby units should be considered in the calculation of the O&M adder.

4. For purposes of PG&E's 1989 ECAC case, it is reasonable to calculate the O&M adder as set forth in this decision.

5. For purposes of PG&E's 1990 ECAC case, it is reasonable to calculate the O&M adder under the basic methodology set forth in this decision, with only minor refinements.

6. PG&E should investigate whether data on the marginal O&M costs associated with different levels of generation for each of its fossil-fueled units can be extracted or developed from existing records. PG&E should present the results of its investigation, including any data PG&E is able to develop, with the application in its 1990 ECAC case.

7. Because the method adopted in this decision must be implemented in PG&E's 1989 ECAC proceeding, this decision should be served on all parties to A.89-04-001.

O R D E R

Therefore, IT IS ORDERED that:

1. For the 1989 Energy Cost Adjustment Clause (ECAC) proceeding for Pacific Gas and Electric Company (PG&E), the calculation of the operation and maintenance (O&M) adder paid to variably priced qualifying facilities (QFs) shall be as follows:

For each operating unit (including reserve units not yet converted to cold standby status), the change in generation between the QFs-in and QFs-out runs used to calculate the Incremental Energy Rate (IER) should be multiplied by the appropriate variable O&M figure from PG&E's filings in the Energy Commission's Sixth and Seventh Common Forecasting Methodology (CFM) proceeding to develop a total avoided O&M cost for each unit. The avoided costs for all operating units should then be added together to arrive at the total O&M savings from operating units.

For cold standby units, the amount of capacity needed to meet target reserve margins, based on the peak demand assumed for the model runs, shall be compared with PG&E's resources without the capacity associated with variably priced QFs. The amount of added capacity needed to meet target reserve margins divided by the total capacity of cold standby units provides the ratio (of no more than 1.0) that is multiplied by the five-year O&M savings associated with standby units, $6,525,000, to arrive at the long-term O&M savings associated with standby units.

The amount of generation from any restarted standby units in the QFs-out run times the cost of consumables, 0.37 mills/kWh, is the short-term savings associated with standby units. The sum of the short-term and long-term savings gives the estimated total avoided O&M costs for cold standby units.

For retired plants, if resources (including cold standby units) without variably priced QFs' capacity are sufficient to meet target reserve margins, then no savings will be credited to QFs. If added capacity is needed to meet target reserve margins, then the amount of needed capacity should be compared to the capacity of the retired units (179 MW). The ratio of needed capacity to total capacity of the retired plants (again limited to 1.0) is multiplied by the recorded five-year savings associated with the retired plants, $8.1 million, to get the O&M savings for retired plants.

After appropriate escalation to 1990 dollars and adjustment for associated savings in pensions and benefits expense

3. This decision shall be served on all parties to Application 89-04-001, PG&E's 1989 ECAC proceeding.

This order is effective today.

Dated ____________________, at San Francisco, California.

and payroll taxes, the savings from the three types of plants--operational, standby, and retired--should be totaled. The sum should be divided by the energy forecasted to be generated by variably priced QFs in the 1989 ECAC proceeding to arrive at the amount of the adder.

2. Subject to minor refinements, the basic methodology adopted in this proceeding shall be used in calculating the O&M adder in PG&E's 1990 ECAC proceeding. PG&E shall investigate whether data on the marginal O&M costs associated with different levels of generation for each of its fossil-fueled units can be extracted or developed from existing records. PG&E shall present the results of its investigation, including any data PG&E is able to develop, with the application in its 1990 ECAC case.

3. This decision shall be served on all parties to Application 89-04-001, PG&E's 1989 ECAC proceeding.

This order is effective today.

Dated SEP 2 7 1989, at San Francisco, California.

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

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

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LIST OF APPEARANCES

Applicant: Roger J. Peters, Kermit R. Kubitz, and Michelle L. Wilson, Attorneys at Law, for Pacific Gas and Electric Company.

