ALJ/SK/fs Item 3

Decision **88 09 026** SEP 14 1988 ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

(See Appendix F for appearances.)

FINAL DECISION, COMPLIANCE PHASE: GENERAL RESOURCE PLANNING ISSUES, PERFORMANCE FEATURES ("ADDERS"); AVAILABILITY OF STANDARD OFFER 2

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**FINAL DECISION, COMPLIANCE PHASE:
GENERAL RESOURCE PLANNING ISSUES,
PERFORMANCE FEATURES ("ADDERS");
AVAILABILITY OF STANDARD OFFER 2**

I. Introduction

Today's decision completes a nine-year process. In this process, we have developed various standardized power purchase contracts (Standard Offers 1 through 4) to help integrate electrical generation from certain non-utility sources (Qualifying Facilities or QFs) in the electric utilities' supply mix.

Summarizing a nine-year process is itself a lengthy task. We won't burden the text of this decision with such a summary. However, the appendixes provide citations of major CPUC decisions on QF matters, descriptions of the various offers, an account of how the resource plan-based offer (final Standard Offer 4) works, a table of acronyms and abbreviations, and a timetable for the next biennial resource plan review. Implementation of final Standard Offer 4, reinstatement of Standard Offer 2, and coordinated updating procedures for all of the offers are the major issues in the compliance phase.

A series of interim decisions has resolved most of these issues. Today's decision addresses some of the key policy questions in resource plan updating and filling resource needs, makes a proposal for regulating the future availability of Standard Offer 2, and resolves outstanding motions and petitions. The final task in this proceeding concerns increasing the uniformity of the form and terminology of the standard offer contracts among the utilities. With the completion of this task in the fall, we will at last be able to close the consolidated standard offer proceeding.

II. The Interim Decisions

Four interim opinions precede today's final decision. All of these concern utility compliance filings pursuant to Decision (D.) 86-07-004 and D.86-11-071, in which we created a foundation for correlating QF development with resource planning and capacity valuation.

The first of these interim opinions approves a detailed protocol for conducting the second price auction for final Standard Offer 4 (D.87-05-060, mimeo. pp. 7-25), resolves a variety of pricing issues (pp. 25-39), and discusses the treatment of uncertainty and negotiated contracts in resource planning (pp. 39-49). These were the compliance phase issues that did not directly relate to the resource plans developed by the utilities in response to the Sixth Electricity Report (ER-6).

The subsequent interim opinions deal with our conclusions from our review of resource plans submitted in compliance with the newly created biennial planning process. In the second interim opinion (D.87-11-024, mimeo. pp. 2-29), we found that none of the utilities had an avoidable resource within the eight-year "window" that we established for purposes of final Standard Offer 4. We also discussed the concept of "disaggregated resource need" and how it relates to avoidable resources (pp. 29-31). Finally, we decided to continue the suspension of Standard Offer 2 for Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (Edison), but reinstated the offer, with certain restrictions, for San Diego Gas & Electric Company (SDG&E). (Id., pp. 31-42; see also D.87-12-056 regarding queue management and related contract provisions for Standard Offer 2.)

The third interim opinion, D.88-03-026, is essentially a matrix showing how and where we will update the provisions of the various standard offers. The fourth interim opinion completes the development of reliability targets for resource planning and capacity valuation purposes, with the single exception of the short-term capacity value adjustment for PG&E (D.88-03-079, mimeo. pp. 6-18). We also resolved a long-standing issue on energy-pricing for QFs receiving variable energy payments (pp. 21-34) and certain contract drafting problems in final Standard Offer 4 (pp. 34-48).

In today's decision, we draw some further conclusions concerning our resource plan review and the process of coordinating that effort with the California Energy Commission's (CEC) Electricity Report. We also consider the utility filings on additional performance features; these features will receive more study in the next biennial update proceeding. Finally, we explain the continuing role of Standard Offer 2 (firm capacity, variable energy payments) in the portfolio of offers and propose for comment a new approach to regulating the availability of Standard Offer 2.

III. Review of the Resource Plans Responding to ER-6

We have already dealt with some of the major implications of the resource plan filings; here, we discuss various issues that we think will significantly affect future filings. We do not undertake a line-by-line dissection of the plans or a response to every planning issue raised by the parties but rather concentrate on those matters that significantly influence our conclusions during this (our first) biennial resource planning cycle.[1]

1 Given this approach, the parties should not interpret our failure to expressly criticize (or approve) any particular aspect of a utility's resource plan as an endorsement (or rejection) of how the utility handled that aspect.

A. Procurement Strategy

One of the most significant issues raised in our first resource plan review is how we should deal with the utilities' strategic preferences. Judgment affects resource planning because all forecasts are more or less uncertain. The planner must examine a whole range of outcomes that differ from the case deemed most likely to occur, in order to determine the financial risks that a given utility faces and how to mitigate those risks through the utility's selection among resource options.

This issue may affect final Standard Offer 4 in various ways. Fundamentally, the utility may prefer to add different resources and/or fewer resources than those suggested solely by cost-effectiveness analysis of a base-case scenario.[2] SDG&E's "50/50" procurement strategy (see D.87-05-060, pp. 41-45), under which SDG&E would fill all its projected near-term needs but only half of the long-term needs arising within the final Standard Offer 4 "deferral window," is an example of such a preference. The strategy reflects the value that SDG&E attaches to maintaining flexibility at a time when its resource options seem plentiful. This flexibility enables SDG&E to take advantage of surplus power that it thinks may be available at low cost over the next few years from other utilities, and mitigates what SDG&E regards as a major risk at this time, namely, the risk of premature commitment to major new facilities. Stated differently, SDG&E believes that, in its present circumstances, the costs of premature commitment would likely exceed the costs of bringing a new resource on-line some time after the optimal point.

2 However, the biennial update process does not contemplate making any more megawatts available to final Standard Offer 4 QFs than would be found to be needed under the CEC's then-current Electricity Report. (See D.86-11-071, mimeo. p. 19.)

The main purpose of our resource plan updating process is to periodically quantify the megawatts that QFs could fill on the basis of each utility's long-run marginal costs, as revealed by the utility's current resource plan formulated according to least-cost principles. Such a plan must account for uncertainty but there may be many ways to do this. Our job is not to dictate strategy to the utilities. Rather, we must determine whether, under the circumstances of the particular utility, the discretionary aspects of its procurement strategy are consistent with reasonable planning assumptions (including perceived uncertainties) and a long-run least-cost resource plan.

We do not imagine that this will be an easy determination to make, but one principle is clear. Any acceptable procurement strategy must be non-discriminatory, i.e., it must apply to the utility's own projects and purchases from non-QF sources as well as to QFs. This is not to say that all generation resources have equal value; on the contrary, we expect the utilities to quantify asserted operational differences and system needs, and to capture such benefits, wherever possible, through "adders" from final Standard Offer 4 and other QFs. (See Section IV below.)

The present resource plan review does not require us to evaluate procurement strategies in detail. Only SDG&E made an explicit presentation on this issue, and we have found that, under any of the scenarios, SDG&E does not have an avoidable resource at this time. Nevertheless, we think SDG&E's focus on this issue is both helpful and appropriate. In future biennial update proceedings, the applicants should explicitly present strategic elements in their resource plan filings. These presentations should reveal the applicant's risk preferences and indicate how the applicant believes that its strategy responds to uncertainty and contributes to least-cost planning. Other parties are free to critique strategic elements as well as other aspects of each resource plan.

B. Consistency with CEC Assumptions

The biennial resource planning process requires the utilities, at a minimum, to prepare a resource plan based on the CEC's latest adopted Electricity Report. Problems arose in the compliance phase because (according to the utilities) some of the information that the utilities needed for plan preparation was not separately stated in ER-6 or readily available from CEC staff. ER-7 will probably present fewer problems of this type because ER-6 was well under way before we adopted our first implementation order (D.86-07-004), while ER-7 should benefit from the experience gained in this resource plan review cycle. We direct our staff to cooperate in any effort to prepare standardized forms or other means that might help the flow of information that must take place on almost an on-going basis between the CEC, the CPUC, and the utility applicants.

A more fundamental problem concerns the treatment by the utilities of certain CEC assumptions.[3] For example, how should the resource plans account for projected loads of municipal utilities within the CEC "supply planning areas" of the respective investor-owned utilities? (I.e., should municipal load in excess of municipal resources be treated as demand on the investor-owned utility system that is potentially required to serve that load?) Also, how should the resource plans account for self-generation (as a reduction of demand or as a source of both demand and supply)? We think that, for purposes of the CEC-based resource plans, the utilities ought to adopt the treatment preferred by the CEC. If

3 See also Section III.D.4 below.

the utilities have concerns about how to implement the CEC's preferred treatment, those concerns should be addressed to the CEC.[4]

We recognize that municipal loads and self-generation are two matters that involve much uncertainty and therefore are the source of some of the risks confronting the investor-owned utilities. The utilities' biennial update filings should specifically explore these risks in their showing on uncertainty and procurement strategy.

C. Purchases from the Pacific Northwest

The Bonneville Power Administration (BPA), a federal entity, influences electrical supply planning in California through BPA's ratemaking authority over certain federal hydroelectric facilities and its control of transmission capacity interconnecting California with the Pacific Northwest. The CPUC, the CEC, and other California parties have differed with BPA over both its rates and its allocation of transmission capacity through the Intertie Access Policy. Litigation has ensued, and many fundamental differences of legal opinion are not yet definitively resolved. Inevitably, California planners must recognize the uncertainty that results from these unsettled differences and must choose strategies that ensure reliable and economic service in California under various possible outcomes.

The remarks that follow do not consider or purport to analyze the legality of BPA's past or present policies. We intend the remarks solely to indicate the steps that California planners may take, considering the possibility that BPA would continue its current policies on rates and transmission access.

4 We suspect that these concerns, to the extent that they have not already been resolved, can be dealt with in workshops with CEC staff.

We hope BPA would make appropriate modifications to its current policies. However, despite some recent progress, BPA has still not provided the kind of assurances to California that, consistent with sound planning strategy, would justify reliance on Pacific Northwest energy to the extent that BPA apparently wishes.

1. BPA's Ratemaking Policies

Electricity supply planning must distinguish between short-term and long-term resources. BPA has set prices to California that in recent years have tracked just below the short-run marginal costs of California utilities. Such pricing sharply reduces the attractiveness of BPA's energy. The reason is that, as California utilities' short-run marginal costs increase, we fear BPA's prices would also rise, regardless of whether BPA has a lot of surplus energy or a little.[5] In contrast, long-run marginal costs recognize that a utility will eventually devote capital to acquiring a resource that improves its operating efficiency, i.e., lowers its short-run marginal costs.

In the resource planning portion of the compliance phase hearings, much time was spent estimating the quantity of surplus energy that might be available to California from the Pacific Northwest. The Pacific Northwest will typically have large surpluses for some years to come, but those surpluses mean little without assurance on price. The key planning assumption is the price associated with varying amounts of energy. Until and unless BPA (or the Federal Energy Regulatory Commission or the courts in their review of BPA's decisions) provides appropriate assurance as to some other price assumption, we arguably should assume that all purchases of "economy" energy from BPA will be slightly below

5 Given BPA's Intertie Access Policy, we would expect similar upward pressure on the prices of other energy sellers in the Pacific Northwest.

short-run marginal cost. Under these circumstances, and given reasonable projections that oil and gas prices will steadily increase over the long-term, we expect that cost-effective long-term alternatives to purchases from BPA will appear at the biennial resource plan update. We further expect our utilities to pursue these alternatives, whether they be new utility power plants, purchases from other out-of-state sellers (such as Southwest utilities), or QFs bidding against these plants and purchases.

BPA, in its 1987 rate case, has tried to respond to some of the concerns of California parties. It adopted a "long-term nonfirm energy rate cap." (See Chapter VIII of BPA's 1987 Draft and Final Records of Decision, which are Exhibits 459 and 460, respectively.) As described by BPA witness Fama (Tr. 7645-46), "The long-term cap is a formula Bonneville proposes to place in effect for 12 years. It would go through 1999. That formula is independent of any particular rate design that might be placed in effect during those 12 years. It was proposed [to ensure] a significant amount of savings for California purchasers, more than one or two mills--in the area of four to five mills--[for] much greater amounts of service" as compared to price assurance under nonfirm energy rate design or short-term caps.

We appreciate BPA's appearance in this proceeding, as well as its participation in the development of ER-6. We are particularly gratified at BPA's tacit recognition of the planning quandary that its ratemaking policies have created for California.

Unfortunately, the long-term cap offers only nominal assurance of savings--certainly nothing that causes us to qualify the planning assumption described above.[6]

The long-term cap itself is a good concept and can be useful to California planners in direct proportion to the level of benefits and the degree of assurance provided. This cap provides little assurance either qualitatively or quantitatively.

First, the long-term cap is a decision of BPA that BPA can reverse. At current oil and gas prices, the cap means little, but as oil and gas prices rise, the difference between California's marginal costs and the cost of the Pacific Northwest's largely hydro-based generation will increase, which in turn will create pressure on BPA to abandon the cap precisely when it begins to produce significant benefits for California. The cap must be backed up by contracts with California utilities before we can be satisfied with the quality of the assurance provided.

On this important point, BPA's Final Record of Decision says, "BPA will begin contract negotiations upon interim FERC approval of the rate cap." BPA says repeatedly that it fears actions by regulatory or legislative bodies in California that are "detrimental to BPA's economy energy market" and that it is "specifically looking for appropriate California regulatory decisions," i.e., "reciprocal action from the regulators." (Exhibit 460, pp. 178-79.) The only prudent reciprocal regulatory action that we can conceive of, based solely on the long-term cap,

6 We must emphasize that the root problem for California is BPA's nonfirm energy rate design, which has given California reason to doubt that any significant amount of benefits will accrue to California from future energy purchases from the Pacific Northwest. Our preference is still that BPA reform its rate design policies; a rate cap might enable us to calculate a "worst case" scenario for California, but such a scenario does not present a very persuasive argument for protecting the BPA market share.

is to encourage contract negotiations as soon as possible, but not to otherwise commit California to purchases from BPA pending the result of such negotiations.[7]

Second, the assured savings under the long-term cap are not impressive. The quantity of such savings depends on the size of the discount from California's marginal costs, the amount of energy to which the cap applies, and the length of time when the cap is in effect. Tradeoffs are possible: for example, a relatively small discount could still be significant if coupled with larger amounts of energy and a longer period subject to the cap. But BPA's long-term cap seems skimpy in all respects. The 12-year duration is less than the fixed-price period (15 years) in final Standard Offer 4, and the amount of energy, which in any event is nonfirm, declines (due to increased demand in the Pacific Northwest) when benefits to California from the price cap would otherwise increase. The 4-5 mill discount mentioned in BPA's testimony is unlikely to be attractive compared to the total costs and benefits of a long-term resource, and while the cap's formula could in theory provide greater discounts as California's marginal costs rise, the realization of such discounts depends on BPA's adherence to the cap. In the absence of contracts, and considering the fiscal pressures that affect BPA, we cannot confidently assume such adherence.

In short, we think that BPA, with the long-term rate cap, has taken a small step in the right direction. BPA falls short of its goal, to protect its California market share, because the cap seems less attractive than the long-term resource opportunities that compete for BPA's market share.

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7 We are also pursuing "economic curtailment" and similar performance features in QF contracts to ensure that to California utilities can take full advantage of attractive prices when available from BPA and other non-QF sellers of energy.

2. BPA's Transmission Access Policies

BPA owns and operates most of the Pacific Northwest-Pacific Southwest Intertie transmission lines above the Oregon-California border. BPA currently allocates access to these lines under a "Near Term Intertie Access Policy."

The Intertie Access Policy is currently the subject of litigation between BPA and California parties. Significantly, a panel of the federal Ninth Circuit Court of Appeals, while divided on the merits of the case, has unanimously agreed with California parties that the Intertie Access Policy is clearly anticompetitive. The panel majority describes the result of the Intertie Access Policy as "a regularly shifting, horizontal division of the market for surplus nonfirm energy; each eligible producer is temporarily granted sole access to a specified share of the capacity, which it may either use or allow to remain unused without fear of competition by other producers." The dissenting judge agrees with this characterization and further notes that the Intertie Access Policy favors Pacific Northwest utilities generally (not just BPA) and acts as an output restriction as well as suppressing price competition.[8]

BPA's adoption of the Access Policy was on an interim basis, although BPA has already twice deferred the policy's expiration. We had urged BPA to adopt a long-term policy that eliminates the anticompetitive impact of the interim policy. However, in the absence of such a long-term policy, and with the

8 California parties have petitioned for writ of certiorari from the United States Supreme Court. The matter is still pending.

interim policy in effect for an indeterminate period, prudent planning to meet California's electricity demand is seriously complicated.[9]

Resource planners must consider physical constraints of the existing transmission system, but the Access Intertie Access Policy is not a physical constraint. It expressly contemplates that Intertie capacity will on occasion go unused even when California utilities are willing to pay prices attractive to some energy sellers in the Pacific Northwest. For purposes of QF recruitment under final Standard Offer 4, should California planners imagine that these power purchase opportunities do not exist, solely because the Intertie Access Policy chokes them off?

If we assume that the Intertie Access Policy effectively forecloses some power purchase opportunities, such as might be created, e.g., by development of potential generation in British Columbia, then we become BPA's unwilling accomplices in limiting competition for the California market. Essentially, our assumption for the price of BPA's own output (that it would be priced just below California utilities' short-run marginal costs) would then extend to all power purchases from the Pacific Northwest. This assumption would certainly spur the QF program because avoided costs would be higher; the advantage to California from such a policy is that it would lead to maximum use of California's indigenous energy sources. On the other hand, we are troubled by the implications of this assumption, both for least-cost planning and for avoided cost principles.

9 On May 17, 1988, BPA adopted in final form a "Long-Term Intertie Access Policy." The CEC comments note that this policy contains many of the objectionable features of the interim policy but does provide 800 megawatts of "assured delivery" (i.e., firm transmission). While litigation continues on the interim policy, the CPUC and CEC have both filed a petition for review of the latest policy in the Ninth Circuit Court of Appeals.

Another possibility is to assume that potential sellers in Canada and the Pacific Northwest (other than BPA) would compete to sell their surplus energy and capacity on a long-term basis into the California market, based on competitive forces and their own costs, despite BPA's attempts to sustain its own artificially high price through the Intertie Access Policy. We think this assumption is consistent with avoided cost principles and a reasonable level of QF development. On the other hand, the assumption requires us to model as resource options some transactions that could not occur until the Intertie Access Policy is set aside.[10]

The Intertie Access Policy seriously distorts California's energy planning whichever assumption is used. Our preferred solution is that the policy be modified to enable energy sellers in the Pacific Northwest to participate in the California market up to their full potential. As long as that policy continues in effect, then the mitigation of the policy's price distortions will be a principal task in the biennial update proceeding.

D. The Evolving Resource Planning Process

1. CEC/CPUC Procedural Coordination

The biennial resource plan proceeding is a new feature of electric utility regulation in California. It dovetails with the "integrated assessment of need" performed biennially by the CEC in the Electricity Report; it is essentially the forum where the largest of the investor-owned electric utilities (PG&E, SDG&E, and Edison) and other parties identify generation resources potentially avoidable by QFs under long-run contracts (final Standard Offer 4).

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10 Thus, a utility should not use this assumption to reduce its need assessment by hypothesizing nondeferrable resources constrained by the policy.

This necessarily involves consideration of overall strategies (including demand management and power purchases as well as construction of new power plants) for filling the needs projected for these utilities.

We recognize that this is an ambitious process, requiring (among other things) close coordination between the CEC and the CPUC. The CEC presented an excellent overall coordination proposal in last summer's hearings; however, we were unable to respond to that proposal in time for ER-7, which was under way before the filing of briefs in the current (compliance) phase of this proceeding.

The CEC proposal envisions a "concurrent approach" under which the CEC's findings on need and the CPUC's findings on avoidable resources would be developed, in part, through joint hearings and decisions. This contrasts with the "sequential approach" exemplified in this, the first, biennial resource plan review, in which the CEC's adoption of ER-6 was followed by the filing of CEC-based resource plans (and in the case of SDG&E and Edison, alternative scenarios) at the CPUC.

The sequential approach should be retained, at least for the time being. The main reason is that the "Integrated Schedule" presented by CEC witnesses Deter and Praul (see Figure 1 of Exhibit 406 and their discussion in that exhibit) seems to combine the CEC's adoption of supply and demand forecasts with the consideration of alternative planning strategies that must, among other things, respond to those forecasts and to the uncertainty surrounding them. However the CEC chooses to deal with such uncertainty, it seems fair and logical to allow utility planners some time in formulating their resource strategies to think about the CEC base case after that case is established.

There is obvious concern that the CPUC consideration of "alternative scenarios" could subvert the CEC's adopted planning assumptions; this concern, together with the desire to avoid potentially duplicative proceedings and the CEC's own interest in dealing with uncertainty issues, seems to underlie the CEC's coordination proposal.

We recognize the CEC's concern and strongly support the explicit consideration of forecast uncertainty by the CEC. However, our review of the utilities' resource plan strategies is not inherently subversive of the CEC forecasts. We are directing the utilities to file--not their preferred forecast--but rather a resource plan that (1) is devised to meet the CEC's integrated assessment of need, and (2) does not result in undue exposure to increased costs should their actual need turn out to be greater or less than anticipated. The use of alternative scenarios initially seemed to us the most promising way to investigate this exposure, but SDG&E has made a persuasive presentation to support forecasts with "bands" to denote uncertainty, while Edison focuses on flexible planning that "choose[s] resources considering their strategic value, including their ability to be expanded or changed as time goes on to cover uncertainty." (Edison Concurrent Brief, Compliance Phase, regarding resource plan issues, p. III-11.) There are doubtless many ways for a resource planner to hedge risks and thus minimize costs over the long-run; in this respect, the goals of the regulator and the regulated utilities coincide.

For these reasons, the question is not so much a procedural issue of aligning the CEC and CPUC processes as it is a substantive issue of how the CEC wants to deal in its Electricity Reports with the universally acknowledged uncertainty of all forecasting efforts. The CEC response to the latter issue may well take care of both the procedural problems and the objections expressed by some parties to what they feel is a deterministic (and therefore unduly risky) reliance on the CEC forecast.

In the meantime, we reaffirm our commitment in D.86-07-004 to base the availability of final Standard Offer 4 on projections of need that are consistent with the findings of the CEC's then-current Electricity Report.[11]

Besides the procedural issue of aligning the Electricity Report with the resource plan review, there are a number of substantive areas where the parties have expressed need for further direction on the use of CEC methods or assumptions in the CPUC proceeding. We discuss these areas below.

2. Connecting Short-range and Long-range Forecasts

The resource planning process involves projection of the utility's loads and supplies during the forecast period. We have directed the utilities to present a "base case" planning scenario that uses the CEC's current long-range demand forecast (which begins in year 5 and runs through year 20) and the current short-range forecast adopted for the respective utility by the CPUC (typically, in a general rate case or ECAC proceeding).

There will be a gap between the first year of the CEC long-range forecast and the end of a short-range forecast used in our proceedings. Filling the gap between short-range and long-range forecasts is tricky because, as most parties agree, the two

11 CEC witnesses indicated that there is now a process at the CEC whereby the Electricity Report Committee, upon motion and appropriate showing, could modify some of the then-current report's findings. This process might affect the biennial resource plan proceeding, e.g., if an earthquake or other disaster were to cause a supply emergency (and consequently a finding of increased need) of indefinite duration.

However, our understanding and strong recommendation is that the CEC would resort to this process very sparingly. Some stability in base case planning assumptions is necessary if a resource plan review is to be feasible. Moreover, the biennial forecasting cycle seems sufficiently frequent in itself to mitigate risk from all but the most extreme unforeseen events.

types of forecast use markedly different methodologies.[12] Seemingly anomalous jumps or dips in the connecting years might not have practical consequences where a utility appears not to have new resource needs in those years. However, where a utility (such as SDG&E in this phase) has a near- or mid-term need for new resources, proper specification and timing of resource additions may require more systematic projections for the connecting years.

Our approach for this phase called for trending from the short-range forecast to the CEC's year 5. Upon consideration of this record, we believe some additional flexibility is appropriate. We will allow the utility in its base case scenario to choose among the following: the trending approach used in this phase; repetition of the CPUC short-range forecast for the connecting years; or repetition of the CEC year 5 forecast for the connecting years. All of these approaches respect the integrity of the CEC and CPUC forecasts, while allowing the utility to choose the most reasonable way to bridge those forecasts.

In the next biennial resource plan proceeding, each utility should choose explicitly among these approaches and also indicate whether the choice has a material impact on its conclusions regarding avoidable resources.

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12 The chief reason for the difference is that short-range forecasts are designed to be sensitive to transitory phenomena (business cycles, unusual weather conditions, etc.), which tend to even out over time, while long-range forecasts deal with more fundamental changes, such as turnover in the capital stock of energy-consuming equipment. Thus, for example, a long-range forecast might project steadily rising fuel prices while a contemporary short-range forecast shows falling fuel prices. Short-range and long-range forecasts serve different purposes; it is generally unnecessary (and impossible) to get them to mesh perfectly.

3. Common Terminology

Everyone agrees on the need for the CPUC and the CEC to arrive at a common terminology for resource planning purposes. Without a common terminology, and agreement on the concepts behind that terminology, we would spend a lot of time fitting square pegs into round holes.

