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Decision 92-11-046 November 23, 1992

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY For Authority to Adjust its Electric Rates Effective January 1, 1993, and to Adjust its Gas Rates Effective January 1, 1993, and for Commission Order Finding that Gas and Electric Operations During the Reasonableness Review Period from January 1, 1991 to December 31, 1991 were Prudent.	ORIGINAL Application 92-04-001 (Filed April 1, 1992)

(See Appendix G for appearances.)

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O P I N I O N

1. Summary of Decision

By this decision, we approve an increase in Pacific Gas and Electric Company's (PG&E) Electric Department revenues of $30,867,000, and Gas Department revenues of $3,414,000 based on a 12-month forecast period beginning January 1, 1993. This increase is composed of the following elements:

Ratemaking element	Revenue Requirement Increase (Decrease) ($000's)	
	Electric Department	Gas Department
Energy Cost Adjustment Clause (ECAC)	($167,897)	
Annual Energy Rate (AER)	(9,626)	
Electric Revenue Adjustment Mechanism (ERAM)	185,068	
Low-Income Ratepayer Assistance (LIRA) Program	9,765	-
Customer Energy Efficiency (CEE)	13,556	$3,414
Total	$ 30,867	$3,414

We present the computation of total revenue requirement for each of these elements in Appendix A. In conjunction with our adopted revenue requirement adjustments, this decision also adopts the forecasted resource mix, energy prices, and payment factors for purchases from variably priced qualifying facilities (QFs), (i.e., those QFs without fixed contract prices), presented in Appendices B and C. We also authorize recovery of incentive payments earned by PG&E during 1991 under our adopted CEE procedures.

2. Procedural Background

Our adopted ECAC procedures permit annual changes in electric rates to reflect updated forecasts of fuel and purchased power expense outside of the utility's three-year general rate case cycle. In Decision (D.) 89-01-040, we adopted a schedule for processing ECAC proceedings with an annual rate revision date of November 1 for PG&E. In D.92-02-051, we amended PG&E's ECAC forecast period to commence on January 1, annually. Since the previously adopted forecast period ends on October 31, 1992, there are two transition months of November and December to deal with. In D.92-02-051, we directed PG&E to prepare a 14-month forecast covering November 1, 1992 through December 31, 1993 to cover this transition. PG&E has interpreted this requirement by computing a 12-month forecast (January 1-December 31, 1993) for rate-fixing purposes and a separate two-month forecast (November-December, 1992) to compute a more timely year-end balancing account amortization factor. We concur with PG&E's interpretation and will accordingly adopt a 12-month forecast for the period ending December 31, 1993. We shall incorporate the November and December 1992 forecast in deriving year-end balancing account values.

PG&E's application filed April 1, 1992 initially requested an increase of $190.6 million in its annual electric department revenues on an annualized basis effective January 1, 1993. The application also seeks a finding that its gas and electric operations during the 1991 record period were prudent. Reasonableness review issues relative to PG&E's operations during the 1991 record period will be considered in a subsequent phase (or phases) of this proceeding. We will designate forecast issues as Phase I and reasonableness issues as Phase II of this proceeding. Revenue allocation issues have been consolidated with PG&E's 1993 General Rate Case, Application (A.) 91-11-036, and will be addressed in our final order in that proceeding. This decision disposes of all Phase I issues.

In accordance with the adopted schedule, PG&E submitted an update on June 5, 1992. The update reflected, among other things, updated hydro electric availability and more recent balancing account data.

The elements of PG&E's requested rate increase are summarized below, comparing its initial April 1 filing with its June 5 update:

Table 1

Changes in Applicant's Request

Ratemaking Element:	April 1 Filing	June 5 Update
	($000's)	
ECAC	$ 19,804	($ 78,555)
AER	(730)	(5,310)
ERAM	151,288	242,649
LIRA	7,507	7,561
CEE	12,733	12,772
Total	$190,602	$179,118

The reasons for the changes between the initial and update testimony are discussed separately for each ratemaking element heading later in this decision.

Parties sponsoring testimony on Phase I issues are: the Commission's Division of Ratepayer Advocates (DRA), Independent Energy Producers (IEP), California Cogeneration Council (CCC), Cogenerators of Southern California (CSC), and California Large Energy Consumers Association (CLECA). Other than the Applicant, DRA was the only party to present testimony covering all aspects of Phase I, including CEE issues. IEP, CCC, and CSC (the QF intervenors) presented testimony only on ECAC-related resource assumptions and QF-pricing issues. CLECA presented testimony only on the issue of the Energy Reliability Index.

Prehearing conferences occurred April 28 and July 13, 1992. Evidentiary hearings were held from July 27 through August 4, 1992. An Administrative Law Judge (ALJ) ruling was released September 4, 1992 designating resource assumptions to use for final incremental energy rate (IER) model runs. PG&E submitted final IER and revenue calculations consistent with the ALJ ruling in Exhibit 72A. Those calculations form the basis for our adopted revenue requirements and IERs.

3. Overview of ECAC/AER - Forecast Issues

In its initial application, PG&E requested an ECAC revenue increase of $19.8 million and an AER revenue decrease of $0.7 million. In its June 5 Update Testimony, PG&E revised its forecast to reflect a decrease in its ECAC/AER revenue requirement of $83.86 million. The updated changes are primarily due to forecasts of reduced power plant fossil fuel use, lower gas prices, elimination of gas curtailment oil burns, lower QF and geothermal expense and a lower balancing account undercollection based on April 30, 1992 recorded data.

Under the normal operation of the AER, PG&E bears the risk of AER revenue recovery without balancing account treatment. The AER allocates 9% of total forecast fuel and purchase power expenses to PG&E. Currently, however, the AER remains suspended under Investigation (I.) 90-08-006. Accordingly, 100% of AER revenues and expenses are presently included in the ECAC balancing account. As a contingency, we adopt an AER revenue requirement adjustment in this proceeding representing 10% of our adopted fuel and purchase power forecast decrease. In the event that we reinstitute the AER mechanism during 1993, AER revenues and expenses would be subsequently excluded from the ECAC balancing account. On the assumption, however, that the AER suspension continues through 1993, we authorize PG&E to continue full balancing account treatment for AER revenues and expenses through the 1993 ECAC forecast period.

DRA submitted its ECAC forecast report on June 27, 1992, incorporating its study of both PG&E's initial and update forecast data. DRA initially proposed an ECAC/AER decrease of $144.2 million. DRA's forecast is lower than PG&E's primarily because of lower forecasted gas prices, which in turn produce lower economy energy and QF prices. After the start of hearings, DRA and PG&E entered into a joint stipulation on gas prices, as described in detail below.

The intervenors participating in the forecast phase presented testimony relating to the basis used for determining payments to QFs for power purchased under variably priced contracts. In this context, intervenors contested a number of resource assumptions and modeling conventions which impact the ECAC/AER revenue requirement. The contested issues raised by intervenors are discussed under Sections 6 and 7 regarding QF Price Factors.

In D.88-12-083, we ordered PG&E to develop a Diablo Canyon Incremental Energy Rate (DIER) to be filed in its ECAC proceedings. The DIER is used to adjust the AER expense at the end of the forecast period to account for differences between forecast and actual Diablo Canyon generation. PG&E presents a detailed explanation of the derivation of the DIER (Exh. 1, pp. 3, 47-48). Our adopted DIER of 7,040 BTU/kWh is set forth at Appendix C.

4. Adopted ECAC/AER Revenue Requirements

The range of ECAC/AER revenue requirement adjustments sponsored by the active parties (prior to any stipulations) is summarized below and compared with our adopted revenue requirement decrease.

Table 2
Range of ECAC/AER Revenue Requirement Adjustments
$ Millions Incr (Decr)

	PG&E	DRA	CCC	IEP	Adopted
ECAC	($78.6)	($141.0)	($25.7)	($23.5)	($167.9)
AER	(5.3)	(3.4)	0.7	0.9	(9.6)

Our adopted ECAC/AER revenue requirements result from the application of our adopted resource assumptions to the forecasted simulation of PG&E's electric department operations during 1993 using PROMOD III, a production cost model. Our adopted revenue requirement decrease also incorporates recorded balancing account overcollections through August 31, 1992 (versus through April 30 in

PG&E's June update), and includes additional revenues expected during 1993 from a settlement with the Western Area Power Administration (WAPA). Appendix A presents a complete derivation of revenue requirements.

5. Overview of QF Price Factors

This decision adopts updated price factors which PG&E shall pay for power purchased from QFs with variably priced contracts during 1993. The ECAC proceeding is the appropriate forum in which to update QF prices. The resource assumptions used to determine ECAC revenue requirements also affect the determination of the utility's generating efficiency at the margin, and consequently, the value of QF energy.

QF prices are determined based upon the utility's avoided cost. The intent of avoided-cost pricing is to leave ratepayers economically neutral relative to whether the utility or the QF supplies incremental power. Variable QF prices are the sum of three basic payment components: energy costs, nonfuel operating and maintenance (O&M) costs, and capacity costs. These price components are described under separate headings below.

The QF price factors and customer revenue requirements adopted herein are based upon production cost model results which simulate the manner in which utility resources meet system loads. This simulation is driven by PG&E Electric Department resource and load assumptions that are inputs into the model. In this proceeding, a number of model input assumptions were contested. Our resolution of these contested issues form the basis for our adopted QF price factors and ratepayer revenue requirements.

The use of different computer models poses issues as to how the modeler and the model translate the complexities of a utility system into simplified terms that the model can utilize. Over time, we have instituted procedures to facilitate the full exchange of information among parties pertinent to understanding the computer modeling conventions and assumptions used in ECAC proceedings.

To this end, D.89-01-040 incorporated a requirement that a workshop be held early in each ECAC proceeding to permit parties to investigate modeling issues, to develop a base case set of assumptions and modeling conventions, and to explain any differences resulting from use of different models.

A modeling workshop for this proceeding was held on May 12, 1992. The Commission Advisory and Compliance Division (CACD) whose representative conducted the workshop, submitted a final Workshop Modeling Report dated July 1992. The report noted that all active modeling parties agreed to use the assumptions in PG&E's filing as the base case. PG&E, DRA, and CCC have all used the PROMOD III model. IEP used the PROSYM model. The Workshop Modeling Report provided an explanation of the differences in the model results. Given that both models produce essentially similar results, we base our adopted revenue requirement and QF price factors on the PROMOD model.

6. QF Energy Price and the Incremental Energy Rate

6.1 Background

The energy component paid to QFs is based upon the IER. The IER measures the utility's incremental efficiency in converting heat energy to electricity. The IER is expressed in units of British Thermal Units (BTUs) per kilowatt-hour (kWh).

The IER is multiplied by the utility's incremental fuel cost to produce the price the utility pays for the variably priced QFs' energy. D.88-12-120 ordered that prices paid to QFs be time-differentiated to reflect the fact that the value of the power they provide varies with the time of day when it is supplied.

The IER is calculated using the "QFs-in/QFs-out" method. This method requires two separate production simulation computer model runs. The only difference in resource availability between the two runs is in the treatment of QFs. The QFs-out run represents system commitment and dispatch with all variably priced QFs removed. The QFs-in run adds back all variably priced QFs anticipated to be online during the forecast period. The difference in total system costs between the two runs equals the avoided costs of all variably priced QFs. The avoided costs are expressed in terms of cents/kWh and are then divided by the average gas cost used for electric generation from the QFs-in run to derive the annual average IER.

In its filing, PG&E raises concerns over the continuing validity of the QFs-in/out method as a realistic measure of avoided cost payments to QFs. Because of the increasing size of the forecast block of variably priced QFs, PG&E states it is unrealistic to assume that resources and fuel prices do not change between the QFs-in and QFs-out runs. While PG&E does not propose a change in this proceeding, it does urge the Commission to schedule a forum to address this issue as soon as possible in the Phase 3 of the Biennial Resource Plan Update (BRPU) proceeding, I.89-07-004. We note PG&E's comments. PG&E is free to raise its concerns in the BRPU proceeding as to the priority to assign to this issue.

6.2 Parties' Positions

The proposals of the active parties relative to the IER (prior to stipulations) are summarized below:

Table 3
Comparison of IER Estimates:
Parties' Positions Versus Adopted
(BTU/kWh)

PG&E	DRA	IEP	CCC	Joint Recommendation	Adopted
9,355	9,106	9,615	9,578	9,478	9,156

After the start of hearings, DRA and QF intervenors entered into a Joint Recommendation sponsoring an IER of 9,478 BTU/kWh. Although CSC had not prepared previous testimony on a proposed IER, it joined as a party sponsoring the Joint Recommendation. While agreeing on the IER, the stipulating parties do not concede or support any particular resource assumption, modeling convention, or position underlying its IER. The stipulated IER is simply intended to reflect a point within a "reasonable range" of IER values.

PG&E did not enter into the Joint Recommendation on the IER and contested it, charging that DRA unreasonably made too many concessions without any evidence of offsetting benefits.

Since the IER calculation is predicated on a forecast of utility system operations given a set of resource assumptions, a change in the IER implies a change in the underlying resource assumptions used to compute it. The DRA/QF intervenor stipulation did not, however, specify any particular set of resource assumptions which would yield the stipulated value. In a separate exhibit jointly sponsored by only the QF intervenors, but not DRA, a set of resource assumptions were illustrated which could yield the stipulated IER.

6.3 Discussion

Since the Joint Recommendation on the IER was contested by PG&E, we will first evaluate its reasonableness in the context of how well it resolves disputes just among the stipulating parties. Then we will evaluate it relative to how it differs from the IER proposed by PG&E.

The sponsoring parties argue that the Joint Recommendation provides an IER within the range of reasonable outcomes in this proceeding. In Exhibit 71, the QF intervenors presented an illustrative run showing one combination of adopted resource assumptions which assumed various parties would prevail on various contested issues.

We believe that DRA's support for the Joint IER Recommendation to be a key element of its validity since DRA was the only stipulating party with a significantly different pre-stipulation IER position. DRA entered into the Joint IER

Recommendation shortly after reaching agreement with PG&E on a gas price stipulation. Thus, for purposes of examining DRA's bargaining stance, DRA's pre-stipulation IER was effectively increased to 9,230 BTU/kWh, reflecting the PG&E/DRA gas price stipulation impacts. This means that DRA effectively agreed to support an IER of 248 BTU/kWh higher than its pre-stipulation position.

On the other hand, CCC and IEP sponsored pre-stipulation IERs that averaged 9,596 BTU/kWh (i.e., [9,615 + 9,578]/2). Thus, the QF intervenors gave up an average 118 BTU/kWh. DRA appears to have conceded more than CCC/IEP. Thus, viewing the stipulation purely from the standpoint of bargaining tradeoffs, it is not clear that the Joint IER Recommendation produced a reasonable disposition of parties' disputes.

This conclusion is further supported by DRA's own admission as to its basis for support of the Joint Recommendation. In its opening brief, DRA reveals that it entered into the Joint Recommendation contemplating that it would prevail on the O&M adder issue. We have rejected DRA's position on the O&M adder. Consequently, we cannot conclude that the stipulated value is in the public interest as it does not reasonably resolve DRA's substantive differences with the QF intervenors in the case as a whole.

By agreeing to the Joint Recommendation, DRA also places itself in the position of supporting an IER which is not consistent with its sponsored revenue requirements. DRA objects to changing its revenue requirement or supporting stipulated resource assumptions consistent with the Joint Recommendation's IER. While DRA supports the stipulated IER, it refuses to join the intervenors in sponsoring Exhibit 71, which purports to offer an illustrative mix of resource assumptions that could be adopted to yield an IER within the range proposed by the joint stipulation.

Our adopted revenue requirements and IER values must be based upon a sound and consistent evidentiary record. The failure of the Joint Recommendation to offer an underlying set of consistent resource assumptions that all sponsoring parties agree to support undermines its reasonableness, in our view. We require fundamental consistency among the the QF price factors, the underlying resource assumptions, and the retail revenue requirements which we adopt herein.