Interested Parties: Lindsay, Hart, Neil & Weigler, by Michael P. Alcantar, Attorney at Law, for Cogenerators of Southern California; Barkovich & Yap, by Barbara R. Barkovich and Jackson, Tufts, Cole & Black, by William H. Booth, Attorney at Law, for California Large Energy Consumers Association; Morrison & Foerster, by Jerry R. Bloom, Attorney at Law, for California Cogeneration Council; Mathew V. Brady, Attorney at Law, for California Department of General Services; David R. Branchcomb, for Henwood Energy Services; Walter Cavagnaro, for Anchor Glass Container and Energy Systems Engineers, Inc.; Thomas P. Corr, Attorney at Law, for Independent Power Corporation; Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Phil Di Virgilio, for PSE, Inc.; Karen Edson, for KKE & Associates; Jeff Fabbri, for Power Users Protection Council; David B. Follett, for Southern California Gas Company; Steven Geringer and Karen Norene Mills, Attorneys at Law, for California Farm Bureau Federation; Law Office of Dian M. Grueneich, by Dian M. Grueneich and Barry H. Epstein, Attorneys at Law, for California Department of General Services and California Institute of Energy Efficiency; Biddle & Hamilton, by Richard L. Hamilton and Christian M. Keiner, Attorneys at Law, for Western Mobilehome Association; Steve Harris, for Enron/Transwestern Pipeline Company; Caryn Hough, Attorney at Law, for California Energy Commission; Jan Hamrin and Jan Smutny-Jones, Attorney at Law, for Independent Energy Producers; Hanna & Morton, by Douglas K. Kerner, Attorney at Law, for Santa Fe Geothermal, Inc., UNOCAL Corporation, and Freeport-McMoRan Resource Partners; Lindsay, Hart, Neil & Weigler, by Paul J. Kaufman, Attorney at Law, for Kern River Cogeneration Company; Alannah Kinser, for the Office of the Public Advisor; Richard K. Durant, Carol B. Henningson, James M. Lehrer, Frank A. McNulty, and Carol A. Schmid-Frazee, Attorneys at Law, and John Hughes, for Southern California Edison Company; William G. Fleckles, Attorney at Law, for California Travel Parks Association; William B. Marcus, for JBS Energy, Inc.; Graham & James, by Martin A. Mattes, Attorney at Law, for Amerada Hess Corporation; Michael McQueen, for UNOCAL; Joseph G. Meyer, for Joseph Meyer Associates; John D. Quinley, for

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Cogeneration Service Bureau; Kathi Robertson and Wayne Meeks, for Simpson Paper Company; Donald G. Salow, for Association of California Water Agencies; Chester & Schmidt, by Reed V. Schmidt, and McCracken, Byers & Martin, by David J. Byers, Attorney at Law, for California City-County Street Light Association; Donald W. Schoenbeck, for Regulatory and Cogeneration Services; Thomas R. Sheets, Attorney at Law, and Thomas J. O'Rourke, for Southwest Gas Corporation; Law Offices of Kathryn Dickson, by Joel R. Singer, Attorney at Law, and Sylvia M. Siegel, for Toward Utility Rate Normalization; Armour St. John, Wilcox, Goodin & Schlotz, by James Squeri, Attorney at Law, for California Building Industry Association; Downey, Brand, Seymour & Rohwer, by Deborah K. Tellier and Philip A. Stohr, Attorneys at Law, for Industrial Users; Nancy Thompson, for Barakat, Howard & Chamberlin; John Vickland, Attorney at Law, for San Francisco Bay Area Rapid Transit District; Robert B. Weisenmiller, for Morse, Richard & Weisenmiller & Associates, Inc.; Alvin Pak, Attorney at Law, and Bruce J. Williams, for San Diego Gas & Electric Company; Harry K. Winters, for University of California; James Adams, for Energy and Resource Advocates; William M. Bennett, for himself; Maurice Brubaker, for Drazen-Brubaker & Associates; Stephen F. Diamond, for Electrical Workers, Local 1245; Norman J. Furuta, Attorney at Law, and Sharon K. Matsumura, for Federal Executive Agencies; Donald H. Maynor, Attorney at Law, for Northern California Power Agency; Ken Meyer, for Energy Consulting Group; Roger Poynts, for Utility Design, Inc.; Andrew Safir and Scott Tomashefsky, for Recon Research Corporation and Salmon Resources, Inc.; E. D. Yates, for California League of Food Processors; Messrs. Brady & Berliner, by John W. Simison, Attorney at Law, for Canadian Producer Group; Bryan Gaynor, Attorney at Law, for Energy and Resource Advocates; C. Hayden Ames, Attorney at Law, for Chickering & Gregory; Ben Hudnall, Jonathan Siegel, and Brian D'Arcy, Attorneys at Law, for Engineers & Scientists of California, MEBA, AFLCIO; Jane Brunner and Tom Dalzell, Attorneys at Law, for Local 1245 IBEW, Engineers and Scientists of California, and Coalition of California Utility Workers; Randolph L. Wu, Attorney at Law, and Phyllis Huckabee, for El Paso Natural Gas Company; and Charles E. Doering, for Salmon Resources, Inc.

Division of Ratepayer Advocates: Philip Scott Weismehl, Alberto Guerrero, Irene Moosen, and Judi Allen, Attorneys at Law, and David Fukutome and Lloyd Rowe.

(END OF APPENDIX A)