CEC witnesses presented a common terminology proposal in the compliance hearings, and we understand that the proposal has been refined in discussions with CPUC staff and workshops in ER-7. We direct our staff, in coordination with CEC staff, to prepare and serve on the parties in A.82-04-44 et al. a status report on this effort. The report is due no later than October 21, 1988, and should indicate areas of agreement as well as those areas that are still problematic. If the CEC and CPUC staffs have reached complete agreement on terminology, then we encourage them to submit the report jointly.[13]

We recognize that terminology should not try to mask or eliminate methodological differences that may exist between the two commissions; in fact, one virtue of a common terminology is that it may clarify where those differences arise. We also note that whether a given resource falls in one of several possible categories is generally an issue of fact before one or both commissions. The goal of a common terminology is not to preclude different results but only to ensure that we are talking about the same problem.

4. Analytical Consistency Between Regulators

The CPUC and CEC must frequently analyze the reliability of electric utility systems and the cost-effectiveness of utility programs to add supply or manage demand. In this proceeding,

13 We see no need of a CPUC decision to ratify a common terminology. However, we urge completion of this effort in time for ER-7 to incorporate the terminology.

parties have noted that the CPUC and CEC sometimes use different methods for conducting these analyses; these differences make it hard for utilities to prepare their compliance filings and could lead to conflicting conclusions on resource needs.

We feel the differing system reliability approaches are not currently a pressing problem. The reason is that we have taken steps to reconcile the results. For PG&E, we are using CEC-based target reserve margins for long-term planning purposes (and are considering a proposal for adjustment, using CEC targets, of as-available capacity payments), while the EUE targets that we have approved for SDG&E and Edison are applied so as to be consistent with CEC planning criteria. (See D.88-03-079, pp. 8-18.)

However, we also note that methods for measuring and valuing system reliability continue to be controversial as new models are developed, existing models are refined, and the merits of the value-of-service approach are examined. The biennial update proceeding is the forum where we consider methodological changes for the standard offers. We will use our existing reliability methodology for the update to follow ER-7, but to the extent that developments in the reliability area warrant changes thereafter, the parties should describe those developments and their proposed changes in their testimony submitted in this update. We endorse the CEC's goal of ultimately arriving at a reliability methodology that is common to both commissions.

The CEC and CPUC staffs have dealt with cost-effectiveness testing in a series of workshops, aiming to modify the existing Standard Practice Manual to permit more direct comparison of generation resources with demand-side options. (See D.87-11-024, pp. 19-22.) It seems clear at this time that substantial progress has been made, but that all problems will not be resolved in this update cycle. Because of the importance of this issue in the treatment of those conservation/load management programs designated "conditional RETO" (discussed below), we feel that modifications to the Standard Practice Manual should continue to command a high priority.

As part of DRA's filing in the next biennial update proceeding, DRA should include a status report on progress toward the development of a standardized and uniform methodology for the treatment of costs and benefits of all resource options (both generation and nongeneration).

In D.87-11-024, we noted the disparate views on how the CEC's adopted estimate of long-term demand-side management (DSM) program impacts should be integrated into the long-run standard offer process. The CEC's forecasts of DSM program impacts include (under the term "conditional RETO" [reasonably expected to occur]) some programs subject to future regulatory action. Examples are anticipated CEC building and appliance energy efficiency standards as well as utility-sponsored programs whose level of funding is set by the CPUC. In D.87-11-024, we held that committed DSM programs are nondeferrable by QFs, and for uncommitted programs we accepted the CEC estimates of conditional RETO in preference to SDG&E's position (under which no conditional RETO would be included in SDG&E's resource plan). However, we also noted (id., p. 20) that in the future, the level of conditional RETO included in the resource plans should depend on more definitive demonstrations that such programs constitute cost-effective supply options. We supported expected enhancements to the cost-effectiveness methodology, via joint CEC and CPUC staff workshops on revisions to the Standard Practice Manual, as the vehicle for these demonstrations.

We reaffirm our intention to review long-term DSM program impacts and to integrate them into our long-run resource planning activities. The adopted CEC forecasts of uncommitted conservation should be presented by the CEC and reviewed by our staff and other parties in terms consistent with any enhancements developed in the joint CEC/CPUC staff workshops on integrated least-cost methodologies. Based on our review, we expect that we will consider some or all of the estimated uncommitted conservation as nondeferrable resource additions for purposes of final Standard Offer 4. Projection of long-term DSM costs and impacts by this Commission in the resource plan update proceeding should also be given weight in subsequent short-term DSM funding requests in the respective general rate cases.

IV. Performance Features and Disaggregated Resource Needs

We are satisfied, on the whole, with the utility compliance filings in what is the first time through a complex new proceeding. The filings of PG&E and Edison, however, fall short of what we required in D.86-07-004 regarding the assessment of need for additional performance features (e.g., full dispatchability, voltage support) on their respective systems:

> "[The utilities] shall file and serve...a report preliminarily assessing the value and feasibility on their respective systems of additional performance features potentially supplied by Qualifying Facilities (QFs). The report will address specifications that QFs would have to meet, methods for quantifying and costing the features, implementation procedures, and other particulars...." (Id., Ordering Paragraph 2.)

The reticence of PG&E and Edison contrasts with the careful analysis that SDG&E devoted to this issue.

Additional performance features ("adders") refer to system benefits that a generation resource (including both a utility's own plants and purchases from QF and non-QF sources) may provide beyond the resource's basic energy and capacity.[14] These features may have local or system-wide value, depending on the other resources, transmission configuration, and other characteristics of the utility receiving the resource's power. (For further discussion of the genesis of the "adders" concept, see D.86-07-004, pp. 11-13, 74-75; D.87-11-024, pp. 29-31.)

These additional features are important for many reasons. In particular, they can enhance reliability and help the utility to add resources, consistent with economic dispatch and smooth system operation. Furthermore, they play a role in the utility's planning of its own resources and negotiations with non-QF sellers. To the extent that QFs are able to provide such features, this may mitigate the utilities' stated concerns about minimum load problems that may accompany higher reserve margins, and also help to place QFs on the same plane as the utilities' other resource options.

A. PG&E's Report on Performance Features

PG&E's comments on performance features are contained in Part D, pages 93-112, of its Fifth Amendment to Application 82-04-44 (which we shall refer to as the Amended Application), in Exhibit 416 (pp. B IV-1 to -4), in Exhibit 417 (pp. 28-30), and in its concurrent brief on resource planning issues (pp. 58-61). PG&E makes some good points, but its comments are often more argumentative than analytic.

14 Note that standard offer contracts already contain performance requirements of various types. For example, all except very small QFs (100 kilowatts or less) are required to provide "reasonable" reactive power support, and QFs holding contracts to provide firm capacity are dispatchable upward by the purchasing utility to any level up to the contract capacity. We therefore directed consideration of "adders" only to the extent that they concern a feature to which the utility is not already entitled under its contract with the QF. (D.86-07-004, p. 74.)

PG&E notes, and we agree, that what "adders" are appropriate depends on the "basic pricing concept" for the QF, including such matters as the kinds of performance required of QFs under the various standard offers and the frequency of updating for the factors that affect the calculation of QF prices. Since some of our decisions on updating are quite recent, PG&E to that extent had reasonable grounds for insisting that it could not precisely determine the value of load-following features (e.g., coordination of maintenance, prescheduled dispatch, full dispatchability). PG&E also makes the helpful observation that system stability features (e.g., availability during emergencies, black-start capability), where appropriate, should be compensated through a capacity adder rather than an energy adder. PG&E's analysis barely goes beyond this. The report has little on how to implement adders, how to quantify need for adders, or how to price them, even under PG&E's recommendations for updating.

PG&E argues that, for load-following features, "the key issues are (1) what payment structure is used to calculate the base price, and (2) is the avoided utility plant dispatchable? PG&E's candidate avoided plants are dispatchable and were modeled as dispatchable in cost-effectiveness analysis. As a result, must-run QFs should receive a decrement to energy payments." (Concurrent brief, p. 58.) This argument is faulty. PG&E may only be considering dispatchable resources right now, but eventually it, like any other electric utility, will need additional baseload generation resources. The QFs that defer or avoid baseload additions may be able and willing to follow load in varying degrees, even though the avoidable resource would not. Furthermore, we agree with the analysis of IEP witness Marcus: "To pay [load-following] QFs ... a price based on the average avoided costs, which assume no load following, will underpay those QFs." (Exhibit 432, p. 25.)

PG&E itself concedes that "[d]ispatchable resources should always have some incremental value." (Exhibit 417, p. 29.)[15] We asked the utilities to investigate, through the adders concept, how to cost-effectively obtain potential additional load-following capability from QFs. PG&E has not done so.[16]

Regarding system stability features, PG&E argues that "there is no question that the features identified as appropriate in determining an adder would be inherent in the avoided plant. Any plant that PG&E constructs would automatically incorporate these and other features.... Likewise, the cost estimates for constructing and operating the avoided plant would include the cost of these features." (Exhibit 417, p. 29.) We don't doubt that PG&E designs its plants with system stability in mind, along with a great many other things. However, the site chosen for an avoidable resource is bound to be a compromise: a site that is suitable for environmental reasons may or may not have system stability advantages, and the site (no matter how advantageous) will certainly not enable PG&E to meet system stability requirements at other areas in its service territory. (Cf. D.86-07-004, p. 60,

15 PG&E also notes, "[A] dispatchable QF could be relied [upon] for spinning and regulating reserve, area power factor correction, attenuation of local disturbances, local voltage support, ensuring system security, and more efficient area load regulation, just as PG&E relies upon its own dispatchable resources for such purposes." (Amended Application, Part D, pp. 109-10.) We agree. Furthermore, some of these benefits might be provided even by QFs that are not fully dispatchable.

16 We also disagree with PG&E's suggestion that "must-run" QFs deferring intermediate resources (which are the only dispatchable resources deferrable under final Standard Offer 4) are overpaid. Time-differentiated energy prices and the treatment of energy-related capital costs in that offer ensure that such QFs, if they operate when the avoidable resource would not, are paid no more than avoided cost during those hours. See also our discussion of load-following features in Section IV.B below.

note 37.)[17] Thus, it is possible for QFs avoiding a resource, and even existing QFs that do not defer or avoid a specified resource, to provide system stability benefits to the purchasing utility.

More important, PG&E ignores the fact that the avoidable resource may not be a plant but rather a purchase of energy and capacity from a non-QF seller. In that case, the load-following and other features of the purchase are generally a part of the negotiations between the purchasing utility and the non-QF seller. Moreover, the purchasing utility generally claims substantial value for these features in reasonableness reviews and other proceedings. We understand the importance of these features in off-system transactions and desire only that QFs be permitted to compete on an even footing. In our view, that goal requires analysis of disaggregated resource needs, especially those system requirements that might not be met by any single avoidable plant but could be met by purchases from some combination of QF or non-QF sources.

B. Edison's Report on Performance Features

Edison's comments on performance features are contained in Chapter IV of Exhibit 421, Chapter IV of Exhibit 424, and Chapter V of its concurrent brief. Edison has priced four of the seven performance features identified in D.86-07-004 (emergency availability, coordination of maintenance, reactive power support, and full dispatchability). Like PG&E, Edison believes that system stability features are properly reflected in capacity payments. Edison would pay for full dispatchability through an adder to the QF's "base energy price."

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17 As PG&E notes, many types of system stability requirements tend to be local in nature. The best-planned power plant would not meet such requirements if they affect an area remote from the plant; the utility would have to satisfy them through other means, among which QFs might be a cost-effective alternative.

Edison apparently believes that the term "adder" is a misnomer for what should generally be a decrement to QF payments, at least as they are currently calculated. For example, under final Standard Offer 4, if the QF does not agree to supply all the performance features of the avoidable resource, "the QF should only be paid for the performance features it agrees to supply and actually does supply; otherwise, the ratepayer pays for a service that is not provided." (Exhibit 421, p. IV-3.) As for existing QFs, Edison says that "implementation [of adders] is not feasible at this time. The majority of existing QF contracts includes capacity payments that are based on the full value of a [combustion turbine] which already includes most of the performance adders identified. To allow QFs with existing contracts to seek adders would result in compensating them twice for the same performance feature." (Id., p. IV-8.)

Edison cautions that it had to make many assumptions in order to develop the values shown in its preliminary assessments of adders. "As experience is gained, these assessments and derivations will need to be updated to capture other effects not presently quantifiable ... or other methods for attempting to 'unbundle' the value of various performance characteristics from the cost of the [avoidable resource]. As currently derived, the value of the adders is based more on how the [avoidable resource] was to be operated than how it was constructed." (Exhibit 421, p. IV-4.)

We find Edison's comments helpful in some respects, and Edison has been more forthcoming than PG&E in trying to determine values for at least some of the adders. However, Edison exhibits the same tunnel vision as PG&E in thinking about avoidable resources, and we are sceptical about Edison's proposed valuation methods.

We accept, in principle, the proposition that capacity or energy payments to a final Standard Offer 4 QF could be lower, as well as higher, depending on the mix of performance features that the QF supplies, as compared to the performance features associated with the avoidable resource. Edison seems to think that the effect of considering performance features would generally be to lower QF payments. We think that remains to be seen.[18] However, as Independent Energy Producers Association (IEP) notes, QFs' system stability features would very likely be adders whenever out-of-service-area resources are the avoidable resources. (See Exhibit 432, pp. 28-29.)[19] When the avoidable resource is an in-area power plant, the question is more complex. As we've noted above, the site chosen for that plant is apt to be a compromise. QFs avoiding or deferring that plant may make a greater or lesser contribution to system stability, depending on their technology, location, and willingness to make appropriate commitments.

We reject Edison's assertion that adders are "not feasible" for existing QFs. Edison mixes up short-run and long-run methodologies and misconstrues the role of the combustion turbine in calculating capacity payments to these QFs. Final Standard Offer 4 is the only plant-based offer. The combustion turbine is used simply as a proxy for the purchasing utility's short-run marginal cost of capacity. Nobody ever expected QFs to run like a combustion turbine or designed a standard offer to replace

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18 Since both Edison and PG&E apparently take the position that the correct treatment of performance features would effectively reduce QF payments overall, we find it surprising that their response to our request that they quantify and evaluate these features is so tepid.

19 "Many emergencies in fact are caused by transmission line failures, such as loss of the Northwest Intertie on December 22, 1982 and February 29, 1984, and out-of-service-area resources may well be unavailable as a result of such line failures. In addition, out-of-service-area resources cannot support voltage." (Prepared Testimony of IEP witness Marcus, Exhibit 432, pp. 28-29, citations omitted.)

combustion turbines in the utilities' resource mix. We therefore do not reduce capacity payments to QFs for failure to match the system stability features of a combustion turbine. (We do, however, reduce prices to QFs that receive variable capacity payments to reflect the purchasing utility's current need for capacity.)[20] It follows that there is no overpayment or methodological inconsistency if utilities were to pay existing QFs for supplying performance features that such QFs are not otherwise obligated to provide.

Turning to specific system stability features, IEP has demonstrated a flaw in Edison's valuation of emergency availability. Edison uses a formula that relates increased spinning reserve requirements to potential emergency unavailability of QF capacity on its system. Positing such a relationship seems a reasonable way to begin the analysis. However, Edison values this feature in dollars per kilowatt of increased spinning reserve costs rather than dollars per kilowatt of QF capacity projected to be unavailable. This is inaccurate since, even if Edison were actually to increase its spinning reserves per the model (Edison says that it in fact does not do this, see Exhibit 424, p. IV-1), it would do so on less than a kilowatt-for-kilowatt basis. Edison thus significantly overstates the value of QF emergency availability under its own formula. (See also Section IV.D below.)

Edison also evaluates an adder for voltage support. SDG&E calculates a similar dollars per kilowatt value for this adder, which would apply to support provided beyond the minimum

20 Thus, Edison's and PG&E's current capacity payments to variably priced QFs are deeply discounted from the full annualized fixed costs of a combustion turbine, to reflect the relative abundance of capacity on their systems. Such discounting would not happen under a plant-based offer: the utility cannot build a fraction of a power plant.

interconnection requirements in the respective utility's tariff rule (Rule 21). The value assigned to this adder (roughly $1 per kilowatt-year) seems reasonably derived from the cost of proxy capacitors. We also agree with Edison and SDG&E that the adder should be made available only in specified areas of need on the system, since reactive power cannot be transmitted over long distances. IEP prefers SDG&E's approach, which uses distribution capacitors, because (according to IEP) most QFs are located at the distribution level. This can be discussed further in workshops, but we are satisfied that the parties have established a good basis for implementing this adder.

There has been a lot of work on load-following features since Edison prepared its report. The key to our preferred approach (which we think is followed in the curtailment provision developed for final Standard Offer 4) is that any kind of load-following is basically a device for concentrating the QF's output within relatively high-cost hours on the utility system. This leaves the purchasing utility free to achieve optimal dispatch during low-cost periods. The load-following adder should therefore be calculated as the differential between the QF's potentially operating at random over all hours of the year and whatever limitation to higher cost hours is imposed by the performance feature to which the QF commits. (See D.87-08-047, mimeo. pp. 7-8.) We agree with IEP that, wherever the QF would otherwise be paid on an average cost or time-differentiated basis, the QF's commitment to follow load justifies an increase in its energy payments.

The approach that Edison takes in its preliminary assessment of load-following features is quite different, and we doubt that Edison (one of the chief architects of the curtailment provision) would adhere fully to its former proposal at this time. Edison makes a good observation that full dispatchability may be analyzed as a composite of various other adders such as prescheduled dispatch. However, much work still needs to be done in order to derive a full dispatchability adder made up of the sum of discrete load-following increments. In Exhibit 421, Edison suggests valuing full dispatchability on the basis of efficiency savings realized by the purchasing utility. The efficiency savings result from the reduced cycling of the utility's own plants that is made possible by QFs' commitments to follow load. Such savings might indeed occur, but they seem quite speculative and hard to quantify relative to our preferred approach, and also seem to be only a small component of the total load-following benefits attributable to full dispatchability.

C. <u>SDG&E's Report on Performance Features</u>

SDG&E's comments on performance features are contained in Exhibit 429, pages 28-33, and Appendix A of that exhibit. SDG&E favors valuing performance features, using historical data wherever possible, by determining a "base" level of service (with energy-related and capacity-related components). What is or is not included in "base" service is open to dispute, as is the question of whether some of the standard offers already require, and compensate QFs for, some of the performance features beyond "base" service. Nonetheless, the "base" service concept is a useful way to structure this analysis. SDG&E also discusses the compatibility of different types of performance features and provides a "Matrix of Adders Interaction" that neatly defines the possible combinations of adders that a QF could select.

As we noted earlier, SDG&E's valuation of the voltage support feature is definitive. SDG&E would only make the adder available on a case-by-case basis, arguing that "an assessment of need for var support near the QF site must be made by [SDG&E] personnel." (Exhibit 429, p. A-8.) We recognize that the need for this feature is site-specific; however, the utility should be able to specify some criteria that would at least alert the QF operator or planner of its potential eligibility for the adder.[21]

SDG&E expresses its suggested load-following adders as a percentage of the energy price. It calculates an adder of 0.8% for coordination of maintenance. For curtailment (which SDG&E prefers to prescheduled dispatch), SDG&E calculates an adder of 4.1% for 1000 hours of allowable curtailment, increasing to 6.5% where the curtailment level is set at 2000 hours, and to 7.9% for 3000 hours. Finally, the full dispatchability adder works out to 16.5%.

SDG&E derives these percentage adders by comparing its hourly marginal energy costs (using 1985 recorded data) with its Time-of-Use rates. This seems reasonable as an initial quantification. However, there may be other ways to compute the effect of concentrating the QF's output within relatively high-cost hours. We are also concerned about the possible sensitivity of the adder to the choice of historical base year. SDG&E itself urges in its concurrent brief that we not implement adders at this time but instead convene workshops to further develop these concepts.

D. Conclusions

1. Specific Performance Features: System Stability

All parties agree that none of the utility applicants currently has a need for black-start capability on its system. We will defer further consideration of this feature indefinitely.

Voltage support is the feature most satisfactorily analyzed to date. A price range of $1 to $1.20 per kilowatt-year

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21 We do not now have a multi-attribute bidding system for final Standard Offer 4, but adders (if the QF developer has sufficient information about their availability and price) can serve a similar function. For example, a QF developer that knows that its plant could qualify for certain adders could take this into consideration both in its plant design and in calculating its bid for the second price auction. This is a "win-win" situation: the QF optimizes its economics while increasing its value to the purchasing utility.

appears reasonable. Analytical work on this feature now needs to concentrate on QF eligibility, including geographic and operational criteria.

The utilities show a wide variation in their treatment of emergency availability and perhaps in how they define it. PG&E and SDG&E believe that they are already entitled to this feature from QFs and thus claim that it should be priced at zero. On the other hand, Edison assigns a very high price to emergency availability. It appears, however, that Edison has unique criteria for underfrequency load-shedding, under which (according to IEP witness Marcus) QFs interconnected at below 220 kilovolts are cut off automatically during system disturbances. (See Exhibit 432, p. 27.) Edison calculates that typical QF power deliveries, and roughly half of the total megawatts provided by QFs, come from stations subject to such disconnection. (Exhibit 421, p. IV-6.) The ironic result is that PG&E complains of QFs that (according to PG&E) trip off-line during frequency deviations less severe than would cause damage to the QF's generator, while QFs complain that Edison trips them off-line (and would reduce their capacity payments on account of this utility-imposed unavailability) even during frequency deviations when they could remain on-line.

We have rejected Edison's valuation of emergency availability. Thus, there is no basis for Edison to use that value either to increase or decrease payments to QFs. However, we agree in principle with PG&E that, if relay settings are established to automatically disconnect the QF where frequency deviations would damage the QF's generator, it is reasonable to expect the QF not to manually separate from the system during lesser deviations. At least for a QF that defers or avoids an in-area power plant, this logic would dictate a <u>reduction</u> in capacity payments unless that QF commits to reliance on the relays or direct authorization from the purchasing utility before separating from the system. Neither PG&E nor SDG&E has calculated an appropriate level for such a reduction.

In D.88-03-079, p. 45, we said that "appropriate QF response to emergencies is vital if utilities are to rely on large amounts of QF power." We repeat our call in that decision for more QF/utility consultation on this subject, particularly on matters such as variations in practice between the utilities and manual separation by QFs.

2. Specific Performance Features: Load Following

For reasons that we explained in Section IV.B above, load-following features must generally be treated as adders to the energy payments to QFs providing such features. SDG&E's report, and the work done on "economic curtailment" for final Standard Offer 4, create a sound basis for further efforts in this area. SDG&E has also indicated that it intends to develop a simplified curtailment procedure for use with its final Standard Offer 4. (See Section VIII below.) We hope that procedure would also be adaptable for purposes of reinstated Standard Offer 2. We direct DRA to hold a public workshop to discuss load-following features generally, define future tasks and priorities, and review SDG&E's proposal. The workshop should take place within a reasonable time after SDG&E publishes its proposal.

3. **General Observations on Performance Features and Disaggregated Resource Needs**

Our original interest in this topic was prompted by two concerns.

First, the utilities have said that the larger than anticipated response to the standard offers has created or will create operational problems because existing QFs are subject to few performance requirements and are not dispatched downward by the purchasing utility. From the utility reports, we had hoped to get more knowledge of the types and severity of these alleged problems.

Second, the "adders" concept seemed adaptable to both new and existing QFs. This was attractive because it (1) involved existing QFs in the solution of problems attributed to their development, and (2) suggested cost-effective forms of relief for QFs that were looking for ways to boost their revenue streams.[22]

Our experience in the compliance phase of this proceeding has heightened and broadened our interest in the "unbundling" of resource needs. This is because the resource plans have underscored two additional concerns.

First, over the long term, we are looking for ways to bring into the QF procurement process other factors besides basic capacity and energy. Whether this enhancement of the process takes the form of multi-attribute bidding, RFP-type solicitation (see D.86-07-004, p. 21), or adders/subtractors to a contract base price, we would need to establish in advance at least the relative worth of each factor. Performance features seem to be the logical place to begin this analysis, both because of the utility operational concerns mentioned above and because there seem to be objective bases for pricing these features.[23]

Second, the record to date suggests that the avoidable resource is apt to be a purchase from non-QF sources, and that

22 Some QFs predate the standard offers. These "pioneers" often receive little or no capacity payment and an energy payment based on short-run avoided energy costs. When oil and gas prices dropped sharply, so did the energy payments. (See D.87-01-049.) Load-following and other adders are especially suitable in these circumstances since they provide higher payments based on increased value of the QF's deliveries to the purchasing utility. This is fair to QFs and fair to ratepayers.

23 For example, we already time-differentiate electric utility costs and rates for various purposes; such time-differentiation has obvious relevance to the load-following features. Some factors that do not directly relate to performance might also be considered in QF procurement. These factors (e.g., fuel diversity, impact on California economy and environment) are generally more subjective and/or remote from "traditional" (i.e., before passage of CEQA and the Warren-Alquist Act) resource planning: hence, our decision to start with performance features.

performance features would figure importantly in such purchases.[24] According to SDG&E, current power purchase negotiations between utility systems usually involve a "base package" of assets and services; the process of negotiating takes the form of "repackaging" to explore ways to add value or reduce costs. We certainly have no desire to replace such purchases with purchases from QFs unless QFs provide equivalent value. On the other hand, we will not make the a priori assumption that QFs cannot provide equivalent value. The development of performance features should give us a measure against which to test the QFs' response.