The reasonableness of the Joint Recommendation is further undermined by parties' failure to elicit unanimous support for it. We cannot adopt the Joint Recommendation without considering the conflicting evidence presented by PG&E, which proposes a lower IER based on detailed testimony on the various resource assumptions underlying it. Accordingly, upon consideration of the complete evidentiary record, we have reached findings concerning a reasonable set of resource assumptions from which we may derive an IER value. Our adopted resource assumptions conflict in certain respects with the resource assumptions chosen in Exhibit 71 to illustrate the reasonableness of the Joint IER Recommendation.

Accordingly, we reject the Joint IER Recommendation as failing to reasonably resolve the underlying disputes relating to the IER. We adopt an IER for the 1993 forecast period of 9,156 BTU/kWh, which is based upon a production cost simulation of PG&E's operations using the resource assumptions and modeling conventions which we have concluded are reasonable for this proceeding, as discussed in Sections 9 and 10. We shall evaluate each resource assumption on its underlying merits based upon the evidentiary record, as discussed in detail below. The derivation of our adopted IER is presented in Appendix C.

7. Operations and Maintenance Adder

7.1 Background

Another component normally included in the QF price is the "O&M adder," representing nonfuel variable O&M costs that the utility avoids by purchasing QF power instead of generating from its own system. The O&M adder is designed to compensate variably priced QFs for these avoided O&M costs. The proper valuation of the O&M adder has presented major challenges over recent years and continues to be a major issue in this proceeding.

In D.88-11-052, we first determined that an avoided O&M payment should be calculated separately from other elements of avoided cost and paid as an "adder" to the base QF energy payment. PG&E had previously combined the avoided O&M cost with the calculation of the IER. In D.88-11-052, we noted, however, that a lack of information made it difficult to calculate a precise O&M adder value. Accordingly, we directed PG&E to present a study of O&M costs avoided by QFs' generation for consideration the following year.

In D.89-09-093, based upon our review of PG&E's study, we adopted a method for computing an O&M adder. Our adopted method incorporated avoided O&M cost savings for three elements: operating units, cold standby units, and retired units. We developed an O&M adder by developing a unit cost applied to the generation avoided by QFs, using the QFs-in/QFs-out method. In D.89-09-093, we noted our adopted method had shortcomings and we did not view it as a final or permanent method. As we further stated in that decision, we expect to consider adoption of a generic method for calculating the O&M adder in a future BRPU proceeding. Until then, we expressed our preference to refine the existing method adopted in D.89-09-093, with particular emphasis on simpler approaches to derivation of the adder.

In the following ECAC proceeding, A.90-04-003, parties presented a range of alternative measures of avoided O&M costs. We ultimately adopted an O&M adder of 2.8 mills/kWh to cover the following two-year period. The adopted price reflected a compromise stipulation reached by all active parties, but did not incorporate any definitive measurement methodology. Thus, the ultimate issue of the proper O&M adder measurement remained unresolved as the present proceeding opened.

7.2 Overview of Parties' Positions

In this proceeding, PG&E proposes a significant reduction in the O&M adder from 2.8 mills down to 0.18 mills/kWh. The proposed reduction is largely based upon the findings of a study conducted by Decision Focus Incorporated (DFI), PG&E's consultant. PG&E asserts that marginal O&M costs associated with generation are very small, if not zero, based upon the DFI study.

Based upon its review and independent check of the DFI study methodology, DRA supports PG&E's proposed reduction in the O&M adder and asserts that it has independently validated the methodology underlying PG&E's study. DRA notes that adoption of PG&E's O&M adder would save ratepayers almost $27 million in lower QF payments. The QF Intervenors oppose PG&E and DRA's proposed changes in the adder, contending they are based upon a faulty methodology and failure to comply with Commission directives concerning the O&M adder calculation. The QF intervenors believe that the scope of issues relating to the O&M adder methodology are in any case too complex to dispose of in this ECAC proceeding, and that such changes should be more fully addressed in the BRPU. Although the QF intervenors propose differing refinements to the O&M adder calculation, they all essentially agree on basic principles.

We summarize below the range of proposals for the O&M adder as sponsored by the respective parties and compare them to our adopted O&M adder of 1.36 mills/kWh.

Table 4
Summary of Proposed O&M Adder Values Vs. Adopted
(Mills/kWh) 1/

	PG&E	DRA	CCC	CSC	Adopted
Savings for:					
Operating Units	-0.27	-0.27	1.89	1.51	0.58
Cold Standby Units	-0.01	-0.01	0.43	0.32	0.32
Retired Units	0.46	0.46	1.20	1.41	0.46
Total O&M Adder	0.18	0.18	3.52	3.24	1.36

1/ The mills/kWh values are equal to avoided cost savings in 1993 dollars divided by estimated QF deliveries of 10,459 GWh.

We will address separately each of the three elements comprising the O&M adder since parties' disputes underlying each of the elements involve different issues. We will first discuss each party's position, and then explain our rationale for our adopted O&M adder of 1.36 mills/kWh.

7.3 Avoided O&M Savings Due to Operating Units

The O&M adder component for "operating units" measures the O&M costs, if any, which are avoided due to displacement of PG&E's currently operating generation units with QF generation. The methodology we adopted in D.89-09-093 computed the avoided cost savings for operating units by multiplying the change in generation due to QFs by the appropriate variable O&M unit cost from PG&E's filings in its CFM-6 and -7 filings with the California Energy Commission. While adopting this method, we noted that it had shortcomings. We further directed PG&E to investigate ways to improve the data on the marginal O&M costs associated with different levels of generation for each fossil-fueled plant.

7.3.1 Proposal of PG&E and DRA: O&M Adder for Operating Units

In this proceeding, PG&E sponsors the study of its consultant, DFI, in support of a downward adjustment in the O&M Adder for Operating Units from the existing level, +0.82, to a -0.27 mills/kWh. DFI constructed a series of regression models using PG&E's internal Steam Department data from 1968-1990 to test the correlation of different fossil-plant-related variables with O&M costs. In particular, DFI tested the correlation between generation and O&M expenses on an annual basis to determine the amount of avoided variable O&M cost savings, if any, which QF generation provides.

The DFI study asserts that generation is a poor correlate of O&M expenditures and that its regression models which included generation have less descriptive power than the models which exclude generation. Using the DFI study, PG&E finds not only a lack of O&M savings, but an actual cost increase of $2.8 million from QF displacement of operating units. Accordingly PG&E's calculation results effectively in an O&M "subtractor" of -0.27 mills/kWh applicable to operating units (i.e., -$2.8 million ÷ 10,459 GWh QF deliveries).

We show PG&E's calculation of the negative O&M savings of $2.8 million for operational units below:

Table 5
Derivation of PG&E's Negative O&M Savings for Operating Units

(1) Operating Unit Class (MW)	(2) Plant and Unit	(3) QF In/QF Out Delta Generation GWH	(4) Variable O&M mills/kWh	(5)=(3)*(4) Savings (000$)
53	Humboldt Bay 1-2	17.7	.35	$ 6
104	Hunters Point 2-3	22.9	-.39	-9
110	Conta Costa 1-2	174.2	2.37	413
	Moss Landing 2-3			
120	Contra Costa 4-5	319.4	.05	16
	Moss Landing 4-5			
163	Hunters Point 4	216.8	-5.05	-1,095
170	Morro Bay 1-2	1,887	-.24	-453
	Pittsburg 1-4			
210	Potrero 3	254.4	-5.87	-1,493
330	Contra Costa 6-7	3,072.7	-.02	-61
	Morro Bay 3-4			
	Pittsburg 5-6			
720	Pittsburg 7	864	.22	190
750	Moss Landing 6-7	1,609.1	.07	113
	Total (1992 $)	8,438.2		-$2,374
	Converted to 1993 $ (-$2,374 * 1.1904)			-$2,826

Source: Exh. 11 - Table C-2

DRA supports using the findings of the DFI study. For informational purposes, DRA also developed its own statistical model of the DFI data, estimating a simple multi-regression of natural logarithms of the O&M expenses against the independent variables tested in the DFI study. Although DRA expresses some criticisms of the DFI study, it finds its overall conclusions reasonable. On this basis, DRA also proposes an O&M "subtractor" for operating units of -0.27 mills/kWh.

The QF intervenors all strongly contest the findings of the DFI study, but differ somewhat among themselves as to the proper O&M adder to adopt for this proceeding. All QF intervenors contend that the DFI study is seriously flawed and is unacceptable as a basis to derive an O&M adder. We address the substance of intervenors' criticisms below in our discussion.

7.3.2 Discussion

Before we can accept the DFI model as valid, we must conclude it is really modeling the relationship we are interested in studying. That relationship involves a comparison between generation for each fossil unit and the variable costs which may be incurred as a result of that generation. While we can easily measure generation within a given period such as a year, the period over which resulting costs may occur is much more elusive and may cover a period of years and include extended periods for maintenance outages.

A fundamental problem with PG&E's DFI model is that it forces multi-year cycles of generation and maintenance outages to conform to 12-month time units. O&M costs for any given year are largely a function of when a scheduled or forced maintenance outage occurs on a unit, and may have little or no relationship to generation during the same year from other units. (Exh. 42, pp. II-10-12.) Furthermore, the timing and duration of these maintenance cycles are formulated each year and constantly subject to changes as system conditions change.

Yet the costs incurred during an outage may conceivably have a relevant relationship to generation from a unit which operated in previous periods. The wear and tear caused by previous years' generation may not result in added costs until the unit is removed from service for maintenance. There may also be subtle long-term increases in costs from the cumulative effects of wear and tear caused by generation. This observation would be consistent with the finding of the DFI study that O&M costs do in fact increase as units age (Exh. 1, pg. C-36). Thus, the relationships which the DFI model seeks to correlate are not necessarily captured within the 12-month timeframe demanded by the model. Yet, the DFI model relies on this limited timeframe to make its conclusions.

PG&E argues that its DFI model overcomes the measurement anomalies caused by multi-year maintenance cycles through its use of grouped data to derive regression variables. The DFI model groups similar generating units together based upon size, age, and technology criteria and treats the group as a single regression variable. The intent is that the cyclic swings of one unit are "smoothed" by other units in the group with countervailing swings in maintenance cycles. To illustrate this argument, PG&E offers a series of graphs depicting the maintenance durations for each unit within class groupings (Exhibit 8).

PG&E's Exhibit 8 graphs fail to satisfy us that the unit groupings sufficiently overcome the problems of applying 12-month measurements to multi-year cyclic data. PG&E's graphs provide limited insight as to whether the claimed "smoothing" of data is correcting or rather, simply obscuring and masking the direction of the underlying anomalies inherent in the model's design. Without comparing an individual plant's generation with its own O&M costs over the full range of years over which its maintenance cycles occur, we cannot fully answer this question.

Essentially, PG&E's Exhibit 8 graphs merely show that maintenance durations occur in uneven and changing patterns, even for units grouped together with similar characteristics. Estimated maintenance cycles are formulated every year and are constantly subject to changes and modifications as conditions on the system and at individual generating plants change (PG&E Opening Brief, pp. 32, 33). Given such continuing changes from year to year, we find it questionable that current-year generation data from one unit can be meaningfully grouped with current-year O&M

data from another unit, since the generation and costs are driven by factors occuring at different times under changing circumstances.

Further, even if the unit groupings otherwise corrected for single-unit anomalies, it is not clear that groupings of six or fewer units is a large enough population statistically to smooth out anomalistic effects. Given these concerns, we harbor doubts over the DFI model's conclusion that generation is a poor descriptor of O&M costs. We suspect rather that the model variables, themselves, may poorly describe of how generation and O&M costs actually interact.

PG&E asserts that the DFI model shows a 95% probability that the O&M costs correlated with generation are either zero or very small. We find this asserted high degree of probability only as good as the underlying premise behind the regression variable. Essentially, the DFI model tells us that it is 95% likely that <u>the relationship it measures</u> shows no correlation between generation and O&M costs. The bigger question is whether the relationship being modeled is a realistic proxy for the real world interaction between generation and O&M costs.

As IEP witness House testified:

> "Remember what linear regressions are going to tell you, they're trying to tell you if the number is different than zero. If the regression model can't make a decision, it's going to say, I can't tell you it's different than zero, so it's zero.
>
> "It's pretty clear if you're applying a single year, you're cutting this four-year maintenance schedule into one-year increments. It's going to say I don't recognize that there's a maintenance schedule that's going on, and I'm going to conclude, like the DFI study, that it's zero because I can't make up my mind what's going on." (Tr. 362-63.)

PG&E argues that the DFI model's groupings of units are no different than the groupings of like generating units which underlie the CFM-7 data upon which we relied in adopting the O&M adder methodology in D.89-09-093. Yet, it is not merely the practice of grouping or averaging data which is wrong, but rather it is the improper application of grouped data in the wrong context. We explained the purpose for which we were using the grouped CFM data in D.89-09-093:

> "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." (32 CPUC 2d, 478, 492.)

The DFI grouped data goes beyond this limited application. The use of statistical averages and linear regressions are two independent tools to explain aggregate data. Yet, DFI applies the one tool to explain the other. In effect, the model's use of averaged grouped variables forces us to accept on faith a premise critical to the conclusions of the regression analysis. We must assume the grouped data, forced into one-year measurements, is a realistic proxy for how generation and cost data for individual plants behave over multi-year cycles. PG&E has not met the burden of proof for this assumption.

Also, as stated in D.89-09-093, the averaging of CFM-7 data is done with the intent to avoid skewing the overall results. By contrast, PG&E's methodology yields skewed results by its manner of weighting multi-unit groups with single-unit groups (as explained below). The single-unit groups bear an inordinately large share of the negative savings computed by DFI. This skewing is a direct result of DFI's regression model's specifications, and is the very problem we sought to avoid by using CFM-7-averaged data.

PG&E further defends the DFI's model's use of annual time periods by noting that DFI explored potential lagged relationships between O&M expenditures and the prior five years' generation. DFI found a relationship exists for the 110 and 210 MW unit classes, but not for other multi-unit classes. (Exh. 1, p. C-46.) On this basis, PG&E discounts criticisms that use of annual time periods distorts its findings. We find this defense unsatisfying. DFI's test of lagged relationships is still limited to observations of single discrete years and fails to capture as a single variable the multi-year nature of O&M expenses. No one single year, lagged or not, will necessarily capture adequately the full cause-and-effect relationship which occurs over a longer duration. As such, DFI's lagged test still fails to overcome the drawbacks inherent in using annual data instead of complete maintenance cycle data that exhibits varying frequencies for different equipment among various units over multiple years.

Even if we set aside problems with the grouping of units, we still confront the problem of PG&E's single-unit classes which were not grouped because of their distinctive features. DFI's model incorporates data for Potrero Unit 3 and Hunters Point Unit 4, both of which the model treats as separate classes comprised of a single unit. Unlike the multi-unit classes, DFI's model did find a statistically significant correlation for the single-unit classes. But interestingly, the correlation was negative rather than positive.

PG&E seeks to minimize the significance of these two single-unit groups with negative correlations, stating that for most unit classes, annual O&M expenditures are largely independent of generation. While these two units account for only about 5% of total QF in/out generation, they have an overwhelming 108% impact on the measure of total O&M savings (i.e., $2.6/$2.4 million - see Table 5 - Col. 5). This is due to the fact that the magnitude of the negative savings per kWh computed by DFI for the single units is so large relative to that of the multi-unit groups. Together, the variable O&M for the two single-unit groups is -10.92 mills/kWh, producing a negative savings of -$2.6 million (1992 $). This value compares with a total -$2.4 million (1992$) negative savings which the DFI model computes for all units.

These single-unit "negative savings" not only skew the avoided cost calculation significantly, but they are counterintuitive. The logical inference of PG&E's calculation is that nonfuel O&M costs are less than zero for each increment of generation from PG&E's units. The anomaly of such a result for the single-unit classes leads us to further suspect that similar anomalies may be masked within the multi-unit classes.

PG&E seeks to explain the negative savings phenomenon as being associated with San Francisco area operating criteria constraints and the small number of units in these classes. We find neither of these explanations justify the use of these anomalistic results in PG&E's adder calculation. PG&E does not satisfactorily explain how or to what extent San Francisco operating criteria may yield a negative correlation between generation and costs. PG&E's other explanation -- the small number of units in these classes -- merely confirms the problem with the DFI model.

