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ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's own motion to implement the Biennial Resource Plan Update following the California Energy Commission's Seventh Electricity Report.	I.89-07-004 (Filed July 6, 1989)

(See Attachment 4 for appearances.)

I N D E X

INTERIM OPINION: PG&E'S INTERIM STANDARD OFFER 4 CURTAILMENT GAP; UPDATING FINAL STANDARD OFFER 4 CAPACITY FACTOR

I. Summary

In today's order, we address two standard offer contract issues that were deferred to this proceeding: (1) the appropriate treatment of curtailment adders under Pacific Gas and Electric Company's (PG&E's) interim Standard Offer 4 (ISO4), and (2) whether the capacity factor assumed for the final Standard Offer 4 (FSO4) deferrable resource should be updated and, if so, how.[1]

We adopt PG&E's "pay-as-you-go" proposal for calculating adders under Curtailment Option B, at the expiration of the ISO4 fixed price period. We determine that updating curtailment adders at the expiration of the fixed price period does not constitute a contract modification, and that PG&E's proposal is a reasonable method for updating those adders.

However, we decline to adopt capacity factor updating for FSO4. We determine that capacity factor updating is not necessary for maintaining ratepayer indifference, given the current structure of that offer. Moreover, we find the specific proposals of Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), and PG&E (collectively, respondents) to be administratively unworkable. At the same time, we reject

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1 In discussing the issues addressed in today's order, we refer to each of our standard offer contracts. To aid the unfamiliar reader, we've summarized the payment provisions of each offer in Attachment 1.

Attachment 5 explains each technical acronym or other abbreviation that appears in this decision, and also refers the reader to the section of the opinion where the abbreviation first appears.

recommendations to automatically fix the capacity factor over the contract term, based on generic data. Instead, we direct respondents to use model-derived capacity factors, based on the resource planning assumptions we adopt in this Biennial Resource Plan Update (BRPU) proceeding.

II. PG&E's ISO4 Curtailment Gap

In developing our standard offer contracts, we have included provisions to allow the utility to curtail, or pay reduced prices to qualifying facilities (QFs) during certain hours of the year.[2] During the compliance hearings in Application (A.) 82-04-44 et al., PG&E identified a gap in the curtailment provisions of its ISO4. The gap affects Curtailment Option B, which is unique to PG&E's offer.[3] In order to better understand the issues related to this curtailment gap, it is useful to review the history of curtailment provisions, as well as the basic concepts underlying their development.

A. Curtailment Options Under Our Standard Offers

Under our standard offers, curtailment options address, to varying degrees, three general types of operating situations: (1) periods of negative avoided costs, (2) hydro spill conditions, and (3) periods when QF energy can be replaced with cheaper sources (economic curtailment).

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2 Throughout this order, we use the term curtailment, and its derivatives (e.g., curtailable, non-curtailment) to refer <u>either</u> to (1) periods when the utility may refuse to purchase energy from QFs <u>or</u> (2) periods when the utility may offer reduced prices for energy (and the QF decides whether or not to curtail production).

3 See Decision (D.) 83-09-054 in A.82-04-44 et al., mimeo. pp. 36-38.

Negative avoided costs exist when, due to operational circumstances, purchases from QFs would result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself. For example, a baseload or large oil-fired intermediate load plant is shut down at night due to an excess of QF electricity but then cannot be restarted and brought up to its rated output for the next day's peak load. In this situation, the utility must start up a plant with very high operating costs (e.g., a gas turbine peaker) or purchase expensive emergency capacity to meet demand.[4]

Hydro spill conditions occur when system demand would require that a utility spill water over its own hydroelectric facilities in order to purchase from QFs. Economic curtailment conditions occur when avoided costs are positive, but the utility can replace QF energy with cheaper sources (e.g., economy energy).

Each of these curtailment conditions is treated differently under current contract provisions. Pursuant to D.82-01-103, D.82-04-071 and D.82-12-120, utilities can physically curtail a QF (i.e., refuse to purchase) only under negative avoided cost conditions. In D.82-04-071, we also allowed utilities to offer a lower "hydro savings" price during hydro spill conditions. However, for Standard Offers 1 and 2 (SO1 and SO2), the Commission did not permit a lower price to be established when economy energy is purchased or when avoided costs are positive. Anticipated economy energy purchases were to be averaged in the avoided cost applied for the entire period.[5] The Commission also declined to

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4 See D.83-09-054, mimeo. p. 38.

5 In contrast, utilities were directed to exclude from averaged prices the lower avoided costs that occur during hydro spill conditions. See D.82-04-071, mimeo. p. 6.

establish any limits on the number of hours when curtailment/hydro savings prices would be offered.[6]

During the development of our ISO4 and FSO4 contracts, utilities and QFs negotiated alternate curtailment options that provided for (1) reduced prices during economic curtailment conditions, and (2) fixed limits on the number of hours of curtailment/reduced prices per year. Attachment 2 summarizes and compares the current curtailment provisions under (1) PG&E's ISO4 and (2) FSO4 for all utilities.[7]

The common concept behind these alternate curtailment options is that QFs are compensated for periods of reduced payments by computing an adder to energy prices paid during non-curtailable hours. Under FSO4 and PG&E's ISO4, the adder is calculated as the difference between the QF's energy price and the utility's lower marginal cost, summed over a forecast of all curtailable (or reduced price) hours. This difference is then spread over the non-curtailed off-peak hours, in the form of an energy price adder. (See Attachment 2, Figure A-1.)

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6 Refusal to purchase, except in cases of emergency and scheduled maintenance, is limited to QFs of 1 MW or larger. Therefore, by definition, these provisions do not apply to Standard Offer 3 (SO3), which is offered to QFs of 100 kW or less. For a discussion of refusal to purchase/hydro spill pricing, see D.82-01-103, mimeo. pp. 72-79; D.82-04-071, mimeo. pp. 4-6, and D.82-12-120, mimeo. pp. 113-116.

7 See, in particular, Option II of FSO4 and Option B of PG&E's ISO4. In approving these provisions, we recognized that they did not conform with the narrowly defined negative avoided cost and hydro spill conditions established for SO1 and SO2. However, we accepted the disparities as part of the negotiation process and as integral to the parties' arriving at a negotiated package. (See D.83-09-054, mimeo. p. 38 and D.88-03-079, mimeo. p. 42.)

As we explained in D.87-08-047, an adder adjustment is necessary because of the way we currently compute energy payments under our standard offers:

> "Our standard offers compute energy payments to QFs based on the purchasing utility's fuel and fuel-burning efficiency (including expected hydro generation and purchases of economy energy) at the margin. We determine an average avoided operating cost and then time-differentiate this cost to reflect the utility's different operating costs depending on the magnitude of demand at the different times of day and seasons of the year. The time differentiation is such that a QF operating at random over all hours will receive the average avoided operating cost...." (D.87-08-047, mimeo. p. 9.)

Curtailment provisions effectively remove a number of the low-cost hours (or reduce the prices paid during those hours) that were averaged into the approved energy prices. Therefore, without any adders to prices paid during non-curtailable hours, the curtailable QF would receive, on average, less than avoided costs. As described more fully below, the adder gap identified in PG&E's ISO4 provisions relates specifically to the calculation of these adders for Curtailment Option B.

B. <u>PG&E's ISO4 Curtailment Adder Gap</u>

As described in Attachment 1, PG&E's ISO4 contract provides for three energy payment options. Under Energy Payment Options 1 or 2 (EPO1, EPO2), a QF is paid the forecasted energy prices specified in the contract over a fixed price period. A QF choosing EPO1 or EPO2 may also elect to have a percentage of its energy payment based on current published energy prices (i.e., short-run avoided operating costs), even over the fixed price period of its contract. Under Energy Payment Option 3 (EPO3), energy prices during the fixed price period are based on fixed forecasted incremental energy rates (IERs) and utility oil and gas costs. After the fixed price period is over, for the balance of the contract, all energy payments under ISO4 are based on current, published avoided costs.

Under Curtailment Option B of PG&E's ISO4, PG&E can reduce energy payments to QFs for up to 1,000 hours when:

(1) PG&E's energy source at the margin is not a PG&E oil- or gas-fueled plant, and PG&E can replace the QF's energy with energy from this source at a cost less than the price otherwise paid to the QF;

(2) PG&E would incur negative avoided costs due to continued acceptance of energy deliveries under the ISO4; or

(3) PG&E is experiencing minimum system conditions.[8]

For reasons discussed above, QFs choosing Option B are compensated for this curtailment right by computing an energy adder to prices paid during non-curtailable hours.

PG&E's ISO4 contract specifies some of the adders needed to implement Curtailment Option B for EPO1 and EPO2: 7.7% for Seasonal Period A (May 1 through September 30) and 9.6% for Seasonal Period B (October 1 through April 30). However, the contract does not specify the adders to be applied to published energy prices for EPO1 or EPO2 during or at the expiration of the fixed price period. Nor does the contract establish adders for EPO3.

C. Procedural Background

In D.88-09-026, we adopted PG&E's proposal to apply the contractually specified adders to published energy prices during

8 Minimum system conditions (commonly referred to as "minimum load") exist when a utility has turned down all of its generating units to their minimum operating levels in response to decreased system load, and must still spill hydro-energy/reject other energy to decrease generation. Although often used interchangeably with the term hydro spill, minimum load encompasses a broader set of conditions.

the fixed price period under EPO1 and EPO2. We left open for consideration another possibility for EPO3 and for EPO1 and EPO2 at the expiration of the fixed price period. Specifically, we solicited comment on the adaptability of our FSO4 curtailment provisions to PG&E's ISO4:

> "Since August 1985, when PG&E filed its proposed solution, we have gained much experience in devising curtailment provisions for standard offer contracts. In particular, final Standard Offer 4 has a curtailment approach that in some ways is a refinement on PG&E's Curtailment Option B....These newer curtailment provisions are designed to give the utility enhanced flexibility without disadvantage to the QF; moreover, they will provide for updated adders, which should be preferable to simply continuing the use of the adders calculated by PG&E in 1983 for the duration of its interim Standard Offer 4 contracts." (D.88-09-026, mimeo. p. 51.)

At the April 7, 1989 Prehearing Conference in A.82-04-44 et al., Administrative Law Judge (ALJ) Gottstein directed parties to file written comments and conduct workshops to address this issue. Comments were filed by PG&E, the Division of Ratepayer Advocates (DRA), and SDG&E on May 5, 1989. Interested parties held a workshop on May 18, 1989, and PG&E filed its report on that workshop on May 31. Following the first workshop, PG&E introduced a "pay-as-you-go" proposal for ISO4 adders and circulated it to the interested parties for comment. A second workshop was held on June 21, 1989 to explore PG&E's proposal in greater detail. On July 17, 1989, PG&E filed a report on the second workshop.