For all these reasons, the "unbundling" of resource needs is the logical culmination of a resource plan-based QF procurement methodology. Only SDG&E seems (from this record) to have grasped this point, or to have expended the analytical effort to make significant progress.

To be fair, we must also note that since the preparation of these utility reports, all of the utilities and many QFs have done much work on load-following features. This work has resulted in an "economic curtailment" option for final Standard Offer 4 and many individually negotiated curtailment or dispatchability features.

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24 SDG&E witness Niggli asserts that "a utility can obtain services from a power purchase contract with a utility that a QF resource frequently is unable to provide." Niggli mentions the following "services:" energy storage arrangements; energy banking arrangements; capacity and energy from multiple units at a plant; back-up service from the utility system; diversity exchange arrangements (hourly, daily, seasonally); marketing services; transmission access. (Exhibit 214, p. 10.) We think that the ability of QFs to provide such services is largely untested. QFs come in many sizes and technologies, so there should be at least a potential for QFs to meet or beat performance adders offered by non-QF competition. We encourage both utilities and QF developers to explore contractual arrangements whereby QFs would provide these or other services.

In the resource plan update following ER-7, the utility applicants should each file revised reports on performance features. The reports should cover at least the same system stability (except for black-start capability) and load-following features that were in the original reports; the utilities may also propose additional features. The utilities should indicate the performance features that have been incorporated to date in any contracts with QFs, and should provide a statistical analysis. The analysis need not identify individual QFs but should indicate, by QF technology, the number of megawatts on the respective utility system that are subject to curtailment or other special performance requirements.

Finally, the reports should analyze the potential for a resource plan-based long-run offer made up of disaggregated resource needs. Such an offer would include components for "basic" energy and capacity set at projected long-run marginal costs; system stability adders and line loss impacts calculated for various districts within the purchasing utility's service area; and load-following adders calculated for a range of load-following options up to and including direct utility dispatch of the QF plant. There are other factors in resource planning that are not strictly performance-based. The "unbundled" generation resource offer could include premiums for various attributes deemed desirable by the planner. Such attributes would include, but are not limited to, various types of security that the QF might post, an option to delay or advance the QF's on-line date, and use by the QF of renewable fuels or other fuels that meet fuel diversity criteria.

V. The Future of Standard Offer 2

Standard Offer 2, like interim Standard Offer 4, has been suspended (i.e., is not available for new QF contracts). Similar problems underlie both suspensions: inadequate provisions for updating, coupled with price terms that, in view of then-current expectations of need, were seemingly too generous to QFs seeking new contracts.

Revised updating and capacity value adjustment procedures are now in place. (See D.87-11-024 and D.88-03-026.) Block pricing, an overall megawatt limit, and a time limit on availability are additional features that we approved for Standard Offer 2. These developments made it possible to reinstate Standard Offer 2, up to a maximum of 100 megawatts in two blocks of 50 megawatts each, for SDG&E. (See D.88-03-079.)

However, we decided not to reinstate Standard Offer 2 for PG&E or Edison. (See D.87-11-024.) These utilities, unlike SDG&E, showed very little need for new generation capacity over the next five years.[25] This causes concern because the levelized capacity payments in Standard Offer 2 would mute the price signal that the capacity value adjustment and block pricing was supposed to give to potential QFs. Thus, the outstanding issues for Standard Offer 2 are (1) under what circumstances should it be made available, and (2) what megawatt limits should apply when it is available.

Standard Offer 2 uses short-run energy and capacity prices (using the annualized fixed costs of a combustion turbine as a proxy for the short-run marginal cost of capacity). However, the capacity price is projected and levelized over the life of the contract (up to 30 years). This feature means that Standard Offer 2 has greater price certainty than the other offers based on short-run methodology, where the capacity price is subject to annual adjustment. Also, Standard Offer 2 is the only one of our current offers to have any degree of front-loading in the payment

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25 Standard Offer 2 currently requires the new QF to come on-line within five years after contract execution.

stream.[26] Finally, Standard Offer 2, unlike the other short-run offers, requires the QF to be available during periods of peak demand on the purchasing utility's system and recognizes the ability of many QFs to provide firm capacity.[27]

There is no doubt that Standard Offer 2 has a continuing role to play in a balanced portfolio of standard offers. For example, SDG&E has noted the importance of the QF's commitment under Standard Offer 2 to meet peak demand; during its suspension, the only short-run offer available to a QF over 100 kilowatts capacity is Standard Offer 1, which entails no such commitment. Moreover, we are convinced that need generally should not be an issue with Standard Offer 2 since, like the other short-run offers (and subject to our concern regarding levelization), payments to Standard Offer 2 QFs reflect the purchasing utility's short-run marginal costs. Considering these features, we seek comment on the following proposal for regulating the availability of Standard Offer 2.

Standard Offer 2 would be made available, for a specified time and subject to block pricing and overall megawatt limits, for PG&E, SDG&E, and Edison after each biennial update proceeding. The block sizes would be 50 megawatts for SDG&E and 150 megawatts for PG&E and Edison. The number of blocks to be made available for

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26 Interim Standard Offer 4 also has front-loaded payment options. However, final Standard Offer 4 supplants the earlier version as our long-run offer and only provides "ramped" (i.e., inflation-adjusted) payment streams.

27 Time-differentiated capacity payments under Standard Offers 1 and 3 give the QF a powerful incentive to be on-line during peak periods; however, the QF does not have to meet any performance requirement for such periods, i.e., the QF delivers only "as available" capacity. In contrast, the QF under Standard Offer 2 must generally be available for all on-peak hours in the peak months (subject to a 20% allowance for forced outages in any month) in order to receive full capacity payments.

each utility would be an issue in the update proceeding. Generally, we would make available an amount of capacity not less than 2% of the respective utility's peak demand; this corresponds to about one year's growth in peak demand and represents a conservative amount of capacity to be made available, since there are two years between updates.

To meet our concern about levelization, we would add to Standard Offer 2 a new requirement that the QF come on-line no sooner than the first year in the eight-year "window" that the purchasing utility's ERI is projected to equal or exceed a stated threshold.[28] (The higher the ERI, the greater is the relative value to the utility of additional capacity.) We propose to set this threshold initially at 0.8. If the ERI does not reach the threshold during the "window," no new Standard Offer 2 contracts would be made available at that update. A Standard Offer 2 QF that comes on-line before the ERI threshold is projected to be reached would receive forecast unlevelized capacity payments during that interval. (This is the same way that we treat final Standard Offer 4 QFs coming on-line before the projected on-line date of the avoidable resource.)

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28 The projection would be made in the biennial update proceeding and would be based on the resource plan used for purposes of final Standard Offer 4. The Standard Offer 2 contract would have a specific date when the QF could begin to receive levelized capacity payments. This date would be redetermined at each update proceeding for new Standard Offer 2 contracts, but existing contracts would not be affected. Both the Standard Offer 2 capacity price table and the number of blocks of Standard Offer 2 contracts to be made available would be determined assuming full subscription of whatever number of final Standard Offer 4 megawatts is authorized in that biennial update proceeding. In other words, any identified avoidable resource would be deemed avoided or deferred by final Standard Offer 4 QFs when we establish the pricing and availability of Standard Offer 2.

The threshold would modify the current requirement in Standard Offer 2 that the QF come on-line within five years of contract execution; instead, like final Standard Offer 4 QFs, the Standard Offer 2 QF would have up to eight years to come on-line (depending on when the threshold is reached rather than the projected on-line date of an avoidable resource). This feature, together with capacity price levelization, would make Standard Offer 2 particularly attractive to QFs using new or capital-intensive technologies that typically require some degree of front-loading in order to be financed and that often need more than five years to come on-line.[29]

Standard Offer 2 presently provides for contracts of up to 30 years. In contrast, Period 2 (the fixed price period) for final Standard Offer 4 contracts is set at 15 years. We invite comment on whether to modify the maximum length of new Standard Offer 2 contracts.

It may be useful to receive comments on our proposal before the next biennial update proceeding. Accordingly, the schedule for comments will be set by Assigned Commissioner or ALJ Ruling.

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29 Given these adjustments to reinstated Standard Offer 2, we hope to see fewer requests for approval of nonstandard contracts. We also regard Standard Offer 2 as setting the limit for front-loading payments to QFs, while final Standard Offer 4 sets the limit for price certainty. We do not preclude greater front-loading or price certainty in a nonstandard power purchase agreement, but the utility and QF supporting such an agreement will bear a heavy burden in demonstrating that it is fair to ratepayers and consistent with avoided cost principles.

VI. Uniform Standard Offer Contract Language

Our basic policy governing the form and terminology used in the standard offer contracts is that they should be uniform among the utilities except for the very few aspects that must be utility-specific due to different operating characteristics. See D.83-09-054, ordering paragraph 5; D.83-10-093, ordering paragraph 20. This ensures evenhanded treatment of QFs and promotes a common understanding of the standard offer provisions.

Final Standard Offer 4 already fully implements this policy for that offer. Also, pursuant to the cited decisions, workshops held earlier in this proceeding have produced uniform contract language for the other standard offers. However, our review of the uniform language was delayed, while we devoted our attention to Standard Offer 4.

Before our review and possible approval of the uniform language, we think the parties should have an opportunity to reconsider that language, particularly in light of the products of the final Standard Offer 4 drafting effort. That effort, which we summarize in D.88-03-079, resulted in clarifications and imaginative solutions in a number of problem areas. These clarifications and solutions should be incorporated in the short-run offers, on a prospective basis for new QFs signing those offers, wherever appropriate. However, we agree with PG&E that the consideration of uniform language for Standard Offer 2 should await action on our proposal in Section V above.

We intend to review the uniform language before the next biennial resource plan update. Also, we need to review the parties' recommended specific language implementing the new curtailment provision (see D.88-03-079, pp. 40-41); these recommendations were filed on June 27, 1988. Ideally, we can complete both tasks in a single decision in the fall.

With this timetable in mind, we direct the utilities to examine the existing uniform language proposals for the short-run standard offers (other than Standard Offer 2) and file revised proposals on November 16, 1988, for Commission approval. We encourage continuation of the consultative process that reached general agreement on contract drafting issues for final Standard Offer 4.

VII. Disposition of Pending Petitions and Motions

We have postponed consideration of several petitions and motions because of the priority given to the replacement of interim Standard Offer 4 with a long-run standard offer based on utility resource plans. Now that final Standard Offer 4 is in place, we turn to these other matters relating to the standard offers.

A. Request for Hearing on Line Loss Issues

Part of the calculation of avoided cost is the variation in transmission line losses caused by QFs. In other words, does QF development save money (in the form of reduced line losses) for the utility that purchases the QF output, or does QF development cost money (in the form of increased line losses), as compared to generation and transmission of an equivalent amount of electricity from the utility's other resources? Note that line losses affect the value of both the energy and capacity purchased from a QF or from a non-QF seller. (See D.84-03-092, mimeo. pp. 38-39.)

Many issues would have to be resolved to answer these questions precisely. We would have to consider, for example, QFs' proximity to the utility's load centers and the characteristics of the utility's transmission system. We would also have to decide whether to predicate the answers on analysis of the aggregate impact of QFs, or whether a project-specific line-loss methodology is necessary or desirable.

We addressed line losses in several of the early standard offer decisions. We ordered the utility applicants to include in their offers the costs or savings from line losses for QFs in the aggregate. (D.82-01-103, 8 CPUC 2d 20, ordering paragraphs 6.d and 8.e.) However, we created an exception for remote QF projects one megawatt or larger: losses from such QFs were to be examined individually. (Id., 8 CPUC 2d at 45.) In D.82-12-120, we noted the paucity of utility line loss studies to date and determined for the time being to adopt a loss factor of 1.0 to be applied by all utilities for all QF energy. This essentially treats the line losses associated with QFs as equivalent to those from utility plants. (D.82-12-120, 10 CPUC 2d 553, 625.) We also determined that adjustments for remote QFs were not then practicable, and we suspended that exception pending utility study of how to identify such QFs and to reflect a different energy loss rate. (Id.) However, we rejected a PG&E suggestion that individual line losses be established, instead affirming our prior decision to analyze QF line losses in the aggregate. (Id.)

Following D.82-12-120, PG&E revised its previous line loss study, reviewed the new study with an advisory group that it had convened, and filed the study at the CPUC on September 30, 1983. Not surprisingly, the results of the new study were controversial, and on November 8, 1983, a "Request for Evidentiary Hearing" before taking action on PG&E's proposals was filed jointly by Ultrasystems Incorporated and Occidental Geothermal, Inc.

(Utrasystems/OGI).[30] SDG&E and Edison have also filed line loss studies; to date, no hearings have been held on any of the studies, which are now at least four years old.[31]

With work in this proceeding near completion, and our investigation of the impacts of out-of-state and out-of-service-area QFs (I.85-11-008) about to resume, the latter proceeding seemed to be the logical forum for examining line loss issues. This was suggested by ALJ Wu's Ruling of January 7, 1988. However, at a prehearing conference on February 11, 1988, in that proceeding, most parties did not support expanding the scope of the investigation to include these issues. Thus, our order restructuring I.85-11-008 made no provision for addressing line losses. (See D.88-04-070.)

We see little benefit at this time to refining the treatment of line losses in our established methodology for pricing energy from existing QFs, or even future QFs under the short-run

30 Santa Fe Geothermal, Inc., an active participant in the final Standard Offer 4 compliance phase, is successor to OGI.

31 However, in D.84-03-092, we did modify D.82-12-120 in response to a petition by SDG&E. As the latter decision was modified, the adopted energy line loss adjustment factor of 1.0 is to be applied only by PG&E; for SDG&E and Edison, we set the transmission and primary distribution loss adjustment for energy equal to the respective utility's marginal line loss factor. We also concluded that, for SDG&E and Edison, no additional line loss savings would accrue from QFs at the secondary distribution level.

We also addressed the subject of a line loss adjustment for capacity in D.84-03-092. We noted that capacity pricing involves payments set further into the future than those for energy and on that basis determined that failure to include a capacity line loss adjustment would expose ratepayers to excessive risk. We approved PG&E's line loss adjustments for capacity, and we also directed PG&E to determine such adjustments remote QFs on an individual basis. SDG&E and Edison (and PG&E for its non-remote QFs) were to continue to calculate capacity line loss adjustments for QFs on an aggregated basis.

standard offers. Not only are the studies old and likely to need revision, but also the issues involved in making line loss adjustments for such QFs are complex, and there is no assurance that after wrestling with these issues, we would emerge with significantly improved price signals to QFs. We therefore will not proceed to hearing on whether to adjust our present approach to QF line loss impacts in existing short-run standard offers.

We reach a different conclusion for the resource plan-based offer, final Standard Offer 4. First, line loss analysis seems substantially more practicable when QFs' impact is judged against a specific avoidable resource instead of the entire utility system.[32] Second, and more important, line losses may be significant when considering the utility's "disaggregated resource need." (See D.87-11-024, mimeo. pp. 29-31.) Consider two examples. The utility's choice of site for the avoidable resource may depend in part on the configuration of the utility's load centers and existing system; this suggests that QFs avoiding that resource may be significantly less well situated in terms of their line loss impact. However, where the avoidable resource is an out-of-state purchase, we are reluctant to assume a priori that QFs (particularly those in-state and in the purchasing utility's service area) would have line losses equivalent to the out-of-state purchase, which would be the effect of applying a loss factor of 1.0. In both examples, there is a good chance that a given final Standard Offer 4 QF should have a loss factor higher or lower than 1.0.

The line loss impact of potential QF avoidance of an identified avoidable resource should be analyzed by the utility in

32 Furthermore, within the confines of final Standard Offer 4, it may be both feasible and desirable to judge <u>each</u> QF's impact, rather than taking QFs in the aggregate.

its resource plan submitted in the biennial update proceeding. We expect each utility to present a line loss adjustment method that is sufficiently detailed to enable each potential QF bidder to calculate its loss factor precisely, based on the resource against which it is bidding and the location of its own project. The bidder could then take its loss factor into account when preparing its bid; there would be no need to change the second price auction to weight the bids by the loss factor.

If we are able to develop a line loss adjustment method for final Standard Offer 4, we may then investigate extending or adapting the method, on a prospective basis, to encompass new QFs that choose a short-run standard offer.[33]

Since we have decided not to hear or otherwise act upon the utilities' 1983 line loss studies at this time, the Ultrasystems/OGI request for hearing should be dismissed as moot.

B. Petition for Modification Regarding Duration of As-available Contracts (Standard Offers 1 and 3)

SDG&E has asked that we provide for (1) a fixed term in as-available standard offer contracts (as we do for firm capacity contracts), and (2) a contractual obligation that the QF develop

33 The comments of SDG&E and Edison on the ALJ's Proposed Decision urge that we apply possible future revisions of line loss adjustment factors to existing as well as new QFs. In D.84-03-092, mimeo. pp. 36-39, we said that such revisions, if and when approved, would apply to all QFs. We agree with the reasoning of that decision, but more than four years have passed since then, and several more years will pass before new studies (encompassing all of the offers) have been prepared and hearings held. The existing utility line loss studies are both old and untested, and none of the utilities has asked for hearings on them. We thus have no basis for concluding that the current line loss adjustment factors result in overpayments (or underpayments) to QFs. Furthermore, the need to give correct price signals is greatest for new QFs, especially under final Standard Offer 4. We affirm the priorities proposed by the ALJ.

its project substantially as set forth in the power purchase agreement. To the extent that the QF either does not develop the facility or the facility cannot be operated at the level contemplated in the agreement, SDG&E urges that "allocated line capacity should be reduced and the contract modified or terminated, as appropriate." SDG&E says that the as-available short-run offers, in their current form, present enforcement problems, complicate the utility's resource planning, and permit a floundering QF project to tie up transmission capacity, to the likely detriment of future QFs.

The QF Milestone Procedure, which we authorized in a series of decisions beginning with D.85-01-038 (Jan. 16, 1985), was developed after SDG&E filed its petition (Nov. 16, 1984) and responds in part to the kinds of problems that SDG&E identifies. Also, final Standard Offer 4 contains an abandonment provision that would apply to as-available QFs under that offer and that appears to handle the kinds of problems that prompt SDG&E's request for a fixed term in as-available contracts. Modification of Standard Offers 1, 2, and 3 to incorporate appropriate provisions from final Standard Offer 4 is one of the remaining tasks to be completed after today's decision.

In short, many of SDG&E's concerns appear either already resolved or resolvable through fine-tuning of the short-run offers that is already under way. (See Section VI above.) Therefore, we deny SDG&E's petition without prejudice.

C. Request for Approval of Off-peak Energy Adjustment Factor for Interim Standard Offer 4 (PG&E)

PG&E has found a gap in the provisions of its interim Standard Offer 4. The gap affects a curtailment option that is unique to PG&E's offer. (See D.83-09-054, mimeo. pp. 36-38.)

Specifically, Curtailment Option B allows PG&E to offer an adjusted energy price for various reasons (not limited to negative avoided cost and hydro spill conditions, as is the case with Curtailment Option A). Curtailment Option B gives PG&E increased operational flexibility and the possibility of reduced energy payments for up to 1000 hours, while QFs choosing this option get an energy price "adder" for certain periods during which the adjusted price cannot be offered. The percentage of this adder is contractually established for that part of the QF's payments based on energy prices set forth in the contract; however, part of the energy payments to certain of these QFs depends on the current published energy prices (i.e., short-run avoided operating costs), and the adder applicable to these prices is not specified.[34] PG&E seeks Commission approval of an adder to apply to these latter prices.

PG&E suggests a solution. PG&E's interim Standard Offer 4 does specify some of the adders needed to implement Curtailment Option B. These apply to the forecasted prices and levelized prices (Energy Payment Options 1 and 2, respectively) specified in the contract. The contractually established adders are 7.7% for Seasonal Period A (May 1 through September 30) and 9.6% for Seasonal Period B (October 1 through April 30). PG&E's solution is to also apply these adders to Curtailment Option B energy prices for any portion of the QF's energy payments based on the current published energy price. PG&E believes its solution would be appropriate as long as the Commission-approved method for

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34 Specifically, a QF choosing Energy Payment Option 1 or 2 may also choose to have a percentage of its energy payment based on current published energy prices, even for the so-called "fixed price period" of its contract. After that period is over, for the balance of the contract term, all energy payments are based on current avoided costs. Under Energy Payment Option 3, all energy payments throughout the contract term use current published energy prices with possible year-end adjustments to reflect the floor and ceiling price bands chosen by the QF.

calculating short-run avoided operating costs does not already capture the effect of the Curtailment Option B adjustment.

PG&E's solution is attractive for many reasons, not least of which is its simplicity. The record concerning this aspect of PG&E's interim Standard Offer 4 is not detailed; as with the rest of that offer, the contractually established adders are the product of the 1983 negotiating conference between utilities and QFs. So far as we can determine, there is no reason to apply the adders to energy payments based on forecasted or levelized prices but not to those payments using current published energy prices. PG&E's solution also provides both utility and QF with the price certainty that is one of the primary goals of the fixed price period in interim Standard Offer 4. Therefore, we adopt this solution, at least for the duration of fixed price periods (under Energy Payment Option 1 or 2) specified in interim Standard Offer 4 contracts.

Nevertheless, we will consider another possibility for Energy Payment Option 3 and for Energy Payment Options 1 and 2 at the expiration of the fixed price period. 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, and the parties are also reworking this approach for reinstated Standard Offer 2. 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.

The parties have not previously had an opportunity to consider whether the newer curtailment provisions are reasonably adaptable to purposes of interim Standard Offer 4. The complexity of the various energy payment options dictates care in applying a curtailment approach developed with a different standard offer in mind. We therefore solicit comment on the appropriate treatment of adders under PG&E's Curtailment Option B for Energy Payment Option 3 and Energy Payment Options 1 and 2 at the expiration of the fixed price period. The parties shall file their comments in the biennial resource plan update following ER-7.

VIII. Curtailment Provision for Final Standard Offer 4

On June 27, Edison, on behalf of the utility/QF/DRA working group, filed the group's joint proposal for implementation of the "economic curtailment" option that we approved in principle in D.88-03-079. However, SDG&E doubts the workability of the option for its system and requests authorization to develop a simpler curtailment approach, in consultation with other group members.

SDG&E's problems with the "economic curtailment" option are not clear. Basically, SDG&E finds the option, as implemented under the working group's proposal, (1) hard to administer, and (2) risky for the utility.

Concerning the first point, we are not convinced. The utility has to track much cost information in order to maximize its benefits under the option. However, the utility's system dispatchers already track (or should be tracking) most of this information. The utility's billing department may have additional tasks, as SDG&E suggests, but there are presently no final Standard Offer 4 QFs on-line, and there won't be any for at least a year. SDG&E does not estimate the time required to develop the needed infrastructure.

SDG&E also feels that administration of the option would be costly, relative to the small size of the typical QF on its system. In D.86-07-004, we said that the utility should establish reasonable specifications to govern QF eligibility for performance features. The specifications could include minimum size qualifications for the QF. (Id., p. 74.)[35] How small is too small probably depends on each utility's system. We note that for SDG&E, telemetering is required of QF projects of two megawatts or greater. This may be an appropriate threshold for the "economic curtailment" option.[36]

Concerning the second point, SDG&E's allegation that the utility must determine exactly the lowest cost 1,500 hours on its system just to "break even," our understanding of the "economic curtailment" option is completely different. If the QF continues to generate during the hours subject to the option, it gets paid "actual incremental cost" or the forecast short-run avoided cost for those hours, whichever is less. If the utility's access to cheap energy is greater than the forecast, the QF's energy is priced at the cheaper alternative; if there is less cheap energy around than was forecast, the QF's energy is priced on the forecast basis even though the utility's available alternative energy is more expensive.[37] This effectively shifts much risk of forecast

35 If SDG&E was concerned about large numbers of tiny QFs signing up for this option, SDG&E could have brought up this concern in the working group. The same observation applies to SDG&E's problems with the term "actual incremental cost" as used in the option.

36 The threshold would screen out QFs whose enrollment in the option would do little to enhance the utility's flexibility. For example, SDG&E asserts that the numerical majority of QFs on its system are less than a megawatt, but IEP has calculated that over 85% of SDG&E's QF capacity is concentrated among the larger QFs that are subject to the telemetering requirement. (See D.87-05-060, p. 50.) Thus, the administrative burden can easily be minimized while capturing most of the option's benefits. Alternatively, the option could be made available to QFs smaller than two megawatts that agree to pay for telemetering.

37 Moreover, the utility can still require the QF to actually curtail its output during "negative avoided cost" conditions.

error to the QF, although the utility would get more or less benefit from this, depending on its skill in scheduling the hours subject to the option. However, the utility has the right under the option to revise the Curtailment Schedule at any time up to four hours in advance of a scheduled curtailment hour.

We have allowed SDG&E the opportunity to develop a simpler curtailment approach.[38] We also welcome the offer of the rest of the working group to assist in that effort. Our decision is prompted chiefly by administrability concerns. We had hoped that the "economic curtailment" option would be readily adaptable for use with the other standard offers, in particular, SDG&E's reinstated Standard Offer 2. If this hope is to be realized, the utility needs to be able to implement the option quite readily. Our allowing this opportunity to SDG&E is not to be construed as agreement in any respect with SDG&E's objections to the "economic curtailment" option presented by the working group for final Standard Offer 4.

We therefore request that the working group convene shortly after today's decision and report on the pros and cons of SDG&E's proposal. The report of the working group should be filed no later than October 21, 1988.

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38 SDG&E filed its separate views on the working group's curtailment provision at the same time as the group's filing. On August 2, SDG&E filed an alternative economic curtailment proposal, and some of the parties have filed initial comments on that proposal.