PG&E dismisses the effects of generation on O&M costs by noting that the descriptive power of its models (i.e., the R-squared value) decreases when generation is added as a variable. We do not interpret this result as impugning the validity of generation as a relevant contributor to O&M costs. Rather, we question the extent to which the real culprit is the DFI model itself, rather than the significance of generation.

The relatively large negative correlations of generation and O&M costs for the single-unit groups stand at odds with PG&E's overall premise that there is generally no significant relationship between generation and O&M costs. Although PG&E claims that "the DFI study was carefully structured and tested to ensure that its results were not biased by this effect [of the large negative correlations]," (PG&E Opening Brief, pg. 40) it fails to show how such bias was avoided. Instead, its calculation of avoided O&M savings in Exhibit 11 simply includes the negative savings from the single-unit groups to derive total negative savings of -$2.8 million. The alternative of simply resetting the value of the single-unit plant groups to zero contradicts the model's finding that the units' costs are statistically different than zero. PG&E offers no other viable solution to this problem. We are left with a model which we cannot rely upon to derive an O&M adder. PG&E's inclusion of the single-unit negative savings in its calculation undermines both the logical and empirical credibility of the model results.

We are also unpersuaded by DRA's support of the DFI model based upon its own independent check of the statistical validity of the model. We do not take issue with the fact that DFI correctly executed the statistical steps required to run its model. Our concern is with the fundamental premises underlying the design of the model itself. Since DRA and DFI incorporated similar assumptions regarding the convention of single-year regression measurements, it is not surprising DRA concurs with the DFI findings.

As noted above, DRA developed a simple multi-regression of natural logarithms of O&M expenses against similar independent variables as tested by the DFI model. DRA's model showed results similar to the DFI model. DRA also presented "visual presentations of the data used by DFI in their study for PG&E" (Tr. 248) as further corroboration of DFI's finding that generation is not related to variable O&M costs. DRA's independent checks adhere to a similar conceptual premise as the DFI model. Both the DRA and PG&E approaches assume that failure to detect a contemporaneous direct relationship between generation and O&M costs for aggregate data proves that no significant relationship exists for individual units.

We are unpersuaded that DRA's regression analysis and visual inspection of generation and O&M costs proves there is no causal relationship between these variables. Given the complexities and variations in the multi-year maintenance cycles for different units and pieces of equipment at different intervals, obvious relationships between generation and cost variables would not necessarily be detectable by inspection of aggregated annual data. DRA's visual inspection does not differentiate different levels of generation for individual fossil units. (Tr. 252.)

PG&E objects to recasting its study on a maintenance cycle basis because the requisite data simply does not exist. Different parts of a generating unit are maintained at different intervals affecting different cycles. Also, PG&E does not keep data on a maintenance cycle basis. Even if PG&E could reconstruct the requisite data, the effort to do so would be impossibly complex, unwieldy, and unduly burdensome, according to PG&E. While we have no reason to doubt this is true, we find it lacking as support to go forward with a study using improperly aggregated data, just because it's all that's available. We prefer not to rely on the DFI study at all, rather than use it in a misdirected way to reach wrong conclusions.

Parties also dispute the raw data source used by DFI. In D.89-09-093, we directed the use of data filed in the California Energy Commission's CFM-6 and CFM-7 proceedings for computing the O&M adder. Although we expressed reservations over the reliability of this data, we noted that at least it represented costs averaged over a long term, presumably including a fairly wide range of generation levels for each plant. In conducting the DFI study, PG&E used its own internal Steam Department management accounting data from 1968-1990. DRA reviewed PG&E's data to some degree and found no problems with it. The QF parties questioned the validity of PG&E's internal data since they had not independently verified it.

Given the complexities of the operational and cost accounting for generating units, a satisfactory measure of the requisite regression variables to test the true relationship between generation and variable costs may simply not be practical. The task of proving that there is no relationship between generation and O&M costs is very difficult. This is a more sweeping undertaking than the comparatively limited task which we asked for in D.89-09-093, namely, "to improve the data on marginal O&M costs associated with different levels of generation for each fossil-fuel plant." We further comment on this directive in Section 7.3.10 in our discussion of the adopted O&M adder.

We find no particular reason to impugn the raw data sources which PG&E used from its steam generation management department to perform its calculations. As PG&E points out, both the data used by DFI and in CFM-7 originated from the same steam generation department data. Although this record did not develop in great detail what exactly makes up the steam department data, the same may be said of the CFM-7 data. For that reason, we expressed our desire in D.89-09-093 to further refine the CFM-7 data sources in future ECAC proceedings.

Yet, while we do not fault PG&E's use of its own steam department data, we still find significant problems with the manner in which DFI has specified and interpreted the data used in its model to arrive at its conclusions concerning the O&M adder for operating units. Thus, for the reasons explained above, we cannot rely on the DFI findings as a basis for adoption of an O&M adder in this proceeding.

In summary, we find that PG&E's model fails to inform us adequately concerning the "essential refinement" we asked for in D.89-09-093 of its data on marginal O&M costs associated with different levels of generation for each fossil-fuel plant." In light of the PG&E model deficiencies discussed above, we find no basis to accept the O&M subtractor for operational units of -0.27 mills/kWh as computed using PG&E's DFI model.

7.3.3 Review of QF Intervenors' O&M Adder for Operating Units

While all three QF intervenors differed in some respects as to the O&M adder calculation for operating units, they all generally arrive at comparable values which differ markedly from those of PG&E and DRA.

7.3.4 CSC Proposal

CSC proposes an O&M adder for operating units of 1.51 mills/kWh based upon an allocation of fixed and variable costs using data gleaned from the Electric Power Research Institute (EPRI) Technical Assessment Guide (TAG). Under the CSC approach, the fixed cost component of O&M is first determined by multiplying PG&E's total O&M costs by the nominal capacity factor for each category of generating unit. The remaining costs are treated as variable. CSC derived its capacity factors by averaging the five highest capacity factors over the 1968-90 period. CSC then derives per-unit variable O&M costs by dividing total variable costs by total generation by unit class for the years 1986-1990.

PG&E and DRA oppose the CSC methodology. PG&E asserts that the EPRI TAG methodology lacks evidentiary support, is inappropriately applied by CSC, incorporates imprecise and arbitrary decisions about O&M costs, and tends to support PG&E's own findings of an inverse relationship between generation and variable O&M costs.

7.3.5 Discussion

We conclude that the EPRI TAG method used by CSC is not supportable based upon the evidentiary record and we reject it. The TAG allocations are based upon industry-wide data developed for use in planning research and development projects. EPRI, itself, warns that the TAG data cannot be compared to actual costs and performance for specific utilities. Given this limitation, we find no basis to rely on the the TAG data to determine the relationship between fixed and variable O&M costs. Accordingly, we reject CSC's O&M adder for operating units.

7.3.6 CCC Proposal

CCC proposes an O&M adder for operating units of 1.89 mills/kWh based upon use of the methodology adopted in D.89-09-093. CCC escalates the CFM-7 cost figures used in that decision to 1993 dollars and then applies the resulting variable cost to the current forecast of incremental generation based on QF-in/QF-out runs.

PG&E and DRA oppose the CCC proposal. PG&E argues that use of the previous methodology is inappropriate in this proceeding, noting our expressions of dissatisfaction with the method we adopted in D.89-09-093, and our intention to refine the existing method in subsequent ECAC cases. PG&E faults CCC for being unable to identify how much or what sorts of O&M costs are caused by generation, and points to its own DFI study as providing a far more accurate assessment of variable O&M costs related to operating units.

7.3.7 Discussion

As discussed in Section 7.3.10, we believe that more current data is available, and therefore using CFM-7 data decline to adopt CCC's proposed adder. We address this problem further in our discussion of the adopted O&M adder below.

7.3.8 IEP Proposal

IEP proposes the continued use of the O&M adder now in effect for PG&E of 2.8 mills/kWh (including standby and retirement unit components). Changes in methodology or O&M values should be addressed in the BRPU, according to IEP.

IEP presents what it terms an illustrative calculation to independently check the methodology used in PG&E's DFI study. IEP substituted PG&E accounting data from the Federal Energy Regulatory Commission (FERC) Form 1 Report instead of DFI data. IEP complains that it could not verify the O&M values used in the study with any other filing made by PG&E. Yet, FERC Form 1 data is publicly available verifiable data, in IEP's view. IEP calculated an O&M adder of 2.13 mills/kWh. PG&E, however, demonstrated a number of data errors in IEP's calculations which largely invalidated the credibity of IEP's computed value of 2.13 mills. IEP does not recommend use of the 2.13 mills value, arguing that it still reflects other flaws in the DFI method, including improper grouping of cost data.

7.3.9 Discussion

Since IEP's illustrative calculation was shown to be largely flawed by PG&E and since it does not constitute IEP's primary recommendation, we will not discuss it in detail. We have already found sufficient grounds to reject the DFI model without the need to rely on IEP's alternative calculations. IEP's complaints concerning undercompensation of fixed capacity payments, to the extent they may have merit, are beyond the scope of our consideration of a variable O&M adder in this proceeding. As to the IEP proposal to continue to use the existing O&M adder, we reject this alternative as explained in the following section.

7.3.10 Adopted O&M Adder for Operating Units

We find regrettably that none of the parties to this proceeding has presented an O&M adder methodology which significantly improves our ability to measure avoided O&M costs.

As we stated in D.89-09-093, we are interested in developing more refined measures of marginal O&M costs associated with different levels of generation for each fossil-fueled plant. The record developed in this proceeding fails to make significant progress toward that goal. We are left with limited alternatives in adopting an O&M adder.

Although we must reject PG&E's O&M subtractor of -0.27 mills/kWh for QF generation displacing operating units, we also reject an adder which simply reflects the methodology used in D.89-09-093 applied to CFM-7 data. There are indications that variable O&M costs underlying CFM-7 data may be overstated. For example, in PG&E's 1990 ECAC proceeding (A.90-04-003), PG&E initially sponsored an O&M adder utilizing CFM-8 costs, which were significantly less than those filed in its CFM-7. DRA makes an alternative calculation using CFM-9 data to arrive at an adder of 0.585 mills/kWh for operating units, using the methodology adopted in D.89-09-093 (Exhibit 25, Table 14-3).

Although the QF parties contested the validity of CFM-8 costs in A.90-04-003, they did ultimately enter into a joint recommendation with PG&E and DRA covering the O&M adder that agreed upon a compromise of 2.8 mills/kWh, a full mill below the value QFs computed using our D.89-09-093 methodology. Thus, the stipulation lent at least some credence to the belief that CFM-7 data erred on the high side. The complete reasons for the drop in avoided O&M savings using CFM-9 data is not clear, although PG&E attributes it to a "refinement of previous definitions of variable costs" and CFM-9's different treatment of consumables (Tr. 762).

As another alternative value for variable O&M, DRA points to the California Power Pool which employs a contract value of 0.23 mills purportedly representing avoided O&M costs. There is insufficient basis in this record, however, to adopt an adder equal to the Power Pool value. No party showed how this value is derived, how long it has existed, whether it is merely a nominal contract proxy, or to what extent it realistically measures avoided O&M costs of PG&E. We expect parties to provide additional information on the basis for the California Power Pool value in PG&E's next ECAC proceeding to enable us to evaluate this comparative measure.

Accordingly, a range of O&M adder values result from use of alternative data base sources. We must exercise a measure of subjective judgment in adopting an O&M adder given the lack of a single clearly superior derivation of avoided cost savings. We take into account the range of O&M adders presented in this proceeding as well as our standards for O&M adders set forth in our previous decisions.

In D.89-09-093, we relied upon CFM-7 data to make the calculation of avoided O&M costs. We believe that the proper way to progress toward a better measure of the O&M adder is improve our understanding of what makes up the CFM data and its measure of variable O&M. We note that the measure of variable O&M costs has dropped in CFM-9 as compared to CFM-7. As noted above, for CFM-9, PG&E identifies nonlabor consumable costs at a more refined cost level than was done for CFM-7, for example (Tr. 762). Although it is unclear as to all of the detailed explanations of differences between the two data sources, PG&E's statement suggests some progress has already been made toward refining the measure of variable O&M costs.

We previously observed in D.88-09-093 that: "No party has presented a detailed description of what exactly makes up the CFM figures, which leaves us with many question about the appropriateness of basing the adder on them." In the present proceeding, significant questions still remain about the makeup of the CFM data. We recognize that the QF intervenors object to the use of CFM-9 data for deriving the O&M adder, claiming it has not been adequately reviewed. Yet, as we note above, CFM-7 also suffers from a similar lack of complete review. Nontheless, we still have used CFM-7 data for deriving an O&M adder. On balance, we conclude that CFM-9 data provides the best available source at this time for deriving an O&M adder for operational units. It represents a more updated data base than does CFM-7 or 8 and yields a result between CFM-7 and 8 ranges. The CFM-9 data was reviewed and used by DRA in making its alternative O&M adder calculations (see Exh. 25/Table 14-3). Based upon the methodology adopted in D.89-090-093 using the CFM-9 filing, DRA computes an O&M adder for operating units of 0.585 mills/kwhr. Accordingly, we will adopt this value for the operating units component of the O&M adder.

We recognize that there may be practical limitations on the quality and accuracy of data which can be extracted and measured for discerning the variable costs avoided by QFs. Nontheless, in PG&E's next ECAC proceeding, we expect a more complete showing regarding what factors account for the the measure of variable O&M costs in the most currently available CFM filing. We expect this review of CFM data to provide a basis to further refine previous definitions of variable costs and to promote a better measure of marginal O&M costs associated with different levels of generation. As a result, we hope to be able to make a more informed judgment concerning the proper measurement of avoided costs allowed in the O&M adder."

We renew our directive expressed in D.89-09-093 for PG&E and other parties to work towards ways to refine the measurement of marginal O&M costs relating to changes in generation for each fossil fuel plant. We expect to explore this issue of the O&M adder further in PG&E's next ECAC proceeding. By declining to adopt PG&E's DFI study, we don't intend to discourage further exploration of ways to improve these measures. We are not convinced that PG&E has exhausted the universe of plausible avoided O&M measurement approaches with its DFI study.

Moreover, while PG&E, as the holder of data on the operations and maintenance of its power plants, bears the initial affirmative burden to make that data available to interested parties, we do not intend that PG&E, alone, bear the affirmative burden of establishing a reasonable value for avoided variable O&M costs, or of proving or disproving the existence of a measurable relationship between variable O&M costs and generation. We expect PG&E to put forward an affirmative showing supporting the value and the relationship it advances in its next ECAC filing. However, we expect other interested parties, particularly QFs, to do the same. We advise parties that we will scrutinize all showings and may accord little evidentiary weight to the challenge of any party if that party does not also put forward an affirmative showing of its own.

<u>7.3.11 Cold Standby and Retirement Units - O&M Adder</u>

Under our methodology adopted in D.89-09-093, the O&M adder includes savings associated with units which have been retired or placed on cold standby status. In that decision, we derived avoided cost savings from these sources based upon recorded plant data during the most recent five-year period.

For cold standby units, the adopted method in D.89-09-093 first determined the capacity needed to meet target reserve margins. Next, this capacity was compared with PG&E's resources absent variable QF capacity. The ratio of added capacity needed to meet target reserve margins to total capacity was multiplied by the five-year savings related to standby units to derive the avoided O&M savings for standby units.

For retired plants, the adopted method in D.89-09-093 compared the ratio of needed capacity to total capacity of the retired plants. This ratio was then multiplied by savings associated with plants retired during the 1984-88 period.

<u>7.3.12 Position of PG&E</u>

For computing avoided cost savings for standby and retirement units, PG&E applies the methodology as directed in D.89-09-093, but uses an updated five-year period of 1987-91. On this basis, PG&E computes an O&M adder of -0.01 mills/kWh for cold standby units. For retirement units, PG&E computes an adder of +0.46 mills/kWh. PG&E arrives at these results by using a later five-year period of 1987-1991 recorded data as compared to the 1984-88 period used in D.89-09-093. Since the net O&M costs for maintaining the units in cold standby status have increased over this period, PG&E computes a slightly negative O&M adder of -0.01 mills/kWh.