Parties reached agreement on the treatment of adders for EPO3 during the fixed price period. They agreed that an adder would be redundant, since the effect of Curtailment Option B is already captured in the contractually established IERs. However, parties could not reach agreement on the appropriate adder for any of the ISO4 energy payment options at the end of the fixed price period. Since agreement could not be reached via the informal workshop process, PG&E, DRA, and Santa Fe Geothermal, Inc., Unocal Corporation and Freeport-McMoran Resource Partners (SF/U/F) filed testimony on this issue in Phase 1A of this proceeding. Evidentiary hearings on this and other Phase 1A issues were held on November 13 to 17, November 28 to December 1, and December 4, 1989. Concurrent briefs on this issue were filed on January 5, 1990.[9]

D. <u>Position of the Parties</u>

The critical issue separating parties is their position on what does and does not constitute a modification of the terms of the ISO4. All parties apparently agree that changing or eliminating the system conditions restricting the curtailment, increasing or decreasing the hours available for curtailment, or offering each QF a new curtailment option potentially constitutes a modification of the terms of the ISO4. In other words, replacing Curtailment Option B with Option II of FSO4 would require contract modification and, under California law, consent of the parties.

In addition, SF/U/F believes that recalculation of the adder or changes to assumptions in calculation of the adder constitutes a modification of ISO4. PG&E and DRA, on the other hand, take the position that these types of changes do not represent contract modifications.

In support of its position, SF/U/F argues that a fair reading of the ISO4 contract would lead one to conclude that the contractually specified adders also apply to published energy

9 Concurrent briefs on other Phase 1A issues, relating to resource planning assumptions and methodology, were filed on December 22 and (for DRA only) December 29, 1989. On March 28, 1990, we issued D.90-03-060 which addressed these issues. Today's order addresses the two remaining Phase 1A issues for this update cycle.

prices. SF/U/F also argues that the ISO4 negotiators anticipated that these adders would be constant through the term of the ISO4. With regard to PG&E's curtailment proposal (see below), SF/U/F asserts that it is effectively a "split-the-savings" mechanism, similar to what the Commission rejected in D.89-04-047.

Under PG&E's and DRA's interpretation of ISO4, the contractually specified adders apply to the fixed price period only. In PG&E's opinion, the Commission explicitly recognized that the adders after the fixed price period would need to be adjusted, and invited consideration of new and refined approaches for doing so. Furthermore, PG&E argues that the original calculation of the adders is based on outdated resource assumptions. In PG&E's and DRA's view, the adders should not only be recalculated but, as discussed below, updated on a pay-as-you-go basis for the remaining years of the contract.

E. <u>PG&E's Pay-As-You-Go Proposal</u>

PG&E recommends a pay-as-you-go adder, designed to be conceptually equivalent to the curtailment adder calculation in both FSO4 and the ISO4 fixed price period. As described in Section II.A. above, adders are calculated by taking the difference between the QF's energy price (for example, short-run avoided cost, SRAC) and the utility's lower marginal costs (Alternate Price) over the forecasted curtailable hours. However, instead of spreading this difference over non-curtailment hours, as is done under FSO4, PG&E proposes to pay for curtailment "as-we-go".

Specifically, when curtailment conditions exist on the PG&E system, PG&E would give a QF notice that PG&E is invoking curtailment and would notify the QF of the Alternate Price for those hours of curtailment. PG&E would pay the QF the difference between the price normally paid to the QF for generation during those hours and this Alternate Price, regardless of whether or not the QF curtails. This difference is termed the Curtailment Price.

Under PG&E's proposal, if the QF decides to continue operating during these hours, PG&E would pay the Alternate Price plus this Curtailment Price. This sum represents the price normally paid during those hours if the QF was not curtailed (the SRAC for that time-of-use period). If the QF decides to reduce its deliveries, PG&E would still pay the Curtailment Price for those deliveries that would have occurred if the project had not been curtailed, but would not pay the Alternate Price. The calculation of curtailed generation would be based on the difference between (1) the QF's average level of operation during partial peak hours in the same billing period as the curtailment, and (2) the actual level of operation during the hours of curtailment. PG&E's proposal is described in greater detail in Attachment 3.[10]

PG&E believes that its pay-as-you-go proposal maintains the principles behind ISO4, and at the same time corrects a major defect of Curtailment Option B. In PG&E's view, this defect arises from the inherent difficulty in accurately forecasting the cost of replacement energy during curtailment and the number of curtailment hours, coupled with the restrictive ISO4 provisions for invoking curtailment.[11] Since the pay-as-you-go proposal eliminates the need to forecast these variables, PG&E argues that it also eliminates the risk of forecasting errors.

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10 PG&E notes in its comments to the Proposed Decision that the method of calculating curtailed generation described above will yield accurate results for all QF technologies except for wind projects. PG&E has stated its willingness to meet with wind project owners to develop a mutually acceptable method of calculating curtailed deliveries.

11 See Exhibit 2, pp. 43-44, PG&E's Concurrent Brief, dated January 5, 1990, pp. 10-11, and Reporter's Transcript (TR) at 481. As PG&E notes, FSO4 does not restrict curtailment to certain system conditions, as does ISO4. As a result, the curtailment provisions under FSO4 do not raise the same concerns.

Moreover, PG&E argues that QFs would also benefit from a pay-as-you-go approach. Under the current Curtailment Option B, a QF must operate during the remaining non-curtailed off-peak hours in order to recapture, through the adder, any lost revenue. PG&E asserts that the pay-as-you-go proposal eliminates this burden on QFs.

F. Discussion

In California, a contract can be modified only with the consent of all parties to the agreement.[12] The parties to this proceeding have not succeeded in reaching agreement on the curtailment gap issue. In order to resolve this issue in a manner consistent with California contract law, we focus upon interpreting the ISO4 contract, rather than modifying it. Other than SF/U/F's stated opinion regarding the intent of the negotiating parties, there is no extrinsic evidence that can be brought to bear on interpreting the ISO4 contract language. We therefore turn to the contract language itself for guidance on this issue.

A contract modification is defined as the alteration of the details of an agreement, where the general purpose of the agreement remains unchanged.[13] Article 4 of ISO4 describes the energy pricing provisions for EPO1 and EPO2, as follows:

> "During the fixed price period, Seller shall be paid for energy delivered at prices equal to (X) percent of the [forecasted/levelized] energy prices set forth in Table [B-1/B-2], Appendix B... plus (100-X) percent of PG&E's full short-run avoided operating costs.[14]

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12 Riverside Rancho Corp. v. Cowan, 88 Cal. App. 2d 197 (1948).

13 Travelers Ins. Co. v. Workman's Compensation Appeals Board, 68 Cal. 2d 7 (1967).

14 The Seller may elect to set X equal to 20, 40, 60, 80, or 100.

"For the remaining years of the term of agreement, Seller shall be paid for energy delivered at prices equal to PG&E's full short-run avoided operating costs." (Emphasis in original.)

The only details pertaining to curtailment adders under Curtailment Option B (for EPO1 and EPO2) are described in Appendix B of ISO4, in conjunction with the contractually specified energy prices during the fixed price period:

"Pursuant to Article 4, the energy payment calculation for Seller's energy deliveries during the fixed price period shall include the appropriate prices set forth in Table [B-1/B-2].... If Seller has selected Curtailment Option B in Article 7, the [forecasted/levelized] off-peak hours' energy prices listed in Table [B-1/B-2] shall be adjusted upward by 7.7% for Period A and 9.6% for Period B." (Emphasis in original.)

Appendix A defines the term "full short-run avoided operating costs" as follows:

"CPUC-approved costs which are the basis of PG&E's published energy prices. PG&E's current energy price calculation is shown in Table B-5, Appendix B. PG&E's published off-peak hours' prices shall be adjusted, as appropriate, if Seller has selected Curtailment Option B." (Emphasis in original.)

SF/U/F argues that the phrase "as appropriate" (Appendix A) clearly implies that, after the fixed price period, the percentage adders in Appendix B will be calculated based on the published energy prices. We disagree. The details of the contract do not in any way link the percentage adders defined for EPO1 and EPO2 during the fixed price period (Appendix B), with the definition of full short-run avoided operating costs (Appendix A). Nor does the agreement expressly specify what adders will apply to short-run avoided operating costs. The plain reading of the contract supports PG&E's and DRA's interpretation, namely, that we could change the administration of the agreement, with respect to the adders, when full short-run avoided operating costs are the basis of payments, rather than the fixed prices specified in Appendix B. As long as we find such changes to be appropriate, they would not constitute a modification of the contract. A parallel is our authority to alter the methodology for calculating short-run avoided operating costs.

As PG&E and DRA point out, we adopted an "appropriate" adder for short-run avoided operating costs during the fixed price period, namely, application of the same percentages established for the fixed price period. Our reason for adopting this approach was, in addition to its attractive simplicity, to provide both the utility and QF "with the price certainty that is one of the primary goals of the <u>fixed price period</u> in interim Standard Offer 4." (D.88-09-026, mimeo. p. 51, emphasis added.) However, we declined to extend this solution to prices after the fixed price period. Instead, we solicited proposals for newer curtailment approaches, along the lines adopted for FSO4, stating:

> "These newer curtailment provisions are designed to give the utility enhanced flexibility without disadvantage to the QF; moreover, they will provide for updated adders, which should be preferable to simply continuing the use of the adders calculated in 1983 for the duration of its interim Standard Offer 4 contracts." (D.88-09-026, mimeo. p. 51.)

PG&E's pay-as-you-go proposal accomplishes these objectives, and maintains the principles by which adders are calculated under FSO4 and ISO4 during the fixed price period. SF/U/F's assertion that PG&E's pay-as-you-go proposal is equivalent to a split-the-savings mechanism results from a misunderstanding of PG&E's proposal.[15] Unlike the split-the-savings proposal we

15 See TR at 934-936.

rejected in D.89-04-047, PG&E's proposal returns all of the direct economic savings from curtailment to the QF. As a result, the curtailable QF continues to receive, on average, full avoided costs.

As described in Section II.B. above, PG&E's proposal also eliminates the need to forecast the cost of replacement energy during curtailment and the number of curtailment hours. This, in turn, eliminates the need for regulatory approval of these forecasts.[16] Moreover, pay-as-you-go can be implemented without modifying the ISO4 curtailment provisions, outlined in Attachment C of the agreement.