IX. Response to Comments on ALJ's Proposed Decision

Pursuant to Public Utilities Code Section 311 and to our governing Rules of Practice and Procedure (California Code of Regulations, Title 20, Rules 77 to 77.5), the Proposed Decision of ALJ Kotz was issued before today's decision. Seven parties (BPA, CEC, DRA, IEP, PG&E, SDG&E, and Edison) filed timely comments on the proposed decision, and the CEC filed comments replying to IEP.

We have made many changes, all nonsubstantive. Chiefly, we have modified the deadline for several of the follow-up tasks to allow additional time, updated our discussion of BPA and of SDG&E's alternative "economic curtailment" option, and clarified our proposal for regulating the availability of Standard Offer 2.

Various parties have commented on developments affecting BPA since the close of the record in this phase. We have acknowledged some of these developments but have not attempted to analyze them in detail, even when they are subject to official notice, since the parties have had little opportunity to debate their significance. We prefer to leave such analysis for the biennial update proceeding to follow ER-7.

Findings of Fact

1. Strategic considerations play a part in electric utility resource planning. The utility must provide for uncertainty underlying its planning assumptions in order to create a long-run least-cost resource plan. Any acceptable procurement strategy must be non-discriminatory, i.e., it must apply to the utility's own projects and purchases from non-QF sources as well as to QFs.

2. A resource plan should make explicit its strategic elements, reveal the planner's risk preferences, and indicate how the strategy responds to uncertainty.

3. The utilities' CEC-based planning scenarios should use the treatment preferred by the CEC for accounting for municipal loads and self-generation. The utilities' biennial update filings

should specifically discuss uncertainty regarding municipal loads and self-generation in their respective service areas.

4. California electricity planners should recognize the uncertainty of the price of, and access to, surplus power from the Pacific Northwest and Canada.

5. Under BPA's current ratemaking policies, BPA has set prices to California that in recent years have tracked just below the short-run marginal costs of California utilities. BPA's "long-term nonfirm energy rate cap" does not provide assurance that this pattern will change.

6. BPA's Intertie Access Policy acts to restrict output and suppress competition among Pacific Northwest electricity suppliers.

7. California's electricity planning should try to mitigate the anticompetitive impacts of BPA's Intertie Access Policy.

8. One logical approach to electric resource planning is to formulate base-case assumptions on future supply and demand, and then to analyze strategies to meet the needs identified in the base case, considering also any uncertainties that underlie the base-case assumptions.

9. A resource planner needs some flexibility in order to reasonably bridge the gap between short-range and long-range forecasts. For the biennial resource plan review, the utility may choose between the trending approach used in this phase, repetition of a current CPUC short-range forecast for the connecting years, or repetition of the CEC year 5 forecast for the connecting years.

10. There is a need for the CEC and CPUC to use common terminology in a consistent way when analyzing electric resource planning issues.

11. DRA's filing in the biennial update proceeding to follow ER-7 should include a status report on progress toward the development of a standarized and uniform methodology for the treatment of costs and benefits of all resource options (both generation and nongeneration).

12. The CEC's forecasts of DSM program impacts include (in the category "Uncomitted Conservation," formerly "Conditional RETO") some utility-sponsored programs whose level of funding is subject to CPUC review and possible approval. The projection of impacts from such utility-sponsored programs should be analyzed in the biennial update proceeding in terms consistent with enhancements developed in the joint CEC/CPUC staff workshops on integrated least-cost methodologies.

13. Standard Offer 2 has a continuing role to play in a balanced portfolio of standard offers.

14. Workshops held earlier in this proceeding have produced uniform contract language for the short-run standard offers. The parties should have an opportunity to further consider the uniform language in light of the provisions more recently approved for purposes of final Standard Offer 4. The latter provisions should be incorporated in the short-run offers, on a prospective basis for new QFs signing those offers, wherever appropriate.

15. QFs, individually or in the aggregate, may increase or decrease the transmission line losses that the utility purchasing the QF's output would otherwise incur. Prior CPUC decisions have established policy regarding treatment of line losses in payments to QFs under the short-run standard offers. Refining that policy for short-run QFs presents formidable problems and should not be pursued at this time.

16. Line loss analysis for individual QFs may be both feasible and desirable for purposes of final Standard Offer 4.

17. The QF Milestone Procedure and the abandonment provision developed for final Standard Offer 4 address some of the concerns underlying SDG&E's request for additional requirements applicable to as-available QFs.

18. PG&E has found a gap in the provisions of its interim Standard Offer 4. The gap affects a curtailment option that is unique to PG&E's offer. Some but not all of the adders needed to

implement this option are specified in the offer. PG&E's suggested solution (which is to apply the specified adders to those payments under the offer that are based on the current published energy price) is reasonable, at least for the duration of fixed price periods, under Energy Payment Option 1 or 2, in interim Standard Offer 4 contracts, provided that the Commission approved method for calculating short-run avoided operating costs is not changed in a way that would make such adders inapplicable. Other treatments of these adders may be appropriate for Energy Payment Option 3 (under which all energy payments throughout the contract are made at current postings) and for Energy Payment Options 1 and 2 at the expiration of the fixed price period.

19. Additional performance features may have local or system-wide value, depending on the other resources, transmission configuration, and other characteristics of the utility receiving the QF's power. Such features can enhance reliability and help the utility to integrate new QFs, consistent with economic dispatch and smooth system operation. Such features also must be quantified and priced in order to enable QFs to compete on an even footing with potential purchases from non-QF sellers to the California market.

20. None of the utility applicants currently has a need for black-start capability on its system.

21. The full annualized fixed costs of a combustion turbine, adjusted for current capacity need on the utility system, serve only as a proxy for the short-run marginal cost of capacity. QFs are not required or intended to replace combustion turbines on a utility system.

22. PG&E has not priced any of the adders specified in D.86-07-004. Edison has priced four the seven adders. However, only its analysis of the voltage support feature (based on the cost of proxy capacitors) is reasonable.

23. Load-following features serve to concentrate the QF's output within relatively high-cost hours on the utility system.

24. Adders for load following may reasonably be structured as follows. The adder increases the energy payment to QFs committed to provide a given load-following feature. The adder applies during hours when the QF's output is not subject to curtailment, scheduling, or other control by the utility, pursuant to the feature.

25. SDG&E has priced all of the adders specified in D.86-07-004. SDG&E's valuation of the voltage support feature is reasonable. Further work by the utilities on this feature should concentrate on QF eligibility, including geographic and operational criteria.

26. The adders concept, if properly implemented, can serve a similar function to multi-attribute bidding, and may also provide some of the analytical basis for such a bidding system.

27. A reduction in capacity payments may be appropriate for QFs that separate from the system without (1) being tripped off automatically at predetermined settings, or (2) getting authorization from the purchasing utility. No utility has reasonably evaluated such a reduction.

28. The "unbundling" of resource needs is the logical culmination of a resource plan-based QF procurement methodology. More work is needed to develop this concept, which includes both performance features and other factors (such as fuel type and security) of concern to energy planners.

Conclusions of Law

1. SDG&E's request for additional requirements applicable to as-available QFs should be denied without prejudice.

2. PG&E's proposed solution for the interim Standard Offer 4 problem described in Finding of Fact 18 should be approved for the duration of fixed price periods in contracts under Energy Payment Option 1 or 2. Other solutions should be considered for Energy Payment Option 3, and for Energy Payment Options 1 and 2 at the expiration of the fixed price period.

3. The request of Ultrasystems/OGI for hearing on PG&E's 1983 line loss study should be dismissed as moot.

4. PG&E, SDG&E, and Edison should be required to file, in the resource plan update following ER-7, revised reports on performance features and disaggregated resource needs.

5. In future biennial update proceedings, the applicants should explicitly present strategic elements in their resource plan filings.

6. For the biennial resource plan review, the utility should choose a reasonable way to bridge the connecting years between any current CPUC short-range forecast, applicable to that utility, and the current CEC long-range forecast, as described in Finding of Fact 9. However, the utility shall not change the adopted forecast of either commission. The utility should justify its choice and indicate whether the choice materially affects the type or timing of avoidable resources on its system.

7. The parties to biennial update proceedings to follow ER-7 and subsequent Electricity Reports should evaluate forecasts of uncommitted conservation programs in terms consistent with any enhancements developed in the joint CEC/CPUC staff workshops on integrated least-cost methodologies. Based on such evaluation, the CPUC should consider some or all of the estimated uncommitted conservation as nondeferrable resource additions for purposes of final Standard Offer 4. Projection of long-term DSM costs and impacts by this Commission in the resource plan update proceeding should also be given weight in subsequent short-term DSM funding requests in the respective general rate cases.

8. PG&E, SDG&E, and Edison should be required to file revised reports on performance features in the biennial resource plan update following ER-7. The reports should cover at least the same system stablility (except for black-start capability) and load-following features that were in the original reports; the utilities may also propose additional features. The utilities

should indicate the performance features that have been incorporated to date in any contracts with QFs, and should provide a statistical analysis. The analysis need not identify individual QFs but should indicate, by QF technology, the number of megawatts on the respective utility system that are subject to curtailment or other special performance requirements.

9. The reports on performance features should also analyze the potential for a resource plan-based long-run offer made up of disaggregated resource needs. Such an offer would include components for "basic" energy and capacity set at projected long-run marginal costs; system stability adders and line loss impacts calculated for various districts within the purchasing utility's service area; and load-following adders calculated for a range of load-following options up to and including direct utility dispatch of the QF plant. There are other factors in resource planning that are not strictly performance-based. The "unbundled" generation resource offer should include premiums for various attributes deemed desirable by the planner. Such attributes would include, but are not limited to, various types of security that the QF might post, an option to delay or advance the QF's on-line date, and use by the QF of renewable fuels or other fuels that meet fuel diversity criteria.

10. Standard Offer 2 should be made available from all utilities, subject to reasonable restrictions, on a regular basis.

11. The power purchase agreements under the standard offers of the respective utilities should have a common format and terminology, except for the very few aspects that should be utility-specific due to different operating characteristics.

12. This order should be made effective immediately in order to ensure that remaining issues in this proceeding are resolved in advance of ER-7 and the following biennial update proceeding.

FINAL ORDER - COMPLIANCE PHASE

IT IS ORDERED that:

1. The Division of Ratepayer Advocates (DRA) shall prepare a status report on the development of a common terminology for use at this Commission and the California Energy Commission (CEC) for resource planning purposes. DRA shall file this report, in coordination with CEC staff, and serve it on the parties to Application (A.) 82-04-44 et al., no later than October 21, 1988.

2. DRA's testimony in the biennial update proceeding that follows CEC adoption of the Seventh Electricity Report (ER-7) shall include a status report on progress toward the development of a standardized and uniform methodology for the treatment of costs and benefits of all resource options (both generation and nongeneration).

3. The approximate timeline for the biennial update proceeding to follow ER-7 is shown in Appendix B.

4. The utility/QF/DRA working group shall file, no later than October 21, 1988, a report on San Diego Gas & Electric Company's (SDG&E) alternative for an economic curtailment option. The report shall assess the potential advantages and disadvantages of that alternative without taking a position on Commission approval.

5. Pacific Gas and Electric Company (PG&E), SDG&E, and Southern California Edison Company (Edison) shall include revised reports on performance features, as described in Conclusions of Law 8 and 9, in their application in the biennial update proceeding to follow ER-7.

6. The Assigned Commissioner or Administrative Law Judge shall set by ruling a schedule for comment on the proposal, in Section V of today's decision, for regulating the availability of Standard Offer 2.

7. PG&E, SDG&E, and Edison shall examine the existing uniform language proposals for the short-run standard offers (other than Standard Offer 2) and shall file revised proposals on November 16, 1988, for Commission approval. We encourage continuation of the consultative process that reached general agreement on contract drafting issues for final Standard Offer 4.

8. SDG&E's request for additional requirements applicable to as-available Qualifying Facilities (QFs) is denied without prejudice.

9. The request of Ultrasystems and Occidental Geothermal, Inc., for hearing on PG&E's 1983 line loss study is dismissed as moot.

10. PG&E's proposed solution for the interim Standard Offer 4 problem described in Finding of Fact 18 is approved for the duration of fixed price periods in contracts under Energy Payment Option 1 or 2, provided that the Commission-approved method for calculating short-run avoided operating costs is not changed in a way that would make such adders inapplicable. Other solutions may be proposed for Energy Payment Option 3, and for Energy Payment Options 1 and 2 at the expiration of the fixed price period. PG&E shall file its own preference, and other parties may file comments or alternative proposals, in the biennial update proceeding to follow ER-7.

11. PG&E, SDG&E, and Edison shall analyze the line loss impact of potential QF avoidance of an identified avoidable resource in their respective resource plan filings submitted in the biennial update proceeding to follow ER-7. Each utility shall present a line loss adjustment method that is sufficiently detailed to enable each potential QF bidder to precisely calculate its loss factor, based on the resource against which it is bidding and the location of its own project.

12. DRA shall notice a public workshop on integrating price and non-price factors in QF procurement under different types of

auctions (e.g., discriminative, second-price) or outside of an auction framework. The workshop shall be held within 90 days of the date of this order. The focus of the workshop shall be to discuss issues that might arise in formulating an "unbundled" generation resource offer, as described in Conclusion of Law 9. DRA shall file and serve in this proceeding a draft of the minutes of the workshop after circulating the minutes among the workshop participants.

This order is effective today.

Dated SEP 14 1988, at San Francisco, California.

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

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

Victor Weisser

Victor Weisser, Executive Director

APPENDIX A
Page 1

How Final Standard Offer 4 Works

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.

We have adapted the following chronological overview from prior orders. We think the details of the final Standard Offer 4 resource planning process are more easily grasped with the total design in mind. See also Appendix B ("Timeline for Biennial Update Proceeding Following CEC Adoption of the Seventh Electricity Report") of today's decision.

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The first step is the utility application. Following the latest Electricity Report of the California Energy Commission (CEC), the Pacific Gas and Electric Company, the San Diego Gas & Electric Company, and the Southern California Edison Company each file a resource plan with a 12-year planning horizon. The plan identifies within the horizon those potential resource additions that the applicant believes are cost-effective for its system. The plan states the costs associated with each such resource and the point in the planning horizon when that resource becomes cost-effective. The plan also states all relevant assumptions. The applicant presents its assumptions in internally consistent "scenarios." The latest CEC Electricity Report forecasts give the supply and demand assumptions for the base case scenario. The applicant may also file additional scenarios, or otherwise deal with the range of uncertainties underlying the forecasts, in order to explain the applicant's preferred procurement strategy. If the applicant has filed alternative scenarios, it specifies the scenario that it believes is best suited to the determination of avoidable plants for purposes of the long-run standard offer. ("Avoidable plant" could include potential purchases of electricity from non-QF sellers.)

The second step is hearings on the utility applications. The Commission's staff and other participants critique each resource plan. They may note internal inconsistencies in any of the applicants' scenarios, present alternative scenarios of their own, criticize the applicant's assessment of uncertainty, and challenge the reasonableness of an applicant's assumptions. They also check that the applicants have correctly implemented the

Commission's cost-effectiveness methodology. Finally, these participants may explain their choice of the scenario best suited to the determination of avoidable plants.

The <u>third step</u> is Commission determination of avoidable plants for the respective utilities. Avoidable plants are essentially the cost-effective baseload or intermediate resource additions appearing in the first eight years of the resource plan that is preferred by the Commission. This choice is the key Commission act in the long-run standard offer process. The Commission makes this choice according to the following criteria, among others: Are the plan and underlying assumptions plausible (i.e., internally consistent and reasonable, given known forecast uncertainties)? Does the plan expose ratepayers to unnecessary risks, either of premature commitments or of shortages? Is the plan consistent with energy regulatory goals and policies? The Commission decision comes about five months after filing of the applications.

The <u>fourth step</u> is the utilities' solicitation process and QF auction. After making any modifications ordered by the Commission, the utilities announce the availability of long-run standard offer contracts based on the capacity and the fixed and variable costs of the avoidable resource(s). QFs have a three-month solicitation period to respond. Each interested QF indicates (1) the resource that the QF seeks to avoid, (2) the QF's own technology and capacity, and (3) the QF's bid, which is the lowest percentage of the resource's fixed costs that the QF would be willing to accept. The bid cannot exceed the resource's fixed costs. The utility opens the responses at the end of the solicitation period. If QFs seeking to avoid a resource do not cumulatively exceed the resource's capacity, all these QFs are offered contracts at the full fixed costs of the resource. If such QFs do exceed the resource's capacity, contracts up to that MW limit are offered to the low-bidding QFs, and they receive that percentage of the resource's fixed costs bid by the lowest losing bidder. (This is known as a "second price" auction.) Contract signing occurs after the winning bidder complies with the prerequisites of the QF Milestone Procedure, roughly one year after the utility applications.

The fifth step is the update to the long-run standard offer. The update is scheduled every two years and follows each CEC Electricity Report. The utilities file new resource plans, and Steps 1 through 4 are repeated, with such modifications to the process as the parties may suggest and the Commission approves.

(END OF APPENDIX A)

APPENDIX B

Timeline for Biennial Update Proceeding Following CEC Adoption of the Seventh Electricity Report

Time (Approximate) After CEC Final Adoption	Event
9 weeks	Utility resource plan applications filed
13 weeks	CPUC, CEC staffs, other parties serve testimony critiquing resource plans
15 weeks	Resource plan hearings start (lasting 2-3 weeks)
21 weeks	Concurrent briefs filed
25 weeks	ALJ's proposed decision mailed
29 weeks	CPUC decision
33 weeks	Solicitation period for final Standard Offer 4 contracts begin
45 weeks	Solicitation period for final Standard Offer 4 contracts closes
46 weeks	Utilities open bid packages and award contracts

A precise schedule setting forth specific dates and an initial service list will be issued by ALJ or assigned Commissioner Ruling following the Seventh Electricity Report.

(END OF APPENDIX B)

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Landmark CPUC Decisions on
Avoided Cost, Standard Offers

The following list, although not exhaustive, shows where to find answers to the key questions that the Commission has addressed regarding QFs. The summaries are necessarily terse and are not intended either to indicate each issue in any given decision or to substitute for review of the actual text of the opinion and order. In addition to these decisions, our general rate case decisions have been used in the past to update certain standard offer terms. Finally, decisions in general rate case and fuel offset proceedings often contain analysis of marginal cost that is broadly relevant to QF policy.

I. Foundational Decisions

D.91109 - adopted "avoided cost" pricing for utility purchases from "private energy producers"

D.82-01-103 - guidelines for standard offers

D.82-04-071 - authorized "hydro savings prices" during spill conditions

D.85-07-022 - long-run avoided cost methodology

II. Decisions Implementing Variable Energy Payments and Standard Offers 1 2, and 3 (the Short-run Offers)

D.82-12-120	D.84-03-092	D.88-07-024
D.83-10-093	D.84-04-012	

III. Decisions on Interim Standard Offer 4 (the Interim Long-run Offer)

D.83-09-054	D.85-04-075
D.83-12-050	D.85-06-163
D.84-08-035	D.85-07-121
D.84-10-098	D.86-10-038
D.85-01-040	D.86-12-013
D.85-02-069	D.86-12-104

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IV. Show Cause Proceeding (PG&E)

D.84-03-093
D.84-08-031 - "good faith" guidelines for utilities in negotiating with QFs

V. Investigation of Transmission Constraints, Development of QF Milestone Procedure, and Administration of Transmission Priority

D.84-08-037
D.85-01-038
D.85-01-039
D.85-08-045
D.85-09-058
D.85-11-017
D.85-12-075
D.86-02-033
D.86-04-053
D.86-11-005
D.86-12-017
D.87-04-039
D.87-08-028
D.87-09-030
D.88-04-067

VI. Standard Offer 2: Suspension and Reinstatement

D.86-03-069
D.86-05-024
D.86-11-071
D.87-09-025
D.87-11-024
D.87-12-056

VII. Development of the Resource Plan-based Offer (Final Standard Offer 4)

D.86-07-004
D.86-10-030
D.87-05-060
D.87-11-024
D.88-03-026
D.88-03-079

VIII. "Orphans," "Pioneers," and Nonstandard Contracts

D.93035
D.93364
D.82-04-087
D.82-07-021
D.83-05-043
D.83-05-047
D.83-06-109
D.84-05-057
D.86-03-030
D.86-06-060
D.86-07-032
D.86-08-017
D.86-09-040
D.86-10-039
D.86-10-044
D.86-12-018
D.86-12-061
D.86-12-062
D.86-12-098
D.86-12-100
D.87-01-049
D.87-03-068
D.87-05-065
D.87-07-086
D.87-08-047
D.87-09-074
D.87-09-080
D.87-10-038
D.87-11-063
D.88-03-036

(END OF APPENDIX C)

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 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 & gas-fired cogenerators limited to 20% of the price being based on the forecasted prices.

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

Energy Option 3) Energy prices are based on fixed, forecasted utility incremental energy rates and utility oil & 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

See Appendix A.

(END OF APPENDIX D)

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Table of Acronyms and Abbreviations

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

ALJ	Administrative Law Judge (VII.A)
BPA	Bonneville Power Administration (III.C)
CEC	California Energy Commission (II)
CEQA	California Environmental Quality Act (IV.D.3)
Conditional RETO	See RETO (III.D.4)
CPUC or Commission	California Public Utilities Commission (I)
D.	Decision (I)
DRA	Division of Ratepayer Advocates (part of CPUC staff) (III.D.4)
DSM	Demand-side Management (III.D.4)
ECAC	Energy Cost Adjustment Clause (III.D.2)
Edison	Southern California Edison Company (II)
ER-6	The CEC's Sixth Electricity Report (II)
ER-7	The CEC's Seventh Electricity Report (III.B)
I.	Order Instituting Investigation (VII.A)
IEP	Independent Energy Producers Association (IV.B)
PG&E	Pacific Gas & Electric Company (II)
QF	Qualifying Facility (I)

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Table of Acronyms and Abbreviations
(continued)

RETO	Reasonably Expected to Occur; "Conditional RETO" is used by the CEC to designate conservation and load management programs deemed desirable but awaiting additional regulatory approval (III.D.4)
RFP	Request for Proposal (IV.D.3)
SDG&E	San Diego Gas & Electric Company (II)
Tr.	Reporter's Transcript (III.C)
Ultrasystems/OGI	Ultrasystems Incorporated and Occidental Geothermal, Inc. (VII.A)
VAR	Volt-Amperes Reactive (a measure of power lost to reactive loads) (IV.C.)

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List of Appearances

Applicants: Howard Golub, Linda Agerter, and JoAnn Shaffer, Attorneys at Law, for Pacific Gas and Electric Company; Wayne P. Sakarias, Attorney at Law, for San Diego Gas & Electric Company; and Julie Miller, Attorney at Law, for Southern California Edison Company.

Other Parties: Armour, St. John, Wilcox, Goodin & Schlotz, by James D. Squeri, Attorney at Law, for AMAX, Inc. and Kelco Division of Merck, Inc.; Kathryn L. Stein, Attorney at Law, for Barakat, Howard & Chamberlin, Inc.; Susan Ackerman and D. J. Adler, for Bonneville Power Administration; Steven Cohn and A. Kirk McKenzie, Attorneys at Law, for California Energy Commission; Kent Fickett, Attorney at Law, for California Energy Company, Inc.; Brobeck, Phleger & Harrison, by Richard C. Harper, Attorney at Law, for IMOTEK, Inc.; Matthew V. Brady, Attorney at Law, Alice Levine, and Law Offices of Dian Grueneich, by Dian M. Grueneich, for State of California, Department of General Services; Neal A. Johnson, for California Waste Management Board; Robert Grow and Donna Stone, for California Department of Water Resources - Energy Division; Lawrence W. Campbell, Attorney at Law, for Caterpillar Capital Company, Inc.; John D. Quinley, for Cogeneration Service Bureau; John W. Gulledge, for County Sanitation Districts of Los Angeles County; Graham & James, by Martin Mattes and Dianne Fellman, Attorneys at Law, and Barry Sheingold, for Delmarva Capital Technology Company; Philip A. Stohr, Attorney at Law, for Downey, Brand, Seymour & Rohwer; Lindsay, Hart, Neil & Weigler, by Michael P. Alcantar and Clyde E. Hirschfeld, Attorneys at Law, and Drazen-Brubaker & Associates, Inc., by Donald W. Schoenbeck, for Cogenerators of Southern California; Karen Edson, for KKE & Associates; Gary Simon, for El Paso Natural Gas Company; Kenneth R. Meyer, for Energy Consulting Group; James S. Thomson, for Energy Factors, Inc.; Robert Logan, for Exeter Associates; Graham & James, by Norman A. Pedersen, Attorney at Law, for Champlin Petroleum Company; Leslie C. Confair, for GWF Power Systems Company and The Signal Companies; Hanna and Morton, by Douglas K. Kerner, Attorney at Law, for Union Oil Company of California, Freeport- McMoRan Resource Partners, Santa Fe Geothermal Inc., and Hanna and Morton; David R. Branchcomb, for Henwood Energy Services, Inc.; Patrick V. Agnello, for Howden Wind Parks, Inc.; Janice G. Hamrin, for

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Independent Energy Producers Association; Judith Alper, Attorney at Law, for Independent Power Corporation; William B. Marcus, for JBS Energy, Inc.; Marron, Reid, & Sheehy, by M. Baller, Attorney at Law, for Foster Wheeler Power Systems, Inc., Santa Monica Aggregate Company, California Agricultural Power Company, Pacific Thermonetics, Inc., and Crockett Cogeneration Company; Eugene J.M. McFadden, for McFadden Farm; Morrison & Foerster, by Jerry R. Bloom and Barbara A. Reeves, Attorneys at Law, and Morse, Richard, Weisenmiller & Associates, Inc., by Robert E. Weisenmiller, for California Cogeneration Council; Wally Gibson, for Northwest Power Planning Council; M. Bobbitt and J. Kroesche, for Orrick, Herrington & Sutcliffe; Les Toth, for Pacific Hydro Power; Douglas Kent Porter, Attorney at Law, for Pacific Lighting Energy Systems; Pettit & Martin, by Edward B. Lozowicki, Attorney at Law, for California Energy Company and Co-Generation Services, Inc.; Recon Research Corporation, by Ronald G. Oechsler, and Squire, Sanders & Dempsey, by James L. Trump, Attorney at Law, for Alenco Resources, Inc.; Bryan Cope, for Sierra Energy and Risk Assessment; R. Rawlings, for Southern California Gas Company; Michel Peter Florio, Attorney at Law, for TURN; Paul Dolan, for Thermo Electron Energy Systems; Michael J. Ruffatto, Attorney at Law, for Trigen Resources Corporation; Harry K. Winters, for University of California, Thomas R. Sparks, for Unocal Geothermal; Margaret Rueger, for U. S. Windpower, Inc.; and Robert Feraru, State Public Utilities Commission-Office of Public Advisor; and Jon Castor; Arturo Gandara, Attorney at Law; Joseph G. Meyer; Milt Pace; Timothy P. Duane; and William Walzer; for themselves.