Yet, in its brief, PG&E appears to have revised its position and to advocate the complete elimination of retirement units from the O&M adder calculation. PG&E argues that all three retirement units would have been over 50 years old by now and would certainly have been retired irrespective of QF availability.

7.3.13 Position of DRA

In its prepared testimony, DRA's computation of standby and retirement unit savings follows PG&E's method. Likewise, in its brief, DRA departs from its previous avoided cost calculations and supports PG&E's argument that the avoided cost allowance for retirement units should now simply be eliminated.

7.3.14 Position of QF Intervenors

The QF intervenors advocate retention of the O&M adder for standby and retirement units. CCC and CSC each sponsor independent calculations of O&M adders for standby and retirement units based upon somewhat different measurement periods. CCC uses the original 1984-88 period. CSC uses an expanded seven-year period (1985-91). IEP simply proposes continuation of the existing O&M adder, which incorporates a 1.98 mills/kWh factor for standby and retirement units.

The QF intervenors object to PG&E's computation using 1987-91 data, arguing that PG&E has misinterpreted the Commission's intent as expressed in D.89-09-093 in its use of a five-year average to measure avoided cost savings. The QFs argue that the Commission did not intend simply to use the most recent five-year period, as PG&E believes, without regard to the underlying cause-and-effect relationships between QF generation and avoided cost savings from standby and retirement units. By truncating the previously used data covering 1984-86, PG&E eliminates most of the savings otherwise attributable to retired units and computes an actually negative savings for standby units.

CSC and CCC each present a somewhat different recorded period in their calculations, but both periods begin early enough to capture the period when the retired and standby units were still operational. The QF intervenors also fault PG&E's arguments to simply eliminate the retired units from the calculation. QFs contend that PG&E did not develop a record on the pertinent issues respecting how long to treat a retired plant as being displaced by QFs, and that this issue has been reserved for consideration in a generic proceeding.

7.3.15 Discussion

The resolution of parties' disputes over the proper measurement of standby and retirement unit savings must be consistent with our underlying goal: namely, to determine the extent to which QF generation yields ratepayer savings by permitting PG&E units to be placed on cold standby or retired. To perform this exercise, we must first determine which units are affected by the presence of QFs. We must next determine the avoided cost savings of these units by comparing their cost assuming they were in operative status (i.e., QFs-out) with their cost given their inoperative status (i.e., QFs-in).

As to the question of which standby units are subject to the calculation, there is no apparent disagreement among the parties. The cold standby units include Kern 1 and 2, Contra Costa 3 and Moss Landing 1. The dispute arises over the proper time period over which to measure the avoided cost savings for these units resulting from the presence of QFs.

In D.88-11-052, we stated that: "The study [of avoided O&M costs] 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."

PG&E interprets this language to justify a moving average of a five-year period to compute avoided cost savings. Thus, PG&E begins its calculation in 1987 when standby and retirement units were already inoperable. We disagree with PG&E's interpretation of our intention in D.88-11-052. We did not intend to establish five years as an arbitrary cutoff for determining avoided cost savings. On this basis, we find PG&E's calculation of avoided cost savings for standby units to be incomplete since it fails to capture a period during which the standby units were in operation. Thus, using PG&E's five-year period, we are unable to determine operational costs which were avoided since such costs predated 1987.

The QF intervenors both reflect recorded data that captures some period during which the standby units were operating. The different time frames used by CCC and CSC provide a basis to observe the sensitivity of the calculation to use of differing time periods. CCC applies the five-year methodology adopted in D.89-09-093 based on the original 1984-88 time period, adjusted for inflation. CSC expands the timeframe to include 1985-1991. Reactivated unit costs are excluded. Use of either timeframe results in relatively comparable results. As Table 4 above illustrates, CCC's calculation results in a slightly higher value for standby units of 0.43 mills/kWh, compared with CSC's value of 0.32 mills/kWh. We select 0.32 mills/kWh, as our adopted O&M adder for standby units. We adopt this value since it covers both a period during which the units operated and also incorporates more recent data than does CCC's calculation.

As to the treatment of retired units, PG&E's use of a five-year moving average of recorded data yields an O&M adder value of 0.46 mills/kwhr. As noted above, we do not believe a five-year moving average should be arbitrarily applied to derive an O&M adder for retired units. Nontheless, we do conclude that PG&E's five-year average for retired units yields a more reasonable result than QF intervenors' estimates, given the specific facts of this proceeding.

In D.89-09-093, we stated the basis upon which we would evaluate the extent to which retirement units should be included in the O&M Adder in future proceedings:

> "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 the 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 that proceeding, PG&E argued that the three plant units in question would have long since been retired even absent QF generation. PG&E further argued that the three units had been operated well beyond their useful life and were being retired for safety and economic efficiency reasons. In D.89-09-093, however, we rejected PG&E's explanation that the three units were retired for reasons unrelated to QF generation. We noted contrary evidence in that proceeding that PG&E's reserve margin would fall below target levels if QFs were not present to fill in for retired and standby plants.

We conclude that PG&E has now made a reasonable showing on the limited point that the three units of Avon, Martinez, and Oleum would have been retired with or without QFs, given the advanced age they have attained. Four additional years have passed since PG&E's initial arguments concerning the treatment of these retired units. All of the units are now over 50 years old. This compares with the 45-year retirement age assumed by the Energy Information Administration in its Annual Energy Outlook study; the 38 to 42 year age for retirement that plants of 100 mw have averaged nationally. On this basis, then, it is not necessary to determine precise uniform criteria as to when the plant units would have been retired absent QFs.

The question of when the units would have been retired absent QFs may be less relevant to measuring QF avoided costs, however, than the question of whether the capacity needs of PG&E would fall below target levels if the equivalent capacity of the retired units was not satisfied by QFs. As we stated in D.89-09-093: "If no QFs existed, a utility would typically replace a worn-out plant with a newer generation plant with lower overall costs of operation...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." This premise implies that referencing the costs of the retired plants rather than the new replacement plant could overstate avoided costs. Accordingly, by merely showing that retired plants would have been retired absent QFs, PG&E has not shown that the capacity needs represented by the retired plants would not still need to be replaced by some other resource, absent QFs. On the other hand, if a replacement source had a lower cost, then basing the QF adder purely on retirement unit costs could overstate avoided cost savings.

Given these considerations, we reject the revised proposal of PG&E and DRA to eliminate completely the retirement element of the O&M adder in this proceeding. We instead adopt PG&E's O&M adder for retirement units of 0.46 mills/kwhr based upon a five-year average of 1987-91 recorded data. The calculation of the QF intervenors tends to overstate the avoided cost value of the retired units to the extent they include earlier recorded periods. PG&E's calculation reflects a gradual decline in the avoided cost value of the retired units over time, consistent with the idea that their avoided cost value becomes less apparent as their age lengthens. It is also consistent with the idea that a replacement resource would be cheaper and yield lower avoided cost savings than would the retired units. In its opening brief, DRA suggests that such a proxy can realistically be developed on this basis using PG&E's short-term fossil-fueled marginal resource. In next year's ECAC proceeding, we expect a further showing on this question of replacement capacity and its implications for the O&M adder.

8. Energy Reliability Index

The Energy Reliability Index (ERI) is a valuation formula we use to determine capacity prices paid to QFs. As determined in D.88-03-026, we update the ERI annually in ECAC proceedings for QFs which have signed Standard Offer #1 or #3 contracts, or have selected the As-Delivered Capacity Payment Option #1 in Interim Standard Offer #4. The ERI is computed based upon electric-system capacity needs under a given set of reserve margin and resource assumptions. The the annualized cost of a combustion turbine (CT) serves as a proxy for PG&E's avoided capacity costs in deriving the ERI. In D.89-06-048, we adopted an ERI methodology incorporating a ceiling value of 1.0 and a floor value of 0.4. An ERI of 1.00 signifies that a utility needs capacity, and that the value of additional capacity is equal to 100% of the CT cost. As the utility acquires excess capacity, the ERI value declines, but not below the floor of 0.40.

8.1 Positions of Parties

Parties dispute the appropriate value for the ERI in this proceeding. All parties agree that the ERI is equal to 1.0 during 1993 using our adopted ERI methodology. PG&E, however, proposes modifications to the existing methodolgy which would lower the ERI from 1.0 to 0.40 for purposes of this proceeding. All other active parties opposed PG&E's proposed ERI change, including DRA, the QF intervenors, and CLECA. All these parties advocate continuation of the ERI of 1.0 during 1993. For the reasons discussed in detail below, we decline to adopt the changes in ERI input assumptions, as proposed by PG&E, which would reduce the ERI below 1.0. Accordingly, we adopt an ERI of 1.0 for the 1993 forecast period.

PG&E's proposed changes to the ERI methodology entail the following changes in input assumptions:

a. Include Pacific Northwest capacity other than firm contract amounts in the ERI up to available transmission line capacity.

b. Assume normal precipitation rather than the dry-year hydro capacity assumption used for long-term planning.

c. Include interruptible capacity as a resource in the ERI.

DRA and QF intervenors object to PG&E's proposed changes on the basis that PG&E has proposed these changes in past ECAC proceedings and had them rejected. DRA and QF intervenors further note that we have designated the BRPU as the proper forum in which to consider ERI changes of the sort proposed by PG&E. CLECA also objects based upon its concern over how changes in the ERI would impact the incentive amount reflected in interruptible rates paid by PG&E's nonfirm customers.

We discuss below each of the proposed ERI methodology changes of PG&E, and our disposition of its arguments.

8.2 Northwest Capacity Assumptions

PG&E proposes to assume that all transmission capacity is filled with short-term firm capacity purchases. Such an assumption would reduce the ERI from 1.0 to 0.40. PG&E believes this assumption is consistent with its recent purchases from the Northwest and with the California Energy Commission's (CEC) treatment of capacity purchases in its 1992 Electricity Reports (ER 92).

8.2.1 Discussion

PG&E's arguments are essentially similar to those which it previously made and which we rejected in D.89-12-015. PG&E provides no compelling reasons to warrant a change from our previous position. As we previously stated in D.89-12-015, capacity assumptions applied in the IER calculation should consistently apply to the ERI as well. Since PG&E excludes short-term firm capacity purchases from its IER calculations, it would be inconsistent to impute such purchases into the ERI. Accordingly, we reject PG&E's Northwest capacity adjustment for ERI purposes.

8.3 Hydro Assumptions

PG&E also proposes a change in the hydro assumptions underlying the ERI. Our adopted ERI methodology utilizes a dry-year hydro assumption. PG&E argues that the ERI calculation should assume normal precipitation rather than dry-year conditions. PG&E believes such as change is appropriate given the short-term perspective of the ECAC forecast period. Since the ECAC forecast resource mix is predicated on normal precipitation assumptions, PG&E argues that QF capacity payments should be based on the same assumptions of normal precipitation. Under such a revised assumption, the ERI would be reduced from 1.0 to 0.40.

8.3.1 Discussion

PG&E has repeatedly presented arguments similar to those presented in this application advocating elimination of the dry-year hydro assumptions underlying the ERI. We have previously considered and rejected PG&E's arguments. In this proceeding, PG&E has presented no new arguments which persuade us reverse our long-standing policy of basing the ERI on dry-year assumptions.

We have always assumed adverse hydro conditions when doing reliability planning because it is impossible to forecast actual hydro conditions in a subsequent year. Because of its heavy reliance on hydro power, PG&E's system is particularly sensitive to changes in hydro availability. Thus, its system is relatively less reliable in dry years. This sensitivity increases the value of other sources of capacity and must be considered, even in short-term forecasts. Accordingly, the use of dry-year assumptions produces a reliability target ensuring smooth system operations.

We understand that dry-year assumptions may produce higher-than-needed QF capacity payments in some years. The risks of such occurrences are already considered in our design of the ERI. As we stated in D.88-03-079, the ERI incorporates ceiling and floor provisions which provide a reasonable balance of interests on a system where hydro plays such an important part.

8.4 Interrruptible Capacity as a Resource Assumption

In its ERI calculation, PG&E also includes 400 MW of interruptible capacity. PG&E claims the 400 MW is a reliable resource for up to 30 emergencies per year with a maximum of 100 hours of use. IEP actively contests this assumption. IEP challenges this inclusion on the basis that such interruptible service is only available on a limited basis, and that its inclusion is inconsistent with the fact that the 400 MW capacity is not included in PG&E's IER determination. We are not persuaded by PG&E that we should include the 400 MW in the ERI determination, and agree with IEP's reasoning.

8.5 Inclusion of SMUD's Resources and Loads

PG&E's ERI also includes Sacramento Municipal Utility District's (SMUD) loads and resources. CLECA is the only party to contest this assumption. CLECA claims this treatment is inappropriate in that SMUD's operations are no longer integrated with those of PG&E as of January 1990, and that the mere fact of interconnection between PG&E and SMUD does not justify PG&E's ERI treatment. We are persuaded by PG&E's arguments that the manner in which the two systems operate justify PG&E's inclusion of SMUD's loads and resources in its ERI determination. Despite the January 1990 contract designating that PG&E and SMUD are no longer run as one system, SMUD remains in PG&E's control area. Operationally, PG&E is still responsible for ensuring that all of its control area, including SMUD, meets reliability and emergency operating criteria. Although we agree with PG&E on this point, an ERI of 1.0 still results from our disposition of other ERI assumptions discussed above.

9. Uncontested Resource Assumptions and Modeling Conventions

PG&E's forecast incorporated a number of resource assumptions and modeling conventions which were uncontested by any party (as reproduced in Appendices D & E herein). Upon our review, we conclude that these uncontested items are reasonable and accordingly adopt them in deriving QF price factors and ECAC/AER revenue requirements.

10. Contested Resource Assumptions

10.1 Irrigation Districts and Water Agencies Generation

IEP contested PG&E's forecast of 1,676 GWh of generation for the Yuba County Water Agency (YCWA) for 1993. YCWA owns and operates two hydroelectric facilities on the Yuba River: the Colgate Power House and the Narrows 2 power plant. PG&E buys electricity from these facilities from YCWA, based on contractual production and storage targets in the reservoirs. IEP contends that PG&E fails to account for present diversion demands from the Yuba River, resulting in an overstated forecast of hydroelectric generation from the YCWA generators.

In recent proceedings before the California Department of Water Resources (DWR), YCWA's water rights and operations of the Yuba River have been under consideration. After YCWA's initial filing, the DWR requested that YCWA reestimate hydroelectric generation from its generators. The revised study was performed by Bookman-Edmonston Engineering, Inc. (BEE), YCWA's consultant, and was filed with DWR on March 16, 1992. The BEE study concluded that under a median year hydro forecast and using 1992 diversion demands, that the YCWA power plants would produce 1,410 GWh. The study noted that additional diversion demands would be developed in 1993, potentially producing even lower generation. By contrast, PG&E estimates 1,676 GWh during 1993.

The 1,410 GWh reported in the study includes generation for Narrows Unit 1, however, which is owned by PG&E. Thus, generation from Unit 1 must be excluded in computing sales to PG&E.

10.1.1 Discussion

We conclude that PG&E's forecast of hydrogeneration from YCWA is reasonable and we will adopt it as a resource assumption. PG&E's rebuttal witness indicates that PG&E did use the same diversion forecasts that came from Yuba County as part of its 1993 operating plan and which were provided on a worksheet developed by BEE. The only difference between the forecasts is that PG&E assumes normal precipitation while BEE assumed a dry year.

We also find PG&E's forecast more reliable than a speculative forecast as to what decision DWR may or may not make in its proceedings affecting YCWA. IEP merely raised the possibility of an effect of diversion demands, but did not provide firm evidence beyond speculation as to what the outcome of the DWR proceedings may be.