For all of the reasons discussed above, we adopt PG&E's pay-as-you-go approach for calculating adders at the expiration of the fixed price period, for QFs who elected Curtailment Option B under PG&E's ISO4.

III. FSO4 Capacity Factor Updating

Payments to QFs under FSO4 are based on the costs of an identified deferrable resource, or IDR. An IDR is a cost-effective resource that a utility would have built and operated if not for the availability of QFs to provide power at or below the IDR's costs. We determine the need for IDRs every two years in our BRPU proceeding.[17] Under the payment provisions of FSO4, QFs are paid

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16 We note that PG&E's pay-as-you-go proposal does require an estimate of the QF's assumed level of operation if PG&E had not curtailed the QF. During the workshop process, PG&E proposed calculating curtailed deliveries based on the average level of the project's operation during non-curtailed days. (See Attachment 3.) This approach seems reasonable, and is adopted in today's order for all QF technologies except wind projects.

17 The BRPU is our industry-wide forum for updating FSO4 prices and addressing generic issues related to utility purchases from QFs. See Order Instituting Investigation 89-07-004, dated July 6, 1989, for a detailed description of this proceeding.

for energy based on the operating costs of the IDR to the extent that the IDR would have operated. The maximum level of energy purchased on the basis of IDR operating costs is determined by the estimated capacity factor of the IDR, i.e., the percentage of time an IDR is projected to operate relative to the amount of time the resource is available. Energy sales in excess of this level are made at SRACs.

The issue for resolution in today's order is whether the capacity factor of the IDR should be updated periodically and, if so, how. This issue, in turn, affects the proportion of QF production that receives energy prices under FS04, based on projected IDR operating costs.[18] As described below, parties in support of capacity factor updating have presented several implementation approaches for our consideration.

A. Procedural Background

In D.88-03-079, the Commission adopted the FS04 contract provisions contained in the Joint Testimony filed by respondents, QF representatives, and DRA. In that decision, the Commission accepted the joint position of the parties that the capacity factor update issue be deferred for later resolution in the next biennial update:

> "One area put at issue in testimony served before the Joint Testimony relates to the capacity factor assumed for the avoidable resource. Some parties would fix this factor

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18 As described in Attachment 1, there are three components to FS04 payments: (1) payments based on capacity, or shortage value, (2) energy-related capital costs, and (3) energy payments. The first two payment components would be unaffected by updates to the IDR capacity factor. Updating the capacity factor would, however, increase or decrease the quantity of QF production that receives energy prices that are fixed by the terms of the contract. QFs would still be permitted to produce energy in excess of the capacity factor of the IDR, and would receive variable SRACs for this excess production.

for the duration of the contract at the time the resource is identified; other parties would make some provision for updating this factor.

"The parties basically ran out of time to deal with this issue. They jointly request that we approve the final Standard Offer 4 contract as presented in the Joint Testimony, while deferring the capacity factor issue to the next round of utility resource plan filings... In the absence of an avoidable resource for any of the utilities at this time, we feel no urgency in addressing this issue. We accordingly defer this issue to the biennial update proceeding."[19]

On April 7, 1989, ALJ Gottstein ruled that the capacity factor updating issue would be heard as part of Phase 1A of this BRPU proceeding. She also directed that workshops be held to investigate the potential for a stipulation among the parties on this issue.[20] Pre-workshop comments were filed on May 5, 1989 by interested parties. Workshops were held on May 19, 1989 and on July 27, 1989, and workshop reports were filed on June 9, 1989 and August 3, 1989.

Since agreement could not be reached via the informal workshop process, the following parties filed testimony on capacity factor updating in Phase 1A: SCE, PG&E, SDG&E, DRA, and SF/U/F. Evidentiary hearings were held on this and other Phase 1A issues on November 13 to 17, November 28 to December 1, and December 4, 1989. Concurrent briefs on this issue were filed on

19 D.88-03-079, mimeo. pp. 39-40. See also Ordering Paragraph 11.

20 See Order Instituting Investigation 89-07-004, Appendix B, p. 2.

January 5, 1990 by respondents, DRA, SF/U/F, and the California Energy Commission (CEC).[21]

B. <u>Position of the Parties</u>

Respondents take the position that the capacity factor of the IDR should be updated to reflect the economic operation of the IDR in response to changing system conditions. In their view, capacity factor updating is needed to maintain ratepayer indifference. They claim that ratepayers are adversely affected by an incorrect capacity factor whether the capacity factor is too high or too low. In its testimony, SCE presents the following examples to explain this potential ratepayer "lose-lose" situation:

> "In the first example, assume the IDR is planned as a baseload unit, but unexpected rising IDR fuel prices (relative to other fuels) would cause Edison to convert the unit to intermediate status. The IDR would be more economic as an intermediate unit because variable operating cost for the unit would exceed system marginal energy cost during some hours, and Edison would generate power from other sources during these hours. If the IDR capacity factor were fixed in the SO4, Edison would be required to pay the QF for power at the higher variable operating cost price during all hours even though the power could be generated more cheaply from other sources during some hours."

> "In the second example, assume the IDR is planned as an intermediate unit, but falling IDR fuel prices (relative to other fuels) would cause Edison to convert the unit to baseload status. The IDR would be more economic as a baseload unit because variable operating cost

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21 We note that SCE wrote and served on all parties a reply to SF/U/F's concurrent brief on January 15, 1990. SCE's letter is improper, and was not considered in today's deliberations. In the future, SCE should refrain from submitting comments on other parties' briefs unless the ALJ directs that reply briefs be filed by all interested parties.

> for the unit would be below system marginal cost during all hours. If the IDR capacity factor were fixed in the SO4, the QF would (presumably) operate its facility as a baseload unit, but would receive higher system marginal energy cost payments instead of lower variable operating cost prices during production hours in excess of the original IDR capacity factor."

SDG&E performed modelling sensitivities on its Phase 1A resource plan to illustrate the potential ratepayer effects whenever the IDR capacity factor varies above or below the value reflected in the FSO4 contract. More specifically, SDG&E examined the effect of improved heat rates and lower gas price assumptions on the capacity factors of two IDRs, the Heber geothermal plant and the combined cycles at South Bay. While Heber's capacity factors did not change with these sensitivities, the capacity factors at South Bay did change (i.e., increase). As a result of holding the South Bay capacity factor constant, SDG&E estimates yearly overpayments ranging from $50,000 to nearly $2 million over the 1995-2007 period.[22]

Although respondents all agree that the capacity factor of the IDR should be updated, they present different proposals for our consideration. PG&E proposes that the capacity factor be updated annually in the Energy Cost Adjustment Clause (ECAC) proceeding. PG&E argues that updating the capacity factor in ECACs would be straightforward, since an up-to-date input data set is already developed in ECAC for production simulation modelling to forecast PG&E's operating expenses. In PG&E's view, the updated IDR capacity factor could be readily obtained by substituting the IDR for the FSO4 QFs in the ECAC input data set.

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22 See Exhibit 20, pp. 4-7, Tables 1 and 2. PG&E also presented an illustrative calculation of potential ratepayer overpayments in its May 5, 1989 filing.

SCE proposes that the IDR capacity factor be updated (a) upon application of the utilities in BRPU proceedings, and (b) only if the update would seek a change in the IDR capacity factor of at least (plus or minus) 10%. In SCE's view, this approach provides some measure of stability and opportunity for notice and comment on any proposed change. At the same time, SCE argues that it protects ratepayers from the consequences of relatively significant operational changes, such as SCE's conversion of oil/gas units from baseload to intermediate operation in the late 1960s and 1970s. SCE does not specify, however, exactly how the updated IDR capacity factor would be determined.

SDG&E's updating proposal would build the updating mechanism directly into the FS04 contract itself. Under SDG&E's proposal, the modelling work done in the BRPU proceedings would not only lead to specification of an IDR, but would also identify those variables (such as changes in fuel price or economy energy availability) that could cause the IDR's capacity factor to change during the life of the FS04 contract. Based on sensitivity runs, changes of a certain magnitude in these variables would automatically trigger changes in the IDR capacity factor. These variables, and the resultant changes, would all be pre-specified in the FS04 contract. In SDG&E's opinion, one advantage of this approach is that it enables QFs to assess the risks to its payment stream at the time the contract was under consideration. Another is that a change in capacity factor would go into effect as soon as indicated under the contract; there would be no need to wait for either an ECAC or BRPU hearing.

DRA recommends periodic review and update of the IDR capacity factor, and supports SCE's proposal. However, DRA believes that the methodology for updating requires further review. CEC also supports the concept of IDR updating, but finds serious fault with respondents' implementation proposals. CEC recommends that the Commission instruct parties to hold new workshops in which refinements to the existing proposals, as well as new proposals, be considered.

SF/U/F, on the other hand, opposes any form of IDR capacity factor updating, and proposes that the capacity factor be fixed at a generic level for each particular type of potential IDR. SF/U/F suggests the use of the CEC's Technology Characterizations Report (September 6, 1989) for the source of this generic data.

In support of its position, SF/U/F argues that the concept of varying the capacity factor of the IDR throughout the contract term threatens to erode what little price stability is present in the FS04. Moreover, in SF/U/F's opinion, respondents' evaluation of capacity forecasting errors is an incomplete analysis of ratepayer impacts. According to SF/U/F, a great deal of ratepayer risk is mitigated by having the QF build a resource because: (1) there is no risk of cost overrun as there is with utility construction, (2) the QF only gets paid when it delivers energy and capacity, and (3) it is likely that the QF will receive only a fraction of the IDR cost after bidding. Hence, FS04 taken as a whole maintains ratepayer indifference, in SF/U/F's opinion.

Moreover, SF/U/F argues that utilities may not always operate their plants at an optimal capacity factor, i.e., one which would minimize system production costs in light of that year's loads, fuel prices, hydroelectric conditions, and availability of less expensive power from other sources. In particular, SF/U/F points to Diablo Canyon which, SF/U/F asserts, is not being operated consistent with reliability considerations, or as economics would dictate. In SF/U/F's view, updating IDR capacity factors based on optimization assumptions would foster the "QF ghetto" for which PG&E was chastised in D.87-11-024. Finally, SF/U/F argues that, by proposing IDR capacity factor updating, respondents are relitigating the issue of IDR emulation that the Commission rejected in D.86-07-004.