Division of Ratepayer Advocates: Carol Matchett, Attorney at Law, and Julian Aiello.

Commission Advisory and Compliance Division: Frank Crua.

(END OF APPENDIX F)

ALJ/SK/fs

Decision ____________

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

(See Appendix F for appearances.)

FINAL DECISION, COMPLIANCE PHASE:
GENERAL RESOURCE PLANNING ISSUES,
PERFORMANCE FEATURES ("ADDERS");
AVAILABILITY OF STANDARD OFFER 2

A.82-04-44 et al. ALJ/SK/fs

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**FINAL DECISION, COMPLIANCE PHASE:
GENERAL RESOURCE PLANNING ISSUES,
PERFORMANCE FEATURES ("ADDERS");
AVAILABILITY OF STANDARD OFFER 2**

I. Introduction

Today's decision completes a nine-year process. In this process, we have developed various standardized power purchase contracts (Standard Offers 1 through 4) to help integrate electrical generation from certain non-utility sources (Qualifying Facilities or QFs) in the electric utilities' supply mix.

Summarizing a nine-year process is itself a lengthy task. We won't burden the text of this decision with such a summary. However, the appendixes provide citations of major CPUC decisions on QF matters, descriptions of the various offers, an account of how the resource plan-based offer (final Standard Offer 4) works, a table of acronyms and abbreviations, and a timetable for the next biennial resource plan review. Implementation of final Standard Offer 4, reinstatement of Standard Offer 2, and coordinated updating procedures for all of the offers are the major issues in the compliance phase.

A series of interim decisions has resolved most of these issues. Today's decision addresses some of the key policy questions in resource plan updating and filling resource needs, makes a proposal for regulating the future availability of Standard Offer 2, and resolves outstanding motions and petitions. The final task in this proceeding concerns increasing the uniformity of the form and terminology of the standard offer contracts among the utilities. With the completion of this task in the fall, we will at last be able to close the consolidated standard offer proceeding.

II. The Interim Decisions

Four interim opinions precede today's final decision. All of these concern utility compliance filings pursuant to Decision (D.) 86-07-004 and D.86-11-071, in which we created a foundation for correlating QF development with resource planning and capacity valuation.

The first of these interim opinions approves a detailed protocol for conducting the second price auction for final Standard Offer 4 (D.87-05-060, mimeo. pp. 7-25), resolves a variety of pricing issues (pp. 25-39), and discusses the treatment of uncertainty and negotiated contracts in resource planning (pp. 39-49). These were the compliance phase issues that did not directly relate to the resource plans developed by the utilities in response to the Sixth Electricity Report (ER-6).

The subsequent interim opinions deal with our conclusions from our review of resource plans submitted in compliance with the newly created biennial planning process. In the second interim opinion (D.87-11-024, mimeo. pp. 2-29), we found that none of the utilities had an avoidable resource within the eight-year "window" that we established for purposes of final Standard Offer 4. We also discussed the concept of "disaggregated resource need" and how it relates to avoidable resources (pp. 29-31). Finally, we decided to continue the suspension of Standard Offer 2 for Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (Edison), but reinstated the offer, with certain restrictions, for San Diego Gas & Electric Company (SDG&E). (Id., pp. 31-42; see also D.87-12-056 regarding queue management and related contract provisions for Standard Offer 2.)

The third interim opinion, D.88-03-026, is essentially a matrix showing how and where we will update the provisions of the various standard offers. The fourth interim opinion completes the development of reliability targets for resource planning and capacity valuation purposes, with the single exception of the short-term capacity value adjustment for PG&E (D.88-03-079, mimeo. pp. 6-18). We also resolved a long-standing issue on energy-pricing for QFs receiving variable energy payments (pp. 21-34) and certain contract drafting problems in final Standard Offer 4 (pp. 34-48).

In today's decision, we draw some further conclusions concerning our resource plan review and the process of coordinating that effort with the California Energy Commission's (CEC) Electricity Report. We also consider the utility filings on additional performance features; these features will receive more study in the next biennial update proceeding. Finally, we explain the continuing role of Standard Offer 2 (firm capacity, variable energy payments) in the portfolio of offers and propose for comment a new approach to regulating the availability of Standard Offer 2.

III. Review of the Resource Plans Responding to ER-6

We have already dealt with some of the major implications of the resource plan filings; here, we discuss various issues that we think will significantly affect future filings. We do not undertake a line-by-line dissection of the plans or a response to every planning issue raised by the parties but rather concentrate on those matters that significantly influence our conclusions during this (our first) biennial resource planning cycle.[1]

1 Given this approach, the parties should not interpret our failure to expressly criticize (or approve) any particular aspect of a utility's resource plan as an endorsement (or rejection) of how the utility handled that aspect.

A. Procurement Strategy

One of the most significant issues raised in our first resource plan review is how we should deal with the utilities' strategic preferences. Judgment affects resource planning because all forecasts are more or less uncertain. The planner must examine a whole range of outcomes that differ from the case deemed most likely to occur, in order to determine the financial risks that a given utility faces and how to mitigate those risks through the utility's selection among resource options.

This issue may affect final Standard Offer 4 in various ways. Fundamentally, the utility may prefer to add different resources and/or fewer resources than those suggested solely by cost-effectiveness analysis of a base-case scenario.[2] SDG&E's "50/50" procurement strategy (see D.87-05-060, pp. 41-45), under which SDG&E would fill all its projected near-term needs but only half of the long-term needs arising within the final Standard Offer 4 "deferral window," is an example of such a preference. The strategy reflects the value that SDG&E attaches to maintaining flexibility at a time when its resource options seem plentiful. This flexibility enables SDG&E to take advantage of surplus power that it thinks may be available at low cost over the next few years from other utilities, and mitigates what SDG&E regards as a major risk at this time, namely, the risk of premature commitment to major new facilities. Stated differently, SDG&E believes that, in its present circumstances, the costs of premature commitment would likely exceed the costs of bringing a new resource on-line some time after the optimal point.

2 However, the biennial update process does not contemplate making any more megawatts available to final Standard Offer 4 QFs than would be found to be needed under the CEC's then-current Electricity Report. (See D.86-11-071, mimeo. p. 19.)

The main purpose of our resource plan updating process is to periodically quantify the megawatts that QFs could fill on the basis of each utility's long-run marginal costs, as revealed by the utility's current resource plan formulated according to least-cost principles. Such a plan _must_ account for uncertainty but there may be many ways to do this. Our job is not to dictate strategy to the utilities. Rather, we must determine whether, under the circumstances of the particular utility, the discretionary aspects of its procurement strategy are consistent with reasonable planning assumptions (including perceived uncertainties) and a long-run least-cost resource plan.

We do not imagine that this will be an easy determination to make, but one principle is clear. Any acceptable procurement strategy must be non-discriminatory, i.e., it must apply to the utility's own projects and purchases from non-QF sources as well as to QFs. This is not to say that all generation resources have equal value; on the contrary, we expect the utilities to quantify asserted operational differences and system needs, and to capture such benefits, wherever possible, through "adders" from final Standard Offer 4 and other QFs. (See Section IV below.)

The present resource plan review does not require us to evaluate procurement strategies in detail. Only SDG&E made an explicit presentation on this issue, and we have found that, under any of the scenarios, SDG&E does not have an avoidable resource at this time. Nevertheless, we think SDG&E's focus on this issue is both helpful and appropriate. In future biennial update proceedings, the applicants should explicitly present strategic elements in their resource plan filings. These presentations should reveal the applicant's risk preferences and indicate how the applicant believes that its strategy responds to uncertainty and contributes to least-cost planning. Other parties are free to critique strategic elements as well as other aspects of each resource plan.

B. Consistency with CEC Assumptions

The biennial resource planning process requires the utilities, at a minimum, to prepare a resource plan based on the CEC's latest adopted Electricity Report. Problems arose in the compliance phase because (according to the utilities) some of the information that the utilities needed for plan preparation was not separately stated in ER-6 or readily available from CEC staff. ER-7 will probably present fewer problems of this type because ER-6 was well under way before we adopted our first implementation order (D.86-07-004), while ER-7 should benefit from the experience gained in this resource plan review cycle. We direct our staff to cooperate in any effort to prepare standardized forms or other means that might help the flow of information that must take place on almost an on-going basis between the CEC, the CPUC, and the utility applicants.

A more fundamental problem concerns the treatment by the utilities of certain CEC assumptions.[3] For example, how should the resource plans account for projected loads of municipal utilities within the CEC "supply planning areas" of the respective investor-owned utilities? (I.e., should municipal load in excess of municipal resources be treated as demand on the investor-owned utility system that is potentially required to serve that load?) Also, how should the resource plans account for self-generation (as a reduction of demand or as a source of both demand and supply)? We think that, for purposes of the CEC-based resource plans, the utilities ought to adopt the treatment preferred by the CEC. If

3 See also Section III.D.4 below.

the utilities have concerns about how to implement the CEC's preferred treatment, those concerns should be addressed to the CEC.[4]

We recognize that municipal loads and self-generation are two matters that involve much uncertainty and therefore are the source of some of the risks confronting the investor-owned utilities. If the utilities deem these risks significant, then they should explore these risks in their showing on uncertainty and procurement strategy, as we discussed above.

C. <u>Purchases from the Pacific Northwest</u>

The Bonneville Power Administration (BPA), a federal entity, influences electrical supply planning in California through BPA's ratemaking authority over certain federal hydroelectric facilities and its control of transmission capacity interconnecting California with the Pacific Northwest. The CPUC, the CEC, and other California parties have differed with BPA over both its exercise of ratemaking authority and its allocation of transmission capacity through the Intertie Access Policy. Litigation has ensued, and many fundamental differences of legal opinion are not yet definitively resolved. Inevitably, California planners must recognize the uncertainty that results from these unsettled differences and must choose strategies that ensure reliable and economic service in California under various possible outcomes.

The remarks that follow do not consider or purport to analyze the legality of BPA's past or present policies. We intend the remarks solely to indicate the steps that California planners must take, considering the possibility that BPA would continue its current policies on rates and transmission access.

4 We suspect that these concerns, to the extent that they have not already been resolved, can be dealt with in workshops with CEC staff.

We hope these steps do not become necessary. They would not be necessary if BPA would make appropriate modifications to its current policies. However, despite some recent progress, BPA has still not provided the kind of assurances to California that would justify reliance on Pacific Northwest energy, consistent with sound least-cost planning strategy.

1. BPA's Ratemaking Policies

Electricity supply planning must distinguish between short-term and long-term resources. BPA has essentially set prices to California that track just below the short-run marginal costs of California utilities. Such pricing sharply reduces the attractiveness of BPA's energy. The reason is that, as short-run marginal costs increase, so do BPA's prices, regardless of whether BPA has a lot of surplus energy or a little. In contrast, long-run marginal costs recognize that a utility will eventually devote capital to acquiring a resource that improves its operating efficiency, i.e., lowers its short-run marginal costs. As long as BPA pursues its current ratemaking policies, California ratepayers will lose money if our utilities prefer purchases from BPA to developing cost-effective long-term resources.

In the resource planning portion of the compliance phase hearings, much time was spent estimating the quantity of surplus energy that might be available to California from the Pacific Northwest. It is clear that the Pacific Northwest will typically have large surpluses for some years to come, but those surpluses mean little without assurance on price. The key planning assumption is the price associated with varying amounts of energy. Until and unless BPA provides appropriate assurance as to some other price assumption, we are compelled to assume that all purchases from BPA will be slightly below short-run marginal cost. Under these circumstances, and given reasonable projections that oil and gas prices will steadily increase over the long-term, we expect that cost-effective long-term alternatives to purchases from

BPA will appear at the biennial resource plan update. We further expect our utilities to pursue these alternatives, whether they be new utility power plants, purchases from other out-of-state sellers (such as Southwest utilities), or QFs bidding against these plants and purchases.

BPA, in its 1987 rate case, has tried to respond to some of the concerns of California parties. It there adopted a "long-term nonfirm energy rate cap." (See Chapter VIII of BPA's 1987 Draft and Final Records of Decision, which are Exhibits 459 and 460, respectively.) As described by BPA witness Fama (Tr. 7645-46), "The long-term cap is a formula Bonneville proposes to place in effect for 12 years. It would go through 1999. That formula is independent of any particular rate design that might be placed in effect during those 12 years. It was proposed [to ensure] a significant amount of savings for California purchasers, more than one or two mills--in the area of four to five mills--[for] much greater amounts of service" as compared to price assurance under nonfirm energy rate design or short-term caps.

We appreciate BPA's appearance in this proceeding, as well as its participation in the development of ER-6. We are particularly gratified at BPA's tacit recognition of the planning quandary that its ratemaking policies have created for California. Unfortunately, the long-term cap offers only nominal assurance of savings--certainly nothing that causes us to qualify the planning assumption described above.[5]

5 We must emphasize that the root problem for California is BPA's nonfirm energy rate design, which has given California good reason to doubt that any significant amount of benefits will accrue to California from future energy purchases from the Pacific Northwest. Our preference is still that BPA reform its rate design policies; a rate cap might enable us to calculate a "worst case" scenario for California, but such a scenario does not present a very persuasive argument for protecting the BPA market share.

The long-term cap itself is a good concept and can be useful to California planners in direct proportion to the degree of assurance provided. This cap provides little assurance either qualitatively or quantitatively.

First, the long-term cap is a decision of BPA that BPA can reverse. At current oil and gas prices, the cap means little, but as oil and gas prices rise, the difference between California's marginal costs and the cost of the Pacific Northwest's largely hydro-based generation will increase, which in turn will create pressure on BPA to abandon the cap precisely when it begins to produce significant benefits for California. The cap must be backed up by contracts with California utilities before we can be satisfied with the quality of the assurance provided.

On this important point, BPA's Final Record of Decision says, "BPA will begin contract negotiations upon interim FERC approval of the rate cap." BPA says repeatedly that it fears action by regulatory or legislative bodies in California that are "detrimental to BPA's economy energy market" and that it is "specifically looking for appropriate California regulatory decisions," i.e., "reciprocal action from the regulators." (Exhibit 460, pp. 178-79.) The only prudent reciprocal regulatory action that we can conceive of, based solely on the long-term cap, is to encourage contract negotiations as soon as possible, but not to otherwise commit California to purchases from BPA pending the result of such negotiations.

Second, the assured savings under the long-term cap are not impressive. The quantity of such savings depends on the size of the discount from California's marginal costs, the amount of energy to which the cap applies, and the length of time when the cap is in effect. Tradeoffs are possible: for example, a relatively small discount could still be significant if coupled with larger amounts of energy and a longer period subject to the cap. But BPA's long-term cap seems skimpy in all respects. The

12-year duration is less than the fixed-price period (15 years) in final Standard Offer 4, and the amount of energy, which in any event is nonfirm, declines (due to increased demand in the Pacific Northwest) when benefits to California from the price cap would otherwise increase. The 4-5 mill discount mentioned in BPA's testimony is unlikely to be attractive compared to a long-term resource, and while the cap's formula could in theory provide greater discounts as California's marginal costs rise, the realization of such discounts depends on BPA's adherence to the cap. In the absence of contracts, and considering the fiscal pressures that affect BPA, we cannot confidently assume such adherence.

In short, we think that BPA, with the long-term rate cap, has taken a small step in the right direction. BPA falls short of its goal, to protect its California market share, because the cap is demonstrably less attractive than the long-term resource opportunities that compete for BPA's market share.

2. <u>BPA's Transmission Access Policies</u>

BPA owns and operates most of the Pacific Northwest-Pacific Southwest Intertie transmission lines above the Oregon-California border. BPA currently allocates access to these lines under a "Near Term Intertie Access Policy" (Access Policy).

The Access Policy is currently the subject of litigation between BPA and California parties. For present purposes, it is most significant to note that a panel of the federal Ninth Circuit Court of Appeals, while divided on the merits of the case, has unanimously agreed with California parties that the Access Policy is clearly anticompetitive. The panel majority describes the result of the Access Policy as "a regularly shifting, horizontal division of the market for surplus nonfirm energy; each eligible producer is temporarily granted sole access to a specified share of the capacity, which it may either use or allow to remain unused without fear of competition by other producers." The dissenting judge agrees with this characterization and further notes that the Access Policy favors Pacific Northwest utilities generally (not just BPA) and acts as an output restriction as well as suppressing price competition.[6]

BPA's adoption of the Access Policy is on an interim basis, although BPA has already twice deferred the policy's expiration. We urge BPA to adopt a long-term policy that eliminates the anticompetitive impact of the interim policy. However, in the absence of such a long-term policy, and with the interim policy in effect for an indeterminate period, prudent planning to meet California's electricity demand is seriously complicated.

Resource planners must consider physical constraints of the existing transmission system, but the Access Policy is not a physical constraint. The Access Policy expressly contemplates that Intertie capacity will on occasion go unused even when California utilities are willing to pay prices attractive to some energy sellers in the Pacific Northwest. For purposes of QF recruitment under final Standard Offer 4, should California planners imagine that these power purchase opportunities do not exist, solely because the Access Policy chokes them off?

If we assume that the Access Policy effectively forecloses some power purchase opportunities, such as might be created, e.g., by development of potential generation in British Columbia, then we become BPA's unwilling accomplices in limiting competition for the California market. Essentially, our assumption for the price of BPA's own output (that it would be priced just below California utilities' short-run marginal costs) would then extend to all power purchases from the Pacific Northwest. This assumption would certainly spur the QF program because avoided

6 California parties have petitioned for writ of certiorari from the United States Supreme Court. The matter is still pending.

costs would be higher; the advantage to California from such a policy is that it would lead to maximum use of California's indigenous energy sources. On the other hand, we are troubled by the implications of this assumption, both for least-cost planning and for avoided cost principles.

The other possibility is to assume that potential sellers in Canada and the Pacific Northwest (other than BPA) would compete to sell their surplus energy and capacity into the California market, based on competitive forces and their own costs, despite BPA's attempts to sustain its own artificially high price through the Access Policy. We think that this assumption is consistent with avoided cost principles and a reasonable level of QF development. On the other hand, the assumption requires us to model as resource options some transactions that could not occur until the Access Policy is set aside.

It is apparent that the Access Policy seriously distorts California's energy planning whichever assumption is used. Our preferred solution is that the policy be modified to enable energy sellers in the Pacific Northwest to participate in the California market up to their full potential. If that policy continues in effect, then we believe on balance that California planners should use the latter assumption, which mitigates but cannot eliminate the policy's price distortions.

D. The Evolving Resource Planning Process

1. CEC/CPUC Procedural Coordination

The biennial resource plan proceeding is a new feature of electric utility regulation in California. It dovetails with the "integrated assessment of need" performed biennially by the CEC in the Electricity Report; it is essentially the forum where the largest of the investor-owned electric utilities (PG&E, SDG&E, and Edison) and other parties identify generation resources potentially avoidable by QFs under long-run contracts (final Standard Offer 4). This necessarily involves consideration of overall strategies (including demand management and power purchases as well as construction of new power plants) for filling the needs projected for these utilities.

We recognize that this is an ambitious process, requiring (among other things) close coordination between the CEC and the CPUC. The CEC presented an excellent overall coordination proposal in last summer's hearings; however, we were unable to respond to that proposal in time for ER-7, which was under way before the filing of briefs in the current (compliance) phase of this proceeding.

The CEC proposal envisions a "concurrent approach" under which the CEC's findings on need and the CPUC's findings on avoidable resources would be developed, in part, through joint hearings and decisions. This contrasts with the "sequential approach" exemplified in this, the first, biennial resource plan review, in which the CEC's adoption of ER-6 was followed by the filing of CEC-based resource plans (and in the case of SDG&E and Edison, alternative scenarios) at the CPUC.

The sequential approach should be retained, at least for the time being. The main reason is that the "Integrated Schedule" presented by CEC witnesses Deter and Praul (see Figure 1 of Exhibit 406 and their discussion in that exhibit) seems to combine the CEC's adoption of supply and demand forecasts with the consideration of alternative planning strategies that must, among other things, respond to those forecasts and to the uncertainty surrounding them. However the CEC chooses to deal with such uncertainty, it seems fair and logical to allow utility planners some time in formulating their resource strategies to think about the CEC base case after that case is established.

There is obvious concern that the CPUC consideration of "alternative scenarios" could subvert the CEC's adopted planning assumptions; this concern, together with the desire to avoid potentially duplicative proceedings and the CEC's own interest in dealing with uncertainty issues, seems to underlie the CEC's coordination proposal.

We recognize the CEC's concern and strongly support the explicit consideration of forecast uncertainty by the CEC. However, our review of the utilities' resource plan strategies is not inherently subversive of the CEC forecasts. We are directing the utilities to file--not their preferred forecast--but rather a resource plan that (1) is devised to meet the CEC's integrated assessment of need, and (2) does not result in undue exposure to increased costs should their actual need turn out to be greater or less than anticipated. The use of alternative scenarios initially seemed to us the most promising way to investigate this exposure, but SDG&E has made a persuasive presentation to support forecasts with "bands" to denote uncertainty, while Edison focuses on flexible planning that "choose[s] resources considering their strategic value, including their ability to be expanded or changed as time goes on to cover uncertainty." (Edison Concurrent Brief, Compliance Phase, regarding resource plan issues, p. III-11.) There are doubtless many ways for a resource planner to hedge risks and thus minimize costs over the long-run; in this respect, the goals of the regulator and the regulated utilities coincide.

For these reasons, the question is not so much a procedural issue of aligning the CEC and CPUC processes as it is a substantive issue of how the CEC wants to deal in its Electricity Reports with the universally acknowledged uncertainty of all forecasting efforts. The CEC response to the latter issue may well take care of both the procedural problems and the objections expressed by some parties to what they feel is a deterministic (and therefore unduly risky) reliance on the CEC forecast.

In the meantime, we reaffirm our commitment in D.86-07-004 to base the availability of final Standard Offer 4 on projections of need that are consistent with the findings of the CEC's then-current Electricity Report.[7]

Besides the procedural issue of aligning the Electricity Report with the resource plan review, there are a number of substantive areas where the parties have expressed need for further direction on the use of CEC methods or assumptions in the CPUC proceeding. We discuss these areas below.

2. Connecting Short-range and Long-range Forecasts

The resource planning process involves projection of the utility's loads and supplies during the forecast period. We have directed the utilities to present a "base case" planning scenario that uses the CEC's current long-range demand forecast (which begins in year 5 and runs through year 20) and the current short-range forecast adopted for the respective utility by the CPUC (typically, in a general rate case or fuel offset proceeding).

There will be a gap between the first year of the CEC long-range forecast and the end of a short-range forecast used in our proceedings. Filling the gap between short-range and long-range forecasts is tricky because, as most parties agree, the two

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7 CEC witnesses indicated that there is now a process at the CEC whereby the Electricity Report Committee, upon motion and appropriate showing, could modify some of the then-current report's findings. This process might affect the biennial resource plan proceeding, e.g., if an earthquake or other disaster were to cause a supply emergency (and consequently a finding of increased need) of indefinite duration.

However, our understanding and strong recommendation is that the CEC would resort to this process very sparingly. Some stability in base case planning assumptions is necessary if a resource plan review is to be feasible. Moreover, the biennial forecasting cycle seems sufficiently frequent in itself to mitigate risk from all but the most extreme unforeseen events.

types of forecast use markedly different methodologies.[8] Seemingly anomalous jumps or dips in the connecting years might not have practical consequences where a utility appears not to have new resource needs in those years. However, where a utility (such as SDG&E in this phase) has a near- or mid-term need for new resources, proper specification and timing of resource additions may require more systematic projections for the connecting years.

Our approach for this phase called for trending from the short-range forecast to the CEC's year 5. Upon consideration of this record, we believe some additional flexibility is appropriate. We will allow the utility in its base case scenario to choose among the following: the trending approach used in this phase; repetition of the CPUC short-range forecast for the connecting years; or repetition of the CEC year 5 forecast for the connecting years. All of these approaches respect the integrity of the CEC and CPUC forecasts, while allowing the utility to choose the most reasonable way to bridge those forecasts.