10.2 PG&E Hydro Generation

PG&E differs with IEP as to forecasted hydro generation. PG&E forecasts 11,992 GWh versus a forecast of 10,220 GWh by IEP. DRA concurs with PG&E while CCC concurs with IEP. IEP faults

PG&E's forecast for failing to capture the effects of six years of drought in forecasting hydro availability. IEP alleges that PG&E has assumed normal precipitation results in normal runoff, and has ignored the reduced runoff due to the prolonged California drought. To compute an alternative forecast, IEP constructed two regression equations to measure the relationship among the variables of precipitation, runoff, and PG&E hydroelectric generation. IEP based its runoff on the Sacramento River Index (SRI) since over three-quarters of PG&E's hydro capacity is in basins covered by the index.

10.2.1 Discussion

We adopt PG&E's hydro generation of 11,992 GWh as the more reasonable forecast. IEP's principal basis to reject PG&E's forecast is its alleged failure to reduce its forecast for the expected effects of lower runoff due to the six-year California drought. We conclude, however, that PG&E did properly reduce its 1993 forecast runoff to recognize carryover effects of a prior dry years' drought, to the extent warranted. A principal point of difference between PG&E and IEP concerns the extent to which carryover from prior dry years has any impact on PG&E's current hydroelectric generation. As PG&E explains, only a fraction of the runoff from the river basins comprising the SRI show measurable carryover effects from prior dry years due to geological factors. PG&E computes that only 27% of PG&E's total hydrogeneration is affected by dry-year carryover.

Thus, PG&E did reduce forecast runoff below median year values, but only for those watersheds which are actually impacted by carryover effects of prior dry years. PG&E's hydro forecast of 11,992 GWh for 1993 is 6% lower than the long-term historical average year hydro generation of 12,730 GWh. IEP's forecast understates the hydro forecast to the extent that it assumes PG&E's entire system is impacted by prior dry year carryover effects.

10.3 Northwest Power Availability

PG&E forecasts Northwest power availability up to its line entitlements on the large capacity alternating current (AC) and direct current (DC) transmission lines connecting California and the Pacific Northwest (the Pacific Intertie). IEP contends that a reduction in Northwest economy energy availability of 10%, 4%, and 7% in April, June, and July, respectively, is warranted. IEP believes these reductions are appropriate in view of recently announced changes in the operation of the Columbia-Snake River system.

10.3.1 Discussion

We adopt PG&E's forecast of full availability up to line entitlements as reasonable. IEP bases its assumption of reduced energy availability on expected mitigation measures to be taken on the Pacific Northwest river systems to protect endangered species. These measures involve reservoir drawdowns and flow augmentation during the April through August period which will lower the level of hydroelectricity otherwise available. In addition, IEP contends that water conditions experienced during 1992-93 will reduce the chances of nonfirm energy being available should 1993 be a normal precipitation year.

The effects of the California drought are another concern raised by IEP in assessing shortages of Northwest energy availability. The Pacific Northwest is currently experiencing one of the worst runoff years on record. IEP did not, however, quantify to what extent, if any, the low current-year runoff impacts its forecast reductions in hydroelectric availability. Instead, IEP focuses on salmon mitigation measures as the key factor warranting a forecast of reduced nonfirm hydroelectricity.

IEP states that the anticipated mitigation measures on the Columbia-Snake River facilities are expected to reduce energy availability by 700-1,100 MW-months from April through August. This anticipated reduction, however, is compensated for by PG&E's

short-term agreements with Northwest power suppliers for purchase of 1,100 MW of capacity and associated energy during the summer and fall months. Of these agreements, only that with Bonneville Power Administration (BPA) for 400 MW must be returned. Yet, since these agreements begin in July, they would not provide energy during April. Thus, PG&E would still be at risk for the 10% reduction in availability in April as forecast by IEP.

Another compensating source of Northwest energy available to PG&E is from the capacity entitlement of Southern California Edison (SCE). Given that SCE's forecast of 1993 Northwest purchases of economy and short-term firm energy are below historic purchases, there is a likelihood of unused energy which PG&E may purchase. SCE has a basic entitlement of 1,631 MW of AC and DC Intertie capacity. On this basis, a forecast of full line entitlements is reasonable.

10.4 Pacific Northwest Prices

PG&E and IEP were in dispute concerning the price of Northwest economy energy during May and June of 1993. PG&E forecasts its economy energy prices based upon historic relationships between California decremental thermal operation cost and the price of Northwest economy energy. On this basis, PG&E forecasts May prices at 80% and June prices at 85% of system incremental cost.

IEP contests this forecast in that it fails to factor in BPA's added costs of salmon mitigation measures on the Snake River. Based upon IEP's calculations, BPA's proposed spring nonfirm energy price of 15 mills/kWh would result in an increase in PG&E's price expressed as a percentage of incremental fuel costs to 90% in May and 95% in June.

10.4.1 Discussion

The parties' dispute focuses on whether BPA's proposed price increase will affect PG&E's purchased power price. We agree with PG&E that BPA's forecast of the value of its energy at

15 mills/kWh does not automatically dictate what PG&E or any utility would be willing to pay for such energy. The price of nonfirm energy is determined primarily by the cost of the buyer's alternative sources. Thus, PG&E's incremental energy costs are more relevant than suppliers' proposed prices in determining what PG&E can be expected to pay for purchased power. With PG&E's incremental energy costs ranging between 12.6 and 15.7 mills/kWh, BPA's 15 mills proposed price would tend to be uncompetitive with PG&E's alternatives, particularly after added transmission losses are factored in.

We will accordingly adopt PG&E's Northwest price assumptions for purchased power, which reflect May prices at 80% and June prices at 85% of PG&E's system incremental cost. These price ratios reflect several years of monthly data under a variety of market and weather conditions. We find such price ratios to reflect a more reliable basis for a forecast as compared with reliance on the short-term price proposal of BPA.

10.5 Target Spinning Reserve Criteria

Parties dispute the assumptions concerning target spinning reserves for resource modeling purposes. As inputs to its PROMOD runs, PG&E uses average spinning reserves based upon recorded data for 1989, 1990, and 1991, resulting in the following spinning reserve percentages:

	Weekdays	Weekends
January - April	7.0%	8.0%
May - September	7.0%	11.5%
October - December	7.0%	8.0%

DRA and IEP contest the use of recorded spinning reserve data as a modeling input, and recommend the retention of the 7% spinning reserve assumption for all time periods. CCC follows PG&E's assumption.

10.5.1 Discussion

As DRA points out, PROMOD does not provide a forecast of the actual spinning reserve at the time of system peak, but instead dispatches based upon a typical week. We conclude that a 7% spinning reserve assumption is a reasonable modelling convention for all subperiods since PG&E dispatchers use the 7% criteria in practice for unit planning and commitment. As IEP points out, PG&E's modeling conventions already incorporate separate constraints that tend to increase spinning reserves above the 7% target. Thus, we find no need to separately increase the spinning reserve modeling convention to reflect recorded levels above the 7% target.

In addition to the basic spinning reserve percentage input discussed above, PG&E further adjusts spinning reserve for the operation of PG&E's Helms Pumped Storage units. While PROMOD treats the total capacity of Helms' three units as firm, in reality, only two of Helms' three units are used during monthly peaks due to water constraints. To reflect the proper operation of all three Helms units, PROMOD increases the input for commitment level by the 404 MW capacity of one generator at Helms. We accept this adjustment as proper since an overcommitment of capacity for modeling purposes would otherwise result.

10.6 Utility Electric Generation Gas Prices

PG&E's conventional fossil-fuel plants use available natural gas as a fuel source to generate electricity. A disputed issue concerns the price assumptions applicable to natural gas used for utility electric generation (UEG) purposes. PG&E and DRA initially differed with respect to their forecasts of gas prices for UEG. The principal gas price variables initially in dispute between PG&E and DRA were the core subscription price, the UEG self-procurement price, the percentage of UEG demand served from core-subscription, and the Transwestern Pipeline demand charge.

Subsequently, PG&E and DRA entered into a Joint Recommendation addressing each of these natural gas forecast assumptions. The QF intervenors support PG&E's initial gas price assumptions. IEP, in particular, believes the stipulated UEG self-procurement price is unrealistically low, based upon current market information.

10.6.1 Core Portfolio Price

PG&E based its estimate in its June 5 update on a stipulation in its 1992 Biennial Cost Allocation Proceeding (BCAP) ((A.91-11-001), Exh. 31) among DRA, Toward Utility Rate Normalization (TURN), and PG&E on the core portfolio weighted average cost of gas (WACOG). DRA's initial estimate, adjusted for math errors, differed by only $0.02/Dth from that of PG&E. The PG&E/DRA Joint Recommendation in this proceeding split the difference to arrive at a stipulated core WACOG of $1.77. The QF intervenors did not challenge the stipulation with respect to the core portfolio price. Accordingly, given the uncontested nature of this forecast variable, we find the core WACOG of $1.77 to be reasonable and hereby adopt it.

10.6.2 UEG Self-Procured Gas

PG&E can only satisfy a portion of its UEG demand through core subscription. PG&E must procure the remainder of its UEG needs through supply sources independent of the core portfolio. PG&E and DRA differed both as to the percentage of UEG demand to be met through self-procurement and the price of such gas supplies.

In its update, PG&E based its incremental gas price on the Data Resources, Inc.'s (DRI) estimated price of spot gas from the U.S. Southwest supply region, resulting in a price of $1.80/MMBTU at the California border.

DRA forecasted an incremental gas price of $1.45/MMBTU, based upon an average of 50% Canadian spot gas and 50% U.S. Southwest spot gas. DRA followed its forecast methodology used in

PG&E's 1992 BCAP which relied on a time-series trend of past recorded data to extrapolate future prices.

In the Joint Recommendation, DRA and PG&E agreed on a compromise price of $1.65/MMBTU. The stipulation, however, does not make any explicit assumptions concerning the mix of gas supply sources or statistical methods for deriving the forecast.

10.6.2.1 Discussion

The Joint Recommendation of a $1.65/MMBTU yields a reasonable resolution of the disputes between DRA and PG&E over self-procured gas, and we will adopt it. It represents the midpoint of the range of differences between the forecasts. As such, it does not favor one party's position over the other. Adoption of the stipulation avoids the need to render findings on the issue of PG&E's ability to self-procure Canadian spot gas supplies for the UEG. This issue has proven to be a highly controversial topic in PG&E's pending 1988-90 gas reasonableness review. The expedited schedule of the ECAC forecast phase does not easily lend itself to the time-consuming demands for full litigation of such a complex, controversial issue. Accordingly, the parties' stipulation provides a reasonable gas price forecast for the limited purpose of this proceeding without prejudice to any party's position on Canadian gas issues in other proceedings.

We remain unpersuaded by IEP's challenges to the Joint Recommendation regarding its self-procured UEG gas prices. IEP presented statistics indicating recent upward movement in prices for natural gas futures contracts, and attempted to infer a general upturn in gas prices as a result. PG&E's witness on gas prices discounted the validity of current futures prices as a good indicator of actual future gas prices. IEP offered no witness to rebut PG&E's conclusions.

Even if we were to accept IEP's assertions regarding the upward trend of natural gas prices, we are still left with the unresolved question of the relative mix of gas from the U.S. versus

Canada. The reduction in price between PG&E's initial showing and the Joint Recommendation resolved PG&E's differences with DRA not just as to price but also as to supplier source mix differences. IEP offers no insights on this issue of supply mix and thus, no sound basis upon which to challenge the relative mix of U.S. and Canadian sources initially proposed by DRA. The only credible alternative before us is the PG&E/DRA Joint Recommendation. Thus, IEP offers no viable challenge to the Joint Recommendation on self-procured gas price.

10.6.3 Percentage of UEG Demand Satisfied by Core Subscription

PG&E and DRA also differed initially on the percentage of UEG demand which would be met through core subscription. PG&E forecasted 65% while DRA only forecasted 50%. DRA bases its assumption on its reading of D.91-11-025 which states that the Electric Department's core subscription purchases are limited to 50% during the first two years of the capacity brokering program. PG&E based its 65% assumption on the premise that no changes to the gas industry structure resulting from D.91-11-025 would be in place during 1993. PG&E notes the uncertainty as to when capacity brokering, or a substitute capacity release program, would be approved by the FERC. In the Joint Recommendation, parties compromise by agreeing on an estimate that 57.5% of UEG demand will be met through core subscription, with the remaining 42.5% coming from self-procured sources during 1993.

We agree that the uncertainty as to the timing of subsequent FERC action on capacity brokering will influence PG&E's ability to meet UEG's demand through core subscription. No party contested the Joint Recommendation's resolution of this issue, and we find it to be a reasonable compromise of the differences between DRA and PG&E. We accordingly adopt this assumption of the Joint Recommendation.

10.6.4 Transwestern Demand Charge

PG&E has reserved 50 MMBTU/day of capacity on the Transwestern Pipeline for its UEG needs. The reservation charge is the fixed monthly fee that PG&E pays to Transwestern for the right to rely on access to this capacity. In computing its cost of gas in its update testimony, PG&E initially included the full monthly reservation charge in its UEG avoided costs. Yet, for purposes of computing its avoided cost payments to QFs during April through June, PG&E reflected only 31% of the reservation charge.

DRA, in its initial testimony, opposed the recovery of any costs of the Transwestern demand charge on a forecast basis. Consistent with its recommendation in the capacity brokering proceeding, DRA proposes PG&E establish a memorandum account to track the costs and to apply for cost recovery in a subsequent reasonableness review.

CCC contested PG&E's initial treatment of the Transwestern demand charge in that it resulted in inconsistent treatment between the method used to compute QF payments versus its revenue requirements. CCC proposes that the full cost of the Transwestern demand charge should be included in its payment to QFs.

In the PG&E/DRA Joint Recommendation on Natural Gas Forecasts, the parties stipulated to the removal of the Transwestern demand charges from the revenue requirement and from the avoided fuel cost used to determine the IER. Although PG&E and DRA disagree on the reason for the removal, we conclude that the end result agreed upon is a reasonable resolution for purposes of deriving a revenue requirement and IER for this proceeding. We shall adopt the Joint Recommendation's treatment of this issue. PG&E should record the Transwestern demand charges in its ECAC balancing account subject to a subsequent reasonableness review.

10.7 Avoided Cost of Gas Transportation for QF Pricing

CCC raises an issue concerning the manner in which the cost of gas transportation is incorporated into the QF pricing formula. In D.91-05-029, we adopted a change in cogeneration gas rate design to promote pricing stability and consistency by setting cogeneration gas rates at parity with the average UEG rate forecast adopted in PG&E's BCAP.

CCC notes that a disparity still exists between the gas rates for cogenerators who chose a level of service similar to PG&E's UEG and the forecast gas transportation rate component of short-run avoided cost (SRAC) energy payments. As a result, cogenerators have paid more for gas than the gas rate component in SRAC energy payments. This disparity occurs because PG&E derives the SRAC gas component in its annual ECAC proceeding from a different forecast of UEG throughput than is used in the BCAP proceeding to set the Schedule G-COG cogeneration rate. CCC proposes that SRAC energy payments be based on UEG throughput estimates adopted in BCAP proceedings to promote price consistency. PG&E opposes this proposal.

10.7.1 Discussion

CCC's proposal would not solve the problems of timing differences in the forecasts between ECAC and BCAP proceedings. It would simply shift the effects of gas forecast disparities from QFs to retail ratepayers. Granted, CCC's proposal would promote consistency for QFs with respect to their payments for gas and the prices they receive for QF energy. Such consistency would be achieved, however, by creating an inconsistency between the PG&E's avoided cost used to compute QF payments and its actual avoided cost as measured using updated UEG throughput estimates produced in the ECAC proceeding.

The proper reference point of the SRAC energy payment is the utility's cost, not that of the QFs. Thus, the risk of forecast disparities between BCAP and ECAC forecasts is the responsibility of QFs, not PG&E or its ratepayers.