C. Discussion

As a general policy, we are reluctant to adjust a single component of avoided cost pricing, to account for forecasting errors, when all other components are adopted on a forecasted basis. Identifying cost-effective IDRs is, in the first place, a function of many assumptions, including demand projections, fuel prices, operating characteristics of existing utility resources, availability of economy energy, and the cost of the IDR. All of these factors are subject to forecasting errors which, depending on the direction and magnitude of change, could result in ratepayers paying significantly more or less than true long-run avoided costs.

It is also conceivable that the type and timing of IDRs forecasted during the BRPU process would change significantly in the face of updates or "true-ups" at a later date. Still, we do not adjust long-run avoided cost payments to QFs, based on the IDR that might have been, if we had accurately predicted the relevant variables. Nor do we adjust energy payments under SO1, SO2, and SO3 to account for errors in forecasting the incremental fuel for the quarter. Similarly, we do not true-up IERs, based on information about how the utility's existing resources actually operated during the ECAC forecast period (for SO1, SO2, and SO3), or during Period 1 for FSO4. In fact, we have never adopted true-up mechanisms for any of the forecasted variables that affect short-run or long-run avoided costs, despite proposals to do so.

In sum, our general approach to assuring ratepayer indifference to forecasting errors has been to ignore them. The rationale for this benign neglect is that we expect forecasting errors to generally be unbiased and evenly distributed over time. In other words, we expect that potential ratepayer over- and underpayments will cancel each other out by virtue of the statistical randomness of all the potential forecasting errors. By attempting to remove the variation associated with individual variables, selective updating can actually change the overall distribution of forecasting errors, thereby biasing the results in favor of either ratepayers, or QFs.

We are therefore skeptical of respondents' capacity factor updating proposals, since they attempt to adjust for the forecasting errors associated with one variable, in isolation of all others. Before seriously considering such proposals, we would first need to be persuaded that, without IDR capacity factor updating, ratepayer indifference would be unequivocally violated. Moreover, we would need to be convinced that accurate updates to the IDR capacity factor are not only theoretically possible, but administratively feasible as well.

We first turn to the issue of ratepayer indifference. The principle of ratepayer indifference is that ratepayers are left economically indifferent when a utility purchases power from QFs, relative to the utility providing the power itself, or purchasing it elsewhere. Respondents and others argue that updating the IDR capacity factor is needed because otherwise ratepayers pay more than actual avoided costs, regardless of the direction of the forecasting error. All parties agree that this risk exists, at least theoretically. However, ratepayer indifference does not, in our view, require that every discrete contract term maintain that indifference. We agree with SF/U/F that a potential "lose-lose" situation for a single contract term, or cost component, should not be viewed in isolation.

Rather, in evaluating the need for capacity factor updating, we must consider the allocation of risks and benefits associated with both energy and capital costs, under the current structure of FSO4. We ask ourselves whether or not, on balance, FSO4 provides ratepayers with reasonable opportunities for experiencing benefits, enough to offset the risk associated with capacity factor forecasting errors. Recognizing that the balancing of risks and benefits is not an exact science, we make the following general observations.

Under FS04, QFs submit bids based on a percentage of the IDR capital costs when the FS04 offer is oversubscribed. Hence, from a total cost perspective, ratepayers benefit whenever the QF bidding process discounts IDR capital costs. If the utility had built that resource at the estimated IDR cost, ratepayers would have paid the full capital cost, instead of the lower bid price. As SF/U/F also points out, the capital recovery streams for utility-built and FS04 contracts are significantly different. The utility receives a downward ramping stream of payments, whereas the FS04 QF receives an upward ramping stream. The utility receives this full stream of payments even if the plant is retired before the end of its projected useful life.[23] The QF, on the other hand, only receives its capital-related payments as long as it operates.

In its testimony, SF/U/F presented a numerical example, using the data from PG&E's Phase 1A filing, to illustrate the difference between payments to a utility under traditional ratemaking treatment and payments to a QF under FS04. Using PG&E's assumptions for a 206 MW combined cycle plant, SF/U/F estimates that ratepayers would pay $40 million more in net present value dollars, if the utility were to build the plant. SF/U/F concludes that ratepayers benefit greatly by having the QF build a resource, rather than the utility.

However, as pointed out by CEC and others, SF/U/F only compared the first 15 years of 30-year payment streams. If the utility plant operates for the full 30 years, most if not all of

23 Unless, of course, the utility is found to have acted imprudently in retiring the plant before the end of its projected useful life.

the $40 million difference would disappear.[24] Therefore, it is inappropriate to imply, as SF/U/F does, that ratepayers will always pay a premium for utility-constructed plants. Nonetheless, SF/U/F's analysis does illustrate how the structure of FSO4 ameliorates the risk of project abandonment, to the benefit of ratepayers. Using SF/U/F's example, ratepayers would pay $40 million more under traditional utility ratemaking than under FSO4 if both the utility and QF ceased operation in year 15.

Our recognition of certain aspects of FSO4 that are favorable to ratepayers is not intended to suggest that FSO4 is unduly biased in favor of ratepayers, at the sole expense of QFs. Nor should it be inferred from the above discussion that there are no counterbalancing benefits to QFs, relative to ratepayers, in our adopted FSO4 structure and contract terms. In making our determinations concerning the payment structure of FSO4, as well as the bidding protocol, we carefully weighed a variety of risks and benefits from the perspective of both the ratepayer and QF in order to achieve a reasonable balance. The point of the above discussion is to satisfy ourselves that there are aspects of FSO4 that are clearly beneficial to ratepayers, and are thereby capable of offsetting the risk of capacity factor forecasting errors.

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24 This is because, by definition, the capital cost payment streams under FSO4 and traditional ratemaking are equivalent on a net present value basis. If FSO4 were a 30-year contract, the $40 million in higher payments under traditional ratemaking would be exactly offset by lower payments in the latter years of the contract. However, FSO4 fixed capital payments only extend for 15 years. After that time, the QF can negotiate a new contract, or sign one of the short-run contracts. Hence, we do not know for sure what the back-end of the 30-year payment stream for FSO4 QFs will look like. In any event, there is likely to be some amount of off-setting payments beyond year 15, unless the QF ceases to operate altogether.

Moreover, we are not convinced that, relative to the forecasts developed in the BRPU, IDR capacity factors are likely to change significantly over time, as respondents would have us believe. As SDG&E witness Brown acknowledged during cross-examination, forecasting errors in the variables that would counsel in favor of changing the IDR capacity factor could conceivably cancel each other out.[25] SCE's theoretical example, as well as SDG&E's numerical one, assumed that only a single variable (e.g., fuel prices) would change at any given time.

We also observe that the significant operational changes experienced by SCE in the late 1960s and 1970s are not likely to recur in the near future. During that period, fuel prices were not only highly volatile, but utilities were adding very large baseload units with relatively low operating costs. Based on the CEC's Seventh Electricity Report and the Phase 1A filings in this proceeding, we do not see these circumstances repeating themselves in the foreseeable future. In addition, we agree with DRA that a utility plant would not switch from baseload to intermediate and back on an annual cycle, in response to changing hydro conditions.[26] Rather, the utility would adjust its purchases of economy energy and/or curtail QFs under the curtailment provisions contained in the FSO4 contract.

Even if we were convinced that the lack of capacity factor updating would unequivocally disadvantage ratepayers, we would have second thoughts at the prospect of updating projections of operating characteristics for a unit that is never built and operated. This is, in fact, what respondents propose we do, either by pre-specifying the updating formulas (SDG&E), or by updating the

25 TR at 315-319.

26 Exhibit 24, pp. III-4, TR at 539.

projections "as we go" (PG&E/SCE). Not surprisingly, parties raised a number of concerns regarding the complexities of the IDR capacity factor updating methods proposed by PG&E and SDG&E.[27] As SF/U/F points out, simply introducing the IDR into the ECAC production cost simulation runs will not capture the effect of the IDR, had it been built and operated. This is because, as the capacity factor of the IDR changes, so will its effective heat rates, with a concomitant change in its variable operating cost.[28] Without an appropriate adjustment in variable operating costs, the production cost simulation will be inaccurate. Hence, the accuracy which purportedly underlies PG&E's proposal is not achieved.

Moreover, PG&E has no satisfactory answer to the basic question of how to price the energy produced by FS04 QFs in excess of the amounts produced by the variable capacity factor IDR.[29] Finally, as CEC and DRA point out, our ECAC proceedings are already burdened with issues, and adding one more that could involve considerable modelling complexity will only aggravate the situation.

We also agree with CEC that SDG&E's proposal involves a great deal of modelling complexity that could further complicate BRPU hearings and lead to a significant risk of forecasting error. Both SDG&E and DRA acknowledge that if SDG&E's approach is to work, one must account not only for the major variables that could affect the IDR's capacity factor, but also for the interrelationships

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27 As noted in Section III.B. above, SCE did not submit a specific proposal for how to update the IDR capacity factor.

28 TR at 324.

29 See SF/U/F's <u>Concurrent Brief</u>, January 5, 1990, pp. 8-10; TR at 72.

among those variables.[30] Even with only a few variables, this could quickly become a very complex exercise. And since the possible changes in these variables would have to be specified for the full life of the FS04 contract, significant forecasting errors might well result.

Despite the drawbacks outlined above, CEC and DRA urge us to adopt capacity factor updating in principle, and work out the implementation details later. We disagree. As discussed above, we do not believe that IDR capacity factor updating is necessary for maintaining ratepayer indifference, given the current structure of FS04. We would have to be convinced of that fact before altering the balance of risks and benefits inherent in the contract.

Moreover, based on the record in this proceeding, we are not convinced that capacity factor updating methods are likely to <u>improve</u> the accuracy of the IDR capacity factor forecasts, and resultant price signals, adopted as part of the BRPU.[31] Updating the IDR capacity factor under any of respondents' proposals involves additional projections and resource plan simulations. All of the variables involved in these calculations are, in turn, projections of what might occur, or what might have occurred with a resource that is never actually built. The difficulty in translating the theory of IDR capacity factor updating into workable practice is evidenced by the lack of specificity in

30 TR at 317-319; 549-550.

31 Contrary to SF/U/F's assertions, our rejection in D.86-07-004 of IDR emulation requirements does not preclude parties from proposing refinements to IDR price signals, based on expected operating performance. At the same time, proposals to fine tune our FS04 price signals will not be adopted without careful scrutiny of their alleged advantages and administrative feasibility.

respondents' proposals, despite many months of deliberations.[32] In short, we are unwilling to direct parties to commit additional time and resources to an exercise that imputes a theoretical rigor to the resource planning process, that may very well not exist.