In the next biennial resource plan proceeding, each utility should choose explicitly among these approaches and also indicate whether the choice has a material impact on its conclusions regarding avoidable resources.

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8 The chief reason for the difference is that short-range forecasts are designed to be sensitive to transitory phenomena (business cycles, unusual weather conditions, etc.), which tend to even out over time, while long-range forecasts deal with more fundamental changes, such as turnover in the capital stock of energy-consuming equipment. Thus, for example, a long-range forecast might project steadily rising fuel prices while a contemporary short-range forecast shows falling fuel prices. Short-range and long-range forecasts serve different purposes; it is generally unnecessary (and impossible) to get them to mesh perfectly.

3. Common Terminology

Everyone agrees on the need for the CPUC and the CEC to arrive at a common terminology for resource planning purposes. Without a common terminology, and agreement on the concepts behind that terminology, we would spend a lot of time fitting square pegs into round holes.

CEC witnesses presented a common terminology proposal in the compliance hearings, and we understand that the proposal has been refined in discussions with CPUC staff and workshops in ER-7. We direct our staff to prepare and serve on the parties in A.82-04-44 et al. a status report on this effort. The report is due no later than September 16, 1988, and should indicate areas of agreement as well as those areas that are still problematic. If the CEC and CPUC staffs have reached complete agreement on terminology, then we encourage them to submit the report jointly.[9]

We recognize that terminology should not try to mask or eliminate methodological differences that may exist between the two commissions; in fact, one virtue of a common terminology is that it may clarify where those differences arise. We also note that whether a given resource falls in one of several possible categories is generally an issue of fact before one or both commissions. The goal of a common terminology is not to preclude different results but only to ensure that we are talking about the same problem.

4. Analytical Consistency Between Regulators

The CPUC and CEC must frequently analyze the reliability of electric utility systems and the cost-effectiveness of utility programs to add supply or manage demand. In this proceeding,

9 We see no need of a CPUC decision to ratify a common terminology. However, we urge completion of this effort in time for ER-7 to incorporate the terminology.

parties have noted that the CPUC and CEC sometimes use different methods for conducting these analyses; these differences make it hard for utilities to prepare their compliance filings and could lead to conflicting conclusions on resource needs.

We feel the differing system reliability approaches are not currently a pressing problem. The reason is that we have taken steps to reconcile the results. For PG&E, we are using CEC-based target reserve margins for long-term planning purposes, while the EUE targets that we have approved for SDG&E and Edison are applied so as to be consistent with CEC planning criteria. (See D.88-03-079, pp. 8-18.)

However, we also note that methods for measuring and valuing system reliability continue to be controversial as new models are developed, existing models are refined, and the merits of the value-of-service approach are examined. The biennial update proceeding is the forum where we consider methodological changes for the standard offers. We will use our existing reliability methodology for the update to follow ER-7, but to the extent that developments in the reliability area warrant changes thereafter, the parties should describe those developments and their proposed changes in their testimony submitted in this update.

The CEC and CPUC staffs have dealt with cost-effectiveness testing in a series of workshops, aiming to modify the existing Standard Practice Manual to permit more direct comparison of generation resources with demand-side options. (See D.87-11-024, pp. 19-22.) It seems clear at this time that substantial progress has been made, but that all problems will not be resolved in this update cycle. Because of the importance of this issue in the treatment of those conservation/load management programs designated "conditional RETO" (discussed below), we feel that modifications to the Standard Practice Manual should continue to command a high priority.

As part of DRA's filing in the next biennial update proceeding, DRA should include a status report on progress toward the development of a standardized and uniform methodology for the treatment of costs and benefits of all resource options (both generation and nongeneration).

In D.87-11-024, we noted the disparate views on how the CEC's adopted estimate of long-term demand-side management (DSM) program impacts should be integrated into the long-run standard offer process. The CEC's forecasts of DSM program impacts include (under the term "conditional RETO" [reasonably expected to occur]) some programs subject to future regulatory action. Examples are anticipated CEC building and appliance energy efficiency standards as well as utility-sponsored programs whose level of funding is set by the CPUC. In D.87-11-024, we held that committed DSM programs are nondeferrable by QFs, and we accepted the CEC estimates of conditional RETO in preference to SDG&E's position (under which no conditional RETO would be included in SDG&E's resource plan). However, we also noted (id., p. 20) that in the future, the level of conditional RETO included in the resource plans should depend on more definitive demonstrations that such programs constitute cost-effective supply options. We supported expected enhancements to the cost-effectiveness methodology, via joint CEC and CPUC staff workshops on revisions to the Standard Practice Manual, as the vehicle for these demonstrations.

We reaffirm our intention to review long-term DSM program impacts and to integrate them into our long-run resource planning activities. The adopted CEC conditional RETO forecasts should be presented by the CEC and reviewed by our staff and other parties in terms consistent with any enhancements developed in the joint CEC/CPUC staff workshops on integrated least-cost methodologies. Based on our review, we expect that we will consider some or all of the estimated conditional RETO as nondeferrable resource additions for purposes of final Standard Offer 4. Projection of long-term

DSM costs and impacts by this Commission in the resource plan update proceeding should also be given weight in subsequent short-term DSM funding requests in the respective general rate cases.

IV. Performance Features and Disaggregated Resource Needs

We are satisfied, on the whole, with the utility compliance filings in what is the first time through a complex new proceeding. The filings of PG&E and Edison, however, fall short of what we required in D.86-07-004 regarding the assessment of need for additional performance features (e.g., full dispatchability, voltage support) on their respective systems:

> "[The utilities] shall file and serve...a report preliminarily assessing the value and feasibility on their respective systems of additional performance features potentially supplied by Qualifying Facilities (QFs). The report will address specifications that QFs would have to meet, methods for quantifying and costing the features, implementation procedures, and other particulars...." (Id., Ordering Paragraph 2.)

The reticence of PG&E and Edison contrasts with the careful analysis that SDG&E devoted to this issue.

Additional performance features ("adders") refer to system benefits that a generation resource (including both a utility's own plants and purchases from QF and non-QF sources) may provide beyond the resource's basic energy and capacity.[10] These features may have local or system-wide value, depending on the other resources, transmission configuration, and other characteristics of the utility receiving the resource's power. (For further discussion of the genesis of the "adders" concept, see D.86-07-004, pp. 11-13, 74-75; D.87-11-024, pp. 29-31.)

These additional features are important for many reasons. In particular, they can enhance reliability and help the utility to add resources, consistent with economic dispatch and smooth system operation. Furthermore, they play a role in the utility's planning of its own resources and negotiations with non-QF sellers. To the extent that QFs are able to provide such features, this may mitigate the utilities' stated concerns about minimum load problems that may accompany higher reserve margins, and also help to place QFs on the same plane as the utilities' other resource options.

A. PG&E's Report on Performance Features

PG&E's comments on performance features are contained in Part D, pages 93-112, of its Fifth Amendment to Application 82-04-44 (which we shall refer to as the Amended Application), in Exhibit 416 (pp. B IV-1 to -4), in Exhibit 417 (pp. 28-30), and in its concurrent brief on resource planning issues (pp. 58-61). PG&E makes some good points, but its comments are often more argumentative than analytic.

10 Note that standard offer contracts already contain performance requirements of various types. For example, all except very small QFs (100 kilowatts or less) are required to provide "reasonable" reactive power support, and QFs holding contracts to provide firm capacity are dispatchable <u>upward</u> by the purchasing utility to any level up to the contract capacity. We therefore directed consideration of "adders" only to the extent that they concern a feature to which the utility is not already entitled under its contract with the QF. (D.86-07-004, p. 74.)

PG&E notes, and we agree, that what "adders" are appropriate depends on the "basic pricing concept" for the QF, including such matters as the kinds of performance required of QFs under the various standard offers and the frequency of updating for the factors that affect the calculation of QF prices. Since some of our decisions on updating are quite recent, PG&E to that extent had reasonable grounds for insisting that it could not precisely determine the value of load-following features (e.g., coordination of maintenance, prescheduled dispatch, full dispatchability). PG&E also makes the pointed observation that system stability features (e.g., availability during emergencies, black-start capability), where appropriate, should be compensated through a capacity adder rather than an energy adder. PG&E's analysis barely goes beyond this. The report has little on how to implement adders, how to quantify need for adders, or how to price them, even under PG&E's recommendations for updating.

PG&E argues that, for load-following features, "the key issues are (1) what payment structure is used to calculate the base price, and (2) is the avoided utility plant dispatchable? PG&E's candidate avoided plants are dispatchable and were modeled as dispatchable in cost-effectiveness analysis. As a result, must-run QFs should receive a decrement to energy payments." (Concurrent brief, p. 58.) This argument is faulty. PG&E may only be considering dispatchable resources right now, but eventually it, like any other electric utility, will need additional baseload generation resources. The QFs that defer or avoid baseload additions may be able and willing to follow load in varying degrees, even though the avoidable resource would not. PG&E itself concedes that "[d]ispatchable resources should always have some incremental value." (Exhibit 417, p. 29.)[11] We asked the utilities to investigate, through the adders concept, how to cost-effectively obtain potential additional load-following capability from QFs. PG&E has not done so.[12]

Regarding system stability features, PG&E argues that "there is no question that the features identified as appropriate in determining an adder would be inherent in the avoided plant. Any plant that PG&E constructs would automatically incorporate these and other features.... Likewise, the cost estimates for constructing and operating the avoided plant would include the cost of these features." (Exhibit 417, p. 29.) We don't doubt that PG&E designs its plants with system stability in mind, along with a great many other things. However, the site chosen for an avoidable resource is bound to be a compromise: a site that is suitable for environmental reasons may or may not have system stability advantages, and the site (no matter how advantageous) will certainly not enable PG&E to meet system stability requirements at other areas in its service territory. (Cf. D.86-07-004, p. 60,

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11 PG&E also notes, "[A] dispatchable QF could be relied [upon] for spinning and regulating reserve, area power factor correction, attenuation of local disturbances, local voltage support, ensuring system security, and more efficient area load regulation, just as PG&E relies upon its own dispatchable resources for such purposes." (Amended Application, Part D, pp. 109-10.) We agree. Furthermore, some of these benefits might be provided even by QFs that are not fully dispatchable.

12 We also disagree with PG&E's suggestion that "must-run" QFs deferring intermediate resources (which are the only dispatchable resources deferrable under final Standard Offer 4) are overpaid. Time-differentiated energy prices and the treatment of energy-related capital costs in that offer ensure that such QFs, if they operate when the avoidable resource would not, are paid no more than avoided cost during those hours. See also our discussion of load-following features in Section IV.B below.

note 37.)[13] Thus, it is possible for QFs avoiding a resource, and even existing QFs that do not defer or avoid a specified resource, to provide system stability benefits to the purchasing utility.

More important, PG&E ignores the fact that the avoidable resource may not be a plant but rather a purchase of energy and capacity from a non-QF seller. In that case, the load-following and other features of the purchase are generally a part of the negotiations between the purchasing utility and the non-QF seller. Moreover, the purchasing utility generally claims substantial value for these features in reasonableness reviews and other proceedings. We understand the importance of these features in off-system transactions and desire only that QFs be permitted to compete on an even footing. In our view, that goal requires analysis of disaggregated resource needs, especially those system requirements that might not be met by any single avoidable plant but could be met by purchases from some combination of QF or non-QF sources.

B. <u>Edison's Report on Performance Features</u>

Edison's comments on performance features are contained in Chapter IV of Exhibit 421, Chapter IV of Exhibit 424, and Chapter V of its concurrent brief. Edison has priced four of the seven performance features identified in D.86-07-004 (emergency availability, coordination of maintenance, reactive power support, and full dispatchability). Like PG&E, Edison believes that system stability features are properly reflected in capacity payments. Edison would pay for full dispatchability through an adder to the QF's "base energy price."

13 As PG&E notes, many types of system stability requirements tend to be local in nature. The best-planned power plant would not meet such requirements if they affect an area remote from the plant; the utility would have to satisfy them through other means, among which QFs might be a cost-effective alternative.

Edison apparently believes that the term "adder" is a misnomer for what should generally be a decrement to QF payments, at least as they are currently calculated. For example, under final Standard Offer 4, if the QF does not agree to supply all the performance features of the avoidable resource, "the QF should only be paid for the performance features it agrees to supply and actually does supply; otherwise, the ratepayer pays for a service that is not provided." (Exhibit 421, p. IV-3.) As for existing QFs, Edison says that "implementation [of adders] is not feasible at this time. The majority of existing QF contracts includes capacity payments that are based on the full value of a [combustion turbine] which already includes most of the performance adders identified. To allow QFs with existing contracts to seek adders would result in compensating them twice for the same performance feature." (Id., p. IV-8.)

Edison cautions that it had to make many assumptions in order to develop the values shown in its preliminary assessments of adders. "As experience is gained, these assessments and derivations will need to be updated to capture other effects not presently quantifiable ... or other methods for attempting to 'unbundle' the value of various performance characteristics from the cost of the [avoidable resource]. As currently derived, the value of the adders is based more on how the [avoidable resource] was to be operated than how it was constructed." (Exhibit 421, p. IV-4.)

We find Edison's comments helpful in some respects, and Edison has been more forthcoming than PG&E in trying to determine values for at least some of the adders. However, Edison exhibits the same tunnel vision as PG&E in thinking about avoidable resources, and we are sceptical about Edison's proposed valuation methods.

We accept, in principle, the proposition that capacity or energy payments to a final Standard Offer 4 QF could be lower, as well as higher, depending on the mix of performance features that the QF supplies, as compared to the performance features associated with the avoidable resource. Edison seems to think that the effect of considering performance features would generally be to lower QF payments. We think that remains to be seen.[14] However, as Independent Energy Producers Association (IEP) notes, QFs' system stability features would very likely be adders whenever out-of-service-area resources are the avoidable resources. (See Exhibit 432, pp. 28-29.)[15] When the avoidable resource is an in-area power plant, the question is more complex. As we've noted above, the site chosen for that plant is apt to be a compromise. QFs avoiding or deferring that plant may make a greater or lesser contribution to system stability, depending on their technology, location, and willingness to make appropriate commitments.

We reject Edison's assertion that adders are "not feasible" for existing QFs. Edison mixes up short-run and long-run methodologies and misconstrues the role of the combustion turbine in calculating capacity payments to these QFs. Final Standard Offer 4 is the only plant-based offer. The combustion turbine is used simply as a proxy for the purchasing utility's short-run marginal cost of capacity. Nobody ever expected QFs to run like a combustion turbine or designed a standard offer to replace

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14 Since both Edison and PG&E apparently take the position that the correct treatment of performance features would effectively reduce QF payments overall, we find it surprising that their response to our request that they quantify and evaluate these features is so tepid.

15 "Many emergencies in fact are caused by transmission line failures, such as loss of the Northwest Intertie on December 22, 1982 and February 29, 1984, and out-of-service-area resources may well be unavailable as a result of such line failures. In addition, out-of-service-area resources cannot support voltage." (Prepared Testimony of IEP witness Marcus, Exhibit 432, pp. 28-29, citations omitted.)

combustion turbines in the utilities' resource mix. We therefore do not reduce capacity payments to QFs for failure to match the system stability features of a combustion turbine. (We do, however, reduce prices to QFs that receive variable capacity payments to reflect the purchasing utility's current need for capacity.)[16] It follows that there is no overpayment or methodological inconsistency if utilities were to pay existing QFs for supplying performance features that such QFs are not otherwise obligated to provide.

Turning to specific system stability features, IEP has demonstrated a flaw in Edison's valuation of emergency availability. Edison uses a formula that relates increased spinning reserve requirements to potential emergency unavailability of QF capacity on its system. Positing such a relationship seems a reasonable way to begin the analysis. However, Edison values this feature in dollars per kilowatt of increased spinning reserve costs rather than dollars per kilowatt of QF capacity projected to be unavailable. This is inaccurate since, even if Edison were actually to increase its spinning reserves per the model (Edison says that it in fact does not do this, see Exhibit 424, p. IV-1), it would do so on less than a kilowatt-for-kilowatt basis. Edison thus significantly overstates the value of QF emergency availability under its own formula. (See also Section IV.D below.)

Edison also evaluates an adder for voltage support. SDG&E calculates a similar dollars per kilowatt value for this adder, which would apply to support provided beyond the minimum

16 Thus, Edison's and PG&E's current capacity payments to variably priced QFs are deeply discounted from the full annualized fixed costs of a combustion turbine, to reflect the relative abundance of capacity on their systems. Such discounting would not happen under a plant-based offer: the utility cannot build a fraction of a power plant.

interconnection requirements in the respective utility's tariff rule (Rule 21). The value assigned to this adder (roughly $1 per kilowatt-year) seems reasonably derived from the cost of proxy capacitors. We also agree with Edison and SDG&E that the adder should be made available only in specified areas of need on the system, since reactive power cannot be transmitted over long distances. IEP prefers SDG&E's approach, which uses distribution capacitors, because (according to IEP) most QFs are located at the distribution level. This can be discussed further in workshops, but we are satisfied that the parties have established a good basis for implementing this adder.

There has been a lot of work on load-following features since Edison prepared its report. The key to our preferred approach (which we think is followed in the curtailment provision developed for final Standard Offer 4) is that any kind of load-following is basically a device for concentrating the QF's output within relatively high-cost hours on the utility system. This leaves the purchasing utility free to achieve optimal dispatch during low-cost periods. The load-following adder should therefore be calculated as the differential between the QF's potentially operating at random over all hours of the year and whatever limitation to higher cost hours is imposed by the performance feature to which the QF commits. (See D.87-08-047, mimeo. pp. 7-8.) We agree with IEP that, wherever the QF would otherwise be paid on an average cost or time-differentiated basis, the QF's commitment to follow load justifies an increase in its energy payments.

The approach that Edison takes in its preliminary assessment of load-following features is quite different, and we doubt that Edison (one of the chief architects of the curtailment provision) would adhere fully to its former proposal at this time. Edison makes a good observation that full dispatchability may be analyzed as a composite of various other adders such as prescheduled dispatch. However, much work still needs to be done in order to derive a full dispatchability adder made up of the sum of discrete load-following increments. In Exhibit 421, Edison suggests valuing full dispatchability on the basis of efficiency savings realized by the purchasing utility. The efficiency savings result from the reduced cycling of the utility's own plants that is made possible by QFs' commitments to follow load. Such savings might indeed occur, but they seem quite speculative and hard to quantify relative to our preferred approach, and also seem to be only a small component of the total load-following benefits attributable to full dispatchability.

C. SDG&E's Report on Performance Features

SDG&E's comments on performance features are contained in Exhibit 429, pages 28-33, and Appendix A of that exhibit. SDG&E favors valuing performance features, using historical data wherever possible, by determining a "base" level of service (with energy-related and capacity-related components). What is or is not included in "base" service is open to dispute, as is the question of whether some of the standard offers already require, and compensate QFs for, some of the performance features beyond "base" service. Nonetheless, the "base" service concept is a useful way to structure this analysis. SDG&E also discusses the compatibility of different types of performance features and provides a "Matrix of Adders Interaction" that neatly defines the possible combinations of adders that a QF could select.

As we noted earlier, SDG&E's valuation of the voltage support feature is definitive. SDG&E would only make the adder available on a case-by-case basis, arguing that "an assessment of need for var support near the QF site must be made by [SDG&E] personnel." (Exhibit 429, p. A-8.) We recognize that the need for this feature is site-specific; however, the utility should be able to specify some criteria that would at least alert the QF operator or planner of its potential eligibility for the adder.[17]

SDG&E expresses its suggested load-following adders as a percentage of the energy price. It calculates an adder of 0.8% for coordination of maintenance. For curtailment (which SDG&E prefers to prescheduled dispatch), SDG&E calculates an adder of 4.1% for 1000 hours of allowable curtailment, increasing to 6.5% where the curtailment level is set at 2000 hours, and to 7.9% for 3000 hours. Finally, the full dispatchability adder works out to 16.5%.

SDG&E derives these percentage adders by comparing its hourly marginal energy costs (using 1985 recorded data) with its Time-of-Use rates. This seems reasonable as an initial quantification. However, there may be other ways to compute the effect of concentrating the QF's output within relatively high-cost hours. We are also concerned about the possible sensitivity of the adder to the choice of historical base year. SDG&E itself urges in its concurrent brief that we not implement adders at this time but instead convene workshops to further develop these concepts.

D. Conclusions

1. Specific Performance Features: System Stability

All parties agree that none of the utility applicants currently has a need for black-start capability on its system. We will defer further consideration of this feature.

Voltage support is the feature most satisfactorily analyzed to date. A price range of $1 to $1.20 per kilowatt-year

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17 We do not now have a multi-attribute bidding system for final Standard Offer 4, but adders (if the QF developer has sufficient information about their availability and price) can serve a similar function. For example, a QF developer that knows that its plant could qualify for certain adders could take this into consideration both in its plant design and in calculating its bid for the second price auction. This is a "win-win" situation: the QF optimizes its economics while increasing its value to the purchasing utility.

appears reasonable. Analytical work on this feature now needs to concentrate on QF eligibility, including geographic and operational criteria.

The utilities show a wide variation in their treatment of emergency availability and perhaps in how they define it. PG&E and SDG&E believe that they are already entitled to this feature from QFs and thus claim that it should be priced at zero. On the other hand, Edison assigns a very high price to emergency availability. It appears, however, that Edison has unique criteria for underfrequency load-shedding, under which (according to IEP witness Marcus) QFs interconnected at below 220 kilovolts are cut off automatically during system disturbances. (See Exhibit 432, p. 27.) Edison calculates that typical QF power deliveries, and roughly half of the total megawatts provided by QFs, come from stations subject to such disconnection. (Exhibit 421, p. IV-6.) The ironic result is that PG&E complains of QFs that (according to PG&E) trip off-line during frequency deviations less severe than would cause damage to the QF's generator, while QFs complain that Edison trips them off-line (and would reduce their capacity payments on account of this utility-imposed unavailability) even during frequency deviations when they could remain on-line.

We have rejected Edison's valuation of emergency availability. Thus, there is no basis for Edison to use that value either to increase or decrease payments to QFs. However, we agree in principle with PG&E that, if relay settings are established to automatically disconnect the QF where frequency deviations would damage the QF's generator, it is reasonable to expect the QF not to manually separate from the system during lesser deviations. At least for a QF that defers or avoids an in-area power plant, this logic would dictate a <u>reduction</u> in capacity payments unless that QF commits to reliance on the relays or direct authorization from the purchasing utility before separating from the system. Neither PG&E nor SDG&E has calculated an appropriate level for such a reduction.

In D.88-03-079, p. 45, we said that "appropriate QF response to emergencies is vital if utilities are to rely on large amounts of QF power." We repeat our call in that decision for more QF/utility consultation on this subject, particularly on matters such as variations in practice between the utilities and manual separation by QFs.

2. Specific Performance Features: Load Following

For reasons that we explained in Section IV.B above, load-following features must generally be treated as adders to the energy payments to QFs providing such features. SDG&E's report, and the work done on "economic curtailment" for final Standard Offer 4, create a sound basis for further efforts in this area. SDG&E has also indicated that it intends to develop a simplified curtailment procedure for use with its final Standard Offer 4. (See Section VIII below.) We hope that procedure would also be adaptable for purposes of reinstated Standard Offer 2. We direct DRA to hold a public workshop to discuss load-following features generally, define future tasks and priorities, and review SDG&E's proposal. The workshop should take place within a reasonable time after SDG&E publishes its proposal.

3. General Observations on Performance Features and Disaggregated Resource Needs

Our original interest in this topic was prompted by two concerns.

First, the utilities have said that the larger than anticipated response to the standard offers has created or will create operational problems because existing QFs are subject to few performance requirements and are not dispatched downward by the purchasing utility. From the utility reports, we had hoped to get more knowledge of the types and severity of these alleged problems.

Second, the "adders" concept seemed adaptable to both new and existing QFs. This was attractive because it (1) involved existing QFs in the solution of problems attributed to their development, and (2) suggested cost-effective forms of relief for QFs that were looking for ways to boost their revenue streams.[18]

Our experience in the compliance phase of this proceeding has heightened and broadened our interest in the "unbundling" of resource needs. This is because the resource plans have underscored two additional concerns.

First, over the long term, we are looking for ways to bring into the QF procurement process other factors besides basic capacity and energy. Whether this enhancement of the process takes the form of multi-attribute bidding, RFP-type solicitation (see D.86-07-004, p. 21), or adders/subtractors to a contract base price, we would need to establish in advance at least the relative worth of each factor. Performance features seem to be the logical place to begin this analysis, both because of the utility operational concerns mentioned above and because there seem to be objective bases for pricing these features.[19]

Second, the record to date suggests that the avoidable resource is apt to be a purchase from non-QF sources, and that

18 Some QFs predate the standard offers. These "pioneers" often receive little or no capacity payment and an energy payment based on short-run avoided energy costs. When oil and gas prices dropped sharply, so did the energy payments. (See D.87-01-049.) Load-following and other adders are especially suitable in these circumstances since they provide higher payments based on increased value of the QF's deliveries to the purchasing utility. This is fair to QFs and fair to ratepayers.