10.8 Fuel Oil Inventory

If PG&E's available natural gas supply to serve total conventional steam-plant requirements is curtailed, the remaining demand is met by residual fuel oil. PG&E forecasts no curtailment-related fuel oil burns during 1993. The only inventory reductions are forecast to be for operational testing purposes. DRA was the only other party to sponsor testimony on the issue of fuel oil requirements. DRA and PG&E agree on the average and peak fuel oil inventory levels forecast for 1993. Nonetheless, DRA disagrees in principle with PG&E's assumption concerning fuel oil resupply lead time. The dispute involves the proper level of fuel oil inventory to cover the lead time required to purchase, receive, and distribute additional quantities of low-sulfur fuel oil (LSFO) under adverse circumstances. DRA forecasts a shorter fuel oil resupply lead time (60 days) and lower safety stock levels as compared to 90 days forecasted by PG&E. While disputing PG&E's resupply assumption, DRA agrees to accept PG&E's overall fuel oil inventory forecast. DRA believes this inventory level is acceptable to cover potential gas curtailments in the 1992-93 winter season.

DRA, however, expresses concerns over the excess inventory level being carried forward into next year's ECAC period, and anticipates an excess inventory problem if gas curtailments do not occur in the winter of 1992-93. DRA therefore recommends that PG&E perform a study on economic alternatives to reduce its excess inventory.

10.8.1 Discussion

Noting that there is no dispute over the forecasted volume of inventory, we adopt as reasonable PG&E's forecasted LSFO volume of 8.06 million average Bbls and distillate volume of 0.128 million average Bbls. Carrying costs shall be allowed based upon a weighted average oil price of $17.81/Bbl and a bankers' acceptance rate of 5.11%. Since it does not affect parties' ultimate forecasts, it is not necessary to resolve the dispute over the appropriate resupply period. We acknowlege DRA's concerns, however, over the need to reduce inventory levels in a cost-effective manner. We adopt DRA's recommendations requiring PG&E to conduct an economic study on alternatives to reduce its inventory, and direct PG&E to submit such study in its 1993 ECAC filing.

10.9 PG&E Sales to Irrigation Districts

CCC includes in its forecast IER an assumed sale by PG&E of electricity to the Modesto and Turlock Irrigation Districts (MID and TID) in the amount of 263.7 GWh and 84.4 GWh, respectively. PG&E disputes this assumption, and contends that no sales to MID or TID are expected to occur during 1993.

10.9.1 Discussion

We reject CCC's forecast of sales to MID and TID. It is true that MID and TID are expected to have coordination agreements in place for purchase of reserve capacity from PG&E during 1993. CCC infers that a sale of reserve capacity entails a sale of associated energy. Yet, there are no provisions in the coordination agreements which require that associated energy be taken. MID and TID would take only energy from PG&E if less expensive energy purchases were unavailable. PG&E demonstrated that MID and TID have ample alternative sources available at cheaper rates. These alternative sources include access to Southwest power on the 500-kV AC transmission lines and additional capacity under the California-Oregon Transmission project. Thus, it is reasonable to conclude that MID/TID purchases from PG&E would not be needed.

10.10 SMUD Purchases

CCC contends that PG&E's forecast understates the amount of energy which SMUD will purchase from PG&E during 1993. CCC forecasts 1,458 GWh in PG&E sales to SMUD while PG&E forecasts only

1,070.5 GWh. CCC assumes SMUD's energy purchases for 1993 will be halfway between its monthly minimum energy purchase based on its capacity reservation for the most recent 12 months and the actual monthly energy purchase for the same period. CCC believes its forecast is justified given SMUD minimum energy purchase commitments from PG&E and the lack of any new firm resources for SMUD in 1993. PG&E disagrees, stating that CCC has overlooked energy sources available to SMUD through its own hydro capacity and transmission access rights to Southwest and Northwest power. When these sources are considered, PG&E contends that its forecast of SMUD sales is reasonable as a component of SMUD's overall purchases.

10.10.1 Discussion

We adopt PG&E's forecast of SMUD sales as reasonable. PG&E successfully rebutted CCC's criticisms of PG&E's forecast assumptions for SMUD sales. PG&E's forecast takes into account both capacity and related energy purchases which SMUD will require from PG&E. PG&E differs with CCC not because it ignores SMUD's purchase needs related to capacity, but because it forecasts reduced needs for both capacity and energy relative to recorded levels. CCC relies on recorded SMUD data which reflects dry-year conditions. Since our adopted forecast assumes normal precipitation, use of such recorded data would be inconsistent. Based upon average-year conditions, PG&E indicates up to 300 MW of additional capacity would be available to SMUD from its own hydro projects. SMUD also has 400 MW of bidirectional firm transmission access to the Southwest. When these additional sources of capacity and energy are considered, we conclude that PG&E's forecast of SMUD sales is sufficiently high, and we will adopt it.

11. ERAM and LIRA Revenue Requirements

PG&E's application includes a request to increase rates to recover shortfalls in its revenue requirements for ERAM and the LIRA program.

The ERAM balancing account was established by the Commission to eliminate fluctuations in base revenue recovery due to variations in sales. The balancing account accumulates the difference between the actual billed base rate revenue versus the authorized base revenue amount. Revenue adjustments to amortize the under- or overcollection in the ERAM balancing account are customarily adopted in ECAC proceedings.

The LIRA program was adopted by D.89-07-062 and D.89-09-044. The LIRA program provides for a 15% discount on residential rates for customers who qualify under a low-income criterion. PG&E is reimbursed for its costs of the LIRA program through a rate surcharge. The LIRA balancing account accumulates the difference between LIRA surcharge revenues collected and related program costs. D.89-09-044 ordered that LIRA-related rate revisions be reviewed and adopted through the ECAC proceeding.

PG&E's initial and updated requests for revenue increases for ERAM and LIRA are as follows:

Table 6

Summary of ERAM and LIRA Revenue Requirements
Proposed Versus Adopted

($000's)

	April 1 filing	June Update	Adopted
ERAM	$151,288	$242,649	$185,068
LIRA	$ 7,507	$ 7,561	$ 9,765

The amounts shown in PG&E's April 1 filing included an allowance to amortize the respective undercollections forecasted to exist as of December 31, 1992 in the ERAM and LIRA balancing accounts. The projected undercollections reflected recorded data through February 29, 1992. The increased ERAM revenue requirement in the June update reflects additional recorded data through March and April, 1992. Thus, PG&E's update forecast reflects a larger undercollection of $67 million as of December 31, 1992 and a reduction in revenues at present rates of $24 million. The LIRA revenue requirement remains virtually unchanged.

DRA was the only other party to sponsor testimony on ERAM/LIRA revenue requirements. DRA performed auditing procedures with respect to the ERAM balancing account for the record and forecast period. Based upon its audit and review, DRA proposes that $75,017 plus accrued interest be credited to the ERAM balancing account to reflect an adjustment to the allowance for doubtful accounts related to the Conservation Financing Adjustment (CFA). DRA proposes to reduce the allowance from 9.5% to 5.4% of outstanding conservation loans. The electric portion of this credit adjustment, $75,017, should be credited to the ERAM account in DRA's opinion. Thus, DRA proposes an ERAM revenue requirement of $242,571,000.

DRA recommends that PG&E's requested LIRA revenue requirement be granted while noting that the program's incurred administrative costs will be subject to subsequent reasonableness review in DRA's upcoming reasonableness report.

In Exhibit 72A, PG&E submitted updated balancing account balances through August 31, 1992. The updated balances yield a smaller ERAM undercollection which is expected to exist on December 31, 1992. Accordingly, our adopted ERAM and LIRA revenue requirements reflect the updated information presented in Exhibit 72A, and incorporate the CFA adjustment proposed by DRA of approximately $75,000 plus interest.

12. Customer Energy Efficiency

In accordance with D.90-08-068, PG&E is authorized to seek recovery of shareholder incentive payments earned for its CEE programs through the ECAC procedure. In this application, PG&E requests: (1) approval of the gas and electric deparment shareholder incentives earned during 1991; (2) recovery in 1993 of 1/3 of those incentives; and (3) the interest estimated to accrue in the CEE gas and electric balancing accounts through December 31, 1992.

PG&E initially claimed $47,391,000 in earned CEE incentives covering the 1991 calendar year. Incentive payments authorized for recovery are normally amortized over a three-year period.

CEE incentives are applicable to either "resource programs" or "cost-plus programs." Resource programs are intended to produce net avoided-cost resource savings. PG&E may earn incentive payments equal to 15% of the estimated lifecycle energy savings of installed measures, less costs of customer rebates and administration. Cost-plus programs, by contrast, involve customer information services regarding CEE. Cost-plus programs qualify for an incentive equal to 5% of program costs.

DRA was the only party to offer testimony on CEE issues. In its intitial testimony, DRA proposed a disallowance of $11 million, resulting in a recommended 1991 earned shareholder incentive payment claim of $35,619,000. DRA's disallowance was due to two factors:

a. Dispute over how to calculate shareholder incentive caps applicable to commercial, industrial, and agricultural (CIA) program sectors.

b. Imposition of a $5 million disallowance for lack of documentation and quality control on PG&E's customized rebate applications.

DRA and PG&E subsequently entered into a Joint Recommendation which resolved all disputes between the parties relating to CEE issues in this proceeding. The Joint Recommendation was uncontested. The Joint Recommendation proposes that PG&E shareholder incentive payments of $45.6 million be recovered from ratepayers over three years. This represents a $1.8 million reduction from the level initially requested by PG&E. DRA agrees to waive the issue regarding how to apply the earnings cap in computing 1991 CIA incentive payments for this proceeding only. DRA reserves the right to raise this issue in the 1993 ECAC proceeding with respect to 1992 CIA incentive payments. The Joint Recommendation further proposes various documentation, quality control and reporting measures to be implemented within 60 days of the date of the settlement. The specific reporting requirements are outlined in the Joint Recommendation which is attached as Appendix F of this decision.

12.1 Discussion

We conclude that the Joint Recommendation represents a fair resolution of the issues initially in dispute between DRA and PG&E. The resolution reached involved compromises and concessions on both sides. Although DRA conceded a major portion of the disallowance it originally proposed, PG&E, in return, agreed to a number of reporting and documentation measures which were important to DRA's overall concerns as raised in its report. Thus, in evaluating the merits of the Joint Recommendation, we consider it to fairly resolve the parties' underlying disputes.

Part 4 of the Joint Recommendation requires PG&E to work with DRA to establish improved documentation and quality control standards for New Construction and CIA customized rebate programs. On September 25, 1992, PG&E and DRA jointly submitted a report to the assigned ALJ entitled "PG&E's Report on Compliance with the Joint Recommendation." This report documents parties efforts to date to comply with the Joint Recommendation. PG&E is directed to follow through on implementing the standards and procedures set forth in the September 25, 1992 report in conformance with the Joint Recommendation.

As to parties' dispute over how to apply the earnings cap to CIA incentive payments, each party presented conflicting interpretations of whether to apply the cap separately to each program or in total to all programs. Accordingly, we will not render a conclusion as to the merits of arguments on this issue.

Rather, we believe the Joint Recommendation's proposal not to litigate this issue in exchange for other concessions to be reasonable. There is uncertainty as to which alternative interpretation we would adopt if this issue were to be fully litigated.

Based upon the Joint Recommenation, we adopt 1991 earned shareholder incentive payments of $36.46 million for the electric department and $9.131 million for the gas department. The CEE revenue requirement provides for recovery during 1993 of 1/3 of these amounts along with amortization of 1990 and 1991 incentive payments previously authorized. We accordingly adopt a CEE revenue requirement increase of $13,556,000 for the Electric Department and $3,414,000 for the Gas Department effective January 1, 1993, as derived in Appendix A.

12.2 1990 Customized Rebate Program

In D.91-12-015, Ordering Paragraph 7, we directed CACD to conduct an audit of PG&E's Customized Rebate Program to determine the reasonableness of rebate levels and incentive payments covering the year 1990. We made PG&E's 1990 incentive payments subject to refund pending the results of this audit. CACD determined that the most effective approach was to hire a panel of technical experts to review an audit conducted by PG&E. Although we set a deadline of June 30, 1992 for submission of the audit report, the report was not completed by then due to unavoidable delays. Accordingly, we shall hold over the pending issue of the 1990 Customized Rebate Incentive Program payments until next year's ECAC proceeding.

Findings of Fact

1. PG&E filed this application on April 1, 1992, requesting an annualized increase of $190.6 million effective January 1, 1993.

2. PG&E also proposed to update the price factors used to determine payments to variably priced qualifying facilities.

3. All active parties agreed on a number of resource assumptions and modeling conventions attached as Appendices D and E.

4. DRA entered into an agreement with the active QF intervenors to sponsor a Joint Recommendation for an IER of 9,478 BTU/kWh, while PG&E opposed the Joint Recommendation on the IER.

5. The Joint IER Recommendation purported to offer an IER within a range of reasonable outcomes, but did not embody any particular resource assumptions that all parties stipulated to.

6. An IER of 9,156 BTU/kWh is consistent with the application of our adopted methodology and assumed resource assumptions and modeling conventions.

7. PG&E presented a study by Decision Focus Inc. which tested the correlation between generation and O&M costs and which computed an O&M adder for operating units of -0.27 mills/kWh.

8. The DFI study constructed a series of linear regression models to test the relationship of O&M costs with various fossil-power plant characteristics.

9. The DFI study derived variables by grouping together generating units with similar characteristics and then performing linear regression measurements using annual time intervals.

10. PG&E failed to prove that the grouping of data used in the DFI model regressed on an annual basis realistically models the relationship between individual fossil units' generation and the O&M costs which may relate thereto over time.

11. PG&E failed to justify the inclusion in its DFI model of the anomalous results of its two plants treated as single-unit variables which resulted in large "negative" savings and which alone result in a 108% swing in the value computed by the model.

12. DRA's independent check of the DFI model incorporated similar conceptual premises concerning grouping of data and limiting measurement periods to one year.

13. In its computation of an O&M adder, CSC failed to show that the EPRI TAG data results in a realistic allocation between fixed and variable costs for PG&E.

14. The CCC computed an O&M adder following the methodology adopted in D.89-09-093.

15. No party to this proceeding offered a methodology for computing the O&M adder which represented a significant improvement over the method adopted in D.89-09-093.

16. An O&M adder of 0.58 mills/kWh for operating units results from use of the method adopted in D.89-09-093 applied to CFM-9 data as computed by DRA.

17. An O&M adder of 0.58 mills/kWh for operating units is a reasonable representation of avoided variable O&M cost savings for use in this proceeding, given the range of values computed by parties on various bases and given the lack of a superior alternative.

18. Parties' differences in avoided cost savings calculated for retired and cold standby units are attributable to the different periods of recorded data used by each.

19. Avoided costs savings for retired and standby units require a comparison of the difference between costs of the units with versus without QFs available as a resource.

20. A measurement period of 1985-91 is reasonable for determining an O&M adder for cold standby units since it begins with a period when the units were in operation and ends with the most recent recorded period.

21. An O&M adder of 0.32 mills/kWhr for cold standby units results from the use of a 1985-91 measurement period.

22. PG&E's three units at Avon, Martinez, and Oleum would have likely been retired even absent QF generation considering the advanced age of the units relative to comparable statistics of useful plant lives.

23. An O&M Adder of 0.46 mills/kWhr for retired units results from use of a 1987-91 measurement period.

24. A measurement period of 1987-91 is reasonable for determining an O&M adder for PG&E's retired units since it reflects a gradual decline in avoided cost savings which become less apparent as the age of the units since retirement increases.

25. There is uncertainty as to whether PG&E's capacity needs would fall below target levels if the equivalent capacity of the reitred units was not satisfied by QFs.

26. An overall O&M adder of 1.36 mills/kWh results from adoption of 0.58 mills/kWh for operating units, 0.32 mills/kWh for standby units, and 0.46 mills/kWh for retired units.

27. An Energy Reliability Index of 1.0 results from application of our adopted methodology and assumed resource assumptions.

28. A target spinning reserve of 7% for all subperiods is a reasonable modeling convention.

29. PG&E and DRA entered into a Joint Recommendation resolving their disputes concerning natural gas resource assumptions.

30. No party presented evidence on natural gas resource assumptions which successfully refuted the PG&E/DRA Joint Recommendation.