At the same time, we are unwilling to automatically fix the IDR capacity factor throughout the contract term based on generic data, as SF/U/F recommends. SF/U/F's proposal would keep the IDR capacity factor constant irrespective of any variations that may be forecasted as part of the BRPU planning process. We prefer to use IDR capacity factors that derive from the base case BRPU resource planning assumptions. For some IDRs (e.g., baseload units), the forecasted capacity factor may remain constant throughout the planning period. For others, (e.g., intermediate load resources), the projected capacity factor may vary over its lifetime, as relative fuel prices change or other cost-effective resources are added during the planning horizon. The FSO4 limit on fixed energy payments should reflect these variations.

The production cost models used in our BRPU proceeding will automatically derive annual IDR capacity factors for each year of the planning horizon. Accordingly, the IDR capacity factor under Section 1.1 (i) of FSO4 should be set equal to the model-derived capacity factors resulting from the base case scenario. For contract years that extend beyond the BRPU planning horizon,

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32 The methodology for updating the IDR capacity factor has been an issue for nearly three years. In A.82-04-44 et al., it was the subject of some discussion by the parties as they attempted to develop FSO4 contract provisions. In this investigation, parties have been refining their proposals since May, 1989. (See Section III.A. above.)

the IDR capacity factor should be fixed at the level adopted for the final year of the planning horizon.[33]

For this purpose, a separate schedule of annual IDR capacity factors must be referenced in Section 1.1 (i) of FSO4. In addition, Section 14.4 must be modified to ensure that the total energy-related capital cost payment, for which the QF is eligible, is not altered. Within 20 days from the effective date of this order, respondents should file conformed FSO4 modifications to reflect these changes.

If the IDRs adopted for the FSO4 solicitation are the same as the IDRs found cost-effective in the base case scenario, then the annual capacity factors can simply be read off the base case output files. If, on the other hand, we adopt IDRs that differ from those found cost-effective in the base case scenario (in terms of size, type, or timing), an additional model simulation is required.[34] We will need to rerun the base case scenario, this time with the adopted IDRs included, to produce model-derived capacity factors for those units. In either case, in each update proceeding we will need to adopt model-derived IDR capacity factors

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33 The BRPU planning horizon is 12 years, whereas the FSO4 contract term is 15 years. Hence, there is at least a three-year period for each contract where the IDR capacity factor will need to be fixed. There may be more years where this is the case, depending on when the IDR comes on line during the planning horizon. For example, if the IDR comes on line in year 4 of the planning horizon, there will be only 8 years of model-derived capacity factors for that resource. For years 9 to 15 of the contract, the IDR capacity factor will be fixed at the level derived from the base case resource plan in year 8.

34 This could happen in Phase 1B if (1) parties are successful in negotiating a reasonable settlement before we explicitly consider uncertainty surrounding the base case assumptions, or (2) after considering the Phase 1B sensitivities, we decide to adopt a different set of IDRs than indicated in the base case scenario.

before issuing an FS04 solicitation. For this update, we will adopt IDR capacity factors in Phase 1B, assuming that QF deferrable resources are identified.

IV. Response to Comments on ALJ's Proposed Decision

Pursuant to Public Utilities Code § 311 and to our Rules of Practice and Procedure (California Code of Regulations, Title 20, Rules 77 to 77.5), the Proposed Decision of ALJ Gottstein was filed before today's decision on April 5, 1990. Respondents and U.S. Windpower filed comments on the proposed decision. No reply comments were filed.

We have carefully reviewed the comments, but have not summarized them in this order. To the extent that they required discussion, or changes to the proposed decision, the discussion and changes have been incorporated into the body of this order. Although several pages have changes, we have made no substantive modifications to the analysis or disposition of issues in the proposed decision.

Findings of Fact

1. Curtailment Option B under PG&E's IS04 allows PG&E to reduce energy payments to QFs for up to 1,000 hours under specific operating circumstances.

2. QFs choosing Curtailment Option B are compensated for curtailment by computing an energy adder to prices paid during non-curtailable hours.

3. The energy adder is computed such that, on average, curtailable QFs are paid full avoided costs.

4. PG&E's IS04 contract specifies the adders needed to implement Curtailment Option B for EP01 and EP02 during the fixed price period: 7.7% for Seasonal Period A (May 1 through September 30) and 9.6% for Seasonal Period B (October 1 through April 30).

5. PG&E's ISO4 contract does not specify the adders to be applied to published energy prices for EPO1 or EPO2 during the fixed price period.

6. PG&E's ISO4 contract does not specify the adders to be applied to published energy prices for EPO1, EPO2, or EPO3 at the expiration of the fixed price period.

7. In D.88-09-026, we adopted PG&E's proposal to apply the contractually specified adders to published energy prices during the fixed price period for EPO1 and EPO2.

8. In D.88-09-026, we solicited comments on the adaptability of our adopted FSO4 curtailment provisions for EPO3, and for EPO1 and EPO2 at the expiration of the fixed price period.

9. An adder for EPO3 during the fixed price period would be redundant, since the effect of Curtailment Option B is already captured in the contractually established IERs.

10. Under California law, a contract can be modified only with the consent of all parties to the agreement.

11. Replacing ISO4 Curtailment Option B with Option II of FSO4 would constitute a modification of the ISO4 contract.

12. The percentage adders for Curtailment Option B are specified in Appendix B of ISO4, which presents the fixed prices under the three energy payment options.

13. ISO4 specifies that, at the expiration of the fixed price period, prices will be based on full short-run avoided operating costs.

14. Appendix A of ISO4 defines full short-run avoided operating costs as CPUC-approved costs which are the basis of PG&E's published energy prices.

15. Appendix A states only that PG&E's published off-peak hours' prices shall be adjusted, as appropriate, if the Seller has selected Curtailment Option B.

16. Other than SF/U/F's stated opinion, there is no extrinsic evidence that the negotiating parties intended the fixed

percentages specified in Appendix B to apply to PG&E's published prices, either during or following the fixed price period.

17. SF/U/F interprets the ISO4 language to mean that the contractually specified adders also apply to published energy prices after the fixed price period.

18. Under PG&E's and DRA's interpretation of ISO4, the contractually specified adders apply to the fixed price period only.

19. PG&E's and DRA's interpretation of ISO4 does not alter any of the details of the ISO4 agreement.

20. Changes in the curtailment adder to be applied following expiration of the fixed price period are consistent with the terms of ISO4, so long as this Commission deems such a change to be appropriate.

21. Under PG&E's pay-as-you-go proposal, if the QF decides to continue operating when curtailment conditions exist, the QF receives the price normally paid during those hours (i.e., the SRACs for that time-of-use period). If the QF decides to reduce its deliveries, it receives an "adder", the Curtailment Price, for deliveries that would have occurred if the project had not been curtailed.

22. The Curtailment Price under PG&E's pay-as-you-go proposal is equal to the difference between SRACs and the utility's lower marginal costs.

23. Unlike the curtailment adder calculation in FSO4 and ISO4 during fixed price period, PG&E's proposal does not require forecasts of the number of curtailable hours, or of the cost of replacement energy during those hours.

24. The method of calculating curtailed generation under PG&E's pay-as-you-go proposal will yield accurate results for all QF technologies except for wind projects.

25. Unlike the split-the-savings proposal we rejected in D.89-04-047, PG&E's proposal enables the QF to receive, on average, full avoided costs.

26. PG&E's pay-as-you-go proposal can be implemented without modifying the ISO4 curtailment provisions.

27. PG&E's pay-as-you-go proposal accomplishes the objectives we set forth in D.88-09-026, and maintains the principles by which adders are calculated under FSO4 and ISO4 during the fixed price period.

28. Payments to QFs under FSO4 are based on the costs of an identified deferrable resource, or IDR.

29. An IDR is a cost-effective resource that a utility would have built and operated, if not for the availability of QFs to provide power at or below the IDR's costs.

30. Under FSO4, the maximum level of energy purchased on the basis of the IDR's operating costs is determined by the estimated capacity factor of the IDR.

31. The issue of whether (and how) to periodically update the capacity factor of the IDR was deferred to this BRPU.

32. SF/U/F proposes to fix the IDR capacity factor throughout the planning horizon, based on generic data.

33. Respondents recommend updating the estimated capacity factor of the IDR.

34. PG&E and SCE propose updating IDR capacity factors periodically, either in ECAC proceedings (PG&E) or during future BRPU proceedings (SCE).

35. SDG&E proposes to pre-specify formulas for future changes in the IDR capacity factor, based on sensitivity runs conducted in the BRPU.

36. Identifying cost-effective IDRs is a function of myriad assumptions, including demand projections, fuel prices, operating characteristics of existing utility resources, availability of economy energy, and the cost of the IDR.

37. All the factors that go into forecasting cost-effective IDRs are subject to forecasting errors which, depending on the direction and magnitude of change, could result in ratepayers paying more or less than true long-run avoided costs.

38. We expect forecasting errors to generally be unbiased and evenly distributed, whereby potential ratepayer over- and underpayments will cancel each other out over time.

39. By attempting to remove the variation associated with individual variables, selective updating can change the overall distribution of forecasting errors, thereby biasing the results in favor of either ratepayers or QFs.

40. Respondents' capacity factor updating proposals attempt to adjust for the forecasting errors associated with one variable, in isolation of all others.

41. The principle of ratepayer indifference is that ratepayers are left economically indifferent when a utility purchases power from QFs, relative to the utility providing the power itself, or purchasing it elsewhere.

42. All other things being equal, ratepayers will pay more than actual avoided costs when the IDR capacity factor is inaccurately forecasted, regardless of the direction of the forecasting error.

43. Ratepayer indifference does not require that every discrete contract term maintain that indifference.

44. From a total cost perspective, ratepayers benefit under FSO4 whenever the QF bidding process discounts IDR capital costs.

45. The current structure of FSO4 ameliorates the risk of project abandonment, to the benefit of ratepayers.

46. The current structure of FSO4 provides ratepayers with reasonable opportunities for offsetting the risk of capacity factor forecasting errors.

47. Forecasting errors in the variables that would counsel in favor of changing the IDR capacity factor could cancel each other out.

48. The theoretical and numerical examples presented in this proceeding assumed that only a single variable would change at any given time.

49. During the late 1960s and 1970s, when SCE experienced significant operational changes, fuel prices were highly volatile and utilities were adding very large increments of baseload units with relatively low operating costs.

50. The significant operational changes experienced by SCE in the late 1960s and 1970s are not likely to recur in the foreseeable future.