19 For example, we already time-differentiate electric utility costs and rates for various purposes; such time-differentiation has obvious relevance to the load-following features. Some factors that do not directly relate to performance might also be considered in QF procurement. However, these factors (e.g., fuel diversity, impact on California economy and environment) are generally more subjective and/or remote from traditional resource planning: hence, our decision to start with performance features.

performance features would figure importantly in such purchases.[20] According to SDG&E, current power purchase negotiations between utility systems usually involve a "base package" of assets and services; the process of negotiating takes the form of "repackaging" to explore ways to add value or reduce costs. We certainly have no desire to replace such purchases with purchases from QFs unless QFs provide equivalent value. On the other hand, we will not make the a priori assumption that QFs cannot provide equivalent value. The development of performance features should give us a measure against which to test the QFs' response.

For all these reasons, the "unbundling" of resource needs is the logical culmination of a resource plan-based QF procurement methodology. Only SDG&E seems (from this record) to have grasped this point, or to have expended the analytical effort to make significant progress.

To be fair, we must also note that since the preparation of these utility reports, all of the utilities and many QFs have done much work on load-following features. This work has resulted in an "economic curtailment" option for final Standard Offer 4 and many individually negotiated curtailment or dispatchability features.

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20 SDG&E witness Niggli asserts that "a utility can obtain services from a power purchase contract with a utility that a QF resource frequently is unable to provide." Niggli mentions the following "services:" energy storage arrangements; energy banking arrangements; capacity and energy from multiple units at a plant; back-up service from the utility system; diversity exchange arrangements (hourly, daily, seasonally); marketing services; transmission access. (Exhibit 214, p. 10.) We think that the ability of QFs to provide such services is largely untested. QFs come in many sizes and technologies, so there should be at least a potential for QFs to meet or beat performance adders offered by non-QF competition. We encourage both utilities and QF developers to explore contractual arrangements whereby QFs would provide these or other services.

In the resource plan update following ER-7, the utility applicants should each file revised reports on performance features. The reports should cover at least the same system stability (except for black-start capability) and load-following features that were in the original reports; the utilities may also propose additional features. The utilities should indicate the performance features that have been incorporated to date in any contracts with QFs, and should provide a statistical analysis. The analysis need not identify individual QFs but should indicate, by QF technology, the number of megawatts on the respective utility system that are subject to curtailment or other special performance requirements.

Finally, the reports should analyze the potential for a resource plan-based long-run offer made up of disaggregated resource needs. Such an offer would include components for "basic" energy and capacity set at projected long-run marginal costs; system stability adders and line loss impacts calculated for various districts within the purchasing utility's service area; and load-following adders calculated for a range of load-following options up to and including direct utility dispatch of the QF plant. There are other factors in resource planning that are not strictly performance-based. The "unbundled" generation resource offer could include premiums for various attributes deemed desirable by the planner. Such attributes would include, but are not limited to, various types of security that the QF might post, an option to delay or advance the QF's on-line date, and use by the QF of renewable fuels or other fuels that meet fuel diversity criteria.

V. The Future of Standard Offer 2

Standard Offer 2, like interim Standard Offer 4, has been suspended (i.e., is not available for new QF contracts). Similar problems underlie both suspensions: inadequate provisions for updating, coupled with price terms that, in view of then-current expectations of need, were seemingly too generous to QFs seeking new contracts.

Revised updating and capacity value adjustment procedures are now in place. (See D.87-11-024 and D.88-03-026.) Block pricing, an overall megawatt limit, and a time limit on availability are additional features that we approved for Standard Offer 2. These developments made it possible to reinstate Standard Offer 2, up to a maximum of 100 megawatts in two blocks of 50 megawatts each, for SDG&E. (See D.88-03-079.)

However, we decided not to reinstate Standard Offer 2 for PG&E or Edison. (See D.87-11-024.) These utilities, unlike SDG&E, showed very little need for new generation capacity over the next five years.[21] This causes concern because the levelized capacity payments in Standard Offer 2 would mute the price signal that the capacity value adjustment and block pricing was supposed to give to potential QFs. Thus, the outstanding issues for Standard Offer 2 are (1) under what circumstances should it be made available, and (2) what megawatt limits should apply when it is available.

Standard Offer 2 uses short-run energy and capacity prices (using the annualized fixed costs of a combustion turbine as a proxy for the short-run marginal cost of capacity). However, the capacity price is projected and levelized over the life of the contract (up to 30 years). This feature means that Standard Offer 2 has greater price certainty than the other offers based on short-run methodology, where the capacity price is subject to annual adjustment. Also, Standard Offer 2 is the only one of our current offers to have any degree of front-loading in the payment

21 Standard Offer 2 currently requires the new QF to come on-line within five years after contract execution.

stream.[22] Finally, Standard Offer 2, unlike the other short-run offers, requires the QF to be available during periods of peak demand on the purchasing utility's system and recognizes the ability of many QFs to provide firm capacity.[23]

There is no doubt that Standard Offer 2 has a continuing role to play in a balanced portfolio of standard offers. For example, SDG&E has noted the importance of the QF's commitment under Standard Offer 2 to meet peak demand; during its suspension, the only short-run offer available to a QF over 100 kilowatts capacity is Standard Offer 1, which entails no such commitment. Moreover, we are convinced that need generally should not be an issue with Standard Offer 2 since, like the other short-run offers (and subject to our concern regarding levelization), payments to Standard Offer 2 QFs reflect the purchasing utility's short-run marginal costs. Considering these features, we seek comment on the following proposal for regulating the availability of Standard Offer 2.

Standard Offer 2 would be made available, for a specified time and subject to block pricing and overall megawatt limits, for PG&E, SDG&E, and Edison after each biennial update proceeding. The block sizes would be 50 megawatts for SDG&E and 150 megawatts for PG&E and Edison. The number of blocks to be made available for

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22 Interim Standard Offer 4 also has front-loaded payment options. However, final Standard Offer 4 supplants the earlier version as our long-run offer and only provides "ramped" (i.e., inflation-adjusted) payment streams.

23 Time-differentiated capacity payments under Standard Offers 1 and 3 give the QF a powerful incentive to be on-line during peak periods; however, the QF does not have to meet any performance requirement for such periods, i.e., the QF delivers only "as available" capacity. In contrast, the QF under Standard Offer 2 must generally be available for all on-peak hours in the peak months (subject to a 20% allowance for forced outages in any month) in order to receive full capacity payments.

each utility would be an issue in the update proceeding. Generally, we would make available an amount of capacity not less than 2% of the respective utility's peak demand; this corresponds to about one year's growth in peak demand and represents a conservative amount of capacity to be made available, since there are two years between updates.

To meet our concern about levelization, we would add to Standard Offer 2 a new requirement that the QF come on-line no sooner than the first year in the eight-year "window" that the purchasing utility's ERI is projected to equal or exceed a stated threshold.[24] (The higher the ERI, the greater is the relative value to the utility of additional capacity.) We propose to set this threshold initially at 0.8. A Standard Offer 2 QF that comes on-line before the ERI threshold is projected to be reached would receive Standard Offer 1 capacity payments during that interval. (This is the same way that we treat final Standard Offer 4 QFs coming on-line before the projected on-line date of the avoidable resource.)

The threshold would modify the current requirement in Standard Offer 2 that the QF come on-line within five years of contract execution; instead, like final Standard Offer 4 QFs, the

24 The projection would be made in the biennial update proceeding and would be based on the resource plan used for purposes of final Standard Offer 4. The Standard Offer 2 contract would have a specific date when the QF could begin to receive levelized capacity payments. This date would be redetermined at each update proceeding for new Standard Offer 2 contracts, but existing contracts would not be affected. Both the Standard Offer 2 capacity price table and the number of blocks of Standard Offer 2 contracts to be made available would be determined assuming full subscription of whatever number of final Standard Offer 4 megawatts is authorized in that biennial update proceeding. In other words, any identified avoidable resource would be deemed avoided or deferred by final Standard Offer 4 QFs when we establish the pricing and availability of Standard Offer 2.

Standard Offer 2 QF would have up to eight years to come on-line (depending on when the threshold is reached rather than the projected on-line date of an avoidable resource). This feature, together with capacity price levelization, would make Standard Offer 2 particularly attractive to QFs using new or capital-intensive technologies that typically require some degree of front-loading in order to be financed and that often need more than five years to come on-line.[25]

It may be useful to receive comments on our proposal before the next biennial update proceeding. Accordingly, the schedule for comments will be set by Assigned Commissioner or ALJ Ruling.

VI. Uniform Standard Offer Contract Language

Our basic policy governing the form and terminology used in the standard offer contracts is that they should be uniform among the utilities except for the very few aspects that must be utility-specific due to different operating characteristics. See D.83-09-054, ordering paragraph 5; D.83-10-093, ordering paragraph 20. This ensures evenhanded treatment of QFs and promotes a common understanding of the standard offer provisions.

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25 Given these adjustments to reinstated Standard Offer 2, we hope to see fewer requests for approval of nonstandard contracts. We also regard Standard Offer 2 as setting the limit for front-loading payments to QFs, while final Standard Offer 4 sets the limit for price certainty. We do not preclude greater front-loading or price certainty in a nonstandard power purchase agreement, but the utility and QF supporting such an agreement will bear a heavy burden in demonstrating that it is fair to ratepayers and consistent with avoided cost principles.

Final Standard Offer 4 already fully implements this policy for that offer. Also, pursuant to the cited decisions, workshops held earlier in this proceeding have produced uniform contract language for the other standard offers. However, our review of the uniform language was delayed, while we devoted our attention to Standard Offer 4.

Before our review and possible approval of the uniform language, we think the parties should have an opportunity to reconsider that language, particularly in light of the products of the final Standard Offer 4 drafting effort. That effort, which we summarize in D.88-03-079, resulted in clarifications and imaginative solutions in a number of problem areas. These clarifications and solutions should be incorporated in the short-run offers, on a prospective basis for new QFs signing those offers, wherever appropriate.

We intend to review the uniform language before the next biennial resource plan update. Also, we need to review the parties' recommended specific language implementing the new curtailment provision (see D.88-03-079, pp. 40-41); these recommendations were filed on June 27, 1988. Ideally, we can complete both tasks in a single decision in the fall.

With this timetable in mind, we direct the utilities to examine the existing uniform language proposals for the short-run standard offers and file revised proposals on October 14, 1988, for Commission approval. We encourage continuation of the consultative process that reached general agreement on contract drafting issues for final Standard Offer 4. Under this process, the utilities and interested parties would file a joint proposal on October 14, indicating agreed-upon provisions, utility-specific language where appropriate, and any contested matters. Other parties may comment on the proposal(s); such responsive comments must be filed no later than November 4, 1988.

VII. Disposition of Pending Petitions and Motions

We have postponed consideration of several petitions and motions because of the priority given to the replacement of interim Standard Offer 4 with a long-run standard offer based on utility resource plans. Now that final Standard Offer 4 is in place, we turn to these other matters relating to the standard offers.

A. Request for Hearing on Line Loss Issues

Part of the calculation of avoided cost is the variation in transmission line losses caused by QFs. In other words, does QF development save money (in the form of reduced line losses) for the utility that purchases the QF output, or does QF development cost money (in the form of increased line losses), as compared to generation and transmission of an equivalent amount of electricity from the utility's other resources? Note that line losses affect the value of both the energy and capacity purchased from a QF or from a non-QF seller. (See D.84-03-092, mimeo. pp. 38-39.)

Many issues would have to be resolved to answer these questions precisely. We would have to consider, for example, QFs' proximity to the utility's load centers and the characteristics of the utility's transmission system. We would also have to decide whether to predicate the answers on analysis of the aggregate impact of QFs, or whether a project-specific line-loss methodology is necessary or desirable.

We addressed line losses in several of the early standard offer decisions. We ordered the utility applicants to include in their offers the costs or savings from line losses for QFs in the aggregate. (D.82-01-103, 8 CPUC 2d 20, ordering paragraphs 6.d and 8.e.) However, we created an exception for remote QF projects one megawatt or larger: losses from such QFs were to be examined individually. (Id., 8 CPUC 2d at 45.) In D.82-12-120, we noted the paucity of utility line loss studies to date and determined for the time being to adopt a loss factor of 1.0 to be applied by all utilities for all QF energy. This essentially treats the line losses associated with QFs as equivalent to those from utility plants. (D.82-12-120, 10 CPUC 2d 553, 625.) We also determined that adjustments for remote QFs were not then practicable, and we suspended that exception pending utility study of how to identify such QFs and to reflect a different energy loss rate. (Id.) However, we rejected a PG&E suggestion that individual line losses be established, instead affirming our prior decision to analyze QF line losses in the aggregate. (Id.)

Following D.82-12-120, PG&E revised its previous line loss study, reviewed the new study with an advisory group that it had convened, and filed the study at the CPUC on September 30, 1983. Not surprisingly, the results of the new study were controversial, and on November 8, 1983, a "Request for Evidentiary Hearing" before taking action on PG&E's proposals was filed jointly by Ultrasystems Incorporated and Occidental Geothermal, Inc. (Utrasystems/OGI).[26] SDG&E and Edison have also filed line loss

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26 Santa Fe Geothermal, Inc., an active participant in the final Standard Offer 4 compliance phase, is successor to OGI.

studies; to date, no hearings have been held on any of the studies, which are now at least four years old.[27]

With work in this proceeding near completion, and our investigation of the impacts of out-of-state and out-of-service-area QFs (I.85-11-008) about to resume, the latter proceeding seemed to be the logical forum for examining line loss issues. This was suggested by ALJ Wu's Ruling of January 7, 1988. However, at a prehearing conference on February 11, 1988, in that proceeding, most parties did not support expanding the scope of the investigation to include these issues. Thus, our order restructuring I.85-11-008 made no provision for addressing line losses. (See D.88-04-070.)

We see little benefit at this time to refining the treatment of line losses in our established methodology for pricing energy from existing QFs, or even future QFs under the short-run standard offers. Not only are the studies old and likely to need revision, but also the issues involved in making line loss adjustments for such QFs are complex, and there is no assurance

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27 However, in D.84-03-092, we did modify D.82-12-120 in response to a petition by SDG&E. As the latter decision was modified, the adopted energy line loss adjustment factor of 1.0 is to be applied only by PG&E; for SDG&E and Edison, we set the transmission and primary distribution loss adjustment for energy equal to the respective utility's marginal line loss factor. We also concluded that, for SDG&E and Edison, no additional line loss savings would accrue from QFs at the secondary distribution level.

We also addressed the subject of a line loss adjustment for <u>capacity</u> in D.84-03-092. We noted that capacity pricing involves payments set further into the future than those for energy and on that basis determined that failure to include a capacity line loss adjustment would expose ratepayers to excessive risk. We approved PG&E's line loss adjustments for capacity, and we also directed PG&E to determine such adjustments remote QFs on an individual basis. SDG&E and Edison (and PG&E for its non-remote QFs) were to continue to calculate capacity line loss adjustments for QFs on an aggregated basis.

that after wrestling with these issues, we would emerge with significantly improved price signals to QFs. We therefore will not proceed to hearing on whether to adjust our present approach to QF line loss impacts in existing short-run standard offers.

We reach a different conclusion for the resource plan-based offer, final Standard Offer 4. First, line loss analysis seems substantially more practicable when QFs' impact is judged against a specific avoidable resource instead of the entire utility system.[28] Second, and more important, line losses may be significant when considering the utility's "disaggregated resource need." (See D.87-11-024, mimeo. pp. 29-31.) Consider two examples. The utility's choice of site for the avoidable resource may depend in part on the configuration of the utility's load centers and existing system; this suggests that QFs avoiding that resource may be significantly less well situated in terms of their line loss impact. However, where the avoidable resource is an out-of-state purchase, we are reluctant to assume a priori that QFs (particularly those in-state and in the purchasing utility's service area) would have line losses equivalent to the out-of-state purchase, which would be the effect of applying a loss factor of 1.0. In both examples, there is a good chance that a given final Standard Offer 4 QF should have a loss factor higher or lower than 1.0.

The line loss impact of potential QF avoidance of an identified avoidable resource should be analyzed by the utility in its resource plan submitted in the biennial update proceeding. We expect each utility to present a line loss adjustment method that is sufficiently detailed to enable each potential QF bidder to

28 Furthermore, within the confines of final Standard Offer 4, it may be both feasible and desirable to judge <u>each</u> QF's impact, rather than taking QFs in the aggregate.

calculate its loss factor precisely, based on the resource against which it is bidding and the location of its own project. The bidder could then take its loss factor into account when preparing its bid; there would be no need to change the second price auction to weight the bids by the loss factor.

If we are able to develop a line loss adjustment method for final Standard Offer 4, we may then investigate extending or adapting the method, on a prospective basis, to encompass new QFs that choose a short-run standard offer.

Since we have decided not to hear or otherwise act upon the utilities' 1983 line loss studies at this time, the Ultrasystems/OGI request for hearing should be dismissed as moot.

B. Petition for Modification Regarding Duration of As-available Contracts (Standard Offers 1 and 3)

SDG&E has asked that we provide for (1) a fixed term in as-available standard offer contracts (as we do for firm capacity contracts), and (2) a contractual obligation that the QF develop its project substantially as set forth in the power purchase agreement. To the extent that the QF either does not develop the facility or the facility cannot be operated at the level contemplated in the agreement, SDG&E urges that "allocated line capacity should be reduced and the contract modified or terminated, as appropriate." SDG&E says that the as-available short-run offers, in their current form, present enforcement problems, complicate the utility's resource planning, and permit a floundering QF project to tie up transmission capacity, to the likely detriment of future QFs.

The QF Milestone Procedure, which we authorized in a series of decisions beginning with D.85-01-038 (Jan. 16, 1985), was developed after SDG&E filed its petition (Nov. 16, 1984) and responds in part to the kinds of problems that SDG&E identifies. Also, final Standard Offer 4 contains an abandonment provision that would apply to as-available QFs under that offer and that appears to handle the kinds of problems that prompt SDG&E's request for a fixed term in as-available contracts. Modification of Standard Offers 1, 2, and 3 to incorporate appropriate provisions from final Standard Offer 4 is one of the remaining tasks to be completed after today's decision.

In short, many of SDG&E's concerns appear either already resolved or resolvable through fine-tuning of the short-run offers that is already under way. (See Section VI above.) Therefore, we deny SDG&E's petition without prejudice.

C. Request for Approval of Off-peak Energy Adjustment Factor for Interim Standard Offer 4 (PG&E)

PG&E has found a gap in the provisions of its interim Standard Offer 4. The gap affects a curtailment option that is unique to PG&E's offer. (See D.83-09-054, mimeo. pp. 36-38.)

Specifically, Curtailment Option B allows PG&E to offer an adjusted energy price for various reasons (not limited to negative avoided cost and hydro spill conditions, as is the case with Curtailment Option A). Curtailment Option B gives PG&E increased operational flexibility and the possibility of reduced energy payments for up to 1000 hours, while QFs choosing this option get an energy price "adder" for certain periods during which the adjusted price cannot be offered. The percentage of this adder is contractually established for that part of the QF's payments based on energy prices set forth in the contract; however, part of the energy payments to certain of these QFs depends on the current published energy prices (i.e., short-run avoided operating costs), and the adder applicable to these prices is not specified.[29] PG&E seeks Commission approval of an adder to apply to these latter prices.

PG&E suggests a solution. PG&E's interim Standard Offer 4 does specify some of the adders needed to implement Curtailment Option B. These apply to the forecasted prices and levelized prices (Energy Payment Options 1 and 2, respectively) specified in the contract. The contractually established adders are 7.7% for Seasonal Period A (May 1 through September 30) and 9.6% for Seasonal Period B (October 1 through April 30). PG&E's solution is to also apply these adders to Curtailment Option B energy prices for any portion of the QF's energy payments based on the current published energy price. PG&E believes its solution would be appropriate as long as the Commission-approved method for calculating short-run avoided operating costs does not already capture the effect of the Curtailment Option B adjustment.

PG&E's solution is attractive for many reasons, not least of which is its simplicity. The record concerning this aspect of PG&E's interim Standard Offer 4 is not detailed; as with the rest of that offer, the contractually established adders are the product of the 1983 negotiating conference between utilities and QFs. So far as we can determine, there is no reason to apply the adders to energy payments based on forecasted or levelized prices but not to those payments using current published energy prices. PG&E's

29 Specifically, a QF choosing Energy Payment Option 1 or 2 may also choose to have a percentage of its energy payment based on current published energy prices, even for the so-called "fixed price period" of its contract. After that period is over, for the balance of the contract term, all energy payments are based on current avoided costs. Under Energy Payment Option 3, all energy payments throughout the contract term use current published energy prices with possible year-end adjustments to reflect the floor and ceiling price bands chosen by the QF.

solution also provides both utility and QF with the price certainty that is one of the primary goals of the fixed price period in interim Standard Offer 4. Therefore, we adopt this solution, at least for the duration of fixed price periods (under Energy Payment Option 1 or 2) specified in interim Standard Offer 4 contracts.

Nevertheless, we will consider another possibility for Energy Payment Option 3 and for Energy Payment Options 1 and 2 at the expiration of the fixed price period. 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, and the parties are also reworking this approach for reinstated Standard Offer 2. 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.

The parties have not previously had an opportunity to consider whether the newer curtailment provisions are reasonably adaptable to purposes of interim Standard Offer 4. The complexity of the various energy payment options dictates care in applying a curtailment approach developed with a different standard offer in mind. We therefore solicit comment on the appropriate treatment of adders under PG&E's Curtailment Option B for Energy Payment Option 3 and Energy Payment Options 1 and 2 at the expiration of the fixed price period. The parties shall file their comments no later than September 1, 1988.

VIII. Curtailment Provision for Final Standard Offer 4

On June 27, Edison, on behalf of the utility/QF/DRA working group, filed the group's joint proposal for implementation of the "economic curtailment" option that we approved in principle in D.88-03-079. However, SDG&E doubts the workability of the option for its system and requests authorization to develop a simpler curtailment approach, in consultation with other group members. SDG&E says that it expects to publish its proposed approach in late July.

SDG&E's problems with the "economic curtailment" option are not clear. Basically, SDG&E finds the option, as implemented under the working group's proposal, (1) hard to administer, and (2) risky for the utility.

Concerning the first point, we are not convinced. The utility has to track much cost information in order to maximize its benefits under the option. However, the utility's system dispatchers already track (or should be tracking) most of this information. The utility's billing department may have additional tasks, as SDG&E suggests, but there are presently no final Standard Offer 4 QFs on-line, and there won't be any for at least a year. SDG&E does not estimate the time required to develop the needed infrastructure.

SDG&E also feels that administration of the option would be costly, relative to the small size of the typical QF on its system. In D.86-07-004, we said that the utility should establish reasonable specifications to govern QF eligibility for performance features. The specifications could include minimum size qualifications for the QF. (*Id.*, p. 74.)[30] How small is too small probably depends on each utility's system. We note that for SDG&E, telemetering is required of QF projects of two megawatts or greater. This may be an appropriate threshold for the "economic curtailment" option.[31]

Concerning the second point, SDG&E's allegation that the utility must determine exactly the lowest cost 1,500 hours on its system just to "break even," our understanding of the "economic curtailment" option is completely different. If the QF continues to generate during the hours subject to the option, it gets paid "actual incremental cost" or the forecast short-run avoided cost for those hours, whichever is <u>less</u>. If the utility's access to cheap energy is greater than the forecast, the QF's energy is priced at the cheaper alternative; if there is <u>less</u> cheap energy around than was forecast, the QF's energy is priced on the forecast basis even though the utility's available alternative energy is more expensive.[32] This effectively shifts much risk of forecast error to the QF, although the utility would get more or less

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30 If SDG&E was concerned about large numbers of tiny QFs signing up for this option, SDG&E could certainly have brought up this concern in the working group. The same observation applies to SDG&E's problems with the term "actual incremental cost" as used in the option. Surely SDG&E, as an active participant in the working group, could have sought to have the term defined to its satisfaction.

31 The threshold would screen out QFs whose enrollment in the option would do little to enhance the utility's flexibility. For example, SDG&E asserts that the numerical majority of QFs on its system are less than a megawatt, but IEP has calculated that over 85% of SDG&E's QF capacity is concentrated among the larger QFs that are subject to the telemetering requirement. (See D.87-05-060, p. 50.) Thus, the administrative burden can easily be minimized while capturing most of the option's benefits.

32 Moreover, the utility can still require the QF to actually curtail its output during "negative avoided cost" conditions.

benefit from this, depending on its skill in scheduling the hours subject to the option. However, the utility has the right under the option to revise the Curtailment Schedule at any time up to four hours in advance of a scheduled curtailment hour.

On balance, we will allow SDG&E the opportunity to develop a simpler curtailment approach, as it requests. We also welcome the offer of the rest of the working group to assist in that effort. Our decision is prompted chiefly by administrability concerns. We had hoped that the "economic curtailment" option would be readily adaptable for use with the other standard offers, in particular, SDG&E's reinstated Standard Offer 2. If this hope is to be realized, the utility needs to be able to implement the option quite readily. Our allowing this opportunity to SDG&E is not to be construed as agreement in any respect with SDG&E's objections to the "economic curtailment" option presented by the working group for final Standard Offer 4.

We therefore request that the working group convene shortly after SDG&E has published its proposed approach. Any party may also file written comments on that approach. Such comments, and the report of the working group, should be filed no later than September 30, 1988. The report should include the working group's recommendation for an "economic curtailment" option suitable for inclusion in the short-run standard offers.

Findings of Fact

1. Strategic considerations play a part in electric utility resource planning. The utility must provide for uncertainty underlying its planning assumptions in order to create a long-run least-cost resource plan. Any acceptable procurement strategy must be non-discriminatory, i.e., it must apply to the utility's own projects and purchases from non-QF sources as well as to QFs.