31. PG&E's forecast of generation from the Yuba County Water Agency offers a reliable estimate and incorporates Yuba County water diversion forecasts.

32. PG&E's forecast of hydroelectric self-generation properly recognizes the carryover effects of prior years' drought and results in a reasonable estimate.

33. PG&E's forecast of the availabilty of purchased power from the Pacific Northwest is reasonable given unused capacity entitlements of Southern California Edison (SCE) and PG&E's short-term agreements with Northwest suppliers.

34. The short-run avoided cost of gas (SRAC) reflected in QF payments is properly based on updated utility electric generation (UEG) throughput estimates in PG&E's annual ECAC proceedings.

35. The Modesto and Turlock Irrigation Districts are not expected to purchase energy from PG&E during 1993 given the availability of cheaper alternatives.

36. PG&E initially requested three-year recovery of $47,391,000 of incentive payments claimed under its Customer Energy Efficiency Programs (CEE) for recorded calendar year 1991 performance.

37. DRA initially disputed PG&E's CEE incentive payment claims, and proposed that incentive payments for 1991 performance be limited to $35,619,000, due to differences over interpretation of incentive caps and over the adequacy of customized rebate documentation.

38. PG&E and DRA subsequently entered into a joint recommendation which resolved the dispute over 1991 incentive payment recovery and over documentation and quality control measures.

39. The CEE Joint Recommendation proposed recovery of $45.6 million over three years for 1991 CEE earned incentives and proposed documentation and quality control measures are presented in Appendix F herein.

40. The Commission Advisory and Compliance Division has not yet submitted its report on the Audit of PG&E's 1990 Customized Rebate Program as directed in D. 91-12-015, Ordering Paragraph 7.

Conclusions of Law

1. The resource assumptions which were not contested by any party, set forth in Appendix E, should be adopted.

2. PG&E should adjust its adopted revenue requirements for ECAC/AER/ERAM/LIRA/CEE as set forth in Appendix A based upon a forecast period January 1, 1993 to December 31, 1993, and should

incorporate these adopted adjustments into its total rate changes to become effective January 1, 1993.

3. The price factors for variably priced QFs which should be adopted for the January 1-December 31, 1993 forecast period for PG&E are set forth in Appendix C for the IER, the time-differentiated IERs, the O&M adders, and the DIER.

4. An ERI value of 1.0 should be adopted in conformance with the adopted methodology for pricing QF capacity payments.

5. The Joint Recommendation relating to the IER does not reasonably resolve the disputed resource assumptions at issue in this proceeding.

6. The proper methodology for determining the O&M adder should be further refined in subsequent ECAC proceedings and addressed generically in upcoming phases of the Biennial Resource Update Proceeding.

7. The DRA/PG&E Joint Recommendation on gas price assumptions provides a reasonable resolution of the underlying disputes relating to the price for the core portfolio, UEG self-procured gas, the mix of core-subscription gas, and treatment of the Transwestern demand charge.

8. A target spinning reserve criterion of 7% is reasonable as a modeling convention for all subperiods covering the 1993 forecast year.

9. PG&E's resource assumptions not specifically noted above are reasonable and should be adopted for the 1993 forecast period.

10. The DRA/PG&E Joint Recommendation on Customer Energy Efficiency issues reasonably resolves the underlying issues in dispute between DRA and PG&E and should be adopted.

ORDER

IT IS ORDERED that:

1. Effective January 1, 1993, Pacific Gas and Electric (PG&E) is authorized and directed to record amounts in its respective balancing accounts covered by this order consistent with the following adjustments in adopted revenue requirements: A decrease in the Energy Cost Adjustment Clause (ECAC) of $167,897,000; a decrease in the Annual Energy Rate of $9,626,000; an increase in the Electric Revenue Adjustment Mechanism of $185,068,000; an increase in the Low Income Ratepayer Assistance Program of $9,765,000; an increase in the Customer Energy Efficiency Program of $13,556,000 for the Electric Department and $3,414,000 for the Gas Department.

2. The rate adjustments related to the revenue requirements changes adopted in Ordering Paragraph 1 shall be included in the revenue allocation phase of PG&E's 1993 General Rate Case and consolidated with other pending rate adjustments with an effective rate change date of January 1, 1993.

3. The incremental energy rate (IER), time-differentiated IERs, the Diablo Canyon IER, the Operation and Maintenance Adder, and the energy reliability index set forth in Appendix C are adopted for the ECAC forecast period beginning January 1, 1993.

4. PG&E shall implement the documentation and quality-control measures as summarized in the Division of Ratepayer Advocates/PG&E Joint Recommendation on Customer Energy Efficiency issues (Exh. 49) and incorporated into Appendix F.

5. In its next ECAC proceeding, PG&E and other interested parties shall comply with our directives herein concerning refinements in the measure of the O&M adder. Specifically, this should include a showing as to the appropriate measure of variable O&M costs in PG&E's most currently available CMF filing. Parties' showings should also evaluate other relevant benchmarks of PG&E's

avoided O&M costs, such as the basis for the value used by the California Power Pool.

6. PG&E shall complete and submit in its next ECAC proceeding an economic study on alternatives to reduce its fuel oil inventory level, as proposed by DRA.

This order is effective today.

Dated November 23, 1992, at San Francisco, California.

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

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

NEAL J. SHULMAN, Executive Director

APPENDIX A
TABLE 1
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
SUMMARY OF REVENUE CHANGES
Effective January 1, 1993

LINE	REVENUE ELEMENT	(a) PRESENT RATE REVENUE (1) $(000)	(b) REVENUE CHANGE $(000)	(c) ADOPTED REVENUE REQUIREMENT $(000)	(d) AVERAGE RATE(2) ($/Kwh)
1	ENERGY COST ADJUSTMENT CLAUSE (ECAC)				
2	ECAC Costs	$3,867,171	($192,081)	$3,495,091	
3	Estimated ECAA Balance on December 31, 1992		($6,554)	($6,554)	
4	OC Safety Committee Fee	$718		$718	
5	Less: Designated Sales Transactions to Resale Customers	($41,479)		($41,479)	
6	Subtotal	$3,844,877	($197,203)	$3,447,774	
7	Franchise Fees & Uncollectible Accounts Expense @ .85%		$29,306	$29,306	
8	TOTAL ECAC REVENUE REQUIREMENT	$3,844,877	($167,897)	$3,477,080	$0.04902
9	AER REVENUE REQUIREMENT				
10	AER Costs	$207,766	($11,261)	$196,505	
11	Less: Designated Sales Transactions to Resale Customers	($4,102)		($4,102)	
12	Subtotal	$203,664	($11,261)	$192,403	
13	Franchise Fees & Uncollectible Accounts Expense @ .85%		$1,635	$1,635	
14	TOTAL AER REVENUE REQUIREMENT	$203,664	($9,626)	$194,038	$0.00274
15	ERAM REVENUE REQUIREMENT				
16	Base Revenue Amount	$3,834,059	$32,972	$3,867,031	
17	Estimated ERAM Balance on December 31, 1992		$152,096	$152,096	
18	Less: LIRA Shortfall	($29,118)		($29,118)	
19	Less: Designated Sales Transactions to Resale Customers	($54,417)		($54,417)	
20	TOTAL ERAM REVENUE REQUIREMENT	$3,350,524	$185,068	$3,735,592	$0.05267
21	LIRA REVENUE REQUIREMENT				
22	LIRA Shortfall	$18,515	$10,603	$29,118	
23	Estimated LIRA Balance on December 31, 1992		($838)	($838)	
24	Administrative Costs			$0	
25	TOTAL LIRA REVENUE REQUIREMENT	$18,515	$9,765	$28,280	$0.00040
26	CEE REVENUE REQUIREMENT				
27	1/3 of 1990 and 1991 Shareholder Incentive	$4,256	$11,965	$16,221	
28	Estimated CEEIA Interest Balance on December 31, 1992		$1,441	$1,441	
29	Franchise Fees & Uncollectible Accounts Expense @ .85%		$150	$150	
30	TOTAL CEE REVENUE REQUIREMENT	$4,256	$13,556	$17,812	$0.00025
31	CONSERVATION FINANCING ADJUSTMENT (CFA)	$1,444		$1,444	
32	CALIFORNIA PUBLIC UTILITIES COMMISSION FEES	$8,552		$8,552	
33	OTHER REVENUES	$43,334		$43,334	
34	TOTAL ELECTRIC DEPARTMENT REVENUE REQUIREMENT	$7,475,266	$30,867	$7,506,133	$0.10583
35	PERCENTAGE INCREASE		0.41%		

(1) Based on rates effective 8/1/92.
(2) Average rates based on the forecasted retail sales of 70,926 GWh, A.92-04-001 ALJ Ruling, dated August 6,1992.

APPENDIX A
TABLE 2
PACIFIC GAS AND ELECTRIC COMPANY
GAS DEPARTMENT
SUMMARY OF REVENUE CHANGES
Effective January 1, 1993

LINE	REVENUE ELEMENT	(a) PRESENT RATE REVENUE (1) $(000)	(b) REVENUE CHANGE $(000)	(c) ADOPTED REVENUE REQUIREMENT $(000)
1	GCEE REVENUE REQUIREMENT			
2	1/3 of 1990 and 1991 Shareholder Incentive	$901	$3,036	$3,937
3	Estimated CEEIA Interest Balance on December 31, 1992		$340	$340
4	Franchise Fees & Uncollectible Accounts Expense @ .899%		$30	$38
5	TOTAL GAS DEPARTMENT GCEE REVENUE REQUIREMENT	$901	$3,414	$4,315

(1) Based on rates effective 6/1/92.

(END OF APPENDIX A)

A 92-04-001 ALJ/TRP
CACD/CC

APPENDIX B
TABLE 1
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED ENERGY COSTS

Forecast Period January 1, 1993 through December 31, 1993

Line No.		(a) Purchases/ Generation MDth or GWh	(b) Percent	(c) Price(1) $/Dth or KWh	(d) Total Costs $(000)	(e) Total CPUC Costs(2) $(000)	(f) ECAC Costs(3) $(000)	(g) AER Costs(4) $(000)
1	Fossil Fuel							
2	Commodity	179,748	73.14%	$1.81032	$325,402	$324,165	$294,991	$29,175
3	Transportation				$164,197	$163,573	$148,851	$14,722
4	Subtotal Gas	179,748	73.14%	$2.72381	$489,599	$487,739	$443,842	$43,896
5	Residual Oil	3,150	1.28%	$2.99937	$9,448	$9,412	$8,565	$847
6	Distillate Oil	36	0.01%	$4.52778	$163	$162	$148	$15
7	Subtotal Fossil Fuel	182,934	74.44%	$2.72891	499,210	$497,313	$452,555	$44,758
8	Geothermal Steam	6,296	2.56%	$0.01327	$83,543	$83,226	$75,735	$7,490
9	Purchased Power							
10	Irrigation Districts	4,884	1.99%	$0.00113	$5,501	$5,480	$4,987	$493
11	CVP	(2,710)	-1.10%	$0.01755	($47,546)	($47,565)	($43,102)	($4,263)
12	Variably Priced OF Energy	10,459	4.26%	$0.02626	$274,638	$273,594	$248,971	$24,624
13	Other OF Including Capacity Payments	10,066	4.10%	$0.12728	$1,263,751	$1,278,873	$1,163,774	$115,099
14	Northwest	6,260	2.55%	$0.01275	$79,821	$79,518	$72,361	$7,157
15	Southwest(Including Sales)	124	0.05%	$0.01553	$1,928	$1,921	$1,748	$173
16	CDWR	0	0.00%		$0	$0	$0	$0
17	Other	6	0.00%	$0.05783	$347	$346	$315	$31
18	Subtotal Purchased Power	29,110	11.85%	$0.05491	$1,598,441	$1,592,366	$1,449,053	$143,313
19	Water for Power	12,016	4.89%	$0.00008	$909	$906	$824	$81
20	Oil Inventory Carrying Cost				$7,452	$7,424	$6,756	$668
21	Variable Wheeling				$2,163	$2,155	$1,961	$194
22	Losses(Gains) on Fuel Oil Sales				$0	$0	$0	$0
23	Subtotal Energy Expense	230,355		$0.00951	$2,191,718	$2,183,389	$1,986,884	$196,505
24	DC Settlement Revenues	15,394	6.26%	$0.09844	$1,704,146	$1,697,670	$1,697,670	
25	Excess Oil Inventory Carrying Cost				($1)	($1)	($1)	
26	Less: DC Basic Revenue Requirement				($189,463)	($189,463)	($189,453)	
27	TOTALS	245,750	100.00%	$0.01508	$3,706,400	$3,691,596	$3,495,091	$196,505

(1) Average Rate for DC Settlement Revenues excludes the basic revenue requirement and FF&U expenses and includes the Safety Committee Fee.
(2) Jurisdictionalized at 99.62%
(3) ECAC Cost are 91% of CPUC Total Cost
(4) AER Costs are 9% of CPUC Total Cost

(END OF APPENDIX B)

APPENDIX C

PACIFIC GAS AND ELECTRIC COMPANY

TOTAL EQUIVALENT QFIER CALCULATION

Line No.		
1	Average Conv.Thermal Cost - $/MMbtu	2.706
2	Total QF-In Cost - Thousand $	$1,390,201
3	Total QF-Out Cost - Thousand $	$1,649,353
4	Change in Total Cost - Thousand $	$259,153
5	Variable QF's - Gwh	10459.3
6	Marginal Energy Cost - mills/kwh (excl. O & M Adder)	24.78
7	QFIER - Btu/kwh	9,156
8	Variable O & M Adder - mills/kwh	1.36
9	Geothermal adder - mills/kwh (1)	0.578
10	Cash Working Capital - mills/kwh (2)	0.0948
11	Total Marginal Energy Cost - mills/kwh	26.81
12	Equivalent QFIER - Btu/kwh	9,908

(1) Geothermal Adder from Advice Filing No. 1387-E-A dated March 13, 1992.
(2) Cash Working Capital as adopted in Decision No. 89-12-057

APPENDIX C

PACIFIC GAS AND ELECTRIC COMPANY

DIABLO CANYON
INCREMENTAL ENERGY RATE (DIER)

DIER = 7,040 BTU/kwh
based on the total average cost of fossil fuel of $2.7060 million Btu
excluding customer charge

The DIER is developed using the fossil fuel assumptions consistent with the ECAC period January 1993 - December 1993

Average value of Diablo Canyon energy =
[($production cost DC OCF - 8.9 percent) less
($production cost DC OCF + 8.9 percent)] divided by
kwh change in DC generation for + 8.9 percent OCF

DC OCF = Diablo Canyon operating capacity factor

APPENDIX C

PACIFIC GAS AND ELECTRIC COMPANY

Derivation of Time-Differentiated QF Incremental Energy Rates
(QFIERS)

Line No.		Marginal Energy Costs ($/mwh)	MEC Factor	Annual Avg QFIER (Btu/Kwh)	QFIER By Time Period (Btu/kwh)	Hours In Period (Hrs.)
	Summer:					
1	Peak	$14.82	0.995		9,113	789
2	Partial-Peak	$14.15	0.950		8,701	920
3	Off-Peak	$13.19	0.886		8,111	1,971
4	Super Off-Peak	$12.65	0.850		7,779	736
5	Seasonal Avg.	$13.59	0.913		8,357	
6	Seasonal Total					4,416
	Winter:					
7	Partial-Peak	$16.86	1.132		10,368	1,681
8	Off-Peak	$15.93	1.070		9,796	1,939
9	Super Off-Peak	$15.42	1.036		9,482	724
10	Seasonal Avg.	$16.21	1.089		9,968	
11	Seasonal Total				4,344	
12	Annual Avg.	$14.89	1.000	9,156	9,156	
13	Annual Total					8,760

Notes:

(a) Summer includes May through October 1993.
Winter includes January through April 1993, November, December 1993.

(b) QFIER based on overall average conventional thermal rate of $2.706/MMBtu.
Rate calculations include commodity charge, demand charge and volumetric transportation charges.