51. In response to fluctuating hydro conditions, a utility would adjust its purchases of economy energy and/or curtail QFs under the curtailment provisions in FS04, rather than switching units from baseload to intermediate on an annual basis.

52. As the capacity factor of the IDR changes, so will its effective heat rates, with a concomitant change in its variable operating cost.

53. PG&E's proposal to simply introduce the IDR into ECAC production cost simulations does not take account of these changes in IDR variable operating costs.

54. PG&E's proposal is silent on the issue of how to price the energy produced by FS04 QFs in excess of the amounts produced by the variable capacity factor IDR.

55. SCE's proposal does not specify a methodology for updating the IDR capacity factor.

56. SDG&E's prospective approach requires that all major variables, as well as the interrelationships among those variable, be pre-specified over the full life of the FS04 contract.

57. All of the variables involved in updating the capacity factor are themselves projections of what might occur (SDG&E) or

what might have occurred (SCE, PG&E) with a resource that is never actually built and operated.

58. It is not evident that capacity factor updating will, in practice, improve the accuracy of the IDR capacity factors that are forecasted as part of the BRPU.

59. In some instances (e.g., for intermediate load resources), the projected IDR capacity factor will vary over its lifetime, as relative fuel prices change or other cost-effective resources are added during the BRPU planning horizon.

60. SF/U/F's proposed approach would fix the IDR's capacity factor throughout the contract term, irrespective of any variations that may be forecasted as part of the BRPU base case scenario.

61. The model used to simulate the base case resource plan in the BRPU also derives annual capacity factors for each IDR. These model-derived capacity factors can be used to limit the fixed energy payments under FSO4.

<u>Conclusions of Law</u>

1. PG&E's pay-as-you-go proposal, as described in Attachment 3 to this order, is reasonable and should be adopted for calculating the curtailment adders under Curtailment Option B of PG&E's ISO4, at the expiration of the fixed price period under EPO1, EPO2, and EPO3.

2. PG&E should meet with wind project owners to develop a mutually acceptable method of calculating curtailed deliveries under the pay-as-you-go approach.

3. Adoption of the pay-as-you-go method for calculating curtailment adders at the expiration of the fixed price period does not constitute a modification of PG&E's ISO4.

4. Updating the IDR capacity factor is not necessary for maintaining ratepayer indifference, given the current structure of FSO4.

5. Respondents' proposals for updating the capacity factor are unworkable.

6. It is reasonable to set the annual capacity factors for each IDR equal to the model-derived capacity factors, based on the resource planning assumptions we adopt in our BRPU proceeding.

INTERIM ORDER

IT IS ORDERED that:

1. For all qualifying facilities who selected Curtailment Option B under Pacific Gas and Electric Company's (PG&E) interim Standard Offer 4, PG&E shall calculate curtailment adders at the expiration of the fixed price period using the pay-as-you-go method described in Attachment 3 to this order.

2. PG&E shall meet with wind project owners to develop a mutually acceptable method of calculating curtailed deliveries for wind projects under the pay-as-you-go method. Within sixty (60) days from the effective date of this order, PG&E shall file a description of the agreed-upon method with the Commission's Docket Office and serve a copy of the filing on all appearances and the state service list in this proceeding.

3. Before issuing a final Standard Offer 4 (FSO4) solicitation, the Commission shall adopt forecasted annual capacity factors for each identified deferrable resource (IDR), as follows:

   a. The Commission shall adopt a base case resource plan in each Biennial Resource Plan Update (BRPU) proceeding, consisting of the utility's existing and committed resources, plus all resource additions found to be cost-effective using the Commission-adopted iterative cost-effectiveness method;

   b. The annual capacity factors for each IDR shall be set equal to the model-derived capacity factors resulting from the base case simulation;

   c. If the Commission adopts IDRs that differ from those identified in the base case resource plan, model-derived capacity factors shall be produced by rerunning the base case resource plan with the adopted IDRs included; and

d. For contract years that extend beyond the BRPU planning horizon, the IDR capacity factor shall be fixed at the level adopted for the final year of the planning horizon.

4. Within forty (40) days from the effective date of this order, respondents shall file with the Commission's Docket Office an original and 12 copies of FS04 contract provisions, including appropriate amendments, consistent with this order. The amendments shall reflect the changes described in Ordering Paragraph 2, by:

a. Referencing a separate schedule of annual IDR capacity factors in Section 1.1 (i) of FS04;

b. Modifying Section 14.4 of FS04 to ensure that the total energy-related capital cost payment, for which the Seller is eligible, is not altered; and

c. Making any other language modifications, as required, to reflect the changes described in Ordering Paragraph 2.

Respondents shall develop and file uniform contract language for these amendments.

5. Within forty (40) days from the effective date of this order, respondents shall serve copies of the filings described in Ordering Paragraph 3 on all appearances and the state service list in this proceeding, and provide two (2) copies to the Commission Advisory and Compliance Division, Energy Branch. Respondents shall make additional copies of the filings available to interested parties, upon written request.

This order is effective today.

Dated JUN 06 1990, at San Francisco, California.

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

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

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

AB

Summary of Standard Offers

STANDARD OFFER 1: Variable Capacity and Energy

The QF's energy and capacity are sold on an as-available basis, meaning that the amount and time of delivery of the energy is not guaranteed. The QF is paid full short-run avoided energy cost, plus current shortage cost, on a per kilowatt-hour basis, for all energy delivered to the utility. Energy and shortage costs are updated quarterly and annually (respectively), with the energy cost based on the incremental energy rates established in the utility's last fuel offset proceeding and the expected fuel costs for that quarter. Shortage costs are based on the utility's cost of a combustion turbine. This contract is used by all technologies, but particularly wind, due to the uncertain nature of that resource.

STANDARD OFFER 2: Firm Capacity and Variable Energy

The QF's capacity is sold on a firm basis, meaning that an amount of capacity is guaranteed to be available to the utility during its peak load period. The capacity payments are based on levelized, forecasted shortage costs, which are stated in the contract and are fixed for the life of the contract. Energy prices are the same as in Standard Offer 1. Many cogenerators and biomass QFs hold Standard Offer 2 contracts.

STANDARD OFFER 3: Variable Capacity and Energy From QFs Not More Than 100 Kilowatts

This offer is the same as Standard Offer 1 in practice, but the contract terms and QF responsibilities are less involved, due to the small size of the facilities.

INTERIM STANDARD OFFER 4: Long-term Capacity and Energy, Based on Forecast of Short-run Marginal Cost

This offer has fixed payment rates over long-time spans (up to 10 years). There are three energy payment options and two capacity options.

Energy Payment Option 1) Energy prices are fixed and are based on forecasted avoided energy costs. The QF can choose to have a mix of forecasted and current short-run avoided costs for the energy price, with oil and gas-fired cogenerators limited to 20% of the price being based on the forecasted prices.

Energy Payment Option 2) This is similar to Option 1, except that the forecasted energy prices are levelized and oil and gas-fired cogenerators may not use this option at all.

Energy Payment Option 3) Energy prices are based on fixed, forecasted utility incremental energy rates and utility oil and gas costs. Payments are made based on short-run costs, then adjusted at the end of the year to reflect the forecasted prices. This option is used by cogenerators and is designed to have the energy price reflect changes in fuel costs.

Capacity Option 1) As-available: The QF can choose payments based on either short-run shortage costs, or fixed, forecasted shortage costs, which are not levelized.

Capacity Option 2) Firm: Payments are based on fixed, forecasted, levelized shortage costs.

FINAL STANDARD OFFER 4: Long-term Capacity and Energy, Based on Avoidable Resource

Unlike the short-run standard offers and the interim long-run standard offer, final Standard Offer 4 derives from the respective utility's resource plan (including potential new plant construction, refurbishments, power purchases, etc.), as reviewed by the Commission in a biennial update proceeding. Pricing under final Standard Offer 4 varies according to when the QF comes on-line. During Period 2, the QF avoids a specific utility generation resource, and the QF receives payments based on the fixed and variable costs of the avoided resource. If the QF comes on-line in Period 1, i.e., before the date when the avoided resource would have begun delivery of electricity, the QF meets near-term demand growth, and therefore the QF receives short-run marginal cost-based payments until the start of Period 2. The Commission considers uncertainties and procurement strategies for each utility in determining a megawatt (MW) limit at each update proceeding. Whenever the capacity of QFs seeking final Standard Offer 4 contracts from a given utility exceeds that utility's MW limit, the available contracts are allocated through bidding. The utilities are also authorized to pay QFs additional sums for providing performance features (e.g., downward dispatchability at the utility's direction) not otherwise required under the standard offers.

Period 1 Payments) Energy prices are the same as in Standard Offer 1. Capacity payments for both firm and as-available QFs are based on forecasted shortage costs, ramped for inflation, which are stated in the contract and are fixed for Period 1.

Period 2 Payments) Period 2 shortage cost payments are also fixed and ramped for inflation for both firm and as-available QFs.

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For QFs other than cogenerators, energy payments are equal to the avoided plant's heat rate, times the fuel price (updated quarterly) for the fuel the plant would have consumed. Energy-related capital cost payments equal the annualized cost of the avoided plant, excluding the fixed costs associated with shortage costs. These energy-related capital cost payments are ramped for inflation.

Oil and gas-fired cogenerators are paid under the incremental energy rate (IER) payment option. This option combines and ramps the identified deferrable resources (IDR) energy and energy-related capital costs so as to give the same expected value as the avoided resource, but with a higher proportion of payments represented by energy costs than would be the case with the avoided resource. Cogenerators are paid fixed, forecasted IERs, derived from the costs of the avoided plant, times actual system marginal fuel costs (updated quarterly).