2. A resource plan should make explicit its strategic elements, reveal the planner's risk preferences, and indicate how the strategy responds to uncertainty.

3. The utilities' CEC-based planning scenarios should adopt the treatment preferred by the CEC for accounting for municipal loads and self-generation.

4. California electricity planners should recognize the uncertainty of the price of, and access to, surplus power from the Pacific Northwest and Canada.

5. Under BPA's current ratemaking policies, BPA has set prices to California that track just below the short-run marginal costs of California utilities. As long as BPA pursues its current ratemaking policies, California ratepayers will lose money if California utilities prefer purchases from BPA to developing cost-effective long-term resources. Purchases from BPA should be assumed to be slightly below short-run marginal cost until and unless BPA provides appropriate assurance on some other price assumption. BPA's "long-term nonfirm energy rate cap" does not provide such assurance.

6. BPA's Intertie Access Policy acts to restrict output and suppress competition among Pacific Northwest electricity suppliers.

7. California's electricity planning should try to mitigate the anticompetitive impacts of BPA's Intertie Access Policy.

8. One logical approach to electric resource planning is to formulate base-case assumptions on future supply and demand, and then to analyze strategies to meet the needs identified in the base case, considering also any uncertainties that underlie the base-case assumptions.

9. A resource planner needs some flexibility in order to reasonably bridge the gap between short-range and long-range forecasts. For the biennial resource plan review, the utility may choose between the trending approach used in this phase, repetition of a current CPUC short-range forecast for the connecting years, or repetition of the CEC year 5 forecast for the connecting years.

10. There is a need for the CEC and CPUC to use common terminology in a consistent way when analyzing electric resource planning issues.

11. DRA's filing in the biennial update proceeding to follow ER-7 should include a status report on progress toward the development of a standarized and uniform methodology for the treatment of costs and benefits of all resource options (both generation and nongeneration).

12. The CEC's forecasts of DSM program impacts include (in the category "Conditional RETO") some utility-sponsored programs whose level of funding is subject to CPUC review and possible approval. The projection of impacts from such utility-sponsored programs should be analyzed in the biennial update proceeding in terms consistent with enhancements developed in the joint CEC/CPUC staff workshops on integrated least-cost methodologies.

13. Standard Offer 2 has a continuing role to play in a balanced portfolio of standard offers.

14. Workshops held earlier in this proceeding have produced uniform contract language for the short-run standard offers. The parties should have an opportunity to further consider the uniform language in light of the provisions more recently approved for purposes of final Standard Offer 4. The latter provisions should be incorporated in the short-run offers, on a prospective basis for new QFs signing those offers, wherever appropriate.

15. QFs, individually or in the aggregate, may increase or decrease the transmission line losses that the utility purchasing the QF's output would otherwise incur. Prior CPUC decisions have established policy regarding treatment of line losses in payments to QFs under the short-run standard offers. Refining that policy for short-run QFs presents formidable problems and should not be pursued at this time.

16. Line loss analysis for individual QFs may be both feasible and desirable for purposes of final Standard Offer 4.

17. The QF Milestone Procedure and the abandonment provision developed for final Standard Offer 4 address some of the concerns underlying SDG&E's request for additional requirements applicable to as-available QFs.

18. PG&E has found a gap in the provisions of its interim Standard Offer 4. The gap affects a curtailment option that is unique to PG&E's offer. Some but not all of the adders needed to implement this option are specified in the offer. PG&E's suggested solution (which is to apply the specified adders to those payments under the offer that are based on the current published energy price) is reasonable, at least for the duration of fixed price periods, under Energy Payment Option 1 or 2, in interim Standard Offer 4 contracts. Other treatments of these adders may be appropriate for Energy Payment Option 3 (under which all energy payments throughout the contract are made at current postings) and for Energy Payment Options 1 and 2 at the expiration of the fixed price period.

19. Additional performance features may have local or system-wide value, depending on the other resources, transmission configuration, and other characteristics of the utility receiving the QF's power. Such features can enhance reliability and help the utility to integrate new QFs, consistent with economic dispatch and smooth system operation. Such features also must be quantified and priced in order to enable QFs to compete on an even footing with potential purchases from non-QF sellers to the California market.

20. None of the utility applicants currently has a need for black-start capability on its system.

21. The full annualized fixed costs of a combustion turbine, adjusted for current capacity need on the utility system, serve only as a proxy for the short-run marginal cost of capacity. QFs are not required or intended to replace combustion turbines on a utility system.

22. PG&E has not priced any of the adders specified in D.86-07-004. Edison has priced four the seven adders. However, only its analysis of the voltage support feature (based on the cost of proxy capacitors) is reasonable.

23. Load-following features serve to concentrate the QF's output within relatively high-cost hours on the utility system.

24. Adders for load following may reasonably be structured as follows. The adder increases the energy payment to QFs committed to provide a given load-following feature. The adder applies during hours when the QF's output is not subject to curtailment, scheduling, or other control by the utility, pursuant to the feature.

25. SDG&E has priced all of the adders specified in D.86-07-004. SDG&E's valuation of the voltage support feature is reasonable. Further work by the utilities on this feature should concentrate on QF eligibility, including geographic and operational criteria.

26. The adders concept, if properly implemented, can serve a similar function to multi-attribute bidding, and may also provide some of the analytical basis for such a bidding system.

27. A reduction in capacity payments may be appropriate for QFs that separate from the system without (1) being tripped off automatically at predetermined settings, or (2) getting authorization from the purchasing utility. No utility has reasonably evaluated such a reduction.

28. The "unbundling" of resource needs is the logical culmination of a resource plan-based QF procurement methodology. More work is needed to develop this concept, which includes both performance features and other factors (such as fuel type and security) of concern to energy planners.

Conclusions of Law

1. SDG&E's request for additional requirements applicable to as-available QFs should be denied without prejudice.

2. PG&E's proposed solution for the interim Standard Offer 4 problem described in Finding of Fact 18 should be approved for the duration of fixed price periods in contracts under Energy Payment Option 1 or 2. Other solutions should be considered for Energy Payment Option 3, and for Energy Payment Options 1 and 2 at the expiration of the fixed price period.

3. The request of Ultrasystems/OGI for hearing on PG&E's 1983 line loss study should be dismissed as moot.

4. PG&E, SDG&E, and Edison should be required to file, in the resource plan update following ER-7, revised reports on performance features and disaggregated resource needs.

5. In future biennial update proceedings, the applicants should explicitly present strategic elements in their resource plan filings.

6. For the biennial resource plan review, the utility should choose a reasonable way to bridge the connecting years between any current CPUC short-range forecast, applicable to that utility, and the current CEC long-range forecast, as described in Finding of Fact 9. However, the utility shall not change the adopted forecast of either commission. The utility should justify its choice and indicate whether the choice materially affects the type or timing of avoidable resources on its system.

7. The parties to biennial update proceedings to follow ER-7 and subsequent Electricity Reports should evaluate conditional RETO forecasts in terms consistent with any enhancements developed in the joint CEC/CPUC staff workshops on integrated least-cost methodologies. Based on such evaluation, the CPUC should consider some or all of the estimated conditional RETO as nondeferrable resource additions for purposes of final Standard Offer 4. Projection of long-term DSM costs and impacts by this Commission in the resource plan update proceeding should also be given weight in subsequent short-term DSM funding requests in the respective general rate cases.

8. PG&E, SDG&E, and Edison should be required to file revised reports on performance features in the biennial resource plan update following ER-7. The reports should cover at least the same system stability (except for black-start capability) and load-following features that were in the original reports; the utilities may also propose additional features. The utilities should indicate the performance features that have been incorporated to date in any contracts with QFs, and should provide a statistical analysis. The analysis need not identify individual QFs but should indicate, by QF technology, the number of megawatts on the respective utility system that are subject to curtailment or other special performance requirements.

9. The reports on performance features should also analyze the potential for a resource plan-based long-run offer made up of disaggregated resource needs. Such an offer would include components for "basic" energy and capacity set at projected long-run marginal costs; system stability adders and line loss impacts calculated for various districts within the purchasing utility's service area; and load-following adders calculated for a range of load-following options up to and including direct utility dispatch of the QF plant. There are other factors in resource planning that are not strictly performance-based. The "unbundled" generation resource offer should include premiums for various attributes deemed desirable by the planner. Such attributes would include, but are not limited to, various types of security that the QF might post, an option to delay or advance the QF's on-line date, and use by the QF of renewable fuels or other fuels that meet fuel diversity criteria.

10. Standard Offer 2 should be made available from all utilities, subject to reasonable restrictions, on a regular basis.

11. The power purchase agreements under the standard offers of the respective utilities should have a common format and terminology, except for the very few aspects that should be utility-specific due to different operating characteristics.

12. This order should be made effective immediately in order to ensure that remaining issues in this proceeding are resolved in advance of ER-7 and the following biennial update proceeding.

FINAL ORDER - COMPLIANCE PHASE

IT IS ORDERED that:

1. The Division of Ratepayer Advocates (DRA) shall prepare a status report on the development of a common terminology for use at this Commission and the California Energy Commission (CEC) for resource planning purposes. DRA shall file this report, and serve it on the parties to Application (A.) 82-04-44 et al., no later than September 30, 1988.

2. DRA's testimony in the biennial update proceeding that follows CEC adoption of the Seventh Electricity Report (ER-7) shall include a status report on progress toward the development of a standardized and uniform methodology for the treatment of costs and benefits of all resource options (both generation and nongeneration).

3. The approximate timeline for the biennial update proceeding to follow ER-7 is shown in Appendix B.

4. DRA shall notice a public workshop on load-following features generally, San Diego Gas & Electric Company's (SDG&E) proposal for a simplified curtailment option, and defining future tasks and priorities. The workshop shall take place shortly after SDG&E publishes its proposal.

5. Pacific Gas and Electric Company (PG&E), SDG&E, and Southern California Edison Company (Edison) shall include revised reports on performance features, as described in Conclusions of

Law 8 and 9, in their application in the biennial update proceeding to follow ER-7.

6. The Assigned Commissioner or Administrative Law Judge shall set by ruling a schedule for comment on the proposal, in Section V of today's decision, for regulating the availability of Standard Offer 2.

7. PG&E, SDG&E, and Edison shall examine the existing uniform language proposals for the short-run standard offers and shall file revised proposals on October 14, 1988, for Commission approval. We encourage continuation of the consultative process that reached general agreement on contract drafting issues for final Standard Offer 4. Under this process, the utilities and interested parties would file and serve a joint proposal on October 14, indicating agreed-upon provisions, utility-specific language where appropriate, and any contested matters. Other parties may comment on the proposal(s); such responsive comments shall be filed no later than November 4, 1988.

8. SDG&E's request for additional requirements applicable to as-available Qualifying Facilities (QFs) is denied without prejudice.

9. The request of Ultrasystems and Occidental Geothermal, Inc., for hearing on PG&E's 1983 line loss study is dismissed as moot.

10. PG&E's proposed solution for the interim Standard Offer 4 problem described in Finding of Fact 18 is approved for the duration of fixed price periods in contracts under Energy Payment Option 1 or 2. Other solutions may be proposed for Energy Payment Option 3, and for Energy Payment Options 1 and 2 at the expiration of the fixed price period. Any such proposed alternative solutions shall be filed no later than September 30, 1988. PG&E shall file its own preference at or before that time.

11. PG&E, SDG&E, and Edison shall analyze the line loss impact of potential QF avoidance of an identified avoidable resource in their respective resource plan filings submitted in the biennial update proceeding to follow ER-7. Each utility shall present a line loss adjustment method that is sufficiently detailed to enable each potential QF bidder to precisely calculate its loss factor, based on the resource against which it is bidding and the location of its own project.

12. Any party may file comments on SDG&E's proposal for a simplified curtailment option. Such comments shall be filed no later than September 30, 1988.

This order is effective today.

Dated ____________________, at San Francisco, California.

APPENDIX A
Page 1

How Final Standard Offer 4 Works

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.

We have adapted the following chronological overview from prior orders. We think the details of the final Standard Offer 4 resource planning process are more easily grasped with the total design in mind. See also Appendix B ("Timeline for Biennial Update Proceeding Following CEC Adoption of the Seventh Electricity Report") of today's decision.

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The first step is the utility application. Following the latest Electricity Report of the California Energy Commission (CEC), the Pacific Gas and Electric Company, the San Diego Gas & Electric Company, and the Southern California Edison Company each file a resource plan with a 12-year planning horizon. The plan identifies within the horizon those potential resource additions that the applicant believes are cost-effective for its system. The plan states the costs associated with each such resource and the point in the planning horizon when that resource becomes cost-effective. The plan also states all relevant assumptions. The applicant presents its assumptions in internally consistent "scenarios." The latest CEC Electricity Report forecasts give the supply and demand assumptions for the base case scenario. The applicant may also file additional scenarios, or otherwise deal with the range of uncertainties underlying the forecasts, in order to explain the applicant's preferred procurement strategy. If the applicant has filed alternative scenarios, it specifies the scenario that it believes is best suited to the determination of avoidable plants for purposes of the long-run standard offer. ("Avoidable plant" could include potential purchases of electricity from non-QF sellers.)

The second step is hearings on the utility applications. The Commission's staff and other participants critique each resource plan. They may note internal inconsistencies in any of the applicants' scenarios, present alternative scenarios of their own, criticize the applicant's assessment of uncertainty, and challenge the reasonableness of an applicant's assumptions. They also check that the applicants have correctly implemented the

Commission's cost-effectiveness methodology. Finally, these participants may explain their choice of the scenario best suited to the determination of avoidable plants.

The <u>third step</u> is Commission determination of avoidable plants for the respective utilities. Avoidable plants are essentially the cost-effective baseload or intermediate resource additions appearing in the first eight years of the resource plan that is preferred by the Commission. This choice is the key Commission act in the long-run standard offer process. The Commission makes this choice according to the following criteria, among others: Are the plan and underlying assumptions plausible (i.e., internally consistent and reasonable, given known forecast uncertainties)? Does the plan expose ratepayers to unnecessary risks, either of premature commitments or of shortages? Is the plan consistent with energy regulatory goals and policies? The Commission decision comes about five months after filing of the applications.

The <u>fourth step</u> is the utilities' solicitation process and QF auction. After making any modifications ordered by the Commission, the utilities announce the availability of long-run standard offer contracts based on the capacity and the fixed and variable costs of the avoidable resource(s). QFs have a three-month solicitation period to respond. Each interested QF indicates (1) the resource that the QF seeks to avoid, (2) the QF's own technology and capacity, and (3) the QF's bid, which is the lowest percentage of the resource's fixed costs that the QF would be willing to accept. The bid cannot exceed the resource's fixed costs. The utility opens the responses at the end of the solicitation period. If QFs seeking to avoid a resource do not cumulatively exceed the resource's capacity, all these QFs are

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offered contracts at the full fixed costs of the resource. If such QFs do exceed the resource's capacity, contracts up to that MW limit are offered to the low-bidding QFs, and they receive that percentage of the resource's fixed costs bid by the lowest losing bidder. (This is known as a "second price" auction.) Contract signing occurs after the winning bidder complies with the prerequisites of the QF Milestone Procedure, roughly one year after the utility applications.

The fifth step is the update to the long-run standard offer. The update is scheduled every two years and follows each CEC Electricity Report. The utilities file new resource plans, and Steps 1 through 4 are repeated, with such modifications to the process as the parties may suggest and the Commission approves.

(END OF APPENDIX A)

APPENDIX B

Timeline for Biennial Update Proceeding
Following CEC Adoption of the Seventh Electricity Report

Time (Approximate) After CEC Final Adoption	Event
9 weeks	Utility resource plan applications filed
13 weeks	CPUC, CEC staffs, other parties serve testimony critiquing resource plans
15 weeks	Resource plan hearings start (lasting 2-3 weeks)
21 weeks	Concurrent briefs filed
25 weeks	ALJ's proposed decision mailed
29 weeks	CPUC decision
33 weeks	Solicitation period for final Standard Offer 4 contracts begin
45 weeks	Solicitation period for final Standard Offer 4 contracts closes
46 weeks	Utilities open bid packages and award contracts

A precise schedule setting forth specific dates and an initial service list will be issued by ALJ or assigned Commissioner Ruling following the Seventh Electricity Report.

(END OF APPENDIX B)

APPENDIX C
Page 1

Landmark CPUC Decisions on Avoided Cost, Standard Offers

The following list, although not exhaustive, shows where to find answers to the key questions that the Commission has addressed regarding QFs. The summaries are necessarily terse and are not intended either to indicate each issue in any given decision or to substitute for review of the actual text of the opinion and order. In addition to these decisions, our general rate case decisions have been used in the past to update certain standard offer terms. Finally, decisions in general rate case and fuel offset proceedings often contain analysis of marginal cost that is broadly relevant to QF policy.

I. Foundational Decisions

D.91109 - adopted "avoided cost" pricing for utility purchases from "private energy producers"

D.82-01-103 - guidelines for standard offers

D.82-04-071 - authorized "hydro savings prices" during spill conditions

D.85-07-022 - long-run avoided cost methodology

II. Decisions Implementing Standard Offers 1, 2, and 3 (the Short-run Offers)

D.82-12-120	D.84-03-092
D.83-10-093	D.84-04-012

III. Decisions on Interim Standard Offer 4 (the Interim Long-run Offer)

D.83-09-054	D.85-04-075
D.83-12-050	D.85-06-163
D.84-08-035	D.85-07-121
D.84-10-098	D.86-10-038
D.85-01-040	D.86-12-013
D.85-02-069	D.86-12-104

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IV. Show Cause Proceeding (PG&E)

D.84-03-093
D.84-08-031 - "good faith" guidelines for utilities in negotiating with QFs

V. Investigation of Transmission Constraints, Development of QF Milestone Procedure, and Administration of Transmission Priority

D.84-08-037	D.85-11-017	D.86-12-017
D.85-01-038	D.85-12-075	D.87-04-039
D.85-01-039	D.86-02-033	D.87-08-028
D.85-08-045	D.86-04-053	D.87-09-030
D.85-09-058	D.86-11-005	D.88-04-067

VI. Standard Offer 2: Suspension and Reinstatement

D.86-03-069	D.87-09-025
D.86-05-024	D.87-11-024
D.86-11-071	D.87-12-056

VII. Development of the Resource Plan-based Offer (Final Standard Offer 4)

D.86-07-004	D.87-11-024
D.86-10-030	D.88-03-026
D.87-05-060	D.88-03-079

VIII. "Orphans," "Pioneers," and Nonstandard Contracts

D.93035	D.86-07-032	D.87-01-049
D.93364	D.86-08-017	D.87-03-068
D.82-04-087	D.86-09-040	D.87-05-065
D.82-07-021	D.86-10-039	D.87-07-086
D.83-05-043	D.86-10-044	D.87-08-047
D.83-05-047	D.86-12-018	D.87-09-074
D.83-06-109	D.86-12-061	D.87-09-080
D.84-05-057	D.86-12-062	D.87-10-038
D.86-03-030	D.86-12-098	D.87-11-063
D.86-06-060	D.86-12-100	D.88-03-036

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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.

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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 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 & gas-fired cogenerators limited to 20% of the price being based on the forecasted prices.

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

Energy Option 3) Energy prices are based on fixed, forecasted utility incremental energy rates and utility oil & 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

See Appendix A.

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Table of Acronyms and Abbreviations

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

ALJ	Administrative Law Judge (VII.A)
BPA	Bonneville Power Administration (III.C)
CEC	California Energy Commission (II)
Conditional RETO	_See_ RETO (III.D.4)
CPUC or Commission	California Public Utilities Commission (I)
D.	Decision (I)
DRA	Division of Ratepayer Advocates (part of CPUC staff) (III.D.4)
DSM	Demand-side Management (III.D.4)
Edison	Southern California Edison Company (II)
ER-6	The CEC's Sixth Electricity Report (II)
ER-7	The CEC's Seventh Electricity Report (III.B)
I.	Order Instituting Investigation (VII.A)
IEP	Independent Energy Producers Association (IV.B)
PG&E	Pacific Gas & Electric Company (II)
QF	Qualifying Facility (I)

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Table of Acronyms and Abbreviations
(continued)

RETO	Reasonably Expected to Occur; "Conditional RETO" is used by the CEC to designate conservation and load management programs deemed desirable but awaiting additional regulatory approval (III.D.4)
RFP	Request for Proposal (IV.D.3)
SDG&E	San Diego Gas & Electric Company (II)
Tr.	Reporter's Transcript (III.C)
Ultrasystems/OGI	Ultrasystems Incorporated and Occidental Geothermal, Inc. (VII.A)
VAR	Volt-Amperes Reactive (a measure of power lost to reactive loads) (IV.C.)

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List of Appearances

Applicants: Howard Golub, Linda Agerter, and JoAnn Shaffer, Attorneys at Law, for Pacific Gas and Electric Company; Wayne P. Sakarias, Attorney at Law, for San Diego Gas & Electric Company; and Julie Miller, Attorney at Law, for Southern California Edison Company.

Other Parties: Armour, St. John, Wilcox, Goodin & Schlotz, by James D. Squeri, Attorney at Law, for AMAX, Inc. and Kelco Division of Merck, Inc.; Kathryn L. Stein, Attorney at Law, for Barakat, Howard & Chamberlin, Inc.; Susan Ackerman and D. J. Adler, for Bonneville Power Administration; Steven Cohn and A. Kirk McKenzie, Attorneys at Law, for California Energy Commission; Kent Fickett, Attorney at Law, for California Energy Company, Inc.; Brobeck, Phleger & Harrison, by Richard C. Harper, Attorney at Law, for IMOTEK, Inc.; Matthew V. Brady, Attorney at Law, Alice Levine, and Law Offices of Dian Grueneich, by Dian M. Grueneich, for State of California, Department of General Services; Neal A. Johnson, for California Waste Management Board; Robert Grow and Donna Stone, for California Department of Water Resources - Energy Division; Lawrence W. Campbell, Attorney at Law, for Caterpillar Capital Company, Inc.; John D. Quinley, for Cogeneration Service Bureau; John W. Gulledge, for County Sanitation Districts of Los Angeles County; Graham & James, by Martin Mattes and Dianne Fellman, Attorneys at Law, and Barry Sheingold, for Delmarva Capital Technology Company; Philip A. Stohr, Attorney at Law, for Downey, Brand, Seymour & Rohwer; Lindsay, Hart, Neil & Weigler, by Michael P. Alcantar and Clyde E. Hirschfeld, Attorneys at Law, and Drazen-Brubaker & Associates, Inc., by Donald W. Schoenbeck, for Cogenerators of Southern California; Karen Edson, for KKE & Associates; Gary Simon, for El Paso Natural Gas Company; Kenneth R. Meyer, for Energy Consulting Group; James S. Thomson, for Energy Factors, Inc.; Robert Logan, for Exeter Associates; Graham & James, by Norman A. Pedersen, Attorney at Law, for Champlin Petroleum Company; Leslie C. Confair, for GWF Power Systems Company and The Signal Companies; Hanna and Morton, by Douglas K. Kerner, Attorney at Law, for Union Oil Company of California, Freeport- McMoRan Resource Partners, Santa Fe Geothermal Inc., and Hanna and Morton; David R. Branchcomb, for Henwood Energy Services, Inc.; Patrick V. Agnello, for Howden Wind Parks, Inc.; Janice G. Hamrin, for

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Independent Energy Producers Association; Judith Alper, Attorney at Law, for Independent Power Corporation; William B. Marcus, for JBS Energy, Inc.; Marron, Reid, & Sheehy, by M. Baller, Attorney at Law, for Foster Wheeler Power Systems, Inc., Santa Monica Aggregate Company, California Agricultural Power Company, Pacific Thermonetics, Inc., and Crockett Cogeneration Company; Eugene J.M. McFadden, for McFadden Farm; Morrison & Foerster, by Jerry R. Bloom and Barbara A. Reeves, Attorneys at Law, and Morse, Richard, Weisenmiller & Associates, Inc., by Robert E. Weisenmiller, for California Cogeneration Council; Wally Gibson, for Northwest Power Planning Council; M. Bobbitt and J. Kroesche, for Orrick, Herrington & Sutcliffe; Les Toth, for Pacific Hydro Power; Douglas Kent Porter, Attorney at Law, for Pacific Lighting Energy Systems; Pettit & Martin, by Edward B. Lozowicki, Attorney at Law, for California Energy Company and Co-Generation Services, Inc.; Recon Research Corporation, by Ronald G. Oechsler, and Squire, Sanders & Dempsey, by James L. Trump, Attorney at Law, for Alenco Resources, Inc.; Bryan Cope, for Sierra Energy and Risk Assessment; R. Rawlings, for Southern California Gas Company; Michel/Peter Florio, Attorney at Law, for TURN; Paul Dolan, for Thermo Electron Energy Systems; Michael J. Ruffatto, Attorney at Law, for Trigen Resources Corporation; Harry K. Winters, for University of California, Thomas R. Sparks, for Unocal Geothermal; Margaret Rueger, for U. S. Windpower, Inc.; and Robert Feraru, State Public Utilities Commission-Office of Public Advisor; and Jon Castor; Arturo Gandara, Attorney at Law; Joseph G. Meyer; Milt Pace; Timothy P. Duane; and William Walzer; for themselves.

Division of Ratepayer Advocates: Carol Matchett, Attorney at Law, and Julian Ajello.

Commission Advisory and Compliance Division: Frank Crua.

(END OF APPENDIX F)