(c) The marginal energy costs by time period are based on the Promod simulation run that includes QF's in the resource plan. Steam generation valued at gas dispatch price.

(d) The marginal energy cost factor is the marginal energy cost for that time period divided by the annual average marginal energy cost.

(e) The QFIER for a time period is equal to the marginal energy cost factor for that time period multiplied by the annual average QFIER.

(f) The number of hours in the various time periods will differ slightly from those approved in CPUC Decision 86-12-091 because PROMOD does not reflect weekdays, holidays, and the load forecast assumes that the calendar year always begins on a Sunday.

(END OF APPENDIX C)

APPENDIX D

PACIFIC GAS AND ELECTRIC COMPANY
1992 ECAC/AER/ERAM/LIRA/CEE CASE

SUMMARY OF UNCONTESTED MODELING CONVENTIONS
BASED ON JUNE UPDATE

1. Dispatchers Risk Aversion feature (PROMOD)
   100% of weekends with a MW adjustment, zero weeknights and weekdays.

2. Minimum Thermal Generation
   Use in PROMOD the minimum fuel burn feature to assure at least 505 GWh / month generation from the conventional thermal generating plants. In PROSYM, units are combined into stations, with a station minimum specified in order to produce the minimum generation each hour.

3. Must Run Units
   Combination of designating units as must run or use of PROMOD's area protection feature. At least seven units are maintained on line, with additional units during the summer peak period.

4. Minimum Load Conditions
   Backdown order according to economic and contractual rules as shown on pages 3-24 and 3-25 of PG&E's Forecast Report. In PROMOD, FRPL records are used to mimic the order.

5. Minimum Downtime
   72 hours for 750 MW and 330 MW class units. 48 hours for the smaller classes of units.

(END OF APPENDIX D)

PACIFIC GAS AND ELECTRIC COMPANY
1992 ECAC/AER/ERAM/LIRA/CEE CASE

SUMMARY OF UNCONTESTED RESOURCE ASSUMPTIONS BASED ON JUNE UPDATE

1. Area Load Forecast - June update forecast
   ECAC test year Jan, 1993 - Dec. 1993 — 102,252.0 GWh

2. Hydroelectric Generation - May snow survey

a.	USBR (WAPA) Hydro	3,179.8 GWh
b.	NCPA	287.4 GWh
c.	SMUD	1,711.4 GWh
d.	CCSF	1,932.8 GWh
e.	MID/TID	525.0 GWh

3. Helms Pumped Storage
   Three units with a combined generating capacity of 1212 MW and pumping capacity of 966 MW. Inflows and water management operations represented in both PROMOD and PROSYM.

4. Northwest firm purchases by PG&E from PP&L - 250.3 GWh
   Firm peaking purchase from PP&L based on contract, 80 MW/ 100 MW capacity seasonal.

5. Northwest purchases by CSC - 97.7 GWh
   On-peak firm takes over 25 MW share of DC line capacity.

6. Southwest Miscellaneous purchases by PG&E - 192.0 GWh, priced at 16.6 mills/kwh
   Fixed off-peak purchases based on historical quantities.

7. California Power Pool Sales - 72.0 GWh
   Fixed unscheduled energy sale transaction based on historical quantities.

8. California Power Pool Purchases
   Economic energy purchases assumed at an incremental heat rate of 11,000 Btu/kwh.

9. Sierra Pacific Purchases - 3.6 GWh at a cost of $307,000.
   Around the clock deliveries to serve PG&E customers in the Echo Summit Area

10. NCPA Resources
    a. NCPA Geothermal - 1175.8 GWh
       Unit with cycling operations - 238 MW on-peak and 90 MW off-peak.
    b. NCPA COG - 36.2 GWh
       Fixed firm unscheduled transaction based on historical quantities.
    c. NCPA CT - 10.0 GWh
       Fixed non-firm peaking transaction based on historical quantities.

PACIFIC GAS AND ELECTRIC COMPANY
1992 ECAC/AER/ERAM/LIRA/CEE CASE

SUMMARY OF UNCONTESTED RESOURCE ASSUMPTIONS
BASED ON JUNE UPDATE

11. QF Generation - 20,544.5 GWh, including hydro QFs.
Includes 10,459.3 GWh of variably priced QF generation.
a. Firm capacity contracts modeled at their firm capacity ratings. Remaining QFs reflect average megawatts.
b. Gilroy is scheduled to be curtailed in agreement with provisions of the fourth amendment of the contract dated June 6, 1991. 100% variable.
c. BAF is scheduled to be curtailed in agreement with provisions of the second amendment to the contract dated June 6, 1991. 20% fixed and 80% variable.
d. No minimum load based curtailments (600 hour or SO4 curtailment option B) are forecasted to occur. However, non-standard curtailment provisions not tied to minimum load conditions are forecast.
e. Hydro capacity factor for 1992 is adjusted to reflect May hydro conditions.

12. SMUD Resources
a. NW for SMUD
Assumes utilization of 200 MW AC line entitlement, plus their share of the COT project in 1993.
b. SMUD PV, SMUD CT - 6.3 GWh
Fixed peaking transaction based on historical quantities.
c. SMUD Geothermal - 565.1 GWh
Unit availability based on two year average historical outage statistics.
d. SCE sales to SMUD
SMUD elected 300 MW contract capacity. Takes are based on contract, availability of other resources and SMUD's loads. SMUD's deficit energy supplies by 60-40 split between PG&E and SCE. Modeled as a hydro unit with 25% minimum take and scheduled 100 MW weekday takes in most months except summer when SMUD needs more capacity.

13. CCPA Geothermal - 436.1 GWh
One 62 MW unit available based on actual operations. Energy split 50% to SMUD, 40% to MID/TID, and 10% to CSC based on ownership.

14. MID/TID CT - 9.0 GWh
Fixed peaking transaction based on historical quantities.

15. MUNI Imports
a. 100 MW firm peaking contract between BPA and MSR with 438 GWh of energy takes during the delivery year.
b. MID/TID/NCPA/CSC purchases in amounts needed to balance their loads and available resources (both owned and operated by them or purchased in the area). One-half of the purchases scheduled around the clock, with the remaining scheduled during the daytime.

PACIFIC GAS AND ELECTRIC COMPANY
1992 ECAC/AER/ERAM/LIRA/CEE CASE

SUMMARY OF UNCONTESTED RESOURCE ASSUMPTIONS
BASED ON JUNE UPDATE

16. Northwest for WAPA - 4176.2 GWh
Forecast based on WAPA's estimate of their firm and economy imports from the Northwest. Assumes full utilization of both their 400 MW AC entitlement and their share of the COT project in 1993. Resource may be backed down during minimum loads.

17. Northwest for PG&E
a. 6.6% forced outage rate on the DC line to account for forced outages, and AC loop flow causing 10% line limitations from April through June. 50% of WAPA's unused NW line entitlement available to PG&E.
b. Layoffs and AC/DC line capacity swaps between participants in the COT project and PG&E reflected in 1993.
c. Transmission losses are 6% on the AC line and 7.5 % on the DC line.
d. 150 MW long-term contract with WWP for firm capacity with 217 GWh of energy June through September, with a return provision from November through February. Exchange agreement has no monetary component.
e. 300 MW long-term contract with PUGET for firm capacity with 413 GWh of energy June through September, with a return provision from November through February. Exchange agreement has no monetary component.

18. Geysers Units
Unit availability based on three years average historical forced outage statistics. Steam supply limitations modeled as capacity derations. Forecast period capacity factor 58.8%.

19. Conventional Thermal Plants
Unit availability based on five years' average historical forced outage statistics. Heat rate performance factor of 2.8%.

20. Combustion Turbine Units
Unit availability based on five year average historical forced outage statistics.

21. Unserved Energy
Emergency purchases are made fro the California Power Pool and priced at 115 percent of the dispatch cost of gas and a heat rate of 11,000 Btu/kwh.

(END OF APPENDIX E)

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CUSTOMER ENERGY EFFICIENCY PROVISIONS

PG&E shall comply with the provisions summarized below relating to its Customer Energy Efficiency Programs as excerpted from the DRA/PG&E Joint Recommendation (Exh. 49). PG&E shall further implement the standards and procedures set forth in the September 25, 1992 report entitled: "PG&E's Report on Compliance with the ECAC Joint Recommendation."

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1. The parties agree that PG&E's shareholder earnings for its 1991 Customer Energy Efficiency programs be $45.6 million, or $1.8 million less than PG&E requested. This $45.6 million represents a reasonable compromise of the amount requested by PG&E and that recommended in DRA's testimony, in light of the changes recommended below. The parties also agree that the first one-third of this sum, or $15.2 million be recovered in rates over the 12-month period beginning January 1, 1993, and the remaining two-thirds be recovered in 1994 and 1995, in accordance with the ratemaking procedures described in Application 90-04-041, and adopted in Decision Nos. 90-08-068 and 90-12-071.

2. Within 60 days of this settlement, PG&E will file an amendment to its Annual DSM Report filed with the Commission on March 31, 1992, to revise the energy savings estimates for its 1991 New Construction and Commercial-Industrial-Agricultural (CIA) customized rebate programs. The energy savings adjustment will be based on the data supporting the findings contained in the audit report prepared by Arthur D. Little, Inc., dated March 31, 1992.

3. The DRA agrees to waive the issue regarding whether PG&E's 1991 CIA Energy Management Incentive program(s) should be treated as a single program or as three individual programs for purposes of calculating the shareholder earnings cap(s). The DRA reserves the right to address this issue, regarding PG&E's earnings claim from 1992 CIA program(s), in the 1993 ECAC proceeding.

4. PG&E agrees to establish documentation and quality control as a priority for New Construction and CIA customized rebate programs. PG&E agrees to implement the following procedures:

   (A) Documentation: PG&E will adopt the documentation requirements recommended in DRA's testimony for all CIA customized rebates paid after August 31, 1992; for the rebates paid from January 1, 1992 through August 31, 1992, PG&E will strengthen documentation to the extent practical. PG&E and DRA will work together to develop an implementable interpretation of these documentation requirements by August 15, 1992. PG&E will work with the DRA to develop documentation requirements for the New Construction customized rebate program by August 31, 1992.

   (B) Quality Control: PG&E will establish, within 60 days of the signing of this Joint Recommendation, an independent quality control function within PG&E, separate from

PG&E's marketing function, for all New Construction and CIA customized rebate applications, and incorporate specific quality control requirements into the review and acceptance of each customized rebate application. The independent quality control function shall be the ultimate arbiter within PG&E of the standards and completeness of the application. PG&E will work closely with DRA to develop and implement, within 60 days of the signing of this Joint Recommendation, quality control criteria, including, but not limited to, the following:

- Documentation of energy savings in customized rebate applications should be self-explanatory to an engineer, with the sources or derivations of all the data used in the calculations clearly explained.

- Energy savings calculations should be straight forward and computed correctly; data and methodology used should be consistent with generally acceptable engineering principles and practices.

- For all the CIA rebates of $1,000 or more, post-inspection shall be required. For smaller CIA rebates, at least 25 percent shall be post-inspected.

- For Residential New Construction, 25 percent of the units receiving rebates shall be post-inspected.

- For Commercial New Construction, all rebates of $5,000 or more shall be post-inspected.

- PG&E will include a summary of its quality control activities as a part of its 1992 and 1993 CEE shareholder earnings request in subsequent ECAC proceedings.

The above-mentioned quality control criteria will be applied to all New Construction and CIA customized applications paid after 60 days of the signing of this Joint Recommendation; for rebates paid in 1992, but prior to 60 days after the signing of this Joint Recommendation, PG&E will strengthen quality control to the extent practical.

General Terms and Conditions:

1. If the terms and conditions of this Recommendation are not fulfilled by PG&E within the established schedule, the parties agree that PG&E's 1991 CEE shareholder incentive amount adopted in this proceeding's decision will be readdressed in PG&E's 1993 ECAC proceeding, subject to a downward adjustment of $2 million in that proceeding.

2. This agreement embodies compromises of positions and interests of the parties hereto. No individual term of this agreement is assented to by any party except in consideration of other parties' assents to all other terms of this agreement. Thus, the agreement is indivisible, and each part is interdependent on all other parts. Any party may withdraw from this agreement if the Commission modifies, deletes from or adds to the disposition of PG&E's application stipulated herein.

3. PG&E shall implement the recommendation of Item 4 of this agreement to the fullest extent possible consistent with all subsequent Demand Side Management (DSM) rulings of the Commission. PG&E agrees to bring quickly to DRA's attention any changes that PG&E believes require modification of this agreement. DRA and PG&E shall agree to reasonable modifications necessary to continue the intent and purpose of these recommendations.

4. The foregoing provisions, including PG&E's application, contain the entire agreement of the parties hereto. The terms and conditions of this agreement may only be modified by writing subscribed to by all parties.

(END OF APPENDIX F)

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List of Appearances

Applicant: Carmen G. Gonzalez, Michelle Wilson, Harry W. Long, Jr., Robert B. McLennan, and Wright & Talisman, by Michael B. Day and Joseph Fryxell, Attorneys at Law, for Pacific Gas and Electric Company.

Interested Parties: Ater, Wynne, Hewitt, Dodson & Skerritt, by Michael P. Alcantar, Attorney at Law, for Cogenerators of Southern California; Barbara R. Barkovich, for Barkovich and Yap; Morrison & Foerster, by Jerry R. Bloom, and Lynn M. Haug, Attorneys at Law, for California Cogeneration Council; Jackson, Tufts, Cole & Black, by William H. Booth and Evelyn Elsesser, Attorneys at Law, for California Large Energy Consumers Association; Beth Bowman, by Betty McNab, and David B. Clark, Attorney at Law, and Lynn G. Van Wagene, for San Diego Gas & Electric Company; David R. Branchcomb, for Henwood Energy Services, Inc.; Thomas R. Brill, Attorney at Law, for Southern California Gas Company; Andrew Brown, for Barakat & Chamberlin; McCracken, Byers & Martin, by David J. Byers, Attorney at Law, for California City-County Street Light Association (CAL-SLA); Lisa Danyluk, for Transwestern Pipeline Company; Steven A. Geringer, Attorney at Law, for California Farm Bureau Federation; Grueneich, Ellison & Schneider, by Dian Grueneich, Attorney at Law, for Department of General Services; Graham & James, by Peter W. Hanschen and Melissa S. Waksman, Attorneys at Law, for Agricultural Energy Consumers Association; David R. Hinman, for Southern California Edison Company; Paul J. Kaufman, Attorney at Law, for Kern River Cogeneration; Carolyn Kehrein, for Procter & Gamble; Douglas K. Kerner, Attorney at Law, for Independent Energy Producers Association; Wayne Lepire and Randolph Wu, Attorneys at Law, for El Paso Natural Gas Company; D. B. MacNamara, Vice President, and Patrick J. Keeley, Attorney at Law, by Kathy L. Tarlton, for Canadian Petroleum Association; William Marcus, for JBS Energy; Joseph G. Meyer, for Joseph Meyer Associates; Steven Moss, for Spectrum Economics, Inc.; Patrick J. Power, Attorney at Law, for Sacramento Municipal Utility District; John D. Quinley, for Cogeneration Service Bureau; K. Justin Reidhead, Michel Peter Florio, and Robert Finkelstein, Attorneys at Law, for Toward Utility Rate Normalization (TURN); Donald G. Salow, for Association of California Water Agencies; Reed V. Schmidt, for Marin Street Light Joint Powers Authority; Donald W. Schoenbeck, for

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Regulatory & Cogeneration Services, Inc.; Downey, Brand, Seymour & Rohwer, by Philip A. Stohr and Ronald Liebert, for Industrial Users; Mark Younger, for MRW & Associates; Patrick Bittner, for California Energy Commission; Knox, Lemon & Brady, by Matthew Brady, for State of California; Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Norman Furuta, for Federal Executive Agencies; Karen Peterson, for Edson & Modisette; and Michael Boccadoro, for himself.

Division of Ratepayer Advocates: Camden Collins and Hallie Yacknin, Attorneys at Law.

Commission Advisory and Compliance Division: Cherrie Conner.

(END OF APPENDIX G)