(END OF ATTACHMENT 1)

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FSO4 and ISO4 Curtailment Provisions

Characteristics	D.89-04-047 Adopted FSO4 Option I	D.89-04-047 Adopted FSO4 Option II	Current ISO4 for PG&E Option A	Current ISO4 for PG&E Option B
Selection	QF selects at contract exec.		QF selects at contract exec.	
Curtail/Alt Price Condition	Neg. avoided costs or hydrospill. 1/	Utility sole discretion. Designates Type A (Economic) or Type B (Neg. avoided cost).	Neg. avoided costs or hydrospill. 1/	Neg. avoided costs; margin <u>not</u> oil or gas (and PG&E can replace QF energy with cheaper source); min. system conditions (e.g., hydrospill).
Level of Operation	QF curtails to 30% of effective capacity.	QF selects, except for neg. avoided cost where QF curtails to 30%	QF selects for hydrospill; PG&E may interrupt or reduce for neg. avoided costs.	QF selects, but price may be zero.
Number of Hours	Unlimited	1,500 max. annually	Unlimited	1,000 max. annually
Low Cost Hours	Not applicable	Not necessary because curtailment unrestricted.	Not applicable	Not accounted for
Time periods	All	Off-peak and super off-peak	All	Super off-peak
Other limits	None	One-day max. 3 hours min. duration.	None	None

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FSO4 and ISO4 Curtailment Provisions

Characteristics	D.89-04-047 Adopted FSO4 Option I	D.89-04-047 Adopted FSO4 Option II	Current ISO4 for PG&E Option A	Current ISO4 for PG&E Option B
Payment	Energy: None during curtailment for either hydro-spill or neg. avoided costs.	Energy: QF receives lesser of actual incremental cost or avrg. s-r avoided op. cost (SRAOC) forecast. Price during non-curtailment hours adjusted based on production costing runs.3/ No energy price for neg. avoided cost curtailments even when QF operates at authorized level below 30%.	Hydro savings prices for hydrospill; no payment for neg. avoided cost.	Adjusted price equal to PG&E's available alternative source. Prices in other super off-peak hours increased to compensate.2/
	EROC and Capacity: Based on 12-month rolling average of historical operation (APF).4/	EROC and Capacity: Same as Option I.		
Frequency of Adjustments	Not applicable	Annual	Periodic	None
Resource Inputs	Not applicable	Same as for SRAOC	Not applicable	1984 GRC '84, '88, '92
Non-Compliance	No energy or capacity for hours of non-compliance.	Same as Option I	Not applicable	Not applicable

Note: EROC (Energy-related Capital Costs) apply only to FSO4 payments.

FS04 and IS04 Curtailment Provisions

	D.89-04-047 Adopted FS04		Current IS04 for PG&E	
Characteristics	Option I	Option II	Option A	Option B
Notice	Utility gives reasonable notice when possible.	Utility publishes preliminary schedule annually. QF notifies of intended operation 1 week prior to curtailment hour. Utility may change schedule of curtailments up to 4 hours prior to curtailment.	PG&E to give as much advance notice as practical.	PG&E to give as much advance notice as practical. QF may schedule maintenance, with notice and apply to annual limit.

1/ Negative avoided cost conditions occur when due to operational circumstances, the acceptance of QF power would cost the utility more than generating an equivalent amount of energy itself. Example: A baseload or large oil-fired intermediate load plant is shut down at night due to an excess of QF electricity but then cannot be restarted and brought up to its rated output for the next day's peak load. In this situation, the utility must start up a plant with very high generating costs (e.g., a gas turbine peaker) or purchase expensive emergency capacity to meet demand. Hydrospill conditions occur when system demand would require that hydro-energy be spilled to reduce generation.

2/ The percentage of this adder is contractually established for that part of QF's payments based on energy payments set forth in the contract (during the fixed price period). These are 7.7% for Seasonal Period A (May 1 through September 30) and 9.6% for Seasonal Period B (October 1 through April 30). In D.88-09-026, we adopted the same percentage adders for the portion of energy payments (during the fixed price period) that depend on the current published energy prices.

3/ The procedure for adjusting energy prices based on SRAOC is described in Appendix A. The reduction in energy payments during the 1,500 hours of curtailment is added to the remaining hours of non-curtailment in the super off-peak and off-peak hours. The adder is paid under both Type A and Type B curtailment.

4/ Assumed Production Factor (APF) is defined in Appendix B.

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APPENDIX A
Page 1

FSO4 Procedure for Adjusting Energy Prices in Off-Peak and Super Off-Peak Time Periods*

A. This procedure for adjusting energy prices applies only to QFs selecting Curtailment Option II.

B. Adjustments to energy prices shall be accomplished by adjusting the time-differentiated incremental energy rates (IERs) used in calculating Short-Run Avoided Operating Costs (see Figure A-1).

C. Adjustments to energy prices apply only to payments for energy delivered during off-peak and super-off-peak time periods which is not delivered during periods of curtailment and which, during Period 2, is in excess of energy purchased at avoided plant-based rates.

D. The energy pricing adjustment shall be updated whenever new time-differentiated IERs are determined for Short-Run Avoided Operating Costs.

E. The step-by-step procedure for adjusting IERs for Short-Run Avoided Operating Costs shall be as follows:

1. Develop a Short-Run Avoided Operating Costs IER duration curve as shown in Figure A-1.

   NOTE: (Figure A-1 is an idealized curve for illustrative purposes only.)

2. Determine the average IER during off-peak periods (IERop).

3. Determine the average IER during super-off-peak periods (IERsop).

4. Assume that curtailments will occur during the 1,500 hours with the lowest IERs and determine the average IER during the assumed curtailment periods (IERc).

*Source: July 1987 Joint Testimony, (Exhibit 447, Appendix A) in A.82-04-44 et al.

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Page 2

5. Calculate the total value of the difference between IERsop and IERc during the curtailment periods (represented by Area "A" on Figure A-1).

$$A = (\text{IERsop} - \text{IERc})\ \ (1{,}500 \text{ hours})$$

6. Calculate the adjustment (IERadj) to IERop and IERsop by distributing equally over the remaining (i.e., non-curtailment) off-peak and super-off-peak hours, the total value of the difference between IERsop and IERc determined in Step 5, above.

$$\text{IERadj} = \frac{A}{\text{Hop} + \text{Hsop} - 1{,}500}$$

Where:

Hop = Total off-peak hours

Hsop = Total super-off-peak hours

A = Total value of the difference between IERsop and IERc during the curtailment periods calculated in Step 5.

7. Adjust IERop and IERsop as follows:

$$\text{IERopadj} = \text{IERop} + \text{IERadj}$$

$$\text{IERsopadj} = \text{IERsop} + \text{IERadj}$$

The total value of the adjustments to IERop and IERsop are shown as Areas "B" and "C", respectively, on Figure A-1.

NOTE: Area "A" equals the sum of Areas "B" and "C".

8. If the Time Period definitions are modified in the future, causing inconsistencies in the calculations, the parties will work together to resolve the problems.

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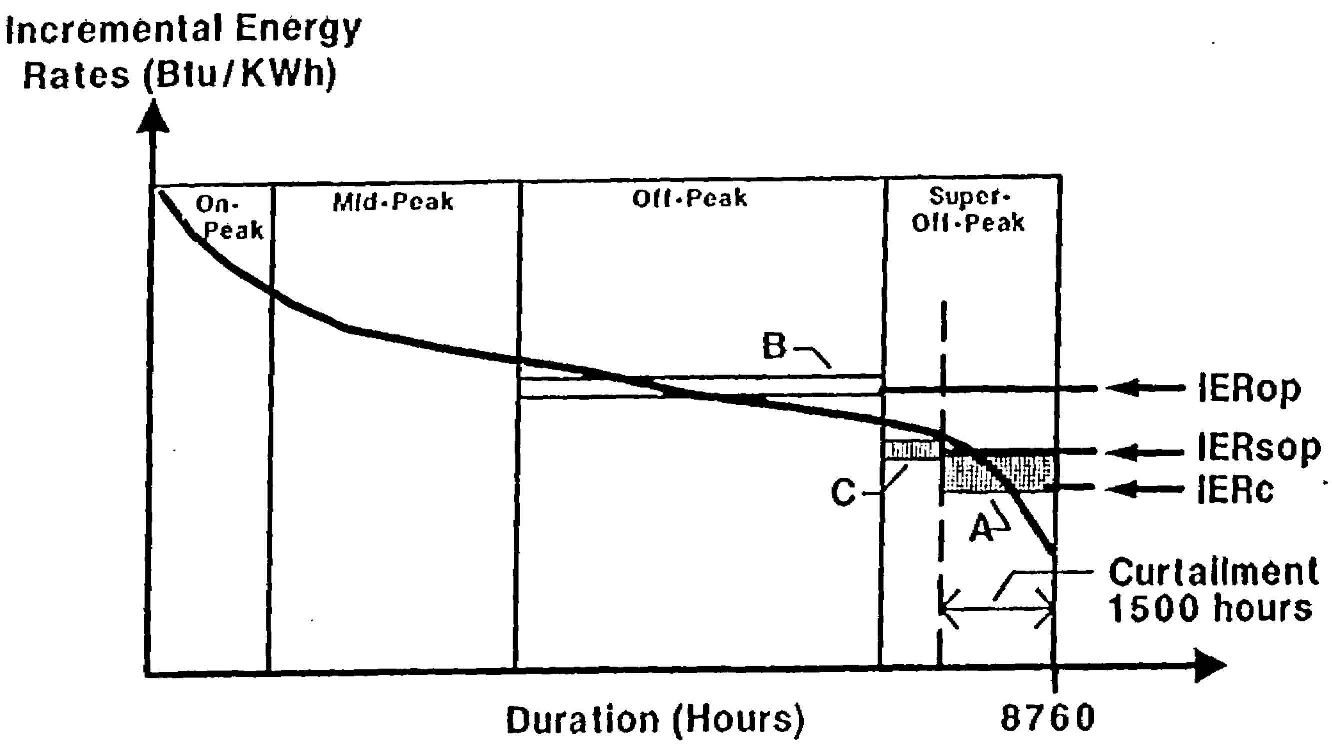
APPENDIX A

Figure A-1

IDEALIZED

Short-Run Avoided Operating Costs Incremental Energy Rate Duration Curve



NOTE: The IER Duration Curve is determined from the computer model run that forms the basis of the short-run avoided cost IERs adopted in ECAC proceedings.

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APPENDIX B

Derivation of Assumed Production Factor (APF)*

Under the FS04 Curtailment Options I and II, the utility continues to pay Energy-Related Capital Costs (ERCC) and shortage cost payments based on Assumed Production Factor (APF) calculated for the time period in which the curtailment occurs; provided, however, that ERCC payments in any billing period shall not exceed the maximum allowed under avoided plant pricing.

APF for the relevant time period(s) is calculated as follows:

$$APF = \frac{kWh}{EC \times Hours}$$

kWh = Energy delivered to utility during the relevant Time Period(s) less any energy delivered during curtailment in the relevant Time Period(s) during the previous 12 monthly billing periods. Such energy shall exclude any energy delivered at rates in excess of Firm Capacity for Firm QFs and Nameplate Capacity for As-Available QFs.

EC = Effective Capacity

Hours = Total hours during the relevant Time Period(s) less (1) curtailment hours, (2) scheduled maintenance hours (applies only to firm QFs), and (3) hours when Seller is required to interrupt or reduce deliveries pursuant to the curtailment provisions in the relevant Time Period(s) during the previous 12 monthly billing periods.

Notes on calculation of APF:

(i) "Time Period(s)" refers to on-peak, off-peak, and super-off-peak time periods.

(ii) For curtailment during off-peak or super-off-peak, a combined off-peak and super-off-peak APF will be used to determine payment credits.

(iii) During the first year of operation, the APF will be calculated from available billing data accumulated monthly until such time as a full twelve (12) monthly billing periods have passed.

*Source: July 1987 Joint Testimony, (Exhibit 447, Appendix A) in A.82-04-44 et al.

(END OF ATTACHMENT 2)

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PG&E's Pay-As-You-Go Proposal[1/]

Summary

PG&E designed this proposal to be conceptually equivalent to the curtailment adder calculation in both FSO4 and ISO4 during the fixed price period. The concept behind these adder calculations is that the difference between the QF's energy price (for example, short-run avoided cost, "SRAC") and the lower marginal costs (for example, the Alternate Price) is summed over all curtailed hours and then spread over the non-curtailed off-peak hours. Instead of spreading this difference over non-curtailment hours, PG&E is proposing to pay for curtailment "as-we-go". Specifically, PG&E's proposal is as follows:

When curtailment conditions exist on the PG&E system, PG&E gives a QF notice that PG&E is invoking curtailment and notifies the QF of the Alternate Price for those hours of curtailment. PG&E will pay the QF the difference between the price normally paid to the QF for generation during those hours and this Alternate Price (we can call this difference the "Curtailment Price"), regardless of whether or not the QF curtails. If the QF decides to continue operating during these hours, PG&E will pay the Alternate Price plus this Curtailment Price. This sum is equal to the price normally paid to the QF during those hours if the QF wasn't curtailed (the SRAC for that time-of-use period). If the QF decides to reduce its deliveries, PG&E will still pay the Curtailment Price for those deliveries that would have occurred if the project had not been curtailed, but will of course not pay the Alternate Price.

The QF's choice to continue operating will depend on the project's variable cost to operate, its cost to cycle, and the Curtailment Price. If the project's variable costs are greater than the sum of the Alternate Price and the project's cost to cycle, the QF is likely to curtail deliveries. If the reverse is true, that the variable costs are less than the sum of the Alternate Price and the project's cost to cycle, then the QF is likely to continue operating.

1/ To apply only to PG&E's ISO4, Curtailment Option B, at the expiration of the fixed price period.

Source: Exhibit 8, Appendices B and D.

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Illustration

Curtailment Price = SRAC - Alternate Price

If SRAC = 30 mils, Alternate Price = 20 mils, then
Curtailment Price = 10 mils

Example:

Say Variable Operating Costs = 25 mils

If QF operates, profit = (20 mils + 10 mils) - 25 mils = 5 mils

If QF backs-down, profit = 10 mils

So the QF would choose to back-down

Example 2:

Say Variable Operating Costs = 15 mils

If QF operates, profit = (20 mils + 10 mils) - 15 mils = 15 mils

If QF backs-down, profit = 10 mils

So the QF would choose to operate.

(For simplicity, both of these examples ignore the cost of cycling.)

Calculation of Curtailed Deliveries

Under PG&E's proposal, PG&E would pay the "Curtailment Price" for those deliveries that would have occurred if the project had not been curtailed. PG&E would calculate these "curtailed deliveries" from the average level of partial-peak deliveries (in kW) for the billing period in which the curtailment occurs minus the average level of deliveries during the curtailment (in kW) with this difference multiplied by the hours in the curtailment period. PG&E notes in its comments to the Proposed Decision that the method of calculating curtailed generation described above will yield accurate results for all QF technologies except for wind projects. PG&E has stated its willingness to meet with wind project owners to develop a mutually acceptable method of calculating curtailed deliveries.

[Partial Peak Deliveries (kWh) / Partial Peak Hours (hr)] - [Curtailed Deliveries (kWh) / Curtailed Hours (hr)] = X

X (kW) * Curtailed Hours (hr) = Curtailed Deliveries

Curtailment Notice Period

PG&E will continue its current practices in notifying the QFs of curtailment under Option B. PG&E makes every attempt to provide as much advance notification as possible. However, PG&E cannot forecast with sufficient certainty the minimum system conditions required to invoke curtailment under Option B. On occasion PG&E has had to cancel curtailment orders when fossil plants were no longer at minimum operating levels as expected. Cancelling curtailment orders is administratively burdensome for PG&E's Power Control Department. Longer advance notification would lead to more frequent curtailment cancellations and less operating certainty for QFs.

(END OF ATTACHMENT 3)

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List of Appearances

Respondents: John T. Guardalabene, Attorney at Law, for Pacific Gas and Electric Company; Julie Miller, Attorney at Law, for Southern California Edison Company; and Wayne Sakarias, Attorney at Law, for San Diego Gas & Electric Company.

Interested Parties: James D. Squeri, Attorney at Law, for Armour, St. John, Wilcox, Goodin & Schlotz; Nancy Thompson, for Barakat, Howard & Chamberlin; Barbara R. Barkovich, for Barkovich and Yap; C. Clark Leone, for Bonneville Power Administration; Neal A. Johnson, for California Waste Management Board; John Chandley, A. Kirk McKenzie, Attorneys at Law, Scott Matthews, Sanford Miller, and Paul Richins, for California Energy Commission; Reed V. Schmidt, for Bartle Wells Associates; C. Hayden Ames, for Chickering & Gregory; John D. Quinley, for Cogeneration Service Bureau; Randolph L. Wu, Attorney at Law, for El Paso Natural Gas Company; Kenneth R. Meyer, for Energy Consulting Group; Martin A. Mattes, Attorney at Law, for Graham & James; Barry Epstein and Dian Grueneich, for Law Offices of Dian M. Grueneich; David Branchcomb, for Henwood Energy Services, Inc.; Jan Smutney-Jones, for Independent Energy Producer Association; Thomas P. Corr, Attorney at Law, for Independent Energy Producers/Independent Power Corporation; William Marcus, for JBS Energy, Inc.; William Booth and Joseph Faber, Attorneys at Law, for Jackson, Tufts, Cole & Black; Norman A. Pedersen, Attorney at Law, for Jones, Day, Reavis & Pogue; Karen Edson, for KKE & Associates; Michael P. Alcantar, Attorney at Law, for Lindsay, Hart, Neil & Weigler; John Gulledge, for Los Angeles County Sanitation Districts; Michael Lotker, for LUZ International; Emilio E. Varanini, III, for Marron, Reid & Sheehy; Grant Nelson, for The Metropolitan Water District of Southern California; Joseph G. Meyer, for Joseph Meyer Associates; Jerry R. Bloom, Attorney at Law, for Morrison & Foerster; Robert B. Weisenmiller, for Morse, Richard, Weisenmiller & Associates, Inc.; Ralph Cavanagh, Attorney at Law, for Natural Resources Defense Council; Ronald F. Helbling, for Nevada Electric Investment Company; Wallace Gibson, for Northwest Power Planning Council; Philip J. Di'Virgilio, for PSE, Inc.; Donald W. Schoenbeck, for Regulatory & Cogeneration Services; Roberts and Kerner, by Douglas K. Kerner, Attorney at Law, for Santa Fe Geothermal, Unocal Corporation and Freeport-McMoran Resource Partners; Deborah L. Berger, Attorney at Law, for City of San Diego; Robert Weatherwax, for Sierra Energy & Risk Assessment, Inc.; Joyce Holtzclaw, for Sierra Pacific Resources; Kathi Robertson, for Simpson Paper Company; Steven Greenwald, Attorney at Law, and Glenn Berger, for Skadden, Arps,

List of Appearances

Slate, Meagher & Flom; Roy Rawlings, for Southern California Gas Company; Ronald L. Knecht, for Spectrum Economics; Michel Peter Florio, Attorney at Law, for TURN; Michael J. Ruffatto, Attorney at Law, for Trigen Resources Corporation; Lori Govan, for U.S. Windpower, Inc.; Nancy Jo Albers, for Unocal; Law Offices of Matthew V. Brady, by Matthew V. Brady, Attorney at Law, for California Department of General Services; Donna Stone, for California Department of Water Resources; David L. Modisette, for Joint Committee on Energy Regulations and the Environment; John S. Castor, Tim Duane, Donald H. Maynor, Attorney at Law, and Donald G. Salow, for themselves.

Division of Ratepayer Advocates: Ida Passamonti, Attorney at Law.

(END OF ATTACHMENT 4)

Table of Acronyms and Abbreviations

This table contains an expansion of each acronym and abbreviation used in today's decision. Following the expansion is a reference to the section in the body of the decision where the acronym or abbreviation first appears.

A.	Application (II.)
ALJ	Administrative Law Judge (II.C.)
Alternate Price	This term refers to the utility's lower marginal cost over curtailable hours (either forecasted or actual) (II.E.)
BRPU	Biennial Resource Plan Update (I.)
CEC	California Energy Commission (III.A.)
Curtailment Price	Under PG&E's pay-as-you-go proposal, this term refers to the difference between the price normally paid to the QF for generation during curtailable hours (i.e., SRAC) and the Alternate Price. (II.E.)
D.	Decision (II.)
DRA	Division of Ratepayer Advocates (II.C.)
ECAC	Energy Cost Adjustment Clause (III.B.)
EPO1	Energy Payment Option 1 (under PG&E's ISO4) (II.B.)
EPO2	Energy Payment Option 2 (under PG&E's ISO4) (II.B.)
EPO3	Energy Payment Option 3 (under PG&E's ISO4) (II.B.)
FSO4	Final Standard Offer 4 (I.)
IDR	Identified Deferrable Resource (III.)
IER	Incremental Energy Rate (II.B.)
ISO4	Interim Standard Offer 4 (I.)
PG&E	Pacific Gas and Electric Company (I.)
QF	Qualifying Facility (II.)
SCE	Southern California Edison Company (I.)
SDG&E	San Diego Gas & Electric Company (I.)
SF/U/F	Santa Fe Geothermal, Inc., Unocal Corporation and Freeport-McMoran Resource Partners (II.C.)

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Table of Acronyms and Abbreviations

SO1	Standard Offer 1 (II.A.)
SO2	Standard Offer 2 (II.A.)
SO3	Standard Offer 3 (II.A.)
SRAC	Short-Run Avoided Cost (II.E.)
TR	Reporter's Transcript (II.E.)

(END OF ATTACHMENT 5)